Appendix J: Phase 1 Comments and Responses

Attachments

energize
EASTSIDE
EIS

March 8, 2016

Dear council members,

CENSE would like the opportunity to dispute some of the "facts" stated by PSE representative Keri Pravitz before the Bellevue City Council on March 7, 2016.

1. "1,500 MW EXPORTED TO CANADA IS A NORMAL PLANNING REQUIREMENT FOR NORTHWEST UTILITIES." – PSE

There are many times of year when 1,500 MW can be transmitted to Canada without a problem. However, this level of flow is **not required during peak consumption**. This is clear from the Memorandum of Agreement signed by PSE, BPA, and Seattle City Light in January 2012: *"When large amounts of energy are being delivered [from] the Puget Sound area through the Northern Intertie to Canada, transmission lines at times become congested. To relieve this congestion and avoid unplanned power interruptions to customers, **BPA currently limits or curtails** the amount of energy Puget Sound-area utilities and Canadian utilities can deliver across certain transmission lines."*

This quote mentions a curtailment solution that BPA has used for nearly a decade: reduced energy flow to Canada. If BPA and PSE want to avoid such curtailments, PSE's customers should not have to bear the entire cost. There are many less expensive solutions to our local needs that don't require a 230 kV line to be constructed through heavily residential areas.

Further, the Lauckhart-Schiffman study clearly shows that it would take an additional line across the Cascades to deliver 1,500 MW to Canada on a cold winter day. There are no plans to build such a line.

2. "THE 1,500 MW DOESN'T FLOW THROUGH BELLEVUE." – PSE

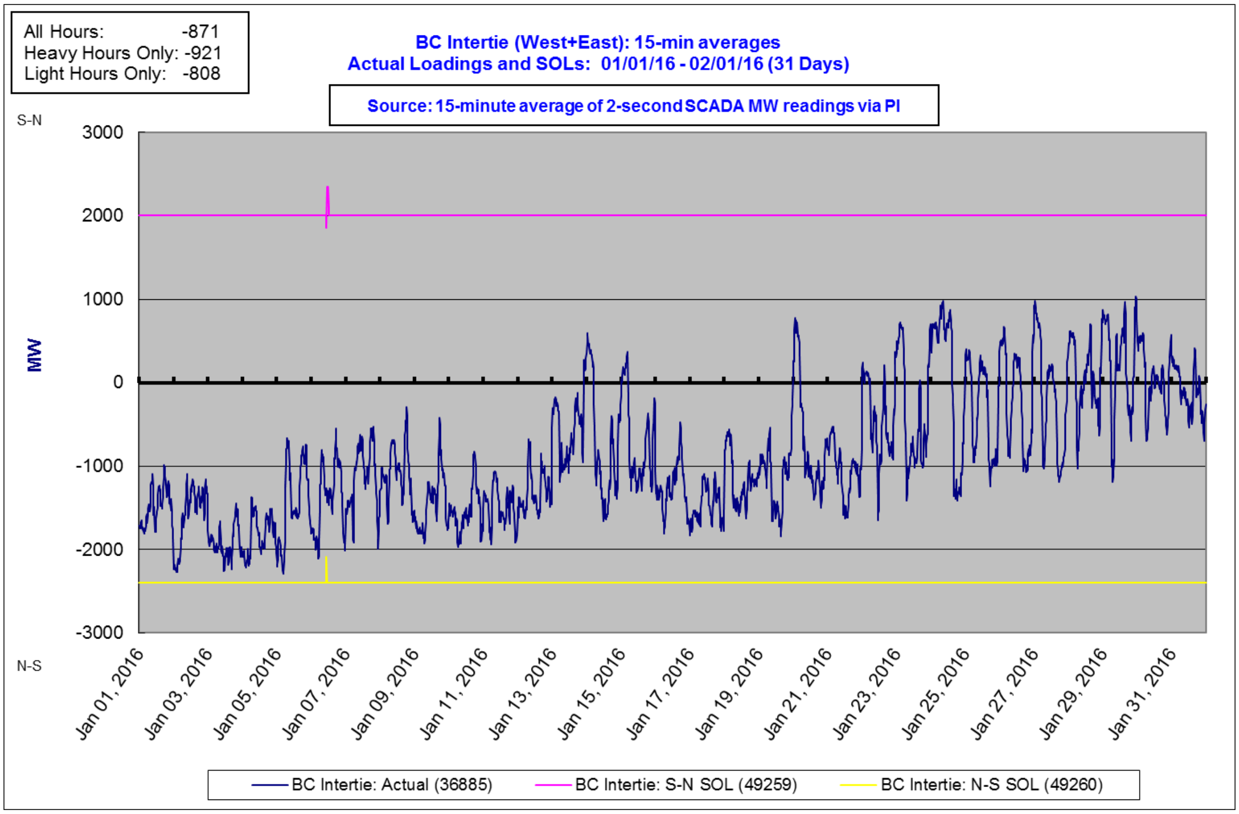
CENSE has never said that the entire 1,500 MW flows through Bellevue. However, some portion of this flow does go through Bellevue, and it adds stress to our local infrastructure. PSE says this is just a distraction. If it isn't a central issue, then PSE should have no objection to removing this assumption from the load flow study, as USE did (and almost all of the overloads on PSE's equipment disappeared).

3. "1,500 MW IS ASSUMED IN BASE CASES." – PSE

Lauckhart and Schiffman started with the same WECC Heavy Winter Base Case for 2017-18 that PSE used in the Eastside Needs Assessment. The amount of electricity exported to Canada in that Base Case is 500 MW. Does PSE dispute this?

4. REALITY CHECK

Do large amounts of electricity actually flow to Canada when temperatures are low in the Puget Sound area? There is a BPA web site where anyone can look at electricity flow on the Northern Intertie. Let's check what happened in January 2016, when the region had very cold weather for the first half of the month:

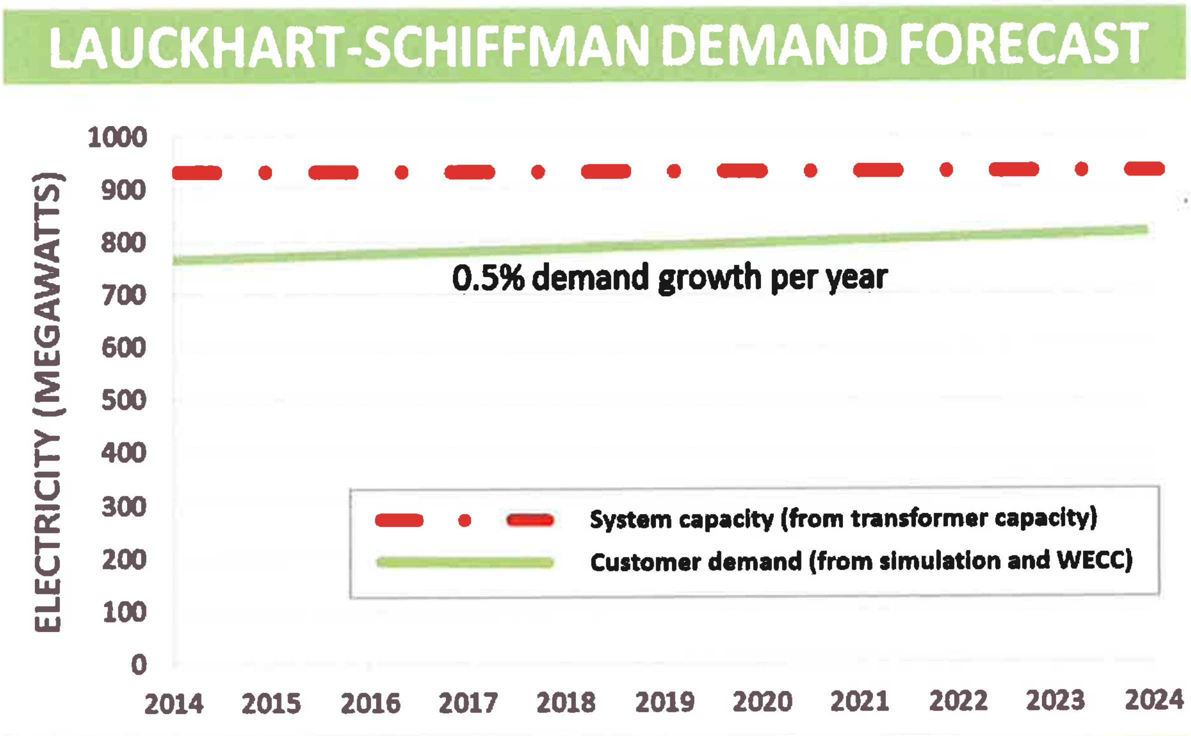


In the above graph, the squiggly line indicates flow on the transmission lines that connect the Northwest to British Columbia. Any time the line is below the central black line, energy is flowing from Canada to the US. You can see that for most of the month, Canada was delivering electricity to our region, not vice versa.

We have looked at data for the last decade, and it is very rare for electricity to flow northwards during the cold winter scenarios that PSE uses as a basis for Energize Eastside. If the flow were reversed in any dramatic way, the 11 transmission lines that deliver electricity to the Puget Sound from central Washington would not be able to satisfy the demand.

We conclude that Energize Eastside is being justified using a fantasy scenario that cannot happen in real life.

Don Marsh, President
CENSE.org



Load Flow modeling

for "Energize Eastside"

Richard Lauckhart

Roger Schiffman

February 18, 2016

Executive Summary

In November 2015, the citizen group CENSE asked Richard Lauckhart and Roger Schiffman to study the scenario that motivates Puget Sound Energy's transmission project known as "Energize Eastside." We (Lauckhart and Schiffman) are nationally recognized power and transmission planners with specific knowledge of the Northwest power grid.

It is standard industry practice to use a "load flow model" to determine the need for a transmission project like Energize Eastside. In order to assess the reliability of the grid, analysts use specialized computer software to simulate failure of one or two major components while serving peak load conditions. For Energize Eastside, PSE simulates the failure of two major transformers during a peak winter usage scenario (temperature below 23° F and peak hours between 7-10 AM and 5-8 PM).

We ran our own load flow simulations based on data that PSE provided to the Western Electricity Coordinating Council (WECC). We used a "Base Case" for winter peak load projected for 2017-2018. PSE confirms this is the same data used as the basis for the company's "Eastside Needs Assessment."

Our findings differ from PSE's as follows:

1. PSE modified the Base Case to increase transmission of electricity to Canada from 500 MW to 1,500 MW. This level of energy transfer occurring simultaneously with winter peak loads creates instability in the regional grid. Transmission lines connecting the Puget Sound area to sources in central Washington do not have enough capacity to maintain this level of demand.
2. PSE assumed that six local generation plants were out of service, adding 1,400 MW of demand for transmission. This assumption also causes problems for the regional grid.
3. Even if the regional grid could sustain this level of demand, it is unlikely that regional grid coordinators would continue to deliver 1,500 MW to Canada while emergency conditions were occurring on the Eastside.
4. We found that the WECC Base Case contains a default assumption that PSE may not have corrected. The ratings for critical transformers are based on "summer normal" conditions, but the simulation should use significantly higher "winter emergency" ratings. The default value could cause PSE to underestimate System Capacity and overstate urgency to build the project.
5. The Base Case shows a demand growth rate of 0.5% per year for the Eastside. This is much lower than the 2.4% growth rate that PSE cites as motivation for Energize Eastside.

Our study finds critical transformers operating at only 85% of their winter emergency rating, providing enough capacity margin to serve growth on the Eastside for 20 to 40 years.

Qualifications

Richard Lauckhart served as a high level decision maker at Puget Sound Power & Light (the predecessor of Puget Sound Energy). His employment with the company spanned 22 years as a financial and transmission planner as well as power planning. He served as the company's Vice President of Power Planning for four years.

Richard took a voluntary leave package when Puget Power merged with Washington Energy Company in 1997. He provided additional contract services to PSE for more than a year following the merger. After leaving PSE, Richard worked as an energy consultant, providing extensive testimony on transmission system load flow modeling before the California Public Utility Commission.

Roger Schiffman has 23 years of energy industry experience covering utility resource planning, electricity market evaluation, market assessment and simulation modeling, regulatory policy development, economic and financial analysis, and contract evaluation. Roger has led a large number of consulting engagements for many clients. He has extensive knowledge of industry standard modeling software used for power market analysis and transmission planning.

We are well acquainted with the physical layout and function of the Northwest power grid and the tools used to analyze its performance. Our resumes can be found in Appendix H.

Richard has provided pro bono consultation to CENSE since April 2015. He has received no financial compensation other than reimbursement of travel expenses. Roger had no relationship with CENSE prior to this report.

Methodology

The power grid is a complex interconnected system with behaviors that cannot be easily understood without computer modeling software. We acquired a license to run the industry standard simulation software known as "GE PSLF"[1] to perform our studies.

The PSLF software uses a database that is supplied by the operator. We had hoped to use the same database that PSE used in its studies, but PSE refused to share it after months of negotiations. Instead, we received clearance from the Federal Energy Regulatory Commission (FERC) to access the database PSE submitted to the Western Electricity Coordinating Council (WECC). FERC determined that we presented no security threat and had a legitimate need to access the database (see FERC's letter in Appendix A).

We used the WECC Base Case for the winter of 2017-18, which PSE confirms is the database the company used for that time period. We and PSE have made subsequent changes to the Base Case model in order to incorporate various assumptions. We don't know exactly what changes PSE made to the database, but we will be explicit about the changes we made.

N-0 base scenario

To ensure that everything was set up correctly, we ran a simulation using the unmodified Base Case and checked to see if the results aligned with those reported by WECC. This is referred to as an "N-0" scenario, meaning that zero major components of the grid are offline and the system is operating normally. The outputs of this simulation matched reported results.

The WECC Base Case assumes that the Energize Eastside project has been built. In order to determine the need for the project, we needed to study the performance of the grid without it. We reset the transmission configuration using parameters from an earlier WECC case that did not include the project.

N-1-1 contingency scenario

An "N-1-1" scenario models what would happen if two major grid components fail in quick succession. Utilities are generally required

[1] http://www.geenergyconsulting.com/pslf-re-envisioned

to serve electricity without overloads or outages in this scenario to meet federal reliability standards.

PSE determined that the two most critical parts of the Eastside grid are two large transformers that convert electricity at 230,000 volts to 115,000 volts, the voltage used by all existing transmission lines within the Eastside. To simulate the N-1-1 scenario, the Base Case is modified to remove these two transformers from service.

PSE apparently made two additional modifications to the WECC Base Case. First, the amount of electricity flowing to Canada was increased from 500 MW to 1,500 MW. Next, the company reduced the amount of power being produced by local generation plants from 1,654 MW to 259 MW. The rationale behind these modifications isn't obvious, and we were concerned how the regional grid (not just the Eastside) would perform with these assumptions in place.

To our surprise, simply increasing the flow to Canada to 1,500 MW while also serving peak winter power demand in the Puget Sound region was enough to create problems for the regional grid. The simulation software could not resolve these problems (Appendix E describes the problems in greater detail). While it's possible that PSE and Utility System Efficiencies found ways to work around these challenges by making additional changes to the Base Case, we do not know what these changes were. We are confident that prudent grid operators would reduce flows to Canada if an N-1-1 contingency occurs on the Eastside during heavy winter consumption. PSE would turn on every local generation plant. These responses resolve the problems. This is the more realistic scenario we modeled in our N-1-1 simulation.

The WECC Base Case uses default values for transformer capacity ratings that correspond to a "summer normal" scenario. The summer rating is reduced in order to protect transformers from overheating during hot summer weather. The "winter emergency" rating would be consistent with best engineering practice for equipment outages during very cold conditions (less than 23° F) that produce peak winter demand. We used this higher rating in our simulation.

Results

N-0 results

To compare the N-1-1 results with normal operation of the grid serving peak winter demand, we ran an N-0 study using the WECC Base Case for winter 2017-18 with the following modifications:

1 Energize Eastside transmission lines are reverted to present capacity.

2. Flow to Canada is reduced from 500 MW to 0 MW.

3. Transformers run at "winter normal" capacity.

Figure 1 shows load as a perentage of "winter normal" capacity on each of the four transformers.

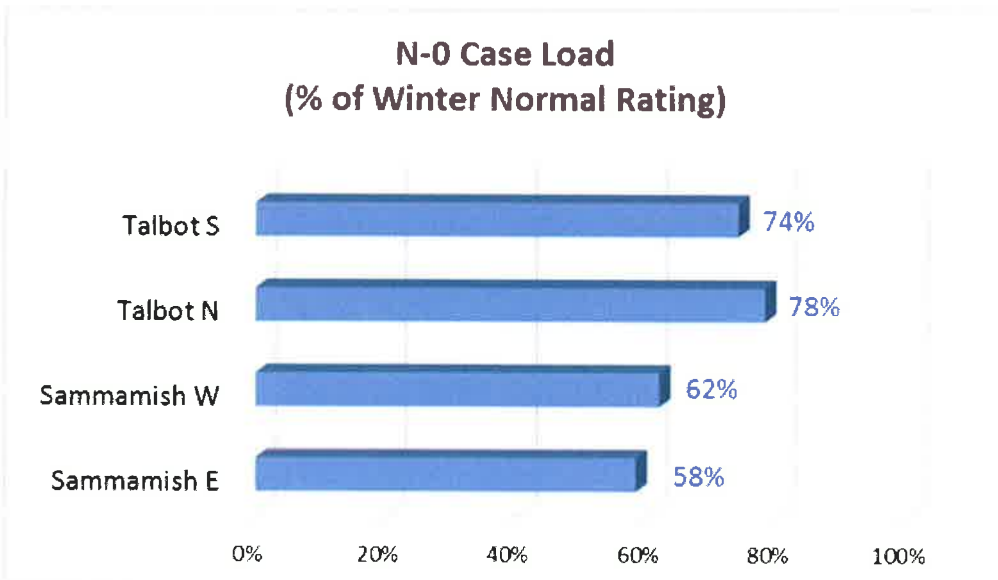


Figure 1: With all transformers in service, winter peak load causes no overloads.

N-1-1 results

The N-1-1 results are based on the WECC Base Case for winter 2017-18 with the following modifications:

1 Two transformers are out of service.

2. Energize Eastside transmission lines are reverted to present capacity.

3. Flow to Canada is reduced from 500 MW to 0 MW.

4. Transformers run at "winter emergency" capacity.

Figure 2 shows that the remaining two transformers, Talbot N and Sammamish W, remain within "winter emergency" capacity ratings.

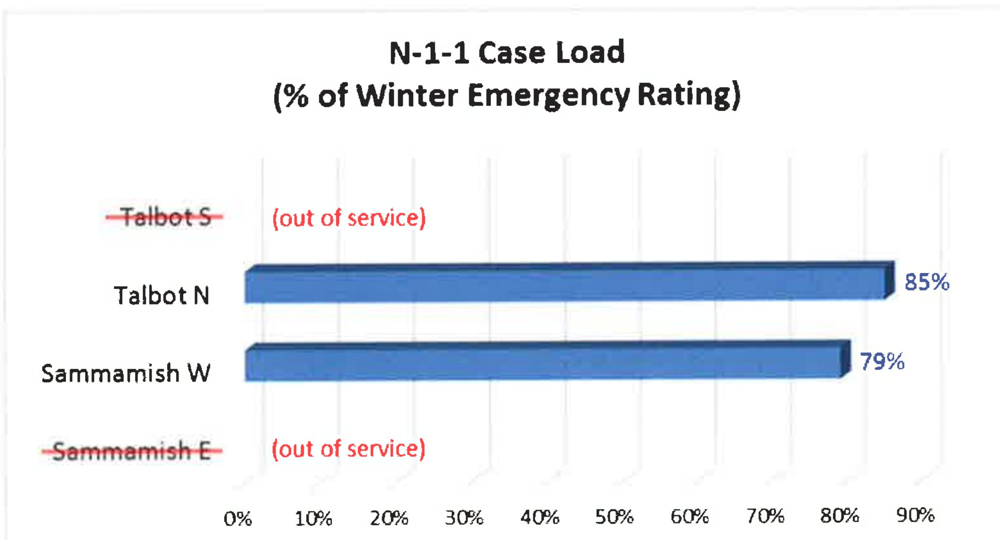


Figure 2: Loads on two remaining transformers are in a safe range.

Analysis

We carefully analyzed the results of the N-1-1 simulation to get a broader view of how the grid is behaving in this scenario. Electricity is served by a combination of high-voltage transformers (transforming 230,000 volts to 115,000 volts) and low-voltage transformers (115,000 volts to 12,500 volts).

When we simulated failure of two high-voltage transformers located at Sammamish and Talbot Hill, as PSE did, we discovered that some of the load is redistributed to other high-voltage transformers in the Puget Sound area (see Figure 3). This is a natural adaptation of the networked grid that occurs without active management by PSE or other utilities. The regional grid has enough redundant capacity to balance the load without causing overloads on any transformer or transmission line in the region.

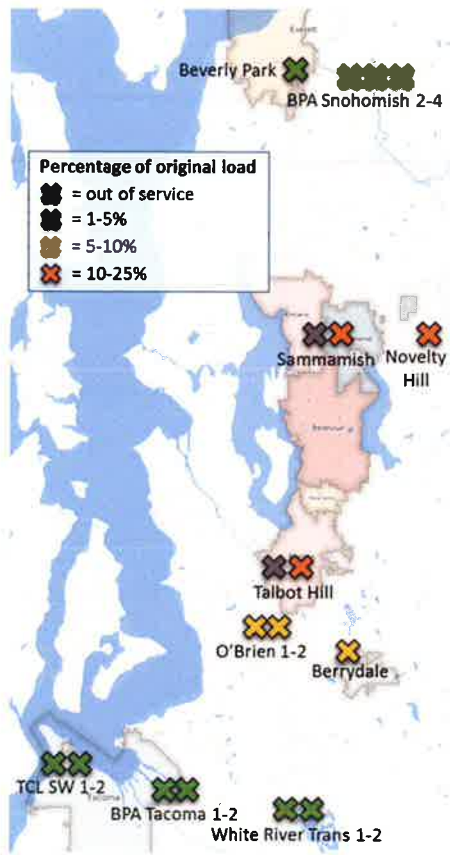


Figure 3: Load is distributed among other transformers after two transformers fail.

We conclude that the grid is capable of meeting demand in emergency circumstances in the winter of 2017-18. How soon after that will system capacity become strained?

Concerns about future capacity are illustrated in Figure 5, PSE's demand forecast graph.[2] This graph raises several questions. For example, it's not clear how PSE determined the "System capacity range" of approximately 700 MW. If this value is derived from the transformer capacities listed in the WECC Base Case, these capacities are set to default values corresponding to "summer normal" conditions.

PSE's graph shows Customer Demand growing at an average rate of 2.7% per year. However, data submitted by PSE to WECC shows a growth rate of only 0.5% per year. An explanation of this discrepancy is necessary to understand this graph.

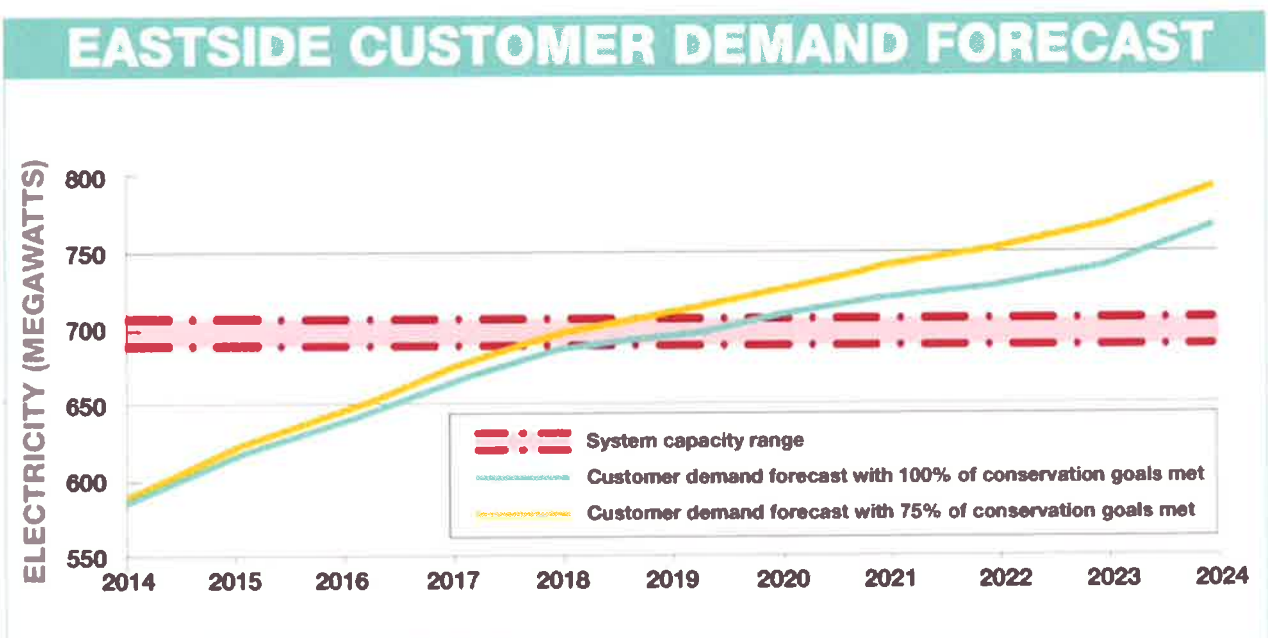


Figure 4: PSE's graph shows customer demand exceeding system capacity in 2018.[2]

[2] *http://www.energizeeastside.com/need*

Although we don't have enough information to create a graph suitable for long-term planning, we we feel Figure 5 is a better approximation of system capacity and demand growth on the Eastside.

The "System capacity" is based on "winter emergency" transformer ratings, which are more appropriate than summer ratings for this scenario. The higher ratings raise the overall capacity to approximately 930 MW.

The "Customer demand" line shown in Figure 5 is based on loads reported in the load flow simulation for the two remaining Eastside transformers. The 2014 value is higher than in PSE's graph, because these transformers serve loads outside the Eastside area. The growth rate matches the 0.5% rate observed in WECC Base Cases.

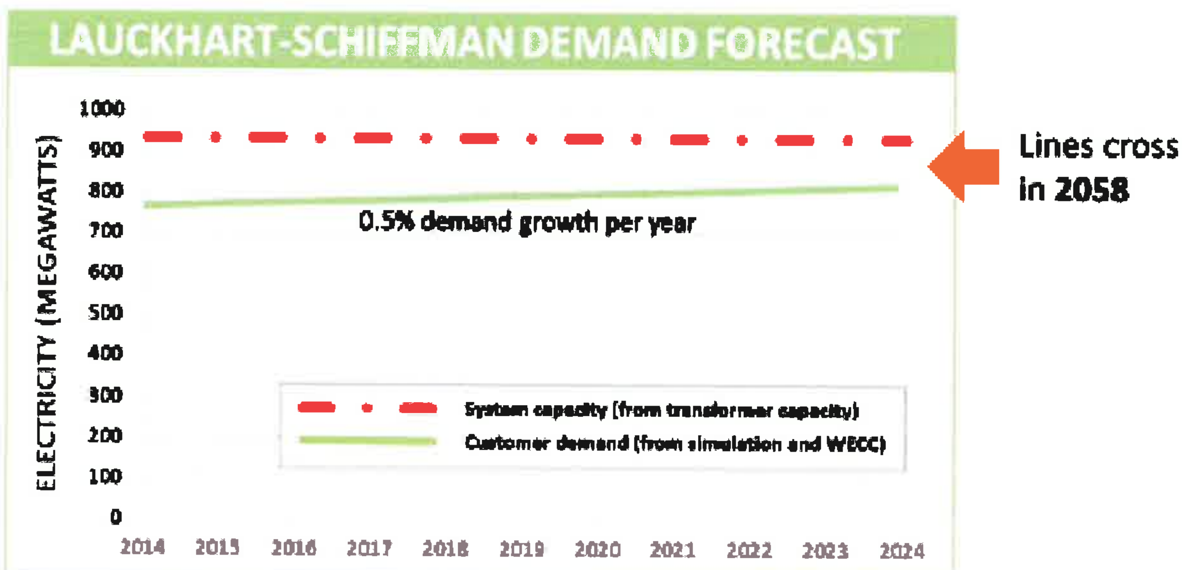


Figure 5: Alternative Demand Forecast shows slower demand growth and higher system capacity (based on "winter emergency" transformer ratings).

Comparison with other studies

The conclusions of the Lauckhart-Schiffman study differ from previous studies. We stand by our conclusions and will share our models and results with anyone who has clearance from FERC.

Here we review the other studies and explain why their conclusions might differ from ours.

PSE/Quanta

Two different load flow simulations were performed by PSE and Quanta, a consultant employed by PSE. We have the following concerns with both studies:

1. An unrealistic level of electricity is transmitted to Canada.
2. Nearly all of the local generation plants are turned off.
3. The appropriate seasonal ratings for the critical transformers were not used.
4. It's not clear how the customer demand forecast was developed, but there is an unexplained discrepancy between the forecast used for Energize Eastside (2.4% annual growth) and the forecast reported to WECC (0.5% annual growth).

The first two assumptions cause regional reliability problems for the WECC Base Case that must have required additional adjustments by PSE/Quanta. We don't know what those adjustments were.

Utility System Efficiencies

The City of Bellevue hired an independent analyst, Utility System Efficiencies (USE), to validate the need for Energize Eastside. USE ran one load flow simulation that stopped electricity flow to Canada. According to USE, 4 of the 5 overloads described in the PSE/Quanta studies were eliminated, and the remaining overload was minor.

Our load flow simulation studied the same scenario (N-1-1 contingency with no flow to Canada and local generators running), but we did not find any overloads. We believe three assumptions explain the different outcomes:

1. USE does not specify what level of generation was assumed for local generation plants. In verbal testimony before the Bellevue

City Council, USE consultants said that they did not assume all of the capability of local generation was operating. Our study assumes these plants will run at their normal capacity.

2. USE says emergency ratings were used for the critical transformers, but it isn't clear if USE used "winter emergency" ratings. Our study assumes winter emergency ratings.
3. USE does not independently evaluate the customer demand forecast (2.4% annual growth is assumed). Our study assumes the load growth forecast that PSE provided to WECC.

We believe our assumptions more accurately reflect the actual conditions that would occur in this scenario.

Stantec Consulting Services

In July 2015, the independent consulting firm Stantec was asked to review the studies done by PSE and USE. Stantec issued its professional opinion without performing any independent analysis or load flow simulations. Stantec says PSE's methodology was "thorough" and "industry standard." However, Stantec does not address the shortcomings we have identified with previous studies.

Appendix A
Clearance from FERC

Federal Energy Regulatory Commission
Washington, DC 20426

SEP 0 1 2015

Letter of Release,
Re: CEII No. CE15-130

VIA CERTIFIED MAIL
Richard Lauckhart
[redacted]

Dear Mr. Lauckhart:

This is in response to the July 15, 2015 request you submitted under the Federal Energy Regulatory Commission's (Commission or FERC) Critical Energy Infrastructure Information (CEII) regulations at 18 C.F.R. § 388.113(d)(4) (2015). Specifically, you requested a copy of the Puget Sound Energy, Inc. FERC Form No. 715, *Annual Transmission Planning and Evaluation Report*.

By letter dated August 21, 2015, the Commission issued a finding that you are a legitimate requester with a need for the information. In accordance with 18 C.F.R. § 388.112(e), the enclosed DVD contains the information requested and is being released to you subject to the non-disclosure agreement executed by you concerning this matter.

As provided by 18 C.F.R. § 388.113(d)(4)(iv) of the Commission's regulations, you may appeal this determination pursuant to 18 C.F.R. § 388.110. Any appeal from this determination must be filed within 45 days of the date of this letter. The appeal must be in writing, addressed to David L. Morenoff, General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426. Please include a copy to Charles A. Beamon, Associate General Counsel, General and Administrative Law, at the same address.

Sincerely,

Leonard M. Tao

Leonard M. Tao
Director
Office of External Affairs

Enclosure

Appendix B
Choice of Base Case

To perform a load flow study, one needs a database reflecting the physical characteristics of the power grid. FERC has recognized that stakeholders need to have access to a Base Case that reflects the system. Each utility or a designated agent is required to file power flow base cases with FERC on an annual basis.[3] WECC acts as a designated agent for most of the utilities operating in the western U.S. In an email dated November 19, 2015 Jens Nedrud, the Senior Program Manager for Energize Eastside, confirmed that PSE uses Base Cases filed by WECC as its Base Cases.

For the purposes of this study, Lauckhart and Schiffman obtained the 2014 WECC Base Cases from FERC.[4] These included 13 Base Case runs, four of which are Heavy Winter scenarios. In order to evaluate the need for the EE project, the heavy winter 2017-18 Base Case was modified so that the Energize Eastside project was not included. [5]

We do not know if this modified 2017-18 Base Case is identical to the one used by PSE to justify the project, because PSE has refused to share their 2017-18 Base Cases for independent review. The WECC Base Case assumes 500 MW is transmitted to Canada. PSE apparently increased that amount to 1,500 MW. The WECC Base Case assumes local generation in the Puget Sound Area is running at normal capacity. PSE appears to have reduced those contributions by 1,395 MW. Our PSLF modeling suggests that PSE's modifications are not feasible and grid operators would not allow these conditions to occur on a heavy winter load day.[6]

Load data from the WECC Heavy Winter Load 2017-18 Base Case is chosen as the basis for this study. This is the latest data provided by FERC/WECC for the winter of 2018. PSE was involved in the development of this Base Case along with other utilities including BPA and Seattle City Light (SCL). All utilities use these Base Cases to determine if the grid is capable of moving power from sources to loads. Further, it is the only data available in which there are identified loads on specific substations.

The loads on the main Eastside substations in the WECC Heavy Winter 2013-14 and 2017-18 Base Cases have been examined and analyzed. All of the Eastside substations were included:

Medina	Overlake	South Bellevue
Clyde Hill	Lochleven	Factoria
Bridle Trails	North Bellevue	College
Evergreen	Center	Phantom Lake
Ardmore	Midlakes	Eastgate
Kenilworth	Lake Hills	Somerset

The total load on these substations in the 2013-14 Base Case was 394.6 MW. The total load on these substations in the 2017-18 Base Case was 402.4 MW. This is a peak load growth of 2.0% over the 4 year period (an average increase of 0.5% per year). This is in line with predicted growth of energy and peak in King County.

PSE and USE appear to be extrapolating the higher growth rate of a few substations due to "block loads" and applying it uniformly to 600 MW of existing substation load. This simplification overestimates the overall growth rate. Furthermore, the total load on the substations listed above is only 400 MW. It is not clear how PSE arrived at a 600 MW load.

[3] *http://www.ferc.gov/docs-filing/forms/form-715/instructions.asp#General%20Instructions*

[4] *On July 9, 2015 FERC provided Lauckhart the most recent WECC Base Cases that it had available to send to requesters. Those Base Cases were ones filed in 2014 by WECC.*

[5] *On Dec. 4, 2015 Lauckhart also received from FERC a copy of the 2015 WECC FERC Form 715 filing. In that filing there was no Base Case filed for the winter of 2018. However, there was a Base Case filed for the winter of 2020. A review of that 2020 Base Case showed very little growth on the Eastside from the 2018 Base Case. It also showed that the rest of the Northwest actually reduced their load forecast for the year 2020 over their forecast for 2018. In total, the loading on the eastside 230/115 KV transformers in the 2020 case were lower than the loading on the Eastside 230/115 KV transformers in the 2018 case. The trend is that the situation is not getting worse since the load forecasts for the northwest are dropping overall which also reduces loading on the Eastside 230/115 KV transformers.*

[6] *With no other changes to the WECC Base Case for the winter of 2018, increasing PNW to BC transfers to 1,500 causes the system to need to import more power across the Cascades from Central Washington. This causes the PSLF model run to fail to find a solution. When we say no solution, we mean the voltage in the Puget Sound region gets too low and the model cannot find a way to correct that.*

Appendix C
Generation pattern used

PSE's gas-fired generation plants located in the Puget Sound area have a total rated capacity of 1,654 MW. How much of this capacity should be used to serve peak demand during a heavy winter load event? There are three choices:

1. The Eastside Needs Assessment prepared for PSE by Quanta assumed generation of only 259 MW, without explaining why such a low level was used.
2. The load flow study performed by USE also ran the plants at a reduced rate, but the study did not specify the exact amount.
3. Three of the four WECC heavy winter Base Cases assume the plants are running at their rated capacity of 1,654 MW. One of the Base Cases turns off one plant for reasons that are not clear, resulting in a lower level of generation at 1,414 MW.

The 1,654 MW capacity used by WECC in 3 of its 4 heavy winter Base Cases is a prudent choice for several reasons. First, PSE built and/or acquired these plants for the explicit purpose of meeting its load obligations during cold winter events. Second, PSE has a well-documented shortfall of generation capacity to serve peak demand, and it will be less risky and less expensive to run these plants than to buy power on the spot market. Third, because these plants generate electricity at 115 kV, the strain on PSE's overloaded 230/115 kV transformers would be reduced by increasing the supply of 115 kV electricity.

Appendix D
Exports to Canada

PSE and USE assume that 1,500 MW of power must be delivered to Canada, even if PSE is experiencing failure of two critical system components (an N-1-1 contingency) during heavy winter load conditions (temperatures less than 23° F in the Puget Sound region).

The WECC Base Cases assume otherwise. In the WECC Base Case for heavy winter 2013-14, 500 MW of power is flowing south from Canada to the U.S. In the WECC Base Case for heavy winter 2017-18, with the Energize Eastside project in place, 500 MW of power is flowing north to Canada, not 1,500 MW.

PSE and USE imply that it is the Columbia River Treaty that provides a Firm Commitment to deliver 1,500 MW of power to Canada. It is clear from reading numerous Treaty documents (e.g. the original treaty, the amendment to the treaty in 1999, and related documents) that the Treaty itself imposes no obligation on the United States to deliver Treaty Power to Canada. To the contrary, Canada has stated they do not want the Treaty Power delivered to Canada. Instead, PowerEx takes delivery of Canada's share of Treaty Power at the point of generation in the U.S. and delivers it for sale to U.S. entities. Canada finds it preferable to receive money for their share of Treaty Power rather than having the power delivered to Canada.

The reasonable assumption for this study is that no power will flow from the U.S. to Canada during a major winter weather event and simultaneous facility outages in the Eastside.

Appendix E

Regional grid capacity limitations

Most of the electrical generation facilities that serve the Puget Sound region are located east of the Cascade Mountains. The electricity they produce is transmitted to customers in the Puget Sound area through eleven major transmission lines known collectively as the "West of Cascades – North" (WOCN) transmission path.

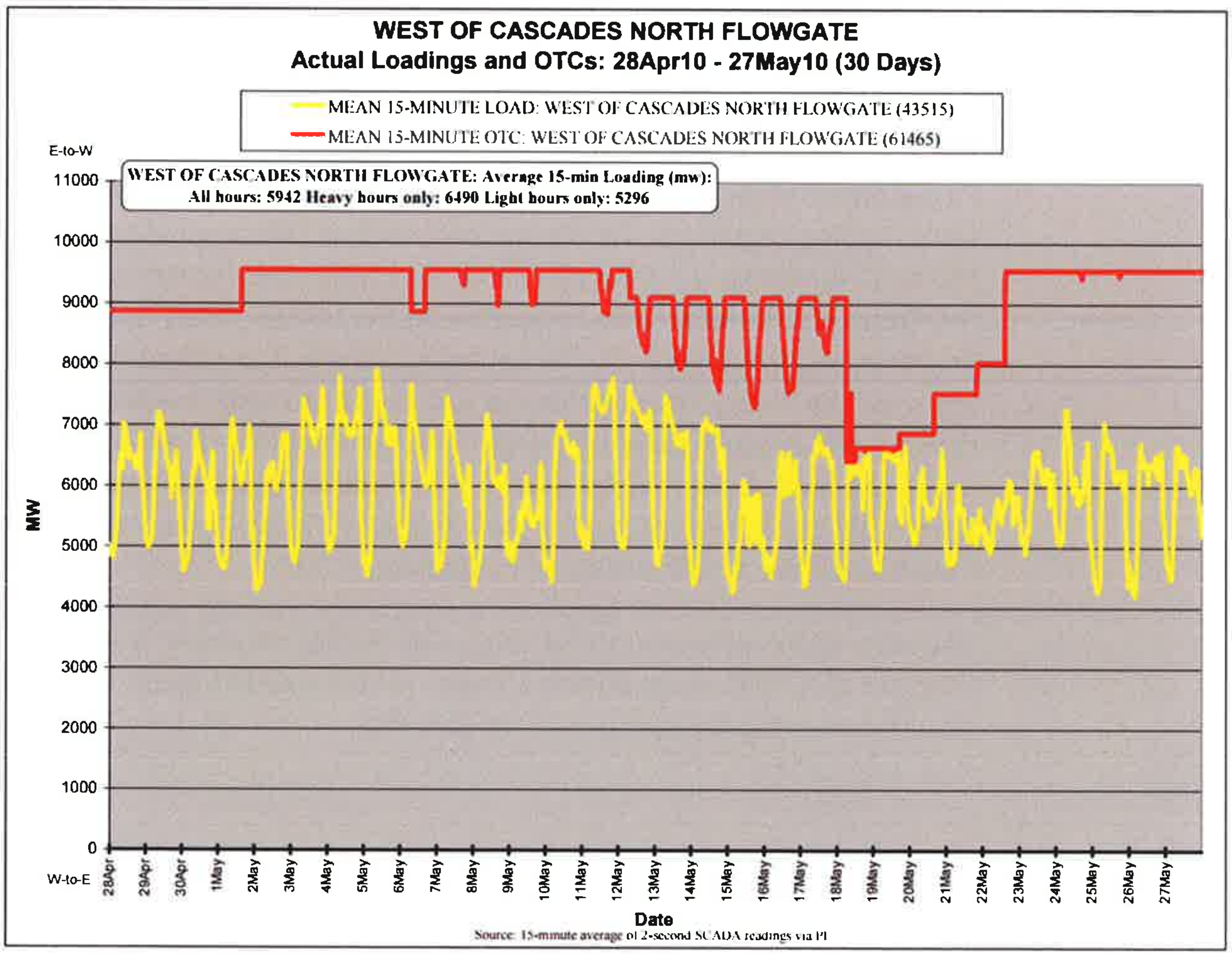


Figure 6: Chart from BPA shows load (in yellow) and maximum capacity (in red) for the WOCN path.

The exact transmission capacity of the WOCN path is confidential information which cannot be discussed in detail here. However, there is a report available on the web from the Bonneville Power Administration that discusses a problem that occurred on the WOCN path in May 2010.[7] On page 31, the report includes a chart showing loads and capacities of the WOCN path over a 30-day period. The load (shown in yellow) varies from 5000–7000 MW and the path capacity (in red) varies from 7000–9000 MW.

During a heavy winter usage scenario, the loads are likely to be higher than during relatively mild weather conditions in May. PSE's assumptions for Energize Eastside would further increase the load. To deliver 1,500 MW to Canada, loads on the WOCN path would need to increase by approximately 1,000 MW. To make up for the loss of electricity that could have been generated by six local generation plants, an additional 1,400 MW must be transmitted on the WOCN path. In total, loads would increase by approximately 2,400 MW.

If the increased load exceeds the capacity of the WOCN path, grid operators and utilities would have to make adjustments like they did in May 2010. Some of these steps and consequences are described on page 40 of the BPA report:

> "Many customers (e.g., TransAlta, Calpine, PSE, PGE) were not able to use low cost power purchases, and instead had to operate higher cost thermal projects that otherwise were idled or were out or planned for maintenance. Although there were multiple complaints regarding the ability to serve load, the basis for the complaints appeared to be economic or financial impacts."

We feel that WOCN path capacity limits explain why the simulation software could not find a way to maintain voltage levels in the Eastside given PSE's assumptions. We conclude that it is not reasonable to build local infrastructure to support these conditions if regional infrastructure cannot reliably serve the implied loads.

[7] *http://pnucc.org/sites/default/files/BPAWOCNLessonsLearned.pdf*

Appendix F
Equipment ratings

Ambient temperature affects the capacity of electrical transmission facilities. Colder temperatures help avoid overheating. For this reason, it is industry standard practice to provide different ratings for summer and winter seasons.

It is also industry standard practice to allow higher loading of equipment, including transformers, during emergency events due to the fact that emergencies do not last long. Utilities can take advantage of the fact that transformers can safely handle brief over-peak conditions to reduce installation costs and maintain system reliability.

The WECC Data Preparation Manual requires transmission owners to provide the following ratings for its transformers:

- Summer Normal Rating
- Summer Emergency Rating
- Winter Normal Rating
- Winter Emergency Rating

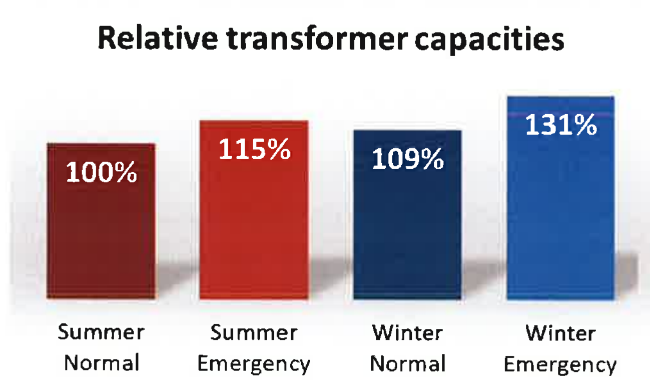


Figure 7: Ratings for different scenarios, normalized to Summer Normal rating.

PSE has indicated that the rating on the Sammamish and Talbot Hill transformers are approximately 352 MVA (Mega-volt amperes). According to the data that PSE provided to WECC, this is the Summer Normal Rating of these transformers. PSE has advised WECC that (a) its Winter Normal ratings are about 9% higher than Summer Normal, and (b) Winter Emergency Ratings are about 21% higher than Winter Normal Ratings.

When running the PSLF model, the run parameters must be set to point to the correct rating that has been provided in the data base. [8]

In the N-0 analysis, our load flow studies used the winter normal rating which is 9% higher than the 352 MVA summer normal rating.

In the N-1-1 analysis, our load flow studies used the winter emergency rating that is 21% higher than the winter normal rating.

Appendix G
Summer load scenario

Most of the load flow modeling done by PSE and USE to justify Energize Eastside has been focused on a winter peak load scenario. Recently, PSE has mentioned reliability concerns in the summer to provide additional motivation to build Energize Eastside. So far, PSE has refused to provide input data and results for both winter and summer scenarios.

We briefly reviewed the WECC Base Case for heavy summer demand in 2019. The peak load on Eastside substations is 281 MW in this scenario. This is 30% lower than the total load for heavy winter demand in 2017-18 (402 MW). The drop in transformer ratings due to summer heat is only 9%, so this scenario should be significantly less stressful on PSE's infrastructure than the winter scenario. Rapid growth in air conditioning is a concern, but if there is a summer need, then rooftop solar in Bellevue and other cities will be helpful and should be encouraged. Further study is warranted.

Appendix H
Resumes

J. Richard Lauckhart
Energy Consulting

J. Richard Lauckhart has 40 years of experience in power supply planning, electricity price forecasting and asset valuation. He began his career as a distribution engineer with Pacific Gas & Electric Co., and held various positions at Puget Sound Power & Light Co. (now Puget Sound Energy) in power supply planning, culminating as vice president of power planning.

For the last 12 years Mr. Lauckhart has performed consulting assignments related to power market analyses, price forecasting services, asset market valuation, integrated resource planning, transmission line congestion analysis, and management of strategic consulting engagements for clients in North America, including investor-owned and municipal utilities, independent power producers, and lenders.

Mr. Lauckhart received a bachelor of science degree in electrical engineering from Washington State University in 1971 and a masters degree in business administration from the University of Washington in 1975

Representative Project Experience

Black & Veatch
September 2008 to October 2011
Managing Director
Mr. Lauckhart oversees wholesale electricity price forecasting, project revenue analysis, consults regarding wind integration matters electric interconnection and transmission arrangements for new power projects, and other related matters in the electric power industry. In addition, he heads Black & Veatch's WECC regional power markets analysis team.

WECC Power Market Analysis and Transmission Analysis, Henwood/Global Energy Decisions/Ventyx
2000 - 2008
Senior Executive
Mr. Lauckhart oversaw wholesale electricity price forecasting, project revenue analysis, consulted regarding electric interconnection and transmission arrangements for new power projects, and other related matters in the electric power industry. In addition, he headed Global Energy's WECC regional power markets analysis team.

Lauckhart Consulting, Inc.
1996 – 2000
President
Primary client - Puget Sound Energy (formerly Puget Sound Power & Light Company): Involved in power contract restructuring, market power analysis, FERC 888 transmission tariffs, and other matters. Testified at FERC regarding Puget's 888 tariff. Testified for Puget in June, 1999 arbitration with BPA regarding transmission capability on the Northern Intertie.

Northwest IPP
Under retainer with IPP from July 1996 through December 31, 1999. Involved primarily in merchant power plant development activities including permitting activity, owner's engineer identification, environmental consultant identification, water supply

arrangement, transmission interconnection and wheeling arrangements, gas pipeline arrangements, economic analysis, forward price forecasting, marketing, and related issues.

Levitan & Associates (Boston)

Participated in teams involved in electric system acquisition activities. Performed preliminary analysis for a major retail corporation regarding possible participation as an aggregator in the California deregulated electric market. Involved in the evolving discussions about deregulation in the state of Washington including participant in HB 2831 report and ESSB 6560 report.

Member of advisory task force for Northwest Power Planning Council study of generation reliability in the Pacific Northwest. Participating writer in a newsletter advocating electric deregulation in the state of Washington.

Puget Sound Power & Light Company
1991 – 1996
Vice President, Power Planning
Involved in all aspects of a $700 million per year power supply for a hydro/thermal utility with a 4,600 MW peak and 2,200 aMW energy retail electric load. Included responsibility for a 22 person department involved in power scheduling (for both retail and wholesale power activity), power and transmission contract negotiation and administration, regulatory and NERC compliance, forward price forecasting, power cost accounting, and retail rate activity related to power costs. Activity included matters related to 650 MW of existing gas-fired, simple cycle combustion turbines. In addition, 660 MW of combined cycle cogeneration "qualifying facilities" were developed by others for Puget during this time frame. Detailed understandings of the projects were developed both for initial contractual needs and later for economic restructuring negotiations. Mr. Lauckhart was the primary person involved in developing Puget's Open Access transmission tariff in accordance with FERC Order 888.

Puget Sound Power & Light Company
1986 – 1991
Manager, Power Planning
The company's key person in developing (1) a WUTC approved competitive bidding process for administering PURPA obligations, and (2) a WUTC approved regulatory mechanism for recovery of power costs called the Periodic Rate Adjustment Mechanism (PRAM).

Puget Sound Power & Light Company
1981 – 1986
Director, Power Planning
The company's key person in developing a power cost forecasting model that was customized to take into account the unique nature of the hydro generation system that exists in the Pacific Northwest.

Puget Sound Power & Light Company
1979 – 1981
Manager, Corporate Planning
Responsible for administering the corporate goals and objectives program.

Puget Sound Power & Light Company

1976 – 1979
Financial Planning
Improved and ran a computerized corporate financial forecasting model for the company that was used by the CFO.

Puget Sound Power & Light Company
1974 – 1976
Transmission Planner
Performed transmission engineering to assure a reliable transmission system.

Pacific Gas & Electric Company
1971 – 1974
Distribution Engineer
Performed distribution engineering to assure a reliable distribution system.

Other Relevant Experience

- Expert testimony for Montana Independent Renewable Generators related to avoided cost regulations and pricing filed February 2009 at the Montana PSC
- Expert Testimony for LS Power in the SDG&E Sunrise Proceeding regarding economics of in-area generation vs. the cost of transmission and imported power Spring 2007
- Expert Testimony for BC Hydro in the Long Term Resource Plan, February 2009 dealing with natural gas price forecasts and REC price forecasting
- Expert Testimony for John Deere Wind in a proceeding in Texas in November 2008 related to avoided costs and wind effective load carrying capability
- Expert Testimony for Two Dot Wind before the Montana commission regarding wind integration costs Spring 2008
- Expert Testimony in the BC Hydro Integrated Electricity Plan proceeding regarding WECC Power Markets. November 2006.
- Expert Testimony for Colstrip Energy Limited Partnership before Montana PUC regarding administration of QF contract prices. July 2006.
- Expert Testimony for Pacific Gas & Electric regarding current PURPA implementation in each of the 50 states. January 2006.
- Expert Testimony in CPUC proceeding regarding modeling procedures and methodologies to justify new transmission based on reduction of congestion costs (Transmission Economic Analysis Methodology – TEAM). Summer 2006.
- Expert Testimony for BC Hydro regarding the expected operation of the proposed Duke Point Power Project on Vancouver Island, January 2005
- Expert Testimony for PG&E regarding the cost alternative generation to the proposed replacement of steam generators for Diablo Canyon, Summer of 2004.
- Expert Testimony in an arbitration over a dispute about failure to deliver power under a Power Purchase Agreement, Fall 2004.
- Integrated Resource Plan Development. For a large investor-owned utility in the Pacific Northwest, Global Energy provided advanced analytics support for the development of a risk-adjusted integrated resource plan using RISKSYM to provide a stochastic analysis of the real cost of alternative portfolios.
- Expert Testimony for SDG&E, Southern California Edison, and PG&E regarding IRPs, WECC markets and LOLP matters before the California PUC, 2003.

- Miguel-Mission Transmission Market Analysis-San Diego Gas & Electric. San Diego Gas & Electric retained Global Energy to oversee an analysis of the economic benefits associated with building the Mission-Miguel transmission line and the Imperial Valley transformer. Global Energy performed an analysis of the economic benefits of the Mission-Miguel line, prepared a report, sponsored testimony at the CPUC, and testified at the CPUC regarding the report.
- Valley-Rainbow Transmission Market Analysis-San Diego Gas & Electric. San Diego Gas & Electric also engaged Global Energy to analyze the economic benefits associated with building the Valley-Rainbow transmission line and to respond to the CPUC scoping memo that "SDG&E should describe its assessment of how a 500 kV interconnect, like Valley-Rainbow, will impact electricity markets locally, regionally, and statewide." Global Energy analyzed the economic benefits of the Valley-Rainbow line, prepared a report, sponsored testimony at the CPUC, and testified at the CPUC regarding the report.
- Damages Assessment Litigation Support. Global Energy was engaged by Stoel Rives to provide damages analysis, expert testimony and litigation support in for its client in a power contract damages lawsuit. Global Energy quantified the range of potential damages, assessed power market conditions at the time, and provided expert testimony to enable Stoel Rives' client to prevail in a jury trial.
- Expert Testimony, Concerning the Economic Benefits Associated with Transmission Line Expansion. Testimony prepared on behalf of San Diego Gas & Electric Company, September 2001.
- Expert Testimony, Concerning market price forecast in support of Pacific Gas and Electric hydro divesture case, December 2000.
- Expert Testimony, Prepared on behalf of AES Pacific regarding value of sale for Mohave Coal project to AES Pacific for Southern California Edison, December 2000.
- Expert Testimony, Prepared on behalf of a coalition of 12 entities regarding the impact of Direct Access of utility costs in California. June 2002.

Mr. Lauckhart was Puget's primary witness on power supply matters in eight different proceedings before the Washington Utilities and Transportation Commission.

Mr. Lauckhart was Puget's chief witness at FERC in hearings involving Puget's Open Access Transmission Tariff and testified for Puget in BPA rate case and court proceedings.

ROGER SCHIFFMAN

SUMMARY OF QUALIFICATIONS

Mr. Schiffman has 23 years of energy industry experience covering utility resource planning, electricity market evaluation, market assessment and simulation modeling; regulatory policy development; economic and financial analysis, and contract evaluation. Mr. Schiffman has worked with public and private utility companies on resource planning decisions, power plant retirement decisions, avoided cost determinations, and on power supply procurement activity. Mr. Schiffman has worked extensively with electric utility staff, power plant developers, regulatory personnel, investment bankers and other industry participants in both consulting and regulatory environments. Mr. Schiffman possesses extensive financial analysis skills, supported by thorough knowledge of financial, economic and accounting principles. He has a strong technical understanding of the electric utility industry and excellent analytical problem-solving skills, including quantitative analysis and computer modeling techniques.

EXPERIENCE

Principal, Black and Veatch Corporation, Inc., Sacramento, CA, March 2009 to October, 2015

- Initiated Integrated Resource Plan for the Virgin Islands Water & Power Authority. This project is a multi-faceted IRP, where detailed planning and potential siting impacts must be considered in the overall planning, due to geographic and topology limitations on the islands. Mr. Schiffman directed the analysis and playing the lead analytic role in assessing resource needs. This included directing the data gathering efforts, taking technical lead in completing production cost and financial modeling, and managing Black & Veatch's team of technical experts. Mr. Schiffman also developed a stakeholder process and gave multiple presentations before stakeholder and customer groups.
- Completed nodal market simulation and congestion study for a concentrating solar plant in Northern Nevada. This engagement includes a review of transmission system impact studies, power flow data and development of a PROMOD nodal simulation database to assess congestion likelihood for the project.
- Completed economic assessment of a large pumped storage project in Southern California, including development of energy market arbitrage, capacity market and ancillary services market revenue forecasts. Developed pro forma financial statements examining economics of project under different ownership and off-take agreement structures.
- Completed Integrated Resource Plan for Azusa Light & Water, a municipal utility in southern California. This project involved using Black & Veatch's EMP database and price forecast, specifying thermal and renewable resource options, and completing detailed market simulation and financial modeling to determine a preferred power supply plan for Azusa. A key focus of the study is to identify resource options to replace output from the San Juan 3 coal plant, which is scheduled to retire.
- Completed Integrated Resource Plan for Pasadena Water & Power, a municipal utility in southern California. This project involved using Black & Veatch's EMP database and price forecast, specifying thermal and renewable resource options, and completing detailed market simulation and financial modeling to determine a preferred power supply plan for Pasadena. The project also included reflection of key stakeholder input, and testing stakeholder driven

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policy proposals for advancing renewable resource procurement beyond state-mandated RPS levels. A key focus of the study is to identify resource options to replace output from the Intermountain coal plant, which is scheduled to retire.

- Completed generation reliability study for the Brownsville Public Utility Board. This study included directing the completion of detailed reliability modeling using GE-MARS, and evaluating loss-of-load probabilities for BPUB based on its existing system and based on the addition of a 200 MW ownership share in the combined cycle power plant being developed in Brownsville by Tenaska. The study also included detailed pro forma modeling of partial ownership of the combined cycle plant, and a financial and risk assessment presented to BPUB's Board of Directors, and also used to address rating agency questions about credit impacts of the new power plant. On behalf of Southern California Edison, completed nodal power price forecast and assessment of high voltage transmission upgrades and additions in Southern California. This project included an assessment of congestion, locational marginal pricing, transmission system losses, and economic impacts of adding new transmission facilities in WECC, with particular focus on Southern California. PROMOD IV was used to complete the nodal market analysis, and PROMOD simulation results were translated into GE-PSLF for more detailed transmission system modeling of power flow cases under a variety of supply and demand conditions throughout the year.
- Completed four projects focused on nodal market modeling in California, Arizona and Southern Nevada. These studies were used to assess congestion risk faced by solar and wind generation projects at the sites where each is being developed. Completed PROMOD IV dispatch and nodal analyses for each project, and developed risk assessments for generation curtailment risk. Also developed analyses of transmission system congestion along delivery paths for each project, and on key economic transmission paths in Northern and Southern California, transmission import paths into Southern California, and transmission paths in Southern Nevada.
- Completed resource and power supply planning/procurement project for confidential SPP energy supplier. Completed a competitiveness assessment of major electricity supplier in Nebraska, examining cost structure, net resource position, generation asset characteristics, transmission access and delivery options, and overall competitive positioning of SPP, MISO and MRO entities that have potential to provide wholesale electricity service in Nebraska. Worked collaboratively with client and a wholesale customer task force
- Completed due diligence analysis of portfolio of power supply assets to support bid development. The generators being sold were located in SPP, WECC, and the Northeast. The WECC asset is a qualifying facility, which required detailed representation and modeling of the California PUC Short-Run Avoided Cost tariff and pricing formula. One of the SPP assets is also a qualifying facility, which required detailed analysis of the steam load and interaction between joint power and steam production. Completed modeling analysis and risk assessment of power supply agreements, developed revenue forecasts for each power plant, and completed merchant plant analysis of plant operations after PPA expiration.
- On behalf of a municipal utility client, developed database of renewable energy resource bids solicited through an RFP process, developed assessment of delivery terms and transmission tariffs associated with power delivery from distant resources, and completed bid screening analysis of 240 separate bids/pricing options.
- Completed PROMOD IV dispatch analysis and economic assessment of 6,000 MW portfolio of coal and natural gas-fueled resources operating in the Midwest ISO market region. Developed expected operations, cost, market sales and revenue forecasts for portfolio assets,

under several market scenarios. Prepared Independent Market Report for potential use in Offering Memorandum.

- Completed detailed review of California ISO ancillary services markets, and opportunity for renewable energy and energy storage markets to participate in those markets. Analysis included assessment of day-ahead, hour-ahead, and real-time market operation.
- Completed dispatch modeling and power supply planning study examining construction of a pumped storage hydro project in Hawaii. The evaluation included assessments of project revenue in energy, ancillary services, and capacity markets in Hawaii, expected dispatch and operation of the pumped storage project, and comparison of long-term power supply plans with and without addition of the pumped storage project.
- Completed deliverability and congestion analysis of wind energy resources being located in California. Developed nodal market simulations, and examined locational marginal price differences, congestion components, and transmission line loadings of facilities impacted by the wind assets being studied.
- Completed detailed financial and dispatch modeling (deterministic and stochastic) of energy storage project being developed in Southern California, to create dispatch profile and estimated long-term project value of the facility. The evaluation included assessments of project revenue in energy, ancillary services, and capacity markets in Southern California.
- Completed dispatch analysis and financial modeling of pumped storage hydro project in Colorado, for use in regulatory proceedings. The evaluation included assessments of project revenue in energy, ancillary services, and capacity markets in Colorado.
- Completed nodal power price forecast and assessment of high voltage transmission upgrades and additions in Southern California. This project included an assessment of congestion, locational marginal pricing, transmission system losses, and economic impacts of adding new transmission facilities in WECC, with particular focus on Southern California. PROMOD IV was used to complete the nodal market analysis, and PROMOD simulation results were translated into GE-PSLF for more detailed transmission system modeling of power flow cases under a variety of supply and demand conditions throughout the year.
- Completed PROMOD IV dispatch and economic analysis of Lodi Energy Center, with focus upon expected dispatch of the project, and its fit into the overall power supply portfolio of a Southern California Municipal Utility.
- Completed PROMOD IV dispatch analysis of a 100 MW biomass project in Florida, with focus upon expected dispatch and market revenue for the project in Florida wholesale power markets. Prepared Independent Market Report for use in financing construction of this project.
- Completed PROMOD IV market price forecasts and detailed analyses of power markets in all North American regions, including hourly energy price forecasts, annual capacity price forecasts, and detailed assessment of supply/demand conditions and generator dispatch. The assessments included forecasts of renewable energy development in each region/submarket, forecast greenhouse gas regulation, and economic assessment of fossil and renewable energy technologies.

Vice President, Ventyx, Inc., Sacramento, CA, June 2007 to March 2009

- Managed project and led analysis for consortium of upper Midwest utilities focused on developing plans for long-term transmission expansion to ensure reliability in the region and to accommodate economic transfer of large-scale wind-based electricity generation. This project examined congestion, reliability and economic benefits associated with large-scale wind generation expansion in the upper Midwest, and accompanying needs for transmission system expansion. Evaluation was completed on both nodal and zonal basis.
- Assisted investor-owned utility in the upper Midwest in completing an economic transmission planning study consistent with FERC requirements. Provided guidance to client in establishing study framework, and in completing detailed technical evaluation of transmission upgrade projects. Provided assistance with stakeholder group interactions and debriefing.
- Conducted study for Western Area Power Administration examining economic impacts of wind project integration from new wind projects located on Native American lands. Worked with multi-party stakeholder group in completing study. Specific focus was upon power system modeling and economic evaluation of long-term costs and benefits of wind energy integration into the WAPA system.
- Developed projections of expected dispatch, revenue, and operating costs for new combined-cycle power plant under development in Southern California. Prepared financial projections under merchant plant and other likely economic scenarios. Completed evaluation of tolling agreement terms and conditions.
- Assisted Southern California energy supplier in completing due diligence analysis for investment and development of 300-500 MW wind generation project located in Central/Southern California. Reviewed due diligence documents and completed economic evaluation of expected revenue, operating costs and investment cash flows for the project at a range of capacities varying from 100 MW to 500 MW.

Director, Navigant Consulting, Inc., Sacramento, CA, April, 2000 to June, 2007

- Responsible for managing the price forecasting subpractice within Navigant Consulting's Energy Market Assessment group. Responsibilities included a wide variety of engagements focused on evaluating wholesale power market conditions. Completed market assessment and simulation studies of all North American regional power markets, including Canada and Mexico.
- Created and Developed NCI's PROSYM market simulation practice and capabilities in modeling WECC and Eastern Interconnected markets. Completed numerous market simulation and assessment engagements throughout the U.S. covering all North American market regions.
- With a team of consultants, assisting the California Energy Commission in defining and evaluating scenarios for its 2007 Integrated Energy Plan. Reviewing market simulation results from each of the scenarios and completing analysis of industry and consumer risks likely to be faced in California over the next decade (ongoing).
- Directed NCI's market simulation efforts as independent consultant to the State of California Department of Water Resources, leading to the successful underwriting of $11 billion in bond financing and supporting the execution of power supply agreements aggregating to over 13,000 MW.

- Developed projections of lost revenue and operating profits due to construction delays at a large combined-cycle project in the Desert Southwest. Prepared evaluation of WECC power market conditions during the construction period for this project, and completed power market simulations used to measure likely dispatch, revenue and operating profits of the project during the construction delay period. Successfully presented and defended those estimates before an Arbitration Panel, resulting in a significant financial award for our client.
- Completed PJM Market simulations and led analytical support for recent financing of a large coal plant in PJM-West. Worked closely with investment banks and rating agencies in identifying and assessing cash flow risks to the project.
- Prepared carbon regulation risk assessment of a new coal plant being developed in Nevada, to evaluate long-term potential impacts on project costs. Evaluated ratepayer risks associated with this new project.
- Developed and maintained power market simulations to evaluate likely dispatch, costs, and spot market purchases and sales associated with the California Department of Water Resources purchased power contract portfolio. Results from these simulations have been used in each of the last five years to support CDWR's annual revenue requirement filing before the California Public Utilities Commission. Provide ongoing regulatory support to CDWR, including consultation and limited training of CPUC staff in power market modeling.
- Directed a number of nationwide market simulation and valuation engagements examining current market value of power plant portfolios owned by Calpine, Mirant, NRG and other independent power producers. Worked with bond investors to develop refined valuation estimates for subsets of each portfolio.
- Served on WECC's Power Simulation Task Force which was formed to assess available options for the WECC to procure, maintain and use a power market simulation database and model in its generation and transmission planning efforts. Participated in task force meetings where criteria were developed for selecting a simulation database and model, and assisted in evaluating proposals submitted to the WECC task force
- Performed power market simulations of Mexico, using NewEnergy Associates' MarketPower simulation model. Developed market price forecast and dispatch analysis of the Altamira II project under a variety of projected fuel market conditions. Results from these analyses were used by Senior Lenders to evaluate ongoing feasibility of the project under its financing terms. Annual updates were provided to the lenders.
- Assisted a California investor-owned utility in conducting RFP and in evaluating bids received for short-term and medium-term power supply contracts. Developed cost rankings, economic screening, risk assessment and preferred bid evaluations, and assisted the utility's planning and bid evaluation staff in presenting results to the company's senior management.
- Developed WECC market simulations and assessment of investment conditions for numerous clients used in feasibility analysis and financing support of new generation projects being developed in WECC markets. These analyses included separate evaluation of power market conditions in California, Mexico (Baja), Arizona, Colorado, Nevada, Oregon, Washington, British Columbia, and Alberta.
- Reviewed and verified long-term resource plans of a major investor-owned utility located in the Desert Southwest region. Conducted power market simulations of preferred and competing resource plans and developed relative ranking of results.

Senior Consultant, Henwood Energy Services, Inc., Sacramento, CA, 1998 to 2000

- Prepared numerous forecasts of wholesale market electricity prices using Henwood's proprietary market simulation tools. Drafted reports presenting price forecasts to consulting clients. Worked closely with clients and sponsors of new merchant power plants to provide customized market price forecasts and to serve individual client needs. Presented study results to clients and their constituents.
- Directed project evaluation and revenue forecast for major merchant power plant in Texas. Presented revenue forecast to investment bankers, and to several potential equity investors. Advised and worked with project developer to successfully obtain debt and equity financing for the project, which is currently under construction.
- Conducted economic study of market rules and entry barriers faced by developers of new merchant power plants in domestic electricity markets. Applied study results to specific conditions in Texas. Met with a variety of industry representatives in Texas including project developers, transmission service providers, power marketers, utility regulators and environmental regulators to gather market intelligence and develop study conclusions.
- Advised and worked with PricewaterhouseCoopers to perform economic evaluation and market simulations of proposed Purchase Power Arrangements under development in Alberta, Canada. The Power Purchase Arrangements are to be sold at auction in coming months. Prepared economic study of market power held by incumbent electricity suppliers in Alberta.
- Developed software and modeling tools to estimate investment cash flows and pro forma financial results for new merchant power plants. Developed Henwood approach for evaluating profitability of new market entrants and incorporating equilibrium amounts of new entry in its market studies.

Senior Financial Analyst, Public Service Commission of Wisconsin, Madison, WI, 1990 to 1998

- Developed policy proposals for restructuring wholesale and retail electricity markets. Evaluated competing policy proposals for impacts upon consumers and upon electrical system operation. Drafted formal electricity industry restructuring policy adopted by the Wisconsin Commission.
- Developed policies for addressing wholesale and retail market power in Primergy and Interstate Energy Corporation merger cases. Evaluated feasibility and corporate finance implications of asset divestiture and spin-off options for mitigating market power.
- Presented evaluation of proposed electric utility merger legislation to subcommittee of Wisconsin legislature. Advised individual legislators on merger policy.
- Developed policy proposal and draft legislation for reforming power plant siting law and for allowing development of new merchant power plants in Wisconsin.
- Directed industry-wide efforts to revise the PSCW generation competitive bidding procedures. Conducted workshops on proposed revisions for utility and other industry participants. Drafted policy reforms adopted by the Wisconsin Commission.
- Conducted primary economic and engineering analysis of power plant proposals submitted in generation competitive bidding cases. Prepared financial analyses of key contract terms and risks. Evaluated economic and engineering characteristics of bid proposals using production

cost and system expansion computer modeling. Recommended preferred projects to Wisconsin Commission.

- Completed numerous financial analyses of new stock and bond issuances by Wisconsin investor-owned utilities to evaluate investment risks and impacts upon the corporation. Drafted formal administrative orders authorizing each issuance.

Research Assistant, University of Wisconsin, Madison, WI, 1989-1990

- Co-authored and provided research support for study of consolidation and mergers in the electric utility industry.

EDUCATION

University of Wisconsin-Madison

- Graduate Studies toward MS-Finance, September 1988 - May 1990.
- Bachelor of Business Administration, Finance, Investment and Banking, May 1988.
- Curriculum concentrated heavily upon financial economics, with additional emphasis upon economics, mathematics, and accounting.

PUBLICATIONS

Electric Utility Mergers and Regulatory Policy, Ray, Stevenson, Schiffman, Thompson. National Regulatory Research Institute, 1992.

The Future of Wisconsin's Electric Power Industry: Environmental Impact Statement, co-author, Public Service Commission of Wisconsin, October 1995, Docket 05-EI-114.

Report to the Governor on Electric Reliability, co-author, Public Service Commission of Wisconsin, Summer 1997.

TESTIMONY

Public Service Commission of Wisconsin, Docket 6630-UR-104, Wisconsin Electric Power Company Rate Case, 1990, "Rate of Return on Equity, Cost of Capital and Financial Condition."

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Public Service Commission of Wisconsin, Docket 4220-UR-105, Northern States Power Company (Wisconsin) Rate Case, 1991, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Rate of Return on Equity, Cost of Capital and Financial Condition, Wisconsin Electric Power Company, Docket 6630-UR-105, Public Service Commission of Wisconsin, 1991

Public Service Commission of Wisconsin, Docket 05-EP-6, Advance Plan 6, 1992, "Alignment of Managerial Interests and Incentives with Integrated Resource Planning Goals" (with Paul Newman).

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Public Service Commission of Wisconsin, Docket 4220-UR-106, Northern States Power Company (Wisconsin) Rate Case, 1992, "Rate of Return on Equity, Cost of Capital and Financial Condition."

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TESTIMONY (CONTINUED)

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Public Service Commission of Wisconsin, Docket 4220-UR-107, Northern States Power Company (Wisconsin) Rate Case, 1993, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 6630-CE-202, Wisconsin Electric Power Company Auburn to Butternut Transmission Line Case, 1994, "Economic Cost Comparison of Transmission Upgrade and Distributed Generation Wind Turbine Project."

Public Service Commission of Wisconsin, Docket 3270-UR-107, Madison Gas and Electric Company, 1994 "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin,. Docket 6690-CE-156, Application of Wisconsin Public Service Corporation for Authority to Increase Electric Generating Capacity (Stage One Competition Among Alternative Suppliers), 1994 & 1995, "Economic Analysis of Competitively Bid Power Plant Proposals" (with Paul Newman), "Contract Risk in Purchased Power Arrangements," "Accounting Treatment for Long-Term Purchased Power Contracts," "Contract Risk and Analysis of True-Up Mechanisms and Balancing Accounts."

Public Service Commission of Wisconsin, Docket 6630-UM-100/4220-UM-101, Wisconsin Electric Power Company/Northern States Power Company Merger Case, 1996, "Market Power Remedies; State/Federal Jurisdictional Issues."

Public Service Commission of Wisconsin, Docket 05-EP-7, Advance Plan 7, 1996, "Risk-Adjusted Discount Rates."

TESTIMONY (CONTINUED)

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North Dakota Public Service Commission, Docket No. PU-399-01-186, Montana-Dakota Utilities Co., 2000 Electric Operations Annual Report (Commission Investigation of Excess Earnings), February, 2002, "Wholesale power market conditions in the upper midwest, and the impact on the level and profitability of off-system sales for Montana-Dakota Utilities Co."

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The INGAA Foundation, Inc.

Criteria for Pipelines Co-Existing with Electric Power Lines

Prepared For:
The INGAA Foundation

Prepared By:
DNV GL

October 2015

See page 4

The INGAA Foundation
FINAL Report No. 2015-04

Report name:	Criteria for Pipelines Co-Existing with Electric Power Lines	
Customer:	The INGAA Foundation, Inc.	
Contact person:	Richard Hoffmann	
Date of issue:	October 5, 2015	
Project No.:	PP105012	
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Objective:

The primary objective of this report is to present the technical background, and provide best practice guidelines and summary criteria for pipelines collocated with high voltage AC power lines. The report addresses interference effects with respect to corrosion and safety hazards, and fault threats.

Prepared by:	Verified by:	Approved by:
Shane Finneran Senior Engineer	Barry Krebs Principal Engineer	Lynsay Bensman Head of Section, Materials Advisory Service

Rev. No.	Date	Reason for Issue	Prepared by	Verified by	Approved by
Draft	2015-06-18	First Issue	SF	BK	LB
0	2015-10-05	Final Issue	SF	BK	LB

EXECUTIVE SUMMARY

The primary objective of this report is to present the technical background, and provide best practice guidelines and summary criteria for pipelines collocated with high voltage AC power lines. The report addresses interference effects with respect to corrosion and safety hazards, and fault threats. The guidelines presented address mitigation and monitoring, encroachment and construction, risk severity classification, and recommendations for further industry development.

This report addresses the technical background to high voltage interference with respect to collocated and crossing pipelines, and presents basic procedures for dealing with interference scenarios. The provisions of this document are recommended to be used under the direction of competent persons, who are qualified in the practice of corrosion control on metallic structures, with specific suitable experience related to AC and/or DC interference and mitigation. This document is intended for use in conjunction with the reference materials cited herein.

Collocated pipelines, sharing, paralleling, or crossing high voltage power line rights-of-way (ROW), may be subject to electrical interference from electrostatic coupling, electromagnetic inductive, and conductive effects. If the interference effects are high enough, they may pose a safety hazard to personnel or the public, or may compromise the integrity of the pipeline. Because of increased opposition to pipeline and power line siting, many future projects propose collocating high voltage alternating current (HVAC) and high voltage direct current (HVDC) power lines and pipelines in shared corridors, worsening the threat.

Predicting HVAC interference on pipelines is a complex problem, with multiple interacting variables affecting the influence and consequences. In some cases, detailed modeling and field monitoring is used to estimate a collocated pipeline's susceptibility to HVAC interference, identify locations of possible AC current discharge, and design appropriate mitigation systems to reduce the effects of AC interference. This detailed computer modeling generally requires extensive data collection, field work, and subject-matter expertise. Basic industry guidelines are needed to help determine when more detailed analysis is warranted, or when detailed analysis can be ruled out based on the known collocation and loading parameters. A consistent technical guidance document will benefit the pipeline industry by increasing public safety and allowing for an efficient approach in assessment and mitigation of threats related to high voltage interference.

The INGAA Foundation contracted Det Norske Veritas (U.S.A), Inc. (DNV GL) to develop this guidance document. The project included a detailed industry literature review to identify applicable technical reports, international standards, existing guidance and operator procedures. In addition to the literature review, numerical modeling was performed to determine the effects of key parameters on the interference levels. The document addresses interference effects with respect to corrosion and safety hazards, mitigation, monitoring, encroachment and construction, prioritization and modeling. It also includes recommendations for further development.

The following severity ranking tables were developed for key variables and their impact on the severity of AC interference. Further background for the development of these rankings is provided throughout the report. Guidelines for determining the need for detailed analysis and applying these severity rankings are provided in Section 6.2.

Separation Distance

Table 3-Severity Ranking of Separation Distance

Separation Distance - D (Feet)	Severity Ranking of HVAC Interference
$D < 100$	High
$100 < D < 500$	Medium
$500 < D < 1{,}000$	Low
$1{,}000 < D \leq 2{,}500$	Very Low

HVAC Power Line Current

Table 4-Relative Ranking of HVAC Phase Current

HVAC Current - I (amps)	Relative Severity of HVAC Interference
$I \geq 1{,}000$	Very High
$500 < I > 1{,}000$	High
$250 < I < 500$	Med-High
$100 < I < 250$	Medium
$I < 100$	Low

Soil Resistivity

Table 5-Relative Ranking of Soil Resistivity

Soil Resistivity - ρ (ohm-cm)	Relative Severity of HVAC Co
$\rho < 2{,}500$	Very High
$2{,}500 < \rho < 10{,}000$	High
$10{,}000 < \rho < 30{,}000$	Medium
$\rho > 30{,}000$	Low

We worry that Energize Eastside combined with the Olympic Pipeline would score high on these risk criteria. Our concerns are reasonable according to two pipeline safety experts.

Collocation Length

Table 6-Relative Ranking of Collocation Lengt

Collocation Length: L (feet)	Relative Severity
$L > 5{,}000$	High
$1{,}000 < L < 5{,}000$	Medium
$L < 1{,}000$	Low

Collocation / Crossing Angle

Table 7-Relative Ranking of Crossing Angle

Collocation/Crossing Angle - θ (°)	Relative Severity
$\theta < 30$	High
$30 < \theta < 60$	Med
$\theta > 60$	Low

The research and analytical studies accentuated the need for accurate power line current load data when assessing the susceptibility of a steel transmission line to high voltage interference. For this reason, collaboration between the respective pipeline and power line operators is advised to accurately determine where detailed assessment is required, and develop efficient mitigation where necessary.

The general safety recommendations and guidelines for interference analysis presented in Section 6 provide guidance on the relative susceptibility of AC interference associated with the selected variables. They primarily address the likelihood or susceptibility of AC interference, and do not address the consequence aspect of an overall risk assessment, as these details are specific to each individual assessment.

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Acronyms

AC	Alternating Current
CAPP	Canadian Association of Petroleum Producers
CFR	Code of Federal Regulation
CP	Cathodic Protection
CSA	Canadian Standards Association
CTS	Coupon Test Station
DC	Direct Current
DCD	DC Decoupler
DOC	Depth of Cover
DOT	Department of Transportation
EMI	Electromagnetic Interference
ER	Electrical Resistance
FBE	Fusion Bonded Epoxy
GPR	Ground Potential Rise
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEEE	Institute of Electrical and Electronics Engineers
IF	Isolation Flange
INGAA	Interstate Natural Gas Association of America
LEF	Longitudinal Electric Field
MPY	Mils per year
OSHA	Occupational Safety and Health Administration
PRCI	Pipeline Research Council International
ROW	Right(s) of Way
TLM	Transmission Line Model

1 INTRODUCTION

Trends within both the electric power and pipeline industries have increased the number of projects that co-locate high voltage alternating current (HVAC) and high voltage direct current (HVDC) power lines with steel transmission pipelines in shared rights-of-way (ROW). The primary objective of this report is to provide technical guidance and present best practice guidelines and summary criteria for steel transmission pipelines collocated with high voltage AC power lines.

Topography, permitting requirements, land access, increasingly vocal public opposition to infrastructure projects, and environmental concerns, including protected regions, all have led to an increase in sharing of common utility corridors. While there are numerous benefits to common utility corridors, there are also many concerns. Collocated steel transmission pipelines that share, parallel, or cross high voltage power line ROW may be subject to electrical interference from electrostatic coupling, electromagnetic inductive, and conductive effects. If these interference effects are high enough, they may pose a safety hazard to personnel or compromise the integrity of the pipeline.

Pipelines collocated with overhead HVAC lines account for a significant portion of the high voltage interference conditions encountered in the transmission pipeline industry. However, interference effects due to buried power lines and HVDC are also of concern to pipeline operators where close collocations exist. As aboveground HVAC is still the primary concern for pipeline interference, it is the primary focus of this report. However, comparison background and technical discussion is included related to HVDC and buried power line interference as well, and the effects of both should be considered on a case-by-case basis when steel transmission pipelines are closely collocated with these systems.

Numerous methodologies exist to analyze alternating current (AC) interference for specific collocations and crossings, but the analysis generally requires extensive data collection and detailed computational modeling. The accuracy of these models is sensitive to the HVAC power line operating parameters, which can often be difficult or costly for pipeline operators to obtain from electric power companies. Basic guidelines and prioritization criteria have been established in this report to provide guidance for pipeline operators to aid in a risk-based decision-making process and help prioritize regions for detailed modeling and mitigation design, or exclude further modeling analysis for a given region.

This report addresses interference effects related to encroachment and construction, corrosion and safety hazards, mitigation, and monitoring. This project included a detailed industry literature review to identify applicable technical reports, international standards and, guidance documents. Several INGAA members provided procedures. In addition to the literature review, numerical models were developed and trends presented detailing the effects of critical variables on interference levels under the conditions defined.

2 INDUSTRY LITERATURE REVIEW

There has been extensive research performed to understand the risks of high voltage interference and to develop efficient mitigation techniques. The effects of HVAC interference from a personnel safety and corrosion standpoint are a risk identified in much of the literature. Case studies in North America, the UK, and continental Europe have identified and documented AC corrosion concerns. Through-wall defects have been reported with corrosion rates greater than 50 mils/year (mpy) observed.[1]

In development of this guidance document a literature review identified and reviewed more than fifty technical references, US and International standards, existing guidance documents, research theses, journal manuscripts, and technical symposia papers. Additionally, INGAA collected operating procedures and guidelines from 10 member companies for review and comparison.

Where published, historically identified corrosion defects and pipeline failures associated with AC corrosion degradation have been reviewed and a selection are presented as case studies in Appendix A, demonstrating the magnitudes and variability in corrosion rates possible with AC accelerated corrosion.

The primary finding from this review is that there is significant variation in operating procedures and technical literature with respect to AC interference. Various companies' procedures were compared with published industry guidance, historical project data, and project experience to determine a best practice approach. Details and cross references are presented in each of the subsections of this document with a detailed review of the technical literature, case studies, and company procedures provided in Appendix A.

3 HIGH VOLTAGE INTERFERENCE ON ADJACENT PIPELINES

3.1 HVAC Interference Modes

Electrical interference from capacitive, electromagnetic inductive, and conductive coupling can affect pipelines collocated in close proximity to HVAC power lines. The subject of AC interference has been a growing concern across multiple industries in recent decades as improved pipeline coatings and utility ROW congestion has contributed to an increase in identified AC corrosion incidents. Recent trends in the high voltage electric power transmission industry are leading to increased power capacity and higher operating currents in certain systems, in part to overcome long distance transmission line losses.[2] This increase in operating current has a direct effect on the level of electromagnetic interference (EMI) and the corresponding magnitude of AC interference on affected pipelines. This trend toward elevated operating currents may present a significant challenge for achieving adequate mitigation on pipelines crossing or collocated with the high voltage power lines.

The three primary physical phenomena by which AC can interfere or "couple" with pipelines are through capacitive, resistive, or inductive coupling as detailed in Sections 3.1.1 through 3.1.3. High voltage interference can occur during normal operation, generally referred to as steady state, or during a power line fault. HVAC power line faults are any abnormal current flow from the standard intended operating conditions, and discussed further in Section 3.1.4.

3.1.1 Capacitive Coupling

Capacitive coupling, or electrostatic interference, occurs due to the electromagnetic field produced by AC current flowing in the conductors of a high voltage power line, which can induce a charge on an above ground steel pipeline that is electrically isolated from the ground. Capacitive effects are primarily a concern during construction when sections of the pipeline are aboveground on insulating supports, as indicated in Figure 1. The pipeline can build up charge as a capacitor with the surrounding air acting as the dielectric, which can maintain the electric field with a minimum loss in power, resulting in a potential difference with surrounding earth.

The magnitude of potential is primarily dependent on the pipeline proximity to the HVAC conductors, the magnitude of power line current, and the individual phase arrangement. If the potential buildup due to capacitive coupling is significant, electrostatic interference may present a risk of electric shock or arcing. While elevated capacitive voltages may exist, the corresponding current is generally low, resulting in low shocking consequence[3,4].

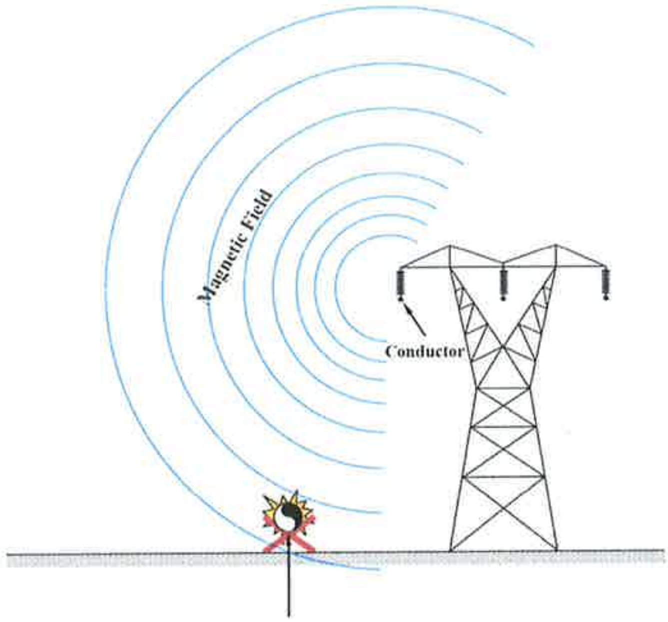

Figure 1. Illustration of Capacitive Coupling

3.1.2 Inductive Coupling

Electromagnetic induction is the primary interference effect of an HVAC power line on a buried steel pipeline during normal steady state operation. EMI occurs when AC flowing along power line conductors generates an electromagnetic field around the conductor, which can couple with adjacent buried pipelines, inducing an AC voltage, and corresponding current, on the structure as depicted in Figure 2. This induced AC potential may present a safety hazard to personnel, and can contribute to AC corrosion of the pipeline, as discussed in Section 3.3.1.

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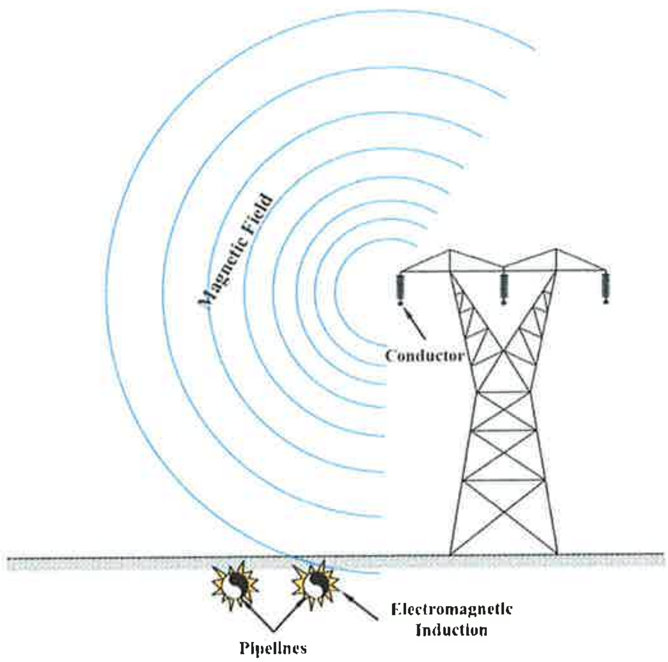

Figure 2. Illustration of Steady State HVAC Inductive Interference

The inductive effects of the HVAC power line on an adjacent pipeline are a function of geometry, soil resistivity, coating resistance, and the power line operating parameters. The geometry characteristics include separation distance between the pipeline and the towers, depth of cover (DOC), pipe diameter, angle between pipeline and power line, tower footing design, and phase conductor configuration. These parameters remain relatively constant over the life of the installation. The coating resistance, power system resistance, and soil resistivity may vary with the seasonal changes and as the installations age, but they are considered constants for most analyses. However, the operating parameters of the power line – such as phase conductor load, phase balance, voltage, and available fault current – all have an influence on the effects of AC interference, and can vary significantly. The individual conductor current load and phase balance is dynamic and changes with load requirements and switching surges. These variations in operating parameters contribute to variations in levels of AC interference. During normal HVAC operation, the current load varies as the load demand changes both daily and seasonally.[3,5] While normal operating conditions are often referred to as "steady state" throughout the industry, the term is somewhat misleading as the current loads and corresponding induced AC potentials can be continuously varying, adding further complexity to quantifying interference magnitude.

For a straight, parallel, homogenous collocation, induced potentials are highest at the ends of the collocated segment, and fall exponentially with distance past the point of divergence.[6] For more complex collocations, voltage peaks may occur at geometric or electrical discontinuities, where there is an abrupt change in the collocation geometry or electromagnetic field. Specifically, voltage peaks commonly occur where the pipeline converges or diverges with the HVAC power line, separation distance or soil resistivity changes significantly, isolation joints are present on the pipeline, or where the electromagnetic field varies such as at phase transpositions.[3,7,8,9]

3.1.3 Resistive Coupling

Current traveling through the soil to a pipeline can cause resistive or conductive coupling. As the grounded tower of an HVAC power system shares an electrolytic path with adjacent buried pipelines through the soil, fault currents may transfer to adjacent steel pipelines if the pipeline presents a lower resistance electrical path. Resistive interference is primarily a concern when a phase-to-ground fault occurs in an area where a pipeline is in close proximity to an HVAC power line, and magnitudes of fault currents in the ground are high. However, a phase imbalance on an HVAC system with a grounded neutral can contribute to resistive interference as return currents will travel through the ground and may transfer to a nearby pipeline.

During a fault condition (see Section 3.1.4), the primary concern is the resistive interference transferred through the soil. However, inductive interference can also be a concern as the phase current, and corresponding EMI, of at least one conductor can be high, as depicted in Figure 3. In other words, during a fault, the inductive effects during normal operation as described in Section 3.1.2 increase due the elevated EMI during the fault period.

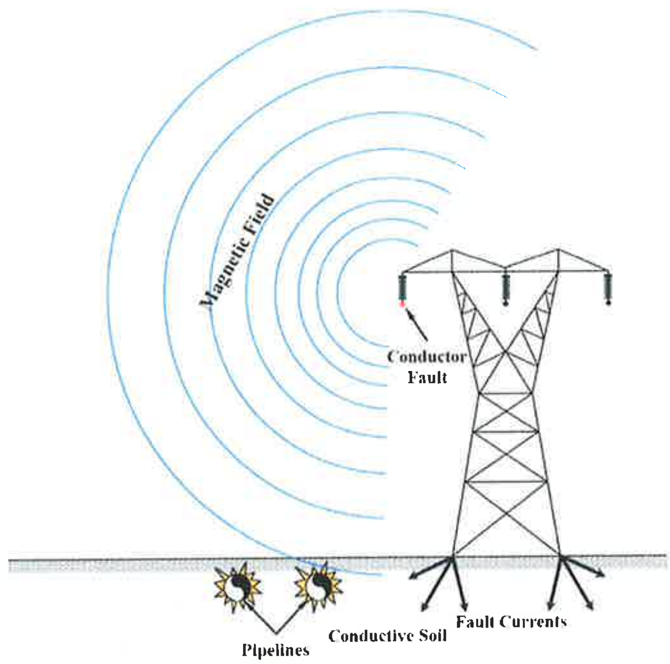

Figure 3. Illustration of HVAC Fault Condition – Inductive and Conductive Interference

If any of these electrical effects are high enough during operation, a possible shock hazard exists for anyone that touches an exposed part of the pipeline such as a valve, cathodic protection (CP) test station, or other aboveground appurtenance. During steady state normal power line operation, AC current density at a coating holiday (flaw) above a certain threshold may cause accelerated external corrosion damage to the pipeline. In addition, damage to the pipeline or its coating can occur if the voltage between the pipeline and surrounding soil becomes excessive during a fault condition.

3.1.4 AC Faults

For HVAC power lines, a fault is any abnormal current flow from the standard intended operating conditions. A fault can occur between one or more phase wires and the ground, or simply between adjacent phase wires. Faults can occur when one or more of the conductors are grounded or come in contact with each other, or due to other unforeseen events. This may be due to vegetation contacting the conductors, conductors contacting the towers or each other during high winds, physical damage to a tower, conductor, or insulator, flashover due to lightning strikes, or other abnormal operating condition. A phase-to-ground fault on a power line causes large currents in the soil at the location of the fault and large return currents on the phase conductor and ground return.

Faults are generally short duration transient events. Typical clearing times for faults range from approximately 5 to 60 cycles (0.08 to 1.0 seconds for 60-hertz transmission) depending on the location of the fault, breakers and type of communications. While the fault effects are transient, high-induced potentials or resistive coupled voltages along the ROW present a possible shocking hazard for personnel or anyone who may be in contact with above grade pipeline or appurtenances.

3.2 HVAC – Personnel Safety Hazards

An evaluation of the possible safety hazards for those working on a pipeline should take place whenever a pipeline is operating or constructed in close proximity to a HVAC power line. Personnel safety hazards are present during both pipeline construction and maintenance, and during normal steady state operation.

3.2.1 Hazards During Operation

Touch and Step Potential Limits

Personnel safety is of concern when a person is touching or standing near a pipeline when high voltages are present. The "touch potential" is defined as the voltage between an exposed feature of the pipeline, such as a CP test station or valve, and the surrounding soil or a nearby isolated metal object, such as a fence that can be touched at the same time. The touch potential is the voltage a person may be exposed to when contacting a pipe or electrically continuous appurtenance. The "step potential" is the voltage across a person's two feet and defined as the difference in the earth's surface potential between two spots one meter apart. The touch potential can be a concern during both normal steady state inductive and fault conductive/inductive conditions. Typically, the step potential is a concern during conductive fault conditions due to high currents and voltage gradients in the soil.

The Canadian Standards Association (CSA) and NACE International (NACE) have published standards addressing HVAC interference hazards. Both NACE and CSA standards[10,12] recommend reducing the steady state touch and step potential below 15 volts at any location where a person could contact the pipeline or any electrically continuous appurtenance. The 15-volt threshold is designed to limit the available maximum current through a typical human body to less than 10 mA. An 8 to 15 mA current results in a painful shock but is still in the maximum "let go" current range, for which a person can release an object or withdraw from contact.[10] The Institute of Electrical and Electronics Engineers (IEEE) Guide for Safety in AC Substation Grounding, indicates that a current in the range of 9 to 25 mA range may produce painful shock and involuntary muscular contraction, making it difficult to release an energized object.[13] Elevated body current in the range of 60 to 100 mA may cause severe injury or death as it can induce ventricular fibrillation, or inhibition of respiration. Current lower than nine (9) mA will generally result in a mild shock, but involuntary movement could still cause an accident.[10]

The touch potential is equal to the difference in voltage between an object and a contact point some distance away, and may be nearly the full voltage across the grounded object if that object is grounded at a point remote from where the person is in contact with it. For example, a crane that was grounded to the system neutral and that contacted an energized line would expose any person in contact with the crane or its un-insulated load line to a touch potential nearly equal to the full fault voltage.

The step potential may pose a risk during a fault simply by standing near the grounding point due to large potential gradients present in the soil, typically during a short duration fault condition.

A risk evaluation of the possible hazards to personnel for those working on the pipeline and possible pipeline coating damage should take place whenever a pipeline is in close proximity to a HVAC power line. This assessment should consider the possible likelihood and consequence of HVAC interference hazards to determine if further analytical assessment or mitigation is necessary. NACE International Standard Practice SP0177-2014 (Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems) indicates mitigation is necessary in those cases where step or touch potentials are in excess of 15 volts. Mitigation is further discussed in Section 5.

3.2.2 Encroachment and Construction Hazards

There are multiple safety hazards to consider associated with pipeline construction near a high voltage power line, the most obvious of which is the possibly lethal hazard of equipment directly contacting an energized overhead conductor.[3] The Occupational Safety and Health Administration (OSHA) has multiple regulations for safety requirements and limitations for working near power lines that must be considered in addition to pertinent company standards, and industry best practice guidelines. These include, but are not limited to the following:

- 29 CFR 1910.269: Electric power generation, transmission, and distribution
- 29 CFR 1910.333: Selection and use of work practices
- 29 CFR 1926, SUBPART V: Power Transmission and Distribution

The OSHA standards address requirements for working near energized equipment, overhead power lines, underground power lines, and construction nearby.

Elevated capacitive potentials generated on pipeline sections isolated from the ground on insulating skids as described in Section 3.1.1 can pose a safety hazard. Pipeline segments that are supported aboveground during pipeline construction near an HVAC power line are subject to EMI and electrical capacitance can build up between the pipeline segments and earth. If no electrical path to ground is present, even a relatively short section of piping may experience elevated AC potential, presenting a shock hazard to personnel near the pipeline.

Cases presented in published literature indicate scenarios of measured potentials greater than 1,000 volts on a pipeline segment exposed to an HVAC corridor.[4] In general, while the capacitive coupled voltages can exceed the NACE 15 volt touch potential safety threshold, the corresponding current is low reducing shocking hazard. However, arcing due to capacitive coupling may present a possible safety hazard, as an arc may be a possible ignition source for construction vehicles refueling along the ROW. Grounding pipelines in HVAC ROW will reduce the possibility of shocking or arcing.

Capacitive coupling is generally mitigated by connecting temporary grounding or bonding during construction to provide a low resistance path to ground for any electrostatic interference. Section 6 addresses further mitigation techniques and guidance for construction practices.

3.3 HVAC Threat to Pipeline Integrity

High voltage interference poses multiple threats to pipeline integrity for collocated and crossing pipelines under both steady state and fault conditions. During normal steady state HVAC power line operation, the inductive interference can contribute to accelerated external corrosion damage to the pipeline. Under faulted conditions, elevated potentials can lead to coating damage or a direct arcing to the pipeline.

The steady state 15 VAC threshold presented in NACE and CSA standards[10,12] considers personnel safety and does not necessarily address corrosion issues. Research and experience has shown that AC accelerated corrosion can occur in low resistivity soils at AC voltages well below this threshold.[3,6,14]

3.3.1 AC Corrosion

External corrosion, whether controlled by AC or DC, may pose a threat to the integrity of an operating pipeline. DC corrosion protection utilizes a system of corrosion resistant coatings and a CP system to provide electrochemical protection at coating holidays to reduce corrosion rate. However, AC corrosion is possible even in the presence of cathodically protected DC potentials due to high AC current density at coating holidays.

The concept of AC corrosion has been around since the early 1900s with only minor effects expected for many years.[3,10] AC accelerated corrosion has been recognized as a legitimate threat for collocated steel since the early 1990s, after several occurrences of accelerated pitting and leaks, ultimately associated with HVAC interference, were reported on cathodically protected pipelines.

Historically, there has been little consensus on specific mechanisms driving AC corrosion, and the severity of degradation attributed. However, several recent publications show tentative agreement in a plausible mechanism.[6,15,17] The explanation presented by Buchler, Tribollet, et al, suggests that AC corrosion on cathodically protected pipelines may be attributed to destabilization of pseudo-passive film that can normally form on exposed steel at a coating holiday under DC cathodic protection polarization. Due to the cyclic nature of AC current, the charge at the steel surface is continuously varying between anodic and cathodic polarization, which acts to reduce the passive film at the steel surface as shown in Figure 4. It is not the intention of this report to identify the specific mechanism driving material degradation due to AC corrosion, but rather to summarize a previously proposed mechanism and clarify the risks and contributing factors associated with AC corrosion.

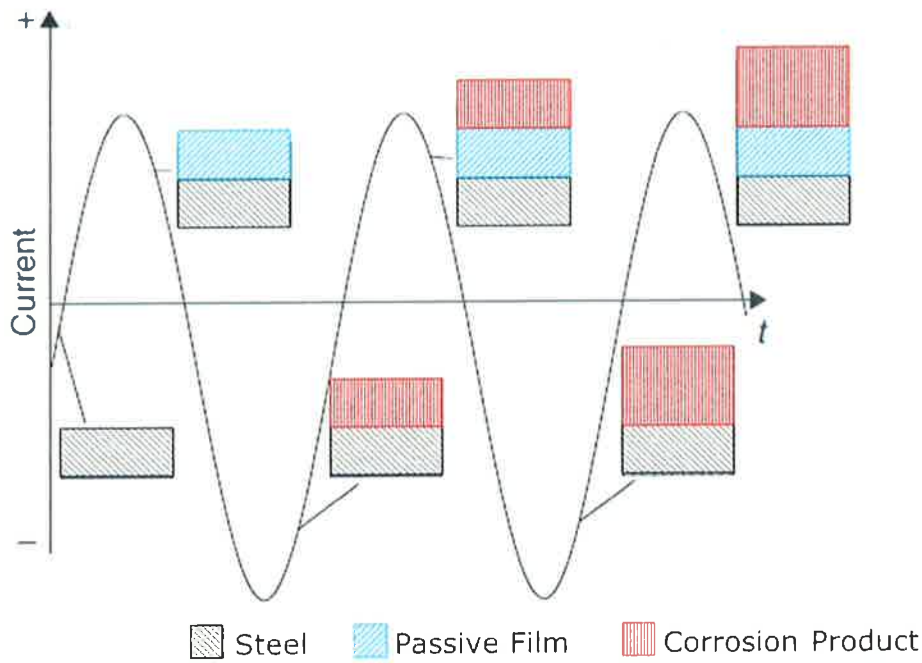

Figure 4. Graphical representation of proposed processes occurring during AC corrosion. Reproduced from Tribollet.[6]

3.3.1.1 AC Current Density

While there may be disagreement regarding the specific mechanism driving AC corrosion, AC current density is generally recognized as being an indicator of the likelihood of AC corrosion for a given location. In January of 2010, NACE International prepared and published a report entitled "AC Corrosion State-of-the-Art: Corrosion Rate, Mechanism, and Mitigation Requirements," which provides the following insight on AC corrosion current density.

> *"In 1986, a corrosion failure on a high-pressure gas pipeline in Germany was attributed to AC corrosion. This failure initiated field and laboratory investigations that indicated induced AC-enhanced corrosion can occur on coated steel pipelines, even when protection criteria are met. In addition, the investigations ascertained that above a minimum AC density, typically accepted levels of CP would not control AC-enhanced corrosion. The German AC corrosion investigators' conclusions can be summarized as follows:*
>
> - *AC-induced corrosion does not occur at AC densities less than 20 A/m² (1.9 A/ft²).*
> - *AC corrosion is unpredictable for AC densities between 20 to 100 A/m² (1.9 to 9.3 A/ft²).*
> - *AC corrosion occurs at current densities greater than 100 A/m² (9.3 A/ft²)."*[31]

The AC density for a given location is dependent on soil resistivity, induced voltage, and the size of a coating holiday. Research has indicated that the highest corrosion rates occur at holidays with surface areas of 1 to 3 cm^2 (0.16 to 0.47 in^2).[1] AC current density is best obtained through direct measurement of a correctly sized coupon or probe. However, the theoretical AC current density can be calculated, utilizing the soil

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resistivity and AC potential on a pipeline, in conjunction with Equation 1, presented in the State of the Art Report.[1]

$$I_{AC} = \frac{8V_{AC}}{\rho \pi d} \qquad \text{Equation (1)}$$

Where:

I_{AC}	=	Theoretical AC Current Density (A/m^2)
V_{ac}	=	Pipe AC Voltage to Remote Earth (V)
ρ	=	Soil Resistivity (ohm-m) (*1 ohm-m = 100 ohm-cm*)
d	=	Diameter of a circular holiday having an area equal to that of the actual holiday (m)

Multiple industry references discuss a current density threshold below which AC corrosion is not a significant factor; however, there is still disagreement on the magnitude of this threshold. While the majority of technical literature indicates AC corrosion is possible at current densities between 20 to 30 A/m^2, there is experimental evidence presented by Goidanich, et al[14] indicating that AC current densities as low as 10 A/m^2 can contribute to a measureable increase in corrosion rate[14]. A significant conclusion of study published by Yunovich and Thompson in 2004[9], reiterated in the NACE AC Corrosion State of the Art Report in 2010, indicated that there might not be a theoretical threshold below which AC corrosion is active. The focus should rather be on a practical limit, below which the contribution of AC interference to the overall corrosion rate is low, or rate of corrosion due to AC is not appreciably greater than the free corrosion rate for the particular conditions.[3,9] The results of the experimental study showed that a current density of approximately 20 A/m^2 produced a 90% or greater increase in the corrosion rate versus the control, in the absence of CP.[9] Experimental studies performed by Goidanich, Lazzari, et al in 2010 and 2014, in the presence of CP, concluded that while it was apparent AC current density greater than 30 A/m^2 showed a considerable increase in the corrosion rate, a current density as low as 10 A/m^2 resulted in a corrosion rate nearly double that of the specimens without AC.[14, 18]

For reference, the European Standard EN 15280:2013, "Evaluation of AC corrosion Likelihood of Buried Pipelines Applicable to Cathodically Protected Pipelines" adopted the 30 A/m^2 current density magnitude as a lower threshold, below which the likelihood of AC corrosion likelihood is low. In an effort to address the practical application seen in operation, considering interaction effects of CP current and AC interference, recent research has assessed the likelihood of AC corrosion in terms of the ratio between AC and DC current density (I_{AC}/I_{DC}).

3.3.1.2 Current Density Ratio

Recent research has shown that the likelihood of AC corrosion on pipelines is dependent on both the level of AC interference and the level of cathodic current from either CP or other stray current sources.[3, 15, 18] In general, AC current density values below the previously cited 20 A/m^2 recommended limits were shown to accelerate corrosion rates in the presence of elevated DC current density due to excessive CP overprotection.

The latest revision of EN 15280:2013 was revised to present criteria based upon the AC interference and DC current due to CP. Alternative acceptance criteria are presented in terms of limiting cathodic current density, or limiting the AC to DC current density ratio (I_{AC}/I_{DC}) below a specified level.

Current density obtained by use of coupons or electrical resistance (ER) probes will provide this ratio. However, both AC and DC current density data required to utilize these limits are often not available or easily obtained along the pipeline in practice. Therefore, the current density ratio limits provided within the EN 15280 standard are not widely used or easily applicable criteria. This reference demonstrates the recognized interaction of AC interference and CP systems, presenting an alternative approach that may be valuable for specific scenarios where data is available.

As mentioned previously, the measurement or calculation of AC current density has been the primary indicator to determine the likelihood of AC corrosion across industry in North America. It is possible to measure AC current density on a representative holiday through the installation and use of metallic coupons. A coupon representative of the pipe material, with a defined bare surface area, buried near the pipeline and connected to the pipeline routed through a test station will allow the measurement of current. These current measurements along with the known surface area of the coupon, allow for calculation of a representative current density. In many cases, the coupons are supplemented with additional instrumentation such as ER probes and reference electrodes to provide additional pertinent information. The ER probes provide a time based corrosion rate while the reference electrodes provide both and AC and DC pipe-to-soil potentials.

Section 6 provides further details related to mitigation and monitoring methods for to AC corrosion. Appendix A includes additional details related to literature review, historical AC corrosion rates, and industry case studies.

3.3.2 Faults

During a phase-to-ground fault on a power line, an adjacent or crossing pipeline may be subject to both resistive and inductive interference. Although these faults are normally of short duration (generally less than one second), pipeline damage can occur from high potential breakdown of the coating and conductive arcing across the coating near the fault. Further, the fault current is typically carried by a single conductor, resulting in short term elevated induced voltages that can reach thousands of volts or greater. This presents a significant risk to personnel in contact with the pipeline or electrically continuous appurtenance during a fault.

A phase-to-ground fault, or a lightning strike, on an HVAC power line can result in large potential differences with respect to the adjacent or crossing pipelines. If the potential gradient through the soil is sufficient, a direct arc to a collocated or crossing pipeline is possible, which can result in coating damage, or arc damage to the pipe wall up to the point of burn-through. Even if an arc is not sustained long enough to cause burn through, a short duration elevated current can cause molten pits on the pipe surface that may lead to crack development as the pipe cools. Fault arcing is generally a concern where fault potentials are greater than the dielectric strength of the coating, or at coating holidays within the possible arcing distance. Section 7.3 provides guidance limits for both issues. Where necessary, installation of grounding and shield wires can be used to mitigate the fault hazards as discussed in Section 6.

3.3.2.1 Coating Stress Voltage

During fault conditions, damage to the pipeline or its coating can occur if the voltage between the pipeline and surrounding soil becomes excessive. Fault conditions that produce excess coating stress voltages across the coating are of concern for dielectric coatings. The main factors to consider are the magnitude of the voltage gradient and the dielectric strength of the coating type. It should be noted that there are several

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parameters that are utilized to assess these issues: magnitude of the fault current, distance between the pipeline and fault, soil resistivity, coating age/quality, duration of the fault and coating thickness.

Guidance on allowable coating stress voltage varies across references. NACE SP0177-2014 indicates, "Limiting the coating stress voltage should be a mitigation objective." Multiple references offer varying coating stress limits and are generally considered to be in the range of 1 to 1.2 kV for bitumen, as low as 3 kV for coal tar and asphalt, and 3 to 5 kV for fusion-bonded epoxy (FBE) and polyethylene, for a short-duration fault."[10]

For reference, NACE SP0490-2007 "Holiday Detection of Fusion-Bonded Epoxy External Pipeline Coating of 250 to 760 μm (10 to 30 mil)" uses an equation for calculating test voltages which recommends a 15 mil (14 to 16 mils is a common specification for FBE coatings) fusion bonded coating (FBE) be tested at 2,050 volts.

NACE SP0188 2006 "Discontinuity (Holiday) Testing of New Protective Coatings" also uses an equation for calculating test voltages for coatings in general.

$$TV=1{,}250\sqrt{T} \qquad \text{Equation (2)}$$

Where:

TV = Test Voltage (V)

T = Average coating thickness in mils

This results in a test voltage of 8,840 volts +/- 20% for a pipeline coated with a 50-mil coal tar coating.

The first standard above is the subject of AC mitigation and the following two standards are the recommendations for holiday testing; however, there appear to be inconsistences as to what voltage will actually damage the various pipeline coatings. The inconsistences appear to be due to the unidentified coating thickness in SP0177-2014 and actual duration of the fault resulting in conservative values.

Gummow et al. in their paper "Pipeline AC Mitigation Misconceptions"[19] present data that include the duration and coating thickness in the analysis resulting in values that are more practical. They conclude that FBE coatings with a 16 mil thickness should conservatively use a voltage gradient limit of 5,000 volts and that the 3kv to 5 kV range indicated in NACE SP0177-2014 would be more applicable in the range of 7.5 kV to 12.5 kV.

3.4 HVDC / Underground HVAC

High voltage power interference is primarily a concern for pipelines collocated with HVAC overhead power lines, due to the widespread sharing of common ROW, and the interference effects associated. However, there are associated concerns across industry regarding interference effects of aboveground HVDC transmission and underground AC power lines. Presently, the U.S. transmission grid consists of approximately 200,000 miles of 230 kV or greater high voltage transmission lines, with an estimate that underground transmission lines account for less than 1% of this total.[20] Industry trends indicate that due to significant disparity in overall installation costs, it is expected that while buried transmission lines will continue to be developed and implemented, overhead transmission will remain the primary means for electric transmission for the foreseeable future.[2]

In general, the level of interference from buried HVAC power lines is typically lower as the proximity between the individual phase conductors acts to balance electromagnetic fields, reducing EMI on foreign structures. Depending on the type of construction, sheathing or conduit may offer some level of electromagnetic shielding, further reducing inductive interference effects.

As aboveground HVAC is still the primary concern for pipeline interference, it is the primary focus of this report. However, the effects of both aboveground HVDC and buried transmission cables require review on a case-by-case basis when pipelines are closely collocated. There are currently less than 30 identified high voltage direct current (HVDC) transmission lines operating in the United States[21]. Although there are few relative to overhead HVAC, and the interference effects on a pipeline are different from HVAC transmission lines, they do warrant a brief discussion so that pipeline operators are aware of potential issues. The Canadian Association of Petroleum Producers (CAPP)[22] have produced a technical document that addresses in detail the issues associated with HVDC transmission lines influence on metallic pipelines. Due to the technical differences, the detailed extent of HVDC transmission line interference on steel pipelines necessitates its own study, beyond the scope of this document, however a summary overview of design and interference comparisons follows.

HVDC transmission systems in operation today are typically of monopole or bipole design. In each case, the systems consist of a transmission line between stations with the major components being DC-AC convertors and large ground electrodes. In monopole systems, a single conductor transports the power with an earth return, as depicted in Figure 5. It should be noted that where HVDC systems use a ground return, the interference concerns are similar to typical DC stray current interference, which is addressed in NACE SP0169 and is outside the scope of this document.

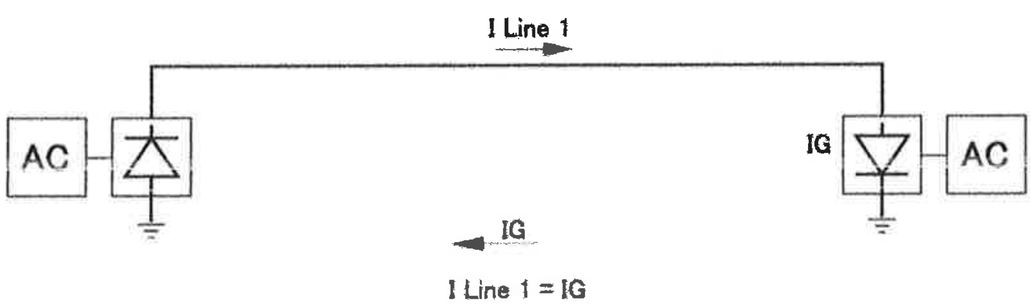

Figure 5. Monopole System (34)

In bipole systems, two conductors between stations allow the system to transport power through both conductors, one conductor and an earth return, or a combination of both, as depicted in Figure 6. The most common use of monopole systems is in submarine applications using the seawater as the earth return. The most common use of bipole systems consist of onshore overhead transmission towers to transport the power.

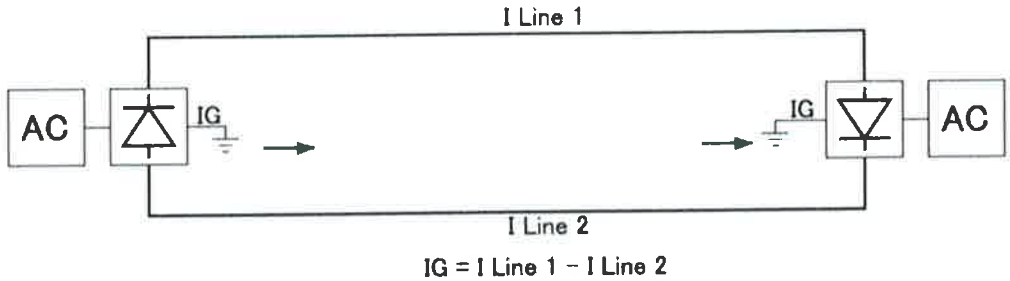

Figure 6. Bipole System (34)

Tripole configurations have been considered and reviewed in research, but have not seen widespread use in practice. There are several types of designs and operation modes within the broad parameters of the monopole and bipole systems. During emergencies and in maintenance of the bipole system, an earth return is used. In an earth return mode there is a potential gradient generated and metallic objects, such as pipelines, can be subject to varying potentials and become a conductor of the return current if they provide a low resistance path. Where current is collected or received by the pipeline generally no damage occurs, unless the current is high enough to damage the coating. However, corrosion will occur at current discharge locations. The amount of corrosion is dependent on the amount of current and duration of discharge. In the case of large discharge current, significant corrosion damage can occur in relatively short time periods. The effects are similar to the interference currents caused by other DC power sources such as traction systems, cathodic protection systems or welding with an improper ground.

HVDC transmission lines also have the same coupling modes with pipelines that occur with HVAC transmission lines capacitive, inductive, and resistive. Although under typical circumstances these effects may be negligible. However, interference levels under faulted conditions can be significant.

3.4.1.1 Capacitive coupling

The results of research presented by Koshcheev indicate the electrical field below HVDC transmission lines does not generally require significant safety measures during construction when the pipe is isolated on skids, as the electric field influence associated with HVDC transmission is limited compared to HVAC.[21]

3.4.1.2 Inductive coupling

CAPP indicates the voltages induced due to HVDC, under steady state conditions tend to be negligible. The magnitude of induction may contribute to minor interference problems with telephone lines, and possibly other communications systems, but is typically low enough that neither pipeline integrity nor safety hazards are considered likely under steady state conditions. However, during fault conditions, there is a possibility for short duration of elevated inductive coupling.

3.4.1.3 Resistive coupling

During faulting both HVAC and HVDC transmission systems can present personnel safety issues and compromise pipeline integrity, with possible damage to the pipeline, coating, and associated equipment. A faulted HVDC power line presents a possible integrity concern for nearby pipelines. CAPP indicates that the fault current discharged to ground at the power line tower causes a ground potential rise (GPR) near the ground electrode. A voltage gradient exists relative to remote earth. A pipeline within the voltage gradient will experience a coating stress voltage as discussed in Section 3.3.2.1. If high enough, the voltage stress could puncture the insulating coating possibly damaging the pipeline.

3.5 Industry Procedure Summary

The lack of industry consensus on the subject of AC corrosion guidelines has led to varied practices among pipeline operators in regards to mitigating AC interference on pipelines. As part of this study, The INGAA Foundation requested a review of industry practices and procedures related to AC interference. Based upon this review, all of the procedures address a safety concern and define a maximum allowable AC pipe-to-soil potential limit for above-grade appurtenances. For pipelines in close proximity to HVAC power lines, faults are identified as a hazard in almost all of the procedures. However, few addressed coating stress limit above which mitigation is required. For current density criteria, several procedures had clearly defined limits, while others addressed it as a concern for AC corrosion but did not specify a targeted limit of AC current density or define limits for mitigation. Table 1 provides a summary comparison of the industry procedures reviewed.

Table 1-Industry Procedure Summary

Induced AC Potential Limit Requiring Mitigation	*Fault Protection/Coating Stress Voltage Limit Requiring Mitigation*	*Current Density Criteria Requiring Mitigation*
In accordance with NACE: 15 V	Not specified	Not Specified
15 V	2500 V	Not Specified
15 V	Mentions damage possible from faults but no limit	Not Specified
15 V or higher - No work unless approved by area supervisor	Not specified	Not Specified
Modeling Required > 2 V	Consider with Modeling	30 A/m^2
15 V	5000 V	75 A/m^2 requires mitigation, 50 A/m^2 requires further evaluation
10-15 V	150-2000 V depending on fault duration	30 A/m^2
15 V	Faults to be considered along with a minimum separation distance, but no limit specified	20 A/m^2
15 V	Faults to be considered during mitigation analysis, but no limit specified	50 A/m^2
15 V	Faults to be considered during mitigation analysis, but no limit specified	50 A/m^2

4 NUMERICAL MODELING

Predicting high voltage interference is a complex problem, with multiple interacting variables affecting the influence and impact. In recent decades, development of advanced calculation methods and computer-based tools for simulation of interference effects, analysis of faults, and development of mitigation methods has been significant.2[3,5,9,10] Computer based numerical modeling can be utilized to examine the collocated pipeline's susceptibility to HVAC interference, help identify locations of possible AC current discharge, and where necessary design appropriate mitigation systems to reduce the effects of AC voltage, fault currents, and AC current density to meet accepted industry standards. These numerical models are capable of analyzing the interacting contribution of multiple variables to the overall magnitude of AC interference.

Computer modeling is used to analyze the interactions and sensitivity of the variables that affect the magnitude of AC induction on pipelines. This section provides a brief review of numerical modeling software in general, as well as the results of the individual variable analyses.

4.1 Modeling Software

Previous research has compared the benefits of specific industry standard software; literature is available for each of the common software packages.[3,9,2023] This review addresses the generalizations concerning the present industry standard software, but does not aim to address or endorse specific software packages.

For the majority of simple collocations considering a single pipeline and single HVAC power line numerous industry-accepted models have shown to be consistent in the assessment of HVAC interference. Often, for these simple cases, the benefit of a more complex model is not gained due to uncertainty in the analysis inputs. That is to say that for a majority of simple collocations, any of several industry accepted models are capable of providing an accurate analysis. The applicability is limited by the accuracy of the input data, and expertise of the analyst in utilizing the specific model. Often the uncertainty in critical input variables, such as the HVAC load current and phasing, outweighs the benefits gained from a more complex model. However, as the collocation complexity increases, both in terms of the number of structures and geometric routing, the limitations of some basic models support the benefits of the more detailed modeling software.

Typical industry standard software packages that were reviewed use a transmission line model (TLM) to calculate longitudinal electrical field (LEF), based on established fundamental Carson or Maxwell equations for electromagnetic fields. The geometry and routing of the complete pipeline and transmission line network incorporated in the model considers multiple pipelines, transmission lines, tower sections, and other collocation parameters. Collocations are simplified as a connected series of finite sections and nodes, with appropriate parameters applied simulating the pipeline, soil, and transmission load-ins. The modeling software can then calculate the LEF for each section and solve the fundamental equations to calculate the potential, current, and theoretical current density along a given collocation.

Calculation of the EMI and corresponding effects on buried pipelines requires a thorough understanding of the variables involved. Detailed modeling requires knowledge of electric field interactions, transmission current, tower design, bulk and local soil resistivity, and pipeline parameters such as geometry, coating, depth, diameter, electrical connections or isolations, and existing CP. All of these variables may significantly affect the AC interference model, and similarly the analogous real world interference. Likewise, the assumptions and simplifications made during the model setup can have significant impact on the accuracy and applicability of the outputs.

While most of the available models are able to analyze each of these variables, either directly or indirectly, the accuracy of the analysis is dependent on the expertise and understanding of the analyst to assess the given variables. Similarly, the accuracy of the models can only be as good as the input data. Multiple sources are required for the collection of data, i.e. measured in field, provided by power line or pipeline operators, or based off published nominal data. For that reason, the accuracy of the results is ultimately dependent on the expertise of analyst and the reliability of the data input to ensure technically appropriate setup, despite the presence of multiple models that have been shown to be capable of providing accurate analysis when used within their applicable limitations.

4.2 Variable Analyses

Due to the number of interacting variables affecting the overall levels of AC interference, it is difficult to isolate the effects of a single variable for all collocations scenarios encountered. Consequently, it is difficult to determine distinct limits for individual variables outside of which interference becomes negligible. Considering several key interacting variables is a more viable approach. For example, reported recommendations cite a distance of 1,000 feet as considered 'far' and assumed low risk for HVAC interference. However, in cases where power line current loads are greater than 1,000 amps and in regions of low soil resistivity, elevated induced AC potentials and corresponding current density exceeding recommended thresholds have resulted at even greater distances. Therefore, separation distance alone may not provide sufficient justification to exclude a collocation from further assessment. Conversely, considering the interacting effect of the key variables identified is necessary when determining the need for detailed analysis for a collocation.

DNV GL developed a series of computer models to illustrate the influence of key variables affecting induced AC on pipelines from nearby HVAC power lines. The software used is a graphical simulation platform developed to predict the steady state interference and resistive fault effects of HVAC power lines on buried pipelines in shared right-of-ways (ROWs). Using a TLM and appropriate input data, the software calculated the LEF, which then calculated the magnitude of induced AC potential, and current along the modeled collocated pipelines.

The models created for these studies are simplistic in terms of geometry and serve as a demonstration of the variables' influence on AC induction on adjacent pipelines. Based upon the number of variables and their interactions with respect to AC interference on pipelines, these studies determine the relevancy of the various parameters. The studies offer guidance demonstrating the trends associated with each parameter on the overall level of interference, and were used along with existing industry guidance and literature findings to develop the recommended guidelines presented in Section 6.

The primary variables analyzed as part of this study are as follows:

- HVAC Power Line Current
- Soil Resistivity
- Separation Distance Between Pipeline and Power Line
- Collocation Length of Pipeline and Transmission Line
- Angle Between Pipeline and Transmission Line
- Coating Resistance
- Pipeline Diameter and Depth of Cover

The results of these studies are presented and summarized in the following sub-sections.

4.2.1 HVAC Power Line Current

A primary variable influencing the magnitude of induced AC potential on a pipeline collocated with HVAC power lines is the magnitude of the phase conductor current. The current load of the nearby power lines has a direct influence on the LEF generated by the HVAC power line circuit(s). The intensity of the LEF varies with the current loads affecting both magnitude of induced AC potential on the nearby pipeline, as well as the area of influence. The area of influence affects the separation distance at which a collocated pipeline experiences significant interference and is further discussed in Section 4.2.3.1.

To demonstrate the sensitivity of power line current on pipeline interference, DNV GL created a computer model simulating a single circuit vertical transmission line, parallel to a 10-inch diameter pipeline for 5,000 feet at a horizontal separation distance of 100 feet. The pipeline approaches the transmission line at a 90-degree angle and parallels the transmission line for 5,000 feet before receding from the transmission line at a 90-degree angle, as depicted in Figure 7. The HVAC load current was varied while all other model inputs remained constant, to analyze the influence of current alone. A uniform soil resistivity of 10,000 ohm-cm was applied and constant throughout the analyses. The transmission line current loads analyzed were 250, 500, 1,000, 2,500, and 5,000 amps based on ranges of operating and emergency loading conditions reported in literature and previously provided from power transmission operator's design conditions. Figure 8 shows the maximum induced AC potential as a function of transmission line current load.

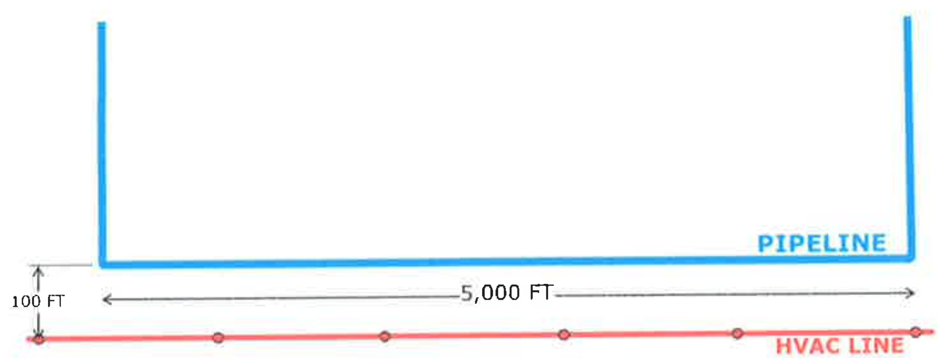

Figure 7. Simplified ROW Model Geometry

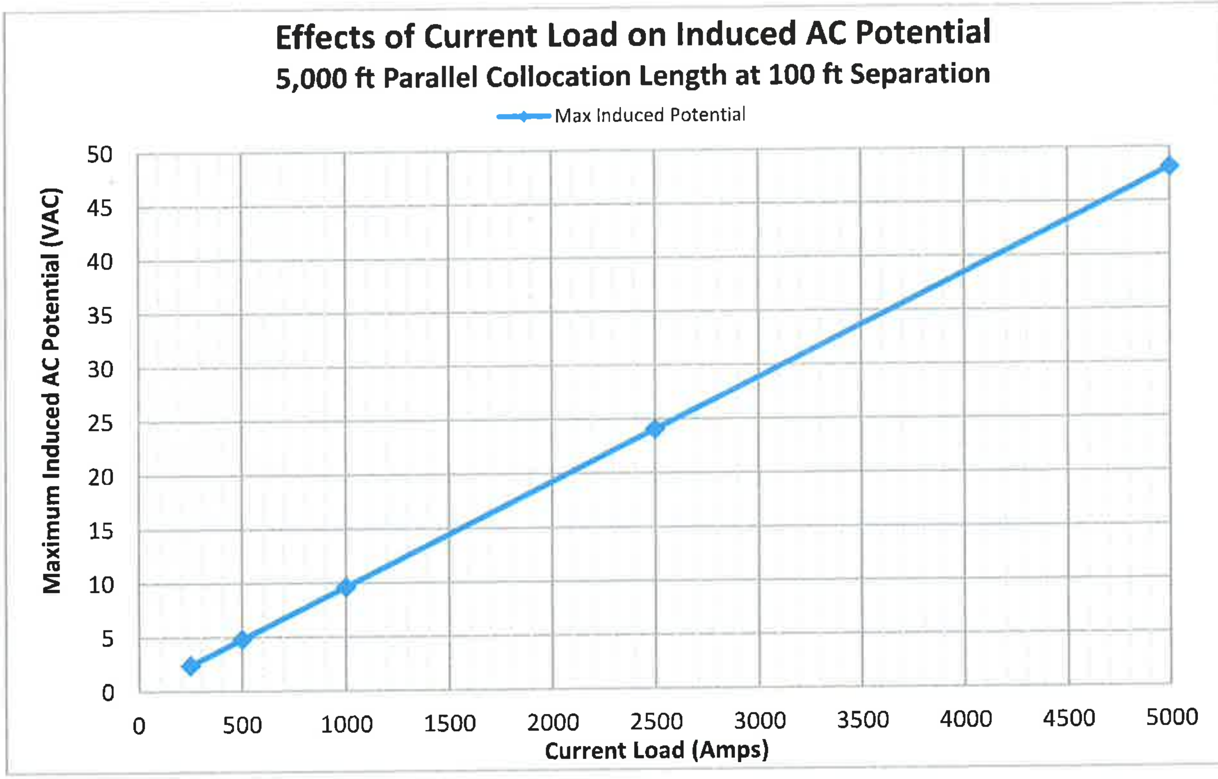

Figure 8. Maximum Induced AC Potential as a Function of HVAC Transmission Line Current

The results of this analysis show that the relationship between transmission line current and maximum induced AC potential on the pipeline is linear for a parallel collocation, considering a single interfering power line. When all other variables remain constant, the HVAC operating current load has a direct linear effect on the magnitude of the induced AC potential. This relationship allows for estimating influence of elevated current loads based on field measured AC pipe-to-soil potentials. For the specific case, with a pipeline collocated with a single HVAC circuit, if sufficient measurements of AC pipe-to-soil potential are taken, and corresponding transmission line current loads are provided for the specific time of measurement, the values can be scaled linearly to estimate the induced AC potential likely at the correspondingly scaled transmission current. This may be applicable, for example, for estimating the effects associated with a power line upgrade with a new current load. However, this method of approximation is only applicable for pipelines collocated with a single transmission line where sufficient data is available. As the number of transmission line circuits increases, the multiple interference sources and interaction the complexity of the interference increases such that the simply linear relationship is no longer valid. As the number of influencing HVAC circuits and pipelines within the area of influence are increased, the complexity of the interaction necessitates analysis that is more detailed.

It is known that while the higher current loads presented represent the high end of typical reported design loads, recent trends in the power transmission industry have shown development and installation of higher capacity HVAC transmission systems capable of carrying significantly greater current loads. For example, previous references indicate a typical load for 345kV to 500kV systems to be approximately 500 to 1,000 amps per circuit.3[24] Recent research indicates increased capacity for 345kV lines carrying up to 5,000 amps per circuit, and over 6,000 amps for 500kV systems.[2,24] While these magnitudes are not considered typical, numerous projects have developed recently that require mitigation for circuits operating at these elevated loads, indicating a need to consider actual current ratings for certain collocations. For this reason, loads are presented in terms of current rather than line voltage rating, as current is the driving load to control the level of EMI. It is noted that line ratings are typically given in terms of voltage ratings such as 138 kV, 345 kV, etc. however, the current load is the more relevant variable when determining the level of HVAC interference. Voltage rating alone can be misleading as the associated loads can be significantly higher or lower than the 'typical' current loads for that kV rating. For this reason, it is recommended to obtain current load data from the power utility company when assessing risk of interference.

4.2.2 Soil Resistivity

The soil resistivity along the collocation affects the magnitude of induced AC potential distribution as well as the theoretical AC current density along a given pipeline. It is necessary to consider both the bulk and specific layer resistivity when assessing likelihood and severity of interference. The bulk resistivity to the pipeline depth is one of the controlling factors in the analysis of induced AC potential. The bulk resistivity is the average soil resistivity measured in a half-hemisphere to the depth of the pipe, as shown in Figure 9 below. However, the specific resistivity of the soil layer directly next to the pipe surface, shown as Layer 2 in Figure 9, is a primary factor affecting the corrosion activity at a coating holiday, considering both conventional galvanic and AC assisted corrosion. The bulk soil resistivity combined with the coating resistance of the pipeline affect the level of induced AC potential expected along the pipeline.

Figure 9. Graphical representation of soil resistivity measurements, showing bulk and layer zones

To demonstrate the sensitivity of soil resistivity on pipeline interference and current density, DNV GL created a computer model simulating a single circuit vertical transmission line, parallel to a 10-inch diameter pipeline with a configuration similar to the model setup described in Section 4.2.1. The soil resistivity was varied along the pipeline while all other model inputs remained constant, to analyze the influence of resistivity alone. The soil resistivity was uniform along the entire modeled collocation, considering 100, 1,000, 10,000, and 100,000 ohm-cm. Figure 10 shows the maximum induced AC potential corresponding to varying current loads.

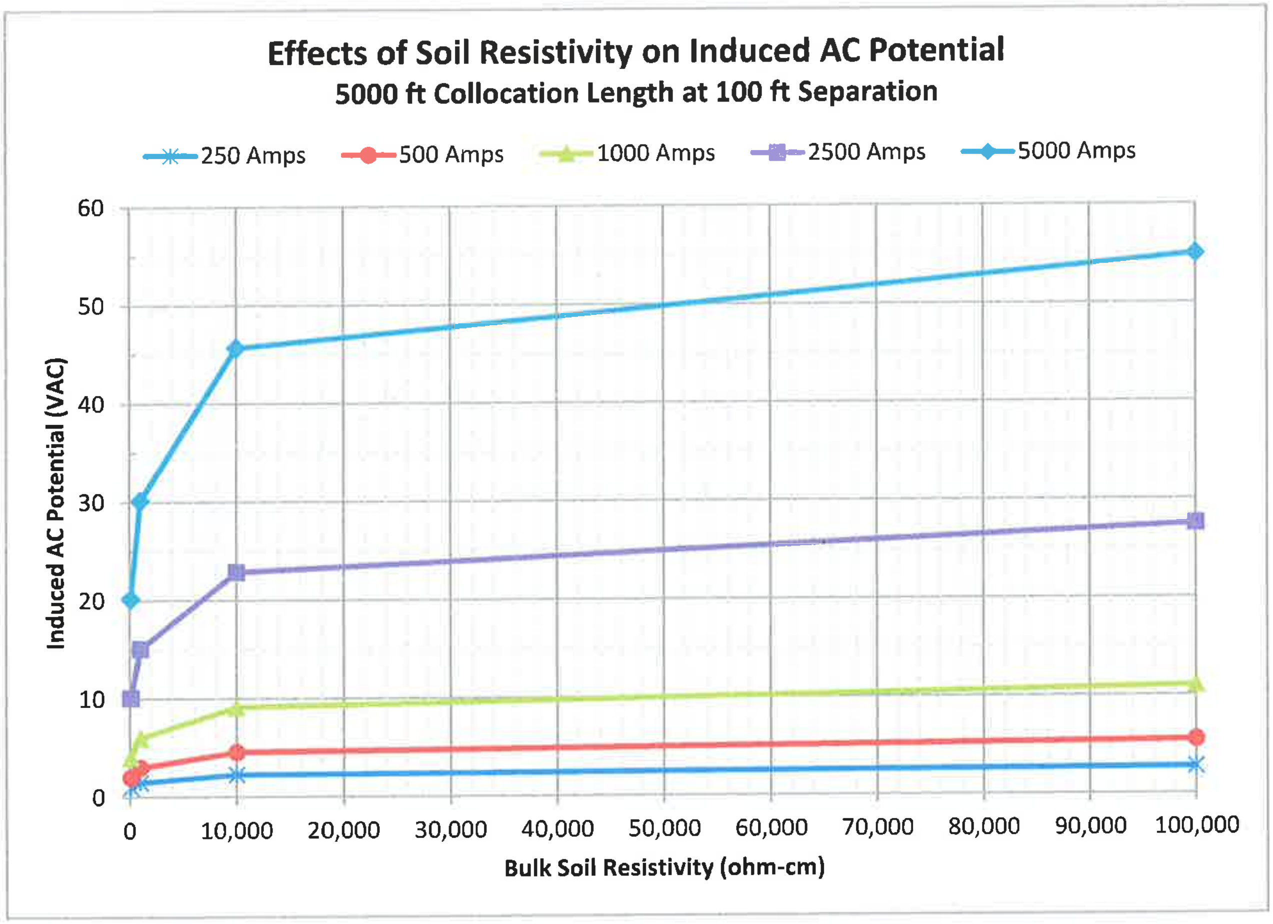

Figure 10. Maximum Induced AC Potential as a Function of Soil Resistivity

The results of the analyses show that the induced AC potential increases logarithmically with increasing soil resistivity. This increase in induced AC potential changes significantly between 100 and 10,000 ohm-cm but approaches asymptotical limit at soil resistivity values greater than 10,000 ohm-cm.

The effects of soil resistivity have greater influence however on the current density. While an increase in soil resistivity can result in a slight increase in the magnitude of induced AC voltage for a given collocation, the theoretical current density and associated risk of AC corrosion decreases linearly with the increased resistivity. The layer resistivity of the soil directly next to the pipe surface is a primary factor in the corrosion activity at a coating holiday. The specific resistivity near the pipe at a holiday is inversely related to theoretical AC current density, as shown by the calculation for theoretical AC current density in Equation 1. Thus, an increase in soil resistivity results in a decrease in theoretical AC current density.

Considering the 250 amp current load case from Figure 10, the theoretical current density was calculated from the induced AC potential for each magnitude of soil resistivity, considering a 1 cm^2 holiday, shown in Figure 11 and Table 2. While the soil resistivity values increase several orders of magnitude across the range, the theoretical current density decreases on similar order, with minimal change in the overall induced AC potential, as shown in Figure 11 and 0 Table 2. The red dashed line represents the lower bound 20 amps/m^2 threshold for current density as discussed in Section 3.3.1.1. It can be seen that based on the calculations provided by Equation 1, a very high theoretical AC current density is possible for relatively low AC potential, if soil resistivity values are below 10,000 ohm-cm. This results in elevated risk for AC corrosion for soil resistivity ranges below 10,000 ohm-cm.

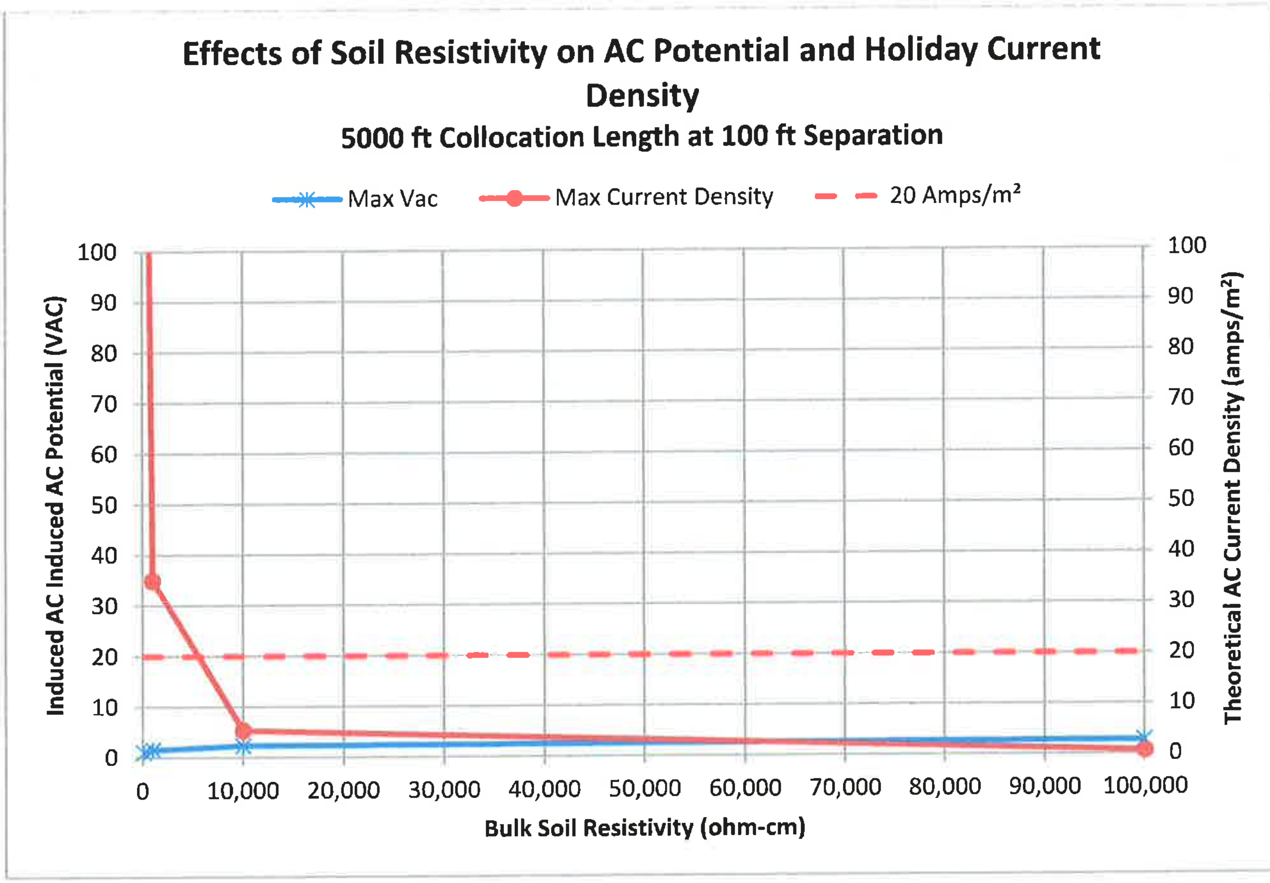

Figure 11. Effects of Soil Resistivity on Induced AC Potential and Corresponding Holiday Current Density. Current density presented for a theoretical 1cm^2 holiday

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Table 2-Calculated current density and induced AC potential

ρ (ohm-cm)	Calculated Current Density (A/m^2)	Induced Potential (V_{ac})
100	234	1.0
1,000	35	1.5
10,000	5	2.3
100,000	0.6	2.8
Based on 5,000ft parallel collocation with a power line operating at 250 A load, 100-ft separation distance		

4.2.3 Collocation Geometry

The geometry of the pipeline relative to the transmission line is critical in determining the magnitude and distribution of induced AC potential along the pipeline. The level of AC interference for a given collocation or crossing, with respect to collocation geometry, is dependent on the relative distance between the phase conductors and pipeline, the locations of convergence or divergence, and angle of approach or crossing. Each of these variables affects the overall level of induction or susceptibility to fault hazards, and their influence is dependent on all other configuration variables. When assessing susceptibility to AC interference all of these variables are considered. However, for the sake of this assessment, the following studies analyzed each independently in order to provide a simplified assessment of the influence of each parameter.

The figures presented in Section 4.2.3.1 to 4.2.3.3 incorporate a dashed line similar to the current density threshold indicator in Figure 11. The limit lines provide reference to the AC potential limit that may result in a theoretical AC current density of 20 amps/m^2 for a hypothetical 1 cm^2 holiday, at soil resistivity of 1,000 and 10,000 ohm-cm. The limit lines are included to provide guidance illustrating the levels that may pose an elevated risk of AC corrosion at potentials below the NACE specified 15 volt limit for personnel safety.

4.2.3.1 Separation Distance Between Pipeline and Power Line

The separation distance between the pipeline and transmission line is a significant variable controlling the level of induced AC potential influencing a given pipeline. The proximity of the pipeline to the phase wires limits the strength of the LEF to which the pipeline is exposed.

To demonstrate the sensitivity of separation distance on pipeline interference, DNV GL created a computer model simulating a single 10-inch pipeline, and single circuit vertical transmission line, with similar configuration as described in Section 4.2.1. The separation distance was varied between the models while all other model inputs remained constant, to analyze the influence of separation alone. Induced AC potential results are plotted for separation distances of 50, 100, 500, 1,000, and 2,500 feet in Figure 12. The results indicate that for the higher load currents, the 20 A/m^2 recommended current density threshold is exceeded for separation distances greater than 500 feet is exceeded.

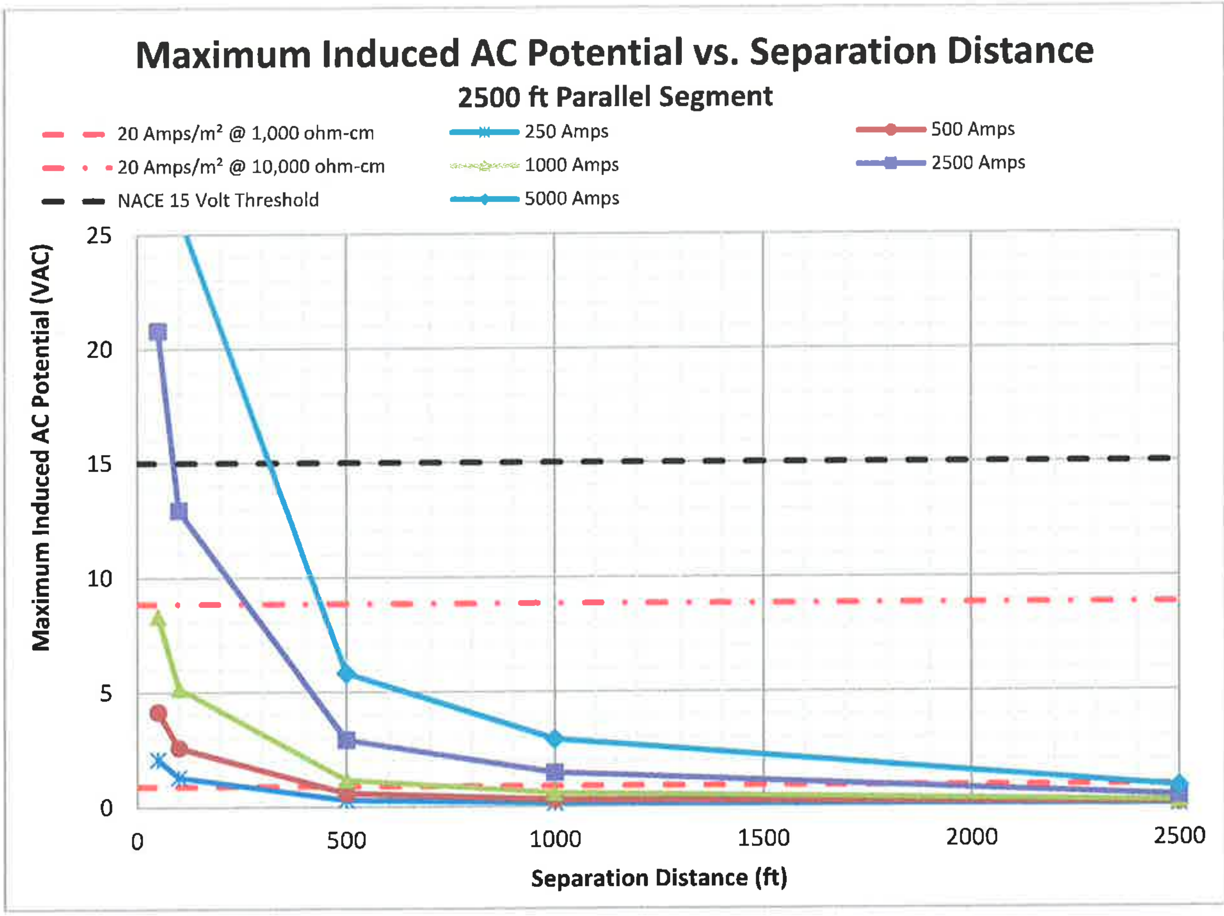

Figure 12. Effects of separation distance on induced AC potential. Current density limits presented for a theoretical 1cm² holiday.

As the distance between the pipeline and transmission line increases, the induction on the pipeline decreases. This is expected as where the distance between the pipeline and phase conductors increase the distance from the LEF origin increases, decreasing the coupling effects. The results of this study as presented in Figure 12 illustrate an important effect of the load current as well. The area of influence or separation distance at which a collocated pipeline experiences significant interference increases accordingly.

The figure also depicts potential levels corresponding to a 20 amp/m² current density for both 1,000 and 10,000 ohm-cm soil resistivity for reference. For the given parameters analyzed, a current load of 250 amps results in an induced potential of approximately 2 volts at a 50 foot separation distance which quickly decreases to less than 0.5 volts at a distance of 500 feet. However, a load of 2,500 amps results in an induced AC potential of approximately 21 volts at a separation distance of 50 feet, and approximately 1.5 volts at a separation distance of 1,000 feet. This is important when determining which pipeline collocations require detailed analysis, as there is variation among industry guidance documents for the limiting distance. A limiting distance of 1,000 feet is common practice, however, for HVAC current loads greater than 1,000 amps, significant interference might be possible at distances exceeding 1,000 feet. While the induced AC potentials magnitudes may appear relatively low in Figure 12, for separation greater than 2,000 feet, it should be noted this example is considering a single HVAC circuit, and only an approximately 0.5 mile collocation length. In practice additional interfering circuits collocated for longer distances would result in higher induced AC potentials. Further, as discussed in Section 4.2.2, it is possible to have an elevated AC current density under relatively low soil resistivity conditions, such that AC corrosion is a concern at relatively low induced potential.

It is necessary to consider separation distance in conjunction with the other factors to exclude a collocation from further analysis for separation distances within 2,500 feet. At a minimum, operating current, or an estimate of it, is also necessary when determining if further analysis is required.

4.2.3.2 Collocation Length of Pipeline and Transmission Line

Just as separation distance affects the magnitude and distribution of induced AC potential along the pipeline, so does the length of collocation. The collocation length is the distance along the ROW that a pipeline parallels or crosses the transmission line within a separation distance and angle that allow for inductive coupling. The collocation length affects the magnitude of induced AC potential that accumulates on the pipeline as it defines the length of the pipeline exposed to the LEF of the phase wires.

To demonstrate the sensitivity of collocation length on pipeline interference, DNV GL created a computer model simulating a single 10-inch pipeline, parallel to a single circuit vertical transmission line at a 50 foot offset. The collocation length was varied between the models while all other model inputs remained constant, to analyze the influence of collocation length alone. Collocation lengths of 500, 1,000, 2,500, 5,000, and 10,000 feet of the pipeline and transmission line compare the maximum induced AC potential in Figure 13.

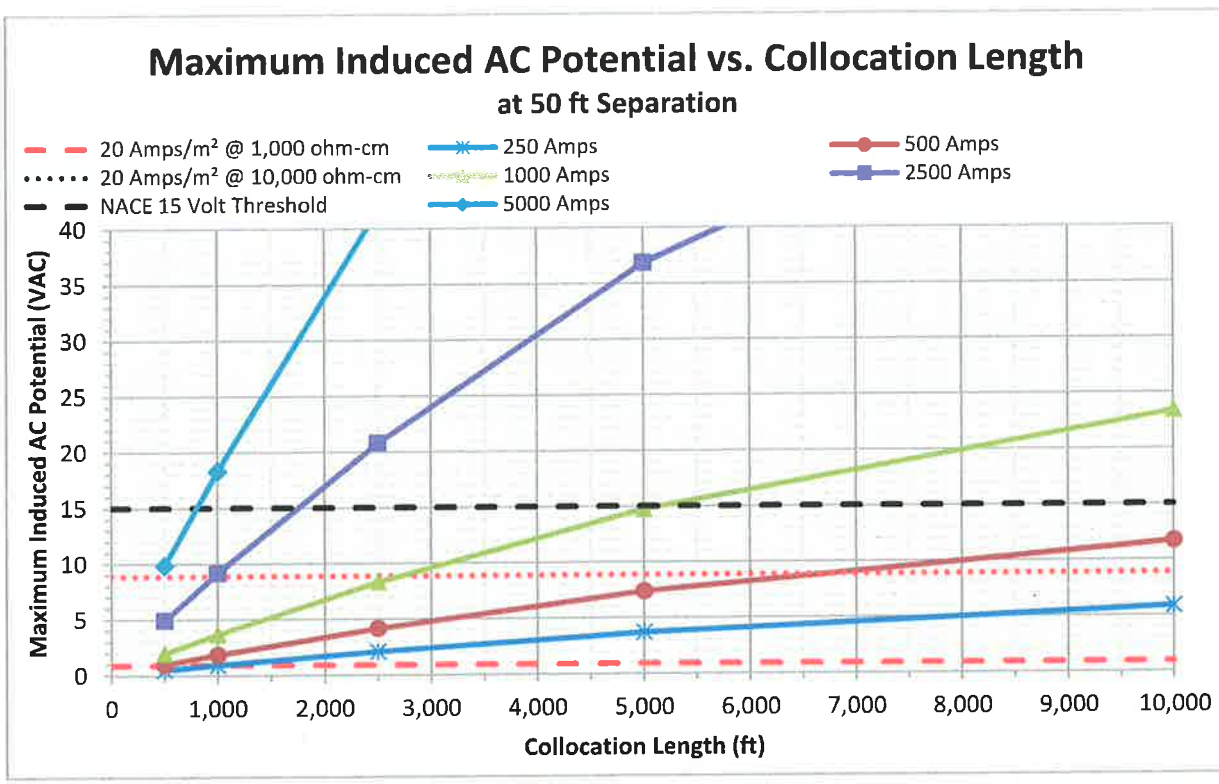

Figure 13. Maximum Induced AC Potential as a Function of Collocation Length

As the collocation length increases, the magnitude of induced AC potential on the pipeline increases, as the length of pipeline exposed to the LEF is increased. Collocation lengths as short as 500 feet are capable of inducing 2 – 10 VAC or greater considering a single collocated power line operating at 1,000 amps or greater.

The potential levels corresponding to a 20 amp/m^2 current density for both 1,000 and 10,000 ohm-cm soil resistivity have been included for reference. Considering a relatively low soil resistivity of 1,000 ohm-cm, the 20 amps/m^2 current density criteria is exceeded at a 2,500 foot collocation length for all load currents analyzed.

The results of the collocation length study also accentuate the sensitivity to HVAC load current as previously discussed in Section 4.2.1. The collocation length required prior to exceeding the 15 volt safety threshold for the 2,500 and 5,000 amp load conditions is approximately 1,750 and 800 feet respectively. These conditions are further increased in complex collocations where multiple lines exist.

It is necessary to consider collocation length in conjunction with the other factors to exclude a collocation from further analysis for separation distances within 2,500 feet. At a minimum, operating current, or an estimate of it, is also necessary when determining if further analysis is necessary.

4.2.3.3 Angle Between Pipeline and Transmission Line

The angle at which the pipeline and HVAC transmission line cross has an effect on the magnitude of induction on the pipeline at the crossing. As the angle increases between the pipeline and transmission line, the magnitude of the induction decreases as the component of the pipeline exposed to induction decreases. For a perpendicular crossing, with the pipeline crossing at or near 90° to the power line, the induction on the pipeline is minimized as the effective parallel length is minimized. The magnitude of the current on the transmission line also has a significant impact on the induced AC potential at crossing locations. Previous 'rule-of-thumb' practices throughout industry may have indicated crossings greater than 60° resulted in negligible induction on adjacent pipelines.[2] However, recent studies have resulted in HVAC installations with significantly greater current capacity, which acts to increase the corresponding interference resulting in cases with induced AC voltage at relatively high angle crossings.

To demonstrate the sensitivity of collocation angle on pipeline interference, DNV GL created a computer model simulating a single 10-inch pipeline, and single circuit vertical transmission line, with similar configuration as described in Section 4.2.1. The pipeline was approximately 2 miles long and the angle between the pipeline and transmission line varied between models while all other model inputs remained constant, in order to analyze the influence of crossing angle alone. Figure 14 shows the results of an analysis of crossing angles between 15 and 90 degrees and the calculated maximum induced AC potential for each case.

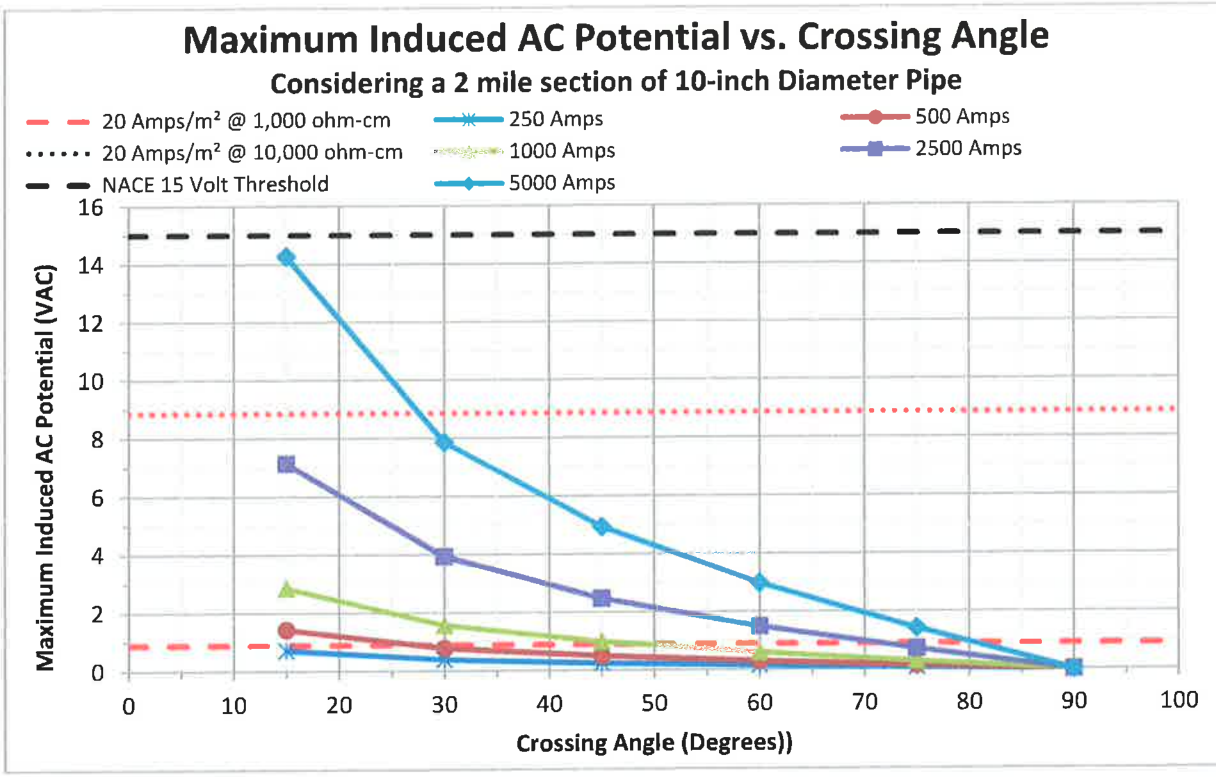

Figure 14. Maximum calculated induced voltage at various HVAC line crossing angles

Considering a typical 345kV circuit, and current loads of up to 1,000 amps, a crossing angle of greater than 45° degrees resulted in an induced potential of less than two (2) VAC for the study presented. A crossing angle of greater than 60° induces minimal potential such that the corresponding current density is less than 20 amps/m^2 even in a relatively low soil resistivity at 1,000 ohm-cm. Previous industry experience and general guidance practices across industry appear consistent with this understanding that crossings of greater than 60° are typically low-severity with respect to induction.

However, as the transmission line load increases to greater than 1,000 amps, it can be shown that crossing angles up to 60° may induce potentials such that corresponding current density exceeds 100 amps/m^2, in low resistivity soil conditions. Depending on target limits for current density, models show that crossing angles of 80° can cause high current density in relatively low soil resistivity locations.

The crossing angles discussed above are with respect to induced AC interference specifically. Assessment for susceptibility to faults, and coating breakdown due to fault voltage, is required for all crossings where pipelines pass in close proximity to a tower ground.

4.2.4 Coating Resistance

The resistance of the pipeline coating to ground is a significant factor controlling the level of induced potential that may build up on a pipeline. However, in practice the coating resistance is typically not known with great certainty and is generally inconsistent along the pipeline length. The coating resistance to ground is a function of the coating type, condition, thickness, and local soil resistivity, all of which may vary along a typical collocation length.

In general, a poorly coated pipeline, or deteriorated coating with low resistance to ground allows multiple paths to ground for AC potential to dissipate. This reduces the buildup of induction, resulting in lower AC potential and lower current density discharge at any individual holiday. Conversely, considering a well coated line with high dielectric strength and excellent coating condition, the resistance to earth along the length of the pipeline is relatively high allowing for greater induction build up over longer distances. For example, this case may exist with a newly FBE coated pipeline, with minimal holidays, in proximity to a collocated HVAC power line. Due to the high resistance to ground, and relatively few ground paths, the induced AC potential can build along the collocation length. This can generate elevated AC potentials, which may be hazardous from a safety standpoint, but also create a possible corrosion risk, as the AC current can discharge from a relatively few holidays after a physical or electromagnetic discontinuity, such as the pipeline diverging from the collocation.

Relative estimates of coating resistance are provided by Dabkoski in the report for Pipeline Research Council International (PRCI) and Parker[24,25], and summarized in Appendix B for reference, to be utilized in detailed modeling analysis based on coating quality, and soil resistivity, however specific guidance is not provided for a relative risk associated with the various coating resistance values.

4.2.5 Pipeline Diameter and Depth of Cover

The diameter of the pipeline collocated with or crossing an HVAC power line affects the level of induced AC potential on the pipeline. However, historical experience has indicated that the effect is relatively minor compared with the influence of other variables.

To demonstrate the sensitivity of pipe diameter on pipeline interference, DNV GL created a computer model simulating a single pipeline, parallel to a single circuit vertical transmission line for 5,000 feet at a horizontal separation distance of 100 feet. The pipeline approaches the transmission line at a 90-degree angle and parallels the transmission line for 5,000 feet before receding from the transmission line at a 90-degree angle. The pipeline model considered diameters of 6, 10, 18, 24, 36, and 48 inches, while all other model inputs remained constant, to analyze the influence of diameter alone. The model used a uniform soil resistivity of 10,000 ohms-cm. The results of this study indicate that the magnitude of induced AC potential decreases with an increase in pipeline diameter, as shown in Figure 15.

As the diameter of the pipeline decreases, the surface area exposed to the LEF also decreases. However, the magnitude of LEF generated by the transmission line remains unchanged. For a smaller diameter pipeline, the LEF influences a smaller surface area resulting in greater induced AC potential compared to a larger diameter line, considering all other variables equal. Further, the pipeline characteristic impedance varies inversely with pipeline diameter, as presented in previous work by PRCI3[24]. Considering all other parameters equal, a larger diameter pipeline will have a generally lower effective resistance to ground, and therefore a lower tendency of HVAC interference. For relative comparison, an increase in diameter from 6 to 48 inches resulted in a 20% decrease in induced AC potential on the pipeline, regardless of the interfering current level.

In the previous analysis, the models used 10-inch diameter pipeline, which will provide a conservative estimate relative to typical larger diameter transmission lines. This was chosen to clearly demonstrate the effects of the individual variables.

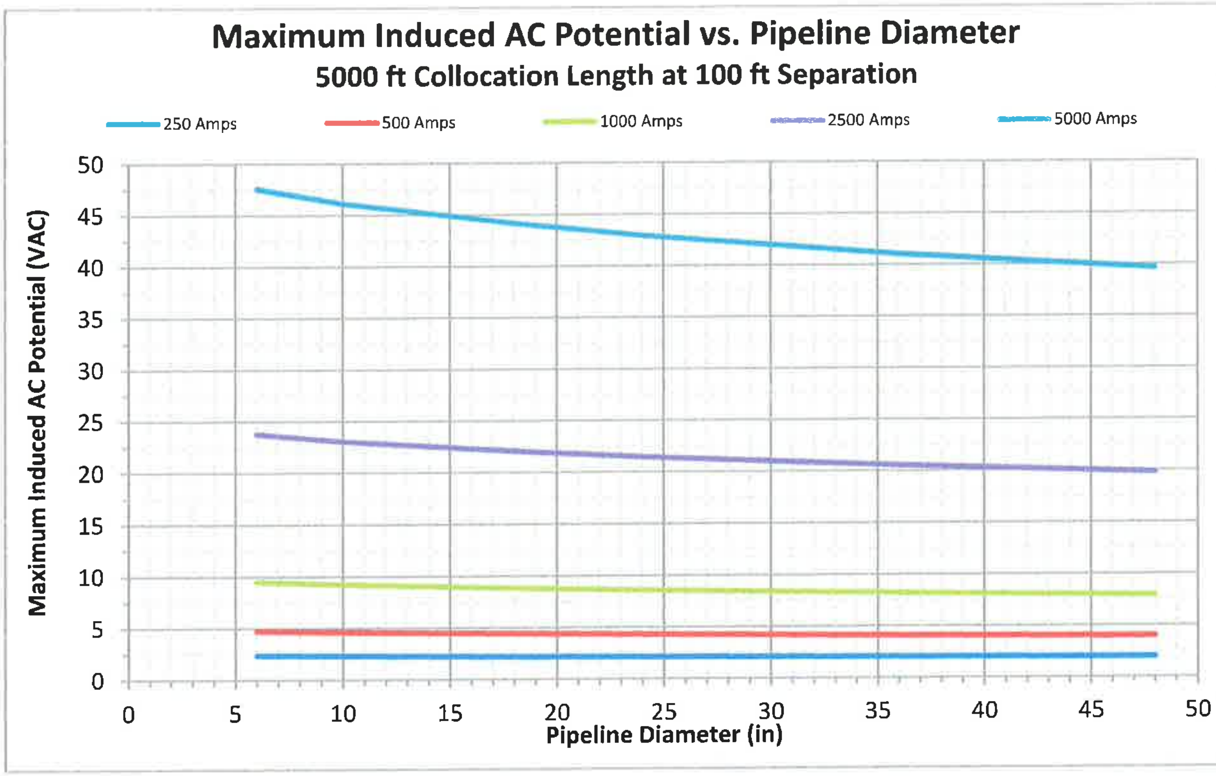

Figure 15. Maximum Induced AC Potential as a Function of Pipeline Diameter

Similar to pipeline diameter, the pipeline depth of cover has a relatively minor influence on the induced AC potential on the pipeline. In general, the level of AC interference decreases with increasing depth of cover as the distance from the individual phase conductors and total resistance to the LEF is increased, though the effect is relatively minor for typical burial depths. A fixed depth of cover of approximately 5 feet was used in the sensitivity studies above.

5 MITIGATION

NACE International Standard Practice SP0177-2014 requires a mitigation system designed for pipelines where HVAC interference is present.[10] Mitigation system design varies across the industry, but in general all involve a low resistance grounding system to pass interfering AC to ground. Typical mitigation system designs can be either surface or deep grounding designs. Both designs have benefits and detriments considering performance, cost, and constructability.

Liquid and gas transmission pipelines are regulated under the Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) Regulations §49 CFR Part 195 Subpart H Corrosion Control (195.551 – 195.589)[26] and §49 CFR Part 192 Subpart I Requirements for Corrosion Control (192.451 – 192.491)[27], respectively. The regulations have various requirements for corrosion control of which CP and electrical isolation are major factors in compliance. CP systems apply a DC to the pipeline, and electrical isolation quantifies the surface area or limits of the system. CP systems designed for transmission pipelines must meet federally regulated criteria.

5.1.1 DC Decouplers

When designing mitigation systems for induced AC and faults on transmission pipelines, detrimental effects to the CP system must be considered. It is essential to ensure they do not compromise the operation of the CP systems. Additional structures such as grounding and shield wires used in mitigating induced AC attached directly to the pipeline change the operating characteristics of the CP system, changing the surface area intended for the CP compromising its effectiveness. Direct current decouplers (DCD) alleviate this situation. However, there are some cases where the design of CP accounts for the mitigation. The decouplers, designed into the circuit, allow AC current to pass to ground, while blocking the DC CP current, maintaining the pipeline surface area. There are various types, sizes and ratings of decouplers used depending on the predicted faults or induced AC and mitigation design. DCDs are also used to block DC current at grounded above grade appurtenances, such as block valves, metering stations, and launcher/receiver stations.

Decouplers installed across electrical isolation flanges (IF) prevent "burn over" which can occur when an AC fault current or lightening surge is large enough in magnitude to arc over the gap between flange faces or exceeds the rating of the IF.

5.2 Surface Grounding

Surface grounding generally refers to one of several types of mitigation grounding installed at or near the surface or pipe depth. Typical designs may consist of bare copper cable, zinc ribbon, or engineered systems buried generally parallel to the pipe path and connected to the pipeline through a DCD. During new construction, surface grounding can be installed directly in the pipe trench, or laid parallel to the pipe in an adjacent trench or bore. This approach allows for cost-effective installation of a significant length of mitigation at a lower cost relative to alternative forms of mitigation, but is dependent on construction access along the ROW.[16]

If necessary, connecting additional mitigation ribbon in parallel and even adding shallow vertical anodes to the circuit will further reduce grounding resistance up to a certain extent. Installing this type of mitigation system at distributed, targeted locations, optimized from the interference model, reduces the induction along the pipeline. Additionally, when laid parallel to the pipeline in regions where transmission line towers are in close proximity, the mitigation ribbon also acts to protect and shield the pipeline from damage resulting from fault and arcing scenarios.

Analysis of the reduction in ground resistance possible with various installation approaches included a calculation of the resistance of 1,000 foot long mitigation ribbon in varying soil resistivity, using the modified Dwight's Equation for multiple anodes installed horizontally[28]. Figure 16 illustrates how this calculated grounding resistance varies with the number of ribbons connected in parallel at multiple levels of soil resistivity. While numerous sizes of ribbon cables exist, the length is a much more significant factor in determining total resistance than diameter, when considering typical ribbon diameters, therefore this analysis considers a constant diameter ribbon.

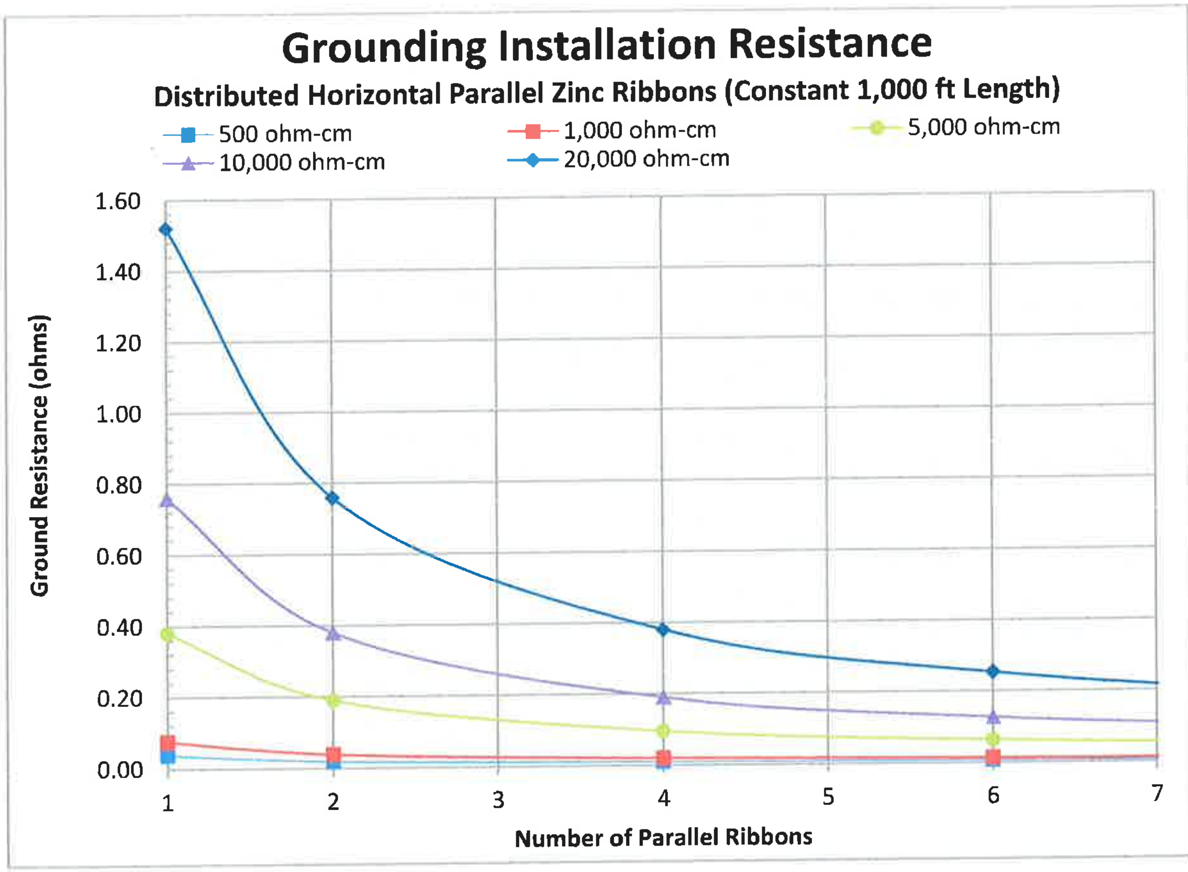

Figure 16. **Grounding Resistance of Horizontal Parallel Zinc Ribbons at Varying Soil Resistivities**

As shown in Figure 17, at low soil resistivities, very low grounding resistance results with a single, relatively short ribbon length. As the soil resistivity increases, so does the achievable grounding resistance. The data is presented considering multiple parallel mitigation ribbons to demonstrate that further reduction in ground resistance is possible by adding additional grounding at a particular installation. However, diminishing returns exist such that further increasing the extent of grounding at a specific site, beyond a certain threshold, results in minimal additional reduction, as shown in Figure 16.

The length of vertical grounding installations requires review of economics, construction, and practical design considerations. Multiple shorter grounding rods can be incorporated to achieve a low resistance to ground without requiring deep drilling, where parallel surface grounding does not sufficiently reduce the ground resistance. Vertical ground rods should be separated horizontally by the length of the ground rods at minimum for optimum efficiency.[23]

For locations of high surface resistivity, one drawback for horizontal surface grounding is the length of mitigation ribbon wire required to achieve a low resistance. Where multiple parallel ribbons are required to achieve sufficient grounding resistance significant ROW access may be required. As discussed, the shared utility ROW may limit construction access for mitigation parallel to a collocated pipeline. Additionally, as pipelines cross physical obstructions, such as roadways, railroads, access may limit the extent of parallel mitigation systems. However, surface grounding still continues to be the preferred mitigation technique and can efficiently provide adequate mitigation grounding for a majority of collocations.

5.3 Deep Grounding

Deep drilled ground wells (deep wells) offer another form of mitigation grounding, and may be considered for select applications. Deep wells generally consist of one or more anodes drilled vertically into the ground in order to achieve low ground resistance. Actual deep well depths can vary based on needs, but they generally range greater than 100 feet in depth.

In general, construction costs are generally higher for deep well grounding than for comparable surface mitigation. However, deep well grounding can be a viable option in specific applications where one or both of the following criteria are satisfied.

1. The soil resistivity at the surface is significantly greater than (>20 x) the soil resistivity at lower depths.
2. Horizontal surface grounding is not feasible due to construction obstacles (roads, railways, right-of-way access, etc.)

For typical mitigation systems, where parallel ribbon and deep grounding are both options, parallel ribbon proves to be more efficient and economical because it can achieve a lower resistance to ground for lower overall cost. For comparison, ground resistance calculations were analyzed to determine the approximate equivalency in effective ground resistance between parallel zinc ribbon, and an individual deep well anode.

Figure 17 below shows a comparison of parallel horizontal grounding configurations compared to a single 6-inch diameter deep well anode approximately 200 feet deep. The soil resistivity ratio, plotted on the x-axis, is the ratio between the bulk soil resistivity to a depth of 10 feet for surface ribbon and the bulk soil resistivity to a 200 foot depth for a deep well. Along the y-axis is the equivalent length of horizontal surface grounding required to meet the same level of grounding resistance as the deep well anode. The two curves in the figure below display this trend for single and double surface ribbon installations.

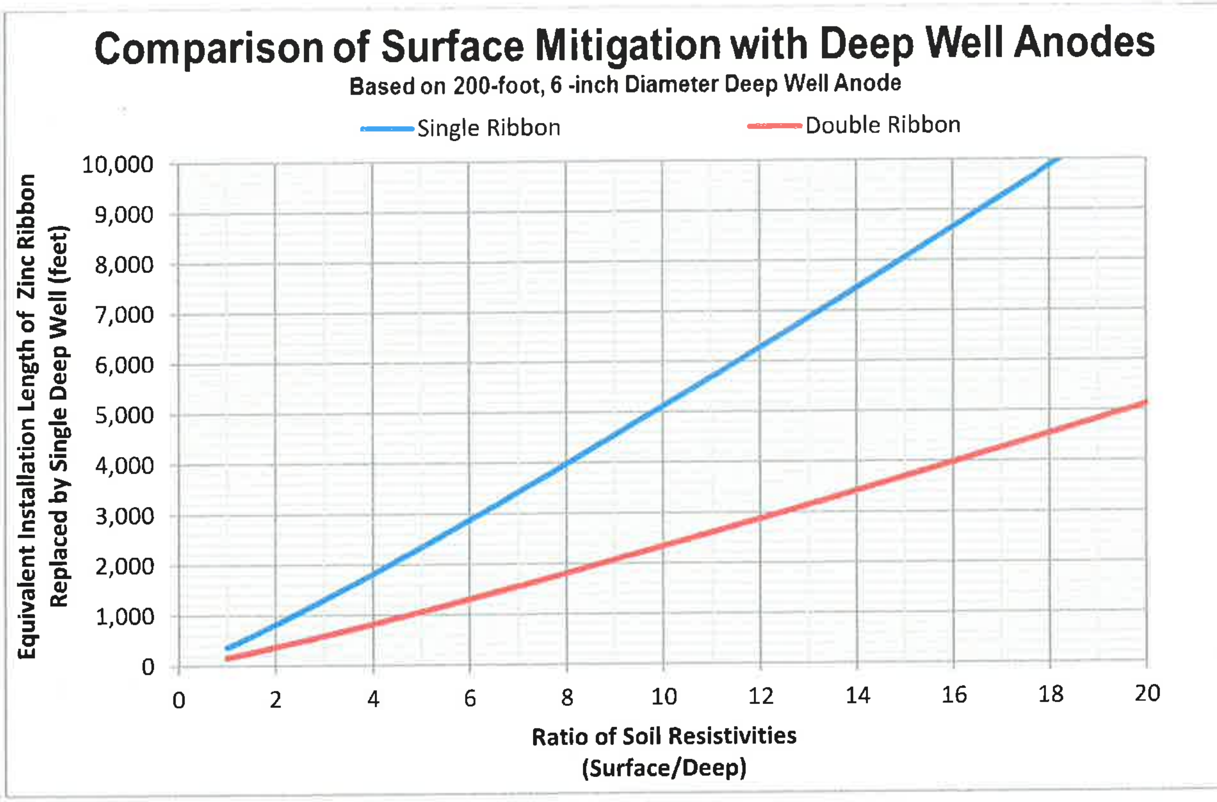

Figure 17. **Comparison of Surface Mitigation to Deep Well Anodes**

Considering a typical scenario where deep soil resistivity values are of similar order to the surface resistivity, a single deep well grounding installation would be necessary for approximately every 1,000 to 2,000 feet of individual parallel ribbon. However, considering a hypothetical location where the deep soil resistivity is an order of magnitude lower than at the surface (soil ratio of 10), it can be shown that a single deep well installation could provide a similar ground resistance as approximately 5,000 feet of individual parallel ribbon. Under certain scenarios, where the ratio between the surface and deep soil resistivity is high, deep well anodes may become a viable solution to obtain a low grounding resistance. Previous case studies and project experience have rarely shown soil resistivity ratios of this magnitude, such that deep well grounding was a preferred option. However, where construction access is limited, not allowing for installing longer lengths of surface grounding to achieve the required mitigation deep well grounding may be beneficial. In scenarios where grounding is only necessary at a single specific location on the pipeline, deep well grounding may be an option.

5.4 Mitigation Comparison

Deep well anodes may provide a viable mitigation option under specific circumstances, but industry practice, historical assessments, and construction practice have generally shown that surface mitigation provides more economical and efficient mitigation for the majority of collocations. In cases where arc shielding protection is required to guard against fault scenarios, deep well anodes do not provide such protection, thus necessitating the installation of surface ribbon in addition to primary mitigation. Surface mitigation can also serve as fault shielding, protecting against damage to the pipeline and its coating when properly placed between the pipeline and power transmission ground.

A primary benefit for surface mitigation is ease of installation and a lower associated cost. Mitigation installed in the same trench beside the pipe during pipeline construction further reduces installation costs. Typical industry construction estimates indicate that the cost of a single drilled deep well anode installation may be ten times the cost of a 1,000-foot surface installation, if installed during pipe construction. This would indicate that each deep well anode would need to replace approximately 10,000 feet of surface mitigation before it is economically viable from a ground resistance standpoint alone. That said, the decision between surface and deep grounding installation methods most often comes down to a number of other considerations, including construction access, grounding distribution, and contractor preference in addition to cost alone. [Appendix C contains a simplified summary, presents the pros and cons for various mitigation materials and methods for reference.] The comparison information provides guidance and demonstrates the comparative benefits of each approach based on various soil resistivity layers.

5.5 Additional Mitigation Methodologies

The AC mitigation techniques discussed utilize low-resistance grounding to transmit induced AC voltage to ground. While grounding can be an effective mitigation technique for many interference cases, recent industry experience has identified collocations where induced potentials or current density reduction to adequate levels cannot be achieved by grounding alone. This is generally due to a combination of elevated transmission currents and unfavorable soil resistivity conditions. Trends in the power transmission industry have led to increased power capacity and corresponding operating currents, for some long distance transmission systems as shown. This increase in operating current has a direct effect on the level of EMI. In many cases, this has presented a significant challenge for achieving adequate mitigation on pipelines crossing or collocated with the power transmission lines. In these cases, additional mitigation techniques should be considered.

In terms of risk reduction or prevention, the approach to AC interference mitigation can be categorized on a primary, secondary, or tertiary level. Primary prevention targets controlling or reducing the source of the risk, through elimination or control. Secondary prevention targets reducing exposure to a risk factor, and tertiary prevention targets treating the response or consequences of the risk factor, generally after exposure to the risk. By these terms, a standard practice of mitigating AC induction by grounding alone is considered a tertiary form of mitigation. That is to say, the treatment targets only the consequence of the interference by reducing the detrimental AC effects at the pipeline level, after allowing the pipeline to be exposed to the interference risks. While not currently in widespread application, further research of primary and secondary risk controls should be considered in future development, to reduce overall interference and risks associated with AC interference, especially considering cases that cannot be effectively mitigated by traditional means. While the concepts presented may not be readily employed by pipeline operators without further research, they are presented to address the need for continued research and development of more robust high voltage interference mitigation methodologies, and pursue improved collaboration between the power line and pipeline operators.

5.5.1 Primary Threat Control of AC Interference

Although mitigation grounding is a common industry practice, cases exist where grounding alone is insufficient to reduce interference levels on collocated pipelines. For such cases, additional techniques should be considered. From an engineering risk basis, with respect to overall risk reduction, a preferred approach is to reduce the source of interference. Specifically, this means reducing the interference prior to it reaching the pipeline, generally through design controls during the development phase prior to construction, where modifications to the pipeline or transmission line are possible. The level of interference experienced at the pipeline is dependent on the magnitude of EMI generated at the source, and the collocation parameters that limit the EMI levels reaching the pipeline. Specifically, revising collocation routing, and tower and circuit configuration modifications can reduce or optimize the level of EMI produced. Conductor arrangements can be designed to balance individual phases producing the lowest levels of EMI for a given circuit configuration.

For a given circuit configuration (single circuit horizontal/vertical, double circuit horizontal/vertical/delta, etc.) there exists an ideal phase sequence which minimizes the LEF at the pipeline location and thus results in lower magnitudes of AC interference. Dabkowski studied the magnitudes of the LEF for varying circuit types and phase sequence. The results demonstrated that for a single horizontal circuit a reduction of up to 9 percent of the LEF may be achieved, by choosing the proper phase sequence.[24] With the single circuit vertical case, the LEF at the pipeline location could be reduced by as much as 15% with the proper phase sequence.

The double circuit vertical tower configuration presents a unique scenario for phase sequencing. There are 36 possible phase sequences, classified into five sets of phase combinations: center point symmetric, full roll, partial roll upper, partial roll lower, and center line symmetric. The LEF magnitude between the various phasing configurations can vary significantly.[29] Generally, the ideal phase sequence for a double vertical circuit is the center point symmetric phase configuration, which generates an LEF approximately 65% to 90% less than the center line symmetric phase configuration.[29] This is significant when considering this is simply the result of the physical interaction between conductors, and primary mitigation reduction at the source reduces the interference levels that ever reach the collocated pipeline. Additionally, optimization of the phase configuration does not require unconventional installation methods to obtain this reduction in LEF magnitude.[29] It is recognized that for existing installations, pipeline operators generally may not be able to influence HVAC power design; however, for new construction and power system expansions where interference is a concern, communication between pipeline operators and transmission owners of possible effects is recommended in order to review possible interference hazards prior to construction. Where possible, pipeline and HVAC power line design controls can limit EMI and interference on adjacent pipelines.

The addition of phase transpositions along a given collocation can also act to reduce the overall EMI influencing a collocated pipeline. However, phase transpositions should only considered as part of a detailed analysis, as the discontinuity presented by a phase transposition can create a localized point of elevated interference, and may have further impact on the power transmission design.[24] However, where appropriate, phase transpositions can create discontinuities and effectively break up long line interference built up on long collocations. Further, in areas where construction access may be limited, phase transpositions can be located strategically to reduce interference at the source.

5.5.2 Secondary Threat Control of AC Interference

With respect to overall threat reduction, a secondary control works by means of isolating a threat from a structure. In the case of AC interference, this specifically means intercepting and grounding the EMI prior to reaching the pipeline.

One proposed example is overhead shielding, which is used to mitigate AC interference in other industries including rail transport systems, but is notably less common in mitigating AC interference on pipelines. An overhead shielding technique works by placing a conductor, grounded at regular intervals, within a targeted region between the pipeline and the adjacent transmission line. This shielding conductor, located in the same LEF generated by the conductor circuit, induces a current and an accompanying LEF 180 degrees out of phase with the field generated by the transmission line. In so doing the conductor acts to cancel part of the LEF generated by the transmission line, resulting in lower levels of induction on the pipeline. Dabkowski studied the effectiveness of this technique for the same tower configurations discussed in Section 5.5.1.[29] The results indicated a substantial reduction in the induced potential on the pipeline was possible; however, the mitigating effectiveness was highly sensitive to loading conditions, and the precise location of the shielding conductor. For the single circuit horizontal circuit, an auxiliary overhead ground wire resulted in a reduction of approximately 25% in the LEF, and thus the corresponding induction on the pipeline. The ideal placement of this overhead auxiliary shield wire was approximately the same height as the phase wires, which for single circuit horizontal circuits may make this solution impractical. For the single circuit vertical tower configuration, Dabkowski found a maximum LEF reduction of approximately 60% to 75% by mounting the overhead shield wire at an optimum height on the tower centerline. Reductions in the LEF generated by the double circuit vertical configuration were found to be range from 50%-95%. However, when examining slight imbalances of +/-5 to 15% between phase wires, the benefits realized by this auxiliary shield wire quickly diminished to 20% or less when compared to uniform current across all phase wires of the circuit.29[23] While this is generally not a common practice in mitigation of pipeline interference, overhead shielding has been considered and studied in the past, and is used within other industries. Specific overhead shielding installations require detailed design, and precise locating but this approach may present an alternative means of mitigation where ineffective through more traditional means. Further research and testing is required on a case-specific basis to determine if this is a viable technique.

Fault and arc shielding, which are used to reduce the risk of damage to the pipeline and the coating near tower grounds during fault conditions are another form of secondary risk control. Fault protection typically takes the form of a parallel shield wire, similar to mitigation ribbon discussed in Section 5.2. However, the primary function of fault and arc shielding protection acts to intercept transmission line fault current and transfer to ground prior to reaching the pipeline. For this reason, the location and placement of the arc shielding mitigation is far more critical when protecting against conductive (fault) interference than for inductive interference.

5.5.3 Tertiary Threat Control of AC Interference

With respect to overall risk reduction, tertiary controls rely on reducing the consequences of the threat after exposure to the structure. Per this definition, typical grounding mitigation can be considered a tertiary control. Mitigation grounding works by transmitting the AC potential to ground, only after it has already reached the pipeline. While grounding has proven to be an effective means of mitigation for many historical installations, and installation is generally within the capabilities and access of the pipeline operators, scenarios occur where grounding alone is not sufficient to reduce interference to acceptable levels.

Ideally, a combination of primary, secondary, and tertiary mitigation techniques would provide the highest level of threat reduction and protection for the pipeline. However, addressing a threat at the lowest level possible will provide reduction in severity, increasing the likelihood that mitigation will be effective. That is to say, reducing AC interference at its source or shielding EMI from reaching an adjacent pipeline can provide greater risk reduction than simply allowing the interference to pass to the structure and dissipating to ground via tertiary mitigation methods. In practice however, it may not always be possible or practical to address interference at a primary or even secondary level. Tertiary mitigation through low resistance grounding techniques may provide adequate risk reduction for a majority of interference collocations. However, further research and continued development into additional mitigation techniques would benefit the industry.

5.6 MONITORING

As mentioned previously, the measurement or calculation of AC current density has been the primary indicator to determine the likelihood of AC corrosion across industry in North America. It is possible to measure AC current density on a representative holiday through the installation and use of metallic coupons or ER probes. A test wire connected to the coupon, routed to the surface and connected to the pipeline through a test station is an example of a simple installation. By inserting an ammeter into the circuit, an AC and DC current can be measured which when can be used to calculate the current density at that location. In many cases, test stations with coupons also include additional instrumentation such as ER probes and reference electrodes. The ER probes provide a time based corrosion rate while the reference electrodes provide both and AC and DC pipe-to-soil potentials for comparison.

Using coupon test stations (CTS), and ER probes, real-time monitoring can provide a better understanding of the interference effects acting on a collocated pipeline. However, as previously discussed, the magnitude of interference depends on the magnitude of current loads on the associated power lines. Correlation of the CTS and ER probe data with power line loads provides a thorough understanding of the system performance. While it has historically been difficult to obtain this information from power line operators, there is a recognized need to have good understanding of the operating power line loads to determine relevance of coupon test station or ER probe data. Additionally, best practices dictate obtaining data over a representative period (days or weeks as relevant) in order to assess the interference response during high load conditions. A measurement for AC potential or AC current density at a single point in time with unknown operating current loads may not be representative of the actual risk for interference on the pipeline.

6 GUIDELINES FOR INTERFERENCE ANALYSIS

The following steps are provided as best practice procedures for determining where detailed analysis is recommended based on the results of this study, industry standards, historical technical publications, and previous industry experience.

Pipeline operators are faced with many existing and new construction pipelines collocated and crossing power line ROW. Little guidance exists to assist in selecting and prioritizing collocations for detailed analysis and modeling. Under certain conditions, it may be possible to justify the low likelihood of AC interference, and exclude specific locations from further detailed modeling with detailed monitoring, or justification that the risk due to interference is low.

It is recommended to collect the following information, where possible, to determine if a detailed AC analysis is required. Appendix D is a sample of data to collect from the powerline company. Use the corresponding severity limits in Sections 6.1.1 through 6.1.5 to assist with this methodology:

- Peak and Emergency load rating (amps) for collocated power lines
- Line rating (kV) for collocated power lines
- Soil resistivity along the collocation at multiple depths
- Collocation and / or crossing routing geometry for the pipeline and power line
- AC pipe-to-soil (P/S) measurements (for existing pipelines)
- AC Current density using coupons or probes where previously installed
- Maximum fault potential and fault clearing time

Detailed "analysis" in the context of this document refers either to data collection using detailed monitoring or to specific application of numerical calculation of interference magnitudes. This analysis is done using detailed computer modeling or similar application of interference calculation methods.

6.1 Severity Ranking Guidelines

This section provides general guidance with respect to the relative severity ranking for the identified variables with respect to their impact on the severity of AC interference.

6.1.1 Separation Distance

Separation distance and load current are key factors in determining whether a collocation will experience significant AC interference. Generally, the separation distance is readily available or easily determined, so it is often a primary screening variable. However, it has been shown that significant interference is possible for distances greater than 1,000 feet when considering collocations with load capacity greater than 1,000 amps.[7] It is therefore recommended to consider collocations within 2,500 feet, and the decision for further analysis should also incorporate estimate of the power line current.

Severity ranking for separation distance is provided in Table 3.The following generalized rankings have been determined through review of industry data, parametric studies, and historical experience.

Table 3-Severity Ranking of Separation Distance

Separation Distance - D (Feet)	Severity Ranking of HVAC Interference
$D < 100$	High
$100 < D < 500$	Medium
$500 < D < 1{,}000$	Low
$1{,}000 < D \leq 2{,}500$	Very Low

6.1.2 HVAC Power Line Current

The magnitude of transmission line currents is one of the most influential parameters determining the likelihood and severity of AC interference. However, there is often debate as to which load rating to consider for interference analysis and mitigation design. HVAC power lines generally have multiple ratings that specify the operating loads allowable during normal operation and peak or emergency load ratings allowable during short duration scenarios. Ultimately, the load rating considered should be a risk-based decision made by the pipeline operator, considering the frequency of occurrence for the load level, typical duration throughout operation, and the consequence associated.

From a personnel safety standpoint, it is recommended to consider the maximum load that a power line can carry for any duration. The terminology for this varies among transmission operators, but it is commonly referred to as "Emergency Load", defined as the maximum load a transmission circuit is capable of carrying for a short duration such as during an emergency or maintenance condition. Considering personnel safety, elevated step or touch potential could pose an instantaneous threat as a shocking hazard, regardless of duration of the elevated power line current. As the pipeline operator is generally unaware of an emergency load condition on the power line, it may not be feasible to reduce or prevent exposure during even a short-duration elevated current load. It is therefore generally best practice to consider the maximum capacity or emergency loading conditions when assessing the risk of personnel safety threats such as shocking, unless other provisions can be made to prevent exposure.

However, AC corrosion is a time-dependent threat. The magnitude of AC current density possible on a pipeline under AC interference will be sensitive to the current load on the adjacent HVAC conductor. While emergency loads, or other spikes in power line current may cause an elevated current density, the associated corrosion damage may be low as the duration is limited.

The power line current is often the most controlling parameter influencing the magnitude of AC interference. For this reason, we recommend obtaining the power line load limits from the relevant power transmission operator when assessing the risk of AC interference on a given pipeline. These limits should include the various operating ratings (generally 'Normal', 'Peak', and 'Emergency'), the allowable duration for each, and expected frequency of occurrence.

Transmission operating parameters are not always readily available to pipeline operators, and this information may be difficult to obtain. However, the power line current is a primary factor, and the relevance and accuracy of an AC analysis may vary greatly with the accuracy of the operating current. Where actual load data is unavailable, published reference currents for various HVAC power line ratings are available in literature[24]. However, these guidelines are for reference only, and may provide over or under conservative results. In practice, there are cases where the operating currents provided for a specific power line significantly exceeded these estimates. Additionally, as discussed in Section 4.2.1, increase load capacity on new and upgraded systems may result in load ratings above the provided reference levels.

Severity rankings associated with HVAC load current for a collocated power line is provided in Table 4.

The following generalized rankings have been determined through review of published technical literature, industry data, parametric studies, and historical experience.

Section 5.2.1 contains further background and detailed information for effects of power line phase current.

Table 4-Relative Ranking of HVAC Phase Current

HVAC Current - I (amps)	Relative Severity of HVAC Interference
$I \geq 1{,}000$	Very High
$500 < I > 1{,}000$	High
$250 < I < 500$	Med-High
$100 < I < 250$	Medium
$I < 100$	Low

6.1.3 Soil Resistivity

Soil resistivity affects both the magnitude of induced AC and the susceptibility to AC corrosion. The AC corrosion process, as presented in Section 3.3.1 is a function of the AC current density at a coating holiday, which in turn is dependent on the level of AC voltage on the pipeline and the local spread resistance. The bulk soil resistivity is a primary factor controlling overall level of induction, while the local soil resistivity near a holiday is a primary factor in the corrosion activity, as discussed in Section 4.2.2. The following generalized severity rankings have been determined based on industry experience and guidance provided in EN 15280:2013, with respect to AC corrosion.[15]

Table 5-Relative Ranking of Soil Resistivity

Soil Resistivity - ρ (ohm-cm)	Relative Severity of HVAC Corrosion
$\rho < 2,500$	Very High
$2,500 < \rho < 10,000$	High
$10,000 < \rho < 30,000$	Medium
$\rho > 30,000$	Low

6.1.4 Collocation Length

The collocation length of the pipeline and transmission line affects the magnitude of induced AC potential accumulating on the pipeline as it defines the length of the pipeline exposed to the LEF of the phase wires. The following generalized rankings have been determined through parametric studies, and historical experience.

Table 6-Relative Ranking of Collocation Length

Collocation Length: L (feet)	Relative Severity
$L > 5,000$	High
$1,000 < L < 5,000$	Medium
$L < 1,000$	Low

6.1.5 Collocation / Crossing Angle

The angle of collocation or crossing of the pipeline and power line limits the influence of induction. The following generalized rankings have been determined through parametric studies, and historical experience.

Table 7-Relative Ranking of Crossing Angle

Collocation/Crossing Angle - θ (°)	Relative Severity
$\theta < 30$	High
$30 < \theta < 60$	Med
$\theta > 60$	Low

6.2 Recommendations for Detailed Analysis

The guidance parameters presented are based on industry literature and standards where available. Where guidance has not previously been provided, qualitative classifications have been provided to aid in severity ranking and prioritization. The qualitative guidance parameters have been determined based on published industry guidance, numerical modeling parametric studies, previous analytical experience, laboratory studies, and failure investigations for AC corrosion related damage. The intention is not to replace or remove detailed analysis from the design decisions, but rather to aid in severity ranking and prioritization when determining where additional detailed analysis and mitigation design is required.

The guidelines within should be used by the operators as part of an overall risk-based decision. The details within this report and this section can only provide guidance regarding the severity of HVAC interference or AC corrosion. When determining whether to perform further detailed analysis, add location specific monitoring, or where no further action is required, possible consequences must be a part of the decision process and reviewed on a case-specific basis.

As discussed in Section 4.2, collocations with power lines operating at greater than 1,000 amps are subject to interference under conditions where likelihood would otherwise be low. Special consideration required for collocations where the power line loads are greater than or equal to 1,000 amps. For this reason, an understanding of the power line load current is necessary for evaluating the need for further analysis. The two cases below provide an assessment of collocations and crossings encountered, based on:

Case 1 – Current Load greater than or equal to 1,000 amps, pipeline crossing or collocated within 2,500 feet

Case 2 – Current Load less than 1,000 amps, pipeline crossing or collocated within 1,000 feet

6.2.1 Case 1

For scenarios where power line current is known or can be estimated to operate at or above 1,000 amps, and a steel pipeline is crossing or collocated within 2,500 feet of the power line, a detailed analysis is recommended when one or more of the following conditions are met:

- Collocation Length severity is characterized as "High"
- Soil resistivity severity is characterized as "High" or worse
- Three or more of the variables identified in Section 6.1 are categorized as "Medium" or worse

6.2.2 Case 2

For scenarios where power line current is known or estimated to operate below 1,000 amps, and a steel pipeline is crossing or collocated within 1,000 feet of the power line, a detailed analysis is recommended when one or more of the following conditions are met:

- Phase current severity is characterized as "High" or worse
- Collocation length severity is characterized as "High"
- Soil resistivity severity is characterized as "High" or worse
- Three or more of the variables of severity rankings identified in Section 6.1 are categorized as "Medium" or worse

High angle crossings, with crossing angles of greater than 60°, while considered low-risk for inductive interference, are susceptible to fault or lightning arcing, as well as coating breakdown due to fault voltage. Crossings with an angle greater than 60° may still be susceptible to inductive interference if subject to very high current load, or multiple HVAC power lines.

6.2.3 Faults

As fault conditions are generally infrequent and of short duration, it is not practical to obtain measurements of AC potential during a fault condition. Analysis of fault voltages generally requires numerical modeling. Fault current levels or estimates of possible magnitudes, are generally obtained by HVAC power line operators and can vary significantly depending on tower design, power capacity, and location relative to substation and generation source.

Whenever a pipeline crosses or is collocated in close proximity within 500 feet an HVAC tower, it is susceptible to faults. Detailed calculations or modeling is required to determine the possibility of fault arcing and possible coating damage due to GPR.

6.2.4 Fault Arcing Distance

When a pipeline crosses or is collocated in close proximity to an HVAC tower ground, a theoretical fault arcing radius can be calculated. The fault arcing radius is the distance from a HVAC tower ground that a sustained lighting or fault arc may reach an adjacent metallic structure. The arcing radius is primarily a function of the fault or lightning current and the local soil resistivity magnitude, and is estimated using equations 2 and 3 based on Sunde's equations for lightning arc distance.[30] The equations presented were developed to predict a safe separation distance considering an elevated current due to lightning strike, and can be utilized to provide an estimate of possible fault arcing distance from a faulted high voltage tower ground as well.

$$r_a = 0.08\sqrt{I_{ac}x\frac{\rho}{100}} \qquad \text{If } \rho \leq 100{,}000\ \Omega\cdot\text{cm} \qquad (2)$$

$$r_a = 0.047\sqrt{I_{ac}x\frac{\rho}{100}} \qquad \text{if } \rho > 100{,}000\ \Omega\cdot\text{cm} \qquad (3)$$

Where: r_a= arc distance in m

ρ= soil resistivity in Ω·cm

I_{ac} = the fault current in kA

6.3 Data and Documentation Requirements

Where the Severity Rankings Guidelines criteria indicated a more detailed analysis is necessary, collect the following information where possible, to facilitate development of an AC interference model. Appendix D contains a sample data log provided for reference:

Pipeline Parameters:

- Routing geometry
- Depth of cover
- Diameter
- Coating details
- Coating resistance
- Existing CP installations
- Location of bonds
- Soil resistivity at multiple depths and locations along the ROW
- Location of insulating joints

Power line Parameters:

- Routing geometry
- Number of circuits
- Conductor configuration (dimensions, orientation, phasing)
- Conductor loading (Peak and Emergency current)

- Tower ground resistance
- Maximum fault voltage
- Fault clearing time
- Shield wire configuration

6.4 General Recommendations

As the operating current is a controlling parameter influencing AC interference, it is recommended to obtain the power line load current from the relevant electrical utility operator when assessing a collocation for the threat of AC interference. Historically, lack of collaboration between pipeline and power line operators has led to projects being assessed without accurate understanding of the power line data. This can lead to either an overly conservative and costly design or an under-designed system not adequately reducing the interference. Collaboration between the respective pipeline and power line operators is critical to accurate assessment and efficient mitigation of any possible interference effects.

In addition to the assessment described in previous sections, the following general recommendations apply for collocations and crossings where AC interference is a concern:

- Install coupon test stations or ER probes to monitor AC Current density, a coupon surface area of 1.0 cm^2 is recommended.
- During pipeline construction near HVAC transmission lines, confirm that the contractor safety program complies with the recommended 15 VAC limit for shock hazards, and applicable OSHA construction standards as referenced in Section 3.2.2.
- Record AC pipe-to-soil potentials along with the DC pipe-to-soil potentials during the annual cathodic protection survey on sections where AC interference threats may exist. This can provide information, should the power transmission company change its operating parameters, or unexpected changes occur between the pipeline and transmission line.
- Request power line loads corresponding to the time of AC pipe-to-soil potential measurement to provide thorough understanding of the interference measurements
- Measure soil resistivity at locations where AC interference threats may exist. This data can be used with the measured AC potentials to estimate theoretical AC current density for specific locations in the absence of coupons or ER probes.
- Operating personnel should be trained in the hazards and safe practices associated with working on pipelines subject to HVAC interference
- Suspend work (when possible) along the collocated or crossing section of pipeline during weather conditions that may lead to a transmission line fault.

Safety precautions are required when making electrical measurements:

- Only knowledgeable and qualified personnel trained in electrical safety precautions install, adjust, repair, remove, or test impressed current cathodic protection and AC mitigation equipment.
- Properly insulated test lead clips and terminals should be used to prevent direct contact with the high voltage source.
- Attach test clips one at a time using a single-hand technique for each connection when possible.

- Extended test leads require caution near overhead HVAC power lines, which can induce hazardous voltages onto the test leads, or present a source of data error.

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Where published, historically identified corrosion defects and pipeline failures associated with AC corrosion degradation were reviewed and are presented to demonstrate the magnitudes and variability in corrosion rates possible with AC accelerated corrosion. The general findings, discussion, technical details, and results are utilized and summarized throughout this document.

This lack of industry consensus on the subject of AC corrosion guidelines has led to varied practices among pipeline operators in regards to mitigating AC interference on pipelines. As part of this study, The INGAA Foundation requested a review of industry practices and procedures related to AC interference. The INGAA Foundation provided DNV GL with the procedures related to AC interference or mitigation for 10 pipeline operators who are members of the Foundation. The primary finding from this review is that there is significant variation in company procedures with respect to AC interference. Based upon this review, all of the procedures provided address a safety concern and define a maximum allowable AC pipe-to-soil potential limit for above grade appurtenances. Faults were included as a concern/risk for pipelines in close proximity to HVAC power lines in almost all of the procedures. However, few addressed coating stress limit above which mitigation is required. For current density criteria, several procedures had clearly defined limits, while others addressed it as a concern for AC corrosion but did not specify a targeted limit of AC current density or define limits for mitigation.

Case Studies

Numerous studies, both laboratory and field based, have been performed that attempt to determine magnitudes of corrosion rates associated with AC interference. However, reviewing available technical literature confirms a wide range of experimental rates, and a scarcity of controlled field measured rates.

Where published, historically identified corrosion defects and pipeline failures associated with AC corrosion degradation have been reviewed and are presented to demonstrate the magnitudes and variability in corrosion rates possible with AC accelerated corrosion.

Field investigations reported by Ragault[31] considering a coated cathodically protected pipeline, identified corrosion rates between 12 and 54 mpy (0.3 and 1.4 mm/yr), for AC current densities ranging between 84 and 1,100 A/m^2.

Wakelin, Gummow, et al[32] provided three case studies where field inspections identified defects as AC corrosion-related degradation. Based on inspection intervals and corrosion degradation, corrosion rates were identified ranging from 17 to 54 mpy (0.4 to 1.4 mm/yr) for AC current densities between 75 and 200 A/m^2.

A German field coupon study, published by Prinz, and Shoneich,[7] indicated general AC corrosion rates between 2 to 4 mpy (0.015 to 0.1 mm/yr) for a current density of 100 A/m^2, and 12 mpy (0.3 mm/yr) at 400 A/m^2. However, pitting rates were considerably greater and showed a wider range between 8 and 56 mpy (0.2 to 1.4 mm/yr), with considerably less dependence on AC density.[6]

A doctoral thesis study by Goidanich presents similar findings concluding that AC current density as low as 10 A/m^2 may be considered hazardous as the experimental studies showed it nearly doubled the free corrosion rate of the experimental samples in simulated soil tests.[33]

A 1998 report by Wakelin, Gummow, et al published by NACE reviewed several case studies dating back to the 1960's where AC corrosion was identified or suspected to be the primary mechanism of degradation. The report summarized recorded details on multiple case studies with specific focus on comparison of corrosion rates and AC current density where known. In 1991, a failure investigated on a 12-inch diameter pipeline concluded AC accelerated corrosion after only four (4) years of service. Induced AC potentials measured as high as 28 volts. Based on the nominal wall thickness and time to leak, an average pitting rate for the through wall pit was estimated to be greater than 55 mpy. Two other case studies indicated the average AC induced corrosion rates for the identified sites between 11 and 24 mpy.

A 2004 paper by Hanson and Smart, published by NACE, presents a case study for a gas pipeline installed in the summer of 2000.[8] The pipeline was collocated in a shared ROW with a 230 kV transmission line for approximately 9 miles, and then entered a shared power corridor with six power transmission lines, two of which were rated at 500 kV, all within sufficient proximity of the pipeline to cause interference. A leak occurred within 5 months of installation, before the line was in operation. Several other leaks were identified shortly after, with four leaks within close proximity. Induced AC potential measurements found AC voltages as high as 90 volts on the pipeline. The failure assessment indicated the corrosion was due to induced AC corrosion, and estimated rates in excess of 400 mpy.

The majority of literature reviewed indicates AC corrosion rates in the range of 5 to 60 mpy.[3, 9, 10] However, cases have been identified with localized corrosion rates significantly greater, in excess of 400 mpy. There is general agreement that higher AC current density leads to greater risk of AC corrosion. While higher current density may lead to accelerated corrosion rates, the correlation is not simple or direct.

International Standards

Review and comparison of multiple international standards identified the consistencies and variations across accepted industry standards.

Recent laboratory and field work has focused on the interaction between AC and DC current density in determining overall risk of AC corrosion, and the latest European standards reflect this as discussed in Section 3.3.1.1.[15] However, there is no generally accepted method of correlating current density or any other measurable indicator to an expected corrosion rate. A direct method of approximating the AC corrosion rate using a buried coupon or probe would provide accurate information.

The Canadian Standards Association (CSA), NACE International (NACE), and the European Committee for Standardization (CEN) have developed published standards addressing HVAC interference issues, as below:

- CAN/CSA-C22.3 No. 6-13 "Principles and Practices of Electrical Coordination Between Pipelines and Electric Supply Lines
- NACE SP0177-2014 "Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems
- CEN EN 50443:2012 "Effects of Electromagnetic Interference on Pipelines Caused by High Voltage AC Electric Traction Systems and/or High Voltage AC Power Supply Systems"
- CEN EN 15280:2013 "Evaluation of AC Corrosion likelihood of buried pipelines applicable to cathodically protected pipelines"

Of these standards, the first three primarily discuss safety issues, interference effects, and mitigation systems but do not explicitly address criteria for AC corrosion control. The European Standard EN15280:2013 deals specifically with corrosion due to AC interference, and establishing criteria or tolerable limits for interference effects, as presented in Section 3.3.1.1.

NACE Standard Practice SP0177-2014, *Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems*, addresses problems caused primarily by the proximity of metallic structures to AC power transmission systems. In this standard practice document, SP0177-2014 defines a steady state touch voltage of 15 volts or more with respect to local earth at above-grade or exposed sections and appurtenances to constitute a shock hazard. Findings presented in the standard indicate the average hand-to-hand or hand-to-foot resistance for adult male ranges from 600 ohms to 10,000 ohms. NACE uses "a reasonable safe value" of 1,500 ohms (hand-to-hand or hand-to-foot) for estimating body currents. Based upon work by C.F. Dalziel regarding muscular contraction, SP0177-2014 indicates the inability to release contact occurs between 6 mA and 20 mA for adult males.[10] Ten milliamps (hand-to-hand or hand-to-foot) is recognized as the maximum safe let-go current. This 15-volt safety threshold is therefore determined based upon 1,500 ohms hand-to-hand or hand-to-foot resistance and an absolute maximum let-go current of 10 mA. However, under certain circumstances, an even lower value is required. One such circumstance specifically identified where a lower touch potential safety threshold should be considered is "areas (such as urban residential zones or school zones) in which a high probability exists that children (who are more sensitive to shock hazard than are adults) can come in contact with a structure under the influence of induced AC voltage."[10] This standard practice document requires remedial measures to reduce the touch potential on the pipeline where shock hazards exist.

During construction of metallic structures in regions of AC interference, SP0177-2014 requires minimum protective requirements of the following:

- "On long metallic structures paralleling AC power systems, temporary electrical grounds shall be used at intervals not greater than 300 m (1,000 feet), with the first ground installed at the beginning of the section. Under certain conditions, a ground may be required on individual structure joints or sections before handling."
- "All temporary grounding connections shall be left in place until immediately prior to backfilling. Sufficient temporary grounds shall be maintained on each portion of the structure until adequate permanent grounding connections have been made."

The intent of the temporary grounds is to reduce AC potentials on the structure, and thus the shock hazard to personnel during construction. SP0177-2014 advises against direct connections to the electrical utility's grounding system during construction as this could actually increase the probability of a shock hazard to personnel.

Regarding AC corrosion, there are no established criteria for AC corrosion control provided in SP0177-2014. Further, this standard states that the subject of AC corrosion is "not quite fully understood, nor is there an industry consensus on this subject. There are reported incidents of AC corrosion on buried pipelines under specific conditions, and there are also many case histories of pipelines operating under the influence of induced AC for many years without any reports of AC corrosion."

While not a Standard Practice document, NACE published "AC Corrosion State-of-the-Art: Corrosion Rate, Mechanism, and Mitigation Requirements"[1] in 2010, providing guidance for evaluating AC current density, and providing recommended limits as discussed in Section 3.3.1.1.

The State-of-the-Art report also cites European Standard CEN/TS 15280:2006[15], which previously offered the following guidelines related to the likelihood of AC corrosion:

> *"The pipeline is considered protected from AC corrosion if the root mean square (RMS) AC density is lower than 30 A/m^2 (2.8 A/ft^2).*

In practice, the evaluation of AC corrosion likelihood is done on a broader basis:

- *Current density lower than 30 A/m^2 (2.8 A/ft^2): no or low likelihood;*
- *Current density between 30 and 100 A/m^2 (2.8 and 9.3 A/ft^2): medium likelihood; and*
- *Current density higher than 100 A/m^2 (9.3 A/ft^2): very high likelihood"*

EN 15280:2013

The latest revision of EN 15280:2013 was revised to present criteria based upon the AC interference and DC current due to CP. EN 15280:2013 presents using the cathodic protection system of the pipeline to ensure the levels of induced AC potential do not cause AC corrosion under the following conditions:

1. AC voltage on the pipeline should be decreased to a target value, which should be less than 15 V (measured over a representative time period, i.e. 24 hr)
2. Effective AC corrosion mitigation can be achieved while maintaining cathodic protection criteria as defined in EN 12954:2001
3. One of the following conditions is satisfied in addition to items 1 and 2:
   - Maintain AC current density (RMS) over a representative period of time (i.e. 24 hr) less than 30 A/m^2 (2.8 A/ft^2) on a 1cm^2 coupon or probe
   - If AC current density is greater than 30 A/m^2 (2.8 A/ft^2), maintain the average cathodic (DC) current density over a representative period of time (i.e. 24 hr) less than 1 A/m^2 on a 1cm^2 coupon or probe
   - Maintain a ratio between AC current density and DC current density (J_{AC}/J_{DC}) less than 5 over a representative period of time (i.e. 24 hr)

The NACE State-of-the-Art report also references experimental studies by Yunovich and Thompson that concluded

> *"AC density discharge on the order of 20 A/m^2 (1.9 A/ft^2) can produce significantly enhanced corrosion (higher rates of penetration and general attack without applied CP). Further, the authors stated that there likely was not a theoretical 'safe' AC density (i.e., a threshold below which AC does not enhance corrosion); however, a practical one for which the increase in corrosion because AC is not appreciably greater than the free-corrosion rate for a particular soil condition may exist."*[1]

APPENDIX B COATING RESISTANCE ESTIMATES

Pipe Coating Conductance/Resistance

Pipe Line Corrosion and Cathodic Protection, Marshall E. Parker & Edward G. Peattie

No.	Coating Quality	Soil Resistivity	Conductance Range		Resistance Range					
			µmhos/ft2		ohm-m²		ohm-ft²		Kohm-ft²	
1	Excellent	High	1	10	92,903	9,290	1,000,000	100,000	1,000	100
2	Good	High	10	50	9,290	1,858	100,000	20,000	100	20
3	Excellent	Low	50	100	1,858	929	20,000	10,000	20	10
4	Good	Low	100	250	929	372	10,000	4,000	10	4
5	Average	Low	250	500	372	186	4,000	2,000	4	2
6	Poor	Low	500	1,000	186	93	2,000	1,000	2	1

PRCI

No.	Coating Quality	Soil Resistivity (ohm-m)	Coating Resistance (Kohm-ft2)		
1	Excellent	25	Multiply Soil Resistivity (ohm-m) by 5	5	125
	Excellent	50	Multiply Soil Resistivity (ohm-m) by 5	5	250
	Excellent	200	Multiply Soil Resistivity (ohm-m) by 5	5	1,000
	Excellent	600	Multiply Soil Resistivity (ohm-m) by 5	5	3,000
2	Good	25	Multiply Soil Resistivity (ohm-m) by 2	2	50
	Good	50	Multiply Soil Resistivity (ohm-m) by 2	2	100
	Good	200	Multiply Soil Resistivity (ohm-m) by 2	2	400
	Good	600	Multiply Soil Resistivity (ohm-m) by 2	2	1,200
3	Fair	25	Multiply Soil Resistivity (ohm-m) by 0.5	0.5	13
	Fair	50	Multiply Soil Resistivity (ohm-m) by 0.5	0.5	25
	Fair	200	Multiply Soil Resistivity (ohm-m) by 0.5	0.5	100
	Fair	600	Multiply Soil Resistivity (ohm-m) by 0.5	0.5	300

APPENDIX C MITIGATION COMPARISON SUMMARY

Zinc Ribbon

Advantages
- Can typically be installed during pipeline construction minimizing installation costs
- Cost of raw material is typically one third the cost of copper
- Can be trenched or plowed in relatively inexpensively after pipeline installation
- Typically results in very low resistances
- Historically has performed as intended
- Surface mitigation ribbon can double as shielding for fault mitigation

Disadvantages
- Zinc clad ribbon is more difficult to work with compared to copper
- Life expectancy is generally less than comparable copper installation

Copper Cable

Advantages
- Can typically be installed during pipeline construction minimizing installation costs
- Can be trenched or plowed in relatively inexpensively after pipeline installation
- Typically results in very low resistances
- Historically has performed as intended
- Surface mitigation cable can double as shielding for fault mitigation
- Depending on the size cable the material cost of a copper installation can be lower than a zinc installation

Disadvantages
- Cost of raw material is typically higher than the cost of zinc
- Risk of having a more noble metal (cathodic) near or connected to pipeline even if through a decoupler

Deep Grounding (anodes used as the ground)

Advantages
- May be advantageous when surface resistivity is extremely high

Disadvantages
- Typically high cost for both installation and materials
- Generally not suitable for mitigating ground potential rises (GPR) or arcing issues associated with faults

Shallow Grounding (driven ground rods or bored ribbon or cable)

Advantages
- Can be used to supplement horizontal ribbon or cable installation if required
- Magnitude of the surface resistivity affects the resistance

Disadvantages
- Generally not suitable for mitigating ground potential rises (GPR) or arcing issues associated with faults

Engineered mitigation and/or Additives (no specific product identified)

Advantages
- Could increase design life

Disadvantages
- Typically increases the material costs

Notes:
1) These are typical statements and there are instances where they do not apply.
2) All mitigation installations are considered connected through a decoupling device such that there is no direct passage of DC current to or from the mitigation.

APPENDIX D DATA REQUEST TEMPLATE

Company: ______________________________________
Project: ______________________________________
Project Number: ______________________________________

High Voltage Alternating Current (HVAC) Power Transmission Parameters

No.	Information Requested	T-Line 1	T-Line 2	T-Line 3
	General			
1	Owner:			
2	Power transmission voltage (kV):			
3	Average Tower Span (feet)			
4	Substation ground grid impedance (ohms):			
	Phase Wires			
5	No. of circuits:			
6	Circuit type:			
	Conductors:			
7	No. 1 average height (ft):			
8	No. 1 average horizontal distance (ft):			
9	No. 1 phasing (degrees):			
10	No. 2 average height (ft):			
11	No. 2 average horizontal distance. (ft):			
12	No. 2 phasing (degrees):			
13	No. 3 average height (ft):			
14	No. 3 average horizontal distance (ft):			
15	No. 3 phasing (degrees):			
16	Other: Cable Sag, Lowest point (feet):			
	Circuit Loading			
17	Peak loading (amps):			
18	Emergency loading (amps):			
19	Emergency loading time (hours):			
	Shield Wires			
20	No. of conductors:			
21	No. 1 type:			
22	No. 1 conductor GMR (ft):			
23	No. 1 conductor resistance (ohms/mil):			
24	No. 1 average height (ft):			
25	No. 1 average horizontal distance (ft):			
26	No.2 type:			
27	No. 2 conductor GMR (ft):			
28	No. 2 conductor resistance (ohms/mil):			
29	No. 2 average height (ft):			
30	No. 2 average horizontal distance (ft):			
	Fault Current Parameters			
31	Fault clearing time (cycles):			
32	Average tower resistance (ohms):			
33	Beginning of Collocation: Total______from left substation ___________ from right substation			
34	Middle of Collocation: Total______from left substation ___________ from right substation			
35	End of Collocation: Total______from left substation ___________ from right substation			

Company: ____________________
Project: ____________________
Project Number: ____________________

Pipeline Parameters

No.	Information Requested	Pipeline 1	Pipeline 2	Pipeline 3
	General			
1	Pipeline number:			
2	Pipeline owner:			
3	Pipeline name:			
4	Product transported:			
5	Diameter (in.):			
6	Burial depth (ft.):			
7	Wall Thickness (inch):			
8	Length of Collocation (feet/miles):			
	Coatings			
9	Coating type (majority):			
10	Coating resistance (kohm-ft2):			
11	Coating thickness (mils):			
	Cathodic Protection			
12	Location of cathodic protection:			
13	Resistance of cathodic protection groundbed(s):			
14	Bonding to foreign pipelines? (Y/N):			
15	Existing AC mitigation measures? (Y/N):			
16	Describe existing AC mitigation:			

CENSE concerns about pipeline safety for Draft EIS

February 15, 2016

CENSE expresses concerns about the safety risks of locating two transmission lines (operating at 230 kV and 115 kV, respectively) and two petroleum pipelines in a single narrow utility corridor. The corridor is only 100 feet wide in some places. Along its 18-mile run through the Eastside, the corridor passes through heavily populated residential neighborhoods, schoolyards, parks, and commercial properties. Given its proximity to dense population, a pipeline fire would be devastating to our community, as described in the Bellevue Fire Department Standards of Response Coverage: "Given that pipeline incidents continue to occur in this country, and many for undetermined reasons, the community is still at risk. The combination of: a highly flammable liquid, in large quantities, and in urban environment translates into a significant consequence risk that approaches the 'catastrophic' level."[1]

Three risks

Construction risk

If the Energize Eastside project proceeds as proposed, PSE will install steel monopoles 85-130 feet high in the corridor. Heavy equipment will be used to excavate fairly large and deep foundations close to the pipelines. The pipelines, which are 40 to 50 years old, will be subjected to vibration and pressure. An accidental nick in the pipeline could cause ignition of the high-pressure contents, creating a fireball like the one which claimed three lives in Bellingham in 1999, on the same pipeline. In Texas in 2010, a worker lost his life when construction equipment hit a buried gas line while digging holes for transmission poles, so this is not just a theoretical risk. [2]

Arcing risk

During EIS scoping meetings, Bellevue resident Lloyd Arnesen described an incident where a downed power line operating at 115 kV discharged electricity into one of the pipelines, causing sufficient damage that Olympic had to replace a section of the pipe. Although no breach was caused in this case, a recent report by the respected risk analyst DNV-GL confirms that breaching is possible, and would occur more rapidly at 230 kV than 115 kV. According to the report, "A direct arc to a collocated or crossing pipeline is possible, which can result in coating damage, or arc damage to the pipe wall up to the point of burn-through. Even if an arc is not sustained long enough to cause burn through, a short duration elevated current can cause molten pits on the pipe surface that may lead to crack development as the pipe cools."[3]

Arcing can happen even when wires do not fall. Such a possibility is described in a BPA safety guide available on the web: "Proper positioning of underground utilities is required to prevent

[1] http://www.bellevuewa.gov/pdf/Fire/Standards_of_Coverage.pdf, p. 66

[2] http://www.wfaa.com/story/news/2014/08/09/13587360/

[3] http://www.ingaa.org/File.aspx?id=24732, p. 19

an accident in an extreme case when an unusual condition might cause electricity to arc from the high-voltage wire to the tower and then to ground. This could produce a dangerous voltage on underground piping…"[4]

Corrosion risk

The Executive Summary of the aforementioned report from DNV-GL describes risk factors that can accelerate corrosion of the pipeline. Some of these factors are parallel orientation, length of co-location, distance between wires and the pipeline, and total current running through the wires. We were dismayed to find that we rated a "high" or "very high" level of risk on at least 4 of the 5 risk factors. As a result, we engaged Dr. Frank Cheng, a recognized authority on the topic of electricity-induced pipeline corrosion, to describe what kind of study would be required to ensure safe practices are followed in the co-location of this infrastructure. His report and CV are included at the end of this comment.

Our level of concern is increased by an apparently nonchalant attitude regarding these safety issues demonstrated by the following remarks from PSE consultant Mark Williamson to the Newcastle Planning Commission on February 2, 2016:

> *"… if you are more than 50 feet from a lattice tower or more than 25 feet from a single monopole (which is what's being contemplated here), you don't need to do any engineering studies. That's far enough that you can just be laissez-faire and let it go. Everything else that's closer (and most facilities in this country are much closer) require good coordination and studies between the utility company that has electricity and the one that runs the pipeline so you're sure those interactions don't adversely affect either facility."*

We remain unsure which standards or safety practices will be followed. We believe it would be appropriate for the EIS to provide sound, independent analysis about risks and potential mitigations. We seek objective information untainted by conflicts of interest. Dr. Cheng's report provides a good description of the kind of analysis we would like to see. In addition to this corrosion analysis, we would like to understand best practices to minimize the possibility of fires initiated by arcing events.

Sincerely,

Don Marsh, President
CENSE.org

[4] *http://www.bpa.gov/news/pubs/GeneralPublications/lusi-Living-and-working-safely-around-high-voltage-power-lines.pdf, p. 6*

Given that pipeline incidents continue to occur in this country, and many for undetermined reasons, the community is still at risk. The combination of: a highly flammable liquid, in large quantities, and in urban environment translates into a significant consequence risk that approaches the 'catastrophic' level.

Bellevue Fire Department Standards of Response Coverage

Safety of Collocation of Electric Power Lines and Pipelines

Date: February 15, 2016

Prepared for Mr. Don Marsh, President
Coalition of Eastside Neighborhoods for Sensible Energy (CENSE)

Prepared by Dr. Frank Cheng, Professor and Canada Research Chair in Pipeline Engineering
University of Calgary, Calgary, Alberta, Canada (fcheng@ucalgary.ca)

A 230 kV high-voltage alternating current (HVAC) electric power line is proposed by way of an energy transmission corridor, where two steel pipelines carrying refined liquid petroleum products such as diesel, aviation fuel and gasoline are collocated and parallel to the power line for about 16 miles. In this corridor that is as narrow as 100 feet, there is another 115 kV HVAC line in operation. Furthermore, the corridor passes through heavily residential areas, including the largest suburbs of Seattle, Washington.

It is generally acknowledged that buried pipelines can be corroded at an accelerated rate in the presence of AC interference. Recently, there have been mounting evidences of AC induced corrosion of pipelines and their failures. For example, a natural gas leak occurred due to a pinhole perforation near the center of pit on a natural gas pipeline in Oswego, New York in 2002. It was attributed to AC induced corrosion of the pipeline.

Generally, the HVAC affects adversely the integrity and safety of buried pipelines that are collocated with electric power lines right-of-way by three mechanisms, as briefed below, all of which are able to result in pipeline failures.

Accelerated corrosion of pipelines and initiation of localized pitting corrosion at high AC current densities. The dramatic anodic polarization on pipe steels occurring during positive cycles of AC can cause significant corrosion on the steel. This is particularly serious at coating defects, where a high AC current density can result in localized pitting corrosion. This is the key mechanism resulting in pipeline perforation under AC interference.

Increased disbondment of external coating from the pipeline. An alkaline environment can generate on the pipe steel surface during AC corrosion. The high solution pH can weaken and/or break the adhesion of polymeric coatings to steel substrate, resulting in coating disbonding. Generally, the coating disbondment is increased with the local AC current density.

Shift of cathodic protection (CP) for corrosion protection. The AC is able to deviate the potential of the pipeline from the applied CP value, and reduce the CP effectiveness to protect the pipeline from corrosion attack. Sometimes, misleading information about the actual cathodic potential of the pipeline can be caused by AC interference, which makes it incapable of evaluating CP performance by potential monitoring. 1 potential and reduced CP effectiveness

In addition to the effects on integrity of pipelines, AC interference also threatens the safety of operating personnel and the public when they are in contact with the pipeline system or standing in close proximity to the pipeline and HVAC transmission lines.

To evaluate the potential effect of the HVAC power lines on integrity of the collocated buried pipelines, a comprehensive study program would be developed prior to construction of the power lines. This includes collection of relevant information, numerical modeling and conductance of on-site testing for prediction and analysis of AC interference and the resulting consequences on the pipelines, acquisition of corrosion data for modeling validation, and pipeline integrity assessment.

Essential information that is collected from the utility company and pipeline operator includes:

AC source data: Phase-to-phase voltage, load current, tower configuration and construction material, phase data and frequency, conductor characteristics (material, height, spacing), and alignment of power lines to pipelines (height, distance, angle, length in collocation).

Pipeline data: Age of pipelines, outside and inside diameters of the pipe, burial depth, grade and mechanical properties of pipe steel, inclinations of the pipe, fluid carried, operating temperature and pressure, and incident history.

CP data: At least two latest CP survey reports, including the CP performance evaluation.

Coating data: Types of mainline and joint coatings, age of the coatings, coating permeability to water and CP current, distributions of the size and geometry of coating defects, coating performance (evaluated by direct current voltage gradient, DCVG, and alternating current voltage gradient, ACVG, methods), and coating repair history.

Tests to be planned and conducted in the field include:

Monitoring of AC potential and AC current density: Testing coupons made of the same steel as the pipeline and coated with the same pipeline coating are buried at certain distance intervals in the electric power lines/pipelines corridor. The AC potential and AC current density are monitored at least 24 hours on the coated steel coupons.

Monitoring of CP potential: Additional batches of testing coupons buried are under NACE2 recommended CP potential. The direct current (DC) potential of the coupons is monitored at least 24 hours. The free corrosion potential of the steel coupon in the soils will be measured.

Collection of soil samples and analysis of soil properties: The soil resistivity at various depths along the entire pipeline alignment will be measured. The soil humidity and oxygen content are recorded. Soil samples are collected at locations where the testing coupons are buried, and soil chemistry is analyzed.

Analysis of AC corrosion and CP potential of the pipeline: The latest CP survey and performance evaluation reports will be analyzed to assess the coating performance status. The recorded AC potential data are analyzed to extract the DC component from the recorded signals, which will be used to analyze the corrosion activity of the steel. The recorded AC current density is used to determine the AC corrosion rate of the steel. The DC potential of the CP-applied coupons is used to determine the "true" cathodic potential of pipe steel in the presence of AC interference. The soil resistivity and soil chemistry are used to evaluate the corrosiveness of the soil, and for modeling of the AC interference.

The field testing and data analysis will be performed by an independent, third party corrosion solution company. The company will issue the lead authority a formal report including AC corrosion modeling and measurement results, ranking of the risk of AC interference on the collocated pipelines, and evaluation of the threat of AC corrosion to the integrity of pipelines, as well as recommendations of AC mitigation measures implemented to minimize the effects of interference to acceptable levels.

Dr. Frank Cheng
Professor and Canada Research Chair

[1] *An electrochemical corrosion control technique by applying a cathodic current on protected structures, such as pipelines, to make them the cathode of a corrosion cell. The structures possess a reasonably negative potential in the corrosion-immunity region. All buried pipelines must be protected by CP according to regulations.*

[2] *National Association of Corrosion Engineers. An globally recognized premier authority for corrosion control solutions.*

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HIGHLIGHTS

- An internationally recognized authority in corrosion science and engineering in oil/gas and pipeline systems
- Canada Research Chair in Pipeline Engineering
- Fellow, NACE International, the Corrosion Society
- Recipient, 2014 NACE International, the Corrosion Society, H.H. Uhlig Award
- Recipient, 2015 Shi Chang-Xu Award, Chinese Society for Corrosion and Protection
- Chair, NACE International Task Group 521 "Testing of nonshielding property of pipeline coatings to CP"
- Member, U.S. National Academy of Sciences (NAS) Committee on Pipeline Transportation of Bitumen
- Country (Canada) Leader, NACE International IMPACT Study Program
- Theme Editor, Pipeline Engineering of the *Encyclopaedia of Life Support System* (EOLSS) developed under the auspices of UNESCO
- An author of 1 book, 4 book chapters, 145 journal articles (including one commentary article accepted by *Nature*) and 70 conference papers, as well as 18 invited plenary/keynote talks in international conferences
- In Google Scholar, 3980 citations, h-index 37 (there are 37 publications cited over 37 times), and i10-index 103 (there are 103 publications cited over 10 times) (up to Dec. 2015)

I. EDUCATION

2000 - 2002 Postdoctoral Fellow in Materials Engineering, NOVA Research and Technology Center, Canada

1996 - 2000 Ph.D. in Materials Engineering, University of Alberta, Canada

1990 – 1993 M.Sc. in Corrosion, Institute of Metal Research, Chinese Academy of Sciences, China

1986 – 1990 B.Sc. in Corrosion, Hunan University, China

II. PROFESSIONAL EXPERIENCES

2011 – present Professor, Canada Research Chair in Pipeline Engineering University of Calgary, Calgary, Canada

2009 – 2011 Associate Professor, Canada Research Chair in Pipeline Engineering University of Calgary, Calgary, Canada

2005 – 2009 Assistant Professor, Canada Research Chair in Pipeline Engineering University of Calgary, Calgary, Canada

2002 – 2005 Research Scientist Centre for Nuclear Energy Research, University of New Brunswick, Canada

1993 – 1996 Research Assistant Institute of Metal Research, Chinese Academy of Sciences, Shenyang, China

III. AWARDS

2015 Fellow, NACE International, the Corrosion Society

2015 Shi Chang-Xu Award, Chinese Society for Corrosion and Protection

2014 NACE International, the Corrosion Society, H.H. Uhlig Award

2010 Engineering Students' Society Teaching Excellence Award, University of Calgary

2009 Departmental Research Excellence Award, University of Calgary

2000 Industrial Research Fellowship (IRF), NSERC

1999 Excellence in Presentation Award, the 38th Conference of Metallurgical Society of CIM

IV. SERVICES

2015 – present: Country (Canada) Leader, NACE International IMPACT Study Program

2014 – present:Chair, NACE International TG 521 "Testing of Nonshielding Property of Pipeline Coatings to Cathodic Protection"

2014 – present: Treasurer and Board Director, NACE Foundation of Canada

2014 – present: Member, International Scientific Advisory Board, Institute of Oceanology, Chinese Academy of Science

2014 – present: Faculty Advisor, NACE International Calgary Student Section

2011 – present: Member, Editorial Board, the journal *Corrosion Engineering, Science and Technology*

2014 – 2015: Chair, NSERC Site Visit and Review Committee for Industrial Research Chair (IRC) in Nuclear Materials Corrosion at the University of Toronto

2014 – 2015: Member, Panel for Performance Review of the Institute of Oceanology, Chinese Academy of Sciences

2014 – 2015: Guest Editor, Special Issue on Pipeline Corrosion, the journal *Corrosion Engineering Science and Technology*

2013 – 2015: Member, U.S. Congressional Technical Advisory on Safety of Oil Pipeline Transportation

2014: Member, British Columbia Ministry of Transportation Panel on "Pacific Gateway" Kitimat West Douglas Channel Corridor Analysis

2013 – 2014: Member, Alberta Innovate-CEPA (Canadian Energy Pipeline Association) Crude Transmission Pipeline Roadmap Project Steering Committee

2012 – 2013: Member, U.S. National Academy of Sciences (NAS) Committee on Pipeline Transportation of Diluted Bitumen

2012 – 2013: Member, University of Calgary's Professorship and Chairs Committee

2009 – 2011: Member, Board of Directors, Canadian Fracture Research Corporation

2007 – 2013: Invited examiner, Alberta Professional Engineer and Geoscientist Association

2006 – 2009: Honorary Theme Editor in Pipeline Engineering, *Encyclopedia of Life Support System* (EOLSS) developed under the auspices of UNESCO

V. CONFERENCE/WORKSHOP ORGANIZATION

2015 Chair, Symposium on Pipeline Integrity, the 25th International Offshore and Polar Engineering Conference, ISOPE, Kona, Hawaii, USA, Jun. 21-26.

2015 Member, Scientific Committee, International Conference on Mining, Materials and Metallurgical Engineering (MMME'15), Barcelona, Spain, Jul. 19-21.

2014 Member, Panel for Asset Integrity - from Selection to Implementation, 2014 Crude Pipeline Integrity Congress, Houston, USA, Nov. 19-20.

2014 Member, Scientific Committee, International Conference on Mining, Materials and Metallurgical Engineering (MMME'14), Prague, Czech Republic, Aug. 11-12.

2014 Member, Technical Program Committee, the 24th International Offshore and Polar Engineering Conference, ISOPE, Busan, Korea, Jun. 15-20.

2013 Member, Technical Program Committee, the 23rd International Offshore and Polar Engineering Conference, ISOPE, Anchorage, USA, Jun. 30-Jul. 5.

2011 Chair, Plenary Session, the 16th Chinese National Surface Engineering and Technology Conference, Wuhan, China, May 5-7.

2011 Organizer, the 2nd Workshop on Pipeline Material Reliability, Calgary, Canada, Apr. 3.

2010 Co-Chair, International Symposium on Fracture Control in Engineering, Conference of Metallurgists 2010, Canadian Metallurgical Society, Vancouver, Canada, Oct. 3-6.

2010 Organizer, the 1st Workshop on Pathway for Future Collaborations - Network on Pipeline Engineering R & D, Calgary, Canada, Mar. 3.

2006 Session Chair, the 14th Asia-Pacific Corrosion Control Conference, Shanghai, China, Oct. 21-24.

2006 Session Chair, the 6th International Pipeline Conference, Calgary, Canada, Sept. 25-29.

VI. EXTERNAL REVIEW

Grant Review

Icelandic Research Fund

Chilean FONDECYT National Research Funding

Kazakhstan National Center of Science and Technology Grant

Chinese National Natural Science Foundation

Canada Research Chairs Program

NSERC Discovery Grant (DG)

NSERC Strategic Project Grant (SPG)

NSERC Industrial Research Chairs (IRC) Grant

NSERC Collaborative Research and Development (CRD) Grant

NSERC Industrial R & D Fellowship

Canadian Foundation of Innovation (CFI) Leaders Opportunity Fund

Resource for the Innovation of Engineered Materials (RIEM) Grant

Initiative for Automotive Manufacturing Innovation (IAMI) Grant

Tenure Appointment and Promotion Review

University of Wollongong, Australia

University of Western Ontario, Canada

Dalhousie University, Canada

Jordan University of Science and Technology, Jordan

McMaster University, Canada

China Petroleum University (Beijing), China

Huazhong University of Science and Technology, China

SCI Journal Manuscript Review

Review manuscripts for over 30 SCI journals

VII. TALKS AND SEMINARS

Invited Plenary and Keynote Talks

2015 "Study of early-stage features of corrosion by an electrochemical atomic force microscope", the 8th Chinese National Corrosion Conference, Xiamen, China, Nov. 14-16.

2015 "Effect of steel metallurgy on pipeline corrosion studied by micro-electrochemical techniques", 2nd International Conference on Mining, Materials and Metallurgical Engineering, Barcelona, Spain, Jul. 19-21.

2015 "Corrosion, cracking and risk assessment of high-strength steel pipelines", 2015 International Pipeline and Line Pipe Steel Conference, Xi-An, China, Apr. 26-28.

2014 "Understanding internal corrosion of pipelines for improved inhibitor/ biocide performance", 2014 Crude Pipeline Integrity Congress, Houston, USA, Nov. 19-20.

2014 "Preventing pipeline external corrosion by integration of coating with cathodic protection", 2014 Crude Pipeline Integrity Congress, Houston, USA, Nov. 19-20.

2014 "Modeling of internal corrosion of pipelines in oil/gas production", the 248th American Chemical Society (ACS) Meeting, Symposium on Challenges and Opportunities in Petroleum Oil Production, Refining and Utilization, San Francisco, USA, Aug. 10-14.

2014 "Reliable prediction of maximum operating pressure of pipelines by defect assessment", NACE International Sino-Corr Biannual Conference, Beijing, China, May 19-22.

2013 "Innovation in failure pressure prediction based on defect assessment on pipelines", the 7th Chinese National Corrosion Conference, Changyuan, China, Jul. 26-29.

2013 "Analysis of corrosion of oil transmission pipelines in North America", the 7th Chinese National Corrosion Conference, Changyuan, China, Jul. 26-29.

2012 "Assessing the impacts of corrosion on pipeline integrity", the Canadian Institute's Pipeline Integrity Strategies Meeting, Calgary, Canada, Mar. 19-20.

2011 "Technical challenges of the high-strength steel pipeline technology", the 4th Chinese International Pipeline Conference, Langfang, China, Sept. 5-8.

2011 "Pipeline corrosion under disbonded coating", the 6th Chinese National Corrosion Congress, Yinchuan, China, Aug. 21-24.

2011 "New trends and challenges in development of high-strength steel pipeline technology", the 3rd Iranian Pipe and Pipeline Conference, Tehran, Iran, May 24-25.

2011 "Recent developments on monitoring of the coating disbondment", the 3rd Iranian Pipe and Pipeline Conference, Tehran, Iran, May 24-25.

2010 "Application of micro-electrochemical techniques in corrosion research", the 2010 National Corrosion Electrochemistry Conference, Hangzhou, China, Aug. 15-18.

2010 "Understand the fundamentals of stress corrosion cracking of high-strength pipeline steels", the 7th Taiwan-Mainland China Corrosion Conference, Kunming, China, Aug. 9-12.

2006 "Pipeline stress corrosion cracking: Experimental research and modeling development", the 14th Asia-Pacific Corrosion Control Conference, Shanghai, China, Oct. 21-24.

2005 "Fundamental research in pipeline corrosion and stress corrosion cracking", the 13th National Conference on Electrochemistry, Guangzhou, China, Nov. 24-28.

Invited Seminars

2015 "Technical challenges in maximizing pipeline integrity and safety", Safety Engineering Institute, SINOPEC, Qingdao, China, Dec. 17.

2015 "Uses of micro- and nano-electrochemical techniques in corrosion research", Shanghai University, Shanghai, China, Nov. 18.

2015 "R & D hot topics in pipeline corrosion", CH2M Breakfast Event, Calgary, Canada, Jun. 19.

2015 "Corrosion and cracking of high-strength steel pipelines", Xi-An Jiaotong University, Xi-An, China, Apr. 28.

2014 "Mechanism, modeling and management of internal corrosion of pipelines", Beijing Chemical Technology University, Beijing, China, Dec. 12.

2014 "An overview of microbiologically influenced corrosion of oil transmission pipelines", SPE-ICoTA Inter-Society Technical Event, Calgary, Canada, Sept. 10.

2014 "An overview of pipeline corrosion research", Safety Engineering Institute, SINOPEC, Qingdao, China, Jul. 15.

2014 "Mechanistic understanding and modeling prediction of internal corrosion of oil pipelines", Institute of Oceanology, Chinese Academy of Sciences, Qingdao, China, Jul. 14.

2014 "Initiation of pitting corrosion at non-metallic inclusions in X100 steel", 2014 Pipeline Materials Workshop, University of Alberta, Edmonton, Canada, May 30.

2014 "Canadian pipelines and corrosion management", Pipeline College, Petro-China, Langfang, China, May 19.

2014 "Pipeline integrity: An overview", ASME Southern Alberta Technical Luncheon, Calgary, Canada, Mar. 4.

2013 "Pipeline integrity: public concerns, root analysis and technology innovation", Engineering Associates Program (EAP) Breakfast, University of Calgary, Calgary, Canada, Nov. 22.

2013 "Internal corrosion of transmission pipelines in crude oil", Huazhong University of Science and Technology, Wuhan, China, Nov. 12.

2013 "Canadian pipelines: Opportunities and technical challenges", Rotary Club of Calgary Centennial, Calgary, Canada, Oct. 16.

2013 "Innovation in pipeline internal corrosion management by direct assessment", SINOPEC, Dazhou, China, Jul. 30.

2013 "Evolution of high-strength line pipe steels and the associated technical challenges", Capital Steel Group Research Center, Beijing, China, Jul. 25.

2013 "Corrosion at pipeline weld and its correlation with local microstructure", Pipeline Materials Welding Workshop, University of Alberta, Edmonton, Canada, May 29.

2013 "Pipeline as energy highway - An overview of pipelines in Canada", Generate 2013 Alberta Youth Energy Literacy Summit, Kananaskis, Canada, Mar. 15.

2012 "A mini-review of pipeline failure mechanisms", U.S. National Academy of Sciences (NAS), Washington DC, USA, Oct. 24.

2012 "Latest progress in pipeline corrosion and materials research", China University of Petroleum (East China), Qingdao, China, Jun. 11.

2012 "The fundamental aspects of pipeline corrosion and the associated monitoring, predictive and assessment techniques", Southwest Petroleum University, Chengdu, China, Jun. 7.

2012 "Mechanoelectrochemical effect of pipeline corrosion", Beijing University of Aeronautics and Astronautics, Beijing, China, Jun. 5.

2012 "Corrosion assessment and failure pressure prediction of pipelines under complex stress/strain conditions", TNO, Delft, The Netherland, Apr. 3.

2012 "Measurements and mechanism of AC corrosion of pipelines and its effect on cathodic protection", Elsyca, Leuven, Belgium, Apr. 2.

2012 "Characterization of pipeline coatings and corrosion of steel under coating", University of Oxford, Oxford, U.K., Mar. 30.

2011 "Typical scenarios of pipeline corrosion and cracking: micro-electrochemical uses", Shanghai Jiao-Tong University, Shanghai, China, Dec. 5.

2011 "Metallurgical aspects of corrosion and cracking of high-strength pipeline steels", Politecnico di Milano, Milan, Italy, Nov. 2.

2011 "Fundamental aspects and research in pipeline corrosion", Chimie ParisTech, Paris, France, Oct. 24.

2011 "Studies of corrosion of pipelines by micro-electrochemical measurement techniques", Xiamen University, Xiamen, China, Aug. 12.

2011 "Risk assessment and integrity maintenance of oil/gas pipelines", China University of Geoscience, Wuhan, China, Jul. 18.

2011 "Application of advanced micro-electrochemical techniques in pipeline corrosion research", University of Western Ontario, London, Canada, Jun. 1.

2010 "Integrity management to address pipeline corrosion and stress corrosion cracking", Pipeline R & D Center of Petro-China, Langfang, China, Aug. 6.

2010 "Canadian pipeline development and research in stress corrosion cracking of line pipe steels", R& D Center of Wuhan Iron & Steel Co., Wuhan, China, Jul. 29.

2010 "An overview of pipeline corrosion research at the University of Calgary", Workshop for Pathway for Future Collaborations, Calgary, Canada, Mar. 3.

2009 "Improved safety and efficiency in pipeline operation", ASME International Southern Alberta Section Luncheon Meeting, Calgary, Canada, Nov. 26.

2008 "Electrochemical measurements in corrosion research I. Macroscopic electrodes", University of Science and Technology Beijing, China, Dec. 16.

2008 "Electrochemical measurements in corrosion research II. Microscopic electrodes", University of Science and Technology Beijing, China, Dec. 17.

VIII. PUBLICATIONS

Book

1. Y. Frank Cheng, *Stress Corrosion Cracking of Pipelines*, John Wiley Publishing, Hoboken, NJ, USA, Feb. 2013.

Books chapters

4. Frank Y. Cheng, Application of Micro-Electrochemical Techniques in Corrosion Research, in: *Green Corrosion Chemistry and Engineering*, S.K. Sharma, Editor, Wiley-VCH Publisher, Germany, 2011, p.71-96.

3. Frank Y. Cheng, Erosion Accelerated Corrosion in Flow System-Behavior of Aluminum Alloys in the Automotive Cooling System, in: *Tribocorrosion of Passive Metals and Alloys*, D. Landolt, S. Mischler, Eds, Woodhead Publishing, Cambridge, 2011, p. 475-497.

2. Y.F. Frank Cheng, Internal Corrosion of Pipelines in Oil/Gas Production, in: *Advances in Chemistry Research*, Volume 6, J.C. Taylor, Editor, ISBN 978-1-61728-982-8, Nova Science Publishers, Inc., New York, 2010.

1. Frank. Y. Cheng, Pipeline Engineering, in: Pipeline Engineering, Ed. Yufeng F. Cheng, in: *Encyclopedia of Life Support System*, Developed under the Auspices of the UNESCO, EOLSS Publishers, Oxford, UK, 2010.

Papers in Peer-Reviewed Journals

145. Frank Cheng, Are our pipelines safe? *Nature*, accepted on Dec. 23, 2015.

144. Huiwen Tian, Y. Frank Cheng, Novel inhibitors containing multi-functional groups for pipeline corrosion inhibition in oilfield formation water, *Corrosion*, accepted on Dec. 1, 2015.

143. Zhong Wu, Y. Frank Cheng, Lei Liu, Weijie Lv, Wenbin Hu, Effects of elastic and plastic deformations on corrosion of an aluminum bronze alloy in NaCl solution, *Corrosion* 72 (2016) 33-41.

142. Yuanhao Feng, Y. Frank Cheng, Inhibitive performance of benzotriazole for steel corrosion studied by electrochemical and AFM characterization, *Journal of Materials Engineering and Performance* 24 (2015) 4997-5001.

141. Huiwen Tian, Y. Frank Cheng, Weihua Li, Baorong Hou, Triazolyl-acylhydrazone derivatives as novel inhibitors for copper corrosion in chloride solutions, *Corrosion Science* 100 (2015) 341-352.

140. Da Kuang, Y. Frank Cheng, Study of cathodic protection shielding under coating disbondment on pipelines, *Corrosion Science* 99 (2015) 249-257.

139. Zhong Wu, Y. Frank Cheng, Lei Liu, Weijie Lv, Wenbin Hu, Effect of heat treatment on microstructure evolution and erosion-corrosion behaviour of a nickel-aluminum bronze alloy in chloride solution, *Corrosion Science* 98 (2015) 260-270.

138. Y. Frank Cheng, Pipeline corrosion, *Corrosion Engineering, Science and Technology* 50 (2015) 161-162.

137. D. Kuang, Y.F. Cheng, Probing potential and solution pH under disbanded coating on pipelines, *Materials Performance* 54 (2015) 40-45.

136. D. Kuang, Y.F. Cheng, Effect of alternating current interference on coating disbondment and cathodic protection shielding on pipelines, *Corrosion Engineering Science and Technology* 50 (2015) 211-217.

135. D. Kuang, Y.F. Cheng, AC corrosion at coating defect on pipelines, Corrosion 71 (2015) 267-276.

134. X.D. Zhao, Y.F. Cheng, W. Fan, C. Vladimir, V. Volha, T. Alla, Inhibitive performance of a rust converter on corrosion of mild steel, *Journal of Materials Engineering and Performance* 23 (2014) 4102-4108.

133. X.D. Zhao, J.Z. Duan, B.R. Hou, Y.F. Cheng, Corrosion of mild steel in sea mud containing sulfate-reducing bacteria, *Canadian Metallurgical Quarterly* 53 (2014) 450-454.

132. D. Kuang, Y.F. Cheng, Understand the AC induced pitting corrosion on pipelines in both high pH and neutral pH carbonate/bicarbonate solutions, *Corrosion Science* 85 (2014) 304-310.

131. R.J. Jiang, E. Slingerland, Y.F. Cheng, Corrosion of galvanized steel cord reinforcement in HDPE composite pipes in petroleum production, *Corrosion Engineering, Science and Technology* 49 (2014) 296-302.

130. X.Y. Peng, Y.F. Cheng, Hydrogen permeation and the resulting corrosion enhancement of pipeline steels, *Canadian Metallurgical Quarterly* 53 (2014) 107-111.

129. L.Y. Xu, Y.F. Cheng, Experimental and numerical studies of effectiveness of cathodic protection at corrosion defects on pipelines, *Corrosion Science* 78 (2014) 162-171.

128. C. Zhong, W.B. Hu, Y.F. Cheng, Recent advances in eletrocatalysts for electro-oxidation of ammonia, *Journal of Materials Chemistry A* 1 (2013) 3216-3238.

127. D. Han, Y.F. Cheng, Mechanism of electrochemical corrosion of carbon steel under deoxygenated water drop and sand deposit, *Electrochimica Acta* 114 (2013) 403–408.

126. G.C. Liang, E. Sanjuan, Y.F. Cheng, Strain aging of X100 steel in service and the enhanced susceptibility of pipelines to stress corrosion cracking, *Journal of Materials Engineering and Performance* 22 (2013) 3778–3782.

125. G.C. Liang, X.Y. Peng, L.Y. Xu, Y.F. Cheng, Erosion-corrosion of carbon steel pipes in oil sands slurry studied by weight-loss testing and CFD simulation, *Journal of Materials Engineering and Performance* 22 (2013) 3043–3048.

124. X.Y. Peng, T.Y. Jin, Y.F. Cheng, Correlation of initiation of corrosion pits and metallurgical features of X100 pipeline steel, *Canadian Metallurgical Quarterly* 52 (2013) 484–487.

123. Y. Yang, Y.F. Cheng, Mechanistic aspects of electrodeposition of Ni-Co-SiC composite nano-coating on carbon steel, *Electrochimica Acta* 109 (2013) 638–644.

122. R.J. Jiang, Y.F. Cheng, Mechanism of electrochemical corrosion of steel under water drop, *Electrochemistry Communication* 35 (2013) 8–11.

121. Frank Cheng, Controversy contained: In-depth look at CP shielding, *World Pipelines* 13 (2013) (9) 50–54.

120. L.Y. Xu, Y.F. Cheng, Development of a finite element model for simulation and prediction of mechano-electrochemical effect of pipeline corrosion, *Corrosion Science* 73 (2013) 150–160.

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Conference Presentations and Proceedings

70 conferences papers and presentations. The invited Plenary and Keynote talks are listed in Section VII. Other talks and the papers are not listed.

The Best Alternative

Executive Summary

PSE and CENSE (Coalition of Eastside Neighborhoods for Sensible Energy) may not agree on the feasibility of the company's proposed transmission project through four Eastside cities.

But at least we agree on one thing. The five alternative solutions evaluated in the Draft EIS are not practical solutions to power future growth of the Eastside.

- **Alternative 1B** (use existing Seattle City Light corridor): Seattle City Light has said they don't want to share these lines with PSE. We don't know how to change that conclusion.
- **Alternative 1C** (underground transmission lines): The state tariff enforced by the Washington Utilities and Transportation Commission makes it prohibitively expensive for communities to request undergrounding.
- **Alternative 1D** (underwater transmission lines): This alternative may be subject to the same expensive undergrounding tariff, and also raises questions about disturbing a Superfund site, shoreline issues, and concerns about salmon.
- **Alternative 2** (integrated resource approach): The analysis of integrated resources is based on incorrect or obsolete information, making this option appear more expensive and less feasible than it actually is.
- **Alternative 3** (new 115 kV lines and transformers): With 60 miles of new transmission lines, this alternative does not seem like an attractive or realistic option to anyone.

Alternative 2 would be the most attractive option for residents and businesses if it were redesigned using more up-to-date and accurate information. Such a solution would be less expensive, less damaging to communities and the environment, and safer for homes and schools in close proximity to the power lines and high-pressure petroleum pipelines.

Sadly, Alternative 2 was not designed or reviewed by experts in new technologies that make Demand Response and Electrical Efficiency the most important factors in planning the electrical grid of the future. This is validated by a quote from the Northwest Power Plan[1] that was finalized this year:

> *In more than 90 percent of future conditions, cost-effective efficiency met all electricity load growth through 2035. It's not only the single largest contributor to meeting the region's future electricity needs, it's also the single largest source of new winter peaking capacity.*

EQL's full report is included following this introduction. The full report is quite detailed and technical. It may be more appropriate for analysis by industry experts, so this introduction attempts to distill the main points for the general public.

[1] *https://www.nwcouncil.org/media/7149671/7thplandraft_chap01_execsummary_20151020.pdf*

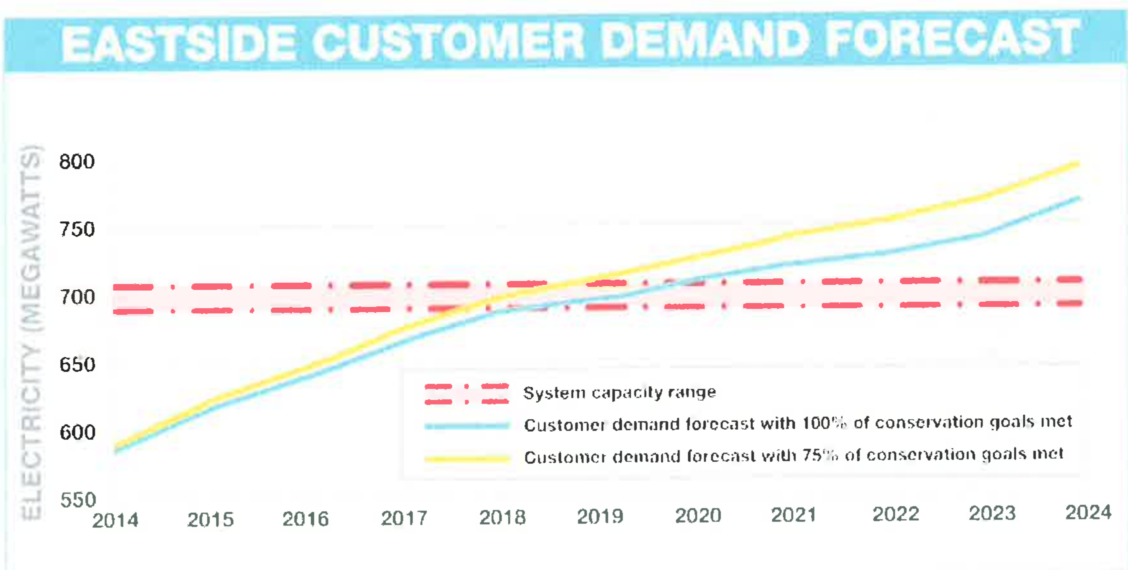
A clear definition of need and cost

In order to determine the feasibility of any alternative solution, it is important to be clear about two crucial parameters:

1. How big is the need? Or, as the DEIS poses the question in section 2.3.3, what is the "projected deficiency in transmission capacity on the Eastside?"
2. What is the relative cost of alternatives compared to the cost of PSE's proposed project?

How big is the need?

In section 2.3.3, the DEIS says that Alternative 2 must cover 205 MW of projected shortfall by 2024. It is not clear in the DEIS where this number comes from. It is nearly three times the shortfall of approximately 70 MW shown for 2024 in PSE's famous Eastside Customer Demand Forecast:



The DEIS explains that Alternative 2 must be evaluated by a different standard than a solution based on transmission lines because "*every solution has a different degree of effectiveness and reliability*." The DEIS seems to dwell on every possible downside of the technologies included in Alternative 2 while turning a blind eye to the reliability risks of Alternative 1A. For example, suppose two of the approximately 150 power poles in PSE's proposal fall down (a scenario we are allowed to consider under N-1-1 contingency planning, and not hard to imagine during a big earthquake). In that case, the capacity of Alternative 1A would be reduced by 20%, about 140 MW. It is difficult to imagine a scenario in which an N-1-1 failure would lead to a similar drop in capacity for Alternative 2. It improves reliability by not placing all our eggs in one basket.

There is evidence that PSE has been gradually skewing requirements to reduce the competitiveness of alternatives. In April 2015, an update to Quanta's Eastside Needs Assessment estimated the shortfall in transmission capacity at 123 MW. A few months later, the EIS consultant Stantec raised the estimate to 133 MW. In January 2016, PSE's latest Integrated Resource Plan pegged the number at 166 MW. A few weeks later, the DEIS was published with an estimate of 205 MW.

The shortfall has grown by 54% in less than a year, calling into question the stability of the methodology used to determine this number or the motives of the information source.

The important point is that size matters. The mix of technologies and programs needed to cover a 205 MW shortfall is different from the mix that would be used to cover a shortfall of 123 MW. One wouldn't simply "scale up" the smaller solution.

It's important to note that CENSE is skeptical of even the lesser 123 MW figure. The Lauckhart-Schiffman Load Flow Study[2] exposes errors in PSE's assumptions and simulations that would dramatically alter the size and timeframe of the need. For the purposes of this report, we assume that the shortfall is 123-133 MW in order to critique the DEIS, but we do not agree that this is a realistic estimate.

What is the cost?

The DEIS treats cost as irrelevant for the purposes of evaluating environmental impact. However, in the real world, cost is an important factor in choosing one alternative over another.

PSE has not estimated the cost of the project for at least a year. The last cost estimates that were shared with the Community Advisory Group were in the range of $150 million. EQL expects the actual cost will be closer to $300 million, for the following reasons:

1. PSE initially thought that two transmission lines could be carried on a single set of monopoles. However, due to the meanderings of the Olympic pipelines in the shared corridor, there are many places where the lines must be carried by two poles to meet safety requirements. The number of poles and construction costs will increase.
2. PSE initially thought that the current transmission poles could be removed before construction of the new line began. Recently, the company has admitted that operation of the system with no lines in place during many months of construction would present a reliability risk. Therefore, the design must be altered to accommodate both sets of transmission lines in place simultaneously.

[2] *http://cense.org/Lauckhart-Schiffman%20Load%20Flow%20Study.pdf*

Taller poles will be required to maintain a safe distance between the old lines and the new lines. Also, the complexity of construction is significantly increased. Both of these factors will increase the cost of the project.

3. PSE assumed that it would be safe enough to put two transmission lines and two high-pressure petroleum pipelines in a utility corridor that is as narrow as 100 feet in densely settled residential neighborhoods. The DEIS wisely assumes that the corridor will have to be widened by up to 50 feet. This will require condemnation of homes and new easements, significantly increasing project costs.

4. Resistance to the project is much higher than PSE expected. The costs of advertising, public relations, and potential legal actions are correspondingly higher.

EQL's report points out a hidden cost of Alternative 1A. If PSE invests hundreds of millions of dollars in a transmission project, the amount of investment dedicated to important programs like Demand Response and Energy Efficiency will be reduced. Consequently, overall energy use will be higher with Alternative 1A than Alternative 2. That higher consumption must be matched by new generation, and PSE anticipates that need in the 2015 Integrated Resource Plan. PSE expects to build nearly 600 MW of new gas generation plants in 2021, just a few years after Energize Eastside is complete:

Figure 1-7: Electric Resource Plan Forecast, Cumulative Nameplate Capacity of Resource Additions

	2021	2027	2030	2035
Conservation (MW)	411	695	768	906
Demand Response (MW)	130	153	160	172
Wind (MW)	-	206	337	337
Combined Cycle Gas (MW)	599	969	1354	1354
Peaker/CT Dual Fuel (MW)	-	228	479	707

Alternative 2 could reduce overall energy use enough to eliminate the need for one 200 MW generation plant, saving ratepayers $300 million. In the long run, Alternative 2 could save ratepayers the cost of both transmission and generation infrastructure, at least $600 million. Including both of these avoided costs in the analysis makes Alternative 2 the better choice for cost effectiveness.

Expert analysis from EQL Energy

To better understand how Distributed Energy Resources (DER) might contribute to the future operation of our energy grid, CENSE engaged industry expert EQL Energy from Portland, Oregon. EQL has been an important contributor to alternative energy solutions in Portland and other parts of the Pacific Northwest.

EQL possesses a different skill set than that needed to plan transmission lines. These skills have not been demonstrated by PSE or the EIS consultant Stantec. Consequently, Alternative 2 is not a credible DER solution. The description included in DEIS section 2.3.3.1 would lead the reasonable reader to conclude that this option is difficult to implement and dangerous for reliability.

Consequently, EQL's list of technologies and policies differs significantly from those included in the DEIS:

DER program	PSE estimate (MW in 2024)	EQL estimate (MW in 2024)
Targeted Energy Efficiency	42?	30
Distribution Efficiency (CVR)	0	18.8
Combined Heat & Power	0	30
Energy Storage	121	15
Peak Generation Plant	60	0
Dispatchable Standby Generation	?	18.8
Demand Response (unspecified)	32	
Demand Response (day ahead)		30
Demand Response (10 minute)		11.3
Total	**255?**	**153.9**

Energy Efficiency

It is difficult to directly compare PSE's and EQL's estimates of potential savings from Energy Efficiency. In section 2.3.3.1, the DEIS states that 42 MW of savings would be required, but offers no clear idea of how that would be achieved: "*The potential for additional energy efficiency on the Eastside is not currently known and would require additional evaluation.*" CENSE is disappointed that no more definitive estimate could be made of the potential.

The DEIS claims that savings of this magnitude would be "*an aggressive goal.*" Also, "*The additional energy efficiency assumed for Alternative 2 would be triple the amount that PSE estimated is achievable after 2024, and that additional energy efficiency would have to be accomplished before 2024.*" The DEIS analysis makes it seems pretty hopeless.

In contrast, EQL has estimated 30 MW can be saved through Energy Efficiency. This is lower than PSE's goal, and EQL believes it is more easily achieved because PSE and its consultants are using load data that is decades out of date. The obsolete data makes Energy Efficiency appear to be less effective than it actually has been in more recent years.

To get more accurate data, a "Request for Proposals" should be issued to companies that specialize in Energy Efficiency technologies and programs. A competitive bidding process would yield better estimates of the potential than the obsolete data being used by PSE and EIS consultants.

Distribution Efficiency

Energy Efficiency achieves savings on the consumer's side of the electric meter by using less electricity to accomplish tasks such as lighting, heating, operating appliances and electronics, and charging batteries. In contrast, Distribution Efficiency increases the efficiency of how PSE and other utilities deliver electricity to consumers. This reduces overall electricity usage by up to 4% without any impact on customers. PSE has already incorporated this technology in a few substations, but the program can be expanded to more broadly reduce peak loads.

EQL included 18.8 MW of savings in its DER estimates, based on a somewhat conservative estimate of 2.5% of peak load. No estimate is included for Distribution Efficiency in the DEIS.

Combined Heat & Power

Combined Heat & Power is a technology that generates electricity from the waste heat produced by burning natural gas to heat or cool a building. It is most effectively incorporated in new buildings, and it provides two benefits. The very efficient use of natural gas reduces total carbon emissions compared to long-distance transmission of electricity, and local generation of electricity can provide a degree of immunity from power outages. Widespread use could reduce the need for new generation facilities and transmission lines, benefitting all customers.

Bellevue has a special opportunity to incorporate this technology due to the number of new buildings planned for construction in downtown Bellevue and the Spring District. If these projects are contributing to the need for Energize Eastside, it seems fair to ask them to help solve the problem of increased energy use. It is not fair to place the burden of rising downtown energy use on residential neighborhoods with increased industrialization and lower property values.

EQL estimates 30 MW of savings due to Combined Heat & Power. No estimate is included in the DEIS.

Energy Storage

DEIS section 2.3.3.4 describes a battery solution that would provide 121 MW to serve peak demand. However, the practicality of such a system is immediately dismissed: *"An energy storage system with power and energy storage ratings large enough to reduce normal overloads has not yet been installed anywhere in the world. For comparison, the largest operational transmission scale battery facility in the U.S. can provide 32 MW of power for about 40 minutes."* The DEIS analysisi makes it sounds like you'd have to be crazy to consider this idea.

EQL proposes a battery solution with a capacity of only 15 MW, approximately 8 times smaller than PSE's solution. For comparison, Southern California Edison is funding a project to install batteries with 250 MW of capacity. EQL's proposal is 16 times smaller, and by PSE's metric, 16 times more feasible.

But what about cost? EQL found a major error in the cost analysis included in the Strategen report referenced in the DEIS. Strategen ignored the cost of avoided transmission, leading to the improbable assumption that we would build transmission lines and battery storage units. When the error is corrected, the cost of batteries is approximately two times more cost effective than building new transmission lines. And battery costs will continue to fall, while the cost of transmission lines usually rises due to increasing property values.

Even PSE admits that battery storage will become a game changer as we increasingly rely on intermittent renewable energy sources like wind and solar power. We can prepare for the future by investing in small amounts of battery storage now, so we can learn from our experience and advance the state of the art. If possible, we should use products like grid batteries manufactured by the Mukilteo-based company UniEnergy. That's a smart investment in our energy future and our economy.

EQL estimates 15 MW of battery storage. The DEIS estimates 121 MW, but notes that the consultants skipped evaluation of a summer scenario because "*energy storage would not be a feasible stand-alone alternative.*" This is an odd criteria to apply to energy storage, because the components of an "*integrated resource approach*" are designed to work together, not as stand-alone pieces.

Peak Generation Plant

DEIS section 2.3.3.1 describes "three 20 MW generators to be implemented in combination with the other components described for Alternative 2." As an important caveat, the DEIS notes that "PSE had eliminated this option from consideration" because "these types of generators produce a high noise level that would be incompatible with [residential] surroundings." In discussion with Bellevue city council members, CENSE has learned that there is little political will to consider these generators.

EQL's proposal does not rely on gas-fired peak generation plants. The DEIS assumes 60 MW of capacity.

Dispatchable Standby Generation

Dispatchable Standby Generation (DSG) generates power on a customer's site, as explained in DEIS section 2.3.3.3. The DEIS mentions many technologies that could be used for this purpose, such as gas turbines, microturbines, reciprocating engines, fuel

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Dispatchable Standby Generation

Dispatchable Standby Generation (DSG) generates power on a customer's site, as explained in DEIS section 2.3.3.3. The DEIS mentions many technologies that could be used for this purpose, such as gas turbines, microturbines, reciprocating engines, fuel cells, and anaerobic digesters. However, no estimate is given regarding which ones are most practical or how much energy they might be expected to generate.

EQL describes a solution that they helped design in Portland, Oregon. Generators owned by businesses, hospitals, and government buildings are networked to the utility company. These generators are usually idle unless there is a power failure, when they are turned on to supply emergency power. The utility is provided a way to remotely control the generators when electricity demand peaks. The owner gets an attractive incentive for participating, and the generator reverts to its previous purpose (backup power) if an outage occurs.

Using the Portland program as a template, EQL used a scale factor to determine DSG potential for the Eastside. EQL estimates 18.8 MW of additional energy produced by DSG. The DEIS provides no estimate.

Demand Response

The importance of Demand Response as a primary part of future energy planning is underscored by the recently published Seventh Northwest Power Plan from the Northwest Power and Conservation Council, as well as a major victory for the Federal Energy Regulatory Commission in the U.S. Supreme Court[3] A 2015 article in Forbes explains how Demand Response will save U.S. consumers billions of dollars.[4]

DEIS section 2.3.3.2 mentions some rather vague ways to implement Demand Response programs, including real-time monitoring, utility control of heating and cooling systems, programmatic options to reduce peak demand (nothing specific), incentives and pricing structures to shift peak demand, continuous wireless signals to the utility (huh?)

The DEIS doesn't provide any realistic estimate of how much energy can be saved through these programs, but it says it must be at least 32 MW. According to the DEIS, "this would triple the expected rate of adoption of demand response in PSE's Integrated Resource Plan..."

EQL is more specific. There are actually two types of Demand Response programs: one anticipates needs one day before peak loads materialize (it's not hard to predict very cold weather one day ahead), and one responds to emergency needs with 10 minutes' notice.

EQL estimates 30 MW of savings for day-ahead Demand Response (4% of peak load based on a conservative estimate from industry analyst Navigant), and 11.3 MW for the 10-minute program (1.5% of peak load). The DEIS cites a goal of 32 MW, but is not specific or optimistic about achieving it.

[3] *https://www.washingtonpost.com/news/energy-environment/wp/2016/01/26/the-supreme-court-just-gave-a-great-explanation-of-our-baffling-electricity-system/*

[4] *http://www.forbes.com/sites/jamesconca/2015/02/24/solving-americas-energy-future-requires-a-demand-response/#5964a1457a9f*

Conclusions

The DEIS vaguely describes Alternative 2 using a resigned, pessimistic tone. The alternative seems risky and infeasible, because it was not developed or reviewed by experts with the specialized experience to accurately assess the technologies and potential energy savings.

EQL has described a more realistic way to achieve these energy goals in a manner that is cost-effective, better for the environment, better for our local economy, safer for residents, and more in sync with the Eastside's leading edge, high-tech roots.

Alternative 2 has another advantage. PSE's transmission line is an all-or-nothing proposal. It won't deliver a single electron until every pole is installed and every wire strung. It will not be operational until PSE's customers have spent at least $300 million for it.

By comparison, Alternative 2 can be built incrementally. According to PSE's famous chart, the Eastside Customer Demand Forecast, there will be a shortfall of approximately 10 MW in 2020. It should be easy to meet that shortfall in the next four years using a subset of the technologies described by EQL. Two years after that, we need to find another 15 MW. That shouldn't be too hard. As time progresses, technology will improve, and batteries will become cheaper and more efficient. We may find that it's pretty easy to meet these goals.

But there's another possibility. What if we have another recession? Or what happens if the ridiculous rate of growth (2.4% per year) that PSE is predicting doesn't materialize? In these cases, we could scale back ongoing investments in Alternative 2, saving PSE's customers hundreds of millions of dollars.

The DEIS describes many risks, but it doesn't explain this one. A huge investment in Alternative 1A could create a technology dinosaur that industrializes the Eastside, does nothing to mitigate greenhouse gas emissions, and saddles our children and grandchildren with higher utility bills, leaving less money to invest in the energy technologies of the future. That doesn't seem like a very smart investment.

CENSE.org
February 24, 2016

Alternatives to Energize Eastside

Response to Draft EIS

February 15, 2016

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Figures

1 Introduction

EQL was asked to comment on Alternative 2 "Integrated Resource Approach" discussed in Chapter 2 of the Energize Eastside Draft EIS January 28, 2016.

EQL has reviewed and commented Energize Eastside studies and has participated in several PSE IRP advisory group meetings, EQL has commented on the following topics through Energize Eastside and IRP Advisory process:

1. Distributed energy resources (DER), (e.g., energy efficiency, demand response, dispatchable standby generation, solar, storage, EV charging, CHP, distributed generation, etc.),
2. Demand Side Resource and transmission alternatives to Energize Eastside.
3. Integration of transmission and distribution planning/costs into the utility least cost planning process,
4. Resource adequacy modeling and methods (e.g., EUE expected unserved energy, focus on resource types), and
5. Reliability in IRP, Transmission Planning, and SAIFI/SAIDI statistics, as well as scenario and sensitivity analysis.

EQL is an energy industry consultancy started in 2010 to assist utilities, utility customers, and vendors develop smart grid technologies and business cases that lower cost of utility service, improve reliability, and integrate renewable energy. Our staff has supported IRPs throughout the Western Electricity Coordinating Council and MISO since 1993. Since 2010, our work has been related to smart grid technology evaluation/planning, and integration of renewable energy and distributed energy resources (DER).

EQL's comments are those of EQL, and are meant to promote improved least cost utility planning.

2 Critical Points on EIS Alternative 2

Alternative 2 if done properly could meet criteria for Eastside expected growth in peak load. Unfortunately, the work and discussion of Alternative 2 in the EIS is confusing, insufficient to determine feasibility, uses bad data and forecasts, and demonstrates very little attention by City of Bellevue and PSE.

Many utilities around the world are considering Distributed Energy Resources (DER) to defer or avoid transmission infrastructure, including ConEd (NY), SCE (CA) BC Hydro (BC), BPA (OR/WA), etc.[1], DERs include targeted energy efficiency, demand response, dispatchable standby generation, solar, storage, EV charging, CHP, distributed generation, etc.

2.1 A proper Alternative 2 analysis would prevent increases in Eastside winter peaks and meet all 15 electrical criteria, and 4 non-electrical criteria.

A proper analysis would include accurate peak load forecast, cost effectiveness analysis, and ideally an all source RFI. A rule of thumb Eastside forecast is provided in Figure 1 below.

To put it simply, Alternative 2 DER would avoid ratepayer funding for transmission, distribution, generation, and environmental costs. To meet the peak load growth Puget Sound Energy will request to spend over $300MM on Energize Eastside and another $300MM for a peaking power plant (PSE 2015 IRP). If we assume that expected peak load to be met is 200 MW, the capital expenditure would be $3,000/kW. Most DER, TODAY, can be installed and operated for less. When you consider expected cost reductions and performance improvements Alternative 2 is the lowest cost choice.[2]

[1] https://www.raponline.org/document/download/id/4765

[2] storage cost reductions expected to be 50% over next 5 years, Internet of things, sensors and controls for demand response will become more cost effective and prevalent, EV charging control to avoid peak.

Figure 1: DER potential at PSE above the DSR 100% forecast

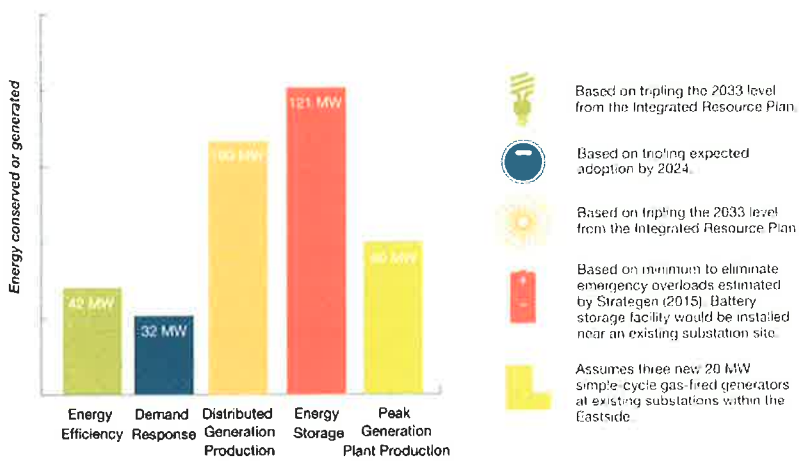
DER Measure	% of winter peak
System Winter Peak load	
Solar	0.0%
Targeted Energy Efficiency	4.0%
Distribution Efficiency (CVR)	2.5%
Combned Heat & Power (CHP)	4.0%
Storage	2.0%
Dispatchable Standby Generation (10 minute)	2.5%
DR Day Ahead	4.0%
DR (10 minute)	1.5%
Total	20.5%

If PSE proceeds with transmission and generation, then DER will become less cost effective. In fact, Idaho Power after finishing construction of their Langley Gulch gas plant tried to shut off all their demand response programs. You don't need DER capacity if your trying to pay off a new gas plant.

2.2 Alternative 2 assessment is insufficient to determine feasibility and lacks credible analysis or estimate.

The EIS provides only a theoretical example of technology that could address winter peak load reductions which has no value in determining feasibility. See example graph in Fig. 2-14 in EIS.

(EIS Fig. 2-14) Theoretical example of Energy conserved or distributed generation



Energy conserved or generated beyond the conservation included in the No Action Alternative

In order to properly assess an Integrated Approach the EIS should either hire independent consulting firm to estimate cost effective DER on Eastside, or issue an all source RFP for all DER in affected eastside area. This process would include all avoided costs and provide actual estimates for DER capacity amounts and cost, as well as real vendors estimates. This process is being used in New York's Brooklyn-Queens Demand Management program which started in 2014. New York utility ConEd is expected to invest $200MM to implement DER to avoid transmission build.

2.3 PSE Eastside winter peak load forecast has been a moving target throughout planning process, and has steadily increased over study period.

PSE has been changing the required winter peak load reduction on the Eastside throughout the Energize Eastside planning process. (see figure below). PSE has a history of changing methods and planning standards when justifying capital expenditures, e.g., peaking power plants. In the 2015 Integrated Resource Plan, PSE changed their planning standard, which led to an increase in 2021 peak load of 351 MW. Figure 1 below summarizes the source and the estimate of peak load reduction required to meet Eastside load requirement.

Figure 2: Range of Estimates for Eastside Peak Load increase through 2024

Source	2024	Date of Source	Page
E3 Non-Wires Study	70 MW	Oct 2014	
Quanta - Eastside Needs Assessment	123	Apr 2015	Page 19
Stantec Review Memo (referenced in EIS)	133	July 2015	Page 1-7 Draft EIS
PSE 2015 IRP	166	Jan 2016	IRP Ch.5 page 31
Draft EIS (2016)	205	Jun 2015	EIS Page 2-34

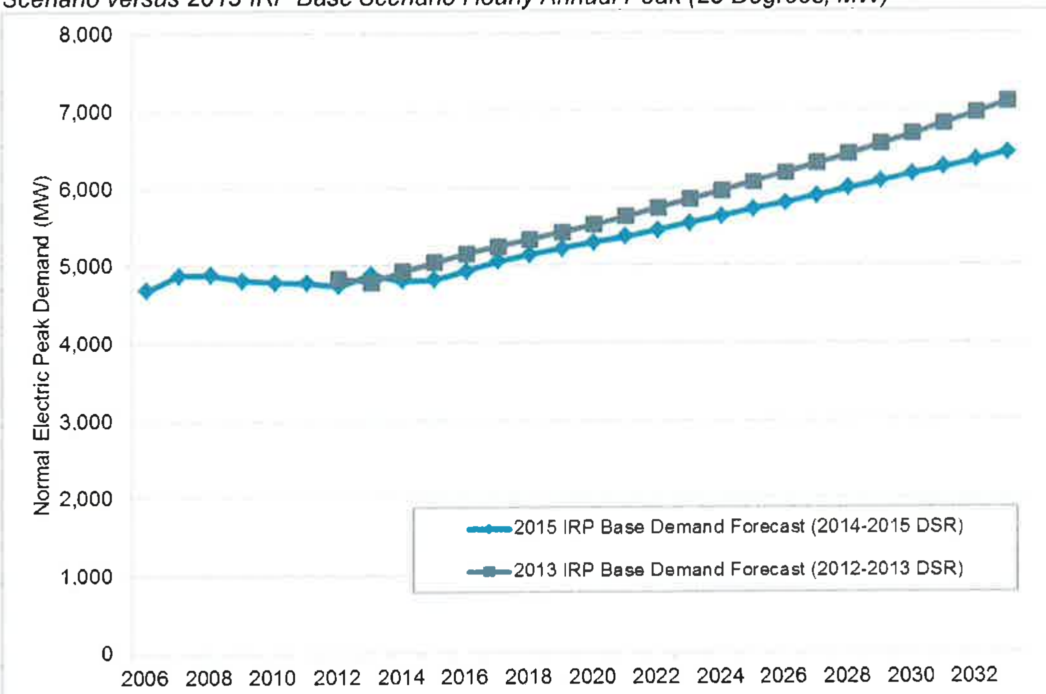
* Assumes peak load after planned baseline energy conservation

The Draft EIS discusses 205MW non-transmission resources needed by 2024, which is a likely mistake. This value stems from an email from Jens Nedrud, Energize Eastside project manager, where he explains that the amount of conservation required to be equivalent to transmission capacity is 205 MW. Mr. Nedrud only mentions conservation, not other DER. Mr. Nedrud is the project manager for Energize Eastside, so estimates from him should be questioned.

2.4 PSE Eastside winter peak load forecast is wrong and has been consistently too high for the past 6 years.

Figure 2 below shows how peak load is historically flat, then suddenly takes off in the future. You'll find this to be true with PSE's previous peak load forecasts. I understand that forecasts are, by their nature are wrong, but PSE has a habit of overestimating peak load.

Figure 3: PSE 2015 IRP *Figure 5-21: Electric Peak Demand Forecast before DSR 2015 IRP Base Scenario versus 2013 IRP Base Scenario Hourly Annual Peak (23 Degrees, MW)*



<u>Winter peaks have gone down</u> in the Pacific Northwest in the last 5 years, and growth in the winter peak will continue to be less than the increase in growth in energy use. PSE's winter peak decreased by 11 MW from 2013 to 2014. This holds true because:

1. Electric heating load is saturated. I.e., new growth does not include electric heating that contribute to winter peak,
2. Fuel Conversion from electric to gas and propane are reducing winter peaks,
3. Milder winter temperatures reduce chance of extreme cold weather, and
4. Higher growth in multifamily and commercial,

PSE's 2011 IRP had peak forecasts rising from 2011 forward.[3] This is not happening.

Notice in Figure 5-27 from PSE's 2015 IRP, the peak demand does not begin to increase until 2024.

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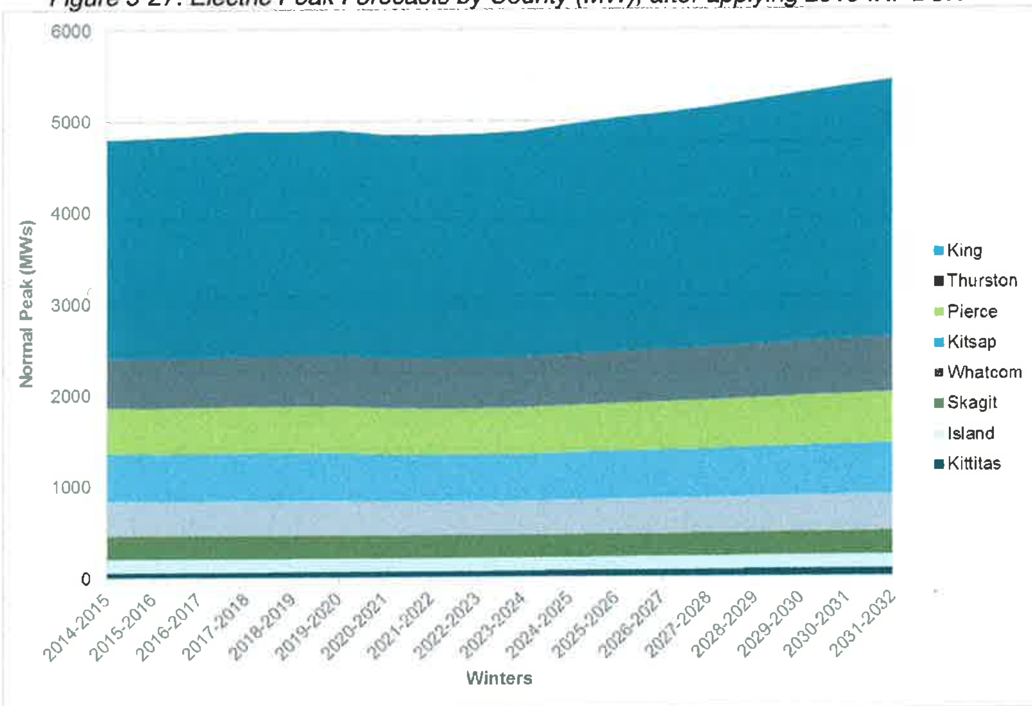
[3] http://www.utc.wa.gov/_layouts/CasesPublicWebsite/GetDocument.ashx?docID=42&year=2010&docketNumber=100961

Figure 5-27: Electric Peak Forecasts by County (MW), after applying 2013 IRP DSR



3 Other Points on EIS Alternative 2

3.1 PSE local needs assessment is not a local cause

PSE has suggested the transmission need is based on local winter peak demand on the eastside. This is only a small part of the story. The issue arises by modeling a series of unlikely regional wholesale power scenarios (e.g., plants offline, Canadian imports, transmission line outages, and high winter peak demand) that creates: 1) high winter power flows South to North through the PSE's eastside transmission corridor, and 2) increased loads on eastside substations. These modeled events would lead to equipment exceeding their thermal limits and the need to shed load at substations or limit power flow on the PSE 115kV system through eastside.

Based on the 2012 Memorandum of Agreement between PSE, Seattle City Light (SCL), and BPA, PSE has agreed to provide expanded transmission service through Puget Sound Area. SCL agreed to projects that would limit flow through their system by placing series inductors at two of their substations. This demonstrates that the issue and needs are indeed a regional one, not just local

This local problem, if it were ever to occur, would happen for a few hours of the year during extreme cold days and hours of peak load on eastside. The EIS extreme scenarios suggest up to 13 days this could occur, but does not forecast number of hours. Given PSE's winter peak is in morning (8am) or evening (6pm) The load reduction would need to be for a few hours during these times. EQL's experience suggests that the winter peaks come in 2-3 day consecutive days (cold snaps) and last maybe one to two hours per day.

According to EIS scenarios, in 2026 eastside load will need to <u>shed 133MW</u> to accommodate flows to Canada over PSE 115kV system.

Another troubling area is how PSE attributed winter peak demand reductions to forecasted energy efficiency measures. It is impossible to determine how PSE and its contractors did this conversion. However, EQL Energy is familiar with the issue that load shapes used in the Pacific Northwest to attribute capacity reductions from energy efficiency are inaccurate and out of date. Some end use load shapes (ELCAP) date back to the 1980s. The topic of inaccurate load shapes and hence capacity contribution of energy efficiency has been consistently discussed and agreed upon by the Northwest Power and Planning Council, as well as the Regional Technical Forum on energy efficiency.

3.1.1 The Problem – several days and a few hours in the winter

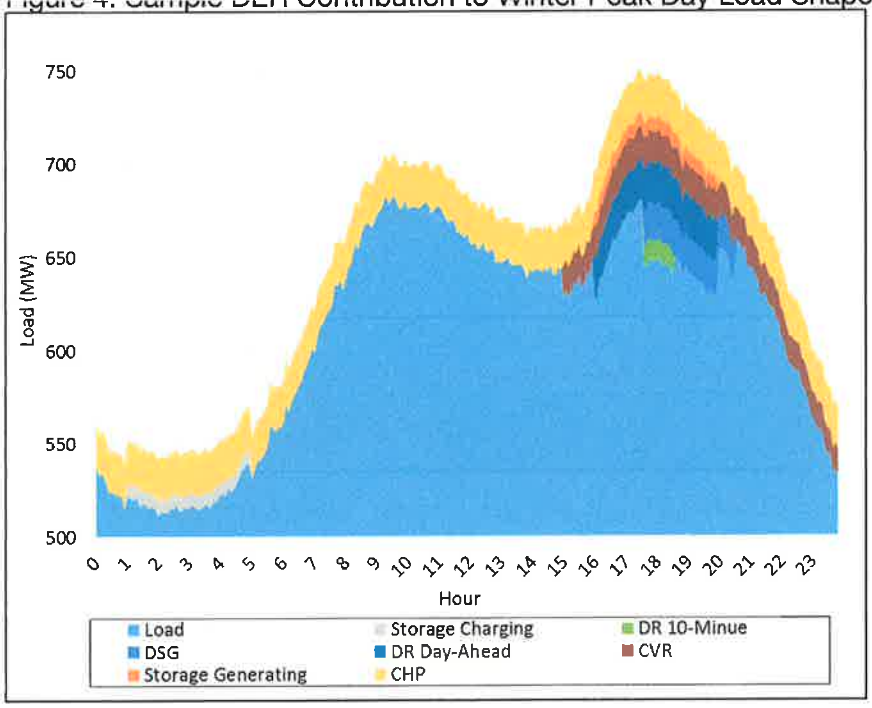
The problem PSE has identified in their Energize Eastside proposal comes about through a series of unlikely events that lead to high winter power flows South to North through the Eastside and creates overloads on certain substations. This problem, if it were ever to occur, would only happen for a few hours of the year. PSE has not estimated the number of hours because the scenarios and stress cases they use don't lend themselves to firm estimates. If PSE could estimate the number of hours they would need winter peak demands to be reduced, it likely would come in 2-3 day consecutive days (cold snaps) and last maybe one to two hours per day.

If Energize Eastside or one of the alternatives were not to be pursued, power outages would not be imminent during these peak demand hours unless at least three failures occur in the grid, a scenario that exceeds NERC reliability requirements. The total number of customers affected by these unlikely outages would be 3 to 5 percent of the 1.1 million customers that will pay for the project with higher electricity bills for the next 40 years.

3.1.2 The DER Solution

Distributed Energy Resources are well suited for targeting winter peak demands in the Eastside Area. Many North American electric system operators invest in DER to avoid transmission and peaking generation. These DER include demand response, storage, EV charging control, DSG, and Distribution Efficiency. If the problem is less than 60 hours per year, it is often much less expensive to manage demand than build Transmission and Generation. Efficiency and CHP tend to provide reductions throughout the day, but can be targeted for time of day contributions. Figure 4 shows a sample peak day load shape for the Puget Sound area with a stack of resources deployed both throughout the day and during a dispatch at 5:30PM during the peak to depict what could happen in the event of an outage.

Figure 4: Sample DER Contribution to Winter Peak Day Load Shape[4]



4 Data source for load shape: Puget Area Net Load for 12.20.2008 http://transmission.bpa.gov/Business/Operations/Misc/default.aspx

* This is not an Eastside area load shape, but is representative of typical winter peak load patterns for NW utilities.

3.2 PSE lags rest of country in DER

Utilities like Puget Sound Energy are way behind other areas of the country in investing in DER, especially demand response. For example, the rest of North America relies on over 60,000MW of demand response, and has eliminated billions of dollars of investments in peaking generation and transmission. The Northwest Power and Conservation Council in their recently released 7th Power Plan, identified 4,300 megawatts of regional demand response potential. PSE currently has no demand response resources it can rely upon.

One example of a DER approach to avoiding transmission project is New York's Brooklyn-Queens demand management project.[5] Growth began to occur in this area from gentrification and employment growth. The utility ConEd estimated the cost to meet this growth would require a $1Billion investment in expanded transmission and substation capacity. In 2014 the Public Service Commission approved the Brooklyn/ Queens Demand Management program to invest up to $200MM to avoid the larger infrastructure costs.

The Northwest is not new to Non-Wire Alternatives. In the 1990s BPA was considering transmission across the Cascades to support Puget Sound Area growth and reliability. The transmission cost assessment led to a plan that included aggressive demand side resources in Puget Sound Area, and use of series capacitors for voltage support. These lower cost alternatives deferred the project to the point of never being built.

3.3 EIS Impacts of Alt 2

The negative impacts of Alternative 2 were primarily associated with peaking generation and storage located on the Eastside, and relate to land and greenhouse gas (GHG) emissions.

EQL Energy, however, is not suggesting any new reciprocating engines, or peaking power units as part of EIS Alt. 2. We would expect primarily Combined Heat and Power (CHP) to be constructed in this alternative. CHP often uses biomass/biogas as well as natural gas, and would contribute to GHG, or could have noise impact. CHP has the benefit of also being "energy efficient" because the low value heat is used in industrial or commercial processes. Puget Sound Area has examples of CHP, e.g.,

a. Renton, WA South Treatment Plant that can produce up to 8MW of power. [6]

b. Seattle, WA Enwave Seattle uses biomass and natural gas to produce 50 MW of electricity, and 35 MW of heat equivalent.

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[5] http://www.neep.org/file/2414/download?token=bNV2vVea, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B83594C1C-51E2-4A1A-9DBB-5F15BCA613A2%7D

[6] http://www.kingcounty.gov/services/environment/wastewater/resource-recovery/Energy/Renewable/cogen.aspx

c. Univ. of Washington has 5MW natural gas CHP

CHP would require capacity on natural gas infrastructure.

A Dispatchable Standby Generation (DSG) program would have to go through air permitting compliance, but it is a permittable use. PSCleanAir has suggested that a DSG program like PGE would follow EPA NESHAP RICE rules.

EQL Energy would not recommend storage implementation as described in Alt. 2 of EIS. Six acres of storage does not make much sense. Energy storage highest value is utility owned and managed, yet behind the meter at a customer site. This means customers get backup and reliability, and utility can use for system issues, e.g., winter peak demands. This also avoids the 6 acres of storage containers suggested in the EIS draft (which is ridiculous). Fire and environmental authorities are becoming comfortable with both Li-ion and flow battery technology. PSE is working on a Li-ion storage system at Glacier. State of Washington is also granting $40MM to projects in grid modernization and storage.

Alt 2 would cost less than Alt 1 and provide secondary benefits to customers through improved reliability and resiliency.

Alt 2 would have less risk during weather and natural disasters. DERs would provide backup power during intermediate or sustained outage.

3.4 Alt 2 works with PSE Economic Study of Flexible AC Transmission (FACTS).

Flexible AC Transmission systems on high voltage lines would protect PSE transmission facilities from reaching thermal limits while providing required service to loads. Combining this alternative with appropriately procured and analyzed DER provides a good alternative in Draft EIS.

See PSE Economic Study request at link below.

http://www.oasis.oati.com/PSEI/PSEIdocs/
Oct_31_PSET_Economic_Study_Request_from_EQL.PDF

4 Alternative 2 Issue Details

In estimating Non-Wires Alternatives (NWA) like Alternative 2, PSE and its contractors have miscalculated both the technical and cost effective potential for DER in the Eastside area. They have used outdated information and methods, overestimated winter peak demand, improperly calculated "cost effectiveness", and have not considered forecasts of technology cost and performance improvements.

4.1 2014 Non-Wires Alternative Screening Study underestimates DER Potential for Eastside

PSE relies on 2013 Cadmus report and a 2014 E3 report to estimate DER potential on the eastside. These analysis both have used bad or out-of-date data, improper analysis, and have underestimated the DER potential for the Eastside.

E3's 2014 Screening study[7] has bad data and provides no data or description of DER measures that were considered cost effective beyond the PSE baseline:

i. Estimated cost of Energize Eastside at the time of the Screening Study was $220 MM. The cost has been stated to be between $150 and $300MM.

ii. Avoided cost analysis should use avoided cost of Transmission, Generation, and Distribution over 10 year period. A non-wires study should be performed that combines EE project deferral ($155/kW-yr) with avoided cost of peaking Generation Capacity ($184/kW-yr) and generic T&D deferral ($23/kW-yr[8]). The sum of these ($362/kW-yr) will buy PSE more DER than that forecasted by E3 and PSE. Other avoided costs that could play a role include environmental costs, customer cost savings, etc.

    PSE's proposal to rebuild Sammamish-Lakeside-Talbot 115 kV line to 230 kV (Energize Eastside) is a project PSE says is needed to support a 65 to 133MW load growth in PSE's eastside. This transmission project is estimated to cost $300MM or $1,500/kW, about the same capital cost of a 200MW reciprocating engine. By integrating cost of transmission with system generation the cost to serve this 200MW load growth is $600MM or $3,000/kW capital cost.

iii. DER alternatives and cost estimates are not well defined, so it is difficult to evaluate the accuracy of Alternative 2.

iv. Include backup generators to be used as contingency reserve (e.g., Portland General Electric).

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[7] http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/attachment_5_-_screening_study.pdf

[8] E3 2014, page 23 PSE's IRP team also provided avoided generation capacity cost of $184/kW-year and an avoided generic T&D cost of $23/kW-year, which are both represented in 2014 dollars. For this analysis, we assumed that PSE's generic T&D avoided cost and the specific transmission line deferral value related to PSE upgrades are additive. This additive assumption presumes that load reductions in King County can defer the need for more general planned distribution system upgrades, in addition to deferring the construction of the specific Eastside upgrades.

v. Storage is quickly becoming more cost effective and accepted as an alternative to T&D investments.

Recommendation. PSE should redo DSR, DR, and DER forecasts on Eastside using all levelized costs, including transmission (e.g., Energize Eastside), distribution, and supply-side resource alternatives. This will undoubtedly increase the amount of DSR and DER PSE has forecasted in the Draft IRP.

2016 PSE all source RFP. In 2016 PSE is expected to issue an all source RFP for distributed resources. WUTC should ensure that the avoided cost for resources in the Eastside accurately reflect all avoided costs, e.g., transmission, generation, distribution, customer benefits, environmental costs, etc. Through needs assessment of Energize Eastside, PSE's Eastside zone needs winter capacity resources to address transmission congestion and reliability by 2018. The IRP analysis supports addition of further distributed energy resources by 2021.

4.1.1 Defining distribution located resources

PSE should move away from current categories of distribution-side resources towards resource descriptions that meet utility requirements (energy, capacity, reserves, etc). As mentioned above these requirements need better descriptions than just MW and aMW. These requirements need amount, duration, time of day/season, etc.. The distribution located resources PSE has used 3 categories of distribution located resources seen in Cadmus report 2014:[9]

1. DSR, Demand Side Resources, energy efficiency. (which uses bad estimates for peak demand reductions (MW)
2. DR, demand-response
    a. Residential DLC- Water Heat
    b. Residential DLC – Space and Water heat
    c. Residential Critical Peak Pricing (CPP)
    d. C&I CPP
    e. C&I Load Curtailment
3. DG, distributed generation, solar

Figure 5 is suggests a better way to describe all distribution level resources. This categorization allows planners to place different values on a resource based on its quality and location. For instance, getting dispatchable capacity for winter peaks is more valuable ($/kW-year) than non-dispatchable capacity.

[9] https://pse.com/aboutpse/EnergySupply/Documents/IRPAG_Cadmus_presentation_2014-12-08.pdf

Figure 5: EQL Categories of Distributed Energy Resources

4.2 Energy Efficiency contribution to peak demand reductions underestimated

PSE and its consultants use end use load shapes that are out of date to calculated peak demand reduction from energy efficiency programs. Many of these load shapes are based on end uses and technologies from the 1980s. This leads to lower peak reduction (MW) per unit of energy efficiency (MWh). The Northwest Power and Conservation Council has been building a business case to update these load shapes, and is expected to pursue this work in 2016.[10]

4.3 Puget Sound DER and DSR avoided Cross-Cascades Transmission in 1990s

In the 1990s BPA was considering transmission across the Cascades to support Puget Sound Area growth and reliability. The transmission cost assessment led to a plan that included aggressive demand side resources in and use of series capacitors for voltage support. These lower cost alternatives deferred the project to the point of never being built.

DER, when cost of Transmission is considered, will increase dramatically. Estimates in Figure 2 below are estimates based on EQL estimates from WECC and NPCC forecasts.

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[10] http://rtf.nwcouncil.org/subcommittees/enduseload/

4.4 Western electricity markets

On March 5, 2015, PSE announced it would participate in the California ISO energy imbalance market that will provide imbalance energy via locational marginal pricing. This decision by PSE management to participate in EIM, demonstrates that PSE believes in a planning and operational paradigm that explicitly recognizes locational value of generating and demand-side resources.

PSE participation in Western energy imbalance market will allow better management of existing transmission assets to existing generation and load balance. In Energize Eastside assessment, PSE has not considered the operational improvements that will exist for generation, demand management, and DER.

PSE joining the EIM does not have much effect on capacity procurement, except a possible reduction in flexibility requirement for resources.

5 Assessment of Eastside DER Potential

EQL Energy expects PSE could add over 160MW of capacity to Eastside DSR forecast by 2021. below. Using an Avoided Cost analysis that includes avoiding cost of Transmission, Distribution, and supply-side generation should include:

Capital Cost ($/kW)	$1,500/kW	Transmission
Capital Cost ($/kW)	$1,500/kW	Thermal Resource (e.g., Peaker)
Capital Cost ($/kW-yr)	$31.00	Distribution
O&M Fixed $/kW-yr	$10.55	
O&M Variable $/MWh	$2.96	

5.1 DSR and DER Contribution

The terminology around resources on the distribution side can be confusing. PSE uses DSR or demand side resources, which includes energy efficiency, demand response, and distributed generation. The EE Documents we reviewed focus on energy efficiency and do not fully address DSR and its impact on peak capacity (MW). Analysis that is reported in Annual Average Megawatts (aMW) provides limited useful information for analyzing for transmission and distribution infrastructure needs.

In our report, we distinguish between DSR and DER forecasts and work to not double count resources.

<u>DSR – Demand Side Resources</u>: efficiency, demand response, and distributed generation (detail and types are unknown in PSE EE analysis). Cadmus 2013 IRP DSR

assessment does not include kW or peak contribution, nor do they provide DR assessments.
DER – Distributed Energy Resources: EQL uses this term to refer to all resources on the distribution system, including distribution efficiency (CVR and power factor correction), demand response, combined heat and power, dispatchable standby generation, and storage.[11]

DER and load management in critical areas is an opportunity to invest in measures that address infrastructure costs and regional load growth while engaging and benefitting customers, just like energy efficiency. Through the evaluation of Energize Eastside it is unclear the extent to which PSE has considered the use of distributed energy resources (DER) in their modeling, either as a resource or as a means to reduce load.

The DER resources described below should be considered in addition to the PSE's DSR contribution to the 100% conservation load forecast.

Many of these DERs are dispatchable, including demand response, dispatchable standby generation (DSG), and energy storage and can therefore target peak load and reduce the need for infrastructure expansion in transmission and distribution.

5.1.1 Distributed Resource Planning

The DER contribution to peak load should be appropriately allocated among existing and future Eastside substations such that DER quantity reasonably matches the load assumed to be present at these substations.

Figure 8 below shows substation locations in the Eastside area that have historically recorded higher load and may be more likely to serve larger customers sites with high DER potential such as commercial/industrial, multifamily residential, institutional, government, campus and hospital loads.

Distributed Resource Planning is a process which more accurately calculates capacity and value for DER in specific areas of a utility distribution system.

On February 6, 2015 the CPUC released a ruling providing guidance to IOUs with respect to the DRPs that are to be filed by July 1, 2015. The document[12] provides additional guidance to utilities beyond AB 327. The guidance specifics 11 components that are to be included, at a minimum, in the locational DER benefits analysis.

Figure 6: Distributed Resource Planning Value Analysis

Locational Value Component	
1	Avoided Sub-transmission, Substation and Feeder Capital and Operating Expenditures: DER ability to avoid Utility costs incurred to increase capacity to ensure the system can accommodate forecasted load growth

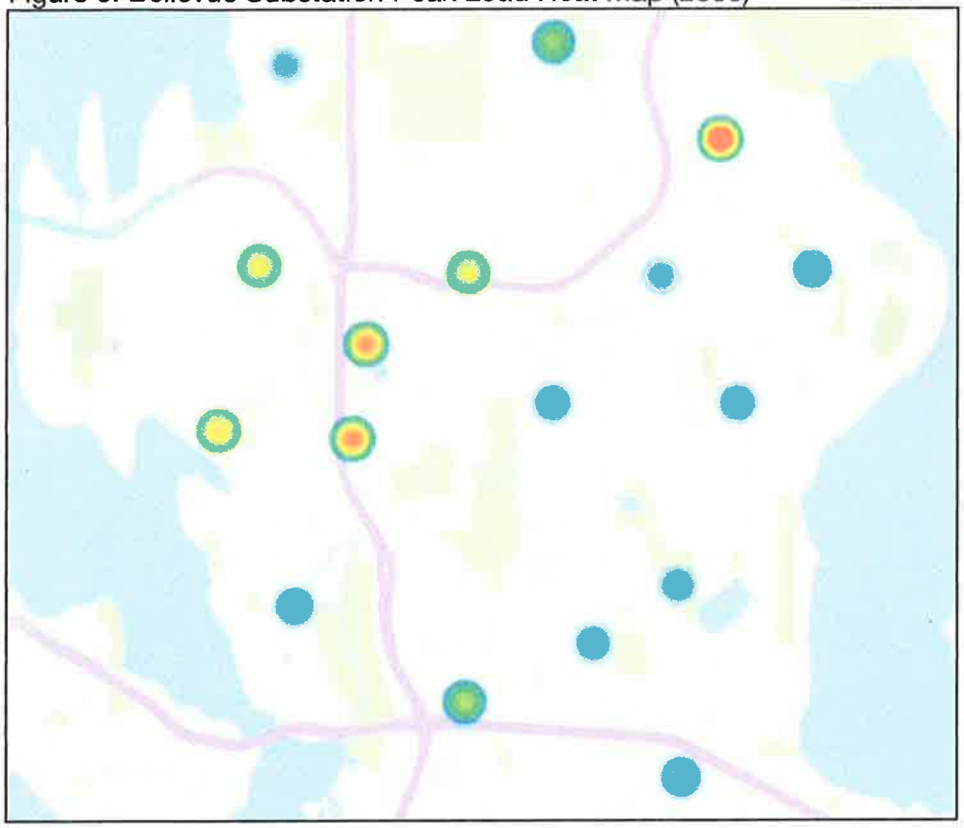
[11] In California Distribution Resources Planning they include energy efficiency into their DER analysis.

12 Docket R14-08-013 DRP Guidance: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K374/146374514.PDF

2	Avoided Distribution Voltage and Power Quality Capital and Operating Expenditures: DERs ability to avoid Utility costs incurred to ensure power is delivered within required operating specifications, including transient and steady-state voltage, reactive power and harmonics
3	Avoided Distribution Reliability and Resiliency Capital and Operating Expenditures: DERs ability to avoid Utility reliability related costs incurred to prevent, mitigate and respond to routine outages (Utilities shall identify specific reliability metrics DERs could improve), and resiliency related costs incurred to prevent, mitigate, or respond to major or catastrophic events (Utilities shall identify specific resiliency metrics DERs could improve)
4	Avoided Transmission Capital and Operating Expenditures: DERs ability to avoid need for system and local area transmission capacity
5	Avoided Flexible Resource Adequacy (RA) Procurement: DERs ability to reduce Utility flexible RA requirements
6	Avoided Renewables Integration Costs: DERs ability to reduce Utility costs associated with renewable integration (for this line item, the Utilities shall attempt to coordinate their efforts with the development of the updated RPS Calculator and the Renewables Integration Charge)
7	Any societal avoided costs which can be clearly linked to the deployment of DERs
8	Any avoided public safety costs which can be clearly linked to the deployment of DERs
9	Definition for each of the value components included in the locational benefits analysis
10	Definition of methodology used to assess benefits and costs of each value component explicitly outlined above, irrespective of its treatment in the E3 Cost-Effectiveness Calculator
11	Description of how a locational benefits methodology can be a into long-term planning initiatives like the Independent System Operator's (ISO) Transmission Planning Process (TPP), the Commission's Long Term Procurement Plan (LTPP), and the California Energy Commission's (CEC) Independent Energy Policy Report (IEPR), including any changes that could be made to these planning process to facilitate more integrated analysis

Figure 7: DRP locational value components (CPUC DRP Guidance)
Notes:
The Resource Adequacy (RA) program, administered by the CPUC and CAISO is a 1-year forward bilateral capacity market. Utilities must procure sufficient resources to meet their expected peak load. Since it began in 2006, utilities were required to procure system-wide peak capacity resources, and local resources as needed in constrained areas. In 2013, a flexible resource requirement was added.

Figure 8: Bellevue Substation Peak Load Heat Map (2006)



Sources:
Data: City of Bellevue substation peak load for 2002 and 2005[13]
See Appendix A for data table
Map: EQL (using Microsoft Excel/Bing Maps)
Note: PSE's transmission topology in this area has changed and is expected to continue to change to serve changing load patterns, therefore this rendering is for sample purposes only.

PSE's existing 115 kV network in the Eastside with suggestions of areas that may experience higher load growth, may require additional infrastructure such as new substations, and therefore would represent advantageous locations for PSE and/or other appropriate parties to incentivize and site distributed energy resources.

Customer Driven DER

DER adoption behavior and demand for services is customer driven based on broad socio-economic factors and technology advancements –not strictly regional or based only on energy cost.

Customer desire for self-reliance is increasing

13 City of Bellevue Comprehensive Plan Utilities Element Update, November 2006 http://www.ci.bellevue.wa.us/pdf/PCD/PSE_System_Plan_Update_November_2006.pdf (accessed 06.08.2015)

- **Ernst & Young**: **33%**of the multi-national firms are expected to meet a greater share of their energy needs through **self-generation over the next five years**
- **Navigant**: nearly **75%** of surveyed **residential customers** have "**concerns about the impact electricity costs** have on their monthly budgets, and **63%** are interested in **managing energy used in their homes**"
- **Best Buy**: **36% of residential** customers desire to "financially and physically protect the home" (Home Safeguarding persona)

5.1.2 Distributed Solar

PSE currently has 2,800 customers and 17.4MW of capacity producing 17,037MWh of energy a year. As mentioned above, the Cadmus March 2015 memorandum has many errors regarding PV Solar forecasting and should not be reference by PSE. EQL suggests the following as an estimate of growth in energy from distributed solar.

Figure 9: Range of Distributed Solar by 2030

MW	Capacity	Energy	
	MW	MWh	aMW
Minimum	5	5,000	0.57
BaseCase	50	50,000	5.71
Maximum	400	400,000	45.66

5.1.3 Distribution Efficiency (aka CVR)

In 2007 Puget Sound and 12 other Pacific Northwest Utilities participated in a Northwest Energy Efficiency Alliance (NEEA) pilot to evaluate the energy and capacity savings from operating Conservation Voltage Reduction. [14] The study tested and found a 2 to 4 percent capacity reduction through distribution efficiency projects. An updated 2014 NEEA study found that over half the CVR projects operating in the United States are used for peak demand reductions versus energy efficiency. [15]

Wide scale adoption is beginning. One hurdle to adoption was mentioned in NEEA paper as, "hurdle to CVR implementation includes the lost customer revenue due to CVR rollout. End users reduce energy consumption with CVR and thus lower utility revenue. Utilities are often reluctant to recuperate lost revenue through rate increases, especially during times of slow or no load growth in the utility service area. Utilities can recuperate lost revenue from CVR more easily during periods of more rapid load growth. BPA currently offers incentives for CVR initiatives, which can help with utility cost recovery."

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[14] https://www.leidos.com/NEEA-DEI_Report.pdf

[15] http://neea.org/docs/default-source/reports/long-term-monitoring-and-tracking-distribution-efficiency.pdf?sfvrsn=5 (page 45)

In Washington, Energy efficiency standard I-937 is currently a main driver for CVR implementation for IOUs in Washington State. I-937 mandates IOUs to undertake cost effective energy efficiency measures, such as CVR.

PSE has implemented Conservation Voltage Reduction (CVR) on three to six PSE substations before energy is sent to customers, thereby reducing customers' electric power consumption at the point of consumption on the customers' side of the meter.

CVR will be useful to PSE during winter peak load events due to the influence of resistive loads during those times. Reducing voltage is more effective for winter resistance heating load than for other types of load such as motors that experience greater use in summer for cooling loads.

CVR Target: 2.5% of peak load

5.1.4 Demand Response

By 2021 NPCC estimates the Pacific Northwest states will obtain between 600 and 1,080 MW (or 3%) of winter peak through demand response. At present, only a fraction of that quantity is operational. The Council is currently preparing their 7th power plan and has been working with regional utilities and industry stakeholders. [16]

In a 2015 report for NPCC, Navigant estimates that by 2030 Northwest utilities will have achieved nearly **9% of winter peak** load from demand response.

> *The estimated cumulative DR market potential for capacity programs represents nearly 9% of winter peak load by 2030. This estimate is in line with estimates of other DR potential studies conducted both in the Northwest and other parts of the country.*[17]

Cadmus 2013 DSR report for PSE IRP (page 7) suggests that by 2033 PSE could expect **4.7% of winter peak** to be reduced by Demand Response. Cadmus (2013) is approximately half of Navigant (2015) winter peak reduction forecast.

Two types of DR are likely to be beneficial for eastside areas:

1. Day-Ahead notification peak load reduction DR
2. Emergency 10-minute response DR

Because PSE identifies a peak load resource requirement for the Eastside, we have identified a need to study a demand response program to operate during these times, when PSE's most expensive resources will likely be supplying power. DR programs are often cost effective when displacing this expensive generation, such as PSE's peaking units in Whatcom County. When combined with the additional value of

[16] https://www.nwcouncil.org/news/meetings/2015/06/

[17] http://www.nwcouncil.org/media/7148943/npcc_assessing-dr-potential-for-seventh-power-plan_updated-report_1-19-15.pdf

providing an infrastructure alternative, the cost effectiveness of such a DR program is improved. Many utilities have implemented day-ahead notification DR programs that call upon enrolled customer or 3rd party resources to reduce their demand for a specified duration, typically 2-4 hours.

In addition, emergency DR programs have successfully been implemented that are capable of fast response for contingency reserve purposes. An example is a 10-minute response program run by Southern California Edison.[18] These programs are typically of higher value due to the short notice time and reliability service provided. SCE's program pays customers $240/kW-year for capacity that successfully participates.

For purposes of the EIS analysis, we have requested conservative DR quantities, shown in Figure 10, for the eastside area that are reflective of percentages of peak load that have been achieved in other areas and below those estimated by Navigant (2015).

Figure 10: Eastside Area DR by 2021

	Eastside DR Estimate
Day-Ahead DR quantity	4%
10-minute DR quantity	1.5%

Because PSE has indicated it may include DR at a level of approximately 2.7% of load by 2020, the 4% DR estimate above for day-ahead programs is incorporated into the 100% conservation forecast used by PSE.[19]

WECC rule Bal-002-WECC-1 was referenced by PSE[20] as one of the reasons the reserve amounts are increasing. This same rule allows a balancing authority to use a number of different resources to meet this requirement including demand response:

> "* A resource, other than generation or load, that can provide energy or reduce energy consumption
> * Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement."

5.1.5 Dispatchable Standby Generation (DSG)

Portland General Electric's DSG program can be used as an example for one designed to provide enhanced reliability in the Eastside area. The DSG program connects customer backup generators to the distribution grid using parallel switchgear at sites such as hospitals, commercial/industrial, and government buildings. PGE remotely dispatches the generators, which are capable of providing uninterrupted service to

[18] https://www.sce.com/NR/rdonlyres/7A1BC024-698D-44A0-98D1-ABD8DEE9E451/0/NR572V20810_BIP.pdf

[19] May 19 PSE IRP Advisory Group meeting materials

[20] PSE IRP Chapter 6 page 16

customers in the event of a grid outage. As part of the program, PGE invests in and owns some of the interconnection equipment, pays for fuel, and performs ongoing testing – required for units at many sites such as hospitals.

DSG potential is determined by using a simple proportion of peak load to DSG capacity installed at PGE and applying it to PSE, as shown in Figure 11 below.

Figure 11: Potential DSG by 2021

DSG Potential	MW
2018 PGE System Peak	4000
Current PGE DSG Capacity	94
DSG MW per System MW	2.5%
2018 PSE System Peak	6000
2018 Eastside Peak Load Forecast	750
PSE System DSG Potential	141
PSE Eastside Area DSG Potential	**18.8**

Note that the size of PGE's DSG program is growing and has plans to increase the program capacity to 125 MW in the next 5 years. Using the proportion method described above, Eastside DSG potential would increase to 22.7 MW.

While the simple DSG potential figures provided here are adequate to inform planning at this stage, additional detailed analysis of DSG capacity will be valuable to PSE and Eastside reliability regardless which transmission projects are built. PSCleanAir has suggested that a DSG program like PGE would follow EPA NESHAP RICE rules. Developer of DSG program would have to go through air permitting compliance, but it is a permittable use.

PSE evaluated using DSG as part of a stipulation in Washington Utilities and Transportation Commission (WUTC) Order 06 in docket UE-130617, in which both parties agreed that PSE should perform an evaluation. Specifically, the Settlement agreement states: PSE agrees to evaluate the PGE Dispatchable Standby Generation (DSG) program, described in the testimony of staff witness Juliana Williams, and either provide a report to the Commission of PSE's conclusions and recommendations by December 1, 2014, regarding the financial and technical feasibility of PSE implementing a similar DSG program in its territory, or file a tariff implementing DSG service by December 1, 2014.

EQL evaluated the PSE report and finds it evasive, inconclusive, and provides the following feedback.

Specific Comments on PSE DSG Findings and select sections. (Dec. 1, 2014)

PSE Findings and Issues	Comment
The primary benefit of the PGE DSG program has been the ability to use the standby generators as a cost-effective resource to meet non-spin operating reserve obligations.	True

PSE does not have a near-term need for non-spin operating reserves and has maintained more than adequate operating reserves during peak events	PSE can use DSG to meet winter peak demands.
While originally established as peaking resource, PGE's use of its distributed standby generator fleet as a peaking resource has been *de minimis* during the life of the program	True. Program is not used as peaking resource.
New Environmental Protection Agency (EPA) emissions requirements that limit operation and testing on diesel-fired emergency standby generators create uncertainty and potential operational constraints during times of peak need	True that EPA rules are in flux for legal reasons. Current laws to watch are state and local air permits. PSCleanAir has suggested that a DSG program like PGE would follow EPA NESHAP RICE rules
Under normal conditions, PGE's standby generator fleet is not economic compared to other alternatives during dispatch decisions	DSG resources are not part of normal dispatched resources
PSE lacks sufficient market research of its customers that would justify investment in a DSG program including potential participation rates and standby generator inventory	Getting this information would be very easy
It is unlikely PSE would be able to implement a DSG program to meet any near-term capacity needs given time, resources, and current systems capability	PSE has time to develop DSG
Section 4.6 Compliance	
Section 5.2 Constraints and Opportunities	
Market Barrier. The 2011 CBRE market search led to no customers expressing interest in further engagement with PSE to interconnect a standby generation system to the grid.	PGE Customers are not that different than PSE Customers. It takes a clear customer value proposition and a few key customers to get it started.
Monitoring and dispatch. PSE does not own software that allows for monitoring and dispatch. PSE need operational and technical knowledge to operate new software.	EQL can assist.
Interconnection. PSE needs specifications for interconnecting standby generators. PSE does not have interconnection agreement	EQL Team can assist
PSE has several low-cost resources to meet non-spin reserve obligations.	**Contradicted in IRP**
Operating reserves exceed need by 200-400MW in most peak hours.	**Contradiction with IRP forecasts**

The NERC contingency reserves standard (BAL-002-WECC-2[21]) applies to the NW Power Pool Reserve Sharing Group (RSG), and requires the RSG to carry the larger of: 3% of load + 3% of generation OR the **Most Severe Single Contingency (what is this for PSE?).** Contingency reserves can be comprised of any combination of seven types defined in the standard. DSG is categorized as the Operating Reserve – Supplemental subcategory of Contingency Reserve. This reserve type was formerly

21 http://www.nerc.com/files/BAL-002-WECC-2.pdf

defined as Non-Spin reserve, but was changed to supplemental in the current standard to be inclusive of demand side management pursuant to FERC Order 740.[22]

E3 incorrectly ruled out DSG in their 2014 non-wires study for Energize Eastside. They wrote,

> "The US Environmental Protection Agency (EPA) prohibits PSE from relying on customer-sited backup generation for peak shaving of utility loads for resource planning purposes, which PSE planners believe would prevent them from planning grid conditions that rely on backup generation to defer transmission upgrades. This regulation exists primarily to protect local air quality. Therefore, customer-sited backup generation was excluded from the DG non-wires potential estimates."

5.1.6 Combined Heat and Power (CHP)

CHP is the simultaneous use of a fuel, primarily natural gas, to generate electricity and provide heat. When properly designed, CHP is capable of operating at higher efficiency than typical central station power plants.

PSE's Non-Wires Screening Study[23] CHP analysis, performed by E3 and informed by earlier work by Cadmus, found approximately 1 MW of peak CHP resource by 2023 across all of PSE's King County service area. Because this quantity can reasonably be achieved in a single building, the previous estimate is likely not reflective of actual potential. In order to determine this potential, a new study is warranted, especially in light of the amount of growth expected to occur in Bellevue and PSE's need for peak capacity resources.

With the cost of capacity to utilities often exceeding $100/kW-year, infrastructure deferral benefits and electricity sales revenue are components that contribute to cost effectiveness determination and would inform the ultimate potential of this resource. PSE needs over 1000 MW of new capacity by 2025, according to recent IRP development information.[24]

150 MW of load growth could occur in the Bellevue downtown and Bel-Red areas in the next 20 years.[25] The new development represents a large opportunity because many DER technologies such as CHP make the most sense when incorporated during the design phase and provide further benefits when central utility plants serve multiple buildings. But such a strategy requires deliberate planning and clear leadership to become successful.

Because Downtown and Bel-Red will consume significant quantities of natural gas regardless of PSE's electricity infrastructure decisions, the extent to which this gas can be put to use generating electricity should be studied. Additionally, the civil construction work to occur in these areas in future years points toward investigation of co-locating energy infrastructure and potentially common use infrastructure such as district energy where central utility plants supply heating, cooling and electricity to a potentially large development, such as the Spring District.

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[22] http://www.ferc.gov/whats-new/comm-meet/2010/102110/E-6.pdf

[23] http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/attachment_5_-_screening_study.pdf

[24] May 19 PSE IRP Advisory Group meeting materials

[25] Exponent Reliability Study

Recommendation: Explore 3rd party or PSE owned central utility plants with CHP in parts of the Eastside that will experience the most new construction.

Figure 12: Base CHP Quantity 2021

	Eastside CHP Estimate
CHP	4% of peak load

Note:
Transmission topology alternative D adds Eastside generation. Because a larger central plant CHP project should be considered for this option, selection of this alternative could result in a substantially higher CHP penetration.

5.1.7 Energy Storage

Energy Storage is receiving a great deal of attention right now due to the cost declines seen in recent years and an increasing number of predictions for continuing storage cost reduction.[26] PSE, Avista, and Snohomish PUD have received $15MM to study use of energy storage.

Figure 13: Energy Storage Quantity 2021

	Eastside Storage Estimate
Storage	2% of peak load

5.1.8 PSE DER Potential & Interconnection

Many existing and future commercial, multifamily residential, institutional and corporate campus sites are centered near downtown Bellevue, Bel-Red and South Redmond– areas that are driving the need for new transmission and distribution infrastructure. Cost effectiveness of DER investments in these areas stands to be influenced to the extent they can substantively contribute to load service and reliability needs. In other words, a next-generation energy system, which is being pursued by leading utilities, will make full use of DERs by integrating their capabilities into utility planning and operations, a step that may well deliver cost reductions to PSE ratepayers – and one that will require developing appropriate compensation mechanisms to DER owners. In addition, PSE or 3rd parties could own DERs that may be designed to provide benefits directly to specific customers (i.e. storage installed behind-the-meter), while simultaneously providing infrastructure deferral benefits enjoyed by all ratepayers.

DER interconnection and operations practices will become more important as these resources grow in quantity and take on additional performance obligations related to reliability and system resiliency. Should PSE and Eastside communities decide to move to make full use of DER options as part of a strategy to support and enhance regional growth, appropriate technical interconnection and operations procedures and

[26] Sample media story addressing storage:
http://cleantechnica.com/2015/03/04/energy-storage-could-reach-cost-holy-grail-within-5-years/

standards will be needed. DER best practices are emerging from California, New York, and Hawaii, states that have taken the lead. The standards by which PSE designs and operates the 12.5 kV distribution system will be important for DERs so as to ensure maximum utilization of the system, including supporting 2-way power flows.

Most distribution systems move electricity in one direction – from power plants to substations to customers. But when customers interconnect generation resources, their power will flow the other direction, serving other customers and in some cases flowing power back to the substation itself and serving load further upstream, possibly at higher voltages. While there is no fundamental reason why these new flows of electricity cannot occur, investments in additional monitoring equipment and advanced control technologies will be needed.

These types of investments, involving software, communications, controls, and switching equipment, are also likely to provide reliability benefits by enhancing the ability of utilities to automatically switch customers to alternate feeds in the event of an outage on a given distribution circuit.

Heidi Bedwell, Energize Eastside EIS Program Manager,

372 people have signed a petition on Action Network telling you to Correct flaws in the Energize Eastside Draft EIS.

Here is the petition they signed:

> Dear Ms. Bedwell,
>
> I am very concerned about Puget Sound Energy's "Energize Eastside" project, which proposes to build 18 miles of high-voltage transmission lines through four Eastside cities (Alternative 1A).
>
> PSE tries to justify the need for the project using an impossible scenario that would cause regional blackouts, according to the Lauckhart-Schiffman Load Flow Study, available at CENSE.org.
>
> Alternative 1A would place new lines and poles much too close to aging petroleum pipelines. Responsible safety standards require at least a 50 foot separation. A construction or operational accident could cause a catastrophic pipeline explosion like the one that killed three Bellingham residents in 1999. This risk is not adequately addressed in the EIS.
>
> Alternative 2, the Integrated Resources Approach, is a safer and less costly alternative. But the solution described in the EIS was not developed or reviewed by independent experts that have suitable experience with modern electrical grid technologies, including Demand Side Management and Distributed Energy Resources. The costs and capabilities are based on inaccurate and obsolete studies. As the Northwest Power Council's Seventh Power Plan makes clear, a carefully developed plan would easily beat alternative 1A in cost, safety, and support for the environment.
>
> The other transmission line options (1B, 1C, 1D and Alternative 3) are not practical for financial or political reasons.
>
> Ratepayers are asked to spend more than a billion dollars over the lifetime of PSE's transmission line. The Draft EIS must answer these basic questions in order to convince residents that we are getting the best possible plan for our energy future.

You can view each petition signer and the comments they left you below.

Thank you,

Don Marsh

---

1. Limei Xie (*zip code: 98006)*

2. Susan Smith (*zip code: 98006)*
The safety of residents living near the natural gas pipelines should be of the utmost concern. Building

high voltage transmission lines on top of aging pipelines puts my family and my neighbors at risk. Please reconsider the necessity and safety of "Energize Eastside" proposal.

3. li_qin xie (*zip code: 98006)*
negative impacts on environments; safety issues to our communities;

4. Aaron Peloquin (*zip code: 98056)*

5. Jenny Choi (*zip code: 98006)*

6. meifang zhou (*zip code: 98006)*
It is a disaster, too dangerous to control if happening accidence

7. Aileen Wu (*zip code: 98006)*
Please do not sacrifice the environment for us and our future generations so PSE can make big profit by selling power to Canada!

8. Gary Albert (*zip code: 98006)*
The experts (USE, Stantec, etc.) who have reviewed the PSE Energize Eastside project did not complete an independent "load flow" analysis to determine the actual "need." They said the procedures PSE used were standard for the industry. That's garbage in garbage out without an independent load study. If you set up the criteria for the load flow to tilt heavily in favor of PSE, as PSE has done with energy directed to Canada and not utilizing peaking power, then there has never truly been an independent review. PSE said numerous times they would allow a citizen review of their load flow study, i.e. someone from CENSE, if they could get the appropriate security clearances. When CENSE located a retired PSE manager willing to help answer this question and able to get the appropriate security clearances needed, PSE changed their position and said EE had already been independently verified by several other experts and CENSE therefore did not have a need to know. What are they afraid of, a little sunlight on their boondoggle to pad the bottom line with unnecessary infrastructure building while sticking unsightly power poles dangerously close to fuel petroleum lines. Time for a real review by picked by someone not influenced by the city or PSE.

9. Annie Everett (*zip code: 98927)*
I am definitely opposed to the new PSE power lines!

10. Alice wang (*zip code: 98006)*
Please stop PSE from using "energize Eastside" as its excuse to expand their international business to push up revenu at the expense of forcing local residents to lose their property value, beautiful environment, school and street Safty, neighborhood lift style. PSE will benefit financially while local residents will suffer the consequences and pay the high price for PSE's corporate gain!!! If PSE truly want to energize Eastside, not their corporate wallet, they should go with alternative 2!!!

11. Aileen Leo (*zip code: 98006)*

12. Eng Teck Po (*zip code: 98006)*

13. Anna Coy *(zip code: 98005)*
From everything I have seen or heard, we do not need to have this huge power line gouged through Bellevue!

14. Amy Lee *(zip code: 98008)*

15. Yan Zhen *(zip code: 98006)*

16. Andrea Borgmann *(zip code: 98005)*
Despite PSE's alarmist statements about the imminent threat of blackouts starting in less than two years (2018!), PSE has not validated the need for this project. PSE's report "validating" the need assume significant transfer to Canada during peak load times (1,500 MW) and turning off local gas generation plants. These assumptions are not defensible or reasonable as fundamental assumptions in assessing local electrical needs.

The EIS process must seriously assess the question of need in order to assess reasonable alternatives. The City's role is not simply to take at face value the utility's assertions.

The proposed project will come at significant cost to ALL PSE ratepayers due to the WUTC's allowance of billing for capital projects for 40 years with a 10% rate of return. There are simply more cost effective, more appropriately scaled projects to meet the Eastside's electrical needs over the coming years.

17. Angela Byers *(zip code: 98006)*

18. Anna Ceberio-Verghese *(zip code: 98027)*
Listen to CENSE.

19. Anne Kim *(zip code: 98006)*

20. WEI TUNG *(zip code: 98006)*
GAS pipeline underneath the proposed route is a major safety issue during construction and future operation.

Also need to consider underground line option, at least for the residential area.

21. April Tan *(zip code: 98006)*

22. Allen Rauschendorfer *(zip code: 98056)*
PSE has not established a need to expand the existing grid. Generating and transferring power through my Olympus neighborhood so PSE can sell power to Canada is an unacceptable situation. The on going health risks, property devaluations, and making an already high risk proximity of a gas line to high voltage power lines situation even worse is not only unacceptable but unfathomable. PSE is taking profits over public safety and we cannot stand and watch them do it!

23. archana verma *(zip code: 98006)*
We believe that Energize Eastside is a misguided project driven only by a motivation for corporate

profits. It will sacrifice the well being of families living close to the proposed power towers. Plus independent studies have shown that the claims made by PSE to the effect that Energize Eastside is needed for future customer demands are false and misleading. We strongly oppose Energize Eastside and we believe that PSE has not proven at all the need and validity for going ahead with this project. Please stop PSE.

24. Astrid Zuppinger (*zip code: 98005)*
PSE is attempting to build an unnecessary project in one of the most educated areas in the world. This will harm the Puget Sound with huge transmission poles and wires and we will be targeted to have more health issues. If you love the beautiful Northwest, then allow the intelligent Engineers in this area to come up with a better solution then doing a quick wiring up that will effect the world around us.

25. Any Tappen (*zip code: 98008)*

26. Bill Jacobs (*zip code: 98056)*

27. Paul Gibbons (*zip code: 98006)*
My Rate for Power should not be used to pay for "RETURN ON INVESTMENT" for a foreign company.

28. Peiqi Shen (*zip code: 98006)*
Devastating impact to environment and people's health ! Put cables underground.

29. Fran Kutoff (*zip code: 98006)*
Please take the time (there is NO hurry) and study the safest and most community-friendly and environmental-friendly solution to this issue. Bellevue is a beautiful city; let's not muck it up with huge power poles!

30. Beibei Chen (*zip code: 98006)*

31. Barbara Braun (*zip code: 98006)*
Please, please, please pause the EIS process to evaluate the alternatives properly using independent experts

Also pass city ordinances to insure the proper safety regulations are in place around the pipeline especially given the earthquake danger.

32. Rebecca Peck (*zip code: 98006)*
We don't need Energize Eastside. Please read the honest, unbiased Lauckhart-Schiffman load study.

33. Beth Billington (*zip code: 98004)*

34. Binchi Zhang (*zip code: 98006)*

35. William Weston (*zip code: 98005-3154)*
Poles and lines as high as 15 story buildings should be avoided if humanly possible.

36. W. Robert Moore *(zip code: 98006)*
Demand forecast not credible, project does not analyze alternative sources of energy, and public safety is at risk.

37. Cindy Williams *(zip code: 98006)*
Consider this me signing this petition. I agree with Russell.

38. Robert Wiley *(zip code: 98006)*
This project is unnecessary and must not go forward.

39. Bonnie Lau *(zip code: 98006)*
I am very concerned about Puget Sound Energy's "Energize Eastside" project, which proposes to build 18 miles of high-voltage transmission lines through four Eastside cities (Alternative 1A).

40. Michael Boyce *(zip code: 98006)*
Energize Eastside is DUMB:
D-Dangerous
U-Unnecessary
M-Misguided
B-Boondoggle

41. Brett Fidler *(zip code: 98005)*
We do not need more towers and lines. Let's use a smarter grid and new alternative energy sources.

42. Michele Brown-Ruegg *(zip code: 98006)*
I do not support your proposal to build new high-voltage power lines across the eastside and through family neighborhoods

43. Brian Schafer *(zip code: 98006)*

44. ellen kerr *(zip code: 98005)*

45. Sheng XU *(zip code: 98006)*

46. Hengyu Xu *(zip code: 98006)*
It will bring lots of negative impacts on environments and safety issues to our communities.

47. Carol Xiang *(zip code: 98006)*
Effect health of the Newport high school students.

48. Carol Almero *(zip code: 98008)*
Stop PSE from this scare tactic to capitalize on outdated technology.

49. Cheryl Shannon (*zip code: 98033)*

50. Cherie Carchano (*zip code: 98008)*

51. Carin Chatterton (*zip code: 98056)*
Use the proper data for this study. New lines ARE NOT NEEDED!

52. Lauren Ulatoski-Root (*zip code: 98008)*
This plan has been appalling from the start.

53. Tyler Armstrong (*zip code: 98007)*

54. Hong chang (*zip code: 98006)*
Negative impacts on the environment; not safety to our community.

55. Chen Zhao (*zip code: 98006)*

56. Mei Chen (*zip code: 98006)*

57. Lin Gong (*zip code: 98006)*
We do not need a new PSE transmission line.

58. Richard Guttu (*zip code: 98006)*
We oppose the intrusion this would cause.

59. Chris Burges (*zip code: 98005)*
EIS is a project of greed, not of necessity. Why would EIS tell the City Councils and the public a much higher percentage growth (7%) rather than .5% that it tells WECC? There are so many problems with the information they put out. Switching to LEDs had greatly decreased load at many homes and businesses. There is no mention of this, or of so many other factors in what energy is needed. Building these huge transmission lines won't create more electricity. It will just allow PSE to sell more electricity to Canada - which should not be a cost that PSE citizens will have to bear.
Greed. PUre greed.

60. Chris Liang (*zip code: 98006)*

61. Cindy Fang (*zip code: 98006)*

62. Xue Song (*zip code: 98006)*

63. Carol Kunde (*zip code: 98052)*
I don't not understand why people living in established communities have to be subjected to huge structures in their neighborhoods without a vote of the residents. For some of my neighbors, the proposed power lines will be placed, literally) in their back yards.

64. Qing Ye (*zip code: 98006)*
For better environment and community!

65. David & Claudia Lee (*zip code: 98005)*
We are Woodridge residents, and are opposed to the Energize Eastside project which proposes to build 18 miles of high voltage transmission lines. As proud residents of our community, these high voltage transmission lines would devalue our property as well as deface the community.

66. Corrin Ponte (*zip code: 98006)*
Stop the lies! Save our homes and our trees!

67. Wei Wei Chen (*zip code: 98006)*
Negative impacts on environments; safety issues to our communities.

68. Dan Wu (*zip code: 98059)*
Please correct.

69. Dana Luhr (*zip code: 98058)*

70. Daniel Kaner (*zip code: 98011)*

71. David Luk (*zip code: 98006)*

72. Deb Engevik (*zip code: 98005)*

73. Debra Burges (*zip code: 98005)*
Energize Eastside is unnecessary for the energy needs of the eastside until 2058. PSE has been unwilling to be honest in where their predictions come from. THey have not used available resources to generate extra power when it is needed. They have dismantled an emergency power plant without authority of regional energy planning boards, and now want to reap more profit building unnecessary, ugly, dangerous power lines. Digging to build 230 watt lines over gas lines is crazy. Taking trees down in our "City in a Park" in areas where they help clean the air from incessant traffic is environmental terrorism. The only reason this is needed is to make money for the Australian investors that don't care at all about our region. Trying to block the legal authority of East Bellevue Community Council to block this removal of 300 trees is incredibly troublesome. EIS will require removal of 8,000 trees. We cannot even remove a diseased tree that threatens our home without City permits, but a corporation can bully their way into devastating our environment. It is not necessary. It is ugly. It is unethical. It is dishonest. It is pure greed.
Encourage energy preservation. Encourage CLEAN energy. Value our environment. Value property values. Do not blindly do what a corporation wants without considering what is best for the people of the region.

74. Joe Michaels (*zip code: 98005)*

75. David Herbig (*zip code: 98006)*
There is no need for this project at this time. PSE is only doing this to increase revenues to PSE and

49. Cheryl Shannon (*zip code: 98033)*

50. Cherie Carchano (*zip code: 98008)*

51. Carin Chatterton (*zip code: 98056)*
Use the proper data for this study. New lines ARE NOT NEEDED!

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Encourage energy preservation. Encourage CLEAN energy. Value our environment. Value property values. Do not blindly do what a corporation wants without considering what is best for the people of the region.

74. Joe Michaels *(zip code: 98005)*

75. David Herbig *(zip code: 98006)*
There is no need for this project at this time. PSE is only doing this to increase revenues to PSE and

is ignoring the impact on rate payers.

76. Diane Fern (*zip code: 98006)*

77. Denise Dice (*zip code: 98006)*

78. Alison Dildine (*zip code: 98056)*
I do not approve of PSE's plan to install larger power poles and lines through our Olympus neighborhood. There is no urgent need for them and they will ruin our great neighborhood. PSE has not been up front about supplying CENSE with the requested documents to back up PSE's claim that this project is needed.

79. Jason Hong (*zip code:)*

80. David Xie (*zip code: 98006)*

81. Bruce Williams (*zip code: 98056)*
The Energize Eastside project will do a huge amount of aesthetic and environmental damage while placing residents in danger of pipeline explosions. A complete and accurate load study proves the project is not needed.

82. Don Miller (*zip code: 98006)*
The City of Bellevue is failing to fulfill their responsibilities as the Lead Agency on this EIS process. Action by concerned and informed citizens has been repeatedly rejected in favor of the deceptive and profit motivated actions of this foreign owned company. You can take steps now to avoid the permanent burden on all Puget Sound rate payers but you have to accept that the work done by citizens in our community is driven neither by profit nor deception. Do the job you are expected to do.

83. Hu Dong (*zip code: 98006)*

84. Yan Dong (*zip code: 98006)*

85. Donald Lionetti (*zip code: 98005)*

86. Don Marsh (*zip code: 98006)*

87. Donald Ray (*zip code: 98005)*
A 100 year old problem with the same 100 year old solution.
1. A fully independent and fair analysis still has not been accomplished. Most who works on this study are still attached in someway to the conclusions.
2. Variable "time-of-day-rates" is too quickly dismissed when peak power, not total demand, is the reason for this huge capital and old school solution. 3. We need a solution that is geared to a managed approach. I would even pay more to get a future system in line with greater energy management and not just charge me for an increase in capacity.
Can't we manage our peak power differently today? Please verify what century we live in.

88. Devon Shannon (*zip code: 98033)*

89. Jessie Xu (*zip code: 98006)*

90. tong wu (*zip code: 98006)*
Make it underground and don't impact our neighborhood

91. Eva Downs (*zip code: 98056)*
Not only is this project dangerous, disruptive and damaging to neighborhoods and families, there is no need to build these huge transmission poles.

92. Elizabeth Minkin (*zip code: 98006)*
I am very concerned about the safety of placing new high voltage lines too close to aging petroleum pipelines and the possible risks and damage to proximate residential properties.

93. Qinghui Liu (*zip code: 98006)*
My family and I would love the keep the view of our community as it is, not with the huge power poles. We don't want to live under those poles either.

94. Edward Huang (*zip code: 98006)*
We don't need new PSE transmission line!!!

95. S Ekelmann (*zip code: 98007)*

96. Kenneth Vasilik (*zip code: 98006)*

97. Erica Johnson (*zip code: 98006)*

98. Erin Kenway (*zip code: 98005)*
We recently moved to the Woodridge community because of the gorgeous views, great location, strong community and quality of schools. These amenities are what bring up the value of our homes and keeps our community strong. This project would have an extremely negative effect on home values in a community that is consistently ranked among the top in the nation.

99. Wenchun Lo (*zip code: 98006)*

100. Jamie Moy (*zip code: 98006)*

101. Dena Fantle (*zip code: 98006)*
Dear Council members, please represent myself and all the other the residents of our wonderful city and ensure a thorough due diligence is done on PSE's Energize Eastside project, including a full review of the concrete findings in the CENSE report proving the project is absolutely not necessary (& possibly motivated by the greed of this privately held utility). In addition please implement a 6-12 month moratorium prior to moving forward with a phase 2 EIS for this unnecessary project. Thank you

102. Fran k Bosone *(zip code: 98006)*
Stop this ridiculous project now. Keep Bellevue beautiful.

103. feifei zhang *(zip code: 98006)*
I am very concerned about Puget Sound Energy's power lines project.

104. Phyllis Flood *(zip code: 98006)*

105. Ying Zhao *(zip code: 98006)*
Oppose the PSE project

106. Frances Lee *(zip code: 98006)*
THIS PROPOSED HIGH-TENSION CABLE IS AN AFFRONT TO OUR HEALTH (REGARDLESS OF WHAT YOUR "EXPERTS" CLAIM) AND UNJUSTIFIABLE INVASION OF OUR ABILITY TO PAY OVER THE LONG RUN. CEASE YOUR ATTACK ON OUR FINANCES AND ENVIRONMENT.

107. Steven Fricke *(zip code: 98007)*

108. Guanghai Zhang *(zip code: 98006)*

109. Gang Zhai *(zip code: 98006)*
We think the high voltage power line should not be close to schools and residential community because
1. it's dangerous for kids
2.the high voltage power tower and power lines cause health issues.
3. the high voltage power tower and line will hurt the real estate value.

thanks

110. Gabriele Neighbors *(zip code: 98004-8610)*

111. Dee Mulford *(zip code: 12302)*

112. Glenna White *(zip code: 98056)*
I support and adopt the objections to the draft EIS as raised by CENSE. Do the right thing!

113. Glenn Gregory *(zip code: 98006)*

114. Stephen Lee *(zip code: 98006)*
Against power line in Somerset neighborhood

115. Margaret Niendorff *(zip code: 98004)*
Please review PSE's assumptions - they appear overblown and unnecessary. And "Energize Eastside" harms our City in a Park.

116. Margot Smith (*zip code: 98006)*
PSE's Energize Eastside proposal and in particular, its preferred 1A alternative are deeply flawed on many counts. I am among many Bellevue residents opposing Alternative 1A and urging that the Integrated Resources Approach (Alternative 2) be given comprehensive consideration. The EIS under consideration does not include reliable and complete information by independent experts qualified in these technologies.

117. Grace Li (*zip code: 98006)*

118. Julie Chen (*zip code: 98006)*
We don't want this project in our neighborhood for many reasons, which are probably already addressed by many residents.

I just wanted to say this project is going backward from the trend--- while other countries and cities are going underground, PSE is doing the opposite.

119. Patricia and Bruce Brown (*zip code: 98006)*

120. Gregg Smith (*zip code: 98006)*

121. Gretchan Lindsey (*zip code: 98006)*
As a rate payer and citizen, I expect your data, scenarios and options to be up- to- date using current data and methods, accurate and not misleading.

122. Roy Grinnell (*zip code: 98006)*
To: Heidi Bedwell, Energize Eastside EIS Program Manager
From: Roy Grinnell, P.E.

Dear Ms. Bedwell,

I am very concerned about Puget Sound Energy's "Energize Eastside" project, which proposes to build 18 miles of high-voltage transmission lines through four Eastside cities (Alternative 1A).

PSE tries to justify the need for the project using an impossible scenario with improper and flawed assumptions that would cause regional blackouts, according to the Lauckhart-Schiffman Load Flow Study, available at CENSE.org.

Alternative 1A would place new lines and poles much too close to aging petroleum pipelines. Responsible safety standards require at least a 50 foot separation. A construction or operational accident could cause a catastrophic pipeline explosion like the one that killed three Bellingham residents in 1999. Pipeline corrosion along this line is already a problem. This risk is not adequately addressed in the EIS.

Alternative 2, the Integrated Resources Approach, is a safer and less costly alternative. But the solution described in the EIS was not developed or reviewed by independent experts that have suitable experience with modern electrical grid technologies, including Demand Side Management and Distributed Energy Resources. The costs and capabilities are based on inaccurate and obsolete studies. As the Northwest Power Council's Seventh Power Plan makes clear, a carefully developed plan would easily beat alternative 1A in cost, safety, and support for the environment.

The other transmission line options (1B, 1C, 1D and Alternative 3) are not practical for financial or political reasons.

Ratepayers are asked to spend more than a billion dollars over the lifetime of PSE's transmission line. The Draft EIS must answer these basic questions in order to convince residents that we are getting the best possible plan for our energy future.

123. Grace Drone (*zip code: 98006)*
Dear Ms. Bedwell,

I am very concerned about Puget Sound Energy's "Energize Eastside" project, which proposes to build 18 miles of high-voltage transmission lines through four Eastside cities (Alternative 1A).

PSE tries to justify the need for the project using an impossible scenario that would cause regional blackouts, according to the Lauckhart-Schiffman Load Flow Study, available at CENSE.org.

Alternative 1A would place new lines and poles much too close to aging petroleum pipelines. Responsible safety standards require at least a 50 foot separation. A construction or operational accident could cause a catastrophic pipeline explosion like the one that killed three Bellingham residents in 1999. This risk is not adequately addressed in the EIS.

Alternative 2, the Integrated Resources Approach, is a safer and less costly alternative. But the solution described in the EIS was not developed or reviewed by independent experts that have suitable experience with modern electrical grid technologies, including Demand Side Management and Distributed Energy Resources. The costs and capabilities are based on inaccurate and obsolete studies. As the Northwest Power Council's Seventh Power Plan makes clear, a carefully developed plan would easily beat alternative 1A in cost, safety, and support for the environment.

The other transmission line options (1B, 1C, 1D and Alternative 3) are not practical for financial or political reasons.

Ratepayers are asked to spend more than a billion dollars over the lifetime of PSE's transmission line. The Draft EIS must answer these basic questions in order to convince residents that we are getting the best possible plan for our energy future.

124. haili sun (*zip code: 98006)*

125. Hannah Ge (*zip code: 98006)*
I'm very concerned about this project. My suggestions: first, let's evaluate if this project is indeed needed and have no alternative solutions e.g. green energy or other lower energy consumption approach for households or commercial estates in Bellevue, second, let's find out if the project can go through a less invasive route than have to cut through residential areas including schools and busy shopping areas.

126. Norm Hansen (*zip code: 98005)*
Phase 1 EIS needs a final report since the line may not be needed. See new load flow studies by CENSE. Phase 2 would be a waste to rate payers if not needed.

127. Helen Si (*zip code: 98006)*

128. Helen Tian (*zip code: 98006)*

129. Li Han (*zip code: 98006)*

130. David Herman (*zip code: 98056)*

131. Angela Allison (*zip code: 98006)*

132. Richard Howell (*zip code: 98056)*
PSE needs to listen to us. This project is not needed nor welcome. This is simply a corporate profit grab at the expense of the rate payers and eastside residents.

133. Huatong Sun (*zip code: 98006)*

134. Hui Lu (*zip code: 98006)*
Against Energize Eastside project!

135. Huiying Ye (*zip code: 98006)*

136. Dana Tillson (*zip code: 98005)*
No need for new transmission lines

137. Chuanzhong Nie (*zip code: 98006)*

138. Kevin Iden (*zip code: 98056)*
I am very concerned about Puget Sound Energy's "Energize Eastside"!!!

139. Irene Kearns (*zip code: 98005)*

140. LU ZHANG (*zip code: 98006)*

141. Test Cense (*zip code: 98006)*
A little comment

142. Jennifer Pinkowski (*zip code: 98006)*

143. Julie Huang (*zip code: 98005)*

144. Jacqueline Becker (*zip code: 98006)*

145. jamie kim (*zip code: 98005)*

I am very opposed to this project because it appears independent evidence contradicts the need for this project.

146. Jing chang (*zip code: 98052)*

147. Barbara Bobbitt (*zip code: 98007)*

148. Jane Kim (*zip code: 98006)*
NO HIGH POLE AND WIRE TOWERS in our neighborhood. There is eminent danger of hitting the gas pipeline. Higher transmission wires and poles create sound and health dangers to people as well.

149. JC McCabe (*zip code: 98006)*

150. Judy Mock (*zip code: 98006)*
Thank you for your time and concern with this important issue.

151. Jeffrey Byers (*zip code: 98006)*

152. Jennifer Xu (*zip code: 98006)*
No PSEG high voltage power line

153. Jennifer Wilson (*zip code: 98006)*

154. Jessie Chow (*zip code: 98034)*
We need to find a better solution for the future of our children and the environment, not for the short term Corp profits.

155. Jeff Felix (*zip code: 98005)*
Based on all of the analysis that I've seen, we don't need this project.

156. Jian Chen (*zip code: 98006)*

157. Helen Liang (*zip code: 98006)*

158. NAN ZHU (*zip code: 98006)*
STOP PSE PROFITIBG AT LOCAL'S COST

159. JD Yu (*zip code: 98006)*
According to expert lauckhart-schiffman load flow study, there is enough capacity margin to serve growth on the eastside for 20 to 40 years. There is no need to build new transmission line.

160. John Laughlin (*zip code: 98006)*
I'm concerned about safety with respect to the pipeline and neighborhood character.

161. Linda Galluzzo (*zip code: 98056)*

162. Julie Lionetti (*zip code: 98005)*

163. Jodi Gable (*zip code: 98006)*

164. jodis zhu (*zip code: 98006)*
this is not good for our living environment

165. Joe DeGennaro (*zip code: 98056)*
To: Heidi Bedwell, Energize Eastside EIS Program Manager
From: Joe & Cathy DeGennaro

Dear Ms. Bedwell,

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166. John Merrill (*zip code: 98006)*

167. Robert Jones (*zip code: 98056)*
Why are we wasting time on Puget Sound Energy's proposal when it is not needed, not safe, a blight on the communities involved, and its only purpose is to make money for their investors?

168. joy paltiel (*zip code: 98006)*
I am signing this petition instead of writing my own letter simply because I share the concern of others

and don't need to rewrite the message in any other way in order for you to get it. There are so many reasons to stop this disaster from happening. I trust you will recognize that this because the transmission lines need to be stop... for all the right reasons. Thank you for your attention.

169. Joy Phelps (*zip code: 98006)*
This unnecessary project exposes the greed of PSE, which puts the 9.8% ROI it will gain ahead of public safety.

170. Yanping Liu (*zip code: 98006)*

171. Janet Berg (*zip code: 98006)*

172. Angela Juan (*zip code: 98006)*
I live right by the side of the trail along with the tall power line and Olympic Patroleum pipline in Newport Hills Bellevue. It is scary enough already for us to live by those thing every day.

We definitely don't want Pugent Sound Energy to build even more taller, bigger, and stronger power line by our house. These tall power lines will threaten our lives in the future if there's something wrong with it and it will cause the explosion with the petroleum pipline and burn us into ashes in one second!

If there's an seismetic gigantic earthquake which is expecting, happen in the future in our or our children lifetime, these tall power lines will cause even more damage such as fire and burn down all the houses and all the people when they fall from the earthquake because they are so Huge! We don't need More Tragedy on top of the catastrophe! We PREVENT it!!!

We got way enough radiation already everyday live by these tall power lines, we Don't want those huge tall power lines to NUKE us even more everyday in our life. We want to live healthy and Not to get life threatening Cancer from those Huge power lines in our life.

We work hard in our life and finally we could afford to buy the house we live in now with 30 years of mortgage. We Can't afford to lose our house value dropped by 20% or more because of those Huge power lines!

Eastside is a very nice neighborhood here and we Don't want PSE to build those Huge Gigantic power line to destroy and to threaten our lives, our health, our peace of mind, our property, and the beauty of the nature where we live! So NO Giant Power Lines in Eastside!!! Seriously!!! Please and Thank You!

173. Judith Mercer (*zip code: 98006)*
Please reject the PSE's Energize Eastside. It is unnecessary, expensive and dangerous.

174. Julia Chan (*zip code: 98006)*
No new energize project at somerset

175. kenn gennari (*zip code: 98006)*

176. Kalai Socha-Leialoha (*zip code: 98005)*

We live in Bridle Trails. I agree with CENSE that what PSE wants to do is unnecessary on many levels. I would not like to see their current plan go through if at all possible.
~ thank you,
Kalai Socha-Leialoha

177. Karen Xu *(zip code: 98006)*
Building high voltage power line at residential area and schools are huge potential hazard to local community.

178. An anonymous signer *(zip code: 98005)*
As a homeowner I am Opposed the the proposed towers in Woodbridge; look beyond these residential neighborhoods!

179. Katherine ma *(zip code: 98006)*

180. Kathleen Sherman *(zip code: 98006)*

181. Kathy Judkins *(zip code: 98006)*
Alternative 1A could cause my over a million dollar home to be demolished due to the 50 foot clearance required from the pipeline. Also during construction I would have no access to my garage or street on the easement. I will fight this plan until I die.

182. Kathleen Millen *(zip code: 98059)*

183. Kathy Woodman *(zip code: 98005)*

184. Kausik Kayal *(zip code: 98056)*

185. Keith Collins *(zip code: 98005)*
The whole process was flawed from the start. City hall seems to be in the pocket of PSE. Stop this nonsense now!

186. Grace Zhang *(zip code: 98006)*

187. Kenneth YAMAMOTO *(zip code: 98006)*
The upgraded evidence convinces me that we do not need this extensive upgrade that PSE proposed. If we can wait for the battery backups in in 10 to 20 years a less expensive and simpler solution will be the way to go.

188. Kristin Quam *(zip code: 98006)*
I support the no action alternative because it gives the community time to increase conservation efforts and to harness technological advancements. If alternative one is approved there will be no going back. Please do what is best for our neighborhoods and community. PSE can find another way to satisfy their foreign investors.

189. Karen Esayian *(zip code: 98006)*

190. Kristi Weir *(zip code: 98006)*
DEIS should be about protecting the environment. The best thing for the environment would be NOT to build Energize Eastside as it is to needed. We can meet our energy needs by renewable resources as well as conservation through building design. It would be hard to replace the carbon sequestration that 8000 tree provide and which Energize Eastside would cut down.

191. Steven Shimamoto *(zip code: 98006)*
NO POWER LINES!!

192. Shioon Kim *(zip code: 98006)*
Before PSE processes the high voltage project, they needs to prove it is safe or not for electric magnetic field.
It looks like for them for their business grow but not for our residents.

193. Eri Koizumi *(zip code: 98056)*
After all, please think about what if your house is in this zone.

194. Kathleen Quam *(zip code: 98006)*
I support a no-action alternative. With the 15 year anniversary of the Nisqually earthquake, I am reminded of the unique safety concerns our region faces. The proposed transmission lines are too close to the aging Olympic pipeline.

195. Krishna Nareddy *(zip code: 98006)*
Please do not abuse the existing easement to install a high powered power transmission line whose main purpose is to sell power to Canada.

Our neighborhoods will pay the price and that's not fair!

196. Kristen McSherry *(zip code: 98005)*

197. Larry Johnson *(zip code: 98056)*
I support and adopt the objections to the draft EIS as raised by CENSE. Do the right thing!

198. Laura Liutkiene *(zip code: 98006)*

199. yueqin wang *(zip code: 98006)*
Protect our beautiful home. Please give up or change new high voltage power line design in Somerset. Thanks.

200. Laura Boylan *(zip code: 98008)*

201. Leah Willert *(zip code: 98027)*

202. Leslie Milstein *(zip code: 98006)*
Let's have better studies of the project.

203. Anita Li (*zip code: 98006)*

204. Jeanette Liao (*zip code: 98006)*

205. Steve wu (*zip code: 98006)*
support CENSE, keep our community safe for kids.

206. Linda Anderson (*zip code: 98005)*

207. Lindsey Kaner (*zip code: 98055)*

208. liping ke (*zip code: 98006)*
Make it less impact to our neighborhood make it environmental friendly

209. Lisa Howard (*zip code: 98006)*

210. Lori Elworth (*zip code: 98056)*
Pause this EIS here and get the truth. Determine energy need that is unbiased. The city of Bellevue, as the lead agency, should determine need. You have the responsibility to control this process with regard to safety and cost. Use your independent technical experts and legal council and pause the DEIS. PSE is not providing answers to questions asked by CENSE. I am a member of CENSE.

211. Lori Wheatley (*zip code: 98006)*
To: Heidi Bedwell, Energize Eastside EIS Program Manager
From: Lori Wheatley

Dear Ms. Bedwell,

I am very concerned about Puget Sound Energy's "Energize Eastside" project, which proposes to build 18 miles of high-voltage transmission lines through four Eastside cities (Alternative 1A).

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212. Luxi Ji (*zip code: 98006)*

213. Lorraine Meyer (*zip code: 98005)*
I do not feel that this project is in the best interests for the Eastside and the residents. The logistics of installing these mammoth poles in our area is certainly unreasonable due to access to the proposed area.

214. Lucy Regan (*zip code: 98006)*
I am against locating the proposed power lines in close proximity to aging petroleum pipelines, next to Tyee middle school to put potential safety risk to our neighborhood and students.

215. Matthew Luhr (*zip code: 98058)*
Enough is enough.

216. Lori White (*zip code: 98005-1353)*

217. Laurie Wick (*zip code: 98005)*
Go back to the drawing board! The need for Energize Eastside as proposed has NOT been demonstrated.

218. Michelle Liu (*zip code: 98006)*
Negative impact to the environment, safety issues for the community.

219. Lily Yin (*zip code: 98006)*
EIS program will definitely damage all scenic view from eastside. We love this land because it is becautiful. We enjoyed the land and against any program would destroy the view.

220. Lynn Ang (*zip code: 98006)*
There is no need for a 18 foot overhead transmission line. Any new lines should be underground. It's ugly, outdated and dangerous to have such a thing in a neighborhood. It's also expensive and destroy the beauty of our neighbour.

221. Lynne Prevette (*zip code: 98056)*
Because the DEIS used PSE's Load Flow data to prove the actual need for the project, it seems glaringly flawed. I would encourage a fair report. Certainly the cost of your own Load Flow Study would look small compared with the cost and damage of Energize Eastside.
Thank you.

222. Linda Young (*zip code: 98056)*
STOP THIS NOW - IT IS NOT NEEDED.

YOU CANNOT DESTROY HOMES AND WRECK FAMILIES LIVES
YOU CANNOT CHOP DOWN 8000 TREES
YOU CANNOT PUT PEOPLE IN DANGER - OLYMPIC PIPE LINE IN THE EXACT SAME PATH AS 230 VOLTAGE - DO YOU WANT TO BE RESPONSIBLE FOR PEOPLE BEING BURNT TO DEATH?

223. mingmei xu (*zip code: 98006)*
pse is crazy for money. They think of none for local residence.

224. Lisa Beelin (*zip code: 98005)*

225. Marcia LeVeque (*zip code: 98006)*
Please be progressive in planning to keep Bellevue a safe place for all our neighborhoods without high voltage poles near an oil pipeline. It's important to consider different alternatives that other states are already using to help provide the power we need for our beautiful city.

226. Marty Arnot (*zip code: 98006)*
Let's not destroy our neighborhoods with unneeded power poles. There are better solutions for the Eastside

227. Mei Qi (*zip code: 98006)*

228. Melinda Carbon (*zip code: 98008)*

229. Michael Evered (*zip code: 98006)*
This project is not needed, would endanger pubic safety and would be a visual blight on our City

230. Linda Meyer (*zip code: 98005)*
I do not feel it is necessary for large high wire lines. If energy is needed their is other options. Do not believe energy is needed for this area.

231. Mark Grossbard (*zip code: 98005)*

232. Michael Kenway (*zip code: 98005)*

233. Tomiko Teramoto (*zip code: 98056)*
We are retired couple and hope to end our life here. If our home is purchased by PSE, we can not get similar value and environment house any more. We can not get mortgage because we live with limited income.

You are destroying our life!

234. Michael Zwilling (*zip code: 98007)*

235. Michele Miller (*zip code: 98005)*
Enough is enough I already have the four lines of power and two pipelines. The people that maintain

these utilities forget the properties belong to the home owners and not them. All this happens on less then an acre of land. My family has owned this property since 1971. This is all about PSE selling more power outside this area and making money not protecting us for the future.

236. Mina Peterson (*zip code: 98005)*
As a full time real estate professional for 30 years, I can say unequivocally putting any visible towers in this or any neighborhood will dramatically devalue homes considerably throughout the neighborhoods and have a continued impact indefinitely.

The impact will be felt immediately and even the possibility of this project proceeding will and is something that buyers who might be considering a move to the area are asking about and rethinking the locations they are considering.

Whether or not the energy companies care or consider our home values, Buyers and Homeowners do care.

I know many many buyers and property owners believe, living near these towers can cause cancers and have other potential harmful health effects. This belief is particularly evident with the wave of many cultures new to the area. It is definitely seen as bad luck and bad energy.

Just having the power towers that currently run through these areas or any other, I can attest to the fact that 80% or more of the potential buyers to a particular home in close proximity to these current towers will NOT purchase a home due to health concerns alone, real or not real.

The values of homes with views will drop as well just having the eye sore of possible huge towers, not just possible health concerns.

RUN THE CABLE UNDERGROUND AND IN CABLES ON THE FLOOR OF LAKES! NOT THROUGH OUR NEIGHBORHOODS.

237. Mary Lynne Poole (*zip code: 98005)*
Puget Sound is pushing ugly, unnecessary and dangerous high tension wires throughout the East side. Please rule against Puget Sound.

238. Min Chen (*zip code: 98006)*

239. Michelle Molan (*zip code: 98006)*

240. Margaret Moore (*zip code: 98006)*
PSE cannot be allowed to move forward with this project as planned. There is ample evidence that it is poorly conceived for many of the wrong reasons. Help us now!

241. Money Wan (*zip code: Wa98056)*
Do not agree with PSE plan .

242. Mindy Suurs (*zip code: 98006)*

243. Mei yan (*zip code: 98006)*

244. Natalie Duryea (*zip code: 98005)*
Save our City!!!!

245. Thomas Neighbors (*zip code: 98004-8610)*

246. Hao Wang (*zip code: 98006)*
Dear Ms. Bedwell:

We are very concerned about PSE's proposal to build 130 ft tall power lines that potentially go through several Bellevue residential neighborhoods. The concept to build high voltage transmission lines in the middle of residential homes is extremely irresponsible. It will creat significant risks to the people who live in the adjacent areas. Our city is located in a seismic active zone. And those transmission lines are too close to the petroleum pipelines and residential homes.

As a public official, you are in the position can change this project into right direction. We ask you to listen to the voices of local residents. Please don't let the big cooperation dictate the future of our beautiful city.

Thank you very much!

Sincerely yours,

Hao Wang
Yingli Xu
Emily Wang

247. Choy Leng Yeong (*zip code: 98006)*

248. Judith Odell (*zip code: 98006)*
Please do not have these built.

249. Orville Gunnoe (*zip code: 98007)*
There is a reason why responsible power/utility companies found their origins as government-owned organizations. PSE could learn lessons by not trying to bulldoze or steamroll its customers to submit to poorly devised and flawed plans for the future.

250. Ontie Griebel (*zip code: 98005)*

251. Michael Oldham (*zip code: 98006)*
I am against any new power transmission lines being added next to the Lake Lanes corridor.

252. Jin Wang (*zip code: 98006)*

253. Eugen Pajor (*zip code: 98056)*
Please stop the "not needed" and unsafety PSE project

254. Patricia Magnani (*zip code: 98006)*

255. Patricia Janes (*zip code: 98005)*
The PSE proposal is dangerous, will destroy the views of many, will send the power to Canada, will send the profits to Australia at the expense of all the rate payers in All the cities involved. There are alternatives that would give the extra power, if really needed. These have been neglected by PSE. The city of Bellevue and others involved deserve more respect. Please ask for it Thank you.

256. Paul Kim (*zip code: 98006)*

257. Pal Nichoson (*zip code: 98052)*
This "Energize Eastside" project by Puget sound Energy is a badly flawed idea that is not needed. Lets put a hold on this now.

258. Julie Baker (*zip code: 98005)*
We are very concerned about the PSE powerline project and do not believe that adequate research has been performed to justify the need for these proposed towers.

259. PING CHEN (*zip code: 98006)*

260. Penny Bahner (*zip code: 98005)*
The PSE's Energize Eastside project is shown to not be necessary per the Lauckhart-Schiffman Load Flow Study and it is just another way that a government agency believes we, the people, are stupid and uninformed. I am absolutely not in favor of this project being jammed down our throats.

261. Peter Wise (*zip code: 98007)*
Please think harder and more deeply about how you can improve service without putting Eastside residents in danger and destroying our views with giant poles and pylons.

262. Petra Sixl (*zip code: 98006)*
I have great fears regarding safety in our area and communities. In the Seattle Times on Sunday, 2/28/16, was an article about a Quake drill in June. The article says, the next Quake will be far more damaging then the one in 2001, magnitude 9, which is equivalent to 35,2 billion tons of TNT and will last 4-5 minutes.
I think, we all should keep this in mind when we plan for our future!

263. Phil Sherman (*zip code: 98006)*

264. Margie Pietz (*zip code: 98056)*
I really resent the way PSE is trying to ram this project down our throats. It will not only be a huge blight to our neighborhood but take away some of our homes. PSE has not shown that this project is needed and the net result of building this mega project is we get to pay for it and PSE makes money selling the extra power to Canada, etc.

265. ping yin (*zip code: 98006)*

266. Huimin Huang (*zip code: 98056)*

267. Qiang Zhang *(zip code: 98006)*
negative impacts on environments; safety issues to our communities; et al

268. Li Qiao *(zip code: 98006)*
To: Heidi Bedwell, Energize Eastside EIS Program Manager
From: [Your Name]

Dear Ms. Bedwell,

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269. Qi Li *(zip code: 98006)*

270. Angela qu *(zip code: 98006)*

271. Bin Xu *(zip code: 98006)*

272. Rachel Ting *(zip code: 98006)*

273. Rajendra Kuramkote *(zip code: 98056)*
To: Heidi Bedwell, Energize Eastside EIS Program Manager
From: Rajendra Kuramkote

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274. William Rambo (*zip code: 98006)*
Marylin an I have attended many PSE meetings at City Hall, Hotels and neighborhood discussions. We have done it:
- Out of SAFETY concerns with the gas lines (Possible fires will run up the hill very fast).
- The PSE forecast on growth in demand vs actual expectations seem to be greatly overblown.
- PSE's inputs into the simulations neglect the supplemental generation that the "rate payers" have already funded for peak shaving in emergencies.
- the analysis gives no importance to the negative property value impact of the industrial look on one of the largest and best Puget Sound Basin/ Olympic Mt. view subdivisions which invested in underground distribution to protect the views.

We don't see a need or justification for this significant investment at the expense of rate payers.
Respectfully,
Marylin and Bill Rambo

275. Randy Chung (*zip code: 98056)*

276. Russell Borgmann (*zip code: 98005)*
Please address fundamental flaws in EIS assumptions and the EIS process.

277. Michael Davis (*zip code: 98006)*
Very concerned about damage to pipeline and noise from wires. Our house is very close. and existing electrical line crosses over our backyard. The pipeline also is in our backyard.

278. Frank Song (*zip code: 98006)*
this is not good for our environmemt

279. Rebecca Kinnestrand (*zip code: 98052)*
I do not believe PSE has the welfare of the citizens of this area in mind. Building power lines over the gas pipeline is an extreme danger to our house and my children who play within 20 yards of the buried pipeline. The Eastside does not need more power, that is only what PSE is saying to push through this project.

280. Rebecca Laughlin (*zip code: 98006)*

281. Rhee Eliker (*zip code: 98006)*
I strongly believe, based on the research done by CENSE, that this project is neither necessary nor safe for the citizens of Bellevue and the surrounding communities.

282. Richard Chen (*zip code: 98006)*

283. Bo Han (*zip code: 98006)*
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284. Rita Lei (*zip code: WA98006)*

285. Robert Zapalski (*zip code: 98056)*

286. Ronda Woodcox *(zip code: 98006)*

287. Rachel Primeau *(zip code: 98007)*

288. Ronald Redpath *(zip code: 98056)*
The justification for this project appears to have been manipulated to arrive at the desired answer. In addition, I am very concerned about the safety of this project in that it shares space with the Olympic Pipeline.

289. Ruth Marsh *(zip code: 98006)*

290. Kathryn Behrens *(zip code: 98006)*
Many children play in the Forest Hill Neighborhood park which is adjacent to the Olympic Pipeline, not to mention the homes that are also adjacent to this pipeline. Please do not place new poles and lines close to these aging pipelines, parks, and homes.

291. Ryan Shan *(zip code: 98006)*

292. Shannon Rome *(zip code: 98033)*

293. Sandra Alston *(zip code: 98004)*
Please make available to customers more info to explain contradictory findings. This would include--need,cost.and hazards.

294. Sandy Seppi *(zip code: 98027)*

295. Sarah Daniels *(zip code: 98006)*

296. scally liang *(zip code: 98006)*

297. Scott LeVeque *(zip code: 98006)*
Please hold PSE accountable to respond to the numerous concerns raised against this project. I've attended multiple meetings where PSE simply deflects, or refuses to answer, questions which get raised that challenge their own internal agenda.
Thank you.

298. Sean Cox *(zip code: 98006)*

299. Kayla Laughlin *(zip code: 98056)*
I am yet to be convinced we need this expensive project. I am very concerned for neighborhood safety, and the detrimental impact on our communities and environment. I now hear that homes in my neighborhood may need to be removed to expand the easement that runs through Newcastle (which has two gas pipelines)! If and when this project is needed, we all know there are other alternatives with less impact on our neighborhoods and our pocketbooks.

300. Yanbing Wang (*zip code: 98006)*
I have two little kids. I am really concern the impact on kids' health.

301. Sam Esayian (*zip code: 98006)*

302. Susan Hagensen (*zip code: 98006)*
Please consider the findings of CENSE.

303. Sharon Chen (*zip code: 98006)*

304. Shi Sun (*zip code: 98006)*

305. xiao Meng (*zip code: 98006)*
We don't want power line going through Somerset area.

306. Jamie Tan (*zip code: 98006)*

307. Zhi Sun (*zip code: 98006)*
I am against the PSE's plans to build 230kv 130-foot power poles though Somerset and our city.

308. helen wu (*zip code: 98006)*
no high voltage power transmission line in Somerset area, we want Green tree and safety park for family.

309. Shyan Griffith (*zip code: 98006)*
We want to preserve the appearance of our neighborhood and protect the environment for our children by fighting against PSE's plans to build 230kv 130-foot power poles though Somerset and our city.

310. Sirisha Dontireddy (*zip code: 98006)*

311. Steven Geagan (*zip code: 98056)*

312. LeMoin Beckman (*zip code: 98006)*
Please do not let this ugly, costly, and unnecessary tragedy happen.

313. Charles Cobb (*zip code: 98006)*
Bring Sanity back to Bellevue. Stop this unneeded corporate ripoff

314. Chao Song (*zip code: 98006)*

315. Sonia Zwilling (*zip code: 98007)*

316. sue johnson (*zip code: 98007)*

I don't believe PSE really needs to do this and that it is simply a way to increase their profits.

317. Sorin Gherman *(zip code: 98006)*

318. Spencer Hinds *(zip code: 98006)*

319. Sue Stronk *(zip code: 98056)*
Stop this process now and unite Lauckhart and PSE in front of EFSEC and settle NEED once and for all!

320. Star Evans *(zip code: 98006)*
The eagles have a nest in the tree above my house and the lines would literally span OVER the top of my house!

321. Stuart Campbell *(zip code: 98006)*
Is this really necessary?

322. mary lienhard *(zip code: 98005)*
im against this project

323. Stanislav Rumega *(zip code: 98006)*

324. Su Yamamura *(zip code: 98006)*

325. Xun Sun *(zip code: 98005)*

326. susan wu *(zip code: 98006)*
We need keep our community safe.

327. Suzie Lyons *(zip code: 98005)*
Please take Cense's viewpoint very seriously. These types of big business pushes happen all over the world because individuals do not have the time or resources to respond to the bully tactics of wealthy businesses. Cense is doing something positive for the individuals of Bellevue (and surrounding communities) so please listen.

328. Terry and Kari Block *(zip code: 98006)*
Please correct the flaws in the Energize Eastside draft EIS. Protect our neighborhoods!

329. Tammy Alford *(zip code: 98006)*

330. Yuhong Liu *(zip code: 98006)*

331. Tanya Franzen-Garrett *(zip code: 98006)*
The lack of regulation, oversight and accountability with regards to PSE and their proposed "necessary project" greatly disturbs me. A privately, foreign owned company should not be allowed to

bully it's will and profit gain onto the backs of unwilling citizens. Not only will it cost us Millions of dollars, but it will greatly affect our neighborhoods, the esthetics that we have worked hard to build and maintain, and our property values.

332. Thomas Cezeaux (*zip code: 98056)*
I don't believe PSE's rationale for the need of this project is accurate.

333. Randy Tada (*zip code: 98006)*
Please eliminate this wasteful and unnecessary project to protect our neighborhoods and our pocketbooks.

334. Irene Endow (*zip code: 98006)*
I am very concerned about the enormous poles being so close to the pipeline. No good can come of this combination. Please don't let this unnecessary plan go through.

335. Richard Kaner (*zip code: 98006)*

336. erich kirsch (*zip code: 98005)*

337. Tim liu (*zip code: 98006)*
support CENSE, keep our community safe for kids.

338. Todd Johnson (*zip code: 98006)*

339. Ron Wilson (*zip code: 98006)*

340. Todd Dunlap (*zip code: 98005)*

341. Trent Wheatley (*zip code: 98006)*

To: Heidi Bedwell, Energize Eastside EIS Program Manager
From: Trent Wheatley

Dear Ms. Bedwell,

I am very concerned about Puget Sound Energy's "Energize Eastside" project, which proposes to build 18 miles of high-voltage transmission lines through four Eastside cities (Alternative 1A).

PSE tries to justify the need for the project using an impossible scenario that would cause regional blackouts, according to the Lauckhart-Schiffman Load Flow Study, available at CENSE.org.

Alternative 1A would place new lines and poles much too close to aging petroleum pipelines. Responsible safety standards require at least a 50 foot separation. A construction or operational accident could cause a catastrophic pipeline explosion like the one that killed three Bellingham residents in 1999. This risk is not adequately addressed in the EIS.

Alternative 2, the Integrated Resources Approach, is a safer and less costly alternative. But the solution described in the EIS was not developed or reviewed by independent experts that have suitable experience with modern electrical grid technologies, including Demand Side Management and Distributed Energy Resources. The costs and capabilities are based on inaccurate and obsolete studies. As the Northwest Power Council's Seventh Power Plan makes clear, a carefully developed plan would easily beat alternative 1A in cost, safety, and support for the environment.

The other transmission line options (1B, 1C, 1D and Alternative 3) are not practical for financial or political reasons.

Ratepayers are asked to spend more than a billion dollars over the lifetime of PSE's transmission line. The Draft EIS must answer these basic questions in order to convince residents that we are getting the best possible plan for our energy future.

342. Terry Sinclair (*zip code: 98006)*
Fixed-income senior, home is part of my retirement plan. This unneeded project will depreciate home values & is high safety-risk to implement. No justification for the project, if one is honest about load study assumptions.

343. Tom Weir (*zip code: 98006)*
This project is not needed and the there are other technologies to use to meet any future demand which are less harmful to the environment and would make the system more flexible and less prone to blackouts.

344. Yuqiong Liu (*zip code: 98006)*

345. Gary A. Johnson (*zip code: 98006)*
Supports Alternative 2

346. ning wang (*zip code: 98006)*
Negative impact on environment.

347. William Herling (*zip code: 98006)*
To: Heidi Bedwell, Energize Eastside EIS Program Manager
From: William Herling

Dear Ms. Bedwell,

I am very concerned about Puget Sound Energy's "Energize Eastside" project, which proposes to build 18 miles of high-voltage transmission lines through four Eastside cities (Alternative 1A).

PSE tries to justify the need for the project using an impossible scenario that would cause regional blackouts, according to the Lauckhart-Schiffman Load Flow Study, available at CENSE.org.

Alternative 1A would place new lines and poles much too close to aging petroleum pipelines. Responsible safety standards require at least a 50 foot separation. A construction or operational accident could cause a catastrophic pipeline explosion like the one that killed three Bellingham residents in 1999. This risk is not adequately addressed in the EIS.

Alternative 2, the Integrated Resources Approach, is a safer and less costly alternative. But the solution described in the EIS was not developed or reviewed by independent experts that have suitable experience with modern electrical grid technologies, including Demand Side Management and Distributed Energy Resources. The costs and capabilities are based on inaccurate and obsolete studies. As the Northwest Power Council's Seventh Power Plan makes clear, a carefully developed plan would easily beat alternative 1A in cost, safety, and support for the environment.

The other transmission line options (1B, 1C, 1D and Alternative 3) are not practical for financial or political reasons.

Ratepayers are asked to spend more than a billion dollars over the lifetime of PSE's transmission line. The Draft EIS must answer these basic questions in order to convince residents that we are getting the best possible plan for our energy future.

348. Baicen Wang (*zip code: 98006)*

349. Yuan Li (*zip code: 98006)*

350. Wendy Dore (*zip code: 98006)*

351. JOHN WOO (*zip code: 98056-1796)*
Home/property was purchased in 1987 knowing that Olympic Pipeline was in "my backyard", safe from further development. Boy was I wrong. If Alternative 1A moves forward, my home/property will be "MARKED FOR DEATH". Why should I continue to pay Property Tax if the only value left is with PSE?

352. Le Wang (*zip code: 98006)*

353. Wolfgang Sixl (*zip code: 98006)*
Please correct the flaws

354. Xudan He (*zip code: 98006)*
No new high voltage power lines in the neighborhood please. Thanks.

355. Xiaohong yang (*zip code: 98006)*
Please don't build the new powerline in our neighbor. It's not safe, and lower our neighborhood environment.

356. Xiao Shang (*zip code: 98006)*
Not safe for dense neighborhoods

357. Xin Yu (*zip code: 98006)*

358. Xueyi Wang (*zip code: 98006)*
Strongly support CENSE!

359. Yan Jiang (*zip code: 98006)*
please don't hang power lines over our neighborhood schools. our kids need a safe environment to grow up.

360. Yan zhou (*zip code: 5402301158)*
I strongly object this project since it will have an negative effect on environment and people.

361. Allen Su (*zip code: 98008)*
The right thing needs to be done. The proper assessement should be made before reaching any decision.

362. Grace Huang (*zip code: 98006)*

To: Heidi Bedwell, Energize Eastside EIS Program Manager
From: Grace Huang

Dear Ms. Bedwell,

I am very concerned about Puget Sound Energy's "Energize Eastside" project, which proposes to build 18 miles of high-voltage transmission lines through four Eastside cities (Alternative 1A).

PSE tries to justify the need for the project using an impossible scenario that would cause regional blackouts, according to the Lauckhart-Schiffman Load Flow Study, available at CENSE.org.

Alternative 1A would place new lines and poles much too close to aging petroleum pipelines. Responsible safety standards require at least a 50 foot separation. A construction or operational accident could cause a catastrophic pipeline explosion like the one that killed three Bellingham residents in 1999. This risk is not adequately addressed in the EIS.

Alternative 2, the Integrated Resources Approach, is a safer and less costly alternative. But the solution described in the EIS was not developed or reviewed by independent experts that have suitable experience with modern electrical grid technologies, including Demand Side Management and Distributed Energy Resources. The costs and capabilities are based on inaccurate and obsolete studies. As the Northwest Power Council's Seventh Power Plan makes clear, a carefully developed plan would easily beat alternative 1A in cost, safety, and support for the environment.

The other transmission line options (1B, 1C, 1D and Alternative 3) are not practical for financial or political reasons.

Ratepayers are asked to spend more than a billion dollars over the lifetime of PSE's transmission line.

The Draft EIS must answer these basic questions in order to convince residents that we are getting the best possible plan for our energy future.

363. Ying Liu *(zip code: 98006)*
I live close to the power line. There're studies showed that the high voltage power lines have negative effects to children's development. It's unfair to sacrifice my children's health to "energize Canada"

364. Yiting huang *(zip code: 98006)*
i strongly against this PSE project

365. Maya Keselman *(zip code: 98006)*
No to new power lines.

366. Yun Li *(zip code: 98056)*

367. David Zhang *(zip code: 98006)*
Save our environment! No Powerlines!

368. yong zhang *(zip code: 98006)*
The power line is too close to tyee middle school. It also damage housing market in my neighborhood. I am strongly against it

369. Mingyan Li *(zip code: 98006)*

370. Wei Zhuang *(zip code: 98006)*
negative impacts on environments; safety issues to our communities

371. Zhenming Jiang *(zip code: 98006)*

372. jian zhang *(zip code: 98006)*
Pse shluld consider the safety and property value of local residents, in stead of only corporate profit.

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January 13, 2016

Mr. Donald Porter
President
BP Pipelines (North America), Inc.
150 W. Warrenville Road
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Re: CPF No. 5-2015-5014

Dear Mr. Porter:

Enclosed please find the Final Order issued in the above-referenced case to your affiliate, Olympic Pipe Line Company. It makes findings of violation and specifies actions that need to be taken by Olympic Pipe Line Company to comply with the pipeline safety regulations. When the terms of the compliance order have been completed, as determined by the Director, Western Region, this enforcement action will be closed. Service of the Final Order by certified mail is deemed effective upon the date of mailing, or as otherwise provided under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Chris Hoidal, Director, Western Region, OPS
Ms. Clorinda Nothstein, Operations Manager, BP Pipelines (North America), Inc.

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

FINDINGS OF VIOLATION

In its Response, OPL did not contest the allegations in the Notice that it violated 49 C.F.R. Part 195, as follows:

Item 1: The Notice alleged that Respondent violated 49 C.F.R. § 195.573(e), which states:

> **§ 195.573 What must I do to monitor external corrosion control?**
> (a) . . .
> (e) *Corrective action.* You must correct any identified deficiency in corrosion control as required by §195.401(b). However, if the deficiency involves a pipeline in an integrity management program under §195.452, you must correct the deficiency as required by §195.452(h).

The Notice alleged that Respondent failed to correct identified deficiencies in its corrosion control system that could adversely affect the safe operation of the pipeline, as required by 49 C.F.R. § 195.401(b). That section provides, in relevant part:

> **§ 195.401 General requirements.**
> (a) . . .
> (b) An operator must make repairs on its pipeline system according to the following requirements:
> (1) *Non Integrity management repairs.* Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time.

The Notice also alleged that Respondent violated 49 C.F.R. § 195.452(h)(1), cited in § 195.573(e), which states:

> **§ 195.452 Pipeline integrity management in high consequence areas.**
> (a) *Which pipelines are covered by this section?* This section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. . .
> (h) *What actions must an operator take to address integrity issues?*
> (1) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long-term integrity of the pipeline. An operator must comply with §195.422 when making a repair.

The Notice alleged that Respondent failed to correct deficiencies in its corrosion control system within a reasonable time, in accordance with § 195.401(b)(1). According to the Notice, in 2010 Respondent performed an in-line-inspection (ILI) that revealed discrepancies in the ILI data, revealing unrecorded casings on the pipeline system. Subsequent excavations performed by Respondent revealed additional unrecorded casings, sleeves, and half-sections of pipe at several locations. In 2011, OPL allegedly initiated a "Casing Wire Repairs" project to further evaluate and repair casing deficiencies within a 10-year time frame. The Notice alleged that Respondent's 10-year time frame to complete the inspections and repairs was not a reasonable period of time in which to correct the identified deficiencies.

In addition, the Notice alleged that OPL violated 49 C.F.R. § 195.452(h)(1) by failing to take prompt action to address all anomalous conditions in high consequence areas (HCAs).[2] Specifically, the Notice alleged that Respondent's "Casing Wire Repairs" project did not differentiate between anomalous conditions discovered in HCA areas versus non-HCA areas and that the company's 10-year time frame for completing the project did not constitute prompt action for remediating deficiencies found in such areas.

Respondent did not contest these allegations of violation. Accordingly, based upon a review of all of the evidence, I find that Respondent violated 49 C.F.R. §§ 195.573(e), 195.401(b)(1), and 195.452(h)(1), by failing to correct identified deficiencies in corrosion control within a reasonable time and to take prompt action to address all anomalous conditions that could affect HCAs discovered through its integrity assessment or information analysis.

Item 2: The Notice alleged that Respondent violated 49 C.F.R. § 195.575(c), which states:

> **§ 195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?**
> (a) . . .
> (c) You must inspect and electrically test each electrical isolation to assure the isolation is adequate.

The Notice alleged that Respondent violated 49 C.F.R. § 195.575(c) by failing to test the electrical isolation of each buried pipeline in the OPL system to assure that the isolation was adequate. Specifically, the Notice alleged the Respondent failed to test the electrical isolation of previously unrecorded casings, as described in Item 1 above, to ensure that the isolation from other metallic structures was adequate. The Notice alleged that several casings were not present on alignment sheets or other cathodic protection records, indicating previously unrecorded pipelines had not been tested for adequate isolation.

Respondent did not contest this allegation of violation. Accordingly, based upon a review of all of the evidence, I find that Respondent violated 49 C.F.R. 49 C.F.R. § 195.575(c), by failing to

[2] An HCA is defined as: (1) a *commercially navigable waterway*, which means a waterway where a substantial likelihood of commercial navigation exists; (2) a *high population area*, which means an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 per square mile; (3) an *other populated area*, which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area; and (4) an *unusually sensitive area*. *See* 49 C.F.R. § 195.450.

test the electrical isolation of each buried pipeline to assure that the isolation was adequate.

These findings of violation will be considered prior offenses in any subsequent enforcement action taken against Respondent.

COMPLIANCE ORDER

The Notice proposed a compliance order with respect to Items 1 and 2 in the Notice for violations of 49 C.F.R. §§ 195.573(e) and 195.575(c), respectively. Under 49 U.S.C. § 60118(a), each person who engages in the transportation of hazardous liquids or who owns or operates a pipeline facility is required to comply with the applicable safety standards established under chapter 601. In its Response, OPL indicated that it had taken certain actions to comply with the Proposed Compliance Order. The Director has reviewed such actions and recommended that this Compliance Order be modified accordingly. Therefore, pursuant to the authority of 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217, Respondent is ordered to take the following actions to ensure compliance with the pipeline safety regulations applicable to its operations:

1. With respect to the violations of § 195.573(e) (**Item 1**) and § 195.575(c) (**Item 2**), Respondent must:

   A. Schedule the "Casings Wire Repair" project to mitigate all remaining indications in HCAs and non-HCAs no later than 18 months from the date of this Order;

   B. Determine whether additional casings exist on its pipeline. Update maps and records, as necessary, to ensure all programmatic systems which use this data, including IMP, are accurate; and

   C. Submit changes to the "Casing Wire Repair" project within 30 days after the receipt of this Final Order to Mr. Chris Hoidal, Director, Western Region, Pipeline and Hazardous Materials Safety Administration.

2. It is requested (not mandated), that Respondent maintain documentation of the safety improvement costs associated with fulfilling this Final Order and submit the total to Mr. Chris Hoidal, Director, Western Region, Pipeline and Hazardous Materials Safety Administration. It is requested these costs be reported in two categories: 1) total costs associated with preparation/revision of plans, procedures, studies an analyses; and 2) total cost associated with replacements, additions and other changes to pipeline infrastructure.

The Director may grant an extension of time to comply with any of the required items upon a written request timely submitted by the Respondent and demonstrating good cause for an extension.

Failure to comply with this Order may result in the administrative assessment of civil penalties not to exceed $200,000 for each violation for each day the violation continues or in referral to the Attorney General for appropriate relief in a district court of the United States.

Under 49 C.F.R. § 190.243, Respondent has a right to submit a Petition for Reconsideration of this Final Order. The petition must be sent to: Associate Administrator, Office of Pipeline Safety, PHMSA, 1200 New Jersey Avenue, SE, East Building, 2nd Floor, Washington, DC 20590, with a copy sent to the Office of Chief Counsel, PHMSA, at the same address. PHMSA will accept petitions received no later than 20 days after receipt of service of this Final Order by the Respondent, provided they contain a brief statement of the issue(s) and meet all other requirements of 49 C.F.R. § 190.243. Unless the Associate Administrator, upon request, grants a stay, the terms and conditions of this Final Order are effective upon service in accordance with 49 C.F.R. § 190.5.

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Date Issued

ColumbiaGrid

2013 System Assessment

See page 12.

DSD 007863

Copies of this report are available from:
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July 2013

Photos provided by: Bonneville Power Administration, Grant County PUD, NW Power and Conservation Council, Seattle City Light, Chelan County PUD, iStock Photo, Douglas County PUD, Cowlitz County PUD

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PacifiCorp
Portland General Electric

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***Critical Electrical Infrastructure Information (CEII) protected documents are available upon request in accordance with ColumbiaGrid CEII policies at (http://www.columbiagrid.org/basecases-results-documents.cfm)*

Executive Summary

ColumbiaGrid was formed in 2006 to improve the operational efficiency, reliability, and planned expansion of the Northwest transmission grid. ColumbiaGrid's Planning and Expansion Functional Agreement (PEFA) was developed to support and facilitate multi-system transmission planning through an open and transparent process. The Federal Energy Regulatory Commission (FERC) accepted the agreement April 3, 2007, noting support for ColumbiaGrid's effort to coordinate planning on a regional basis and to implement a single utility planning process for both public utility and non-public utility transmission providers. Eleven parties have signed the PEFA. Any interested person can participate in ColumbiaGrid's open planning process.

A significant feature of ColumbiaGrid's planning process is its single utility planning approach. The plan is developed as if the region's transmission grid were owned and operated by a single entity. This approach results in a more comprehensive, efficient, and coordinated plan than would otherwise be possible if each transmission owner completed a separate independent analysis.

The primary product of the ColumbiaGrid Planning process is the ColumbiaGrid Biennial Transmission Expansion Plan that looks out over a ten-year planning horizon and identifies projected transmission needs. ColumbiaGrid has produced three Biennial Transmission Expansion Plans that were approved by the ColumbiaGrid Board of Directors in February 2009, February 2011 and February 2013. Updates to the 2009 and 2011 plans were also produced and approved by the ColumbiaGrid Board of Directors in February 2010 and 2012, respectively.

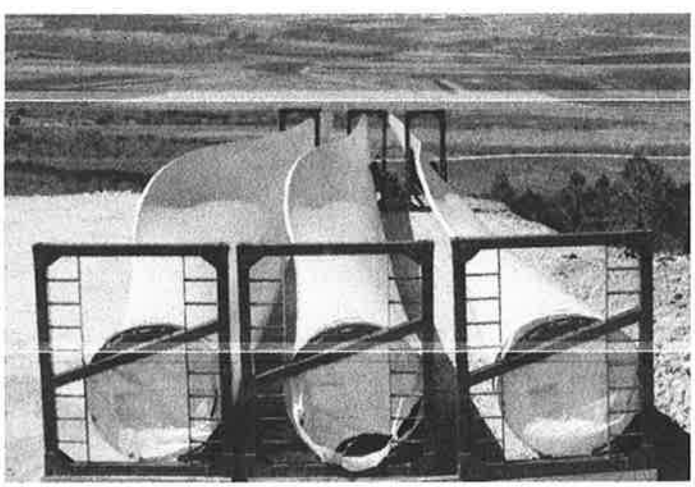
The foundation for the Biennial Transmission Expansion Plan is the ColumbiaGrid System Assessment, which is an evaluation of whether or not the planned transmission grid can meet established reliability standards. Any deficiencies in meeting these standards are noted in the System Assessment and then addressed either by the Transmission Owners themselves or through ColumbiaGrid Study Teams.

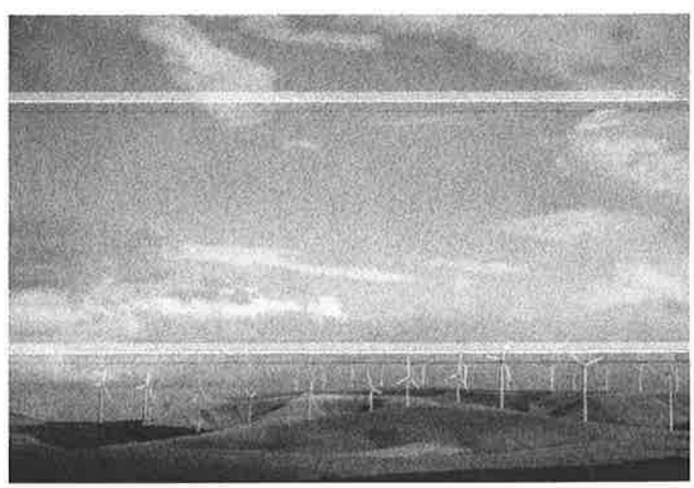
A ColumbiaGrid System Assessment is completed each year. In completing the assessment, ColumbiaGrid develops comprehensive computer models to test the adequacy of the grid under a wide variety of future system conditions. The work also entails compiling forecasts for loads, resources, and transmission facilities, which are key assumptions that form the basis for the power flow models studied. ColumbiaGrid used the output of the modeling to gauge the performance of the transmission system. The results were compared to standards adopted by the North American Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC), and the individual transmission system owners.

In completing this assessment, the study participants held numerous full-day meetings and conference calls. A typical meeting had 30 or more participants. ColumbiaGrid planning engineers developed the series of power flow models that were used in the assessment from standard WECC base cases. These cases were modified to correct errors, update the system topology, and to more precisely model the system conditions of interest. The transmission system modeled in these studies is based on the ColumbiaGrid Ten-Year Plan which is shown in Table C-1. The projects in this list include only those that utilities have made a firm commitment to build in the planning horizon. This typically means that they are under construction or the utilities have, or soon will have, budget approval. Some of these projects may be pending permitting approval.

Using these cases, the planning engineers simulated contingencies, documented cases where the system performance did not meet the standards, coordinated the review of each of these potential violations, and recommended further analysis and/or formation of a ColumbiaGrid Study Team to develop plans to mitigate the problems identified. ColumbiaGrid included a high-level assessment of non-transmission alternatives where viable to address potential violations such as load tripping, redispatch, etc.

All of the facility overloading conditions on 115 kV and above facilities were identified for

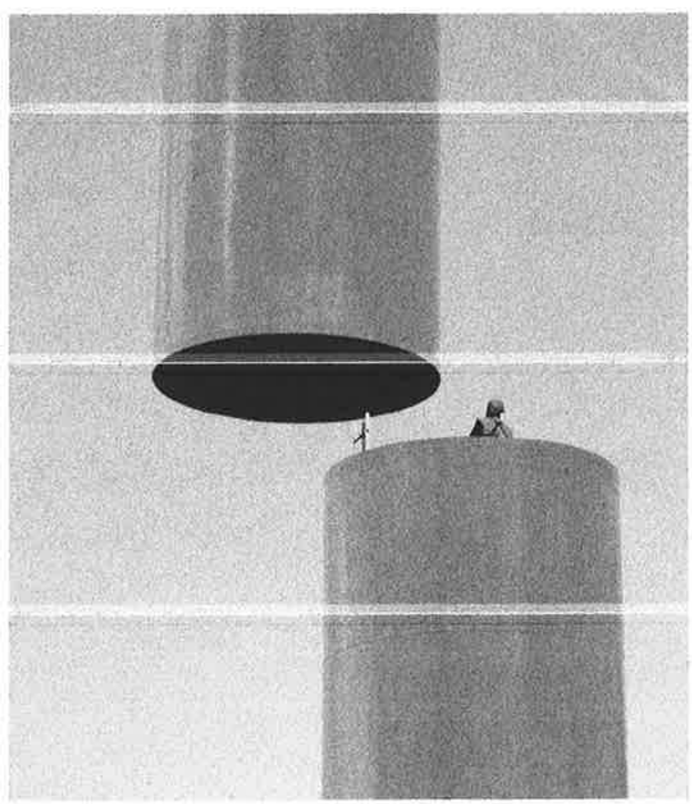




resolution. All 230 kV and above stations with voltage excursions following contingencies that exceeded the WECC criteria of a 5% change for a Category B contingency (single contingency) or 10% for a Category C contingency (double contingency) were identified and mitigation was proposed. Voltage violations on lower voltage facilities were left to the individual facility owners to mitigate. Table G-1 shows the interim mitigation for addressing the voltage violations identified at 230 kV and above.

The initial assessment results identified several areas of concern. Areas of concern were identified for those areas that would require planning decisions within the next planning cycle. For areas that only affect a single transmission owner, it is left to that owner to develop the final mitigation plans. For violations that affect more than one ColumbiaGrid member, a ColumbiaGrid study team may be formed to develop the final mitigation. The final mitigation for these areas of concern will be included in the next Biennial Transmission Expansion Plan Update, which will be completed in early 2014.

As discussed in the Study Results section of this report, 12 areas of concern were identified that affect more than one utility system. One of the areas is related to Northern Intertie transfer issues and can be addressed through the existing Puget Sound Area Study Team. The remaining areas have ongoing study efforts among the utilities or involve only one ColumbiaGrid member. These study efforts will be monitored to determine if a ColumbiaGrid Study Team is needed for resolution.



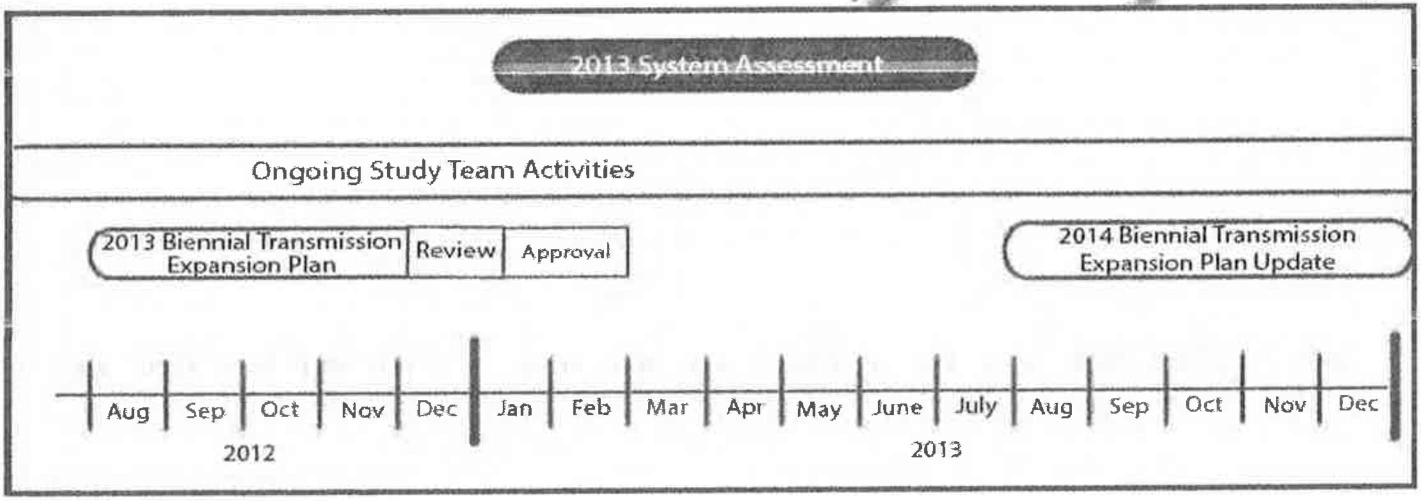


Figure B-1: Process Timeline

Introduction

ColumbiaGrid was formed with seven founding members in 2006 to improve the operational efficiency, reliability, and planned expansion of the Northwest transmission grid. Eleven parties have signed ColumbiaGrid's Planning and Expansion Functional Agreement (PEFA) to support and facilitate multi-system transmission planning through an open and transparent process.

One of the primary activities outlined under PEFA is the development of a Biennial Transmission Expansion Plan that looks out over a ten-year planning horizon and identifies projected long-term firm transmission needs on the systems of parties to the agreement.

A significant feature of the ColumbiaGrid Biennial Transmission Expansion Plan is its single-utility planning approach. The Biennial Transmission Expansion Plan is being developed as if the region's transmission grid were owned and operated by a single entity. This approach results in a more comprehensive, efficient, and coordinated plan than would otherwise be developed if each transmission owner completed a separate independent analysis.

PEFA requires that "ColumbiaGrid, in coordination with the Planning Parties and Interested Persons, shall perform a System Assessment through screening studies of the Regional Interconnected Systems using the Planning Criteria to determine the ability of each (Party's system) to serve, consistent with the Planning Criteria, its network load and native load obligations, if any, and other existing long-term firm transmission service commitments that are anticipated to occur during the Planning Horizon." The assessment is required to be completed annually.

The ColumbiaGrid System Assessment described in this report was designed to meet those requirements. It is the first phase of the Biennial

Transmission Expansion Planning process. The System Assessment process timeline is shown in Figure B-1. As with other ColumbiaGrid activities, the assessment was conducted in an open process. (See the sidebar below for further information.)

This ColumbiaGrid 2013 System Assessment Report describes an evaluation of the transmission grid. The assessment began with developing comprehensive computer models to test the adequacy of the planned grid under a wide variety of system conditions. This included forecasts for loads, resources, and transmission facilities, which are key assumptions and the building blocks for the cases that were analyzed.

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At the outset, notice of the System Assessment was sent to the ColumbiaGrid 'Interested Persons' list. The process for the assessment was developed and implemented in an open and transparent manner, and meetings were open to all interested participants. The results of the assessment studies were analyzed in a joint effort by all participating entities.

Meeting materials were posted on the ColumbiaGrid website, except when information was determined to be Critical Energy Infrastructure Information (CEII). CEII was made available through a password protected area on the website and access was granted to participants upon request. To acquire a password and access CEII data, entities were required to sign and comply with ColumbiaGrid Non-disclosure and Risk of Use Agreements. In compliance with WECC requirements, WECC base cases were only available to WECC members through the password-protected portion of the ColumbiaGrid website.

For the assessment, ColumbiaGrid Planning engineers gauged the performance of the system using these models, and the results were compared to standards adopted by the North American Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC), and individual transmission system owners.

The NERC, WECC, and owner-adopted standards require that the system be able to continue to function within a specific range of voltages and with transmission loading below facility ratings under a wide variety of operating conditions. These operating conditions include events such as a loss of a transmission line and/or substation facility and various weather patterns.

ColumbiaGrid's planning engineers studied thousands of contingencies using computer simulations for each of the base case models to complete the System Assessment. In cases where the system performance did not meet NERC, WECC, and owner standards, ColumbiaGrid recommended a strategy to resolve the problem. These strategies include further analysis, sensitivity studies or the formation of a ColumbiaGrid Study Team charged with developing plans to mitigate the identified system performance concern.

Ten-year Plan

The ColumbiaGrid Ten-Year Plan comprises a list of projects planning participants are committed to build in the coming years to address known transmission deficiencies. The projects in the ten-year plan fill a variety of needs such as serving load, integrating new resources, or facilitating economic transfers. To be included in the plan, the projects need to be committed projects that are typically in the permitting, design, or construction phases. The projects in the plan may have been generated in a variety of forums such as earlier System Assessments, studies completed by the study teams, or individual planning participant studies. ColumbiaGrid's Ten-Year Plan is shown in Figure C-1 and Table C-1. More detailed information for each of the projects is provided in Attachment B of this report. Changes in this Plan from the prior plan are also noted along with estimated costs for the ColumbiaGrid member projects.

The following are the major projects that comprise the Ten-year Plan:

- Big Eddy-Knight 500 kV line which provides additional transmission capability to move renewable resources in the Gorge area to load centers.
- Ponderosa 500/230 kV transformer which provides additional transformer capacity for the Central Oregon area.
- Raver 500/230 kV transformer which provides additional transformer capacity for the greater Puget Sound area.
- Douglas-Rapids-Columbia 230 kV line which provides additional transformation in the east Wenatchee area along with additional transmission capability.
- Columbia-Larson 230 kV line which provides addition transmission capability to the Moses Lake area.
- Lakeside 230/115 kV transformer and conversion of Sammamish-Lakeside-Talbot line to 230 kV which provides additional transformer capacity for the Bellevue area and additional transmission capability through the Puget Sound area.
- Beverly Park 230/115 kV transformer which provides additional transformer capacity for the Everett area.
- The Montana-Alberta Transmission Line (MATL) which provides transmission capability between Montana and Alberta to move renewable resources.
- Moscow 230 kV Substation Rebuild and Transformer Replacement which upgrades an aging substation and provides additional transformer capacity.
- Westside 230 kV Substation Rebuild and Transformer Replacement which upgrades an aging substation and provides additional transformer capacity in the Spokane area.
- Castle Rock-Troutdale 500 kV line (I-5 Corridor) which provides additional transmission capability between the Puget Sound and Portland load areas.

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Table C-1: ColumbiaGrid Ten-Year Plan

	Project Name	Sponsor	Date	Change from Last Plan	Estimated Cost
A1	Moscow 230 kV Substation Rebuild and Transformer Replacement	Avista		Delayed	$10 Million
A2	Benton-Othello 115 kV Line Upgrade	Avista		Delayed	$10 Million
A3	Westside 230 kV Rebuild and Transformer Upgrades	Avista		Delayed	$15 Million
A4	Irvin Project - Spokane Valley Transmission Reinforcements	Avista		Delayed	$5 Million
A5	Lancaster Combustion Turbine Project Integration	Avista	2013		$3 Million
A6	Bronx - Cabinet 115 kV Line Rebuild	Avista	2016	Delayed from 2015	$10 Million
B1	Big Eddy - Knight 500 kV line and Knight Substation	Bonneville Power	2014-15		$124 Million
B2	Fairmount Backtripping Scheme	Bonneville Power	2013		$0.9 Million
B3	Ponderosa 500/230 kV #2 Transformer Addition	Bonneville Power	2013		$19.5 Million
B4	Ostrander Breaker Addition	Bonneville Power	2014		$2.4 Million
B5	Castle Rock - Troutdale 500 kV line (I-5 Corridor Reinforcement Project)	Bonneville Power	2018		$342 Million
B6	Lower Valley Reinforcement - Hooper Springs	Bonneville Power	2015	Delayed from 2014	$48 Million
B7	Pearl 500 kV Breaker Addition	Bonneville Power	2016		$1.7 Million
B7	Pearl 230 kV Bus Section Breaker	Bonneville Power	2017		$1.5 Million
B8	Franklin 115 kV Capacitors (52 MVAR)	Bonneville Power	2014		$3.7 Million
B9	Monroe 500 kV Capacitors	Bonneville Power	2014		$5.6 Million
B10	Columbia Falls 230 Bus Reliability Improvements	Bonneville Power	2013		$1 Million
B11	Alvey 500 kV Shunt Reactor	Bonneville Power	2014		
B12	John Day - Big Eddy 500 kV #1 line reconductor	Bonneville Power	2016		$6 Million
B13	Keeler 230 kV Bus Reliability Improvements	Bonneville Power	2014		$2.6 Million
B14	Raver 500/230 kV Transformer, 230 kV line to Covington Substation	Bonneville Power	2016		$45 Million
B15	Longview - Lexington 230 kV Line Retermination into Longview Annex	Bonneville Power	2015		$2 Million
B15	Longview 115 kV Bus Section Breaker	Bonneville Power	2013	New project	$1 Million
B16	East Omak 115 kV Shunt Capacitors (28 MVARs)	Bonneville Power	2013	New project	$0.9 Million
B17	Big Eddy 230/115 kV Transformer #1 Replacement	Bonneville Power	2015		
B17	Celilo Terminal Replacement (PDCI upgrade 3220 MW)	Bonneville Power	2016		$450 Million
B18	McNary 230 kV Shunt Capacitors (2x150 MVAR banks)	Bonneville Power	2013		$5.7 Million
B19	Rogue Static VAR Compensator	Bonneville Power	2013	Completed	$9 Million
B20	Paul 500 kV Shunt Reactor	Bonneville Power	2017	Delayed from 2016	$6 Million
B21	Split Pearl-Sherwood 230 kV Line Upgrade	Bonneville Power	2017-18		$1.5 Million
B22	Split McLoughlin-Pearl-Sherwood 230 kV lines	Bonneville Power	2017-18		$1.5 Million
B23	Salem - Chemawa 230 kV Line Upgrade	Bonneville Power	2014-15	Moved up from 2016	$1 Million
B24	Tucannon River 115 kV Shunt Capacitors (2x6.5 MVARs)	Bonneville Power	2013		$2 Million
B25	Troutdale 230 kV Bus Section Breaker	Bonneville Power	2018		$1 Million
B25	North Bonneville - Troutdale 230 kV #2 Line Retermination	Bonneville Power	2015		$2 Million
B26	Walla Walla - Pendleton 69 kV Line Upgrade	Bonneville Power	2014	New project	$2.1 Million
B27	LaPine Reactive (19 MVAR Cap, 40 MVAR reactor)	Bonneville Power	2014		$3.3 Million
B28	Bell 230 kV Bus Section Breaker	Bonneville Power	2015		$1 Million
B29	Kalispell 115 kV Shunt Capacitors (2x16 MVARs)	Bonneville Power	2014		$3.1 Million
B30	Schultz - Raver 500 kV Series Capacitors	Bonneville Power	2017-18		$35 Million
B31	White Bluffs 115 kV Shunt Capacitors (39 MVARs)	Bonneville Power	2013		$2 Million
B32	Tacoma 230 kV Bus Section Breaker	Bonneville Power	2016		$1.5 Million
B33	Sappho 69 kV Shunt Capacitors (10 MVARs)	Bonneville Power	2017	New project	$0.6 Million
CH1	McKenzie - Andrew York 115 kV #1 and #2 line Rerating	Chelan County PUD	2013		$0.5 Million
CO1	Longview - Lexington #2 upgrade from 69 kV to 115 kV	Cowlitz County PUD	2014-16		$4.9 Million
CO1	Longview - Lexington - Cardwell upgrade from 69 kV to 115 kV	Cowlitz County PUD	2015-17		$10.1 Million
CO2	South Cowlitz County Project	Cowlitz County PUD	2017-19	New project	$7.7 Million
D1	Douglas - Rapids 230 kV line and Rapids 230/115 kV Substation	Douglas County PUD	2013		$17 Million
D2	Rapids - Columbia 230 kV line and Columbia Terminal	Douglas County PUD	2015		$14 Million
G1	Columbia - Larson 230 kV line	Grant County PUD	2014		$42 Million
G2	Rocky Ford - Dover 115 kV line	Grant County PUD	2016		$5 Million
I1	Hemingway - Boardman 500 kV line	Idaho Power/BPA	2018		$820 Million

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PG1	Blue Lake - Gresham 230 kV line	Portland General Electric	2017		
PS1	Alderton 230/115 kV transformer in Pierce County	Puget Sound Energy	2015		$28 Million
PS2	St. Clair 230/115 kV Transformer in Thurston County	Puget Sound Energy	2013		$30 Million
PS3	Lakeside 230/115 kV Transformer and Sammamish-Lakeside-Talbot line rebuild to 230 kV	Puget Sound Energy	2017		$70 Million
PS4	Starwood Autotransformer Removal	Puget Sound Energy	2013		$1 Million
PS5	Woodland - Gravelly Lake 115 kV Line	Puget Sound Energy	2015		$13 Million
PS6	Portal Way 230/115 kV Transformer #2 and Line Upgrades	Puget Sound Energy/BPA	2018	Delayed from 2016	$25 Million
SC1	Bothell - SnoKing 230 kV Double Circuit Line Reconductor	Seattle City Light/BPA	2016		$3 Million
SC2	Series Inductors on Massachusetts - Union - Broad and Denny - Broad 115 kV Underground Cables	Seattle City Light	2016		$13 Million
SC2	Denny Substation - Phase 1	Seattle City Light	2016		$120 Million
SC2	Upgrade Denny Substation Transmission - Phase 2	Seattle City Light	2020		$50 Million
SC3	Delridge - Duwamish 230 kV Line Reconductor	Seattle City Light	2016		$2 Million
SN1	Berverly Park 230/115 kV Transformer	Snohomish County PUD	2016		$25 Million
SN2	Granite Falls 115 kV Transmission Loop	Snohomish County PUD	2013	Completed	$7 Million
SN3	Swamp Creek 115 kV Switching Station	Snohomish County PUD	2019	New project	$6 Million
T1	Cowlitz 230 kV Line Retermination Project	Tacoma Power	2012-13		$1 Million
T1	Cowlitz 230 kV Substation Reliability Improvement Project	Tacoma Power	2015-16		$3 Million
T2	Southwest Substation 230 kV Bus Reliability Improvement Project	Tacoma Power	2013-14		$3Million
TB1	Montana Alberta Tie - Line (MATL) Project	Enbridge/MATL LLP	2013		$209 Million
			Total of all ColumbiaGrid Projects		**$2,719 Million**

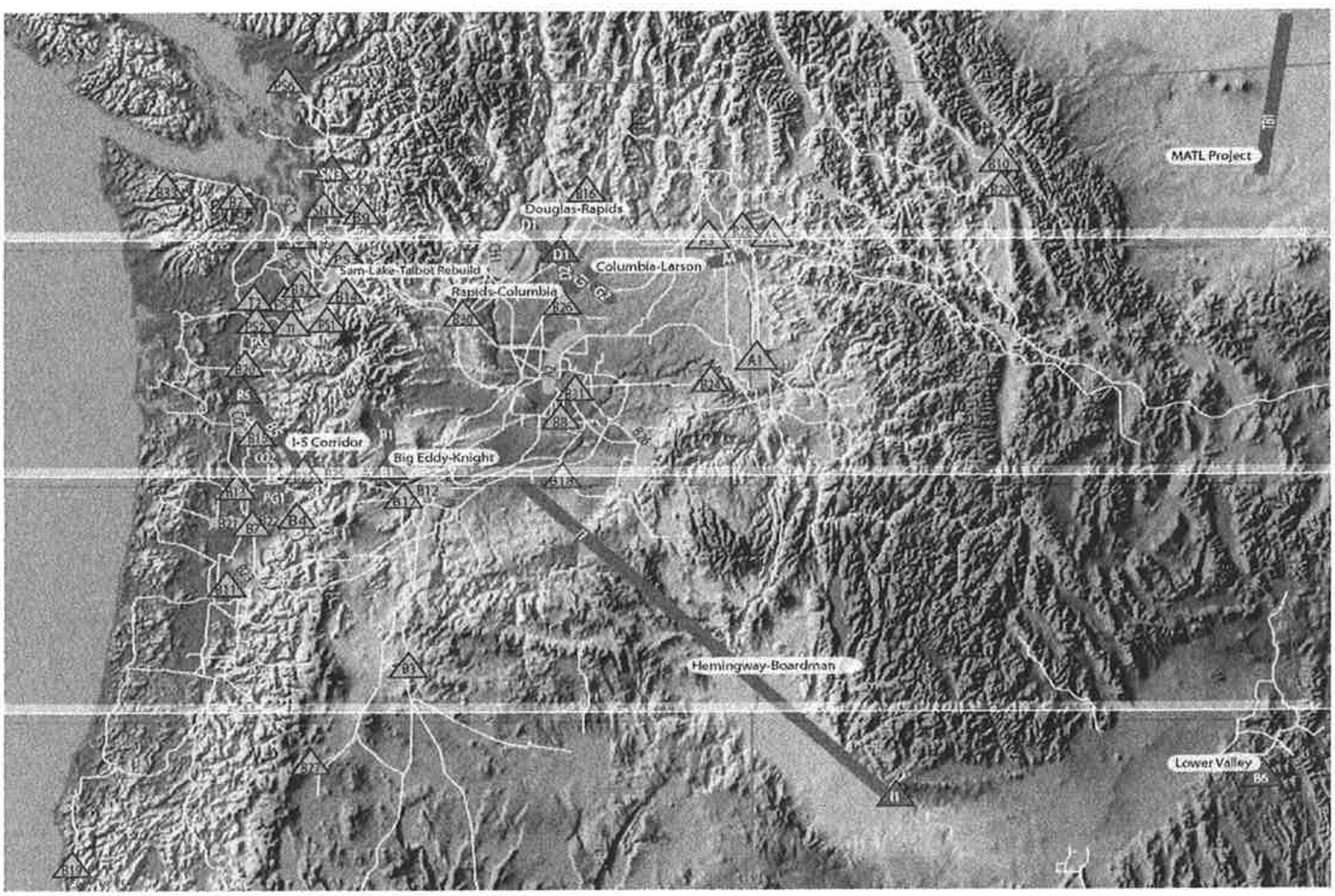


Figure C-1: Location of Committed Projects

• Schultz-Raver Series Capacitors which enhances transmission capability to move east side resources to the west side load centers.

• Alvey 500 kV Shunt Reactor which provides voltage control in the southern Willamette area.

• Hemingway-Boardman 500 kV Line which increases transmission capability between the Northwest and Idaho.

• Blue Lake-Gresham 230 kV line which increases transmission capability in the Gresham/Troutdale area.

• Portal Way 230/115 kV transformer #2 which provides additional transformation in the Bellingham area.

• Denny Substation Phase 1 and Phase 2 Projects which create a new substation for load service in the Seattle area.

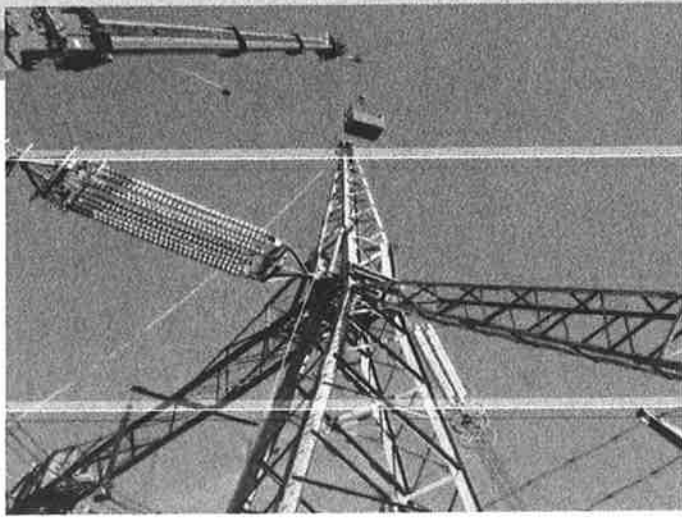
• Bothell-SnoKing double circuit reconductor and Duwamish-Delridge reconductor of 230 kV transmission lines and Massachusetts-Union-Broad and Denny-Broad 115 kV transmission line inductors to increase transmission capability in the Puget Sound Area.

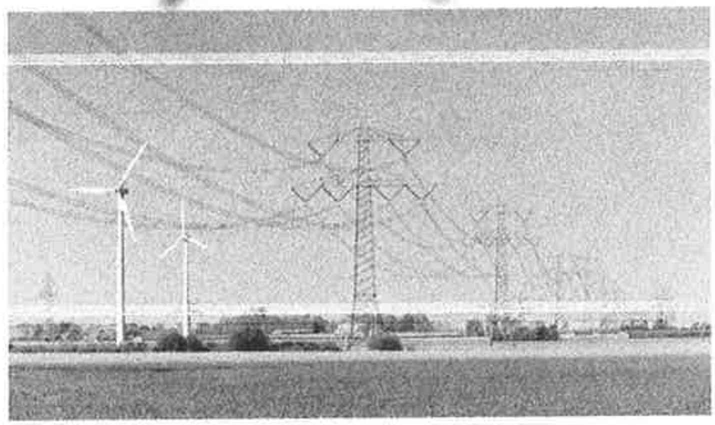
The ColumbiaGrid ten-year plan has been coordinated directly with other regional planning groups (e.g., the Northern Tier Transmission Group) and with the rest of the Western Interconnection through the Western Electricity Coordinating Council. During 2013, WECC will be developing an overall plan for the Western Interconnection. The ColumbiaGrid Ten-Year plan will be part of the foundation for this interconnection-wide plan.

Several projects were removed from the Ten-year Plan this year. The main reason for this change is due to a reduction in the commitment level from the project sponsor or project requestors. The project may have been delayed or the sponsor is investigating other options to satisfy the need. The projects removed from the Ten-year Plan include:

• Central Ferry-Lower Monumental 500 kV line
• Montana to Washington Project
• Monroe-Novelty 230 kV Upgrade
• Lane 230 kV bus sectionalizing breaker
• Olympia-Shelton 230 kV line #5 Upgrade
• Northern Intertie RAS extension
• Hatwai 230 kV Bus Reliability Improvements
• Talbot 230 kV Bus improvements
• Cascade Crossing Project

The projects in the ten-year plan primarily address issues that occur in the first five years of the ten-year planning horizon. Additional projects will be required to meet the needs in the latter part of the ten-year planning horizon. These additional projects are still being developed as there is sufficient time to study these areas and refine the projects that will address those needs. This System Assessment is one part of those ongoing studies. As additional projects mature into committed plans to meet these long-range needs, they will be incorporated into future ColumbiaGrid ten-year plans.





System Assessment Process

The parties to ColumbiaGrid's PEFA are: Avista Corporation, Bonneville Power Administration, Chelan County PUD, Cowlitz County PUD, Douglas County PUD, Enbridge, Grant County PUD, Puget Sound Energy, Seattle City Light, Snohomish County PUD, and Tacoma Power. The combined facilities of these participants are shown in Figure D-1 (on the next page).

The Northwest transmission grid is interconnected and as result, it is necessary for all Northwest entities to participate in the System Assessment whether or not they are parties to the ColumbiaGrid PEFA. Major transmission owners in the Northwest were notified individually and encouraged to participate in the System Assessment process. Northern Tier, PacifiCorp and Portland General Electric were all very active in the System Assessment process. All participants in the System Assessment who provided input to the study or helped to screen results, had access to the same information, whether or not they were parties to PEFA.

Study Assumptions

The major assumptions that form the basis of the System Assessment are load, generation, external path flows, and planned transmission additions. These assumptions were used to develop the cases that were studied in the System Assessment. The approach used for developing each of these assumptions is summarized below.

Base Case Development

Standard five-year and ten-year base cases for winter peak load, summer peak load and light load conditions were used for this System Assessment. The five-year cases used were based on the recent heavy winter case 2017-18HW2, the heavy summer case 2018HS2 and light load case 2016LSP1-S. The ten-year summer case was based on 23HS1. A recent ten-year winter peak load case was not available and one was created by using the five-year winter case with loads increased to reflect expected load growth in the ten-year timeframe. A ten-year extreme winter peak load case (with 5% probability loads) was also

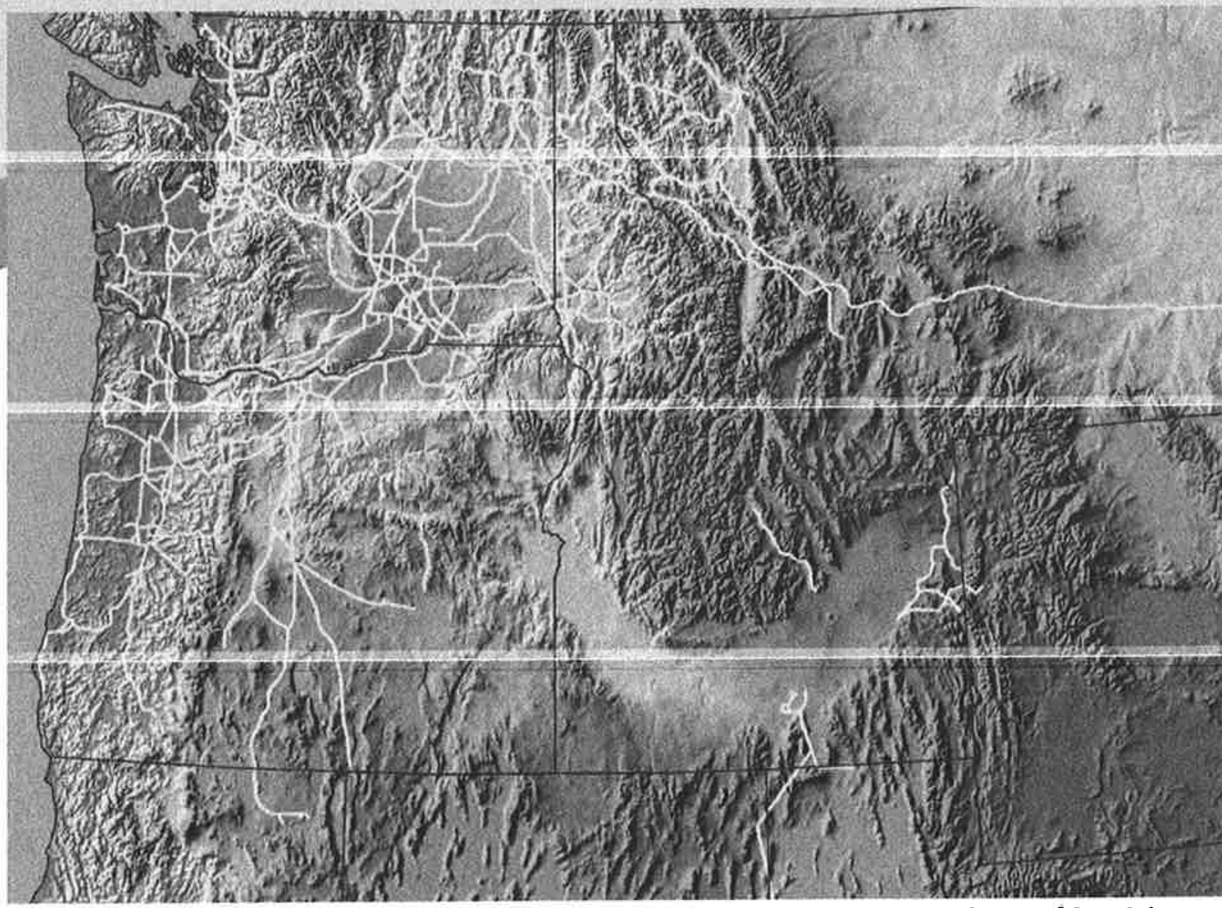


Figure D-1: Combined Facilities of Participants

created from this ten-year winter case and studied for informational purposes (ie, no mitigation was required for areas that did not meet reliability standards for this case as these system conditions are beyond those required in the Planning Standards). Ten-year light load studies were run on 2022LSP1B which included high renewable generation in the Western Interconnection and light spring loads. More detail on each of the cases is provided below:

Five-year cases

• Five-year heavy summer: 2018HS2 case with no alterations to transfers or generation.

• Five-year heavy winter: 2017-18HW2 case with no alterations to transfers or generation except for increasing Northwest to British Columbia transfers to 1500 MW.

• Five-year light load: 2016 LSP1-S case with no alterations to transfers or generation.

Ten-year cases

• Ten-year heavy summer: 2023HS1 case with Boardman and Centralia #1 removed from service and new Centralia CT was added (250 MW). Transfers to California were adjusted to make up for the difference in generation.

• Ten-year heavy winter: 2017-18HW2 case with loads increased to model an additional five years of growth, Boardman and Centralia #1 were removed and new Centralia and Port Westward CTs added as in the heavy summer case as well as a Boardman gas turbine (430 MW). The Northwest to British Columbia transfer was increased to 1500 MW. Transfers from California were increased to make up for the changes made in load, generation and transfers.

- Ten-year extra heavy winter: 2017-18HW2 with loads increased to model five years of load growth plus approximately 12% additon to load represent an extra heavy (5% probability of occurrence) load for 2023, Boardman and Centralia #1 were removed, Centralia and Port Westward CTs were added as in the heavy summer case, transfers from California were increased to make up the difference in load and generation. The Northwest to British Columbia transfer was increased to 1500 MW and the West of Cascades North transfer was increased to near its limit (10,200 MW) by reducing local west side gas generation. This case is being studied for information purposes and mitigation is not required as it goes beyond what is required in the NERC Reliability Standards

- Ten-year light load: 22LSP1B with no alterations to transfers or generation. This case models high wind and high hydro generation with heavy exports to California. All local coal generation was modeled as out of service along with the new CT's modeled in the other cases at Centralia and Port Westward (no changes were required as these assumptions were already included in the WECC base case).

The transmission configuration in each of the cases was updated to include the committed projects listed in Table E2.

The same philosophy that was used for resource assumptions in the 2012 System Assessment was used again this year. In earlier years, resources were modeled in the base cases based on firm commitments. Those assumptions have been tested for several years now. The actual system may encounter a variety of different dispatches depending upon load
outages and possibly oth
System Assessment, the
WECC used in each case
possible dispatches. Imp
Canada to the Northwest
would still be loaded to
Some generation changes
the desired intertie flows
more fully in this section.

Energize Eastside is based on assumptions that go "beyond what is required in the NERC Reliability Standards."

All of the base case assumptions, such as the load levels and the transmission projects, were selected by the ColumbiaGrid Planning participants during open meetings. Corrections and updates to the transmission system were made to all of the cases to ensure consistency. Each case was analyzed under pre-outage and outage conditions and any deficient areas were noted and corrections or updates were made as appropriate.

Load Modeling Assumptions

As required in the NERC Reliability Standards, the transmission system is planned for expected peak load conditions. Normal summer and winter peak loads were based on a probability of 50 percent not to exceed the target load. The loads in the extreme winter peak case were based on a probability of 5 percent not to exceed the target load. The loads in the WECC light load case were to reflect typical loads in the target timeframe and were not changed.

As modeled in the base cases, the total winter peak load for the Northwest system is forecasted to be 32,716 MW in the five-year case (this is down from the 32,913 MW in the five-year case in last year's System Assessment) and 34,324 MW in the ten-year winter case, 37,999 MW in extreme winter. The forecast summer peak load is 26,393 MW in the five-year case (this is up from the 26,268 MW modeled in last year's case) and 27,884 MW in the ten-year case (27,450 MW was modeled in last year's ten-year case). The five-year light spring case includes 17,386 MW of load in the Northwest while the ten-year light spring case includes 19,692 MW of load.

Although the Northwest system as a whole peaks in the winter, this does not mean that summer conditions require less attention. The capacity of electrical equipment is often limited by high temperatures, which means the equipment has lower capacity in summer than in winter. As a result, it is possible that a lower summer load can be more limiting than a higher winter load due to the ambient temperature differences and the impact on equipment.

Resource Modeling Assumptions

Resource additions ten years into the future are much more difficult to forecast than loads. Although there are numerous potential generating projects in the region in various stages of development, there is much uncertainty for a variety of reasons about whether and when they will come into service. Many of the variables are outside the control of the transmission providers. Adding to the complexity, these resource assumptions are particularly important. Depending upon their location, some resources can mask transmission problems while others can create new problems.

Previous System Assessments modeled the firm transfer commitments on Northwest paths and this dispatch has been studied numerous times. There are a variety of feasible dispatches within these firm commitment levels that could impact the transmission system. The WECC base cases are not developed with these firm commitments specifically modeled. To study other feasible dispatches, planning participants agreed that the System Assessment base cases would use the generation dispatch within each WECC base case to test other dispatches. Only changes to include known generation retirements, changes to load and adjustments to selected external paths to obtain desired levels were made. The resource assumptions for each base case are listed in Attachment A.

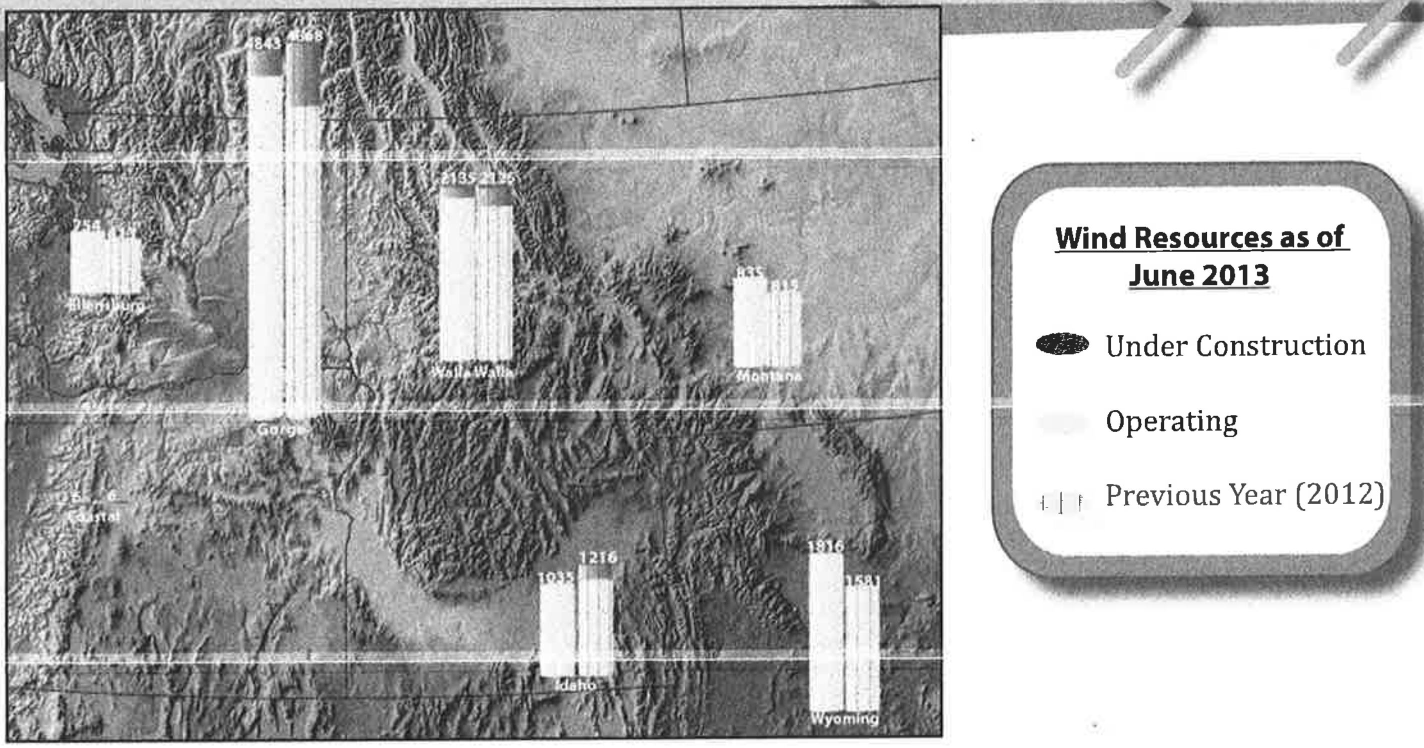
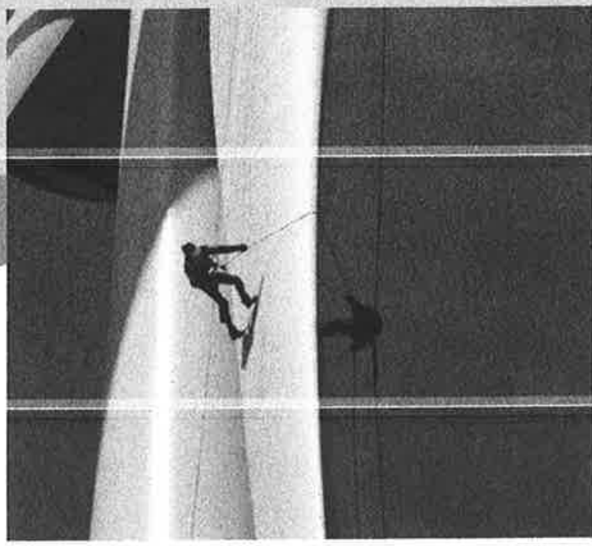


Figure E-1: Wind Resources

While the existing Northwest resources are adequate to meet summer loads, they are not adequate to meet winter peak loads. Northwest utilities rely on seasonal diversity in resource needs with other regions to meet winter load obligations by importing from California and the Southwest. For this reason, imports into the Northwest from California were used to meet the shortfall of new resource additions in the Northwest. However, there are many indicators, such as the number of requests for interconnection that transmission providers have received, to suggest that other resources will be developed in the region during this ten-year planning horizon. The addition of proposed generation projects, especially thermal projects on the west-side of the Cascades, could have a significant impact on the performance of the transmission system and reduce the reliance on California imports that was assumed in the winter cases. Planned transmission projects will be reviewed periodically to determine whether changes in resource additions would impact the need for, or scope of, these projects.

Two generation retirements were included in the assessment. The state of Washington has come to an agreement with the owner of the Centralia Power Plant that one 700 MW coal-fired unit will be retired in 2020 and the second unit in 2025. To match these system conditions, the base cases were run with one unit on (the transmission impacts of the retirement of both units was studied in 2011 and this study report is posted on the ColumbiaGrid website). A new combustion turbine was added at Centralia to provide the replacement power members thought was needed. The state of Oregon has reached agreement with Portland General Electric to retire the Boardman Coal Power Plant in 2020. Portland General Electric plans to replace the coal generation with gas-fired generation



(an additional unit was added at Port Westward and adjacent to Boardman). These changes are modeled in the Ten-Year cases.

There is a significant amount of new wind generation proposed in the ColumbiaGrid footprint. Figure E-1 shows the existing wind resources, along with projects under construction and projects proposed as of June 2013. The development of new wind projects has slowed. The amount of total wind in service or under construction is similar to previous years especially in Oregon and Washington. However, more of this generation is now in service and less is in the construction phase. The significant wind generation potential in Idaho, Montana, and Wyoming has been slower to develop primarily due to the transmission additions required to deliver those remote resources to major load areas.

Although there are several thousand MWs of wind generation in the Northwest, none is usually modeled during peak load conditions in the System Assessment. Historical operation has shown there is often little wind generation during either winter or summer peak load conditions. Operation without wind generation results in increased reliance on local gas generation and/or increased imports from California and the southwest.

The ten-year light spring base case used this year has significant wind generation in operation. This is typical operation since wind generation is usually highest during off peak conditions. The five-year light load case has no wind generation. These cases will be used to investigate transmission problems that may occur for these types of conditions.

To balance the load and generation in the Northwest, ColumbiaGrid assumed 1,522 MW was exported to California from the Northwest over the California-Oregon and Pacific DC Interties in the five-year winter study. For the ten-year winter study, ColumbiaGrid assumed 421 MW was imported into the Northwest on the combined Interties.

A list of all the resources used in the base cases is included in Attachment A.

Transmission Modeling Assumptions

As required by the NERC Reliability Standards and PEFA, it was necessary to model firm transmission service commitments in the System Assessment. PEFA requires that plans be developed to address any projected inability of the PEFA planning parties' systems to serve the existing long-term firm transmission service commitments during the planning horizon, consistent with the planning criteria. The NERC Reliability Standards do not allow any loss of demand or curtailed firm transfers for Level B contingencies (single elements) and allow only planned and controlled loss of demand or curtailment of firm transfers for Level C contingencies (multiple elements).

The ColumbiaGrid planning process assumes that all ColumbiaGrid members' transmission service and native load customer obligations represented in WECC and ColumbiaGrid base cases are firm, unless specifically identified otherwise (such as interruptible loads).

The firm transmission service commitments between the Northwest and British Columbia are scheduled. The other external paths (Montana-Northwest and Idaho-Northwest) were modeled at loading levels used in the original WECC base cases.

Of the external paths, the British Columbia-Northwest and the two California Interties are most crucial during peak load conditions. These paths are bi-directional and there are often different stresses during winter and summer conditions. The Montana-Northwest and Idaho-Northwest paths are stressed more during off-peak load conditions and are less important during peak load conditions. The adequacy of these latter paths is verified annually through operational and light load studies.

Conversely, the transmission paths internal to the Northwest are not scheduled. The flows on internal paths are a result of flows on the external paths, internal resource dispatch, internal load level, and the transmission facilities that are in service.

During the winter, returning the firm Canadian Entitlement to British Columbia is the predominant stress on the Puget Sound area and the British Columbia-Northwest path. In the winter, the California interties were used to balance the load and generation modeled in the studies. This results in moderate imports which is not uncommon in winter.

In the summer, transfers on the British Columbia-Northwest and California Interties are typically in the opposite direction as in winter. Surplus power resources from Canada and the Northwest are often sent south to California and the Southwest.

	18HS	17-18HW	23HS	22-23HW	22-23EHW	16LSP	22LSP
Northwest Load	26,393	32,716	27,884	34,324	37,999	17,386	19,692
Northwest Generation	30,852	35,809	33,511	35,198	35,400	18,171	22,985
Northwest - BC Hydro Flow	-2,300	1,500	-2,298	1,499	1,501	1,249	-295
Idaho - Northwest Flow	-293	164	-962	433	756	1,133	527
Montana - Northwest Flow	1,051	1,060	806	1,114	1,185	2,173	1,426
PDCI Flow	2,801	789	2,604	192	-912	1,400	2,200
COI Flow	3,512	723	3,860	-613	-2,856	779	2,353
North of John Day Flow	6,308	2,835	7,157	2,353	998	1,254	3,141
South of Allston Flow	3,305	1,314	2,774	750	279	893	-253
West of Cascades North Flow	3,825	8,829	4,557	9,042	9,785	4,363	6,272
West of Cascades South Flow	4,272	5,769	5,232	6,407	7,113	2,996	4,866
West of Hatwai Flow	533	590	395	548	314	2,534	937

Table E-1: Base Case Summary

The path flows in the assessment were within their limits. The West of Hatwai and West of McNary flows are quite low in these cases but that is expected, as these paths typically experience stress only during off-peak conditions.

The path flows modeled in the System Assessment is shown in Table E-1. The background for the specific existing firm transmission service commitments on members' paths that were modeled in the Transmission Expansion Plan is as follows:

1. Canada to Northwest Path

The capacity of this path in the north to south direction is 2,850 MW on the west-side and 400 MW on the east-side with a combined total transfer capability limit of 3,150 MW. The total capacity of the path in the south to north direction is now 3,000 MW, with a limit of 400 MW on the east-side (this path has recently been upgraded in this direction). Both of these directional flows can impact the ability of the system to serve loads in the Puget Sound area.

The Canadian Entitlement return is the predominant south to north commitment on this path and is critical during winter conditions. Although the total amount of commitment varies somewhat, 1,350 MW of firm transmission service commitments are projected for the ten-year studies. Puget Sound Energy also has a 200 MW share at full transfer capability into British Columbia, which translates to a 130 MW allocation at the 1,350 MW level. Bonneville has committed to maintaining this pro-rata share of the Northern Intertie above its firm transmission service commitments. Both of these firm transmission service commitments are on the west-side of the path so 1,500 MW of transfers are modeled in the south to north direction in winter.

With reduced loads in the Puget Sound area in the summer, the return of the Canadian Entitlement is not typically a problem. The most significant stressed condition in the summer is north to south flows of Canadian resources to meet loads south of the border.

Powerex has long-term firm rights for about 242 MW for their Skagit contract, plus 193 MW to Big Eddy and 450 MW to John Day, for a total of 885 MW in the north–to-south direction. Powerex also owns 200 MW of transmission rights for the Cherry Point Project which is just south of the Canadian border and can be reassigned to the border. Puget Sound Energy has long-term firm contracts for 150 MW and Snohomish has firm contracts for 100 MW. The total of all of these contracts is 1,335 MW.

The Puget Sound Area Study Team has been planning the system in the Puget Sound area to maintain 1,500 MW in the north to south direction to cover these firm transfers. Bonneville is making commitments to increase the firm transactions to 2300 MW through the Network Open Season that will show up in the five-year time frame. 200 MW of this new commitment is planned to be scheduled on the east side of the Northern Intertie at Nelway. Therefore the summer cases will model 2300 MW to cover the additional commitments that are being made on the Northern Intertie including the 200 MW on the east side of the tie at Nelway.

2. Montana to Northwest Path

This path is rated at 2,200 MW east to west and 1,350 MW west to east. The predominant flow direction is east to west. The path can only reach its east to west rating during light load conditions. Imports into Montana usually only occur when the Colstrip Power Plant facilities are out of service.

The firm commitments on this path exceed 1,400 MW east to west. There are also some counter-schedules that reduce the actual flows on the system. For the five-year studies, flow was modeled as 1,060 MW in normal winter and 1,051 MW in summer. Flows are similar in the outer-year cases. Flows are highest in the five-year light load case at 2,173 MW.

3. Northwest to California/Nevada Path

The combined COI and Pacific DC Intertie are rated at 7,900 MW in the north to south direction, although the combined operating limit can be lower due to the North of John Day nomogram. The COI is individually rated at 4,800 MW and the Pacific DC Intertie is rated at 3,100 MW. The 300 MW Alturas tie from Southern Oregon into Nevada utilizes a portion of the 4,800 MW COI capacity. In the south to north direction, the COI is rated at 3,675 MW and the Pacific DC Intertie is rated at 3,100 MW.

Bonneville has constructed upgrades to these paths to increase the potential to use these paths at their full capability. With these upgrades, the long-term firm transmission service commitments on these paths are increasing to total about 7,700 MW. To investigate the stress that results from these commitments, these two interties were loaded close to their combined limit of 7,900 MW in the summer cases used in the System Assessment.

Bonneville is also planning a major equipment replacement at the Celilo terminal of the Pacific DC Intertie to replace the aging equipment there. These replacements are planned for 2016 at which time the rating of the PDCI will increase from 3,100 MW to 3,220 MW.

There are some firm transmission service commitments on this path in the south–to-north direction but not a significant amount. Non-firm sales are relied on by many parties in the winter, especially during very cold weather, when there are insufficient resources within the Northwest to meet the load level. For the base cases, Northwest resources were dispatched first, and firm transmission service commitments were modeled on external paths. Additional resources needed to meet the remaining load obligations in the Northwest were imported from the south, split between the COI and Pacific DC Intertie.

In the five-year heavy winter base case, the exports into California totaled 1,512 MW with 723 MW on the COI and 789 MW on the PDCI. Previous system assessments have mostly had imports from California during winter peak conditions, which are more typical of early winter conditions. Conditions with exports to California during peak Northwest winter load are more typical of late winter conditions when more hydro is available in the northwest. The ten-year peak winter case has a total of 421 MW import on the combined COI and PDCI paths while the extra heavy case has 3,768 MW import on the combined interties. In the five-year peak summer cases, the combined exports were modeled at about 6,300 MW. In the ten-year peak summer cases, the combined exports were modeled at about 6,400 MW. The five-year light load case has 2,179 MW export on the two interties and the ten-year case has 4,553 MW.

4. Idaho to Northwest Path

The Idaho to Northwest path is rated at 2,400 MW east to west and 1,200 MW west to east. This path has about 300 MW of firm schedules into Idaho to meet firm transfer loads, in addition to a 100 MW point-to-point service contract. Summer conditions with flows at these levels are typical as there are few surplus resources to export from the east. In the winter, these transfer loads are reduced and PacifiCorp typically exports its east-side resources into the Northwest to meet its west-side load obligations. Due to the nature of the flows from Idaho, they are not expected to cause significant system problems in the Northwest during peak load periods. With the addition of the Hemingway-Boardman project, the rating of this path is expected to increase by 800 MW in the east to west direction and 1,300 MW west to east.

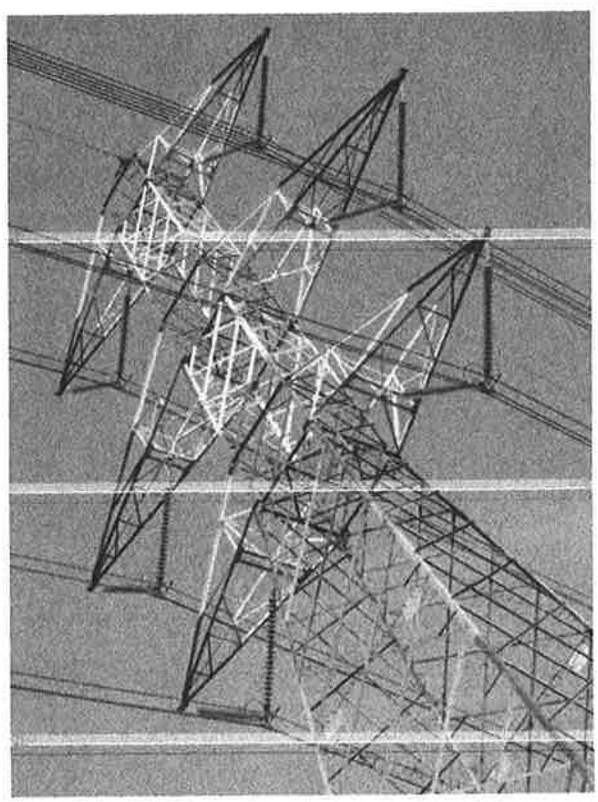
For the five-year winter cases, 164 MW is modeled flowing into the Northwest. In summer, 293 MW was modeled flowing into Idaho. Flows increased in the ten-year summer case to 962 MW flow into Idaho. The five- and ten-year light load cases had 1,133 MW and 527 MW respectively flowing into the Northwest from Idaho.

5. West of Hatwai Path

The West of Hatwai path is rated at 4,277 MW in the east to west direction but it is not a scheduled path. This path is stressed most during light-load conditions when eastern loads are down and the excess resources from the east flow into Washington. This path is loaded to 533 MW in the summer and 590 MW in winter in the five-year cases. In the outer-year cases, the path is loaded to 395 MW in the summer and 548 MW in winter. In the light load cases with high wind, the West of Hatwai path is loaded to 2,534 MW in the five-year case and 937 MW in the ten-year case.

6. West of Cascades North and South Paths

The West of Cascades North path is rated at 10,200 MW and the West of Cascades South path is rated



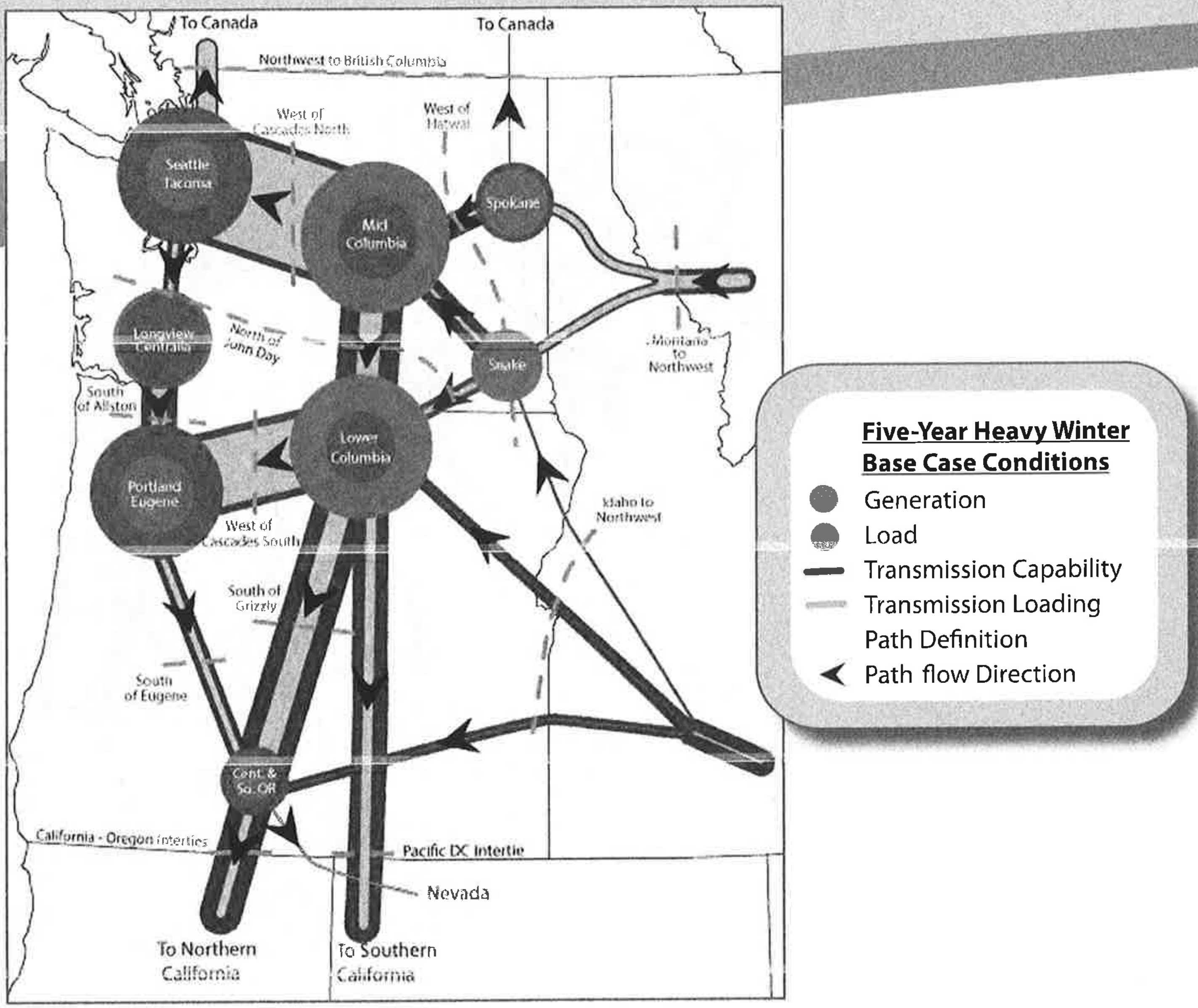


Figure E-2: Flows Modeled for Five-Year Winter Peak Conditions

at 7,200 MW, both in the east to west direction. These paths are not scheduled paths but transfer east-side resources to the west-side loads. These paths are most stressed during winter load conditions, especially when west-side generation is low. The north path was loaded to 3,825 MW in the five-year summer base case and 8,829 MW in the winter base case. These loadings are 4,557 MW in summer and 9,042 MW in heavy winter and 9,785 MW in extreme winter in the outer-year cases. In the five-year cases, the south path was loaded to 4,272 MW in the summer base case and 5,769 MW in the winter base case. These loadings increase to 5,232 MW in summer, 6,407 MW in heavy winter and 7,113 MW in extreme winter in the outer-year cases. For the five-year light load case, the north path is loaded to 4,363 MW and the south path is loaded to 2,996 MW. For the ten-year light load case, the north path is loaded to 6,272 MW and the south path is loaded to 4,886 MW.

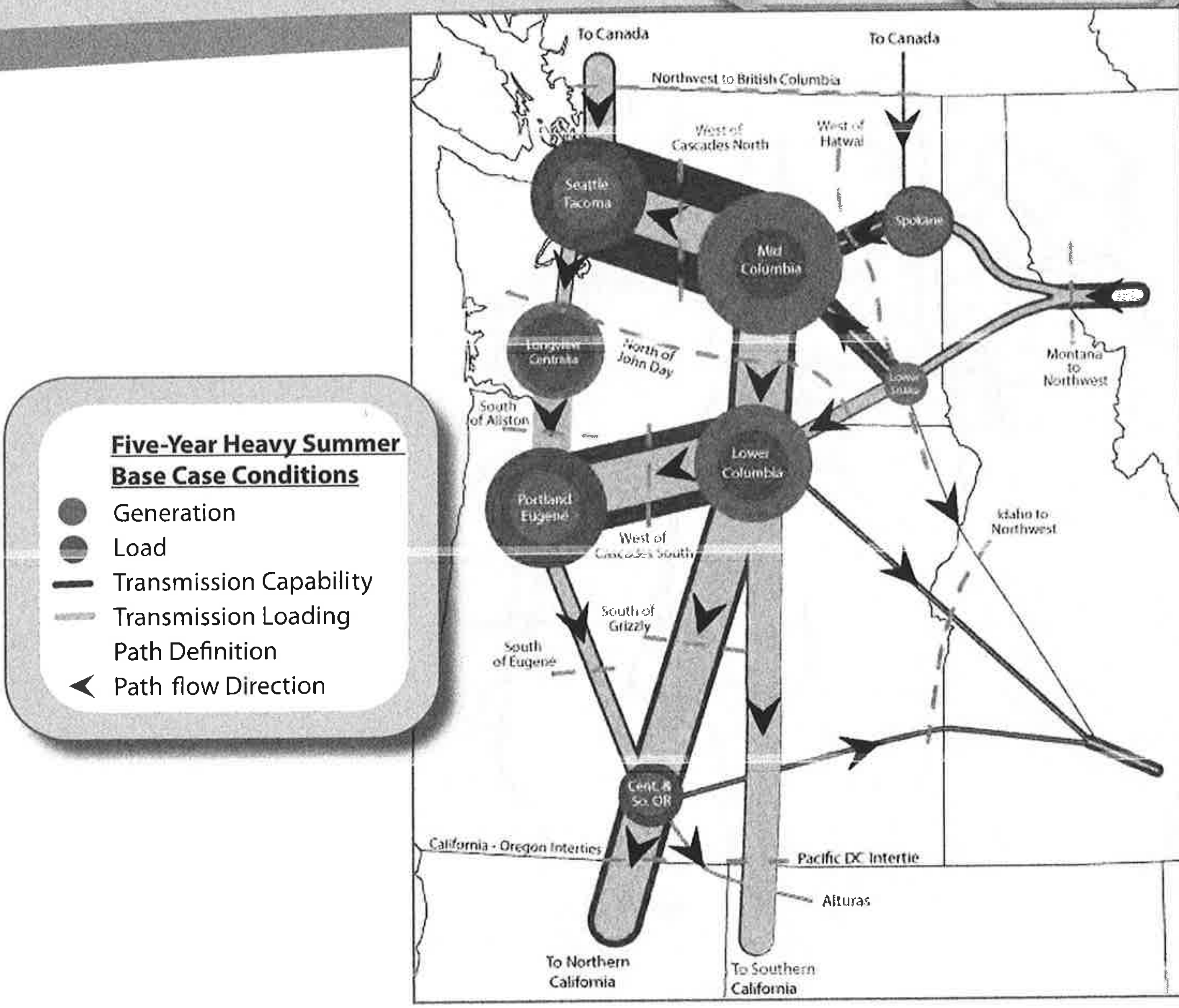


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Figure E-3: Flows Modeled for Five-Year Summer Peak Conditions

Flow Diagrams

The loads, generation and flows modeled in the base cases are shown in Figures E-2, E-3, E-4, E-5, E-6, E-7 and E-8. The Seattle-Tacoma area includes the area west of the cascades from the Canadian border south through Tacoma. The Longview/Centralia bubble includes the areas south of Tacoma through Longview and west to include the Olympic Peninsula. The Portland/Eugene area includes the Willamette Valley and Vancouver, Washington area. The Southern/Central Oregon bubble includes the Roseburg area down to the California border and east to the Bend-Redmond area. The Mid-Columbia Area includes load in the Washington area east of the Cascades, west of Spokane, south of the Canadian border and north of the Columbia River. The Lower Columbia bubble includes loads to the south of Mid-Columbia to Central Oregon. The Spokane area includes loads to the east in Western Montana, north to the Canadian border and south to the Oregon border. The Lower

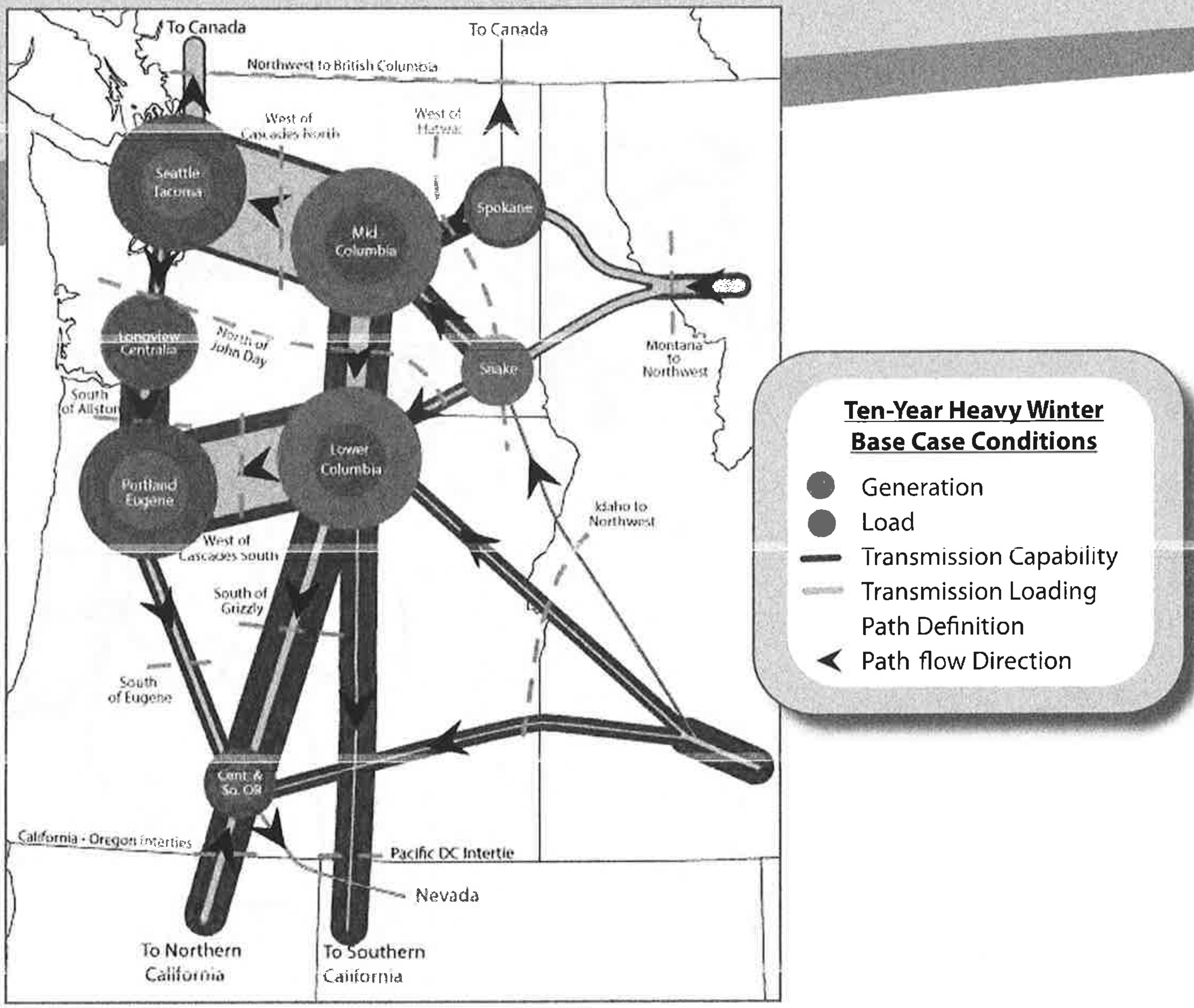

Figure E-4: Flows Modeled for Ten-Year Heavy Winter Peak Conditions

Snake bubble includes the major generation in the area. Figures E-2 and E-3 show the five-year peak winter and summer peak conditions. Figures E-4, E-5 and E-6 show the ten-year peak winter, ten-year extreme winter peak and summer peak conditions. Figure E-7 and E-8 shows the five and ten-year light load spring conditions.

The red circles in the figures represent the load levels in the identified areas; the load level is proportional to the area of the circle. The two major west-side load areas, Seattle/Tacoma and Portland/Eugene, each have approximately 10,000 MW of load in the five-year peak winter case as shown in Figure E-2. The area of the green circles represents the amount of generation in that area. The Seattle/Tacoma and Portland/Eugene load areas have more load than generation and rely on other areas to supply the load resource balance. The Mid-Columbia, Lower Columbia and Lower Snake areas have surplus generation that is used in other areas. The Mid-

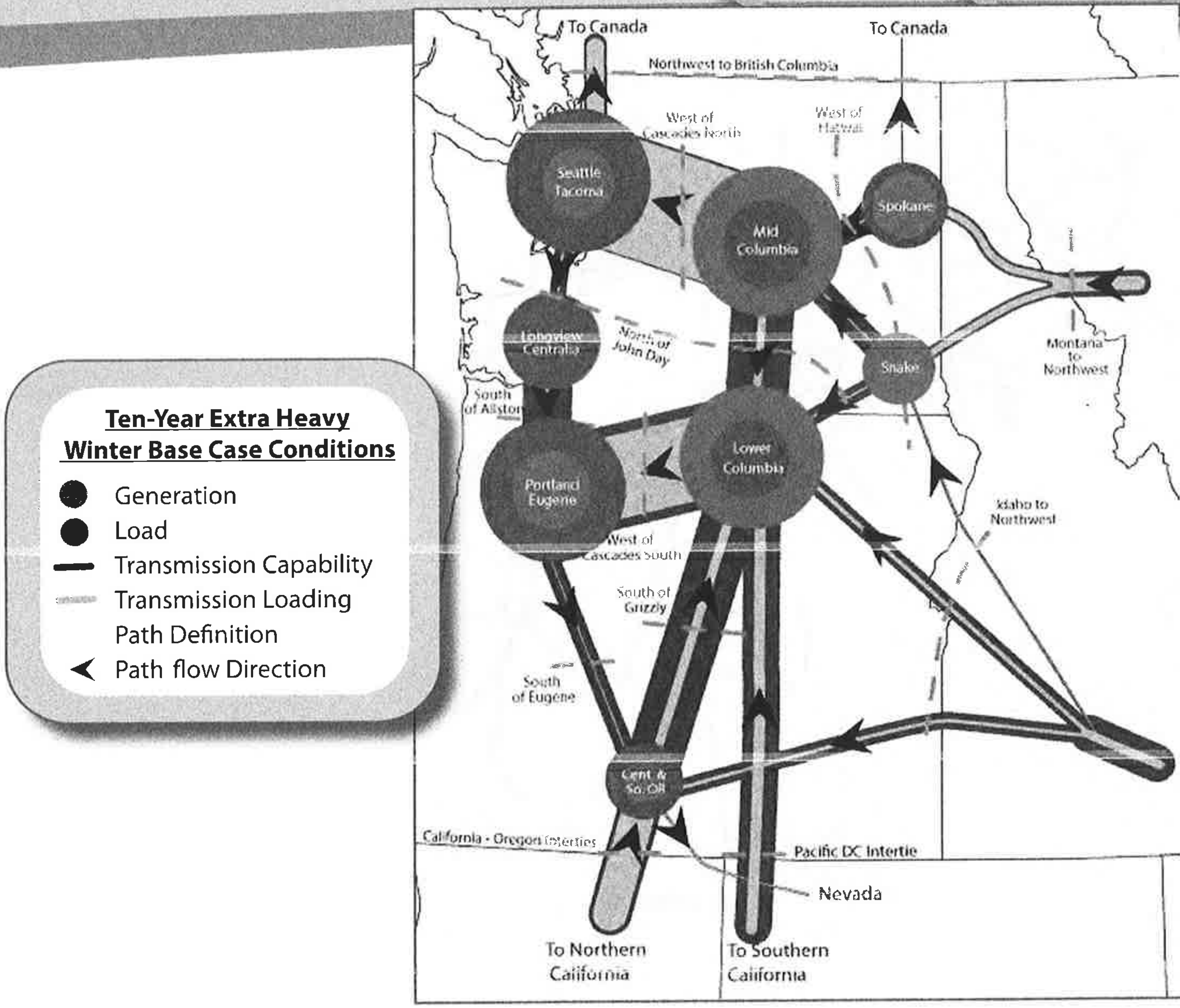

Figure E-5: Flows Modeled for Ten-Year Extreme Winter Peak Conditions

Columbia area has about 11,000 to 12,000 MW of generation represented in the peak load cases. The load/resource ratios in the Spokane, Central/Southern Oregon and Longview/Centralia areas have greater balance.

The dark blue lines between the areas represent the major transmission paths that connect the areas. The width of the dark blue lines represents the relative capacity of the paths. For example, the West of Cascades North path is rated at 10,200 MW. The light blue lines within these paths represent the capacity that is used in the studies. In the winter cases, the West of Cascades paths are heavily used to meet the load levels in the west-side areas while the North of John Day and West of Hatwai paths are lightly loaded. The external path to Canada is loaded to the firm obligations on the path as discussed earlier which is mostly the downstream benefit return. Power is exchanged with California to provide overall load resource balance in the Northwest in the winter.

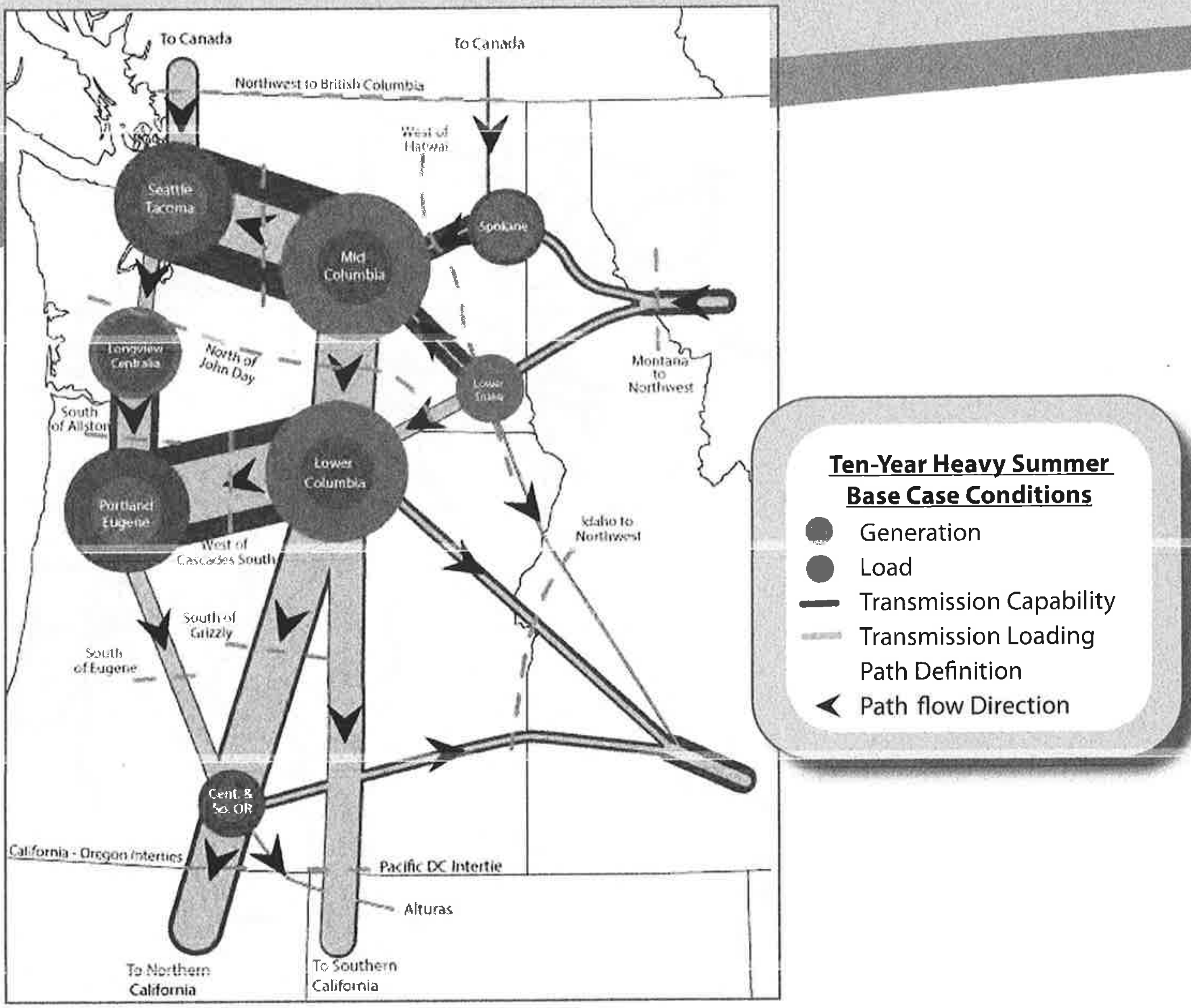

Figure E-6: Flows Modeled for Ten-Year Summer Peak Conditions

The five-year peak summer conditions modeled in the base cases are shown in Figure E-3. The load levels are typically lower in summer than in winter in the west-side areas, and are shown here with proportionally smaller bubbles. Also note that the Portland/Eugene area load level is greater than Seattle/Tacoma in the summer. These two areas had similar load levels in the winter case. This difference is due to a greater use of air conditioning. The Mid-Columbia and Lower Columbia areas have higher levels of generation in the summer as compared to the winter.

The path usage levels change significantly between summer and winter. In the summer, Canadian hydro generation exceeds the internal loads in British Columbia and excess generation is exported to the Northwest and California. The Northwest load levels are also lower in summer and there are available resources to export to

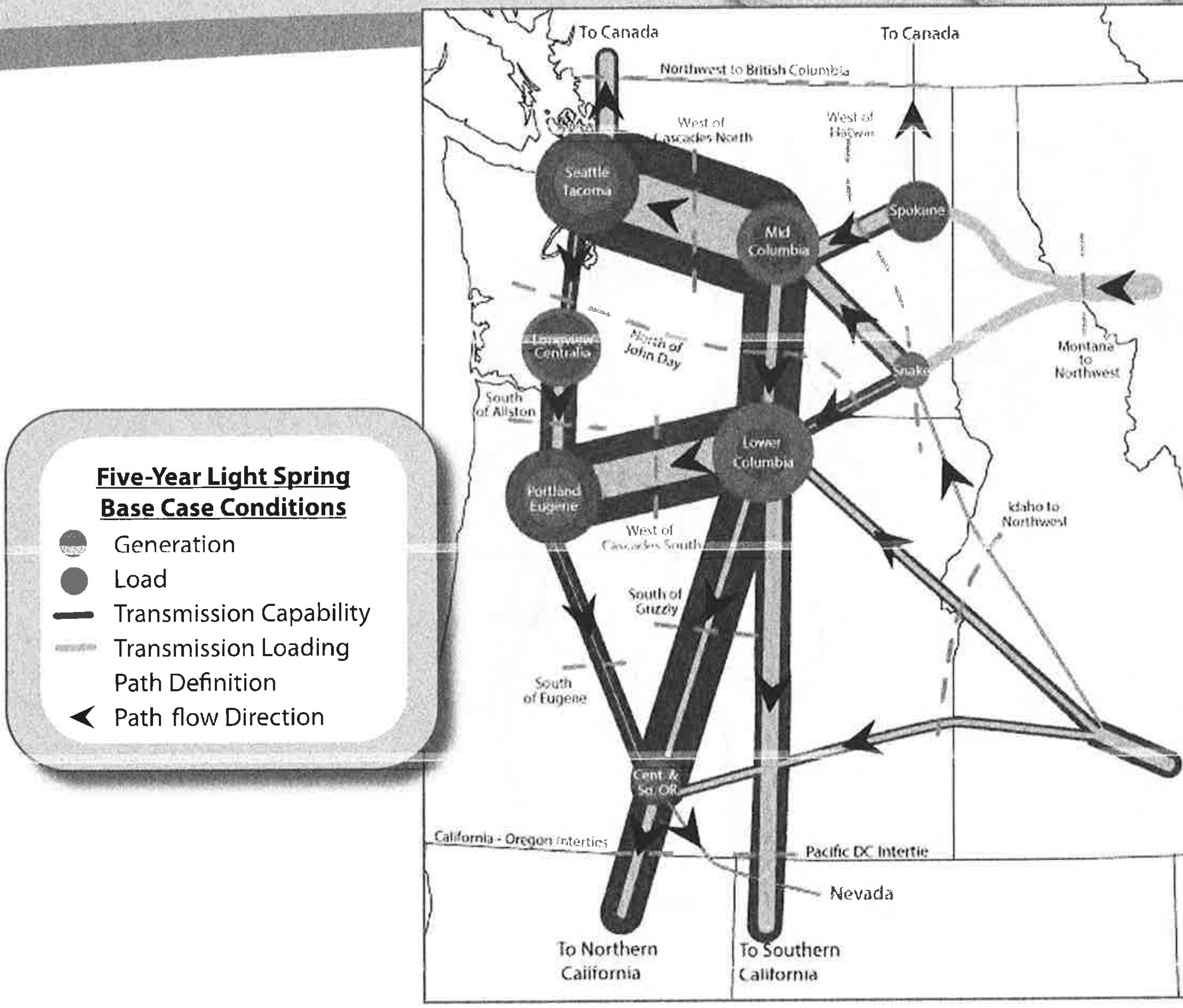

Figure E-7: Flows Modeled for Five-Year Light Spring Peak Conditions

the south. All of the north-to-south paths load much heavier in the summer due to these flows. The interties to California are loaded to their limit in the summer peak cases to represent the firm commitments on those paths. The loading on the west of Cascades paths is reduced in summer due to the reduced load level in the west-side. The ties to Idaho are mostly floating with little power moving on that path.

The pattern modeled in the light spring, high wind cases are unique for those conditions. The cross cascades flows are even lighter than the summer cases described above due to the reduced westside load. The majority of the Northwest wind is located in the Gorge which is within the Lower Columbia bubble. During this high wind condition, the generation in the Mid-Columbia area is reduced significantly to accommodate the high wind level. The north to south flow is still high.

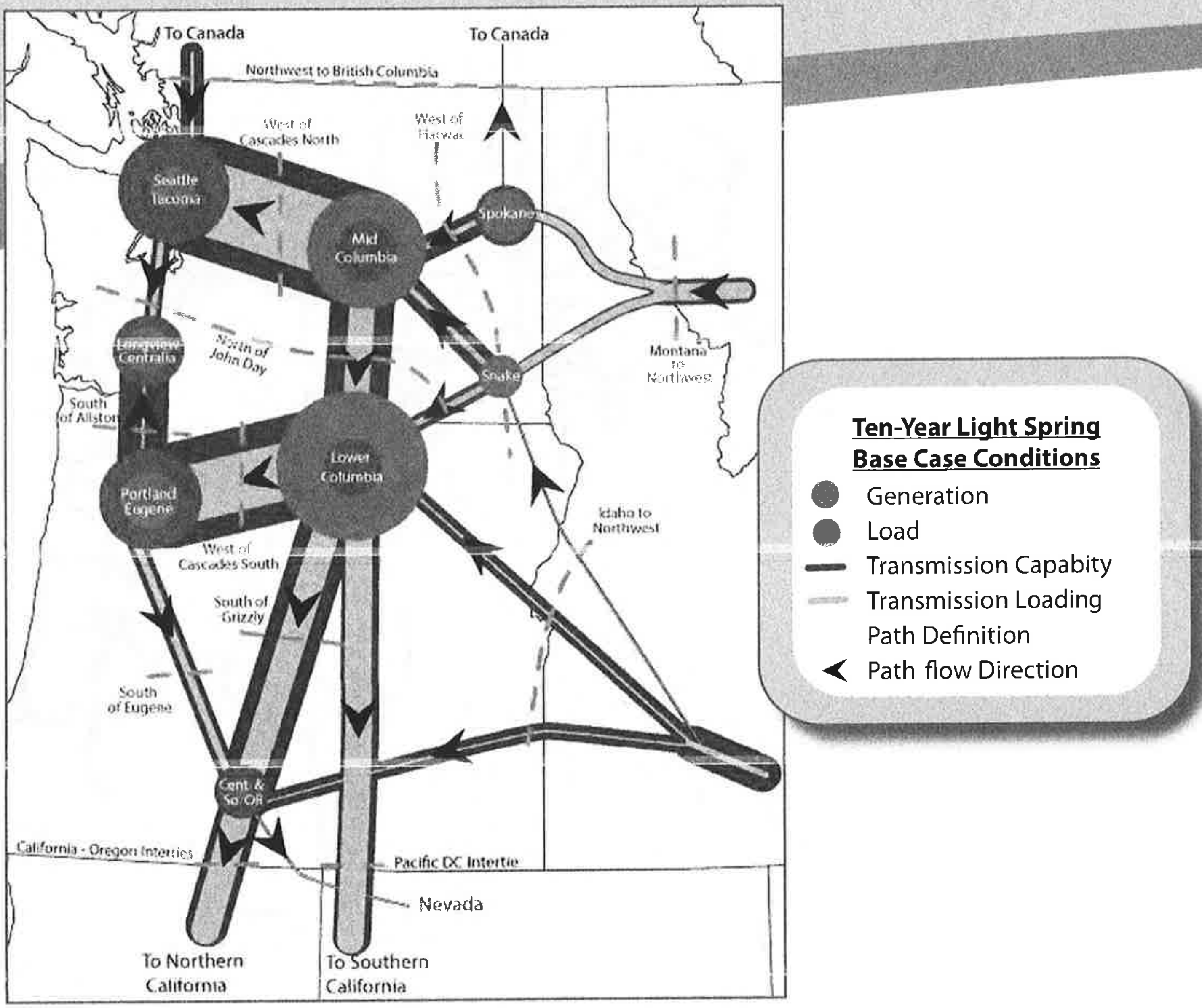

Figure E-8: Flows Modeled for Ten-Year Light Spring Peak Conditions

Special Protection System Assumptions

At the transfer levels modeled in the base cases, existing Special Protection Systems are required for reliable operation of the transmission system. Some of these Special Protection Systems will trigger tripping or ramping of generation (some of which have firm transmission rights) for specified single and double line outages. This Special Protection System generation dropping relies on the use of operating reserves to meet firm transfer requirements (no schedule adjustments are made until the next scheduling period and no firm transfers are curtailed). If the outages are permanent, firm transfers might then need to be curtailed during the next scheduling period to meet the new operating conditions. Firm transmission service commitments are met with this use of Special Protection Systems consistent with NERC and WECC standards.

Transmission Additions Modeled

Since the last System Assessment, the following projects have been placed in service:

1. Longview-Bakers Corner-Lexington 115 kV line
2. Sammamish Bus Reliability Improvements
3. Sedro Woolley Substation 230/115 kV Transformer #2 Addition
4. North Bonneville-Ross/North Bonneville-Troutdale 230 kV Line Swap
5. Cowlitz 230 kV Substation Line Re-termination Phase 1
6. Ostrander 500/230 kV Transformer Addition
7. Longview-Cowlitz #2 Upgrade from 69 kV to 115 kV
8. Keeler-Horizon 230 kV line and Horizon 230/115 kV Transformer
9. The Rogue 115 kV Static VAR Compensator.
10. Granite Falls 115 kV Transmission Loop

The Montana - Alberta Tie Line (MATL) project is expected to be completed in August.

These transmission additions and the future committed projects listed in Table E-2 were modeled in the base cases used in this System Assessment. These projects are more fully described in Attachment B entitled Transmission Expansion Projects.

Major Additions in the Five-Year Case

The following projects were included in all System Assessment base cases.

West of McNary Area Reinforcement Project – Big Eddy-Knight 500 kV Line

This Bonneville project includes two new lines (McNary-John Day 500 kV line and a Big Eddy-Knight 500 kV line) and miscellaneous upgrades. The project in its entirety includes about 110 miles of new line construction and is proposed to increase the capacity of the West of McNary, West of Slatt, West of John Day and West of Cascades South transmission paths. This project provides additional transmission capability to accommodate transmission service requests in eastern Oregon that are being addressed in the Bonneville Network Open Season process. The McNary-John Day line has been completed and energized. The Big Eddy-Knight line is expected to be completed in 2014 or 2015 pending environmental review.

Montana Alberta Tie Line

Enbridge is constructing the Montana Alberta Tie Ltd (MATL) project that is a 200 mile, 300 MW, 230 kV line connecting Lethbridge, Alberta and Great Falls, Montana going through Cutbank, Montana which has significant wind generation potential. This project is fully permitted with construction underway. Energization is expected in August of this year. The WECC rating process for this line has been completed.

Mid-Columbia Area Reinforcements

The plan for the Northern Mid-C area that has been developed in the ColumbiaGrid Northern

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Table E-2: Transmission Projects included in the Base Cases

Committed Projects Included in All Cases	Sponsor	Date
Lancaster Combustion Turbine Project Integration	Avista	2013
Bronx-Cabinet 115 kV Line Rebuild	Avista	2016
Big Eddy - Knight 500 kV Line	Bonneville Power	2014-15
Fairmount Backtripping Scheme	Bonneville Power	2013
Ponderosa 500/230 kV #2 Transformer Addition	Bonneville Power	2013
Ostrander Breaker Addition	Bonneville Power	2014
Lower Valley Reinforcement - Hooper Springs	Bonneville Power	2015
Pearl 500 kV Breaker Addition	Bonneville Power	2016
Franklin 115 kV Capacitors (52 MVAR)	Bonneville Power	2014
Monroe 500 kV Capacitors (316 MVARS)	Bonneville Power	2014
Columbia Falls 230 Bus Reliability Improvements	Bonneville Power	2013
Alvey 500 kV Shunt Reactor	Bonneville Power	2014
Keeler 230 kV Bus Reliability Improvements	Bonneville Power	2014
Raver 500/230 kV Transformer, 230 kV Line to Covington Substation	Bonneville Power	2016
Longview - Lexington 230 kV Line Retermination into Longview Annex	Bonneville Power	2015
Celilo Terminal Replacement (PDCI upgrade 3220 MW)	Bonneville Power	2016
McNary 230 kV Shunt Capacitors (2x150 MVAR banks)	Bonneville Power	2013
Rogue Static VAR Compensator	Bonneville Power	2013
Tucannon River 115 kV Shunt Capacitors (2x6.5 MVARs)	Bonneville Power	2013
North Bonneville - Troutdale 230 kV #2 Line Retermination	Bonneville Power	2015
Columbia 230 kV Bus Section Breaker	Bonneville Power	2016
LaPine Reactive (19 MVAR Capacitors 40 MVAR reactor)	Bonneville Power	2014
Bell 230 kV Bus Section Breaker	Bonneville Power	2015
Kalispell 115 kV Shunt Capacitors (2x16 MVARs)	Bonneville Power	2014
White Bluffs 115 kV Shunt Capacitors (39 MVARs)	Bonneville Power	2013
Tacoma 230 kV Bus Section Breaker	Bonneville Power	2016
McKenzie - Andrew York 115 kV #1 and #2 Line Rerating	Chelan County PUD	2013
Longview - Lexington #2 upgrade from 69 kV to 115 kV	Cowlitz County PUD	2014-16
Longview - Lexington - Cardwell upgrade from 69 kV to 115 kV	Cowlitz County PUD	2015-2017
South Cowlitz County Project	Cowlitz County PUD	2017-2019
Douglas - Rapids 230 kV Line and Rapids 230/115 kV Substation	Douglas County PUD	2013
Rapids - Columbia 230 kV Line and Columbia Terminal	Douglas County PUD	2015
Columbia - Larson 230 kV Line	Grant County PUD	2014
Rocky Ford - Dover 115 kV Line	Grant County PUD	2016
Whetstone 230/115 kV Transformer	PacifiCorp	
Alderton 230/115 kV Transformer in Pierce County	Puget Sound Energy	2015
St. Clair 230/115 kV Transformer in Thurston County	Puget Sound Energy	2013

Committed Projects Included in All Cases	Sponsor	Date
Lakeside 230/115 kV Transformer and Sammamish-Lakeside-Talbot Line Rebuild to 230 kV	Puget Sound Energy	2017
Starwood Autotransformer Removal	Puget Sound Energy	2013
Woodland - Gravelly Lake 115 kV Line	Puget Sound Energy	2015
Bothell - SnoKing 230 kV Double Circuit Line Reconductor	Seattle City Light/BPA	2016
Series Inductors on Massachusetts - Union - Broad and Denny - Broad 115 kV Underground Cables	Seattle City Light	2016
Denny Substation - Phase 1	Seattle City Light	2016
Delridge - Duwamish 230 kV Line Reconductor	Seattle City Light	2016
Beverly Park 230/115 kV Transformer	Snohomish County PUD	2014-16
Granite Falls 115 kV Transmission Loop	Snohomish County PUD	2014
Swamp Creek 115 kV Switching Station	Snohomish County PUD	2018
Cowlitz 230 kV Line Retermination Project	Tacoma Power	2012-2013
Cowlitz 230 kV Substation Reliability Improvement Project	Tacoma Power	2015-2016
Southwest Substation 230 kV Bus Reliability Improvement Project	Tacoma Power	2013-2014
Montana Alberta Tie - Line (MATL) Project	Enbridge/MATL LLP	2013
Committed Projects in 10 Year Cases Only		
Moscow 230 kV Substation Rebuild and Transformer Replacement	Avista	
Benton - Othello 115 kV Line Upgrade	Avista	
Westside 230 kV Rebuild and Transformer Upgrades	Avista	
Irwin Project - Spokane Valley Transmission Reinforcements	Avista	
Castle Rock - Troutdale 500 kV Line (I-5 Corridor Reinforcement Project)	Bonneville Power	2018
Pearl 230 kV Bus Section Breaker	Bonneville Power	2017
Split Pearl - Sherwood 230 kV Lines	Bonneville Power	2017-18
Split McLoughlin - Pearl - Sherwood 230 kV Lines	Bonneville Power	2017-18
Troutdale 230 kV Bus Section Breaker	Bonneville Power	2018
Sappho 69 kV Shunt Capacitors (10 MVARs)	Bonneville Power	2017
Hemingway - Boardman 500 kV Line	Idaho Power/BPA	2018
Cascade Crossing (Coyote - Boardman - Bethel 500 kV Line)	Portland General Electric	2017
Blue Lake - Gresham 230 kV Line	Portland General Electric	2017
Trojan - Horizon 230 kV Line and Horizon 230/115 kV Transformer #2	Portland General Electric	2017
Portal Way 230/115 kV Transformer #2 and Line Upgrades	Puget Sound Energy/BPA	2018
Upgrade Denny Substation Transmission - Phase 2	Seattle City Light	2020

Mid-C Study Team was included. It includes a Grant County PUD Columbia-Larson 230 kV line; the Douglas PUD Douglas-Rapids-Columbia 230 kV line, Rapids Substation and a 230/115 kV transformer; and upgrades to the Chelan County PUD's McKenzie-Wenatchee Tap line and line re-terminations at Chelan's Andrew York Substation. These projects are planned to be energized by 2015 or earlier. Cost allocation for the Rapids-Columbia 230 kV line has been agreed to by the impacted parties and Douglas is proceeding with construction of this project.

Puget Sound Area Transmission Expansion Plan Reinforcements

Six of the recommended projects in the expansion plan developed in the Puget Sound Area Study Team are planned to be energized by 2017 or before. These projects include reconductoring the Bothell–SnoKing 230 kV double circuit line, reconductoring the Delridge – Duwamish 230 kV line, installing a Raver 500/230 kV transformer, a Lakeside Substation 230/115 kV transformer, Northern Intertie RAS extension to include the combined loss of Monroe-SnoKing-Echo Lake and Chief Joseph-Monroe 500 kV lines (not modeled in this Assessment), and adding series inductors to the Massachusetts–Union-Broad and Denny-Broad 115 kV underground cables. The Raver 500/230 kV transformer project would add a new 500/230 kV transformer at Raver Substation and would utilize an existing transmission line to create a new Raver–Covington 230 kV line. The Lakeside Substation 230/115 kV Transformer Project would add a 230/115 kV transformer at Lakeside Substation and rebuild both Sammamish–Lakeside–Talbot 115 kV lines to 230 kV. Only one line will be initially operated at 230 kV and the other line will remain operated at 115 kV. These projects support south to north transfer capability on the northern intertie and load service reliability in the Puget Sound Area. Cost allocation for these projects has been agreed to by the impacted parties and they are proceeding with the projects.

Denny Substation Phase 1 Project

Phase 1 of the Denny Substation project creates a new 115/13 kV Denny Substation looped into the East Pine–Broad 115 kV underground cable. Some load would be transferred to this substation from Broad Street Substation.

Ponderosa Reinforcements

Bonneville and PacifiCorp have developed a plan to provide additional transformation in the Bend/Redmond area with a transformer added at Ponderosa connected to the Grizzly-Captain Jack 500 kV line. This project is planned for a 2013 energization.

Whetstone 230/115 kV Transformer

There were considerable low voltages in the Grants Pass area in the winter cases. The Whetstone project is PacifiCorp's preferred project to solve these area problems but this project has not moved into the construction phase in a timely manner. Originally PacifiCorp elected not to model this project as committed but in order to address the low voltage needs in the Grants Pass area (which can affect power flow solutions throughout the system), the PacifiCorp Whetstone Substation project was added to all cases.

Major Additions in the Ten-year cases

The ten-year System Assessment cases also included some additional projects beyond those in the five-year cases. There were a few projects that utilities have committed to build, however, due to significant lead times they are not expected to be completed until the latter part of the ten-year planning horizon. These additional projects were only included in the ten-year cases and are listed below:

Hemingway - Boardman 500 kV Project

This Idaho Power project includes a 300-mile 500 kV line from the Boise Idaho area to Boardman Substation. This project is intended to provide 1,300 MW of capacity in the west to east directions and 800 MW in the east to west direction. Idaho Power would like to have this project energized by 2016 but to obtain all siting, permitting and regulatory approvals, energization before 2018 is unlikely.

I-5 Corridor Reinforcement Project

This Bonneville project consists of a 70-90 mile 500 kV line from a new Castle Rock Substation north of Longview to Troutdale Substation east of Portland. The project is scheduled to be energized in the 2018 timeframe and is planned to remove the most limiting bottleneck along the I-5 corridor, the South of Allston Cutplane.

Cascade Crossing Project

The Portland General Electric Cascade Crossing Project is a new transmission line to bring power into the Salem area. Originally, PGE proposed a 200-mile 500 kV line starting at the Coyote Springs

Generation Plant and terminating into a new 500/230 kV transformer at Bethel Substation. This line would also interconnect at a new Grassland Substation connecting to the Boardman Power Plant and a new Cedar Spring Substation approximately 36 miles southwest of Boardman where it interconnects with new wind generation. The proposed rating of the initial project is 1,500 MW and it is scheduled for energization in 2017.

PacifiCorp and Bonneville have partnered with Portland General to study this project and may participate in a modified project. Since the System Assessment was started, new options were developed that minimize line construction and PGE is no longer pursuing the transmission project. A study of these new options will be done in future system assessments when they are more fully developed.

Blue Lake-Gresham Project

The Portland General Electric Blue Lake-Gresham project is planned for 2017 in east Portland and consists of a new 4 mile 230 kV line.

Trojan - Sewell - Horizon Project

This Portland General Electric Project is planned for 2017 in west Portland and consists of a 40 mile 230 kV line and a 230/115 kV transformer at Sewell. (PGE has recently decided not to pursue this project at this time).

Portal Way 230/115 kV Transformer Project

Puget Sound Energy and Bonneville are planning to add a second 230/115 kV transformer in north Skagit County, Washington. This project is part of the Puget Sound Area Transmission Expansion Plan and is planned to be energized in 2018. The project will help improve north to south transfer capability on the Northern Intertie.

Denny Substation Phase 2 Project

Seattle City Light is planning the second phase of the Denny Substation project for 2020. This project expands on Phase 1 of the Denny Substation project. Phase 2 adds a new 115 kV transmission line from Massachusetts Street Substation to Denny Substation.

Celilo/PDCI Replacement/Upgrade Project

This Bonneville project will replace the aging equipment at the northern Celilo terminal of the PDCI (the southern terminal at Sylmar has already been replaced). This project is planned to be completed in 2016 and will increase the capacity of the PDCI from 3,100 MW to 3,220 MW.

All transmission facility ratings included in this study were determined by the owner of the facility.

Major Project Changes

Two utilities took a slightly different approach in deciding which projects should be modeled in this year's System Assessment. Once preferred projects are selected and committed by utilities, they are usually modeled in the base cases so the focus can then be on subsequent needs of the system. However, if utilities are having difficulty obtaining support for projects, or the projects are not moving to the construction phase in a timely manner, they can remove these projects to demonstrate the system problems without those projects and highlight the need again. Projects can also be delayed and only modeled in the ten-year cases. These are the approaches Avista and PacifiCorp took this year for the following projects:

1. Moscow 230 kV Substation Rebuild and Transformer Replacement (only modeled in ten-year cases),
2. Benton-Othello 115 kV Line Upgrade (only modeled in ten-year cases),
3. Westside 230 kV Substation Rebuild and Transformer Replacement (only modeled in ten-year cases),
4. Irvin Project – Spokane Valley Transmission Reinforcement Project (only modeled in ten-year cases),
5. Union Gap 230/115 kV Transformer #3 (not modeled),
6. Vantage-Pomona Heights 230 kV Line (not modeled),
7. Wallula-McNary 230 kV Line (not modeled)
8. Whetstone 230/115 kV Transformer (originally the intent was to not model this project but it was included in the base cases due to voltage problems that occurred in the area that impacted power flow solutions).

The projects in the Ten-year Plan are very similar to the projects modeled in the base cases. There are a few exceptions such as the Whetstone transformer described above. Also, the following five projects from the Ten-year Plan were not modeled in the base cases because project information was not available at the time the studies were run. Future System Assessments will include these projects:

1. Schultz-Raver 500 kV Series capacitors
2. Paul 500 kV Shunt Reactor
3. Salem-Chemawa 230 kV Line Upgrade
4. Big Eddy 230/115 kV transformer #1 Replacement
5. John Day-Big Eddy 500 kV #1 Line Reconductor

Study Methodology

The system was analyzed for all base cases without outages (N-0 conditions) and tuned to be within required voltage limits. Any voltage violations or facility overloads that could not be resolved through this tuning were noted.

All single element (N-1 or NERC Category B) outages down to 115 kV were studied on each base case (at Portland General's and PacifiCorp's request; only outages at voltages greater than or equal to 230 kV were studied). Participants in the System Assessment provided ColumbiaGrid with information on the multiple contingencies that they wanted to be studied. These included common mode outages, which are plausible outages of multiple facilities caused by a single event, also called Category C events. These common-mode outages are listed in Attachment C (CEII protected and available upon request). Included in this System Assessment were inadvertent breaker openings, which are especially important on multi-terminal lines. The System Assessment also included known automatic and manual actions associated with each contingency. Loadings greater than 98% were identified in the results along with voltage violations.

As of April 1, 2012, the WECC Planning Criteria for adjacent circuits changed to include only circuits within 250 feet of each other if both circuits are greater than 300 kV. The older criteria did not specify a voltage level and the minimum circuit spacing was based on the maximum span length between towers which was typically in the order of 1000 feet or more. Although most of the adjacent circuits by the old criteria were studied, only those now required to meet the new criteria need to be mitigated.

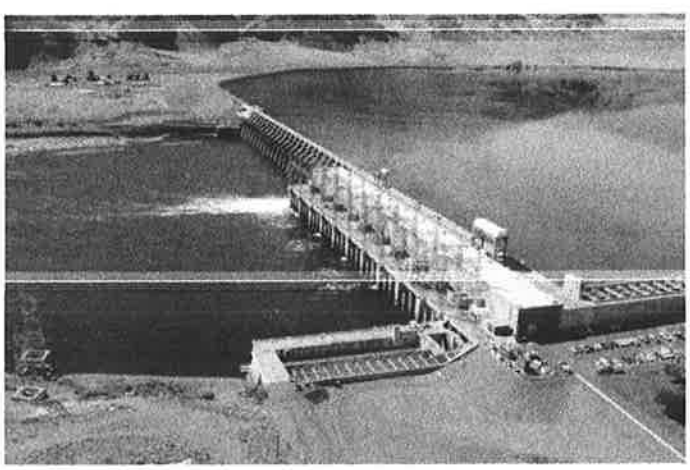
Chelan, Douglas and Grant requested that numerous N-1-1 outages be studied as part of the System Assessment. These outages were studied for information and shared with all participants but no mitigation was suggested for these outages.

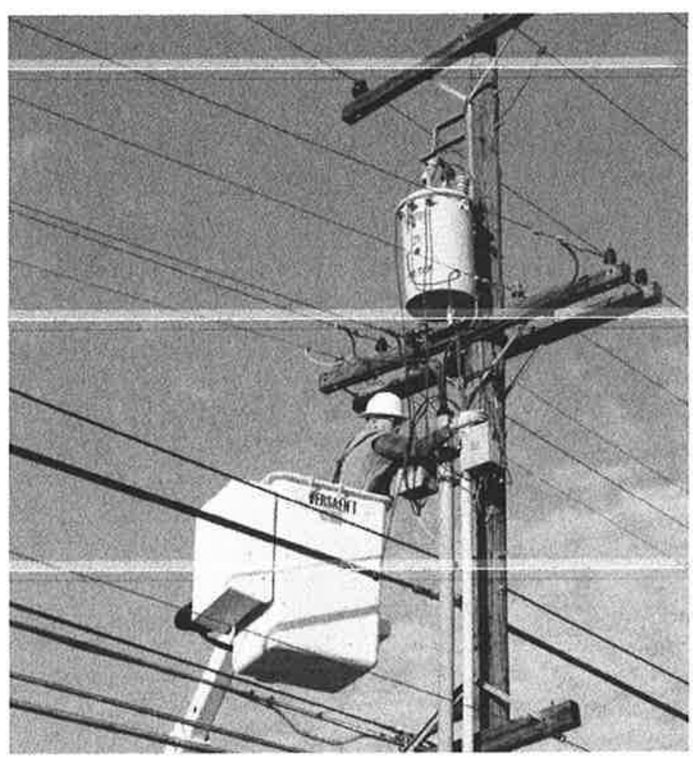
In identifying the voltage violations, the WECC criteria of no more than a 5% voltage drop following a Category B (single) contingency or a 10% voltage drop following a credible Category C (multiple) contingency was used. Outages that did not solve were noted for further exploration.

Participants were not only asked to review outages of their facilities that caused problems, but also to review any violation of limits on their facilities that were caused by any owner's outage. ColumbiaGrid staff also reviewed the results. Participants were also encouraged to provide a peer review of all results regardless of ownership.

Although the focus of this System Assessment is the facilities of the PEFA planning parties, the interconnected nature of the system requires that neighboring facilities also are modeled to determine if there are any interactions between the systems. As mentioned earlier, ColumbiaGrid invited the owners of systems neighboring PEFA parties to participate in the System Assessment.

All study results were available to the planning participants. Single system issues (events where the outage facility and the overloaded facilities were owned by the same utility) were assumed to be the responsibility of that utility to mitigate. The focus of this report is the joint issues where the outages and associated overloads were owned by multiple utilities and joint transmission planning may be needed.





Study Results

Five-Year Study Results

There were no loading violations on ColumbiaGrid planning participant facilities in the five-year base cases with all facilities in-service. All outages that resulted in loadings or voltages outside of criteria were listed in spreadsheets and individually reviewed. Some of the more severe outages did not converge during the initial power flow simulations. Unsolved solutions are an indicator that the voltage stability limit may be exceeded. The Assessment resulted in 17 failed solutions in the summer, 53 failed solutions in the winter and 9 failed solutions in the spring. ColumbiaGrid has studied all of these unsolved outages to more fully understand these issues. (page 39)

The System Assessment identified 65 line sections in the 2018 heavy winter case operated at 115 kV and above that overloaded during various outage conditions where mitigation was not identified. Of these overloaded lines, 36 are owned by ColumbiaGrid planning participants. A total of 112 line sections overloaded in the 2018 heavy summer case where mitigation was not identified; of these overloaded lines, 66 are owned by ColumbiaGrid planning participants. A total of 20 line sections operated at 115 kV and above were identified in the 2016 light spring cases that overloaded during outage conditions where mitigation was not identified. Of these overloaded lines, 12 are owned by ColumbiaGrid planning participants. No specific mitigation was identified in the five-year studies.

Although many types of mitigation would be possible in that timeframe, this study concentrated on mitigation for the ten-year studies (below).

Ten-Year Study Results

Contingencies were studied on the ten-year peak summer, peak winter, extra heavy peak winter and light spring cases in the same manner as the five-year cases. Additional problems were noted in these studies. As noted above, the ten-year studies also included the Hemingway – Boardman 500 kV Project, I-5 Corridor Reinforcement Project, Cascade Crossing Project, Blue Lake-Gresham Project, Portal Way 230/115 kV Transformer Project, Denny Substation Phase 2 Project, and the Celilo Replacement/Upgrade. There were no loading violations on ColumbiaGrid planning participant facilities in the ten-year base cases with all facilities in-service.

Table G-1: Potential Reactive Mitigation Projects

Substation	MVARs	Owner
Albany	55	Bonneville
Chiquin	20	PacifiCorp
Dixonville	55	PacifiCorp
East Omak	10	Bonneville
Flathead	15	Bonneville
Garrison	30	Bonneville
Martin Creek	10	Bonneville
McKenzie W	60	Eugene Water & Elec Bd
Pilot Butte	90	PacifiCorp
Roundup	30	Bonneville
Tahkenich	20	Bonneville
Tillamook	30	Bonneville
Troutdale	10	PacifiCorp
Union Gap	60	PacifiCorp

The System Assessment identified 84 line sections in the 2023 heavy winter case operated at 115 kV and above that overloaded during various outage conditions where mitigation was not identified. Of these overloaded lines, 48 are owned by ColumbiaGrid planning participants. A total of 122 line sections operated at 115 kV and above overloaded in the 2023 extra heavy winter case where mitigation was not identified; 73 are owned by ColumbiaGrid planning participants. A total of 150 line sections operated at 115 kV and above overloaded in the 2023 heavy summer case where mitigation was not identified; 92 of these overloaded lines are owned by ColumbiaGrid planning participants. A total of 23 line sections operated at 115 kV and above overloaded in the 2022 light spring case where mitigation was not identified; 16 of these overloaded lines are owned by ColumbiaGrid planning participants. It was assumed that these line sections could be rerated, reconductored, or rebuilt as mitigation and these types of projects are considered "placeholder" projects until more thorough reviews can be completed by the affected parties and specific transmission projects can be identified. These assessment cases also resulted in 17 failed solutions in the heavy summer, 67 failed solutions in the heavy winter, and 35 failed solutions in the light spring. ColumbiaGrid has analyzed these failed solutions further (see page 39).

Voltage Problems

In this report, voltage problems were addressed similarly to the overload issues and consistent with the practices that were conducted in the previous System Assessment. In general, when potential reactive issues were identified, interim corrective action was proposed by assuming capacitor additions will be used rather than rerating, reconductoring, or rebuilding transmission lines. In order to identify the locations where additional reactive power might be needed, WECC criteria which require no more than 5% voltage drop following a credible category B contingency or a 10% voltage drop following credible category C (multiple) contingency were used. The reactive requirements to prevent voltage violations were studied for the 230 and 500 kV buses. For this assessment, the total reactive additions necessary to mitigate voltage problems for the ten-year planning horizon totaled 495 MVARs of shunt capacitors in 14 locations, all at the 230 kV level. These additions are listed in table G-1 (at the top of the previous page).

Voltage Stability Issues and Unsolved Outages

The unsolved outages listed in Attachment C of the 2013 System Assessment (CEII protected) required further investigation to determine the cause and mitigation of the failed solutions. Outages involving several areas of the system were investigated:

- Redmond-Bend area in central Oregon.
- Grays Harbor area in western Washington
- McNary-Santiam area in north central Oregon
- Northern Mid-Columbia area in Central Washington
- The Centralia/Olympic Peninsula area in northwestern Washington.
- The Palouse area in southeastern Washington
- Sandpoint-Libby area in northwestern Montana/Northern Idaho
- The Klamath Falls/Grants Pass area in south central Oregon
- The Southern Oregon Coast
- The Yakima area in Central Washington
- The Wasco area in north central Oregon

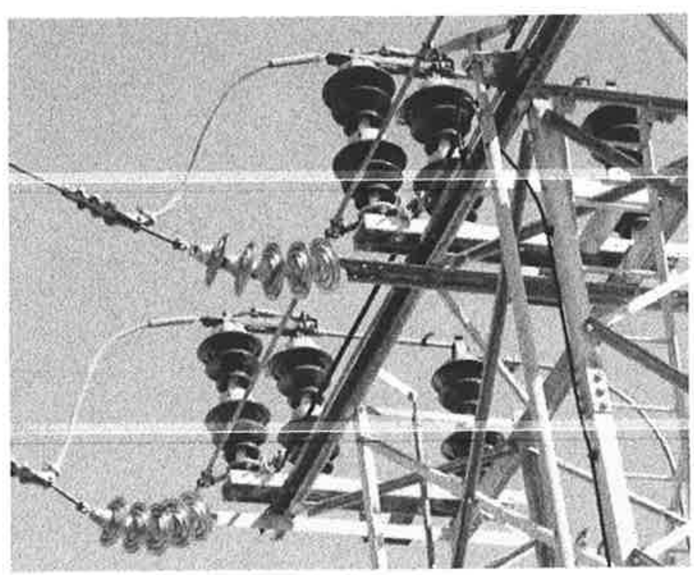
All unsolved outages were tested with the WECC post transient power flow solution methodology, which eliminated simulation of manual and slow automatic actions. Failed solutions are often caused by the modeled conditions exceeding voltage stability or angular stability solution limits. As a screening tool, the voltage threshold for voltage sensitive loads was set to 0.90 per unit voltage. During the power flow solution iterations, if the voltage at a load is below 0.90 per unit, the load is no longer constant power and it decreases with voltage. The decrease is nonlinear to facilitate the solution. The sections below provide more details of unsolved cases and potential mitigation plans in each geographical area.

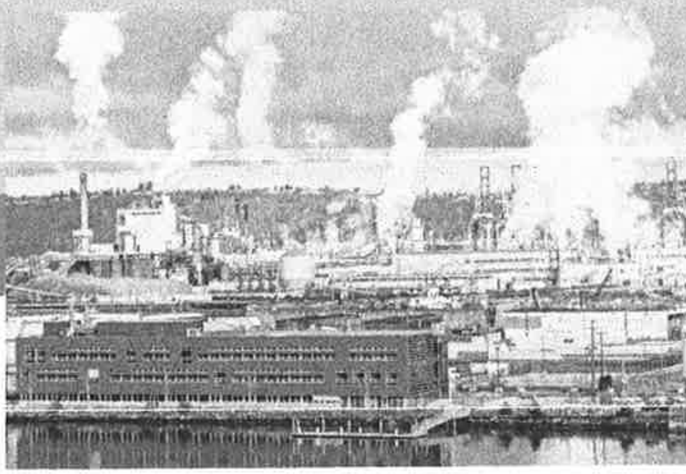
For the Redmond-Bend area, there are three sub-areas that have potential to cause voltage instability. First, under heavy winter conditions, voltage instability may occur following an N-2 outage of Pilot Butte – Ponderosa 230 kV and Pilot Butte – Redmond 230 kV lines. This can be mitigated with a new 150 MVAR SVC at Pilot Butte or nearby substations. Second, breaker failures at Redmond West 230 kV substation can cause voltage instability due to low voltage in the area which can be mitigated by installing approximately 75 MVAR of reactive support around Redmond 69 kV system. Third, bus fault at Round Butte 230 kV disconnects the Cove 230 kV bus from other 230 kV network which results in voltage instability. Approximately 100 MVAR of additional reactive support around Cove area or tripping local load can be used to mitigate this problem.

In the Grays Harbor area, under heavy winter loading conditions, a number of N-1 line outages, bus faults, and breaker outages around Satsop substation could result in voltage instability due to loss of the connection between the Satsop 230 kV system from its 500 kV bus which resulted in low voltages. However, the Investigation showed that these instability incidents were likely to be caused by modeling issues which result in very high VAR flow between 500kV and 230 kV system around Satsop in the base case which are not realistic. Correction of the VAR flow mitigates the problem.

In McNary area, there are potential voltage instability problems under light spring conditions in two sub-areas. First, loss of McNary 500/230 kV transformer and a number of 230 kV breaker failures can result in instability due to insufficient transmission capability to export the amount of power from generators in the area to the 500 kV system. This problem can be addressed by BPA plans to add the second McNary Transformer. Similar incidents were observed in the McNary-Santiam subarea following various N-1 and N-2 line outages that disconnect the 230 kV transmission facilities between Tumble Creek and McNary substations. In this case, instability incidents were identified due to insufficient transmission capability to accommodate the output from generators that connected to Jones Canyon. In order to mitigate this problem, the total output from generators at Jones Canyon should not exceed 280 MW under these study conditions or additional transmission facilities must be added to increase system capability.

The study results also showed potential system instability in Northern Mid-Columbia area triggered by two contingencies. First, a breaker failure at Andrew York 115 kV bus (category C) may cause voltage instability under heavy winter loading conditions. Opening the 115 kV tie





line to Summit mitigated this problem (which is functionally similar to Chelan's under voltage relay at Anderson Canyon that is used to mitigate this problem). Second, the outages of Wells 230 kV bus and Wells – Douglas 230 kV lines can cause an instability problem due to insufficient transmission capability to accommodate generators in the area. In order to mitigate this problem, the total output from generators that are connected to Wells Bus 2 should not exceed 300 MW. There is a run back scheme in place to do this but it was not modeled.

In the Olympic Peninsula, a number of contingencies consisting of bus faults, breaker failures, and line outages along the transmission corridor between Olympia to Port Angeles may cause voltage instability. Investigation showed these instability incidents were caused by modeling issues which involve initial voltage setting and insufficient reactive support in the area. Once the modeling issues are corrected, in order to mitigate the remaining problems, approximately 40 MVAR of reactive support around Port Angeles is needed.

In Palouse area under light spring loading conditions, instability due to insufficient transmission capability to accommodate generation output following a number of contingencies such as breaker failure at North Lewiston 115 kV bus and various N-1 line outages on the 115 kV transmission corridor between Walla Walla and North Lewiston were identified. The investigation showed that these problems may be caused by modeling issues where some reactive devices may not be set properly or too slow to react to voltage decline after contingencies. In order to mitigate this problem, the addition of approximately 10 MVAR of reactive support is needed. Alternatively, the amount of total output from generators that are connected to this 115 kV transmission corridor could be limited to 110 MW under the study conditions.

Potential instability in Sandpoint/Libby area was identified from the study under heavy summer, winter and light spring conditions due to the N-2 outages of Libby – Noxon and Libby – Conkelly 230 kV lines which removes the major transmission out of Libby powerhouse from service. The investigation results showed that a possible mitigation plan to this problem is to limit the amount of Libby generation to approximately 110 MW under these conditions (a tripping scheme similar to this is in place but not modeled.)

Instability in the Santiam area was also identified due to Marion – Alvey 500 kV and Marion – Lane 500 kV double line outage under heavy winter conditions. This potential problem can be mitigated with a new 35 MVAR reactive addition at Tahkenich (along the coast near Florence, Oregon). There may also be local RAS that addresses this issue.

In the Southern Oregon area, potential instability incidents were identified in two sub-areas. First, the outage of LaPine 230/115 kV transformer results in voltage collapse around LaPine 115 kV system under heavy winter and heavy summer conditions. The investigation results show that this may be caused by a modeling issue around LaPine substation where the second LaPine 230/115 kV transformer was mistakenly taken offline in the base case. Consequently, this problem can be mitigated if the second transformer is placed into service. Second, two n-1 line outages and breaker failure outages in Meridian and Klamath Falls area can cause voltage instability due to low voltages around the Meridian 230 kV bus. In order to mitigate these problems, approximately 100 MVAR of additional reactive support would be needed at this location.

Potential voltage instability incidents in the Southern Oregon Coast area were also identified under heavy winter, heavy summer, and light spring conditions due to breaker failure and bus outage at Fairview 230 kV bus (Category C). In general these contingencies disconnect the Fairview 115 kV system from its 230 kV source which could trigger voltage instability. Possible mitigation plans for this area include installing addition reactive support or other alternatives such as load dropping.

In the Yakima area, under heavy winter conditions, breaker failures at the Wanapum 230 kV bus has resulted in potential voltage instability. In order to address this issue, approximately 80 MVAR of additional reactive support at Union Gap or Pomona Heights in the Yakima area is needed.

In addition, in the Wasco area, a breaker failure at the Big Eddy 115 kV bus could result in voltage instability under heavy winter conditions. The addition of approximately 10 MVAR of reactive support around the Demoss 115 kV bus can mitigate this problem.

Joint Areas of Concern

Joint areas of concern (those that occurred between systems or that involve the bulk grid) are the primary focus of ColumbiaGrid's System Assessment. These areas were identified when multiple planning parties had outages that caused overloads and/or had facilities that overloaded as a result of such outages. ColumbiaGrid will organize study teams as necessary to resolve these system deficiencies between ColumbiaGrid members.

If a problem did not involve multiple utilities, it was considered to be a single-system issue and remained the responsibility of the individual owner. In this instance the owner is obligated through PEFA to report back to the ColumbiaGrid process on the measures they have planned to mitigate the single-system problem. ColumbiaGrid will use these mitigation plans to update its future base cases.

The following areas were identified in the System Assessment in the ten-year planning horizon and involve more than one system. Several of these will require further study over the remainder of the year to determine the extent of the system problems and to develop mitigation.

Twelve problem areas were noted in this assessment while seventeen problem areas were noted in last year's assessment. Problem areas that were resolved from last year's System Assessment include:

1. Longview Area

In the 2012 System Assessment, overloads were seen in the Longview area due to increased load forecast for Cowlitz County PUD. The ten year forecast has decreased this year and these overloads were not seen in the 2013 System Assessment.

2. Tacoma Area

In the 2012 System Assessment, a bus section breaker outage at the Tacoma 230 kV bus caused a number of overloads. This issue was not present this year, as Bonneville has made a commitment to add a series bus section breaker in 2016 that will resolve the issue.

3. South of Allston

Problems identified in previous System Assessments for the South of Allston area were not flagged in this year's system assessment. Better RAS modeling may have helped eliminate these issues.

4. SnoKing/Everett Area

In the 2012 System Assessment, outages of the SnoKing 115 kV bus caused overloads in the area which did not show up in 2013. Improved modeling of the Swamp Creek Switching Station project and other area facilities appears to have resolved those issues.

5. Spokane Reliability

In the 2012 System Assessement, the outage of the Bell 230 kV bus section breaker overloaded the Beacon 230/115 kV transformers. These facilities are owned by Bonneville and Avista and BPA has committed to a project to add a series bus section breaker at Bell, which has resolved this problem.

Problem areas identified in prior System Assessment that were also identified in this System Assessment.

1. The Olympia – Shelton Area

In the winter cases, several 230 kV bus outages at Shelton did not solve. These problems were identified in previous system Assessments. Bonneville and Puget Sound Energy own facilities in this area. Load shedding is a possible mitigation measure for these outages.

2. Orofino Area in Northern Idaho

In five-year and ten-year summer cases, the outage of the Dworshak-Hatwai 500 kV line or the Hatwai 500/230 kV transformer overloads the Ahsahka-Orofino 115 kV line and the Dworshak 115/13.8 kV transformer. Avista and Bonneville have operating procedures and RAS in place to sectionalize the system and redispatch generation for these outages. No further study team effort is needed.

3. McNary Area

In the summer five and ten-year cases, an outage of the McNary 230 kV Bus 2 and 3 overloads the Badger-Nine Canyon Wind-H2F-Berrian 115 kV lines. An outage of McNary 230 kV bus section #3 overloads the Cold Springs 230/69 kV transformer. Redispatch of generation at McNary could relieve these problems. This problem appears to be confined to the local area. These are joint problems between Bonneville and PacifiCorp. Since there is only one ColumbiaGrid member, no study team will be formed. In last year's biennial plan, high loadings of the Cold Springs 230/69 kV transformer were investigated to determine the impact if the transformer were to trip before operators could re-adjust the system. This analysis showed that the McNary bus outage removes all generation and voltage support from the McNary 230 kV bus and the Cold Springs substation tries to provide voltage support to McNary. Tripping the Cold Springs transformer removes the parallel 69 kV systems and improves the flows in the area although there were still low voltages. There is also a proposed project to add a second McNary 500/230 kV transformer, which would provide generation and voltage support to the McNary 230 kV bus during the problem outages.

4. Okanogan Area

In the five and ten-year winter cases, a breaker failure at Wells 230 kV bus would overload the Okanogan-Ophir Tap 115 kV line. These facilities are owned by Douglas County PUD and Okanogan. Since there is only one ColumbiaGrid member involved, these issues will be the responsibility of affected parties and no study team is proposed. Possible solutions include bus sectionalizing or line upgrades.

5. Pearl-Sherwood Area

In the summer, the N-2 outage of the double circuit Carlton-Sherwood 230 kV and Newberg-Sherwood 115 kV lines overloads the Sherwood-Springbrook 115 kV line for both the five and ten-year cases; this same outage overloads the Forest Grove-McMinnville 115 kV line in both the summer and winter five and ten-year cases. BPA and PGE are working on a solution to this double circuit outage problem.

A bus section breaker failure at the Pearl 230 kV bus could overload the Canemah-Sullivan 115 kV line in the ten-year winter case, but this issue will be resolved by the planned Bonneville 230 kV bus section breaker at Pearl. These system issues in the Pearl-Sherwood area have been identified in previous system assessments and involve Bonneville and Portland General Electric facilities. Since there is only one ColumbiaGrid member involved, these issues will be the responsibility of the affected parties and no study team is proposed.

6. Bend Area Voltage Stability

In the ten-year winter case, bus outages at Pilot Butte 230 kV overload the Pilot Butte 230/69 kV transformers. In the ten-year summer case, breaker failures at Redmond West 230 kV bus overload the Cove 230/69 kV transformers. Breaker failures at Pilot Butte 230 kV and Redmond 230 kV buses did not solve which may be a symptom of voltage instability.

These facilities are owned by PacifiCorp and Bonneville and these problems were identified in previous system assessments. The unsolved outages could cause voltage stability issues in the Bend-Redmond area. Since there is only one ColumbiaGrid member involved, these issues will be the responsibility of affected parties and no study team is proposed. Bonneville has plans to build an additional 230/115 kV station in the area (Bonanza) that could help mitigate these problems.

7. Yakima/Wanapum Area

In the summer, breaker failures and bus outages at Wanapum 230 kV cause overloads on the Outlook-Punkin Center, Moxee-Hopland, Union Gap-Voelker and Ringold-Mesa 115 kV lines, as well as the Outlook 230/115 kV transformer. An outage of the Midway-Wine Country 230 kV line overloads the Outlook 230/115 kV transformer and the Outlook-Sunnyside 115 kV line.

In the winter a Wanapum 230 kV bus outage overloads the Outlook-Punkin Center 115 kV line. These issues were identified in previous System Assessments, however overloads on DOE and Avista lines that were previously identified have been resolved. The remaining overloaded facilities are owned by Bonneville and PacifiCorp, with outage ownership by Grant County PUD. PacifiCorp has identified a project to build a Vantage-Pomona 230 kV line to mitigate this problem but they have not made a firm commitment to this project. Since there is essentially only one ColumbiaGrid member involved (Bonneville) and the worst overloads are on PacifiCorp's system for outages of PacifiCorp facilities, final resolution of these issues will be the responsibility of those parties and no study team is proposed, but these issues will continue to be monitored for resolution.

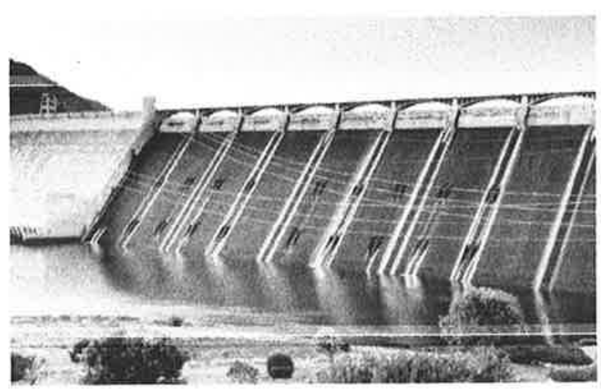
8. Clark County/Troutdale Area

In the summer ten-year case, a breaker failure outage of the Troutdale west 230 kV bus overloads the Troutdale-Linneman 230 kV line, Lacamas-Sifton 115 kV and the St John-Bloss 115 kV line. Loss of the N-2 Ross-Rivergate and Ross-St John lines overloads the Fruit Valley-Hayden-St John 115 kV line.

In the ten-year winter, a Ross 230 kV bus section breaker outage overloads the Troutdale 230/115 kV transformer. These system issues involve Bonneville, PacifiCorp and Clark County facilities. Since there is only one ColumbiaGrid member, these issues will be the responsibility of the affected parties and no study team is proposed. Possible mitigation includes line upgrades or redispatching generation at Merwin Dam.

9. Centralia Area

In the ten-year winter case, the N-1 Paul-Satsop 500 kV line outage, the N-2 Paul-Olympia 500kV/ Paul-Satsop 500 kV, and Satsop breaker failures did not solve indicating a possible voltage stability issue. Failed solutions only occurred for the N-2 outage involving the Paul-Satsop and Olympia-Satsop 500 kV line outage in last year's assessment, but the failed solution for the N-1 outage is new this year which may indicate that the problem has



gotten worse. Load shedding may be a possible solution for this problem.

10. Salem-Eugene Area

In both the five-year and ten-year summer cases, a breaker failure outage at the Albany 115 kV bus overloads the Fry-Oromet 115 kV line. This same outage also overloads the Bethel-Parish Gap line in the ten-year summer case. In the winter, there were failed solutions for an N-2 outage of the Marion-Alvey and Marion-Lane 500 kV lines. These problems were identified in previous system assessments, although the issues are less numerous and less severe than in previous years. The problems involve outages of Bonneville facilities and could cause problems on the PacifiCorp system.

11. Sandpoint, Idaho Area

A Libby 115 kV bus outage causes minor overloads the Bronx-Sand Point line in the five and ten-year spring cases. These facilities are owned by Bonneville and Avista. Similar issues were identified in previous System Assessments for the summer season. Reconductoring the Bronx-Sand Point 115 kV line has eliminated these overloads for the summer, but is not sufficient to correct for the loading levels seen in the spring cases. Generation redispatch at Cabinet Gorge would resolve this remaining overload.

12. Northern Intertie Transfer Issues

In the five and ten-year summer cases, the N-2 loss of Custer-Monroe 500 kV #1 and #2 lines overloads the Sedro-Murray, Sedro-Bellingham and Sedro-Horse Ranch 230 kV lines. These overloads are likely due to RAS arming levels. Additional generation tripping will eliminate this issue. In both summer cases, a breaker failure outage at the Bothell 230 kV bus overloads the Snohomish-Bothell 230 kV #1 line. This latter problem was noted in the 2012 System Assessment.

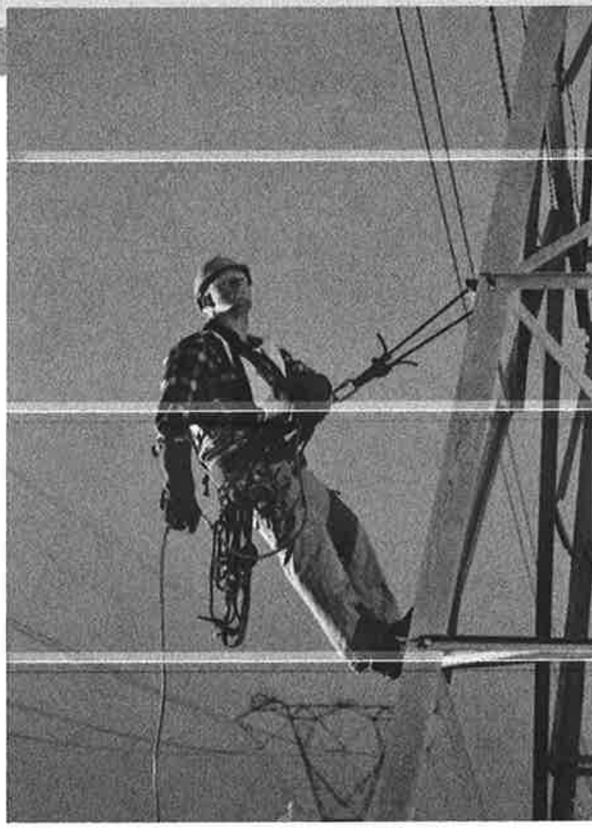
New issues from this System Assessment

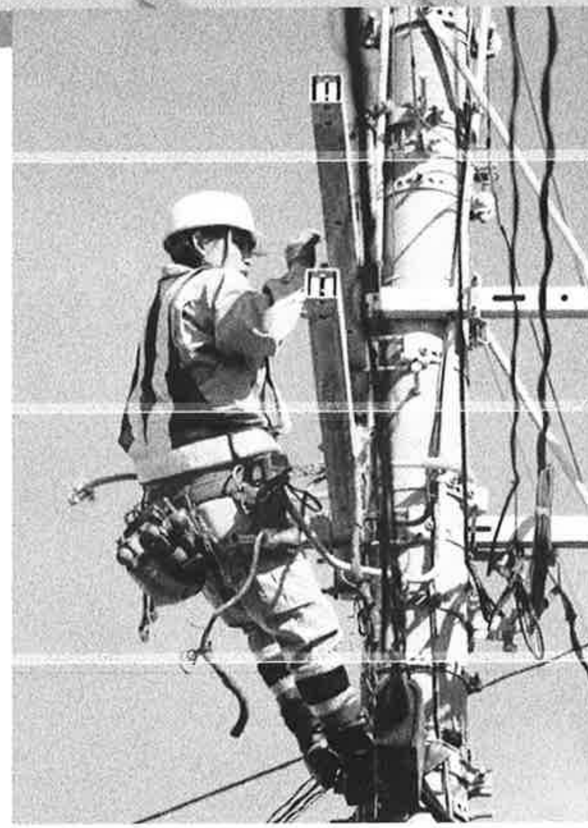
No new issues were identified in this System Assessment.

Proposed joint study efforts

Puget Sound Area Study Team

One issue was identified in the Puget Sound area that relates to the operation of the Northern Intertie and the Puget Sound Transmission Expansion Plan that includes the N-2 Custer – Monroe #1 and #2 lines overloading the Sedro – Murray, Sedro – Bellingham and Sedro – Horse Ranch 230 kV lines. This issue is likely caused by RAS arming levels in the model that are calibrated for the near term system, while arming levels in the five and ten-year horizon may be different. This issue will be directed to the ongoing efforts of the Puget Sound Area Study Team for resolution.





Planned Sensitivity Studies for 2013

The following sensitivities are proposed for analysis in 2013:

1. Production/Cost Studies

This year production/cost studies will be run to test the impact of new California policies for internal Renewable Portfolio Standard (RPS) development on transmission paths into California especially from the northwest (COI and PDCI).

This study will be run using the WECC TEPPC data base in the ten-year timeframe for comparison both with and without the new policy.

2. Power flow analysis of reduced conservation

A significant amount of conservation is included in the load forecasts that are used in the System Assessment. This conservation offsets load growth and consequently the need for some transmission projects. In other words, if the conservation were not included, or if the conservation targets are not met, some transmission projects may be needed sooner and additional transmission projects may also be needed. For this sensitivity, a comparison between the Heavy Winter and Extra Heavy Winter case results will be made to assess the impact of not meeting the conservation goals. The Extra Heavy Winter case is projected to be similar to the Heavy Winter case without conservation. The assessment will include evaluating the impact on project schedules and the possible need for additional projects. The focus of this study will be on facilities at or above 230 kV.

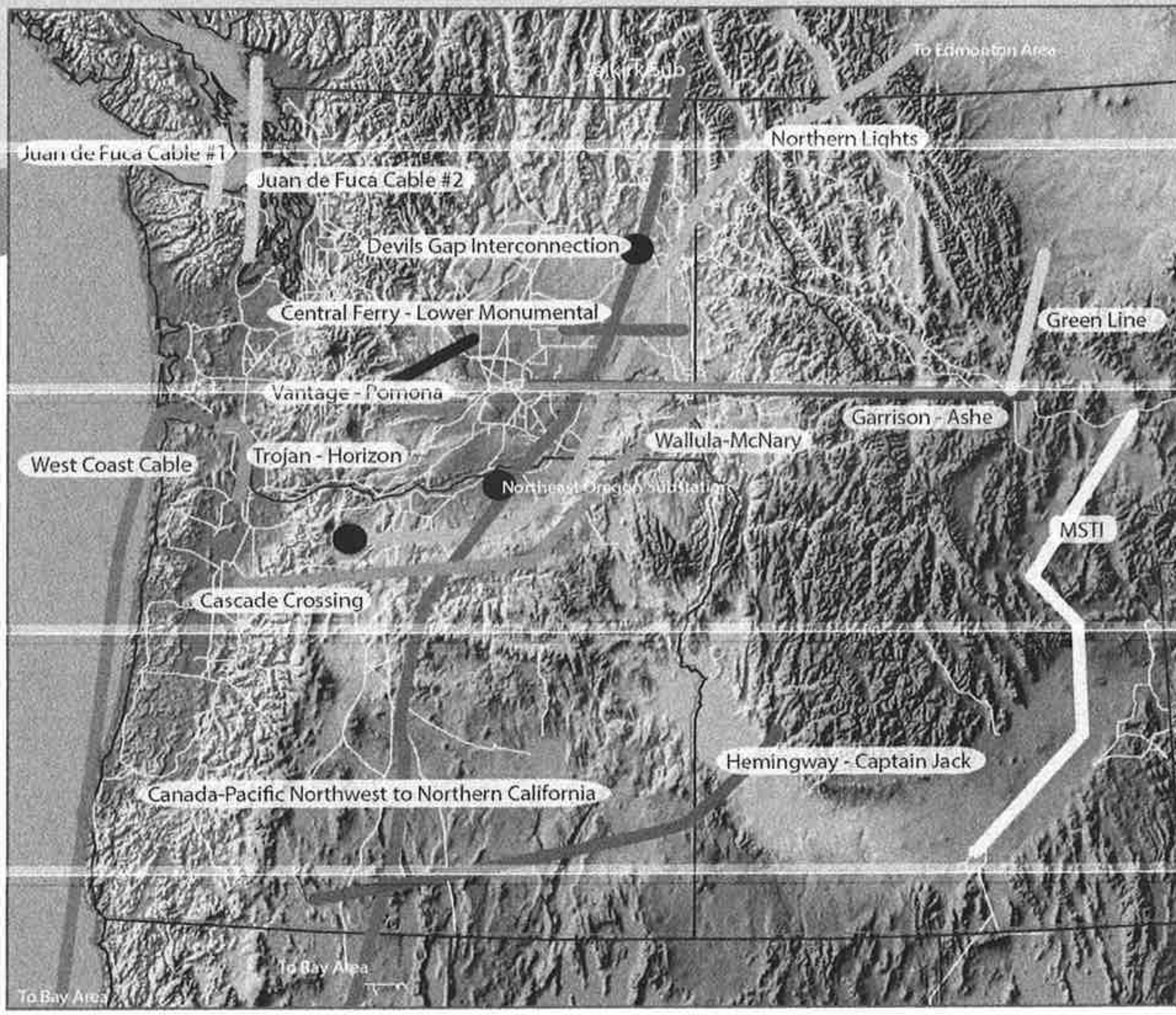


Figure J-1: Major Transmission Projects

Potential Major Transmission Projects

Several large transmission projects have been proposed in the region to integrate new resources and accommodate economy transfers to access lower cost resources. There are firm commitments by sponsors to build several of these projects; Big Eddy - Knight, Hemingway - Boardman, Montana - Alberta Transmission Line (MATL), and the I-5 Corridor Reinforcement. These projects were included in the assessment cases but the projects without firm commitments were not (since the I-5 Corridor project, and Boardman - Hemingway are not expected to be completed until at least 2017, they were only included in the ten-year studies). This approach avoids masking problems on the transmission systems that would need to be addressed if the more speculative projects are not built. Analysis of impacts that these major projects might have on the load service and firm transmission service commitments of the PEFA parties will be addressed later by the appropriate

ColumbiaGrid study teams.

The other major projects in the region that do not have commitment to be built are described below. See Figure J-1 for a map of these projects. If these projects are firmed up, they will be modeled in future system assessments. However, support for these projects has diminished over the last couple of years. These projects are electrically in parallel with ColumbiaGrid member facilities and could have impacts to the existing system.

a. Garrison-Ashe Project

The 2010 BPA Network Open Season included several requests that could not be accommodated by the Colstrip Upgrade Project. To gain additional capacity to fulfill these requests, a 430 mile series compensated Garrison-Ashe 500 kV line was proposed with an intermediate station between Taft and Hot Springs. Due to the high cost of this project, BPA has not made any commitment to pursue this project. No WECC Regional Planning or Rating studies have been started.

b. Canada-Pacific Northwest to Northern California Project

The Canada-Pacific Northwest-California (CNC) Project is a 1000 mile transmission line from British Columbia to northern California that was sponsored by Avista, BC Hydro and Pacific Gas and Electric. The plan of service involves a 500 kV AC transmission line from Selkirk Substation to Devils Gap Substation to NEO (Northeast Oregon) Substation (Northern Segment) and a +/-500 kV DC transmission line from NEO Substation to the San Francisco Bay Area (Southern Segment). The project has a Planned Rating of 3000 MW in the north-to-south direction.

Since developing this project, the sponsors have analyzed a scaled down, 2000 MW version of the project as their needs for renewable generation have changed. They also investigated aligning the Northern and Southern Segments of their project in a common corridor with existing facilities to reduce the Project's environmental impact. A study completed called the "Pacific Northwest-California New Transmission Feasibility Assessment" showed acceptable system performance for several options. An investigation was also made into the availability of existing capacity on COI in lieu of constructing the Southern Segment. This COI Utilization analysis indicated some unused transmission capacity from time-to-time, but such capacity would not be sufficient to meet the needs of the generation and load entities. These two reports were completed in April and May of 2011 and are available on the ColumbiaGrid website. The Project Sponsors have since put these projects on hold.

c. Northern Lights Project

The Northern Lights project is a 970-mile high-voltage DC line (+/- 500 kV) beginning at Edmonton, Alberta and ending at a new substation near the existing Buckley Substation in north central Oregon. At least one intermediate terminal is planned in a location south of Calgary, near Alberta's largest wind development region. The project is planned to have bi-directional capacity as high as 3,000 MW. This project takes advantage of the diversities in load and generation between the two areas. The project is currently on hold.

d. Juan de Fuca Cable #1 Project

Sea Breeze Pacific is proposing an underwater 550 MW high-voltage DC +/-150 kV cable across the Strait of Juan de Fuca from Pike Substation near Victoria on Vancouver Island Canada to the Port Angeles Substation in Port Angeles, Washington. This project rating is planned to be fully controllable and bi-directional. According to the Bonneville and BC Hydro interconnection studies completed to date, the project will also require existing system reinforcements, including 230 kV line upgrades from Satsop to Port Angeles Substations. This project was granted Phase 2 rating status on June 29, 2007.

e. Juan de Fuca Cable #2 Project

Sea Breeze Pacific is proposing a Multi-terminal underwater 1,100 MW high-voltage DC cable (+/- 300 kV) across the Strait of Juan de Fuca from Ingledow Substation near Vancouver, British Columbia, Canada to Pike Substation near Victoria on Vancouver Island Canada, to either the Shelton or Olympia Substations on the Olympic Peninsula, Washington. The 1100 MW project rating is planned to be fully controllable and bi-directional.

f. West Coast Cable Project

Sea Breeze Pacific is proposing an underwater high-voltage DC cable from Allston Substation in northwest Oregon near Rainier to the San Francisco Bay area. This project has a planned rating of 1,600 MW. This project is intended to bring renewable resources from the Northwest to California.

g. Green Line

In conjunction with the MATL project, Enbridge is proposing the Green Line Project to provide access to the Mid-Columbia Hub. This project is a 100 mile extension of the MATL project to connect to the Colstrip Transmission system at Garrison or Townsend. This project is expected to provide up to 1000 MW capacity and is in the feasibility stage.

h. Hemingway-Captain Jack Line

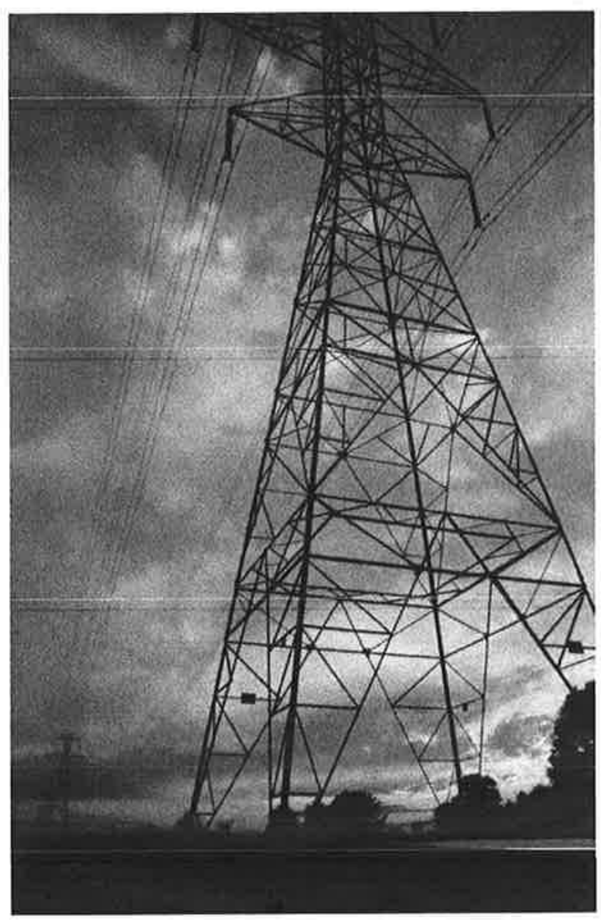
PacifiCorp had proposed to build a new 375-mile 500 kV line from Hemingway Substation in the Boise area to Captain Jack Substation in southern Oregon. PacifiCorp is no longer pursuing this project.

i. Mountain States Transmission Intertie

NorthWestern Energy had been pursuing construction of the Mountain States Transmission Intertie (MSTI), a 500 kV single-circuit electric transmission line that would begin about five miles south of Townsend, Montana and proceed south to Jerome, Idaho. This project was expected to add about 1500 MW to Path 18, the Montana to Idaho Intertie. Due to lack of sponsorship, this project is currently on hold.

j. Central Ferry - Lower Monumental 500 kV line Project

The 2010 BPA Network Open Season included this project to provide transmission capacity to serve identified requests. Although this project was included in past Ten-year Plans as a committed project, the requestors for this service are uncertain whether they want to proceed so this project is currently on hold.



k. Wallula-McNary 230 kV Line Project

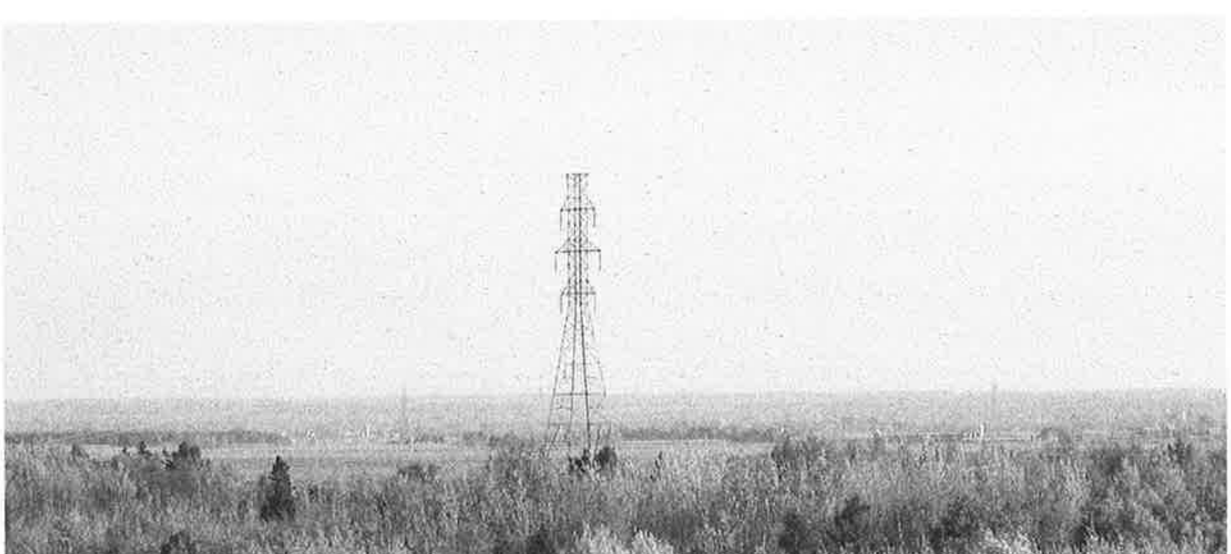
In order to continue to provide reliable, safe and cost-effective electricity to customers, and support new renewable energy development, PacifiCorp had proposed a 230 kV line between Wallula and McNary Substation. Although PacifiCorp still supports this project, it was not making adequate progress so it was removed from the Ten-Year Plan.

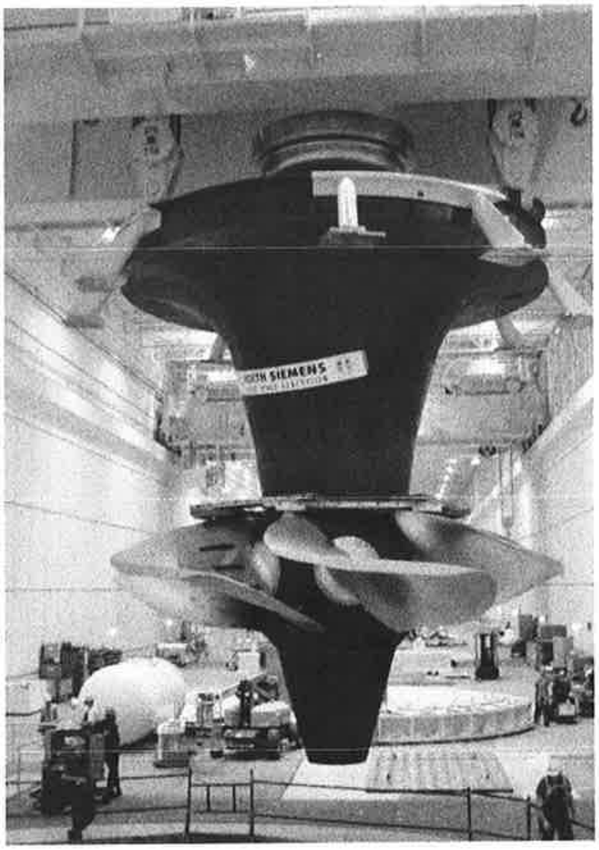
l. Vantage-Pomona Heights 230 kV Line Project

In order to continue to provide reliable, safe and cost-effective electricity to customers, PacifiCorp had proposed a 230 kV line between Vantage and Pomona Heights Substations. Although PacifiCorp still supports this project, it was not making adequate progress so it was removed from the Ten-Year Plan.

m. Trojan-Horizon Project

The Portland General Electric Trojan-Horizon Project consists of a new 37-mile 230 kV transmission line from the existing Trojan Substation to Horizon through the new Sewell substation in NW Portland. A new 230/115 kV transformer will be added at Sewell. This project is the result of a merchant request and will provide capacity to integrate new generation at Port Westward. No commitment to the project has been made.





n. Cascade Crossing Project

The Portland General Electric Cascade Crossing Project is a new transmission line proposed to bring power from Central Oregon into the Salem area. Originally, PGE proposed a 200-mile 500 kV line starting at the Coyote Springs Generation Plant and terminating into a new 500/230 kV transformer at Bethel Substation. This line would also interconnect at a new Grassland Substation connecting to the Boardman Power Plant and a new Cedar Spring Substation approximately 36 miles southwest of Boardman where it interconnects with new wind generation.

Bonneville and Portland General have found options to upgrade the existing system to obtain the additional transmission capacity they need so the Cascade Crossing Transmission Project has been canceled. This project remains a viable alternative once the capacity from optimizing the existing system is used up.

Attachment A: Resource Assumptions for Base Cases (MW Output)

Name	5 Year Heavy Summer	10 Year Heavy Summer	5 Year Heavy Winter	10 Year Heavy & Extra Heavy Winter	5 Year Light Spring	10 Year Light Spring
Adair	6	6	6	6	6	6
Albeni Falls	28	28	28	28	28	28
Alder	20	22	30	30	15	15
Beaver	464	464	465	465	0	0
Big Cliff	0	0	0	0	16	0
Big Hanaford	252	255	255	255	0	0
Biomass	10	10	10	10	10	7
Boardman	612	430	612	430	612	0
Bonneville	835	941	1008	1008	197	544
Boulder	0	0	0	0	0	0
Boundary	486	191	357	357	0	66
Box Canyon	57	14	65	65	58	57
Boyle	79	61	61	61	61	30
Bull Run	3	3	13	13	11	3
Cabinet Gorge	185	185	120	120	240	185
Camas Mill	23	23	23	23	23	23
Carmen	81	47	50	50	25	81
Cedar Falls	4	4	6	6	4	0
Centralia	1420	947	1424	947	1424	0
Chandler	3	7	7	7	7	3
Chehalis	513	513	513	513	513	513
Chelan	62	62	62	62	62	62
Chemical	50	50	50	50	50	50
Chief Jo	2062	2090	2185	2185	153	1228
Clearwater AVA	50	50	50	50	50	50
55 Clearwater PAC	40	11	11	11	11	11
Coffin Rock	15	15	15	15	15	15
Columbia Generating Station	1139	1151	1151	1151	1150	1139
Copco	30	30	30	30	30	30
Cosmo SP Fiber	0	0	16	16	0	0
Cougar	12	12	12	12	12	12
Coulee	5311	5703	5703	5527	1386	1925
Covanta	12	12	12	12	12	5
Cowlitz Falls	17	40	40	40	20	17
Coyote Springs	480	480	508	508	480	0
Cushman	45	52	101	101	0	0
Detroit	103	104	104	104	52	51
Dexter	14	14	14	14	14	14
Diablo	80	80	99	99	65	48
Dworshak	181	408	408	408	316	181
Electron Heights	13	13	13	13	13	13
Enid Road	15	15	15	15	15	16
Enserch	155	155	187	187	173	0
Evergreen Bio	10	10	10	10	10	3
Faraday	11	11	32	32	37	11
Finley	28	0	28	28	0	28
Fish Creek	11	4	4	4	4	4

Name	5 Year Heavy Summer	10 Year Heavy Summer	5 Year Heavy Winter	10 Year Heavy & Extra Heavy Winter	5 Year Light Spring	10 Year Light Spring
Foster	14	5	9	9	10	7
Frederickson	134	134	162	162	144	144
Frederickson CCCT	247	247	247	247	247	0
Fredonia	281	281	349	349	304	0
Glenoma	29	29	29	29	29	29
Goldendale Energy Center	247	247	247	247	247	0
Gorge	112	112	123	123	81	75
Grays Harbor	620	559	609	609	0	0
Green Peter	8	0	80	80	40	8
Green Spring	16	16	16	16	16	16
Harbor Paper	7	19	19	19	7	7
Headwork	25	25	0	0	20	11
Hermiston Gen Project	213	468	468	468	468	0
Hermiston Power Project	551	557	557	557	557	0
Hills Creek	30	30	30	30	15	15
Hungry Horse	281	381	380	380	190	94
Ice Harbor	284	498	498	498	295	154
Iron Gate	18	17	17	17	17	17
Jackson	43	38	54	54	35	35
John Day	1500	2077	2042	2042	831	554
Kettle Falls	45	45	45	45	45	15
Klamath	577	424	583	583	533	0
Lagrande	25	28	52	52	27	27
Lake Siskiyou	2	1	1	1	1	1
Lancaster	249	249	249	249	0	0
Leburgs	7	7	13	13	13	7
Lemolo	29	13	13	13	46	13
Libby Gen	320	323	539	539	323	213
Little Falls	16	16	32	32	32	16
Little Goose	310	694	694	694	139	274
Longlake	42	42	84	84	84	42
Longview Fiber	27	27	27	27	27	27
Lookout Point	74	40	120	120	40	49
Lost Creek	30	30	30	30	30	15
Lower Baker	74	74	75	75	71	71
Lower Granite	310	693	832	832	139	274
Lower Monumental	240	668	787	787	274	240
March Point	138	138	150	150	138	0
Mayfield	99	64	129	129	52	52
McNary	657	932	932	932	287	294
Merwin	84	129	129	129	43	45
Mint Farm	232	235	235	235	235	0
Monroe A	7	7	14	14	14	7
Morro	23	24	24	24	0	23
Mossy Rock	250	173	259	259	13	13
Nine Mile	7	7	9	9	16	2
North Fork	9	9	33	33	33	9
Northeast	0	0	0	0	0	0
Noxon	400	400	300	300	400	400

Name	5 Year Heavy Summer	10 Year Heavy Summer	5 Year Heavy Winter	10 Heavy & Extra Heavy Winter	5 Year Light Spring	10 Year Light Spring
Oak Grove	20	20	32	32	34	20
Pelton	85	85	120	120	120	85
Port Westward	378	378	399	624	378	0
Post Falls	2	2	7	7	11	2
Priest Rapids	700	700	877	877	351	439
Prospect	42	27	27	27	26	27
Rathdrum	0	0	0	0	0	0
River Road	232	209	209	209	0	0
Rivermill	5	5	14	14	17	5
Rock Island	350	350	302	302	164	408
Rocky Reach	799	799	819	819	330	1014
Roseburg Lumber	0	0	0	0	0	3
Ross	60	60	128	128	52	2
Round Butte	161	161	270	270	241	161
Roza	8	8	8	8	8	8
Sawmill	25	25	25	25	25	25
Simpson	44	64	64	64	64	17
Slate Creek	2	1	1	1	1	1
Slide Creek	18	8	8	8	8	8
Smith Falls	0	36	36	36	0	0
Snoqualmie Falls	0	0	0	0	0	0
Soda Springs	11	5	5	5	5	5
Spokane Waste	18	18	18	18	18	18
Stone Creek	5	5	5	5	0	5
Sullivan	15	14	15	15	15	14
Sumas	124	124	138	138	134	0
Summer Falls	90	92	0	0	71	30
Swift	207	275	209	209	209	140
Tenaska	246	246	267	267	246	0
The Dalles	1295	1685	1610	1610	318	765
Tieton	6	6	6	6	6	6
Toketee	42	20	20	20	20	20
Tolt River	9	9	10	10	9	9
Twin Falls	0	0	0	0	0	0
Upper Baker	92	92	82	82	82	82
UpRiver	7	7	7	7	15	7
Wanapum	852	852	947	947	473	757
Wauna	31	32	32	32	32	0
Wells	576	576	576	576	432	576
Weyerhauser (EWEB)	36	25	25	25	37	0
White Creek	6	34	34	34	14	11
Whitehorn	134	134	162	162	144	0
Wynooche	2	3	2	2	2	2
Yale	120	35	35	35	35	72
Wind Generation						
Antelope R Wind	0	0	0	0	0	110
Big Horn Wind	0	0	0	0	0	244
Biglow Canyon Wind	0	0	0	0	0	440

Name	5 Year Heavy Summer	10 Year Heavy Summer	5 Year Heavy Winter	10 Heavy & Extra Heavy Winter	5 Year Light Spring	10 Year Light Spring
Combine Hills Wind	0	0	0	0	0	103
Condon Wind	0	0	0	0	0	49
Dodge Jct Wind	0	0	0	0	0	0
Echanis Wind	0	0	0	0	0	0
Echo Wind	0	0	0	0	0	57
FPL_II_LT Wind	0	0	0	0	0	0
Goldendale Wind	0	0	0	0	0	201
Goodnoe Hills Wind	0	0	0	0	0	125
H Canyon Wind	0	0	0	0	0	98
Harvest Wind	0	0	0	0	0	64
Hopkins Ridge Wind	0	0	0	0	0	152
Jordan Butte Wind	0	0	0	0	0	204
Juniper Creek Wind	0	0	0	0	0	251
Kittitas Valley Wind	0	0	0	0	0	107
Klondike Wind	0	0	0	0	0	297
Leaning Juniper Wind	0	0	0	0	0	286
Linden Wind	0	0	0	0	0	49
Marengo Wind	0	0	0	0	0	208
Miller Ranch	0	0	0	0	0	140
Montague Wind	0	0	0	0	0	393
Nine Canyon Wind	0	0	0	0	0	94
Nine Mile Wind	0	0	0	0	0	0
Palouse Wind	0	0	0	0	0	101
Patu Wind	0	0	0	0	0	10
Pebble Springs Wind	0	0	0	0	0	97
PHLNG Wind	0	0	0	0	0	727
Rattlesnake Wind	0	0	0	0	0	100
Saddleback Wind	0	0	0	0	0	68
Shepards Flat Wind	0	0	0	0	0	829
Simpson R Wind	0	0	0	0	0	10
Stateline Wind	0	0	0	0	0	208
STRPT Wind	0	0	0	0	0	97
TULMN Wind	0	0	0	0	0	134
Vansycle Wind	0	0	0	0	0	226
WDSTCLM Wind	0	0	0	0	0	160
WEBFT Wind	0	0	0	0	0	95
White Creek Wind	0	0	0	0	0	210
WHT F Wind	0	0	0	0	0	95
Wild Horse Wind	0	0	0	0	0	272
Willow Creek Wind	0	0	0	0	0	147
Windy Flat Wind	0	0	0	0	0	301
RPS Bio	0	0	0	0	0	12
RPS GeoThermal	0	0	0	0	0	49
RPS Solar	0	0	0	0	0	0
RPS Wind	0	0	0	0	0	794
Totals	**30,825**	**33,182**	**35,790**	**35,180**	**18,135**	**22,927**

Attachment B: Transmission Expansion Projects

Olympic Peninsula Projects

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
Olympia 230/115 kV Transformer Bank No.3	Add a new 230/115 kV Transformer at Olympia Substation	BPA			Conceptual Project for future need
Shelton-Fairmount-Port Angeles Area	Construct a new double circuit 230 kV line (approximately 60 miles) between Shelton and Fairmount Substations, to create Shelton-Fairmount 230 kV line No. 4 & 5	BPA			Conceptual Project for future need
Fairmount-Port Angeles #2 230 kV line	Upgrade Fairmount-Port Angeles #2 230 kV line	BPA			Conceptual Project for future need
Port Angeles 230 kV bus and Transformer	Develop breaker and half 230 kV yard at Port Angeles and add second 230/69 kV transformer	BPA			Funded
North of Fairmount Back-tripping Safety Net	Back-Tripping scheme to open Fairmount-Port Angeles 230 kV lines for double line outage of Shelton-Fairmount 230 kV lines (non-wires solution)	BPA	PSE		Funded
Olympia-Shelton 230 kV line #5	Reconductor 7.25 miles of Olympia-Shelton #5 line from Olympia to Olympia-Satsop corridor with Deschutes conductor	BPA			Conceptual Project for future need
Kitsap-South Bremerton 115 kV line	Construct second Kitsap-South Bremerton 115 kV line or PSE Foss Corner options	BPA	PSE		Conceptual Project for future need
West Kitsap Transmission Project Phase II	Installation of 230/115 kV transformer at Foss Corner Substation along with a 230 kV line from Foss Corner to the future BPA Kitsap 230 kV Substation	PSE	BPA		Conceptual Project for future need
Kitsap 230 kV yard	Develop breaker and half 230 kV yard at Kitsap for Shelton-South Bremerton and Kitsap-Foss Corner lines.	BPA	PSE		Conceptual Project for future need
Sappho 69kV Shunt Cap Addition	Add 10 MVAR shunt capacitor to Sappho 69V	BPA			Plan of Service determined

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
	2021	$7 M	Load growth			Single System Project with possible impacts	
	2022	$21.5 M	Load growth			Single System Project	
Only if non-wires project fails			Load growth			Single System Project	
Only if non-wires project fails	2014	$15 M	Load growth and System Reliability			Single System Project	
	2013	$0.9 M	Load growth	Project name was changed from "North of Shelton Back-tripping Scheme		Single System Project	
			Load growth			Single System Project	
			Load growth			Single System Project	
	2018		Provide additional capacity to serve projected load growth in Kitsap County			Single System Project with possible impacts	
			Load growth			Single System Project	
Included in sponsors budget	2017		voltage support			Single System Project	

Puget Sound Projects

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage	Project Commitment Level
Cowlitz Substation 230 kV Line Re-termination Project.	This project involves the re-termination of BPA's South Tacoma-Cowlitz (#1) 230 kV line from TPWR's Cowlitz 230 kV Bus into TPWR's Southwest (#4) line. It also includes the re-termination of TPWR's Cowlitz-Southwest (#3) and Cowlitz-Tacoma (#2) 230 kV lines to create a new Southwest-Tacoma 230 kV line.	Tacoma Power	BPA		Study completed by BPA in June 2008	
Pierce County transformer capacity (Alderton)	A new 230/115 kV transformer at Alderton Substation in central Pierce County with a new 230 kV line from White River.	PSE			Plan of Service determined	Included in sponsor's budget
Thurston County transformer capacity (St Clair)	A new 230/115 kV transformer at Saint Clair Substation in Thurston County with a looped transmission interconnection to BPA's Olympia - South Tacoma 230 kV line.	PSE			Plan of Service determined	Included in sponsor's budget
Denny Substation (Phase 1)	Proposed new 150 MVA substation in the north of downtown Seattle area. Loop existing Eastpine-Broad 115 kV line (additional capacity in future).	SCL			Preliminary Design	Budgeted
Denny Substation (Phase 2) -- Massachusetts-Denny Transmission Line	New transmission line from Massachusetts Substation to Denny substation (built at 230 kV, operated at 115 kV).	SCL			Preliminary Design	Project identified as future need
Southwest Substation 230 kV Bus Reliability Improvement Project	Modify bus section breaker arrangement at Southwest Substation to eliminate single point of failure of bus section breaker.	Tacoma Power				
Beverly Park 115 kV Bus Configuration and 230/115 kV Capacity Addition	Rebuild the existing 115 kV switching station and add one 230/115 kV 300 MVA transformer at Beverly Park. An existing 115 kV line from BPA Snohomish to the Glenwood Tap will be converted to 230 kV to provide the source for this substation. Add a new 115 kV line from Everett.	Snohomish County PUD	BPA		Project is in the design and construction Phase	
IP line conversion to 230 kV	Convert PSE's 115 kV "IP" line to 230 kV between Wind Ridge Substation and Lake Tradition Substation in King County to increase cross-Cascade capacity and interconnect Kittitas County wind projects	PSE	PSE		Conceptual Project for future need	
North Cross Cascades Reinforcement - Schultz-Raver Series Caps	This project includes adding 500 kV series capacitors (30-40%) to the Schultz-Raver 500 kV lines No.3 & 4 to serve growing loads in the Puget Sound area	BPA	PSE		Project under study	
Seattle Area 500/230 kV Transformer Bank (Raver)	Add a 500/230 kV transformer at Raver and a 230 kV terminal at Raver for a Raver-Covington 230 kV line.	BPA	PSE, SCL		Project identified in PSAST Expansion Plan	Utilities have negotiated cost allocation

Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
Phase 1: 2012 (completed) Phase 2: 2013	$750K to $1M	Reliability improvement			Single System Project, possible impacts	Puget Sound Area Study Team
2015	$28 M	Load service, Capacity Increase, Reliability	Project delayed from 2014		Single System Project, possible impacts	Puget Sound Area Study Team
2013	$30 M	Load service, Capacity Increase, Reliability			Single System Project, possible impacts	Puget Sound Area Study Team
2016	$120 M	Load service and System Reliability			Single-System project possible impacts	Puget Sound Area Study Team
2020	$50 M	Load service and System Reliability			Single-System project possible impacts	Puget Sound Area Study Team
2013-14	$3 M	The purpose of this project is to improve system reliability by preventing any bus fault or a stuck breaker on one of the 230 kV buses from resulting in total loss of service to the substation.			Single System Project	Puget Sound Area Study Team
2016	$20 M	Load growth and expected local reliability deficiency in Paine Field and Everett areas requires capacity increases to meet District level of service guidelines			Single System Project, possible impacts	Puget Sound Area Study Team
2020+		Load growth in Puget Sound and generation integration, related to North Cross Cascades Improvements			Capacity Increase Project	West of Cascades Study Team
2017/2018	$35 M	Load growth in Puget Sound and Transmission Service Requests	Delayed from 2016		Existing Obligation Project	West of Cascades Study Team
2016	$45 M	Load growth in Puget Sound area			Existing Obligation Project	Puget Sound Area Study Team

Puget Sound Projects continued

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage	Project Commitment Level
Cowlitz Substation 230 kV Bus Reliability Improvement Project.	Modify the bus section breaker arrangement at Cowlitz Substation to eliminate single point of failure of bus section breaker.	Tacoma Power				
Swamp Creek 115 kV Switching Station	Construct a four breaker 115 kV switching station with a ring bus arrangement. This switching station will terminate 115 kV lines from SnoKing, Halls Lake, Brightwater and Beverly Park.	Snohomish County PUD				Committed
Paine Field 115 kV Switching Station	Construct a six 115 kV breaker ring bus adjacent to the existing Paine Field Substation. The switching station will terminate lines from Paine Field, Mukilteo, Olivia Park, Boeing, Gibson, Beverly Park via Casino (new), and Swamp Creek via Picnic Point tap (new).	Snohomish County PUD			Project under study	
Swamp Creek to Picnic Point Tap 115 kV Line	Construct a 115 kV line (2.9 miles) with 1272 kCM conductor from Swamp Creek Substation to the Picnic Point tap. A new 115 kV line position and breaker will be added to the Swamp Creek 115 kV Switching Station. The Picnic Point Tap to the Picnic Point Substation 115 kV Line will be operated normally opened.	Snohomish County PUD			Project under study	
North County 230/115 kV Transformer Addition	Add a new 230/115 kV 300 MVA transformer either in Stimson Crossing Switching Station or in BPA Murray substation. For the Stimson option, the existing BPA Murray-Snohomish 230 kV line will be looped into the station.	Snohomish County PUD	BPA		Project under study	
Beverly Park and South Snohomish County 115 kV Expansion	Beverly Park-Boeing 115 kV line reconductor and Beverly Park-Everett 115 kV line capacity increase.	Snohomish County PUD			Design and Construction	
East King County Transformer Capacity (Lake Tradition)	This project involves looping the Maple Valley-Sammamish #1 230 kV line into PSE's Lake Tradition Substation and installing a new 230/115 kV transformer.	PSE	BPA - loop through of BPA owned and PSE leased 230 kV line		Conceptual	
Skagit County Transformer Capacity	This project involves installing an additional 230/115 kV transformer into PSE's Sedro Woolley Substation.	PSE			Included in sponsor's budget	
Monroe Substation Improvements	Monroe 500 kV 316 MVAR Shunt capacitor bank	BPA				Committed
East King County Transformer Capacity	Rebuild the Sammamish-Lakeside-Talbot 115 kV lines and energize one at 230 kV and install a new 230/115 kV transformer at Lakeside.	PSE	BPA, SCL		Project identified in PSAST Expansion Plan	Utilities have negotiated cost allocation

Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
2015-16	$3 M	The purpose of this project is to increase system reliability and operational flexibility			Single System Project	
2018	$6 M	South County area load growth and expected reliability deficiencies. This is part of a multi-project effort to provide three 115 kV ties between BPA SnoKing and BPA Snohomish Substations.			Single System Project	
2021		South County area load growth and expected reliability deficiencies. This is part of a multi-project effort to provide three 115 kV ties between BPA SnoKing and BPA Snohomish Substations.			Single System Project	
2020		South County area load growth and expected reliability deficiencies. This is part of a multi-project effort to provide three 115 kV ties between BPA SnoKing and BPA Snohomish Substations.			Single System Project	
2021	$4 M	Marysville area load growth and expected North County reliability deficiencies			Single System Project, possible impacts	
2014		Beverly Park and South Everett area load growth and expected local reliability deficiencies			Single System Project	
2017+	$13 M	Load service, Capacity Increase, Reliability			Single System Project, possible impacts	Puget Sound Area Study Teams
Project completed	$9.4 M	Load service, Capacity Increase, Reliability	Project completed		Single System Project, possible impacts	Puget Sound Area Study Team
2014	$5.6 M	Service to Puget Sound Load area and System Reliability	Delayed from 2013		Single System Project, possible impacts	
2017	$65-$80 M	Load service, Capacity Increase, Reliability, prevent curtailment of firm transfers			Single System Project	Puget Sound Area Study Team

Puget Sound Projects continued

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage	Project Commitment Level
Expand Northern Intertie RAS	Extend the Northern Intertie RAS to trip for the combined outage of the Chief Joseph-Monroe and Monroe-SnoKing-Echo Lake 500 kV lines	BPA			Project identified in PSAST Expansion Plan	Utilities have negotiated cost allocation, other options being considered
Reconductor Delridge-Duwamish 230 kV line	Reconductor Delridge - Duwamish double circuit 230 kV Line with high temperature conductor	SCL	BPA, PSE		Project identified in PSAST Expansion Plan	Budgeted
Downtown Seattle 115 kV Series Inductors	Add 6 ohm inductors on Denny - Broad and Massachusetts - Union - Broad 115 kV underground cables	SCL	BPA, PSE		Project identified in PSAST Expansion Plan	Budgeted
Reconductor Bothell-Snoking 230 kV lines	Reconductor Bothell-SnoKing 230 kV #1 and #2 with high temperature conductor	SCL, BPA	PSE		Project identified in PSAST Expansion Plan	Budgeted
Portal Way Substation - Install 2nd 230-115 kV Transformer	Construct a new 230 kV line from BPA Custer Substation to PSE Portal Way Substation. Install a 230-115 kV, 325 MVA transformer, and install another 115 kV bus section breaker in Portal Way Substation	PSE, BPA			Project identified in PSAST Expansion Plan	Utilities negotiating cost allocation
Sedro-Woolley-Bellingham #4 115 kV line	Reconductoring Sedro-Woolley-Bellingham #4 115 kV line	PSE			Design and Construction	Included in sponsors budget
PSE Bellingham Substation Rebuild	Construct a new breaker and a half 115 kV substation	PSE			Project under study	Project identified as future need
Sammamish Reliability Improvements	Add 2nd 230 kV bus section breaker	PSE			Design and Construction	Funding approved by sponsor
Woodland-Gravelly Lake	Add new Woodland-Gravelly Lake 115 kV line	PSE			Design and Construction	Committed Project
White River Bus Improvements	Add 2nd 115 kV Bus Section breaker at White River (230 kV bus completed)	PSE			Design and Construction	Included in sponsors budget
Talbot 230 kV Bus Improvements	Improve 230 kV bus at Talbot: Terminate new 230 kV line from Lakeside. Revise 230 kV protection. This will be a phased process to construct a double bus double breaker configuration.	PSE	BPA - Talbot - Maple Valley #1 and #2 230 kV lines		Project under study	Included in sponsors budget
Berrydale 230 kV Transformer Addition	Install second 230/115 kV transformer at Berrydale Substation.	PSE			Conceptual Project for future need	Project identified as future need
Christopher 230 kV Substation	Develop Christopher 230 kV Substation: loop BPA Covington-Tacoma 230 kV line into Christopher, construct a 230 kV bus with the necessary breakers, and add 230/115 kV transformation and a 115 kV auxiliary bus.	PSE	BPA - Covington Tacoma #2,3,4 230 kV lines		Conceptual Project for future need	Project identified as future need
Starwood autotransformer removal	Remove 115-110 kV autotransformer at Starwood Substation	PSE	PSE, TPWR		Engineering Design	Included in sponsors budget

Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
2018	$3 M	Load service, Capacity Increase, Reliability, prevent curtailment of firm transfers				Puget Sound Area Study Team
2016	$2 M	Load service, Capacity Increase, Reliability, prevent curtailment of firm transfers				Puget Sound Area Study Team
2016-2017	$13 M	Load service, Capacity Increase, Reliability, prevent curtailment of firm transfers				Puget Sound Area Study Team
2017	$3 M	Load service, Capacity Increase, Reliability, prevent curtailment of firm transfers				Puget Sound Area Study Team
2016	$25 M	Capacity increase				Puget Sound Area Study Team
2015	$14 M	Load service, Reliability			Single System Project	
2016	$20 M	Replace aging infrastructure (existing Bellingham Sub) and increase system reliability			Single System Project	
Project completed	$1 M	Load service, Capacity increase, Reliability	Project completed		Single System Project	
2015	$13 M	Reliability			Single System Project	
2014	$0.6 M	Reliability			Single System Project	
2015-2017 (to accommodate the new line to Lakeside)	$11 M	Maintenance and/or repairs, Reliability			Single System Project	
2017+	$8 M	Load service, Capacity increase, Reliability			Single System Project	
2017+	$20 M	Load service, Capacity increase, Reliability			Single System Project	
2013	$1 M	Load service, Capacity increase, Reliability	New Project		Single System Project, possible impacts	

Puget Sound Projects continued

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage	Project Commitment Level
Tacoma Bus Section Breaker	Add a series bus section breaker at Tacoma 230 kV substation	BPA	PSE, TPWR		Project under study	
Granite Falls 115kV Transmission Loop	Construct 4.8 miles of 115kV transmission line to improve service to Granite Falls Substation.	Snohomish County PUD	BPA		Plan of service determined	
Monroe-Novelty 230 kV line Upgrade	Increase capacity of Monroe-Novelty 230 kV line	BPA			under study	
Paul 500 kV Shunt Reactor	Add 500 kV 180 MVAR Shunt Reactor	BPA			Plan of Service determined	Committed

Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
2016	$1.0 M	Load service, Capacity increase, Reliability			Existing Obligation Project	
2014	$7 M	Load service, System Reliability			Single System Project	
2016	$6 M	Maintain voltage schedules			Single System Project	

Central Washington Projects

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
Mid-Columbia Area Reinforcement	Vantage-Pomona Heights 230 kV #2 Line in the Yakima area.	PAC	BPA, Grant		
Northern Mid-Columbia Area Support	Douglas-Rapids 230 kV line, Douglas 230/115 kV transformer, Rapids 115 kV Substation with terminations for Pangborn, South Nile and Hanna 115 kV lines	Douglas	Chelan, BPA, Grant		Under Construction
Northern Mid-Columbia Area Support	Build new Rapids-Columbia 230 kV line	Douglas, Grant, Chelan, BPA	Douglas, Grant, Chelan, BPA		Routing, design
Mid-Columbia Area Reinforcement, Phase 2	Upgrade Wanapum-Midway 230 kV line in central WA.	Grant County PUD			
Columbia - Larson 230 kV Line	Construct a new 230 kV line from Rocky Ford to Columbia, connect to existing Rocky Ford-Larson 230 kV line to form Columbia-Rocky Ford line.	Grant County PUD	Interconnect w/BPA at Columbia Sub		
Ashe 500/115 kV Transformer	Add a 500/115 kV transformer at Ashe with a line tapping the proposed Ashe-Benton 115 kV line	BPA			Conceptual Project for Future Need
Union Gap Transformation	Add third 230/115 kV transformer at Union Gap	PacifiCorp			
Okanogan Area	Add 26 MVAR capacitor at East Omak Substation	BPA			
Sacajawea 115 kV Tie Line	Construct a 115 kV line (0.5 mile) from Sacajawea Substation to tap the Ice Harbor-Franklin 115 kV #3 line	BPA			
McKenzie - Andrew York #1 Re-rate	Re-rate the existing McKenzie - Andrew York #1 115 kV line from 50 C MOT to 75 C MOT	Chelan County PUD			Plan of Service Determined
McKenzie - Andrew York #2 Re-rate	Re-rate the existing McKenzie - Andrew York #2 115 kV line from 50 C MOT to 75 C MOT	Chelan County PUD			Plan of Service Determined
Rocky Ford - Dover 115 kV line	Construct 115 kV Rocky Ford-Dover 115 kV line	Grant County PUD			
Tri-Cities Reinforcements	Franklin 115 kV 104 MVAR capacitor addition	BPA			
White Bluffs Capacitors	Add 39 MVAR shunt capacitor at White Bluffs Substation	BPA			
Columbia Bus Section Breaker	Add a series bus section breaker at Columbia 230 kV substation	BPA			Plan of Service Determined

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
	2015		Load growth in Yakima area	Delayed from 2013		External Project	NTAC
Sponsor committed	2013	$16.9 M	Load growth		No	Existing Obligation Project	Northern Mid-Columbia Study Group
Sponsors committed, cost allocation complete	2015	$14 M	Load growth and transfers		No	Existing Obligation Project	Northern Mid-Columbia Study Group
Project identified as future need	2019		Load growth, new wind generation plants and transfers of generation out of the area	Delayed from 2017		Existing Obligation Project	
	2014	$42 M	Load growth, increase transmission system reliability and improve voltage stability performance.			Single System Project with possible parallel impacts	Northern Mid-Columbia Study Group
Project identified as future need						Single System	
	2016		Load growth	Delayed from 2013	No	Single System Project	
	2013	$930,000	Load growth and system reliability			Single System Project	
Committed	2015	$3 M	Load growth			Single System Project	
	2013	$200,000	Increase transmission system reliability		No	Single System Project	
	2013	$300,000	Increase transmission system reliability		No	Single System Project	
	2016	$5 M	Increase transmission system reliability			Single System Project	
Committed	2014	$3.1 M	Voltage Support and load growth	changed from 2016		Single System Project	
Committed	2013	$2.0 M	Reliability for Columbia Generating Station			Single System	
	2016	$1.0 M	Load service, Reliability			Single System Project	

Northeastern Projects

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
Spokane Area 230 kV Reinforcement	Add a 230/115 kV transformer in Garden Springs Substation with 230 kV lines to Westside and either Beacon/Boulder 230 kV switching stations	Avista			Project identified as future need
Benton-Othello 115 kV Rebuild	Rebuild Benton-Othello 115 kV line	Avista			Committed project
Westside Project	Westside 230 kV Substation rebuild and transformer upgrades	Avista			Committed project
Moscow 230/115 kV Upgrade	Increase Moscow transformer capacity to 250 MVA and rebuild 230 kV substation	Avista			Committed project
Spokane Valley Transmission Reinforcements	New Irvin-IEP 115 kV transmission line and reconductor Beacon-Boulder and Opportunity Tap 115 kV lines	Avista			Committed project
Lancaster CT Integration	Loop Boulder-Rathdrum 230 kV line into Lancaster	Avista			Committed project
Bronx-Cabinet 115 kV Rebuild	Rebuild/reconductor Bronx-Cabinet 115 kV line	Avista			Committed project
Lewiston 10 Year Plan	Second Hatwai-Lolo 230 kV line is one solution, long range study needed	Avista	BPA, IPCO, PAC		Project identified as long term need
Little Goose Area Reinforcement	Add 40 mile 500 kV line from new wind collection station called Central Ferry to Lower Monumental Substation	BPA			Funding for NEPA and preliminary engineering is Committed under NOS
Wallula-McNary 230 kV line	A new 230 kV line from Wallula to the McNary (BPA)	PAC	BPA		In WECC Rating Process
Hatwai 230 kV Bus Section Breaker	Add 230 kV bus section breaker at Hatwai Substation	BPA			Plan of Service determined
Tucannon Shunt Capacitors	Add two groups of 6.5 MVAR, 115 kV capacitors at Tucannon Substation	BPA			
Columbia Falls Bus Section Breakers	Add 230 kV and 115 kV bus section breaker at Columbia Falls	BPA			
MATL Project	The Montana Alberta Tie Ltd Project is a 200 mile, 300 MW, 230 kV line connecting Lethbridge, Alberta and Great Falls, Montana going through Cutbank, Montana which has significant wind generation potential.	Enbridge			Under Construction
Green Line Project	This project is a 100 mile extension of the MATL project to connect to the Colstrip Transmission. This project will provide access to the Mid-Columbia Hub (up to 1000 MW Capacity).	Enbridge	Colstrip Transmission Owners		Feasibility State

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
	2015		Load Growth in the south Spokane area			Single System Project with possible impacts	
	2016	$10 M				Single System Project with possible	
	2016	$15 M				Single System Project	
	2014	$10 M				Single System Project	
	2016	$5 M				Single System Project	
	2013	$3 M				Single System Project with possible impacts	
	2016	$10 M				Single System Project with possible impacts	
	10 years		Loss of Hatwai-Lolo and Hatwai-North Lewiston 230 kV lines for heavy flows to Walla Walla and Idaho				Needed
Project on Hold	2014	$99 M	To serve requests made under 2008 Network Open Season			Requested Service Project	
	2014		Transmission Service Requests	Delayed from 2013		Requested Service Project	
under study	2015	$4.2 M	Load growth and system reliability			Single System	
Committed	2013	$2 M	Voltage support and generation integration			Single System	
Committed	2013	$1 M	Load growth and system reliability			Single System	
Permitted	August 2013	$209 M	Transmission Service Requests	delayed until 2013			
			Transmission Service Requests				

Northeastern Projects continued

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
Montana to Washington Project	This project is proposed to meet a portion of the 2010 BPA NOS requests. Upgrades to the Montana to Northwest and West of Hatwai paths is proposed without any new line construction by upgrading existing and adding new series compensation in the lines. With the new project, the capability of the system will be increased between 550 and 700 MW.	BPA	AVA and other Colstrip Owners		
Garrison-Ashe Project	This project is proposed to meet the full capacity of the 2010 BPA NOS requests. A 430 mile series compensated Garrison-Ashe 500 kV line is proposed with an intermediate station between Taft and Hot Springs.	BPA	AVA		Conceptual Project
Kalispell Shunt Capacitors	Add 115 kV Shunt Capacitors (two groups of 16 MVARs)	BPA			Plan of Service determined
Bell 230 kV Bus sectionalizing breaker	Add series Bus section Breaker at Bell 230 S1-S2 to mitigate BSB failures	BPA	AVA		Plan of Service determined

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
Project Under Study	2015	$115 M	Committed under BPA NOS			Requested Service Project	
None			Meet 2010 NOS Requests			Requested Service Project	
Committed	2014	$3.1 M	Local load growth and reliability	New Project		Single System Project	
Committed	2015/16	$1 M	Local load growth and reliability	New Project		Existing Obligation Project	

Western Projects

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
Lebanon Area Reinforcement	Add a 19.6 MVAR, 115 kV shunt capacitor bank at Lebanon Substation	BPA			Plan of service determined
I-5 Corridor (SW Washington - NW Oregon Reinforcement)	Construct a new 500 kV line (approx. 70 miles) from Troutdale Substation to the new Castle Rock Substation located approximately 12 miles north of Allston Substation on the Paul-Allston No.1 500 kV line.	BPA	PGE, PAC, CCP, Clark		Funding for NEPA and preliminary engineering is committed under NOS
Pearl – Sherwood and McLoughlin-Pearl-Sherwood 230 kV Line Reconfiguration	PGE and BPA plan to re-terminate the existing double circuit operating in parallel between BPA's Pearl Substation and PGE's Sherwood Substation. In addition, PGE will re-terminate at Sherwood the existing double circuit operating in parallel as the McLoughlin-Pearl-Sherwood 230kV circuit. This will require two new circuit breakers at Sherwood and two new circuit breakers at Pearl. When the project is completed, there will be a Pearl-Sherwood #1 230 kV circuit, a Pearl-Sherwood #2 230 kV circuit, a Pearl-Sherwood #3 230kV circuit, and a McLoughlin-Pearl-Sherwood 230kV circuit.	PGE and BPA			Plan of service determined
Cross-Cascades South	Station K development connecting Ashe-Marion, Buckley-Marion and both John Day-Grizzly lines together at a new station where the lines cross.	BPA	PGE, PAC		
Cascade Crossing Project	The Cascade Crossing Project is a 200 mile 500 kV line from PGE's Coyote Springs generation plant in the town of Boardman, Oregon west to PGE's Bethel Substation in Salem, Oregon where the line will be terminated into a new 500/230 kV transformer bank. The new line will interconnect at a new Grassland Substation adjacent to the existing Boardman power plant and a new Cedar Spring Substation approximately 26 miles southwest of the Boardman power plant. BPA and PGE have recently signed a MOU to explore and evaluate a proposed change to this project. PGE would build Cascade Crossing beginning at Boardman, but would terminate the dual circuit, 500 kV transmission line at a new substation near Maupin, Oregon, called Pine Grove. PGE would invest in several enhancements to BPA's system (series compensation).	PGE, PAC, BPA		http://cascadecrossingproject.com/	In WECC Rating Process
Trojan - Sewell 230 kV Line	This project consists of a new Trojan-Sewell 230 kV line and Sewell 230/115 kV transformer. This project is the result of a merchant request and will provide the capacity needed to integrate proposed generation near Port Westward and provide local load service.	PGE	Impacts to South of Allston		Plan of service determined
Blue Lake-Gresham 230 kV Line	Construct a transmission line from Blue Lake Substation (Troutdale, Oregon) to Gresham Substation (Gresham, Oregon). This project requires 4.2 miles of new 230 kV transmission line.	PGE	BPA		Plan of service determined
Longview-Bakers Corner-Lexington 115 kV Line	Create a connection between BPA Longview and Lexington Substations through Cowlitz Substations (Bakers Corner, Olive Way, and Mint Farm), creating a 3-Terminal Line.	Cowlitz	BPA		Longview BKR B331, new BKR at Bakers Corner, Lexington BKR B1468

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
Funding approved by sponsor	Energized	$3 M	Load growth	Energized		Single System	
Depends upon NEPA	2016-2018	$342 M	Transmission Service Requests			Requested Service Project	I-5 Corridor Regional Planning Study Team
Committed	2017	$2.7M	Reliability			Multi-system EOP with only one ColGrid participant	
Conceptual project for future need	2020		Load growth			Multi-system EOP with only one ColGrid participant	West of Cascades Study Team
Cancelled	2017	$610-825 M	Transmission service request	New options being considered			
Cancelled	2017		A strategic investment to increase transmission capacity for future generation projects and local load-service.	Formerly called Horizon Phase II		Single System Project	
Included in sponsors budget	2017		Reliability			External Project	
Funding approved by sponsor & BPA	2008-12 Construction scheduled for 2012		Reliability and load growth	Project Energized Dec 2012		Single System Project	

Western Projects continued

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage	Project Commitment Level
Cowlitz-Lexington-Cardwell 115 kV Line	Create a connection between BPA Cowlitz, East Kelso, Lexington, and Cardwell Substations through Cowlitz Substations (with a connection by rebuilding old 69kV Lines for 115kV with 1272 AAC from 7th Avenue to East Kelso).	Cowlitz			New BKR at East Kelso, New BKR at 7th Ave	Funding approved by sponsor
Longview-Lexington 115 kV line #2	Create a connection between BPA Longview and Lexington Substations through Cowlitz Substations (Mint Farm, Olive Way, 20th and Ocean Beach and West Kelso).	Cowlitz	BPA will replace 115 kV Breaker			Funding approved by sponsor
Longview-Lexington-Cardwell 115 kV line	Create a connection between BPA Longview, Lexington, East Kelso and Cardwell Substations through Cowlitz Substations (with a connection by rebuilding old 69kV Lines for 115kV with 1272 AAC from East Kelso to West Kelso to the 115kV Line feeding Olson Rd to Lexington BKR B1466).	Cowlitz	BPA will replace 115 kV Breaker			Funding approved by sponsor
Kalama Energy	Construct new 230 kV line from BPA Longview to Kalama.	Cowlitz	BPA		Project under study	Conceptual project for future need
Rogue SVC (South Oregon Coast)	Add a -45 to +50 MVAR, Static VAR Compensator (SVC) at Rogue Substation connected to the 115 kV bus	BPA			Construction	
South Oregon Coast Transmission Reinforcement	Rebuild Bandon-Rogue 115 kV line or construct a new 115 kV transmission line to provide a new source to the South Oregon Coast load area	BPA				Project under study
Whetstone 230/115 kV Transformer addition	Add a 230/115 kV substation in the Medford area fed from the Grants Pass-Meridian 230 kV line	PAC				
77 Lookingglass Substation	New Lookingglass Substation on Dixonville-Reston 230 kV line	PAC				
North Bonneville-Ross and North Bonneville-Troutdale Line Swap	This line swap places the North Bonneville-Troutdale #2 230 kV line on the double circuit towers with the North Bonneville-Ross #2 line to prevent thermal overloads which could result from the existing double circuit line outage.	BPA			Energized	
Forest Grove Loop-in of the Tillamook-Keeler 115 kV line	Loop the Keeler-Tillamook 115 kV line into Forest Grove Substation and upgrade the Keeler-Forest Grove section of the Keeler-Tillamook 115 kV line.	BPA				Committed
Pearl 500 kV Bay Addition	Construct a new Pearl 500 kV bay #6 and reterminate the Ostrander-Pearl 500 kV line into the new bay (double breaker, double bus)	BPA				Committed
Keeler 230 kV Bus Section Breaker	Install a 230 kV bus sectionalizing break at Keeler between bays #4 and #5 to balance the sources and loads at Keeler.	BPA				Committed
Ostrander Additions	Add a new 500 kV breaker in bay 5 at Ostrander for the Troutdale #1 line	BPA	PGE			Committed
Longview-Lexington 230 kV Re-termination	This project involves re-terminating the Longview-Lexington 230 kV line to the Longview Annex	BPA				Committed

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
Funding approved by sponsor	2014-16		Reliability and load growth			Single System Project	
Funding approved by sponsor	2017-19	$4.9 M	Reliability and load growth			Single System Project	
Funding approved by sponsor	2015-17	$10.1 M	Reliability and load growth			Single System Project	
Conceptual project for future need	2016	$20 M	To connect the new Kalama Energy 346 MW gas turbine project and/or to provide for load growth in area	Project scheduled to 2016 energization		Single System Project	
	2013	$9 M	Southern Oregon load growth - needs dynamic SVC control v. static caps.			Single System Project	
Project under study			Load growth along southern Oregon coast			Single System Project	
	2015		Reliability and load growth	delayed from 2014		Single System Project	
	delayed		Reliability and load growth	delayed beyond planning horizon		Single System Project	
	Energized		Load growth and system reliability			Single System Project	
Committed	2013	$2.135 M	Local load growth	Delayed from 2012		Single System Project	
Committed	2016	$1.7 M	Local load growth			Single System Project, possible impacts	
Committed	2014	$2.33 M	Local load growth			Single System Project	
Committed	2014	$2.4 M	System reliability			Single System Project, possible impacts	
Committed	2015	$2 M	Local load growth			Single System Project	

Western Projects continued

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
South Cowlitz County Support	Build a new 115 kV Line from Cowlitz' Lewis River Sub to PAC Merwin 115 kV Sub. Source Cowlitz' Ariel Sub on new Line. Reconductor 115 kV back to Cowlitz' North Woodland Sub	Cowlitz	PacifiCorp.		Cowlitz is in discussion with PAC
Grants Pass 500/230 kV transformer	New 500/230 kV substation tapping PAC's Meridian to Dixonville 500 kV line. 230 kV line construction will included looping the existing Grants Pass to Meridian 230 kV line into the new substation as well as construction of a new 230 kV transmission line for the new substation to the existing Grants Pass 230 kV Substation.	PAC	BPA		Preliminary Study
Klamath Falls 500/230 kV Substation	New 500 kV substation tapping PAC's Captain Jack to Klamath Co-Gen 500 kV line. The 230 kV line construction will included looping the existing Klamath Falls to J.C. Boyle 230 kV line into the new substation.	PAC	BPA		Project under study
Santiam-Chemawa 230 kV Line Upgrade	Upgrade Santiam-Chemawa 230 kV line to higher capacity	BPA	PGE		Plan of service determined
North Bonneville 230 kV Line Re-termination	This project involves re-terminating the North Bonneville-Troutdale 230 kV line into a different bus position at North Bonneville Substation	BPA			Plan of service determined
Troutdale 230 Series bus sectionalizing breaker	Add another breaker in series with the existing bus section breaker	BPA			Plan of service determined
Pearl 230 Series bus sectionalizing breaker	Add another breaker in series with the existing bus section breaker	BPA			Plan of service determined
Alvey 500 kV Shunt Reactor	Add 180 MVAR Shunt Reactor at Alvey for voltage control	BPA			Plan of service determined
Lane 230 kV Bus Sectionalizing Breaker	Add 230 kV Sectionalizing Breaker at Lane substation	BPA			Project under study

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
	2017-2019	$7.7 M	Local load growth and needed voltage/ reliability support			Single System Project, possible impacts	
Under study	2019			Delayed from 2016		Single System Project, possible impacts	
Under study	2015			Moved up from 2018		Single System Project, possible impacts	
Committed	2016	$900,000	local load service			Single System Project, possible impacts	
Committed	2015	$2.1 M	Local load growth			Single System Project	
Committed	2018	$1.0 M	Reliability and load growth			Single System Project	
Committed	2017	$1.0 M	Reliability and load growth			Single System Project	
Committed	2014						

Eastern Projects

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
Lower Valley Reinforcement (Hooper Springs)	This is a joint project with BPA, PacifiCorp, and Lower Valley Energy. PacifiCorp will construct Three Mile Knoll - a new 345/138 kV substation. The Goshen-Bridger 345 kV line will be looped into the new substation. BPA will construct Hooper Springs - a new 138/115 kV substation. Lower Valley Energy will construct a new double circuit 115 kV line (approximately 20 miles) from Hooper Springs to Lanes Creek/Valley Substations.	BPA/ PAC/ Lower Valley Electric			
Big Eddy - Knight 500 kV line	Construct a new 500 kV line (approximately 29 miles) from Big Eddy to a new Knight Station, which connects to the Wautoma-Ostrander 500 kV line. (3 breaker ring bus)	BPA			Project Committed under Network Open Season
Central Oregon 500/230 kV Transformer Bank Addition	Add second 500/230 kV 700 MVAR transformer at Ponderosa.	BPA	PAC		Preliminary engineering and NEPA
La Pine capacitors	Add a 19 MVAR shunt capacitor at La Pine Substation	BPA			Committed
La Pine Reactor	Add 230 kV 40 MVAR shunt reactor at La Pine Substation	BPA			Committed
McNary 230 kV Shunt Capacitors	Add 2 groups of 230 kV 150 MVAR shunt capacitors at McNary	BPA			plan of service determined
De Moss-Fossil 115 kV Line Upgrade	Upgrade De Moss-Fossil 69 kV Line to 115 kV	BPA			
Hilltop Shunt Reactor	Add a 40 MVAR 230 kV shunt reactor at Hilltop Substation	BPA			
Bonanza 230/115 kV Substation	Add a 230/115 kV Bonanza Substation in the Prineville area	BPA	PAC		Project under Study
McNary 500/230 kV Transformer #2	Add a second 500/230 kV transformer at McNary (1428 MVA) and 230 kV bus section breaker	BPA	PAC		plan of service determined
Big Eddy 230/115 kV transformer	Replace Big Eddy 230/115 kV transformer #1	BPA			plan of service determined
John Day-Big Eddy 500 kV #1 Reconductor	Upgrade the John Day-Big Eddy 500 kV #1 Line	BPA			plan of service determined
Celilo Terminal Replacement	Celilo Terminal Replacement (PDCI Upgrade to 3220 MW). Replace aging DC terminal and line upgrades to accommodate 3220 MW rating	BPA			

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
construction on hold pending agreement	2014	$48 M	Load growth in eastern Idaho			Multi-system EOP with only one ColGrid participant	
Under Construction	2014	$115 M	Transmission Service Requests	delayed from 2013 due to cultural and land acquisition issues		Requested Service Project	West of McNary Regional Planning Study Team
Under Construction	2013	$31 M	Load growth and loss of the existing transformer			Multi-system EOP with only one ColGrid participant	
Committed	2014	$1.3 M	Load growth and system reliability	delayed from 2012		Single System Project	
Committed	2015	$2 M	Voltage support (off peak)	delayed from 2014		Single System	
Committed	2013	$5.7 M	Voltage support and generation integration			Single System	
Committed	Energized	$7.5 M	Voltage support and generation integration	Energized		Single System	
Committed	Energized	2.5 M	Voltage support	Energized		Single System	
	2014		Load growth			Single System	
Under Study	2016	$18.5 M	Reliable Generation Interconnection				
Committed	2015						
Committed	2016-17						
Committed	2016	$320 M	Replace aging equipment				

Regional Projects

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
West of McNary Area Reinforcement Project: Big Eddy - Knight Line	This project consists of a new 500 kV line from McNary Substation to John Day Substation which has been completed and a new 500 kV line (approximately 29 miles) from Big Eddy Substation to a tap point (3 breaker Ring at a new station called Knight) along the Wautoma-Ostrander 500 kV line.	BPA			Completed WECC Regional Planning, now in Technical Coordination Work Group (TCWG)
I-5 Corridor Project (SW Washington - NW Oregon Reinforcement)	This project consists of a new 500 kV line (70-90 miles) from Troutdale Substation to a Castle Rock Substation located approximately 12 miles north of Allston Substation on the Paul-Allston No.1 500 kV line.	BPA	PGE, PAC, CCP, Clark		Completed WECC Regional Planning
Cascade Crossing Project	The Cascade Crossing Project is a 200 mile 500 kV line from PGE's Coyote Springs generation plant in the town of Boardman, Oregon west to PGE's Bethel Substation in Salem, Oregon where the line will be terminated into a new 500/230 kV transformer bank. The new line will interconnect at a new Grassland Substation adjacent to the existing Boardman power plant and a new Cedar Spring Substation approximately 26 miles southwest of the Boardman power plant. BPA and PGE have recently signed a MOU to explore and evaluate a proposed change to this project. PGE would build Cascade Crossing beginning at Boardman, but would terminate the dual circuit, 500 kV transmission line at a new substation near Maupin, Oregon, called Pine Grove. PGE would invest in several enhancements to BPA's system (series compensation).	PGE, PAC, BPA		http://cascadecrossingproject.com/	In WECC Rating Process
Gateway West Project	Idaho Power and PacifiCorp are proposing a joint project with a 500 kV line from Winstar Substation (near Glenrock Wyoming) to Hemingway Substation in the Boise area.	Idaho and PAC			In WECC Rating Process
Hemingway - Boardman Project	In conjunction with the Gateway West project, Idaho Power is looking to extend this project from Hemingway Substation further to the north and west to the Boardman Substation.	Idaho/PAC/BPA	BPA, Avista, PAC		In WECC Rating Process
PG&E Canada - Pacific Northwest – Northern California Transmission Line Project	PG&E is proposing a 500 kV AC line from Selkirk Substation in SE British Columbia to NEO, along with an High Voltage DC line from NEO to the Tesla/Tracy area in the San Francisco Bay area. The bi-directional capacity of this line is planned to be 3,000 MW. Interconnections are also being considered at Devils Gap in the Spokane area and Round Mountain Substation in Northern California.	PG&E/AVA/BCH	BPA, PSE, PGE, PAC		
Devil's Gap Interconnection to Canada - PNW – Northern California Transmission Line Project	In conjunction with the PG&E Canada-NW-Northern California Project, Avista is proposing an interconnection at Devil's Gap west of Spokane.	Avista	BPA		
Northern Lights Project	High Voltage Direct Current line beginning at Edmonton, Alberta and ending near Maupin, Oregon. At least one intermediate terminal is planned in a location south of Calgary, near Alberta's largest wind development region. The project is planned to be a bi-directional line with an expected capacity of up to 3,000 MW.	Northern Lights	BPA		
Juan de Fuca Cable Project #1	SeaBreeze Pacific is proposing an underwater 550 MW HVDC Light cable from Vancouver Island in BC to the Port Angeles, WA area across the Strait of Juan de Fuca. This project rating is planned to be bi-directional.	SeaBreeze	BPA, PSE		In WECC Rating Process
Juan de Fuca Cable Project #2	Sea Breeze Pacific is proposing a Multi-terminal underwater 1,100 MW high-voltage DC cable (+/- 300 kV) across the Strait of Juan de Fuca from Ingledow Substation near Vancouver, British Columbia, Canada to Pike Substation near Victoria on Vancouver Island Canada, to either the Shelton or Olympia Substations on the Olympic Peninsula, Washington. The 1100 MW project rating is planned to be fully controllable and bi-directional.	SeaBreeze	BPA		In WECC Rating Process

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
Project Committed under Network Open Season. In permitting process.	2014		Transmission Service Requests	Big Eddy-Knight delayed from 2013			ColGrid West of McNary Regional Planning Study Team
Funding for NEPA and preliminary Engineering is Committed under Network Open Season	2016-18	$342 M	Transmission Service Requests			Requested Service Project	ColGrid I-5 Corridor Regional Planning Study Team
cancelled	2017	$610-825 M	Transmission service request	New options being considered		Multi-system EOP with only one ColGrid participant	
	2018-21		Transmission Service Requests				
	2016	$630-820 M	Transmission Service Requests				
	on hold			Lower capacity alternatives being considered			
	on hold						
	on hold						

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Regional Projects continued

Project Name	Description	Sponsor	Parties Impacted by Project	Link to More Detail	Project Stage
West Coast Cable	SeaBreeze Pacific is proposing an underwater HVDC cable from Allston Substation in NW Oregon near Rainier to San Francisco Bay area. This project has a planned capacity of 1600 MW.	SeaBreeze	BPA		In WECC Rating Process
Montana to Washington Project	This project is proposed to meet a portion of the 2010 BPA NOS requests. Upgrades to the Montana to Northwest and West of Hatwai paths is proposed without any new line construction by upgrading existing and adding new series compensation in the lines. With the new project, the capability of the system will be increased between 550 and 700 MW.	BPA	AVA and other Colstrip Owners		Project under study
Garrison-Ashe Project	This project is proposed to meet the full capacity of the 2010 BPA NOS requests. A 430 mile series compensated Garrison-Ashe 500 kV line is proposed with an intermediate station between Taft and Hot Springs.	BPA	AVA		Conceptual Project
MATL Project	The Montana Alberta Tie Ltd Project is a 200 mile, 300 MW, 230 kV line connecting Lethbridge, Alberta and Great Falls, Montana going through Cutbank, Montana which has significant wind generation potential.	Enbridge			Under Construction
Green Line Project	This project is a 100 mile extension of the MATL project to connect to the Colstrip Transmission. This project will provide access to the Mid-Columbia Hub (up to 1000 MW Capacity).	Enbridge	Colstrip Transmission Owners		Feasibility State
Mountain States Transmission Intertie (MSTI)	A 500 kilovolt (kV), single-circuit electric transmission line from Townsend, Montana south to Midpoint Substation near Jerome, Idaho.	NWE	Colstrip Owners		

Project Commitment Level	Scheduled Completion	Cost Estimate	Project Need/Driver & Other Notes	Changes from Previous Plan	Plan cross tribal lands	Type of Project	Study Team(s)
	2015	$115 M	Meet 2010 NOS Requests			Requested Service Project	
None	on hold		Meet 2010 NOS Requests			Requested Service Project	
Permitted	Aug-13	$209 M	Transmission Service Requests				
			Transmission Service Requests				
	on hold						

ColumbiaGrid

Energize Eastside
DEIS Comments

Submitted by CENSE

14 March 2016

CENSE submits the following comments as part of CENSE's comments to the DEIS of the PSE project Energize Eastside.

CENSE also incorporates by reference any comments made by CENSE members who have sent individual comments.

---------- Forwarded message ----------
From: Mary Kenny <silversneakers@icloud.com>
To: <eis@cense.org>
Cc:
Date: Tue, 8 Mar 2016 12:27:45 -0800
Subject: Energize Eastside
Dear Ms. Bedwell,

I am a resident of Somerset and I'm one of the "new" residents of only 15 years. Most others have been here 25 or 30 years. They have raised their families, seen the tremendous growth of Boeing, Microsoft, Amazon and Costco but have stayed on their hill feeling a sense of home and family.

I urge you to consider other alternatives to the plan to bring high powered electrical lines through this beautiful area. Not only will you be destroying a signature neighborhood but will be causing a visual "blight" that will impact the financial livelihood of many of the residents. Please don't support a movement to negatively impact this beautiful area.

Mary Kenny
14018 SE 51st PL
98006

Jeanne DeMund
2811 Mountain View Ave. N
Renton, WA 98056
206-898-9818
February 24, 2016

Ms. Heidi Bedwell,
Senior Planner
Land Use Division-Development Services
City of Bellevue
450 110th Avenue NE
Bellevue, WA 98004

Dear Ms. Bedwell

I appreciate the opportunity to comment on the Draft Environmental Impact Statement for the Energize Eastside Project. As you may recognize from my address, I live along one of the routes that was not selected for this project. However, after considering the information provided by PSE, by the EIS, and by independent sources, I am compelled to comment.

1. The project is not needed: The assumptions underlying PSE's load flow are critically flawed, as explained by independent experts Richard Lauckhart and Roger Shiffman in their February 2016 report. Here are just 2 examples:

PSE has inflated electric demand growth estimates by as much as 500%. The Northwest Power and Conservation Council estimates overall demand growth at just 0.5 to 1.0%…right in line with the 0.5% that PSE told the Western Energy Coordinating Council they anticipate in their Base Case data So why is PSE using a 2.4% annual growth rate as a key element in their justification for Energize Eastside?

PSE did load flow analysis of winter peak demand rates using summer load limits on transformers. This effectively shrinks actual transformer capacity by 25-30%, creating an artificial shortfall.

If either or both of these anomalies is an error, it raises grave questions in my mind about PSE's competence, and the possibility for other errors in both their assumptions and their analysis. If either is a deliberate attempt to rig the outcome of the analysis, PSE's integrity as a member of our community is at issue.

You can read the entire report on line at: http://cense.org/Lauckhart-Schiffman%20Load%20Flow%20Study.pdf

2. Environmental impacts: This project will require cutting down thousands of trees, somewhere in the neighborhood of 8,000 trees over its 18 mile length. A mature tree can absorb up to 48 lbs of carbon dioxide per year. The Eastside will potentially suffer an increase of over 14,000 MT of carbon dioxide that is not being absorbed by these trees (EIS amount). Any mitigate might occur off site, require purchase of carbon credits, and leave the some or all of the impact in our area.This is an unacceptable environmental impact, even more so given that the entire project is not needed for either capacity or reliability of the electric system.

3. Safety: As cited in the EIS, there is potential for damage to the Olympic Pipeline during construction, in chapter 16, maintenance in chapter 18 and increased corrosion due to electromagnetic interference during ongoing operations, Chapter 16 again. The EIS attempts throughout these chapters to minimizes perception of these risks, for example in chapter 18, using the word “theoretical” in describing the potential for damage to the Olympic pipeline during routine power pole and line maintenance.

The Olympic Pipeline is only 3-10 feet below the surface of the ground, and it carries gasoline, diesel and jet fuel. All of these are flammable and hazardous. We all know that gasoline is so flammable that we’re not supposed to touch our car after we start fueling in the winter, to avoid static electricity that could start a fire. To give you an idea of the scale of potential damage, a 2014 pipeline spill of 7 gallons resulted in $1.5 million in property damage in Skagit County according the federal records.

Here’s what really sent chills up my spine: the Olympic Pipeline is currently under a Final Order to comply with standards of the Office of Pipeline Safety, part of the federal Department of Transportation The problems relate to corrosion control, and the Order states that Olympic Pipeline failed to correct identified deficiencies in its corrosion control system that could adversely affect the safe operation of the pipeline. You can see the details of both the Final Order, and the prior documents at:
http://primis.phmsa.dot.gov/comm/reports/enforce/CaseDetail_cpf_520155014.html#_TP_1_tab_1

The inspection that ultimately lead to this Final Order was conducted in August of 2014. This final order was only issued in January 2016. The condition has gone uncorrected for 18 months, and the pipeline has a further 18 months to complete corrective action, a time period that overlaps with PSE proposed construction. And PSE wants a green light for construction right next to this pipeline, wants to increase the potential for corrosion and wants us to believe that these risks are “theoretical”. These two corporate citizens might deserve each other as neighbors, but we do not.

Ms. Bedwell, the citizens of King County rely on you and your colleagues in Bellevue and the other jurisdictions to do the right thing to protect us, both physically and fiscally. I submit to you that risking lives, property and the environment in this way for a project that is not needed is irresponsible, unacceptable and should not be condoned. There is time to develop an integrated resource approach in sync with the recommendations of the Northwest Power and Conservation Planning Council, and different in some respects from the alternative offered by PSE, and such an approach should be developed.

Thank you for the opportunity to comment.

Sincerely,

Jeanne DeMund

cc:

Carol Helland

Development Services Land Use Director City of Bellevue

450 110th Avenue NE

Bellevue, WA 98004

City of Kirkland

Jeremy McMahan

Development Services - Planning Manager (425) 587-3229 jmcmahan@kirklandwa.gov

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City of Renton

Jennifer Henning Planning Director

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ENERGIZE EASTSIDE: COMMENTS ON ENERGIZE EASTSIDE STATEMENT (EIS) February, 2016

I am very concerned about PSE's intention to build a large transmission line from Redmond, WA to Renton, WA. for several reasons:

1. The **need** for expanded capacity outlined in Chapter 1.3 of the DEIS has been questioned by the Lauckhart-Schiffman load-flow study dated February 18, 2016. This study indicates there are many flaws in PSE's assumptions. If winter emergency conditions are used instead of summer normal conditions and if .5%/year growth for Eastside energy demand is used, demand does not exceed flow until 2058. PSE's inflated rate of growth of 2.4%/year indicates the capacity is not exceeded until 2027. This should provide plenty of time to implement rapidly developing new technologies which would be much less expensive and intrusive.

It appears the real motive for PSE's desire to expand capacity has more to do with the transfer of power to British Columbia, thereby enhancing the profitability of PSE and increasing the return on investment for the hedge fund owners of PSE who made a 10-year investment which anticipated high returns. These profits would on the backs of the customers who would pay for the huge capital investment with increased rates.

2. **Public safety** is of primary concern. Given that we live in a seismic zone and the existing power line is built along a gas line, the possibility of a human catastrophe is exacerbated by construction and long term operations activities. Chapter 8.5.1.3 only mentions earthquakes during construction. What about seismic events in the future? I am reminded of the 1999 Bellingham disaster. In addition while effects on humans is hard to prove and controversial, why risk any adverse health effects, such as bone marrow cancer in infants and brain cancer in adults?

3. The detrimental impact to the **environment** cannot be overemphasized. We are looking at the destruction of several thousand trees and clear cutting many acres of vegetation. Bellevue and other eastside cities pride themselves on the largely attractive and desirable living conditions that have been developed over the years. Does it make sense to downgrade these admirable results and diminish the quality of life and the investments in homes and public places, especially when the demand need that has been proposed by PSE is highly suspect?

For these main reasons I urge those officials responsible for the evaluation of the Energize Eastside Project to reject the building of the proposed energy infrastructure and turn to the more sensible Alternative 2 – Integrated Resource Approach-outlined in the DEIS, pp2-32 to 2-49.

Furthermore, I urge the current EIS Step 1 Review to reach a conclusion and remand the final findings to the Bellevue City Council for review and a decision about proceeding to step 2.

W. Robert Moore

4707 135th Place Bellevue, WA 98006

Tel: 425-747-1388

Email: bmooreii@comcast.net

Date: Tue, 1 Mar 2016 23:11:35 -0800

Subject: Energize Eastside DEIS Public Comments: Cite Specific Federal Reliability Standards

PSE Says: Our hands are tied – we must meet Federal Reliability Standards.

Citizens Say: If Energize Eastside is so clearly needed, please cite the specific Federal regulations that compel building Energize Eastside. It should be simple to produce the federally mandated regulations.

Sadly, PSE does not cite specific mandatory Federal Reliability Standards to support the need for Energize Eastside.

PSE says: The Lauckhart-Schiffman Study raises red flags because it did not mention federally mandated standards which became more stringent in 2007.

Citizens Say: Quote the 2007 federally mandated standards - Chapter and Verse - that require PSE to supply 1,500MW of power to Canada during peak load events? Where is the federally mandated standard that says to reduce local west side gas generation by turning off emergency generation plants during peak load events? Where specifically are those requirements mandated federally?

Our region's electricity reliability and efficiency planning is performed by an organization called **ColumbiaGrid.** Here's what the ***ColumbiaGrid 2013 System Assessment Report*** says:

*"…The Northwest to British Columbia transfer was increased to 1500MW and the West of Cascades North transfer was increased to near its limit (10,200 MW) by reducing local west side gas generation. This case is being studied **for information purposes** and **mitigation is not required** as it **goes beyond what is required in the NERC Reliability Standards."***

https://www.columbiagrid.org/client/pdfs/2013SAforweb(7.1.13)FINAL.pdf (2017-18HW2, pg 12, PDF pg 17 of 92)

So, ColumbiaGrid conducted an **informational study** which exported 1,500MW to Canada and turned off local generation plants. These are precisely the same assumptions PSE is using to justify the need for Energize Eastside in PSE's***Eastside***

Needs Assessment Report. This was a hypothetical situation – "***for information purposes". "Mitigation is not required." "It goes beyond what is required in the NERC Reliability Standards."***

Note: PSE does not dispute the facts presented in the independent Lauckhart-Schiffman Study.

Note: PSE has not cited specific mandatory Federal Reliability Standards.

And **ColumbiaGrid** asserts:

- N**o Federal regulation violation** if 1,500MW is NOT sent to Canada during peak load events
- **No Federal regulation violation** if all Puget Sound gas-fired emergency generation plants are turned ON during peak load events
- **No Federal regulation violation** if heavy winter emergency loading on a transformer exceeds the **summer** normal rating of that transformer. **Winter transformer ratings** are to be used when assessing **winter peak loads**. NOTE: PSE mistakenly used SUMMER transformer ratings in their load flow studies, when this region experiences WINTER peak loads.

The ***ColumbiaGrid 2013 System Assessment*** Report undeniably contradicts PSE's key assumptions for building Energize Eastside as stated in PSE's ***Eastside Needs Assessment Report***.

http://energizeeastside.com/Media/Default/Library/Reports/Eastside_Needs_Assessment_Final_Draft_10-31-2013v2REDACTEDR1.pdf

City of Bellevue, please RE-START a transparent process to determine the Eastside's future electricity needs. Please analyze and assess how to make measureable, meaningful improvements to the electricity grid for a fraction of the cost of Energize Eastside. Better alternatives have been identified that promote smart, sustainable growth and are more cost-effective, more scalable, more reliable, more energy-efficient, and less damaging to the environment. The Programmatic DEIS must include those alternatives.

City Council, please require the City of Bellevue to issue a Final EIS at the end of the Phase 1 "Programmatic" EIS. Issue a Final Phase 1 EIS. Submit the Phase 1 EIS to a

Hearing Examiner for review/approval. Then, and only then, proceed to a Phase 2 "Project" EIS if, and only if, the proposed Energize Eastside project is found necessary.

Sincerely,

Russell Borgmann

2100 120th Place SE

Bellevue WA 98005

rborgmann@hotmail.com

--------- Forwarded message ----------

From: Russell Borgmann <rborgmann@hotmail.com>

To: <info@energizeeastsideeis.org>

Cc: <rborgmann@hotmail.com>, <jstokes@bellevuewa.gov>, <jchelminiak@bellevuewa.gov>, <j.robertson@bellevuewa.gov>, <lrobinson@bellevuewa.gov>, <clee@bellevuewa.gov>, <krwallace@bellevuewa.gov>, <vslatter@bellevuewa.gov>, <chelland@bellevuewa.gov>, <bmiyake@bellevuewa.gov>, <hbedwell@bellevuewa.gov>, <kberens@bellevuewa.gov>, <rkouchi@utc.wa.gov>, <arendahl@utc.wa.gov>, <simon@atg.wa.gov>, <eis@cense.org>

Date: Tue, 23 Feb 2016 09:40:48 -0800

Subject: Energize Eastside DEIS Public Comments: Comparison of Annual Growth Rates

As I understand the EIS process, the public is permitted to comment on:

- EIS Elements (per WAC 197-11-444)
- Alternatives
- Process

As part of the public record for the Energize Eastside project, I submit the following questions and information regarding the DEIS Alternatives. The DEIS appears to use inaccurate growth rates that limit evaluation of viable alternatives.

Northwest Power and Conservation Council	0.4%
Seattle City Light	**0.5%**
Energy Information Administration	0.6% - 0.9%
Puget Sound Regional Council	1.2%
Sound Transit East Link Expansion	33% by 2040 = 1.3% per year
Puget Sound Energy	**2.4%**

http://www.seattle.gov/light/news/issues/irp/docs/SeattleCityLight2014_IRPUpdateandProgressReport.pdf **(pg 12)**

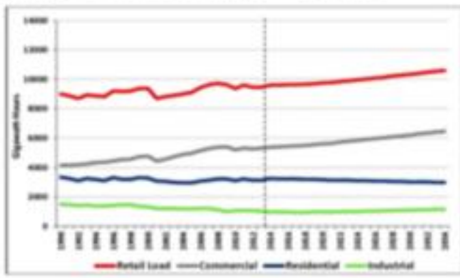
https://www.nwcouncil.org/news/press-releases/2016-02-10_7th_plan_adopted/

http://www.eia.gov/todayinenergy/detail.cfm?id=10491

http://www.seattletimes.com/business/energy-of-downtown-seattle-grows-ever-stronger/

Is the eastside really growing almost 5 TIMES as fast as Seattle? NO. Much of Bellevue's growth is energy-efficient new construction. Seattle has a higher number of older, less efficient buildings still in need of energy-efficient retrofitting, in addition to extensive new growth. Seattle's high-density in-fill and South Lake Union expansion are significant, yet Seattle City Light's growth forecast is closely aligned with EIA estimates. It stands to reason that Seattle's growth in Peak Demand would be HIGHER than the eastside.

History and Forecast Electricity Demand by Sector



Overall demand growth is forecast to average 0.5% annually from 2014 to 2034.

http://www.seattle.gov/light/news/issues/irp/docs/SeattleCityLight2014_IRPUpdateandProgressReport.pdf

Figure 1-2. Eastside Customer Demand Forecast

Source: Gentile et al. 2015.

Energize Eastside Draft EIS, pg 1-6

Seattle City Light Growth Projections
Integrated Resource Plan, pg 12

Puget Sound Energy Growth Projections
Draft EIS, pg 1-6

The slope of the curve is important. PSE has artificially inflated growth predictions to justify Energize Eastside. When realistic growth forecasts are used (0.5% to 1.2%), the Puget Sound eastside will not experience a "deficiency in transmission capacity" for decades. PSE has not provided independent evidence or justification for using a growth rate of 2.4%. Instead PSE has provided "internal forecasting conducted by PSE", national demographic data "with adjustments for PSE's service territory", and "**PSE has projected** that electrical demand will grow at an annual rate of 2.4 percent." (DEIS pgs 1-5, 1-6). Instead of forecasting an emergency in 2018, the Puget Sound eastside has time to plan and implement 21st century solutions to be ready by 2035 to 2040 when multiple independent data sources indicate a potential for transmission deficiency.

As recently as February 10, 2016, The Northwest Power and Conservation Council stated, *"By maximizing cost-effective energy efficiency, the plan projects that the region's electricity loads can be maintained at the current level of about 20,000 average megawatts, sustaining a 20-year trend of low load growth. Since 1995, annual energy loads grew at an average rate of **only 0.40 percent**, thanks to the region's investment in efficiency."*

https://www.nwcouncil.org/news/press-releases/2016-02-10_7th_plan_adopted/

PSE's false advertising inaccurately claims that infrastructure has not been updated in 50 years. In the past 50 years, **PSE has built 3 additional north-south high voltage transmission lines**, increasing the eastside's capacity from 2 lines to 5 lines. Public records searches with the City of Bellevue show that 3 of the 5 transmission lines running north-south through Bellevue were built over time during the last 30 years, at least one as recently as 1997.

Block Loads. PSE states that their growth rate forecast accounts for "expected 'block load' growth that PSE is aware will be coming in the next 10 years." (DEIS pg 1-6) Block loads are energy demands from PSE's largest customers. If there are large customers driving block load demand, the DEIS should clearly identify the sources of the forecast block load demands. Seattle City Light is subject to the same block load growth (Amazon, Boeing, Expedia (future), Expeditors International, F5 Networks, Fred Hutchinson, Pike Place Market (tourism & cruise ships), Port of Seattle, Russell Investments, Starbucks, UW, Vulcan, Weyerhauser (future), Zillow - to name a few), yet SCL has found a way to manage block loads in a way that forecasts electricity demand growth of 0.5% annually.

City Planners know that an annualized growth rate of 2.4% is unsustainable. Other critical city infrastructure (water, transportation, etc.) would strain to the point of failure before the region experiences an electricity transmission capacity deficiency. It's time for officials overseeing approval of this project to ask critical questions and carefully examine fundamental assumptions underlying Energize Eastside.

The DEIS appears to skim the surface of several important topics: expected increase in reliability, cost/benefit analyses of alternatives, independent analysis of need, cost allocation, and effects of Demand Side Resources, to name a few. Are we merely going through the motions, or are we really critically examining how to meet the future electricity needs of the eastside?

The City of Bellevue has a fiduciary duty to its citizens to explore all viable alternatives for reliable, affordable electricity. The Programmatic EIS does not adequately analyze the annualized growth rate for the region which is limiting evaluation of viable alternatives. Better alternatives have been identified that promote smart, sustainable growth and are more cost-effective, more reliable, more energy-efficient, and less damaging to the environment. The Programmatic DEIS must include those alternatives.

City of Bellevue, please RE-START a transparent process to determine the Eastside's future electricity needs.

Sincerely,

Russell Borgmann

2100 120th Place SE

Bellevue, WA 98005

rborgmann@hotmail.com

From: Russell Borgmann

Sent: Friday, March 11, 2016 9:11 AM

To: info@energizeeastsideEIS.org

Cc: rborgmann@hotmail.com, rmurray@soundpublishing.com, chelland@bellevuewa.gov, bmiyake@bellevuewa.gov, jstokes@bellevuewa.gov

Per the SEPA Handbook (pg 57, Section 3.3.5) **a cost/benefit analysis** may be included in the EIS if the lead agency (Bellevue) determines this information would be helpful in evaluating the proposal.

Where is a Cost/Benefit Analysis similar to this study performed in 2014 (see URL below)? In 2014, a study was conducted to compare the impact of electricity prices on economic growth, as measured by Gross State Product (GSP). ***"Two important conclusions emerge. First, GSP is very sensitive to changes in electric prices over time. Second, it is clear the correlation between high electric prices and lower or negative economic growth is statistically significant."***

http://www.insidesources.com/high-electric-prices-hurt-economic-growth/

Simple elasticity of GDP Growth with Respect to Electricity Prices

US	15.78	-7.23 * LOG(US Price)
se	(2.25)	(1.29)
t	(7.00)	(-5.57)
DELAWARE	9.99	-3.76 * LOG(DE Price)
se	(4.28)	(2.25)
t	(2.34)	(-1.67)
MARYLAND	10.08	-3.66 * LOG(MD Price)
se	(1.51)	(0.79)
t	(6.62)	(-4.62)
NEW JERSEY	15.88	-6.10 * LOG(NJ Price)
se	(5.93)	(2.63)
t	(2.67)	(2.32)
PENNSYLVANIA	11.25	-4.85 * LOG(PA Price)
se	(3.08)	(1.66)
t	(3.66)	(-2.91)

Source: BEA and US Energy Information Administration
se = standard error t = value for student's "t" test

Why is no such analysis found in the DEIS? One would expect the Phase 1 "Programmatic" EIS to contain a similar analysis of how high electricity prices might suppress regional economic activity, business growth, and business development on the eastside and greater Puget Sound.

PSE customers already pay some of the highest electricity rates in WA State. PSE's proposed Energize Eastside project will result in higher electricity rates for ALL business and residential customers.

What are PSE customers getting for the money? One would also expect the DEIS to include a numerical analysis of the expected increase in reliability vs. the relative cost of each alternative. Why is there no chart in the DEIS similar to this?

Alternative	Environmental Impact	Calculated Increase in Reliability	Estimated Cost to Customers
1 Energize Eastside	Greatest land use and housing impacts (DEIS chapter 10-1)	0.2%	Approx. $1 billion over 40yrs
2 Integrated Resource Approach	Fewest land use and housing impacts (DEIS chapter 10-1)	Incrementally increases based on need	Incrementally implemented depending on demand
3 New 115kV Lines & Transformers		?	?

Bellevue's reliability is more than 3 TIMES BETTER than the WUTC goals.

	Frequency of Outages Per Customer	Duration of Outage
Bellevue	0.44	66 minutes
WUTC Goal	1.3	320 minutes

Bellevue's electricity reliability was reviewed in 2012. "The overall system in Bellevue is reliable...reliability in Bellevue measured 0.44 (frequency of outages per customer) and 66 minutes (length of outage)...Bellevue has significantly BETTER reliability performance than PSE's overall system reliability for its total service area." (pgs 1, 14 EXPONENT Report, 2012). PSE has repeated stated that Energize Eastside is a "LOCAL" project that will benefit Bellevue because "…the huge amounts of power Downtown Bellevue sucks up is unsustainable…" (Bellevue Reporter Feb 26, 2016). PSE's most recent advertising claims, "Is the [Energize Eastside] project **needed to address reliability** of the electric grid on the Eastside? Yes". **If Bellevue's reliability is already more than 3 TIMES better than the WUTC goals, what are customers getting for the money?**

The high price of Energize Eastside will ultimately LIMIT growth as businesses and families re-locate to other regions to live and expand due to high energy costs. Energize Eastside is a losing outcome for all of our communities, the Puget Sound eastside, and Washington as a whole.

Please analyze and assess how to make measureable, meaningful improvements to the electricity grid for a fraction of the cost. Better alternatives have been identified that promote smart, sustainable growth and are more cost-effective, more scalable, more reliable, more energy-efficient, and less damaging to the environment. **The Programmatic DEIS must include those alternatives.**

Until the DEIS can accurately assess the advantages and disadvantages of this proposed project, the City of Bellevue must choose the NO ACTION Alternative.

Sincerely,

Russell Borgmann

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Bellevue, WA 98005

rborgmann@hotmail.com

Mike Abel
4401 138th Ave SE
Bellevue, WA 98006

425.643.9626
Mike.abel@comcast.net

I would like to submit for the record these comments regarding the Alternatives proposed in the Draft Environmental Impact Statement. I am primarily concerned with Alternative 1, Option A which is the course of action initially pursued by Puget Sound Energy.

Environment – The proposed route for the Energize Eastside project includes many environmentally sensitive areas. Impact due to construction Activity as well as long term destruction of valuable wildlife and vegetative resources is inevitable. Chapter 11.6.3.5.1 of the DEIS concedes that as many as 327 acres of land may need to be cleared of vegetation should Alternative 1 option A be chosen. This is simply not acceptable.

Safety – Alternative 1 Option A would require 18 miles of new construction much of which would be built on top of the existing Olympic Gas Pipeline. The DEIS minimizes the risk to public safety that will be generated. PSE has in the past expressed little or no concern regarding this aspect of the project despite the fact that examples exist of prior serious incidents involving leaks and explosions due to construction activity near gas pipelines. Additionally, there are examples in the academic literature warning of the risks associated with co-location of flammable liquid pipelines and electrical power transmission infrastructure. Chapters 16.3.7, 16.6.1.3 16.6.3.11 16.6.4.3 and 5.5.3.1.6 of the DEIs address some of these issues in a superficial manner however it would be prudent to conduct additional study on these topics with the aim of better quantifying the risks associated with Alternative 1 option A.

Neighborhood Character – Alternative 1 option A would require tall power transmission poles which are not consistent with the City of Bellevue comprehensive plan. Additionally, in some locations utility easements would need to be widened severely impacting the neighborhoods through which the project would traverse. This would result in loss of property and in some instances complete loss of dwelling units.

Project Need - Need for the Energize Eastside project, as proposed by PSE appears to be based on a flawed analysis. As illustrated by the independent Laukhard-Schiffman Study (2/18/2016) PSE’s in-house produced load flow study appears to have been conducted using assumptions designed to generate a report supporting the need for the project. As a result, I simply cannot trust PSE’s stated motivations and intentions for promoting the project.

Because of these concerns I feel strongly that the only prudent course of action is to stop the project until such time that the need and benefit of the project can be re-evaluated.

Mike Abel

---------- Forwarded message ----------

From: denisemickelson <denisemickelson@comcast.net>

To: <eis@cense.org>

Cc: <j.robertson@bellevuewa.gov>, <clee@bellevuewa.gov>

Date: Sun, 21 Feb 2016 15:27:39 -0800

Subject: Energize Eastside Project

Here is a copy of my remarks that I sent to PSE's Energize Eastside Project online comments:

I am responding to the Draft EIS for the Energize Eastside Project.

As a resident of Bellevue for 55 years, I am very disappointed in the Alternatives that are presented to our Somerset neighborhood for the Energize Eastside Project by Puget Sound Energy.

The Olympic Pipeline runs in front of our home and the existing 115kV transmission lines currently run through our backyard. We are squeezed by these two utilities.

My main concern besides disrupting the character of our neighborhood is that the proposed high voltage transmission lines are located too close to the Olympic Pipeline and would increase the risk of a catastrophic explosion. We have jokingly asked ourselves, would we run up the hill (towards the downed lines) or down the hill (towards the burning fuel) should a catastrophe indeed occur.

Having attended the meetings both at the Bellevue City Hall to learn the details of the Energize Eastside Project as well as the meetings offered by CENSE, I am convinced that the project has been mismanaged and that the No Action Alternative 4 should be the choice as a short-term solution.

Sincerely,

Denise Mickelson

Somerset Resident

4518 Somerset Dr. SE

Bellevue, WA

Name: Robert Jones Address: 8434 128 Ave SE Newcastle WA 98056

Summary: **Section 1.3** says that determining the need for a project is part of defining the project.. PSE claims there is an immediate need. No state or Federal agency is concerned with this 18 mile long local project. Only the cities involved have oversight over Energize Eastside. PSE used industry standard methods to create its Eastside Needs Assessment but the data was based on implausible assumptions. The Needs Assessment produced by Lauckhart and Schiffman using the same method and database but with logical assumptions indicates there is no immediate need for the transmission line. So the best alternative for Energize Eastside is the no action alternative.

According section 1.3 of the draft Environmental Impact statement

> "it is the responsibility of the lead agency to make certain that a proposal that is the subject of an environmental review is properly defined as outlined in WAC 197-11-060 (3)(a)".
> And "the process of defining the proposal includes an objective understanding of the <u>need</u> for the project".

So it was perfectly logical for the EIS consultant team to engage Stantec to represent them to review internal utility planning and operations information used by PSE in developing the Energize Eastside Project proposal. Stantec in a memorandum confirmed that PSE's Eastside Needs Assessment <u>was conducted in accordance with industry standards for utility planning</u>.

Stantec simply <u>validated the method used by PSE</u> without questioning the assumptions made in PSE's Needs Assessment. No one is questioning the method used by PSE to assess the need for a new transmission line. The method consists of entering data into a computer simulation program for load flow modeling then looking at the results. The results however depend on the data entered. And the data used by the computer depend on the assumptions of those running the program.

To illustrate the effect of different assumptions, Richard Lauckhart and Roger Schiffman acquired a license to run the industry standard simulation software known as "GE PSLF"1. They ran the program with the same database used by PSE but with different assumptions. The result indicates that there is no immediate need for a new larger transmission line.

PSE Assumptions Changed by Lauckhart and Schiffman

PSE assumed that the amount of electricity sent to Canada would triple from 500 MW to 1500 MW while at peak demand locally.

Lauckhart and Schiffman assumed that during a local peak power load in below freezing weather the power sent to Canada would be reduced from 500 MW to 0 MW during peak time.

PSE assumed that the power generated by local generation plants would be reduced from 1,654 MW to 259 MW during the 10 winter days of peak load.

Lauckhart and Schiffman assumed that only 2 transformers were totally out of service in accordance with federal reliability standard N-1-1.

PSE used the WECC "summer normal" reduced transformer capacity ratings.

A transformer produces heat which it must dissipate. During summer, radiation is more difficult so transformer ratings are reduced for summer use. Excess heat breaks down the insulation in a transformer causing them to fail.

Lauckhart and Schiffman assumed that the below 23 degrees F temperature occurred in the winter and so used the higher winter emergency capacity ratings of the transformers instead of the summer ratings.

The unlikely assumptions of PSE that determined what data to enter into the computer caused the program to produce the need for a larger transmission line.

The more reasonable assumptions of Lauckhart and Schiffman indicate that there is no immediate need for a larger transmission line.

Section 1.3 also states that "This EIS will not be used to reject or validate the need for the proposal." Then who is responsible for establishing the need. Only the cities are overseeing the PSE Energize Eastside project because it is classified as a local project.

The Federal Energy Regulatory Commission, FERC, regulates interstate transmission of electricity.

So the FERC has no jurisdiction and is not interested in the project.

The North American Electric Reliability Corporation, NERC, is concerned with the reliability of the North American bulk power system so NERC does not have jurisdiction over the project.

The Western Electric Coordinating Council, WECC, is the western region of the FERC which deals with the bulk power systems so WECC does not have jurisdiction over the project

The Washington Utilities and Transportation Commission, WUTC, regulates the rates and services of utility companies to ensure that services are fairly priced, available, reliable and safe and so has no jurisdiction over the need for, planning of, or construction of transmission lines in general and this project in particular.

Validating or rejecting the project is necessary in deciding which alternative best meets the purpose of the EIS. No action is a valid alternative to adding 18 miles of transmission line through 4 cities. If there is no need for additional power then no action is the best alternative.

Section 1.3 of the draft EIS states "the EIS is intended to identify alternatives that could attain or approximate PSE's objectives at a lower environmental cost and disclose potential significant adverse environmental impacts associated with all alternatives identified."

What was Puget Sound Energy's goal when they set up a very unlikely scenario in order to justify Energize Eastside? PSE is allowed to make 10% above the cost of the project so the more it costs the more they can legally charge its customers. The only way for PSE to meet this goal is by the EIS committee's allowing Energize Eastside to be completed as PSE wants it. I don't think that is what the EIS committee wants to do.

Why are we wasting time and money on Puget Sound Energy's proposal when it is not needed, not safe, a blight on the communities involved, and its only purpose is to make money for its investors?

Robert Jones

Frank and Joan Cohee

12109 SE 23rd Street, Bellevue WA 98005

As fifty year residents of the Woodridge neighborhood in Bellevue, we are submitting comments on the Draft Environmental Impact Statement for the Energize Eastside Project. We have studied the reports, attended meetings, joined CENSE and are advocating the No Action Alternative and, as a second choice, Alternative 2, the Integrated Resource Approach, for two reasons.

Reason #1 Pipeline safety concerns.

PSE's easement for high voltage power lines lies concurrent with the Olympic Pipe Line Company's petroleum pipeline on the Eastside. The pipelines are considered hazardous liquid pipelines and, if damaged, could cause explosions or fires. These pipelines run near residential neighborhood and schools. These pipelines could be damaged by corrosion from proximity to electromagnetic interference from high voltage power lines. These pipelines could also be damaged in the process of siting and construction of towers.

In addition, the location of high voltage power lines and petroleum pipelines in close proximity pose risks during seismic events and lightning strikes.

Reason #2 Costs of Energize Eastside

What will be the total cost (direct and indirect) of Energize Eastside Alternative 1? We have seen several different estimates of the direct financial costs of the project, each higher than the prior one. In addition, the indirect costs involved with losing 8000 trees or disrupting family homes and property taken by condemnation have not been fully evaluated and considered.

When considering conflicting assumptions regarding customer utility demands this project should be placed on hold and alternative technologies fully studied. PSE's forecast of energy problems as early as 2018 conflicts with the Lauckhart-Schiffman Load Flow Study that shows 'customer demand won't approach current system capacity until 2058.' Please look at all the evidence before approving the Draft Environmental Impact Statement for the unsafe, costly, and disruptive Energize Eastside Project

Frank and Joan Cohee

12109 SE 23rd Street, Bellevue WA 98005

March 1, 2016
Comments on Energize Eastside EIS
To: Heidi Bedwell, Program Manager
From: Lindy Bruce

I am Lindy Bruce, 13624 SE 18th St., Bellevue 98005 speaking tonight on behalf of the Sunset Community Assn. , which has six neighborhoods that border PSE's right-of-way in central Bellevue. I was an alternate to PSE's CAG and currently serve on the board of CENSE.

I wholeheartedly endorse the comments and recommendations of CENSE president, Don Marsh. While PSE consistently disallowed the CAG and the DEIS from considering need, we now have studies and comments suggesting fundamental questions of need, reliability and appropriate solutions have not been adequately addressed.

More specifically, I would like you to address some of the construction issues that will affect our neighborhoods if PSE's preferred Alternative 1A were to proceed. Here are a few facts for Segment E which runs through our neighborhoods:

1. The City of Bellevue Critical Hazards Map shows the ROW from SE 24th St. north to SE 2nd St as a Very Severe Soil Erosion Hazard. We already know that the neighborhoods lowest down the hill deal with underground streams that percolate down College Hill towards Richards Creek. These streams produced huge quantities of mud when Parkland Estates was built a few years ago.

2. The ROW is already occupied by Olympic Pipeline's 20" and 16" pipes that carry millions of gallons of jet and gasoline fuels per day to Seattle and Portland airports. Olympic Pipeline is currently under a Final Order to rectify deficiencies in their corrosion control program. PSE's 230kv lines produce EMF's that accelerate corrosion. [See Dr. Frank Cheng's comments "Safety of Co-location of Electric Power Lines and Pipelines" at CENSE.org. See DEIS Ch. 16.3.7]

3. When PSE rolled out Energize Eastside, they told us that the two sets of "H" poles would be replaced by a single monopole. Much later, they admitted one set of "H" poles might be retained. Later yet, at a neighborhood meeting, PSE's expert from Power Rangers Utility Consultants told us that wherever the pipeline is in the middle of the ROW, they would need a tandem set of the tall monopoles. The pipeline is in the middle of much of the ROW. BPA recommends poles should be at least 50' from pipelines

4. During construction, PSE must retain both sets of "H" poles to continue distributing electricity in Bellevue. So we will have 4 65-foot wooden poles, 2 85-135-foot steel poles and excavating equipment building cement support bases for the poles. All this in an area with an aging, corroding pipeline and sodden soils, as well as homes

and our neighborhood park. [See DEIS Ch. 16.6.1.3 See also DEIS Ch. 5.5.3.1.6 See also DEIS Ch. 11.6.3.5.3]. We don't yet know where they will stage all the materials and vehicles, but there's limited street access to the ROW.

5. For safety reasons, some parts of the entire ROW will have to be expanded by as much as 50 feet. Some homeowners have already been advised that their houses may be condemned or parts of their property will have to be added to the ROW. Uses on property near the 230kv lines can be restricted – again, for safety reasons. [See DEIS Ch. 10.7.3.1.2 See also Ch. 11.6.3.5.1]

6. The cause of the 1999 Olympic Pipeline explosion in Bellingham was traced to a 1 mm chip out of the pipe that occurred when a maintenance truck hit the pipe 5 years before the explosion. Our corridor will be crowded with poles, excavating machinery, construction equipment and pipelines. How long will we have to wait before we feel safe? [The Bellingham Herald, June 7, 2009]

Energize Eastside is a massive infrastructure project with enormous impacts for its 18-mile length. Even good intentions, careful engineering and adherence to code haven't prevented Brightwater, Bertha or even Sound Transit's tunnel digger, Pamela, from causing soil subsidence, gaping sinkholes and huge delays.

Are we really ready for those possibilities when our new information suggests that Alternative 2 can provide electrical reliability for less cost, has almost no adverse impacts on land use, housing, tree canopy, parks and schools, and has no new safety risks? [See DEIS Ch. 10.7.1].

I would like to see a specific study of all construction-related issues and any precedents for overburdening the ROW in a dense urban corridor as Alternative 1A would most certainly do.

Thank you.

Comments submitted by Richard A. Kaner, MD. Member of CENSE.

6025 Hazelwood Lane SE

Bellevue, WA 98006

thekaners@comcast.net

Chapter 1.3 of the DEIS discusses PSE determining “there is a need to construct a new 230 kV bulk electrical transmission line” This is not an accepted fact despite PSE’s assertions that the EIS is not to assess need and that need has been unequivocally established. The Lauckhart-Schiffman load-flow study dated February 18, 2016 shows multiple flaws in PSE’s assumptions:

1) PSE submitted a rate of growth in energy demand of 0.5%/year to the federal agency Western Electricity Coordinating council (WECC). This is similar to that of the Seattle submission for their rapid growth in apartments and South Lake Union. For the EE project they submitted 2.4%/year which is closer to the population growth projections; NOT energy demand growth.
2) They used **summer normal** ratings for their existing transformers which limits load to 700mW. If **winter emergency** ratings are used (as they should be for this **WINTER EMERGENCY**) the loads increase 30% to 930mW.
3) PSE has turned **OFF** all 6 of their existing power plant generators during this **WINTER EMERGENCY**.
4) PSE has factored in sending 1,500 mW of power North to Canada during this **WINTER EMERGENCY** .

If the proper data is used, there is **NO SHORTAGE** until 2058. **40 years** further down the road!

In short, a project of this size is not needed and the NO BUILD OPTION (Alternative 4) actually becomes the most logical if the Eastside needs are the driving force. The fact, however, is that the Eastside needs are not the driving force; transfer of electricity to and from Canada and the profit to be made from that transfer are amongst the main reasons for Energize Eastside(EE). This is outlined in the 2013 Annual Report from PSE to WECC and the 2013 memo from ColumbiaGrid to WECC that I submitted 3/1/16 for the record. The latter states that the purpose of EE is to “improve South-to-North transfer capability between the Northwest and British Columbia.”

ALTERNATIVES:

In reviewing the alternatives proposed, the only alternative not preferable to Energize Eastside (1-A) is alternative 3 which would add a spider web of new wires. Use of the Seattle City Light (SCL) corridor (1-

B) is preferable since it already exists and would have little additional impact on corridor size, trees and property values. We have been told that this is off limits since SCL will not grant access. Options to underground and submerge (1-C & 1-D) are preferable options that are safer with less impact on property and environment. We have been told flat-out that both of these options are cost prohibitive.

Therefore, if the NO BUILD option is dismissed and the project moves forward, I am in support of alternative 2 that is referenced in chapter 2.3.3. PSE has claimed in the DEIS that this option is risky and undesirable. In fact, the presentation of this alternative was not created nor evaluated by analysts familiar with the technologies and policies involved. I feel that an evaluation of the data shows that it is derived from studies that are now outdated with the rapid changes in technologies. As an example, the article on Forbes.com January 13, 2015 titled "Battery Revolution: A Technology Disruption, Economics and Grid Level Application Discussion with EOS Energy Storeage." highlights the improvements in capacity and drop in prices seen with battery technology. Throughout this document, verbiage is used to magnify the possible impact of Alternative 2 and minimize the impact of Alternative 1-A.

PSE has been disingenuous raising the estimate of winter peak load from 123 mW in April 2015 to 205 mW mentioned in a recent memo without documentation of how they arrive at their figures. Energize Eastside 1-A certainly has capacity and the greater the shortfall the less desirable other options become.

Alternative 2 allows us to add improvements and capacity to the existing grid as needed. It won't involve tearing down 8,000 mature trees, disrupting the existing pipeline, invoking Eminent Domain with its significant associated costs and it avoids blighting the character of our neighborhoods. Since it doesn't rely on a single line, Alternative 2 is a more reliable alternative. The DEIS seems to minimize the benefits of Alternative 2 and minimize the adverse impacts of Alternative 1-A. We should be investing in 21^{st} century technology to create a better energy future for our children and preserve our "city in a park."

SAFETY:

We live in a seismic zone and the fault line is the I-90 corridor. Chapter 8.5.1.3 talks only about earthquakes during construction. Why is there no discussion of risk after construction?

Dr. Frank Cheng's study on "Safety of Collocation of Electrical Power Lines and Pipelines" (on CENSE.org) discusses the arcing that can occur. We have citizens in the Bridle Trails Community who have dealt with this involving lower voltage lines after windstorms. Furthermore, his report discusses the effects of EMF accelerating metal corrosion.

The proposed route of Alt 1-A does not meet industry standards and federal guidelines for separation of these 2 entities-power poles and gas lines. Any type of disruption from corrosion, earthquake or terrorist action is a recipe for disaster. Have we already forgotten the lessons of the 1999 Bellingham pipeline disaster?

EMF effects on humans are hard to prove and controversial. There are multiple articles in the medical and general literature discussing EMF. While it is difficult to get a study population large enough to show statistical significance, many authorities agree that EMF proximity is associated with increased numbers of bone marrow cancers in growing children and brain cancer in adults. If EMF accelerates metal corrosion, it is hard to imagine no impact upon the human body. The DEIS fails to adequately discuss this controversy. Certainly, regardless of your position, this should be part of an environmental assessment. Beyond people's home, these lines will run in close proximity to at least 2 schools.

The discussion of Alternative 1-A again minimizes these risks which are nearly non-existent in Alternative 2.

ENVIRONMENT:

Chapter 6.6.3.1.1 describes impacts on widening the corridor in Alternative 1-A. I cannot overemphasize the impact of losing 8,000 trees (roughly 500 trees/mile) and clear-cutting 327 acres of vegetation (11.6.3.5.1). Whether you look at impact on carbon footprint, animal habitat, noise buffering, water and soil stabilization or the destruction of neighborhood character and addition of visual blight, "significant" just doesn't do justice to the devastating impact and permanent damage to Eastside neighborhoods.

Alternative 2 avoids this horrific impact by utilizing and upgrading existing infrastructure.

NEIGHBORHOODS:

Bellevue is touted as a "City in a Park." The surrounding Eastside cities of Redmond, Kirkland, Newcastle and Renton take equal pride in their lush greenery and surrounding beauty. Chapter 10.7.3.1.2 under-emphasizes the need to invoke Eminent domain to widen the corridor. In addition to removing these homes from the tax base, a whole new group of homes will now border the corridor and suffer depreciated values. The DEIS is deficient in that it minimizes the true impact of Alternative 1-A on lost revenues to the cities and lost value to the Eastside neighborhoods.

In 10.7.1.4, the DEIS uses 1 study by The Electric Power Research Institute (EPRI). This study was prepared by the power industry, which has a vested interest in property not being devalued by transmission lines, and does not use recognized real estate experts. Using that study, the DEIS declares that impacts on values are "inconclusive" even while they cite 10 aspects that can have impact on values. Over half are negative and apply to the situation at hand. In their discussion, they acknowledge that an ~6% depreciation could be expected and further quote their sources as stating that *"Higher-end properties are more likely to experience a reduction in selling price than lower end properties."* The Eastside is by any measure considered higher-end. How is that inconclusive and how hard is it to extract real estate data on home values in our area when a new corridor is created. This is, in fact, the situation when by Eminent Domain the corridor is widened, existing homes are destroyed and new homes become adjacent to the corridor when before they were buffered from it. The DEIS fails to address this issue and trivializes a major issue impacting most people's largest investment.

Chapter 11.6.3.5.3 discusses pole height going from the current 65 feet to the proposed 85-135 feet. This will impact the entire Eastside. These poles exceed the height of the tree canopy in many places and blight the views of many homes at varying heights including high-rise condos being constructed in downtown Bellevue. People on East Mercer Island will be seeing these poles and wires and are already expressing concern. This amounts to a much greater impact than the 100 lots/mile referenced in the chapter.

While the impact of Alternative 1-A is consistently downplayed, 10.7.4.2 acknowledges the negligible land use impact of Alternative 2. If EE is to be built, Alternative 2 is the only option that consistently has minimal impact while allowing for growth in load to be met with augmented supply and flow using smart grid technologies, demand-side management and distributed energy resources.

Richard A. Kaner, MD. Member of CENSE.

March 2016

RE: Proposed PSE Energize Eastside Project

The Proposed PSE project which is now in Phase 1 of the DEIS process is of great concern to me and all citizens who live on the Eastside. In addition to having enormous environmental impact on the entire region, it is increasingly being disproven as a necessary project. Touted by PSE - an off-shore consortium - as critical to future needs, it is designed to enhance its investment and ensure emergency power to Canada at the expense of rate-payers throughout our region. Better methods to meet future needs are available and will continue to be developed before our Eastside requirements become crucial.

1. Of primary significance to the current EIS process, **the ENVIRONMENTAL IMPACT is enormous**. Over the 18 mile length of the plan, thousands of trees and numerous homes must be destroyed to make way for the required easement for 240kV wires on up to 135 foot poles. This is to say nothing of the archaic, ugly towers required to complete the installation. Far better ways exist to meet future needs than to revert to this old-fashioned method of power transmission. New, proven ways are happening -- new technologies are coming on line, utility efficiencies are developing, to say nothing of people and businesses reducing their consumption voluntarily and/or through pricing schedules.

2. It is **unthinkable to ignore the public SAFETY issues** around constructing these heavy-duty transmission wires over an existing, aging pipeline carrying high octane jet fuel under great pressure. In this active earthquake zone so much could happen to damage both the fuel line and the transmission towers/lines. It's hard enough to think about the existing situation, let alone consider having the new lines involved with the Olympic Pipeline in a seismic event. We have had ample evidence of the unthinkable happening in similar situations to not be extremely concerned about the possibility here and do everything we can to prevent it.

3. Finally, **the NEED is not there** for the foreseeable future. PSE has created a scenario to enhance their investment within the window in which they must divest, thereby increasing profits for Australian and Canadian investors. Who pays for this $215 million dollar project? We the rate-payers will, while they continue to receive their guaranteed 9.84% ROI. PSE selected and edited data to enhance their request. It refused to allow a citizen's panel offer solutions or comments that were outside PSE's preferred scenario. (A surprising number of citizens on that review panel refused to sign the final report because it was shaped by PSE and did not allow a truly open process.) PSE has refused to acknowledge the Lauckhart-Schiffman load-flow study created by experts in energy planning – indeed Lauckhart previously was PSE's expert!

It is very important that the current DEIS review pay attention to all data and information available and come to a conclusion that truly reflects more than the self-serving rationale presented by PSE. When a recommendation is made now, it should closely reflect Alternative 2 – an option that truly considers more than 20th century thinking about how to continue power flowing to the Eastside far into the future.

Sincerely,

Margaret R. Moore
4707135th PL SE
Bellevue, WA 98006
425-747-1388

Barbara Braun
Feb 25, 2016
13609 SE 43rd Place
Bellevue WA 98006

Subject: Energize Eastside Public Hearings
Renton City Hall – 6:00 PM - 8:00 PM
1055 S Grady Way
Renton, WA 98057
Thursday, February 25

Energize Eastside Call to Action

1. The need for the project and ANY alternative is not established. The fact that the EIS ignores this is an EIS process oversight and should be re-visited. The independent "determination of need" run by Stantec did not run load flow studies and merely concluded that PSE study was conducted "according to industry standards." The load flow analysis done by Lauckhart and Schiffman calls in to question (in a big way) the need for the project. If the city of Bellevue felt like they got an unbiased assessment from Stantec, they are mistaken and the citizens know it. The cities should band together to acquire a thorough independent and auditable assessment of need. The conclusions should be audited by unbiased experts.
2. Further the assumption that we need to ship 1500MW to Canada during a temporary power shortage seems downright dishonest. If we actually experienced this scenario, we would decrease the flow to Canada temporarily and avoid the problem. This therefore eliminates the need for the project. The EIS process should clearly establish the facts about what we need to ship to Canada and the commitments around that.
3. The EIS process should assume the Do Nothing Alterative is the right and preferred alternative and prove beyond a shadow of a doubt with facts and data all interested parties can see and verify if this is not the case.
4. Assuming there is a need for this project at all, if we pursue Alternative 1 as PSE wishes, the cost to our communities and to our environment outweigh any benefit to the communities it serves. Examples
    a. Astronomically increasing the risk of pipeline explosions and accidents
    b. Condemning of homes to erect unneeded industrial blight that will last several generations
    c. Hugh climate impact by cutting 1000s of tree and proliferating a carbon based electricity solution for the next 50-65 years.
    d. Lastly the sheer cost of the project only benefits the PSE and it's shareholders and does not provide a good ROI for the citizens.

We simply cannot afford the cost of the project – in our communities, in our country, in the world.

5. Alternative 2 – The Integrated Resource study is not scoped or assessed properly. It does not use the appropriate "need" assumptions. It does not use the latest available technologies. It does not use the latest or future cost projections. For example, we need to include advanced solutions such as the Ambri and Eos Energy Storage aimed of bringing storage costs down significantly for utilities ($150/kWh).
6. If any alternative is pursued, and frankly even if we adopt the Do Nothing Alterative, there are studies out assessing the safety of co-locating powerlines with hazardous materials pipelines. The risk we face currently, with our existing powerlines, is very high to high, using the "Criteria for Pipelines Co-Existing with Electric Power Lines" study prepared by DNV-GL, October 2015. Part of ANY PSE plan should be to permanently remove ALL powerlines in the pipeline corridor. This should be a base requirement of all the cities involved. Ordinances should be passed to insure this. Otherwise the city governments could be found negligent in their duty to protect the safety of their communities.

Barbara Braun

Barbara Braun
13609 SE 43rd Place
Bellevue WA 98006
bbraun@stratery.com
Feb 2016

1. Respected industry experts Rich Lauckhart and Roger Schiffman show the PSE needs analysis and conclusion for this project are not only flawed but likely fraudulent. This independent analysis was completed by these experts with CEII clearance and using PSE data provided by the WECC Base Cases from FERC. Their conclusion: PSE is using an impossible load scenario to try to scare residents into funding a billion-dollar project.
2. The EIS provides does not question the need to the project. The City of Bellevue and PSE say they have done all the needs analyses that are going to be done, case closed. In fact the Lauckhart/Schiffman analysis suggests that the No Acton alternative is the one to select at this time because we have no immediate need for additional power. In the future, Alternative #2 would be the alternative to pursue as new technologies become more viable and cost effective. Alternative #2 is more scalable, more reliable and more cost effective. The EIS analysis of Alternative #2 is based on outdated data and needs to be revisited by people with the right expertise, not by PSE who has every motivation to maintain status quo, antiquated solutions.
3. The Bellevue City Council, along with all the city organizations, should pause the EIS process and truly review the need for this project by either accepting the Lauckhart/Schiffman analysis or contracting for a truly independent study that includes an honest, transparent and verifiable load flow study. The Council needs to either use the services of CENSE or some other truly independent counsel to insure they get unbiased modeling and analysis. This has not happened to date. The independent studies have either not run their own load flow studies or have used the flawed (impossible scenario) assumptions provided by PSE. The Council should agree with the base case scenario and assumptions being used in any independent load flow analysis. It should also get an independent assessment of the demand forecast as the PSE demand forecast also looks to be flawed – overstated and with incorrect assumptions. PSE used forecast growth of 2.4% per year to justify the project. PSE sent WECC a forecast of only 0.5% per year. Can this discrepancy be explained? If you use PSE's own forecast to WECC, it clearly indicates the project is not needed. The Council has the authority to require a pause in the EIS and to get an independent assessment done. The Council should partner with the other cities to do this and to get them to participate. The Council should not shirk their duty on this.
4. Energize Eastside is a needless waste of ratepayer funds, to the Eastside and the environment, not the best solution for reliability or safety, is motivated to maximize investor returns.
5. PSE also states there are no issues with co-locating HVAC in a pipeline right of way. {Mark Williamson said, "You don't need to do any engineering studies. [25 feet of separation is] far enough that you can just be laissez-faire and let it go."}. CENSE investigated this and finds the logic highly suspect. In looking at "Criteria for Pipelines Co-Existing with Electric Power Lines," prepared by DNV-GL, October 2015, Energize Eastside looks to be extremely high risk. They contacted Dr. Frank Cheng, a recognized pipeline safety expert, who concluded "HVAC affects adversely the integrity and safety of buried pipelines that are collocated with electric power lines right-of-way and

that "… a comprehensive study program would be developed prior to construction of the power lines."

6. In fact, it looks as if the current power lines in this right of way are very high risk and should be removed to improve the safety of the community, especially since the City of Bellevue just signed a 10-year agreement with Olympic Pipeline.

7. The City of Bellevue should complete an independent study to dismantle the current power poles that run in the right of way and remove them from the grid altogether. I suspect that an independent study would reveal that given the collective capacity already running through the eastside, from all providers, provides more than enough power to meet future demand. The antiquated poles should be removed and no transmission lines should ever be put through that corridor. This is a basic safety need of the community. The City of Bellevue should pass a resolution to put a moratorium on construction of anything in the pipeline right of way.

8. The final version of the Seventh Power Plan from the Northwest Power and Conservation Council will be released in late February. They are concluding Energy Eastside is not needed. Why would we put our head in the sand and ignore the evidence that is all around us? This project is not needed.

9. We need to take PSE out of private sector and make it a public utility district.

10. If the City of Bellevue allows this project to proceed without question and there are accidents or even cost overruns. What will this say about City officials? Will the City be negligent? PSE will certainly be found negligent. Just think of the countless pipeline accidents. Think of Bellingham. Why are we being dismissive and irresponsible about our own safety? Does Bellevue want to be known for blatantly exposing it's citizenry to off the charts safety risks? Like Flint Michigan? Think of the highway tunneling project in Seattle. Does Bellevue want to be known for costing rate payers billions of dollars? Think about it.

11. Include Olympic Pipeline in the EIS. Make all decisions with Olympic at the table. Please include an evaluation of the safety issues of both the construction in the Olympic pipeline easement, but also the maintenance in the easement. Please do a survey of the history of human caused accidents and consequences by these 2 companies as well as similar projects around the world by all companies. https://hip.phmsa.dot.gov. Please also include weather related and seismic related accidents and dangers. Insure a truly independent assessment of both PSE and Olympic findings, calculations and recommendations. Both are huge multinational for profit identities that don't necessarily represent local community interests. Clearly both companies have a reputation for accidents and lack of proper safety measures and practices. Both companies have a history of unconcern for communities and the environment. Thank you!

12. What is the operating plan for the Olympic Pipeline during construction? How will ALL safety risks be mitigated? How will BP be included in this project? Thank you!

13. Please add to the EIS a more careful analysis of the need for the project. There has been a cursory review of prior studies by a firm called Stantec, but no new or independent analysis is done. Questions raised by CENSE about the amount of electricity sent to Canada and local generation being turned off have been ignored. Thank you!

14. I am disappointed that the EIS evaluates a number of alternatives that aren't realistic, but no indication of the viability of each option is given. For example, the EIS studies underground and submerged lines that are cost prohibitive due to state regulations. There are only two realistic alternatives: the overhead transmission line proposed by PSE, and Alternative 2, a solution using

smart technology and energy policies. There is no justification for the overhead transmission line proposed by PSE. The State has concluded that these solutions are obsolete and not needed in the next 20 years anywhere in the state. Alternative 2, as presented by CENSE president Don Marsh explained to the Bellevue City Council on Feb 1, 2016 is the right alternative.

15. Include a thorough seismic evaluation in all alternatives. The EIS provides very cursory and says everything will be better because it will be built to new standards. Does thin include a retrofit of the aging Olympic Pipeline? We will not be safer with this aging pipeline sitting next to bulk power lines. Bellevue should actually require the removal of all existing power lines in the pipeline corridor and the upgrading of the Olympic pipeline to insure the safety of its community and citizens from the massive earthquake we are going to have. Thank you!

16. Make the cutting of trees an off limits criterion for any alternative. We cannot replace the climate protection capacity of 8000 trees with new seedlings. We cannot wait 100 years for this to be restored. This is antiquated thinking. The trees should be given higher value and weighting in any analysis. Thank you!

17. We should pursue Alternative 2 by making Bellevue and the other eastside communities national leaders in energy conservation and management. We should upgrade our city codes, ordinances, building standards and zoning rules for both commercial and residential. For example, implementing LEED standards for ALL new construction. Requiring buildings to retrofit. Requiring retrofits and remodels to comply with LEED or other energy conversation and management standards. Requiring all new construction to be net zero construction. Bellevue could lead the country and the world for the most net zero energy buildings! Be leaders in innovation and creativity not installers of antiquated technology. Thank you!

18. Why has the City of Bellevue not gotten a truly independent view of the demand forecast? Will this be done? We cannot passively stand by and let PSE tell us we have already validated the demand numbers. WE HAVE NOT! The consultants retained by Bellevue DID NOT conduct an independent review of demand. They simply said PSE didn't make any math errors in their calculations. Bellevue can do better than this. Please stand up and represent your citizens as you are elected and/or employed to do. Thank you!

19. I hate to say this, but it appears Bellevue and the other municipalities are in collusion with PSE. Bellevue city representatives – elected and employed, need to be accountable to the citizens of Bellevue and represent our interests, not PSE's or any corporation's interests. The city elected and employed representatives, and their hired consultants, need to firewall themselves from these conflicts of interest. We need to be transparent in how we're doing this. We need to recuse those who receive any moneys – directly or indirectly from PSE. The citizenry needed to have an explicit review of how we are maintaining impartiality during this process. Thank you!

20. The Bellevue citizens have spent countless hours and their own money analyze this project. Please listen to them. Please engage them and other experts in helping to develop plans for alternative 2 if we cannot rely on PSE to do this for us. Thank you!

21. All EIS alternatives need to fully assess, address and mitigate carbon emission and sequestration issues. Not only should NO trees be cut for this project (i.e. we must insure NO net reduction in carbon sequestration capacity in our city), but we need to require carbon offsets for all incremental fossil fuel based power that flows through our community. We should in fact require that all new projects provide carbon offsets in "arrears" for all *existing* fossil fuel power flowing through

our community as a requirement to implement any incremental fossil fuel projects. Let's lead the nation in being a green city!

22. There have been repeated requests for unbiased evaluation of the needs and the development of alternatives by the citizens of Bellevue as well as the citizens of the other eastside communities. Consultants hired to date have not completed an independent evaluation of load demand, nor have they developed alternatives to PSE's proposal. When will this happen? When are we going to seriously review the demand and develop alternatives? Where in the process does this happen? We need to understand these issues and clearly establish plans and dates for these things.

23. We need to do a side by side comparison of all alternatives. Apples to apples. We need to actually evaluate the alternatives, which has not been done. We need to insure the evaluation of alternatives have a clearly established, transparent and complete set of criteria for evaluation including – economics, property values, climate change, environment, safety, seismic, aesthetics, etc. We need to do this at a regional, national and international level, not a PSE or local only level.

24. We need a fully transparent decision making process and timeline. We need to understand who is creating alternatives, who is evaluating them, what decisions are being made, who are the decision makers, what is the timeline for decision making, specific dates and public participation for each decision, what recourse citizens will have, etc.

25. High power overhead transmission lines have no place in residential areas. They create visual blight. They are noisy. They enable the spread of invasive species. The argument that recreational opportunities will be enhanced by powerlines is bogus. I have been all over this state and find the environmental destruction from transmission lines horrific. I don't want to ski, hike or bike near more transmission lines. The amount we already have is shameful and embarrassing.

26. Why does the Bellevue City Council want Alternative 1 as part of their legacy? To be one of the last cities in America to approve an antiquated power solution? Are the council members so influenced by PSE money that they are willing to have this on their hands?

Barbara Braun

From: Russell Borgmann [mailto:rborgmann@hotmail.com]
Sent: Thursday, March 10, 2016 9:25 AM
To: info@energizeeastsideEIS.org
Cc: rborgmann@hotmail.com; eis@cense.org
Subject: Energize Eastside DEIS Public Comments: Pipeline Safety

The recent natural gas explosion in Seattle's Greenwood neighborhood is a reminder not to take pipeline safety lightly.

The Olympic Pipeline traverses 16 miles of the proposed Energize Eastside route. This pipeline carries jet fuel, which is substantially more volatile (requires less oxygen and ignites at a lower temperature) than natural gas. In the case of the Greenwood explosion, it took PSE **OVER 5 HOURS** to locate all of the gas shutoff valves and get the gas fully shut-off to the region.

I contrast this to recent comments that Mr. Mark Williamson made to the Newcastle Planning Commission. Mr. Williamson, one of PSE's lead consultants for Energize Eastside, stated, *"You don't need to do any engineering studies. {25 feet of separation is] far enough that **you can just be laissez-faire and let it go.**"* (February 2, 2016)

I wish I could say that Mr. Williamson was kidding. Sadly, he was not. On frequent other occasions, when questioned about the proximity of Energize Eastside to high-pressure jet fuel pipelines, PSE has said, "Don't worry. We are a pipeline company. We know what we are doing." **Really? Let's examine PSE's record:**
"…In 2005, an anonymous caller alerted state regulators that a PSE contractor was falsifying records related to inspecting natural-gas leaks…. And in 2008, **PSE paid a $1.25 million fine for the fraudulent gas-leak reports**, the largest penalty the state has imposed on a natural-gas distributor…."
"…a September 2004 blast in Bellevue incinerated a home and killed the owner. **[PSE] settled** with her family **for $8 million**."
"…In 2003, state pipeline officials inspected PSE's facilities in King and Pierce counties and found numerous violations of requirements to inspect and replace corroded pipelines. In 2004, a badly corroded pipeline operated by the utility leaked gas that filled the Bellevue home of Frances Schmitz, 68, and ignited, killing her…."
"…[**PSE] reported 872 hazardous gas leaks** on service lines that connect to homes and businesses in 2014, the most recent year available…"
"…"I know they had some problems," Carl Weimer, executive director of the **Pipeline Safety Trust,** in Bellingham, said of PSE…."

"…After a 2011 pipeline explosion in the Pinehurst neighborhood destroyed a home and injured the couple inside, **state regulators fined PSE $275,000** and required it to evaluate its public-awareness program and emergency plans for gas leaks…."
"…In a **September [2015]** inspection report, the Utilities and Transportation Commission identified four probable violations and another area of concern….The **state also identified problems with PSE's maps, gas-leak documentation and other records** — issues the company was working to correct…."
http://www.seattletimes.com/seattle-news/under-close-watch-puget-sound-energy-has-worked-to-improve-safety/

PSE does NOT instill confidence in their pipeline safety record. Their track record with gas pipeline safety speaks for itself - the examples above are only a sampling of their shortcomings and violations.

In the short-term, the City of Bellevue has no option but to choose the NO ACTION Alternative. In the longer-term, the City of Bellevue must more fully analyze Alternative 2 (Integrated Resource Approach) with up-to-date information. The DEIS uses outdated information for Alternative 2, which renders the DEIS inadequate to make an accurate assessment of the merits of Alternative 2.
Sincerely,

Russell Borgmann
2100 120th Place SE
Bellevue, WA 98005
rborgmann@hotmail.com

From: Julie Beffa [mailto:j.e.beffa@gmail.com]
Sent: Friday, March 11, 2016 4:05 PM
To: info@energizeeastsideeis.org
Cc: doncense@gmail.com; council@bellevuewa.gov
Subject: Writing in Opposition to PSE'S Draft EIS by Energize Eastside

As a resident of Bellevue for 47 years, 35 in Clyde Hill, I am appaulled that the Bellevue City Council has endorsed the proposed plan to put a 230-kilovolt line 18 miles through Bellevue from Redmond to Renton. The estimated costs of between $150 and $300 million depending on the alternative PSE selects, is outrageous and so beyond the needs of our area. PSE claims that if plan isn't implemented we could see rolling blackouts by as early as 2017, but the Lauckhart-Schiffman load-flow study CENSE paid for, claims the number is close to 2050 before system is affected. That is a huge difference. Not surprising now that PSE is owned by an Australian investment bank Macquarie Group Limited, which it took over in 2007. Its' a corporation and reports to its' shareholders. That should sound an alert to our community's best interests.

After PSE applied for the needed permits from Bellevue, obtained approval from the Hearing Examiner and the City Council, they then reapproached the East Bellevue Community Council (refused the first time), for the conditional use permit approval. It was refused the first time, and fortunately for our city, the EBCC had the courage to disapprove the CUP again. Where was that integrity and representation of the Bellevue City Council? PSE continues the blind path, but then the KC Superior Court upheld the EBCC decision. Another appeal this summer? Let's allow common sense to prevail and disallow this project to go forward for good.

There are many alternatives to mowing down hundreds of trees and decimating our suburban environment that many of us have worked so hard to protect and encourage. Proposals such as this, with it's massive swath of destruction, make me think that none of these planners, engineers, investment bankers, ever live in the community they select to wipeout. No doubt living with 300ft steel power poles in your backyard instead of the 8,000 mature trees obliterated we all need for oxygen making, wouldn't bother anyone who lives elsewhere, but for me the trade-off is NOT worth it.

Julie Beffa
9110 NE 21st Place
Clyde Hill, WA 98004

From: Jennifer Neighbors [mailto:jenniferneighbors@hotmail.com]

Sent: Saturday, March 12, 2016 5:14 PM

To: info@EnergizeEastsideEIS.org

Cc: eis@cense.org

Subject: comment on Energize Eastside Draft EIS

To Energize Eastside:

I write in strong opposition to Option A of Alternative 1 from the Draft EIS for Energize Eastside, which proposes a new 230kV transmission line as well as a new transformer. My reasons for opposing that option are as follows:

- The new high-voltage line is not needed. While PSE argues, and the Chapter 1.3 of the Draft EIS states, that a new high-voltage power line is necessary to meet short term energy needs on the Eastside, the Lauckhart-Schiffman Load Flow Study (from 2/18/2016) shows that this is not the case. To quote that study, “PSE’s system can avoid overloads and outages even when two critical transformers have failed during winter peak usage.”

- A new high-voltage power line that follows, and towers above, the aging Olympic gas pipeline is a catastrophe waiting to happen.

○ Chapter 16.3.7 of the Draft EIS mentions pipeline corrosion. Electromagnetic interference leads to pipeline corrosion, meaning a potential leak and devastating fire at any time during or after construction. Dr. Y. Frank Cheng of the University of Calgary and an expert on pipeline safety, has submitted, via CENSE, information confirming the dangers of locating high voltage power lines in close proximity to gas pipelines.

○ The installation of the poles for the power lines, as well as any maintenance activities further down the line, would be a dangerous enterprise. Though downplaying those dangers, the Draft EIS does note (Chapter 8.5.3.1.2) that “significant adverse impact to public safety could occur if a leak or an explosion… resulted from the project” and (Chapter 8.6.1.2) that “ongoing maintenance activities during operation could theoretically damage or break the OPLC pipelines or other pipelines in the area, leading to a chemical release or explosion."

○ The location of the gas pipelines underground can shift over the years due to soil erosion,[1][1] potentially bringing the (aged) pipelines into closer proximity to the power lines and leading to further dangers during maintenance activities. Keep in mind that the pipeline is already many decades old and has already had one major explosion (Bellingham, WA in 1999) resulting in loss of life.

○ BP, the operator of the Olympic Pipeline, noted that "the location of the pipelines may be found anywhere within the easement form the center of the right-of-way to either side" and as a result recommended against route segments Oak and Willow.[2][2] Yet Oak and Willow are the only two routes still being considered.

○ As noted by CENSE, the Bellevue Fire Department writes in their Standards of Response Coverage, "Given that pipeline incidents continue to occur in this country, and many for undetermined reasons, the community is still at risk. The combination of a highly flammable liquid, in large quantities, and in [an] urban environment translates into a significant consequence risk that approaches the 'catastrophic' level."[3][3] Thus, local emergency responders feel this is a dangerous proposition.

○ Most importantly, this entire proposed power line lies upon a major fault line. As recent media attention has shown, and as has been confirmed by national government agencies, the Pacific Northwest is long overdue for a major earthquake. A high voltage power line on top of an aging gas pipeline that runs through almost exclusively residential neighborhoods will cause a catastrophic and easily predictable loss of life. In the Somerset and Eastgate neighborhoods alone, where I live, aside from running through many residents' back yards, the pipeline/powerline combination runs underneath and above the neighborhood swim and tennis pool, where multi-generational families spend their summer days and evenings. The combination runs over and below the public Tyee Middle School, where hundreds of local children spend 8-9 hours a day, 5 days a week studying. The combination runs right alongside a Bright Horizons daycare facility, where our community's youngest, most vulnerable (and least likely to be successfully evacuated) members spend their days year-round. Somerset/Eastgate is but one of the many potentially-impacted neighborhoods. Further south in Newport Hills, these lines will come dangerously close to yet another public school, Jing Mei Elementary. Other neighborhoods will be similarly impacted.

In sum, choosing Alternative 1 Option A is a negligent, if not clearly reckless, choice on the part of our local governments and government agencies.

Alternative 2 from the Draft EIS for Energize Eastside is the only safe option. The EQL Energy study, submitted by CENSE, shows that Alternative 2, if properly implemented, would be much more energy efficient for our wider community and have lower long-term costs. It will have a much lower impact on the local community than Alternative 1 Option A (see Chapter 10.7.1 and Chapter 11.6.3.5.1 of the Draft EIS), which, in addition to all of the concerns listed above, requires the widening of the existing utility corridor and thus the destruction of many homes and other community resources - indeed, it's hard to fathom how places like the Somerset Community Pool could continue to exist if Alternative 1 Option A is put into place since it is well within the 120-150 foot "clear zones" that Alternative 1 Option A requires (Chapter 11.6.3.5.1). Alternative 2 options were not adequately analyzed during the Draft EIS process and should be given greater attention going forward. Our community leaders should not allow a foreign-owned, private, and profit-driven company (PSE) to determine the course of our energy future.

Sincerely,

Jennifer Wilson

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Bellevue, WA 98006

jenniferneighbors@hotmail.com

[1][1] Frank Cheng. 2013. *Stress Corrosion Cracking of* Pipelines. Section 8.7.1.

[2][2] For a copy of the letter from the Olympic Pipeline Company, follow the link at the following web address: http://sane-eastside-energy.org/2014/04/02/olympic-pipeline-company-opposes-transmission-lines-over-its-pipelines-for-several-reasons-including-safety/

[3][3] http://www.bellevuewa.gov/pdf/Fire/Standards_of_Coverage.pdf, p. 66

Mike Abel
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I would like to submit for the record these comments regarding the Alternatives proposed in the Draft Environmental Impact Statement. I am primarily concerned with Alternative 1, Option A which is the course of action initially pursued by Puget Sound Energy.

Environment – The proposed route for the Energize Eastside project includes many environmentally sensitive areas. Impact due to construction Activity as well as long term destruction of valuable wildlife and vegetative resources is inevitable. Chapter 11.6.3.5.1 of the DEIS concedes that as many as 327 acres of land may need to be cleared of vegetation should Alternative 1 option A be chosen. This is simply not acceptable.

Safety – Alternative 1 Option A would require 18 miles of new construction much of which would be built on top of the existing Olympic Gas Pipeline. The DEIS minimizes the risk to public safety that will be generated. PSE has in the past expressed little or no concern regarding this aspect of the project despite the fact that examples exist of prior serious incidents involving leaks and explosions due to construction activity near gas pipelines. Additionally, there are examples in the academic literature warning of the risks associated with co-location of flammable liquid pipelines and electrical power transmission infrastructure. Chapters 16.3.7, 16.6.1.3 16.6.3.11 16.6.4.3 and 5.5.3.1.6 of the DEIs address some of these issues in a superficial manner however it would be prudent to conduct additional study on these topics with the aim of better quantifying the risks associated with Alternative 1 option A.

Neighborhood Character – Alternative 1 option A would require tall power transmission poles which are not consistent with the City of Bellevue comprehensive plan. Additionally, in some locations utility easements would need to be widened severely impacting the neighborhoods through which the project would traverse. This would result in loss of property and in some instances complete loss of dwelling units.

Project Need - Need for the Energize Eastside project, as proposed by PSE appears to be based on a flawed analysis. As illustrated by the independent Laukhard-Schiffman Study (2/18/2016) PSE's in-house produced load flow study appears to have been conducted using assumptions designed to generate a report supporting the need for the project. As a result, I simply cannot trust PSE's stated motivations and intentions for promoting the project.

Because of these concerns I feel strongly that the only prudent course of action is to stop the project until such time that the need and benefit of the project can be re-evaluated.

Mike Abel

From: denisemickelson [mailto:denisemickelson@comcast.net]
Sent: Sunday, February 21, 2016 3:28 PM
To: eis@cense.org
Cc: j.robertson@bellevuewa.gov; clee@bellevuewa.gov
Subject: Energize Eastside Project

Here is a copy of my remarks that I sent to PSE's Energize Eastside Project online comments:

I am responding to the Draft EIS for the Energize Eastside Project.

As a resident of Bellevue for 55 years, I am very disappointed in the Alternatives that are presented to our Somerset neighborhood for the Energize Eastside Project by Puget Sound Energy.

The Olympic Pipeline runs in front of our home and the existing 115kV transmission lines currently run through our backyard. We are squeezed by these two utilities.

My main concern besides disrupting the character of our neighborhood is that the proposed high voltage transmission lines are located too close to the Olympic Pipeline and would increase the risk of a catastrophic explosion. We have jokingly asked ourselves, would we run up the hill (towards the downed lines) or down the hill (towards the burning fuel) should a catastrophe indeed occur.

Having attended the meetings both at the Bellevue City Hall to learn the details of the Energize Eastside Project as well as the meetings offered by CENSE, I am convinced that the project has been mismanaged and that the No Action Alternative 4 should be the choice as a short-term solution.

Sincerely,

Denise Mickelson
Somerset Resident
4518 Somerset Dr. SE
Bellevue, WA

Barbara Braun Feb 24, 2016 13609 SE 43rd Place Bellevue WA 98006
To: Bellevue City Council Subject: Energize Eastside Call to Action

As a citizen who has watched the City Council in action regarding PSE projects for the last couple of years, I am stuck by the level of passivity the Council has and is exhibiting concerning one of the largest, most impactful projects facing our city.

As CENSE and other community organizations have demonstrated, the citizens are gravely concerned about the need for and the trajectory this project is taking, and that no one but the citizens are investigating alternatives in any serious way. Many citizens are putting a lot of time and personal money into this. Why isn't the Council reciprocating?

I would like to sound a CALL TO ACTION for the City Council to get proactively involved in questioning the need for this project and for insuring that our energy future is both responsible and forward looking by pursuing Alternative 2 – The Integrated Resource Approach, incrementally, over time, and as it is needed.

The claim that the Council's hands are tried is bogus. Note the council played this card on the Lake Hills/Phantom Lake Transmission project and said there was nothing they could do. Thankfully the East Bellevue Community Council stepped up to do the right thing and they prevailed! With Energize Eastside being so blatantly flawed and unnecessary, it seems patently negligent for the Council to passive sit by and let this project steamroll through our community.

What can and should the Council do? Here are some suggestions:

1. Get a lawyer! Obtain a thorough independent legal opinion on your rights and jurisdiction as Council Members;

2. Provide full comments on EIS 1 stating 1) the need for the project is not adequately established; 2) Alternative 2 is not fully developed or vetted by independent experts; 3) the criteria for selecting alternatives and decision making in this process is not clear and transparent; 4) require PSE to share ALL their data and analysis, including their load flow data with the public; and 5) require an independent study of pipeline safety and mitigation requirements be done.

3. Do not allow the EIS process to move forward with PSE selecting the wrong alternative. Pause after EIS 1 and revisit the need for this project. Require that Alternative 2 be studied in depth and demonstrate how it CAN meet our energy future needs. Make sure independent industry experts assess Alternative 2, not PSE who doesn't have the expertise or motivation to properly vet this option;

4. Build a coalition of independent advisors and get the expert advice you need to help you understand this project. Require Stantec, or another more independent third party, to run the load flow study using PSE data. Engage State and Federal agencies with expertise to review the need for this project and its alternatives;

5. Pass ordinances strengthening safety regulations and setbacks around the Olympic Pipeline in accordance with the latest pipeline/electrical transmission colocation studies. Insure our earthquake risks are accommodated;

6. Prepare to refuse permits to PSE. Investigate and develop a plan for this. Warn PSE that you will not be issuing permits; and

7. Conduct a ballot measure to move PSE to a Public Utility District so citizens can insure this utility is managed in a way that best benefits the community, not a private, for-profit company. There are many in our state, and it may be time for us to join them.

Thank you in advance for doing all you can to do the right thing and for making Bellevue a great place to live and work!

Barbara Braun

To: Bellevue City Council

Below is a message for your information which I have mailed to Heidi Bedwell, Senior Planner, Land Use Division-Development Services, City of Bellevue:

ENERGIZE EASTSIDE: COMMENTS ON ENERGIZE EASTSIDE STATEMENT (EIS) February, 2016

I am very concerned about PSE's intention to build a large transmission line from Redmond, WA to Renton, WA. for several reasons:

1. The **need** for expanded capacity outlined in Chapter 1.3 of the DEIS has been questioned by the Lauckhart-Schiffman load-flow study dated February 18, 2016. This study indicates there are many flaws in PSE's assumptions. If winter emergency conditions are used instead of summer normal conditions and if .5%/year growth for Eastside energy demand is used, demand does not exceed flow until 2058. PSE's inflated rate of growth of 2.4%/year indicates the capacity is not exceeded until 2027. This should provide plenty of time to implement rapidly developing new technologies which would be much less expensive and intrusive. It appears the real motive for PSE's desire to expand capacity has more to do with the transfer of power to British Columbia, thereby enhancing the profitability of PSE and increasing the return on investment for the hedge fund owners of PSE who made a 10-year investment which anticipated high returns. These profits would on the backs of the customers who would pay for the huge capital investment with increased rates.
2. **Public safety** is of primary concern. Given that we live in a seismic zone and the existing power line is built along a gas line, the possibility of a human catastrophe is exacerbated by construction and long term operations activities. Chapter 8.5.1.3 only mentions earthquakes during construction. What about seismic events in the future? I am reminded of the 1999 Bellingham disaster. In addition while effects on humans is hard to prove and controversial, why risk any adverse health effects, such as bone marrow cancer in infants and brain cancer in adults?
3. The detrimental impact to the **environment** cannot be overemphasized. We are looking at the destruction of several thousand trees and clear cutting many acres of vegetation. Bellevue and other eastside cities pride themselves on the largely attractive and desirable living conditions that have been developed over the years. Does it make sense to downgrade these admirable results and diminish the quality of life and the investments in homes and public places, especially when the demand need that has been proposed by PSE is highly suspect?

For these main reasons I urge those officials responsible for the evaluation of the Energize Eastside Project to reject the building of the proposed energy infrastructure and turn to the more sensible Alternative 2 – Integrated Resource Approach-outlined in the DEIS, pp2-32 to 2-49.

Furthermore, I urge the current EIS Step 1 Review to reach a conclusion and remand the final findings to the Bellevue City Council for review and a decision about proceeding to step 2.

W. Robert Moore

4707 135th Place Bellevue, WA 98006

Tel: 425-747-1388

Email: bmooreii@comcast.net

From: amy faith [mailto:amygfaith@yahoo.com]
Sent: Monday, February 29, 2016 9:12 PM
To: eis@cense.org
Subject: Comments in support of the NO ACTION ALTERNATIVE

I am writing to support the NO ACTION ALTERNATIVE . Here is why:
1. PSE manipulated the data when doing the load study to create the appearance of need for this project.
2. When citizen advocacy group Cense asked you to redo your load study due to suspected inconsistencies, you refused, saying you were done doing studies.
3. When Cense asked for permission to see the data you used for your load study, you refused, saying there was no need for anyone to review your work.
4. Instead, Cense had to go through FERC in order to gain access to your data.
5. When Cense had a load study done using the same data as you, they only got your results after entering incorrect weather conditions, not clicking the proper boxes, adding the sale of energy to Canada and adding unrealistic situations that would not happen at the same time in real life.
6. The project would bring in a profit of 8.9% a year for PSE , while costing customers over a billion dollars over the life of the project.
7. Factoring in the sale of energy to Canada when the energy produced should be used to provide power for the cities the lines are to be going through instead.
This is not the way to work with the residents who would be adversely affected by your proposed project. All options, except that of the NO ACTION alternative would have significant negative effects on the environment, plants, animals, and people in those neighborhoods. The combination of over head power lines and pipeline adds even more danger. We need to work together to find an economically reasonable solution that meets our energy needs without jeopardizing our health or the environment.

Amy Faith
Bellevue

15210 NE 8th St
Unit D4
Bellevue WA 98007

Energize Eastside Draft Environmental Impact Statement (DEIS) Comments

Submitted by Don Miller, 5205 Lakehurst Lane SE, Bellevue (email: donald_c_miller@hotmail.com)

I Support the NO BUILD OPTION 4 based on the deceptive representation (or flawed analysis) of need by PSE, the outrageous environmental impacts and the inadequate consideration of viable alternatives.

COMMENTS DIRECTED TO THE CITY OF BELLEVUE AS LEAD AGENCY:

I'd like to start by acknowledging the work of the City staff to include alternatives in this DEIS that were never considered by PSE from the introduction of Energize Eastside; namely underground, underwater and energy efficiency options. Not only did PSE fail to consider alternatives, the company worked aggressively to undermine consideration and feasibility of these options. Further, the members of the Community Advisory Group (CAG) that represented municipalities and business worked in concert with PSE to denounce and repress consideration of alternatives. Thank you to the City of Bellevue staff who worked to include the alternatives in this DEIS.

Interestingly, what has not been considered in the Energy Efficiency Alternative are specific code changes to the Building Code in the City of Bellevue that would ensure a sufficient power supply by modifying the way residential and commercial buildings are constructed.

PROJECT NEED Section 1.3:

The DEIS states "PSE has determined that there is a need" As a foreign owned for profit energy company we cannot merely accept their determination as justification to destroy our environment, property values, neighborhood character and to burden the entire Puget Sound rate-payer base with the enormous cost of this project. This section of the DEIS goes on to discuss the secrecy and complexity of determining the need. While there are certain security concerns, the process is not as exotic as the DEIS would lead one to believe. I have attended a presentation of the Lauckhart-Schiffman load-flow study dated February 18, 2016 and found that with the appropriate security clearance and qualified engineers to conduct an alternative analysis the engineering concepts used to determine need are straightforward and rational. The extent to which PSE attempted to thwart this alternative analysis must be added to the actions of this foreign owned company. Although the City of Bellevue accepted validation of PSE's analysis the firm the City of Bellevue hired to validate PSE's analysis of need is a close ally and in PSE's pocket. **In this regard, the City of Bellevue has failed to obtain an independent review of the need for this project.**

Further, the data used in the Lauckhart-Schiffman load-flow study uses the very database which PSE supplied to the Western Electricity Coordinating Council (WECC) prior to the conception of the Energize Eastside project. In that earlier version of PSE's own database, there was NO NEED for this project. **NO NEED**. Even in the extreme scenarios. Only after PSE *altered the model* to a state of **substantial system failure combined with an excessive flow of power to Canada** were they able to manipulate the database to create justification of the Energize Eastside project. The recent actions of PSE to justify this project continue to be based on discrediting valid information while simultaneously failing to provide any substantiation to their claims. The bottom line is what matters here and as a foreign owned power company PSE's only concern is profit. They are burdening generations of Puget Sound citizens with the expense of this unneeded project as all rate-payers will bear the cost, not just the Eastside.

SECTION 6.1 UNAVOIDABLE ENVIRONMENTAL IMPACTS:

The DEIS states pursuing the Energize Eastside project with Overhead lines will create "significant unavoidable adverse impacts to plants and animals." This is probably the most important statement in the DEIS. While the City of Bellevue has gone to great lengths to suggest they will no longer consider if the need for the project is for energy or for profit, the analysis in this section is complete. To allow this project to go forward would be a catastrophe to the City of Bellevue and our neighbors. We must do everything we can to preserve the limited habitats that remain and therefore must re-evaluate the need using the independent Lauckhart-Schiffman load-flow study.

The simple environmental analysis conducted by PSE while the CAG evaluated route alternatives showed that over 8000 mature trees would be cut down if PSE builds overhead lines. The final project EIS will show permanent damage to dozens of streams, hundreds of wetlands, untold wildlife, foliage and trees. This project will devastate the remaining natural areas in our Cities. While our cities enact countless restrictions to protect the environment they seem willing to allow this un-needed project to proceed on the backs of the hard working taxpayers and the defenseless environment. No Mitigation will ever replace the damage wrought by this profit motivated initiative.

SECTION 10.7.2 NO ACTION ALTERNATIVE:

This section was written based on this assumption "No Action Alternative would likely lead to declining reliability of the electrical power supply on the Eastside" which the Lauckhart-Schiffman Load Flow Study shows to be a distortion of fact. The projected growth in the Eastside will not stop developers from building or people from moving here. If, in fact, there is a power supply issue it will be managed by PSE and the developers will be long gone and the houses will be occupied. This is a red herring that PSE has created to scare municipalities into approved this un-needed project.

SECTION 10.7.3.1.2 EXISTING CORRIDOR:

I am dumbfounded as to the purpose of Table 10-2 where it lists restrictions in Beaux Arts, Hunts Point and Yarrow Point areas of Bellevue. These areas have never been under consideration as a part of the Energize Eastside project. Is this boilerplate, diversion or just a waste of City resources as it has no value in this report.

SECTION 10.7.1.14 PROPERTY VALUES:

The DEIS states " one study prepared for The Electric Power research Institute (EPRI) titled *Transmission Lines and Property Values: State of Science* (Mullins et al., 2003) was chosen for use as the source of information for this EIS because it synthesizes and summarizes the findings of over 50 surveys and studies."

Let's look at the problems with this study:

(1) It is something that was prepared for the power industry, not a study conducted by **recognized experts in real estate value.**

(2) It is a consolidation of 50 independent studies and without statistical validation of the individual studies it is **merely opinion**. As the DEIS quotes "*no quantitative generalizations about findings from the studies can be made with any degree of reliability"* This EPRI study masks the geographical and socioeconomic demographics that impacted the results of these studies. It is common knowledge that the Property values of undeveloped land increases with the introduction of utilities whereas the value of affluent neighborhoods decline with such intrusions yet the DEIS used a study that could provide neither of these conclusions.

(3) The DEIS claims "land use analysis in this Phase 1Draft EIS considered effects on property values but found them to be inconclusive" yet the Draft EIS cites 12 conclusions from the EPRI study and over half of these conclusions point to decreased property value, increased selling times, negative opinion and other factors negatively impacting property values. The evidence from your selected and flawed study doesn't even support the claim you made in the DEIS.

(4) The DEIS makes no indication that real estate professionals were consulted to obtain valid information about the impact of power transmission lines on property values in affluent US communities which would have been a reasonable source to seek out.

Again, in this regard, the City of Bellevue has failed to obtain an independent analysis as the lead agency.

SECTION 11.6.3.5.3 NEIGHBORHOOD IMPACTS:

The DEIS states "It is anticipated that 85- to 100-foot-tall steel or wood poles would be used" which represents new and avoidable risks to citizens and their property due to the presence of the Cascadia Subduction Seismic Zone. Recent predictions are not "if" a big earthquake will hit in the Pacific Northwest but "when." An article in The New Yorker describes the likely scenario as defined by the Federal Emergency Management Agency (FEMA)

A link to FEMA and the associated article can be found here: http://www.fema.gov/blog/2015-07-15/big-one-pacific-northwest-taking-conversation-action

Introducing new risk to our communities is **entirely preventable**. The obvious choice is the NO BUILD OPTION, Alternative 4.

Don Miller

Date: 10 March 2016

To: Heidi Bedwell,
Energize Eastside EIS Program Manager
450 110th Ave NE Bellevue, WA 98004

From: Curtis Allred
13609 SE 43rd Pl
Bellevue, WA 98006

Dear Heidi,

The more I learn about PSE's deceit in the Energize Eastside project, the more infuriated I become. This project has to be stopped. I have summarized the situation as seen by those of us following developments. Following are details on the summary points.

SUMMARY

Financial Motivation: PSE is financially motivated to build a rate-payer subsidized power line through the eastside. Besides being paid for by us, the customers of PSE, it will also boost the sale value of the company and give them a 9.8% return on capital, guaranteed by the state and covered by us, the customers of PSE. They may also be using this project to boost capacity so they can move more power to Canada, further enhancing their potential revenue and company valuation.

Fabricated Demand: PSE is using a fabricated and flawed power simulation to try to scare residents into supporting and funding this lucrative project. Based on a recent load flow analysis by two industry experts, one of them a former Puget Sound Power planner, it is evident that PSE faked the input data and parameters in their flow analysis to justify the need for the power lines.

Flawed EIS: The current Environmental Impact Study starts with the assumption that the additional power capacity is needed, and accepts PSE's analysis as-is without question. Further, PSE has attempted to discredit the other two EIS alternatives to the powerline, again by faking the numbers, and saying that new technology and conservation measures will not work.

Cost: It is estimated that this project will cost PSE customers between one and two billion dollars over the life of the project (see references). This is money that should be spent on conservation, demand side management, and modern grid technologies. Thousands of trees will be cut down and our city will be scarred with ugly power lines for generations to come. For us, it’s a big cost with no benefit. The only ones benefiting are PSE executives and shareholders.

This level of deceit and opaqueness by a private company for a public works project is reprehensible. It has to be illegal, and therefore stoppable by local governments. Otherwise we will need to take legal action against PSE.

Please do everything possible to stop this project.

DETAILS

Following are details on the above points.

Financial motivation:
Why is PSE so motivated to build these powerlines? Washington state policy guarantees PSE a return on investment of 9.8% per year for infrastructure projects. A low estimate of the cost of the project is $250 million. It will probably be higher due to complications (relocating families, dual poles in some areas, having to deal with existing power lines, pipeline safety issues, etc.). Using the low estimate of $250M means the PSE will charge us ratepayers $24.5M per year. This is money that could be used for energy conservation, alternative energy sources, and modern grid technology. So they charge us $250M to install it, then bill us an extra billion or two over the next 40-50 years. It is speculated that PSE's Australian parent company is gearing up to sell PSE and wants to maximize its market value. In fact, the parent company's original stated intent of buying PSE was to turn around and sell it after 10 years. Is it any wonder they're going to such lengths to force this project through, going so far as to fabricate a study to justify the project and lying about it to the public?

Fabricated demand:
Based on a recent independent load flow simulation, it is evident that PSE faked the inputs to the load flow simulation in these ways:

- Overstated population and demand growth
- Estimating too much power going to Canada
- Turned off 6 local power sources
- Used lower transformer ratings
- Did not take into account power line resistance

This created an invalid and impossible scenario that could only be solved by adding power lines coming from the Cascades. Using a realistic worst-case scenario with industry-standard assumptions, the project cannot be justified.

The above simulation "errors" are summarized below, and explained in detail in an independent study by power industry experts Richard Lauckhart and Roger Schiffman, available on the CENSE website. Richard Lauckhart has 40 years experience in power planning and was Vice President of Power Planning for Puget Sound Power & Light before becoming a power planning consultant. Roger Schiffman has 23 years of energy industry experience including simulation modeling, utility resource planning, and electricity market evaluation.

Richard and Roger gained CEII clearance from FERC, which should have granted them access to PSE's load flow simulation data. However, PSE rejected their request, saying they did not have a "justifiable need" for the data. (CEII is intended to protect against criminals and terrorists, not citizens trying to validate a power study.) So Rich went to FERC who gave him the data PSE submitted for the WECC Base Cases. They ran this data on the industry standard load flow analysis simulation software and published their findings in the report: Load Flow modeling for Energize Eastside, by Richard Lauckhart and Roger Schiffman, February 18, 2016.

Summary of the above 5 "errors" in PSE's simulation, detailed in the Lauckhart/Schiffman report:

Overstated population and demand growth: PSE projected 2.4% growth per year which is way higher than other estimates by governments and agencies. PSE themselves forecast 0.5% to the WECC.

Too much power going to Canada: PSE ran the simulation with triple the WECC base case of 500 MW, amping it up to 1500 MW for their scenario. Why would we be transmitting three times the normal power to Canada during an emergency? Normal procedure during a power emergency would be to cut all power to Canada.

Turned off 6 local power sources: With the local power sources turned off, more power distribution burden was transferred onto the high voltage long distance power lines. The rationale for turning off 6 local power generation stations could not be explained by independent power industry experts, including Richard Lauckhart and Roger Schiffman. PSE will of course not explain. Still, the above errors cannot fully justify the power line. Richard and Roger suspect altered the simulation data in other ways:

Used lower transformer ratings: They seem to have used "summer normal" instead of the much higher "winter emergency" value for transformer ratings. The summer normal rating is only 700 MW, while the winter emergency rating is 950 MW. Did not take into account power line resistance: It appears that they turned off the power-line resistance aspect of the simulation to make the flawed simulation run. Otherwise the power from the Cascades would show too much voltage drop, resulting in brownout, and the simulation would fail.

Environmental Impact Statement flaws:
The EIS accepts PSE's flawed justification study and assumes the power problem needs to be solved. Since the justification is not valid and the need does not exist, the "No Action" alternative should be chosen and EIS halted.

Comments on the EIS Alternatives:
Alternative 1 is the power line option. It is based on a fraudulent power analysis, and therefore invalid. PSE should be punished and fined for their deception and this alternative thrown out.

Alternative 2 calls for technology and conservation solve future energy shortfalls. This was rejected by PSE as infeasible based on outdated data and PSEs inexperience in this area. It needs to be revisited by experts in new conservation, generation, and distribution technologies, not by PSE who has every motivation to disqualify it to justify their lucrative power line project.

Alternative 3 originally called for simply adding transformers. But PSE demanded that power lines be added to this alternative, thus making it less attractive. The solution does not actually require new transmission lines. Those transmission lines are only needed to supply Canada with an inflated power estimate (triple the base case as explained earlier).

The "No Action" alternative is the only sensible choice at this time. There is no short term need for increasing power capacity, and Alternative 2 can be revisited and implemented on a gradual timeline.

Cost:
Including the hundreds of millions of initial cost, the project will cost taxpayers and ratepayers many times more in subsequent years. The "Energize Eastside Economic Analysis" study (on CENSE website) estimates $1.5B to $2B over the life of the project. In addition, property values will decrease, impacting homeowners and reducing property tax revenues. An estimated 8000 trees will be removed over the length of the power line. Our neighborhoods will be scarred with the loss of trees and ugly industrial power poles and lines dominating the skyline.

Legal issues:
It appears that PSE is exploiting a weakness in the Washington state law and regulatory process. According to Richard Lauckhart, PSE would not be able to exploit the public like this in California and most other states due to stricter oversight. PSE's deception and fraud in Washington has to be considered criminal! The energy system is public works infrastructure. I refuse to believe PSE is legally able to deceive and exploit the public in this way, and to be so opaque as to not reveal their simulation data.

I urge you to halt the EIS process and investigate these matters thoroughly.

Thank you,

Curtis Allred
13609 SE 43rd Place; Bellevue, WA 98006

References

- Lauckhart-Schiffman Load Flow Study: http://cense.org/LauckhartSchiffman%20Load%20Flow%20Study.pdf
- CENSE: http://cense.org
- Energize Eastside Project Phase I Draft Environmental Impact Statement: http://www.energizeeastsideeis.org/draft-eis.html

Energize Eastside Economic Analysis: http://cense.org/Lifetime%20Cost.pdf

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From: Barbara Braun [mailto:bbraun@stratery.com]
Sent: Sunday, March 13, 2016 4:52 PM
To: info@EnergizeEastsideEIS.org
Cc: eis@cense.org; Barbara Braun <bbraun@stratery.com>
Subject: Energy Eastside DEIS Comments

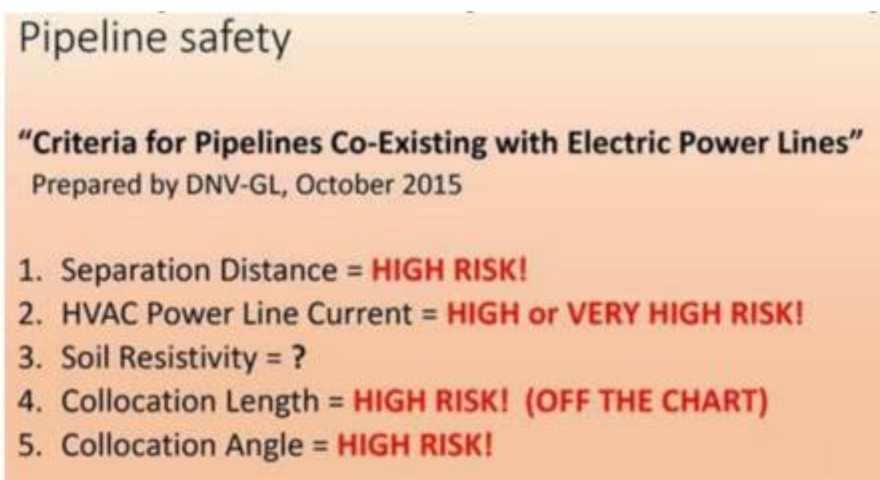
Barbara Braun
CENSE Member
13609 SE 43rd Place
Bellevue WA 98006

Note this document was submitted to info@EnergizeEastsideEIS.org on March 13, 2016. One supporting file was attached for the public record. The file contains a "sticky note" with my name and physical address to assure these documents are added to the public record:

- **Criteria for Pipelines Co-Existing with Electric Power Lines.pdf**

The following comment pertains to **Chapter 12: Recreation**

Alternative 1A claims that "If transmission lines are located in recreation sites they could impact recreation users." This statement is false and misleading. Parks that would be substantially impacted include Viewpoint Park, Kelsey Creek Park, and May Creek Park. It appears
Forest Hill Neighborhood Park, Sierra Heights Park would be eliminated altogether. Further community programs such as the farm at Kelsey Creek would have to be shut down or moved in order to prevent safety issues.



The DEIS claims "There would be permanent loss of vegetation, including trees, because a 230 kV transmission line would require a cleared corridor of 120 to 150 feet wide (or up to 50 feet of clearing where the existing PSE easement is used)." The DEIS needs to reassess the amount of ROW needed to meet current day safety standards for utility corridors with transmission and pipeline co-location and its impact on park lands.

While the DEIS admits the following, there is no off setting measure or cost provisions added to Alternative 1A - “Impacts from vegetation loss would be considered significant if there is a permanent conversion of vegetation type (e.g., from forested to low-growing vegetation) that would substantively change or negatively impact the
scenic nature of a recreation site. In recreation sites where there is a permanent conversion of vegetation type, a loss of habitat for animals that may use these areas would result, which could reduce user enjoyment. In addition, benches, playground equipment, gazebos, or other structures may be removed underneath the transmission lines. Visitors may avoid a recreation site if it no longer offers the amenities they previously used at that site. Refer to Chapter 6 and Chapter 11 for further description of potential impacts to plants, animals, and visual quality.”

The DEIS does fails to address at all: the safety issues for children and other park users and the cost to insure the safety of parkland users that Alternative 1A runs through: the impact to the quality of life of adding industrial blight and environmental destruction to our parks and recreational corridors; the impact of eliminating certain “unsafe” recreation activities such as kite flying, and the expansion of severely impacted lands from the clearing of native plants, habitat elimination and unmaintained ROW corridors that invite invasive species, dumping and other pollution, and inappropriate uses such as homeless encampments. There is plenty of evidence around our state that substantiate these concerns and from which the cost and significant impacts can be assessed.

The DEIS needs to more accurately assess the loss of recreation acreage and utility in Alternative 1A and add the cost of replacement park lands within community boundaries into the cost and add this cost into Alternative A1 and also reassess the significance of this impact compared to other alternatives such as Alternative 2 which would have the flexibility to locate infrastructure away from park lands and would require less clearly and environmental destruction.

2 Attachments

From: Kathleen Sherman [mailto:kathleen.sherman@comcast.net]
Sent: Wednesday, March 09, 2016 4:27 PM
To: eis@cense.org
Subject: Draft EIS comment

I have questions about this for- profit utility's [PSE] evaluations of need and cost of this project because it is owned and associated with the Australian business MacQuarie. Three reason is that :
1.MacQuaries other questionable projects
2. A 2014 inquiry by the Australian Senate called for the Australian Securities and Investments Commission "to put Macquarie Group's financial planning unit under 'intensive surveillance,'" according to the Sydney Morning Herald. The inquiry was sparked by reports of "misconduct by financial planners at the Commonwealth Bank," but concerns about financial practices spread beyond Commonwealth. The Senate report stated, "The committee is concerned with the efficacy of the enforceable undertaking entered into as a result of serious compliance deficiencies within Macquarie Private Wealth."[11] About the inquiry, the Australian Financial Review reported that "Macquarie Group's private wealth unit [was] accused of not co-operating with the Senate committee that delved into unethical financial planning -practices at the Commonwealth Bank of Australia."[12]
3. Is this construction project part of plan to pay off debts acquired with the purchase of PSE and not a benefit for consumers?
"In 2008, Macquarie and a group of Canadian pension funds purchased Puget Sound Energy (PSE), the largest energy company in Washington, which provides electricity and natural gas to Seattle and the surrounding area. The Macquarie-led consortium purchased PSE from its shareholders for $7.4 billion, which was financed in large part by borrowing $4.2 billion. Commentators worried from the beginning of the transaction that Macquarie's heavy borrowing would "saddle Puget Energy with debt, sapping its financial standing and creating pressure in the future to raise rates."[56] The Washington Utilities and Transportation Commission staff and the Public Counsel Section of the Washington state Attorney General's Office also opposed the transaction during its initial stages due to the large amount of debt financing. Public Counsel Section Chief Simon Fitch warned "at the same time, customers have no assurance that capital for infrastructure will be any more available or affordable than without the merger. Consumers appear to get little or nothing in return for the increased financial risk."[57]
http://www.sourcewatch.org/index.php/Macquarie 3\9\2016 12:11 pm

Kathleen Sherman
4741 132nd Ave SE
Bellevue WA 98006

2/27/16

David McCray

6815 Ripley Ln SE Renton, WA 98056-1529

I believe the flow studies that were used to justify the "Energize Eastside project" were flawed and consequently incorrect alternatives and conclusions are being presented. PSE has refused to provide information to clarify the assumptions used in their flow study. In addition, a load flow study was produced by Lauckhart-Schiffman that reaches significantly different results and they have offered the study to PSE who has refused to enter into discussions regarding the discrepancies.

Essentially, PSE has based their flow study on several significant faulty assumptions. The winter season is the peak period of usage in our region. However, the PSE load flow study does not appear to use the winter seasonal ratings for critical transformers in the study. The winter ratings are significantly higher than summer ratings and consequently using the incorrect season causes a significant understated distortion in capacity.

In addition PSE did not reflect utilization of local generator capacity in their load flow study. Again this significantly distorts and understates the projected capacity.

Another aspect of the PSE study that makes no sense, is they actually show the flow to Canada increasing during local peak season needs. There is no requirement for PSE to transfer power to Canada and that faulty assumption falsely increases apparent usage in the local area.

The Laukhart-Shiffman load flow study was prepared with corrected assumptions and they have offered to make that study available for review and discussion. This study needs to be followed up on.

PSE is a foreign "for profit" company who has a clear profit motive for distorting the load flow results and getting the project approved for a guaranteed near 10% rate of return. The process and proposal is outrageous and the brakes need to be put on to get to the truth behind the numbers.

As far as alternatives presented in the EIS, only Alternative 2 - Integrated approach is justifiable. This alternative is safe and cost effective. It is better for the environment as it preserves thousands of trees, reduces carbon emissions, and provides for improved appearance of our neighborhoods.

I understand PSE sold the Shuffleton power plant in recent years. This reduction of local production capacity has the effect of reducing the local energy supply and narrowing the margin between peak demand and available resources.

PSE obviously has a plan to make significant profits for it's foreign shareholders. It doesn't seem right for PSE to pocket the proceeds from selling the local power plant and turn around and try to falsely justify the need for local ratepayers to pay for investing in increased capacity.

PSE should be required to put the proceeds from the Shuffleton power plant back into additional power generation capabilities in the local market place. Local rate payers paid for the Shuffleton plant and PSE should not be allowed to sell off the asset and reduce important local power generation capability.

Comments submitted by Sally McCray on 2/27/16.

Comment #1

I support and endorse Alternative 2, an Integrated Resource approach. It is cost effective (a lifetime cost of 1.4 - 2 billion to rate payers is outrageous!), more reliable, better for the environment, smart and secure. The only objective it doesn't meet is making the PSE owners more money via the WUTC 10% investment boondoggle. When can we rate payers get in on that deal? Oh, right, it is the unfortunate rate payers who get to PAY PSE the 10% for 30 years. No wonder they found a need and then proposed the costliest "solution" possible.

I believe that if a need for an additional transmission capacity is revealed, in the next 40 years, over and above what the Integrated Resource approach can provide, then and only then should a massive upgrade to a utility corridor running through a heavily populated area. Transmission to Canada and California can easily happen on the east side of the Cascades. Transmission to benefit the Eastside, only, should run on one of the two North South corridors already in existence, starting with the substantially unused 230kv corridor owned by Seattle City Light.

Comment #2

I believe the need for this massive project does not exist. PSE cooked the books to come up with an analysis demonstrating the need. Bellevue, to their credit, hired an independent consultant. However, the City Council is made up of ordinary folks and politicians, who are easily misled in a billion dollar game with a corporation with millions to spend on marketing. Thus the independent consultant was hired to do the wrong job, review PSE's calculations. NOT to do the more important work of reviewing the assumptions. You've heard the term garbage in, garbage out? That is what Bellevue got for their money, they didn't ask the right question.

Fortunately, others did ask the question. And when their assumptions were different than PSE's? PSE refused to explain their assumptions. For example, why did they assume so much more load going to Canada than required? PSE has said time and again that this is a local project, yet they tripled or even quadrupled the load to Canada in their peak demand calculation. Why would they assume this load going to Canada on during peak demand locally? There is no requirement to continue that flow during a peak demand time - a time that might not last any longer than a few hours to a few days at most. Garbage in, garbage out.

As another example, why isn't there an assumption of a peaker station or two, supplying power in peak demand times, like the old Shuffleton station? It doesn't take a EE degree; it is just common sense that the management of power delivery would include a peak demand generator or two. It is the low cost, reliable, smart alternative. If we didn't know that PSE had its rate payer's interests at heart, it would almost seem PSE was planning, even then, to "need" to build a giant project to increase return on capital for the private corporation, at the expense of rate payers on the Eastside. I wonder how the sale of that asset was justified? Probably that there was no conceivable need for power generation to support the Eastside - quite the opposite of what they are saying now. Can we see those records and learn for ourselves? Regardless, a reasonable need analysis should assume at least two peak demand generation facilities.

Independent analysts should be hired to review all the PSE "need" assumptions, and justifications for those assumptions. How is the 205MW shortfall in the EIS calculated? Why are there so few transformers in PSE's calculations? (They are a low cost, proven alternative).

PSE should comment on the Lauckhart-Schiffman Load Flow Study. Respected industry experts Rich Lauckhart and Roger Schiffman ran computer simulations of the need for PSE's "Energize Eastside". They used the same industry software that PSE uses. Their conclusion: PSE is using an impossible situation to try to scare residents into funding a billion-dollar project. In other words: garbage in, garbage out.

PSE should be required to reveal the rational for its assumptions. In the medical field, no one takes a study seriously unless it is peer reviewed. Even the best make mistakes. It is the best way to avoid: garbage in, garbage out.

Comment 3

Alternative 1, Option A should be avoided due to the huge and significant adverse impacts to people who live near the project. Chapter 11.6.3.5.3 states that permanent clear zones would be required for Alternative 1, Option A. This is not consistent with Eastside esthetic values, anywhere but in downtown areas. (Where transmission lines are always underground). Alternative 2 would have much fewer land use impacts and is thus preferred.

The only worse alternative to Alternative 1, Option A would be to put the transmission lines in an area that didn't already have transmission lines.

Comment 4

This project is not needed and should be rejected. The Northwest Power Plan report, dated Feb 2016, states that even though the population is forecast to grow..."the region's electricity loads are expected to stay at the current level....continuing a 20 year trend of low load growth"

PSE's own annual reports, found on the SEC website support this conclusion, power demand has been decreasing; peak demand for PSE was in the winter of 2009.

The Wall Street Journal, New York Times and other respected periodicals have all reported that electrical demand is decreasing all around the country. At the same time, alternatives to ever more wires are being developed. It is outrageous that a project like this would be approved for a "potential" demand that may never materialize, with the most expensive and environmentally destructive solution possible. The only people this could make sense to sit in the PSE board room or stockholders meeting. It makes absolutely no sense for PSE rate payers.

Sally McCray

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FROM:
Janis Philbin Medley
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Bellevue, WA 98006

TO:
Ms. Heidi Bedwell, Senior Planner
Land Use Division-Development Services
City of Bellevue
450 110th Ave NE
Bellevue, WA 98004

RE:
Comments on the Phase I Draft EIS for PSE's Energize Eastside Transmission Line Project
Submitted on behalf of **CENSE** Coalition of Eastside Neighborhoods for Sensible Energy

March 11, 2016

CHAPTER 1 INTRO & SUMMARY

1.8 / p 1-16 What are Applicants Objectives

Address PSE's identified deficiency in transmission capacity

Refer to Laukhart-Schiffler Load Flow Study to see arguments against PSE's claim of deficient transmission capacity.

Tables 1-2 and 1-3 / p 1-50 to 1-55

Impact Categories

The impact categories assume that if all local, state, and federal regulations are followed, then impacts will be minor. This totally dismisses the very real possibility of human error during construction and operation of all alternatives. It also dismisses the very real fact, that Olympic Pipeline has both been sited and fined for a variety of pipeline safety violations, and still has not completed all required repairs required by OPS. **(refer to letters submitted with my oral comments at the March 1 Comments Meeting in Bellevue)**

1.12.3 / p 1-57 Impacts from Project

Although significant impacts could occur with any alternative, the most controversial impacts relate to concerns about the visual impacts and potential for conflicts between electrical and flammable-liquid pipelines. Fear of these and other impacts led to concerns in the community about reduced property values, degradation of neighborhood character, and public safety. ***The Phase 1 Draft EIS acknowledges these concerns and provides the results of relevant studies prepared by local and national experts on the topics.***

Many of the "relevant" studies used in the DESI are very dated. Other comments by CENSE have addressed the inadequacies of the research data used to create the components of Alternative 2, and I refer you to those submitted by EQL.

CHAPTER 2 PROJECT ALTERNATIVES

2.3.2.2 / p 2-21 & 22 Option A: New Overhead Transmission Lines

While there is not an immediate need for a second 230 kV circuit through the Eastside, ***there are cost efficiencies with installing a second circuit transmission facility in the same corridor as the proposed 230 kV line. PSE will consider this as part of efforts to identify the least costly infrastructure to serve its customers.***

If there is a possibility of installing a second 230kV line, will there be another EIS to determine the impacts of construction and operation of that second line? What are the SEPA requirements for installing a second line?

2.3.2.2.1 / p 22 Overhead Transmission Line Locations

Consideration *is also made to avoid placing poles in environmentally critical areas like wetlands and unstable slopes.*

What does **consideration** mean? Just thinking about avoiding environmentally critical areas and unstable slopes does not avoid damaged areas if concrete preventative or avoidance actions are not taken.

2.3.2.2.2 / p 2-22 Pole Types and Heights for Overhead Lines

Generally, for a double circuit system, pole heights would range from 85 to 100 feet. In some configurations that could occur under Alternative 1, Option A, a double circuit would incorporate an existing 115 kV line with a new 230 kV line on poles similar to those shown in Figure 2-2. In special cases, such as crossing a ravine or highway, pole heights could be shorter ***or taller.***

What would be the maximum height of pole used?

2.3.2.2.3 / p 2-23 Construction Option A-1

In practice, PSE ***may be able to reduce the required clear zone****, in which case impacts would be less than those assumed for this phase of the EIS.*

What would PSE do to reduce the required clear zone. This needs to describe specific actions taken.

The clear zone for an overhead 230 kV line ***could be*** *approximately 120 to 150 feet wide. The transmission line* ***could be*** *located along existing 115 kV easements, which are typically 70 to 100 feet wide. Therefore, this analysis assumes that use of a 115 kV corridor* ***could require*** *the corridor to be widened by up to 50 feet. Section 2.3.5 summarizes the clear zone widths and other assumptions used for all alternatives in this EIS.*

The bolded words in the paragraph above are so conditional, they do not give a clear, accurate or honest statement of the range of feet the corridor would be widened. It begs the question if a 230 kV line could also be wider than 150 feet. If a property owner is next to an easement that is currently 70 feet wide, then it could require an additional 80 feet to create a 150 foot wide clear zone, which is 30 feet wider than "could require the corridor to be widened by up to 50 feet."

Coordination with Olympic Pipeline. If located along the existing 115 kV easement, construction of a 230 kV line has the ***potential to disrupt*** *the Olympic Pipeline. Extensive coordination with the Olympic Pipe Line Company would be required during project design and construction to avoid disruption to the two lines, or to establish relocation procedures.*

What does "potential to disrupt" the Olympic Pipeline mean. The specific disruptions need to be described.

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on behalf of **CENSE** Coalition of Eastside Neighborhoods for Sensible Energy

p 2-23 continued

*Pole installation. Poles can be directly embedded in the ground or utilize an anchor bolt cage, which is a drilled pier foundation that involves setting the anchor bolt cage in a poured column of concrete. Foundations for new 230 kV poles are typically **augered (drilled) 4 to 8 feet in diameter** with steel reinforcements that **could extend 25 to 50 feet deep depending on the structure type.** Steel poles are set and anchored to the foundations. In some cases, a caisson foundation is used for greater stability. (No foundations are used for wooden poles.) Approximately 100 pole foundations would need to be installed with a typical spacing between poles of 1,000 feet to extend the 18-mile distance between the Sammamish and Talbot Hill substations.*

The drilling activity described in the bolded words would certainly increase the probability of damage to the Olympic pipeline. While construction equipment is listed in Appendix B, there is no indication of the dimensions or weight of each piece of equipment, nor is there a description of where equipment would be located when in use. Would it be operating in the right of way, where would it be in juxtaposition to the pipeline, (above, how many feet away from the pipeline.)?

CHAPTER 3 EARTH

3.6.1.5 / p 3-14 Olympic Pipeline

*In addition to the aforementioned hazards, portions of the existing 115 kV overhead easement corridor are shared with the Olympic Pipe Line Company (OPLC) which operates two steel pipelines that transport petroleum products. The pipelines are 16 inches and 20 inches in diameter and buried approximately 3 to 4 feet below the ground surface. Construction of new transmission lines in the vicinity of the petroleum pipelines or other earthwork activities in or near these pipelines could represent potential hazards from inadvertent contact, causing excessive ground vibrations, or result in damage from erosion. **Although a significant adverse impact could occur during construction near petroleum pipelines, these potential hazards do not constitute a probable impact due to existing regulations and practices in place for pipeline safety. OPLC has stringent construction requirements in the area of its pipelines and would continue close coordination with PSE for all construction activities located adjacent to these pipelines. Therefore, no potentially significant adverse impacts related to work near pipelines are expected under any of the alternatives**.*

and p 8-28

Because compliance with all applicable requirements would help to reduce the probability of an occurrence to a very low likelihood, potential adverse impacts associated with construction of the project are characterized as minor

Dangerously simplistic thinking to state that potential hazards do not constitue a probable impact because regulations and practices for pipeline safety will eliminate any signficiant adverse impacts related to work near pipelines. Semantics and statistics do not negate the dangers of digging holes up to 50 feet deep near the Olympic Pipeline

CHAPTER 5 WATER

5.5.1.6 / p 5-12 Potential Pipeline Damage

*While **unlikely due to measures employed to prevent such accidents**, **it is possible** that the Olympic Pipeline could be damaged during construction. A pipeline rupture could have significant adverse effects on surface water and groundwater quality, depending on the location, size, and length of time of the rupture.*

Drilling holes 6-8 feet wide and 25 -50 feet deep, using large cranes to install a power pole, then filling the holes with concrete greatly increases the risk of damage to the pipeline. Even if small cracks are not

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detected during the construction phase, construction activities near the Olympic pipeline might create a ticking time bomb like occurred in Bellingham. In that case, excessive pressure in the pipeline due to a malfunction of a block valve and human error resulted in a devastating explosion erupting from a construction nick that occurred 5 years earlier.

CHAPTER 8 ENVIRONMENTAL HEALTH

8.2.2.1 / p 8-2 Activities Near Pipelines

Appendix M provides a list of identified regulations that apply to pipelines, along with response plans implemented by the Olympic Pipeline Company (OPLC) in particular, since OPLC's facilities were identified as a source of concern during EIS scoping. Some of the regulations are described here.

It is an oversimplificaton to assume that if all local, state, and federal regulations are followed, then impacts will be minor. This totally dismisses the very real possibility of human error during construction and operation of all alternatives. It also dismisses the very real fact, that Olympic Pipeline has both been sited and fined for a variety of pipeline safety violations, and still has not completed all required repairs required by OPS.
(refer to letters submitted with my oral comments at the March 1 Comments Meeting in Bellevue)

8.2.2.1 / p 8-4 Box

To comply with federal regulations, the Olympic Pipe Line Company has an integrity management program, including requirements to regularly inspect and monitor both natural gas and petroleum pipelines. Inspections are performed using a combination of tools to determine the suitability of the pipeline based on any anomalies detected, including corrosion, dents, or actual wall loss (loss of material on the inside or outside of the pipeline due to corrosion) (West, personal communication, 2015).

and 16.3.3 p 16-11&12 Petroleum Pipelines

OPLC operates its lines pursuant to its own easements and, where they overlap, subject to agreement with PSE and PSE's prior rights. In entering this agreement with PSE, OPLC agreed to: (1) install its pipeline at a depth and in a manner that would not interfere with PSE's facilities; (2) install and maintain permanent markers to give notice of the location of the pipeline; and (3) adjust and/or relocate the pipeline in the event of a conflict with PSE facilities.

Hazardous liquid pipelines are regulated by federal and state rules (see Appendix M, Pipeline Safety Requirements and Plans Relating to Petroleum Pipelines). The standards and enforcement actions are the responsibility of the federal Office of Pipeline Safety (OPS), as described in Chapter 8. Through passage of the Washington Pipeline Safety Act of 2000 (E2SHB 2420), the UTC was directed and obtained the authority from the OPS to inspect interstate hazardous liquid pipelines in Washington State in accordance with federal standards (UTC, 2015). OPLC is subject to full compliance with the applicable provisions of Title 49, CFR Part 195 for hazardous liquid pipelines, and as reinforced by the company's franchise agreements with the study area cities. These regulations address safety in design, construction, testing, operation, maintenance, and emergency response for pipeline facilities. In accordance with 49 CFR Part 195, regular inspections and monitoring of the pipelines are performed using a combination of tools to determine the suitability of the pipeline based on any anomalies detected, including wall loss, corrosion, or dents. The pipelines through the combined study area are currently on a 5-year general inspection schedule. If anomalies were to be detected, this timeframe would be shortened in accordance with federal requirements (West, 2015).

if OPLC becomes aware that a third party conducts any excavation or other significant work that may affect the pipeline, the company is required to conduct such inspections and testing as is necessary to determine that no direct or indirect damage was done to the pipeline and that the work did not abnormally load the pipeline or impair the effectiveness of the cathodic protection system (City of Bellevue, 2005; City of Kirkland, 2011; City of Newcastle, 2008; City of Renton, 2006).

and 16.3.3.1.1 / p 21

If located along the existing PSE 115 kV easement, construction of a 230 kV line has the potential to disrupt existing natural gas lines or the Olympic Pipeline. Extensive coordination with OPLC would be required during project design to avoid disruption to the two lines, or to establish relocation procedures. For large projects, such as Energize Eastside, OPLC would establish a team to review design, identify any vulnerabilities, and identify measures to avoid potential impacts, in coordination with the project proponent (West, 2015). Construction risks associated with the Olympic Pipeline include potential for compression damage from heavy vehicles or machinery driving or placed above the buried lines, potential for pipe disturbance during *excavations for new poles, and potential for pipe disturbance from removal of current poles. Certain machinery, such as auger equipment, can be a particular concern because of how heavy the equipment is. If there is a concern, measures can be used to avoid crossing the pipeline by taking a different route, or reducing or eliminating the concern by placing matting or other material to distribute the load to acceptable levels or relocating the pipeline.*

- When was the last inspection date for the section of the pipeline that is collocated with EE project?
- Were any anomalies found?
- If found have they been repaired?
- Would the increase from 115 kV to 230 kV require changes in your cathodic protection system?
- If yes, what changes would be required and how and when would they be implemented?
- What percentage of pressure drop in the pipeline is required to set off an alarm in HCA's?
- When a pipeline is located under a street, how is a leak detected?
- What is the minimum acceptable thickness of the pipeline wall to meet all OPS regulations
- On page 16-21 of the DEIS, you stated that construction of a 230kV line has the potential to disrupt existing natural gas lines or the Olympic Pipeline. What exactly do you mean by the word DISRUPT?
- Is it legally possible for OPL to say NO PSE's Energize Eastside Project?
- If not, why not?
- If there were a pipeline explosion during construction, how would liability be assigned to OPL, PSE, Sub contractors other entities?

8.2.2.1 / p 8-5

The ***combined study area communities*** *(Alternatives 1, 2, and 3 as depicted on Figure 1-4 in* Chapter 1) do not directly regulate pipeline safety, **but they have the authority to regulate land uses near pipelines within their jurisdictions to protect public health and safety. Some communities encourage co-location of pipelines with other utilities where safe, while others specifically co-location of critical utilities with hazardous fluid pipelines like the Olympic Pipeline.**

Why does Bellevue City Council believe they do not have the authority to regulate land uses near pipelines in their jurisdiction? Yes, they are the "legislative" branch of the city government, but they are also the managers of the "Executive" branch and are elected by the citizens to look after the best interests and safety of our community.

From MRSC - Municipal Resource Service Center in Seattle, WA:

http://mrsc.org/Home/Explore-Topics/Public-Safety/Special-Topics/Pipeline-Safety/Planning-Near-Pipelines.aspx

Planning Near Pipelines - Stakeholders

"Before considering changes to local land use procedures and regulations concerning transmission pipelines, it is necessary to understand who is involved (the stakeholders) and their respective roles in the process.

Stakeholders and Their Roles

Local Governments. Cities and counties have primary authority to establish land use regulations within their jurisdictions, including all lands crossed by or near transmission pipeline easements.

excavations for new poles, and potential for pipe disturbance from removal of current poles. Certain machinery, such as auger equipment, can be a particular concern because of how heavy the equipment is. If there is a concern, measures can be used to avoid crossing the pipeline by taking a different route, or reducing or eliminating the concern by placing matting or other material to distribute the load to acceptable levels or relocating the pipeline.

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Developers. Developers of residential or commercial projects (both large and small) are frequently direct landowners or have an ownership interest in properties crossed by or near transmission pipeline easements. They often are not knowledgeable about pipeline safety issues.

Private Landowners. They typically own most of the land crossed by the pipeline operators' easements or near the easements. They will be directly affected by any new land use regulations that impose restrictions on development. [Keep in mind that transmission pipeline easements also cross public lands owned by federal, state, local and tribal governments, or use rights of way controlled by local governments.]

Pipeline Operators. Easements provide pipeline operators the right to install, operate and repair their pipelines, and to place limits on what can be done by private and public landowners within those easements.

There Are Three Options Open to Local Governments:

• Do nothing and keep your fingers crossed, hoping that no serious pipeline failures occur within your jurisdiction. There are no federal or state "mandates" requiring that you consider these pipeline safety issues.

• Assume the worst and impose draconian regulations to safeguard the public from all possible risk in the event that a pipeline does rupture and ignite.

• Choose from a wide range of "recommended practices" that seek to protect the pipeline from damage and lessen the injuries and damage if a pipeline failure occurs.

Options one and two are extreme positions, and are probably not consistent with the values of your populace. Option three requires that planners and local government officials educate themselves about pipeline safety concerns and the recommended practices discussed here, assess the level of safety concern in their community, then adopt reasonable measures to promote the health and safety of the community.

8.2.2.1 / p 8-6

• The City of Kirkland's comprehensive plan includes policies that: establish standards to minimize pipeline damage, prohibit new **high consequence land uses**[1] from locating near a hazardous liquid pipeline corridor, support coordination with the pipeline operator when developments are proposed near the pipeline corridor, and require maintenance of the hazardous liquid pipeline corridor through their franchise agreement and other mechanisms (City of Kirkland, 2015).(City of Newcastle, 2015).

Footnote 1 regarding High Consequence Land Uses is defined in the DEIS as

1 High Consequence Land Use: A land use that if located in the vicinity of a hazardous liquid pipeline represents an unusually high risk in the event of a pipeline failure due to characteristics of the inhabitants or functions of the use. High consequence land uses include: 1. Land uses that involve a high-density on-site population that are more difficult to evacuate. These uses include: *continued on next page*

- *Schools (through grade 12)*
- *Hospitals, clinics, and other facilities primarily for use by the elderly or handicapped, other than those within single-family residences.*
- *Stadiums or arenas.*
- *Day care centers, and does not extend to family day care or adult family homes.*

A list of sensitive areas in the 18 miles transmission corridor follows.
The source is:

FACILITY RESPONSE PLAN pages 6-23 to 6-25
BP Pipelines (North America)
U.S. Pipelines and Logistics
Northwest Pipelines District
Prepared for:
Northwest Pipelines
600 SW 39th Street, Suite 275 Renton, WA 98057

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on behalf of **CENSE** Coalition of Eastside Neighborhoods for Sensible Energy

SS2	Seattle - 3	Sole Source Aquifer	Cross Valley Aquifer
HP3	Seattle - 3	Historic Building	North Creek School
HP4	Seattle - 3	Historic Building	Winningham Farm
HP5	Seattle - 3	Historic Building	Bates–Tanner Farm
HP6	Seattle - 3	Historic Building	Bothell Pioneer Cemetery
HP7	Seattle - 3	Historic Building	Chase, Dr. Reuben, House
HP8	Seattle - 3	Historic Building	Hollywood Farm
HP9	Seattle - 3	Historic Building	USCGC FIR
HP10	Seattle - 3	Historic Building	Turner-Koepf House
HP11	Seattle - 3	Historic Building	14th Avenue South Bridge
HP12	Seattle - 3	Historic Building	Cooper, Frank B., Elementary School
HP13	Seattle - 3	Historic Building	Seattle Public Library
HP14	Seattle - 3	Historic Building	Columbia City Historic District
HP15	Seattle - 3	Historic Building	Old Georgetown City Hall
HP16	Seattle - 3	Historic Building	Pacific Coast Company House No. 75
HP17	Seattle - 3	Historic Building	Building No. 105, Boeing Airplane Company
PK12	Seattle - 3	Park	Gold Creek County Park
PK13	Seattle - 3	Park	E Norway Hill Park
PK14	Seattle - 3	Park	Sammamish River Regional Park
PK15	Seattle - 3	Park	Mark Twain Park
PK16	Seattle - 3	Park	Willows Creek Neighborhood Park
PK17	Seattle - 3	Park	Grass Lawn Park
PK18	Seattle - 3	Park	King County Park
PK19	Seattle - 3	Park	Bridle Trails State Park
PK20	Seattle - 3	Park	Cherry Crest Park
PK21	Seattle - 3	Park	Bellevue Highlands Park
PK22	Seattle - 3	Park	Kelsey Creek Park
PK23	Seattle - 3	Park	Bannerwood Park
PK24	Seattle - 3	Park	Woodridge Park
PK25	Seattle - 3	Park	Robinswood Park
PK26	Seattle - 3	Park	Sweyolocken Park
PK27	Seattle - 3	Park	Sunset Ravine Park
PK28	Seattle - 3	Park	Jefferson Park
PK29	Seattle - 3	Park	Eastgate Park
PK30	Seattle - 3	Park	Puget Park
PK31	Seattle - 3	Park	Coal Creek Park
PK32	Seattle - 3	Park	Dearborn Park
PK33	Seattle - 3	Park	Hazelwood Park
PK34	Seattle - 3	Park	Atlantic City Park
PK35	Seattle - 3	Park	May Creek Park
PK36	Seattle - 3	Park	Kennydale Lions Park
PK37	Seattle - 3	Park	Lakeridge Park
SC30	Seattle - 3	School	Sunnyside Preschool and Kindergarten School Lake Stevens Campus
SC31	Seattle - 3	School	East Everett School
SC32	Seattle - 3	School	Cavelero Mid High School
SC33	Seattle - 3	School	Prove High School
SC34	Seattle - 3	School	Swans Trail School
SC35	Seattle - 3	School	Seattle Hill Elementary School
SC36	Seattle - 3	School	Small World Montessori School
SC37	Seattle - 3	School	Archbishop Murphy High School
SC38	Seattle - 3	School	Penny Creek Elementary School

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SC39	Seattle - 3	School	Kindercare Learning Center 1707
SC40	Seattle - 3	School	Silver Firs Elementary School
SC41	Seattle - 3	School	Mill Creek Elementary School
SC42	Seattle - 3	School	Nancys Noahs Ark Daycare Center
SC43	Seattle - 3	School	Forest View Elementary School
SC44	Seattle - 3	School	Gateway Middle School
SC45	Seattle - 3	School	Cedar Wood Elementary School
SC46	Seattle - 3	School	Fernwood Elementary School
SC47	Seattle - 3	School	Canyon Creek Elementary School
SC48	Seattle - 3	School	Skyview Junior High School
SC49	Seattle - 3	School	Skyview Junior High School
SC50	Seattle - 3	School	Kokanee Elementary School
SC51	Seattle - 3	School	Canyon Park Montessori School
SC52	Seattle - 3	School	Northshore School District - Special Services
SC53	Seattle - 3	School	Northshore School District Office
SC54	Seattle - 3	School	Woodinville High School
SC55	Seattle - 3	School	Learning Garden School Bothell
SC56	Seattle - 3	School	Woodin Elementary School
SC57	Seattle - 3	School	Woodinville Montessori School North Creek Bothell Campus
SC58	Seattle - 3	School	University of Washington - Bothell Campus
SC59	Seattle - 3	School	Cascadia Community College
SC60	Seattle - 3	School	University of Washington Bothell Campus Building 1
SC61	Seattle - 3	School	University of Washington Bothell Campus Commons
SC62	Seattle - 3	School	Dartmoor School
SC63	Seattle - 3	School	Kids Country Woodinville
SC64	Seattle - 3	School	Woodinville Elementary School
SC65	Seattle - 3	School	C O Sorenson School
SC66	Seattle - 3	School	Bellevue Christian School-Woodinville
SC67	Seattle - 3	School	Kindercare Learning Center 1617
SC68	Seattle - 3	School	Woodinville Montessori School
SC69	Seattle - 3	School	Woodinville Children Center
SC70	Seattle - 3	School	Cedar Park Christian School
SC71	Seattle - 3	School	Evergreen Academy Elementary School
SC72	Seattle - 3	School	Northshore Junior High School
SC73	Seattle - 3	School	Kindercare Learning Center 898
SC74	Seattle - 3	School	Woodmoor Elementary School
SC75	Seattle - 3	School	Lil' People's World Child Care Center
SC76	Seattle - 3	School	Tree of Life Daycare Center
SC77	Seattle - 3	School	Kamiakin Junior High School
SC78	Seattle - 3	School	John Muir Elementary School
SC79	Seattle - 3	School	Elite Kids Preschool Kirkland Center
SC80	Seattle - 3	School	Lake Washington Technical College
SC81	Seattle - 3	School	Lake Washington Technical College Early Learning Center
SC82	Seattle - 3	School	Kindercare Learning Center 1024
SC83	Seattle - 3	School	Springhurst School
SC84	Seattle - 3	School	Mark Twain Elementary School
SC85	Seattle - 3	School	City Kids Preschool

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SC86	Seattle - 3	School	Rose Hill Presbyterian Preschool
SC87	Seattle - 3	School	Discovery Center
SC88	Seattle - 3	School	Rose Hill Elementary School
SC89	Seattle - 3	School	Kindercare Learning Center 1053
SC90	Seattle - 3	School	The Orchard Daycare Center
SC91	Seattle - 3	School	Stella Schola Middle School
SC92	Seattle - 3	School	Rose Hill Junior High School
SC93	Seattle - 3	School	Benjamin Franklin Elementary School
SC94	Seattle - 3	School	Benjamin Rush Elementary School
SC95	Seattle - 3	School	Bright Horizons Overlake Daycare Center
SC96	Seattle - 3	School	Cherry Crest Elementary School
SC97	Seattle - 3	School	Bridle Trails Toys and Tots Daycare Center
SC98	Seattle - 3	School	Bellevue Children's Academy
SC99	Seattle - 3	School	Learning Garden School
SC100	Seattle - 3	School	Planet Kids Montessori School
SC101	Seattle - 3	School	America's Child Montessori School
SC102	Seattle - 3	School	The Academic Institute
SC103	Seattle - 3	School	Bel - Red Bilingual Academy
SC104	Seattle - 3	School	Highland Middle School
SC105	Seattle - 3	School	Early World Childrens School
SC106	Seattle - 3	School	A+ Alternative School
SC107	Seattle - 3	School	Dartmoor School
SC108	Seattle - 3	School	Eastside Academic School of Transit
SC109	Seattle - 3	School	Stevenson Elementary School
SC110	Seattle - 3	School	Cedar Park Christian School - Bellevue Campus
SC111	Seattle - 3	School	Odle Middle School
SC112	Seattle - 3	School	Three Cedars Waldorf School
SC113	Seattle - 3	School	Olympus Northwest Middle School
SC114	Seattle - 3	School	Jing Mei Elementary School
SC115	Seattle - 3	School	Bellevue School District Office
SC116	Seattle - 3	School	Wilburton Elementary School
SC117	Seattle - 3	School	Sammamish High School
SC118	Seattle - 3	School	Hyak Junior High School (historical)
SC119	Seattle - 3	School	International School
SC120	Seattle - 3	School	Lake Hills Elementary School
SC121	Seattle - 3	School	Kelsey Creek Home School Center
SC122	Seattle - 3	School	Robinswood Middle School
SC123	Seattle - 3	School	Robinswood High School
SC124	Seattle - 3	School	Robinswood Elementary School
SC125	Seattle - 3	School	Woodridge Elementary School
SC126	Seattle - 3	School	Eastside Christian School
SC127	Seattle - 3	School	Chestnut Hill Academy South Campus
SC128	Seattle - 3	School	Bellevue Community College
SC129	Seattle - 3	School	Learning Garden School Sunset
SC130	Seattle - 3	School	Career Link School
SC131	Seattle - 3	School	John Stanford Center for Educational Excellence
SC132	Seattle - 3	School	Jose Martin Child Development Center
SC133	Seattle - 3	School	Puesta del Sol Elementary School
SC134	Seattle - 3	School	Kimball Elementary School
SC135	Seattle - 3	School	Tyee Middle School

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SC136	Seattle - 3	School	Denise Louie Education Center Beacon Hill
SC137	Seattle - 3	School	Kindercare Learning Center 946
SC138	Seattle - 3	School	Eastgate Elementary School
SC139	Seattle - 3	School	Newport Childrens School
SC140	Seattle - 3	School	Mustard Seed Child Care Center
SC141	Seattle - 3	School	Newport High School
SC142	Seattle - 3	School	Asa Mercer Middle School
SC143	Seattle - 3	School	Mercer Middle School
SC144	Seattle - 3	School	Somerset Elementary School
SC145	Seattle - 3	School	Pathfinder K - 8 School
SC146	Seattle - 3	School	Southwest Youth and Family Services
SC147	Seattle - 3	School	Interagency Alder Academy
SC148	Seattle - 3	School	Interagency Camp School
SC149	Seattle - 3	School	Interagency Fairview Academy
SC150	Seattle - 3	School	Interagency King County Jail School
SC151	Seattle - 3	School	Interagency Orion Center
SC152	Seattle - 3	School	Interagency Ryther Center
SC153	Seattle - 3	School	Interagency Southwest Youth and Family School
SC154	Seattle - 3	School	Interagency U District Youth Center
SC155	Seattle - 3	School	Zion Preparatory Academy
SC156	Seattle - 3	School	Sunnyside Montessori School
SC157	Seattle - 3	School	Forest Ridge School of the Sacred Heart
SC158	Seattle - 3	School	Orca Alternative
SC159	Seattle - 3	School	Columbia Elementary School
SC160	Seattle - 3	School	The New School at Columbia
SC161	Seattle - 3	School	Maple Elementary School
SC162	Seattle - 3	School	Saint George Parish School
SC163	Seattle - 3	School	Lake Heights Elementary School
SC164	Seattle - 3	School	Damascus Daycare Center
SC165	Seattle - 3	School	Alternative School Number One
SC166	Seattle - 3	School	Primm ABC Child Care Center and Preschool
SC167	Seattle - 3	School	Dearborn Park Elementary School
SC168	Seattle - 3	School	Newport Hills School
SC169	Seattle - 3	School	Cleveland High School
SC170	Seattle - 3	School	Newport Heights Elementary
SC171	Seattle - 3	School	Saint Edward Parish School
SC172	Seattle - 3	School	Ringdall Junior High School
SC173	Seattle - 3	School	Torah Day School of Seattle
SC174	Seattle - 3	School	Aki Kurose Middle School Academy
SC175	Seattle - 3	School	Sharples Junior High School
SC176	Seattle - 3	School	Gloryland Daycare Center
SC177	Seattle - 3	School	Martin Luther King Junior Elementary School
SC178	Seattle - 3	School	Renton Academy
SC179	Seattle - 3	School	Megumi Preschool Seattle
SC180	Seattle - 3	School	Van Asselt Elementary School
SC181	Seattle - 3	School	Hazelwood Elementary School
SC182	Seattle - 3	School	Seattle Urban Academy
SC183	Seattle - 3	School	Wing Luke Elementary School

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SC136	Seattle - 3	School	Denise Louie Education Center Beacon Hill
SC137	Seattle - 3	School	Kindercare Learning Center 946
SC138	Seattle - 3	School	Eastgate Elementary School
SC139	Seattle - 3	School	Newport Childrens School
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SC150	Seattle - 3	School	Interagency King County Jail School
SC151	Seattle - 3	School	Interagency Orion Center
SC152	Seattle - 3	School	Interagency Ryther Center
SC153	Seattle - 3	School	Interagency Southwest Youth and Family School
SC154	Seattle - 3	School	Interagency U District Youth Center
SC155	Seattle - 3	School	Zion Preparatory Academy
SC156	Seattle - 3	School	Sunnyside Montessori School
SC157	Seattle - 3	School	Forest Ridge School of the Sacred Heart
SC158	Seattle - 3	School	Orca Alternative
SC159	Seattle - 3	School	Columbia Elementary School
SC160	Seattle - 3	School	The New School at Columbia
SC161	Seattle - 3	School	Maple Elementary School
SC162	Seattle - 3	School	Saint George Parish School
SC163	Seattle - 3	School	Lake Heights Elementary School
SC164	Seattle - 3	School	Damascus Daycare Center
SC165	Seattle - 3	School	Alternative School Number One
SC166	Seattle - 3	School	Primm ABC Child Care Center and Preschool
SC167	Seattle - 3	School	Dearborn Park Elementary School
SC168	Seattle - 3	School	Newport Hills School
SC169	Seattle - 3	School	Cleveland High School
SC170	Seattle - 3	School	Newport Heights Elementary
SC171	Seattle - 3	School	Saint Edward Parish School
SC172	Seattle - 3	School	Ringdall Junior High School
SC173	Seattle - 3	School	Torah Day School of Seattle
SC174	Seattle - 3	School	Aki Kurose Middle School Academy
SC175	Seattle - 3	School	Sharples Junior High School
SC176	Seattle - 3	School	Gloryland Daycare Center
SC177	Seattle - 3	School	Martin Luther King Junior Elementary School
SC178	Seattle - 3	School	Renton Academy
SC179	Seattle - 3	School	Megumi Preschool Seattle
SC180	Seattle - 3	School	Van Asselt Elementary School
SC181	Seattle - 3	School	Hazelwood Elementary School
SC182	Seattle - 3	School	Seattle Urban Academy
SC183	Seattle - 3	School	Wing Luke Elementary School

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8.5.1.2 Public Safety Risks – Activities Near Pipelines

Construction of the project could theoretically damage the hazardous liquid pipelines operated by OPLC and other gas lines mentioned in Section 8.3.2, creating an explosion risk if safety policies and regulations were not implemented as required. The UTC identifies five major reasons why gas pipelines leak or fail, potentially creating a public safety hazard: (1) third-party excavation damage; (2) corrosion; (3) construction defects; (4) material defects; and (5) outside forces resulting from earth movement, including earthquakes, washouts, landslides, frost, lightning, ice, snow, and damage done by authorized on-site personnel. TMinor - If damage to pipelines could lead to leaks of materials that could be cleaned up and sites fully restored in accordance with applicable regulatory requirements, impacts would be considered minor. Moderate - If implementation of regulatory requirements and project design would address most potential adverse impacts, but there is a reasonable potential for some damage to pipelines that could result in impacts to property or human health, impacts would be considered moderate. Significant–Even with implementation of regulatory requirements and design measures, if substantial damage, injury, or death would likely occur associated with pipeline damage, leaks, or explosions, impacts would be considered significant. P 8-24

Source:

GAO Report to Congressional Committee on Pipeline Safety January 2013
Pipeline Safety: Better Data amd Guidance Needed to Improve Pipeline Operator Incident Response

While prior research shows that most of the fatalities and damage from an incident occur in the first few minutes following a pipeline rupture, operators can reduce some of the consequences by taking actions that include closing valves that are spaced along the pipeline to isolate segments. The amount of time it takes to close a valve depends upon the equipment installed on the pipeline. For example, valves with manual controls (referred to as "manual valves") require a person to arrive on site and either turn a wheel crank or activate a push-button actuator. Valves that can be closed without a person located at the valve location (referred to as "automated valves") include both remote-control valves, which can be closed via a command from a control room, and automatic-shutoff valves, which can close without human intervention based on sensor Page 11 GAO-13-168.) Automated valves generally take less time to close than manual valves. PHMSA's minimum safety standards dictate the spacing of all valves, regardless of type of equipment installed to close them,while integrity management regulations require that transmission pipeline operators conduct a risk assessment for highconsequence areas that includes the consideration of automated valves.

From Appendix C-6 Olympic Pipeline System Overview - Report to Dept of Ecology, March 2015

Location of Block Valves and which ones are manually or remotely operated.

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FIGURE C.6 – BLOCK VALVE DRIVING DIRECTIONS (CONTINUED)

Anacortes Lateral	Latitude	Longitude	Driving Directions
MP 79 Block Valve 16" (MOV) & 20" Check Valve	47.903305	-122.169114	From I-405, take exit #23 and head north on Hwy 522 to Hwy 9 exit. Turn left (north) on Hwy 9, go approximately 6.9 miles to Lowell-Larimer Rd. and turn west (left) at this light. Go approximately 2 miles to intersection of Marsh/Lowell-Larimer and Seattle Hill Rds. Bear right then turn left back onto Lowell-Larimer Rd. and continue on for approximately 1.4 miles. Watch for the pipeline markers and gated area of the road, the Block Valve site is 200' north of the road down the gravel driveway behind fencing.
MP 80 Block Valve 20" (HOV)	47.895546	-122.169323	From I-5, take exit #186, head east on 128th St/Hwy 96 to 35th Ave. SE. Turn left at light; go north approximately 1 mile to 116th St SE, turn right. Go approximately 0.7 miles to Pinehurst housing development; turn left on 45th Dr SE, then immediately east (right) on 115th PL SE, which eventually turns into 47th Ave SE heading north. Follow 47th Ave till you get to 113th St SE turn west (left) total trip from 116th is 0.3 miles. The Block Valve site will be on your right hand side gated and clearly visible from the road approx. 25'. From I-405, take exit # 26, Bothell-Everett Hwy north (right) on 180th. Left on 35th Ave Se travel north approx 3.5 miles to 116th St SE, turn right. Follow directions as above.
Allen Station to Renton Station	**Latitude**	**Longitude**	**Driving Directions**
Woodinville Station	47.798892	-122.171062	From I-405, take exit # 23 and head north on Hwy 522 to Hwy 9 exit. Turn left (north) at light, head north for 0.7 miles, then turn west (left) at 228th St SE for Approx. 1.4 miles till you reach 45th Ave SE, then turn north (right). Follow 45th Ave 0.5 miles till you come to address 21909 45th Ave SE and turn right at driveway.
MP 89 Block Valve 16" & 20" (MOV)	47.762627	-122.173828	From I-405, take exit # 24 (Beardslee Blvd exit) and head east on NE 195th St. Follow for approx. 0.4 miles to 120th Ave NE, turn south (right). After about 0.5 miles turn left at first driveway of the Archstone apartment complex across from Home Depot and between the Starbucks coffee house and Seattle times parking lot end. Go down new Apartment complex road till you come to pipeline markers (approx. 4 blocks). The Block Valves are north of that location gated and visible from the road (follow dirt road north (left) for access). MP marker 89 is clearly visible from the road.
MP 89.5 16" Check Valve & 20" Block Valve (HOV)	47.75547162	-122.1738939	From I-405, to exit # 23 (Hwy 522), go approx. 1 mile to the Woodinville exit and head south (right) on Hwy 202 for 0.2 miles to NE 175th St/Hwy 202 and turn west (right) at the light. Travel 0.3 miles across bridge and railroad tracks and turn west (right) on NE 173rd PL. Follow to the first driveway on right, approx. 0.3 miles - you'll cross over the pipeline at this time before you get to the driveway. Go over the railroad tracks again and turn east (right) and follow to the pipeline crossing approx. 2 blocks, with the Block Valve on the North side within the small island in the parking lot.
MP 95.5 Block Valve 16" & 20" (MOV)	47.67776	-122.158556	From I-405, take exit # 18 (NE 85th St) and head east approx. 1.4 miles, look for the pipeline markers around the 13600 block of NE 85th St. The Block Valve's will be on the south side of the road gated and clearly visible from the road.
MP 98.5 Block Valve 16" & 20" (MOV)	47.63138	-122.159494	From I-405, take exit # 14, Hwy 520, heading east towards Redmond. Take the very first exit on 520 which is Northrup Way and turn east (left) at the light stay in the left hand lane, go about 6 blocks then turn north (left) on 130th Ave NE and go approx. 4 blocks to NE 24th St. Turn east (right) on 24th and go approx. 5 ½ blocks until you come to the pipeline crossing. The Block Valve's will be on the south side of road at the 13500 block clearly gated and visible from the road, approx. 100'.
MP 100.1 Block Valve 20" (HOV)	47.603459	-122.158769	From I-405, take exit # 12 (SE 8th St) and go east approx. 0.4 miles to Lake Hills Connector, take this road east (right) and go approx. 1.5 miles to 140th Ave SE. Turn north (left) on 140th and go 1 block north to SE 7th St and turn west (left), go all the way to the end of the road where it dead ends at a trail. Follow the gravel trail downhill till you come to the pipeline Right of Way which is 1 or 2 blocks of walking, the pipeline Block Valve site is on the south (left) hand side at the bottom of the trail approx. 25'.

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FIGURE C.6 – BLOCK VALVE DRIVING DIRECTIONS (CONTINUED)

Allen Station to Renton Station	Latitude	Longitude	Driving Directions
MP 101.8 Block Valve 20" (MOV)	47.588158	-122.158339	From I-405, take exit # 10 (Coal Creek Pkwy) and head east for approx. 0.5 miles to Factoria Blvd/128th Ave SE, turn north (left) at the light. Follow this road for approx. 1.6 miles and stay in your right hand lane when approaching SE 26th St. (you will go underneath I-90). Turn east (right) on SE 26th St (Kamber Rd.) and go approx. 0.3 miles to the pipeline crossing at 13615 SE 26th St. The 16" Block Valve site will be on the south side of the road gated and clearly visible within 50' of the road. The 20" Block Valve site will be on the north side of the road.
MP 102 Block Valve 16" (MOV)	47.587143	-122.158356	From I-405, take exit # 10 (Coal Creek Pkwy) and head east for approx. 0.5 miles to Factoria Blvd/128th Ave SE, turn north (left) at the light. Follow this road for approx. 1.6 miles and stay in your right hand lane when approaching SE 26th St. (you will go underneath I-90). Turn east (right) on SE 26th St (Kamber Rd.) and go approx. 0.3 miles to the pipeline crossing at 13615 SE 26th St. The 16" Block Valve site will be on the south side of the road gated and clearly visible within 50' of the road. The 20" Block Valve site will be on the north side of the road.
MP 103 Check Valve 20"	47.56302	-122.169659	From I-405, take exit 10 and head east on Coal Creek Parkway for .6 miles. Check valve is in a vault in north edge of parking lot.
MP 103 Check Valve 16"	47.571255	-122.157082	From I-405, take exit #10 (Coal Creek Pkwy) and head east and take a left at Factoria Blvd. Right on SE Newport way for .7 miles and turn right at Somerset Blvd Se, left on Somerset Blvd valve is on your left at chain link fence.
MP 105 Block Valve 16" & 20" (MOV)	47.537778	-122.169522	From I-405, take exit # 10 (Coal Creek Pkwy) and head east, continue on Coal Creek Pkwy in a Southeast direction for approx. 2.5 miles. Turn west (right) on SE 69th Way and go .2 miles to the pipeline crossing at the 12800 block, open the Right of Way gate and head south (left) down gravel road for 2 blocks. The Block Valve is approx. 250' south of the gravel road.
MP 106 Block Valve 16" & 20" (MOV)	47.513218	-122.171135	From I-405, take exit # 5 (NE Park Dr/Sunset Blvd) and head east off the freeway, stay on Sunset for approx. 1.8 miles and turn north (left) at Union Ave NE for approx. 0.6 miles then turn west (left) on SE 101st St which eventually becomes SE 100th St. Follow down 101st for 0.3 miles to the pipeline crossing at the 12500-12600 block, then turn left on the gravel road to the clearly visible gated area 100' south of 100th
MP 106 Block Valve 16" & 20" (MOV)	47.513218	-122.171135	From I-405, take exit # 5 (NE Park Dr/Sunset Blvd) and head east off the freeway, stay on Sunset for approx. 1.8 miles and turn north (left) at Union Ave NE for approx. 0.6 miles then turn west (left) on SE 101st St which eventually becomes SE 100th St. Follow down 101st for 0.3 miles to the pipeline crossing at the 12500-12600 block, then turn left on the gravel road to a visible gated area 100' south of 100th St.
MP 110 Block Valve 16" & 20" (MOV)	47.476309	-122.171624	From I-405, take exit # 4 (Maple Valley Hwy) and head east for approx. 0.1 mile, turn northeast (left) on SE 5th St 0.4 miles to the pipeline crossing. The Block Valves are gated and clearly visible on the north side of the road approx. 50' from road.
MP 110.5 Check Valve 16" & 20"	47.473652	-122.176681	From I-405, take exit #2 (Rainier Ave/Hwy 167) north to S Grady Way. Turn right (east) follow for 0.4 miles to Talbot Rd. turn south (right). Take Talbot Rd. for 0.5 miles to S. Puget Dr. and turn southwest (left) and take this for approx. 1.4 miles until you get to the intersection of Royal Hills Dr/Edmonds Dr. SE. Turn northeast (left) onto Royal Hills Dr. for 0.4 miles to new road called Harrington Pl. SE, this is a new development called the Shadow Hawk Town homes (Code Key-Key 0415). Once on Harrington Pl. continue on 0.2 miles to the pipeline crossing, from here the MP marker 110 should be clearly visible. From MP 110 marker go ¼ mile north to the valve sites, which are in concrete vaults.
MP 111 Block Valve 20" (HOV)	47.469956	-122.191586	From I-405, take exit #2 (Rainier Ave/Hwy 167) north for one block and turn west (right) on SW Grady Way and follow for 0.4 miles to Talbot Rd. turn south (right). Take Talbot Rd. for 0.5 miles to S. Puget Dr., turn southwest (left) and follow for approx. 1.4 miles to a PSE service road, which is approx. ½ block from the intersection of Royal Hills/S Puget Dr./Edmonds Dr. SE. Take this service road west (left) for 0.3 miles and look for the pipeline crossing - the Block Valve site is on the south side of the service road approx. 100' in a concrete vault.

FIGURE C.6 – BLOCK VALVE DRIVING DIRECTIONS (CONTINUED)

Allen Station to Renton Station	Latitude	Longitude	Driving Directions
MP 112 Block Valve 20" (HOV)	47.459059	-122.218799	From I-405, take exit # 2 (Rainier Ave/Hwy 167) north one block to SW Grady Way then turn west (left) and go 0.3 miles to Lind Ave SW. Turn south (left) on Lind Ave over the 405 over pass to the first light which is SW 16th St. Turn east (left) and follow approx 0.7 miles (becomes East Valley Rd.) to the pipeline crossing around the 2300 block of East Valley, turn west (right) on driveway to clearly visible and gated area approx. 100' west of the road.
Renton Station	47.458068	-122.224366	From I-405, take exit # 2 (Rainier Ave/Hwy 167) north one block to SW Grady Way, turn west (left), go 0.3 miles to Lind Ave SW and turn south (left). Go 0.9 miles on Lind to the driveway address of 2319 Lind Ave SW on the west side of the road.
Sea-Tac Lateral	**Latitude**	**Longitude**	**Driving Directions**
MP 1.5 Block Valve 12" (HOV)	47.476437	-122.227465	From I-405, take exit # 2 (Rainier Ave/Hwy 167) north, proceed 0.3 miles to SW 7th St. Turn west (left) on 7th 0.1 miles to Hardie Ave SW and turn north (right), follow Hardie Ave for 0.2 miles then turn west (left) on SW 5th PL. Go approx. 0.3 miles and turn west (left) on SW 5th Ct., go 0.1 miles and follow to the left of apartment building "H" driveway of the Avalon Greenbriar Apts. The Block Valve site is on the right side of apartment building "K" slightly downhill and approx. 100' from the driveway.
MP 2 Check Valve 12"	47.481663	-122.226964	From SR 167, heading north take the SR 900/SW Sunset Blvd headed west. Go .5 miles and turn (right) north on Earlington Ave Sw left on SW Langston Rd. Valve site is 450' up the road on your right.
MP 6 Block Valve 12" (MOV)	47.523506	-122.278396	Take I-5, north to exit # 157 (Martin Luther King Jr. Way). Stay in the right hand lane for approx. 1.1 miles and turn east (right) on S Henderson St. proceed on Henderson for 100' and look for pipeline crossing markers, the Block Valve site is on the north (left) side of Henderson St. gated and clearly visible from the road within 50'.
MP 10 Block Valve 12" (MOV)	47.569684	-122.326049	Take I-5, south to exit # 163 (Safeco Field/Spokane St. exit). Once off the exit at the bottom of the ramp at the first light, which is 6th Ave S go 0.1 miles heading west on Spokane St. to the first left hand "U" turn heading east on Spokane St. Go 0.1 miles back to 6th Ave S then turn south (right) on 6th and follow for 0.1 miles, the Block Valve site on the SE corner of 6th and Charlestown approx. 50' from 6th Ave S.
MP 1.5 Block Valve	47.476356	-122.227467	From SR 167 and I 405 intersections take Rainer Ave S North for .18 miles and turn left and go straight onto Stevens Ave Sw. Turn left on SW 5th st. Valve is located down the hill in yard.
MP 2 Check Valve	47.48767	-122.22697	From SR 167 and I 405 intersections take Rainer Ave S North for .66 miles and turn left on SR 900/Sunset Blvd. Go .11 miles and turn right on Hardie Ave Sw and keep left onto Langston. CV will be on your right at .38 miles.
MP 6 Block Valve (MOV)	47.523506	-122.278397	From I-5 south bound take exit 158 and turn left on Boeing Access rd. Turn left onto Martin Luther King Jr Way South. Go for .95 miles and turn then right onto South Henderson St. Valve site will be on your left. From I-5 North bound take exit 157 and go straight onto Martin Luther King Jr Way South for 1.72 miles and turn then right onto South Henderson St. Valve site will be on your left.
MP 10 Block Valve (MOV)	47.56966	-122.32604	From I-5 South bound take exit 163A and go straight on West Seattle Freeway ramp. Take the South Spokane St ramp and head east on South Spokane St and turn right onto 6th Ave South and then turn left onto South Charlstown St. Valve will be on your right. From I-5 North bound take exit 163 and keep left on South Spokane St ramp. Turn left onto 6th Ave South and then turn left onto South Charlstown St. Valve will be on your right.
Seattle DF	47.582619	-122.351571	From I-5, north take exit # 163 the West Seattle Freeway exit, on the West Seattle Freeway go for approx. 0.9 miles to the Harbor Island/11th Ave SW exit. Once the exit is made go 0.6 miles staying in the middle lane to Klickitat Ave SW. Turn north (right) on Klickitat Ave SW and continue on for 0.6 miles until you reach SW Lander St. and turn east (right). Follow Lander for 0.1 mile and turn north (left) on 13th Ave SW, follow 13th for 0.2 miles to the address of 2444 13th Ave SW on the east (right) side of the road.

Submitted by **Janis Philbin Medley** 4609 Somerset Drive SE • Bellevue, WA 98006 • 425 922 7415
on behalf of **CENSE** Coalition of Eastside Neighborhoods for Sensible Energy

Fire Engineering

JET FUEL

10/01/2002

By Frank L. Fire

Commercial jet fuel is essentially kerosene that has been hydrotreated to improve its burning properties. Hydrotreatment is a process proprietary to the producer of the fuel utilizing a particular catalyst. It will contain some additives to produce the anti-icing, anti-oxidation, anti-corrosion, and anti-static properties required.

Kerosene is a mixture of aliphatic (straight-chain alkanes or saturated) hydrocarbons, usually beginning with octane (eight carbons in the chain) and going up to hexadecane (16-carbon hydrocarbon). Alkanes have the general formula CnH2n+2. The n stands for the number of carbons in the chain, so hexadecane's molecular formula would be C16H34. Kerosene is formulated to fit the definition of a combustible liquid rather than a flammable liquid. The flash point of kerosene is controlled to be 100°F, or 37.8°C, to be classified as a combustible liquid.

Commercial jet fuel has many synonyms and trade names, including Jet A or JP-8. It is also known as aviation kerosene, Jet A-1, Jet A-50, Jet B, jet kerosene, jet kerosine, Turbo fuel A, and Turbo fuel A-1. Kerosene may also be called kerosine.

Commercial jet fuel is a pale yellow liquid with a petroleum odor. It has an auto-ignition temperature of 410°F (210°C). Its explosive limits are from 0.6 to 4.7 percent by volume in air. Coupled with its flash point, this means that at 100°F there is enough vapor in the air to reach the lower explosive limit so that even if an ignition source is not present and the fuel reaches a temperature of 410°F (and this is considerably below all common ignition sources), an explosion will occur.

Commercial jet fuel has a vapor density of 5.7 (where air = 1.0), which means the vapors are extremely heavy relative to air and will fall to the lowest point in the terrain and "hang" together for a long time where there is no appreciable breeze. These vapors will flow a considerable distance as if they were seeking an ignition source. They always find one.

Its specific gravity is 0.87, and it is not soluble in water. This means that the liquid will float on top of any water it contacts.

A flash point of 100°F means that it must be warmed to that temperature before it will produce enough vapors to burn (or explode). Any airplane with fuel in it is a flying bomb. If it crashes accidentally into the ground or on purpose as at the World Trade Center (WTC), the friction of the crash produces enough heat energy to ignite the fuel (which has been released by the crash) in a spectacular explosion. Even though the explosion is violent, all of the fuel is not involved, since much of it will be hurled away from the original point of energy release. At the WTC, after the initial explosion, some of the fuel was expelled from the building, but the remaining walls and windows confined much of it.

Hydrocarbons are essentially all fuel, since both the carbon and hydrogen will burn. There is a tremendous amount of energy tied up in the covalent bonds holding the hydrogen atoms to the carbon atoms in the hydrocarbon chain. When these bonds are broken, the energy is released in the fire as the fuel's heat of combustion. This is defined as the total amount of energy released as a fuel burns completely. Jet fuel has a heat of combustion of more than 19,000 Btus per pound of fuel, or more than 128,000 Btus per gallon of fuel. Multiply this by the amount of fuel in the airliner, and even though some of it was involved in the original explosion, you can understand that there was a tremendous amount of energy released in a short period of time during the ensuing fire of the remaining fuel. The burning jet fuel, plus whatever combustibles were present in the area of impact, produced more than enough heat to raise the temperature of the structural steel above its softening point, causing the floor or floors above the fire to collapse pancake style. There probably can be no tall building built that would withstand the heat generated by the quantity of jet fuel present in the WTC attack. If one can be built, no one would be able to pay for it.

Many victims probably were incinerated in the fireballs of jet fuel that roared through the upper floors of the towers. Many others were dismembered in the crashes or the collapses that followed. Firefighters and others at the scene have reported finding few intact bodies.

"The heat of the fire—estimated by FEMA at 1,700 degrees—would make identification difficult because it consumed smaller body parts," said Dr. Steven Symes, a professor of forensic pathology at the University of Tennessee.—*"NY Shifts from Rescue to Recovery," Richard Pyle, AP writer with contribution from AP reporter Diego Ibarguen, Sept. 17, 2001*

FRANK L. FIRE is executive vice president, marketing and international, for Americhem, Inc. in Cuyahoga Falls, Ohio. He is an instructor of hazardous-materials chemistry at the University of Akron as well as an adjunct instructor of haz mats at the National Fire Academy. Fire is the author of Common Sense Approach to Hazardous Materials (first and second editions) and an accompanying study guide; The Combustibility of Plastics; and Chemical Data Notebook: A User's Manual, published by Fire Engineering. He is an editorial advisory board member of Fire Engineering.

----- Energize Eastside Draft EIS Comment -----

James Loring
1815 153rd Avenue South East
Bellevue, Washington 98007-6141

I would urge you to adopt Alternative 4, “No Action.”

There is enough documentation submitted in this EIS process to cast doubt on the assumptions Puget Sound Energy has made in its rationale for this 8 mile, 230,000-volt transmission line and has failed to identify all adverse environmental impacts resulting from this proposal.

It has been asserted by local community groups and private experts that PSE has been less forthcoming in providing the rationale or data for its assumptions. Indeed, nationally recognized power and transmission planners have been unable to duplicate PSE's modeling under the assumptions the PSE has made in justification of this project.

The Lauckhart and Schiffman report submitted for your consideration indicates decades will pass before demand exceeds supply capacity for the area under study. PSE appears to be using a summer rating capacity for its transformers during a winter peak scenario. The winter rating is up to 31 percent higher, significantly increasing the capacity available for winter peak demand. PSE Further, the project proponent assumes little or no generation in the Puget Sound area while continuing transmission to Canada in the event of major disruption or winter peak scenario.

Puget Sound Energy's faulty assumptions permeate this proposal. Its justifications for the necessity of new power lines unfounded. While building major regional electrical transmission infrastructure through residential neighborhoods destroying some 8,000 tress, promoting blight across public parks, wetlands, and recreational facilities, it does nothing to bring the Puget Sound region's power grid to any semblance of the “Smart Grid” of the future. It is simply ignored in the assumption stringing more wire is the future. We deserve better.

The “No Action” Alternative 4 is the best course at this juncture. It's time Puget Sound Energy went back to the drawing board, seeking a more collaborative approach with the local jurisdictions and community groups such as CENSE.

----- Energize Eastside Draft EIS Comment -----

To: Heidi Bedwell, Energize Eastside EIS Program Manager
450 110th Ave NE
Bellevue, WA 98004

From: Curtis Allred
CENSE member
13609 SE 43rd Pl
Bellevue, WA 98006

Subject: **Comments on Energize Eastside Phase 1 Draft EIS - Historic and Cultural Resources**

Date: 14 March, 2016

Section 13.5.4

This section suggests Alternative 2 could have significant impacts to archaeological and historical resources, based on the quantity of sites in the study area:

> ***13.5.4 Alternative 2: Integrated Resource Approach***
>
> *The components being considered under Alternative 2 have the potential for minor to significant impacts to archaeological resources, if present, depending on the proposed locations. If the historic properties are King County Landmarks, a Certificate of Appropriateness (COA) may be necessary depending on the terms of the designating ordinance.*
>
> *The Alternative 2 study area contains 39 historic register properties (the second highest amount of the three study areas) and 43 recorded archaeological resources (the least of the three study areas). Existing surveys provide coverage of about 25 percent of the study area, which is the highest amount of all the alternatives. The Alternative 2 study area includes the eastern shoreline of Lake Sammamish. There are many recorded archaeological resources along these shorelines. Alternative 2 contains the same 8 recorded historic period cemeteries as Alternative 1 and impacts would be the same.*

This is misleading, as Alternative 2 has considerable flexibility in the location of the distributed power components, and thus can avoid disturbing important sites. Construction sites in other alternatives are relatively fixed and rigid, thus increasing the risk that Archaeological and Historical sites will be disturbed. For example, in Alternative 1, power lines must be placed in a fixed corridor and poles planted in specific locations based on engineering requirements. In contrast, Alternative 2 components such as power storage facilities and solar farms have much more flexibility with respect to location, so they can be placed in locations which minimize disturbance to important Archaeological and Historical sites.

It should be stated that Alternative 2 would actually have minor impact, because solution components would be sited in locations which do not disturb important Archaeological and Historical sites.

Section 13.5.4.5

This section discusses impacts of construction of Peak Generation Plants.

We believe that Alternative 2 does not require construction of additional generation plants. When Alternative 2 is updated to reflect modern, proven technologies, it will not be necessary to build Peak Generation Plants to meet the requirements for Energize Eastside. This section should be removed, or at least rewritten to make it clear that additional generation is an option and will likely not be required for Alternative 2.

Sections 13.5.4.1 and 13.6.4.1

These sections discuss the Construction phase and Operation phase, respectively, of the "Energy Efficiency Component" of Alternative 2, concluding that there could be "significant impacts" to historic properties and archaeological resources:

> ***13.5.4.1 Energy Efficiency Component***
>
> *The types of potential impacts from energy efficiency efforts may include modifications to existing buildings (weatherization, efficient lighting). Weatherization could include replacement of original windows which has the potential to diminish a building or structure's integrity of design, materials, workmanship, and feeling, if the replacement windows are not in-kind with their original architectural character, thus impacting the property's potential for conveying its historical significance (Myers, 1981). Any modifications that are permanent have the potential to impact a property's ability to convey its historical significance, which would be significant impact, as described in Section 13.4. ... Continued implementation of existing energy efficient improvements may result in minor to significant impacts to historic properties and archaeological resources.*
>
> ***13.6.4.1 Energy Efficiency Component***
>
> *An increase in energy efficiency implementation (for example, replacement of windows with styles that are not in-kind with the original architectural style) may reduce the integrity of the design, materials, and workmanship of historic resources, if present. This may result in minor to moderate impacts to historic and cultural resources, as described in Section 13.5.1.*

It should be stated here that buildings of historical significance will be exempt from energy efficiency upgrades in cases where the upgrade would moderately or significantly impact their cultural or historical value.

Such exemptions would have no impact on achieving the conservation goals of Alternative 2, as the number of buildings would represent a negligible portion of the total regional power consumption.

Therefore, the EIS document should state that the use of exemptions in these cases will result in an overall "minor impact" to historically significant buildings.

Thank you,
Curtis Allred

I have been a resident of the Olympus neighborhood for nearly 28 years. I have serious objections to Alternative 1 of the PSE Energize Eastside project. My primary objections are Safety Concerns and Neighborhood Character.

Clearly, safety is the most critical requirement for any action taken to address power needs in this area. Alternative 1, Option A introduces a high risk of explosion and/or fire both during construction and in the on-going operation of co-located power, gas, and potentially natural gas lines. This is well documented in the report from Dr. Frank Cheng. As stated in the DEIS, PSE workers have knowledge of the risks and we have regulations in place, however, we know that accidents do occur. Only last week, there was a natural gas explosion in Greenwood, destroying multiple businesses.

In section 11.1.2 of the DEIS, Property Values are briefly discussed. Relying on the technical designation by the King County Assessor of what properties have a view that affects the value of the property does not even touch the impact of a neighborhood forced to view massive towers of from 85-135 feet ripping through the development. Not only are they unsightly, but they also “look” dangerous. Alternative 1 will have a significant negative effect on property values for the homes that remain and that assumes that current properties surrounding the affected areas could even be sold. In section 11.2.9 of the document, the Newcastle plan states that power is to be provided that is aesthetically acceptable to the community. This alternative violates that requirement.

Section 2.5 of the DEIS provides the benefits and disadvantages of delaying the proposal, which could easily be applied to taking the steps identified in Alternative 2. All benefits identified are key and important. The most dramatic impact of the delay is that major investments would be avoided prior to actually identifying if they are even partially needed. There are only 2 disadvantages identified. First, power outages could develop over time. Given the results of the Lauckhart-Schiffman Load Flow Study, this appears very unlikely, especially given the conservation steps suggested AND rewarded by PSE. The second disadvantage is that development would be discouraged with the risk of power outages. Development would be discouraged even more from unsightly and dangerous massive power lines built through the neighborhoods.

Given the risks, impacts, and unproven need of this project, it is my strong belief that Alternative 2 could be implemented over time to satisfy all power requirements of the area without destroying the character of the Eastside. I would be most interested in reviewing the business case for this project, which is not part of the DEIS.

Sincerely,

Tamra Kammin

8604 129th CT SE

Newcastle, WA 98056

March 14, 2016

Energize Eastside EIS

Puget Sound Energy has proposed a new transmission line that runs from Renton to Redmond based on 1960's technology. However this is 2016,
and today the rules are different.

One example of the differences was demonstrated in a recent meeting between the community and PSE: PSE showed their slide show and a member of the community asked to see the data that supported one of PSE claims on the charts. He was told that PSE could not provide the data to him until he gets clearance from the Department of Homeland Security.

We have been told that the United States needs to protect our critical infrastructure against the threat of terrorism. We have seen major changes implemented toward meeting this goal. One spectacular example
is the new Highway 93 bridge over the Colorado River which bypasses the road over the
top of Hoover Dam in Nevada. Cars are no longer allowed on the top of this and other dams.

So in the interest of national security which is better:
a new transmission line encased in concrete and buried underground, or a new transmission line
dangling on the top of a 130 foot steel pole? In addition PSE insists putting lighting on top of these new poles in some places making them greater targets.

Thank you for your consideration.

Richard Bateman
4565 135th Place SE
Bellevue, WA 98006
(425) 747-7775
rebateman@msn.com

This letter is intended to reach the Bellevue City Council, The Bellevue City Manager and the Energize Eastside EIS Management:

From:
Barbara Braun
13609 SE 43rd Place
Bellevue WA 98006

Dear Leaders,

This is your time. This is your day to step up. This is the opportunity you dreamed of when you entered your position of public leadership. Now is your time to demonstrate you truly are a leader! That you are a true American and a true leader in ensuring Truth, Justice and Quality of Life for all.

The citizens of Bellevue are calling you to lead and adjust the Energize Eastside process so that is not rigged in favor of the corporations (PSE and British Petroleum) but represents the true needs of the citizenry you represent and work for. The Energize Eastside CAG and EIS process have not adequately established the need for this project or the alternatives described in the DEIS. The public has voiced concern about this for several years, since the beginning of the process, and they have spent their own money and time to retain independent industry experts to conduct independent studies that have brought more realistic assessments of need and alternatives. The citizens have done this because our leaders have not. The current process is so flawed and biased in favor of the VERY costly and VERY dangerous Alternative 1A PSE wants that it should be thrown out and restarted with a new and independently verified assessment of need that is aligned with state and regional authorities using a new, publically transparent Load Flow Study. Alternative 1 needs to be reassessed using a more complete assessment of impact and cost, as well as adherence to contemporary safety requirements for collocating transmission lines with gas pipelines. Also a new, more contemporary Alternative 2 should be formulated in a new DEIS that is independently designed and assessed by renewable/alternative energy industry experts and not by PSE. Last, Bellevue City Council, and the other City Councils involved, need to update their land use and safety laws to reflect contemporary safety requirements for collocating transmission lines and gas pipelines prior to any planning or permitting of a project with this level of risk to the public safety. Further laws and oversight processes need to be put on place to insure PSE and BP Olympic Pipeline comply with these laws and requirements and are penalized for non-compliance. Without this, it would seem that the City of Bellevue, as well as other Cities considering Energize Eastside, are grossly negligent in their duty to protect the public's safety.

This is your time. This is your day to step up. This is the opportunity you dreamed of when you entered your position of community leadership. Now is your time to demonstrate you truly are a leader! That you are a true American and a true leader in ensuring Truth, Justice and Quality of Life for all.

Thank you!

ARAMBURU & EUSTIS, LLP
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March 14, 2016

Heidi Bedwell
Senior Planner
City of Bellevue
450 110th Avenue N.E.
Bellevue WA 98004

Via Email:
HBedwell@bellevuewa.gov

Re: Comments on DEIS for "Energize Eastside" Project.

Dear Ms. Bedwell:

This office represents CENSE, the Coalition of Eastside Neighbors for Sensible Energy, which is concerned with the proposed construction of new 230 kV electric transmission lines through Bellevue and other eastside communities. I write today to comment on the Phase 1 Draft environmental impact statement prepared and circulated on January 28, 2016.

I have previously commented on the scoping process and other elements of the 230 kV transmission proposal. My letters to the city of June 15, 2015, August 27, 2015, and December 23, 2015 are attached and incorporated by reference herein. In addition, questions have arisen as to whether the PSE 230 kV proposal is an "essential public facility" under the Growth Management Act. I have prepared a memo to you on that subject which is also attached hereto.

My prior correspondence has focused on the seeming unwillingness of the City to give serious consideration to alternatives to address the supposed need for the current proposal. My letter of December 23, 2015, which addressed a DEIS, provided comments on this subject. The City has ignored my correspondence and discussion of alternatives is still insufficient to meet SEPA requirements. The DEIS, while hundreds of pages long, still does not provide the kind of detailed review and analysis necessary to meet SEPA requirements for discussion of alternatives.

In addition, the process of preparing two consecutive draft environmental impact statements before a final environmental impact statement is prepared is unprecedented and inconsistent with SEPA regulations, as indicated in my June 15, 2015 letter attached hereto. In my forty years of working with SEPA, I have never encountered the bizarre proposition that two DEISs will be prepared before a FEIS. This orderly process that has been a part of the SEPA Rules for more than thirty years is that a non-project DEIS and FEIS are prepared to consider a "programmatic" decision. Indeed, pages 1-13 of the DEIS confirms this procedure. But this procedure requires a decision on the programmatic elements, here whether the claimed need can be met by conservation and demand response or whether the 230 kV Transmission lines or other alternatives are appropriate. Only when a decision is made on the program to be adopted is further SEPA review contemplated on a site specific "project-level" action.

The adoption of the concept of preparing two DEISs, one after the other, also violates another fundamental tenet of SEPA. No decision regarding non-project proposals can be made without full SEPA compliance, which of course includes the preparation of a final EIS. As stated in WAC 197-11-443:

> (2) A nonproject proposal may be approved based on an EIS assessing its broad impacts. When a project is then proposed that is consistent with the approved nonproject action, the EIS on such a project shall focus on the impacts and alternatives including mitigation measures specific to the subsequent project and not analyzed in the nonproject EIS. The scope shall be limited accordingly. Procedures for use of existing documents shall be used as appropriate, see Part Six.

In the present case, no programmatic decision can be made absent the preparation of a final EIS. However, as stated at page 1-4 of the DEIS:

> The Phase 1 Draft EIS broadly evaluates the general impacts and implications associated with feasible and reasonable options available to address PSE' identified objectives for the project. <u>The evaluations conducted during Phase 1 will be used to narrow the range of alternatives for consideration in the Phase 2 Draft EIS.</u> The approach is consistent with the requirements for Phased Review outlined in WAC 197-11-060(5)(c).

(Emphasis supplied.) WAC 197-11-060(5)(c) provides as follows:

> (5) Phased review.
> (a) Lead agencies shall determine the appropriate scope and level of detail of environmental review to coincide with meaningful points in their planning and decision-making processes. (See WAC 197-11-055 on timing of environmental review.)
> (b) Environmental review may be phased. If used, phased review assists agencies and the public to focus on issues that are ready for decision and exclude from consideration issues already decided or not yet ready. Broader environmental documents may be followed by narrower documents, for example,

that incorporate prior general discussion by reference and concentrate solely on the issues specific to that phase of the proposal.

(c) Phased review is appropriate when:

(i) The sequence is from a nonproject document to a document of narrower scope such as a site specific analysis (see, for example, WAC 197-11-443); or

(ii) The sequence is from an environmental document on a specific proposal at an early stage (such as need and site selection) to a subsequent environmental document at a later stage (such as sensitive design impacts).

As stated, the apparent intention is to select the alternative which will undergo detailed consideration by staff and which will then be the subject of the Phase II DEIS. However, it would be illegal and inconsistent with SEPA to make this important decision without the FEIS required by SEPA.

The City should proceed to prepare the required final EIS on the programmatic aspect of the project before proceeding to narrow options for site-specific review.

In addition, CENSE's December 23, 2015 letter, attached hereto, made specific reference to the then-pending 7th Pacific Northwest Power Plan. Since that letter the Plan has been formally adopted. See http://www.nwcouncil.org/energy/power plan/7/home/. The plan makes clear that conservation, demand response and gas turbines can meet electric need over the next twenty years. Claims by PSE that such efforts will not reduce incremental load are simply incorrect.

Thank you for this opportunity to comment on the Phase 1 DEIS.

Sincerely,

ARAMBURU & EUSTIS, LLP

J. Richard Aramburu

JRA:cc
cc: CENSE

Attachments

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June 15, 2015

City of Bellevue
Development Services Department
Attn: David Pyle
450 110th Avenue N.E.
Bellevue 98004

Scoping Comments: 14-139122-L "Energize Eastside"
Scoping@EnergizeEastsideEIS.org

Dear Mr. Pyle:

I write today to provide scoping comments on Puget Sound Energy's "Energize Eastside" proposal on behalf of the Coalition of Eastside Neighborhoods for Sensible Energy (CENSE), a volunteer coalition of residents and local citizens concerned with the "Energize Eastside" proposal. These comments are in response to a Determination of Significance and Scoping Notice issued by the City in April, 2015, herein referenced as the "DS."

These comments are supplemental to others submitted by CENSE and its members. This letter incorporates by reference all other comments entered by other parties on scoping.

Comments on the process and scoping set forth below.

1. LACK OF A PROJECT APPLICATION

As a beginning point, the City is inappropriately processing the "Energize Eastside" proposal as a concept as promoted by PSE, rather than as a project proposal. "Energize Eastside" is essentially a promotional or branding characterization by PSE. The City should reference the proposal in "Description of Proposal" found in the DS as the construction of "a new 230 kV electrical transmission line and substation."

In addition, in correspondence with CENSE, the City admits that PSE has not filed any type of land use or building permit application with the City for this new transmission line. This is despite the fact that PSE has continuously identified the intended location of its proposed new transmission line along a defined and well known corridor and has made decisions concerning the design of the transmission lines. See the "Energize Eastside" website at http://www.energizeeastside.com/design. This website also has photo simulations of the proposed construction and tower locations in many places. See http://www.energizeeastside.com/photo-simulations. There is certainly sufficient information available to prepare a permit application for this work.

Indeed, the City has stated in the DS that during scoping interested persons may comment on "licenses or other approvals that may be required." However, without a specific application, it is impossible to know the licenses or approvals that will be required for the transmission line. For example, all material prepared by PSE indicates that the transmission line route will extend through the East Bellevue Community Council area for more than a mile, but City staff says that issue is still up in the air in an email from Carol Helland to CENSE on June 3, 2015:

> EBCC jurisdiction has authority only to approve or disapprove applications within the jurisdiction of the Community Council. Refer to LUC section 20.35.365. <u>The determination is made at the time of application. If PSE applies for a conditional use permit to approve an Energize Eastside alignment that is located within the boundaries of the EBCC, then the application would be characterized as a Process III application. Refer to LUC 20.35.015.D.2.</u> If PSE apples for a conditional use permit to approve an Energize Eastside alignment that is located outside the boundaries of the EBCC, then the application would be characterized as a Process I application. Refer to LUC 20.35.015.B.

(Emphasis supplied). Of course, EBCC has approval/disapproval authority over any conditional use permit application that PSE may make for its new 20 kV line. It is inappropriate for City staff to hide the ball on this important issue; the Draft EIS (DEIS) needs to confirm that the jurisdiction of EBCC will be invoked by this application and that the review will be under Process III review rules and procedures.

The lack of a specific permit application is particularly important for any Phase 2 considerations. The DS states that: "Construction and operation level impacts will be addressed with Phase 2 of the EIS process." Similarly at the third page, the DS states that Phase 2 "will examine project level alternatives, include possible alternative routes for transmission lines." It is impossible for local citizens to consider "construction and operation level impacts" without a specific project application to determine the location of the new transmission line with locations and descriptions of proposed towers.

The City should require the filing of a permit application as a precondition to additional SEPA review. That application will disclose critical detail concerning the PSE proposal and allow informed comment by the public. Such an application would not foreclose or affect the review in the EIS process of reasonable alternatives.

2. THE PREPARATION OF TWO SERIAL DRAFT ENVIRONMENTAL IMPACT STATEMENTS IS INCONSISTENT WITH SEPA AND THE SEPA RULES.

The DS states that the City plans to prepare two draft EISs for the "Energize Eastside" proposal. The second phase is described as follows:

> The second phase of the project will select among the Phase 1 alternatives and examine project level alternatives, including alternative routes for transmission lines. A second opportunity for scoping will be provided and a second Draft EIS will be issued for Phase 2.

The outlined process is inconsistent with SEPA and requires immediate revision.

For many years, the SEPA Rules have provided for "Phased Review" in WAC 197-11-060(5). Phased review involves the preparation of a "nonproject EIS" which focuses "on issues that are ready for decision and exclude from consideration issues . . . not yet ready." Subsection (b). Indeed, WAC 197-11-442 sets forth criteria to be followed for a nonproject EIS, and states:

> (2) The lead agency shall discuss impacts and alternatives in the level of detail appropriate to the scope of the nonproject proposal and to the level of planning for the proposal. Alternatives should be emphasized. In particular, agencies are encouraged to describe the proposal in terms of alternative means of accomplishing a stated objective (see WAC 197-11-060(3)).

The nonproject EIS follows the usual sequence of scoping, draft EIS <u>and</u> final EIS. Once a decision is made on a broader nonproject proposal, a project level EIS will be prepared based on the nonproject analysis. As described in WAC 197-11-443:

> (2) A nonproject proposal may be approved based on an EIS assessing its broad impacts. When a project is then proposed that is consistent with the approved nonproject action, the EIS on such a project shall focus on the impacts and alternatives including mitigation measures specific to the subsequent project and not analyzed in the nonproject EIS. The scope shall be limited accordingly. Procedures for use of existing documents shall be used as appropriate, see Part Six.

Thus, the SEPA provisions for phasing require a draft and final EIS on the nonproject proposal and a decision on the nonproject alternatives. Following that decision, if the applicant wishes to pursue a specific project, then preparation of a project level draft and final EIS will follow.

However, the City of Bellevue procedures for "Energize Eastside" do not follow the SEPA Rules for nonproject EIS. Instead of adherence to the rules, the City of Bellevue intends to prepare the Phase 1 DEIS, but <u>not</u> prepare a final EIS on Phase 1. Instead it will inexplicably move to a second DEIS without preparing a Phase 1 final EIS. No reason is stated for the bizarre process. The SEPA Rules are absolutely clear that: "The lead agency shall prepare a final environmental impact statement whenever a DEIS has been prepared, unless the proposal is withdrawn or indefinitely postponed." WAC 197-11-560(1). The FEIS is the key element in the SEPA decision making process. Under the rules, citizens and agencies may comment on the EIS and the City is required to respond in one or more of the means found in WAC 197-11-560(1). The City should prepare a final EIS on Phase 1 based on comments from the public which will inform the staff and public on the selection of an alternative for consideration in the Phase 2 project level draft and final EIS.

Further, the description of Phase 2 indicates that: "The second phase of the project will select among the Phase 1 alternatives . . ." Obviously, a "phase" does not "select" among alternatives; a person or persons must make that selection. The DS does not identify who that person or persons will be. As noted above, no "selection" of this nature can proceed without the preparation of a final EIS on Phase 1. WAC 197-11-070, specifically establishes "Limitations on actions during the SEPA Process" states:

> (1) Until the responsible official issues a final determination of nonsignificance or final environmental impact statement, no action concerning the proposal shall be taken by a governmental agency that would:
>
> (a) Have an adverse environmental impact; or
>
> (b) Limit the choice of reasonable alternatives.

(Emphasis supplied.) The City is obligated to issue a final EIS on the Phase 1, nonproject level review, before it proceeds to select or limit alternatives.

The City must bring its environmental review process consistent with the SEPA rules or it risks having the process overturned at a later time with consequent delays to the applicant a waste of money and the public interest.

3. "ENERGIZE EASTSIDE" IS NOT AN ESSENTIAL PUBLIC FACILITY (EPF) .

Correspondence with city staff indicates that the City considers the "Energize Eastside" an Essential Public Facility (EPF) though the DS does not describe it as such. As will be demonstrated below, "Energize Eastside" is not an EPF for numerous reasons. However, CENSE is concerned that this inaccurate characterization may result in a crabbed analysis of the proposal in the DEIS, especially Phase 1.

Provisions relating to EPFs are set forth in RCW 36.70A.200. Subsection 1 of the statute lists eight EPFs; however, "electric transmission facilities" are not listed among them. WAC 365-196-550(1)(d) provides a more comprehensive list of EPFs, but again, electric transmission lines are not included.

In *Residents Opposed to Kittitas Turbines v. State Energy Facility Site Evaluation Council (EFSEC),* 197 P.3d 1153, 165 Wn.2d 275 (2008), an issue was raised as to whether the GMA provisions for EPF repealed the authority of the State Energy Facility Site Evaluation Council (EFSEC) to regulate energy facilities. (The EFSEC statute was adopted long before GMA). In rejecting that proposition, the court noted that: "The GMA makes no mention of an energy facility. . ." in RCW 36.70A.200. However, in the EFSEC statute at RCW 80.50.020, the following definition is provided: (10) "Electrical transmission facilities" means electrical power lines and related equipment." The Court held that GMA did not supersede EFSEC rules.

The exclusion of "electrical transmission facilities" from the list of EPFs is both deliberate and a part of the overall statutory scheme for regulation and permitting for energy plants or transmission lines. Should PSE wish to provide specialized consideration for its new electric transmission lines, it could file an application with EFSEC under RCW 80.50.060(3). However, it has chosen to engage in local permitting under the municipal codes of the several jurisdictions through which its proposed line will run, obviously running the risk that one or more jurisdiction may find its proposal inconsistent with its regulations.

Consistent with the Supreme Court decision in *Residents,* the City of Bellevue Comprehensive Plan, Capital Facilities Element at page 82 provides as follows:

> POLICY CF-14. Require land use decisions on essential public facilities meeting the following criteria to be made consistent with the process and criteria set forth in Policy CF-16 :
>
> 1. The facility meets the Growth Management Act definition of an essential public facility at RCW 36.70A.200(1) now and as amended; or
> 2. The facility is on the statewide list maintained by the Office of Financial Management, ref. RCW 36.70A.200(4) or on the countywide list of essential public facilities;
>
> AND
>
> 3. The facility is not otherwise regulated by the Bellevue Land Use Code.

(Emphasis supplied.) As is seen, because electrical transmission lines are specifically regulated by the Land Use Code, they are not considered an EPF. Ms. Helland's comments on page 2, *infra*, confirm this.

The City will make a serious error in its SEPA review of the "Energize Eastside" project if it considers the proposal an EPF. The responsible official should direct the drafters of the draft EIS to not consider the "Energize Eastside" proposal an EPF.

4. THE DRAFT AND FINAL PHASE 1 ENVIRONMENTAL IMPACT STATEMENTS MUST GIVE THOROUGH CONSIDERATION TO ALL ALTERNATIVES.

As the City is aware, consideration of alternatives is the most important part of SEPA analysis. Indeed SEPA itself, at RCW 43.21C.030(2)(e), has a separate, action forcing provision that agencies "study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative uses of available resources." Alternatives are in the forefront of environmental analysis. The SEPA rules direct that the EIS text comparatively analyze "alternatives including the proposed action." WAC 197-11-440(5).

In the present situation, alternatives analysis revolves around three basic issues. First, is there an identified and plausible need for a new transmission line? Second, are there alternative methods to meet the identified need? For an electric transmission line, are there nonstructural means to meet the need including demand management or reconfiguration of existing resources? Third, are there alternative structural methods to meet the need?

CENSE will be providing expert analysis of alternatives together with an identification of the kinds and types of review and study necessary to fully consider these alternatives. This material is incorporated by reference herein. We look forward to the careful review of these matters in the draft EIS.

Aramburu & Eustis, LLP
CENSE Scoping Comment
June 15, 2015
Page 6

In conclusion, this letter identifies serious defects and inconsistencies with SEPA Rules and statutes in the DS and associated communications with the City. These matters must be corrected immediately and before the city begins preparation of a draft EIS.

Thank you for your consideration of these comments.

Sincerely,

Aramburu & Eustis, LLP

J. Richard Aramburu

JRA:cc
cc: Clients

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August 27, 2015

City of Bellevue
Development Services Department
Attn: David Pyle
450 110th Avenue N.E.
Bellevue 98004

Scoping@EnergizeEastsideEIS.org

Re: **Scoping Summary**
PSE STATED OBJECTIVE FOR ENERGIZE EASTSIDE, STANTEC REPORT 14-139122-L "Energize Eastside"

Dear Mr. Pyle:

As you are aware, this office represents Coalition of Eastside Neighbors for Sensible Energy, or CENSE, a Washington non profit corporation that is concerned about proposals by PSE to construct new transmission lines through eastside residential neighborhoods. CENSE submitted scoping comments on the "Energize Eastside" proposal on June 15, 2015. Those comments addressed various issues including the lack of any permit application to consider in the environmental review process, the plans for two DEISes prior to preparation of a final EIS, that the transmission proposal of PSE is not an essential public facility and the failure to consider all appropriate alternatives.

On July 30, 2015, the City posted on its website for this project, three documents a) a Memo from Stantec Engineering (Keith DeClerck) regarding the "Energize Eastside" Project, 2) a document entitled "Phase 1 Draft EIS Scoping Summary and Final Alternatives" (hereinafter "Scoping Summary"and 3) "PSE's Stated Objectives for Energize Eastside." In this letter, CENSE will provide comments on these documents.

1. STANTEC MEMO.

1.1 Use of Stantec Report in DEIS Process.

The Stantec Memo is offered as "validation" of the need for the 230 kv transmission corridor proposed by PSE but it is only a narrative of previous work offering no new analysis. However, it offers a variety of scare tactics including references to "cascading blackouts" (page 6), when the "lights go out" (page 9) and "hazards" related to power losses to "hospitals, nursing homes and fire departments" (page 10). This kind of unsupported hyperbole is distinctly inappropriate in environmental analysis.

The Scoping Summary also identifies that Stantec is an important player in deciding which alternatives will be considered in the DEIS:

> The Phase 1 Draft EIS will evaluate three action alternatives and a "No Action" Alternative, as described below. Each alternative includes a range of possible options that will be considered. The preliminary alternatives presented as part of the Scoping Notice and the alternative approaches recommended by the community were evaluated to determine if they would meet PSE's stated objectives (see Attachment 1) as required by SEPA (WAC 197-11-060, WAC 197-11-408, and WAC 197-11-440) and the project's purpose. <u>This evaluation was done with assistance from electrical engineers from Stantec</u>, a consulting firm that is part of the EIS consultant team, <u>and PSE engineers</u>.

Scoping Summary at page 14 (emphasis supplied). Similarly at page 16, the Scoping Summary states:

> <u>The consulting firm Stantec reviewed</u> unredacted results from the model in PSE's Needs Analysis and the Energize Eastside Solutions Reports (2013 and 2015) to ensure that the EIS consultant team had <u>a clear and unbiased picture of the purpose of the project</u> and what types of options are viable for achieving that purpose (Stantec has security clearance). Stantec and other members of the EIS consultant team had questions that were posed to PSE. In some cases this required PSE to do additional calculations. These were reported to the EIS consultant team by email. <u>In each case, Stantec reviewed the analysis for consistency with industry practice and for internal consistency among the various PSE-provided documents</u>.

(Emphasis supplied). At page 16, the Scoping Summary states:

> For potential alternatives that were not evaluated by PSE in its Solutions Report analysis, Stantec provided a <u>professional opinion</u> as to whether the proposed alternative would meet PSE's criteria. Stantec's findings were reviewed by the EIS consultant team <u>and the Eastside Cities</u>, and <u>the Eastside Cities agreed upon the alternatives to be analyzed</u>. Generally, alternatives that would not meet PSE's objectives were not included (see section titled "Which alternatives were considered and will not be included" below for more discussion).

(Emphasis supplied).

1.2 <u>Stantec Conflict of interest</u>.

In checking on the qualifications for Stantec to provide "unbiased" analysis, we discovered that the company has done substantial work for PSE. On the Stantec website, under the "Summary Experience List," Stantec described the following work done for PSE:

> **Replacements Puget Sound Energy, Various Locations, WA**
> Stantec prepared the detail design and material lists for the replacement of 230 and 115kV power circuit breakers located at various facilities in Western Washington. Stantec was responsible for preparing plans, elevations, bus details, grounding, and conduit and cable details for replacing existing oil circuit breakers with new gas breakers. In addition, Stantec revised control schematics to integrate the new breakers into the existing protection and control schemes including the SCADA system.

We find nothing in the Stantec Memo or the project website that discloses this prior work for the project applicant.

Doing this kind of substantial work for PSE raises issues as to whether Stantec can prepare an objective and "unbiased" report in this environmental review process.[1] This potential or actual conflict of interest should not taint the environmental review process.[2] Accordingly, we ask that the Stantec Memo be withdrawn to assure that documents will not be used or considered in the review process.[3]

1.3 <u>Stantec Qualifications to Participate in Evaluation of Alternative and EIS Process</u>.

In addition to the clear conflict of interest, there are serious questions concerning the qualifications of Stantec as well as of the author of the memo itself.

The "Energize Eastside" EIS website does not disclose the process by which Stantec was hired for the work it performed. No one outside the "project team" was informed that Stantec was being hired and it appears that no request for proposal was circulated. No resume of the author of the Stantec Memo, Keith DeClerck, has been provided, only a general summary of his qualifications on page 1 of the Memo. There is no reference to projects in the Pacific Northwest nor indication of knowledge of the regulatory structures or the operations in this region. Given the broad number of experts qualified for this work, we think that this individual, with a clear conflict of interest, should not be acting as an advisor for the DEIS team.

1.4 <u>Use of Unredacted Materials by Stantec and the DEIS Team.</u>

In addition, we note from your memo dated July 31, 2015 that accompanied the

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[1]We are not aware if Stantec has actually done other additional work for PSE. Accordingly we request that the City and the EIS team disclose all contracts or work that Stantec has performed for PSE.

[2]In this regard we note that PSE sent the Stantec Memo to FERC almost immediately after it was issued.

[3]The Scoping Summary says that Stantec's engineer provided a "professional opinion." But no resume is provided for Mr. DeClerck, no engineer stamp is found on the report and no information is provided as to whether he is a licensed professional engineer in the state of Washington.

report that:

> the EIS project team has obtained clearance to access un-redacted sensitive (protected in accordance with industry security protocol) utility planning and operations information used by PSE in developing the Energize Eastside project.

It appears that PSE and those working on the DEIS are using information to make decisions that has not been previously released to commenters on this proposal. We ask that the City provide this information to us immediately so it may be reviewed by our consultants who have previously commented during the scoping process. The withholding of pertinent information useful in project analysis is a serious defect in SEPA compliance and must be corrected immediately.

1.5 Failure of Stantec to Understand Basic Transmission Requirements.

As noted above, the Stantec Memo has multiple problems that make it unreliable for use in making decisions on the content of the DEIS for this project, including Stantec's patent conflict of interest and an author with questionable background to provide opinion on this important matter. It is little wonder that the Stantec Memo fails to understand a basic element of the Columbia River Treaty, and the Canadian Entitlement.

Stantec appears to assume that transmission flows on PSE lines must take account of operating conditions which include the return of the Canadian Entitlement (approximately 1300 MW at present) to Canada. What Stantec does not understand (or ignores) is that there is no current legal obligation for return of the Canadian Entitlement to Canada.

In 1999, the Americans and Canadians signed an "Entity Agreement on Aspects of Delivery on the Canadian Entitlement For April 1, 1998 though September 15, 2024." See www.bcuc.com/Documents/Proceedings/2006/DOC_10966_B1-131_Columbia%20River%20Treaty%20Agree.pdf. This Agreement is referenced herein as the "Entity Agreement". In that agreement, it was acknowledged that both the US and Canadians agree that the long practice (50+ years) for sale of the Canadian Entitlement to US utilities could continue. That practice continues today and there is no indication that the Canadians want their entitlement back; indeed, in the more than 50 years the CRT has existed, Canada has never taken firm delivery of this power, being content to take advantage of the favorable market for power in the US.

Indeed, with passage of the Clean Energy Act by the Province of British Columbia on June 3, 2010 (Bill 17), BC made three important policy and regulatory decisions impacting the import of power. First, the Clean Energy Act established the objective in Paragraph 2(a) "to achieve electricity self-sufficiency[.]" Second, Paragraph 2(b) sets an energy objective to:

> (b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

Third, an additional objective of the Act is that BC intends to become a "net exporter" of energy:

> (n) to be a net exporter of electricity from clean or renewable

> resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

Paragraph 2(n) (emphasis supplied). Paragraph 3(d) of the Act requires the preparation of an "Integrated Resource Plan" which includes actions to further net export of energy.

Given that the Canadian Entitlement has never been delivered to Canada on a firm basis and that the intent of the Province is to become a net exporter of electricity, proposing to spend $200,000,000 for the "Energize Eastside" proposal on the basis that the Canadian Entitlement will be delivered to BC is an obvious and expensive error of judgment.

Even if, implausibly, the Canadians want the Canadian Entitlement back at the border, it will require notice to the US, an analysis of flow paths and a determination that "firm transmission" is available for purchase. See Section 11 of the Entity Agreement. Since the Canadians will have to pay for this privilege, and the obligation is a "take or pay" firm transmission contract, it is difficult to accept this is a real possibility.

Stantec's unfamiliarity with these circumstances has caused it to make a major error. Planning for "Energize Eastside" should delete the impact of the return of the Canadian Entitlement as a factor in transmission planning.

2. SCOPING SUMMARY AND ALTERNATIVES.

As noted above, the major function of the Scoping Summary is to eliminate certain alternatives from further consideration in the EIS process. The analysis here is deeply flawed and inconsistent with the SEPA Rules.

One defect is the mischaracterization of concerns regarding the existing electric system, found at page 19 of the Scoping Summary. There it is indicated that comments suggested that PSE should "disconnect the [PSE] system from the region or from adjacent electric lines." However, the alternative suggested by commenters was that certain through power flows, particularly the 1300 MW Canadian treaty flow, be eliminated from calculation of load on the PSE system during peak periods. Reports submitted by CENSE show that these through power flows are not firm obligations and in any event they would be eliminated during peak periods of demand. As described above, the Canadian Entitlement is not a factor in this situation. The City cannot eliminate alternative analyses based on an inaccurate recasting of public comments. This issue must be considered in the DEIS.

Of particular concern is the apparent decision to eliminate any gas-fired peaking plants as described on page 20-21 of the Scoping Summary. It is indicated that these facilities are not within the "stated objectives" of PSE. However, PSE is not entitled to eliminate alternatives that reasonably approximate the stated concern of PSE, which is to meet load. This is particularly true given that this is the scoping stage leading to a DEIS on a "programmatic" decision. Thus, the arbitrary and premature elimination of several alternatives is not consistent with the SEPA Rules.

This is nowhere more evident than in the elimination of peaking plants as alternatives. The Scoping Summary says (page 20) that:

> ***Generation Facilities***
>
> For a generation facility or group of facilities to be effective, PSE found that it would have to be located near the center of the Eastside area, such as near the Lakeside Substation. Any such facility would likely have to be gas-fired in order to be capable of producing power reliably whenever it is needed. PSE determined that at <u>least 300 MW of power generating capacity would be needed and the most cost effective way to generate that amount of power would be in a single plant.</u> . . . .In addition, the increased usage of gas-fired plants over time would have difficulty meeting clean air regulations. Even if it were economically feasible to create multiple smaller facilities, they would need to be clustered close to the center of the Eastside and would likely impose similar or even greater impacts than a single plant. <u>This alternative is not included because it does not meet the criterion of being environmentally acceptable to PSE and the Eastside communities.</u>

(Emphasis supplied). These conclusory statements, without support or technical or environmental analysis, cannot form the basis for the elimination of this alternative. Nor can unsubstantiated references to "most cost effective" solution be the basis for exclusion of alternatives. In addition, there is no description of how the "Eastside communities" reached a decision on this subject, what information was available to them and whether the elected decision-makers actually made these decisions. For example, were these decision makers informed that smaller gas peaking plants would run only rarely and then only during times of extreme cold conditions?

Both PSE and the "Eastside communities" run a serious risk by summarily eliminating alternatives without analysis before a DEIS is prepared. This was apparently done without a record of consideration and in private meetings between the project proponent PSE, staff from several communities and Stantec. The interested members of the public, other governmental agencies and impacted property owners are excluded from the process.

On the other hand, the DEIS is subject to peer review, agency analysis and public comment. As described in the Scoping Summary, <u>only at that time</u> will alternatives be culled out continuing review:

> Following publication of the Phase 1 Draft EIS, there will be a 45-day comment period (WAC 197-11-455) (see Figure 6). The Eastside cities will evaluate the input received and determine which alternatives should be carried forward into the more detailed Phase 2 Draft EIS, and what elements of the environment will be evaluated.

The City and EIS team should reconsider these perfunctory dismissals of a variety of alternatives. It would not be in the interest of the public, the participating cities and indeed PSE to have to redo the SEPA process in the event that a reviewing body or court determines this process was in error.[4] This is especially true where PSE has indicated time is a factor in these considerations.

In conclusion, the City and EIS team have improperly and prematurely eliminated completely reasonable alternatives from review in the DEIS. This analysis has apparently been influenced by an engineering firm with a patent conflict and based on information that was not available during the scoping process.

CENSE requests that the eliminated alternatives instead be maintained and studied in the environmental review process and included in the forthcoming DEIS.

Sincerely,

Aramburu & Eustis, LLP

J. Richard Aramburu

JRA:cc
cc: Clients

[4]Consideration of alternatives is a key to environmental review under SEPA. As Richard Settle, a leading commentor on SEPA says:

> Open-minded, imaginative design and consideration of alternative courses of agency action is crucial to SEPA's ultimate quest - environmentally enlightened government decision making.

The Washington State Environmental Policy Act: A Legal and Policy Analysis §14(b)(I) (2014). Our court have insisted not only on thorough consideration of alternatives, but a complete discussion of alternatives in environmental impact statements. Thus in *Weyerhaeuser v. Pierce County*, 124 Wn.2d 26, 873 P.2d 498 (1994), the Washington Supreme Court held the discussion of alternatives in a final environmental impact statement inadequate:

> LRI claims it has complied with these requirements, and cites the final EIS at pages 19 to 33 (Ex. 1(c)) as containing sufficient discussion of offsite alternatives. However, pages 19 to 33 of the final EIS do not contain the required discussion. Instead, those pages contain a discussion of LRI's site selection process, and the brief descriptions of rejected sites consist of conclusory statements of LRI's assessment of possible sites examined in the site selection process. They do not contain any location information such as a map, street address, and legal description. They do not contain any description of principal features of any alternatives. They do not tailor the level of description to the significance of environmental impacts, and, in fact, it is impossible from the brief, conclusory descriptions to engage in any meaningful comparison of the alternatives. There is absolutely no useful comparison of the environmental impacts of the alternatives.

124 Wn.2d at 41-42. The remedy of the Court was as follows:

> Because the EIS completely fails to discuss any offsite alternatives, it is inadequate as a matter of law. The EIS must be revised to contain a discussion of alternative sites. *Barrie*, 93 Wn.2d at 857. The trial court's invalidation of the conditional use permit must be upheld in light of the inadequate EIS.

124 Wn.2d at 42. In the present case, the City intends to eliminate alternatives even before a draft EIS is prepared, a process that will not survive administrative or judicial review and would create needless delay.

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December 23, 2015

Carol Helland
City of Bellevue
450 110th Ave. NE
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Re: Draft DEIS for the 230 kV Transmission Lines proposed by PSE

Dear Ms. Helland:

As you know, this office represents CENSE, the local citizens organization concerned with the proposal by Puget Sound Energy (PSE) to construct 230 kV transmission lines through Bellevue and other Eastside communities, together with a new substation. Though PSE has branded its proposal as "Energize Eastside" we decline to accept this obvious attempt to control the perceived content of the proposal and accordingly will not use its characterization of the project. In this letter we will refer to the matter under review as the PSE Transmission Proposal or PSETP

In response to CENSE's request, you provided us with a copy of the "Preliminary Review Draft" ("PRD") for the PSETP. You cautioned that we should not be providing detailed comments on the PRD. CENSE will follow your guidance on a majority of the content of the PRD. However, we feel compelled to provide comment on Chapter 2 of the PRD entitled "Project Alternatives." As described more fully herein, this part of the PRD is completely inadequate and inconsistent with the spirit and letter of SEPA. Accordingly we urge that the DEIS for the PSETP be completely rewritten and expanded to provide a meaningful analysis of alternatives.

The Alternatives section of an environmental impact statement is by far the most important section of the document. The SEPA statute itself requires that local governments:

> (e) Study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative uses of available resources;

RCW 43.21C.030f. Indeed, DOE's SEPA Handbook says that:

> Alternatives are one of the basic building blocks of an EIS. They present options in a meaningful way for decision-makers. The EIS examines all areas of probable significant adverse environmental impacts associated with the various alternatives including the no-action alternative and the proposal.

See Section 3.3.2.

The emphasis on alternatives continues in the SEPA Rules and particularly WAC 197-11-440(5), which requires the EIS preparer to: "(v) Devote sufficiently detailed analysis to each reasonable alternative to permit a comparative evaluation of the alternatives including the proposed action." Because PSE has not submitted a project application the proposal must be considered a "nonproject proposal" governed by WAC 197-11-442, "Content of EIS on nonproject proposals." Alternatives are given special emphasis in a nonproject EIS:

> (2) The lead agency shall discuss impacts and alternatives in the level of detail appropriate to the scope of the nonproject proposal and to the level of planning for the proposal. Alternatives should be emphasized. In particular, agencies are encouraged to describe the proposal in terms of alternative means of accomplishing a stated objective (see WAC 197-11-060(3)). Alternatives including the proposed action should be analyzed at a roughly comparable level of detail, sufficient to evaluate their comparative merits (this does not require devoting the same number of pages in an EIS to each alternative).

As noted below, Chapter 2 of the PRD falls far short of the requirements for fair and thorough consideration of alternatives required by SEPA and the SEPA Rules.

Chapter 2 of the PRD, while entitled "Project Alternatives," has its first ten pages directed to "project objectives" with the next several pages describing the PSE proposal itself. The alternatives that do not include new transmission are limited to only four pages (2-21 to 2-24) with only the most vague and general discussion, actually little more than a description. Nothing here is sufficient to permit a comparative evaluation as required by SEPA and the SEPA Rules. For example, there are only two paragraphs devoted to demand response (the "voluntary and temporary reduction in consumers' use of electricity when the power system is stressed") and only one to energy efficiency.

By contrast, the draft Seventh Northwest Conservation and Electric Power Plan (the 7th Plan), just released, says that:

> In more than 90% of future conditions, cost-effective efficiency met *all* electricity load growth through 2035.

Emphasis in original. See page 1-1. The second priority under the 7th Plan is demand response, described as follows:

> While the region's hydroelectric system has long provided ample peaking capacity, it's likely that under low water and extreme weather conditions we'll need additional winter peaking capacity to maintain system adequacy. Because the probability of such events is low (but real), demand response resources, which have low development and "holding" costs are best-suited to meet this need.

Page 1-2. Another non-transmission alternative, natural gas generation, is completely excluded in just two paragraphs at pages 2-35 and 2-36 because of possible impacts, without any analysis of possible equipment, facility locations or capabilities. This is in stark contrast to the 7th Plan which states:

> After energy efficiency and demand response, new natural gas-fired generation is the most cost-effective option for the region in the near-term.

See page 1-2. In short, PSE has refused to consider reasonable alternatives that are identified and relied upon in the 7th Plan.

The reason that these alternatives are excluded is obvious: as a for-profit company, PSE wants to build facilities that generate income for its investors. Energy efficiency and demand response in fact reduce income because they encourage the reduction of consumption. Natural gas plants, as noted by the 7th Plan, will run so rarely that they produce no dependable stream of income. On the other hand, PSE is allowed a substantial return on investment by the WUTC from its proposed transmission project, to be paid by its rate payers (Bellevue residents).

The SEPA process cannot be hijacked by the profit motives of the applicant here. The City should assure that all reasonable alternatives are considered, in sufficient detail that a local government decision-maker can pick between them, even if it contradicts the PSE business model.

An additional concern relates to the timing of the EIS process as it relates to the project development. Page 2-9 of the PRD states that one of the non-electrical criteria is that :

> Alternatives must be reviewed to ensure that they are reasonably constructible by the 2018 in-service target date.

The section explains that to meet this date, construction must begin in 2017. *Id.* However, PSE (along with the Eastside cities) has so constructed its SEPA review process that there will be two draft environmental impact statements prepared before a final EIS is prepared, an unheard process under the SEPA, which requires a draft EIS be followed by a final.

This extended review process will have the final EIS distributed in the spring of 2017. See http://www.energizeeastside.com/schedule, a copy of which is attached hereto. Only then can the permit review process begin, which includes Hearing Examiner hearings and Council review. It is apparent that by the time the permitting process begins, with construction required to commence in 2017, PSE will argue there is no alternative but its transmission line proposal because of the limited time that will be left until the in-service date. Given that PSE will be gathering data on its transmission proposal, including surveying, wetland delineation, tree inventories, pipeline location and geotechnical investigation[1], and doing nothing to further any other alternative, PSE is deliberately painting the Eastside cities into a corner; i.e. there will be nothing else that can be done but to give PSE its desired permits. Indeed, this is even stated in the PRD at page 2-9:

> Any delay in the schedule would push the in-service date beyond the 2018 timeframe, which would increase PSE's reliance on the use of CAPs and load shedding. For example, some specialized equipment can take up to three years to procure. Therefore, PSE would not be able to meet the target in-service date.

The Cities should not allow themselves to be so blatantly manipulated by this private utility. The Cities should order an FEIS on the Phase I proposal and reach a decision on Phase I before going forward with detailed and site-specific review of this transmission proposal. In conjunction with this course of action, Chapter 2 of the DEIS should be modified to assure that Bellevue and the other Eastside councils have sufficient information about the alternatives to make a meaningful decision about the appropriate course of action.

Thank you for this opportunity to provide further comments on the process.

Sincerely,

ARAMBURU & EUSTIS, LLP

J. Richard Aramburu

JRA:cc
cc: CENSE

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[1] PSE describes this fieldwork in detail in the "Energize Eastside" Environmental Impact Statement website.

Search

ENVIRONMENTAL IMPACT STATEMENT (EIS) For more information on the EIS, please visit **EnergizeEastsideEIS.org**

(http://www.energizeeastsideeis.org/)

The Energize Eastside project launched in December 2013 and is planned to be complete and operational in 2018.

Click details in the schedule below for additional information.

Attachment A

From: Loretta Lopez
Sent: Monday, March 14, 2016 4:05 PM
To: HBedwell@bellevuewa.gov; 'info@EnergizeEastsideEIS.org'
Subject: Comments to DEIS PROPSED PSE Project/Citation to federal standards

The DEIS states that based upon federally mandated planning standards PSE analysis found the existing transmission lines could place Eastside customers at risk of power outages. Page 1.2

There is no footnote which sets forth the citation to the federally mandated planning standards. The DEIS should contain a specific citation to the federal standards. The reason: Then all readers can go directly to the source and read the standards.

What is the specific citation to federal standards?

Loretta Lopez

Bridle Trails Community Club, Vice President

CENSE Member

13419 NE 33rd Lane Bellevue WA 98005

On Mon, Mar 14, 2016 at 5:00 PM, Don Marsh <don.m.marsh@hotmail.com> wrote:

Dear EIS Officials,

Attached is a document which endorses a new alternative developed by EQL Energy, an expert in the design of forward-thinking, cost-effective smart grid technology and policies. The document also points out shortcomings in the design and evaluation of Alternative 2 in the Draft EIS.

We believe that the EIS cannot fulfill its goal of fairly comparing the impacts of the Energize Eastside project and alternatives without an accurate formulation of those alternatives. Therefore, we ask that “Alternative 2.B” be added to the EIS and evaluated by independent experts with knowledge of smart grids, demand response, electrical efficiency, distributed generation, energy storage, etc.

Sincerely,

Don Marsh, President
CENSE.org

My address is: 4411 137th Ave. SE, Bellevue, 98006

Attachment from Don Marsh 3/14/16:

Alternative 2 can be improved

The Draft EIS for Puget Sound Energy's Energize Eastside project includes a "non-wires" alternative based on intelligent management of energy, sometimes referred to as a "smart grid." While CENSE endorses this concept, the design and evaluation of Alternative 2 are flawed, making it seem less feasible and realistic. We would like to propose a better "Integrated Resource Approach" based on analysis performed by industry expert EQL Energy. The new proposal is reasonable from both an economic and environmental perspective.

To distinguish between the proposals, CENSE refers to the original proposal as "Alternative 2.A" and the new proposal from EQL as "Alternative 2.B."

The primary differences between Alternatives 2.A and 2.B are:

- Alternative 2.B reduces or eliminates the need to locate gas-fired peaker plants in residential neighborhoods.
- Alternative 2.B reduces the size of battery storage by a factor of four, eliminating concerns about recharging time and siting.
- Alternative 2.B uses a more realistic assessment of energy efficiency potential.
- Alternative 2.B proposes two classes of Demand Response, which are more specific and accurate than Demand Response proposed in Alternative 2.A.
- Alternative 2.B includes "Combined Heat and Power," which incentivizes new buildings to combine heating and electricity production, thereby reducing carbon emissions and increasing grid reliability.

Those are just some of the highlights. The following table shows a summary of the differences:

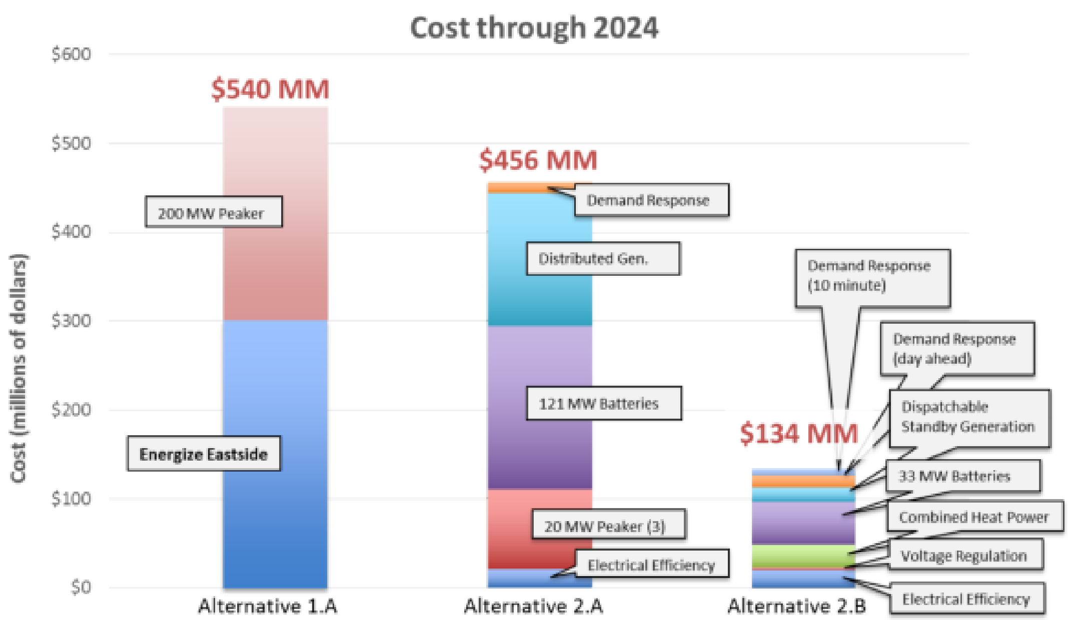
Component	Alternative 2.A (MW in 2024)	Alternative 2.B (MW in 2024)
Targeted Energy Efficiency	42*	39
Distribution Efficiency (CVR)	0	4
Combined Heat & Power	0	27
Energy Storage	121	31
Peak Generation Plant	60	0
Dispatchable Standby Generation	0*	22
Demand Response (unspecified)	32	
Demand Response (day ahead)		34
Demand Response (10 minute)		12
Total	**255**	**169**

* Incompletely specified in Draft EIS

Compared to Alternative 2.A, Alternative 2.B has 86 MW less of energy potential by 2024, but that is sufficient to meet the projected local need (although CENSE continues to dispute the magnitude of this need based on the Lauckhart-Schiffman Load Flow Study).

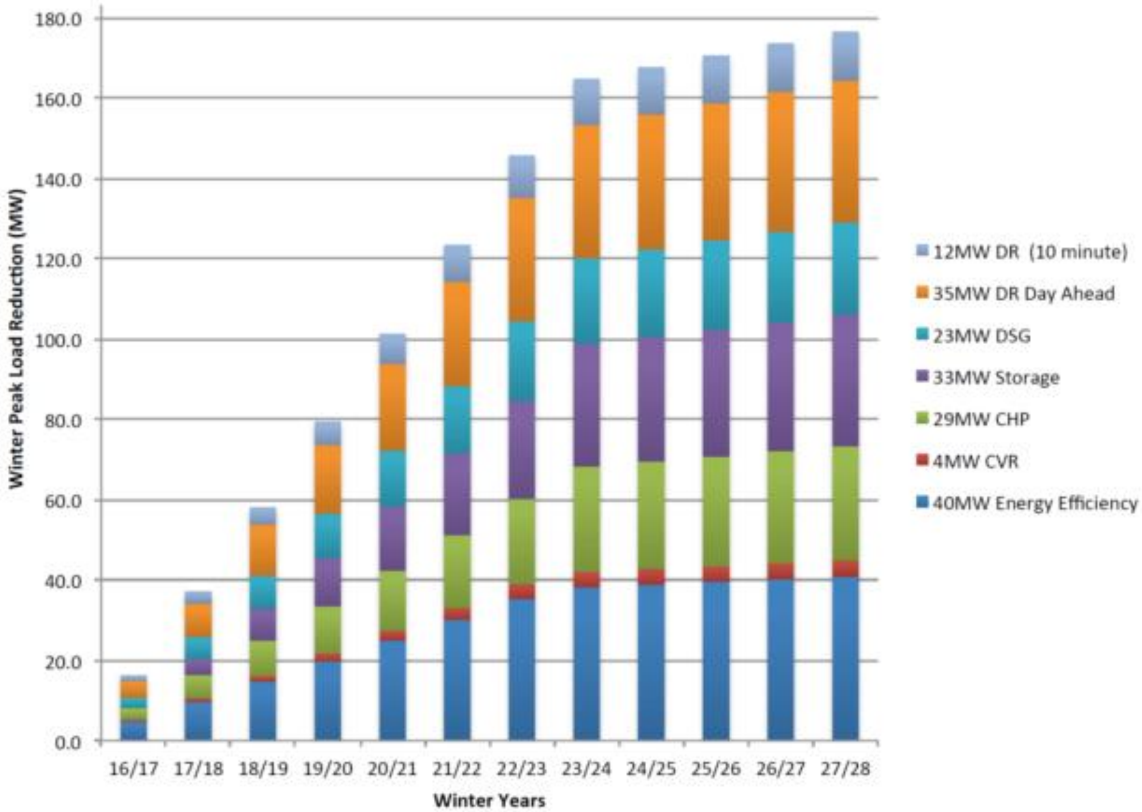
Compared to Alternative 1.A, Alternative 2.B offers many advantages that communities will find attractive. For example, EQL has shown that Alternative 2.B will reduce peak load demand and therefore delay the need for a new gas-fired peaker plant that PSE has stated the company may need to build in 2021, just a few years after Energize Eastside is built.

The graph below compares outlays for Alternatives 1.A, 2.A, and 2.B until the year 2024, including a new 200 MW peaker that may be needed if winter peak demand is not moderated through smart integrated resource approaches:



Both Alternative 2.A and 2.B have lower total cost and reduced carbon emissions compared to the transmission line proposed in Alternative 1.A. Both Alternative 2 plans have another economic advantage. Unlike Alternative 1.A, which can't transmit its first electron until it is completely built and paid for, the Integrated Resource Approach can be built incrementally, a little bit each year. EQL proposes outlays of about $20 million per year, which can be scaled down if demand does not increase as fast as PSE predicts. Incremental investment has the added advantage of profiting from the rapid development and associated cost reductions of energy technologies, especially battery storage.

The following graph shows the expected ramp of peak reduction (in megawatts) for each component over the next 8 years:



These technologies and energy policies are being used effectively in other parts of the country. For example, the table below lists companies contracting with Southern California Edison to deliver 510 MW of energy savings and storage.[1] There are many examples of projects in other states that suggest that these kinds of solutions are feasible and cost effective.

Seller	Resource Type	MW
NRG	Energy Efficiency	102.5
Onsite Energy Corporation	Energy Efficiency	11
Sterling Analytics LLC	Energy Efficiency	16.7
NRG	Demand Response	75
SunPower Corp.	Behind-the-Meter Renewable	44
Ice Energy Holdings, Inc.	Behind-the-Meter Thermal Energy	25.6
Advanced Microgrid Solutions	Behind-the-Meter Battery Energy Storage	50
Stem	Behind-the-Meter Battery Energy Storage	85
AES	In-Front-of-the-Meter Battery Energy Storage	100
Total		**509.8**

[1] http://www.greentechmedia.com/articles/read/The-Worlds-Biggest-Battery-is-Being-Built-in-Southern-California

The exact mix of technologies, incentives, and energy policies that will be used is subject to further study and debate. EQL has provided specific capacity and cost estimates to provide illustrations of what is practical and cost-effective. A final plan will need to be developed in discussion with PSE, independent experts, local officials, and community representatives.

Alternatives 2.A and 2.B differ in the use of small peaker plants located in Eastside substations. PSE mentions concerns about noise and impact on residential areas. CENSE has a keen interest in these issues. However, if peaker plants are proven to be necessary and economically attractive, a small plant located in the light industrial area next to Bellevue's Lakeside substation (also near the new garbage transfer facility) could be an acceptable compromise.

In summary, we believe Alternative 2.B is less expensive, less dangerous, more reliable, less damaging to the environment, and less impactful to communities than the 18-mile scar through five Eastside cities that would result from building Alternative 1.A. We find Alternative 2.B to meet the definition of a "Reasonable alternative" described in WAC 197-11-786.[2]

We respectfully request Alternative 2.B be added to the EIS and receive fair evaluation by independent experts with experience in delivering solutions based on energy efficiency, demand response, distributed generation, and battery storage during Phase 2 of the EIS process.

Feedback on Draft EIS components

According to the Washington State Environmental Policy Handbook,

> *Alternatives are one of the basic building blocks of an EIS. They present options in a meaningful way for decision-makers. The EIS examines all areas of probable significant adverse environmental impact associated with the various alternatives including the no-action alternative and the proposal.* [3]

Alternative 2.A is distorted by incomplete information and questionable assumptions. Its impacts cannot be honestly compared to the impacts of PSE's proposal (Alternative 1.A).

Here are some of the problems we saw in the design and evaluation of Alternative 2.A:

1. An "Integrated Resource Approach" must be designed by a consultant with expertise and practical experience in creating solutions based on Distributed Energy Resources.
2. The solution must be designed by an entity independent of PSE, because the project proponent has a vested interest in making Alternative 1.A look good.
3. The solution must not be based on information in PSE's Integrated Resource Plans (IRPs), because **IRPs are not required to incorporate feedback from stakeholders or the Washington Utilities and Transportation Commission.**
4. The DEIS should cite examples from other cities in which a proposed solution or component was successfully applied, and note if any unanticipated problems arose.
5. The solution should cite other Northwest agencies that were consulted and/or referenced. For example, alternatives should note agreement or disagreement with recommendations made by

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[2] http://apps.leg.wa.gov/wac/default.aspx?cite=197-11-786

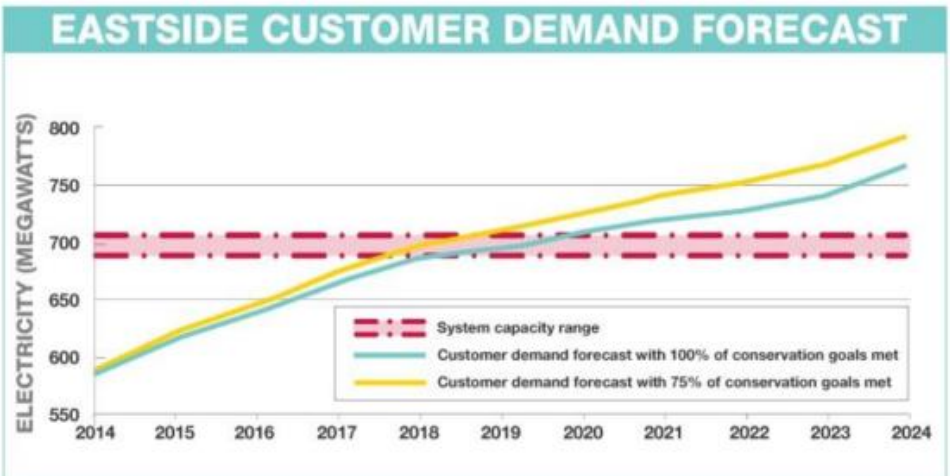
[3] https://fortress.wa.gov/ecy/publications/documents/98114.pdf, p. 53

the Northwest Power and Conservation Council in the recently released *Seventh Northwest Power Plan*.

Specific reactions to DEIS Alternative 2.A

- 2.3.3: *"According to PSE projections, it would take 74 MW of additional transmission capacity to marginally meet the demand through 2018 (Gentile et al., 2015). However, to address the capacity deficiency in 2018 with non-transmission resources would take approximately 163 MW of additional conservation, storage, and new generation within the Eastside…"*

  PSE seems to be changing the rules as the Energize Eastside proposal proceeds. The 74 MW figure quoted above for 2018 is significantly higher than the need PSE shows the public on its website:



  This graph shows a deficit of about 74 MW in 2024, six years later than the reference from Gentile et al. implies. We wonder why there is such a significant difference between PSE's public and private communications on the size of the capacity deficit.

  When consultant E3 studied a non-wires solution in February 2014, the requirement was simply stated: *"Assuming typical weather conditions of 23° F during PSE's winter peak demand, PSE powerflow cases identified that 70 MW of incremental peak demand reduction (beyond the reduction included in the baseline load forecast reflecting 100% of IRP target conservation levels) would be required in King County to defer transmission need until 2021."*[4]

  As one can see in the graph on page 3 of this document, EQL projects over 121 MW of peak load reduction by 2021. But PSE now says the company needs 163 MW of reductions by 2018. This higher number seems to be based on a new standard of effectiveness that is described in this

[4] https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/PSEScreeningStudyFebruary2014.pdf, p. 6

email from Energize Eastside Program Manager Jens Nedrud: http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/pse_emails_referenced_in_the_deis.pdf. We wonder why this issue did not arise in the E3 study. Is it real, or is this an obfuscation designed to cast doubt on non-transmission alternatives in the EIS? If it is real, is the magnitude correctly stated by PSE?

We suspect that the different requirements for transmission and non-wires solutions stem from PSE's stated requirement that the Eastside grid must assist in the export of 1,500 MW to Canada during peak demand. This requirement favors transmission-based alternatives. However, the export of electricity at this level has never been proven, and the *Lauckhart-Schiffman Load Flow Study* raises important questions about whether the regional grid can sustain this level of transmission.

All of these fundamental questions have yet to be studied by a neutral and independent expert. Since many questions have come to light only after the EIS process began, they must be validated in order for non-wires solutions to be appropriately scaled. After that, the impacts of these alternatives can be appropriately compared.

A fair and independent expert must answer questions about how much electricity must be exported to Canada during winter peak loads and an N-1-1 failure. The number should reflect how much electricity is required by contractual agreement, and also how much can be reasonably delivered by the regional grid. Once this is known, the effectiveness of non-wires alternatives must be independently derived. This should lead to a clear determination of the level of peak load reduction that is required for each alternative in each year.

2.3.3: *"[Alternative 2.A] could address the project need but results in uncertainty about how much infrastructure would be installed and how much additional supply would be needed each year."*

Vague, unsubstantiated statements like this reinforce an impression that the DEIS is biased against this alternative. Many utilities have used similar solutions without excessive fear and uncertainty about their infrastructure and supply.

The DEIS should provide positive and negative examples from other utilities that have employed these approaches. We can learn from the trials and successes of others. Let's not make decisions based on unfounded fears and doubts.

2.3.3.1: *"The potential for additional energy efficiency on the Eastside is not currently known and would require additional evaluation."*

There is plenty of data for making a more accurate determination, and an independent expert can provide a good estimate based on the experience of other communities as well as particular details that apply to our region. To avoid bias and conflicts of interest, "additional evaluation" should not be performed by PSE. Further, PSE has not demonstrated an ability to evaluate the potential of energy efficiency in a credible way. The WUTC and the Sierra Club have roundly criticized PSE's energy efficiency estimates in recent Integrated Resource Plans.

To maintain credibility and independence, the DEIS must employ an expert who can provide a reasonable estimate of potential savings on the Eastside through cost-effective energy efficiency technologies and policies.

- 2.3.3.1: *"PSE's Integrated Resource Plan (2013a) estimated PSE could achieve approximately 100 MW of additional energy efficiency during the period from 2024 to 2033 systemwide, which would equate to approximately 14 MW of energy efficiency gains on the Eastside during that time period. The additional energy efficiency assumed for Alternative 2 would be triple the amount that PSE estimated is achievable after 2024."*

  PSE's 2013 IRP is not a credible source to cite as a basis for energy efficiency projections. The IRP is known to be deficient in its evaluation of energy efficiency. The company's data was incomplete and out of date. Quoting the IRP without independent confirmation allows PSE to indirectly sabotage the viability of solutions that rely on accurate energy efficiency projections.

  It is also unreasonable to assume that energy efficiency gains are directly proportional to the Eastside's share of total system load. The mostly urban Eastside has a different level of energy intensity than more rural areas, and the potential for substantial gains through energy efficiency is greater. Quoting a back-of-the-napkin estimate like 14 MW is an affront to the honest and independent process we expected from the EIS. The earlier statement was preferable: "[energy efficiency potential] is not known and would require additional evaluation."

  To maintain credibility and independence, PSE's Integrated Resource Plans cannot be referenced as a source of data used to design or evaluate non-wire solutions. The DEIS must cite credible experts and case studies instead of rough calculations based on IRPs written by the project proponent.

- 2.3.3.2: *"The Integrated Resource Plan (PSE, 2013) estimated that demand response systems would result in 116 MW systemwide reduction in capacity needed by 2024. Because the Eastside represents approximately 14 percent of the systemwide load, and assuming that adoption of demand response would be proportional on the Eastside to the rest of PSE service areas, it is assumed that approximately 14 percent of the systemwide reduction (16 MW of conservation by 2024) would occur on the Eastside."*

  PSE's 2013 IRP has been strongly criticized for its lack of credible analysis on Demand Response. The Eastside has significantly greater potential for savings from Demand Response compared to other parts of PSE's service area. The Eastside potential is not proportional to other PSE service areas.

  PSE will be sending out an RFP for Demand Response solutions as part of its 2017 IRP process. Let's see what kind of Demand Response potential the competitive market can identify. Market-driven answers are likely to be more informative and aggressive than PSE's weak efforts were 3 or 4 years ago.

Demand Response is a central feature of the Seventh Northwest Power Plan. The DEIS must be much more specific about the kinds of Demand Response that will be incorporated in alternative solutions. For example, EQL Energy describes different programs for "day ahead" and "10 minute" Demand Response. These two programs deliver 43% more savings than the vaguely described program in the DEIS. Many states are far ahead of Washington in using Demand Response programs. The DEIS should cite positive and negative examples in other states to better inform the public and policymakers about the potential for these solutions in PSE's service area.

- 2.3.3.3.1: *"In order to address the Eastside transmission deficiency with distributed generation alone, approximately 300 to 400 MW of capacity would be needed by 2024 depending on the geographic location of the generation (PSE, 2013; Strauch, personal communication, 2015a)."*

  The use of distributed generation alone is not a scenario proposed by any alternative in the DEIS. This statement obfuscates the facts and may confuse the public. Worse, it states large numbers of megawatts that depend on an unspecified geographic location. What purpose does this serve? How would those numbers change if the generation were located in a more advantageous location? No useful information is provided.

  It is disappointing to see PSE's 2013 IRP again cited as a source. This corrupts the supposedly independent EIS process. Although the IRP documents are reviewed by the WUTC and other stakeholders, **no one has the authority to correct inaccurate statements in the IRP.** If the DEIS must cite the IRP as a source, it should also cite the criticism that those citations generated during the IRP review.

  The DEIS should engage experts in the field of distributed generation and provide positive and negative examples from communities that have used distributed generation strategies to address peak load issues.

- 2.3.3.3.1: *"To ensure adequate capacity even when some equipment is not working, a substantial degree of redundancy is needed in distributed generation resources."*

  This statement ignores the fact that successful Distributed Standby Generation programs have been deployed in the Pacific Northwest. For example, Portland Gas & Electric has a program in which the utility is responsible for testing and maintaining generators that are owned by private businesses and hospitals. The businesses get free maintenance in return for allowing their generators to be used by the utility during peak load scenarios that happen only a few hours each year. This is a good deal for the businesses who don't have to do maintenance themselves. It's also a good deal for customers who don't have to pay for extra infrastructure.

  To address the questions of adequate supply and redundancy, the DEIS must describe what

kind of maintenance programs would be needed to keep these generators in good working order. The cost of these programs must be compared with the cost of having redundant generators that are maintained in a less regular fashion.

- 2.3.3.4: *"While it is possible that home battery storage could occur in homes using technology that is currently being developed, [we won't consider it]."*

  It may be true that home battery storage won't be so widespread in the next few years that it will make a big difference in the Eastside's energy mix. However, it is worth considering how a utility might incentivize customers to consider this investment. PSE could offer rebates for installing home batteries. Or the company could give battery customers a special discount on electricity if they charge the battery during non-peak hours and then use the stored electricity during peak hours. Incentives could make it financially attractive for customers to install batteries for the purpose of saving money on their electricity bills and having a backup source of electricity during power outages. This would especially appeal to customers with solar panels. A battery would allow these customers to bank their solar output and survive power outages spanning multiple days (with a big enough battery and judicious use of electricity).

  Instead of dismissing home batteries in a single sentence, the DEIS should describe incentives in other states that encourage home battery installation. How do incentive costs, impacts, and benefits compare to other alternatives? Of course, the DEIS should account for the societal cost of carbon emissions, and the possibility that carbon will be taxed in the future.

- 2.3.3.4: *"This analysis considers a PSE controlled facility capable of storing 121 MW, which would be adequate to eliminate emergency overloads (Strategen, 2015). This would require a site of approximately 6 acres."*

  We disagree that a battery of this size is necessary. A huge battery is needed only because the DEIS significantly underestimates the amount of energy that could be addressed through energy efficiency, demand response, and distributed generation. According to our expert, EQL Energy, the Eastside could realistically install a battery that is 4 times smaller than described in the DEIS. A smaller battery would take less land to site.

  The DEIS would do well to reference a project that is currently being installed by Southern California Edison.[5] It's a mix of utility-side and behind-the-meter batteries that might work on the Eastside at a much smaller scale. There are exciting batteries being produced locally (UniEnergy Technologies in Mukilteo[6]) and intriguing salt-water batteries that are inexpensive, non-toxic, non-flammable, and non-corrosive (Aquion Energy[7]). Battery technology is evolving quickly, and even PSE says batteries will be transformative soon. The main questions are how big, how much, and when?

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[5] http://www.utilitydive.com/news/inside-southern-california-edisons-energy-storage-strategy/406044/
[6] http://www.uetechnologies.com/
[7] http://www.aquionenergy.com/products/grid-scale-batteries

Because the huge battery described in Alternative 2.A is practically impossible to charge and difficult to site, the DEIS must consider smaller batteries that are enabled by better energy efficiency, demand response, and distributed generation. Also, the DEIS must correct a significant error in the Strategen report that fails to account for the avoided cost of transmission, making batteries look less cost-competitive that they actually are (the table below shows batteries to be twice as cost-efficient as PSE's transmission project if an additional peaker plant can be avoided). The benefit of reduced carbon emissions must be recognized if additional peaker plants are supplanted by energy storage.

Benefits (avoided capital costs)			
Transmission Deferral cost	155	$/kW-yr	$220MM capital cost for Energize Eastside
Generation Capacity Cost	184	$/kW-yr	E3 based on SCCT $190/kW -yr levelized cost
Distirbution costs	31	$/kW-yr	Based on NWPCC value
Flexibility (Ancillary Services)	99	$/kW-yr	Strategen report
Oversupply	1.4	$/kW-yr	
Storage Benefit	**470.4**	**$/kW-yr**	
Storage Cost	**218**	**$/kW-yr**	2015 Strategen report EE EIS
Benefit/Cost ratio	**216%**		

- 2.3.3.4: *"The Eastside system has significant constraints during off-peak periods that could prevent an energy storage system from maintaining sufficient charge to eliminate or sufficiently reduce normal overloads over multiple days."*

  This is only a concern for the huge batteries proposed in the DEIS. It is not a problem for the more realistically-sized batteries proposed by EQL Energy.

  The DEIS must redo analysis of battery charging limitations with smaller batteries.

- 2.3.3.4: *"A system large enough to address the entire transmission capacity deficiency would need to deliver approximately 328 MW of electricity and store 2,338 (MWh) of power. A storage system of this size is not technically feasible."*

  This statement might be misread by the public. Someone might conclude that batteries are not technically feasible, when they are only infeasible if they are used to address the **entire deficiency** without any other components included.

  The DEIS should not include statements that confuse or obfuscate the issues. Statements like this must be moved into a separate section clearly labeled "Ideas that were considered but proven unworkable." Some readers might be confused by the proximity of this fantastical speculation to realistic proposals.

- 2.3.3.4: *"Summer requirements were not evaluated because the limitations identified during the winter study indicated that energy storage would not be a feasible stand-alone alternative."*

  Everyone agrees that energy storage is not a *stand-alone* alternative. This statement applies only to the previous fantastical speculation.

  The DEIS must remove or clearly separate fantastical speculation from factual information.

- 2.3.3.1 (Peak Generation Plant Component – the section numbers are wrong, it should be 2.3.3.5): *"Most of the substations on the Eastside are in residential areas, and these types of generators produce a high noise level that would be incompatible with those surroundings. For this reason PSE had eliminated this option from consideration."*

  CENSE remains keenly interested in protecting residential neighborhoods from the impacts of demand growth that are mostly driven by the commercial sector. The DEIS does not consider how the costs of serving demand growth should be shared with commercial enterprises and developers who create increased demand.

- 2.3.3.2 (Construction, also incorrectly numbered): *"Construction of battery storage facilities would last approximately 6 months and would require standard construction equipment similar to what is required for construction of a substation under Alternative 1."*

  This statement compares the construction impact for a huge battery (which is way too aggressive) to the construction of a substation under Alternative 1. Shouldn't the DEIS also consider the construction impact of removing thousands of mature trees and bulldozing dozens of homes in order to install 18 miles of transmission lines in Alternative 1.A? It is a mockery of the SEPA process to worry about the impact of 6 acres of development while ignoring 18 miles of impacted neighborhoods, parks, schools, and businesses.

  To be fair, the DEIS must compare apples to apples. The total construction impact of an alternative should be compared to the total construction impact of another alternative. Comparing the impact of one subpart of one alternative to the impact of a selected subpart of another alternative is not useful.

- 16.7.4: *"Uncertainties about the feasibility and performance of certain technologies, customer participation levels, and achievable conservation result in a risk to reliability."*

  These unsubstantiated statements about reliability, coming from the project proponent, might be used to eliminate non-wires solutions from consideration. However, these solutions rely on many different technologies and policies, and are actually more reliable than a transmission line. A transmission line is vulnerable to earthquakes, extreme weather, solar flares, and terrorism. For example, an extreme wind or ice storm may jeopardize more than a single pole. If two poles fail, the entire transmission line that PSE proposes to build could be knocked out, reducing the capacity of the Eastside grid by up to 20%. The same storm is unlikely to disable more than 5%

of the capacity of Alternative 2 solutions.

The DEIS must compare apples to apples. The overall reliability of one alternative must be compared to the overall reliability of another alternative.

Why is the Eastside an exception?

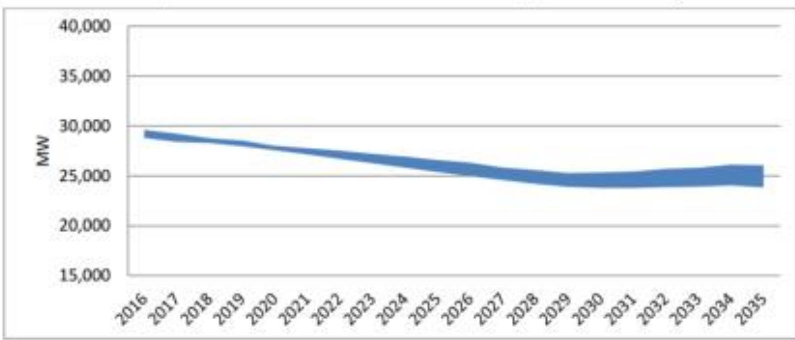
The *Seventh Northwest Power Plan*[8] published by the Northwest Power and Conservation Council says

> *In more than 90 percent of future conditions, cost-effective efficiency met all electricity load growth through 2030 and in more than half of the futures all load growth for the next 20 years. It's not only the single largest contributor to meeting the region's future electricity needs; it's also the single largest source of new peaking capacity.*

CENSE wonders why efficiency is not the answer to the Eastside's load growth. Obviously, the Eastside is growing quickly. However, the 2.4% annual growth rate in demand that PSE predicts is nearly five times the rate that Seattle City Light predicts. It is not obvious that the Eastside is growing five times faster than Seattle.

Perhaps PSE projections do not rely enough on conservation and demand response. Here is a graph of expected **Winter Peak Demand** included in the Seventh Plan:

Figure 7 - 11: Sales (Net Load After Conservation and DR) Forecast Range – Winter Peak



Even if the Eastside is growing quickly, we would expect winter peak growth to be flat or very slightly positive, not the explosive 2.4% growth that PSE projects.

The DEIS must clarify what level of growth is realistic, and evaluate the impacts of alternatives that are specifically designed to address that level of growth. Each alternative must be vetted by experts. If possible, the DEIS should cite positive and negative examples from communities that have gained experience with an alternative. Above all, the DEIS must be clear, unbiased, and independent. The Draft EIS fails these criteria and must be corrected.

Sincerely,
Don Marsh, President
CENSE.org

[8] https://www.nwcouncil.org/energy/powerplan/7/plan/

From: Loretta Lopez
Sent: Monday, March 14, 2016 5:43 PM
To: 'HBedwell@bellevuewa.gov'; 'info@EnergizeEastsideEIS.org'
Subject: Comments to DEIS PROPOSED PSE Project/January 28 DEIS/1.5 paragraph 4

According to DEIS, the set of facilities is proposed in order to address a deficiency that PSE has identified by PSE through its system planning process. Page 1.1

The DEIS states that the deficiency is based upon a number of factors. Page 1-5. The DEIS continues that deficiency arises from growing population and employment, changing consumption patters associated with large buildings, more air conditioned space and a changing regulatory structure that requires a higher level of reliability than what was required in the past. Page 1.5. Paragraph 4.

What is the basis for the statement regarding changing patterns of consumption associated with larger buildings?

What is the source of information regarding more air conditioned space?

What are the specific regulatory changes that require higher reliability than what was required in the past? What is the specific set of citations?

Loretta Lopez

13419 NE 33rd Lane
Bellevue Wa 98005

Bridle Trails Community Club, Vice President

CENSE Member

From: Loretta Lopez
Sent: Monday, March 14, 2016 6:40 PM
To: 'HBedwell@bellevuewa.gov'; 'info@EnergizeEastsideEIS.org'
Subject: Comments to DEIS PROPOSED PSE Project/January 28 DEIS/RCW/WAC Need

The DEIS states that the EIS will not be used to reject or validate the need for the proposal. Rather, the EIS is intended to identify the alternatives that could attain or approximate PSE's objectives at a lower environmental cost and disclose potential significant adverse environmental impacts associated with all alternatives identified. Page 1-5

If the information cannot be validated or checked then this means that PSE's assertions cannot be questioned. If this were the case, that citizens cannot question PSE assertions, then it would be impossible to suggest or assess Alternatives. The reason: One cannot determine a solution to a problem if one cannot understand the problem or analyze the problem. This is inconsistent with the purpose of SEPA.

What is the citation to the RCW or the WAC which supports the statement that "the EIS will not be used to reject or validate the need for the proposal?

Loretta Lopez

13419 NE 33rd Lane
Bellevue Wa 98005

Bridle Trails Community Club, Vice President

CENSE Member

From: Loretta Lopez
Sent: Monday, March 14, 2016 6:15 PM
To: 'HBedwell@bellevuewa.gov'; 'info@EnergizeEastsideEIS.org'
Subject: Comments to DEIS PROPOSED PSE Project/January 28 DEIS/Page 1-5 P 5/Growth

The DEIS states that the population of the Eastside is expected to grow at a rate of approximately 1.2 percent annually over the next decade and employment is expected to grow at an annual rate of approximately 2.1 per cent, a projection based upon internal forecasting conducted by PSE. Page 1-5 paragraph 5.

The DEIS continues and states that PSE used demographic data based upon based on U.S. Census Information and the Puget Sound Regional Council. Page 1-5

Both organizations publish many reports. What is the specific document or report published by the U.S. Census Information and the Puget Sound Regional Council that PSE relied upon? Did anyone other than PSE employees review the information which formed the basis of PSE's assertions as set forth above regarding population growth? If so, who reviewed?

The DEIS further states that PSE relies on Moody's Analytics U.S. Macroeconomic Forecast, a long term forecast for the U.S. Economy with adjustments for PSE's service territory using equations that relate to national to regional conditions. Page 1-5.

What is the date and year of the Moody's Macroeconomic Forecast that PSE relied upon? What equations did PSE use to relate national to regional conditions? Did anyone other than PSE employees review the equations and check the results that PSE used to relate national to regional conditions? If so, who reviewed?
Did anyone other than PSE employees review the information which formed the basis of PSE's assertions as set forth above regarding population growth? If so, who reviewed?

The DEIS continues with local economic data are provided by the Washington State Department Employment Security Department, U.S. Bureau of Labor Statistics and Bureau of Economic Analysis, and local organizations such as the Washington Builders Association. Page 1-5

What are the citations to the specific information or reports that PSE relied upon?

The DEIS states: "This forecast is based upon the assumption that economic activity has a significant effect on energy demand. Given the nature of expected development, PSE has projected that electrical demand will grow at an annual rate of 2.4 percent."

Is "forecast" stated in the DEIS statement above referring to PSE's population forecast. PSE's employment forecast, PSE's energy demand forecast?

Loretta Lopez

13419 NE 33rd Lane
Bellevue Wa 98005

Bridle Trails Community Club, Vice President

CENSE Member

From: Loretta Lopez
Sent: Monday, March 14, 2016 7:32 PM
To: 'HBedwell@bellevuewa.gov'; 'info@EnergizeEastsideEIS.org'
Subject: Comments to DEIS PROPOSED PSE Project/January 28 DEIS/Authority for Phased EIS

The DEIS states that the Phase 1 Draft EIS broadly evaluates the general impacts and implications associated with feasible and reasonable options available to address PSE 's identified objectives for the project. The evaluations conducted during Phase 1 to will be used to narrow the range of alternatives for consideration in Phase 2 Draft EIS. Section 1-2, page 1-4

The City of Bellevue's decision to refusal to issue a Final Decision after Phase 1 prevents citizens from addressing the problem regarding the lack of appropriate Alternatives and to assess the big picture issue of Need until end of Phase 2. The decision to conduct the EIS in consecutive phases without a Final Decision after Phase 1 is an unwise use of time, energy and taxpayer and rate payer's money.

What is the specific citation to an RCW or WAC which supports the basis of the City's decision to conduct the EIS in this manner?

The DEIS continues and states that the Phase 2 Draft EIS will be a project level evaluation, describing impacts a site specific and project- specific level. Section 1-2. page 1-4.

I assume that this statement means that the citizens will know the exact route and will know exactly which trees will be cut. PSE, however, has not yet filed an application for a permit for this project. And according to Carol Helland, City of Bellevue, PSE will not file an application until PSE applies for a conditional use permit. See email 3/11/16 from Carol Helland.

How will the citizens know the project specific details of the proposed project if there is no application filed? How can PSE assess the information submitted in Phase 1 and plan to issue scoping for Phase 2 on April 8 in such a short amount of time? Is this possible due to the lack of specific information? If so, then why have citizens been told that the site specific details will be addressed in Phase 2?

****

From: CHelland@bellevuewa.gov [mailto:CHelland@bellevuewa.gov]
Sent: Friday, March 11, 2016 7:39 PM
To: Loretta Lopez
Subject: Re: PSE Application

PSE filed an application for an EIS, which is customary for a project that ends up with a determination of significance. They have not formally submitted for a conditional use permit (which will be required once the EIS is complete).

Once a application for a conditional use permit is filed, a notice of the application will go out broadly. Hope this information is useful.

Carol Helland

On Mar 11, 2016, at 7:08 PM, Loretta Lopez <loretta@mstarlabs.com> wrote:

Carol,

I assume that PSE has not yet filed and application. Is this correct?

Would you let me know as soon as PSE files an application.

Thank you.

Loretta
****

Loretta Lopez

13419 NE 33rd Lane
Bellevue Wa 98005

Bridle Trails Community Club, Vice President

CENSE Member

From: todd@MATADORTECH.COM [mailto:todd@MATADORTECH.COM]
Sent: Monday, March 14, 2016 6:37 PM
To: info@energizeeastsideEIS.org; council@bellevuewa.gov
Cc: Don Marsh <don.m.marsh@hotmail.com>; Larry Johnson <larry.ede@gmail.com>; Janis Medley <jpmedley@mac.com>; sdofour@aol.com; Richard Kaner <thekaners@comcast.net>; Richard <lauckjr@hotmail.com>; info@cense.org; todd@matadortech.com
Subject: Energize Eastside draft EIS comments from Todd Andersen & Jennifer Steinman

To: Bellevue City Council and City of Bellevue Energize Eastside draft EIS staff
From: Todd Andersen (MS Electrical Engineering, BS Mechanical Engineering) and Jennifer Steinman (MS IT/ED – Stanford University)
Address: 4419 138th Ave SE, Bellevue WA 98006
Attached: PDF of comments on Draft Energize Eastside EIS

Please accept my apologies in advance for not having the time to clean up the attached written comments as the 42 day comment window is so short and there is so much wrong with the Energize Eastside draft EIS.

Anybody have a copy of the Olympic Pipeline break disaster plan?

On the very last page of the attached doc is a picture of the damage from the 2010 San Francisco metro natural gas explosion, San Burno, that went up mostly into the air, unlike what an Olympic pipeline break will do. Its jet fuel being liquid will spread horizontally and rush downhill. Even with automated shut off the jet fuel could easily result in the burning of hundreds if not thousands of homes unlike the natural gas pipeline explosion in San Bruno CA fire which killed 8.

Having personally conducted fire protection testing on the V-22 Osprey, it takes AFFF “A triple F” (Aqueous Film Forming Foam) to put out a jet fuel fire. And putting out just 40 gallons of jet fuel is not easy, even with prepositioned and built in fire fighting equipment on our testing pads it could take 20 minutes to put out 40 gallons. Using water just spreads the fire. AFFF works great if you have enough of it and there is no wind. Given the size of the Olympic pipeline it is going to take a lot of AFFF equipped fire trucks at all the local firehouses. The stuff at SEATAC will be too late to help.

Todd Andersen
425-449-8889

Date: March 13, 2016
Email Subject: Energize Eastside draft EIS comments
Email date: March 14, 2016 due to PSE 177,000 customer power outage on March 13th.
To: Bellevue City Manager, Council and City of Bellevue Energize Eastside draft EIS staff
From: Todd Andersen (MS Electrical Engineering, BS Mechanical Engineering) and Jennifer Steinman (MS IT/ED – Stanford University) 4419 138th Ave SE, Bellevue WA 98006

Please accept my apologies in advance for not having the time to clean up these written comments as the 42 day comment window is so short and they is so much wrong with the draft EIS.

The City of Bellevue (COB), which is overseeing the State EIS, is as capable in detecting PSE falsehoods (or possible fraud) has the COB has been in detecting its own staff's credit card fraud in its Parks department, taking over two years to do so. Something that requires a small bit of technical expertise to evaluate PSE's Energize Eastside grid expansion is way over COB's head. COB current performance on the draft EIS proves this lack of expertise in spades and will unfortunately land the COB in court, wasting taxpayer dollars. To date the COB actions on EE and the draft EIS have severely damaged the City of Bellevue's credibility. The below comments are geared to reduce the potential damage to COB and citizens.

<u>The first request</u> is that COB halt the EIS until the need for Energize Eastside is independently proven. This author has PSE's lawyer/Profession Engineer (P.E.)/utility grid consultant Mark Williams on video stating that if FERC or NERC or WECC stated that the 1500 MW to/from Canada was not "firm" (required at all times) than PSE would have to redo its all of its load flow studies. If that 1500 MW load is not firm, then PSE's deception of need disappears for more than 3 decades, sometime starting in 2060.

If this 1500 MW flow is assumed to be valid **then** conservation savings through the entire region of PSE's territory is valid and all saving has to be included in alternatives not just 14% of PSE territory, Energize Eastside, as the draft EIS/PSE claims. See page 143 of 714 (page 2-34) of the draft EIS. "*The Eastside represents approximately 14 percent of the total load for the PSE system, and therefore 14 percent of the total projected conservation (119 MW of conservation).*" Using just 14% is utter garbage thinking and analyzes given the EIS is considering it is valid to include power flows and suspensions of generation out of Eastside. Yet another blow to COB's credibility.

The overall theme of the need for Energize Eastside is multiple falsehoods if not out right fraud. Lauckhart Schiffman have documented PSE's claim of need for new power lines called for in Energize Eastside to be false on numerous fronts, which CENSE and others have given to COB. The two authors used PSE's power grid database to do so. PSE provided that database to the Western Electricity Coordinating Council (WECC) and the Federal Energy Regulatory Commission required WECC to release the PSE database to Lauckhart and Schiffman. Lauckhart Schiffman have shown numerous errors including using summer transformer temperatures not winter temperatures where peak loading would occur. Others include unrealistic complete shut down of 10 backup generators and sever reduction of many others during the few winter peak load and the delivery of 1500 MW to Canada during a rare peak load emergency. See my Jun 14 2015 testimony, attached to this doc.

Second request – for the City to hire consults that have the necessary technical skills to detail electrical power alternatives to Energize Eastside. The City of Bellevue (COB) or the contractors the City has hired to date are not uncovering PSE's falsehoods by not doing technical engineering work that is **independent** of PSE work but rather just reviews PSE's assertions. The COB is continuing with the past incompetent actions include:

1) Choosing a State Environmental Impact Statement (SEIS) when power loads used by PSE to justify the project include international flows to/from Canada AND power flowing over Energize Eastside lines will be from dams both in the US and Canadian already built or in planning stages but cannot be built until power lines like PSE's EE are in place. These dams effect endanger species of Orca and salmon and thus require a National Environmental Impact Statement. The City was previous notified by me in written and verbal testimony during other Energize Eastside comment periods that a National EIS is required. See item 2 in the EE EIS testimony submitted June 14 2015 and reattached, see item 2 (page 24 of 40 of this doc) on why Energize Eastside requires a National EIS is needed.

2) Not using work independent of PSE for other alternatives including conservations. When one uses independent sources one gets significantly different results disproving PSE's /COB's draft EIS results which rely solely on PSE's work or those hired by PSE. All of these have been documented and sent to the City by me in past comment periods. See that testimony June 14 2015 attached below starting on page 23 of this doc.

Detailed comments

I will comment on just the process issues with the State EIS and then the lack of critical information not in the draft phase 1 EIS.

Process issues with the Energize Eastside draft EIS.

1. The contractor selected for the EIS is completely incompetent in citing references appropriately and is deliberately hampering citizens' review documenting the very limited and poor EIS information. Foremost is that the draft EIS do not use even use standard reference citations required by all technical and even most non technical organizations. Thus the allowed time to comment is vastly insufficient for even citizens skilled in the Energize Eastside controversy and technologies to comment. **Please extent the comment period at least 3 months.** The draft EIS was release on Jan 28 , 2016 leaving 42 days to comment on a 715 page which do not use detailed nor specific references but yet vauguely point to over 2000 page of additional documents.
   a) The draft EIS goes out of it way to complicate and deplete the citizens time to review the DEIS with hundreds vague and obfuscating and non-standard methods of referencing sources, **never with page numbers to the source as is common practice**. Given the project is well over $1 billion dollars including the $800 million in profits PSE is guaranteed, this level of vagary is unacceptable. One of hundreds of examples is on page 2-34 (page 143 of 714pages) of the DEIS (Draft EIS) is "According to PSE

projections, it would take 74 MW of additional transmission capacity to marginally meet the demand through 2018 (Gentile et al., 2015)" No page number is referenced nor which version of the document nor is an full accounting of all relevant documents provided. The draft EIS's most complete documentation to these document(s) which is the far from complete, references to PSE's core "need" documents from page 1-4 (pg56/715) as "PSE provided two documents that describe the need: the *Eastside Needs Assessment Report* and the *Supplemental Eastside Needs Assessment Report* (Gentile et al., 2014, 2015)."

b) Continuing with above point of PSE's claim on page 2-34 (page 143 of 714pages) of the DEIS (Draft EIS) that "74 MW of additional transmission capacity to marginally meet the demand through 2018 (Gentile et al., 2015)" the 74MW **never appears** in the Oct 2013 (and orginal version) *Eastside Needs Assessment Report Transmission System King County Redacted Version October 2013 Puget Sound Energy Report prepared by: Thomas J.* ***Gentile,*** *P.E. – Quanta Technology Donald J. Morrow, P.E. – Quanta Technology Zach Gill Sanford – Puget Sound Energy Carol O. Jaeger, P.E. – Puget Sound Energy.* PSE does manage to sneak 74 MW in to a *Supplemental Eastside Needs Assessment Report* dated April 2015 two years after the first Needs assessment report but the reader is left to guess where the correct document referenced is. Given the vagary of the DEIS references one is forced to wade through thousands of pages of documents at the PSE and City of Bellevue's EIS websites. Looking at the EE EIS.org website setup by the COB on Mar 1, 2016 we find these possible relevant documents with no reference to Gentile without requiring to the Citizens to opening up all documents 15 on PSE website and over three dozen on PSE's website.

Here is a screen shot of draft EIS website show the vagary of references not aligning with the 715 page draft EIS for Energize Eastside. No reference to *Gentile et al., 2014, 2015* without opening up all the docs. And the below are just a partial view of the available docs.

www.energizeeastsideeis.org/library.html

Background Documents - Project Need

Supplemental Eastside Solution Study Report - Redacted Version - May 2015
Independent Technical Analysis of Energize Eastside - April 2015
Supplemental Eastside Needs Assessment Report - Redacted Version - April 2015
Eastside Transmission Solutions Report – Redacted Version - February 2014
Eastside Needs Assessment Report – Redacted Draft - October 2013
Electrical Reliability Study Phase 2 Report - February 2012

Background Documents - PSE Energize Eastside Reports

and looking at PSE website we find the same lack of ability to reference without opening up all the documents and each citizen developing it own document management and reference system.

www.energizeeastside.com/documents

Study	Author	Description
Needs assessment executive summary Needs assessment report (redacted)* 2013 Supplemental needs assessment report (redacted)* 2015	PSE and Quanta Technology	Explains the need for the Energize Eastside project
Solutions report executive summary Solutions report (redacted)* 2014 Supplemental solutions report (redacted)* 2015	PSE and Quanta Technology	Describes potential options for solving the identified problem, and details the preferred solution

PSE's claim of 74 MW (on page 2-34 (page 143 of 714pages) of the DEIS (Draft EIS) quoted as "According to PSE projections, it would take 74 MW of additional transmission capacity to marginally meet the demand through 2018 (Gentile et al., 2015)" not in the following documents:

TransmissionSolutionStudyFebruary2014REDACTEDv2-118pgs.pdf
SupplementalSolutionsReport_Redacted_May2015-146pgs.pdf
Eastside_Needs_Assessment_Final_Draft_10-31-2013v2REDACTEDR1-78pgs.pdf

The 74 MW is found on page 21of32 in SupplementalNeedsAssessmentReport_Redacted_April2015-32pgs.pdf but given the vast amount of time to find it AND yet another PSE outage this weekend 177,000 without power for which EE does nothing to fix, this author has not time left to comment further to meet the March 14 2016 deadline.

c) The underlying PSE documents have had updates and the vague referenced to 2013 PSE's Integrated Resource Plan alone is exactly 1000 pages (245 pages for chapter 1 to 7 and 755 pages of Appendixes which have the core of the technical details)
d) The only way to efficiently review the draft EIS is electronically, not paper, and as a single pdf However the document in that form is not effectively usable in the common Adobe pdf readers without crashing a computer that is not the latest hardware and operating system. This leaves out poorer citizens without the latest computer hw and sw and retirees with the most time to comment but are not able to effectively do so. Paper copies cannot effectively be reviewed at the City given the hundreds of hours it would take to do so and the lack of effective references. The City could print them and allowed them to be taken home but 42 days to review is simply not enough time.
e) The draft EIS has no hyper links within reference internal to the document as is common publishing standard. And had a cumbersome page numbering system that does not allow common pdf viewer total page vs specific page tools to be used. The reviewer is forced to moved to internally referenced pages manually looking at each pdf page.

f) The reviewer had to use specialized pdf reviewing software (non Adobe) meant for reviewing long and dense medical and scientific papers. None of my follow citizens are using such software.

Some of Conservations issues with the Energize Eastside draft EIS ~~due to the vague references used in the draft EIS.~~

If the 1500 MW flow to/from Canada Energize Eastside claims and the shutting off generators outside of the Eastside is assumed to be valid for load **then** the same assumption has to be made for than conservation **that savings through the entire region of PSE's territory is valid to be included in alternatives not just 14% territory of Energize Eastside as the draft EIS/PSE claims.** See page 143 of 715 pages (or page 2-34) *"The Eastside represents approximately 14 percent of the total load for the PSE system, and therefore 14 percent of the total projected conservation (119 MW of conservation)."* Using just 14% is technically a double standard. If generation outside the Eastside can be turned off or load to from Canada can be included even though the Columbia River Treaty allows it to be schedulable, then the load via conservation saving outside Eastside must also be included.

2. THE EIS's review of LED is thoroughly incompetent. Pg 70 of 715 (1-18) is the only mention of LED light bulbs in the entire document. The current EIS uses the word LED lightbulb just once! Please detail LED Street lights currently installed and the remaining lights that are not yet LED and the saving from switching out old street lights to LED. Please detail the entire load on PSE's system not only in the Energize Eastside area but PSE's entire territory load outside of Eastside is counted then reductions of load outside Eastside needs to be counted too. Please include lights on federal, state, county and city roads. The power savings of street light to LED counts 100% toward peak load reduction as the load PSE is the claiming overloading is occurring at a winter peak load at 23F temperature load (see draft EIS pg 559 of 715 which is page A-1) from 4pm to 8pm (work to home transition time) that will be dark to dark twilight light with ALL street lights on as it is nighttime that time of year.

   Switching out Federal, state, county and City street like seems much easier and cheaper the the many houses PSE will have to take via Eminent Domain.

3. Please detail LED Residential and commercial remaining incandescent stock, taking into account the Dept of Energy's multiple reports on the CFL failure rates which has driven most users back to incandescent lighting. LEDs light bulbs have a 85% to 90% power and energy savings over incandescent and at least 50% over CFL with proven longevity unlike CFL. This should be easy once the COB hire staff competent in this area. Given the extreme short time of 42 days that citizens have to review all I have time for is the punch lines. There are 600 Mega Watts of incandescent & halogen & high pressure sodium & related power reduction left in PSE's territory using NEEA.org and Dept of Energy reports. That least 200 megawatts of that savings will come from non-street-light bulbs that will be on during

peaking winter load, more counting street lights. PSE has never advertised the +85% saving of LED over incandescent light bulbs yet will spend for thousands of full and half page ads touting the "need" for Energize Eastside to date. Citizens have full documented this online, in Home Depots/Lowes/Costcos, PSEs on cable TV and PSE bill insert (I think these will be particularly powerful in any court case action on Energize Eastside with ones before the Stephen Colbert Shows and bill inserts particularly damning to PSE)

Some relevant DOE reports for the EIS to pay attention to are : www.energystar.gov/ia/partners/downloads/ENERGY_STAR_CFLs_OEM_Performance_Assessment_May_2013.pdf?0544-2a1e and the three batch reports. The first report, published in May 2011, covers the 68 models that completed testing by February 5, 2011 (Batch 1), and the second report covers the 68 models that completed testing between February 6 and July 31, 2011 (Batch 2). A later report covers the 118 models that completed testing between August 1, 2011 and July 31, 2012. On average, the models in Batch 3 came on the market nearly 1 year after those in Batch 2, and thus represent newer models. And the newer results are even more damning to CFL viability. See the 62 page, ENERGY_STAR_CFLs_Batch_3_Report_Public_Feb_2013.pdf

Here is a taste of how bad compact Florence light bulbs are per Dept of Energy:

Bare Spiral or Bare Specialty CFLs

Covered CFLs

Best case in PSE's favor = worst case for environment.
71/129=55% and 67/111=60.3%

Table 1: Summary Performance Results of All CFL Products Tested May 2009 – March 2013**

Year	Products Tested	Passed All Tests	Failures	Passing Rate
2010	61	39	22	64%
2011	129	71	58	55%
2012	111	67	43	60%
2013	33	8	25	24%
Cumulative	334	185	148	55%

** The markedly reduced passing rate for 2013 testing is likely a result of recent changes to the testing program. For 2013 testing, EPA removed the product testing cap that limited a partner's total testing exposure to 3 products per testing cycle and had somewhat distorted testing exposure among manufacturers. Once the cap was removed, EPA, utilities, and other parties were better able to nominate without constraints products of interest, including those with potential performance concerns, as well as products from sources with limited verification data.

The above are first year failure rates NOT counting any failures that occur in the first 3 months of use as the consumer is assumed to return those to the store for refund replacement. If the Dept of energy counted the failure rates in first three months or light flipping by little kids the failure sky rockets from 45% to well over 70%. Thus it is easily to see why there is still so much incandescent light bulbs installed and why all PSE CFL bulb give-aways have been an enviromental disaster.

First Important LED conservation Note:

Compact Florescent Bulbs (CFL) failure rate is so well know as demonstrate they show up in culture including comics, see below. Yet PSE is pretending it has had great successes in this conservation effort including PSE's massive rebating of them well after it was shown by DOE that CFL are a disaster and only LED should be rebated. Where are the regulators on PSE? A massive environmental crime. In fact, as of this writing PSE still is rebating CLFs in a continuation of what I consider to be a highly fraudulent conservation program.

'And the beauty of these low energy bulbs is they're so pathetically dim that if your wife or kids leave them on in an empty room you won't even notice.'

Compact Florescent Bulbs (CFL) are a massive failure and is well known to honest conservation experts and anyone who has tried CFLs. The reports from the US Dept of Energy on the failure rates of CFL explain the light bulb demographics report from

NEEA.org for WA OR ID and Montana. And I look forward to the Energize Eastside EIS detailing this failure rate and the rate reverting back to the incandescent bulbs. The answer is at least 600MW of savings of which at least 200 MW will be pure peak power reduction.

The below just a taste of what explains why there are far more incandescent lights to be replace with LED's than NEEA is recognizing because CFLs failure rate is so high and why "stored" rates are climbing very year. People are not storing very expensive and good CFL's so much has they can't bring themselves to throwaway CFLs they just bought for 7x over incandescent bulbs, threw away the receipt before the bulb went bad. The 7x pricing is for the time periods when the below chart was made. Why else would the "CFL currently stored" number go up every year? Or is it because people wanted to buy 7x more expensive bulbs to store on their shelves to show off to friends? I will bet those "stored" are really just bad bulbs.

Below from pg27/375 NEEA-2011-2012.375pg.-northwest-residential-lighting-tracking-and-monitoring-study.pdf

Table 3
Lamp Disposition in Purchaser Households by Survey Year, 2005–2012

Disposition of All CFLs Ever Acquired by Purchaser Household	2005 Survey (n=220)		2006 Survey (n=411)		2010 Survey (n=399)		2011 Survey (n=646)		2012 Survey (n=459)	
	Mean # of lamps	% of lamps	Mean # of lamps	% of lamps	Mean # of lamps	% of lamps	Mean # of lamps	% of lamps	Mean # of lamps	% of lamps
CFLs currently installed	6.1	70%	6.3	68%	10.9*	64%	11.0	53%*	10.2	49%
CFLs ever removed	0.3	4%	0.4	4%	1.4	8%*	3.8*	18%*	4.3	21%
CFLs currently stored	2.3	26%	2.6*	28%	4.8*	28%	6.0	29%	6.2	30%
Total CFLs ever acquired	8.7	100%	9.3*	100%	17.1*	100%	20.7	100%	20.7	100%
Purchaser base	**58%**		**67%***		**81%***		**75%***		**77%**	

* Difference from prior study period is statistically significant.

The reason CFL use went down is CFLs are a disaster. Are people really buying CFL bulbs that are 7X more expensive and just storing them more and more every years? Really or is the real fact that people have stopped buying and just going back to incandescence. The EIS will need to dig through a lot of NEEA.org reports on lighting but with staff with the right skill it is just a 80 hour job to get the 600MW over all savings number.

Second Important LED conservation Note: PSE will claim they funded million of CFLs and that there is simply little saving to be gained going to LED. However the VAST majority of the millions of CFL's PSE funded went into the trash per Dept of Energy CFL failure rate studies and as the above NEEA.org chart (funded 19% by PSE) show in painful detail.

4. Besides analyzing the lithium Ion, redox flow battery and other grid storage batteries, please include grid storage using simple lead acid grid storage which even Alaska utilities use, read in production. This is impressive and relevant given their poor performance during cold temperature yet Alaska still uses. This temp issue is something which will not be an issue for PSE's worse case temperature of 23F given their use in Alaska.

5. How does grid level battery storage compare cost wise to pump storage (pumping water up hill to a reservoir during low usage time) to meet PSE's (claimed) high peak load issue. Los Angles' uses pumped storage facility is rated at 1,247 Megawatts. See https://en.wikipedia.org/wiki/Castaic_Power_Plant Even with PSE's highly unrealistic assumptions, over load occurs just few hours once every 20 years, every 50 years if global warming is considered. And given the PSE's Needs reports can include shutting down power outside of the Eastside area, then hilltops and **plateaus in those same areas or equivalent distance from other part of the grid OR where the grid (Non PSE) where 1500 MW to/from flows Canada can be considered for pumped storage.** Pump storage could also consider local water towers as reservoirs for the PSE EE peak load "problem" as the water usage during PSE's 23F low temperature also corresponds to the lowest water usage during the year, leaving plenty of spare current water storage for peak electrical demand use.

6. Please analyze distributed electric car batteries run in reverse, that is powering the grid. This will have a cost outlay in both invertor and net meter will be an order of magnitude cheaper than PSE's fraudulent Energize Eastside (the latter is I my opinion, the former is fact). PSE is very interested in the electric car count and usage characteristics as PSE has given $700 conservation rebates for electric car chargers to home owners. Environmental groups have testified car charger rebates do nothing to reduce energy use. However here they will reduce unnecessary grid expansion and in the summer can be used to counter excess solar PV power generation which over powers the electrical grid as has been seen massively in Germany and in Hawaii which has stopped new solar panel installs for over a year. Old Tesla cars have 60, 70 and 85 kWh batteries and the latest ones are 90 kWh. Nissan Leafs have 48 kwh batteries, KC Metro has many electric buses with massive batteries. All of these can be run in reverse for a few hours to counter peak winter load. The buses can offer Uber free pass which PSE pays for the once every 20 year peak load event. Assume one can only discharge 50% of the car for the next day use then 1000 Teslas at 70kWH= .5(1000)(70kWH) = 35,000kWh or 3.5 MegaWatthours of peak savings. 2000 Electric Leafs yield (.5)(48kwH)(2000)= 4.8 MW-hours. What is the growth rate of electric cars/buses and what is overall total potential for all vehicle in PSE's territory not just the Eastside. Using just the Eastside cars is a false standard as PSE is using load needs and generation losses outside of Eastside to justify this grid expansion so using conservation and temp generation (electric vehicle batteries discharging to the grid) outside Eastside is valid too.

7. The draft EIS has zero mention of time-based pricing as the means of load reduction. This is simply unacceptable. PSE has already successfully implemented this to counter impacts that the Enron frauds from California where having on the WA grid during the late 1990s and early 2000s. The reduction (via time shifting, washing, microwave vs oven etc) of peak loading must be studied in detail. All +1.2 million of PSE electrical meters were converted to FM transmitters around 2000 to allow time based pricing and PSE has already ran time based pricing during the Enron frauds and PSE personnel publically praised the results in the

press. This time-based peak load reduction will have the lowest of cost of all alternatives including both monetary and environmental. Please detail the success of other utilities both non profit and for profit utilities in using demand pricing in addition to PSE's efforts has it is widely used by other utilities in the US and other countries.

One source of information for the COB for the EE EIS is *"A new mobile app from People Power has helped customers in a small pilot program on Oahu cut their energy use by up to 10%, according to Energy Efficient Markets."* http://www.utilitydive.com/news/customers-reduce-use-up-to-10-in-hawaii-behavioral-dr-pilot/370344/ People Power is going after demand response market of Opower, which PSE is already a bottom level customer. People Power is doing so because after going public Opower was forced to morphed into a shill for for-profit utilities to hide behind, meaning PSE wants to act like are doing reductions so they can show stuff to tiny bit of regulators PSE to see. Opower is now claiming just 3% reduction power yet use to say 20%. In reality PSE is/was just using Opower's graphing function to make those little charts on your PSE bill. As Opower realized it can't make money from the 20% energy saving it promised at it IPO on CNBC from government run utilities it was forced to for-profit utilities which depend upon massive inefficacies to make money. Even NEEA.org has detailed how PSE has 28% more expensive electrical rates than ALL other 137 government run utilities in WA, OR, ID and Montana. Cutting 20% power consumption from for-profit utilities would kill profit margins as Opower depends on the for-profit utilities ability to generate MASSIVE excess profits from unneed grid expansion.

On the other hand is People Power *"In a pilot program from People Power, a new mobile app, "Presence," being tested in Hawaii, is yielding surprising energy savings–9 percent to 10 percent –by motivating people to change their energy use behavior. That's nearly three times higher than the energy savings reaped by Opower's program, also designed to change consumers' behavior, said Gene Wang, CEO and co-founder of People Power*." PSE is not using the stuff that matters. Eastside Citizens expect a full accounting of real alternatives. So far the draft EIS is a joke in this regard. The EIS needs to evaluate this and other like systems including those in other countries. Please use this thing called the internet, call me at 425-449-8889 if you need help.

8. Please include the type and quality "demand response" programs that have been testified to the WA State legislature committees including joint committee hearings. Some are already out of pilot phase and are in full production demand response here in WA. Please detail why those same actions can or cannot be done throughout PSE's territory. Given the very limited time the COB has given citizens to respond I cannot provide specific at this time. Call 425-449-8889 and I can give you specific programs in WA underway by responsible utilities in the State of WA. See item 6 h) in my comments to the EIS start process on June 14 2015 which the draft EIS ignores several key comments on need and alternatives. They are attached to the end of this doc.

9. Please detail the Electrical savings by converting current electrical customers using electrical heating to natural gas. This is a 100% reduction of the peak power load PSE is claiming to

try to solve. Natural gas is something that is readily stored and for which PSE has much experience in adding natural gas trucks onto pipes line during rare winter peak loads. Natural gas usage can be reduced further with cold water ozone laundry expansion across hotel and anyone doing large amounts of laundry. Two Puget Sound region Marriott owned Hotesl one in Renton and the other in Seattle having been using ozone based laundry for over a decade now in the, each reducing their natural gas bill by over $35,000 dollars per year. ROI on commercial ozone year as system generally cost $30K.

The draft EIS falsely states that "Conservation is achieved mainly by customers implementing voluntary energy efficiency improvements". (see draft EIS pg 559 of 715 which is page A-1) The facts prove this wrong! This is a strong indication that the COB has chosen staff and contractors that are at not technically skilled enough to analyze the available energy information and coherently detail actual alternatives requiring ZERO voluntary implementation or get voluntary participation as PSE has gone out of it way to discourage participation with PSE's HomePrint program just one example. Why is this the staff of EIS simply parroting PSE and in particular PSE's Manager of Communication Initiatives Gretchen Aliabadi? She has used this theme publically for over three years now and the EIS is parroting it. Edward Bernays is proud but the people thrown in the gas chambers of pollution are not. Here are significant non voluntary conservation facts that need to be included in the EIS. I find the lack of detailing the savings and instead choosing to claim conservation is mainly the consumers responsibility after feed them false propaganda is highly unacceptable.

Example 1 of massive Non voluntary conservation: WA State currently allows hot climate windows to be sold in WA as there is no minimum requirement for how much solar energy the window should be required to pass, a minimum solar heat gain coefficient. The draft EIS mentions windows 22 times yet details no magnitude energy savings and only false states that "Conservation is achieved mainly by customers implementing voluntary energy efficiency improvements". Completely wrong and ignorant. A windows code change would significantly flatten any peak winter power load that occurred during the work/home transition period.

The savings using Lawrence Berkeley National Labs (LBNL) analysis is 29.5 annual MegaWatts (aMW) PER year just for residential windows, more if adding nonresidential windows. And valid for the 2009-2015 time period, past that, the savings will be higher as the area of window sold is increasing. And since the 2009 economic stimulus only rebated hot climate windows; cold climate windows did not qualify and since the WA building code allows hot climate windows to be sold in WA; the total extra energy waste installed in WA from 2009 to 2015 is 206.5 aMW using LBNL analysis and growing by at least 29.5 aMW per year! No wonder Bernie and Trump are doing so well. Even President Reagan's NAFTA negotiator Clyde Prestowitz agrees with Sanders on CNBC March 14 2016. Can't wait to see what the DOE Secretary for Reagan says about PSE and the EPA! More than just the PSE falsehoods are falling.

The above is LBNL energy savings is completely and independently validated using by the UK government. Measured a second way, using the UK government's Window Energy Rating (WER) equation, WA would save 20.77 aMW for the residential window area sold in 2015. The results from LBNL and UK government are remarkably close ~30% error given the values for total WA/USA window sales (mine vs LBNL) and air leakage per house stock (LBNL vs UK Gov) is likely different. Maybe LBNL include small commercial too, I did not.

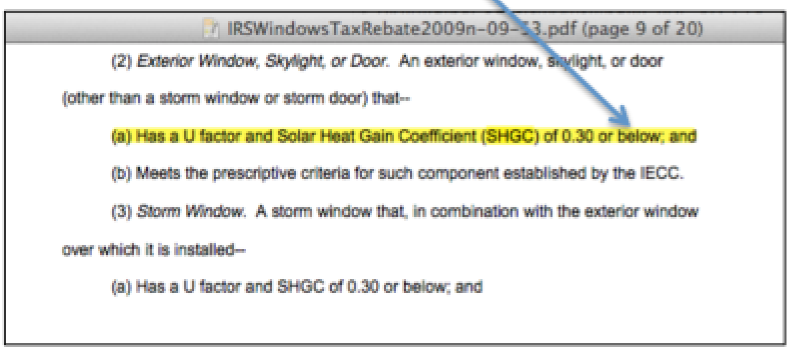
The accumulated extra energy waste from 2009 to 2015 in WA State via the UK government's mythology is 123.2aMW by not using cheaper and more energy efficient cold climate windows but instead allowing hot climate windows to be the only windows sold in WA. This saving would be built in and additive every year. Instead we have and are continuing to dig a deeper energy waste hole. Assuming 10% of this total energy saving would be electrical vs gas, thus ~3 aMW reduced energy use per year for just residential windows. In ten years this would be over 35 aMW per year saving, we already have at least a 123 to 206 aMW hole dug as detailed below. The peak power reduction could easily be 30 MegaWatts (not aMW which is energy, MW as in power) just in the first year as sub 25F temperatures (23F) only happen during largely clear skies in PSE's territory, (see NOAA data) meaning solar heat gain via windows would push the heating peak later and thus dampen peak load as the work-home transition effect are both starting from lower energy need levels.

As the average reader does have a feel for how much energy 3 aMW is lets compare it to the total energy installs in WA from solar PV panels. To date, all years included going back to the 1990 to Jan 2016, about ~2aMW of energy production from PV have been installed. This comes from 9 MW peak power worth of solar panels. Given they can only produce when the Sun is up, 1/3 of the time out of 24 hours, and are limited further by clouds we only get ~2 aMW/yr. The cost for this Solar PV is massive in comparision to solar PV. The average price to install 10kW is $50,000 using the lowest price period of 2015. Thus the 9 MW of peak power costs (10,000W/$50000= 0.5Watt/$ or $2 per Watt. Thus 9MW cost at least $18 million not counting tax rebate cost and other subsidies. Stopping the sale of hot climate window sold in WA would not cost but rather save $12.65 million up front in just 2015 in just the residential market. In 2015 there were about 2.53 million square meters of residential window glass sold in WA; all of it (+99.9%) is hot climate glass hoping for another 2009 tax rebate round 2. Assuming and $5 extra per square meter for the silver coatings from Cardinal Glass (they do 70% of the entire USA residential market coatings) to make a hot climate window the savings going to cold climate window is $12.65 million plus 20.77 to 29.5 aMW of annual energy savings!

Details of the Window code Change Energy Savings (given the current staff preparing the draft EIS is severely below the technical level needed to properly address the alternatives to Energize Eastside's life cycle cost to rate payers of $1.2 billion dollars at present and growing.)

One example is this residential building code change. A simple updating of the eastside building codes and WA States window code to ban hot climate windows from being sold in WA has massive energy saving capability. (Cities have the power to do such code changes if it is more restrictive than the State's) Hot climate windows are the **only** windows offered for sale in WA since a hot climate window is the only window rebated by the 2009 economic stimulus plan.

See the screenshot of the IRS's only 2009 economic stimulus plan below www.irs.gov/pub/irs-drop/n-09-53.pdf. A u value =0.3 and SHGC=0.3 is a very hot climate window!!!



IRSWindowsTaxRebate2009n-09-53.pdf (page 9 of 20)

(2) *Exterior Window, Skylight, or Door.* An exterior window, skylight, or door (other than a storm window or storm door) that--

(a) Has a U factor and Solar Heat Gain Coefficient (SHGC) of 0.30 or below; and

(b) Meets the prescriptive criteria for such component established by the IECC.

(3) *Storm Window.* A storm window that, in combination with the exterior window over which it is installed--

(a) Has a U factor and SHGC of 0.30 or below; and

The momentum of all 635 window makers in the USA taking off ALL cold climate windows off there sales pipelines/websites/brochure to gain back from government handouts the 40% sales in lost by 2008, never resulted in the window makers placing the cold climate windows back into the sales pipeline. Some have been hopping for a second round of rebates, most are just on status quo. However the NFRC's database shows hundreds of window makers know better and have cold climate windows already approved and teed up for shipment. There are thousands of cold climate windows in the NFRC database all ready to go as window makers have undoubtedly expecting this code loop hole / stupidity to be fixed as many have testified to the EPA. This code hole is a massive energy waste for the northern climate zone as will be detailed below. These cold windows are even slightly cheaper as they do not need silver coatings and are massive energy savers for Washington State 4 to 9 time more than any other northern state given we have the highest heating cooling ratio.

A hot climate window as defined by the EPA is u value ≤ 0.3 and solar heat gain(SHGC) ≤ 0.3 setting a ceiling for SHGC. A cold climate window would be u value ≤ 0.3 and SHGC ≥ say 0.6 meaning letting in 60% of the suns energy, setting a floor for SHGC. The EPA has yet to detail a cold climate window for the consumer, as the EPA knows how badly it screwed up. The EPA's official and very delayed response in 2014 to massive testimony from 2009 about the Northern climate zone window code is this: "EPA is in the process of developing consumer materials that provide additional information on high-gain windows See ref [1]

[1] pg8/20 www.energystar.gov/sites/default/files/ESWDS-ResponseToComments-Part1.pdf

Also see [2]." As of 2016 no consumer material have yet to be produced by the EPA on cold climate windows.

The US Dept of Energy and the UK government both see the massive savings of requiring only cold climate windows to be sold in cool and cold climates. The UK took action, the EPA is doing its best to sweep yet another massive screw up under the rug[3]

The UK government banned hot climate windows in England as of at least 2010 something the US Dept of Energy testified should be done in the northern zone of the USA done as well. **The UK's 2010 code for new construction for England requires windows to have a SHGC=0.63 and u-value=0.246 or better or offset the energy using the Window Energy Rating (WER)[4] equation. The USA uses SHGC and the UK's/Europe's uses g-value which equals SHGC, they both measure exactly the same thing. Existing construction requires a $WER_{UK\ Gov.\ grade}$ of C or better for any new windows.[5] In order to achieve a rating of $C_{UK\ Gov.}$ or better using the USA's insulation value of u ≤0.3 needing a SHGC 0.49 or better per the $WER_{UK\ Gov.}$ equation.** This lower requirement for existing is the result of matching existing gridded windows, the new code of 0.63 effectively banns gridded windows as offsetting is so expensive. **Note the $WER_{UK\ Gov.}$ equation is a close but not the same as the non government WER_{BFRC}. The $WER_{UK\ Gov.}$ equation is a bit more refined than the British Fenestration Rating Council's equation. It is important to note that while Denmark, Germany and the European Commission have or are in process of following the UK window code; the EPA, the Dept of Energy and the Canadian agencies gov and non gov are nearly completely ignorant of the UK's progress with key players at DOE and EPA admitting such. Regardless, the Dept of Energy has arrived to the same conclusions as the UK and testified to the EPA on the stupidity of their northern zone window code with the publically available testimony.**

WA should exactly copy England as England has an identical climate to WA and all of PSE's territory. England and WA have identical in Heating Degree Days (HHD) and Cooling Degree Days (CDD) and the ratio of 30 HDD to every 1 CDD is the same in England as WA as a whole. This high ratio means any changes gaining free heating is winter is vastly better

[2] For the high level site of all testimony to the EPA docs see www.energystar.gov/products/spec/residential_windows_doors_and_skylight_specification_version_6_0_pd

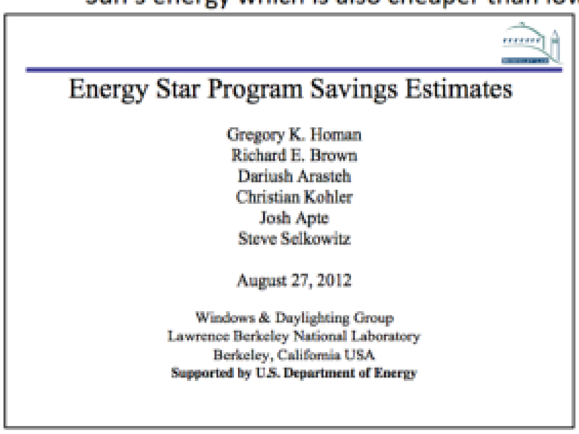
[3] pg 8 of 20 www.energystar.gov/sites/default/files/ESWDS-ResponseToComments-Part1.pdf

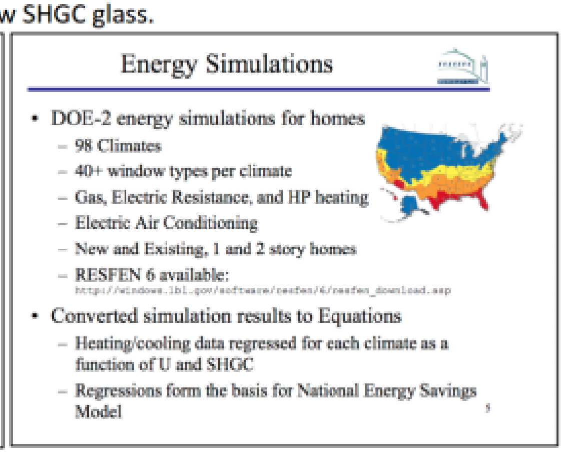
4 For new dwellings in England the baseline requirement to meet or tradeoff are a SHGC=0.63 (UK & Europe use g-value notation for SHGC with the exact same meaning both dimensionless unit from 0 to 1) and a u-value of 0.2465 $Btu/hr\text{-}ft^2\text{-}F$ which is 1.4 $W/m^2\text{-}K$ in the UK as Britian/England use SI units. See page 34 for SHGC=g-value =0.63, and u-value. Also see pg 12 and 24of 48 of this UK building code www.planningportal.gov.uk/uploads/br/BR_PDF_AD_L1A_2013.pdf. Page2/48 states *"A summary of the Part L 2013 notional dwelling is published at Table 4 in the approved document with the full detail in SAP 2012 Appendix R. If the actual dwelling is constructed entirely to the notional dwelling specifications it will meet the carbon dioxide and fabric energy efficiency targets and the limiting values for individual fabric elements and buildings services. Developers are, however, free to vary the specification, provided the same overall level of carbon dioxide emissions and fabric energy efficiency performance is achieved or bettered."* For a detailed historical review British window code see www.pilkington.com/en-gb/uk/architects/glass-information/energycontrolthermalsolarproperties/window-energy-ratings

5 www.planningportal.gov.uk/buildingregulations/approveddocuments/partl/ For existing dwellings see Table1 pg16/31 of www.planningportal.gov.uk/uploads/br/BR_PDF_ADL1B_2010.pdf. The UK Gov.'s WER is nearly the same but a bit more refined than the BFRC's WER. The UK Gov. is stricter using $WER = 196.7 \times ((1 \times f) \times g_{glass}) - 68.5 \times (U \times (0.0165 \times AL))$ and the BFRC's is $218.6g_{window} - 68.5 \times (U_{window} + \text{Effective } L50)$ both with the units of [kWh/m2/yr] where m2 is square meters of glass.

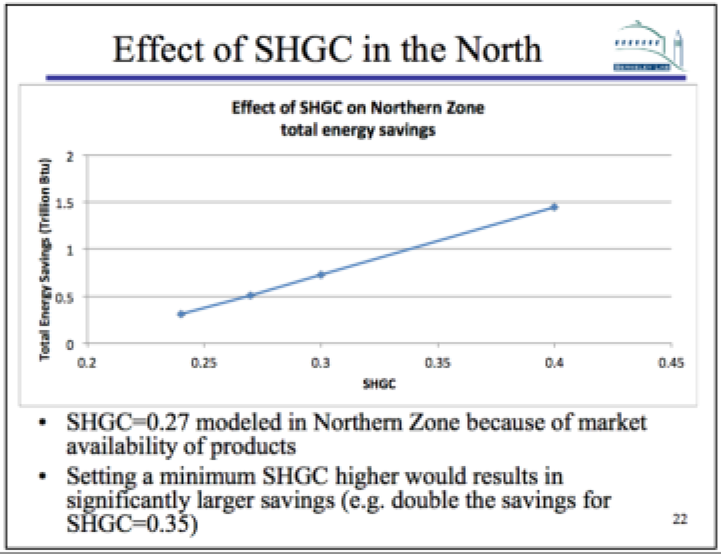
than the extra cooling spent in the summer. DOE modeled this down to the county level. However the EPA threw the northern US climate zone under the bus to fix the EPA's previous screw-up of having a very bad southern climate zone window code starting in 2009. That is a very poor insulation value, u-value. This bad code was blow back from the EPA's bad change management process which resulted in the southern climate zone window makers hiring a bunch of ex US Senators and House members to hand the EPA their behind to the massive detriment to the environment; with WA State suffering the greatest damage has it has 4 to 9 times greater heating to cooling ratio than all other northern climate States.

The Dept of Energy's also sees how much energy can be saved banned hot climate windows Window and Building Envelop lab and has the detailed this to the Environmental Protection Agency in 2012. Below is the energy savings as the solar heat gain of windows is increased for the USA housing stock. This was Lawrence Berkeley National Lab's (LBNL) Window and Building Envelope Group determination by for the Northern climate Zone.[6] .[7] LBNL is the preeminent experts for energy usage/generation from windows for the USA . The northern zone is in blue on the map below and is the same as the EPA's northern zone or IECC zones 4(maritime), 5,6 and 7. This work was done specifically for the EPA's ENERGY STAR Windows group by LBNL and presented to the EPA's public meeting on August 27th, 2012. LBNL shows the higher the SHGC, the higher the savings in the northern zone. The UK sets Englands code at 0.63 forcing the window makers to use the most transparent glass to the Sun's energy which is also cheaper than low SHGC glass.





[6] www.energystar.gov/sites/default/files/WindowsEnergySavingsAnalysis-LBNL.pdf For the high level site of all docs see www.energystar.gov/products/spec/residential_windows_doors_and_skylight_specification_version_6_0_pd
[7] http://windows.lbl.gov/energystar/version6/



Cut off of graph at 0.4 is only an artifact of the 2009 Stimulus Act rebating only hot climate windows SHGC≤0.3 EVEN in cold climates including Alaska. The line is linear and straight to at least 0.63 as the UK has shown. The leadership of LBNL and EPA windows group were not even aware of the UK's work as of 2015 . Varing the SHGC from 0.2 to 0.4 gives 1.45.Trillion BTU of savings, thus every 0.1 increase in SHGC is worth 0.725 trillion BTU/per year.

LBNL is the core technical resource for energy performance of windows in the USA for all relevant governing bodies, EPA, NFRC, LEED etc. They also build & maintain the "blessed" computer software to model all the energy characteristics of windows for which the IECC, EPA and NFRC depend on and require others to use. LBNL is also the main technical advisor to the EPA's Window Group.[8] This includes the determination of u-values and solar heat gain coefficients of windows.

Calculation for Non Voluntary window energy Savings for WA State.
First Way =Using LBNL's work.
LBNL calculated the savings at the county by county level for the Northern region and rolled it all up to get the above energy savings to per increase in SHGC graph. Given the 2009 tax rebate was solely for hot climate windows the average SHGC sold in northern climate is SHGC=0.224. This number is from averaging 1363 Pella windows rated by the NFRC. The results from other window maker's data are very similar as the SHGC values between the hot and cold climate windows. This is not surprising as ~70% of the coatings for all +600 window makers in the USA are done by Cardinal Glass. Thus using a UK's window code for England of 0.63 we have 0.63-.224 =0.406 delta between current US northern climate window code as of 2009 and what England is using.

The energy saving can be picked off LBNL graph from above and corrected foe WA climate. The saving is completely linear as one would expect particularly for the high heating to cooling ratio areas like WA at 30:1. From the LBNL graph every 0.1 increase in a windows

[8] http://windows.lbl.gov/energystar/version6/

solar heat gain coefficient saves 0.725 Trillion BTU/ per year. Thus a 0.406 delta between current WA window installs and what a code banning hot climate windows in WA, using England's 0.63 requirement for solar heat gain gives 4.06 (0.406/.1) times 0.725 Trillion BTU/ per year per 0.1 SHGC increase. This math gives 2.9435 trillion BTU/yr. Using 1 BTU_{IT} = 0. 29307 Watt-hr we can covert 2.9435 tillion BTU/yr to Wat-hrs. Multiplying 2.9435 TBTU/yr by 0.29307(Watt-hr/BTU) gives 0.863 tillion Watt-hrs/yr. Or more simply, 863 billion Watt-hr/yr of saving for the Northern USA climate zone.

To get WA only energy saving we need to reduce the entire northern region number to just WA's population and correct for Washington climate which has the highest heating to cooling energy use ratio out of all states save Alaska.

Assuming 100 million people live in the Northern Zone and prorating to 7 million for WA. This gives 7/100 times 863 billion Watt-hr/yr or 60.39 Billion Watt-hr/yr. To get a better feel for how much energy that is lets convert that to a constant power level for and entire year. To get that we that we divide by the number of hours in a year. (60.39 BillionWhr)/(24*365)= 6.89 aMW. This is uncorrected for WA's climate. The real number for WA state is much higher.

Next to correct for Washington States climate. This is needed because LBNL rolled up nearly hundred northern micro climates, county by county. These climates vary greatly from Puget Sound with 31 times heating to cooling, Kansas City with 4.2 heating as cooling, Chicago at 8.6, Washington DC at 5 and NY City at 7.2. Thus correcting for this one can see WA would see much higher energy savings per capita that the rest of the northern states. Using the population weighted and blended heating to cooling ratio average for LBNL graph as 7, then the correction factor for savings for WA is 30/7 or 4.28 times greater than the blended average. I confirmed this methodology this LBNL staff. This 4.28 correction factor times 4.28 equals **29.5 aMW per year of waste**. I used 30 as the blended population weighted average of Puget Sound and mountains with Spokane. Using this potential energy waste built in since 2009 and the window sale growth of since 2012 is roughly offset by the lesser sale 2009 to 2012 the overall EXTRA energy use from having hot climate windows in WA is 7 years times 29.5 aMW= 206.5 aMW

Second Way =Using UK's window building code work

No voluntary participation in England, you want a window then it had better be an energy saving cold climate window or you have to offset the energy waste in other permanent manner.

Here is the UK's new building code for windows.[9]

9 For new dwellings in England the baseline requirement to meet or tradeoff are a SHGC=0.63 (UK & Europe use g-value notation for SHGC with the exact same meaning both dimensionless unit from 0 to 1) and a u-value of 0.2465 Btu/hr-ft^2-F which is 1.4 W/m^2-K in the UK as Britian/England use SI units. See page 34 for SHGC=g-value =0.63, and u-value. Also see pg 12 and 24of 48 of this UK building code www.planningportal.gov.uk/uploads/br/BR_PDF_AD_L1A_2013.pdf. Page2/48 states *"A summary of the Part L 2013 notional dwelling is published at Table 4 in the approved document with the full detail in SAP 2012*

UKBuildingCodeNewDwellingBR_PDF_AD_L1A_2013.pdf (page 33 of 48)

Table 4 Summary of concurrent notional dwelling specification

Element or system	Values
Opening areas (windows and doors)	Same as actual dwelling up to a maximum proportion of 25% of total floor area
External walls (including opaque elements of curtain walls)	0.18 W/(m²·K)
Party walls	0.0 W/(m²·K)
Floor	0.13 W/(m²·K)
Roof	0.13 W/(m²·K)
Windows, roof windows, glazed roof-lights and glazed doors	1.4 W/(m²·K) 1.4W/(m2.K)(5.678)=0.2465 BTU/ft2F (whole window U-value)
	g-value = 0.63 UK's g value is the same as USA's SHGC, both are a number between 0 and 1 where 0.63 means 63% of the sun's energy or more come through the glass and into the home.
Opaque doors	1.0 W/(m²·K)
Semi-glazed doors	1.2 W/(m²·K)
Airtightness	5.0 m³/(h·m²)
Linear thermal transmittance	Standardised psi values – see SAP 2012 Appendix R, except use of y = 0.05 W/(m²·K) if the default value of y = 0.15 W/(m²·K) is used in the actual dwelling
Ventilation type	Natural (with extract fans)
Air-conditioning	None

Building Regulations 2010 ONLINE VERSION Approved Document L1A, 2013 edition 25

Existing construction requires a $WER_{UK\ Gov.}$ grade of C or better for any new windows. The UK historical building look and feel has orders of magnitude more gridded windows than the USA which is why they have an effective SHGC=g-value= 0.49 or better for existing buildings using the USA's northern climate zone u-value of u ≤0.3. Using the UK's government's window energy rating equation for England, which has exactly the same climate as WA, we have: [10]

$\mathbf{WER}_{UK\ Gov.}$ = 196.7 x ((1 x f) x g_{glass}) – 68.5 x (U x (0.0165 x AL))

Where:

Appendix R. If the actual dwelling is constructed entirely to the notional dwelling specifications it will meet the carbon dioxide and fabric energy efficiency targets and the limiting values for individual fabric elements and buildings services. Developers are, however, free to vary the specification, provided the same overall level of carbon dioxide emissions and fabric energy efficiency performance is achieved or bettered." For a detailed historical review British window code see www.pilkington.com/en-gb/uk/architects/glass-information/energycontrolthermalsolarproperties/window-energy-ratings

10 www.planningportal.gov.uk/buildingregulations/approveddocuments/partl/ For existing dwellings see Table1 pg16/31 of www.planningportal.gov.uk/uploads/br/BR_PDF_ADL1B_2010.pdf. The UK Gov.'s WER is nearly the same but a bit more refined than the BFRC's WER. The UK Gov. is stricter using WER = 196.7 x ((1 x f) x g_{glass}) - 68.5 x (U x (0.0165 x AL)) and the BFRC's is 218.6g_{window} - 68.5 x (U_{window} + Effective L50) both with the units of [kWh/m2/yr] where m2 is square meters of glass.

f= the frame factor i.e the percentage of the window obscured by frame and gaskets;

g_{glass}= the normal total solar energy transmittance of the glass as determined by BS EN 410,

U= the whole window U-value as specified in paragraph 4.20 and 4.21; and

AL = the air leakage through the window in $m^3/h.m^2$ at 50 Pa pressure difference based on testing to BS 6375–1:2009.

Using UK government's SGHC value (g-value) building code requirement for England we can see the delta between our EPA's u-value for the USA and that what the UK requires. All we need is the amount of residential window glass sold in Washington State to understand how big the energy disaster the current residential building code has caused WA since 2009.

To get this information let us turn to the Northwest Energy Efficiency Alliance (NEEA.org) which covers the four state region of Washington, Oregon, Idaho and Montana. NEEA has done a great job at is detailing the energy usage infrastructure in the four state area, such has total window sales. This can be found in NEEA's Long-Term Monitoring and Tracking Report on 2011 Activities. This reports gives us the foundation data we need up to 2011. NEEA got its core data from Ducker Research, the Window and Door Manufacturing Association (WDMA) and the American Architectural Manufacturers Association (AAMA, those folks we will see later on testifying to the EPA for a SHGC ≥ 0.4 in the Northern Zone, and rightfully so, note that for just WA they would undoubtedly support a SHGC≥ 0.63).

NEEA.org adjusted the national data to get the four state sales numbers for the Pacific NW. We will update this NEEA blessed data with the 2015 and 2014 updates from WDMA and AAMA for residential prime window sales. Prime windows are defined as building envelope enclosures made of glass, window, glass doors and skylights, with the latter making up just 0.8% of units. We will prorate NEEA's four state numbers to just Washington State by population. As one can see prorating WDMA/AAMA data for 2013 for all USA to WA significantly under reports WA units sold when comparing to NEEA's work narrowing the same source data to the four Pacific Northwest states. Given NEEA has only published data to 2011 we will use the USA growth rate to get the residential window sales for Washington State for the years 2012-2015. This is a very conservative assumption as WA is in the top two or three fastest growing states from the financial crisis to date.

Residential Prime Windows (Windows, glass doors, skylights=0.8%)

	NEEA 2012 Window Sales Tracking Rpt. (Ducker, WDMA/AAMA data, scrubbed by NEEA.org for PacNW). Prorated with 2010 popul. data. **The best known window sales data for WA.**		WDMA/AAMA 2014&15 updates. Use USA growth rates to update NEEA.org data		
	PacNW	**WA prorated NEEA.org**	**USA**	**Yr/yr growth %**	
Year	**Millions of Units**		**Millions of Units**		**Notes**
2006	2.736	1.41	66.7		
2007	2.425	1.25	59.1		
2008	1.973	1.01	48.4		
2009	1.945	1.00	38.9		
2010	2.096	1.08	41.6		
2011	2.159	1.11	37.9		
2012			43.9	15.83%	note 1
2013			44.5	1.37%	note 2
2014			46.73	5.00%	note 3
2015			49.061	5.00%	note 3

Table 1.

Note 1. May 1, 2014 AAMA updates 2012 sales to 43.9M units & 15.8% growth, see www.aamanet.org/news/2/10/0/all/1058/aama-predicts-fenestration-industry-trends-in-new-market-studies All growth rates are AAMA or WDMA data.

Note 2. June 10,2014 WDMA article states 44.5M unit number, http://windowanddoor.com/news-item/markets/new-wdma-report-predicts-market-growth-through-2015

Note 3. Apr 30, 2015 AAMA article= 5% residential window growth (+10% new, 2% remodel increase for 2015, a repeat of 2014) www.aamanet.org/news/1/10/0/all/1179/aama-releases-2014-2015-industry-review-and-forecast

Now that we have actual units of residential windows, glass doors and skylights sold, we have to convert those to square meters of total glass installed. Luckily NEEA.org faced the same problem and we will copy their methodology. See appendix of this report for a snap shot of that methodology. In a nutshell the average window unit has 16ft2 of glass, patio door has 40 and average skylight has 6. The blend ratio of those three types of units sold over the years per NEEA data is very constant at 17.3 ft2. We will use this blended area per unit of 17.3 for the for 2012 to 2015 data, see third column in the table 2 below, to get the total surface area sold in each year.

Residential Prime Windows surface area sold per year

	WA prorated with USA growth rates. Conservative as WA has grown faster in 2009-15 than USA			
	WA	**Feet²/unit NEEA.org #'s, pg88 (95of159)**		
Year	**Million of Units**		**Milion-Ft²**	**Million SqMeters**
2006	1.41	17.308	24.34	2.26
2007	1.25	17.301	21.57	2.00
2008	1.01	17.333	17.58	1.63
2009	1.00	17.367	17.36	1.61
2010	1.08	17.325	18.67	1.73
2011	1.11	17.333	19.23	1.79
2012	1.29	17.33	22.27	2.07
2013	1.43	17.33	24.71	2.30
2014	1.50	17.33	25.95	2.41
2015	1.57	17.33	27.25	2.53

Table 2

see Reference for square foot per window unit see pg 96/159 of NEEA report http://neea.org/docs/default-source/reports/long-term-monitoring-and-tracking-report-on-2011-activities.pdf?sfvrsn=18

Next, using the WER energy equation from the UK government we can calculate the energy waste that is locked into Washington State for each year of hot climate window sales in Washington State since 2009. As explained above this is done taking the average hot climate window parameter sold in WA by taking a typical series of windows in the NFRC database that meets the USA northern climate zone u-value code requirement, plugging those parameters in the equation. In this case it was one of six of Pella's single hung vinyl windows. This gives a very good sample of the average hot climate window sold in Washington State. This is an annual summary of energy used (if negative) or saved if positive by a specific window accounting for extra cooling energy used in the summer and extra heat gained in winter. See table 3 energy saved [aMW/year] for windows sold in WA for 2015.

fx =196.7*G1897 - 68.5*(F1897*5.678 +0)	U-factor	SHGC	UK Equation Energy with U value correct to SI units [W/m2/Kelvin]	Energy Delta Ave Hot C.W. sold in WA vs UK [kWhr/m2/yr]	aMW/year saved for windows installed in 2015
Ave Uval and SHGC Hot Climate Windows in WA	0.2818	0.224	-60.75		
Englands SHGC=g New dwelling w/ uk Uvalue	0.246	0.63	28.24	88.99	23.2
Englands SHGC=g New dwelling w/ Pella ave Uval for C.W.	0.285	0.63	13.07	73.82	19.25
Englands SHGC=g New dwelling w/LBNL ave Uval,2012 study	0.27	0.63	18.91	79.66	20.77

Table 3 The extra energy that could have been saved had cheaper and more energy efficient windows be used in WA over the hot climates windows that are the only window sold in the WA due to the EPA's 2009 hot climate windows tax rebate policy and a building code which allows hot climate windows to be sold in cold climates.

Using a window with the insulation value (u-value) and solar gain (g-value) as the UK requires in England would save **23.2 aMW/year of 2015 windows sold**. Using LBNL u and SHGC values (which are poor energy saving value but ones LBNL sees as out of the box viable) in their 2012 massive analyses for the EPA we get **20.77 aMW.** Using the even poorer USA insulation value of 0.285 (this is EPA driven, from the EPA that dumps toxic mining sluge into rivers) and the same solar gain value (SHGC=0.63) as England requires its builders we get 19.25 aMW. This uses the average cold climate windows u-value for a typical vinyl series with 446 Pella cold climate windows that are in the Nation Fenestration Rating Council database. This a bit lower than from the energy saved than that using the Lawrence Livermore Nation Labs value of 29.5 aMW. This level of delta could easily be from air leakage values assumed for each respective house stock, UK vs USA. The delta could also be from my total square footage of windows assumptions vs that what LBNL made. Given they are only 30% off (29.5 from LBNL and 20.77 from UK WER equation) their agreement is remarkable close.

Three important item are:

1) these cold climate windows are cheaper as they do not require silver coatings as used for hot climate window to reflected away the suns energy) using the UK's methodology.

2) the energy saving is additive year over year. By using the u-values for cold climate window current in the NFRC data (seems that many window makers are ready for the EPA to fix the 2009 northern climate window build code) and the NEEA.org/Ducker/WDM/AAAMA window sales data for 2009 to 2015, WA has already built in 123.2aMW using the 79.66 kWhr/m2/yr energy delta for cold climate windows. This is growing by at least 20.77 aMW per year and more like the 29.5 a MW the LBNL derived number.

3) the above energy saving from either methodology UK or LBNL is only for residential housing stock. And does not include small commercial buildings which when added will further increase the savings. And given no one in the commercial building industry stood up to testify to the EPA on the EPA's mistake (like the window and glass makers have) it is quite possible commercial energy saving work is as bad as the EPA's when it comes to the northern climate zone. All of the major glass makers and window makers for Washington State did testify to the stupidly of the EPA's window building code not having a solar heat gain minimum. And the EPA even admitted it in 2014 as detailed above.

10. Please detail the electric load change from climate change as a warming climate in WA means the assumption of 23F is vanishing small. The Eastside & Puget Sounds energy peak is always in the winter, overall warming will just reduce that peak and any need for grid expansion in the next decades. This July 2015 report from the Dept of Energy is one of many places to start. "Predicting the Response of Electricity Load to Climate Change" http://www.nrel.gov/docs/fy15osti/64297.pdf

11. The EIS relies solely on PSE studies or studies for which PSE selected and paid the consultants to conduct for both conservation and non conservation alternatives!
    a) Let us look at page 143 of 715 of the draft EIS (page 2-34) {notice this author's full use of standard reference quoting page numbers that the DEIS is going out of its way not to use} Here the DEIS states "Determining the amount of non-transmission resources that would be needed to address the capacity deficiency that PSE has identified is complex because every solution has a different degree of effectiveness and reliability."

    {unfinished – time ran out}

12. Pg76of 715 "Peak generation plants could produce GHG emissions during operation and result in a moderate GHG impact." This is a worthless statement if not show in context of the green house gas that the new powerlines would allow to be transmitted like dams (dams do emit GHG, warmer the water the higher the emission) Please provide this statement and ones like in in context with range level not just vague assertion of low moderate high.

13. Please detail rate, cost impacts the US governments complaints against the Olympic Pipeline company and electromagnetic field corrosion from current power line including the 115 kV powerlines running over the Olympic Pipeline pipes and what additional corrosion, environmental to mitigate and cost impact new 230 kV lines would cost citizen local and otherwise. Also detail the time line to turn off pipelines should a leak occur.

14. HomePrint another other PSE vauge and obfuscated conservation programs [=author ran out of time to finish}
15. I see the draft EIS has ignored the real reason PSE whats this project to get power to from Canada and California see item
16. UNANSWERED CENSE QUESTIONS

A resubmittal of our June 14, 2015 comments
Date: June 14, 2015
Email Subject: Energize Eastside EIS - Scoping input and requirement for use of NEPA vs SEPA
To: City Manager and Council
From: Todd Andersen, Jennifer Steinman 4419 138th Ave SE, Bellevue WA 98006

My feedback on scoping comes in three areas. These are summarized below, with supporting details following.

1. UNANSWERED CENSE QUESTIONS
   While I was initially encouraged that Bellevue was acting in the best interest of its citizens by approving the "Independent Technical Analysis of Energize Eastside, April 29, 2015 by Utility System Efficiency, Inc.", I am deeply disappointed that we have wasted more taxpayer money on a study that failed to answer the fundamental questions many of the citizens of Bellevue have been asking. These questions and incongruities were recapped in CENSE.org's response "Cense rejects U.S.E's report on Eastside Energy, May 4, 2015."

   Most importantly, an independent load forecast was not created based on more realistic parameters for demand/growth, local generation, energy savings and trends, and north-south transfer. It is critical these questions be carried forward into the input and scope of the EIS. Without this, the entire EIS is based on a shaky foundation that doesn't have community support.

2. FEDERAL / NEPA RULES
   It's clear from reading Bonneville Power Administration (BPA), Seattle City Lights(SCL) and Columbia Grid consortium (BPA, SCL, PSE) documentation that we can't consider Energize Eastside (EE) as an independent or local project to be governed by SEPA. BPA, a federal agency, is the driver of this, and as EE is a subset of a federal effort and should fall within Federal / NEPA jurisdiction. Columbia Grid documents clearly show EE is only one possible way to address North-South Transfer Reliability and is only part of the broader picture of the grid /bulk power planning spanning Canada, Pacific Northwest, California.

   Also, the majority of power and energy sent over the proposed lines are from hydro operations both in the US and Canadian, and for some of the cases conditions PSE/BPA/ColumbiaGrid are using for justification of EnergizeEastside(EE) <u>ALL</u> power/energy are from hydro operations. Hydro operations are specifically called out in the US government's 10 year review of threat to the Salish orca (a.k.a Southern Resident Orca) listed as an endangered species

   As such, the EIS for EE should clearly be governed under NEPA / Federal guidelines and possibly be expanded to look at the broader Columbia Grid plans. Legal challenges arise when large-scale projects are broken up into smaller projects to avoid federal oversight.

   It is my understanding that under NEPA (versus SEPA), the scoping impact would primarily mean EE would need to be evaluated in the context of the regional strategy as a whole and alternatives would need to be considered more broadly.

   - Under NEPA, more comprehensive inclusion of the impacts should be weighted including the evaluation of the impact of international endangered species, the risk of massive build out on top of an aging gas pipeline that already sits on fault line (when an safer alternative exists with SCL), and degradation of property values in cost calculations.

- Under NEPA, broader consideration should be given to alternatives such as SCL (Maple-Valley SnoKing) improvements/re-conductoring to support N-S Transfer or alternatives for balancing peak loads with PSE. Today, the only alternatives being promoted by PSE are minor route permutations.

3. ALTERNATIVE SOLUTIONS
   Please make sure a thorough analysis of demand side reductions are not only investigated but as stated before, factored into the demand forecast. These solutions are key to why cities keep growing but their traditional energy needs do not.
   a. Grid Batteries to manage peak load
   b. Solar Power for continual cost reduction
   c. Geothermal as cost effective alternative
   d. Building Materials (e.g. LED Bulbs, Canada/UK Window Standards vs California)

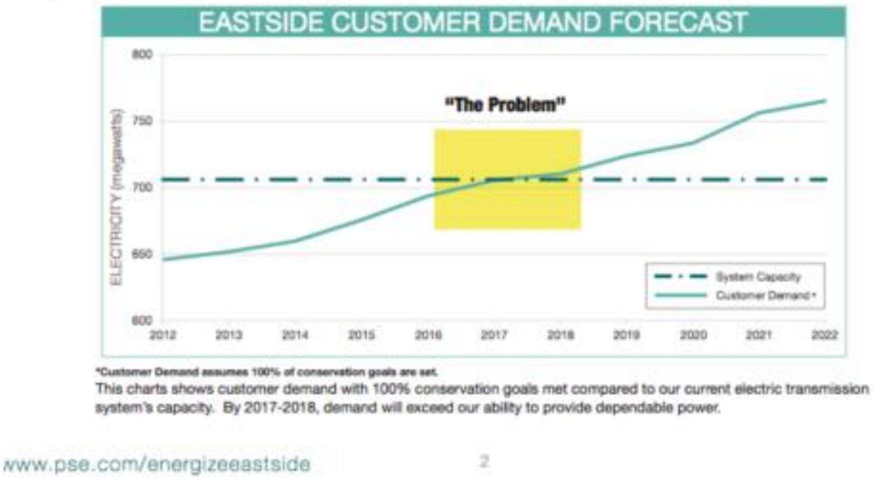
Under the guise of EE, BPA benefits as their reliability challenges are solved by PSE despite more cost effective solutions being available, PSE can charge higher rates with a 40-year guarantee of profits on their investment, and PSE customers (who already pay 28% higher rates than those served by cooperatives, municipalities or public utility districts) will bear the burden, not only of higher costs but also the negative impact to their neighborhoods.

Lastly, I wanted to make you aware of two "off-the-record" comments that I have heard in recent months that highlight the possible collusion that goes on within these organizations – the City of Bellevue, PSE, BPA. These are the types of comments that erode public confidence.

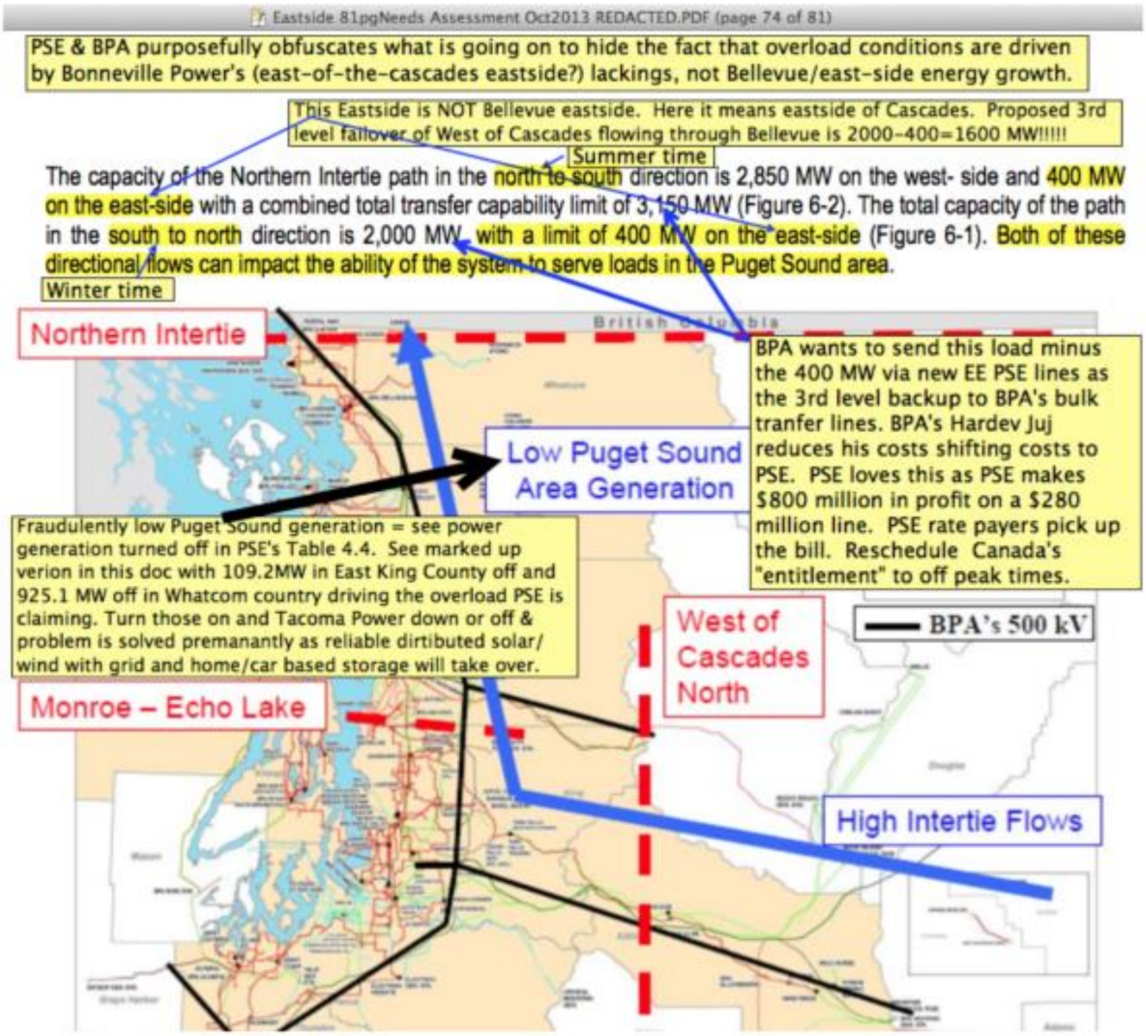
- Hardev Juj – formerly with SCL & PSE, is VP or Transition Planning and Asset Management at BPA. He actually made the comment that EE is largely to serve BPAs needs and BPA would be swapping costs on other projects. Seems Mr. Juj expectantly retired from BPA this month and this author finds that very odd. As BPA is a federal agency, which BPA itself is/was under several federal sanctions for misbehavior, EE should be a NEPA supervised project.
- Nicolas Matz – City of Bellevue Senior Planner. I commented that EE's need is about keeping PSE (a Bellevue company) solvent. Nicholas' response was "that was a need as well". Given PSE's rates per NEEA are 28% higher than all other utilities in WA maybe that is not a need as clearly public utilities are better run for the ratepayers.

SUPPORTING MATERIAL

1. UNANSWERED CENSE QUESTIONS – The biggest unanswered question has to do with the supply / demand forecast. PSE states demand will exceed supply in 2017 based on the chart below, but there are many issues with their analysis that remain unanswered. An independent forecast was requested but not completed.



1. The next series of charts comes directly from PSE's own documentation "Eastside Needs Assessment Report – Transmission System – King County, October 2013".
   i. Since its original publication, PSE has redacted (hidden) the details behind their assumptions posted on their website, however, I downloaded a copy before they hid the few facts they show, so can highlight specific questions. Comments in yellow.
   ii. This first chart is an overview that explains the high-level flow of the Northern Intertie path.



2. This second chart below shows the Puget Sound Generation Capability that was "used" in the PSE modeling. This is a key input into their model and will be discussed below.

Eastside_78pgNeeds_Assessment_Final_Draft_10-31-2013v2 REDACTED R1.pdf (page 32 of 78)

change.

These are schedulable with flexible timetable and not required to happen during peak system loads. And could go away completely depending of Columbia River Treaty renewal/cancelation in 2015/16. Why is PSE/BPA hiding this?

4.1.8 Transfer Levels

The NI (Northern Intertie) flows were assumed based on season and historic flows; Winter Peak NI-1500 MW S-N and Summer Peak NI-2850 MW N-S.

Why is Tocoma Power left off table 4.4? Is it not a generator? Does adding it raise too many questions? It took careful cherry picking to get those WECC computer simulations to overload!

4.1.9 Generation Dispatch Scenarios

For the winter peak load cases, no PSE and SCL generation west of the Cascades were run. Tacoma Power generation was left on, due certain internal system constraints. The generators off-line in the Eastside Needs Assessment are listed in Table 4-4.

A low-generation case was simulated as a sensitivity. The Puget Sound area generation run during that case is indicated in Table 4-4.

How is this valid? 925.1 MW of power generation turned off?? Even the Low case is fraudulently set up!!

Table 4-4: List of Puget Sound Area Generators Adjusted in the 2013 Eastside Needs Assessment

Simply turning on East King County dams just 10% of winter rating will support massive 3rd level failure power flows through Bellevue (EE)

Generation Plant	Winter MW Rating	Expected MW Output during Winter Peak for Low-Generation Sensitivity Case	Type	Owner	Transmission Delivery
Enserch	184.8	125	Natural Gas, Combined Cycle	PSE	Whatcom County
Sumas	139.8	0	Natural Gas, Combined Cycle	PSE	Whatcom County
Ferndale	282.1	0	Natural Gas, Combined Cycle	PSE	Whatcom County
Whitehorn	162.2	0	Natural Gas, Simple Cycle	PSE	Whatcom County
Fredonia	341	0	Natural Gas, Simple Cycle	PSE	Skagit County
Sawmill	31	22	Biomass	Private Owner	Skagit County
Upper Baker	106	80	Hydro Dam	PSE	Skagit County
Lower Baker	78	54	Hydro Dam	PSE	Skagit County
Komo Kulshan	14	0	Hydro Run-of-River	Private Owner	Skagit County
March Point	151.6	134	Natural Gas, Combined Cycle	Shell	Skagit County
Ross	450	295	Hydro Dam	SCL	Snohomish County
Gorge	190.7	157	Hydro Dam	SCL	Snohomish County
Diablo	166	160	Hydro Dam	SCL	Snohomish County
South Tolt River	16.8	0	Hydro Run-of-River	SCL	Northeast King County
Snoqualmie	37.8	0	Hydro Run-of-River	PSE	East King County
Twin Falls	24.6	0	Hydro Run-of-River	Private Owner	East King County
Cedar Falls	30	0	Hydro Run-of-River	SCL	East King County
Freddy 1	270	0	Natural Gas, Combined Cycle	Atlantic Power/PSE	Pierce County
Electron	20	4	Hydro Run-of-River	PSE	Pierce County
Frederickson	162.2	0	Natural Gas, Simple Cycle	PSE	Pierce County

Bellingham

Tacoma

Expected MW output during Winter peak is based off of actual 2011-2012 Winter peak output except for SCL hydro, which is based off of modeled generation levels in WECC winter peak case.

Total Generation= 2858.6 MW

109.2MW

Low Generation = 1031 MW

How MASSIVELY overbuilt is PSE currently in Bellevue/Renton/Redmond/Kirkland??? (Sammamish-Lakeside-Talbot Hill power lines) Putting ALL to ZERO and adding ~2.5x times Eastside's PEAK power from 3rd level failures from BPA AND leaving on Tacoma Power to drive even more power through Bellevue to barely overload PSE.

3. This third chart below shows the Assumptions used in their models to calculate the capacity gap and overload percentages. This is a key input into their model and will be discussed below.
    a. For Northern Intertie, the full amount is included in PSE's calculations, however, several areas should be checked:
        i. Why is PSE EE being proposed when it highest overload is 127.8% for a 115kV line when SCL's Maple Valley-Snoking- line overloads at 157.8% see table 6-5 below. SCL's line is a 230kV line carrying 4 time the power. Fixing that first is cheaper by rewiring with modern higher load lines like ceramic core and solves BPA's issues. Beside BPA already leases those lines from SCL, with any known compensation to SCL. Maybe EE is SCL's payment from BPA? Is that legal?
        ii. Assumes the full amount during an overload situation. What are the Columbia River Treaty rules for power transmission during an overload scenario? Thought there was flexibility.
        iii. What is the status/details of the renewal of the treaty, which expires here in 2015/16 or so. Local & national press report the US wants to scale back power sent back to Canada by 90%. As such, this number in the model is high.
    b. For PSE/SCL Westside Generation, winter was reduced to 0.
        iv. The base case, is 2858 MW
        v. The low generation scenario was 1031.
        vi. How can zero be justified as a good parameter? Unless PSE decides to behave like Enron and turn off the power as they did during California's energy crisis!

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Table 5-2: Winter and Summer Case Study Assumptions

When is this ever valid? This is 100% BPA issue 0% PSE's. Schedulable per US treaty agreement. The USA plans are to cut this way back or zeroed, if treaty is not renewed then this is zero. If not schedule transfers off peak.

Winter and Summer Case Study Assumptions

When is this ever valid? All 20 generators west of cascades shut off? See table 4.4 to understand how fraudulent this is.

Case Name	Amount of Conservation	System Load	Eastside Load	Northern Intertie	PSE/SCL Westside Gen	Other Adjustments Modeled
1 100% Conservation 2013-14 Winter	100%	5055 MW	652 MW	1500 MW Export	0 MW	Saint Clair 230-115 kV transformer; Talbot Hill - Berrydale #1 line uprate; Starwood autotransformer removal with Tacoma Power voltage increase
1 75% Conservation 2013-14 Winter	75%	5090 MW	656 MW	1500 MW Export	0 MW	Saint Clair 230-115 kV transformer; Talbot Hill - Berrydale #1 line uprate; Starwood autotransformer removal with Tacoma Power voltage increase
2014 Heavy Summer	100%	3343 MW	516 MW	2850 Import	2171 MW	Saint Clair 230-115 kV transformer; Talbot Hill - Berrydale #1 line uprate; Starwood autotransformer removal with Tacoma Power voltage increase
2018 Heavy Summer	100%	3554 MW	552 MW	2850 Import	2276 MW	Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; White River - Electron Heights 115 kV line re-route into Alderton; White River 2nd bus section breaker; Lake Hills - Phantom Lake 115 kV line; Sammamish-Juanita 115 kV line

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Magically PSE can turn on 80% of the power generation while the system imports 5x the Eastside load of 552MW

4. This fourth chart (snapshot) below shows the "Eastside" overloads predicted for 2017/18 are based on these assumptions at specific substations – all based on the above faulty assumptions.

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>
> **4.1.7 Load Power Factor Assumptions**
>
> The power factor at each substation was based on the MW and MVAR loadings at the time of the January 18, 2012 system peak. As the load levels changed based on the load forecast, the power factor at each substation did not change.

   a. In addition, the data shows overload trends at specific sub-stations, however, the modeling was done another "cherry picked" at a point in time? What are the loads and power factors at each substation going back 10-15 years for the winter and summer peaks? Electric car charging is improving this power factor with capacitive load, how much? There are mitigations at the sub-station level that are far cheaper than a $1 billion dollar power line ($280M plus $800 million in profit interests and O&M). Grid batteries and electric cars need to be modeled for power factor effects.

5. FEDERAL / NEPA RULES – The following documents provide evidence that Energize Eastside should not be considered as a local project subject to SEPA rules, but rather part of a broader strategy across BPA, a federal agency, and PSE, a for-profit utility, for overall international energy plans that should fall under Federal or NEPA jurisdiction.

   1. Columbia Grid documentation clearly shows EE is part of their broader plans. I have highlighted key points in yellow.
      i. EE is part of the larger project to increase international power flows between Canada and the US as required by Bonneville Power Authority (BPA), treaty obliterations, and to prepare for Canada's "Site C" dam coming on line with ~1,200 MegaWatts of power. A NEPA process is required for international projects, which both BPA and Canadian power authority want to deny, but is clearly the case.
      ii. Furthermore, using PSE's own document "Eastside Needs Assessment Report Transmission System King County", EE is for reliability of the grid SOLEY for BPA purposes. If one takes out BPA's bulk power flow to Canada OR not use a falsified low power generation case of shutting off all the northern gas turbine generators at the exact same time as all the hydro dams are off, then EE's business case falls apart. PSE/BPA went extraordinary lengths to get the model to show overloads.
      iii. The new hydro dam will further stress the endangered species listed as the Salish Orca (aka as Southern Resident Orca). A 10 year study published by NOAA in June 2014 states expanding hydro dam use threatens the habits of several endangered species including pacific salmon and the last remaining 77 Salish Orca (these Orca are 1 million years distinct for other Orca) which are an international endangered species further supporting NEPA review.

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There are six (6) potential thermal violations (same as 2013-14) of PSE lines or transformers in the King County area for Category C contingencies. These facilities are highlighted in yellow on Table 6-5, which shows that the potential thermal overloads vary up to a high of 128%. Overloads caused by BPA facility outages which are controlled by BPA generation dispatch are not highlighted.

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Table 6-5: Elements above Emergency and Operating Limits: 2017-18 Winter Peak, 100% Conservation, Normal Weather, Thermal Loadings (CONTINUED) (Redacted)

words for are also on pg54

A 230kV line carries is 4 times the power as115kV line

Here is the CHEAPEST solution = replace M.V-Skoking 40 year old wires with much higher capacity wires.

Case	Category	Worst Contingency	Owner of Facilities Out	Element(s)	Owner of Overloaded Facilities	Percent Overload
2017-18 Winter	C	N-1-1: Echo Lake - SnoKing - Monroe 500 kV line & Maple Valley - SnoKing #1 230 kV line	BPA & SCL	Maple Valley - SnoKing #2 230 kV line	SCL	157.8%
2017-18 Winter	C	N-1-1: Echo Lake - SnoKing - Monroe 500 kV line & Talbot Hill - Lakeside #2 115 kV line	BPA & PSE	Talbot Hill - Lakeside #1 115 kV line (Redispatch not enough)	PSE	127.8%
2017-18 Winter	C	N-1-1: Echo Lake - SnoKing - Monroe 500 kV line & Talbot Hill - Lakeside #1 115 kV line	BPA & PSE	Talbot Hill - Lakeside #2 115 kV line (Redispatch not enough)	PSE	127.6%
2017-18 Winter	C	N-1-1: Talbot Hill 230-115 kV transformer #2 & Berrydale 230-115 kV transformer	PSE	Talbot Hill 230-115 kV transformer #1 (Redispatch not enough)	PSE	105.7%
2017-18 Winter	C	N-1-1: Echo Lake - SnoKing - Monroe 500 kV line & O'Brien - Falcon 115 kV line section	BPA & PSE	Talbot Hill - Boeing Renton - Shuffleton 115 kV line (Redispatch not enough)	PSE	110.6%
2017-18 Winter	C	N-1-1: Talbot Hill 230-115 kV transformer #1 & Berrydale 230-115 kV transformer	PSE	Talbot Hill 230-115 kV transformer #2 (Redispatch not enough)	PSE	105.7%

The greatest levels of failures in all of PSE's Senerios. Lets look what is causing them!!

REQUIRES National Environmental Impact Review Process, not SEPA as requirements driving overload are for BPA's needs to do bulk power transfer to Canada, for one example see this case. And NEPA required as power flows come from hydro operations in an endangered species habitat.

Below are the case study assumptions causing "PSE's" "overloading". Sure looks like BPA power to Canada and all generators "West of the Cascades" off causing the "problem".

Table 5-2: Winter and Summer Case Study Assumptions

How is this BPA's requirement to ship "entitlement" power back to Canada valid during outages? This is 100% BPA issue 0% PSE's. Schedulable per US treaty agreement. USA plans are to cut this way back or zeroed in 2015/16

Winter and Summer Case Study Assumptions

When is this ever valid? All 20 generators west of cascades shut off? See table 4.4 to understand how fraudulent this is.

Case Name	Amount of Conservation	System Load	Eastside Load	Northern Intertie	PSE/SCL Westside Gen	Other Adjustments Modeled
2 100% Conservation 2017-18 Winter	100%	5208 MW	706 MW	1500 MW Export	0 MW	Block load allocated per King Co Dist. Planers; Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; Raver 500-230 kV transformer; SCL series inductors
2 75% Conservation 2017-18 Winter	75%	5325 MW	722 MW	1500 MW Export	0 MW	Block load allocated per King Co Dist. Planers; Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; Raver 500-230 kV transformer; SCL series inductors
3d 100% Conservation 2017-18 Extreme Winter	100%	5742 MW	782 MW	1500 MW Export	0 MW	Block load allocated per King Co Dist. Planers; Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; Raver 500-230 kV transformer; SCL series inductors

yet PSE can magically generate 2171MW in Summer both 2014 and 2018 when they

Eastside 81pgNeeds Assessment Oct2013 REDACTED.PDF (page 46 of 81)

2014 Heavy Summer	100%	3343 MW	516 MW	2850 Import	2171 MW	Saint Clair 230-115 kV transformer; Talbot Hill - Berrydale #1 line uprate; Starwood autotransformer removal with Tacoma Power voltage increase
2018 Heavy Summer	100%	3554 MW	552 MW	2850 Import	2276 MW	Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; White River - Electron Heights 115 kV line re-route into Alderton; White River 2nd bus section breaker; Lake Hills - Phantom Lake 115 kV line; Sammamish-Juanita 115 kV line

want to. Winter is Bellevue/Eastside's greatest local power need, summer is much lower locally. Power headed to California is at its greatest in summer as the 2850 MW import numbers above show.

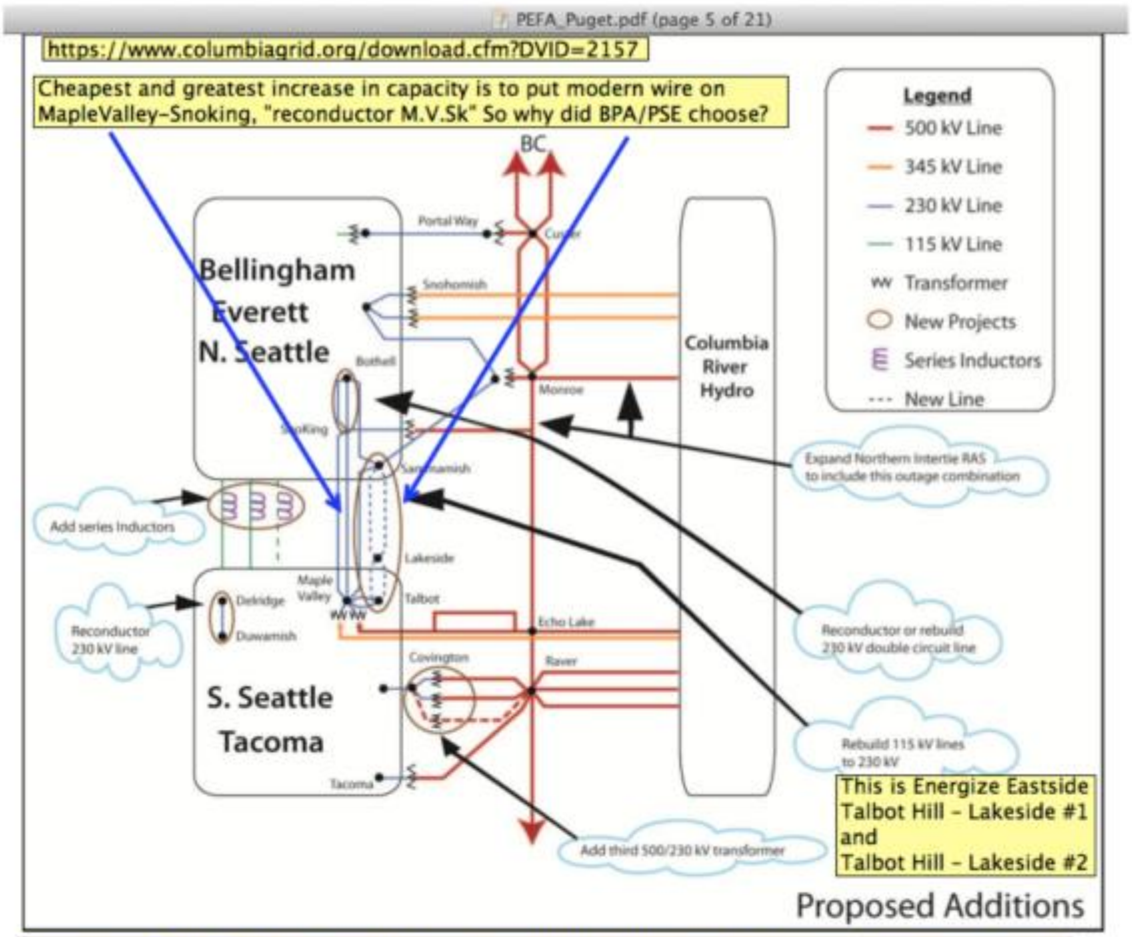
Here is Columbia Grid comments on what EE is for.[11] Even the reliability issues are BPA's as PSE's 81 page "Eastside Needs" report clearly shows.

PEFA_Puget.pdf (page 2 of 21)

Introduction and Conclusions

In October of 2010, the Puget Sound Area Study Team issued a report entitled "Transmission Expansion Plan for the Puget Sound Area." The report is available via the ColumbiaGrid website. The report details a transmission plan for the Puget Sound region that would, as a basic requirement, provide for reliable system performance while significantly improving the ability of the transmission grid to support power transfers between the Northwest and British Columbia. Since the release of the original report, the following changes have occurred that have led to the need for the Puget Sound Area Study Team to revise their transmission plan:

[11] https://www.columbiagrid.org/download.cfm?DVID=2157



Columbia Grib Doc tells you the real reason for EnergizeEast project = to move power to from Canada/California. NOT FOR LOCAL Bellevue energy growth!!!!!!!

Figure Two: Revised Puget Sound Area Transmission Expansion Plan for Supporting South-to-North Transfers

With Canada's Site C dam coming on line 2024 with 1200 MW of power with no place to sell but USA, Canada is over supplied. PSE plans to have EE done so it move this power and use when joining EIM in 2016

https://www.columbiagrid.org/download.cfm?DVID=2157
See Site C dam progress at https://en.wikipedia.org/wiki/Site_C_dam

More on EIM, CA-ISO's energy market, which even Hardev Juj, BPA's head of grid planning touch on, see very end.

This is a screen shot below from NOAA's 10 year study on the endangered Orca whales, with only 78 leave in the entire world. This alone forces the EIS to be a NEPA not a SEPA as issues cross international boundary with Canada.

Orca10yearStudyresults-June2014smallreport62514.pdf (page 9 of 28)

2005

Southern Resident killer whale distinct population segment listed as endangered under ESA.

2006

Co-hosted a symposium with the Department of Fisheries and Oceans Canada to share new research results.

Southern Resident Killer Whales: 10 Years of Research and Conservation

Reducing Threats to Southern Resident Killer Whales

Federal agencies must insure that any action they authorize, fund, or carry out is not likely to jeopardize the continued existence of any endangered or threatened species or destroy or adversely modify critical habitat. NOAA Fisheries consults on federal actions under section 7 of the Endangered Species Act to reduce or mitigate impacts and ensure the survival and recovery of Southern Resident killer whales. Section 7 consultations are an important and effective management tool to reduce impacts on Southern Residents.

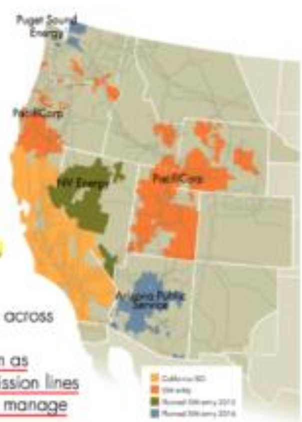
	Types of Actions	Mitigation/Conservation Measures
Actions that affect the salmon prey of Southern Residents	• Harvest management, such as fisheries regulations or fishery management plans • Hydropower operations • Hatchery production and management • Freshwater and estuary habitat projects	• Risk analysis to assess salmon abundance levels and relationships to killer whale survival and recovery. • Identify workgroups and research projects to address data gaps. • Minimize occurrence of derelict gear. • Protective measures for salmon habitat, populations, and hatchery operations.

http://www.nwfsc.noaa.gov/news/features/killer_whale_report/pdfs/smallreport62514.pdf
http://www.nwfsc.noaa.gov/news/features/killer_whale_report/pdfs/bigreport62514.pdf
www.nmfs.noaa.gov/pr/species/mammals/whales/killer-whale.html
http://www.nwfsc.noaa.gov/news/features/killer_whale_report/

2. PSE announces plans to join EIM (Energy Imbalance Market) in 2016. Again, key points are highlighted or underscored.
    i. As PSE operates primarily in Puget Sound's East Side (and near British Columbia), Bellevue needs to question if the proposed highly expandable, and much taller 230kv lines are really to serve Bellevue's needs or to prepare for expansion efforts to maximize profit via North-South Transfer expansion and EIM agreement. PSE will need to have the capacity to sell/transport bulk high voltage power from Canada. PSE has no other plans for expansion that could support this outside of EE, so we can only assume the ulterior motive. Again, the Energize Eastside project is a small part of a much bigger picture.

CAISO.EIMFAQ.pdf (page 1 of 2)

EIM FAQ



Expanding regional energy partnerships

WHAT DOES IT MEAN TO PARTICIPATE IN THE EIM?

The Energy Imbalance Market (EIM) strengthens grid reliability by allowing participants to buy and sell power closer to when electricity is consumed and by allowing system operators real-time visibility across neighboring grids, which supports balancing supply and demand at less cost. The ISO market systems identify fluctuations in supply and demand and then automatically finds the best resource from across a larger region to meet immediate power needs (demand). This activity optimizes the interconnected high-voltage system as market systems automatically manage congestion on transmission lines which not only helps maintain reliability (system up time) but manage and mitigate the cost of congestion as well.

WHO ARE THE CURRENT PARTICIPANTS IN EIM?

The ISO and PacifiCorp, which serves customers in six states, launched the first western real-time energy balancing market on November 1, 2014. Las Vega-based NV Energy has approvals from both the Federal Energy Regulatory Commission (FERC) and the Public Utilities Commission of Nevada (PUCN) and will begin participating in the EIM on October 2015.

Puget Sound Energy of Bellevue, Washington, and Arizona Public Service headquartered in Phoenix, Arizona, have announced their plans to enter the EIM on October 1, 2016. This means the EIM will provide cost savings for consumers in eight western states. In addition, comprehensive studies show significant reliability benefits result from leveraging generation resources across the entire EIM region with the added benefit of more frequent power plant dispatching in real time to cost efficiently use available energy supplies.

i. Even with PSE's inflated demand picture, an alternative is to install 50 foot poles (+5 feet from today) to support the 230kv and easily meet their demand projections for next 40 years. PSE argues that it is more cost effective to install fewer 130 foot poles (+85 feet from today); however, it is out of character for a residential area, and would end in deadly disaster with the added stress to the and aging gas pipeline running directly underneath.

   The real reason to go with larger poles is that they can easily be expanded to carry 500kv with no additional permissions or pole installation required. Again, not needed to meet Eastside demand, only needed for North-South Transfer. The picture below (Antelope-Pardee corridor in Lancaster) shows unsightly 500kv being proposed by PSE. These are typically rural not urban. And, PSE can add a wireless cable company to the area and expand the poles to 150feet with new federal rules without even have to ask the City of Bellevue permission.

[1] http://www.cpuc.ca.gov/Environment/info/aspen/antelopepardee/photos.htm

6. ALTERNATIVE ENERGY

   a. Grid Batteries / Storage – Lots of press and real world examples on this – New York, California, Hawaii are examples. Many states have already implemented this as alternative to infrastructure / power line build out, and more cost effective way to achieve reliability. With this trend, it's hard to believe we are even having a discussion around EE.
   b. Solar – Given solar is now cheaper than grid in 20 states (including WA Hydro) what are the projections of solar displacing utility power? Major banks are now funding hundreds of utility scale solar projects in the 50 states.
      i. See Deutsche Bank's work reference in on page 3/12 of *Tech & financial issues with PSE Energize Eastside1.4w.o.affil.doc*
      ii. References Edison Electric Institute's, (the lobbying group for the utilities) urgent call to action in their 2013 report *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business.*
      iii. This was sent to the City of Bellevue on 2/12/2014 for the independent consultant review.
   c. LED bulb replacement - Confirm via statistically significant survey that there is at least 600MW (calculated in detail by this MSEE for PSE service area) at peak load of incandescent bulbs inside PSE's territory per NEEA.org numbers when accounting for the 45% first year failure rate of compact florescence bulbs as determined by the Dept of Energy reports across +300 bulb models sold. I look forward to comparing

numbers to what the NEPA EIS gets. Fix the current 11kW of incandescent waste at City Hall!

d. Windows – Washington currently only sells hot climate windows in Washington State wasting at least 100 aMW/year. These windows would retain heat reducing peak load in winter. What is PSE's share of saving when hot climate windows are banned in WA and only cold climate ones allowed? New building code proposals are with the Washington legislature.
e. Geothermal – My former employer let a 280 MW geothermal power plant be installed on our Navy Lab without cost to it in 1986, assuming the research and develop lab with 5000 employees (China Lake) got all its power for free and what was left over, then the California Energy Inc, could sell the rest. PSE's territory is as close, if not lot closer, to geothermal in terms of drilling depth. The major cost here is replacing heat exchangers; far cheaper over 40 years than $1 billion dollars of new power lines. Please fully detail that option. May need to confirm if BLM land is available for this purpose. The Navy had to have ownership transferred from BLM to Navy which Clean Air Act 111D and related rules can expedite transfer to City of Bellevue or other state/city government agency.
f. Callable Power - Solve PSE's inflated power needs with reverse Demand Response "call to turn on power" from distributed from electric car batteries to solve peak power loads. See more on flatten peak loads with Energy North West below.
g. Please evaluate all power options in the National Association of Clean Air Agencies (NACAA) May 2015 many of which have been testified to the WA State House and Senate committees . This is the +400 page document of menu items for states to get onto better energy resources.
www.4cleanair.org/sites/default/files/Documents/NACAA_Menu_of_Options_HR.pdf
h. What is the total cost of EE including profit, interests and assumed operation & maintenance fees over the 40 year payback period? And how does this compare to lifecycle costs for distributed generation or Demand Response (ability to call-to-turn-off-as-desired) actual project and potential projects by the likes of Stan Gent, CEO of Seattle Steam Company (just bought by the largest US private equity for renewable energy Brookfield and is now called Enwave Seattle, but for WA Senate/House invited presentations search with Seattle Steam) & WSU's Energy Program specialist Dave Sjoding or Energy North West's John A. Steiger's 509-377-4547 (the civil service guys running the grid/nuke facilities in eastern WA) 100MW Demand Response project in WA. All these folk of whom invited to give presentations to WA House and Senate Energy Committees represent the future. Demand Response is measured in 1000s of MegaWatts in East coast which is far more advanced than WA which has just 100MW which John A. Steiger has put together for sale to utilities even PSE. How about Overlake Hospital get more reliable power like Huston's medical center did with co-heat-power and ditched ALL of their emergency generators.
i. Peaking generator. PSE's technical consultants claimed to have asked Dept of Ecology for permission to install a peaking generator but was turned down. Please detail why and the cost and environmental impact to install a peaking generator at

say the lite rail garage/system or in the Spring Business District as co-heat-power systems.

j. Heliostats = $300 dollar self powered sun tracking mirror reflecting 500Watts of sun energy into home. What if PSE bought all it electric heating homes one? Costs & impact?
k. What are Canada's site C dams impacts for any WECC or other computer modeling?

7. Investor owned utility (primarily PSE) customers already pay 28% higher rates than those served by cooperatives, municipalities or public utility districts.

NEEA 2014-WA-report-final.pdf (page 5 of 21)

neea

UTILITY AND ENERGY STATISTICS[2]

There are 3.2 million utility customers in Washington, 2.85 million of which are residential accounts. Residential customers in Washington account for 4,079 average megawatts (aMW) of demand and 35 million megawatt hours (MWh) of usage. More than 55 percent of residential customers in Washington (representing 58 percent of annual usage) are with Cooperatives, Municipalities, or Public Utility Districts. Investor Owned Utilities customers in Washington pay 28 percent more per killowatt-hour (kWh) than other utility types, but use about 14 percent less kWh per month.

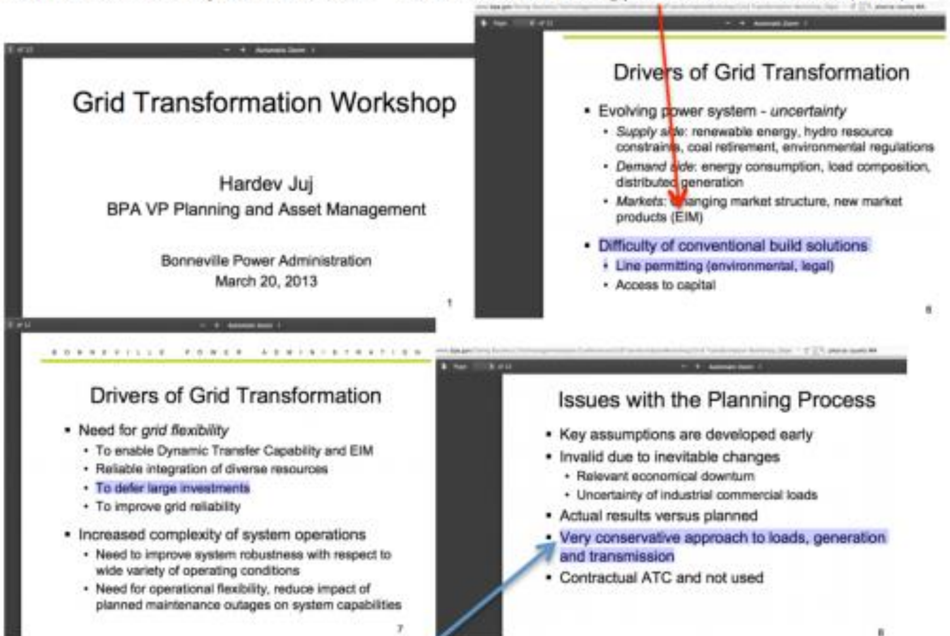
Customers by Utility Type (2012)	Cooperatives	Municipalities	Public Utility Districts	Investor Owned Utilities	BPA	Total
Residential	141,165	572,208	861,085	1,278,302	-	2,852,760
Commercial & Industrial	23,135	69,915	115,136	175,505	9	383,700
Public Street & Highway Lighting	-	-	-	-	-	-
Other Public Authorities/ Transportation	-	5	-	1	-	6
Other Sales to Retail Energy Customers	-	-	-	-	-	-
Total Customers	**164,300**	**642,128**	**976,221**	**1,453,808**	**9**	**3,236,466**

Residential Electricity Costs	Cooperatives	Municipalities	Public Utility Districts	Investor Owned Utilities	BPA	Total
Average Cost per kWh	7.84¢	7.62¢	7.82¢	9.91¢	-	8.53¢
Average Monthly Cost	$101.44	$65.31	$95.42	$96.32	-	$88.48
Average Annual Cost	$1,400.43	$927.71	$1,320.82	$1,052.02	-	$1,122.80
Average Monthly kWh	1,294	857	1,220	972	-	1,037
Average Annual kWh	15,526	10,285	14,643	11,663	-	12,448
Total Annual MWh	2,191,697	6,083,474	12,326,735	14,909,055	-	35,510,961
Total Annual aMW	252	699	1,416	1,713	-	4,079

i. PSE is happy to take on capital investment projects. They are guaranteed profits for 40 years through their contracts with the state and can pass the costs (with profit margin) along to their customers.

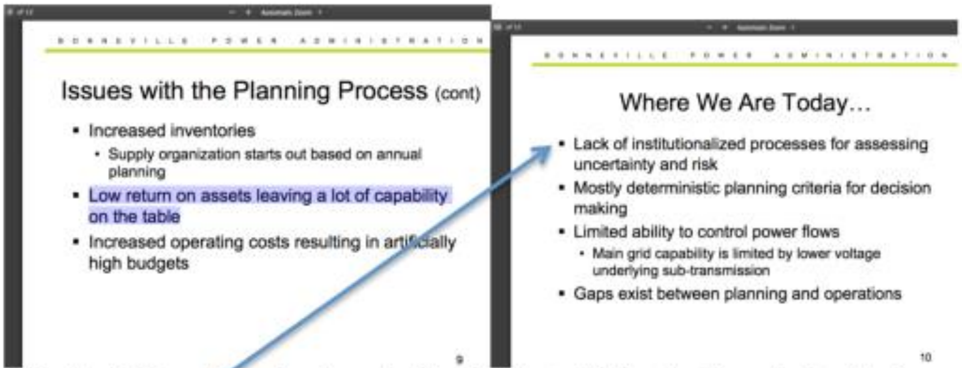
ii. With the profit protection in place, there is no downside to this investment, and only possible upsides with North-South Transfer expansion.

Here is another reason why PSE & BPA are obfuscating the real need behind Energize Eastside in BPA's Hardev Juj's own words.[12] See above for Energy Imbalance Market (EIM)



What is being said here is we MASSIVELY over Build.

12 www.bpa.gov/Doing%20Business/TechnologyInnovation/ConferencesGridTransformationWorkshop/Grid%20Transformation%20Workshop_Objectives_by%20Hardev%20Juj.pdf



Is Hardev Juj foreshadowing Energize Eastside destabilizing the Olympic pipe line?

Here is picture of the damage from the 2010 San Burno natural gas explosion in San Francisco metro that went up into the air, unlike what the Olympic pipeline break will do with its jet fuel which will spread horizontally. Even with automated shut off the jet fuel could easily result in thousands of deaths unlike the natural gas pipeline explosion in San Bruno CA fire which killed 8. A liquid jet fuel spill will flood neighborhoods quickly and instead of just 100 homes damaged or destroyed there will be a thousands.

Having personally conducted fire protection testing on the V-22 Osprey it takes AFFF "A triple F" (Aqueous Film Forming Foam) to put out jet fuel fire. Using water just spreads the fire. AFFF works great if you have enough of it and there is no wind. Given the size of the Olympic pipeline it is going to take a lot of AFFF at all the local firehouses. The stuff at SEATAC will be too late to help. Anybody have a copy of that Olympic Pipeline break disaster plan?

From: Curt [mailto:curtallred@hush.com]
Sent: Monday, March 14, 2016 5:48 PM
To: info@EnergizeEastsideEIS.org
Cc: eis@cense.org; Curt@hush <curtallred@hush.com>
Subject: Comments on Energize Eastside Phase 1 Draft EIS - Pipeline Safety

To: Heidi Bedwell, Energize Eastside EIS Program Manager

450 110th Ave NE

Bellevue, WA 98004

From: Curtis Allred

CENSE member

13609 SE 43rd Pl

Bellevue, WA 98006

Subject: **Comments on Energize Eastside Phase 1 Draft EIS - Pipeline Safety**

Date: 14 March, 2016

The EIS does not adequately address safety issues related to powerline and pipeline co-location. Pipeline safety issues related to co-located High Voltage AC (HVAC) lines are serious and well known in the pipeline industry, yet are barely mentioned in the Draft EIS document.

The EIS must address and provide mitigation for issues raised in the 2 documents cited below. It must also state the potential for a major disaster, and that the City of Bellevue has said that it does not have sufficient emergency response personnel and resources to deal with a pipeline explosion.

Documents:

1. The INGAA document "Criteria for Pipelines Co-Existing with Electric Power Lines" (http://www.ingaa.org/File.aspx?id=24732) lists five criteria that determine the risk of accelerated corrosion when pipelines and transmission lines are located in close proximity. When the Olympic pipeline is paired with

PSE's proposed transmission line, at least 4 of the 5 risk criteria are raised to the highest level of risk. It considers a co-location length of 5000 feet or more to be "high risk". The co-location distance for Energize Eastside power lines and the Olympic Pipeline will be 20 times this high-risk threshold! This seems like a major red flag that must be addressed by the EIS.

2. Dr. Frank Cheng, an internationally recognized pipeline safety expert created a report "Olympic Pipeline" (http://cense.org/Olympic%20Pipeline.pdf) which considers the safety risks of putting high voltage transmission lines so close to petroleum pipelines. He describes 3 mechanisms by which High Voltage AC adversely effects the integrity and safety of buried pipelines that are collocated with electric power lines, all of which are able to result in pipeline failures.

—

From: Loretta Lopez
Sent: Monday, March 14, 2016 7:08 PM
To: 'HBedwell@bellevuewa.gov'; 'info@EnergizeEastsideEIS.org'
Subject: Comments to DEIS PROPOSED PSE Project/January 28 DEIS/Request for clarification

Don Marsh, President of CENSE has repeatedly asked for information from PSE supports PSE's assertions about Need. See stream of email messages attached below to this email. Email from Don Marsh to Jens Nedrud 1/18/16, 1/25/16, 1/26/16 and 1/29/16,
PSE bases, in part, its refusal to provide information upon CEII requirements. Section 1-3, page 1-4.
Citizens cannot assess PSE's assertions of need without the access to information. The City states it cannot release the information. See email 2/23/16 message from Carol Helland to Loretta Lopez in email stream below.
I request that the City of Bellevue, determine a method for providing the information that Don Marsh has requested in his emails which are forth below.
Loretta Lopez
13419 NE 33rd Lane
Bellevue Wa 98005

Bridle Trails Community Club, Vice President

CENSE Member

From: CHelland@bellevuewa.gov [mailto:CHelland@bellevuewa.gov]
Sent: Tuesday, February 23, 2016 3:08 PM
To: Loretta Lopez
Subject: RE: PSE Refusal to provide information#2

Apologies Loretta for the delay. The issue that you raised about information sharing was previously responded to as part of the City Attorney's reply to Rich Aramburu. Specifically, the City Attorney included the following information in her October 23, 2015, letter.
4. Access to Critical Energy Infrastructure Information
Stantec plays an important role on the EIS team as reviewer of the utility planning and operations information associated with PSE's electrical utility system that is protected as Critical Energy Infrastructure Information (as such term is defined in 18 C.F.R. 388.113 or as amended, otherwise known as CEII). The City is precluded from releasing un-redacted utility planning and operation information protected by federal law, therefore we are unable to comply with your request that we produce the CEII document related to this project. This does not mean that the information is unavailable to your clients. The information reviewed by Stantec is available upon request from PSE with appropriate advance security clearance. PSE has a standardized security screening process in place to assist in providing access to un-redacted information. We understand that there is some ongoing disagreement between PSE and CENSE about PSE's screening process impacting your client's ability to access the documents, however the City does not have authority to resolve that disagreement. Parties interested in reviewing the protected utility planning and operations information associated with PSE's electrical utility system, can request a security clearance from NERC.
One of the reasons that Stantec was included on the EIS consultant team was to evaluate the process utilized by PSE to model operation of their electrical system. Reviewers that are either unable to secure CEII clearance or unwilling to go through the necessary security steps should review the materials prepared by Stantec as a component of the development of the DEIS. With respect to the "need"

question, PSE is a privately held regulated utility, and as such they are responsible for identifying the objectives they are trying to achieve with their proposed project. That said, I have forwarded to your comment regarding consultation on to the City Attorney and to Nicholas and Kate.
Regards, Carol

From: Loretta Lopez [mailto:loretta@mstarlabs.com]
Sent: Tuesday, February 23, 2016 12:51 PM
To: Helland, Carol <CHelland@bellevuewa.gov>
Subject: RE: PSE Refusal to provide information#2

Carol,
I am checking on whether you received my message below.
Please let me know that you received it.
Loretta
PS I was at the City Council meeting last night. I was surprised to hear Nicolas Matz and Kate Berens response regarding the issue of Need for PSE project. Their position is that the neither the City nor the public can question the Need for the project. I suggest that they consult with the City Attorney for clarification and provide substantive legal support for advice to the City Council.

From: Loretta Lopez
Sent: Friday, February 19, 2016 11:01 AM
To: CHelland@bellevuewa.gov
Subject: PSE Refusal to provide information

Carol,

Don Marsh has repeatedly asked for information from PSE. See the stream of email messages below. PSE has not provided the information.

The information Don Marsh is requesting is necessary for citizens to understand the basis of PSE's assertions. The City has a responsibility to require PSE to provide information to support its position that there is a need for the proposed project.

PSE refusal to respond to Don's question is unacceptable. PSE cannot assert that its position is true and expect citizens to accept without question.

We request that you, as the Environmental Coordinator for this EIS, require PSE to respond to Don's requests.

Thank you.

Loretta

From: Nedrud, Jens V [mailto:jens.nedrud@pse.com]
Sent: Thursday, February 11, 2016 11:19 AM
To: 'Don Marsh' <don.m.marsh@hotmail.com>; Pravitz, Keri <Keri.Pravitz@pse.com>
Cc: council@bellevuewa.gov; BMiyake@bellevuewa.gov; MKBerens@bellevuewa.gov
Subject: RE: Two questions regarding Eastside need

Don -

It is apparent from your response that we are at a point where continued email exchanges are not helpful. I have done my best to explain complex issues in a way that you can understand, and clearly that is not working. All the experts agree that the need has been established.

On other issues you may wish to engage in the public process - currently there is a public comment period for Phase I of the Draft Environmental Impact Statement in which you can participate – please see the cities' **EnergizeEastsideEIS.org** website.

Sincerely,

Jens

Jens Nedrud, P.E.
Senior Project Manager
PUGET SOUND ENERGY
PO Box 97034, EST03W, Bellevue, WA 98009
d (425) 462-3818 | c (425) 533-5307 | jens.nedrud@pse.com

The Energize Eastside project is undergoing environmental review, which includes preparation of a Washington State Environmental Policy Act (SEPA) Environmental Impact Statement (EIS). The City of Bellevue is leading the EIS process in cooperation with Kirkland, Newcastle, Redmond and Renton. The City ofBellevue and the coordinating jurisdictions published the Phase 1 Draft EIS on Jan. 28, 2016. The public comment period for the Phase 1 Draft EIS ends on Monday, March 14, 2016. For more information on the EIS and to submit comments to be included as part of the EIS and the public record, please visit**EnergizeEastsideEIS.org**.

Please note:

- The City of Bellevue is leading the SEPA EIS process. **No comments or questions submitted to Puget Sound Energy will be considered part of the EIS.** To submit comments as part of the EIS, please visit EnergizeEastsideEIS.org.
- For background information about the Energize Eastside project, please visit pse.com/energizeeastside or refer to the project's Frequently Asked Questions.

From: Don Marsh [mailto:don.m.marsh@hotmail.com]
Sent: Friday, January 29, 2016 8:25 AM
To: Nedrud, Jens V; Pravitz, Keri
Cc: council@bellevuewa.gov; BMiyake@bellevuewa.gov; MKBerens@bellevuewa.gov
Subject: RE: Two questions regarding Eastside need

Dear Jens,
Thank you for your lengthy (and quick) response. You have explained a bit of your methodology. However, there are still some things that are not made clear in your answers or the studies you mention:

1. Did you or your team personally review each of the 6.25 million contingency cases that you simulated to determine the system capacity line?
2. If not, how many of the cases were reviewed?

3. Was the system capacity determined by the worst case you observed, or did you combine some number of cases to calculate the capacity?
4. In any system that has a limited capacity, the limit is usually determined by one or two "weak links." For example, my car engine may be able to go 100 mph, but if my tires are only rated for 90 mph, that's as fast as my car can go. I must ask again, is the system capacity limited by the two 230 kV transformers that are overloading, or is there some other component of the system that is limiting the total capacity?

Your answers to these questions are important, because neither PSE, Quanta, Utility System Efficiencies, nor Stantec has described the methodology used to produce the result. If the need for the project is as obvious as you claim, and if the methodology is as solid as you imply, then we should be satisfied as soon as we know these details.
We seem to have different interpretations of the FERC ruling on our complaint. You have focused on one part of FERC's ruling, but we think the following conclusion is important: "The record before us shows that the Energize Eastside Project is located completely within Puget Sound's service territory, … and that neither Puget Sound, nor any other eligible party, requested to have the project selected in the regional transmission plan for purposes of cost allocation; therefore, the project is not subject to the Order No. 1000 regional approval process." In other words, FERC dismissed the case at least partly because the commission lacked jurisdiction. FERC did not say PSE is correct in its assertion that it must transmit electricity to Canada under all conditions. In fact, FERC seems to think that the project will play no significant role in regional transmission.

Your email says PSE must participate in "regional power flows" that are not optional. Your consultant, Mark Williamson, told the Newcastle Planning Commission that the project has nothing to do with Canada, and that there are better ways to transmit energy to Canada than pushing it through the Eastside. Can you explain these apparent contradictions?
It is also puzzling to us that you seem unaware that the NERC Reliability Coordinator headquartered in Vancouver, Washington would cut power flows to Canada within minutes if an N-1-1 emergency occurred during peak winter loads. Do you assert that the coordinators responsible for grid reliability would force you to overload your transformers to continue transmitting a large flow of electricity to Canada when it isn't required to keep lights on in British Columbia?
Sincerely,
Don Marsh

From: Nedrud, Jens V [mailto:jens.nedrud@pse.com]
Sent: Thursday, January 28, 2016 4:24 PM
To: 'Don Marsh' <don.m.marsh@hotmail.com>; Pravitz, Keri <Keri.Pravitz@pse.com>
Cc: council@bellevuewa.gov; BMiyake@bellevuewa.gov; MKBerens@bellevuewa.gov
Subject: RE: Two questions regarding Eastside need

Don,
I am sorry you do not think we have answered your questions; I do know that we have discussed these very issues with you and your CENSE colleagues several times. Perhaps this is a case of not understanding the answers. Therefore, in an effort to explain our answers to you again, I have addressed each question below.

Question 1: "Is this capacity determined by adding the capacities of the two 230/115 kV transformers that would serve the Eastside in the event of an N-1-1 outage of the other two transformers?"

ANSWER: The simple, non-technical answer is No. The system capacity lines on the graph were NOT determined by the ratings of the two 230 kV transformers. They were determined from power flow studies as a result of simulating approximately 6.25 million contingencies. As we have previously discussed, the "system capacity" or "level of concern" shown on the graph relates to system performance primarily under N-1-1 or N-2 contingency conditions as required by federal mandates. After my colleagues met with John Merrill and Steve O'Donnell some time ago, you even acknowledged your understanding of this in emails you exchanged with us. The system capacity range of 688 MW to 708 MW is based on power flow studies. PSE's power flow studies are conducted pursuant to mandatory federal regulations with the assistance of nationally recognized system planning experts using industry established study protocols. There is no simple "adding" of nameplate capacities of transformers in power flows studies. Power flow equations are non-linear which requires a numerical iterative solution to solve such equations. The equations use complex numbers (vectors), which include magnitudes and phase angles in determining the power flows.

Also, your continued insistence that PSE can eliminate the power flows to Canada shows your misunderstanding of electric system planning and its mandatory regulations. All regional power flows are included in the base cases from WECC and ColumbiaGrid. They are required to be included in PSE's load flow studies, as the electrical system serving the Eastside is part of the regionally integrated electric system. It is not optional. We have explained this to you numerous times and FERC agreed with our methodology in dismissing your complaint regarding our planning process.

Question 2: "…is about the "Customer Demand" level shown at approximately 580 MW in 2014. Is this number based on a measurement of the demand on the two transformers calculated by a load flow simulation of the N-1-1 contingency? Or is it the summation of loads on individual Eastside substations?"

ANSWER: The 2014 customer demand value is NOT based on loads on the remaining two 230 kV transformers or the summation of loads on substation transformers. Customer Demand value is a **forecasted** value; please note the chart is labeled as "Customer Demand Forecast." As we have explained multiple times, PSE's corporate load forecast process has been performed for many years and the results have served PSE customers well. Our forecasts are a complex econometric model that takes into account not just historical data but a variety of other inputs, such as information about regional and national economic growth, demographic changes, weather, prices, seasonality, and other customer usage and behavior factors. Growth data used in the studies were primarily provided by **third party agencies**, such as the PSRC and Eastside jurisdictions. The usage data appropriate to producing a valid electric load forecast is incorporated, along with all other appropriate forecasting data, in the PSE load forecast. The same data has been reviewed by Bellevue's consultant, Utility System Efficiencies, Inc. (USE), as part of the "Independent Technical Analysis of Energize Eastside" commissioned by Bellevue for reviewing the project. The result of their analysis is consistent with PSE's load forecasts and confirmed the need for the project.

To explain further, the data is split: Actuals in winter 2013-14 and Forecasted in winter 2014-15. You can see this more clearly in USE's report, page 33, Figure 6.19. Due to the split, PSE considers the graph you have attached for 2014 Customer Demand Forecast as a **Forecast**, and is labeled as such. To clarify further, actuals for 2013 and before are noted in USE's Report on page 33. It is the actual peak loadings of substations on the Eastside. The specific list of substations and their peak loadings is confidential.

I cannot emphasize enough, the Forecasted customer demand is what we are required to use in meeting our mandatory federal planning requirements. Your list of questions regarding electric system planning and customer demand forecast leads me to believe you misunderstand the regulatory requirements regarding how utilities study and plan electric power systems. You appear to be confusing the operation of the electric system with planning of the electric system. PSE is required to comply with mandatory planning standards, which includes planning to **Forecasted numbers**. Independently, PSE's electrical operations department operates the system on a day-to-day basis based on actual conditions and expected load levels.

Regarding your request for experts to see the data and results, this has been accomplished. Multiple experts in power system engineering and transmission planning have reviewed, studied and confirmed the need for this project. Five total studies have been completed, three of which were publically funded. USE, Bellevue's analyst, was one of those five and not only reviewed PSE's studies (as mentioned previously in this response) but also performed studies of their own which showed there was a clear need for the project, and even if you change some of the assumptions, there are still overloads. As previously stated, the Federal Energy Regulatory Commission (FERC), dismissed your complaint and determined that PSE complied with the mandatory federal requirements in evaluating the Energize Eastside project. In short, the experts have reviewed the studies and confirmed that the project is needed.

I truly hope this provides some clarity for you.

Sincerely,

Jens

Jens Nedrud, P.E.
Senior Project Manager
PUGET SOUND ENERGY
PO Box 97034, EST03W, Bellevue, WA 98009
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The Energize Eastside project is undergoing environmental review, which includes preparation of a Washington State Environmental Policy Act (SEPA) Environmental Impact Statement (EIS). The City of Bellevue is leading the EIS process in cooperation with Kirkland, Newcastle, Redmond and Renton. For more information on the EIS, please visit **EnergizeEastsideEIS.org**.

Please note: Inquiries made to Puget Sound Energy will not be included as part of the EIS process.

From: Don Marsh [mailto:don.m.marsh@hotmail.com]
Sent: Tuesday, January 26, 2016 10:11 AM
To: Nedrud, Jens V; Pravitz, Keri
Cc: council@bellevuewa.gov; BMiyake@bellevuewa.gov; MKBerens@bellevuewa.gov
Subject: RE: Two questions regarding Eastside need

Dear Jens,

Your reply did not answer our specific questions.

We are asking to what extent the system capacity line is determined by the ratings of the two operational transformers. We are also asking what the **2014** customer demand value is based on: loads on the remaining two 230 kV transformers or the summation of loads on substation transformers?

The answers to these questions are not contained in your previous replies or the studies you mentioned. Bellevue's analyst, USE, performed a load flow study that showed four of the five overloads identified in the Quanta study were eliminated if 1,500 MW of energy transmitted to Canada were removed from the study assumptions. Other than that interesting finding, USE only examined the *process* used to produce the Eastside Needs Assessment, not the underlying *data*. Stantec performed no independent analysis of the data, but again rubber-stamped the process.

The questions we ask are practically the most basic questions that one can ask about this graph. They should not be hard to answer.

The ratepayers who will pay nearly a billion dollars for this project over the next 40 years deserve to understand the case you are making for the need. If you believe the data and the methodology are too complex for us to understand, you must allow our experts to verify that.

Please respond more precisely or grant our experts clearance to see your data.

Sincerely,
Don Marsh

From: Nedrud, Jens V [mailto:jens.nedrud@pse.com]
Sent: Monday, January 25, 2016 12:43 PM
To: 'Don Marsh'; Pravitz, Keri
Cc: council@bellevuewa.gov; BMiyake@bellevuewa.gov; MKBerens@bellevuewa.gov
Subject: RE: Two questions regarding Eastside need

Don,
Perfect timing, I was just hitting send on my response. Regarding your latest inquiry, our team has provided responses to these same questions for you in the past; the answers have not changed.

As we previously told you, the "system capacity" or "level of concern" shown on the graph relates to system performance primarily under N-1-1 or N-2 conditions as required as part of the federal mandates. The N-1-1 and N-2 system capacity level is dependent on system conditions and system topology as it is anticipated to exist at the time of modeled contingencies. This is explained in the Needs Assessment. The usage data appropriate to producing a valid electric load forecast is incorporated, along with all other appropriate forecasting data, in the PSE load forecast. The same data has been reviewed by Bellevue's consultant U.S.E. as part of the "Independent Technical Analysis of Energize Eastside" commissioned by Bellevue for reviewing the project. The result of their analysis is consistent with PSE's load forecasts and confirmed the need for the project.

And, as we have previously advised you many times, the customer demand you ask about is "Customer Demand Forecast." PSE's corporate load forecast process has been performed for many years and the results have served PSE customers well. As we have discussed before, the process utilizes historic data and the latest information available at the time as well as captures achievable conservation potential. Growth data used in the studies were primarily provided by third party agencies, such as the PSRC and Eastside jurisdictions. PSE's studies are conducted pursuant to mandatory federal regulations with the assistance of nationally recognized system planning experts using industry established study protocols. As you also may know, the Federal Energy Regulatory Commission confirmed this in its ruling in dismissing CENSE's complaint and stating PSE complied with the transmission planning responsibilities in proposing and evaluating the Energize Eastside Project.

The need for Energize Eastside has not changed; the need is driven by PSE's responsibility to comply with federal rules. Five studies have been completed – two by PSE and three by independent consultants – that all confirm the need for the Energize Eastside project.

Respectfully,

Jens

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The Energize Eastside project is undergoing environmental review, which includes preparation of a Washington State Environmental Policy Act (SEPA) Environmental Impact Statement (EIS). The City of Bellevue is leading the EIS process in cooperation with Kirkland, Newcastle, Redmond and Renton. For more information on the EIS, please visit **EnergizeEastsideEIS.org**.

Please note: Inquiries made to Puget Sound Energy will not be included as part of the EIS process.

From: Don Marsh [mailto:don.m.marsh@hotmail.com]
Sent: Monday, January 25, 2016 12:39 PM
To: Nedrud, Jens V; Pravitz, Keri
Cc: council@bellevuewa.gov; BMiyake@bellevuewa.gov; MKBerens@bellevuewa.gov
Subject: RE: Two questions regarding Eastside need

Dear Jens and Energize Eastside team,
Seven days ago, I sent you two basic questions about a graph showing the Eastside Customer Demand Forecast. This is the graph PSE has been used to illustrate the need for Energize Eastside for the past two years. It still appears on the Energize Eastsidewebsite today: http://www.energizeeastside.com/need.
I am puzzled why I haven't received a response. No acknowledgment of my email. No estimate of when you will provide answers. Just silence.
Since this graph is fundamental to our understanding of the project need, it is important for people to know what they're looking at. We need a level of transparency and critical review that has not yet happened. We have asked PSE to allow well-qualified industry experts engaged by CENSE to examine your data and verify that the need exists. Only then can we be satisfied that this project (or a less expensive, less damaging alternative) benefits the Eastside.
Sincerely,
Don Marsh, President
CENSE.org

From: Don Marsh [mailto:don.m.marsh@hotmail.com]
Sent: Monday, January 18, 2016 8:49 AM
To: 'Nedrud, Jens V'; 'Pravitz, Keri'
Cc: council@bellevuewa.gov; BMiyake@bellevuewa.gov; MKBerens@bellevuewa.gov
Subject: Two questions regarding Eastside need

Dear Jens and Energize Eastside team,
In preparation for the release of the Draft EIS later this week, we have two basic questions regarding the Eastside Customer Demand Forecast. I am copying council members and the city manager on this email, so we can all appreciate the timeliness and thoroughness of your response.
Our first question is about the "System Capacity" line shown at approximately 700 MW in this graph:

Is this capacity determined by adding the capacities of the two 230/115 kV transformers that would serve the Eastside in the event of an N-1-1 outage of the other two transformers?
Our second question is about the "Customer Demand" level shown at approximately 580 MW in 2014. Is this number based on a measurement of the demand on the two transformers calculated by a load flow simulation of the N-1-1 contingency? Or is it the summation of loads on individual Eastside substations? If so, which substations were included in this summation? Were those loads measured on a particular date, or calculated as a peak or average of some number of samples?
We seek timely answers to these questions of methodology because we have a limited time to comment on the Draft EIS after it is issued this week. As you know, this phase of the EIS establishes the need for

the project and the viability and desirability of project alternatives. Transparent information is needed so that all stakeholders can be sure we are appropriately addressing our need for reliable power and properly evaluating solutions that maximize cost effectiveness and environmental responsibility.

Sincerely,

Don Marsh, President
CENSE.org

From: John Merrill [mailto:john@merrillimages.com]
Sent: Monday, March 14, 2016 6:58 PM
To: Energize Eastside EIS <info@energizeeastsideeis.org>
Cc: Don Marsh <donmarsh@cense.org>; John Merrill <john@merrillimages.com>
Subject: DEIS Comments by John Merrill of CENSE

Dear Ms. Bedwell,

My comments on the DEIS for Energize Eastside are attached. It is just before 7 pm on Monday March 14, 2016. Please reply to this email to acknowledge receipt of my comments prior to the midnight deadline for DEIS comments.

Thank you for your efforts and this opportunity to comment.

John Merrill
CENSE Board Member

John Merrill DEIS Comments re Puget Sound Energy Proposed Eastside Transmission Lines

March 14, 2016

Thank you for this opportunity to comment on an issue that is very high stakes for the future of the Eastside. I am a member of the Coalition of Eastside Neighborhoods for Sensible Energy (CENSE.org) and live at 4800 134th Place SE in Bellevue. My comments extend to all members of CENSE.

CENSE's Vision

CENSE envisions an Eastside energy future that embraces our community's values rather than clinging to an outdated alternative of the past which is not aligned with our values. The Eastside can and should be a leader in implementing modern energy solutions that reflect our high-tech community, reinforce the livability of our neighborhoods, are safe and reliable and enhance our environment. These values make the Eastside a wonderful place to live and work and provide our business community with a competitive advantage to recruit and retain the best employees. The Eastside gets so many growth issues right; we can also have a bright energy future aligned with our values.

High Level Comparison of Alternatives 2 and 1A

Alternative/Choice Criteria	**Alternative 2: Integrated Resources ***	**Alternative 1A – Proposed Overhead Lines**
Desirability as place to work/live	Enhances community attractiveness	Degrades the attractiveness of our community
Technology	Uses modern technologies aligned with our high-tech community values	Uses outdated "dinosaur technology"
Reliability	Proven in communities across the U.S.	Exceeds Federal industry standard requirements
Safety	Safe	Increases risk of catastrophic fire for 18 miles
Environmental Impact	Benign *	Significant negative impacts

Appropriate size	Incremental capacity increases over time	Grossly oversized
Alignment	Aligned with community values	Unaligned
	***- With modifications (explained below)**	

General Comments on the DEIS:

- We now have new information provided by Lauckhart and Schffman, two unassailably qualified experts in determining the timing for and quantity of need for new electrical infrastructure, which shows the Eastside has ample time to plan for and incrementally implement forward-thinking solutions to the Eastside's energy future rather than rushing into an inferior solution which has much greater impacts.
- The DEIS asserts that the need for Alternative 1A is justified because PSE used the industry standard methodology for determining need. This is false. Alternative 1A greatly exceeds the industry standard. It goes far beyond Federal minimum requirements which are the industry standard. It greatly exceeds the industry standard test of reliability by imposing not only the industry standard Federal N-1-1 outage criteria but further burdens the system with additional equipment outages, lower than standard component capacities and a significantly increased flow of power to non-Eastside customers, among other stressors.
- The Lauckhart Schiffman study shows unequivocally that the timing for and amount of need is not established. The EIS process must be corrected for this fundamental deficiency. Until such time as the timing for and amount of need is established through a transparent, fair and accurate process, the basis for the DEIS as written is invalid and any conclusions of the EIS process are, unfortunately, invalid.
- Puget Sound Energy's (PSE) 19 criteria listed in Chapter 2 are un-vetted by any unbiased and expert authority on the provision of a reliable supply of electricity to power the growth of the Eastside. PSE's assertion, for instance, that any selected alternative must be implementable by a 2018 timeframe is simply untrue and unnecessary. (Although Alternative 2 could do so.) <u>PSE's project criteria, along with the way that Alternatives 2 and 3 are characterized, appear purposely designed to preclude serious consideration of more aligned solutions to the Eastside's actual needs.</u> The argument that the Lead Agency or EIS Consultant has no responsibility to question the proponent's specifications of need and the project criteria of acceptable alternatives is highly questionable. If for instance, PSE proposed to build an above ground 500kV transmission line through downtown Bellevue which required a 200 foot wide right of way through the Downtown Park and the demolition of 20 high-rise buildings, the City of Bellevue as lead agency would certainly both seriously question the need as well as acceptable criteria for alternatives. The bias toward the proponent's preferred alternative shown by the Lead Agency's blind acceptance of PSE's definition of need and 19 project criteria, tragically, makes a mockery of the entire EIS process and further invalidates its conclusions.
- The lead agency has put the EIS team in a very difficult position by instructing the EIS team to proceed as if the timing for and quantity of need were credibly established. The City of Bellevue as lead agency must change the EIS process to credibly establish both the timing for and quantity of need before any EIS analysis can be considered valid. Unfortunately, at least some of

the large amount of work that the EIS consultant team has obviously put into the Phase 1 DEIS will likely need to be redone when the timing of and quantity of need is accurately established.

- The definition, characterization and analysis of Alternative 2 is inaccurate, outdated and biased. For instance, to insist that 3 small peaking plants are a necessary component rather than one larger one or none at all and the inclusion of such a large battery storage facility both show either ignorance about these types facilities or willful bias against Alternative 2. Alternative 2, or a new Alternative, must be corrected by an expert in the field of 21st Century grid solutions to reflect both expertise in this relatively new field and up to date information. Alternative 2, or a new Alternative, should be changed to reflect recommendations of a consultant like EQL Energy which has relevant expertise and experience with 21st Century grid solutions that is not yet represented on the EIS team.
- A modified Alternative 2, or a new alternative, which reflects best practices in the implementation of 21st Century grid solutions, would both satisfy the need, even that which is used as the basis for the Phase 1 DEIS, and have the lowest environmental impacts of any alternative (perhaps other than no action). The Lauckhart Schiffman study shows unequivocally that the Eastside has time to incrementally implement forward-thinking solutions to the Eastside's energy future rather than implementing an oversized, outdated technology which has far greater impacts.
- The lack of a permit application with a specific design of Alternative 1A by the project proponent renders meaningful Phase 1 evaluation impossible. For instance, the absence of the locations of the proposed poles relative to the existing fuel pipelines makes evaluation of safety subject to so much uncertainty as to be meaningless. We also do not know with certainty whether or not PSE would remove the existing 115kV system under Alternative 1A and the high likelihood that the old lines will remain indefinitely are not assessed in the DEIS. The ultimate width of the right of way under Alternative 1A and the potentially huge number of homes that will have to be destroyed are likewise unknown and thus the devastating impacts of widening the right of way cannot be adequately analyzed. Thus the DEIS is premature and its conclusions further compromised. The lack of detailed analysis of these major impacts in a glaring deficiency that can only be remedied after the proponent provides detailed design specifications.
- The DEIS does not adequately assess the safety of co-locating Alternative 1A with hazardous liquid transport pipelines. Numerous experts warn against the proximity of these two conflicting right of way uses and the risks have not been identified properly let alone analyzed in detail. The DEIS says that current regulations regarding pipeline safety are adequate to protect adjacent homeowners and their families. This is inadequate given that pipeline explosions and fires happen regularly in the presence of pipeline safety rules and the existing rules are not well enforced. For instance, in 2010 Texas had rules designed to prevent catastrophic conflicts between fuels pipelines and electrical infrastructure which did not prevent the death of 3 workmen installing transmission line poles. The first responders could not get within ½ mile of the victims for over an hour because the heat from the flames was so intense. If this accident had occurred in a neighborhood like those on the Eastside adjacent to the route of Alternative 1A, hundreds of deaths would have resulted and the fire and police departments would have been helpless to prevent them.
- The DEIS all but ignores the fact that Alternative 1 would encourage the use of more electricity leading to more environmental impact both locally and elsewhere whereas a modified

Alternative 2 would decrease the use of electricity and reduce environmental impacts. Not evaluating the impacts of other pollutants from electricity production including acid gases, heavy metals and particulates is a glaring omission.

Other Alternatives: There are other and better alternatives which must be added to the Phase 1 analysis, including but not limited to:

- A modified Alternative 3 without miles of new wires. Relatively simple transformers additions and associated upgrades at Talbot Hill and/or Sammamish substations and possibly replacing existing conductors as needed would increase peak capacity by approximately 200MW. This would satisfy even PSE's exaggerated statement of need. It is also standard industry practice to run 230kV circuits on poles approximately the same height as the existing 115kV poles to replace one of the two existing circuits. In fact, PSE has such dual voltage circuits running side by side just north of Sammamish.
- A combination of pieces of a modified Alternative 3, as described above, and portions of Alternative 2 would best serve the Eastside's needs with the least impacts.
- PSE's 2015 Integrated Resource Plan shows that PSE plans to build several hundred MW of new gas-fired generation in Western Washington beginning in 2021. As stated above, the Lauckhart Schiffman report shows we have plenty of capacity until then. The addition of just 200 MW of additional capacity at 115kV would satisfy even PSE's exaggerated statement of local need.
- Flexible AC transmission system (FACTS) control devices – as described in the EQL paper attached would keep our existing 115kV system from overloading eliminating the need to supplement it for many years while still providing reliable service.

Comments on specific parts of the DEIS:

Chapter 1 Introduction and Summary

1.1 Alternative 1A is grossly oversized to serve even PSE's exaggerated estimate of need over the next several decades. PSE asserts that the need in the next 10 years is 133 MW (Section 1.3) and the longer term need is roughly 200 MW. (note this is an exaggeration of need given this estimate of need greatly exceeds industry standard criteria.) Yet the installation of a single new transformer, utilizing only 1 of 2 new circuits on Alternative 1A, would increase capacity by roughly 350 MW. Alternative 1A could easily double increased capacity to 700 MW by energizing the second circuit at 230kV and adding a 6th transformer to the system. That would increase peak capacity by 100%. The conductors PSE has specified for the 2 new circuits on Alternative 1A would actually support the addition of a total of 8 new like-sized transformers before the conductor capacity was exceeded. Thus Alternative 1A would actually increase peak capacity by approximately 400% if fully utilized. This is grossly out of scale with even PSE's exaggerated estimate of local need but greatly increases PSE's contribution to the capacity of the regional grid to serve non-local customers including Canada. Again, this is grossly out of scale with local need.
Table 1-2 Construction Impacts Comparison shows that the DEIS concludes that Alternative 1A (Alt 1A) has negligible or minor impacts on Earth, Green House Gas Emissions, Plants and Animals, Energy and Natural Resources, Environmental Health, Land Use and Housing, and Views and Visual Resources. This is a gross understatement of the actual impacts. All these categories should show Significant Impacts for

Alt 1A. To say that the impacts of Alt 1A is equal to the impacts of No Action or Alt 2 does not pass the common sense test. For instance, it is makes no sense to equate the Earth impact of 18 miles of heavy construction to the impact of Alt 2 if Alt 2 is correctly characterized without peaker plants.

1.3 The Stantec memorandum, which purportedly supports PSE's assertion of need, is not included in the DEIS as advertised. This memo is apparently an important basis of the DEIS determination of need. Without the opportunity to review and verify this memo, it is impossible for reviewers of the DEIS to concur. In the absence of this memo, the need cannot be determined to be established. By not including this memo, the DEIS reinforces the impression that the review team is biased toward the proponents preferred alternative.

The electrical load growth rate of 2.4% per year used by PSE in its determination of need appears highly exaggerated. PSE and the DEIS state that it is based upon 3 factors: a population increase of 1.2 % per year, an employment increase of 2.1 percent per year and the addition of "block loads" from proposed construction projects. The population increase rate is based on a credible, independent forecast from the Puget Sound Regional Council, however, the job growth rate forecast was done by PSE and lacks transparency and thus credibility. Moreover, including "block loads" double counts both the effects of population and employment growth depending on whether the block loads are residential or office buildings. To be credible, the methodology must be transparent and independently verified by experts.

The largest fallacy in the load growth rate projection, however, is the completely unsupported assertion that lower growth rates in both population and job growth could somehow increase electricity use at a greater rate than either of them. This flies in the face of common sense when one understands that peak per capita electricity use, both at home and at work is falling - largely because energy conservation, such as switching to LED bulbs, greater use of energy efficient home appliances and increasing use of lower power computers and office equipment. More and more homeowners and businesses are also switching from electric space heat furnaces and electric hot water heaters as the price of natural gas continues at historic lows. PSE's assertion that peak electricity use is growing twice as fast as population and faster than employment growth has no rational basis and must be independently vetted before it can be used to justify the need for any alternative in the EIS.

1.6 Paragraph 3 is totally disingenuous in that it implies that only Alternative 1 meets PSE's 19 project criteria as Alternatives 2 and 3 only "address the objectives sufficiently enough to be reasonable for consideration" in Phase 1 of the DEIS, but by inference not in Phase 2. This reinforces the conclusion that the DEIS is designed to support only PSE's proposal and eliminate all other alternatives. This does not serve the intent or purpose of an EIS when there in fact are other viable alternatives.

1.12.1 PSE's need evaluation process has NOT been conducted according to industry standards. The evaluation criteria used by PSE and its consultants greatly exceed the standards required by NERC and WECC and are not standard in the industry. The load flow simulations run by PSE and subsequently by its consultants and Utility Systems Efficiencies go well beyond federal and regional reliability requirements which are the industry norm. For instance, PSE's and its consultants load flow studies simulate not just the required N-1-1 situation, which is the industry standard wherein two critical pieces of equipment fail sequentially during a rare peak demand event as required by NERC and WECC. The PSE studies go far beyond the requirement by taking another approximately 8 pieces of critical equipment (Western Washington gas-fired generators, some of which are "peaking plants" designed and built specifically to run during peak demand hours) offline IN ADDITION TO the required and industry standard N-1-1 equipment outages. In addition to this non-industry-standard simulation of a highly unrealistic "N-1-1-8" event, PSE and its consultants further stress an already highly compromised system by subjecting it to a huge flow of power to Canada. (There is no firm contract to deliver power to Canada during a peak demand event on the Eastside and PSE has not produced any evidence that there is such an obligation.) The simulation of an N-1-1-8 event, with or without the added stress of enormous power flows to Canada, is not "in accordance with industry standards for utility planning" as asserted in the DEIS. In its load flow modelling, PSE apparently also incorrectly used summer ratings for the remaining operating transformers during the winter peak event simulation. This yet further stresses the system reducing its ability to adequately handle load. Thus the need for any alternative, other than no action, is not yet established. The need must be transparently established in accordance with industry standard practices (i.e., based on NERC and WECC minimum requirements of an N-1-1 event during peak demand hours alone) without additional, non-standard stresses modeled on the system before the Phase II DEIS scoping can proceed.

Chapter 4 Greenhouse Gas Emissions

Alternatives 1 A, C and D would have a very significant impact on GHG emissions (GHGs). With regard to construction, the metal extraction from the earth, transportation of ore, manufacture of metal, fabrication of metal, and shipping of the rebar, conductors and towers would emit significant quantities of Scope 1, 2 and 3 emissions as well as the installation.

With regard to operation, the DEIS ignores the relationship between the production of electricity using carbon-intensive fuels and the construction of Alt 1. Alt 1 encourages the use of both local and distant carbon-intensive generation plants like Colstrip whereas Alt 2 would actually decrease the amount of electricity used from all sources. Alt 1A is an enabler of PSE’s plans, as documented in its 2015 Integrated Resource Plan, to build hundreds of megawatts of new gas-fired, carbon intensive generators beginning in 2021 and prolong the life of Colstrip. For instance, without the construction of an Alt 1, which would be treated as a sunk cost in an economic analysis of new gas-fired generators, new gas-fired generators would not be built because they would not be a least cost source of power. Colstrip might even be shut down sooner if Alt 1 is not implemented. Simply put, if these fossil fuel-fired plants were burdened with the cost of transmission, they would not be built or their life extended. Thus the impacts of any of the Alt 1 options must account for the increase in electricity use they enable. The amount of new or existing carbon intensive generation capacity they enable is at least 1000 MW. 1000MW capacity is the difference between the 1500 MW of Canadian flow in the PSE load flow studies used to justify the need for Alt 1 and the 500 MW of Canadian flow in the PSE base case and Lauckhart Schiffman studies.

4.5.3.1.2 The implicit assertion that only the production of concrete and not the production of steel, aluminum and other metals does not produce GHGs in significant quantities is simply wrong. The extraction and production of metals is extremely energy intensive and produces huge quantities of GHGs. <u>To include the impacts of production of battery storage components under 4.5.4.4.2 but not the impacts of production of components of Alt 1 shows bias for Alt 1 and must be corrected.</u>

Ignoring the significant production of GHGs from these activities directly caused by Alt 1A biases the analysis against Alternative 2, which absent peaker plant which are not needed in an effective Integrated Resource solution, produce little to no GHGs.

4.5.3.1.3 In general, the use of the State quantitative criteria for determining GHG impacts is inadequate and misleading given the negligible impacts from a corrected Alt 2 which does not require peaker plants and only small storage amounts. Alt 2 can and should rely primarily on energy efficiency, conservation, demand side management and non-impactful distributed energy resources. The DEIS analysis and results imply that the impacts of Alt 2 are somehow in the same ballpark as the other alternatives, especially Alt 1A, which is entirely biased and misleading.

The statement that 44 acres of forested land “under a worst case scenario” would be deforested is not adequately supported. First it is less than half of the roughly 110 acres that would have to be added to the 100 foot right of way for expansion by 50 feet. Second, the assertion that the expansion would have to be only 50 feet is not adequately supported elsewhere in the EIS. The actual expansion required may be 100 feet or more in order to provide adequate separation of Alt 1A and the two high-pressure fuel lines as well as the 115kV lines in the existing right of way. The described impacts are not worst case.

4.6.4.4 No peaking capacity is needed for Alt 2 to satisfy the need, even though PSE’s quantification of need is overstated. It is misleading to included peaking plants in Alt 2 in the first place, let alone to include a moderate impact “warranting mitigation” to color people’s impression of Alt 2.

4.9 The conclusion that none of the alternatives would significantly impact GHG emissions, as stated above, ignores the cause-effect relationship between Alt 1 and the generation of more carbon fuel-generated electricity as well as the construction of up to 1000 MW of new carbon intensive generation capacity. This is a glaring defect in the analysis and must be corrected by experts who understand these relationships and their consequences for GHGs and other impacts.

Chapter 7 Energy and Natural Resources

The assertion in the side bar in 7.1 that Alt 2 would lead to Eastside generation of non-renewable power rests on the faulty characterization of Alt 2. Alt 2 does not require new Eastside peaking capacity to be an effective solution to even PSE’s exaggerated quantification of need. Moreover, if Alt 1 is built, fossil fuels will be burned and water consumed and contaminated somewhere else to satisfy the increased demand for electricity it enables and it is wrong to ignore distant impacts. The impacts of PSE’s Colstrip plant for instance are ignored. The fact remains that Alt 2 would reduce demand for energy and Alt 1 would significantly increase both capacity of and demand for electrical energy.

7.6.3 and 7.6.4 Again, the assertion that Alt 1A would not lead to additional need for new power generation or additional use of resources is not supported and ignores the cause-effect relationship between the construction of transmission and the construction of new and increased use of existing resource-intensive generators. This relationship must be adequately analyzed by experts who understand these relationships and their consequences. Alt 1 would enable the construction of up to 1000MW of new generation and the attendant energy resource use impacts.

Chapter 10

10.7.3.1.2 Alt 1A does not comply with King County, Redmond and Kirkland policies or regulations that specifically prohibit co-locating new or expanded transmission lines with hazardous material pipelines. The reasons for this prohibition should be analyzed and an in-depth assessment of risk to neighboring communities included in the DEIS. The feasibility of Alt 1A is questionable given these regulations.

10.7.3.1.1 The DEIS states that Alternative 1A could require up to 327 acres of housing, businesses and other land uses to be condemned and demolished for use as a utility corridor. It also states that at a minimum an additional 50 feet width of adjacent property would have to be added to the existing right of way. This would be an additional approximately 109 acres of housing and businesses that would have to be cleared of structures and trees. This analysis likely underestimates the amount of land required because it does not contain an analysis of how far away from the hazardous material pipelines the new lines must be built. If either of the two pipelines in the existing right of way are near the edge of the existing right of way, the proposed transmission lines in Alt 1A would, to be safe, have to be located at least 50 feet away. And to that 50 feet another 50 or so feet would have to be cleared of houses and other structures in order to maintain sufficient clearance from the new power lines. The current analysis is also inadequate because it does not include a discussion of the number of homes, businesses, other structures and trees which would have to be torn or cut down. For instance, if the average housing lot size along the right of way is 1/3 of an acre, the addition of 109 acres of additional right of way could require the condemnation and removal of up to 327 homes which is equivalent to every home located on one side or the other of the existing right of way. To obscure this impact in the fine print of such a long document and to label the impact of this amount of dislocation and trauma to the communities along the right of way anything less than beyond significant is untruthful and disingenuous at best.

10.7.1.4 The cost discussion and analysis provided is totally inadequate because it relies entirely on only one out-of-date study which may or may not be relevant to property values in this particular location. The analysis contains no evidence that the study is applicable to the Eastside. Real estate values are widely known to depend on location, location, location yet the analysis makes no attempt to enlist the knowledge and expertise of local real estate experts. This must be done, otherwise the analysis is inadequate.

Documents Incorporated By Reference

1. Lauckhart Schiffman Load Flow Study
2. The Best Alternative document by EQL Energy
3. Alternatives To Energize Eastside by EQL Energy
4. Grow Eastside Smart Transmission Project Local Economic Study Request Oct 31, 2015 (Flexible AC transmission system (FACTS) control devices) by EQL Energy

From: Loretta Lopez
Sent: Monday, March 14, 2016 8:23 PM
To: 'HBedwell@bellevuewa.gov'; 'info@EnergizeEastsideEIS.org'
Subject: Comments to DEIS PROPOSED PSE Project/January 28 DEIS/City review of process

The DEIS states that the purpose of this EIS is not to determine whether the project is needed, but to confirm that the methods used to define the need are consistent with industry standards and generally accepted methods. After determining that PSE's evaluation process has been conducted according to industry standards, the lead agency and the partner cities… Section 1.12.1, page 1-56.

Does this statement mean that the Cities only reviewed the process but not the actual data? And if the data was reviewed who reviewed it? The City of Bellevue does not have anyone on its staff who has the technical expertise to review the data.

The DEIS continues and states that the Cities have worked to understand the nature of the need that PSE has identified and to look broadly at the possible alternatives that could address the need. Section 1.12.1, page 1-56.

The citizens also want to understand the nature of the need in order to review alternatives. The City of Bellevue, as the lead agency, has refused to allow the citizens the ability to understand the need.

I request that the City of Bellevue, as lead agency, facilitate and require the release of information from PSE. The City continues to assert that PSE is a private company and it (City) cannot regulate PSE. PSE plans to use our community to build the lines it chooses. It is unacceptable that PSE could possibly do so without questions. The City staff is not asking questions so the citizens must.

What is the source of authority that the City of Bellevue has no authority to require PSE to answer questions about it assertion of need?

Loretta Lopez

13419 NE 33rd Lane
Bellevue Wa 98005

Bridle Trails Community Club, Vice President

CENSE Member

From: Loretta Lopez
Sent: Monday, March 14, 2016 8:05 PM
To: 'HBedwell@bellevuewa.gov'; 'info@EnergizeEastsideEIS.org'
Subject: Comments to DEIS PROPOSED PSE Project/January 28 DEIS/NW 7th Power Plan

The DEIS states that PSE has determined that there is a deficiency in electrical transmission capacity and that the PSE proposed project of building 18 miles of 230KV transmission lines is the solution. Page 1-1

The City and PSE refuse to acknowledge that that growth and demand will not be as great at PSE asserts.

Recently, the Northwest's official power planning agency – the Northwest Power and Conservation Council -- conducts a fresh assessment of the region's long-term electricity needs and issues a blueprint for meeting them. This year the Council released the 7th Northwest Power Plan https://www.nwcouncil.org/energy/powerplan/7/home/

This plan establishes that the need for power can be met with a combination of demand response, conservation, new technology.

Loretta Lopez

13419 NE 33rd Lane
Bellevue Wa 98005

Bridle Trails Community Club, Vice President

CENSE Member

From: Loretta Lopez
Sent: Monday, March 14, 2016 8:33 PM
To: 'HBedwell@bellevuewa.gov'; 'info@EnergizeEastsideEIS.org'
Subject: Comments to DEIS PROPOSED PSE Project/January 28 DEIS/Findings

The DEIS states the findings from this Phase 1 Draft EIS will and comments received on it will be used to help outline proposed alternatives for inclusion in the Phase 2 (project level) Draft EIS. Section 1.13 page 1-57.

What if citizens do not agree with the findings that will be issued after Phase 1? What remedy does the community have to take issue with the findings?

Loretta Lopez

13419 NE 33rd Lane
Bellevue Wa 98005

Bridle Trails Community Club, Vice President

CENSE Member

February 2 2016 Newcastle City Council and Planning Commission meeting.

Council members, commissioners, staff thank you good evening my name is mark Williamson I'm a utility consultant for Madison Wisconsin and I represent Puget Sound energy. I'm working on their energized Eastside Project, before I retired and went into consulting I was executive vice president of Madison Gas &Electric Company a company not much different than Puget Sound in the Wisconsin area where I ran generation transmission gas operations, for a little over thirty years. So I have a little perspective on what I'd like to talk about tonight which is pipeline safety and high voltage transmission lines. You heard a little bit at the planning commission last week, my perspective is quite a bit different based on this is my 89th high voltage transmission project and like I say 30 years in the industry. First of all we should all remember that there are significant Federal standards that guide us both on pipeline work and on high voltage electric work. Those standards specify how pipelines have to operate with great detail including their safety procedures testing their pipes to make sure aging has worn them so that their safe, solid, and secure for all of us. They also guide different regulations guide how we do high voltage electric transmission. Those regulations also are very strict and require that we make sure that we can keep the lights on a very safe and secure way. A final set of regulations guides the interaction and those interactions are common in the United States. I myself have collocated several 100 miles of extra high voltage transmission with pipelines. You've experienced it here actually in Newcastle around a corridor that shared between high pressure petroleum pipelines and high voltage electric the corridor that the 115 KV lines in the Olympic now BP pipeline runs through. So you've all experienced that and the interaction because of the diligence of the companies. Both utilities safety is a high priority that's common across the country. You've had a safe and decent interaction for almost 50 years on what's going on. So it's not unusual to see these facilities put in the same place. In fact, it's a policy matter many communities and in fact many states required the colocation of utility facilities both gas and electric. The key is the companies have to work together to maintain safety. There's a strong interaction between pipelines and Electric Utilities both as a physical matter and as an operating matter and the fact that you manage to get through 50 years without a problem is not unusual. That's the norm in North America. We don't have a lot of accidents and especially in collocated facilities because you have to two set of people from different companies keeping an eye on those facilities. So you get sort of a double down when you actually collocate which is one of the reasons many states mandate that we put facilities together. The next thing that we ought to think about is that those regulations and how some of that interacts have been set pretty in in pretty good detail in a lot of depth in the draft EIS you all commissioned for the energize project. There's a chapter dedicated to the safe interaction of pipelines and high voltage transmission lines. And the reason is because people take those responsibilities seriously and that's why it's been working for so long. Um the thing that you need to do to make this work is to actually have good engineering studies that make sure that the pipeline is protected and transmission facilities are protected. Now I saw on the transcript that you heard some things last week that there are some prohibitions about locating facilities within several feet of each other. I think somebody quoted the Bonneville power standards that you need 50 feet between a pipeline and transmission line. If you actually read the standard which is available online, they say that if you are more than 50 feet from a lattice tower or more than 25 feet from a single monopole which is what's being contemplated here, you don't need to do any engineering studies that's far enough that you can just be laissez-faire and let it go. Everything else that's closer and most facilities in this country are much closer require good coordination and studies between the utility company that has electricity and the one that runs the pipeline so you're sure those interactions don't adversely affect either facility. We all do this commonly and as I say you had experience with its been working here quite well for many many decades. On the last thing I think I want to point out is the draft EIS also talks about this new construction is actually more rigidly control than old construction. So any new facilities that are built in that corridor will actually be built to higher safety standards than what you have existing. And that's going to give you an improvement. I heard some things from the transcript that people are concerned about construction methods which is legitimate. They should be concerned. But we do this every day in this country by specialists who make sure we know where the pipe is. We know where the hole is. We know what kind of soil we have. We know what kind of weight that can bear. These these things are done routinely and I understand that it's new for people but but it's very interesting to me, coming from the outside. Most of these discussions occur in new corridors. You guys have actually had this with much older equipment that's been carefully maintained for 50 years and every indication is that new construction actually gives you benefits. So those were the seeds I wanted to plant. ... told me to take a minute and a half. I think I took two so I'd be happy to answer any questions otherwise that's it. ...

... Washington doesn't have a lot of collocation requirements. You guys have a very unusual regulatory system here. Your state system's much looser which is why community councils get to make decisions on infrastructure location. Most states have a statewide system. Washington doesn't have a strong collocation policy. But it's a little unusual that way. ....

(...how many states require collocation?...)

I'm not precise in this but I know I've work in about half the states as in this country and most of the Canadian Provinces for for that happens about 2/3 yes, 1/3

Speaker #34 Public Hearing phase 1
DEIS Bellevue 3.1.16
Steve Odonell

Hi David,

I would like to offer my sincere thanks and appreciation for inviting us to your Olympus Homeowners Association meeting on Monday, February 24. It is a rarity when people have the opportunity to gather together and communicate their differences face to face. It was an opportunity for us to learn about our shared concerns over the future projects in Newcastle. As a follow-up to the meeting, I would like to recap some of the highlights that Mr. Ed Cimaroli, Vice President of Olympic Pipe Line Company discussed.

Olympic has two pipelines that run approximately the entire length of segments C, E, J, and M in a shared easement within Puget Sound Energy's electric transmission corridor. The location of the pipelines may be found anywhere within the easement from the center of the Right-Of-Way to either side and can run together or separate.

The route selection will be our prime concern for a variety of reasons including safety, impact to landowners, future maintenance, and customer impacts to name just a few. Therefore we feel that segments B, F, H, and L best address the concerns mentioned above.

Should the pipeline be required to relocate, the pipeline design and precise impacts cannot be determined until PSE selects a final route and develop a final design. The schedule and timeline are also dependent on the route selection and as a recent example, a pipeline reroute was required because of the city of Bellevue's culvert relocation project at Coal Creek. It took over four years from conception to construction completion and involved many hours of working with property owners, permitting through wetlands and parks before we could complete the project. It is important to note that anytime a permit is required there can be a reiteration of the design before the final design can be created which can push out the project schedule.

Unfortunately we were running out of time at the end of the meeting and I wanted to mention that a source for locating pipelines in the state of Washington can be found at the Washington Utilities and Transportation, Pipeline Safety map website at:http://www.utc.wa.gov/regulatedIndustries/transportation/pipeline/Pages/pipelineMaps.aspx

Hopefully this email will be the first step in a process to work toward a project of mutual concern. Again, I would like to thank you for extending an invitation for us to hear your Homeowner's concerns. Please feel free to forward these discussion points forward to whomever you feel would benefit from knowing more about the Olympic Pipeline. I look forward to working together on this project.

Kindest regards,

Kim

Kim L. West,
Area Maintenance Engineer

BP Pipelines and Logistics (North America) Inc.
Operating Agent for Olympic Pipeline Co.
600 SW 39th ST, Suite 275
Renton, WA 98057
Office: 425-981-2541
Cell: 425-864-1315
No Accidents, No Harm to People, No Damage to the Environment

Energize Eastside: An Environmental Disaster Waiting to Happen

Puget Sound Energy is planning to install a 230kV high-voltage transmission line, “Energize Eastside”, on 12-story tall (130ft) mono-poles along an 18-mile residential corridor that traverses Renton, Newcastle, Bellevue, Redmond, and Kirkland. To put that into perspective, the photo below shows the size of the base of these poles:

What’s involved in building a 230kV high-voltage transmission line? Photos are worth a thousand words. The photos below provide insight into the size and amount of equipment needed to install these 12-story mono-poles. This heavy equipment will be rolling over the top of TWO high pressure gas pipelines. Notice in the photos below, *<u>there are no houses within miles</u>*. Energize Eastside will be installed through dense residential neighborhoods with homes in close proximity on both sides of the corridor:


7-7000
BINGGELI


CAT


CAT

The link below provides more details describing the effort required to install a 230kV high-voltage transmission line:

https://www.youtube.com/watch?v=WSV3L481mow

What Does the Proposed Corridor for Energize Eastside Look Like?

Here's a look at the existing narrow corridor, through Newcastle, Somerset, College Hill, and Bridle Trails - residential neighborhoods with houses in close proximity on both sides of a corridor that already contains a 115kV line as well as **TWO** gas pipelines (Olympic Gas Pipeline and a Boeing high pressure jet fuel pipeline running from Cherry Point to Seatac Airport). Note that houses are within a short distance on both sides.


WARNING
PETROLEUM
PIPELINE
PLEASE CALL
OLYMPIC PIPE LINE CO.

The link below provides an excellent summary of the Olympic Gas Pipeline accident in Bellingham in 1999. That accident was triggered by a faulty pipeline valve that exerted pressure on a portion of the pipeline that was clipped by a backhoe during earlier excavation near the pipeline.

https://www.youtube.com/watch?v=AJRwePrctGw

And finally, the link below is an example of a gas pipeline explosion that occurred during the installation of a high-voltage transmission power line in rural Texas in 2010:

https://www.youtube.com/watch?v=RSCz-35M9hA

The San Bruno, CA gas pipeline explosion occurred in 2010 as the result of flawed record keeping, shoddy maintenance, and lax oversight by a regulatory agency "disturbing close to a utility it was supposed to oversee":

http://www.mercurynews.com/business/ci_27880159/san-bruno-pg-e-faces-record-penalty-punishment

Puget Sound Energy has had its own experience with filing fraudulent gas pipeline records:

http://www.seattletimes.com/seattle-news/puget-sound-energy-to-pay-125-million-fine-for-falsifying-inspection-records/

What Can You Do?

1. Express your concerns during the Environmental Impact Study (EIS) now underway for "Energize Eastside". **Your comments are needed BEFORE JUNE 15, 2015**.

http://www.energizeeastsideeis.org/
David Pyle
Energize Eastside EIS Program Manager
Senior Land Use Planner
City of Bellevue
425-452-2973
info@EnergizeEastsideEIS.org

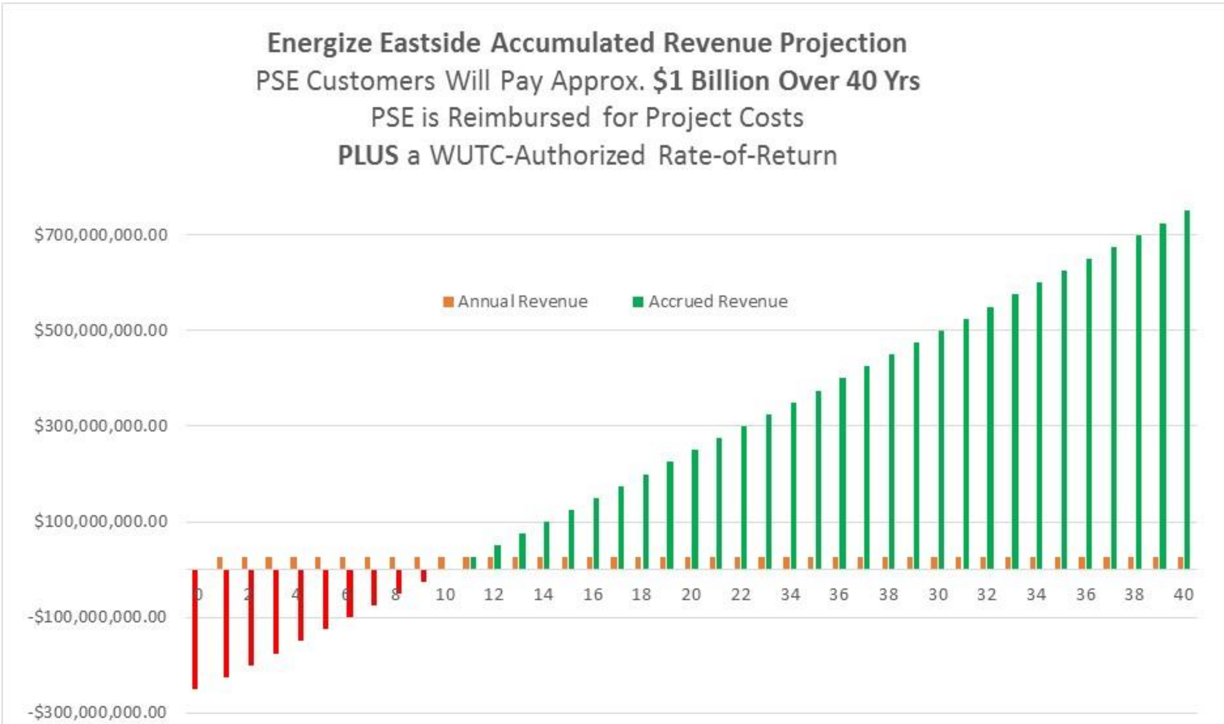
2. Contact your city, state, and federal representatives. Express your concerns about "Energize Eastside".

http://cense.org/email-the-key-stakeholders/

Need More Information?

www.CENSE.org

Why is Energize Eastside Important to PSE?



Energize Eastside is NOT a $250M project – PSE customers will pay over <u>$1 Billion</u>. PSE isn't just reimbursed for the cost of the project. PSE also gains a WUTC-authorized rate of return of about 10% annually for 40 years or more. Current weak WA state regulation actually REWARDS PSE for over-building infrastructure, so Investor-Owned Utilities, like PSE, engage in "gold-plating" infrastructure projects to qualify for higher rates of Return-On-Equity / Return-On-Assets.

The graph above is a conservative estimate. The final price tag of Energize Eastside is likely to be much higher, and likewise the costs to PSE customers will be much higher. The payout to PSE increases dramatically – the bigger the project, the bigger the payout to PSE.

Energize Eastside is the perfect investment for a pension fund and a hedge fund. The owners of PSE are the Canadian Pension Plan Investment Board (CPPIB) and Macquarie Infrastructure Partners (MIP), a 10-yr closed hedge fund. Projects like Energize Eastside offer a guaranteed, fixed, high rate-of-return for over a long term, usually 40 years or more. Energize Eastside poses minimal financial risk and offers a sustained guaranteed high return. Low risk, high reward - precisely the type of investment where we'd enjoy investing our own individual retirement portfolios, if only we could be so fortunate.

City of Bellevue, please RE-START a transparent process to determine the Eastside's future electricity needs. Please analyze and assess how to make measureable, meaningful improvements to the electricity grid for a fraction of the cost of Energize Eastside. Better alternatives have been identified that promote smart, sustainable growth and are more cost-effective, more scalable, more reliable, more energy-efficient, and less damaging to the environment. The Programmatic DEIS must include those alternatives. It is the City's fiduciary duty to its citizens to provide affordable, reliable electricity – not to be intimidated by an Investor-Owned Utility.

THE WALL STREET JOURNAL.

http://www.wsj.com/articles/utilities-profit-recipe-spend-more-1429567463

BUSINESS (HTTP://WWW.WSJ.COM/NEWS/BUSINESS)

Utilities' Profit Recipe: Spend More

To expand regulator-imposed earnings caps, electricity producers splurge on new equipment, boosting customers' bills

Every time Southern California Edison replaces a 50-year-old pole with a new one, it has a fresh investment on which it is eligible to earn an annual profit. *PHOTO: FRED PROUSER/REUTERS*

By **REBECCA SMITH**

April 20, 2015 6:04 p.m. ET

Families in New York are paying 40% more for electricity than they were a decade ago. Meanwhile, the cost of the main fuel used to generate electricity in the state—natural gas—has plunged 39%.

Why haven't consumers felt the benefit of falling natural-gas prices, especially since fuel accounts for at least a quarter of a typical electric bill?

One big reason: utilities' heavy capital spending. New York power companies poured $17 billion into new equipment—from power plants to pollution-control devices—in the past decade, a spending surge that customers have paid for.

DSD 008164

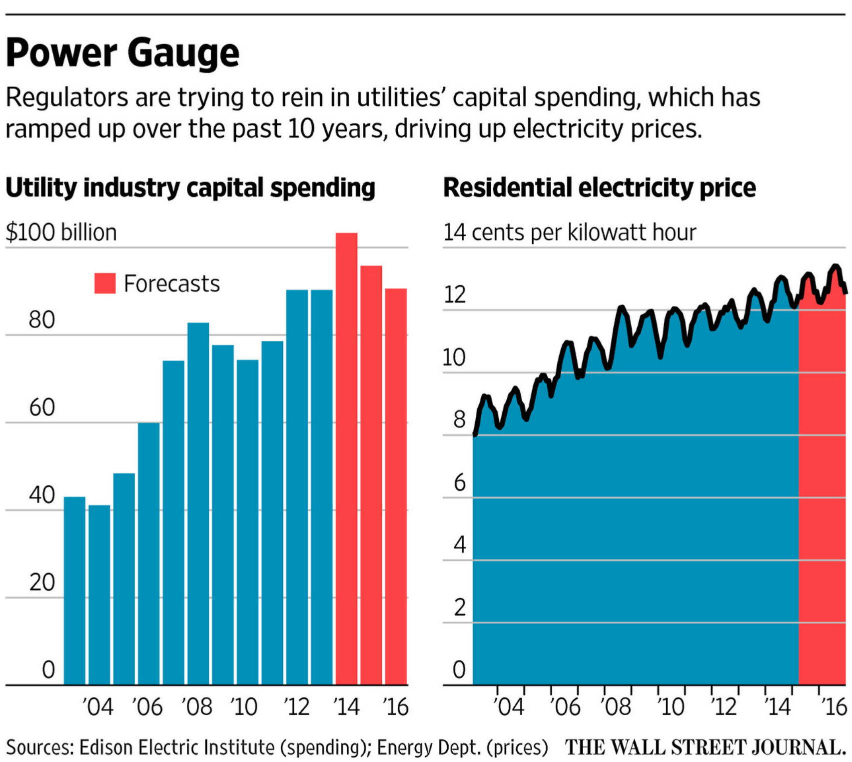
New York utilities' spending plans could push electricity prices up an additional 63% in the next decade, said Richard Kauffman, the former chairman of Levi Strauss & Co. who became New York's energy czar in 2013. It's "not a sustainable path for New York," he said.

New York is no outlier. Capital spending has climbed at utilities nationwide—and so have their customers' bills.

The average price of a kilowatt-hour of electricity rose 3.1% last year to 12.5 cents a kilowatt-hour, far above the rate of inflation. Since 2004, U.S. residential electricity prices have jumped 39%, according to federal statistics.

Over that same period, annual capital expenditures by investor-owned utility companies more than doubled—jumping to $103 billion in 2014 from $41 billion in 2004, according to the Edison Electric Institute, a trade association. The group expects total capital spending from 2003 through 2016 to top $1 trillion.

"This is the biggest splurge in capital spending we've seen in at least 30 years—it's the reason rates have been going up," said Bob Burns, an independent consultant and former energy researcher at Ohio State University.



The biggest chunk of that spending—38% in 2013—went into new power lines and other delivery systems, the Edison Electric Institute said. Almost as much went to generation, often for new gas-fired plants to replace coal-fired ones that don't meet new environmental rules.

Experts say there are several reasons for soaring spending, including environmental mandates, and the need to harden the grid to protect it from storms, physical attacks and cyber hacking.

DSD 008165

But utilities have another incentive for heavy spending: It actually boosts their bottom lines—the result of a regulatory system that turns corporate accounting on its head.

In most industries, companies generate revenue, deduct their costs, and are left with profits, which can be expressed as a percentage of revenues—the profit margin. Regulated utilities work differently. State regulators usually set an acceptable profit margin for utilities, and then set electric rates at levels that generate enough revenue to cover their expenses and allow them to make a profit.

At the moment, it is common for utilities' allowable profit to be capped at 10% or so of the shareholders' equity that they have tied up in transmission lines, power plants and other assets. So the more they spend, the more profits they earn.

Critics say this can prompt utilities to spend on projects that may not be necessary, like electric-car charging stations, or to choose high-cost alternatives over lower-cost ones.

"Until we change things so utilities don't get rewarded based on how much they spend, it's hard to break that mentality," says Jerry R. Bloom, an energy lawyer at Winston & Strawn in Los Angeles who often represents independent power companies.

Southern California Edison, a unit of Edison International in Rosemead, Calif., plans to spend about $1 billion in debt and equity replacing or repairing thousands of power poles, which cost $13,000 each. Every time the company replaces a 50-year-old pole with a new one, it has a fresh investment on which it is eligible to earn an annual profit, currently 10.45%, for 45 years.

The sudden interest in poles "suggests they've been negligent in the past or they're just looking for ways to spend money," said Bob Finkelstein, a lawyer at the Utility Reform Network, a San Francisco-based watchdog group.

Mike Marelli, SoCal Edison's rates director, said his company analyzed 5,000 poles before deciding a massive program was needed to deal with deferred maintenance.

Overall, SoCal Edison intends to spend $15 billion to $17 billion on dozens of initiatives from 2014 through 2017. Similarly, Charlotte, N.C.-based Duke Energy Corp. expects to make $17 billion worth of capital expenditures from 2014 and 2016. A rule of thumb it recently shared with investors: for every billion dollars in assets it adds to its inventory, it boosts earnings by about 8 cents a share.

Utilities can't bill customers for new capital expenditures without first getting the

> *'Until we change things so utilities don't get rewarded based on how much they spend, it's hard to break that mentality.'*
>
> —Jerry R. Bloom, an energy lawyer at Winston & Strawn

consent of state or federal regulators, notes Richard McMahon, a vice president at the Edison Electric Institute.

But Ken Rose, an energy consultant in Chicago, says that regulators don't always do enough to make sure projects are the best deal for the customers footing the bills. He says companies have a propensity to choose expensive solutions to problems—building a new power plant instead of promoting energy efficiency, for example—because it puts big chunks of capital to work that lift profits.

Some analysts say utilities' capital spending has been necessary and smart at a time of low interest rates.

"I don't subscribe to the belief that utility companies are gold-plating their systems just to increase profits," says Jim Hempstead, associate managing director of the global infrastructure finance at Moody's Investors Service.

Utilities earned $36 billion in 2013, excluding nonrecurring items, up 36% from 2004, according to the Edison Electric trade group.

So long as electricity consumption is growing, utilities can spread hefty costs across their customers without increasing rates. But since 2008, power sales haven't been growing fast enough to absorb the impact of all the added spending.

Kansas City Power & Light has raised rates about 60% since it kicked off its current investment cycle in 2007. It is seeking rate increases of 12.5% in Kansas and 15.5% in Missouri.

Some states are pushing back.

In New York, regulators balked at Consolidated Edison Inc. 's plan to build a $1 billion electrical substation in Brooklyn and Queens by 2017. Instead, the company has decided to help customers cut energy use by improving the efficiency of their electrical

DSD 008167

equipment through a $500 million program that defers a decision about a new substation for at least a decade.

“What we’re doing is an alternative that’s less costly,” said Stuart Nachmias, vice president of regulatory affairs for ConEd.

From now on, utilities must prove that their spending will make an electric system cleaner, more efficient or stronger, says Audrey Zibelman, chair of the New York Public Service Commission. “Business as usual has become unaffordable.”

Write to Rebecca Smith at rebecca.smith@wsj.com

Utilities for dummies: How they work and why that needs to change

By David Roberts on 21 May 2013
Grist.org

Last week, I posted on the fight between electric utilities and solar advocates over rooftop solar power. Today, I want to pull back the lens and begin to tackle the bigger question: How *should* utilities work? What's the right way to provision and manage electricity in the 21st century?

There's very little public discussion of utilities or utility regulations, especially relative to sexier topics like fracking or electric cars. That's mainly because the subject is excruciatingly boring, a thicket of obscure institutions and processes, opaque jargon, and acronyms out the wazoo. Whether PURPA allows IOUs to customize RFPs for low-carbon QFs is actually quite important, but you, dear reader, don't know it, because you fell asleep halfway through this sentence. Utilities are shielded by a force field of tedium.

It's is an unfortunate state of affairs, because this is going to be the century of electricity. Everything that can be electrified will be. (This point calls for its own post, but mark my words: transportation, heat, even lots of industrial work is going to shift to electricity.) So the question of how best to manage electricity is key to both economic competitiveness and ecological sustainability.

It's time to start talking about utilities. I, your courageous blogger and servant, am going to attempt to lay out, at a high level, how utilities work and why, the challenges facing them, and what a utility more suited to the 21st century might look like. It's a complicated problem, but I think the basics are approachable by ordinary citizens, who very much need to get involved and speak up on these issues. Occupy PUCs! (You'll get that joke after you read my next few posts.)

Why utilities are the way they are

To understand why utilities need to change, it helps to understand why they are the way they are. That takes us back to the turn of the 20th century, as electricity was just getting a foothold in some big American cities. Small power plants, using reciprocating steam engines to generate electricity, were popping up all over, but the power they produced could reach only about a mile's distance before fading on the copper lines.

Then along came two technologies that changed our relationship to electricity and have shaped American life ever since.

First, reciprocating steam engines gave way to more efficient, more scalable steam turbines. And second, local direct current (DC) power was joined by alternating current (AC) transformers that could ramp up voltage enough to allow electricity to travel very long distances with relatively little loss. Together, steam turbines and AC transmission lines formed the foundation of the modern electrical system and remain its dominant technologies.

Steam turbines exhibited classic economies of scale. The bigger you made them, the cheaper the power. And with AC transmission lines, you could send the power as far as needed to find customers. To take full advantage of these capabilities, though, you needed *scale*. The bigger the better.

Economies of scale, with the concomitant need for large, long-term capital investments, made utilities what were called at the time "natural monopolies." As with railroads, it didn't make sense to lay down multiple competing networks; it would be wasteful, and neither competitor would be able to capture the full benefits of scale. It was inevitable that one entity would end up provisioning power. And by maximizing the benefits of scale, a monopoly would be best for consumers too.

At the time, however, railroads and other monopolies were notably unpopular, for good reason — they were often corrupt and lawless. Utility folks didn't want progressive reformers attacking them. It was in everyone's interest to put a stable structure in place.

So that's what happened. In the early 20th century, the American people struck a deal with the utilities, an enduring agreement known as the "regulatory compact." It remains in place, more or less intact, to this day.

Here's how the regulatory compact works.

In a particular service area, a utility is granted a monopoly; in that area, it is the sole electricity provider. It is allowed to charge its customers whatever rates are necessary to cover costs and provide for a reasonable rate of return on investments. In exchange, the utility has to make investments sufficient to provide reliable, low-cost power to any customer in the area who wants it, with minimal "line losses" (i.e., "leakage" of power from power lines). To ensure the utility does not abuse its power, a public utility commission (PUC) monitors its activities and has to sign off on its rates.

That's the bargain: The utility provides low-cost, reliable power. In exchange, it gets a captive customer base.

Why the utility structure no longer works

There are a few key things to note about the regulatory compact.

First, note that this arrangement looks almost nothing like a "free market" as envisioned by classical economists. These are entities legally protected from competition, charging government-approved prices, receiving guaranteed returns. It is the most Soviet of economic sectors. (Keep this in mind the next time someone glibly refers to "the market" in discussions of coal or solar.)

Second, note that the utility makes money not primarily by selling electricity, but by making investments and receiving returns on them. If it builds more power plants and power lines, it makes more money.

Add these together and you see the basic incentive structure at work. In most economic sectors, businesses live in fear of competing businesses coming in and providing customers with a better value proposition. They must be vigilant, cut costs, and innovate. That is the power of markets.

But utilities do not fear competition. Their customers cannot live without their product, or purchase it elsewhere. Their profits are guaranteed so long as they can justify their rates to a PUC. All they need to do to increase profits is to build more stuff — more power plants, more substations, more power lines, more.

When the regulatory compact was established, this made perfect sense. The demand for power was inexorably rising and there was a need to scale up rapidly. Given all the *un*regulated monopolies at the time, the regulatory compact was actually fairly progressive — at least it provided explicitly for public oversight.

But make no mistake: it was designed to electrify the country, to enable more people in more places to find more uses for electricity. Demand grew so fast that utilities were proposing, getting approval for, and making huge investments right and left, as fast as they could. And everything got bigger. The mania for gigantism reached its peak in the ’70s, with the nuclear craze. Finally, a technology powerful enough to fuel the meteoric rise in electricity consumption that was going to last forever. (Ahem.)

Now fast-forward to the present. The regulatory compact remains the same, the incentive structure it created remains the same, but circumstances in the U.S. have changed in two big, overarching ways.

The first, which has just begun to emerge but will accelerate in coming years, is that demand for utilities’ services is slowing. Depending on which forecasts you believe, electricity consumption may even begin declining in some states over the next few decades.

Why? Some of it is merely the “offshoring” of industrial activity. But a substantial chunk is the recent explosion of energy-efficiency technologies and investments. Alongside that is the maturation of what’s called “demand response,” the ability to shift electricity use forward or backward in time in response to price signals. (Demand response doesn’t reduce total load, but it can reduce *peak* load; utilities have to invest/build enough to meet peak load, so if you reduce peak load, you reduce needed investments.)

Alongside *that*, individuals now have the power to generate their own electricity with solar panels and other distributed generation technologies. Utilities do not own that distributed generation; it’s an investment upon which they receive no returns. And it represents a reduction in demand for what they are selling, a reduction in use of their grid infrastructure, and a reduction in the need for future power infrastructure.

For all these reasons, many energy nerds believe that electricity demand in the U.S. will never again rise as fast as it did this century, and might even plateau or fall. But remember, utilities are in the midst of paying off large, 20-plus-year investments. If they get less than expected from some customers, they have to charge the other customers more in order to get the same rate of return. They do not like that one bit (nor do the other customers). Furthermore, the unpredictable rise of all these disruptive technologies casts their future investments into doubt. In the long term, they face the threat of lower profits and, well, shrinkage. They don't like that one bit either.

And that is perverse, because the other broad change since the early 1900s is a recognition of the threat of climate change and an understanding of the radical reduction in fossil-fuel use required to address it. As a society, we *need* energy efficiency and demand response. We *need* distributed renewable energy. We *need* to cancel out future power plants and transmission lines. All those things are to the good, economically and ecologically. Yet utilities have every incentive to oppose them, as they are direct threats to their familiar, comfortable business model, which has survived nearly a century unchanged.

And so I think we need to do more than fiddle with rate structures or mandate arbitrary levels of efficiency or renewable energy. We need a ground-up rethink of how utilities work, how they are structured, and how they can be reformed in a way that enables and accelerates long-overdue innovation in the electricity space. More on that soon.

The Best Alternative

Executive Summary

PSE and CENSE (Coalition of Eastside Neighborhoods for Sensible Energy) may not agree on the feasibility of the company's proposed transmission project through four Eastside cities.

But at least we agree on one thing. The five alternative solutions evaluated in the Draft EIS are not practical solutions to power future growth of the Eastside.

- **Alternative 1B** (use existing Seattle City Light corridor): Seattle City Light has said they don't want to share these lines with PSE. We don't know how to change that conclusion.
- **Alternative 1C** (underground transmission lines): The state tariff enforced by the Washington Utilities and Transportation Commission makes it prohibitively expensive for communities to request undergrounding.
- **Alternative 1D** (underwater transmission lines): This alternative may be subject to the same expensive undergrounding tariff, and also raises questions about disturbing a Superfund site, shoreline issues, and concerns about salmon.
- **Alternative 2** (integrated resource approach): The analysis of integrated resources is based on incorrect or obsolete information, making this option appear more expensive and less feasible than it actually is.
- **Alternative 3** (new 115 kV lines and transformers): With 60 miles of new transmission lines, this alternative does not seem like an attractive or realistic option to anyone.

Alternative 2 would be the most attractive option for residents and businesses if it were redesigned using more up-to-date and accurate information. Such a solution would be less expensive, less damaging to communities and the environment, and safer for homes and schools in close proximity to the power lines and high-pressure petroleum pipelines.

Sadly, Alternative 2 was not designed or reviewed by experts in new technologies that make Demand Response and Electrical Efficiency the most important factors in planning the electrical grid of the future. This is validated by a quote from the Northwest Power Plan[1] that was finalized this year:

> *In more than 90 percent of future conditions, cost-effective efficiency met all electricity load growth through 2035. It's not only the single largest contributor to meeting the region's future electricity needs, it's also the single largest source of new winter peaking capacity.*

EQL's full report is included following this introduction. The full report is quite detailed and technical. It may be more appropriate for analysis by industry experts, so this introduction attempts to distill the main points for the general public.

[1] *https://www.nwcouncil.org/media/7149671/7thplandraft_chap01_execsummary_20151020.pdf*

A clear definition of need and cost

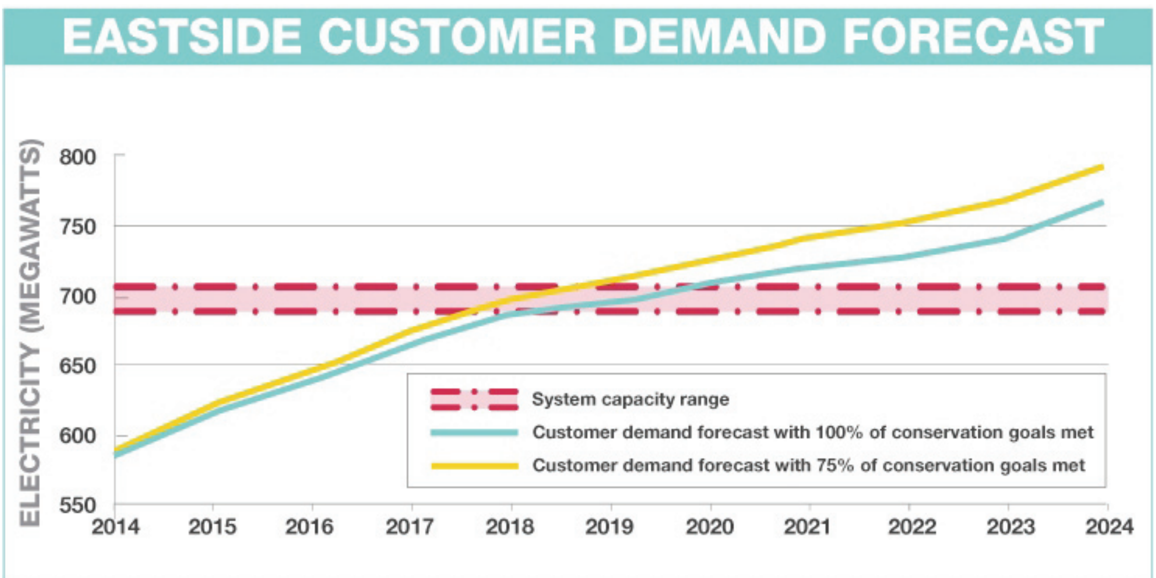
In order to determine the feasibility of any alternative solution, it is important to be clear about two crucial parameters:

1. How big is the need? Or, as the DEIS poses the question in section 2.3.3, what is the "projected deficiency in transmission capacity on the Eastside?"

2. What is the relative cost of alternatives compared to the cost of PSE's proposed project?

How big is the need?

In section 2.3.3, the DEIS says that Alternative 2 must cover 205 MW of projected shortfall by 2024. It is not clear in the DEIS where this number comes from. It is nearly three times the shortfall of approximately 70 MW shown for 2024 in PSE's famous Eastside Customer Demand Forecast:



The DEIS explains that Alternative 2 must be evaluated by a different standard than a solution based on transmission lines because "*every solution has a different degree of effectiveness and reliability*." The DEIS seems to dwell on every possible downside of the technologies included in Alternative 2 while turning a blind eye to the reliability risks of Alternative 1A. For example, suppose two of the approximately 150 power poles in PSE's proposal fall down (a scenario we are allowed to consider under N-1-1 contingency planning, and not hard to imagine during a big earthquake). In that case, the capacity of Alternative 1A would be reduced by 20%, about 140 MW. It is difficult to imagine a scenario in which an N-1-1 failure would lead to a similar drop in capacity for Alternative 2. It improves reliability by not placing all our eggs in one basket.

There is evidence that PSE has been gradually skewing requirements to reduce the competitiveness of alternatives. In April 2015, an update to Quanta's Eastside Needs Assessment estimated the shortfall in transmission capacity at 123 MW. A few months later, the EIS consultant Stantec raised the estimate to 133 MW. In January 2016, PSE's latest Integrated Resource Plan pegged the number at 166 MW. A few weeks later, the DEIS was published with an estimate of 205 MW.

The shortfall has grown by 54% in less than a year, calling into question the stability of the methodology used to determine this number or the motives of the information source.

The important point is that size matters. The mix of technologies and programs needed to cover a 205 MW shortfall is different from the mix that would be used to cover a shortfall of 123 MW. One wouldn't simply "scale up" the smaller solution.

It's important to note that CENSE is skeptical of even the lesser 123 MW figure. The Lauckhart-Schiffman Load Flow Study[2] exposes errors in PSE's assumptions and simulations that would dramatically alter the size and timeframe of the need. For the purposes of this report, we assume that the shortfall is 123-133 MW in order to critique the DEIS, but we do not agree that this is a realistic estimate.

What is the cost?

The DEIS treats cost as irrelevant for the purposes of evaluating environmental impact. However, in the real world, cost is an important factor in choosing one alternative over another.

PSE has not estimated the cost of the project for at least a year. The last cost estimates that were shared with the Community Advisory Group were in the range of $150 million. EQL expects the actual cost will be closer to $300 million, for the following reasons:

1. PSE initially thought that two transmission lines could be carried on a single set of monopoles. However, due to the meanderings of the Olympic pipelines in the shared corridor, there are many places where the lines must be carried by two poles to meet safety requirements. The number of poles and construction costs will increase.

2. PSE initially thought that the current transmission poles could be removed before construction of the new line began. Recently, the company has admitted that operation of the system with no lines in place during many months of construction would present a reliability risk. Therefore, the design must be altered to accommodate both sets of transmission lines in place simultaneously.

[2] *http://cense.org/Lauckhart-Schiffman%20Load%20Flow%20Study.pdf*

Taller poles will be required to maintain a safe distance between the old lines and the new lines. Also, the complexity of construction is significantly increased. Both of these factors will increase the cost of the project.

3. PSE assumed that it would be safe enough to put two transmission lines and two high-pressure petroleum pipelines in a utility corridor that is as narrow as 100 feet in densely settled residential neighborhoods. The DEIS wisely assumes that the corridor will have to be widened by up to 50 feet. This will require condemnation of homes and new easements, significantly increasing project costs.

4. Resistance to the project is much higher than PSE expected. The costs of advertising, public relations, and potential legal actions are correspondingly higher.

EQL's report points out a hidden cost of Alternative 1A. If PSE invests hundreds of millions of dollars in a transmission project, the amount of investment dedicated to important programs like Demand Response and Energy Efficiency will be reduced. Consequently, overall energy use will be higher with Alternative 1A than Alternative 2. That higher consumption must be matched by new generation, and PSE anticipates that need in the 2015 Integrated Resource Plan. PSE expects to build nearly 600 MW of new gas generation plants in 2021, just a few years after Energize Eastside is complete:

Figure 1-7: Electric Resource Plan Forecast,
Cumulative Nameplate Capacity of Resource Additions

	2021	2027	2030	2035
Conservation (MW)	411	695	768	906
Demand Response (MW)	130	153	160	172
Wind (MW)	-	206	337	337
Combined Cycle Gas (MW)	599	969	1354	1354
Peaker/CT Dual Fuel (MW)	-	228	479	707

Alternative 2 could reduce overall energy use enough to eliminate the need for one 200 MW generation plant, saving ratepayers $300 million. In the long run, Alternative 2 could save ratepayers the cost of both transmission and generation infrastructure, at least $600 million. Including both of these avoided costs in the analysis makes Alternative 2 the better choice for cost effectiveness.

Expert analysis from EQL Energy

To better understand how Distributed Energy Resources (DER) might contribute to the future operation of our energy grid, CENSE engaged industry expert EQL Energy from Portland, Oregon. EQL has been an important contributor to alternative energy solutions in Portland and other parts of the Pacific Northwest.

EQL possesses a different skill set than that needed to plan transmission lines. These skills have not been demonstrated by PSE or the EIS consultant Stantec. Consequently, Alternative 2 is not a credible DER solution. The description included in DEIS section 2.3.3.1 would lead the reasonable reader to conclude that this option is difficult to implement and dangerous for reliability.

Consequently, EQL's list of technologies and policies differs significantly from those included in the DEIS:

DER program	PSE estimate (MW in 2024)	EQL estimate (MW in 2024)
Targeted Energy Efficiency	42?	30
Distribution Efficiency (CVR)	0	18.8
Combined Heat & Power	0	30
Energy Storage	121	15
Peak Generation Plant	60	0
Dispatchable Standby Generation	?	18.8
Demand Response (unspecified)	32	
Demand Response (day ahead)		30
Demand Response (10 minute)		11.3
Total	**255?**	**153.9**

Energy Efficiency

It is difficult to directly compare PSE's and EQL's estimates of potential savings from Energy Efficiency. In section 2.3.3.1, the DEIS states that 42 MW of savings would be required, but offers no clear idea of how that would be achieved: "*The potential for additional energy efficiency on the Eastside is not currently known and would require additional evaluation*." CENSE is disappointed that no more definitive estimate could be made of the potential.

The DEIS claims that savings of this magnitude would be "*an aggressive goal*." Also, "*The additional energy efficiency assumed for Alternative 2 would be triple the amount that PSE estimated is achievable after 2024, and that additional energy efficiency would have to be accomplished before 2024.*" The DEIS analysis makes it seems pretty hopeless.

In contrast, EQL has estimated 30 MW can be saved through Energy Efficiency. This is lower than PSE's goal, and EQL believes it is more easily achieved because PSE and its consultants are using load data that is decades out of date. The obsolete data makes Energy Efficiency appear to be less effective than it actually has been in more recent years.

To get more accurate data, a "Request for Proposals" should be issued to companies that specialize in Energy Efficiency technologies and programs. A competitive bidding process would yield better estimates of the potential than the obsolete data being used by PSE and EIS consultants.

Distribution Efficiency

Energy Efficiency achieves savings on the consumer's side of the electric meter by using less electricity to accomplish tasks such as lighting, heating, operating appliances and electronics, and charging batteries. In contrast, Distribution Efficiency increases the efficiency of how PSE and other utilities deliver electricity to consumers. This reduces overall electricity usage by up to 4% without any impact on customers. PSE has already incorporated this technology in a few substations, but the program can be expanded to more broadly reduce peak loads.

EQL included 18.8 MW of savings in its DER estimates, based on a somewhat conservative estimate of 2.5% of peak load. No estimate is included for Distribution Efficiency in the DEIS.

Combined Heat & Power

Combined Heat & Power is a technology that generates electricity from the waste heat produced by burning natural gas to heat or cool a building. It is most effectively incorporated in new buildings, and it provides two benefits. The very efficient use of natural gas reduces total carbon emissions compared to long-distance transmission of electricity, and local generation of electricity can provide a degree of immunity from power outages. Widespread use could reduce the need for new generation facilities and transmission lines, benefitting all customers.

Bellevue has a special opportunity to incorporate this technology due to the number of new buildings planned for construction in downtown Bellevue and the Spring District. If these projects are contributing to the need for Energize Eastside, it seems fair to ask them to help solve the problem of increased energy use. It is not fair to place the burden of rising downtown energy use on residential neighborhoods with increased industrialization and lower property values.

EQL estimates 30 MW of savings due to Combined Heat & Power. No estimate is included in the DEIS.

Energy Storage

DEIS section 2.3.3.4 describes a battery solution that would provide 121 MW to serve peak demand. However, the practicality of such a system is immediately dismissed: *"An energy storage system with power and energy storage ratings large enough to reduce normal overloads has not yet been installed anywhere in the world. For comparison, the largest operational transmission scale battery facility in the U.S. can provide 32 MW of power for about 40 minutes."* The DEIS analysisi makes it sounds like you'd have to be crazy to consider this idea.

EQL proposes a battery solution with a capacity of only 15 MW, approximately 8 times smaller than PSE's solution. For comparison, Southern California Edison is funding a project to install batteries with 250 MW of capacity. EQL's proposal is 16 times smaller, and by PSE's metric, 16 times more feasible.

But what about cost? EQL found a major error in the cost analysis included in the Strategen report referenced in the DEIS. Strategen ignored the cost of avoided transmission, leading to the improbable assumption that we would build transmission lines and battery storage units. When the error is corrected, the cost of batteries is approximately two times more cost effective than building new transmission lines. And battery costs will continue to fall, while the cost of transmission lines usually rises due to increasing property values.

Even PSE admits that battery storage will become a game changer as we increasingly rely on intermittent renewable energy sources like wind and solar power. We can prepare for the future by investing in small amounts of battery storage now, so we can learn from our experience and advance the state of the art. If possible, we should use products like grid batteries manufactured by the Mukilteo-based company UniEnergy. That's a smart investment in our energy future and our economy.

EQL estimates 15 MW of battery storage. The DEIS estimates 121 MW, but notes that the consultants skipped evaluation of a summer scenario because "*energy storage would not be a feasible stand-alone alternative*." This is an odd criteria to apply to energy storage, because the components of an "*integrated resource approach*" are designed to work together, not as stand-alone pieces.

Peak Generation Plant

DEIS section 2.3.3.1 describes "three 20 MW generators to be implemented in combination with the other components described for Alternative 2." As an important caveat, the DEIS notes that "PSE had eliminated this option from consideration" because "these types of generators produce a high noise level that would be incompatible with [residential] surroundings." In discussion with Bellevue city council members, CENSE has learned that there is little political will to consider these generators.

EQL's proposal does not rely on gas-fired peak generation plants. The DEIS assumes 60 MW of capacity.

Dispatchable Standby Generation

Dispatchable Standby Generation (DSG) generates power on a customer's site, as explained in DEIS section 2.3.3.3. The DEIS mentions many technologies that could be used for this purpose, such as gas turbines, microturbines, reciprocating engines, fuel

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Dispatchable Standby Generation

Dispatchable Standby Generation (DSG) generates power on a customer's site, as explained in DEIS section 2.3.3.3. The DEIS mentions many technologies that could be used for this purpose, such as gas turbines, microturbines, reciprocating engines, fuel cells, and anaerobic digesters. However, no estimate is given regarding which ones are most practical or how much energy they might be expected to generate.

EQL describes a solution that they helped design in Portland, Oregon. Generators owned by businesses, hospitals, and government buildings are networked to the utility company. These generators are usually idle unless there is a power failure, when they are turned on to supply emergency power. The utility is provided a way to remotely control the generators when electricity demand peaks. The owner gets an attractive incentive for participating, and the generator reverts to its previous purpose (backup power) if an outage occurs.

Using the Portland program as a template, EQL used a scale factor to determine DSG potential for the Eastside. EQL estimates 18.8 MW of additional energy produced by DSG. The DEIS provides no estimate.

Demand Response

The importance of Demand Response as a primary part of future energy planning is underscored by the recently published Seventh Northwest Power Plan from the Northwest Power and Conservation Council, as well as a major victory for the Federal Energy Regulatory Commission in the U.S. Supreme Court.[3] A 2015 article in Forbes explains how Demand Response will save U.S. consumers billions of dollars.[4]

DEIS section 2.3.3.2 mentions some rather vague ways to implement Demand Response programs, including real-time monitoring, utility control of heating and cooling systems, programmatic options to reduce peak demand (nothing specific), incentives and pricing structures to shift peak demand, continuous wireless signals to the utility (huh?)

The DEIS doesn't provide any realistic estimate of how much energy can be saved through these programs, but it says it must be at least 32 MW. According to the DEIS, "this would triple the expected rate of adoption of demand response in PSE's Integrated Resource Plan…"

EQL is more specific. There are actually two types of Demand Response programs: one anticipates needs one day before peak loads materialize (it's not hard to predict very cold weather one day ahead), and one responds to emergency needs with 10 minutes' notice.

EQL estimates 30 MW of savings for day-ahead Demand Response (4% of peak load based on a conservative estimate from industry analyst Navigant), and 11.3 MW for the 10-minute program (1.5% of peak load). The DEIS cites a goal of 32 MW, but is not specific or optimistic about achieving it.

[3] *https://www.washingtonpost.com/news/energy-environment/wp/2016/01/26/the-supreme-court-just-gave-a-great-explanation-of-our-baffling-electricity-system/*

[4] *http://www.forbes.com/sites/jamesconca/2015/02/24/solving-americas-energy-future-requires-a-demand-response/#5964a1457a9f*

Conclusions

The DEIS vaguely describes Alternative 2 using a resigned, pessimistic tone. The alternative seems risky and infeasible, because it was not developed or reviewed by experts with the specialized experience to accurately assess the technologies and potential energy savings.

EQL has described a more realistic way to achieve these energy goals in a manner that is cost-effective, better for the environment, better for our local economy, safer for residents, and more in sync with the Eastside's leading edge, high-tech roots.

Alternative 2 has another advantage. PSE's transmission line is an all-or-nothing proposal. It won't deliver a single electron until every pole is installed and every wire strung. It will not be operational until PSE's customers have spent at least $300 million for it.

By comparison, Alternative 2 can be built incrementally. According to PSE's famous chart, the Eastside Customer Demand Forecast, there will be a shortfall of approximately 10 MW in 2020. It should be easy to meet that shortfall in the next four years using a subset of the technologies described by EQL. Two years after that, we need to find another 15 MW. That shouldn't be too hard. As time progresses, technology will improve, and batteries will become cheaper and more efficient. We may find that it's pretty easy to meet these goals.

But there's another possibility. What if we have another recession? Or what happens if the ridiculous rate of growth (2.4% per year) that PSE is predicting doesn't materialize? In these cases, we could scale back ongoing investments in Alternative 2, saving PSE's customers hundreds of millions of dollars.

The DEIS describes many risks, but it doesn't explain this one. A huge investment in Alternative 1A could create a technology dinosaur that industrializes the Eastside, does nothing to mitigate greenhouse gas emissions, and saddles our children and grandchildren with higher utility bills, leaving less money to invest in the energy technologies of the future. That doesn't seem like a very smart investment.

CENSE.org
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Alternatives to Energize Eastside

Response to Draft EIS

February 15, 2016

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Figures

DSD 008186

1 Introduction

EQL was asked to comment on Alternative 2 “Integrated Resource Approach” discussed in Chapter 2 of the Energize Eastside Draft EIS January 28, 2016.

EQL has reviewed and commented Energize Eastside studies and has participated in several PSE IRP advisory group meetings, EQL has commented on the following topics through Energize Eastside and IRP Advisory process:

1. Distributed energy resources (DER), (e.g., energy efficiency, demand response, dispatchable standby generation, solar, storage, EV charging, CHP, distributed generation, etc.),
2. Demand Side Resource and transmission alternatives to Energize Eastside.
3. Integration of transmission and distribution planning/costs into the utility least cost planning process,
4. Resource adequacy modeling and methods (e.g., EUE expected unserved energy, focus on resource types), and
5. Reliability in IRP, Transmission Planning, and SAIFI/SAIDI statistics, as well as scenario and sensitivity analysis.

EQL is an energy industry consultancy started in 2010 to assist utilities, utility customers, and vendors develop smart grid technologies and business cases that lower cost of utility service, improve reliability, and integrate renewable energy. Our staff has supported IRPs throughout the Western Electricity Coordinating Council and MISO since 1993. Since 2010, our work has been related to smart grid technology evaluation/planning, and integration of renewable energy and distributed energy resources (DER).

EQL’s comments are those of EQL, and are meant to promote improved least cost utility planning.

2 Critical Points on EIS Alternative 2

Alternative 2 if done properly could meet criteria for Eastside expected growth in peak load. Unfortunately, the work and discussion of Alternative 2 in the EIS is confusing, insufficient to determine feasibility, uses bad data and forecasts, and demonstrates very little attention by City of Bellevue and PSE.

Many utilities around the world are considering Distributed Energy Resources (DER) to defer or avoid transmission infrastructure, including ConEd (NY), SCE (CA) BC Hydro (BC), BPA (OR/WA), etc.[1], DERs include targeted energy efficiency, demand response, dispatchable standby generation, solar, storage, EV charging, CHP, distributed generation, etc.

2.1 A proper Alternative 2 analysis would prevent increases in Eastside winter peaks and meet all 15 electrical criteria, and 4 non-electrical criteria.

A proper analysis would include accurate peak load forecast, cost effectiveness analysis, and ideally an all source RFI. A rule of thumb Eastside forecast is provided in Figure 1 below.

To put it simply, Alternative 2 DER would avoid ratepayer funding for transmission, distribution, generation, and environmental costs. To meet the peak load growth Puget Sound Energy will request to spend over $300MM on Energize Eastside and another $300MM for a peaking power plant (PSE 2015 IRP). If we assume that expected peak load to be met is 200 MW, the capital expenditure would be $3,000/kW. Most DER, TODAY, can be installed and operated for less. When you consider expected cost reductions and performance improvements Alternative 2 is the lowest cost choice.[2]

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[1] https://www.raponline.org/document/download/id/4765

[2] storage cost reductions expected to be 50% over next 5 years, Internet of things, sensors and controls for demand response will become more cost effective and prevalent, EV charging control to avoid peak.

Figure 1: DER potential at PSE above the DSR 100% forecast

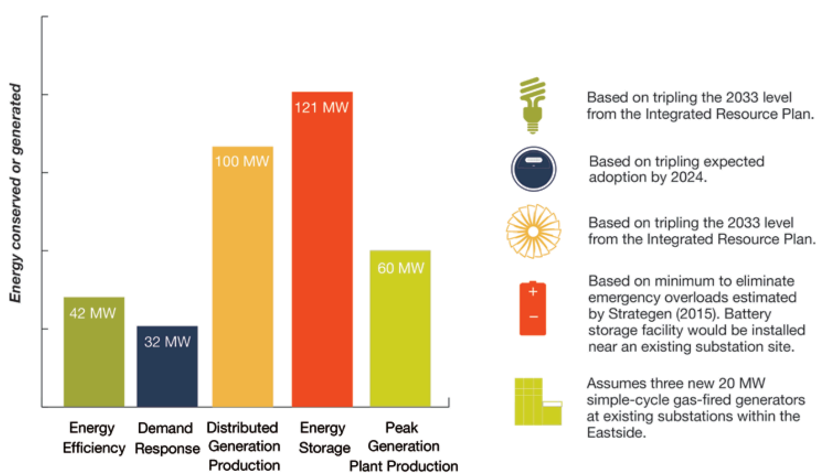
DER Measure	% of winter peak
System Winter Peak load	
Solar	0.0%
Targeted Energy Efficiency	4.0%
Distribution Efficiency (CVR)	2.5%
Combned Heat & Power (CHP)	4.0%
Storage	2.0%
Dispatchable Standby Generation (10 minute)	2.5%
DR Day Ahead	4.0%
DR (10 minute)	1.5%
Total	20.5%

If PSE proceeds with transmission and generation, then DER will become less cost effective. In fact, Idaho Power after finishing construction of their Langley Gulch gas plant tried to shut off all their demand response programs. You don't need DER capacity if your trying to pay off a new gas plant.

2.2 Alternative 2 assessment is insufficient to determine feasibility and lacks credible analysis or estimate.

The EIS provides only a theoretical example of technology that could address winter peak load reductions which has no value in determining feasibility. See example graph in Fig. 2-14 in EIS.

(EIS Fig. 2-14) Theoretical example of Energy conserved or distributed generation



Energy conserved or generated beyond the conservation included in the No Action Alternative

In order to properly assess an Integrated Approach the EIS should either hire independent consulting firm to estimate cost effective DER on Eastside, or issue an all source RFP for all DER in affected eastside area. This process would include all avoided costs and provide actual estimates for DER capacity amounts and cost, as well as real vendors estimates. This process is being used in New York's Brooklyn-Queens Demand Management program which started in 2014. New York utility ConEd is expected to invest $200MM to implement DER to avoid transmission build.

2.3 PSE Eastside winter peak load forecast has been a moving target throughout planning process, and has steadily increased over study period.

PSE has been changing the required winter peak load reduction on the Eastside throughout the Energize Eastside planning process. (see figure below). PSE has a history of changing methods and planning standards when justifying capital expenditures, e.g., peaking power plants. In the 2015 Integrated Resource Plan, PSE changed their planning standard, which led to an increase in 2021 peak load of 351 MW. Figure 1 below summarizes the source and the estimate of peak load reduction required to meet Eastside load requirement.

Figure 2: Range of Estimates for Eastside Peak Load increase through 2024

Source	2024	Date of Source	Page
E3 Non-Wires Study	70 MW	Oct 2014	
Quanta - Eastside Needs Assessment	123	Apr 2015	Page 19
Stantec Review Memo (referenced in EIS)	133	July 2015	Page 1-7 Draft EIS
PSE 2015 IRP	166	Jan 2016	IRP Ch.5 page 31
Draft EIS (2016)	205	Jun 2015	EIS Page 2-34

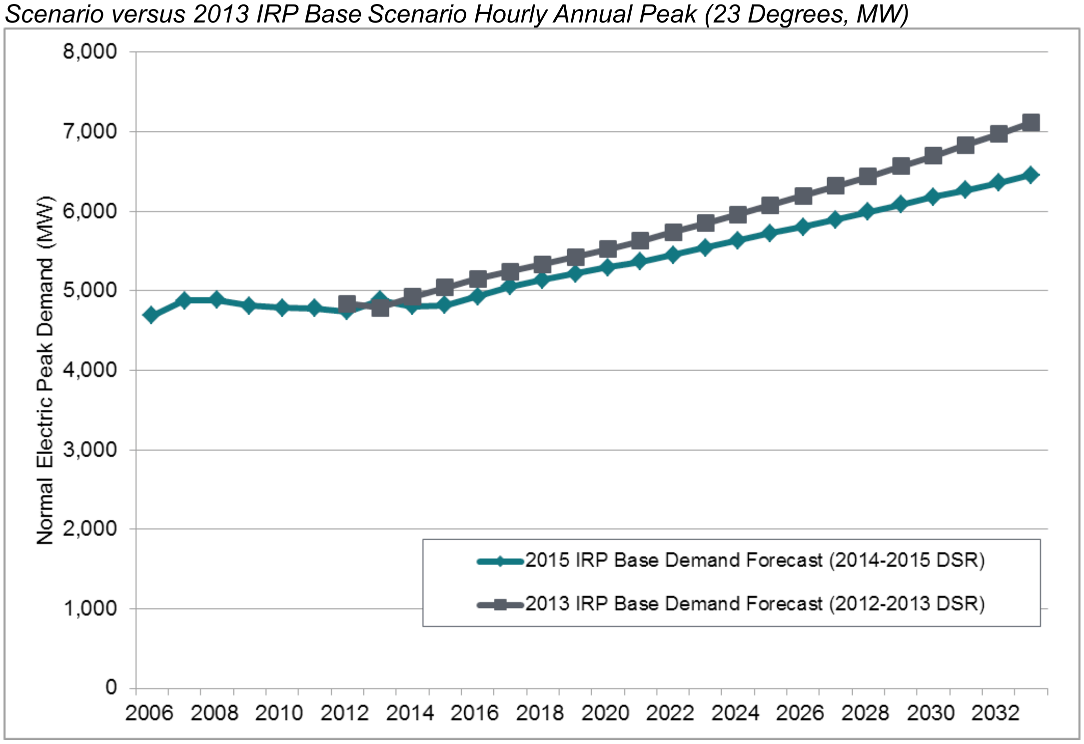
* Assumes peak load after planned baseline energy conservation

The Draft EIS discusses 205MW non-transmission resources needed by 2024, which is a likely mistake. This value stems from an email from Jens Nedrud, Energize Eastside project manager, where he explains that the amount of conservation required to be equivalent to transmission capacity is 205 MW. Mr. Nedrud only mentions conservation, not other DER. Mr. Nedrud is the project manager for Energize Eastside, so estimates from him should be questioned.

2.4 PSE Eastside winter peak load forecast is wrong and has been consistently too high for the past 6 years.

Figure 2 below shows how peak load is historically flat, then suddenly takes off in the future. You'll find this to be true with PSE's previous peak load forecasts. I understand that forecasts are, by their nature are wrong, but PSE has a habit of overestimating peak load.

Figure 3: PSE 2015 IRP *Figure 5-21: Electric Peak Demand Forecast before DSR 2015 IRP Base Scenario versus 2013 IRP Base Scenario Hourly Annual Peak (23 Degrees, MW)*



Winter peaks have gone down in the Pacific Northwest in the last 5 years, and growth in the winter peak will continue to be less than the increase in growth in energy use. PSE's winter peak decreased by 11 MW from 2013 to 2014. This holds true because:

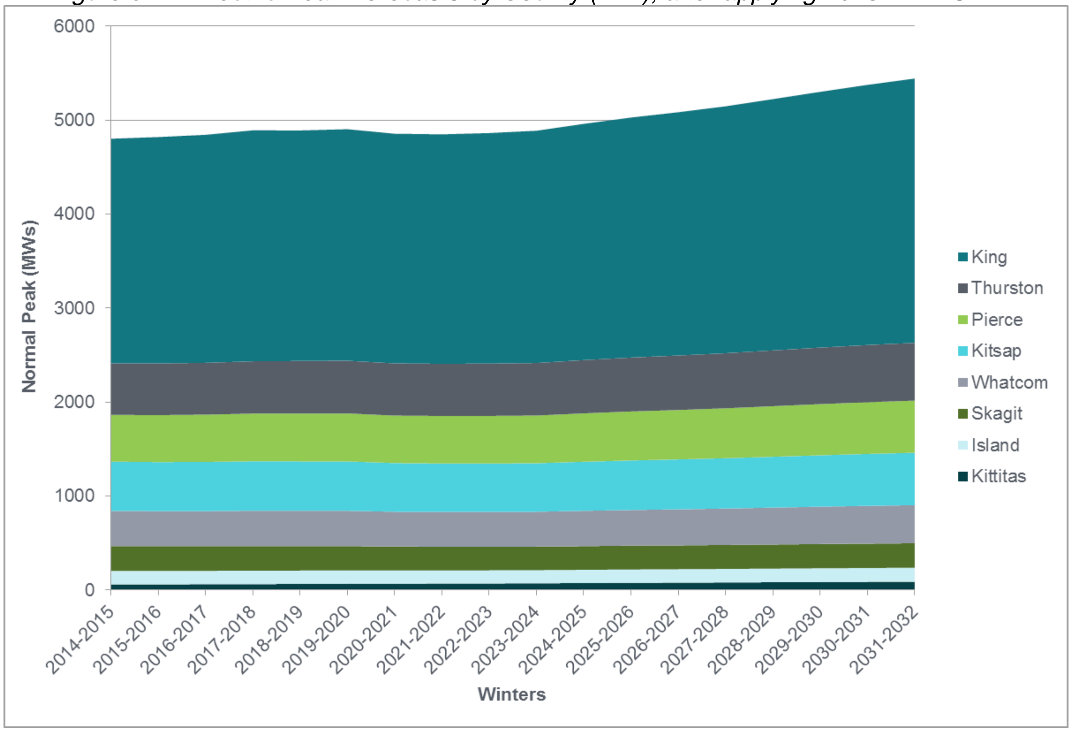
1. Electric heating load is saturated. I.e., new growth does not include electric heating that contribute to winter peak,
2. Fuel Conversion from electric to gas and propane are reducing winter peaks,
3. Milder winter temperatures reduce chance of extreme cold weather, and
4. Higher growth in multifamily and commercial,

PSE's 2011 IRP had peak forecasts rising from 2011 forward.[3] This is not happening.

Notice in Figure 5-27 from PSE's 2015 IRP, the peak demand does not begin to increase until 2024.

[3] http://www.utc.wa.gov/_layouts/CasesPublicWebsite/GetDocument.ashx?docID=42&year=2010&docketNumber=100961

Figure 5-27: Electric Peak Forecasts by County (MW), after applying 2013 IRP DSR



3 Other Points on EIS Alternative 2

3.1 PSE local needs assessment is not a local cause

PSE has suggested the transmission need is based on local winter peak demand on the eastside. This is only a small part of the story. The issue arises by modeling a series of unlikely regional wholesale power scenarios (e.g., plants offline, Canadian imports, transmission line outages, and high winter peak demand) that creates: 1) high winter power flows South to North through the PSE's eastside transmission corridor, and 2) increased loads on eastside substations. These modeled events would lead to equipment exceeding their thermal limits and the need to shed load at substations or limit power flow on the PSE 115kV system through eastside.

Based on the 2012 Memorandum of Agreement between PSE, Seattle City Light (SCL), and BPA, PSE has agreed to provide expanded transmission service through Puget Sound Area. SCL agreed to projects that would limit flow through their system by placing series inductors at two of their substations. This demonstrates that the issue and needs are indeed a regional one, not just local

This local problem, if it were ever to occur, would happen for a few hours of the year during extreme cold days and hours of peak load on eastside. The EIS extreme scenarios suggest up to 13 days this could occur, but does not forecast number of hours. Given PSE's winter peak is in morning (8am) or evening (6pm) The load reduction would need to be for a few hours during these times. EQL's experience suggests that the winter peaks come in 2-3 day consecutive days (cold snaps) and last maybe one to two hours per day.

According to EIS scenarios, in 2026 eastside load will need to <u>shed 133MW</u> to accommodate flows to Canada over PSE 115kV system.

Another troubling area is how PSE attributed winter peak demand reductions to forecasted energy efficiency measures. It is impossible to determine how PSE and its contractors did this conversion. However, EQL Energy is familiar with the issue that load shapes used in the Pacific Northwest to attribute capacity reductions from energy efficiency are inaccurate and out of date. Some end use load shapes (ELCAP) date back to the 1980s. The topic of inaccurate load shapes and hence capacity contribution of energy efficiency has been consistently discussed and agreed upon by the Northwest Power and Planning Council, as well as the Regional Technical Forum on energy efficiency.

3.1.1 The Problem – several days and a few hours in the winter

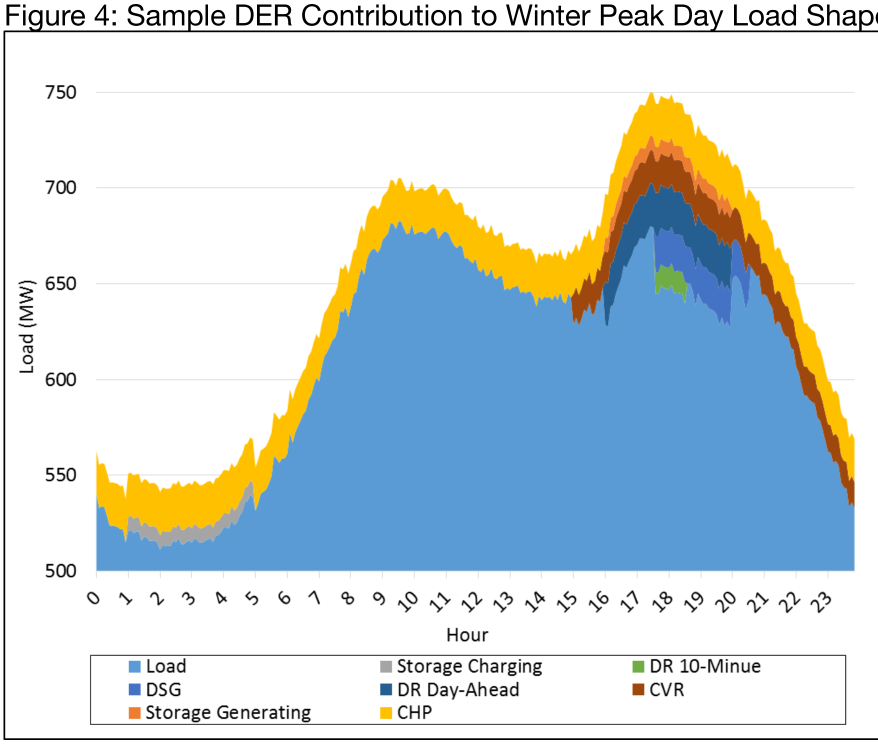
The problem PSE has identified in their Energize Eastside proposal comes about through a series of unlikely events that lead to high winter power flows South to North through the Eastside and creates overloads on certain substations. This problem, if it were ever to occur, would only happen for a few hours of the year. PSE has not estimated the number of hours because the scenarios and stress cases they use don't lend themselves to firm estimates. If PSE could estimate the number of hours they would need winter peak demands to be reduced, it likely would come in 2-3 day consecutive days (cold snaps) and last maybe one to two hours per day.

If Energize Eastside or one of the alternatives were not to be pursued, power outages would not be imminent during these peak demand hours unless at least three failures occur in the grid, a scenario that exceeds NERC reliability requirements. The total number of customers affected by these unlikely outages would be 3 to 5 percent of the 1.1 million customers that will pay for the project with higher electricity bills for the next 40 years.

3.1.2 The DER Solution

Distributed Energy Resources are well suited for targeting winter peak demands in the Eastside Area. Many North American electric system operators invest in DER to avoid transmission and peaking generation. These DER include demand response, storage, EV charging control, DSG, and Distribution Efficiency. If the problem is less than 60 hours per year, it is often much less expensive to manage demand than build Transmission and Generation. Efficiency and CHP tend to provide reductions throughout the day, but can be targeted for time of day contributions. Figure 4 shows a sample peak day load shape for the Puget Sound area with a stack of resources deployed both throughout the day and during a dispatch at 5:30PM during the peak to depict what could happen in the event of an outage.

Figure 4: Sample DER Contribution to Winter Peak Day Load Shape[4]



4 Data source for load shape: Puget Area Net Load for 12.20.2008
http://transmission.bpa.gov/Business/Operations/Misc/default.aspx

* This is not an Eastside area load shape, but is representative of typical winter peak load patterns for NW utilities.

3.2 PSE lags rest of country in DER

Utilities like Puget Sound Energy are way behind other areas of the country in investing in DER, especially demand response. For example, the rest of North America relies on over 60,000MW of demand response, and has eliminated billions of dollars of investments in peaking generation and transmission. The Northwest Power and Conservation Council in their recently released 7th Power Plan, identified 4,300 megawatts of regional demand response potential. PSE currently has no demand response resources it can rely upon.

One example of a DER approach to avoiding transmission project is New York's Brooklyn-Queens demand management project.[5] Growth began to occur in this area from gentrification and employment growth. The utility ConEd estimated the cost to meet this growth would require a $1Billion investment in expanded transmission and substation capacity. In 2014 the Public Service Commission approved the Brooklyn/Queens Demand Management program to invest up to $200MM to avoid the larger infrastructure costs.

The Northwest is not new to Non-Wire Alternatives. In the 1990s BPA was considering transmission across the Cascades to support Puget Sound Area growth and reliability. The transmission cost assessment led to a plan that included aggressive demand side resources in Puget Sound Area, and use of series capacitors for voltage support. These lower cost alternatives deferred the project to the point of never being built.

3.3 EIS Impacts of Alt 2

The negative impacts of Alternative 2 were primarily associated with peaking generation and storage located on the Eastside, and relate to land and greenhouse gas (GHG) emissions.

EQL Energy, however, is not suggesting any new reciprocating engines, or peaking power units as part of EIS Alt. 2. We would expect primarily Combined Heat and Power (CHP) to be constructed in this alternative. CHP often uses biomass/biogas as well as natural gas, and would contribute to GHG, or could have noise impact. CHP has the benefit of also being "energy efficient" because the low value heat is used in industrial or commercial processes. Puget Sound Area has examples of CHP, e.g.,

a. Renton, WA South Treatment Plant that can produce up to 8MW of power. [6]

b. Seattle, WA Enwave Seattle uses biomass and natural gas to produce 50 MW of electricity, and 35 MW of heat equivalent.

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[5] http://www.neep.org/file/2414/download?token=bNV2vVea, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B83594C1C-51E2-4A1A-9DBB-5F15BCA613A2%7D

[6] http://www.kingcounty.gov/services/environment/wastewater/resource-recovery/Energy/Renewable/cogen.aspx

c. Univ. of Washington has 5MW natural gas CHP

CHP would require capacity on natural gas infrastructure.

A Dispatchable Standby Generation (DSG) program would have to go through air permitting compliance, but it is a permittable use. PSCleanAir has suggested that a DSG program like PGE would follow EPA NESHAP RICE rules.

EQL Energy would not recommend storage implementation as described in Alt. 2 of EIS. Six acres of storage does not make much sense. Energy storage highest value is utility owned and managed, yet behind the meter at a customer site. This means customers get backup and reliability, and utility can use for system issues, e.g., winter peak demands. This also avoids the 6 acres of storage containers suggested in the EIS draft (which is ridiculous). Fire and environmental authorities are becoming comfortable with both Li-ion and flow battery technology. PSE is working on a Li-ion storage system at Glacier. State of Washington is also granting $40MM to projects in grid modernization and storage.

Alt 2 would cost less than Alt 1 and provide secondary benefits to customers through improved reliability and resiliency.

Alt 2 would have less risk during weather and natural disasters. DERs would provide backup power during intermediate or sustained outage.

3.4 Alt 2 works with PSE Economic Study of Flexible AC Transmission (FACTS).

Flexible AC Transmission systems on high voltage lines would protect PSE transmission facilities from reaching thermal limits while providing required service to loads. Combining this alternative with appropriately procured and analyzed DER provides a good alternative in Draft EIS.

See PSE Economic Study request at link below.

http://www.oasis.oati.com/PSEI/PSEIdocs/Oct_31_PSET_Economic_Study_Request_from_EQL.PDF

4 Alternative 2 Issue Details

In estimating Non-Wires Alternatives (NWA) like Alternative 2, PSE and its contractors have miscalculated both the technical and cost effective potential for DER in the Eastside area. They have used outdated information and methods, overestimated winter peak demand, improperly calculated "cost effectiveness", and have not considered forecasts of technology cost and performance improvements.

4.1 2014 Non-Wires Alternative Screening Study underestimates DER Potential for Eastside

PSE relies on 2013 Cadmus report and a 2014 E3 report to estimate DER potential on the eastside. These analysis both have used bad or out-of-date data, improper analysis, and have underestimated the DER potential for the Eastside.

E3's 2014 Screening study[7] has bad data and provides no data or description of DER measures that were considered cost effective beyond the PSE baseline:

i. Estimated cost of Energize Eastside at the time of the Screening Study was $220 MM. The cost has been stated to be between $150 and $300MM.

ii. Avoided cost analysis should use avoided cost of Transmission, Generation, and Distribution over 10 year period. A non-wires study should be performed that combines EE project deferral ($155/kW-yr) with avoided cost of peaking Generation Capacity ($184/kW-yr) and generic T&D deferral ($23/kW-yr[8]). The sum of these ($362/kW-yr) will buy PSE more DER than that forecasted by E3 and PSE. Other avoided costs that could play a role include environmental costs, customer cost savings, etc.

  PSE's proposal to rebuild Sammamish-Lakeside-Talbot 115 kV line to 230 kV (Energize Eastside) is a project PSE says is needed to support a 65 to 133MW load growth in PSE's eastside. This transmission project is estimated to cost $300MM or $1,500/kW, about the same capital cost of a 200MW reciprocating engine. By integrating cost of transmission with system generation the cost to serve this 200MW load growth is $600MM or $3,000/kW capital cost.

iii. DER alternatives and cost estimates are not well defined, so it is difficult to evaluate the accuracy of Alternative 2.

iv. Include backup generators to be used as contingency reserve (e.g., Portland General Electric).

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[7] http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/attachment_5_-_screening_study.pdf

[8] E3 2014, page 23 PSE's IRP team also provided avoided generation capacity cost of $184/kW-year and an avoided generic T&D cost of $23/kW-year, which are both represented in 2014 dollars. For this analysis, we assumed that PSE's generic T&D avoided cost and the specific transmission line deferral value related to PSE upgrades are additive. This additive assumption presumes that load reductions in King County can defer the need for more general planned distribution system upgrades, in addition to deferring the construction of the specific Eastside upgrades.

v. Storage is quickly becoming more cost effective and accepted as an alternative to T&D investments.

Recommendation. PSE should redo DSR, DR, and DER forecasts on Eastside using all levelized costs, including transmission (e.g., Energize Eastside), distribution, and supply-side resource alternatives. This will undoubtedly increase the amount of DSR and DER PSE has forecasted in the Draft IRP.

2016 PSE all source RFP. In 2016 PSE is expected to issue an all source RFP for distributed resources. WUTC should ensure that the avoided cost for resources in the Eastside accurately reflect all avoided costs, e.g., transmission, generation, distribution, customer benefits, environmental costs, etc. Through needs assessment of Energize Eastside, PSE's Eastside zone needs winter capacity resources to address transmission congestion and reliability by 2018. The IRP analysis supports addition of further distributed energy resources by 2021.

4.1.1 Defining distribution located resources

PSE should move away from current categories of distribution-side resources towards resource descriptions that meet utility requirements (energy, capacity, reserves, etc). As mentioned above these requirements need better descriptions than just MW and aMW. These requirements need amount, duration, time of day/season, etc.. The distribution located resources PSE has used 3 categories of distribution located resources seen in Cadmus report 2014:[9]

1. DSR, Demand Side Resources, energy efficiency. (which uses bad estimates for peak demand reductions (MW)
2. DR, demand-response
    a. Residential DLC- Water Heat
    b. Residential DLC – Space and Water heat
    c. Residential Critical Peak Pricing (CPP)
    d. C&I CPP
    e. C&I Load Curtailment
3. DG, distributed generation, solar

Figure 5 is suggests a better way to describe all distribution level resources. This categorization allows planners to place different values on a resource based on its quality and location. For instance, getting dispatchable capacity for winter peaks is more valuable ($/kW-year) than non-dispatchable capacity.

[9] https://pse.com/aboutpse/EnergySupply/Documents/IRPAG_Cadmus_presentation_2014-12-08.pdf

Figure 5: EQL Categories of Distributed Energy Resources

4.2 Energy Efficiency contribution to peak demand reductions underestimated

PSE and its consultants use end use load shapes that are out of date to calculated peak demand reduction from energy efficiency programs. Many of these load shapes are based on end uses and technologies from the 1980s. This leads to lower peak reduction (MW) per unit of energy efficiency (MWh). The Northwest Power and Conservation Council has been building a business case to update these load shapes, and is expected to pursue this work in 2016.[10]

4.3 Puget Sound DER and DSR avoided Cross-Cascades Transmission in 1990s

In the 1990s BPA was considering transmission across the Cascades to support Puget Sound Area growth and reliability. The transmission cost assessment led to a plan that included aggressive demand side resources in and use of series capacitors for voltage support. These lower cost alternatives deferred the project to the point of never being built.

DER, when cost of Transmission is considered, will increase dramatically. Estimates in Figure 2 below are estimates based on EQL estimates from WECC and NPCC forecasts.

[10] http://rtf.nwcouncil.org/subcommittees/enduseload/

4.4 Western electricity markets

On March 5, 2015, PSE announced it would participate in the California ISO energy imbalance market that will provide imbalance energy via locational marginal pricing. This decision by PSE management to participate in EIM, demonstrates that PSE believes in a planning and operational paradigm that explicitly recognizes locational value of generating and demand-side resources.

PSE participation in Western energy imbalance market will allow better management of existing transmission assets to existing generation and load balance. In Energize Eastside assessment, PSE has not considered the operational improvements that will exist for generation, demand management, and DER.

PSE joining the EIM does not have much effect on capacity procurement, except a possible reduction in flexibility requirement for resources.

5 Assessment of Eastside DER Potential

EQL Energy expects PSE could add over 160MW of capacity to Eastside DSR forecast by 2021. below. Using an Avoided Cost analysis that includes avoiding cost of Transmission, Distribution, and supply-side generation should include:

Capital Cost ($/kW)	$1,500/kW	Transmission
Capital Cost ($/kW)	$1,500/kW	Thermal Resource (e.g., Peaker)
Capital Cost ($/kW-yr)	$31.00	Distribution
O&M Fixed $/kW-yr	$10.55	
O&M Variable $/MWh	$2.96	

5.1 DSR and DER Contribution

The terminology around resources on the distribution side can be confusing. PSE uses DSR or demand side resources, which includes energy efficiency, demand response, and distributed generation. The EE Documents we reviewed focus on energy efficiency and do not fully address DSR and its impact on peak capacity (MW). Analysis that is reported in Annual Average Megawatts (aMW) provides limited useful information for analyzing for transmission and distribution infrastructure needs.

In our report, we distinguish between DSR and DER forecasts and work to not double count resources.

DSR – Demand Side Resources: efficiency, demand response, and distributed generation (detail and types are unknown in PSE EE analysis). Cadmus 2013 IRP DSR

assessment does not include kW or peak contribution, nor do they provide DR assessments.
DER – Distributed Energy Resources: EQL uses this term to refer to all resources on the distribution system, including distribution efficiency (CVR and power factor correction), demand response, combined heat and power, dispatchable standby generation, and storage.[11]

DER and load management in critical areas is an opportunity to invest in measures that address infrastructure costs and regional load growth while engaging and benefitting customers, just like energy efficiency. Through the evaluation of Energize Eastside it is unclear the extent to which PSE has considered the use of distributed energy resources (DER) in their modeling, either as a resource or as a means to reduce load.

The DER resources described below should be considered in addition to the PSE's DSR contribution to the 100% conservation load forecast.

Many of these DERs are dispatchable, including demand response, dispatchable standby generation (DSG), and energy storage and can therefore target peak load and reduce the need for infrastructure expansion in transmission and distribution.

5.1.1 Distributed Resource Planning

The DER contribution to peak load should be appropriately allocated among existing and future Eastside substations such that DER quantity reasonably matches the load assumed to be present at these substations.

Figure 8 below shows substation locations in the Eastside area that have historically recorded higher load and may be more likely to serve larger customers sites with high DER potential such as commercial/industrial, multifamily residential, institutional, government, campus and hospital loads.

Distributed Resource Planning is a process which more accurately calculates capacity and value for DER in specific areas of a utility distribution system.

On February 6, 2015 the CPUC released a ruling providing guidance to IOUs with respect to the DRPs that are to be filed by July 1, 2015. The document[12] provides additional guidance to utilities beyond AB 327. The guidance specifics 11 components that are to be included, at a minimum, in the locational DER benefits analysis.

Figure 6: Distributed Resource Planning Value Analysis

	Locational Value Component
1	Avoided Sub-transmission, Substation and Feeder Capital and Operating Expenditures: DER ability to avoid Utility costs incurred to increase capacity to ensure the system can accommodate forecasted load growth

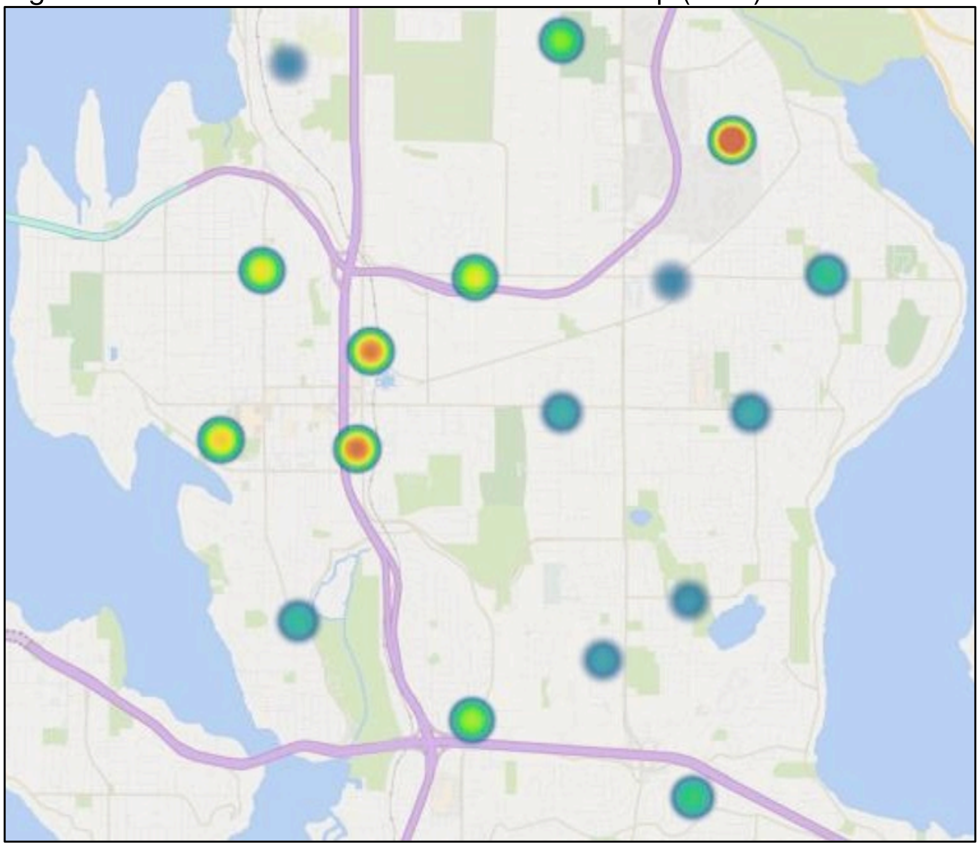
[11] In California Distribution Resources Planning they include energy efficiency into their DER analysis.

12 Docket R14-08-013 DRP Guidance: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M146/K374/146374514.PDF

2	Avoided Distribution Voltage and Power Quality Capital and Operating Expenditures: DERs ability to avoid Utility costs incurred to ensure power is delivered within required operating specifications, including transient and steady-state voltage, reactive power and harmonics
3	Avoided Distribution Reliability and Resiliency Capital and Operating Expenditures: DERs ability to avoid Utility reliability related costs incurred to prevent, mitigate and respond to routine outages (Utilities shall identify specific reliability metrics DERs could improve), and resiliency related costs incurred to prevent, mitigate, or respond to major or catastrophic events (Utilities shall identify specific resiliency metrics DERs could improve)
4	Avoided Transmission Capital and Operating Expenditures: DERs ability to avoid need for system and local area transmission capacity
5	Avoided Flexible Resource Adequacy (RA) Procurement: DERs ability to reduce Utility flexible RA requirements
6	Avoided Renewables Integration Costs: DERs ability to reduce Utility costs associated with renewable integration (for this line item, the Utilities shall attempt to coordinate their efforts with the development of the updated RPS Calculator and the Renewables Integration Charge)
7	Any societal avoided costs which can be clearly linked to the deployment of DERs
8	Any avoided public safety costs which can be clearly linked to the deployment of DERs
9	Definition for each of the value components included in the locational benefits analysis
10	Definition of methodology used to assess benefits and costs of each value component explicitly outlined above, irrespective of its treatment in the E3 Cost-Effectiveness Calculator
11	Description of how a locational benefits methodology can be a into long-term planning initiatives like the Independent System Operator's (ISO) Transmission Planning Process (TPP), the Commission's Long Term Procurement Plan (LTPP), and the California Energy Commission's (CEC) Independent Energy Policy Report (IEPR), including any changes that could be made to these planning process to facilitate more integrated analysis

Figure 7: DRP locational value components (CPUC DRP Guidance)
Notes:
The Resource Adequacy (RA) program, administered by the CPUC and CAISO is a 1-year forward bilateral capacity market. Utilities must procure sufficient resources to meet their expected peak load. Since it began in 2006, utilities were required to procure system-wide peak capacity resources, and local resources as needed in constrained areas. In 2013, a flexible resource requirement was added.

Figure 8: Bellevue Substation Peak Load Heat Map (2006)



Sources:
Data: City of Bellevue substation peak load for 2002 and 2005[13]
See Appendix A for data table
Map: EQL (using Microsoft Excel/Bing Maps)
Note: PSE's transmission topology in this area has changed and is expected to continue to change to serve changing load patterns, therefore this rendering is for sample purposes only.

PSE's existing 115 kV network in the Eastside with suggestions of areas that may experience higher load growth, may require additional infrastructure such as new substations, and therefore would represent advantageous locations for PSE and/or other appropriate parties to incentivize and site distributed energy resources.

Customer Driven DER

DER adoption behavior and demand for services is customer driven based on broad socio-economic factors and technology advancements –not strictly regional or based only on energy cost.

Customer desire for self-reliance is increasing

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13 City of Bellevue Comprehensive Plan Utilities Element Update, November 2006
http://www.ci.bellevue.wa.us/pdf/PCD/PSE_System_Plan_Update_November_2006.pdf
(accessed 06.08.2015)

- **Ernst & Young**: **33%**of the multi-national firms are expected to meet a greater share of their energy needs through **self-generation over the next five years**
- **Navigant**: nearly **75%** of surveyed **residential customers** have "**concerns about the impact electricity costs** have on their monthly budgets, and **63%** are interested in **managing energy used in their homes**"
- **Best Buy**: **36% of residential** customers desire to "financially and physically protect the home" (Home Safeguarding persona)

5.1.2 Distributed Solar

PSE currently has 2,800 customers and 17.4MW of capacity producing 17,037MWh of energy a year. As mentioned above, the Cadmus March 2015 memorandum has many errors regarding PV Solar forecasting and should not be reference by PSE. EQL suggests the following as an estimate of growth in energy from distributed solar.

Figure 9: Range of Distributed Solar by 2030

MW	Capacity	Energy	
	MW	MWh	aMW
Minimum	5	5,000	0.57
BaseCase	50	50,000	5.71
Maximum	400	400,000	45.66

5.1.3 Distribution Efficiency (aka CVR)

In 2007 Puget Sound and 12 other Pacific Northwest Utilities participated in a Northwest Energy Efficiency Alliance (NEEA) pilot to evaluate the energy and capacity savings from operating Conservation Voltage Reduction. [14] The study tested and found a 2 to 4 percent capacity reduction through distribution efficiency projects. An updated 2014 NEEA study found that over half the CVR projects operating in the United States are used for peak demand reductions versus energy efficiency. [15]

Wide scale adoption is beginning. One hurdle to adoption was mentioned in NEEA paper as, "hurdle to CVR implementation includes the lost customer revenue due to CVR rollout. End users reduce energy consumption with CVR and thus lower utility revenue. Utilities are often reluctant to recuperate lost revenue through rate increases, especially during times of slow or no load growth in the utility service area. Utilities can recuperate lost revenue from CVR more easily during periods of more rapid load growth. BPA currently offers incentives for CVR initiatives, which can help with utility cost recovery."

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[14] https://www.leidos.com/NEEA-DEI_Report.pdf

[15] http://neea.org/docs/default-source/reports/long-term-monitoring-and-tracking-distribution-efficiency.pdf?sfvrsn=5 (page 45)

In Washington, Energy efficiency standard I-937 is currently a main driver for CVR implementation for IOUs in Washington State. I-937 mandates IOUs to undertake cost effective energy efficiency measures, such as CVR.

PSE has implemented Conservation Voltage Reduction (CVR) on three to six PSE substations before energy is sent to customers, thereby reducing customers' electric power consumption at the point of consumption on the customers' side of the meter.

CVR will be useful to PSE during winter peak load events due to the influence of resistive loads during those times. Reducing voltage is more effective for winter resistance heating load than for other types of load such as motors that experience greater use in summer for cooling loads.

CVR Target: 2.5% of peak load

5.1.4 Demand Response

By 2021 NPCC estimates the Pacific Northwest states will obtain between 600 and 1,080 MW (or 3%) of winter peak through demand response. At present, only a fraction of that quantity is operational. The Council is currently preparing their 7th power plan and has been working with regional utilities and industry stakeholders. [16]

In a 2015 report for NPCC, Navigant estimates that by 2030 Northwest utilities will have achieved nearly **9% of winter peak** load from demand response.

> *The estimated cumulative DR market potential for capacity programs represents nearly 9% of winter peak load by 2030. This estimate is in line with estimates of other DR potential studies conducted both in the Northwest and other parts of the country.*[17]

Cadmus 2013 DSR report for PSE IRP (page 7) suggests that by 2033 PSE could expect **4.7% of winter peak** to be reduced by Demand Response. Cadmus (2013) is approximately half of Navigant (2015) winter peak reduction forecast.

Two types of DR are likely to be beneficial for eastside areas:

1. Day-Ahead notification peak load reduction DR
2. Emergency 10-minute response DR

Because PSE identifies a peak load resource requirement for the Eastside, we have identified a need to study a demand response program to operate during these times, when PSE's most expensive resources will likely be supplying power. DR programs are often cost effective when displacing this expensive generation, such as PSE's peaking units in Whatcom County. When combined with the additional value of

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[16] https://www.nwcouncil.org/news/meetings/2015/06/

[17] http://www.nwcouncil.org/media/7148943/npcc_assessing-dr-potential-for-seventh-power-plan_updated-report_1-19-15.pdf

providing an infrastructure alternative, the cost effectiveness of such a DR program is improved. Many utilities have implemented day-ahead notification DR programs that call upon enrolled customer or 3rd party resources to reduce their demand for a specified duration, typically 2-4 hours.

In addition, emergency DR programs have successfully been implemented that are capable of fast response for contingency reserve purposes. An example is a 10-minute response program run by Southern California Edison.[18] These programs are typically of higher value due to the short notice time and reliability service provided. SCE's program pays customers $240/kW-year for capacity that successfully participates.

For purposes of the EIS analysis, we have requested conservative DR quantities, shown in Figure 10, for the eastside area that are reflective of percentages of peak load that have been achieved in other areas and below those estimated by Navigant (2015).

Figure 10: Eastside Area DR by 2021

	Eastside DR Estimate
Day-Ahead DR quantity	4%
10-minute DR quantity	1.5%

Because PSE has indicated it may include DR at a level of approximately 2.7% of load by 2020, the 4% DR estimate above for day-ahead programs is incorporated into the 100% conservation forecast used by PSE.[19]

WECC rule Bal-002-WECC-1 was referenced by PSE[20] as one of the reasons the reserve amounts are increasing. This same rule allows a balancing authority to use a number of different resources to meet this requirement including demand response:

> "* A resource, other than generation or load, that can provide energy or reduce energy consumption
> * Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement."

5.1.5 Dispatchable Standby Generation (DSG)

Portland General Electric's DSG program can be used as an example for one designed to provide enhanced reliability in the Eastside area. The DSG program connects customer backup generators to the distribution grid using parallel switchgear at sites such as hospitals, commercial/industrial, and government buildings. PGE remotely dispatches the generators, which are capable of providing uninterrupted service to

18 https://www.sce.com/NR/rdonlyres/7A1BC024-698D-44A0-98D1-ABD8DEE9E451/0/NR572V20810_BIP.pdf

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customers in the event of a grid outage. As part of the program, PGE invests in and owns some of the interconnection equipment, pays for fuel, and performs ongoing testing – required for units at many sites such as hospitals.

DSG potential is determined by using a simple proportion of peak load to DSG capacity installed at PGE and applying it to PSE, as shown in Figure 11 below.

Figure 11: Potential DSG by 2021

DSG Potential	MW
2018 PGE System Peak	4000
Current PGE DSG Capacity	94
DSG MW per System MW	2.5%
2018 PSE System Peak	6000
2018 Eastside Peak Load Forecast	750
PSE System DSG Potential	141
PSE Eastside Area DSG Potential	**18.8**

Note that the size of PGE's DSG program is growing and has plans to increase the program capacity to 125 MW in the next 5 years. Using the proportion method described above, Eastside DSG potential would increase to 22.7 MW.

While the simple DSG potential figures provided here are adequate to inform planning at this stage, additional detailed analysis of DSG capacity will be valuable to PSE and Eastside reliability regardless which transmission projects are built. PSCleanAir has suggested that a DSG program like PGE would follow EPA NESHAP RICE rules. Developer of DSG program would have to go through air permitting compliance, but it is a permittable use.

PSE evaluated using DSG as part of a stipulation in Washington Utilities and Transportation Commission (WUTC) Order 06 in docket UE-130617, in which both parties agreed that PSE should perform an evaluation. Specifically, the Settlement agreement states: PSE agrees to evaluate the PGE Dispatchable Standby Generation (DSG) program, described in the testimony of staff witness Juliana Williams, and either provide a report to the Commission of PSE's conclusions and recommendations by December 1, 2014, regarding the financial and technical feasibility of PSE implementing a similar DSG program in its territory, or file a tariff implementing DSG service by December 1, 2014.

EQL evaluated the PSE report and finds it evasive, inconclusive, and provides the following feedback.

Specific Comments on PSE DSG Findings and select sections. (Dec. 1, 2014)

PSE Findings and Issues	Comment
The primary benefit of the PGE DSG program has been the ability to use the standby generators as a cost-effective resource to meet non-spin operating reserve obligations.	True

PSE does not have a near-term need for non-spin operating reserves and has maintained more than adequate operating reserves during peak events	PSE can use DSG to meet winter peak demands.
While originally established as peaking resource, PGE's use of its distributed standby generator fleet as a peaking resource has been *de minimis* during the life of the program	True. Program is not used as peaking resource.
New Environmental Protection Agency (EPA) emissions requirements that limit operation and testing on diesel-fired emergency standby generators create uncertainty and potential operational constraints during times of peak need	True that EPA rules are in flux for legal reasons. Current laws to watch are state and local air permits. PSCleanAir has suggested that a DSG program like PGE would follow EPA NESHAP RICE rules
Under normal conditions, PGE's standby generator fleet is not economic compared to other alternatives during dispatch decisions	DSG resources are not part of normal dispatched resources
PSE lacks sufficient market research of its customers that would justify investment in a DSG program including potential participation rates and standby generator inventory	Getting this information would be very easy
It is unlikely PSE would be able to implement a DSG program to meet any near-term capacity needs given time, resources, and current systems capability	PSE has time to develop DSG
Section 4.6 Compliance	
Section 5.2 Constraints and Opportunities	
Market Barrier. The 2011 CBRE market search led to no customers expressing interest in further engagement with PSE to interconnect a standby generation system to the grid.	PGE Customers are not that different than PSE Customers. It takes a clear customer value proposition and a few key customers to get it started.
Monitoring and dispatch. PSE does not own software that allows for monitoring and dispatch. PSE need operational and technical knowledge to operate new software.	EQL can assist.
Interconnection. PSE needs specifications for interconnecting standby generators. PSE does not have interconnection agreement	EQL Team can assist
PSE has several low-cost resources to meet non-spin reserve obligations.	**Contradicted in IRP**
Operating reserves exceed need by 200-400MW in most peak hours.	**Contradiction with IRP forecasts**

The NERC contingency reserves standard (BAL-002-WECC-2[21]) applies to the NW Power Pool Reserve Sharing Group (RSG), and requires the RSG to carry the larger of: 3% of load + 3% of generation OR the **Most Severe Single Contingency (what is this for PSE?).** Contingency reserves can be comprised of any combination of seven types defined in the standard. DSG is categorized as the Operating Reserve – Supplemental subcategory of Contingency Reserve. This reserve type was formerly

[21] http://www.nerc.com/files/BAL-002-WECC-2.pdf

defined as Non-Spin reserve, but was changed to supplemental in the current standard to be inclusive of demand side management pursuant to FERC Order 740.[22]

E3 incorrectly ruled out DSG in their 2014 non-wires study for Energize Eastside. They wrote,

> "The US Environmental Protection Agency (EPA) prohibits PSE from relying on customer-sited backup generation for peak shaving of utility loads for resource planning purposes, which PSE planners believe would prevent them from planning grid conditions that rely on backup generation to defer transmission upgrades. This regulation exists primarily to protect local air quality. Therefore, customer-sited backup generation was excluded from the DG non-wires potential estimates."

5.1.6 Combined Heat and Power (CHP)

CHP is the simultaneous use of a fuel, primarily natural gas, to generate electricity and provide heat. When properly designed, CHP is capable of operating at higher efficiency than typical central station power plants.

PSE's Non-Wires Screening Study[23] CHP analysis, performed by E3 and informed by earlier work by Cadmus, found approximately 1 MW of peak CHP resource by 2023 across all of PSE's King County service area. Because this quantity can reasonably be achieved in a single building, the previous estimate is likely not reflective of actual potential. In order to determine this potential, a new study is warranted, especially in light of the amount of growth expected to occur in Bellevue and PSE's need for peak capacity resources.

With the cost of capacity to utilities often exceeding $100/kW-year, infrastructure deferral benefits and electricity sales revenue are components that contribute to cost effectiveness determination and would inform the ultimate potential of this resource. PSE needs over 1000 MW of new capacity by 2025, according to recent IRP development information.[24]

150 MW of load growth could occur in the Bellevue downtown and Bel-Red areas in the next 20 years.[25] The new development represents a large opportunity because many DER technologies such as CHP make the most sense when incorporated during the design phase and provide further benefits when central utility plants serve multiple buildings. But such a strategy requires deliberate planning and clear leadership to become successful.

Because Downtown and Bel-Red will consume significant quantities of natural gas regardless of PSE's electricity infrastructure decisions, the extent to which this gas can be put to use generating electricity should be studied. Additionally, the civil construction work to occur in these areas in future years points toward investigation of co-locating energy infrastructure and potentially common use infrastructure such as district energy where central utility plants supply heating, cooling and electricity to a potentially large development, such as the Spring District.

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[22] http://www.ferc.gov/whats-new/comm-meet/2010/102110/E-6.pdf

[23] http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/attachment_5_-_screening_study.pdf

[24] May 19 PSE IRP Advisory Group meeting materials

[25] Exponent Reliability Study

Recommendation: Explore 3rd party or PSE owned central utility plants with CHP in parts of the Eastside that will experience the most new construction.

Figure 12: Base CHP Quantity 2021

	Eastside CHP Estimate
CHP	4% of peak load

Note:
Transmission topology alternative D adds Eastside generation. Because a larger central plant CHP project should be considered for this option, selection of this alternative could result in a substantially higher CHP penetration.

5.1.7 Energy Storage

Energy Storage is receiving a great deal of attention right now due to the cost declines seen in recent years and an increasing number of predictions for continuing storage cost reduction.[26] PSE, Avista, and Snohomish PUD have received $15MM to study use of energy storage.

Figure 13: Energy Storage Quantity 2021

	Eastside Storage Estimate
Storage	2% of peak load

5.1.8 PSE DER Potential & Interconnection

Many existing and future commercial, multifamily residential, institutional and corporate campus sites are centered near downtown Bellevue, Bel-Red and South Redmond– areas that are driving the need for new transmission and distribution infrastructure. Cost effectiveness of DER investments in these areas stands to be influenced to the extent they can substantively contribute to load service and reliability needs. In other words, a next-generation energy system, which is being pursued by leading utilities, will make full use of DERs by integrating their capabilities into utility planning and operations, a step that may well deliver cost reductions to PSE ratepayers – and one that will require developing appropriate compensation mechanisms to DER owners. In addition, PSE or 3rd parties could own DERs that may be designed to provide benefits directly to specific customers (i.e. storage installed behind-the-meter), while simultaneously providing infrastructure deferral benefits enjoyed by all ratepayers.

DER interconnection and operations practices will become more important as these resources grow in quantity and take on additional performance obligations related to reliability and system resiliency. Should PSE and Eastside communities decide to move to make full use of DER options as part of a strategy to support and enhance regional growth, appropriate technical interconnection and operations procedures and

[26] Sample media story addressing storage:
http://cleantechnica.com/2015/03/04/energy-storage-could-reach-cost-holy-grail-within-5-years/

standards will be needed. DER best practices are emerging from California, New York, and Hawaii, states that have taken the lead. The standards by which PSE designs and operates the 12.5 kV distribution system will be important for DERs so as to ensure maximum utilization of the system, including supporting 2-way power flows.

Most distribution systems move electricity in one direction – from power plants to substations to customers. But when customers interconnect generation resources, their power will flow the other direction, serving other customers and in some cases flowing power back to the substation itself and serving load further upstream, possibly at higher voltages. While there is no fundamental reason why these new flows of electricity cannot occur, investments in additional monitoring equipment and advanced control technologies will be needed.

These types of investments, involving software, communications, controls, and switching equipment, are also likely to provide reliability benefits by enhancing the ability of utilities to automatically switch customers to alternate feeds in the event of an outage on a given distribution circuit.

Lifetime cost analysis for Energize Eastside

What will Energize Eastside cost customers over its lifetime?

February 17, 2016

If those numbers seem large, it's mostly

because state policy guarantees PSE

a return on investment of 9.8% per year

for infrastructure projects.

Interest adds up quickly at that rate.

What will Energize Eastside cost customers over its lifetime?

CENSE engaged Jeffrey King, a utility financing expert, to give us better answers to this question. Mr. King worked as a Senior Resource Analyst for the Northwest Power Planning Council for nearly 30 years.

Mr. King used MicroFin modeling software to come up with three different lifetime scenarios (45, 55, and 65 years) using a project base cost of $100 million. The details of his analysis can be found in the following pages of this document.

A base cost of $100 million is considerably less than PSE's cost estimates, but the results of the model can simply be scaled by the ratio of the actual cost to the base cost. For example, if the cost were to be $300 million (three times the base cost), the results from Mr. King's analysis could simply be multiplied by a factor of 3.

PSE has not updated cost estimates for Energize Eastside, and the EIS contains no reference to the project's cost. Our best guess is that it will cost at least $250 million. We scaled the results of Mr. King's analysis by a factor of 2.5 to arrive at the following lifetime costs:

Lifetime of Energize Eastside *transmission line*	*Total cost to ratepayers*
45 years	$1.45 billion
55 years	$1.74 billion
65 years	$2.03 billion

If those numbers seem large, it's mostly because state policy guarantees PSE a return on investment of 9.8% per year for infrastructure projects. Interest adds up quickly at that rate.

Revenue collected by PSE for this level of investment would be approximately $32 million per year. This is an important number, because it is possible to buy quite a bit of technology to implement alternative solutions with expenditures of that size. Because alternative solutions can be built incrementally as the need arises, we probably wouldn't need to continue that level of investment for 45-65 years.

We see an opportunity to build a solution of just the size we need and save a lot of money for ourselves, our children, and our grandchildren.

Estimation of the fixed charge rate and revenue requirements for the proposed Energize Eastside transmission project

Prepared for CENSE.org by Jeffrey C. King & Associates
February 10, 2016

The Energize Eastside transmission project is intended to reinforce the Puget Sound Energy electrical distribution system on the east side of Lake Washington in King County, Washington, an area that has experienced significant growth over the past several decades without concurrent expansion of the local transmission system. The Energize Eastside project is proposed to be an overhead single-circuit 230 kV transmission line[1] extending from the existing Talbot Hill substation in Renton approximately 18 miles north and east to the existing Sammamish substation in Redmond, passing through Bellevue, Kirkland and other Eastside communities. The line would feed, from both ends, a new or expanded substation in the Bellevue vicinity. Preconstruction fieldwork commenced in January 2015 and construction is proposed to commence in the second quarter of 2017 for fourth quarter 2018 energization.

The purpose of the work described in this paper is to estimate the levelized fixed charge rate (FCR)[2] and revenue requirement[3] of the proposed Energize Eastside project. Revenue requirement can subsequently be used to estimate the rate impact of the proposed project.

The MicroFin Levelized Project Revenue Requirements model, developed by the Bonneville Power Administration and the Northwest Power and Conservation Council is used to calculate project FCRs and revenue requirements. MicroFin uses normalization accounting[4] to simulate investor-owned utility financing of electric power projects. MicroFin calculates total project investment costs using a construction cost estimate, construction cash flows and financing information. Annual cash flows over the forecast service life of the project are then calculated. Components of annual cash flows for transmission projects include debt service, debt interest, return on equity, equity recovery, income and property taxes, insurance, operation and maintenance expenses, interim capital replacement costs and the cost of losses. The net

[1] *The project may use towers capable of carrying a future second 230KV line.*

[2] *The Fixed Charge Rate is the levelized annual cost of financing the construction of a project over the economic life of the project, expressed as a percentage of total investment cost. The total investment cost is the cost of developing and constructing a project (capital cost), including price escalation and interest incurred during the construction period.*

[3] *Project Revenue Requirements are the annual costs of constructing and operating a project. Revenue requirements consist of the annual financing costs (Fixed Charge Rate x Total Investment Cost) plus annual operation and maintenance costs (expensed and capitalized).*

[4] *Normalization accounting shifts a portion of the benefit of accelerated tax depreciation to later years of the life of a project. Normalization accounting is mandated by the Internal Revenue Service for investor-owned utilities.*

of these comprise annual revenue requirements. Annual revenue requirements may vary over the life of a project due to factors such as cost escalation and a service life that exceeds the financing life. A levelized revenue requirement (an equivalent constant value) is then calculated by taking the net present value of the series of annual revenue requirements, then calculating a constant series of annual payments with equivalent net present value.

For calculating the FCR and revenue requirements of a transmission project, MicroFin requires information regarding project capital costs, operation and maintenance (O&M) costs, interim capital replacement costs; construction cash flows; the project owner's financial structure, tax obligations and incentives, if any; forecast general inflation and escalation rates of capital and O&M costs; and electrical losses. Other MicroFin input data such as fuel cost and emission costs are not applicable to a transmission project. The information needed by MicroFin to calculate a fixed charge rate and revenue requirement for a transmission project is shown in Table 1 with the known or assumed values for the Energize Eastside project and sources of this information. Additional information regarding the derivation of certain input assumptions is provided in the Appendix.

Capital costs for transmission projects vary widely and the capital cost estimates for the proposed Energize Eastside project were not available for this analysis. $100 million is used as a placeholder. $100 million is substantially greater than typical cost for a 230kV project of this size, however the congested nature and environment of the proposed corridor will likely increase construction cost well above typical costs. Once construction cost estimates are available, revenue requirements can be calculated by taking ratios of $100 million. Because all cost input assumptions for this project are a constant percentage of the capital cost and all input costs are independent of the load factor of the line, the relationship of overnight capital to revenue requirements is linear.

An uncertainty of some importance is the assumed service life of the project. PSE estimates that the service life of transmission facilities will range from 45 to 65 years. For this reason, FCR and revenue requirements calculations were run for 45, 55 and 65 year service lives.

The estimated fixed charge rates and levelized annual revenue requirements for a $100 million overnight capital cost investment in a project with the characteristics of the proposed Energize Eastside project are shown in ***Table 2*** for 45, 55 and 65 year service lives. Also shown is the AFUDC ratio, to calculate total plant investment *(basis of the fixed charge rate)* from the overnight construction cost. All values are "nominal", e.g., include the effects of forecast general inflation, and therefore represent the actual dollar impact on rates.

Table 1: Modeling input data values and sources

Input	Value	Source	Note
Plant Data:			
Start of construction	1/1/2017	Approximation of PSE Q2 2017	Closest MicroFin time series increment.
Service date	1/1/2019	Approximation of PSE end of Q3 2018	Closest MicroFin time series increment
Service life	44, 55 and 65 years	PSE 2014 FERC Form 1 page 123.14	
Overnight capital cost	100 million	Placeholder	
Annual construction cash flow	50%/yr	JCK assumption	
Capital cost real escalation	Zero	JCK assumption	Reflects currently low rates of labor and equipment price escalation.
Annual operation and maintenance expenses	1.3% of overnight capital cost	See Appendix	Exclusive of property tax and insurance.
O&M cost real escalation	Zero	JCK assumption	Reflects currently low rates of labor and equipment price escalation.
Generation integration costs	n/a		No significant generation would be interconnected to the proposed project.
Control and dispatch costs	Zero		Project is assumed not to significantly affect the control and dispatch costs of the PSE system
Cost of losses	Zero		Project will likely reduce system losses overall but extent not known w/o load-flow analysis
Interim capital replacement	1.2% of overnight capital cost	See Appendix	Levelized annual cost of replacing major equipment over the life of the project.
Input price year dollars	2016		Cost estimates are assumed current
Project financing			
Debt term	30 years	JCK assumption	
Equity recovery period	30 years	JCK assumption	
Debt/Equity ratio	52/48	PSE 2014 FERC Form 1, page 109.2	WUTC approved, effective 1/2014
Debt interest rate (nominal)	5.75%	See Appendix	Average of recent PSE 30-year issues plus 0.25% for Dec 2015 Federal Reserve increase.
Return on equity (nominal)	9.8%	PSE 2014 FERC Form 1, page 109.2	WUTC approved, effective 1/2014
Debt financing fee	1.0% of issue	See Appendix	Average of recent PSE 30-year issues.
Discount rate (nominal)	6.7%	Calculated	After-tax cost of capital for the assumed financial parameters (PSE perspective)
General inflation rate	See Appendix	NPCC 7th Plan (draft)	
Taxes and Insurance			
Federal income tax rate	35%	PSE 2014 FERC Form1	
FIT recovery period	20 years	IRS Pub 946	Recovery period for transmission assets
Federal investment tax credit	None		
State income tax rate	None		
State investment tax credit	None		
Annual property tax rate	0.95% of overnight capital cost	See Appendix	Average King Co. property tax rate x ratio of assessed to true value for King Co.
Annual property insurance rate	0.06% of overnight capital cost	See Appendix	Average PSE property insurance cost on electric plant property

Table 2: Estimated AFUDC ratio, fixed charge rates and revenue requirements *(Nominal values)*

Case	AFUDC Ratio	Annual FCR (% Total Plant Investment)	Annual Revenue Requirement ($/yr)
$100 MM overnight cost; 45-year useful life	1.038	9.9%	$12,869,000
$100 MM overnight cost; 55-year useful life	1.038	9.7%	$12,622,000
$100 MM overnight cost; 65-year useful life	1.038	9.6%	$12,505,000

Appendix: Derivation of certain modeling input assumptions

Operation and maintenance costs: Operation and maintenance costs for this project include the expensed costs of operating and maintaining the system plus administrative and general costs. Major equipment replacement costs are normally capitalized and are considered separately. System control and dispatch costs are not included because it is believed that PSE control and dispatch costs would not be significantly affected by the proposed project. Generation integration costs are also excluded because no significant generation would be interconnected to the proposed project. Operating and maintenance costs were estimated from PSE operation and maintenance cost data appearing on page 321 of the PSE 2014 Federal Energy Regulatory Commission (FERC) Form 1 annual report. Administrative and General (A&G) costs (Form 1 page 323), excluding property insurance (entered separately in MicroFin) were calculated as a percentage of total O&M. That percentage was applied to transmission O&M, as calculated above, to obtain an estimate of transmission A&G. The transmission O&M estimate plus the transmission A&G estimate were then divided by total transmission asset value (Form 1 page 206) to obtain transmission O&M plus transmission A&G as a percentage of transmission capital cost.

Interim capital replacement cost: Interim capital replacement cost is the annual cost of replacing major components over the expected service life of the project. Information regarding utility interim capital replacement costs is scarce – these costs are rolled into annual capital costs that also include system expansion and disaster recovery expenditures. Reported interim capital replacement expenditures by North American utilities for substation and transmission assets are relatively high, about 5% of asset value annually. However, North American transmission systems are aging - the average age of large power transformers is reported to be 40 years. Because replacement costs increase with age, the levelized lifetime replacement rate for a new transmission line will be less than the replacement rate for a 40 year old facility. Assuming an exponential increase in replacement costs over the service life of a facility, a 5% rate at age 40 yields a levelized lifetime rate of 1.2% of asset value for a facility with an expected service life of 55 years (midpoint of PSE service life estimates).

Debt interest rate and financing fee: The average interest rate of 30-year PSE bonds issued from 2009 through 2014 is 5.48% (PSE FERC Form 1 page 256 and 257). To this was added 0.25% to account for the December 2015 Federal Reserve rate increase. The result was rounded to 5.75%. The same source was used to calculate an average debt placement fee of 1.03% (rounded to 1%) for the same bond issues.

General inflation rate: The forecast general inflation rate used by the Northwest Power & Conservation Council for its 7th power Plan (draft) was adopted for this study. That series is 1.6% for 2015, 1.7% for 2016, 1.6% for 2017, 1.7 % for 2018-2028 and 1.8% for 2029 and on.

Property tax: An average property tax rate for King County, Washington was calculated as the product of assessed property value to true property value (Property Tax Ratio) and the average King County property tax rate, as follows:

Property tax ratio for King Co.	93.800%	(WA Dept. of Revenue)
Average property tax rate for King Co.	1.014%	(www.smartasset.com)
Average property tax rate on true value	0.950%	

Property insurance: Total PSE insurance expenditures (2014 PSE FERC Form 1 page 323) were divided by total electric plant in-service asset value (Form 1 page 206) to yield a 0.06% rate based on asset value.

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January 2016

EXPERIENCE

2011 - Present: President, Jeffrey C. King and Associates. Jeffrey C. King and Associates is a consulting firm engaged in energy-related analysis for public and private clients. The principal topics of the firm include energy policy analysis, technical, economic and environmental assessment of electric power generating technologies and power price forecasting.

2011: Planning Approaches for Water Resource Development in the Lower Mekong Basin. The purpose of this project, funded by USAID through AECOM International Development and Portland State University, was to propose and evaluate methods for improving planning for energy development of the Lower Mekong Basin (LMB). Mr. King was responsible for preparing the assessment of potential alternatives for power production in the LMB.

1984 - 2011: Senior Resource Analyst, Northwest Power Planning Council, Portland, Oregon. Mr. King was responsible for assessing the commercial availability, performance, economics, development potential and issues associated with development and operation of electric power generating resources. Mr. King was also responsible for the Council's forecast of wholesale electric power prices, using the AURORAxmp® Electric Market Model, a proprietary model of the western electric power system. The model is also used to assess the CO2 production and other effects of regulations and policies affecting the power system. Mr. King's activities included assessment and analysis, operation of computer models, preparation of issue papers, organization and chairing of advisory committees, administration of contracts, presentations to the Council and interested organizations, and work with utilities, government agencies, research organizations, resource developers and public interest groups. Information developed by Mr. King is widely employed by utilities, agencies and others outside the Council.

2008 - 2010: Chief Planner, National Energy Development Framework Project, State of Eritrea. Mr. King served as the chief planner for preparation of a 20-year energy development framework and five-year action plan for the State of Eritrea. The framework, funded by USAID, presents a vision for a future energy supply system for Eritrea to support an adequate, reliable, affordable, and sustainable energy supply for rural and urban areas, transportation, industry, and water resource, port and tourism development. Mr. King fashioned the contributions of specialists in various energy resources into a coherent description of Eritrean energy resource potential, formulated goals and objectives in response to concepts provided by the State of Eritrea, and lead the development of a proposed Eritrean energy future, action plan and framework for implementation.

1974 - 1984: Staff Engineer, Energy Systems Department, Battelle, Pacific Northwest Laboratories, Richland, Washington - Mr. King managed and contributed to projects involving assessment of the economic and environmental aspects of electric power conservation and supply resources and application of decision analysis techniques to energy policy and technology issues. Projects included the first assessment of conservation and generating resources for the newly-formed Northwest Power Planning Council, assessment of generating resource alternatives for the State of Alaska, assessment of decommissioning costs and priorities for retired nuclear facilities and analysis of high-level nuclear waste disposal alternatives.

1964 - 1970: Test Engineer, Nuclear Power Division, Puget Sound Naval Shipyard, Bremerton, Washington - Mr. King was responsible for the planning and execution of acceptance testing procedures for the construction, overhaul and refueling naval nuclear power plants.

EDUCATION

Bachelor of Science in Mechanical Engineering, University of Washington, Seattle, Washington. 1964.

Graduate Studies, Zoology, University of Washington, Seattle, Washington. (1970-1972).

Graduate Studies, Regional Planning, University of Pennsylvania, Philadelphia, Pennsylvania. (1972-1974).

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The INGAA Foundation, Inc.

Criteria for Pipelines Co-Existing with Electric Power Lines

Prepared For:
The INGAA Foundation

Prepared By:
DNV GL

October 2015

The INGAA Foundation
FINAL Report No. 2015-04

Report name:	Criteria for Pipelines Co-Existing with Electric Power Lines
Customer:	The INGAA Foundation, Inc.
Contact person:	Richard Hoffmann
Date of issue:	October 5, 2015
Project No.:	PP105012
Organization unit:	OAPUS310 / OAPUS312
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Document No.:	1E02G9N-4

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Objective:

The primary objective of this report is to present the technical background, and provide best practice guidelines and summary criteria for pipelines collocated with high voltage AC power lines. The report addresses interference effects with respect to corrosion and safety hazards, and fault threats.

Prepared by:	Verified by:	Approved by:
Shane Finneran Senior Engineer	Barry Krebs Principal Engineer	Lynsay Bensman Head of Section, Materials Advisory Service

Rev. No.	Date	Reason for Issue	Prepared by	Verified by	Approved by
Draft	2015-06-18	First Issue	SF	BK	LB
0	2015-10-05	Final Issue	SF	BK	LB

EXECUTIVE SUMMARY

The primary objective of this report is to present the technical background, and provide best practice guidelines and summary criteria for pipelines collocated with high voltage AC power lines. The report addresses interference effects with respect to corrosion and safety hazards, and fault threats. The guidelines presented address mitigation and monitoring, encroachment and construction, risk severity classification, and recommendations for further industry development.

This report addresses the technical background to high voltage interference with respect to collocated and crossing pipelines, and presents basic procedures for dealing with interference scenarios. The provisions of this document are recommended to be used under the direction of competent persons, who are qualified in the practice of corrosion control on metallic structures, with specific suitable experience related to AC and/or DC interference and mitigation. This document is intended for use in conjunction with the reference materials cited herein.

Collocated pipelines, sharing, paralleling, or crossing high voltage power line rights-of-way (ROW), may be subject to electrical interference from electrostatic coupling, electromagnetic inductive, and conductive effects. If the interference effects are high enough, they may pose a safety hazard to personnel or the public, or may compromise the integrity of the pipeline. Because of increased opposition to pipeline and power line siting, many future projects propose collocating high voltage alternating current (HVAC) and high voltage direct current (HVDC) power lines and pipelines in shared corridors, worsening the threat.

Predicting HVAC interference on pipelines is a complex problem, with multiple interacting variables affecting the influence and consequences. In some cases, detailed modeling and field monitoring is used to estimate a collocated pipeline's susceptibility to HVAC interference, identify locations of possible AC current discharge, and design appropriate mitigation systems to reduce the effects of AC interference. This detailed computer modeling generally requires extensive data collection, field work, and subject-matter expertise. Basic industry guidelines are needed to help determine when more detailed analysis is warranted, or when detailed analysis can be ruled out based on the known collocation and loading parameters. A consistent technical guidance document will benefit the pipeline industry by increasing public safety and allowing for an efficient approach in assessment and mitigation of threats related to high voltage interference.

The INGAA Foundation contracted Det Norske Veritas (U.S.A), Inc. (DNV GL) to develop this guidance document. The project included a detailed industry literature review to identify applicable technical reports, international standards, existing guidance and operator procedures. In addition to the literature review, numerical modeling was performed to determine the effects of key parameters on the interference levels. The document addresses interference effects with respect to corrosion and safety hazards, mitigation, monitoring, encroachment and construction, prioritization and modeling. It also includes recommendations for further development.

The following severity ranking tables were developed for key variables and their impact on the severity of AC interference. Further background for the development of these rankings is provided throughout the report. Guidelines for determining the need for detailed analysis and applying these severity rankings are provided in Section 6.2.

Separation Distance

Table 3-Severity Ranking of Separation Distance

Separation Distance - D (Feet)	Severity Ranking of HVAC Interference
$D < 100$	High
$100 < D < 500$	Medium
$500 < D < 1{,}000$	Low
$1{,}000 < D \leq 2{,}500$	Very Low

HVAC Power Line Current

Table 4-Relative Ranking of HVAC Phase Current

HVAC Current - I (amps)	Relative Severity of HVAC Interference
$I \geq 1{,}000$	Very High
$500 < I > 1{,}000$	High
$250 < I < 500$	Med-High
$100 < I < 250$	Medium
$I < 100$	Low

Soil Resistivity

Table 5-Relative Ranking of Soil Resistivity

Soil Resistivity - ρ (ohm-cm)	Relative Severity of HVAC Corrosion
$\rho < 2{,}500$	Very High
$2{,}500 < \rho < 10{,}000$	High
$10{,}000 < \rho < 30{,}000$	Medium
$\rho > 30{,}000$	Low

Collocation Length

Table 6-Relative Ranking of Collocation Length

Collocation Length: L (feet)	Relative Severity
$L > 5{,}000$	High
$1{,}000 < L < 5{,}000$	Medium
$L < 1{,}000$	Low

Collocation / Crossing Angle

Table 7-Relative Ranking of Crossing Angle

Collocation/Crossing Angle - θ (°)	Relative Severity
$\theta < 30$	High
$30 < \theta < 60$	Med
$\theta > 60$	Low

The research and analytical studies accentuated the need for accurate power line current load data when assessing the susceptibility of a steel transmission line to high voltage interference. For this reason, collaboration between the respective pipeline and power line operators is advised to accurately determine where detailed assessment is required, and develop efficient mitigation where necessary.

The general safety recommendations and guidelines for interference analysis presented in Section 6 provide guidance on the relative susceptibility of AC interference associated with the selected variables. They primarily address the likelihood or susceptibility of AC interference, and do not address the consequence aspect of an overall risk assessment, as these details are specific to each individual assessment.

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Acronyms

AC	Alternating Current
CAPP	Canadian Association of Petroleum Producers
CFR	Code of Federal Regulation
CP	Cathodic Protection
CSA	Canadian Standards Association
CTS	Coupon Test Station
DC	Direct Current
DCD	DC Decoupler
DOC	Depth of Cover
DOT	Department of Transportation
EMI	Electromagnetic Interference
ER	Electrical Resistance
FBE	Fusion Bonded Epoxy
GPR	Ground Potential Rise
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEEE	Institute of Electrical and Electronics Engineers
IF	Isolation Flange
INGAA	Interstate Natural Gas Association of America
LEF	Longitudinal Electric Field
MPY	Mils per year
OSHA	Occupational Safety and Health Administration
PRCI	Pipeline Research Council International
ROW	Right(s) of Way
TLM	Transmission Line Model

1 INTRODUCTION

Trends within both the electric power and pipeline industries have increased the number of projects that co-locate high voltage alternating current (HVAC) and high voltage direct current (HVDC) power lines with steel transmission pipelines in shared rights-of-way (ROW). The primary objective of this report is to provide technical guidance and present best practice guidelines and summary criteria for steel transmission pipelines collocated with high voltage AC power lines.

Topography, permitting requirements, land access, increasingly vocal public opposition to infrastructure projects, and environmental concerns, including protected regions, all have led to an increase in sharing of common utility corridors. While there are numerous benefits to common utility corridors, there are also many concerns. Collocated steel transmission pipelines that share, parallel, or cross high voltage power line ROW may be subject to electrical interference from electrostatic coupling, electromagnetic inductive, and conductive effects. If these interference effects are high enough, they may pose a safety hazard to personnel or compromise the integrity of the pipeline.

Pipelines collocated with overhead HVAC lines account for a significant portion of the high voltage interference conditions encountered in the transmission pipeline industry. However, interference effects due to buried power lines and HVDC are also of concern to pipeline operators where close collocations exist. As aboveground HVAC is still the primary concern for pipeline interference, it is the primary focus of this report. However, comparison background and technical discussion is included related to HVDC and buried power line interference as well, and the effects of both should be considered on a case-by-case basis when steel transmission pipelines are closely collocated with these systems.

Numerous methodologies exist to analyze alternating current (AC) interference for specific collocations and crossings, but the analysis generally requires extensive data collection and detailed computational modeling. The accuracy of these models is sensitive to the HVAC power line operating parameters, which can often be difficult or costly for pipeline operators to obtain from electric power companies. Basic guidelines and prioritization criteria have been established in this report to provide guidance for pipeline operators to aid in a risk-based decision-making process and help prioritize regions for detailed modeling and mitigation design, or exclude further modeling analysis for a given region.

This report addresses interference effects related to encroachment and construction, corrosion and safety hazards, mitigation, and monitoring. This project included a detailed industry literature review to identify applicable technical reports, international standards and, guidance documents. Several INGAA members provided procedures. In addition to the literature review, numerical models were developed and trends presented detailing the effects of critical variables on interference levels under the conditions defined.

2 INDUSTRY LITERATURE REVIEW

There has been extensive research performed to understand the risks of high voltage interference and to develop efficient mitigation techniques. The effects of HVAC interference from a personnel safety and corrosion standpoint are a risk identified in much of the literature. Case studies in North America, the UK, and continental Europe have identified and documented AC corrosion concerns. Through-wall defects have been reported with corrosion rates greater than 50 mils/year (mpy) observed.[1]

In development of this guidance document a literature review identified and reviewed more than fifty technical references, US and International standards, existing guidance documents, research theses, journal manuscripts, and technical symposia papers. Additionally, INGAA collected operating procedures and guidelines from 10 member companies for review and comparison.

Where published, historically identified corrosion defects and pipeline failures associated with AC corrosion degradation have been reviewed and a selection are presented as case studies in Appendix A, demonstrating the magnitudes and variability in corrosion rates possible with AC accelerated corrosion.

The primary finding from this review is that there is significant variation in operating procedures and technical literature with respect to AC interference. Various companies' procedures were compared with published industry guidance, historical project data, and project experience to determine a best practice approach. Details and cross references are presented in each of the subsections of this document with a detailed review of the technical literature, case studies, and company procedures provided in Appendix A.

3 HIGH VOLTAGE INTERFERENCE ON ADJACENT PIPELINES

3.1 HVAC Interference Modes

Electrical interference from capacitive, electromagnetic inductive, and conductive coupling can affect pipelines collocated in close proximity to HVAC power lines. The subject of AC interference has been a growing concern across multiple industries in recent decades as improved pipeline coatings and utility ROW congestion has contributed to an increase in identified AC corrosion incidents. Recent trends in the high voltage electric power transmission industry are leading to increased power capacity and higher operating currents in certain systems, in part to overcome long distance transmission line losses.[2] This increase in operating current has a direct effect on the level of electromagnetic interference (EMI) and the corresponding magnitude of AC interference on affected pipelines. This trend toward elevated operating currents may present a significant challenge for achieving adequate mitigation on pipelines crossing or collocated with the high voltage power lines.

The three primary physical phenomena by which AC can interfere or "couple" with pipelines are through capacitive, resistive, or inductive coupling as detailed in Sections 3.1.1 through 3.1.3. High voltage interference can occur during normal operation, generally referred to as steady state, or during a power line fault. HVAC power line faults are any abnormal current flow from the standard intended operating conditions, and discussed further in Section 3.1.4.

3.1.1 Capacitive Coupling

Capacitive coupling, or electrostatic interference, occurs due to the electromagnetic field produced by AC current flowing in the conductors of a high voltage power line, which can induce a charge on an above ground steel pipeline that is electrically isolated from the ground. Capacitive effects are primarily a concern during construction when sections of the pipeline are aboveground on insulating supports, as indicated in Figure 1. The pipeline can build up charge as a capacitor with the surrounding air acting as the dielectric, which can maintain the electric field with a minimum loss in power, resulting in a potential difference with surrounding earth.

The magnitude of potential is primarily dependent on the pipeline proximity to the HVAC conductors, the magnitude of power line current, and the individual phase arrangement. If the potential buildup due to capacitive coupling is significant, electrostatic interference may present a risk of electric shock or arcing. While elevated capacitive voltages may exist, the corresponding current is generally low, resulting in low shocking consequence[3,4].

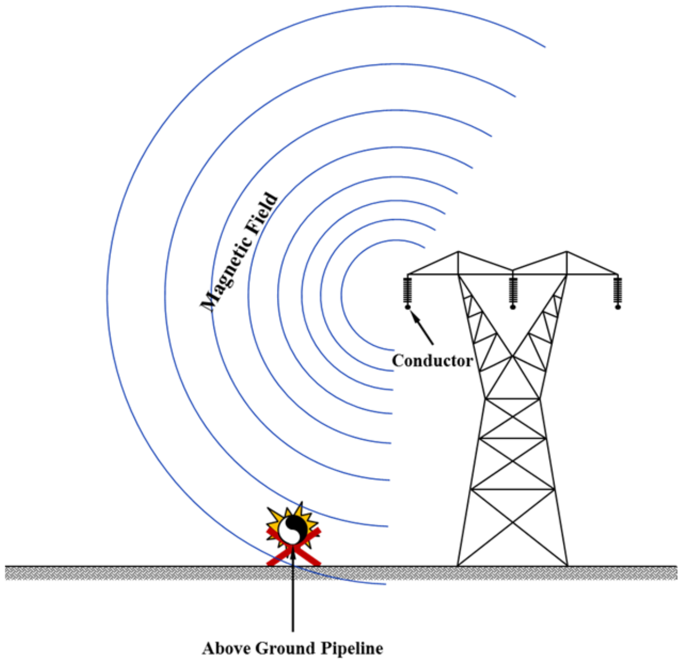

Figure 1. Illustration of Capacitive Coupling

3.1.2 Inductive Coupling

Electromagnetic induction is the primary interference effect of an HVAC power line on a buried steel pipeline during normal steady state operation. EMI occurs when AC flowing along power line conductors generates an electromagnetic field around the conductor, which can couple with adjacent buried pipelines, inducing an AC voltage, and corresponding current, on the structure as depicted in Figure 2. This induced AC potential may present a safety hazard to personnel, and can contribute to AC corrosion of the pipeline, as discussed in Section 3.3.1.

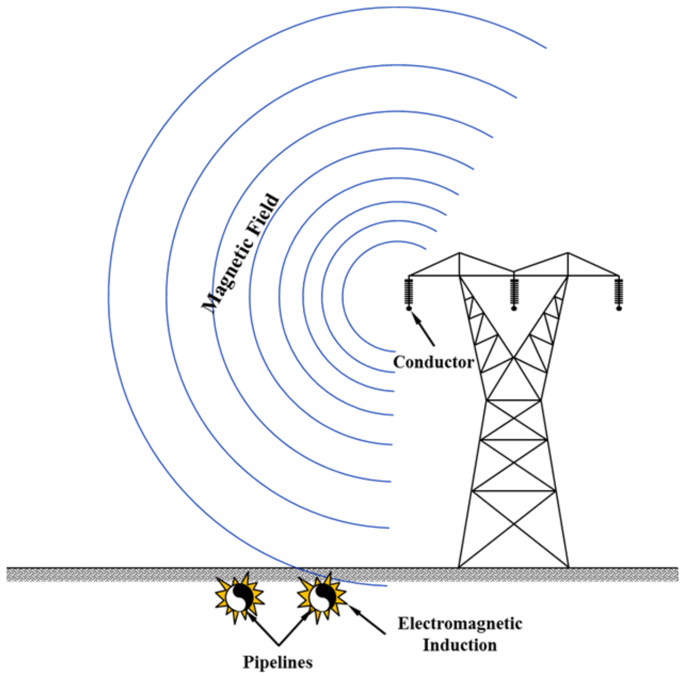

Figure 2. Illustration of Steady State HVAC Inductive Interference

The inductive effects of the HVAC power line on an adjacent pipeline are a function of geometry, soil resistivity, coating resistance, and the power line operating parameters. The geometry characteristics include separation distance between the pipeline and the towers, depth of cover (DOC), pipe diameter, angle between pipeline and power line, tower footing design, and phase conductor configuration. These parameters remain relatively constant over the life of the installation. The coating resistance, power system resistance, and soil resistivity may vary with the seasonal changes and as the installations age, but they are considered constants for most analyses. However, the operating parameters of the power line – such as phase conductor load, phase balance, voltage, and available fault current – all have an influence on the effects of AC interference, and can vary significantly. The individual conductor current load and phase balance is dynamic and changes with load requirements and switching surges. These variations in operating parameters contribute to variations in levels of AC interference. During normal HVAC operation, the current load varies as the load demand changes both daily and seasonally.[3,5] While normal operating conditions are often referred to as "steady state" throughout the industry, the term is somewhat misleading as the current loads and corresponding induced AC potentials can be continuously varying, adding further complexity to quantifying interference magnitude.

For a straight, parallel, homogenous collocation, induced potentials are highest at the ends of the collocated segment, and fall exponentially with distance past the point of divergence.[6] For more complex collocations, voltage peaks may occur at geometric or electrical discontinuities, where there is an abrupt change in the collocation geometry or electromagnetic field. Specifically, voltage peaks commonly occur where the pipeline converges or diverges with the HVAC power line, separation distance or soil resistivity changes significantly, isolation joints are present on the pipeline, or where the electromagnetic field varies such as at phase transpositions.[3,7,8,9]

3.1.3 Resistive Coupling

Current traveling through the soil to a pipeline can cause resistive or conductive coupling. As the grounded tower of an HVAC power system shares an electrolytic path with adjacent buried pipelines through the soil, fault currents may transfer to adjacent steel pipelines if the pipeline presents a lower resistance electrical path. Resistive interference is primarily a concern when a phase-to-ground fault occurs in an area where a pipeline is in close proximity to an HVAC power line, and magnitudes of fault currents in the ground are high. However, a phase imbalance on an HVAC system with a grounded neutral can contribute to resistive interference as return currents will travel through the ground and may transfer to a nearby pipeline.

During a fault condition (see Section 3.1.4), the primary concern is the resistive interference transferred through the soil. However, inductive interference can also be a concern as the phase current, and corresponding EMI, of at least one conductor can be high, as depicted in Figure 3. In other words, during a fault, the inductive effects during normal operation as described in Section 3.1.2 increase due the elevated EMI during the fault period.

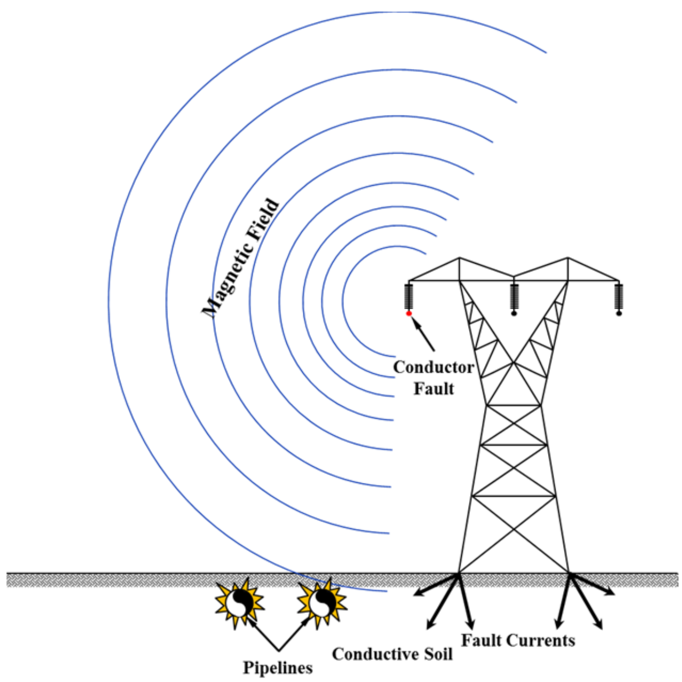

Figure 3. Illustration of HVAC Fault Condition – Inductive and Conductive Interference

If any of these electrical effects are high enough during operation, a possible shock hazard exists for anyone that touches an exposed part of the pipeline such as a valve, cathodic protection (CP) test station, or other aboveground appurtenance. During steady state normal power line operation, AC current density at a coating holiday (flaw) above a certain threshold may cause accelerated external corrosion damage to the pipeline. In addition, damage to the pipeline or its coating can occur if the voltage between the pipeline and surrounding soil becomes excessive during a fault condition.

3.1.4 AC Faults

For HVAC power lines, a fault is any abnormal current flow from the standard intended operating conditions. A fault can occur between one or more phase wires and the ground, or simply between adjacent phase wires. Faults can occur when one or more of the conductors are grounded or come in contact with each other, or due to other unforeseen events. This may be due to vegetation contacting the conductors, conductors contacting the towers or each other during high winds, physical damage to a tower, conductor, or insulator, flashover due to lightning strikes, or other abnormal operating condition. A phase-to-ground fault on a power line causes large currents in the soil at the location of the fault and large return currents on the phase conductor and ground return.

Faults are generally short duration transient events. Typical clearing times for faults range from approximately 5 to 60 cycles (0.08 to 1.0 seconds for 60-hertz transmission) depending on the location of the fault, breakers and type of communications. While the fault effects are transient, high-induced potentials or resistive coupled voltages along the ROW present a possible shocking hazard for personnel or anyone who may be in contact with above grade pipeline or appurtenances.

3.2 HVAC – Personnel Safety Hazards

An evaluation of the possible safety hazards for those working on a pipeline should take place whenever a pipeline is operating or constructed in close proximity to a HVAC power line. Personnel safety hazards are present during both pipeline construction and maintenance, and during normal steady state operation.

3.2.1 Hazards During Operation

Touch and Step Potential Limits

Personnel safety is of concern when a person is touching or standing near a pipeline when high voltages are present. The "touch potential" is defined as the voltage between an exposed feature of the pipeline, such as a CP test station or valve, and the surrounding soil or a nearby isolated metal object, such as a fence that can be touched at the same time. The touch potential is the voltage a person may be exposed to when contacting a pipe or electrically continuous appurtenance. The "step potential" is the voltage across a person's two feet and defined as the difference in the earth's surface potential between two spots one meter apart. The touch potential can be a concern during both normal steady state inductive and fault conductive/inductive conditions. Typically, the step potential is a concern during conductive fault conditions due to high currents and voltage gradients in the soil.

The Canadian Standards Association (CSA) and NACE International (NACE) have published standards addressing HVAC interference hazards. Both NACE and CSA standards[10,12] recommend reducing the steady state touch and step potential below 15 volts at any location where a person could contact the pipeline or any electrically continuous appurtenance. The 15-volt threshold is designed to limit the available maximum current through a typical human body to less than 10 mA. An 8 to 15 mA current results in a painful shock but is still in the maximum "let go" current range, for which a person can release an object or withdraw from contact.[10] The Institute of Electrical and Electronics Engineers (IEEE) Guide for Safety in AC Substation Grounding, indicates that a current in the range of 9 to 25 mA range may produce painful shock and involuntary muscular contraction, making it difficult to release an energized object.[13] Elevated body current in the range of 60 to 100 mA may cause severe injury or death as it can induce ventricular fibrillation, or inhibition of respiration. Current lower than nine (9) mA will generally result in a mild shock, but involuntary movement could still cause an accident.[10]

The touch potential is equal to the difference in voltage between an object and a contact point some distance away, and may be nearly the full voltage across the grounded object if that object is grounded at a point remote from where the person is in contact with it. For example, a crane that was grounded to the system neutral and that contacted an energized line would expose any person in contact with the crane or its un-insulated load line to a touch potential nearly equal to the full fault voltage.

The step potential may pose a risk during a fault simply by standing near the grounding point due to large potential gradients present in the soil, typically during a short duration fault condition.

A risk evaluation of the possible hazards to personnel for those working on the pipeline and possible pipeline coating damage should take place whenever a pipeline is in close proximity to a HVAC power line. This assessment should consider the possible likelihood and consequence of HVAC interference hazards to determine if further analytical assessment or mitigation is necessary. NACE International Standard Practice SP0177-2014 (Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems) indicates mitigation is necessary in those cases where step or touch potentials are in excess of 15 volts. Mitigation is further discussed in Section 5.

3.2.2 Encroachment and Construction Hazards

There are multiple safety hazards to consider associated with pipeline construction near a high voltage power line, the most obvious of which is the possibly lethal hazard of equipment directly contacting an energized overhead conductor.[3] The Occupational Safety and Health Administration (OSHA) has multiple regulations for safety requirements and limitations for working near power lines that must be considered in addition to pertinent company standards, and industry best practice guidelines. These include, but are not limited to the following:

- 29 CFR 1910.269: Electric power generation, transmission, and distribution
- 29 CFR 1910.333: Selection and use of work practices
- 29 CFR 1926, SUBPART V: Power Transmission and Distribution

The OSHA standards address requirements for working near energized equipment, overhead power lines, underground power lines, and construction nearby.

Elevated capacitive potentials generated on pipeline sections isolated from the ground on insulating skids as described in Section 3.1.1 can pose a safety hazard. Pipeline segments that are supported aboveground during pipeline construction near an HVAC power line are subject to EMI and electrical capacitance can build up between the pipeline segments and earth. If no electrical path to ground is present, even a relatively short section of piping may experience elevated AC potential, presenting a shock hazard to personnel near the pipeline.

Cases presented in published literature indicate scenarios of measured potentials greater than 1,000 volts on a pipeline segment exposed to an HVAC corridor.[4] In general, while the capacitive coupled voltages can exceed the NACE 15 volt touch potential safety threshold, the corresponding current is low reducing shocking hazard. However, arcing due to capacitive coupling may present a possible safety hazard, as an arc may be a possible ignition source for construction vehicles refueling along the ROW. Grounding pipelines in HVAC ROW will reduce the possibility of shocking or arcing.

Capacitive coupling is generally mitigated by connecting temporary grounding or bonding during construction to provide a low resistance path to ground for any electrostatic interference. Section 6 addresses further mitigation techniques and guidance for construction practices.

3.3 HVAC Threat to Pipeline Integrity

High voltage interference poses multiple threats to pipeline integrity for collocated and crossing pipelines under both steady state and fault conditions. During normal steady state HVAC power line operation, the inductive interference can contribute to accelerated external corrosion damage to the pipeline. Under faulted conditions, elevated potentials can lead to coating damage or a direct arcing to the pipeline.

The steady state 15 VAC threshold presented in NACE and CSA standards[10,12] considers personnel safety and does not necessarily address corrosion issues. Research and experience has shown that AC accelerated corrosion can occur in low resistivity soils at AC voltages well below this threshold.[3,6,14]

3.3.1 AC Corrosion

External corrosion, whether controlled by AC or DC, may pose a threat to the integrity of an operating pipeline. DC corrosion protection utilizes a system of corrosion resistant coatings and a CP system to provide electrochemical protection at coating holidays to reduce corrosion rate. However, AC corrosion is possible even in the presence of cathodically protected DC potentials due to high AC current density at coating holidays.

The concept of AC corrosion has been around since the early 1900s with only minor effects expected for many years.[3,10] AC accelerated corrosion has been recognized as a legitimate threat for collocated steel since the early 1990s, after several occurrences of accelerated pitting and leaks, ultimately associated with HVAC interference, were reported on cathodically protected pipelines.

Historically, there has been little consensus on specific mechanisms driving AC corrosion, and the severity of degradation attributed. However, several recent publications show tentative agreement in a plausible mechanism.[6,15,17] The explanation presented by Buchler, Tribollet, et al, suggests that AC corrosion on cathodically protected pipelines may be attributed to destabilization of pseudo-passive film that can normally form on exposed steel at a coating holiday under DC cathodic protection polarization. Due to the cyclic nature of AC current, the charge at the steel surface is continuously varying between anodic and cathodic polarization, which acts to reduce the passive film at the steel surface as shown in Figure 4. It is not the intention of this report to identify the specific mechanism driving material degradation due to AC corrosion, but rather to summarize a previously proposed mechanism and clarify the risks and contributing factors associated with AC corrosion.

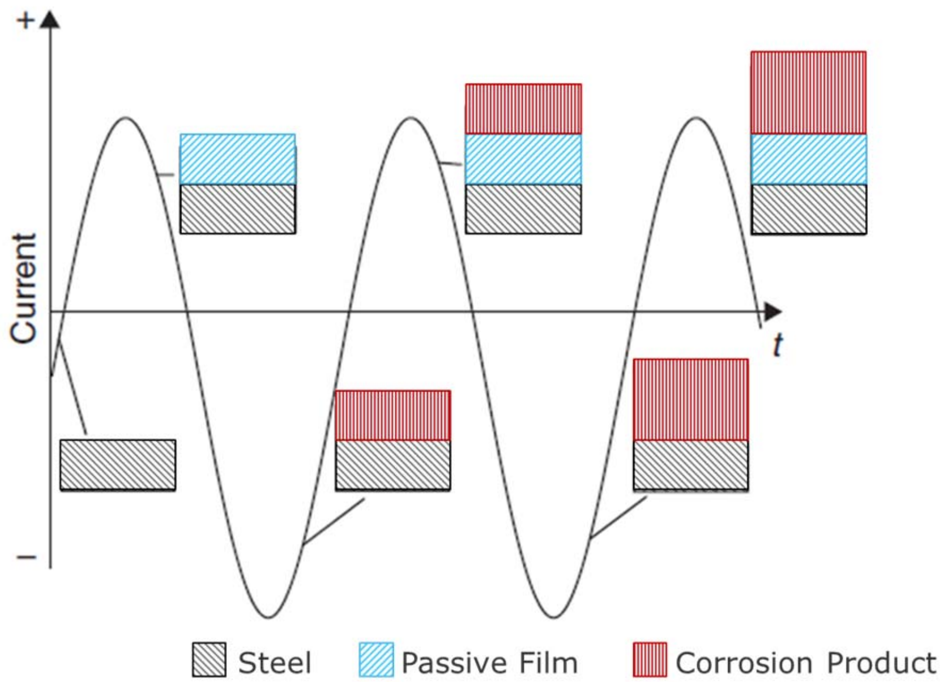

Figure 4. Graphical representation of proposed processes occurring during AC corrosion. Reproduced from Tribollet.[6]

3.3.1.1 AC Current Density

While there may be disagreement regarding the specific mechanism driving AC corrosion, AC current density is generally recognized as being an indicator of the likelihood of AC corrosion for a given location. In January of 2010, NACE International prepared and published a report entitled "AC Corrosion State-of-the-Art: Corrosion Rate, Mechanism, and Mitigation Requirements," which provides the following insight on AC corrosion current density.

> *"In 1986, a corrosion failure on a high-pressure gas pipeline in Germany was attributed to AC corrosion. This failure initiated field and laboratory investigations that indicated induced AC-enhanced corrosion can occur on coated steel pipelines, even when protection criteria are met. In addition, the investigations ascertained that above a minimum AC density, typically accepted levels of CP would not control AC-enhanced corrosion. The German AC corrosion investigators' conclusions can be summarized as follows:*
>
> - *AC-induced corrosion does not occur at AC densities less than 20 A/m² (1.9 A/ft²).*
> - *AC corrosion is unpredictable for AC densities between 20 to 100 A/m² (1.9 to 9.3 A/ft²).*
> - *AC corrosion occurs at current densities greater than 100 A/m² (9.3 A/ft²)."*3[1]

The AC density for a given location is dependent on soil resistivity, induced voltage, and the size of a coating holiday. Research has indicated that the highest corrosion rates occur at holidays with surface areas of 1 to 3 cm^2 (0.16 to 0.47 in^2).[1] AC current density is best obtained through direct measurement of a correctly sized coupon or probe. However, the theoretical AC current density can be calculated, utilizing the soil resistivity and AC potential on a pipeline, in conjunction with Equation 1, presented in the State of the Art Report.[1]

$$I_{AC} = \frac{8V_{AC}}{\rho \pi d} \qquad \text{Equation (1)}$$

Where:

I_{AC}	=	Theoretical AC Current Density (A/m^2)
V_{ac}	=	Pipe AC Voltage to Remote Earth (V)
ρ	=	Soil Resistivity (ohm-m) (*1 ohm-m = 100 ohm-cm*)
d	=	Diameter of a circular holiday having an area equal to that of the actual holiday (m)

Multiple industry references discuss a current density threshold below which AC corrosion is not a significant factor; however, there is still disagreement on the magnitude of this threshold. While the majority of technical literature indicates AC corrosion is possible at current densities between 20 to 30 A/m^2, there is experimental evidence presented by Goidanich, et al[14] indicating that AC current densities as low as 10 A/m^2 can contribute to a measureable increase in corrosion rate[14]. A significant conclusion of study published by Yunovich and Thompson in 2004[9], reiterated in the NACE AC Corrosion State of the Art Report in 2010, indicated that there might not be a theoretical threshold below which AC corrosion is active. The focus should rather be on a practical limit, below which the contribution of AC interference to the overall corrosion rate is low, or rate of corrosion due to AC is not appreciably greater than the free corrosion rate for the particular conditions.[3,9] The results of the experimental study showed that a current density of approximately 20 A/m^2 produced a 90% or greater increase in the corrosion rate versus the control, in the absence of CP.[9] Experimental studies performed by Goidanich, Lazzari, et al in 2010 and 2014, in the presence of CP, concluded that while it was apparent AC current density greater than 30 A/m^2 showed a considerable increase in the corrosion rate, a current density as low as 10 A/m^2 resulted in a corrosion rate nearly double that of the specimens without AC.[14, 18]

For reference, the European Standard EN 15280:2013, "Evaluation of AC corrosion Likelihood of Buried Pipelines Applicable to Cathodically Protected Pipelines" adopted the 30 A/m^2 current density magnitude as a lower threshold, below which the likelihood of AC corrosion likelihood is low. In an effort to address the practical application seen in operation, considering interaction effects of CP current and AC interference, recent research has assessed the likelihood of AC corrosion in terms of the ratio between AC and DC current density (I_{AC}/I_{DC}).

3.3.1.2 Current Density Ratio

Recent research has shown that the likelihood of AC corrosion on pipelines is dependent on both the level of AC interference and the level of cathodic current from either CP or other stray current sources.[3, 15, 18] In general, AC current density values below the previously cited 20 A/m^2 recommended limits were shown to accelerate corrosion rates in the presence of elevated DC current density due to excessive CP overprotection.

The latest revision of EN 15280:2013 was revised to present criteria based upon the AC interference and DC current due to CP. Alternative acceptance criteria are presented in terms of limiting cathodic current density, or limiting the AC to DC current density ratio (I_{AC}/I_{DC}) below a specified level.

Current density obtained by use of coupons or electrical resistance (ER) probes will provide this ratio. However, both AC and DC current density data required to utilize these limits are often not available or easily obtained along the pipeline in practice. Therefore, the current density ratio limits provided within the EN 15280 standard are not widely used or easily applicable criteria. This reference demonstrates the recognized interaction of AC interference and CP systems, presenting an alternative approach that may be valuable for specific scenarios where data is available.

As mentioned previously, the measurement or calculation of AC current density has been the primary indicator to determine the likelihood of AC corrosion across industry in North America. It is possible to measure AC current density on a representative holiday through the installation and use of metallic coupons. A coupon representative of the pipe material, with a defined bare surface area, buried near the pipeline and connected to the pipeline routed through a test station will allow the measurement of current. These current measurements along with the known surface area of the coupon, allow for calculation of a representative current density. In many cases, the coupons are supplemented with additional instrumentation such as ER probes and reference electrodes to provide additional pertinent information. The ER probes provide a time based corrosion rate while the reference electrodes provide both and AC and DC pipe-to-soil potentials.

Section 6 provides further details related to mitigation and monitoring methods for to AC corrosion. Appendix A includes additional details related to literature review, historical AC corrosion rates, and industry case studies.

3.3.2 Faults

During a phase-to-ground fault on a power line, an adjacent or crossing pipeline may be subject to both resistive and inductive interference. Although these faults are normally of short duration (generally less than one second), pipeline damage can occur from high potential breakdown of the coating and conductive arcing across the coating near the fault. Further, the fault current is typically carried by a single conductor, resulting in short term elevated induced voltages that can reach thousands of volts or greater. This presents a significant risk to personnel in contact with the pipeline or electrically continuous appurtenance during a fault.

A phase-to-ground fault, or a lightning strike, on an HVAC power line can result in large potential differences with respect to the adjacent or crossing pipelines. If the potential gradient through the soil is sufficient, a direct arc to a collocated or crossing pipeline is possible, which can result in coating damage, or arc damage to the pipe wall up to the point of burn-through. Even if an arc is not sustained long enough to cause burn through, a short duration elevated current can cause molten pits on the pipe surface that may lead to crack development as the pipe cools. Fault arcing is generally a concern where fault potentials are greater than the dielectric strength of the coating, or at coating holidays within the possible arcing distance. Section 7.3 provides guidance limits for both issues. Where necessary, installation of grounding and shield wires can be used to mitigate the fault hazards as discussed in Section 6.

3.3.2.1 Coating Stress Voltage

During fault conditions, damage to the pipeline or its coating can occur if the voltage between the pipeline and surrounding soil becomes excessive. Fault conditions that produce excess coating stress voltages across the coating are of concern for dielectric coatings. The main factors to consider are the magnitude of the voltage gradient and the dielectric strength of the coating type. It should be noted that there are several parameters that are utilized to assess these issues: magnitude of the fault current, distance between the pipeline and fault, soil resistivity, coating age/quality, duration of the fault and coating thickness.

Guidance on allowable coating stress voltage varies across references. NACE SP0177-2014 indicates, "Limiting the coating stress voltage should be a mitigation objective." Multiple references offer varying coating stress limits and are generally considered to be in the range of 1 to 1.2 kV for bitumen, as low as 3 kV for coal tar and asphalt, and 3 to 5 kV for fusion-bonded epoxy (FBE) and polyethylene, for a short-duration fault."[10]

For reference, NACE SP0490-2007 "Holiday Detection of Fusion-Bonded Epoxy External Pipeline Coating of 250 to 760 µm (10 to 30 mil)" uses an equation for calculating test voltages which recommends a 15 mil (14 to 16 mils is a common specification for FBE coatings) fusion bonded coating (FBE) be tested at 2,050 volts.

NACE SP0188 2006 "Discontinuity (Holiday) Testing of New Protective Coatings" also uses an equation for calculating test voltages for coatings in general.

$$TV=1{,}250\sqrt{T} \qquad \text{Equation (2)}$$

Where:

TV = Test Voltage (V)

T = Average coating thickness in mils

This results in a test voltage of 8,840 volts +/- 20% for a pipeline coated with a 50-mil coal tar coating.

The first standard above is the subject of AC mitigation and the following two standards are the recommendations for holiday testing; however, there appear to be inconsistences as to what voltage will actually damage the various pipeline coatings. The inconsistences appear to be due to the unidentified coating thickness in SP0177-2014 and actual duration of the fault resulting in conservative values.

Gummow et al. in their paper "Pipeline AC Mitigation Misconceptions"[19] present data that include the duration and coating thickness in the analysis resulting in values that are more practical. They conclude that FBE coatings with a 16 mil thickness should conservatively use a voltage gradient limit of 5,000 volts and that the 3kv to 5 kV range indicated in NACE SP0177-2014 would be more applicable in the range of 7.5 kV to 12.5 kV.

3.4 HVDC / Underground HVAC

High voltage power interference is primarily a concern for pipelines collocated with HVAC overhead power lines, due to the widespread sharing of common ROW, and the interference effects associated. However, there are associated concerns across industry regarding interference effects of aboveground HVDC transmission and underground AC power lines. Presently, the U.S. transmission grid consists of approximately 200,000 miles of 230 kV or greater high voltage transmission lines, with an estimate that underground transmission lines account for less than 1% of this total.[20] Industry trends indicate that due to significant disparity in overall installation costs, it is expected that while buried transmission lines will continue to be developed and implemented, overhead transmission will remain the primary means for electric transmission for the foreseeable future.[2]

In general, the level of interference from buried HVAC power lines is typically lower as the proximity between the individual phase conductors acts to balance electromagnetic fields, reducing EMI on foreign structures. Depending on the type of construction, sheathing or conduit may offer some level of electromagnetic shielding, further reducing inductive interference effects.

As aboveground HVAC is still the primary concern for pipeline interference, it is the primary focus of this report. However, the effects of both aboveground HVDC and buried transmission cables require review on a case-by-case basis when pipelines are closely collocated. There are currently less than 30 identified high voltage direct current (HVDC) transmission lines operating in the United States[21]. Although there are few relative to overhead HVAC, and the interference effects on a pipeline are different from HVAC transmission lines, they do warrant a brief discussion so that pipeline operators are aware of potential issues. The Canadian Association of Petroleum Producers (CAPP)[22] have produced a technical document that addresses in detail the issues associated with HVDC transmission lines influence on metallic pipelines. Due to the technical differences, the detailed extent of HVDC transmission line interference on steel pipelines necessitates its own study, beyond the scope of this document, however a summary overview of design and interference comparisons follows.

HVDC transmission systems in operation today are typically of monopole or bipole design. In each case, the systems consist of a transmission line between stations with the major components being DC-AC convertors and large ground electrodes. In monopole systems, a single conductor transports the power with an earth return, as depicted in Figure 5. It should be noted that where HVDC systems use a ground return, the interference concerns are similar to typical DC stray current interference, which is addressed in NACE SP0169 and is outside the scope of this document.

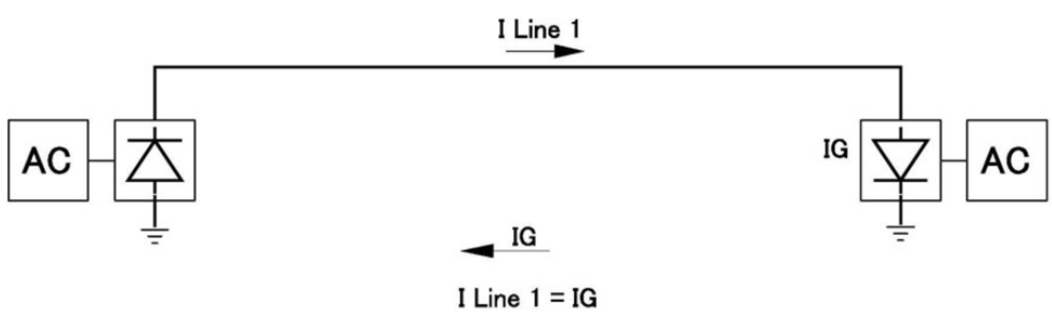

Figure 5. Monopole System (34)

In bipole systems, two conductors between stations allow the system to transport power through both conductors, one conductor and an earth return, or a combination of both, as depicted in Figure 6. The most common use of monopole systems is in submarine applications using the seawater as the earth return. The most common use of bipole systems consist of onshore overhead transmission towers to transport the power.

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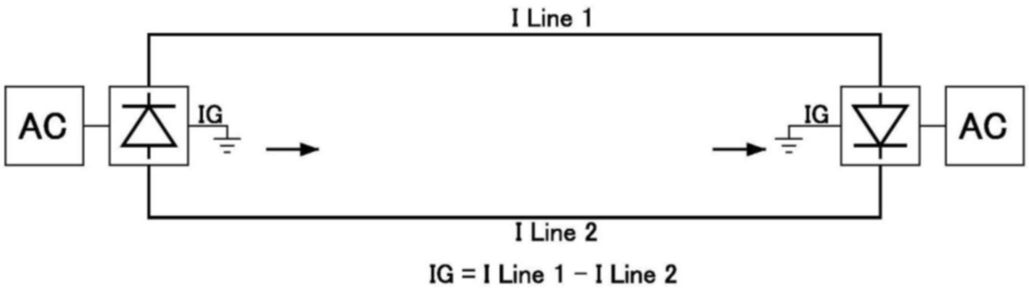

Figure 6. Bipole System (34)

Tripole configurations have been considered and reviewed in research, but have not seen widespread use in practice. There are several types of designs and operation modes within the broad parameters of the monopole and bipole systems. During emergencies and in maintenance of the bipole system, an earth return is used. In an earth return mode there is a potential gradient generated and metallic objects, such as pipelines, can be subject to varying potentials and become a conductor of the return current if they provide a low resistance path. Where current is collected or received by the pipeline generally no damage occurs, unless the current is high enough to damage the coating. However, corrosion will occur at current discharge locations. The amount of corrosion is dependent on the amount of current and duration of discharge. In the case of large discharge current, significant corrosion damage can occur in relatively short time periods. The effects are similar to the interference currents caused by other DC power sources such as traction systems, cathodic protection systems or welding with an improper ground.

HVDC transmission lines also have the same coupling modes with pipelines that occur with HVAC transmission lines capacitive, inductive, and resistive. Although under typical circumstances these effects may be negligible. However, interference levels under faulted conditions can be significant.

3.4.1.1 Capacitive coupling

The results of research presented by Koshcheev indicate the electrical field below HVDC transmission lines does not generally require significant safety measures during construction when the pipe is isolated on skids, as the electric field influence associated with HVDC transmission is limited compared to HVAC.[21]

3.4.1.2 Inductive coupling

CAPP indicates the voltages induced due to HVDC, under steady state conditions tend to be negligible. The magnitude of induction may contribute to minor interference problems with telephone lines, and possibly other communications systems, but is typically low enough that neither pipeline integrity nor safety hazards are considered likely under steady state conditions. However, during fault conditions, there is a possibility for short duration of elevated inductive coupling.

3.4.1.3 Resistive coupling

During faulting both HVAC and HVDC transmission systems can present personnel safety issues and compromise pipeline integrity, with possible damage to the pipeline, coating, and associated equipment. A faulted HVDC power line presents a possible integrity concern for nearby pipelines. CAPP indicates that the fault current discharged to ground at the power line tower causes a ground potential rise (GPR) near the ground electrode. A voltage gradient exists relative to remote earth. A pipeline within the voltage gradient will experience a coating stress voltage as discussed in Section 3.3.2.1. If high enough, the voltage stress could puncture the insulating coating possibly damaging the pipeline.

3.5 Industry Procedure Summary

The lack of industry consensus on the subject of AC corrosion guidelines has led to varied practices among pipeline operators in regards to mitigating AC interference on pipelines. As part of this study, The INGAA Foundation requested a review of industry practices and procedures related to AC interference. Based upon this review, all of the procedures address a safety concern and define a maximum allowable AC pipe-to-soil potential limit for above-grade appurtenances. For pipelines in close proximity to HVAC power lines, faults are identified as a hazard in almost all of the procedures. However, few addressed coating stress limit above which mitigation is required. For current density criteria, several procedures had clearly defined limits, while others addressed it as a concern for AC corrosion but did not specify a targeted limit of AC current density or define limits for mitigation. Table 1 provides a summary comparison of the industry procedures reviewed.

Table 1-Industry Procedure Summary

Induced AC Potential Limit Requiring Mitigation	*Fault Protection/Coating Stress Voltage Limit Requiring Mitigation*	*Current Density Criteria Requiring Mitigation*
In accordance with NACE: 15 V	Not specified	Not Specified
15 V	2500 V	Not Specified
15 V	Mentions damage possible from faults but no limit	Not Specified
15 V or higher - No work unless approved by area supervisor	Not specified	Not Specified
Modeling Required > 2 V	Consider with Modeling	30 A/m^2
15 V	5000 V	75 A/m^2 requires mitigation, 50 A/m^2 requires further evaluation
10-15 V	150-2000 V depending on fault duration	30 A/m^2
15 V	Faults to be considered along with a minimum separation distance, but no limit specified	20 A/m^2
15 V	Faults to be considered during mitigation analysis, but no limit specified	50 A/m^2
15 V	Faults to be considered during mitigation analysis, but no limit specified	50 A/m^2

4 NUMERICAL MODELING

Predicting high voltage interference is a complex problem, with multiple interacting variables affecting the influence and impact. In recent decades, development of advanced calculation methods and computer-based tools for simulation of interference effects, analysis of faults, and development of mitigation methods has been significant.2[3,5,9,10] Computer based numerical modeling can be utilized to examine the collocated pipeline's susceptibility to HVAC interference, help identify locations of possible AC current discharge, and where necessary design appropriate mitigation systems to reduce the effects of AC voltage, fault currents, and AC current density to meet accepted industry standards. These numerical models are capable of analyzing the interacting contribution of multiple variables to the overall magnitude of AC interference.

Computer modeling is used to analyze the interactions and sensitivity of the variables that affect the magnitude of AC induction on pipelines. This section provides a brief review of numerical modeling software in general, as well as the results of the individual variable analyses.

4.1 Modeling Software

Previous research has compared the benefits of specific industry standard software; literature is available for each of the common software packages.[3,9,2023] This review addresses the generalizations concerning the present industry standard software, but does not aim to address or endorse specific software packages.

For the majority of simple collocations considering a single pipeline and single HVAC power line numerous industry-accepted models have shown to be consistent in the assessment of HVAC interference. Often, for these simple cases, the benefit of a more complex model is not gained due to uncertainty in the analysis inputs. That is to say that for a majority of simple collocations, any of several industry accepted models are capable of providing an accurate analysis. The applicability is limited by the accuracy of the input data, and expertise of the analyst in utilizing the specific model. Often the uncertainty in critical input variables, such as the HVAC load current and phasing, outweighs the benefits gained from a more complex model. However, as the collocation complexity increases, both in terms of the number of structures and geometric routing, the limitations of some basic models support the benefits of the more detailed modeling software.

Typical industry standard software packages that were reviewed use a transmission line model (TLM) to calculate longitudinal electrical field (LEF), based on established fundamental Carson or Maxwell equations for electromagnetic fields. The geometry and routing of the complete pipeline and transmission line network incorporated in the model considers multiple pipelines, transmission lines, tower sections, and other collocation parameters. Collocations are simplified as a connected series of finite sections and nodes, with appropriate parameters applied simulating the pipeline, soil, and transmission load-ins. The modeling software can then calculate the LEF for each section and solve the fundamental equations to calculate the potential, current, and theoretical current density along a given collocation.

Calculation of the EMI and corresponding effects on buried pipelines requires a thorough understanding of the variables involved. Detailed modeling requires knowledge of electric field interactions, transmission current, tower design, bulk and local soil resistivity, and pipeline parameters such as geometry, coating, depth, diameter, electrical connections or isolations, and existing CP. All of these variables may significantly affect the AC interference model, and similarly the analogous real world interference. Likewise, the assumptions and simplifications made during the model setup can have significant impact on the accuracy and applicability of the outputs.

While most of the available models are able to analyze each of these variables, either directly or indirectly, the accuracy of the analysis is dependent on the expertise and understanding of the analyst to assess the given variables. Similarly, the accuracy of the models can only be as good as the input data. Multiple sources are required for the collection of data, i.e. measured in field, provided by power line or pipeline operators, or based off published nominal data. For that reason, the accuracy of the results is ultimately dependent on the expertise of analyst and the reliability of the data input to ensure technically appropriate setup, despite the presence of multiple models that have been shown to be capable of providing accurate analysis when used within their applicable limitations.

4.2 Variable Analyses

Due to the number of interacting variables affecting the overall levels of AC interference, it is difficult to isolate the effects of a single variable for all collocations scenarios encountered. Consequently, it is difficult to determine distinct limits for individual variables outside of which interference becomes negligible. Considering several key interacting variables is a more viable approach. For example, reported recommendations cite a distance of 1,000 feet as considered 'far' and assumed low risk for HVAC interference. However, in cases where power line current loads are greater than 1,000 amps and in regions of low soil resistivity, elevated induced AC potentials and corresponding current density exceeding recommended thresholds have resulted at even greater distances. Therefore, separation distance alone may not provide sufficient justification to exclude a collocation from further assessment. Conversely, considering the interacting effect of the key variables identified is necessary when determining the need for detailed analysis for a collocation.

DNV GL developed a series of computer models to illustrate the influence of key variables affecting induced AC on pipelines from nearby HVAC power lines. The software used is a graphical simulation platform developed to predict the steady state interference and resistive fault effects of HVAC power lines on buried pipelines in shared right-of-ways (ROWs). Using a TLM and appropriate input data, the software calculated the LEF, which then calculated the magnitude of induced AC potential, and current along the modeled collocated pipelines.

The models created for these studies are simplistic in terms of geometry and serve as a demonstration of the variables' influence on AC induction on adjacent pipelines. Based upon the number of variables and their interactions with respect to AC interference on pipelines, these studies determine the relevancy of the various parameters. The studies offer guidance demonstrating the trends associated with each parameter on the overall level of interference, and were used along with existing industry guidance and literature findings to develop the recommended guidelines presented in Section 6.

The primary variables analyzed as part of this study are as follows:

- HVAC Power Line Current
- Soil Resistivity
- Separation Distance Between Pipeline and Power Line
- Collocation Length of Pipeline and Transmission Line
- Angle Between Pipeline and Transmission Line
- Coating Resistance
- Pipeline Diameter and Depth of Cover

The results of these studies are presented and summarized in the following sub-sections.

4.2.1 HVAC Power Line Current

A primary variable influencing the magnitude of induced AC potential on a pipeline collocated with HVAC power lines is the magnitude of the phase conductor current. The current load of the nearby power lines has a direct influence on the LEF generated by the HVAC power line circuit(s). The intensity of the LEF varies with the current loads affecting both magnitude of induced AC potential on the nearby pipeline, as well as the area of influence. The area of influence affects the separation distance at which a collocated pipeline experiences significant interference and is further discussed in Section 4.2.3.1.

To demonstrate the sensitivity of power line current on pipeline interference, DNV GL created a computer model simulating a single circuit vertical transmission line, parallel to a 10-inch diameter pipeline for 5,000 feet at a horizontal separation distance of 100 feet. The pipeline approaches the transmission line at a 90-degree angle and parallels the transmission line for 5,000 feet before receding from the transmission line at a 90-degree angle, as depicted in Figure 7. The HVAC load current was varied while all other model inputs remained constant, to analyze the influence of current alone. A uniform soil resistivity of 10,000 ohm-cm was applied and constant throughout the analyses. The transmission line current loads analyzed were 250, 500, 1,000, 2,500, and 5,000 amps based on ranges of operating and emergency loading conditions reported in literature and previously provided from power transmission operator's design conditions. Figure 8 shows the maximum induced AC potential as a function of transmission line current load.

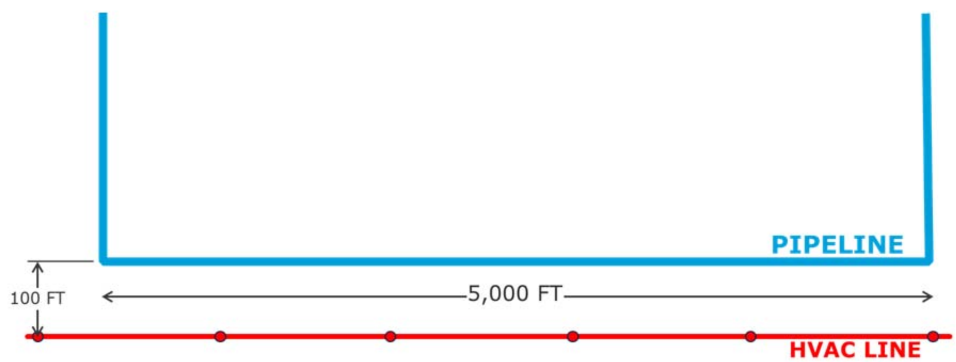

Figure 7. Simplified ROW Model Geometry

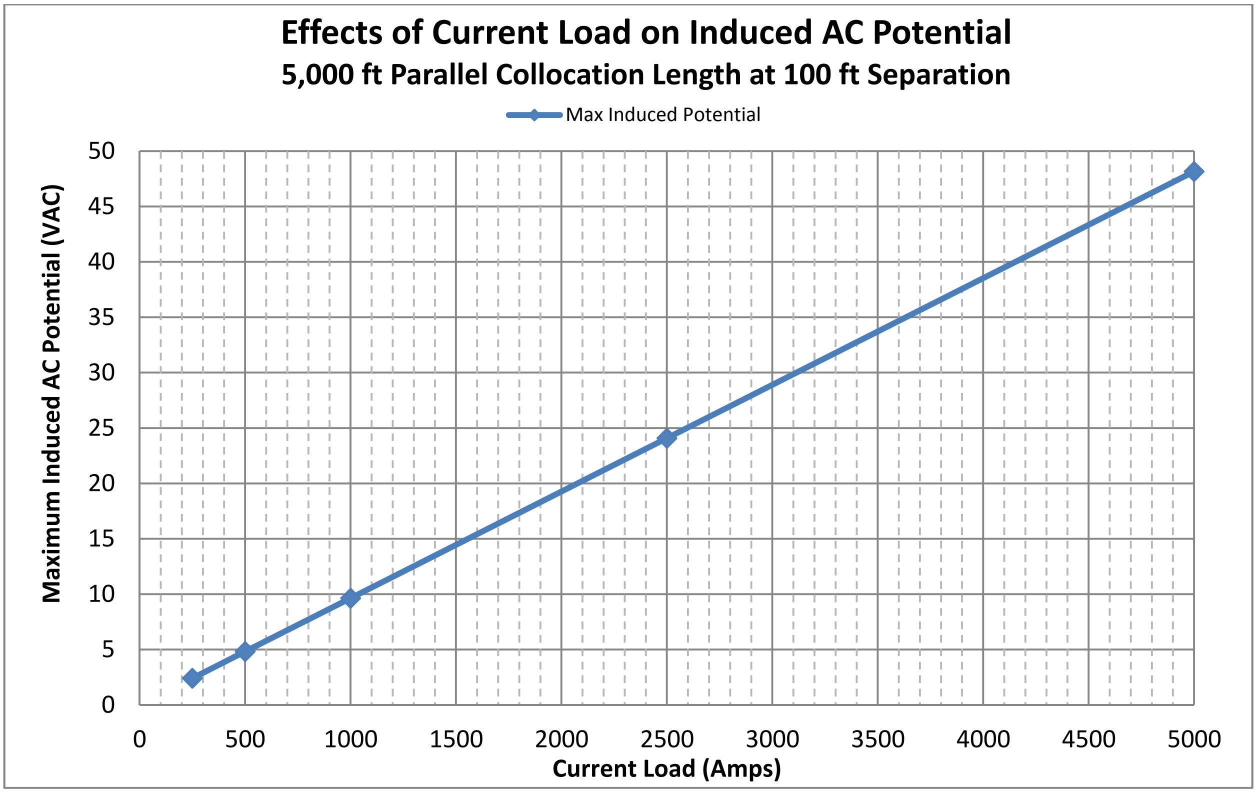

Figure 8. Maximum Induced AC Potential as a Function of HVAC Transmission Line Current

The results of this analysis show that the relationship between transmission line current and maximum induced AC potential on the pipeline is linear for a parallel collocation, considering a single interfering power line. When all other variables remain constant, the HVAC operating current load has a direct linear effect on the magnitude of the induced AC potential. This relationship allows for estimating influence of elevated current loads based on field measured AC pipe-to-soil potentials. For the specific case, with a pipeline collocated with a single HVAC circuit, if sufficient measurements of AC pipe-to-soil potential are taken, and corresponding transmission line current loads are provided for the specific time of measurement, the values can be scaled linearly to estimate the induced AC potential likely at the correspondingly scaled transmission current. This may be applicable, for example, for estimating the effects associated with a power line upgrade with a new current load. However, this method of approximation is only applicable for pipelines collocated with a single transmission line where sufficient data is available. As the number of transmission line circuits increases, the multiple interference sources and interaction the complexity of the interference increases such that the simply linear relationship is no longer valid. As the number of influencing HVAC circuits and pipelines within the area of influence are increased, the complexity of the interaction necessitates analysis that is more detailed.

It is known that while the higher current loads presented represent the high end of typical reported design loads, recent trends in the power transmission industry have shown development and installation of higher capacity HVAC transmission systems capable of carrying significantly greater current loads. For example, previous references indicate a typical load for 345kV to 500kV systems to be approximately 500 to 1,000 amps per circuit.3[24] Recent research indicates increased capacity for 345kV lines carrying up to 5,000 amps per circuit, and over 6,000 amps for 500kV systems.[2,24] While these magnitudes are not considered typical, numerous projects have developed recently that require mitigation for circuits operating at these elevated loads, indicating a need to consider actual current ratings for certain collocations. For this reason, loads are presented in terms of current rather than line voltage rating, as current is the driving load to control the level of EMI. It is noted that line ratings are typically given in terms of voltage ratings such as 138 kV, 345 kV, etc. however, the current load is the more relevant variable when determining the level of HVAC interference. Voltage rating alone can be misleading as the associated loads can be significantly higher or lower than the 'typical' current loads for that kV rating. For this reason, it is recommended to obtain current load data from the power utility company when assessing risk of interference.

4.2.2 Soil Resistivity

The soil resistivity along the collocation affects the magnitude of induced AC potential distribution as well as the theoretical AC current density along a given pipeline. It is necessary to consider both the bulk and specific layer resistivity when assessing likelihood and severity of interference. The bulk resistivity to the pipeline depth is one of the controlling factors in the analysis of induced AC potential. The bulk resistivity is the average soil resistivity measured in a half-hemisphere to the depth of the pipe, as shown in Figure 9 below. However, the specific resistivity of the soil layer directly next to the pipe surface, shown as Layer 2 in Figure 9, is a primary factor affecting the corrosion activity at a coating holiday, considering both conventional galvanic and AC assisted corrosion. The bulk soil resistivity combined with the coating resistance of the pipeline affect the level of induced AC potential expected along the pipeline.

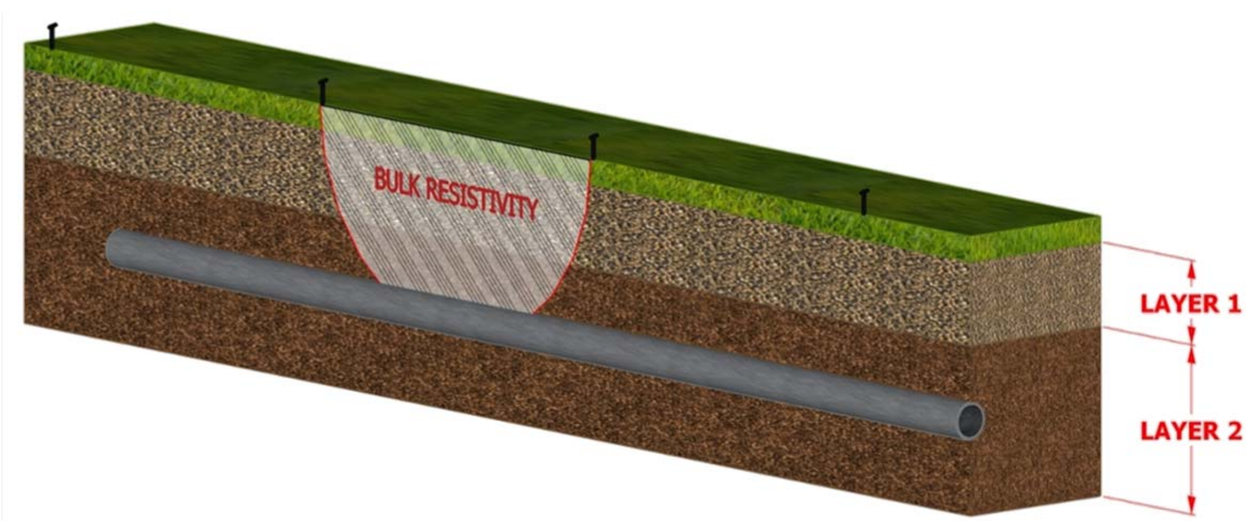

Figure 9. Graphical representation of soil resistivity measurements, showing bulk and layer zones

To demonstrate the sensitivity of soil resistivity on pipeline interference and current density, DNV GL created a computer model simulating a single circuit vertical transmission line, parallel to a 10-inch diameter pipeline with a configuration similar to the model setup described in Section 4.2.1. The soil resistivity was varied along the pipeline while all other model inputs remained constant, to analyze the influence of resistivity alone. The soil resistivity was uniform along the entire modeled collocation, considering 100, 1,000, 10,000, and 100,000 ohm-cm. Figure 10 shows the maximum induced AC potential corresponding to varying current loads.

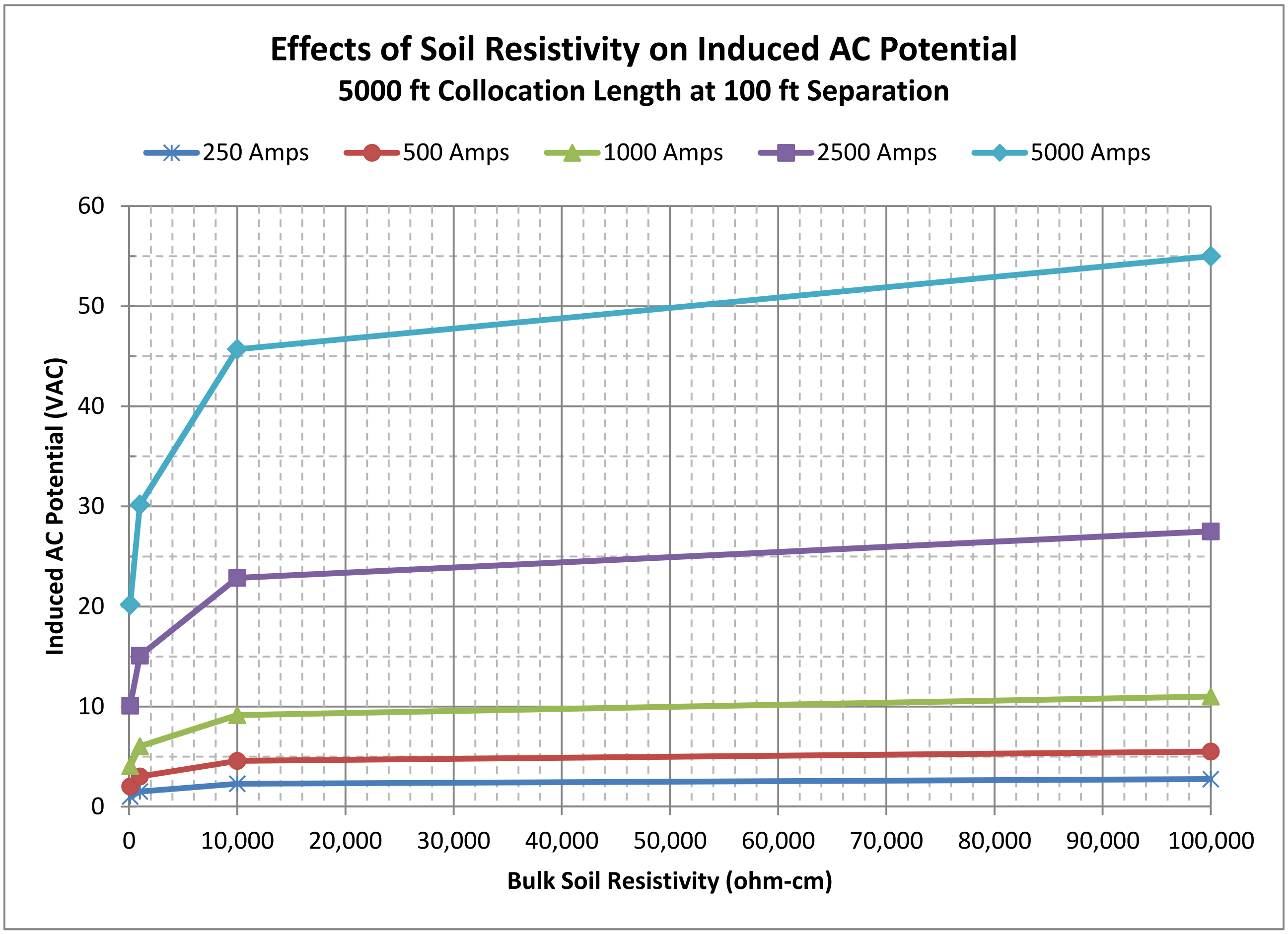

Figure 10. Maximum Induced AC Potential as a Function of Soil Resistivity

The results of the analyses show that the induced AC potential increases logarithmically with increasing soil resistivity. This increase in induced AC potential changes significantly between 100 and 10,000 ohm-cm but approaches asymptotical limit at soil resistivity values greater than 10,000 ohm-cm.

The effects of soil resistivity have greater influence however on the current density. While an increase in soil resistivity can result in a slight increase in the magnitude of induced AC voltage for a given collocation, the theoretical current density and associated risk of AC corrosion decreases linearly with the increased resistivity. The layer resistivity of the soil directly next to the pipe surface is a primary factor in the corrosion activity at a coating holiday. The specific resistivity near the pipe at a holiday is inversely related to theoretical AC current density, as shown by the calculation for theoretical AC current density in Equation 1. Thus, an increase in soil resistivity results in a decrease in theoretical AC current density.

Considering the 250 amp current load case from Figure 10, the theoretical current density was calculated from the induced AC potential for each magnitude of soil resistivity, considering a 1 cm^2 holiday, shown in Figure 11 and Table 2. While the soil resistivity values increase several orders of magnitude across the range, the theoretical current density decreases on similar order, with minimal change in the overall induced AC potential, as shown in Figure 11 and 0 Table 2. The red dashed line represents the lower bound 20 $amps/m^2$ threshold for current density as discussed in Section 3.3.1.1. It can be seen that based on the calculations provided by Equation 1, a very high theoretical AC current density is possible for relatively low AC potential, if soil resistivity values are below 10,000 ohm-cm. This results in elevated risk for AC corrosion for soil resistivity ranges below 10,000 ohm-cm.

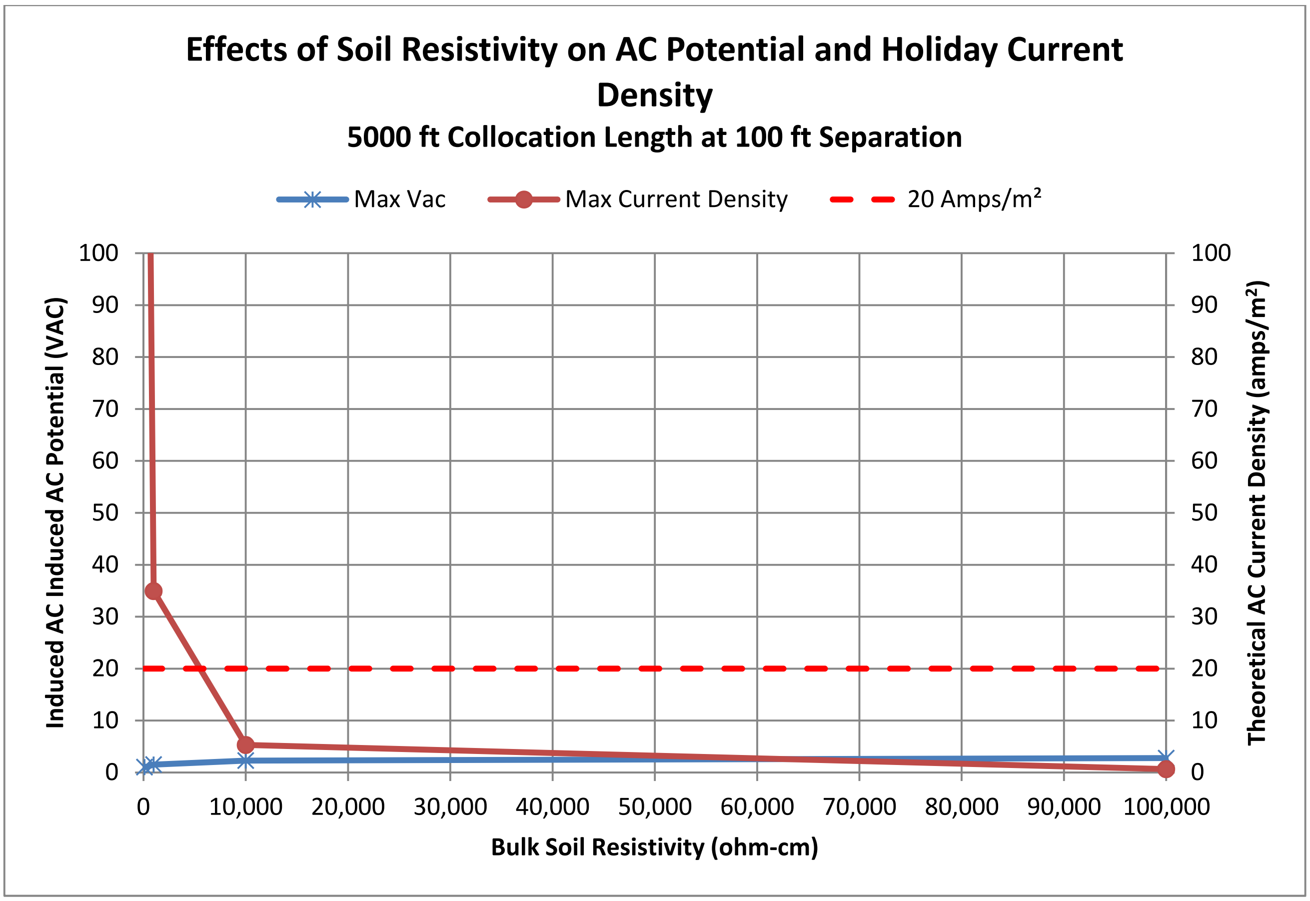

Figure 11. Effects of Soil Resistivity on Induced AC Potential and Corresponding Holiday Current Density. Current density presented for a theoretical 1cm^2 holiday

Table 2-Calculated current density and induced AC potential

ρ (ohm-cm)	Calculated Current Density (A/m^2)	Induced Potential (V_{ac})
100	234	1.0
1,000	35	1.5
10,000	5	2.3
100,000	0.6	2.8
Based on 5,000ft parallel collocation with a power line operating at 250 A load, 100-ft separation distance		

4.2.3 Collocation Geometry

The geometry of the pipeline relative to the transmission line is critical in determining the magnitude and distribution of induced AC potential along the pipeline. The level of AC interference for a given collocation or crossing, with respect to collocation geometry, is dependent on the relative distance between the phase conductors and pipeline, the locations of convergence or divergence, and angle of approach or crossing. Each of these variables affects the overall level of induction or susceptibility to fault hazards, and their influence is dependent on all other configuration variables. When assessing susceptibility to AC interference all of these variables are considered. However, for the sake of this assessment, the following studies analyzed each independently in order to provide a simplified assessment of the influence of each parameter.

The figures presented in Section 4.2.3.1 to 4.2.3.3 incorporate a dashed line similar to the current density threshold indicator in Figure 11. The limit lines provide reference to the AC potential limit that may result in a theoretical AC current density of 20 amps/m^2 for a hypothetical 1 cm^2 holiday, at soil resistivity of 1,000 and 10,000 ohm-cm. The limit lines are included to provide guidance illustrating the levels that may pose an elevated risk of AC corrosion at potentials below the NACE specified 15 volt limit for personnel safety.

4.2.3.1 Separation Distance Between Pipeline and Power Line

The separation distance between the pipeline and transmission line is a significant variable controlling the level of induced AC potential influencing a given pipeline. The proximity of the pipeline to the phase wires limits the strength of the LEF to which the pipeline is exposed.

To demonstrate the sensitivity of separation distance on pipeline interference, DNV GL created a computer model simulating a single 10-inch pipeline, and single circuit vertical transmission line, with similar configuration as described in Section 4.2.1. The separation distance was varied between the models while all other model inputs remained constant, to analyze the influence of separation alone. Induced AC potential results are plotted for separation distances of 50, 100, 500, 1,000, and 2,500 feet in Figure 12. The results indicate that for the higher load currents, the 20 A/m^2 recommended current density threshold is exceeded for separation distances greater than 500 feet is exceeded.

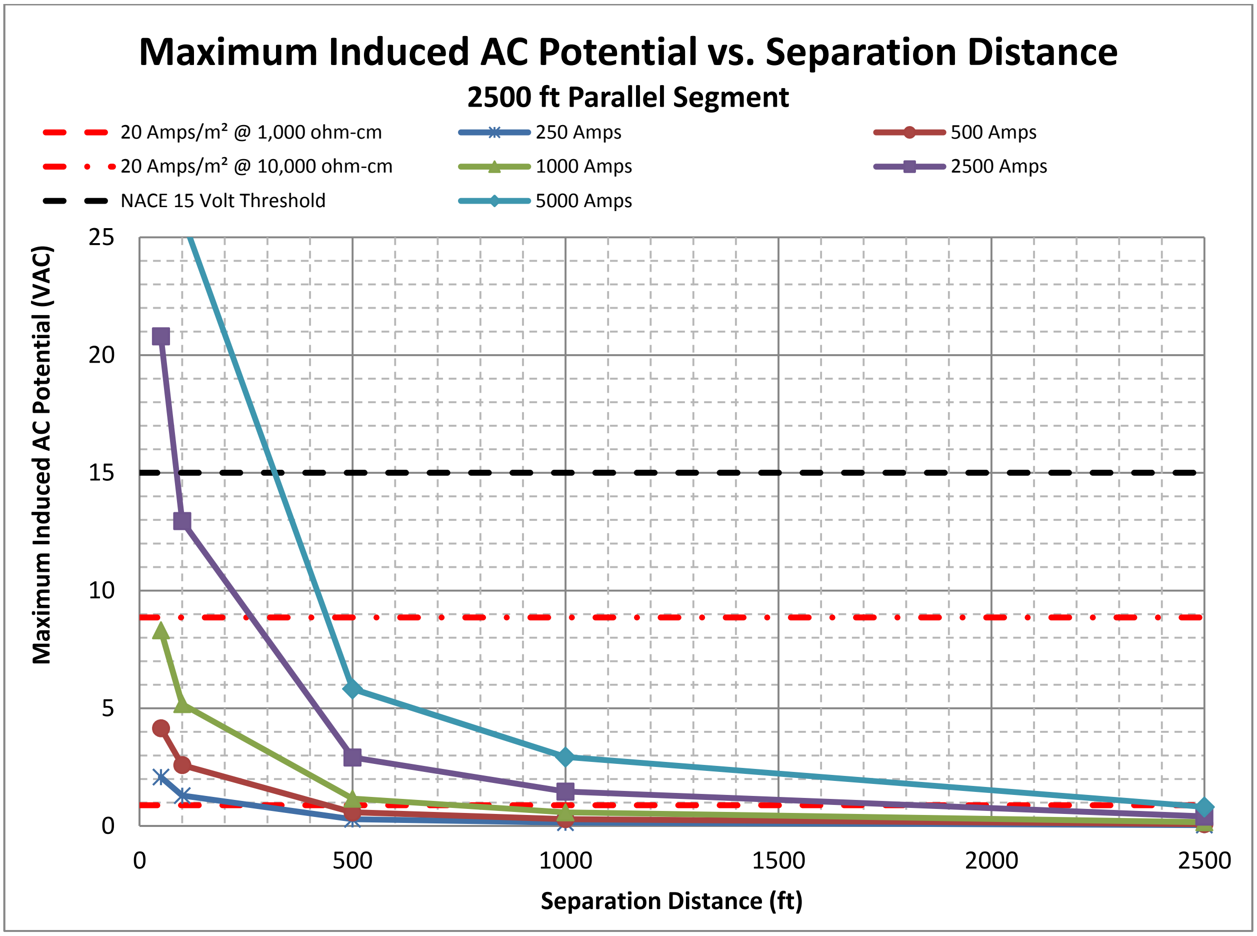

Figure 12. Effects of separation distance on induced AC potential. Current density limits presented for a theoretical 1cm^2 holiday.

As the distance between the pipeline and transmission line increases, the induction on the pipeline decreases. This is expected as where the distance between the pipeline and phase conductors increase the distance from the LEF origin increases, decreasing the coupling effects. The results of this study as presented in Figure 12 illustrate an important effect of the load current as well. The area of influence or separation distance at which a collocated pipeline experiences significant interference increases accordingly.

The figure also depicts potential levels corresponding to a 20 amp/m^2 current density for both 1,000 and 10,000 ohm-cm soil resistivity for reference. For the given parameters analyzed, a current load of 250 amps results in an induced potential of approximately 2 volts at a 50 foot separation distance which quickly decreases to less than 0.5 volts at a distance of 500 feet. However, a load of 2,500 amps results in an induced AC potential of approximately 21 volts at a separation distance of 50 feet, and approximately 1.5 volts at a separation distance of 1,000 feet. This is important when determining which pipeline collocations require detailed analysis, as there is variation among industry guidance documents for the limiting distance. A limiting distance of 1,000 feet is common practice, however, for HVAC current loads greater than 1,000 amps, significant interference might be possible at distances exceeding 1,000 feet. While the induced AC potentials magnitudes may appear relatively low in Figure 12, for separation greater than 2,000 feet, it should be noted this example is considering a single HVAC circuit, and only an approximately 0.5 mile collocation length. In practice additional interfering circuits collocated for longer distances would result in higher induced AC potentials. Further, as discussed in Section 4.2.2, it is possible to have an elevated AC current density under relatively low soil resistivity conditions, such that AC corrosion is a concern at relatively low induced potential.

It is necessary to consider separation distance in conjunction with the other factors to exclude a collocation from further analysis for separation distances within 2,500 feet. At a minimum, operating current, or an estimate of it, is also necessary when determining if further analysis is required.

4.2.3.2 Collocation Length of Pipeline and Transmission Line

Just as separation distance affects the magnitude and distribution of induced AC potential along the pipeline, so does the length of collocation. The collocation length is the distance along the ROW that a pipeline parallels or crosses the transmission line within a separation distance and angle that allow for inductive coupling. The collocation length affects the magnitude of induced AC potential that accumulates on the pipeline as it defines the length of the pipeline exposed to the LEF of the phase wires.

To demonstrate the sensitivity of collocation length on pipeline interference, DNV GL created a computer model simulating a single 10-inch pipeline, parallel to a single circuit vertical transmission line at a 50 foot offset. The collocation length was varied between the models while all other model inputs remained constant, to analyze the influence of collocation length alone. Collocation lengths of 500, 1,000, 2,500, 5,000, and 10,000 feet of the pipeline and transmission line compare the maximum induced AC potential in Figure 13.

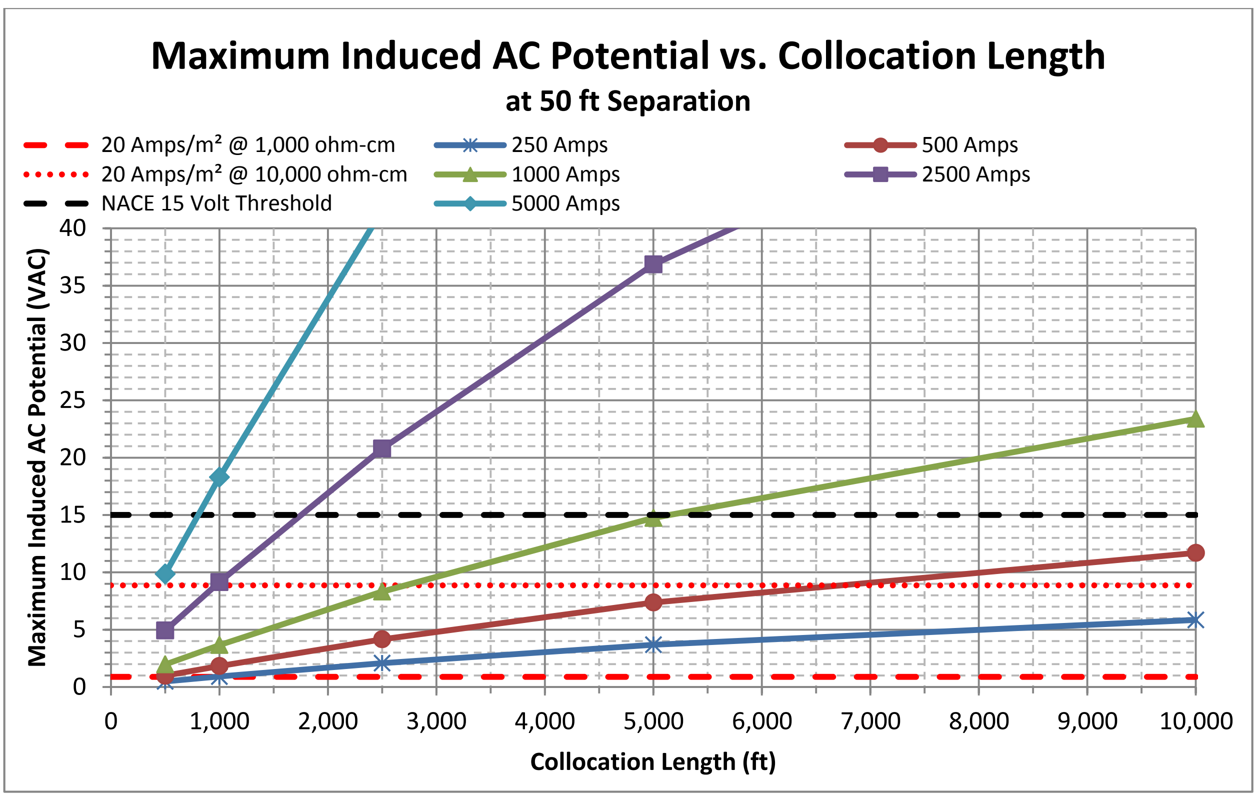

Figure 13. Maximum Induced AC Potential as a Function of Collocation Length

As the collocation length increases, the magnitude of induced AC potential on the pipeline increases, as the length of pipeline exposed to the LEF is increased. Collocation lengths as short as 500 feet are capable of inducing 2 – 10 VAC or greater considering a single collocated power line operating at 1,000 amps or greater.

The potential levels corresponding to a 20 amp/m^2 current density for both 1,000 and 10,000 ohm-cm soil resistivity have been included for reference. Considering a relatively low soil resistivity of 1,000 ohm-cm, the 20 amps/m^2 current density criteria is exceeded at a 2,500 foot collocation length for all load currents analyzed.

The results of the collocation length study also accentuate the sensitivity to HVAC load current as previously discussed in Section 4.2.1. The collocation length required prior to exceeding the 15 volt safety threshold for the 2,500 and 5,000 amp load conditions is approximately 1,750 and 800 feet respectively. These conditions are further increased in complex collocations where multiple lines exist.

It is necessary to consider collocation length in conjunction with the other factors to exclude a collocation from further analysis for separation distances within 2,500 feet. At a minimum, operating current, or an estimate of it, is also necessary when determining if further analysis is necessary.

4.2.3.3 Angle Between Pipeline and Transmission Line

The angle at which the pipeline and HVAC transmission line cross has an effect on the magnitude of induction on the pipeline at the crossing. As the angle increases between the pipeline and transmission line, the magnitude of the induction decreases as the component of the pipeline exposed to induction decreases. For a perpendicular crossing, with the pipeline crossing at or near 90° to the power line, the induction on the pipeline is minimized as the effective parallel length is minimized. The magnitude of the current on the transmission line also has a significant impact on the induced AC potential at crossing locations. Previous 'rule-of-thumb' practices throughout industry may have indicated crossings greater than 60° resulted in negligible induction on adjacent pipelines.[2] However, recent studies have resulted in HVAC installations with significantly greater current capacity, which acts to increase the corresponding interference resulting in cases with induced AC voltage at relatively high angle crossings.

To demonstrate the sensitivity of collocation angle on pipeline interference, DNV GL created a computer model simulating a single 10-inch pipeline, and single circuit vertical transmission line, with similar configuration as described in Section 4.2.1. The pipeline was approximately 2 miles long and the angle between the pipeline and transmission line varied between models while all other model inputs remained constant, in order to analyze the influence of crossing angle alone. Figure 14 shows the results of an analysis of crossing angles between 15 and 90 degrees and the calculated maximum induced AC potential for each case.

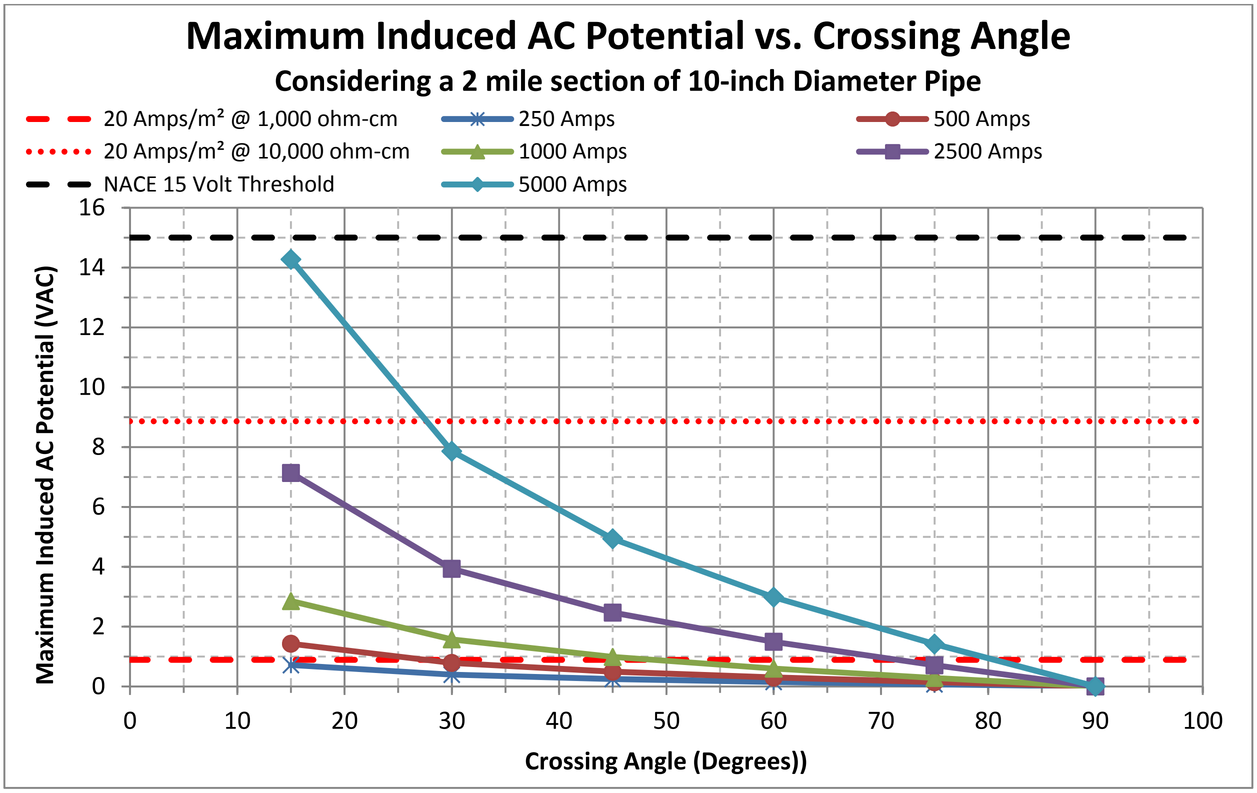

Figure 14. Maximum calculated induced voltage at various HVAC line crossing angles

Considering a typical 345kV circuit, and current loads of up to 1,000 amps, a crossing angle of greater than 45° degrees resulted in an induced potential of less than two (2) VAC for the study presented. A crossing angle of greater than 60° induces minimal potential such that the corresponding current density is less than 20 amps/m^2 even in a relatively low soil resistivity at 1,000 ohm-cm. Previous industry experience and general guidance practices across industry appear consistent with this understanding that crossings of greater than 60° are typically low-severity with respect to induction.

However, as the transmission line load increases to greater than 1,000 amps, it can be shown that crossing angles up to 60° may induce potentials such that corresponding current density exceeds 100 amps/m^2, in low resistivity soil conditions. Depending on target limits for current density, models show that crossing angles of 80° can cause high current density in relatively low soil resistivity locations.

The crossing angles discussed above are with respect to induced AC interference specifically. Assessment for susceptibility to faults, and coating breakdown due to fault voltage, is required for all crossings where pipelines pass in close proximity to a tower ground.

4.2.4 Coating Resistance

The resistance of the pipeline coating to ground is a significant factor controlling the level of induced potential that may build up on a pipeline. However, in practice the coating resistance is typically not known with great certainty and is generally inconsistent along the pipeline length. The coating resistance to ground is a function of the coating type, condition, thickness, and local soil resistivity, all of which may vary along a typical collocation length.

In general, a poorly coated pipeline, or deteriorated coating with low resistance to ground allows multiple paths to ground for AC potential to dissipate. This reduces the buildup of induction, resulting in lower AC potential and lower current density discharge at any individual holiday. Conversely, considering a well coated line with high dielectric strength and excellent coating condition, the resistance to earth along the length of the pipeline is relatively high allowing for greater induction build up over longer distances. For example, this case may exist with a newly FBE coated pipeline, with minimal holidays, in proximity to a collocated HVAC power line. Due to the high resistance to ground, and relatively few ground paths, the induced AC potential can build along the collocation length. This can generate elevated AC potentials, which may be hazardous from a safety standpoint, but also create a possible corrosion risk, as the AC current can discharge from a relatively few holidays after a physical or electromagnetic discontinuity, such as the pipeline diverging from the collocation.

Relative estimates of coating resistance are provided by Dabkoski in the report for Pipeline Research Council International (PRCI) and Parker[24,25], and summarized in Appendix B for reference, to be utilized in detailed modeling analysis based on coating quality, and soil resistivity, however specific guidance is not provided for a relative risk associated with the various coating resistance values.

4.2.5 Pipeline Diameter and Depth of Cover

The diameter of the pipeline collocated with or crossing an HVAC power line affects the level of induced AC potential on the pipeline. However, historical experience has indicated that the effect is relatively minor compared with the influence of other variables.

To demonstrate the sensitivity of pipe diameter on pipeline interference, DNV GL created a computer model simulating a single pipeline, parallel to a single circuit vertical transmission line for 5,000 feet at a horizontal separation distance of 100 feet. The pipeline approaches the transmission line at a 90-degree angle and parallels the transmission line for 5,000 feet before receding from the transmission line at a 90-degree angle. The pipeline model considered diameters of 6, 10, 18, 24, 36, and 48 inches, while all other model inputs remained constant, to analyze the influence of diameter alone. The model used a uniform soil resistivity of 10,000 ohms-cm. The results of this study indicate that the magnitude of induced AC potential decreases with an increase in pipeline diameter, as shown in Figure 15.

As the diameter of the pipeline decreases, the surface area exposed to the LEF also decreases. However, the magnitude of LEF generated by the transmission line remains unchanged. For a smaller diameter pipeline, the LEF influences a smaller surface area resulting in greater induced AC potential compared to a larger diameter line, considering all other variables equal. Further, the pipeline characteristic impedance varies inversely with pipeline diameter, as presented in previous work by PRCI3[24]. Considering all other parameters equal, a larger diameter pipeline will have a generally lower effective resistance to ground, and therefore a lower tendency of HVAC interference. For relative comparison, an increase in diameter from 6 to 48 inches resulted in a 20% decrease in induced AC potential on the pipeline, regardless of the interfering current level.

In the previous analysis, the models used 10-inch diameter pipeline, which will provide a conservative estimate relative to typical larger diameter transmission lines. This was chosen to clearly demonstrate the effects of the individual variables.

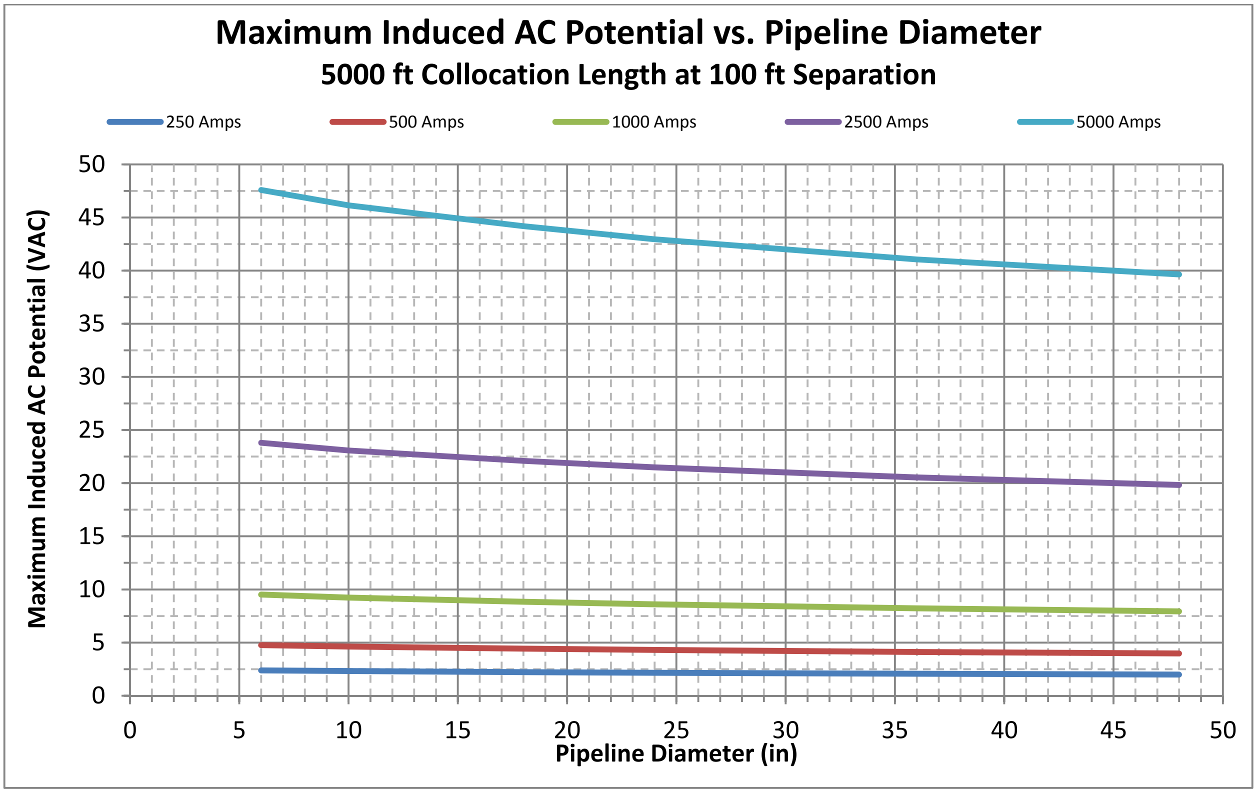

Figure 15. Maximum Induced AC Potential as a Function of Pipeline Diameter

Similar to pipeline diameter, the pipeline depth of cover has a relatively minor influence on the induced AC potential on the pipeline. In general, the level of AC interference decreases with increasing depth of cover as the distance from the individual phase conductors and total resistance to the LEF is increased, though the effect is relatively minor for typical burial depths. A fixed depth of cover of approximately 5 feet was used in the sensitivity studies above.

5 MITIGATION

NACE International Standard Practice SP0177-2014 requires a mitigation system designed for pipelines where HVAC interference is present.[10] Mitigation system design varies across the industry, but in general all involve a low resistance grounding system to pass interfering AC to ground. Typical mitigation system designs can be either surface or deep grounding designs. Both designs have benefits and detriments considering performance, cost, and constructability.

Liquid and gas transmission pipelines are regulated under the Department of Transportation (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) Regulations §49 CFR Part 195 Subpart H Corrosion Control (195.551 – 195.589)[26] and §49 CFR Part 192 Subpart I Requirements for Corrosion Control (192.451 – 192.491)[27], respectively. The regulations have various requirements for corrosion control of which CP and electrical isolation are major factors in compliance. CP systems apply a DC to the pipeline, and electrical isolation quantifies the surface area or limits of the system. CP systems designed for transmission pipelines must meet federally regulated criteria.

DSD 008259

5.1.1 DC Decouplers

When designing mitigation systems for induced AC and faults on transmission pipelines, detrimental effects to the CP system must be considered. It is essential to ensure they do not compromise the operation of the CP systems. Additional structures such as grounding and shield wires used in mitigating induced AC attached directly to the pipeline change the operating characteristics of the CP system, changing the surface area intended for the CP compromising its effectiveness. Direct current decouplers (DCD) alleviate this situation. However, there are some cases where the design of CP accounts for the mitigation. The decouplers, designed into the circuit, allow AC current to pass to ground, while blocking the DC CP current, maintaining the pipeline surface area. There are various types, sizes and ratings of decouplers used depending on the predicted faults or induced AC and mitigation design. DCDs are also used to block DC current at grounded above grade appurtenances, such as block valves, metering stations, and launcher/receiver stations.

Decouplers installed across electrical isolation flanges (IF) prevent "burn over" which can occur when an AC fault current or lightening surge is large enough in magnitude to arc over the gap between flange faces or exceeds the rating of the IF.

5.2 Surface Grounding

Surface grounding generally refers to one of several types of mitigation grounding installed at or near the surface or pipe depth. Typical designs may consist of bare copper cable, zinc ribbon, or engineered systems buried generally parallel to the pipe path and connected to the pipeline through a DCD. During new construction, surface grounding can be installed directly in the pipe trench, or laid parallel to the pipe in an adjacent trench or bore. This approach allows for cost-effective installation of a significant length of mitigation at a lower cost relative to alternative forms of mitigation, but is dependent on construction access along the ROW.[16]

If necessary, connecting additional mitigation ribbon in parallel and even adding shallow vertical anodes to the circuit will further reduce grounding resistance up to a certain extent. Installing this type of mitigation system at distributed, targeted locations, optimized from the interference model, reduces the induction along the pipeline. Additionally, when laid parallel to the pipeline in regions where transmission line towers are in close proximity, the mitigation ribbon also acts to protect and shield the pipeline from damage resulting from fault and arcing scenarios.

Analysis of the reduction in ground resistance possible with various installation approaches included a calculation of the resistance of 1,000 foot long mitigation ribbon in varying soil resistivity, using the modified Dwight's Equation for multiple anodes installed horizontally[28]. Figure 16 illustrates how this calculated grounding resistance varies with the number of ribbons connected in parallel at multiple levels of soil resistivity. While numerous sizes of ribbon cables exist, the length is a much more significant factor in determining total resistance than diameter, when considering typical ribbon diameters, therefore this analysis considers a constant diameter ribbon.

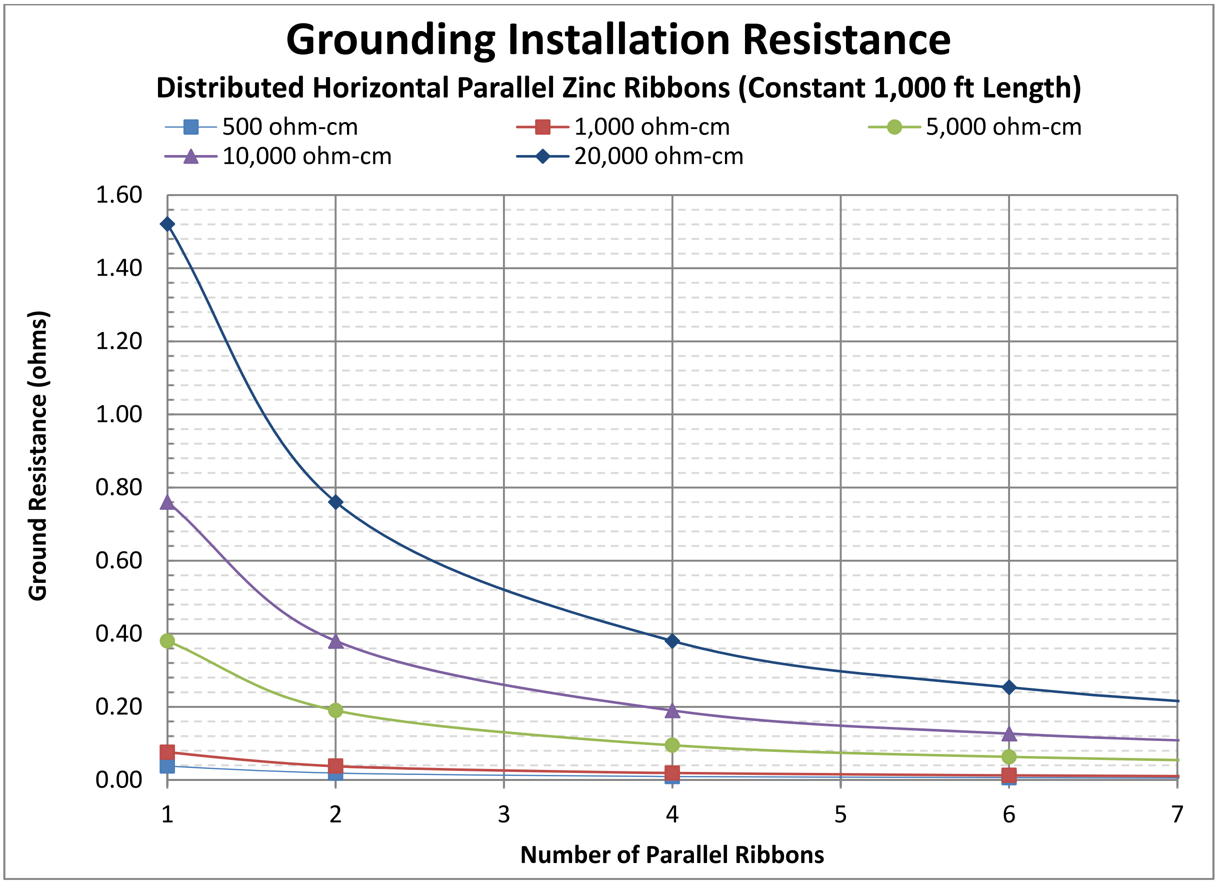

Figure 16. **Grounding Resistance of Horizontal Parallel Zinc Ribbons at Varying Soil Resistivities**

As shown in Figure 17, at low soil resistivities, very low grounding resistance results with a single, relatively short ribbon length. As the soil resistivity increases, so does the achievable grounding resistance. The data is presented considering multiple parallel mitigation ribbons to demonstrate that further reduction in ground resistance is possible by adding additional grounding at a particular installation. However, diminishing returns exist such that further increasing the extent of grounding at a specific site, beyond a certain threshold, results in minimal additional reduction, as shown in Figure 16.

The length of vertical grounding installations requires review of economics, construction, and practical design considerations. Multiple shorter grounding rods can be incorporated to achieve a low resistance to ground without requiring deep drilling, where parallel surface grounding does not sufficiently reduce the ground resistance. Vertical ground rods should be separated horizontally by the length of the ground rods at minimum for optimum efficiency.[23]

For locations of high surface resistivity, one drawback for horizontal surface grounding is the length of mitigation ribbon wire required to achieve a low resistance. Where multiple parallel ribbons are required to achieve sufficient grounding resistance significant ROW access may be required. As discussed, the shared utility ROW may limit construction access for mitigation parallel to a collocated pipeline. Additionally, as pipelines cross physical obstructions, such as roadways, railroads, access may limit the extent of parallel mitigation systems. However, surface grounding still continues to be the preferred mitigation technique and can efficiently provide adequate mitigation grounding for a majority of collocations.

5.3 Deep Grounding

Deep drilled ground wells (deep wells) offer another form of mitigation grounding, and may be considered for select applications. Deep wells generally consist of one or more anodes drilled vertically into the ground in order to achieve low ground resistance. Actual deep well depths can vary based on needs, but they generally range greater than 100 feet in depth.

In general, construction costs are generally higher for deep well grounding than for comparable surface mitigation. However, deep well grounding can be a viable option in specific applications where one or both of the following criteria are satisfied.

1 The soil resistivity at the surface is significantly greater than (>20 x) the soil resistivity at lower depths.

2 Horizontal surface grounding is not feasible due to construction obstacles (roads, railways, right-of-way access, etc.)

For typical mitigation systems, where parallel ribbon and deep grounding are both options, parallel ribbon proves to be more efficient and economical because it can achieve a lower resistance to ground for lower overall cost. For comparison, ground resistance calculations were analyzed to determine the approximate equivalency in effective ground resistance between parallel zinc ribbon, and an individual deep well anode.

Figure 17 below shows a comparison of parallel horizontal grounding configurations compared to a single 6-inch diameter deep well anode approximately 200 feet deep. The soil resistivity ratio, plotted on the x-axis, is the ratio between the bulk soil resistivity to a depth of 10 feet for surface ribbon and the bulk soil resistivity to a 200 foot depth for a deep well. Along the y-axis is the equivalent length of horizontal surface grounding required to meet the same level of grounding resistance as the deep well anode. The two curves in the figure below display this trend for single and double surface ribbon installations.

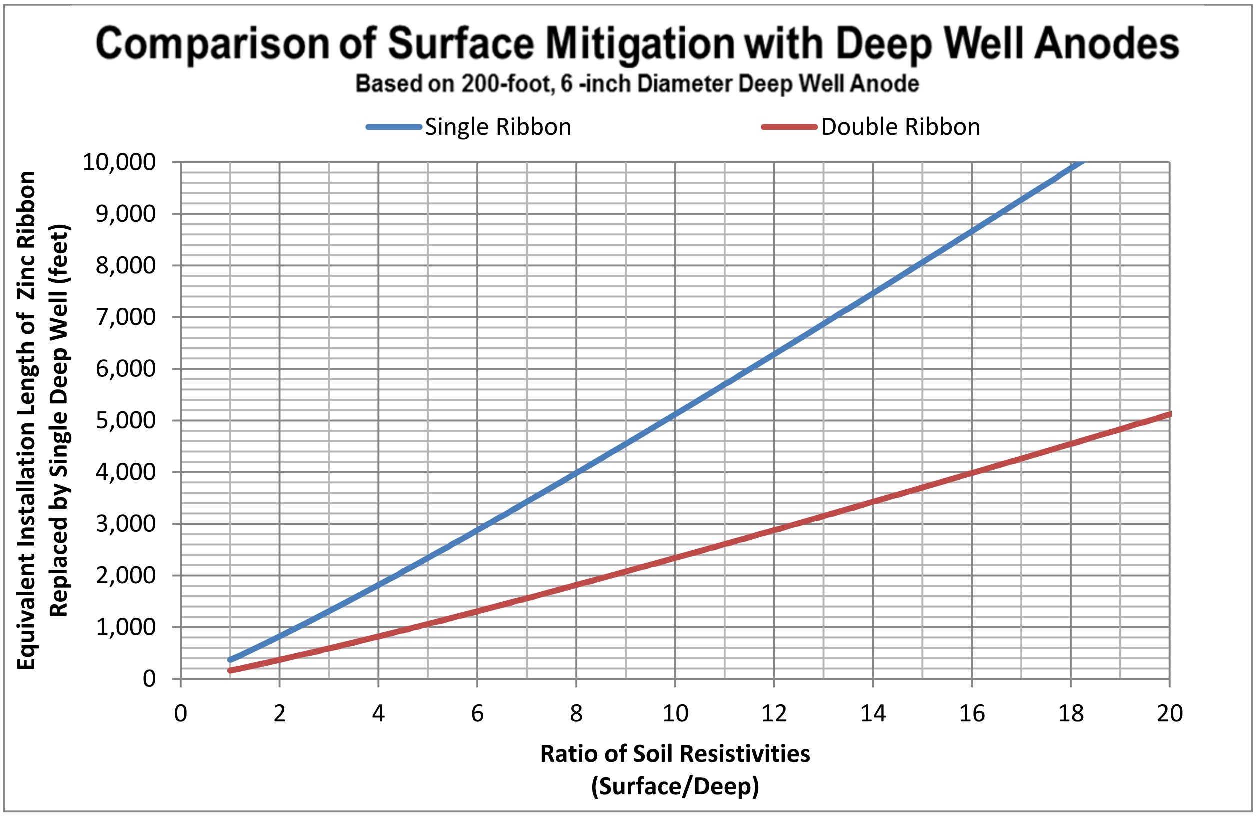

Figure 17. Comparison of Surface Mitigation to Deep Well Anodes

Considering a typical scenario where deep soil resistivity values are of similar order to the surface resistivity, a single deep well grounding installation would be necessary for approximately every 1,000 to 2,000 feet of individual parallel ribbon. However, considering a hypothetical location where the deep soil resistivity is an order of magnitude lower than at the surface (soil ratio of 10), it can be shown that a single deep well installation could provide a similar ground resistance as approximately 5,000 feet of individual parallel ribbon. Under certain scenarios, where the ratio between the surface and deep soil resistivity is high, deep well anodes may become a viable solution to obtain a low grounding resistance. Previous case studies and project experience have rarely shown soil resistivity ratios of this magnitude, such that deep well grounding was a preferred option. However, where construction access is limited, not allowing for installing longer lengths of surface grounding to achieve the required mitigation deep well grounding may be beneficial. In scenarios where grounding is only necessary at a single specific location on the pipeline, deep well grounding may be an option.

5.4 Mitigation Comparison

Deep well anodes may provide a viable mitigation option under specific circumstances, but industry practice, historical assessments, and construction practice have generally shown that surface mitigation provides more economical and efficient mitigation for the majority of collocations. In cases where arc shielding protection is required to guard against fault scenarios, deep well anodes do not provide such protection, thus necessitating the installation of surface ribbon in addition to primary mitigation. Surface mitigation can also serve as fault shielding, protecting against damage to the pipeline and its coating when properly placed between the pipeline and power transmission ground.

A primary benefit for surface mitigation is ease of installation and a lower associated cost. Mitigation installed in the same trench beside the pipe during pipeline construction further reduces installation costs. Typical industry construction estimates indicate that the cost of a single drilled deep well anode installation may be ten times the cost of a 1,000-foot surface installation, if installed during pipe construction. This would indicate that each deep well anode would need to replace approximately 10,000 feet of surface mitigation before it is economically viable from a ground resistance standpoint alone. That said, the decision between surface and deep grounding installation methods most often comes down to a number of other considerations, including construction access, grounding distribution, and contractor preference in addition to cost alone. [Appendix C contains a simplified summary, presents the pros and cons for various mitigation materials and methods for reference.] The comparison information provides guidance and demonstrates the comparative benefits of each approach based on various soil resistivity layers.

5.5 Additional Mitigation Methodologies

The AC mitigation techniques discussed utilize low-resistance grounding to transmit induced AC voltage to ground. While grounding can be an effective mitigation technique for many interference cases, recent industry experience has identified collocations where induced potentials or current density reduction to adequate levels cannot be achieved by grounding alone. This is generally due to a combination of elevated transmission currents and unfavorable soil resistivity conditions. Trends in the power transmission industry have led to increased power capacity and corresponding operating currents, for some long distance transmission systems as shown. This increase in operating current has a direct effect on the level of EMI. In many cases, this has presented a significant challenge for achieving adequate mitigation on pipelines crossing or collocated with the power transmission lines. In these cases, additional mitigation techniques should be considered.

In terms of risk reduction or prevention, the approach to AC interference mitigation can be categorized on a primary, secondary, or tertiary level. Primary prevention targets controlling or reducing the source of the risk, through elimination or control. Secondary prevention targets reducing exposure to a risk factor, and tertiary prevention targets treating the response or consequences of the risk factor, generally after exposure to the risk. By these terms, a standard practice of mitigating AC induction by grounding alone is considered a tertiary form of mitigation. That is to say, the treatment targets only the consequence of the interference by reducing the detrimental AC effects at the pipeline level, after allowing the pipeline to be exposed to the interference risks. While not currently in widespread application, further research of primary and secondary risk controls should be considered in future development, to reduce overall interference and risks associated with AC interference, especially considering cases that cannot be effectively mitigated by traditional means. While the concepts presented may not be readily employed by pipeline operators without further research, they are presented to address the need for continued research and development of more robust high voltage interference mitigation methodologies, and pursue improved collaboration between the power line and pipeline operators.

5.5.1 Primary Threat Control of AC Interference

Although mitigation grounding is a common industry practice, cases exist where grounding alone is insufficient to reduce interference levels on collocated pipelines. For such cases, additional techniques should be considered. From an engineering risk basis, with respect to overall risk reduction, a preferred approach is to reduce the source of interference. Specifically, this means reducing the interference prior to it reaching the pipeline, generally through design controls during the development phase prior to construction, where modifications to the pipeline or transmission line are possible. The level of interference experienced at the pipeline is dependent on the magnitude of EMI generated at the source, and the collocation parameters that limit the EMI levels reaching the pipeline. Specifically, revising collocation routing, and tower and circuit configuration modifications can reduce or optimize the level of EMI produced. Conductor arrangements can be designed to balance individual phases producing the lowest levels of EMI for a given circuit configuration.

For a given circuit configuration (single circuit horizontal/vertical, double circuit horizontal/vertical/delta, etc.) there exists an ideal phase sequence which minimizes the LEF at the pipeline location and thus results in lower magnitudes of AC interference. Dabkowski studied the magnitudes of the LEF for varying circuit types and phase sequence. The results demonstrated that for a single horizontal circuit a reduction of up to 9 percent of the LEF may be achieved, by choosing the proper phase sequence.[24] With the single circuit vertical case, the LEF at the pipeline location could be reduced by as much as 15% with the proper phase sequence.

The double circuit vertical tower configuration presents a unique scenario for phase sequencing. There are 36 possible phase sequences, classified into five sets of phase combinations: center point symmetric, full roll, partial roll upper, partial roll lower, and center line symmetric. The LEF magnitude between the various phasing configurations can vary significantly.[29] Generally, the ideal phase sequence for a double vertical circuit is the center point symmetric phase configuration, which generates an LEF approximately 65% to 90% less than the center line symmetric phase configuration.[29] This is significant when considering this is simply the result of the physical interaction between conductors, and primary mitigation reduction at the source reduces the interference levels that ever reach the collocated pipeline. Additionally, optimization of the phase configuration does not require unconventional installation methods to obtain this reduction in LEF magnitude.[29] It is recognized that for existing installations, pipeline operators generally may not be able to influence HVAC power design; however, for new construction and power system expansions where interference is a concern, communication between pipeline operators and transmission owners of possible effects is recommended in order to review possible interference hazards prior to construction. Where possible, pipeline and HVAC power line design controls can limit EMI and interference on adjacent pipelines.

The addition of phase transpositions along a given collocation can also act to reduce the overall EMI influencing a collocated pipeline. However, phase transpositions should only considered as part of a detailed analysis, as the discontinuity presented by a phase transposition can create a localized point of elevated interference, and may have further impact on the power transmission design.[24] However, where appropriate, phase transpositions can create discontinuities and effectively break up long line interference built up on long collocations. Further, in areas where construction access may be limited, phase transpositions can be located strategically to reduce interference at the source.

5.5.2 Secondary Threat Control of AC Interference

With respect to overall threat reduction, a secondary control works by means of isolating a threat from a structure. In the case of AC interference, this specifically means intercepting and grounding the EMI prior to reaching the pipeline.

One proposed example is overhead shielding, which is used to mitigate AC interference in other industries including rail transport systems, but is notably less common in mitigating AC interference on pipelines. An overhead shielding technique works by placing a conductor, grounded at regular intervals, within a targeted region between the pipeline and the adjacent transmission line. This shielding conductor, located in the same LEF generated by the conductor circuit, induces a current and an accompanying LEF 180 degrees out of phase with the field generated by the transmission line. In so doing the conductor acts to cancel part of the LEF generated by the transmission line, resulting in lower levels of induction on the pipeline. Dabkowski studied the effectiveness of this technique for the same tower configurations discussed in Section 5.5.1.[29] The results indicated a substantial reduction in the induced potential on the pipeline was possible; however, the mitigating effectiveness was highly sensitive to loading conditions, and the precise location of the shielding conductor. For the single circuit horizontal circuit, an auxiliary overhead ground wire resulted in a reduction of approximately 25% in the LEF, and thus the corresponding induction on the pipeline. The ideal placement of this overhead auxiliary shield wire was approximately the same height as the phase wires, which for single circuit horizontal circuits may make this solution impractical. For the single circuit vertical tower configuration, Dabkowski found a maximum LEF reduction of approximately 60% to 75% by mounting the overhead shield wire at an optimum height on the tower centerline. Reductions in the LEF generated by the double circuit vertical configuration were found to be range from 50%-95%. However, when examining slight imbalances of +/-5 to 15% between phase wires, the benefits realized by this auxiliary shield wire quickly diminished to 20% or less when compared to uniform current across all phase wires of the circuit.29[23] While this is generally not a common practice in mitigation of pipeline interference, overhead shielding has been considered and studied in the past, and is used within other industries. Specific overhead shielding installations require detailed design, and precise locating but this approach may present an alternative means of mitigation where ineffective through more traditional means. Further research and testing is required on a case-specific basis to determine if this is a viable technique.

Fault and arc shielding, which are used to reduce the risk of damage to the pipeline and the coating near tower grounds during fault conditions are another form of secondary risk control. Fault protection typically takes the form of a parallel shield wire, similar to mitigation ribbon discussed in Section 5.2. However, the primary function of fault and arc shielding protection acts to intercept transmission line fault current and transfer to ground prior to reaching the pipeline. For this reason, the location and placement of the arc shielding mitigation is far more critical when protecting against conductive (fault) interference than for inductive interference.

5.5.3 Tertiary Threat Control of AC Interference

With respect to overall risk reduction, tertiary controls rely on reducing the consequences of the threat after exposure to the structure. Per this definition, typical grounding mitigation can be considered a tertiary control. Mitigation grounding works by transmitting the AC potential to ground, only after it has already reached the pipeline. While grounding has proven to be an effective means of mitigation for many historical installations, and installation is generally within the capabilities and access of the pipeline operators, scenarios occur where grounding alone is not sufficient to reduce interference to acceptable levels.

Ideally, a combination of primary, secondary, and tertiary mitigation techniques would provide the highest level of threat reduction and protection for the pipeline. However, addressing a threat at the lowest level possible will provide reduction in severity, increasing the likelihood that mitigation will be effective. That is to say, reducing AC interference at its source or shielding EMI from reaching an adjacent pipeline can provide greater risk reduction than simply allowing the interference to pass to the structure and dissipating to ground via tertiary mitigation methods. In practice however, it may not always be possible or practical to address interference at a primary or even secondary level. Tertiary mitigation through low resistance grounding techniques may provide adequate risk reduction for a majority of interference collocations. However, further research and continued development into additional mitigation techniques would benefit the industry.

5.6 MONITORING

As mentioned previously, the measurement or calculation of AC current density has been the primary indicator to determine the likelihood of AC corrosion across industry in North America. It is possible to measure AC current density on a representative holiday through the installation and use of metallic coupons or ER probes. A test wire connected to the coupon, routed to the surface and connected to the pipeline through a test station is an example of a simple installation. By inserting an ammeter into the circuit, an AC and DC current can be measured which when can be used to calculate the current density at that location. In many cases, test stations with coupons also include additional instrumentation such as ER probes and reference electrodes. The ER probes provide a time based corrosion rate while the reference electrodes provide both and AC and DC pipe-to-soil potentials for comparison.

Using coupon test stations (CTS), and ER probes, real-time monitoring can provide a better understanding of the interference effects acting on a collocated pipeline. However, as previously discussed, the magnitude of interference depends on the magnitude of current loads on the associated power lines. Correlation of the CTS and ER probe data with power line loads provides a thorough understanding of the system performance. While it has historically been difficult to obtain this information from power line operators, there is a recognized need to have good understanding of the operating power line loads to determine relevance of coupon test station or ER probe data. Additionally, best practices dictate obtaining data over a representative period (days or weeks as relevant) in order to assess the interference response during high load conditions. A measurement for AC potential or AC current density at a single point in time with unknown operating current loads may not be representative of the actual risk for interference on the pipeline.

6 GUIDELINES FOR INTERFERENCE ANALYSIS

The following steps are provided as best practice procedures for determining where detailed analysis is recommended based on the results of this study, industry standards, historical technical publications, and previous industry experience.

Pipeline operators are faced with many existing and new construction pipelines collocated and crossing power line ROW. Little guidance exists to assist in selecting and prioritizing collocations for detailed analysis and modeling. Under certain conditions, it may be possible to justify the low likelihood of AC interference, and exclude specific locations from further detailed modeling with detailed monitoring, or justification that the risk due to interference is low.

It is recommended to collect the following information, where possible, to determine if a detailed AC analysis is required. Appendix D is a sample of data to collect from the powerline company. Use the corresponding severity limits in Sections 6.1.1 through 6.1.5 to assist with this methodology:

- Peak and Emergency load rating (amps) for collocated power lines
- Line rating (kV) for collocated power lines
- Soil resistivity along the collocation at multiple depths
- Collocation and / or crossing routing geometry for the pipeline and power line
- AC pipe-to-soil (P/S) measurements (for existing pipelines)
- AC Current density using coupons or probes where previously installed
- Maximum fault potential and fault clearing time

Detailed “analysis” in the context of this document refers either to data collection using detailed monitoring or to specific application of numerical calculation of interference magnitudes. This analysis is done using detailed computer modeling or similar application of interference calculation methods.

6.1 Severity Ranking Guidelines

This section provides general guidance with respect to the relative severity ranking for the identified variables with respect to their impact on the severity of AC interference.

6.1.1 Separation Distance

Separation distance and load current are key factors in determining whether a collocation will experience significant AC interference. Generally, the separation distance is readily available or easily determined, so it is often a primary screening variable. However, it has been shown that significant interference is possible for distances greater than 1,000 feet when considering collocations with load capacity greater than 1,000 amps.[2] It is therefore recommended to consider collocations within 2,500 feet, and the decision for further analysis should also incorporate estimate of the power line current.

Severity ranking for separation distance is provided in Table 3.The following generalized rankings have been determined through review of industry data, parametric studies, and historical experience.

Table 3-Severity Ranking of Separation Distance

Separation Distance - D (Feet)	Severity Ranking of HVAC Interference
$D < 100$	High
$100 < D < 500$	Medium
$500 < D < 1{,}000$	Low
$1{,}000 < D \leq 2{,}500$	Very Low

6.1.2 HVAC Power Line Current

The magnitude of transmission line currents is one of the most influential parameters determining the likelihood and severity of AC interference. However, there is often debate as to which load rating to consider for interference analysis and mitigation design. HVAC power lines generally have multiple ratings that specify the operating loads allowable during normal operation and peak or emergency load ratings allowable during short duration scenarios. Ultimately, the load rating considered should be a risk-based decision made by the pipeline operator, considering the frequency of occurrence for the load level, typical duration throughout operation, and the consequence associated.

From a personnel safety standpoint, it is recommended to consider the maximum load that a power line can carry for any duration. The terminology for this varies among transmission operators, but it is commonly referred to as "Emergency Load", defined as the maximum load a transmission circuit is capable of carrying for a short duration such as during an emergency or maintenance condition. Considering personnel safety, elevated step or touch potential could pose an instantaneous threat as a shocking hazard, regardless of duration of the elevated power line current. As the pipeline operator is generally unaware of an emergency load condition on the power line, it may not be feasible to reduce or prevent exposure during even a short-duration elevated current load. It is therefore generally best practice to consider the maximum capacity or emergency loading conditions when assessing the risk of personnel safety threats such as shocking, unless other provisions can be made to prevent exposure.

However, AC corrosion is a time-dependent threat. The magnitude of AC current density possible on a pipeline under AC interference will be sensitive to the current load on the adjacent HVAC conductor. While emergency loads, or other spikes in power line current may cause an elevated current density, the associated corrosion damage may be low as the duration is limited.

The power line current is often the most controlling parameter influencing the magnitude of AC interference. For this reason, we recommend obtaining the power line load limits from the relevant power transmission operator when assessing the risk of AC interference on a given pipeline. These limits should include the various operating ratings (generally 'Normal', 'Peak', and 'Emergency'), the allowable duration for each, and expected frequency of occurrence.

Transmission operating parameters are not always readily available to pipeline operators, and this information may be difficult to obtain. However, the power line current is a primary factor, and the relevance and accuracy of an AC analysis may vary greatly with the accuracy of the operating current. Where actual load data is unavailable, published reference currents for various HVAC power line ratings are available in literature[24]. However, these guidelines are for reference only, and may provide over or under conservative results. In practice, there are cases where the operating currents provided for a specific power line significantly exceeded these estimates. Additionally, as discussed in Section 4.2.1, increase load capacity on new and upgraded systems may result in load ratings above the provided reference levels.

Severity rankings associated with HVAC load current for a collocated power line is provided in Table 4.

The following generalized rankings have been determined through review of published technical literature, industry data, parametric studies, and historical experience.

Section 5.2.1 contains further background and detailed information for effects of power line phase current.

Table 4-Relative Ranking of HVAC Phase Current

HVAC Current - I (amps)	Relative Severity of HVAC Interference
$I \geq 1{,}000$	Very High
$500< I > 1{,}000$	High
$250 < I < 500$	Med-High
$100< I < 250$	Medium
$I < 100$	Low

6.1.3 Soil Resistivity

Soil resistivity affects both the magnitude of induced AC and the susceptibility to AC corrosion. The AC corrosion process, as presented in Section 3.3.1 is a function of the AC current density at a coating holiday, which in turn is dependent on the level of AC voltage on the pipeline and the local spread resistance. The bulk soil resistivity is a primary factor controlling overall level of induction, while the local soil resistivity near a holiday is a primary factor in the corrosion activity, as discussed in Section 4.2.2. The following generalized severity rankings have been determined based on industry experience and guidance provided in EN 15280:2013, with respect to AC corrosion.[15]

Table 5-Relative Ranking of Soil Resistivity

Soil Resistivity - ρ (ohm-cm)	Relative Severity of HVAC Corrosion
$\rho < 2{,}500$	Very High
$2{,}500 < \rho < 10{,}000$	High
$10{,}000 < \rho < 30{,}000$	Medium
$\rho > 30{,}000$	Low

6.1.4 Collocation Length

The collocation length of the pipeline and transmission line affects the magnitude of induced AC potential accumulating on the pipeline as it defines the length of the pipeline exposed to the LEF of the phase wires. The following generalized rankings have been determined through parametric studies, and historical experience.

Table 6-Relative Ranking of Collocation Length

Collocation Length: L (feet)	Relative Severity
$L > 5{,}000$	High
$1{,}000 < L < 5{,}000$	Medium
$L < 1{,}000$	Low

6.1.5 Collocation / Crossing Angle

The angle of collocation or crossing of the pipeline and power line limits the influence of induction. The following generalized rankings have been determined through parametric studies, and historical experience.

Table 7-Relative Ranking of Crossing Angle

Collocation/Crossing Angle - θ (°)	Relative Severity
$\theta < 30$	High
$30 < \theta < 60$	Med
$\theta > 60$	Low

6.2 Recommendations for Detailed Analysis

The guidance parameters presented are based on industry literature and standards where available. Where guidance has not previously been provided, qualitative classifications have been provided to aid in severity ranking and prioritization. The qualitative guidance parameters have been determined based on published industry guidance, numerical modeling parametric studies, previous analytical experience, laboratory studies, and failure investigations for AC corrosion related damage. The intention is not to replace or remove detailed analysis from the design decisions, but rather to aid in severity ranking and prioritization when determining where additional detailed analysis and mitigation design is required.

The guidelines within should be used by the operators as part of an overall risk-based decision. The details within this report and this section can only provide guidance regarding the severity of HVAC interference or AC corrosion. When determining whether to perform further detailed analysis, add location specific monitoring, or where no further action is required, possible consequences must be a part of the decision process and reviewed on a case-specific basis.

As discussed in Section 4.2, collocations with power lines operating at greater than 1,000 amps are subject to interference under conditions where likelihood would otherwise be low. Special consideration required for collocations where the power line loads are greater than or equal to 1,000 amps. For this reason, an understanding of the power line load current is necessary for evaluating the need for further analysis. The two cases below provide an assessment of collocations and crossings encountered, based on:

Case 1 – Current Load greater than or equal to 1,000 amps, pipeline crossing or collocated within 2,500 feet

Case 2 – Current Load less than 1,000 amps, pipeline crossing or collocated within 1,000 feet

6.2.1 Case 1

For scenarios where power line current is known or can be estimated to operate at or above 1,000 amps, and a steel pipeline is crossing or collocated within 2,500 feet of the power line, a detailed analysis is recommended when one or more of the following conditions are met:

- Collocation Length severity is characterized as "High"
- Soil resistivity severity is characterized as "High" or worse
- Three or more of the variables identified in Section 6.1 are categorized as "Medium" or worse

6.2.2 Case 2

For scenarios where power line current is known or estimated to operate below 1,000 amps, and a steel pipeline is crossing or collocated within 1,000 feet of the power line, a detailed analysis is recommended when one or more of the following conditions are met:

- Phase current severity is characterized as "High" or worse
- Collocation length severity is characterized as "High"
- Soil resistivity severity is characterized as "High" or worse
- Three or more of the variables of severity rankings identified in Section 6.1 are categorized as "Medium" or worse

High angle crossings, with crossing angles of greater than 60°, while considered low-risk for inductive interference, are susceptible to fault or lightning arcing, as well as coating breakdown due to fault voltage. Crossings with an angle greater than 60° may still be susceptible to inductive interference if subject to very high current load, or multiple HVAC power lines.

6.2.3 Faults

As fault conditions are generally infrequent and of short duration, it is not practical to obtain measurements of AC potential during a fault condition. Analysis of fault voltages generally requires numerical modeling. Fault current levels or estimates of possible magnitudes, are generally obtained by HVAC power line operators and can vary significantly depending on tower design, power capacity, and location relative to substation and generation source.

Whenever a pipeline crosses or is collocated in close proximity within 500 feet an HVAC tower, it is susceptible to faults. Detailed calculations or modeling is required to determine the possibility of fault arcing and possible coating damage due to GPR.

6.2.4 Fault Arcing Distance

When a pipeline crosses or is collocated in close proximity to an HVAC tower ground, a theoretical fault arcing radius can be calculated. The fault arcing radius is the distance from a HVAC tower ground that a sustained lighting or fault arc may reach an adjacent metallic structure. The arcing radius is primarily a function of the fault or lightning current and the local soil resistivity magnitude, and is estimated using equations 2 and 3 based on Sunde's equations for lightning arc distance.[30] The equations presented were developed to predict a safe separation distance considering an elevated current due to lightning strike, and can be utilized to provide an estimate of possible fault arcing distance from a faulted high voltage tower ground as well.

$$r_a = 0.08\sqrt{I_{ac}x\frac{\rho}{100}} \qquad \text{If } \rho \leq 100{,}000\ \Omega\cdot\text{cm} \qquad (2)$$

$$r_a = 0.047\sqrt{I_{ac}x\frac{\rho}{100}} \qquad \text{if } \rho > 100{,}000\ \Omega\cdot\text{cm} \qquad (3)$$

Where: r_a= arc distance in m

ρ= soil resistivity in Ω·cm

I_{ac} = the fault current in kA

6.3 Data and Documentation Requirements

Where the Severity Rankings Guidelines criteria indicated a more detailed analysis is necessary, collect the following information where possible, to facilitate development of an AC interference model. Appendix D contains a sample data log provided for reference:

Pipeline Parameters:

- Routing geometry
- Depth of cover
- Diameter
- Coating details
- Coating resistance
- Existing CP installations
- Location of bonds
- Soil resistivity at multiple depths and locations along the ROW
- Location of insulating joints

Power line Parameters:

- Routing geometry
- Number of circuits
- Conductor configuration (dimensions, orientation, phasing)
- Conductor loading (Peak and Emergency current)

- Tower ground resistance
- Maximum fault voltage
- Fault clearing time
- Shield wire configuration

6.4 General Recommendations

As the operating current is a controlling parameter influencing AC interference, it is recommended to obtain the power line load current from the relevant electrical utility operator when assessing a collocation for the threat of AC interference. Historically, lack of collaboration between pipeline and power line operators has led to projects being assessed without accurate understanding of the power line data. This can lead to either an overly conservative and costly design or an under-designed system not adequately reducing the interference. Collaboration between the respective pipeline and power line operators is critical to accurate assessment and efficient mitigation of any possible interference effects.

In addition to the assessment described in previous sections, the following general recommendations apply for collocations and crossings where AC interference is a concern:

- Install coupon test stations or ER probes to monitor AC Current density, a coupon surface area of 1.0 cm^2 is recommended.
- During pipeline construction near HVAC transmission lines, confirm that the contractor safety program complies with the recommended 15 VAC limit for shock hazards, and applicable OSHA construction standards as referenced in Section 3.2.2.
- Record AC pipe-to-soil potentials along with the DC pipe-to-soil potentials during the annual cathodic protection survey on sections where AC interference threats may exist. This can provide information, should the power transmission company change its operating parameters, or unexpected changes occur between the pipeline and transmission line.
- Request power line loads corresponding to the time of AC pipe-to-soil potential measurement to provide thorough understanding of the interference measurements
- Measure soil resistivity at locations where AC interference threats may exist. This data can be used with the measured AC potentials to estimate theoretical AC current density for specific locations in the absence of coupons or ER probes.
- Operating personnel should be trained in the hazards and safe practices associated with working on pipelines subject to HVAC interference
- Suspend work (when possible) along the collocated or crossing section of pipeline during weather conditions that may lead to a transmission line fault.

Safety precautions are required when making electrical measurements:

- Only knowledgeable and qualified personnel trained in electrical safety precautions install, adjust, repair, remove, or test impressed current cathodic protection and AC mitigation equipment.
- Properly insulated test lead clips and terminals should be used to prevent direct contact with the high voltage source.
- Attach test clips one at a time using a single-hand technique for each connection when possible.

- Extended test leads require caution near overhead HVAC power lines, which can induce hazardous voltages onto the test leads, or present a source of data error.

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APPENDIX A LITERATURE REVIEW

Where published, historically identified corrosion defects and pipeline failures associated with AC corrosion degradation were reviewed and are presented to demonstrate the magnitudes and variability in corrosion rates possible with AC accelerated corrosion. The general findings, discussion, technical details, and results are utilized and summarized throughout this document.

This lack of industry consensus on the subject of AC corrosion guidelines has led to varied practices among pipeline operators in regards to mitigating AC interference on pipelines. As part of this study, The INGAA Foundation requested a review of industry practices and procedures related to AC interference. The INGAA Foundation provided DNV GL with the procedures related to AC interference or mitigation for 10 pipeline operators who are members of the Foundation. The primary finding from this review is that there is significant variation in company procedures with respect to AC interference. Based upon this review, all of the procedures provided address a safety concern and define a maximum allowable AC pipe-to-soil potential limit for above grade appurtenances. Faults were included as a concern/risk for pipelines in close proximity to HVAC power lines in almost all of the procedures. However, few addressed coating stress limit above which mitigation is required. For current density criteria, several procedures had clearly defined limits, while others addressed it as a concern for AC corrosion but did not specify a targeted limit of AC current density or define limits for mitigation.

Case Studies

Numerous studies, both laboratory and field based, have been performed that attempt to determine magnitudes of corrosion rates associated with AC interference. However, reviewing available technical literature confirms a wide range of experimental rates, and a scarcity of controlled field measured rates.

Where published, historically identified corrosion defects and pipeline failures associated with AC corrosion degradation have been reviewed and are presented to demonstrate the magnitudes and variability in corrosion rates possible with AC accelerated corrosion.

Field investigations reported by Ragault[31] considering a coated cathodically protected pipeline, identified corrosion rates between 12 and 54 mpy (0.3 and 1.4 mm/yr), for AC current densities ranging between 84 and 1,100 A/m^2.

Wakelin, Gummow, et al[32] provided three case studies where field inspections identified defects as AC corrosion-related degradation. Based on inspection intervals and corrosion degradation, corrosion rates were identified ranging from 17 to 54 mpy (0.4 to 1.4 mm/yr) for AC current densities between 75 and 200 A/m^2.

A German field coupon study, published by Prinz, and Shoneich,[7] indicated general AC corrosion rates between 2 to 4 mpy (0.015 to 0.1 mm/yr) for a current density of 100 A/m^2, and 12 mpy (0.3 mm/yr) at 400 A/m^2. However, pitting rates were considerably greater and showed a wider range between 8 and 56 mpy (0.2 to 1.4 mm/yr), with considerably less dependence on AC density.[6]

A doctoral thesis study by Goidanich presents similar findings concluding that AC current density as low as 10 A/m^2 may be considered hazardous as the experimental studies showed it nearly doubled the free corrosion rate of the experimental samples in simulated soil tests.[33]

A 1998 report by Wakelin, Gummow, et al published by NACE reviewed several case studies dating back to the 1960's where AC corrosion was identified or suspected to be the primary mechanism of degradation. The report summarized recorded details on multiple case studies with specific focus on comparison of corrosion rates and AC current density where known. In 1991, a failure investigated on a 12-inch diameter pipeline concluded AC accelerated corrosion after only four (4) years of service. Induced AC potentials measured as high as 28 volts. Based on the nominal wall thickness and time to leak, an average pitting rate for the through wall pit was estimated to be greater than 55 mpy. Two other case studies indicated the average AC induced corrosion rates for the identified sites between 11 and 24 mpy.

A 2004 paper by Hanson and Smart, published by NACE, presents a case study for a gas pipeline installed in the summer of 2000.[8] The pipeline was collocated in a shared ROW with a 230 kV transmission line for approximately 9 miles, and then entered a shared power corridor with six power transmission lines, two of which were rated at 500 kV, all within sufficient proximity of the pipeline to cause interference. A leak occurred within 5 months of installation, before the line was in operation. Several other leaks were identified shortly after, with four leaks within close proximity. Induced AC potential measurements found AC voltages as high as 90 volts on the pipeline. The failure assessment indicated the corrosion was due to induced AC corrosion, and estimated rates in excess of 400 mpy.

The majority of literature reviewed indicates AC corrosion rates in the range of 5 to 60 mpy.[3, 9, 10] However, cases have been identified with localized corrosion rates significantly greater, in excess of 400 mpy. There is general agreement that higher AC current density leads to greater risk of AC corrosion. While higher current density may lead to accelerated corrosion rates, the correlation is not simple or direct.

International Standards

Review and comparison of multiple international standards identified the consistencies and variations across accepted industry standards.

Recent laboratory and field work has focused on the interaction between AC and DC current density in determining overall risk of AC corrosion, and the latest European standards reflect this as discussed in Section 3.3.1.1.[15] However, there is no generally accepted method of correlating current density or any other measurable indicator to an expected corrosion rate. A direct method of approximating the AC corrosion rate using a buried coupon or probe would provide accurate information.

The Canadian Standards Association (CSA), NACE International (NACE), and the European Committee for Standardization (CEN) have developed published standards addressing HVAC interference issues, as below:

- CAN/CSA-C22.3 No. 6-13 "Principles and Practices of Electrical Coordination Between Pipelines and Electric Supply Lines
- NACE SP0177-2014 "Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems
- CEN EN 50443:2012 "Effects of Electromagnetic Interference on Pipelines Caused by High Voltage AC Electric Traction Systems and/or High Voltage AC Power Supply Systems"
- CEN EN 15280:2013 "Evaluation of AC Corrosion likelihood of buried pipelines applicable to cathodically protected pipelines"

Of these standards, the first three primarily discuss safety issues, interference effects, and mitigation systems but do not explicitly address criteria for AC corrosion control. The European Standard EN15280:2013 deals specifically with corrosion due to AC interference, and establishing criteria or tolerable limits for interference effects, as presented in Section 3.3.1.1.

NACE Standard Practice SP0177-2014, *Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems*, addresses problems caused primarily by the proximity of metallic structures to AC power transmission systems. In this standard practice document, SP0177-2014 defines a steady state touch voltage of 15 volts or more with respect to local earth at above-grade or exposed sections and appurtenances to constitute a shock hazard. Findings presented in the standard indicate the average hand-to-hand or hand-to-foot resistance for adult male ranges from 600 ohms to 10,000 ohms. NACE uses "a reasonable safe value" of 1,500 ohms (hand-to-hand or hand-to-foot) for estimating body currents. Based upon work by C.F. Dalziel regarding muscular contraction, SP0177-2014 indicates the inability to release contact occurs between 6 mA and 20 mA for adult males.[10] Ten milliamps (hand-to-hand or hand-to-foot) is recognized as the maximum safe let-go current. This 15-volt safety threshold is therefore determined based upon 1,500 ohms hand-to-hand or hand-to-foot resistance and an absolute maximum let-go current of 10 mA. However, under certain circumstances, an even lower value is required. One such circumstance specifically identified where a lower touch potential safety threshold should be considered is "areas (such as urban residential zones or school zones) in which a high probability exists that children (who are more sensitive to shock hazard than are adults) can come in contact with a structure under the influence of induced AC voltage."[10] This standard practice document requires remedial measures to reduce the touch potential on the pipeline where shock hazards exist.

During construction of metallic structures in regions of AC interference, SP0177-2014 requires minimum protective requirements of the following:

- "On long metallic structures paralleling AC power systems, temporary electrical grounds shall be used at intervals not greater than 300 m (1,000 feet), with the first ground installed at the beginning of the section. Under certain conditions, a ground may be required on individual structure joints or sections before handling."
- "All temporary grounding connections shall be left in place until immediately prior to backfilling. Sufficient temporary grounds shall be maintained on each portion of the structure until adequate permanent grounding connections have been made."

The intent of the temporary grounds is to reduce AC potentials on the structure, and thus the shock hazard to personnel during construction. SP0177-2014 advises against direct connections to the electrical utility's grounding system during construction as this could actually increase the probability of a shock hazard to personnel.

Regarding AC corrosion, there are no established criteria for AC corrosion control provided in SP0177-2014. Further, this standard states that the subject of AC corrosion is "not quite fully understood, nor is there an industry consensus on this subject. There are reported incidents of AC corrosion on buried pipelines under specific conditions, and there are also many case histories of pipelines operating under the influence of induced AC for many years without any reports of AC corrosion."

While not a Standard Practice document, NACE published "AC Corrosion State-of-the-Art: Corrosion Rate, Mechanism, and Mitigation Requirements"[1] in 2010, providing guidance for evaluating AC current density, and providing recommended limits as discussed in Section 3.3.1.1.

The State-of-the-Art report also cites European Standard CEN/TS 15280:2006[15], which previously offered the following guidelines related to the likelihood of AC corrosion:

> *"The pipeline is considered protected from AC corrosion if the root mean square (RMS) AC density is lower than 30 A/m^2 (2.8 A/ft^2).*

In practice, the evaluation of AC corrosion likelihood is done on a broader basis:

- *Current density lower than 30 A/m^2 (2.8 A/ft^2): no or low likelihood;*
- *Current density between 30 and 100 A/m^2 (2.8 and 9.3 A/ft^2): medium likelihood; and*
- *Current density higher than 100 A/m^2 (9.3 A/ft^2): very high likelihood"*

EN 15280:2013

The latest revision of EN 15280:2013 was revised to present criteria based upon the AC interference and DC current due to CP. EN 15280:2013 presents using the cathodic protection system of the pipeline to ensure the levels of induced AC potential do not cause AC corrosion under the following conditions:

1. AC voltage on the pipeline should be decreased to a target value, which should be less than 15 V (measured over a representative time period, i.e. 24 hr)
2. Effective AC corrosion mitigation can be achieved while maintaining cathodic protection criteria as defined in EN 12954:2001
3. One of the following conditions is satisfied in addition to items 1 and 2:
    - Maintain AC current density (RMS) over a representative period of time (i.e. 24 hr) less than 30 A/m^2 (2.8 A/ft^2) on a 1cm^2 coupon or probe
    - If AC current density is greater than 30 A/m^2 (2.8 A/ft^2), maintain the average cathodic (DC) current density over a representative period of time (i.e. 24 hr) less than 1 A/m^2 on a 1cm^2 coupon or probe
    - Maintain a ratio between AC current density and DC current density (J_{AC}/J_{DC}) less than 5 over a representative period of time (i.e. 24 hr)

The NACE State-of-the-Art report also references experimental studies by Yunovich and Thompson that concluded

> *"AC density discharge on the order of 20 A/m^2 (1.9 A/ft^2) can produce significantly enhanced corrosion (higher rates of penetration and general attack without applied CP). Further, the authors stated that there likely was not a theoretical 'safe' AC density (i.e., a threshold below which AC does not enhance corrosion); however, a practical one for which the increase in corrosion because AC is not appreciably greater than the free-corrosion rate for a particular soil condition may exist."*[1]

APPENDIX B COATING RESISTANCE ESTIMATES

Pipe Coating Conductance/Resistance

Pipe Line Corrosion and Cathodic Protection, Marshall E. Parker & Edward G. Peattie

No.	Coating Quality	Soil Resistivity	Conductance Range		Resistance Range					
			µmhos/ft2		ohm-m^2		ohm-ft^2		Kohm-ft^2	
1	Excellent	High	1	10	92,903	9,290	1,000,000	100,000	1,000	100
2	Good	High	10	50	9,290	1,858	100,000	20,000	100	20
3	Excellent	Low	50	100	1,858	929	20,000	10,000	20	10
4	Good	Low	100	250	929	372	10,000	4,000	10	4
5	Average	Low	250	500	372	186	4,000	2,000	4	2
6	Poor	Low	500	1,000	186	93	2,000	1,000	2	1

PRCI

No.	Coating Quality	Soil Resistivity (ohm-m)	Coating Resistance (Kohm-ft2)		
1	Excellent	25	Multiply Soil Resistivity (ohm-m) by 5	5	125
	Excellent	50	Multiply Soil Resistivity (ohm-m) by 5	5	250
	Excellent	200	Multiply Soil Resistivity (ohm-m) by 5	5	1,000
	Excellent	600	Multiply Soil Resistivity (ohm-m) by 5	5	3,000
2	Good	25	Multiply Soil Resistivity (ohm-m) by 2	2	50
	Good	50	Multiply Soil Resistivity (ohm-m) by 2	2	100
	Good	200	Multiply Soil Resistivity (ohm-m) by 2	2	400
	Good	600	Multiply Soil Resistivity (ohm-m) by 2	2	1,200
3	Fair	25	Multiply Soil Resistivity (ohm-m) by 0.5	0.5	13
	Fair	50	Multiply Soil Resistivity (ohm-m) by 0.5	0.5	25
	Fair	200	Multiply Soil Resistivity (ohm-m) by 0.5	0.5	100
	Fair	600	Multiply Soil Resistivity (ohm-m) by 0.5	0.5	300

APPENDIX C MITIGATION COMPARISON SUMMARY

Zinc Ribbon

Advantages

- Can typically be installed during pipeline construction minimizing installation costs
- Cost of raw material is typically one third the cost of copper
- Can be trenched or plowed in relatively inexpensively after pipeline installation
- Typically results in very low resistances
- Historically has performed as intended
- Surface mitigation ribbon can double as shielding for fault mitigation

Disadvantages

- Zinc clad ribbon is more difficult to work with compared to copper
- Life expectancy is generally less than comparable copper installation

Copper Cable

Advantages

- Can typically be installed during pipeline construction minimizing installation costs
- Can be trenched or plowed in relatively inexpensively after pipeline installation
- Typically results in very low resistances
- Historically has performed as intended
- Surface mitigation cable can double as shielding for fault mitigation
- Depending on the size cable the material cost of a copper installation can be lower than a zinc installation

Disadvantages

- Cost of raw material is typically higher than the cost of zinc
- Risk of having a more noble metal (cathodic) near or connected to pipeline even if through a decoupler

Deep Grounding (anodes used as the ground)

Advantages

- May be advantageous when surface resistivity is extremely high

Disadvantages

- Typically high cost for both installation and materials
- Generally not suitable for mitigating ground potential rises (GPR) or arcing issues associated with faults

Shallow Grounding (driven ground rods or bored ribbon or cable)

Advantages

- Can be used to supplement horizontal ribbon or cable installation if required
- Magnitude of the surface resistivity affects the resistance

Disadvantages

- Generally not suitable for mitigating ground potential rises (GPR) or arcing issues associated with faults

Engineered mitigation and / or Additives (no specific product identified)

Advantages

- Could increase design life

Disadvantages

- Typically increases the material costs

Notes:

1) These are typical statements and there are instances where they do not apply.
2) All mitigation installations are considered connected through a decoupling device such that there is no direct passage of DC current to or from the mitigation.

APPENDIX D DATA REQUEST TEMPLATE

Company: ____
Project: ____
Project Number: ______________________________________

High Voltage Alternating Current (HVAC) Power Transmission Parameters

No.	Information Requested	T-Line 1	T-Line 2	T-Line 3
	General			
1	Owner:			
2	Power transmission voltage (kV):			
3	Average Tower Span (feet)			
4	Substation ground grid impedance (ohms):			
	Phase Wires			
5	No. of circuits:			
6	Circuit type:			
	Conductors:			
7	No. 1 average height (ft):			
8	No. 1 average horizontal distance (ft):			
9	No. 1 phasing (degrees):			
10	No. 2 average height (ft):			
11	No. 2 average horizontal distance. (ft):			
12	No. 2 phasing (degrees):			
13	No. 3 average height (ft):			
14	No. 3 average horizontal distance (ft):			
15	No. 3 phasing (degrees):			
16	Other: Cable Sag, Lowest point (feet):			
	Circuit Loading			
17	Peak loading (amps):			
18	Emergency loading (amps):			
19	Emergency loading time (hours):			
	Shield Wires			
20	No. of conductors:			
21	No. 1 type:			
22	No. 1 conductor GMR (ft):			
23	No. 1 conductor resistance (ohms/mil):			
24	No. 1 average height (ft):			
25	No. 1 average horizontal distance (ft):			
26	No.2 type:			
27	No. 2 conductor GMR (ft):			
28	No. 2 conductor resistance (ohms/mil):			
29	No. 2 average height (ft):			
30	No. 2 average horizontal distance (ft):			
	Fault Current Parameters			
31	Fault clearing time (cycles):			
32	Average tower resistance (ohms):			
33	Beginning of Collocation: Total______from left substation ___________ from right substation			
34	Middle of Collocation: Total______from left substation ___________ from right substation			
35	End of Collocation: Total______from left substation ___________ from right substation			

Company: ____
Project: ____
Project Number: ______________________________________

Pipeline Parameters

No.	Information Requested	Pipeline 1	Pipeline 2	Pipeline 3
	General			
1	Pipeline number:			
2	Pipeline owner:			
3	Pipeline name:			
4	Product transported:			
5	Diameter (in.):			
6	Burial depth (ft.):			
7	Wall Thickness (inch):			
8	Length of Collocation (feet/miles):			
	Coatings			
9	Coating type (majority):			
10	Coating resistance (kohm-ft2):			
11	Coating thickness (mils):			
	Cathodic Protection			
12	Location of cathodic protection:			
13	Resistance of cathodic protection groundbed(s):			
14	Bonding to foreign pipelines? (Y/N):			
15	Existing AC mitigation measures? (Y/N):			
16	Describe existing AC mitigation:			


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NO UNAUTHORIZED ENTRY
WASHINGTON FENCE COMPANY
755-7052

DSD 008289

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April 2, 2014

To: Olympus Residents, Newcastle City Staff

Re: Energize Eastside Project

At my request, on April 2nd Lowell Rogers called me to answer the questions I had raised about construction of steel monopoles in the Olympus transmission corridor. Lowell is an engineer with POWER Engineers, a global consulting engineering company that specializes in power projects. Lowell is assisting PSE in the siting and preliminary design phase of the Energize Eastside project, and could be asked to do final design as well. He or a colleague will have to put his professional engineering stamp on the design. It was clear in our conversation that he takes that responsibility seriously. He and his colleagues have assisted in the siting and design of dozens of transmission line projects around the country.

Following are the questions I asked PSE and Lowell's answers. Questions 1 and 2 in my original letter were related, so I combined them in this letter.

Question 1. The PSE website shows a photo of a steel monopole foundation being constructed by vertical boring using high-intensity vibration. The intense ground vibrations generated by this method could cause settlement damage to homes and their foundations, as well as damage to the high pressure (up to 500 psi) Olympic Pipeline Company petroleum pipelines that run parallel to PSE's transmission lines. Damage to pipelines could cause leaks and/or catastrophic rupture. Results could include burning, toxic liquid or asphyxiating gases flowing downhill through the neighborhood, or major explosions. Please provide detailed descriptions (and schematics as needed) showing how PSE would:

- Minimize the impacts of vibration on homes and their foundations, and evaluate and compensate for any damage.
- Ensure that the petroleum pipelines are depressurized and not damaged during construction of monopole foundations.
- Detect and control any leakage of petroleum products from the pipelines, either liquid or vapor.

Native bedrock is often present just under the surface throughout the Olympus neighborhood. Please provide detailed descriptions (and schematics as needed) showing how PSE would:

- Excavate the bedrock to construct monopole foundations.
- Perform blasting, if required.
- Minimize vibration (and vibration damage) in homes if blasting or excavator-mounted hydraulic hammer chisels are used.
- Prevent damage to the high-pressure petroleum pipelines from rock movement.

Answer. Lowell had not specifically seen the photo that I was referencing, but thought that it was of another project of PSE's and was a stock photo. The vibration method of installing monopole foundations (shown in photo) is typically used when soils are soft, which is unlikely to be the case in Line M. It is more likely that a typical auger system would be used. If bedrock is present, they would use a pneumatic hammer or core drill. If the bedrock is solid, they would not need to drill as deep, and could create tenon foundation anchors into the bedrock. Regardless of the conditions encountered, they would excavate in a controlled way so as to minimize the potential for damage to the fuel pipelines or nearby homes. There would be no blasting.

During the design phase, detailed geologic studies would be undertaken. Results of these studies would dictate the installation method and steps that would be taken to protect the Olympic fuel pipelines during construction. At this point, based on pipeline location and likely monopole construction methods, Lowell doesn't think it would be necessary to move or depressurize the pipelines. PSE would work closely with Olympic Pipeline Company to determine measures needed to protect public safety during construction. This would be a primary emphasis.

Question 2. Will steel monopoles be erected at approximately the same locations as the existing wooden towers, or are entirely new locations possible? How will PSE protect homes from the potential for wooden towers to fall during removal, or for monopoles to fall while being erected?

Answer. PSE has not designed the line, because an alignment has not yet been determined. Therefore, it's too early to know if the poles would be replaced at the same location. As part of the routing process, the community has requested information in order to understand what options PSE may have with regard to height and configuration. During the actual design, engineers would determine the height of each pole at the different segments, which would determine the location of the poles.

In addition to meeting safety requirements, there are a number of factors to consider in locating the poles, such as easement configuration, existing utilities, and environmental factors. If these factors allow for flexibility in locating the poles, PSE would discuss the pole locations with homeowners adjacent to the corridor. At the request of a homeowner, a transmission pole could be moved somewhat, as long it is not moved adjacent to someone else's house. If necessary to protect public safety when an existing pole is removed or new one installed, the PSE construction manager would recommend vacation of potentially affected homes. Any such vacation would be short-term.

Question 3. Newcastle is located in the area that would be most affected by a Seattle fault earthquake. Because it is so shallow, and capable of earthquakes of greater than Richter 7 magnitude, the Seattle fault is considered the greatest seismic risk in this area. What Richter magnitude earthquake will the towers and their foundations be designed and constructed to withstand? Would they withstand vertical as well as horizontal seismic forces?

Answer. Pole and foundation design would meet seismic codes for this area, which anticipate earthquakes of the magnitude that would be expected from the Seattle Fault. However, unless

there is a potential for liquefaction, which is unlikely on Line M, the potential for seismic loads to damage monopoles and their foundations is low. Seismic loads are more damaging to heavier structures such as buildings, and much less of a concern with relatively light structures such as transmission monopoles. Of more concern with transmission monopoles are forces due to wind and ice loading (see following question and answer).

Question 4. How will PSE ensure that the monopoles will withstand the highest potential winds in this area? For example, there were sustained winds of 75 mph, with gusts to 90 mph, in a December storm that caused much damage.

Answer. During final design of the monopoles, the American Society of Civil Engineers (ASCE) and National Electric Safety Code (NESC) codes for wind loading will be used. These codes are based on historic climatological data to determine the highest recurring wind speeds and gusts in the area, and the potential for and severity of ice storms. These loading requirements will be adjusted upward if and as PSE's design guidelines note the need. This will determine the response and strength factors to be incorporated in monopole, foundation and transmission line design. The design will meet or exceed all safety codes for wind and ice loading.

Question 5. Transmission of power at 230,000 volts, which is nearly double the existing voltage, will significantly increase the electromagnetic field surrounding the transmission lines. This field would potentially create powerful induced voltage and electrical current in the steel petroleum pipelines. Please provide detailed descriptions (and schematics as needed) showing how PSE would:

- Reduce the risk of electrical shock from the high-pressure petroleum pipes and appurtenances, including from the casing vents at the road crossings.
- Prevent increased current-induced corrosion and risk of leakage or catastrophic rupture of the pipelines.

Answer. Electromagnetic fields (EMF) are created by amps (electric current). There is no correlation of EMF with voltage. After the new transmission lines are installed, amps (and EMF) would start out lower and rise with increasing demand for electricity due to growth in the area. EMF could be lowered with different arrangements of the three conductors of the power lines carrying the three phases of current. The existing horizontal configuration of conductors creates the largest EMF strength on the ground. With new monopoles, the conductors would be at a higher elevation than the existing conductors. The increased height of the conductors results in lower EMF on the ground (EMF drops off exponentially with distance). Also, the new conductors would be arranged differently. For example, one three-phase circuit could be arranged with the three conductors in a vertical array in an ABC pattern. The other circuit could be arranged in a CBA pattern, which would have the effect of cancelling out much of the EMF. The goal is to configure the lines so they have the lowest EMF, while also considering other factors related to configuration.

With any of the anticipated line configurations for a monopole, EMF would likely be lower than with the existing configuration. As noted above, the final route and design configuration have not *Page 4*

been determined. PSE is preparing an evaluation of existing and potential future EMF, assuming a range of line configurations and amps. This evaluation will be released to the public in the near future.

Undergrounding would generally reduce EMF, in part because the close proximity of phases (or conductors) to each other reduces magnetic fields. However, for walkers in the corridor, EMF directly over the underground lines at times could be more than EMF from overhead lines, because of the reduced distance between the walker and the underground line as compared to an overhead line.

As part of the design process, PSE, in coordination with Olympic Pipeline Company, would analyze the potential for induced voltage in the Olympic fuel pipelines and determine what protective measures are needed. For example, additional grounds or cathodic protection could be installed on the pipelines.

Question 6. Although not one of my original questions, I asked Lowell about PSE's projections of future energy needs.

Answer. Lowell reviewed PSE's system studies, including projected energy needs. He said the energy needs projections that are shown in the Eastside Needs Assessment Report, Transmission System, King County, appear to be in line with other regional studies that he has reviewed. He didn't see anything that raised red flags with him.

Speaker #16 NewCastle Public Hearing 2.27.16

Intel catches the wind with rooftop micro-turbine array

By Pete Carey

SANTA CLARA -- Intel is turning the roof of its Santa Clara headquarters into a mini-wind farm with what it says is one of the largest micro-turbine arrays in the country.

The V-shaped formation of 58 wind-powered turbines, being installed this week, is expected to generate about 65 kilowatt-hours of power that will be used to provide electricity to the conference center in the rambling Robert Noyce Building on Mission Boulevard.

The chipmaker called the micro-turbines a "proof of concept" project.

"We are trying to understand how this type of technology integrates into Intel and where are the best locations for it around the world," said Marty Sedler, director of Intel's global utilities and infrastructure.

JLM Energy crew members install their Zefr micro wind turbines on the rooftop of Intel Corporation's Headquarters in Santa Clara, Calif., on Thursday, May 21, 2015. (LiPo Ching/Bay Area News Group)

"We'll share the data and share the information so other people can apply it to their own businesses and homes," he said.

The micro-turbines are 6 to 7 feet tall, weigh about 30 pounds each and are positioned at the roof's edge where they can gather the most wind, which averages about 8 to 9 miles per hour in the area. They share the roof with an array of solar panels.

"This is just another prong adding to our sustainability program," Sedler said

Intel's new wind turbines arrive at a time when major tech companies are turning to green power. Apple and Google announced green projects in February. Apple is building a solar farm in Monterey County and Google is developing a forest of wind turbines on Altamont Pass near Livermore.

Intel says it has been green for years, and was recently recognized by the U.S. Environmental Protection Agency, for the seventh year in a row, as the largest voluntary purchaser of green power in the country. It has solar installations on 12 Intel campuses in the U.S., Israel and Vietnam that generate more than 12 million kilowatt-hours of power per year of clean energy, as well as a solar hot water system that supplies nearly all the needs of Intel's two campuses in India.

The new array "is one of the largest we've identified anywhere," Sedler said. "One of the things Intel does that's a little different from other companies is that all the projects we have done to date have been on our campuses. It's not the answer, it's one of the answers. The key is to get off the grid."

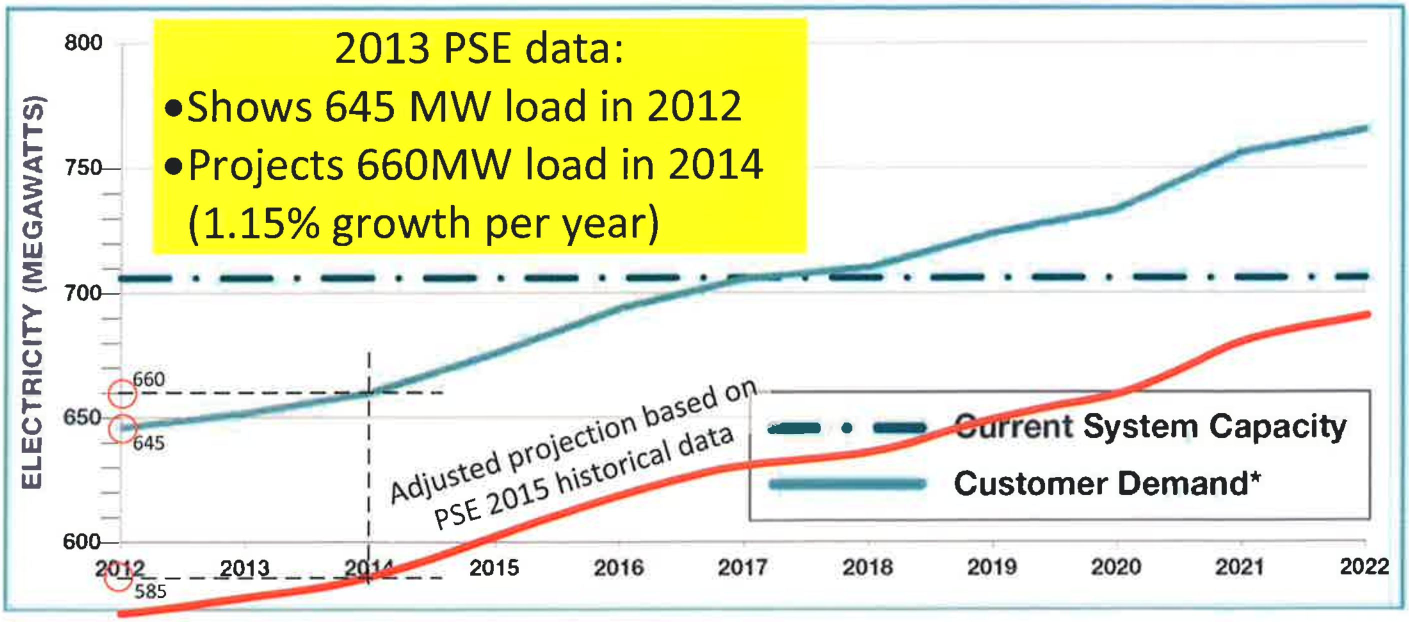
Contact Pete Carey at 408-920-5419. Follow him on ***Twitter.com/petecarey***.

http://www.mercurynews.com/business/ci_28164774/intel-catches-wind-rooftop-micro-turbine-array


This streetlight
is powered
by the sun
and the wind!
A pilot project of the
Urban Green Energy
Wind/Solar Streetlight
study.
Real Estate
& Facilities
Microsoft

Submitted by Brian Elsworth Renton
Phase 1 DEIS public hearing 2.25.16

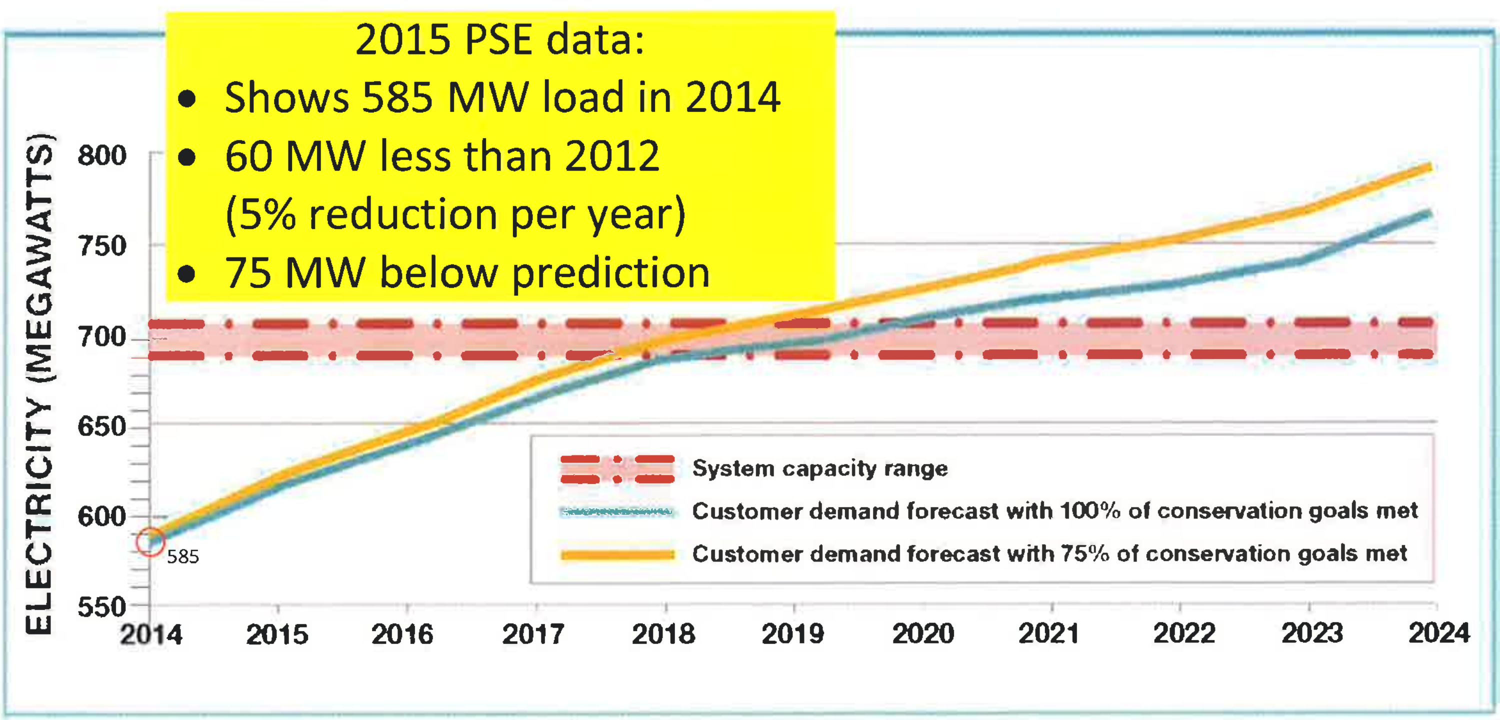
Eastside customer demand forecast



*Customer Demand assumes 100% of conservation goals are met.

This chart shows customer demand with 100% conservation goals met compared to our current electric transmission system's capacity. By 2017-2018, demand will exceed our ability to provide dependable power.

December 2013

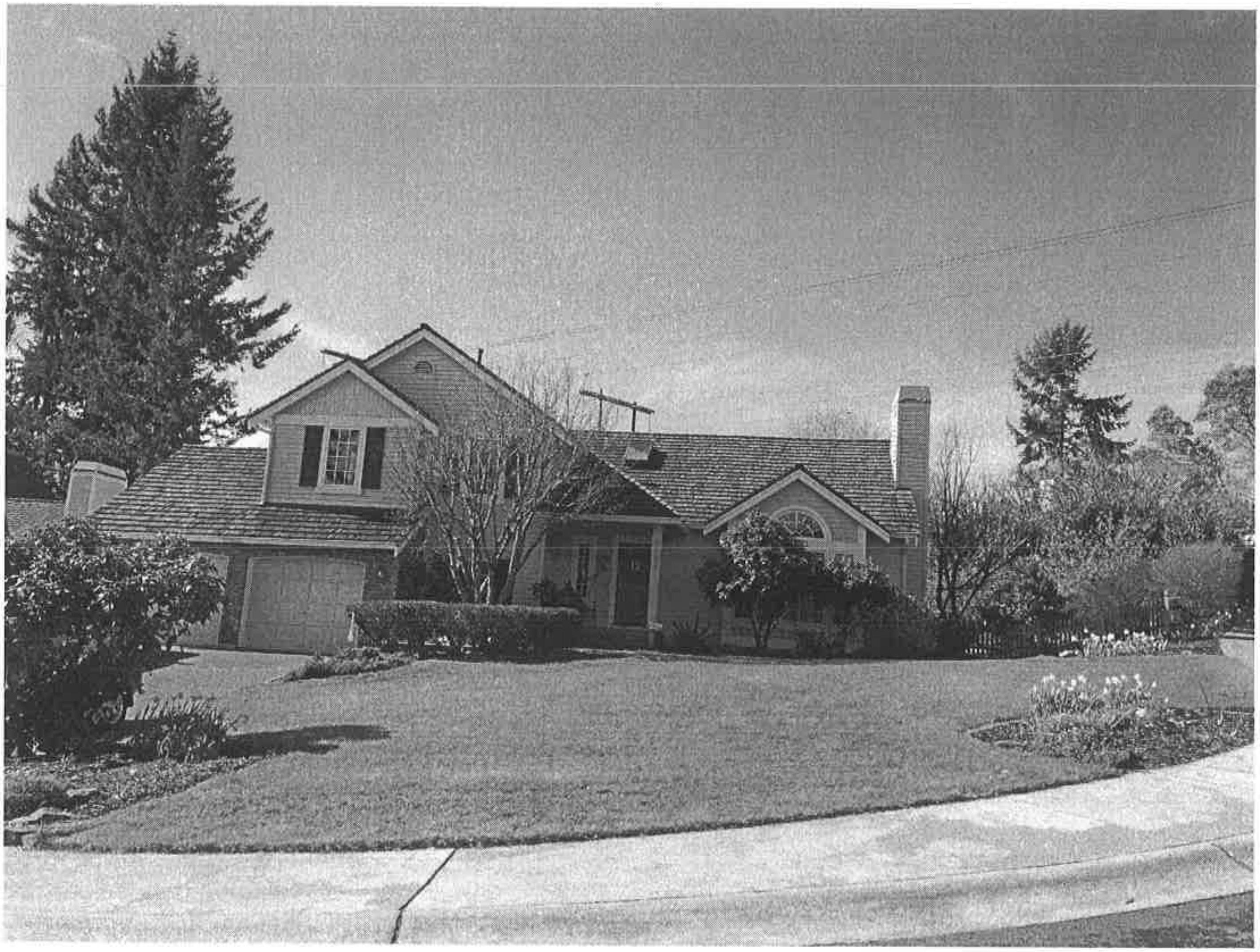


Source: Gentile et al., 2015.

Bottom line: PSE simulation and prediction tools and methodology are not credible.

[redacted]
Subject: **3-10-16 Olympus Elworth Home Newcastle**
Date: March 11, 2016 11:07:54 AM PST
[redacted]
1 Attachment, 2.8 MB

FIGURE 1



From: [redacted]
Subject: **3-11-16 Olympus Trail shared easement between Neighbors (Elworth Home)**
Date: March 11, 2016 11:11:50 AM PST
To: [redacted]
1 Attachment, 2.5 MB

FIGURE 2

FROM: Lori Elworth CENSE member file
TO: Eastside City Councils
DATE: 25 February, 2016
RE: Energize Eastside DEIS Public Comment

One aspect of the project that has not been addressed in the DEIS is the need. It states on page 1-56 that the purpose of the DEIS is not to determine that the project is needed as if that is a given however I question that claim and believe that PSE has done a poor job establishing the necessity of the Energize Eastside project.

CENSE a citizens group asked nationally recognized power and transmission planners Richard Lauckhart and Roger Schiffman who have specific knowledge of the Northwest power grid to study this project. On November 18, 2015 they concluded their study of the project titled *Load Flow Modeling for Energize Eastside.* The study found that the current system has sufficient capacity and will continue to meet customer demands until the year 2058, without any improvements. Unless PSE can offer a legitimate explanation for where they got their assumptions, and why they claim that customer demand will exceed the system capacity in 2018 then the need remains in question. This project should be paused until need is demonstrated.

Continuing on with a project without a need established is a pointless exercise that serves no purpose other than to waste the time of the cities and tax payer money.

My question for the City Councils is why was the need not addressed in the DEIS and in light of recent conflicting studies will a independent Load Flow Study be performed?

Thank you for your time,

Lori Elworth
8605 129th Ct SE
Newcastle, WA 98056

FROM: Lori Elworth
TO: Eastside City Councils
DATE: 29 February, 2016
RE: Energize Eastside DEIS Public Comment

CENSE member lde

My comments tonight are directed mainly at Alternative 1, option A. I live with my husband and our two kids just a few miles from where we grew up in Newport Hills, and where our parents still live. The PSE/Olympic Pipeline corridor has allows us to easily walk and bike over to their houses while avoiding the busy streets and traffic along Coal Creek Parkway. My 90 year old mother takes advantage of the corridor to go on 4 mile round trip walks to the Newcastle Safeway. She has been doing this daily for the last 25 years, and it has helped her remain in excellent health. But we are not the only people who enjoy use of the utility corridor. Countless other families, bikers, dog walkers, and even some horse riders all can be found out and about getting their exercise along the pipeline at all times of the day.

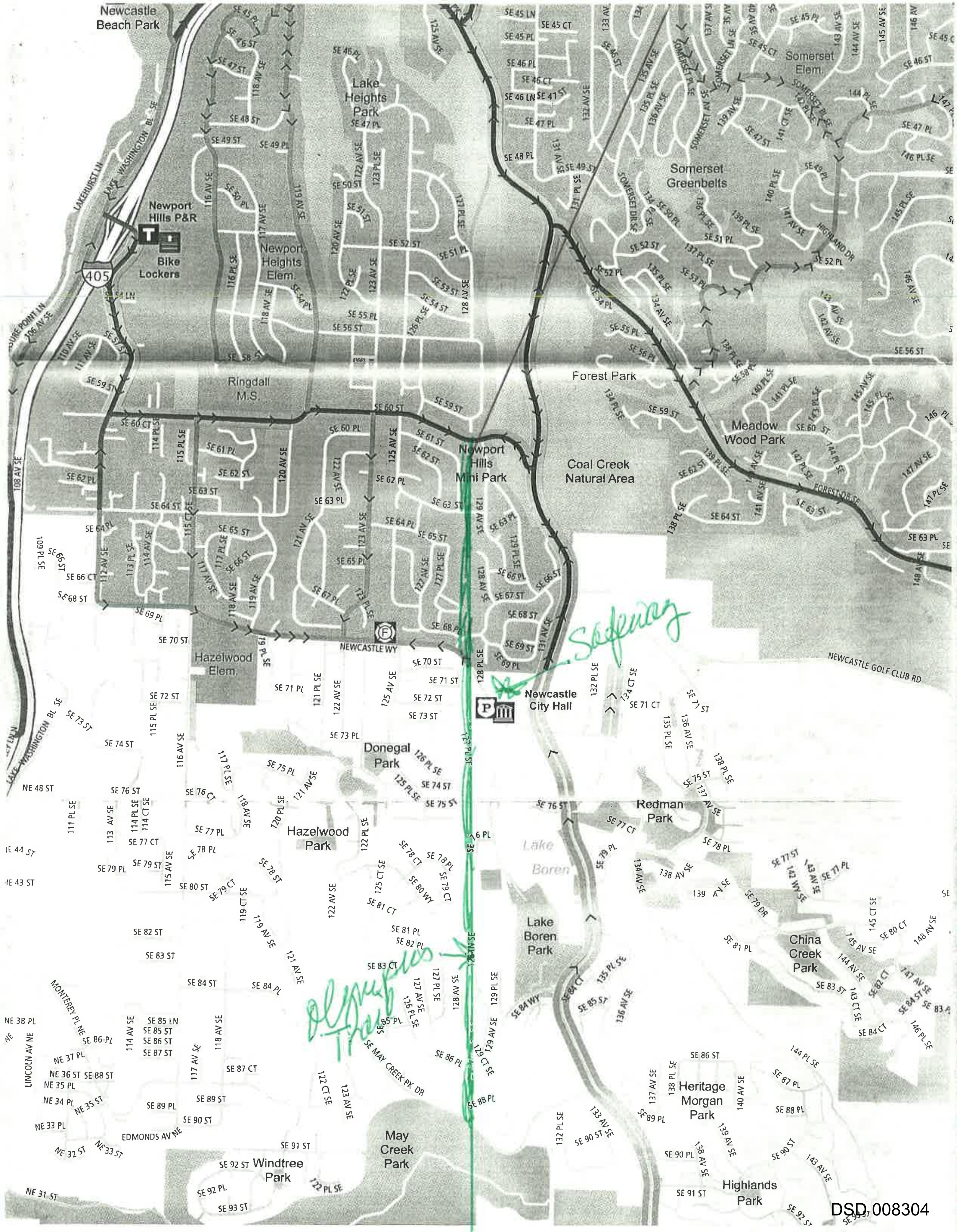
The utility corridor is a significant part of the Newcastle trail system. Every resident that enjoys making use of it will be negatively impacted by any restrictions of access that the Energize Eastside project will cause. The DEIS fails to adequately or reasonably address how much this project will adversely affect these people. We live in a hilly area that sees more and more traffic every day. The flat, sheltered trail that is the corridor is a blessing for senior citizens, people with young children or strollers. I know this first hand. I have lived here my entire life.

Never mind all the beautiful trees that will be destroyed, and the many houses that will need to be condemned to ensure that the power lines are installed at a safe distance from the gas pipeline. This unnecessary project will destroy some of the neighborhood character that makes this area a great place to live.

Thank you,

Lori Elworth
8605 129th Ct SE
Newcastle, WA 98056

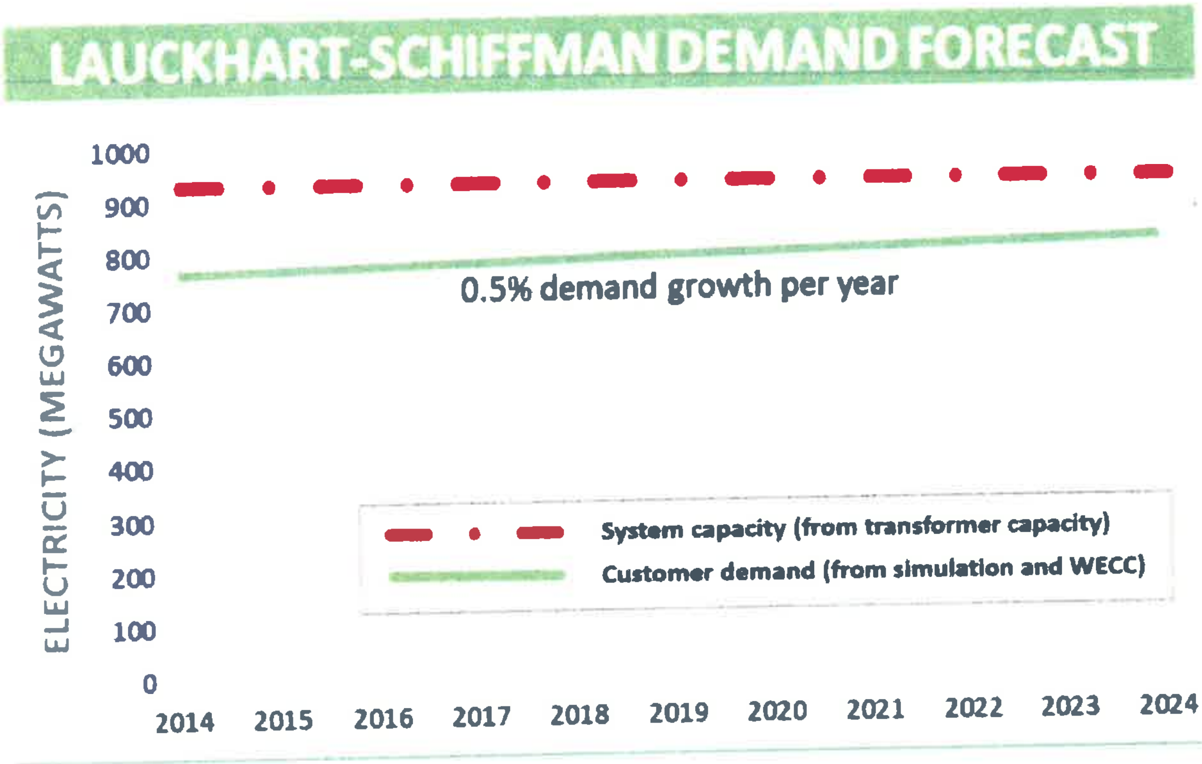
See Trail



Newcastle Beach Park
Lake Heights Park
Somerset Elem.
Somerset Greenbelts
Newport Hills P&R
Bike Lockers
405
Newport Heights Elem.
Forest Park
Ringdall M.S.
Meadow Wood Park
Newport Hills Mini Park
Coal Creek Natural Area
NEWCASTLE WY
NEWCASTLE GOLF CLUB RD
Hazelwood Elem.
Newcastle City Hall
Safeway
Donegal Park
Redman Park
Hazelwood Park
Lake Boren
Lake Boren Park
China Creek Park
Olympus Trail
Heritage Morgan Park
May Creek Park
Windtree Park
Highlands Park
LAKE WASHINGTON BL SE
FOREST DR SE
SOMERSET BL SE
HIGHLAND DR
SE 60 ST
SE MAY CREEK PK DR
EDMONDS AV NE
MONTEREY PL NE
LINCOLN AV NE

DSD 008304

Submitted by Darius Richards
2.25.16 Renton Phase 1
DEIS public hearing



Load Flow modeling

for "Energize Eastside"

Richard Lauckhart

Roger Schiffman

February 18, 2016

The entire report, including appendices,

is available at

CENSE.org

Executive Summary

In November 2015, the citizen group CENSE asked Richard Lauckhart and Roger Schiffman to study the scenario that motivates Puget Sound Energy's transmission project known as "Energize Eastside." We (Lauckhart and Schiffman) are nationally recognized power and transmission planners with specific knowledge of the Northwest power grid.

It is standard industry practice to use a "load flow model" to determine the need for a transmission project like Energize Eastside. In order to assess the reliability of the grid, analysts use specialized computer software to simulate failure of one or two major components while serving peak load conditions. For Energize Eastside, PSE simulates the failure of two major transformers during a peak winter usage scenario (temperature below 23° F and peak hours between 7-10 AM and 5-8 PM).

We ran our own load flow simulations based on data that PSE provided to the Western Electricity Coordinating Council (WECC). We used a "Base Case" for winter peak load projected for 2017-2018. PSE confirms this is the same data used as the basis for the company's "Eastside Needs Assessment."

Our findings differ from PSE's as follows:

1. PSE modified the Base Case to increase transmission of electricity to Canada from 500 MW to 1,500 MW. This level of energy transfer occurring simultaneously with winter peak loads creates instability in the regional grid. Transmission lines connecting the Puget Sound area to sources in central Washington do not have enough capacity to maintain this level of demand.

2. PSE assumed that six local generation plants were out of service, adding 1,400 MW of demand for transmission. This assumption also causes problems for the regional grid.

3. Even if the regional grid could sustain this level of demand, it is unlikely that regional grid coordinators would continue to deliver 1,500 MW to Canada while emergency conditions were occurring on the Eastside.

4. We found that the WECC Base Case contains a default assumption that PSE may not have corrected. The ratings for critical transformers are based on "summer normal" conditions, but the simulation should use significantly higher "winter emergency" ratings. The default value could cause PSE to underestimate System Capacity and overstate urgency to build the project.

5. The Base Case shows a demand growth rate of 0.5% per year for the Eastside. This is much lower than the 2.4% growth rate that PSE cites as motivation for Energize Eastside.

Our study finds critical transformers operating at only 85% of their winter emergency rating, providing enough capacity margin to serve growth on the Eastside for 20 to 40 years.

Qualifications

Richard Lauckhart served as a high level decision maker at Puget Sound Power & Light (the predecessor of Puget Sound Energy). His employment with the company spanned 22 years as a financial and transmission planner as well as power planning. He served as the company's Vice President of Power Planning for four years.

Richard took a voluntary leave package when Puget Power merged with Washington Energy Company in 1997. He provided additional contract services to PSE for more than a year following the merger. After leaving PSE, Richard worked as an energy consultant, providing extensive testimony on transmission system load flow modeling before the California Public Utility Commission.

Roger Schiffman has 23 years of energy industry experience covering utility resource planning, electricity market evaluation, market assessment and simulation modeling, regulatory policy development, economic and financial analysis, and contract evaluation. Roger has led a large number of consulting engagements for many clients. He has extensive knowledge of industry standard modeling software used for power market analysis and transmission planning.

We are well acquainted with the physical layout and function of the Northwest power grid and the tools used to analyze its performance. Our resumes can be found in Appendix H.

Richard has provided pro bono consultation to CENSE since April 2015. He has received no financial compensation other than reimbursement of travel expenses. Roger had no relationship with CENSE prior to this report.

Methodology

The power grid is a complex interconnected system with behaviors that cannot be easily understood without computer modeling software. We acquired a license to run the industry standard simulation software known as "GE PSLF"[1] to perform our studies.

The PSLF software uses a database that is supplied by the operator. We had hoped to use the same database that PSE used in its studies, but PSE refused to share it after months of negotiations. Instead, we received clearance from the Federal Energy Regulatory Commission (FERC) to access the database PSE submitted to the Western Electricity Coordinating Council (WECC). FERC determined that we presented no security threat and had a legitimate need to access the database (see FERC's letter in Appendix A).

We used the WECC Base Case for the winter of 2017-18, which PSE confirms is the database the company used for that time period. We and PSE have made subsequent changes to the Base Case model in order to incorporate various assumptions. We don't know exactly what changes PSE made to the database, but we will be explicit about the changes we made.

N-0 base scenario

To ensure that everything was set up correctly, we ran a simulation using the unmodified Base Case and checked to see if the results aligned with those reported by WECC. This is referred to as an "N-0" scenario, meaning that zero major components of the grid are offline and the system is operating normally. The outputs of this simulation matched reported results.

The WECC Base Case assumes that the Energize Eastside project has been built. In order to determine the need for the project, we needed to study the performance of the grid without it. We reset the transmission configuration using parameters from an earlier WECC case that did not include the project.

N-1-1 contingency scenario

An "N-1-1" scenario models what would happen if two major grid components fail in quick succession. Utilities are generally required

[1] http://www.geenergyconsulting.com/pslf-re-envisioned

to serve electricity without overloads or outages in this scenario to meet federal reliability standards.

PSE determined that the two most critical parts of the Eastside grid are two large transformers that convert electricity at 230,000 volts to 115,000 volts, the voltage used by all existing transmission lines within the Eastside. To simulate the N-1-1 scenario, the Base Case is modified to remove these two transformers from service.

PSE apparently made two additional modifications to the WECC Base Case. First, the amount of electricity flowing to Canada was increased from 500 MW to 1,500 MW. Next, the company reduced the amount of power being produced by local generation plants from 1,654 MW to 259 MW. The rationale behind these modifications isn't obvious, and we were concerned how the regional grid (not just the Eastside) would perform with these assumptions in place.

To our surprise, simply increasing the flow to Canada to 1,500 MW while also serving peak winter power demand in the Puget Sound region was enough to create problems for the regional grid. The simulation software could not resolve these problems (Appendix E describes the problems in greater detail). While it's possible that PSE and Utility System Efficiencies found ways to work around these challenges by making additional changes to the Base Case, we do not know what these changes were. We are confident that prudent grid operators would reduce flows to Canada if an N-1-1 contingency occurs on the Eastside during heavy winter consumption. PSE would turn on every local generation plant. These responses resolve the problems. This is the more realistic scenario we modeled in our N-1-1 simulation.

The WECC Base Case uses default values for transformer capacity ratings that correspond to a "summer normal" scenario. The summer rating is reduced in order to protect transformers from overheating during hot summer weather. The "winter emergency" rating would be consistent with best engineering practice for equipment outages during very cold conditions (less than 23° F) that produce peak winter demand. We used this higher rating in our simulation.

DSD 008311

Results

N-0 results

To compare the N-1-1 results with normal operation of the grid serving peak winter demand, we ran an N-0 study using the WECC Base Case for winter 2017-18 with the following modifications:

1. Energize Eastside transmission lines are reverted to present capacity.
2. Flow to Canada is reduced from 500 MW to 0 MW.
3. Transformers run at "winter normal" capacity.

Figure 1 shows load as a perentage of "winter normal" capacity on each of the four transformers.

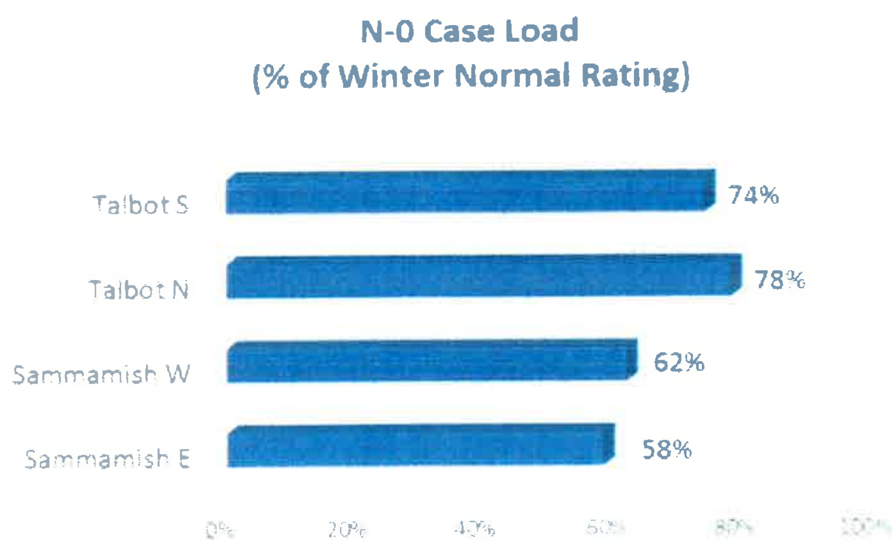


Figure 1: With all transformers in service, winter peak load causes no overloads.

N-1-1 results

The N-1-1 results are based on the WECC Base Case for winter 2017-18 with the following modifications:

1. Two transformers are out of service.
2. Energize Eastside transmission lines are reverted to present capacity.
3. Flow to Canada is reduced from 500 MW to 0 MW.
4. Transformers run at "winter emergency" capacity.

Figure 2 shows that the remaining two transformers, Talbot N and Sammamish W, remain within "winter emergency" capacity ratings.

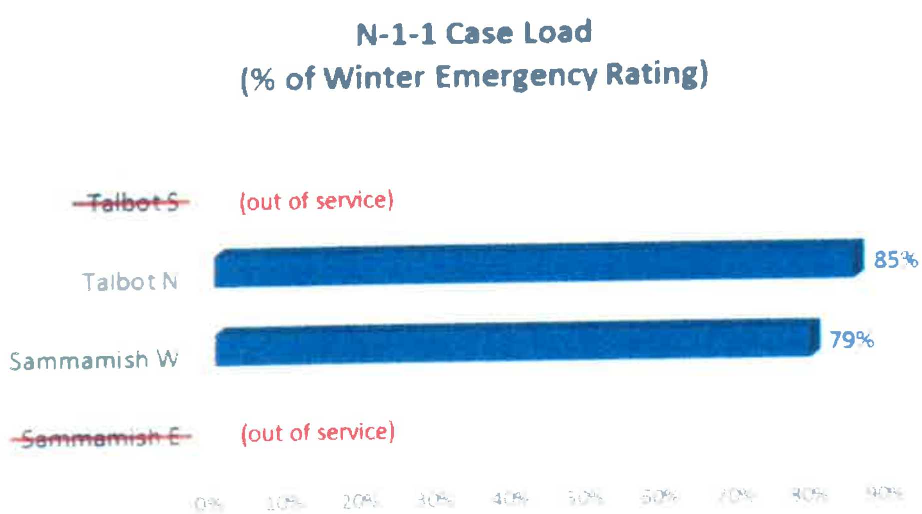


Figure 2: Loads on two remaining transformers are in a safe range.

DSD 008313

Analysis

We carefully analyzed the results of the N-1-1 simulation to get a broader view of how the grid is behaving in this scenario. Electricity is served by a combination of high-voltage transformers (transforming 230,000 volts to 115,000 volts) and low-voltage transformers (115,000 volts to 12,500 volts).

When we simulated failure of two high-voltage transformers located at Sammamish and Talbot Hill, as PSE did, we discovered that some of the load is redistributed to other high-voltage transformers in the Puget Sound area (see Figure 3). This is a natural adaptation of the networked grid that occurs without active management by PSE or other utilities. The regional grid has enough redundant capacity to balance the load without causing overloads on any transformer or transmission line in the region.

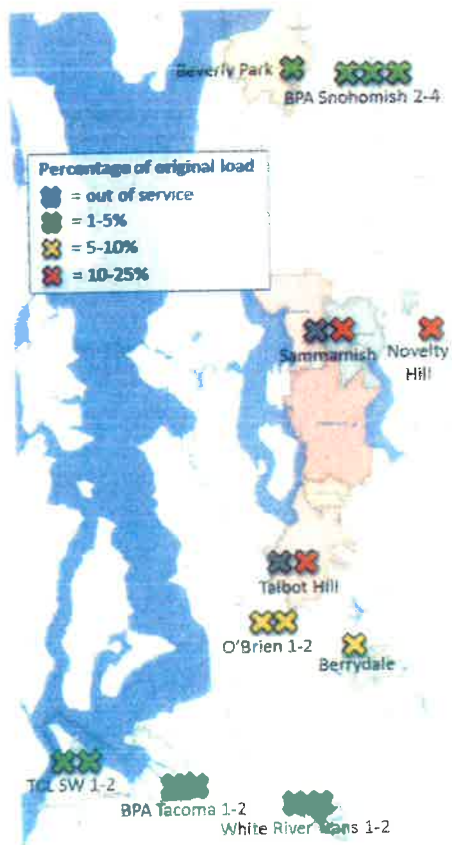


Figure 3: Load is distributed among other transformers after two transformers fail.

We conclude that the grid is capable of meeting demand in emergency circumstances in the winter of 2017-18. How soon after that will system capacity become strained?

Concerns about future capacity are illustrated in Figure 5, PSE's demand forecast graph.[2] This graph raises several questions. For example, it's not clear how PSE determined the "System capacity range" of approximately 700 MW. If this value is derived from the transformer capacities listed in the WECC Base Case, these capacities are set to default values corresponding to "summer normal" conditions.

PSE's graph shows Customer Demand growing at an average rate of 2.7% per year. However, data submitted by PSE to WECC shows a growth rate of only 0.5% per year. An explanation of this discrepancy is necessary to understand this graph.

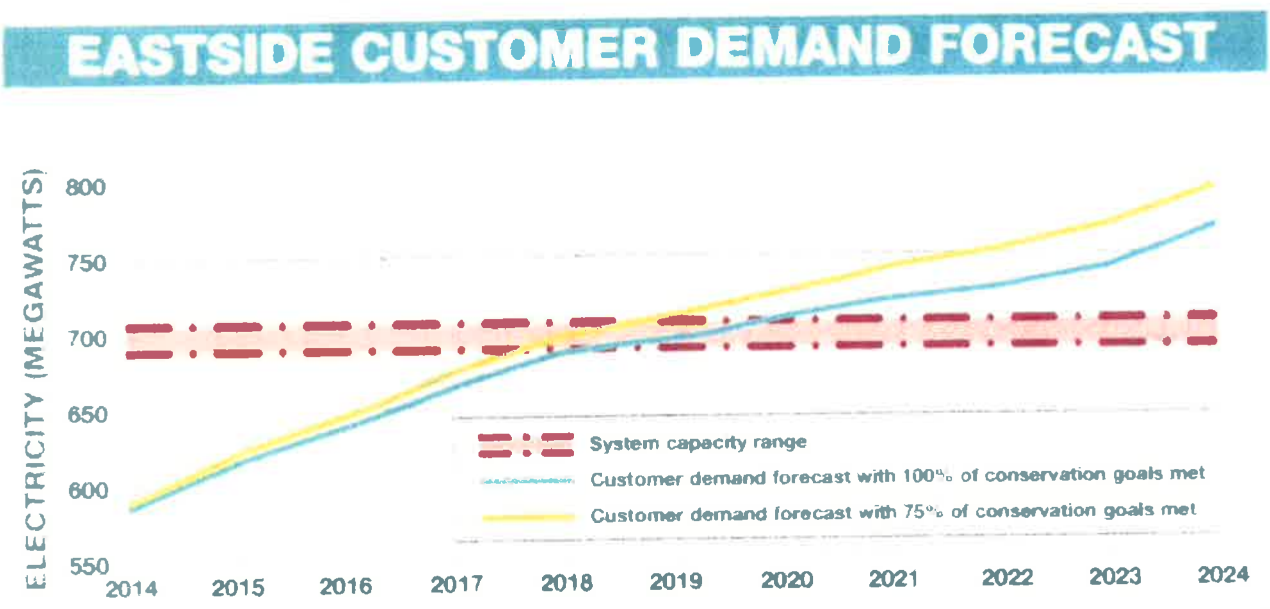


Figure 4: PSE's graph shows customer demand exceeding system capacity in 2018.[2]

[2] *http://www.energizeeastside.com/need*

Although we don't have enough information to create a graph suitable for long-term planning, we we feel Figure 5 is a better approximation of system capacity and demand growth on the Eastside.

The "System capacity" is based on "winter emergency" transformer ratings, which are more appropriate than summer ratings for this scenario. The higher ratings raise the overall capacity to approximately 930 MW.

The "Customer demand" line shown in Figure 5 is based on loads reported in the load flow simulation for the two remaining Eastside transformers. The 2014 value is higher than in PSE's graph, because these transformers serve loads outside the Eastside area. The growth rate matches the 0.5% rate observed in WECC Base Cases.

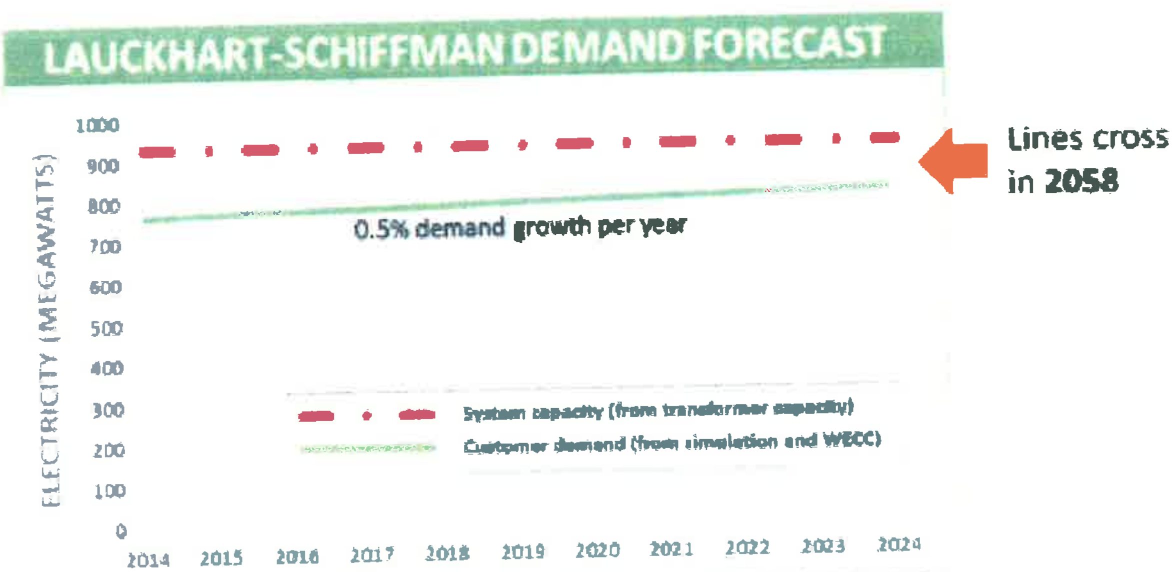


Figure 5: Alternative Demand Forecast shows slower demand growth and higher system capacity (based on "winter emergency" transformer ratings).

Comparison with other studies

The conclusions of the Lauckhart-Schiffman study differ from previous studies. We stand by our conclusions and will share our models and results with anyone who has clearance from FERC.

Here we review the other studies and explain why their conclusions might differ from ours.

PSE/Quanta

Two different load flow simulations were performed by PSE and Quanta, a consultant employed by PSE. We have the following concerns with both studies:

1. An unrealistic level of electricity is transmitted to Canada.
2. Nearly all of the local generation plants are turned off.
3. The appropriate seasonal ratings for the critical transformers were not used.
4. It's not clear how the customer demand forecast was developed, but there is an unexplained discrepancy between the forecast used for Energize Eastside (2.4% annual growth) and the forecast reported to WECC (0.5% annual growth).

The first two assumptions cause regional reliability problems for the WECC Base Case that must have required additional adjustments by PSE/Quanta. We don't know what those adjustments were.

Utility System Efficiencies

The City of Bellevue hired an independent analyst, Utility System Efficiencies (USE), to validate the need for Energize Eastside. USE ran one load flow simulation that stopped electricity flow to Canada. According to USE, 4 of the 5 overloads described in the PSE/Quanta studies were eliminated, and the remaining overload was minor.

Our load flow simulation studied the same scenario (N-1-1 contingency with no flow to Canada and local generators running), but we did not find any overloads. We believe three assumptions explain the different outcomes:

1. USE does not specify what level of generation was assumed for local generation plants. In verbal testimony before the Bellevue

City Council, USE consultants said that they did not assume all of the capability of local generation was operating. Our study assumes these plants will run at their normal capacity.

2. USE says emergency ratings were used for the critical transformers, but it isn't clear if USE used "winter emergency" ratings. Our study assumes winter emergency ratings.

3. USE does not independently evaluate the customer demand forecast (2.4% annual growth is assumed). Our study assumes the load growth forecast that PSE provided to WECC.

We believe our assumptions more accurately reflect the actual conditions that would occur in this scenario.

Stantec Consulting Services

In July 2015, the independent consulting firm Stantec was asked to review the studies done by PSE and USE. Stantec issued its professional opinion without performing any independent analysis or load flow simulations. Stantec says PSE's methodology was "thorough" and "industry standard." However, Stantec does not address the shortcomings we have identified with previous studies.

The entire report, including appendices,

is available at

CENSE.org

Speaker #23 Public Hearing Phase I
DEIS Bellevue 3.1.16

ColumbiaGrid

February 21, 2013

Kent Bolton
Staff Engineer
Western Electricity Coordinating Council
155 North 400 West, Suite 200
Salt Lake City, UT 84103-1114

Dear Mr. Bolton:

The WECC Project Coordination Process states that project sponsors can use Subregional Planning Groups to meet its requirements: "a project sponsor may use TEPPC or a Subregional Planning Group to meet the requirements of Project Coordination Process in lieu of forming an independent PCRG for the project." The projects summarized below used the ColumbiaGrid planning process via the Puget Sound Area Study Team to meet the requirements of the WECC Project Coordination Process. The ColumbiaGrid planning process provided for open participation and included all the interested transmission owners and other interested stakeholders. These projects have been reviewed by the Puget Sound Area Study Team and a consensus has been reached that they are the best solution for the area. Project reports are available from ColumbiaGrid at www.columbiagrid.org.

1. **Project Name:** Reconductor Bothell – SnoKing 230 kV lines
    a. **Project Purpose:** Improve South-to-North transfer capability between the Northwest and British Columbia.
    b. **Facility Owners:** Seattle City Light, Bonneville Power Administration
    c. **Project Description:** Reconductor the double circuit Bothell-SnoKing 230 kV lines with high temperature conductor.
    d. **Estimated In-Service Date:** 2016
2. **Project Name:** Reconductor Delridge-Duwamish 230 kV line
    a. **Project Purpose:** Improve South-to-North transfer capability between the Northwest and British Columbia.
    b. **Facility Owners:** Seattle City Light
    c. **Project Description:** Reconductor the Delridge – Duwamish 230 kV line.

   d. **Estimated In-Service Date:** 2016

3. **Project Name:** Lakeside 230/115 kV Substation

   a. **Project Purpose:** Improve South-to-North transfer capability between the Northwest and British Columbia. Provide a 230/115 kV source to Puget Sound Energy customer load service.

   b. **Facility Owners:** Puget Sound Energy

   c. **Project Description:** Rebuild both of the Sammamish-Lakeside-Talbot 115 kV lines to 230 kV. Energize one line at 230 kV and the other at 115 kV. Build a 230 kV bus and 230/115 kV transformer at Lakeside Substation.

   d. **Estimated In-Service Date:** 2017

Please feel free to contact me or Jonathan Young at (503) 943-4957 if you have any questions.

Sincerely,

Jeffrey C. Miller

Jeffrey C. Miller
ColumbiaGrid, Vice President and Manager of Planning
(503) 943-4951 office
(503) 975-4969 cell

Speaker #23 Public Hearing Phase 1
DEIS Bellevue 3.1.16

PUGET SOUND ENERGY

March 1, 2013

Mr. David Franklin, Chairman
WECC Technical Studies Subcommittee
Southern California Edison
1 Innovation Way
Pomona, CA 91768-2560

Mr. Enoch Davies
WECC Technical Staff
155 North 400 West, Suite 200
Salt Lake City, Utah 84103-1114

2013 ANNUAL PROGRESS REPORT

In accordance with reporting guidelines by the WECC Planning Coordinating Committee (PCC), please find attached Puget Sound Energy's 2013 Annual Progress Report on significant additions and changes to our system. Please call me at (425) 462-3171 if you have any questions.

Sincerely,

Puget Sound Energy, Inc.

By Peter M. Jones, PE
Senior Engineer, PSE

Enclosure

cc: Joe Seabrook
John Phillips
TSS Members

2013 Annual Progress Report to WECC
Puget Sound Energy

The following projects will be reported in the 2013 "Existing Generation and Significant Additions and Changes to System Facilities" report in accordance with pages III-110 though III-119 of the "WECC Progress Report Policies and Procedures". These projects do not have regional impacts to the WECC Interconnected System.

Recently Completed Projects

1. Sedro Woolley 230 kV Transformer Addition

The project added a second 230-115 kV transformer and two 115 kV, 21-MVAr shunt capacitor banks at the Sedro Woolley Substation. PSE requested a waiver of significant transmission project status for this project. This project addresses NERC planning criteria and provides additional capacity to serve the projected load growth in Skagit and Island Counties. It has no impact to the WECC or any neighboring electric systems.

Transmission Additions and Changes

Request for waiver of "Significant Transmission Project" Status

2. Eastside 230 kV Transformer Addition and Line
Estimated Date of Operation: 2017

This project had been titled "Lakeside Substation 230 kV Transformer Addition" in prior years' progress reports.

The project will involve installation of a 230-115 kV transformer at Lakeside Substation. This project includes rebuilding the Sammamish-Lakeside-Talbot 115 kV lines, energizing one or both at 230 kV to provide a source to Lakeside Substation and transmission capacity. This is more effective for local load service and transmission reliability than the alternative of installing a 230-115 kV transformer at Lake Tradition Substation. This transformer will address NERC planning criteria and provide additional capacity to serve the projected load growth in north central King County and surrounding areas.

ColumbiaGrid is a Subregional Planning Group in the Pacific Northwest and has open participation in its planning meetings and the Puget Sound Area Study Team (PSAST). This project has been developed by and has achieved consensus via the ColumbiaGrid PSAST, which included all the transmission owners that could be impacted by this project. The "Eastside 230 kV Transformer Addition and Line Rebuilds" project began to be studied by the PSAST in mid-2009, and was in PSE's Annual Progress Report last year. The most recent report is entitled "Updated Recommended Transmission Expansion Plan for the Puget Sound Area to Support Winter South-to-North Transfers", June 17, 2011. The report recommends this project and four other transmission improvements, and is available from ColumbiaGrid www.columbiagrid.org . The requirements of project coordination review for this project have been met through the ColumbiaGrid acting as a Subregional Planning Group.

The attached document, 'WECC Comprehensive Project Coordination Review Letter_PSAST 2-21-13.pdf', describes the coordinated ColumbiaGrid study efforts.

Request for waiver of "Significant Transmission Project" Status, cont.

3. **Starwood-Tideflats 115/110 kV Transformer Removal**
   Estimated Date of Operation: 2013

   With Tacoma Power increasing its sub-transmission voltage schedule from 110 kV to 115 kV in 2013, the existing 'step down' Starwood transformer will no longer be necessary. A bypass of the existing bank is therefore planned for summer of 2013 to coincide with the timing of Tacoma Power's voltage schedule increase. This project is a combined engineering effort between PSE and Tacoma Power; it has no impact to the WECC or any additional neighboring electric systems.

Waiver of "Significant Transmission Project" has been granted on the following -

4. **Thurston County Transformer Addition**
   Estimated Date of Operation: 2013

   The project is to install a 230-115 kV transformer at St. Clair Substation and build a 5-mile 230 kV transmission loop between St. Clair and the existing BPA Olympia – S. Tacoma 230 kV line. PSE requests a waiver of significant transmission project status for this project. The project is intended to provide additional capacity to serve the projected load growth in Thurston County and surrounding areas. It has no impact to the WECC or any neighboring electric systems.

5. **Pierce County Transformer Addition and Line Reroutes**
   Estimated Date of Operation: 2015

   The project is to install a 230-115 kV transformer at Alderton Substation and build 8 miles of 230 kV transmission line from White River Substation to Alderton Substation, as well as re-routing 115 kV lines. PSE requests a waiver of significant transmission project status for this project. The project is intended to provide additional capacity to serve the projected load growth in Pierce County and surrounding areas. It has no impact to the WECC or any neighboring electric systems.

6. **Tono Transformer Improvements**
   Estimated Date of Operation: 2015

   This project will involve replacement of limiting current transformers at the Tono bank. This improvement will increase capacity from the existing limit of 398 MVA up to 546 MVA. The project is intended to increase reliability for serving approximately half of the existing load in Thurston County. It has no impact to the WECC or any neighboring electric systems.

7. **West Kitsap Transmission Project Phase II**
   Estimated Date of Operation: 2018

   The project is to install a 230-115 kV transformer at Foss Corner Substation, and build a 230 kV line from Foss Corner to a future line bay position in the BPA Kitsap 230 kV Substation. PSE requests a waiver of significant transmission project status for this project. The project is intended to provide additional capacity to serve the projected load growth in Kitsap County and surrounding areas. It has no impact to the WECC or any neighboring electric systems.

attach this to 30 pages of DEIS comments from:
SUE STRONK / 12917 SE 86TH PLACE / NEWCASTLE, WA 98056

THE WALL STREET JOURNAL.

http://www.wsj.com/articles/utilities-profit-recipe-spend-more-1429567463

BUSINESS (HTTP://WWW.WSJ.COM/NEWS/BUSINESS)

Utilities' Profit Recipe: Spend More

To expand regulator-imposed earnings caps, electricity producers splurge on new equipment, boosting customers' bills

Every time Southern California Edison replaces a 50-year-old pole with a new one, it has a fresh investment on which it is eligible to earn an annual profit. *PHOTO: FRED PROUSER/REUTERS*

By REBECCA SMITH

April 20, 2015 6:04 p.m. ET

Families in New York are paying 40% more for electricity than they were a decade ago. Meanwhile, the cost of the main fuel used to generate electricity in the state—natural gas—has plunged 39%.

Why haven't consumers felt the benefit of falling natural-gas prices, especially since fuel accounts for at least a quarter of a typical electric bill?

One big reason: utilities' heavy capital spending. New York power companies poured $17 billion into new equipment—from power plants to pollution-control devices—in the past decade, a spending surge that customers have paid for.

New York utilities' spending plans could push electricity prices up an additional 63% in the next decade, said Richard Kauffman, the former chairman of Levi Strauss & Co. who became New York's energy czar in 2013. It's "not a sustainable path for New York," he said.

New York is no outlier. Capital spending has climbed at utilities nationwide—and so have their customers' bills.

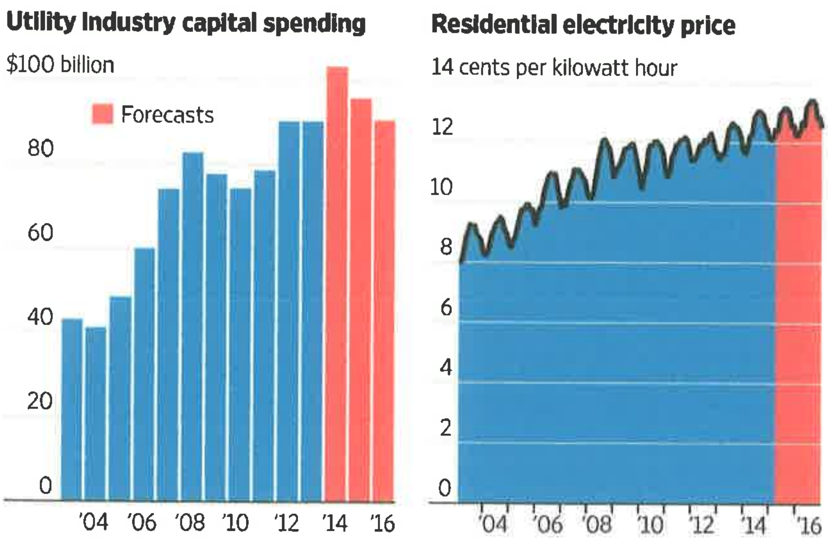
The average price of a kilowatt-hour of electricity rose 3.1% last year to 12.5 cents a kilowatt-hour, far above the rate of inflation. Since 2004, U.S. residential electricity prices have jumped 39%, according to federal statistics.

Over that same period, annual capital expenditures by investor-owned utility companies more than doubled—jumping to $103 billion in 2014 from $41 billion in 2004, according to the Edison Electric Institute, a trade association. The group expects total capital spending from 2003 through 2016 to top $1 trillion.

"This is the biggest splurge in capital spending we've seen in at least 30 years—it's the reason rates have been going up," said Bob Burns, an independent consultant and former energy researcher at Ohio State University.

Power Gauge

Regulators are trying to rein in utilities' capital spending, which has ramped up over the past 10 years, driving up electricity prices.



Sources: Edison Electric Institute (spending); Energy Dept. (prices) THE WALL STREET JOURNAL.

The biggest chunk of that spending—38% in 2013—went into new power lines and other delivery systems, the Edison Electric Institute said. Almost as much went to generation, often for new gas-fired plants to replace coal-fired ones that don't meet new environmental rules.

Experts say there are several reasons for soaring spending, including environmental mandates, and the need to harden the grid to protect it from storms, physical attacks and cyber hacking.

But utilities have another incentive for heavy spending: It actually boosts their bottom lines—the result of a regulatory system that turns corporate accounting on its head.

In most industries, companies generate revenue, deduct their costs, and are left with profits, which can be expressed as a percentage of revenues—the profit margin. Regulated utilities work differently. State regulators usually set an acceptable profit margin for utilities, and then set electric rates at levels that generate enough revenue to cover their expenses and allow them to make a profit.

At the moment, it is common for utilities' allowable profit to be capped at 10% or so of the shareholders' equity that they have tied up in transmission lines, power plants and other assets. So the more they spend, the more profits they earn.

Critics say this can prompt utilities to spend on projects that may not be necessary, like electric-car charging stations, or to choose high-cost alternatives over lower-cost ones.

"Until we change things so utilities don't get rewarded based on how much they spend, it's hard to break that mentality," says Jerry R. Bloom, an energy lawyer at Winston & Strawn in Los Angeles who often represents independent power companies.

Southern California Edison, a unit of Edison International in Rosemead, Calif., plans to spend about $1 billion in debt and equity replacing or repairing thousands of power poles, which cost $13,000 each. Every time the company replaces a 50-year-old pole with a new one, it has a fresh investment on which it is eligible to earn an annual profit, currently 10.45%, for 45 years.

The sudden interest in poles "suggests they've been negligent in the past or they're just looking for ways to spend money," said Bob Finkelstein, a lawyer at the Utility Reform Network, a San Francisco-based watchdog group.

Mike Marelli, SoCal Edison's rates director, said his company analyzed 5,000 poles before deciding a massive program was needed to deal with deferred maintenance.

Overall, SoCal Edison intends to spend $15 billion to $17 billion on dozens of initiatives from 2014 through 2017. Similarly, Charlotte, N.C.-based Duke Energy Corp. expects to make $17 billion worth of capital expenditures from 2014 and 2016. A rule of thumb it recently shared with investors: for every billion dollars in assets it adds to its inventory, it boosts earnings by about 8 cents a share.

Utilities can't bill customers for new capital expenditures without first getting the

'Until we change things so utilities don't get rewarded based on how much they spend, it's hard to break that mentality.'

—Jerry R. Bloom, an energy lawyer at Winston & Strawn

consent of state or federal regulators, notes Richard McMahon, a vice president at the Edison Electric Institute.

But Ken Rose, an energy consultant in Chicago, says that regulators don't always do enough to make sure projects are the best deal for the customers footing the bills. He says companies have a propensity to choose expensive solutions to problems—building a new power plant instead of promoting energy efficiency, for example—because it puts big chunks of capital to work that lift profits.

Some analysts say utilities' capital spending has been necessary and smart at a time of low interest rates.

"I don't subscribe to the belief that utility companies are gold-plating their systems just to increase profits," says Jim Hempstead, associate managing director of the global infrastructure finance at Moody's Investors Service.

Utilities earned $36 billion in 2013, excluding nonrecurring items, up 36% from 2004, according to the Edison Electric trade group.

So long as electricity consumption is growing, utilities can spread hefty costs across their customers without increasing rates. But since 2008, power sales haven't been growing fast enough to absorb the impact of all the added spending.

Kansas City Power & Light has raised rates about 60% since it kicked off its current investment cycle in 2007. It is seeking rate increases of 12.5% in Kansas and 15.5% in Missouri.

Some states are pushing back.

In New York, regulators balked at Consolidated Edison Inc. 's plan to build a $1 billion electrical substation in Brooklyn and Queens by 2017. Instead, the company has decided to help customers cut energy use by improving the efficiency of their electrical equipment through a $500 million program that defers a decision about a new substation for at least a decade.

"What we're doing is an alternative that's less costly," said Stuart Nachmias, vice president of regulatory affairs for ConEd.

From now on, utilities must prove that their spending will make an electric system cleaner, more efficient or stronger, says Audrey Zibelman, chair of the New York Public Service Commission. "Business as usual has become unaffordable."

Write to Rebecca Smith at rebecca.smith@wsj.com

ANNALS OF SEISMOLOGY

THE REALLY BIG ONE

An earthquake will destroy a sizable portion of the coastal Northwest. The question is when.

BY KATHRYN SCHULZ

When the 2011 earthquake and tsunami struck Tohoku, Japan, Chris Goldfinger was two hundred miles away, in the city of Kashiwa, at an international meeting on seismology. As the shaking started, everyone in the room began to laugh. Earthquakes are common in Japan—that one was the third of the week—and the participants were, after all, at a seismology conference. Then everyone in the room checked the time.

Seismologists know that how long an earthquake lasts is a decent proxy for its magnitude. The 1989 earthquake in Loma Prieta, California, which killed sixty-three people and caused six billion dollars' worth of damage, lasted about fifteen seconds and had a magnitude of 6.9. A thirty-second earthquake generally has a magnitude in the mid-sevens. A minute-long quake is in the high sevens, a two-minute quake has entered the eights, and a three-minute quake is in the high eights. By four minutes, an earthquake has hit magnitude 9.0.

When Goldfinger looked at his watch, it was quarter to three. The conference was wrapping up for the day. He was thinking about sushi. The speaker at the lectern was wondering if he should carry on with his talk. The earthquake was not particularly strong. Then it ticked past the sixty-second mark, making it longer than the others that week. The shaking intensified. The seats in the conference room were small plastic desks with wheels. Goldfinger, who is tall and solidly built, thought, No way am I crouching under one of those for cover. At a minute and a half, everyone in the room got up and went outside.

It was March. There was a chill in the air, and snow flurries, but no snow on the ground. Nor, from the feel of it, was there ground on the ground. The earth snapped and popped and rippled. It was, Goldfinger thought, like driving through rocky terrain in a vehicle with no shocks, if both the vehicle and the terrain were also on a raft in high seas. The quake passed the two-minute mark. The trees, still hung with the previous autumn's dead leaves, were making a strange rattling sound. The flagpole atop the building he and his colleagues had just vacated was whipping through an arc of forty degrees. The building itself was base-isolated, a seismic-safety technology in which the body of a structure rests on movable bearings rather than directly on its foundation. Goldfinger lurched over to take a look. The base was lurching, too, back and forth a foot at a time, digging a trench in the yard. He thought better of it, and lurched away. His watch swept past the three-minute mark and kept going.

Oh, shit, Goldfinger thought, although not in dread, at first: in amazement. For decades, seismologists had believed that Japan could not experience an earthquake stronger than magnitude 8.4. In 2005, however, at a conference in Hokudan, a Japanese geologist named Yasutaka Ikeda had argued that the nation should expect a magnitude 9.0 in the near future—with catastrophic consequences, because Japan's famous earthquake-and-tsunami preparedness, including the height of its sea walls, was based on incorrect science. The presentation was met with polite applause and thereafter largely ignored. Now, Goldfinger realized as the shaking hit the four-minute mark, the planet was proving the Japanese Cassandra right.

For a moment, that was pretty cool: a real-time revolution in earthquake science. Almost immediately, though, it became extremely uncool, because Goldfinger and every other seismologist standing outside in Kashiwa knew what was coming. One of them pulled out a cell phone and started streaming videos from the Japanese broadcasting station NHK, shot by helicopters that had flown out to sea soon after the shaking started. Thirty minutes after Goldfinger first stepped outside, he watched the tsunami roll in, in real time, on a two-inch screen.

In the end, the magnitude-9.0 Tohoku earthquake and subsequent tsunami killed more than eighteen thousand people, devastated northeast Japan, triggered the meltdown at the Fukushima power plant, and cost an estimated two hundred and twenty billion dollars. The shaking earlier in the week turned out to be the foreshocks of the largest earthquake in the nation's recorded history. But for Chris Goldfinger, a paleoseismologist at Oregon State University and one of the world's leading experts on a little-known fault line, the main quake was itself a kind of foreshock: a preview of another earthquake still to come.

Most people in the United States know just one fault line by name: the San Andreas, which runs nearly the length of California and is perpetually rumored to be on the verge of unleashing "the big one." That rumor is misleading, no matter what the San Andreas ever does. Every fault line has an upper limit to its potency, determined by its length and width, and by how far it can slip. For the San Andreas, one of the most extensively studied and best understood fault lines in the world, that upper limit is roughly an 8.2—a powerful earthquake, but, because the Richter scale is logarithmic, only six per cent as strong as the 2011 event in Japan.

Just north of the San Andreas, however, lies another fault line. Known as the Cascadia subduction zone, it runs for seven hundred miles off the coast of the Pacific Northwest, beginning near Cape Mendocino, California, continuing along Oregon and Washington, and terminating around Vancouver Island, Canada. The "Cascadia" part of its name comes from the Cascade Range, a chain of volcanic mountains that follow the same course a hundred or so miles inland. The "subduction zone" part refers to a region of the planet where one tectonic plate is sliding underneath (subducting) another. Tectonic plates are those slabs of mantle and crust that, in their epochs-long drift, rearrange the earth's continents and oceans. Most of the time, their movement is slow, harmless, and all but undetectable. Occasionally, at the borders where they meet, it is not.

Take your hands and hold them palms down, middle fingertips touching. Your right hand represents the North American tectonic plate, which bears on its back, among other things, our entire continent, from One World Trade Center to the Space Needle, in Seattle. Your left hand represents an oceanic plate called Juan de Fuca, ninety thousand square miles in size. The place where they meet is the Cascadia subduction zone. Now slide your left hand under your right one. That is what the Juan de Fuca plate is doing: slipping steadily beneath North America. When you try it, your right hand will slide up your left arm, as if you were pushing up your sleeve. That is what North America is not doing. It is stuck, wedged tight against the surface of the other plate.

Without moving your hands, curl your right knuckles up, so that they point toward the ceiling. Under pressure from Juan de Fuca, the stuck edge of North America is bulging upward and compressing eastward, at the rate of, respectively, three to four millimetres and thirty to forty millimetres a year. It can do so for quite some time, because, as continent stuff goes, it is young, made of rock that is still relatively elastic. (Rocks, like us, get stiffer as they age.) But it cannot do so indefinitely. There is a backstop—the craton, that ancient unbudgeable mass at the center of the continent—and, sooner or later, North America will rebound like a spring. If, on that occasion, only the southern part of the Cascadia subduction zone gives way—your first two fingers, say—the magnitude of the resulting quake will be somewhere between 8.0 and 8.6. *That's* the big one. If the entire zone gives way at once, an event that seismologists call a full-margin rupture, the magnitude will be somewhere between 8.7 and 9.2. That's the very big one.

Flick your right fingers outward, forcefully, so that your hand flattens back down again. When the next very big earthquake hits, the northwest edge of the continent, from California to Canada and the continental shelf to the Cascades, will drop by as much as six feet and rebound thirty to a hundred feet to the west—losing, within min-

utes, all the elevation and compression it has gained over centuries. Some of that shift will take place beneath the ocean, displacing a colossal quantity of seawater. (Watch what your fingertips do when you flatten your hand.) The water will surge upward into a huge hill, then promptly collapse. One side will rush west, toward Japan. The other side will rush east, in a seven-hundred-mile liquid wall that will reach the Northwest coast, on average, fifteen minutes after the earthquake begins. By the time the shaking has ceased and the tsunami has receded, the region will be unrecognizable. Kenneth Murphy, who directs FEMA's Region X, the division responsible for Oregon, Washington, Idaho, and Alaska, says, "Our operating assumption is that everything west of Interstate 5 will be toast."

In the Pacific Northwest, everything west of Interstate 5 covers some hundred and forty thousand square miles, including Seattle, Tacoma, Portland, Eugene, Salem (the capital city of Oregon), Olympia (the capital of Washington), and some seven million people. When the next full-margin rupture happens, that region will suffer the worst natural disaster in the history of North America. Roughly three thousand people died in San Francisco's 1906 earthquake. Almost two thousand died in Hurricane Katrina. Almost three hundred died in Hurricane Sandy. FEMA projects that nearly thirteen thousand people will die in the Cascadia earthquake and tsunami. Another twenty-seven thousand will be injured, and the agency expects that it will need to provide shelter for a million displaced people, and food and water for another two and a half million. "This is one time that I'm hoping all the science is wrong, and it won't happen for another thousand years," Murphy says.

In fact, the science is robust, and one of the chief scientists behind it is Chris Goldfinger. Thanks to work done by him and his colleagues, we now know that the odds of the big Cascadia earthquake happening in the next fifty years are roughly one in three. The odds of the very big one are roughly one in ten. Even those numbers do not fully reflect the danger—or, more to the point, how unprepared the Pacific Northwest is to face it. The truly worrisome figures in this story are these: Thirty years ago, no one knew that the Cascadia subduction zone had ever produced a major earthquake. Forty-five years ago, no one even knew it existed.

In May of 1804, Meriwether Lewis and William Clark, together with their Corps of Discovery, set off from St. Louis on America's first official cross-country expedition. Eighteen months later, they reached the Pacific Ocean and made camp near the present-day town of Astoria, Oregon. The United States was, at the time, twenty-nine years old. Canada was not yet a country. The continent's far expanses were so unknown to its white explorers that Thomas Jefferson, who commissioned the journey, thought that the men would come across woolly mammoths. Native Americans had lived in the Northwest for millennia, but they had no written language, and the many things to which the arriving Europeans subjected them did not include seismological inquiries. The newcomers took the land they encountered at face value, and at face value it was a find: vast, cheap, temperate, fertile, and, to all appearances, remarkably benign.

A century and a half elapsed before anyone had any inkling that the Pacific Northwest was not a quiet place but a place in a long period of quiet. It took another fifty years to uncover and interpret the region's seismic history. Geology, as even geologists will tell you, is not normally the sexiest of disciplines; it hunkers down with earthly stuff while the glory accrues to the human and the cosmic—to genetics, neuroscience, physics. But, sooner or later, every field has its field day, and the discovery of the Cascadia subduction zone stands as one of the greatest scientific detective stories of our time.

The first clue came from geography. Almost all of the world's most powerful earthquakes occur in the Ring of Fire, the volcanically and seismically volatile swath of the Pacific that runs from New Zealand up through Indonesia and Japan, across the ocean to Alaska, and down the west coast of the Americas to Chile. Japan, 2011, magnitude 9.0; Indonesia, 2004, magnitude 9.1; Alaska, 1964, magnitude 9.2; Chile, 1960, magnitude 9.5—not until the late nineteen-sixties, with the rise of the theory of plate tectonics, could geologists explain this pattern. The Ring of Fire, it turns out, is really a ring of subduction zones. Nearly all the earthquakes in the region are caused by continental plates getting stuck on oceanic plates—as North America is stuck on Juan de Fuca—and then getting abruptly unstuck. And nearly all the volcanoes are caused by the oceanic plates sliding deep beneath the continental ones, eventually reaching temperatures and pressures so extreme that they melt the rock above them.

The Pacific Northwest sits squarely within the Ring of Fire. Off its coast, an oceanic plate is slipping beneath a continental one. Inland, the Cascade volcanoes mark the line where, far below, the Juan de Fuca plate is heating up and melting everything above it. In other words, the Cascadia subduction zone has, as Goldfinger put it, "all the right anatomical parts." Yet not once in recorded history has it caused a major earthquake—or, for that matter, any quake to speak of. By contrast, other subduction zones produce major earthquakes occasionally and minor ones all the time: magnitude 5.0, magnitude 4.0, magnitude why are the neighbors moving their sofa at midnight. You can scarcely spend a week in Japan without feeling this sort of earthquake. You can spend a lifetime in many parts of the Northwest—several, in fact, if you had them to spend—and not feel so much as a quiver. The question facing geologists in the nineteen-seventies was whether the Cascadia subduction zone had ever broken its eerie silence.

In the late nineteen-eighties, Brian Atwater, a geologist with the United States Geological Survey, and a graduate student named David Yamaguchi found the answer, and another major clue in the Cascadia puzzle. Their discovery is best illustrated in a place called the ghost forest, a grove of western red cedars on the banks of the Copalis River, near the Washington coast. When I paddled out to it last summer, with Atwater and Yamaguchi, it was easy to see how it got its name. The cedars are spread out across a low salt marsh on a wide northern bend in the river, long dead but still standing. Leafless, branchless, barkless, they are reduced to their trunks and worn to a smooth silver-gray, as if they had always carried their own tombstones inside them.

What killed the trees in the ghost forest was saltwater. It had long been assumed that they died slowly, as the sea level around them gradually rose and submerged their roots. But, by 1987, Atwater, who had found in soil layers evidence of sudden land subsidence along the Washington coast, suspected that that was backward—that the trees had died quickly when the ground beneath them plummeted. To find out, he teamed up with Yamaguchi, a specialist in dendrochronology, the study of growth-ring patterns in trees. Yamaguchi took samples of the cedars and found that they had died simultaneously: in tree after tree, the final rings dated to the summer of 1699. Since trees do not grow in the winter, he and Atwater concluded that sometime between August of 1699 and May of 1700 an earthquake had caused the land to drop and killed the cedars. That time frame predated by more than a hundred years the written history of the Pacific Northwest—and so, by rights, the detective story should have ended there.

But it did not. If you travel five thousand miles due west from the ghost forest, you reach the northeast coast of Japan. As the events of 2011 made clear, that coast is vulnerable to tsunamis, and the Japanese have kept track of them since at least 599 A.D. In that fourteen-hundred-year history, one incident has long stood out for its strangeness. On the eighth day of the twelfth month of the twelfth year of the Genroku era, a six-hundred-mile-long wave struck the coast, levelling homes, breaching a castle moat, and causing an accident at sea. The Japanese understood that tsunamis were the result of earthquakes, yet no one felt the ground shake before the Genroku event. The

"Perhaps I've said too much."

DSD 008332

wave had no discernible origin. When scientists began studying it, they called it an orphan tsunami.

Finally, in a 1996 article in *Nature*, a seismologist named Kenji Satake and three colleagues, drawing on the work of Atwater and Yamaguchi, matched that orphan to its parent—and thereby filled in the blanks in the Cascadia story with uncanny specificity. At approximately nine o'clock at night on January 26, 1700, a magnitude-9.0 earthquake struck the Pacific Northwest, causing sudden land subsidence, drowning coastal forests, and, out in the ocean, lifting up a wave half the length of a continent. It took roughly fifteen minutes for the Eastern half of that wave to strike the Northwest coast. It took ten hours for the other half to cross the ocean. It reached Japan on January 27, 1700: by the local calendar, the eighth day of the twelfth month of the twelfth year of Genroku.

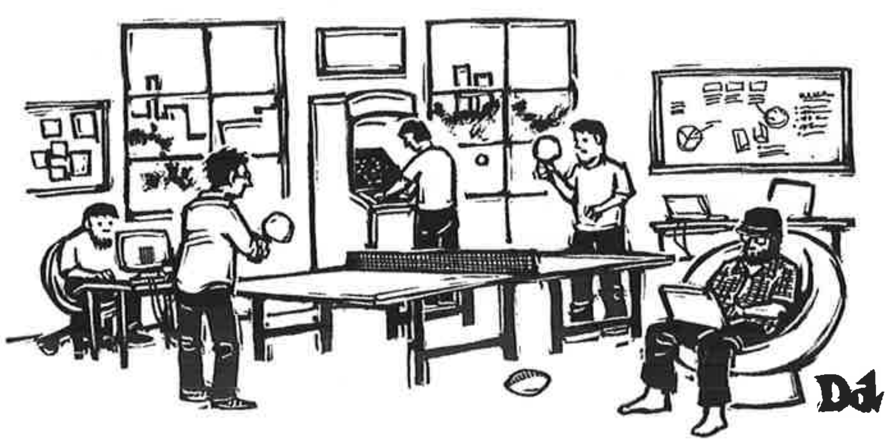
Once scientists had reconstructed the 1700 earthquake, certain previously overlooked accounts also came to seem like clues. In 1964, Chief Louis Nookmis, of the Huu-ay-aht First Nation, in British Columbia, told a story, passed down through seven generations, about the eradication of Vancouver Island's Pachena Bay people. "I think it was at nighttime that the land shook," Nookmis recalled. According to another tribal history, "They sank at once, were all drowned; not one survived." A hundred years earlier, Billy Balch, a leader of the Makah tribe, recounted a similar story. Before his own time, he said, all the water had receded from Washington State's Neah Bay, then suddenly poured back in, inundating the entire region. Those who survived later found canoes hanging from the trees. In a 2005 study, Ruth Ludwin, then a seismologist at the University of Washington, together with nine colleagues, collected and analyzed Native American reports of earthquakes and saltwater floods. Some of those reports contained enough information to estimate a date range for the events they described. On average, the midpoint of that range was 1701.

It does not speak well of European-Americans that such stories counted as evidence for a proposition only after that proposition had been proved. Still, the reconstruction of the Cascadia earthquake of 1700 is one of those rare natural puzzles whose pieces fit together as tectonic plates do not: perfectly. It is wonderful science. It was wonderful *for* science. And it was terrible news for the millions of inhabitants of the Pacific Northwest. As Goldfinger put it, "In the late eighties and early nineties, the paradigm shifted to 'uh-oh.'"

Goldfinger told me this in his lab at Oregon State, a low prefab building that a passing English major might reasonably mistake for the maintenance department. Inside the lab is a walk-in freezer. Inside the freezer are floor-to-ceiling racks filled with cryptically labelled tubes, four inches in diameter and five feet long. Each tube contains a core sample of the seafloor. Each sample contains the history, written in seafloorese, of the past ten thousand years. During subduction-zone earthquakes, torrents of land rush off the continental slope, leaving a permanent deposit on the bottom of the ocean. By counting the number and the size of deposits in each sample, then comparing their extent and consistency along the length of the Cascadia subduction zone, Goldfinger and his colleagues were able to determine how much of the zone has ruptured, how often, and how drastically.

Thanks to that work, we now know that the Pacific Northwest has experienced forty-one subduction-zone earthquakes in the past ten thousand years. If you divide ten thousand by forty-one, you get two hundred and forty-three, which is Cascadia's recurrence interval: the average amount of time that elapses between earthquakes. That timespan is dangerous both because it is too long—long enough for us to unwittingly build an entire civilization on top of our continent's worst fault line—and because it is not long enough. Counting from the earthquake of 1700, we are now three hundred and fifteen years into a two-hundred-and-forty-three-year cycle.

It is possible to quibble with that number. Recurrence intervals are averages, and averages are tricky: ten is the average of nine and eleven, but also of eighteen and two. It is not possible, however, to dispute the scale of the problem. The devastation in Japan in 2011 was the result of a discrepancy between what the best science predicted and what the region was prepared to withstand. The same will hold true in the Pacific Northwest—but here the discrepancy is enormous. "The science part is fun," Goldfinger says. "And I love doing it. But the gap between what we know and what we should do about it is getting bigger and bigger, and the action really needs to turn to responding. Otherwise, we're going to be hammered. I've been through one of these massive earthquakes in the most seismically prepared nation on earth. If that was Portland"—Goldfinger finished the sentence with a shake of his head before he finished it with words. "Let's just say I would rather not be here."



"I'll do what everybody does—sell this startup just before we have to hire a female employee."

The first sign that the Cascadia earthquake has begun will be a compressional wave, radiating outward from the fault line. Compressional waves are fast-moving, high-frequency waves, audible

GIVING AND GETTING

I like that, he said in the hospital, where I was rubbing his feet
which were dry and smelled a bit.

Ahh, he said, *ahhh,* as I worried
what the nurse in the corridor might think,

pushing my thumbs into the pads and calluses,
the skin that had grown leathery and hard
over a lifetime of streets and shoes—

and me trying but unable to forget
some of the things he had done

over the course of our long friendship.
Rubbing his feet was like reaching into some

thick part of my heart that couldn't feel
and kneading away at it—

Blame caught inside the love
like a fishhook, or a bug in honey.

It is in my character, this
persistent selfishness—

one of my hands offering the gift, the other
trying to take something back.

Giving and getting
like two horses arriving at the same time

from opposite directions
at the stone gate

that will allow only one to pass.

—*Tony Hoagland*

to dogs and certain other animals but experienced by humans only as a sudden jolt. They are not very harmful, but they are potentially very useful, since they travel fast enough to be detected by sensors thirty to ninety seconds ahead of other seismic waves. That is enough time for earthquake early-warning systems, such as those in use throughout Japan, to automatically perform a variety of lifesaving functions: shutting down railways and power plants, opening elevators and firehouse doors, alerting hospitals to halt surgeries, and triggering alarms so that the general public can take cover. The Pacific Northwest has no early-warning system. When the Cascadia earthquake begins, there will be, instead, a cacophony of barking dogs and a long, suspended, what-was-that moment before the surface waves arrive. Surface waves are slower, lower-frequency waves that move the ground both up and down and side to side: the shaking, starting in earnest.

Soon after that shaking begins, the electrical grid will fail, likely everywhere west of the Cascades and possibly well beyond. If it happens at night, the ensuing catastrophe will unfold in darkness. In theory, those who are at home when it hits should be safest; it is easy and relatively inexpensive to seismically safeguard a private dwelling. But, lulled into nonchalance by their seemingly benign environment, most people in the Pacific Northwest have not done so. That nonchalance will shatter instantly. So will everything made of glass. Anything indoors and unsecured will lurch across the floor or come crashing down: bookshelves, lamps, computers, cannisters of flour in the pantry. Refrigerators will walk out of kitchens, unplugging themselves and toppling over. Water heaters will fall and smash interior gas lines. Houses that are not bolted to their foundations will slide off—or, rather, they will stay put, obeying inertia, while the foundations, together with the rest of the Northwest, jolt westward. Unmoored on the undulating ground, the homes will begin to collapse.

Across the region, other, larger structures will also start to fail. Until 1974, the state of Oregon had no seismic code, and few places in the Pacific Northwest had one appropriate to a magnitude-9.0 earthquake until 1994. The vast majority of buildings in the region were constructed before then. Ian Madin, who directs the Oregon Department of Geology and Mineral Industries (DOGAMI), estimates that seventy-five per cent of all structures in the state are not designed to withstand a major Cascadia quake. FEMA calculates that, across the region, something on the order of a million buildings—more than three thousand of them schools—will collapse or be compromised in the earthquake. So will half of all highway bridges, fifteen of the seventeen bridges spanning Portland's two rivers, and two-thirds of railways and airports; also, one-third of all fire stations, half of all police stations, and two-thirds of all hospitals.

Certain disasters stem from many small problems conspiring to cause one very large problem. For want of a nail, the war was lost; for fifteen independently insignificant errors, the jetliner was lost. Subduction-zone earthquakes operate on the opposite principle: one enormous problem causes many other enormous problems. The shaking from the Cascadia quake will set off landslides throughout the region—up to thirty thousand of them in Seattle alone, the city's emergency-management office estimates. It will also induce a process called liquefaction, whereby seemingly solid ground starts behaving like a liquid, to

the detriment of anything on top of it. Fifteen per cent of Seattle is built on liquefiable land, including seventeen day-care centers and the homes of some thirty-four thousand five hundred people. So is Oregon's critical energy-infrastructure hub, a six-mile stretch of Portland through which flows ninety per cent of the state's liquid fuel and which houses everything from electrical substations to natural-gas terminals. Together, the sloshing, sliding, and shaking will trigger fires, flooding, pipe failures, dam breaches, and hazardous-material spills. Any one of these second-order disasters could swamp the original earthquake in terms of cost, damage, or casualities—and one of them definitely will. Four to six minutes after the dogs start barking, the shaking will subside. For another few minutes, the region, upended, will continue to fall apart on its own. Then the wave will arrive, and the real destruction will begin.

Among natural disasters, tsunamis may be the closest to being completely unsurvivable. The only likely way to outlive one is not to be there when it happens: to steer clear of the vulnerable area in the first place, or get yourself to high ground as fast as possible. For the seventy-one thousand people who live in Cascadia's inundation zone, that will mean evacuating in the narrow window after one disaster ends and before another begins. They will be notified to do so only by the earthquake itself—"a vibrate-alert system," Kevin Cupples, the city planner for the town of Seaside, Oregon, jokes—and they are urged to leave on foot, since the earthquake will render roads impassable. Depending on location, they will have between ten and thirty minutes to get out. That time line does not allow for finding a flashlight, tending to an earthquake injury, hesitating amid the ruins of a home, searching for loved ones, or being a Good Samaritan. "When that tsunami is coming, you run," Jay Wilson, the chair of the Oregon Seismic Safety Policy Advisory Commission (OSSPAC), says. "You protect yourself, you don't turn around, you don't go back to save anybody. You run for your life."

The time to save people from a tsunami is before it happens, but the region has not yet taken serious steps toward doing so. Hotels and businesses are not required to post evacuation routes or to provide employees with evacuation training. In Oregon, it has been illegal since 1995 to build hospitals, schools, firehouses, and police stations in the inundation zone, but those which are already in it can stay, and any other new construction is permissible: energy facilities, hotels, retirement homes. In those cases, builders are required only to consult with DOGAMI about evacuation plans. "So you come in and sit down," Ian Madin says. "And I say, 'That's a stupid idea.' And you say, 'Thanks. Now we've consulted.'"

These lax safety policies guarantee that many people inside the inundation zone will not get out. Twenty-two per cent of Oregon's coastal population is sixty-five or older. Twenty-nine per cent of the state's population is disabled, and that figure rises in many coastal counties. "We can't save them," Kevin Cupples says. "I'm not going to sugarcoat it and say, 'Oh, yeah, we'll go around and check on the elderly.' No. We won't." Nor will anyone save the tourists. Washington State Park properties within the inundation zone see an average of seventeen thousand and twenty-nine guests a day. Madin estimates that up to a hundred and fifty thousand people visit Oregon's beaches on summer weekends. "Most of them won't have a clue as to how to evacuate," he says. "And the beaches are the hardest place to evacuate from."

Those who cannot get out of the inundation zone under their own power will quickly be overtaken by a greater one. A grown man is knocked over by ankle-deep water moving at 6.7 miles an hour. The tsunami will be moving more than twice that fast when it arrives. Its height will vary with the contours of the coast, from twenty feet to more than a hundred feet. It will not look like a Hokusai-style wave, rising up from the surface of the sea and breaking from above. It will look like the whole ocean, elevated, overtaking land. Nor will it be made only of water—not once it reaches the shore. It will be a five-story deluge of pickup trucks and doorframes and cinder blocks and fishing boats and utility poles and everything else that once constituted the coastal towns of the Pacific Northwest.

To see the full scale of the devastation when that tsunami recedes, you would need to be in the international space station. The inundation zone will be scoured of structures from California to Canada. The earthquake will have wrought its worst havoc west of the Cascades but caused damage as far away as

Sacramento, California—as distant from the worst-hit areas as Fort Wayne, Indiana, is from New York. FEMA expects to coördinate search-and-rescue operations across a hundred thousand square miles and in the waters off four hundred and fifty-three miles of coastline. As for casualties: the figures I cited earlier—twenty-seven thousand injured, almost thirteen thousand dead—are based on the agency's official planning scenario, which has the earthquake striking at 9:41 A.M. on February 6th. If, instead, it strikes in the summer, when the beaches are full, those numbers could be off by a horrifying margin.

Wineglasses, antique vases, Humpty Dumpty, hip bones, hearts: what breaks quickly generally mends slowly, if at all. OSSPAC estimates that in the I-5 corridor it will take between one and three months after the earthquake to restore electricity, a month to a year to restore drinking water and sewer service, six months to a year to restore major highways, and eighteen months to restore health-care facilities. On the coast, those numbers go up. Whoever chooses or has no choice but to stay there will spend three to six months without electricity, one to three years without drinking water and sewage systems, and three or more years without hospitals. Those estimates do not apply to the tsunami-inundation zone, which will remain all but uninhabitable for years.

How much all this will cost is anyone's guess; FEMA puts every number on its relief-and-recovery plan except a price. But whatever the ultimate figure—and even though U.S. taxpayers will cover seventy-five to a hundred per cent of the damage, as happens in declared disasters—the economy of the Pacific Northwest will collapse. Crippled by a lack of basic services, businesses will fail or move away. Many residents will flee as well. OSSPAC predicts a mass-displacement event and a long-term population downturn. Chris Goldfinger didn't want to be there when it happened. But, by many metrics, it will be as bad or worse to be there afterward.

On the face of it, earthquakes seem to present us with problems of space: the way we live along fault lines, in brick buildings, in homes made valuable by their proximity to the sea. But, covertly, they also present us with problems of time. The earth is 4.5 billion years old, but we are a young species, relatively speaking, with an average individual allotment of three score years and ten. The brevity of our lives breeds a kind of temporal parochialism—an ignorance of or an indifference to those planetary gears which turn more slowly than our own.

This problem is bidirectional. The Cascadia subduction zone remained hidden from us for so long because we could not see deep enough into the past. It poses a danger to us today because we have not thought deeply enough about the future. That is no longer a problem of information; we now understand very well what the Cascadia fault line will someday do. Nor is it a problem of imagination. If you are so inclined, you can watch an earthquake destroy much of the West Coast this summer in Brad Peyton's "San Andreas," while, in neighboring theatres, the world threatens to succumb to Armageddon by other means: viruses, robots, resource scarcity, zombies, aliens, plague. As those movies attest, we excel at imagining future scenarios, including awful ones. But such apocalyptic visions are a form of escapism, not a moral summons, and still less a plan of action. Where we stumble is in conjuring up grim futures in a way that helps to avert them.

That problem is not specific to earthquakes, of course. The Cascadia situation, a calamity in its own right, is also a parable for this age of ecological reckoning, and the questions it raises are ones that we all now face. How should a society respond to a looming crisis of uncertain timing but of catastrophic proportions? How can it begin to right itself when its entire infrastructure and culture developed in a way that leaves it profoundly vulnerable to natural disaster?

The last person I met with in the Pacific Northwest was Doug Dougherty, the superintendent of schools for Seaside, which lies almost entirely within the tsunami-inundation zone. Of the four schools that Dougherty oversees, with a total student population of sixteen hundred, one is relatively safe. The others sit five to fifteen feet above sea level. When the tsunami comes, they will be as much as forty-five feet below it.

In 2009, Dougherty told me, he found some land for sale outside the inundation zone, and proposed building a new K-12 campus there. Four years later, to foot the hundred-and-twenty-eight-million-dollar bill, the district put up a bond measure. The tax increase for residents amounted to two dollars and sixteen cents per thousand dollars of property value. The measure failed by sixty-two per cent. Dougherty tried seeking help from Oregon's congressional delegation but came up empty. The state makes money available for seismic upgrades, but buildings within the inundation zone cannot apply. At present, all Dougherty can do is make sure that his students know how to evacuate.

Some of them, however, will not be able to do so. At an elementary school in the community of Gearhart, the children will be trapped. "They can't make it out from that school," Dougherty said. "They have no place to go." On one side lies the ocean; on the other, a wide, roadless bog. When the tsunami comes, the only place to go in Gearhart is a small ridge just behind the school. At its tallest, it is forty-five feet high—lower than the expected wave in a full-margin earthquake. For now, the route to the ridge is marked by signs that say "Temporary Tsunami Assembly Area." I asked Dougherty about the state's long-range plan. "There is no long-range plan," he said.

Dougherty's office is deep inside the inundation zone, a few blocks from the beach. All day long, just out of sight, the ocean rises up and collapses, spilling foamy overlapping ovals onto the shore. Eighty miles farther out, ten thousand feet below the surface of the sea, the hand of a geological clock is somewhere in its slow sweep. All across the region, seismologists are looking at their watches, wondering how long we have, and what we will do, before geological time catches up to our own. ♦

Welcome to the new world of energy

EDF ENVIRONMENTAL DEFENSE FUND®
Finding the ways that work

Solutions

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SENT IN BY:

Mr. and Mrs. Tom & Kristi Weir
4639 133rd Ave SE
Bellevue, WA 98006

By Leslie Valentine

Over 3,000 electric utilities make up the U.S. power grid, which is sometimes called the largest machine in the world. But it's an antiquated system—largely unchanged from horse-and-buggy days. Because of this, electricity generation is today the single largest contributor to U.S. global warming pollution. Now, change is coming. Big energy states are boldly reimagining how electricity is produced and distributed, making the system cheaper and cleaner. With EDF's help, they're providing a model for the rest of the country—and the world.


MCCONNELL PHOTOGRAPHY

A modernized grid will promote homegrown power, as in this Austin, TX, neighborhood.

WALLY BAZEMORE NEVER WANTS a repeat of what he and his neighbors went through three years ago, when Superstorm Sandy battered his Brooklyn community of Red Hook, leaving its 11,000 residents without power for weeks. At the time, he was caring for his 93-year-old bedridden mother. "It was rough," he says. "She was wrapped in Red Cross blankets to keep warm—she looked like a refugee."

These days, Bazemore is meeting with officials to get an energy system in place that will keep the electricity on the next time the central power grid fails.

Superstorm Sandy was a wakeup call not only for Red Hook residents. New York Gov. Andrew Cuomo openly criticized his own state's energy system and vowed to reform it.

There's a lot to reform. Today, the power grid uses the same one-way model that Thomas Edison designed more than a century ago. Typically, a power plant burns fossil fuel to produce electricity, losing power by the time it reaches customers, who have a single energy choice: on or off. Moreover, most utilities are monopolies that profit by selling more electricity and by building more infrastructure—substations, polluting power plants, poles and wires—and passing the cost on to customers. That is a road to climate disaster—and a recipe for more blackouts. Add a tangle of public utility rules and you have formidable barriers to a clean, reliable power system.

What if utilities were rewarded for managing and saving energy, not just generating it? Today, EDF's clean energy team is working with the Cuomo administration to bring that vision to life with a new energy policy for New York. A key goal is to find ways for utilities to profit from fully integrating renewable energy into their operations and helping customers use energy more efficiently. The challenge is to cut pollution and lower customers' energy bills while creating a more reliable electrical system. To ensure the changes take effect nationally, EDF is working in eight other states that make up about half the nation's electricity market.

8,079 pounds


the amount of coal it takes to produce the electricity for the average household in the U.S. each year.

New York's goals are ambitious: The state aims to get half of its power from renewable sources by 2030 (up from roughly 25% in 2014) and increase the overall energy efficiency of buildings by 23%.

"This is a huge opportunity to remake the system so it is fair and affordable—and cuts climate pollution," says Rory Christian, who directs EDF's clean energy work in New York.

If successful, the policy solutions New York develops could be a model for other states looking for ways to meet the goals of EPA's Clean Power Plan *(see page 16)*. Success in New York could also guide other countries aiming to meet their climate goals quickly and at low cost.

With the historic Paris climate agreement now signed, reform of the electricity system will be a critical component in many nations' plans to meet their obligations. It's no surprise then, that policy makers around the world are keeping a close watch on the New York experiment. Such sweeping reform to integrate clean energy into the entire system, from power plants to the power outlet on your wall, has never been attempted.

EDF is also leading the way in designing financing methods to pay for the

THE LONG ROAD TO CLEAN ENERGY

Ever since Thomas Edison flipped the switch on America's first central power plant in New York City in 1882, the business model has remained essentially unchanged. The goal: Add customers. Build coal-fired power plants. This archaic system is now being transformed.

1882: ELECTRIFYING THE NATION

The first power plant begins producing electricity, sparking a 130-year building spree of power plants and transmission lines across the country.

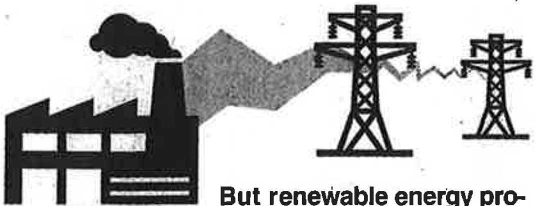
1954: SOLAR TECHNOLOGY IS BORN

Scientists at Bell Labs invent the first solar cell that uses the sun's energy to run everyday electrical equipment.

1987: SCIENTISTS WARN OF CLIMATE CHANGE

Atmospheric physicist Dr. Michael Oppenheimer, then at EDF, helped call international policy makers' attention to the problem of climate change.

About 75% of energy generated from traditional power plants is lost...



But renewable energy produced locally, like rooftop solar, is less wasteful.

How do you ensure that during blackouts people aren't forced to rely on diesel generators that are highly polluting? And how do you protect low-income families, for whom even a small, temporary rise in their utility bill can impact the food budget?

"It is crucial that low-income people and communities of color benefit from the coming changes and are not unduly burdened by pollution and higher costs, as they have so often been in the past," says Peggy Shepard, EDF trustee and director of Harlem-based WE ACT for Environmental Justice.

Changing an entrenched system requires delicate footwork. In 2014, New York City's utility, Consolidated Edison (Con Ed), proposed a new $1 billion substation to meet increasing demand for 700,000 residents of Brooklyn and Queens, who would have had to contend with higher utility bills as a result. EDF and our allies showed the state public service commission that there was a better way. By implementing energy-saving strategies, such as paying people to use less electricity during peak demand hours, we could cut pollution and costs. State regulators agreed and directed Con Ed to pursue alternatives to the $1 billion project, saving customers hundreds of millions of dollars and laying the foundation for the broader energy reform now under way.

MICHAEL FRIEDMAN

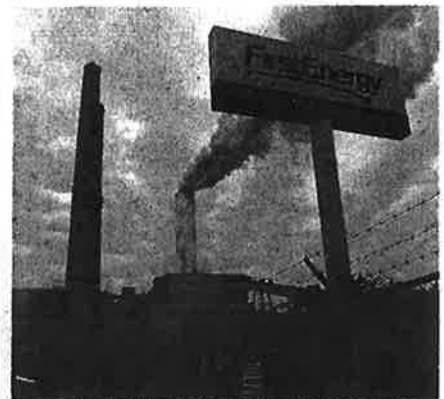
EDF's Rory Christian (right) teamed up with community leader Eddie Bautista.

EDF's Rory Christian enlisted community support for the cheaper alternative. "EDF's guidance in helping community activists frame their campaign around energy reform has been invaluable," says Eddie Bautista, executive director of New York City Environmental Justice Alliance. With EDF's support, a powerful coalition of community leaders is now working with Con Ed to develop projects that benefit residents.

One such initiative—and winner of state funding—is a community microgrid that could produce income for residents. "In projects like this, there is great potential not only for green job creation but also for an ownership stake for residents," adds Bautista.

Meanwhile, in Red Hook, Bazemore is happy that a microgrid is coming to his venerable waterfront community. "There's still a lot to do, and we must be vigilant," the father of three says. "We have to think of the world we're passing to the next generation."

Stuck in the past



THE AKRON BEACON JOURNAL

Across the country, a battle is playing out between vested interests in old, polluting energy and states and utilities adapting to a new energy landscape. While many utilities are retooling to join the clean tech revolution, Ohio-based FirstEnergy is fighting tooth-and-nail to keep the antiquated system in place.

Over the last decade, FirstEnergy, which operates in five states in the Midwest, has made a series of bad bets in the coal industry—for example, investing $1.8 billion to retrofit a 50-year-old coal-fired power plant. These poor business decisions have led to a financial fiasco for FirstEnergy. Now, it is asking for a $3 billion bailout, leaving customers to foot the bill. Not content with that, the company is trying to force Ohio to scrap its energy efficiency standards and other energy-saving programs.

"That's a losing strategy if ever there was one," says Dick Munson, director of EDF's Midwest clean energy program. EDF is fighting to stop FirstEnergy's desperate gambit to derail reform. We've rolled out ads in Ohio and mobilized supporters to urge Ohio's Public Utility Commission to reject the utility's request. A decision is imminent as we go to press.

2013: LAUNCHING A PLAN FOR CLEAN ENERGY REFORM

EDF launches a project in nine states to knock down barriers to a clean power system. New York announces plans for a total overhaul of its energy system.

2014: THE REVOLUTION IS UNDER WAY

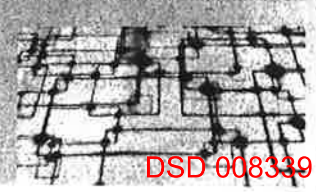
Solar and wind provide more than half of added U.S. generating capacity in 2014.

2015: ENDING THE ERA OF UNLIMITED POLLUTION

California passes a bill to up the state's renewable energy mix to 50% and double energy efficiency. EPA unveils the Clean Power Plan requiring states to develop plans to cut power plant emissions.

2018: ENERGY USE IS DEMOCRATIZED

Nearly 20 million New Yorkers can now manage their energy use, opt for renewable energy and gain access to microgrids. EDF's target states are on track to transform their energy systems.




DEREK GEE/BUFFALO NEWS

Winds of change: On Lake Erie in Lackawanna, NY, wind turbines are humming where a steel plant once stood.

renovations and innovations that New York's energy plan will entail.

"What we're doing here," says Richard Kauffman, New York's chairman of energy and finance, "is building a new market platform to unleash clean energy technology and the financing needed so that we can reach our greenhouse gas reduction goals and grow our economy."

The state has rolled out a number of initiatives to spur private investment and innovation, including the creation of a state Green Bank to help provide the billions of dollars needed to retool the system. Gov. Cuomo has committed $1 billion to grow New York's solar industry. With EDF's help, the state also launched a $40 million competition to help communities develop microgrids—highly efficient local power networks—and 83 winners have been announced around the state.

From Buffalo to Brooklyn, change is already evident. There are giant wind turbines along Lake Erie where a Bethlehem Steel plant once stood. In economically struggling Buffalo, one of the nation's largest solar panel factories is being built. Red Hook and a number of other New York City communities are seeking to install microgrids that would keep the electricity on in hospitals, relief centers and other essential buildings if the larger grid shuts down.

Besides providing reliable energy more efficiently, microgrids open up the distribution system to local energy produced onsite, through rooftop solar or wind, for example. Ultimately this puts affordable clean energy into many more people's hands. What's more, New York City is becoming a thriving hub for the clean tech industry. Solar installations have tripled in the past two years, and Cornell University recently broke ground for a new high-tech campus on Roosevelt Island.

A seismic shift

Across the country, the clean energy market is booming, and not just in New York. Nationwide, in 2014, the industry expanded by 14%, to almost $200 billion. The cost of solar panels has dropped 82% since 2009, and in some states energy from the sun is cost competitive with conventional power. This signifies a fundamental shift toward clean energy produced locally, giving people true control over how they use, produce and interact with energy.

What does this mean for you? EDF sought to answer that in 2009, when we co-founded Pecan Street, Inc., centered on the Mueller neighborhood, a typical middle-class community in Austin, TX, with one big difference: It's a living laboratory for the technological future.

Pecan Street residents, many of whom live in homes with solar panels on their roofs and electric cars in their garages, can alter their energy usage in real time on their smart phones. They get a credit on their utility bill when they produce more energy than they use. Thanks in part to the work going on at Pecan Street, solar-powered dryers that shut off when the sun goes behind a cloud will be available in the not-too-distant future, and solar-powered homes will automatically switch to an alternate source of energy at night.

Not everyone is thrilled with the changes under way. Several states, including Florida (the Sunshine State), are charging fees to make up for lost revenue from rooftop solar customers, but poorly designed rate changes can impede adoption of solar and other renewables.

Other hurdles need to be cleared as well. Financing to upgrade buildings is lagging. That's why EDF developed a way to standardize how energy efficiency projects are developed and brought to market, similar to what was developed for solar, car loans and mortgages. California, New Jersey, New York and Texas are among the states starting to use the protocol, and we're adapting it for EU countries, including the UK and Germany.

And then there's the issue of justice.

2003: THE GREAT NORTHEASTERN BLACKOUT
A transmission line brushed against a tree in Ohio, shutting down the grid and leaving 50 million people in the Northeast and Midwest without power.

2006: CALIFORNIA OFFERS AN ALTERNATE FUTURE
California passes AB32, an EDF-cosponsored law that promotes renewable energy and efficiency, and requires reductions in climate pollution.

2008: EDF PIONEERS A SMART GRID
EDF helps launch Pecan Street Inc., an initiative with the high-tech industry and the city of Austin, TX, to develop a clean, smart grid.

2012: DISASTER IN NEW YORK CITY
Superstorm Sandy devastates the metropolitan area. The power grid fails, plunging much of New York into darkness and showing the system's vulnerability to climate change.

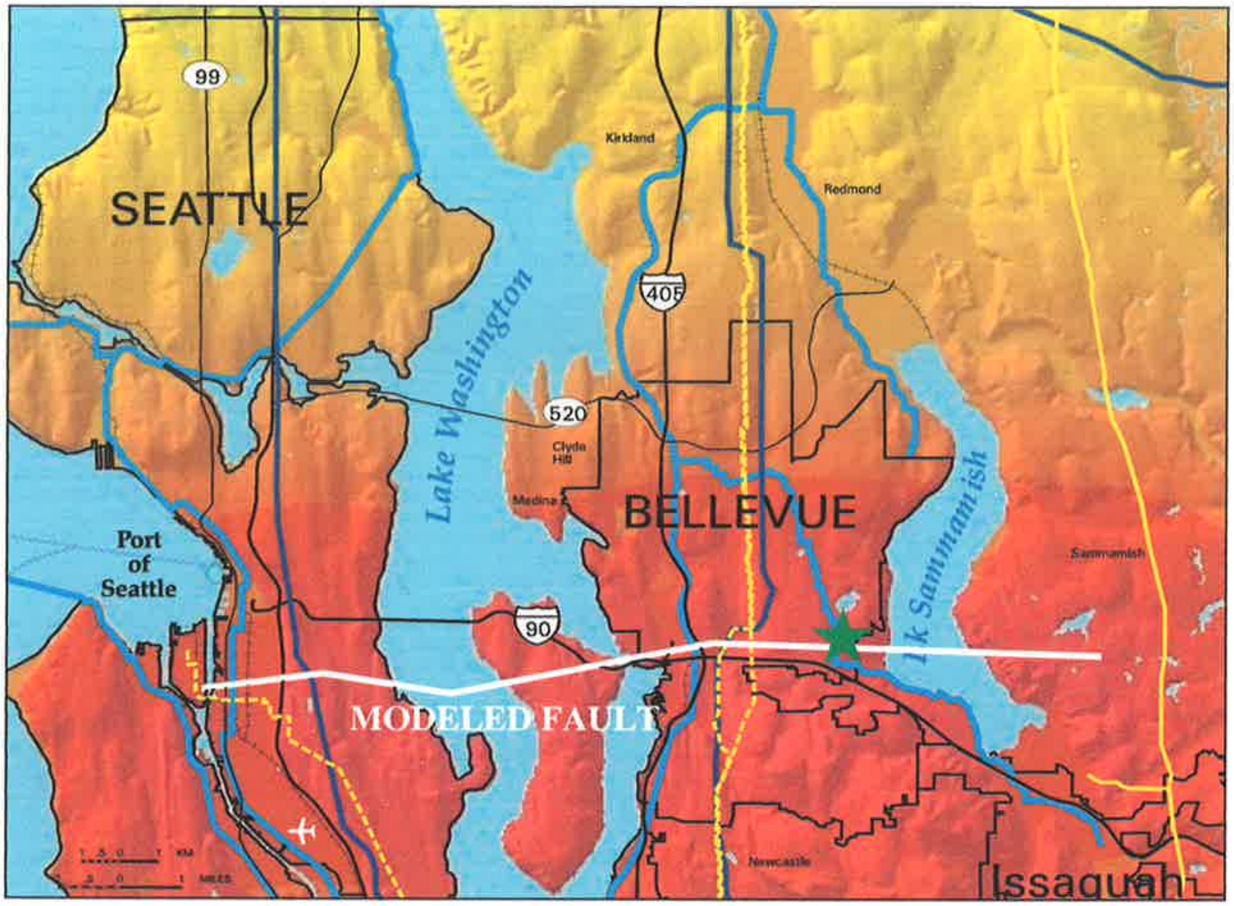


Figure 1-7: Location of the surface fault rupture for the scenario earthquake. The white line shows the modeled rupture where it intersects the surface. It goes through the Vasa Park trench (indicated by the green star). The black lines represent highways, rail lines (crossed lines) and ferry routes (squiggly lines from the Port of Seattle). The yellow lines represent regional natural gas and liquid fuels pipelines. The dark blue lines are major water transmission lines. Lighter blue lines represent primary sewer trunk lines. Graphic / US Geological Survey

Modeling the Scenario Earthquake and Calculating the Ground Motions

An earthquake scenario uses estimates of ground motion to allow engineers and planners to develop the possible effects of the event on the built and natural environments. The first step is to compute median ground motions at the earth's surface for rock site conditions.

The scenario earthquake used in this project has a magnitude of 6.7 and a surface rupture of 6.5 feet, matching the observed faulting at Vasa Park in Bellevue. The fault ruptured length is 14 miles; the rupture extends from Harbor Island to east of Lake Sammamish (Figure 1-7), passing through Seattle, Mercer Island, Bellevue, and north of Issaquah. We calculated peak horizontal ground acceleration often used by emergency managers to guide response planning, as well as spectral response values at 0.3 and 1.0 second periods typically of interest to engineers.

DSD 008341

Taking into account differences in local site and soil conditions provides a more realistic picture of the expected pattern of ground shaking; National Earthquake Hazard Reduction Program (NEHRP) amplification factors for different soil conditions were used. A 2003 Seattle-area soils map (Figure 1-8) shows the softest soils, class E, in major river valleys and some smaller drainages. These soils amplify ground motions more than other soil types and are most prone to liquefaction. The stiffest soils, class B, are least prone to amplifying ground motions and liquefying. The other soil classes – C and D – perform in between class B and class E soils.

Applying appropriate soil amplification factors conditions results in very large ground motions for the scenario earthquake. A wide area will experience very strong ground motions in excess of 0.3g, or 30 percent of gravity. Peak ground accelerations over the modeled fault rupture exceed 0.7g, or 70 percent of gravity (Figure 1-9). In comparison, the largest peak accelerations recorded during the Nisqually earthquake were under 0.3g. The scenario event on the Seattle Fault puts ground motions that exceed those experienced in the Nisqually earthquake over virtually all of Seattle, Bellevue, Redmond, Kirkland, and Mercer Island.

Peak ground acceleration helps emergency responders understand the possible effects of an earthquake. Engineers, on the other hand, use the concept of spectral acceleration to explain the effects of strong shaking on various structures. The two ground motion maps, Figure 1-10, show spectral accelerations at 0.3-second period and 1.0-second period. The 0.3-second spectral acceleration map represents the acceleration experienced by a three-story building, and the 1.0-second map represents the acceleration experienced by a 10-story building.

The 0.3-second spectral acceleration values shown in Figure 1-10 are generally proportional to the peak ground acceleration values shown in Figure 1-9. The map of 1.0-second spectral acceleration in Figure 1-10 highlights the amplification of ground motions in areas of E-class soils. Since building damage better correlates with 1.0-second spectral acceleration than with peak ground acceleration, this map indicates that buildings on soil class E have a higher likelihood of damage from shaking than structures built on other soil types.

DSD 008342

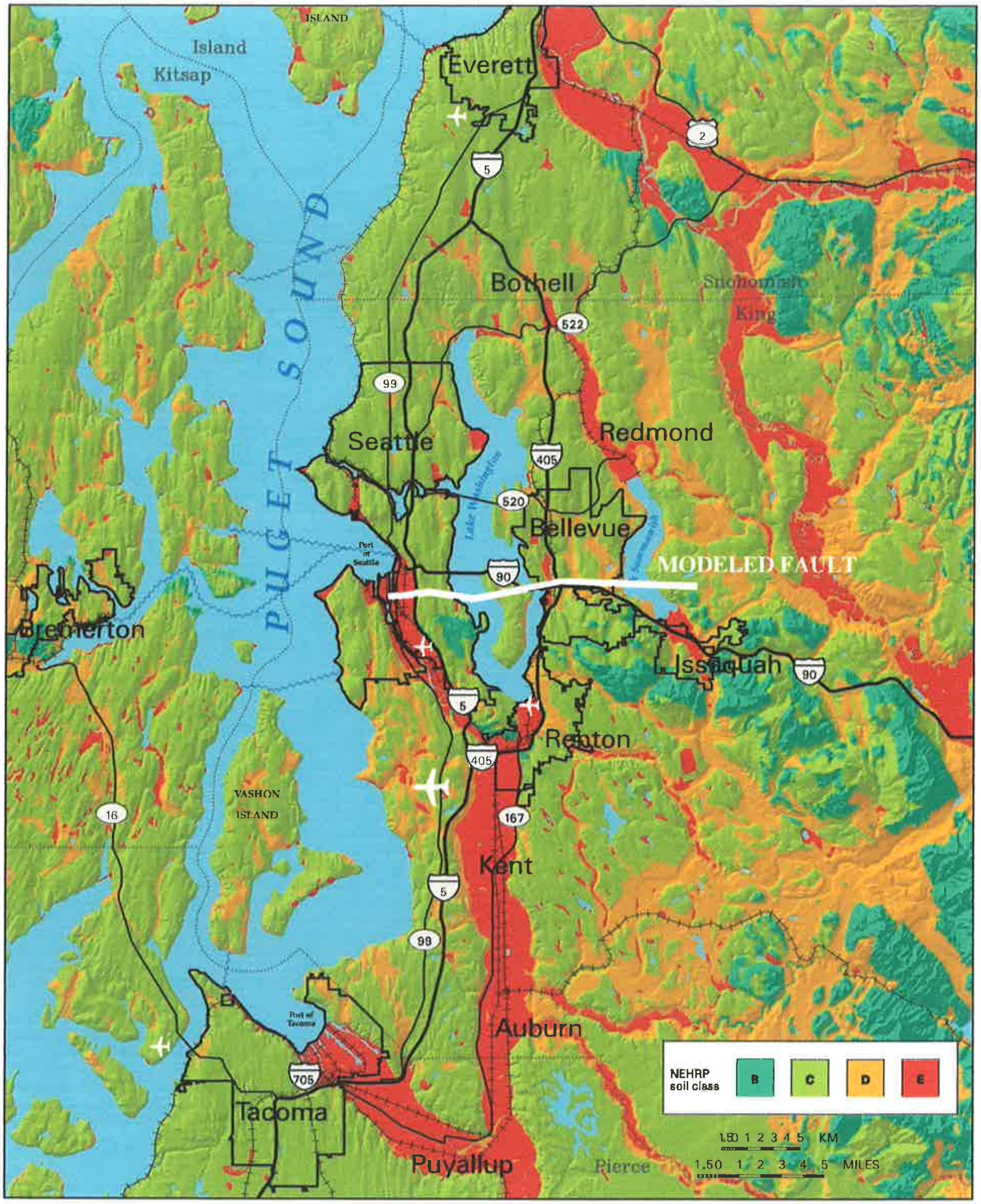


Figure 1-8: NEHRP soils maps for the study region. Earth scientists categorize the upper 100 feet into soil classes based in large part on how they amplify ground motions and their resistance to liquefaction. Class E soils amplify ground motions the most and are the least resistant (most prone) to liquefaction.

Graphic / Washington Department of Natural Resources and US Geological Survey

DSD 008343

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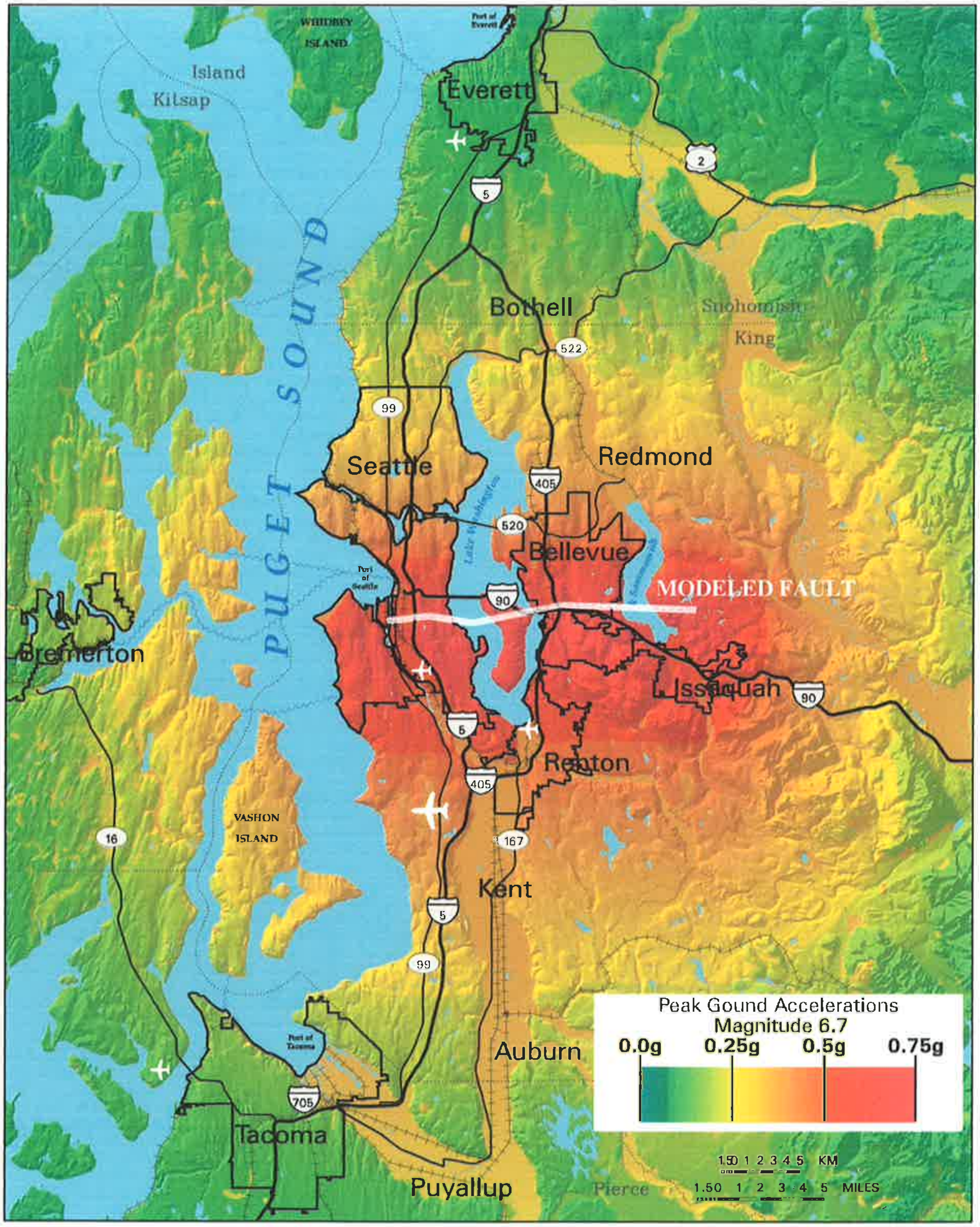

Figure 1-9: Peak ground accelerations for Seattle Fault scenario earthquake using soils map.

Graphic /US Geological Survey

DSD 008344

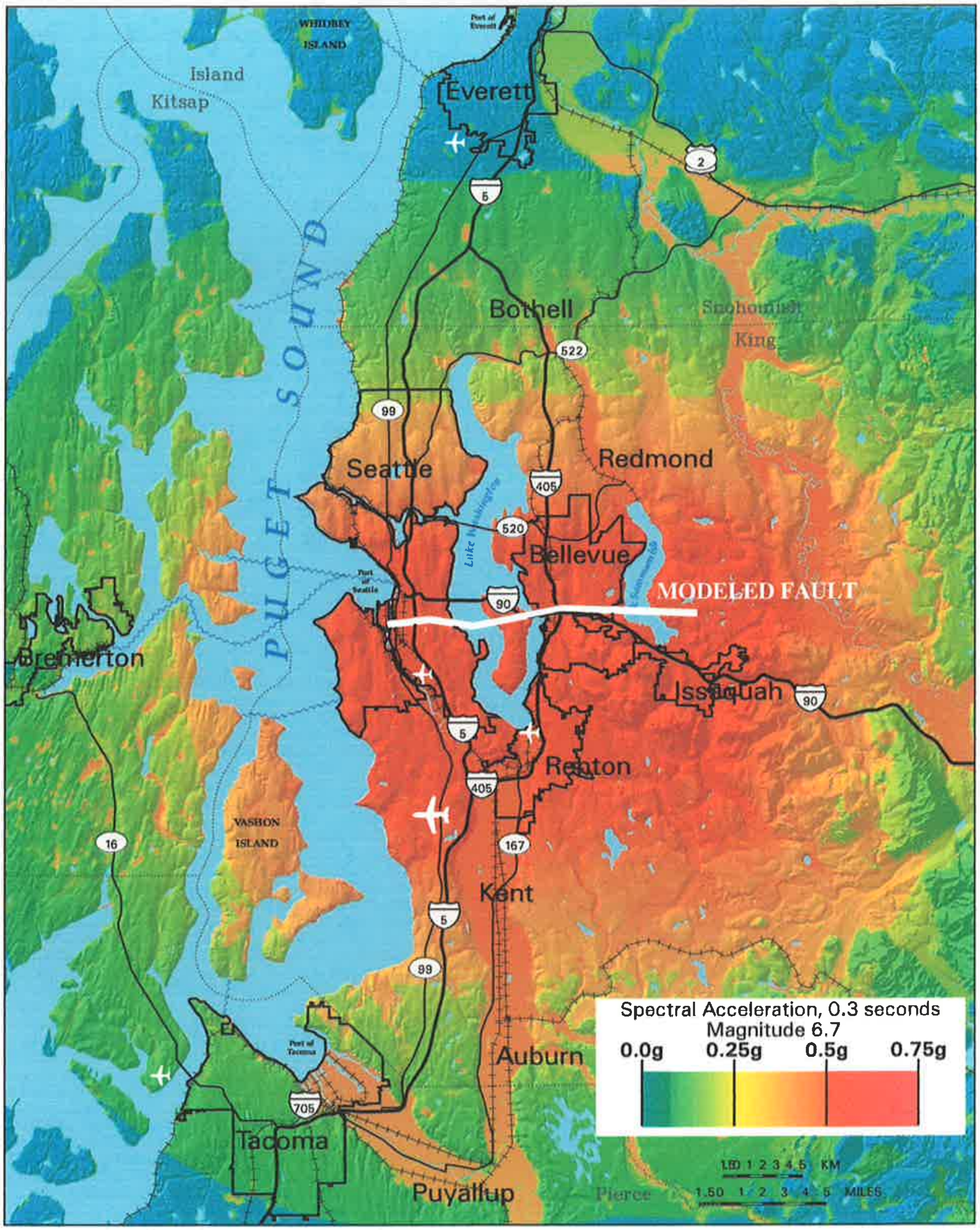

Figure 1-10a: Spectral acceleration at 0.3 seconds for M6.7 scenario earthquake.

Graphic / US Geological Survey

DSD 008345

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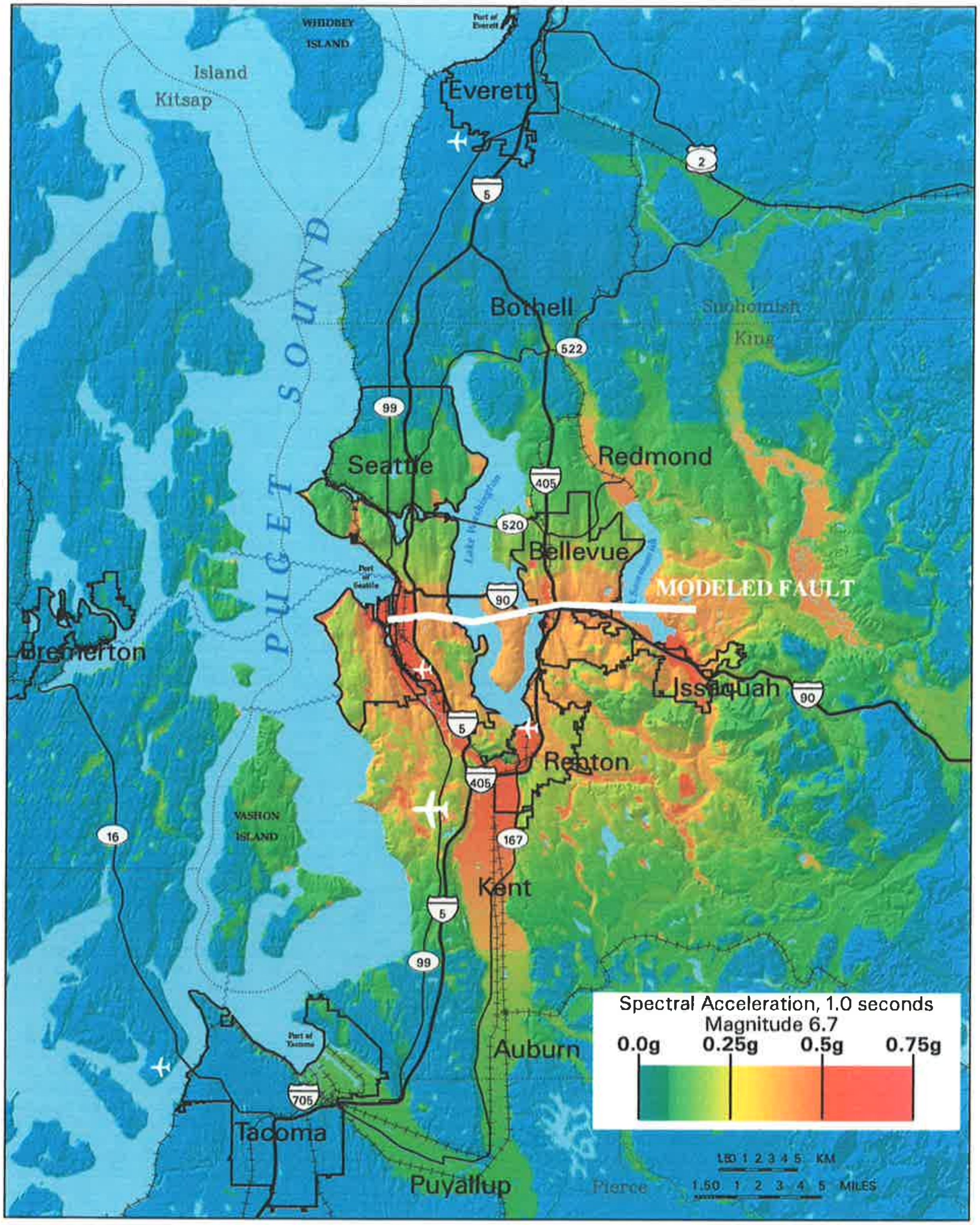
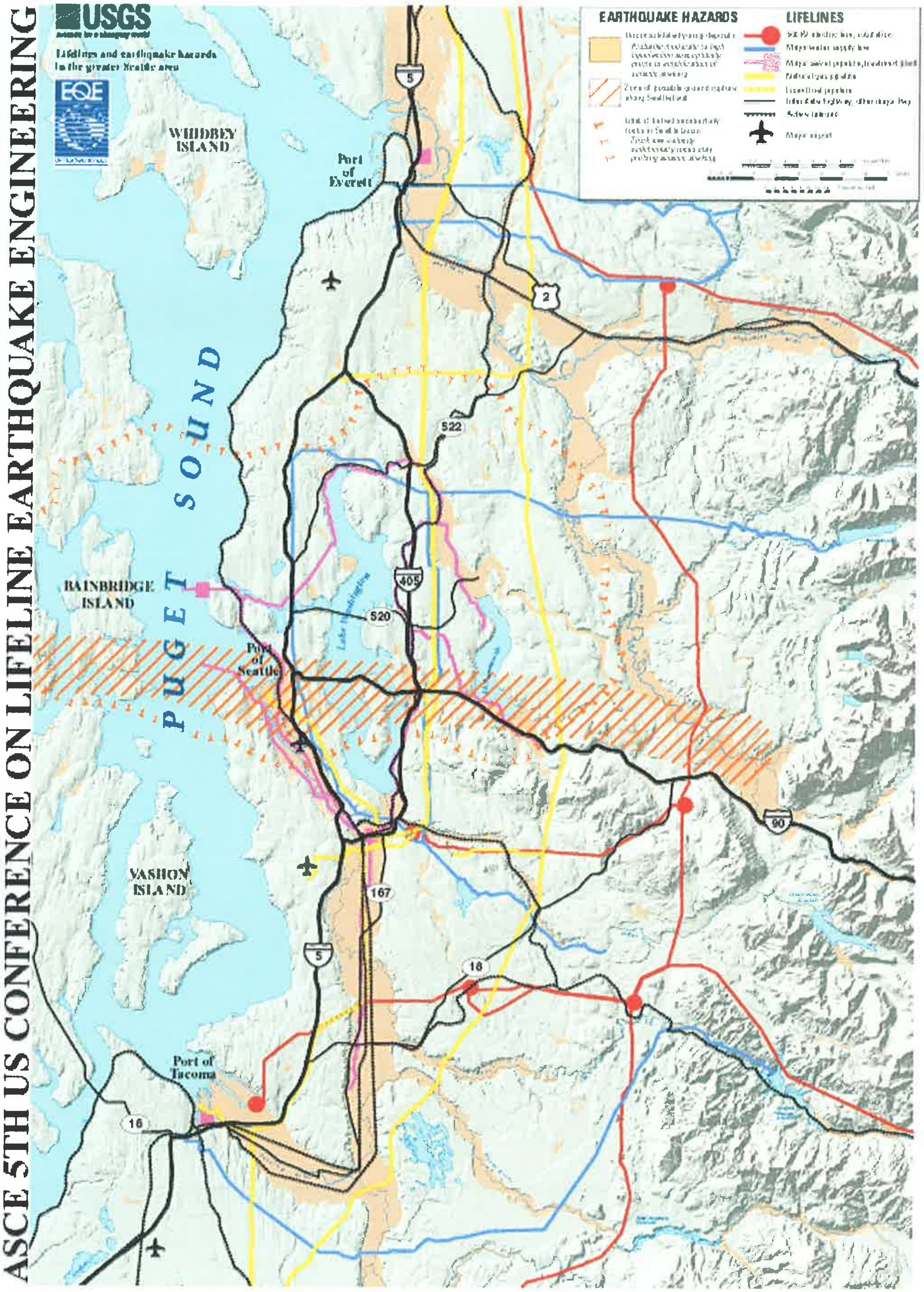


Figure 1-10b: Spectral acceleration at 1.0 seconds for M6.7 scenario earthquake.

Graphic / US Geological Survey

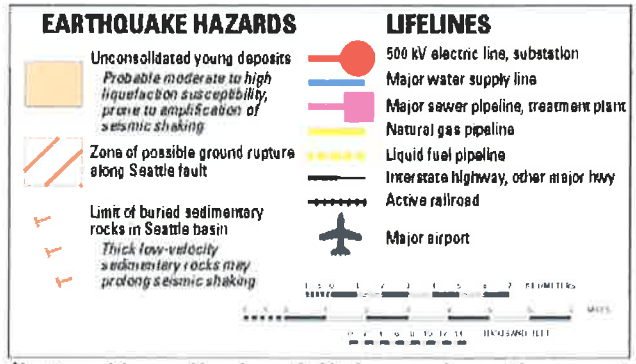
DSD 008346


ASCE 5TH US CONFERENCE ON LIFELINE EARTHQUAKE ENGINEERING
USGS
Lifelines and earthquake hazards in the greater Seattle area
EQE
EARTHQUAKE HAZARDS
LIFELINES
WHIDBEY ISLAND
Port of Everett
PUGET SOUND
BAINBRIDGE ISLAND
Port of Seattle
Lake Washington
VASHON ISLAND
Port of Tacoma
5
2
522
405
520
90
167
18
16

(http://mediad.publicbroadcasting.net/p/kuow/files/styles/x_large/public/20150 map-with-legend.gif)

CREDIT U.S. GEOLOGICAL SURVEY

By the 1990s, a new consensus had formed. The Cascadia subduction zone was not only active, but it was thought to unleash a major earthquake every 500 years or so.



(http://mediad.publicbroadcasting.net/p legends-map.gif)

But that wasn't the end of the story. The more scientists looked into the geologic record, the more surprises they found.

In the early 1990s, scientists began examining rocks along the shoreline near Alki Point in West Seattle. They found evidence that sometime in the recent geologic past, those rocks had suddenly been thrust upwards by about 20 feet.

Scientists believe the cause of that big earthquake was a fault that lies right beneath our feet. The Seattle fault bisects the city west to east, from Alki Point in West Seattle, through downtown, along the I–90 corridor and all the way towards Issaquah.

Brian Sherrod, a geologist with the U.S. Geological Survey says thousands of years can separate the really big earthquakes, but smaller ones can recur every 600 or 700 years.

The last one was about 1,000 years ago.

"I just basically say that we are in the window of opportunity for a big earthquake," he said. "It could occur tomorrow, it could occur 100 years from now. It could occur 1,000 years from now. We don't know."

DSD 008348

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Janis Medley

4609 Somerset Drive SE • Bellevue, WA 98006 • 425 922 7415

The construction and operations impacts on Environmental Health were rated as negligible or minor.

Of course that might be true in a perfect world where OPL and PSE conform to all the regulatory requirements. But in the real world, ignoring their history of non-compliance is irresponsible and dangerously simplistic. Section 8.9 as written is unacceptable.

Attachments:

Eight Communications between Olympic Pipeline and WUTC and the Pipeline and Hazardous Materials Safety Adminstration

Utilities and Transportation Commission
Standard Inspection Report for Intrastate Hazardous Liquid Systems
Records Review and Field Inspection

S – Satisfactory U – Unsatisfactory N/A – Not Applicable N/C – Not Checked
If an item is marked U, N/A, or N/C, an explanation must be included in this report.

A completed **Inspection Checklist, Cover Letter and Field Report, IMP and OQ Field Validation Forms** are to be submitted to the Chief Engineer within **30 days** from completion of the inspection.

Inspection Report			
Inspection ID/ Docket Number	5821		
Inspector Name & Submit Date	Dennis Ritter, December 15, 2014		
Chief Engineer Name & Review Date	Joe Subsits, December 31, 2015		
Operator Information			
Name of Operator:	Olympic Pipe Line Company	**OPID #:**	30781
Name of Unit(s):	Laterals- Seattle, Sea Tac, Tacoma, Olympia, Vancouver		
Records Location:	Renton, WA		
Date(s) of Last Review:	June 18 – 22, 2012	**Inspection Date(s)**	November 17-20, 2014

Inspection Summary:
November 17-First day of inspection, Renton, WA Records
Nov 18-Field Seattle, SeaTac, Tacoma Laterals
Nov 19-Field Vancouver, Olympia Laterals
Exit Interview: November 20, 2014
All of the Olympic Pipeline laterals were inspected. These include the Seattle lateral (12" line, 12.83 miles long), SeaTac lateral (12" line, 5.54 miles long), Tacoma lateral (8" line, 3.72 miles long), Olympia lateral (6" line, 14.9 miles long), and Vancouver lateral (12" line, 4.4 miles long). The Olympia lateral has been out-of-service since early 2009. The 6" pipeline was purged and filled with nitrogen gas at 13 psig pressure. A section of the Olympia lateral was removed for construction of a new road at approximately MP 12.2 88th Ave. Records were reviewed in Renton WA at Renton Station. A field visit to selected facilities was conducted on Nov 18 and 19. See Field Notes for locations. Results of this inspection were as follows:

- **No. 147)** *WAC 480-75-510 Pipeline companies must initiate remedial action as necessary to correct any deficiency observed during corrosion monitoring, within ninety days after the pipeline company detects the deficiency.*
  OPL has a listing of corrosion control deficiencies. On this list are test lead stations which cannot be read and need to be dug up to repair. According to OPL personnel, this listing was originally prepared by the previous CP technician, who has been gone since 2012. It is not known when these deficiencies were found, however, it was at least prior to 2012 and mitigation has not been initiated. It cannot be determined whether the pipeline is adequately cathodically protected in these areas.
- **No. 149)** *§195.573 What must I do to monitor external corrosion control?*
  (a) Protected pipelines. You must do the following to determine whether cathodic protection required by this subpart complies with Sec. 195.571:
  (1) Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done at least once every 3 calendar years, but with intervals not exceeding 39 months.
  OPL was late in reading 3 distinct test points at the Tacoma DF for the year 2012.
- **No. 160)** *§195.583 What must I do to monitor atmospheric corrosion control?*
  (a) You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:
  If the pipeline is located: Then the frequency of inspection is:
  Onshore At least once every 3 calendar years, but with intervals not exceeding 39 months
  For the Seatac DF, Tacoma Junction, and Tacoma DF, the Maximo work order system did not have these input correctly resulting in late reads for 2014 for these assets. They should have been read in March, 2014, they were read in November, 2014.

4C

U.S. Department of Transportation

Pipeline and Hazardous Materials Safety Administration

1200 New Jersey Ave, S.E.
Washington, D.C. 20590

JAN 1 3 2016

Mr. Donald Porter
President
BP Pipelines (North America), Inc.
150 W. Warrenville Road
Naperville, IL 60563

Re: CPF No. 5-2015-5014

Dear Mr. Porter:

Enclosed please find the Final Order issued in the above-referenced case to your affiliate, Olympic Pipe Line Company. It makes findings of violation and specifies actions that need to be taken by Olympic Pipe Line Company to comply with the pipeline safety regulations. When the terms of the compliance order have been completed, as determined by the Director, Western Region, this enforcement action will be closed. Service of the Final Order by certified mail is deemed effective upon the date of mailing, or as otherwise provided under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

for: Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Chris Hoidal, Director, Western Region, OPS
Ms. Clorinda Nothstein, Operations Manager, BP Pipelines (North America), Inc.

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

U.S. DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, D.C. 20590

In the Matter of	)	
	)	
Olympic Pipe Line Company, an affiliate of BP Pipelines (North America), Inc.,	)	**CPF No. 5-2015-5014**
	)	
Respondent.	)	

FINAL ORDER

Between August 11 and 29, 2014, pursuant to 49 U.S.C. § 60117, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), and the Washington Utilities and Trade Commission (WUTC), conducted an on-site pipeline safety inspection of the facilities and records of Olympic Pipe Line Company (OPL or Respondent) in the States of Oregon and Washington. OPL is jointly owned by BP Pipelines (North America), Inc. (BPNA) and Enbridge Energy Partners, LP, and is operated by BPNA. The OPL hazardous liquid products pipeline consists of approximately 400 miles of intrastate and interstate pipelines running from Blaine, Washington, to Portland, Oregon. The system transports gasoline, diesel, and jet fuel, with a capacity of 315,000 barrels, and includes 10 breakout tanks.[1]

As a result of the inspection, the Director, Western Region, OPS (Director), issued to Respondent, by letter dated July 2, 2015, a Notice of Probable Violation and Proposed Compliance Order (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that OPL had violated 49 C.F.R. §§ 195.573 and 195.575, and proposed ordering Respondent to take certain measures to correct the alleged violations.

BPNA responded to the Notice on behalf of OPL, by letter dated August 6, 2015 (Response). Respondent did not contest the allegations of violation but provided information concerning the corrective actions it had taken since the August 2014 inspection. Respondent did not request a hearing and therefore has waived its right to one.

[1] BP Pipelines (North America), Inc., website, available at http://www.olympicpipeline.com/ (last accessed November 27, 2015).

FINDINGS OF VIOLATION

In its Response, OPL did not contest the allegations in the Notice that it violated 49 C.F.R. Part 195, as follows:

Item 1: The Notice alleged that Respondent violated 49 C.F.R. § 195.573(e), which states:

> **§ 195.573 What must I do to monitor external corrosion control?**
> (a) . . .
> (e) *Corrective action.* You must correct any identified deficiency in corrosion control as required by §195.401(b). However, if the deficiency involves a pipeline in an integrity management program under §195.452, you must correct the deficiency as required by §195.452(h).

The Notice alleged that Respondent failed to correct identified deficiencies in its corrosion control system that could adversely affect the safe operation of the pipeline, as required by 49 C.F.R. § 195.401(b). That section provides, in relevant part:

> **§ 195.401 General requirements.**
> (a) . . .
> (b) An operator must make repairs on its pipeline system according to the following requirements:
> (1) *Non Integrity management repairs.* Whenever an operator discovers any condition that could adversely affect the safe operation of its pipeline system, it must correct the condition within a reasonable time.

The Notice also alleged that Respondent violated 49 C.F.R. § 195.452(h)(1), cited in § 195.573(e), which states:

> **§ 195.452 Pipeline integrity management in high consequence areas.**
> (a) *Which pipelines are covered by this section?* This section applies to each hazardous liquid pipeline and carbon dioxide pipeline that could affect a high consequence area, including any pipeline located in a high consequence area unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. . .
> (h) *What actions must an operator take to address integrity issues?*
> (1) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment or information analysis. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the long-term integrity of the pipeline. An operator must comply with §195.422 when making a repair.

The Notice alleged that Respondent failed to correct deficiencies in its corrosion control system within a reasonable time, in accordance with § 195.401(b)(1). According to the Notice, in 2010 Respondent performed an in-line-inspection (ILI) that revealed discrepancies in the ILI data, revealing unrecorded casings on the pipeline system. Subsequent excavations performed by Respondent revealed additional unrecorded casings, sleeves, and half-sections of pipe at several locations. In 2011, OPL allegedly initiated a "Casing Wire Repairs" project to further evaluate and repair casing deficiencies within a 10-year time frame. The Notice alleged that Respondent's 10-year time frame to complete the inspections and repairs was not a reasonable period of time in which to correct the identified deficiencies.

In addition, the Notice alleged that OPL violated 49 C.F.R. § 195.452(h)(1) by failing to take prompt action to address all anomalous conditions in high consequence areas (HCAs).[2] Specifically, the Notice alleged that Respondent's "Casing Wire Repairs" project did not differentiate between anomalous conditions discovered in HCA areas versus non-HCA areas and that the company's 10-year time frame for completing the project did not constitute prompt action for remediating deficiencies found in such areas.

Respondent did not contest these allegations of violation. Accordingly, based upon a review of all of the evidence, I find that Respondent violated 49 C.F.R. §§ 195.573(e), 195.401(b)(1), and 195.452(h)(1), by failing to correct identified deficiencies in corrosion control within a reasonable time and to take prompt action to address all anomalous conditions that could affect HCAs discovered through its integrity assessment or information analysis.

Item 2: The Notice alleged that Respondent violated 49 C.F.R. § 195.575(c), which states:

> **§ 195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?**
> (a) . . .
> (c) You must inspect and electrically test each electrical isolation to assure the isolation is adequate.

The Notice alleged that Respondent violated 49 C.F.R. § 195.575(c) by failing to test the electrical isolation of each buried pipeline in the OPL system to assure that the isolation was adequate. Specifically, the Notice alleged the Respondent failed to test the electrical isolation of previously unrecorded casings, as described in Item 1 above, to ensure that the isolation from other metallic structures was adequate. The Notice alleged that several casings were not present on alignment sheets or other cathodic protection records, indicating previously unrecorded pipelines had not been tested for adequate isolation.

Respondent did not contest this allegation of violation. Accordingly, based upon a review of all of the evidence, I find that Respondent violated 49 C.F.R. 49 C.F.R. § 195.575(c), by failing to

---

[2] An HCA is defined as: (1) a *commercially navigable waterway*, which means a waterway where a substantial likelihood of commercial navigation exists; (2) a *high population area*, which means an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 per square mile; (3) an *other populated area*, which means a place, as defined and delineated by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area; and (4) an *unusually sensitive area*. *See* 49 C.F.R. § 195.450.

test the electrical isolation of each buried pipeline to assure that the isolation was adequate.

These findings of violation will be considered prior offenses in any subsequent enforcement action taken against Respondent.

COMPLIANCE ORDER

The Notice proposed a compliance order with respect to Items 1 and 2 in the Notice for violations of 49 C.F.R. §§ 195.573(e) and 195.575(c), respectively. Under 49 U.S.C. § 60118(a), each person who engages in the transportation of hazardous liquids or who owns or operates a pipeline facility is required to comply with the applicable safety standards established under chapter 601. In its Response, OPL indicated that it had taken certain actions to comply with the Proposed Compliance Order. The Director has reviewed such actions and recommended that this Compliance Order be modified accordingly. Therefore, pursuant to the authority of 49 U.S.C. § 60118(b) and 49 C.F.R. § 190.217, Respondent is ordered to take the following actions to ensure compliance with the pipeline safety regulations applicable to its operations:

1. With respect to the violations of § 195.573(e) **(Item 1)** and § 195.575(c) **(Item 2)**, Respondent must:

   A. Schedule the "Casings Wire Repair" project to mitigate all remaining indications in HCAs and non-HCAs no later than 18 months from the date of this Order;

   B. Determine whether additional casings exist on its pipeline. Update maps and records, as necessary, to ensure all programmatic systems which use this data, including IMP, are accurate; and

   C. Submit changes to the "Casing Wire Repair" project within 30 days after the receipt of this Final Order to Mr. Chris Hoidal, Director, Western Region, Pipeline and Hazardous Materials Safety Administration.

2. It is requested (not mandated), that Respondent maintain documentation of the safety improvement costs associated with fulfilling this Final Order and submit the total to Mr. Chris Hoidal, Director, Western Region, Pipeline and Hazardous Materials Safety Administration. It is requested these costs be reported in two categories: 1) total costs associated with preparation/revision of plans, procedures, studies an analyses; and 2) total cost associated with replacements, additions and other changes to pipeline infrastructure.

The Director may grant an extension of time to comply with any of the required items upon a written request timely submitted by the Respondent and demonstrating good cause for an extension.

Failure to comply with this Order may result in the administrative assessment of civil penalties not to exceed $200,000 for each violation for each day the violation continues or in referral to the Attorney General for appropriate relief in a district court of the United States.

Under 49 C.F.R. § 190.243, Respondent has a right to submit a Petition for Reconsideration of this Final Order. The petition must be sent to: Associate Administrator, Office of Pipeline Safety, PHMSA, 1200 New Jersey Avenue, SE, East Building, 2nd Floor, Washington, DC 20590, with a copy sent to the Office of Chief Counsel, PHMSA, at the same address. PHMSA will accept petitions received no later than 20 days after receipt of service of this Final Order by the Respondent, provided they contain a brief statement of the issue(s) and meet all other requirements of 49 C.F.R. § 190.243. Unless the Associate Administrator, upon request, grants a stay, the terms and conditions of this Final Order are effective upon service in accordance with 49 C.F.R. § 190.5.

for: Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

JAN 13 2016
Date Issued

4B

NOTICE OF PROBABLE VIOLATION
and
PROPOSED COMPLIANCE ORDER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

July 2, 2015

Mr. Donald Porter
President
BP Pipeline NA
Olympic Pipe Line Company
150 W. Warrenville Rd.
Naperville, IL 60563

CPF 5-2015-5014

Dear Mr. Porter:

Between August 11 and August 29, 2014, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA), and Washington Utilities and Trade Commission (WUTC), pursuant to Chapter 601 of 49 United States Code, inspected your Olympic Pipe Line Co. (OPL) system in the States of Oregon and Washington.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

1. **§195.573 What must I do to monitor external corrosion control?**
   (e) Corrective action. You must correct any identified deficiency in corrosion control as required by Sec. 195.401(b). However, if the deficiency involves a pipeline in an integrity management program under Sec. 195.452, you must correct the deficiency as required by Sec. 195.452(h).

OPL failed to correct identified deficiencies in corrosion control as required by Sec. 195.401(b) and Sec. 195.452(h). After a 2010 in-line-inspection (ILI), OPL found discrepancies in the ILI data that indicated the presence of unrecorded casings on the pipeline system. OPL subsequently performed excavations which revealed casings, sleeves, or half sections of pipe at these locations. Some of these casings OPL knew about, but many were previously unknown by the operator's staff. In 2011, OPL initiated the "Casing Wire Repairs" project to evaluate ILI indications that suggested the presence of these casings, investigate the indications, and either remove the casing or add test leads to inspect and test for casing isolation.

Section 195.401(b) requires OPL to correct "any condition that could adversely affect the safe operation of its pipeline system… within a reasonable time." Section 195.452(h) requires OPL to take "prompt action to address all anomalous conditions the operator discovers" in high consequence areas (HCAs). As of August 2014, OPL had mitigated about 100 of the ILI indications, with 97 suspected casings remaining to evaluate. OPL's projected timeline for completion is 2020. OPS alleges that 10 years to correct these anomalies is not a reasonable or prompt schedule. In addition, the written Casing Wire Repair project does not differentiate between HCA versus non-HCA locations when prioritizing casing investigation digs.

2. § 195.575 Which facilities must I electrically isolate and what inspections, tests, and safeguards are required?
(a) You must electrically isolate each buried or submerged pipeline from other metallic structures, unless you electrically interconnect and cathodically protect the pipeline and the other structures as a single unit.
(b) You must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.
(c) You must inspect and electrically test each electrical isolation to assure the isolation is adequate.

OPL failed to test the electrical isolation of each buried pipeline to ensure the isolation from other metallic structures was adequate. Casings are buried metallic structures in close proximity to the pipeline. As described in Item 1 above, OPL has discovered casings and casing test leads on the pipeline that were not on alignment sheets or other cathodic protection records. The electrical isolation of the previously-unrecorded casings was not tested to assure adequate isolation from the pipeline.

Proposed Compliance Order

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $200,000 per violation per day the violation persists up to a maximum of $2,000,000 for a related series of violations. For violations occurring prior to January 4, 2012, the maximum penalty may not exceed $100,000 per violation per day, with a maximum penalty not to exceed $1,000,000 for a related series of violations.

We have reviewed the circumstances and supporting documents involved in this case, and have decided not to propose a civil penalty assessment at this time.

With respect to Items 1 and 2 pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration proposes to issue a Compliance Order to OPL. Please refer to the *Proposed Compliance Order*, which is enclosed and made a part of this Notice.

Response to this Notice

Enclosed as part of this Notice is a document entitled *Response Options for Pipeline Operators in Compliance Proceedings*. Please refer to this document and note the response options. Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b). If you do not respond within 30 days of receipt of this Notice, this constitutes a waiver of your right to contest the allegations in this Notice and authorizes the Associate Administrator for Pipeline Safety to find facts as alleged in this Notice without further notice to you and to issue a Final Order.

In your correspondence on this matter, please refer to **CPF 5-2015-5014** and for each document you submit, please provide a copy in electronic format whenever possible.

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

Enclosures: *Proposed Compliance Order*
Response Options for Pipeline Operators in Compliance Proceedings

cc: PHP-60 Compliance Registry
PHP-500 C. Allen (Activities: 147690 and 147691)
WUTC

Pursuant to 49 United States Code § 60118, the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposes to issue to Olympic Pipeline Company (OPL) a Compliance Order incorporating the following remedial requirements to ensure the compliance of OPL with the pipeline safety regulations:

1. In regard to Items 1 and 2 of the Notice, OPL must make the following changes to the Casing Wire Repairs project:
   a. OPL must schedule the project to mitigate all remaining indications no later than 30 months from the date of the Final Order.
   b. OPL must determine whether additional casings exist on their pipeline and update maps and records as necessary to ensure all programmatic systems which use this data, including IMP, are accurate.
   c. The project must prioritize HCAs when scheduling casing investigation digs. All indications within HCAs must be completed no later than 18 months from the date of the Final Order.
   d. OPL must submit the changes to the Casing Wire Repair project within 30 days after receipt of the Final Order.

2. OPL must submit annual status reports to the Director regarding the status of the Casing Wire Project, with the first report due January 15, 2016.

3. PHMSA requests that OPL maintain documentation of the safety improvement costs associated with fulfilling this Compliance Order and submit the total to Chris Hoidal, Director, Western Region, Pipeline and Hazardous Materials Safety Administration. It is requested that these costs be reported in two categories: 1) total cost associated with preparation/revision of plans, procedures, studies and analyses, and 2) total cost associated with replacements, additions and other changes to pipeline infrastructure.

4A

bp

03-07-15 12:12 RCVD

Donald W. Porter
President
BP Pipelines (North America) Inc.

BP Pipelines (North America) Inc.
150 W. Warrenville Road
Suite 605-3501K
Naperville, IL 60563

SENT VIA FED-EX

August 6, 2015

Mr. Chris Hoidal, P.E.
Director, Western Region
Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
12300 W. Dakota Avenue, Suite 110
Lakewood, CO 80228

Re: Notice of Probable Violation/Proposed Compliance Order CPF 5-2015-5014

Dear Mr. Hoidal:

This letter is in response to the Pipeline & Hazardous Materials Safety Administration's (PHMSA's) Notice of Probable Violation (NOPV) and Proposed Compliance Order (PCO) dated July 2, 2015, and received by BP on July 7, 2015 that resulted from a hazardous liquid standard inspection that was conducted between August 11 and 29, 2014 on the Olympic Pipe Line Company (OPL) system by representatives from PHMSA and the Washington Utilities and Transportation Commission (WUTC).

BP Pipelines (North America) Inc., operator of OPL, is not contesting the NOPV or PCO but wishes to submit additional information to clarify the alleged findings and PCO remedial requirements and timeframes. For ease of reference, the code citations along with PHMSA and WUTC's findings are restated below in italics and are followed by BP's response.

Probable Violations

1. **49 CFR §195.573 What must I do to monitor external corrosion control?**

   (e) Corrective action. You must correct any identified deficiency in corrosion control as required by Sec. 195.401(b). However if the deficiency involves a pipeline in an integrity management program under Sec. 195.452, you must correct the deficiency as required by Sec. 195.452(h).

   Finding(s):
   OPL failed to correct identified deficiencies in corrosion control as required by Sec 195.401(b) and Sec. 195.452(h). After a 2010 in-line-inspection (ILI), OPL found discrepancies in the ILI data that indicated the presence of unrecorded casings on the

pipeline system. OPL subsequently performed excavations which revealed casings, sleeves, or half sections of pipe at these locations. Some of these casings OPL knew about, but many were previously unknown by the operator's staff. In 2011, OPL initiated the "Casing Wire Repairs" project to evaluate ILI indications that suggested the presence of these casings, investigate the indications, and either remove the casing or add test leads to inspect and test for casing insolation.

Section 195.401(b) requires OPL to correct "any condition that could adversely affect the safe operation of its pipeline system...within a reasonable time." Section 195.452(h) requires OPL to take "prompt action to address all anomalous conditions the operator discovers" in high consequence areas (HCAs). As of August 2014, OPL had mitigated about 100 of the ILI indications, with 97 suspected casings remaining to evaluate. OPL's projected timeline for completion is 2020. OPS alleges that 10 years to correct these anomalies is not a reasonable or prompt schedule. In addition, the written Casing Wire Repair project does not differentiate between HCA versus non-HCA locations when prioritizing casing investigation digs.

BP Response:
Since the August 2014 audit, OPL has further analyzed data to identify the number of remaining sites needing resolution and has found that there were 120 sites in need of further investigation. Through July 2015, OPL has mitigated 74 of 120 possible casing locations, resulting in a total of 46 potential casing locations that require additional investigation to resolve.

Thus far, further investigation including field activities has resulted in the following resolutions:

Already monitored: reconciled/updated data systems	33/120
New test station installed	25/120
Casing removed or did not exist	16/120

The remaining 46 potential casing sites are all in HCA locations (42 Direct HCA, 4 Indirect HCA) and will be scheduled for resolution in accordance with the PHMSA Final Order. Any delays due to permitting approval timeframes, site access/landowner issues, and construction/weather/fish windows that could compromise compliance with the Final Order timeframes will be identified and communicated to PHMSA for awareness on a case-by-case basis and when necessary, will include a request for assistance and extension for time.

2. 49 CFR §195.575 Which facilities must I electrically isolate and what inspections, test, and safeguards are required?

(a) You must electrically isolate each buried or submerged pipeline from other metallic structures, unless you electrically interconnect and cathodically protect the pipeline and the other structures as a single unit.

(b) You must install one or more insulating devices where electrical isolation of a portion of a pipeline is necessary to facilitate the application of corrosion control.

(c) You must inspect and electrically test each electrical isolation to assure the isolation is adequate.

Finding(s):
OPL failed to test the electrical isolation of each buried pipeline to ensure the isolation from other metallic structures was adequate. Casings are buried metallic structures in close proximity to the pipeline. As described in Item 1 above, OPL has discovered casings and casing test leads on the pipeline that were not on alignment sheets or other cathodic protection records. The electrical isolation of the previously-unrecorded casings was not tested to assure adequate isolation from the pipeline.

BP Response:
As noted in BP's response for item 1 above, not all potential casing locations have been determined to be actual casing locations because of the analysis and field validation that is necessary to provide resolution. OPL is in the process of resolving the remaining 46 sites to determine which sites are actual casing locations and to assure test stations are in place at these sites to test for electrical isolation. While ILI metal loss and deformation tool data is not and cannot be used in determining electrical isolation from metallic structures, it is used to assess pipe integrity at these locations, and to date there have been no pipeline integrity concerns at these locations.

Regarding the Proposed Compliance Order, BP does not have any additional comments or concerns other than unforeseen delays in the permitting, site access, or construction timeframes and will escalate as needed any site that may be at risk of on-time completion.

If you have any questions, please feel free to contact Dave Barnes at (630) 536-3419 or (331) 702-4292.

Sincerely,

Donald W. Porter
President
BP Pipelines (North America) Inc.

cc: Ms. Clorinda Nothstein, Operations Manager, BP Pipelines (North America) Inc.
File copy

Enforcement Action Details

OLYMPIC PIPE LINE COMPANY

Case CPF 520155014

This report lists key information pertaining to a particular enforcement case(1). For cases initiated after January 1, 2007, electronic files of PHMSA's initial notice letter, the operator's initial response letter (if any), and PHMSA's Final Order (if an Order is issued) are provided. PHMSA only issues Final Orders in certain situations. For example, Final Orders are not issued for Warning Letters and most Notices of Amendment.

Case Summary | Documents

The Response Options for Pipeline Operators in Compliance Proceedings provides a more detailed description of an operator's options in responding to enforcement cases. This document accompanies all NOPV and NOA letters. The document linked here is the current version. The corresponding document at the time the case was opened may differ from the current version.

The set of documents provided here may be incomplete.

Name	Size	Notes
520155014_Final Order_01132016.pdf	294 KB	scanned version
520155014_Final Order_01132016_text.pdf	25 KB	accessible version
✓ 520155014_NOPV PCO_07022015.pdf	97 KB	scanned version
520155014_NOPV PCO_07022015_text.pdf	16 KB	accessible version
✓ 520155014_Operator Response to Notice_08062015.pdf	60 KB	scanned version

NOTE: Most documents provided on these pages are in PDF format. To read them, you may need to download a free viewer.

Also see

- Enforcement Home Page
- Inspection and Enforcement Process Flow Chart
- Additional Information on Regulatory Enforcement Mechanisms and Operator Compliance
- Enforcement Information on a Specific Pipeline Operator
- National Pipeline Mapping System

Sources

1. PHMSA Safety Monitoring and Reporting Tool (SMART) for the Pipeline Safety Enforcement Tracking System as of February 11, 2016.

3A

WARNING LETTER

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

March 27, 2015

Mr. Donald Porter
President
Olympic Pipe Line Company
BP Pipeline NA
150 W. Warrenville Rd.
Naperville, IL 60563

CPF 5-2015-5009W

Dear Mr. Porter:

Between August 11, 2014 and August 29, 2014, representatives of the Pipeline and Hazardous Materials Safety Administration (PHMSA) and Washington Utilities and Transportation Commission (WUTC), pursuant to Chapter 601 of 49 United States Code, inspected your Olympic Pipe Line (OPL) system in the States of Oregon and Washington.

As a result of the inspection, it appears that you have committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The items inspected and the probable violations are:

1. **§195.573 What must I do to monitor external corrosion control?**

(a) Protected pipelines. You must do the following to determine whether cathodic protection required by this subpart complies with Sec. 195.571:
(1) Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done at least once every 3 calendar years, but with intervals not exceeding 39 months.

Olympic Pipe Line Co (OPL) did not comply with §195.573(a)(1) in 2012 and 2013. Prior to our inspection, OPL personnel met with WUTC representatives to disclose that their annual pipe-to-soil potential tests conducted between 2012 and 2013 exceeded the maximum testing interval of 15 months. Our review of OPL's test records for annual pipe-to-soil potential readings, which determine adequacy of cathodic protection (CP), confirmed that the CP inspections exceeded the maximum inspection frequency a total of 121 times between 2012 and 2013.

Specifically, the number of late test readings are as follows:

- 78 late annual pipe-to-soil readings in 2013 for the North Unit of Washington State (Cherry Pt. to Renton Station), and
- 20 late annual pipe-to-soil readings in 2012, and 23 late annual pipe-to-soil readings in 2013 for the South Unit of Washington State (Renton Station to WA/OR State Boundary).

2. §195.573 What must I do to monitor external corrosion control?

(c) Rectifiers and other devices. You must electrically check for proper performance each device in the first column at the frequency stated in the second column.

Device	Check frequency
Rectifier................................ Reverse current switch. Diode. Interference bond whose failure would jeopardize structural protection (critical bond).	**At least six times each calendar year, but with intervals not exceeding 2 ½ months**
Other interference bond............	**At least once each calendar year, but with intervals not exceeding 15 months.**

OPL did not comply with Part 195.573(c) which requires checking the rectifier and critical bond devices for proper performance. OPL personnel met with WUTC representatives to disclose their rectifier and critical bond checks exceeded the time monitoring intervals required by Part 195.573(c). Our review of records confirmed there was a total of six (6) rectifier or bond checks that exceeded the maximum time monitoring intervals for inspection. The late readings are as follows:

- Three (3) late rectifier readings and two (2) late critical bond readings in 2013 for the OPL North Unit of Washington State, and
- One (1) late critical bond readings in 2013 for the OPL South Unit of Washington State

3. **§195.589 What corrosion control information do I have to maintain?**

(c) You must maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. You must retain these records for at least 5 years, except that records related to Secs. 195.569, 195.573(a) and (b), and 195.579(b)(3) and (c) must be retained for as long as the pipeline remains in service.

OPL failed to fully follow their corrosion control procedures, OPL Procedure P195.551.2.2 states, "*Any AC interference on pipeline 15 Volts AC or greater will be investigated and remediated as necessary*." Furthermore, investigation records were not produced during the inspection to show implementation of your corrosion control procedures. It was noted that OPL did not maintain records for investigating potential AC interference. The number of AC readings that exceeded 15 Volts AC is as follows:

- Four (4) in 2011 and ten (10) in 2013 for the North Unit of Washington State, and Eight (8) in 2011 and six (6) in 2013 for the South Unit of Washington State (primarily in King County).

4. **§195.583 What must I do to monitor atmospheric corrosion control?**

(a) You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	**Then the frequency of inspection is:**
Onshore……………………………………	**At least once every 3 calendar years, but with intervals not exceeding 39 months.**
Offshore…………………………………	**At least once each calendar year, but with intervals not exceeding 15 months.**

OPL did not comply with Part 195.583(a) for inspecting each pipeline or portion of pipeline for evidence of atmospheric corrosion. During the field inspection, it was noted that metal jacketed insulation on prover pipe at several of the pump stations prevented actual inspection of the pipeline for atmospheric corrosion. Pipelines with removable insulation jackets or non-removable jackets with inspection ports must be inspected at least once every 3 years (not to exceed 15 months) for evidence of atmospheric corrosion.

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $200,000 per violation per day the violation persists up to a maximum of $2,000,000 for a related series of violations. For violations occurring prior to January 4, 2012, the maximum penalty may not exceed $100,000 per violation per day, with a maximum penalty not to exceed $1,000,000 for a related series of violations. We have reviewed the circumstances and supporting documents involved in this case, and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to correct the items identified in this letter. Failure to do so will result in Olympic Pipe Line Co being subject to additional enforcement action.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 5-2015-5009W.** Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP-500 C. Allen and WUTC

Item 1 through 4 – Activity #147690 and #147691

Enforcement Action Details

OLYMPIC PIPE LINE COMPANY

Case CPF 520155009W

This report lists key information pertaining to a particular enforcement case[1]. For cases initiated after January 1, 2007, electronic files of PHMSA's initial notice letter, the operator's initial response letter (if any), and PHMSA's Final Order (if an Order is issued) are provided. PHMSA only issues Final Orders in certain situations. For example, Final Orders are not issued for Warning Letters and most Notices of Amendment.

Case Summary | Documents

The Response Options for Pipeline Operators in Compliance Proceedings provides a more detailed description of an operator's options in responding to enforcement cases. This document accompanies all NOPV and NOA letters. The document linked here is the current version. The corresponding document at the time the case was opened may differ from the current version.

The set of documents provided here may be incomplete.

Name	Size	Notes
✓ 520155009W_warning letter_03272015.pdf	95 KB	scanned version
520155009W_warning letter_03272015_text.pdf	20 KB	accessible version

NOTE: Most documents provided on these pages are in PDF format. To read them, you may need to download a free viewer.

Also see

- Enforcement Home Page
- Inspection and Enforcement Process Flow Chart
- Additional Information on Regulatory Enforcement Mechanisms and Operator Compliance
- Enforcement Information on a Specific Pipeline Operator
- National Pipeline Mapping System

Sources

1. PHMSA Safety Monitoring and Reporting Tool (SMART) for the Pipeline Safety Enforcement Tracking System as of February 11, 2016.

For comments and questions on the enforcement information presented on this site, please send us feedback.

Check each critical bond
at intervals not exceeding 2 ½ months

2

U.S. Department
of Transportation

**Pipeline and
Hazardous Materials Safety
Administration**

12300 W. Dakota Ave., Suite 110
Lakewood, CO 80228

WARNING LETTER

<u>CERTIFIED MAIL - RETURN RECEIPT REQUESTED</u>

January 15, 2013

Mr. Steve Pankhurst
President
Olympic Pipe Line Company
150 W. Warrenville Rd.
Naperville, IL 60563

CPF 5-2013-5001W

Dear Mr. Pankhurst:

On October 30-November 1, 2012, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), pursuant to Chapter 601 of 49 United States Code, inspected your operations and maintenance (O&M) procedures and records in Renton, Washington and performed a field evaluation of your facility in Portland, Oregon.

As a result of the inspection, it appears that you have committed a probable violation of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations. The item inspected and the probable violation(s) are:

1. **§195.573 What must I do to monitor external corrosion control?**

(c) Rectifiers and other devices. You must electrically check for proper performance each device in the first column at the frequency stated in the second column.

<u>Device</u>	**<u>Check frequency</u>**
Interference bond whose failure would jeopardize structural protection.	**At least six times each calendar year, but with intervals not exceeding 2 ½ months**

Per §195.573, the operator must electrically check for proper performance each critical bond at least six times each calendar year, but with intervals not exceeding 2 ½ months. At the time of the inspection, records required by 195.589(c) indicated that the check for each critical bond was not performed within the required time interval referenced in 195.573(c). The PD-AR-14 (Portland Delivery) to ARCO records for 2010 show that a critical bond was checked on April 5, 2010 and August 25, 2010. The two and half month maximum time interval between test dates was exceeded by 65 days in 2010. Olympic Pipe Line Company must electrically check at the required time intervals.

Under 49 United States Code, § 60122, you are subject to a civil penalty not to exceed $200,000 per violation per day the violation persists up to a maximum of $2,000,000 for a related series of violations. For violations occurring prior to January 4, 2012, the maximum penalty may not exceed $100,000 per violation per day, with a maximum penalty not to exceed $1,000,000 for a related series of violations We have reviewed the circumstances and supporting documents involved in this case, and have decided not to conduct additional enforcement action or penalty assessment proceedings at this time. We advise you to correct the item(s) identified in this letter. Failure to do so will result in Olympic Pipe Line Company being subject to additional enforcement action.

No reply to this letter is required. If you choose to reply, in your correspondence please refer to **CPF 5-2013-5001W.** Be advised that all material you submit in response to this enforcement action is subject to being made publicly available. If you believe that any portion of your responsive material qualifies for confidential treatment under 5 U.S.C. 552(b), along with the complete original document you must provide a second copy of the document with the portions you believe qualify for confidential treatment redacted and an explanation of why you believe the redacted information qualifies for confidential treatment under 5 U.S.C. 552(b).

Sincerely,

Chris Hoidal
Director, Western Region
Pipeline and Hazardous Materials Safety Administration

cc: PHP-60 Compliance Registry
PHP-500 D. Hubbard (#138089)

U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration

1200 New Jersey Ave, S.E.
Washington, D.C. 20590

NOV 23 2009

VIA CERTIFIED MAIL – RETURN RECEIPT REQUESTED [7009 1410 0000 2464 5775]

Mr. Steve Pankhurst
President
BP Pipelines (North America) Inc.
U.S. Pipelines and Logistics
28100 Torch Parkway
Warrenville, IL 60555

Re: CPF No. 5-2006-5034

Dear Mr. Pankhurst:

Enclosed is this agency's decision denying your company's Petition for Reconsideration in this case. The penalty payment terms are set forth in the Final Order. This enforcement action closes automatically upon payment. Your receipt of this Decision constitutes service of that document under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Chris Hoidal, P.E., Director, Western Region, PHMSA

Mr. David O. Barnes, P.E.
Manager DOT & Integrity
BP Pipelines (North America) Inc.

SEP 01 2009

Mr. Jim Lamanna
President
BP Pipelines (North America) Inc.
Olympic Pipe Line Company
28100 Torch Parkway
Warrenville, IL 60555

Re: CPF No. 5-2006-5034

Dear Mr. Lamanna:

Enclosed is the Final Order issued in the above-referenced case. It makes a finding of violation and assesses a civil penalty of $23,000. It further finds that you have completed the actions specified in the Notice required to comply with the pipeline safety regulations. When the civil penalty is paid, this enforcement action will be closed. Your receipt of the Final Order constitutes service of that document under 49 C.F.R. § 190.5.

Thank you for your cooperation in this matter.

Sincerely,

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Enclosure

cc: Mr. Chris Hoidal, Director, Western Region, PHMSA

CERTIFIED MAIL – RETURN RECEIPT REQUESTED **[7005 0390 0005 6162 5791]**

DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION
OFFICE OF PIPELINE SAFETY
WASHINGTON, DC 20590

In the Matter of	)	
	)	
BP Pipelines (North America), Inc.,	)	
	)	**CPF No. 5-2006-5034**
Respondent.	)	
	)	

FINAL ORDER

From February 27 to March 2, 2006, pursuant to 49 U.S.C. § 60117, a representative of the Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), inspected a 15-mile portion of BP Pipelines (North America), Inc.'s (Respondent's or BP's) Olympic Pipeline and related facilities near Portland, Oregon, as well as Respondent's operation and maintenance records at its Renton, Washington office. Located entirely within a High Consequence Area (HCA),[1] the relevant portion of the Olympic Pipeline originates at the Washington-Oregon border near the Columbia River and transports petroleum products to delivery facilities and terminals along the Williamette River.

As a result of the inspection, the Director, Western Region, PHMSA, issued to Respondent, by letter dated September 8, 2006, a Notice of Probable Violation, Proposed Civil Penalty, and Proposed Compliance Order (Notice). In accordance with 49 C.F.R. § 190.207, the Notice proposed finding that Respondent had violated 49 C.F.R. § 195.432(b), assessing a civil penalty of $23,000, and ordering Respondent to take certain measures to correct the alleged violation.

BP responded to the Notice by letters dated October 16 and November 9, 2006 (Response). Respondent did not contest the allegation of violation, but provided information concerning the corrective actions it had taken and requested that the civil penalty be reduced or eliminated. Respondent also waived its right to an informal hearing.

[1] An HCA is defined for purposes of Part 195 as a "commercially navigable waterway, . . . [a] high population area, . . . [a]n other populated area, . . . [or] [a]n unusually sensitive area . . ." 49 C.F.R. § 195.450. A commercially navigable waterway is "a waterway where a substantial likelihood of commercial navigation exists;" a high population area is "an urbanized area, as defined and delineated by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1,000 people per square mile;" an other populated area is "a place, as defined by the Census Bureau, that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area." *Id;* and, an unusually sensitive area is "a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release." 49 C.F.R. § 195.6.

FINDING OF VIOLATION

Item 1 of the Notice alleged that BP violated 49 C.F.R. Part 195, which states:

> **§ 195.432 Inspection of in-service breakout tanks.**
> (a) …
> (b) Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel above-ground breakout tanks according to section 4 of API Standard 653….

The Notice alleged that Respondent violated 49 C.F.R. § 195.432(b) by failing to properly inspect the physical integrity of two in-service atmospheric and low-pressure steel above-ground breakout tanks according to section 4 of API Standard 653. BP has not disputed the allegation. Accordingly, I find that Respondent violated § 195.432(b) by failing to properly inspect the physical integrity of two in-service atmospheric and low-pressure steel above-ground breakout tanks according to section 4 of API Standard 653.

This finding of violation will be considered a prior offense in any subsequent enforcement action taken against Respondent.

ASSESSMENT OF PENALTY

Under 49 U.S.C. § 60122, Respondent is subject to a civil penalty not to exceed $100,000 per violation for each day of the violation up to a maximum $1,000,000 for any related series of violations.

49 U.S.C. § 60122 and 49 C.F.R. § 190.225 require that, in determining the amount of the civil penalty, I consider the following criteria: the nature, circumstances, and gravity of the violation, including adverse impact on the environment; the degree of Respondent's culpability; the history of Respondent's prior offenses; Respondent's ability to pay the penalty and any effect that the penalty may have on its ability to continue doing business; and the good faith of Respondent in attempting to comply with the pipeline safety regulations. In addition, I may consider the economic benefit gained from the violation without any reduction because of subsequent damages, and such other matters as justice may require.

The Notice proposed a total civil penalty of $23,000 for violation of 49 C.F.R. § 195.432(b). Respondent argues that the proposed civil penalty should be reduced or eliminated. In particular, BP states that its consultant completed an analysis of the two breakout tanks at issue after the OPS inspection, and that the contractor's analysis showed that neither of those tanks posed "an imminent threat to public safety . . ."[2] BP also contends that these post-inspection actions show that it "continues to act within the spirit of the regulations, which are designed to foster continuous improvement of safety

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[2] Response at 2.

programs."[3] For these reasons, BP argues that a compliance order is not necessary and that a reduction or elimination of the proposed civil penalty is warranted.

Respondent's arguments are not persuasive. First, BP knew that it had to conduct an engineering evaluation of these two breakout tanks several years prior to the 2006 OPS inspection. Specifically, Respondent's 2001 inspection records note that the out-of-plane-edge settlement of these tanks did not comply with API's guidelines, and that an engineering analysis of the tanks was required.

BP did not conduct the recommended engineering analysis for the next five years and only did so when prompted by the OPS inspection. Contrary to Respondent's assertions, such inaction and delay clearly undermined public safety. While the results of its belated engineering analysis ultimately showed that the nature of the threat was not serious, the fact that Respondent failed to act promptly potentially placed the health and welfare of the public in jeopardy. Respondent's conduct was not consistent with the text or spirit of the pipeline regulations.

With regard to the statutory factors, the unusual length of time from discovery to remediation aggravates the gravity of this particular offense. It is also true, as BP states, that PHMSA considers the "good faith" of an operator in calculating and assessing civil penalties. However, such good faith is ordinarily limited to only those actions that an operator took in a reasonable attempt to achieve compliance before an inspection or enforcement action. Indeed, once a violation is discovered, PHMSA expects any prudent operator to cooperate in remediating and preventing a reoccurrence of that condition. Respondent also has the ability to pay this penalty without adversely affecting its ability to continue in business.

Accordingly, having reviewed the record and considered the assessment criteria, I assess Respondent a total civil penalty of $23,000 for failing to perform the necessary engineering analysis or properly evidencing why an analysis was not required at the time of inspection.

Payment of the civil penalty must be made within 20 days of service. Federal regulations (49 C.F.R. § 89.21(b)(3)) require this payment be made by wire transfer, through the Federal Reserve Communications System (Fedwire), to the account of the U.S. Treasury. Detailed instructions are contained in the enclosure. Questions concerning wire transfers should be directed to: Financial Operations Division (AMZ-341), Federal Aviation Administration, Mike Monroney Aeronautical Center, P.O. Box 25082, Oklahoma City, OK 73125; (405) 954-8893.

COMPLIANCE ORDER

The Notice proposed a Compliance Order with respect to Item 1 in the Notice for violation of 49 C.F.R. Part 195.

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[3] *Id.*

Under 49 U.S.C. § 60118(a), each person who engages in the transportation of gas or who owns or operates a pipeline facility is required to comply with the applicable safety standards established under chapter 601. The Director has indicated that Respondent has satisfactorily completed the following actions specified in the Proposed Compliance Order:

1. 49 C.F.R. § 195.432(b) -- With regard to the violation described in Item 1 of the Notice, in its Responses BP included the final reports for the engineering analysis of breakout tanks 105 and 106 that were undertaken after the PHMSA inspection to ensure the out-of-plane settlements were within the specified API 653 limits. The Director, Western Region, PHMSA has reviewed this information and indicated it satisfies the terms of the proposed Compliance Order.

Accordingly, since compliance has been achieved with respect to this violation, the compliance terms are not included in this Order.

Under 49 C.F.R. § 190.215, Respondent has the right to submit a petition for reconsideration of this Final Order. Should Respondent elect to do so, the petition must be received within 20 days of Respondent's receipt of this Final Order and must contain a brief statement of the issue(s). The filing of a petition automatically stays the payment of any civil penalty assessed. However if Respondent submits payment for the civil penalty, the Final Order becomes the final administrative decision and the right to petition for reconsideration is waived. The terms and conditions of this Final Order shall be effective upon receipt

Jeffrey D. Wiese
Associate Administrator
for Pipeline Safety

Date Issued

SS2	Seattle - 3	Sole Source Aquifer	Cross Valley Aquifer
HP3	Seattle - 3	Historic Building	North Creek School
HP4	Seattle - 3	Historic Building	Winningham Farm
HP5	Seattle - 3	Historic Building	Bates--Tanner Farm
HP6	Seattle - 3	Historic Building	Bothell Pioneer Cemetery
HP7	Seattle - 3	Historic Building	Chase, Dr. Reuben, House
HP8	Seattle - 3	Historic Building	Hollywood Farm
HP9	Seattle - 3	Historic Building	USCGC FIR
HP10	Seattle - 3	Historic Building	Turner-Koepf House
HP11	Seattle - 3	Historic Building	14th Avenue South Bridge
HP12	Seattle - 3	Historic Building	Cooper, Frank B., Elementary School
HP13	Seattle - 3	Historic Building	Seattle Public Library
HP14	Seattle - 3	Historic Building	Columbia City Historic District
HP15	Seattle - 3	Historic Building	Old Georgetown City Hall
HP16	Seattle - 3	Historic Building	Pacific Coast Company House No. 75
HP17	Seattle - 3	Historic Building	Building No. 105, Boeing Airplane Company
PK12	Seattle - 3	Park	Gold Creek County Park
PK13	Seattle - 3	Park	E Norway Hill Park
PK14	Seattle - 3	Park	Sammamish River Regional Park
PK15	Seattle - 3	Park	Mark Twain Park
PK16	Seattle - 3	Park	Willows Creek Neighborhood Park
PK17	Seattle - 3	Park	Grass Lawn Park
PK18	Seattle - 3	Park	King County Park
PK19	Seattle - 3	Park	Bridle Trails State Park
PK20	Seattle - 3	Park	Cherry Crest Park
PK21	Seattle - 3	Park	Bellevue Highlands Park
PK22	Seattle - 3	Park	Kelsey Creek Park
PK23	Seattle - 3	Park	Bannerwood Park
PK24	Seattle - 3	Park	Woodridge Park
PK25	Seattle - 3	Park	Robinswood Park
PK26	Seattle - 3	Park	Sweyolocken Park
PK27	Seattle - 3	Park	Sunset Ravine Park
PK28	Seattle - 3	Park	Jefferson Park
PK29	Seattle - 3	Park	Eastgate Park
PK30	Seattle - 3	Park	Puget Park
PK31	Seattle - 3	Park	Coal Creek Park
PK32	Seattle - 3	Park	Dearborn Park
PK33	Seattle - 3	Park	Hazelwood Park
PK34	Seattle - 3	Park	Atlantic City Park
PK35	Seattle - 3	Park	May Creek Park
PK36	Seattle - 3	Park	Kennydale Lions Park
PK37	Seattle - 3	Park	Lakeridge Park
SC30	Seattle - 3	School	Sunnyside Preschool and Kindergarten School Lake Stevens Campus
SC31	Seattle - 3	School	East Everett School
SC32	Seattle - 3	School	Cavelero Mid High School
SC33	Seattle - 3	School	Prove High School
SC34	Seattle - 3	School	Swans Trail School
SC35	Seattle - 3	School	Seattle Hill Elementary School
SC36	Seattle - 3	School	Small World Montessori School
SC37	Seattle - 3	School	Archbishop Murphy High School
SC38	Seattle - 3	School	Penny Creek Elementary School

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SC39	Seattle - 3	School	Kindercare Learning Center 1707
SC40	Seattle - 3	School	Silver Firs Elementary School
SC41	Seattle - 3	School	Mill Creek Elementary School
SC42	Seattle - 3	School	Nancys Noahs Ark Daycare Center
SC43	Seattle - 3	School	Forest View Elementary School
SC44	Seattle - 3	School	Gateway Middle School
SC45	Seattle - 3	School	Cedar Wood Elementary School
SC46	Seattle - 3	School	Fernwood Elementary School
SC47	Seattle - 3	School	Canyon Creek Elementary School
SC48	Seattle - 3	School	Skyview Junior High School
SC49	Seattle - 3	School	Skyview Junior High School
SC50	Seattle - 3	School	Kokanee Elementary School
SC51	Seattle - 3	School	Canyon Park Montessori School
SC52	Seattle - 3	School	Northshore School District - Special Services
SC53	Seattle - 3	School	Northshore School District Office
SC54	Seattle - 3	School	Woodinville High School
SC55	Seattle - 3	School	Learning Garden School Bothell
SC56	Seattle - 3	School	Woodin Elementary School
SC57	Seattle - 3	School	Woodinville Montessori School North Creek Bothell Campus
SC58	Seattle - 3	School	University of Washington - Bothell Campus
SC59	Seattle - 3	School	Cascadia Community College
SC60	Seattle - 3	School	University of Washington Bothell Campus Building 1
SC61	Seattle - 3	School	University of Washington Bothell Campus Commons
SC62	Seattle - 3	School	Dartmoor School
SC63	Seattle - 3	School	Kids Country Woodinville
SC64	Seattle - 3	School	Woodinville Elementary School
SC65	Seattle - 3	School	C O Sorenson School
SC66	Seattle - 3	School	Bellevue Christian School-Woodinville
SC67	Seattle - 3	School	Kindercare Learning Center 1617
SC68	Seattle - 3	School	Woodinville Montessori School
SC69	Seattle - 3	School	Woodinville Children Center
SC70	Seattle - 3	School	Cedar Park Christian School
SC71	Seattle - 3	School	Evergreen Academy Elementary School
SC72	Seattle - 3	School	Northshore Junior High School
SC73	Seattle - 3	School	Kindercare Learning Center 898
SC74	Seattle - 3	School	Woodmoor Elementary School
SC75	Seattle - 3	School	Lil' People's World Child Care Center
SC76	Seattle - 3	School	Tree of Life Daycare Center
SC77	Seattle - 3	School	Kamiakin Junior High School
SC78	Seattle - 3	School	John Muir Elementary School
SC79	Seattle - 3	School	Elite Kids Preschool Kirkland Center
SC80	Seattle - 3	School	Lake Washington Technical College
SC81	Seattle - 3	School	Lake Washington Technical College Early Learning Center
SC82	Seattle - 3	School	Kindercare Learning Center 1024
SC83	Seattle - 3	School	Springhurst School
SC84	Seattle - 3	School	Mark Twain Elementary School
SC85	Seattle - 3	School	City Kids Preschool

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SC86	Seattle - 3	School	Rose Hill Presbyterian Preschool
SC87	Seattle - 3	School	Discovery Center
SC88	Seattle - 3	School	Rose Hill Elementary School
SC89	Seattle - 3	School	Kindercare Learning Center 1053
SC90	Seattle - 3	School	The Orchard Daycare Center
SC91	Seattle - 3	School	Stella Schola Middle School
SC92	Seattle - 3	School	Rose Hill Junior High School
SC93	Seattle - 3	School	Benjamin Franklin Elementary School
SC94	Seattle - 3	School	Benjamin Rush Elementary School
SC95	Seattle - 3	School	Bright Horizons Overlake Daycare Center
SC96	Seattle - 3	School	Cherry Crest Elementary School
SC97	Seattle - 3	School	Bridle Trails Toys and Tots Daycare Center
SC98	Seattle - 3	School	Bellevue Children's Academy
SC99	Seattle - 3	School	Learning Garden School
SC100	Seattle - 3	School	Planet Kids Montessori School
SC101	Seattle - 3	School	America's Child Montessori School
SC102	Seattle - 3	School	The Academic Institute
SC103	Seattle - 3	School	Bel - Red Bilingual Academy
SC104	Seattle - 3	School	Highland Middle School
SC105	Seattle - 3	School	Early World Childrens School
SC106	Seattle - 3	School	A+ Alternative School
SC107	Seattle - 3	School	Dartmoor School
SC108	Seattle - 3	School	Eastside Academic School of Transit
SC109	Seattle - 3	School	Stevenson Elementary School
SC110	Seattle - 3	School	Cedar Park Christian School - Bellevue Campus
SC111	Seattle - 3	School	Odle Middle School
SC112	Seattle - 3	School	Three Cedars Waldorf School
SC113	Seattle - 3	School	Olympus Northwest Middle School
SC114	Seattle - 3	School	Jing Mei Elementary School
SC115	Seattle - 3	School	Bellevue School District Office
SC116	Seattle - 3	School	Wilburton Elementary School
SC117	Seattle - 3	School	Sammamish High School
SC118	Seattle - 3	School	Hyak Junior High School (historical)
SC119	Seattle - 3	School	International School
SC120	Seattle - 3	School	Lake Hills Elementary School
SC121	Seattle - 3	School	Kelsey Creek Home School Center
SC122	Seattle - 3	School	Robinswood Middle School
SC123	Seattle - 3	School	Robinswood High School
SC124	Seattle - 3	School	Robinswood Elementary School
SC125	Seattle - 3	School	Woodridge Elementary School
SC126	Seattle - 3	School	Eastside Christian School
SC127	Seattle - 3	School	Chestnut Hill Academy South Campus
SC128	Seattle - 3	School	Bellevue Community College
SC129	Seattle - 3	School	Learning Garden School Sunset
SC130	Seattle - 3	School	Career Link School
SC131	Seattle - 3	School	John Stanford Center for Educational Excellence
SC132	Seattle - 3	School	Jose Martin Child Development Center
SC133	Seattle - 3	School	Puesta del Sol Elementary School
SC134	Seattle - 3	School	Kimball Elementary School
SC135	Seattle - 3	School	Tyee Middle School

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SC136	Seattle - 3	School	Denise Louie Education Center Beacon Hill
SC137	Seattle - 3	School	Kindercare Learning Center 946
SC138	Seattle - 3	School	Eastgate Elementary School
SC139	Seattle - 3	School	Newport Childrens School
SC140	Seattle - 3	School	Mustard Seed Child Care Center
SC141	Seattle - 3	School	Newport High School
SC142	Seattle - 3	School	Asa Mercer Middle School
SC143	Seattle - 3	School	Mercer Middle School
SC144	Seattle - 3	School	Somerset Elementary School
SC145	Seattle - 3	School	Pathfinder K - 8 School
SC146	Seattle - 3	School	Southwest Youth and Family Services
SC147	Seattle - 3	School	Interagency Alder Academy
SC148	Seattle - 3	School	Interagency Camp School
SC149	Seattle - 3	School	Interagency Fairview Academy
SC150	Seattle - 3	School	Interagency King County Jail School
SC151	Seattle - 3	School	Interagency Orion Center
SC152	Seattle - 3	School	Interagency Ryther Center
SC153	Seattle - 3	School	Interagency Southwest Youth and Family School
SC154	Seattle - 3	School	Interagency U District Youth Center
SC155	Seattle - 3	School	Zion Preparatory Academy
SC156	Seattle - 3	School	Sunnyside Montessori School
SC157	Seattle - 3	School	Forest Ridge School of the Sacred Heart
SC158	Seattle - 3	School	Orca Alternative
SC159	Seattle - 3	School	Columbia Elementary School
SC160	Seattle - 3	School	The New School at Columbia
SC161	Seattle - 3	School	Maple Elementary School
SC162	Seattle - 3	School	Saint George Parish School
SC163	Seattle - 3	School	Lake Heights Elementary School
SC164	Seattle - 3	School	Damascus Daycare Center
SC165	Seattle - 3	School	Alternative School Number One
SC166	Seattle - 3	School	Primm ABC Child Care Center and Preschool
SC167	Seattle - 3	School	Dearborn Park Elementary School
SC168	Seattle - 3	School	Newport Hills School
SC169	Seattle - 3	School	Cleveland High School
SC170	Seattle - 3	School	Newport Heights Elementary
SC171	Seattle - 3	School	Saint Edward Parish School
SC172	Seattle - 3	School	Ringdall Junior High School
SC173	Seattle - 3	School	Torah Day School of Seattle
SC174	Seattle - 3	School	Aki Kurose Middle School Academy
SC175	Seattle - 3	School	Sharples Junior High School
SC176	Seattle - 3	School	Gloryland Daycare Center
SC177	Seattle - 3	School	Martin Luther King Junior Elementary School
SC178	Seattle - 3	School	Renton Academy
SC179	Seattle - 3	School	Megumi Preschool Seattle
SC180	Seattle - 3	School	Van Asselt Elementary School
SC181	Seattle - 3	School	Hazelwood Elementary School
SC182	Seattle - 3	School	Seattle Urban Academy
SC183	Seattle - 3	School	Wing Luke Elementary School

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SC184	Seattle - 3	School	Tiny Tots Child Development Center Number 1
SC185	Seattle - 3	School	African American Academy
SC186	Seattle - 3	School	Newcastle Elementary School
SC187	Seattle - 3	School	Dunlap Elementary School
SC188	Seattle - 3	School	South Lake High School
SC189	Seattle - 3	School	Rainier Beach High School
SC190	Seattle - 3	School	Seattle School District Office
SC191	Seattle - 3	School	South Shore Middle School
SC192	Seattle - 3	School	Children's House Montessori School
SC193	Seattle - 3	School	Emerson Elementary School
SC194	Seattle - 3	School	Sierra Heights Elementary School
SC195	Seattle - 3	School	Amazing Grace Christian School
SC196	Seattle - 3	School	Saint Paul School
SC197	Seattle - 3	School	Hillcrest Middle School
SC198	Seattle - 3	School	Hillcrest Special Services Center
SC199	Seattle - 3	School	Hillcrest Early Childhood Center
SC200	Seattle - 3	School	McKnight Middle School
SC201	Seattle - 3	School	Kindercare Learning Center 1137
SC202	Seattle - 3	School	Renton Child Care Center
SC203	Seattle - 3	School	Hazen High School
SS3	Tacoma - 4	Sole Source Aquifer	Cedar Valley Aquifer
SS4	Tacoma - 4	Sole Source Aquifer	Central Pierce County Aquifer
TR5	Tacoma - 4	Tribal Lands	Puyallup Reservation
TR6	Tacoma - 4	Tribal Lands	Nisqually Reservation
HP18	Tacoma - 4	Historic Building	Drum, Henry, House
HP19	Tacoma - 4	Historic Building	Masonic Temple Building–Temple Theater
HP20	Tacoma - 4	Historic Building	Wright Park and Seymour Conservatory
HP21	Tacoma - 4	Historic Building	Balfour Dock Building
HP22	Tacoma - 4	Historic Building	Fire Alarm Station
HP23	Tacoma - 4	Historic Building	Fire Station No. 1
HP24	Tacoma - 4	Historic Building	Walker Apartment Hotel
HP25	Tacoma - 4	Historic Building	Yuncker, John F., House
HP26	Tacoma - 4	Historic Building	House at 605 South G Street
HP27	Tacoma - 4	Historic Building	Northern Pacific Office Building
HP28	Tacoma - 4	Historic Building	Old City Hall
HP29	Tacoma - 4	Historic Building	Building at 712--716 Sixth Avenue
HP30	Tacoma - 4	Historic Building	Y.M.C.A. Building
HP31	Tacoma - 4	Historic Building	Old City Hall Historic District
HP32	Tacoma - 4	Historic Building	Lynn, C.O., Co. Funeral Home
HP33	Tacoma - 4	Historic Building	Rhodes Medical Arts Building
HP34	Tacoma - 4	Historic Building	South J Street Historic District
HP35	Tacoma - 4	Historic Building	Bowes Building
HP36	Tacoma - 4	Historic Building	House at 802–804 South G Street
HP37	Tacoma - 4	Historic Building	House at 708--710 South 8th Street
HP38	Tacoma - 4	Historic Building	Rialto Theater
HP39	Tacoma - 4	Historic Building	Pantages Theatre
HP40	Tacoma - 4	Historic Building	Fireboat Station
HP41	Tacoma - 4	Historic Building	Pythian Temple
HP42	Tacoma - 4	Historic Building	City Waterway Bridge
HP43	Tacoma - 4	Historic Building	National Bank of Tacoma
HP44	Tacoma - 4	Historic Building	McIlvaine Apartments

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P 8-24

Construction of the project could theoretically damage the hazardous liquid pipelines operated by OPLC and other gas lines mentioned in Section 8.3.2, creating an explosion risk if safety policies and regulations were not implemented as required. The UTC identifies five major reasons why gas pipelines leak or fail, potentially creating a public safety hazard: (1) third-party excavation damage; (2) corrosion; (3) construction defects; (4) material defects; and (5) outside forces resulting from earth movement, including earthquakes, washouts, landslides, frost, lightning, ice, snow, and damage done by authorized on-site personnel. TMinor - If damage to pipelines could lead to leaks of materials that could be cleaned up and sites fully restored in accordance with applicable regulatory requirements, impacts would be considered minor. Moderate - If implementation of regulatory requirements and project design would address most potential adverse impacts, but there is a reasonable potential for some damage to pipelines that could result in impacts to property or human health, impacts would be considered moderate. Significant–Even with implementation of regulatory requirements and design measures, if substantial damage, injury, or death would likely occur associated with pipeline damage, leaks, or explosions, impacts would be considered significant. P 8-24

Source:

GAO Report to Congressional Committee on Pipeline Safety January 2013
Pipeline Safety: Better Data amd Guidance Needed to Improve Pipeline Operator Incident Response

While prior research shows that most of the fatalities and damage from an incident occur in the first few minutes following a pipeline rupture, operators can reduce some of the consequences by taking actions that include closing valves that are spaced along the pipeline to isolate segments. The amount of time it takes to close a valve depends upon the equipment installed on the pipeline. For example, valves with manual controls (referred to as "manual valves") require a person to arrive on site and either turn a wheel crank or activate a push-button actuator. Valves that can be closed without a person located at the valve location (referred to as "automated valves") include both remote-control valves, which can be closed via a command from a control room, and automatic-shutoff valves, which can close without human intervention based on sensor Page 11 GAO-13-168.) Automated valves generally take less time to close than manual valves. PHMSA's minimum safety standards dictate the spacing of all valves, regardless of type of equipment installed to close them,while integrity management regulations require that transmission pipeline operators conduct a risk assessment for highconsequence areas that includes the consideration of automated valves.

From Appendix C-6 Olympic Pipeline System Overview - Report to Dept of Ecology, March 2015
Location of Block Valves and which ones are manually or remotely operated.

FIGURE C.6 – BLOCK VALVE DRIVING DIRECTIONS (CONTINUED)

Anacortes Lateral	Latitude	Longitude	Driving Directions
MP 79 Block Valve 16" (MOV) & 20" Check Valve	47.903305	-122.169114	From I-405, take exit #23 and head north on Hwy 522 to Hwy 9 exit. Turn left (north) on Hwy 9, go approximately 6.9 miles to Lowell-Larimer Rd. and turn west (left) at this light. Go approximately 2 miles to intersection of Marsh/Lowell-Larimer and Seattle Hill Rds. Bear right then turn left back onto Lowell-Larimer Rd. and continue on for approximately 1.4 miles. Watch for the pipeline markers and gated area of the road, the Block Valve site is 200' north of the road down the gravel driveway behind fencing.
MP 80 Block Valve 20" (HOV)	47.895546	-122.169323	From I-5, take exit #186, head east on 128th St/Hwy 96 to 35th Ave. SE. Turn left at light; go north approximately 1 mile to 116th St SE, turn right. Go approximately 0.7 miles to Pinehurst housing development; turn left on 45th Dr SE, then immediately east (right) on 115th PL SE, which eventually turns into 47th Ave SE heading north. Follow 47th Ave till you get to 113th St SE turn west (left) total trip from 116th is 0.3 miles. The Block Valve site will be on your right hand side gated and clearly visible from the road approx. 25'. From I-405, take exit # 26, Bothell-Everett Hwy north (right) on 180th. Left on 35th Ave Se travel north approx 3.5 miles to 116th St SE, turn right. Follow directions as above.
Allen Station to Renton Station	**Latitude**	**Longitude**	**Driving Directions**
Woodinville Station	47.798892	-122.171062	From I-405, take exit # 23 and head north on Hwy 522 to Hwy 9 exit. Turn left (north) at light, head north for 0.7 miles, then turn west (left) at 228th St SE for Approx. 1.4 miles till you reach 45th Ave SE, then turn north (right). Follow 45th Ave 0.5 miles till you come to address 21909 45th Ave SE and turn right at driveway.
MP 89 Block Valve 16" & 20" (MOV)	47.762627	-122.173828	From I-405, take exit # 24 (Beardslee Blvd exit) and head east on NE 195th St. Follow for approx. 0.4 miles to 120th Ave NE, turn south (right). After about 0.5 miles turn left at first driveway of the Archstone apartment complex across from Home Depot and between the Starbucks coffee house and Seattle times parking lot end. Go down new Apartment complex road till you come to pipeline markers (approx. 4 blocks). The Block Valves are north of that location gated and visible from the road (follow dirt road north (left) for access). MP marker 89 is clearly visible from the road.
MP 89.5 16" Check Valve & 20" Block Valve (HOV)	47.75547162	-122.1738939	From I-405, to exit # 23 (Hwy 522), go approx. 1 mile to the Woodinville exit and head south (right) on Hwy 202 for 0.2 miles to NE 175th St/Hwy 202 and turn west (right) at the light. Travel 0.3 miles across bridge and railroad tracks and turn west (right) on NE 173rd PL. Follow to the first driveway on right, approx. 0.3 miles - you'll cross over the pipeline at this time before you get to the driveway. Go over the railroad tracks again and turn east (right) and follow to the pipeline crossing approx. 2 blocks, with the Block Valve on the North side within the small island in the parking lot.
MP 95.5 Block Valve 16" & 20" (MOV)	47.67776	-122.158556	From I-405, take exit # 18 (NE 85th St) and head east approx. 1.4 miles, look for the pipeline markers around the 13600 block of NE 85th St. The Block Valve's will be on the south side of the road gated and clearly visible from the road.
MP 98.5 Block Valve 16" & 20" (MOV)	47.63138	-122.159494	From I-405, take exit # 14, Hwy 520, heading east towards Redmond. Take the very first exit on 520 which is Northrup Way and turn east (left) at the light stay in the left hand lane, go about 6 blocks then turn north (left) on 130th Ave NE and go approx. 4 blocks to NE 24th St. Turn east (right) on 24th and go approx. 5 ½ blocks until you come to the pipeline crossing. The Block Valve's will be on the south side of road at the 13500 block clearly gated and visible from the road, approx. 100'.
MP 100.1 Block Valve 20" (HOV)	47.603459	-122.158769	From I-405, take exit # 12 (SE 8th St) and go east approx. 0.4 miles to Lake Hills Connector, take this road east (right) and go approx. 1.5 miles to 140th Ave SE. Turn north (left) on 140th and go 1 block north to SE 7th St and turn west (left), go all the way to the end of the road where it dead ends at a trail. Follow the gravel trail downhill till you come to the pipeline Right of Way which is 1 or 2 blocks of walking, the pipeline Block Valve site is on the south (left) hand side at the bottom of the trail approx. 25'.

FIGURE C.6 – BLOCK VALVE DRIVING DIRECTIONS (CONTINUED)

Allen Station to Renton Station	Latitude	Longitude	Driving Directions
MP 101.8 Block Valve 20" (MOV)	47.588158	-122.158339	From I-405, take exit # 10 (Coal Creek Pkwy) and head east for approx. 0.5 miles to Factoria Blvd/128th Ave SE, turn north (left) at the light. Follow this road for approx. 1.6 miles and stay in your right hand lane when approaching SE 26th St. (you will go underneath I-90). Turn east (right) on SE 26th St (Kamber Rd.) and go approx. 0.3 miles to the pipeline crossing at 13615 SE 26th St. The 16" Block Valve site will be on the south side of the road gated and clearly visible within 50' of the road. The 20" Block Valve site will be on the north side of the road.
MP 102 Block Valve 16" (MOV)	47.587143	-122.158356	From I-405, take exit # 10 (Coal Creek Pkwy) and head east for approx. 0.5 miles to Factoria Blvd/128th Ave SE, turn north (left) at the light. Follow this road for approx. 1.6 miles and stay in your right hand lane when approaching SE 26th St. (you will go underneath I-90). Turn east (right) on SE 26th St (Kamber Rd.) and go approx. 0.3 miles to the pipeline crossing at 13615 SE 26th St. The 16" Block Valve site will be on the south side of the road gated and clearly visible within 50' of the road. The 20" Block Valve site will be on the north side of the road.
MP 103 Check Valve 20"	47.56302	-122.169659	From I-405, take exit 10 and head east on Coal Creek Parkway for .6 miles. Check valve is in a vault in north edge of parking lot.
MP 103 Check Valve 16"	47.571255	-122.157082	From I-405, take exit #10 (Coal Creek Pkwy) and head east and take a left at Factoria Blvd. Right on SE Newport way for .7 miles and turn right at Somerset Blvd Se, left on Somerset Blvd valve is on your left at chain link fence.
MP 105 Block Valve 16" & 20" (MOV)	47.537778	-122.169522	From I-405, take exit # 10 (Coal Creek Pkwy) and head east, continue on Coal Creek Pkwy in a Southeast direction for approx. 2.5 miles. Turn west (right) on SE 69th Way and go .2 miles to the pipeline crossing at the 12800 block, open the Right of Way gate and head south (left) down gravel road for 2 blocks. The Block Valve is approx. 250' south of the gravel road.
MP 106 Block Valve 16" & 20" (MOV)	47.513218	-122.171135	From I-405, take exit # 5 (NE Park Dr/Sunset Blvd) and head east off the freeway, stay on Sunset for approx. 1.8 miles and turn north (left) at Union Ave NE for approx. 0.6 miles then turn west (left) on SE 101st St which eventually becomes SE 100th St. Follow down 101st for 0.3 miles to the pipeline crossing at the 12500-12600 block, then turn left on the gravel road to the clearly visible gated area 100' south of 100th
MP 106 Block Valve 16" & 20" (MOV)	47.513218	-122.171135	From I-405, take exit # 5 (NE Park Dr/Sunset Blvd) and head east off the freeway, stay on Sunset for approx. 1.8 miles and turn north (left) at Union Ave NE for approx. 0.6 miles then turn west (left) on SE 101st St which eventually becomes SE 100th St. Follow down 101st for 0.3 miles to the pipeline crossing at the 12500-12600 block, then turn left on the gravel road to a visible gated area 100' south of 100th St.
MP 110 Block Valve 16" & 20" (MOV)	47.476309	-122.171624	From I-405, take exit # 4 (Maple Valley Hwy) and head east for approx. 0.1 mile, turn northeast (left) on SE 5th St 0.4 miles to the pipeline crossing. The Block Valves are gated and clearly visible on the north side of the road approx. 50' from road.
MP 110.5 Check Valve 16" & 20"	47.473652	-122.176681	From I-405, take exit #2 (Rainier Ave/Hwy 167) north to S Grady Way. Turn right (east) follow for 0.4 miles to Talbot Rd. turn south (right). Take Talbot Rd. for 0.5 miles to S. Puget Dr. and turn southwest (left) and take this for approx. 1.4 miles until you get to the intersection of Royal Hills Dr/Edmonds Dr. SE. Turn northeast (left) onto Royal Hills Dr. for 0.4 miles to new road called Harrington Pl. SE, this is a new development called the Shadow Hawk Town homes (Code Key-Key 0415). Once on Harrington Pl. continue on 0.2 miles to the pipeline crossing, from here the MP marker 110 should be clearly visible. From MP 110 marker go ¼ mile north to the valve sites, which are in concrete vaults.
MP 111 Block Valve 20" (HOV)	47.469956	-122.191586	From I-405, take exit #2 (Rainier Ave/Hwy 167) north for one block and turn west (right) on SW Grady Way and follow for 0.4 miles to Talbot Rd. turn south (right). Take Talbot Rd. for 0.5 miles to S. Puget Dr., turn southwest (left) and follow for approx. 1.4 miles to a PSE service road, which is approx. ½ block from the intersection of Royal Hills/S Puget Dr./Edmonds Dr. SE. Take this service road west (left) for 0.3 miles and look for the pipeline crossing - the Block Valve site is on the south side of the service road approx. 100' in a concrete vault.

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FIGURE C.6 – BLOCK VALVE DRIVING DIRECTIONS (CONTINUED)

Allen Station to Renton Station	Latitude	Longitude	Driving Directions
MP 112 Block Valve 20" (HOV)	47.459059	-122.218799	From I-405, take exit # 2 (Rainier Ave/Hwy 167) north one block to SW Grady Way then turn west (left) and go 0.3 miles to Lind Ave SW. Turn south (left) on Lind Ave over the 405 over pass to the first light which is SW 16th St. Turn east (left) and follow approx 0.7 miles (becomes East Valley Rd.) to the pipeline crossing around the 2300 block of East Valley, turn west (right) on driveway to clearly visible and gated area approx. 100' west of the road.
Renton Station	47.458068	-122.224366	From I-405, take exit # 2 (Rainier Ave/Hwy 167) north one block to SW Grady Way, turn west (left), go 0.3 miles to Lind Ave SW and turn south (left). Go 0.9 miles on Lind to the driveway address of 2319 Lind Ave SW on the west side of the road.
Sea-Tac Lateral	**Latitude**	**Longitude**	**Driving Directions**
MP 1.5 Block Valve 12" (HOV)	47.476437	-122.227465	From I-405, take exit # 2 (Rainier Ave/Hwy 167) north, proceed 0.3 miles to SW 7th St. Turn west (left) on 7th 0.1 miles to Hardie Ave SW and turn north (right), follow Hardie Ave for 0.2 miles then turn west (left) on SW 5th PL. Go approx. 0.3 miles and turn west (left) on SW 5th Ct., go 0.1 miles and follow to the left of apartment building "H" driveway of the Avalon Greenbriar Apts. The Block Valve site is on the right side of apartment building "K" slightly downhill and approx. 100' from the driveway.
MP 2 Check Valve 12"	47.481663	-122.226964	From SR 167, heading north take the SR 900/SW Sunset Blvd headed west. Go .5 miles and turn (right) north on Earlington Ave Sw left on SW Langston Rd. Valve site is 450' up the road on your right.
MP 6 Block Valve 12" (MOV)	47.523506	-122.278396	Take I-5, north to exit # 157 (Martin Luther King Jr. Way). Stay in the right hand lane for approx. 1.1 miles and turn east (right) on S Henderson St. proceed on Henderson for 100' and look for pipeline crossing markers, the Block Valve site is on the north (left) side of Henderson St. gated and clearly visible from the road within 50'.
MP 10 Block Valve 12" (MOV)	47.569684	-122.326049	Take I-5, south to exit # 163 (Safeco Field/Spokane St. exit). Once off the exit at the bottom of the ramp at the first light, which is 6th Ave S go 0.1 miles heading west on Spokane St. to the first left hand "U" turn heading east on Spokane St. Go 0.1 miles back to 6th Ave S then turn south (right) on 6th and follow for 0.1 miles, the Block Valve site on the SE corner of 6th and Charlestown approx. 50' from 6th Ave S.
MP 1.5 Block Valve	47.476356	-122.227467	From SR 167 and I 405 intersections take Rainer Ave S North for .18 miles and turn left and go straight onto Stevens Ave Sw. Turn left on SW 5th st. Valve is located down the hill in yard.
MP 2 Check Valve	47.48767	-122.22697	From SR 167 and I 405 intersections take Rainer Ave S North for .66 miles and turn left on SR 900/Sunset Blvd. Go .11 miles and turn right on Hardie Ave Sw and keep left onto Langston. CV will be on your right at .38 miles.
MP 6 Block Valve (MOV)	47.523506	-122.278397	From I-5 south bound take exit 158 and turn left on Boeing Access rd. Turn left onto Martin Luther King Jr Way South. Go for .95 miles and turn then right onto South Henderson St. Valve site will be on your left. From I-5 North bound take exit 157 and go straight onto Martin Luther King Jr Way South for 1.72 miles and turn then right onto South Henderson St. Valve site will be on your left.
MP 10 Block Valve (MOV)	47.56966	-122.32604	From I-5 South bound take exit 163A and go straight on West Seattle Freeway ramp. Take the South Spokane St ramp and head east on South Spokane St and turn right onto 6th Ave South and then turn left onto South Charlstown St. Valve will be on your right. From I-5 North bound take exit 163 and keep left on South Spokane St ramp. Turn left onto 6th Ave South and then turn left onto South Charlstown St. Valve will be on your right.
Seattle DF	47.582619	-122.351571	From I-5, north take exit # 163 the West Seattle Freeway exit, on the West Seattle Freeway go for approx. 0.9 miles to the Harbor Island/11th Ave SW exit. Once the exit is made go 0.6 miles staying in the middle lane to Klickitat Ave SW. Turn north (right) on Klickitat Ave SW and continue on for 0.6 miles until you reach SW Lander St. and turn east (right). Follow Lander for 0.1 mile and turn north (left) on 13th Ave SW, follow 13th for 0.2 miles to the address of 2444 13th Ave SW on the east (right) side of the road.

Fire Engineering

JET FUEL

10/01/2002

By Frank L. Fire

Commercial jet fuel is essentially kerosene that has been hydrotreated to improve its burning properties. Hydrotreatment is a process proprietary to the producer of the fuel utilizing a particular catalyst. It will contain some additives to produce the anti-icing, anti-oxidation, anti-corrosion, and anti-static properties required.

Kerosene is a mixture of aliphatic (straight-chain alkanes or saturated) hydrocarbons, usually beginning with octane (eight carbons in the chain) and going up to hexadecane (16-carbon hydrocarbon). Alkanes have the general formula CnH2n+2. The n stands for the number of carbons in the chain, so hexadecane's molecular formula would be C16H34. Kerosene is formulated to fit the definition of a combustible liquid rather than a flammable liquid. The flash point of kerosene is controlled to be 100°F, or 37.8°C, to be classified as a combustible liquid.

Commercial jet fuel has many synonyms and trade names, including Jet A or JP-8. It is also known as aviation kerosene, Jet A-1, Jet A-50, Jet B, jet kerosene, jet kerosine, Turbo fuel A, and Turbo fuel A-1. Kerosene may also be called kerosine.

Commercial jet fuel is a pale yellow liquid with a petroleum odor. It has an auto-ignition temperature of 410°F (210°C). Its explosive limits are from 0.6 to 4.7 percent by volume in air. Coupled with its flash point, this means that at 100°F there is enough vapor in the air to reach the lower explosive limit so that even if an ignition source is not present and the fuel reaches a temperature of 410°F (and this is considerably below all common ignition sources), an explosion will occur.

Commercial jet fuel has a vapor density of 5.7 (where air = 1.0), which means the vapors are extremely heavy relative to air and will fall to the lowest point in the terrain and "hang" together for a long time where there is no appreciable breeze. These vapors will flow a considerable distance as if they were seeking an ignition source. They always find one.

Its specific gravity is 0.87, and it is not soluble in water. This means that the liquid will float on top of any water it contacts.

A flash point of 100°F means that it must be warmed to that temperature before it will produce enough vapors to burn (or explode). Any airplane with fuel in it is a flying bomb. If it crashes accidentally into the ground or on purpose as at the World Trade Center (WTC), the friction of the crash produces enough heat energy to ignite the fuel (which has been released by the crash) in a spectacular explosion. Even though the explosion is violent, all of the fuel is not involved, since much of it will be hurled away from the original point of energy release. At the WTC, after the initial explosion, some of the fuel was expelled from the building, but the remaining walls and windows confined much of it.

Hydrocarbons are essentially all fuel, since both the carbon and hydrogen will burn. There is a tremendous amount of energy tied up in the covalent bonds holding the hydrogen atoms to the carbon atoms in the hydrocarbon chain. When these bonds are broken, the energy is released in the fire as the fuel's heat of combustion. This is defined as the total amount of energy released as a fuel burns completely. Jet fuel has a heat of combustion of more than 19,000 Btus per pound of fuel, or more than 128,000 Btus per gallon of fuel. Multiply this by the amount of fuel in the airliner, and even though some of it was involved in the original explosion, you can understand that there was a tremendous amount of energy released in a short period of time during the ensuing fire of the remaining fuel. The burning jet fuel, plus whatever combustibles were present in the area of impact, produced more than enough heat to raise the temperature of the structural steel above its softening point, causing the floor or floors above the fire to collapse pancake style. There probably can be no tall building built that would withstand the heat generated by the quantity of jet fuel present in the WTC attack. If one can be built, no one would be able to pay for it.

Many victims probably were incinerated in the fireballs of jet fuel that roared through the upper floors of the towers. Many others were dismembered in the crashes or the collapses that followed. Firefighters and others at the scene have reported finding few intact bodies.

"The heat of the fire—estimated by FEMA at 1,700 degrees—would make identification difficult because it consumed smaller body parts," said Dr. Steven Symes, a professor of forensic pathology at the University of Tennessee.—*"NY Shifts from Rescue to Recovery," Richard Pyle, AP writer with contribution from AP reporter Diego Ibarguen, Sept. 17, 2001*

FRANK L. FIRE is executive vice president, marketing and international, for Americhem, Inc. in Cuyahoga Falls, Ohio. He is an instructor of hazardous-materials chemistry at the University of Akron as well as an adjunct instructor of haz mats at the National Fire Academy. Fire is the author of Common Sense Approach to Hazardous Materials (first and second editions) and an accompanying study guide; The Combustibility of Plastics; and Chemical Data Notebook: A User's Manual, published by Fire Engineering. He is an editorial advisory board member of Fire Engineering.

From: Patricia M. <pamagnani@gmail.com>
To: Steve O'Donnell <sdofour@aol.com>
Subject: Fwd: Comments from Kim West, Area Maintenance Engineer, Olympic Pipeline, re: PSE EE proposal
Date: Tue, Feb 9, 2016 3:27 pm
Attachments: Letter_from_Kim_West.docx (232K)

Here it is!

Hard Copy Submitted by Steve O'Donnell

---------- Forwarded message ----------
From: **Patricia M.** <pamagnani@gmail.com>
Date: Wed, Jul 16, 2014 at 11:27 PM
Subject: Fwd: Comments from Kim West, Area Maintenance Engineer, Olympic Pipeline, re: PSE EE proposal
To: Keith Collins <keithc@seanet.com>, Russell Borgmann <rborgmann@hotmail.com>, Steve O'Donnell <sdofour@aol.com>, "donmarshworks ." <don.m.marsh@gmail.com>

Hi all,

Attached is the Kim West letter for the Communication/Convince me tool kits. Great idea!

Patricia

From: davidtedmonds@comcast.net
Subject: Comments from Kim West, project manager for Olympic Pipeline
Date: February 26, 2014 at 9:43:11 PM PST

1 Misc

Hello Olympus residents, and Newcastle City Council Members and Employees:

There was a formatting problem with the previous message from Kim West, project manger for Olympic Pipeline. I have forwarded her comments to me in the enclosed attachment. She, along with District Operations Manager, Edward Cimaroli, were at the Olympus HOA meeting on Monday, February 24. PSE Vice President of Corporate Affairs, Andy Wappler, gave the presentation and answered questions from Olympus residents. When I asked what Olympic Pipeline thought about the project, we were told that we were out of time and they were unable to present their case in full. As you can see from the attached comments from Ms. West, Olympic has concerns about safety, impact upon landowners and customers. (Highlights are mine) It is interesting that PSE did not invite Olympic to be part of they Community Advisory Group process--when they clearly are a key player in this. It seems apparent that Olympic Pipeline is presenting an opinion that PSE did not want to be part of public discussion. I would urge Newcastle City Council members to call Ms, West or Mr. Cimaroli to find out more about their concerns--especially their safety concerns. If possible, I think if would be a good idea to have Olympic Pipeline to present information about their concerns of locating PSE's 230KV power-lines along the existing Olympic Pipeline at the next Newcastle City Council meeting.

Please forward these comments and Kim West's letter to anyone you think should see them.

Thank You
David Edmonds
CAG Representative, Olympus Newcastle
(206) 409-9417 (cell)

Olympic Pipeline Contact Information

Edward Cimaroli
District Operations Manager
Olympic Pipeline
edward.cimaroli@bp.com
(425) 227-5213 (direct)
(630) 386-3241 (mobile)

Kim West
Area Maintenance Engineer
Olympic Pipeline
kim.west@bp.com
(425) 981-2541 (direct)
(425) 864-1315 (mobile)

There is a rain creek The full length of The easement between 135th Ave SE and Somerset Drive, Because of steep slopes it flows from north To south,

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- Zoning and Property
- Permits and Construction
- Parks and Trails
- Commercial Property
- **Environmental**
- Geology
- Community Information
- Demographics
- Transit

X there are underground water basins known to neighbors

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-S-

Submitted by
Karen Esayian
4601-135th Ave SE
Bellevue, WA 98006

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Figure 16-1
Existing Electric Transmission and Natural Gas/Petroleum Pipelines

Users may use the "plus" (+) button on the map to zoom in from a regional scale to a neighborhood scale (1:24,000). At a larger scale (more zoomed in) subject matter data and legend will not be displayed. Accuracy and completeness of the information on this map is not guaranteed.

Legend

Existing Substations

Gas Main

Combined Study Area Boundary

Pipeline

Olympic Pipeline Company

Northwest Pipeline (Natural Gas)

PSE Gas Main

Exisiting 230kV

Existing 230kV (PSE)

Existing 115kV (PSE)

Seattle City Light Corridor (230kV)

Coal Creek Basin

Submitted by
Karen Esayian
4601 - 135th Ave SE
Bellevue, WA
98006

Select Language ▼

Existing PSE 115kV transmission line

Click, hold and drag on the map to pan. Use the tabs below to toggle map themes.

Zoning and Property

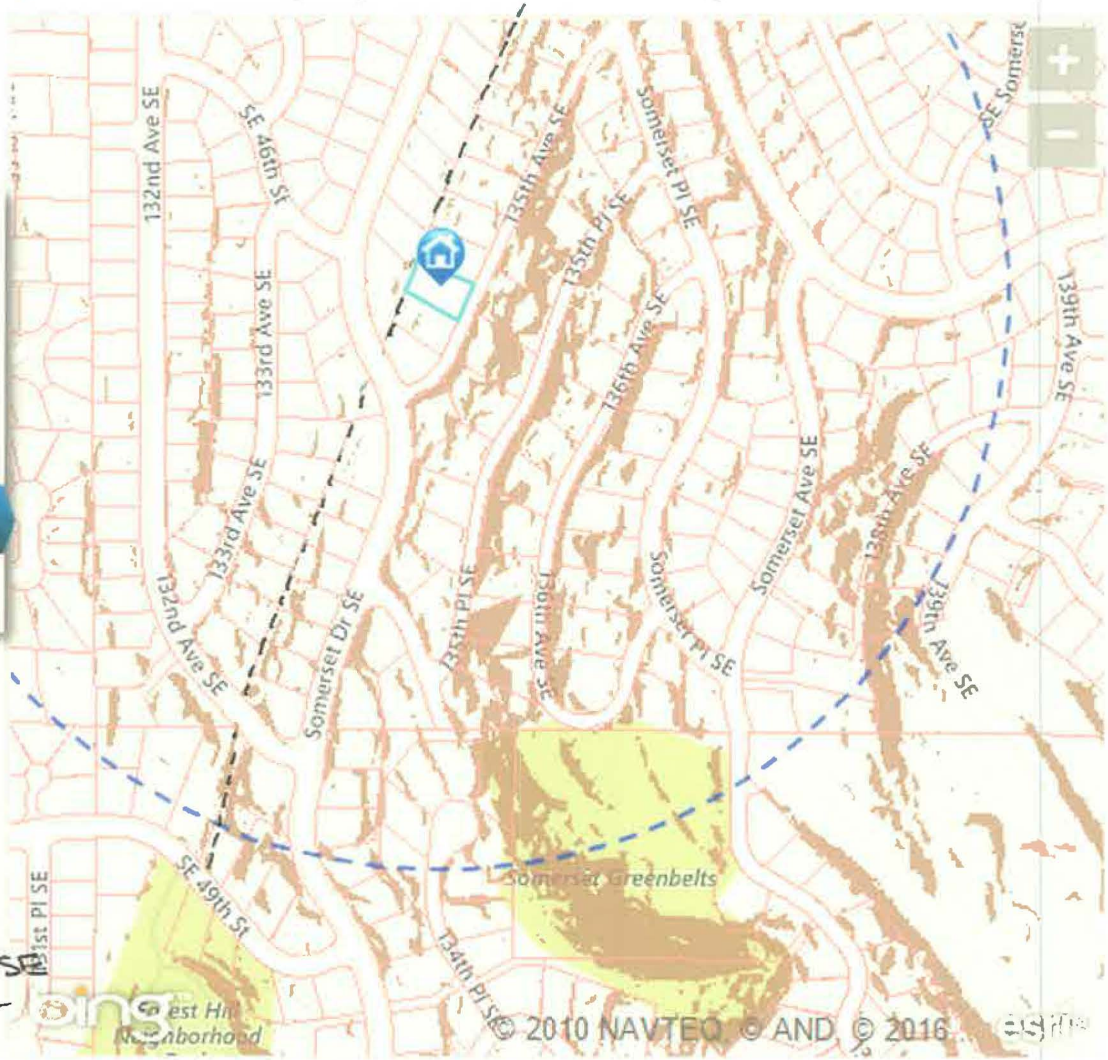
Permits and Construction

Parks and Trails

Commercial Property

Environmental

Community Information



Water Body

Fish and Wildlife Habitat Area

Wetland

Wetland Buffer

Stream Buffer

Landslide Area

Floodway

Steep Slope #

Shoreline Jurisdiction Area

4601-135th Ave SE
Bellevue, WA
98006

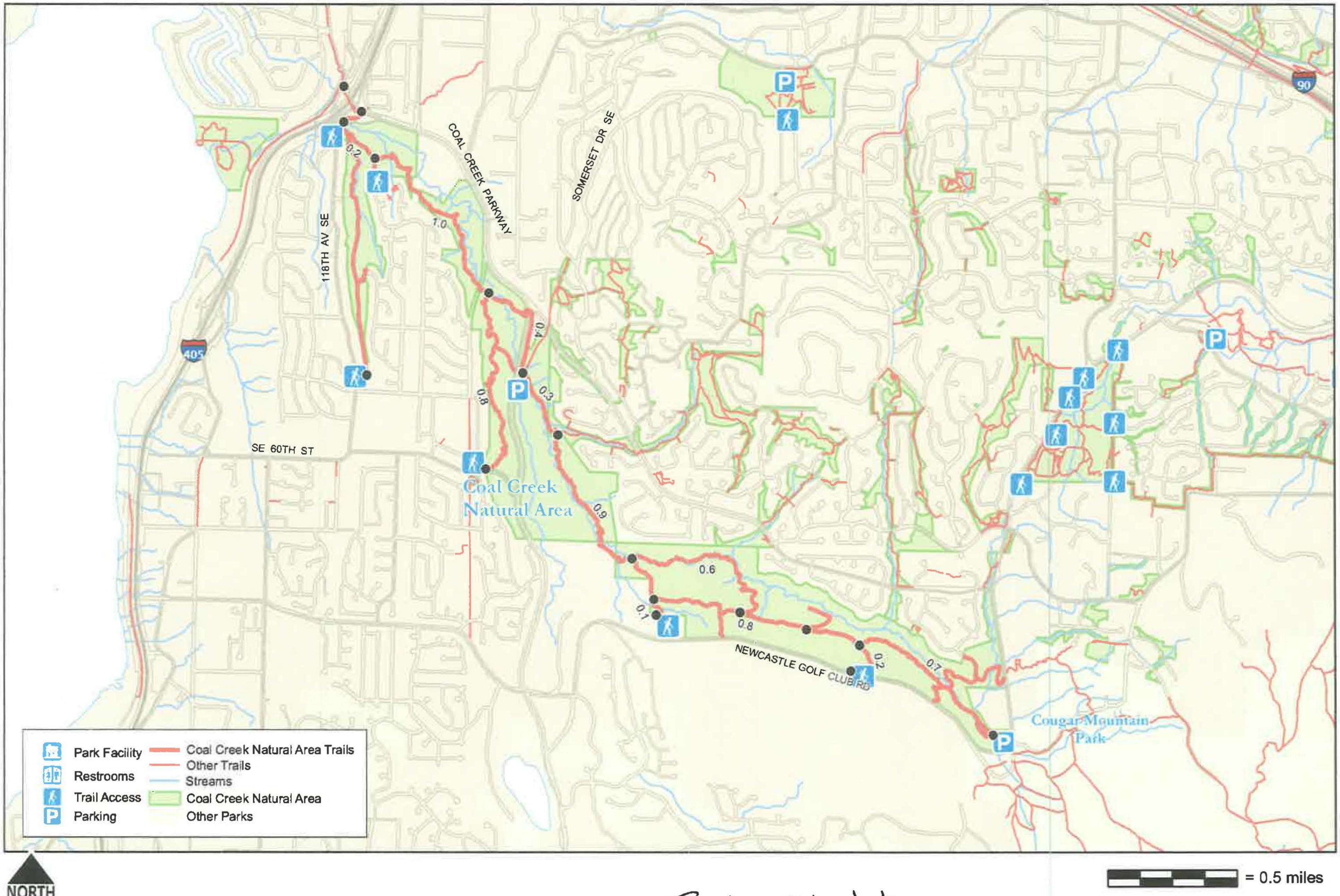
Submitted by
Karen Esayian

From nwmaps.net
a service of e-citygov.net

Please note steep slope areas which result in large amount of rain run off.

DSD 008392

Coal Creek Natural Area



Submitted by
Karen Esayian
4601 - 135th Ave SE
Bellevue, WA 98006

DSD 008393

DRAFT

Landslide and Seismic Hazard Areas

Lake Washington, Mercer Slough, and Kelsey Creek

City of Bellevue Shoreline Master Program

Figure 12b

CITY OF BELLEVUE WASHINGTON

THE WATERSHED COMPANY

0 0.25
Miles

- Slopes Over 40%
- Seismic Hazard Areas (King County)
- King County Landslide Hazard Areas
- Moderate to High Hazard Liquefaction Zones (King County)
- Shoreline Jurisdiction
- Ordinary High Water Mark
- Lakes
- City Boundary
- Highways
- Major Streets

Coal Creek Basin

Lake Washington Watershed (WRIA 8)

State Stream #08-0268

LAND CHARACTERISTICS

Basin Area: 3,990 Total Acres (11% of the City)

Drainage Jurisdiction(s):

2,181.7 Acres - in Bellevue

1,275.7 Acres - in King County

532.1 Acres - in Newcastle

Highest Elevation: 1,561 Ft

Lowest Elevation: 18 Ft

Total Length of Open Channel: 85,838 Ft

Total Length of Storm Drainage Pipes: 266,341 Ft

Built Rain Storage Volume per Acre of Impervious Surface: Less than 0.5 Inches

SALMON PRESENT in BASIN

Chinook*+

Rainbow & cutthroat trout

Coho+

Sockeye

Steelhead

* Listed Federal Endangered Species

\+ City Species of Local Importance (Bellevue Land Use Code 20.25H.150A)

POPULATION

City Basin Population (2000): 10,144 (9.1% of the City)

Basin Population Density: 1,852 People/Square Mile

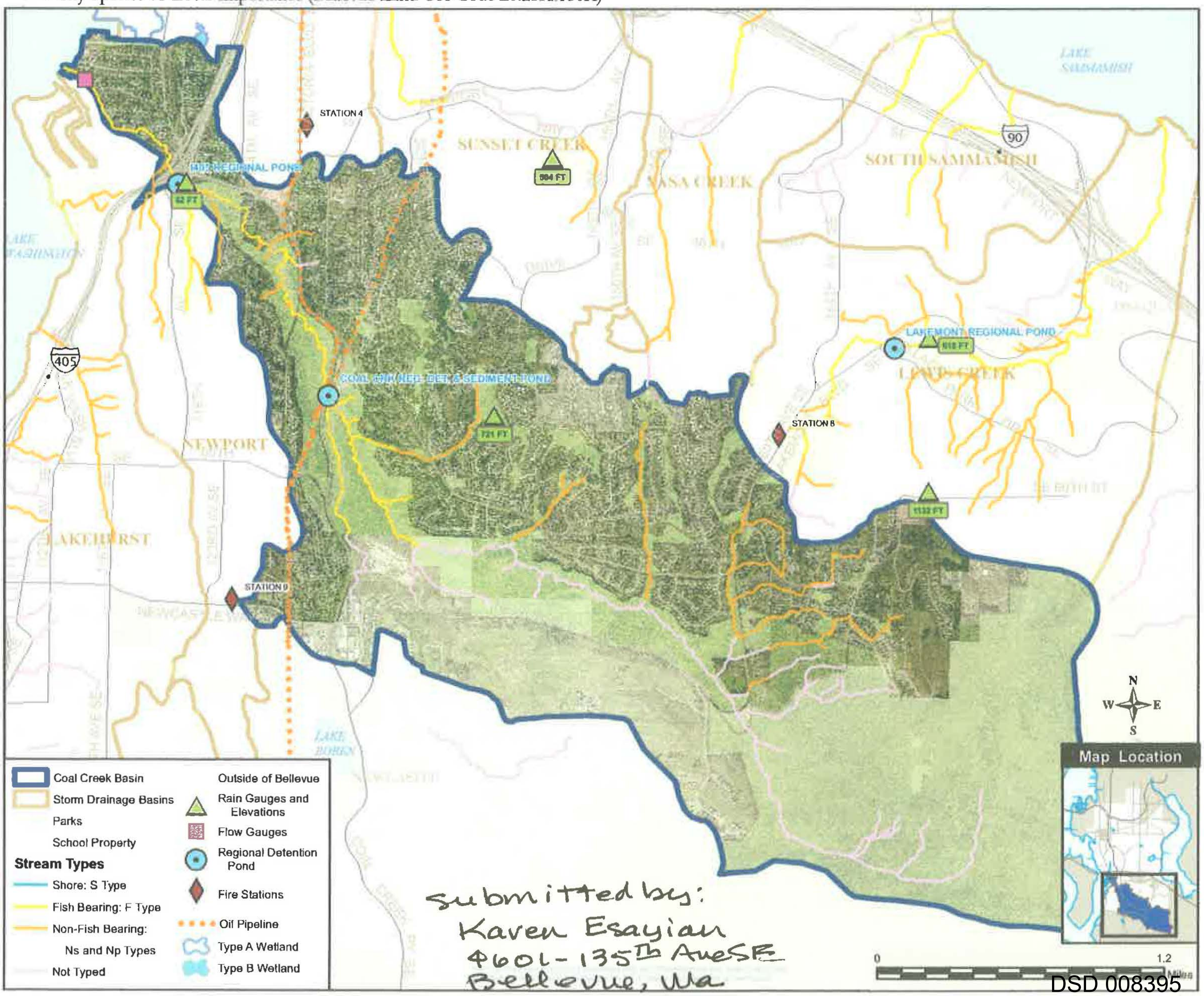
Number 3 of 26 Basins (One is the lowest density)

LAND USE (within Bellevue city limits)

Public Right of Way:	9.16%	365.38 Acres
Commercial/Office:	0.03%	0.6 Acres
Industrial:	0.01%	0.3 Acres
Institutional/Government:	3.06%	66.8 Acres
Mixed Use/Misc:	3.77%	82.2 Acres
Multi-Family Residential:	1.44%	31.4 Acres
Open Space/Park:	10.89%	237.7 Acres
Single Family Residential:	50.14%	1,093.9 Acres

LAND COVER

Impervious:	20%
Tree Canopy:	58%
Impervious in 100 Ft Stream Buffer:	8%
Tree Canopy in 100 Ft Stream Buffer:	85%



Submitted by:
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98006

DSD 008395

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Plot Date: 7/28/2010

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Figure 16-1
Existing Electric Transmission and Natural Gas/Petroleum Pipelines

Users may use the "plus" (+) button on the map to zoom in from a regional scale to a neighborhood scale (1:24,000). At a larger scale (more zoomed in) subject matter data and legend will not be displayed. Accuracy and completeness of the information on this map is not guaranteed.

Legend

Existing Substations

Gas Main

Combined Study Area Boundary

Pipeline

Olympic Pipeline Company

Northwest Pipeline (Natural Gas)

PSE Gas Main

Exisiting 230kV

Existing 230kV (PSE)

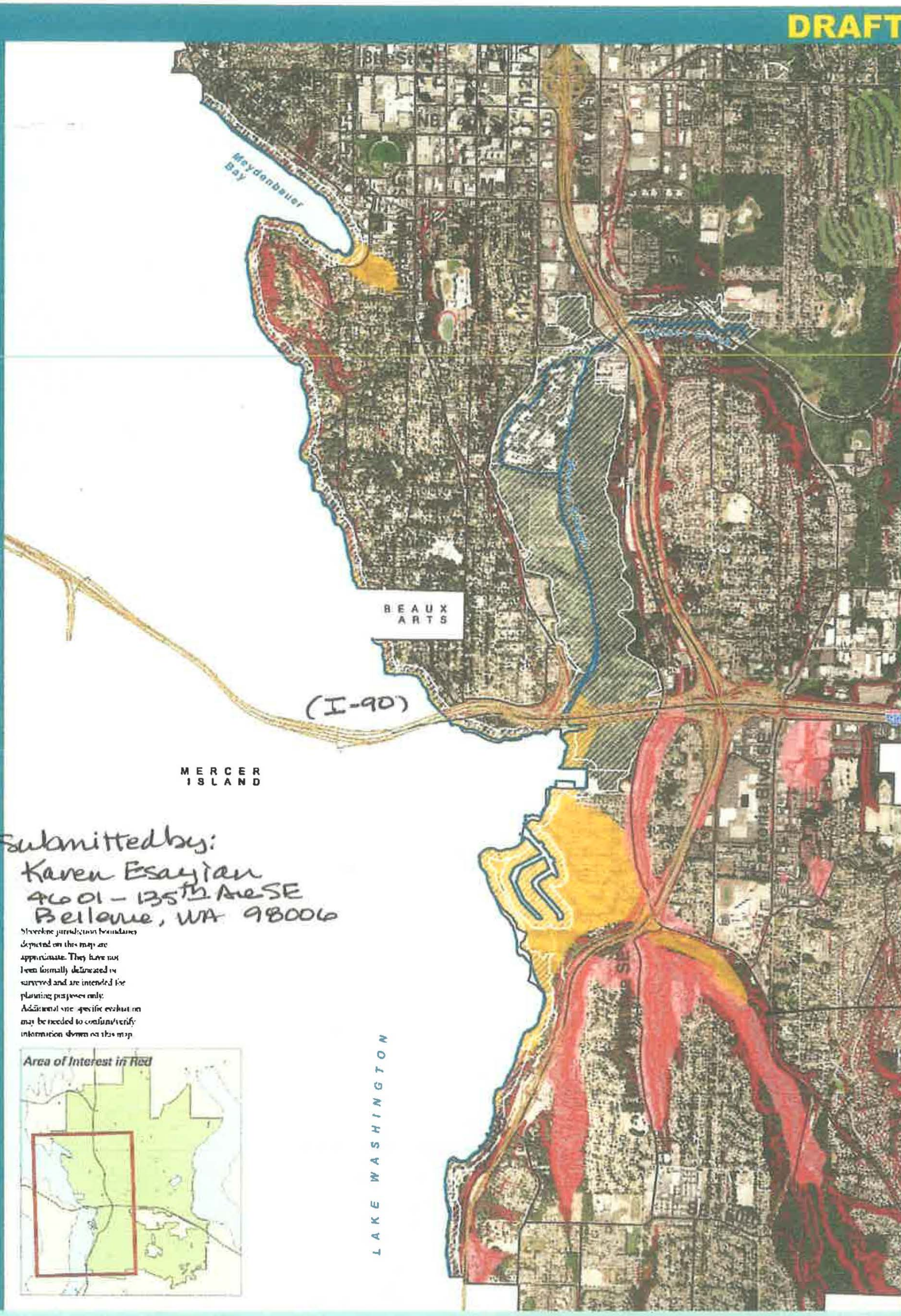
Existing 115kV (PSE)

Seattle City Light Corridor (230kV)

Coal Creek Basin

Submitted by:
Karen Esayian
4601-135th Ave SE
Bellevue, WA 98006

Select Language ▼



Submitted by:
Karen Esayian
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Bellevue, WA 98006

Landslide and Seismic Hazard Areas

Lake Washington, Mercer Slough, and Kelsey Creek

City of Bellevue Shoreline Master Program

Figure 12b

CITY OF BELLEVUE WASHINGTON

THE WATERSHED COMPANY

0 0.25
Miles

- Slopes Over 40%
- Seismic Hazard Areas (King County)
- King County Landslide Hazard Areas
- Moderate to High Hazard Liquefaction Zones (King County)
- Shoreline Jurisdiction
- Ordinary High Water Mark
- Lakes
- City Boundary
- Highways
- Major Streets

DSD 008397

Attachment B
PSE Planning Review of Lauckhart's and Schiffman's Load Flow Modeling for "Energize Eastside"

Carol Jaeger, Eleanor Ewry & Thomas Gentile

March 14, 2016

Electric transmission system planning is a complex and rigorous exercise, performed by industry experts with the experience in and understanding of federally mandated system planning requirements. In recent planning studies performed for Energize Eastside, PSE's team of transmission planning experts has logged over 2,200 hours of computer modeling and has run 550 different scenarios that included approximately 6.3 million contingencies. This is the level of effort required to meet the mandatory federal planning regulations.

The Lauckhart and Schiffman Load Flow study funded by CENSE is misleading, inaccurate, and flawed on several levels, resulting in baseless conclusions.

PSE compared the findings by Lauckhart and Schiffman to PSE's own findings of transmission capacity deficiencies in both the 2013 Eastside Transmission Needs Assessment and 2015 Supplemental Eastside Transmission Needs Assessment Reports. To make the comparison, it was necessary to locate the case used by Lauckhart and Schiffman, then make similar case adjustments. Appendix B of Lauckhart's and Schiffman's document states that the power flow base case they used was a 2017-18 Heavy Winter (HW) case that was created in 2014. Based on the 2014 Base Case Compilation Schedule from WECC, there was not a 2017-18 HW case created in 2014. The last time WECC created a 2017-18 HW case was in 2012, when it was created as a 5-year planning case. The final case was published by WECC in January of 2013.

Seeking the case used by Lauckhart and Schiffman, PSE downloaded the posted WECC 2017-18 heavy winter case and did a case comparison with the case settings reported by Lauckhart and Schiffman. The system interchange flows and PSE loads agreed with the loads and settings reported in the Lauckhart-Schiffman document. Therefore, we conclude that Lauckhart and Schiffman's study used the 2013 WECC 2013-14 and 2017-18 winter base cases as a starting point. These were some of the cases used in PSE's 2013 Eastside Transmission Needs Assessment Report. It appears that Lauckhart' s and Schiffman's study used neither the 2021-22 winter case, nor the 2014 and 2018 summer cases used by PSE in the company's 2013 reports.

The base case that Lauckhart and Schiffman utilized is not the same case that PSE used for the 2015 Supplemental Needs and Solutions studies for a number of reasons. PSE conducted its Supplemental Eastside Transmission Needs Assessment study in 2015 to review whether a need still existed with updated topology and load forecast, and found the need still exists. If Lauckhart and Schiffman used the 2012 case, it would likely require significant modifications to reflect PSE's system as it is planned today, and to reflect PSE's expected loads from the load forecast performed in 2014. In the 2015 Supplemental Eastside Transmission Needs Assessment, PSE did not use a posted 17-18 HW case, but rather modified the 19-20 HW case issued by WECC in 2014 to represent 17-18 HW conditions. Regardless, PSE did a case comparison between the 19-20 HW base case that PSE used to develop the 17-18 HW case for PSE studies and the 2017-18 winter case that we think Lauckhart and Schiffman used. This was done to review their results. There are a significant number of topological and load differences between the two base cases.

PSE's Transmission System Planners and their consultants have reviewed the Lauckhart and Schiffman document and have identified the following critical issues:

1) The study erroneously interprets power flows to Canada.
2) The study does not conform to mandatory federal transmission planning standards.
3) The study confuses planning standards with day-to-day operations.
4) The study contains several other inaccuracies.
5) The study reaches irrational conclusions.

6) Multiple independent experts and the federal government have rejected CENSE's claims and theories.

1. The study erroneously interprets power flows to Canada.

a. The Lauckhart and Schiffman document states "PSE modified the Base Case to increase transmission of electricity to Canada from 500 MW to 1,500 MW." The regional planning authority in conjunction with other regional utilities determines the values at which the Northern Intertie will be studied for planning purposes. PSE's modeling assumptions of the Northern Intertie are consistent with NERC, WECC, and ColumbiaGrid Planning and Expansion Functional Agreement (PEFA) requirements and the Puget Sound Area Study Team. PSE is correct in modeling 1,500 MW south to north for the heavy winter cases. For heavy winter cases, the Northern Intertie has been modeled at 1,500 MW by Columbia Grid as well as BPA. That requirement has been spelled out quite clearly in ColumbiaGrid's Biennial reports (excerpt below).

ColumbiaGrid's 2016 Update to the 2015 Biennial Plan explicitly states how the Northern Intertie is modeled in planning studies:

> *"As required by the NERC Reliability Standards and PEFA, it was necessary to model firm transmission service commitments in the System Assessment….Both of these firm transmission service commitments are on the west side of the path, thus 1,500 MW of transfers are modeled in the south to north direction in heavy winter cases."* [1].

Because PSE is part of the interconnected region and the Energize Eastside project is part of PSE, there are conditions where regional power flows through PSE's transmission system. Under normal system conditions the 1,500 MW of power flow to Canada generally flows on 500 kV and 345 kV transmission lines. Under certain contingencies a small amount will flow through PSE's 230 kV lines.

Lauckhart and Schiffman report that they ran their studies with the Northern Intertie set to 0 MW. While that is one value that may be considered within the range of possible operating conditions, it is not the value used for the Northern Intertie in planning studies. Planning studies must study the regionally agreed upon intertie flows in order to provide system operators the flexibility necessary to operate the system under reasonable conditions. The range to be studied has been established based on approved WECC path ratings, historical winter and summer power flows, and coordinated between Puget Sound Area transmission owners and operators.

2. The Lauckhart and Schiffman study does not conform to mandatory federal transmission planning standards.

a. The study does not stress the system (i.e. test how the system responds with elements out of service) to the rigor required by the federal planning standards[2]. The mandatory federal standards require the Planning Assessment to vary one or more components, such as real and reactive forecasted load, expected transfers, reactive resource capability, generation additions, retirements, or other dispatch scenarios, by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in System response. The Lauckhart and Schiffman study did not stress the system at all.

---

[1] 2016 Update to the 2015 Biennial Plan, pgs. 49-50, ColumbiaGrid, February 2016

[2] NERC TPL-001-4

PUGET SOUND ENERGY

b. The Lauckhart and Schiffman study appears to have reviewed only limited N-1-1 contingencies, rather than the full set that PSE reviewed. The mandatory federal standards[3] require the simulation of contingency categories P0 through P7, which are numerous variations of N-0, N-1, N-1-1, and N-2 contingencies. Based on Lauckhart's and Schiffman's study document and from what we were able to recreate, Lauckhart and Schiffman did not run the appropriate outages on the case.

   By not running the full breadth of scenarios that could impact the Eastside, the Lauckhart-Shiffman study failed to fully evaluate the needs of the Eastside transmission system. PSE's comprehensive studies identified 12-40 different contingencies that violated the NERC standards over the 5-10 year study period. The Lauckhart-Schiffman study only looked at one contingency, based on their written analysis. In reviewing the 2017-18 base case apparently used by Lauckhart and Schiffman, PSE found stresses on the Eastside transmission system when the appropriate contingencies were run, even with the power generation and Northern Intertie settings left as found in the WECC base case.

3. **The study confuses planning standards with day-to-day operations.** Lauckhart and Schiffman appear to have little to no understanding of the NERC, WECC, and ColumbiaGrid Planning requirements, as planning requirements use specific modeling criteria. In error, Lauckhart and Schiffman looked at load flows from an operations perspective and not from the required planning perspective. PSE's modeling and planning assumptions are consistent with NERC, WECC and ColumbiaGrid's Planning and Expansion Functional Agreement. Examples from CENSE's load flow study are as follows:

   a. Lauckhart and Schiffman appear to misunderstand the planning values for the Northern Intertie. Their document shows they looked at the flow across the Northern Intertie from an operations perspective, not as the region models the intertie for planning. The planning requirements are not the same as how one operates the system in real-time. Puget Sound Energy's modeling assumptions are consistent with NERC, WECC, and ColumbiaGrid PEFA requirements and the Puget Sound Area Study Team. (See 2a above)

      Experience has shown that by meeting the NERC and WECC regulatory planning requirements with system sensitivity assessments (such as incremental transfer capability studies or changes in generation dispatch), the system as designed when built would have suitable planning margins to meet the various non-studied conditions faced by operators. If planners met the established criteria with consideration to system uncertainty, operators would have a system that could be operated with acceptable performance, even if the conditions differed significantly from those assumed by the planners.

   b. Lauckhart's and Schiffman's document states, "PSE assumed that six local generation plants were out of service, adding 1,400 MW of demand for transmission. This assumption also causes problems for the regional grid." What the document terms "local" generation is located far from the Eastside; there is no significant generation in the Eastside area.

      Planning studies combine contingency analysis with sensitivity analysis to assess overall system adequacy. Although there is no guarantee that major disturbances cannot or will not happen, the assessment procedures do provide reasonable assurance that the system as designed will ultimately be capable of operating with an acceptable level of reliability over a sufficient range of operating circumstances.

[3] NERC TPL-001-4

The varying of generation dispatch is one of the sensitivity conditions that electric system planners utilize to understand the boundaries of the overall system adequacy of the electric network. There are several types of sensitivity conditions the planner tests. They include but are not limited to system load, transmission configuration, generation, and levels of scheduled interchange. System planners determine these boundaries of system adequacy by performing "what-if" tests (studies or simulations) of a set of credible contingencies at different levels of generation dispatch (real and reactive), demand, and interchange. These "what-if" tests are simulated with various transmission configurations, and then observing whether the electric network meets the mandatory performance requirements.

PSE utilized this concept by varying generation in the northern part of western Washington in PSE area. For the heavy winter cases, PSE simulated a 0 MW generation scenario and a 1,000 MW generation scenario for Seattle City Light and PSE generation in the Puget Sound area. PSE selected the 0 MW value for the Puget Sound area to test the system on the full range of generation, and selected 1000 MW for a low-to-average generation winter day based on history of the area generation. The simulations showed that there still were violations of the mandatory performance requirements on the Eastside system with 1,000 MW of generation added in the in the northern part of western Washington of PSE. In addition, the results showed there was only a 15 MW reduction in loading on the Talbot Hill transformer for a change of 1,000 MW of generation in the north part of western Washington, and therefore, adjusting area generation dispatch did not have a significant effect on Eastside system needs.

4. **The study contains several other inaccuracies.**

   a. Lauckhart's and Schiffman's analysis removed the Energize Eastside 230 kV line and 230-115 kV substation from the case, but PSE does not know whether they restored the 115 kV line that was removed with this project, which will impact flows through the Eastside transformers. PSE had added other regional system improvements planned by PSE and other regional utilities to its winter case. It is not clear what was modified or added to the Lauckhart and Schiffman case.

   b. Lauckhart and Schiffman's document states, "The Base Case shows a demand growth rate of 0.5% per year for the Eastside. This is much lower than the 2.4% growth rate that PSE cites as motivation for Energize Eastside."

   Lauckhart and Schiffman are confusing the load forecast used in the 2013 WECC base case with the load forecast used in the 2015 Supplemental Needs Assessment base cases. There was no Eastside-area load forecast performed for the 2012 and 2013 WECC base cases; PSE only performed a system wide load forecast at that time. The 2015 Supplemental Needs Assessment did include an Eastside-area load forecast.

   Since the development of the WECC base cases utilize the latest information available at the time the cases were developed and it generally takes more than six months to gather and develop stable base cases, the base cases would need to be updated with the latest information when used for specific studies. It is recognized by the system planners that the base cases received from WECC provide a starting point for more company specific planning studies.

   The load forecast used in the PSE reports used 20-year load forecasts developed by their own economists based on econometric methods and reviewed biannually through the Integrated Resource Plan process by the WUTC. For their 2013 studies, PSE further reviewed known development projects for the Eastside area to reflect the most up-to-date growth information. Given that the base cases that were used to determine the demand growth rate quoted above were developed in 2012, the load forecast used to populate the case was different from the forecast used in the 2015 Supplemental Eastside Transmission Needs Assessment and the 2015 Supplemental Solutions Report. The load forecast used to populate the cases used in the 2015 Supplemental Eastside Transmission Needs Assessment and the 2015 Supplemental Solutions Report included a more refined, area-specific load forecast (2.4% Eastside area) that differed from the load forecast available in 2012 in a number of ways, one of which was an appropriate redistribution of load throughout the PSE service territory.

c. Lauckhart and Schiffman failed to consider the summer needs for the Eastside project. They studied PSE's winter findings for the Eastside project but failed to review summer cases, when lower equipment ratings exacerbate rising commercial and residential air-conditioning load. PSE is concerned about summer conditions, as documented in both the 2013 Eastside Transmission Needs Assessment and the 2015 Supplemental Eastside Transmission Needs Assessment reports.

5. The study reaches irrational conclusions.

a. The Lauckhart and Schiffman document states, "This level of energy transfer occurring simultaneously with winter peak loads creates instability in the regional grid. Transmission lines connecting the Puget Sound area to sources in central Washington do not have enough capacity to maintain this level of demand." Lauckhart and Schiffman claimed that when they increased the transfers to Canada to 1,500 MW and with peak load, the load flow did not solve[4] and that is why they are claiming instability in the region. This is an irrational conclusion. The document did not discuss all the changes made to the case when the interchange was increased. So it is not clear whether the "instability" is caused by numerical instability, load flow operator error, or a real instability. For this same condition PSE's load flow solved.

b. The Lauckhart and Schiffman document states, "PSE assumed that six local generation plants were out of service, adding 1,400 MW of demand for transmission. This assumption also causes problems for the regional grid." Again, Lauckhart and Schiffman claimed the load flow did not solve. The document did not discuss all the changes made to the case when the level or locations of generation were changed. So it is not clear whether the instability is caused by numerical instability, load flow operator error, or a real instability. For this same condition PSE's load flow solved.

c. The Lauckhart and Schiffman document states, "This graph [PSE's demand forecast graph] raises several questions. For example, it's not clear how PSE determined the 'System capacity range' of approximately 700 MW. If this value is derived from the transformer capacities listed in the WECC Base Case, these capacities are set to default values corresponding to 'summer normal' conditions."

PSE set the capacity limit marker on its load graph at the Eastside load level, based on the results of many load flow simulations, at which multiple problems were encountered in the study. This reflects loss of two transformers out of the six transformers feeding into the Eastside area, of which four transformers are the main feed. The capacity limit does not reflect the capacity of just two transformers. As Lauckhart and Schiffman pointed out, the transformers serving the Eastside also serve

[4] Solved power flow solution - Due to the nonlinear nature of this problem, numerical methods are employed to obtain a solution that is within an acceptable tolerance. There are several different methods of solving the nonlinear system of equations of a load flow. A popular method is known as the Newton–Raphson method. Based on resulting mismatches in key variables the solution iterates until the mismatch of the key variables reach an acceptable tolerance, which is close to zero. When the mismatch gets close to zero the solution is solved.

load outside the Eastside, and transformers outside the Eastside support Eastside load when necessary. This is a feature of a networked transmission system.

d. The notion that a system built in the 1960s, for system loads that were a small fraction of today's load demands, could last almost 100 years - until 2058 - is unlikely. No electric utility system has that longevity. With the level of growth that has occurred on the Eastside, a capacity increase is needed sooner rather than later.

e. The Lauckhart and Schiffman document notes that the WECC base cases arrived with limit monitoring set for summer normal limits. Lauckhart and Schiffman found that "the WECC Base Case contains a default assumption that PSE may not have corrected." Lauckhart and Schiffman further stated the "ratings for critical transformers are based on 'summer normal' conditions, but the simulation should use significantly higher 'winter emergency' ratings. The default value could cause PSE to underestimate System Capacity and overstate urgency to build the project." To confirm, PSE correctly adjusted the monitoring limits in the studied cases.

6. **Multiple independent experts and the federal government have rejected CENSE's claims and theories**. The Federal Energy Regulatory Commission (FERC); Bellevue's independent expert, Utilities System Efficiencies, Inc. (USE); and the EIS subcontractor, Stantec, have previously rejected the theories behind the Lauckhart and Schiffman study:

   a. *"Contrary to Complainants' vague allegations that the Respondents have violated [Federal transmission planning regulations], the record before us shows that [PSE] and the other Respondents have complied with the applicable transmission planning requirements."* – Federal Energy Regulatory Commission (FERC), Oct. 21, 2015

   b. *"Is the EE project needed to address the reliability of the electric grid on the Eastside? YES."* – Independent Technical Analysis of Energize Eastside, by Utility Systems Efficiencies, Inc., April 28, 2015

   c. *"Based on my expertise, I found that the PSE needs assessment was overall very thorough and applied methods considered to be the industry standard for planning of this nature. Based on the information that the needs assessment contains, I concur with the conclusion that there is a transmission capacity deficiency in PSE's system on the Eastside that requires attention in the near future."* - Review Memo by Stantec Consulting Services Inc., July 31, 2015

PSE PUGET SOUND ENERGY

ATTACHMENT A

energizeEASTSIDE

community advisory group FINAL REPORT

January 2015



prepared by: ei enviroissues

DSD 008404

Table of Contents

The Community Advisory Group reviewed and provided feedback on this report.

Executive summary

The Energize Eastside project will build a new electric substation and higher capacity (230 kV) transmission lines on the Eastside. In order to provide a forum that would generate robust input from diverse community stakeholders, Puget Sound Energy (PSE) convened a Community Advisory Group comprised of 24 representatives from various interests across the Eastside.

The Community Advisory Group's goals were to help identify and assess community values in the context of evaluating which route the new transmission lines should follow, and to develop a route recommendation for PSE's consideration.

Meeting schedule

The Community Advisory Group met eight times between Jan. 22 and Dec. 10, 2014. The advisory group discussed the following topics at each meeting:

- **Jan. 22:** Role of the advisory group and introduction to the project
- **Feb. 12:** Solution selection process and project routing
- **June 4:** Review key findings from the sub-area workshops and Sub-Area Committee meetings
- **June 25:** Review potential route options
- **July 9:** Narrow potential route options and finalize evaluation factors
- **Oct. 1:** Review key findings from the open houses and prepare for route evaluation
- **Oct. 8:** Develop a preliminary route recommendation
- **Dec. 10:** Finalize a route recommendation for PSE's consideration

Additional meeting details are included in section IV (Community Advisory Group activities).

Community outreach

The Community Advisory Group process was supplemented by broad and ongoing community outreach, including public events at key milestones. At outreach events, the community learned about outcomes of the advisory group process to date and submitted feedback that the advisory group considered in their discussions. Key outreach events included:

- **Jan. 29 and 30:** Open House #1
- **March - May:** Six sub-area workshops and three Sub-Area Committee meetings
- **April 21:** Question and Answer Meeting #1
- **July 7:** Question and Answer Meeting #2
- **Sept. 10 and 11:** Open House #2
- **Nov. 12 and 13:** Open House #3

Along with feedback collected at these outreach events, members of the public could also submit input and ask questions via email, voicemail and an online comment form on the project website. To help inform their discussion, the advisory group received monthly public comment summaries of more than 2,300 comments and questions received from the public, as well as summaries of comments received at open houses. Additional activities are detailed in section V (Community involvement).

Recommendation

On Dec. 10, the Energize Eastside Community Advisory Group selected route options Oak and Willow as their final route recommendation for PSE's consideration. Of the 22 advisory group members and four residential association alternates participating in the recommendation discussion, 20 supported the final recommendation.[1]

1 The above count includes the advisory group members and residential association alternates present at the Dec. 10, 2014 meeting, as well as six members and residential association alternates who did not attend the meeting but later provided feedback on the recommendation.

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The final recommendation was based on the advisory group's work throughout 2014, including discussion of community feedback collected throughout the year. Six advisory group members and residential association alternates dissented from the recommendation and supported none of the routes.

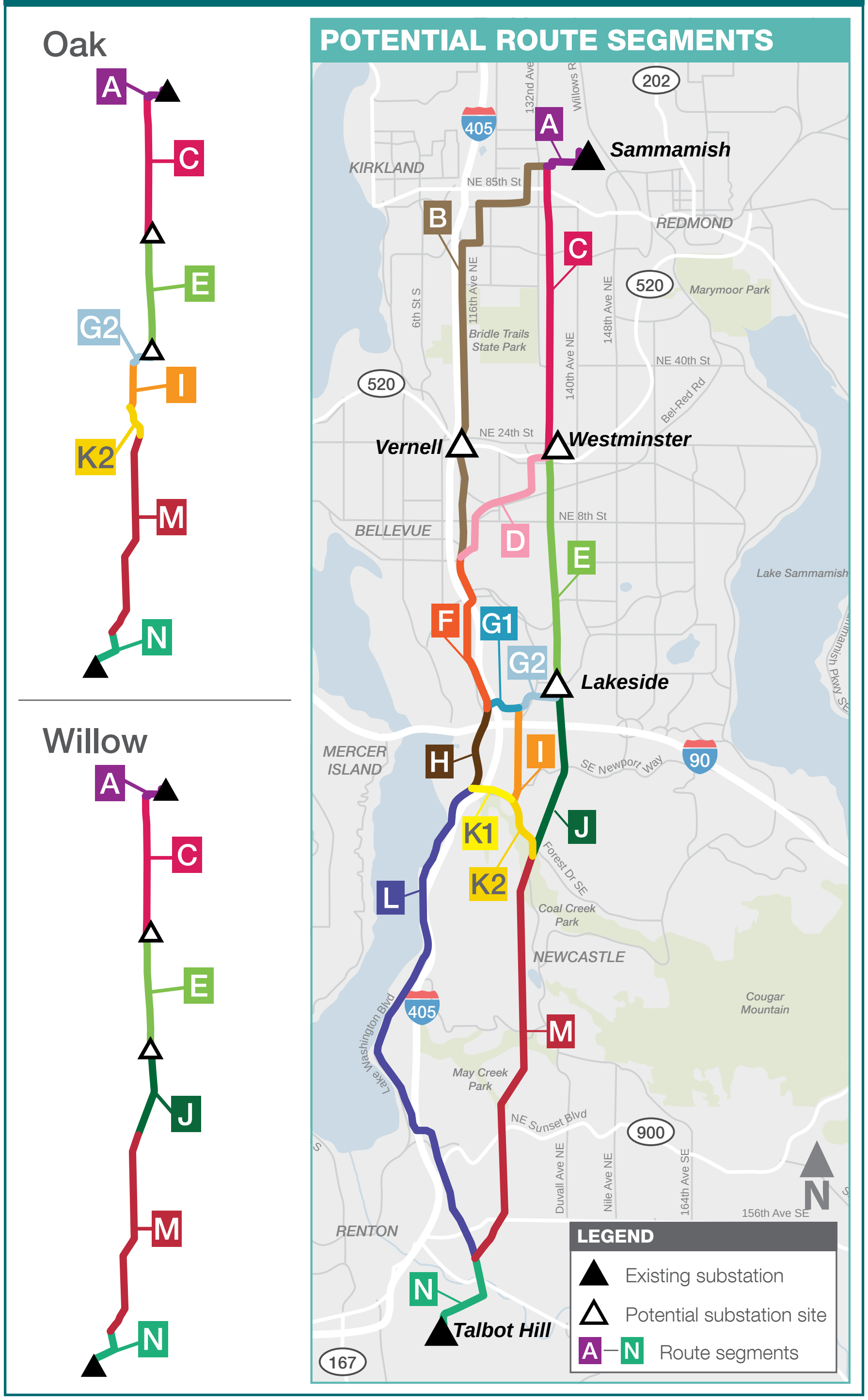
Next steps

Following the completion of the Community Advisory Group's process, PSE's next steps in 2015 are to:

- Take the Community Advisory Group's recommendation under consideration and make an announcement about routing that balances the needs of customers, the local community, property owners and PSE
- Work directly with property owners and tenants to begin detailed fieldwork to inform environmental review, design and permitting
- Ask for community input on project design, which may include pole height, finish and other design considerations
- Work with the City of Bellevue and other affected jurisdictions and agencies on the project's Environmental Impact Statement (EIS) process

Once these steps are complete, PSE will apply for necessary permits from appropriate agencies and jurisdictions. The project design and permitting phase is expected to run through early 2017. Once fully designed and permitted, project construction is expected to begin in 2017, with project completion planned for 2018.

COMMUNITY ADVISORY GROUP FINAL ROUTE RECOMMENDATION



I. Introduction

Growth studies presented by Puget Sound Energy (PSE) and third-party experts project that demand for reliable power on the Eastside will exceed capacity as early as the winter of 2017/2018.[1] These studies indicate that without substantial electrical infrastructure upgrades and aggressive conservation efforts, the Eastside's power system will lose redundancy, increasing the risk of more disruptive and longer outages for as many as 60,000 customers.

The Energize Eastside project will build a new electric substation and higher capacity (230 kV) transmission lines on the Eastside. The new 230 kV transmission lines will extend from the existing Sammamish substation in Redmond to the existing Talbot Hill substation in Renton, connecting with a new substation site in between. These upgrades will provide dependable power for Eastside communities for many years to come.

In January 2014, PSE convened a Community Advisory Group comprised of 24 representatives[2] from various interests across the Eastside. The purpose of the advisory group was to provide a forum that would generate robust input from diverse community stakeholders in compliance with comprehensive plan goals and policies, which promote public participation and/or coordinated utility siting. The Community Advisory Group's goals were to help identify and assess community values in the context of evaluating which route the new transmission lines should follow and to develop a final route recommendation for PSE's consideration.

1 Quanta Technology and Puget Sound Energy, *Eastside Needs Assessment Report*, 2013.

2 The Community Advisory Group consisted of 24 members at the beginning of the process; however, two member organizations (King County and Renton Technical College) withdrew without replacement.

Project Manager Jens Nedrud leads Community Advisory Group members on a tour of the project area.

Purpose of report

The purpose of this report is to document the work and summarize the recommendations of the Community Advisory Group convened by PSE to explore community preferences, priorities and concerns and to assess segments that could be combined to form a final route for the Energize Eastside 230kV transmission lines.

II. Project background

PSE's existing Eastside electric system had its last major upgrade in the 1960s. The electric system serves communities between Redmond to the north, Renton to the south, Lake Washington to the west and Lake Sammamish to the east. Power is currently delivered throughout the Eastside region using 115 kV transmission lines that run between two 230 kV substations – one in Redmond and one in Renton (see Figure 1).

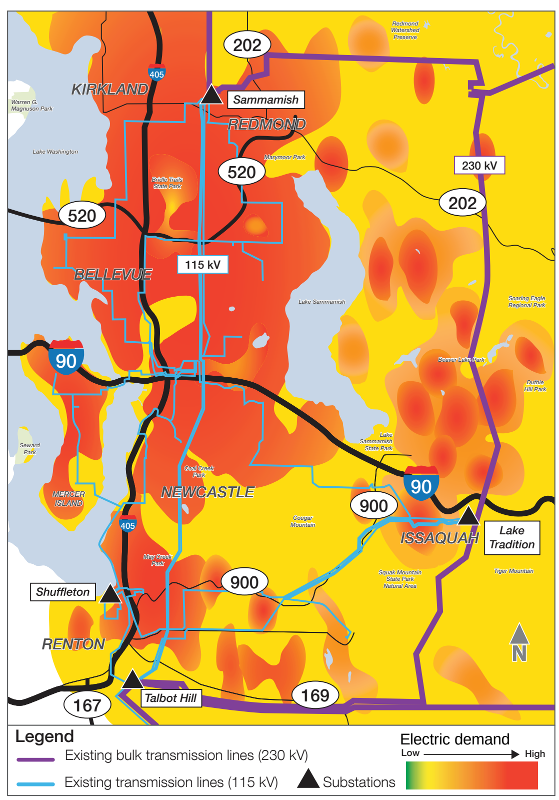
Since the system's last upgrade, the Eastside population has grown from approximately 50,000 to nearly 400,000 people, and this growth trend is expected to continue. Puget Sound Regional Council projections indicate that the Eastside population will grow by more than a third between 2010 and 2040.[1] Not only have Eastside communities grown and prospered, but the way Eastside residents use electricity has changed. Home square footage has increased, requiring more energy for lighting, heating and air conditioning. Additionally, most devices and appliances plugged in today did not exist years ago. Despite improvements in energy efficiency and aggressive conservation efforts, demand for electricity has grown dramatically.

Federal standards require PSE to plan for future forecasted loads and upgrade the system accordingly. Forecasted loads for transmission purposes are based on historical load data as well as a variety of other inputs, including information about weather, regional and national economic growth, demographic changes, conservation, and other customer usage and behavior factors. In 2013, PSE published the *Eastside Needs Assessment*. Prepared with assistance from independent experts, the study demonstrated that the increased demand is already placing a strain on the electric system. As growth continues, the existing system will only become more stressed, increasing the possibility of widespread outages, especially during peak winter loads when customer electricity use is greatest.

To determine a solution, PSE and independent experts conducted multiple independent analyses of the existing system and studied a variety of options to address the growing need on the Eastside, including further reducing demand through conservation, increasing the capacity of existing electric transmission lines, generating energy locally, and building new infrastructure.

After a comprehensive review, PSE determined that a combination of continued conservation and infrastructure upgrades – a new substation and higher capacity 230 kV transmission lines – will meet growing demand on the Eastside and ensure reliable electricity for years to come.[2,3]

Figure 1. The Eastside's electric system and demand



1 Puget Sound Regional Council 2013 Land Use Baseline: Maintenance Release 1 (MR1), update April 2014.

2 Energy + Environmental Economics, *Non-wire Solutions Analysis*, 2014.

3 Quanta Technology and Puget Sound Energy, *Eastside Transmission Solutions Report*, 2013.

III. About the Community Advisory Group

Purpose

The purpose of the Community Advisory Group was to evaluate the potential route options identified by PSE and independent experts, help PSE better understand community and property owner values and concerns, and determine a route recommendation for PSE's consideration. The Community Advisory Group process and final route recommendation will help PSE evaluate and consider routes that balance the needs of its customers, the local community, property owners and PSE.

Throughout the community outreach process, the Community Advisory Group:

- Developed an understanding of the Energize Eastside project and project need
- Reported back to the constituents they represented on project details, gathered feedback from the interests they represented, and provided ongoing communication between PSE and their constituents throughout the process
- As community representatives, provided advice on ways to address community concerns
- Participated in geographic Sub-Area Committee meetings to identify local concerns and values
- Worked collaboratively and constructively to help consider community and property owner values
- Engaged in a process to evaluate route options
- Determined a final route recommendation for PSE's consideration

The Community Advisory Group codified its purpose, process and guidelines in its Charter (Appendix A), agreed upon by consensus.

Membership

The Community Advisory Group was made up of representatives from various interests, including neighborhood organizations, cities, schools, social service organizations, major commercial users, economic development groups, an environmental organization and a property developer. See Table 1 for members, including which interests each member represented and their specific organization or affiliation.

Learning about the project need and advisory group process at Community Advisory Group Meeting #1 in Bellevue.

Table 1: Community Advisory Group members

Interest	Organization or affiliation	Name
City	City of Bellevue	Nicholas Matz
	City of Kirkland	Rob Jammerman
	City of Newcastle	Tim McHarg
	City of Redmond[1]	Pete Sullivan (primary) Lori Peckol (alternate) Cathy Beam (alternate)
	City of Renton	Gregg Zimmerman
Economic development organization	OneRedmond	Bart Phillips
	Renton Chamber of Commerce	Brent Camann
Environmental organization	Mountains to Sound Greenway	Floyd Rogers
Jurisdiction	King County[2]	David St. John (primary) Mary Bourguignon (alternate)
Major commercial/ industrial user	Overlake Hospital Medical Center	Sam Baxter (primary) Jeff Fleming (alternate)
	Renton Technical College[3]	Steve Hanson
Property developer	Master Builders Association	David Hoffman
Puget Sound Energy	Puget Sound Energy	Andy Swayne
Residential organization (Bellevue)	Somerset Community Association	Steve O'Donnell
	Wilburton Community Association	Robert Shay
	Bridle Trails Community Club	Norm Hansen
Residential organization (Kirkland)	South Rose Hill/Bridle Trails Neighborhood Association	Deirdre Johnson (primary) Jim McElwee (alternate)
Residential organization (Newcastle)	Olympus Neighborhood Association	David Edmonds (primary) Sean McNamara (alternate) Sue Stronk (alternate)
Residential organization (Redmond)	Redmond Neighborhoods	David Chicks
Residential organization (Renton)	Kennydale Neighborhood Association	Darius Richards
School district	Bellevue School District	Jack McLeod (primary) Kyle McLeod (alternate)
	Lake Washington School District	Brian Buck
Social service organization	Coal Creek Family YMCA	Marcia Isenberger (primary) Paul Lwali (alternate)
	Hopelink	Nicola Barnes

1 In October 2014, Pete Sullivan relocated and was unable to attend meetings thereafter, but remained involved in the process.

2 King County was invited to have a staff representative serve on the advisory group. King County staff attended two introductory meetings but then withdrew from the process.

3 In October 2014, Steve Hanson of the Renton Technical College resigned due to lack of availability to participate fully in the process.

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Residential association alternates

To provide an opportunity for additional input and representation from the residential community, four residential association alternates were appointed. These alternates were appointed from different neighborhood associations than the advisory group members representing residential interests. The four residential association alternates included:

- **Scott Kaseburg**, Lake Lanes Community Association (Bellevue)
- **Bill Taylor**, Liberty Ridge Homeowners Association (Renton)
- **Lindy Bruce**, Sunset Community Association (Bellevue)
- **Barbara Sauerbrey**, Woodridge Community Association (Bellevue)

Past members and residential association alternates

Over the course of the advisory group's work, the following membership changed due to varying circumstances:

- **Mark Rigos**, City of Newcastle (replaced by Tim McHarg)
- **Jules Dickerson**, Lake Lanes Community Association (replaced by Scott Kaseburg)
- **Lynn Wallace**, Renton Chamber of Commerce (replaced by Brent Camann)
- **Debra Grant**, Hopelink (replaced by Nicola Barnes)

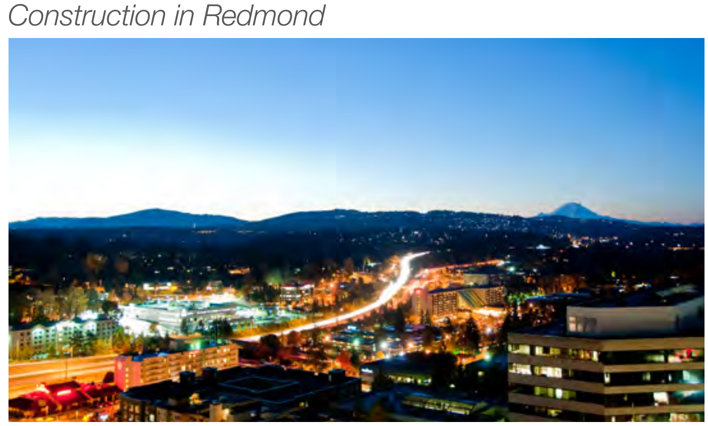
Invited

The following entities were invited and chose not to participate in the Community Advisory Group process, but were informed of project milestones and meetings through postcards and newsletters:

- Muckleshoot Tribe
- Yakama Nation

Aerial view of downtown Renton

Construction in Redmond



Downtown Bellevue at night

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IV. Community Advisory Group activities

Meeting schedule

The Community Advisory Group met eight times from January to December 2014. All Community Advisory Group meetings were open to the public and included a period for public comment. For links to advisory group meeting materials, presentations and summaries, see Appendix C.

During this process, PSE hosted three series of public open houses, during which the public could learn about major advisory group milestones and consult with PSE and advisory group representatives. The advisory group used community input from these open houses as well as from sub-area workshops and Sub-Area Committee meetings, community surveys, public comment periods, monthly public comment summaries, and personal communications with constituents to inform their discussions. See Table 2 for a list of advisory group and community meetings held in 2014.

Table 2: 2014 Community Advisory Group and public outreach meeting schedule

Date	Meeting type	Purpose
Jan. 22	Community Advisory Group meeting	Learned about project need and Community Advisory Group process
Jan. 29 & 30	Open House	Broader community learned about the project need, the Community Advisory Group process, and opportunities to get involved
Feb. 12	Community Advisory Group meeting	Learned about PSE's solution selection process and project routing
February – May	Project area tours and sub-area process	Learned about the potential route segments via project area tours provided by PSE; attended sub-area workshops to identify local community values and concerns; determined key findings from sub-areas (See Table 3 for more details)
June 4	Community Advisory Group meeting	Reviewed key findings about the segments gathered at sub-area workshops and Sub-Area Committee meetings; developed community values-based evaluation factors to be used to evaluate the route options
June 25	Community Advisory Group meeting	Reviewed qualitative and quantitative information about the 18 potential route options made by combining route segments
July 9	Community Advisory Group meeting	Narrowed potential route options and finalized evaluation factors
Sept. 10 & 11	Open House	Broader community provided feedback on narrowed route options and weighting of evaluation factors via survey
Oct. 1	Community Advisory Group meeting	Reviewed key findings from September open houses and prepared for a Multi-Objective Decision Analysis evaluation of the routes
Oct. 8	Community Advisory Group meeting	Determined preliminary route recommendation for public review at November open houses
Nov. 12 & 13	Open House	Broader community provided feedback on advisory group's preliminary route recommendation
Dec. 10	Community Advisory Group meeting	Reviewed key findings from the November open houses; finalized route recommendation for PSE's consideration

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Key Community Advisory Group discussion topics

The Community Advisory Group discussed many topics over the course of the process. The following topics were most commonly addressed. Descriptions include the advisory group's expressed concerns and PSE's response shared over the course of the advisory group process.

Scope confined to an overhead solution

Some members of the advisory group asked whether PSE would consider other alternatives besides an overhead solution. Those members also asked if considering other alternatives could fall under the advisory group's purview. Before launching the Energize Eastside, PSE studied several different solutions in addition to building the new overhead transmission lines. Those alternatives included reducing demand through conservation, increasing the capacity of PSE's existing electric transmission lines, generating energy locally, and building new infrastructure. However, PSE concluded other solutions were inadequate to solve the problem, and the advisory group was formed to gather feedback on an overhead transmission line solution.

Underground transmission lines

Among the most discussed alternatives to an overhead solution was underground transmission lines. PSE explained that overhead transmission lines are PSE's first option for service due to reliability and affordability. The biggest challenge to underground transmission lines is cost. The construction costs for an overhead transmission line are about $3 million to $4 million per mile, versus $20 million to $28 million per mile to construct the line underground. Per state-approved tariff schedule 80, section 34, the local jurisdiction or customer group requesting underground transmission lines must pay the difference between overhead and underground costs. PSE explained they are willing to sit down with interested communities to discuss undergrounding as an option; however, those communities must decide how to pay for the difference in costs, which must be provided up front.

Submarine cables

Some advisory group members expressed interest in PSE pursuing transmission lines submerged under Lake Washington, and pointed to other submerged transmission projects, such as one in San Francisco. PSE presented research on that project, and noted that it costs an average of $56.2 million per mile, compared to the $3 million to $4 million per mile of overhead transmission. As with undergrounding, according to tariff schedule 80, section 34, the local jurisdiction or customer group requesting submerged transmission lines must pay the difference between overhead and submarine costs.

Batteries

Some advisory group members were interested in learning more about battery technology and local energy storage as an alternative to the project. PSE explained that using batteries instead of building a new substation was considered during the solutions identification process, but the technology has not been used for the type and scale of problem facing the Eastside. Additionally, new transmission lines would still be required to distribute electricity from the battery site to PSE's customers.

Seattle City Light corridor

Some advisory group members also asked PSE about using the Seattle City Light (SCL) utility corridor as an alternative to site the new transmission lines. Early on in the solution identification process, PSE identified the SCL transmission corridor as a potential solution to meet the Eastside's energy needs. PSE asked SCL for permission to use their transmission corridor. However, SCL has told PSE that their corridor is a key component of Seattle City Light's transmission system and not available for PSE's use. A letter from SCL articulating this position is available on the Energize Eastside project website. See Appendix D.

Olympic Pipeline safety

Some advisory group members expressed concern over the safety of building the project near the Olympic Pipeline. PSE explained that building 230 kV lines along the Olympic Pipeline (owned and operated by British Petroleum (BP)) would be safe. The Olympic Pipeline has coexisted with PSE transmission lines in the Eastside corridor for over fifty years. PSE also has a long history of working closely with BP and is a natural gas pipeline operator itself. PSE and its contractors are very familiar with concerns regarding pipeline safety and employ safe construction practices when performing work in the vicinity of pipelines. If a selected route is comprised of segments that include the Olympic Pipeline, PSE will continue to work with BP to ensure safety during and after construction.

Property values

Some advisory group members expressed concern about the effects on property values as a result of the Energize Eastside project and asked whether property values could be considered as a factor for evaluating route options. Property values are comprised of many factors, including economic outlook and location, as well as proximity to jobs, schools, transportation, parks and other amenities. PSE explained that it does not use property values as a factor when selecting routes out of fairness to and in consideration for customers of all income levels, noting that it is socially inequitable to site infrastructure based on income-related considerations. Similarly, a project's potential effects on surrounding property values are excluded from consideration of impacts to the environment under Washington's State Environmental Policy Act (SEPA).

Electric and magnetic fields

Several advisory group members asked whether exposure to electric and magnetic fields (EMF) had any effect on health. A third-party, board-certified health physicist explained that over the past 45 years, there have been many scientific studies conducted to determine whether EMF from transmission lines (called "power frequency EMF") has any effect on human health. To date, this large body of research does not show that exposure to power frequency EMF causes adverse health effects.

January-February 2014: Learned about the electric system, project need and routing

The Community Advisory Group began their process by learning about the current electrical system, the need for the project and the solution selection process. During this learning period, the advisory group asked PSE questions on a variety of topics, including transmission line siting, other options considered for the project (e.g., battery technology and conservation), and how a solution was determined. PSE's real estate, engineering and system planning staff provided detailed responses to these questions.

Communications Manager Gretchen Aliabadi explains the undergrounding tariff at Community Advisory Group Meeting #3 in Redmond.

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PSE explained in detail its process to identify a solution and route options, which included the following steps:

1. **Determine the potential approaches to meet the Eastside's electricity needs:** PSE evaluated the potential of several approaches – conservation, local generation and new infrastructure – to meet the Eastside's electricity needs.
2. **Review approaches to provide enough electricity to meet the Eastside's needs:** Engineers reviewed alternatives to each approach, and found that only new generation on the Eastside or new infrastructure located near the center of high electricity demand could meet the Eastside's needs. Additionally, aggressive conservation goals would need to continue.
3. **Review solutions that best deliver electricity to the Eastside:** Engineers reviewed different generation and electric infrastructure alternatives based on system performance, flexibility and longevity. A new generation facility on the Eastside was eliminated from consideration due to difficulties related to siting and operational limitations. It was determined that the best solution to meet the Eastside's electricity needs was to 1) construct a new 230 kV substation and 2) construct new 230 kV transmission lines connecting the new substation with the two existing substations in Redmond and Renton.
4. **Determine which solutions PSE can move forward with:** PSE eliminated the Seattle City Light Corridor and one of the potential Bellevue substation sites as possible new infrastructure locations. Neither the corridor nor the proposed substation property is owned by PSE and other viable sites for new infrastructure were available.
5. **Review where PSE could build a solution:** Engineers used a computer-based modeling tool to analyze key criteria like geographic barriers, land uses and impacts to the environment. Based on this analysis, route segments were identified that could be combined into various complete route options that connect to potential substations (see Figure 2).[1]
6. **Ask what the public thinks:** PSE asked the public to provide input on the combination of route segments that best serves the Eastside's needs. The Community Advisory Group process was part of a larger public outreach process that also included neighborhood briefings, community meetings at key milestones, question and answer sessions, and an interactive project website.

1 TetraTech, *Eastside 230 kV Project Opportunity and Constraints Study for Linear Site Selection*, 2013.

Figure 2. Potential route segments

March-May 2014: Sub-area process and route segment input

In spring 2014, members of the Community Advisory Group participated in one or more of three Sub-Area Committees focused on the following geographic areas:

- North: Kirkland, Redmond and North Bellevue
- Central: Bellevue
- South: Newcastle and Renton

Sub-Area Committee membership included advisory group members and residential association alternates from the geographic

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sub-areas. Invitations to serve on the committees were also extended to a representative from each potentially affected neighborhood association (i.e., those who lived near a potential segment) that did not have a member or residential association alternate on the advisory group.

PSE hosted six sub-area workshops and three Sub-Area Committee meetings across the project area. The three Sub-Area Committees developed findings on specific sub-area values, concerns and considerations about route segments from the workshops conducted in each of the sub-areas. The committees' findings served as a source of information that the Community Advisory Group considered in developing evaluation factors and narrowing the route options. See Table 3 for details on schedule and objectives of the sub-area workshops and Sub-Area Committees.

Discussion about route segments at a Central sub-area workshop in Bellevue.

Discussion about route segments at a South sub-area workshop in Renton.

Table 3: Sub-area workshops schedule and objectives

Dates	Meeting type	Purpose
North: March 19, 2014 Central: March 26, 2014 South: March 27, 2014	Sub-Area Workshop #1	Community members: • Identified key issues and considerations for segments in the sub-area • Brainstormed community values • Requested data that would be helpful to compare segments
North: April 16, 2014 Central: April 23, 2014 South: April 24, 2014	Sub-Area Workshop #2	Community members: • Reviewed data and photo simulations PSE prepared based on requests from Workshop #1 • Used data to score all the route segments individually and as a group • As a group, wrote key messages to the Sub-Area Committee
North: May 7, 2014 Central: May 14, 2014 South: May 15, 2014	Sub-Area Committee meeting	Sub-Area Committees determined key findings from sub-areas to share with the Community Advisory Group

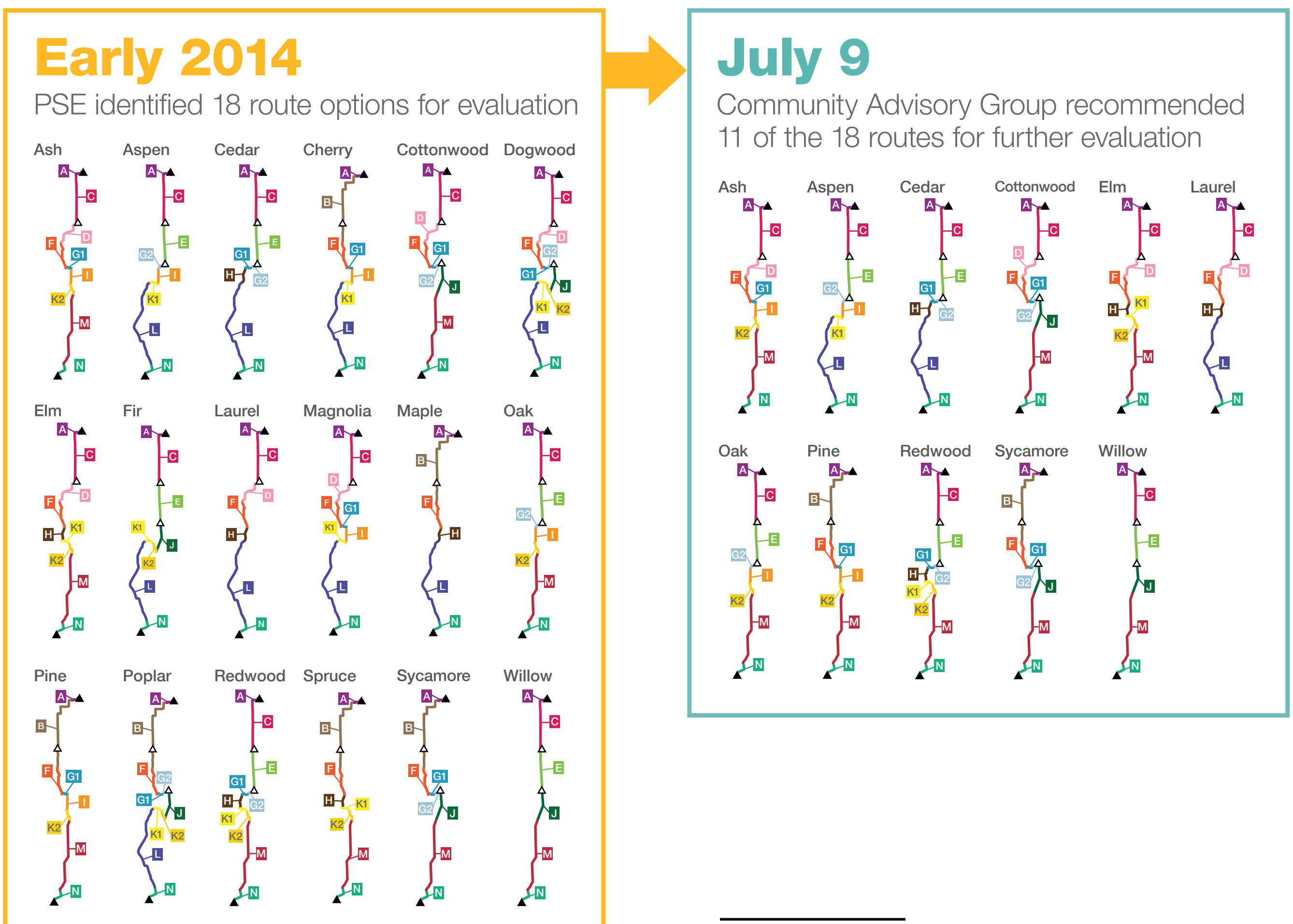
June-July 2014: Narrowed the route options

After segment-specific input was collected through the sub-area process, the Community Advisory Group considered 18 route options made from combining the route segments. (These route options were assigned tree names, such as “Ash,” “Aspen,” and “Cedar,” for easier reference.) The advisory group also identified community values-based evaluation factors.

At their meeting on July 9, the advisory group reviewed the 18 route options and recommended 11 route options for further evaluation.[2] (See Figure 3.) Information that aided their discussion included:

- Feedback from sub-area workshops and Sub-Area Committee meetings, as well as other community input
- Quantifiable data on route options, photo simulations, and information from PSE on route cost, constructability and maintainability
- Results from a blind evaluation of the 18 route options completed by 23 advisory group members
- Initial recommendations submitted before the meeting by eight advisory group members on which route options to remove from further evaluation[3]
- Discussion of route segments and the 18 route options at advisory group meetings

Figure 3: Narrowed route options in July 2014



2 Four advisory group members initially recommended that all or a majority of the 18 routes should move forward for further evaluation.

3 While eight advisory group members provided their initial input before the meeting, all members present at the meeting on July 9 discussed what route options to remove from further evaluation.

October 2014: Evaluated the narrowed route options

The Community Advisory Group used nine evaluation factors (see Table 4), as well as specific route option data, to evaluate the narrowed route options through a process called Multi-Objective Decision Analysis (MODA). MODA is a process for making decisions when there are complex issues involving multiple criteria and multiple parties who may have an interest in the outcome.

Using MODA allows individuals to consider and weight factors and trade-offs while evaluating each alternative (in this case, each route option). Evaluation factors were weighted to reflect the relative importance ascribed to each factor. After scoring each route option for each evaluation factor, the advisory group then discussed the combined group results to help decide on a recommendation. See Figure 4 for a description of the MODA steps and how the advisory group used MODA.

Between Oct. 2 and Oct. 6, 2014, 19 of 24 advisory group members completed individual evaluations of the 11 route options recommended for further evaluation as part of the MODA process. Using online software called Transparent Choice, advisory group members individually scored each route option using each of the nine evaluation factors on a five-point scale. The software then applied two sets of weightings – one determined by the advisory group and another determined by community members who participated in a summer 2014 feedback survey – to the group's averaged scores. See Table 4 for descriptions of the evaluation factors and the two weighting schemes.

Figure 4: Multi-Objective Decision Analysis (MODA)

MODA steps

1. **Factors** - Discuss and agree on evaluation factors
2. **Weighting** - Determine relative importance of each factor and assign corresponding weights
3. **Route options** - Determine route options to evaluate
4. **Scoring** - Score each route option for each weighted factor
5. **Decision** - Discuss results and determine decision

How the Community Advisory Group used MODA

1. **Selected nine evaluation factors** based on community values
2. **Used two sets of weightings** - one determined by the advisory group and a second determined by a community survey
3. **Selected 11 route options** out of 18 to include in the evaluation
4. **Scored** the 11 route options for how well they each met the nine evaluation factors using an online software called Transparent Choice
5. **Considered MODA results** along with community feedback and other sources of information to select four routes as their preliminary route recommendation

Table 4: Evaluation factors and their weightings determined by the advisory group and a community survey

Evaluation factor	Advisory group weighting	Community survey weighting
Avoids impacts to aesthetics (Pole design and views)	5%	14%
Avoids residential areas (Number of residences)	24%	31%
Avoids sensitive community land uses (Parks and other recreational areas, schools, religious institutions, etc.)	13%	10%
Avoids sensitive environmental areas (Wetlands, wildlife habitat, steep slopes, fault lines, etc.)	7%	12.5%
Least cost to the rate payer (Estimated monthly increase to average residential customer; calculation based on total cost)	14%	7%
Maximizes longevity (When in the future additional 230 kV infrastructure is anticipated based on current technology and growth projections)	9%	4%
Maximizes opportunity areas (Runs along existing utility corridors, railroad right of way, public right of way, etc.)	15%	6%
Protects health and safety (Electric and magnetic fields, Olympic Pipeline, etc.)	9%	9%
Protects mature vegetation (Number of trees greater than four inches impacted)	4%	6.5%
Total	100%	100%

On the following page, Figures 5 and 6 present the MODA results for each route option, first using the advisory group weighting and second the community survey weighting. Within the results bar for each route option, colors represent the evaluation factors and show the advisory group's averaged and weighted score for each factor. A higher number equals a better score. Weighting percentages are shown in the weighting keys.

Figure 5: MODA results - Advisory group weighting

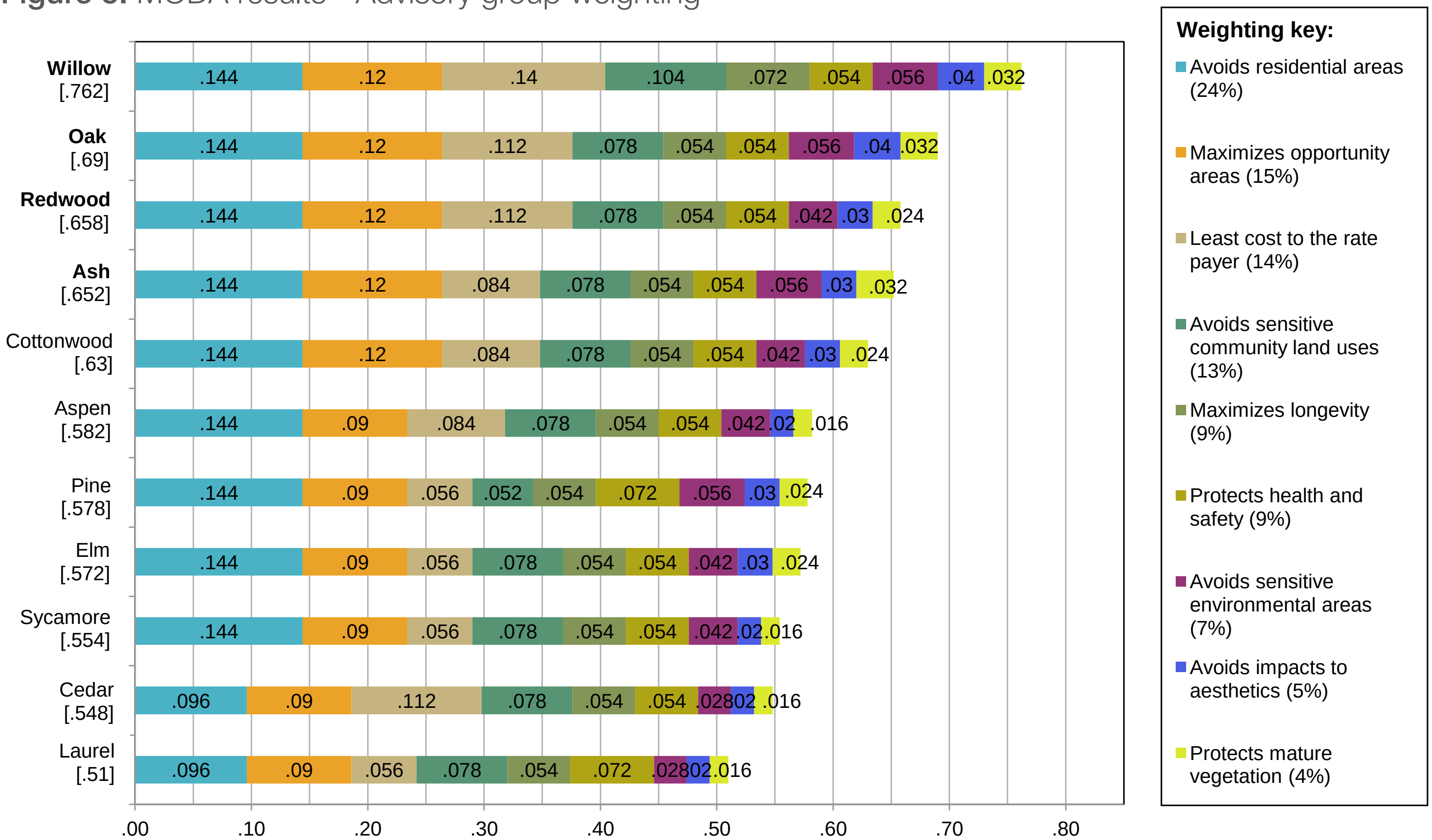
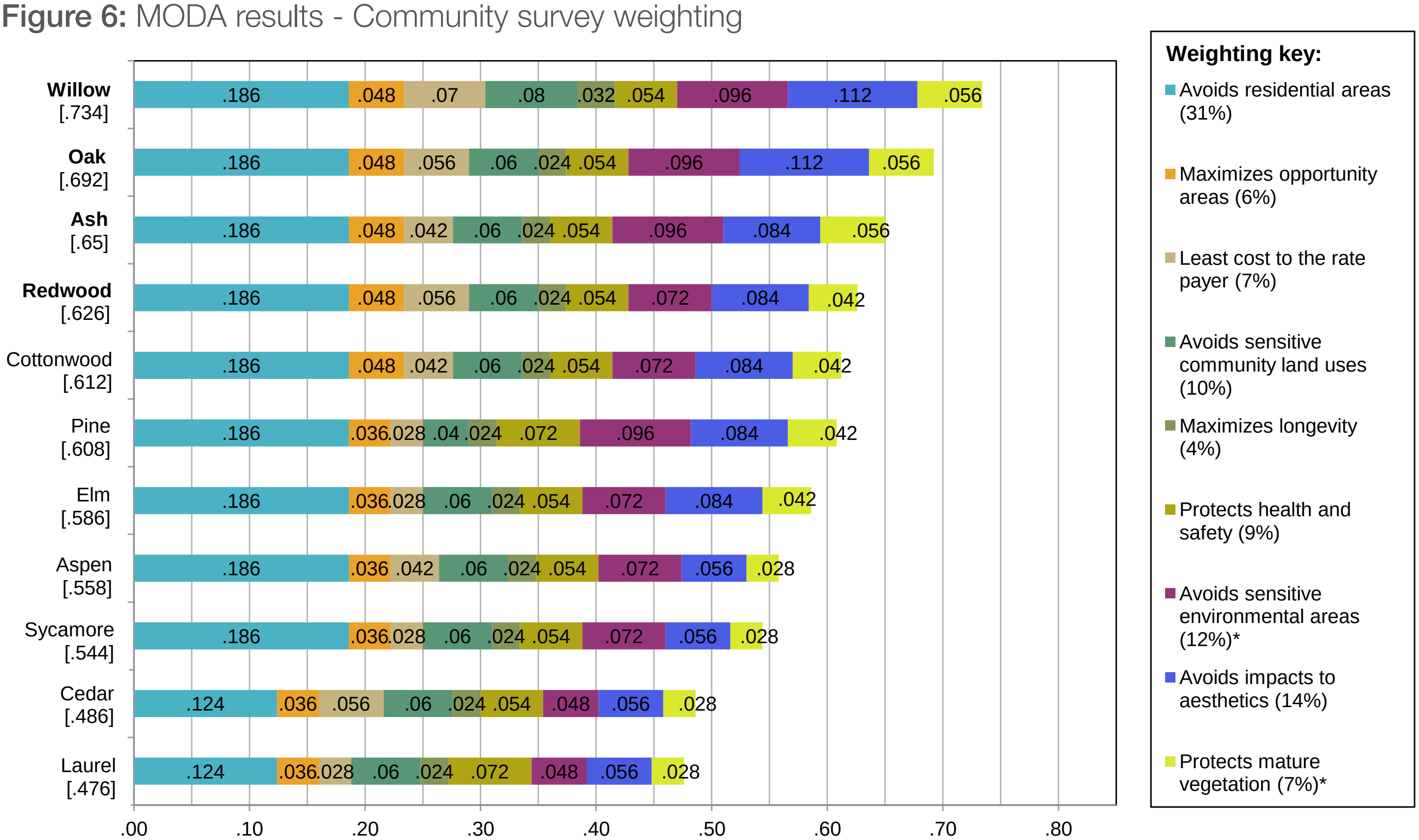


Figure 6: MODA results - Community survey weighting



* Note: Transparent Choice, the online MODA software used to compile and calculate results, can only use weighting values that are whole numbers. As a result, the evaluation factors “Avoids sensitive environmental areas” and “Protects mature vegetation” were rounded to the nearest whole number.

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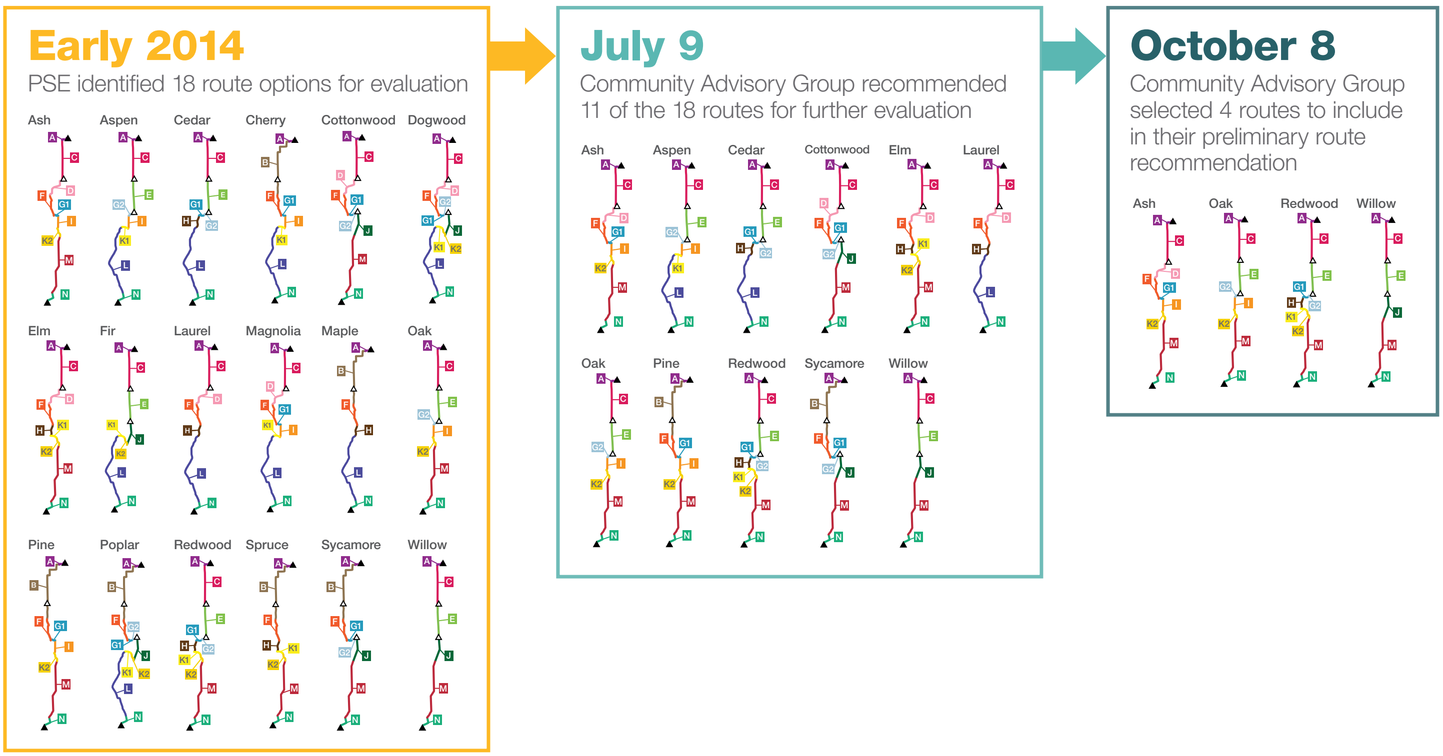
October 2014: Preliminary route recommendation

At their Oct. 8 meeting, the advisory group selected four route options – Ash, Oak, Redwood and Willow – as their preliminary route recommendation (see Figure 7).[4] Information sources that helped the group determine their recommendation included:

- Results of the Multi-Objective Decision Analysis (MODA) using evaluation factor weightings from both the advisory group and community survey results
- Feedback from the summer community survey and other community input
- Discussion of the 11 route options at advisory group meetings

Figure 7. Narrowed route options and the preliminary route recommendation in October 2014



4 Of the 18 members present, 15 supported the recommendation, two members abstained and one had a dissenting opinion to include only three routes.

Reviewing results from the blind evaluation at Community Advisory Group Meeting #4b in Renton.

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V. Community involvement

In addition to convening the Community Advisory Group, PSE involved the community in the public routing discussion from announcement of the project (December 2013) through the completion of the advisory group process (December 2014) by hosting community meetings, briefing organizations and gathering and responding to comments about the project.

PSE community involvement included:

- More than 240 briefings with individuals, neighborhoods, cities and other stakeholder groups
- 6 public open houses at key project milestones
- 2 online open houses
- 2 question and answer community meetings
- 1 webinar on undergrounding and electric and magnetic fields

Additional project outreach included:

- More than 2,300 comments and questions received from the public, summarized in monthly public comment and open house summaries made available to the advisory group
- 6 project newsletters and postcards sent to more than 50,000 residents and business owners
- Attendance at more than 60 community events
- A traveling kiosk displaying project updates throughout the Eastside
- Project update emails to distribution list, community organizations and elected officials
- Targeted outreach to traditionally underrepresented populations

Reviewing route option maps at Open House #1 in Renton.

Community Projects Manager Jackson Taylor providing project background at the Bellevue Strawberry Festival.

Public comment at Question and Answer Meeting #1 in Renton.

VI. Recommendation of the Community Advisory Group

On Dec. 10, 2014, the Community Advisory Group selected routes Oak and Willow as their final route recommendation for PSE's consideration (see Figure 8).

With this recommendation, the Community Advisory Group fulfilled their purpose as outlined in their charter:

"Work collaboratively, creatively and constructively to help determine community/property owner values and engage in a process to evaluate route segments and select a recommended route option."

Twenty-two advisory group members and four residential association alternates participated in the recommendation discussion. Twenty supported the final recommendation as follows:[1]

- Ten expressed preference for the Oak route
- Five expressed preference for the Willow route
- Five did not express a preference

Figure 8. The Community Advisory Group final route recommendation

Four advisory group members and two residential association alternates[2] – representing Bridle Trails Community Club, City of Newcastle, Liberty Ridge Homeowners Association, Olympus Neighborhood Association, Somerset Community Association, and Sunset Community Association – dissented from the recommendation and supported none of the routes. Refer to Appendix B for the dissenting opinion.

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1 The above count includes the advisory group members and residential association alternates present at the Dec. 10, 2014 meeting, as well as six members and residential association alternates who did not attend the meeting but later provided feedback on the recommendation.

2 Darius Richards (Kennydale Neighborhood Association) and Scott Kaseburg (Lake Lanes Community Association), who supported the final recommendation in the meeting, signed the dissenting report after the meeting.

At the Dec. 10 meeting, advisory group members and residential association alternates who expressed a preference for Oak or Willow discussed several benefits and tradeoffs of each. See Table 4.

Table 4. Route benefits and tradeoffs noted by Community Advisory Group members and residential association alternates with a route preference expressed at the Dec. 10 meeting[3]

Routes	Benefits	Tradeoffs
Oak (Segments: A-C-E-G2-I-K2-M-N)	• Has fewer adjacent residential parcels (524) of the two routes • Has one quarter of adjacent residential parcels (31 in segments G2, I, K2) compared to same portion in Willow (123 in Segment J) and less than half the residences within 600 feet (289 vs. 721) • Avoids residential areas by using Segment I, which is a largely commercial corridor	• Estimated cost is $22 million more than Willow ($176 million total cost; $1.03 estimated monthly increase to an average residential customer) • Requires building infrastructure in new areas (83% of the route is within the existing corridor) • Has a larger number of adjacent residential tax accounts (1,425)
Willow (Segments: A-C-E-J-M-N)	• Has fewer adjacent residential tax accounts (1,422) of the two routes (One advisory group member noted that the difference in residences between Oak and Willow was minor.) • Is the most direct route • Has the highest percentage of route within the existing corridor (100%) • Is the least expensive ($154 million total cost; $0.90 estimated monthly increase to an average residential customer) • Has the greatest longevity (2038)	• Has a larger number of adjacent residential parcels (616) of the two routes • Uses Segment J, which is a view neighborhood

3 For more data on Oak, Willow, and all route options considered by the Community Advisory Group, refer to the complete route options data table on the Energize Eastside project website.

Discussing the final route recommendation at Community Advisory Group Meeting #6 in Bellevue.

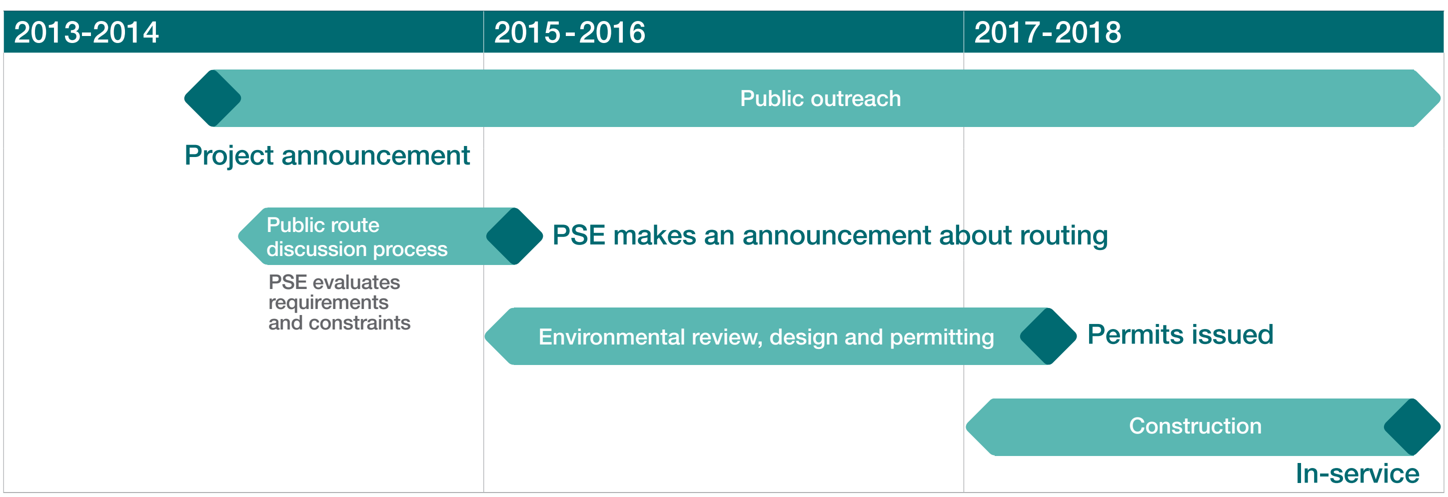
VII. Puget Sound Energy's next steps

Following the completion of the Community Advisory Group's process, PSE's next steps in 2015 are to:

- Take the Community Advisory Group's recommendation under consideration and make an announcement about routing that balances the needs of customers, the local community, property owners and PSE
- Work directly with property owners and tenants to begin detailed fieldwork to inform environmental review, design and permitting
- Ask for community input on project design, which may include pole height, finish and other design considerations
- Work with the City of Bellevue and other affected jurisdictions and agencies on the project's Environmental Impact Statement (EIS) process

Once these steps are complete, PSE will apply for necessary permits from appropriate agencies and jurisdictions. The project design and permitting phase is expected to run through early 2017. Once fully designed and permitted, project construction is expected to begin in 2017, with project completion planned for 2018. See Figure 9.

Figure 9: Project schedule and next steps



Appendices

Appendix A: Community Advisory Group Charter

Appendix B: Minority Report

Appendix C: Community Advisory Group meeting materials, presentations and summaries

Appendix D: Bibliography

DSD 008427

Community Advisory Group Charter

Revised:3/24/14

Purpose

The main purposes of the Community Advisory Group are to:

- Learn about PSE's proposed route segments, PSE's route analysis work to date, and the complexity of identifying the route segments, and to work with PSE to combine segments to develop a Community Advisory Group-recommend route to inform PSE as PSE selects a final route.
- Collaborate with PSE to decide on a community values-based evaluation process that will be used by the Community Advisory Group to consider PSE's various route segments, combine into possible route options, and narrow route options down to a Community Advisory Group-recommended route.
- Provide a forum for the community to give meaningful input on route segments and route options.
- Help PSE better understand community/property owner values as PSE selects the preferred route that balances the needs of their customers, the local community, property owners and PSE.

The Community Advisory Group will:

- Develop an understanding of the Energize Eastside project and project need.
- Report back to the people/groups they represent on project details, gather feedback from the interests they represent and provide ongoing communications between PSE and the group they represent throughout the process.
- Provide advice, as community representatives, on ways to address community concerns.
- Participate in geographic Community Advisory Group Sub-Area Committee meetings to determine recommended route segments.
- Work collaboratively, creatively and constructively to help determine community/property owner values and engage in a process to evaluate route segments and select a recommended route option.
- Partner with PSE to combine route segments into one Community Advisory Group recommended route.

Community Advisory Group Sub-Area Committees

- Sub-Area Committees will consist of Community Advisory Group members and their residential association alternates from each of the geographic sub-areas (North – Kirkland, Redmond and North Bellevue; Central – Bellevue; and South – Newcastle and Renton), as well as a representative from each potentially affected neighborhood association that does not have a member or residential association alternate on the advisory group. Additional community representatives will be invited as needed to ensure comprehensive discussion of issues.
- Community Advisory Group members are expected to attend the Sub-Area Committee meetings for their geographic sub-area. In order to participate in the Sub-Area Committees, members should attend the first two advisory group meetings to ensure they have an understanding of the project.
- Residential association alternates are required to attend the Sub-Area Committees to ensure balanced representation from neighborhoods. Alternates representing other interests are recommended to attend, but it is not required.
- The purpose of the Sub-Area Committees is to have an interest-based conversation on route segments and preferred sub-area options. The outcome of the Sub-Area Committee meetings will

be to develop sub-area segment combination recommendations for the full Community Advisory Group discussion.

PSE staff will:

- Provide information on the area's growth, the need for the project and the factors involved in developing route segments.
- Provide draft materials to Community Advisory Group members one week before meetings.
- Provide technical experts to provide a greater understanding of the topics at hand and inform Community Advisory Group dialogue.
- Consult with the Community Advisory Group, listen carefully and consider advisory group input prior to making final decisions on key technical issues, and explain all decisions made.
- Listen and take into consideration recommendations from the advisory group with regards to providing data and requests for analysis and research to support advisory group deliberations.

Norms for individual work as members of the Community Advisory Group

- We acknowledge our group's diversity and value different points of view. We will respect each other's opinions and will operate in consistently constructive ways.
- We will make every effort to attend meetings, to participate actively, to read and be prepared to discuss information and issues, and to be available for work between formal meetings.
- We will keep an open mind and come to meetings with interests, not entrenched positions. We will share our interests and objectives with all Community Advisory Group members. We will openly explain and discuss the reasons behind our statements, questions and actions.
- We will be responsible for representing the interests and concerns of the community we represent at the table. We will consult with our constituencies on a regular basis concerning the discussions and preferences of the Community Advisory Group.
- We will listen carefully to the views expressed by others, avoid interruptions, and seek ways to reconcile others' views with our own. We will represent information accurately and appropriately.
- We will adhere to the ground rules and respect the procedural guidance and procedural recommendations of the facilitator.

Norms for our work together

Use of time

- We will respect each other's time by being on time. Meetings will begin and end on time, unless otherwise agreed to by the Community Advisory Group members.
- When making our comments, we will consider the time needed for others to share their perspectives.

Recommending a route

- Community Advisory Group members will strive to collectively make reasonable requests and suggestions through a cooperative and collaborative discussion process with PSE. PSE will inform the Community Advisory Group of any areas of flexibility in the route recommendation development process.
- In discussions, suggestions may not represent unanimity. The facilitator is responsible for seeking and probing for group preferences. It is the responsibility of each stakeholder group member to voice dissent if s/he cannot live with any particular suggestion.
- Any recommendations from the Community Advisory Group and sub-area committees will be considered by PSE. PSE will evaluate requirements and constraints, and select a preferred route. PSE is the final decision maker regarding selecting a preferred route.
- If PSE chooses not to move forward with the recommended route as PSE's preferred route for permitting, PSE will explain the reason for its decision.

Facilitator

- We give the facilitator permission to keep the group on track and “table” discussions to keep the group moving.
- We expect the facilitator to help the Community Advisory Group accomplish our purpose in a completely neutral, balanced and fair manner.
- We want the facilitator to:
    - Develop draft meeting agendas.
    - Manage Community Advisory Group meetings and discussions.
    - Consult with Community Advisory Group members between meetings about how to manage the process and address issues of concern.
    - Prepare meeting summaries.

Role of alternates

- Each Community Advisory Group member may have one alternate who will be available to stand in for Community Advisory Group members who are unable to attend meetings. Alternates are encouraged to attend all meetings but will not be asked to participate unless called upon.
- Alternates can participate in the Sub-Area Committee meetings if they have attended both of the initial Community Advisory Group meetings.
- Community Advisory Group members are expected to update alternates between meetings so they can replace members on a moment’s notice.

Role of residential association alternates

- Each Community Advisory Group member representing a residential organization may have an appointed residential association alternate that represents a different neighborhood within their city. Residential association alternates are intended to help balance representation from neighborhoods along the route segments.
- Residential association alternates can ask Community Advisory Group members to yield their seat to ask a question or make a comment during Community Advisory Group meetings.
- Residential association alternates serve as members of their geographic Sub-Area Committee and are expected to attend Sub-Area Committee meetings.

Proposed meeting ground rules

- Start / end on time
- Silence cell phones
- Come prepared
- Listen respectfully
- Speak from interests, not positions
- Participate in the process

Norms for our work with others outside the Community Advisory Group

External communications

- All Community Advisory Group meetings shall be open to the public.
- The public will be given the opportunity to comment during each Community Advisory Group meeting. Those wishing to provide public comment to the advisory group will be strongly encouraged to direct their comments towards the issues and topics of focus on the advisory group’s agenda.

- We will avoid characterizing the views or opinions of other Community Advisory Group members outside of any advisory group meeting or activity.
- We will accurately describe Community Advisory Group preferences that are conveyed to PSE.
- Community Advisory Group meetings will be announced on the Energize Eastside website, and meeting announcements with date, time and location, will be provided to local blogs and other media outlets for distribution to the broader community.
- Community Advisory Group meeting products, such as agendas, summaries, and PowerPoint presentations will be posted at pse.com/energizeeastside and will be available to advisory group members for distribution to their constituents. Note: Community Advisory Group member names and affiliations will be included in these materials and will be listed on the project website.

Appendix B: Minority Report

Some Community Advisory Group members did not concur with the consensus recommendation. The report of the minority is provided here in the interest of inclusiveness. The Community Advisory Group majority has not reviewed this report; consequently, it has not been verified by the Community Advisory Group majority for consistency with the Community Advisory Group charter or for technical accuracy, either independently or in conjunction with engineering support from Puget Sound Energy. This report reflects only the opinion of its signatories.

Appendix B: Minority Report

Dissenting Report

We, the undersigned members of the "Community Advisory Group" (CAG) for PSE's Energize Eastside project, declare our dissent from the recommendations included in the Final Report of the CAG.

The CAG did not truly represent the wishes of the community for the following reasons:

1. CAG members were selected by PSE, not the community.
2. PSE misrepresented the full purpose of Energize Eastside.
3. PSE did not provide real data establishing the need for the project.
4. PSE did not provide a complete list of alternative solutions, and CAG members weren't allowed to discuss alternatives.
5. The CAG was not given real choices, because some of the route segments were never viable.
6. Few CAG members participated in critical evaluations.
7. The CAG facilitator was not impartial and frequently pressured members to support the group's conclusions.
8. CAG members were not asked to officially endorse the outcome of the CAG process.

The remainder of this report will provide additional detail regarding these eight objections.

1. CAG selection

Composition of the CAG was determined by PSE, not the community. PSE diluted the votes of residential neighborhoods that had the most at stake. Only one quarter of the voting members represented neighborhoods, and many affected neighborhoods had no representative. Some members represented organizations which receive generous donations from the PSE Foundation.

2. The full purpose of Energize Eastside

Documents available from ColumbiaGrid, Seattle City Light, and the Bonneville Power Administration make it clear that Energize Eastside solves three simultaneous problems: 1) load for PSE, 2) load for Seattle City Light, and 3) regional grid reliability for Bonneville Power Administration (a federal agency). According to a 2012 Memorandum of Agreement signed by PSE, SCL, and BPA, transmission lines in the Puget Sound region can become congested when high local needs coincide with high flows of electricity to British Columbia, especially when there are faults on BPA's trunk lines. This is a concern because the United States is obligated to provide electricity to Canada through the Columbia River Treaty. The large scale of the Energize Eastside project addresses both local and international electricity needs. However, Energize Eastside is not the only solution that can do this. It might not even be the most economical solution, when the project's impact on the community is considered. Reduced property values along the entire 18-mile length of the line cause declines in economic activity and tax receipts, which must be compensated by increasing tax rates on other residents, or decreasing support to people who need tax-funded services.

PSE never disclosed the whole purpose of the project to CAG members. The company sought to minimize regional questions by claiming only 3-8% of power flow serves Canada. While this might be true on a normal day, Energize Eastside is designed to handle extraordinary power flows that occur in rare emergency conditions. Without a full disclosure of the scope and purpose of the project, CAG members were not able to accurately represent the views of their constituents regarding the project.

3. Eastside need

PSE illustrates the need for Energize Eastside using a graph titled "Eastside Customer Demand Forecast."[1] This graph has been simplified so it can be easily grasped by the public. It shows demand growing at an average rate of 1.9% per year, crossing the "System Capacity" line in 2017. According to PSE, electricity outages will become more likely after that.

CAG members are well-informed individuals who had months to understand the issues. Therefore, we expected PSE would provide CAG members with more detailed information regarding the need for the project. There are many questions that members had. How has the Eastside's electricity demand grown over time? Why is demand supposedly growing at a much faster rate than population or economic growth? Why is PSE's projection of Eastside's demand growth more than double that of Seattle's or Portland's? Would programs such as Demand Response help mitigate our demand growth?

PSE did not answer these questions, saying that they were outside the scope of the CAG's stated mission. The CAG was formed only to provide recommendations on which route the overhead lines should take through the five Eastside cities. PSE said that community input was not needed regarding any other aspect of the project.

4. Alternative solutions

CAG members also raised questions about alternative solutions. They wondered why alternatives were eliminated from consideration and further discussion of alternatives was not allowed.

We believe it is important to list reasonable and viable alternatives to Energize Eastside here, since these ideas do not appear in the limited Final Report. The alternatives described below address only the Eastside's local need. BPA would have to build its own project to solve Canadian reliability issues, at a lower cost to PSE's customers.

The issue of cost is of critical importance to many CAG members, especially organizations representing low-income residents like Hopelink and the YMCA. It is also of interest to businesses that are sensitive to the cost of electricity. Adding 1-2% to electricity costs for the next 40 years may affect their profitability. Many CAG members would have supported lower-cost alternatives if PSE had allowed them to be explored by the CAG.

a. **Demand-side Resources.** Demand-side Resource (DSR) programs are used by utilities in almost every state to reduce the stresses of peak load service and avoid construction of new generation and transmission infrastructure. In the Northwest, Portland General Electric devotes 14 pages of its latest Integrated Resource Plan to descriptions of various programs, including a curtailment tariff, residential direct load control, critical peak pricing, and conservation voltage reduction. Similar programs were studied in a detailed report created by the Cadmus Group for PSE's most recent IRP[2]. Which of these programs is PSE planning to implement? The IRP says, "Demand response program costs are higher than supply-side alternatives at this time, and PSE does not currently have a program in place." Translation: it's cheaper to burn coal in a plant located in Colstrip, Montana (one of the dirtiest coal plants in the nation) that provides nearly 1/3 of the Eastside's electricity. The economics of cheap coal

[1] http://energizeeastside.com/Media/Default/AbouttheProject/2013_1030_Single_Line_Load_Chart_v3.png
[2] https://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppN.pdf

and guaranteed returns for capital improvements like Energize Eastside provide little financial incentive for PSE to pursue DSR programs.

b. **Lake Tradition transformer.** For several years before Energize Eastside was conceived, PSE proposed to meet Eastside demand by adding a new 230/115 kV transformer located at Lake Tradition (near Issaquah). Additional power would be delivered on existing 115 kV lines to the Lakeside substation. PSE now claims that this solution causes other transformers to overload in power flow simulations conducted by the company. However, these simulations include the surge of electricity caused by faults in BPA's trunk lines. If BPA were to solve those problems with their own project, Lake Tradition might become a viable solution with much lower costs and community impacts than Energize Eastside.

c. **Upgrade 115 kV lines.** It's possible to use thicker wire and higher capacity transformers on existing lines to increase capacity by approximately 29%. That is enough to delay further action for at least a decade. During that time, it's likely that technologies such as grid batteries, distributed generation, and increasing efficiency will make other solutions possible. This will be cheaper than Energize Eastside, and better for the environment. Upgrading the lines at their current voltage will spare nearly 8000 mature trees that must be cut or removed along the Oak or Willow routes to accommodate a 230 kV line (according to PSE's counts). There is no record that PSE studied this option. It was never mentioned during CAG meetings.

d. **Gas powered plant.** PSE studied the possibility of meeting Eastside needs using a gas-powered generation plant. They dismissed this option in 3 sentences in their Solutions Study. Two of the potential sites for the plant were judged to be too difficult to permit, although this determination was made solely by the company without input from city officials. A third site was dismissed because it would require construction of transmission lines. Neither the CAG nor the cities were given further details about the costs of such a plant, where the transmission lines would be located, how reliability of local generation compares to remote generation, how it impacts the community, or how it might help reduce use of coal that creates much higher emissions of atmospheric carbon, mercury, and sulfur.

e. **Micro-grids and small turbines.** A national expert says that the Puget Sound area is an ideal place to use small gas turbines to inexpensively and incrementally serve peak loads. There is no record that PSE studied this option.

f. **Grid batteries.** PSE says grid batteries are likely to play an important role in the future. The company already has a pilot battery project in Bainbridge. But according to PSE, batteries are too expensive and too risky to use at this time. The company says it can forecast future demand, but it can't forecast the viability of technology solutions that might address that demand.

We believe that one or more of the above solutions would address Eastside's demand and reliability needs for many years at a lower cost than Energize Eastside, allowing us time to develop clean, sustainable solutions rather than rushing a project that is out of scale for our needs as well as our beautiful scenery.

For completeness, we will mention two other alternatives that CAG members were interested in. Both of these would solve Canadian reliability issues as well as Eastside need, but for a considerably higher price tag:

g. **Underground lines.** We list this alternative because it is the most frequently asked question by the public: "In this day and age, why can't we bury our transmission lines?" PSE has made this option politically impossible, due to a tariff the company proposed to the Washington Utilities and Transportation Commission (and which the UTC subsequently adopted). The tariff requires each community who requests an underground line to bear the high cost of underground infrastructure on their own. With the exorbitant costs estimated by PSE, this is not a realistic option for any community. While this tariff seems reasonable for local distribution lines, we hope its application to regional transmission lines will be revisited by the UTC.

h. **Underwater lines.** There are many examples in the U.S. of high-voltage transmission lines being placed in lakes, rivers, and bays. This technology is maturing rapidly. PSE said they would write a white paper on this alternative. The white paper was not released in time for consideration by the CAG.

5. No real choices

It should be no surprise that the final routes selected by the CAG mostly follow the existing transmission corridor. This is the result PSE expected from the beginning, and was confirmed by a senior PSE engineer who said the process of route selection was needed to help the public feel like they were involved in the project.

In particular, the choice between the L and M segments was a false choice. The L segment was never a legally viable option due to well-known conflicts and impacts. PSE should have known this. It is also highly questionable that the B segment was viable, due to the large amount of new right-of-way that would need to be acquired to construct that segment.

We believe the CAG process was more about PR for PSE than real choices for the community.

6. CAG participation

In several cases, only a few CAG members participated in important evaluations. For example, at the July 9th meeting, it was revealed that only 8 CAG members (less than a third of the CAG membership) participated in an evaluation process to eliminate potential routes. These low participation rates didn't occur because CAG members were lazy or on vacation. Many of the residential representatives refused to participate because they objected to the process.

7. CAG process

The facilitator for the CAG was a contractor hired by PSE, harming the appearance of impartiality. The facilitator appeared to have two goals: 1) produce a route recommendation that isn't too onerous to PSE, and 2) achieve this result using "consensus building" techniques.

Unfortunately, these goals were achieved by pressuring or cajoling CAG members to abandon their preferences and join the consensus view. For example, the facilitator would often say to a reluctant member, "Could you live with the emerging consensus of the group?" Or, "Do you want your name to be listed as the dissenting vote?" There were many times when a dissenting member would reluctantly give up significant objections to avoid appearing obstinate or going against the other members. An anonymous ballot would have produced a different result than the facilitated outcome.

Do decisions made in this manner truly represent community values? One need only observe the audience at the final CAG meeting to answer that question. At least 90% of the 400-member audience enthusiastically supported dissenting remarks made by members of the CAG. We conclude the recommendations of the CAG do not represent the desires of the community.

This is also evident in the routes that were finally selected. Both the CAG and hundreds of residents voting online agreed that the top factor to be used to judge routes was "Avoids residential areas." For both the CAG and the community, this factor rated significantly higher than any other. However, in the rush to consensus, the CAG ignored the criterion they previously agreed was the most important and focused instead on cost. All of the routes inequitably burden residential neighborhoods with poles as high as 135 feet that are out of scale with residential land use codes.

8. No endorsements

As of December 15, CAG members were not asked to endorse the Final Report with their signatures. We note a stark contrast with the outcome of a different advisory group for a previous PSE project:

> *"We, the members of the Sammamish-Juanita 115 kV Project Stakeholder Advisory Group, affirm and support this recommendations report to Puget Sound Energy. We believe PSE's community-involved siting process for this project has been transparent and reflects community input."*

Why aren't members of our CAG signing a similar statement in support of their recommendations for Energize Eastside? Could members of this CAG sign a positive statement like this in good faith?

Conclusion

Energize Eastside is one possible step towards our energy future. This is a decision that should be made by citizens and their elected representatives, taking into account values such as community impact, environmental impact, cost, reliability, and safety. This decision should not be made by a utility company or an advisory group with little community support.

The undersigned members of the CAG declare our dissent with the CAG's Final Report.

(By signing this document, we are not rescinding the opinions we expressed or votes we cast during CAG meetings, but simply stating our dissent with the overall project and process.)

Norman Hansen CAG, BELLEVUE BRIDLE TRAILS COMMUNITY

L Kaseburg

TIM McHARG, CITY OF NEWCASTLE

Darius F. Richards

Steven D. O'Donnell

David T. Evans

Lindy Bruce Sunset Community Assn.

Appendix C: Community Advisory Group Meeting Materials, Presentations, and Summaries

The following links provide all Community Advisory Group meeting materials, presentations and meeting summaries:

Jan. 22, 2014 - Community Advisory Group Meeting #1
Convened the advisory group

Feb. 12, 2014 - Community Advisory Group Meeting #2
Learned about the solution selection process and project routing

June 4, 2014 - Community Advisory Group Meeting #3
Reviewed key findings from the Sub-Area Workshops and Committee Meetings

June 25, 2014 - Community Advisory Group Meeting #4a
Reviewed potential route options

July 9, 2014 - Community Advisory Group Meeting #4b
Narrowied potential route options and finalizing evaluation factors

Oct. 1, 2014 - Community Advisory Group Meeting #5a
Reviewed key findings from the open houses and preparing for route evaluation

Oct. 8, 2014 - Community Advisory Group Meeting #5b
Developed preliminary route recommendation

Dec. 10, 2014 - Community Advisory Group Meeting #6
Finalized route recommendation for PSE to consider

Appendix D: Bibliography

The list below includes key reports developed by PSE and/or third-party experts, the findings of which were shared with the Community Advisory Group. All linked documents are available on the Energize Eastside project website at pse.com/energizeeastside.

Quanta Technology and Puget Sound Energy, *Eastside Needs Assessment Report*, 2013.

- Executive Summary
- Full Report

Quanta Technology and Puget Sound Energy, *Eastside Transmission Solutions Report,* 2013.

- Executive Summary
- Full Report

TetraTech, *Eastside 230 kV Project Opportunity and Constraints Study for Linear Site Selection,* 2013.

- Executive Summary
- Full Report

Energy + Environmental Economics, *Non-wire Solutions Analysis*, 2014.

- Full report

Power Engineers, *Underground Feasibility Study,* 2014.

- Full report
- Appendix A - Aerial Route Drawings (part 1)
- Appendix A - Aerial Route Drawings (part 2)
- Appendix B - Typical Detail Drawings

Additional documents referenced throughout the Final Report:

Puget Sound Regional Council 2013 Land Use Baseline: Maintenance Release 1 (MR1), update April 2014.

Letter from Seattle City Light, June 2, 2014.

Tariff schedule 80, section 34, 2006

Attachment B: OAK 1

(Segments A-C-E-G2-I-K2-M-N)

Route options are configured to go from Segment A to Segment N and connect with Lakeside substation site.

LEGEND

- ==== Double-circuit transmission line
- ▲ Existing substation
- △ A Route segments and substation undergoing additional analysis

NOTE: These maps are for illustrative purposes only. Preliminary route, pole types, and pole heights are subject to change pending design, engineering, and environmental review. Poles may need to be taller in certain locations such as when crossing a highway.

energizeEASTSIDE

PSE PUGET SOUND ENERGY

March 2016

Attachment C: WILLOW 1

(Segments A-C-E-J-M-N)

Route options are configured to go from Segment A to Segment N and connect with Lakeside substation site.

LEGEND

- Double-circuit transmission line
- Single-circuit transmission line
- ▲ Existing substation
- △ A Route segments and substation undergoing additional analysis

NOTE: These maps are for illustrative purposes only. Preliminary route, pole types, and pole heights are subject to change pending design, engineering, and environmental review. Poles may need to be taller in certain locations such as when crossing a highway.

energize**EASTSIDE**

PSE PUGET SOUND ENERGY

March 2016

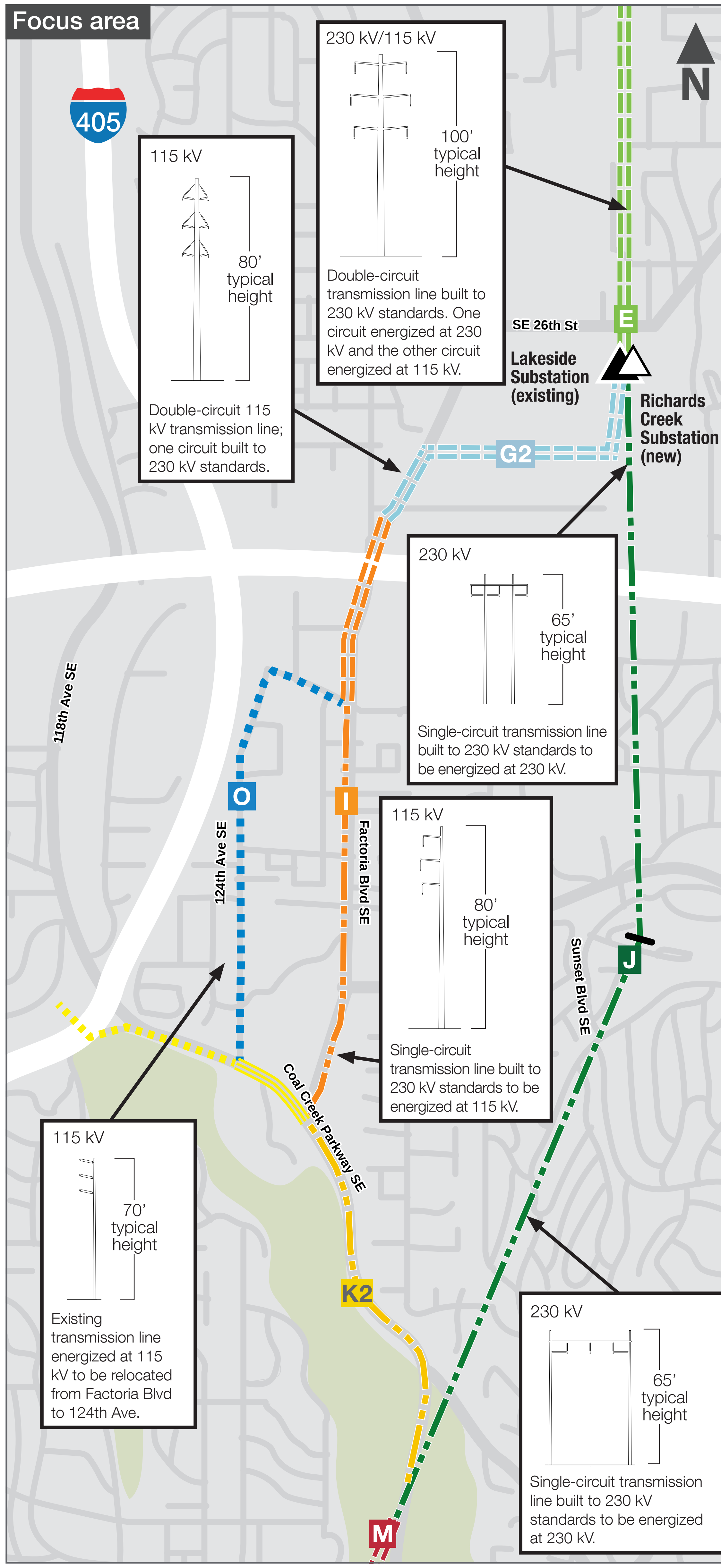
Attachment D: OAK 2

(Segments A-C-E-M-N, connection choices utilizing G2-I-J-K1-K2)

Route options are configured to go from Segment A to Segment N and connect with Lakeside substation site.

LEGEND

- Single-circuit transmission line
- Potential relocation routes for existing 115 kV transmission line
- Double-circuit transmission line
- Existing 115 kV transmission line to be removed
- ▲ Existing substation
- △ A Route segments and substation undergoing additional analysis



NOTE: These maps are for illustrative purposes only. Preliminary route, pole types, and pole heights are subject to change pending design, engineering, and environmental review. Poles may need to be taller in certain locations such as when crossing a highway.

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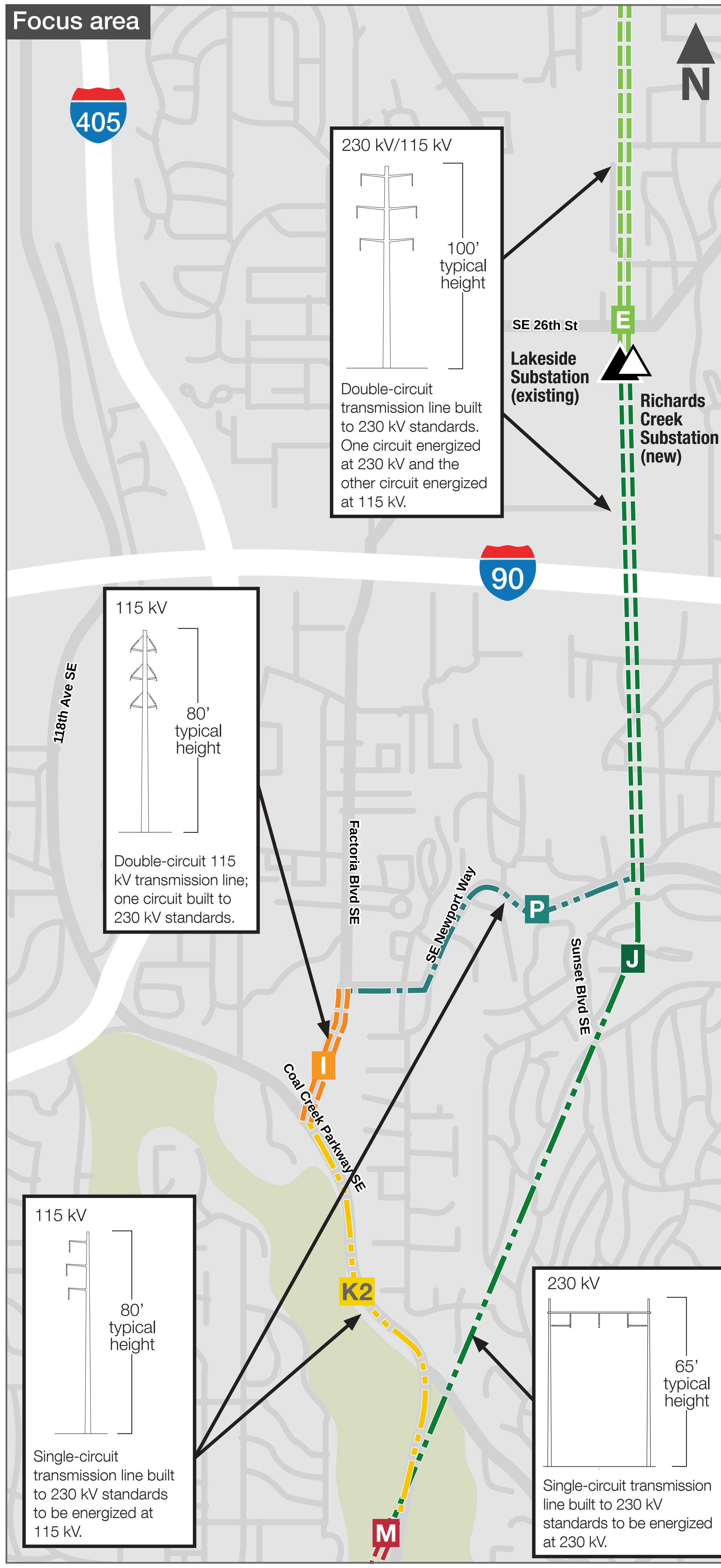
PSE PUGET SOUND ENERGY

March 2016

Attachment E: WILLOW 2

(Segments A-C-E-M-N, connection choices utilizing I-J-K2 and SE Newport Way)

Route options are configured to go from Segment A to Segment N and connect with Lakeside substation site.



LEGEND

- Single-circuit transmission line
- Double-circuit transmission line
- ▲ Existing substation
- △ A Route segments and substation undergoing additional analysis

NOTE: These maps are for illustrative purposes only. Preliminary route, pole types, and pole heights are subject to change pending design, engineering, and environmental review. Poles may need to be taller in certain locations such as when crossing a highway.

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PSE PUGET SOUND ENERGY

March 2016

DSD 008445

Speaker #17 Public Hearing
Phase 1 DEIS Bellevue 3.1.16

DSD 008446

DSD 008447

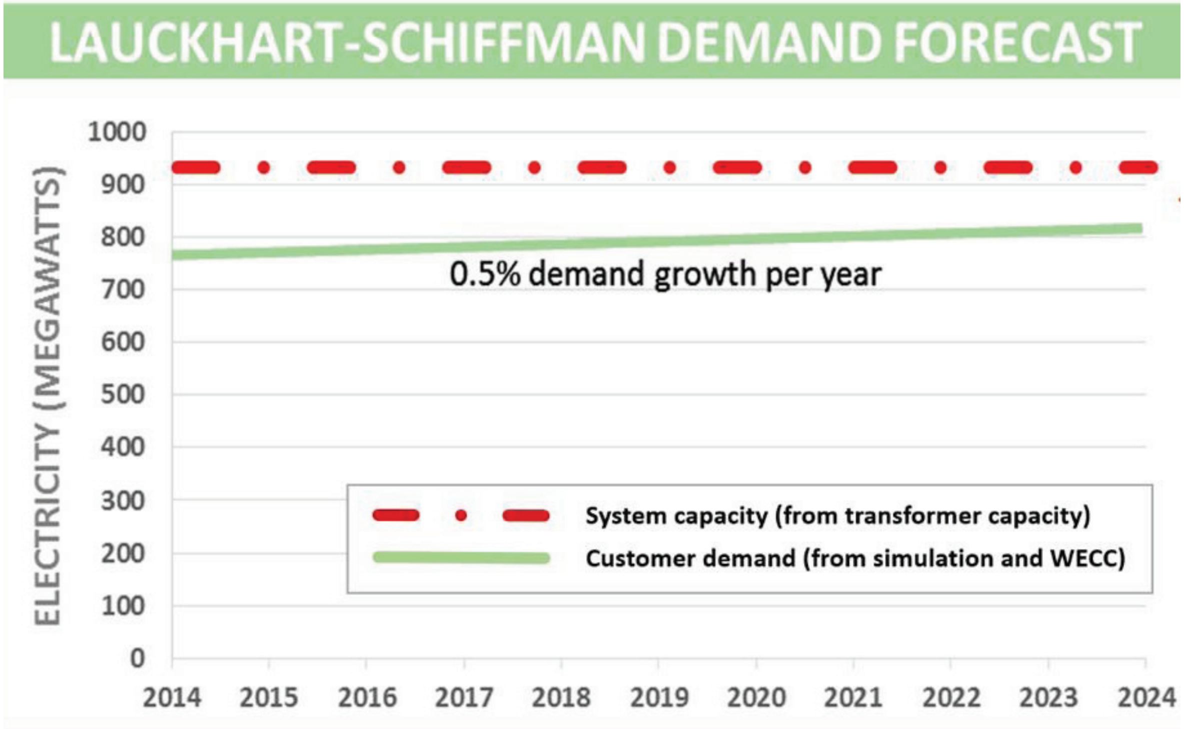
134th PL SE

Speaker #17 Public Hearing
Phase I DEIS Bellevue 3.1.16

DSD 008449

Speaker # 17 Public Hearing
Phase I DEN - Bellevue 3.1.16

David Erbig



Load Flow modeling

for "Energize Eastside"

Richard Lauckhart

Roger Schiffman

February 18, 2016

Executive Summary

In November 2015, the citizen group CENSE asked Richard Lauckhart and Roger Schiffman to study the scenario that motivates Puget Sound Energy's transmission project known as "Energize Eastside." We (Lauckhart and Schiffman) are nationally recognized power and transmission planners with specific knowledge of the Northwest power grid.

It is standard industry practice to use a "load flow model" to determine the need for a transmission project like Energize Eastside. In order to assess the reliability of the grid, analysts use specialized computer software to simulate failure of one or two major components while serving peak load conditions. For Energize Eastside, PSE simulates the failure of two major transformers during a peak winter usage scenario (temperature below 23° F and peak hours between 7–10 AM and 5–8 PM).

We ran our own load flow simulations based on data that PSE provided to the Western Electricity Coordinating Council (WECC). We used a "Base Case" for winter peak load projected for 2017–2018. PSE confirms this is the same data used as the basis for the company's "Eastside Needs Assessment."

Our findings differ from PSE's as follows:

1. PSE modified the Base Case to increase transmission of electricity to Canada from 500 MW to 1,500 MW. This level of energy transfer occurring simultaneously with winter peak loads creates instability in the regional grid. Transmission lines connecting the Puget Sound area to sources in central Washington do not have enough capacity to maintain this level of demand.
2. PSE assumed that six local generation plants were out of service, adding 1,400 MW of demand for transmission. This assumption also causes problems for the regional grid.
3. Even if the regional grid could sustain this level of demand, it is unlikely that regional grid coordinators would continue to deliver 1,500 MW to Canada while emergency conditions were occurring on the Eastside.
4. We found that the WECC Base Case contains a default assumption that PSE may not have corrected. The ratings for critical transformers are based on "summer normal" conditions, but the simulation should use significantly higher "winter emergency" ratings. The default value could cause PSE to underestimate System Capacity and overstate urgency to build the project.
5. The Base Case shows a demand growth rate of 0.5% per year for the Eastside. This is much lower than the 2.4% growth rate that PSE cites as motivation for Energize Eastside.

Our study finds critical transformers operating at only 85% of their winter emergency rating, providing enough capacity margin to serve growth on the Eastside for 20 to 40 years.

Qualifications

Richard Lauckhart served as a high level decision maker at Puget Sound Power & Light (the predecessor of Puget Sound Energy). His employment with the company spanned 22 years as a financial and transmission planner as well as power planning. He served as the company's Vice President of Power Planning for four years.

Richard took a voluntary leave package when Puget Power merged with Washington Energy Company in 1997. He provided additional contract services to PSE for more than a year following the merger. After leaving PSE, Richard worked as an energy consultant, providing extensive testimony on transmission system load flow modeling before the California Public Utility Commission.

Roger Schiffman has 23 years of energy industry experience covering utility resource planning, electricity market evaluation, market assessment and simulation modeling, regulatory policy development, economic and financial analysis, and contract evaluation. Roger has led a large number of consulting engagements for many clients. He has extensive knowledge of industry standard modeling software used for power market analysis and transmission planning.

We are well acquainted with the physical layout and function of the Northwest power grid and the tools used to analyze its performance. Our resumes can be found in Appendix H.

Richard has provided pro bono consultation to CENSE since April 2015. He has received no financial compensation other than reimbursement of travel expenses. Roger had no relationship with CENSE prior to this report.

Methodology

The power grid is a complex interconnected system with behaviors that cannot be easily understood without computer modeling software. We acquired a license to run the industry standard simulation software known as "GE PSLF"[1] to perform our studies.

The PSLF software uses a database that is supplied by the operator. We had hoped to use the same database that PSE used in its studies, but PSE refused to share it after months of negotiations. Instead, we received clearance from the Federal Energy Regulatory Commission (FERC) to access the database PSE submitted to the Western Electricity Coordinating Council (WECC). FERC determined that we presented no security threat and had a legitimate need to access the database (see FERC's letter in Appendix A).

We used the WECC Base Case for the winter of 2017–18, which PSE confirms is the database the company used for that time period. We and PSE have made subsequent changes to the Base Case model in order to incorporate various assumptions. We don't know exactly what changes PSE made to the database, but we will be explicit about the changes we made.

N-0 base scenario

To ensure that everything was set up correctly, we ran a simulation using the unmodified Base Case and checked to see if the results aligned with those reported by WECC. This is referred to as an "N–0" scenario, meaning that zero major components of the grid are offline and the system is operating normally. The outputs of this simulation matched reported results.

The WECC Base Case assumes that the Energize Eastside project has been built. In order to determine the need for the project, we needed to study the performance of the grid without it. We reset the transmission configuration using parameters from an earlier WECC case that did not include the project.

N-1-1 contingency scenario

An "N–1–1" scenario models what would happen if two major grid components fail in quick succession. Utilities are generally required

[1] http://www.geenergyconsulting.com/pslf-re-envisioned

to serve electricity without overloads or outages in this scenario to meet federal reliability standards.

PSE determined that the two most critical parts of the Eastside grid are two large transformers that convert electricity at 230,000 volts to 115,000 volts, the voltage used by all existing transmission lines within the Eastside. To simulate the N–1–1 scenario, the Base Case is modified to remove these two transformers from service.

PSE apparently made two additional modifications to the WECC Base Case. First, the amount of electricity flowing to Canada was increased from 500 MW to 1,500 MW. Next, the company reduced the amount of power being produced by local generation plants from 1,654 MW to 259 MW. The rationale behind these modifications isn't obvious, and we were concerned how the regional grid (not just the Eastside) would perform with these assumptions in place.

To our surprise, simply increasing the flow to Canada to 1,500 MW while also serving peak winter power demand in the Puget Sound region was enough to create problems for the regional grid. The simulation software could not resolve these problems (Appendix E describes the problems in greater detail). While it's possible that PSE and Utility System Efficiencies found ways to work around these challenges by making additional changes to the Base Case, we do not know what these changes were. We are confident that prudent grid operators would reduce flows to Canada if an N–1–1 contingency occurs on the Eastside during heavy winter consumption. PSE would turn on every local generation plant. These responses resolve the problems. This is the more realistic scenario we modeled in our N–1–1 simulation.

The WECC Base Case uses default values for transformer capacity ratings that correspond to a "summer normal" scenario. The summer rating is reduced in order to protect transformers from overheating during hot summer weather. The "winter emergency" rating would be consistent with best engineering practice for equipment outages during very cold conditions (less than 23° F) that produce peak winter demand. We used this higher rating in our simulation.

Results

N-0 results

To compare the N-1-1 results with normal operation of the grid serving peak winter demand, we ran an N-0 study using the WECC Base Case for winter 2017-18 with the following modifications:

1. Energize Eastside transmission lines are reverted to present capacity.
2. Flow to Canada is reduced from 500 MW to 0 MW.
3. Transformers run at “winter normal” capacity.

Figure 1 shows load as a perentage of “winter normal” capacity on each of the four transformers.

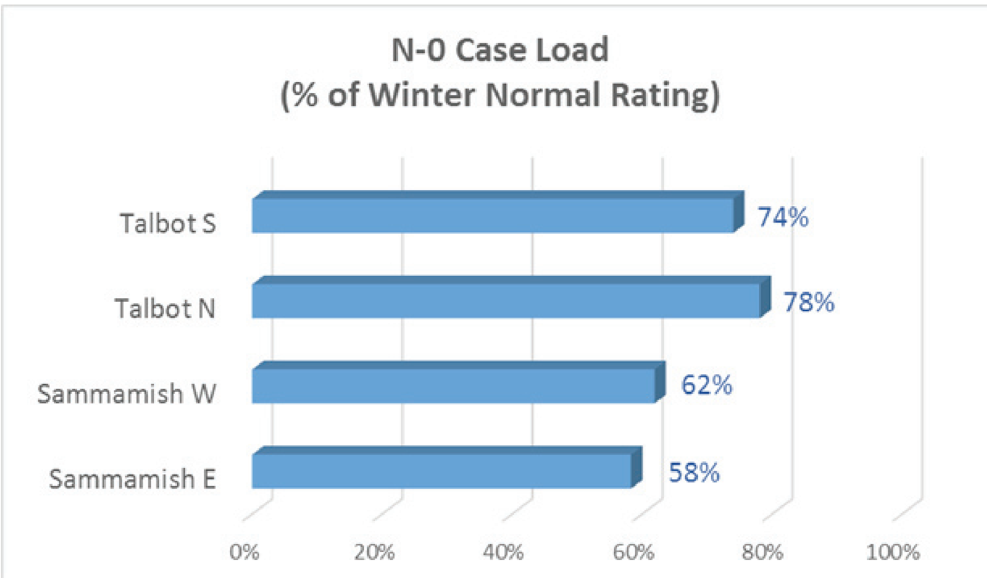


Figure 1: With all transformers in service, winter peak load causes no overloads.

DSD 008458

N-1-1 results

The N–1–1 results are based on the WECC Base Case for winter 2017–18 with the following modifications:

1 Two transformers are out of service.

2. Energize Eastside transmission lines are reverted to present capacity.

3. Flow to Canada is reduced from 500 MW to 0 MW.

4. Transformers run at “winter emergency” capacity.

Figure 2 shows that the remaining two transformers, Talbot N and Sammamish W, remain within “winter emergency” capacity ratings.

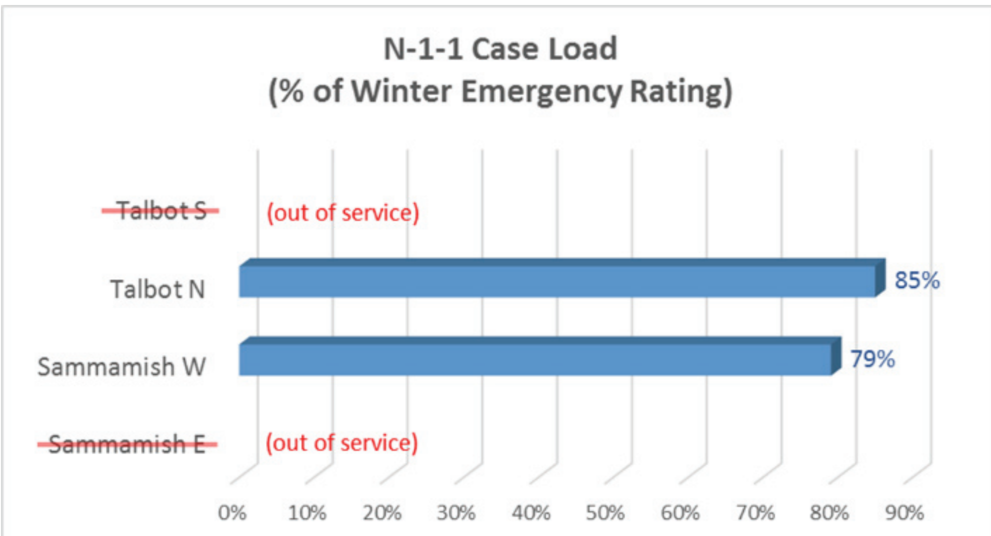


Figure 2: Loads on two remaining transformers are in a safe range.

Analysis

We carefully analyzed the results of the N-1-1 simulation to get a broader view of how the grid is behaving in this scenario. Electricity is served by a combination of high-voltage transformers (transforming 230,000 volts to 115,000 volts) and low-voltage transformers (115,000 volts to 12,500 volts).

When we simulated failure of two high-voltage transformers located at Sammamish and Talbot Hill, as PSE did, we discovered that some of the load is redistributed to other high-voltage transformers in the Puget Sound area (see Figure 3). This is a natural adaptation of the networked grid that occurs without active management by PSE or other utilities. The regional grid has enough redundant capacity to balance the load without causing overloads on any transformer or transmission line in the region.

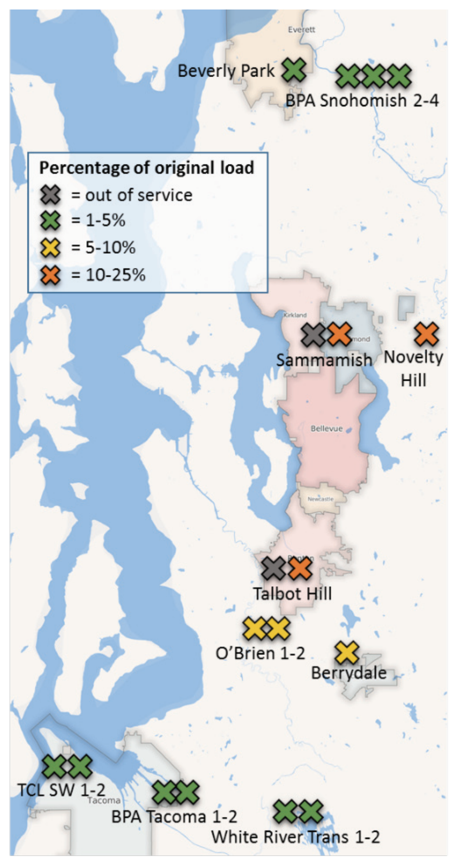


Figure 3: Load is distributed among other transformers after two transformers fail.

DSD 008460

We conclude that the grid is capable of meeting demand in emergency circumstances in the winter of 2017–18. How soon after that will system capacity become strained?

Concerns about future capacity are illustrated in Figure 5, PSE's demand forecast graph.[2] This graph raises several questions. For example, it's not clear how PSE determined the "System capacity range" of approximately 700 MW. If this value is derived from the transformer capacities listed in the WECC Base Case, these capacities are set to default values corresponding to "summer normal" conditions.

PSE's graph shows Customer Demand growing at an average rate of 2.7% per year. However, data submitted by PSE to WECC shows a growth rate of only 0.5% per year. An explanation of this discrepancy is necessary to understand this graph.

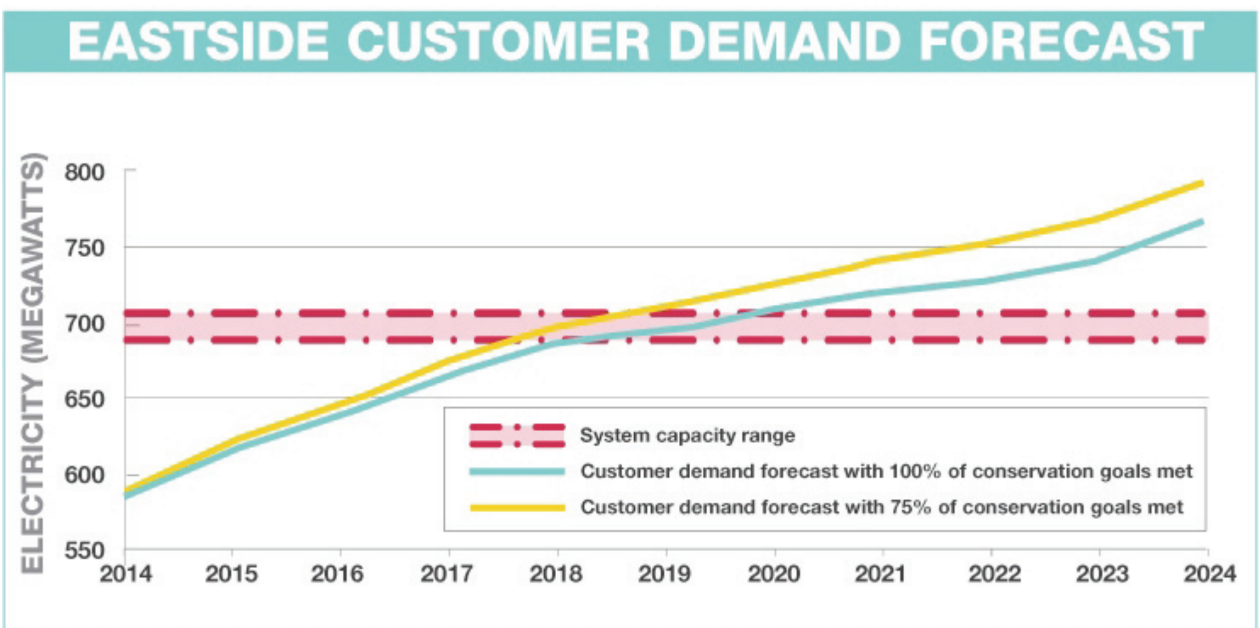


Figure 4: PSE's graph shows customer demand exceeding system capacity in 2018.[2]

[2] *http://www.energizeeastside.com/need*

DSD 008461

Although we don't have enough information to create a graph suitable for long-term planning, we we feel Figure 5 is a better approximation of system capacity and demand growth on the Eastside.

The "System capacity" is based on "winter emergency" transformer ratings, which are more appropriate than summer ratings for this scenario. The higher ratings raise the overall capacity to approximately 930 MW.

The "Customer demand" line shown in Figure 5 is based on loads reported in the load flow simulation for the two remaining Eastside transformers. The 2014 value is higher than in PSE's graph, because these transformers serve loads outside the Eastside area. The growth rate matches the 0.5% rate observed in WECC Base Cases.

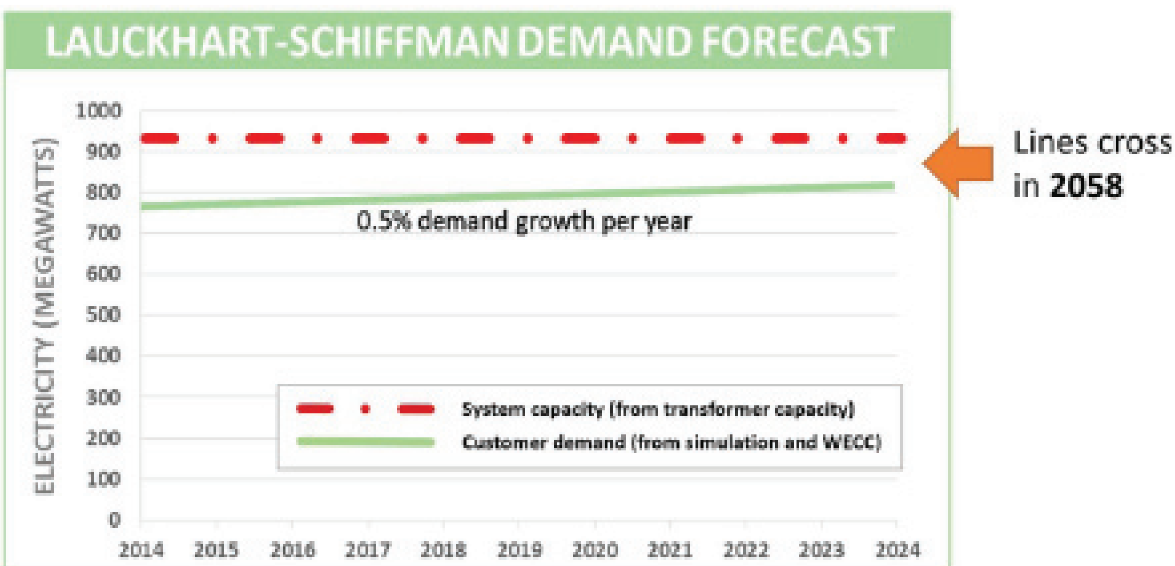


Figure 5: Alternative Demand Forecast shows slower demand growth and higher system capacity (based on "winter emergency" transformer ratings).

DSD 008462

Comparison with other studies

The conclusions of the Lauckhart-Schiffman study differ from previous studies. We stand by our conclusions and will share our models and results with anyone who has clearance from FERC.

Here we review the other studies and explain why their conclusions might differ from ours.

PSE/Quanta

Two different load flow simulations were performed by PSE and Quanta, a consultant employed by PSE. We have the following concerns with both studies:

1. An unrealistic level of electricity is transmitted to Canada.
2. Nearly all of the local generation plants are turned off.
3. The appropriate seasonal ratings for the critical transformers were not used.
4. It's not clear how the customer demand forecast was developed, but there is an unexplained discrepancy between the forecast used for Energize Eastside (2.4% annual growth) and the forecast reported to WECC (0.5% annual growth).

The first two assumptions cause regional reliability problems for the WECC Base Case that must have required additional adjustments by PSE/Quanta. We don't know what those adjustments were.

Utility System Efficiencies

The City of Bellevue hired an independent analyst, Utility System Efficiencies (USE), to validate the need for Energize Eastside. USE ran one load flow simulation that stopped electricity flow to Canada. According to USE, 4 of the 5 overloads described in the PSE/Quanta studies were eliminated, and the remaining overload was minor.

Our load flow simulation studied the same scenario (N-1-1 contingency with no flow to Canada and local generators running), but we did not find any overloads. We believe three assumptions explain the different outcomes:

1. USE does not specify what level of generation was assumed for local generation plants. In verbal testimony before the Bellevue

City Council, USE consultants said that they did not assume all of the capability of local generation was operating. Our study assumes these plants will run at their normal capacity.

2. USE says emergency ratings were used for the critical transformers, but it isn't clear if USE used "winter emergency" ratings. Our study assumes winter emergency ratings.

3. USE does not independently evaluate the customer demand forecast (2.4% annual growth is assumed). Our study assumes the load growth forecast that PSE provided to WECC.

We believe our assumptions more accurately reflect the actual conditions that would occur in this scenario.

Stantec Consulting Services

In July 2015, the independent consulting firm Stantec was asked to review the studies done by PSE and USE. Stantec issued its professional opinion without performing any independent analysis or load flow simulations. Stantec says PSE's methodology was "thorough" and "industry standard." However, Stantec does not address the shortcomings we have identified with previous studies.

Appendix A
Clearance from FERC

Federal Energy Regulatory Commission
Washington, DC 20426

SEP 01 2015

Letter of Release,
Re: CEII No. CE15-130

<u>VIA CERTIFIED MAIL</u>
Richard Lauckhart
[redacted]

Dear Mr. Lauckhart:

This is in response to the July 15, 2015 request you submitted under the Federal Energy Regulatory Commission's (Commission or FERC) Critical Energy Infrastructure Information (CEII) regulations at 18 C.F.R. § 388.113(d)(4) (2015). Specifically, you requested a copy of the Puget Sound Energy, Inc. FERC Form No. 715, *Annual Transmission Planning and Evaluation Report*.

By letter dated August 21, 2015, the Commission issued a finding that you are a legitimate requester with a need for the information. In accordance with 18 C.F.R. § 388.112(e), the enclosed DVD contains the information requested and is being released to you subject to the non-disclosure agreement executed by you concerning this matter.

As provided by 18 C.F.R. § 388.113(d)(4)(iv) of the Commission's regulations, you may appeal this determination pursuant to 18 C.F.R. § 388.110. Any appeal from this determination must be filed within 45 days of the date of this letter. The appeal must be in writing, addressed to David L. Morenoff, General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426. Please include a copy to Charles A. Beamon, Associate General Counsel, General and Administrative Law, at the same address.

Sincerely,

Leonard M. Tao

Leonard M. Tao
Director
Office of External Affairs

Enclosure

Appendix B
Choice of Base Case

To perform a load flow study, one needs a database reflecting the physical characteristics of the power grid. FERC has recognized that stakeholders need to have access to a Base Case that reflects the system. Each utility or a designated agent is required to file power flow base cases with FERC on an annual basis.[3] WECC acts as a designated agent for most of the utilities operating in the western U.S. In an email dated November 19, 2015 Jens Nedrud, the Senior Program Manager for Energize Eastside, confirmed that PSE uses Base Cases filed by WECC as its Base Cases.

For the purposes of this study, Lauckhart and Schiffman obtained the 2014 WECC Base Cases from FERC.[4] These included 13 Base Case runs, four of which are Heavy Winter scenarios. In order to evaluate the need for the EE project, the heavy winter 2017-18 Base Case was modified so that the Energize Eastside project was not included. [5]

We do not know if this modified 2017-18 Base Case is identical to the one used by PSE to justify the project, because PSE has refused to share their 2017-18 Base Cases for independent review. The WECC Base Case assumes 500 MW is transmitted to Canada. PSE apparently increased that amount to 1,500 MW. The WECC Base Case assumes local generation in the Puget Sound Area is running at normal capacity. PSE appears to have reduced those contributions by 1,395 MW. Our PSLF modeling suggests that PSE's modifications are not feasible and grid operators would not allow these conditions to occur on a heavy winter load day.[6]

Load data from the WECC Heavy Winter Load 2017-18 Base Case is chosen as the basis for this study. This is the latest data provided by FERC/WECC for the winter of 2018. PSE was involved in the development of this Base Case along with other utilities including BPA and Seattle City Light (SCL). All utilities use these Base Cases to determine if the grid is capable of moving power from sources to loads. Further, it is the only data available in which there are identified loads on specific substations.

The loads on the main Eastside substations in the WECC Heavy Winter 2013-14 and 2017-18 Base Cases have been examined and analyzed. All of the Eastside substations were included:

Medina	Overlake	South Bellevue
Clyde Hill	Lochleven	Factoria
Bridle Trails	North Bellevue	College
Evergreen	Center	Phantom Lake
Ardmore	Midlakes	Eastgate
Kenilworth	Lake Hills	Somerset

The total load on these substations in the 2013-14 Base Case was 394.6 MW. The total load on these substations in the 2017-18 Base Case was 402.4 MW. This is a peak load growth of 2.0% over the 4 year period (an average increase of 0.5% per year). This is in line with predicted growth of energy and peak in King County.

PSE and USE appear to be extrapolating the higher growth rate of a few substations due to “block loads” and applying it uniformly to 600 MW of existing substation load. This simplification overestimates the overall growth rate. Furthermore, the total load on the substations listed above is only 400 MW. It is not clear how PSE arrived at a 600 MW load.

[3] *http://www.ferc.gov/docs-filing/forms/form-715/instructions.asp#General%20Instructions*

[4] *On July 9, 2015 FERC provided Lauckhart the most recent WECC Base Cases that it had available to send to requesters. Those Base Cases were ones filed in 2014 by WECC.*

[5] *On Dec. 4, 2015 Lauckhart also received from FERC a copy of the 2015 WECC FERC Form 715 filing. In that filing there was no Base Case filed for the winter of 2018. However, there was a Base Case filed for the winter of 2020. A review of that 2020 Base Case showed very little growth on the Eastside from the 2018 Base Case. It also showed that the rest of the Northwest actually reduced their load forecast for the year 2020 over their forecast for 2018. In total, the loading on the eastside 230/115 KV transformers in the 2020 case were lower than the loading on the Eastside 230/115 KV transformers in the 2018 case. The trend is that the situation is not getting worse since the load forecasts for the northwest are dropping overall which also reduces loading on the Eastside 230/115 KV transformers.*

[6] *With no other changes to the WECC Base Case for the winter of 2018, increasing PNW to BC transfers to 1,500 causes the system to need to import more power across the Cascades from Central Washington. This causes the PSLF model run to fail to find a solution. When we say no solution, we mean the voltage in the Puget Sound region gets too low and the model cannot find a way to correct that.*

Appendix C
Generation pattern used

PSE's gas-fired generation plants located in the Puget Sound area have a total rated capacity of 1,654 MW. How much of this capacity should be used to serve peak demand during a heavy winter load event? There are three choices:

1. The Eastside Needs Assessment prepared for PSE by Quanta assumed generation of only 259 MW, without explaining why such a low level was used.
2. The load flow study performed by USE also ran the plants at a reduced rate, but the study did not specify the exact amount.
3. Three of the four WECC heavy winter Base Cases assume the plants are running at their rated capacity of 1,654 MW. One of the Base Cases turns off one plant for reasons that are not clear, resulting in a lower level of generation at 1,414 MW.

The 1,654 MW capacity used by WECC in 3 of its 4 heavy winter Base Cases is a prudent choice for several reasons. First, PSE built and/or acquired these plants for the explicit purpose of meeting its load obligations during cold winter events. Second, PSE has a well-documented shortfall of generation capacity to serve peak demand, and it will be less risky and less expensive to run these plants than to buy power on the spot market. Third, because these plants generate electricity at 115 kV, the strain on PSE's overloaded 230/115 kV transformers would be reduced by increasing the supply of 115 kV electricity.

Appendix D
Exports to Canada

PSE and USE assume that 1,500 MW of power must be delivered to Canada, even if PSE is experiencing failure of two critical system components (an N–1–1 contingency) during heavy winter load conditions (temperatures less than 23° F in the Puget Sound region).

The WECC Base Cases assume otherwise. In the WECC Base Case for heavy winter 2013–14, 500 MW of power is flowing south from Canada to the U.S. In the WECC Base Case for heavy winter 2017–18, with the Energize Eastside project in place, 500 MW of power is flowing north to Canada, not 1,500 MW.

PSE and USE imply that it is the Columbia River Treaty that provides a Firm Commitment to deliver 1,500 MW of power to Canada. It is clear from reading numerous Treaty documents (e.g. the original treaty, the amendment to the treaty in 1999, and related documents) that the Treaty itself imposes no obligation on the United States to deliver Treaty Power to Canada. To the contrary, Canada has stated they do not want the Treaty Power delivered to Canada. Instead, PowerEx takes delivery of Canada's share of Treaty Power at the point of generation in the U.S. and delivers it for sale to U.S. entities. Canada finds it preferable to receive money for their share of Treaty Power rather than having the power delivered to Canada.

The reasonable assumption for this study is that no power will flow from the U.S. to Canada during a major winter weather event and simultaneous facility outages in the Eastside.

Appendix E

Regional grid capacity limitations

Most of the electrical generation facilities that serve the Puget Sound region are located east of the Cascade Mountains. The electricity they produce is transmitted to customers in the Puget Sound area through eleven major transmission lines known collectively as the "West of Cascades – North" (WOCN) transmission path.

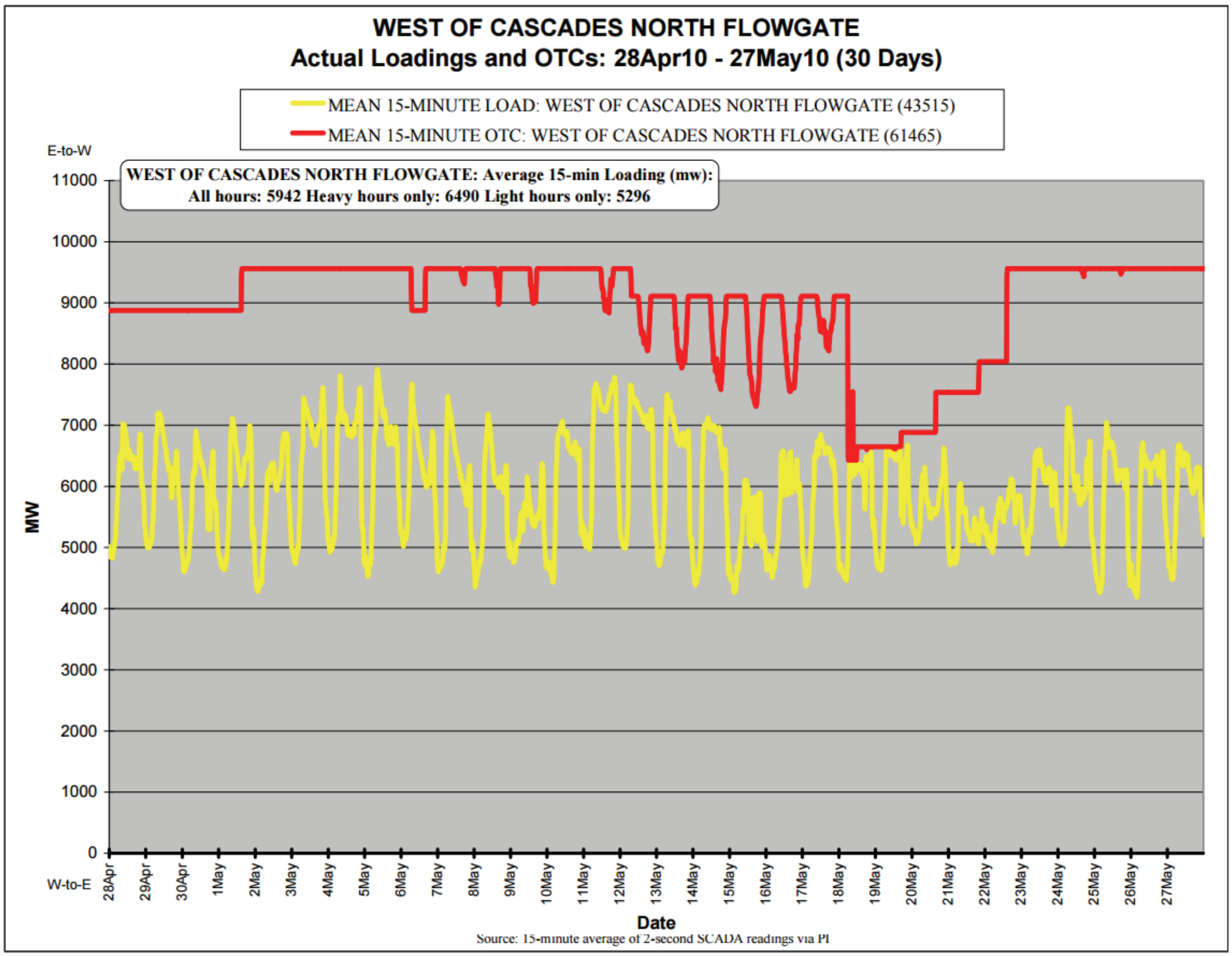


Figure 6: Chart from BPA shows load (in yellow) and maximum capacity (in red) for the WOCN path.

The exact transmission capacity of the WOCN path is confidential information which cannot be discussed in detail here. However, there is a report available on the web from the Bonneville Power Administration that discusses a problem that occurred on the WOCN path in May 2010.[7] On page 31, the report includes a chart showing loads and capacities of the WOCN path over a 30-day period. The load (shown in yellow) varies from 5000–7000 MW and the path capacity (in red) varies from 7000–9000 MW.

During a heavy winter usage scenario, the loads are likely to be higher than during relatively mild weather conditions in May. PSE's assumptions for Energize Eastside would further increase the load. To deliver 1,500 MW to Canada, loads on the WOCN path would need to increase by approximately 1,000 MW. To make up for the loss of electricity that could have been generated by six local generation plants, an additional 1,400 MW must be transmitted on the WOCN path. In total, loads would increase by approximately 2,400 MW.

If the increased load exceeds the capacity of the WOCN path, grid operators and utilities would have to make adjustments like they did in May 2010. Some of these steps and consequences are described on page 40 of the BPA report:

> "Many customers (e.g., TransAlta, Calpine, PSE, PGE) were not able to use low cost power purchases, and instead had to operate higher cost thermal projects that otherwise were idled or were out or planned for maintenance. Although there were multiple complaints regarding the ability to serve load, the basis for the complaints appeared to be economic or financial impacts."

We feel that WOCN path capacity limits explain why the simulation software could not find a way to maintain voltage levels in the Eastside given PSE's assumptions. We conclude that it is not reasonable to build local infrastructure to support these conditions if regional infrastructure cannot reliably serve the implied loads.

[7] *http://pnucc.org/sites/default/files/BPAWOCNLessonsLearned.pdf*

Appendix F
Equipment ratings

Ambient temperature affects the capacity of electrical transmission facilities. Colder temperatures help avoid overheating. For this reason, it is industry standard practice to provide different ratings for summer and winter seasons.

It is also industry standard practice to allow higher loading of equipment, including transformers, during emergency events due to the fact that emergencies do not last long. Utilities can take advantage of the fact that transformers can safely handle brief over-peak conditions to reduce installation costs and maintain system reliability.

The WECC Data Preparation Manual requires transmission owners to provide the following ratings for its transformers:

- Summer Normal Rating
- Summer Emergency Rating
- Winter Normal Rating
- Winter Emergency Rating

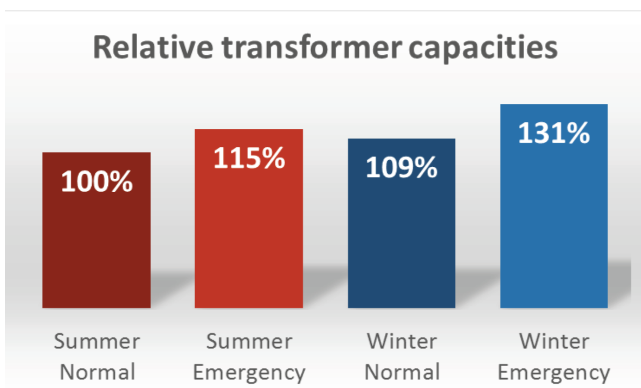


Figure 7: Ratings for different scenarios, normalized to Summer Normal rating.

PSE has indicated that the rating on the Sammamish and Talbot Hill transformers are approximately 352 MVA (Mega-volt amperes). According to the data that PSE provided to WECC, this is the Summer Normal Rating of these transformers. PSE has advised WECC that (a) its Winter Normal ratings are about 9% higher than Summer Normal, and (b) Winter Emergency Ratings are about 21% higher than Winter Normal Ratings.

When running the PSLF model, the run parameters must be set to point to the correct rating that has been provided in the data base. [8]

In the N-0 analysis, our load flow studies used the winter normal rating which is 9% higher than the 352 MVA summer normal rating.

In the N-1-1 analysis, our load flow studies used the winter emergency rating that is 21% higher than the winter normal rating.

Appendix G
Summer load scenario

Most of the load flow modeling done by PSE and USE to justify Energize Eastside has been focused on a winter peak load scenario. Recently, PSE has mentioned reliability concerns in the summer to provide additional motivation to build Energize Eastside. So far, PSE has refused to provide input data and results for both winter and summer scenarios.

We briefly reviewed the WECC Base Case for heavy summer demand in 2019. The peak load on Eastside substations is 281 MW in this scenario. This is 30% lower than the total load for heavy winter demand in 2017–18 (402 MW). The drop in transformer ratings due to summer heat is only 9%, so this scenario should be significantly less stressful on PSE's infrastructure than the winter scenario. Rapid growth in air conditioning is a concern, but if there is a summer need, then rooftop solar in Bellevue and other cities will be helpful and should be encouraged. Further study is warranted.

Appendix H
Resumes

J. Richard Lauckhart
Energy Consulting

J. Richard Lauckhart has 40 years of experience in power supply planning, electricity price forecasting and asset valuation. He began his career as a distribution engineer with Pacific Gas & Electric Co., and held various positions at Puget Sound Power & Light Co. (now Puget Sound Energy) in power supply planning, culminating as vice president of power planning.

For the last 12 years Mr. Lauckhart has performed consulting assignments related to power market analyses, price forecasting services, asset market valuation, integrated resource planning, transmission line congestion analysis, and management of strategic consulting engagements for clients in North America, including investor-owned and municipal utilities, independent power producers, and lenders.

Mr. Lauckhart received a bachelor of science degree in electrical engineering from Washington State University in 1971 and a masters degree in business administration from the University of Washington in 1975

Representative Project Experience

Black & Veatch
September 2008 to October 2011
Managing Director
Mr. Lauckhart oversees wholesale electricity price forecasting, project revenue analysis, consults regarding wind integration matters electric interconnection and transmission arrangements for new power projects, and other related matters in the electric power industry. In addition, he heads Black & Veatch's WECC regional power markets analysis team.

WECC Power Market Analysis and Transmission Analysis, Henwood/Global Energy Decisions/Ventyx
2000 - 2008
Senior Executive
Mr. Lauckhart oversaw wholesale electricity price forecasting, project revenue analysis, consulted regarding electric interconnection and transmission arrangements for new power projects, and other related matters in the electric power industry. In addition, he headed Global Energy's WECC regional power markets analysis team.

Lauckhart Consulting, Inc.
1996 – 2000
President
Primary client - Puget Sound Energy (formerly Puget Sound Power & Light Company): Involved in power contract restructuring, market power analysis, FERC 888 transmission tariffs, and other matters. Testified at FERC regarding Puget's 888 tariff. Testified for Puget in June, 1999 arbitration with BPA regarding transmission capability on the Northern Intertie.

Northwest IPP
Under retainer with IPP from July 1996 through December 31, 1999. Involved primarily in merchant power plant development activities including permitting activity, owner's engineer identification, environmental consultant identification, water supply

arrangement, transmission interconnection and wheeling arrangements, gas pipeline arrangements, economic analysis, forward price forecasting, marketing, and related issues.

Levitan & Associates (Boston)
Participated in teams involved in electric system acquisition activities. Performed preliminary analysis for a major retail corporation regarding possible participation as an aggregator in the California deregulated electric market. Involved in the evolving discussions about deregulation in the state of Washington including participant in HB 2831 report and ESSB 6560 report.

Member of advisory task force for Northwest Power Planning Council study of generation reliability in the Pacific Northwest. Participating writer in a newsletter advocating electric deregulation in the state of Washington.

Puget Sound Power & Light Company
1991 – 1996
Vice President, Power Planning
Involved in all aspects of a $700 million per year power supply for a hydro/thermal utility with a 4,600 MW peak and 2,200 aMW energy retail electric load. Included responsibility for a 22 person department involved in power scheduling (for both retail and wholesale power activity), power and transmission contract negotiation and administration, regulatory and NERC compliance, forward price forecasting, power cost accounting, and retail rate activity related to power costs. Activity included matters related to 650 MW of existing gas-fired, simple cycle combustion turbines. In addition, 660 MW of combined cycle cogeneration "qualifying facilities" were developed by others for Puget during this time frame. Detailed understandings of the projects were developed both for initial contractual needs and later for economic restructuring negotiations. Mr. Lauckhart was the primary person involved in developing Puget's Open Access transmission tariff in accordance with FERC Order 888.

Puget Sound Power & Light Company
1986 – 1991
Manager, Power Planning
The company's key person in developing (1) a WUTC approved competitive bidding process for administering PURPA obligations, and (2) a WUTC approved regulatory mechanism for recovery of power costs called the Periodic Rate Adjustment Mechanism (PRAM).

Puget Sound Power & Light Company
1981 – 1986
Director, Power Planning
The company's key person in developing a power cost forecasting model that was customized to take into account the unique nature of the hydro generation system that exists in the Pacific Northwest.

Puget Sound Power & Light Company
1979 – 1981
Manager, Corporate Planning
Responsible for administering the corporate goals and objectives program.

Puget Sound Power & Light Company

1976 – 1979
Financial Planning
Improved and ran a computerized corporate financial forecasting model for the company that was used by the CFO.

Puget Sound Power & Light Company
1974 – 1976
Transmission Planner
Performed transmission engineering to assure a reliable transmission system.

Pacific Gas & Electric Company
1971 – 1974
Distribution Engineer
Performed distribution engineering to assure a reliable distribution system.

Other Relevant Experience

- Expert testimony for Montana Independent Renewable Generators related to avoided cost regulations and pricing filed February 2009 at the Montana PSC
- Expert Testimony for LS Power in the SDG&E Sunrise Proceeding regarding economics of in-area generation vs. the cost of transmission and imported power Spring 2007
- Expert Testimony for BC Hydro in the Long Term Resource Plan, February 2009 dealing with natural gas price forecasts and REC price forecasting
- Expert Testimony for John Deere Wind in a proceeding in Texas in November 2008 related to avoided costs and wind effective load carrying capability
- Expert Testimony for Two Dot Wind before the Montana commission regarding wind integration costs Spring 2008
- Expert Testimony in the BC Hydro Integrated Electricity Plan proceeding regarding WECC Power Markets. November 2006.
- Expert Testimony for Colstrip Energy Limited Partnership before Montana PUC regarding administration of QF contract prices. July 2006.
- Expert Testimony for Pacific Gas & Electric regarding current PURPA implementation in each of the 50 states. January 2006.
- Expert Testimony in CPUC proceeding regarding modeling procedures and methodologies to justify new transmission based on reduction of congestion costs (Transmission Economic Analysis Methodology – TEAM). Summer 2006.
- Expert Testimony for BC Hydro regarding the expected operation of the proposed Duke Point Power Project on Vancouver Island, January 2005
- Expert Testimony for PG&E regarding the cost alternative generation to the proposed replacement of steam generators for Diablo Canyon, Summer of 2004.
- Expert Testimony in an arbitration over a dispute about failure to deliver power under a Power Purchase Agreement, Fall 2004.
- Integrated Resource Plan Development. For a large investor-owned utility in the Pacific Northwest, Global Energy provided advanced analytics support for the development of a risk-adjusted integrated resource plan using RISKSYM to provide a stochastic analysis of the real cost of alternative portfolios.
- Expert Testimony for SDG&E, Southern California Edison, and PG&E regarding IRPs, WECC markets and LOLP matters before the California PUC, 2003.

- Miguel-Mission Transmission Market Analysis-San Diego Gas & Electric. San Diego Gas & Electric retained Global Energy to oversee an analysis of the economic benefits associated with building the Mission-Miguel transmission line and the Imperial Valley transformer. Global Energy performed an analysis of the economic benefits of the Mission-Miguel line, prepared a report, sponsored testimony at the CPUC, and testified at the CPUC regarding the report.
- Valley-Rainbow Transmission Market Analysis-San Diego Gas & Electric. San Diego Gas & Electric also engaged Global Energy to analyze the economic benefits associated with building the Valley-Rainbow transmission line and to respond to the CPUC scoping memo that "SDG&E should describe its assessment of how a 500 kV interconnect, like Valley-Rainbow, will impact electricity markets locally, regionally, and statewide." Global Energy analyzed the economic benefits of the Valley-Rainbow line, prepared a report, sponsored testimony at the CPUC, and testified at the CPUC regarding the report.
- Damages Assessment Litigation Support. Global Energy was engaged by Stoel Rives to provide damages analysis, expert testimony and litigation support in for its client in a power contract damages lawsuit. Global Energy quantified the range of potential damages, assessed power market conditions at the time, and provided expert testimony to enable Stoel Rives' client to prevail in a jury trial.
- Expert Testimony, Concerning the Economic Benefits Associated with Transmission Line Expansion. Testimony prepared on behalf of San Diego Gas & Electric Company, September 2001.
- Expert Testimony, Concerning market price forecast in support of Pacific Gas and Electric hydro divesture case, December 2000.
- Expert Testimony, Prepared on behalf of AES Pacific regarding value of sale for Mohave Coal project to AES Pacific for Southern California Edison, December 2000.
- Expert Testimony, Prepared on behalf of a coalition of 12 entities regarding the impact of Direct Access of utility costs in California. June 2002.

Mr. Lauckhart was Puget's primary witness on power supply matters in eight different proceedings before the Washington Utilities and Transportation Commission.

Mr. Lauckhart was Puget's chief witness at FERC in hearings involving Puget's Open Access Transmission Tariff and testified for Puget in BPA rate case and court proceedings.

ROGER SCHIFFMAN

SUMMARY OF QUALIFICATIONS

Mr. Schiffman has 23 years of energy industry experience covering utility resource planning, electricity market evaluation, market assessment and simulation modeling; regulatory policy development; economic and financial analysis, and contract evaluation. Mr. Schiffman has worked with public and private utility companies on resource planning decisions, power plant retirement decisions, avoided cost determinations, and on power supply procurement activity. Mr. Schiffman has worked extensively with electric utility staff, power plant developers, regulatory personnel, investment bankers and other industry participants in both consulting and regulatory environments. Mr. Schiffman possesses extensive financial analysis skills, supported by thorough knowledge of financial, economic and accounting principles. He has a strong technical understanding of the electric utility industry and excellent analytical problem-solving skills, including quantitative analysis and computer modeling techniques.

EXPERIENCE

Principal, Black and Veatch Corporation, Inc., Sacramento, CA, March 2009 to October, 2015

- Initiated Integrated Resource Plan for the Virgin Islands Water & Power Authority. This project is a multi-faceted IRP, where detailed planning and potential siting impacts must be considered in the overall planning, due to geographic and topology limitations on the islands. Mr. Schiffman directed the analysis and playing the lead analytic role in assessing resource needs. This included directing the data gathering efforts, taking technical lead in completing production cost and financial modeling, and managing Black & Veatch's team of technical experts. Mr. Schiffman also developed a stakeholder process and gave multiple presentations before stakeholder and customer groups.
- Completed nodal market simulation and congestion study for a concentrating solar plant in Northern Nevada. This engagement includes a review of transmission system impact studies, power flow data and development of a PROMOD nodal simulation database to assess congestion likelihood for the project.
- Completed economic assessment of a large pumped storage project in Southern California, including development of energy market arbitrage, capacity market and ancillary services market revenue forecasts. Developed pro forma financial statements examining economics of project under different ownership and off-take agreement structures.
- Completed Integrated Resource Plan for Azusa Light & Water, a municipal utility in southern California. This project involved using Black & Veatch's EMP database and price forecast, specifying thermal and renewable resource options, and completing detailed market simulation and financial modeling to determine a preferred power supply plan for Azusa. A key focus of the study is to identify resource options to replace output from the San Juan 3 coal plant, which is scheduled to retire.
- Completed Integrated Resource Plan for Pasadena Water & Power, a municipal utility in southern California. This project involved using Black & Veatch's EMP database and price forecast, specifying thermal and renewable resource options, and completing detailed market simulation and financial modeling to determine a preferred power supply plan for Pasadena. The project also included reflection of key stakeholder input, and testing stakeholder driven

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policy proposals for advancing renewable resource procurement beyond state-mandated RPS levels. A key focus of the study is to identify resource options to replace output from the Intermountain coal plant, which is scheduled to retire.

- Completed generation reliability study for the Brownsville Public Utility Board. This study included directing the completion of detailed reliability modeling using GE-MARS, and evaluating loss-of-load probabilities for BPUB based on its existing system and based on the addition of a 200 MW ownership share in the combined cycle power plant being developed in Brownsville by Tenaska. The study also included detailed pro forma modeling of partial ownership of the combined cycle plant, and a financial and risk assessment presented to BPUB's Board of Directors, and also used to address rating agency questions about credit impacts of the new power plant. On behalf of Southern California Edison, completed nodal power price forecast and assessment of high voltage transmission upgrades and additions in Southern California. This project included an assessment of congestion, locational marginal pricing, transmission system losses, and economic impacts of adding new transmission facilities in WECC, with particular focus on Southern California. PROMOD IV was used to complete the nodal market analysis, and PROMOD simulation results were translated into GE-PSLF for more detailed transmission system modeling of power flow cases under a variety of supply and demand conditions throughout the year.
- Completed four projects focused on nodal market modeling in California, Arizona and Southern Nevada. These studies were used to assess congestion risk faced by solar and wind generation projects at the sites where each is being developed. Completed PROMOD IV dispatch and nodal analyses for each project, and developed risk assessments for generation curtailment risk. Also developed analyses of transmission system congestion along delivery paths for each project, and on key economic transmission paths in Northern and Southern California, transmission import paths into Southern California, and transmission paths in Southern Nevada.
- Completed resource and power supply planning/procurement project for confidential SPP energy supplier. Completed a competitiveness assessment of major electricity supplier in Nebraska, examining cost structure, net resource position, generation asset characteristics, transmission access and delivery options, and overall competitive positioning of SPP, MISO and MRO entities that have potential to provide wholesale electricity service in Nebraska. Worked collaboratively with client and a wholesale customer task force
- Completed due diligence analysis of portfolio of power supply assets to support bid development. The generators being sold were located in SPP, WECC, and the Northeast. The WECC asset is a qualifying facility, which required detailed representation and modeling of the California PUC Short-Run Avoided Cost tariff and pricing formula. One of the SPP assets is also a qualifying facility, which required detailed analysis of the steam load and interaction between joint power and steam production. Completed modeling analysis and risk assessment of power supply agreements, developed revenue forecasts for each power plant, and completed merchant plant analysis of plant operations after PPA expiration.
- On behalf of a municipal utility client, developed database of renewable energy resource bids solicited through an RFP process, developed assessment of delivery terms and transmission tariffs associated with power delivery from distant resources, and completed bid screening analysis of 240 separate bids/pricing options.
- Completed PROMOD IV dispatch analysis and economic assessment of 6,000 MW portfolio of coal and natural gas-fueled resources operating in the Midwest ISO market region. Developed expected operations, cost, market sales and revenue forecasts for portfolio assets,

under several market scenarios. Prepared Independent Market Report for potential use in Offering Memorandum.

- Completed detailed review of California ISO ancillary services markets, and opportunity for renewable energy and energy storage markets to participate in those markets. Analysis included assessment of day-ahead, hour-ahead, and real-time market operation.
- Completed dispatch modeling and power supply planning study examining construction of a pumped storage hydro project in Hawaii. The evaluation included assessments of project revenue in energy, ancillary services, and capacity markets in Hawaii, expected dispatch and operation of the pumped storage project, and comparison of long-term power supply plans with and without addition of the pumped storage project.
- Completed deliverability and congestion analysis of wind energy resources being located in California. Developed nodal market simulations, and examined locational marginal price differences, congestion components, and transmission line loadings of facilities impacted by the wind assets being studied.
- Completed detailed financial and dispatch modeling (deterministic and stochastic) of energy storage project being developed in Southern California, to create dispatch profile and estimated long-term project value of the facility. The evaluation included assessments of project revenue in energy, ancillary services, and capacity markets in Southern California.
- Completed dispatch analysis and financial modeling of pumped storage hydro project in Colorado, for use in regulatory proceedings. The evaluation included assessments of project revenue in energy, ancillary services, and capacity markets in Colorado.
- Completed nodal power price forecast and assessment of high voltage transmission upgrades and additions in Southern California. This project included an assessment of congestion, locational marginal pricing, transmission system losses, and economic impacts of adding new transmission facilities in WECC, with particular focus on Southern California. PROMOD IV was used to complete the nodal market analysis, and PROMOD simulation results were translated into GE-PSLF for more detailed transmission system modeling of power flow cases under a variety of supply and demand conditions throughout the year.
- Completed PROMOD IV dispatch and economic analysis of Lodi Energy Center, with focus upon expected dispatch of the project, and its fit into the overall power supply portfolio of a Southern California Municipal Utility.
- Completed PROMOD IV dispatch analysis of a 100 MW biomass project in Florida, with focus upon expected dispatch and market revenue for the project in Florida wholesale power markets. Prepared Independent Market Report for use in financing construction of this project.
- Completed PROMOD IV market price forecasts and detailed analyses of power markets in all North American regions, including hourly energy price forecasts, annual capacity price forecasts, and detailed assessment of supply/demand conditions and generator dispatch. The assessments included forecasts of renewable energy development in each region/submarket, forecast greenhouse gas regulation, and economic assessment of fossil and renewable energy technologies.

Vice President, Ventyx, Inc., Sacramento, CA, June 2007 to March 2009

- Managed project and led analysis for consortium of upper Midwest utilities focused on developing plans for long-term transmission expansion to ensure reliability in the region and to accommodate economic transfer of large-scale wind-based electricity generation. This project examined congestion, reliability and economic benefits associated with large-scale wind generation expansion in the upper Midwest, and accompanying needs for transmission system expansion. Evaluation was completed on both nodal and zonal basis.
- Assisted investor-owned utility in the upper Midwest in completing an economic transmission planning study consistent with FERC requirements. Provided guidance to client in establishing study framework, and in completing detailed technical evaluation of transmission upgrade projects. Provided assistance with stakeholder group interactions and debriefing.
- Conducted study for Western Area Power Administration examining economic impacts of wind project integration from new wind projects located on Native American lands. Worked with multi-party stakeholder group in completing study. Specific focus was upon power system modeling and economic evaluation of long-term costs and benefits of wind energy integration into the WAPA system.
- Developed projections of expected dispatch, revenue, and operating costs for new combined-cycle power plant under development in Southern California. Prepared financial projections under merchant plant and other likely economic scenarios. Completed evaluation of tolling agreement terms and conditions.
- Assisted Southern California energy supplier in completing due diligence analysis for investment and development of 300-500 MW wind generation project located in Central/Southern California. Reviewed due diligence documents and completed economic evaluation of expected revenue, operating costs and investment cash flows for the project at a range of capacities varying from 100 MW to 500 MW.

Director, Navigant Consulting, Inc., Sacramento, CA, April, 2000 to June, 2007

- Responsible for managing the price forecasting subpractice within Navigant Consulting's Energy Market Assessment group. Responsibilities included a wide variety of engagements focused on evaluating wholesale power market conditions. Completed market assessment and simulation studies of all North American regional power markets, including Canada and Mexico.
- Created and Developed NCI's PROSYM market simulation practice and capabilities in modeling WECC and Eastern Interconnected markets. Completed numerous market simulation and assessment engagements throughout the U.S. covering all North American market regions.
- With a team of consultants, assisting the California Energy Commission in defining and evaluating scenarios for its 2007 Integrated Energy Plan. Reviewing market simulation results from each of the scenarios and completing analysis of industry and consumer risks likely to be faced in California over the next decade (ongoing).
- Directed NCI's market simulation efforts as independent consultant to the State of California Department of Water Resources, leading to the successful underwriting of $11 billion in bond financing and supporting the execution of power supply agreements aggregating to over 13,000 MW.

- Developed projections of lost revenue and operating profits due to construction delays at a large combined-cycle project in the Desert Southwest. Prepared evaluation of WECC power market conditions during the construction period for this project, and completed power market simulations used to measure likely dispatch, revenue and operating profits of the project during the construction delay period. Successfully presented and defended those estimates before an Arbitration Panel, resulting in a significant financial award for our client.
- Completed PJM Market simulations and led analytical support for recent financing of a large coal plant in PJM-West. Worked closely with investment banks and rating agencies in identifying and assessing cash flow risks to the project.
- Prepared carbon regulation risk assessment of a new coal plant being developed in Nevada, to evaluate long-term potential impacts on project costs. Evaluated ratepayer risks associated with this new project.
- Developed and maintained power market simulations to evaluate likely dispatch, costs, and spot market purchases and sales associated with the California Department of Water Resources purchased power contract portfolio. Results from these simulations have been used in each of the last five years to support CDWR's annual revenue requirement filing before the California Public Utilities Commission. Provide ongoing regulatory support to CDWR, including consultation and limited training of CPUC staff in power market modeling.
- Directed a number of nationwide market simulation and valuation engagements examining current market value of power plant portfolios owned by Calpine, Mirant, NRG and other independent power producers. Worked with bond investors to develop refined valuation estimates for subsets of each portfolio.
- Served on WECC's Power Simulation Task Force which was formed to assess available options for the WECC to procure, maintain and use a power market simulation database and model in its generation and transmission planning efforts. Participated in task force meetings where criteria were developed for selecting a simulation database and model, and assisted in evaluating proposals submitted to the WECC task force
- Performed power market simulations of Mexico, using NewEnergy Associates' MarketPower simulation model. Developed market price forecast and dispatch analysis of the Altamira II project under a variety of projected fuel market conditions. Results from these analyses were used by Senior Lenders to evaluate ongoing feasibility of the project under its financing terms. Annual updates were provided to the lenders.
- Assisted a California investor-owned utility in conducting RFP and in evaluating bids received for short-term and medium-term power supply contracts. Developed cost rankings, economic screening, risk assessment and preferred bid evaluations, and assisted the utility's planning and bid evaluation staff in presenting results to the company's senior management.
- Developed WECC market simulations and assessment of investment conditions for numerous clients used in feasibility analysis and financing support of new generation projects being developed in WECC markets. These analyses included separate evaluation of power market conditions in California, Mexico (Baja), Arizona, Colorado, Nevada, Oregon, Washington, British Columbia, and Alberta.
- Reviewed and verified long-term resource plans of a major investor-owned utility located in the Desert Southwest region. Conducted power market simulations of preferred and competing resource plans and developed relative ranking of results.

Senior Consultant, Henwood Energy Services, Inc., Sacramento, CA, 1998 to 2000

- Prepared numerous forecasts of wholesale market electricity prices using Henwood's proprietary market simulation tools. Drafted reports presenting price forecasts to consulting clients. Worked closely with clients and sponsors of new merchant power plants to provide customized market price forecasts and to serve individual client needs. Presented study results to clients and their constituents.
- Directed project evaluation and revenue forecast for major merchant power plant in Texas. Presented revenue forecast to investment bankers, and to several potential equity investors. Advised and worked with project developer to successfully obtain debt and equity financing for the project, which is currently under construction.
- Conducted economic study of market rules and entry barriers faced by developers of new merchant power plants in domestic electricity markets. Applied study results to specific conditions in Texas. Met with a variety of industry representatives in Texas including project developers, transmission service providers, power marketers, utility regulators and environmental regulators to gather market intelligence and develop study conclusions.
- Advised and worked with PricewaterhouseCoopers to perform economic evaluation and market simulations of proposed Purchase Power Arrangements under development in Alberta, Canada. The Power Purchase Arrangements are to be sold at auction in coming months. Prepared economic study of market power held by incumbent electricity suppliers in Alberta.
- Developed software and modeling tools to estimate investment cash flows and pro forma financial results for new merchant power plants. Developed Henwood approach for evaluating profitability of new market entrants and incorporating equilibrium amounts of new entry in its market studies.

Senior Financial Analyst, Public Service Commission of Wisconsin, Madison, WI, 1990 to 1998

- Developed policy proposals for restructuring wholesale and retail electricity markets. Evaluated competing policy proposals for impacts upon consumers and upon electrical system operation. Drafted formal electricity industry restructuring policy adopted by the Wisconsin Commission.
- Developed policies for addressing wholesale and retail market power in Primergy and Interstate Energy Corporation merger cases. Evaluated feasibility and corporate finance implications of asset divestiture and spin-off options for mitigating market power.
- Presented evaluation of proposed electric utility merger legislation to subcommittee of Wisconsin legislature. Advised individual legislators on merger policy.
- Developed policy proposal and draft legislation for reforming power plant siting law and for allowing development of new merchant power plants in Wisconsin.
- Directed industry-wide efforts to revise the PSCW generation competitive bidding procedures. Conducted workshops on proposed revisions for utility and other industry participants. Drafted policy reforms adopted by the Wisconsin Commission.
- Conducted primary economic and engineering analysis of power plant proposals submitted in generation competitive bidding cases. Prepared financial analyses of key contract terms and risks. Evaluated economic and engineering characteristics of bid proposals using production

cost and system expansion computer modeling. Recommended preferred projects to Wisconsin Commission.

- Completed numerous financial analyses of new stock and bond issuances by Wisconsin investor-owned utilities to evaluate investment risks and impacts upon the corporation. Drafted formal administrative orders authorizing each issuance.

Research Assistant, University of Wisconsin, Madison, WI, 1989-1990

- Co-authored and provided research support for study of consolidation and mergers in the electric utility industry.

EDUCATION

University of Wisconsin-Madison

- Graduate Studies toward MS-Finance, September 1988 - May 1990.
- Bachelor of Business Administration, Finance, Investment and Banking, May 1988.
- Curriculum concentrated heavily upon financial economics, with additional emphasis upon economics, mathematics, and accounting.

PUBLICATIONS

Electric Utility Mergers and Regulatory Policy, Ray, Stevenson, Schiffman, Thompson. National Regulatory Research Institute, 1992.

The Future of Wisconsin's Electric Power Industry: Environmental Impact Statement, co-author, Public Service Commission of Wisconsin, October 1995, Docket 05-EI-114.

Report to the Governor on Electric Reliability, co-author, Public Service Commission of Wisconsin, Summer 1997.

TESTIMONY

Public Service Commission of Wisconsin, Docket 6630-UR-104, Wisconsin Electric Power Company Rate Case, 1990, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 6690-UR-106, Wisconsin Public Service Corporation Rate Case, 1991, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 4220-UR-105, Northern States Power Company (Wisconsin) Rate Case, 1991, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Rate of Return on Equity, Cost of Capital and Financial Condition, Wisconsin Electric Power Company, Docket 6630-UR-105, Public Service Commission of Wisconsin, 1991

Public Service Commission of Wisconsin, Docket 05-EP-6, Advance Plan 6, 1992, "Alignment of Managerial Interests and Incentives with Integrated Resource Planning Goals" (with Paul Newman).

Public Service Commission of Wisconsin, Docket 6680-UR-107, Wisconsin Power & Light Company Rate Case, 1992, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 4220-UR-106, Northern States Power Company (Wisconsin) Rate Case, 1992, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 6630-UR-106, Wisconsin Electric Power Company Rate Case, 1992, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 05-EI-112, Investigation on the Commission's Own Motion Into Barriers to Contracts Between Electric Utilities and Non-Utility Cogenerators and Certain Related Policy Issues, 1992, "Contract Risk in Long-Term Purchase Power Arrangements."

Public Service Commission of Wisconsin, Docket 3270-UR-106, Madison Gas and Electric Company Rate Case, 1993, "Rate of Return on Equity, Cost of Capital and Financial Condition."

TESTIMONY (CONTINUED)

Public Service Commission of Wisconsin, Docket 6630-CE-187, Wisconsin Electric Power Company, 1993, "Memorandum to Commission Presenting Economic Analysis of Competitively Bid Proposals for New Power Plants" (co-authored).

Public Service Commission of Wisconsin, Docket 6680-UR-108, Wisconsin Power & Light Company Rate Case, 1993, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 4220-UR-107, Northern States Power Company (Wisconsin) Rate Case, 1993, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 6630-CE-202, Wisconsin Electric Power Company Auburn to Butternut Transmission

Line Case, 1994, "Economic Cost Comparison of Transmission Upgrade and Distributed Generation Wind Turbine Project."

Public Service Commission of Wisconsin, Docket 3270-UR-107, Madison Gas and Electric Company, 1994 "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin,. Docket 6690-CE-156, Application of Wisconsin Public Service Corporation for Authority to Increase Electric Generating Capacity (Stage One Competition Among Alternative Suppliers), 1994 & 1995, "Economic Analysis of Competitively Bid Power Plant Proposals" (with Paul Newman), "Contract Risk in Purchased Power Arrangements," "Accounting Treatment for Long-Term Purchased Power Contracts," "Contract Risk and Analysis of True-Up Mechanisms and Balancing Accounts."

Public Service Commission of Wisconsin, Docket 6630-UM-100/4220-UM-101, Wisconsin Electric Power Company/Northern States Power Company Merger Case, 1996, "Market Power Remedies; State/Federal Jurisdictional Issues."

Public Service Commission of Wisconsin, Docket 05-EP-7, Advance Plan 7, 1996, "Risk-Adjusted Discount Rates."

TESTIMONY (CONTINUED)

Public Service Commission of Wisconsin, Docket 6680-UM-100, WPL Holdings/IES Industries/Interstate Power Merger Case, 1997, "Market Power Remedies; State/Federal Jurisdictional Issues."

Public Service Commission of Wisconsin, Docket 6630-UR-110, Wisconsin Electric Power Company Rate Case, 1997, "Rate of Return on Equity, Cost of Capital and Financial Condition."

Public Service Commission of Wisconsin, Docket 05-EP-8, Advance Plan 8, 1997, "Purchased Power Costs, Supply Planning Risks and Supply Planning Parameters."

North Dakota Public Service Commission, Docket No. PU-399-01-186, Montana-Dakota Utilities Co., 2000 Electric Operations Annual Report (Commission Investigation of Excess Earnings), February, 2002, "Wholesale power market conditions in the upper midwest, and the impact on the level and profitability of off-system sales for Montana-Dakota Utilities Co."

California Public Utilities Commission, Rulemaking 02-01-011 Implementation of the Suspension of Direct Access Pursuant to Assembly Bill 1X and Decision 01-09-0. June, 2002. "Rebuttal Testimony of Roger Schiffman on behalf of the California Department of Water Resources: Market modeling issues."

Washington DC Arbitration Panel, "Estimate of lost energy sales and lost revenue due to construction delay" for two new combined cycle projects that were built in Michigan and Arizona markets, January-February, 2006.

Alternative 2 can be improved

The Draft EIS for Puget Sound Energy's Energize Eastside project includes a "non-wires" alternative based on intelligent management of energy, sometimes referred to as a "smart grid." While CENSE endorses this concept, the design and evaluation of Alternative 2 are flawed, making it seem less feasible and realistic. We would like to propose a better "Integrated Resource Approach" based on analysis performed by industry expert EQL Energy. The new proposal is reasonable from both an economic and environmental perspective.

To distinguish between the proposals, CENSE refers to the original proposal as "Alternative 2.A" and the new proposal from EQL as "Alternative 2.B."

The primary differences between Alternatives 2.A and 2.B are:

- Alternative 2.B reduces or eliminates the need to locate gas-fired peaker plants in residential neighborhoods.
- Alternative 2.B reduces the size of battery storage by a factor of four, eliminating concerns about recharging time and siting.
- Alternative 2.B uses a more realistic assessment of energy efficiency potential.
- Alternative 2.B proposes two classes of Demand Response, which are more specific and accurate than Demand Response proposed in Alternative 2.A.
- Alternative 2.B includes "Combined Heat and Power," which incentivizes new buildings to combine heating and electricity production, thereby reducing carbon emissions and increasing grid reliability.

Those are just some of the highlights. The following table shows a summary of the differences:

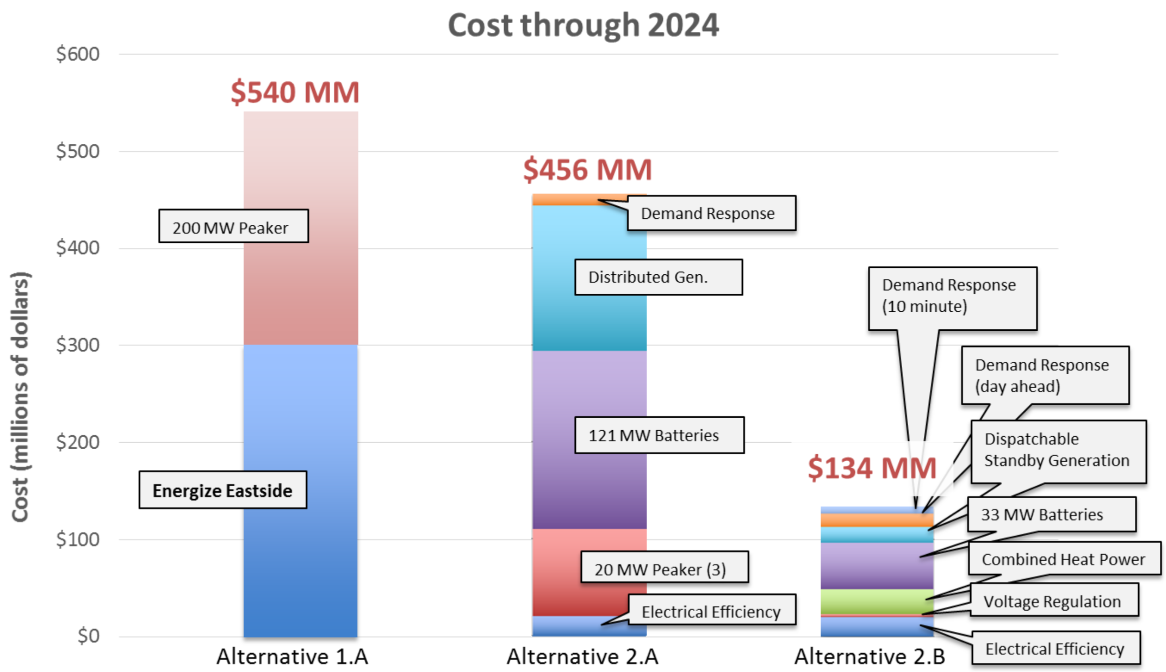
Component	Alternative 2.A (MW in 2024)	Alternative 2.B (MW in 2024)
Targeted Energy Efficiency	42*	39
Distribution Efficiency (CVR)	0	4
Combined Heat & Power	0	27
Energy Storage	121	31
Peak Generation Plant	60	0
Dispatchable Standby Generation	0*	22
Demand Response (unspecified)	32	
Demand Response (day ahead)		34
Demand Response (10 minute)		12
Total	**255**	**169**

* Incompletely specified in Draft EIS

Compared to Alternative 2.A, Alternative 2.B has 86 MW less of energy potential by 2024, but that is sufficient to meet the projected local need (although CENSE continues to dispute the magnitude of this need based on the Lauckhart-Schiffman Load Flow Study).

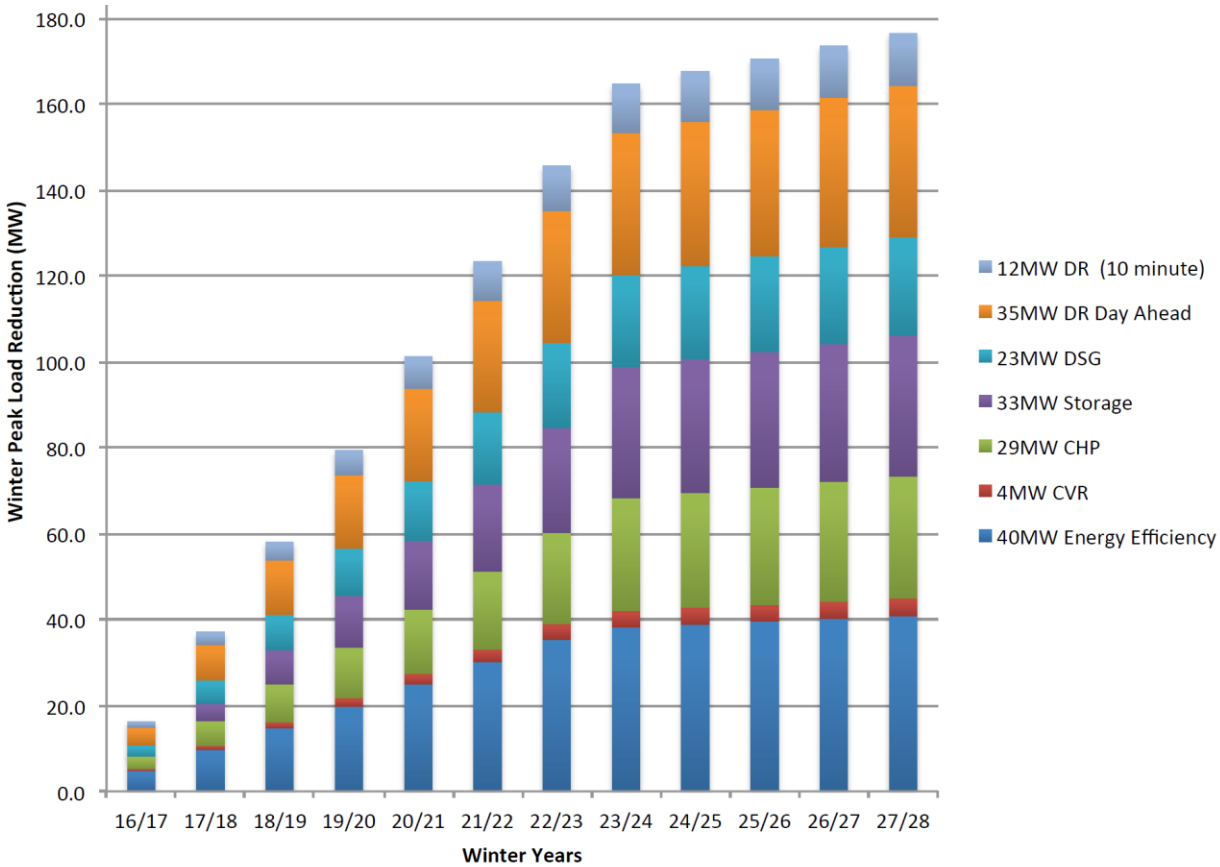
Compared to Alternative 1.A, Alternative 2.B offers many advantages that communities will find attractive. For example, EQL has shown that Alternative 2.B will reduce peak load demand and therefore delay the need for a new gas-fired peaker plant that PSE has stated the company may need to build in 2021, just a few years after Energize Eastside is built.

The graph below compares outlays for Alternatives 1.A, 2.A, and 2.B until the year 2024, including a new 200 MW peaker that may be needed if winter peak demand is not moderated through smart integrated resource approaches:



Both Alternative 2.A and 2.B have lower total cost and reduced carbon emissions compared to the transmission line proposed in Alternative 1.A. Both Alternative 2 plans have another economic advantage. Unlike Alternative 1.A, which can't transmit its first electron until it is completely built and paid for, the Integrated Resource Approach can be built incrementally, a little bit each year. EQL proposes outlays of about $20 million per year, which can be scaled down if demand does not increase as fast as PSE predicts. Incremental investment has the added advantage of profiting from the rapid development and associated cost reductions of energy technologies, especially battery storage.

The following graph shows the expected ramp of peak reduction (in megawatts) for each component over the next 8 years:



These technologies and energy policies are being used effectively in other parts of the country. For example, the table below lists companies contracting with Southern California Edison to deliver 510 MW of energy savings and storage.[1] There are many examples of projects in other states that suggest that these kinds of solutions are feasible and cost effective.

Seller	**Resource Type**	**MW**
NRG	Energy Efficiency	102.5
Onsite Energy Corporation	Energy Efficiency	11
Sterling Analytics LLC	Energy Efficiency	16.7
NRG	Demand Response	75
SunPower Corp.	Behind-the-Meter Renewable	44
Ice Energy Holdings, Inc.	Behind-the-Meter Thermal Energy	25.6
Advanced Microgrid Solutions	Behind-the-Meter Battery Energy Storage	50
Stem	Behind-the-Meter Battery Energy Storage	85
AES	In-Front-of-the-Meter Battery Energy Storage	100
Total		**509.8**

[1] http://www.greentechmedia.com/articles/read/The-Worlds-Biggest-Battery-is-Being-Built-in-Southern-California

The exact mix of technologies, incentives, and energy policies that will be used is subject to further study and debate. EQL has provided specific capacity and cost estimates to provide illustrations of what is practical and cost-effective. A final plan will need to be developed in discussion with PSE, independent experts, local officials, and community representatives.

Alternatives 2.A and 2.B differ in the use of small peaker plants located in Eastside substations. PSE mentions concerns about noise and impact on residential areas. CENSE has a keen interest in these issues. However, if peaker plants are proven to be necessary and economically attractive, a small plant located in the light industrial area next to Bellevue's Lakeside substation (also near the new garbage transfer facility) could be an acceptable compromise.

In summary, we believe Alternative 2.B is less expensive, less dangerous, more reliable, less damaging to the environment, and less impactful to communities than the 18-mile scar through five Eastside cities that would result from building Alternative 1.A. We find Alternative 2.B to meet the definition of a "Reasonable alternative" described in WAC 197-11-786.[2]

We respectfully request Alternative 2.B be added to the EIS and receive fair evaluation by independent experts with experience in delivering solutions based on energy efficiency, demand response, distributed generation, and battery storage during Phase 2 of the EIS process.

Feedback on Draft EIS components

According to the Washington State Environmental Policy Handbook,

> *Alternatives are one of the basic building blocks of an EIS. They present options in a meaningful way for decision-makers. The EIS examines all areas of probable significant adverse environmental impact associated with the various alternatives including the no-action alternative and the proposal.* [3]

Alternative 2.A is distorted by incomplete information and questionable assumptions. Its impacts cannot be honestly compared to the impacts of PSE's proposal (Alternative 1.A).

Here are some of the problems we saw in the design and evaluation of Alternative 2.A:

1. An "Integrated Resource Approach" must be designed by a consultant with expertise and practical experience in creating solutions based on Distributed Energy Resources.
2. The solution must be designed by an entity independent of PSE, because the project proponent has a vested interest in making Alternative 1.A look good.
3. The solution must not be based on information in PSE's Integrated Resource Plans (IRPs), because **IRPs are not required to incorporate feedback from stakeholders or the Washington Utilities and Transportation Commission.**
4. The DEIS should cite examples from other cities in which a proposed solution or component was successfully applied, and note if any unanticipated problems arose.
5. The solution should cite other Northwest agencies that were consulted and/or referenced. For example, alternatives should note agreement or disagreement with recommendations made by

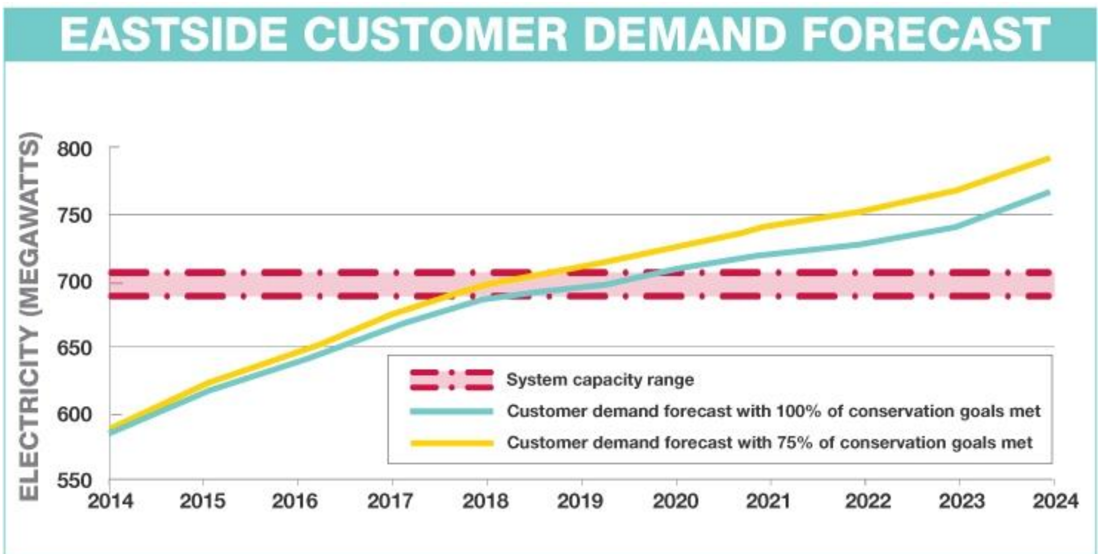
[2] http://apps.leg.wa.gov/wac/default.aspx?cite=197-11-786
[3] https://fortress.wa.gov/ecy/publications/documents/98114.pdf, p. 53

the Northwest Power and Conservation Council in the recently released *Seventh Northwest Power Plan*.

Specific reactions to DEIS Alternative 2.A

- 2.3.3: *"According to PSE projections, it would take 74 MW of additional transmission capacity to marginally meet the demand through 2018 (Gentile et al., 2015). However, to address the capacity deficiency in 2018 with non-transmission resources would take approximately 163 MW of additional conservation, storage, and new generation within the Eastside…"*

  PSE seems to be changing the rules as the Energize Eastside proposal proceeds. The 74 MW figure quoted above for 2018 is significantly higher than the need PSE shows the public on its website:



  This graph shows a deficit of about 74 MW in 2024, six years later than the reference from Gentile et al. implies. We wonder why there is such a significant difference between PSE's public and private communications on the size of the capacity deficit.

  When consultant E3 studied a non-wires solution in February 2014, the requirement was simply stated: *"Assuming typical weather conditions of 23˚ F during PSE's winter peak demand, PSE powerflow cases identified that 70 MW of incremental peak demand reduction (beyond the reduction included in the baseline load forecast reflecting 100% of IRP target conservation levels) would be required in King County to defer transmission need until 2021."*[4]

  As one can see in the graph on page 3 of this document, EQL projects over 121 MW of peak load reduction by 2021. But PSE now says the company needs 163 MW of reductions by 2018. This higher number seems to be based on a new standard of effectiveness that is described in this

[4] https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/PSEScreeningStudyFebruary2014.pdf, p. 6

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email from Energize Eastside Program Manager Jens Nedrud: http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/pse_emails_referenced_in_the_deis.pdf. We wonder why this issue did not arise in the E3 study. Is it real, or is this an obfuscation designed to cast doubt on non-transmission alternatives in the EIS? If it is real, is the magnitude correctly stated by PSE?

We suspect that the different requirements for transmission and non-wires solutions stem from PSE's stated requirement that the Eastside grid must assist in the export of 1,500 MW to Canada during peak demand. This requirement favors transmission-based alternatives. However, the export of electricity at this level has never been proven, and the *Lauckhart-Schiffman Load Flow Study* raises important questions about whether the regional grid can sustain this level of transmission.

All of these fundamental questions have yet to be studied by a neutral and independent expert. Since many questions have come to light only after the EIS process began, they must be validated in order for non-wires solutions to be appropriately scaled. After that, the impacts of these alternatives can be appropriately compared.

A fair and independent expert must answer questions about how much electricity must be exported to Canada during winter peak loads and an N-1-1 failure. The number should reflect how much electricity is required by contractual agreement, and also how much can be reasonably delivered by the regional grid. Once this is known, the effectiveness of non-wires alternatives must be independently derived. This should lead to a clear determination of the level of peak load reduction that is required for each alternative in each year.

- 2.3.3: *"[Alternative 2.A] could address the project need but results in uncertainty about how much infrastructure would be installed and how much additional supply would be needed each year."*

  Vague, unsubstantiated statements like this reinforce an impression that the DEIS is biased against this alternative. Many utilities have used similar solutions without excessive fear and uncertainty about their infrastructure and supply.

  The DEIS should provide positive and negative examples from other utilities that have employed these approaches. We can learn from the trials and successes of others. Let's not make decisions based on unfounded fears and doubts.

- 2.3.3.1: *"The potential for additional energy efficiency on the Eastside is not currently known and would require additional evaluation."*

  There is plenty of data for making a more accurate determination, and an independent expert can provide a good estimate based on the experience of other communities as well as particular details that apply to our region. To avoid bias and conflicts of interest, "additional evaluation" should not be performed by PSE. Further, PSE has not demonstrated an ability to evaluate the potential of energy efficiency in a credible way. The WUTC and the Sierra Club have roundly criticized PSE's energy efficiency estimates in recent Integrated Resource Plans.

To maintain credibility and independence, the DEIS must employ an expert who can provide a reasonable estimate of potential savings on the Eastside through cost-effective energy efficiency technologies and policies.

- 2.3.3.1: *"PSE's Integrated Resource Plan (2013a) estimated PSE could achieve approximately 100 MW of additional energy efficiency during the period from 2024 to 2033 systemwide, which would equate to approximately 14 MW of energy efficiency gains on the Eastside during that time period. The additional energy efficiency assumed for Alternative 2 would be triple the amount that PSE estimated is achievable after 2024."*

  PSE's 2013 IRP is not a credible source to cite as a basis for energy efficiency projections. The IRP is known to be deficient in its evaluation of energy efficiency. The company's data was incomplete and out of date. Quoting the IRP without independent confirmation allows PSE to indirectly sabotage the viability of solutions that rely on accurate energy efficiency projections.

  It is also unreasonable to assume that energy efficiency gains are directly proportional to the Eastside's share of total system load. The mostly urban Eastside has a different level of energy intensity than more rural areas, and the potential for substantial gains through energy efficiency is greater. Quoting a back-of-the-napkin estimate like 14 MW is an affront to the honest and independent process we expected from the EIS. The earlier statement was preferable: "[energy efficiency potential] is not known and would require additional evaluation."

  To maintain credibility and independence, PSE's Integrated Resource Plans cannot be referenced as a source of data used to design or evaluate non-wire solutions. The DEIS must cite credible experts and case studies instead of rough calculations based on IRPs written by the project proponent.

- 2.3.3.2: *"The Integrated Resource Plan (PSE, 2013) estimated that demand response systems would result in 116 MW systemwide reduction in capacity needed by 2024. Because the Eastside represents approximately 14 percent of the systemwide load, and assuming that adoption of demand response would be proportional on the Eastside to the rest of PSE service areas, it is assumed that approximately 14 percent of the systemwide reduction (16 MW of conservation by 2024) would occur on the Eastside."*

  PSE's 2013 IRP has been strongly criticized for its lack of credible analysis on Demand Response. The Eastside has significantly greater potential for savings from Demand Response compared to other parts of PSE's service area. The Eastside potential is not proportional to other PSE service areas.

  PSE will be sending out an RFP for Demand Response solutions as part of its 2017 IRP process. Let's see what kind of Demand Response potential the competitive market can identify. Market-driven answers are likely to be more informative and aggressive than PSE's weak efforts were 3 or 4 years ago.

Demand Response is a central feature of the Seventh Northwest Power Plan. The DEIS must be much more specific about the kinds of Demand Response that will be incorporated in alternative solutions. For example, EQL Energy describes different programs for "day ahead" and "10 minute" Demand Response. These two programs deliver 43% more savings than the vaguely described program in the DEIS. Many states are far ahead of Washington in using Demand Response programs. The DEIS should cite positive and negative examples in other states to better inform the public and policymakers about the potential for these solutions in PSE's service area.

- 2.3.3.3.1: *"In order to address the Eastside transmission deficiency with distributed generation alone, approximately 300 to 400 MW of capacity would be needed by 2024 depending on the geographic location of the generation (PSE, 2013; Strauch, personal communication, 2015a)."*

  The use of distributed generation alone is not a scenario proposed by any alternative in the DEIS. This statement obfuscates the facts and may confuse the public. Worse, it states large numbers of megawatts that depend on an unspecified geographic location. What purpose does this serve? How would those numbers change if the generation were located in a more advantageous location? No useful information is provided.

  It is disappointing to see PSE's 2013 IRP again cited as a source. This corrupts the supposedly independent EIS process. Although the IRP documents are reviewed by the WUTC and other stakeholders, **no one has the authority to correct inaccurate statements in the IRP.** If the DEIS must cite the IRP as a source, it should also cite the criticism that those citations generated during the IRP review.

  The DEIS should engage experts in the field of distributed generation and provide positive and negative examples from communities that have used distributed generation strategies to address peak load issues.

- 2.3.3.3.1: *"To ensure adequate capacity even when some equipment is not working, a substantial degree of redundancy is needed in distributed generation resources."*

  This statement ignores the fact that successful Distributed Standby Generation programs have been deployed in the Pacific Northwest. For example, Portland Gas & Electric has a program in which the utility is responsible for testing and maintaining generators that are owned by private businesses and hospitals. The businesses get free maintenance in return for allowing their generators to be used by the utility during peak load scenarios that happen only a few hours each year. This is a good deal for the businesses who don't have to do maintenance themselves. It's also a good deal for customers who don't have to pay for extra infrastructure.

  To address the questions of adequate supply and redundancy, the DEIS must describe what

kind of maintenance programs would be needed to keep these generators in good working order. The cost of these programs must be compared with the cost of having redundant generators that are maintained in a less regular fashion.

- 2.3.3.4: *"While it is possible that home battery storage could occur in homes using technology that is currently being developed, [we won't consider it]."*

  It may be true that home battery storage won't be so widespread in the next few years that it will make a big difference in the Eastside's energy mix. However, it is worth considering how a utility might incentivize customers to consider this investment. PSE could offer rebates for installing home batteries. Or the company could give battery customers a special discount on electricity if they charge the battery during non-peak hours and then use the stored electricity during peak hours. Incentives could make it financially attractive for customers to install batteries for the purpose of saving money on their electricity bills and having a backup source of electricity during power outages. This would especially appeal to customers with solar panels. A battery would allow these customers to bank their solar output and survive power outages spanning multiple days (with a big enough battery and judicious use of electricity).

  Instead of dismissing home batteries in a single sentence, the DEIS should describe incentives in other states that encourage home battery installation. How do incentive costs, impacts, and benefits compare to other alternatives? Of course, the DEIS should account for the societal cost of carbon emissions, and the possibility that carbon will be taxed in the future.

- 2.3.3.4: *"This analysis considers a PSE controlled facility capable of storing 121 MW, which would be adequate to eliminate emergency overloads (Strategen, 2015). This would require a site of approximately 6 acres."*

  We disagree that a battery of this size is necessary. A huge battery is needed only because the DEIS significantly underestimates the amount of energy that could be addressed through energy efficiency, demand response, and distributed generation. According to our expert, EQL Energy, the Eastside could realistically install a battery that is 4 times smaller than described in the DEIS. A smaller battery would take less land to site.

  The DEIS would do well to reference a project that is currently being installed by Southern California Edison.[5] It's a mix of utility-side and behind-the-meter batteries that might work on the Eastside at a much smaller scale. There are exciting batteries being produced locally (UniEnergy Technologies in Mukilteo[6]) and intriguing salt-water batteries that are inexpensive, non-toxic, non-flammable, and non-corrosive (Aquion Energy[7]). Battery technology is evolving quickly, and even PSE says batteries will be transformative soon. The main questions are how big, how much, and when?

[5] http://www.utilitydive.com/news/inside-southern-california-edisons-energy-storage-strategy/406044/
[6] http://www.uetechnologies.com/
[7] http://www.aquionenergy.com/products/grid-scale-batteries

Because the huge battery described in Alternative 2.A is practically impossible to charge and difficult to site, the DEIS must consider smaller batteries that are enabled by better energy efficiency, demand response, and distributed generation. Also, the DEIS must correct a significant error in the Strategen report that fails to account for the avoided cost of transmission, making batteries look less cost-competitive that they actually are (the table below shows batteries to be twice as cost-efficient as PSE's transmission project if an additional peaker plant can be avoided). The benefit of reduced carbon emissions must be recognized if additional peaker plants are supplanted by energy storage.

Benefits (avoided capital costs)			
Transmission Deferral cost	155	$/kW-yr	$220MM capital cost for Energize Eastside
Generation Capacity Cost	184	$/kW-yr	E3 based on SCCT $190/kW -yr levelized cost
Distirbution costs	31	$/kW-yr	Based on NWPCC value
Flexibility (Ancillary Services)	99	$/kW-yr	Strategen report
Oversupply	1.4	$/kW-yr	
Storage Benefit	**470.4**	**$/kW-yr**	
Storage Cost	**218**	**$/kW-yr**	2015 Strategen report EE EIS
Benefit/Cost ratio	**216%**		

- 2.3.3.4: *"The Eastside system has significant constraints during off-peak periods that could prevent an energy storage system from maintaining sufficient charge to eliminate or sufficiently reduce normal overloads over multiple days."*

  This is only a concern for the huge batteries proposed in the DEIS. It is not a problem for the more realistically-sized batteries proposed by EQL Energy.

  The DEIS must redo analysis of battery charging limitations with smaller batteries.

- 2.3.3.4: *"A system large enough to address the entire transmission capacity deficiency would need to deliver approximately 328 MW of electricity and store 2,338 (MWh) of power. A storage system of this size is not technically feasible."*

  This statement might be misread by the public. Someone might conclude that batteries are not technically feasible, when they are only infeasible if they are used to address the **entire deficiency** without any other components included.

  The DEIS should not include statements that confuse or obfuscate the issues. Statements like this must be moved into a separate section clearly labeled "Ideas that were considered but proven unworkable." Some readers might be confused by the proximity of this fantastical speculation to realistic proposals.

- 2.3.3.4: *"Summer requirements were not evaluated because the limitations identified during the winter study indicated that energy storage would not be a feasible stand-alone alternative."*

  Everyone agrees that energy storage is not a *stand-alone* alternative. This statement applies only to the previous fantastical speculation.

  The DEIS must remove or clearly separate fantastical speculation from factual information.

- 2.3.3.1 (Peak Generation Plant Component – the section numbers are wrong, it should be 2.3.3.5): *"Most of the substations on the Eastside are in residential areas, and these types of generators produce a high noise level that would be incompatible with those surroundings. For this reason PSE had eliminated this option from consideration."*

  CENSE remains keenly interested in protecting residential neighborhoods from the impacts of demand growth that are mostly driven by the commercial sector. The DEIS does not consider how the costs of serving demand growth should be shared with commercial enterprises and developers who create increased demand.

- 2.3.3.2 (Construction, also incorrectly numbered): *"Construction of battery storage facilities would last approximately 6 months and would require standard construction equipment similar to what is required for construction of a substation under Alternative 1."*

  This statement compares the construction impact for a huge battery (which is way too aggressive) to the construction of a substation under Alternative 1. Shouldn't the DEIS also consider the construction impact of removing thousands of mature trees and bulldozing dozens of homes in order to install 18 miles of transmission lines in Alternative 1.A? It is a mockery of the SEPA process to worry about the impact of 6 acres of development while ignoring 18 miles of impacted neighborhoods, parks, schools, and businesses.

  To be fair, the DEIS must compare apples to apples. The total construction impact of an alternative should be compared to the total construction impact of another alternative. Comparing the impact of one subpart of one alternative to the impact of a selected subpart of another alternative is not useful.

- 16.7.4: *"Uncertainties about the feasibility and performance of certain technologies, customer participation levels, and achievable conservation result in a risk to reliability."*

  These unsubstantiated statements about reliability, coming from the project proponent, might be used to eliminate non-wires solutions from consideration. However, these solutions rely on many different technologies and policies, and are actually more reliable than a transmission line. A transmission line is vulnerable to earthquakes, extreme weather, solar flares, and terrorism. For example, an extreme wind or ice storm may jeopardize more than a single pole. If two poles fail, the entire transmission line that PSE proposes to build could be knocked out, reducing the capacity of the Eastside grid by up to 20%. The same storm is unlikely to disable more than 5%

of the capacity of Alternative 2 solutions.

The DEIS must compare apples to apples. The overall reliability of one alternative must be compared to the overall reliability of another alternative.

Why is the Eastside an exception?

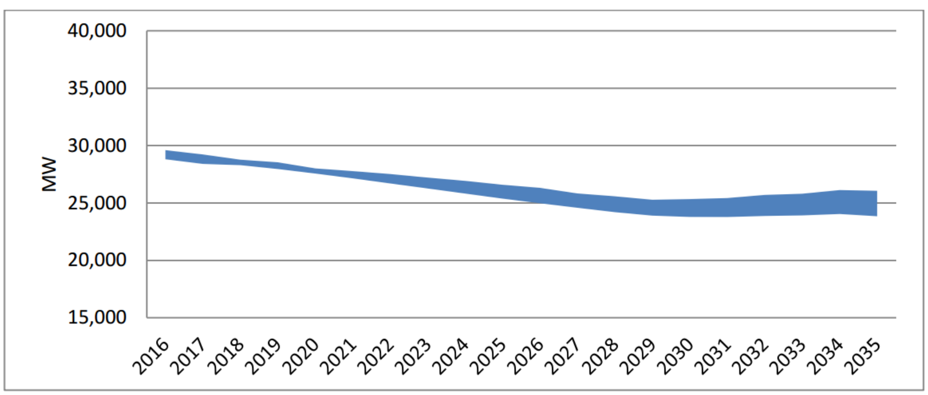
The *Seventh Northwest Power Plan*[8] published by the Northwest Power and Conservation Council says

> *In more than 90 percent of future conditions, cost-effective efficiency met all electricity load growth through 2030 and in more than half of the futures all load growth for the next 20 years. It's not only the single largest contributor to meeting the region's future electricity needs; it's also the single largest source of new peaking capacity.*

CENSE wonders why efficiency is not the answer to the Eastside's load growth. Obviously, the Eastside is growing quickly. However, the 2.4% annual growth rate in demand that PSE predicts is nearly five times the rate that Seattle City Light predicts. It is not obvious that the Eastside is growing five times faster than Seattle.

Perhaps PSE projections do not rely enough on conservation and demand response. Here is a graph of expected **Winter Peak Demand** included in the Seventh Plan:

Figure 7 - 11: Sales (Net Load After Conservation and DR) Forecast Range – Winter Peak



Even if the Eastside is growing quickly, we would expect winter peak growth to be flat or very slightly positive, not the explosive 2.4% growth that PSE projects.

The DEIS must clarify what level of growth is realistic, and evaluate the impacts of alternatives that are specifically designed to address that level of growth. Each alternative must be vetted by experts. If possible, the DEIS should cite positive and negative examples from communities that have gained experience with an alternative. Above all, the DEIS must be clear, unbiased, and independent. The Draft EIS fails these criteria and must be corrected.

Sincerely,
Don Marsh, President
CENSE.org

[8] https://www.nwcouncil.org/energy/powerplan/7/plan/

Attachments

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June 15, 2015

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Scoping Comments: 14-139122-L "Energize Eastside"
Scoping@EnergizeEastsideEIS.org

Dear Mr. Pyle:

I write today to provide scoping comments on Puget Sound Energy's "Energize Eastside" proposal on behalf of the Coalition of Eastside Neighborhoods for Sensible Energy (CENSE), a volunteer coalition of residents and local citizens concerned with the "Energize Eastside" proposal. These comments are in response to a Determination of Significance and Scoping Notice issued by the City in April, 2015, herein referenced as the "DS."

These comments are supplemental to others submitted by CENSE and its members. This letter incorporates by reference all other comments entered by other parties on scoping.

Comments on the process and scoping set forth below.

1. LACK OF A PROJECT APPLICATION

As a beginning point, the City is inappropriately processing the "Energize Eastside" proposal as a concept as promoted by PSE, rather than as a project proposal. "Energize Eastside" is essentially a promotional or branding characterization by PSE. The City should reference the proposal in "Description of Proposal" found in the DS as the construction of "a new 230 kV electrical transmission line and substation."

In addition, in correspondence with CENSE, the City admits that PSE has not filed any type of land use or building permit application with the City for this new transmission line. This is despite the fact that PSE has continuously identified the intended location of its proposed new transmission line along a defined and well known corridor and has made decisions concerning the design of the transmission lines. See the "Energize Eastside" website at http://www.energizeeastside.com/design. This website also has photo simulations of the proposed construction and tower locations in many places. See http://www.energizeeastside.com/photo-simulations. There is certainly sufficient information available to prepare a permit application for this work.

Indeed, the City has stated in the DS that during scoping interested persons may comment on "licenses or other approvals that may be required." However, without a specific application, it is impossible to know the licenses or approvals that will be required for the transmission line. For example, all material prepared by PSE indicates that the transmission line route will extend through the East Bellevue Community Council area for more than a mile, but City staff says that issue is still up in the air in an email from Carol Helland to CENSE on June 3, 2015:

> EBCC jurisdiction has authority only to approve or disapprove applications within the jurisdiction of the Community Council. Refer to LUC section 20.35.365. <u>The determination is made at the time of application. If PSE applies for a conditional use permit to approve an Energize Eastside alignment that is located within the boundaries of the EBCC, then the application would be characterized as a Process III application. Refer to LUC 20.35.015.D.2.</u> If PSE apples for a conditional use permit to approve an Energize Eastside alignment that is located outside the boundaries of the EBCC, then the application would be characterized as a Process I application. Refer to LUC 20.35.015.B.

(Emphasis supplied). Of course, EBCC has approval/disapproval authority over any conditional use permit application that PSE may make for its new 20 kV line. It is inappropriate for City staff to hide the ball on this important issue; the Draft EIS (DEIS) needs to confirm that the jurisdiction of EBCC will be invoked by this application and that the review will be under Process III review rules and procedures.

The lack of a specific permit application is particularly important for any Phase 2 considerations. The DS states that: "Construction and operation level impacts will be addressed with Phase 2 of the EIS process." Similarly at the third page, the DS states that Phase 2 "will examine project level alternatives, include possible alternative routes for transmission lines." It is impossible for local citizens to consider "construction and operation level impacts" without a specific project application to determine the location of the new transmission line with locations and descriptions of proposed towers.

The City should require the filing of a permit application as a precondition to additional SEPA review. That application will disclose critical detail concerning the PSE proposal and allow informed comment by the public. Such an application would not foreclose or affect the review in the EIS process of reasonable alternatives.

2. THE PREPARATION OF TWO SERIAL DRAFT ENVIRONMENTAL IMPACT STATEMENTS IS INCONSISTENT WITH SEPA AND THE SEPA RULES.

The DS states that the City plans to prepare two draft EISs for the "Energize Eastside" proposal. The second phase is described as follows:

> The second phase of the project will select among the Phase 1 alternatives and examine project level alternatives, including alternative routes for transmission lines. A second opportunity for scoping will be provided and a second Draft EIS will be issued for Phase 2.

The outlined process is inconsistent with SEPA and requires immediate revision.

For many years, the SEPA Rules have provided for "Phased Review" in WAC 197-11-060(5). Phased review involves the preparation of a "nonproject EIS" which focuses "on issues that are ready for decision and exclude from consideration issues . . . not yet ready." Subsection (b). Indeed, WAC 197-11-442 sets forth criteria to be followed for a nonproject EIS, and states:

> (2) The lead agency shall discuss impacts and alternatives in the level of detail appropriate to the scope of the nonproject proposal and to the level of planning for the proposal. Alternatives should be emphasized. In particular, agencies are encouraged to describe the proposal in terms of alternative means of accomplishing a stated objective (see WAC 197-11-060(3)).

The nonproject EIS follows the usual sequence of scoping, draft EIS and final EIS. Once a decision is made on a broader nonproject proposal, a project level EIS will be prepared based on the nonproject analysis. As described in WAC 197-11-443:

> (2) A nonproject proposal may be approved based on an EIS assessing its broad impacts. When a project is then proposed that is consistent with the approved nonproject action, the EIS on such a project shall focus on the impacts and alternatives including mitigation measures specific to the subsequent project and not analyzed in the nonproject EIS. The scope shall be limited accordingly. Procedures for use of existing documents shall be used as appropriate, see Part Six.

Thus, the SEPA provisions for phasing require a draft and final EIS on the nonproject proposal and a decision on the nonproject alternatives. Following that decision, if the applicant wishes to pursue a specific project, then preparation of a project level draft and final EIS will follow.

However, the City of Bellevue procedures for "Energize Eastside" do not follow the SEPA Rules for nonproject EIS. Instead of adherence to the rules, the City of Bellevue intends to prepare the Phase 1 DEIS, but not prepare a final EIS on Phase 1. Instead it will inexplicably move to a second DEIS without preparing a Phase 1 final EIS. No reason is stated for the bizarre process. The SEPA Rules are absolutely clear that: "The lead agency shall prepare a final environmental impact statement whenever a DEIS has been prepared, unless the proposal is withdrawn or indefinitely postponed." WAC 197-11-560(1). The FEIS is the key element in the SEPA decision making process. Under the rules, citizens and agencies may comment on the EIS and the City is required to respond in one or more of the means found in WAC 197-11-560(1). The City should prepare a final EIS on Phase 1 based on comments from the public which will inform the staff and public on the selection of an alternative for consideration in the Phase 2 project level draft and final EIS.

Further, the description of Phase 2 indicates that: "The second phase of the project will select among the Phase 1 alternatives . . ." Obviously, a "phase" does not "select" among alternatives; a person or persons must make that selection. The DS does not identify who that person or persons will be. As noted above, no "selection" of this nature can proceed without the preparation of a final EIS on Phase 1. WAC 197-11-070, specifically establishes "Limitations on actions during the SEPA Process" states:

> (1) Until the responsible official issues a final determination of nonsignificance or final environmental impact statement, no action concerning the proposal shall be taken by a governmental agency that would:
>
> (a) Have an adverse environmental impact; or
>
> (b) Limit the choice of reasonable alternatives.

(Emphasis supplied.) The City is obligated to issue a final EIS on the Phase 1, nonproject level review, before it proceeds to select or limit alternatives.

The City must bring its environmental review process consistent with the SEPA rules or it risks having the process overturned at a later time with consequent delays to the applicant a waste of money and the public interest.

3. "ENERGIZE EASTSIDE" IS NOT AN ESSENTIAL PUBLIC FACILITY (EPF) .

Correspondence with city staff indicates that the City considers the "Energize Eastside" an Essential Public Facility (EPF) though the DS does not describe it as such. As will be demonstrated below, "Energize Eastside" is not an EPF for numerous reasons. However, CENSE is concerned that this inaccurate characterization may result in a crabbed analysis of the proposal in the DEIS, especially Phase 1.

Provisions relating to EPFs are set forth in RCW 36.70A.200. Subsection 1 of the statute lists eight EPFs; however, "electric transmission facilities" are not listed among them. WAC 365-196-550(1)(d) provides a more comprehensive list of EPFs, but again, electric transmission lines are not included.

In *Residents Opposed to Kittitas Turbines v. State Energy Facility Site Evaluation Council (EFSEC),* 197 P.3d 1153, 165 Wn.2d 275 (2008), an issue was raised as to whether the GMA provisions for EPF repealed the authority of the State Energy Facility Site Evaluation Council (EFSEC) to regulate energy facilities. (The EFSEC statute was adopted long before GMA). In rejecting that proposition, the court noted that: "The GMA makes no mention of an energy facility. . ." in RCW 36.70A.200. However, in the EFSEC statute at RCW 80.50.020, the following definition is provided: (10) "Electrical transmission facilities" means electrical power lines and related equipment." The Court held that GMA did not supersede EFSEC rules.

The exclusion of "electrical transmission facilities" from the list of EPFs is both deliberate and a part of the overall statutory scheme for regulation and permitting for energy plants or transmission lines. Should PSE wish to provide specialized consideration for its new electric transmission lines, it could file an application with EFSEC under RCW 80.50.060(3). However, it has chosen to engage in local permitting under the municipal codes of the several jurisdictions through which its proposed line will run, obviously running the risk that one or more jurisdiction may find its proposal inconsistent with its regulations.

Consistent with the Supreme Court decision in *Residents,* the City of Bellevue Comprehensive Plan, Capital Facilities Element at page 82 provides as follows:

> POLICY CF-14. Require land use decisions on essential public facilities meeting the following criteria to be made consistent with the process and criteria set forth in Policy CF-16 :
>
> 1. The facility meets the Growth Management Act definition of an essential public facility at RCW 36.70A.200(1) now and as amended; or
>
> 2. The facility is on the statewide list maintained by the Office of Financial Management, ref. RCW 36.70A.200(4) or on the countywide list of essential public facilities;
>
> AND
>
> 3. The facility is not otherwise regulated by the Bellevue Land Use Code.

(Emphasis supplied.) As is seen, because electrical transmission lines are specifically regulated by the Land Use Code, they are not considered an EPF. Ms. Helland's comments on page 2, *infra*, confirm this.

The City will make a serious error in its SEPA review of the "Energize Eastside" project if it considers the proposal an EPF. The responsible official should direct the drafters of the draft EIS to not consider the "Energize Eastside" proposal an EPF.

4. THE DRAFT AND FINAL PHASE 1 ENVIRONMENTAL IMPACT STATEMENTS MUST GIVE THOROUGH CONSIDERATION TO ALL ALTERNATIVES.

As the City is aware, consideration of alternatives is the most important part of SEPA analysis. Indeed SEPA itself, at RCW 43.21C.030(2)(e), has a separate, action forcing provision that agencies "study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative uses of available resources." Alternatives are in the forefront of environmental analysis. The SEPA rules direct that the EIS text comparatively analyze "alternatives including the proposed action." WAC 197-11-440(5).

In the present situation, alternatives analysis revolves around three basic issues. First, is there an identified and plausible need for a new transmission line? Second, are there alternative methods to meet the identified need? For an electric transmission line, are there nonstructural means to meet the need including demand management or reconfiguration of existing resources? Third, are there alternative structural methods to meet the need?

CENSE will be providing expert analysis of alternatives together with an identification of the kinds and types of review and study necessary to fully consider these alternatives. This material is incorporated by reference herein. We look forward to the careful review of these matters in the draft EIS.

In conclusion, this letter identifies serious defects and inconsistencies with SEPA Rules and statutes in the DS and associated communications with the City. These matters must be corrected immediately and before the city begins preparation of a draft EIS.

Thank you for your consideration of these comments.

Sincerely,

Aramburu & Eustis, LLP

J. Richard Aramburu

JRA:cc
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August 27, 2015

City of Bellevue
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Scoping@EnergizeEastsideEIS.org

Re: **Scoping Summary**
PSE STATED OBJECTIVE FOR ENERGIZE EASTSIDE, STANTEC REPORT 14-139122-L "Energize Eastside"

Dear Mr. Pyle:

As you are aware, this office represents Coalition of Eastside Neighbors for Sensible Energy, or CENSE, a Washington non profit corporation that is concerned about proposals by PSE to construct new transmission lines through eastside residential neighborhoods. CENSE submitted scoping comments on the "Energize Eastside" proposal on June 15, 2015. Those comments addressed various issues including the lack of any permit application to consider in the environmental review process, the plans for two DEISes prior to preparation of a final EIS, that the transmission proposal of PSE is not an essential public facility and the failure to consider all appropriate alternatives.

On July 30, 2015, the City posted on its website for this project, three documents a) a Memo from Stantec Engineering (Keith DeClerck) regarding the "Energize Eastside" Project, 2) a document entitled "Phase 1 Draft EIS Scoping Summary and Final Alternatives" (hereinafter "Scoping Summary"and 3) "PSE's Stated Objectives for Energize Eastside." In this letter, CENSE will provide comments on these documents.

1. STANTEC MEMO.

1.1 Use of Stantec Report in DEIS Process.

The Stantec Memo is offered as "validation" of the need for the 230 kv transmission corridor proposed by PSE but it is only a narrative of previous work offering no new analysis. However, it offers a variety of scare tactics including references to "cascading blackouts" (page 6), when the "lights go out" (page 9) and "hazards" related to power losses to "hospitals, nursing homes and fire departments" (page 10). This kind of unsupported hyperbole is distinctly inappropriate in environmental analysis.

The Scoping Summary also identifies that Stantec is an important player in deciding which alternatives will be considered in the DEIS:

> The Phase 1 Draft EIS will evaluate three action alternatives and a "No Action" Alternative, as described below. Each alternative includes a range of possible options that will be considered. The preliminary alternatives presented as part of the Scoping Notice and the alternative approaches recommended by the community were evaluated to determine if they would meet PSE's stated objectives (see Attachment 1) as required by SEPA (WAC 197-11-060, WAC 197-11-408, and WAC 197-11-440) and the project's purpose. <u>This evaluation was done with assistance from electrical engineers from Stantec</u>, a consulting firm that is part of the EIS consultant team, <u>and PSE engineers</u>.

Scoping Summary at page 14 (emphasis supplied). Similarly at page 16, the Scoping Summary states:

> <u>The consulting firm Stantec reviewed</u> unredacted results from the model in PSE's Needs Analysis and the Energize Eastside Solutions Reports (2013 and 2015) to ensure that the EIS consultant team had <u>a clear and unbiased picture of the purpose of the project</u> and what types of options are viable for achieving that purpose (Stantec has security clearance). Stantec and other members of the EIS consultant team had questions that were posed to PSE. In some cases this required PSE to do additional calculations. These were reported to the EIS consultant team by email. <u>In each case, Stantec reviewed the analysis for consistency with industry practice and for internal consistency among the various PSE-provided documents</u>.

(Emphasis supplied). At page 16, the Scoping Summary states:

> For potential alternatives that were not evaluated by PSE in its Solutions Report analysis, Stantec provided a <u>professional opinion</u> as to whether the proposed alternative would meet PSE's criteria. Stantec's findings were reviewed by the EIS consultant team <u>and the Eastside Cities</u>, and <u>the Eastside Cities agreed upon the alternatives to be analyzed</u>. Generally, alternatives that would not meet PSE's objectives were not included (see section titled "Which alternatives were considered and will not be included" below for more discussion).

(Emphasis supplied).

1.2 <u>Stantec Conflict of interest</u>.

In checking on the qualifications for Stantec to provide "unbiased" analysis, we discovered that the company has done substantial work for PSE. On the Stantec website, under the "Summary Experience List," Stantec described the following work done for PSE:

> **Replacements Puget Sound Energy, Various Locations, WA**
> Stantec prepared the detail design and material lists for the replacement of 230 and 115kV power circuit breakers located at various facilities in Western Washington. Stantec was responsible for preparing plans, elevations, bus details, grounding, and conduit and cable details for replacing existing oil circuit breakers with new gas breakers. In addition, Stantec revised control schematics to integrate the new breakers into the existing protection and control schemes including the SCADA system.

We find nothing in the Stantec Memo or the project website that discloses this prior work for the project applicant.

Doing this kind of substantial work for PSE raises issues as to whether Stantec can prepare an objective and "unbiased" report in this environmental review process.[1] This potential or actual conflict of interest should not taint the environmental review process.[2] Accordingly, we ask that the Stantec Memo be withdrawn to assure that documents will not be used or considered in the review process.[3]

1.3 <u>Stantec Qualifications to Participate in Evaluation of Alternative and EIS Process</u>.

In addition to the clear conflict of interest, there are serious questions concerning the qualifications of Stantec as well as of the author of the memo itself.

The "Energize Eastside" EIS website does not disclose the process by which Stantec was hired for the work it performed. No one outside the "project team" was informed that Stantec was being hired and it appears that no request for proposal was circulated. No resume of the author of the Stantec Memo, Keith DeClerck, has been provided, only a general summary of his qualifications on page 1 of the Memo. There is no reference to projects in the Pacific Northwest nor indication of knowledge of the regulatory structures or the operations in this region. Given the broad number of experts qualified for this work, we think that this individual, with a clear conflict of interest, should not be acting as an advisor for the DEIS team.

1.4 <u>Use of Unredacted Materials by Stantec and the DEIS Team.</u>

In addition, we note from your memo dated July 31, 2015 that accompanied the

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[1]We are not aware if Stantec has actually done other additional work for PSE. Accordingly we request that the City and the EIS team disclose all contracts or work that Stantec has performed for PSE.

[2]In this regard we note that PSE sent the Stantec Memo to FERC almost immediately after it was issued.

[3]The Scoping Summary says that Stantec's engineer provided a "professional opinion." But no resume is provided for Mr. DeClerck, no engineer stamp is found on the report and no information is provided as to whether he is a licensed professional engineer in the state of Washington.

report that:

> the EIS project team has obtained clearance to access un-redacted sensitive (protected in accordance with industry security protocol) utility planning and operations information used by PSE in developing the Energize Eastside project.

It appears that PSE and those working on the DEIS are using information to make decisions that has not been previously released to commenters on this proposal. We ask that the City provide this information to us immediately so it may be reviewed by our consultants who have previously commented during the scoping process. The withholding of pertinent information useful in project analysis is a serious defect in SEPA compliance and must be corrected immediately.

1.5 Failure of Stantec to Understand Basic Transmission Requirements.

As noted above, the Stantec Memo has multiple problems that make it unreliable for use in making decisions on the content of the DEIS for this project, including Stantec's patent conflict of interest and an author with questionable background to provide opinion on this important matter. It is little wonder that the Stantec Memo fails to understand a basic element of the Columbia River Treaty, and the Canadian Entitlement.

Stantec appears to assume that transmission flows on PSE lines must take account of operating conditions which include the return of the Canadian Entitlement (approximately 1300 MW at present) to Canada. What Stantec does not understand (or ignores) is that there is no current legal obligation for return of the Canadian Entitlement to Canada.

In 1999, the Americans and Canadians signed an "Entity Agreement on Aspects of Delivery on the Canadian Entitlement For April 1, 1998 though September 15, 2024." See www.bcuc.com/Documents/Proceedings/2006/DOC_10966_B1-131_Columbia%20 River%20Treaty%20Agree.pdf. This Agreement is referenced herein as the "Entity Agreement". In that agreement, it was acknowledged that both the US and Canadians agree that the long practice (50+ years) for sale of the Canadian Entitlement to US utilities could continue. That practice continues today and there is no indication that the Canadians want their entitlement back; indeed, in the more than 50 years the CRT has existed, Canada has <u>never</u> taken firm delivery of this power, being content to take advantage of the favorable market for power in the US.

Indeed, with passage of the Clean Energy Act by the Province of British Columbia on June 3, 2010 (Bill 17), BC made three important policy and regulatory decisions impacting the import of power. First, the Clean Energy Act established the objective in Paragraph 2(a) "to achieve electricity self-sufficiency[.]" Second, Paragraph 2(b) sets an energy objective to:

> (b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;

Third, an additional objective of the Act is that BC intends to become a "net exporter" of energy:

> (n) <u>to be a net exporter of electricity</u> from clean or renewable

resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia;

Paragraph 2(n) (emphasis supplied). Paragraph 3(d) of the Act requires the preparation of an "Integrated Resource Plan" which includes actions to further net export of energy.

Given that the Canadian Entitlement has never been delivered to Canada on a firm basis and that the intent of the Province is to become a net exporter of electricity, proposing to spend $200,000,000 for the "Energize Eastside" proposal on the basis that the Canadian Entitlement will be delivered to BC is an obvious and expensive error of judgment.

Even if, implausibly, the Canadians want the Canadian Entitlement back at the border, it will require notice to the US, an analysis of flow paths and a determination that "firm transmission" is available for purchase. See Section 11 of the Entity Agreement. Since the Canadians will have to pay for this privilege, and the obligation is a "take or pay" firm transmission contract, it is difficult to accept this is a real possibility.

Stantec's unfamiliarity with these circumstances has caused it to make a major error. Planning for "Energize Eastside" should delete the impact of the return of the Canadian Entitlement as a factor in transmission planning.

2. SCOPING SUMMARY AND ALTERNATIVES.

As noted above, the major function of the Scoping Summary is to eliminate certain alternatives from further consideration in the EIS process. The analysis here is deeply flawed and inconsistent with the SEPA Rules.

One defect is the mischaracterization of concerns regarding the existing electric system, found at page 19 of the Scoping Summary. There it is indicated that comments suggested that PSE should "disconnect the [PSE] system from the region or from adjacent electric lines." However, the alternative suggested by commenters was that certain through power flows, particularly the 1300 MW Canadian treaty flow, be eliminated from calculation of load on the PSE system during peak periods. Reports submitted by CENSE show that these through power flows are not firm obligations and in any event they would be eliminated during peak periods of demand. As described above, the Canadian Entitlement is not a factor in this situation. The City cannot eliminate alternative analyses based on an inaccurate recasting of public comments. This issue must be considered in the DEIS.

Of particular concern is the apparent decision to eliminate any gas-fired peaking plants as described on page 20-21 of the Scoping Summary. It is indicated that these facilities are not within the "stated objectives" of PSE. However, PSE is not entitled to eliminate alternatives that reasonably approximate the stated concern of PSE, which is to meet load. This is particularly true given that this is the scoping stage leading to a DEIS on a "programmatic" decision. Thus, the arbitrary and premature elimination of several alternatives is not consistent with the SEPA Rules.

This is nowhere more evident than in the elimination of peaking plants as alternatives. The Scoping Summary says (page 20) that:

> ***Generation Facilities***
> For a generation facility or group of facilities to be effective, PSE found that it would have to be located near the center of the Eastside area, such as near the Lakeside Substation. Any such facility would likely have to be gas-fired in order to be capable of producing power reliably whenever it is needed. PSE determined that at <u>least 300 MW of power generating capacity would be needed and the most cost effective way to generate that amount of power would be in a single plant.</u> . . . .In addition, the increased usage of gas-fired plants over time would have difficulty meeting clean air regulations. Even if it were economically feasible to create multiple smaller facilities, they would need to be clustered close to the center of the Eastside and would likely impose similar or even greater impacts than a single plant. <u>This alternative is not included because it does not meet the criterion of being environmentally acceptable to PSE and the Eastside communities.</u>

(Emphasis supplied). These conclusory statements, without support or technical or environmental analysis, cannot form the basis for the elimination of this alternative. Nor can unsubstantiated references to "most cost effective" solution be the basis for exclusion of alternatives. In addition, there is no description of how the "Eastside communities" reached a decision on this subject, what information was available to them and whether the elected decision-makers actually made these decisions. For example, were these decision makers informed that smaller gas peaking plants would run only rarely and then only during times of extreme cold conditions?

Both PSE and the "Eastside communities" run a serious risk by summarily eliminating alternatives without analysis before a DEIS is prepared. This was apparently done without a record of consideration and in private meetings between the project proponent PSE, staff from several communities and Stantec. The interested members of the public, other governmental agencies and impacted property owners are excluded from the process.

On the other hand, the DEIS is subject to peer review, agency analysis and public comment. As described in the Scoping Summary, <u>only at that time</u> will alternatives be culled out continuing review:

> Following publication of the Phase 1 Draft EIS, there will be a 45-day comment period (WAC 197-11-455) (see Figure 6). The Eastside cities will evaluate the input received and determine which alternatives should be carried forward into the more detailed Phase 2 Draft EIS, and what elements of the environment will be evaluated.

The City and EIS team should reconsider these perfunctory dismissals of a variety of alternatives. It would not be in the interest of the public, the participating cities and indeed PSE to have to redo the SEPA process in the event that a reviewing body or court determines this process was in error.[4] This is especially true where PSE has indicated time is a factor in these considerations.

In conclusion, the City and EIS team have improperly and prematurely eliminated completely reasonable alternatives from review in the DEIS. This analysis has apparently been influenced by an engineering firm with a patent conflict and based on information that was not available during the scoping process.

CENSE requests that the eliminated alternatives instead be maintained and studied in the environmental review process and included in the forthcoming DEIS.

Sincerely,

Aramburu & Eustis, LLP

J. Richard Aramburu

JRA:cc
cc: Clients

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[4]Consideration of alternatives is a key to environmental review under SEPA. As Richard Settle, a leading commentor on SEPA says:

> Open-minded, imaginative design and consideration of alternative courses of agency action is crucial to SEPA's ultimate quest - environmentally enlightened government decision making.

The Washington State Environmental Policy Act: A Legal and Policy Analysis §14(b)(I) (2014). Our court have insisted not only on thorough consideration of alternatives, but a complete discussion of alternatives in environmental impact statements. Thus in *Weyerhaeuser v. Pierce County,* 124 Wn.2d 26, 873 P.2d 498 (1994), the Washington Supreme Court held the discussion of alternatives in a final environmental impact statement inadequate:

> LRI claims it has complied with these requirements, and cites the final EIS at pages 19 to 33 (Ex. 1(c)) as containing sufficient discussion of offsite alternatives. However, pages 19 to 33 of the final EIS do not contain the required discussion. Instead, those pages contain a discussion of LRI's site selection process, and the brief descriptions of rejected sites consist of conclusory statements of LRI's assessment of possible sites examined in the site selection process. They do not contain any location information such as a map, street address, and legal description. They do not contain any description of principal features of any alternatives. They do not tailor the level of description to the significance of environmental impacts, and, in fact, it is impossible from the brief, conclusory descriptions to engage in any meaningful comparison of the alternatives. There is absolutely no useful comparison of the environmental impacts of the alternatives.

124 Wn.2d at 41-42. The remedy of the Court was as follows:

> Because the EIS completely fails to discuss any offsite alternatives, it is inadequate as a matter of law. The EIS must be revised to contain a discussion of alternative sites. *Barrie,* 93 Wn.2d at 857. The trial court's invalidation of the conditional use permit must be upheld in light of the inadequate EIS.

124 Wn.2d at 42. In the present case, the City intends to eliminate alternatives even before a draft EIS is prepared, a process that will not survive administrative or judicial review and would create needless delay.

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December 23, 2015

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Re: Draft DEIS for the 230 kV Transmission Lines proposed by PSE

Dear Ms. Helland:

As you know, this office represents CENSE, the local citizens organization concerned with the proposal by Puget Sound Energy (PSE) to construct 230 kV transmission lines through Bellevue and other Eastside communities, together with a new substation. Though PSE has branded its proposal as "Energize Eastside" we decline to accept this obvious attempt to control the perceived content of the proposal and accordingly will not use its characterization of the project. In this letter we will refer to the matter under review as the PSE Transmission Proposal or PSETP

In response to CENSE's request, you provided us with a copy of the "Preliminary Review Draft" ("PRD") for the PSETP. You cautioned that we should not be providing detailed comments on the PRD. CENSE will follow your guidance on a majority of the content of the PRD. However, we feel compelled to provide comment on Chapter 2 of the PRD entitled "Project Alternatives." As described more fully herein, this part of the PRD is completely inadequate and inconsistent with the spirit and letter of SEPA. Accordingly we urge that the DEIS for the PSETP be completely rewritten and expanded to provide a meaningful analysis of alternatives.

The Alternatives section of an environmental impact statement is by far the most important section of the document. The SEPA statute itself requires that local governments:

> (e) Study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative uses of available resources;

RCW 43.21C.030f. Indeed, DOE's SEPA Handbook says that:

> Alternatives are one of the basic building blocks of an EIS. They present options in a meaningful way for decision-makers. The EIS examines all areas of probable significant adverse environmental impacts associated with the various alternatives including the no-action alternative and the proposal.

See Section 3.3.2.

The emphasis on alternatives continues in the SEPA Rules and particularly WAC 197-11-440(5), which requires the EIS preparer to: "(v) Devote sufficiently detailed analysis to each reasonable alternative to permit a comparative evaluation of the alternatives including the proposed action." Because PSE has not submitted a project application the proposal must be considered a "nonproject proposal" governed by WAC 197-11-442, "Content of EIS on nonproject proposals." Alternatives are given special emphasis in a nonproject EIS:

> (2) The lead agency shall discuss impacts and alternatives in the level of detail appropriate to the scope of the nonproject proposal and to the level of planning for the proposal. Alternatives should be emphasized. In particular, agencies are encouraged to describe the proposal in terms of alternative means of accomplishing a stated objective (see WAC 197-11-060(3)). Alternatives including the proposed action should be analyzed at a roughly comparable level of detail, sufficient to evaluate their comparative merits (this does not require devoting the same number of pages in an EIS to each alternative).

As noted below, Chapter 2 of the PRD falls far short of the requirements for fair and thorough consideration of alternatives required by SEPA and the SEPA Rules.

Chapter 2 of the PRD, while entitled "Project Alternatives," has its first ten pages directed to "project objectives" with the next several pages describing the PSE proposal itself. The alternatives that do not include new transmission are limited to only four pages (2-21 to 2-24) with only the most vague and general discussion, actually little more than a description. Nothing here is sufficient to permit a comparative evaluation as required by SEPA and the SEPA Rules. For example, there are only two paragraphs devoted to demand response (the "voluntary and temporary reduction in consumers' use of electricity when the power system is stressed") and only one to energy efficiency.

By contrast, the draft Seventh Northwest Conservation and Electric Power Plan (the 7th Plan), just released, says that:

> In more than 90% of future conditions, cost-effective efficiency met *all* electricity load growth through 2035.

Emphasis in original. See page 1-1. The second priority under the 7th Plan is demand response, described as follows:

> While the region's hydroelectric system has long provided ample peaking capacity, it's likely that under low water and extreme weather conditions we'll need additional winter peaking capacity to maintain system adequacy. Because the probability of such events is low (but real), demand response resources, which have low development and "holding" costs are best-suited to meet this need.

Page 1-2. Another non-transmission alternative, natural gas generation, is completely excluded in just two paragraphs at pages 2-35 and 2-36 because of possible impacts, without any analysis of possible equipment, facility locations or capabilities. This is in stark contrast to the 7th Plan which states:

> After energy efficiency and demand response, new natural gas-fired generation is the most cost-effective option for the region in the near-term.

See page 1-2. In short, PSE has refused to consider reasonable alternatives that are identified and relied upon in the 7th Plan.

The reason that these alternatives are excluded is obvious: as a for-profit company, PSE wants to build facilities that generate income for its investors. Energy efficiency and demand response in fact reduce income because they encourage the reduction of consumption. Natural gas plants, as noted by the 7th Plan, will run so rarely that they produce no dependable stream of income. On the other hand, PSE is allowed a substantial return on investment by the WUTC from its proposed transmission project, to be paid by its rate payers (Bellevue residents).

The SEPA process cannot be hijacked by the profit motives of the applicant here. The City should assure that all reasonable alternatives are considered, in sufficient detail that a local government decision-maker can pick between them, even if it contradicts the PSE business model.

An additional concern relates to the timing of the EIS process as it relates to the project development. Page 2-9 of the PRD states that one of the non-electrical criteria is that :

> Alternatives must be reviewed to ensure that they are reasonably constructible by the 2018 in-service target date.

The section explains that to meet this date, construction must begin in 2017. *Id.* However, PSE (along with the Eastside cities) has so constructed its SEPA review process that there will be two draft environmental impact statements prepared before a final EIS is prepared, an unheard process under the SEPA, which requires a draft EIS be followed by a final.

This extended review process will have the final EIS distributed in the spring of 2017. See http://www.energizeeastside.com/schedule, a copy of which is attached hereto. Only then can the permit review process begin, which includes Hearing Examiner hearings and Council review. It is apparent that by the time the permitting process begins, with construction required to commence in 2017, PSE will argue there is no alternative but its transmission line proposal because of the limited time that will be left until the in-service date. Given that PSE will be gathering data on its transmission proposal, including surveying, wetland delineation, tree inventories, pipeline location and geotechnical investigation[1], and doing nothing to further any other alternative, PSE is deliberately painting the Eastside cities into a corner; i.e. there will be nothing else that can be done but to give PSE its desired permits. Indeed, this is even stated in the PRD at page 2-9:

> Any delay in the schedule would push the in-service date beyond the 2018 timeframe, which would increase PSE's reliance on the use of CAPs and load shedding. For example, some specialized equipment can take up to three years to procure. Therefore, PSE would not be able to meet the target in-service date.

The Cities should not allow themselves to be so blatantly manipulated by this private utility. The Cities should order an FEIS on the Phase I proposal and reach a decision on Phase I before going forward with detailed and site-specific review of this transmission proposal. In conjunction with this course of action, Chapter 2 of the DEIS should be modified to assure that Bellevue and the other Eastside councils have sufficient information about the alternatives to make a meaningful decision about the appropriate course of action.

Thank you for this opportunity to provide further comments on the process.

Sincerely,

ARAMBURU & EUSTIS, LLP

J. Richard Aramburu

J. Richard Aramburu

JRA:cc
cc: CENSE

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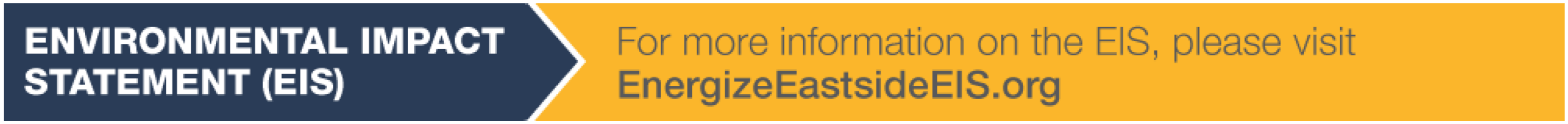
[1] PSE describes this fieldwork in detail in the "Energize Eastside" Environmental Impact Statement website.

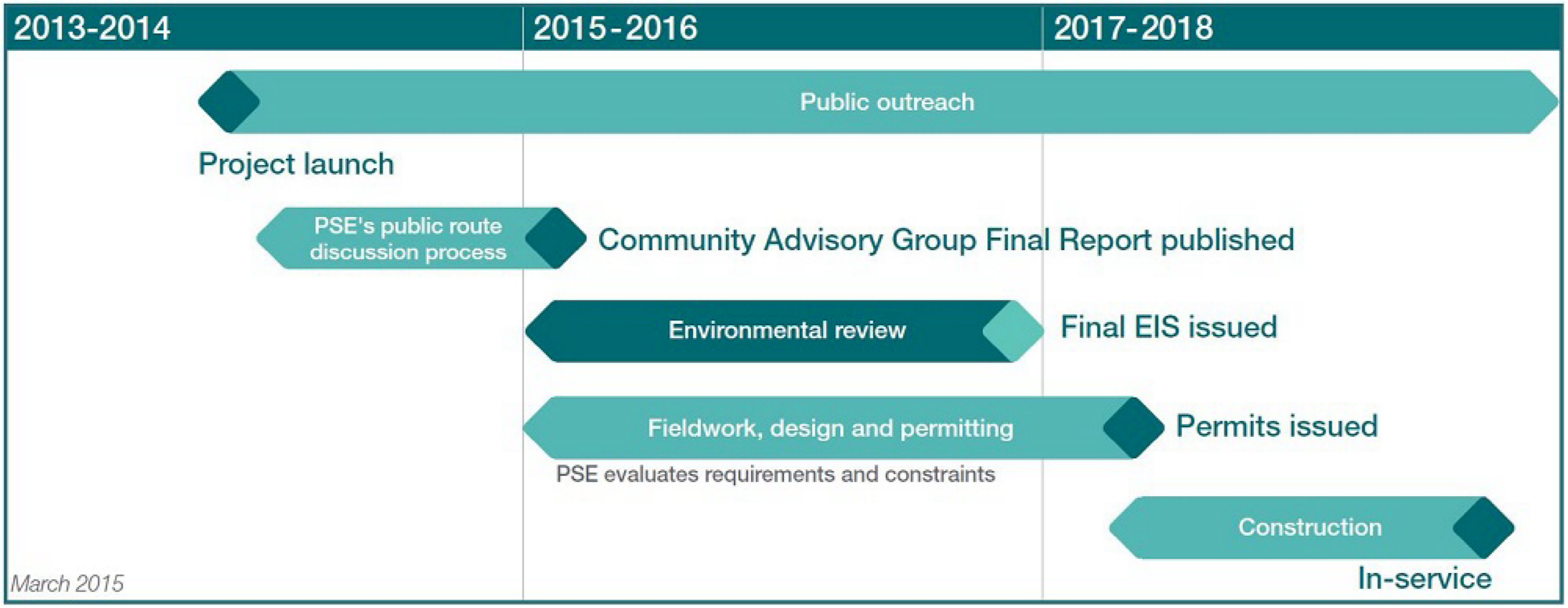
Search



(http://www.energizeeastsideeis.org/)

The Energize Eastside project launched in December 2013 and is planned to be complete and operational in 2018.

Click details in the schedule below for additional information.



Attachment A

DSD 008521

SUBMIT SIGNED ORIGINAL CEII REQUEST FORM TO: Puget Sound Energy, Inc. 355 110th Avenue NE, EST-06E P.O. Box 97034 EST-06E Bellevue WA 98009-9734 Attn: Manager, Transmission Contracts--CEII Request	
Name of Requester: Donald M. Marsh	
Requester's street address and phone number: 4411 137th Ave. SE Bellevue, WA 98006 (425) 502-8279	
Name of individual submitting request on behalf of Requester: Donald M. Marsh	Phone number and e-mail address of individual submitting request on behalf of Requester: (425) 502-8279 don.m.marsh@gmail.com
Description of information requested: Please see attached list.	
Statement explaining need for requested information and use to be made of requested information: The Lauckhart-Schiffman Load Flow Study has raised questions about the need for Energize Eastside. I would like to review technical data with Richard Lauckhart that requires CEII clearance.	
Is the Requester willing to sign and abide by an appropriate agreement limiting the Requester's use and disclosure of the information requested? Yes ☒ No ☐	
Requester: Donald M. Marsh By Donald M. Marsh Title President, CENSE.org	Date: 3/6/2016

DSD 008522

Request for CEII information

1. The study PSE and/or Quanta did for the year 2018 (or similar timeframe) without the EE project in service and all facilities in service (i.e. N-0).
2. All the contingency studies PSE/Quanta did for the year 2018 (or similar timeframe) without the EE project in service in which there were contingency outages of elements of the grid (e.g. the N-1 and N-2 studies or any other contingency studies used to determine the need for the EE line).
3. The study for the year 2018 (or similar timeframe) with the EE line in service and all facilities in service (i.e. N-0)
4. All the contingency studies for the year 2018 (or similar timeframe) with the EE project in service with contingency outages of elements of the grid (e.g. the N-1 and N-1-1 studies, or any other contingency studies used to determine the need for the EE line).

I request all files associated with each load flow run requested above. These files would include at a minimum:

1. areatie.lst
2. buslist.lst
3. flows.lst
4. owner.lst
5. summary.lst
6. .raw file

In addition to the load flow data I would like to get historical loading on each of the 230/115 KV substations you consider to be on the Eastside as well as each of the 115/12 KV substations you consider to be on the Eastside. Specifically I request the following data for each of the last 6 years: please provide the five highest peak load days on the PSE total system, the one hour total system peak load on those days and the hour on which that peak occurred. Then for those system peak load hours, please provide the one hour peak load on each of the 230/115 KV and 115/12 KV substations in the Eastside. This would result in 5 peak loads on each Eastside substation for each of the 6 historical years.