Appendix K: Phase 2 Comments and Responses

Attachments

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[Article]

A Regional and Geomorphic Reference for Quantities and Volumes of Instream Wood in Unmanaged Forested Basins of Washington State

MARTIN FOX*
Post Office Box 569, Roslyn, Washington 98941, USA

SUSAN BOLTON
College of Forest Resources, University of Washington, Box 352100, Seattle, Washington 98105, USA

Abstract.—We collected field data on instream wood quantities and volumes from 150 stream segments draining unmanaged basins within Washington State to develop reference conditions for restoration and management. The wood loads in these streams provide a reference for management since it is assumed that they incorporate the range of conditions to which salmonids and other species have adapted. We also used these data to evaluate existing standards for large wood in streams. Large wood is an important component of salmonid habitat, and stream channel assessments and restoration and enhancement efforts often associate habitat quality for salmon *Oncorhynchus* spp. with the quantity and volume of woody debris; however, the wood targets currently used to assist resource managers typically do not account for variations in quantity or volume owing to differences in geomorphology, forest zones, or disturbance regimes. For restoring the appropriate range of conditions in salmon habitat, we offer a percentile wood distribution of natural and unmanaged wood-loading ranges based on regional and geomorphic variation for the purpose of reestablishing central tendencies. We recommend that streams in a degraded state (e.g., below the 25th percentile) be managed for an interim target at or above the 75th percentile until the basin-scale wood loads achieve these central tendencies. Based on the sample distribution, these reference conditions are applicable to streams with bank-full widths between 1 and 100 m, gradients between 0.1% and 47%, elevations between 91 and 1,906 m, drainage areas between 0.4 and 325 km^2, glacial and rain- or snow-dominated origins, forest types common to the Pacific Northwest, and several other distinguishing physical and regional classifications.

Because large woody debris (LWD) is an important indicator of salmonid habitat, resource managers often rely on standards for the number and size of large pieces of wood to evaluate and restore wood to streams. Typically, these standards are not applicable to all channel types and regions owing to multiple factors that influence variability. Wood loads in natural and unmanaged streams are often assumed to provide a reasonable reference for management since they incorporate the range of conditions to which salmonids and other species have adapted.

This paper examines data on the number and volume of wood from unmanaged streams to (1) develop reference ranges as a resource management tool to assess, protect, restore, and enhance salmonid habitat in streams as it relates to wood and (2) evaluate existing management targets for geomorphic and regional compatibility. The objective of this study is to develop references for instream wood quantities based on natural geomorphic and regional characteristics for streams both east and west of the Cascade Mountains of Washington State. These references will be compared with instream wood standards currently applied to streams in the Pacific Northwest.

The role of LWD in Pacific Northwest streams is linked to channel processes that benefit salmonids. Woody debris plays an important role in controlling channel morphology, the storage and routing of sediment and organic matter, and the creation of fish habitat (Bisson et al. 1987; Bjornn and Reiser 1991). Large wood creates habitat heterogeneity by forming pools, back eddies, and side channels, and by increasing channel sinuosity and hydraulic complexity (Spence et al. 1996). Pools are, perhaps, one of the most important habitat features for salmon *Oncorhynchus* spp. formed by LWD (Keller and Swanson 1979). In high-energy channels, LWD functions to retain spawning gravel and can also provide thermal and physical cover for salmonids (Schuett-Hames et al. 1994). Wood indirectly serves as an important food source for salmonids by providing nutrients and insects to the stream (Naiman and Sedell 1979; Spence et al. 1996) or by retaining salmon carcasses (Cederholm et al. 1989; Bilby et al. 1996). Wood serves as cover for

* Corresponding author: martin.fox@muckleshoot.nsn.us

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juvenile salmonids, which are particularly vulnerable to predators when migrating (Larsson 1985). The geomorphic potential of the channel to process wood into features that benefit salmonids is often limited by the quantity and size of wood (Abbe and Montgomery 1996).

Channel responses to wood vary with the geomorphic characteristics of the stream (Murphy and Koski 1989; Robison and Beschta 1990; Montgomery et al. 2003). In high-energy channels, LWD functions to retain spawning gravel and can also provide thermal and physical cover for salmonids (Schuett-Hames et al. 1994). Logjams can create sections of low gradients with alluvial substrates in bedrock channels by storing sediment upstream of the jam (Montgomery et al. 1996; Massong and Montgomery 2000), which can provide localized low-gradient habitats in steep valley segments where none would otherwise have existed.

Restoration activities in the Pacific Northwest often involve long-term recovery of riparian and channel processes and are frequently combined with short-term "fixes" by the placement of habitat structures. Often, to expedite habitat recovery while riparian areas convalesce, wood is placed in streams to provide habitat for salmonid use (Reich et al. 2003; Roni et al. 2003). We assume that, to maximize the success of improving habitat, the amount of wood placed in a channel or intended to be recruited from riparian management areas is representative of the wood quantities and volumes to which salmonids have adapted. A one-size-fits-all wood target approach may diminish habitat heterogeneity by reducing the natural range of wood conditions. Therefore, knowledge of the natural variation of instream wood loads among different stream types and regions should improve restoration activities as well as the scientific defensibility of regulatory thresholds.

The number and volume of instream wood are highly variable owing to several types of processes that influence the mass balance of wood in a system (Benda et al. 2003). Geomorphological features, such as channel size, channel type, and confinement, can influence wood loads and distribution (Bilby and Ward 1989; Montgomery and Buffington 1997; Rot et al. 2000; Martin and Benda 2001). Anthropological disturbances, such as riparian vegetation modifications, forest practices (Bilby and Ward 1991; Ralph et al. 1991), flow regulation (Nakamura and Swanson 2003), urban development, and agricultural practices, can also alter the amount of wood in channels. Natural disturbances, such as fire (Rot et al. 2000; Fox 2001), floods (Braudrick and Grant 2000), debris flows (Ikeya 1981; Costa 1984), and snow avalanches (Keller and Swanson 1979), are other factors having an impact on variability in wood loading over space and time. Regional considerations due to climate influences often dictate riparian characteristics that ultimately are reflected in instream wood loads (Tappeiner et al. 1997; McHenry et al. 1998; Rot et al. 2000).

Stream channel assessments often associate the size, distribution, and abundance of woody debris with salmon habitat quality. As a result, wood targets have been developed by state and federal agencies to evaluate the adequacy of instream wood quantities in the Pacific Northwest (Table 1). Efforts to restore riparian areas with the aid of various recruitment models tied to riparian characteristics and to enhance stream habitat through the artificial placement of wood often use objectives derived from these management targets.

The LWD piece quantity targets now frequently used as management and restoration standards were developed with the most complete data available for relating wood frequency to channel width in Pacific Northwest streams (Peterson et al. 1992). However, Spence et al. (1996) note that those targets do not fully consider potential sources of variation found throughout their application range and that they should only be applied to the types of streams for which they were derived. Because the current targets do not fully account for this variation and are applied generically, they may be inappropriate for some channel types and regions outside the area where the targets were developed. For example, a stream enhancement project may place wood in a stream channel based on the quantities recommended by target references, but these efforts may not provide the quantities or volumes of wood representative of local conditions to which salmonids have adapted. Because of the reliance upon wood targets by resource managers for critical decision making, a need exists to reevaluate existing wood targets and refine these values where appropriate.

Methods

To better characterize the natural quantities and volumes of instream wood within Washington State, survey sites were chosen within stream basins that are relatively unaffected by anthropogenic disturbance. Selected basins are characterized by forests that are loosely termed as "natural and unmanaged" and meet the following criteria: (1) no part of the basin upstream of the survey site was ever logged using forest practices common after European settlement and (2) the basin upstream of the survey site contains no roads or human modifications to the landscape that could affect the hydrology, slope stability, or other natural processes of wood recruitment and transport in streams. These basins will hereafter be referred to simply as "natural

TABLE 1.—Various state and federal management targets for large woody debris (LWD) used to define adequate salmonid habitat in Pacific Northwest streams.

Agency	Applicable region	Wood metric
National Marine Fisheries Service[a]	Coastal Washington	Number of LWD pieces
	Eastern Washington	Number of LWD pieces
U.S.Forest Service and Bureau of Land Management[b]	Anadromous fish-producing watersheds in western Oregon, Washington, Idaho, and portions of California	Number of LWD pieces
	Anadromous fish-producing watersheds in eastern Oregon, Washington, Idaho, and portions of California	Number of LWD pieces
Washington Forest Practices Board[c]	All forested streams of Washington, channels <20 m bank-full width	Number of LWD pieces
	Western Washington, channels <20 m in bank-full width (BFW)	Number of key pieces
Oregon Watershed Enhancement Board[d]	Western Oregon	Number of LWD pieces
		Volume of LWD pieces
		Number of key pieces

[a] Matrix of pathways and indicators (NMFS 1996) to address Endangered Species Act listed aquatic species in the Pacific Coast Salmon Plan (NMFS 1998).
[b] USFS and BLM (1995).
[c] WFPB (1997).
[d] Watershed Professionals Network (1998).

and unmanaged basins," although it is acknowledged that some basins are managed to remain pristine and that management may include fire suppression. The purpose of choosing sites in natural, unmanaged forested basins is based on the assumption that natural wood characteristics that have been influenced by natural disturbance cycles as found in these basins are those to which salmonids and other aquatic species have adapted and, hence, should provide a reasonable reference condition to the quantities and volumes of wood for management purposes.

Sites were stratified to represent a broad array of forest types, channel morphologies, and hydrological origins in Washington State. The strata served to characterize the channel in relation to the processes that drive fluvial geomorphology and represent a wide range of climates and vegetation types occurring in the Pacific Northwest (Table 2) that are also potential influences on the quantity and quality of instream wood. Comparisons with other Pacific Northwest management standards where similar forest types exist will offer valuable insight for managers, although the data were collected entirely in Washington State. Regional climatic variations that were presumed to control the characteristics of forest vegetation common to Pacific Northwest streams were grouped into forest zones using the classifications of Franklin and Dyrness (1973), Henderson et al. (1992), and Agee (1993; Table 2; Figure 1). Although riparian forests have some structural difference from their upland counterparts owing to soil heterogeneity, moisture, and other factors that may influence stand attributes, these regional climatic influences that classify forest zones provide information on the general characteristics of riparian areas of streams flowing through these forests.

All wood pieces greater than 10 cm in midpoint diameter and 2 m in length were counted and measured with tape and calipers within each survey reach. Stream survey methods used many components of the Timber–Fish–Wildlife (TFW) Monitoring Program method manuals (Pleus and Schuett-Hames 1998; Schuett-Hames et al. 1999), and riparian inventories were conducted following the methods of Cottam and Curtis (1956). Randomly selected stream segments were divided into three partitions before sampling to avoid clumping of survey reaches. Each survey reach was 100 m in length for channels up to 20 m in bank-full width (BFW) and 200–300 m in length for channels more than 20 m BFW. Minimum total sample length was 20 channel widths to fully represent repetitive patterns of the stream (Leopold et al. 1964; MacDonald et al. 1991; Montgomery and Buffington 1997); however, in channels approaching 100 m in width, surveys ceased at cumulative distances of approximately 1 km owing to time and personnel constraints.

Sites were evaluated in the field for disturbances caused by fires (date of stand origin) from the Cascade crest westward, floods (exceedance probability of 0.04 [25-year flood] recurrence within 10 years from preceding surveys), debris flows ($\leq$15 years from preceding surveys), and snow avalanches ($\leq$15 years from preceding surveys). Other forms of disturbances, such as catastrophic wind throw, insect and disease mortality, or other causes of tree mortality, are acknowledged as significant sources of wood recruitment to streams; however, these other disturbances were seldom observed in the surveys. Field crews had

TABLE 1.—Extended.

Agency	LWD minimum size criteria	Necessary quantity for adequate fish habitat
National Marine Fisheries Service[a]	15.2 m in length × 0.6 in diameter	>80 pieces/mile
	10.7 m in length × 0.35 in diameter	>20 pieces/mile
U.S.Forest Service and Bureau of Land Management[b]	15.2 m in length × 0.6 in diameter	>80 pieces/mile
	10.7 m in length × 0.35 in diameter	>20 pieces/mile
Washington Forest Practices Board[c]	2 m in length × 0.10 in diameter	>2 pieces/channel width
	1 m^3 (channels 0–5 m BFW); 2.5 m^3 (channels. >5–10 m BFW); 6 m^3 (channels. >10–15 m BFW); 9 m^3 (channels. >15–20 m BFW)	>0.3 pieces/channel width for streams <10 m BFW, and >0.5 pieces/channel width for streams 10–20 m BFW
Oregon Watershed Enhancement Board[d]	3 m in length × 0.15 in diameter	>20 pieces/100 m of stream
		>30 m^3/100 m of stream
	10 m in length × 0.60 in diameter	>3 pieces/100 m of stream

received formal training in TFW field methods through the stream monitoring programs at the Northwest Indian Fisheries Commission, and quality assurance–quality control (QA–QC) surveys were conducted on each crew member to ensure data replicability and accuracy. Based on the positive results of the QA–QC surveys (within 10%), confidence in the quality and accuracy of the data are high.

Data were analyzed by means of a three-pronged approach. First, descriptive statistics were calculated to establish correlations, check for normality, and evaluate correlation coefficients to eliminate variables that had less mechanistic value toward influencing wood loads based on field observations. Second, hypotheses relating to the variability of both (1) wood volume and (2) number of pieces as influenced by the above-referenced variables were evaluated with the Akaike information criterion (AIC). Based on our understanding of the processes that lead to wood in streams, we used AIC as a measure of fit for specific variables to an ordinary-least-squares (OLS) regression. Variables were chosen in a forward-model-selection, backward-elimination procedure based on the lowest AIC score (Burnham and Anderson 2002) to explain the full range of variability in the model. Third, we chose the best-fitting variables from the AIC subset based on the lowest *P*-values ($\alpha = 0.05$) and further tested these variables by comparing means of categorical groupings rather than individually using analysis of variance (ANOVA), post hoc tests of Tukey's least significant difference, and Fisher *F*-tests for testing variances (Zar 1999). Categorical groupings were combined, when warranted, based on homogenous means, which also increased statistical power of tests. Determining the strongest predictors for instream wood was done to enable practical graphical relationships to illustrate the range of the data and to make comparisons with other wood standards. Instream wood was scaled by a unit length (per 100 m) because of statistical advantages when grouping classes of different BFWs based on an independent analysis by Fox (2001). Data were $\log_{10}$ transformed to meet the assumptions of the general linear model and to test hypotheses from normally distributed populations (Zar 1999). Regressions were conducted with continuous and categorical data for the independent variables. All possible combinations of BFW classes (starting at 3- to 5-m bins) were initially based on visual fine groupings (histograms, scatter-plots, and box plots), then tested and further grouped in this manner where warranted. Forest zones were grouped if they exhibited similar instream wood loads and riparian basal areas. Box-and-whisker plots are used to present the range of nonnormal data distributions, and the median and 75th and 25th percentiles are offered as reference points for management purposes.

Creating minimum-size definitions of qualifying "key pieces" was first needed to more widely assess key-piece quantities since the Washington Forest Practices Board (WFPB) has no standards for minimum key-piece volume for eastern Washington streams and none for western Washington streams greater than 20 m BFW (WFPB 1997). A "functional" piece of wood is likely to vary in size with stream size owing to the variation in physical forces that move wood in relation to stream size (WFPB 1997; Braudrick and Grant 2000); therefore, establishing minimum piece sizes according to channel size is justifiable. This rationale is also applicable to Oregon targets, where the minimum-size definition for key pieces as defined by the Oregon watershed assessment manual (Watershed Professionals Network 1998; Table 1) is applicable to all western Oregon channels rather than according to channel size. To accomplish this objective, minimum key-piece volumes for western Washington channels (>20 m BFW) were based on the geomorphic definition for "stability and function" given in WFPB (1997), namely,

> a log and/or rootwad that is (1) independently stable in the stream bank-full width (not functionally held by another factor, i.e., pinned by another log, buried, trapped against a

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TABLE 2.—Forest zone, gradient, drainage area, confinement, bedform, channel type, and origin classes used to stratify surveyed stream reaches in Washington, 1999–2000.

Forest zone (abbreviation)[a]	Gradient (%)	Drainage area (km^2)[b]	Confinement[b]	Bedform[c]	Channel type	Origin
Sitka spruce *Picea sitchensis* (SS)	≤1	0–2	Confined	Plane bed	Alluvial	Snow melt or rain
Western hemlock *Tsuga heterophylla* (WH)	>1–2	>2–4	Moderately confined	Pool or riffle	Bedrock	Glacial melt
Silver fir *Abies amabilis* (SF)	>2–4	>4–8	Unconfined	Step pool		
Mountain hemlock *T. mertensiana* (MH)	>4–8	>8–20		Cascade		
Subalpine fir *A. lasiocarpa* (SF)	>8–20	>20–100				
Grand fir *A. grandis* (GF)[d]	20	>100				
Douglas-fir *Pseudotsuga menziesii*–ponderosa pine *Pinus ponderosa* (DF–PP)[d]						

[a] As described in Franklin and Dyrness (1973), Agee (1993), and Henderson et al. (1992).
[b] As defined in Pleus and Schuett-Hames (1998).
[c] As described in Montgomery and Buffington (1997).
[d] Predominantly found east of the Cascade crest.

rock or bed form) and (2) retaining (or [having] the potential to retain) other pieces of organic debris.

The length and diameter of key pieces are factors influencing buoyancy and mobility. Although some dimensional combinations (independent of rootwads) may influence piece stability more than others as they interact with channel shape, we assume that piece volume provides a reasonable representation of both length and diameter proportions factored into stability determinations. The presence of rootwads was also assessed in combination with key-piece size to determine their influence on stability.

Results

During the summer and fall of 1999 and 2000, 150 sites were surveyed that totaled nearly 38 km of stream length. Sampled stream gradients ranged between 0.04% and 49% and 139 of the sites (93%) met the WFPB (2001) physical criteria for fish presence. Although every possible combination of strata (Table 2) could not be sampled because of their unavailability

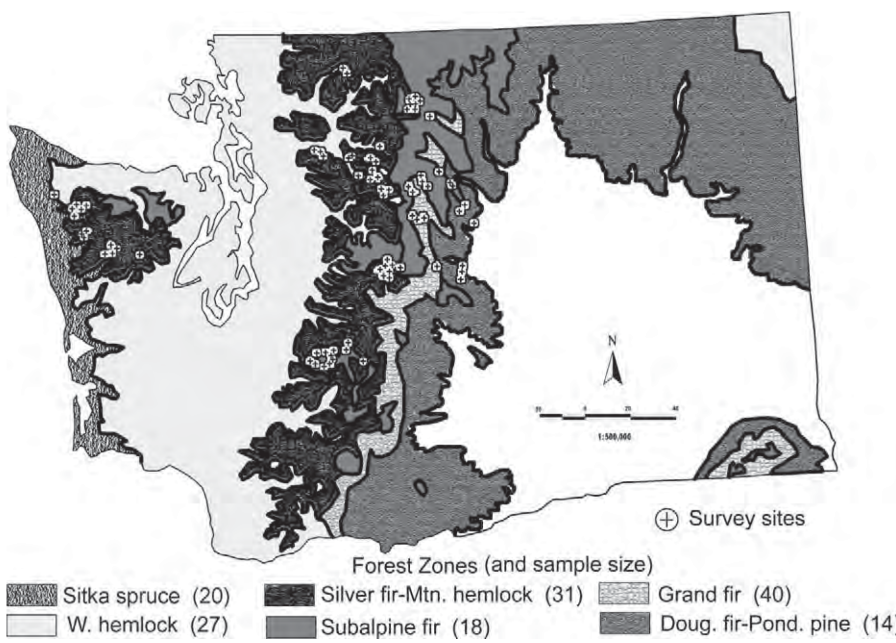

FIGURE 1.—Survey site distribution according to forest zones across Washington State, 1999 and 2000. Each point represents one or more streams ($n = 150$). The shadings represent forest zones and a vegetation classification system largely based on (1) natural fire succession and potential climax tree species, (2) elevation, and (3) climate. The forest zone boundaries depicted here are greatly simplified, and multiple plant associations can be found within these areas owing to microclimatic differences (after Franklin and Dyrness 1984; Henderson et al. 1992; Agee 1993).

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TABLE 3.—Best-fitting regressions for the $\log_{10}$ transformed number of pieces and volume (m^3) of large woody debris (LWD) per 100 m of stream, as determined by Akaike information criterion values. Abbreviations are as follows: BFW = bank-full width; GF, SAF, SF–MH, and SS–WH = grand fir, subalpine fire, silver fire–mountain hemlock, and Sitka spruce–western hemlock forest types; BR = bedrock bedform; MC and U = moderately confined and unconfined classes; slope = channel reach slope. Times signs denote interaction terms.

Variable	Coefficient	SE	*t*-value	*P*-value
Pieces of LWD[a]				
Intercept	1.1326	0.2998	3.778	0.0002
$\log_{10}$(BFW)	−0.2385	0.2272	−1.0499	0.2958
GF	0.5357	0.3219	1.6642	0.0986
SAF	−0.568	0.4116	−1.3797	0.1701
SF–MH	0.6053	0.3607	1.6781	0.0958
SS–WH	0.4535	0.3155	1.4372	0.1532
BR	1.4232	0.4669	3.0482	0.0028
MC	−0.0922	0.1497	−0.6159	0.5391
U	−0.0033	0.164	−0.0202	0.9839
$\log_{10}$(slope)	−0.0508	0.2387	−0.213	0.8317
$\log_{10}$(BFW) × GF	0.2776	0.2481	1.1187	0.2654
$\log_{10}$(BFW) × SAF	1.591	0.4367	3.6431	0.0004
$\log_{10}$(BFW) × SF–MH	−0.117	0.3097	−0.3778	0.7062
$\log_{10}$(BFW) × SS–WH	0.5249	0.2377	2.2084	0.029
$\log_{10}$(BFW) × BR	−0.634	0.2456	−2.5815	0.011
$\log_{10}$(BFW) × MC	0.1193	0.1501	0.7952	0.428
$\log_{10}$(BFW) × U	0.2853	0.1536	1.857	0.0657
GF × BR	−0.9373	0.3627	−2.5846	0.0109
SAF × BR	−1.0202	0.4522	−2.2563	0.0258
SF–MH × BR	−1.3031	0.3707	−3.5149	0.0006
SS–WH × BR	−1.0778	0.3657	−2.9476	0.0038
GF × $\log_{10}$(slope)	0.2608	0.2567	1.0158	0.3117
SAF × $\log_{10}$(slope)	−0.0588	0.3064	−0.1917	0.8483
SF–MH × $\log_{10}$(slope)	−0.1878	0.2923	−0.6425	0.5217
SS–WH × $\log_{10}$(slope)	0.2865	0.2521	1.1363	0.258
Volume of LWD[b]				
Intercept	−0.1823	0.2361	−0.7721	0.4414
$\log_{10}$(BFW)	1.1338	0.2527	4.4876	0
GF	0.684	0.2511	2.7237	0.0073
SAF	0.2482	0.3741	0.6635	0.5082
SF–MH	1.9225	0.3355	5.7299	0
SS–WH	1.4871	0.2315	6.423	0
BR	0.194	0.2731	0.7104	0.4787
MC	0.5146	0.2256	2.2808	0.0242
U	−0.0952	0.3435	−0.2772	0.782
$\log_{10}$(slope)	−0.1459	0.1112	−1.3122	0.1917
$\log_{10}$(BFW) × GF	−0.6076	0.2971	−2.0451	0.0428
$\log_{10}$(BFW) × SAF	0.4256	0.5091	0.836	0.4047
$\log_{10}$(BFW) × SF–MH	−1.3385	0.3573	−3.7465	0.0003
$\log_{10}$(BFW) × SS–WH	−0.8448	0.2732	−3.0925	0.0024
$\log_{10}$(BFW) × BR	−0.4857	0.2759	−1.7607	0.0806
MC × $\log_{10}$(slope)	0.4001	0.1718	2.3291	0.0214
U × $\log_{10}$(slope)	−0.1219	0.2196	−0.5553	0.5796

[a] Standard error = 0.2731, df = 125, $R^2 = 0.5966$, $F_{24,;t3125} = 7.703$, $P = 3.442 \times 10^{-15}$.

[b] Standard error = 0.3737, df = 133, $R^2 = 0.6168$, $F_{16,;t3133} = 13.38$, $P = 0$.

in nature, the time constraints of the study, or both, sites nevertheless represented a diverse array of channel types, confinement classes, bedforms, dominant water origins, disturbance histories (fire, debris flows, snow avalanches, and floods), and forest types common in the Pacific Northwest. Basin drainages ranged between 0.4 km^2 and 325 km^2. Site elevations ranged between 91 m and 1,906 m (above mean sea level). A total of 21,671 LWD pieces were counted and measured. The general distribution of sites within each forest zone of Washington State is illustrated in Figure 1. Detailed sampling stratifications and site maps can be found in Fox (2001).

Modeling and Exploratory Analyses

We found that a $\log_{10}$ transformation provided normal distributions in the continuous data. Using these transformed data, we found that the AIC approach produced the best fit for predicting the number of LWD pieces and volume per 100 m of stream reach by including covariates of BFW, forest type, bedform, gradient, and confinement in the OLS regression along with several combinations of interactions (Table 3). Interactions predicting LWD number of pieces per 100 m are between BFW and forest type, BFW and bedrock bedform, BFW and confinement class, bedrock bedform and forest region, and channel reach slope and forest region. Interactions predicting LWD volume per 100 m are between BFW and forest type, BFW and bedrock bedform, and confinement class and channel reach slope.

In the exploratory analysis of these variables, we found that BFW and forest zone were also correlated with wood volume, but the covariates of bedform, gradient, and confinement were insignificantly correlated despite being included in the AIC selection process. This disparity between the two analyses is probably due to the difference in selection criteria and the low test power for regressions, ANOVA (among groupings), and other tests involving multiple strata, which often resulted in small samples. The descriptive analysis also suggests that wood loads have a high variance; however, there are differences in the distributions by discrete channel size-classes among regions. The following sections describe these differences as well as correlations in further detail.

Regional and Geomorphological Processes Affecting Instream Wood

Watershed and valley morphology play complex roles in the number and volume of instream wood. The number and volume of instream wood per 100 m of channel length generally increase as drainage area increases (linear regression: $P < 0.001$) and as streams become less confined, particularly in watersheds greater than about 10 km^2 in drainage area. We found that BFW is a significantly better predictor of wood parameters than basin size (paired-sample *t*-test: $P = 0.05$), which stems from the fact that similar BFWs can

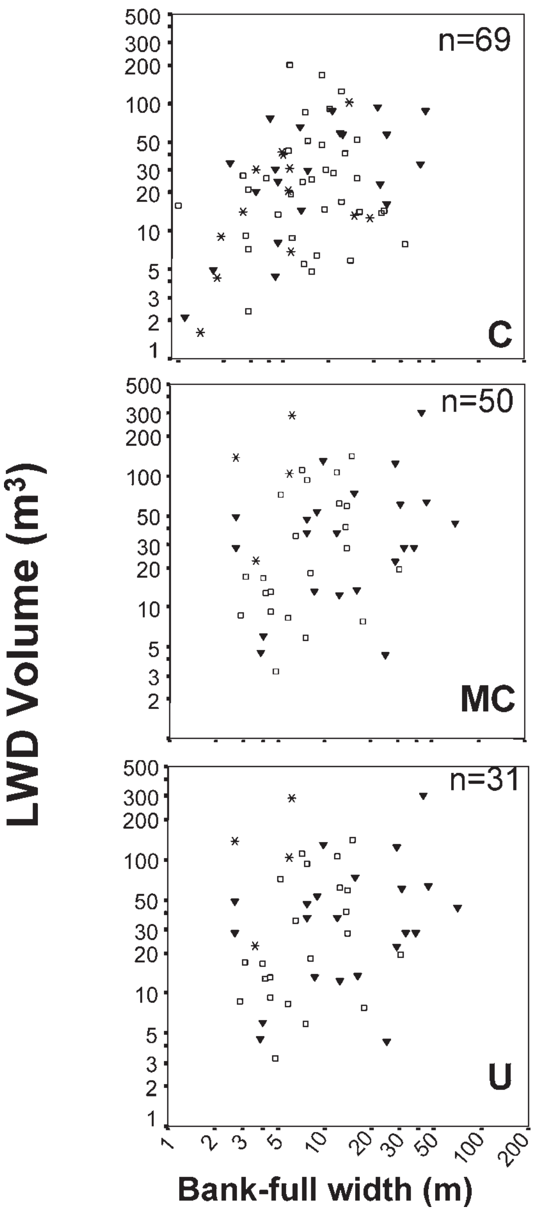


FIGURE 2.—The combined effect of gradient (triangles = 0–4%, squares = 4–20%, and asterisks = 20% or more) and confinement (confined [C], moderately confined [MC], and unconfined [U]) on the volume of instream wood (LWD) per 100 m of channel length by bank-full width for surveyed streams in Washington, 1999–2000.

be produced by different basin sizes owing to regional disparities in precipitation (e.g., western versus eastern Washington); however, because of the high error among all comparisons ($R^2 < 0.37$), there is probably little difference in predictive qualities between the two variables when wood is scaled per 100 m of channel length. The relationship of channel cross-sectional area to BFW is also strongly correlated ($R^2 = 0.93$) and highly significant ($P < 0.001$), suggesting that the cross-sectional area of high flow can be predicted by a BFW measurement. The isolated influences of gradient and confinement upon wood volumes are largely inconsistent (Figure 2) as well as for number of wood pieces, suggesting that there may be other controlling factors governing wood quantities; however, the small sample sizes per gradient and confinement stratification could not support statistical inferences.

In all basin sizes, more wood volume is generally observed in alluvial channels than in bedrock channels (Figure 3A), but the relatively small sample of bedrock channels does not allow statistical conclusions. This phenomenon, whether a cause or effect of the channel condition–wood relationship, holds true even when isolating the influence of gradient and confinement (Figure 3B). It should be noted that over 90% of the bedrock channels surveyed were in confined valleys.

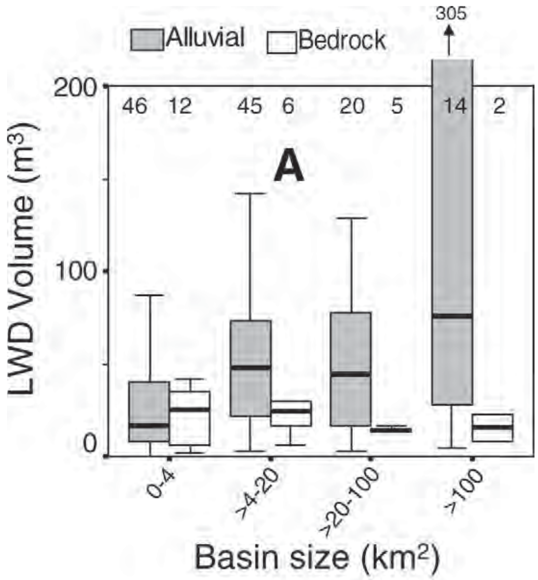
In basin drainages of 70 km^2 or more, streams predominantly originating from glacial sources (e.g., Mount Rainier, Glacier Peak, and Mount Olympus) had significantly more wood volume per 100 m than streams fed predominantly with snowmelt and rain. This may be related to the larger number of side channels in streams originating from glacial sources, which averaged 3 per 100-m stream reach ($n = 7$) compared with only 1.8 in snow- or rain-dominated channels ($n = 17$). Although this phenomenon is noteworthy, the sample size of glacial-origin streams was too small to create a separate classification.

Although there is no significant relationship between channel morphology and the volume of wood, pool–riffle channels (where lateral migration is typical) commonly exhibited greater volume per 100 m than plane-bed, step-pool, or cascade morphologies.

Influences on Instream Wood by Channel Disturbance

Fire, as it affects riparian trees, was found to influence instream wood quantities and volumes in streams from the Cascade crest westward. Regression analysis suggests that instream wood volumes increase with adjacent riparian timber age, as dictated by the last stand replacement fire ($P = 0.013$). Riparian characteristics, such as mean tree diameter at breast height and basal area (m^2/ha), are influenced by timber age, increasing as stands grow older (both with $P < 0.001$).

Debris flows and snow avalanches probably have an effect on instream wood, although because of the paucity of sites that exhibited these forms of disturbance, statistical verification was not possible (power of test <20% in most cases). Trend analyses suggest



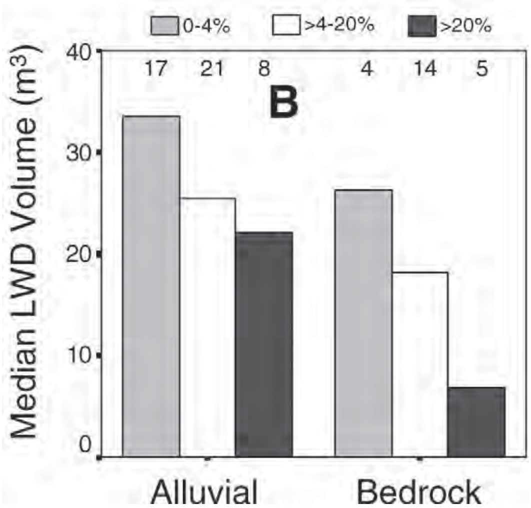


FIGURE 3.—Comparisons of instream wood volume (LWD [m^3 per 100 m]) in surveyed stream channels in Washington, 1999–2000, by **(A)** channel type (alluvial or bedrock) and basin size (km^2) and **(B)** channel type and gradient class (confined channels only). The number above each bar is the number (sample size) of stream reaches in that category (channel type–basin size or channel type–gradient). In the box-and-whisker diagrams, the horizontal lines within the boxes represent the medians, the upper and lower edges of the boxes the central 50% of the distribution, and the whiskers the highest and lowest values, including "outliers" (circles) and "extreme values" (asterisks). Outliers are defined as values between 1.5 and 3 box lengths from the upper and lower edges of the boxes and extreme values as values more than 3 box lengths from the upper and lower edges of the boxes.

that debris flows and snow avalanches reduce the number and volume of LWD per 100 m of channel length in channels exceeding 10% in gradient compared with similar-gradient channels without recent disturbance. Notably, channels less than 6% in gradient with and without debris flows and snow avalanches have nearly the same number of wood pieces per 100 m of channel; however, wood volumes (m^3/100 m) are greater in channels of this gradient with recent debris flows but less with recent snow avalanches than in channels of this gradient without recent disturbance.

Recent floods did not appear to have a significant effect on instream wood in the streams surveyed. The comparison of regressions between channels with and without recent floods (within 10 years of survey and having a magnitude $\geq$25-year flood recurrence) suggests that floods do not significantly decrease the quantity and volume of instream wood per 100 m with increasing channel width ($P > 0.6$ for both regression slopes and intercepts). Although this phenomenon is implied by these data, the effects of floods depicted in these relationships are, perhaps, poorly defined owing to the lack of equal replication of sites containing similar morphologies and regional characteristics. Without controlling for these variables, relationships are probably biased by one or multiple regional and geomorphic influences.

Reference Conditions for Instream Wood Quantity and Size

Minimum key piece volumes for channels greater than 20 m BFW.—The length and diameter of key pieces are factors influencing buoyancy and mobility. Although some dimensional combinations (independent of rootwads) may influence piece stability more than others as they interact with channel shape, we assume that piece volume provides a reasonable representation of both length and diameter proportions factored into stability determinations.

The range of volumes for wood pieces meeting the geomorphic definition for stability and function (WFPB 1997) is presented in the form of percentile distribution plots (box plots) for channel classes greater than 20 m BFW, as distinguished by differences in variances (Fisher *F*-tests: $P < 0.01$; Figure 4). From this distribution, the recommended minimum volumes, as we define by the 25th percentiles, are approximately 9.7 m^3 for the 20- to 30-m BFW class, 10.5 m^3 for the 30- to 50-m^3 BFW class, and 10.7 m^3 for channels greater than 50 m BFW. A plot of these minimum volumes, including those currently defined by WFPB (1997), is presented in Figure 5.

The influence of rootwads on key pieces.—Of the pieces composing the volume percentile distributions (>25th percentile) presented in Figure 4 and the

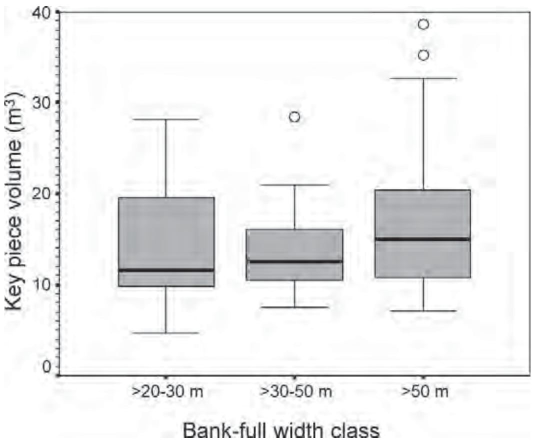


FIGURE 4.—Distributions of instream wood volumes for individual pieces meeting the definition of "key pieces" (i.e., pieces with independent stability; WFPB 1997) for surveyed channels with bank-full widths greater than 20 m in Washington, 1999–2000. According to our methods, the minimum volume for key pieces in channels greater than 20 m is defined as the 25th percentile. The box-and-whisker diagrams are as described in Figure 3.

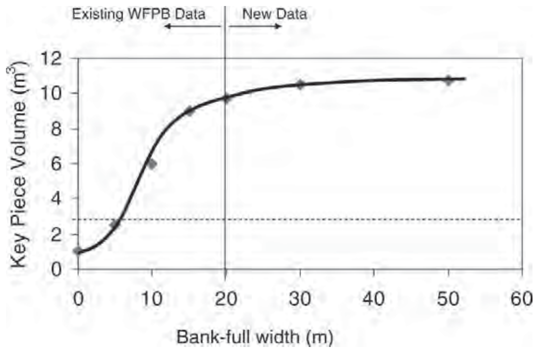


FIGURE 5.—Plot of the minimum wood volumes in surveyed channels used to define key pieces in both western and eastern Washington, 1999–2000. The points to the right of the vertical line represent the new minimum volumes defined in this analysis, the points to the left the values currently used in Washington's "Watershed Analysis for Western Washington" (WFPB 1997), and the dashed line the minimum key-piece volume (2.83 m^3) interpreted from the Oregon Watershed Enhancement Board (based on minimum length and diameter criteria; Watershed Professionals Network 1998).

corresponding curve in Figure 5, it would appear that the recommended minimum volumes defining key pieces are very similar in all channels with BFWs greater than 20 m (and they are not, in fact, significantly different). As channels become larger, one would also expect the wood mobility to increase owing to wood buoyancy and higher-unit stream power. The reason that this is not reflected by an increase in the minimum key-piece volumes as channels become larger probably lies in the presence of rootwads, which compensate for stability in lieu of volume increases. Indeed, 96% of the wood pieces meeting the WFPB definition for key pieces in channels greater than 50 m BFW had rootwads attached to them. In channels with BFWs between 30 m and 50 m, 91% of the pieces had rootwads, and in channels with BFWs between 20 m and 30 m, 71% had rootwads attached. Notably, when selecting for wood functioning as key pieces without rootwads attached, the 25th percentile of individual piece volumes in channels 50–100 m is over 26 m^3, suggesting a linear trajectory with the sizes defined for channels less than 20 m. However, because of the small sample size (n = 13) for key pieces without rootwads in channels between 20 m and 100 m, this observed trend could not be supported with statistical inference.

The application of key-piece minimum volumes to eastern Washington.—As described previously, the minimum volume required for a piece of wood to achieve independent stability as defined by WFPB (1997) currently applies only to western Washington streams less than 20 m BFW. Based on the minimum key-piece volume definitions provided by WFPB for channels less than 20 m BFW and the results of this study presented above for channels greater than 20 m BFW, the percent of LWD qualifying as a key piece per 100-m reach is not significantly different among forest zones (ANOVA: $P = 0.073$). This suggests that the minimum key-piece volumes established on the basis of fluvial forces rather than region are reasonable criteria for evaluating key-piece frequencies in both eastern and western Washington.

Volumes, LWD numbers, and key-piece quantities.—Overall, both the number and volume of LWD per 100 m of channel length increased with increasing BFW; however, the variance is not well explained by regressions ($R^2 = 0.14$ and 0.23, respectively). Therefore, a classification approach of BFW is more practical as a management tool than a regression or general linear model, since a range of conditions is provided rather than a single point estimate predicted by an equation.

Based on the similarities in LWD volume and riparian basal area, the Sitka spruce, western hemlock, silver fir, and mountain hemlock forest zones are grouped to form the "Western Washington Region," and the subalpine fir and the grand fir forest zones are grouped to form the "Alpine Region" (Figure 6). The Douglas-fir and ponderosa pine (DF–PP) forest zone

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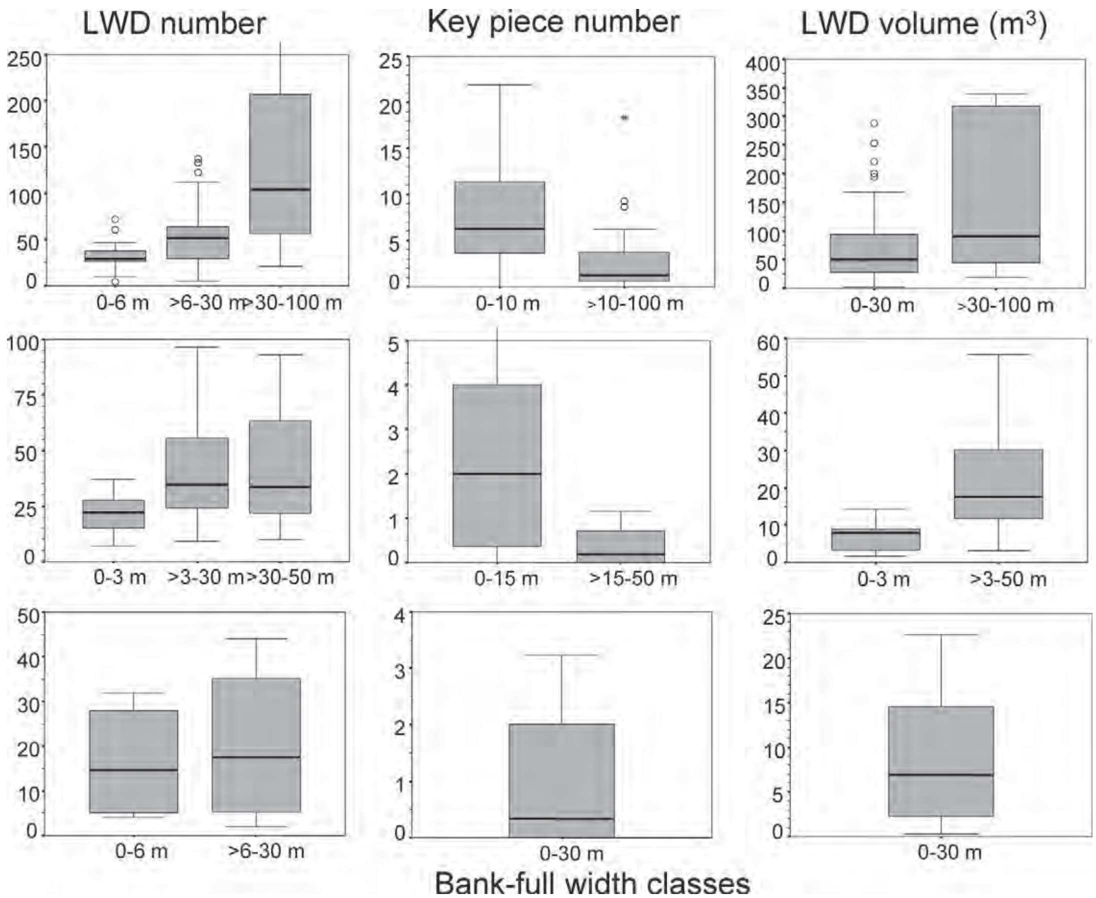

FIGURE 6.—Distributions of the number of wood pieces (LWD) per 100 m, the number of key pieces per 100 m, and the volume of LWD (m^3) per 100 m in channel reaches in the Western Washington Region (first row; $n = 78$), the Alpine Region (second row; $n = 58$), and the Douglas-fir–ponderosa pine forest zone (third row; $n = 14$), 1999–2000. Note that the scales of the *y*-axes differ and that the bank-full width classes are specific to each region based on discrete homogeneous groupings. See Figure 3 for an explanation of the box-and-whisker diagrams.

did not have significant similarities to any of the other forest zones; therefore, it remains simply the "DF–PP" forest zone.

The percentile distribution of these data, as distinguished by BFW classifications, provides reference conditions for wood quantity, key-piece quantity, and wood volume for Washington State and potentially synonymous forested regions of the Pacific Northwest based on these regional groupings. Based on significant differences in lognormal means and variances, distinct BFW classes were identified to report the natural ranges of LWD numbers, numbers of key pieces, and LWD volume per 100 m of stream for each region (Figure 6). Numeric summaries for these distributions and minimum volume-defining key pieces (Figures 4, 5) are presented in Tables 4 and 5.

Discussion

Choice of Predictor Variables

Geomorphological influence.—Channel bedform, origin, gradient, and confinement are predictive of geomorphological influence on instream wood quantities and volumes to some degree, based on the AIC analysis; however, the significance of these correlations (*P*-value) appears to be inconsistent among categories or interactions. This is also reflected in the exploratory analysis, which suggests the small sample stratification in each geomorphic category cannot consistently isolate the effects of these factors for making statistical inferences. Greater certainty regarding these influences would require additional sampling of these morphologies.

Bank-full width is supported as the most significant geomorphic indicator for predicting instream wood

TABLE 4.—Distributions of large woody debris (number of pieces, volume [m^3], and number of key pieces, all per 100 m of channel) by region and bank-full width (BFW) class. Large wood debris is defined as a pieces exceeding 10 cm in diameter and 2 m in length. Data are portrayed visually in Figure 6.

Region	BFW class	75th percentile	Median	25th percentile
Number of pieces				
Western Washington	0–6 m	>38	29	<26
	>6–30 m	>63	52	<29
	>30–100 m	>208	106	<57
Alpine	>0–3 m	>28	22	<15
	>3–30 m	>56	35	<25
	>30–50 m	>63	34	<22
DF–PP forest zone	0–6 m	>29	15	<5
	>6–30 m	>35	17	<5
Volume				
Western Washington	0–30 m	>99	51	<28
	>30–100 m	>317	93	<44
Alpine	>0–3 m	>10	8	<3
	>3–50 m	>30	18	<11
DF–PP forest zone	0–30 m	>15	7	<2
Number of key pieces				
Western Washington	0–10 m	>11	6	<4
	>10–100 m	>4	1.3	<1
Alpine	>0–15 m	>4	2	<0.5
	>15–50 m	>1	0.3	<0.5
DF–PP forest zone	0–30 m	>2	0.4	<0.5

volumes and number of pieces. This is based on (1) the results of the trend analysis with wood volumes with increasing basin size, (2) the correlation of BFW to basin size and cross-sectional area, (3) the demonstration that BFW has better predictive qualities than basin size for instream wood, and (4) the interaction and correlation this variable has with the previously discussed reach geomorphology influences. For example, streams with large BFWs are often less confined and of lower gradient than streams with small BFWs; thus, BFW may effectively be representative of multiple reach geomorphological influences. Due to the development of these BFW relationships with basin area in unmanaged streams, caution is needed if applied to streams in managed basins, human-modified channels, or recently disturbed channels. Bank-full width and cross-sectional area of flow are probably more representative of the hydraulic forces that influence the distribution and retention of wood than basin size, further favoring the use of BFW rather than basin size as a predictor of instream wood numbers and volumes.

Influence of disturbance.—The AIC analysis supports a better fit using the five forest zones for predicting wood numbers and volumes compared with using the three state regions in the OLS model; however, we chose to simplify these categories by

TABLE 5.—Minimum volume required for key pieces of large woody debris, by bank-full width (BFW) class.

BFW class	Minimum volume (m^3)
0–5 m	1.00[a]
5–10 m	2.50[a]
10–15 m	6.00[a]
15–20 m	9.00[a]
20–30 m	9.75
30–50 m	10.50[b]
50–100 m	10.75[b]

[a] Current WFPB (1997) definition.
[b] Piece must have an attached rootwad.

grouping them into the state regions based on the descriptive analysis. Through the descriptive analysis, the forest zones grouping did not substantially increase the variability; thus, we believe little was lost while gaining utility in simplification. Therefore, we chose state regions as the best single regional indicator for predicting instream wood loads in relation to various forms of climate-induced disturbance. Tree age, as influenced by natural fire history, increases with wetter climates. Because the adjacent riparian trees influence instream wood loads, the characteristics of riparian trees, as influenced by fire recurrence, vary by forest zones.

We could not isolate any other form of disturbance as a significant predictor of instream wood loads; however, the wide range of wood loads found within any one grouping probably reflects some level of natural disturbance that creates typical patchy stream habitat. From our data, floods do not appear to have a significant influence on long-term wood abundance and therefore are inconsequential to variable selection. Observationally, debris flows and snow avalanches, perhaps, have some local influence on instream wood loads; however, this influence could not be verified with statistical rigor because of the small number of disturbed sites relative to nondisturbed sites.

Setting Management Targets

The percentile (box plot) distributions for LWD quantity, volume, and key-piece quantity (Figure 6) represent the range of conditions found in streams draining unmanaged forests that are subject to a natural rate of disturbance (except fire suppression). Assuming these data include both favorable and unfavorable salmonid habitat conditions as they relate to instream wood, this range can be used to set management targets for riparian recruitment objectives, regulation, habitat restoration, enhancement, and evaluation. For restoration and enhancement of instream wood loads, we recommend that streams be managed to meet this natural distribution at a basin scale, where restoring the

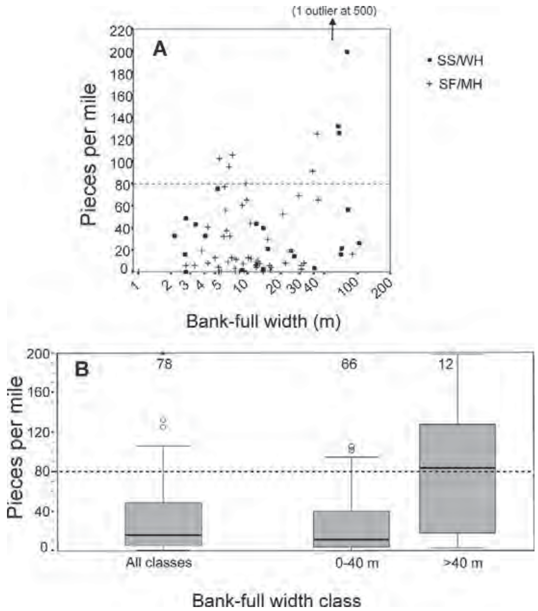

FIGURE 7.—Distribution of surveyed channel sites in western Washington, indicating the number of instream wood pieces that meet the National Marine Fisheries Service criteria for "properly functioning condition" (PFC) and the identical "resource management objective" (RMO) of the U.S. Forest Service and Bureau of Land Management for coastal Oregon and Washington. To illustrate disparities among bank-full widths, panel **(A)** presents a scatterplot of the data by forest zone (squares = the Sitka spruce–western hemlock zone [SS/WH], plus signs = the silver fir–mountain hemlock zone [SF/MH]), while panel **(B)** shows percentile distributions for all bank-full width classes and for two classes separately. The horizontal dashed line represents the lower threshold for streams meeting the PFC–RMO criteria. The number of channel reaches appears above the bars in (B); in (A), the number of channel reaches is 78. See Figure 3 for an explanation of the box-and-whisker diagrams.

natural heterogeneity of wood loads is the primary objective. Streams in a degraded state (e.g., below the median) should be managed for wood inputs exceeding the median of this range. We recommend that the top of these distributions, the 75th percentile and above, be used as an interim management "target" until the basin-scale wood loads achieve the central tendencies of natural and unmanaged wood-loading ranges.

The precise quantities and volumes of wood needed by salmonids for successful production are not well understood. Statistically sound studies to link instream wood loads to salmonid production would be expensive and have high levels of uncertainty owing to the multiple variables influencing salmon production (Roni et al. 2003). However, we do know that historic salmon populations were much higher than those found today and, as noted earlier, we assume that unmanaged forests offer the best source of information on wood loads as one component of habitat to which salmonids have adapted. In degraded streams, where management is needed to restore favorable conditions, wood loads are often no longer found in the upper distribution of these ranges, or the distribution is centered around a lower mean. In these cases, merely managing for the mean or median will not restore the natural ranges of heterogeneity. Thus, for management purposes intending to restore natural wood-loading conditions, establishing instream wood targets based on the upper portion of the distribution observed in natural systems (i.e., the 75th percentile) rather than the lower portion of the distribution are reasonable as well as prudent to restore natural ranges.

Comparison of Data with Existing Management Standards

National Marine Fisheries Service (NMFS) and U.S. Forest Service (USFS)–Bureau of Land Management (BLM): number of LWD pieces.—Streams achieving a "properly functioning condition" or the "resource management objective," as defined by NMFS and USFS–BLM, respectively (Table 1), for Pacific Northwest streams were assessed. Of the 78 natural and unmanaged streams sampled in western Washington, only 11 met the requirements of 80 pieces per mile (1 mile = 1.61 km) put forth by these federal agencies (Figure 7A); however, of the 54 streams sampled in eastern Washington, 30 met the federal standard of 20 pieces per mile (Figure 8A). Percentile distributions and one-sample *t*-tests with normalized data suggest that the sample mean of qualifying wood pieces per mile is significantly lower than the federal target for western (coastal) Pacific Northwest streams ($P < 0.001$), but significantly higher than the federal target for eastern Pacific Northwest streams ($P = 0.02$). The data in western Washington also suggest that the mean is similar to the federal standard only in channels greater than 40 m BFW (Figure 7B). The 75th percentile of data from streams equal to or less than 5 m BFW sampled in eastern Washington is near the federal target of 20 pieces per mile for eastern Washington streams, but only near the 25th percentile in streams 5–50 m BFW (Figure 8B).

In comparisons of natural and unmanaged wood-loading ranges with the federal management targets for coastal areas of the Pacific Northwest, we found that the 75th percentile derived from our data meets the federal target only in streams greater than 40 m BFW, suggesting that 80 pieces per mile seems to be a reasonable target only for the larger streams (Figure 7B). For interior Pacific Northwest streams, the federal

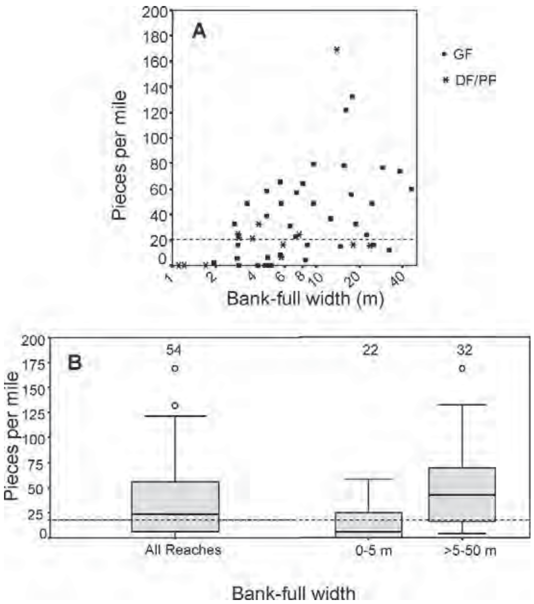

FIGURE 8.—Distribution of surveyed channel sites in eastern Washington, indicating the number of instream wood pieces that meet the National Marine Fisheries Service criteria for "properly functioning condition" and the identical "resource management objective" of the U.S. Forest Service and Bureau of Land Management for eastern Oregon and Washington. To illustrate disparities among bank-full widths, panel **(A)** (n = 53) presents a scatterplot of the data by forest zone (squares = the grand fir zone [GF] and asterisks = the Douglas-fir–ponderosa pine zone [DF/PP]), while panel **(B)** shows percentile distributions for all bank-full width classes and for two classes separately. See Figure 7 for additional details.

target is near the 75th percentile for Washington streams 0–5 m BFW in this study, but only near the 25th percentile for streams 5–50 m BFW (Figure 8B), suggesting that the federal target may be set too low for these streams. As applied, however, the NMFS and USFS–BLM targets do not differentiate between BFW classes and are applied to all streams (i.e., those with potential to provide habitat for salmonid species).

Washington Forest Practices Board: number of LWD and key pieces.—Comparing the data mean from this study for instream LWD quantities in Washington streams (channels < 20 m BFW) with the WFPB target of two pieces per channel width, there was no significant difference (one-sample t-test: $P = 0.969$; $n = 121$). The distribution of data (Figure 9a) suggests that this target is not applicable for all channel widths less than 20 m because of the significantly positive regression slope ($P < 0.001$) described by the equation

$$Y = 0.22x^{1.26}, \tag{1}$$

where Y is the predicted number of LWD pieces per channel width and x is the BFW in meters. Based on data partitioning of LWD quantity to define three distinct BFW classes (Figure 9b), one-sample t-tests suggest that the WFPB target is higher than the mean of the data distributions for channels less than 3 m BFW ($P < 0.001$), not different in channels greater than 3–12 m BFW ($P < 0.194$), and lower in channels greater than 12–20 m BFW ($P < 0.001$).

One-sample t-tests suggest that the lognormal mean of these data is not significantly different from the WFPB target of 0.3 key pieces per channel width for channels 0–10 m BFW in western Washington ($P = 0.897$); however, the mean for key pieces per channel width in channels 10–20 m BFW is significantly different from the WFPB target of 0.5 pieces per channel width ($P = 0.001$). The percentile distribution (Figure 9c) suggests the data mean in channels 10–20 m BFW is *less* than the WFPB target. The relationship of the number of key pieces per channel width to BFW is not significant ($P = 0.625$).

Oregon Watershed Enhancement Board (OWEB) targets.—There was a significant difference when comparing the data mean from this study with the OWEB "desirable" habitat quality rating (Table 1) for numbers ($P < 0.001$) and volumes ($P < 0.001$), but not for key pieces ($P = 0.061$; each with one-sample t-tests, $n = 78$) of instream LWD per 100 m of stream (Watershed Professionals Network 1998). Figure 10a suggests that the OWEB standard for numbers of LWD per 100 m of stream is lower than expected in natural and unmanaged streams of similar forest types in Washington. Furthermore, regression analysis suggests that the OWEB target is not applicable for all channel widths, where the number of pieces per 100 m of this study increases with increasing channel widths ($P = 0.004$). Figure 10b suggests that the OWEB standard for LWD volume is lower than expected in natural and unmanaged streams. As with the number of LWD, regression analysis of these data also suggests a positive relationship with LWD volume as channel width increases. Figure 10c suggests no significant difference between the OWEB standard and the data of this study. Regression analysis ($P = 0.197$) suggests no significant increase or decrease in the number of key pieces per 100 m, as defined by the OWEB key-piece size criteria with BFW.

The appropriateness of Washington and Oregon state LWD standards may be reasonable only for a select channel size. Figure 9b illustrates that the WFPB target is only near the median for streams between 3 m and 12 m BFW (yet below the 75th percentile) and quite different from the distributions found in smaller and larger natural and unmanaged streams. Regressions using the WFPB LWD metrics (Figure 9a) and the OWEB metrics further suggest that numbers of LWD pieces vary by channel size, and a single target may not serve well for all stream sizes. This relationship is similar for LWD volume, suggesting a similar discrepancy with the OWEB volume targets. However, the state targets for LWD numbers and volume do not differentiate between channel sizes and are, overall, lower than the 75th percentiles of distributions found in natural and unmanaged streams, which, therefore, suggests that the state targets may be set too low.

The state LWD targets may also not be appropriate for all forest types. Figure 9a illustrates that there is regional variation with numbers of wood pieces, suggesting that applications of a fixed management target may not be judicious across different forest zones of Washington and Oregon. As applied, however, the Washington targets for piece numbers are applied to all forest types across the state, and the Oregon targets are applied to all forest types in western Oregon.

The key-piece standards of Washington and Oregon are quite different in size definition and hence are difficult to compare. The WFPB key-piece size definition increases by channel size, where the OWEB key-piece size definition is constant for all channels. Based on the functional definition for independent stability (WFPB 1997) and what we know about increasing fluvial forces acting upon wood as stream size increases (Braudrick and Grant 2000), it would seem that the minimum size of an independently stable piece of LWD must increase with channel size. Certainly, the size definitions of the WFPB (1997), which are based on data collected under this definition

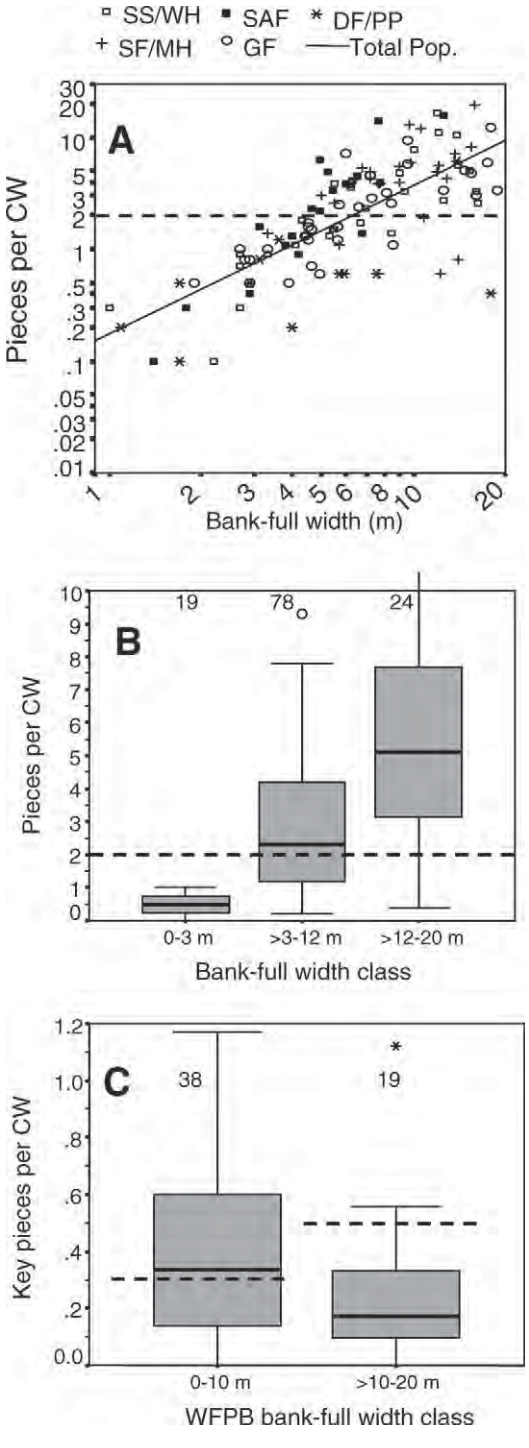

FIGURE 9.—Number of pieces and key pieces of wood (LWD) per channel width (CW) by bank-full width for surveyed channels in Washington with bank-full widths less than 20 m for comparison with the Washington Forest Practices Board (WFPB) targets. Panel **(A)** presents a scatterplot in which the points represent the mean quantities per sample by discrete forest region (open rectangles = the Sitka spruce–western hemlock zone [SS/WH], filled rectangles = the subalpine fir zone [SAF], asterisks = the Douglas-fir–ponderosa pine zone [DF/PP], plus signs = the silver fir–mountain hemlock zone [SF/MH], and circles = the grand fir zone [GF]). The sloping line is the fitted regression line $y = 0.191x^{1.29}$, where y represents pieces per channel width and x bank-full width. Panel **(B)** presents box plots illustrating the range of data among discrete bank-full width classes and panel **(C)** box plots illustrating the data distribution as compared with the WFPB targets for key-piece quantities per CW (applicable to western Washington only). The horizontal dashed lines represent the WFPB targets that indicate "good" habitat quality (WFPB 1997). The number of channel reaches appears above the bars in (B) and (C); in (A), the number of channel reaches is 121. See Figure 3 for an explanation of the box-and-whisker diagrams.

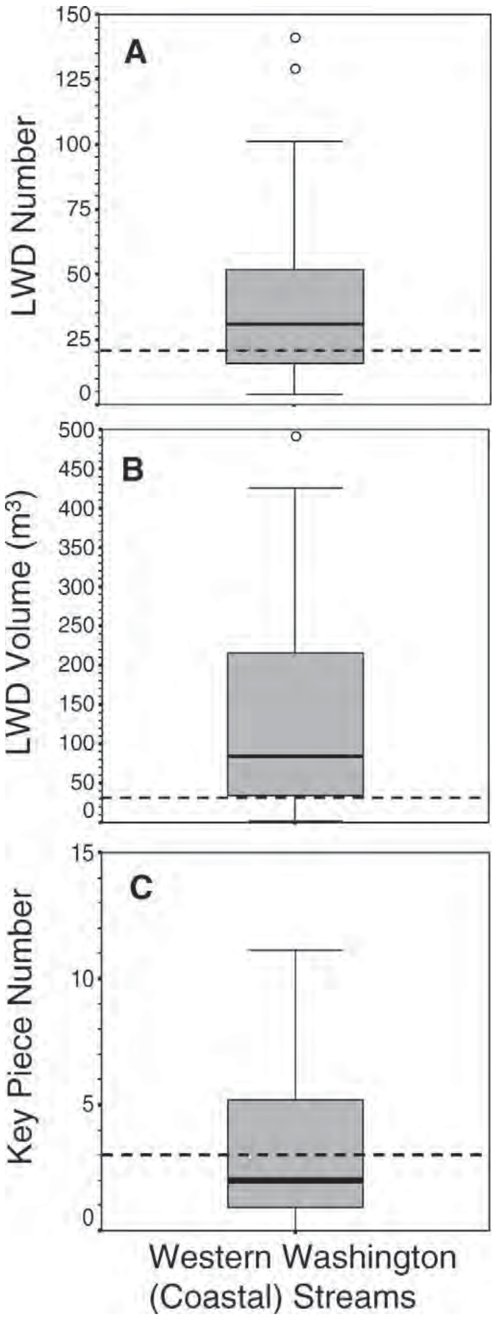

FIGURE 10.—Distributions of **(A)** the number of pieces of wood (LWD), **(B)** the volume of LWD, and **(C)** the number of key pieces of LWD per 100 m of stream in surveyed channels in Washington that meet the Oregon Watershed Enhancement Board's qualifying criteria (Table 1). The dashed horizontal lines indicate the board's "desirable" condition (Watershed Professionals Network 1998) for each wood habitat metric. For each plot, $n = 78$. See Figure 3 for an explanation of the box-and-whisker diagrams.

(M. J. Fox, 1994 memorandum to the Cumulative Effects Steering Committee from the Muckleshoot Tribe on LWD key piece size and distribution data set for several late-successional Douglas-fir forests of western Washington), reflect this increase. Thus, the Oregon single size definition for key pieces is likely to overestimate independently stable LWD pieces (i.e., key pieces) in smaller streams, but qualify pieces that are, perhaps, not functioning as true key pieces in larger streams. Although the OWEB key-piece target is not significantly different than the data mean quantity from natural and unmanaged streams, it may not reflect true key-piece quality and the intended geomorphic role of those pieces. Therefore, the OWEB target for key pieces may better serve as a reference to the quantity of "large" pieces of LWD rather than true "key pieces" expected in coastal streams, yet may fall short as a management target since it is lower than the 75th percentile of pieces meeting that size definition in natural and unmanaged streams. The WFPB targets for key pieces are also different from the 75th percentile (Figure 9c), and adjusting the target to meet the quantities expected in natural and unmanaged streams may more prudently facilitate some management objectives.

Defining New Key-Piece Minimum Volumes for Channels Greater Than 20 m BFW

The minimum volumes established in Figure 4 illustrate that the size of the pieces in channels greater than 20 m BFW do not increase at the same rate as the minimum defined volumes in channels between 0 and 20 m BFW (WFPB 1997). The change in rate is illustrated in Figure 5 as channels reach 15–20 m BFW (i.e., 9 m^3) and suggests that the relationship between BFW (as representative of potential fluvial forces such as buoyancy) and wood volume (as a function of stability) is not linear. Certainly, one would expect that wood must be larger to counter the tendency to mobilize as channels become larger. This is not the case and is probably attributed to the presence of rootwads to help anchor logs. Clearly, this often compensates for the need of increased volume for stability. This is illustrated by the increased prevalence of rootwads attached to key pieces as BFW increased, although the minimum volumes did not increase proportionately. The data suggest that without root-wads attached, the minimum volume required to meet the definitions for key pieces may indeed follow the near-linear relationship with BFW established by the WFPB in channels 0–20 m BFW. However, this relationship may not be fully realized because samples for pieces this large without rootwads were rare ($n = 3$).

Application of Key-Piece Size Definitions to Eastern Washington Streams

The application of the minimum key-piece volumes established for western Washington (WFPB 1997) to eastern Washington is demonstrable. First, there was no significant difference in the total percent of wood qualifying as key pieces between eastern and western Washington forest zones. Second, fluvial forces for a given channel size are likely to be the same and, thus, the mobilization of wood is likely to be the same. Indeed, Fox (2001) found that the physical dry densities of wood species commonly distributed in the riparian areas are not significantly different between forest zones. Although the quantities of key pieces vary among regions (Figure 6), the physical criteria used to define a key piece (using the WFPB definition) should be similar. Therefore, the application of minimum key-piece volumes established for western Washington streams to eastern Washington streams is appropriate and, thus, applicable among these forest types.

Restoration and Management Recommendations

Instream wood is merely one indicator of stream and salmonid habitat conditions; however, it is one of the few tangible stream features that can be manipulated by the management of riparian areas or used in wood restoration intended to "jump-start" habitat recovery until natural processes recover. Management objectives are most valid if they are based on reference conditions to which salmonids have adapted. The percentile (box plot) distributions for LWD quantity, volume, and key-piece quantity (Figure 6) provide this range of reference conditions for discrete regions and channel sizes and can be used in habitat restoration, enhancement, evaluation, regulation and, perhaps, to develop riparian recruitment objectives. Because these data represent a wide range of conditions found in streams draining unmanaged forests that are subject to a natural rate of disturbance (except fire suppression), the recommendations provided herein are relevant to basin-scale objectives intended to restore the natural heterogeneity of wood distributions found in unmanaged systems. In many cases, conditions in impacted streams often reside in a reduced range of historic heterogeneity or are grouped around a different mean. As such, reestablishing values within the historic range that "pull" the mean closer to the historic mean will probably better serve the restoration of habitat conditions. Due to the effect of past management practices on instream wood, impacted streams commonly contain conditions lower than the historic range. Thus, merely managing for the mean or median will not likely restore the natural ranges of heterogeneity, and achieving this range in degraded systems may initially require setting objectives above the mean or median of this range (e.g., the 75th percentile) to expedite recovery and resemble the central tendencies of natural and unmanaged wood-loading ranges.

Current management targets often do not consider the regional or geomorphic variation in wood loads, and hence caution should be exercised in applying these standards broadly. The data in this study illustrate these significant variations by forest type and channel size and offer improved references in which to base management objectives.

The minimum piece volumes used to define a key piece should also consider the role rootwads play in achieving stability. In channels greater than 30 m BFW, more than 91% of all key pieces had rootwads attached. Therefore, in order to meet the objective of defining a key piece, not only do the prescribed minimum volumes need to be met but also rootwads must be considered in this definition. Without rootwads to stabilize key pieces, the minimum volume needed for stability in large channels would be extremely large. Logs of this size are rare and probably impossible to obtain for stream habitat enhancement projects, let alone transporting and positioning them into a channel. Therefore, we recommend that for channels greater than 30 m, a log must have a rootwad attached to be defined as a key piece and meet the minimum-volume requirements defined in Figure 4. Although having a rootwad attached to a log placed in a stream channel as part of a restoration or enhancement effort adds stability and longevity (Braudrick and Grant 2000), the data do not justify a requirement that all key pieces meeting the minimum-volume requirement have an attached rootwad for BFW classes smaller than 30 m.

Table 4 summarizes the central percentile distributions for instream wood loadings based on Figure 6. These values offer typical ranges of conditions for the quantities and volumes of wood found within the historical variability of watershed conditions, given the natural disturbance regime in forest zones of Washington State. These ranges can be used to (1) assess current instream wood condition and ratings for the evaluation of stream habitat; (2) identify target wood load levels for restoration, enhancement, and mitigation projects; and (3) develop land-use regulations, ordinances, and laws to protect and manage salmon habitat.

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Accufacts Inc.
"Clear Knowledge in the Over Information Age"

8040 161st Ave NE, #435
Redmond, WA 98052
Ph (425) 802-1200
Fax (805 980-4204
kuprewicz@comcast.net

Date: June 20, 2017

To: Rob Wyman
City Manager
City of Newcastle
12835 Newcastle Way, Ste 200
Newcastle, WA 98056

Re: Accufacts Review of Puget Sound Energy's Energize Eastside Transmission project along Olympic Pipe Line's two petroleum pipelines crossing the City of Newcastle

I. Introduction and Scope

Accufacts Inc. ("Accufacts") was asked to perform a technical review of several specific documents identified below ("Documents") related to the Energize Eastside ("EE") project's possible impact on the 16-inch and 20-inch Olympic Pipe Line product pipelines crossing the City of Newcastle ("City"). Within the City, the existing 16 and 20-inch Olympic Pipe Line products pipelines ("Olympic") are collocated on or near Puget Sound Energy's ("PSE's") electric transmission pipeline right-of-way ("ROW") proposed for electrical expansion from 115 KV to 230 KV.

With regard to PSE's EE project, the City asked Accufacts to specifically review and briefly comment on the following Documents:

1. DNV-GL Final Report, AC Interference Analysis – 230 KV Transmission Line Collocated with Olympic Pipelines OPL 16 and OPL 20, dated December 13, 2016,

2. Phase 2 Draft EIS dated May 2017: Chapter 3, Long-Term (Operation) Impacts and Potential Mitigation; and Chapter 4, Short-Term (Construction) Impacts and Mitigation, and

3. Phase 2 Draft EIS Preliminary Draft V-2, "Appendix I. Pipeline Safety, Appendix I-1 through I-5," dated April 2017.

The EE project can present a threat to the pipelines during two separate phases: 1) the construction phase from possible abnormal loading or impact threats that could damage the pipelines, and 2) an operational phase when the electrical power lines are operated at the higher KV that can introduce stray currents, also known as interference currents, that can remove steel from buried pipelines if not properly addressed.

In reviewing the Documents, Accufacts has the following major findings:

1. Olympic Pipe Line bears the ultimate responsibility for possible PSE's EE project interactions that could result in an Olympic pipeline failure.
2. The Documents do not provide sufficient details to assure Accufacts that appropriate precautions will be implemented or effective in protecting the pipelines during the construction phase.
3. The DNV-GL Final Report explains how pipelines address stray current risks near high power electrical transmission lines, but correctly indicates that Olympic must provide additional field verifications to support key assumptions once EE goes operational.
4. Appendix I-5 of the Phase 2 Draft EIS EE Pipeline Safety Technical Report ("Technical Report") risk assessment approach is not relevant nor does it represent the Olympic pipelines, especially within the City.

It is Accufacts' opinion that the PSE's EE can be safely collocated with the pipelines if sufficient details, identified in the Accufacts Detailed Recommendations for EE within the City, Section III below, are implemented by PSE and Olympic, and adequately conveyed to the City. Some of these details may be sensitive and may not be publicly disseminated for obvious reasons, even in a right-to-know state, such as Washington State. My attached CV will demonstrate some of my pipeline investigative background and experience, which included evaluating the Olympic Pipe Line operation for the City of Bellingham after the June 10, 1999 pipeline rupture and tragedy.

II. Additional Accufacts observations related to EE and the Olympic pipelines within the City:

1. Olympic Pipe Line bears the ultimate responsibility for possible PSE's EE project's interactions that could result in an Olympic pipeline failure.

It is not unusual to have liquid transmission pipelines collocated in the same or nearby rights-of-way of high power electrical transmission pipelines. Federal minimum pipeline safety regulations clearly place the ultimate responsibility to assure protection of the hazardous liquid pipeline(s) in such locations squarely on the pipeline operator. Long standing minimum federal pipeline safety regulations are very clear: "An operator may make arrangements with another person for the performance of any action required by this part. However, the operator is not thereby relieved from the responsibility for compliance with any requirement of this part."[1] "Part" in this context means the federal pipeline safety regulation incorporated as 49CFR§195 setting minimum pipeline safety standards governing the transportation of hazardous liquids by pipeline. The operator of Olympic Pipe Line is ultimately responsible for the operation of their pipelines regardless of studies or actions performed by others.

As further discussed below, while the PSE commissioned DNV-GL Final Report presents a prudent analysis of the possible interactions related to stray current threats from the EE project, and includes rational electrical design/operational suggestions to reduce possible infrastructure impacts by the PSE electrical system, the ultimate threats to the pipeline are the responsibility of Olympic Pipe Line. PSE must provide details as to how Olympic will verify all key assumptions in the DNV-GL Final Report and, more importantly, confirm that actual pipeline field operations are relevant to assure pipeline safety.

2. **The Documents do not provide sufficient details to assure Accufacts that appropriate precautions will be implemented or effective in protecting the pipelines during the construction phase.**

During the construction phase, threats to the pipelines can be introduced from abnormal loads either from surface activity such as heavy equipment or excessive forces such as excavation/auguring. While construction activity can also introduce threats that can contact the pipelines and directly damage them, one does not have to hit a pipeline to cause damage that can fail at a later time as a delayed failure, such as abnormal loading that can deform a steel pipeline. Fortunately, the science and engineering associated with evaluating such construction activity threats to buried pipelines is well established. Depending on the specific location, such potential threats diminish rapidly with lateral distance from a pipeline, and adequate depth can quickly provide a safety factor, depending on the abnormal loading threat expected near/above a pipeline.

The Phase 2 Draft EIS report indicates that, across the City, the pipelines are in the "center of the {PSE} right-of-way."[2] It is important to note that some of the Documents

[1] 49CFR§195.10 - Responsibility of operator for compliance with this part.
[2] EE EIS, "Chapter 3 Long-Term (Operation) Impacts and Potential Mitigation," May 2017, p. 3.9-9.

could mislead the reader regarding the requirement for pipeline depth.[3] Much of the Olympic system, including the segments crossing the City, is classified as interstate and not subject to the additional conditions imposed by the Washington Administrative Code that instill additional requirements beyond federal regulations on the limited intrastate portions of the Olympic system. I believe the pipeline segments spanning the City are classified as interstate and thus have no requirement to maintain pipeline depths at the initial installation depths that occurred many decades ago. It is thus Olympic Pipe Line's responsibility to confirm pipeline lateral and, more importantly, depth to avoid construction threats that could result in pipeline failure, as actual depth could have changed over the years.

PSE must work with Olympic to readily demonstrate to the City that adequate protections are to be utilized to avoid these short-term threat activities during construction. Depending on the right-of-way, there is no "one size fits all" distance, either lateral or depth, that should be used, as such safe distance determinations regarding abnormal loading on pipelines are ROW site specific and depend on various factors such as load which can change by project/location.

Given the challenging elevation profile of the pipelines across the City, PSE also needs to confirm that EE activities (either on or off the electrical transmission ROW) will not introduce landslide potential on the Olympic pipelines. No pipeline can withstand massive breakaway landslide abnormal loading that can occur from soil liquification in areas of steep elevation profile experiencing high rainfall or flooding, such as that which can occur in Western Washington. Breakaway landslide usually results in a pipeline rupture (high rate releases). This potential threat should be an easy threat to identify, evaluate, and assess, but has not been mentioned in the Technical Report.

3) **The DNV-GL Final Report explains how pipelines address stray current risks near high power electrical transmission lines, but correctly indicates that Olympic must provide additional field verifications to support key assumptions once EE goes operational.**

During the operational phase of the EE effort, a phenomenon commonly known in the pipeline industry as "stray current" or interference current can impact pipeline integrity if not properly addressed. Stray current is a term that captures an electrical current path generated from, among other things, high voltage power lines, poor CP system

[3] EDM Technical Services, Inc., Appendix I-5, "Technical Report, Pipeline Safety and Risk of Upset," p. 28.

design/operation, inadequate foreign crossing design/installation, or electrical "fault" short circuits from lightning or downed power lines where high energy current reaches a pipeline and causes pipe metal loss.

Federal pipeline safety regulations have been codified and prescribed for many years concerning stray current interference/interactions.[4] Even before placement into federal regulations, experienced pipeline operators were well aware of the possible interactions of high energy electrical power transmission systems on pipelines that can cause the rapid loss of buried pipeline steel. Olympic should be well aware of and experienced in stray current interaction as much of their product pipelines are collocated in high energy electrical transmission ROWs in other areas of the state that has successfully operated for over 50 years.[5] Current federal pipeline safety regulation, 49CFR195.3, places explicit prescribed regulatory obligations in the area of interference or stray current interactions on hazardous liquid pipeline operators.[6]

The DNV-GL Final Report does suggest several design modifications that PSE can utilize to reduce and control the risk of stray current to the pipelines from the EE project.[7] The DNV-GL Final Report also correctly recommends further field follow-up by Olympic Pipe Line and PSE concerning additional field monitoring and verification of both the electrical line and liquid pipeline operation to assure effectiveness of the design/operational approaches concerning possible stray current impacts from PSE's project.

Given the wide variation in field measurement conditions, PSE must have the pipeline operator confirm that key assumptions in the DNV-GL Final Report are indeed conservative and appropriate for their pipelines once the power lines go into operation at their higher voltage. AC interference, ground fault, and high energy arc potential that might reach a buried pipeline, need additional verification from Olympic as to their assumption/field measured accuracy. For example, arcing potential to pipelines from faults is highly dependent on the quality of the pipeline's external coating at a specific

[4] 49CFR§195.577 - What must I do to mitigate interference currents? Added to federal pipeline safety regulations Dec. 27, 2001.
[5] U.S. Department of Energy, "State of Washington Energy Sector Risk Profile," 2014, pp. 2 & 4.
[6] NACE SP0169-2007, Standard Practice, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems," reaffirmed March 15, 2007 (NACE 0169), IBR approved for §§ 195.571 and 195.573(a).
[7] DNV-GL Final Report, "AC Interference Analysis – 230 KV Transmission Line Collocated with Olympic Pipelines OPL 16 and OPL 20," dated December 13, 2016, p. vi.

possible threat location. Only Olympic may know such coating conditions using various field measurements. Coating quality at a specific location can have a critical influence on arc safety distances in the rare occurrence of a ground fault from high power electrical sources. While electrical arcing into a pipeline can leave clear evidence of such an event, the real danger occurs where such energy leaves the buried pipeline, a location which can be highly unpredictable along a pipeline system.

Application of prudent integrity management principles, such as sound in-line inspection ("ILI"), or smart pigging, corrosion assessment can assist in demonstrating past approach effectiveness in dealing with possible stray current interactions from such sources that can cause pipe steel removal. I must caution, however, that some stray current interactions can occur quite quickly causing rapid pipe wall metal loss and possible pipeline failure. Since ILI inspections may also occur infrequently, ILI inspection should not be the only approach to guard against stray current interaction possible threats.[8] A prudent pipeline operator will employ and integrate other measures beyond ILI, such as incorporating effective cathodic protection monitoring and analysis, to assure more timely gauging of pipeline safety approaches to confirm pipeline integrity in such collocated high power electrical transmission rights-of-way. ILI should not be the only method to verify pipeline integrity in stray current high-risk threat potential areas.

III. Accufacts Detail Recommendations for EE within the City:

In light of the above discussion, Accufacts specifically advises, in addition to the general recommendations outlined in the DNV-GL Final Report and Draft EIS, the following more detailed requirements be imposed by the City:[9, 10, 11]

1) Given the criticality of the location of the pipelines, especially their depth, to avoid construction threats that could harm the pipelines, PSE and, especially, Olympic Pipe Line should:
    a) confirm and identify specific pipeline lateral locations, including the important depth values which will vary along the pipelines,

[8] 49CFR§195.452(j)(3) & (4) *Assessment Intervals* requiring reassessment intervals of up to five years not to exceed 68 months unless a variance for longer reassessment is justified.
[9] DNV-GL Final Report, "AC Interference Analysis – 230 KV Transmission Line Collocated with Olympic Pipelines OPL 16 and OPL 20," dated December 13, 2016, p. vi.
[10] EE EIS, "Chapter 4 Short-Term (Construction) Impacts and Mitigation," May 2017, p. 4.9-7 thru 4.9-9.
[11] EE EIS, "Chapter 3 Long-Term (Operation) Impacts and Potential Mitigation," May 2017, pp. 3.9-54 & 55.

b) pinpoint what specific construction activities, including their locations and possible maximum loads, that may occur during the EE installation effort that could be a threat to the pipelines,
c) for these identified possible construction threats, commit to detailed precautions that will be required, implemented, and monitored/checked to avoid construction damage to the pipelines, and
d) verify EE activity does not introduce breakaway landslide threats to the pipelines.

2) During the operational phase of EE, Olympic, in conjunction with PSE, should:
   a. verify that the actual current densities do not pose a threat near the pipelines, especially during the early phase of EE when the power lines may be operated imbalanced (230/115 KV),
   b. establish notification protocols that would alert Olympic of possible major PSE power transmission imbalances,
   c. not only rely on periodic corrosion tool ILI to assure pipeline wall loss from possible interference currents is not occurring, and
   d. verify pipeline coating reasonable integrity to substantiate fault arcing distance determinations.

PSE, with Olympics' cooperation, should be able to sufficiently demonstrate to the City such details, including documented engineering analysis as needed, proving that sufficient safety factors exist to avoid threats to the pipelines during the construction and operational phases of EE.

IV. Accufacts General Observations on Appendix I-5 of the Phase 2 Draft EIS EE Pipeline Safety Technical Report ("Technical Report"):

It is not unusual to see a risk management approach similar to that presented in the Technical Report. From my perspective, however, the Technical Report approach is not relevant to the EE project's possible impact threat to the pipelines. Some key reasons for this are:

1) The risk assessment approaches utilized in the Technical Report are not incorporated into U.S. pipeline safety regulations.

The risk approach utilized in the Technical Report is not defined in federal pipeline safety regulations. There are many assumptions and approaches in the Technical Report that are not specifically representative of the Olympic pipelines, especially in the event of a significant release such as a pipeline rupture. Based on my extensive experience in hydrocarbon releases, including incident response, attempts to characterize the impact area in the Technical Report are unrealistic small. For example, the pipelines' elevation profile, an important consideration in liquid pipeline operation, is neither discussed nor provided. In fairness to EDM, certain critical sensitive information known to Olympic that would assist EDM in a risk assessment approach if it were permitted, in all probability has not been disclosed to EDM given the information's sensitivity**.** It is, however, important to recognize such risk assessments are not codified in U.S. pipeline safety regulations for many good reasons.

In all probability, important additional safeties incorporated into Olympics' operation after the 1999 Olympic rupture tragedy in Bellingham have also not been made public. In addition, it is my experience that the Bellingham rupture cannot be well modeled by a "pool fire" as presented in the Technical Report. The challenging terrain, the pipeline elevation profile and location, as well as other considerations play a critical part in determining an impact area in the event of a release.

2) Acceptable pipeline risk thresholds (individual or societal) are neither defined nor codified in U.S. pipeline safety regulations.

The U.S. has more gas and liquid transmission pipeline mileage than any other country in the world by a considerable margin. While some countries have defined and incorporated certain "consequence" risk thresholds, such as acceptable mortality thresholds, into their country's pipeline safety approaches, such as the use of Quantitative Risk Assessment ("QRA"), U.S. pipeline safety regulations do not incorporate the use of this type of risk assessment approach.

The EE EIS correctly mentions that "there are no adopted federal or Washington State criteria for acceptable levels of individual risks" and "there are no adopted federal or Washington State criteria for acceptable levels of societal risk."[12] This same document cites risk thresholds for another state and other countries, but the matter quite simply is not defined, codified, nor accepted in the U.S. or Washington State pipeline safety regulations.

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[12] EE EIS, "Chapter 3 Long-Term (Operation) Impacts and Potential Mitigation," May 2017, pp. 3.9-36 & 37.

3) **Assigning risk factors utilizing PHMSA/OPS historical reporting databases can be misrepresentative, as the databases are often woefully incomplete, inadequate, and can be easily misused for a specific pipeline.**

For many reasons, historical PHMSA/OPS database files can be inadequate and incomplete so as to make their use in assigning risk probability inappropriate or inadequate, for a specific pipeline operation, even with "normalization" attempts such as releases per pipeline mile. While PHMSA has made considerable attempts to make pipeline incident/accident information reported to the agency public, reports are often filed before sufficient information can be supplied to accurately complete a pipeline failure report. It is well known that numerous initial reports are not accurately updated. This can be especially problematic as to actual cause, or released volumes, which historically have been found to be inaccurate or misleading. In my experience, I have seen probability analysis abuses based on PHMSA/OPS databases on both sides of the fence, usually to drive false agendas or preordained conclusions about pipelines. These databases should be applied with great caution.

4) **Historical database files do not predict nor represent future risk probabilities on a specific pipeline system in a specific location.**

Risk probabilities derived from industry-wide databases do not represent the risks that may exist on a specific pipeline operation as management safety cultures can vary widely. Such safety culture variations can significantly increase the risk of pipeline failure. While I can appreciate that attempts to characterize pipeline releases into "simple models" that might make engineering analysis easier, the fact remains that the June 10, 1999 Olympic pipeline rupture release in Bellingham is not well represented by modeling as a pool fire. Any efforts trying to define a release impact zone from a pool fire in such a challenging terrain are overly simplistic, and unrealistic, likely underrepresenting the actual impact area. Following the Bellingham rupture release, the pipeline elevation profile played a key role in the technical safety team's role in assisting the pipeline operator in adding/applying at the time unregulated integrity management approaches to assure pipeline integrity, as well as installing additional "safeties" to the Olympic Pipe Line operation.

V. Conclusions

As discussed above, cooperation and proper management between PSE and Olympic concerning the EE project should allow the EE project to not increase risks to the Olympic pipelines. Both PSE and Olympic, however, need to demonstrate to the City those important details as outlined in Section III above to assure the pipelines are protected during the design, construction, and future operation of the EE effort. Lastly, Accufacts understands that, for the Olympic Pipe Line Company, the majority ownership has changed from BP to Enbridge. Such changes can introduce risks in operational approaches caused by a loss in pipeline operational experience and/or a shift in management safety culture, (such as not incorporating proper levels of safety to avoid a pipeline release). It is imperative that the new majority ownership understands the risks that can be introduced to the pipelines from the EE effort, and that prudent prevention efforts are in place and implemented to avoid a release.

Richard B. Kuprewicz

Richard B. Kuprewicz,
President,
Accufacts Inc.

Curriculum Vitae.

Richard B. Kuprewicz

8040 161st Ave NE, #435
Redmond, WA 98052

Tel: 425-802-1200 (Office)
E-mail: kuprewicz@comcast.net

Profile:

As president of Accufacts Inc., I specialize in gas and liquid pipeline investigation, auditing, risk management, siting, construction, design, operation, maintenance, training, SCADA, leak detection, management review, emergency response, and regulatory development and compliance. I have consulted for various local, state and federal agencies, NGOs, the public, and pipeline industry members on pipeline regulation, operation and design, with particular emphasis on operation in unusually sensitive areas of high population density or environmental sensitivity.

Employment:

Accufacts Inc. **1999 – Present**

Pipeline regulatory advisor, incident investigator, and expert witness on all matters related to gas and liquid pipeline siting, design, operation, maintenance, risk analysis, and management.

Position: President
Duties: > Full business responsibility
> Technical Expert

Alaska Anvil Inc. **1993 – 1999**

Engineering, procurement, and construction (EPC) oversight for various clients on oil production facilities, refining, and transportation pipeline design/operations in Alaska.

Position: Process Team Leader
Duties: > Led process engineers group
> Review process designs
> Perform hazard analysis
> HAZOP Team leader
> Assure regulatory compliance in pipeline and process safety management

ARCO Transportation Alaska, Inc. **1991 - 1993**

Oversight of Trans Alaska Pipeline System (TAPS) and other Alaska pipeline assets for Arco after the Exxon Valdez event.

Position: Senior Technical Advisor
Duties: > Access to all Alaska operations with partial Arco ownership
> Review, analysis of major Alaska pipeline projects

ARCO Transportation Co. **1989 – 1991**

Responsible for strategic planning, design, government interface, and construction of new gas pipeline projects, as well as gas pipeline acquisition/conversions.

Position: Manager Gas Pipeline Projects
Duties: > Project management
> Oil pipeline conversion to gas transmission
> New distribution pipeline installation
> Full turnkey responsibility for new gas transmission pipeline, including FERC filing

Four Corners Pipeline Co. 1985 – 1989

Managed operations of crude oil and product pipelines/terminals/berths/tank farms operating in western U.S., including regulatory compliance, emergency and spill response, and telecommunications and SCADA organizations supporting operations.

Position: Vice President and Manager of Operations
Duties: > Full operational responsibility
> Major ship berth operations
> New acquisitions
> Several thousand miles of common carrier and private pipelines

Arco Product CQC Kiln 1985

Operations manager of new plant acquisition, including major cogeneration power generation, with full profit center responsibility.

Position: Plant Manager
Duties: > Team building of new facility that had been failing
> Plant design modifications and troubleshooting
> Setting expense and capital budgets, including key gas supply negotiations
> Modification of steam plant, power generation, and environmental controls

Arco Products Co. 1981 - 1985

Operated Refined Product Blending, Storage and Handling Tank Farms, as well as Utility and Waste Water Treatment Operations for the third largest refinery on the west coast.

Position: Operations Manager of Process Services
Duties: > Modernize refinery utilities and storage/blending operations
> Develop hydrocarbon product blends, including RFGs
> Modification of steam plants, power generation, and environmental controls
> Coordinate new major cogeneration installation, 400 MW plus

Arco Products Co. 1977 - 1981

Coordinated short and long-range operational and capital planning, and major expansion for two west coast refineries.

Position: Manager of Refinery Planning and Evaluation
Duties: > Establish monthly refinery volumetric plans
> Develop 5-year refinery long range plans
> Perform economic analysis for refinery enhancements
> Issue authorization for capital/expense major expenditures

Arco Products Co. 1973 - 1977

Operating Supervisor and Process Engineer for various major refinery complexes.

Position: Operations Supervisor/Process Engineer
Duties: > FCC Complex Supervisor
> Hydrocracker Complex Supervisor
> Process engineer throughout major integrated refinery improving process yield and energy efficiency

Qualifications:

Currently serving as a member representing the public on the federal Technical Hazardous Liquid Pipeline Safety Standards Committee (THLPSSC), a technical committee established by Congress to advise PHMSA on pipeline safety regulations.

Committee members are appointed by the Secretary of Transportation.

Served seven years, including position as its chairman, on the Washington State Citizens Committee on Pipeline Safety (CCOPS).

Positions are appointed by the governor of the state to advise federal, state, and local governments on regulatory matters related to pipeline safety, routing, construction, operation and maintenance.

Served on Executive subcommittee advising Congress and PHMSA on a report that culminated in new federal rules concerning Distribution Integrity Management Program (DIMP) gas distribution pipeline safety regulations.

As a representative of the public, advised the Office of Pipeline Safety on proposed new liquid and gas transmission pipeline integrity management rulemaking following the pipeline tragedies in Bellingham, Washington (1999) and Carlsbad, New Mexico (2000).

Member of Control Room Management committee assisting PHMSA on development of pipeline safety Control Room Management (CRM) regulations.

Certified and experienced HAZOP Team Leader associated with process safety management and application.

Education:

MBA (1976)	Pepperdine University, Los Angeles, CA
BS Chemical Engineering (1973)	University of California, Davis, CA
BS Chemistry (1973)	University of California, Davis, CA

Publications in the Public Domain:

1. "An Assessment of First Responder Readiness for Pipeline Emergencies in the State of Washington," prepared for the Office of the State Fire Marshall, by Hanson Engineers Inc., Elway Research Inc., and Accufacts Inc., and dated June 26, 2001.

2. "Preventing Pipeline Failures," prepared for the State of Washington Joint Legislative Audit and Review Committee ("JLARC"), by Richard B. Kuprewicz, President of Accufacts Inc., dated December 30, 2002.

3. "Pipelines - National Security and the Public's Right-to-Know," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated May 14, 2003.

4. "Preventing Pipeline Releases," prepared for the Washington City and County Pipeline Safety Consortium, by Richard B. Kuprewicz, dated July 22, 2003.

5. "Pipeline Integrity and Direct Assessment, A Layman's Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated November 18, 2004.

6. "Public Safety and FERC's LNG Spin, What Citizens Aren't Being Told," jointly authored by Richard B. Kuprewicz, President of Accufacts Inc., Clifford A. Goudey, Outreach Coordinator MIT Sea Grant College Program, and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated May 14, 2005.

7. "A Simple Perspective on Excess Flow Valve Effectiveness in Gas Distribution System Service Lines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated July 18, 2005.

8. "Observations on the Application of Smart Pigging on Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated September 5, 2005.

9. "The Proposed Corrib Onshore System - An Independent Analysis," prepared for the Centre for Public Inquiry by Richard B. Kuprewicz, dated October 24, 2005.

10. "Observations on Sakhalin II Transmission Pipelines," prepared for The Wild Salmon Center by Richard B. Kuprewicz, dated February 24, 2006.

11. "Increasing MAOP on U.S. Gas Transmission Pipelines," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2006. This paper was also published in the June 26 and July 1, 2006 issues of the Oil & Gas Journal and in the December 2006 issue of the UK Global Pipeline Monthly magazines.

12. "An Independent Analysis of the Proposed Brunswick Pipeline Routes in Saint John, New Brunswick," prepared for the Friends of Rockwood Park, by Richard B. Kuprewicz, dated September 16, 2006.

13. "Commentary on the Risk Analysis for the Proposed Emera Brunswick Pipeline Through Saint John, NB," by Richard B. Kuprewicz, dated October 18, 2006.

14. "General Observations On the Myth of a Best International Pipeline Standard," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated March 31, 2007.

15. "Observations on Practical Leak Detection for Transmission Pipelines – An Experienced Perspective," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated August 30, 2007.

16. "Recommended Leak Detection Methods for the Keystone Pipeline in the Vicinity of the Fordville Aquifer," prepared for TransCanada Keystone L.P. by Richard B. Kuprewicz, President of Accufacts Inc., dated September 26, 2007.

17. "Increasing MOP on the Proposed Keystone XL 36-Inch Liquid Transmission Pipeline," prepared for the Pipeline Safety Trust by Richard B. Kuprewicz, dated February 6, 2009.

18. "Observations on Unified Command Drift River Fact Sheet No 1: Water Usage Options for the current Mt.

Redoubt Volcano threat to the Drift River Oil Terminal," prepared for Cook Inletkeeper by Richard B. Kuprewicz, dated April 3, 2009.

19. "Observations on the Keystone XL Oil Pipeline DEIS," prepared for Plains Justice by Richard B. Kuprewicz, dated April 10, 2010.

20. "PADD III & PADD II Refinery Options for Canadian Bitumen Oil and the Keystone XL Pipeline," prepared for the Natural Resources Defense Council (NRDC), by Richard B. Kuprewicz, dated June 29, 2010.

21. "The State of Natural Gas Pipelines in Fort Worth," prepared for the Fort Worth League of Neighborhoods by Richard B. Kuprewicz, President of Accufacts Inc., and Carl M. Weimer, Executive Director Pipeline Safety Trust, dated October, 2010.

22. "Accufacts' Independent Observations on the Chevron No. 2 Crude Oil Pipeline," prepared for the City of Salt Lake, Utah, by Richard B. Kuprewicz, dated January 30, 2011.

23. "Accufacts' Independent Analysis of New Proposed School Sites and Risks Associated with a Nearby HVL Pipeline," prepared for the Sylvania, Ohio School District, by Richard B. Kuprewicz, dated February 9, 2011.

24. "Accufacts' Report Concerning Issues Related to the 36-inch Natural Gas Pipeline and the Application of Appleview, LLC Premises: 7009 and 7010 River Road, North Bergen, NJ," prepared for the Galaxy Towers Condominium Association Inc., by Richard B. Kuprewicz, dated February 28, 2011.

25. "Prepared Testimony of Richard B. Kuprewicz Evaluating PG&E's Pipeline Safety Enhancement Plan," submitted on behalf of The Utility Reform Network (TURN), by Richard B. Kuprewicz, Accufacts Inc., dated January 31, 2012.

26. "Evaluation of the Valve Automation Component of PG&E's Safety Enhancement Plan," extracted from full testimony submitted on behalf of The Utility Reform Network (TURN), by Richard B. Kuprewicz, Accufacts Inc., dated January 31, 2012, Extracted Report issued February 20, 2012.

27. "Accufacts' Perspective on Enbridge Filing to NEB for Modifications on Line 9 Reversal Phase I Project," prepared for Equiterre Canada, by Richard B. Kuprewicz, Accufacts Inc., dated April 23, 2012.

28. "Accufacts' Evaluation of Tennessee Gas Pipeline 300 Line Expansion Projects in PA & NJ," prepared for the Delaware RiverKeeper Network, by Richard B. Kuprewicz, Accufacts Inc., dated June 27, 2012.

29. "Impact of an ONEOK NGL Pipeline Release in At-Risk Landslide and/or Sinkhole Karst Areas of Crook County, Wyoming," prepared for landowners, by Richard B. Kuprewicz, Accufacts Inc., and submitted to Crook County Commissioners, dated July 16, 2012.

30. "Impact of Processing Dilbit on the Proposed NPDES Permit for the BP Cherry Point Washington Refinery," prepared for the Puget Soundkeeper Alliance, by Richard B. Kuprewicz, Accufacts Inc., dated July 31, 2012.

31. "Analysis of SWG's Proposed Accelerated EVPP and P70VSP Replacement Plans, Public Utilities Commission of Nevada Docket Nos. 12-02019 and 12-04005," prepared for the State of Nevada Bureau of Consumer Protection, by Richard B. Kuprewicz, Accufacts Inc., dated August 17, 2012.

32. "Accufacts Inc. Most Probable Cause Findings of Three Oil Spills in Nigeria," prepared for Bohler Advocaten, by Richard B. Kuprewicz, Accufacts Inc., dated September 3, 2012.

33. "Observations on Proposed 12-inch NGL ONEOK Pipeline Route in Crook County Sensitive or Unstable Land Areas," prepared by Richard B. Kuprewicz, Accufacts Inc., dated September 13, 2012.

34. “Findings from Analysis of CEII Confidential Data Supplied to Accufacts Concerning the Millennium Pipeline Company L.L.C. Minisink Compressor Project Application to FERC, Docket No. CP11-515-000,” prepared by Richard B. Kuprewicz, Accufacts Inc., for Minisink Residents for Environmental Preservation and Safety (MREPS), dated November 25, 2012.

35. “Supplemental Observations from Analysis of CEII Confidential Data Supplied to Accufacts Concerning Tennessee Gas Pipeline’s Northeast Upgrade Project,” prepared by Richard B. Kuprewicz, Accufacts Inc., for Delaware RiverKeeper Network, dated December 19, 2012.

36. “Report on Pipeline Safety for Enbridge’s Line 9B Application to NEB,” prepared by Richard B. Kuprewicz, Accufacts Inc., for Equiterre, dated August 5, 2013.

37. “Accufacts’ Evaluation of Oil Spill Joint Investigation Visit Field Reporting Process for the Niger Delta Region of Nigeria,” prepared by Richard B. Kuprewicz for Amnesty International, September 30, 2013.

38. “Accufacts’ Expert Report on ExxonMobil Pipeline Company Silvertip Pipeline Rupture of July 1, 2011 into the Yellowstone River at the Laurel Crossing,” prepared by Richard B. Kuprewicz, November 25, 2013.

39. “Accufacts Inc. Evaluation of Transco’s 42-inch Skillman Loop submissions to FERC concerning the Princeton Ridge, NJ segment,” prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated June 26, 2014, and submitted to FERC Docket No. CP13-551.

40. Accufacts report “DTI Myersville Compressor Station and Dominion Cove Point Project Interlinks,” prepared by Richard B. Kuprewicz for Earthjustice, dated August 13, 2014, and submitted to FERC Docket No. CP13-113-000.

41. “Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco’s Leidy Southeast Expansion Project,” prepared by Richard B. Kuprewicz for the Princeton Ridge Coalition, dated September 3, 2014, and submitted to FERC Docket No. CP13-551.

42. Accufacts’ “Evaluation of Actual Velocity Critical Issues Related to Transco’s Leidy Expansion Project,” prepared by Richard B. Kuprewicz for Delaware Riverkeeper Network, dated September 8, 2014, and submitted to FERC Docket No. CP13-551.

43. “Accufacts’ Report to Portland Water District on the Portland – Montreal Pipeline,” with Appendix, prepared by Richard B. Kuprewicz for the Portland, ME Water District, dated July 28, 1014.

44. “Accufacts Inc. Report on EA Concerning the Princeton Ridge, NJ Segment of Transco’s Leidy Southeast Expansion Project,” prepared by Richard B. Kuprewicz and submitted to FERC Docket No. CP13-551.

45. Review of Algonquin Gas Transmission LLC’s Algonquin Incremental Market (“AIM Project”), Impacting the Town of Cortlandt, NY, FERC Docket No. CP14-96-0000, Increasing System Capacity from 2.6 Billion Cubic Feet (Bcf/d) to 2.93 Bcf/d,” prepared by Richard B. Kuprewicz, and dated Nov, 3, 2014.

46. Accufacts’ Key Observations dated January 6, 2015 on Spectra’s Recent Responses to FERC Staff’s Data Request on the Algonquin Gas Transmission Proposal (aka “AIM Project”), FERC Docket No. CP 14-96-000) related to Accufacts’ Nov. 3, 2014 Report and prepared by Richard B. Kuprewicz.

47. Accufacts’ Report on Mariner East Project Affecting West Goshen Township, dated March 6, 2015, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.

48. Accufacts’ Report on Atmos Energy Corporation (“Atmos”) filing on the Proposed System Integrity Projects (“SIP”) to the Mississippi Public Service Commission (“MPSC”) under Docket No. 15-UN-049 (“Docket”), prepared by Richard B. Kuprewicz,

dated June 12, 2015.

49. Accufacts' Report to the Shwx'owhamel First Nations and the Peters Band ("First Nations") on the Trans Mountain Expansion Project ("TMEP") filing to the Canadian NEB, prepared by Richard B. Kuprewicz, dated April 24, 2015.

50. Accufacts Report Concerning Review of Siting of Transco New Compressor and Metering Station, and Possible New Jersey Intrastate Transmission Pipeline Within the Township of Chesterfield, NJ ("Township"), to the Township of Chesterfield, NJ, dated February 18, 2016.

51. Accufacts Report, "Accufacts Expert Analysis of Humberplex Developments Inc. v. TransCanada Pipelines Limited and Enbridge Gas Distribution Inc.; Application under Section 112 of the National Energy Board Act, R.S.C. 1985, c. N-7," dated April 26, 2016, filed with the Canadian Nation Energy Board (NEB).

52. Accufacts Report, " A Review, Analysis and Comments on Engineering Critical Assessments as proposed in PHMSA's Proposed Rule on Safety of Gas Transmission and Gathering Pipelines," prepared for Pipeline Safety Trust by Richard B. Kuprewicz, dated May 16, 2016.

53. Accufacts' Report on Atmos Energy Corporation ("Atmos") filing to the Mississippi Public Utilities Staff, "Accufacts Review of Atmos Spending Proposal 2017 – 2021 (Docket N. 2015-UN-049)," prepared by Richard B. Kuprewicz, dated August 15, 2016.

54. Accufacts Report, "Accufacts Review of the U.S. Army Corps of Engineers (USACE) Environmental Assessment (EA) for the Dakota Access Pipeline ("DAPL")," prepared for Earthjustice by Richard B. Kuprewicz, dated October 28, 2016.

55. Accufacts' Report on Mariner East 2 Expansion Project Affecting West Goshen Township, dated January 6, 2017, to Township Manager of West Goshen Township, PA, and prepared by Richard B. Kuprewicz.

CITY OF NEWCASTLE
12835 Newcastle Way • Suite 200 • Newcastle, WA 98056-1316 Phone 425.649.4444 • Fax 425.649.4363 • www.ci.newcastle.wa.us

June 15, 2015

David Pyle
Energize Eastside EIS Program Manager/Senior Land Use Planner
City of Bellevue
450 110th Avenue NE
Bellevue, WA 98004

Transmitted via email: info@EnergizeEastsideEIS.org

Dear David:

The City of Newcastle has the following comments on the scope for Phase 1 of the Environmental Impact Statement for the proposed Energize Eastside project:

1. Environmental Health and Risk of Explosion: Any alternative that proposes to construct and operate transmission facilities within the existing corridor for the Olympic Pipeline creates the potential for significant environmental health and public safety impacts as a result of increased risk of explosion.

2. Aesthetics and Scenic Resources: Any alternative that proposes to construct and operate additional overhead transmission lines, either 115 kV or 230 kV, creates the potential for significant impacts to aesthetics and scenic resources. To the extent that the construction and operation of the new overhead transmission lines require removal of existing mature vegetation, these impacts will be exacerbated.

3. Plants and Animals: Any alternative that proposes to construct and operate additional overhead transmission lines, either 115 kV or 230 kV, creates the potential for significant impacts to plants and animals as a result of the need to remove existing mature vegetation.

4. Project Purpose, Need and Timing: The Environmental Impact Statement should review Puget Sound Energy's and Utility System Efficiency's analyses of the purpose, need and timing of the Energize Eastside project to determine their validity relative to established industry standards and to develop additional alternatives for the project.

5. Additional Alternatives: There are other alternatives that meet the need for the project, including, but not limited to:

- An alternative that sites and constructs smaller scale peaking power plants to prevent overloads; and,
- An alternative that utilizes a joint planning process to result in cooperation and coordination between PSE and Seattle City Light to prevent overloads.

5. Other: The Environmental Impact Statement should address all comments received on the City of Bellevue Independent Technical Analysis that were directed to the Energize EIS as indicated in Appendix D, "Ask the Consultant."

Thank you for considering these scoping comments. The City of Newcastle looks forward to working with you and the other partner cities throughout the EIS process.

Regards,

Tim McHarg, AICP
Community Development Director

CC: Rob Wyman, City Manager
Dawn Reitan, City Attorney
David Lee, Senior Planner

CITY OF NEWCASTLE
12835 Newcastle Way • Suite 200 • Newcastle, WA 98056-1316 Phone 425.649.4444 • Fax 425.649.4363 • www.ci.newcastle.wa.us

May 27, 2016

Heidi Bedwell
Energize Eastside EIS Program Manager/Senior Planner
City of Bellevue
450 110th Avenue NE
Bellevue, WA 98004

Transmitted via email: info@EnergizeEastsideEIS.org

Dear Heidi:

The City of Newcastle has the following comments on the scope for Phase 2 of the Environmental Impact Statement for the proposed Energize Eastside project:

1. Environmental Health and Risk of Explosion: Any alternative that proposes to construct and operate electrical transmission facilities within the existing corridor for the Olympic Pipeline creates the potential for significant environmental health and public safety impacts as a result of increased risk of explosion. These impacts include short term construction impacts and long term operational impacts from induced AC corrosion, seismic events, lightning strikes, arcing from transmission lines, transmission line breaks, and other catastrophic events. The Phase 2 DEIS should identify all applicable federal and state regulations for construction and operation of pipelines and electrical transmission facilities and the interaction between these two types of facilities. Significant technical and engineering analysis will need to be included in the Phase 2 DEIS to identify these impacts and to propose mitigations such as setbacks, engineering design, insulators, construction oversight, and safety inspections. It is imperative that Olympic Pipeline Company and its operator, BP Pipelines, be engaged and consulted extensively as part of the Phase 2 DEIS.

2. Aesthetics and Scenic Resources: Any alternative that proposes to construct and operate overhead electrical transmission lines creates the potential for significant impacts to aesthetics and scenic resources. Significant visual analysis will need to be included in the Phase 2 DEIS to identify these impacts and to propose mitigation. It is imperative to include a process to identify the appropriate public vantage points from which to assess these impacts and proposed mitigations based on individual neighborhood natural and built environment character. In Newcastle, these public vantage points should include public parks and rights of way. Because of the topography of Newcastle, vantage points should include locations on the west and east boundaries of the route, as well as vantage

points to the east of Coal Creek Parkway from which the project would be visible. A full range of mitigations must also be assessed, including, but not limited to, undergrounding sections of the transmission lines, a range of pole heights, a range of pole spacing, pole colors, aesthetic treatments to poles, landscaping, and tree replacement.

3. Land Use: Any alternative that proposes to construct and operate electrical transmission facilities creates the potential for property acquisition or condemnation for additional easements and/or rights of way. It is imperative to determine the extent of required property acquisition or condemnation and the resulting land use impacts. These impacts may be significant in existing neighborhoods based on the natural and built environment character. A full range of mitigations must also be assessed, including, but not limited to, designing facilities to eliminate or minimize property acquisition or condemnation, landscaping, tree replacement, screening, and development of compatible land uses and neighborhood enhancement features.

4. Plants and Animals: Any alternative that proposes to construct and operate overhead electrical transmission lines creates the potential for significant impacts to plants and animals as a result of the need to remove existing mature vegetation. These impacts may exacerbate the impacts to aesthetics and scenic resources due to loss of screening.

Thank you for considering these scoping comments. The City of Newcastle looks forward to continuing to work with you and the other partner cities throughout the EIS process.

Regards,

Tim McHarg
Community Development Director

CC: Rob Wyman, City Manager
Dawn Reitan, City Attorney
Thara Johnson, Senior Planner

COMMENT FORM - ENERGIZE EASTSIDE PHASE 2 DRAFT EIS_v2 Review Contact/Phone: Reema Shakra/213.542.6044

Please use this sheet to record your comments and send to rshakra@esassoc.com before 5:00 p.m. on December 13, 2016. Thank you!

Item No.	Page Number	Line Number	Commenter	Comment	ESA Response
1	1-8	28-30	TEM	Recommend expanding this sentence beyond just “off site alternatives.” The Partner Cities do not have the ability to require off site alternatives or other methods/technologies to solve the identified need for the project. These other alternatives included generation, conservation, supplemental distribution, etc. This paragraph should reflect all of the alternatives considered in Phase 1.	
2	1-8	30-31	TEM	Recommend revising the final sentence of this paragraph to read, “Therefore, only those alternatives determined feasible by PSE to solve the identified need are considered.”	
3	1-18		TEM	Newcastle requests review of the Environmental Health EMF summary prior to publication of the Phase 2 DEIS.	
4	1-19		TEM	Newcastle requests review of the Environmental Health Pipeline Safety summary prior to publication of the Phase 2 DEIS.	
5	1-20		TEM	There is no discussion of impacts to the Olympic Pipeline in the consideration of undergrounding the electric transmission facilities. If the loss of tree cover is discussed as an impact of undergrounding, shouldn’t impacts to OPL’s facilities be discussed as well? Please add discussion in this section that undergrounding EE is not a feasible option in all segments due to conflicts with OPL. Identify the segments where undergrounding is feasible and those where it is not feasible.	
6	2-9	25-31	TEM	Given the discussion of the history of utility facilities within the PSE corridor, would it be beneficial to discuss the history of the OPL facilities within the corridor? Alternatively, the discussion of the history of OPL could be added to Page 2-17 in the “Olympic Pipeline” section.	
7	2-15	Table 2.1-2	TEM	Please confirm typical pole height for Newcastle segment will be 85 feet. As recently as November, PSE stated pole height in the Newcastle segment could increase to 140 feet. Please apply this comment throughout the document where the 85 foot pole height for the Newcastle segment is discussed.	
8	2-29		TEM	Regarding the Newcastle Segment, please confirm that all information is current and accurate, given the zoning code requirement for PSE to locate poles a minimum of 5 feet from OPL transmission corridor easements per NMC 18.12.130C.	
9	3.1-16		TEM	Regarding the Newcastle Segment summary table, please note in the table that a portion of the Newcastle Segment is covered by the Community Business Center – Lake Boren Corridor Master Plan and is located within the Community Business Center overlay zone.	
10	3.1-39	8	TEM	Please add discussion of NMC 18.12.130.C in this section. This is the requirement for a 5 foot setback for structures from a regional utility corridor or easement. I summarized this regulation and our interpretation relative to EE in my comments on the first review draft of the Ph 2 DEIS.	
11	3.2	Throughout	TEM	Please confirm maximum pole height for Newcastle segment will be 85 feet. If analysis of visual/aesthetic impacts is based on 85 foot pole height, this will be the maximum height we will permit without supplemental analysis after publication of the FEIS. Newcastle will not support a modification of pole height in the Newcastle segment between the Ph 2 DEIS and FEIS.	
12	3.6-2		TEM	Please add Lake Boren Park to Figure 3.6-1, Recreation Sites in the Study Area.	
13	3.6-6		TEM	Please add Lake Boren Park to Table 3.6-1, Recreation Sites in the Study Area.	
14	3.6-27		TEM	Please add Lake Boren Park to Sec 3.6.5.12. This park is not adjacent to the corridor and would not be impacted. However, consistent with other unaffected parks in other segments, this should be stated in the discussion.	
15	3.7-9		TEM	Why has KCHPP not been consulted directly regarding the potential listing of the Eastside Transmission System in the National Register? Newcastle works closely with KCHPP on all projects with potential impacts to historic resources. PSE and ESA should be following this established protocol.	
16	3.7-10		TEM	The Newcastle Cemetery is listed on the KC Register. Has KCHPP been consulted directly regarding potential impacts to the cemetery? Newcastle works closely with KCHPP on all projects with potential impacts to historic resources. PSE and ESA should be following this established protocol.	
17	3.10-4	2	TEM	Please add discussion in this section that undergrounding EE is not a feasible option in all segments due to conflicts with OPL. Identify the segments where undergrounding is feasible and those where it is not feasible.	

18	3.10-10	14	TEM	Please add discussion in this section that undergrounding EE is not a feasible option in all segments due to conflicts with OPL. Identify the segments where undergrounding is feasible and those where it is not feasible. Would the infeasibility of undergrounding in specific segments alter the ability to spread the costs among groups of 10,000 or 100,000 payees?	
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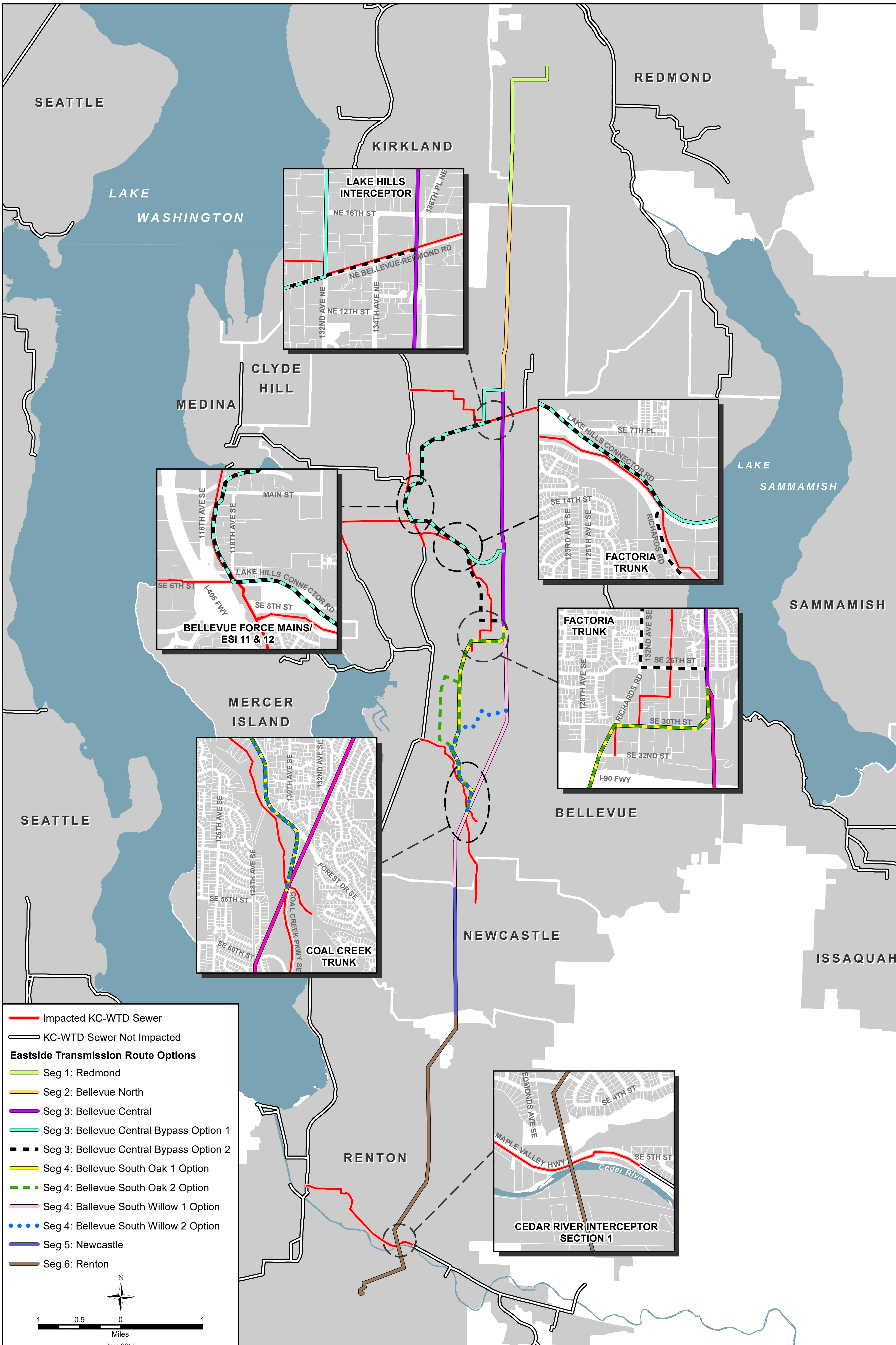


King County
Department of Natural Resources and Parks
Wastewater Treatment Division

File Name: Q:\WTD\Projects\EnergizeEastside\Projects\EnergizeEastsideTransmissionLine_20170607.mxd crosss

Phase 2 Draft EIS

Approximate Locations of KC-WTD Conveyance Impacted by Eastside Transmission Route Options

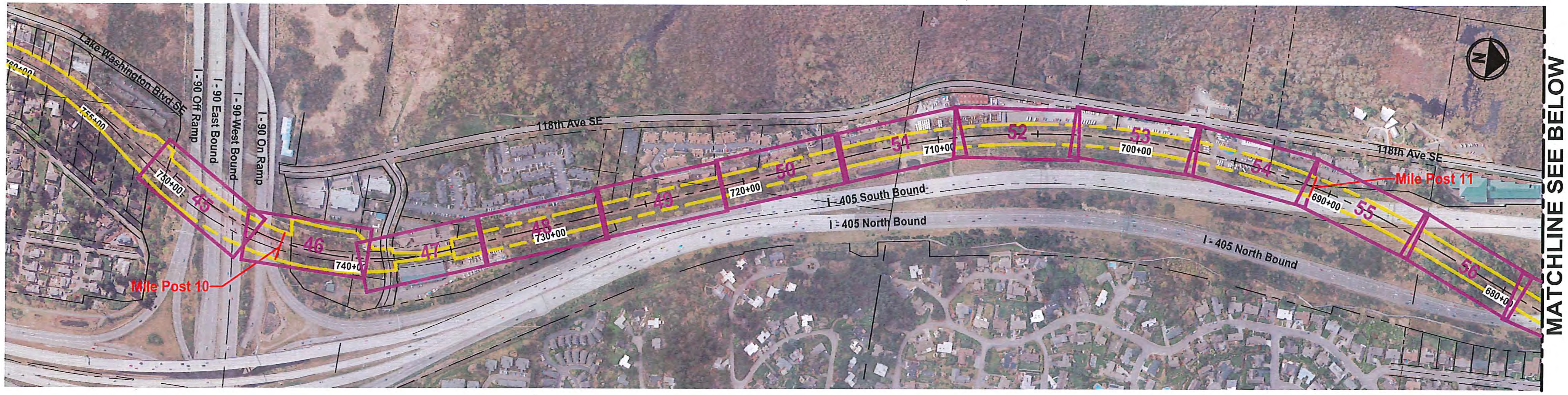
King County
PARKS
Your Big Backyard

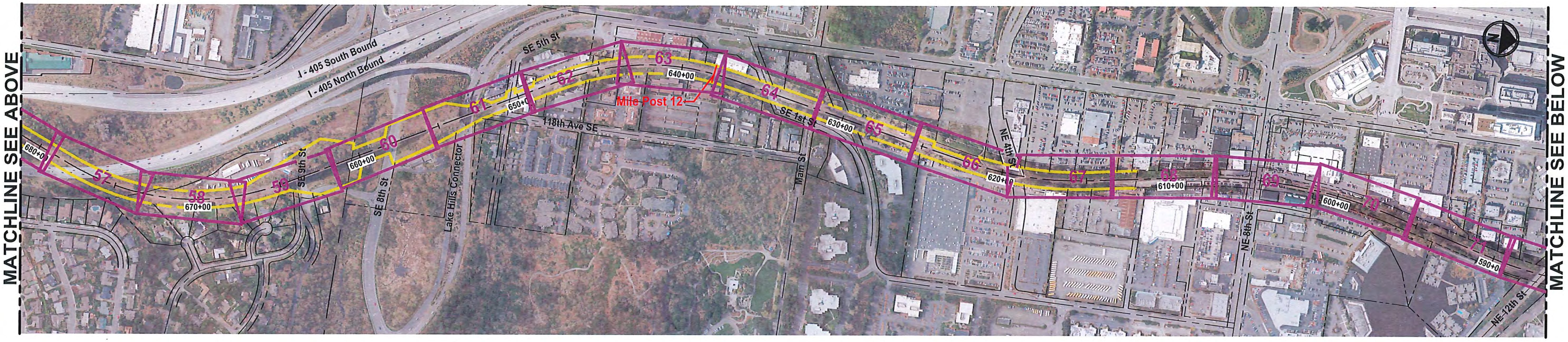
EASTSIDE RAIL CORRIDOR REGIONAL TRAIL FINAL MASTER PLAN

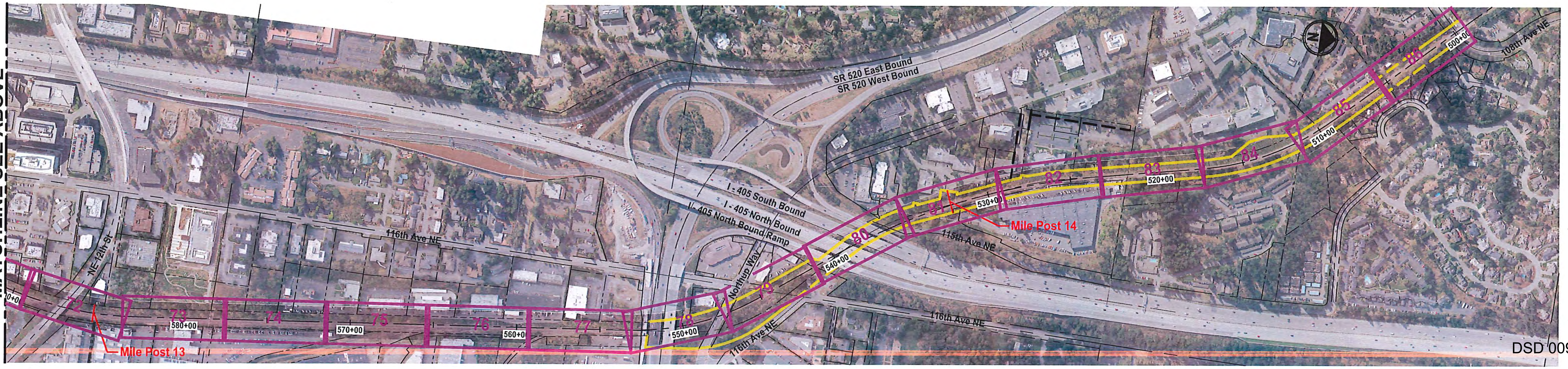
Wilburton Segment Index

VOLUME 2

SCALE IN FEET
0 300 600







DSD 009403

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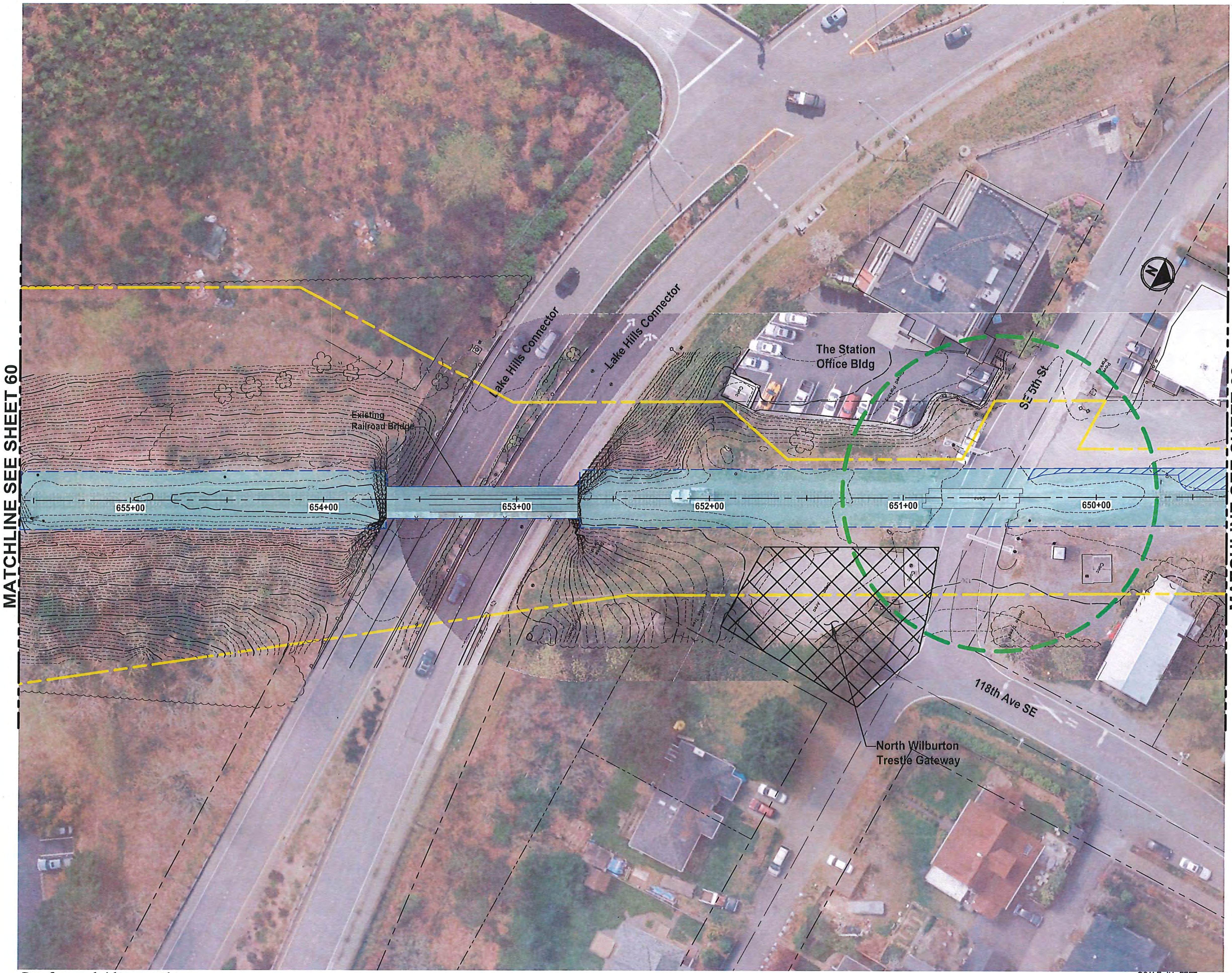


Preferred Alternative

King County
PARKS
Your Big Backyard

EASTSIDE RAIL CORRIDOR REGIONAL TRAIL FINAL MASTER PLAN

Wilburton Segment

VOLUME 2, SHEET 61

LEGEND:

TRAIL PLANNING ENVELOPE

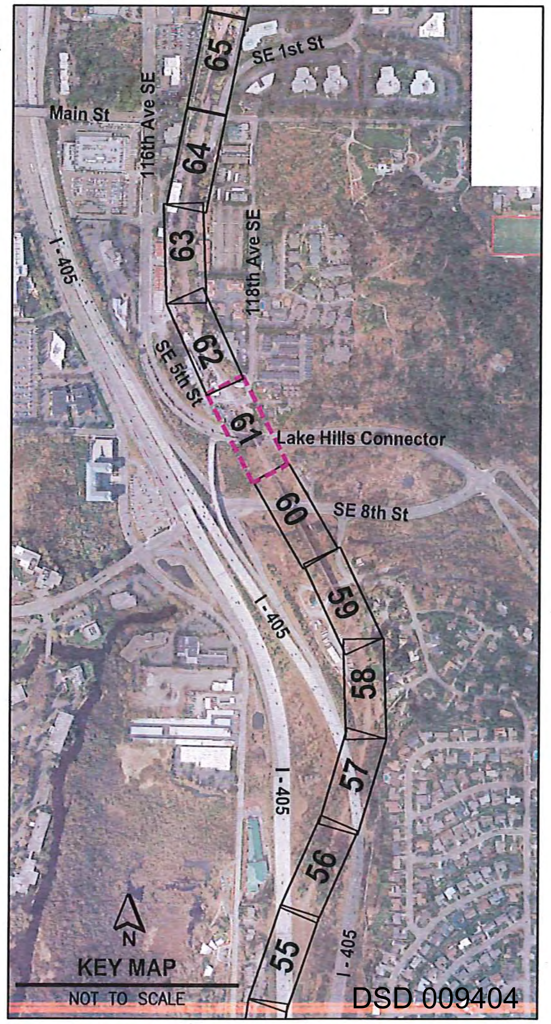
TRAIL PLANNING ENVELOPE WITH EXISTING LAND USE

ERC RIGHT-OF-WAY

MILE POST MARKER

TRAIL ACCESS LOCATION

WETLAND BOUNDARY



DSD 009404

King County
PARKS
Your Big Backyard

EASTSIDE RAIL CORRIDOR REGIONAL TRAIL FINAL MASTER PLAN

Wilburton Segment

VOLUME 2, SHEET 62

Preferred Alternative

SCALE IN FEET
0 25 50

LEGEND:

TRAIL PLANNING ENVELOPE

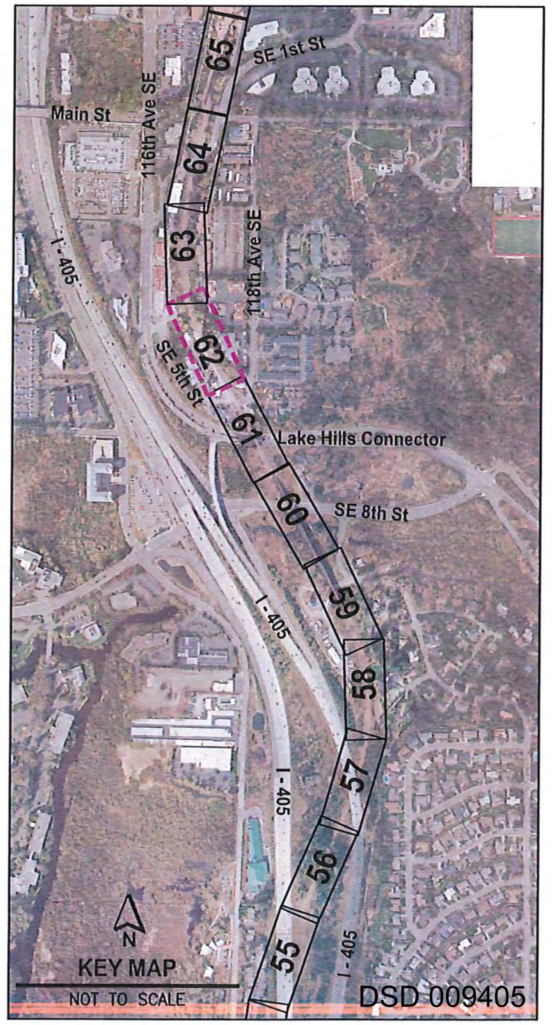
TRAIL PLANNING ENVELOPE WITH EXISTING LAND USE

ERC RIGHT-OF-WAY

MILE POST MARKER

TRAIL ACCESS LOCATION

WETLAND BOUNDARY



KEY MAP
NOT TO SCALE

DSD 009405

King County
PARKS
Your Big Backyard

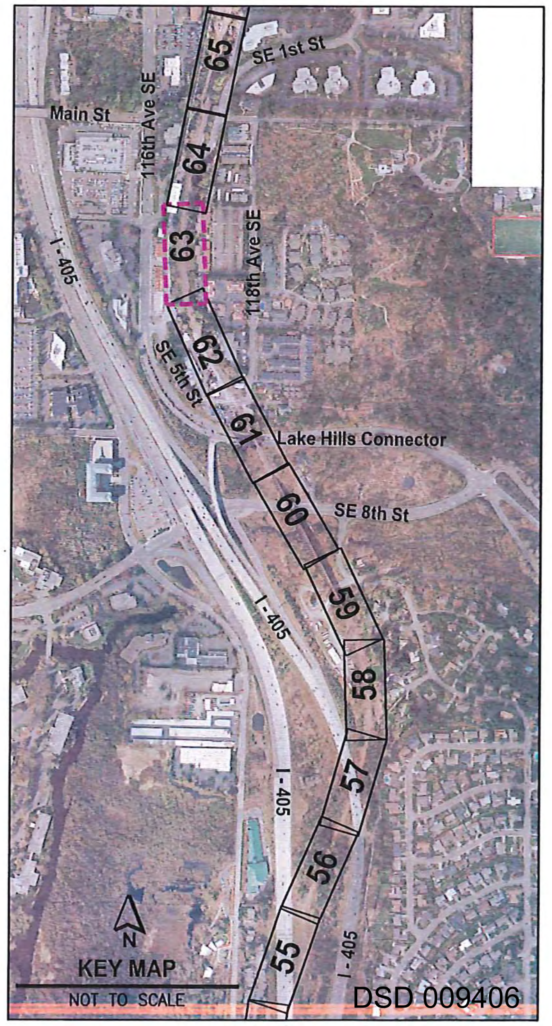
EASTSIDE RAIL CORRIDOR REGIONAL TRAIL FINAL MASTER PLAN
Wilburton Segment
VOLUME 2, SHEET 63

Preferred Alternative

SCALE IN FEET
0 25 50

LEGEND:

- TRAIL PLANNING ENVELOPE
- TRAIL PLANNING ENVELOPE WITH EXISTING LAND USE
- ERC RIGHT-OF-WAY
- MILE POST MARKER
- TRAIL ACCESS LOCATION
- WETLAND BOUNDARY



KEY MAP
NOT TO SCALE

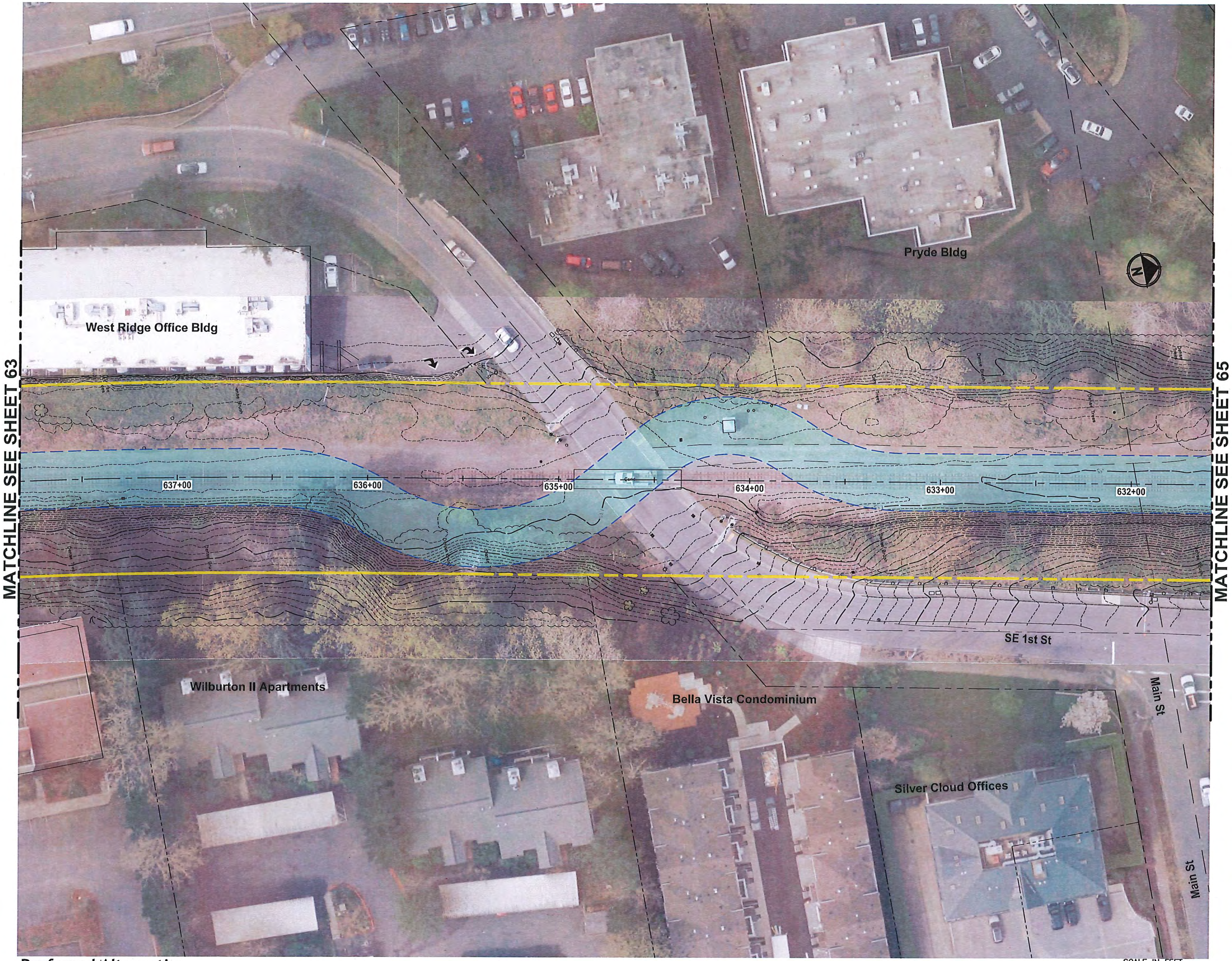
DSD 009406

King County
PARKS
Your Big Backyard

EASTSIDE RAIL CORRIDOR REGIONAL TRAIL FINAL MASTER PLAN

Wilburton Segment

VOLUME 2, SHEET 64



Preferred Alternative

SCALE IN FEET
0 25 50

LEGEND:

TRAIL PLANNING ENVELOPE

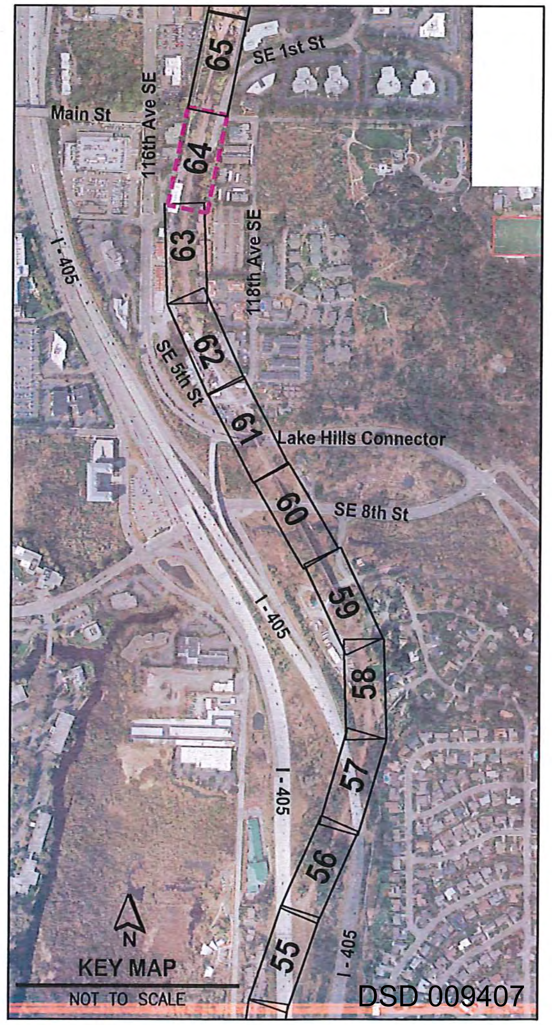
TRAIL PLANNING ENVELOPE WITH EXISTING LAND USE

ERC RIGHT-OF-WAY

MILE POST MARKER

TRAIL ACCESS LOCATION

WETLAND BOUNDARY



KEY MAP
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DSD 009407

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King County
PARKS
Your Big Backyard

EASTSIDE RAIL CORRIDOR REGIONAL TRAIL FINAL MASTER PLAN

Wilburton Segment

VOLUME 2, SHEET 65

Preferred Alternative

SCALE IN FEET
0 25 50

LEGEND:

TRAIL PLANNING ENVELOPE

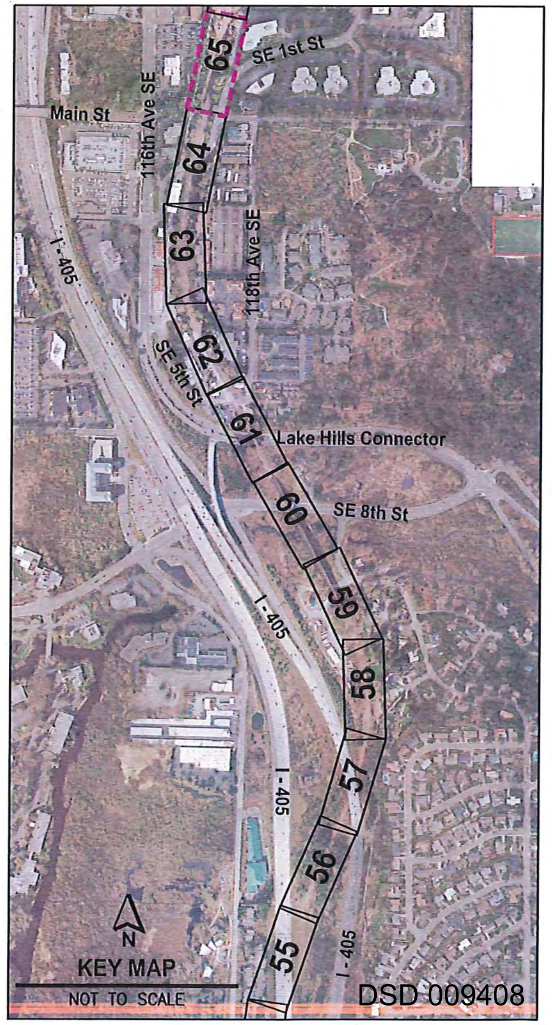
TRAIL PLANNING ENVELOPE WITH EXISTING LAND USE

ERC RIGHT-OF-WAY

MILE POST MARKER

TRAIL ACCESS LOCATION

WETLAND BOUNDARY



KEY MAP
NOT TO SCALE

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1. Don Marsh · CENSE
Renton/Newcastle Public Hearing
~~[illegible]~~ 5.23.17

May 23, 2017

My name is Don Marsh, and I am president of CENSE, the Coalition of Eastside Neighborhoods for Sensible Energy, an all-volunteer organization. For the past three years, we have been shedding light on PSE's Energize Eastside project, engaging multiple industry experts to help us understand all aspects of this proposal.

We have identified seven issues that need to be corrected in the Phase 2 Draft EIS.

1. **FINAL ROUTE:** The Phase 1 Draft EIS stated that the EIS would be divided into two phases. "The Phase 1 Draft EIS broadly evaluates the general impacts and implications associated with feasible and reasonable options ... The Phase 2 Draft EIS will be a project-level evaluation, describing impacts at a site-specific and project-specific level." From this description, we expected to see specific proposals for pole locations, pole designs, and a list of the specific trees that would be removed. Without these specifics, how can the public evaluate or comment on the environmental impacts of this project?

   We request the cities to publish a Supplemental EIS when a final route is chosen and the specific information regarding poles and trees is known.

2. **NEED:** The EIS states it is important to understand the "need for the project, to enable a thorough understanding of the project's objectives." However, the EIS doesn't include any data or charts to substantiate the need. It only says that PSE determined there was a need, and it cites two outdated documents that are collectively known as the "Eastside Needs Assessment." Eastside demand for electricity has not increased in the way these documents assumed.

   We request that the EIS present ten years of historical data for Eastside demand and an updated forecast so the public can observe the trends over time and develop a "thorough understanding of the project's objectives."

3. **RELIABILITY:** The EIS states that Energize Eastside will improve electrical reliability. The public understands this to mean there will be fewer or shorter power outages after the project is built. However, PSE has stated that Energize Eastside will not improve reliability metrics for any neighborhood in Bellevue.

   We request that the EIS quantify the projected improvement in reliability using an industry standard metric such as the average reduction in outage duration per customer per year. Using this metric, stakeholders can compare the cost effectiveness of PSE's preferred solution with other alternatives.

4. **PIPELINE SAFETY:** The EIS references a report on pipeline safety produced by the safety consultant DNV-GL. However, the EIS does not highlight the top two findings of the report: first, that PSE's preferred route (known as "Willow 2") violates safety standards and has an "unpredictable risk range." Second, that PSE's alternate route ("Willow 1") would not be safe without significant design changes. These are important factors in the choice of routes and the

safety of nearby homes and schools.

We request that the EIS specifically describe how DNV-GL's recommendations will be incorporated into the project's design.

5. **SEISMIC HAZARDS:** The EIS states that seismic hazards are "less than significant" and do not require further study. The public still has unanswered questions. What might happen if the Seattle Fault, which roughly parallels the I-90 freeway, were to slip up to 10 feet during a major earthquake? Would the Olympic pipelines, running perpendicular to the fault be ruptured? Would higher voltage levels and bigger poles made of conductive steel pose any greater risk of igniting a catastrophic fire? A man-made catastrophe might follow a natural disaster, requiring the attention of emergency responders at the same time they are needed elsewhere.

   We request that the EIS quantify how much Energize Eastside might increase risk in these circumstances.

6. **ALTERNATIVES:** The EIS states that the Eastside will face rolling blackouts in the summer of 2018. Even though we disagree with that prediction, the only solution that could be built fast enough to meet that timeline is a grid battery. PSE says its Richards Creek substation would take 18 months to build. Even if construction began today, the substation would not be operational by next summer. PSE's solution does not meet the company's required timeline and must be eliminated as a viable alternative to address the stated need.

   We request that the EIS re-evaluate the potential of batteries using current data from grid battery installations such as the one Tesla built in Southern California to protect customers from rolling blackouts. That battery started operation just 3 months after the contract was signed.

7. **CHANGING CONDITIONS:** Last week, the Bonneville Power Administration canceled a $1.2 billion transmission line in southwestern Washington that would have carried increased electricity to California. Changing demand forecasts reduced the need for the line. Instead, the agency found it could save customers hundreds of millions of dollars by employing modern technology such as flow control devices and grid batteries.

   We request that the EIS examine how BPA's reasoning applies to PSE's proposal.

Thank you for considering these changes. We look forward to answers in the Final EIS or Supplemental EIS.

Sincerely,

Don Marsh
4411 137th Ave. SE, Bellevue, WA 98006

② Larry Johnson
Renton/Newcastle Public Hearing
5.23.17

Citizens for Sane Eastside Energy (CSEE)

8505 129th Ave. SE
Newcastle, WA 98056
tel.: 425 227-3352
email: larry.ede@gmail.com

May 22, 2017

Ms. Heidi Bedwell
Energize Eastside EIS Program Manager
City of Bellevue Development Services Dept.
450 110th Ave. NE
Bellevue, WA 98004 <u>submitted by email to info@EnergizeEastsideEIS.org</u>

Re: Comments regarding Energize Eastside Phase 2 Draft EIS

According to section 1.3 of the Phase 2 Draft EIS, "the lead agency is responsible for ensuring that a proposal that is the subject of environmental review is properly defined. **The process of defining the proposal includes an understanding of the need for the project, to enable a thorough understanding of the project's objectives**" (emphasis added). CENSE's expert on Northwest regional power planning, Richard Lauckhart, submitted on May 17, 2017, a white paper detailing the complete failure of the EIS process and EIS drafts to address the fundamental issue of project need. His comments are attached hereto as Attachment A.

We agree. It is manifestly absurd to blindly push ahead with evaluating a proposed project's potential environmental impacts if the project itself makes no sense. And certainly nothing could be more central to the project's "No Action" "alternative" than proof that building Energize Eastside ("EE") would satisfy no legitimate need.

Citizens for Sane Eastside Energy (CSEE) is composed chiefly of persons who are most directly threatened by the dangers to life and property if PSE's proposed Energize Eastside project is allowed to go forward. While some may find it easy to dismiss CSEE as "NIMBY" ("Not In Our Back Yard"), the truth, no matter by whom spoken, still remains the truth. We submit EE is driven solely by PSE's foreign investor owners who stand to make up to a handsome 9.8% return on EE if built. That is the real motivation for PSE's wanting to build a boondoggle that should be in *no-one's* back yard.

It is difficult to assess the many problems associated with EE, not only because of a number of complex technical issues involved, but also because PSE has been from the outset duplicitous and fraudulent in presenting a number of misleading justifications for the project.

There are at least four major areas of such deceit underlying PSE's determined efforts to hard-sell Energize Eastside that will be addressed here. They are:

1. EE is based on a failed ColumbiaGrid flow study that included exaggerated, false NERC criteria.

The project's foundational justification is a uniquely strange, failed load flow study conducted by ColumbiaGrid in 2013, the results of which (the studies did not "solve") were dismissed by ColumbiaGrid then as something one could comfortably ignore since the studies bizarrely *exceeded* NERC requirements.[1] But those unnecessarily beefed-up, false criteria for that failed "informational" study nevertheless found their way into the Quanta flow studies that are fundamental to PSE's argument for the supposed need for EE. For further details, see Attachment A.

In short, the core rationale for EE is based on a fairy tale.

The fact that PSE's aggressive pitches for EE are founded in myth is further buttressed by the fact that PSE steadfastly refuses to release to CENSE's expert the data inputs used in the Quanta studies done under PSE's supervision and control, even though FERC has made it clear to PSE that CENSE's expert is entitled to see and study that information.

The Lauckhart-Schiffman flow studies are the only untainted studies ever done for EE, and they show no need for EE. Yet an email from PSE's Bradley Strauch to Mark Johnson of ESA, dated 3/25/2016, attached hereto as Attachment B, reveals that PSE still clings to the exaggerated "informational" ColumbiaGrid flow studies criteria beyond those required of NERC when criticizing the Lauckhart-Schiffman studies for not meeting those absurd criteria which Strauch mischaracterizes as "minimum:"

> "...as we have already stated in PSEs Phase 1 DEIS comments, the Lauckhart and Schiffman document does not meet the minimum federally required planning standards necessary to provide or develop meaningful results; therefore, it has no relevance when evaluating PSE [sic] thoroughly vetted project proposal."

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[1] See page 12 of the ColumbiaGrid 2013 System Assessment Report, first full bulleted paragraph, which includes this language: **"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"** (emphasis added). That is to say, the study used three major failure events occurring in the scenario tested, or what NERC calls an "N-1-1-1 event," when only two critical system component failures are required for NERC compliance, i.e. an "N-1-1 event." ColumbiaGrid is not known to do studies for "information purposes" only, and we submit that PSE wanted these bizarre studies done in order to create a justification for EE. The ColumbiaGrid 2013 System Assessment Report is available online at https://www.columbiagrid.org/Notices-detail.cfm?NoticeID=109.

Ironically, it is rather the PSE/Quanta studies that are wrong and irrelevant, since their foundation is that failed, bogus ColumbiaGrid study.[2]

CSEE submits that a project of EE's magnitude, costing $200 to $300 million and portending catastrophic and irreversible consequences, should be solidly based on complete and totally transparent flow studies, trust, and clarity, involving simultaneously all stakeholders. If done fairly and openly, all parties affected by this controversial project stand to benefit.

2. PSE has misrepresented its desire and efforts to seek an alternative route with Seattle City Light.

One must conclude from the current EIS draft that PSE has apparently succeeded so far in selling the notion that PSE tried but failed to obtain Seattle City Light's (SCL's) permission to

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[2]Probably aware that its rationale for EE as a reliability solution has become flimsy, PSE's justification for EE has morphed into one based on the need for a vague "system upgrade," discussed further in Item 4 in this document and Attachment F. A chronology:

1) October 2013. PSE/Quanta release their Eastside Needs Assessment. It states the need was identified with a power flow model (a/k/a load flow model). They indicate their input assumptions include 1,500 MW to Canada and a shut down of local generation from several peaker plants (built specifically to meet reliability emergencies!). This results in the very exaggerated NERC N-1-1-1 event that ColumbiaGrid found to be irrelevant and thus merely "informational."

2) December 2013. PSE (without Quanta) provides an Executive Summary of the Eastside Needs Assessment. That Executive Summary provides the infamous "Eastside Capacity and load line (The Problem)" graph where brownouts could start as soon 2017. The Executive Summary indicates that Quanta ran load flow studies, but the Executive Summary changes the justification for EE's need: the need to meet generic customer demand as shown in the "The Problem" graph (included in Attachment F-1 hereto). Note that Quanta did not sign on to this Executive Summary; it is a PSE-developed document.

3) 2014-2015: PSE draws a number of questions and criticisms regarding the assumptions in the Quanta load flow studies. Eventually, PSE's lead project consultant, Mark Williamson, goes on the record to admit that including the 1,500 MW to Canada in the Quanta studies was a mistake (YouTube video at https://youtu.be/UixzsxOmPic), yet PSE has never done anything to correct that mistake or counteract the wrong conclusions others have made from that mistake. PSE also cannot explain why it had Quanta shut down six local generators (peaker plants) in the load flow study. Not surprisingly, PSE has abandoned the myth that EE's need derives from a load flow study. Yet they refuse to re-run the load flow study without 1,500 MW to Canada or with all PSE generators running. The Lauckhart-Schiffman's studies do just that, however, resulting in their conclusion that there is no need for EE.

For the PSE/Quanta 1,500 MW assumption, see page 8 of the Eastside Needs Assessment at https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/Eastside_Needs_Assessment_Final_Draft_10-31-2013v2REDACTEDR1.pdf.
For the PSE/Quanta shut down of local generation, see Table 4-4 on page 32 of the same document.

4) 2016: PSE begins focusing on the aforementioned "Problem" graph that it published in its December 2013 Executive Summary. PSE revises that graph to include a mysterious "capacity" line at 700 MW and an exaggerated Eastside load growth that is some ten times greater than what Seattle City Light predicts for booming Seattle. See Attachment F-2. PSE removes the embarrassing 2013 graph from its website and abandons use of it as the basis for the need for EE.

5) 2017: PSE's selling point for EE is now: "Nothing has been done to update the Eastside grid for 50 years," a blatantly false claim refuted in Attachment F.

share SCL's Eastside line as a route for EE, a route PSE spokespersons repeatedly assured citizens at public meetings was PSE's "first choice" for EE.

A variant of this misleading narrative is found on the FAQ page of PSE's website dedicated to EE:

> "**Routing**
>
> " •Why can't PSE use the Seattle City Light corridor that runs from Redmond to Renton?
>
> "PSE **looked into** using the Seattle City Light corridor and **yes, if rebuilt, the corridor could work to meet the Eastside's energy needs.** However, PSE has been told by Seattle City Light that this corridor is a key component of their transmission system and **is not available for our use**." (emphasis added; from http://energizeeastside.com/faqs)

The underlined words in the last sentence of that paragraph are a link to a June 2, 2014, letter from Uzma Siddiqi, SCL's System Planning Engineer, to the City of Bellevue's Mr. Nicholas Matz, Attachment C, where she writes:

> "SCL foresees current and future uses of these existing east side facilities and **prefers not to utilize** SCL's transmission lines for PSE's native load service needs." (emphasis added).

"Prefers not to utilize" is hardly the same thing as "refuses to allow." And note that Ms. Siddiqi's letter is directed to a City of Bellevue employee and not to PSE, who in fact never even tried to make a formal request for sharing those lines. That conclusion is made crystal clear in an April 25, 2017, letter from SCL's Sephir Hamilton, Engineering and Technology Innovation Officer, to me, Attachment D:

> "As your letter mentions, although PSE and Seattle City Light have had limited discussions about PSE's Energize Eastside Project, **PSE has never formally requested transmission service on Seattle City Light's Eastside transmission lines. Obviously, if PSE would make a formal request for transmission service on Seattle City Light's Eastside lines, Seattle City Light would respond appropriately.**" (emphasis added)

CSEE submits that PSE never tried to act on its "first choice" for an EE route because to have done so would have deprived its owners of a highly lucrative project, boondoggle though it be.

Further, virtually none of the information PSE has provided the authors of this latest draft EIS about the very real and superior SCL Eastside lines alternative to EE (assuming *arguendo*

something like EE is needed) is accurate. In the May 11, 2017, letter of CENSE's expert, Richard Lauckhart, to Ms. Heidi Bedwell, Attachment E, there are paragraphs cited from the current draft EIS which in part or in whole contain incomplete or erroneous information, with his rebuttals of same. Those comments further buttress the conclusion that if PSE were to follow the steps as outlined in FERC Order 888, SCL would have little choice but to cooperate with PSE in coming up with a far more workable, less expensive, and above all, less dangerous solution than EE, assuming there is any objective need for EE.

The Phase 2 draft EIS is woefully inadequate and simply wrong when it comes to the SCL Eastside line alternative, and it needs to be completely done over again without PSE pressure or interference.

3. PSE has mounted an aggressive PR campaign, similar in kind and credibility to a political campaign,[3] in order to mislead the public into thinking EE will fulfill a need to meet future Eastside growth that PSE claims is 10 times that of booming Seattle.

For details, see Attachment F-1 and F-2.

4. PSE repeatedly and falsely advertises the lie that EE is needed as a "long overdue Eastside grid upgrade" despite several expansions of the Eastside grid in the past two decades.

For details, see Attachment F-2 through F-4.

Sincerely,

Larry G. Johnson
Attorney at Law, WSBA #5682
Citizens for Sane Eastside Energy (CSEE)

cc: CENSE

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[3] To head up PSE's aggressive PR campaign, it went as far as Wisconsin to hire lawyer Mark Williamson to act as its chief consultant for getting the project through the approval processes. Williamson's website brags about his prowess in getting projects like Energize Eastside approved by treating them the same way as a political campaign: "Williamson has developed a strategic communications technique patterned on 'election campaigning' – polling, message development and communication – tools that he employs, and has for years, to get utility projects approved, sited, built and on-line. He is a hands-on utility executive that gets the job done from day one." http://prwcomm.com/now/?page_id=71. PSE's strategy is all about winning rather than fairly arguing the merits of the project or considering possible options that would better serve the public interest.

May 17, 2017

Attachment A - 1

Heidi Bedwell
City of Bellevue Development Services Department
450 110th Avenue NE
Bellevue, WA 98004

Re: Comment for Energize Eastside Phase 2 Draft EIS

Dear Ms. Bedwell:

I am writing to submit comments on the Energize Eastside Phase 2 Draft EIS.

<u>These comments relate to the "need" for Energize Eastside</u>

As I have mentioned in previous submissions, the need for Energize Eastside has never been established. I have provided significant documentation which supports the idea that it is not only not needed, but that PSE is attempting to push this project through using multiple baseless justifications.

The debate on need is rooted in a dispute about a proper load flow study. What keeps us from an open and honest discussion of the facts on which this entire project is based is PSE's refusal to allow any kind of scrutiny into the assumptions used by Quanta in load flow studies which they conducted for PSE. These studies, along with the studies conducted by USE, are the centerpieces of the justification for Energize Eastside.

PSE continues to refuse to show the details of the Quanta load flow study despite multiple requests and despite the fact that the Federal Energy Regulatory Commission (FERC) says I have a legitimate need to see this information. Yet the EIS process continues to march forward, presumably to its completion, while multiple red flags exist concerning how Quanta did their load flow study. The EIS staff continues to sidestep any real resolution of these red flags.

A $200-$300 million project with devastating and irrevocable consequences cannot be subject of guess work. No permit for Energize Eastside should be issued until a truly transparent, scientific process has been completed.

A new load flow study needs to be done in an open and transparent fashion with input from all stakeholders. That is what I asked FERC to require ColumbiaGrid to do. But FERC said that since PSE had not asked for Energize Eastside to be a part of the Regional Plan, then Energize Eastside is not subject to Order 1000. If PSE had asked for Energize Eastside to be part of the regional plan, this would have required ColumbiaGrid to do the studies in an open and transparent fashion with full stakeholder input. The ColumbiaGrid Regional Plan looks out over a ten-year planning horizon and identifies the transmission additions necessary to ensure that the parties to the ColumbiaGrid Planning and Expansion Functional Agreement can meet their commitments to serve regional load and meet firm transmission service commitments.

It appears there were many reasons that PSE chose not to ask for Energize Eastside to be a part of a Regional Plan. I believe this was a deliberate step on their part.

- If Energize Eastside were part of a regional plan, then FERC would say how much BPA would pay for Energize Eastside BPA would pay PSE. By doing that, PSE pays less out of its own pocket. And that would mean a smaller increase in the PSE ratebase. Which means smaller PSE investment that will be given the 9.8% return by the WUTC. Macquarie wants to invest more money in PSE new ratebase. It does not help if BPA pays a lot of that money because that reduces what Macquarie spends and therefore the amount of the return on the investment.
- If part of a Regional Plan, ColumbiaGrid would have been required to do the studies (not Quanta) and ColumbiaGrid studies would have to be done in an open and transparent fashion with stakeholder input, and
- If part of a Regional Plan, then stakeholders would also get to identify alternatives. Those alternatives would include, for example,
    - Meeting any identified needs with DSM
    - Simply increasing the capacity of the Talbot Hill transformer
    - Building a small peaker plant somewhere on the Eastside
    - Utilizing the SCL Transmission line option.

According to section 1.3 of the EIS, "*the lead agency is responsible for ensuring that a proposal that is the subject of environmental review is properly defined. The process of defining the proposal includes an* ***understanding of the need for the project****, to enable a thorough understanding of the project's objectives*." Without an open and transparent load flow study with stakeholder input, there can be no shared understanding of the need for the project. The EIS staff needs to ensure full accordance with this statement before the EIS is finalized.

Sincerely,

Richard Lauckhart

Richard Lauckhart
Energy Consultant
44475 Clubhouse Drive
Davis, California 95618
530-759-9390
lauckjr@hotmail.com

From:	Strauch, Bradley R <bradley.strauch@pse.com>
Sent time:	03/25/2016 11:24:12 AM
To:	Mark Johnson <MJohnson@esassoc.com>
Cc:	records@energizeeastsideeis.org; Bedwell, Heidi; Claire Hoffman <CHoffman@esassoc.com>; Nedrud, Jens V <jens.nedrud@pse.com>
Subject:	RE: E2- Questions for PSE regarding the Lauckhart-Schiffman report
Attachments:	Lauckhart-Schiffman Draft responses_20160318 PSE Response.docx

Attachment B

Mark,

PSE is providing the following information in response the questions posed in the attachment. However, as we have already stated in PSEs Phase 1 DEIS comments, the Lauckhart and Schiffman document does not meet the minimum federally required planning standards necessary to provide or develop meaningful results; therefore, it has no relevance when evaluating PSEs thoroughly vetted project proposal.

If you have any additional questions, please let us know as we will be glad to assist.

Brad Strauch

Sr. Land Planner/Environmental Scientist

PUGET SOUND ENERGY

P.O. Box 97034, PSE-09N

Bellevue, WA 98009-9734

Office: 425-456-2556

Fax: 425-462-3233

Cell: 425-214-6250

From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Monday, March 21, 2016 6:25 PM
To: Strauch, Bradley R
Cc: Heidi Bedwell; Claire Hoffman; records@energizeeastsideeis.org
Subject: E2- Questions for PSE regarding the Lauckhart-Schiffman report

Brad
As we mentioned a couple weeks back, we have a few questions that arose from reading the Lauckhart Schiffman Report. We are trying to address issues raised by the report in the comment summary, the first draft of which is due very soon, so we ask for a quick turnaround on these. The attached is a draft section we have created to respond to the issues raised. Our intent here is to clarify facts that we believe PSE can best provide, and the questions are as close-ended as we could make them. Could you take a look and let us know how quickly you can turn this information around? If we could have answers by the end of the week, that would be great.

Mark S Johnson

Director

ESA | Northwest Community Development

5309 Shilshole Avenue NW, Suite 200

Seattle, WA 98107

206.789.9658 main

206.576.3750 direct | 206.550.0723 cell

mjohnson@esassoc.com <mailto:mjohnson@esassoc.com> | <www.esassoc.com>

Follow us on Facebook <http://www.facebook.com/pages/Environmental-Science-Associates/347741357652?

Attachment C

City of Seattle

Seattle City Light

June 2, 2014

Mr. Nicholas Matz
Planning & Community Development Department
450 110th Avenue NE
P.O. Box 90012
Bellevue, WA 98009

Dear Mr. Matz:

Seattle City Light (SCL) has transmission facilities that run through the City of Bellevue and other jurisdictions on the east side of Lake Washington. The SCL transmission lines in Bellevue were installed in the early 1940's to transfer power from hydro-generation in the North Cascades to the west side of Lake Washington. Puget Sound Energy (PSE) has lines in the same general vicinity which primarily serve the PSE customer load east of Lake Washington.

SCL's double circuit 230kV transmission lines are used to meet current and future operating needs. Specifically, SCL needs the connectivity and capacity of these transmission lines to:

- Maintain a contiguous Point of Delivery for transmission service from BPA;
- Serve existing load growth and maintain reliability;
- Provide for future SCL growth;
- Support regional transmission flows; and
- Meet NERC reliability requirements.

SCL foresees current and future uses of these existing east side facilities and prefers not to utilize SCL's transmission lines for PSE's native load service needs.

Please contact me via email at uzma.siddiqi@seattle.gov if you have any questions.

Sincerely,

Uzma Siddiqi

Uzma Siddiqi, PE
System Planning Engineer

cc: Phil West
Tuan Tran

Seattle City Light

700 5th Ave. | P.O. Box 34023 | Seattle WA 98124-4023
TEL (206) 684-3000 TTY/TDD (206) 684-3225 FAX (206) 625-3709
seattle.gov/light
twitter.com/SEACityLight facebook.com/SeattleCityLight

Attachment D

April 25, 2017

Mr. Larry Johnson
Attorney at Law
Citizens for Sane Eastside Energy (CSEE)
8505 129th AVE SE
NEWCASTLE, WA 98056

Re: PSE's Energize Eastside Project

Dear Mr. Johnson,

This letter responds to your letter dated March 20, 2017 to our General Manager, Larry Weis. We appreciate your interest in the regional energy issues and are aware of your concerns regarding Puget Sound Energy's ("PSE") Energize Eastside Project. As your letter mentions, although PSE and Seattle City Light have had limited discussions about PSE's Energize Eastside Project, PSE has never formally requested transmission service on Seattle City Light's Eastside transmission lines.
Obviously, if PSE would make a formal request for transmission service on Seattle City Light's Eastside lines, Seattle City Light would respond appropriately. Likewise, Seattle City Light remains willing to discuss options with PSE regarding the potential use of Seattle's Eastside lines. However, as PSE's project located entirely within its own service territory, PSE's project remains within PSE's discretion.

In addition, the Energize Eastside Project is not subject to the Order No. 1000 regional approval process because it is located completely within Puget Sound's service territory, it was included in Puget Sound's local transmission plan to meet Puget Sound's reliability needs, and neither Puget Sound, nor any other eligible party, requested to have the project selected in the regional transmission plan for purposes of cost allocation.

We trust that this resolves the concerns expressed in your March 20th letter with respect to Seattle City Light.

Sincerely,

Sephir Hamilton
Engineering and Technology Innovation Officer
Seattle City Light

cc: Larry Weis, General Manager, Seattle City Light

Attachment E -1

May 11, 2017

Heidi Bedwell
City of Bellevue Development Services Department
450 110th Avenue NE
Bellevue, WA 98004

Re: Comment for Energize Eastside Phase 2 Draft EIS

Dear Ms. Bedwell:

I am writing to submit comment on the Energize Eastside Phase 2 Draft EIS.

This comment relates to pages 2-52 of the Phase 2 Draft EIS. In particular section 2.2.1 "Seattle City Light Transmission Line" option.

In order to understand how this option works, one needs to be familiar with FERC's ProForma Open Access Transmission Tariff (OATT). The FERC ProForma Open Access Transmission Tariff can be found at:
https://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890-B/pro-forma-open-access.pdf

Section 6 of the OATT discusses "Reciprocity". If SCL uses the lines of one or more FERC directly regulated utilities, then SCL will have agreed to these terms when they use those lines. Meaning under reciprocity, SCL agrees to also deal with requests for use of their transmission grid under the FERC OATT approach.

Other sections of interest to this SCL Transmission Line option are:
Section 15. Service Availability
Section 16. Transmission Customer Responsibility
Section 17. Procedures for arranging for Firm Point to Point transmission service
[*This section is particularly relevant to how PSE needs to ask SCL for use of its line to serve a new 230/115 KV transformer at Lakeside.* ***There is a requirement to make a formal application in the format that is described in the OATT. PSE has never made such an application. An informal request does not meet the required format for making a request to use the SCL line. PSE needs to make this formal request to SCL*****]**.
Section 19. Additional studies procedures for Firm Transmission

With an understanding of how FERC's OATT works, it is clear that just about every sentence in the discussion of the SCL option is incorrect, meaning these sentences are not consistent with the OATT.

First sentence:
"*SCL has indicated to the City of Bellevue that they expect to need the corridor for their own purposes and are not interested in sharing the corridor with PSE (SCL, 2014).*"

The EIS staff should already be aware that FERC does not allow a utility like SCL to "hoard" its transmission capability. Further, the FERC OATT requires a utility like SCL to increase the rating of its infrastructure (with needed construction) if that is what it takes to honor a request for transmission and the requesting utility agrees to pay what FERC requires them to pay. No one has performed a System Impact Study (as required by the OATT) to see what it would take to honor a PSE request to use the SCL line to serve a new 230/115 KV transformer at Lakeside.

Second sentence:
"The existing SCL line would have to be rebuilt to provide a feasible solution for the Energize Eastside project, because the current rating of the SCL line is insufficient to meet PSE's needs (Strauch, personal communication, 2015)."

If it can be shown that the existing SCL line would need to be rebuilt to provide a feasible solution for the Energize Eastside project, then that is what the FERC OATT would require be done as long as PSE agrees to pay what FERC would require them to pay for that construction. Until a study is done, one cannot tell for sure what the rebuild cost would be. But it certainly would be less than the cost of Energize Eastside. Further, it should be clear that the request to use the SCL line is only for purposes of serving a new 230/115 KV transformer at Lakeside. <u>The study to determine what this cost must not include a requirement to deliver 1,500 MW to Canada</u> unless BPA makes that request and BPA would pay the bulk of the needed cost if the SCL line is also being used to increase the ability of BPA to deliver power to Canada.

Third Sentence:
"PSE has estimated that rebuilding the SCL line would provide sufficient capacity for a period of less than 10 years, which does not comply with PSE's electrical criteria (as described in Section 2.2.1 of the Phase 1 Draft EIS) to meet performance criteria for 10 years or more after construction."

Under the FERC OATT rules that SCL needs to comply with, SCL does not get to stop serving Lakeside after ten years even if SCL has a legitimate need for more use of its SCL line at that time. The FERC OATT has clear rules on how a utility like PSE can assure its transmission service from SCL can be retained even after SCL decides it needs the line for its own use. The FERC OATT protects a utility like PSE from SCL stopping to provide them transmission service.

Fourth Sentence:
"Neither the City nor PSE can compel SCL to allow the use of this corridor; therefore, this option is not feasible and was not carried forward."

This statement is wrong. PSE can compel SCL to use its line to serve a new 230/115 KV transformer by making a FERC Order 888 request (under the FERC OATT) for such transmission service. If SCL refuses, FERC will compel them to do so. FERC uses its "reciprocity" ruling to compel SCL. If SCL refuses, FERC will refuse to let SCL use any transmission lines that are under direct FERC jurisdiction. SCL could not meaningfully its service obligations to its own customers without using the transmission lines of FERC directly jurisdictional utilities.

Fifth Sentence:

Attachment E - 3

"Even if compelled use of the corridor were allowed, the negotiations would likely prove lengthy, and would likely preclude completion of the project within the required timeline to meet project objectives."

The FERC OATT has tight timelines for dealing with requests for transmission service. FERC intentionally put in these tight timelines to prohibit a utility like SCL from denying service by delaying service. Further, PSE currently is not saying when it thinks it needs a new 230/115 KV transformer to be in service at Lakeside. Any needed construction on the existing SCL line will take considerably less time than permitting and building EE. Further, according to the only reasonable load flow study done regarding serving the east side (the Lauckhart-Schiffman Load Flow study), there is plenty of time before any new 230/115 KV transformer is needed at Lakeside.

Thank you for the opportunity to clarify how this SCL Transmission Line option would work.

Sincerely,

Richard Lauckhart

Richard Lauckhart
Energy Consultant
Davis, California
530-759-9390
lauckjr@hotmail.com

Citizens for Sane Eastside Energy (CSEE)

May 8, 2017

Attachment F -1

The Washington Utilities and Transportation Commission
98504-7250, 1300 Evergreen Park Dr SW
Olympia, WA 98502

sent by email to the individual Commissioners

Dear Commissioners:

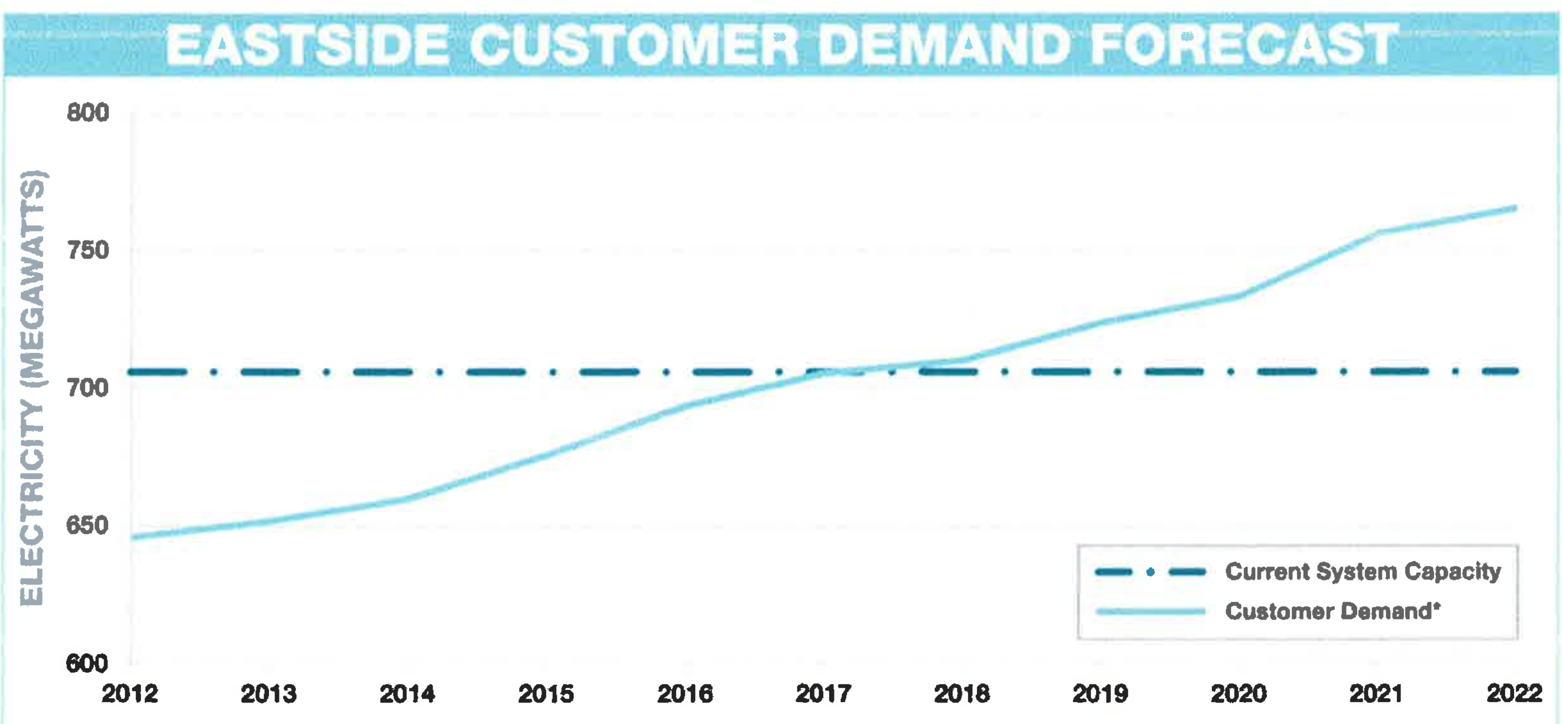
This letter is in response to comments made in an email by Mr. Jens Nedrud of PSE to you and others, dated May 4, 2017, regarding PSE's Energize Eastside project and a 3/16 IRPAG meeting.

Mr. Nedrud's remarks are misleading and distort the facts, yet they are unfortunately consistent with PSE's determined hard-sell methods to get the $200-$300 million project built at all costs, regardless of the economic waste and the grave risk to lives and property if built as proposed, i.e. too close to two aging pipelines transporting highly flammable petroleum products under pressure.

The two chief mantras PSE keeps repeating in its PR efforts to sell Energize Eastside are: 1) There is so much economic and population growth on the Eastside, the project is needed to meet a generic "consumer demand;" and 2) Nothing has been done "since the 1960s" to upgrade the grid in the Eastside. The ads PSE has published in numerous media outlets repeatedly beat these "Consumer Demand" and "Need for Upgrade" drums. CSEE has collected over two dozen of them.

PSE's inflated consumer demand claims

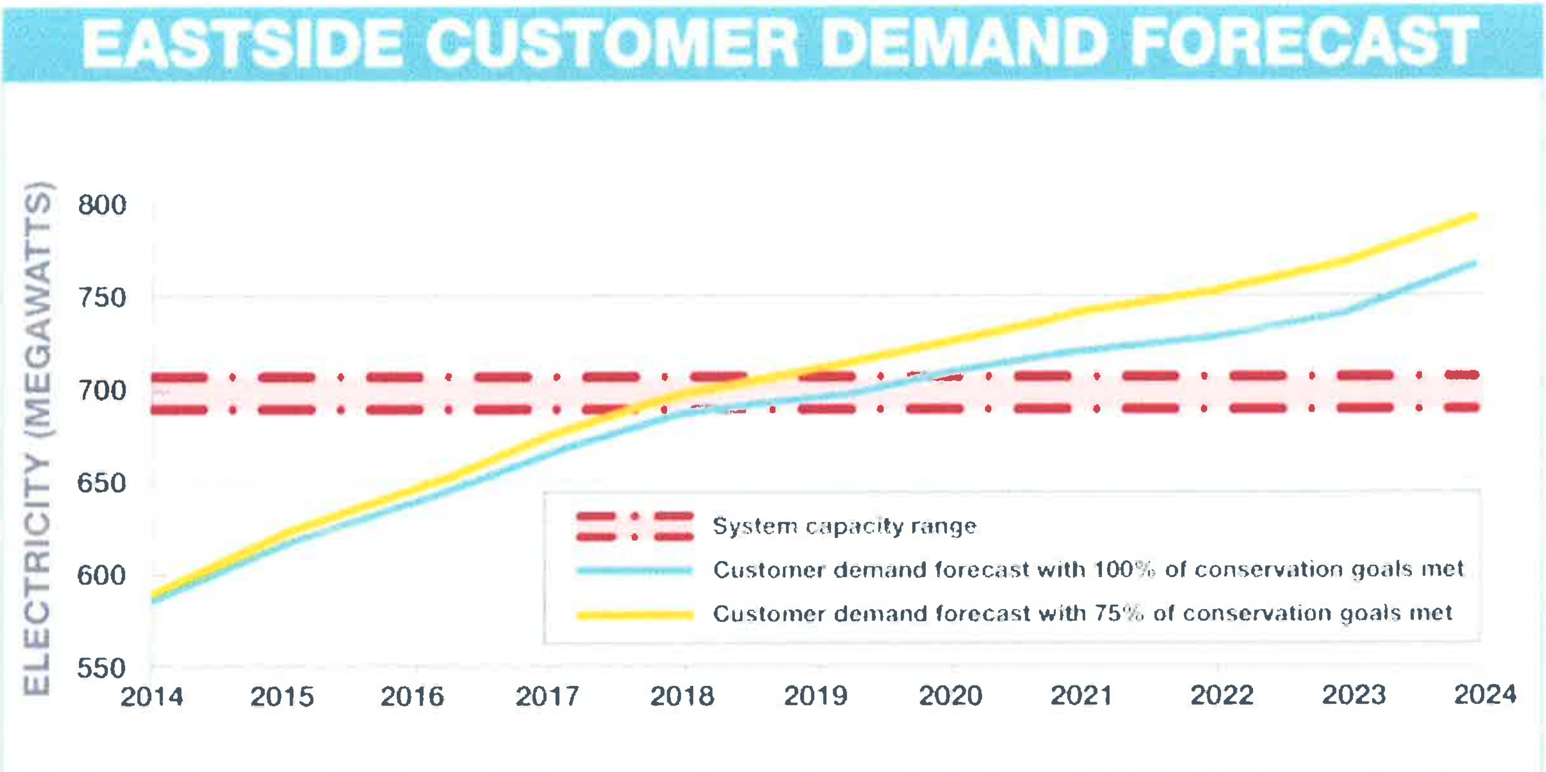
In December of 2013, PSE had on its website dedicated to the Energize Eastside project the following chart, which was its prime lead-in to justify the project. Words introducing the chart stated that "[g]rowth studies predict that demand for reliable power will exceed capacity as early as 2017:"



*Customer Demand assumes 100% of conservation goals are met.

Two years later, in December 2015, that chart was replaced by this one:

Attachment F - 2



This chart was accompanied with a warning: "Without substantial electric infrastructure upgrades, tens of thousands of residents and businesses will be at risk of more frequent and longer power outages."

That is a gross and irresponsible exaggeration. From the graph above, it appears PSE anticipates a spectacular (and preposterous) Eastside demand growth rate of 4% in the next four years. That is ten times the future growth rate predicted for a wildly booming Seattle by Seattle City Light's Sephir Hamilton, Engineering and Technology Innovation Officer, who in 2014 laid out these facts (https://youtu.be/gZWM-yNxwZY, starting at 0:52 into the video):

> "In the last four years nationwide, per-customer energy use has declined by 2%, both residential and non-residential. Here in Seattle it's declined 2.7% for non-residential, and it has declined 7.6% per customer for residential energy use. Even with all the growth that you see here in Seattle and south Lake Union, we're projecting total load growth of less than a half of a percent over the next five years. This is a huge change in the entire makeup of energy use industry in the United States, and especially here in Seattle where we're leading the way."

I have asked Mr. Hamilton to update this data with what is known now in 2017, and I will update with that information when received. Meanwhile, PSE no longer has a chart on its Energize Eastside website with growth projections. But that does not deter it from making outlandish growth claims.

PSE's false "no update since the 1960s" claims

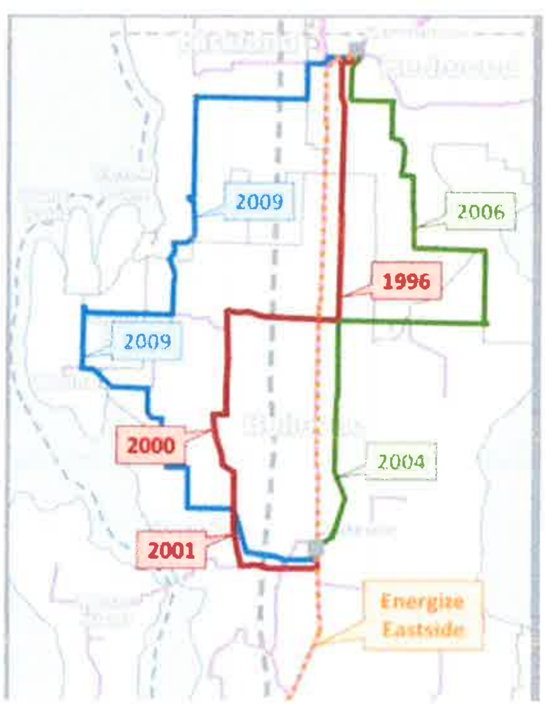
Here is an example of one of several ads of like content that PSE has published in various media outlets:

Attachment F - 3

Note the blatant falsehood contained in this ad: "The Eastside electric grid was last upgraded in the 1960s." The ad also makes a false correlation between general daily electricity usage and power outages, when PSE knows full well the ostensible need for Energize Eastside is to meet very rare N-1-1 emergency events where federally mandated reliability is the only issue, not the general daily supply and demand for electricity.

As former Puget Power Vice President for Power Planning, Richard Lauckhart, has argued in documents he has sent you, there have been numerous upgrades and expansions made to the Eastside grid since the 1960s, as illustrated in this graphic for lines added and the years they were built:

New 115 KV lines built in the Eastside in recent years



In conclusion, whether in terms of PSE's complying with your requirements for a proper and adequate IRP, or whether as evidence at some future rate hearing on Energize Eastside when you will need all the facts, it remains that PSE simply cannot be trusted to tell the truth when so much of its future profits are at stake. You will recall that the WUTC levied its greatest fine ever on a utility, $1.25 million, for PSE's having intentionally falsified gas pipeline safety inspection records over a period of four years (see https://sane-eastside-energy.org/2014/04/30/pse-fined-1-25-million-in-falsifying-gas-pipeline-safety-inspection-reports-for-4-years-running/). It is thus not totally surprising that, while Mr. Nedrud finds flaws in the Lauckhart-Schiffman load flow studies, PSE has yet to release CEII-related data PSE submitted for the studies it relies on that would reveal what sorts of fundamental assumptions were used, even though FERC made it clear to PSE that Mr. Lauckhart and CENSE's Don Marsh have CEII clearances and should be given access to that CEII data.

PSE has stubbornly refused to provide that information. The WUTC should demand that they do.

I realize the power the WUTC has to regulate and influence PSE is woefully inadequate. But for a project with such great potential for irrevocable damage, I hope the WUTC can use its own resources to conduct fully unbiased and untainted flow studies, if need be, to determine for itself the need for Energize Eastside, or at least to establish the validity of such studies as have been done. This is, after all, your area of expertise and public trust. That would be a positive effort undertaken for the common good of all Washingtonians and for the future of our environment.

Sincerely,

Larry G. Johnson
Attorney at Law, WSBA #5682
Citizens for Sane Eastside Energy (CSEE), www.sane-eastside-energy.com
8505 129th Ave. SE
Newcastle, WA 98056
tel.: 425 227-3352
larry.ede@gmail.com

cc: CENSE
City Councils of Bellevue, Newcastle, Redmond and Renton
NW Energy Coalition
Sierra Club

Citizens for Sane Eastside Energy

An open forum for opposition to PSE's "Energize Eastside" project

Four Big Lies in PSE's Hard-Sell of Energize Eastside

PSE will do and say anything to get its boondoggle Energize Eastside ("EE") project past the scrutiny of what appear to be naive and ill-informed consultants charged with the current Environment Impact Studies ("EIS") for EE. CSEE hopes through pubic comment to expose PSE's deceitful acts regarding EE in order to counter notions that PSE is somehow owed special deference by and unlimited access to those consultants. Several emails produced by the City of Bellevue to CSEE under public records requests indicate the relationship between PSE, the City of Bellevue and the EIS consultants is far too cozy.

To download CSEE's submission of its comments on the botched EIS process up until now and the inadequate Phase 2 draft EIS, click here.

To summarize those comments, here are the Four Big Energize Eastside Lies that PSE has gotten away with so far — but should no more:

1. EE is based on a failed ColumbiaGrid flow study that included exaggerated, false NERC criteria. Yet PSE used those studies despite their failures (the studies could not "solve" to a working solution) by having a pliant consulting firm, Quanta, use them for inputs in load flow studies in order to justify EE. The phony data far exceeded the federal reliability requirements as adopted from the North American Electric Reliability Corporation (NERC).

The core rationale for EE is based on a fairy tale. See the full CSEE submission for details.

2. PSE has misrepresented its desire and efforts to seek a much superior alternative route with Seattle City Light, using SCL's existing Eastside lines. Though PSE spokespersons told the public early on that the SCL Eastside lines were its "first choice" for EE and they tried to obtain permission from SCL to utilize that route, the truth is otherwise. **It turns out PSE never made a formal request for those lines.** FERC Order 888 sets out mandatory guidelines on how that process works; if SCL were to refuse to cooperate, FERC would have the right to put SCL out of business by denying it access to any other FERC-regulated lines in the grid.

Despite how easy it was for CSEE to uncover the truth about this common-sense SCL alternative to EE, the writers of the Phase 2 draft EIS appear to have bought hook, line and sinker the PSE's lies about how hard they supposedly worked to get cooperation from SCL, and how supposedly insurmountable such a task would be. It is not, as former PSE VP for Power Planning, Richard Lauckhart, explains in the full CSEE submission. In fact, he says, the SCL lines alternative could be built much faster, safer and cheaper than the bloated EE that PSE would prefer to see built.

We hope the EIS consultants do a better job and do their own homework on this SCL lines alternative rather than simply rely on whatever PSE tells them.

3. PSE has mounted an aggressive PR campaign, similar in kind and credibility to a political campaign, in order to mislead the public into thinking EE will fulfill a need to meet future Eastside growth that PSE claims is 10 times that of booming Seattle.

That absurd falsehood is readily rebutted by SCL's Sephir Hamilton, Engineering and Technology Innovation Officer, who in 2014 laid out these facts, starting at 0:52 into the video:

"In the last four years nationwide, per-customer energy use has declined by 2%, both residential and non-residential. Here in Seattle it's declined 2.7% for non-residential, and it has declined 7.6% per customer for residential energy use. Even with all the growth that you see here in Seattle and south Lake Union, we're projecting total load growth of less than a half of a percent over the next five years. This is a huge change in the entire makeup of energy use industry in the United States, and especially here in Seattle where we're leading the way."

4. PSE repeatedly and falsely advertises the lie that EE is needed as a "long overdue Eastside grid upgrade" despite several expansions of the Eastside grid in the past two decades. We have already discussed this false advertising campaign in depth in a recent post here. The full CSEE submission on the Phase 2 draft EIS includes this discussion in Section 4 of that document.

Public comment on the Phase 2 Draft EIS is now being taken from May 8 through June 21, 2017. You can make your comments by email to info@EnergizeEastsideEIS.org. To have your comment made part of the official record, you must include your name and physical mailing address. For more information, go to http://www.energizeeastsideeis.org/participate.html.

This entry was posted in Uncategorized on May 21, 2017 [https://sane-eastside-energy.org/2017/05/21/four-big-lies-in-pses-hard-sell-of-energize-eastside-project/] .

Citizens for Sane Eastside Energy (CSEE)

8505 129th Ave. SE
Newcastle, WA 98056
tel.: 425 227-3352
email: larry.ede@gmail.com

May 23, 2017

Ms. Heidi Bedwell
Energize Eastside EIS Program Manager
City of Bellevue Development Services Dept.
450 110th Ave. NE
Bellevue, WA 98004

submitted in person at Hazen High School public meeting

Re: Additional Comment regarding Energize Eastside Phase 2 Draft EIS

Yesterday I submitted by email on behalf of CSEE two documents to be included in the public comments record regarding the Energize Eastside Phase 2 Draft EIS. One of those is a print-out of the text at https://sane-eastside-energy.org/2017/05/21/four-big-lies-in-pses-hard-sell-of-energize-eastside-project/. There I state *inter alia*: "Several emails produced by the City of Bellevue to CSEE under public records requests indicate the relationship between PSE, the City of Bellevue and the EIS consultants is far too cozy." Further, "the writers of the Phase 2 draft EIS appear to have bought hook, line and sinker the PSE's lies about how hard [PSE] supposedly worked to get cooperation from SCL, and how supposedly insurmountable such a task would be…We hope the EIS consultants do a better job and do their own homework on this SCL lines alternative rather than simply rely on whatever PSE tells them."

Included in the several emails mentioned above is Attachment A hereto, from City of Bellevue's Nicholas Matz to Chris Salomone, dated May 19, 2014, with subject header, "FW: Mayor's Meeting Notes." The email contains this language: "Energize Eastside: * Tonights [sic] objective is buy-off on plan." That statement alone raises legitimate concerns about the City of Bellevue's ability to serve as an objective and impartial Lead Agency in the EIS process. Other emails produced through public records requests add to a body of evidence that the City of Bellevue's staff is unduly influenced by PSE and clearly biased in its favor.

More important than the substance of the EIS document is the integrity of the EIS process itself. If that process is corrupted than any report resulting from it will be inherently worthless. PSE has had unlimited access to COB employees working on Energize Eastside, while CENSE and CSEE are limited to rushed sound bites at a handful of public occasions. Their pleas for total transparency and disclosure of basic data inputs for load flow studies PSE relies on to justify Energize Eastside fall on deaf ears in Bellevue. Our experts are given not even 1% of the hearing time and access that PSE gets. For example, despite the many legitimate criticisms of Energize Eastside by former Puget Power Vice President for Power Planing, Richard Lauckhart, and the independent flow studies he performed with Mr. Schiffman, *COB staff and the EIS consultants have never contacted him* to discuss his concerns. Indeed, COB staff and the Bellevue City Council have been consistently and remarkably incurious about why Lauckhart and CENSE (on flow studies and several other key issues) never get any straight answers or relevant information from PSE, which as stakeholders they are entitled to.

The entire EIS process to this point is reminiscent of how the SEC was asleep at the wheel for years while Bernie Madoff bilked investors of some $65 billion with his giant Ponzi scheme, even though for most of those years financial experts were screaming at the SEC to investigate. The SEC dropped the ball, apparently thinking Madoff was somehow beyond reproach. The City of Bellevue is following down that same path with PSE.

Some other entity other than the City of Bellevue needs to be in charge of the EIS process if the EIS is to have any integrity and credibility.

Sincerely,

Larry G. Johnson
Attorney at Law, WSBA #5682
Citizens for Sane Eastside Energy (CSEE)

cc: CENSE

From:	Matz, Nicholas
Sent time:	05/19/2014 10:06:22 AM
To:	Salomone, Chris
Subject:	FW: Mayor's Meeting notes

Attachment A

From: Basich, Myrna
Sent: Monday, May 19, 2014 10:05 AM
To: Brennan, Mike; Helland, Carol; Matz, Nicholas; McCormick-Huentelman, Mike
Subject: Mayor's Meeting notes

Energize Eastside: • Tonights objective is buy-off on plan. • Be prepared to describe Essential Public Facility tonight, but may be more appropriate to discuss as part of regulatory discussion later in the process. • Will WUTC and Seattle Public Utilities come to our meeting? Please strongly encourage. • Alert Council when Energize Eastside (from City perspective) web page is published. • Re: Attachment A, this is the public engagement process not the decision-making process. Provide reminder of Council role on return visit. Public needs to understand how gets from talking to decision. • Make sure PSE prepared to show homework. • Start with public process piece and then invite PSE reps to table. PowerPoint PSE representatives will be at table. Please reserve seating in front row for them likely 3 spots. May need room opened up to 1E-108 Confirm that audio system has been remedied Schedule more regular updates to Council on this project going forward.

Mayor's Meeting – May 19, 2014 *Confidential*

General administration	
Item(s)	**Assignments**
Figure out how to provide PowerPoints to Council to view on personal laptops during Council meetings. (provide to Claudia for her Surface) How will this affect use of Granicus for agenda/packet?	
Remind Council to be mindful of tight agenda through Recess. Be aware if missing meetings that may not be able to work around specific topics.	

New Initiatives/Issues discussed	
Item(s)	**Assignments**

Tonight's agenda	
Item(s)	**Assignments**
Executive Session •	
Energize Eastside: • Tonight's objective is buy-off on plan. • Be prepared to describe Essential Public Facility tonight, but may be more appropriate to discuss as part of 'regulatory" discussion later in the process. • Will WUTC and Seattle Public Utilities come to our meeting? Please strongly encourage. • Alert Council when Energize Eastside (from City perspective) web page is published. • Re: Attachment A, this is the public engagement process – not the decision-making process. Provide reminder of Council role on return visit. Public needs to understand how gets from talking to decision. • Make sure PSE prepared to show homework. • Start with public process piece and then invite PSE reps to table.	PowerPoint PSE representatives will be at table. Please reserve seating in front row for them – likely 3 spots. May need room opened up to 1E-108 Confirm that audio system has been remedied Schedule more regular updates to Council on this project going forward.
Operations and Maintenance Satellite Facility: • Council to be tee'd up with questions to pose tonight. They will be emailed later today and provided in Desk Packet. Encourage ST be mindful of short timeframe for some construction decisions. • Focus on slides relating to the ST2 Operating plan, now and beyond ST2. Explain how trains actually travel for service and constraints on the operations. • Send email to Betty Spieth reminding on agenda tonight. • Note significant contribution to regional transportation by siting of Metro bus and OMSF in prime TOD area.	PowerPoint/Desk Packet item ST representatives will be at table. Please reserve seating in front row for them – likely 3 spots. Provide feedback to ST – need "best presenter". Talk to Rick I.
PACE MOU: • Noted Cmbr Chelminiak concern re: "will" v. "may" language, particularly page 3 discussion of City role. • Would have been better for City Council to have seen this before PACE Board signed the MOU.	Print out copies of MOU for Desk Packet tonight.

General administration		
Item(s)	**Assignments**	
Figure out how to provide PowerPoints to Council to view on personal laptops during Council meetings. (provide to Claudia for her Surface) How will this affect use of Granicus for agenda/packet?		
Remind Council to be mindful of tight agenda through Recess. Be aware if missing meetings that may not be able to work around specific topics.		
Council Vision and Priorities: Claudia will introduce/lead the discussion. Action may be postponed if Councilmembers present wish to wait for return of missing members.		
Prepare memo for Human Services Commission appointments.	Desk Packet tonight	
Future Meetings/Calendaring		
Recreational Marijuana • Has sufficient direction been provided to Planning Commission? How is mixed-use zoning implicated in "no residential zones"? • Important for staff and Stokes to be aware that have given direction in form of draft ordinance. Not expecting major changes.		

May 17, 2017

Attachment A - 1

Heidi Bedwell
City of Bellevue Development Services Department
450 110th Avenue NE
Bellevue, WA 98004

Re: Comment for Energize Eastside Phase 2 Draft EIS

Dear Ms. Bedwell:

I am writing to submit comments on the Energize Eastside Phase 2 Draft EIS.

These comments relate to the "need" for Energize Eastside

As I have mentioned in previous submissions, the need for Energize Eastside has never been established. I have provided significant documentation which supports the idea that it is not only not needed, but that PSE is attempting to push this project through using multiple baseless justifications.

The debate on need is rooted in a dispute about a proper load flow study. What keeps us from an open and honest discussion of the facts on which this entire project is based is PSE's refusal to allow any kind of scrutiny into the assumptions used by Quanta in load flow studies which they conducted for PSE. These studies, along with the studies conducted by USE, are the centerpieces of the justification for Energize Eastside.

PSE continues to refuse to show the details of the Quanta load flow study despite multiple requests and despite the fact that the Federal Energy Regulatory Commission (FERC) says I have a legitimate need to see this information. Yet the EIS process continues to march forward, presumably to its completion, while multiple red flags exist concerning how Quanta did their load flow study. The EIS staff continues to sidestep any real resolution of these red flags.

A $200-$300 million project with devastating and irrevocable consequences cannot be subject of guess work. No permit for Energize Eastside should be issued until a truly transparent, scientific process has been completed.

A new load flow study needs to be done in an open and transparent fashion with input from all stakeholders. That is what I asked FERC to require ColumbiaGrid to do. But FERC said that since PSE had not asked for Energize Eastside to be a part of the Regional Plan, then Energize Eastside is not subject to Order 1000. If PSE had asked for Energize Eastside to be part of the regional plan, this would have required ColumbiaGrid to do the studies in an open and transparent fashion with full stakeholder input. The ColumbiaGrid Regional Plan looks out over a ten-year planning horizon and identifies the transmission additions necessary to ensure that the parties to the ColumbiaGrid Planning and Expansion Functional Agreement can meet their commitments to serve regional load and meet firm transmission service commitments.

It appears there were many reasons that PSE chose not to ask for Energize Eastside to be a part of a Regional Plan. I believe this was a deliberate step on their part.

- If Energize Eastside were part of a regional plan, then FERC would say how much BPA would pay for Energize Eastside BPA would pay PSE. By doing that, PSE pays less out of its own pocket. And that would mean a smaller increase in the PSE ratebase. Which means smaller PSE investment that will be given the 9.8% return by the WUTC. Macquarie wants to invest more money in PSE new ratebase. It does not help if BPA pays a lot of that money because that reduces what Macquarie spends and therefore the amount of the return on the investment.
- If part of a Regional Plan, ColumbiaGrid would have been required to do the studies (not Quanta) and ColumbiaGrid studies would have to be done in an open and transparent fashion with stakeholder input, and
- If part of a Regional Plan, then stakeholders would also get to identify alternatives. Those alternatives would include, for example,
    - Meeting any identified needs with DSM
    - Simply increasing the capacity of the Talbot Hill transformer
    - Building a small peaker plant somewhere on the Eastside
    - Utilizing the SCL Transmission line option.

According to section 1.3 of the EIS, "*the lead agency is responsible for ensuring that a proposal that is the subject of environmental review is properly defined. The process of defining the proposal includes an* ***understanding of the need for the project****, to enable a thorough understanding of the project's objectives*." Without an open and transparent load flow study with stakeholder input, there can be no shared understanding of the need for the project. The EIS staff needs to ensure full accordance with this statement before the EIS is finalized.

Sincerely,

Richard Lauckhart

Richard Lauckhart
Energy Consultant
44475 Clubhouse Drive
Davis, California 95618
530-759-9390
lauckjr@hotmail.com

Attachment B

From: Strauch, Bradley R <bradley.strauch@pse.com>
Sent time: 03/25/2016 11:24:12 AM
To: Mark Johnson <MJohnson@esassoc.com>
Cc: records@energizeeastsideeis.org; Bedwell, Heidi; Claire Hoffman <CHoffman@esassoc.com>; Nedrud, Jens V <jens.nedrud@pse.com>
Subject: RE: E2- Questions for PSE regarding the Lauckhart-Schiffman report
Attachments: Lauckhart-Schiffman Draft responses_20160318 PSE Response.docx

Mark,

PSE is providing the following information in response the questions posed in the attachment. However, as we have already stated in PSEs Phase 1 DEIS comments, the Lauckhart and Schiffman document does not meet the minimum federally required planning standards necessary to provide or develop meaningful results; therefore, it has no relevance when evaluating PSEs thoroughly vetted project proposal.

If you have any additional questions, please let us know as we will be glad to assist.

Brad Strauch

Sr. Land Planner/Environmental Scientist

PUGET SOUND ENERGY

P.O. Box 97034, PSE-09N

Bellevue, WA 98009-9734

Office: 425-456-2556

Fax: 425-462-3233

Cell: 425-214-6250

From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Monday, March 21, 2016 6:25 PM
To: Strauch, Bradley R
Cc: Heidi Bedwell; Claire Hoffman; records@energizeeastsideeis.org
Subject: E2- Questions for PSE regarding the Lauckhart-Schiffman report

Brad

As we mentioned a couple weeks back, we have a few questions that arose from reading the Lauckhart Schiffman Report. We are trying to address issues raised by the report in the comment summary, the first draft of which is due very soon, so we ask for a quick turnaround on these. The attached is a draft section we have created to respond to the issues raised. Our intent here is to clarify facts that we believe PSE can best provide, and the questions are as close-ended as we could make them. Could you take a look and let us know how quickly you can turn this information around? If we could have answers by the end of the week, that would be great.

Mark S Johnson

Director

ESA | Northwest Community Development

5309 Shilshole Avenue NW, Suite 200

Seattle, WA 98107

206.789.9658 main

206.576.3750 direct | 206.550.0723 cell

mjohnson@esassoc.com <mailto:mjohnson@esassoc.com> | <www.esassoc.com>

Follow us on Facebook <http://www.facebook.com/pages/Environmental-Science-Associates/347741357652?

Attachment C

City of Seattle

Seattle City Light

June 2, 2014

Mr. Nicholas Matz
Planning & Community Development Department
450 110th Avenue NE
P.O. Box 90012
Bellevue, WA 98009

Dear Mr. Matz:

Seattle City Light (SCL) has transmission facilities that run through the City of Bellevue and other jurisdictions on the east side of Lake Washington. The SCL transmission lines in Bellevue were installed in the early 1940's to transfer power from hydro-generation in the North Cascades to the west side of Lake Washington. Puget Sound Energy (PSE) has lines in the same general vicinity which primarily serve the PSE customer load east of Lake Washington.

SCL's double circuit 230kV transmission lines are used to meet current and future operating needs. Specifically, SCL needs the connectivity and capacity of these transmission lines to:

- Maintain a contiguous Point of Delivery for transmission service from BPA;
- Serve existing load growth and maintain reliability;
- Provide for future SCL growth;
- Support regional transmission flows; and
- Meet NERC reliability requirements.

SCL foresees current and future uses of these existing east side facilities and prefers not to utilize SCL's transmission lines for PSE's native load service needs.

Please contact me via email at uzma.siddiqi@seattle.gov if you have any questions.

Sincerely,

Uzma Siddiqi

Uzma Siddiqi, PE
System Planning Engineer

cc: Phil West
Tuan Tran

Seattle City Light

700 5th Ave. | P.O. Box 34023 | Seattle WA 98124-4023
TEL (206) 684-3000 TTY/TDD (206) 684-3225 FAX (206) 625-3709
seattle.gov/light
twitter.com/SEACityLight facebook.com/SeattleCityLight

Attachment D

April 25, 2017

Mr. Larry Johnson
Attorney at Law
Citizens for Sane Eastside Energy (CSEE)
8505 129th AVE SE
NEWCASTLE, WA 98056

Re: PSE's Energize Eastside Project

Dear Mr. Johnson,

This letter responds to your letter dated March 20, 2017 to our General Manager, Larry Weis. We appreciate your interest in the regional energy issues and are aware of your concerns regarding Puget Sound Energy's ("PSE") Energize Eastside Project. As your letter mentions, although PSE and Seattle City Light have had limited discussions about PSE's Energize Eastside Project, PSE has never formally requested transmission service on Seattle City Light's Eastside transmission lines.
Obviously, if PSE would make a formal request for transmission service on Seattle City Light's Eastside lines, Seattle City Light would respond appropriately. Likewise, Seattle City Light remains willing to discuss options with PSE regarding the potential use of Seattle's Eastside lines. However, as PSE's project located entirely within its own service territory, PSE's project remains within PSE's discretion.

In addition, the Energize Eastside Project is not subject to the Order No. 1000 regional approval process because it is located completely within Puget Sound's service territory, it was included in Puget Sound's local transmission plan to meet Puget Sound's reliability needs, and neither Puget Sound, nor any other eligible party, requested to have the project selected in the regional transmission plan for purposes of cost allocation.

We trust that this resolves the concerns expressed in your March 20th letter with respect to Seattle City Light.

Sincerely,

Sephir Hamilton
Engineering and Technology Innovation Officer
Seattle City Light

cc: Larry Weis, General Manager, Seattle City Light

May 11, 2017

Heidi Bedwell
City of Bellevue Development Services Department
450 110th Avenue NE
Bellevue, WA 98004

Re: Comment for Energize Eastside Phase 2 Draft EIS

Dear Ms. Bedwell:

I am writing to submit comment on the Energize Eastside Phase 2 Draft EIS.

This comment relates to pages 2-52 of the Phase 2 Draft EIS. In particular section 2.2.1 "Seattle City Light Transmission Line" option.

In order to understand how this option works, one needs to be familiar with FERC's ProForma Open Access Transmission Tariff (OATT). The FERC ProForma Open Access Transmission Tariff can be found at:
https://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890-B/pro-forma-open-access.pdf

Section 6 of the OATT discusses "Reciprocity". If SCL uses the lines of one or more FERC directly regulated utilities, then SCL will have agreed to these terms when they use those lines. Meaning under reciprocity, SCL agrees to also deal with requests for use of their transmission grid under the FERC OATT approach.

Other sections of interest to this SCL Transmission Line option are:
Section 15. Service Availability
Section 16. Transmission Customer Responsibility
Section 17. Procedures for arranging for Firm Point to Point transmission service
[*This section is particularly relevant to how PSE needs to ask SCL for use of its line to serve a new 230/115 KV transformer at Lakeside.* ***There is a requirement to make a formal application in the format that is described in the OATT. PSE has never made such an application. An informal request does not meet the required format for making a request to use the SCL line. PSE needs to make this formal request to SCL*****]**.
Section 19. Additional studies procedures for Firm Transmission

With an understanding of how FERC's OATT works, it is clear that just about every sentence in the discussion of the SCL option is incorrect, meaning these sentences are not consistent with the OATT.

First sentence:
"*SCL has indicated to the City of Bellevue that they expect to need the corridor for their own purposes and are not interested in sharing the corridor with PSE (SCL, 2014).*"

Attachment E -2

The EIS staff should already be aware that FERC does not allow a utility like SCL to "hoard" its transmission capability. Further, the FERC OATT requires a utility like SCL to increase the rating of its infrastructure (with needed construction) if that is what it takes to honor a request for transmission and the requesting utility agrees to pay what FERC requires them to pay. No one has performed a System Impact Study (as required by the OATT) to see what it would take to honor a PSE request to use the SCL line to serve a new 230/115 KV transformer at Lakeside.

Second sentence:
"*The existing SCL line would have to be rebuilt to provide a feasible solution for the Energize Eastside project, because the current rating of the SCL line is insufficient to meet PSE's needs (Strauch, personal communication, 2015).*"

If it can be shown that the existing SCL line would need to be rebuilt to provide a feasible solution for the Energize Eastside project, then that is what the FERC OATT would require be done as long as PSE agrees to pay what FERC would require them to pay for that construction. Until a study is done, one cannot tell for sure what the rebuild cost would be. But it certainly would be less than the cost of Energize Eastside. Further, it should be clear that the request to use the SCL line is only for purposes of serving a new 230/115 KV transformer at Lakeside. <u>The study to determine what this cost must not include a requirement to deliver 1,500 MW to Canada</u> unless BPA makes that request and BPA would pay the bulk of the needed cost if the SCL line is also being used to increase the ability of BPA to deliver power to Canada.

Third Sentence:
"*PSE has estimated that rebuilding the SCL line would provide sufficient capacity for a period of less than 10 years, which does not comply with PSE's electrical criteria (as described in Section 2.2.1 of the Phase 1 Draft EIS) to meet performance criteria for 10 years or more after construction.*"

Under the FERC OATT rules that SCL needs to comply with, SCL does not get to stop serving Lakeside after ten years even if SCL has a legitimate need for more use of its SCL line at that time. The FERC OATT has clear rules on how a utility like PSE can assure its transmission service from SCL can be retained even after SCL decides it needs the line for its own use. The FERC OATT protects a utility like PSE from SCL stopping to provide them transmission service.

Fourth Sentence:
"*Neither the City nor PSE can compel SCL to allow the use of this corridor; therefore, this option is not feasible and was not carried forward.*"

This statement is wrong. PSE can compel SCL to use its line to serve a new 230/115 KV transformer by making a FERC Order 888 request (under the FERC OATT) for such transmission service. If SCL refuses, FERC will compel them to do so. FERC uses its "reciprocity" ruling to compel SCL. If SCL refuses, FERC will refuse to let SCL use any transmission lines that are under direct FERC jurisdiction. SCL could not meaningfully its service obligations to its own customers without using the transmission lines of FERC directly jurisdictional utilities.

Fifth Sentence:

"Even if compelled use of the corridor were allowed, the negotiations would likely prove lengthy, and would likely preclude completion of the project within the required timeline to meet project objectives."

The FERC OATT has tight timelines for dealing with requests for transmission service. FERC intentionally put in these tight timelines to prohibit a utility like SCL from denying service by delaying service. Further, PSE currently is not saying when it thinks it needs a new 230/115 KV transformer to be in service at Lakeside. Any needed construction on the existing SCL line will take considerably less time than permitting and building EE. Further, according to the only reasonable load flow study done regarding serving the east side (the Lauckhart-Schiffman Load Flow study), there is plenty of time before any new 230/115 KV transformer is needed at Lakeside.

Thank you for the opportunity to clarify how this SCL Transmission Line option would work.

Sincerely,

Richard Lauckhart

Richard Lauckhart
Energy Consultant
Davis, California
530-759-9390
lauckjr@hotmail.com

Citizens for Sane Eastside Energy (CSEE)

May 8, 2017

Attachment F -1

The Washington Utilities and Transportation Commission
98504-7250, 1300 Evergreen Park Dr SW
Olympia, WA 98502

sent by email to the individual Commissioners

Dear Commissioners:

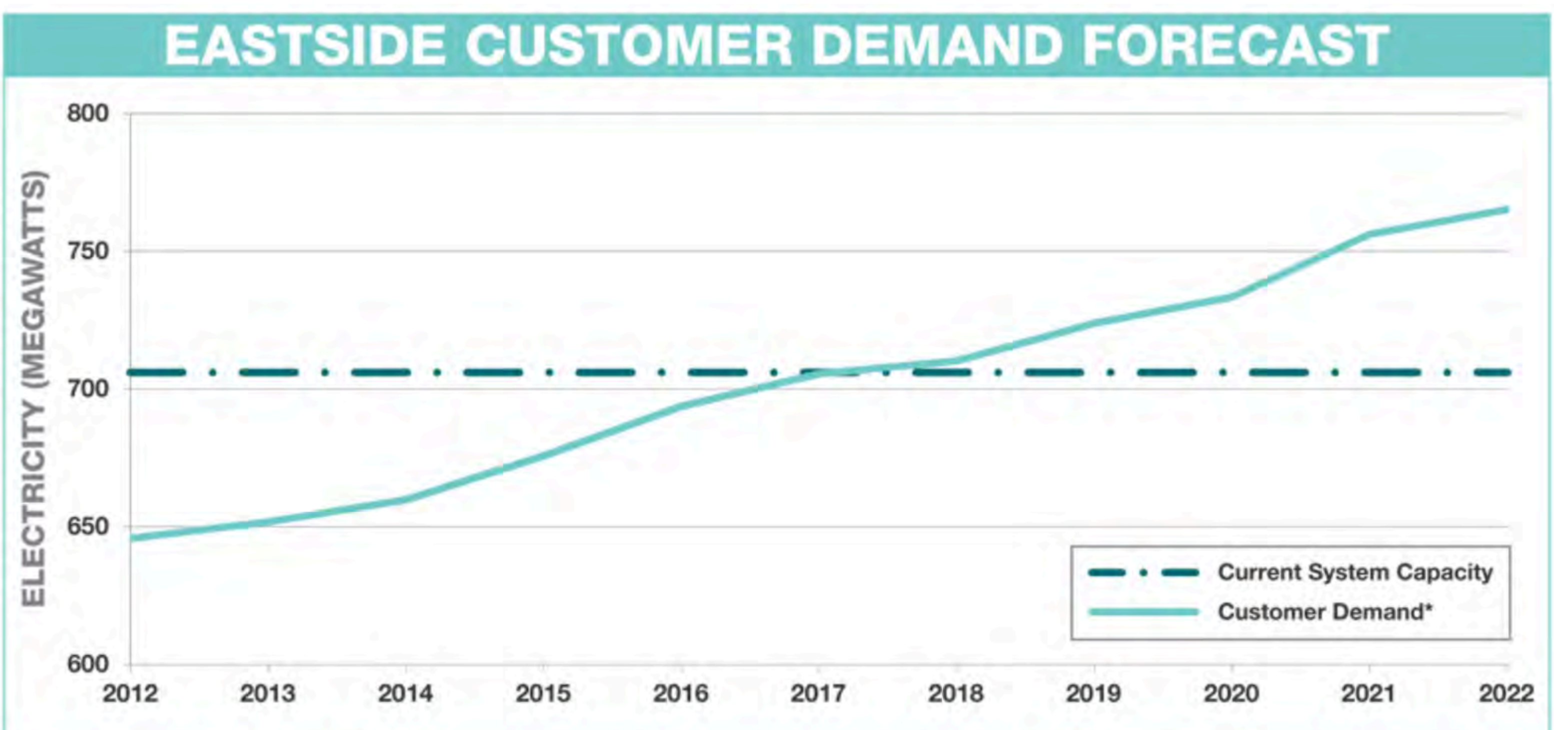
This letter is in response to comments made in an email by Mr. Jens Nedrud of PSE to you and others, dated May 4, 2017, regarding PSE's Energize Eastside project and a 3/16 IRPAG meeting.

Mr. Nedrud's remarks are misleading and distort the facts, yet they are unfortunately consistent with PSE's determined hard-sell methods to get the $200-$300 million project built at all costs, regardless of the economic waste and the grave risk to lives and property if built as proposed, i.e. too close to two aging pipelines transporting highly flammable petroleum products under pressure.

The two chief mantras PSE keeps repeating in its PR efforts to sell Energize Eastside are: 1) There is so much economic and population growth on the Eastside, the project is needed to meet a generic "consumer demand;" and 2) Nothing has been done "since the 1960s" to upgrade the grid in the Eastside. The ads PSE has published in numerous media outlets repeatedly beat these "Consumer Demand" and "Need for Upgrade" drums. CSEE has collected over two dozen of them.

PSE's inflated consumer demand claims

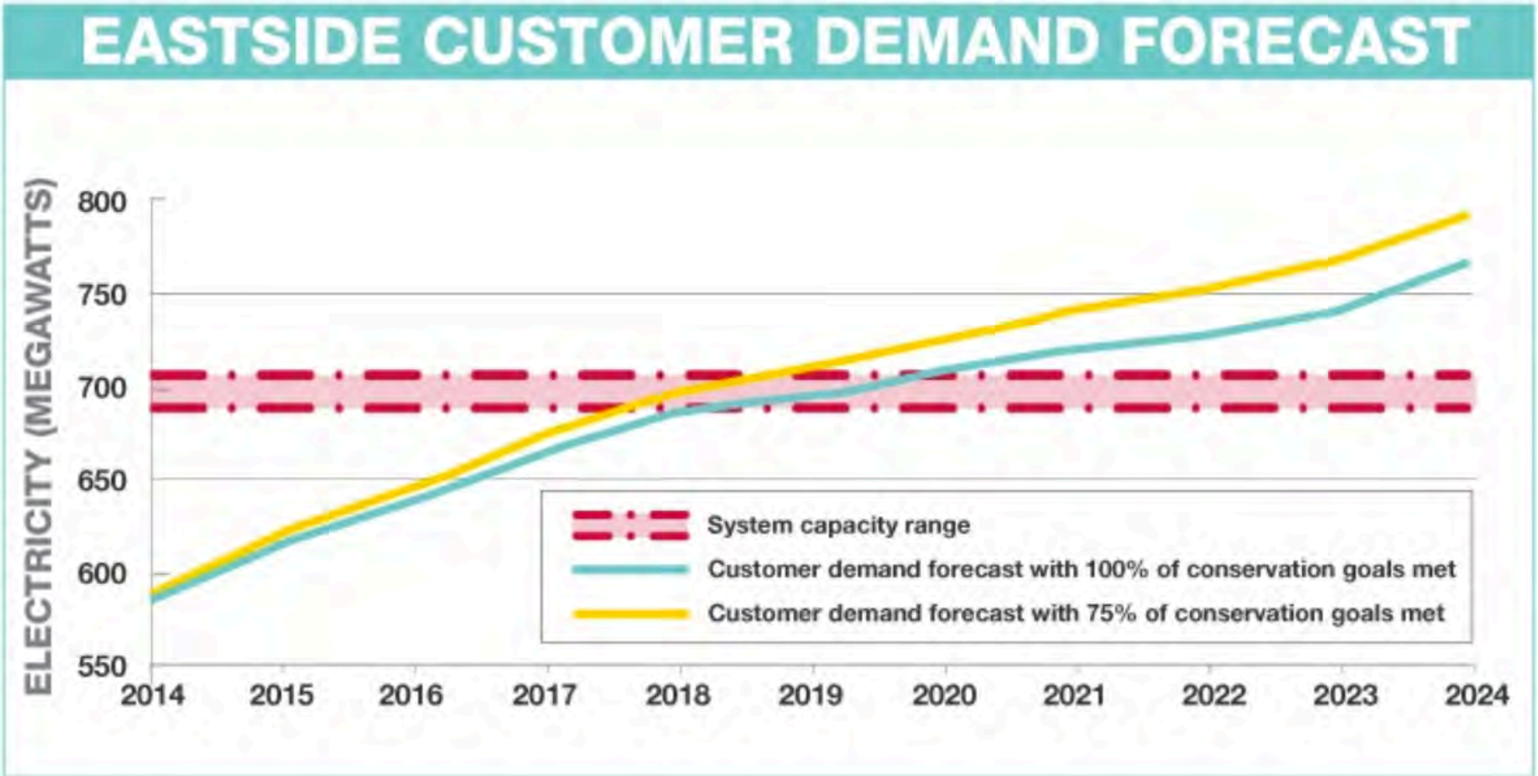
In December of 2013, PSE had on its website dedicated to the Energize Eastside project the following chart, which was its prime lead-in to justify the project. Words introducing the chart stated that "[g]rowth studies predict that demand for reliable power will exceed capacity as early as 2017:"



*Customer Demand assumes 100% of conservation goals are met.

Two years later, in December 2015, that chart was replaced by this one:

Attachment F - 2



This chart was accompanied with a warning: "Without substantial electric infrastructure upgrades, tens of thousands of residents and businesses will be at risk of more frequent and longer power outages."

That is a gross and irresponsible exaggeration. From the graph above, it appears PSE anticipates a spectacular (and preposterous) Eastside demand growth rate of 4% in the next four years. That is ten times the future growth rate predicted for a wildly booming Seattle by Seattle City Light's Sephir Hamilton, Engineering and Technology Innovation Officer, who in 2014 laid out these facts (https://youtu.be/gZWM-yNxwZY, starting at 0:52 into the video):

> "In the last four years nationwide, per-customer energy use has declined by 2%, both residential and non-residential. Here in Seattle it's declined 2.7% for non-residential, and it has declined 7.6% per customer for residential energy use. Even with all the growth that you see here in Seattle and south Lake Union, we're projecting total load growth of less than a half of a percent over the next five years. This is a huge change in the entire makeup of energy use industry in the United States, and especially here in Seattle where we're leading the way."

I have asked Mr. Hamilton to update this data with what is known now in 2017, and I will update with that information when received. Meanwhile, PSE no longer has a chart on its Energize Eastside website with growth projections. But that does not deter it from making outlandish growth claims.

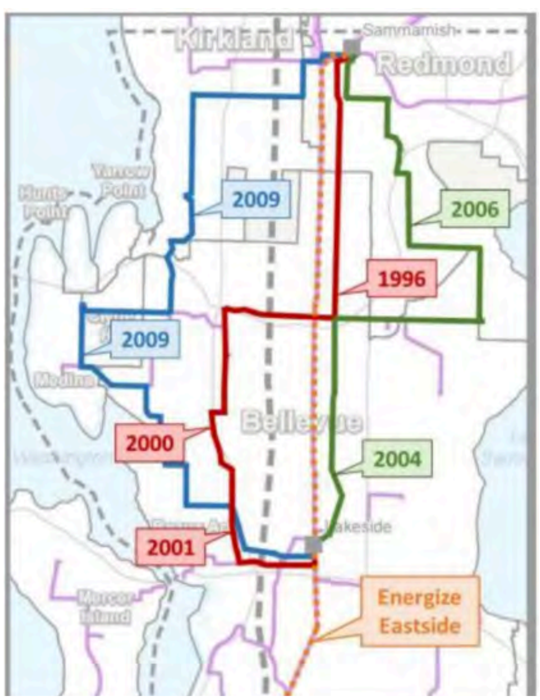
<u>PSE's false "no update since the 1960s" claims</u>

Here is an example of one of several ads of like content that PSE has published in various media outlets:

Note the blatant falsehood contained in this ad: "The Eastside electric grid was last upgraded in the 1960s." The ad also makes a false correlation between general daily electricity usage and power outages, when PSE knows full well the ostensible need for Energize Eastside is to meet very rare N-1-1 emergency events where federally mandated reliability is the only issue, not the general daily supply and demand for electricity.

As former Puget Power Vice President for Power Planning, Richard Lauckhart, has argued in documents he has sent you, there have been numerous upgrades and expansions made to the Eastside grid since the 1960s, as illustrated in this graphic for lines added and the years they were built:

New 115 KV lines built in the Eastside in recent years



In conclusion, whether in terms of PSE's complying with your requirements for a proper and adequate IRP, or whether as evidence at some future rate hearing on Energize Eastside when you will need all the facts, it remains that PSE simply cannot be trusted to tell the truth when so much of its future profits are at stake. You will recall that the WUTC levied its greatest fine ever on a utility, $1.25 million, for PSE's having intentionally falsified gas pipeline safety inspection records over a period of four years (see https://sane-eastside-energy.org/2014/04/30/pse-fined-1-25-million-in-falsifying-gas-pipeline-safety-inspection-reports-for-4-years-running/). It is thus not totally surprising that, while Mr. Nedrud finds flaws in the Lauckhart-Schiffman load flow studies, PSE has yet to release CEII-related data PSE submitted for the studies it relies on that would reveal what sorts of fundamental assumptions were used, even though FERC made it clear to PSE that Mr. Lauckhart and CENSE's Don Marsh have CEII clearances and should be given access to that CEII data.

PSE has stubbornly refused to provide that information. The WUTC should demand that they do.

I realize the power the WUTC has to regulate and influence PSE is woefully inadequate. But for a project with such great potential for irrevocable damage, I hope the WUTC can use its own resources to conduct fully unbiased and untainted flow studies, if need be, to determine for itself the need for Energize Eastside, or at least to establish the validity of such studies as have been done. This is, after all, your area of expertise and public trust. That would be a positive effort undertaken for the common good of all Washingtonians and for the future of our environment.

Sincerely,

Larry G. Johnson
Attorney at Law, WSBA #5682
Citizens for Sane Eastside Energy (CSEE), www.sane-eastside-energy.com
8505 129th Ave. SE
Newcastle, WA 98056
tel.: 425 227-3352
larry.ede@gmail.com

cc: CENSE
City Councils of Bellevue, Newcastle, Redmond and Renton
NW Energy Coalition
Sierra Club

From:	Matz, Nicholas
Sent time:	05/19/2014 10:06:22 AM
To:	Salomone, Chris
Subject:	FW: Mayor's Meeting notes

Attachment A

From: Basich, Myrna
Sent: Monday, May 19, 2014 10:05 AM
To: Brennan, Mike; Helland, Carol; Matz, Nicholas; McCormick-Huentelman, Mike
Subject: Mayor's Meeting notes

Energize Eastside: • Tonights objective is buy-off on plan. • Be prepared to describe Essential Public Facility tonight, but may be more appropriate to discuss as part of regulatory discussion later in the process. • Will WUTC and Seattle Public Utilities come to our meeting? Please strongly encourage. • Alert Council when Energize Eastside (from City perspective) web page is published. • Re: Attachment A, this is the public engagement process not the decision-making process. Provide reminder of Council role on return visit. Public needs to understand how gets from talking to decision. • Make sure PSE prepared to show homework. • Start with public process piece and then invite PSE reps to table. PowerPoint PSE representatives will be at table. Please reserve seating in front row for them likely 3 spots. May need room opened up to 1E-108 Confirm that audio system has been remedied Schedule more regular updates to Council on this project going forward.

Mayor's Meeting – May 19, 2014 *Confidential*

General administration		
Item(s)	**Assignments**	
Figure out how to provide PowerPoints to Council to view on personal laptops during Council meetings. (provide to Claudia for her Surface) How will this affect use of Granicus for agenda/packet?		
Remind Council to be mindful of tight agenda through Recess. Be aware if missing meetings that may not be able to work around specific topics.		

New Initiatives/Issues discussed		
Item(s)	**Assignments**	

Tonight's agenda		
Item(s)	**Assignments**	
Executive Session •		
Energize Eastside: • Tonight's objective is buy-off on plan. • Be prepared to describe Essential Public Facility tonight, but may be more appropriate to discuss as part of 'regulatory" discussion later in the process. • Will WUTC and Seattle Public Utilities come to our meeting? Please strongly encourage. • Alert Council when Energize Eastside (from City perspective) web page is published. • Re: Attachment A, this is the public engagement process – not the decision-making process. Provide reminder of Council role on return visit. Public needs to understand how gets from talking to decision. • Make sure PSE prepared to show homework. • Start with public process piece and then invite PSE reps to table.	PowerPoint PSE representatives will be at table. Please reserve seating in front row for them – likely 3 spots. May need room opened up to 1E-108 Confirm that audio system has been remedied Schedule more regular updates to Council on this project going forward.	
Operations and Maintenance Satellite Facility: • Council to be tee'd up with questions to pose tonight. They will be emailed later today and provided in Desk Packet. Encourage ST be mindful of short timeframe for some construction decisions. • Focus on slides relating to the ST2 Operating plan, now and beyond ST2. Explain how trains actually travel for service and constraints on the operations. • Send email to Betty Spieth reminding on agenda tonight. • Note significant contribution to regional transportation by siting of Metro bus and OMSF in prime TOD area.	PowerPoint/Desk Packet item ST representatives will be at table. Please reserve seating in front row for them – likely 3 spots. Provide feedback to ST – need "best presenter". Talk to Rick I.	
PACE MOU: • Noted Cmbr Chelminiak concern re: "will" v. "may" language, particularly page 3 discussion of City role. • Would have been better for City Council to have seen this before PACE Board signed the MOU.	Print out copies of MOU for Desk Packet tonight.	

General administration		
Item(s)	**Assignments**	
Figure out how to provide PowerPoints to Council to view on personal laptops during Council meetings. (provide to Claudia for her Surface) How will this affect use of Granicus for agenda/packet?		
Remind Council to be mindful of tight agenda through Recess. Be aware if missing meetings that may not be able to work around specific topics.		
Council Vision and Priorities: Claudia will introduce/lead the discussion. Action may be postponed if Councilmembers present wish to wait for return of missing members.		
Prepare memo for Human Services Commission appointments.	Desk Packet tonight	
Future Meetings/Calendaring		
Recreational Marijuana • Has sufficient direction been provided to Planning Commission? How is mixed-use zoning implicated in "no residential zones"? • Important for staff and Stokes to be aware that have given direction in form of draft ordinance. Not expecting major changes.		

Clyde Moore, P.E.

8436-129th Place Southeast *Email: cnmoore@farallonconsulting.com*
Newcastle, WA 98056-1764 *Telephone: (425) 757-0111*

February 24, 2014

Re: Energize Eastside Project

As a civil engineer familiar with design and construction of a wide variety of projects, I have the following comments and questions regarding PSE's Energize Eastside project:

1. Your 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) 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.

2. 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.

3. 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?

4. 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?

5. 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.

6. 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.

Jean Garber

8436-129th Place Southeast *Email: jgarber11@comcast.net*
Newcastle, WA 98056-1764 *Telephone: (425) 277-9327*

February 24, 2014

Re: Energize Eastside Project

Based on 35 years' experience managing the environmental review of major regional projects, I have the following comments and questions regarding PSE's Energize Eastside project:

1. Please provide Olympus residents with computer-generated simulations showing how the proposed transmission facilities would look from various viewpoints in the Olympus neighborhood. For each viewpoint, provide an actual photo of the existing towers and transmission lines side-by-side with a simulated photo in which the current facilities are removed and the new facilities are in place. The viewpoints selected for this photo analysis should be those from which views would be most altered or view blockage would occur (such as blockage of views of Mt. Rainier). Where needed, PSE should seek permission from homeowners to take photos from view windows. Photos should be taken on clear days with good visibility.

2. Please provide Olympus residents with letters from both PSE and from the owner/operator of the gas pipelines in the PSE transmission corridor indicating how they will guarantee public safety in light of the issues raised by my husband, Clyde Moore.

3. Please provide a list of agency permits required for the route through Newcastle.

4. Who will be the lead agency for the EIS? Will there be any federal action or funding that requires compliance with NEPA as well as with SEPA? What alternatives and elements of the environment does PSE propose to subject to detailed analysis in the EIS, and when will formal EIS scoping occur?

5. As a potentially affected Olympus resident, I expect assurance from PSE that any and all environmental analyses, including aesthetics and public safety, will be conducted by expert and objective third-party consultants with no financial or other interest in the outcome of the project.

From: "Hamilton, Sephir" <Sephir.Hamilton@seattle.gov>
Subject: RE: SCL Eastside Line
Date: June 1, 2017 at 1:36:58 PM PDT
To: Larry Johnson <larry.ede@gmail.com>

Mr. Johnson –

After conferring with staff, our currently adopted 2016 load forecast calls for system kWh sales to grow cumulatively by 1.6% from 2016 to 2021. That said, we regularly refine that forecast and it is likely to change later this year. I should also clarify that I believe it was my intent in that video to say that we were projecting load growth of less than half a percent per year over that five year period, and if I omitted the “per year” then I misspoke.

From 2014 to 2016, kWh consumption by all Seattle City Light customers declined by approximately 2.1% for residential customers and 1.5% for non-residential customers.

Best regards,

SEPHIR HAMILTON **SEATTLE CITY LIGHT**
(206) 684-3718

From: Larry Johnson [mailto:larry.ede@gmail.com] **Sent:** Sunday, May 07, 2017 4:22 PM **To:** Hamilton, Sephir <Sephir.Hamilton@seattle.gov> **Cc:** Weis, Larry <Larry.Weis@seattle.gov> **Subject:** Re: SCL Eastside Line

Dear Mr. Hamilton,

Thank you for your reply letter.

I have found a YouTube video where you address an audience in 2014 regarding the success of energy conservation in the Seattle area. Specifically, at https://youtu.be/gZWM-yNxwZY, starting at 0:52 into the video, you state:

"In the last four years nationwide, per-customer energy use has declined by 2%, both residential and non-residential. Here in Seattle it's declined 2.7% for non-residential, and it has declined 7.6% per customer for residential energy use. Even with all the growth that you see here in Seattle and south Lake Union, we're projecting total load growth of less than a half of a percent over the next five years. This is a huge change in the entire makeup of energy use industry in the United States, and especially here in Seattle where we're leading the way."

Since this video was taken in 2014, could you please provide me with updated information about what the demand decline has been up until now for your service area, and whether your projection of growth for the next five years remains at less than 0.5%?

Thank you in advance for updating this information.

Larry

Larry G. Johnson
Attorney at Law, WSBA #5682
Citizens for Sane Eastside Energy (www.sane-eastside-energy.org)
8505 129th Ave. SE
Newcastle, WA 98056
tel.: 425 227-3352
email: larrygh.ede@gmail.com

On Apr 25, 2017, at 3:17 PM, Hamilton, Sephir <Sephir.Hamilton@seattle.gov> wrote:

Dear Mr. Johnson –

Please see the attached letter addressed to you, in response to your March 20 letter to Mr. Weis.

SEPHIR HAMILTON | INTERIM OFFICER ENGINEERING & TECHNOLOGY INNOVATION

<image001.png>

sephir.hamilton @ seattle.gov TEL (206) 684-3718 CELL (206) 595-0705
ASSISTANT (206) 684-3885 the nation's greenest utility | LinkedIn | Facebook

<letter to SCL Weis.pdf><2017 04 25 Citizens for Sane Eastside Energy.pdf>

May 17, 2017

Attachment A - 1

Heidi Bedwell
City of Bellevue Development Services Department
450 110th Avenue NE
Bellevue, WA 98004

Re: Comment for Energize Eastside Phase 2 Draft EIS

Dear Ms. Bedwell:

I am writing to submit comments on the Energize Eastside Phase 2 Draft EIS.

These comments relate to the "need" for Energize Eastside

As I have mentioned in previous submissions, the need for Energize Eastside has never been established. I have provided significant documentation which supports the idea that it is not only not needed, but that PSE is attempting to push this project through using multiple baseless justifications.

The debate on need is rooted in a dispute about a proper load flow study. What keeps us from an open and honest discussion of the facts on which this entire project is based is PSE's refusal to allow any kind of scrutiny into the assumptions used by Quanta in load flow studies which they conducted for PSE. These studies, along with the studies conducted by USE, are the centerpieces of the justification for Energize Eastside.

PSE continues to refuse to show the details of the Quanta load flow study despite multiple requests and despite the fact that the Federal Energy Regulatory Commission (FERC) says I have a legitimate need to see this information. Yet the EIS process continues to march forward, presumably to its completion, while multiple red flags exist concerning how Quanta did their load flow study. The EIS staff continues to sidestep any real resolution of these red flags.

A $200-$300 million project with devastating and irrevocable consequences cannot be subject of guess work. No permit for Energize Eastside should be issued until a truly transparent, scientific process has been completed.

A new load flow study needs to be done in an open and transparent fashion with input from all stakeholders. That is what I asked FERC to require ColumbiaGrid to do. But FERC said that since PSE had not asked for Energize Eastside to be a part of the Regional Plan, then Energize Eastside is not subject to Order 1000. If PSE had asked for Energize Eastside to be part of the regional plan, this would have required ColumbiaGrid to do the studies in an open and transparent fashion with full stakeholder input. The ColumbiaGrid Regional Plan looks out over a ten-year planning horizon and identifies the transmission additions necessary to ensure that the parties to the ColumbiaGrid Planning and Expansion Functional Agreement can meet their commitments to serve regional load and meet firm transmission service commitments.

Attachment A - 2

It appears there were many reasons that PSE chose not to ask for Energize Eastside to be a part of a Regional Plan. I believe this was a deliberate step on their part.

- If Energize Eastside were part of a regional plan, then FERC would say how much BPA would pay for Energize Eastside BPA would pay PSE. By doing that, PSE pays less out of its own pocket. And that would mean a smaller increase in the PSE ratebase. Which means smaller PSE investment that will be given the 9.8% return by the WUTC. Macquarie wants to invest more money in PSE new ratebase. It does not help if BPA pays a lot of that money because that reduces what Macquarie spends and therefore the amount of the return on the investment.
- If part of a Regional Plan, ColumbiaGrid would have been required to do the studies (not Quanta) and ColumbiaGrid studies would have to be done in an open and transparent fashion with stakeholder input, and
- If part of a Regional Plan, then stakeholders would also get to identify alternatives. Those alternatives would include, for example,
    - Meeting any identified needs with DSM
    - Simply increasing the capacity of the Talbot Hill transformer
    - Building a small peaker plant somewhere on the Eastside
    - Utilizing the SCL Transmission line option.

According to section 1.3 of the EIS, "*the lead agency is responsible for ensuring that a proposal that is the subject of environmental review is properly defined. The process of defining the proposal includes an **understanding of the need for the project**, to enable a thorough understanding of the project's objectives*." Without an open and transparent load flow study with stakeholder input, there can be no shared understanding of the need for the project. The EIS staff needs to ensure full accordance with this statement before the EIS is finalized.

Sincerely,

Richard Lauckhart

Richard Lauckhart
Energy Consultant
44475 Clubhouse Drive
Davis, California 95618
530-759-9390
lauckjr@hotmail.com

Attachment B

From: Strauch, Bradley R <bradley.strauch@pse.com>
Sent time: 03/25/2016 11:24:12 AM
To: Mark Johnson <MJohnson@esassoc.com>
Cc: records@energizeeastsideeis.org; Bedwell, Heidi; Claire Hoffman <CHoffman@esassoc.com>; Nedrud, Jens V <jens.nedrud@pse.com>
Subject: RE: E2- Questions for PSE regarding the Lauckhart-Schiffman report
Attachments: Lauckhart-Schiffman Draft responses_20160318 PSE Response.docx

Mark,

PSE is providing the following information in response the questions posed in the attachment. However, as we have already stated in PSEs Phase 1 DEIS comments, the Lauckhart and Schiffman document does not meet the minimum federally required planning standards necessary to provide or develop meaningful results; therefore, it has no relevance when evaluating PSEs thoroughly vetted project proposal.

If you have any additional questions, please let us know as we will be glad to assist.

Brad Strauch

Sr. Land Planner/Environmental Scientist

PUGET SOUND ENERGY

P.O. Box 97034, PSE-09N

Bellevue, WA 98009-9734

Office: 425-456-2556

Fax: 425-462-3233

Cell: 425-214-6250

From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Monday, March 21, 2016 6:25 PM
To: Strauch, Bradley R
Cc: Heidi Bedwell; Claire Hoffman; records@energizeeastsideeis.org
Subject: E2- Questions for PSE regarding the Lauckhart-Schiffman report

Brad
As we mentioned a couple weeks back, we have a few questions that arose from reading the Lauckhart Schiffman Report. We are trying to address issues raised by the report in the comment summary, the first draft of which is due very soon, so we ask for a quick turnaround on these. The attached is a draft section we have created to respond to the issues raised. Our intent here is to clarify facts that we believe PSE can best provide, and the questions are as close-ended as we could make them. Could you take a look and let us know how quickly you can turn this information around? If we could have answers by the end of the week, that would be great.

Mark S Johnson

Director

ESA | Northwest Community Development

5309 Shilshole Avenue NW, Suite 200

Seattle, WA 98107

206.789.9658 main

206.576.3750 direct | 206.550.0723 cell

mjohnson@esassoc.com <mailto:mjohnson@esassoc.com> | <www.esassoc.com>

Follow us on Facebook <http://www.facebook.com/pages/Environmental-Science-Associates/347741357652?

Attachment C

City of Seattle

Seattle City Light

June 2, 2014

Mr. Nicholas Matz
Planning & Community Development Department
450 110th Avenue NE
P.O. Box 90012
Bellevue, WA 98009

Dear Mr. Matz:

Seattle City Light (SCL) has transmission facilities that run through the City of Bellevue and other jurisdictions on the east side of Lake Washington. The SCL transmission lines in Bellevue were installed in the early 1940's to transfer power from hydro-generation in the North Cascades to the west side of Lake Washington. Puget Sound Energy (PSE) has lines in the same general vicinity which primarily serve the PSE customer load east of Lake Washington.

SCL's double circuit 230kV transmission lines are used to meet current and future operating needs. Specifically, SCL needs the connectivity and capacity of these transmission lines to:

- Maintain a contiguous Point of Delivery for transmission service from BPA;
- Serve existing load growth and maintain reliability;
- Provide for future SCL growth;
- Support regional transmission flows; and
- Meet NERC reliability requirements.

SCL foresees current and future uses of these existing east side facilities and prefers not to utilize SCL's transmission lines for PSE's native load service needs.

Please contact me via email at uzma.siddiqi@seattle.gov if you have any questions.

Sincerely,

Uzma Siddiqi

Uzma Siddiqi, PE
System Planning Engineer

cc: Phil West
Tuan Tran

Seattle City Light

700 5th Ave. | P.O. Box 34023 | Seattle WA 98124-4023
TEL (206) 684-3000 TTY/TDD (206) 684-3225 FAX (206) 625-3709
seattle.gov/light
twitter.com/SEACityLight facebook.com/SeattleCityLight

Attachment D

April 25, 2017

Mr. Larry Johnson
Attorney at Law
Citizens for Sane Eastside Energy (CSEE)
8505 129th AVE SE
NEWCASTLE, WA 98056

Re: PSE's Energize Eastside Project

Dear Mr. Johnson,

This letter responds to your letter dated March 20, 2017 to our General Manager, Larry Weis. We appreciate your interest in the regional energy issues and are aware of your concerns regarding Puget Sound Energy's ("PSE") Energize Eastside Project. As your letter mentions, although PSE and Seattle City Light have had limited discussions about PSE's Energize Eastside Project, PSE has never formally requested transmission service on Seattle City Light's Eastside transmission lines.
Obviously, if PSE would make a formal request for transmission service on Seattle City Light's Eastside lines, Seattle City Light would respond appropriately. Likewise, Seattle City Light remains willing to discuss options with PSE regarding the potential use of Seattle's Eastside lines. However, as PSE's project located entirely within its own service territory, PSE's project remains within PSE's discretion.

In addition, the Energize Eastside Project is not subject to the Order No. 1000 regional approval process because it is located completely within Puget Sound's service territory, it was included in Puget Sound's local transmission plan to meet Puget Sound's reliability needs, and neither Puget Sound, nor any other eligible party, requested to have the project selected in the regional transmission plan for purposes of cost allocation.

We trust that this resolves the concerns expressed in your March 20th letter with respect to Seattle City Light.

Sincerely,

Sephir Hamilton
Engineering and Technology Innovation Officer
Seattle City Light

cc: Larry Weis, General Manager, Seattle City Light

Attachment E -1

May 11, 2017

Heidi Bedwell
City of Bellevue Development Services Department
450 110th Avenue NE
Bellevue, WA 98004

Re: Comment for Energize Eastside Phase 2 Draft EIS

Dear Ms. Bedwell:

I am writing to submit comment on the Energize Eastside Phase 2 Draft EIS.

This comment relates to pages 2-52 of the Phase 2 Draft EIS. In particular section 2.2.1 "Seattle City Light Transmission Line" option.

In order to understand how this option works, one needs to be familiar with FERC's ProForma Open Access Transmission Tariff (OATT). The FERC ProForma Open Access Transmission Tariff can be found at:
https://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890-B/pro-forma-open-access.pdf

Section 6 of the OATT discusses "Reciprocity". If SCL uses the lines of one or more FERC directly regulated utilities, then SCL will have agreed to these terms when they use those lines. Meaning under reciprocity, SCL agrees to also deal with requests for use of their transmission grid under the FERC OATT approach.

Other sections of interest to this SCL Transmission Line option are:
Section 15. Service Availability
Section 16. Transmission Customer Responsibility
Section 17. Procedures for arranging for Firm Point to Point transmission service
[*This section is particularly relevant to how PSE needs to ask SCL for use of its line to serve a new 230/115 KV transformer at Lakeside.* ***There is a requirement to make a formal application in the format that is described in the OATT. PSE has never made such an application. An informal request does not meet the required format for making a request to use the SCL line. PSE needs to make this formal request to SCL***].
Section 19. Additional studies procedures for Firm Transmission

With an understanding of how FERC's OATT works, it is clear that just about every sentence in the discussion of the SCL option is incorrect, meaning these sentences are not consistent with the OATT.

First sentence:
"*SCL has indicated to the City of Bellevue that they expect to need the corridor for their own purposes and are not interested in sharing the corridor with PSE (SCL, 2014).*"

The EIS staff should already be aware that FERC does not allow a utility like SCL to "hoard" its transmission capability. Further, the FERC OATT requires a utility like SCL to increase the rating of its infrastructure (with needed construction) if that is what it takes to honor a request for transmission and the requesting utility agrees to pay what FERC requires them to pay. No one has performed a System Impact Study (as required by the OATT) to see what it would take to honor a PSE request to use the SCL line to serve a new 230/115 KV transformer at Lakeside.

Second sentence:
"*The existing SCL line would have to be rebuilt to provide a feasible solution for the Energize Eastside project, because the current rating of the SCL line is insufficient to meet PSE's needs (Strauch, personal communication, 2015).*"

If it can be shown that the existing SCL line would need to be rebuilt to provide a feasible solution for the Energize Eastside project, then that is what the FERC OATT would require be done as long as PSE agrees to pay what FERC would require them to pay for that construction. Until a study is done, one cannot tell for sure what the rebuild cost would be. But it certainly would be less than the cost of Energize Eastside. Further, it should be clear that the request to use the SCL line is only for purposes of serving a new 230/115 KV transformer at Lakeside. <u>The study to determine what this cost must not include a requirement to deliver 1,500 MW to Canada</u> unless BPA makes that request and BPA would pay the bulk of the needed cost if the SCL line is also being used to increase the ability of BPA to deliver power to Canada.

Third Sentence:
"*PSE has estimated that rebuilding the SCL line would provide sufficient capacity for a period of less than 10 years, which does not comply with PSE's electrical criteria (as described in Section 2.2.1 of the Phase 1 Draft EIS) to meet performance criteria for 10 years or more after construction.*"

Under the FERC OATT rules that SCL needs to comply with, SCL does not get to stop serving Lakeside after ten years even if SCL has a legitimate need for more use of its SCL line at that time. The FERC OATT has clear rules on how a utility like PSE can assure its transmission service from SCL can be retained even after SCL decides it needs the line for its own use. The FERC OATT protects a utility like PSE from SCL stopping to provide them transmission service.

Fourth Sentence:
"*Neither the City nor PSE can compel SCL to allow the use of this corridor; therefore, this option is not feasible and was not carried forward.*"

This statement is wrong. PSE can compel SCL to use its line to serve a new 230/115 KV transformer by making a FERC Order 888 request (under the FERC OATT) for such transmission service. If SCL refuses, FERC will compel them to do so. FERC uses its "reciprocity" ruling to compel SCL. If SCL refuses, FERC will refuse to let SCL use any transmission lines that are under direct FERC jurisdiction. SCL could not meaningfully its service obligations to its own customers without using the transmission lines of FERC directly jurisdictional utilities.

Fifth Sentence:

"Even if compelled use of the corridor were allowed, the negotiations would likely prove lengthy, and would likely preclude completion of the project within the required timeline to meet project objectives."

The FERC OATT has tight timelines for dealing with requests for transmission service. FERC intentionally put in these tight timelines to prohibit a utility like SCL from denying service by delaying service. Further, PSE currently is not saying when it thinks it needs a new 230/115 KV transformer to be in service at Lakeside. Any needed construction on the existing SCL line will take considerably less time than permitting and building EE. Further, according to the only reasonable load flow study done regarding serving the east side (the Lauckhart-Schiffman Load Flow study), there is plenty of time before any new 230/115 KV transformer is needed at Lakeside.

Thank you for the opportunity to clarify how this SCL Transmission Line option would work.

Sincerely,

Richard Lauckhart

Richard Lauckhart
Energy Consultant
Davis, California
530-759-9390
lauckjr@hotmail.com

Citizens for Sane Eastside Energy (CSEE)

May 8, 2017

Attachment F -1

The Washington Utilities and Transportation Commission
98504-7250, 1300 Evergreen Park Dr SW
Olympia, WA 98502

sent by email to the individual Commissioners

Dear Commissioners:

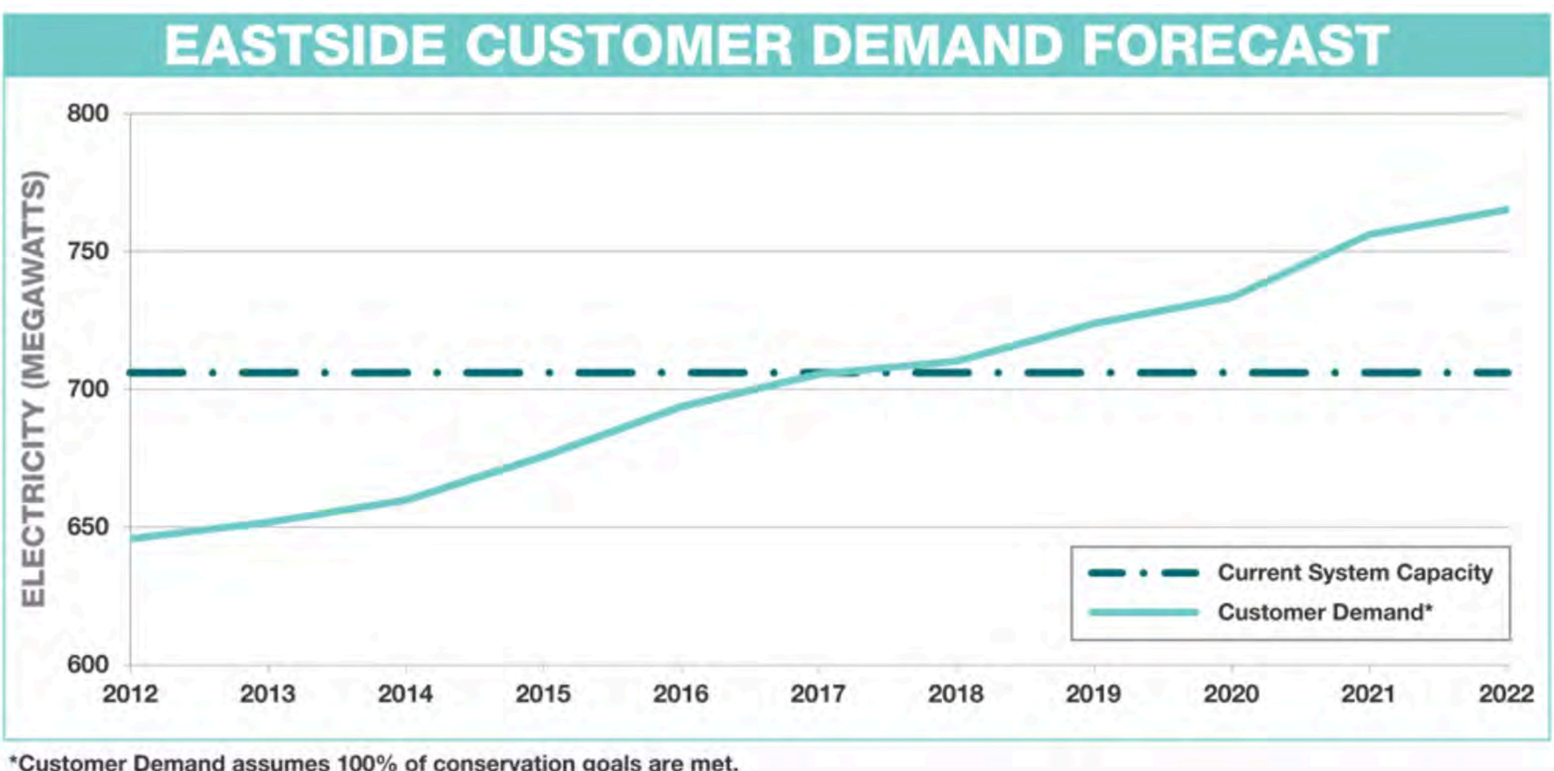
This letter is in response to comments made in an email by Mr. Jens Nedrud of PSE to you and others, dated May 4, 2017, regarding PSE's Energize Eastside project and a 3/16 IRPAG meeting.

Mr. Nedrud's remarks are misleading and distort the facts, yet they are unfortunately consistent with PSE's determined hard-sell methods to get the $200-$300 million project built at all costs, regardless of the economic waste and the grave risk to lives and property if built as proposed, i.e. too close to two aging pipelines transporting highly flammable petroleum products under pressure.

The two chief mantras PSE keeps repeating in its PR efforts to sell Energize Eastside are: 1) There is so much economic and population growth on the Eastside, the project is needed to meet a generic "consumer demand;" and 2) Nothing has been done "since the 1960s" to upgrade the grid in the Eastside. The ads PSE has published in numerous media outlets repeatedly beat these "Consumer Demand" and "Need for Upgrade" drums. CSEE has collected over two dozen of them.

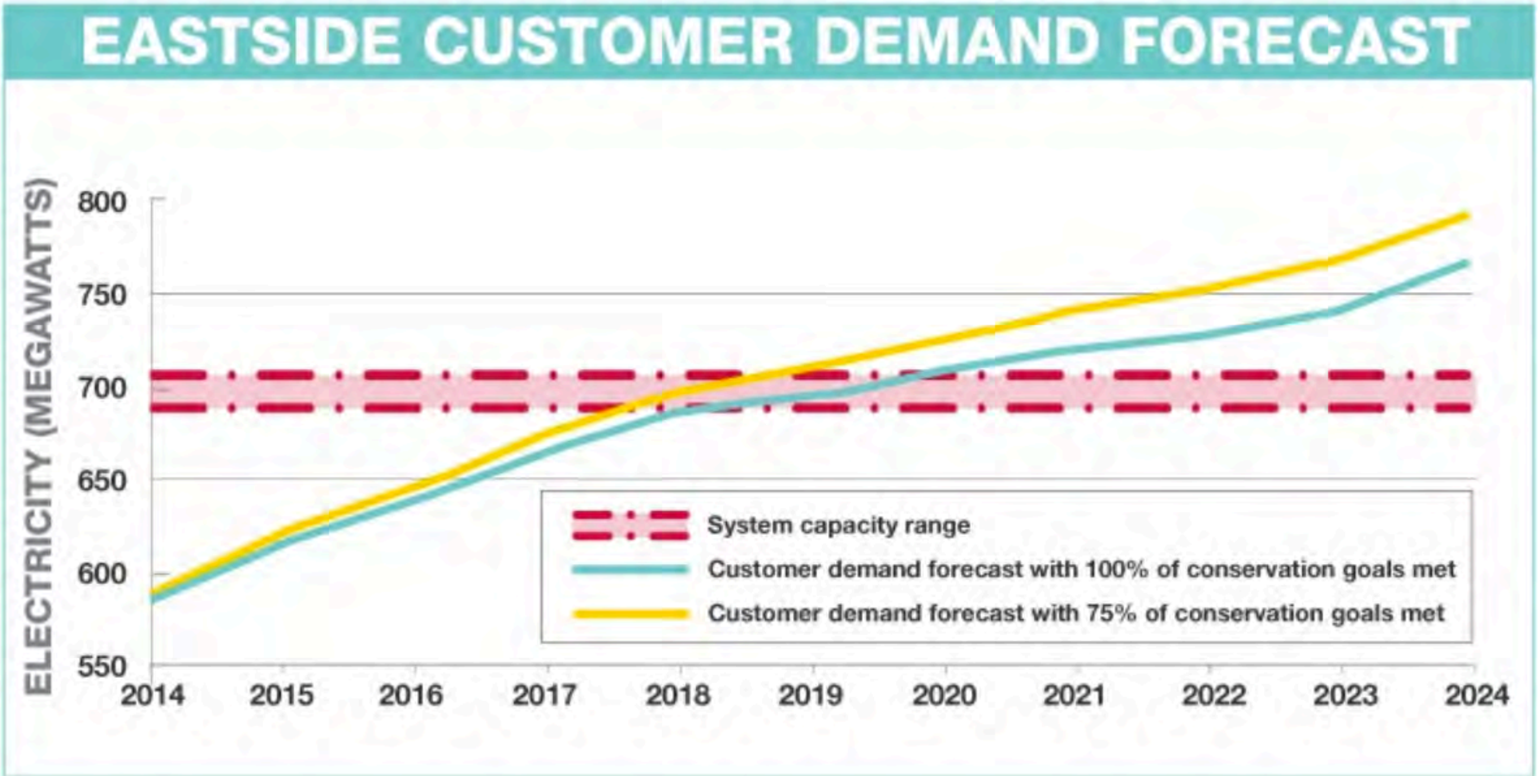
PSE's inflated consumer demand claims

In December of 2013, PSE had on its website dedicated to the Energize Eastside project the following chart, which was its prime lead-in to justify the project. Words introducing the chart stated that "[g]rowth studies predict that demand for reliable power will exceed capacity as early as 2017:"



Two years later, in December 2015, that chart was replaced by this one:

Attachment F - 2



This chart was accompanied with a warning: "Without substantial electric infrastructure upgrades, tens of thousands of residents and businesses will be at risk of more frequent and longer power outages."

That is a gross and irresponsible exaggeration. From the graph above, it appears PSE anticipates a spectacular (and preposterous) Eastside demand growth rate of 4% in the next four years. That is ten times the future growth rate predicted for a wildly booming Seattle by Seattle City Light's Sephir Hamilton, Engineering and Technology Innovation Officer, who in 2014 laid out these facts (https://youtu.be/gZWM-yNxwZY, starting at 0:52 into the video):

> "In the last four years nationwide, per-customer energy use has declined by 2%, both residential and non-residential. Here in Seattle it's declined 2.7% for non-residential, and it has declined 7.6% per customer for residential energy use. Even with all the growth that you see here in Seattle and south Lake Union, we're projecting total load growth of less than a half of a percent over the next five years. This is a huge change in the entire makeup of energy use industry in the United States, and especially here in Seattle where we're leading the way."

I have asked Mr. Hamilton to update this data with what is known now in 2017, and I will update with that information when received. Meanwhile, PSE no longer has a chart on its Energize Eastside website with growth projections. But that does not deter it from making outlandish growth claims.

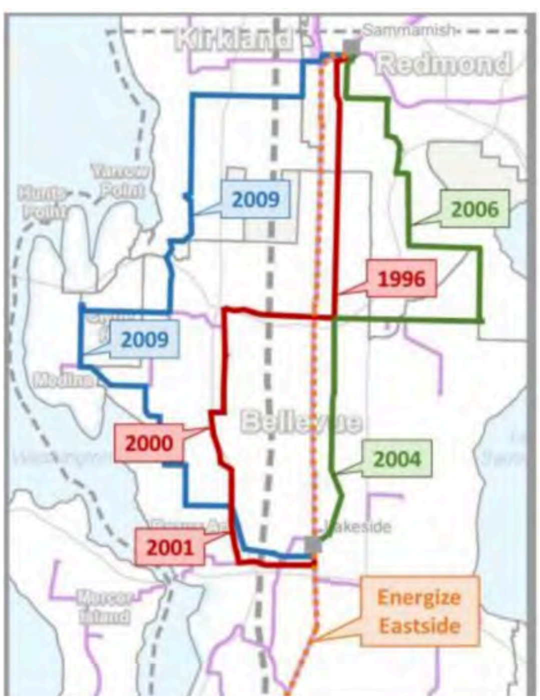
<u>PSE's false "no update since the 1960s" claims</u>

Here is an example of one of several ads of like content that PSE has published in various media outlets:

Note the blatant falsehood contained in this ad: "The Eastside electric grid was last upgraded in the 1960s." The ad also makes a false correlation between general daily electricity usage and power outages, when PSE knows full well the ostensible need for Energize Eastside is to meet very rare N-1-1 emergency events where federally mandated reliability is the only issue, not the general daily supply and demand for electricity.

As former Puget Power Vice President for Power Planning, Richard Lauckhart, has argued in documents he has sent you, there have been numerous upgrades and expansions made to the Eastside grid since the 1960s, as illustrated in this graphic for lines added and the years they were built:

New 115 KV lines built in the Eastside in recent years



In conclusion, whether in terms of PSE's complying with your requirements for a proper and adequate IRP, or whether as evidence at some future rate hearing on Energize Eastside when you will need all the facts, it remains that PSE simply cannot be trusted to tell the truth when so much of its future profits are at stake. You will recall that the WUTC levied its greatest fine ever on a utility, $1.25 million, for PSE's having intentionally falsified gas pipeline safety inspection records over a period of four years (see https://sane-eastside-energy.org/2014/04/30/pse-fined-1-25-million-in-falsifying-gas-pipeline-safety-inspection-reports-for-4-years-running/). It is thus not totally surprising that, while Mr. Nedrud finds flaws in the Lauckhart-Schiffman load flow studies, PSE has yet to release CEII-related data PSE submitted for the studies it relies on that would reveal what sorts of fundamental assumptions were used, even though FERC made it clear to PSE that Mr. Lauckhart and CENSE's Don Marsh have CEII clearances and should be given access to that CEII data.

PSE has stubbornly refused to provide that information. The WUTC should demand that they do.

I realize the power the WUTC has to regulate and influence PSE is woefully inadequate. But for a project with such great potential for irrevocable damage, I hope the WUTC can use its own resources to conduct fully unbiased and untainted flow studies, if need be, to determine for itself the need for Energize Eastside, or at least to establish the validity of such studies as have been done. This is, after all, your area of expertise and public trust. That would be a positive effort undertaken for the common good of all Washingtonians and for the future of our environment.

Sincerely,

Larry G. Johnson
Attorney at Law, WSBA #5682
Citizens for Sane Eastside Energy (CSEE), www.sane-eastside-energy.com
8505 129th Ave. SE
Newcastle, WA 98056
tel.: 425 227-3352
larry.ede@gmail.com

cc: CENSE
City Councils of Bellevue, Newcastle, Redmond and Renton
NW Energy Coalition
Sierra Club

Citizens for Sane Eastside Energy (CSEE)

8505 129th Ave. SE
Newcastle, WA 98056
tel.: 425 227-3352
email: larry.ede@gmail.com

May 22, 2017

Ms. Heidi Bedwell
Energize Eastside EIS Program Manager
City of Bellevue Development Services Dept.
450 110th Ave. NE
Bellevue, WA 98004 submitted by email to info@EnergizeEastsideEIS.org

Re: Comments regarding Energize Eastside Phase 2 Draft EIS

According to section 1.3 of the Phase 2 Draft EIS, "the lead agency is responsible for ensuring that a proposal that is the subject of environmental review is properly defined. **The process of defining the proposal includes an understanding of the need for the project, to enable a thorough understanding of the project's objectives**" (emphasis added). CENSE's expert on Northwest regional power planning, Richard Lauckhart, submitted on May 17, 2017, a white paper detailing the complete failure of the EIS process and EIS drafts to address the fundamental issue of project need. His comments are attached hereto as Attachment A.

We agree. It is manifestly absurd to blindly push ahead with evaluating a proposed project's potential environmental impacts if the project itself makes no sense. And certainly nothing could be more central to the project's "No Action" "alternative" than proof that building Energize Eastside ("EE") would satisfy no legitimate need.

Citizens for Sane Eastside Energy (CSEE) is composed chiefly of persons who are most directly threatened by the dangers to life and property if PSE's proposed Energize Eastside project is allowed to go forward. While some may find it easy to dismiss CSEE as "NIMBY" ("Not In Our Back Yard"), the truth, no matter by whom spoken, still remains the truth. We submit EE is driven solely by PSE's foreign investor owners who stand to make up to a handsome 9.8% return on EE if built. That is the real motivation for PSE's wanting to build a boondoggle that should be in *no-one's* back yard.

It is difficult to assess the many problems associated with EE, not only because of a number of complex technical issues involved, but also because PSE has been from the outset duplicitous and fraudulent in presenting a number of misleading justifications for the project.

There are at least four major areas of such deceit underlying PSE's determined efforts to hard-sell Energize Eastside that will be addressed here. They are:

1. EE is based on a failed ColumbiaGrid flow study that included exaggerated, false NERC criteria.

The project's foundational justification is a uniquely strange, failed load flow study conducted by ColumbiaGrid in 2013, the results of which (the studies did not "solve") were dismissed by ColumbiaGrid then as something one could comfortably ignore since the studies bizarrely *exceeded* NERC requirements.[1] But those unnecessarily beefed-up, false criteria for that failed "informational" study nevertheless found their way into the Quanta flow studies that are fundamental to PSE's argument for the supposed need for EE. For further details, see Attachment A.

In short, the core rationale for EE is based on a fairy tale.

The fact that PSE's aggressive pitches for EE are founded in myth is further buttressed by the fact that PSE steadfastly refuses to release to CENSE's expert the data inputs used in the Quanta studies done under PSE's supervision and control, even though FERC has made it clear to PSE that CENSE's expert is entitled to see and study that information.

The Lauckhart-Schiffman flow studies are the only untainted studies ever done for EE, and they show no need for EE. Yet an email from PSE's Bradley Strauch to Mark Johnson of ESA, dated 3/25/2016, attached hereto as Attachment B, reveals that PSE still clings to the exaggerated "informational" ColumbiaGrid flow studies criteria beyond those required of NERC when criticizing the Lauckhart-Schiffman studies for not meeting those absurd criteria which Strauch mischaracterizes as "minimum:"

> "…as we have already stated in PSEs Phase 1 DEIS comments, the Lauckhart and Schiffman document does not meet the minimum federally required planning standards necessary to provide or develop meaningful results; therefore, it has no relevance when evaluating PSE [sic] thoroughly vetted project proposal."

---

[1] See page 12 of the ColumbiaGrid 2013 System Assessment Report, first full bulleted paragraph, which includes this language: **"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"** (emphasis added). That is to say, the study used three major failure events occurring in the scenario tested, or what NERC calls an "N-1-1-1 event," when only two critical system component failures are required for NERC compliance, i.e. an "N-1-1 event." ColumbiaGrid is not known to do studies for "information purposes" only, and we submit that PSE wanted these bizarre studies done in order to create a justification for EE. The ColumbiaGrid 2013 System Assessment Report is available online at https://www.columbiagrid.org/Notices-detail.cfm?NoticeID=109.

Ironically, it is rather the PSE/Quanta studies that are wrong and irrelevant, since their foundation is that failed, bogus ColumbiaGrid study.[2]

CSEE submits that a project of EE's magnitude, costing $200 to $300 million and portending catastrophic and irreversible consequences, should be solidly based on complete and totally transparent flow studies, trust, and clarity, involving simultaneously all stakeholders. If done fairly and openly, all parties affected by this controversial project stand to benefit.

2. PSE has misrepresented its desire and efforts to seek an alternative route with Seattle City Light.

One must conclude from the current EIS draft that PSE has apparently succeeded so far in selling the notion that PSE tried but failed to obtain Seattle City Light's (SCL's) permission to

---

[2]Probably aware that its rationale for EE as a reliability solution has become flimsy, PSE's justification for EE has morphed into one based on the need for a vague "system upgrade," discussed further in Item 4 in this document and Attachment F. A chronology:

1) October 2013. PSE/Quanta release their Eastside Needs Assessment. It states the need was identified with a power flow model (a/k/a load flow model). They indicate their input assumptions include 1,500 MW to Canada and a shut down of local generation from several peaker plants (built specifically to meet reliability emergencies!). This results in the very exaggerated NERC N-1-1-1 event that ColumbiaGrid found to be irrelevant and thus merely "informational."

2) December 2013. PSE (without Quanta) provides an Executive Summary of the Eastside Needs Assessment. That Executive Summary provides the infamous "Eastside Capacity and load line (The Problem)" graph where brownouts could start as soon 2017. The Executive Summary indicates that Quanta ran load flow studies, but the Executive Summary changes the justification for EE's need: the need to meet generic customer demand as shown in the "The Problem" graph (included in Attachment F-1 hereto). Note that Quanta did not sign on to this Executive Summary; it is a PSE-developed document.

3) 2014-2015: PSE draws a number of questions and criticisms regarding the assumptions in the Quanta load flow studies. Eventually, PSE's lead project consultant, Mark Williamson, goes on the record to admit that including the 1,500 MW to Canada in the Quanta studies was a mistake (YouTube video at https://youtu.be/UixzsxOmPic), yet PSE has never done anything to correct that mistake or counteract the wrong conclusions others have made from that mistake. PSE also cannot explain why it had Quanta shut down six local generators (peaker plants) in the load flow study. Not surprisingly, PSE has abandoned the myth that EE's need derives from a load flow study. Yet they refuse to re-run the load flow study without 1,500 MW to Canada or with all PSE generators running. The Lauckhart-Schiffman's studies do just that, however, resulting in their conclusion that there is no need for EE.

For the PSE/Quanta 1,500 MW assumption, see page 8 of the Eastside Needs Assessment at https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/Eastside_Needs_Assessment_Final_Draft_10-31-2013v2REDACTEDR1.pdf.
For the PSE/Quanta shut down of local generation, see Table 4-4 on page 32 of the same document.

4) 2016: PSE begins focusing on the aforementioned "Problem" graph that it published in its December 2013 Executive Summary. PSE revises that graph to include a mysterious "capacity" line at 700 MW and an exaggerated Eastside load growth that is some ten times greater than what Seattle City Light predicts for booming Seattle. See Attachment F-2. PSE removes the embarrassing 2013 graph from its website and abandons use of it as the basis for the need for EE.

5) 2017: PSE's selling point for EE is now: "Nothing has been done to update the Eastside grid for 50 years," a blatantly false claim refuted in Attachment F.

share SCL's Eastside line as a route for EE, a route PSE spokespersons repeatedly assured citizens at public meetings was PSE's "first choice" for EE.

A variant of this misleading narrative is found on the FAQ page of PSE's website dedicated to EE:

> "**Routing**
>
> " •Why can't PSE use the Seattle City Light corridor that runs from Redmond to Renton?
>
> "PSE **looked into** using the Seattle City Light corridor and **yes, if rebuilt, the corridor could work to meet the Eastside's energy needs.** However, PSE has been told by Seattle City Light that this corridor is a key component of their transmission system and **<u>is not available for our use</u>**." (emphasis added; from <u>http://energizeeastside.com/faqs</u>)

The underlined words in the last sentence of that paragraph are a link to a June 2, 2014, letter from Uzma Siddiqi, SCL's System Planning Engineer, to the City of Bellevue's Mr. Nicholas Matz, Attachment C, where she writes:

> "SCL foresees current and future uses of these existing east side facilities and **prefers not to utilize** SCL's transmission lines for PSE's native load service needs." (emphasis added).

"Prefers not to utilize" is hardly the same thing as "refuses to allow." And note that Ms. Siddiqi's letter is directed to a City of Bellevue employee and not to PSE, who in fact never even tried to make a formal request for sharing those lines. That conclusion is made crystal clear in an April 25, 2017, letter from SCL's Sephir Hamilton, Engineering and Technology Innovation Officer, to me, Attachment D:

> "As your letter mentions, although PSE and Seattle City Light have had limited discussions about PSE's Energize Eastside Project, **PSE has never formally requested transmission service on Seattle City Light's Eastside transmission lines. Obviously, if PSE would make a formal request for transmission service on Seattle City Light's Eastside lines, Seattle City Light would respond appropriately.**" (emphasis added)

CSEE submits that PSE never tried to act on its "first choice" for an EE route because to have done so would have deprived its owners of a highly lucrative project, boondoggle though it be.

Further, virtually none of the information PSE has provided the authors of this latest draft EIS about the very real and superior SCL Eastside lines alternative to EE (assuming *arguendo*

something like EE is needed) is accurate. In the May 11, 2017, letter of CENSE's expert, Richard Lauckhart, to Ms. Heidi Bedwell, Attachment E, there are paragraphs cited from the current draft EIS which in part or in whole contain incomplete or erroneous information, with his rebuttals of same. Those comments further buttress the conclusion that if PSE were to follow the steps as outlined in FERC Order 888, SCL would have little choice but to cooperate with PSE in coming up with a far more workable, less expensive, and above all, less dangerous solution than EE, assuming there is any objective need for EE.

The Phase 2 draft EIS is woefully inadequate and simply wrong when it comes to the SCL Eastside line alternative, and it needs to be completely done over again without PSE pressure or interference.

3. PSE has mounted an aggressive PR campaign, similar in kind and credibility to a political campaign,[3] in order to mislead the public into thinking EE will fulfill a need to meet future Eastside growth that PSE claims is 10 times that of booming Seattle.

For details, see Attachment F-1 and F-2.

4. PSE repeatedly and falsely advertises the lie that EE is needed as a "long overdue Eastside grid upgrade" despite several expansions of the Eastside grid in the past two decades.

For details, see Attachment F-2 through F-4.

Sincerely,

Larry G. Johnson
Attorney at Law, WSBA #5682
Citizens for Sane Eastside Energy (CSEE)

cc: CENSE

---

[3] To head up PSE's aggressive PR campaign, it went as far as Wisconsin to hire lawyer Mark Williamson to act as its chief consultant for getting the project through the approval processes. Williamson's website brags about his prowess in getting projects like Energize Eastside approved by treating them the same way as a political campaign: "Williamson has developed a strategic communications technique patterned on 'election campaigning' – polling, message development and communication – tools that he employs, and has for years, to get utility projects approved, sited, built and on-line. He is a hands-on utility executive that gets the job done from day one." http://prwcomm.com/now/?page_id=71. PSE's strategy is all about winning rather than fairly arguing the merits of the project or considering possible options that would better serve the public interest.

May 17, 2017

Attachment A - 1

Heidi Bedwell
City of Bellevue Development Services Department
450 110th Avenue NE
Bellevue, WA 98004

Re: Comment for Energize Eastside Phase 2 Draft EIS

Dear Ms. Bedwell:

I am writing to submit comments on the Energize Eastside Phase 2 Draft EIS.

<u>These comments relate to the "need" for Energize Eastside</u>

As I have mentioned in previous submissions, the need for Energize Eastside has never been established. I have provided significant documentation which supports the idea that it is not only not needed, but that PSE is attempting to push this project through using multiple baseless justifications.

The debate on need is rooted in a dispute about a proper load flow study. What keeps us from an open and honest discussion of the facts on which this entire project is based is PSE's refusal to allow any kind of scrutiny into the assumptions used by Quanta in load flow studies which they conducted for PSE. These studies, along with the studies conducted by USE, are the centerpieces of the justification for Energize Eastside.

PSE continues to refuse to show the details of the Quanta load flow study despite multiple requests and despite the fact that the Federal Energy Regulatory Commission (FERC) says I have a legitimate need to see this information. Yet the EIS process continues to march forward, presumably to its completion, while multiple red flags exist concerning how Quanta did their load flow study. The EIS staff continues to sidestep any real resolution of these red flags.

A $200-$300 million project with devastating and irrevocable consequences cannot be subject of guess work. No permit for Energize Eastside should be issued until a truly transparent, scientific process has been completed.

A new load flow study needs to be done in an open and transparent fashion with input from all stakeholders. That is what I asked FERC to require ColumbiaGrid to do. But FERC said that since PSE had not asked for Energize Eastside to be a part of the Regional Plan, then Energize Eastside is not subject to Order 1000. If PSE had asked for Energize Eastside to be part of the regional plan, this would have required ColumbiaGrid to do the studies in an open and transparent fashion with full stakeholder input. The ColumbiaGrid Regional Plan looks out over a ten-year planning horizon and identifies the transmission additions necessary to ensure that the parties to the ColumbiaGrid Planning and Expansion Functional Agreement can meet their commitments to serve regional load and meet firm transmission service commitments.

Attachment A - 2

It appears there were many reasons that PSE chose not to ask for Energize Eastside to be a part of a Regional Plan. I believe this was a deliberate step on their part.

- If Energize Eastside were part of a regional plan, then FERC would say how much BPA would pay for Energize Eastside BPA would pay PSE. By doing that, PSE pays less out of its own pocket. And that would mean a smaller increase in the PSE ratebase. Which means smaller PSE investment that will be given the 9.8% return by the WUTC. Macquarie wants to invest more money in PSE new ratebase. It does not help if BPA pays a lot of that money because that reduces what Macquarie spends and therefore the amount of the return on the investment.
- If part of a Regional Plan, ColumbiaGrid would have been required to do the studies (not Quanta) and ColumbiaGrid studies would have to be done in an open and transparent fashion with stakeholder input, and
- If part of a Regional Plan, then stakeholders would also get to identify alternatives. Those alternatives would include, for example,
    - Meeting any identified needs with DSM
    - Simply increasing the capacity of the Talbot Hill transformer
    - Building a small peaker plant somewhere on the Eastside
    - Utilizing the SCL Transmission line option.

According to section 1.3 of the EIS, "*the lead agency is responsible for ensuring that a proposal that is the subject of environmental review is properly defined. The process of defining the proposal includes an* ***understanding of the need for the project****, to enable a thorough understanding of the project's objectives*." Without an open and transparent load flow study with stakeholder input, there can be no shared understanding of the need for the project. The EIS staff needs to ensure full accordance with this statement before the EIS is finalized.

Sincerely,

Richard Lauckhart

Richard Lauckhart
Energy Consultant
44475 Clubhouse Drive
Davis, California 95618
530-759-9390
lauckjr@hotmail.com

From:	Strauch, Bradley R <bradley.strauch@pse.com>
Sent time:	03/25/2016 11:24:12 AM
To:	Mark Johnson <MJohnson@esassoc.com>
Cc:	records@energizeeastsideeis.org; Bedwell, Heidi; Claire Hoffman <CHoffman@esassoc.com>; Nedrud, Jens V <jens.nedrud@pse.com>
Subject:	RE: E2- Questions for PSE regarding the Lauckhart-Schiffman report
Attachments:	Lauckhart-Schiffman Draft responses_20160318 PSE Response.docx

Attachment B

Mark,

PSE is providing the following information in response the questions posed in the attachment. However, as we have already stated in PSEs Phase 1 DEIS comments, the Lauckhart and Schiffman document does not meet the minimum federally required planning standards necessary to provide or develop meaningful results; therefore, it has no relevance when evaluating PSEs thoroughly vetted project proposal.

If you have any additional questions, please let us know as we will be glad to assist.

Brad Strauch

Sr. Land Planner/Environmental Scientist

PUGET SOUND ENERGY

P.O. Box 97034, PSE-09N

Bellevue, WA 98009-9734

Office: 425-456-2556

Fax: 425-462-3233

Cell: 425-214-6250

From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Monday, March 21, 2016 6:25 PM
To: Strauch, Bradley R
Cc: Heidi Bedwell; Claire Hoffman; records@energizeeastsideeis.org
Subject: E2- Questions for PSE regarding the Lauckhart-Schiffman report

Brad
As we mentioned a couple weeks back, we have a few questions that arose from reading the Lauckhart Schiffman Report. We are trying to address issues raised by the report in the comment summary, the first draft of which is due very soon, so we ask for a quick turnaround on these. The attached is a draft section we have created to respond to the issues raised. Our intent here is to clarify facts that we believe PSE can best provide, and the questions are as close-ended as we could make them. Could you take a look and let us know how quickly you can turn this information around? If we could have answers by the end of the week, that would be great.

Mark S Johnson

Director

ESA | Northwest Community Development

5309 Shilshole Avenue NW, Suite 200

Seattle, WA 98107

206.789.9658 main

206.576.3750 direct | 206.550.0723 cell

mjohnson@esassoc.com <mailto:mjohnson@esassoc.com> | <www.esassoc.com>

Follow us on Facebook <http://www.facebook.com/pages/Environmental-Science-Associates/347741357652?

Attachment C

City of Seattle

Seattle City Light

June 2, 2014

Mr. Nicholas Matz
Planning & Community Development Department
450 110th Avenue NE
P.O. Box 90012
Bellevue, WA 98009

Dear Mr. Matz:

Seattle City Light (SCL) has transmission facilities that run through the City of Bellevue and other jurisdictions on the east side of Lake Washington. The SCL transmission lines in Bellevue were installed in the early 1940's to transfer power from hydro-generation in the North Cascades to the west side of Lake Washington. Puget Sound Energy (PSE) has lines in the same general vicinity which primarily serve the PSE customer load east of Lake Washington.

SCL's double circuit 230kV transmission lines are used to meet current and future operating needs. Specifically, SCL needs the connectivity and capacity of these transmission lines to:

- Maintain a contiguous Point of Delivery for transmission service from BPA;
- Serve existing load growth and maintain reliability;
- Provide for future SCL growth;
- Support regional transmission flows; and
- Meet NERC reliability requirements.

SCL foresees current and future uses of these existing east side facilities and prefers not to utilize SCL's transmission lines for PSE's native load service needs.

Please contact me via email at uzma.siddiqi@seattle.gov if you have any questions.

Sincerely,

Uzma Siddiqi

Uzma Siddiqi, PE
System Planning Engineer

cc: Phil West
Tuan Tran

Seattle City Light

700 5th Ave. | P.O. Box 34023 | Seattle WA 98124-4023
TEL (206) 684-3000 TTY/TDD (206) 684-3225 FAX (206) 625-3709
seattle.gov/light
twitter.com/SEACityLight facebook.com/SeattleCityLight

Attachment D

April 25, 2017

Mr. Larry Johnson
Attorney at Law
Citizens for Sane Eastside Energy (CSEE)
8505 129th AVE SE
NEWCASTLE, WA 98056

Re: PSE's Energize Eastside Project

Dear Mr. Johnson,

This letter responds to your letter dated March 20, 2017 to our General Manager, Larry Weis. We appreciate your interest in the regional energy issues and are aware of your concerns regarding Puget Sound Energy's ("PSE") Energize Eastside Project. As your letter mentions, although PSE and Seattle City Light have had limited discussions about PSE's Energize Eastside Project, PSE has never formally requested transmission service on Seattle City Light's Eastside transmission lines.
Obviously, if PSE would make a formal request for transmission service on Seattle City Light's Eastside lines, Seattle City Light would respond appropriately. Likewise, Seattle City Light remains willing to discuss options with PSE regarding the potential use of Seattle's Eastside lines. However, as PSE's project located entirely within its own service territory, PSE's project remains within PSE's discretion.

In addition, the Energize Eastside Project is not subject to the Order No. 1000 regional approval process because it is located completely within Puget Sound's service territory, it was included in Puget Sound's local transmission plan to meet Puget Sound's reliability needs, and neither Puget Sound, nor any other eligible party, requested to have the project selected in the regional transmission plan for purposes of cost allocation.

We trust that this resolves the concerns expressed in your March 20th letter with respect to Seattle City Light.

Sincerely,

Sephir Hamilton
Engineering and Technology Innovation Officer
Seattle City Light

cc: Larry Weis, General Manager, Seattle City Light

Attachment E -1

May 11, 2017

Heidi Bedwell
City of Bellevue Development Services Department
450 110th Avenue NE
Bellevue, WA 98004

Re: Comment for Energize Eastside Phase 2 Draft EIS

Dear Ms. Bedwell:

I am writing to submit comment on the Energize Eastside Phase 2 Draft EIS.

This comment relates to pages 2-52 of the Phase 2 Draft EIS. In particular section 2.2.1 "Seattle City Light Transmission Line" option.

In order to understand how this option works, one needs to be familiar with FERC's ProForma Open Access Transmission Tariff (OATT). The FERC ProForma Open Access Transmission Tariff can be found at:
https://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890-B/pro-forma-open-access.pdf

Section 6 of the OATT discusses "Reciprocity". If SCL uses the lines of one or more FERC directly regulated utilities, then SCL will have agreed to these terms when they use those lines. Meaning under reciprocity, SCL agrees to also deal with requests for use of their transmission grid under the FERC OATT approach.

Other sections of interest to this SCL Transmission Line option are:
Section 15. Service Availability
Section 16. Transmission Customer Responsibility
Section 17. Procedures for arranging for Firm Point to Point transmission service
[*This section is particularly relevant to how PSE needs to ask SCL for use of its line to serve a new 230/115 KV transformer at Lakeside.* ***There is a requirement to make a formal application in the format that is described in the OATT. PSE has never made such an application. An informal request does not meet the required format for making a request to use the SCL line. PSE needs to make this formal request to SCL*]**.
Section 19. Additional studies procedures for Firm Transmission

With an understanding of how FERC's OATT works, it is clear that just about every sentence in the discussion of the SCL option is incorrect, meaning these sentences are not consistent with the OATT.

First sentence:
"*SCL has indicated to the City of Bellevue that they expect to need the corridor for their own purposes and are not interested in sharing the corridor with PSE (SCL, 2014).*"

The EIS staff should already be aware that FERC does not allow a utility like SCL to "hoard" its transmission capability. Further, the FERC OATT requires a utility like SCL to increase the rating of its infrastructure (with needed construction) if that is what it takes to honor a request for transmission and the requesting utility agrees to pay what FERC requires them to pay. No one has performed a System Impact Study (as required by the OATT) to see what it would take to honor a PSE request to use the SCL line to serve a new 230/115 KV transformer at Lakeside.

Second sentence:
"*The existing SCL line would have to be rebuilt to provide a feasible solution for the Energize Eastside project, because the current rating of the SCL line is insufficient to meet PSE's needs (Strauch, personal communication, 2015).*"

If it can be shown that the existing SCL line would need to be rebuilt to provide a feasible solution for the Energize Eastside project, then that is what the FERC OATT would require be done as long as PSE agrees to pay what FERC would require them to pay for that construction. Until a study is done, one cannot tell for sure what the rebuild cost would be. But it certainly would be less than the cost of Energize Eastside. Further, it should be clear that the request to use the SCL line is only for purposes of serving a new 230/115 KV transformer at Lakeside. <u>The study to determine what this cost must not include a requirement to deliver 1,500 MW to Canada</u> unless BPA makes that request and BPA would pay the bulk of the needed cost if the SCL line is also being used to increase the ability of BPA to deliver power to Canada.

Third Sentence:
"*PSE has estimated that rebuilding the SCL line would provide sufficient capacity for a period of less than 10 years, which does not comply with PSE's electrical criteria (as described in Section 2.2.1 of the Phase 1 Draft EIS) to meet performance criteria for 10 years or more after construction.*"

Under the FERC OATT rules that SCL needs to comply with, SCL does not get to stop serving Lakeside after ten years even if SCL has a legitimate need for more use of its SCL line at that time. The FERC OATT has clear rules on how a utility like PSE can assure its transmission service from SCL can be retained even after SCL decides it needs the line for its own use. The FERC OATT protects a utility like PSE from SCL stopping to provide them transmission service.

Fourth Sentence:
"*Neither the City nor PSE can compel SCL to allow the use of this corridor; therefore, this option is not feasible and was not carried forward.*"

This statement is wrong. PSE can compel SCL to use its line to serve a new 230/115 KV transformer by making a FERC Order 888 request (under the FERC OATT) for such transmission service. If SCL refuses, FERC will compel them to do so. FERC uses its "reciprocity" ruling to compel SCL. If SCL refuses, FERC will refuse to let SCL use any transmission lines that are under direct FERC jurisdiction. SCL could not meaningfully its service obligations to its own customers without using the transmission lines of FERC directly jurisdictional utilities.

Fifth Sentence:

"Even if compelled use of the corridor were allowed, the negotiations would likely prove lengthy, and would likely preclude completion of the project within the required timeline to meet project objectives."

The FERC OATT has tight timelines for dealing with requests for transmission service. FERC intentionally put in these tight timelines to prohibit a utility like SCL from denying service by delaying service. Further, PSE currently is not saying when it thinks it needs a new 230/115 KV transformer to be in service at Lakeside. Any needed construction on the existing SCL line will take considerably less time than permitting and building EE. Further, according to the only reasonable load flow study done regarding serving the east side (the Lauckhart-Schiffman Load Flow study), there is plenty of time before any new 230/115 KV transformer is needed at Lakeside.

Thank you for the opportunity to clarify how this SCL Transmission Line option would work.

Sincerely,

Richard Lauckhart

Richard Lauckhart
Energy Consultant
Davis, California
530-759-9390
lauckjr@hotmail.com

Citizens for Sane Eastside Energy (CSEE)

May 8, 2017

Attachment F -1

The Washington Utilities and Transportation Commission
98504-7250, 1300 Evergreen Park Dr SW
Olympia, WA 98502

sent by email to the individual Commissioners

Dear Commissioners:

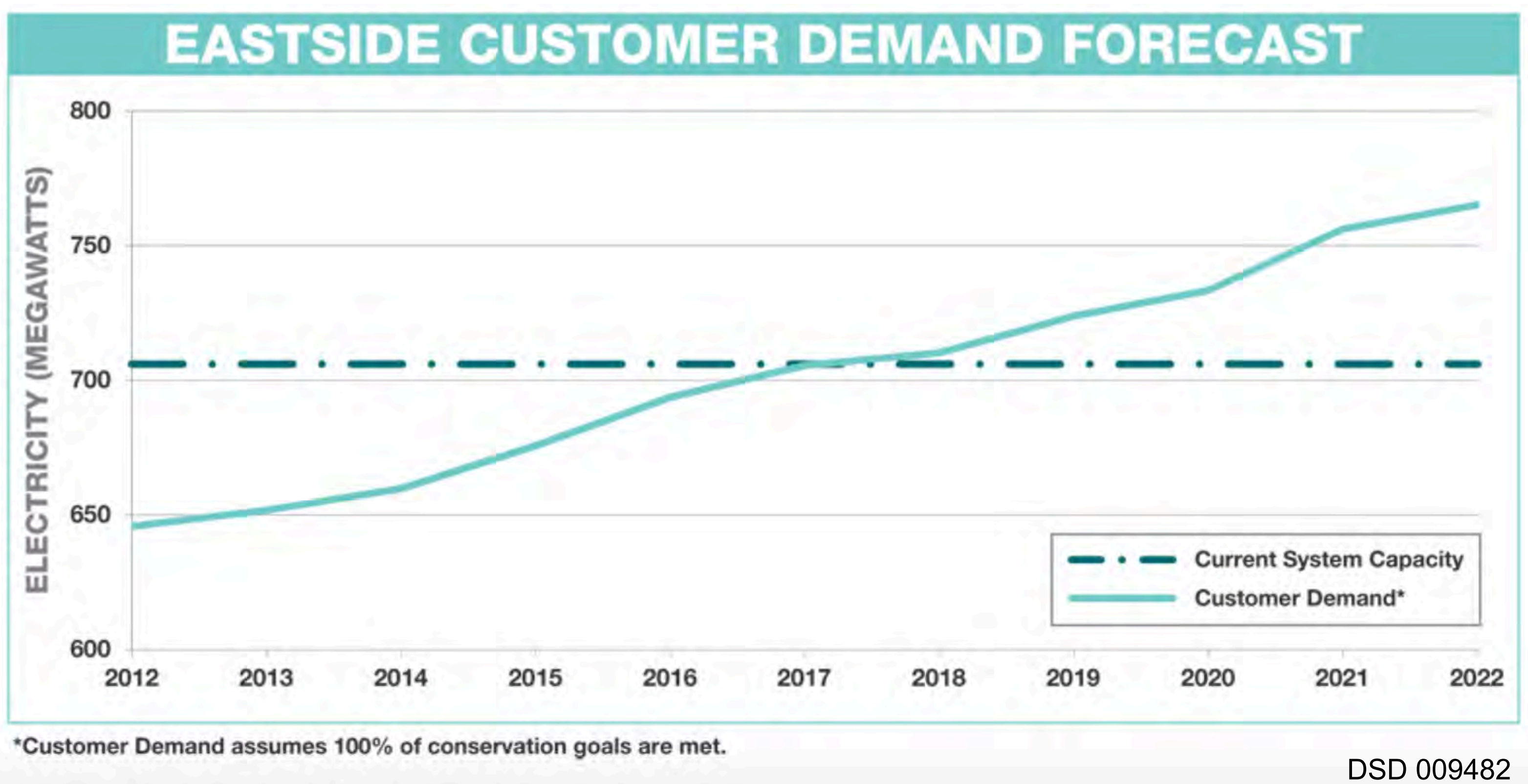
This letter is in response to comments made in an email by Mr. Jens Nedrud of PSE to you and others, dated May 4, 2017, regarding PSE's Energize Eastside project and a 3/16 IRPAG meeting.

Mr. Nedrud's remarks are misleading and distort the facts, yet they are unfortunately consistent with PSE's determined hard-sell methods to get the $200-$300 million project built at all costs, regardless of the economic waste and the grave risk to lives and property if built as proposed, i.e. too close to two aging pipelines transporting highly flammable petroleum products under pressure.

The two chief mantras PSE keeps repeating in its PR efforts to sell Energize Eastside are: 1) There is so much economic and population growth on the Eastside, the project is needed to meet a generic "consumer demand;" and 2) Nothing has been done "since the 1960s" to upgrade the grid in the Eastside. The ads PSE has published in numerous media outlets repeatedly beat these "Consumer Demand" and "Need for Upgrade" drums. CSEE has collected over two dozen of them.

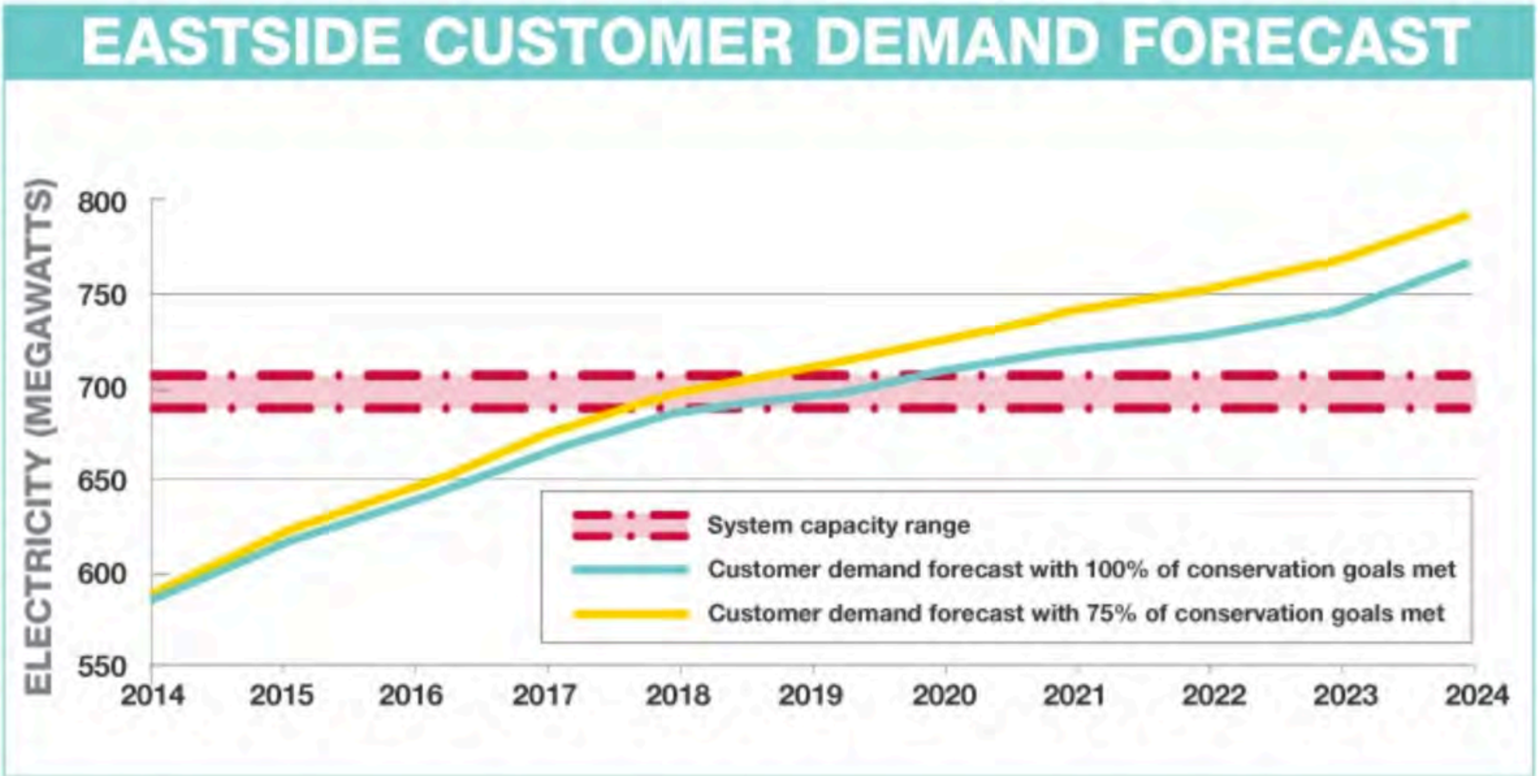
PSE's inflated consumer demand claims

In December of 2013, PSE had on its website dedicated to the Energize Eastside project the following chart, which was its prime lead-in to justify the project. Words introducing the chart stated that "[g]rowth studies predict that demand for reliable power will exceed capacity as early as 2017:"



Two years later, in December 2015, that chart was replaced by this one:

Attachment F - 2



This chart was accompanied with a warning: "Without substantial electric infrastructure upgrades, tens of thousands of residents and businesses will be at risk of more frequent and longer power outages."

That is a gross and irresponsible exaggeration. From the graph above, it appears PSE anticipates a spectacular (and preposterous) Eastside demand growth rate of 4% in the next four years. That is ten times the future growth rate predicted for a wildly booming Seattle by Seattle City Light's Sephir Hamilton, Engineering and Technology Innovation Officer, who in 2014 laid out these facts (https://youtu.be/gZWM-yNxwZY, starting at 0:52 into the video):

> "In the last four years nationwide, per-customer energy use has declined by 2%, both residential and non-residential. Here in Seattle it's declined 2.7% for non-residential, and it has declined 7.6% per customer for residential energy use. Even with all the growth that you see here in Seattle and south Lake Union, we're projecting total load growth of less than a half of a percent over the next five years. This is a huge change in the entire makeup of energy use industry in the United States, and especially here in Seattle where we're leading the way."

I have asked Mr. Hamilton to update this data with what is known now in 2017, and I will update with that information when received. Meanwhile, PSE no longer has a chart on its Energize Eastside website with growth projections. But that does not deter it from making outlandish growth claims.

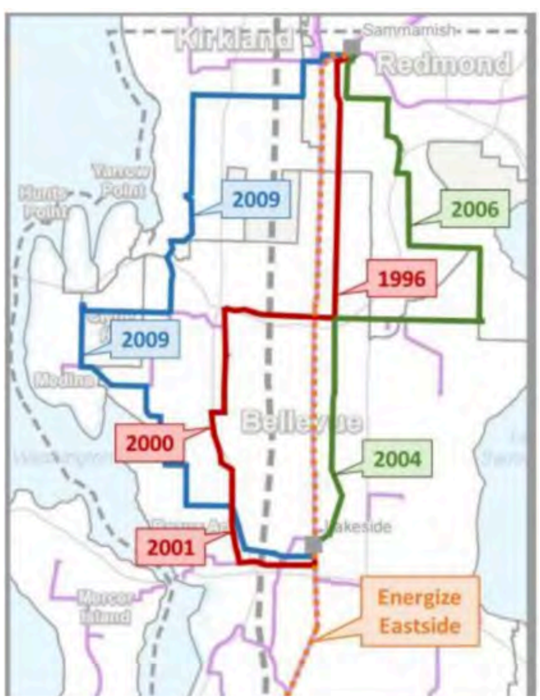
PSE's false "no update since the 1960s" claims

Here is an example of one of several ads of like content that PSE has published in various media outlets:

Note the blatant falsehood contained in this ad: "The Eastside electric grid was last upgraded in the 1960s." The ad also makes a false correlation between general daily electricity usage and power outages, when PSE knows full well the ostensible need for Energize Eastside is to meet very rare N-1-1 emergency events where federally mandated reliability is the only issue, not the general daily supply and demand for electricity.

As former Puget Power Vice President for Power Planning, Richard Lauckhart, has argued in documents he has sent you, there have been numerous upgrades and expansions made to the Eastside grid since the 1960s, as illustrated in this graphic for lines added and the years they were built:

New 115 KV lines built in the Eastside in recent years



In conclusion, whether in terms of PSE's complying with your requirements for a proper and adequate IRP, or whether as evidence at some future rate hearing on Energize Eastside when you will need all the facts, it remains that PSE simply cannot be trusted to tell the truth when so much of its future profits are at stake. You will recall that the WUTC levied its greatest fine ever on a utility, $1.25 million, for PSE's having intentionally falsified gas pipeline safety inspection records over a period of four years (see https://sane-eastside-energy.org/2014/04/30/pse-fined-1-25-million-in-falsifying-gas-pipeline-safety-inspection-reports-for-4-years-running/). It is thus not totally surprising that, while Mr. Nedrud finds flaws in the Lauckhart-Schiffman load flow studies, PSE has yet to release CEII-related data PSE submitted for the studies it relies on that would reveal what sorts of fundamental assumptions were used, even though FERC made it clear to PSE that Mr. Lauckhart and CENSE's Don Marsh have CEII clearances and should be given access to that CEII data.

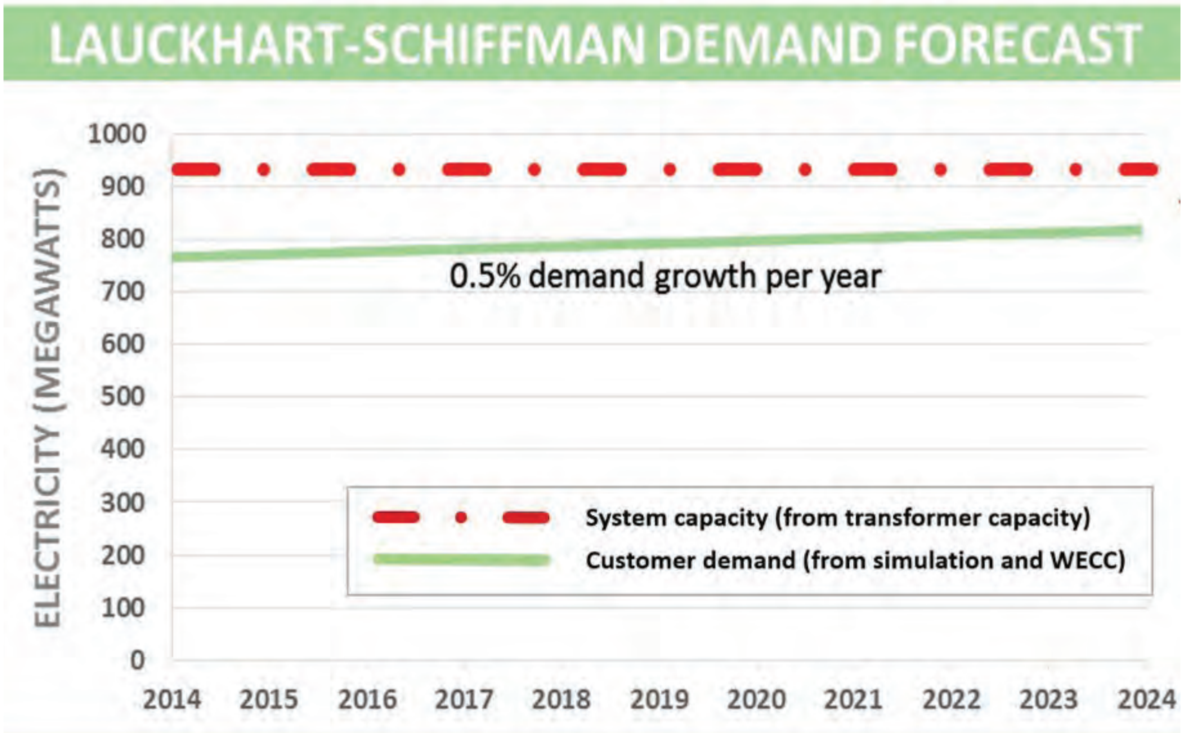
PSE has stubbornly refused to provide that information. The WUTC should demand that they do.

I realize the power the WUTC has to regulate and influence PSE is woefully inadequate. But for a project with such great potential for irrevocable damage, I hope the WUTC can use its own resources to conduct fully unbiased and untainted flow studies, if need be, to determine for itself the need for Energize Eastside, or at least to establish the validity of such studies as have been done. This is, after all, your area of expertise and public trust. That would be a positive effort undertaken for the common good of all Washingtonians and for the future of our environment.

Sincerely,

Larry G. Johnson
Attorney at Law, WSBA #5682
Citizens for Sane Eastside Energy (CSEE), www.sane-eastside-energy.com
8505 129th Ave. SE
Newcastle, WA 98056
tel.: 425 227-3352
larry.ede@gmail.com

cc: CENSE
City Councils of Bellevue, Newcastle, Redmond and Renton
NW Energy Coalition
Sierra Club



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.

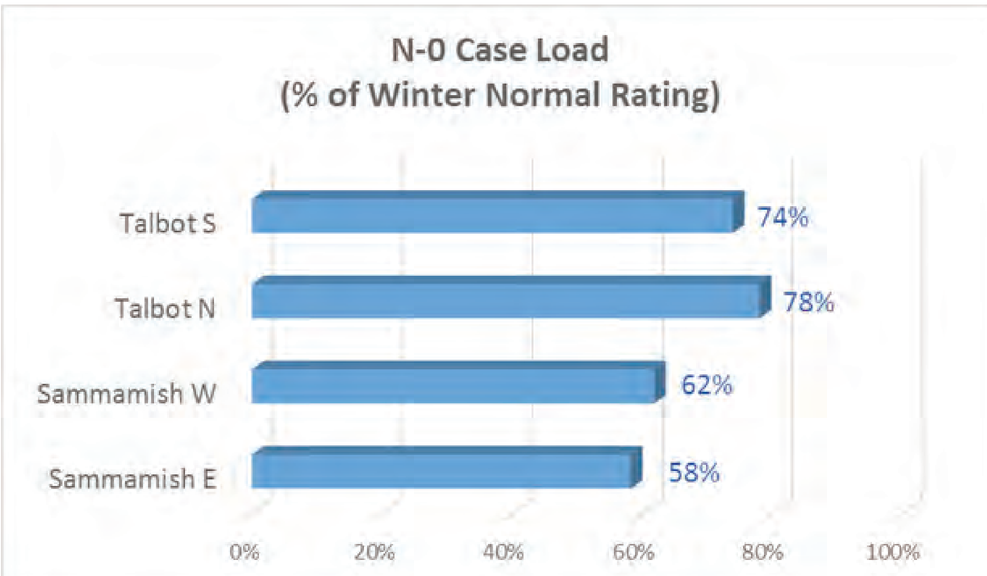


Figure 1: With all transformers in service, winter peak load causes no overloads.

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.

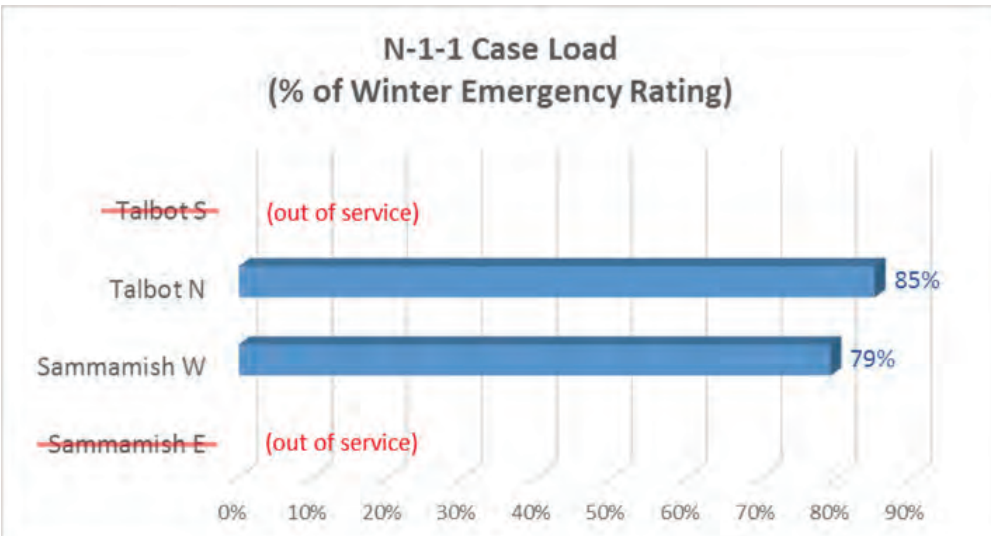


Figure 2: Loads on two remaining transformers are in a safe range.

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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.

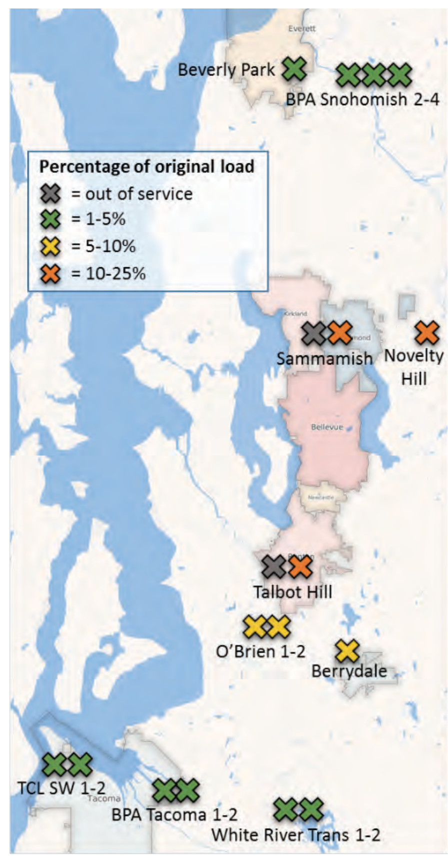

Figure 3: Load is distributed among other transformers after two transformers fail.

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.

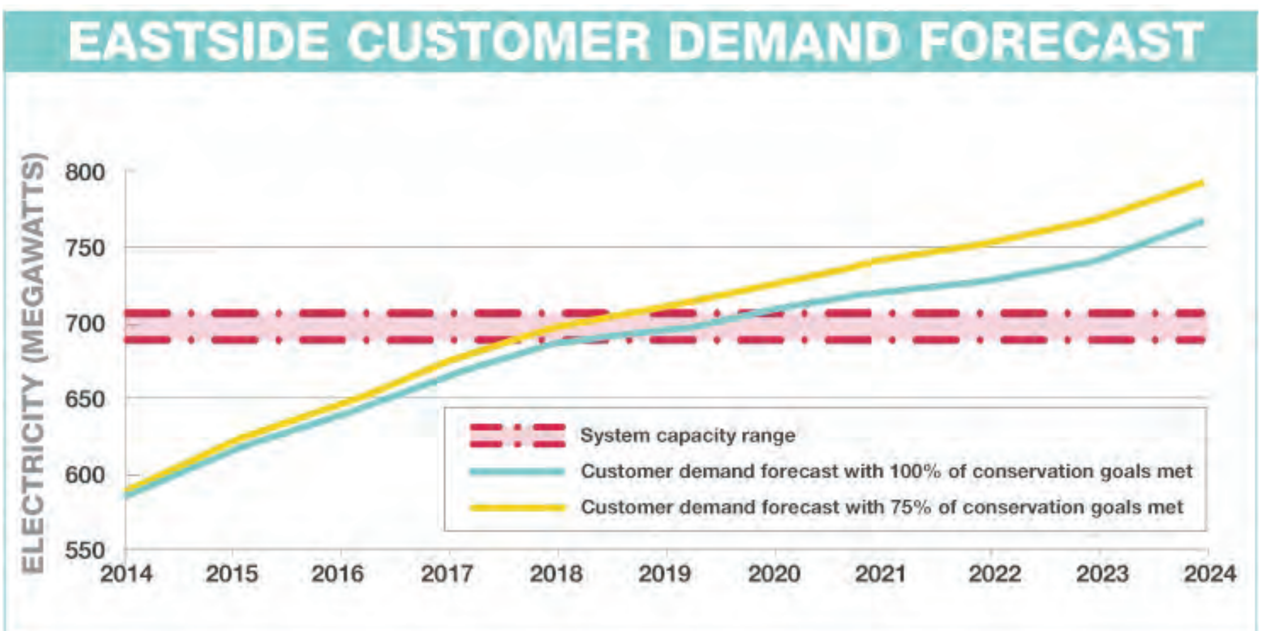

Figure 4: PSE's graph shows customer demand exceeding system capacity in 2018.[2]

[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.

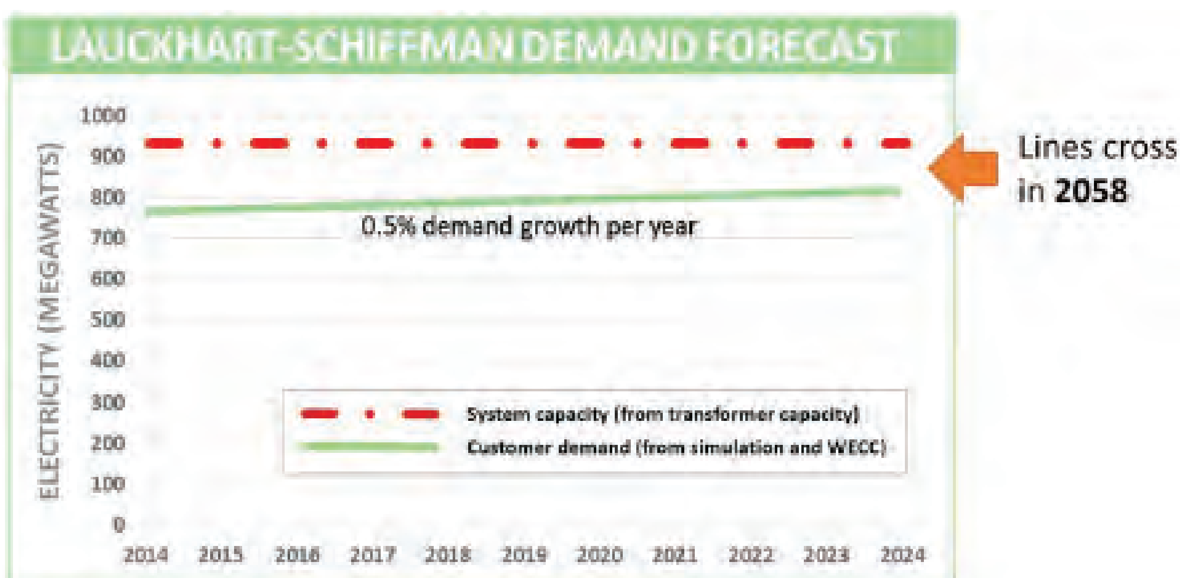

Figure 5: Alternative Demand Forecast shows slower demand growth and higher system capacity (based on "winter emergency" transformer ratings).

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 01 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.

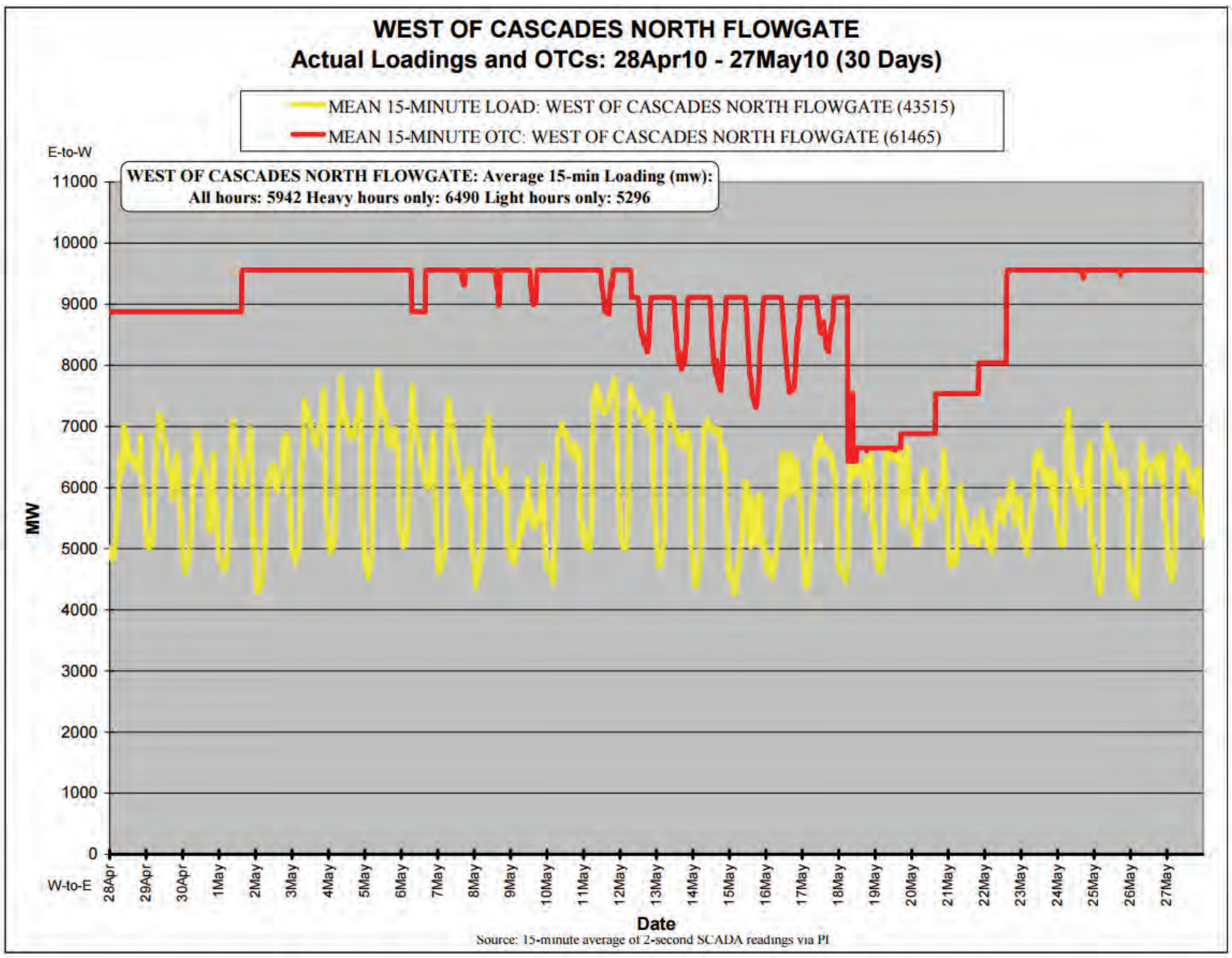

Figure 6: Chart from BPA shows load (in yellow) and maximum capacity (in red) for the WOCN path.

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

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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

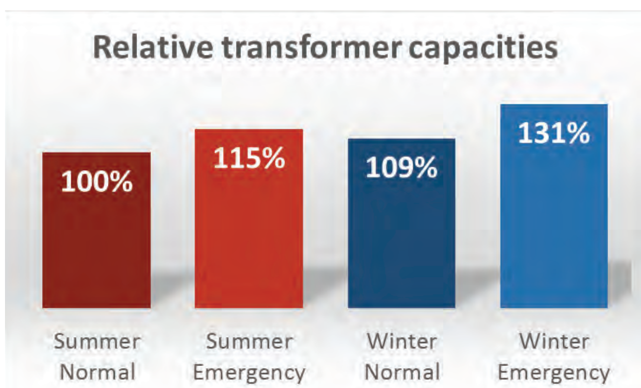

Figure 7: Ratings for different scenarios, normalized to Summer Normal rating.

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

1701 ARENA DRIVE
DAVIS, CA 95618
CELL ((530) 219-7347 HOME OFFICE (530) 405-3304
EMAIL: ROGER_SCHIFFMAN@YAHOO.COM

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.

Citizens for Sane Eastside Energy (CSEE)

8505 129th Ave. SE
Newcastle, WA 98056
tel.: 425 227-3352
www.sane-eastside-energy.org

June 1, 2017

The Washington Utilities and Transportation Commission
98504-7250, 1300 Evergreen Park Dr. SW
Olympia, WA 98502 <u>sent by email to the individual Commissioners</u>

Re: Puget Sound Energy's 2017 Integrated Resource Plan, Docket UE-160918

Dear Commissioners:

On May 8, 2017, I sent you a letter on behalf of Citizens for Sane Eastside Energy (CSEE) regarding PSE's false claims regarding Energize Eastside ("EE"). That letter also makes a brief reference to PSE's need to supplement its inadequate 2017 IRP. This letter is intended to amplify and expand on that statement.

EE is a proposed 18-mile $200-$300 million transmission project that would run through densely residential areas and over two aging Olympic Pipeline Co. petroleum pipelines transporting jet fuel and other flammable products under 500 psi. If allowed, that project would severely hamper PSE's ability to fulfill its already deficient 2017 IRP by misallocating resources to an unnecessary project, or by failing to pursue vastly safer, more proportionate and cheaper least-cost alternatives.

Not only would EE not add any new power generation, it would not even serve the purposes PSE claims it would. According to CSEE's and CENSE's independent expert and former Puget Power Vice President for Power Planning, Richard Lauckhart, "on a cold winter peak load day the existing eleven transmission lines crossing the Cascades from the mid-Columbia area into the Puget Sound area south of Talbot Hill provide just enough power to meet local demand; there would be virtually no power left to move to the Canadian border through a new transmission line (i.e. EE) on the Eastside -- certainly not 1500 MW." Yet those 1500 MW were included in the PSE/Quanta load flow studies as the key factor to justify the need for EE.[1] But besides other flawed assumptions in those studies, they have an additional Achilles' heel: they apparently assume there will be construction of at least one and probably two new cross-Cascades lines that neither BPA nor any other utility contemplates building.

Thus, if built, EE would be "a Bridge to Nowhere."

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[1] Two years after those studies were done, PSE spokespersons Mark Williamson and Keri Kravitz have stated in emails that the inclusion of the 1500 MW to Canada in the Quanta studies was a mistake. But despite that fact, PSE has done nothing since then to reduce the size of EE or redo the load flow studies without the 1500 MW to determine whether EE is needed without that assumption. As noted further in this letter, Richard Lauckhart and Roger Schiffman did those studies and found no need for EE.

In Docket UE-160918, the WUTC issued Order 01, dated April 13, 2017, which includes the following language:

> …
> 5 Following additional discussions with Staff and other stakeholders, PSE filed a revised Petition on April 7, 2017, which includes the following commitments:
> …
> (9) PSE's Chapter on System Planning, which includes a transmission and distribution planning discussion, will include an overview and explanation of the system planning process, including transmission that is not related to resources. This chapter will also identify geographic areas that may become capacity constrained in the future to guide future planning analyses. Additionally, for transmission projects that may affect the topology of PSE's transmission system, the System Planning Chapter will include the following information:
> o List of transmission projects completed since the 2015 IRP;
> o Future planned transmission projects, brief description of the project, and references where interested parties can find additional information that may include needs, alternatives, etc., depending on the magnitude of the project.

PSE thus agrees that a project of EE's magnitude must be scrutinized as part of PSE's IRP, including "needs, alternatives, etc." WUTC's insistence on getting all the relevant detailed facts from PSE may therefore be the only meaningful moment where the WUTC can and should impede this dangerous and wasteful project *before* it is built.[2]

On the issue of the lack of need for EE, please find attached CSEE's May 22, 2017, comments sent to the City of Bellevue regarding the current draft of the EIS for the project, incorporated by reference herein as if fully set out.

The more time, labor and money PSE pours into EE the less it has to devote to its 2017 IRP and future power responsibilities. The WUTC has a duty to thoroughly investigate the need and appropriate size of Energize Eastside, and to require PSE to make the Quanta load flow studies PSE has relied on to justify EE available to all stakeholders.

Such stakeholders include Richard Lauckhart. He and Roger Schiffman performed proper and transparent load flow studies relevant to EE, and they found no need for the project. The report on their studies is attached to the email that includes this letter. Attachment A to that report is a letter from FERC to Lauckhart granting him CEII clearance to examine the data inputs and

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[2] Washington State, despite its often being perceived as a progressive, high-tech state, is inexplicably retrograde in its inability to prevent a disaster like Energize Eastside. Unlike most states that require a Certificate of Public Use and Necessity before a utility project is approved, apparently the WUTC can only stand idly by and do nothing until *after* a project is built to determine its need in the context of a rate-base hearing. Of course, by then it will be too late if there is no need for a project. Not surprisingly, the WUTC has never used even this limited power to disapprove an infrastructure project like EE.
Please see "The Toothless Washington Utilities and Transportation Commission" at https://docs.wixstatic.com/ugd/740e62_f259798f5d1347349610fde60d34ec43.pdf, which urges the WUTC to a least issue non-binding advisory opinions to private utilities regarding the prudence of their proposed future projects. Why should the WUTC be silent if it sees folly unfolding before it? Non-binding advisory opinions could be implemented immediately without the need for new legislation.

basic assumptions PSE used in its load flow studies. Lauckhart is clearly entitled to see that data, yet PSE has stubbornly refused to grant him access to or copies of those studies.

You need to ask PSE: What are you trying to hide?

If the PSE/Quanta studies had been done by ColumbiaGrid in the manner required by FERC Order 1000, such studies would have been done openly and transparently, involving all stakeholders. But PSE as a member of ColumbiaGrid chose not to go that route, claiming Energize Eastside is a local load project only and thus outside ColumbiaGrid's jurisdiction. This, despite the fact that Energize Eastside is identical to the Sammamish-Lakeside-Talbot project that PSE submitted to ColumbiaGrid in 2011-2012 as a regional solution to perceived curtailment problems in the Northern Intertie.

PSE's 2017 IRP (or rather, lack thereof) affects all of Washington ratepayers, not just the Eastside. We are entitled to the whole truth about the supposed need for Energize Eastside. It is a boondoggle that would dramatically subtract from PSE's already depleted resources (e.g., reduced generation from Colstrip; Firm Commitment contracts PSE has allowed to expire).

We hope the WUTC will not act like a captive regulator but rather use all the tools at its disposal, including fines, to assure the public interest is fully served by a detailed, defensible and comprehensive 2017 IRP from PSE.

CSEE is engaged in efforts to replace PSE with a King County Public Utility District where we citizens can directly elect responsive commissioners, assert local control over power decisions, and monitor the PUD's operations through public records requests. We have none of that now with PSE and meanwhile must therefore rely on you to act on our behalf.

Sincerely,

Larry G. Johnson
Attorney at Law, WSBA #5682
Citizens for Sane Eastside Energy (CSEE), www.sane-eastside-energy.com
8505 129th Ave. SE
Newcastle, WA 98056
tel.: 425 227-3352
larry.ede@gmail.com

cc: CENSE
Attorney General Robert W. Ferguson
Lisa Gafken, AG Public Counsel

It appears there were many reasons that PSE chose not to ask for Energize Eastside to be a part of a Regional Plan. I believe this was a deliberate step on their part.

- If Energize Eastside were part of a regional plan, then FERC would say how much BPA would pay for Energize Eastside BPA would pay PSE. By doing that, PSE pays less out of its own pocket. And that would mean a smaller increase in the PSE ratebase. Which means smaller PSE investment that will be given the 9.8% return by the WUTC. Macquarie wants to invest more money in PSE new ratebase. It does not help if BPA pays a lot of that money because that reduces what Macquarie spends and therefore the amount of the return on the investment.
- If part of a Regional Plan, ColumbiaGrid would have been required to do the studies (not Quanta) and ColumbiaGrid studies would have to be done in an open and transparent fashion with stakeholder input, and
- If part of a Regional Plan, then stakeholders would also get to identify alternatives. Those alternatives would include, for example,
    - Meeting any identified needs with DSM
    - Simply increasing the capacity of the Talbot Hill transformer
    - Building a small peaker plant somewhere on the Eastside
    - Utilizing the SCL Transmission line option.

According to section 1.3 of the EIS, "*the lead agency is responsible for ensuring that a proposal that is the subject of environmental review is properly defined. The process of defining the proposal includes an* ***understanding of the need for the project****, to enable a thorough understanding of the project's objectives*." Without an open and transparent load flow study with stakeholder input, there can be no shared understanding of the need for the project. The EIS staff needs to ensure full accordance with this statement before the EIS is finalized.

Sincerely,

Richard Lauckhart

Richard Lauckhart
Energy Consultant
44475 Clubhouse Drive
Davis, California 95618
530-759-9390
lauckjr@hotmail.com

From: Strauch, Bradley R <bradley.strauch@pse.com>
Sent time: 03/25/2016 11:24:12 AM
To: Mark Johnson <MJohnson@esassoc.com>
Cc: records@energizeeastsideeis.org; Bedwell, Heidi; Claire Hoffman <CHoffman@esassoc.com>; Nedrud, Jens V <jens.nedrud@pse.com>
Subject: RE: E2- Questions for PSE regarding the Lauckhart-Schiffman report
Attachments: Lauckhart-Schiffman Draft responses_20160318 PSE Response.docx

Attachment B

Mark,

PSE is providing the following information in response the questions posed in the attachment. However, as we have already stated in PSEs Phase 1 DEIS comments, the Lauckhart and Schiffman document does not meet the minimum federally required planning standards necessary to provide or develop meaningful results; therefore, it has no relevance when evaluating PSEs thoroughly vetted project proposal.

If you have any additional questions, please let us know as we will be glad to assist.

Brad Strauch

Sr. Land Planner/Environmental Scientist

PUGET SOUND ENERGY

P.O. Box 97034, PSE-09N

Bellevue, WA 98009-9734

Office: 425-456-2556

Fax: 425-462-3233

Cell: 425-214-6250

From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Monday, March 21, 2016 6:25 PM
To: Strauch, Bradley R
Cc: Heidi Bedwell; Claire Hoffman; records@energizeeastsideeis.org
Subject: E2- Questions for PSE regarding the Lauckhart-Schiffman report

Brad
As we mentioned a couple weeks back, we have a few questions that arose from reading the Lauckhart Schiffman Report. We are trying to address issues raised by the report in the comment summary, the first draft of which is due very soon, so we ask for a quick turnaround on these. The attached is a draft section we have created to respond to the issues raised. Our intent here is to clarify facts that we believe PSE can best provide, and the questions are as close-ended as we could make them. Could you take a look and let us know how quickly you can turn this information around? If we could have answers by the end of the week, that would be great.

Mark S Johnson

Director

ESA | Northwest Community Development

5309 Shilshole Avenue NW, Suite 200

Seattle, WA 98107

206.789.9658 main

206.576.3750 direct | 206.550.0723 cell

mjohnson@esassoc.com <mailto:mjohnson@esassoc.com> | <www.esassoc.com>

Follow us on Facebook <http://www.facebook.com/pages/Environmental-Science-Associates/347741357652?

Attachment C

City of Seattle

Seattle City Light

June 2, 2014

Mr. Nicholas Matz
Planning & Community Development Department
450 110th Avenue NE
P.O. Box 90012
Bellevue, WA 98009

Dear Mr. Matz:

Seattle City Light (SCL) has transmission facilities that run through the City of Bellevue and other jurisdictions on the east side of Lake Washington. The SCL transmission lines in Bellevue were installed in the early 1940's to transfer power from hydro-generation in the North Cascades to the west side of Lake Washington. Puget Sound Energy (PSE) has lines in the same general vicinity which primarily serve the PSE customer load east of Lake Washington.

SCL's double circuit 230kV transmission lines are used to meet current and future operating needs. Specifically, SCL needs the connectivity and capacity of these transmission lines to:

- Maintain a contiguous Point of Delivery for transmission service from BPA;
- Serve existing load growth and maintain reliability;
- Provide for future SCL growth;
- Support regional transmission flows; and
- Meet NERC reliability requirements.

SCL foresees current and future uses of these existing east side facilities and prefers not to utilize SCL's transmission lines for PSE's native load service needs.

Please contact me via email at uzma.siddiqi@seattle.gov if you have any questions.

Sincerely,

Uzma Siddiqi

Uzma Siddiqi, PE
System Planning Engineer

cc: Phil West
Tuan Tran

Seattle City Light

700 5th Ave. | P.O. Box 34023 | Seattle WA 98124-4023
TEL (206) 684-3000 TTY/TDD (206) 684-3225 FAX (206) 625-3709
seattle.gov/light
twitter.com/SEACityLight facebook.com/SeattleCityLight

Attachment D

April 25, 2017

Mr. Larry Johnson
Attorney at Law
Citizens for Sane Eastside Energy (CSEE)
8505 129th AVE SE
NEWCASTLE, WA 98056

Re: PSE's Energize Eastside Project

Dear Mr. Johnson,

This letter responds to your letter dated March 20, 2017 to our General Manager, Larry Weis. We appreciate your interest in the regional energy issues and are aware of your concerns regarding Puget Sound Energy's ("PSE") Energize Eastside Project. As your letter mentions, although PSE and Seattle City Light have had limited discussions about PSE's Energize Eastside Project, PSE has never formally requested transmission service on Seattle City Light's Eastside transmission lines.
Obviously, if PSE would make a formal request for transmission service on Seattle City Light's Eastside lines, Seattle City Light would respond appropriately. Likewise, Seattle City Light remains willing to discuss options with PSE regarding the potential use of Seattle's Eastside lines. However, as PSE's project located entirely within its own service territory, PSE's project remains within PSE's discretion.

In addition, the Energize Eastside Project is not subject to the Order No. 1000 regional approval process because it is located completely within Puget Sound's service territory, it was included in Puget Sound's local transmission plan to meet Puget Sound's reliability needs, and neither Puget Sound, nor any other eligible party, requested to have the project selected in the regional transmission plan for purposes of cost allocation.

We trust that this resolves the concerns expressed in your March 20th letter with respect to Seattle City Light.

Sincerely,

Sephir Hamilton
Engineering and Technology Innovation Officer
Seattle City Light

cc: Larry Weis, General Manager, Seattle City Light

BBC NEWS

SCIENCE & ENVIRONMENT

12 March 2014 Last updated at 14:03 ET

Animals 'scared' by bursts of light from power cables

By Victoria Gill
Science reporter, BBC News

Animals around the world could be scared away from power cables because these give off UV flashes invisible to humans, scientists have said.

Several species' vision was studied by an international team to identify this ultra-violet (UV) sensitivity.

The findings, published in the journal Conservation Biology, claimed habitats and migration could be disrupted.

The flashes, or corona, occur when charge builds up in a cable and is released into the air.

The international team, including scientists from **University College London** and the **Arctic University of Norway**, measured the spectrum of light emitted by these bursts of charge.

They worked out that although the light was invisible to us, it contained wavelengths seen by many other mammals.

"Most mammals will let some [UV light] into their eye," explained UCL vision expert Prof Glen Jeffery, one of the lead researchers in this project.

"We're weird - us and monkeys - because we don't see UV. Most animals do."

'Previously a mystery'

The first animal to reveal its UV sensitivity was the reindeer. And, as the researchers explained, reindeers' avoidance of the power lines running across the Arctic tundra was part of the inspiration for this project.

Dr Nicholas Tyler, the other lead author, said it had been assumed that rather than avoiding the power cables themselves, animals steered clear of passages cut in forested areas before pylons were installed.

"Forest animals will not cross clear-cuts," he said.

"But for us in the Arctic, avoidance of power lines is difficult to explain - there are no trees, yet the reindeer still avoid the power lines."

The animals keep as much as 5km (3 miles) from either side of the cables.

"This has been a mystery," Dr Tyler added. "We have now come up with a mechanism [to explain it]."

This research required a detailed understanding of animal vision, which was where Prof Jeffery came in.

Having discovered in 2011 that **reindeer eyes were sensitive to UV light**, Prof Jeffery went on to study the eyes of almost 40 mammal species, **revealing all were UV-sensitive**.

Since, as the researchers added, coronas "happen on all power lines everywhere", the avoidance of the flashes could be having a global impact on wildlife.

"It has always been assumed that power lines - masts and the cables strung between them - were passive structures standing immobile in the terrain, and therefore inoffensive for animals," said Dr Tyler.

"As a result of this work, we now consider them as chains of flashing light stretching across the tundra in the winter darkness, and that's why the animals find them so offensive."

The random and unpredictable nature of these flashes were particularly problematic, he added, as the animals could not easily adapt to them.

Prof Jeffery said he hoped power companies would now consider ways to address the issue.

More Science & Environment stories

**'Shocking' scale of pangolin trade [/nature/26549963]**

Official records show that pangolins are being illegally traded on a "shocking" scale, according to a report.

Hints of deep Earth's blue rocks [/news/science-environment-26553115]

Fracking 'could harm wildlife' [/news/science-environment-26553117]

DSD 009535

Citizens for Sane Eastside Energy (CSEE)

8505 129th Ave. SE
Newcastle, WA 98056
tel.: 425 227-3352
email: larry.ede@gmail.com

May 22, 2017

Ms. Heidi Bedwell
Energize Eastside EIS Program Manager
City of Bellevue Development Services Dept.
450 110th Ave. NE
Bellevue, WA 98004 submitted by email to info@EnergizeEastsideEIS.org

Re: Comments regarding Energize Eastside Phase 2 Draft EIS

According to section 1.3 of the Phase 2 Draft EIS, "the lead agency is responsible for ensuring that a proposal that is the subject of environmental review is properly defined. **The process of defining the proposal includes an understanding of the need for the project, to enable a thorough understanding of the project's objectives**" (emphasis added). CENSE's expert on Northwest regional power planning, Richard Lauckhart, submitted on May 17, 2017, a white paper detailing the complete failure of the EIS process and EIS drafts to address the fundamental issue of project need. His comments are attached hereto as Attachment A.

We agree. It is manifestly absurd to blindly push ahead with evaluating a proposed project's potential environmental impacts if the project itself makes no sense. And certainly nothing could be more central to the project's "No Action" "alternative" than proof that building Energize Eastside ("EE") would satisfy no legitimate need.

Citizens for Sane Eastside Energy (CSEE) is composed chiefly of persons who are most directly threatened by the dangers to life and property if PSE's proposed Energize Eastside project is allowed to go forward. While some may find it easy to dismiss CSEE as "NIMBY" ("Not In Our Back Yard"), the truth, no matter by whom spoken, still remains the truth. We submit EE is driven solely by PSE's foreign investor owners who stand to make up to a handsome 9.8% return on EE if built. That is the real motivation for PSE's wanting to build a boondoggle that should be in *no-one's* back yard.

It is difficult to assess the many problems associated with EE, not only because of a number of complex technical issues involved, but also because PSE has been from the outset duplicitous and fraudulent in presenting a number of misleading justifications for the project.

There are at least four major areas of such deceit underlying PSE's determined efforts to hard-sell Energize Eastside that will be addressed here. They are:

1. EE is based on a failed ColumbiaGrid flow study that included exaggerated, false NERC criteria.

The project's foundational justification is a uniquely strange, failed load flow study conducted by ColumbiaGrid in 2013, the results of which (the studies did not "solve") were dismissed by ColumbiaGrid then as something one could comfortably ignore since the studies bizarrely *exceeded* NERC requirements.[1] But those unnecessarily beefed-up, false criteria for that failed "informational" study nevertheless found their way into the Quanta flow studies that are fundamental to PSE's argument for the supposed need for EE. For further details, see Attachment A.

In short, the core rationale for EE is based on a fairy tale.

The fact that PSE's aggressive pitches for EE are founded in myth is further buttressed by the fact that PSE steadfastly refuses to release to CENSE's expert the data inputs used in the Quanta studies done under PSE's supervision and control, even though FERC has made it clear to PSE that CENSE's expert is entitled to see and study that information.

The Lauckhart-Schiffman flow studies are the only untainted studies ever done for EE, and they show no need for EE. Yet an email from PSE's Bradley Strauch to Mark Johnson of ESA, dated 3/25/2016, attached hereto as Attachment B, reveals that PSE still clings to the exaggerated "informational" ColumbiaGrid flow studies criteria beyond those required of NERC when criticizing the Lauckhart-Schiffman studies for not meeting those absurd criteria which Strauch mischaracterizes as "minimum:"

> "…as we have already stated in PSEs Phase 1 DEIS comments, the Lauckhart and Schiffman document does not meet the minimum federally required planning standards necessary to provide or develop meaningful results; therefore, it has no relevance when evaluating PSE [sic] thoroughly vetted project proposal."

---

[1] See page 12 of the ColumbiaGrid 2013 System Assessment Report, first full bulleted paragraph, which includes this language: **"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"** (emphasis added). That is to say, the study used three major failure events occurring in the scenario tested, or what NERC calls an "N-1-1-1 event," when only two critical system component failures are required for NERC compliance, i.e. an "N-1-1 event." ColumbiaGrid is not known to do studies for "information purposes" only, and we submit that PSE wanted these bizarre studies done in order to create a justification for EE. The ColumbiaGrid 2013 System Assessment Report is available online at https://www.columbiagrid.org/Notices-detail.cfm?NoticeID=109.

Ironically, it is rather the PSE/Quanta studies that are wrong and irrelevant, since their foundation is that failed, bogus ColumbiaGrid study.[2]

CSEE submits that a project of EE's magnitude, costing $200 to $300 million and portending catastrophic and irreversible consequences, should be solidly based on complete and totally transparent flow studies, trust, and clarity, involving simultaneously all stakeholders. If done fairly and openly, all parties affected by this controversial project stand to benefit.

2. PSE has misrepresented its desire and efforts to seek an alternative route with Seattle City Light.

One must conclude from the current EIS draft that PSE has apparently succeeded so far in selling the notion that PSE tried but failed to obtain Seattle City Light's (SCL's) permission to

---

[2]Probably aware that its rationale for EE as a reliability solution has become flimsy, PSE's justification for EE has morphed into one based on the need for a vague "system upgrade," discussed further in Item 4 in this document and Attachment F. A chronology:

1) October 2013. PSE/Quanta release their Eastside Needs Assessment. It states the need was identified with a power flow model (a/k/a load flow model). They indicate their input assumptions include 1,500 MW to Canada and a shut down of local generation from several peaker plants (built specifically to meet reliability emergencies!). This results in the very exaggerated NERC N-1-1-1 event that ColumbiaGrid found to be irrelevant and thus merely "informational."

2) December 2013. PSE (without Quanta) provides an Executive Summary of the Eastside Needs Assessment. That Executive Summary provides the infamous "Eastside Capacity and load line (The Problem)" graph where brownouts could start as soon 2017. The Executive Summary indicates that Quanta ran load flow studies, but the Executive Summary changes the justification for EE's need: the need to meet generic customer demand as shown in the "The Problem" graph (included in Attachment F-1 hereto). Note that Quanta did not sign on to this Executive Summary; it is a PSE-developed document.

3) 2014-2015: PSE draws a number of questions and criticisms regarding the assumptions in the Quanta load flow studies. Eventually, PSE's lead project consultant, Mark Williamson, goes on the record to admit that including the 1,500 MW to Canada in the Quanta studies was a mistake (YouTube video at https://youtu.be/UixzsxOmPic), yet PSE has never done anything to correct that mistake or counteract the wrong conclusions others have made from that mistake. PSE also cannot explain why it had Quanta shut down six local generators (peaker plants) in the load flow study. Not surprisingly, PSE has abandoned the myth that EE's need derives from a load flow study. Yet they refuse to re-run the load flow study without 1,500 MW to Canada or with all PSE generators running. The Lauckhart-Schiffman's studies do just that, however, resulting in their conclusion that there is no need for EE.

For the PSE/Quanta 1,500 MW assumption, see page 8 of the Eastside Needs Assessment at https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/Eastside_Needs_Assessment_Final_Draft_10-31-2013v2REDACTEDR1.pdf.
For the PSE/Quanta shut down of local generation, see Table 4-4 on page 32 of the same document.

4) 2016: PSE begins focusing on the aforementioned "Problem" graph that it published in its December 2013 Executive Summary. PSE revises that graph to include a mysterious "capacity" line at 700 MW and an exaggerated Eastside load growth that is some ten times greater than what Seattle City Light predicts for booming Seattle. See Attachment F-2. PSE removes the embarrassing 2013 graph from its website and abandons use of it as the basis for the need for EE.

5) 2017: PSE's selling point for EE is now: "Nothing has been done to update the Eastside grid for 50 years," a blatantly false claim refuted in Attachment F.

share SCL's Eastside line as a route for EE, a route PSE spokespersons repeatedly assured citizens at public meetings was PSE's "first choice" for EE.

A variant of this misleading narrative is found on the FAQ page of PSE's website dedicated to EE:

> "**Routing**
>
> " •Why can't PSE use the Seattle City Light corridor that runs from Redmond to Renton?
>
> "PSE **looked into** using the Seattle City Light corridor and **yes, if rebuilt, the corridor could work to meet the Eastside's energy needs.** However, PSE has been told by Seattle City Light that this corridor is a key component of their transmission system and **is not available for our use**." (emphasis added; from http://energizeeastside.com/faqs)

The underlined words in the last sentence of that paragraph are a link to a June 2, 2014, letter from Uzma Siddiqi, SCL's System Planning Engineer, to the City of Bellevue's Mr. Nicholas Matz, Attachment C, where she writes:

> "SCL foresees current and future uses of these existing east side facilities and **prefers not to utilize** SCL's transmission lines for PSE's native load service needs." (emphasis added).

"Prefers not to utilize" is hardly the same thing as "refuses to allow." And note that Ms. Siddiqi's letter is directed to a City of Bellevue employee and not to PSE, who in fact never even tried to make a formal request for sharing those lines. That conclusion is made crystal clear in an April 25, 2017, letter from SCL's Sephir Hamilton, Engineering and Technology Innovation Officer, to me, Attachment D:

> "As your letter mentions, although PSE and Seattle City Light have had limited discussions about PSE's Energize Eastside Project, **PSE has never formally requested transmission service on Seattle City Light's Eastside transmission lines. Obviously, if PSE would make a formal request for transmission service on Seattle City Light's Eastside lines, Seattle City Light would respond appropriately.**" (emphasis added)

CSEE submits that PSE never tried to act on its "first choice" for an EE route because to have done so would have deprived its owners of a highly lucrative project, boondoggle though it be.

Further, virtually none of the information PSE has provided the authors of this latest draft EIS about the very real and superior SCL Eastside lines alternative to EE (assuming *arguendo*

something like EE is needed) is accurate. In the May 11, 2017, letter of CENSE's expert, Richard Lauckhart, to Ms. Heidi Bedwell, Attachment E, there are paragraphs cited from the current draft EIS which in part or in whole contain incomplete or erroneous information, with his rebuttals of same. Those comments further buttress the conclusion that if PSE were to follow the steps as outlined in FERC Order 888, SCL would have little choice but to cooperate with PSE in coming up with a far more workable, less expensive, and above all, less dangerous solution than EE, assuming there is any objective need for EE.

The Phase 2 draft EIS is woefully inadequate and simply wrong when it comes to the SCL Eastside line alternative, and it needs to be completely done over again without PSE pressure or interference.

3. PSE has mounted an aggressive PR campaign, similar in kind and credibility to a political campaign,[3] in order to mislead the public into thinking EE will fulfill a need to meet future Eastside growth that PSE claims is 10 times that of booming Seattle.

For details, see Attachment F-1 and F-2.

4. PSE repeatedly and falsely advertises the lie that EE is needed as a "long overdue Eastside grid upgrade" despite several expansions of the Eastside grid in the past two decades.

For details, see Attachment F-2 through F-4.

Sincerely,

Larry G. Johnson
Attorney at Law, WSBA #5682
Citizens for Sane Eastside Energy (CSEE)

cc: CENSE

---

[3] To head up PSE's aggressive PR campaign, it went as far as Wisconsin to hire lawyer Mark Williamson to act as its chief consultant for getting the project through the approval processes. Williamson's website brags about his prowess in getting projects like Energize Eastside approved by treating them the same way as a political campaign: "Williamson has developed a strategic communications technique patterned on 'election campaigning' – polling, message development and communication – tools that he employs, and has for years, to get utility projects approved, sited, built and on-line. He is a hands-on utility executive that gets the job done from day one." http://prwcomm.com/now/?page_id=71. PSE's strategy is all about winning rather than fairly arguing the merits of the project or considering possible options that would better serve the public interest.

May 17, 2017

Attachment A - 1

Heidi Bedwell
City of Bellevue Development Services Department
450 110th Avenue NE
Bellevue, WA 98004

Re: Comment for Energize Eastside Phase 2 Draft EIS

Dear Ms. Bedwell:

I am writing to submit comments on the Energize Eastside Phase 2 Draft EIS.

These comments relate to the "need" for Energize Eastside

As I have mentioned in previous submissions, the need for Energize Eastside has never been established. I have provided significant documentation which supports the idea that it is not only not needed, but that PSE is attempting to push this project through using multiple baseless justifications.

The debate on need is rooted in a dispute about a proper load flow study. What keeps us from an open and honest discussion of the facts on which this entire project is based is PSE's refusal to allow any kind of scrutiny into the assumptions used by Quanta in load flow studies which they conducted for PSE. These studies, along with the studies conducted by USE, are the centerpieces of the justification for Energize Eastside.

PSE continues to refuse to show the details of the Quanta load flow study despite multiple requests and despite the fact that the Federal Energy Regulatory Commission (FERC) says I have a legitimate need to see this information. Yet the EIS process continues to march forward, presumably to its completion, while multiple red flags exist concerning how Quanta did their load flow study. The EIS staff continues to sidestep any real resolution of these red flags.

A $200-$300 million project with devastating and irrevocable consequences cannot be subject of guess work. No permit for Energize Eastside should be issued until a truly transparent, scientific process has been completed.

A new load flow study needs to be done in an open and transparent fashion with input from all stakeholders. That is what I asked FERC to require ColumbiaGrid to do. But FERC said that since PSE had not asked for Energize Eastside to be a part of the Regional Plan, then Energize Eastside is not subject to Order 1000. If PSE had asked for Energize Eastside to be part of the regional plan, this would have required ColumbiaGrid to do the studies in an open and transparent fashion with full stakeholder input. The ColumbiaGrid Regional Plan looks out over a ten-year planning horizon and identifies the transmission additions necessary to ensure that the parties to the ColumbiaGrid Planning and Expansion Functional Agreement can meet their commitments to serve regional load and meet firm transmission service commitments.

It appears there were many reasons that PSE chose not to ask for Energize Eastside to be a part of a Regional Plan. I believe this was a deliberate step on their part.

- If Energize Eastside were part of a regional plan, then FERC would say how much BPA would pay for Energize Eastside BPA would pay PSE. By doing that, PSE pays less out of its own pocket. And that would mean a smaller increase in the PSE ratebase. Which means smaller PSE investment that will be given the 9.8% return by the WUTC. Macquarie wants to invest more money in PSE new ratebase. It does not help if BPA pays a lot of that money because that reduces what Macquarie spends and therefore the amount of the return on the investment.
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    - Meeting any identified needs with DSM
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According to section 1.3 of the EIS, "*the lead agency is responsible for ensuring that a proposal that is the subject of environmental review is properly defined. The process of defining the proposal includes an* ***understanding of the need for the project****, to enable a thorough understanding of the project's objectives*." Without an open and transparent load flow study with stakeholder input, there can be no shared understanding of the need for the project. The EIS staff needs to ensure full accordance with this statement before the EIS is finalized.

Sincerely,

Richard Lauckhart

Richard Lauckhart
Energy Consultant
44475 Clubhouse Drive
Davis, California 95618
530-759-9390
lauckjr@hotmail.com

Attachment B

From: Strauch, Bradley R <bradley.strauch@pse.com>
Sent time: 03/25/2016 11:24:12 AM
To: Mark Johnson <MJohnson@esassoc.com>
Cc: records@energizeeastsideeis.org; Bedwell, Heidi; Claire Hoffman <CHoffman@esassoc.com>; Nedrud, Jens V <jens.nedrud@pse.com>
Subject: RE: E2- Questions for PSE regarding the Lauckhart-Schiffman report
Attachments: Lauckhart-Schiffman Draft responses_20160318 PSE Response.docx

---

Mark,

PSE is providing the following information in response the questions posed in the attachment. However, as we have already stated in PSEs Phase 1 DEIS comments, the Lauckhart and Schiffman document does not meet the minimum federally required planning standards necessary to provide or develop meaningful results; therefore, it has no relevance when evaluating PSEs thoroughly vetted project proposal.

If you have any additional questions, please let us know as we will be glad to assist.

Brad Strauch

Sr. Land Planner/Environmental Scientist

PUGET SOUND ENERGY

P.O. Box 97034, PSE-09N

Bellevue, WA 98009-9734

Office: 425-456-2556

Fax: 425-462-3233

Cell: 425-214-6250

From: Mark Johnson [mailto:MJohnson@esassoc.com]
Sent: Monday, March 21, 2016 6:25 PM
To: Strauch, Bradley R
Cc: Heidi Bedwell; Claire Hoffman; records@energizeeastsideeis.org
Subject: E2- Questions for PSE regarding the Lauckhart-Schiffman report

Brad
As we mentioned a couple weeks back, we have a few questions that arose from reading the Lauckhart Schiffman Report. We are trying to address issues raised by the report in the comment summary, the first draft of which is due very soon, so we ask for a quick turnaround on these. The attached is a draft section we have created to respond to the issues raised. Our intent here is to clarify facts that we believe PSE can best provide, and the questions are as close-ended as we could make them. Could you take a look and let us know how quickly you can turn this information around? If we could have answers by the end of the week, that would be great.

Mark S Johnson

Director

ESA | Northwest Community Development

5309 Shilshole Avenue NW, Suite 200

Seattle, WA 98107

206.789.9658 main

206.576.3750 direct | 206.550.0723 cell

mjohnson@esassoc.com <mailto:mjohnson@esassoc.com> | <www.esassoc.com>

Follow us on Facebook <http://www.facebook.com/pages/Environmental-Science-Associates/347741357652?

City of Seattle

Seattle City Light

June 2, 2014

Mr. Nicholas Matz
Planning & Community Development Department
450 110th Avenue NE
P.O. Box 90012
Bellevue, WA 98009

Dear Mr. Matz:

Seattle City Light (SCL) has transmission facilities that run through the City of Bellevue and other jurisdictions on the east side of Lake Washington. The SCL transmission lines in Bellevue were installed in the early 1940's to transfer power from hydro-generation in the North Cascades to the west side of Lake Washington. Puget Sound Energy (PSE) has lines in the same general vicinity which primarily serve the PSE customer load east of Lake Washington.

SCL's double circuit 230kV transmission lines are used to meet current and future operating needs. Specifically, SCL needs the connectivity and capacity of these transmission lines to:

- Maintain a contiguous Point of Delivery for transmission service from BPA;
- Serve existing load growth and maintain reliability;
- Provide for future SCL growth;
- Support regional transmission flows; and
- Meet NERC reliability requirements.

SCL foresees current and future uses of these existing east side facilities and prefers not to utilize SCL's transmission lines for PSE's native load service needs.

Please contact me via email at uzma.siddiqi@seattle.gov if you have any questions.

Sincerely,

Uzma Siddiqi

Uzma Siddiqi, PE
System Planning Engineer

cc: Phil West
Tuan Tran

Seattle City Light

700 5th Ave. | P.O. Box 34023 | Seattle WA 98124-4023
TEL (206) 684-3000 TTY/TDD (206) 684-3225 FAX (206) 625-3709
seattle.gov/light
twitter.com/SEACityLight facebook.com/SeattleCityLight

Attachment D

April 25, 2017

Mr. Larry Johnson
Attorney at Law
Citizens for Sane Eastside Energy (CSEE)
8505 129th AVE SE
NEWCASTLE, WA 98056

Re: PSE's Energize Eastside Project

Dear Mr. Johnson,

This letter responds to your letter dated March 20, 2017 to our General Manager, Larry Weis. We appreciate your interest in the regional energy issues and are aware of your concerns regarding Puget Sound Energy's ("PSE") Energize Eastside Project. As your letter mentions, although PSE and Seattle City Light have had limited discussions about PSE's Energize Eastside Project, PSE has never formally requested transmission service on Seattle City Light's Eastside transmission lines.
Obviously, if PSE would make a formal request for transmission service on Seattle City Light's Eastside lines, Seattle City Light would respond appropriately. Likewise, Seattle City Light remains willing to discuss options with PSE regarding the potential use of Seattle's Eastside lines. However, as PSE's project located entirely within its own service territory, PSE's project remains within PSE's discretion.

In addition, the Energize Eastside Project is not subject to the Order No. 1000 regional approval process because it is located completely within Puget Sound's service territory, it was included in Puget Sound's local transmission plan to meet Puget Sound's reliability needs, and neither Puget Sound, nor any other eligible party, requested to have the project selected in the regional transmission plan for purposes of cost allocation.

We trust that this resolves the concerns expressed in your March 20th letter with respect to Seattle City Light.

Sincerely,

Sephir Hamilton
Engineering and Technology Innovation Officer
Seattle City Light

cc: Larry Weis, General Manager, Seattle City Light

Attachment E -1

May 11, 2017

Heidi Bedwell
City of Bellevue Development Services Department
450 110th Avenue NE
Bellevue, WA 98004

Re: Comment for Energize Eastside Phase 2 Draft EIS

Dear Ms. Bedwell:

I am writing to submit comment on the Energize Eastside Phase 2 Draft EIS.

This comment relates to pages 2-52 of the Phase 2 Draft EIS. In particular section 2.2.1 "Seattle City Light Transmission Line" option.

In order to understand how this option works, one needs to be familiar with FERC's ProForma Open Access Transmission Tariff (OATT). The FERC ProForma Open Access Transmission Tariff can be found at:
https://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890-B/pro-forma-open-access.pdf

Section 6 of the OATT discusses "Reciprocity". If SCL uses the lines of one or more FERC directly regulated utilities, then SCL will have agreed to these terms when they use those lines. Meaning under reciprocity, SCL agrees to also deal with requests for use of their transmission grid under the FERC OATT approach.

Other sections of interest to this SCL Transmission Line option are:
Section 15. Service Availability
Section 16. Transmission Customer Responsibility
Section 17. Procedures for arranging for Firm Point to Point transmission service
[*This section is particularly relevant to how PSE needs to ask SCL for use of its line to serve a new 230/115 KV transformer at Lakeside.* ***There is a requirement to make a formal application in the format that is described in the OATT. PSE has never made such an application. An informal request does not meet the required format for making a request to use the SCL line. PSE needs to make this formal request to SCL***].
Section 19. Additional studies procedures for Firm Transmission

With an understanding of how FERC's OATT works, it is clear that just about every sentence in the discussion of the SCL option is incorrect, meaning these sentences are not consistent with the OATT.

First sentence:
"*SCL has indicated to the City of Bellevue that they expect to need the corridor for their own purposes and are not interested in sharing the corridor with PSE (SCL, 2014).*"

The EIS staff should already be aware that FERC does not allow a utility like SCL to "hoard" its transmission capability. Further, the FERC OATT requires a utility like SCL to increase the rating of its infrastructure (with needed construction) if that is what it takes to honor a request for transmission and the requesting utility agrees to pay what FERC requires them to pay. No one has performed a System Impact Study (as required by the OATT) to see what it would take to honor a PSE request to use the SCL line to serve a new 230/115 KV transformer at Lakeside.

Second sentence:
"The existing SCL line would have to be rebuilt to provide a feasible solution for the Energize Eastside project, because the current rating of the SCL line is insufficient to meet PSE's needs (Strauch, personal communication, 2015)."

If it can be shown that the existing SCL line would need to be rebuilt to provide a feasible solution for the Energize Eastside project, then that is what the FERC OATT would require be done as long as PSE agrees to pay what FERC would require them to pay for that construction. Until a study is done, one cannot tell for sure what the rebuild cost would be. But it certainly would be less than the cost of Energize Eastside. Further, it should be clear that the request to use the SCL line is only for purposes of serving a new 230/115 KV transformer at Lakeside. The study to determine what this cost must not include a requirement to deliver 1,500 MW to Canada unless BPA makes that request and BPA would pay the bulk of the needed cost if the SCL line is also being used to increase the ability of BPA to deliver power to Canada.

Third Sentence:
"PSE has estimated that rebuilding the SCL line would provide sufficient capacity for a period of less than 10 years, which does not comply with PSE's electrical criteria (as described in Section 2.2.1 of the Phase 1 Draft EIS) to meet performance criteria for 10 years or more after construction."

Under the FERC OATT rules that SCL needs to comply with, SCL does not get to stop serving Lakeside after ten years even if SCL has a legitimate need for more use of its SCL line at that time. The FERC OATT has clear rules on how a utility like PSE can assure its transmission service from SCL can be retained even after SCL decides it needs the line for its own use. The FERC OATT protects a utility like PSE from SCL stopping to provide them transmission service.

Fourth Sentence:
"Neither the City nor PSE can compel SCL to allow the use of this corridor; therefore, this option is not feasible and was not carried forward."

This statement is wrong. PSE can compel SCL to use its line to serve a new 230/115 KV transformer by making a FERC Order 888 request (under the FERC OATT) for such transmission service. If SCL refuses, FERC will compel them to do so. FERC uses its "reciprocity" ruling to compel SCL. If SCL refuses, FERC will refuse to let SCL use any transmission lines that are under direct FERC jurisdiction. SCL could not meaningfully its service obligations to its own customers without using the transmission lines of FERC directly jurisdictional utilities.

Fifth Sentence:

"Even if compelled use of the corridor were allowed, the negotiations would likely prove lengthy, and would likely preclude completion of the project within the required timeline to meet project objectives."

The FERC OATT has tight timelines for dealing with requests for transmission service. FERC intentionally put in these tight timelines to prohibit a utility like SCL from denying service by delaying service. Further, PSE currently is not saying when it thinks it needs a new 230/115 KV transformer to be in service at Lakeside. Any needed construction on the existing SCL line will take considerably less time than permitting and building EE. Further, according to the only reasonable load flow study done regarding serving the east side (the Lauckhart-Schiffman Load Flow study), there is plenty of time before any new 230/115 KV transformer is needed at Lakeside.

Thank you for the opportunity to clarify how this SCL Transmission Line option would work.

Sincerely,

Richard Lauckhart

Richard Lauckhart
Energy Consultant
Davis, California
530-759-9390
lauckjr@hotmail.com

Citizens for Sane Eastside Energy (CSEE)

May 8, 2017

Attachment F -1

The Washington Utilities and Transportation Commission
98504-7250, 1300 Evergreen Park Dr SW
Olympia, WA 98502

sent by email to the individual Commissioners

Dear Commissioners:

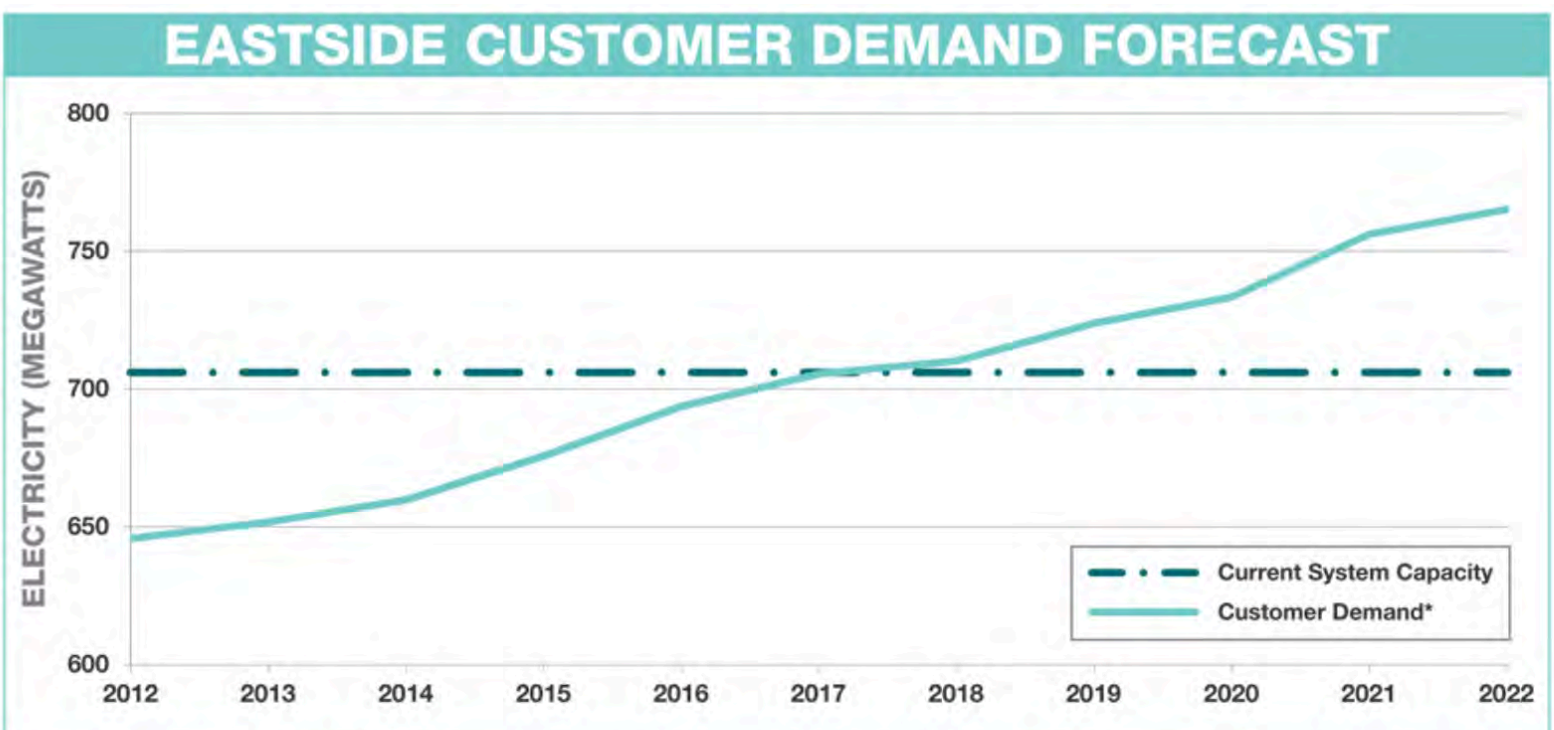
This letter is in response to comments made in an email by Mr. Jens Nedrud of PSE to you and others, dated May 4, 2017, regarding PSE's Energize Eastside project and a 3/16 IRPAG meeting.

Mr. Nedrud's remarks are misleading and distort the facts, yet they are unfortunately consistent with PSE's determined hard-sell methods to get the $200-$300 million project built at all costs, regardless of the economic waste and the grave risk to lives and property if built as proposed, i.e. too close to two aging pipelines transporting highly flammable petroleum products under pressure.

The two chief mantras PSE keeps repeating in its PR efforts to sell Energize Eastside are: 1) There is so much economic and population growth on the Eastside, the project is needed to meet a generic "consumer demand;" and 2) Nothing has been done "since the 1960s" to upgrade the grid in the Eastside. The ads PSE has published in numerous media outlets repeatedly beat these "Consumer Demand" and "Need for Upgrade" drums. CSEE has collected over two dozen of them.

PSE's inflated consumer demand claims

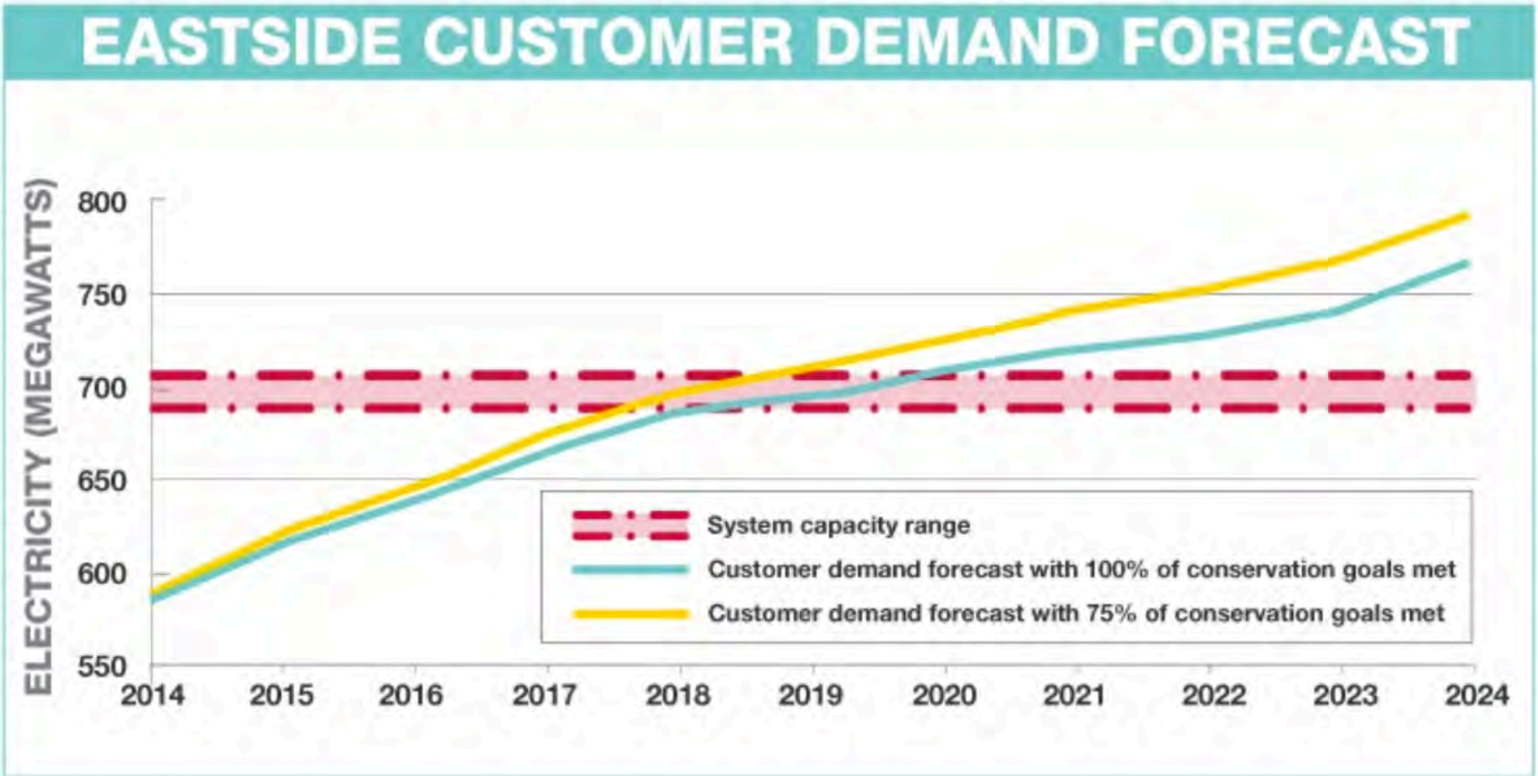
In December of 2013, PSE had on its website dedicated to the Energize Eastside project the following chart, which was its prime lead-in to justify the project. Words introducing the chart stated that "[g]rowth studies predict that demand for reliable power will exceed capacity as early as 2017:"



*Customer Demand assumes 100% of conservation goals are met.

Two years later, in December 2015, that chart was replaced by this one:

Attachment F - 2



This chart was accompanied with a warning: "Without substantial electric infrastructure upgrades, tens of thousands of residents and businesses will be at risk of more frequent and longer power outages."

That is a gross and irresponsible exaggeration. From the graph above, it appears PSE anticipates a spectacular (and preposterous) Eastside demand growth rate of 4% in the next four years. That is ten times the future growth rate predicted for a wildly booming Seattle by Seattle City Light's Sephir Hamilton, Engineering and Technology Innovation Officer, who in 2014 laid out these facts (https://youtu.be/gZWM-yNxwZY, starting at 0:52 into the video):

> "In the last four years nationwide, per-customer energy use has declined by 2%, both residential and non-residential. Here in Seattle it's declined 2.7% for non-residential, and it has declined 7.6% per customer for residential energy use. Even with all the growth that you see here in Seattle and south Lake Union, we're projecting total load growth of less than a half of a percent over the next five years. This is a huge change in the entire makeup of energy use industry in the United States, and especially here in Seattle where we're leading the way."

I have asked Mr. Hamilton to update this data with what is known now in 2017, and I will update with that information when received. Meanwhile, PSE no longer has a chart on its Energize Eastside website with growth projections. But that does not deter it from making outlandish growth claims.

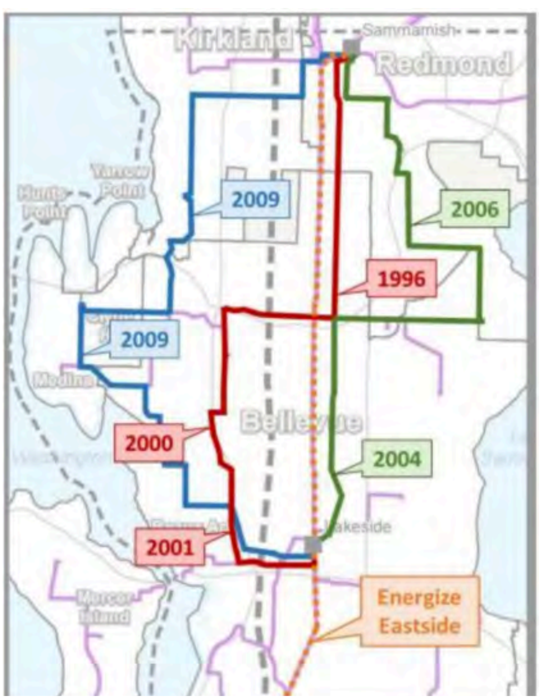
<u>PSE's false "no update since the 1960s" claims</u>

Here is an example of one of several ads of like content that PSE has published in various media outlets:

Note the blatant falsehood contained in this ad: "The Eastside electric grid was last upgraded in the 1960s." The ad also makes a false correlation between general daily electricity usage and power outages, when PSE knows full well the ostensible need for Energize Eastside is to meet very rare N-1-1 emergency events where federally mandated reliability is the only issue, not the general daily supply and demand for electricity.

As former Puget Power Vice President for Power Planning, Richard Lauckhart, has argued in documents he has sent you, there have been numerous upgrades and expansions made to the Eastside grid since the 1960s, as illustrated in this graphic for lines added and the years they were built:

New 115 KV lines built in the Eastside in recent years



In conclusion, whether in terms of PSE's complying with your requirements for a proper and adequate IRP, or whether as evidence at some future rate hearing on Energize Eastside when you will need all the facts, it remains that PSE simply cannot be trusted to tell the truth when so much of its future profits are at stake. You will recall that the WUTC levied its greatest fine ever on a utility, $1.25 million, for PSE's having intentionally falsified gas pipeline safety inspection records over a period of four years (see https://sane-eastside-energy.org/2014/04/30/pse-fined-1-25-million-in-falsifying-gas-pipeline-safety-inspection-reports-for-4-years-running/). It is thus not totally surprising that, while Mr. Nedrud finds flaws in the Lauckhart-Schiffman load flow studies, PSE has yet to release CEII-related data PSE submitted for the studies it relies on that would reveal what sorts of fundamental assumptions were used, even though FERC made it clear to PSE that Mr. Lauckhart and CENSE's Don Marsh have CEII clearances and should be given access to that CEII data.

PSE has stubbornly refused to provide that information. The WUTC should demand that they do.

I realize the power the WUTC has to regulate and influence PSE is woefully inadequate. But for a project with such great potential for irrevocable damage, I hope the WUTC can use its own resources to conduct fully unbiased and untainted flow studies, if need be, to determine for itself the need for Energize Eastside, or at least to establish the validity of such studies as have been done. This is, after all, your area of expertise and public trust. That would be a positive effort undertaken for the common good of all Washingtonians and for the future of our environment.

Sincerely,

Larry G. Johnson
Attorney at Law, WSBA #5682
Citizens for Sane Eastside Energy (CSEE), www.sane-eastside-energy.com
8505 129th Ave. SE
Newcastle, WA 98056
tel.: 425 227-3352
larry.ede@gmail.com

cc: CENSE
City Councils of Bellevue, Newcastle, Redmond and Renton
NW Energy Coalition
Sierra Club

Citizens for Sane Eastside Energy (CSEE)

8505 129th Ave. SE
Newcastle, WA 98056
tel.: 425 227-3352
email: larry.ede@gmail.com

May 23, 2017

Ms. Heidi Bedwell
Energize Eastside EIS Program Manager
City of Bellevue Development Services Dept.
450 110th Ave. NE
Bellevue, WA 98004 submitted in person at Hazen High School public meeting

Re: Additional Comment regarding Energize Eastside Phase 2 Draft EIS

Yesterday I submitted by email on behalf of CSEE two documents to be included in the public comments record regarding the Energize Eastside Phase 2 Draft EIS. One of those is a print-out of the text at https://sane-eastside-energy.org/2017/05/21/four-big-lies-in-pses-hard-sell-of-energize-eastside-project/. There I state *inter alia*: "Several emails produced by the City of Bellevue to CSEE under public records requests indicate the relationship between PSE, the City of Bellevue and the EIS consultants is far too cozy." Further, "the writers of the Phase 2 draft EIS appear to have bought hook, line and sinker the PSE's lies about how hard [PSE] supposedly worked to get cooperation from SCL, and how supposedly insurmountable such a task would be…We hope the EIS consultants do a better job and do their own homework on this SCL lines alternative rather than simply rely on whatever PSE tells them."

Included in the several emails mentioned above is Attachment A hereto, from City of Bellevue's Nicholas Matz to Chris Salomone, dated May 19, 2014, with subject header, "FW: Mayor's Meeting Notes." The email contains this language: "Energize Eastside: * Tonights [sic] objective is buy-off on plan." That statement alone raises legitimate concerns about the City of Bellevue's ability to serve as an objective and impartial Lead Agency in the EIS process. Other emails produced through public records requests add to a body of evidence that the City of Bellevue's staff is unduly influenced by PSE and clearly biased in its favor.

More important than the substance of the EIS document is the integrity of the EIS process itself. If that process is corrupted than any report resulting from it will be inherently worthless. PSE has had unlimited access to COB employees working on Energize Eastside, while CENSE and CSEE are limited to rushed sound bites at a handful of public occasions. Their pleas for total transparency and disclosure of basic data inputs for load flow studies PSE relies on to justify Energize Eastside fall on deaf ears in Bellevue. Our experts are given not even 1% of the hearing time and access that PSE gets. For example, despite the many legitimate criticisms of Energize Eastside by former Puget Power Vice President for Power Planing, Richard Lauckhart, and the independent flow studies he performed with Mr. Schiffman, *COB staff and the EIS consultants have never contacted him* to discuss his concerns. Indeed, COB staff and the Bellevue City Council have been consistently and remarkably incurious about why Lauckhart and CENSE (on flow studies and several other key issues) never get any straight answers or relevant information from PSE, which as stakeholders they are entitled to.

The entire EIS process to this point is reminiscent of how the SEC was asleep at the wheel for years while Bernie Madoff bilked investors of some $65 billion with his giant Ponzi scheme, even though for most of those years financial experts were screaming at the SEC to investigate. The SEC dropped the ball, apparently thinking Madoff was somehow beyond reproach. The City of Bellevue is following down that same path with PSE.

Some other entity other than the City of Bellevue needs to be in charge of the EIS process if the EIS is to have any integrity and credibility.

Sincerely,

Larry G. Johnson
Attorney at Law, WSBA #5682
Citizens for Sane Eastside Energy (CSEE)

cc: CENSE

From:	Matz, Nicholas
Sent time:	05/19/2014 10:06:22 AM
To:	Salomone, Chris
Subject:	FW: Mayor's Meeting notes

Attachment A

From: Basich, Myrna
Sent: Monday, May 19, 2014 10:05 AM
To: Brennan, Mike; Helland, Carol; Matz, Nicholas; McCormick-Huentelman, Mike
Subject: Mayor's Meeting notes

Energize Eastside: • Tonights objective is buy-off on plan. • Be prepared to describe Essential Public Facility tonight, but may be more appropriate to discuss as part of regulatory discussion later in the process. • Will WUTC and Seattle Public Utilities come to our meeting? Please strongly encourage. • Alert Council when Energize Eastside (from City perspective) web page is published. • Re: Attachment A, this is the public engagement process not the decision-making process. Provide reminder of Council role on return visit. Public needs to understand how gets from talking to decision. • Make sure PSE prepared to show homework. • Start with public process piece and then invite PSE reps to table. PowerPoint PSE representatives will be at table. Please reserve seating in front row for them likely 3 spots. May need room opened up to 1E-108 Confirm that audio system has been remedied Schedule more regular updates to Council on this project going forward.

Mayor's Meeting – May 19, 2014 *Confidential*

General administration		
Item(s)	**Assignments**	
Figure out how to provide PowerPoints to Council to view on personal laptops during Council meetings. (provide to Claudia for her Surface) How will this affect use of Granicus for agenda/packet?		
Remind Council to be mindful of tight agenda through Recess. Be aware if missing meetings that may not be able to work around specific topics.		

New Initiatives/Issues discussed		
Item(s)	**Assignments**	

Tonight's agenda		
Item(s)	**Assignments**	
Executive Session •		
Energize Eastside: • Tonight's objective is buy-off on plan. • Be prepared to describe Essential Public Facility tonight, but may be more appropriate to discuss as part of 'regulatory" discussion later in the process. • Will WUTC and Seattle Public Utilities come to our meeting? Please strongly encourage. • Alert Council when Energize Eastside (from City perspective) web page is published. • Re: Attachment A, this is the public engagement process – not the decision-making process. Provide reminder of Council role on return visit. Public needs to understand how gets from talking to decision. • Make sure PSE prepared to show homework. • Start with public process piece and then invite PSE reps to table.	PowerPoint PSE representatives will be at table. Please reserve seating in front row for them – likely 3 spots. May need room opened up to 1E-108 Confirm that audio system has been remedied Schedule more regular updates to Council on this project going forward.	
Operations and Maintenance Satellite Facility: • Council to be tee'd up with questions to pose tonight. They will be emailed later today and provided in Desk Packet. Encourage ST be mindful of short timeframe for some construction decisions. • Focus on slides relating to the ST2 Operating plan, now and beyond ST2. Explain how trains actually travel for service and constraints on the operations. • Send email to Betty Spieth reminding on agenda tonight. • Note significant contribution to regional transportation by siting of Metro bus and OMSF in prime TOD area.	PowerPoint/Desk Packet item ST representatives will be at table. Please reserve seating in front row for them – likely 3 spots. Provide feedback to ST – need "best presenter". Talk to Rick I.	
PACE MOU: • Noted Cmbr Chelminiak concern re: "will" v. "may" language, particularly page 3 discussion of City role. • Would have been better for City Council to have seen this before PACE Board signed the MOU.	Print out copies of MOU for Desk Packet tonight.	

DSD 009556

General administration		
Item(s)	**Assignments**	
Figure out how to provide PowerPoints to Council to view on personal laptops during Council meetings. (provide to Claudia for her Surface) How will this affect use of Granicus for agenda/packet?		
Remind Council to be mindful of tight agenda through Recess. Be aware if missing meetings that may not be able to work around specific topics.		
Council Vision and Priorities: Claudia will introduce/lead the discussion. Action may be postponed if Councilmembers present wish to wait for return of missing members.		
Prepare memo for Human Services Commission appointments.	Desk Packet tonight	
Future Meetings/Calendaring		
Recreational Marijuana • Has sufficient direction been provided to Planning Commission? How is mixed-use zoning implicated in "no residential zones"? • Important for staff and Stokes to be aware that have given direction in form of draft ordinance. Not expecting major changes.		

Accufacts Inc.
"Clear Knowledge in the Over Information Age"

8040 161st Ave NE, #435
Redmond, WA 98052
Ph (425) 802-1200
Fax (805 980-4204
kuprewicz@comcast.net

Date: June 20, 2017

To: Rob Wyman
City Manager
City of Newcastle
12835 Newcastle Way, Ste 200
Newcastle, WA 98056

Re: Accufacts Review of Puget Sound Energy's Energize Eastside Transmission project along Olympic Pipe Line's two petroleum pipelines crossing the City of Newcastle

I. Introduction and Scope

Accufacts Inc. ("Accufacts") was asked to perform a technical review of several specific documents identified below ("Documents") related to the Energize Eastside ("EE") project's possible impact on the 16-inch and 20-inch Olympic Pipe Line product pipelines crossing the City of Newcastle ("City"). Within the City, the existing 16 and 20-inch Olympic Pipe Line products pipelines ("Olympic") are collocated on or near Puget Sound Energy's ("PSE's") electric transmission pipeline right-of-way ("ROW") proposed for electrical expansion from 115 KV to 230 KV.

With regard to PSE's EE project, the City asked Accufacts to specifically review and briefly comment on the following Documents:

1. DNV-GL Final Report, AC Interference Analysis – 230 KV Transmission Line Collocated with Olympic Pipelines OPL 16 and OPL 20, dated December 13, 2016,

2. Phase 2 Draft EIS dated May 2017: Chapter 3, Long-Term (Operation) Impacts and Potential Mitigation; and Chapter 4, Short-Term (Construction) Impacts and Mitigation, and

3. Phase 2 Draft EIS Preliminary Draft V-2, "Appendix I. Pipeline Safety, Appendix I-1 through I-5," dated April 2017.

The EE project can present a threat to the pipelines during two separate phases: 1) the construction phase from possible abnormal loading or impact threats that could damage the pipelines, and 2) an operational phase when the electrical power lines are operated at the higher KV that can introduce stray currents, also known as interference currents, that can remove steel from buried pipelines if not properly addressed.

In reviewing the Documents, Accufacts has the following major findings:

1. Olympic Pipe Line bears the ultimate responsibility for possible PSE's EE project interactions that could result in an Olympic pipeline failure.
2. The Documents do not provide sufficient details to assure Accufacts that appropriate precautions will be implemented or effective in protecting the pipelines during the construction phase.
3. The DNV-GL Final Report explains how pipelines address stray current risks near high power electrical transmission lines, but correctly indicates that Olympic must provide additional field verifications to support key assumptions once EE goes operational.
4. Appendix I-5 of the Phase 2 Draft EIS EE Pipeline Safety Technical Report ("Technical Report") risk assessment approach is not relevant nor does it represent the Olympic pipelines, especially within the City.

It is Accufacts' opinion that the PSE's EE can be safely collocated with the pipelines if sufficient details, identified in the Accufacts Detailed Recommendations for EE within the City, Section III below, are implemented by PSE and Olympic, and adequately conveyed to the City. Some of these details may be sensitive and may not be publicly disseminated for obvious reasons, even in a right-to-know state, such as Washington State. My attached CV will demonstrate some of my pipeline investigative background and experience, which included evaluating the Olympic Pipe Line operation for the City of Bellingham after the June 10, 1999 pipeline rupture and tragedy.

II. Additional Accufacts observations related to EE and the Olympic pipelines within the City:

1. Olympic Pipe Line bears the ultimate responsibility for possible PSE's EE project's interactions that could result in an Olympic pipeline failure.

It is not unusual to have liquid transmission pipelines collocated in the same or nearby rights-of-way of high power electrical transmission pipelines. Federal minimum pipeline safety regulations clearly place the ultimate responsibility to assure protection of the hazardous liquid pipeline(s) in such locations squarely on the pipeline operator. Long standing minimum federal pipeline safety regulations are very clear: "An operator may make arrangements with another person for the performance of any action required by this part. However, the operator is not thereby relieved from the responsibility for compliance with any requirement of this part."[1] "Part" in this context means the federal pipeline safety regulation incorporated as 49CFR§195 setting minimum pipeline safety standards governing the transportation of hazardous liquids by pipeline. The operator of Olympic Pipe Line is ultimately responsible for the operation of their pipelines regardless of studies or actions performed by others.

As further discussed below, while the PSE commissioned DNV-GL Final Report presents a prudent analysis of the possible interactions related to stray current threats from the EE project, and includes rational electrical design/operational suggestions to reduce possible infrastructure impacts by the PSE electrical system, the ultimate threats to the pipeline are the responsibility of Olympic Pipe Line. PSE must provide details as to how Olympic will verify all key assumptions in the DNV-GL Final Report and, more importantly, confirm that actual pipeline field operations are relevant to assure pipeline safety.

2. **The Documents do not provide sufficient details to assure Accufacts that appropriate precautions will be implemented or effective in protecting the pipelines during the construction phase.**

During the construction phase, threats to the pipelines can be introduced from abnormal loads either from surface activity such as heavy equipment or excessive forces such as excavation/auguring. While construction activity can also introduce threats that can contact the pipelines and directly damage them, one does not have to hit a pipeline to cause damage that can fail at a later time as a delayed failure, such as abnormal loading that can deform a steel pipeline. Fortunately, the science and engineering associated with evaluating such construction activity threats to buried pipelines is well established. Depending on the specific location, such potential threats diminish rapidly with lateral distance from a pipeline, and adequate depth can quickly provide a safety factor, depending on the abnormal loading threat expected near/above a pipeline.

The Phase 2 Draft EIS report indicates that, across the City, the pipelines are in the "center of the {PSE} right-of-way."[2] It is important to note that some of the Documents

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[1] 49CFR§195.10 - Responsibility of operator for compliance with this part.

[2] EE EIS, "Chapter 3 Long-Term (Operation) Impacts and Potential Mitigation," May 2017, p. 3.9-9.

could mislead the reader regarding the requirement for pipeline depth.[3] Much of the Olympic system, including the segments crossing the City, is classified as interstate and not subject to the additional conditions imposed by the Washington Administrative Code that instill additional requirements beyond federal regulations on the limited intrastate portions of the Olympic system. I believe the pipeline segments spanning the City are classified as interstate and thus have no requirement to maintain pipeline depths at the initial installation depths that occurred many decades ago. It is thus Olympic Pipe Line's responsibility to confirm pipeline lateral and, more importantly, depth to avoid construction threats that could result in pipeline failure, as actual depth could have changed over the years.

PSE must work with Olympic to readily demonstrate to the City that adequate protections are to be utilized to avoid these short-term threat activities during construction. Depending on the right-of-way, there is no "one size fits all" distance, either lateral or depth, that should be used, as such safe distance determinations regarding abnormal loading on pipelines are ROW site specific and depend on various factors such as load which can change by project/location.

Given the challenging elevation profile of the pipelines across the City, PSE also needs to confirm that EE activities (either on or off the electrical transmission ROW) will not introduce landslide potential on the Olympic pipelines. No pipeline can withstand massive breakaway landslide abnormal loading that can occur from soil liquification in areas of steep elevation profile experiencing high rainfall or flooding, such as that which can occur in Western Washington. Breakaway landslide usually results in a pipeline rupture (high rate releases). This potential threat should be an easy threat to identify, evaluate, and assess, but has not been mentioned in the Technical Report.

3) **The DNV-GL Final Report explains how pipelines address stray current risks near high power electrical transmission lines, but correctly indicates that Olympic must provide additional field verifications to support key assumptions once EE goes operational.**

During the operational phase of the EE effort, a phenomenon commonly known in the pipeline industry as "stray current" or interference current can impact pipeline integrity if not properly addressed. Stray current is a term that captures an electrical current path generated from, among other things, high voltage power lines, poor CP system

[3] EDM Technical Services, Inc., Appendix I-5, "Technical Report, Pipeline Safety and Risk of Upset," p. 28.

design/operation, inadequate foreign crossing design/installation, or electrical "fault" short circuits from lightning or downed power lines where high energy current reaches a pipeline and causes pipe metal loss.

Federal pipeline safety regulations have been codified and prescribed for many years concerning stray current interference/interactions.[4] Even before placement into federal regulations, experienced pipeline operators were well aware of the possible interactions of high energy electrical power transmission systems on pipelines that can cause the rapid loss of buried pipeline steel. Olympic should be well aware of and experienced in stray current interaction as much of their product pipelines are collocated in high energy electrical transmission ROWs in other areas of the state that has successfully operated for over 50 years.[5] Current federal pipeline safety regulation, 49CFR195.3, places explicit prescribed regulatory obligations in the area of interference or stray current interactions on hazardous liquid pipeline operators.[6]

The DNV-GL Final Report does suggest several design modifications that PSE can utilize to reduce and control the risk of stray current to the pipelines from the EE project.[7] The DNV-GL Final Report also correctly recommends further field follow-up by Olympic Pipe Line and PSE concerning additional field monitoring and verification of both the electrical line and liquid pipeline operation to assure effectiveness of the design/operational approaches concerning possible stray current impacts from PSE's project.

Given the wide variation in field measurement conditions, PSE must have the pipeline operator confirm that key assumptions in the DNV-GL Final Report are indeed conservative and appropriate for their pipelines once the power lines go into operation at their higher voltage. AC interference, ground fault, and high energy arc potential that might reach a buried pipeline, need additional verification from Olympic as to their assumption/field measured accuracy. For example, arcing potential to pipelines from faults is highly dependent on the quality of the pipeline's external coating at a specific

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[4] 49CFR§195.577 - What must I do to mitigate interference currents? Added to federal pipeline safety regulations Dec. 27, 2001.

[5] U.S. Department of Energy, "State of Washington Energy Sector Risk Profile," 2014, pp. 2 & 4.

[6] NACE SP0169-2007, Standard Practice, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems," reaffirmed March 15, 2007 (NACE 0169), IBR approved for §§ 195.571 and 195.573(a).

[7] DNV-GL Final Report, "AC Interference Analysis – 230 KV Transmission Line Collocated with Olympic Pipelines OPL 16 and OPL 20," dated December 13, 2016, p. vi.

possible threat location. Only Olympic may know such coating conditions using various field measurements. Coating quality at a specific location can have a critical influence on arc safety distances in the rare occurrence of a ground fault from high power electrical sources. While electrical arcing into a pipeline can leave clear evidence of such an event, the real danger occurs where such energy leaves the buried pipeline, a location which can be highly unpredictable along a pipeline system.

Application of prudent integrity management principles, such as sound in-line inspection ("ILI"), or smart pigging, corrosion assessment can assist in demonstrating past approach effectiveness in dealing with possible stray current interactions from such sources that can cause pipe steel removal. I must caution, however, that some stray current interactions can occur quite quickly causing rapid pipe wall metal loss and possible pipeline failure. Since ILI inspections may also occur infrequently, ILI inspection should not be the only approach to guard against stray current interaction possible threats.[8] A prudent pipeline operator <u>will employ and integrate other measures</u> beyond ILI, such as incorporating effective cathodic protection monitoring and analysis, to assure more timely gauging of pipeline safety approaches to confirm pipeline integrity in such collocated high power electrical transmission rights-of-way. ILI should <u>not</u> be the only method to verify pipeline integrity in stray current high-risk threat potential areas.

III. Accufacts Detail Recommendations for EE within the City:

In light of the above discussion, Accufacts specifically advises, in addition to the general recommendations outlined in the DNV-GL Final Report and Draft EIS, the following more detailed requirements be imposed by the City:[9, 10, 11]

1) Given the criticality of the location of the pipelines, especially their depth, to avoid construction threats that could harm the pipelines, PSE and, especially, Olympic Pipe Line should:
    a) confirm and identify specific pipeline lateral locations, including the important depth values which will vary along the pipelines,

[8] 49CFR§195.452(j)(3) & (4) *Assessment Intervals* requiring reassessment intervals of up to five years not to exceed 68 months unless a variance for longer reassessment is justified.
[9] DNV-GL Final Report, "AC Interference Analysis – 230 KV Transmission Line Collocated with Olympic Pipelines OPL 16 and OPL 20," dated December 13, 2016, p. vi.
[10] EE EIS, "Chapter 4 Short-Term (Construction) Impacts and Mitigation," May 2017, p. 4.9-7 thru 4.9-9.
[11] EE EIS, "Chapter 3 Long-Term (Operation) Impacts and Potential Mitigation," May 2017, pp. 3.9-54 & 55.

b) pinpoint what specific construction activities, including their locations and possible maximum loads, that may occur during the EE installation effort that could be a threat to the pipelines,
c) for these identified possible construction threats, commit to detailed precautions that will be required, implemented, and monitored/checked to avoid construction damage to the pipelines, and
d) verify EE activity does not introduce breakaway landslide threats to the pipelines.

2) During the operational phase of EE, Olympic, in conjunction with PSE, should:
   a. verify that the actual current densities do not pose a threat near the pipelines, especially during the early phase of EE when the power lines may be operated imbalanced (230/115 KV),
   b. establish notification protocols that would alert Olympic of possible major PSE power transmission imbalances,
   c. not only rely on periodic corrosion tool ILI to assure pipeline wall loss from possible interference currents is not occurring, and
   d. verify pipeline coating reasonable integrity to substantiate fault arcing distance determinations.

PSE, with Olympics' cooperation, should be able to sufficiently demonstrate to the City such details, including documented engineering analysis as needed, proving that sufficient safety factors exist to avoid threats to the pipelines during the construction and operational phases of EE.

IV. Accufacts General Observations on Appendix I-5 of the Phase 2 Draft EIS EE Pipeline Safety Technical Report ("Technical Report"):

It is not unusual to see a risk management approach similar to that presented in the Technical Report. From my perspective, however, the Technical Report approach is not relevant to the EE project's possible impact threat to the pipelines. Some key reasons for this are:

1) The risk assessment approaches utilized in the Technical Report are not incorporated into U.S. pipeline safety regulations.

The risk approach utilized in the Technical Report is not defined in federal pipeline safety regulations. There are many assumptions and approaches in the Technical Report that are not specifically representative of the Olympic pipelines, especially in the event of a significant release such as a pipeline rupture. Based on my extensive experience in hydrocarbon releases, including incident response, attempts to characterize the impact area in the Technical Report are unrealistic small. For example, the pipelines' elevation profile, an important consideration in liquid pipeline operation, is neither discussed nor provided. In fairness to EDM, certain critical sensitive information known to Olympic that would assist EDM in a risk assessment approach if it were permitted, in all probability has not been disclosed to EDM given the information's sensitivity**.** It is, however, important to recognize such risk assessments are not codified in U.S. pipeline safety regulations for many good reasons.

In all probability, important additional safeties incorporated into Olympics' operation after the 1999 Olympic rupture tragedy in Bellingham have also not been made public. In addition, it is my experience that the Bellingham rupture cannot be well modeled by a "pool fire" as presented in the Technical Report. The challenging terrain, the pipeline elevation profile and location, as well as other considerations play a critical part in determining an impact area in the event of a release.

2) **Acceptable pipeline risk thresholds (individual or societal) are neither defined nor codified in U.S. pipeline safety regulations.**

The U.S. has more gas and liquid transmission pipeline mileage than any other country in the world by a considerable margin. While some countries have defined and incorporated certain "consequence" risk thresholds, such as acceptable mortality thresholds, into their country's pipeline safety approaches, such as the use of Quantitative Risk Assessment ("QRA"), U.S. pipeline safety regulations do not incorporate the use of this type of risk assessment approach.

The EE EIS correctly mentions that "there are no adopted federal or Washington State criteria for acceptable levels of individual risks" and "there are no adopted federal or Washington State criteria for acceptable levels of societal risk."[12] This same document cites risk thresholds for another state and other countries, but the matter quite simply is not defined, codified, nor accepted in the U.S. or Washington State pipeline safety regulations.

[12] EE EIS, "Chapter 3 Long-Term (Operation) Impacts and Potential Mitigation," May 2017, pp. 3.9-36 & 37.

3) **Assigning risk factors utilizing PHMSA/OPS historical reporting databases can be misrepresentative, as the databases are often woefully incomplete, inadequate, and can be easily misused for a specific pipeline.**

For many reasons, historical PHMSA/OPS database files can be inadequate and incomplete so as to make their use in assigning risk probability inappropriate or inadequate, for a specific pipeline operation, even with "normalization" attempts such as releases per pipeline mile. While PHMSA has made considerable attempts to make pipeline incident/accident information reported to the agency public, reports are often filed before sufficient information can be supplied to accurately complete a pipeline failure report. It is well known that numerous initial reports are not accurately updated. This can be especially problematic as to actual cause, or released volumes, which historically have been found to be inaccurate or misleading. In my experience, I have seen probability analysis abuses based on PHMSA/OPS databases on both sides of the fence, usually to drive false agendas or preordained conclusions about pipelines. These databases should be applied with great caution.

4) **Historical database files do not predict nor represent future risk probabilities on a specific pipeline system in a specific location.**

Risk probabilities derived from industry-wide databases do not represent the risks that may exist on a specific pipeline operation as management safety cultures can vary widely. Such safety culture variations can significantly increase the risk of pipeline failure. While I can appreciate that attempts to characterize pipeline releases into "simple models" that might make engineering analysis easier, the fact remains that the June 10, 1999 Olympic pipeline rupture release in Bellingham is not well represented by modeling as a pool fire. Any efforts trying to define a release impact zone from a pool fire in such a challenging terrain are overly simplistic, and unrealistic, likely underrepresenting the actual impact area. Following the Bellingham rupture release, the pipeline elevation profile played a key role in the technical safety team's role in assisting the pipeline operator in adding/applying at the time unregulated integrity management approaches to assure pipeline integrity, as well as installing additional "safeties" to the Olympic Pipe Line operation.

V. Conclusions

As discussed above, cooperation and proper management between PSE and Olympic concerning the EE project should allow the EE project to not increase risks to the Olympic pipelines. Both PSE and Olympic, however, need to demonstrate to the City those important details as outlined in Section III above to assure the pipelines are protected during the design, construction, and future operation of the EE effort. Lastly, Accufacts understands that, for the Olympic Pipe Line Company, the majority ownership has changed from BP to Enbridge. Such changes can introduce risks in operational approaches caused by a loss in pipeline operational experience and/or a shift in management safety culture, (such as not incorporating proper levels of safety to avoid a pipeline release). It is imperative that the new majority ownership understands the risks that can be introduced to the pipelines from the EE effort, and that prudent prevention efforts are in place and implemented to avoid a release.

Richard B. Kuprewicz,
President,
Accufacts Inc.

Appendix ~~C~~B

RM05-17-~~001, -002~~003 & RM05-25-~~001, -002~~003
(Issued)

PRO FORMA OPEN ACCESS

TRANSMISSION TARIFF

TABLE OF CONTENTS

I. COMMON SERVICE PROVISIONS

1 Definitions

1.1 Affiliate:

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Ancillary Services:

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 Annual Transmission Costs:

The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.4 Application:

A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.5 Commission:

The Federal Energy Regulatory Commission.

1.6 Completed Application:

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.7 Control Area:

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
2. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
3. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and
4. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.8 Curtailment:

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.9 Delivering Party:

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.10 Designated Agent:

Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.11 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.12 Eligible Customer:

i. Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider.

ii. Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.13 Facilities Study:

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.14 Firm Point-To-Point Transmission Service:

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.15 Good Utility Practice:

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

1.16 Interruption:

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.17 Load Ratio Share:

Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff and calculated on a rolling twelve month basis.

1.18 Load Shedding:

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.19 Long-Term Firm Point-To-Point Transmission Service:

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.20 Native Load Customers:

The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.21 Network Customer:

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.22 Network Integration Transmission Service:

The transmission service provided under Part III of the Tariff.

1.23 Network Load:

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.24 Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.25 Network Operating Committee:

A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.26 Network Resource:

Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a ~~Commission-approved~~ reserve sharing program.

1.27 Network Upgrades:

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.28 Non-Firm Point-To-Point Transmission Service:

Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or

Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.29 Non-Firm Sale:

An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

1.30 Open Access Same-Time Information System (OASIS):

The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.31 Part I:

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.32 Part II:

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.33 Part III:

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.34 Parties:

The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.35 Point(s) of Delivery:

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.36 Point(s) of Receipt:

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.37 Point-To-Point Transmission Service:

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.38 Power Purchaser:

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.39 Pre-Confirmed Application:

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.40 Receiving Party:

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.41 Regional Transmission Group (RTG):

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.42 Reserved Capacity:

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.43 Service Agreement:

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.44 Service Commencement Date:

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.45 Short-Term Firm Point-To-Point Transmission Service:

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.46 System Condition

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.47 System Impact Study:

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.48 Third-Party Sale:

Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.49 Transmission Customer:

Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.50 Transmission Provider:

The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.51 Transmission Provider's Monthly Transmission System Peak:

The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.52 Transmission Service:

Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.53 Transmission System:

The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transfer Capability:

For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority For Existing Firm Service Customers:

Existing firm service customers (wholesale requirements and transmission-only, with a contract term of five years or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the

Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service, the existing firm service customer must agree to accept a contract term at least equal to ~~the longest~~ a competing request by any new Eligible Customer and to pay the current just and reasonable rate, as approved by the Commission, for such service; provided that, the firm service customer shall have a right of first refusal at the end of such service only if the new contract is for five years or more. The existing firm service customer must provide notice to the Transmission Provider whether it will exercise its right of first refusal no less than one year prior to the expiration date of its transmission service agreement. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. Service agreements subject to a right of first refusal entered into prior to [the date of the Transmission Provider's filing adopting the reformed rollover language herein in compliance with Order No. 890] or associated with a transmission service request received prior to July 13, 2007, unless terminated, will become subject to the five year/one year requirement on the first rollover date after [the date of the Transmission Provider's filing adopting the reformed rollover language herein in compliance with Order No. 890]; provided that, the one-year notice requirement shall apply to such service agreements with five years or more left in their terms as of the [date of the Transmission Provider’s filing adopting the reformed rollover language herein in compliance with Order No. 890].

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve - Spinning, and (iv) Operating Reserve - Supplemental. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Provider is required to provide (or offer to arrange with the local Control Area Operator as discussed below), to the extent it is physically feasible to do so from its resources or from resources available to it, Generator Imbalance Service when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer using Transmission Service to deliver energy from a generator located within the Transmission Provider's Control Area is required to acquire Generator Imbalance Service, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to (i) have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary Services (discussed in Schedules 3, 4, 5, 6 and 9) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.7 below list the seven Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service:

The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation or Other Sources Service:

The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service:

Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service:

Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve - Spinning Reserve Service:

Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve - Supplemental Reserve Service:

Where applicable the rates and/or methodology are described in Schedule 6.

3.7 Generator Imbalance Service:

Where applicable the rates and/or methodology are described in Schedule 9.

4 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR § 37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities) and 18 C.F.R. § 38 of the Commission's regulations (Business Practice Standards and Communication Protocols for Public Utilities). In the event available transfer capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

The Transmission Provider shall post on OASIS and its public website an electronic link to all rules, standards and practices that (i) relate to the terms and conditions of transmission service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff. The Transmission Provider shall post on OASIS and on its public website an electronic link to the NAESB website where any rules, standards and practices that are protected by copyright may be obtained. The Transmission Provider shall also post on OASIS and its public website an electronic link to a statement of the process by which the Transmission Provider shall add, delete or otherwise modify the rules, standards and practices that are not included in this tariff. Such process shall set forth the means by which the Transmission Provider shall provide reasonable advance notice to Transmission Customers and Eligible Customers of any such additions, deletions or modifications, the associated effective date, and any additional implementation procedures that the Transmission Provider deems appropriate.

5 Local Furnishing Bonds

5.1 Transmission Providers That Own Facilities Financed by Local Furnishing Bonds:

This provision is applicable only to Transmission Providers that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code ("local furnishing bonds"). Notwithstanding any other provision of this Tariff, the Transmission Provider shall not be required to provide transmission service to any Eligible Customer pursuant to this Tariff if the provision of such transmission service would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Provider's facilities that would be used in providing such transmission service.

5.2 Alternative Procedures for Requesting Transmission Service:

(i) If the Transmission Provider determines that the provision of transmission service requested by an Eligible Customer would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance its facilities that would be used in providing such transmission service, it shall advise the Eligible Customer within thirty (30) days of receipt of the Completed Application.

(ii) If the Eligible Customer thereafter renews its request for the same transmission service referred to in (i) by tendering an application under Section 211 of the Federal Power Act, the Transmission Provider, within ten (10) days of receiving a copy of the Section 211 application, will waive its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Transmission Provider's waiver of its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Transmission Provider shall be required to provide the requested transmission service in accordance with the terms and conditions of this Tariff.

6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate Affiliates. A Transmission Customer that is a member of, or takes transmission service from, a power pool, Regional Transmission Group, Regional Transmission Organization (RTO), Independent System Operator (ISO) or other transmission organization approved by the Commission for the operation of transmission facilities also agrees to provide comparable transmission service to the transmission-owning members of such power pool and Regional Transmission Group, RTO, ISO or other transmission organization on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate Affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the Tariff, but also to all parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

7 Billing and Payment

7.1 Billing Procedure:

Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made in immediately available funds payable to the Transmission Provider, or by wire transfer to a bank named by the Transmission Provider.

7.2 Interest on Unpaid Balances:

Interest on any unpaid amounts (including amounts placed in escrow) shall be calculated in accordance with the methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. 35.19a(a)(2)(iii). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment. When payments are made by mail, bills shall be considered as having been paid on the date of receipt by the Transmission Provider.

7.3 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission so approves any such request. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer (i) continues to make all payments not in dispute, and (ii) pays into an independent escrow account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission Customer of its intention to suspend service in sixty (60) days, in accordance with Commission policy.

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues:

Include in a separate operating revenue account or subaccount the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues:

Include in a separate transmission operating expense account or subaccount, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the

Tariff; and include in a separate operating revenue account or subaccount the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make application to the Commission for a change in rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Party receiving service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

10 Force Majeure and Indemnification

10.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

11 Creditworthiness

The Transmission Provider will specify its Creditworthiness procedures in Attachment L.

12 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures:

Any dispute between a Transmission Customer and the Transmission Provider involving transmission service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures:

Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or Regional Transmission Group rules.

12.3 Arbitration Decisions:

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs:

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

1. the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or
2. one half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Rights Under The Federal Power Act:

Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

II. POINT-TO-POINT TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-To-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transfer of such capacity and energy to designated Point(s) of Delivery.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term:

The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority:

(i) Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis, i.e., in the chronological sequence in which each Transmission Customer has requested service.

(ii) Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction or reservation. However, Pre-Confirmed Applications for Short-Term Point-to-Point Transmission Service will receive priority over earlier-submitted requests that are not Pre-Confirmed and that have equal or shorter duration. Among requests or reservations with the same duration and, as relevant, pre-confirmation status (pre-confirmed, confirmed, or not confirmed), priority will be given to an Eligible Customer's request or reservation that offers the highest price, followed by the date and time of the request or reservation.

(iii) If the Transmission System becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, an Eligible Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm

Point-To-Point Transmission Service. When a longer duration request preempts multiple shorter duration reservations, the shorter duration reservations shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which the multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff.

(iv) Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider: The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after [insert date sixty (60) days after publication in Federal

Register] or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements:

The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement. The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in Section 15.4, the Transmission Provider shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions. Concurrent with such notice, the Transmission Provider shall provide the Transmission Customer with the reassessment study and a narrative description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs:

In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its

Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint by redispatching the Transmission Provider's resources, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 and agrees to either (i) compensate the Transmission Provider for any necessary transmission facility additions or (ii) accept the service subject to a biennial reassessment by the Transmission Provider of redispatch requirements as described in Section 15.4. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service:

In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system and the system directly and indirectly interconnected with Transmission Provider's Transmission System, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. Long-Term Firm Point-to-Point Service subject to conditions described in Section 15.4 shall be curtailed with secondary service in cases where the conditions apply, but otherwise will be curtailed on a pro rata basis with other Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The

Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service:

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The

Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved.

13.8 Scheduling of Firm Point-To-Point Transmission Service: Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10:00 a.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term:

Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority:

Non-Firm Point-To-Point Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned first to requests or reservations with a longer duration of service and second to Pre-Confirmed Applications. In the event the Transmission System is constrained, competing requests of the same Pre-Confirmation status and equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term request before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm

Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider:

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after [insert date sixty (60) days after publication in Federal Register] or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements:

The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible

Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification of Non-Firm Point-To-Point Transmission Service: Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service: Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 2:00 p.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. will be accommodated, if practicable. Hour-to-hour schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the

Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service:

The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System or the systems directly and indirectly interconnected with Transmission Provider's Transmission System. Transmission Provider may elect to implement such Curtailments pursuant to the Transmission Loading Relief procedures specified in Attachment J. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm

Point-To-Point Transmission Service of equal duration with a higher price, (4) transmission service for Network Customers from non-designated resources, or (5) transmission service for Firm Point-to-Point Transmission Service during conditional curtailment periods as described in Section 15.4. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of

Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice.

15 Service Availability

15.1 General Conditions:

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transfer Capability:

A description of the Transmission Provider's specific methodology for assessing available transfer capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transfer capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement:

If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System, Redispatch or Conditional Curtailment:

(a) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

(b) If the Transmission Provider determines that it cannot accommodate a Completed Application for Long-Term Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to provide redispatch from its own resources until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide the redispatch, or (iii) the Transmission Customer terminates the service because of redispatch changes resulting from the reassessment. A Transmission Provider shall not unreasonably deny self-provided redispatch or redispatch arranged by the Transmission Customer from a third party resource.

(c) If the Transmission Provider determines that it cannot accommodate a Completed Application for Long-Term Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will offer the Firm Transmission Service with the condition that the Transmission Provider may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s). If the Transmission Customer accepts the service, the Transmission Provider will use due diligence to provide the service until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide such service, or (iii) the Transmission Customer terminates the service because the reassessment increased the number of hours per year of conditional curtailment or changed the System Conditions.

15.5 Deferral of Service:

The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules:

Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

15.7 Real Power Losses:

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers:

Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

(a) The Transmission Customer has pending a Completed Application for service;

(b) The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

(c) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

(d) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation;

(e) The Transmission Customer provides the information required by the Transmission Provider's planning process established in Attachment K; and

(f) The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

16.2 Transmission Customer Responsibility for Third-Party Arrangements:

Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application:

A request for Firm Point-To-Point Transmission Service for periods of one year or longer must contain a written Application to: [Transmission Provider Name and Address], at least sixty (60) days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application:

A Completed Application shall provide all of the information included in 18 CFR̹ 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service;

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement;

(ix) A statement indicating that, if the Eligible Customer submits a

Pre-Confirmed Application, the Eligible Customer will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service; and

(x) Any additional information required by the Transmission Provider's planning process established in Attachment K.

The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

17.3 Deposit:

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned with interest less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned with interest less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, with interest, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service. Applicable interest shall be computed in accordance with the Commission's regulations at 18 CFR. 35.19a(a)(2)(iii), and shall be calculated from the day the deposit check is credited to the Transmission Provider's account.

17.4 Notice of Deficient Application:

If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit, with interest. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application:

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transfer capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1. Responses by the Transmission Provider must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

17.6 Execution of Service Agreement:

Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement or request the filing of an unexecuted service agreement pursuant to Section 15.3, within fifteen (15) days after it is tendered by the Transmission Provider will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded with interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service:

The Transmission Customer can obtain, subject to availability, up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof within 15 days of notifying the Transmission Provider it intends to extend the commencement of service. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application:

Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission

Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application.

18.2 Completed Application:

A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vii) The electrical location of the ultimate load.

The Transmission Provider will treat this information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

(viii) A statement indicating that, if the Eligible Customer submits a Pre-Confirmed Application, the Eligible Customer will execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

18.3 Reservation of Non-Firm Point-To-Point Transmission Service:

Requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence, requests for daily service shall be submitted no earlier than two (2) days before service is to commence, and requests for hourly service shall be submitted no earlier than noon the day before service is to commence. Requests for service received later than 2:00 p.m. prior to the day service is scheduled to commence will be accommodated if practicable [or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

18.4 Determination of Available Transfer Capability:

Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transfer capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty (30) minutes for hourly service, (ii) thirty (30) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service. [Or such reasonable times that are generally accepted in the region and are consistently adhered to by the Transmission Provider].

19 Additional Study Procedures For Firm Point-To-Point Transmission Service Requests

19.1 Notice of Need for System Impact Study:

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the

Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. Once informed, the Eligible Customer shall timely notify the Transmission Provider if it elects to have the Transmission Provider study redispatch or conditional curtailment as part of the System Impact Study. If notification is provided prior to tender of the System Impact Study Agreement, the Eligible Customer can avoid the costs associated with the study of these options. The Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest.

19.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 20.

19.3 System Impact Study Procedures:

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify (1) any system constraints, identified with specificity by transmission element or flowgate, (2) redispatch options (when requested by an Eligible Customer) including an estimate of the cost of redispatch, (3) conditional curtailment options (when requested by an Eligible Customer) including the number of hours per year and the System Conditions during which conditional curtailment may occur, and (4) additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. For customers requesting the study of redispatch options, the System Impact Study shall (1) identify all resources located within the Transmission Provider's Control Area that can significantly contribute toward relieving the system constraint and (2) provide a measurement of each resource's impact on the system constraint. If the Transmission Provider possesses information indicating that any resource outside its Control Area could relieve the constraint, it shall identify each such resource in the System Impact Study. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement pursuant to Section 15.3, or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures:

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer, (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff, and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications:

Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence in Completing New Facilities:

The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The

Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To-Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service:

If the Transmission Provider determines that it will not have adequate transfer capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities:

In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

19.9 Penalties for Failure to Meet Study Deadlines:

Sections 19.3 and 19.4 require a Transmission Provider to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

(i) The Transmission Provider is required to file a notice with the Commission in the event that more than twenty (20) percent of non-Affiliates' System Impact Studies and Facilities Studies completed by the Transmission Provider in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

(ii) For the purposes of calculating the percent of non-Affiliates' System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the Transmission Provider shall consider all System Impact Studies and Facilities Studies that it completes for non-Affiliates during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The Transmission Provider may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.

(iii) The Transmission Provider is subject to an operational penalty if it completes ten (10) percent or more of non-Affiliates' System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the Transmission Provider's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the Transmission Provider completes at least ninety (90) percent of all non-Affiliates' System Impact Studies and Facilities Studies within the 60-day deadline.

(iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to $500 for each day the Transmission Provider takes to complete that study beyond the 60-day deadline.

20 Procedures if The Transmission Provider is Unable to Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

20.1 Delays in Construction of New Facilities:

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the

Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions:

When the review process of Section 20.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Firm Point-To-Point Transmission Service. If the alternative approach solely involves Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender a Service Agreement for Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission

Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

20.3 Refund Obligation for Unfinished Facility Additions:

If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned with interest pursuant to Commission regulations 35.19a(a)(2)(iii). However, the Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions:

The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

21.2 Coordination of Third-Party System Additions:

In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12 or it may refer the dispute to the Commission for resolution.

22 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis:

The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions.

(a) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Native Load Customers.

(b) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement under which such services are provided.

(c) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement in the amount of its original capacity reservation.

(d) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modification On a Firm Basis:

Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service:

Subject to Commission approval of any necessary filings, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to Resellers shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost capped at the Transmission Provider's cost of expansion; provided that, for service prior to October 1, 2010, compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee.

The Assignee must execute a service agreement with the Transmission Provider governing reassignments of transmission service prior to the date on which the reassigned service commences. The Transmission Provider shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Service Agreement with the Transmission Provider or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the Transmission Provider or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service:

If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Transmission Provider and the Reseller through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service:

In accordance with Section 4, all sales or assignments of capacity must be conducted through or otherwise posted on the Transmission Provider's OASIS on or before the date the reassigned service commences and are subject to Section 23.1. Resellers may also use the Transmission Provider's OASIS to post transmission capacity available for resale.

24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations:

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access to Metering Data:

The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor:

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use Part II of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the

Transmission Provider must separately file any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with Commission policy. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved by redispatching the Transmission Provider's resources to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with Commission policy.

III. NETWORK INTEGRATION TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load

Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

28 Nature of Network Integration Transmission Service

28.1 Scope of Service:

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities:

The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 Network Integration Transmission Service:

The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service:

The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses:

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are as follows: [To be completed by the Transmission Provider].

28.6 Restrictions on Use of Service:

The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration

Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System. The Transmission Provider shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve a Network Load.

29 Initiating Service

29.1 Condition Precedent for Receiving Service:

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G, or requests in writing that the

Transmission Provider file a proposed unexecuted Network Operating Agreement.

29.2 Application Procedures:

An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
  - Any periods of restricted operations throughout the year
  - Maintenance schedules
  - Minimum loading level of unit
  - Normal operating level of unit
  - Any must-run unit designations required for system reliability or contract reasons
- Approximate variable generating cost ($/MWH) for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission

Provider Control Area, where only a portion of unit output is designated as a Network Resource;

For each off-system Network Resource, such description shall include:

- Identification of the Network Resource as an off-system resource
- Amount of power to which the customer has rights
- Identification of the control area from which the power will originate
- Delivery point(s) to the Transmission Provider's Transmission System
- Transmission arrangements on the external transmission system(s)
- Operating restrictions, if any
  - Any periods of restricted operations throughout the year
  - Maintenance schedules
  - Minimum loading level of unit
  - Normal operating level of unit
  - Any must-run unit designations required for system reliability or contract reasons

- Approximate variable generating cost ($/MWH) for redispatch computations;

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- 10 year projection of system expansions or upgrades
- Transmission System maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year;

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 29.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program; and

(ix) Any additional information required of the Transmission Customer as specified in the Transmission Provider's planning process established in Attachment K.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service:

Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities:

The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

29.5 Filing of Service Agreement:

The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

30 Network Resources

30.1 Designation of Network Resources:

Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources:

The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. The Network Customer's request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.3 Termination of Network Resources:

The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource by providing notification to the Transmission Provider through OASIS as soon as reasonably practicable, but not later than the firm scheduling deadline for the period of termination. Any request for termination of Network Resource status must be submitted on OASIS, and should indicate whether the request is for indefinite or temporary termination. A request for indefinite termination of Network Resource status must indicate the date and time that the termination is to be effective, and the identification and capacity of the resource(s) or portions thereof to be indefinitely terminated. A request for temporary termination of Network Resource status must include the following:

(i) Effective date and time of temporary termination;

(ii) Effective date and time of redesignation, following period of temporary termination;

(iii) Identification and capacity of resource(s) or portions thereof to be temporarily terminated;

(iv) Resource description and attestation for redesignating the network resource following the temporary termination, in accordance with Section 30.2; and

(v) Identification of any related transmission service requests to be evaluated concomitantly with the request for temporary termination, such that the requests for undesignation and the request for these related transmission service requests must be approved or denied as a single request. The evaluation of these related transmission service requests must take into account the termination of the network resources identified in (iii) above, as well as all competing transmission service requests of higher priority.

As part of a temporary termination, a Network Customer may only redesignate the same resource that was originally designated, or a portion thereof. Requests to redesignate a different resource and/or a resource with increased capacity will be deemed deficient and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.4 Operation of Network Resources:

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm Sales delivered pursuant to Part II of the Tariff, plus losses, plus power sales under a ~~Commission-approved~~ reserve sharing program, plus sales that permit curtailment without penalty to serve its designated Network Load. This limitation shall not apply to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the

Transmission Provider's Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Section 29, unless the Network Customer supports such delivery within the Transmission Provider's Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Section 28.4. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

30.5 Network Customer Redispatch Obligation:

As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The Transmission Provider:

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources:

The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer:

There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the

Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

30.9 Network Customer Owned Transmission Facilities:

The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider, to serve its power and transmission customers. For facilities added by the Network Customer subsequent to the [the effective date of a Final Rule in RM05-25-000], the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission Provider's facilities; provided however, the Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's annual transmission revenue requirement as specified in Attachment H. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31 Designation of Network Load

31.1 Network Load:

The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With the Transmission Provider:

The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer in accordance with Commission policies.

31.3 Network Load Not Physically Interconnected with the Transmission Provider:

This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of (1) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load, or (2) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points:

To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests:

Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g. the addition of a new Network Resource or designation of a new Network

Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates:

The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff including, but not limited to, any information provided under section 29.2(ix) pursuant to the Transmission Provider's planning process in Attachment K. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32 Additional Study Procedures For Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study:

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest.

32.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures:

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify (1) any system constraints, identified with specificity by transmission element or flowgate, (2) redispatch options (when requested by an Eligible Customer) including, to the extent possible, an estimate of the cost of redispatch, (3) available options for installation of automatic devices to curtail service (when requested by an Eligible Customer), and (4) additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. For customers requesting the study of redispatch options, the System Impact Study shall (1) identify all resources located within the Transmission Provider's Control Area that can significantly contribute toward relieving the system constraint and (2) provide a measurement of each resource's impact on the system constraint. If the Transmission Provider possesses information indicating that any resource outside its Control Area could relieve the constraint, it shall identify each such resource in the System Impact Study. In the event that the Transmission Provider is unable to complete the required

System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or request the filing of an unexecuted Service Agreement, or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures:

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned with interest. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission

Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Service Agreement or request the filing of an unexecuted Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

32.5 Penalties for Failure to Meet Study Deadlines:

Section 19.9 defines penalties that apply for failure to meet the 60-day study completion due diligence deadlines for System Impact Studies and Facilities Studies under Part II of the Tariff. These same requirements and penalties apply to service under Part III of the Tariff.

33 Load Shedding and Curtailments

33.1 Procedures:

Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System and on systems directly and indirectly interconnected with Transmission Provider's

Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints:

During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers and any

Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints: Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries: If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement or pursuant to the Transmission Loading Relief procedures specified in Attachment J.

33.5 Allocation of Curtailments: The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding:

To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability:

Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the

Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Native Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with Commission policy, along with the following:

34.1 Monthly Demand Charge:

The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the

Transmission Provider's Annual Transmission Revenue Requirement specified in Schedule H.

34.2 Determination of Network Customer's Monthly Network Load:

The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load:

The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-To-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-To-Point Transmission Service customers.

34.4 Redispatch Charge:

The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with

Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery:

The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff in accordance with the terms, conditions and procedures set forth in FERC Order No. 888. However, the Transmission Provider must separately file any proposal to recover stranded costs under Section 205 of the Federal Power Act.

35 Operating Arrangements

35.1 Operation under The Network Operating Agreement:

The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement:

The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either (i) operate as a Control Area under applicable guidelines of the Electric Reliability Organization (ERO) as defined in 18 C.F.R. § 39.1, (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider, or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies the applicable reliability guidelines of the ERO. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment G.

35.3 Network Operating Committee:

A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for Scheduling, System Control and Dispatch Service are to be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

SCHEDULE 4

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly energy imbalances under this Schedule or a penalty for hourly generator imbalances under Schedule 9 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.

The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of incremental or decremental cost; (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of incremental cost or 75 percent of decremental cost.

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched for any purpose, ~~i.~~e.g., to supply the Transmission Provider's Native Load Customers, correct imbalances, or make off-system sales, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

1) **Yearly delivery**: one-twelfth of the demand charge of $____/KW of Reserved Capacity per year.

2) **Monthly delivery**: $____/KW of Reserved Capacity per month.

3) **Weekly delivery**: $____/KW of Reserved Capacity per week.

4) **Daily delivery**: $____/KW of Reserved Capacity per day.

   The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s)

of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

SCHEDULE 8

Non-Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-To-Point Transmission Service up to the sum of the applicable charges set forth below:

1) **Monthly delivery**: $____/KW of Reserved Capacity per month.

2) **Weekly delivery**: $____/KW of Reserved Capacity per week.

3) **Daily delivery**: $____/KW of Reserved Capacity per day.

   The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any day during such week.

4) **Hourly delivery**: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $____/MWH. The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in kilowatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Resales**: The rates and rules governing charges and discounts stated above shall not apply to resales of transmission service, compensation for which shall be governed by section 23.1 of the Tariff.

SCHEDULE 9

Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator located in the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. The Transmission Provider must offer this service, to the extent it is physically feasible to do so from its resources or from resources available to it, when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule or a penalty for hourly energy imbalances under Schedule 4 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.

The Transmission Provider shall establish charges for generator imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of each month, at 100 percent of incremental or decremental cost, (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of incremental cost or 75 percent of decremental cost, except that an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of this Schedule is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

Notwithstanding the foregoing, deviations from scheduled transactions in order to respond to directives by the Transmission Provider, a balancing authority, or a reliability coordinator shall not be subject to the deviation bands identified above and, instead, shall be settled financially, at the end of the month, at 100 percent of incremental and decremental cost. Such directives may include instructions to correct frequency decay, respond to a reserve sharing event, or change output to relieve congestion.

For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's actual average hourly cost of the last 10 MW dispatched for any purpose, ~~i.~~e.g., to supply the Transmission Provider's Native Load Customers, correct imbalances, or make off-system sales, based on the replacement cost of fuel, unit heat rates, start-up costs (including any commitment and redispatch costs), incremental operation and maintenance costs, and purchased and interchange power costs and taxes, as applicable.

ATTACHMENT A

Form Of Service Agreement For Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between _____________ (the Transmission Provider), and ____________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Transmission Customer:

____

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ________________________ ________________ _______________
Name Title Date

Transmission Customer:

By: ________________________ ________________ _______________
Name Title Date

Specifications For Long-Term Firm Point-To-Point
Transmission Service

1.0 Term of Transaction: ___________________________________

Start Date: ____

Termination Date: ______________________________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt:____________________________________

Delivering Party:____

4.0 Point(s) of Delivery:___________________________________

Receiving Party:____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity):____________________________________

6.0 Designation of party(ies) subject to reciprocal service obligation:____
____
____
____

7.0 Name(s) of any Intervening Systems providing transmission service:____
____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:________________________________

____

8.2 System Impact and/or Facilities Study Charge(s):

____

____

8.3 Direct Assignment Facilities Charge:____________________

____

8.4 Ancillary Services Charges: ______________________

____

____

____

____

____

____

ATTACHMENT A-1

Form Of Service Agreement For The Resale, Reassignment Or Transfer Of Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between ____________ (the Transmission Provider), and ____________ (the Assignee).

2.0 The Assignee has been determined by the Transmission Provider to be an Eligible Customer under the Tariff pursuant to which the transmission service rights to be transferred were originally obtained.

3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Part II of the Transmission Provider's Tariff, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section 23.1 of this Tariff) and the Assignee, to include: contract effective and termination dates, the amount of reassigned capacity or energy, point(s) of receipt and delivery. Changes by the Assignee to the Reseller's Points of Receipt and Points of Delivery will be subject to the provisions of Section 23.2 of this Tariff.

4.0 The Transmission Provider shall credit the Reseller for the price reflected in the Assignee's Service Agreement or the associated OASIS schedule.

5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Assignee:

____

____

____

6.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:______________________________ ________________________ ________________
Name Title Date

Assignee:

By:______________________________ ________________________ ________________
Name Title Date

Specifications For The Resale, Reassignment Or Transfer of
Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction: ____________________________________

Start Date: ____

Termination Date: ______________________________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt:____________________________________

Delivering Party:____

4.0 Point(s) of Delivery:___________________________________

Receiving Party:____

5.0 Maximum amount of reassigned capacity: __________________

6.0 Designation of party(ies) subject to reciprocal service obligation:____
____
____
____

7.0 Name(s) of any Intervening Systems providing transmission service:____
____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:________________________________
____

8.2 System Impact and/or Facilities Study Charge(s):
____
____

8.3 Direct Assignment Facilities Charge:____________________
____

8.4 Ancillary Services Charges: ______________________
____
____
____
____
____
____

9.0 Name of Reseller of the reassigned transmission capacity:
____

ATTACHMENT B

Form Of Service Agreement For Non-Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between _______________ (the Transmission Provider), and ____________ (Transmission Customer).

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the Tariff and has filed a Completed Application for Non-Firm Point-To-Point Transmission Service in accordance with Section 18.2 of the Tariff.

3.0 Service under this Agreement shall be provided by the Transmission Provider upon request by an authorized representative of the Transmission Customer.

4.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Non-Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____

____

____

Transmission Customer:

____

____

____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:	________________	________________	________________
	Name	Title	Date

Transmission Customer:

By:	________________	________________	________________
	Name	Title	Date

ATTACHMENT C

Methodology To Assess Available Transfer Capability

The Transmission Provider must include, at a minimum, the following information concerning its ATC calculation methodology:

(1) A detailed description of the specific mathematical algorithm used to calculate firm and non-firm ATC (and AFC, if applicable) for its scheduling horizon (same day and real-time), operating horizon (day ahead and pre-schedule) and planning horizon (beyond the operating horizon);

(2) A process flow diagram that illustrates the various steps through which ATC/AFC is calculated; and

(3) A detailed explanation of how each of the ATC components is calculated for both the operating and planning horizons.

(a) For TTC, a Transmission Provider shall: (i) explain its definition of TTC; (ii) explain its TTC calculation methodology; (iii) list the databases used in its TTC assessments; and (iv) explain the assumptions used in its TTC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

(b) For ETC, a transmission provider shall explain: (i) its definition of ETC; (ii) the calculation methodology used to determine the transmission capacity to be set aside for native load (including network load), and non-OATT customers (including, if applicable, an explanation of assumptions on the selection of generators that are modeled in service); (iii) how point-to-point transmission service requests are incorporated; (iv) how rollover rights are accounted for; (v) its processes for ensuring that non-firm capacity is released properly (e.g., when real time schedules replace the associated transmission service requests in its real-time calculations); and (vi) describe the step-by-step modeling study methodology and criteria for adding or eliminating flowgates (permanent and temporary).

(c) If a Transmission Provider uses an AFC methodology to calculate ATC, it shall: (i) explain its definition of AFC; (ii) explain its AFC calculation methodology; (iii) explain its process for converting AFC into ATC for OASIS posting; (iv) list the databases used in its AFC assessments; and (v) explain the assumptions used in its AFC assessments regarding load levels, generation dispatch, and modeling of planned and contingency outages.

(d) For TRM, a Transmission Provider shall explain: (i) its definition of TRM; (ii) its TRM calculation methodology (e.g., its assumptions on load forecast errors, forecast errors in system topology or distribution factors and loop flow sources); (iii) the databases used in its TRM assessments; (iv) the conditions under which the transmission provider uses TRM. A Transmission Provider that does not set aside transfer capability for TRM must so state.

(e) For CBM, the Transmission Provider shall state include a specific and self-contained narrative explanation of its CBM practice, including: (i) an identification of the entity who performs the resource adequacy analysis for CBM determination; (ii) the methodology used to perform generation reliability assessments (e.g., probabilistic or deterministic); (iii) an explanation of whether the assessment method reflects a specific regional practice; (iv) the assumptions used in this assessment; and (v) the basis for the selection of paths on which CBM is set aside.

(f) In addition, for CBM, a Transmission Provider shall: (i) explain its definition of CBM; (ii) list the databases used in its CBM calculations; and (iii) demonstrate that there is no double-counting of contingency outages when performing CBM, TTC, and TRM calculations.

(g) The Transmission Provider shall explain its procedures for allowing the use of CBM during emergencies (with an explanation of what constitutes an emergency, the entities that are permitted to use CBM during emergencies and the procedures which must be followed by the transmission providers' merchant function and other load-serving entities when they need to access CBM). If the Transmission Provider's practice is not to set aside transfer capability for CBM, it shall so state.

ATTACHMENT D

Methodology for Completing a System Impact Study

To be filed by the Transmission Provider

ATTACHMENT E

Index Of Point-To-Point Transmission Service Customers

Customer	Date of Service Agreement

ATTACHMENT F

**Service Agreement For
Network Integration Transmission Service**

To be filed by the Transmission Provider

ATTACHMENT G

Network Operating Agreement

To be filed by the Transmission Provider

ATTACHMENT H

Annual Transmission Revenue Requirement For Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be ____________________________.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by the Commission.

ATTACHMENT I

Index Of Network Integration Transmission Service Customers

Customer	Date of Service Agreement

ATTACHMENT J

Procedures for Addressing Parallel Flows

To be filed by the Transmission Provider

ATTACHMENT K

Transmission Planning Process

The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties, including the coordination of such planning with interconnected systems within its region, to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and nondiscriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following nine principles, as defined in the Final Rule in Docket No. RM05-25-000: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process shall also provide a mechanism for the recovery and allocation of planning costs consistent with the Final Rule in Docket No. RM05-25-000.

The Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers and neighboring transmission providers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop transmission plans;

(iv) The method of disclosure of criteria, assumptions and data underlying transmission system plans;

(v) The obligations of and methods for customers to submit data to the transmission provider;

(vi) The dispute resolution process;

(vii) The transmission provider's study procedures for economic upgrades to address congestion or the integration of new resources; and

(viii) The relevant cost allocation procedures or principles.

ATTACHMENT L

Creditworthiness Procedures

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices and must specify quantitative and qualitative criteria to determine the level of secured and unsecured credit

The Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established by the Uniform Commercial Code that protects the Transmission Provider against the risk of non-payment.

Additionally, the Transmission Provider must include, at a minimum, the following information concerning its creditworthiness procedures:

(1) a summary of the procedure for determining the level of secured and unsecured credit;

(2) a list of the acceptable types of collateral/security;

(3) a procedure for providing customers with reasonable notice of changes in credit levels and collateral requirements;

(4) a procedure for providing customers, upon request, a written explanation for any change in credit levels or collateral requirements;

(5) a reasonable opportunity to contest determinations of credit levels or collateral requirements; and

(6) a reasonable opportunity to post additional collateral, including curing any non-creditworthy determination.

Is Energize Eastside needed?

Questioning PSEs Motive and Proof

By: J. Richard Lauckhart
Energy Consultant, Davis, Ca
lauckjr@hotmail.com
Former VP at Puget

Why am I involved?

- I now live in California and will not experience the negative environmental impacts of EE

- But I don't like it when large corporations promulgate a "Scam" on the public to enhance their profitability.

What insights do I have?

- I did not have insights to "blow the whistle" on the VW emissions cheating scam
- I did not have insights to "blow the whistle" on Bernie Madoff's investment scam.
- I did not have insights to "blow the whistle" on Enron's scam.
- But I do have insights and expertise to "blow the whistle" on PSE's EE scam.

What have I done to communicate my insights?

- I have written a paper on PSE’s motivation to build the EE project.
- I have written a paper Setting the Record Straight on Energize Eastside’s Technical Facts
- This presentation provides an overview of what is in those two papers.

PSE's motivation for building EE

- In 2007 PSE and Macquarie announced that Macquarie intended to purchase all of the common stock of PSE
- PSE and Macquarie worked through a long process to get regulatory approval
- In 2009 PSE and Macquarie completed the purchase
- As a result, <u>Macquarie is now the decision maker for PSE</u>

Why did Macquarie want to purchase PSE?

- PSE gets a regulated "rate of return" on its investments. That rate of return is approximately 10%
- Macquarie has access to a large amount of funds that it wants to invest and earn as large a return as possible.
- Where else can Macquarie make 10% on new investments today?

What did Macquarie say publicly about why it wanted PSE?

- Christopher Leslie, chief executive of Macquarie Infrastructure Partners stated:

  "We don't have employees. We're not the neighboring utility. Combining work forces and eliminating redundancies is not the story. ***Our interest is to grow the business.****"*

  Mercer Island Reporter…November 25, 2008

- By "growing the business" Macquarie can invest new funds and get a regulated return of approximately 10%

DSD 009742

How much Money did Macquarie plan to use to grow the business?

- Macquarie stated they were committed to investing $5 Billion dollars in **new** PSE infrastructure.
  - This is no small amount given that the total price paid by the investment group to purchase PSE then **existing** infrastructure was $7.4 billion dollars

How is Macquarie progressing on its plan to make $5 Billion in new investments in PSEs regulated business?

- Indications are that it is not going well:
  - Since its 2007 announcement, the economic slowdown reversed the trend of increasing energy consumption
  - New technology and more focused conservation efforts continued to reduce electricity and natural gas consumption, even as population growth and economic activity rebounded in the Puget Sound region.
  - Part of PSEs service territory has been converted to Public Utility District (PUD) ownership and operation, reducing the need for new investment.

What kind of infrastructure does Macquarie need to invest in to meet its goals?

- New generation and conservation is problematic for Macquarie because of the "competitive bidding" rules that PSE must comply with
- New Transmission Lines and Distribution lines are the best investments…no "competitive bidding" rules

But what do you do if there is no need for $5 Billion of new transmission and distribution line investment?

- You try to justify projects that are not needed
- Avoid using PSE staff to make the "justification" because there might be questions about it
- Use scare tactics like "Blackouts will occur without the project"
- In order to " hide" the fact that the investments are not needed and that blackouts will not occur, refuse to show the "justification" or "proof" of the need

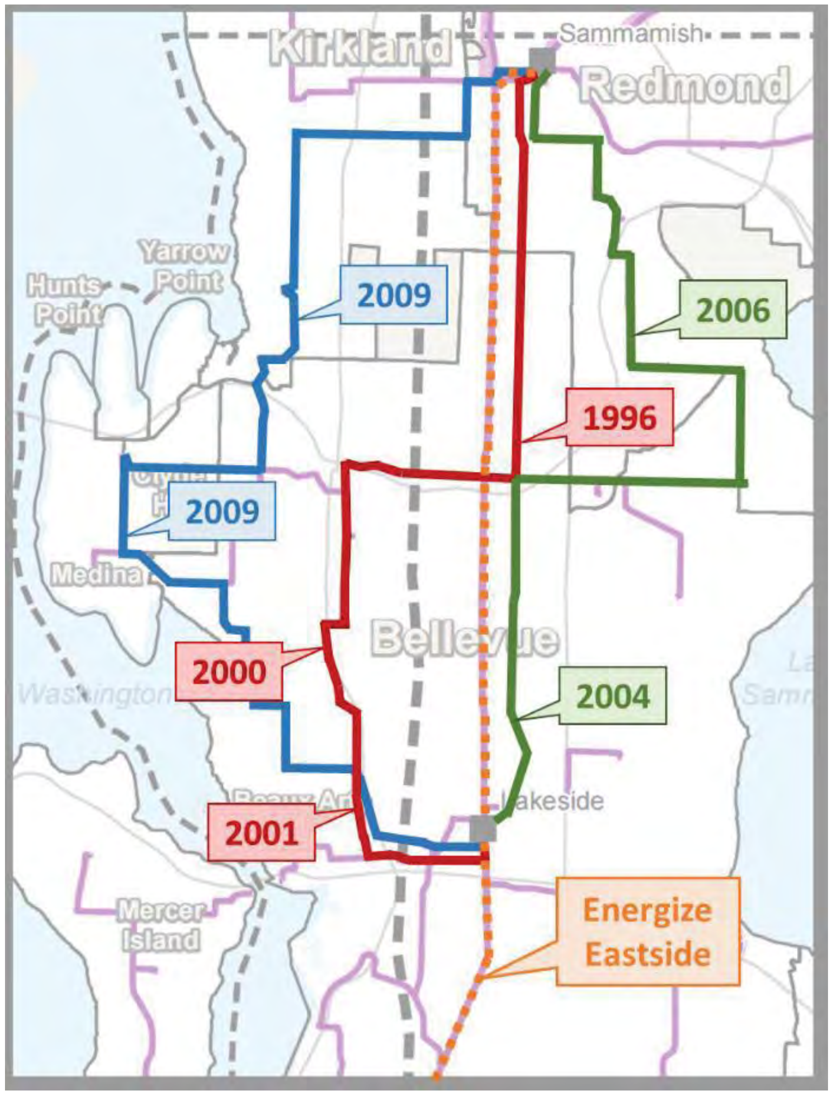
What can be said about Macquarie's attempt to justify EE?

- **Transmission investments can only be justified by use of a "load flow" study**
  - The Macquarie/PSE attempt to justify EE, by saying "nothing has been done to the 'backbone' for 50 years", is **not sufficient**. Only a load flow study can show if the system needs fixing or not.
  - Macquarie/PSE actually used the load flow study approach in their "Eastside Needs Assessment"

The statement "*nothing has been done to the 'backbone' for 50 years*" is wrong!

- In recent years a number of new 115 KV lines have been built on the eastside to serve growing loads
- In essence, the "backbone 115 KV" on the eastside has been replaced with a "Network 115 KV" system.
- See graphic next page…
- **The needed load flow study will necessarily reflect this network of 115 KV lines**

New 115 KV lines built in the eastside in recent years



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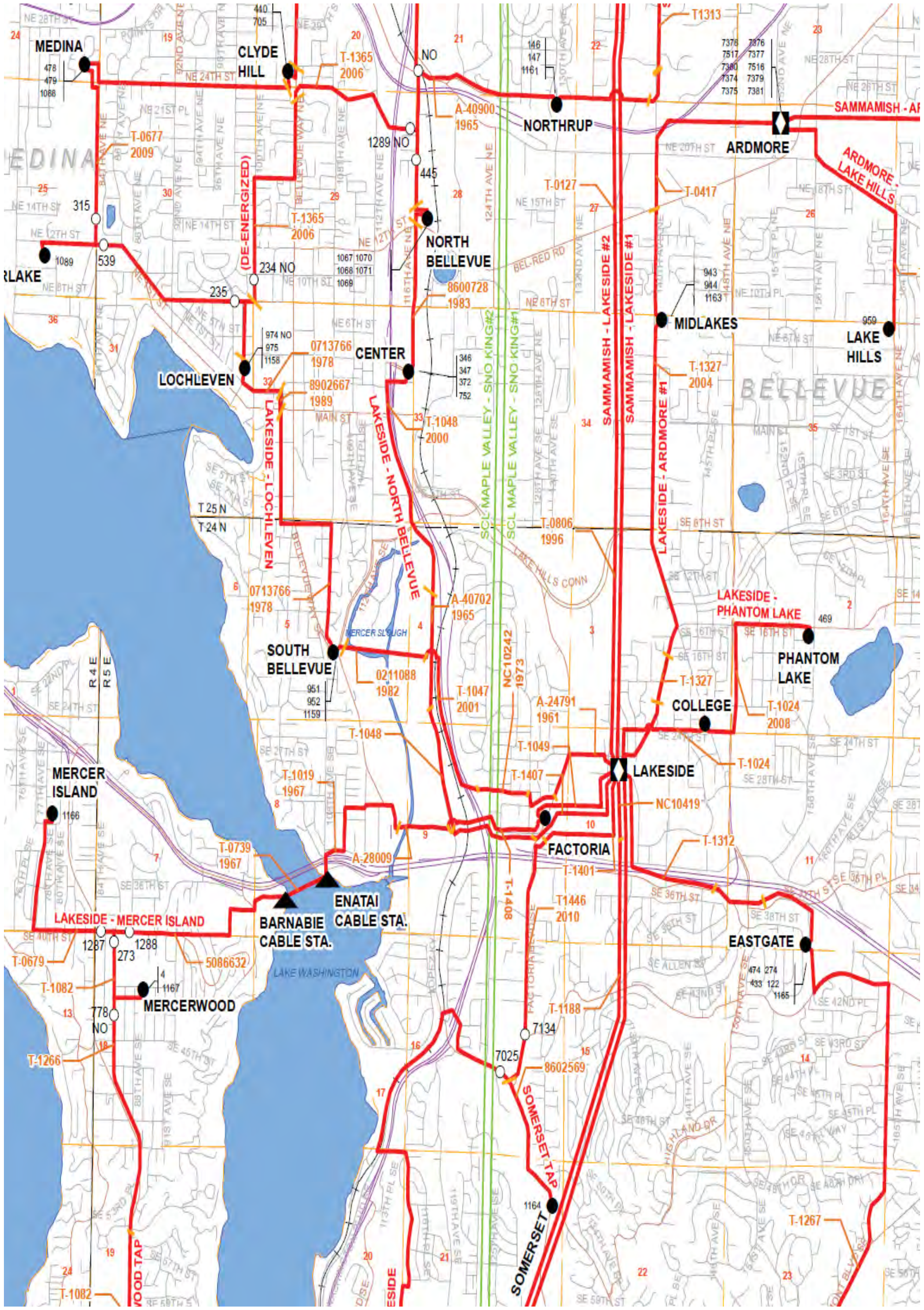
Who did Macquarie/PSE use to perform the load flow study?

– In order to perform the needed load flow study in 2013, Macquarie/PSE took the unusual step of hiring an outside consultant (**Quanta**) to perform the load flow study to prove the need for Energize Eastside. <u>Not using PSE's in-house experts</u>.

Note: Quanta has done considerable consulting work for Macquarie in other areas of the country. Quanta will want to keep Macquarie happy.

What is a *"load flow study?"*



Grids can get complicated.

We use computer simulations to study how the grid reacts in different situations.

Red lines show *transmission* lines not *distribution* lines.

Load flow study

Inputs

- Physical layout of grid
- How much electricity is needed
- How much electricity can be generated
- Resistance in each wire

Outputs

- How much electricity passes through each part
- Warning if any part overloads
- Warning if voltage drops too much

Did Quanta correctly perform the study?

– No, Quanta did not correctly perform the study. In doing their load flow analysis, Quanta:
  - changed the data that PSE reports to federal energy agencies and
  - made a number of questionable assumptions that go beyond normal industry practice.

What does this information cause you to conclude?

- I believe that Macquarie/PSE are pursuing this project for the sole purpose of increasing profits for Macquarie.
  - The transmission line will be expensive for PSE's customers,
  - It won't increase reliability or provide other benefits to PSE customers
  - It will damage the environment.

PSE has provided no legitimate "proof" of the need for EE

- Again…Transmission investments can only be proven necessary by use of a "load flow" study
- The Eastside Needs Assessment performed by PSE/Quanta states the need was identified by a load flow study.
- Quanta concluded that PSE's equipment might overload under extraordinary conditions:
  - simultaneous failure of two transformers,
  - on the coldest day of the year,
  - at the same time a huge amount of electricity is being transmitted to Canada, and
  - half a dozen local generation plants are shut down.

What was your initial reaction to these assumptions?

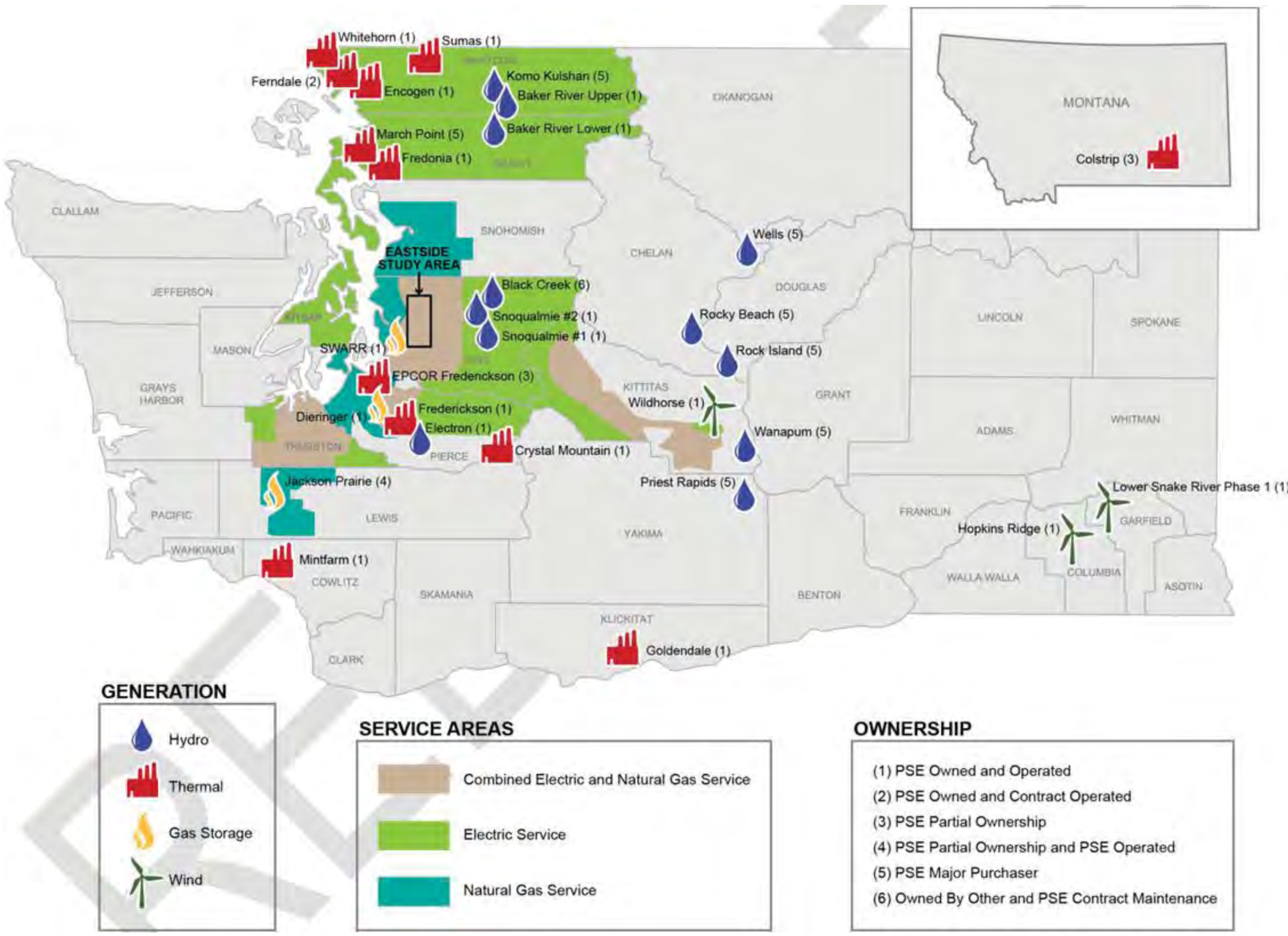
- First I was shocked that their study shut down not one, not two, but **<u>six</u>** local generation plants
  - I was vice president of power planning during the time we acquired these local generation plants. We worked hard to acquire them for the purpose of providing power *in exactly the type of need scenario that Energize Eastside is based on* - peak need on a very cold (less than 23F) winter day.
- After shutting down those six plants, PSE is very short on having sufficient power to cover their System Peak load. **Quanta did not say how PSE would meet its Total System load with these six plants shut down**.

What are the plants that Quanta shut down?

		Max MW	Quanta MW
CCCT	Encogen	185	125
CCCT	Ferndale	282	0
CCCT	Fredrickson 1 (PSE share)	141	0
CCCT	Goldendale	278	278
CCCT	Mint Farm	297	297
CCCT	Sumas	140	0
	sub total	1323	700
SCCT	Fredonia 1&2	225	0
SCCT	Fredonia 3&4	116	0
SCCT	Whitehorn 2&3	162	0
SCCT	Fredrickson 1&2	162	0
	sub total	665	0
	TOTAL	1988	700

Where are those 6 plants located?

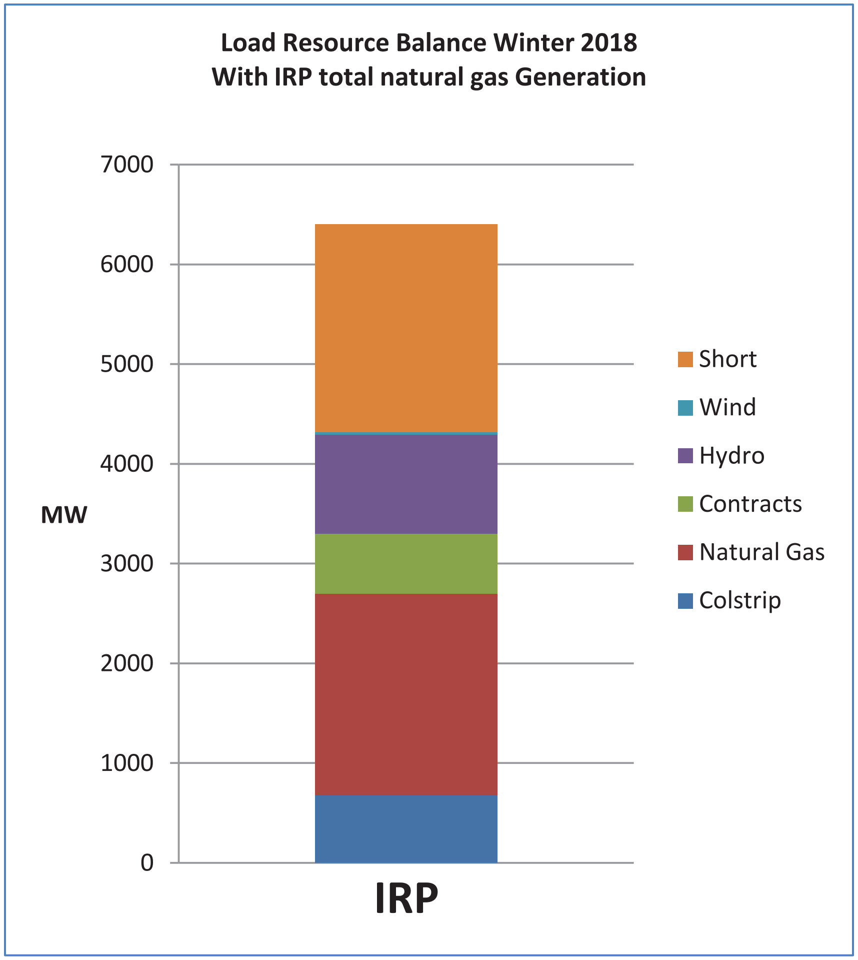
Essentially the red plants in the Puget Sound Region on the map below

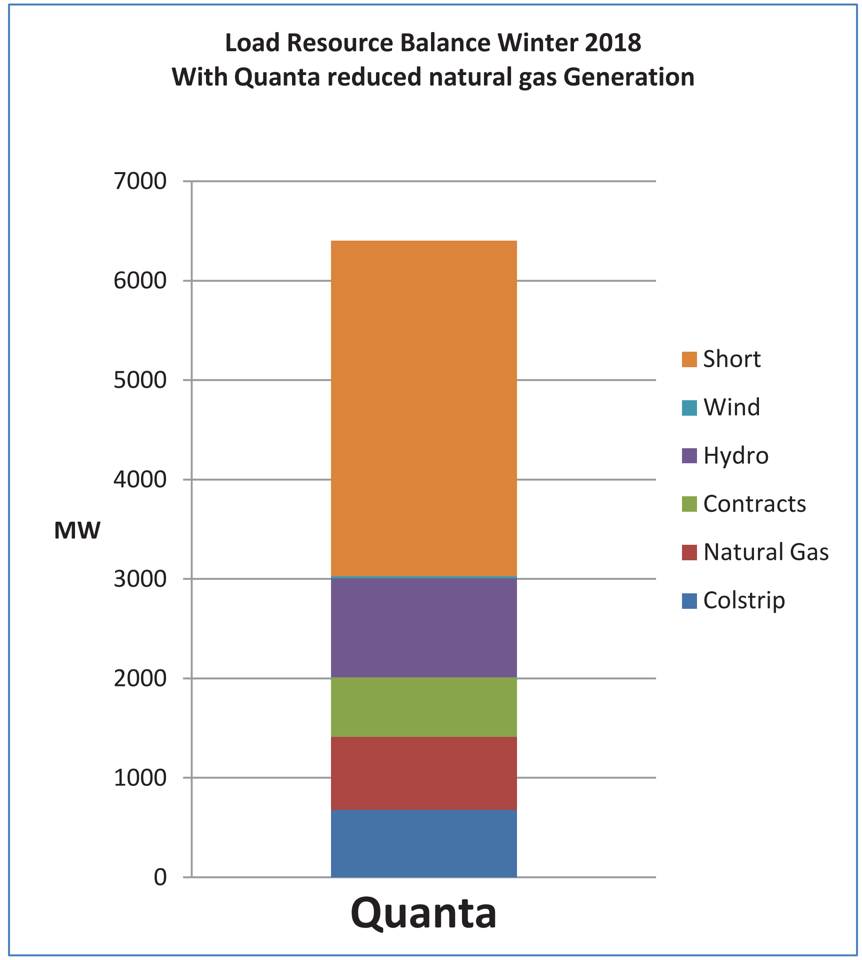


How Much Power does PSE need to meet its System Peak Load in Winter 2018?

- *According to PSE's IRP, PSE needs 6,500 MW of supply to meet its System Peak plus reserve requirements in the winter of 2018*
- *According to PSE's IRP, PSE is "short" by about 2100 MW of having sufficient generation to cover this need.*
- *While that is a very large "shortage", it gets even larger (nearly 3,400 MW) under the Quanta Load Flow model assumptions…an untenable shortage.*
  - *See graphic on next slide*

PSE “Short”: IRP vs Quanta





What other assumptions did Quanta make that you found problematic?

- The assumption that 1,500 MW would be flowing to Canada under this extreme cold event was another problem.
  - I am aware that the Columbia River Treaty does not mandate that 1,500 MW be delivered to Canada under such an extreme cold event.
- I was interested in seeing the Quanta load flow input data file to see what other assumptions that they might have made that I thought were problematic.

Did you ask to see the Quanta files?

- Yes, I requested that PSE provide me the Quanta files
- **PSE denied my request**, which was surprising to me since I had already received the requisite security clearance from the Federal Energy Regulatory Commission (FERC). FERC stated that I had a legitimate need to review the data.

Why did PSE deny your request?

- PSE refuses to show me the Quanta load flow study data file because they fear that I may use the data to find weaknesses in the grid which will allow me to perform terrorist outages on the grid.
- I already have significant knowledge about the grid and the weaknesses in it. I already have the information I would need to perform terrorist activities if I were so inclined, which I am not.
- PSE's reason for denying my request is not legitimate.
  - I believe that PSE is denying my request because they know that I will find (and point out) that the Quanta load flow study is flawed.

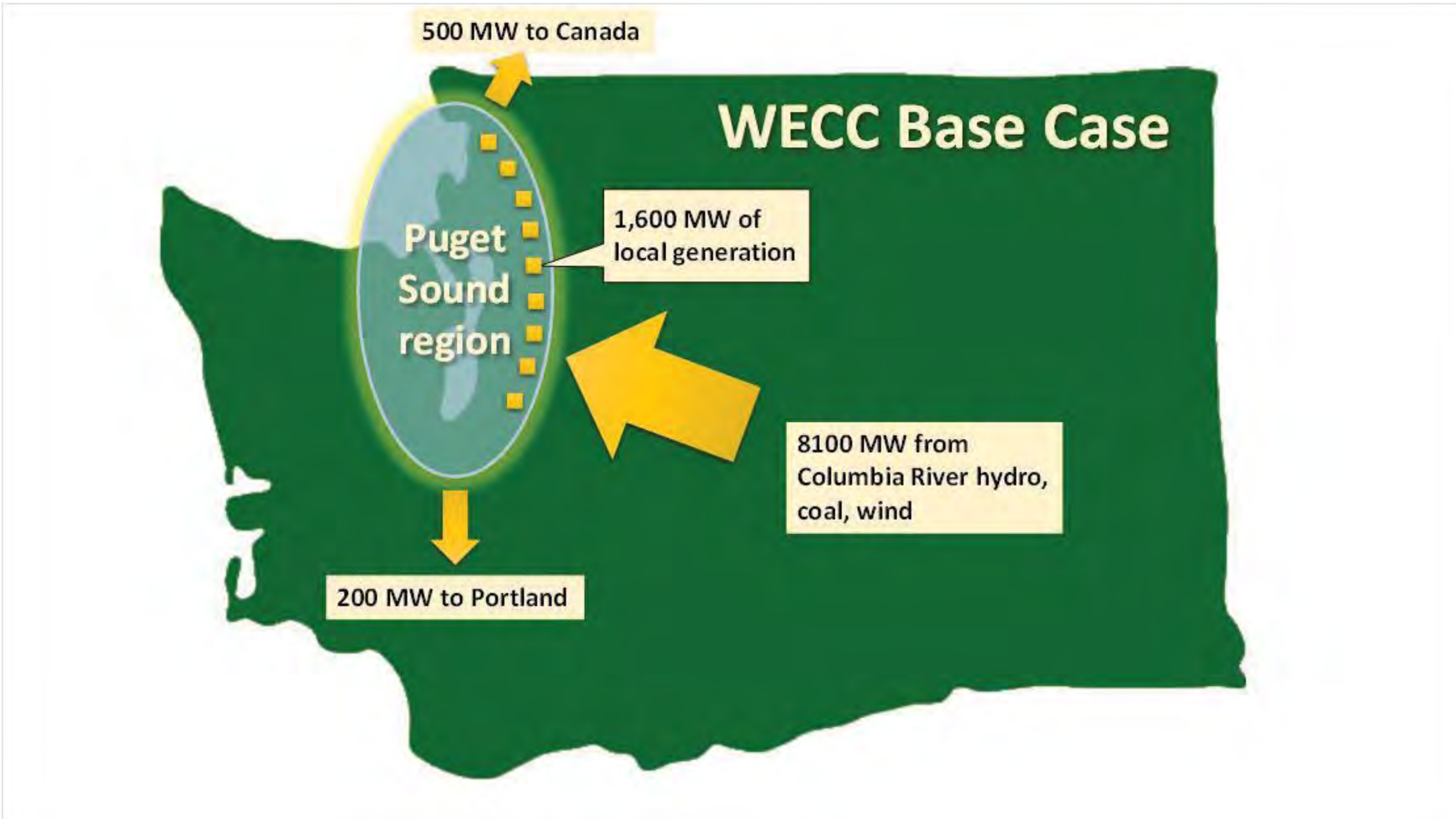
What did you do after PSE denied your request?

- I asked FERC to provide to me the load flow Base Case data that PSE had filed with FERC.
- FERC provided me that PSE load flow Base Case data.
- I observed that PSE's load flow Base Case data for the winter of 2018 has more appropriate assumptions in this cold winter situation regarding (a) local area generation operation and (b) flows to Canada.
- I recruited another transmission expert, Roger Schiffman, to obtain the utility standard load flow study computer model and <u>we conducted our own load flow study of the need for Energize Eastside starting with the load flow Base Case data that PSE filed with FERC.</u>

What did you learn from the Lauckhart-Schiffman load flow study effort?

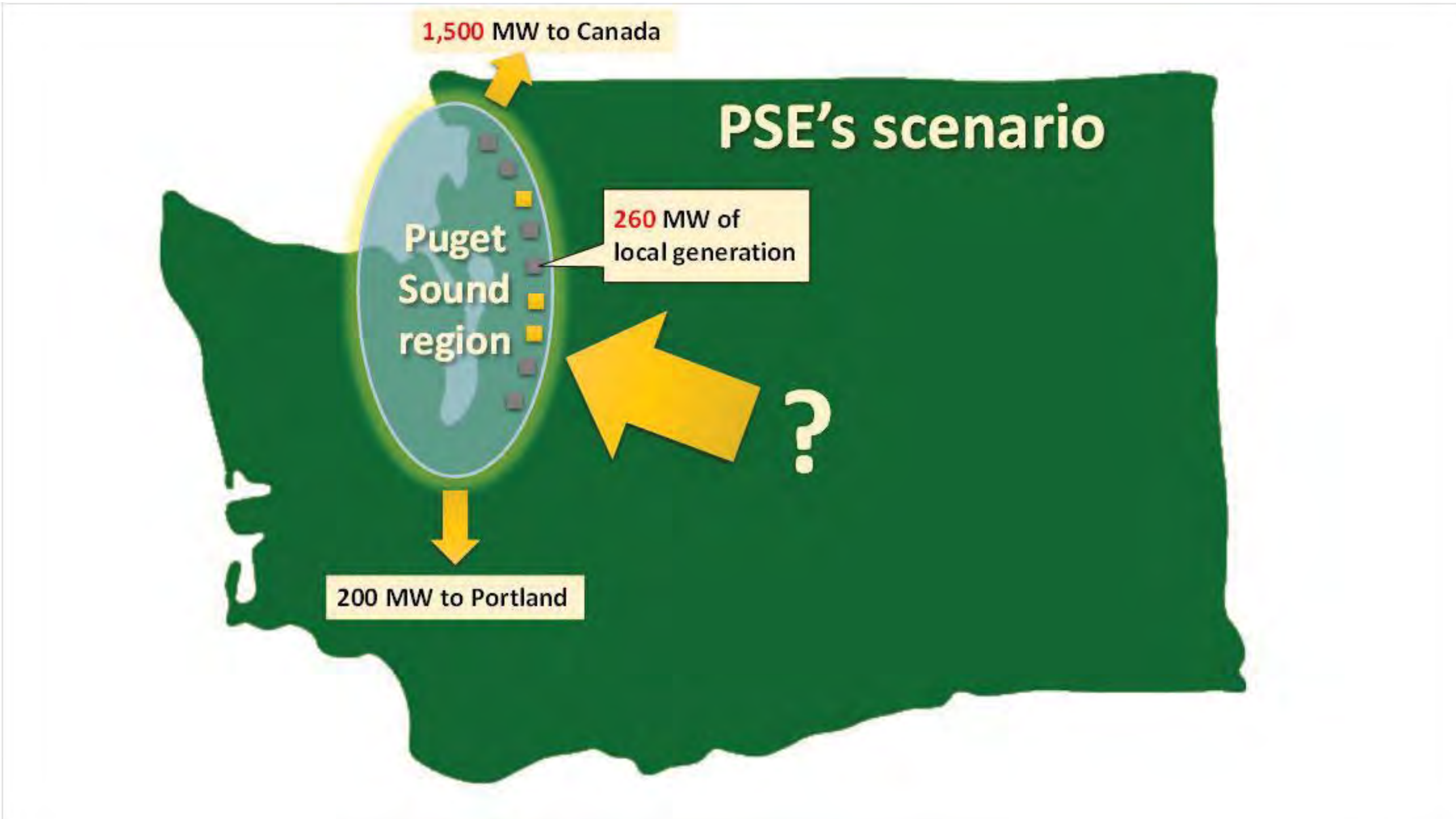
- I learned that Energize Eastside is not needed if appropriate assumptions are reflected in the load flow study. <u>No blackouts will occur if EE is not built</u>.
  - [See Lauckhart-Schiffman *Load Flow modeling for "Energize Eastside"* report dated February 18, 2016]
- I learned that the greater Puget Sound Region of the grid will experience major problems (aka blackouts) with or without Energize Eastside being built *based on Quanta's problematic assumptions.*
- I learned that in order for Quanta to avoid these other blackout problems with their assumptions, that Quanta must have made other changes to the PSE Base Case load flow data for the winter of 2018.

PSE’s Winter 2018 Base Case



The PSE/Quanta Problematic Scenario

And resulting Cross-Cascades problem



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Has PSE provided any information that helps you develop an educated guess of what other changes Quanta made?

- Yes. In the EIS process for Energize Eastside, PSE provided a listing of a number of "electrical criteria" it was using in its studies of the need for Energize Eastside.
- Three of those criteria jumped out at me as being particularly inappropriate

What was the first criterion you found problematic?

- **PSE stated criterion number 7**: "*Adjust regional flows and generation to stress cases similar to annual transmission planning assessment.*"

  Here is what that means!!!:

  – In 2013, ColumbiaGrid had run a "stressed load flow case" **for information purposes** just to see how the system would respond if the Base Case was adjusted to significantly increase stresses on the system. (e.g. shut down Puget Sound Area generation and increase flows to Canada)

  – ColumbiaGrid indicated that this "stressed load flow case" caused significant adverse impacts on the system but there was no need to make any fixes to the system to address those problems as a result of this stressed case run because **the case exceeds NERC Reliability Criteria**.

- *BUT PSE has made this the main scenario for looking at the need for EE!* ***That makes no sense.***

What were other criteria you found problematic?

- **<u>PSE stated criterion number 8</u>**: "*Take into account future transmission improvement projects that are expected to be in service during the study period*."
- **<u>PSE stated criterion number 2</u>**: The "Study Period" was from 2015-2024.

It appears that in order for Quanta to make their Load flow study work without causing blackouts in the greater Puget Sound area that Quanta assumed that at least one and probably two new Cross North-Cascades transmission lines are built. No one is currently pursuing these infrastructure improvements.

What do you conclude about the Quanta load flow study?

- In a nutshell Macquarie/PSE/Quanta have decided to run a Load Flow study to determine the need for EE, which load flow study has major flaws.
- First it starts with a scenario that has negligible probability of occurring.
- A Scenario that vastly exceeds FERC/NERC reliability criteria.
- Then in order to make that Scenario work electrically, Quanta seems to have modeled new Cross North-Cascades transmission lines that no one is working on.
- And no one is working on them because any load flow scenario that is consistent with FERC/NERC reliability criteria shows the new Cross North-Cascades transmission lines are not needed.

Is the Quanta load flow study appropriate for examining the need for Energize Eastside?

- No. This Macquarie/PSE/Quanta load flow study is completely inappropriate for studying the reliability of power service to the Eastside.
- The Lauckhart-Schiffman load flow study is the appropriate way for studying the reliability of power service to the Eastside.
- **The Lauckhart-Schiffman study demonstrates that EE is not needed.**

Has PSE provided "proof" of the need for EE?

- No. PSE has not provided the load flow study that it claims demonstrates the need for Energize Eastside.
- The Lauckhart-Schiffman load flow study, which is based on PSE's Base Case, demonstrates that Energize Eastside is not needed.
  - *PSE has criticized the Lauckhart-Schiffman load flow study for running all the Puget Sound area generation and for not sending 1,500 MW to Canada. These criticisms have been fully rebutted [see attachment to Lauckhart email to EnergizeEastsideEIS dated April 29, 2016]. The Lauckhart-Schiffman assumptions are more in line with what regulators expect and which correctly balance environment, cost and risk of outage. The Lauckhart-Schiffman assumptions are also consistent with PSE's Base Case filed with FERC*

By all indications……

- PSE is promulgating a “scam” on the public to enhance their profitability

- The “scam” imposes significant adverse environmental impacts on the public but no benefits

It must be stopped

Action that the four cities and EBCC should take

- Issue the following ultimatum to PSE

"*If you do not make your load flow studies available for inspection by individuals that have CEII clearance from FERC, we will not even consider issuing a permit for Energize Eastside.*"

Energize Eastside will provide no reliability benefit to the Eastside

- The Eastside has had numerous power outages in the past and will continue to have power outages in the future. These outages are primarily caused by wind blowing trees and limbs into the localized overhead 12 KV distribution lines.
- **<u>Energize Eastside will do nothing to decrease these outages in the future</u>**.

The EIS staff is wrong

- The December 21, 2016 *Phase 2 Draft EIS – Scope of Analysis* includes a discussion of the "No Action" alternative. The following sentence is included in that discussion:

  "*If no action is taken, load shedding (forced power outages within the Eastside) would likely be needed during the highest demand periods in the near future*."

- **<u>As pointed out in the rest of this report, there is no legitimate evidence on the record that this statement is true</u>. <u>In fact, the legitimate evidence on the record is that this statement is false</u>**

PSE's bogus scenario

One more (detailed) look

- Very cold (i.e. 23 degree) weather occurs on the eastside during evening peak load hours…an event that normally occurs only once in every few years
- At that same time, 1,500 MW is being delivered to Canada…but:
  - There is no requirement to deliver 1,500 MW to Canada under such an event. [*See comments filed by Christina Aron-Sycz dated August 1, 2016 which includes a White Paper entitled "Evidence that there is no requirement to deliver 1,500 MW to Canada on a Firm Basis….Resulting Conclusion is that EE is not needed."*], and
  - The Puget Sound Region in total would experience low voltage caused blackouts if 1,500 MW is being delivered to Canada during such a cold weather event.

PSE's bogus scenario (Cont.)

- At the same time PSE has shut down 6 of its Puget Sound Area generators…something that PSE would not do under such a cold event because
  - Puget would not be able to meet its own Total System Load without these generators running (*these generators were built to provide power under these circumstances and it is absurd to say they would not be operated under these circumstances*) , and
  - The Puget Sound Region in total would experience low voltage caused blackouts if 6 Puget Sound Area generators are shut down during such a cold weather event.
- At the same time two major 230/115 KV transformers fail at the same time when all these other things are happening…*But since all these other things cannot happen at the same time without there being low voltage caused blackouts, this scenario makes no sense*.

The EIS Record

- CENSE and Mr. Lauckhart have placed a number of documents on the EIS record that provide evidence that Energize Eastside will not reduce the number of outages on the PSE system on the eastside.

Conclusion from the EIS Record

- The scenario that PSE claims needs the Energize Eastside line in order to increase reliability of electricity supply to the Eastside will never happen. That justification for building Energize Eastside is not legitimate.
- The Lauckhart-Schiffman load flow study (which used PSE's Base Case data set for the Winter of 2018) demonstrates that Energize Eastside will provide no reliability benefit to the eastside.
- <u>**The No Action alternative will not result in any blackouts on the eastside or elsewhere on the grid.**</u>

The backstory: What is truly motivating PSE to try to build Energize Eastside?

To: City staff and council

From: Rich Lauckhart

Introduction

As you may already know, I am an energy consultant who spent the bulk of my career working for Puget Power (PSE's predecessor) as vice president of Power Planning. It was my job to oversee the permitting and construction of many kinds of projects in the Puget Sound region including high voltage transmission lines and nuclear power plants.

What you may not know is that I also hold an M.B.A. in Finance. During my time at Puget Power as well as at other firms, I had great exposure to not only the technical side of power planning, but also to the business side of each project. I know that most customers assume that a company that provides a basic necessity such as electricity is just "trying to keep the lights on" and that there is a lot of inherent trust in power companies. However, both from my long experience in the industry and the multitude of news articles from across the country, it's no secret that privately-held, for profit power companies function just like any other for-profit business. They seek to turn a profit. This is not in and of itself a bad thing.

However, there are too many recent examples of when power companies across the U.S. have attempted to get an unnecessary project built in order to get the guaranteed profit from the state, and I feel that PSE's Energize Eastside is yet another example of this. In the case of Energize Eastside, it is the "perfect storm" for this type of attempt for four reasons. One, Washington state has very outdated regulations compared to other states that incentivize power companies to build big transmission projects rather than invest in smarter technologies currently being used across the U.S. Two, there is remarkably little oversight to PSE's major projects before they get built. In the case of Energize Eastside, this billion dollar, eighteen mile project has the potential to be built without any prior vetting or review by any state regulators - only a permit from four city councils. The project gets approved into the rate base <u>after</u> it is built. Three, Washington offers a generous rate of return of 9.8% on the lifetime of the project. In the case of Energize Eastside, that means over $1 billion for PSE's Canadian and Australian investors. This is a huge incentive. Lastly, both myself and CENSE.org have provided compelling evidence that Energize Eastside is not needed. Yet Puget Sound Energy (PSE) continues to push to build the project. Why would PSE want to build the Energize Eastside project if it is not needed?

This paper discusses these points.

Background

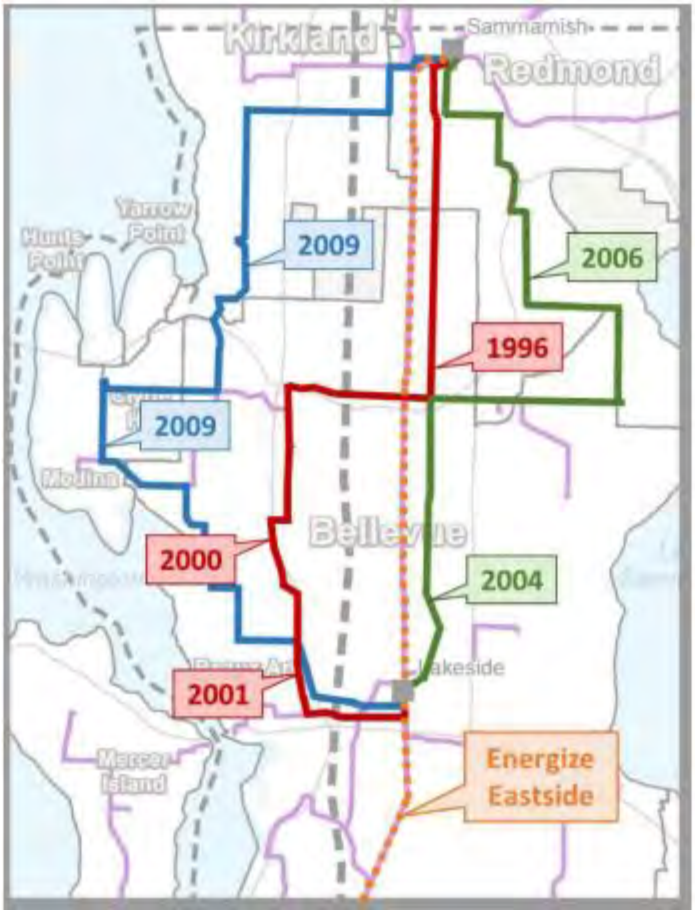
For most of its history, Puget Sound Energy (PSE) had publicly traded common stock. Shareholders elected representatives to serve on PSE's Board of Directors. The board members hired a CEO to run the company, and relied on the CEO to make day-to-day decisions. In this way, PSE was accountable to its shareholders, many of whom lived in PSE's service territory.

This all changed in 2009, when an Australian investment bank named Macquarie purchased all of the company's common stock. The total cost of the acquisition was $7.4 billion. It was and still is highly unusual for a foreign-owned company to own a U.S. utility. Upon purchase, Macquarie stated its intention was to invest an additional $5 billion in the company by building new infrastructure. In so doing, Macquarie planned to collect the guaranteed 9.8% rate of return on infrastructure investments that is allowed by PSE's regulator, the Washington Utilities and Transportation Commission (WUTC).

However, several unforeseen developments thwarted Macquarie's plans. First, shortly after the acquisition was announced in 2007, the recession reversed the trend of increasing energy consumption. Second, new technology and more focused conservation efforts continued to reduce electricity and natural gas consumption even as population growth and economic activity rebounded in the Puget Sound region. Third, a portion of PSE's service territory was converted to Public Utility District (PUD) ownership and service.

Like any profit driven corporation, Macquarie likely pondered what projects they could pursue to bolster PSE's sagging revenues. The 18-mile double circuit 230 KV transmission line running through the Eastside probably looked like a good candidate. For a number of years PSE had considered installing a new 230kV to 115 kV transformer at the Lakeside substation, which would have required building new 230kV lines between Talbot Hill and Lakeside and between Sammamish and Lakeside. However, every time this was studied it was determined that other less costly infrastructure projects were preferable to meet the growing loads on the Eastside.

But when Macquarie was looking for high cost new infrastructure projects, it appears that this older plan was picked up off the shelf and dusted off. The original two 115 kV lines were built almost 50 years ago, and I believe that PSE felt it would be easy to convince local city councils to support the new 230 kV plan by making it sound like a simple "upgrade" to an "old line" which is exactly the language they have chosen in their ads. The "Energize Eastside" project was born, ignoring the reality that the original twin eighteen mile 115 kV lines had been augmented with many new 115 kV lines in recent years (see figure below). In essence, the original twin 115 kV "backbone" lines have been turned into a robust "network" of 115 kV lines. The eighteen mile twin 115 kV line that follows the proposed path of Energize Eastside ceased being a "backbone" decades ago.



Normally, the technical need for a transmission line would be studied by PSE's in-house transmission experts. In my many years at Puget Power, we only used our own in house transmission experts since they knew our area's grid the best. However, PSE instead hired Quanta, a consulting firm based in North Carolina. I could not find any basis that Quanta has prior experience with the Northwest power grid, but they have done quite a bit of work for Macquarie in other areas of the country where Macquarie had made investments.

As I describe in detail in my other paper, "Setting the Record Straight on Energize Eastside's Technical Facts", I believe that In order to make the project data work in PSE's favor, Quanta made several changes to the core data that PSE reports to federal energy agencies and made a number of questionable assumptions that go beyond normal industry practice. As I also explained in my other paper, when I tried to duplicate Quanta's results and implement those same changes to the core data, I found that the Quanta's assumptions caused significant problems for the entire power grid, not just the Eastside. When asked about these problems, PSE refused to provide any data or technical explanation to refute my findings.

In the two decades that I worked for the company, PSE worked closely with the communities and did a good job of supplying reliable power to their customers. I never witnessed a project that put forth without a solid, demonstrated need. However, based on the facts surrounding PSE's highly questionable load flow study and the overall obvious lack of demonstrated technical need for this project, I believe that PSE's main goal with Energize Eastside is to increasing profits for its Australian and Canadian investors. There is simply no evidence of a technical need for this project. Energize Eastside will be extremely expensive for all of PSE's 1.1 million customers, it won't measurably increase reliability, and it will damage the environment. Again, as I mentioned at the outset of this paper, this is unfortunately not an unusual or isolated example in the present day U.S. power grid.

Until PSE provides real, technical evidence in the form of the load flow data that shows why Energize Eastside is necessary, I must conclude that it is not.

New Ownership of PSE in 2009

In 2009 a consortium formed by Macquarie Infrastructure, the Canada Pension Plan Investment Board, the British Columbia Investment Management Corp. purchased all of the common stock of PSE.[1]

Who makes the decisions for PSE after this purchase?

That answer can be found in a filing made in 2007 with the Washington Utilities and Transportation Commission (WUTC) and in a filing made in 2016 with the Federal Energy Regulatory Commission (FERC).

- In the December 2007 filing with the WUTC, the ownership and control of PSE under Macquarie's coordinated purchase of PSE stock, a very complicated picture of ownership and control of PSE was presented. See attachment 1. However, for all practical purposes, it is Macquarie who makes decisions for PSE.
- In the 2016 filing with FERC, Macquarie Energy stated that Macquarie Group Limited ("MGL") maintains ownership and control of PSE.[2]

The important result of the 2009 change in ownership and control of PSE is that for all practical purposes, since 2009, Macquarie makes the decisions on PSE matters.

Why did Macquarie (and partner investment firms) want to purchase all of the stock of PSE?

That answer can be found in a statement made by Christopher Leslie, chief executive of Macquarie Infrastructure Partners. He stated:

> "*We don't have employees. We're not the neighboring utility. Combining work forces and eliminating redundancies is not the story.* ***Our interest is to grow the business.***"[3]

These investors have access to significant funding that they planned on using to "grow PSE's business." In fact, the investors stated they were committed to investing $5 billion in new PSE infrastructure. This is no small amount given that the total price paid by the investment group to purchase PSE was $7.4

[1] http://www.pugetenergy.com/pages/news/011609.html
[2] See July 14, 2016 filing at FREC made by Macquarie Energy in Docket No. ER16-2198
[3] http://www.mi-reporter.com/news/35017809.html

billion dollars.[4]

In this paper I will use the term "Macquarie" to indicate the entity that has ownership and control of PSE.

Why would this investment group want to invest $5 billion in new infrastructure in PSE's system?

It is standard practice that investment firms like Macquarie are trying to find investments that give them a good rate of return. In the case of PSE, the WUTC grants a 9.8% return on new investments. This 9.8% return is a very attractive rate of return compared to the return that the investment firms could get elsewhere. So, investing $5 billion at a 9.8% rate of return is a great investment opportunity. The only catch is that investors only get this return if they can find infrastructure projects that can be shown needed to meet reliability criteria. This determination is made by the WUTC after the project is built.

But what if there is no justification for making $5 billion of new investment in PSE?

As mentioned earlier in this document, there is ample evidence of utilities across the U.S. attempting to build infrastructure projects that, in the end, cannot be justified. Time and time again, the ultimate goal was to get the generous rate of return offered by the state. They will often go to great lengths to get their projects justified.

Why are transmission lines the most lucrative form of investment for PSE?

Washington State has regulations for utilities that offer the 9.8% rate of return on large scale transmission projects. By contrast, new investments in generation (new power plants) or Demand Side Management (DSM, which are programs that reduce the load and/or increase conservation at the customer level) are somewhat problematic for Macquarie's and PSE's goal of achieving a guaranteed profit. This is because the WUTC competitive bidding rule requires PSE to go out for competitive bids for third party entities that can provide the needed generation or DSM for PSE. The WUTC closely monitors this competitive bid activity to be sure that PSE selects the cheapest option. If a third party entity is chosen, then that party makes the investments needed and PSE will generally pay the third party an ongoing fee. By doing this, PSE is not allowed to include these new projects in the PSE rate base and there is no ability to make the desired 9.8% return on investment. However, there is no competitive bidding process for new **transmission and distribution** projects.

Another reason why Macquarie and PSE are so focused on building transmission lines is that Washington's regulations have not been updated much since the 1960s and do not provide anywhere near as generous of an incentive for smarter, 21st century technologies. Many other states, including Oregon, California, Texas, and New York have updated their regulations to incentivize utilities to invest in smarter technologies such as demand side management, more aggressive conservation, and efficiency. Washington is lagging behind the times in this respect.

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[4] http://www.pugetenergy.com/pages/news/011609.html

As a result, Macquarie and PSE closely monitor their service territory to see what investments may make sense. Does this mean that every new, major transmission project is unfounded? Not necessarily. But it does mean that from a business perspective, PSE's first choice is a project that will achieve the greatest rate of return and enhance the profitability of their investment fund. It's simple business math.

How and when did Energize Eastside come to be?

Approximately 4 years ago (2013), Macquarie decided to see if a new, double circuit 230kV transmission line and substation (i.e. Energize Eastside) "EE" could be justified on the Eastside. Such a project would contribute significantly to Macquarie's goal of making $5 billion of new investment in PSE.

Who did Macquarie choose to investigate to see if Energize Eastside could be justified?

Macquarie decided not have PSE's internal transmission planning employees do the analysis. Instead, Macquarie decided to have the load flow work performed by an outside company (Quanta Technologies) rather than by PSE's in house load flow experts. Quanta does a lot of work for Macquarie in areas outside of the Pacific Northwest. Quanta Technology, LLC is headquartered in Raleigh, NC with offices in Boston, MA; Chicago, IL; Oakland, CA; Toronto, Ontario and Ecuador in South America. There is no evidence that Quanta Technology has expertise in Northwest transmission and power supply matters.

A load flow study is the critical study used in the industry to test the reliability of the power grid. A load flow study is also used to justify the need for a new transmission project. The Federal Energy Regulatory Commission (FERC)/NERC also require each utility to develop a Base Case load flow study to show there is at least one mix of load, generation and transmission infrastructure that can be shown to reliably serve load in a future year. Generally, utilities provide FERC with several Base Cases reflecting peak loading periods of several different years in the future. FERC then requires utilities such as PSE to file Base Case studies each year so that third parties (such as myself) can utilize the database in each of these Base Case load flow studies to perform our own load flow studies to investigate whether a project proposed by a utility is really needed or not. PSE filed their Base Case studies with FERC and I obtained PSE's base case from FERC to perform my load flow study, with written permission from FERC .

Did Quanta use the FERC Base Case to perform its load flow study?

No. Macquarie did not have Quanta do its load flow study using the same assumptions in the Base Cases PSE filed with FERC. Instead, Macquarie asked Quanta to make significant changes to that Base Case. For example, Quanta was told to assume a 1,500 MW flow to Canada (rather than the 500 MW included in PSE's Base Case) and to assume that 1,400 MW of gas fired generators in the Puget Sound area would not be running during an extreme cold winter peak day (rather than the assumption in PSE's Base Case that all these generators would be running during a winter peak day).

Was I able to modify the PSE Base Case in this manner?

When I, along with transmission expert Roger Schiffman, performed my own load flow study (see paper entitled "Setting the Record Straight on Energize Eastside's Technical Facts" for more details), I obtained

PSE's Base Cases from FERC. I then tested these non-standard assumptions as described above. The Lauckhart-Schiffman load flow study demonstrates that making these two major changes to the PSE Base Case will result in the model failing to find a solution. The problem is that the lines carrying power across the Cascades from the Columbia River region to the Puget Sound region and then north to Canada are not capable of moving all this power without causing unacceptably low voltage on the grid in the greater Puget Sound area. Yet Quanta failed to disclose this problem.

Was Quanta able to resolve this cross-Cascades problem?

It is unclear how Quanta resolved this problem because PSE has refused to share the load flow study. It is also unclear why Quanta decided to make these major changes to the PSE Base Cases. One can only assume that Macquarie gave Quanta the directive to make these changes to the Base Case in order to produce a load flow study that justified the need for Energize Eastside. Macquarie and PSE have refused to make public the load flow studies that Quanta performed and which PSE claims justify the Energize Eastside line. I must therefore conclude, based on the above, that the load flow study that Macquarie/PSE/Quanta have performed in an attempt to justify the need for Energize Eastside has been artificially/inappropriately adjusted. I believe that if Macquarie/PSE had utilized their own internal transmission experts to run this load flow study, the project would have never progressed to its current status because their internal transmission experts would know that these changes to the Base Case are senseless and incorrect.

Conclusion

My goal in writing this paper was to illustrate that when it comes to utilities and profits, and PSE in particular, there is more going on than meets the eye. It appears that Macquarie and PSE, like some other utilities across the U.S., are pushing heavily for a project with no real basis in order to enhance their profits. The factual basis for this project simply does not add up.

PSE will likely respond by saying that I do not understand or that things are different now compared to when I worked for Puget Power. That is not the case. The burden of proof lies on them, not me. They are not being transparent and have not furnished sufficient material evidence that justifies the need for this project. Instead, they hope to gain permitting of a billion dollar project through the vote of city councils. Furthermore, Macquarie has a history of transactions that were deceptive in nature (see attachment 2).

Attachment 1

WUTC Proceedings[5]

WUTC PROCEEDINGS: On December 17, 2007 Puget Holdings LLC (Puget Holdings) and Puget Sound Energy, Inc. (PSE or Company) filed with the Washington Utilities and Transportation Commission (Commission) a joint application for an order authorizing the proposed transfer of ownership and control of Puget Energy, Inc. (Puget Energy), and its wholly owned subsidiary, PSE, to Puget Holdings. Puget Holdings is a Delaware limited liability company, with its principal offices in New York, formed expressly for the purpose of acquiring, through wholly owned subsidiaries, all of the outstanding shares of common stock issued by Puget Energy. The proposed transfer of ownership is one step in a financial transaction that would ultimately result in Puget Energy no longer being a publicly traded company. Puget Energy and PSE would be privately owned by Puget Holdings, which is an "Investor Consortium" (Consortium) comprised of several private equity investment companies and several government pension fund managers, all of which maintain portfolios of investments, including infrastructure investments, in the U.S., Canada, and several other nations.

December 30, 2008 WUTC Order Synopsis: The Washington Utilities and Transportation Commission, approving and adopting subject to conditions a Settlement Stipulation proposed by all parties except Public Counsel, authorizes Puget Holdings LLC (Puget Holdings) to acquire Puget Energy, Inc. (Puget Energy), and its wholly-owned subsidiary Puget Sound Energy, Inc. (PSE).

The WUTC Order included a number of statements about the sale of Puget Sound Energy

Decision Making for PSE under the new ownership arrangement:

The proposed change in Puget Energy and PSE's ownership would mean that Puget Energy would no longer be a publicly traded company. Thus, the numerous investors who currently benefit from the utility's success and bear the risks of any lack of success will no longer have direct voting rights on matters that must be approved by shareholders. Instead, decision making power will be exercised by the members of the Consortium. Therefore, in evaluating the merits of this transaction it is important to consider carefully the nature of these investors, their plans as owners of Puget Energy and PSE, and the governance structure of their holding company, Puget Holdings.

Puget Holdings is a consortium of six primary investors who own the following percentages:

[5] https://www.sec.gov/Archives/edgar/data/81100/000119312509000402/dex991.htm

- Macquarie Infrastructure Partners, which is comprised of three limited partnerships (i.e., Macquarie Infrastructure Partners A, L.P.; Macquarie Infrastructure Partners International, L.P.; and Macquarie Infrastructure Partners Canada, L.P.) who will indirectly invest in Puget Holdings, holds the largest single minority ownership interest at 31.8 percent.

- Canada Pension Plan Investment Board holds 28.1 percent.

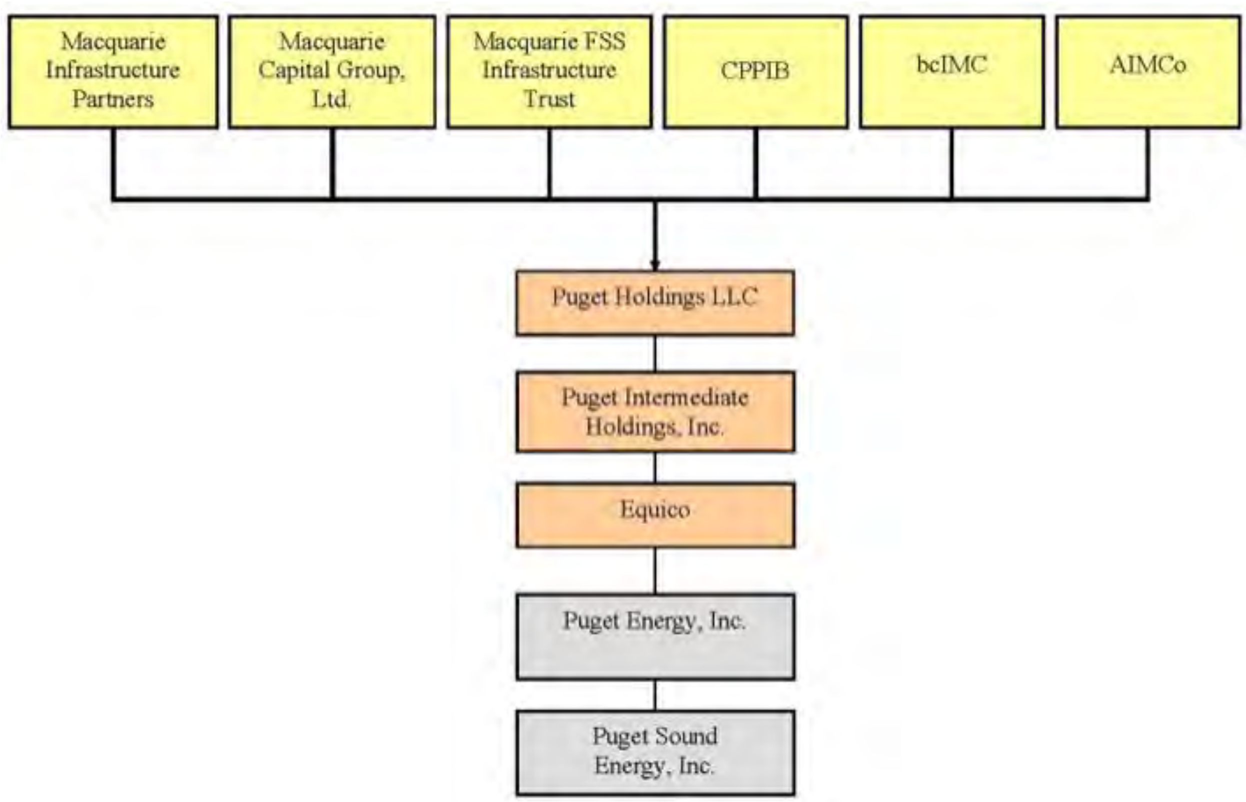
- Macquarie Capital Group Ltd holds 15.9 percent.

- British Columbia Investment Management Corporation holds 14.1 percent.
- Alberta Investment Management holds 6.3 percent.

- Macquarie-FSS Infrastructure Trust holds 3.7 percent.

Although the three Macquarie entities collectively own 51.4 percent of Puget Holdings, this is not a controlling share under Puget Holdings' governance structure, which requires a vote of 55 percent of the shares to support any action and a vote of 80 percent or more of the shares for certain significant corporate decisions.

Organizational Chart governing Puget Sound Energy (PSE):



Macquarie Infrastructure Partners. Macquarie Infrastructure Partners is a diversified, unlisted investment fund that is headquartered in New York. It focuses on infrastructure investments in the United States and Canada. The majority of its investors are US and Canadian institutions such as government pension funds, corporate pension funds, endowments, foundations and labor unions. Macquarie Infrastructure Partners currently has eleven infrastructure investments in the utility, toll road, ports and communications sectors

Macquarie Capital Group Ltd. Macquarie Capital Group Ltd. is a wholly owned subsidiary of the Australian-listed Macquarie Group Limited and the operating company for Macquarie Group Limited's non-banking operations. Macquarie Capital Group Ltd. often invests alongside Macquarie Group-managed funds in investments of this kind in an underwriting capacity. This is the case for Puget Holdings, and Macquarie Capital Group Ltd. expects to sell down its minority position to other Macquarie Group-managed funds or other like-minded third party investors prior to financial close or shortly thereafter.

Macquarie-FSS Infrastructure Trust. Macquarie-FSS Infrastructure Trust is an unlisted Australian infrastructure trust managed by Macquarie Specialized Asset Management Limited. The investment objective of Macquarie-FSS Infrastructure Trust is to make investments in a diversified range of infrastructure and related assets. It currently holds interests in five assets across sectors including communications infrastructure, vehicle inspection, utilities, and water infrastructure in three countries: the United States, Spain, and the U.K.

CPPIB -The Canada Plan Pension Investment Board (CPPIB)

bcIMC - British Columbia Investment Management Corporation (bcIMC)

AIMCo - The Alberta Investment Management Corporation (AIMCo)

Equico - following closing of the Proposed Transaction, all of the common stock of Puget Energy will be owned by "Equico," which will be a new Washington limited liability company. "Equico" will be a wholly-owned subsidiary of Puget Intermediate. "Equico" is expected to be established as a bankruptcy-remote special purpose entity, and shall not have debt.

Puget Holdings, which is an "Investor Consortium" (Consortium) comprised of several private equity investment companies and several government pension fund managers, all of which maintain portfolios of investments, including infrastructure investments, in the U.S., Canada, and several other nations.

Puget Intermediate Holdings - PSE's customers will be held harmless from the liabilities of any non-regulated activity of PSE or Puget Holdings. In any proceeding before the Commission involving rates of PSE, the fair rate of return for PSE will be determined without regard to any adverse consequences that are demonstrated to be attributable to the non-regulated activities. Any new non-regulated subsidiary will be established as a subsidiary of either Puget Holdings or Puget Intermediate Holdings Inc., rather than as a subsidiary of PSE.

Attachment 2

Examples of other transactions involving Macquarie that were deceptive

1. According to a Wikipedia write up on the Macquarie Group,[6] "Macquarie Group through its subsidiary Macquarie Equipment Rentals has allegedly been perpetrating a Telco finance scam. Macquarie Equipment Rentals has sued over 300 victims of the scam which involves bundling a finance equipment contract with a contract from a small telecommunications company, often obscuring that the finance contract exists.
   The scam involves the telecommunications company promising free equipment such as Plasma TVs, while offering a lower cost phone deal that offsets the cost of the equipment. The victim is then tricked into signing two contracts with the true costs often hidden, whilst being verbally promised that they will be free. The telecommunications company is paid an upfront fee by the finance company, and sometime later disappears. The victim is then left with an inflated finance company lease that requires the victim to pay often tens of thousands of dollars for equipment that in reality costs a fraction of the price."
2. Macquarie Capital was the lead underwriter on a secondary public stock offering in 2010 by Puda Coal, which traded on the New York Stock Exchange at the time and purported to own a coal company in the People's Republic of China (PRC). In the offering documents, Puda Coal falsely told investors that it held a 90-percent ownership stake in the Chinese coal company. Macquarie Capital repeated those statements in its marketing materials for the offering despite obtaining a report from Kroll showing that Puda Coal did not own any part of the coal company.[7]

[6] https://en.wikipedia.org/wiki/Macquarie_Group#Criticism
[7] https://www.sec.gov/news/pressrelease/2015-51.html

Setting the Record Straight on Energize Eastside's Technical Facts

From: Rich Lauckhart
To: city council and staff

Executive Summary

The most important aspect of any major transmission project is the underlying technical basis for the project. PSE's Energize Eastside project is a major transmission line that will have a tremendous impact on the entire Eastside. The fact that PSE wants to colocate this high voltage transmission line within a narrow corridor with the Olympic high pressure jet fuel pipelines means that the stakes are even higher.

A project like Energize Eastside should unequivocally have clearly demonstrated need, and the supporting documentation for the project, including PSE's load flow study as well as the EIS record, should be technically and reasonably sound.

I have performed an extensive study of both PSE's load flow study and the current EIS record, and my conclusion is that both fall short, the load flow study in particular. The Eastside cities involved are proceeding with a project that does not pass the bar of clearly demonstrated need and which in my professional opinion "violates the laws of the grid". PSE's claims simply do not add up. Furthermore, the current EIS record contains information that is not technically accurate.

This paper includes a detailed discussion of the following two points:

Assertion A: The current EIS record contains technically inaccurate information

Assertion B: Puget Sound Energy has never provided the actual data which would definitively demonstrate the need for Energize Eastside

Assertion A:

The current EIS record contains technically unsound information

Summary

As indicated in a number of places in the EIS record[1], Energize Eastside will provide no increased reliability benefit to the Eastside. When a utility is determining the need for a new transmission line, they perform a load flow study. This is present day industry standard. The load flow study serves as the primary basis for the decision of whether or not a transmission project is needed.

The assumptions used in the load flow study that PSE claims to have run would result in power outages in the entire Puget Sound Region whether or not Energize Eastside is built. A load flow study that is run with proper grid operation assumptions demonstrates there is no need for Energize Eastside to avoid outages on the Eastside. Therefore, under the "no action" alternative, **the EIS should conclude that a decision not to build Energize Eastside will not result in any more blackouts on the Eastside than if Energize Eastside were to be built. Yet this is not what the EIS record states.**

Background

The December 21, 2016 *Phase 2 Draft EIS – Scope of Analysis* includes a discussion of the "No Action" alternative. The following sentence is included in that discussion:

> "*If no action is taken, load shedding (forced power outages within the Eastside) would likely be needed during the highest demand periods in the near future*."

As pointed out in the rest of this report, there is no legitimate evidence on the record that this statement is true. In fact, the evidence in the record indicates that this statement is false.

Facts

The Eastside has had numerous power outages in the past and will continue to have power outages in the future. These outages are primarily caused by wind blowing trees and limbs into the local overhead 12 KV distribution lines. Energize Eastside will do nothing to decrease these outages in the future.

PSE claims that Energize Eastside will avoid outages on the Eastside under a scenario where:

1) Very cold weather (i.e. 23 degrees or lower) occurs on the Eastside during morning or evening peak load hours - an event that normally occurs only once every few years
2) At that same time, 1,500 MW is being delivered to Canada. This is a tremendous amount of power. However:
   a. There is no **firm** requirement to deliver 1,500 MW to Canada under such an

[1] See (1) Lauckhart-Schiffmann load flow study dated February 28, 2016, (2) August 1, 2016 document referenced in 2a on bottom of page 2 and top of page 3 of this paper, and (3) May 31, 2016 document reference at 2 on page 4 of this paper.

event. [*See comments filed to the EIS by Christina Aron-Sycz dated August 1, 2016 which includes a white paper entitled "Evidence that there is no requirement to deliver 1,500 MW to Canada on a Firm Basis-Resulting Conclusion is that Energize Eastside is not needed."*], and

b. The entire Puget Sound Region would experience blackouts caused by insufficient voltage levels if 1,500 MW is delivered to Canada during such a cold weather event. *There simply isn't enough power <u>currently</u> available that can be <u>moved</u> into the Puget Sound Region to serve all the load in the region (including serving all of PSE's 1.1 million customers) during peak winter load conditions <u>and</u> to send 1500 MW of power to Canada. Building a new <u>transmission</u> line (Energize Eastside) does not bring more power into the Puget Sound Region.*

3) According to PSE's needs assessment, at the same time as the above (very cold weather, 1,500 MW being sent to Canada) PSE/Quanta's Load Flow Study assumed that <u>six</u> of PSE's Puget Sound Area generators would be shut down. This is something that PSE would never do during such a cold event. Here is why:
   a. Energize Eastside is a transmission line. Transmission lines need generation to have power to transmit. Without these six generators running, PSE would not be able to meet its own Total System Load and would be in violation of their duties.
   b. The entire Puget Sound Region (including the service territory of PSE, Seattle City Light, Snohomish PUD, Tacoma City Light and other small utilities in the region, not just the Eastside) would experience blackouts caused by low system voltage if six Puget Sound Area generators are shut down during such a cold weather event even if 1,500 MW isn't being sent to Canada.

4) Lastly, in addition to 1) cold weather, 2) 1,500 MW being sent to Canada, and 3) six generators being offline, PSE assumes two major 230/115 KV transformers would be out of service. This is a preposterous scenario. *Since all these other things cannot happen at the same time without there being blackouts throughout PSE's entire service territory caused by too low of voltage. This scenario makes no sense*.

<u>**The most important thing for you to know is that the PSE scenario (described above) is a hypothetical scenario that will never occur because system operators would not allow it to happen**</u>**.** If system operators allowed the system to operate in the manner that PSE postulates it used in its load flow study, the Puget Sound region in total would experience blackouts caused by low voltage. <u>The above facts refute PSEs statement that Energize Eastside will increase the reliability of power supply to the Eastside.</u>

Both myself and CENSE.org entered a number of documents into the EIS record that provide evidence that Energize Eastside will not reduce the number of outages on the Eastside. These documents include:

1) The Lauckhart-Schiffman Load Flow Study and the report associated with that load flow study. The report is titled "*Load Flow Modeling for Energize Eastside*". It is dated

February 18, 2016.

a. While PSE and Stantec have criticized the Lauckhart-Schiffman load flow study, these criticisms have been fully rebutted. [See attachment in email from myself to EnergizeEastsideEIS dated April 29, 2016]
b. In the April 29, 2016 document referenced above, I asked PSE, Stantec (the outside consulted PSE hired to perform their load flow study) and the EIS staff to provide documentation to support their attempt to discredit my load flow study. To this date neither PSE, Stantec, nor the EIS staff have produced such documentation. All indications are that such supporting documentation does not exist and that my load flow study is fully credible.

2) A document submitted by Christina Aron-Sycz on May 31, 2016 entitled "*Environmental Impacts if Energize Eastside (EE) is not built (i.e. "No Action" on EE)*". This document provides a thorough analysis of the actions that would be taken if grid system operators attempted to run the system the way that PSE claims as the basis for Energize Eastside (peak demand on a very cold winter day, 1,500 MW being sent to Canada, six local generators offline, and failure of two transformers). My document fully explains that system operators would not allow the system to be run the way PSE postulates it would need to be run in order for Energize Eastside to have reliability value. **That document makes it clear that Energize Eastside provides no measurable reliability benefit to the Eastside and that blackouts will not occur if Energize Eastside is not built.**

Conclusion

The scenario that PSE claims as the basis for Energize Eastside could never happen because it violates the "laws of grid operation". Therefore PSE has no legitimate claim to build an eighteen mile, 230 kV transmission line through the heart of your communities. PSE claims that this high voltage power line is needed to increase the electrical reliability of the Eastside. These claims are false because the basis used to justify its need is impossible. The Lauckhart-Schiffman Load Flow Study (which uses PSE's own Base Case data set for heavy winter loading in the winter of 2017-18) demonstrates that Energize Eastside will provide no measurable reliability benefit to the Eastside. **Therefore, the No Action alternative will not result in any blackouts caused by load shedding on the Eastside or elsewhere on the grid and the December 21, 2016 statement by EIS staff is incorrect.**

Assertion B:

Puget Sound Energy has never provided the actual data which would definitively demonstrate the need for Energize Eastside

Summary

Power companies are required by the federal government to be able to provide continuous electricity even in stressed conditions. However, as soon as I read PSE's basis for the need for Energize Eastside (as described below), I realized that something was amiss. PSE is not required by any federal, state or local authority to build their grid to this level of preparedness. Meeting federal criteria is essential. The scenario above can only be described as a "doomsday" scenario. Allowing a power company to build their grid to meet a "doomsday" scenario results in investing hundreds of millions of dollars in a red herring project and needlessly subjecting communities to significant negative environmental impacts.

Background

Utilities demonstrate the need for transmission lines using a "load flow study." This is a computer simulation of how the complex electrical grid operates under various scenarios. PSE has in-house experts that normally perform these studies.

However, in 2013, PSE took the unusual step of hiring an outside consultant, Quanta, to perform a load flow study to prove the need for Energize Eastside. In my entire career at Puget Power (PSE's predecessor), load flow studies performed to assure our own system was reliable were never outsourced.

PSE/Quanta's basis for the need for Energize Eastside

Quanta concluded that PSE's equipment might overload under a combination of four extraordinary conditions:

- peak usage time on a very cold winter day (23 degrees or lower)
- simultaneous failure of two transformers
- at the same time, a huge amount of electricity is being transmitted to Canada (1500 MW)
- and six local generation plants are shut down, even though they were built for the specific purpose of providing power at peak load times (I oversaw the acquisition and building of these plants).

I decided to dig deeper into Quanta's load flow study to view it from all angles. I have overseen dozens of load flow studies on this exact same grid. To understand how the area's grid operates under this very unlikely scenario, I asked to see Quanta's load flow study. PSE declined multiple requests, each time citing reasons that were essentially baseless.
PSE's refusal to show their only load flow study did not deter me but rather compelled me even more to continue my research.

In December 2015, I performed my own load flow study with another transmission expert, Roger Schiffman. We were able to use the same software and same base case data that PSE's consultant had. **Our results show that the consultant's modified base case scenario violates fundamental limitations of the Northwest power grid and could lead to widespread power outages.** Most importantly, our study concludes that building eighteen miles of 230 kV lines through the heart of the Eastside (Energize Eastside) is not a necessary component to provide power to the Eastside and will not improve reliability in any measureable way. Furthermore, Energize Eastside will do nothing to prevent the most common type of blackouts - trees and limbs causing problems with the distribution system.

This remainder of this paper explains why it is important for a truly independent expert to verify the details of this important study, and how other factors lead to the conclusion that Energize Eastside is not necessary to serve the Eastside's energy needs.

Load flow models and the Pacific Northwest Grid

Transmission planning is accomplished by running load flow models[2]. The terms "load flow study" and "load flow model" are interchangeable. PSE has stated that "The computer model used for system planning is one that is used throughout western North America."[3] The system planning computer model needs a very large amount of data on the entire interconnected electrical grid.

PSE's transmission lines are an integral part of the entire electrical grid in the Western Electricity Coordinating Council (WECC) Region. The WECC Region extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 states between. In order for utilities to get the needed data to run these load flow models, the WECC collects the needed data from each of the utilities in the region and compiles a database that can be used to study the grid. The Federal Energy Regulatory Commission (FERC) requires that every utility develop Base Cases to show how the system will operate in the future so that third parties can review and modify these Base Cases if they believe modifications should be made. In the WECC region, the WECC creates these Base Cases and files these Base Cases with FERC. PSE files these same Base Cases (the WECC Base Cases) with FERC in order to comply with FERC's requirement that every utility file Base Cases with FERC. I asked for and received the PSE Base Cases and Lauckhart-Schiffman used these Base Cases in their analysis.

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[2] Load Flow analysis and Power Flow analysis are two different ways of referring to the same analytic process. The load flow model itself is a mathematical simulation of all the components of the interconnected electric system that provides flows and other physical conditions on each of the elements of the interconnected transmission grid.

[3] http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/phase_1_draft_eis_scoping_report.pdf at page 15.

<u>PSE's Needs Assessment</u>

The Eastside Needs Assessment report prepared by PSE and Quanta was based on a load flow study which looked at the reliability of the transmission grid on the Eastside under heavy loading conditions in the winter of 2017-18. The load flow study was conducted by Quanta, a consulting firm headquartered in North Carolina.

<u>CEII learance granted to me by the Federal Government</u>

In July of 2015 I applied for and was granted CEII [Critical Energy Infrastructure Information] clearance from FERC. After that I asked FERC to allow Roger Schiffman and Don Marsh to be included in my CEII clearance. FERC approved my requests. CEII clearance gives us the authority to access and review the Load Flow Base Case data files that PSE files with FERC.

We submitted our CEII clearance letters to PSE and asked for access to the Quanta load flow study.

PSE refused to share Quanta's Load Flow study with both myself and Don Marsh which would have allowed us to perform an even deeper review of the need for the Energize Eastside project. PSE's refusal cited that we may use the data to find weaknesses in the grid which will allow us to perform terrorist outages on the grid. However, FERC's CEII clearance letter stated that neither Don Marsh nor myself are considered terrorists and FERC has also stated that we have a legitimate need to see the load flow data.

FERC has gone so far as to provide both myself and Don Marsh a number of sets of load flow data that include data on PSE's system and every other system in the WECC.

In the Macquarie/PSE/Quanta load flow study performed in the Eastside Needs Assessment, PSE/Quanta took the WECC Base Case and made modifications to it. We know this because when we ran our own study, everything checked out. Yet PSE claims their load flow study resulted in significant outages. This could only happen if PSE had Quanta make alterations to the Base Case data files that they filed with FERC.

PSE's claim that it will not provide its load flow study (and therefore its modifications to the WECC Base Case) because of terrorism concerns is patently baseless. FERC has already provided the information that I or Don Marsh would need to perform terrorist activities if we were so inclined, which we are obviously not. Furthermore, Don Marsh and I have signed agreements with FERC that we will not use the information granted for nefarious purposes.

As indicated below, I believe that the real reason that PSE has chosen not to provide its load flow study is that there is a high likelihood that PSE has artificially and inappropriately made modifications to the Base Case that are outside of the realm of acceptable behavior by a utility.

Critical problems with assumptions in the Quanta load flow study

PSE already had a Base Case filed with FERC for heavy loading conditions in the winter of 2017-18. But rather than using the parameters in that base case, Quanta made major adjustments to it. According to the Eastside Needs Assessment report, Quanta made at least two changes to the Base Case that are highly problematic:

- Quanta shut down 1,340 MW of generation located in the Puget Sound area (six generation plants) when, in the Base Case filed with FERC, all of these generators were running.
- Quanta increased the flow of power to Canada from 500 MW to 1,500 MW.

Then, in order to comply with reliability criteria that says the system should be able to survive the failure of up to two elements on the grid (N-2 or N-1-1), Quanta eliminated one 230/115 KV transformer at its Sammamish Transmission station and eliminated one 230/115 KV transformer at its Talbot Hill Transmission Station.

Further problems with the Quanta study

There are a number of other problems with the Quanta load flow studies as follows:

- Lack of accounting for needed power generation
    - o Quanta said nothing about how PSE would source its total system generation need of 6,500 MW[4] in heavy winter conditions in 2018 if it shut down nearly 1,400 MW of PSE generation resources (the six generation plants) in the Puget Sound region. PSE's Integrated Resource Plan (IRP) indicated that PSE does not have enough firm supply lined up to cover its 2018 needs even if all of the PSE resources in the Puget Sound Area were operating. The IRP indicates a PSE shortfall of 2,000 MW in 2018 even if all of its resources are operating. If another 1,340 MW is not operating during the peak (the six generation plants that Quanta assumes are offline), then that shortfall grows to a whopping 3,340 MW. A shortfall that is more than 50% of its total need. The Eastside Needs Assessment makes no mention of how Quanta thinks PSE would meet its peak generation need under this extreme shortage condition.
- Illegitimate changes to Canadian power flows
    - o Quanta said nothing in the Eastside Needs Assessment about why it decided to increase the flows to Canada to 1,500 MW. In later statements, PSE has indicated that a 1,500 MW flow to Canada is required by the Columbia River Treaty. But that is patently false.
        - ▪ The Treaty was signed in the 1960's. The delivery of power to Canada as a result of this treaty were, according to the terms of the treaty, supposed

[4] Includes required Planning Margin and Operating Margin

to be accomplished by Bonneville Power Administration building a new transmission line in eastern Washington north to the Canadian border near Oliver, BC, east of the Cascades. Also according to the treaty, BC Hydro was then supposed to build from their system in British Columbia to meet the new BPA line. Under that plan, there would be no impact on transmission in Western Washington and PSE ratepayers would not be financially responsible to fulfill the Columbia River Treaty, which, it being an international treaty, is the financial duty of the federal government (of which BPA is an entity). But for the first thirty years of the Columbia River Treaty, Canada chose not to receive the power but instead sold it on the firm power market to US entities.

- Then, in the 1990's as those thirty year sales agreements to US entities were about to expire, both parties (BPA and Canada) decided to see if they could continue to operate without building the twin transmission lines to Oliver (as originally intended in the treaty). To determine if this was possible, BPA ran load flow studies to determine if any issues would arise on the grid if the joint lines to Oliver were never built. BPA's Record of Decision (ROD) that resulted from those studies made a comparison of the "Oliver plan" with a plan that did not include building Transmission to Oliver. That ROD stated the following[5]:
  - In order for at least partial treaty deliveries to be made at Oliver (in accordance with the original treaty), the US would need to build "One new single-circuit 500 -kilovolt (kV) line from Grand Coulee or Chief Joseph Substations to the United States/Canada border near Oliver by 2003" and Canada would need to build "Border-to-Oliver: One new single-circuit 500-kV line and substation by 2003".
  - Alternatively, in order for full delivery of Canada's share of treaty power to be delivered to Blaine and Selkirk,
    - "one cross-Cascades 500-kV transmission line would be accelerated 6 or 7 years under an Eastside generation scenario" and,
    - "a second cross-Cascades line might also be accelerated."
- After completion of the ROD and an evaluation of these findings, the original treaty with Canada was modified to remove the US requirement to build to Oliver. Canada was allowed to continue to sell its share of treaty power in the United States on a short term basis. Canada retained the right to request that its share of treaty power be delivered to Canada on any hour at the Blaine and Selkirk points of delivery; however, if the

[5] United States Entity US Department Of Energy, Bonneville Power Administration US Army Corps of Engineers, North Pacific Division Delivery of the Canadian Entitlement Final Environmental Impact Statement Record of Decision https://www.bpa.gov/news/pubs/RecordsofDecision/rod-19961108-Delivery-of-the-Canadian-Entitlement-Final-Environmental-Impact-Statement.pdf.pdf at page 8.

grid could not accommodate full delivery on any hour (e.g. because the new Cross Cascades lines had not been built), then it would not be delivered to Canada.[6]

- These new cross cascades line have not been built nor is there any written plan to do so in the future.
- Furthermore, Canada (through BC Hydro, Canada's power utility) has stated that it does not include its share of treaty power in the Load/Resource Balance in its IRP because the British Columbia Utilities Commission (BCUC) does not consider it a suitable source of dependable capacity.[7] This means that Canada's internal power planning structure does not formally depend on any transfers of power from the US to Canada.

There is other evidence that there is no requirement to deliver 1,500 MW to Canada. See Attachment 1, which document was filed in the EIS comment period.

<u>PSE's/Quanta's study defies the "laws of the grid"</u>

Loads in the Puget Sound region (including PSE's loads) are served by generation located in the Puget Sound region as well as generation located east of the Cascades which are transmitted to the Puget Sound region on the eleven transmission lines that cross the Cascades. There is a limit on the amount of power that these eleven lines can carry west across the Cascades from eastern Washington to the Puget Sound area. There are mathematical limits to the number of megawatts of power that can be moving on these lines - the "laws of the grid", if you will. The load in the Puget Sound region is greatest in a cold winter scenario. The PSE Base Case load flow for heavy winter conditions in 2017-18 showed very high loading on the eleven cross-Cascades transmission lines, even with all the Puget Sound generation running and with only 500 MW flowing to Canada. In our load flow study, Lauckhart & Schiffman attempted to increase the flow to Canada in this Base Case from 500 MW to 1,500 MW. The computer model found an unacceptable problem on these eleven cross cascades lines. Then, Lauckhart & Schiffman left the flow to Canada at the 500 MW level reflected in PSE's Base Case, but then shut down the 1,340 MW of Puget Sound Area generation that Quanta mentions in the Eastside Needs Assessment. Again the computer model found an

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[6] COLUMBIA RIVER TREATY ENTITY AGREEMENT on ASPECTS OF THE DELIVERY OF THE CANADIAN ENTITLEMENT
For APRIL 1, 1998 THROUGH SEPTEMBER 15,2024 BETWEEN THE CANADIAN ENTITY AND THE UNITED STATES ENTITY DATED MARCH 29,1999 at paragraphs 8 & 9.
http://www.bcuc.com/Documents/Proceedings/2006/DOC_10966_B1-131_Columbia%20River%20Treaty%20Agree.pdf

[7] See BC Hydro November 2013 IRP, Chapter 2 at page 2-20.
http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0002-nov-2013-irp-chap-2.pdf

unacceptable problem on these eleven cross-Cascades lines. You can see how the computer model gets extremely problematic if both assumptions are changed at the same time. Under either of these scenarios, it is important to note that all of PSE's service territory would experience blackouts caused by low voltage, not just the Eastside. Despite numerous requests for explanation by myself and Don Marsh, PSE/Quanta have never said how they addressed these problem in their load flow analysis. The Bellevue city council claims they have requested an explanation of this from PSE, but I know of no response to this request or whether it was in fact actually requested.

PSE's stated "electrical criteria" used in their Eastside Needs Assessment

PSE has not provided the load flow study that Quanta ran that attempts to justify Energize Eastside. The Lauckhart-Schiffman load flow study report raises serious questions about how Quanta conducted its load flow study to prove the need for Energize Eastside. To try to understand why PSE's/Quanta's load flow study deviates from the WECC Base Case, one can look to the eleven "electrical criteria" listed in the Eastside Needs Assessment that PSE claims as their basis for this project. To the layperson, the electrical criteria laid out by PSE cites seem reasonable. However, to my experienced eye, these electrical criteria reveal that PSE/Quanta made unacceptable modifications to its study. Specifically, I believe that they failed to adhere to industry standards and are attempting to override the "laws of the grid". See Attachment 2.

By contrast, the Lauckhart-Schiffman load flow study does adhere to the "laws of the grid" and follows industry standards for studying the reliability of power service to the Eastside. The Lauckhart-Schiffman study demonstrates that Energize Eastside is not only not needed, it also shows evidence that the PSE/Quanta studies used to justified Energize Eastside defy the "laws of the grid".

PSE refuses to discuss these matters with me

I have made numerous attempts to reach out to PSE to discuss all of these matters in person or at least by phone. However, PSE has repeatedly stated that they are not available or not interested.

Despite contrary statements by PSE to the city staff, I harbor no ill will against PSE. It may be hard to believe in this day and age that an individual would devote as much time and energy as I have to studying this project without some kind of ulterior motive. I am a naturally intellectually curious individual and had I seen evidence at the outset that Energize Eastside was simply another important piece in the framework of the Eastside's grid, I would have moved on. However, my deep knowledge of Pacific Northwest transmission planning and my own conscience compel me to make the public, and especially the decision makers, aware of just how flawed this project is.

Conclusion

PSE has not provided the load flow study that it claims demonstrates the need for Energize Eastside. The Lauckhart-Schiffman load flow study, which is based on the heavy winter 2017-18 Base Case that PSE submitted to FERC, demonstrates that Energize Eastside is not only not needed but defies the "laws of the grid". PSE has openly criticized the Lauckhart-Schiffman load flow study for running all the Puget Sound area generation and for not sending 1,500 MW to Canada. But as described in this paper, the Lauckhart-Schiffman assumptions on these matters are more defensible than the assumptions that Quanta used in its load flow analysis. In fact, it is highly unclear how Quanta was able to resolve the cross-Cascades power flow problems that would arise under their assumptions. It simply does not add up, and I compel you to not accept this project at its face value. Your communities are depending on you. I am more than willing to provide you with assistance, at no cost, to help study this further.

Attachment 1

White Paper

Evidence that there is no requirement to deliver 1,500 MW to Canada on a Firm Basis…. Resulting Conclusion is that EE is not needed

PSE attempts to justify the Energize Eastside line by stating that PSE is required to deliver 1,500 MW to Canada on a very cold winter day during the peak load hour at the same time that 1,400 MW of local generation is not running and two major transformers on the Eastside fail. **That there is no Firm Requirement to deliver 1,500 MW to Canada (e.g. under these extreme conditions) is evident from a number of standpoints as follows**:

1) Any Firm Requirement to deliver 1,500 MW to Canada would be evidenced by the existence of a contract that shows such a requirement. No one has produced a contract that includes such a requirement. The EIS record includes a request that either PSE, or Stantec, or the Bellevue EIS staff produce such a contract. No such contract has been produced. We believe there is no such contract.
2) FERC has stated "*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*." For these stated reasons, FERC does not consider the EE line to be a FERC jurisdictional line. Instead FERC calls it a line for local need. **From this FERC finding it is clear that 1,500 MW to Canada (a Regional flow matter) should not be reflected in the study of the need for EE because PSE never requested the EE line be selected in a regional transmission plan.**
3) There have been unsupported claims that the Columbia River Treaty requires PSE (or BPA or some unknown entity) to deliver 1,500 MW to Canada. However that is not true as evidenced by:
    a. The treaty deliveries to Canada were by its terms supposed to be accomplished by BPA building a new transmission line in Eastern Washington north to the Canada border near Oliver, BC, east of the Cascades. BC Hydro was supposed to build from their system in British Columbia to meet the new BPA line. Under that plan, there would be no impact on transmission in Western Washington and PSE ratepayers would have paid nothing to cause the Columbia River Treaty benefits to be moved to Canada. But for the first thirty years of the Columbia River Treaty, Canada's share of Treaty power was sold "Firm" for 30 years to US entities. In 1998 when those sales to US entities expired, the Treaty was amended to eliminate the requirement to build transmission to Oliver in exchange for giving Canada the right to sell its share of Treaty power in the future to US entities on a

short term basis.

b. The 1998 amendment to the treaty stated that if Canada later decided it wanted its share of Treaty Power to be delivered "Firm" to Canada, then Canada needed to ask BPA to study to determine what work would need to be done on the transmission grid to make that happen. After that study, if Canada was willing to pay money for those transmission improvements, then the Treaty power would be delivered "Firm" to Canada. **<u>Canada has never made such a request to have its share of Treaty power delivered to Canada on a Firm Basis as evidenced by BPAs response to a Public Record Act request to search the BPA Transmission Request Queue to locate any such request from Canada. BPA stated that it did not find any such request.</u>**

c. BPA has known since at least 1998 (when the treaty was amended) that it would not be able to deliver Canada's share of downstream benefits to Canada under all weather and contingency conditions. In 2009, Puget Sound Area Study Group members developed a draft report entitled "Assessment of Puget Sound Area/Northern Intertie Curtailment Risk." That study describes certain system operating plans that could reduce the Curtailment Risk in the south-to-north direction on the tie to Canada.

4) On May 13, 2015 Mike Brennan was asked to have Peter Mackin of USE please provide the Firm Transmission Service that would be relevant for his load flow studies. In other words, please provide a copy of any and all contracts that Peter is aware of under which BPA has contracted to provide Firm Transmission Service in the northerly direction over this line. It has been over a year since this request was made and no response has been provided. We believe no response was provided because no such contract exists.

5) Gary Swofford, 38 year Puget employee who recently retired as Chief Operating Officer of PSE VP of PSE, spoke to the Bellevue City Council on December 14, 2015 and stated that "nothing could be further from the truth" than a claim that Energize Eastside is being built to deliver 1,500 MW to Canada. He claims the need for Energize Eastside is simply an eastside load matter. However, apparently unknown to Mr. Swofford, neither the USE load flow study nor the Lauckhart-Schiffman study shows a need for Energize Eastside if 1,500 MW does not need to be delivered to Canada. PSE has never produced a load flow study that says otherwise.

6) PSE claims that NERC/FERC reliability criteria require 1,500 MW to be delivered to Canada. The EIS record includes a request that either PSE, or Stantec, or the Bellevue EIS point to specific language in NERC/FERC reliability criteria that describes such a requirement. PSE generally refers to NERC/FERC Reliability Criteria TPL-001. But TPL-001 is a 20 page document and no one has pointed to specific language in TPL-001 that describes such a requirement. There is a reference in TPL-001 to Firm Commitments, but **<u>no one has shown a contract under which a Firm Commitment to deliver 1,500 MW to Canada exists.</u>**

7) Any Firm Contract to deliver 1,500 MW to Canada would be subject to FERC jurisdiction. Any requirement under NERC/FERC Reliability Criteria would also be subject to FERC jurisdiction. If PSE believes that a denial of their permit to build EE would violate a Firm Contract to deliver 1,500 MW to Canada or would violate a NERC/FERC Reliability Criteria, then PSE should have requested that FERC make such a finding in CENSE's Complaint at FERC. FERC made no such finding in their Order on CENSE's complaint. In fact, to the contrary, FERC stated it had no

jurisdiction over the EE line.

8) The Western Electricity Coordinating Council (WECC) prepares the Base power flow cases for use by western North America power companies such as PSE to help them study the grid and its reliability. WECC prepared Base Case load flow studies for the heavy winter loading conditions for the winter of 2018. WECC ran all of the Puget Sound gas fired generation and transferred 500 MW of power to Canada in that case. The reason WECC did not transfer more power to Canada in its Base Case is that problems occur on the grid if that happens. WECC did not state that the case was not compliant with FERC reliability criteria because WECC did not see a Firm Commitment to deliver 1,500 MW to Canada.
9) The Lauckhart-Schiffman load flow study effort attempted to modify the WECC heavy winter load base case for the year 2018 by increasing the flow to Canada. When they attempted to do this, the load flow study could not find a solution to satisfactorily meet reliability criteria. This was true whether or not the Energize Eastside line was included in the load flow data set being used. Simply put, the loading on the eleven transmission lines crossing the Cascades from the Columbia River to Western Washington could not handle the loading that would be necessary to delivery 1,500 MW to Canada, whether or not the Energize Eastside line is built. And this is true even with all the Puget Sound Area gas fired generation is operating. Clearly it would take a major new transmission line crossing the Cascades (or a new line to Oliver from eastern Washington) for 1,500 MW to be delivered to Canada on a Firm Basis.
10) CENSE has made Herculean efforts to get PSE to divulge its load flow study showing a need for the line. PSE has created a series of excuses for not showing CENSE and its experts its studies. The experts retained by CENSE believe that the real reason that PSE has chosen not to provide its studies is that any such study that they might have is artificially/inappropriately made in some fashion.
11) PSE refuses to show its load flow studies to the experts retained by CENSE because they fear that those experts may use the data to find weaknesses in the grid which will allow them to perform terrorist outages on the grid. FERC has stated that the CENSE experts are not considered terrorists and FERC has stated that the CENSE experts have a legitimate need to see the load flow data. In fact, FERC has provided the CENSE experts a number of sets of load flow data that include data on PSE's system and every other system in the WECC. PSE's claim that it will not provide its modifications to the WECC load flow cases because PSE is concerned about terrorist activities rings untrue. FERC has already provided the information that CENSE's experts would need to perform terrorist activities if they were so inclined. Nothing PSE would provide would give any additional help. But CENSE's experts have signed agreements with FERC in which they promise not to use the data provided them for any nefarious purpose.

Bottom line:

a) It is clear that there is no Firm Requirement to deliver 1,500 MW to Canada.
b) It is clear that the grid cannot deliver 1,500 MW to Canada in an extreme cold situation with or without the Energize Eastside line.
c) **<u>It is clear from (a) the U.S.E. and (b) the Lauckhart-Schiffman load flow studies that Energize Eastside is not needed if 1,500 MW is not being delivered to Canada.</u>**

Attachment 2

PSE "Electrical Criteria" hints at how Quanta ran the load flow model that PSE claims justifies EE

"An inappropriate load flow study"

The Eastside Needs Assessment report prepared by PSE and Quanta states that PSE/Quanta ran a load flow study that concluded that EE is needed in order to reliably serve power to the Eastside. But PSE has refused to show the data from its load flow study. Lauckhart & Schiffman ran a load flow study that concluded that EE was not needed. Lauckhart-Schiffman load flow study was performed using the Base Case load flow study that PSE files with FERC. The Lauckhart-Schiffman load flow study report indicates that if NERC/FERC reliability standards are followed, EE is not needed. Further, the Lauckhart-Schiffman study questions how the PSE/Quanta load flow study could have been made to work given the problems with the loading on the eleven transmission lines that cross the Cascades to northwest Washington from the vicinity of the mid-Columbia River.

By looking at the 19 criteria listed In Chapter 2 of the Phase I Draft EIS, it is possible to make a reasonable guess of how PSE/Quanta ran its load flow study. Assuming this reasonable guess is correct, the PSE/Quanta load flow study that was used to justify EE is plainly inappropriate for this purpose.

The "reasonable guess" is made as follows:

a) PSE stated Criteria number 7: "*Adjust regional flows and generation to stress cases similar to annual transmission planning assessment.*" ColumbiaGrid had run a "stressed load flow case" **for information purposes** just to see how the system would respond if the Base Case was adjusted to significantly increase stresses on the system. Columbia Grid indicated that this stressed case caused significant adverse impacts on the system but there was no need to make any fixes to the system to address those problems as a result of this stressed case run because **the case exceeds the NERC Reliability Criteria**.[8] [*Having a model of the system allows the user to look at any scenario they want. In this case, apparently some party wanted to look at a very stressed condition...so it was run. But the probability of those set of assumptions is excessively low. And neither FERC nor NERC nor ColumbiaGrid (nor any rational person) believe*

[8] 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.** [ColumbiaGrid 2013 System Assessment Pg 12]

that it makes sense to fix the system for this extremely low probability event. That is why ColumbiaGrid did not look to find fixes to the problems under this scenario. However, PSE has made this the main scenario for looking at the need for Energize Eastside - that makes no sense.]

b) As demonstrated by the Lauckhart-Schiffman report, the load flow model will not run under this scenario because of the problems that are created on the grid unless other changes to the data base are also made. From this same "PSE Criteria" document we can get some insight into how Quanta may have made the load flow model run.

c) PSE stated Criteria number 8: "*Take into account future transmission improvement projects that are expected to be in service during the study period*."

d) PSE stated Criteria number 2: The "Study Period" was from 2015-2024.

e) It appears that PSE thinks that sometime prior to 2025 someone will build one or two new Cross Cascade lines. But no one is announcing today they intend to build new Cross Cascade lines. PSE may speculate they will be built, but there is no compelling evidence they will be.

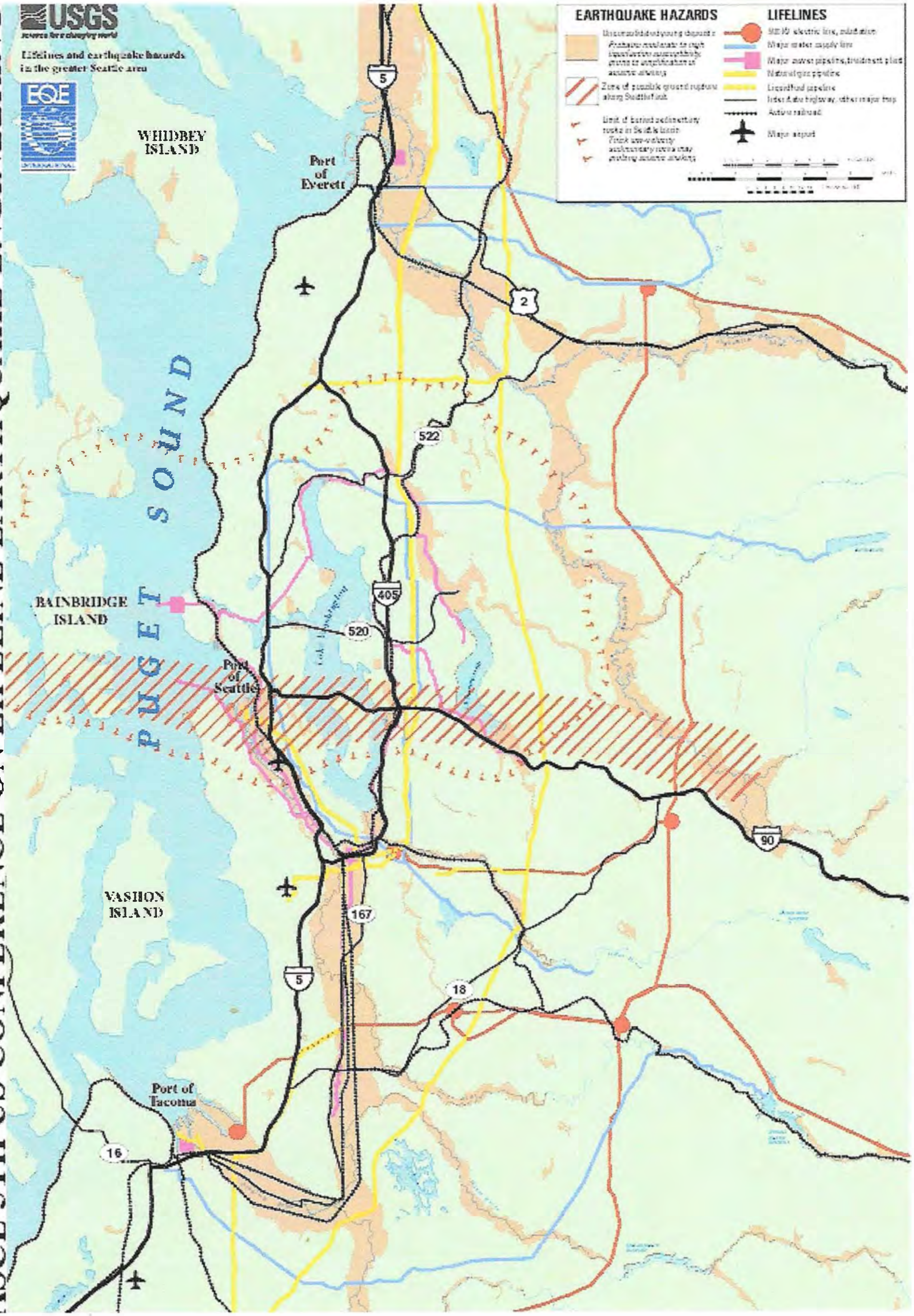
Bottom Line:

In a nutshell PSE/Quanta have decided to run a Load Flow study to determine the need for EE, which load flow study has major flaws.

- First it starts with a Scenario that has negligible probability of occurring
- A Scenario that vastly exceeds FERC/NERC reliability criteria.
- Then in order to make that Scenario work electrically, Quanta seems to have modeled new Cross Cascades transmission lines that no one is working on.
- And no one is working on them because any scenario that is consistent with FERC/NERC reliability criteria says the new Cross Cascades transmission lines are not needed.

This load flow study is completely inappropriate for studying the reliability of power service to the Eastside. The Lauckhart-Schiffman load flow study is the appropriate way for studying the reliability of power service to the Eastside. That study demonstrates that EE is not needed.

ASCE 5TH US CONFERENCE ON LIFELINE EARTHQUAKE ENGINEERING



Renton/Newcastle Public Hearing
5.23.17

From: Lori Elworth
To: Eastside City Councils
Date: May 23, 2017
Subject: Energize Eastside Public Comment

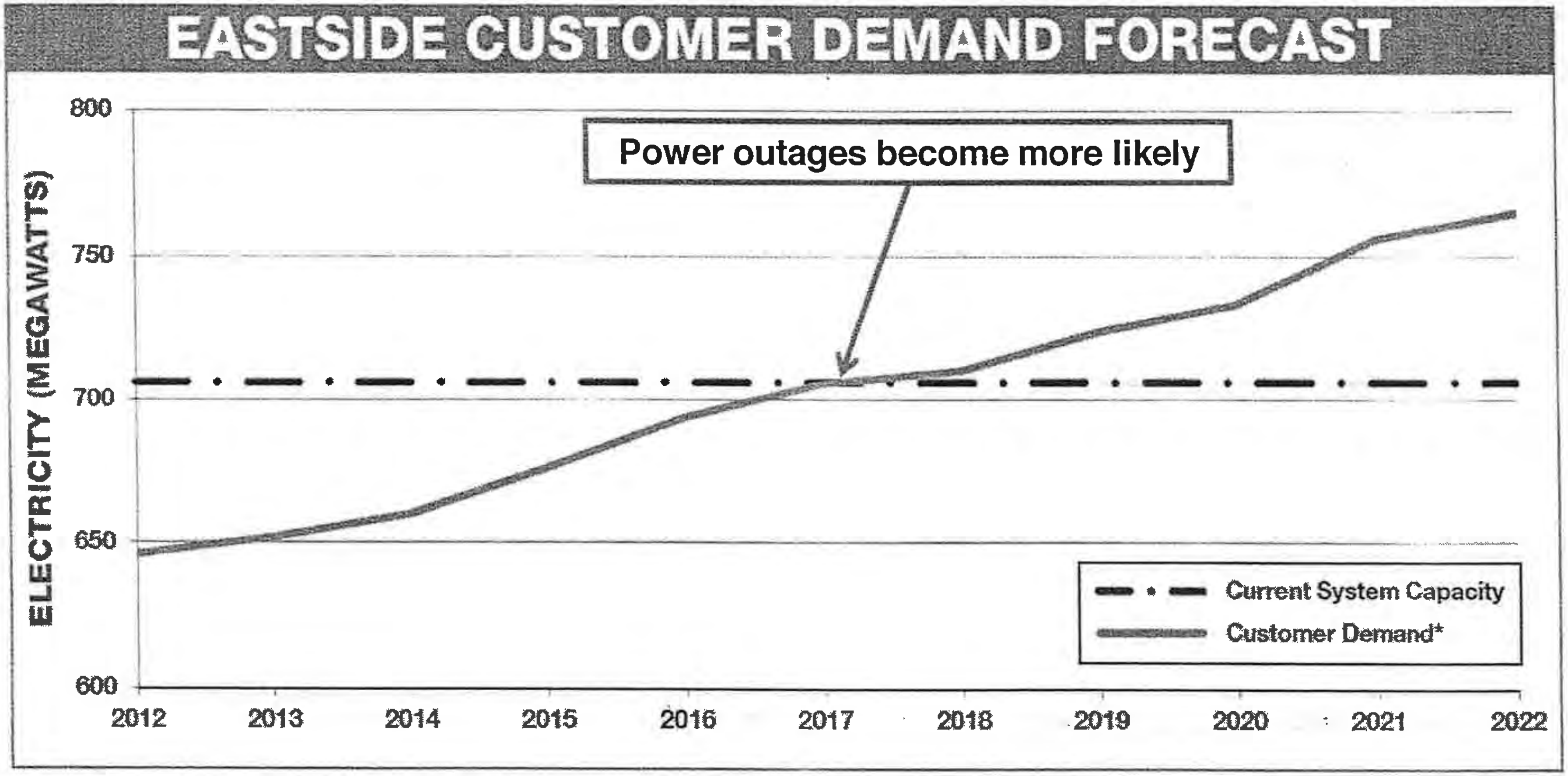
I have lived in the Olympus neighborhood for the last 29 years. My home is located right next to the PSE/Olympic Pipeline corridor. One of the two pipelines, is less then a foot from our backyard property line.

I have a copy of PSE's graph "Eastside Customer Demand Forecast". This graph has been distributed by PSE for the last 3 1/2 years to demonstrate the need for the project. The graph shows us that customer demand will surpass the current system capacity this year, leading to an increased number of power outages in the area. However, we have data from PSE showing that despite a population growth of 7.3% from 2011 to 2015, power consumption is down 5.7% over the same period. This trend can be seen everywhere. Growth is being offset by greener technologies and higher efficiencies.

The only way to determine electrical need is by running a load flow study. PSE claims to have conducted one but refuses to share their data with anyone, including individuals with the appropriate clearance. Because of this, CENSE conducted their own independent study but could not replicate PSE's conclusion. It is the responsibility of the lead agency to define and understand the need. How can the city of Bellevue do this without an independent load flow study?

I am a member and supporter of CENSE
Lori Elworth
8605 129th Ct
Newcastle WA

Customer demand

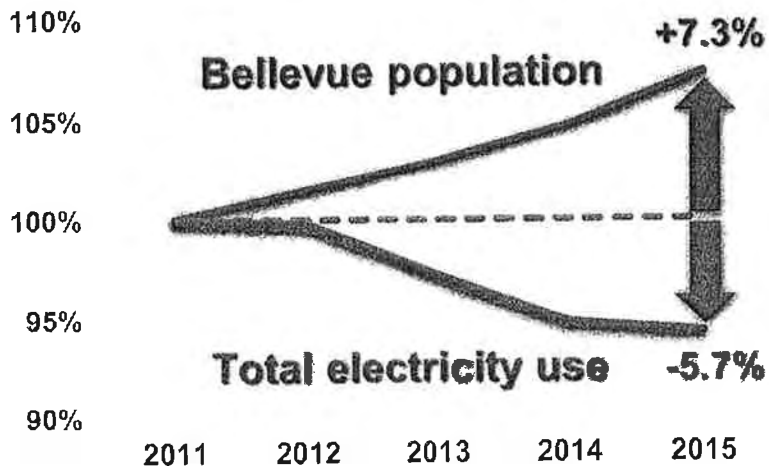


*Customer Demand assumes 100% of conservation goals are met.

energizeEASTSIDE

PSE PUGET SOUND ENERGY

- Here is a chart showing total electricity consumption for Bellevue, one of the Eastside's fastest growing cities. The data comes from PSE. Declining consumption doesn't support PSE's assumption that population growth is causing similar growth in the use of electricity. Energy efficiency and conservation are having a big impact:



Q & A

Olympus Questions
"Segment M"
answers provided
by PSE

2/11/14 email sent to CAG Rep Dave Edmonds

1. We currently have two sets of wooden poles: Will there be only one metal monopole if the new transmission lines go through Olympus?If Segment M is selected as a part of the overall route, replacing the wood structures with a single steel monopole for both circuits is an option (i.e., one steel pole replaces 4 wood poles). Another option includes replacing each wood structure with a steel pole (i.e., one steel pole replaces two wood poles for a total of two steel poles). PSE is still early in the conceptual design phase of potential configurations that could be used for each route segment.

2. Which side of the ROW will the poles be placed on? Currently some poles are on private property; will the large poles be placed on private property as well? As we are just beginning the public routing discussion, we do not yet know which side of the right-of-way poles will be placed on along a given segment.

In general, PSE prefers to site projects along public rights-of-way or existing utility corridors wherever possible. PSE may need to acquire property or access to and use of private property via easements. PSE will strive to locate the poles in easements as a means of establishing durable rights for a line that is integral to reliable power being delivered to the community. When use of private property is required, PSE negotiates fair market value purchase of easements with the affected property owner.

For more information about easements on private property, please visit: http://pse.com/accountsandservices/YourProperty/Pages/Easements.aspx.

3. Will the new poles have three or six transmission lines?There can be confusion between a "line" and a "wire". The term "transmission line" refers to three wires, the pole, the insulators (the piece of equipment that keeps the wire safely from the pole), and other pieces of equipment such as fiber cable and static wire (which is a safety feature to help protect against lightning strikes). So, for each "transmission line" there are three wires (which does not include the fiber cable or static wire).

Segment M currently has two 115 kV transmission lines with three transmission wires on each wood structure. If Segment M is selected, the existing wooden poles would be removed and replaced with structures that would hold the 230 kV lines: we will replace one 115kV line (three wires) with a new 230kV line and the other 115kV line will be rebuilt with higher-capacity wires to maintain reliability to the 115kv system. There will still be six transmission wires with three of the wires being operated at 230 kV while the other three wires will be operated at 115 kV. The fiber-optic cable currently on the easternmost line will be relocated to new structure. If one of the other route segment options is chosen, on the other hand, the existing wood poles along segment M would stay the same.

4. How high will the new poles be? How much higher will they be that existing poles? How far apart will they be--how does this compare with the existing poles?While we do not have the preferred route or final design yet, pole heights will range from 95 feet to 125 feet above ground depending on topography and obstacles, and the spans could range from 400 feet to 700 feet. The existing poles are around 60 feet tall with an average span length of around 500 feet. At this point, the spans for the new poles will be similar to those of the existing spans. However, there is some flexibility in the siting of structures. PSE will strive to minimize the impacts of the project while constructing and operating a safe and reliable transmission line. You may want to visit the design page of our website for sample pole and wire configurations.

5. If you have a choice, why would you want to locate new higher transmission power lines by the Olympic petroleum pipeline. Would this present a possible danger? Has PSE been in contact with Olympic Pipeline to talk about this? Safety is our top priority – a 230 kV transmission line can safely operate near the pipeline. Both the pipeline and PSE's transmission lines have co-existed in the existing corridor for over 65 years. We have been good neighbors, kept the pipeline apprised of our plans and will continue to work with them through this process.

6. Why can't PSE use the existing Bonneville power lines that go through this area to carry additional power? Bonneville Power Administration does have lines that run through the Puget Sound, but those lines do not run through the Eastside area between Lake Washington and Lake Sammamish. Seattle City Light (SCL), on the other hand does have lines that run through the Eastside area: PSE studied the Seattle City Light corridor during the solution identification process. If rebuilt, the corridor could work to meet the Eastside's energy needs. However, PSE approached Seattle City Light and this corridor is a key component of Seattle City Light's transmission system and not available for our use.

7. Has there been any studies done to determine which route would affect a higher number of homes on the M route (Newcastle) or L route (Kennydale)? If so, which path borders more homes? This information, and similar statistics about the route options, will be made available to the

Community Advisory Group and the Sub-Area Committees later in the advisory group process.

8. An electrical engineer in our group says the new transmission lines will provide 4x the amount of power that the current lines do. Why is this much more power needed?The upgrade of the existing line in Segment M will increase the amount of power that the line can carry. The maximum amount of power a line can carry is one of many factors to the amount of additional power that the system can serve to customers. With this improvement the system will have approximately 25% more capacity to serve customers in the Eastside.

9. Was the city of Newcastle paid a fee to allow the power lines to go through this city? No, PSE does not pay the city a fee to have power lines on the utility corridor. The lines have existed since the 1930s when PSE purchased utility easements from the land owners at that time.

10. Residents of Olympus (especially those who have homes that border the power line ROW) are concerned about home values lowering as much as 20% of higher voltage power lines are built. (This number has been verified by a local realtor who has experience with selling homes next to power lines) Please comment PSE will not pay property owners for existing easements, and PSE does not compensate nearby property owners for perceived loss of property value due to the installation of energy infrastructure. If additional easement rights are necessary, PSE will negotiate with the affected property owner and pay fair market value for those easement rights. We know that we'll be bringing changes to any of the neighborhoods where we install lines. We're actively engaging the public to discuss routing, impacts and potential design considerations to reduce these impacts while we move forward with this project which is vital to maintaining reliable power for all of the customers in the area.

11. Residents of Olympus are concerned about the possible adverse health effects of higher voltage power lines. Please comment. Are you referring to possible adverse health effects from EMF, or electromagnetic fields from electric transmission lines? Over the past 30 years, there have been many scientific studies conducted to determine if electromagnetic fields any effect on human health. To date, the scientific community has concluded that current evidence does not support the existence of any health consequences from exposure to EMF.

At PSE, health and safety are always our top priorities. For more details about EMF studies, exposure limits and PSE's approach to EMF, we encourage you to check out this resource: http://pse.com/safety/ElectricSafety/Pages/Electromagnetic-Fields.aspx.

Puget Sound Energy understands that you, and other local residents, may have more questions about electromagnetic fields. PSE has hired Drew Thatcher – an independent, board-certified health physicist. If you or your neighbors would like to ask questions of Drew, we would be happy to connect you with him for more information.

12. Could higher voltage power lines be under-grounded through Olympus? If so, how much would this cost and who would pay for it? Please comment Underground lines are technically an option, but we would need to work with the local requesting jurisdiction or community. While underground lines limit the visual impact compared to overhead lines, there are other factors to consider, including:

- *Underground transmission lines cost more than overhead lines.* Our studies indicate that the cost of installing underground transmission lines in our area will cost three to six times the cost of overhead lines, and, if required or requested by a local jurisdiction or community, the difference cannot be passed on to PSE's customer base. Local customers who benefit must pay the difference, which could exceed $25 million per mile.
- *Putting power lines underground can have bigger environmental and neighborhood impacts.* Undergrounding transmission lines requires extensive vegetation removal, trenching and installation of large (20 feet x 30 feet) access vaults every quarter mile and can be very disruptive to neighborhoods and the environment.
- *Longer repair times for underground lines.* Repairs are much more difficult with underground lines, too. When an overhead line fails, our crews can often repair it within hours. Repair of underground transmission lines can take days and even weeks, depending on the repairs that need to be made.

If you'd like additional information about undergrounding, we recommend you read the PSE underground fact sheet, and this undergrounding board and handout from our first open house.

13. I just received a question from a resident of Olympus who is concerned about the possible noise that might be produced by 230 kV transmission lines. Please discuss this and add the answer to the list of answers from the questions that I sent to you a couple of days ago. I

will share your answers with all my neighbors. Over the years, transmission line design improvements have helped minimize the likelihood of audible noise levels. An evaluation of the audible noise will be conducted as a part of the overall design of the transmission line.

David, please let us know if you or your neighbors have additional questions, and thank you again for contacting us. We look forward to working with you during the Community Advisory Group Process.

Sincerely,

PSE Energize Eastside Project Team

Energize Eastside

Olympus Homeowners Association

Andy Wappler

Vice President, Corporate Affairs, Puget Sound Energy

energize**EASTSIDE**

Feb. 24, 2014

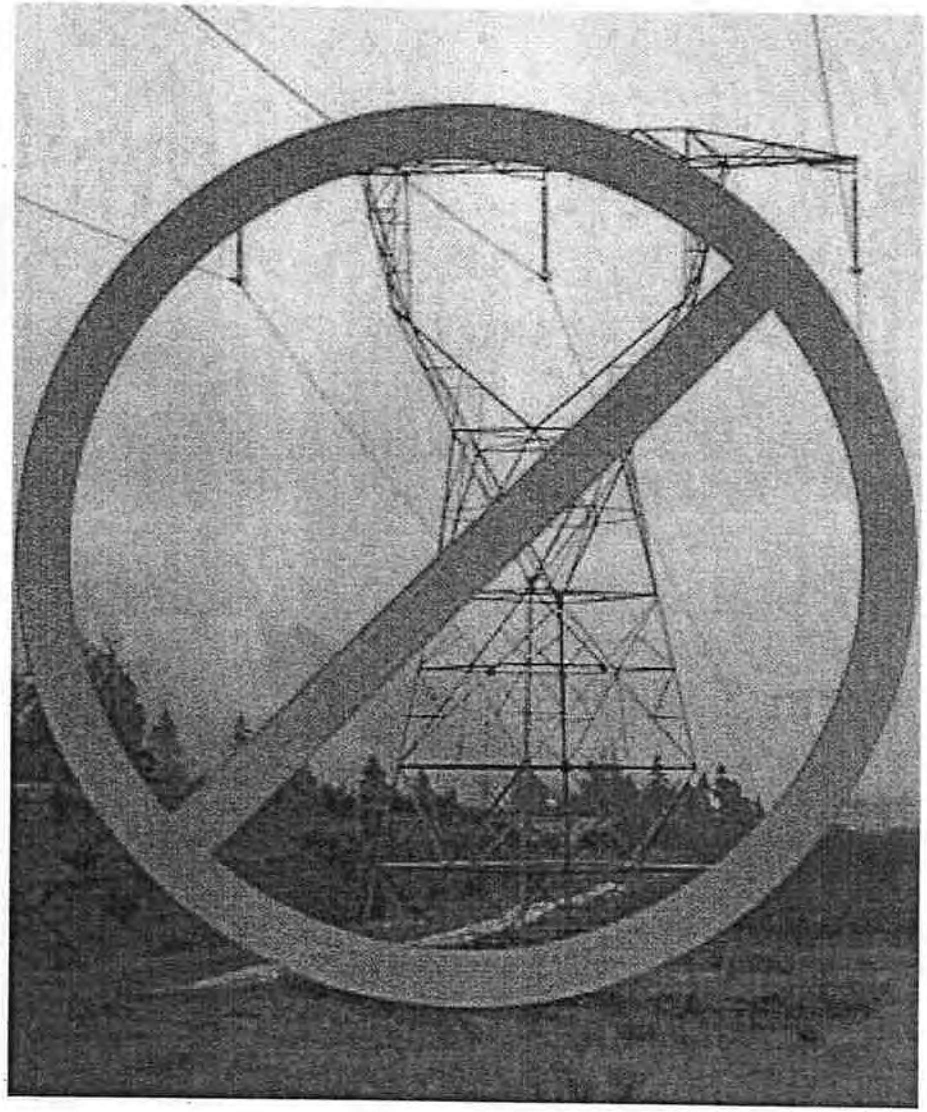
PSE PUGET SOUND ENERGY

Energize Eastside overview

- Growth is straining our region's existing transmission system
- Conservation alone is not enough
- We need to act now
- We will work with the community to identify solutions

Energize Eastside will build new electric transmission infrastructure to ensure dependable power

What we're not building



Eastside system: 1930s to today

System first installed in the **1930s**

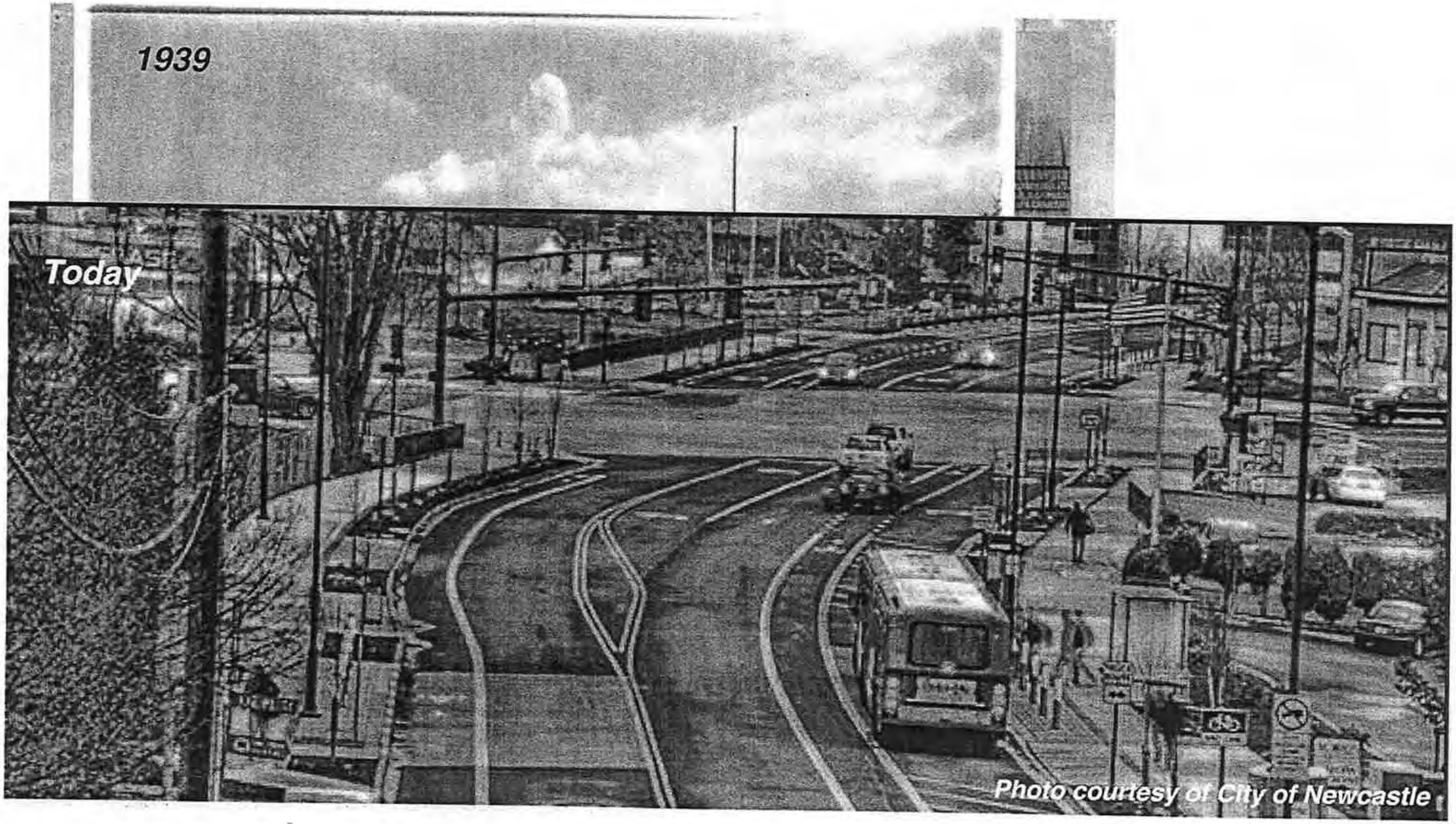
Leary Way, 1940 - Redmond

3rd Avenue looking west, 1920s - Renton

NE 8th Avenue and Bellevue Way, 1930s - Bellevue

Eastside then and now

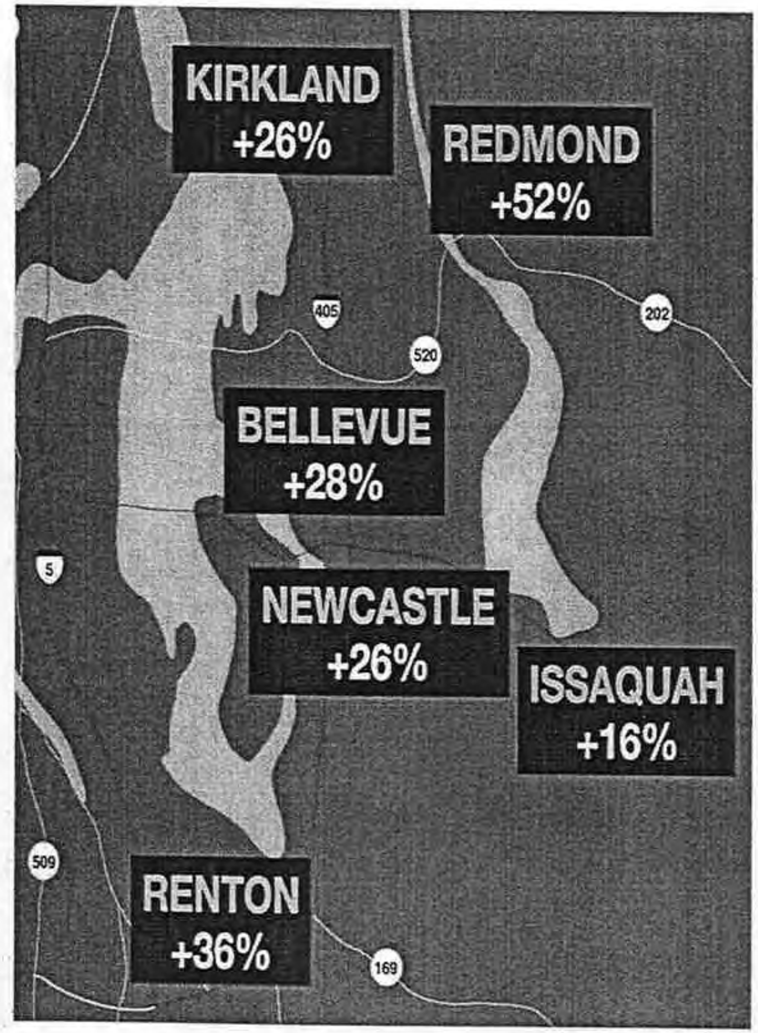
Newcastle



Growth is straining the system

Regional growth

- Population predicted to grow by more than a third
- Employment to grow 70% between 2012 and 2040



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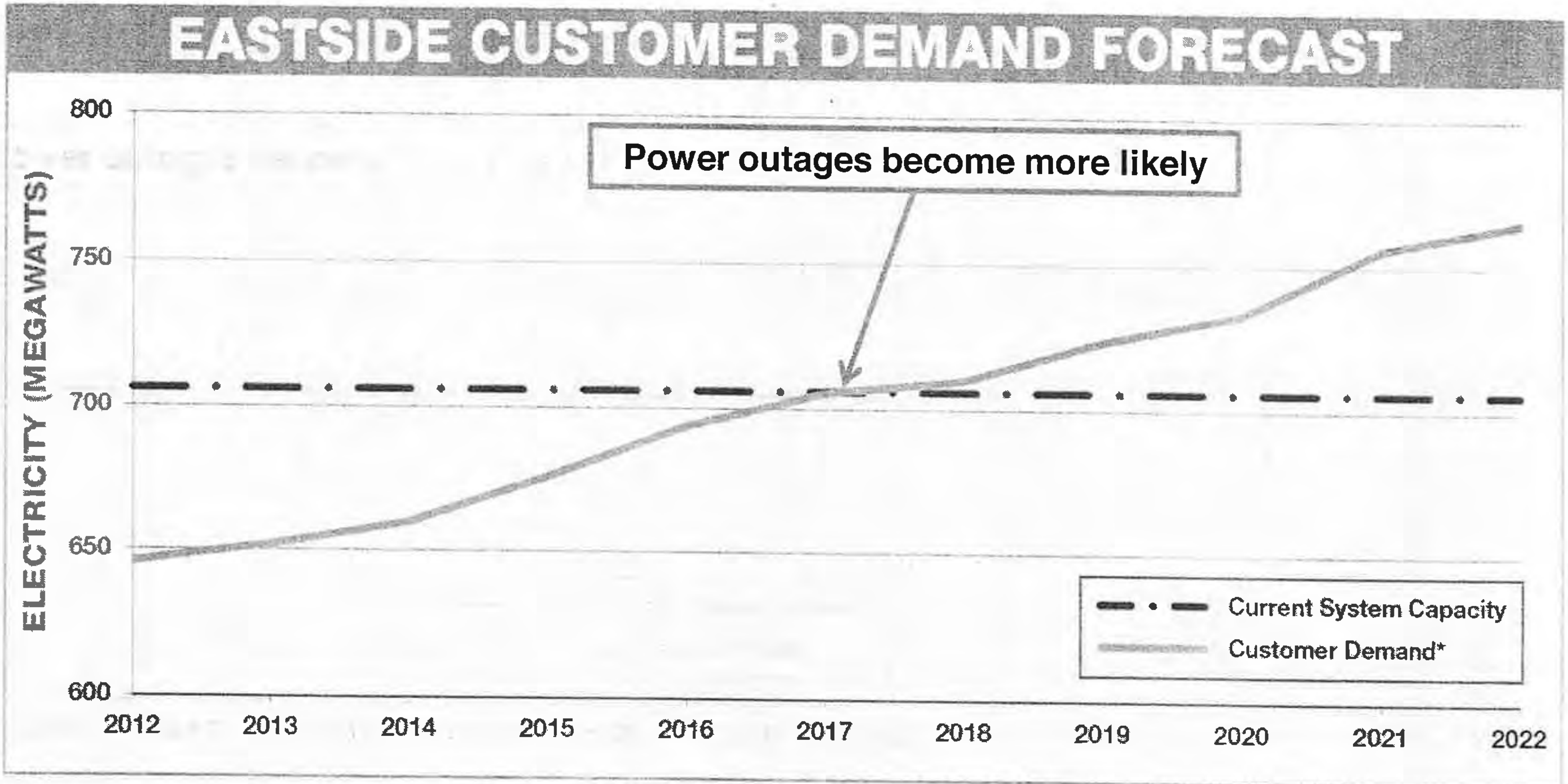
PSE PUGET SOUND ENERGY

DSD 009826

Customer demand



*Customer Demand assumes 100% of conservation goals are met.

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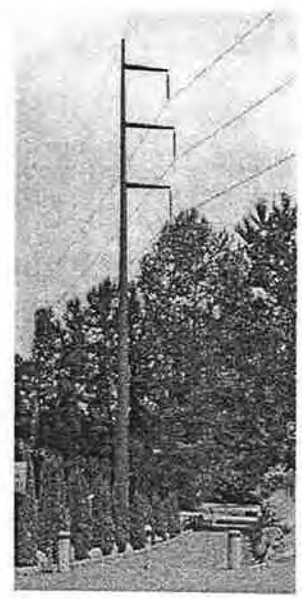
PUGET SOUND ENERGY

Conservation alone is not enough

Energy demand will be met through **both** increased, aggressive **conservation efforts**

And infrastructure upgrades needed to provide reliable power



 energizeEASTSIDE

PSE PUGET SOUND ENERGY

DSD 009828

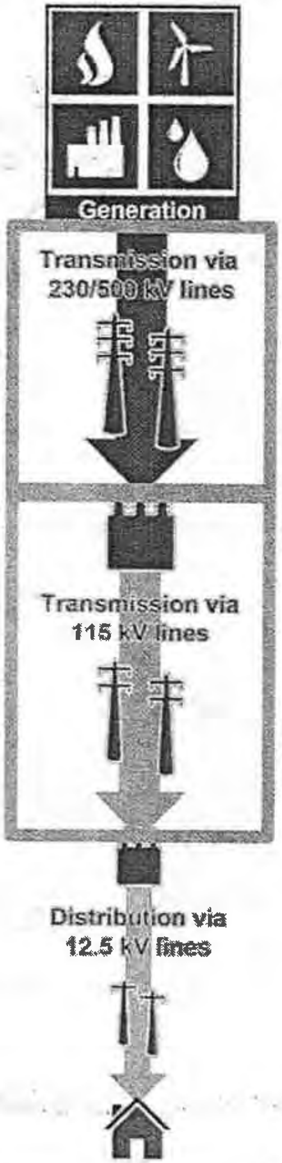
Our solution

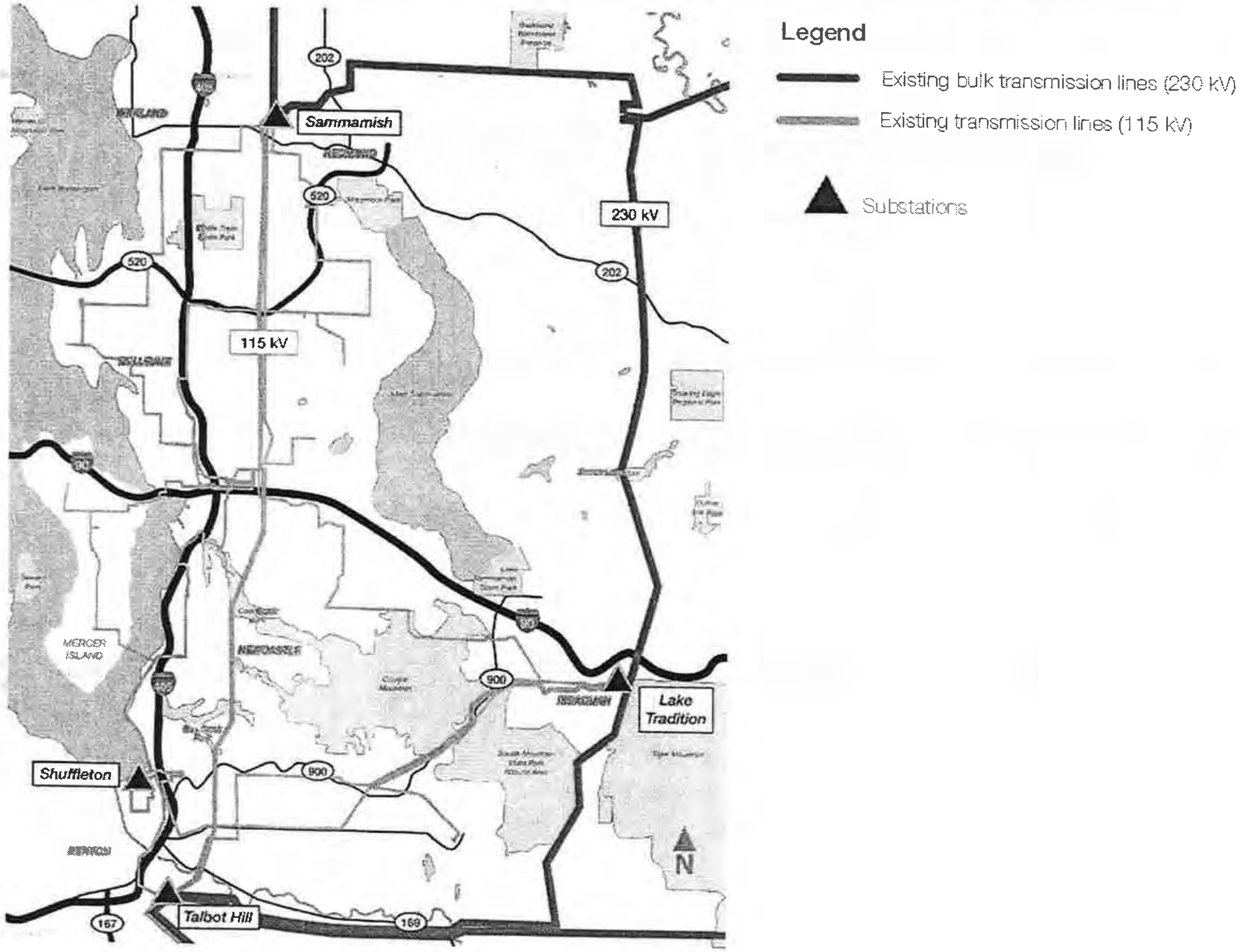
energize**EASTSIDE**

Builds approximately 18 miles of **new 230 kV transmission lines** and a **substation along the route** from Redmond to Renton

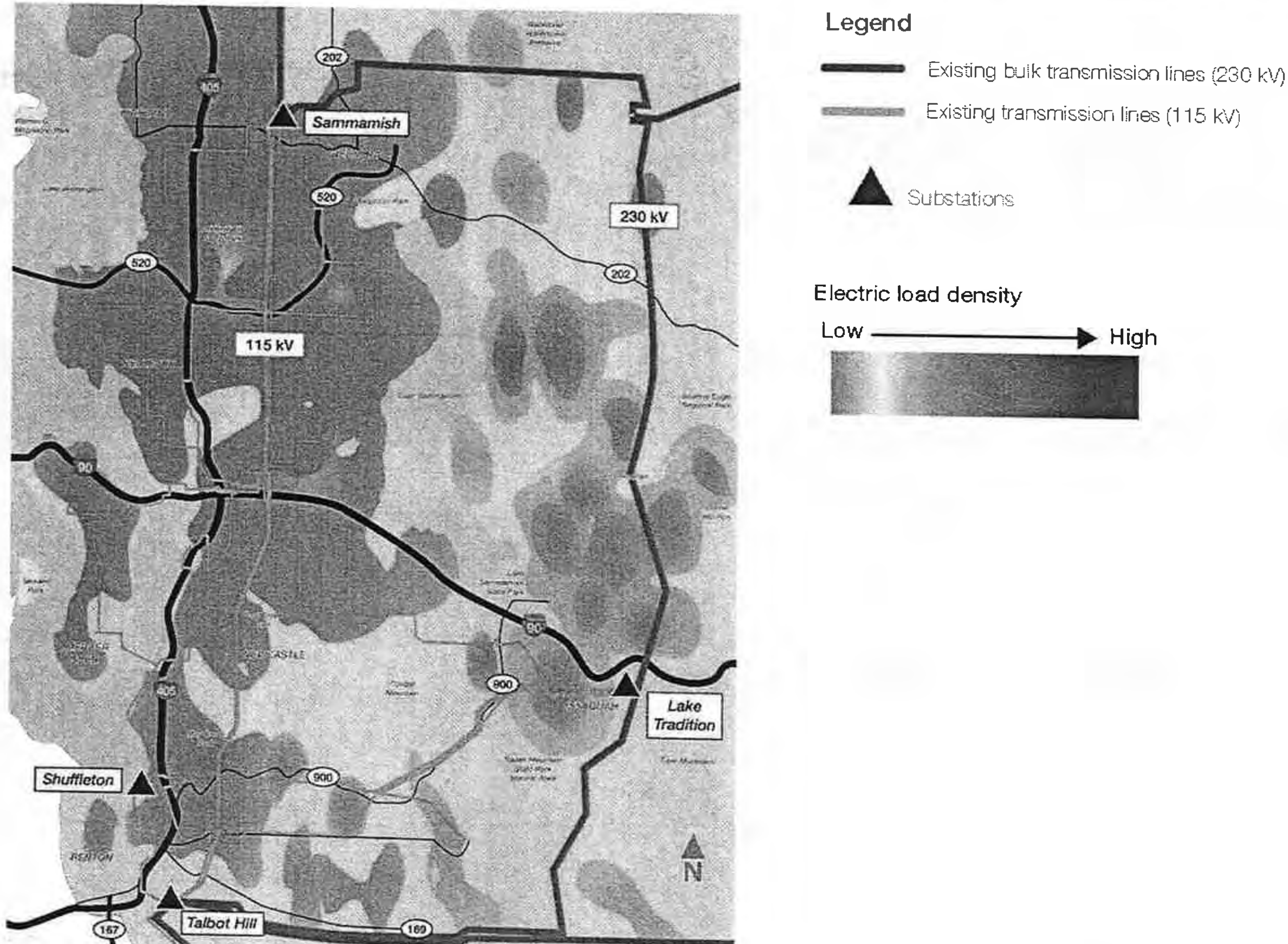
Supports the area's **growth**

How power gets to the Eastside





Where energy use is growing most



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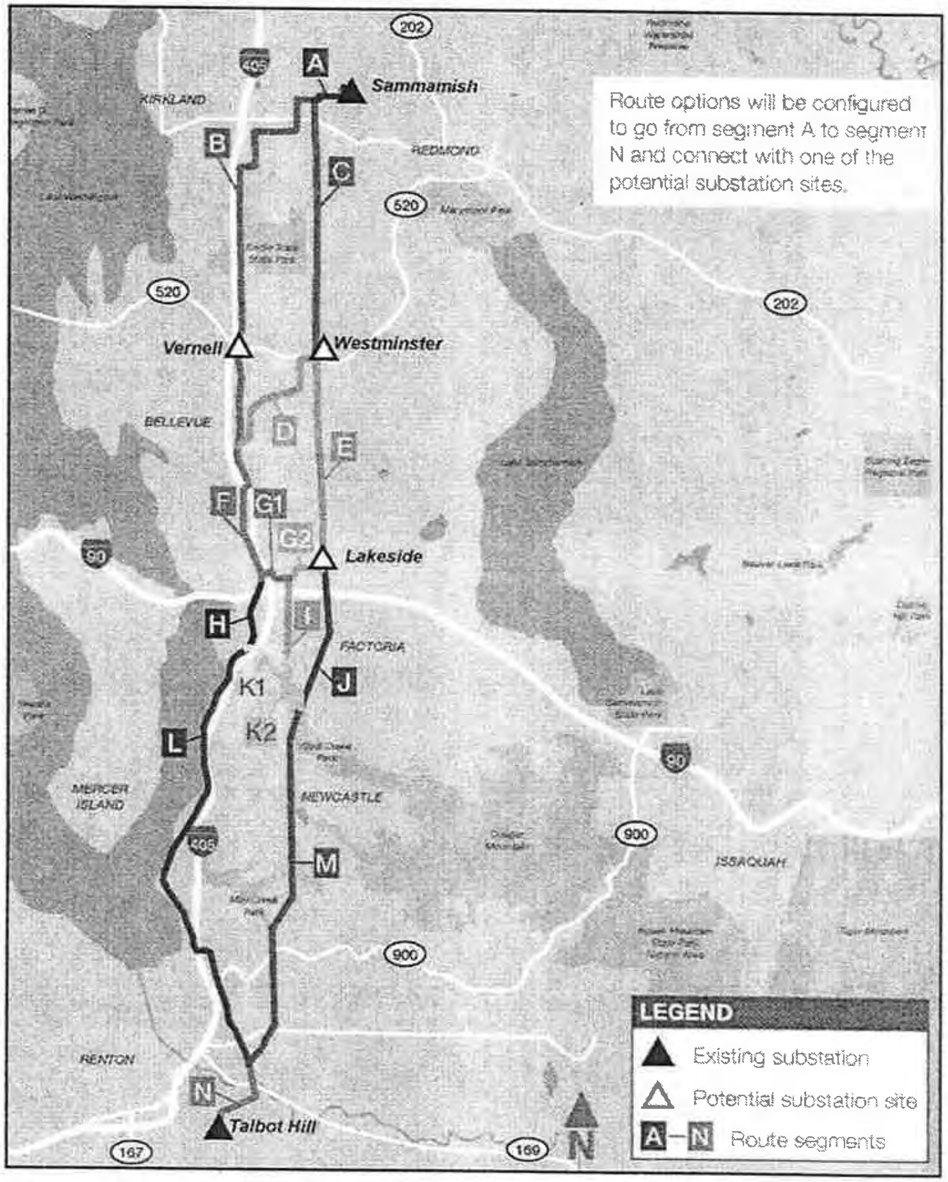
PSE PUGET SOUND ENERGY

DSD 009831

Potential route segments



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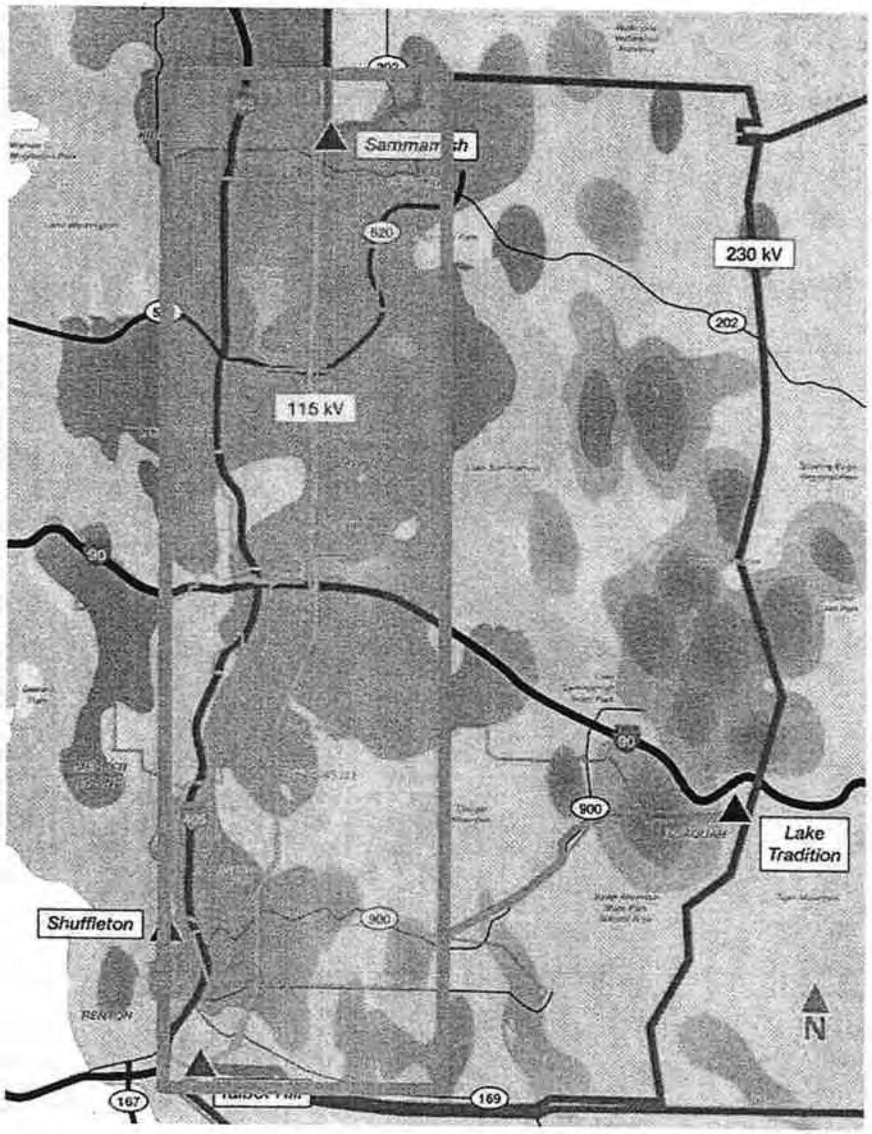
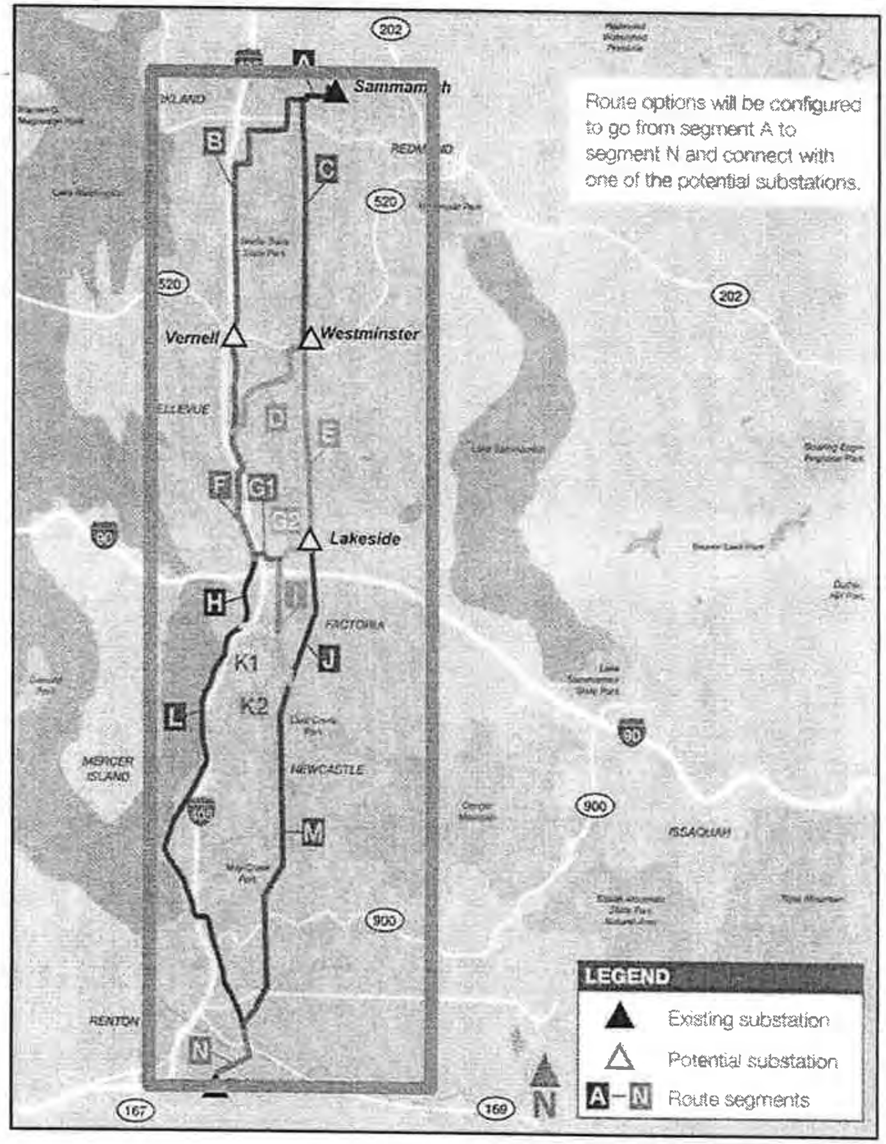
PSE PUGET SOUND ENERGY

DSD 009832

Bringing power to where it's needed





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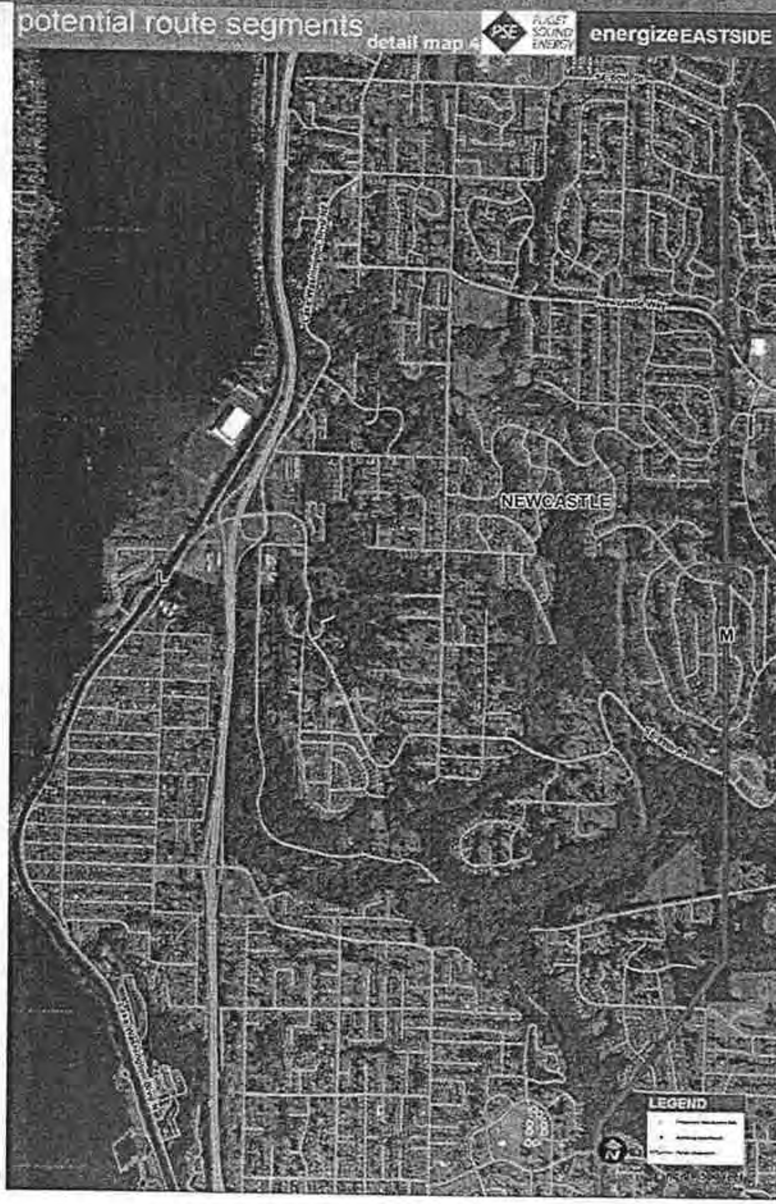
PSE PUGET SOUND ENERGY

DSD 009833

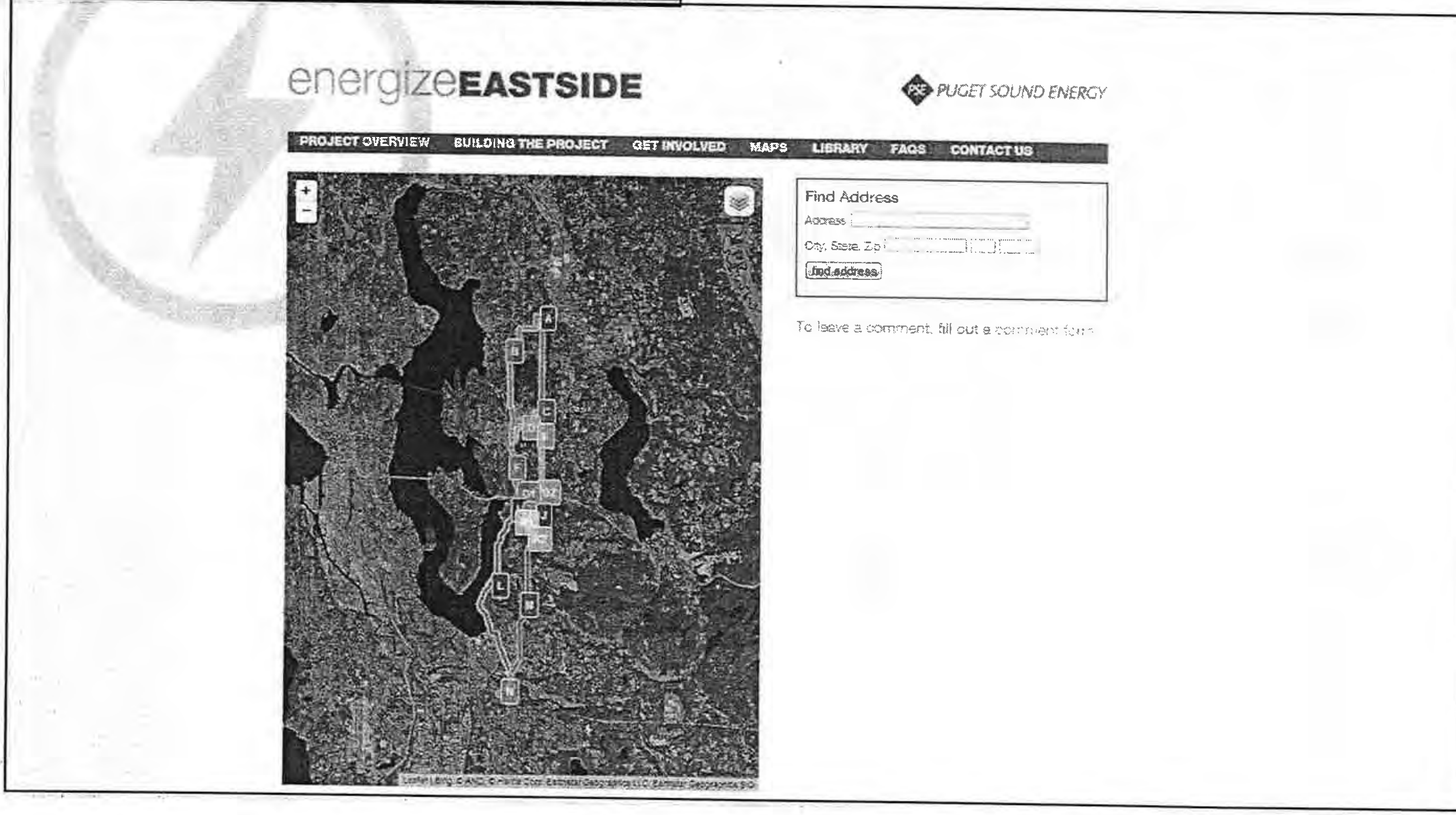
Potential route segments



DSD 009834

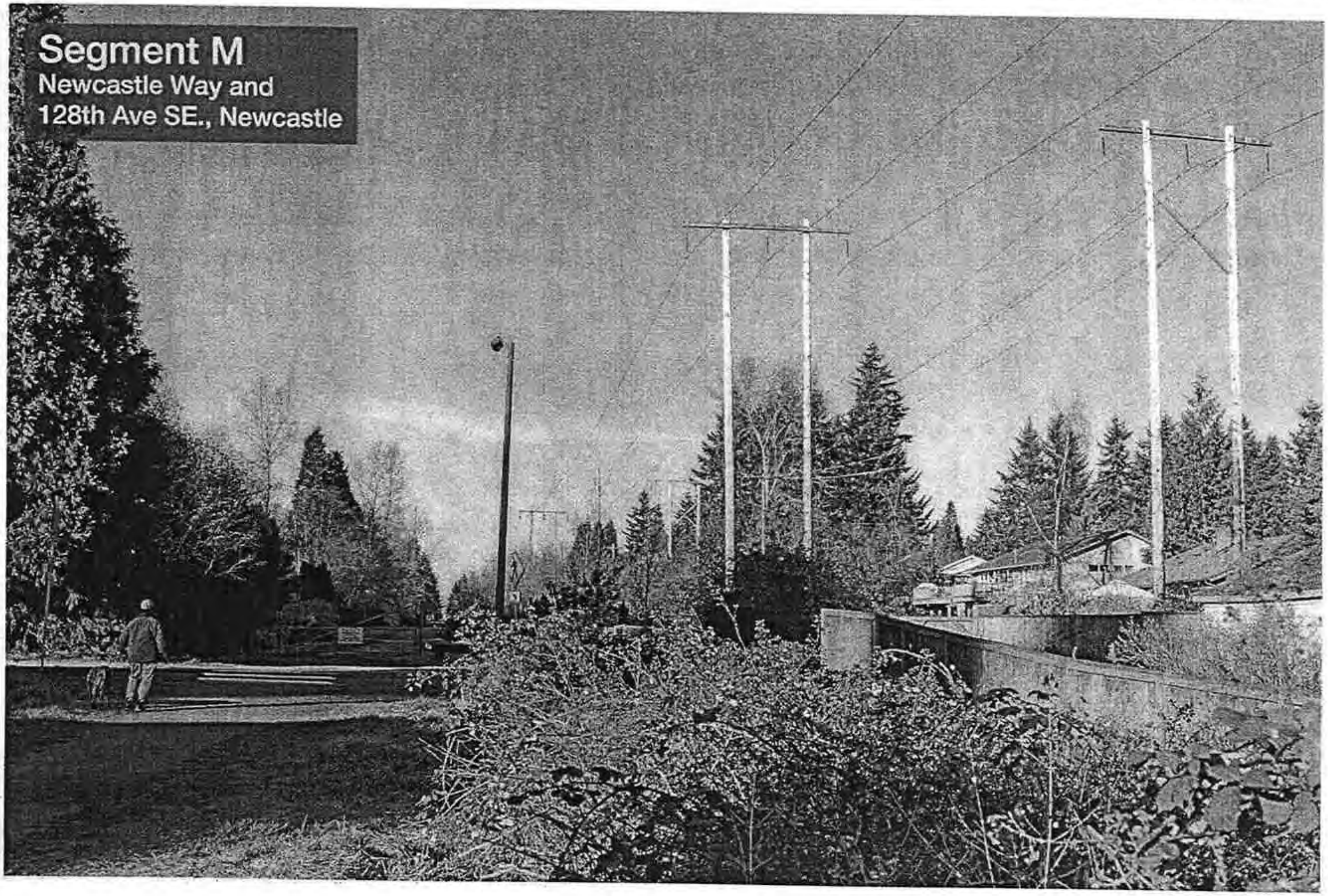
pse.com/energizeeastside

Interactive mapping tool



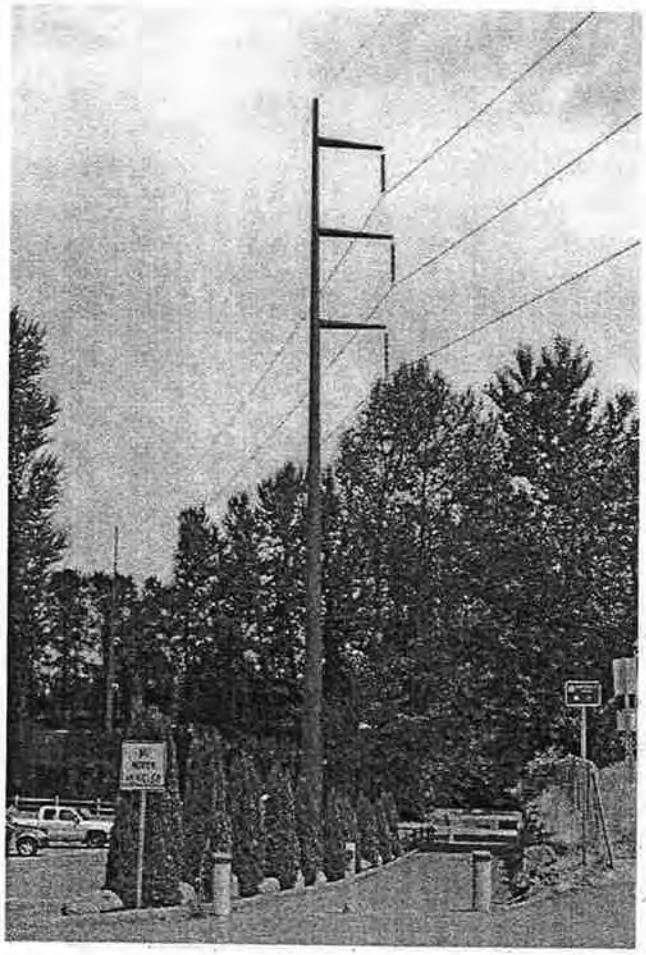
DSD 009835

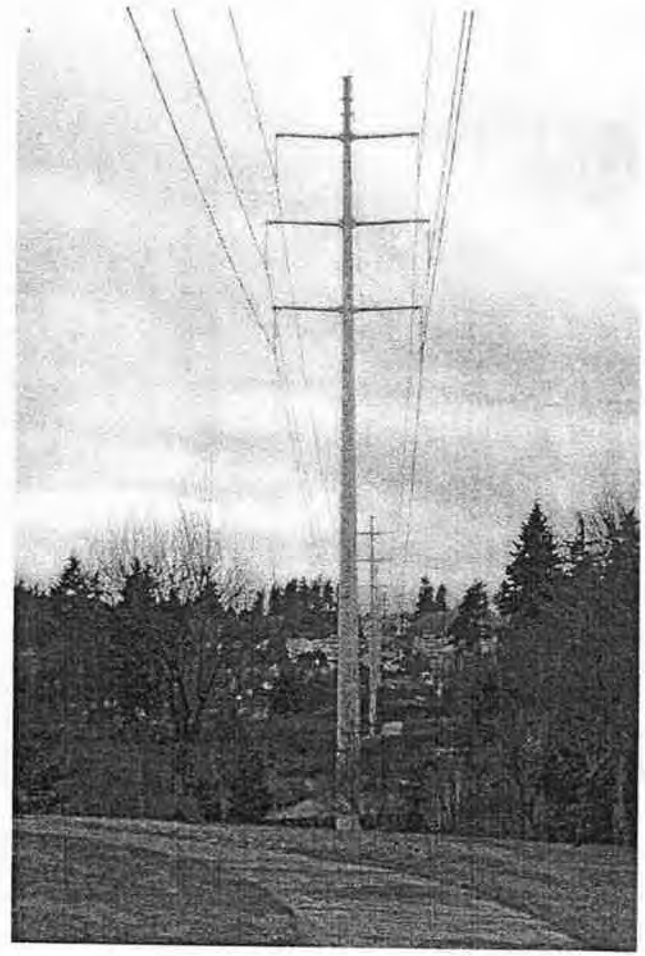
Segment M in Newcastle



Sample transmission lines

Pole height: 95 to 125 feet depending on topography
Span range: 400 to 700 feet depending on topography





How to be involved

Comments

Submit comments and questions

Mailing list

Join our mailing list

31

Calendar

Participate in community meetings

CAG

Observe Community Advisory Group meetings

Sub-Area Committee process

Community Advisory Group

- Looks across the entire project area for system-wide issues and concerns
- Relies on Sub-Area Committees for recommendations on geographic, neighborhood-specific issues and concerns
- Uses input to recommend route to PSE

Sub-Area Committee: Redmond/Kirkland

Sub-Area Committee: Bellevue

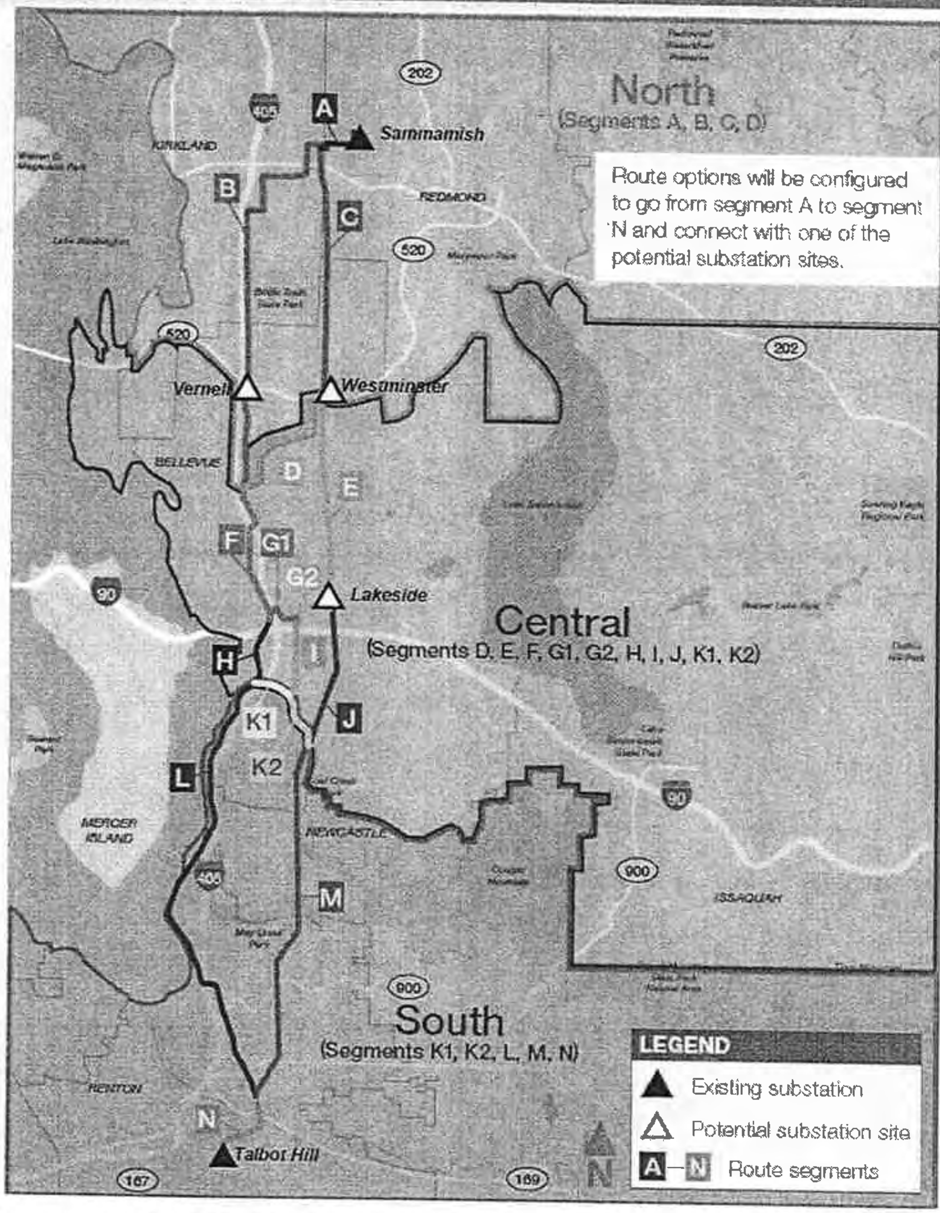
Sub-Area Committee: Newcastle/Renton

Sub-Area Committees

- Provides recommendations to the Community Advisory Group
- Includes a representative from each neighborhood affected by a route segment

Public Input

Sub-area boundaries



 energizeEASTSIDE

PSE PUGET SOUND ENERGY

DSD 009840

Upcoming Activities

- Sub-Area Committee Workshop # 1

  6:30 p.m. – 9:00 p.m.

  - **3/19/2014** North Sub-Area Committee
  - **3/26/2014** Central Sub-Area Committee
  - **3/27/2014** South Sub-Area Committee

- Sub-Area Committee Workshop # 2

  6:30 p.m. – 9:00 p.m.

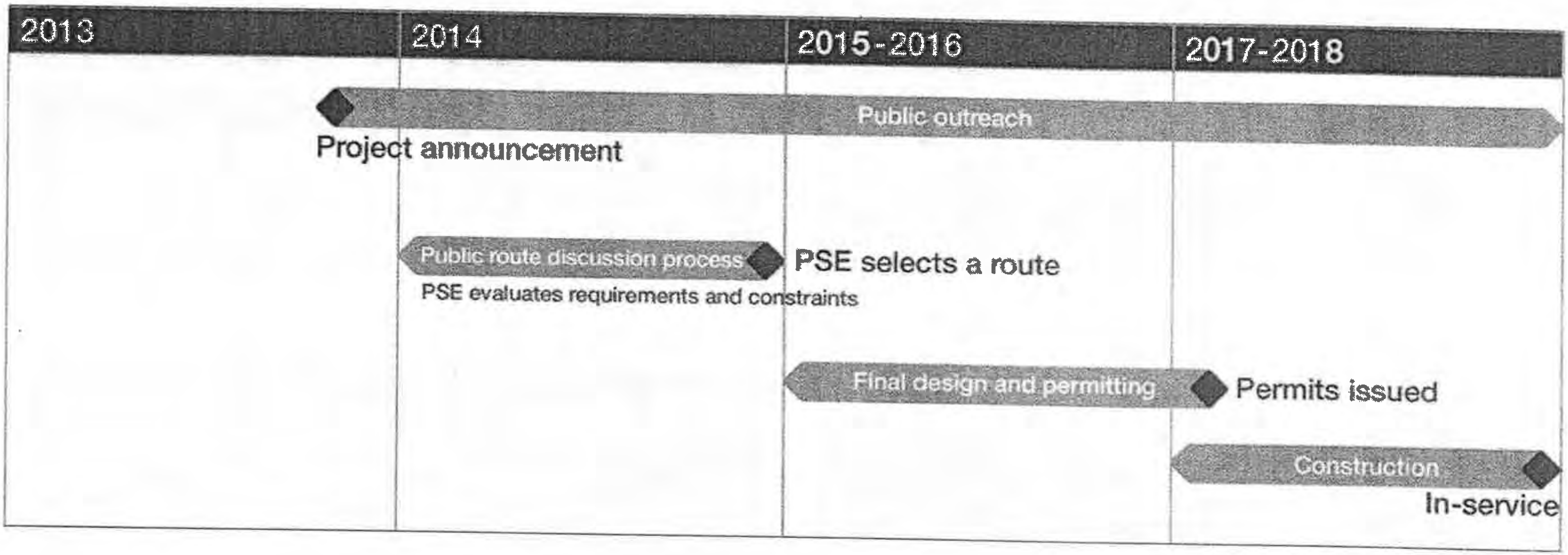
  - **4/16/2014** North Sub-Area Committee
  - **4/23/2014** Central Sub-Area Committee
  - **4/24/2014** South Sub-Area Committee

- Sub-Area Committee Meetings

  6:30 p.m. – 9:00 p.m.

  - **5/7/2014** North Sub-Area Committee
  - **5/14/2014** Central Sub-Area Committee
  - **5/15/2014** South Sub-Area Committee

Project schedule



Learn more about the project

PSE Contacts:

Leann Kostek, Senior Project Manager

Nate Caminos, Senior Local Government Affairs Representative

Stay in touch:

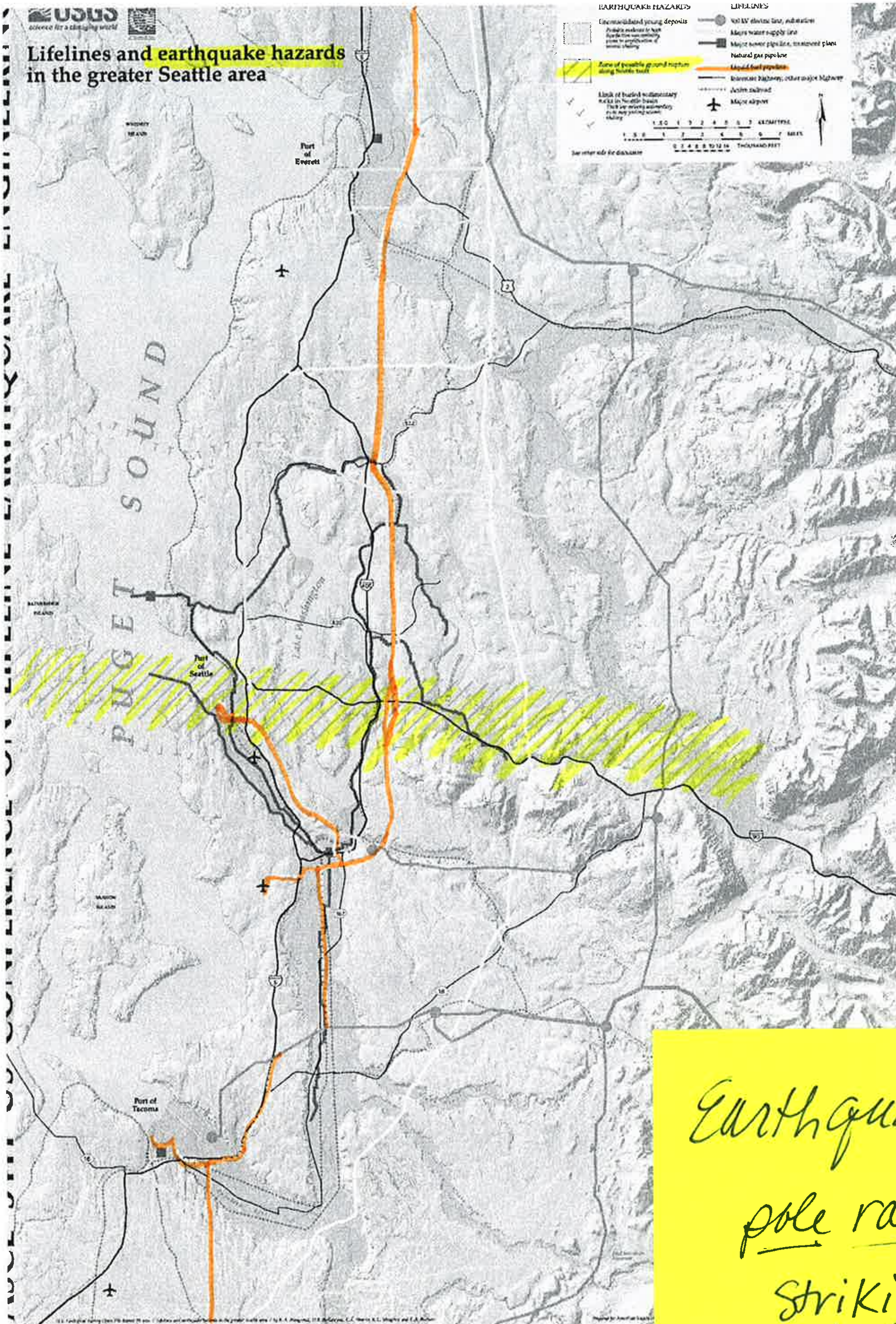
pse.com/energizeeastside

energizeeastside@pse.com

800-548-2614

Questions?

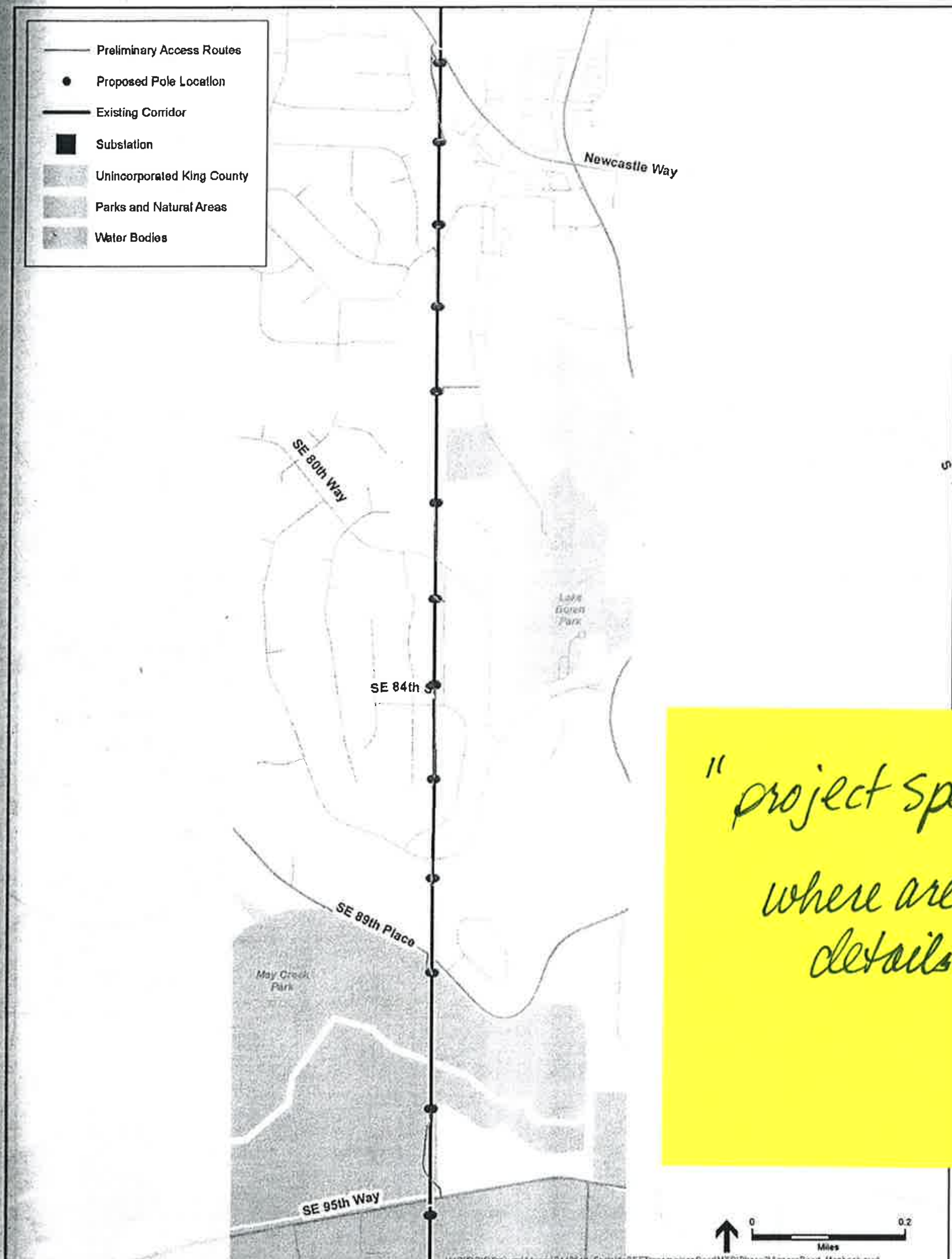
Questions?



Earthquake?

pole radius

Striking of pipeline and homes



Preliminary Construction Access Routes Prior to Property Owner Consultation – Newcastle Segment

"project specific"
where are the
details?

Renton/Newcastle
Public Hearing 5.23.17

The math doesn't add up in several places:

The new lines would involve 15(Willows 1) to 17(Willows 2) stream crossings.(3.3-21)in Central Bellevue alone. If you look at all segments the number is 20-22 excluding unnamed tributaries. ~~This will result~~ THE EIS STATES THAT THERE in WILL BE ~~the~~ removal "~~of~~ " **more than** 5,400 trees." (3.4-16). ~~They say~~ IT SAYS that 17-26% of trees will be removed per acre of area surveyed. However, they also state that they plan retention of at least 5,000 **inventoried** trees. (3.4-14). Another way of looking at the math is that if "inventoried" trees include those to be removed and those to be retained, then 5,400 out of 10,400 inventoried trees will be removed. That's **52%** of the inventoried trees.

There seems to be an even bigger discrepancy when you look at the data for each of the land segments. Of the 5,400 trees, 1,410(26%) are stated to be in critical and stream buffer areas (3.4-16). However, the math doesn't match up with the data in the subsequent sections (3.4.5.2 – 3.4.5.15). If you look at the individual segments, about 5,980 trees out of a total of 7,968 trees would be potentially removed (75%). 3,675 are considered significant trees (61% of cleared trees) and about 1,960 are located in critical or wetland buffer areas (about 33% of cleared trees). ~~It is stated in 3.4-16 that 1,410 of the 5,400 trees potentially removed are in critical and stream buffer areas (26%; not 33%).~~ THAT IS 550 MORE TREES REMOVED IN CRITICAL + BUFFER AREAS.

Either way, this loss of tree canopy and the accompanying loss of 327 acres of vegetation results in reduced shading over streams and changes water temperatures as well as robbing fish of the shade cover they use to avoid predators. This becomes important when looking at the stream designations. I didn't research all but I have data looking at the Coal Creek Basin as an example .

The preferred route for Energize Eastside retraces the existing path through this basin, even though these streams are now designated as a: "Core Summer Salmonid Habitat" for aquatic life use and "Extraordinary Contact" for recreational use according to the King County stream report updated in November 2016. The lower portion of Coal Creek has been assigned an additional "Supplemental Spawning and Incubation Protection". Any project is subject to the requirements of the Endangered Species Act.

The City of Bellevue describes this area as the *Coal Creek Natural Area* with "second growth forests, without a house in sight - echoing the wildness that once covered this area". The City further describes the creek as supporting habitat for Chinook, Rainbow and cutthroat trout, Coho, Sockeye and Steelhead. The creek provides "valuable fish and wildlife habitat, with dense forest protecting water quality and erosion"

I therefore strongly disagree with the assessments stated throughout 3.3 and 3.4 of the "less-than-significant" impact on water, trees and fish. Instead, the loss of trees and other vegetation would have a HIGHLY **significant** impact upon the streams and fish habitat.

RICHARD KANER
6025 HAZELWOOD LN SE
BELLEVUE, WA 98006

I AM A CENSE MEMBER

Sue Stronk
Renton/Newcastle
Public Hearing 5.~~24~~ 23.17

Sue Stronk
12917 SE 86th Place, Newcastle, WA 98056

I am Sue Stronk, a Cense member, and a 30 year resident of Olympus in Newcastle, supporting the "No Action Alternative".

(1) I submit tonight, a scaled drawing of a typical 230kV project as described in the EIS by AEP-Ohio—with 120-150' right of way. And, I also show the Energize Eastside solution—using the existing 100' ROW—where the project cannot be centered because of the 2 Olympic pipelines. EE puts the 100' tall poles within 20 feet of our homes following the Newcastle Code requirements. The EIS states: PSE could apply for a variance, as PSE admits it may not be feasible to build it here— or they could underground the lines—which better NOT be at the citizens' expense.

(2) PSE replaced a wooden pole behind my house and suggested I not be home that day. Each new pole requires 3-7 days for installation over a 2 month time frame. What mitigation is there to homeowners who "should evacuate for safety" during construction? As you see, these poles are well within falling distance of homes as well as the foundations could fracture the pipeline.

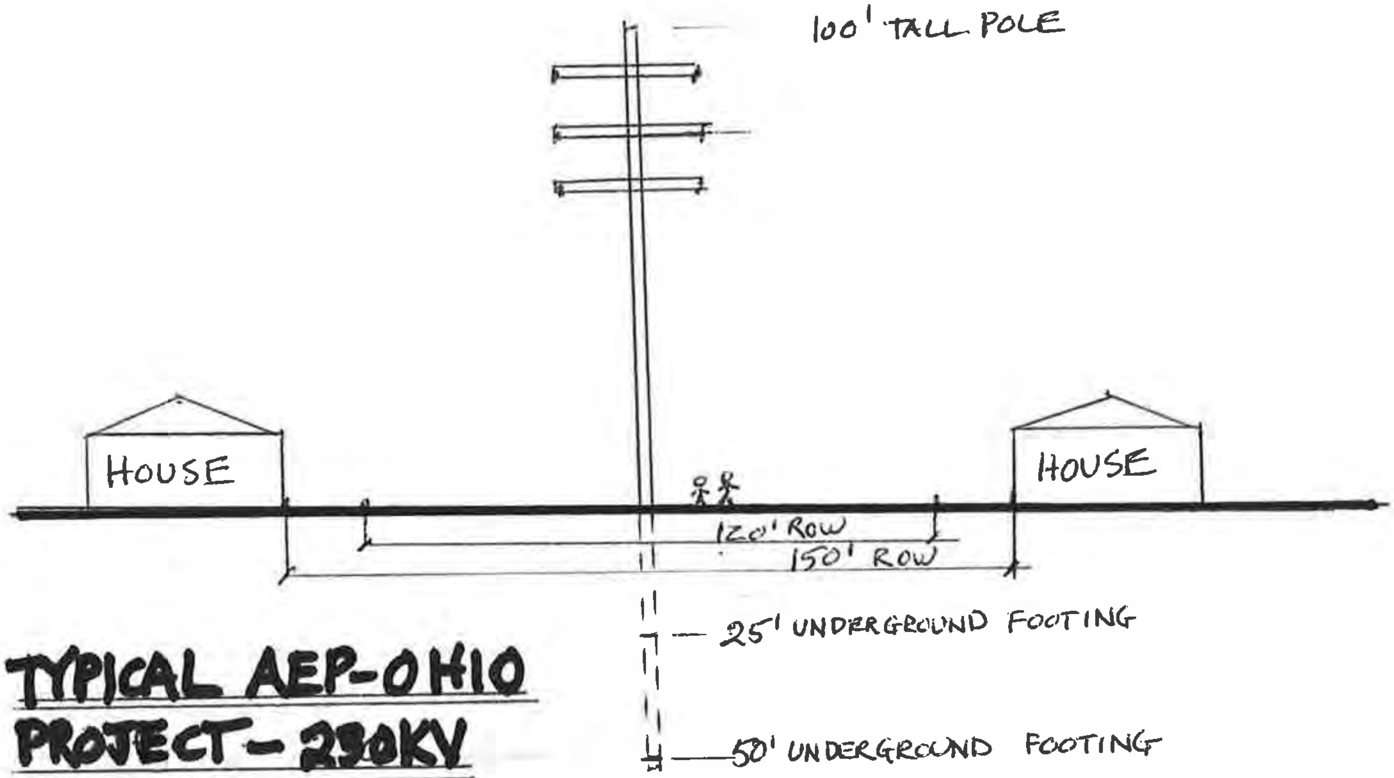
(3) How can PSE's paid consultants also be the authors of the EIS documents? Is that not a conflict of interest?

(4) PSE says we face "rolling blackouts" soon—yet 1 or 2 of the 5 existing transmission lines can be shut down for 12-18 months during the construction of EE without any "scary" consequences?

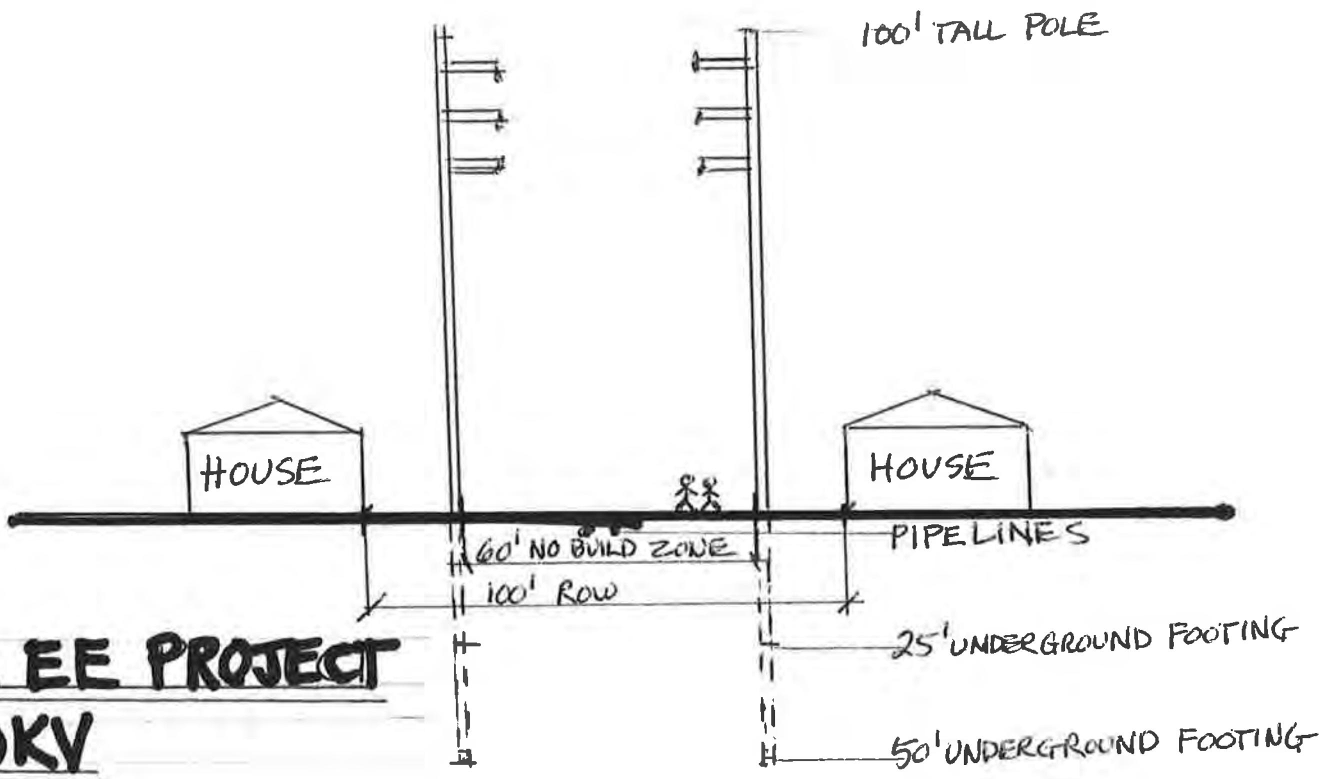
(5) Photo simulations were not updated showing the 100' tall poles now proposed in Newcastle, and many photos are not accurately scaled in the EIS. Locations do NOT represent the true visual impacts of the project and do not show the other 2 wires that will be on each pole— the fiber optic and shield wires— a total of 4 or 5 wires on each pole not just 3.

(6) The consequence of a 10% home devaluation was a "hypothetical study" of Newcastle's 89 homes adjacent to the project resulting in an value decrease of $116K per home and a $20K tax deficit for our city. The EIS says that is "less than significant" because Newcastle could easily raise taxes $5.27 annually from each Newcastle home, or the city could reduce budgets. Tell us again—that a $100K loss in home value is "not significant" when PSE profits over a billion dollars at our expense building this project!

SCALE 1/8" = 5'-0"



TYPICAL AEP-OHIO PROJECT - 230KV



PSE EE PROJECT 230KV

Bellevue Public Hearing
5.25.17
Phase 2 DEIS

Sue Stronk *12917 SE 86th Place* Newcastle Wa 98056 5/25/17 EIS

I am a CENSE member and support the "No Action Alternative.

This EIS is flawed and tainted by PSE's influence and should be stopped now and re-started. I realized this myself—but it is conveniently stated in writing in Chapter 2-page 20: in describing PSE's public outreach it says: —"In 2014 PSE convened the Energize Eastside Community Advisory Group (often) referred to as the "CAG" ". One of those PSE contractors hired, in that CAG process, has it's name throughout this EIS document. They are credited on every "before and after" photo simulation, gave data on EMF, and quoted outdated under-grounding costs. This company was hired and paid by PSE in the CAG process, and then hired and paid again by ESA who prepares this document—which ultimately is paid for by PSE. This data needs to be unbiased and fair in the content or it becomes invalid for analysis.

The word "significant' describing impacts is rarely used in this document. However, under the "scenic views section" describing Newcastle (page 3.2-77), it states the impacts would be "significant" right beside my house. It says- "the poles would almost double in height and be closer to neighboring residences making a strong contrast with the existing. It would also be in conflict of the Newcastle Comprehensive Plan that calls for transmission lines to be sited and designed to minimize visual impacts to adjacent land uses." I would like to note, these same "significant" impacts that I will experience beside my house- will be true for so many others along this project. But here, where "significant impacts" are described— you don't see any "before and after" photos. The photos simulations for Newcastle have not been updated to represent the 100 foot tall poles now proposed for our area.

I have 2 other requests:
"AC current density"—above 20 amps can cause pipe corrosion. The EIS says there are "2 short segments" with readings of 22-35 amps currently. Define these locations where pipelines could be corroding today.

What exactly is the use of the fiber optic cable and does PSE profit from it?

Seattle City Light faces millions in lost revenue

by: **BY MYNORTHWEST.COM** Updated: May 31, 2017 - 6:12 AM

SEATTLE - Seattle residents are using energy quite efficiently. That is bad news for Seattle City Light, which is facing a revenue shortfall worth millions. Between 2012 and 2016, Seattle City Light did not recover $133 million in revenue that the city council had planned for.

City Light's excess revenue goes into a reserve account for such shortfalls. If that account drops below $90 million, a 1.5-percent surcharge is placed on customers' bills to fill it back up. That happened in January.

"This is not a phenomenon that's unique to City Light, it's a phenomenon being experienced across the country," Seattle City Light CFO Paula Laschober told a council committee recently. "Energy use peaked in 2007 and since then has been declining."

At the council's Energy and Environment Committee meeting, members were briefed on the shortfall. Tony Kilduff with council's central staff explained that the city generally sets revenue collection goals in its strategic plan. This ensures the revenue collected covers the cost of energy.

"... That has not been happening over the last few years, not because of under-collecting in the sense of not collecting money from the customers, but the customers are consuming considerably less," Kilduff explained.

Seattle City Light lost revenue

But energy efficiency is only part of the issue. There are a few factors that add up to the declining revenue.

• Mild winters: Winters have not been as frigid for Seattle in recent years. That translates into lower energy bills during the winter when use is typically higher.

• Wholesale energy prices have fallen: Seattle makes much of its own energy with hydroelectric generators. The city often makes more energy than it needs and sells off excess to other utilities. But prices for that energy have gone down.

• Forecasting energy demand: Seattle overshot its forecasting of energy demand by 2-4 percent, meaning it expected to sell more energy to customers than they ended up using in recent years.

Laschober explained that conservation programs and efficient technology have also drawn down on the need for electricity. Energy use has decreased in Seattle's residential areas more than anywhere else – those areas account for a third of consumption, but add up to 57 percent of the lost revenue. Laschober notes that LED lighting, which uses less energy, was 1 percent of sales in 2011. In 2015, it was 24 percent.

Seattle City Light's solution to the issue has been to start the 1.5 percent surcharge to recharge its reserve account. The utility has also brought in a consultant to analyze its forecasting system.

Laschober said that the utility will have to stop relying on data for past customer trends when it predicts future demand. That data doesn't account for newer conservation programs, technology, or weather. Instead, the utility will rely on what is called "end-use-data," which considers the other factors.

Fingers are crossed at Seattle City Light because the utility is expecting energy use to continue to decline.

"All of the things we are seeing on the horizon are indicating that there is likely to be even less demand at the retail level for energy," Kilduff said. "We have ongoing improvements in energy efficiency components, not just LEDs; solar panels have become more cost effective because of all the subsidies provided for them, they are also becoming more efficient. And as battery technology has been improving, this is leading to the likelihood there will be less and less retail demand."

"Unless we can find a way to boost it for some good purpose," he said. "One really good purpose would be displacing gasoline consumption if we could figure out a way to do that – if the state would let us."

Bellevue Public Hearing 5.25.17

EIS ORAL COMMMENTS 05/25/2017: Janis Medley • 4609 Somerset DR SE • Bellevue WA 98006

I had several questions I hoped the EIS would answer.

The first:Approximately how many poles would be on the preferred route.

I found the answer by adding up the number of poles indicated in the construction summaries in chapt 2. My finding 162 poles

My second question was: HOW will the poles be installed - how many would be directly embedded in the ground and how many would require concrete foundations.

Page 2-49 states: approximately 160 -180 CONCRETE pole foundations would need to be installed along the 18-mile route.

That stopped me in my tracks. If there is a TOTAL of 162 poles on the preferred route and 160+ concrete pole foundations are needed, then ALL of the poles would be on concrete foundations. If that's the case, then why not say so?

The other possibility is that the number of concrete pole foundations needed is NOT correctly stated in the EIS.

By this point I was curious to know how deep a hole is required for directly embedded poles.

I found that answer in Appendix A-5 which states: pole depth = 10% of pole height + 2 feet. So a 90' pole requires an 11' deep hole. In contrast Page 2-49 states a concrete foundation requires a 25-50' deep hole filled with concrete and rebar. That's why it is important to know HOW poles will be installed

I suggest that the Final EIS include type of installation in the Summary Charts

I have many more questions, BUT will submit them later in writing.

I want to close by saying that Energize Eastside is a symptom of a much larger problem. That larger problem is inadequate regulation of our state's utilities. If the WA state utilities and transportation commission had the authority to evaluate the NEED for a project, we most likely would not be here tonight. WE would not have spent three years of our lives identifying the dangers of colocating EE with the olympic pipeline and researching the environmental degradation of this project on our communities. Perhaps the ONLY environmental benefit of Energize Eastside is: that it has awakened many ratepayers to the need for regulatory reform.

Belleve Public Hearing
5.25.17
Phase 2 DEIS

My Name is Mike Abel. I live at 4401 138th Ave SE in Bellevue.

I would like to express my opinion that the Phase II EIS fails to adequately address the safety concerns of co-locating the proposed Energize Eastside power lines with the existing Olympic Pipeline.

Section 3.9 of the EIS is presented as a smorgasbord of Federal rules and regulations dealing with pipeline construction and operation. It appears to be intended to convey the message that adequate safeguards exist to ensure safety both during and after construction. I would like to point out that most of these regulations have been in place for decades. Over the years these long standing rules and regulations failed to prevent numerous leaks and explosions.

They failed to prevent the 1989 San Bernardino explosion.

They failed to prevent the 1999 Bellingham explosion.

They failed to prevent the 2010 San Bruno explosion.

They failed to prevent the 2015 Fresno, California leak and explosion.

They failed to prevent the Colonial Pipeline explosion in Alabama in late 2016

Time does not permit me to list all of the incidents.

The Pipeline & Hazardous Material Safety Administration tallied 2,700 incidents in the period from 1990-2009. Of those incidents, approximately 3% or 81 were classified as "serious" with "serious" being defined as involving fatalities and/or injuries requiring hospitalization.

Further, The PHMSA sought to classify the cause of these incidents. The number one cause is documented to be damage related to excavation.

PSE is proposing t to build up to 18 miles of 230KV lines co-located with the Olympic pipeline. Using conservative estimates of pole spacing of 800 feet. This equates to approximately 120 foundation excavations adjacent to the gas pipeline. That's 120 opportunities to damage or degrade the pipeline. This does not even consider the options where two poles are required to straddle the pipe, in which case the number of excavations doubles.

Those issues over which we have some degree of control.

Now shifting gears to things we cannot control...

The EIS fails to address the possible effects of Seismic activity in the region. It is well documented that the Seattle fault bisects the City of Seattle and continues East through Bellevue roughly along the I90 corridor. The collocated power lines and pipeline cross this fault perpendicularly. We have all heard about the possibility of the "Magnitude 9 Megaquake". A temblor of this magnitude would certainly have disasterous consequences to the combined pipeline.power line but to be honest. If we ever get the "big one" we will likely have even far greater issues to deal with. A more likely scenario is a moderate earthquake along the lines of the magnitude 6.7 Nisqually earthquake in 2001. Subsequent to that event, the Earthquake Engineering Research Institute conducted an analysis too predict the effects of similarl 6.7 magnitude earthquake should it occur along the Seattle fault. The results of this analysis were published in 2005 in a report entitled " Scenario for a magnitude 6.7 Earthquake on the Seattle Fault". This document specifically identifies the Olympic Pipeline as being at risk for rupture in such a moderate magnitude earthquake.

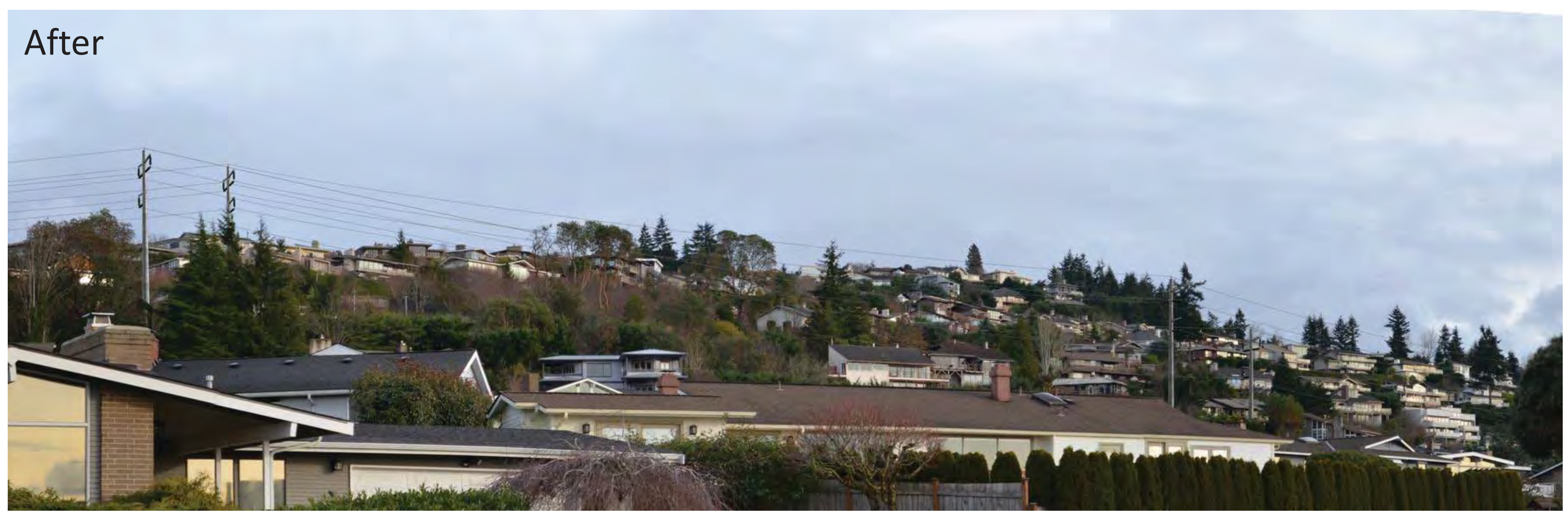
In closing, I refer to the headline of an article that appeared in the January 27th, 2017 Seattle times. It reads:

Washington's 30-year earthquake drill for the 'Big One": Order Studies. Ignore them. Repeat.

In my opinion, this EIS's lack of attention to the seismic hazards of the region is exactly the kind of action that the Seattle times author had in mind when he penned that headline.

Somerset Hill North Panorama

Somerset Hill South Panorama



Tyee Middle School Ballfield

Before

After

Before

Kelsey
Creek
Farm

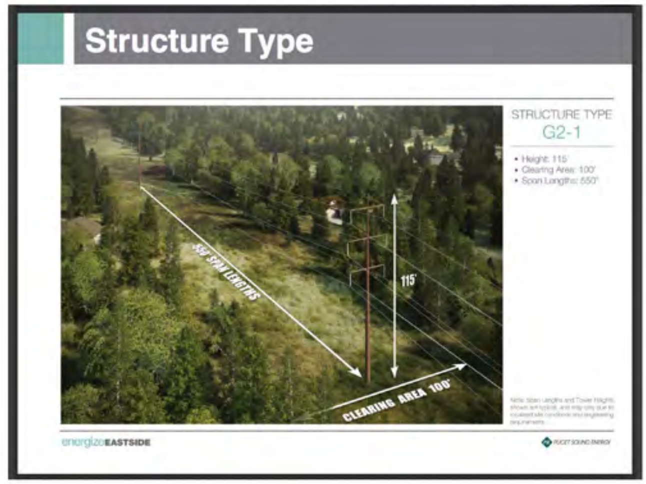
After

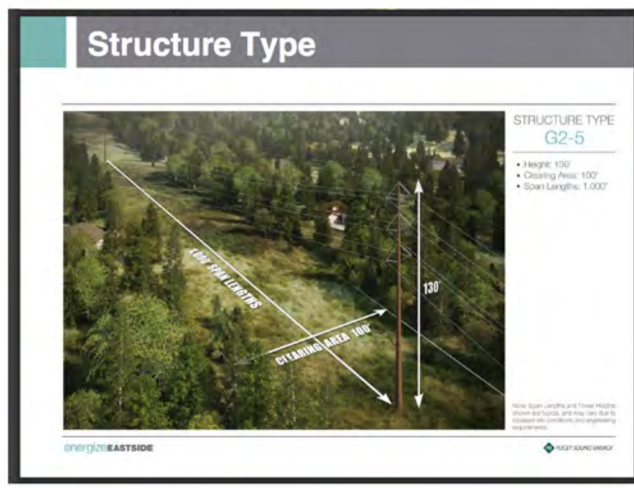
Forest Hill Park

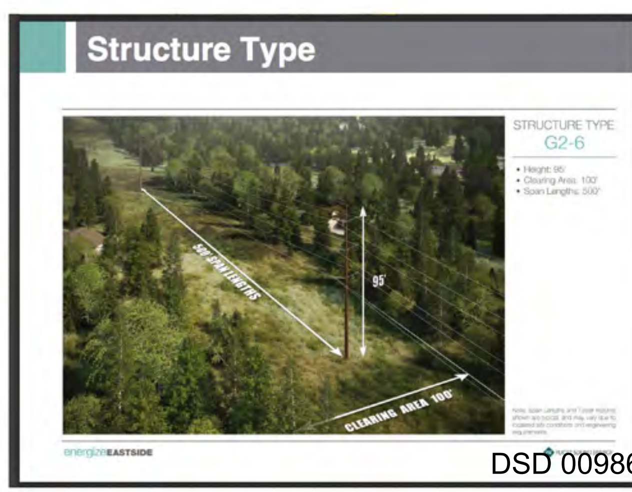
Before

After

PSE Conceptuals for Segment C





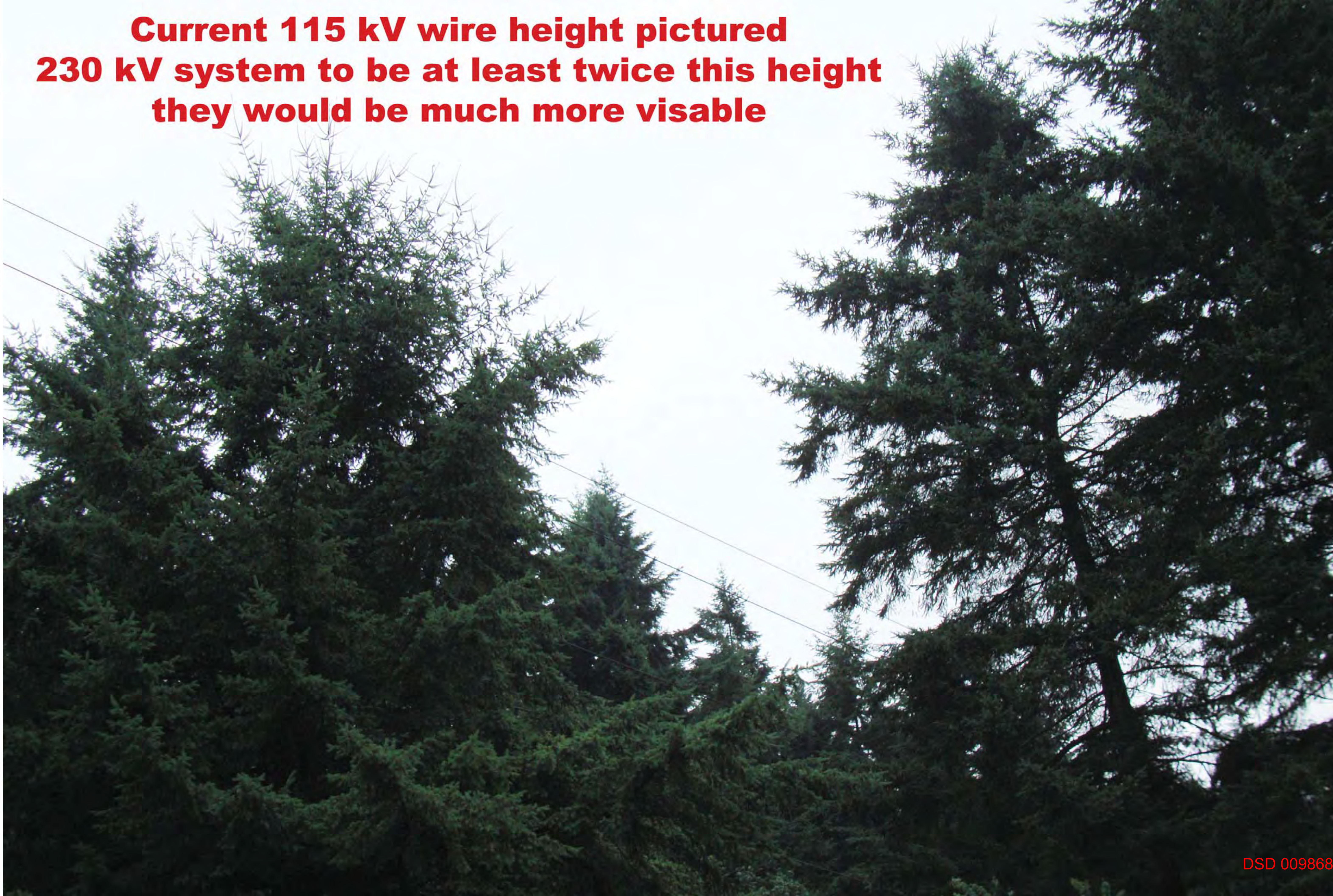


DSD 009862

DSD 009864

DSD 009865


Current 115 kV
pole height
DSD 009866


Current 115 kV wire height pictured
230 kV system to be at least twice this height
they would be much more visable

50’ between the center of the systems (center is represented by the dotted white line)

This document from PSE
25 ft from each center to the outside
100 ft wide total

50' between the center of the systems (center is represented by the dotted white line)

Aerial View Map of Energize Eastside Route Bypass Route Selection(s) along with current Transmission Lines

Current PSE 115v Transmission Line
Current SCL 230v Transmission Line
Proposed PSE 115v Transmission Line – Bypass Option 1 Alternative
Proposed PSE 115v Transmission Line – Bypass Option 2 Alternative

Bypass Route	Street	Poles	Street Crossings	Bypass Route	Street	Poles	Street Crossings
#1, #2	NE 20th Street	4	0	#1, #2	120th Ave NE	8	4
#1, #2	132nd Ave NE	5	1	#1, #2	Eastside Trail	7	2
#1, #2	Bel-Red Rd NE	7	1	#1	Lake Hills Connector	13	3
#1, #2	124th Ave NE	2	1	#2	Lake Hills/Richards Rd	18	1
#1, #2	Bel-Red Rd NE	4	1	#2	SE 26th Street	6	3

#1	**Total**	**50**	**13**	**#2**	**Total**	**61**	**14**

Brian Elworth
8605 129th CT SE
Newcastle 98056

The following questions and statements are on behalf of myself and residents and organizations impacted by this project.

What are Bellevue's standards of ethics regarding its EIS lead agency responsibilities to citizens in the region affected by the Energize Eastside EIS? What are Bellevue's criteria for assessing compliance with its standards of ethics? What is Bellevue's assessment of its compliance against its ethics compliance criteria regarding the Energize Eastside DEIS?

Since there are numerous false statements and omissions in the DEIS and since those false statements and omissions bias the DEIS in support of Alternative 1 and against other, superior alternatives, will Bellevue reissue a corrected DEIS or a supplemental DEIS to address the deficiencies in the DEIS? If not, why not?

First paragraph page FS-i – The DEIS states: "*The project involves improvements to PSE's electrical grid in the Eastside area of King County, Washington, to address a deficiency in electrical transmission capacity.*" Why does Bellevue assert a deficiency exists in electrical transmission capacity exists when there is no credible evidence supporting that claim? On what evidence is this claim based? Why does Bellevue accept a study on electrical transmission line capacity that is not based on sound requirements from governing agencies? Why does Bellevue allow overstated power demands, well beyond governing standards in the analysis of electrical demand? Why does Bellevue consider power siphoned off to Canada as a required load for PSE when no such demand needs to be considered as a PSE requirement?

Third paragraph page FS-i – The DEIS states: "*The purpose of the project is to address a projected deficiency in transmission capacity resulting from growth in electrical demand, which could affect the future reliability of electrical service for the Eastside.*" Why does Bellevue assert a deficiency exists in electrical transmission capacity exists when there is no credible evidence supporting that claim since there is not adequate generation capacity to meet the claimed shortfall? On what evidence is this claim based since it doesn't address the generation capacity shortfall?

Fourth paragraph page FS-i – The DEIS states: "*This Phase 1 Draft EIS evaluates the proposed 230 kV improvements as well as alternatives to PSE's proposal.*" Why were the other alternatives identified in the verbal and written record rejected? What criteria was used? What assumption were made? Did Bellevue enlist independent electrical engineers and other technical experts to evaluate the alternatives? What are their credentials? Is PSE's technical incompetence sufficient rationale for rejecting a well-established, technically feasible, and compliant alternative?

Page fs-ii – The DEIS states "*The new transmission lines may be entirely within existing utility easements…*" Why is corridor M through the Olympus community in Newcastle considered in the proposed route since the existing ROW is too narrow to safely support alternative 1 option A? Does Bellevue consider the safety risk of Newcastle residents not worthy of consideration in promoting PSE's proposed alternative? If not, explain the discrepancy between the statement from the DEIS quoted above and the impacts resulting from safety mitigations requiring proper physical separation between the proposed transmission line and the hazardous liquid pipeline.

Page 1-1 last paragraph – The DEIS states: "*This set of facilities is proposed in order to address a deficiency in electrical transmission capacity during peak periods that has been identified by PSE through its system planning process. This deficiency is expected to arise as a result of anticipated population and employment growth on the Eastside, and it is expected to negatively affect service reliability for Eastside customers within the next few years. The project would improve reliability for Eastside communities and would supply the needed electrical capacity for anticipated growth and development on the Eastside.*" Why is this stated as fact when is it is merely an opinion? Why are unsupported opinions stated as fact?

Washington Administrative Code WAC 197-11-400 "*An EIS shall provide impartial discussion of significant environmental impacts and shall inform decision makers and the public of reasonable alternatives, including mitigation measures, that would avoid or minimize adverse impacts or enhance environmental quality.*" The EIS is essentially a research document. Its purpose is to serve as an organized consolidation of factual information related to the environmental impact of a proposal.

The City of Bellevue as lead agency on PSE's proposed Energize Eastside project must adhere to the highest standards of integrity, transparency, objectivity, and thoroughness in the conduct of the EIS process in compliance with spirit, intent, and letter of the WAC. The cities and residents of Redmond, Kirkland, Newcastle and Renton are depending on Bellevue as lead agency and should be treated fairly and respectfully by Bellevue in this EIS process.

The integrity of the key product, the EIS document, is of utmost importance. There is an appearance that portions of the evaluation and analysis were ghost written by PSE rather than by someone independent, impartial, and objective. Credibility of the EIS requires neutrality.

Errors and omissions in the DEIS must be corrected if the document is to be indicative of the true environmental impact. Contrary, incorrect, and/or unsupported statements in the document must be purged. Some sections of the EIS shows significant laps in factual accuracy. This also greatly undermines the credibility of the document and the process by which it was generated.

Complete truth should be your overarching objective.

SEPA Handbook section 3.3 states "*The lead agency is responsible for the content of the EIS…*". What that means is, regardless of its source, every word, sentence, paragraph, diagram, figure, and table in the DEIS is owned by Bellevue. If you put it in the EIS, you own it. This implies a trust that declarations of fact are vetted by Bellevue for accuracy and completeness. The EIS should meet the basic standards for research integrity. Anything less is betrayal of trust.

There is an apparent lack of research integrity in the DEIS If the concept of research integrity is not well understood or the process is unclear, one source of guidance is a book "On Being a Scientist: A Guide to Responsible Conduct in Research: Third Edition (2009): National Academies Press. Another resource is: "Responsible Science", Volume I: Ensuring the Integrity of the Research Process. A number of other references can be found at:

http://www.nap.edu/catalog/12192/on-being-a-scientist-a-guide-to-responsible-conduct-in

What research integrity training and mentoring on the proper conduct of research is being provided to the individuals who are responsible for the content of the DEIS to assure the DEIS is objective and factual.? If no formal training or mentoring is in place what is the plan to rectify this process deficiency and provide a DEIS for public review that is compliant with basic research standards of integrity?

SEPA Handbook section 3.3.1 "*Agencies are encouraged to describe a proposal as an objective, particularly for agency actions. For example, a city could propose the construction of a series of settling ponds and a chlorination system at the wastewater treatment facility. Instead, the proposal could be described as meeting the wastewater treatment needs of future development for the next 15 years. This encourages the consideration of a wider range of alternatives, where different treatment processes, and even water reuse options are contemplated rather than limiting the consideration to size and location options.* "

If this project is being considered as a potential EPF, that determination and the objective should be produced by the lead agency and partner cities. Instead, Bellevue is focusing the EIS on PSE's ill-conceived problem statement and inferior solution.

Paragraph 1.6 page 1-15 - The DEIS states: "*The EIS was developed under the direction of the City of Bellevue, working closely with its partner Cities and its consultants. As previously noted, the project is proposed by PSE, a regulated utility. Therefore, PSE developed the project objectives and helped to define alternatives that would attain or approximate the proposal's objectives, as required by SEPA*."

At the very outset, the DEIS presumes a very narrow problem and solution. This distorts and distracts from the real dialog that Bellevue and the neighboring cities should be pursuing in regards to energy needs. Why does Bellevue use false statements from PSE as an objective instead of complying with the spirit and intent of the SEPA process by stating a citizen's needs focus? Rather than conjecturing a 74 MW shortfall and a draconian solution, a better objective would be to "Identify and address energy needs along with safe and environmentally sound solutions for the region in the next decade." That statement would be a more appropriate title to the real agenda that should be pursued in this region and shifts the dialog from the ridiculous to the practical and opens up the opportunities for the future. Each Alternative is essentially a proposal to achieve a common objective. That common objective should be expressed in a fair and impartial manner. It should not be the extremely biased words from a profit motivated company. PSE owns their proposal but Bellevue, not PSE, owns the objective. Will Bellevue as lead agency step up its responsibilities to define a citizen oriented objective and seek solutions that benefit the citizens? Given the dangers of installation and operation of PSE proposed solution, shouldn't Bellevue as a minimum, include safety in the objective?

I recommend Bellevue step back, look at the real issues, get the proper research training, and pursue a solution for the common good. Energize Eastside and the current EIS process are not it.

Page 1-15 - The DEIS states "Phase 1 EIS public scoping outreach was conducted to assist in identifying technically viable alternatives that address PSE's reported deficiency in electrical transmission capacity." Contrary to this DEIS statement, a number of technically sound alternatives in use in the US and around the world were documented in the public record but were rejected and excluded from the DEIS without acknowledgement. Why did Bellevue reject these alternatives?

Page 1-17 section 1.9.2 – The DEIS states: "No new 230 kV transmission lines, substations, energy generation, or storage facilities;…" Why does Bellevue make this misleading statement since there are non-PSE options that ColumbiaGrid has available that solves the problem PSE states? No Action should be stated as No PSE Action. The correct statement is: “No new 230 kV transmission lines, substations, energy generation, or storage facilities by PSE;…” ColumbiaGrid has resources that don’t involve PSE projects.

Page 1-30 - For the No Action alternative, the DEIS states: “*No expanded transmission capacity could mean limits to peak energy availability, possibly with lower consumption of electricity than projected.*”

Page 1-36 - For the No Action alternative, the DEIS states: “*Inconsistency with planning goals for adequate power supply could be a significant adverse impacts.*”

Why does Bellevue make these extremely misleading statements? This seems very deceitful. Per the Energize Eastside EIS website, ColumbiaGrid’s determination is: “*A downside of the Sammamish-Lakeside-Talbot project is that its south-to-north Total Transfer Capability (TTC) is 417 MW lower as compared to the Maple Valley-SnoKing reconductor with 680 MW of Puget Sound area generation, with Seattle City Light’s North Downtown Substation (with inductors).*” With the No Action alternative, ColumbiaGrid has the option of proceeding with the preferred Maple Valley-SnoKing reconductor project if deemed necessary. This is a far less intrusive and lower cost ($16M) solution. Why does Bellevue ignore the fact the No Action Alternative leads to a better solution and instead make false assertions?

Page 1-36 - The DEIS states: “*The No Action Alternative could lead to unavoidable significant impacts. If unreliable power supply were to result in growth that is inconsistent with regional growth plans.*” Why does Bellevue make this misleading statement since ColumbiaGrid has resources to solve PSE’s stated problem without PSE’s action?

Page 1-36 - For Alternative 1 the DEIS states: “Moderate to significant land use impacts and housing impacts could occur because up to 327 acres of land could change to utility use, and some housing could be removed to accommodate new transmission lines.” Given the extremely limited remaining property in Newcastle available for residential construction, why does Bellevue ignore the conflict between Alternative 1 and the spirit of the Growth Management Act?

Page 1-36 Mitigation Measures – The DEIS states: “Provide relocation assistance” What exactly is Bellevue’s qualitative intent here? Since there is very little property available in Newcastle for development, how is Bellevue going to assist in relocating displaced Newcastle residents to equivalent locations in Newcastle? How are displaced residents compensated? Why is does Bellevue gloss over Alternative 1 land use impact mitigation given these are the most significant impacts?

Page 1-36 Significant Unavoidable Adverse Impacts – The DEIS states: “No significant unavoidable adverse impacts to land use or housing are expected. Alternative 1, Option A, could have significant impacts if a new corridor were required.” Since Bellevue has been told sections of the corridor are too narrow and there are homes at the ROW boundary, e.g. through Newcastle, why does Bellevue assert this falsehood. Why does Bellevue ignore the housing impact resulting from widening the existing corridor?

Page 1-38 Views & Visual Resources Significant Unavoidable Adverse Impacts - The DEIS states: “Significant impacts from Alternative 1 would be unavoidable if a new corridor were developed”. Significant impacts from Alternative 1 would be unavoidable period. Why does Bellevue include the misleading condition on whether or not a new corridor was developed?

Page 1-46 – For the No Action alternative, The DEIS states: “Although a significant adverse impact could result if a pipeline explosion near the transmission line occurred, the risk is minimized by conformance with regulatory requirements and procedures that address pipeline safety.” For Alternative 1, the DEIS states: “Conformance with regulatory requirements and procedures would ensure that potential hazards are identified, and design plans developed, that minimize adverse effects from pipeline hazards.” There is a far greater danger of pipeline explosion with collocated conductive metal transmission towers compared to the existing insulated structures. Why does Bellevue insinuate the No Action alternative is more dangerous than Alternative 1? Why does Bellevue insist on injecting these harmful biases?

Page 1-48 For the No Action Alternative, the DEIS states: “High electrical loads and lack of bulk transmission in the vicinity of the load could result in moderate to significant adverse impacts to electrical service reliability.” Why does Bellevue make this false assertion? Why does Bellevue ignore ColumbiaGrid resources as identified in the Energize Eastside EIS website?

Page 1-48 – For the No Action alternative, The DEIS states: “A potential significant adverse impact if Olympic Pipeline were damaged and explodes near existing PSE lines. Potential hazards minimized to minor levels with conformance to standards and requirements”.

There is a far greater danger of pipeline explosion with collocated conductive metal transmission towers compared to the existing insulated structures. Why does Bellevue insinuate the No Action alternative is more dangerous than Alternative 1? Why does Bellevue insist on injecting these harmful biases? This seems extremely dishonest.

Page 1-48 Utilities Significant Unavoidable Adverse Impacts - The DEIS states: “No Action Alternative – less reliable service could result in power disturbances and could increase likelihood of power outages.” and “Alternative 2 – uncertainties about feasibility and performance, participation, and conservation levels would result in risk to reliability.” Why does Bellevue make this false assertion? Why does Bellevue ignore ColumbiaGrid resources as identified in the Energize Eastside EIS website? Bellevue’s statements seem extremely dishonest.

Page 1-50 Table 1-2

What is the basis for Bellevue’s conclusion that Alternative 1 option A has “Negligible” impact on Land Use and Housing given it causes so much destruction of housing? Why does Bellevue consider wiping out large sections of neighborhoods as a result of Alternative 1 option A “Negligible” impact instead of significant? What is the basis for that conclusion? That evaluation shows extreme bias by Bellevue against neighborhoods. What is the basis for the conclusion that the No Action alternative has “Minor to Moderate” impact on Historic and Cultural Resources? That makes no sense since nothing is being constructed.

Page 1-53 Table 1-3

What is the basis for Bellevue’s conclusion that the No Action alternative has “Moderate to Significant” impact on Land Use and Housing when it has not impact at all? That makes absolutely no sense.

What is the basis for the conclusion that the No Action alternative has “Moderate to Significant” impact on utilities since ColumbiaGrid has resources to address PSE stated need? Since the No Action alternative has no impact on ColumbiaGrid's pursuit of other options they've identified why isn't the impact on utilities for the No action alternative "Negligible"?

Page 1-56 - The DEIS states: "Some members of the community reject the idea that the project is needed based on their understanding of how much energy actually needs to be transmitted through and into the Eastside area. Other members of the community accept PSE's assertion that the need is real and want only the most efficient and cost effective approach to addressing it." What percentage of the community reject vs accept PSE's assertion? At the public hearings on the DEIS it is 100% reject vs 0% accept. Why does Bellevue reject the needs of those "want only the most efficient and cost effective approach" by excluding the ColumbiaGrid preferred plan to reconductor the Maple Valley – SnoKing transmission line? Why does Bellevue exclude this alternative given it is more reliable and is much lower cost (~$16M) than Alternative 1? Bellevue shows extreme bias in excluding this alternative.

Page 1-56 - The DEIS states: "*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.*" Why does Bellevue continue to make unsupported statements of need through much of the DEIS given the methods are produce erratic and untrustworthy results?

Page 1-56 - The DEIS states: "*Several options suggested by community members would modify assumptions PSE made in its planning analysis regarding the need for the project, specifically around the use of additional power plants outside of the Eastside during peak demand periods, and prohibiting the flow of electricity to Canada during peak demand periods.*" Is Bellevue twisting the facts regarding the flow of electricity to Canada given there are other ColumbiaGrid documented options to deliver even greater capacity to Canada that don't involve PSE?

Page 2-1 – The DEIS states: "*Under SEPA, alternatives evaluated in an EIS must feasibly meet or approximate the project objectives.*" Why did Bellevue reject the feasible and reasonable alternative of conversion of control to a Puget Sound Public Utility District PUD? This alternative is fully compliant with all criteria identified in the DEIS? Given:

- PSE is only responsible to its owners.
- A PUD is only responsible to its customers.
  - The consequential difference is
  - PSE's objective is to squeeze the maximum allowable profit from its customers
  - PUD's objective is to provide the best service and value to its customers.
  - That's the difference between Seattle City Light being the greenest electrical utility and the neighboring PSE being the dirtiest
- PSE's objective:
  - Profit
- PUD's objective:
  - Better forecasting
  - Better management

- Better service
- Better efficiency
- Better environmental stewardship
- Better value
- Better security

The PUD would establish customer oriented policies and rules for operating, maintaining, and upgrading electrical power transmission and distribution. PSE would retain ownership and control of Colstrip. Beyond the superior service, a PUD would allow the most cost effective and rapid departure from coal sourced power, particularly from Colstrip. With a PUD, Bellevue and partner cities would control their own destiny for forwarding looking and sustainable energy.

Page 2-4 - The DEIS states: "Following the FERC direction, as well as prudent planning and operating standards, PSE limits the number of transformers at substations to two 230 – 115 kV transformer banks. In other words, based on security threats to the physical electric infrastructure, it is not reasonable or prudent to "put all your eggs in one basket." Is Bellevue stating additional redundancy is not "reasonable or prudent". If so, that's nonsense and why is Bellevue Is stating additional transformer redundancy is not "reasonable or prudent"?

Page 2-5 – The DEIS states: "All PSE transmission lines of any voltage must remain equal to or below 95 percent of the emergency line-loading limit over the study period in order for a viable alternative to be considered a potential solution. This includes all periods of the year, whether the system is operating under normal or abnormal system configurations, or during light load or peak load conditions." Does Bellevue consider ambient temperature in the assessment of line and transformer load limits? If not, why not?

Page 2-8 2.2.1.10 – The DEIS states: "As is typical of electric service providers, PSE does not use load shedding as a long-term solution to meet mandatory performance requirements. While NERC and WECC allow dropping load for certain contingencies, intentionally dropping firm load for an N-1-1 or N-2 contingency to meet federal planning requirements is not a practice that PSE endorses, because of the costs and inconvenience that outages impose on its customers." This is further proof PSE's needs assessment is not based on requirements. Why does Bellevue assert a capacity deficiency exists based on fictitious requirements? This seems dishonest.

Page 2-9 2.2.1.13 - The DEIS states: "PSE will only accept solutions that will solve any existing or future anticipated loading issues of PSE equipment." Since Alternative 1 fails to address future load issues in generating capacity, Alternative 1 should be rejected. Why is Alternative 1 included since it violates PSEs conditions?

Section 2.2.2 is irrelevant to the DEIS and should be deleted.

Page 2-10 – The DEIS states: "PSE must prepare for project construction several years in advance because some specialized equipment can take up to 3 years to procure. Alternatives must be reviewed to ensure they are reasonably constructible by the in-service target date of 2018." Since there is essentially zero chance to meet an in-service date of 2018 for Alternative 1, why isn't Alternative 1 rejected? Since the go-ahead date for any Alternative 1 options is likely not going to happen in 2016 –

2017 and the lead time for equipment is 3 years, another alternative is needed instead if PSE's deficiency estimates are true. Why is this not being addressed by Bellevue? Why are ColumbiaGrid documented alternatives that can meet the required in-service date ignored?

Page 2-10 2.2.2.3 – The DEIS states: "To PSE, proven technology means technology that has been successfully operated with acceptable performance and reliability within a set of predefined criteria." What is Bellevue's assessment of these criteria? Why are these criteria not available to the public?

Page 2-10 2.2.2.3 – The DEIS states: "Proven technology must have a documented track record for a defined environment, meaning there are multiple examples of installations with a history of reliable operations. Such documentation must provide confidence in the technology from practical operations, with respect to the ability of the technology to meet the specified requirements." Why does Bellevue state this requirement given Bellevue also states the DEIS only qualitative? Why is Bellevue's applying a double standard and betraying the community trust in Bellevue for a fair process?

Page 2-11 2.2.2.4 - The DEIS states: "After a project is complete and before the costs are allowed to be placed into the rate base, PSE must prove to the UTC that the cost to build a project is prudent and reasonable to ratepayers." Since ColumbiaGrid has a documented solution that is approximately 10% to 20% of the cost of Alternative 1, the allowed costs should be zero. Why is Bellevue excluding this preferred solution?

Page 2-11 – The DEIS states: "PSE has a legal obligation to deliver safe, dependable power, and an obligation to do so at a reasonable cost. PSE continually balances these obligations in determining the best solutions to solve problems facing the electric system." Why does Bellevue exclude lower cost options documented by ColumbiaGrid per the Energize Eastside EIS website?

Page 2-12 – The DEIS states: "In a typical year, the PSE system operates in an N-1-1 condition that causes customer outages about 15 to 30 times per year, each of which persists for approximately 4 to 12 hours, or less than 2 percent of the year." The NOAA National Climatic Data Center has a database of daily minimum temperatures for Station GHCND:USW00024233 SEATTLE TACOMA INTERNATIONAL AIRPORT WA US. Based on 16170 daily minimum temperature measurements in a period between January 1st 1970 and April 9th 2014, ambient temperatures were at or below 23°F .95% of the period. This is equivalent to 3.5 days per year. PSE claims there are two 4-hour peak power demand periods a day for a total of 8 hours per day. The number of peak demand hours occurring during conditions of ambient temperatures at or below 23°F is 8 x 3.5 = 28 hours per year or .3% per year. A N-1-1 condition during the worst case low temperature condition would occur 2% x 0.3% = 0.006% of the year or, on average, half an hour per year. Why does Bellevue ignore the extreme low likelihood of occurrence in its statements of deficiency? Why does Bellevue consider it a requirement to support full load demand under this extremely unlikely occurrence given WECC does not?

Page 2-12 – The DEIS states: "An N-2 outage is when a single event trips multiple facilities, such as certain instances when all the breakers in a substation trip offline, leaving several circuits without power, or a problem occurs that affects both circuits of a double circuit transmission line (two transmission circuits located on one structure). This occurs when a problem is detected, or some sort of damage has occurred. It can also be a result of routine maintenance when multiple system components must be taken out of service. However, if at all possible, routine maintenance avoids multiple elements, and if necessary, would most likely not be scheduled during peak load periods or poor weather. In a typical year, the PSE system operates in an N-2 condition about 10 to 20 days per year, and persists for approximately 4 to 12 hours, or less than 1 percent of the year." During the CAG, Andy Wappler stated the problem that PSE asserted would not cause blackouts. This is true with proper management. On August 18, 2015, Andy Wappler stated to the Newcastle City Council that if PSE doesn't get its way and the opportunity occurs, PSE will allow blackouts. Has Bellevue been threatened similarly? Is Bellevue's bias towards Alternative 1 and away from the common sense alternatives a result of this threat?

Page 2-13 – The DEIS states: "The CAPs are seen as temporary measures used to keep the entire system operating, but they can place large numbers of customers at risk of a power outage if anything else on the system begins to fail." What is Bellevue's basis for this assertion? What is the number of customers affected? Where are the customers located? Are the customers in the Puget Sound region or in Canada? What does Bellevue mean by the phrase "anything else on the system"? Supplemental Eastside Needs Assessment Report Transmission System King County April 2015 Puget Sound Energy states: "NERC Standard TPL-001-4 allows CAPs to be used to meet the performance requirements for most N-1-1 and N-2 contingencies while specifying how long they will be needed as part of the CAPs." Is Bellevue including failure conditions for which full demand support is not required?

Page 2-13 – the DEIS states: "Based on U.S. Census and Puget Sound Regional Council population forecast data, PSE's analysis concluded that the population in PSE's service area on the Eastside is projected to grow by approximately 1.2 percent per year over the next 10 years and employment is expected to grow by 2.1 percent per year, resulting in additional electrical demand (Gentile et al., 2015)." Given PSRC forecasts show a 1% population growth rate and a 1.1% employment growth rate from 2014 to 2030, what method and basis did Bellevue use to validate the very inconsistent analysis by PSE's of population and employment growth rate?

Page 2-13 states: "If electrical load growth occurs as PSE has projected, PSE's system would likely experience loads on the Eastside that would place the local and regional system at risk of damage if no system modifications are made." Why does Bellevue make this misleading statement given ColumbiaGrid has documented options it can pursue to prevent the stated situation that don't require PSE involvement?

Page 2-15 – The DEIS states: "Distribution efficiency can include conductor replacement and conservation voltage reduction. Conductor replacement on existing lines could occur under the No Action Alternative as part of normal maintenance. However, these improvements would not substantially increase overall system capacity because capacity issues driving this project are typically associated with transformer overloads rather than conductor overloads." Why does Bellevue make this false statement given reconductor projects that don't involve PSE will increase overall system capacity and not cause transformer overloads. Bellevue's statement seems very dishonest.

Page 2-15 – The DEIS states: "There are no currently known new technologies that PSE would employ that could substantially affect the transmission capacity deficiency on the Eastside. Under the No Action Alternative, PSE would not be precluded from seeking out new technologies, however." Why does Bellevue exclude alternatives that don't involve PSE? Why is Bellevue artificially limiting the alternatives given that superior alternatives not involving PSE exist?

Page 2-13 2.3.2.2.3 Much of planned construction for Alternative 1 is in direct conflict with OLYMPIC PIPE LINE COMPANY / BP PIPELINES NA INC GENERAL CONSTRUCTION & RIGHT OF WAY REQUIREMENTS

(8/17/2010) which states: “The contractor shall not be permitted to transport construction materials or equipment longitudinally over the pipeline.” Since there is no access to the planned transmission line tower locations in some sections of the existing ROW, Alternative 1 is not viable and should be rejected. Why does Bellevue ignore the construction constraints imposed for pipeline safety?

Page 2-23 – The DEIS states: “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.” Why does Bellevue state this given a 50-foot-wide hazardous liquid pipeline corridor is in the middle of the transmission line ROW in sections of the Alternative 1 route and given the transmission tower base, grounding and support provisions must be a minimum of 50 feet from all underground pipe which requires more than 250-foot-wide ROW for the transmission line? This seems very dishonest.

Page 2-23 – the DEIS states: “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.” Why does Bellevue ignore the environmental impacts of pipeline disruption in the DEIS?

Page 2-23 – the DEIS states: “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.” Given the transmission line ROW straddles the hazardous liquid pipeline ROW in some sections, twice as many poles are required in those sections. Given the overlap of transmission line and hazardous liquid pipeline ROWs why does Bellevue make a false statement of the number of transmission line tower foundations?

Page 2-32 Alternative 2 is artificially narrow and excludes two key conservation drivers. The first issue is the statement of the alternative neglects to consider market forces driven by continual reduction in cost of conservation options and alternative local energy sources along with increasing costs of grid sourced energy. With the cost of grid energy going up, and costs of conservation and self-generation going down the reduction in grid demand will accelerate. Already past cross over point in some regions. The Bullet building in Seattle profitably generates 60% more energy than it uses. Energy storage products is a $3.5B local industry. Why does Bellevue ignore this economic driver?

The second issue is Alternative 2 does not address the impact of FERC Order 745 which will give rise to swift growth in demand response markets. FERC Order 745 most directly nullifies PSE’s forecasted peak loads claim. Why does Bellevue ignore the impact of FERC Order 745?

Page 2-52 – The DEIS states “*Although switching to DC could potentially address the problem by marginally increasing the capacity of the lines, it would add complexity to the system that would reduce operational flexibility, which could have adverse impacts to the reliability and the operating characteristics of PSE’s system. For example, if there was a problem within the DC portion of the system, it would not be possible to switch among other sources, as it is when the entire system is on AC. This alternative has not been included because avoiding such adverse impacts to reliability is one of PSE’s stated electrical criteria (electrical criterion #1).*” Why does Bellevue ignore the fact that conversion of the existing 115 kV circuits provides far more capacity than PSE claims is needed, doubles the number of circuits with no change to the transmission line, and provides much more grid resilience for blackout restart conditions than Alternative 1? Why does Bellevue ignore the fact that a DC conversion fully supports a lakeside substation and doubles the redundancy for N-1-1 failure conditions? Why does Bellevue ignore the fact that a DC conversion eliminates the need for conductive metal towers near the hazardous liquid pipeline? Bellevue references U.S.-Canada Power System Outage Task Force. 2004. Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations. April 2004 which states on page 15: "*The province of Québec, although considered a part of the Eastern Interconnection, is connected to the rest of the Eastern Interconnection only by DC ties. In this instance, the DC ties acted as buffers between portions of the Eastern Interconnection; transient disturbances propagate through them less readily. Therefore, the electricity system in Québec was not affected by the outage, except for a small portion of the province's load that is directly connected to Ontario by AC transmission lines.*" And on page 98 states: "*Due to its geography and electrical characteristics, the Québec system in Canada is tied to the remainder of the Eastern Interconnection via high voltage DC (HVDC) links instead of AC transmission lines. Québec was able to survive the power surges with only small impacts because the DC connections shielded it from the frequency swings.*" Why does Bellevue ignore its own references to the reliability advantages of a DC conversion? Is PSE technical incompetence sufficient reason to reject alternatives that are superior to alternative 1?

Page 2-54 – The DEIS states: "*Alternatives that would violate PSE's Planning Standards and Guidelines (such as changing a transmission line from AC to DC) or that could harm other utilities in the region (such as disconnecting the Eastside from the regional grid during peak periods) would not become compliant by combining them with other alternatives (electrical criterion #1).*"Given mixed AC and DC grids are in stable, mature, and reliable operation around the world, why does Bellevue assert this false claim?

Page 8-1 – The DEIS states: "*This chapter provides a high-level discussion of four types of environmental health concerns raised during the scoping period*". Why does Bellevue ignore toxic emissions? The WAC 197-11-960 Environmental checklist includes:

2. Air

a. What types of emissions to the air would result from the proposal during construction, operation, and maintenance when the project is completed? If any, generally describe and give approximate quantities if known.

b. Are there any offsite sources of emissions or odor that may affect your proposal? If so, generally describe.

WAC 197-11-444 Elements of the environment includes:

(b) (i) Air quality

What exempts the DEIS from including Mercury and Air Toxics Standards (MATS) controlled air pollutants from consideration? Per the Union of Concerned Scientists, just 1/70th of a teaspoon of mercury deposited on a 25-acre lake can make the fish unsafe to eat. The EPA ranks the Colstrip power plant among worst in nation for mercury (2011). Coal ash from the Colstrip power plant is a significant source of ground water pollution. Alternative 1 increases GHG and these toxic pollutants. Alternative 2 reduces GHG and these toxic pollutants. Alternative 2 is a huge environmental benefit 24/7/365 not just during conditions stated by PSE. Off-peak wind and solar generation along with battery storage helps mitigate peak load generation (Colstrip) demand every day, not just a couple days a year. This reduces GHG and MATS emissions below current levels. The spirit and intent behind SEPA is environmental protection. Why does Bellevue ignore very significant environmental benefits of alternative 2 and the serious negative environmental impact of alternative 1?

Page 10-1 - The DEIS states: “The No Action Alternative would likely lead to declining reliability of the electrical power supply on the Eastside, which could be inconsistent with local planning policies and constitute a significant adverse impact.” Given the No Action alternative places no constraints on ColumbiaGrid’s pursuit of equivalent options, why does Bellevue make this false assertion? This seems very dishonest.

Page 10-6 – The DEIS states: “A determination of whether the Energize Eastside Project qualifies as an EPF would be made by the permitting agency at the time of permit preparation or submittal.” Since ColumbiaGrid has the option of pursuing other documented projects that achieve equivalent objectives, Alternative 1 is not an EPF.

Page 10-17 – What is Figure 10-7 intended to represent?

Page 10-19 – The DEIS states: “Negligible land use and housing impacts would be expected from project construction under any of the action alternatives”. Given sections of the ROW that cut through R-6 zoned areas are too narrow, what is Bellevue’s basis for determining housing impacts are negligible in Newcastle?

Page 15-6 – The DEIS states: “Additionally, product shut-off valves, located at a distance of up to 5 miles, previously were turned by hand only, but are now automated so product flow can be shut off remotely and immediately (Anderson, 2015; Moulton, personal communication, 2015b).” How did Bellevue validate the automated system would operate correctly and provide correct status to the operator under a failure condition where the pipeline was energized to a high voltage due to a transmission line anomaly or failure?

Page 15-15 – The DEIS states: “The IEEE guide is based on many years of research and practical experience. Engineers can control the conductor gradients by selection of conductor size (larger conductors have lower gradients), phase spacing and arrangement, and sometimes by bundling (use of multiple conductors per phase lowers the surface gradient).” Why does Bellevue include statement regarding bundling? Is Bellevue considering conductor bundling in the project? If so, why does Bellevue ignore the visual impact of bundled conductors?

Page 15-18 – The DEIS states: “The same types of hazards and potential need for emergency services related to operation of new 230 kV transmission lines in proximity to the Olympic Pipeline are already present with the existing 115 kV lines and would remain similar with a 230 kV line, even if it were to be located in a new right-of-way corridor.” Since the 230 kV support towers are conductive and are grounded along a collocated pipeline and therefore far more dangerous than the relatively non-conductive 115 kV support poles why does Bellevue assert this falsehood? Why does Bellevue ignore the fact that colocation safety issues don’t exist if the transmission line and Olympic Pipeline are not collocated? Bellevue’s statement seems very dishonest.

Page 15-20 – The DEIS states: "A fiscal analysis prepared for the Project (FCS Group, 2016) utilized an estimate of a theoretical $10 million decrease in assessed value to demonstrate the relative effect of such a decrease on property tax revenues in one of the study area communities (City of Bellevue)." Why did Bellevue choose to ignore the property tax loss resulting from condemnation of property? Well over $30 million in property value would be lost in Newcastle condemnations alone to widen the existing ROW. That represents a tax loss of over $300,000 per year.

Page 16-30 – The DEIS states: "For example, maintenance activities on the transmission line could require heavy equipment to cross the buried Olympic Pipeline, or excavation at existing pole foundations could require excavation in proximity to the Olympic Pipeline. These same risks are already present with the existing 115 kV lines and would remain with a 230 kV line. Given the structure of the 230 kV and the 115 kV transmission lines are very different, on what basis did Bellevue determine the risks due to maintenance activities would be the same? Why does Bellevue imply the existing 115 kV poles have foundations given they don't have foundations?

Page 16-30 – The DEIS states: "As described under the No Action Alternative, conformance with industry standards and regulatory requirements ensure that potential hazards are identified and operations and maintenance procedures in place that minimize adverse effects from these hazards to minor levels." What basis does Bellevue use to validate this claim? A natural-gas explosion sourced by PSE destroyed three businesses in Greenwood on March 9, 2016. How would Bellevue contrast the standards and regulatory requirements levied on PSE that allowed the explosion vs those that "minimize adverse effects from these hazards to minor levels." Bellevue's statement appears to be very dishonest.

1 Statement of need

Page 1-5 - The DEIS states: "This EIS will not be used to reject or validate the need for the proposal." Yet it contains many contrary and unsupported statements. At least seven unsupported statements in section One falsely state there is need"

- Page 1-1,1-2 - "*This set of facilities is proposed in order to address a deficiency in electrical transmission capacity during peak periods that has been identified by PSE through its system planning process. This deficiency is expected to arise as a result of anticipated population and employment growth on the Eastside, and it is expected to negatively affect service reliability for Eastside customers within the next few years. The project would improve reliability for Eastside communities and would supply the needed electrical capacity for anticipated growth and development on the Eastside.*" This is an unsupported assertion and should be deleted.
- Page 1-2 - "*Based on federally mandated planning standards, PSE's analysis found that the existing transmission system could place Eastside customers and/or the regional power grid at risk of power outages or system damage during peak power events due to cold or hot weather. PSE's analysis concluded that the most effective solution was to add a 230-to-115 kV transformer within the center of the Eastside to relieve stress on the existing 230-to115 kV transformers that currently supply the area.*" (page 1-2). PSE's analysis didn't find anything. An analysis is an inanimate object. PSE may have concluded something regarding their analysis but that's not relevant in this document. This statement should be deleted.

- (page 1-5) "*Stantec prepared a memorandum evaluating the stated need for the project, and confirmed that PSE's Eastside Needs Assessment was conducted in accordance with industry standards for utility planning (Stantec, 2015). See Appendix A for more information.*" This is another unsupported and irrelevant assertion. This statement should be deleted. Appendix A has no information on conducting a needs assessment in accordance with industry standards. Will this reference be corrected so it contains information on "*industry standards for utility planning*" as indicated?
- (page 1-6) "*Without adding at least 74 megawatts (MW) of transmission capacity for local peak periods in the Eastside, a deficiency could develop as early as winter of 2017 - 2018 or summer of 2018, putting customers at risk of load shedding (forced power outages) (Stantec, 2015)*." This is another unsupported and irrelevant assertion. This statement should be deleted.
- (page 1-10) "*The Energize Eastside Project is intended to address an identified deficiency in the capacity of PSE's transmission system.*" This is another unsupported and irrelevant assertion. This statement should be deleted.
- (Fact Sheet FS-i) "*The project involves improvements to PSE's electrical grid in the Eastside area of King County, Washington, to address a deficiency in electrical transmission capacity.*" This is another unsupported and irrelevant assertion. This statement should be deleted.
- (Fact Sheet FS-i) "*The purpose of the project is to address a projected deficiency in transmission capacity resulting from growth in electrical demand, which could affect the future reliability of electrical service for the Eastside.*" This is another unsupported and irrelevant assertion. This statement should be deleted.

As cited above "PSE's Eastside Needs Assessment was conducted in accordance with industry standards for utility planning (Stantec, 2015)". In 2014 PSE advertised figure 1 (published in 2013) to the Community Advisory Group (CAG) as their demand forecast presumably based on the "industry standards for utility planning" PSE claims to follow. Their planning projected a demand of 660 MW in 2014 with approximately 1.15% demand growth per year between 2012 and 2014.

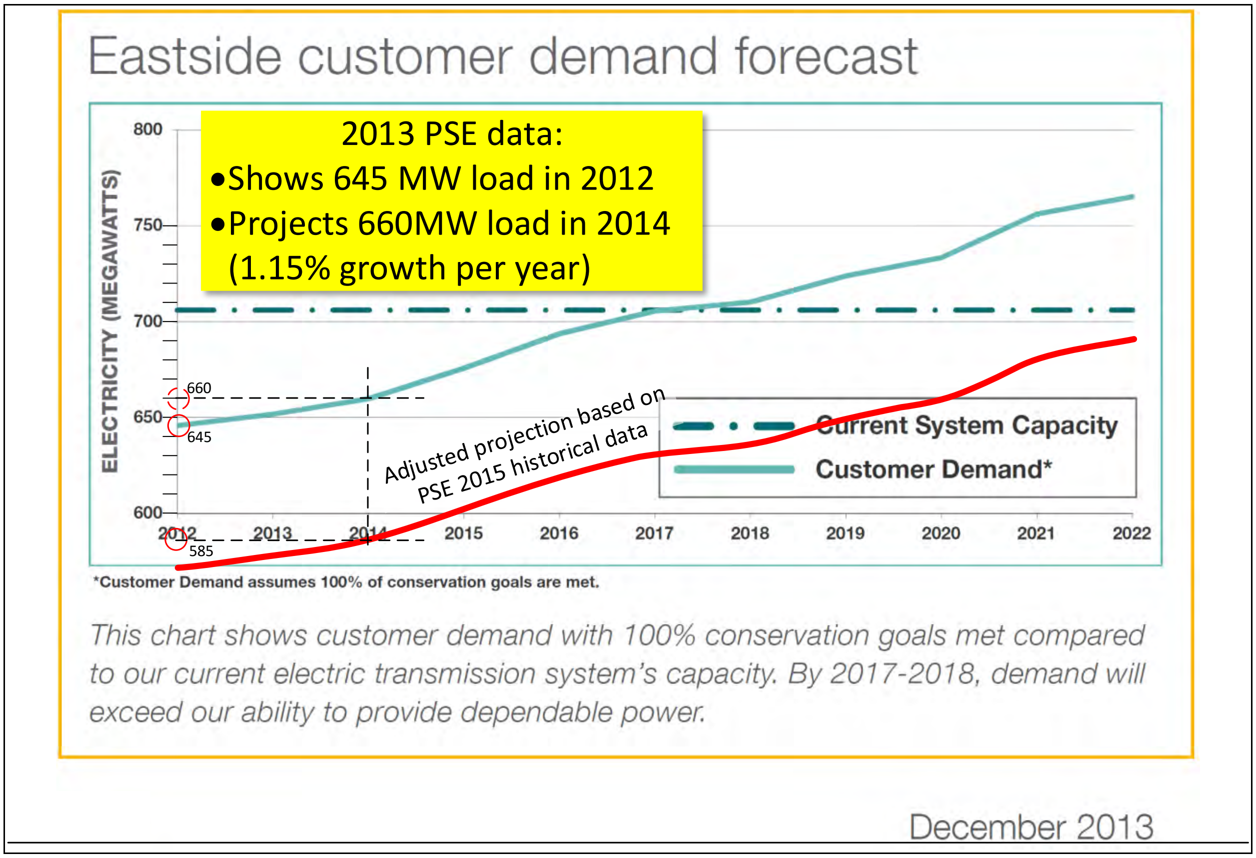


Figure 1

In 2015, PSE shows 2014 demand was 585 MW per figure 2 (published in 2015). This is a 5% per year decrease, not the PSE projected 1.15% increase. Why does Bellevue ignore this discrepancy in forecasted demand increase versus forecasted demand increaser?

This is a six-fold error in the rate of change. It is also in the opposite direction from what PSE projected. The magnitude of the error is a very significant 75 MW and is a net decrease. The 75 MW magnitude error exceeds the magnitude of the 74 MW shortfall projected by PSE. Why does Bellevue ignore this huge discrepancy in PSE's demand forecasted?

This is clearly indicative of poor near term forecasting accuracy. With the projected demand line normalized to PSE's 2014 historical data (shown in red on the 2013 diagram above) it shows significant positive margin out to 2022. Why is this ignored by Bellevue?

PSE's historical data shows poor projection accuracy and clearly undermines their claims regarding a projected shortfall in 2017 – 2018. Why is this ignored by Bellevue?

A truly independent, transparent, and objective assessment is required to forecast true demand and capacity. Without such, no statements regarding shortfalls should be contained in the EIS. Why does Bellevue fail to perform proper research in demand forecast?

Fundamentally, there is no justification for PSE's shortfall claims.

Besides revealing PSE's huge accuracy error, the completely different 2015 forecast from PSE based on the same "industry standards for utility planning" shows a wildly different projection.

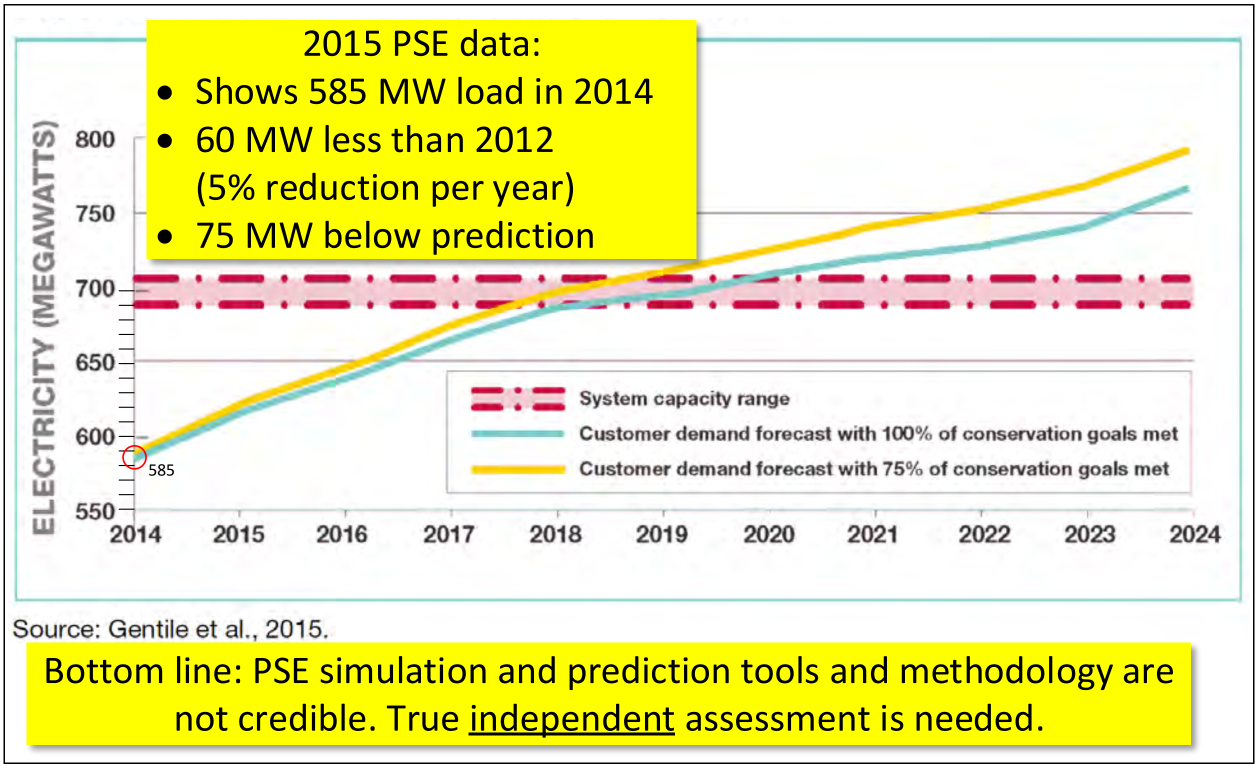


Figure 2

Accuracy and precision are both important qualities of a statistically significant measure or estimate. Accuracy is the proximity of a measurement and the actual value. Precision is the repeatability of a measurement. Figure 3 is an overlay of the two PSE forecasts published in 2013 and 2015. PSE's own data shows forecast are both wildly inaccurate and wildy imprecise. Although based on the "industry standards for utility planning" PSE's forecasts are essentially worthless as support for PSE's energy shortfall claims. Why does Bellevue state these worthless claims as fact?

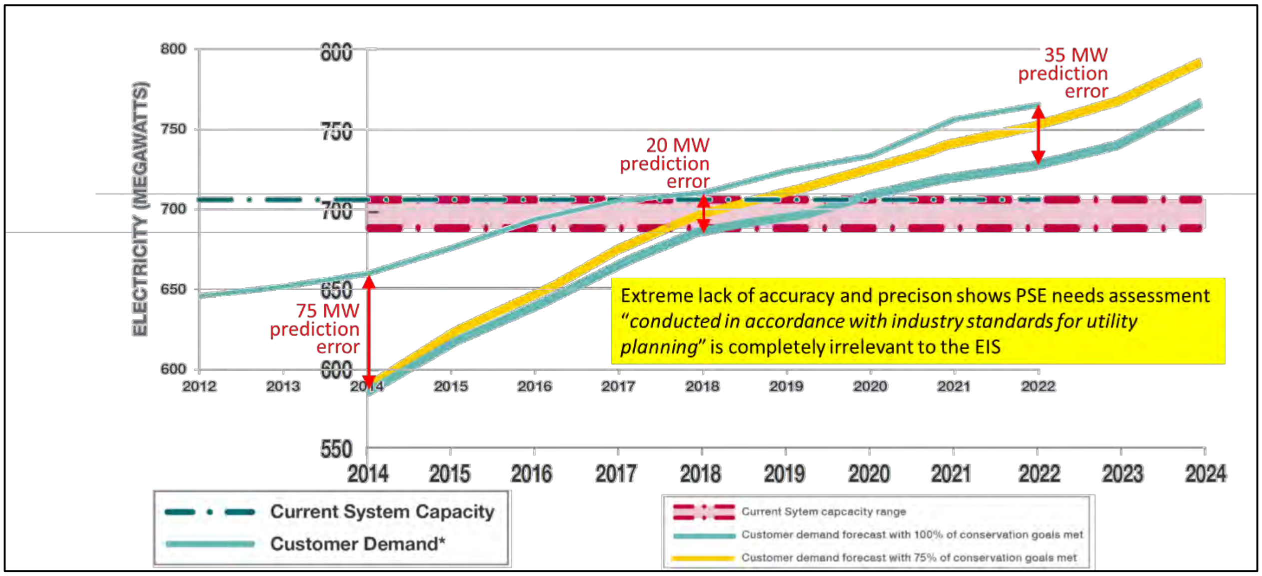


Figure 3

The only statement that should be made in the EIS regarding a deficiency in electrical transmission capacity is that PSE's assertions are baseless, statistically nonsignificant findings.

2 Alternative 1 an inappropriate solution

PSE projects that electrical power demand will begin to exceed peak power capacity by the year 2017. PSE further projects demand will exceed capacity by approximately 10% by 2022. The key point emphasized by PSE is the projected demand is based on days where the air temperature is 23°F or lower.

The question is whether the occurrence of the conditions is so frequent that PSE's intended solution with its enormous impacts is warranted and there are no alternatives. Or is there something being left unsaid that indicates less aggressive solutions may be viable?

The NOAA National Climatic Data Center has a database of daily minimum temperatures for Station GHCND:USW00024233 SEATTLE TACOMA INTERNATIONAL AIRPORT WA US. Figure 4 is a summary of 16170 daily minimum temperature measurements in a period between January 1st 1970 and April 9th 2014. The horizontal scale is the daily minimum temperature in one-degree Fahrenheit increments from the lowest measured value in the period (7°F) to 23°F. The vertical scale ranges from 0% to 100% and is the percentage of the period in which each minimum temperature was recorded.

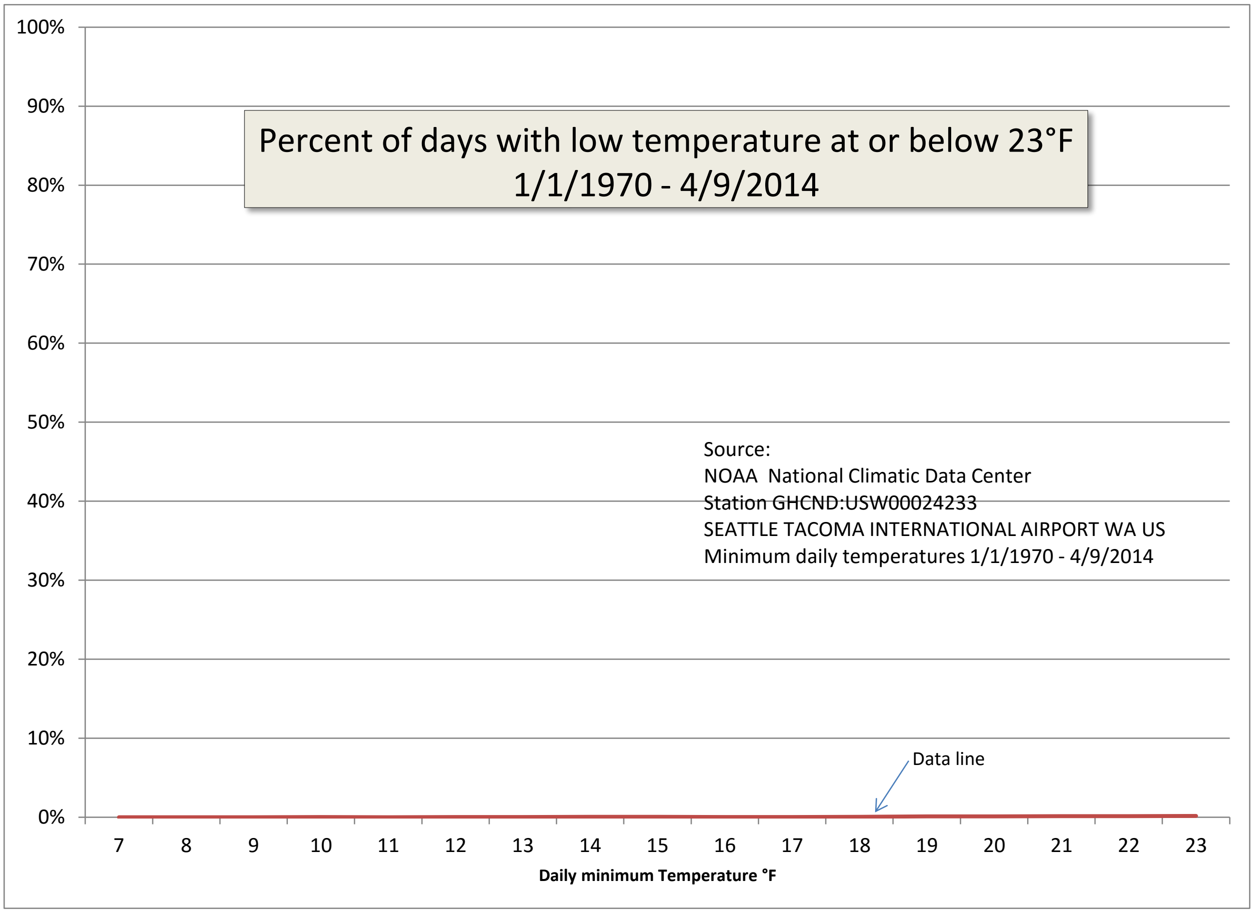


Figure 4

Since the occurrences of 23°F and lower temperatures days are extremely infrequent an expanded view of the bottom 1% is provided in Figure 5.

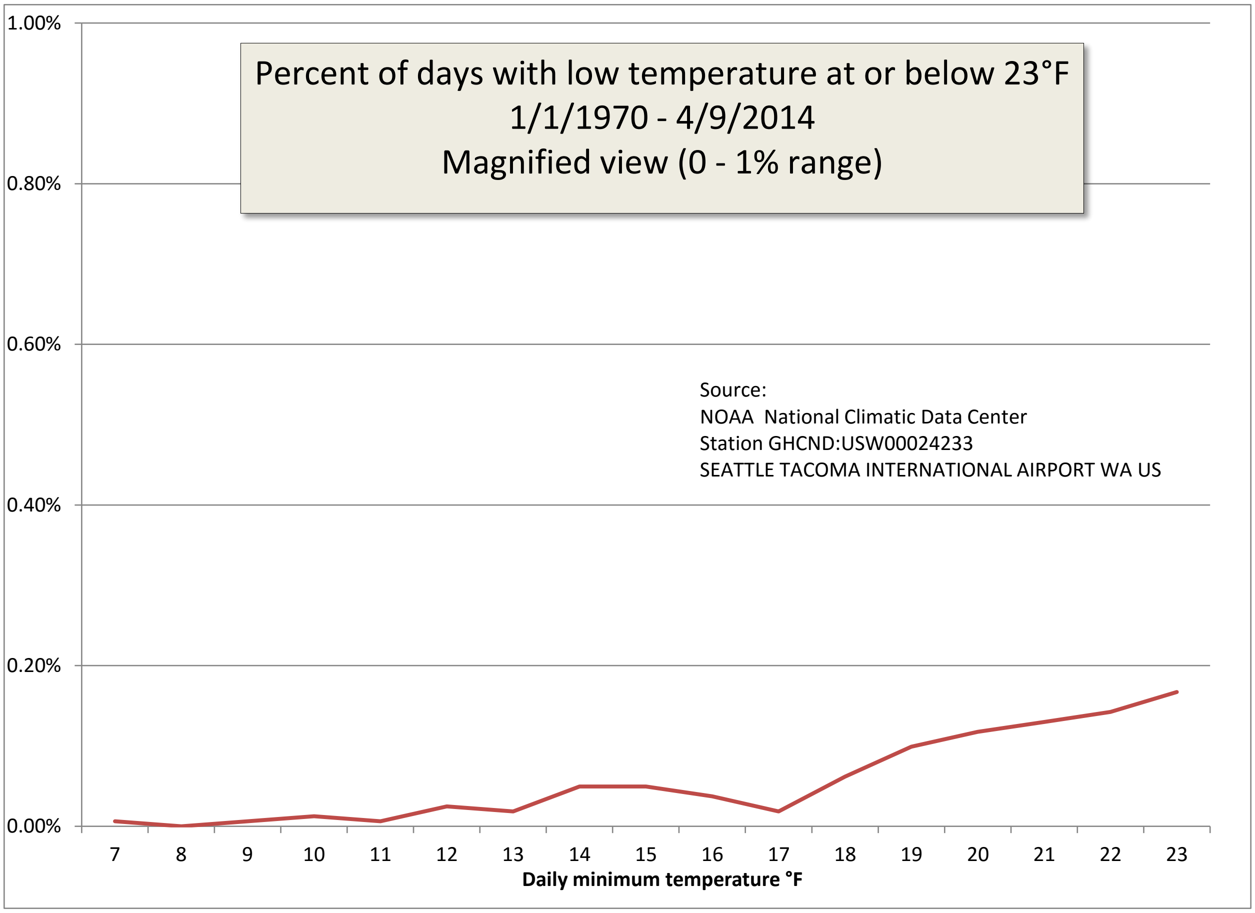


Figure 5

As can be deduced from the charts, the extreme conditions identified by PSE are very infrequent. The total percentage of days with minimums at or below 23°F is .95% (less than 1% or 3.5 days a year) for the entire period. This suggests that the problem stated by PSE is potentially solvable within the realm of smart power management policies without resorting to the unnecessary options within PSE's narrow solution space. PSE has offered no defendable justification for excluding employment of a smart power management approach.

At less than one percent rate of occurrence, the number of days (meeting the conditions for which PSE claims this project is needed) over a ten-year period is: .95% x 365 days/year x 10 years = 34.7 days. PSE claims the cost will be as high as $290 million. That cost spread across the number of occurrences in a ten year period is $290 million / 34.7 days = $8.36 million per day for each low temperature day. PSE claims the periods of peak electrical demand are from 6:00 AM to 10:00AM and from 5:00 PM to 9:00 PM. That is a total of 8 hours per day. Dividing $8.36 million by 8 hours leaves the consumers paying over $1 million dollars an hour. This is a very poor value to the customer and an unnecessary expense. PSE has offered no defendable justification for promoting such an expensive and limited value solution over lower cost, lower impact, and much higher value solutions.

Figure 6 shows the relative scale of PSE's proposed project vs PSE's statement of need during the CAG process.

PSE statements during CAG process and PSE documentation

- PSE states peak demand shortfall under a transmission line failure condition is 55 Megawatts (MW)
- PSE projected demand is based on days where the air temperature is 23°F or lower.
- PSE states peak demand occurs in two 4 hour periods (8 hours total per day)
- PSE intends to add 1407 MW (for N-1-1 conditions, two of four routes failed)
  - Replace 1620 Amp cable (Tern/ACSS/AW 795) with 2576 Amp cable (Falcon/ACSS/AW 1590)
  - 115 KV (line to line) / √3 = 66.4 KV line to neutral
  - 66.4 KV x 1620 Amp x 3 phases = 645 MW existing capacity
  - 230 KV (line to line) / √3 = 132 KV line to neutral
  - 132 KV x 2576 Amp x 3 phases = 2052 MW expanded capacity
  - 2052 MW – 645 MW = 1407 MW total increase from existing to expanded capacity under N-1-1 conditions.

Background

- NOAA National Climatic Data Center has a database of daily minimum temperatures for Station GHCND:USW00024233 SEATTLE TACOMA INTERNATIONAL AIRPORT WA US.
- Summary of 16170 daily minimum temperature measurements in a period between January 1st 1970 and April 9th 2014 by NOAA indicates air temperature is at or below 23°F a total of 3.5 days on average per year

Analysis

- PSE claimed need: 55 MW x 8 hours/day x 3.5 days/year = 1520 MW hours (MWh)/year
- PSE intended increase in capacity: 1407 MW x 24 hours/day x 365 day/year = 12,325,320 MWh/year
- Percent increase in capacity vs need: 12,325,320 MWh/1520 MWh = 810,876%
- Conversely, percent increase needed vs capacity: 1520 MWh/12,325,320 MWh = 0.0123%

To be clear, the percent increase in capacity vs need as stated above is over 800,000 percent. An increase of this magnitude will never ever be needed in the PSE customer base area.

Why does Bellevue believe such an absurdly large growth in capacity is needed while rejecting more reasonable alternatives?

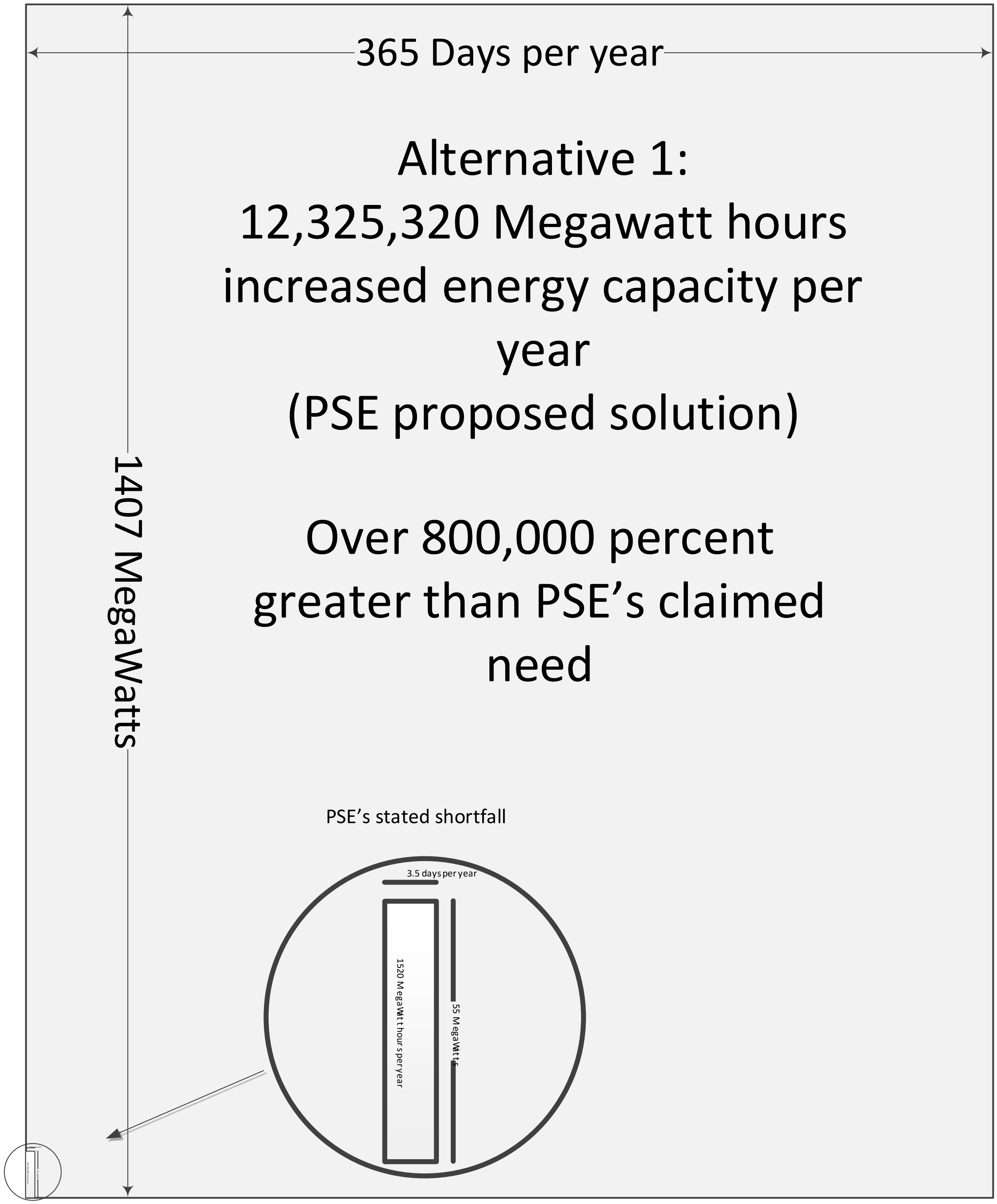

365 Days per year
Alternative 1:
12,325,320 Megawatt hours increased energy capacity per year
(PSE proposed solution)
Over 800,000 percent greater than PSE's claimed need
1407 MegaWatts
PSE's stated shortfall
3.5 days per year
1520 MegaWatt hours per year
55 MegaWatts

Figure 6

3 Scope

The EIS should include safety codes per RCW 81.88 including relevant inputs from CCOPS sanctioned by RCW 81.88.140. Why is CCOPS input and the impact of mitigating safety issues excluded from the DEIS?

The EIS should identify which alternatives are consistent with WAC 480-100-238 Integrated resource planning, specifically items 3a, 3b, 3c. Why are this items excluded?

The EIS should include positive environmental impacts where current ongoing environmental impacts are reduced. Why are the reduced impacts enabled by Alternative 2 excluded?

4 Safety

Safety is the utmost critical consideration and one that was completely ignored by PSE during the CAG process. The EIS should include all impacts caused by the mitigation of safety hazards. Like smoking, lead paint and asbestos consumer product safety, a lot has been learned in the last few decades about transmission lines, hazardous liquid pipelines, and the catastrophic interactions between collocated high energy sources. If we could apply to past decisions what we know now about these interactions, likely we would not have allowed the existing thin safety margins. Like any new demolition/construction project, the new design and construction process must meet current 'code' not the obsolete standards applied and grandfathered along in the past.

The project should not impose safety risks, Therefore the EIS should include complete mitigation of safety risks including:

- Electromagnetic
  - Corrosion from induced AC currents
  - High energy events, e.g., lightning, arcing, structure failure
- Thermal
  - Immediate breach - transmission line has 10,000 times the arc voltage needed to melt ductile iron pipe
  - Latent damage – Event of sufficient energy to rupture cathodic protection insulation
- Mechanically induced failure
  - Immediate rupture
  - Construction induced latent failure, e.g., Bellingham disaster
  - Long term stress from forces on transmission line structure

The project provides a 4X increase in energy available to aggravate a line fault condition. The mitigation for this is physical separation. But worse, the key change in the supporting structure is replacement of the relatively insulating wooden supports with highly conductive metal supports. The mitigation for this is physical separation. In addition, the AC magnetic field in the power lines induce a current in adjacent parallel pipes causing corrosion and shock hazard for personnel contacting the pipe and its fittings and valves. The mitigation for this is physical separation.

In a perfect storm scenario an arc to ground from a transmission line failure, weather, lightning or other event allows the hazardous liquid pipeline to be energized to the point of rupture requiring the pipeline to be shut down. But given the pipeline is energized at lethal potential, there is no automatic or manual means to shut it down. This runaway situation is quite possible. The mitigation for this is physical separation. Other colocation issues:

- Immediate or latent damage to the pipeline during construction. The mitigation for this is physical separation.
- Latent damage to the pipeline due to forces transmitted from the towers to the footing, and to the soil adjacent to the pipeline. The mitigation for this is physical separation.
- Damage to the pipeline cathodic protective insulation through heating caused by lightning strikes to towers conducted to the ground adjacent to the pipeline. The mitigation for this is physical separation.

In regard to facilities sharing a corridor, The Corridor Concept Theory and Application by Charles H. Weir, C.L.S., P.E.N.G and June P. Klassen states: "*The disadvantages include: Increased Disaster Potential. Should a natural catastrophe, a subversive action, or major facility failure occur, the potential for multiple facility failure is increased due to proximity.*" It also states: "*The major conflict between power transmission lines and pipelines in corridors is an unavoidable result of proximity. Spacing between these two facilities should be in the range of 30 metres due to voltage and resultant current flows which may be induced in a pipeline from adjacent powerlines*" The mitigation for this is physical separation.

Page 1-32 - The DEIS states: "Risk to the public is not likely from constructing or operating the project near pipelines due to extensive safety policies and regulations." That statement is, in essence, completely meaningless since is it is completely unsupported. The Bellingham disaster was 5 years after construction. The project leading to the Bellingham disaster was very closely monitored. A cursory review of data from US DOT Pipeline and Hazardous Materials Safety Administration on hazardous pipeline shows numerous incidents with "extensive safety policies and regulations" in place:

- ELECTRICAL ARCING FROM OTHER EQUIPMENT/FACILITY (06/12/2010 - 09/09/2015)
  - $68,772,650
- THIRD PARTY EXCAVATION DAMAGE (01/09/1996 - 12/08/2015)
  - $144,702,203
- UNSPECIFIED CORROSION (10/28/1997 - 11/19/2009)
  - $6,062,845
- Miscellaneous
  - $160,674,585
- Injuries and fatalities (02/27/1996 - 06/22/2015)
  - 34 injuries (8 in 06/10/1999 Bellingham Olympic Pipeline disaster)
  - 37 deaths (3 in 06/10/1999 Bellingham Olympic Pipeline disaster)
  -

Why does Bellevue ignore the historical truth and make this unsupported claim regarding risk to public safety?

5 Inadequate Power Line Right Of Way Width

Figure 7 is a diagram of the current PSE power line Right Of Way (ROW) and the Olympic Pipeline Hazardous Liquid Pipeline ROW through the Olympus residential community in Newcastle. This is a segment of the proposed route 'M'. The hazardous liquids consist of highly flammable petroleum products (kerosene, jet fuel, diesel fuel, and gasoline). The liquid is pumped at very high pressure (approximately 1400 pounds per square inch) through two pipelines within the pipeline ROW. In the Olympus neighborhood, the hazardous liquid pipeline ROW is 50 feet wide and centered within the 100-foot-wide PSE power line ROW.

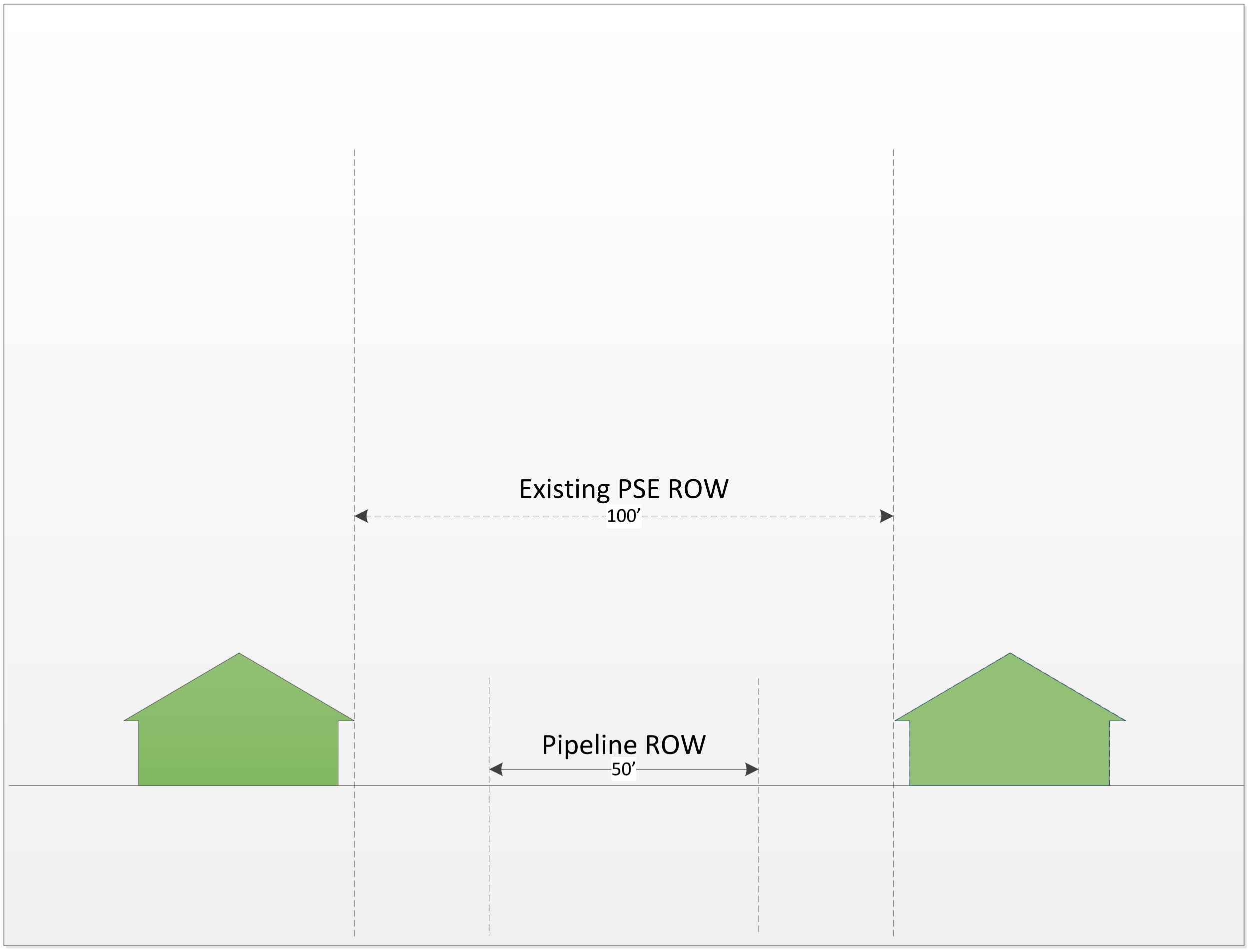


Figure 7

Figure 8 shows the nominal location of 120-foot-tall monopole towers on 6-foot diameter footings to support the proposed 230kV lines. The footings must be placed in undisturbed soil to be able to withstand lateral forces on the monopole. A minimum margin of undisturbed soil around the footing is required and must be within the PSE power line ROW. As can be seen, the footings can only be located within the outer 25 foot margins of the 100-foot-wide PSE power line ROW without directly violating the hazardous liquid pipeline ROW. The edge of the footing is potentially within 9.5 feet of existing and future residential structures given the current 100-foot-wide easement. This is far too narrow.

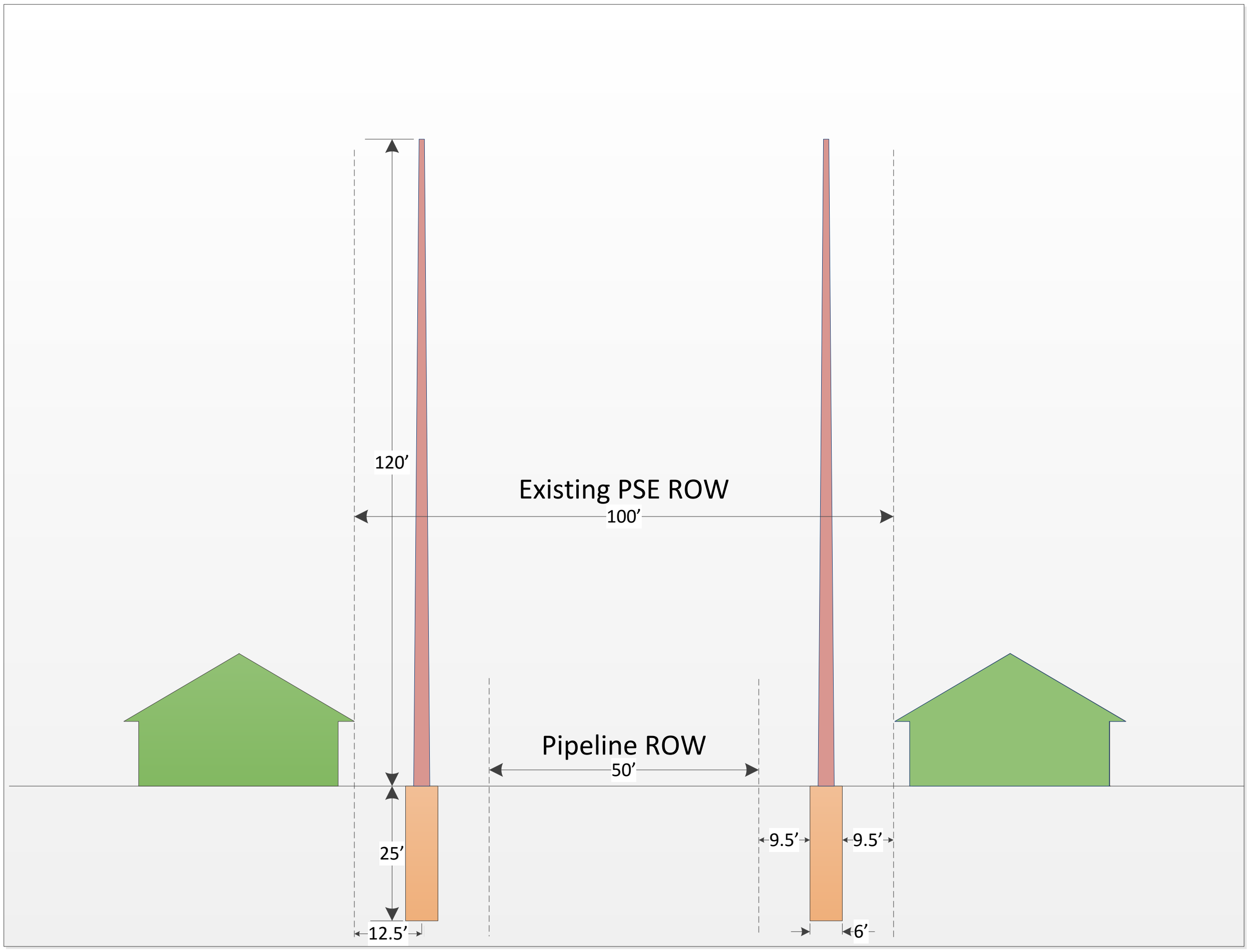


Figure 8

Modern standards of the U.S electrical power industry for 230kV power lines include a minimum 150-foot ROW (nominally 75 feet on each side of the power line support centerline). As an example, PPL Electric utilities with 1.4 million customers and 48,000 miles of power lines in central and eastern Pennsylvania requires the 150-foot ROW (ref PPL Electric Utilities Transmission Line Design Criteria Version 0 12/18/2012. Other examples include: Tri-State Generation and Transmission Association, Public Services Company of Colorado Comanche Transmission Project; Duke Energy Transmission Rights of Way – Ohio, Kentucky & Indiana.

PSE is ignoring modern standards in the selection of 230 KV power line routes through existing 100 foot ROWs. PSE points to historical examples where this has been done. These are artifacts of obsolete and outdated standards. PSE’s error is compounded by the location of the monopole supports. The location at the edge of the existing easement leads to an extremely skewed ROW offset with only 12.5 feet between the support centerline and the ROW boundary.

Chevron states: “*All overhead cable should maintain a minimum height of 20 feet above grade for a distance of 25 feet each side of the pipeline. No part or portion of mechanical supports and service drops, including poles, towers, guy wires, ground rods and anchors, should be within 25 feet of the existing pipeline*” (www.chevronpipeline.com/pdf/Guidelines_for_Property_Development.pdf).

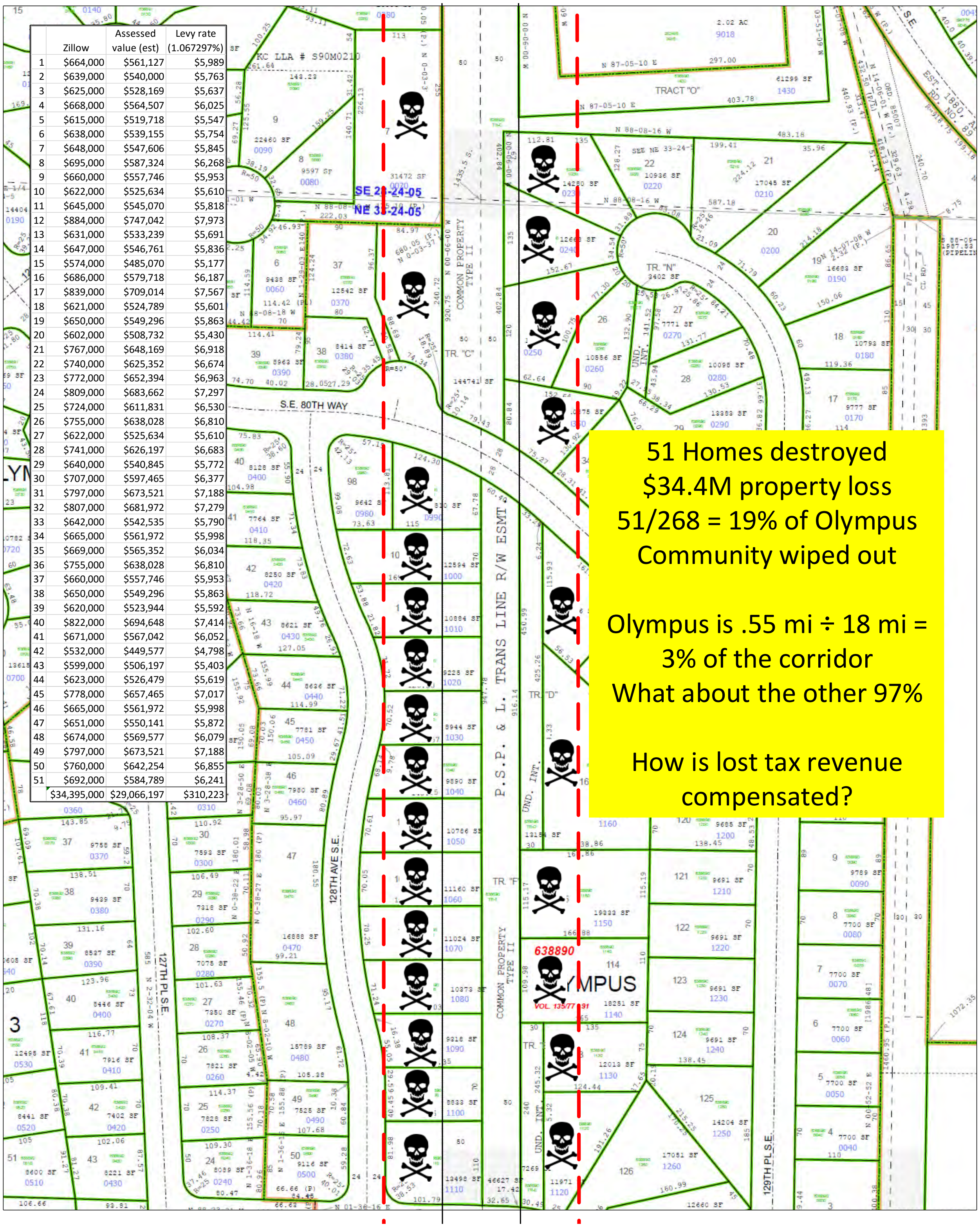
DSD 009896

The Bonneville Power Administration publishes their safety standards for transmission line installation (http://www.bpa.gov/news/pubs/GeneralPublications/lusi-Living-and-working-safely-around-high-voltage-power-lines.pdf). They state: "BPA operates one of the world's largest networks of long-distance, high-voltage lines, ranging from 69,000 volts to 500,000 volts. This system has more than 200 substations and more than 15,000 miles of power lines." One of their most critical safety requirements is:

> "**Pipes and cables should not be installed closer than 50 feet to a BPA tower, any associated guy wires or grounding systems. These grounding systems are long, buried wires that are sometimes attached to the structures and can run up to 300 feet along the right-of-way.**"and "**Proper positioning of underground utilities is required to prevent 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 or cable system.**"

BPA, Chevron, Arco, NACE, DNV GL and many more experts realize significant hazards in colocation. A high energy ignition source next to a highly flammable material is not a good thing. Induced AC corrosion is not a good thing. Need 50' separation between towers, supports, and grounding lines and all underground pipelines and hazardous liquid pipeline corridors. The existing ROW in the 'M" corridor is not wide enough.

Figure 9 shows the proper extent of a 230kV power line ROW adjacent to a pipeline consistent with BPA standards. Although not as rigorous as other U.S electrical power industry standards it does present a moderate safety solution. As can be seen, the existing ROW has insufficient width to accommodate the proposed 230kV power line. Clearly, the application of common sense modern standards precludes the routing of the 230kV power line through route 'M' within the existing corridor.



	Zillow	Assessed value (est)	Levy rate (1.067297%)
1	$664,000	$561,127	$5,989
2	$639,000	$540,000	$5,763
3	$625,000	$528,169	$5,637
4	$668,000	$564,507	$6,025
5	$615,000	$519,718	$5,547
6	$638,000	$539,155	$5,754
7	$648,000	$547,606	$5,845
8	$695,000	$587,324	$6,268
9	$660,000	$557,746	$5,953
10	$622,000	$525,634	$5,610
11	$645,000	$545,070	$5,818
12	$884,000	$747,042	$7,973
13	$631,000	$533,239	$5,691
14	$647,000	$546,761	$5,836
15	$574,000	$485,070	$5,177
16	$686,000	$579,718	$6,187
17	$839,000	$709,014	$7,567
18	$621,000	$524,789	$5,601
19	$650,000	$549,296	$5,863
20	$602,000	$508,732	$5,430
21	$767,000	$648,169	$6,918
22	$740,000	$625,352	$6,674
23	$772,000	$652,394	$6,963
24	$809,000	$683,662	$7,297
25	$724,000	$611,831	$6,530
26	$755,000	$638,028	$6,810
27	$622,000	$525,634	$5,610
28	$741,000	$626,197	$6,683
29	$640,000	$540,845	$5,772
30	$707,000	$597,465	$6,377
31	$797,000	$673,521	$7,188
32	$807,000	$681,972	$7,279
33	$642,000	$542,535	$5,790
34	$665,000	$561,972	$5,998
35	$669,000	$565,352	$6,034
36	$755,000	$638,028	$6,810
37	$660,000	$557,746	$5,953
38	$650,000	$549,296	$5,863
39	$620,000	$523,944	$5,592
40	$822,000	$694,648	$7,414
41	$671,000	$567,042	$6,052
42	$532,000	$449,577	$4,798
43	$599,000	$506,197	$5,403
44	$623,000	$526,479	$5,619
45	$778,000	$657,465	$7,017
46	$665,000	$561,972	$5,998
47	$651,000	$550,141	$5,872
48	$674,000	$569,577	$6,079
49	$797,000	$673,521	$7,188
50	$760,000	$642,254	$6,855
51	$692,000	$584,789	$6,241
	$34,395,000	$29,066,197	$310,223

51 Homes destroyed
$34.4M property loss
51/268 = 19% of Olympus Community wiped out

Olympus is .55 mi ÷ 18 mi = 3% of the corridor
What about the other 97%

How is lost tax revenue compensated?

Figure 10

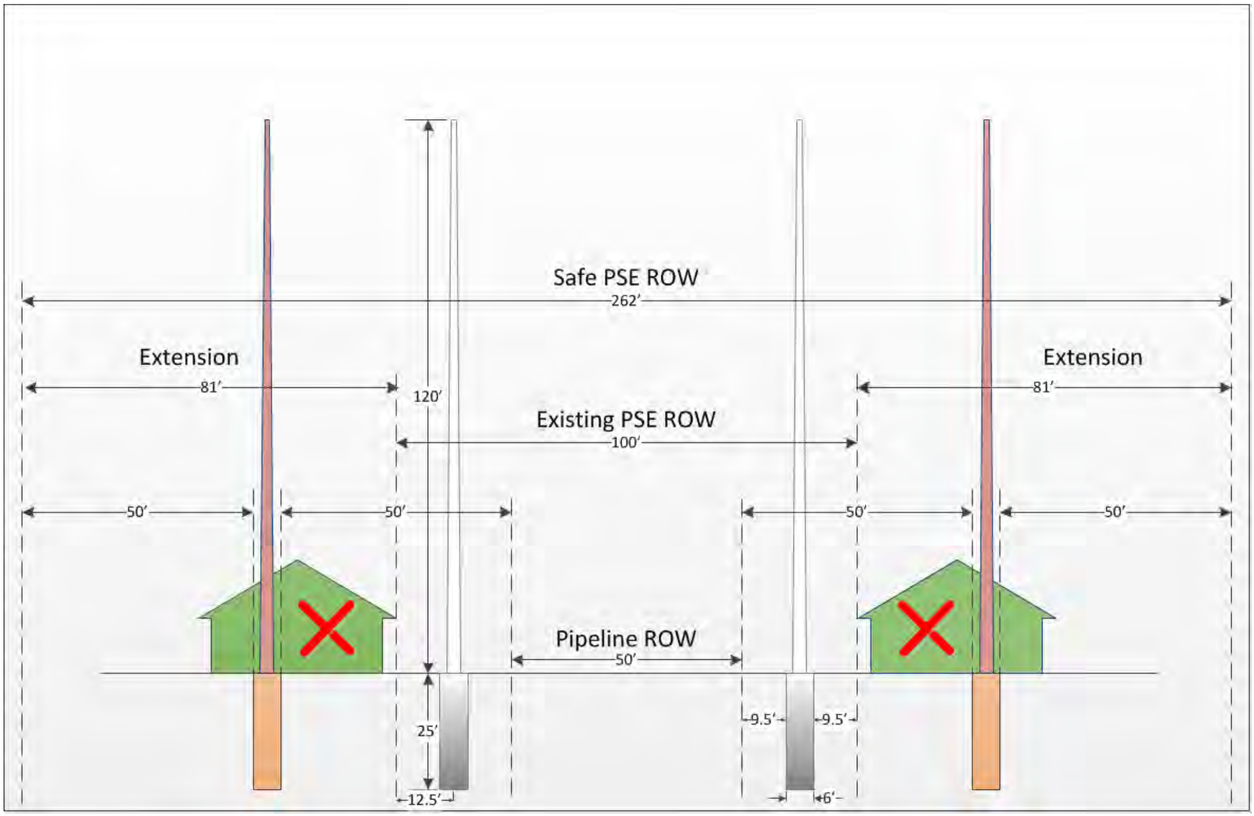


Figure 9

The EIS must address the impact of implementing this safety requirement. The transmission line corridor must be wide enough such that no tower will be within 50 feet of pipes including utility, hazardous liquid, or residential pipes. The current corridor is 100 feet wide. It must be expanded to approximately 260 ft (2.5X) to ensure adequate safety. In addition, no tower should be located such that it is within striking distance of any structure subsequent to a structural failure of the tower. The EIS must address this impact.

Figures 10 and 11 show the location of homes wiped out in the Olympus Neighborhood in Newcastle to allow some margin of safety for location of large conductive transmission towers. Why does Bellevue ignore this impact?

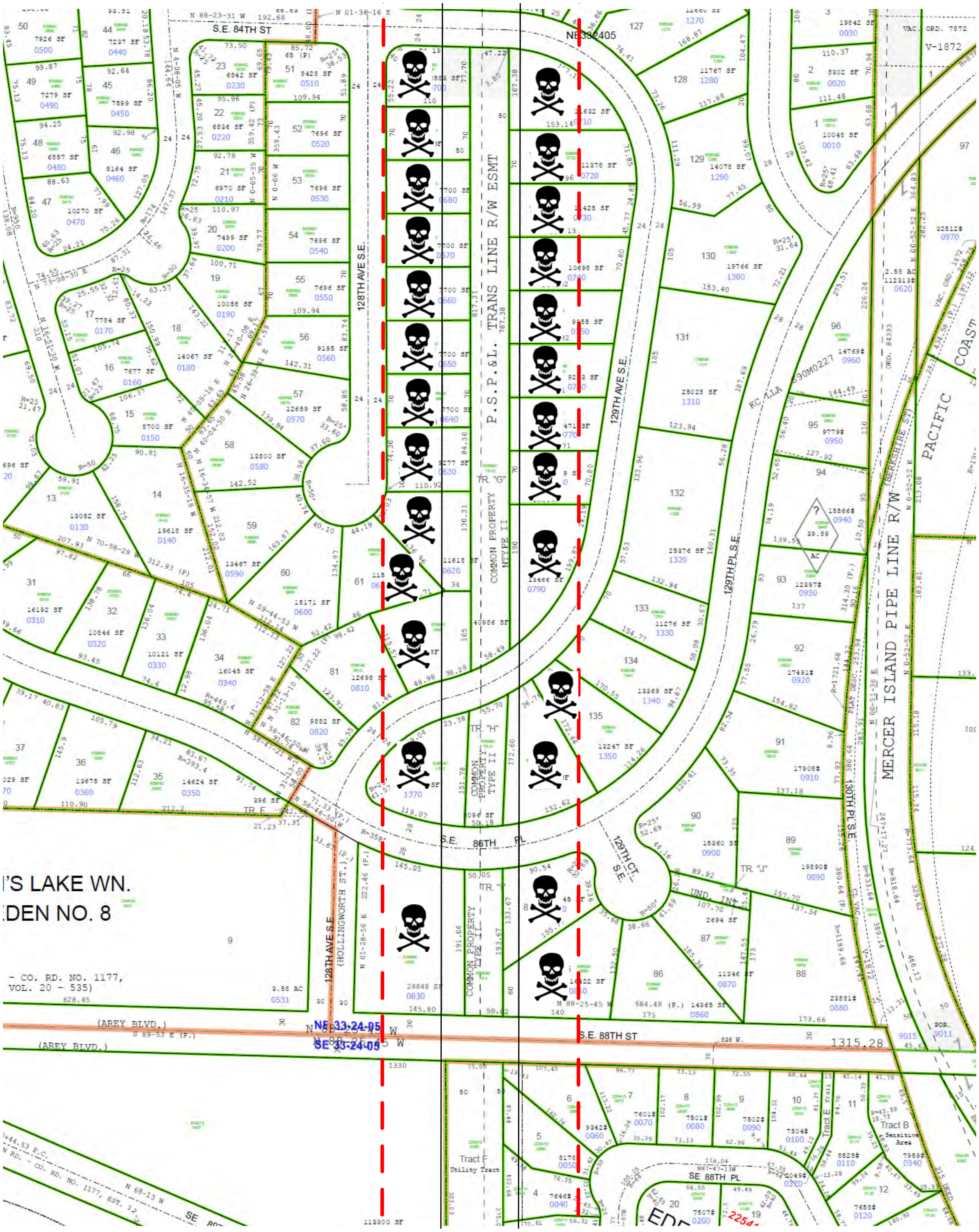
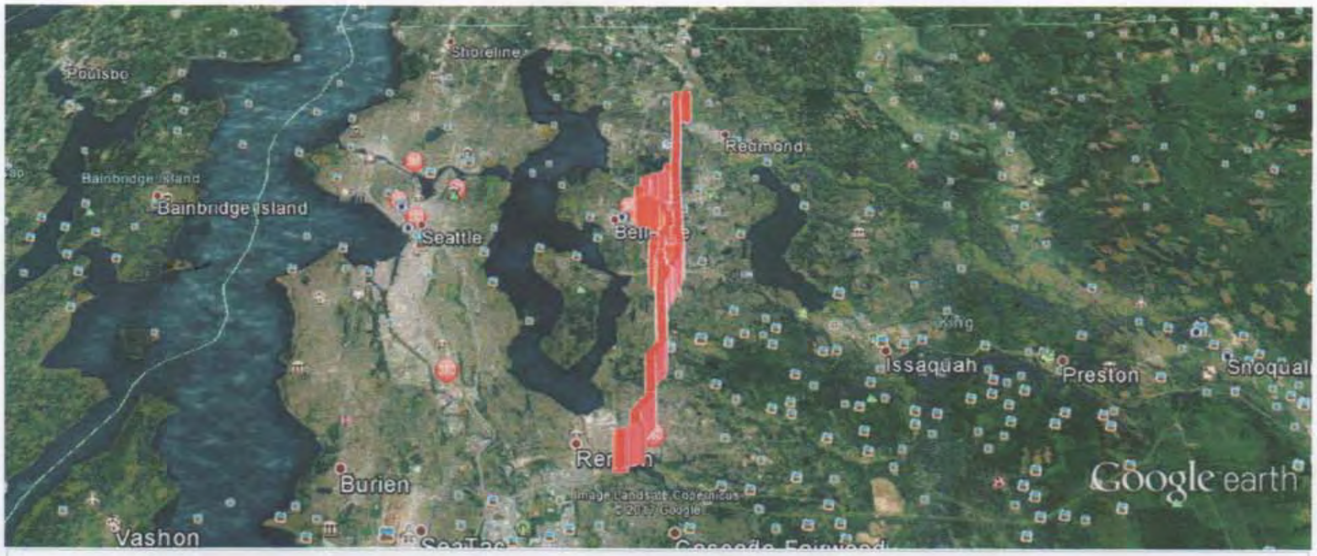


Figure 11

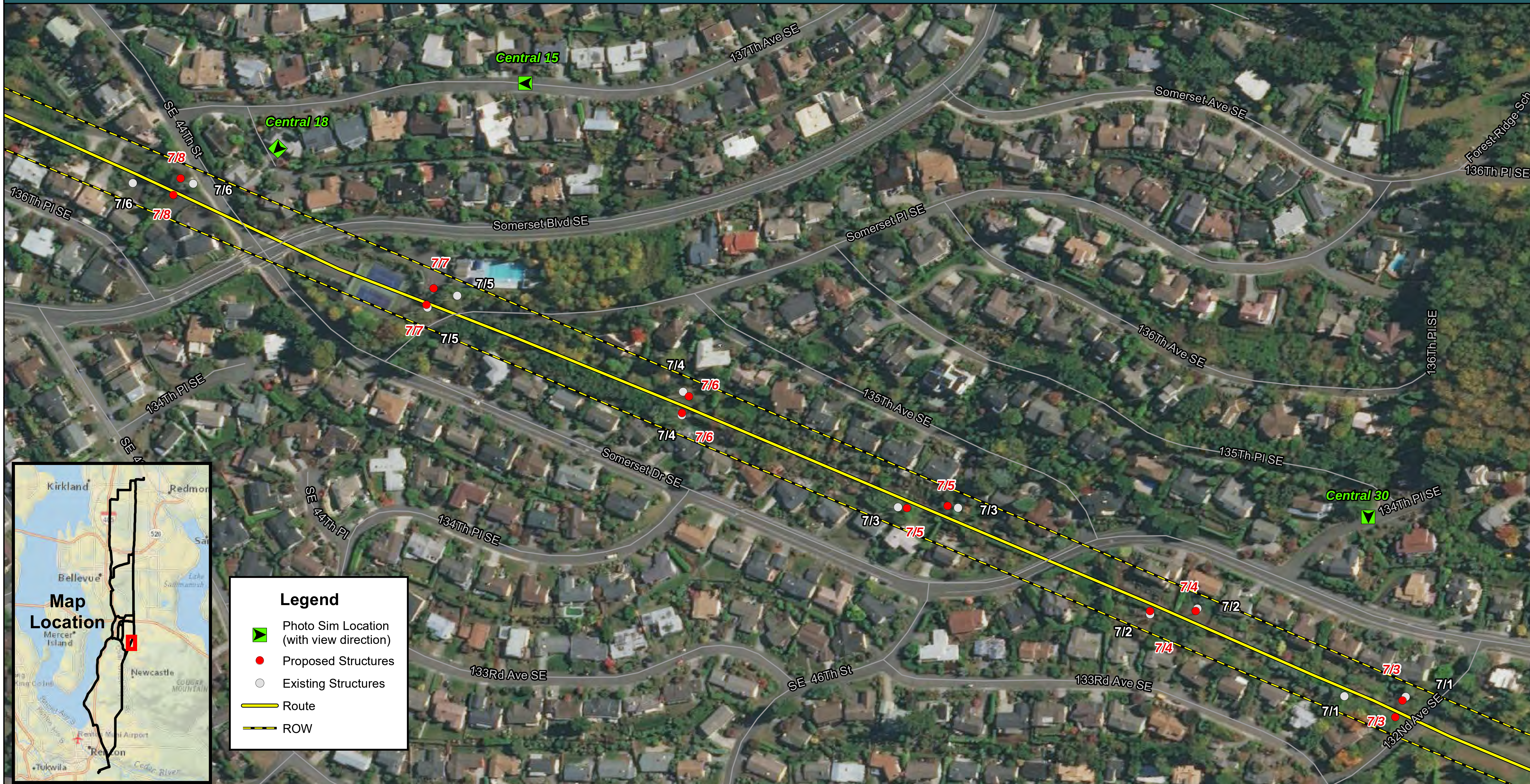
Many homes will be condemned and destroyed to make Alternative 1 safe. Up to 51 homes in Olympus will be gone in order to widen the existing corridor. These are not just concrete, 2x4s, and drywall structures. These are homes of families. Homes are places where children sleep at night. Homes are where neighbors have been neighbors for over a quarter century. Homes are where families enjoy life Homes are part of a community. In Olympus, 20% of a well-established community erased How is the impact of this loss being addressed. What's the visual character of a former neighborhood with metal towers replacing destroyed homes? Why does Bellevue these impacts in the DEIS?



ProposedPoles_Points

Photo Sim Location Map

Somerset Area



energizeEASTSIDE

Feet
0 100 200 400

N

PSE PUGET SOUND ENERGY

DSD 009903

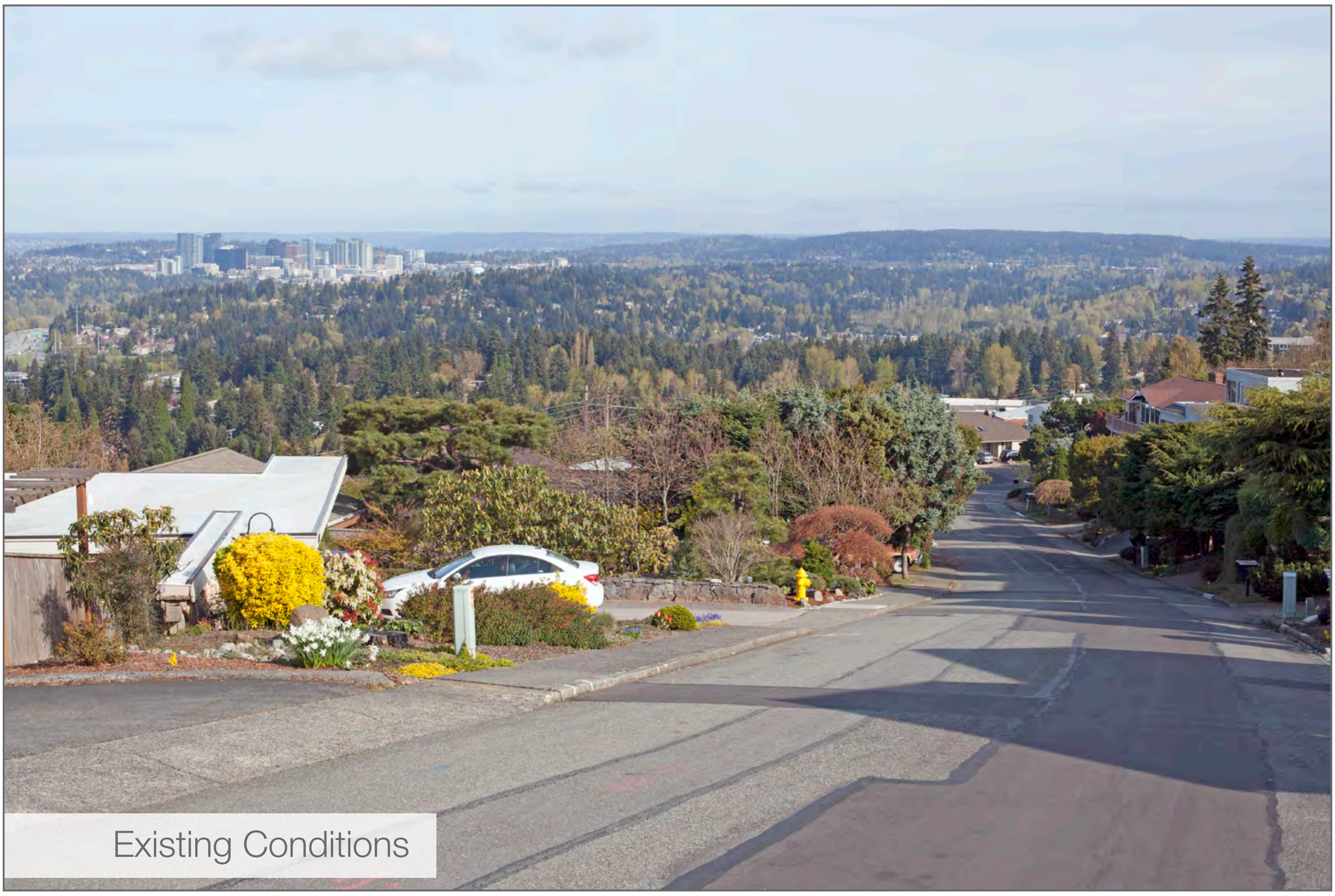


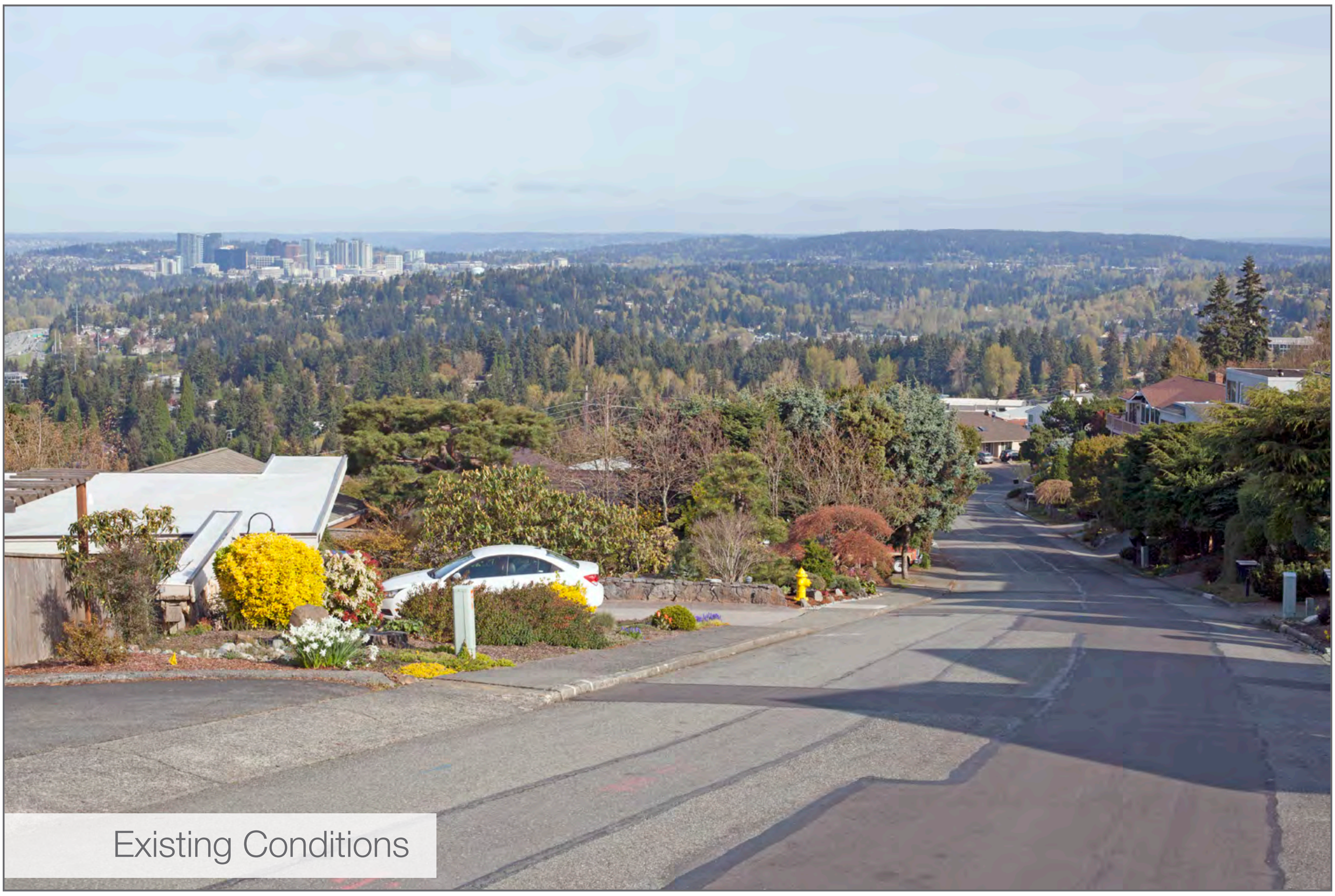
Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 7/6/2017

Address	**4489 137th Ave SE, Bellevue**
Date	**4/10/2014**
Time	**9:32 AM**
Viewing Direction	**North**
Existing Pole Heights	**~55 feet**
Proposed Pole Heights	**~75 feet**

KOP CENTRAL 15
SEGMENT 2

energize**EASTSIDE**

PSE PUGET SOUND ENERGY



Address	**4489 137th Ave SE, Bellevue**
Date	**4/10/2014**
Time	**9:32 AM**
Viewing Direction	**North**
Existing Pole Heights	**~55 feet**
Proposed Pole Heights	**~75 feet**

KOP CENTRAL 15
SEGMENT 2

KOP CENTRAL 18
SEGMENT 2

Address	**4411 137th Ave SE, Bellevue**
Date	**5/7/2014**
Time	**10:53 AM**
Viewing Direction	**Northwest**
Existing Pole Heights	**~55 feet**
Proposed Pole Heights	**~75 feet**

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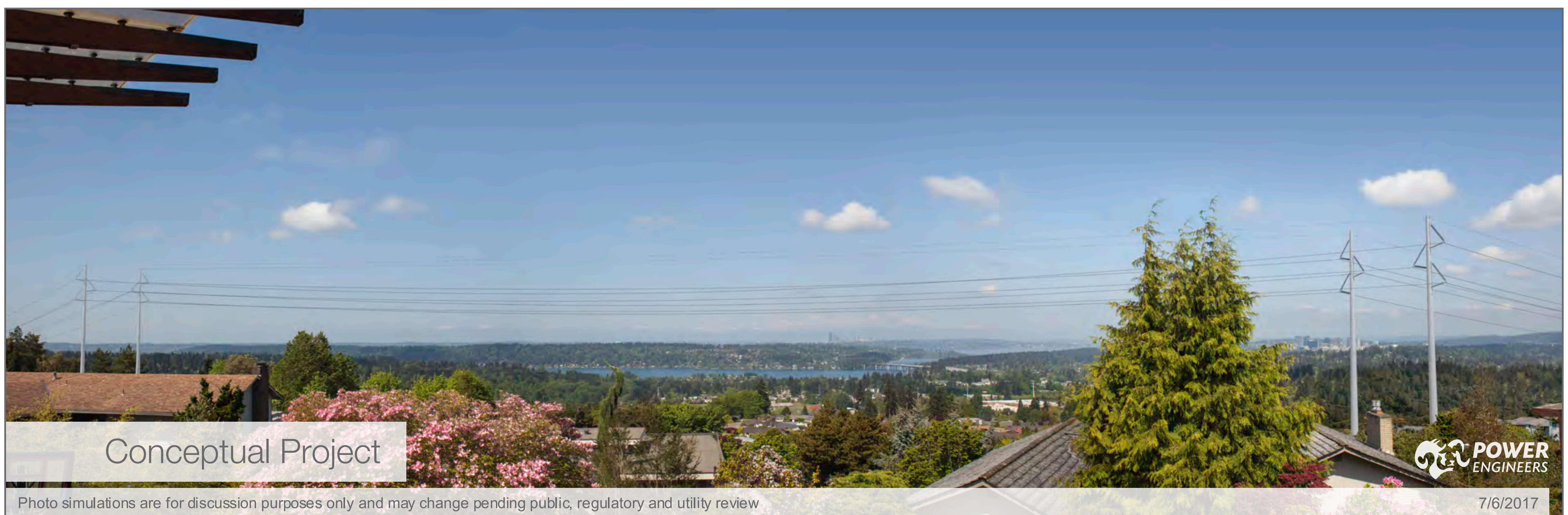
PSE PUGET SOUND ENERGY

KOP CENTRAL 18
SEGMENT 2

Address	4411 137th Ave SE, Bellevue
Date	5/7/2014
Time	10:53 AM
Viewing Direction	Northwest
Existing Pole Heights	~55 feet
Proposed Pole Heights	~75 feet

Existing Conditions



Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 7/6/2017

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PSE PUGET SOUND ENERGY

Address	**4730 134th Place SE, Bellevue**
Date	**8/24/2016**
Time	**3:28 PM**
Viewing Direction	**West**
Existing Pole Heights	**44 feet**
Proposed Pole Heights	**75 feet**

KOP CENTRAL 30
WILLOW 1 - SEGMENT 2

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PSE PUGET SOUND ENERGY

Existing Conditions

Conceptual Project

Photo simulations are for discussion purposes only and may change pending public, regulatory and utility review 11/16/2016

Address	**4730 134th Place SE, Bellevue**
Date	**8/24/2016**
Time	**3:28 PM**
Viewing Direction	**West**
Existing Pole Heights	**44 feet**
Proposed Pole Heights	**75 feet**

KOP CENTRAL 30
WILLOW 1 - SEGMENT 2

energize**EASTSIDE**

PSE PUGET SOUND ENERGY

Photo of underground utility construction methods

Splicing vault installation (Source: POWER Engineers)

References

Joint Legislative Audit and Review Commission. (2006). "Evaluation of Underground Electric Transmission Lines in Virginia." http://jlarc.virginia.gov/pdfs/reports/Rpt343.pdf

Puget Sound Energy's Tariff and Undergrounding - Schedule 80, Section 34 http://pse.com/aboutpse/Rates/Documents/elec_sch_080.pdf

POWER Engineers. (2014). Eastside 230 kV Project Underground Feasibility Study. https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/085-1244PSE_FeasibilityStudy_03-31-2014.pdf

Thank you for your interest in Energize Eastside.

pse.com/energizeeastside 1-800-548-2614 energizeeastside@pse.com

PSE PUGET SOUND ENERGY

energize**EASTSIDE**

underground transmission lines frequently asked questions

With the Energize Eastside project, Puget Sound Energy (PSE) will build a new substation, upgrade approximately 18 miles of existing transmission lines, and continue to implement aggressive conservation to meet the Eastside's electrical demands.

Placing Energize Eastside's transmission lines underground has been a topic of community interest since the project launched. Consistent with this interest, PSE hired POWER Engineers to conduct an underground transmission construction feasibility study from a cost, construction and siting perspective. The report confirmed that undergrounding the project would have more impacts than an overhead line, have significant costs subject to a lengthy schedule, and confront considerable siting obstacles.

Per state regulations, the additional costs of undergrounding must be covered by the local community requesting it. Energize Eastside is planned as an overhead transmission line, as no public entity has agreed to fund the additional costs associated with undergrounding and PSE's schedule can no longer accommodate the time needed to site, engineer, permit and construct underground lines.

We often get questions about placing the lines underground, so we wanted to provide additional details.

Can PSE bury transmission lines underground?

While it is technically possible to build a transmission line underground, it is up to the community to decide whether to make that investment. For Energize Eastside, in addition to the significant siting challenges, no public entity has agreed to invest in undergrounding.

Why is cost sharing required for undergrounding transmission lines?

State regulations require PSE to first consider building overhead transmission lines because of their combination of reliability and affordability, both of which are important to our customers.

Underground transmission lines are considered a "local option" under applicable regulations. This means the local community must pay the cost difference between building overhead and underground lines (rather than having the entire project cost shared by PSE's 1.1 million customers). The requesting community would share the cost of the project from initial preliminary design to construction to ongoing maintenance and repair.

Most communities decide not to invest in undergrounding transmission based on the significant costs and competing investment priorities.

Underground **distribution** cable replacement

Transmission duct bank and vault placement (Source: POWER Engineers)

Why does undergrounding transmission cost more?

Burying the lines increases the cost due to the scale and complexity of underground infrastructure.

Construction costs for an overhead 230 kilovolt (kV) transmission line are about $3 million to $4 million per mile, versus $20 million to $28 million per mile for undergrounding. Additional costs, such as land acquisition and relocation of existing underground utilities, can be very significant – sometimes two to three times the construction costs.

Underground distribution seems fairly common, so why not underground transmission lines, too?

Typical underground transmission lines that move power between substations are larger in scale and more technically complex than the underground distribution lines that serve neighborhoods. The photos on the front page highlight the typical differences in scale between transmission and distribution lines.

The larger underground transmission lines give off more heat than distribution lines. For distribution lines, that heat can be dissipated into the surrounding soil, while the heat from transmission lines is dissipated into thermally-rated fill. In addition, underground transmission cables are typically installed in concrete duct banks that can extend 5 feet or more below the surface causing significant disruption to the local area.

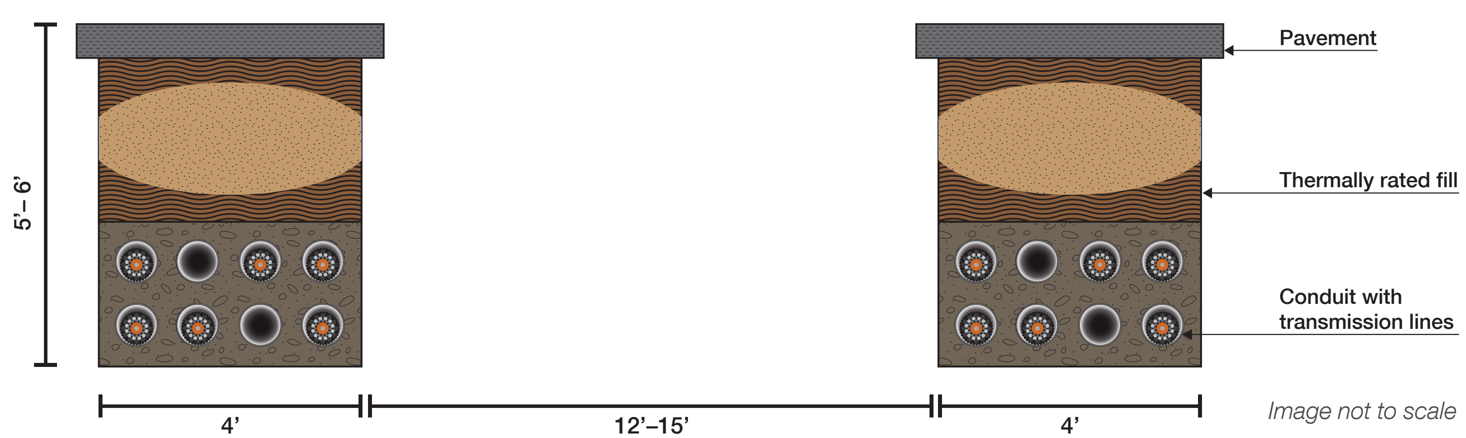
Underground transmission lines are not common. Nationally, less than 1 percent of 230 kV or higher transmission lines are underground. Underground transmission lines are most commonly seen in dense urban areas where overhead lines are infeasible, such as in downtown areas like Manhattan or Los Angeles.

What are the challenges to placing Energize Eastside underground?

In 2014, POWER Engineers conducted a feasibility study for undergrounding Energize Eastside. They confirmed while it is technically feasible to construct the project underground, this approach would face some real challenges on the Eastside and would be more impactful than overhead lines.

The challenges of undergrounding 230 kV transmission lines on the Eastside include:

- **Undergrounding is more costly and requires cost sharing with requesting communities.** PSE shared the cost difference with local cities and they did not express interest in pursuing this option.
- **Finding a new corridor between Redmond and Renton.** The existing utility corridor cannot accommodate the underground transmission lines, so that means placing them somewhere else, such as city streets or a new corridor. This would significantly add to the cost of the project, the differential of cost being borne by local communities.
- **Lengthy design, permit and construction schedule.** Based on current estimates, it would take at least six years for us to design, negotiate easements, permit, procure materials, and construct the underground transmission lines. Such a schedule would mean PSE would have a long-term plan for rolling blackouts until the new underground transmission lines are built.
- **Finding adequate space for garage-sized underground facilities.** Undergrounding requires the construction of underground vaults the size of a two-car garage approximately every ¼ mile to ½ mile. To accommodate each underground vault, we would need at least 30-foot by 50-foot easements.
- **Construction work is more intensive.** Underground lines require a large trench for the conductors, conduit, and vaults along the line. For each mile of construction, we'd need about 500 dump trucks for excavation haul off, 200 dump trucks for thermal concrete backfill, and another 300 dump trucks for the balance of the trench backfill (i.e., about 1,000 truckloads per mile).
- **Moving existing utilities.** There is a complex infrastructure of natural gas, sewer, water and communication lines beneath our roads and utility corridors. Adding the large footprint of underground transmission lines would mean potentially moving existing utilities, which could increase project costs and limit project feasibility.
- **Increased impact to trees and aboveground landscaping.** Trees and shrubs are not allowed to grow over the trench for inspection and operational reasons (e.g., roots cannot be allowed to grow into the conduits).



Typical underground concrete duct banks for two 230 kV lines

Based on these significant challenges, we've planned Energize Eastside as an overhead transmission project.

Could PSE use undergrounding for portions of the project?

Undergrounding the project in segments would face similar challenges as doing so for the entire route. As discussed earlier, the existing utility corridor will not accommodate the underground transmission lines. Therefore, PSE would still need a new corridor to underground segments, which would be more impactful than overhead transmission lines.

What are the trade-offs between overhead and underground transmission lines?

	Overhead 230 kV transmission lines	Underground 230 kV transmission lines
Construction costs[1]	• $3 million to $4 million per mile • Costs shared between PSE's 1.1 million customers	• $20 million to $28 million per mile • Costs shared with requesting party (i.e., city)
Construction impacts	• Construction entails removing existing poles, setting new poles and stringing wire within existing utility corridor	• **Easements:** New utility corridor required at 30 feet to 50 feet wide to place underground concrete duct banks • **Substantial trenching** to fit concrete duct banks • **Large vaults:** Concrete access vaults (20 feet by 30 feet) required every 1/4 mile to 1/2 mile • May require moving existing underground facilities
Vegetation	• Trees under 15 feet in height allowed	• No trees or shrubs for width of new corridor
Reliability	• Lines can fail due to equipment failure • Susceptible to wind, ice storms and third party damage (i.e., car/pole accidents) • Outages infrequent	• Cable can fail due to corrosion, fatigue, other stress • Susceptible to root intrusion and third party damage (i.e., excavation) • Outages very infrequent
Outage Repair	• Easier to find a problem and repair • Repairs typically made within a day during normal weather; longer during storms	• Locating problems and making repairs can take more time, and in some cases for several weeks • Worldwide, there are a limited number of highly trained crews for repair
Maintenance	• Costs less to repair, upgrade and relocate	• Costs more to repair, upgrade or relocate
Aesthetics	• Poles, wires and support anchors visible	• Vaults and transition structures less visible

1 These cost estimates include design, engineering, materials and construction. Additional costs, such as right-of-way acquisition, relocation of underground utilities, permitting and mitigation, can be very significant.

PUGET SOUND ENERGY

SCHEDULE 80
GENERAL RULES AND PROVISIONS (Continued)

34. **CONSTRUCTION OF ELECTRIC FACILITIES:** This section provides for the recovery of Company Costs for Projects requested or required by a Requesting Entity including, but not limited to, Projects resulting from requirements or conditional requirements of a permit or ordinance issued or passed by a Governmental Entity after the initial effective date of this provision. The Company shall not be obligated to undertake requested or required Projects if, in the Company's sole judgment, the Projects are not feasible, are impracticable, are not able to be permitted, or will result in an unreliable or less reliable electric system.

a. Definitions – The following terms, when used in this rule, shall have the meanings listed below whether capitalized or not, unless clearly indicated otherwise. Terms defined in this section control, even if the term is defined in section 2 of this Schedule 80 or elsewhere in this tariff. Terms defined in section 2 of this Schedule 80 that are not in conflict with terms defined in this section will have the meanings given in section 2.

i. Costs: All costs including, but not limited to, costs to produce an estimate of costs, costs for engineering, surveying, pre-construction coordination, reviewing plans and proposals, permits, land, Operating Rights, materials, labor, backfill, traffic control, acquisition and construction of access roads, disposal of spoils and other materials, removal or relocation of electric or other facilities conflicting with the route or location of construction, restoration, replacement, re-engineering and change orders, future increased operating and maintenance costs over the life of the facilities installed, taxes and overheads. Costs shall be determined by the Company using its own cost estimating system in conjunction with sound engineering practices.

ii. Electric Facilities: All necessary electrical and non-electrical components of the electric system including, but not limited to materials, excavation, backfill, land, access roads and Operating Rights that are necessary, in the Company's sole judgment, in order for the Company to provide Electric Service to Customers.

iii. Government Entity: Any agency, instrumentality, or other entity of municipal, county, state or federal government, including multi-jurisdictional agencies, instrumentalities, and entities.

SCHEDULE 80
GENERAL RULES AND PROVISIONS (Continued)

34. **CONSTRUCTION OF ELECTRIC FACILITIES** (Continued)**:**

a. Definitions – (Continued)

iv. Operating Rights: All legal rights necessary, in the Company's sole judgment, for the installation, operation, maintenance, repair or replacement of all Projects constructed pursuant to this schedule, including, without limitation, rights of access over, under, across, or through real property, including real property not owned by the Requesting Entity. Operating Rights shall be obtained by the Requesting Entity for the Company prior to the commencement of construction of such Project. Operating Rights shall be evidenced by one or more written instruments in form and substance satisfactory to the Company. Where Operating Rights are subject to fee, the Requesting Entity shall be responsible for payment of such fee.

v. Project: Electric Facilities constructed, relocated or rebuilt at the request of a Requesting Entity or Electric Facilities that are constructed, relocated or rebuilt in a different manner than initially proposed by the Company upon request of a Requesting Entity. Projects exclude Projects or portions of Projects for line extensions to provide service to new customers under Schedule 85 of this tariff and conversion to underground under Schedules 73 and 74 of this tariff. A Project includes all Electric Facilities necessary to effectuate the request.

vi. Public Thoroughfare: Any municipal, county, state, federal or other public road, highway or throughway, or other public right-of-way or other public real property rights allowing for electric utility use.

vii. Requesting Entity: Any Government Entity or other party or entity requesting or requiring services provided under this schedule.

SCHEDULE 80
GENERAL RULES AND PROVISIONS (Continued)

34. **CONSTRUCTION OF ELECTRIC FACILITIES** (Continued)**:**

b. Conditions – On occasion a Requesting Entity requests or requires the undertaking of, or changes to, a Project relating to the electric system. In order for the Projects undertaken in response to such requests to result in rates for electric service that are fair, just, reasonable and sufficient, the following conditions apply:

i. The Company, in its sole judgment, shall determine the Cost of the Electric Facilities for Projects based on the location, route, design, phase, voltage, capacity, and type of facilities to be constructed in the Company's sole judgment and in accordance with Company standards.

ii. Where the location, route, design, phase, voltage, capacity, type or any other characteristic of Electric Facilities proposed to be used by the Company is requested or required by a Requesting Entity to be different from that proposed by the Company, and that change results in increased Cost for the Electric Facilities which may result in higher costs for electric service, the Requesting Entity requesting or requiring a change in the Electric Facilities, including, but not limited to, a change in location, route, design, phase, voltage, capacity or type of facilities, shall pay the Company for any and all increase in Cost due to such change. Where a change in Electric Facilities proposed by the Company is requested or required by a Requesting Entity, the increased Cost to be paid by the Requesting Entity shall include the cost of additional facilities that are necessary, in the sole judgment of the Company, to achieve the level of reliability of the Electric Facilities originally proposed by the Company, as well as the cost to enhance reliability beyond that proposed by the Company if the Project requested by the Requesting Entity is intended to enhance reliability for the Requesting Entity. Where a change in existing Electric Facilities is requested or required by a Requesting Entity, the Requesting Entity shall pay the Company for the cost due to such change, including the cost of additional facilities that are necessary, in the sole judgment of the Company, to maintain the existing level of reliability, as well as the cost to enhance reliability beyond the existing level of reliability if the Project requested by the Requesting Entity is intended to enhance reliability for the Requesting Entity. Where a Requesting Entity requests a Project that replaces existing Electric Facilities, the Requesting Entity shall pay the Company for all of its Costs, including, but not limited to, the cost of all Electric Facilities removed or no longer of use, due to such Project.

SCHEDULE 80
GENERAL RULES AND PROVISIONS (Continued)

34. **CONSTRUCTION OF ELECTRIC FACILITIES** (Continued)**:**

b. Conditions – (Continued)

iii. The Company, in its sole judgment, shall determine the construction techniques, facility location including separation from other utilities, route, electrical design, phase, voltage, capacity and electrical type of all Electric Facilities to be installed in accordance with its standards.

iv. The Company, in its sole discretion, may determine that the Project or route is not feasible or is impracticable. Zoning or other land use regulations that allow for limited or zero set-back of structures from the property line, thereby leaving inadequate space for the Company's Electric Facilities, and environmental regulations are two of the many items the Company will consider in order to determine feasibility. The Company may determine that a Project is not feasible if it results in less reliable service to any Customer.

v. The Company or its contractor shall construct all Projects unless the Company decides otherwise. The Company shall own, operate and maintain the result of all Projects and shall own all land provided and Operating Rights granted that are necessary for all Projects.

vi. The Costs of any future relocation of the Electric Facilities installed under the provisions of this section shall be paid by the Requesting Entity and the Requesting Entity shall provide all necessary Operating Rights for such relocation at no cost to the Company.

vii. The Company shall not be required to provide service, and may interrupt or discontinue service, if all or any portion of its facilities or Operating Rights are taken through the exercise of police powers or the power of eminent domain or are taken under threat thereof or are otherwise lost, terminated, or canceled.

viii. The Company may refuse any Project requested by a Requesting Entity that has the effect of reducing the reliability or capacity available to other Customers.

SCHEDULE 80
GENERAL RULES AND PROVISIONS (Continued)

34. **CONSTRUCTION OF ELECTRIC FACILITIES** (Continued)**:**

c. Applicable Projects – The provisions of this Section 34 shall apply to Projects involving Electric Facilities including, but not limited to, the following:

i. Electric Facilities operating at 50,000 volts or more that are submarine or underground facilities placed underwater or at or under the surface of the earth, including surface to submarine transition Electric Facilities and overhead to underground transition Electric Facilities. The Company, in its sole judgment, shall determine the electrical and civil design for submarine or underground Electric Facilities. To determine the amount to be paid by the Requesting Entity, the actual Costs of the submarine or underground Electric Facilities shall be compared to the estimated Costs of overhead Electric Facilities and the Requesting Entity shall pay the additional cost. If overhead Electric Facilities are not feasible, the additional cost shall be the increase over an equivalent length of overhead Electric Facilities. The estimated Costs shall be of Electric Facilities connecting the same points in the Company's system, but along the least cost feasible route, as determined by the Company.

ii. Electric Facilities operating below 50,000 volts in Projects or portions of Projects to be located in a Public Thoroughfare that are requested or required by a Requesting Entity other than the Government Entity having authority over the Public Thoroughfare where the Electric Facilities are or will be located. The Requesting Entity shall pay costs in accordance with section b. ii. of this Section 34.

iii. Electric Facilities operating below 50,000 volts in Projects or portions of Projects to be located other than in a Public Thoroughfare. The Requesting Entity shall pay costs in accordance with section b. ii. of this Schedule 34.

d. Schedule 87 – The installation, modification or relocation of facilities under the provisions of this section shall be subject to the provisions of Schedule 87, Income Tax Rider.

e. Payment – The Requesting Entity, unless prohibited by law, shall pay the estimated Costs in advance of design engineering of the Project. If the Requesting Entity cannot lawfully pay the Costs in advance, the Costs shall be paid within fifteen (15) days of the date of the Company's invoice. If the actual Costs are less than or greater than the initial estimated Costs by more than ten percent (10%) of the estimate, the Company shall refund the excess payment to the Requesting Entity or bill the Requesting Entity for the underpayment so that the Requesting Entity pays the actual Costs.

MEMORANDUM

May 6, 2016

TO: ROB WYMAN, CITY OF NEWCASTLE AND LORI RIORDAN, CITY OF BELLEVUE

FROM: LORNA LUEBBE AND JENS NEDRUD

RE: Puget Sound Energy, Inc.'s Interpretation of Schedule 80

To further conversations with municipalities with jurisdiction over the Energize Eastside Project, Puget Sound Energy, Inc. ("PSE") seeks to clarify its interpretation of Electrical Tariff G, Schedule 80, approved by the Washington Utilities and Transportation Commission ("WUTC"), as it would apply to requests to underground 230 kV transmission lines.

Background

PSE is charged under Washington statutes to provide safe and reliable electric service to its customers in an efficient manner and at reasonable rates. *See* RCW 80.28.010(1)(2); RCW 80.28.020. As a regulated utility, the expenditures PSE makes to maintain or improve its electrical infrastructure must be prudent. If expenditures are determined by the WUTC to not be "prudent," PSE cannot recover the cost of those expenditures from customers. Consistent with technical feasibility and its duty to provide electric service efficiently and at reasonable rates, PSE does not propose the underground installation of 230 kV transmission lines (including those currently under consideration in the Energize Eastside Project) unless required for engineering reasons. Underground installation of transmission lines is over five to ten times more costly than analogous overhead configurations.

Overview of Schedule 80

Schedule 80, Section 34 provides that PSE shall not be obligated to undertake electric facility "projects" requested by a government entity, "if, in the Company's sole judgment, the Projects are not feasible, are impracticable, are not able to be permitted, or will result in an unreliable or less reliable electric system." **"**Projects" includes "Electric Facilities constructed, relocated or rebuilt in a different manner than initially proposed by the Company upon request of a Requesting Entity."

Schedule 80, however, provides a mechanism for allowing municipalities to request a design change deviating from company standards, where they assume responsibility for the delta in cost between the project as proposed and project as modified by the municipality. Specifically,

> Where the location, route, design, phase, voltage, capacity, type or any other characteristic of Electric Facilities proposed to be used by the Company is requested or required by a Requesting Entity to be different from that proposed by the Company, and that change results in increased Cost for the Electric Facilities which may result in higher costs for electric service, the Requesting Entity requesting or requiring a change in the Electric Facilities, including, but not limited to, a change in location, route, design, phase, voltage, capacity or type of facilities, shall pay the Company for any and all increase in Cost due to such change.

Schedule 80, Sec. 34.b.ii.

More specifically, Schedule 80 expressly identifies underground installation of Electric Facilities operating at 50,000 volts or more (including conversion of overhead to underground transitions) as "Applicable Projects" for which a Requesting Entity would be required to assume responsibility for the increased cost resulting from a requested change in design. *See* Schedule 80, Sec. 34.c.i. In such cases, "[t]o determine the amount to be paid by the Requesting Entity, the actual Costs of the . . . underground Electric Facilities shall be compared to the estimated Costs of overhead Electric Facilities and the Requesting Entity shall pay the additional cost." Schedule 80, Sec. 34.c.i. Tariffs, including Schedule 80, have the force and effect of state law. *See, e.g., General Tel. Co. v. City of Bothell*, 105 Wn.2d 579, 585, 716 P.2d 879 (1986).

PSE's Interpretation of Schedule 80

Schedule 80 explicitly applies to requests for the underground installation of transmission lines where undergrounding is not required for technical reasons. Schedule 80, Sec. 34.b.ii (applying to requested changes in "route, design… or any characteristic of Electrical Facilities"); Schedule 80, Sec. 34.c.i.. To the extent that they do not conflict with Schedule 80, PSE does not interpret it as applying to mitigation to address specific, identified adverse impacts in an appropriate and proportionate manner, as required by a jurisdiction's municipal code or state law, including the State Environmental Policy Act ("SEPA"). The WUTC has approved for recovery in rates projects that include mitigation as part of the permitting or licensing of the Project. *See, e.g. WUTC v. PSE,* Docket UE-130617 Order 06, ¶¶ 46, 67, 78 (Oct.23, 2013) (finding prudent PSE's hydroelectric project upgrades including mitigation such as floating surface collectors for fish passage).

Federal, state and local law may require that PSE undertake mitigation responsive to adverse impacts resulting from the construction of transmission lines. To avoid a taking under the state and federal constitutions, mandatory mitigation must be tied to a specific impact and be proportionate to that impact. *See, e.g., Isla Verde Int'l Holdings, Inc. v. City of Camas*, 146 Wn. 2d 740, 761, 49 P.3d 867, 879 (2002); RCW 82.02.020; 82.02.050(3)(b) (applying to impact fees). For example, under SEPA, mitigation must "mitigate specific adverse environmental impacts… [and] shall be reasonable and capable of being accomplished." RCW 43.21C.060; WAC 197-11-660(1). "Responsibility for implementing mitigation measures may be imposed upon an applicant <u>only to the extent attributable to the identified adverse impacts of its proposal.</u>" WAC 197-11-660(1)(d) (emphasis added). Because Schedule 80 has the force of state law, a municipal mitigation ordinance that directly conflicts with it is null and void. *Gen.*

Tel. Co. of Nw. v. City of Bothell, 105 Wash. 2d 579, 587, 716 P.2d 879, 884 (1986) ("Whether seen as contractual or police power exercises,… subsequent ordinances do not have the authority to preempt that tariff. Those portions of… ordinances that conflict with [the] tariff are thus rendered null and void.").

PSE has entered into a broad spectrum of mitigation agreements, ranging from comprehensive vegetation replanting plans, to landscaping and screening, to including art projects on transmission line poles. In such cases, PSE itself proposes the mitigation packages in their permit applications and has not sought to recover the costs of mitigation from requesting municipalities under Schedule 80. The WUTC does not have authority to recover such costs from municipalities. PSE remains committed to fully mitigate all identified adverse impacts to the extent required by law and permitted under the WUTC's prudence standard and tariffs.

PSE hopes that the above memorandum assists partner cities in evaluating the application of Schedule 80 to the Energize Eastside Project. Please let us know if you have any additional questions with respect to PSE's interpretation of Schedule 80.

June 22, 2017

Molly Reed
PSE Energize Eastside
355 110th Avenue NE
Bellevue, WA 98004

Re: Richards Creek Substation property, Wetland and Stream Delineation Report
The Watershed Company Reference Number: 111103.6

Dear Molly:

On March 15th and 27th, a wetland and stream delineation study was completed at the Richards Creek Substation parcel located at SE 30th Street in the city of Bellevue (parcel number 1024059130). The purpose of the study was to delineate wetland and stream boundaries on the parcel that could potentially encumber the planned Richards Creek Substation to be developed. This delineation study will update the findings of previous delineation studies conducted on the parcel. This report presents the findings of the 2017 re-delineation effort and details applicable local, state and federal regulations. The following attachments are included:

- Survey-based Wetland Delineation Map
- Wetland Determination Data Forms
- 2004 and 2014 Ecology Wetland Rating Forms and Figures

Methods

Public-domain information on the subject properties was reviewed for this delineation study and include the following:

- USDA Natural Resources Conservation Service, Web Soil Survey (WSS) application
- U.S. Fish and Wildlife Service National Wetland Inventory (NWI) maps
- Washington Department of Fish and Wildlife interactive mapping programs (PHS on the Web, SalmonScape)
- Washington Department of Natural Resources, Forest Practices Application Mapping Tool (FPARS)
- King County's GIS mapping website (iMAP)

Climatic conditions for precipitation were determined to be normal using the WETS table methodology from the USDA NRCS document Part 650 Engineering Field Handbook, National Engineering Handbook, Hydrology Tools for Wetland Identification and Analysis, Chapter 19 (September 2015). The Seattle-Tacoma International AP station as recorded by NOAA (http://agacis.rcc-acis.org/) was used as a source for precipitation data. The WETS table methodology uses climate data from the three months prior to the site visit month to determine if normal conditions are present.

Wetlands

The study area was evaluated for wetlands using methodology from the *Regional Supplement to the Corps of Engineers Wetland Delineation Manual: Western Mountains, Valleys, and Coast Region Version 2.0* (Regional Supplement) (US Army Corps of Engineers [Corps] May 2010). Wetland boundaries were determined on the basis of an examination of vegetation, soils, and hydrology. Areas meeting the criteria set forth in the Regional Supplement were determined to be wetland. Soil, vegetation, and hydrologic parameters were sampled at several locations along the wetland boundaries to make the determination. Data points were marked with yellow- and black-striped flagging. Wetland boundaries were marked with pink- and black-striped flagging.

Delineated wetlands were classified using both *2014 Update to the Western Washington Wetland Rating System* (Publication #14-06-029) (hereafter 2014 Rating System) and the *Washington State Wetland Rating System for Western Washington, Version 2* (Publication #04-06-025) (hereafter 2004 Rating System).

Streams

The study area was also evaluated for streams based on the presence or absence of an ordinary high water mark (OHWM) as defined by the Revised Code of Washington (RCW) 90.58.030 and the Washington Administrative Code (WAC) 220-660-030. The OHWM edge was located by examining the bed and bank physical characteristics and vegetation to ascertain the water elevation for mean annual floods. Stream boundaries were marked with blue- and white-striped flagging.

Streams were classified according to City of Bellevue regulations.

Mapping

Delineation and data point flags were survey-located in May 2017. The attached Wetland Delineation Figure was created using the AutoCAD file of the survey-located flags.

Findings

The subject parcel is approximately 8.5 acres in size and located in the Kelsey Creek/Mercer Slough drainage basin in the Cedar-Sammamish Water Resource Inventory Area (WRIA 8); Section 10 of Township 24N, Range 05E of the Public Land Survey System. The property contains an existing gravel maintenance yard and forested vegetation; it is encumbered by wetland and stream critical areas.

Previous delineation studies conducted by The Watershed Company have occurred on and adjacent to the property. The first of these delineation studies occurred in 2012 followed by supplemental delineation in 2014 associated with work detailed in the Lakeside Substation Rebuild Critical Areas Report. Then, in October 2016 and February 2017, delineation work occurred near the southwest corner of the parcel as part of the Richards Creek culvert replacement and stream restoration studies on the property.

A total of five wetlands and two streams are located on or adjacent to the Richards Creek Substation property that may encumber proposed activities on the parcel. A summary of these features, including delineation date and previously-used names, is provided in Table 1 below. The information contained in this report is meant to supersede any discrepancies that may exist between new information and old reports.

Table 1. Summary of potentially encumbering critical areas located on the Richards Creek parcel including most recent delineation date and formerly-reported critical area name.

Critical Area	Recent Delineation Date	Other Names and Delineation Dates
Wetland A	March 2017	*formerly* Wetland BDC (2012) and Wetland BC (2014)
Wetland B	March 2017	*formerly* Wetland E (2012, 2014)
Wetland C	March 2017	*formerly* Wetland A (2012)
Wetland D	October 2016	*formerly* Wetland FG (2012)
Wetland H	February 2017	*also known as* JB01 in Energize Eastside study (July 2015), previously delineated in 2012
Stream A	March 2017	*no other names*, previously delineated in 2012
Stream C	October 2016 and February 2017	*no other names*, previously delineated in 2012

Wetland A

Wetland A is a slope wetland located in the northwest portion of the parcel. Although parts of the wetland are contiguous with adjacent stream segments, the primary source of hydrology to the wetland is from groundwater seeps. Wetland A generally slopes in one direction draining to streams without impounding water.

Wetland A includes forested, shrub, and emergent Cowardin vegetation communities. Common vegetation observed throughout the wetland includes red alder, western red cedar, black cottonwood, willow species, salmonberry, red-osier dogwood, skunk cabbage, lady fern, reed canarygrass, and giant horsetail among others. The diagnostic soil layers (at DP-1) are a moderately dark brown (10YR 3/2) and a depleted greyish-brown (10YR 4/2) gravelly sandy loam and sandy loam. Both layers contain redoximorphic features (RMFs) of 7.5YR 3/4 which become more prevalent in the lower layer (8-16 inches). Soils were saturated to the surface and a water table was present at eight inches below the ground surface during the site visit.

Wetland A rates as a Category III wetland under both the 2004 and 2014 Rating Systems. Rating forms are attached.

Figure 1. View of forested portion of Wetland A (in background), facing northwest from non-wetland area (February 2012).

Wetland B

Wetland B is a small slope wetland located in the northeast portion of the property. The wetland contains palustrine forested and palustrine scrub-shrub Cowardin vegetation communities dominated by Pacific willow, red alder, salmonberry, Himalayan blackberry, giant horsetail, and lady fern. The diagnostic soil is a dark brown (2.5Y 3/1) sandy loam containing 7.5YR 3/4 RMFs (DP-3). Soils were saturated to the surface and a water table was present at four inches below the ground surface during the site visit. Shallow surface water ponding was also observed near the test pit.

Wetland B rates as a Category III wetland under both the 2004 and 2014 Rating Systems.

Figure 2. Wetland B, facing southeast (March 2017).

Wetland C

Wetland C is a small forested slope wetland located on the eastern parcel boundary at the north end adjacent to Stream A. Stream A flows within the boundaries of Wetland C but does not provide hydrology to the wetland unit; hydrology is provided by groundwater seeps. It is dominated by a palustrine forested Cowardin vegetation community including red alder, black cottonwood, salmonberry, and skunk cabbage. The diagnostic soil layer is a grey-blue (10EG 5/1) gravelly sandy clay loam with 10YR 4/6 RMFs present in the matrix and pore linings (DP-5). Soils were saturated to the surface and a high water table was present at eight inches below the ground surface.

Wetland C rates as a Category III wetland under both the 2004 and 2014 Rating Systems.

Figure 3. Wetland C, facing north (March 2017).

Wetland D

Wetland D is riverine wetland located in the southwest corner of the property. It is contiguous with Stream C. A constructed stormwater detention pond is located immediately north of this wetland and not included within its boundaries. Overbank flooding of Stream C is the primary source of hydrology to the wetland. Twin culverts beneath the access road function as the wetland outlet (Figure 4).

Figure 4. Wetland D, facing southwest adjacent to Richard's Creek substation access drive (October 2016).

Wetland D contains a forested Cowardin vegetation community dominated by Pacific willow, red alder, lady fern, small-fruited bulrush, reed canarygrass and giant horsetail with some Himalayan blackberry rooted along the fringes. The diagnostic soil layer is a very dark gray (10YR 3/1) loamy sand with 10 percent prominent RMFs (DP-9). Soils were saturated to the surface with a water table present at twelve inches below the soil surface.

Wetland D rates as a Category II wetland under both the 2004 and 2014 Rating Systems.

Wetland H

Wetland H is a slope wetland located on the south end of the property and extending offsite to the south. Despite being bordered on the west side by Stream C, its primary source of hydrology is groundwater seeps. Wetland H contains emergent, scrub-shrub, and forested Cowardin vegetation communities. Vegetation is dominated by reed canarygrass, birdsfoot trefoil, giant horsetail, Himalayan blackberry, willow species, and red alder. Sampled soils were a dark brown (10YR 2/1) sandy clay loam and very dark gray (2.5Y 3/1) loamy sand (DP-35); and smelled of hydrogen sulfide. Soils were saturated to the surface and a high water table was present at eight inches below the soil surface.

Wetland H rates as a Category III wetland under both the 2004 and 2014 Rating Systems.

Figure 7. Wetland H, facing south from northern boundary (February 2017).

Stream A

Stream A is a seasonal stream that flows through Wetland C and into Wetland A. In the powerline corridor, channel loses definition and appears to go below the ground through old drainage structures. The stream substrate is composed of sand and gravel, meanders moderately, and averages five feet wide at bankfull width. The left and right banks are well vegetated with trees, shrubs, and herbaceous plants. King County iMap depicts the origins of Stream A approximately 600 feet east of the PSE parcel. Fish cannot access the portion of Stream A located on the east side of the parcel, upstream of the point where the channel transitions to sheetflow and loses definition.

Stream C

The King County iMap database depicts Stream C as originating in two tributaries southeast of the PSE property and running through Wetlands H, D and A. This delineation picks up the stream in Wetland D where it flows northwest to the southwest corner of the property. Here the stream flows through a culvert beneath the PSE property access drive and flows north along the west property boundary, largely on the adjacent property. It collects water from Stream A at the northwest corner of the property and then flows west, where the iMap database shows it to continue roughly west in a mix of natural channels and pipes or culverts. The stream substrate is composed of sand, gravel, and cobbles. The stream meanders slightly and averages six feet wide at bankfull width.

Stream C flows year-round. Downstream of the culvert, the right bank was delineated and flagged; the left bank in this area is bounded by fill from the adjacent development. The right bank is bordered by vegetated buffer and Wetland A, which drains to the stream. Upstream of the culvert, both the right and left bank were flagged. Here the stream flows through Wetland D. The City of Bellevue stream inventory map depicts Stream C as Type F, or fish bearing, and WDFW Priority Habitats and Species maps indicate the presence of resident cutthroat trout in the stream.

Local Regulations

Critical Areas within the City of Bellevue are regulated under Part 20.25H of the City of Bellevue Land Use Code (LUC).

Wetlands

According to LUC 20.25H.095, wetlands are classified based on the 2004 Rating System. Bellevue is in the process of updating the city code to require Ecology's 2014 Rating System update. Furthermore, both state and federal agencies use the 2014 version of the rating system to evaluate direct impacts to wetlands. As this project may directly impact wetland area, both rating systems published by Ecology were used to rate wetlands. For the purposes of discussing Bellevue's regulations, only the 2004 wetland ratings will be presented here.

As stated previously, Wetlands A, B, C, and H classify as Category III slope wetlands; Wetland D is considered to be a Category II riverine wetland. Buffer widths are determined based upon the "developed" or "undeveloped" condition of the site, the water quality and habitat scores generated using the 2004 Rating System, and the wetland category. The Richards Creek parcel is considered undeveloped. Required buffer widths are presented in Table 2.

The proposed Richards Creek Substation is not considered a building or structure that would require an additional 15-foot building setback from critical area buffers. Building setbacks are not included this report or associated delineation map.

Table 2. Summary of 2004 wetland ratings, classifications, and required standard buffer widths.

Wetland Name	HGM Class	2004 Ecology Wetland Rating				Category	Standard Buffer Width (feet)
		Water Quality	Hydrologic Function	Habitat	Total		
A	Slope	6	10	21	37	III	110
B	Slope	6	12	16	34	III	60
C	Slope	6	12	20	38	III	110
D	Riverine	20	22	21	63	II	110
H	Slope	6	16	21	43	III	110

Streams

Streams in Bellevue are rated as one of four types based on inventory status as Shorelines of the State, fish use, and connectivity to other streams. As with wetlands, stream buffer widths are determined based on a combination of the stream type and whether the site is “developed” or “undeveloped.”

None of the onsite streams is a Shoreline of the State due to low flow volumes. The upstream (and onsite) portion of Stream A is a Type N water, as it does not contain fish or fish habitat and is not connected by an above-ground channel to fish-bearing waters. Type N waters on undeveloped sites in Bellevue require regulatory buffers of 50 feet. Stream C is rated as Type F, and requires a 100-foot buffer.

State and Federal Regulations

Wetlands are also regulated by the Army Corps of Engineers under Section 404 of the Clean Water Act. Any filling of Waters of the U.S., including wetlands (except isolated wetlands), would require notification and permits from the Corps. Wetland B may be considered isolated. A formal isolated status inquiry can be requested from the Corps through the Jurisdictional Determination process.

Federally permitted actions that could affect endangered species may also require a biological assessment study and consultation with the U.S. Fish and Wildlife Service and/or the National Marine Fisheries Service. Application for Corps permits may also require an individual 401 Water Quality Certification and Coastal Zone Management Consistency determination from Ecology.

In general, neither the Corps nor Ecology regulates wetland buffers, unless direct wetland impacts are proposed. When direct impacts are proposed, mitigated wetlands may be required to employ buffers based on Corps and Ecology joint regulatory guidance.

Disclaimer

The information contained in this letter is based on the application of technical guidelines currently accepted as the best available science and in conjunction with the manuals and criteria outlined in the methods section. All discussions, conclusions and recommendations reflect the best professional judgment of the author(s) and are based upon information available at the time the study was conducted. All work was completed within the constraints of budget, scope, and timing. The findings of this report are subject to verification and agreement by the appropriate local, state and federal regulatory authorities. No other warranty, expressed or implied, is made.

Please call if you have any questions or if we can provide you with any additional information.

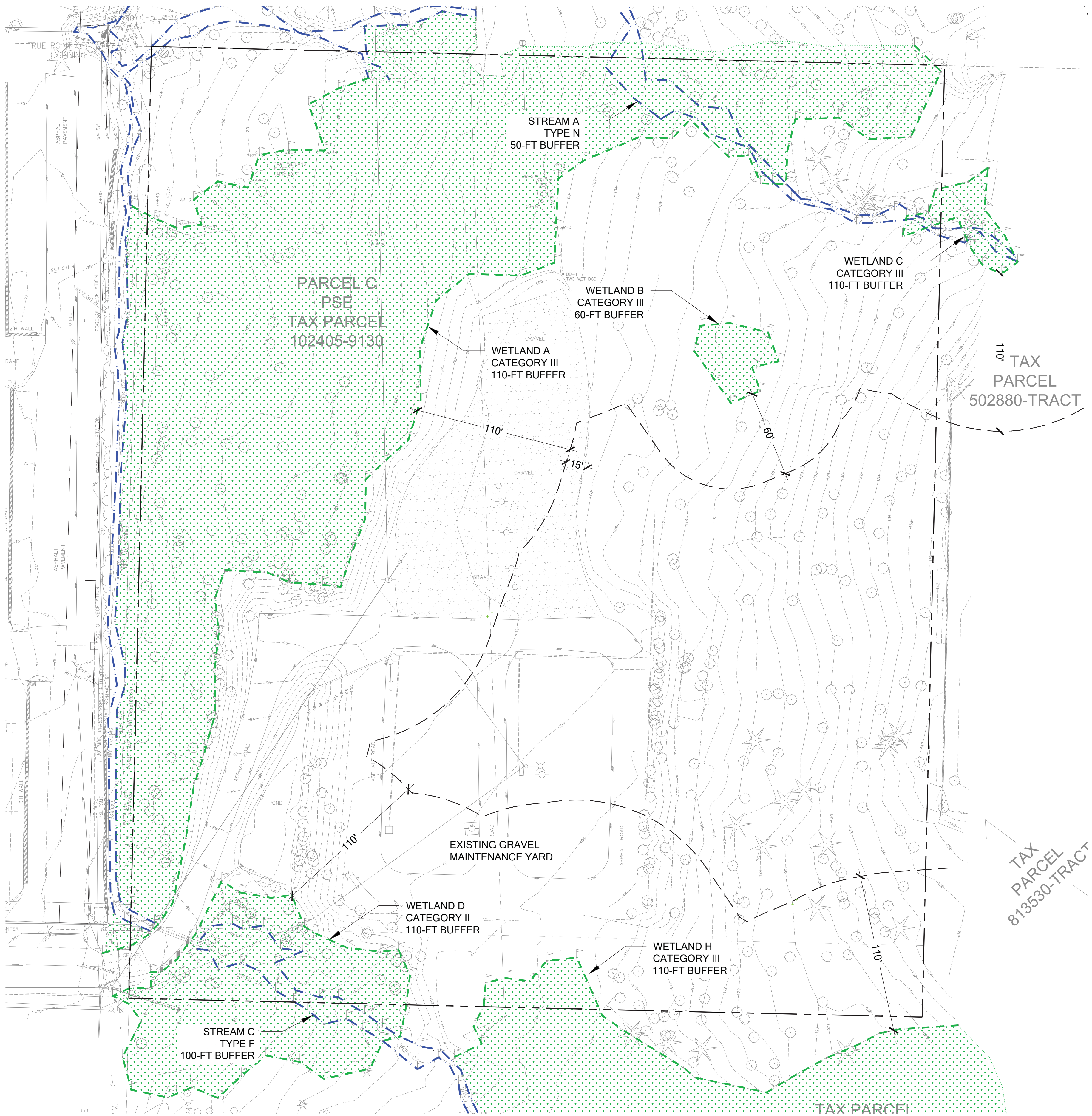
Sincerely,

Katy Crandall

Katy Crandall, WPIT
Ecologist / Arborist

Enclosures

PSE RICHARDS CREEK 230kV SUBSTATION



STREAM AND WETLAND DELINEATION FIGURE

0 20' 40' 80' 160'

LEGEND

- WETLAND BOUNDARY
- WETLAND BOUNDARY (APPROXIMATE)
- STREAM BOUNDARY (OHWM)
- CRITICAL AREA BUFFER
- PROPERTY BOUNDARY

NOTES

1. WETLAND AND STREAM BOUNDARIES BASED ON DELINEATION STUDIES PERFORMED BY THE WATERSHED COMPANY IN OCTOBER 2016, FEBRUARY 2017 AND MARCH 2017.

THE WATERSHED COMPANY

750 Sixth Street South
Kirkland WA 98033

p 425.822.5242
www.watershedco.com
Science & Design

RICHARDS CREEK SUBSTATION
WETLAND AND STREAM DELINEATION
PREPARED FOR: PUGET SOUND ENERGY

13440 SOUTHEAST 30TH STREET
BELLEVUE, WA 98005

SUBMITTALS & REVISIONS

NO.	DATE	DESCRIPTION	BY
1	05-10-2017	DELINEATION FIGURE	LJM
2	05-15-2017	FIRST ROUND DRAFT EDITS	LJM

SHEET SIZE:
ORIGINAL PLAN IS 22" x 34".
SCALE ACCORDINGLY.

PROJECT MANAGER: JC
DESIGNED:
DRAFTED: LJM
CHECKED: KC/AM
JOB NUMBER:
111103.6
SHEET NUMBER:
W1

FILENAME
PRINTED BY
DATE

DSD 009932

THE WATERSHED COMPANY

WETLAND DETERMINATION DATA FORM

Western Mountains, Valleys, and Coast Supplement to the 1987 COE Wetlands Delineation Manual

DP-1

750 Sixth Street South
Kirkland, Washington 98033
(425) 822-5242
watershedco.com

Project Site:	**RICHARDS CREEK SUBSTATION**	Sampling Date:	**3/15/2017**
Applicant/Owner:	**PUGET SOUND ENERGY**	Sampling Point:	DP- **1**
Investigator:	**KC, LM**	City/County:	**BELLEVUE/KING**
Sect., Township, Range:	S **10** T **24** R **05**	State:	**WA**

Landform (hillslope, terrace, etc): **HILLSLOPE** Slope (%): **3** Local relief (concave, convex, none): **NONE**

Subregion (LRR): **A** Lat: **47.5838** Long: **-122.1585** Datum:

Soil Map Unit Name: **EvD VERY GRAVELLY SANDY LOAM, 15-30 PERCENT SLOPES** NWI classification: **N/A**

Are climatic/hydrologic conditions on the site typical for this time of year? ☒ Yes ☐ No (If no, explain in remarks.)
Are "Normal Circumstances" present on the site? ☒ Yes ☐ No
Are Vegetation☐, Soil ☐, or Hydrology ☐ significantly disturbed?
Are Vegetation☐, Soil ☐, or Hydrology ☐ naturally problematic (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ☒	No ☐
Hydric Soils Present?	Yes ☒	No ☐
Wetland Hydrology Present?	Yes ☒	No ☐

Is the Sampling Point within a Wetland? Yes ☒ No ☐

Remarks: **WETLAND A IN PIT, SOUTHEAST CORNER OF WETLAND**

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 5m diam.)	Absolute % Cover	Dominant Species?	Indicator Status
1. ***Salix sp.***	**10**	**Y**	**FAC**
2.			
3.			
4.			
	10	= Total Cover	
Sapling/Shrub Stratum (Plot size: 3m diam.)			
1. ***Rubus armeniacus***	**100**	**Y**	**FAC**
2. ***Rubus spectabilis***	**3**	**N**	**FAC**
3.			
4.			
5.			
		= Total Cover	
Herb Stratum (Plot size: 1m diam.)			
1. ***Equisetum telmateia***	**30**	**Y**	**FACW**
2.			
3.			
4.			
5.			
6.			
7.			
8.			
9.			
10.			
11.			
	30	= Total Cover	
Woody Vine Stratum (Plot size:)			
1.			
2.			
		= Total Cover	
% Bare Ground in Herb Stratum:			

Dominance Test Worksheet

Number of Dominant Species that are OBL, FACW, or FAC:	3	(A)
Total Number of Dominant Species Across All Strata:	3	(B)
Percent of Dominant Species that are OBL, FACW, or FAC:	100	(A/B)

Prevalence Index Worksheet

Total % Cover of		Multiply by
OBL species		x 1 =
FACW species		x 2 =
FAC species		x 3 =
FACU species		x 4 =
UPL species		x 5 =
Column totals	(A)	(B)

Prevalence Index = B / A =

Hydrophytic Vegetation Indicators

☒ Dominance test is > 50%
☐ Prevalence test is ≤ 3.0 *
☐ Morphological Adaptations * (provide supporting data in remarks or on a separate sheet)
☐ Wetland Non-Vascular Plants *
☐ Problematic Hydrophytic Vegetation * (explain)

* Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic

Hydrophytic Vegetation Present? Yes ☒ No ☐

Remarks: ***Athyrium cyclosorum*** **nearby**

SOIL

Sampling Point – DP-1

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix		Redox Features				Texture	Remarks
	Color (moist)	%	Color (moist)	%	Type[1]	Loc[2]		
0-8	**10 YR 3/2**	**95**	**7.5 YR 3/4**	**5**	**C**	**M**	**GRAVELLY SANDY LOAM**	
8-16	**10 YR 4/2**	**85**	**7.5 YR 3/4**	**15**	**C**	**M**	**SANDY LOAM**	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Loc: PL=Pore Lining, M=Matrix

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Mucky Mineral (S1)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Loamy Mucky Mineral (F1) **(except MLRA** 1**)**
- ☐ Loamy Gleyed Matrix (F2)
- ☒ Depleted Matrix (F3)
- ☒ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)

Indicators for Problematic Hydric Soils[3]

- ☐ 2cm Muck (A10)
- ☐ Red Parent Material (TF2)
- ☐ Other (explain in remarks)
- ☐

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic

Restrictive Layer (if present):
Type:
Depth (inches):

Hydric soil present? Yes ☒ No ☐

Remarks:

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required: check all that apply):

- ☐ Surface water (A1)
- ☒ High Water Table (A2)
- ☒ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift Deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Surface Soil Cracks (B6)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Water-Stained Leaves (**except MLRA 1, 2, 4A & 4B**) (B9)
- ☐ Salt Crust (B11)
- ☐ Aquatic Invertebrates (B13)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Stunted or Stressed Plants (D1) (**LRR A**)
- ☐ Other (explain in remarks)

Secondary Indicators (2 or more required):

- ☐ Water-Stained Leaves (B9) (**MLRA 1, 2, 4A & 4B**)
- ☐ Drainage Patterns (B10)
- ☐ Dry-Season Water Table (C2)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ FAC-Neutral Test (D5)
- ☐ Raised Ant Mounds (D6) (**LRR A**)
- ☐ Frost-Heave Hummocks

Field Observations

Surface Water Present?	Yes ☐	No ☒	Depth (in):
Water Table Present?	Yes ☒	No ☐	Depth (in): **8**
Saturation Present? (includes capillary fringe)	Yes ☒	No ☐	Depth (in): **0-16**

Wetland Hydrology Present? Yes ☒ No ☐

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

THE WATERSHED COMPANY

750 Sixth Street South
Kirkland, Washington 98033
(425) 822-5242
watershedco.com

WETLAND DETERMINATION DATA FORM

Western Mountains, Valleys, and Coast Supplement to the 1987 COE Wetlands Delineation Manual

DP-2

Project Site:	**RICHARDS CREEK SUBSTATION**	Sampling Date:	**3/15/2017**
Applicant/Owner:	**PUGET SOUND ENERGY**	Sampling Point:	DP- **2**
Investigator:	**KC, LM**	City/County:	**BELLEVUE/KING**
Sect., Township, Range:	S **10** T **24** R **05**	State:	**WA**
Landform (hillslope, terrace, etc): **HILLSLOPE**	Slope (%): **<5**	Local relief (concave, convex, none): **NONE**	
Subregion (LRR): **A**	Lat: **47.5838**	Long: **-122.1585**	Datum:
Soil Map Unit Name: **EvD VERY GRAVELLY SANDY LOAM, 15-30 PERCENT SLOPES**		NWI classification: **N/A**	

Are climatic/hydrologic conditions on the site typical for this time of year? ☒ Yes ☐ No (If no, explain in remarks.)
Are "Normal Circumstances" present on the site? ☒ Yes ☐ No
Are Vegetation☐, Soil ☐, or Hydrology ☐ significantly disturbed?
Are Vegetation☐, Soil ☐, or Hydrology ☐ naturally problematic (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ☒	No ☐		
Hydric Soils Present?	Yes ☒	No ☐	Is the Sampling Point within a Wetland?	Yes ☒ No ☐
Wetland Hydrology Present?	Yes ☒	No ☐		

Remarks: **WETLAND A IN PIT, NORTH OF DP-1**

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 5m diam.)	Absolute % Cover	Dominant Species?	Indicator Status
1.			
2.			
3.			
4.			
		= Total Cover	
Sapling/Shrub Stratum (Plot size: 3m diam.)			
1. *Rubus armeniacus*	**20**	**Y**	**FAC**
2.			
3.			
4.			
5.			
	20	= Total Cover	
Herb Stratum (Plot size: 1m diam.)			
1. *Phalaris arundinacea*	**100**	**Y**	**FACW**
2.			
3.			
4.			
5.			
6.			
7.			
8.			
9.			
10.			
11.			
	100	= Total Cover	
Woody Vine Stratum (Plot size:)			
1.			
2.			
		= Total Cover	
% Bare Ground in Herb Stratum:			

Dominance Test Worksheet

Number of Dominant Species that are OBL, FACW, or FAC:	**2**	(A)
Total Number of Dominant Species Across All Strata:	**2**	(B)
Percent of Dominant Species that are OBL, FACW, or FAC:	**100**	(A/B)

Prevalence Index Worksheet

	Total % Cover of	Multiply by
OBL species		x 1 =
FACW species		x 2 =
FAC species		x 3 =
FACU species		x 4 =
UPL species		x 5 =
Column totals	(A)	(B)

Prevalence Index = B / A =

Hydrophytic Vegetation Indicators

☒ Dominance test is > 50%
☐ Prevalence test is ≤ 3.0 *
☐ Morphological Adaptations * (provide supporting data in remarks or on a separate sheet)
☐ Wetland Non-Vascular Plants *
☐ Problematic Hydrophytic Vegetation * (explain)

* Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic

Hydrophytic Vegetation Present? Yes ☒ No ☐

Remarks:

SOIL **Sampling Point – DP-2**

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix		Redox Features				Texture	Remarks
	Color (moist)	%	Color (moist)	%	Type[1]	Loc[2]		
0-6	**10 YR 2/2**	**100**					**SANDY LOAM**	**SOME CLAY**
6-13	**2.5 Y 3/1**	**80**	**7.5 YR 3/1**	**20**	**C**	**PL/M**	**SANDY LOAM**	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Loc: PL=Pore Lining, M=Matrix

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Mucky Mineral (S1)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Loamy Mucky Mineral (F1) **(except MLRA** 1)
- ☐ Loamy Gleyed Matrix (F2)
- ☒ Depleted Matrix (F3)
- ☒ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)

Indicators for Problematic Hydric Soils[3]

- ☐ 2cm Muck (A10)
- ☐ Red Parent Material (TF2)
- ☐ Other (explain in remarks)
- ☐

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic

Restrictive Layer (if present):
Type:
Depth (inches):

Hydric soil present? Yes ☒ No ☐

Remarks:

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required: check all that apply):

- ☐ Surface water (A1)
- ☒ High Water Table (A2)
- ☒ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift Deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Surface Soil Cracks (B6)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Water-Stained Leaves (**except MLRA 1, 2, 4A & 4B**) (B9)
- ☐ Salt Crust (B11)
- ☐ Aquatic Invertebrates (B13)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Stunted or Stressed Plants (D1) (**LRR A**)
- ☐ Other (explain in remarks)

Secondary Indicators (2 or more required):

- ☐ Water-Stained Leaves (B9) (**MLRA 1, 2, 4A & 4B**)
- ☐ Drainage Patterns (B10)
- ☐ Dry-Season Water Table (C2)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ FAC-Neutral Test (D5)
- ☐ Raised Ant Mounds (D6) (**LRR A**)
- ☐ Frost-Heave Hummocks

Field Observations

Surface Water Present?	Yes ☐	No ☒	Depth (in):
Water Table Present?	Yes ☒	No ☐	Depth (in): **5**
Saturation Present? (includes capillary fringe)	Yes ☒	No ☐	Depth (in): **0-13**

Wetland Hydrology Present? Yes ☒ No ☐

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks: **PONDING NEARBY ~5' AWAY**

THE WATERSHED COMPANY

750 Sixth Street South
Kirkland, Washington 98033
(425) 822-5242
watershedco.com

WETLAND DETERMINATION DATA FORM

Western Mountains, Valleys, and Coast Supplement to the 1987 COE Wetlands Delineation Manual

DP-3

Project Site:	**RICHARDS CREEK SUBSTATION**	Sampling Date:	**3/27/2017**
Applicant/Owner:	**PUGET SOUND ENERGY**	Sampling Point:	DP- **3**
Investigator:	**KC, LM**	City/County:	**BELLEVUE/KING**
Sect., Township, Range:	S **10** T **24** R **05**	State:	**WA**

Landform (hillslope, terrace, etc): **HILLSLOPE**	Slope (%): **~5**	Local relief (concave, convex, none): **CONCAVE**
Subregion (LRR): **A**	Lat: **47.5838**	Long: **-122.1585** Datum:
Soil Map Unit Name: **EvD VERY GRAVELLY SANDY LOAM, 15-30 PERCENT SLOPES**		NWI classification: **N/A**

Are climatic/hydrologic conditions on the site typical for this time of year? ☒ Yes ☐ No (If no, explain in remarks.)
Are "Normal Circumstances" present on the site? ☒ Yes ☐ No
Are Vegetation☐, Soil ☐, or Hydrology ☐ significantly disturbed?
Are Vegetation☐, Soil ☐, or Hydrology ☐ naturally problematic (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ☒	No ☐		
Hydric Soils Present?	Yes ☒	No ☐	**Is the Sampling Point within a Wetland?**	Yes ☒ No ☐
Wetland Hydrology Present?	Yes ☒	No ☐		

Remarks: **WETLAND B IN PIT**

VEGETATION – Use scientific names of plants.

Stratum / Species	Absolute % Cover	Dominant Species?	Indicator Status
Tree Stratum (Plot size: 5m diam.)			
1. ***Salix lucida***	**10**	**Y**	**FACW**
2.			
3.			
4.			
	10 = Total Cover		
Sapling/Shrub Stratum (Plot size: 3m diam.)			
1. ***Rubus armeniacus***	**95**	**Y**	**FAC**
2. ***Rubus spectabilis***	**8**	**N**	**FAC**
3. ***Lonicera involucrata***	**2**	**N**	**FAC**
4.			
5.			
	105 = Total Cover		
Herb Stratum (Plot size: 1m diam.)			
1. ***Equisetum telmateia***	**70**	**Y**	**FACW**
2.			
3.			
4.			
5.			
6.			
7.			
8.			
9.			
10.			
11.			
	70 = Total Cover		
Woody Vine Stratum (Plot size:)			
1.			
2.			
	= Total Cover		
% Bare Ground in Herb Stratum:			

Dominance Test Worksheet

Number of Dominant Species that are OBL, FACW, or FAC:	**3**	(A)
Total Number of Dominant Species Across All Strata:	**3**	(B)
Percent of Dominant Species that are OBL, FACW, or FAC:	**100**	(A/B)

Prevalence Index Worksheet

Total % Cover of		Multiply by
OBL species		x 1 =
FACW species		x 2 =
FAC species		x 3 =
FACU species		x 4 =
UPL species		x 5 =
Column totals	(A)	(B)

Prevalence Index = B / A =

Hydrophytic Vegetation Indicators

☒ Dominance test is > 50%
☐ Prevalence test is ≤ 3.0 *
☐ Morphological Adaptations * (provide supporting data in remarks or on a separate sheet)
☐ Wetland Non-Vascular Plants *
☐ Problematic Hydrophytic Vegetation * (explain)

* Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic

Hydrophytic Vegetation Present? Yes ☒ No ☐

Remarks:

SOIL

Sampling Point – DP-3

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	Matrix %	Redox Features Color (moist)	Redox %	Type[1]	Loc[2]	Texture	Remarks
0-15	**2.5 Y 3/1**	**90**	**7.5 YR 3/4**	**10**	**C**	**M, PL**	**SANDY LOAM**	
15-18	**2.5 Y 3/1**	**75**	**7.5 YR 3/4**	**15**	**C**	**M**	**SANDY LOAM**	**MIXED MATRIX**
			2.5 Y 4/1	**10**	**D**	**M**		

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Loc: PL=Pore Lining, M=Matrix

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Mucky Mineral (S1)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Loamy Mucky Mineral (F1) **(except MLRA** 1)
- ☐ Loamy Gleyed Matrix (F2)
- ☒ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)

Indicators for Problematic Hydric Soils[3]

- ☐ 2cm Muck (A10)
- ☐ Red Parent Material (TF2)
- ☐ Other (explain in remarks)
- ☐

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic

Restrictive Layer (if present):
Type:
Depth (inches):

Hydric soil present? Yes ☒ No ☐

Remarks:

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required: check all that apply):

- ☒ Surface water (A1)
- ☒ High Water Table (A2)
- ☒ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift Deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Surface Soil Cracks (B6)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Water-Stained Leaves (**except MLRA 1, 2, 4A & 4B**) (B9)
- ☐ Salt Crust (B11)
- ☐ Aquatic Invertebrates (B13)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Stunted or Stressed Plants (D1) (**LRR A**)
- ☐ Other (explain in remarks)

Secondary Indicators (2 or more required):

- ☐ Water-Stained Leaves (B9) (**MLRA 1, 2, 4A & 4B**)
- ☐ Drainage Patterns (B10)
- ☐ Dry-Season Water Table (C2)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ FAC-Neutral Test (D5)
- ☐ Raised Ant Mounds (D6) (**LRR A**)
- ☐ Frost-Heave Hummocks

Field Observations

Surface Water Present?	Yes ☒	No ☐	Depth (in): **1-2**
Water Table Present?	Yes ☒	No ☐	Depth (in): **4**
Saturation Present? (includes capillary fringe)	Yes ☒	No ☐	Depth (in): **0-18**

Wetland Hydrology Present? Yes ☒ No ☐

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks: **PONDING NEXT TO DP**

THE WATERSHED COMPANY

WETLAND DETERMINATION DATA FORM

Western Mountains, Valleys, and Coast Supplement to the 1987 COE Wetlands Delineation Manual

DP-4

750 Sixth Street South
Kirkland, Washington 98033
(425) 822-5242
watershedco.com

Project Site:	**RICHARDS CREEK SUBSTATION**	Sampling Date:	**3/27/2017**
Applicant/Owner:	**PUGET SOUND ENERGY**	Sampling Point:	DP- **4**
Investigator:	**KC, LM**	City/County:	**BELLEVUE/KING**
Sect., Township, Range:	S **10** T **24** R **05**	State:	**WA**
Landform (hillslope, terrace, etc): **HILLSLOPE**	Slope (%): **<5**	Local relief (concave, convex, none): **NONE**	
Subregion (LRR): **A**	Lat: **47.5838**	Long: **-122.1585**	Datum:
Soil Map Unit Name: **EvD VERY GRAVELLY SANDY LOAM, 15-30 PERCENT SLOPES**		NWI classification: **N/A**	

Are climatic/hydrologic conditions on the site typical for this time of year? ☒ Yes ☐ No (If no, explain in remarks.)
Are "Normal Circumstances" present on the site? ☒ Yes ☐ No
Are Vegetation☐, Soil ☐, or Hydrology ☐ significantly disturbed?
Are Vegetation☐, Soil ☐, or Hydrology ☐ naturally problematic
(If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

	Yes	No
Hydrophytic Vegetation Present?	☐	☒
Hydric Soils Present?	☐	☒
Wetland Hydrology Present?	☐	☒

Is the Sampling Point within a Wetland? Yes ☐ No ☒

Remarks: **OUT PIT BETWEEN WETLANDS A & B ON FORESTED SLOPE**

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 5m diam.)	Absolute % Cover	Dominant Species?	Indicator Status
1. ***Acer macrophyllum***	**40**	**Y**	**FACU**
2.			
3.			
4.			
	40	= Total Cover	
Sapling/Shrub Stratum (Plot size: 3m diam.)			
1. ***Corylus cornuta***	**10**	**N**	**FACU**
2. ***Rubus armeniacus***	**100**	**Y**	**FAC**
3.			
4.			
5.			
	83	= Total Cover	
Herb Stratum (Plot size: 1m diam.)			
1. ***Pteridium aquilinum***	**10**	**Y**	**FACU**
2.			
3.			
4.			
5.			
6.			
7.			
8.			
9.			
10.			
11.			
	9	= Total Cover	
Woody Vine Stratum (Plot size:)			
1.			
2.			
		= Total Cover	
% Bare Ground in Herb Stratum:			

Dominance Test Worksheet

Number of Dominant Species that are OBL, FACW, or FAC:	**1**	(A)
Total Number of Dominant Species Across All Strata:	**3**	(B)
Percent of Dominant Species that are OBL, FACW, or FAC:	**33.3**	(A/B)

Prevalence Index Worksheet

	Total % Cover of	Multiply by
OBL species		x 1 =
FACW species		x 2 =
FAC species		x 3 =
FACU species		x 4 =
UPL species		x 5 =
Column totals	(A)	(B)

Prevalence Index = B / A =

Hydrophytic Vegetation Indicators

☐ Dominance test is > 50%
☐ Prevalence test is ≤ 3.0 *
☐ Morphological Adaptations * (provide supporting data in remarks or on a separate sheet)
☐ Wetland Non-Vascular Plants *
☐ Problematic Hydrophytic Vegetation * (explain)

* Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic

Hydrophytic Vegetation Present? Yes ☐ No ☒

Remarks:

SOIL **Sampling Point – DP-4**

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix		Redox Features				Texture	Remarks
	Color (moist)	%	Color (moist)	%	Type[1]	Loc[2]		
0-5	**10 YR 2/2**	**100**					**SANDY LOAM**	
5-12	**10 YR 4/6**	**100**					**GRAVELLY SANDY LOAM**	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Loc: PL=Pore Lining, M=Matrix

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Mucky Mineral (S1)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Loamy Mucky Mineral (F1) **(except MLRA** 1)
- ☐ Loamy Gleyed Matrix (F2)
- ☐ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)

Indicators for Problematic Hydric Soils[3]

- ☐ 2cm Muck (A10)
- ☐ Red Parent Material (TF2)
- ☐ Other (explain in remarks)
- ☐

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic

Restrictive Layer (if present):
Type:
Depth (inches):

Hydric soil present? Yes ☐ No ☒

Remarks:

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required: check all that apply):

- ☐ Surface water (A1)
- ☐ High Water Table (A2)
- ☐ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift Deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Surface Soil Cracks (B6)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Water-Stained Leaves (**except MLRA 1, 2, 4A & 4B**) (B9)
- ☐ Salt Crust (B11)
- ☐ Aquatic Invertebrates (B13)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Stunted or Stressed Plants (D1) (**LRR A**)
- ☐ Other (explain in remarks)

Secondary Indicators (2 or more required):

- ☐ Water-Stained Leaves (B9) (**MLRA 1, 2, 4A & 4B**)
- ☐ Drainage Patterns (B10)
- ☐ Dry-Season Water Table (C2)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ FAC-Neutral Test (D5)
- ☐ Raised Ant Mounds (D6) (**LRR A**)
- ☐ Frost-Heave Hummocks

Field Observations

Surface Water Present?	Yes ☐	No ☒	Depth (in):
Water Table Present?	Yes ☐	No ☒	Depth (in):
Saturation Present? (includes capillary fringe)	Yes ☐	No ☒	Depth (in):

Wetland Hydrology Present? Yes ☐ No ☒

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

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WETLAND DETERMINATION DATA FORM
Western Mountains, Valleys, and Coast Supplement to the 1987 COE Wetlands Delineation Manual

DP-5

750 Sixth Street South
Kirkland, Washington 98033
(425) 822-5242
watershedco.com

Project Site:	**RICHARDS CREEK SUBSTATION**	Sampling Date:	**3/27/2017**
Applicant/Owner:	**PUGET SOUND ENERGY**	Sampling Point:	DP- **5**
Investigator:	**KC, LM**	City/County:	**BELLEVUE/KING**
Sect., Township, Range:	S **10** T **24** R **05**	State:	**WA**

Landform (hillslope, terrace, etc): **HILLSLOPE** | Slope (%): **<5** | Local relief (concave, convex, none): **CONCAVE**

Subregion (LRR): **A** | Lat: **47.5838** | Long: **-122.1585** | Datum:

Soil Map Unit Name: **EvD VERY GRAVELLY SANDY LOAM, 15-30 PERCENT SLOPES** | NWI classification: **N/A**

Are climatic/hydrologic conditions on the site typical for this time of year? ☒ Yes ☐ No (If no, explain in remarks.)
Are "Normal Circumstances" present on the site? ☒ Yes ☐ No
Are Vegetation☐, Soil ☐, or Hydrology ☐ significantly disturbed?
Are Vegetation☐, Soil ☐, or Hydrology ☐ naturally problematic (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ☒	No ☐
Hydric Soils Present?	Yes ☒	No ☐
Wetland Hydrology Present?	Yes ☒	No ☐

Is the Sampling Point within a Wetland? Yes ☒ No ☐

Remarks: **WETLAND C IN PIT, NORTHEAST CORNER OF WETLAND B, NEXT TO STREAM**

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 5m diam.)	Absolute % Cover	Dominant Species?	Indicator Status
1. ***Alnus rubra***	**70**	**Y**	**FAC**
2. ***Populus balsamifera***	**30**	**Y**	**FAC**
3.			
4.			
	100	= Total Cover	
Sapling/Shrub Stratum (Plot size: 3m diam.)			
1. ***Rubus spectabilis***	**80**	**Y**	**FAC**
2. ***Rubus armeniacus***	**3**	**N**	**FAC**
3.			
4.			
5.			
	83	= Total Cover	
Herb Stratum (Plot size: 1m diam.)			
1. ***Tolmiea menziesii***	**4**	**N**	**FAC**
2. ***Lysichiton americanus***	**5**	**N**	**OBL**
3.			
4.			
5.			
6.			
7.			
8.			
9.			
10.			
11.			
	9	= Total Cover	
Woody Vine Stratum (Plot size:)			
1.			
2.			
		= Total Cover	

% Bare Ground in Herb Stratum:

Dominance Test Worksheet

Number of Dominant Species that are OBL, FACW, or FAC:	3	(A)
Total Number of Dominant Species Across All Strata:	3	(B)
Percent of Dominant Species that are OBL, FACW, or FAC:	100	(A/B)

Prevalence Index Worksheet

Total % Cover of		Multiply by
OBL species		x 1 =
FACW species		x 2 =
FAC species		x 3 =
FACU species		x 4 =
UPL species		x 5 =
Column totals	(A)	(B)

Prevalence Index = B / A =

Hydrophytic Vegetation Indicators

- ☒ Dominance test is > 50%
- ☐ Prevalence test is ≤ 3.0 *
- ☐ Morphological Adaptations * (provide supporting data in remarks or on a separate sheet)
- ☐ Wetland Non-Vascular Plants *
- ☐ Problematic Hydrophytic Vegetation * (explain)

* Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic

Hydrophytic Vegetation Present? Yes ☒ No ☐

Remarks:

SOIL

Sampling Point – DP-5

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	Matrix %	Redox Features Color (moist)	Redox %	Type[1]	Loc[2]	Texture	Remarks
0-7	**10 YR 2/1**	**100**					**GRAVELLY SANDY LOAM**	
7-13	**10 EG 5/1**	**93**	**10 YR 4/6**	**7**	**C**	**PL/M**	**GRAVELLY SANDY CLAY LOAM**	**COBBLES**

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Loc: PL=Pore Lining, M=Matrix

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Mucky Mineral (S1)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Loamy Mucky Mineral (F1) **(except MLRA** 1**)**
- ☒ Loamy Gleyed Matrix (F2)
- ☐ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)

Indicators for Problematic Hydric Soils[3]

- ☐ 2cm Muck (A10)
- ☐ Red Parent Material (TF2)
- ☐ Other (explain in remarks)
- ☐

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic

Restrictive Layer (if present):
Type:
Depth (inches):

Hydric soil present? Yes ☒ No ☐

Remarks:

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required: check all that apply):

- ☐ Surface water (A1)
- ☒ High Water Table (A2)
- ☒ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift Deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Surface Soil Cracks (B6)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Water-Stained Leaves (**except MLRA 1, 2, 4A & 4B**) (B9)
- ☐ Salt Crust (B11)
- ☐ Aquatic Invertebrates (B13)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Stunted or Stressed Plants (D1) (**LRR A**)
- ☐ Other (explain in remarks)

Secondary Indicators (2 or more required):

- ☐ Water-Stained Leaves (B9) (**MLRA 1, 2, 4A & 4B**)
- ☐ Drainage Patterns (B10)
- ☐ Dry-Season Water Table (C2)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ FAC-Neutral Test (D5)
- ☐ Raised Ant Mounds (D6) (**LRR A**)
- ☐ Frost-Heave Hummocks

Field Observations

Surface Water Present?	Yes ☐	No ☒	Depth (in):
Water Table Present?	Yes ☒	No ☐	Depth (in): **8**
Saturation Present? (includes capillary fringe)	Yes ☒	No ☐	Depth (in): **0-13**

Wetland Hydrology Present? Yes ☒ No ☐

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

THE WATERSHED COMPANY

750 Sixth Street South
Kirkland, Washington 98033
(425) 822-5242
watershedco.com

WETLAND DETERMINATION DATA FORM

Western Mountains, Valleys, and Coast Supplement to the 1987 COE Wetlands Delineation Manual

DP-6

Project Site:	**RICHARDS CREEK SUBSTATION**	Sampling Date:	**3/27/2017**
Applicant/Owner:	**PUGET SOUND ENERGY**	Sampling Point:	DP- **6**
Investigator:	**KC, LM**	City/County:	**BELLEVUE/KING**
Sect., Township, Range:	S **10** T **24** R **05**	State:	**WA**
Landform (hillslope, terrace, etc): **HILLSLOPE**	Slope (%): **>15**	Local relief (concave, convex, none): **NONE**	
Subregion (LRR): **A**	Lat: **47.5838**	Long: **-122.1585**	Datum:
Soil Map Unit Name: **EvD VERY GRAVELLY SANDY LOAM, 15-30 PERCENT SLOPES**		NWI classification: **N/A**	

Are climatic/hydrologic conditions on the site typical for this time of year? ☒ Yes ☐ No (If no, explain in remarks.)
Are "Normal Circumstances" present on the site? ☒ Yes ☐ No
Are Vegetation☐, Soil ☐, or Hydrology ☐ significantly disturbed?
Are Vegetation☐, Soil ☐, or Hydrology ☐ naturally problematic (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ☐	No ☒
Hydric Soils Present?	Yes ☐	No ☒
Wetland Hydrology Present?	Yes ☐	No ☒

Is the Sampling Point within a Wetland? Yes ☐ No ☒

Remarks: **WETLAND C OUT PIT, NORTHEAST OF WETLAND B**

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 5m diam.)	Absolute % Cover	Dominant Species?	Indicator Status
1. ***Alnus rubra***	**60**	**Y**	**FAC**
2. ***Acer macrophyllum***	**40**	**Y**	**FACU**
3.			
4.			
	100	= Total Cover	
Sapling/Shrub Stratum (Plot size: 3m diam.)			
1. ***Rubus armeniacus***	**10**	**Y**	**FAC**
2.			
3.			
4.			
5.			
	10	= Total Cover	
Herb Stratum (Plot size: 1m diam.)			
1. ***Polystichum munitum***	**25**	**Y**	**FACU**
2. ***Ilex aquifolium***	**3**	**N**	**FACU**
3.			
4.			
5.			
6.			
7.			
8.			
9.			
10.			
11.			
	28	= Total Cover	
Woody Vine Stratum (Plot size:)			
1.			
2.			
		= Total Cover	
% Bare Ground in Herb Stratum:			

Remarks:

Dominance Test Worksheet

Number of Dominant Species that are OBL, FACW, or FAC:	**2**	(A)
Total Number of Dominant Species Across All Strata:	**4**	(B)
Percent of Dominant Species that are OBL, FACW, or FAC:	**50**	(A/B)

Prevalence Index Worksheet

	Total % Cover of	Multiply by
OBL species		x 1 =
FACW species		x 2 =
FAC species		x 3 =
FACU species		x 4 =
UPL species		x 5 =
Column totals	(A)	(B)

Prevalence Index = B / A =

Hydrophytic Vegetation Indicators

☐ Dominance test is > 50%
☐ Prevalence test is ≤ 3.0 *
☐ Morphological Adaptations * (provide supporting data in remarks or on a separate sheet)
☐ Wetland Non-Vascular Plants *
☐ Problematic Hydrophytic Vegetation * (explain)

* Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic

Hydrophytic Vegetation Present? Yes ☐ No ☒

SOIL **Sampling Point – DP-6**

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix		Redox Features				Texture	Remarks
	Color (moist)	%	Color (moist)	%	Type[1]	Loc[2]		
0-9	**10 YR 2/2**	**98**	**7.5 YR 4/6**	**2**	**C**	**M**	**GR SA LOAM**	
9-15	**10 YR 2/1**	**50**					**GR SA LOAM**	**MIX MATRIX**
	10 YR 3/4	**50**						

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Loc: PL=Pore Lining, M=Matrix

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Mucky Mineral (S1)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Loamy Mucky Mineral (F1) **(except MLRA** 1)
- ☐ Loamy Gleyed Matrix (F2)
- ☐ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)

Indicators for Problematic Hydric Soils[3]

- ☐ 2cm Muck (A10)
- ☐ Red Parent Material (TF2)
- ☐ Other (explain in remarks)
- ☐

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic

Restrictive Layer (if present):
Type:
Depth (inches):

Hydric soil present? Yes ☐ No ☒

Remarks: **DAMP, NOT SATURATED**

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required: check all that apply):

- ☐ Surface water (A1)
- ☐ High Water Table (A2)
- ☐ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift Deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Surface Soil Cracks (B6)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Water-Stained Leaves (**except MLRA 1, 2, 4A & 4B**) (B9)
- ☐ Salt Crust (B11)
- ☐ Aquatic Invertebrates (B13)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Stunted or Stressed Plants (D1) (**LRR A**)
- ☐ Other (explain in remarks)

Secondary Indicators (2 or more required):

- ☐ Water-Stained Leaves (B9) (**MLRA 1, 2, 4A & 4B**)
- ☐ Drainage Patterns (B10)
- ☐ Dry-Season Water Table (C2)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ FAC-Neutral Test (D5)
- ☐ Raised Ant Mounds (D6) (**LRR A**)
- ☐ Frost-Heave Hummocks

Field Observations

Surface Water Present?	Yes ☐	No ☒	Depth (in):
Water Table Present?	Yes ☐	No ☒	Depth (in):
Saturation Present? (includes capillary fringe)	Yes ☐	No ☒	Depth (in):

Wetland Hydrology Present? Yes ☐ No ☒

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

THE WATERSHED COMPANY

WETLAND DETERMINATION DATA FORM

Western Mountains, Valleys, and Coast Supplement to the 1987 COE Wetlands Delineation Manual

DP-7

750 Sixth Street South
Kirkland, Washington 98033
(425) 822-5242
watershedco.com

Project Site:	**RICHARDS CREEK SUBSTATION**	Sampling Date:	**3/27/2017**
Applicant/Owner:	**PUGET SOUND ENERGY**	Sampling Point:	DP- **7**
Investigator:	**KC, LM**	City/County:	**BELLEVUE/KING**
Sect., Township, Range:	S **10** T **24** R **05**	State:	**WA**

Landform (hillslope, terrace, etc): **HILLSLOPE** | Slope (%): **>15** | Local relief (concave, convex, none): **NONE**

Subregion (LRR): **A** | Lat: **47.5838** | Long: **-122.1585** | Datum:

Soil Map Unit Name: **EvD VERY GRAVELLY SANDY LOAM, 15-30 PERCENT SLOPES** | NWI classification: **N/A**

Are climatic/hydrologic conditions on the site typical for this time of year? ☒ Yes ☐ No (If no, explain in remarks.)

Are "Normal Circumstances" present on the site? ☒ Yes ☐ No

Are Vegetation☐, Soil ☐, or Hydrology ☐ significantly disturbed?

Are Vegetation☐, Soil ☐, or Hydrology ☐ naturally problematic

(If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ☐	No ☒
Hydric Soils Present?	Yes ☐	No ☒
Wetland Hydrology Present?	Yes ☒	No ☐

Is the Sampling Point within a Wetland? Yes ☐ No ☒

Remarks: **WETLAND A OUT PIT IN NW CORNER OF PROPERTY**

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 5m diam.)	Absolute % Cover	Dominant Species?	Indicator Status
1. ***Alnus rubra***	**100**	**Y**	**FACU**
2. ***Acer macrophyllum***	**5**	**N**	**FACU**
3.			
4.			
	105	= Total Cover	
Sapling/Shrub Stratum (Plot size: 3m diam.)			
1. ***Acer circinatum***	**20**	**Y**	**FAC**
2. ***Rubus armeniacus***	**70**	**Y**	**FAC**
3.			
4.			
5.			
	90	= Total Cover	
Herb Stratum (Plot size: 1m diam.)			
1. ***Dicentra formosa***	**50**	**Y**	**FACU**
2. ***Polystichum munitum***	**20**	**Y**	**FACU**
3.			
4.			
5.			
6.			
7.			
8.			
9.			
10.			
11.			
	70	= Total Cover	
Woody Vine Stratum (Plot size:)			
1.			
2.			
		= Total Cover	
% Bare Ground in Herb Stratum:			

Remarks:

Dominance Test Worksheet

Number of Dominant Species that are OBL, FACW, or FAC:	**2**	(A)
Total Number of Dominant Species Across All Strata:	**5**	(B)
Percent of Dominant Species that are OBL, FACW, or FAC:	**40**	(A/B)

Prevalence Index Worksheet

Total % Cover of		Multiply by
OBL species		x 1 =
FACW species		x 2 =
FAC species		x 3 =
FACU species		x 4 =
UPL species		x 5 =
Column totals	(A)	(B)

Prevalence Index = B / A =

Hydrophytic Vegetation Indicators

- ☐ Dominance test is > 50%
- ☐ Prevalence test is ≤ 3.0 *
- ☐ Morphological Adaptations * (provide supporting data in remarks or on a separate sheet)
- ☐ Wetland Non-Vascular Plants *
- ☐ Problematic Hydrophytic Vegetation * (explain)

* Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic

Hydrophytic Vegetation Present? Yes ☐ No ☒

SOIL **Sampling Point – DP-7**

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix		Redox Features				Texture	Remarks
	Color (moist)	%	Color (moist)	%	Type[1]	Loc[2]		
0-12	**10 YR 2/1**	**100**					**LOAM**	**SOME SAND**
12-14	**10 YR 3/6**	**80**					**LOAM**	**MIXED MATRIX**
	10 YR 2/2	**20**						

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Loc: PL=Pore Lining, M=Matrix

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Mucky Mineral (S1)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Loamy Mucky Mineral (F1) **(except MLRA** 1**)**
- ☐ Loamy Gleyed Matrix (F2)
- ☐ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)

Indicators for Problematic Hydric Soils[3]

- ☐ 2cm Muck (A10)
- ☐ Red Parent Material (TF2)
- ☐ Other (explain in remarks)
- ☐

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic

Restrictive Layer (if present):
Type:
Depth (inches):

Hydric soil present? Yes ☐ No ☒

Remarks: **DAMP, NOT SATURATED**

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required: check all that apply):

- ☐ Surface water (A1)
- ☒ High Water Table (A2)
- ☒ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift Deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Surface Soil Cracks (B6)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Water-Stained Leaves (**except MLRA 1, 2, 4A & 4B**) (B9)
- ☐ Salt Crust (B11)
- ☐ Aquatic Invertebrates (B13)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Stunted or Stressed Plants (D1) (**LRR A**)
- ☐ Other (explain in remarks)

Secondary Indicators (2 or more required):

- ☐ Water-Stained Leaves (B9) (**MLRA 1, 2, 4A & 4B**)
- ☐ Drainage Patterns (B10)
- ☐ Dry-Season Water Table (C2)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ FAC-Neutral Test (D5)
- ☐ Raised Ant Mounds (D6) (**LRR A**)
- ☐ Frost-Heave Hummocks

Field Observations

Surface Water Present?	Yes ☐	No ☒	Depth (in):
Water Table Present?	Yes ☒	No ☐	Depth (in): **14**
Saturation Present? (includes capillary fringe)	Yes ☐	No ☒	Depth (in):

Wetland Hydrology Present? Yes ☒ No ☐

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks: **DAMP, WET MARCH AND FEBRUARY**

WETLAND DETERMINATION DATA FORM

Western Mountains, Valleys, and Coast Supplement to the 1987 COE Wetlands Delineation Manual

THE WATERSHED COMPANY
750 Sixth Street South
Kirkland, Washington 98033
(425) 822-5242
watershedco.com

DP-8

Project Site:	**RICHARDS CREEK SUBSTATION**	Sampling Date:	**3/27/2017**
Applicant/Owner:	**PUGET SOUND ENERGY**	Sampling Point:	DP- **8**
Investigator:	**KC, LM**	City/County:	**BELLEVUE/KING**
Sect., Township, Range:	S **10** T **24** R **05**	State:	**WA**
Landform (hillslope, terrace, etc): **SWALE**	Slope (%): **5-10**	Local relief (concave, convex, none): **CONCAVE**	
Subregion (LRR): **A**	Lat: **47.5838**	Long: **-122.1585**	Datum:
Soil Map Unit Name: **EvD VERY GRAVELLY SANDY LOAM, 15-30 PERCENT SLOPES**		NWI classification: **N/A**	

Are climatic/hydrologic conditions on the site typical for this time of year? ☒ Yes ☐ No (If no, explain in remarks.)
Are "Normal Circumstances" present on the site? ☒ Yes ☐ No
Are Vegetation☐, Soil ☐, or Hydrology ☐ significantly disturbed?
Are Vegetation☐, Soil ☐, or Hydrology ☐ naturally problematic
(If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ☒	No ☐
Hydric Soils Present?	Yes ☒	No ☐
Wetland Hydrology Present?	Yes ☒	No ☐

Is the Sampling Point within a Wetland? Yes ☒ No ☐

Remarks: **WETLAND A IN PIT NEAR NW CORNER OF PROPERTY**

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 5m diam.)	Absolute % Cover	Dominant Species?	Indicator Status
1. ***Acer macrophyllum***	**60**	**Y**	**FACU**
2. ***(partially rooted in)***			
3.			
4.			
	60 = Total Cover		
Sapling/Shrub Stratum (Plot size: 3m diam.)			
1. ***Rubus armeniacus***	**100**	**Y**	**FAC**
2.			
3.			
4.			
5.			
	100 = Total Cover		
Herb Stratum (Plot size: 1m diam.)			
1.			
2.			
3.			
4.			
5.			
6.			
7.			
8.			
9.			
10.			
11.			
	= Total Cover		
Woody Vine Stratum (Plot size:)			
1.			
2.			
	= Total Cover		
% Bare Ground in Herb Stratum:			

Dominance Test Worksheet

Number of Dominant Species that are OBL, FACW, or FAC:	**1**	(A)
Total Number of Dominant Species Across All Strata:	**2**	(B)
Percent of Dominant Species that are OBL, FACW, or FAC:	**50**	(A/B)

Prevalence Index Worksheet

	Total % Cover of	Multiply by	
OBL species		x 1 =	
FACW species		x 2 =	
FAC species	**100**	x 3 =	**300**
FACU species	**60**	x 4 =	**240**
UPL species		x 5 =	
Column totals	(A) **160**	(B) **540**	

Prevalence Index = B / A = **540/160 = 3.38**

Hydrophytic Vegetation Indicators

☐ Dominance test is > 50%
☐ Prevalence test is ≤ 3.0 *
☐ Morphological Adaptations * (provide supporting data in remarks or on a separate sheet)
☐ Wetland Non-Vascular Plants *
☒ Problematic Hydrophytic Vegetation * (explain)

* Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic

Hydrophytic Vegetation Present? Yes ☒ No ☐

Remarks: **Plants currently dominated by invasive blackberry in understory. Bigleaf maple present in canopy is only partially rooted in. Soils and hydrology indicators are strong. Presumed that later in the growing season other wetland-indicative plants like giant horsetail or willowherb may be dominant in herb stratum.**

SOIL

Sampling Point – DP-8

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	Matrix %	Redox Features Color (moist)	Redox %	Type[1]	Loc[2]	Texture	Remarks
0-8	**10 YR 2/2**	**100**					**LOAM**	**SOME SAND**
8-14	**10 YR 5/1**	**75**	**10 YR 3/6**	**20**	**C**	**M**	**GRAVELLY SANDY LOAM**	**DIFFUSE REDOX**
			5 YR 3/4	**5**	**C**	**M**	**GRAVELLY SANDY LOAM**	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Loc: PL=Pore Lining, M=Matrix

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Mucky Mineral (S1)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Loamy Mucky Mineral (F1) **(except MLRA** 1**)**
- ☐ Loamy Gleyed Matrix (F2)
- ☒ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)

Indicators for Problematic Hydric Soils[3]

- ☐ 2cm Muck (A10)
- ☐ Red Parent Material (TF2)
- ☐ Other (explain in remarks)
- ☐

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic

Restrictive Layer (if present):
Type:
Depth (inches):

Hydric soil present? Yes ☒ No ☐

Remarks:

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required: check all that apply):

- ☐ Surface water (A1)
- ☒ High Water Table (A2)
- ☒ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift Deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Surface Soil Cracks (B6)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Water-Stained Leaves (**except MLRA 1, 2, 4A & 4B**) (B9)
- ☐ Salt Crust (B11)
- ☐ Aquatic Invertebrates (B13)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Stunted or Stressed Plants (D1) (**LRR A**)
- ☐ Other (explain in remarks)

Secondary Indicators (2 or more required):

- ☐ Water-Stained Leaves (B9) (**MLRA 1, 2, 4A & 4B**)
- ☐ Drainage Patterns (B10)
- ☐ Dry-Season Water Table (C2)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ FAC-Neutral Test (D5)
- ☐ Raised Ant Mounds (D6) (**LRR A**)
- ☐ Frost-Heave Hummocks

Field Observations

Surface Water Present?	Yes ☐	No ☒	Depth (in):
Water Table Present?	Yes ☒	No ☐	Depth (in): **4**
Saturation Present? (includes capillary fringe)	Yes ☒	No ☐	Depth (in): **0-14**

Wetland Hydrology Present? Yes ☒ No ☐

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

THE WATERSHED COMPANY

WETLAND DETERMINATION DATA FORM

Western Mountains, Valleys, and Coast Supplement to the 1987 COE Wetlands Delineation Manual

DP- 9

750 Sixth Street South
Kirkland, Washington 98033
(425) 822-5242
watershedco.com

Project Site:	**RICHARDS CREEK SUBSTATION**	Sampling Date:	**10/19/2016**
Applicant/Owner:	**PUGET SOUND ENERGY**	Sampling Point:	DP- **9**
Investigator:	**MIKE FOSTER**	City/County:	**BELLEVUE/KING**
Sect., Township, Range:	S **10** T **24** R **05**	State:	**WA**

Landform (hillslope, terrace, etc): | Slope (%): | Local relief (concave, convex, none):

Subregion (LRR): **A** | Lat: **47.5838** | Long: **-122.1585** | Datum:

Soil Map Unit Name: **EvD VERY GRAVELLY SANDY LOAM, 15-30 PERCENT SLOPES** | NWI classification: **N/A**

Are climatic/hydrologic conditions on the site typical for this time of year? ☒ Yes ☐ No (If no, explain in remarks.)
Are “Normal Circumstances” present on the site? ☒ Yes ☐ No
Are Vegetation☐, Soil ☐, or Hydrology ☐ significantly disturbed?
Are Vegetation☐, Soil ☐, or Hydrology ☐ naturally problematic (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ☒	No ☐
Hydric Soils Present?	Yes ☒	No ☐
Wetland Hydrology Present?	Yes ☒	No ☐

Is the Sampling Point within a Wetland? Yes ☒ No ☐

Remarks: **WETLAND D IN PIT**

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 5m diam.)	Absolute % Cover	Dominant Species?	Indicator Status
1. ***Salix lucida***	**75**	**Y**	**FACW**
2. ***Alnus rubra***	**10**	**N**	**FAC**
3.			
4.			
		= Total Cover	
Sapling/Shrub Stratum (Plot size: 3m diam.)			
1.			
2.			
3.			
4.			
5.			
		= Total Cover	
Herb Stratum (Plot size: 1m diam.)			
1. ***Athyrium cyclosorum***	**10**	**N**	**FAC**
2. ***Scirpus microcarpus***	**60**	**Y**	**OBL**
3. ***Phalaris arundinacea***	**15**	**N**	**FACW**
4. ***Equisetum telmateia***	**10**	**N**	**FACW**
5.			
6.			
7.			
8.			
9.			
10.			
11.			
		= Total Cover	
Woody Vine Stratum (Plot size:)			
1. ***Rubus armeniacus***	**2**	**N**	**FAC**
2.			
		= Total Cover	

% Bare Ground in Herb Stratum:

Remarks:

Dominance Test Worksheet

Number of Dominant Species that are OBL, FACW, or FAC:	**2**	(A)
Total Number of Dominant Species Across All Strata:	**2**	(B)
Percent of Dominant Species that are OBL, FACW, or FAC:	**100**	(A/B)

Prevalence Index Worksheet

Total % Cover of		Multiply by
OBL species		x 1 =
FACW species		x 2 =
FAC species		x 3 =
FACU species		x 4 =
UPL species		x 5 =
Column totals	(A)	(B)

Prevalence Index = B / A =

Hydrophytic Vegetation Indicators

- ☒ Dominance test is > 50%
- ☐ Prevalence test is ≤ 3.0 *
- ☐ Morphological Adaptations * (provide supporting data in remarks or on a separate sheet)
- ☐ Wetland Non-Vascular Plants *
- ☐ Problematic Hydrophytic Vegetation * (explain)

* Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic

Hydrophytic Vegetation Present? Yes ☒ No ☐

SOIL

Sampling Point – DP-9

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix		Redox Features				Texture	Remarks
	Color (moist)	%	Color (moist)	%	Type[1]	Loc[2]		
0-4	**10YR 3/2**	**100**					**Loam with high org. cont.**	
4-14	**10YR 3/1**	**90**	**7.5YR 3/3**	**10**	**C**	**M, PL**	**Loamy sand**	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Loc: PL=Pore Lining, M=Matrix

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☐ Hydrogen Sulfide (A4)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Mucky Mineral (S1)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Loamy Mucky Mineral (F1) **(except MLRA 1)**
- ☐ Loamy Gleyed Matrix (F2)
- ☐ Depleted Matrix (F3)
- ☒ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)

Indicators for Problematic Hydric Soils[3]

- ☐ 2cm Muck (A10)
- ☐ Red Parent Material (TF2)
- ☐ Other (explain in remarks)
- ☐

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic

Restrictive Layer (if present):
Type:
Depth (inches):

Hydric soil present? Yes ☒ No ☐

Remarks:

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required: check all that apply):

- ☐ Surface water (A1)
- ☒ High Water Table (A2)
- ☒ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift Deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Surface Soil Cracks (B6)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Water-Stained Leaves (**except MLRA 1, 2, 4A & 4B**) (B9)
- ☐ Salt Crust (B11)
- ☐ Aquatic Invertebrates (B13)
- ☐ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Stunted or Stressed Plants (D1) (**LRR A**)
- ☐ Other (explain in remarks)

Secondary Indicators (2 or more required):

- ☐ Water-Stained Leaves (B9) (**MLRA 1, 2, 4A & 4B**)
- ☐ Drainage Patterns (B10)
- ☐ Dry-Season Water Table (C2)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☐ FAC-Neutral Test (D5)
- ☐ Raised Ant Mounds (D6) (**LRR A**)
- ☐ Frost-Heave Hummocks

Field Observations

Surface Water Present?	Yes ☐	No ☒	Depth (in):
Water Table Present?	Yes ☒	No ☐	Depth (in): **12**
Saturation Present? (includes capillary fringe)	Yes ☒	No ☐	Depth (in): **0-14**

Wetland Hydrology Present? Yes ☒ No ☐

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

THE WATERSHED COMPANY
750 Sixth Street South
Kirkland, Washington 98033
(425) 822-5242
watershedco.com

WETLAND DETERMINATION DATA FORM
Western Mountains, Valleys, and Coast Supplement to the 1987 COE Wetlands Delineation Manual

DP- 35

Project Site:	**Segment J, parcel number 5453300320**	Sampling Date:	**7/1/2015**
Applicant/Owner:	**Puget Sound Energy**	Sampling Point:	DP- **35**
Investigator:	**R. Kahlo, A. Hoenig**	City/County:	**Bellevue**
Sect., Township, Range:	S **10** T **24** R **05**	State:	**WA**

Landform (hillslope, terrace, etc): **Hillslope** Slope (%): **8** Local relief (concave, convex, none): **Concave**

Subregion (LRR): **A** Lat: Long: Datum:

Soil Map Unit Name: **EvD, Everett gravelly sandy loam, 15-30% slopes** NWI classification: **NA**

Are climatic/hydrologic conditions on the site typical for this time of year? ☒ Yes ☐ No (If no, explain in remarks.)
Are "Normal Circumstances" present on the site? ☒ Yes ☐ No
Are Vegetation☐, Soil ☐, or Hydrology ☐ significantly disturbed?
Are Vegetation☐, Soil ☐, or Hydrology ☐ naturally problematic (If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ☒	No ☐
Hydric Soils Present?	Yes ☒	No ☐
Wetland Hydrology Present?	Yes ☒	No ☐

Is the Sampling Point within a Wetland? Yes ☒ No ☐

Remarks: **Wetland H in pit.**

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 5m diam.)	Absolute % Cover	Dominant Species?	Indicator Status
1.			
2.			
3.			
4.			
		= Total Cover	
Sapling/Shrub Stratum (Plot size: 3m diam.)			
1.			
2.			
3.			
4.			
5.			
		= Total Cover	
Herb Stratum (Plot size: 1m diam.)			
1. ***Carex rostrata***	**80**	**Y**	**OBL**
2. ***Lotus corniculatus***	**60**	**Y**	**FAC**
3. ***Scirpus microcarpus***	**10**	**N**	**OBL**
4. ***Phalaris arundinacea***	**5**	**N**	**FACW**
5.			
6.			
7.			
8.			
9.			
10.			
11.			
	155	= Total Cover	
Woody Vine Stratum (Plot size:)			
1.			
2.			
		= Total Cover	
% Bare Ground in Herb Stratum:			

Dominance Test Worksheet

Number of Dominant Species that are OBL, FACW, or FAC:	**2**	(A)
Total Number of Dominant Species Across All Strata:	**4**	(B)
Percent of Dominant Species that are OBL, FACW, or FAC:	**50**	(A/B)

Prevalence Index Worksheet

Total % Cover of		Multiply by
OBL species		x 1 =
FACW species		x 2 =
FAC species		x 3 =
FACU species		x 4 =
UPL species		x 5 =
Column totals	(A)	(B)

Prevalence Index = B / A =

Hydrophytic Vegetation Indicators

☒ Dominance test is > 50%
☐ Prevalence test is ≤ 3.0 *
☐ Morphological Adaptations * (provide supporting data in remarks or on a separate sheet)
☐ Wetland Non-Vascular Plants *
☐ Problematic Hydrophytic Vegetation * (explain)

* Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic

Hydrophytic Vegetation Present? Yes ☒ No ☐

Remarks:

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth	Matrix		Redox Features					
(inches)	Color (moist)	%	Color (moist)	%	Type[1]	Loc[2]	Texture	Remarks
0-4	**10YR 2/1**	**100**					**Sandy clay loam**	
4-12	**2.5Y 3/1**	**100**					**Loamy sand**	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Loc: PL=Pore Lining, M=Matrix

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

- ☐ Histosol (A1)
- ☐ Histic Epipedon (A2)
- ☐ Black Histic (A3)
- ☒ Hydrogen Sulfide (A4)
- ☐ Depleted Below Dark Surface (A11)
- ☐ Thick Dark Surface (A12)
- ☐ Sandy Mucky Mineral (S1)
- ☐ Sandy Gleyed Matrix (S4)
- ☐ Sandy Redox (S5)
- ☐ Stripped Matrix (S6)
- ☐ Loamy Mucky Mineral (F1) **(except MLRA** 1)
- ☐ Loamy Gleyed Matrix (F2)
- ☐ Depleted Matrix (F3)
- ☐ Redox Dark Surface (F6)
- ☐ Depleted Dark Surface (F7)
- ☐ Redox Depressions (F8)

Indicators for Problematic Hydric Soils[3]

- ☐ 2cm Muck (A10)
- ☐ Red Parent Material (TF2)
- ☐ Other (explain in remarks)
- ☐

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic

Restrictive Layer (if present):
Type: ______________________________________
Depth (inches): ____________________________________

Hydric soil present? Yes ☒ No ☐

Remarks:

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required: check all that apply):

- ☐ Surface water (A1)
- ☒ High Water Table (A2)
- ☒ Saturation (A3)
- ☐ Water Marks (B1)
- ☐ Sediment Deposits (B2)
- ☐ Drift Deposits (B3)
- ☐ Algal Mat or Crust (B4)
- ☐ Iron Deposits (B5)
- ☐ Surface Soil Cracks (B6)
- ☐ Inundation Visible on Aerial Imagery (B7)
- ☐ Sparsely Vegetated Concave Surface (B8)
- ☐ Water-Stained Leaves (**except MLRA 1, 2, 4A & 4B**) (B9)
- ☐ Salt Crust (B11)
- ☐ Aquatic Invertebrates (B13)
- ☒ Hydrogen Sulfide Odor (C1)
- ☐ Oxidized Rhizospheres along Living Roots (C3)
- ☐ Presence of Reduced Iron (C4)
- ☐ Recent Iron Reduction in Tilled Soils (C6)
- ☐ Stunted or Stressed Plants (D1) (**LRR A**)
- ☐ Other (explain in remarks)

Secondary Indicators (2 or more required):

- ☐ Water-Stained Leaves (B9) (**MLRA 1, 2, 4A & 4B**)
- ☐ Drainage Patterns (B10)
- ☐ Dry-Season Water Table (C2)
- ☐ Saturation Visible on Aerial Imagery (C9)
- ☐ Geomorphic Position (D2)
- ☐ Shallow Aquitard (D3)
- ☒ FAC-Neutral Test (D5)
- ☐ Raised Ant Mounds (D6) (**LRR A**)
- ☐ Frost-Heave Hummocks

Field Observations

Surface Water Present?	Yes ☐	No ☒	Depth (in):	
Water Table Present?	Yes ☒	No ☐	Depth (in):	**4 BGS**
Saturation Present? (includes capillary fringe)	Yes ☒	No ☐	Depth (in):	**Throughout**

Wetland Hydrology Present? Yes ☒ No ☐

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks: **BGS = below ground surface**

THE WATERSHED COMPANY
750 Sixth Street South
Kirkland, Washington 98033
(425) 822-5242
watershedco.com

WETLAND DETERMINATION DATA FORM

Western Mountains, Valleys, and Coast Supplement to the 1987 COE Wetlands Delineation Manual

DP- 36

Project Site:	**Segment J Parcel 5453300320**	Sampling Date:	**6/15/2015**
Applicant/Owner:	**Puget Sound Energy**	Sampling Point:	DP- **36**
Investigator:	**R. Kahlo, A. Hoenig**	City/County:	**Bellevue**
Sect., Township, Range:	S **10** T **24** R **05**	State:	**WA**

Landform (hillslope, terrace, etc): **Hillslope** | Slope (%): **25** | Local relief (concave, convex, none): **Concave**

Subregion (LRR): **A** | Lat: | Long: | Datum:

Soil Map Unit Name: **EvD, Everett gravelly sandy loam, 15-30% slopes** | NWI classification: **NA**

Are climatic/hydrologic conditions on the site typical for this time of year? ☒ Yes ☐ No (If no, explain in remarks.)
Are "Normal Circumstances" present on the site? ☒ Yes ☐ No
Are Vegetation☐, Soil ☐, or Hydrology ☐ significantly disturbed?
Are Vegetation☐, Soil ☐, or Hydrology ☐ naturally problematic
(If needed, explain any answers in Remarks.)

SUMMARY OF FINDINGS – Attach site map showing sampling point locations, transects, important features, etc.

Hydrophytic Vegetation Present?	Yes ☒	No ☐
Hydric Soils Present?	Yes ☐	No ☒
Wetland Hydrology Present?	Yes ☐	No ☒

Is the Sampling Point within a Wetland? Yes ☐ No ☒

Remarks: **Wetland H out pit**

VEGETATION – Use scientific names of plants.

Tree Stratum (Plot size: 5m diam.)	Absolute % Cover	Dominant Species?	Indicator Status
1.			
2.			
3.			
4.			
		= Total Cover	
Sapling/Shrub Stratum (Plot size: 3m diam.)			
1. *Salix spp. (hybrid)*	**15**	**Y**	**FACW***
2.			
3.			
4.			
5.			
	15	= Total Cover	
Herb Stratum (Plot size: 1m diam.)			
1. *Equisetum telmateia*	**60**	**Y**	**FACW**
2.			
3.			
4.			
5.			
6.			
7.			
8.			
9.			
10.			
11.			
	60	= Total Cover	
Woody Vine Stratum (Plot size:)			
1. *Rubus armeniacus*	**90**	**Y**	**FACU**
2.			
	90	= Total Cover	
% Bare Ground in Herb Stratum:			

Dominance Test Worksheet

Number of Dominant Species that are OBL, FACW, or FAC:	**2**	(A)
Total Number of Dominant Species Across All Strata:	**3**	(B)
Percent of Dominant Species that are OBL, FACW, or FAC:	**67**	(A/B)

Prevalence Index Worksheet

	Total % Cover of	Multiply by
OBL species		x 1 =
FACW species		x 2 =
FAC species		x 3 =
FACU species		x 4 =
UPL species		x 5 =
Column totals	(A)	(B)

Prevalence Index = B / A =

Hydrophytic Vegetation Indicators

- ☒ Dominance test is > 50%
- ☐ Prevalence test is ≤ 3.0 *
- ☐ Morphological Adaptations * (provide supporting data in remarks or on a separate sheet)
- ☐ Wetland Non-Vascular Plants *
- ☐ Problematic Hydrophytic Vegetation * (explain)

* Indicators of hydric soil and wetland hydrology must be present, unless disturbed or problematic

Hydrophytic Vegetation Present? Yes ☒ No ☐

Remarks: ***Presumed**

SOIL **Sampling Point – DP-36**

Profile Description: (Describe to the depth needed to document the indicator or confirm the absence of indicators.)

Depth (inches)	Matrix Color (moist)	Matrix %	Redox Features Color (moist)	Redox %	Type[1]	Loc[2]	Texture	Remarks
0-10	**2.5Y 3/2**	**100**	**None**				**Sandy loam**	
10-14	**2.5Y 4/3**	**100**	**None**				**Loamy sand**	

[1]Type: C=Concentration, D=Depletion, RM=Reduced Matrix, CS=Covered or Coated Sand Grains [2]Loc: PL=Pore Lining, M=Matrix

Hydric Soil Indicators: (Applicable to all LRRs, unless otherwise noted.)

☐ Histosol (A1)
☐ Histic Epipedon (A2)
☐ Black Histic (A3)
☐ Hydrogen Sulfide (A4)
☐ Depleted Below Dark Surface (A11)
☐ Thick Dark Surface (A12)
☐ Sandy Mucky Mineral (S1)
☐ Sandy Gleyed Matrix (S4)
☐ Sandy Redox (S5)
☐ Stripped Matrix (S6)
☐ Loamy Mucky Mineral (F1) **(except MLRA 1)**
☐ Loamy Gleyed Matrix (F2)
☐ Depleted Matrix (F3)
☐ Redox Dark Surface (F6)
☐ Depleted Dark Surface (F7)
☐ Redox Depressions (F8)

Indicators for Problematic Hydric Soils[3]

☐ 2cm Muck (A10)
☐ Red Parent Material (TF2)
☐ Other (explain in remarks)
☐

[3] Indicators of hydrophytic vegetation and wetland hydrology must be present, unless disturbed or problematic

Restrictive Layer (if present):
Type: ______________________________________
Depth (inches): ___________________________________

Hydric soil present? Yes ☐ No ☒

Remarks:

HYDROLOGY

Wetland Hydrology Indicators:

Primary Indicators (minimum of one required: check all that apply):

☐ Surface water (A1)
☐ High Water Table (A2)
☐ Saturation (A3)
☐ Water Marks (B1)
☐ Sediment Deposits (B2)
☐ Drift Deposits (B3)
☐ Algal Mat or Crust (B4)
☐ Iron Deposits (B5)
☐ Surface Soil Cracks (B6)
☐ Inundation Visible on Aerial Imagery (B7)
☐ Sparsely Vegetated Concave Surface (B8)
☐ Water-Stained Leaves (**except MLRA 1, 2, 4A & 4B**) (B9)
☐ Salt Crust (B11)
☐ Aquatic Invertebrates (B13)
☐ Hydrogen Sulfide Odor (C1)
☐ Oxidized Rhizospheres along Living Roots (C3)
☐ Presence of Reduced Iron (C4)
☐ Recent Iron Reduction in Tilled Soils (C6)
☐ Stunted or Stressed Plants (D1) (**LRR A**)
☐ Other (explain in remarks)

Secondary Indicators (2 or more required):

☐ Water-Stained Leaves (B9) (**MLRA 1, 2, 4A & 4B**)
☐ Drainage Patterns (B10)
☐ Dry-Season Water Table (C2)
☐ Saturation Visible on Aerial Imagery (C9)
☐ Geomorphic Position (D2)
☐ Shallow Aquitard (D3)
☐ FAC-Neutral Test (D5)
☐ Raised Ant Mounds (D6) (**LRR A**)
☐ Frost-Heave Hummocks

Field Observations

Surface Water Present? Yes ☐ No ☒ Depth (in):
Water Table Present? Yes ☐ No ☒ Depth (in):
Saturation Present? (includes capillary fringe) Yes ☐ No ☒ Depth (in):

Wetland Hydrology Present? Yes ☐ No ☒

Describe Recorded Data (stream gauge, monitoring well, aerial photos, previous inspections), if available:

Remarks:

WETLAND RATING FORM – WESTERN WASHINGTON

Version 2 – Updated July 2006 to increase accuracy and reproducibility among users
Updated Oct 2008 with the new WDFW definitions for priority habitats

Name of wetland (if known): Richards Creek Substation – Wetland A Date of site visit: 03/27/2017

Rated by: Katy Crandall Trained by Ecology? Yes ☒ No ☐ Date of Training 09/2014

SEC: 1 TWNSHP: 24N RNGE: 05E Is S/T/R in Appendix D? Yes ☐ No ☒

SUMMARY OF RATING

Category based on FUNCTIONS provided by wetland

I ☐ II ☐ III ☒ IV ☐

Category I = Score ≥70
Category II = Score 51-69
Category III = Score 30-50
Category IV = Score < 30

Score for Water Quality Functions	6
Score for Hydrologic Functions	10
Score for Habitat Functions	21
TOTAL score for functions	**37**

Category based on SPECIAL CHARACTERISTICS of wetland

I ☐ II ☐ Does not Apply ☒

Final Category (choose the "highest" category from above) **III**

Check the appropriate type and class of wetland being rated.

Wetland Type		**Wetland Class**	
Estuarine		**Depressional**	
Natural Heritage Wetland		**Riverine**	
Bog		**Lake-fringe**	
Mature Forest		**Slope**	X
Old Growth Forest		**Flats**	
Coastal Lagoon		**Freshwater Tidal**	
Interdunal			
None of the above	X	Check if unit has multiple HGM classes present	

Does the wetland unit being rated meet any of the criteria below?

If you answer YES to any of the questions below you will need to protect the wetland according to the regulations regarding the special characteristics found in the wetland.

Check List for Wetlands That May Need Additional Protection (in addition to the protection recommended for its category)	YES	NO
SP1. *Has the wetland unit been documented as a habitat for any Federally listed Threatened or Endangered* ***animal*** *or* ***plant*** *species (T/E species)?* For the purposes of this rating system, "documented" means the wetland is on the appropriate state or federal database.		X*
SP2. *Has the wetland unit been documented as habitat for any State listed Threatened or Endangered* ***animal*** *species?* For the purposes of this rating system, "documented" means the wetland is on the appropriate state database. Note: Wetlands with State listed plant species are categorized as Category I Natural Heritage Wetlands (see p. 19 of data form).		X*
SP3. *Does the wetland unit contain individuals of Priority species listed by the WDFW for the state?*		X*
SP4. *Does the wetland unit have a local significance in addition to its functions*? For example, the wetland has been identified in the Shoreline Master Program, the Critical Areas Ordinance, or in a local management plan as having special significance.		X

* The study area was reviewed for the presence of endangered, threatened, and priority species using WDFW online Priority Habitat and Species Data, PHS on the Web (http://wdfw.wa.gov/mapping/phs/). Resident coastal cutthroat are mapped as occurring in the stream adjacent to this wetland.

To complete the next part of the data sheet you will need to determine the Hydrogeomorphic Class of the wetland being rated.

The hydrogeomorphic classification groups wetlands into those that function in similar ways. Classifying the wetland first simplifies the questions needed to answer how it functions. The Hydrogeomorphic Class of a wetland can be determined using the key below. See p. 24 for more detailed instructions on classifying wetlands.

Classification of Wetland Units in Western Washington

If the hydrologic criteria listed in each question do not apply to the entire unit being rated, you probably have a unit with multiple HGM classes. In this case, identify which hydrologic criteria in Questions 1-7 apply, and go to Question 8.

1. Are the water levels in the wetland unit usually controlled by tides (i.e. except during floods)?

☒ NO – go to 2 ☐ **YES** – the wetland class is **Tidal Fringe**

If yes, is the salinity of the water during periods of annual low flow below 0.5 ppt (parts per thousand)? **YES – Freshwater Tidal Fringe NO – Saltwater Tidal Fringe (Estuarine)**

If your wetland can be classified as a Freshwater Tidal Fringe use the forms for ***Riverine*** *wetlands. If it is Saltwater Tidal Fringe it is rated as an* ***Estuarine*** *wetland.* Wetlands that were called estuarine in the first and second editions of the rating system are called Salt Water Tidal Fringe in the Hydrogeomorphic Classification. Estuarine wetlands were categorized separately in the earlier editions, and this separation is being kept in this revision. To maintain consistency between editions, the term "Estuarine" wetland is kept. Please note, however, that the characteristics that define Category I and II estuarine wetlands have changed (see p.).

2. The entire wetland unit is flat and precipitation is only source (>90%) of water to it. Groundwater and surface water runoff are NOT sources of water to the unit

☒ NO – go to 3 ☐ **YES** – The wetland class is **Flats**

If your wetland can be classified as a "Flats" wetland, use the form for **Depressional** wetlands.

3. Does the entire wetland unit **meet both** of the following criteria?

☐ The vegetated part of the wetland is on the shores of a body of open water (without any vegetation on the surface) at least 20 acres (8 ha) in size;

☐ At least 30% of the open water area is deeper than 6.6 ft (2 m)?

☒ NO – go to 4 ☐ **YES –** The wetland class is **Lake-fringe (Lacustrine Fringe)**

4. Does the entire wetland unit **meet all** of the following criteria?

☒ The wetland is on a slope (*slope can be very gradual*),

☒ The water flows through the wetland in one direction (unidirectional) and usually comes from seeps. It may flow subsurface, as sheetflow, or in a swale without distinct banks.

☒ The water leaves the wetland **without being impounded**?

NOTE: *Surface water does not pond in these types of wetlands except occasionally in very small and shallow depressions or behind hummocks (depressions are usually <3ft diameter and less than a foot deep).*

☐ NO – go to 5 ☒ **YES –** The wetland class is **Slope**

5. Does the entire wetland unit **meet all** of the following criteria?

☐ The unit is in a valley, or stream channel, where it gets inundated by overbank flooding from that stream or river.

☐ The overbank flooding occurs at least once every two years

NOTE: The riverine unit can contain depressions that are filled with water when the river is not flooding.

☐ NO - go to 6 ☐ **YES** – The wetland class is **Riverine**

6. Is the entire wetland unit in a topographic depression in which water ponds, or is saturated to the surface, at some time during the year. *This means that any outlet, if present, is higher than the interior of the wetland.*

☐ NO – go to 7 ☐ **YES –** The wetland class is **Depressional**

7. Is the entire wetland unit located in a very flat area with no obvious depression and no overbank flooding. The unit does not pond surface water more than a few inches. The unit seems to be maintained by high groundwater in the area. The wetland may be ditched, but has no obvious natural outlet.

☐ NO – go to 8 ☐ **YES –** The wetland class is **Depressional**

8. Your wetland unit seems to be difficult to classify and probably contains several different HGM classes. For example, seeps at the base of a slope may grade into a riverine floodplain, or a small stream within a depressional wetland has a zone of flooding along its sides. GO BACK AND IDENTIFY WHICH OF THE HYDROLOGIC REGIMES DESCRIBED IN QUESTIONS 1-7 APPLY TO DIFFERENT AREAS IN THE UNIT (make a rough sketch to help you decide). Use the following table to identify the appropriate class to use for the rating system if you have several HGM classes present within your wetland. NOTE: Use this table only if the class that is recommended in the second column represents 10% or more of the total area of the wetland unit being rated. If the area of the class listed in column 2 is less than 10% of the unit, classify the wetland using the class that represents more than 90% of the total area.

HGM classes within the wetland unit being rated	*HGM Class to Use in Rating*
Slope + Riverine	Riverine
Slope + Depressional	Depressional
Slope + Lake-fringe	Lake-fringe
Depressional + Riverine along stream within boundary	Depressional
Depressional + Lake-fringe	Depressional
Salt Water Tidal Fringe and any other class of freshwater wetland	Treat as ESTUARINE under wetlands with special characteristics

If you are unable still to determine which of the above criteria apply to your wetland, or you have more than 2 HGM classes within a wetland boundary, classify the wetland as **Depressional** for the rating.

S	Slope Wetlands	Points
	WATER QUALITY FUNCTIONS - Indicators that wetland functions to improve water quality	
S	**S 1. Does the wetland have the potential to improve water quality?**	*(see p. 64)*
S	S 1.1 Characteristics of average slope of wetland: Slope is1% or less *(a 1% slope has a 1 foot vertical drop in elevation horizontal distance) for every 100 ft* .... points = 3 Slope is 1% - 2% .... points = 2 Slope is 2% - 5% .... points = 1 Slope is greater than 5% .... points = 0	0
S	S 1.2 The soil 2 inches below the surface (or duff layer) is clay or organic *(use NRCS definitions)*. YES = 3 points NO = 0 points	0
S	S 1.3 Characteristics of the vegetation in the wetland that trap sediments and pollutants: *Choose the points appropriate for the description that best fits the vegetation in the wetland. Dense vegetation means you have trouble seeing the soil surface. Dense vegetation means you have trouble seeing the soil surface (>75% cover) and uncut means not grazed or mowed and plants are higher than 6 inches.* Dense, ungrazed, herbaceous vegetation > 90% of the wetland area .... points = 6 Dense, ungrazed, herbaceous vegetation > 1/2 of area .... points = 3 Dense, woody, vegetation > ½ of area .... points = 2 Dense, ungrazed, herbaceous vegetation > 1/4 of area .... points = 1 Does not meet any of the criteria above for vegetation .... points = 0	3
S	**Total for S 1** *Add the points in the boxes above*	3
S	**S 2. Does the wetland have the opportunity to improve water quality?** ***(see p. 67)*** Answer YES if you know or believe there are pollutants in groundwater or surface water coming into the wetland that would otherwise reduce water quality in streams, lakes or groundwater downgradient from the wetland? *Note which of the following conditions provide the sources of pollutants. A unit may have pollutants coming from several sources, but any single source would qualify as opportunity.* ☐ Grazing in the wetland or within 150 ft ☐ Untreated stormwater discharges to wetland ☐ Tilled fields, logging or orchards within 150 ft of wetland ☒ A stream or culvert discharges into wetland that drains developed areas, residential areas, farmed fields, roads, or clear-cut logging ☐ Residential, urban areas, or golf courses are within 150 ft upslope of wetland ☒ Other: refuse, turbid runoff observed, gravel pole yard, parking________ **YES** multiplier is **2** **NO** multiplier is **1**	multiplier _2_
S	**TOTAL - Water Quality Functions** Multiply the score from S 1 by S 2 ***Add score to table on p. 1***	**6**

S	Slope Wetlands	Points
	HYDROLOGIC FUNCTIONS - Indicators that wetland functions to reduce flooding and stream erosion	
	S 3. Does the wetland have the potential to reduce flooding and erosion?	***(see p. 68)***
S	S 3.1 Characteristics of vegetation that reduce the velocity of surface flows during storms. *Choose the points appropriate for the description that best fit conditions in the wetland. (stems of plants should be thick enough (usually > 1/8in), or dense enough, to remain erect during surface flows)* Dense, uncut, **rigid** vegetation covers > 90% of the area of the wetland. .... points = 6 Dense, uncut, **rigid** vegetation > 1/2 area of wetland .... points = 3 Dense, uncut, **rigid** vegetation > 1/4 area .... points = 1 More than 1/4 of area is grazed, mowed, tilled or vegetation is not rigid .... points = 0	3
S	S 3.2 Characteristics of slope wetland that holds back small amounts of flood flows: The slope wetland has small surface depressions that can retain water over at least 10% of its area. YES points = 2 NO points = 0	2
S	**Total for S 3** *Add the points in the boxes above*	5
S	**S 4. Does the wetland have the opportunity to reduce flooding and erosion? *(see p. 70)*** Is the wetland in a landscape position where the reduction in water velocity it provides helps protect downstream property and aquatic resources from flooding or excessive and/or erosive flows? *Note which of the following conditions apply.* ☒ Wetland has surface runoff that drains to a river or stream that has flooding problems ☐ Other____ *(Answer NO if the major source of water to the wetland is controlled by a reservoir or the wetland is tidal fringe along the sides of a dike)* **YES** multiplier is **2** **NO** multiplier is **1**	multiplier _2_
S	**TOTAL - Hydrologic Functions** Multiply the score from S 3 by S 4 ***Add score to table on p. 1***	**10**

Comments

These questions apply to wetlands of all HGM classes.

HABITAT FUNCTIONS - Indicators that wetland functions to provide important habitat

H 1. Does the wetland have the potential to provide habitat for many species?

H 1.1 Vegetation structure ***(see p. 72)***

Check the types of vegetation classes present (as defined by Cowardin) if the class is ¼ acre or covers more than 10% of the area of the wetland if unit smaller than 2.5 acres.

- ☐ Aquatic bed
- ☒ Emergent plants
- ☒ Scrub/shrub (areas where shrubs have >30% cover)
- ☒ Forested (areas where trees have >30% cover)
- ☒ Forested areas have 3 out of 5 strata (canopy, sub-canopy, shrubs, herbaceous, moss/ground-cover) that each cover 20% within the forested polygon

Add the number of vegetation types that qualify. If you have:

4 structures or more .... points = 4
3 structures .... points = 2
2 structures .... points = 1
1 structure .... points = 0

4

H 1.2. Hydroperiods ***(see p. 73)***

Check the types of water regimes (hydroperiods) present within the wetland. The water regime has to cover more than 10% of the wetland or ¼ acre to count. (see text for descriptions of hydroperiods)

- ☐ Permanently flooded or inundated — 4 or more types present .... points = 3
- ☐ Seasonally flooded or inundated — 3 types present .... points = 2
- ☒ Occasionally flooded or inundated — 2 types present .... points = 1
- ☒ Saturated only — 1 types present……………………points = 0
- ☐ Permanently flowing stream or river in, or adjacent to, the wetland
- ☐ Seasonally flowing stream in, or adjacent to, the wetland
- ☐ ***Lake-fringe wetland* = 2 points**
- ☐ ***Freshwater tidal wetland* = 2 points**

1

H 1.3. Richness of Plant Species ***(see p. 75)***

Count the number of plant species in the wetland that cover at least 10 ft^2. (*different patches of the same species can be combined to meet the size threshold)*

You do not have to name the species.

Do not include Eurasian milfoil, reed canarygrass, purple loosestrife, Canadian thistle

If you counted: > 19 species .... points = 2

List species below if you want to: 5 - 19 species .... points = 1

< 5 species .... points = 0

2

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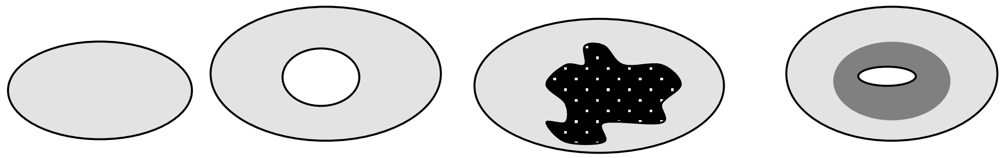
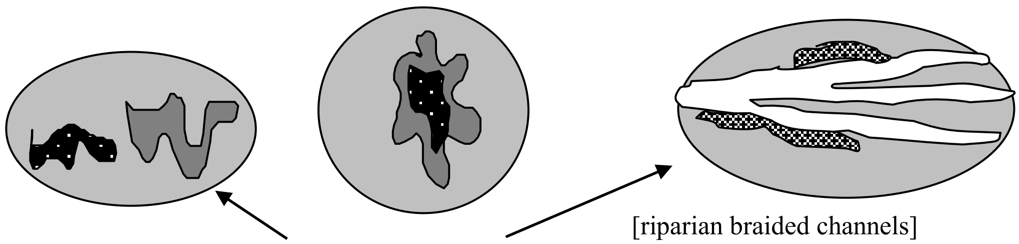
H 1.4. <u>Interspersion of habitats</u> ***(see p. 76)*** Decide from the diagrams below whether interspersion between Cowardin vegetation classes (described in H 1.1), or the classes and unvegetated areas (can include open water or mudflats) is high, medium, low, or none.  None = 0 points Low = 1 point Moderate = 2 points  [riparian braided channels] High = 3 points NOTE: If you have four or more vegetation types or three vegetation types and open water the rating is always “high”.	3
H 1.5. <u>Special Habitat Features:</u> ***(see p. 77)*** *Check the habitat features that are present in the wetland. The number of checks is the number of points you put into the next column.* ☒ Large, downed, woody debris within the wetland (>4in. diameter and 6 ft long). ☒ Standing snags (diameter at the bottom > 4 inches) in the wetland ☒ Undercut banks are present for at least 6.6 ft (2m) and/or overhanging vegetation extends at least 3.3 ft (1m) over a stream for at least 33 ft (10m) ☐ Stable steep banks of fine material that might be used by beaver or muskrat for denning (>30degree slope) OR signs of recent beaver activity are present ☐ At least ¼ acre of thin-stemmed persistent vegetation or woody branches are present in areas that are permanently or seasonally inundated.*(structures for egg-laying by amphibians)* ☐ Invasive plants cover less than 25% of the wetland area in each stratum of plants *Note: The 20% stated in early printings of the manual on page 78 is an error.*	3
H 1. TOTAL Score - potential for providing habitat *Add the scores from H1.1, H1.2, H1.3, H1.4, H1.5*	13

H 2. Does the wetland have the opportunity to provide habitat for many species?	
H 2.1 Buffers *(see p. 80)* *Choose the description that best represents condition of buffer of wetland. The highest scoring criterion that applies to the wetland is to be used in the rating. See text for definition of "undisturbed."* ☐ 100 m (330ft) of relatively undisturbed vegetated areas, rocky areas, or open water >95% of circumference. No developed areas within undisturbed part of buffer. (relatively undisturbed also means no-grazing) .... Points = 5 ☐ 100 m (330 ft) of relatively undisturbed vegetated areas, rocky areas, or open water > 50% circumference........ Points = 4 ☐ 50 m (170ft) of relatively undisturbed vegetated areas, rocky areas, or open water >95% circumference........ Points = 4 ☐ 100 m (330ft) of relatively undisturbed vegetated areas, rocky areas, or open water > 25% circumference........ Points = 3 ☐ 50 m (170ft) of relatively undisturbed vegetated areas, rocky areas, or open water for > 50% circumference........ Points = 3 **If buffer does not meet any of the criteria above** ☐ No paved areas (except paved trails) or buildings within 25 m (80ft) of wetland > 95% circumference. Light to moderate grazing, or lawns are OK........ Points = 2 ☐ No paved areas or buildings within 50m of wetland for >50% circumference. Light to moderate grazing, or lawns are OK........ Points = 2 ☐ Heavy grazing in buffer........ Points = 1 ☐ Vegetated buffers are <2m wide (6.6ft) for more than 95% of the circumference (e.g. tilled fields, paving, basalt bedrock extend to edge of wetland .... Points = 0 ☒ Buffer does not meet any of the criteria above........ Points = 1	1
H 2.2 Corridors and Connections ***(see p. 81)*** H 2.2.1 Is the wetland part of a relatively undisturbed and unbroken vegetated corridor (either riparian or upland) that is at least 150 ft wide, has at least 30% cover of shrubs, forest or native undisturbed prairie, that connects to estuaries, other wetlands or undisturbed uplands that are at least 250 acres in size? (*dams in riparian corridors*, *heavily used gravel roads*, *paved roads, are considered breaks in the corridor*). YES = **4 points** (*go to H 2.3*) **NO** = go to H 2.2.2 H 2.2.2 Is the wetland part of a relatively undisturbed and unbroken vegetated corridor (either riparian or upland) that is at least 50ft wide, has at least 30% cover of shrubs or forest, and connects to estuaries, other wetlands or undisturbed uplands that are at least 25 acres in size? **OR** a **Lake-fringe** wetland, if it does not have an undisturbed corridor as in the question above? YES = **2 points** (*go to H 2.3*) **NO** = H 2.2.3 H 2.2.3 Is the wetland: within 5 mi (8km) of a brackish or salt water estuary OR within 3 mi of a large field or pasture (>40 acres) OR within 1 mi of a lake greater than 20 acres? YES = **1 point** NO = **0 points**	0

H 2.3 Near or adjacent to other priority habitats listed by WDFW ***(see new and complete descriptions of WDFW priority habitats, and the counties in which they can be found, in the PHS report http://wdfw.wa.gov/hab/phslist.htm)*** Which of the following priority habitats are within 330ft (100m) of the wetland? *(NOTE: the connections do not have to be relatively undisturbed)* ☐ **Aspen Stands:** Pure or mixed stands of aspen greater than 0.4 ha (1 acres). ☐ **Biodiversity Areas and Corridors:** Areas of habitat that are relatively important to various species of native fish and wildlife (*full description in WDFW PHS report p. 152*) ☐ **Herbaceous Balds:** Variable size patches of grass and forbs on shallow soils over bedrock. ☐ **Old-growth/Mature forests:** (Old-growth west of Cascade crest) Stands of at least 2 tree species, forming a multi-layered canopy with occasional small openings; with at least 20 trees/ha (8 trees/acre) > 81 cm (32 in) dbh or > 200 years of age. (Mature forests.) Stands with average diameters exceeding 53 cm (21 in) dbh; crown cover may be less that 100%; crown cover may be less that 100%; decay, decadence, numbers of snags, and quantity of large downed material is generally less than that found in old-growth; 80 - 200 years old west of the Cascade crest. ☐ **Oregon white Oak:** Woodlands Stands of pure oak or oak/conifer associations where canopy coverage of the oak component is important (*full descriptions in WDFW PHS report p. 158.)* ☒ **Riparian**: The area adjacent to aquatic systems with flowing water that contains elements of both aquatic and terrestrial ecosystems which mutually influence each other. ☐ **Westside Prairies:** Herbaceous, non-forested plant communities that can either take the form of a dry prairie or a wet prairie (*full descriptions in WDFW PHS report p. 161*) ☒ **Instream:** The combination of physical, biological, and chemical processes and conditions that interact to provide functional life history requirements for instream fish and wildlife resources. ☐ **Nearshore:** Relatively undisturbed nearshore habitats. These include Coastal Nearshore, Open Coast Nearshore, and Puget Sound Nearshore. *(full descriptions of habitats and the definition of relatively undisturbed are in WDFW report: pp. 167-169 and glossary in Appendix A.)* ☐ **Caves:** A naturally occurring cavity, recess, void, or system of interconnected passages under the earth in soils, rock, ice, or other geological formations and is large enough to contain a human. ☐ **Cliffs:** Greater than 7.6 m (25 ft) high and occurring below 5000 ft. ☐ **Talus:** Homogenous areas of rock rubble ranging in average size 0.15 - 2.0 m (0.5 - 6.5 ft), composed of basalt, andesite, and/or sedimentary rock, including riprap slides and mine tailings. May be associated with cliffs. ☒ **Snags and Logs:** Trees are considered snags if they are dead or dying and exhibit sufficient decay characteristics to enable cavity excavation/use by wildlife. Priority snags have a diameter at breast height of >51 cm (20 in) in western Washington and are > 2 m (6.5 ft) in height. Priority logs are > 30cm (12 in) in diameter at the largest end, and > 6m (20 ft) long. If wetland has **3 or more** priority habitats **= 4 points** If wetland has **2** priority habitats = **3 points** If wetland has **1** priority habitat **= 1 point** No habitats = **0 points** *Note: All vegetated wetland are by definition a priority habitat but are not included in this list. Nearby wetlands are addressed in question H2.4.*	4

H 2.4 Wetland Landscape *(choose the* ***one*** *description of the landscape around the wetland that best fits)* ***(see p. 84)*** There are at least 3 other wetlands within ½ mile, and the connections between them are relatively undisturbed (light grazing between wetlands OK, as is lake shore with some boating, but connections should NOT be bisected by paved roads, fill, fields, or other development. .... points = 5 The wetland is Lake-fringe on a lake with little disturbance and there are 3 other lake-fringe wetlands within ½ mile .... points = 5 There are at least 3 other wetlands within ½ mile, BUT the connections between them are disturbed .... points = 3 The wetland is Lake-fringe on a lake **with** disturbance and there are 3 other lake-fringe wetland within ½ mile .... points = 3 There is at least 1 wetland within ½ mile. .... points = 2 There are no wetlands within ½ mile. .... points = 0	3
H 2. TOTAL Score - opportunity for providing habitat *Add the scores from H2.1, H2.2, H2.3, H2.4*	8
TOTAL for H1 from page 14	13
Total Score for Habitat Functions – add the points for H 1, H 2 and record the result on p. 1	**21**

DSD 009965

WETLAND RATING FORM – WESTERN WASHINGTON

Version 2 – Updated July 2006 to increase accuracy and reproducibility among users
Updated Oct 2008 with the new WDFW definitions for priority habitats

Name of wetland (if known): Richards Creek Substation – Wetland B Date of site visit: 03/27/2017

Rated by: Katy Crandall Trained by Ecology? Yes ☒ No ☐ Date of Training 09/2014

SEC: 1 TWNSHP: 24N RNGE: 05E Is S/T/R in Appendix D? Yes ☐ No ☒

SUMMARY OF RATING

Category based on FUNCTIONS provided by wetland

I ☐ II ☐ III ☒ IV ☐

Category I = Score ≥70
Category II = Score 51-69
Category III = Score 30-50
Category IV = Score < 30

Score for Water Quality Functions	2
Score for Hydrologic Functions	16
Score for Habitat Functions	16
TOTAL score for functions	**34**

Category based on SPECIAL CHARACTERISTICS of wetland

I ☐ II ☐ Does not Apply ☒

Final Category (choose the "highest" category from above) **III**

Check the appropriate type and class of wetland being rated.

Wetland Type		Wetland Class	
Estuarine		**Depressional**	
Natural Heritage Wetland		**Riverine**	
Bog		**Lake-fringe**	
Mature Forest		**Slope**	X
Old Growth Forest		**Flats**	
Coastal Lagoon		**Freshwater Tidal**	
Interdunal			
None of the above	X	Check if unit has multiple HGM classes present	

Does the wetland unit being rated meet any of the criteria below?

If you answer YES to any of the questions below you will need to protect the wetland according to the regulations regarding the special characteristics found in the wetland.

Check List for Wetlands That May Need Additional Protection (in addition to the protection recommended for its category)	YES	NO
SP1. *Has the wetland unit been documented as a habitat for any Federally listed Threatened or Endangered* ***animal*** *or* ***plant*** *species (T/E species)?* For the purposes of this rating system, "documented" means the wetland is on the appropriate state or federal database.		X*
SP2. *Has the wetland unit been documented as habitat for any State listed Threatened or Endangered* ***animal*** *species?* For the purposes of this rating system, "documented" means the wetland is on the appropriate state database. Note: Wetlands with State listed plant species are categorized as Category I Natural Heritage Wetlands (see p. 19 of data form).		X*
SP3. *Does the wetland unit contain individuals of Priority species listed by the WDFW for the state?*		X*
SP4. *Does the wetland unit have a local significance in addition to its functions*? For example, the wetland has been identified in the Shoreline Master Program, the Critical Areas Ordinance, or in a local management plan as having special significance.		X

* The study area was reviewed for the presence of endangered, threatened, and priority species using WDFW online Priority Habitat and Species Data, PHS on the Web (http://wdfw.wa.gov/mapping/phs/).

To complete the next part of the data sheet you will need to determine the Hydrogeomorphic Class of the wetland being rated.

The hydrogeomorphic classification groups wetlands into those that function in similar ways. Classifying the wetland first simplifies the questions needed to answer how it functions. The Hydrogeomorphic Class of a wetland can be determined using the key below. See p. 24 for more detailed instructions on classifying wetlands.

Classification of Wetland Units in Western Washington

If the hydrologic criteria listed in each question do not apply to the entire unit being rated, you probably have a unit with multiple HGM classes. In this case, identify which hydrologic criteria in Questions 1-7 apply, and go to Question 8.

1. Are the water levels in the wetland unit usually controlled by tides (i.e. except during floods)?

☒ NO – go to 2 ☐ **YES** – the wetland class is **Tidal Fringe**

If yes, is the salinity of the water during periods of annual low flow below 0.5 ppt (parts per thousand)? **YES – Freshwater Tidal Fringe NO – Saltwater Tidal Fringe (Estuarine)**

If your wetland can be classified as a Freshwater Tidal Fringe use the forms for ***Riverine*** *wetlands. If it is Saltwater Tidal Fringe it is rated as an* ***Estuarine*** *wetland.* Wetlands that were called estuarine in the first and second editions of the rating system are called Salt Water Tidal Fringe in the Hydrogeomorphic Classification. Estuarine wetlands were categorized separately in the earlier editions, and this separation is being kept in this revision. To maintain consistency between editions, the term "Estuarine" wetland is kept. Please note, however, that the characteristics that define Category I and II estuarine wetlands have changed (see p.).

2. The entire wetland unit is flat and precipitation is only source (>90%) of water to it. Groundwater and surface water runoff are NOT sources of water to the unit

☒ NO – go to 3 ☐ **YES** – The wetland class is **Flats**

If your wetland can be classified as a "Flats" wetland, use the form for **Depressional** wetlands.

3. Does the entire wetland unit **meet both** of the following criteria?

☐ The vegetated part of the wetland is on the shores of a body of open water (without any vegetation on the surface) at least 20 acres (8 ha) in size;

☐ At least 30% of the open water area is deeper than 6.6 ft (2 m)?

☒ NO – go to 4 ☐ **YES –** The wetland class is **Lake-fringe (Lacustrine Fringe)**

4. Does the entire wetland unit **meet all** of the following criteria?

☒ The wetland is on a slope (*slope can be very gradual*),

☒ The water flows through the wetland in one direction (unidirectional) and usually comes from seeps. It may flow subsurface, as sheetflow, or in a swale without distinct banks.

☒ The water leaves the wetland **without being impounded**?

NOTE: *Surface water does not pond in these types of wetlands except occasionally in very small and shallow depressions or behind hummocks (depressions are usually <3ft diameter and less than a foot deep).*

☐ NO – go to 5 ☒ **YES –** The wetland class is **Slope**

5. Does the entire wetland unit **meet all** of the following criteria?
- ☐ The unit is in a valley, or stream channel, where it gets inundated by overbank flooding from that stream or river.
- ☐ The overbank flooding occurs at least once every two years

NOTE: The riverine unit can contain depressions that are filled with water when the river is not flooding.

☐ NO - go to 6 ☐ **YES** – The wetland class is **Riverine**

6. Is the entire wetland unit in a topographic depression in which water ponds, or is saturated to the surface, at some time during the year. *This means that any outlet, if present, is higher than the interior of the wetland.*

☐ NO – go to 7 ☐ **YES –** The wetland class is **Depressional**

7. Is the entire wetland unit located in a very flat area with no obvious depression and no overbank flooding. The unit does not pond surface water more than a few inches. The unit seems to be maintained by high groundwater in the area. The wetland may be ditched, but has no obvious natural outlet.

☐ NO – go to 8 ☐ **YES –** The wetland class is **Depressional**

8. Your wetland unit seems to be difficult to classify and probably contains several different HGM classes. For example, seeps at the base of a slope may grade into a riverine floodplain, or a small stream within a depressional wetland has a zone of flooding along its sides. GO BACK AND IDENTIFY WHICH OF THE HYDROLOGIC REGIMES DESCRIBED IN QUESTIONS 1-7 APPLY TO DIFFERENT AREAS IN THE UNIT (make a rough sketch to help you decide). Use the following table to identify the appropriate class to use for the rating system if you have several HGM classes present within your wetland. NOTE: Use this table only if the class that is recommended in the second column represents 10% or more of the total area of the wetland unit being rated. If the area of the class listed in column 2 is less than 10% of the unit, classify the wetland using the class that represents more than 90% of the total area.

HGM classes within the wetland unit being rated	*HGM Class to Use in Rating*
Slope + Riverine	Riverine
Slope + Depressional	Depressional
Slope + Lake-fringe	Lake-fringe
Depressional + Riverine along stream within boundary	Depressional
Depressional + Lake-fringe	Depressional
Salt Water Tidal Fringe and any other class of freshwater wetland	Treat as ESTUARINE under wetlands with special characteristics

If you are unable still to determine which of the above criteria apply to your wetland, or you have more than 2 HGM classes within a wetland boundary, classify the wetland as **Depressional** for the rating.

S	Slope Wetlands	Points
	WATER QUALITY FUNCTIONS - Indicators that wetland functions to improve water quality	
S	**S 1. Does the wetland have the potential to improve water quality?**	*(see p. 64)*
S	S 1.1 Characteristics of average slope of wetland: Slope is1% or less *(a 1% slope has a 1 foot vertical drop in elevation horizontal distance) for every 100 ft* ..... points = 3 Slope is 1% - 2% ..... points = 2 Slope is 2% - 5% ..... points = 1 Slope is greater than 5% ..... points = 0	0
S	S 1.2 The soil 2 inches below the surface (or duff layer) is clay or organic *(use NRCS definitions)*. YES = 3 points NO = 0 points	0
S	S 1.3 Characteristics of the vegetation in the wetland that trap sediments and pollutants: *Choose the points appropriate for the description that best fits the vegetation in the wetland. Dense vegetation means you have trouble seeing the soil surface. Dense vegetation means you have trouble seeing the soil surface (>75% cover) and uncut means not grazed or mowed and plants are higher than 6 inches.* Dense, ungrazed, herbaceous vegetation > 90% of the wetland area ..... points = 6 Dense, ungrazed, herbaceous vegetation > 1/2 of area ..... points = 3 Dense, woody, vegetation > ½ of area ..... points = 2 Dense, ungrazed, herbaceous vegetation > 1/4 of area ..... points = 1 Does not meet any of the criteria above for vegetation ..... points = 0	2
S	**Total for S 1** *Add the points in the boxes above*	2
S	**S 2. Does the wetland have the opportunity to improve water quality? *(see p. 67)*** Answer YES if you know or believe there are pollutants in groundwater or surface water coming into the wetland that would otherwise reduce water quality in streams, lakes or groundwater downgradient from the wetland? *Note which of the following conditions provide the sources of pollutants.A unit may have pollutants coming from several sources, but any single source would qualify as opportunity.* ☐ Grazing in the wetland or within 150 ft ☐ Untreated stormwater discharges to wetland ☐ Tilled fields, logging or orchards within 150 ft of wetland ☐ A stream or culvert discharges into wetland that drains developed areas, residential areas, farmed fields, roads, or clear-cut logging ☐ Residential, urban areas, or golf courses are within 150 ft upslope of wetland ☐ Other: **YES** multiplier is **2** **NO** multiplier is **1**	multiplier _1_
S	**TOTAL - Water Quality Functions** Multiply the score from S 1 by S 2 ***Add score to table on p. 1***	**2**

S	Slope Wetlands	Points
	HYDROLOGIC FUNCTIONS - Indicators that wetland functions to reduce flooding and stream erosion	
	S 3. Does the wetland have the potential to reduce flooding and erosion?	***(see p. 68)***
S	S 3.1 Characteristics of vegetation that reduce the velocity of surface flows during storms. *Choose the points appropriate for the description that best fit conditions in the wetland. (stems of plants should be thick enough (usually > 1/8in), or dense enough, to remain erect during surface flows)* Dense, uncut, **rigid** vegetation covers > 90% of the area of the wetland. .... points = 6 Dense, uncut, **rigid** vegetation > 1/2 area of wetland .... points = 3 Dense, uncut, **rigid** vegetation > 1/4 area .... points = 1 More than 1/4 of area is grazed, mowed, tilled or vegetation is not rigid .... points = 0	6
S	S 3.2 Characteristics of slope wetland that holds back small amounts of flood flows: The slope wetland has small surface depressions that can retain water over at least 10% of its area. YES points = 2 NO points = 0	2
S	**Total for S 3** *Add the points in the boxes above*	8
S	**S 4. Does the wetland have the opportunity to reduce flooding and erosion? *(see p. 70)*** Is the wetland in a landscape position where the reduction in water velocity it provides helps protect downstream property and aquatic resources from flooding or excessive and/or erosive flows? *Note which of the following conditions apply.* ☐ Wetland has surface runoff that drains to a river or stream that has flooding problems ☒ Other: Wetland retains surface water that would otherwise flow to a river or stream with flooding problems *(Answer NO if the major source of water to the wetland is controlled by a reservoir or the wetland is tidal fringe along the sides of a dike)* **YES** multiplier is **2** **NO** multiplier is **1**	multiplier _2_
S	**TOTAL - Hydrologic Functions** Multiply the score from S 3 by S 4 ***Add score to table on p. 1***	**16**

Comments

DSD 009971

These questions apply to wetlands of all HGM classes. **HABITAT FUNCTIONS - Indicators that wetland functions to provide important habitat**	
H 1. Does the wetland have the potential to provide habitat for many species?	
H 1.1 Vegetation structure ***(see p. 72)*** *Check the types of vegetation classes present (as defined by Cowardin) if the class is ¼ acre or covers more than 10% of the area of the wetland if unit smaller than 2.5 acres.* ☐ Aquatic bed ☐ Emergent plants ☒ Scrub/shrub (areas where shrubs have >30% cover) ☒ Forested (areas where trees have >30% cover) ☒ Forested areas have 3 out of 5 strata (canopy, sub-canopy, shrubs, herbaceous, moss/ground-cover) that each cover 20% within the forested polygon *Add the number of vegetation types that qualify. If you have:* 4 structures or more .... points = 4 3 structures .... points = 2 2 structures .... points = 1 1 structure .... points = 0	2
H 1.2. Hydroperiods ***(see p. 73)*** *Check the types of water regimes (hydroperiods) present within the wetland. The water regime has to cover more than 10% of the wetland or ¼ acre to count. (see text for descriptions of hydroperiods)* ☐ Permanently flooded or inundated — 4 or more types present .... points = 3 ☐ Seasonally flooded or inundated — 3 types present............................... points = 2 ☒ Occasionally flooded or inundated — 2 types present .... points = 1 ☒ Saturated only — 1 types present……………………points = 0 ☐ Permanently flowing stream or river in, or adjacent to, the wetland ☐ Seasonally flowing stream in, or adjacent to, the wetland ☐ ***Lake-fringe wetland* = 2 points** ☐ ***Freshwater tidal wetland* = 2 points**	1
H 1.3. Richness of Plant Species ***(see p. 75)*** Count the number of plant species in the wetland that cover at least 10 ft^2. (*different patches of the same species can be combined to meet the size threshold)* *You do not have to name the species.* *Do not include Eurasian milfoil, reed canarygrass, purple loosestrife, Canadian thistle* If you counted: > 19 species............................ points = 2 *List species below if you want to:* 5 - 19 species........................... points = 1 < 5 species .... points = 0	1

DSD 009972

<table>
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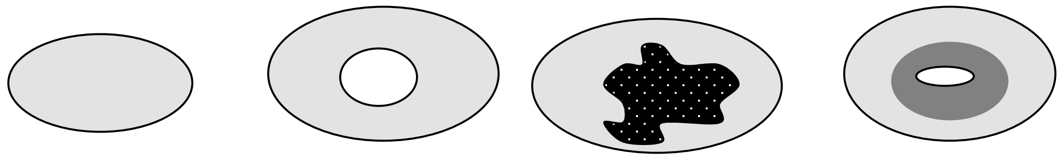
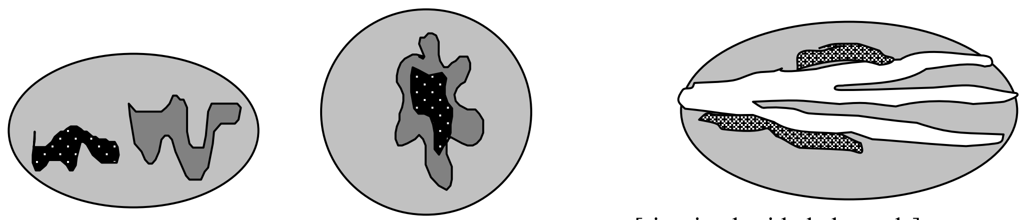
H 1.4. <u>Interspersion of habitats</u> ***(see p. 76)***

Decide from the diagrams below whether interspersion between Cowardin vegetation classes (described in H 1.1), or the classes and unvegetated areas (can include open water or mudflats) is high, medium, low, or none.



None = 0 points Low = 1 point Moderate = 2 points



[riparian braided channels]

High = 3 points

NOTE: If you have four or more vegetation types or three vegetation types and open water the rating is always “high”.

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H 1.5. <u>Special Habitat Features:</u> ***(see p. 77)***

Check the habitat features that are present in the wetland. The number of checks is the number of points you put into the next column.

☒ Large, downed, woody debris within the wetland (>4in. diameter and 6 ft long).
☐ Standing snags (diameter at the bottom > 4 inches) in the wetland
☐ Undercut banks are present for at least 6.6 ft (2m) and/or overhanging vegetation extends at least 3.3 ft (1m) over a stream for at least 33 ft (10m)
☐ Stable steep banks of fine material that might be used by beaver or muskrat for denning (>30degree slope) OR signs of recent beaver activity are present
☐ At least ¼ acre of thin-stemmed persistent vegetation or woody branches are present in areas that are permanently or seasonally inundated.*(structures for egg-laying by amphibians)*
☐ Invasive plants cover less than 25% of the wetland area in each stratum of plants

Note: The 20% stated in early printings of the manual on page 78 is an error.

</td>
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H 1. TOTAL Score - potential for providing habitat
Add the scores from H1.1, H1.2, H1.3, H1.4, H1.5

</td>
<td>6</td>
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<table>
<tr><th>H 2. Does the wetland have the opportunity to provide habitat for many species?</th><th></th></tr>
<tr><td>H 2.1 <u>Buffers</u> (see p. 80)
Choose the description that best represents condition of buffer of wetland. The highest scoring criterion that applies to the wetland is to be used in the rating. See text for definition of “undisturbed.”
☐ 100 m (330ft) of relatively undisturbed vegetated areas, rocky areas, or open water >95% of circumference. No developed areas within undisturbed part of buffer. (relatively undisturbed also means no-grazing) .... Points = 5
☐ 100 m (330 ft) of relatively undisturbed vegetated areas, rocky areas, or open water > 50% circumference........ Points = 4
☐ 50 m (170ft) of relatively undisturbed vegetated areas, rocky areas, or open water >95% circumference........ Points = 4
☐ 100 m (330ft) of relatively undisturbed vegetated areas, rocky areas, or open water > 25% circumference........ Points = 3
☒ 50 m (170ft) of relatively undisturbed vegetated areas, rocky areas, or open water for > 50% circumference. .... Points = 3
If buffer does not meet any of the criteria above
☐ No paved areas (except paved trails) or buildings within 25 m (80ft) of wetland > 95% circumference. Light to moderate grazing, or lawns are OK. .... Points = 2
☐ No paved areas or buildings within 50m of wetland for >50% circumference. Light to moderate grazing, or lawns are OK. .... Points = 2
☐ Heavy grazing in buffer. .... Points = 1
☐ Vegetated buffers are <2m wide (6.6ft) for more than 95% of the circumference (e.g. tilled fields, paving, basalt bedrock extend to edge of wetland .... Points = 0
☐ Buffer does not meet any of the criteria above........ Points = 1</td><td>3</td></tr>
<tr><td>H 2.2 <u>Corridors and Connections</u> (see p. 81)
H 2.2.1 Is the wetland part of a relatively undisturbed and unbroken vegetated corridor (either riparian or upland) that is at least 150 ft wide, has at least 30% cover of shrubs, forest or native undisturbed prairie, that connects to estuaries, other wetlands or undisturbed uplands that are at least 250 acres in size? (dams in riparian corridors, heavily used gravel roads, paved roads, are considered breaks in the corridor).
YES = 4 points (go to H 2.3) NO = go to H 2.2.2
H 2.2.2 Is the wetland part of a relatively undisturbed and unbroken vegetated corridor (either riparian or upland) that is at least 50ft wide, has at least 30% cover of shrubs or forest, and connects to estuaries, other wetlands or undisturbed uplands that are at least 25 acres in size? OR a Lake-fringe wetland, if it does not have an undisturbed corridor as in the question above?
YES = 2 points (go to H 2.3) NO = H 2.2.3
H 2.2.3 Is the wetland:
within 5 mi (8km) of a brackish or salt water estuary OR
within 3 mi of a large field or pasture (>40 acres) OR
within 1 mi of a lake greater than 20 acres?
YES = 1 point NO = 0 points</td><td>0</td></tr>
</table>

DSD 009974

H 2.3 Near or adjacent to other priority habitats listed by WDFW ***(see new and complete descriptions of WDFW priority habitats, and the counties in which they can be found, in the PHS report http://wdfw.wa.gov/hab/phslist.htm)*** Which of the following priority habitats are within 330ft (100m) of the wetland? *(NOTE: the connections do not have to be relatively undisturbed)* ☐ **Aspen Stands:** Pure or mixed stands of aspen greater than 0.4 ha (1 acres). ☐ **Biodiversity Areas and Corridors:** Areas of habitat that are relatively important to various species of native fish and wildlife (*full description in WDFW PHS report p. 152*) ☐ **Herbaceous Balds:** Variable size patches of grass and forbs on shallow soils over bedrock. ☐ **Old-growth/Mature forests:** (Old-growth west of Cascade crest) Stands of at least 2 tree species, forming a multi-layered canopy with occasional small openings; with at least 20 trees/ha (8 trees/acre) > 81 cm (32 in) dbh or > 200 years of age. (Mature forests.) Stands with average diameters exceeding 53 cm (21 in) dbh; crown cover may be less that 100%; crown cover may be less that 100%; decay, decadence, numbers of snags, and quantity of large downed material is generally less than that found in old-growth; 80 - 200 years old west of the Cascade crest. ☐ **Oregon white Oak:** Woodlands Stands of pure oak or oak/conifer associations where canopy coverage of the oak component is important (*full descriptions in WDFW PHS report p. 158.)* ☒ **Riparian**: The area adjacent to aquatic systems with flowing water that contains elements of both aquatic and terrestrial ecosystems which mutually influence each other. ☐ **Westside Prairies:** Herbaceous, non-forested plant communities that can either take the form of a dry prairie or a wet prairie (*full descriptions in WDFW PHS report p. 161*) ☒ **Instream:** The combination of physical, biological, and chemical processes and conditions that interact to provide functional life history requirements for instream fish and wildlife resources. ☐ **Nearshore:** Relatively undisturbed nearshore habitats. These include Coastal Nearshore, Open Coast Nearshore, and Puget Sound Nearshore. *(full descriptions of habitats and the definition of relatively undisturbed are in WDFW report: pp. 167-169 and glossary in Appendix A.)* ☐ **Caves:** A naturally occurring cavity, recess, void, or system of interconnected passages under the earth in soils, rock, ice, or other geological formations and is large enough to contain a human. ☐ **Cliffs:** Greater than 7.6 m (25 ft) high and occurring below 5000 ft. ☐ **Talus:** Homogenous areas of rock rubble ranging in average size 0.15 - 2.0 m (0.5 - 6.5 ft), composed of basalt, andesite, and/or sedimentary rock, including riprap slides and mine tailings. May be associated with cliffs. ☒ **Snags and Logs:** Trees are considered snags if they are dead or dying and exhibit sufficient decay characteristics to enable cavity excavation/use by wildlife. Priority snags have a diameter at breast height of >51 cm (20 in) in western Washington and are > 2 m (6.5 ft) in height. Priority logs are > 30cm (12 in) in diameter at the largest end, and > 6m (20 ft) long. If wetland has **3 or more** priority habitats **= 4 points** If wetland has **2** priority habitats = **3 points** If wetland has **1** priority habitat **= 1 point** No habitats = **0 points** *Note: All vegetated wetland are by definition a priority habitat but are not included in this list. Nearby wetlands are addressed in question H2.4.*	4

H 2.4 Wetland Landscape *(choose the **one** description of the landscape around the wetland that best fits)* ***(see p. 84)*** There are at least 3 other wetlands within ½ mile, and the connections between them are relatively undisturbed (light grazing between wetlands OK, as is lake shore with some boating, but connections should NOT be bisected by paved roads, fill, fields, or other development. .... points = 5 The wetland is Lake-fringe on a lake with little disturbance and there are 3 other lake-fringe wetlands within ½ mile .... points = 5 There are at least 3 other wetlands within ½ mile, BUT the connections between them are disturbed .... points = 3 The wetland is Lake-fringe on a lake **with** disturbance and there are 3 other lake-fringe wetland within ½ mile .... points = 3 There is at least 1 wetland within ½ mile. .... points = 2 There are no wetlands within ½ mile. .... points = 0	3
H 2. TOTAL Score - opportunity for providing habitat *Add the scores from H2.1, H2.2, H2.3, H2.4*	10
TOTAL for H1 from page 14	6
Total Score for Habitat Functions – add the points for H 1, H 2 and record the result on p. 1	**16**

WETLAND RATING FORM – WESTERN WASHINGTON

Version 2 – Updated July 2006 to increase accuracy and reproducibility among users
Updated Oct 2008 with the new WDFW definitions for priority habitats

Name of wetland (if known): Richards Creek Substation – Wetland C Date of site visit: 03/27/2017

Rated by: Katy Crandall Trained by Ecology? Yes ☒ No ☐ Date of Training 09/2014

SEC: 1 TWNSHP: 24N RNGE: 05E Is S/T/R in Appendix D? Yes ☐ No ☒

SUMMARY OF RATING

Category based on FUNCTIONS provided by wetland

I ☐ II ☐ III ☒ IV ☐

Category I = Score ≥70
Category II = Score 51-69
Category III = Score 30-50
Category IV = Score < 30

Score for Water Quality Functions	6
Score for Hydrologic Functions	12
Score for Habitat Functions	20
TOTAL score for functions	**38**

Category based on SPECIAL CHARACTERISTICS of wetland

I ☐ II ☐ Does not Apply ☒

Final Category (choose the "highest" category from above) **III**

Check the appropriate type and class of wetland being rated.

Wetland Type		**Wetland Class**	
Estuarine		**Depressional**	
Natural Heritage Wetland		**Riverine**	
Bog		**Lake-fringe**	
Mature Forest		**Slope**	X
Old Growth Forest		**Flats**	
Coastal Lagoon		**Freshwater Tidal**	
Interdunal			
None of the above	X	Check if unit has multiple HGM classes present	

Does the wetland unit being rated meet any of the criteria below?

If you answer YES to any of the questions below you will need to protect the wetland according to the regulations regarding the special characteristics found in the wetland.

Check List for Wetlands That May Need Additional Protection (in addition to the protection recommended for its category)	YES	NO
SP1. *Has the wetland unit been documented as a habitat for any Federally listed Threatened or Endangered* ***animal*** *or* ***plant*** *species (T/E species)?* For the purposes of this rating system, "documented" means the wetland is on the appropriate state or federal database.		X*
SP2. *Has the wetland unit been documented as habitat for any State listed Threatened or Endangered* ***animal*** *species?* For the purposes of this rating system, "documented" means the wetland is on the appropriate state database. Note: Wetlands with State listed plant species are categorized as Category I Natural Heritage Wetlands (see p. 19 of data form).		X*
SP3. *Does the wetland unit contain individuals of Priority species listed by the WDFW for the state?*		X*
SP4. *Does the wetland unit have a local significance in addition to its functions*? For example, the wetland has been identified in the Shoreline Master Program, the Critical Areas Ordinance, or in a local management plan as having special significance.		X

* The study area was reviewed for the presence of endangered, threatened, and priority species using WDFW online Priority Habitat and Species Data, PHS on the Web (http://wdfw.wa.gov/mapping/phs/).

To complete the next part of the data sheet you will need to determine the Hydrogeomorphic Class of the wetland being rated.

The hydrogeomorphic classification groups wetlands into those that function in similar ways. Classifying the wetland first simplifies the questions needed to answer how it functions. The Hydrogeomorphic Class of a wetland can be determined using the key below. See p. 24 for more detailed instructions on classifying wetlands.

Classification of Wetland Units in Western Washington

If the hydrologic criteria listed in each question do not apply to the entire unit being rated, you probably have a unit with multiple HGM classes. In this case, identify which hydrologic criteria in Questions 1-7 apply, and go to Question 8.

1. Are the water levels in the wetland unit usually controlled by tides (i.e. except during floods)?
☒ NO – go to 2 ☐ **YES** – the wetland class is **Tidal Fringe**

If yes, is the salinity of the water during periods of annual low flow below 0.5 ppt (parts per thousand)? **YES – Freshwater Tidal Fringe NO – Saltwater Tidal Fringe (Estuarine)**

If your wetland can be classified as a Freshwater Tidal Fringe use the forms for ***Riverine*** *wetlands. If it is Saltwater Tidal Fringe it is rated as an* ***Estuarine*** *wetland.* Wetlands that were called estuarine in the first and second editions of the rating system are called Salt Water Tidal Fringe in the Hydrogeomorphic Classification. Estuarine wetlands were categorized separately in the earlier editions, and this separation is being kept in this revision. To maintain consistency between editions, the term "Estuarine" wetland is kept. Please note, however, that the characteristics that define Category I and II estuarine wetlands have changed (see p.).

2. The entire wetland unit is flat and precipitation is only source (>90%) of water to it. Groundwater and surface water runoff are NOT sources of water to the unit
☒ NO – go to 3 ☐ **YES** – The wetland class is **Flats**

If your wetland can be classified as a "Flats" wetland, use the form for **Depressional** wetlands.

3. Does the entire wetland unit **meet both** of the following criteria?
☐ The vegetated part of the wetland is on the shores of a body of open water (without any vegetation on the surface) at least 20 acres (8 ha) in size;
☐ At least 30% of the open water area is deeper than 6.6 ft (2 m)?
☒ NO – go to 4 ☐ **YES –** The wetland class is **Lake-fringe (Lacustrine Fringe)**

4. Does the entire wetland unit **meet all** of the following criteria?
☒ The wetland is on a slope (*slope can be very gradual*),
☒ The water flows through the wetland in one direction (unidirectional) and usually comes from seeps. It may flow subsurface, as sheetflow, or in a swale without distinct banks.
☒ The water leaves the wetland **without being impounded**?
NOTE: *Surface water does not pond in these types of wetlands except occasionally in very small and shallow depressions or behind hummocks (depressions are usually <3ft diameter and less than a foot deep).*
☐ NO – go to 5 ☒ **YES –** The wetland class is **Slope**

5. Does the entire wetland unit **meet all** of the following criteria?

☐ The unit is in a valley, or stream channel, where it gets inundated by overbank flooding from that stream or river.

☐ The overbank flooding occurs at least once every two years

NOTE: The riverine unit can contain depressions that are filled with water when the river is not flooding.

☐ NO - go to 6 ☐ **YES** – The wetland class is **Riverine**

6. Is the entire wetland unit in a topographic depression in which water ponds, or is saturated to the surface, at some time during the year. *This means that any outlet, if present, is higher than the interior of the wetland.*

☐ NO – go to 7 ☐ **YES –** The wetland class is **Depressional**

7. Is the entire wetland unit located in a very flat area with no obvious depression and no overbank flooding. The unit does not pond surface water more than a few inches. The unit seems to be maintained by high groundwater in the area. The wetland may be ditched, but has no obvious natural outlet.

☐ NO – go to 8 ☐ **YES –** The wetland class is **Depressional**

8. Your wetland unit seems to be difficult to classify and probably contains several different HGM classes. For example, seeps at the base of a slope may grade into a riverine floodplain, or a small stream within a depressional wetland has a zone of flooding along its sides. GO BACK AND IDENTIFY WHICH OF THE HYDROLOGIC REGIMES DESCRIBED IN QUESTIONS 1-7 APPLY TO DIFFERENT AREAS IN THE UNIT (make a rough sketch to help you decide). Use the following table to identify the appropriate class to use for the rating system if you have several HGM classes present within your wetland. NOTE: Use this table only if the class that is recommended in the second column represents 10% or more of the total area of the wetland unit being rated. If the area of the class listed in column 2 is less than 10% of the unit, classify the wetland using the class that represents more than 90% of the total area.

HGM classes within the wetland unit being rated	*HGM Class to Use in Rating*
Slope + Riverine	Riverine
Slope + Depressional	Depressional
Slope + Lake-fringe	Lake-fringe
Depressional + Riverine along stream within boundary	Depressional
Depressional + Lake-fringe	Depressional
Salt Water Tidal Fringe and any other class of freshwater wetland	Treat as ESTUARINE under wetlands with special characteristics

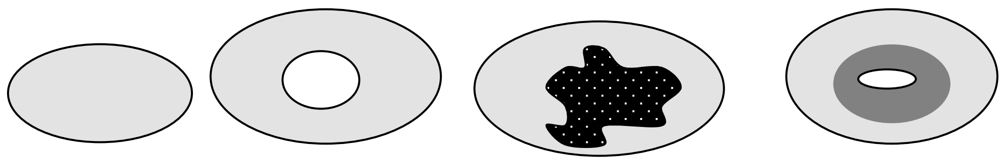
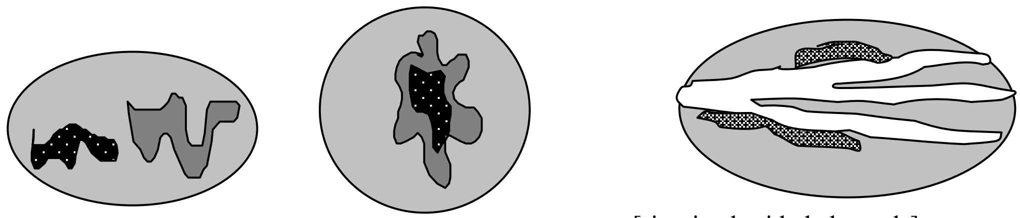
If you are unable still to determine which of the above criteria apply to your wetland, or you have more than 2 HGM classes within a wetland boundary, classify the wetland as **Depressional** for the rating.

S	Slope Wetlands	Points
	WATER QUALITY FUNCTIONS - Indicators that wetland functions to improve water quality	
S	**S 1. Does the wetland have the potential to improve water quality?**	*(see p. 64)*
S	S 1.1 Characteristics of average slope of wetland: Slope is1% or less *(a 1% slope has a 1 foot vertical drop in elevation horizontal distance) for every 100 ft* ...... points = 3 Slope is 1% - 2% ...... points = 2 Slope is 2% - 5% ...... points = 1 Slope is greater than 5% ...... points = 0	0
S	S 1.2 The soil 2 inches below the surface (or duff layer) is clay or organic *(use NRCS definitions)*. YES = 3 points NO = 0 points	0
S	S 1.3 Characteristics of the vegetation in the wetland that trap sediments and pollutants: *Choose the points appropriate for the description that best fits the vegetation in the wetland. Dense vegetation means you have trouble seeing the soil surface. Dense vegetation means you have trouble seeing the soil surface (>75% cover) and uncut means not grazed or mowed and plants are higher than 6 inches.* Dense, ungrazed, herbaceous vegetation > 90% of the wetland area ...... points = 6 Dense, ungrazed, herbaceous vegetation > 1/2 of area ...... points = 3 Dense, woody, vegetation > ½ of area ...... points = 2 Dense, ungrazed, herbaceous vegetation > 1/4 of area ...... points = 1 Does not meet any of the criteria above for vegetation ...... points = 0	3
S	**Total for S 1** *Add the points in the boxes above*	3
S	**S 2. Does the wetland have the opportunity to improve water quality? *(see p. 67)*** Answer YES if you know or believe there are pollutants in groundwater or surface water coming into the wetland that would otherwise reduce water quality in streams, lakes or groundwater downgradient from the wetland? *Note which of the following conditions provide the sources of pollutants.A unit may have pollutants coming from several sources, but any single source would qualify as opportunity.* ☐ Grazing in the wetland or within 150 ft ☐ Untreated stormwater discharges to wetland ☐ Tilled fields, logging or orchards within 150 ft of wetland ☒ A stream or culvert discharges into wetland that drains developed areas, residential areas, farmed fields, roads, or clear-cut logging ☐ Residential, urban areas, or golf courses are within 150 ft upslope of wetland ☐ Other: _____ **YES** multiplier is **2** **NO** multiplier is **1**	multiplier _2_
S	**TOTAL - Water Quality Functions** Multiply the score from S 1 by S 2 ***Add score to table on p. 1***	**6**

S	Slope Wetlands	Points
	HYDROLOGIC FUNCTIONS - Indicators that wetland functions to reduce flooding and stream erosion	
	S 3. Does the wetland have the potential to reduce flooding and erosion?	***(see p. 68)***
S	S 3.1 Characteristics of vegetation that reduce the velocity of surface flows during storms. *Choose the points appropriate for the description that best fit conditions in the wetland. (stems of plants should be thick enough (usually > 1/8in), or dense enough, to remain erect during surface flows)* Dense, uncut, **rigid** vegetation covers > 90% of the area of the wetland. .... points = 6 Dense, uncut, **rigid** vegetation > 1/2 area of wetland .... points = 3 Dense, uncut, **rigid** vegetation > 1/4 area .... points = 1 More than 1/4 of area is grazed, mowed, tilled or vegetation is not rigid .... points = 0	6
S	S 3.2 Characteristics of slope wetland that holds back small amounts of flood flows: The slope wetland has small surface depressions that can retain water over at least 10% of its area. YES points = 2 NO points = 0	0
S	**Total for S 3** *Add the points in the boxes above*	6
S	**S 4. Does the wetland have the opportunity to reduce flooding and erosion?** ***(see p. 70)*** Is the wetland in a landscape position where the reduction in water velocity it provides helps protect downstream property and aquatic resources from flooding or excessive and/or erosive flows? *Note which of the following conditions apply.* ☒ Wetland has surface runoff that drains to a river or stream that has flooding problems ☐ Other____ *(Answer NO if the major source of water to the wetland is controlled by a reservoir or the wetland is tidal fringe along the sides of a dike)* **YES** multiplier is **2** **NO** multiplier is **1**	multiplier 2
S	**TOTAL - Hydrologic Functions** Multiply the score from S 3 by S 4 ***Add score to table on p. 1***	**12**

Comments

These questions apply to wetlands of all HGM classes. **HABITAT FUNCTIONS - Indicators that wetland functions to provide important habitat**	
H 1. Does the wetland have the potential to provide habitat for many species?	
H 1.1 Vegetation structure ***(see p. 72)*** *Check the types of vegetation classes present (as defined by Cowardin) if the class is ¼ acre or covers more than 10% of the area of the wetland if unit smaller than 2.5 acres.* ☐ Aquatic bed ☐ Emergent plants ☒ Scrub/shrub (areas where shrubs have >30% cover) ☒ Forested (areas where trees have >30% cover) ☒ Forested areas have 3 out of 5 strata (canopy, sub-canopy, shrubs, herbaceous, moss/ground-cover) that each cover 20% within the forested polygon *Add the number of vegetation types that qualify. If you have:* 4 structures or more .... points = 4 3 structures .... points = 2 2 structures .... points = 1 1 structure .... points = 0	2
H 1.2. Hydroperiods ***(see p. 73)*** *Check the types of water regimes (hydroperiods) present within the wetland. The water regime has to cover more than 10% of the wetland or ¼ acre to count. (see text for descriptions of hydroperiods)* ☐ Permanently flooded or inundated — 4 or more types present .... points = 3 ☐ Seasonally flooded or inundated — 3 types present............................... points = 2 ☒ Occasionally flooded or inundated — 2 types present .... points = 1 ☒ Saturated only — 1 types present……………………points = 0 ☐ Permanently flowing stream or river in, or adjacent to, the wetland ☐ Seasonally flowing stream in, or adjacent to, the wetland ☐ ***Lake-fringe wetland* = 2 points** ☐ ***Freshwater tidal wetland* = 2 points**	1
H 1.3. Richness of Plant Species ***(see p. 75)*** Count the number of plant species in the wetland that cover at least 10 ft^2. (*different patches of the same species can be combined to meet the size threshold)* *You do not have to name the species.* *Do not include Eurasian milfoil, reed canarygrass, purple loosestrife, Canadian thistle* If you counted: > 19 species............................ points = 2 *List species below if you want to:* 5 - 19 species........................... points = 1 < 5 species .... points = 0	1

H 1.4. Interspersion of habitats ***(see p. 76)*** Decide from the diagrams below whether interspersion between Cowardin vegetation classes (described in H 1.1), or the classes and unvegetated areas (can include open water or mudflats) is high, medium, low, or none.  None = 0 points Low = 1 point Moderate = 2 points  [riparian braided channels] High = 3 points NOTE: If you have four or more vegetation types or three vegetation types and open water the rating is always "high".	2
H 1.5. Special Habitat Features: ***(see p. 77)*** *Check the habitat features that are present in the wetland. The number of checks is the number of points you put into the next column.* ☒ Large, downed, woody debris within the wetland (>4in. diameter and 6 ft long). ☒ Standing snags (diameter at the bottom > 4 inches) in the wetland ☒ Undercut banks are present for at least 6.6 ft (2m) and/or overhanging vegetation extends at least 3.3 ft (1m) over a stream for at least 33 ft (10m) ☐ Stable steep banks of fine material that might be used by beaver or muskrat for denning (>30degree slope) OR signs of recent beaver activity are present ☐ At least ¼ acre of thin-stemmed persistent vegetation or woody branches are present in areas that are permanently or seasonally inundated.*(structures for egg-laying by amphibians)* ☒ Invasive plants cover less than 25% of the wetland area in each stratum of plants *Note: The 20% stated in early printings of the manual on page 78 is an error.*	4
H 1. TOTAL Score - potential for providing habitat *Add the scores from H1.1, H1.2, H1.3, H1.4, H1.5*	10

H 2. Does the wetland have the opportunity to provide habitat for many species?	
H 2.1 Buffers *(see p. 80)* *Choose the description that best represents condition of buffer of wetland. The highest scoring criterion that applies to the wetland is to be used in the rating. See text for definition of "undisturbed."* ☐ 100 m (330ft) of relatively undisturbed vegetated areas, rocky areas, or open water >95% of circumference. No developed areas within undisturbed part of buffer. (relatively undisturbed also means no-grazing) .... Points = 5 ☐ 100 m (330 ft) of relatively undisturbed vegetated areas, rocky areas, or open water > 50% circumference.......... Points = 4 ☐ 50 m (170ft) of relatively undisturbed vegetated areas, rocky areas, or open water >95% circumference.......... Points = 4 ☐ 100 m (330ft) of relatively undisturbed vegetated areas, rocky areas, or open water > 25% circumference.......... Points = 3 ☒ 50 m (170ft) of relatively undisturbed vegetated areas, rocky areas, or open water for > 50% circumference. .... Points = 3 **If buffer does not meet any of the criteria above** ☐ No paved areas (except paved trails) or buildings within 25 m (80ft) of wetland > 95% circumference. Light to moderate grazing, or lawns are OK. .... Points = 2 ☐ No paved areas or buildings within 50m of wetland for >50% circumference. Light to moderate grazing, or lawns are OK. .... Points = 2 ☐ Heavy grazing in buffer. .... Points = 1 ☐ Vegetated buffers are <2m wide (6.6ft) for more than 95% of the circumference (e.g. tilled fields, paving, basalt bedrock extend to edge of wetland .... Points = 0 ☐ Buffer does not meet any of the criteria above.......... Points = 1	3
H 2.2 Corridors and Connections ***(see p. 81)*** H 2.2.1 Is the wetland part of a relatively undisturbed and unbroken vegetated corridor (either riparian or upland) that is at least 150 ft wide, has at least 30% cover of shrubs, forest or native undisturbed prairie, that connects to estuaries, other wetlands or undisturbed uplands that are at least 250 acres in size? (*dams in riparian corridors*, *heavily used gravel roads*, *paved roads, are considered breaks in the corridor*). YES = **4 points** (*go to H 2.3*) **NO** = go to H 2.2.2 H 2.2.2 Is the wetland part of a relatively undisturbed and unbroken vegetated corridor (either riparian or upland) that is at least 50ft wide, has at least 30% cover of shrubs or forest, and connects to estuaries, other wetlands or undisturbed uplands that are at least 25 acres in size? **OR** a **Lake-fringe** wetland, if it does not have an undisturbed corridor as in the question above? YES = **2 points** (*go to H 2.3*) **NO** = H 2.2.3 H 2.2.3 Is the wetland: within 5 mi (8km) of a brackish or salt water estuary OR within 3 mi of a large field or pasture (>40 acres) OR within 1 mi of a lake greater than 20 acres? YES = **1 point** NO = **0 points**	0

<table>
<tr><td>
H 2.3 <u>Near or adjacent to other priority habitats listed by WDFW</u> (see new and complete descriptions of WDFW priority habitats, and the counties in which they can be found, in the PHS report http://wdfw.wa.gov/hab/phslist.htm)
Which of the following priority habitats are within 330ft (100m) of the wetland?
(NOTE: the connections do not have to be relatively undisturbed)
☐ Aspen Stands: Pure or mixed stands of aspen greater than 0.4 ha (1 acres).
☐ Biodiversity Areas and Corridors: Areas of habitat that are relatively important to various species of native fish and wildlife (full description in WDFW PHS report p. 152)
☐ Herbaceous Balds: Variable size patches of grass and forbs on shallow soils over bedrock.
☐ Old-growth/Mature forests: (<u>Old-growth west of Cascade crest</u>) Stands of at least 2 tree species, forming a multi-layered canopy with occasional small openings; with at least 20 trees/ha (8 trees/acre) > 81 cm (32 in) dbh or > 200 years of age. (<u>Mature forests.)</u> Stands with average diameters exceeding 53 cm (21 in) dbh; crown cover may be less that 100%; crown cover may be less that 100%; decay, decadence, numbers of snags, and quantity of large downed material is generally less than that found in old-growth; 80 - 200 years old west of the Cascade crest.
☐ Oregon white Oak: Woodlands Stands of pure oak or oak/conifer associations where canopy coverage of the oak component is important (full descriptions in WDFW PHS report p. 158.)
☒ Riparian: The area adjacent to aquatic systems with flowing water that contains elements of both aquatic and terrestrial ecosystems which mutually influence each other.
☐ Westside Prairies: Herbaceous, non-forested plant communities that can either take the form of a dry prairie or a wet prairie (full descriptions in WDFW PHS report p. 161)
☒ Instream: The combination of physical, biological, and chemical processes and conditions that interact to provide functional life history requirements for instream fish and wildlife resources.
☐ Nearshore: Relatively undisturbed nearshore habitats. These include Coastal Nearshore, Open Coast Nearshore, and Puget Sound Nearshore. (full descriptions of habitats and the definition of relatively undisturbed are in WDFW report: pp. 167-169 and glossary in Appendix A.)
☐ Caves: A naturally occurring cavity, recess, void, or system of interconnected passages under the earth in soils, rock, ice, or other geological formations and is large enough to contain a human.
☐ Cliffs: Greater than 7.6 m (25 ft) high and occurring below 5000 ft.
☐ Talus: Homogenous areas of rock rubble ranging in average size 0.15 - 2.0 m (0.5 - 6.5 ft), composed of basalt, andesite, and/or sedimentary rock, including riprap slides and mine tailings. May be associated with cliffs.
☒ Snags and Logs: Trees are considered snags if they are dead or dying and exhibit sufficient decay characteristics to enable cavity excavation/use by wildlife. Priority snags have a diameter at breast height of >51 cm (20 in) in western Washington and are > 2 m (6.5 ft) in height. Priority logs are > 30cm (12 in) in diameter at the largest end, and > 6m (20 ft) long.
If wetland has 3 or more priority habitats = 4 points
If wetland has 2 priority habitats = 3 points
If wetland has 1 priority habitat = 1 point
No habitats = 0 points
Note: All vegetated wetland are by definition a priority habitat but are not included in this list. Nearby wetlands are addressed in question H2.4.
</td><td>4</td></tr>
</table>

H 2.4 Wetland Landscape *(choose the **one** description of the landscape around the wetland that best fits)* ***(see p. 84)*** There are at least 3 other wetlands within ½ mile, and the connections between them are relatively undisturbed (light grazing between wetlands OK, as is lake shore with some boating, but connections should NOT be bisected by paved roads, fill, fields, or other development. .... points = 5 The wetland is Lake-fringe on a lake with little disturbance and there are 3 other lake-fringe wetlands within ½ mile .... points = 5 There are at least 3 other wetlands within ½ mile, BUT the connections between them are disturbed .... points = 3 The wetland is Lake-fringe on a lake **with** disturbance and there are 3 other lake-fringe wetland within ½ mile .... points = 3 There is at least 1 wetland within ½ mile. .... points = 2 There are no wetlands within ½ mile. .... points = 0	3
H 2. TOTAL Score - opportunity for providing habitat *Add the scores from H2.1, H2.2, H2.3, H2.4*	10
TOTAL for H1 from page 14	10
Total Score for Habitat Functions – add the points for H 1, H 2 and record the result on p. 1	**20**

WETLAND RATING FORM – WESTERN WASHINGTON
Version 2 – Updated July 2006 to increase accuracy and reproducibility among users
Updated Oct 2008 with the new WDFW definitions for priority habitats

Name of wetland: Richards Creek Wetland – Wetland D　　Date of Site visit: 10/2016

Rated by: M. Foster, K. Crandall　Trained by Ecology? Yes☒ No☐　　Date of Training: 09/2014

SEC: 3, 4　TWNSHP: 24N　RNGE: 05E　　Is S/T/R in Appendix D? Yes☐ No ☒

SUMMARY OF RATING

Category based on FUNCTIONS provided by wetland

I ☐　II ☒　III ☐　IV ☐

Category I = Score ≥70
Category II = Score 51-69
Category III = Score 30-50
Category IV = Score < 30

Score for Water Quality Functions	20
Score for Hydrologic Functions	22
Score for Habitat Functions	21
TOTAL score for functions	**63**

Category based on SPECIAL CHARACTERISTICS of wetland

I ☐　II ☐　Does not Apply ☒

Final Category (choose the "highest" category from above)　**II**

Check the appropriate type and class of wetland being rated.

Wetland Type		Wetland Class	
Estuarine	☐	**Depressional**	☐
Natural Heritage Wetland	☐	**Riverine**	☒
Bog	☐	**Lake-fringe**	☐
Mature Forest	☐	**Slope**	☐
Old Growth Forest	☐	**Flats**	☐
Coastal Lagoon	☐	**Freshwater Tidal**	☐
Interdunal	☐		
None of the above	☒	Check if unit has multiple HGM classes present	☐

Does the wetland unit being rated meet any of the criteria below?

If you answer YES to any of the questions below you will need to protect the wetland according to the regulations regarding the special characteristics found in the wetland.

Check List for Wetlands That May Need Additional Protection (in addition to the protection recommended for its category)	YES	NO
SP1. *Has the wetland unit been documented as a habitat for any Federally listed Threatened or Endangered* ***animal*** *or* ***plant*** *species (T/E species)?* For the purposes of this rating system, "documented" means the wetland is on the appropriate state or federal database.		X*
SP2. *Has the wetland unit been documented as habitat for any State listed Threatened or Endangered* ***animal*** *species?* For the purposes of this rating system, "documented" means the wetland is on the appropriate state database. Note: Wetlands with State listed plant species are categorized as Category I Natural Heritage Wetlands (see p. 19 of data form).		X*
SP3. *Does the wetland unit contain individuals of Priority species listed by the WDFW for the state?*		X*
SP4. *Does the wetland unit have a local significance in addition to its functions*? For example, the wetland has been identified in the Shoreline Master Program, the Critical Areas Ordinance, or in a local management plan as having special significance.		X

* The study area was reviewed for the presence of endangered, threatened, and priority species using WDFW online Priority Habitat and Species Data, PHS on the Web (http://wdfw.wa.gov/mapping/phs/).

To complete the next part of the data sheet you will need to determine the Hydrogeomorphic Class of the wetland being rated.

The hydrogeomorphic classification groups wetlands into those that function in similar ways. Classifying the wetland first simplifies the questions needed to answer how it functions. The Hydrogeomorphic Class of a wetland can be determined using the key below. See p. 24 for more detailed instructions on classifying wetlands.

Classification of Wetland Units in Western Washington

If the hydrologic criteria listed in each question do not apply to the entire unit being rated, you probably have a unit with multiple HGM classes. In this case, identify which hydrologic criteria in Questions 1-7 apply, and go to Question 8.

1. Are the water levels in the wetland unit usually controlled by tides (i.e. except during floods)?

☒ NO – go to 2 ☐**YES** – the wetland class is **Tidal Fringe**

If yes, is the salinity of the water during periods of annual low flow below 0.5 ppt (parts per thousand)? **YES – Freshwater Tidal Fringe NO – Saltwater Tidal Fringe (Estuarine)**

*If your wetland can be classified as a Freshwater Tidal Fringe use the forms for **Riverine** wetlands. If it is Saltwater Tidal Fringe it is rated as an **Estuarine** wetland.* Wetlands that were called estuarine in the first and second editions of the rating system are called Salt Water Tidal Fringe in the Hydrogeomorphic Classification. Estuarine wetlands were categorized separately in the earlier editions, and this separation is being kept in this revision. To maintain consistency between editions, the term "Estuarine" wetland is kept. Please note, however, that the characteristics that define Category I and II estuarine wetlands have changed (see p.).

2. The entire wetland unit is flat and precipitation is only source (>90%) of water to it. Groundwater and surface water runoff are NOT sources of water to the unit

☒ NO – go to 3 ☐ **YES** – The wetland class is **Flats**

If your wetland can be classified as a "Flats" wetland, use the form for **Depressional** wetlands.

3. Does the entire wetland unit **meet both** of the following criteria?

☐ The vegetated part of the wetland is on the shores of a body of open water (without any vegetation on the surface) at least 20 acres (8 ha) in size;

☐ At least 30% of the open water area is deeper than 6.6 ft (2 m)?

☒NO – go to 4 ☐**YES –** The wetland class is **Lake-fringe (Lacustrine Fringe)**

4. Does the entire wetland unit **meet all** of the following criteria?

☐ The wetland is on a slope (*slope can be very gradual*),

☐ The water flows through the wetland in one direction (unidirectional) and usually comes from seeps. It may flow subsurface, as sheetflow, or in a swale without distinct banks.

☐ The water leaves the wetland **without being impounded**?
NOTE: *Surface water does not pond in these types of wetlands except occasionally in very small and shallow depressions or behind hummocks (depressions are usually <3ft diameter and less than a foot deep).*

☒ NO – go to 5 ☐ **YES –** The wetland class is **Slope**

5. Does the entire wetland unit **meet all** of the following criteria?

☒ The unit is in a valley, or stream channel, where it gets inundated by overbank flooding from that stream or river.

☒ The overbank flooding occurs at least once every two years

NOTE: The riverine unit can contain depressions that are filled with water when the river is not flooding.

☐ NO - go to 6 ☒ **YES** – The wetland class is **Riverine**

6. Is the entire wetland unit in a topographic depression in which water ponds, or is saturated to the surface, at some time during the year. *This means that any outlet, if present, is higher than the interior of the wetland.*

☐ NO – go to 7 ☐ **YES –** The wetland class is **Depressional**

7. Is the entire wetland unit located in a very flat area with no obvious depression and no overbank flooding. The unit does not pond surface water more than a few inches. The unit seems to be maintained by high groundwater in the area. The wetland may be ditched, but has no obvious natural outlet.

☐ NO – go to 8 ☐ **YES –** The wetland class is **Depressional**

8. Your wetland unit seems to be difficult to classify and probably contains several different HGM classes. For example, seeps at the base of a slope may grade into a riverine floodplain, or a small stream within a depressional wetland has a zone of flooding along its sides. GO BACK AND IDENTIFY WHICH OF THE HYDROLOGIC REGIMES DESCRIBED IN QUESTIONS 1-7 APPLY TO DIFFERENT AREAS IN THE UNIT (make a rough sketch to help you decide). Use the following table to identify the appropriate class to use for the rating system if you have several HGM classes present within your wetland. NOTE: Use this table only if the class that is recommended in the second column represents 10% or more of the total area of the wetland unit being rated. If the area of the class listed in column 2 is less than 10% of the unit, classify the wetland using the class that represents more than 90% of the total area.

HGM classes within the wetland unit being rated	*HGM Class to Use in Rating*
Slope + Riverine	Riverine
Slope + Depressional	Depressional
Slope + Lake-fringe	Lake-fringe
Depressional + Riverine along stream within boundary	Depressional
Depressional + Lake-fringe	Depressional
Salt Water Tidal Fringe and any other class of freshwater wetland	Treat as ESTUARINE under wetlands with special characteristics

If you are unable still to determine which of the above criteria apply to your wetland, or you have more than 2 HGM classes within a wetland boundary, classify the wetland as **Depressional** for the rating.

R	Riverine and Freshwater Tidal Fringe Wetlands	Points
	WATER QUALITY FUNCTIONS - Indicators that wetland functions to improve water quality	
R	**R 1. Does the wetland have the <u>potential</u> to improve water quality?**	*(see p. 52)*
R	**R 1.1 Area of surface depressions within the riverine wetland that can trap sediments during a flooding event:** ☐ Depressions cover >3/4 area of wetland .... points = 8 ☐ Depressions cover > 1/2 area of wetland .... points = 4 ☒ Depressions present but cover < 1/2 area of wetland........ points = 2 ☐ No depressions present .... points = 0	2
R	**R 1.2 Characteristics of the vegetation in the wetland (areas with > 90% cover at person height):** ☒ Forest or shrub > 2/3 the area of the wetland........ points = 8 ☐ Forest or shrub > 1/3 area of the wetland .... points = 6 ☐ Ungrazed, emergent plants > 2/3 area of wetland........ points = 6 ☐ Ungrazed emergent plants > 1/3 area of wetland........ points = 3 ☐ Forest, shrub, and ungrazed emergent < 1/3 area of wetland........ points = 0	8
R	**Total for R 1** *Add the points in the boxes above*	10
R	**R 2. Does the wetland have the <u>opportunity</u> to improve water quality? *(see p. 53)*** Answer YES if you know or believe there are pollutants in groundwater or surface water coming into the wetland that would otherwise reduce water quality in streams, lakes or groundwater downgradient from the wetland? *Note which of the following conditions provide the sources of pollutants.* ☐ Grazing in the wetland or within 150 ft ☒ Untreated stormwater discharges to wetland ☐ Tilled fields or orchards within 150 ft of wetland ☐ A stream or culvert discharges into wetland that drains developed areas, residential areas, farmed fields, roads, or clear-cut logging ☒ Residential, urban areas, golf courses are within 150 ft of wetland ☒ The river or stream linked to the wetland has a contributing basin where human activities have raised levels of sediment, toxic compounds or nutrients in the river water above standards for water quality ☐ Other____________________ **YES** multiplier is **2** **NO** multiplier is **1**	multiplier <u>2</u>
R	**<u>TOTAL</u> - Water Quality Functions** Multiply the score from R 1 by R 2 ***Add score to table on p. 1***	**20**

Comments

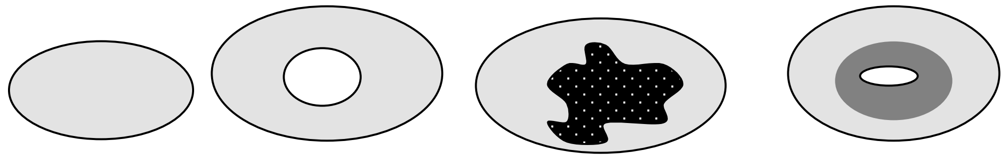
R	**Riverine and Freshwater Tidal Fringe Wetlands**	
	HYDROLOGIC FUNCTIONS - Indicators that wetland functions to reduce flooding and stream erosion	
	R 3. Does the wetland have the potential to reduce flooding and erosion?	***(see p. 54)***
R	**R 3.1 Characteristics of the overbank storage the wetland provides:** *Estimate the average width of the wetland perpendicular to the direction of the flow and the width of the stream or river channel (distance between banks). Calculate the ratio: (width of wetland)/(width of stream).* ☐ If the ratio is more than 20 .... points = 9 ☐ If the ratio is between 10 – 20 .... points = 6 ☒ If the ratio is 5- <10 .... points = 4 ☐ If the ratio is 1- <5 .... points = 2 ☐ If the ratio is < 1 .... points = 1	4
R	**R 3.2 Characteristics of vegetation that slow down water velocities during floods:** *Treat large woody debris as "forest or shrub". Choose the points appropriate for the best description.* (polygons need to have >90% cover at person height NOT Cowardin classes) ☒ Forest or shrub for >1/3 area OR Emergent plants > 2/3 area .... points = 7 ☐ Forest or shrub for > 1/10 area OR Emergent plants > 1/3 area .... points = 4 ☐ Vegetation does not meet above criteria .... points = 0	7
R	**Total for R 3** *Add the points in the boxes above*	11
R	**R 4. Does the wetland have the opportunity to reduce flooding and erosion?** ***(see p. 57)*** Answer YES if the wetland is in a location in the watershed where the flood storage, or reduction in water velocity, it provides helps protect downstream property and aquatic resources from flooding or excessive and/or erosive flows. *Note which of the following conditions apply.* ☒ There are human structures and activities downstream (roads, buildings, bridges, farms) that can be damaged by flooding. ☒ There are natural resources downstream (e.g. salmon redds) that can be damaged by flooding ☐ Other________________ *(Answer NO if the major source of water to the wetland is controlled by a reservoir or the wetland is tidal fringe along the sides of a dike)* **YES** multiplier is **2** **NO** multiplier is **1**	(see p. 57) multiplier 2
R	**TOTAL - Hydrologic Functions** Multiply the score from R 3 by R 4 ***Add score to table on p. 1***	22

These questions apply to wetlands of all HGM classes. **HABITAT FUNCTIONS - Indicators that wetland functions to provide important habitat**	
H 1. Does the wetland have the <u>potential</u> to provide habitat for many species?	
H 1.1 <u>Vegetation structure</u> *(see p. 72)* *Check the types of vegetation classes present (as defined by Cowardin) if the class is ¼ acre or covers more than 10% of the area of the wetland if unit smaller than 2.5 acres.* ☐ Aquatic bed ☒ Emergent plants ☒ Scrub/shrub (areas where shrubs have >30% cover) ☒ Forested (areas where trees have >30% cover) ☒ Forested areas have 3 out of 5 strata (canopy, sub-canopy, shrubs, herbaceous, moss/ground-cover) that each cover 20% within the forested polygon *Add the number of vegetation types that qualify. If you have:* 4 structures or more ....points = 4 3 structures ....points = 2 2 structures ....points = 1 1 structure ....points = 0	4
H 1.2. <u>Hydroperiods</u> *(see p. 73)* *Check the types of water regimes (hydroperiods) present within the wetland. The water regime has to cover more than 10% of the wetland or ¼ acre to count. (see text for descriptions of hydroperiods)* ☐ Permanently flooded or inundated — 4 or more types present ....points = 3 ☐ Seasonally flooded or inundated — 3 types present................................points = 2 ☒ Occasionally flooded or inundated — 2 types present................................points = 1 ☒ Saturated only — 1 types present points = 0 ☒ Permanently flowing stream or river in, or adjacent to, the wetland ☐ Seasonally flowing stream in, or adjacent to, the wetland ☐ ***Lake-fringe wetland* = 2 points** ☐ ***Freshwater tidal wetland* = 2 points**	2
H 1.3. <u>Richness of Plant Species</u> *(see p. 75)* Count the number of plant species in the wetland that cover at least 10 ft^2. (*different patches of the same species can be combined to meet the size threshold)* *You do not have to name the species.* *Do not include Eurasian milfoil, reed canarygrass, purple loosestrife, Canadian thistle* If you counted: ☐ > 19 species points = 2 *List species below if you want to:* ☒ 5 - 19 species points = 1 ☐ < 5 species points = 0	1

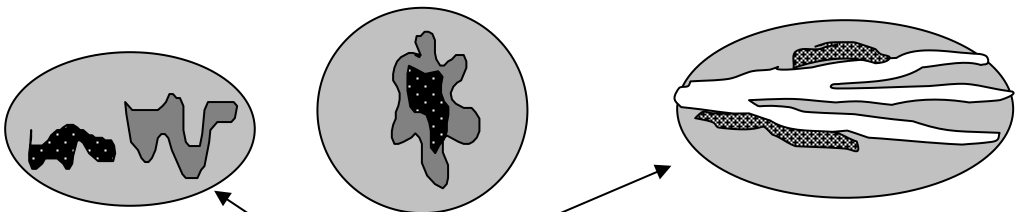
DSD 009994

H 1.4. <u>Interspersion of habitats</u> *(see p. 76)*

Decide from the diagrams below whether interspersion between Cowardin vegetation classes (described in H 1.1), or the classes and unvegetated areas (can include open water or mudflats) is high, medium, low, or none.



☐None = 0 points ☐Low = 1 point ☐Moderate = 2 points



[riparian braided channels]

☒High = 3 points

NOTE: If you have four or more vegetation types or three vegetation types and open water the rating is always “high”.

Score: 3

H 1.5. <u>Special Habitat Features:</u> *(see p. 77)*

Check the habitat features that are present in the wetland. The number of checks is the number of points you put into the next column.

- ☒ Large, downed, woody debris within the wetland (>4in. diameter and 6 ft long).
- ☒ Standing snags (diameter at the bottom > 4 inches) in the wetland.
- ☒ Undercut banks are present for at least 6.6 ft (2m) and/or overhanging vegetation extends at least 3.3 ft (1m) over a stream for at least 33 ft (10m).
- ☐ Stable steep banks of fine material that might be used by beaver or muskrat for denning (>30degree slope) OR signs of recent beaver activity are present.
- ☐ At least ¼ acre of thin-stemmed persistent vegetation or woody branches are present in areas that are permanently or seasonally inundated.*(structures for egg-laying by amphibians)*
- ☐ Invasive plants cover less than 25% of the wetland area in each stratum of plants.

Note: The 20% stated in early printings of the manual on page 78 is an error.

Score: 3

H 1. TOTAL Score - potential for providing habitat
Add the scores from H1.1, H1.2, H1.3, H1.4, H1.5

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H 2. Does the wetland have the opportunity to provide habitat for many species?	
H 2.1 <u>**Buffers**</u> ***(see p. 80)*** *Choose the description that best represents condition of buffer of wetland. The highest scoring criterion that applies to the wetland is to be used in the rating. See text for definition of "undisturbed."* ☐ 100 m (330ft) of relatively undisturbed vegetated areas, rocky areas, or open water >95% of circumference. No developed areas within undisturbed part of buffer. (relatively undisturbed also means no-grazing) .... Points = 5 ☐ 100 m (330 ft) of relatively undisturbed vegetated areas, rocky areas, or open water > 50% circumference.......... Points = 4 ☐ 50 m (170ft) of relatively undisturbed vegetated areas, rocky areas, or open water >95% circumference.......... Points = 4 ☐ 100 m (330ft) of relatively undisturbed vegetated areas, rocky areas, or open water > 25% circumference.......... Points = 3 ☐ 50 m (170ft) of relatively undisturbed vegetated areas, rocky areas, or open water for > 50% circumference. .... Points = 3 **If buffer does not meet any of the criteria above** ☐ No paved areas (except paved trails) or buildings within 25 m (80ft) of wetland > 95% circumference. Light to moderate grazing, or lawns are OK. .... Points = 2 ☐ No paved areas or buildings within 50m of wetland for >50% circumference. Light to moderate grazing, or lawns are OK. .... Points = 2 ☐ Heavy grazing in buffer. .... Points = 1 ☐ Vegetated buffers are <2m wide (6.6ft) for more than 95% of the circumference (e.g. tilled fields, paving, basalt bedrock extend to edge of wetland. ....Points = 0 ☒ Buffer does not meet any of the criteria above..........Points = 1	1
H 2.2 <u>**Corridors and Connections**</u> ***(see p. 81)*** H 2.2.1 Is the wetland part of a relatively undisturbed and unbroken vegetated corridor (either riparian or upland) that is at least 150 ft wide, has at least 30% cover of shrubs, forest or native undisturbed prairie, that connects to estuaries, other wetlands or undisturbed uplands that are at least 250 acres in size? (*dams in riparian corridors*, *heavily used gravel roads*, *paved roads, are considered breaks in the corridor*). ☐ YES = **4 points** (*go to H 2.3*) ☒ **NO** = go to H 2.2.2 H 2.2.2 Is the wetland part of a relatively undisturbed and unbroken vegetated corridor (either riparian or upland) that is at least 50ft wide, has at least 30% cover of shrubs or forest, and connects to estuaries, other wetlands or undisturbed uplands that are at least 25 acres in size? **OR** a **Lake-fringe** wetland, if it does not have an undisturbed corridor as in the question above? ☐ YES = **2 points** (*go to H 2.3*) ☒**NO** = H 2.2.3 H 2.2.3 Is the wetland: ☐ within 5 mi (8km) of a brackish or salt water estuary OR ☐ within 3 mi of a large field or pasture (>40 acres) OR ☐ within 1 mi of a lake greater than 20 acres? ☐ YES = **1 point** ☒ NO = **0 points**	0

H 2.3 **<u>Near or adjacent to other priority habitats listed by WDFW</u>** *(see new and complete descriptions of WDFW priority habitats, and the counties in which they can be found, in the PHS report http://wdfw.wa.gov/hab/phslist.htm)* Which of the following priority habitats are within 330ft (100m) of the wetland? *(NOTE: the connections do not have to be relatively undisturbed)* ☐ **Aspen Stands:** Pure or mixed stands of aspen greater than 0.4 ha (1 acres). ☐ **Biodiversity Areas and Corridors:** Areas of habitat that are relatively important to various species of native fish and wildlife (*full description in WDFW PHS report p. 152*) ☐ **Herbaceous Balds:** Variable size patches of grass and forbs on shallow soils over bedrock. ☐ **Old-growth/Mature forests:** (<u>Old-growth west of Cascade crest</u>) Stands of at least 2 tree species, forming a multi-layered canopy with occasional small openings; with at least 20 trees/ha (8 trees/acre) > 81 cm (32 in) dbh or > 200 years of age. (<u>Mature forests.)</u> Stands with average diameters exceeding 53 cm (21 in) dbh; crown cover may be less that 100%; crown cover may be less that 100%; decay, decadence, numbers of snags, and quantity of large downed material is generally less than that found in old-growth; 80 - 200 years old west of the Cascade crest. ☐ **Oregon white Oak:** Woodlands Stands of pure oak or oak/conifer associations where canopy coverage of the oak component is important (*full descriptions in WDFW PHS report p. 158.)* ☒ **Riparian**: The area adjacent to aquatic systems with flowing water that contains elements of both aquatic and terrestrial ecosystems which mutually influence each other. ☐ **Westside Prairies:** Herbaceous, non-forested plant communities that can either take the form of a dry prairie or a wet prairie (*full descriptions in WDFW PHS report p. 161*) ☒ **Instream:** The combination of physical, biological, and chemical processes and conditions that interact to provide functional life history requirements for instream fish and wildlife resources. ☐ **Nearshore:** Relatively undisturbed nearshore habitats. These include Coastal Nearshore, Open Coast Nearshore, and Puget Sound Nearshore. *(full descriptions of habitats and the definition of relatively undisturbed are in WDFW report: pp. 167-169 and glossary in Appendix A.)* ☐ **Caves:** A naturally occurring cavity, recess, void, or system of interconnected passages under the earth in soils, rock, ice, or other geological formations and is large enough to contain a human. ☐ **Cliffs:** Greater than 7.6 m (25 ft) high and occurring below 5000 ft. ☐ **Talus:** Homogenous areas of rock rubble ranging in average size 0.15 - 2.0 m (0.5 - 6.5 ft), composed of basalt, andesite, and/or sedimentary rock, including riprap slides and mine tailings. May be associated with cliffs. ☒ **Snags and Logs:** Trees are considered snags if they are dead or dying and exhibit sufficient decay characteristics to enable cavity excavation/use by wildlife. Priority snags have a diameter at breast height of >51 cm (20 in) in western Washington and are > 2 m (6.5 ft) in height. Priority logs are > 30cm (12 in) in diameter at the largest end, and > 6m (20 ft) long. If wetland has **3 or more** priority habitats **= 4 points** If wetland has **2** priority habitats = **3 points** If wetland has **1** priority habitat **= 1 point** No habitats = **0 points** *Note: All vegetated wetland are by definition a priority habitat but are not included in this list. Nearby wetlands are addressed in question H2.4.*	4

H 2.4 <u>Wetland Landscape</u> *(choose the* ***one*** *description of the landscape around the wetland that best fits)* ***(see p. 84)*** ☐ There are at least 3 other wetlands within ½ mile, and the connections between them are relatively undisturbed (light grazing between wetlands OK, as is lake shore with some boating, but connections should NOT be bisected by paved roads, fill, fields, or other development. ....points = 5 ☐ The wetland is Lake-fringe on a lake with little disturbance and there are 3 other lake-fringe wetlands within ½ mile ....points = 5 ☒ There are at least 3 other wetlands within ½ mile, BUT the connections between them are disturbed ....points = 3 ☐ The wetland is Lake-fringe on a lake **with** disturbance and there are 3 other lake-fringe wetland within ½ mile ....points = 3 ☐ There is at least 1 wetland within ½ mile. ....points = 2 ☐ There are no wetlands within ½ mile. ....points = 0	3
H 2. TOTAL Score - opportunity for providing habitat *Add the scores from H2.1, H2.2, H2.3, H2.4*	8
TOTAL for H1 from page 14	13
Total Score for Habitat Functions – add the points for H 1, H 2 and record the result on p. 1	21

WETLAND RATING FORM – WESTERN WASHINGTON

Version 2 – Updated July 2006 to increase accuracy and reproducibility among users
Updated Oct 2008 with the new WDFW definitions for priority habitats

Name of wetland (if known): Richards Creek Substation – Wetland H Date of site visit: 7/1/2015, 5/8/2017

Rated by: R. Kahlo, A. Hoenig, K. Crandall Trained by Ecology? Yes ☒ No ☐ Date of Training 09/2014

SEC: 10 TWNSHP: 24N RNGE: 05E Is S/T/R in Appendix D? Yes ☐ No ☒

SUMMARY OF RATING

Category based on FUNCTIONS provided by wetland

I ☐ II ☐ III ☒ IV ☐

Category I = Score ≥70
Category II = Score 51-69
Category III = Score 30-50
Category IV = Score < 30

Score for Water Quality Functions	6
Score for Hydrologic Functions	16
Score for Habitat Functions	21
TOTAL score for functions	**43**

Category based on SPECIAL CHARACTERISTICS of wetland

I ☐ II ☐ Does not Apply ☒

Final Category (choose the "highest" category from above) **III**

Check the appropriate type and class of wetland being rated.

Wetland Type		Wetland Class	
Estuarine		**Depressional**	
Natural Heritage Wetland		**Riverine**	
Bog		**Lake-fringe**	
Mature Forest		**Slope**	X
Old Growth Forest		**Flats**	
Coastal Lagoon		**Freshwater Tidal**	
Interdunal			
None of the above	X	Check if unit has multiple HGM classes present	

Does the wetland unit being rated meet any of the criteria below?

If you answer YES to any of the questions below you will need to protect the wetland according to the regulations regarding the special characteristics found in the wetland.

Check List for Wetlands That May Need Additional Protection (in addition to the protection recommended for its category)	YES	NO
SP1. *Has the wetland unit been documented as a habitat for any Federally listed Threatened or Endangered* ***animal*** *or* ***plant*** *species (T/E species)?* For the purposes of this rating system, "documented" means the wetland is on the appropriate state or federal database.		X
SP2. *Has the wetland unit been documented as habitat for any State listed Threatened or Endangered* ***animal*** *species?* For the purposes of this rating system, "documented" means the wetland is on the appropriate state database. Note: Wetlands with State listed plant species are categorized as Category I Natural Heritage Wetlands (see p. 19 of data form).		X
SP3. *Does the wetland unit contain individuals of Priority species listed by the WDFW for the state?*		X
SP4. *Does the wetland unit have a local significance in addition to its functions*? For example, the wetland has been identified in the Shoreline Master Program, the Critical Areas Ordinance, or in a local management plan as having special significance.		X

*The study area was reviewed for the presence of endangered, threatened, and priority species using WDFW online Priority Habitat and Species Data, PHS on the Web (http://wdfw.wa.gov/mapping/phs/). Resident coastal cutthroat are mapped as occurring in the stream adjacent to this wetland.

To complete the next part of the data sheet you will need to determine the Hydrogeomorphic Class of the wetland being rated.

The hydrogeomorphic classification groups wetlands into those that function in similar ways. Classifying the wetland first simplifies the questions needed to answer how it functions. The Hydrogeomorphic Class of a wetland can be determined using the key below. See p. 24 for more detailed instructions on classifying wetlands.

Classification of Wetland Units in Western Washington

If the hydrologic criteria listed in each question do not apply to the entire unit being rated, you probably have a unit with multiple HGM classes. In this case, identify which hydrologic criteria in Questions 1-7 apply, and go to Question 8.

1. Are the water levels in the wetland unit usually controlled by tides (i.e. except during floods)?
☒☐NO – go to 2 ☐☐**YES** – the wetland class is **Tidal Fringe**

If yes, is the salinity of the water during periods of annual low flow below 0.5 ppt (parts per thousand)? **YES – Freshwater Tidal Fringe NO – Saltwater Tidal Fringe (Estuarine)**

If your wetland can be classified as a Freshwater Tidal Fringe use the forms for ***Riverine*** *wetlands. If it is Saltwater Tidal Fringe it is rated as an* ***Estuarine*** *wetland.* Wetlands that were called estuarine in the first and second editions of the rating system are called Salt Water Tidal Fringe in the Hydrogeomorphic Classification. Estuarine wetlands were categorized separately in the earlier editions, and this separation is being kept in this revision. To maintain consistency between editions, the term "Estuarine" wetland is kept. Please note, however, that the characteristics that define Category I and II estuarine wetlands have changed (see p.).

2. The entire wetland unit is flat and precipitation is only source (>90%) of water to it. Groundwater and surface water runoff are NOT sources of water to the unit
☒☐NO – go to 3 ☐☐**YES** – The wetland class is **Flats**

If your wetland can be classified as a "Flats" wetland, use the form for **Depressional** wetlands.

3. Does the entire wetland unit **meet both** of the following criteria?
☐☐ The vegetated part of the wetland is on the shores of a body of open water (without any vegetation on the surface) at least 20 acres (8 ha) in size;
☐☐ At least 30% of the open water area is deeper than 6.6 ft (2 m)?
☒☐NO – go to 4 ☐☐**YES** – The wetland class is **Lake-fringe (Lacustrine Fringe)**

4. Does the entire wetland unit **meet all** of the following criteria?
☒☐ The wetland is on a slope (*slope can be very gradual*),
☒☐ The water flows through the wetland in one direction (unidirectional) and usually comes from seeps. It may flow subsurface, as sheetflow, or in a swale without distinct banks.
☒☐ The water leaves the wetland **without being impounded**?
NOTE: *Surface water does not pond in these types of wetlands except occasionally in very small and shallow depressions or behind hummocks (depressions are usually <3ft diameter and less than a foot deep).*
☐☐NO – go to 5 ☒☐**YES –** The wetland class is **Slope**

5. Does the entire wetland unit **meet all** of the following criteria?
☐☐ The unit is in a valley, or stream channel, where it gets inundated by overbank flooding from that stream or river.
☐☐ The overbank flooding occurs at least once every two years
NOTE: The riverine unit can contain depressions that are filled with water when the river is not flooding.
☐☐NO - go to 6 ☐☐**YES** – The wetland class is **Riverine**

6. Is the entire wetland unit in a topographic depression in which water ponds, or is saturated to the surface, at some time during the year. *This means that any outlet, if present, is higher than the interior of the wetland.*
☐☐NO – go to 7 ☐☐**YES –** The wetland class is **Depressional**

7. Is the entire wetland unit located in a very flat area with no obvious depression and no overbank flooding. The unit does not pond surface water more than a few inches. The unit seems to be maintained by high groundwater in the area. The wetland may be ditched, but has no obvious natural outlet.
☐☐NO – go to 8 ☐☐**YES –** The wetland class is **Depressional**

8. Your wetland unit seems to be difficult to classify and probably contains several different HGM classes. For example, seeps at the base of a slope may grade into a riverine floodplain, or a small stream within a depressional wetland has a zone of flooding along its sides. GO BACK AND IDENTIFY WHICH OF THE HYDROLOGIC REGIMES DESCRIBED IN QUESTIONS 1-7 APPLY TO DIFFERENT AREAS IN THE UNIT (make a rough sketch to help you decide). Use the following table to identify the appropriate class to use for the rating system if you have several HGM classes present within your wetland. NOTE: Use this table only if the class that is recommended in the second column represents 10% or more of the total area of the wetland unit being rated. If the area of the class listed in column 2 is less than 10% of the unit, classify the wetland using the class that represents more than 90% of the total area.

HGM classes within the wetland unit being rated	*HGM Class to Use in Rating*
Slope + Riverine	Riverine
Slope + Depressional	Depressional
Slope + Lake-fringe	Lake-fringe
Depressional + Riverine along stream within boundary	Depressional
Depressional + Lake-fringe	Depressional
Salt Water Tidal Fringe and any other class of freshwater wetland	Treat as ESTUARINE under wetlands with special characteristics

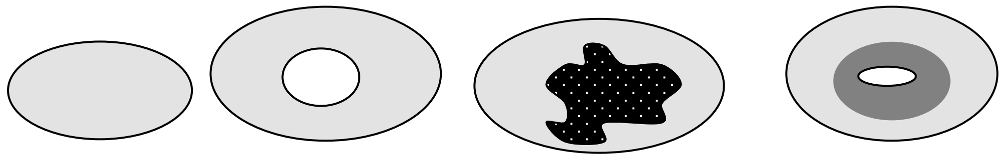
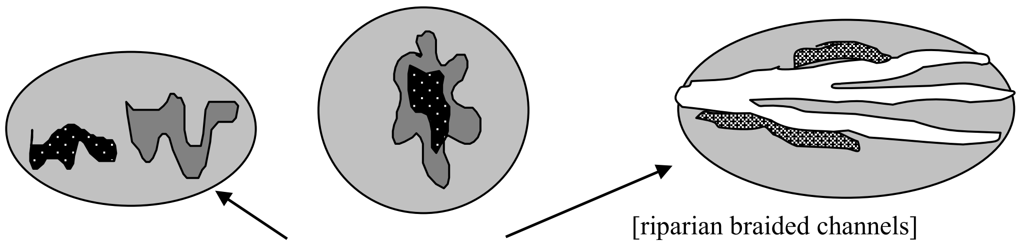
If you are unable still to determine which of the above criteria apply to your wetland, or you have more than 2 HGM classes within a wetland boundary, classify the wetland as **Depressional** for the rating.

S	Slope Wetlands	Points
	WATER QUALITY FUNCTIONS - Indicators that wetland functions to improve water quality	
S	**S 1. Does the wetland have the potential to improve water quality?**	*(see p. 64)*
S	S 1.1 Characteristics of average slope of wetland: Slope is1% or less *(a 1% slope has a 1 foot vertical drop in elevation horizontal distance) for every 100 ft* .... points = 3 Slope is 1% - 2% .... points = 2 Slope is 2% - 5% .... points = 1 Slope is greater than 5% .... points = 0	0
S	S 1.2 The soil 2 inches below the surface (or duff layer) is clay or organic *(use NRCS definitions)*. YES = 3 points NO = 0 points	0
S	S 1.3 Characteristics of the vegetation in the wetland that trap sediments and pollutants: *Choose the points appropriate for the description that best fits the vegetation in the wetland. Dense vegetation means you have trouble seeing the soil surface. Dense vegetation means you have trouble seeing the soil surface (>75% cover) and uncut means not grazed or mowed and plants are higher than 6 inches.* Dense, ungrazed, herbaceous vegetation > 90% of the wetland area .... points = 6 Dense, ungrazed, herbaceous vegetation > 1/2 of area .... points = 3 Dense, woody, vegetation > ½ of area .... points = 2 Dense, ungrazed, herbaceous vegetation > 1/4 of area .... points = 1 Does not meet any of the criteria above for vegetation .... points = 0	3
S	**Total for S 1** *Add the points in the boxes above*	3
S	**S 2. Does the wetland have the opportunity to improve water quality?** ***(see p. 67)*** Answer YES if you know or believe there are pollutants in groundwater or surface water coming into the wetland that would otherwise reduce water quality in streams, lakes or groundwater downgradient from the wetland? *Note which of the following conditions provide the sources of pollutants.A unit may have pollutants coming from several sources, but any single source would qualify as opportunity.* ☐☐ Grazing in the wetland or within 150 ft ☐☐ Untreated stormwater discharges to wetland ☐☐ Tilled fields, logging or orchards within 150 ft of wetland ☒☐ A stream or culvert discharges into wetland that drains developed areas, residential areas, farmed fields, roads, or clear-cut logging ☒☐ Residential, urban areas, or golf courses are within 150 ft upslope of wetland ☐☐ Other________________ **YES** multiplier is **2** **NO** multiplier is **1**	multiplier _2_
S	**TOTAL - Water Quality Functions** Multiply the score from S 1 by S 2 ***Add score to table on p. 1***	**6**

S	Slope Wetlands	Points
	HYDROLOGIC FUNCTIONS - Indicators that wetland functions to reduce flooding and stream erosion	
	S 3. Does the wetland have the potential to reduce flooding and erosion?	***(see p. 68)***
S	S 3.1 Characteristics of vegetation that reduce the velocity of surface flows during storms. *Choose the points appropriate for the description that best fit conditions in the wetland. (stems of plants should be thick enough (usually > 1/8in), or dense enough, to remain erect during surface flows)* Dense, uncut, **rigid** vegetation covers > 90% of the area of the wetland. .... points = 6 Dense, uncut, **rigid** vegetation > 1/2 area of wetland .... points = 3 Dense, uncut, **rigid** vegetation > 1/4 area .... points = 1 More than 1/4 of area is grazed, mowed, tilled or vegetation is not rigid .... points = 0	6
S	S 3.2 Characteristics of slope wetland that holds back small amounts of flood flows: The slope wetland has small surface depressions that can retain water over at least 10% of its area. YES points = 2 NO points = 0	2
S	**Total for S 3** *Add the points in the boxes above*	8
S	**S 4. Does the wetland have the opportunity to reduce flooding and erosion? *(see p. 70)*** Is the wetland in a landscape position where the reduction in water velocity it provides helps protect downstream property and aquatic resources from flooding or excessive and/or erosive flows? *Note which of the following conditions apply.* ☒☐ Wetland has surface runoff that drains to a river or stream that has flooding problems ☐☐ Other_______________________________________ *(Answer NO if the major source of water to the wetland is controlled by a reservoir or the wetland is tidal fringe along the sides of a dike)* **YES** multiplier is **2** **NO** multiplier is **1**	multiplier _2_
S	**TOTAL - Hydrologic Functions** Multiply the score from S 3 by S 4 ***Add score to table on p. 1***	**16**

Comments

These questions apply to wetlands of all HGM classes. **HABITAT FUNCTIONS - Indicators that wetland functions to provide important habitat**	
H 1. Does the wetland have the <u>potential</u> to provide habitat for many species?	
H 1.1 <u>Vegetation structure</u> ***(see p. 72)*** *Check the types of vegetation classes present (as defined by Cowardin) if the class is ¼ acre or covers more than 10% of the area of the wetland if unit smaller than 2.5 acres.* ☐☐ Aquatic bed ☒☐ Emergent plants ☒☐ Scrub/shrub (areas where shrubs have >30% cover) ☒☐ Forested (areas where trees have >30% cover) ☐☐ Forested areas have 3 out of 5 strata (canopy, sub-canopy, shrubs, herbaceous, moss/ground-cover) that each cover 20% within the forested polygon *Add the number of vegetation types that qualify. If you have:* 4 structures or more .... points = 4 3 structures .... points = 2 2 structures .... points = 1 1 structure .... points = 0	2
H 1.2. <u>Hydroperiods</u> ***(see p. 73)*** *Check the types of water regimes (hydroperiods) present within the wetland. The water regime has to cover more than 10% of the wetland or ¼ acre to count. (see text for descriptions of hydroperiods)* ☐☐ Permanently flooded or inundated — 4 or more types present .... points = 3 ☐☐ Seasonally flooded or inundated — 3 types present............................... points = 2 ☒☐ Occasionally flooded or inundated — 2 types present .... points = 1 ☒☐ Saturated only — 1 types present…………………….points = 0 ☐☐ Permanently flowing stream or river in, or adjacent to, the wetland ☐☐ Seasonally flowing stream in, or adjacent to, the wetland ☐☐ ***Lake-fringe wetland* = 2 points** ☐☐ ***Freshwater tidal wetland* = 2 points**	1
H 1.3. <u>Richness of Plant Species</u> ***(see p. 75)*** Count the number of plant species in the wetland that cover at least 10 ft^2. (*different patches of the same species can be combined to meet the size threshold)* *You do not have to name the species.* *Do not include Eurasian milfoil, reed canarygrass, purple loosestrife, Canadian thistle* If you counted: > 19 species............................ points = 2 *List species below if you want to:* 5 - 19 species........................... points = 1 < 5 species .... points = 0	2

H 1.4. <u>Interspersion of habitats</u> ***(see p. 76)*** Decide from the diagrams below whether interspersion between Cowardin vegetation classes (described in H 1.1), or the classes and unvegetated areas (can include open water or mudflats) is high, medium, low, or none.  None = 0 points Low = 1 point Moderate = 2 points  [riparian braided channels] High = 3 points NOTE: If you have four or more vegetation types or three vegetation types and open water the rating is always "high".	3
H 1.5. <u>Special Habitat Features:</u> ***(see p. 77)*** *Check the habitat features that are present in the wetland. The number of checks is the number of points you put into the next column.* ☒☐ Large, downed, woody debris within the wetland (>4in. diameter and 6 ft long). ☒☐ Standing snags (diameter at the bottom > 4 inches) in the wetland ☒☐ Undercut banks are present for at least 6.6 ft (2m) and/or overhanging vegetation extends at least 3.3 ft (1m) over a stream for at least 33 ft (10m) ☐☐ Stable steep banks of fine material that might be used by beaver or muskrat for denning (>30degree slope) OR signs of recent beaver activity are present ☐☐ At least ¼ acre of thin-stemmed persistent vegetation or woody branches are present in areas that are permanently or seasonally inundated.*(structures for egg-laying by amphibians)* ☐☐ Invasive plants cover less than 25% of the wetland area in each stratum of plants *Note: The 20% stated in early printings of the manual on page 78 is an error.*	3
H 1. TOTAL Score - potential for providing habitat *Add the scores from H1.1, H1.2, H1.3, H1.4, H1.5*	11

DSD 010006

H 2. Does the wetland have the opportunity to provide habitat for many species?	
H 2.1 Buffers *(see p. 80)* *Choose the description that best represents condition of buffer of wetland. The highest scoring criterion that applies to the wetland is to be used in the rating. See text for definition of "undisturbed."* ☐☐100 m (330ft) of relatively undisturbed vegetated areas, rocky areas, or open water >95% of circumference. No developed areas within undisturbed part of buffer. (relatively undisturbed also means no-grazing) .... Points = 5 ☐☐100 m (330 ft) of relatively undisturbed vegetated areas, rocky areas, or open water > 50% circumference........ Points = 4 ☐☐50 m (170ft) of relatively undisturbed vegetated areas, rocky areas, or open water >95% circumference........ Points = 4 ☒☐100 m (330ft) of relatively undisturbed vegetated areas, rocky areas, or open water > 25% circumference........ Points = 3 ☐☐50 m (170ft) of relatively undisturbed vegetated areas, rocky areas, or open water for > 50% circumference........ Points = 3 **If buffer does not meet any of the criteria above** ☐☐ No paved areas (except paved trails) or buildings within 25 m (80ft) of wetland > 95% circumference. Light to moderate grazing, or lawns are OK........ Points = 2 ☐☐ No paved areas or buildings within 50m of wetland for >50% circumference. Light to moderate grazing, or lawns are OK........ Points = 2 ☐☐ Heavy grazing in buffer........ Points = 1 ☐☐ Vegetated buffers are <2m wide (6.6ft) for more than 95% of the circumference (e.g. tilled fields, paving, basalt bedrock extend to edge of wetland .... Points = 0 ☐ Buffer does not meet any of the criteria above........ Points = 1	3
H 2.2 Corridors and Connections *(see p. 81)* H 2.2.1 Is the wetland part of a relatively undisturbed and unbroken vegetated corridor (either riparian or upland) that is at least 150 ft wide, has at least 30% cover of shrubs, forest or native undisturbed prairie, that connects to estuaries, other wetlands or undisturbed uplands that are at least 250 acres in size? (*dams in riparian corridors*, *heavily used gravel roads*, *paved roads, are considered breaks in the corridor*). YES = **4 points** (*go to H 2.3*) **NO** = go to H 2.2.2 H 2.2.2 Is the wetland part of a relatively undisturbed and unbroken vegetated corridor (either riparian or upland) that is at least 50ft wide, has at least 30% cover of shrubs or forest, and connects to estuaries, other wetlands or undisturbed uplands that are at least 25 acres in size? **OR** a **Lake-fringe** wetland, if it does not have an undisturbed corridor as in the question above? YES = **2 points** (*go to H 2.3*) **NO** = H 2.2.3 H 2.2.3 Is the wetland: within 5 mi (8km) of a brackish or salt water estuary OR within 3 mi of a large field or pasture (>40 acres) OR within 1 mi of a lake greater than 20 acres? YES = **1 point** NO = **0 points**	0

<table>
<tr><td>
H 2.3 <u>Near or adjacent to other priority habitats listed by WDFW</u> (see new and complete descriptions of WDFW priority habitats, and the counties in which they can be found, in the PHS report <u>http://wdfw.wa.gov/hab/phslist.htm</u>)
Which of the following priority habitats are within 330ft (100m) of the wetland?
(NOTE: the connections do not have to be relatively undisturbed)
☐☐ Aspen Stands: Pure or mixed stands of aspen greater than 0.4 ha (1 acres).
☐ Biodiversity Areas and Corridors: Areas of habitat that are relatively important to various species of native fish and wildlife (full description in WDFW PHS report p. 152)
☐ Herbaceous Balds: Variable size patches of grass and forbs on shallow soils over bedrock.
☐☐ Old-growth/Mature forests: (<u>Old-growth west of Cascade crest</u>) Stands of at least 2 tree species, forming a multi-layered canopy with occasional small openings; with at least 20 trees/ha (8 trees/acre) > 81 cm (32 in) dbh or > 200 years of age. (<u>Mature forests.)</u> Stands with average diameters exceeding 53 cm (21 in) dbh; crown cover may be less that 100%; crown cover may be less that 100%; decay, decadence, numbers of snags, and quantity of large downed material is generally less than that found in old-growth; 80 - 200 years old west of the Cascade crest.
☐☐ Oregon white Oak: Woodlands Stands of pure oak or oak/conifer associations where canopy coverage of the oak component is important (full descriptions in WDFW PHS report p. 158.)
☒☐ Riparian: The area adjacent to aquatic systems with flowing water that contains elements of both aquatic and terrestrial ecosystems which mutually influence each other.
☐☐ Westside Prairies: Herbaceous, non-forested plant communities that can either take the form of a dry prairie or a wet prairie (full descriptions in WDFW PHS report p. 161)
☒ Instream: The combination of physical, biological, and chemical processes and conditions that interact to provide functional life history requirements for instream fish and wildlife resources.
☐ Nearshore: Relatively undisturbed nearshore habitats. These include Coastal Nearshore, Open Coast Nearshore, and Puget Sound Nearshore. (full descriptions of habitats and the definition of relatively undisturbed are in WDFW report: pp. 167-169 and glossary in Appendix A.)
☐☐ Caves: A naturally occurring cavity, recess, void, or system of interconnected passages under the earth in soils, rock, ice, or other geological formations and is large enough to contain a human.
☐☐ Cliffs: Greater than 7.6 m (25 ft) high and occurring below 5000 ft.
☐☐ Talus: Homogenous areas of rock rubble ranging in average size 0.15 - 2.0 m (0.5 - 6.5 ft), composed of basalt, andesite, and/or sedimentary rock, including riprap slides and mine tailings. May be associated with cliffs.
☒ Snags and Logs: Trees are considered snags if they are dead or dying and exhibit sufficient decay characteristics to enable cavity excavation/use by wildlife. Priority snags have a diameter at breast height of >51 cm (20 in) in western Washington and are > 2 m (6.5 ft) in height. Priority logs are > 30cm (12 in) in diameter at the largest end, and > 6m (20 ft) long.
If wetland has 3 or more priority habitats = 4 points
If wetland has 2 priority habitats = 3 points
If wetland has 1 priority habitat = 1 point
No habitats = 0 points
Note: All vegetated wetland are by definition a priority habitat but are not included in this list. Nearby wetlands are addressed in question H2.4.
</td><td>4</td></tr>
</table>

H 2.4 <u>Wetland Landscape</u> *(choose the **one** description of the landscape around the wetland that best fits)* ***(see p. 84)*** There are at least 3 other wetlands within ½ mile, and the connections between them are relatively undisturbed (light grazing between wetlands OK, as is lake shore with some boating, but connections should NOT be bisected by paved roads, fill, fields, or other development. .... points = 5 The wetland is Lake-fringe on a lake with little disturbance and there are 3 other lake-fringe wetlands within ½ mile .... points = 5 There are at least 3 other wetlands within ½ mile, BUT the connections between them are disturbed .... points = 3 The wetland is Lake-fringe on a lake **with** disturbance and there are 3 other lake-fringe wetland within ½ mile .... points = 3 There is at least 1 wetland within ½ mile. .... points = 2 There are no wetlands within ½ mile. .... points = 0	3
H 2. TOTAL Score - opportunity for providing habitat *Add the scores from H2.1, H2.2, H2.3, H2.4*	10
TOTAL for H1 from page 14	11
**Total Score for Habitat Functions – ** add the points for H 1, H 2 and record the result on p. 1	21

CATEGORIZATION BASED ON SPECIAL CHARACTERISTICS

Please determine if the wetland meets the attributes described below and circle the appropriate Category.

Wetland Type *Check off any criteria that apply to the wetland. Circle the Category when the appropriate criteria are met.*	**Category**
SC 1.0 Estuarine wetlands (*see p. 86*) Does the wetland unit meet the following criteria for Estuarine wetlands? ☐ The dominant water regime is tidal, ☐ Vegetated, and ☐ With a salinity greater than 0.5 ppt. YES = Go to SC 1.1 NO ☒	
SC 1.1 Is the wetland unit within a National Wildlife Refuge, National Park, National Estuary Reserve, Natural Area Preserve, State Park or Educational, Environmental, or Scientific Reserve designated under WAC 332-151? ☐YES = Category I ☒NO = go to SC 1.2	**Cat. I**
SC 1.2 Is the wetland unit at least 1 acre in size and meets at least two of the following three conditions? ☐YES = Category I ☒NO = Category II ☐ The wetland is relatively undisturbed (has no diking, ditching, filling, cultivation, grazing, and has less than 10% cover of non-native plant species. If the non-native Spartina spp. are the only species that cover more than 10% of the wetland, then the wetland should be given a dual rating (I/II) The are aof Spartina would be rated a Category II while the relatively undisturbed upper marsh with native species would be a Category I. Do not, however, exclude the area of Spartina in determining the size threshold of 1 acre. ☐ At least ¾ of the landward edge of the wetland has a 100 ft buffer of shrub, forest, or un-grazed or un-mowed wetland. ☐ The wetland has at least 2 or the following features: tidal channels, depressions with open water, or contiguous freshwater wetlands.	**Cat. I** **Cat. II** **Dual rating I/II**

SC 2.0 Natural Heritage Wetlands ***(see p. 87)*** Natural Heritage wetlands have been identified by the Washington Natural Heritage Program/DNR as either high quality undisturbed wetlands or wetlands that support state Threatened, Endangered, or Sensitive plant species. SC 2.1 Is the wetland being rated in a Section/Township/Range that contains a Natural Heritage wetland? *(this question is used to screen out most sites before you need to contact WNHP/DNR)* S/T/R information from Appendix D ☐ or accessed from WNHP/DNR web site ☐ YES☐ – contact WNHP/DNR (see p. 79) and go to SC 2.2 NO ☒ SC 2.2 Has DNR identified the wetland as a high quality undisturbed wetland or as or as a site with state threatened or endangered plant species? YES = Category I NO ☐ Not a Heritage Wetland	**Cat. I**
SC 3.0 Bogs ***(see p. 87)*** Does the wetland (or any part of the unit) meet both the criteria for soils and vegetation in bogs? *Use the key below to identify if the wetland is a bog. If you answer yes, you will still need to rate the wetland based on its functions.* 1. Does the wetland have organic soils horizons (i.e. layers of organic soil), either peats or mucks, that compose 16" or more of the first 32 inches of the soil profile? (See Appendix B for a field key to identify organic soils.) Yes - go to Q.3 NO - go to Q.2 2. Does the wetland have organic soils, either peats or mucks, that are less than 16 inches deep over bedrock or an impermeable hardpan such as clay or volcanic ash, or that are floating on top of a lake or pond? Yes - go to Q.3 NO ☒ is not a bog for purpose of rating 3. Does the wetland have more than 70% cover of mosses at ground level, AND other plants, if present, consist of the "bog" species listed in Table 3 as a significant component of the vegetation (more than 30% of the total shrub and herbaceous cover consists species in Table 3)? Yes – Is a bog for purpose of rating NO - go to Q.4 *NOTE: If you are uncertain about the extent of mosses in the understory, you may substitute that criterion by measuring the pH of the water that seeps into a hole dug at least 16" deep. If the pH is less than 5.0 and the "bog" plant species in Table 3 are present, the wetland is a bog.* 4. Is the wetland forested (>30% cover) with sitka spruce, subalpine fir, western red cedar, western hemlock, lodgepole pine, quaking aspen, Englemann's spruce, or western white pine, WITH any of the species (or combination of species) on the bog species plant list in Table 3 as a significant component of the ground cover (*>30% coverage of the total shrub/herbaceous* cover)? YES = Category I NO ☐ is not a bog for purpose of rating	**Cat. I**

<table>
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SC 4.0 Forested Wetlands *(see p. 90)*

Does the wetland have at least 1 acre of forest that meet one of these criteria for the Department of Fish and Wildlife's forests as priority habitats? *If you answer yes you will still need to rate the wetland based on its functions.*

☐ Old growth forests: (west of Cascade crest) Stands of at least two tree species, forming a multi-layered canopy with occasional small openings; with at least 8 trees/acre (20 trees/hectare) that are at least 200 years of age OR have a diameter at breast height (dbh) of 32 inches (81 cm) or more. *Note: The criterion for dbh is based on measurements for upland forests. Two hundred year old trees in wetlands will often have a smaller dbh because their growth rates are often slower. The DFW criterion is and "OR" so old-growth forests do not necessarily have to have trees of this diameter.*

☐ Mature forests: (west of the Cascade crest) Stands where the largest trees are 80-200 years old OR have average diameters (dbh) exceeding 21 in (53 cm); crown cover may be less than 100%; decay, decadence, numbers of snags, and quanitity of large downed material is generally less than that found in old-growth

YES = Category 1 NO ☒ not a forested wetland with special characteristics

</td><td>

Cat. I

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SC 5.0 Wetlands in Coastal Lagoons (see p. 91)

Does the wetland meet all of the following criteria of a wetland in a coastal lagoon?

☐ The wetland lies in a depression adjacent to marine waters that is wholly or partially separated from marine waters by sandbanks, gravel banks, shingle, or, less frequently, rocks.

☐ The lagoon in which the wetland is located contains surgace water that is saline or brackish (> 0.5 ppt) during most of the year in at least a portion of the lagoon (*needs to be measured near the bottom*)

YES – Go to SC 5.1 NO ☒ not a wetland in a coastal lagoon

SC 5.1 Does the wetland meet all of the following three conditions?

☐ The wetland is relatively undisturbed (has no diking, ditching, filling, cultivation, grazing), and has less than 20% cover of invasive plant species (see list of invasive species on p. 74).

☐ At least ¾ of the landward edge of the wetland has a 100 ft buffer of shrub, forest, or un-grazed or un-mowed grassland.

☐The wetalnd is larger than 1/10 acre (4350 square feet)

YES = Category I NO = Category II

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Cat. I

Cat. II

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DSD 010012

SC 6.0 Interdunal Wetlands (see p. 93) Is the wetalnd unit west of the 1889 line (also called the Westarn Boundary of Upland Ownership or WBUO)? YES – go to SC 6.1 NO ☒ not an interdunal wetland for rating *If you answer yes you will still need to rate the wetland based on its functions.* In practical terms that means the following geographic areas: – Long Beach Peninsula – lands west of SR 103 – Grayland-Westport – lands west of SR 105 – Ocean Shores-Copalis – lands west of SR 115 and SR 109 SC 6.1 Is the wetland 1 acre or larger, or is it in a mosaic of wetlands that is 1 acre or larger? YES = Category II NO – go to SC 6.2	**Cat. II**
SC 6.2 Is the unit between 0.1 and 1 acre, or is it in a mosaic of wetlands that is between 0.1 and 1 acre? YES = Category III	**Cat. III**
Category of wetland based on Special Characteristics *Choose the "highest" rating if wetland falls into several categorie, and record on p. 1 .* If you answered NO for all types enter "Not Applicable" on p.1.	

RATING SUMMARY – Western Washington

Name of wetland (or ID #): Richards Creek Substation – Wetland A Date of site visit: 3/27/2016

Rated by: Katy Crandall Trained by Ecology? ☒Y ☐N Date of training: 09/2014

HGM Class used for rating: Slope Wetland has multiple HGM classes? ☒Y ☐N

NOTE: **Form is not complete without the figures requested** *(figures can be combined)*.
Source of base aerial photo/map: King County iMap and Google Earth

OVERALL WETLAND CATEGORY (based on functions ☒ or special characteristics ☐)

1. Category of wetland based on FUNCTIONS

☐ **Category I** – Total score = 23 - 27

☐ **Category II** – Total score = 20 - 22

☒ **Category III** – Total score = 16 - 19

☐ **Category IV** – Total score = 9 - 15

FUNCTION	Improving Water Quality	Hydrologic	Habitat	
			Circle the appropriate ratings	
Site Potential	H M L	H M L	H M L	
Landscape Potential	H M L	H M L	H M L	
Value	H M L	H M L	H M L	**TOTAL**
Score Based on Ratings	6	6	6	18

Score for each function based on three ratings
(order of ratings is not important)

9 = H,H,H
8 = H,H,M
7 = H,H,L
7 = H,M,M
6 = H,M,L
6 = M,M,M
5 = H,L,L
5 = M,M,L
4 = M,L,L
3 = L,L,L

2. Category based on SPECIAL CHARACTERISTICS of wetland

CHARACTERISTIC	CATEGORY
Estuarine	I II
Wetland of High Conservation Value	I
Bog	I
Mature Forest	I
Old Growth Forest	I
Coastal Lagoon	I II
Interdunal	I II III IV
None of the above	☒

Maps and figures required to answer questions correctly for Western Washington

Slope Wetlands

Map of:	To answer questions:	Figure #
Cowardin plant classes	H 1.1, H 1.4	1
Hydroperiods	H 1.2	2
Plant cover of **dense** trees, shrubs, and herbaceous plants	S 1.3	3
Plant cover of **dense, rigid** trees, shrubs, and herbaceous plants (*can be added to figure above)*	S 4.1	3
Boundary of 150 ft buffer (can be added to another figure)	S 2.1, S 5.1	2
1 km Polygon: Area that extends 1 km from entire wetland edge - including polygons for accessible habitat and undisturbed habitat	H 2.1, H 2.2, H 2.3	8
Screen capture of map of 303(d) listed waters in basin (from Ecology website)	S 3.1, S 3.2	9
Screen capture of list of TMDLs for WRIA in which unit is found (from web)	S 3.3	10

HGM Classification of Wetlands in Western Washington

For questions 1-7, the criteria described must apply to the entire unit being rated.

If the hydrologic criteria listed in each question do not apply to the entire unit being rated, you probably have a unit with multiple HGM classes. In this case, identify which hydrologic criteria in questions 1-7 apply, and go to Question 8.

1. Are the water levels in the entire unit usually controlled by tides except during floods?

   ☒NO – go to 2 ☐**YES** – the wetland class is **Tidal Fringe** – go to 1.1

   1.1 Is the salinity of the water during periods of annual low flow below 0.5 ppt (parts per thousand)?

   NO – Saltwater Tidal Fringe (Estuarine) **YES – Freshwater Tidal Fringe**
   If your wetland can be classified as a Freshwater Tidal Fringe use the forms for ***Riverine*** *wetlands. If it is Saltwater Tidal Fringe it is an* ***Estuarine*** *wetland and is not scored. This method* ***cannot*** *be used to score functions for estuarine wetlands.*

2. The entire wetland unit is flat and precipitation is the only source (>90%) of water to it. Groundwater and surface water runoff are NOT sources of water to the unit.

   ☒NO – go to 3 ☐**YES** – The wetland class is **Flats**
   If your wetland can be classified as a Flats wetland, use the form for ***Depressional*** *wetlands.*

3. Does the entire wetland unit **meet all** of the following criteria?
   ☐The vegetated part of the wetland is on the shores of a body of permanent open water (without any plants on the surface at any time of the year) at least 20 ac (8 ha) in size;
   ☐At least 30% of the open water area is deeper than 6.6 ft (2 m).

   ☒NO – go to 4 ☐**YES** – The wetland class is **Lake Fringe** (Lacustrine Fringe)

4. Does the entire wetland unit **meet all** of the following criteria?
   ☒The wetland is on a slope (*slope can be very gradual*),
   ☒The water flows through the wetland in one direction (unidirectional) and usually comes from seeps. It may flow subsurface, as sheetflow, or in a swale without distinct banks,
   ☒The water leaves the wetland **without being impounded**.

   ☐NO – go to 5 ☒**YES** – The wetland class is **Slope**

   NOTE: Surface water does not pond in these type of wetlands except occasionally in very small and shallow depressions or behind hummocks (depressions are usually <3 ft diameter and less than 1 ft deep).

5. Does the entire wetland unit **meet all** of the following criteria?
   ☐The unit is in a valley, or stream channel, where it gets inundated by overbank flooding from that stream or river,
   ☐The overbank flooding occurs at least once every 2 years.

☐NO – go to 6 ☐**YES –** The wetland class is **Riverine**

NOTE: The Riverine unit can contain depressions that are filled with water when the river is not flooding

6. Is the entire wetland unit in a topographic depression in which water ponds, or is saturated to the surface, at some time during the year? *This means that any outlet, if present, is higher than the interior of the wetland.*

☐NO – go to 7 ☐**YES –** The wetland class is **Depressional**

7. Is the entire wetland unit located in a very flat area with no obvious depression and no overbank flooding? The unit does not pond surface water more than a few inches. The unit seems to be maintained by high groundwater in the area. The wetland may be ditched, but has no obvious natural outlet.

☐NO – go to 8 ☐**YES –** The wetland class is **Depressional**

8. Your wetland unit seems to be difficult to classify and probably contains several different HGM classes. For example, seeps at the base of a slope may grade into a riverine floodplain, or a small stream within a Depressional wetland has a zone of flooding along its sides. GO BACK AND IDENTIFY WHICH OF THE HYDROLOGIC REGIMES DESCRIBED IN QUESTIONS 1-7 APPLY TO DIFFERENT AREAS IN THE UNIT (make a rough sketch to help you decide). Use the following table to identify the appropriate class to use for the rating system if you have several HGM classes present within the wetland unit being scored.

NOTE: Use this table only if the class that is recommended in the second column represents 10% or more of the total area of the wetland unit being rated. If the area of the HGM class listed in column 2 is less than 10% of the unit; classify the wetland using the class that represents more than 90% of the total area.

HGM classes within the wetland unit being rated	HGM class to use in rating
Slope + Riverine	Riverine
Slope + Depressional	Depressional
Slope + Lake Fringe	Lake Fringe
Depressional + Riverine along stream within boundary of depression	Depressional
Depressional + Lake Fringe	Depressional
Riverine + Lake Fringe	Riverine
Salt Water Tidal Fringe and any other class of freshwater wetland	Treat as ESTUARINE

If you are still unable to determine which of the above criteria apply to your wetland, or if you have ***more than 2 HGM classes*** *within a wetland boundary, classify the wetland as Depressional for the rating.*

SLOPE WETLANDS **Water Quality Functions** - Indicators that the site functions to improve water quality	
S 1.0. Does the site have the potential to improve water quality?	
S 1.1. Characteristics of the average slope of the wetland: *(a 1% slope has a 1 ft vertical drop in elevation for every 100 ft of horizontal distance)* ☐ Slope is 1% or less points = 3 ☐ Slope is > 1%-2% points = 2 ☐ Slope is > 2%-5% points = 1 ☒ Slope is greater than 5% points = 0	0
S 1.2. The soil 2 in below the surface (or duff layer) is true clay or true organic *(use NRCS definitions)*: Yes = 3 No = 0	0
S 1.3. Characteristics of the plants in the wetland that trap sediments and pollutants: Choose the points appropriate for the description that best fits the plants in the wetland. *Dense means you have trouble seeing the soil surface (>75% cover), and uncut means not grazed or mowed and plants are higher than 6 in.* ☐ Dense, uncut, herbaceous plants > 90% of the wetland area points = 6 ☒ Dense, uncut, herbaceous plants > ½ of area points = 3 ☐ Dense, woody, plants > ½ of area points = 2 ☐ Dense, uncut, herbaceous plants > ¼ of area points = 1 ☐ Does not meet any of the criteria above for plants points = 0	3
Total for S 1 Add the points in the boxes above	3

Rating of Site Potential If score is: ☐**12 = H** ☐**6-11 = M** ☒**0-5 = L** *Record the rating on the first page*

S 2.0. Does the landscape have the potential to support the water quality function of the site?	
S 2.1. Is > 10% of the area within 150 ft on the uphill side of the wetland in land uses that generate pollutants? ☒Yes = 1 ☐ No = 0	1
S 2.2. Are there other sources of pollutants coming into the wetland that are not listed in question S 2.1? Other sources: refuse, turbid runoff observed, gravel pole yard, parking ☒Yes = 1 ☐ No = 0	1
Total for S 2 Add the points in the boxes above	2

Rating of Landscape Potential If score is: ☒**1-2 = M** ☐**0 = L** *Record the rating on the first page*

S 3.0. Is the water quality improvement provided by the site valuable to society?	
S 3.1. Does the wetland discharge directly (i.e., within 1 mi) to a stream, river, lake, or marine water that is on the 303(d) list? ☒Yes = 1 ☐ No = 0	1
S 3.2. Is the wetland in a basin or sub-basin where water quality is an issue? *At least one aquatic resource in the basin is on the 303(d) list.* ☒Yes = 1 ☐ No = 0	1
S 3.3. Has the site been identified in a watershed or local plan as important for maintaining water quality? *Answer YES if there is a TMDL for the basin in which unit is found.* ☐Yes = 2 ☒ No = 0	0
Total for S 3 Add the points in the boxes above	2

Rating of Value If score is: ☒**2-4 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

SLOPE WETLANDS

Hydrologic Functions - Indicators that the site functions to reduce flooding and stream erosion

S 4.0. Does the site have the potential to reduce flooding and stream erosion?	
S 4.1. Characteristics of plants that reduce the velocity of surface flows during storms: Choose the points appropriate for the description that best fits conditions in the wetland. *Stems of plants should be thick enough (usually >1/8$_8$ in), or dense enough, to remain erect during surface flows.* ☐ Dense, uncut, **rigid** plants cover > 90% of the area of the wetland points = 1 ☒ All other conditions points = 0	0

Rating of Site Potential If score is: ☐**1 = M** ☒**0 = L** *Record the rating on the first page*

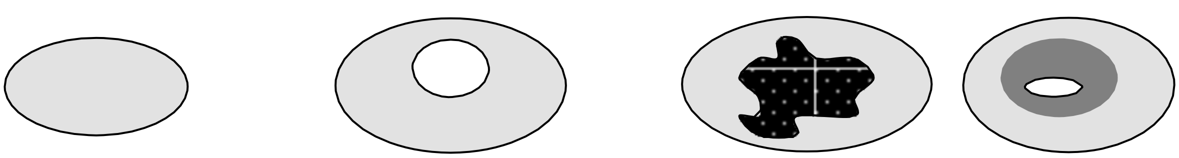
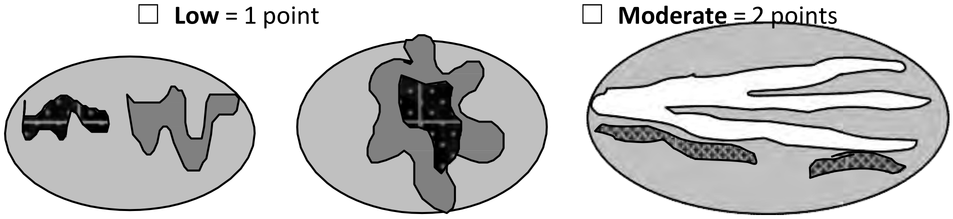
S 5.0. Does the landscape have the potential to support the hydrologic functions of the site?	
S 5.1. Is more than 25% of the area within 150 ft upslope of wetland in land uses or cover that generate excess surface runoff? ☒Yes = 1 ☐ No = 0	1

Rating of Landscape Potential If score is: ☒**1 = M** ☐**0 = L** *Record the rating on the first page*

S 6.0. Are the hydrologic functions provided by the site valuable to society?	
S 6.1. Distance to the nearest areas downstream that have flooding problems: ☒ The sub-basin immediately down-gradient of site has flooding problems that result in damage to human or natural resources (e.g., houses or salmon redds) points = 2 ☐ Surface flooding problems are in a sub-basin farther down-gradient points = 1 ☐ No flooding problems anywhere downstream points = 0	2
S 6.2. Has the site been identified as important for flood storage or flood conveyance in a regional flood control plan? ☐Yes = 2 ☒ No = 0	0
Total for S 6 Add the points in the boxes above	2

Rating of Value If score is: ☒**2-4 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

NOTES and FIELD OBSERVATIONS:

<table>
<tr><th colspan="2">These questions apply to wetlands of all HGM classes.
HABITAT FUNCTIONS - Indicators that site functions to provide important habitat</th></tr>
<tr><td colspan="2">H 1.0. Does the site have the potential to provide habitat?</td></tr>
<tr><td>H 1.1. Structure of plant community: Indicators are Cowardin classes and strata within the Forested class. Check the Cowardin plant classes in the wetland. Up to 10 patches may be combined for each class to meet the threshold of ¼ ac or more than 10% of the unit if it is smaller than 2.5 ac. Add the number of structures checked.
☐ Aquatic bed — 4 structures or more: points = 4
☒ Emergent — 3 structures: points = 2
☒ Scrub-shrub (areas where shrubs have > 30% cover) — 2 structures: points = 1
☒ Forested (areas where trees have > 30% cover) — 1 structure: points = 0
If the unit has a Forested class, check if:
☒ The Forested class has 3 out of 5 strata (canopy, sub-canopy, shrubs, herbaceous, moss/ground-cover) that each cover 20% within the Forested polygon</td><td>4</td></tr>
<tr><td>H 1.2. Hydroperiods
Check the types of water regimes (hydroperiods) present within the wetland. The water regime has to cover more than 10% of the wetland or ¼ ac to count (see text for descriptions of hydroperiods).
☐ Permanently flooded or inundated — 4 or more types present: points = 3
☐ Seasonally flooded or inundated — 3 types present: points = 2
☒ Occasionally flooded or inundated — 2 types present: points = 1
☒ Saturated only — 1 type present: points = 0
☐ Permanently flowing stream or river in, or adjacent to, the wetland
☐ Seasonally flowing stream in, or adjacent to, the wetland
☐ Lake Fringe wetland — 2 points
☐ Freshwater tidal wetland — 2 points</td><td>1</td></tr>
<tr><td>H 1.3. Richness of plant species
Count the number of plant species in the wetland that cover at least 10 ft^2.
Different patches of the same species can be combined to meet the size threshold and you do not have to name the species. Do not include Eurasian milfoil, reed canarygrass, purple loosestrife, Canadian thistle
If you counted: ☒ > 19 species — points = 2
☐ 5 - 19 species — points = 1
☐ < 5 species — points = 0</td><td>2</td></tr>
<tr><td>H 1.4. Interspersion of habitats
Decide from the diagrams below whether interspersion among Cowardin plants classes (described in H 1.1), or the classes and unvegetated areas (can include open water or mudflats) is high, moderate, low, or none. If you have four or more plant classes or three classes and open water, the rating is always high.

☐ None = 0 points ☐ Low = 1 point ☐ Moderate = 2 points

All three diagrams in this row are
☒ HIGH = 3points</td><td>3</td></tr>
</table>

DSD 010020

H 1.5. Special habitat features: Check the habitat features that are present in the wetland. *The number of checks is the number of points.* ☒ Large, downed, woody debris within the wetland (> 4 in diameter and 6 ft long). ☒ Standing snags (dbh > 4 in) within the wetland. ☒ Undercut banks are present for at least 6.6 ft (2 m) **AND/OR** overhanging plants extends at least 3.3 ft (1 m) over a stream (or ditch) in, or contiguous with the wetland, for at least 33 ft (10 m). ☐ Stable steep banks of fine material that might be used by beaver or muskrat for denning (> 30 degree slope) **OR** signs of recent beaver activity are present *(cut shrubs or trees that have not yet weathered where wood is exposed).* ☐ At least ¼ ac of thin-stemmed persistent plants or woody branches are present in areas that are permanently or seasonally inundated *(structures for egg-laying by amphibians).* ☐ Invasive plants cover less than 25% of the wetland area in every stratum of plants (*see H 1.1 for list of strata*).	3
Total for H 1 — Add the points in the boxes above	13

Rating of Site Potential If score is: ☐**15-18 = H** ☒**7-14 = M** ☐**0-6 = L** *Record the rating on the first page*

H 2.0. Does the landscape have the potential to support the habitat functions of the site?	
H 2.1. Accessible habitat (include *only habitat that directly abuts wetland unit*). *Calculate:* % undisturbed habitat + [(%moderate and low intensity land uses)/2] = **3.0% + 0%= 3.0%** If total accessible habitat is: ☐ > 1/3 (33.3%) of 1 km Polygon — points = 3 ☐ 20-33% of 1 km Polygon — points = 2 ☐ 10-19% of 1 km Polygon — points = 1 ☒ < 10% of 1 km Polygon — points = 0	0
H 2.2. Undisturbed habitat in 1 km Polygon around the wetland. *Calculate:* % undisturbed habitat + [(%moderate and low intensity land uses)/2 **= 13.8% + (0%/2) = 13.8%** ☐ Undisturbed habitat > 50% of Polygon — points = 3 ☐ Undisturbed habitat 10-50% and in 1-3 patches — points = 2 ☒ Undisturbed habitat 10-50% and > 3 patches — points = 1 ☐ Undisturbed habitat < 10% of 1 km Polygon — points = 0	1
H 2.3. Land use intensity in 1 km Polygon: If ☒ > 50% of 1 km Polygon is high intensity land use — points = (- 2) ☐ ≤ 50% of 1 km Polygon is high intensity — points = 0	-2
Total for H 2 — Add the points in the boxes above	-1

Rating of Landscape Potential If score is**:** ☐**4-6 = H** ☐**1-3 = M** ☒**< 1 = L** *Record the rating on the first page*

H 3.0. Is the habitat provided by the site valuable to society?	
H 3.1. Does the site provide habitat for species valued in laws, regulations, or policies? *Choose only the highest score that applies to the wetland being rated.* Site meets ANY of the following criteria: — points = 2 ☒ It has 3 or more priority habitats within 100 m (see next page) ☐ It provides habitat for Threatened or Endangered species (any plant or animal on the state or federal lists) ☐ It is mapped as a location for an individual WDFW priority species ☐ It is a Wetland of High Conservation Value as determined by the Department of Natural Resources ☐ It has been categorized as an important habitat site in a local or regional comprehensive plan, in a Shoreline Master Plan, or in a watershed plan ☐ Site has 1 or 2 priority habitats (listed on next page) within 100 m — points = 1 ☐ Site does not meet any of the criteria above — points = 0	2

Rating of Value If score is: ☒**2 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

WDFW Priority Habitats

Priority habitats listed by WDFW (see complete descriptions of WDFW priority habitats, and the counties in which they can be found, in: Washington Department of Fish and Wildlife. 2008. Priority Habitat and Species List. Olympia, Washington. 177 pp. http://wdfw.wa.gov/publications/00165/wdfw00165.pdf or access the list from here: http://wdfw.wa.gov/conservation/phs/list/)

Count how many of the following priority habitats are within 330 ft (100 m) of the wetland unit: ***NOTE:*** *This question is independent of the land use between the wetland unit and the priority habitat.*

☐ **Aspen Stands:** Pure or mixed stands of aspen greater than 1 ac (0.4 ha).

☐ **Biodiversity Areas and Corridors**: Areas of habitat that are relatively important to various species of native fish and wildlife (*full descriptions in WDFW PHS report*).

☐ **Herbaceous Balds:** Variable size patches of grass and forbs on shallow soils over bedrock.

☐ **Old-growth/Mature forests:** Old-growth west of Cascade crest – Stands of at least 2 tree species, forming a multi- layered canopy with occasional small openings; with at least 8 trees/ac (20 trees/ha) > 32 in (81 cm) dbh or > 200 years of age. Mature forests – Stands with average diameters exceeding 21 in (53 cm) dbh; crown cover may be less than 100%; decay, decadence, numbers of snags, and quantity of large downed material is generally less than that found in old-growth; 80-200 years old west of the Cascade crest.

☐ **Oregon White Oak:** Woodland stands of pure oak or oak/conifer associations where canopy coverage of the oak component is important (*full descriptions in WDFW PHS report p. 158 – see web link above*).

☒ **Riparian**: The area adjacent to aquatic systems with flowing water that contains elements of both aquatic and terrestrial ecosystems which mutually influence each other.

☐ **Westside Prairies:** Herbaceous, non-forested plant communities that can either take the form of a dry prairie or a wet prairie (*full descriptions in WDFW PHS report p. 161 – see web link above*).

☒ **Instream:** The combination of physical, biological, and chemical processes and conditions that interact to provide functional life history requirements for instream fish and wildlife resources.

☐ **Nearshore**: Relatively undisturbed nearshore habitats. These include Coastal Nearshore, Open Coast Nearshore, and Puget Sound Nearshore. (*full descriptions of habitats and the definition of relatively undisturbed are in WDFW report – see web link on previous page).*

☐ **Caves:** A naturally occurring cavity, recess, void, or system of interconnected passages under the earth in soils, rock, ice, or other geological formations and is large enough to contain a human.

☐ **Cliffs:** Greater than 25 ft (7.6 m) high and occurring below 5000 ft elevation.

☐ **Talus:** Homogenous areas of rock rubble ranging in average size 0.5 - 6.5 ft (0.15 - 2.0 m), composed of basalt, andesite, and/or sedimentary rock, including riprap slides and mine tailings. May be associated with cliffs.

☒ **Snags and Logs:** Trees are considered snags if they are dead or dying and exhibit sufficient decay characteristics to enable cavity excavation/use by wildlife. Priority snags have a diameter at breast height of > 20 in (51 cm) in western Washington and are > 6.5 ft (2 m) in height. Priority logs are > 12 in (30 cm) in diameter at the largest end, and > 20 ft (6 m) long.

Note: All vegetated wetlands are by definition a priority habitat but are not included in this list because they are addressed elsewhere.

RATING SUMMARY – Western Washington

Name of wetland (or ID #): Richards Creek Substation – Wetland B   Date of site visit: 3/27/2017

Rated by: Katy Crandall   Trained by Ecology? ☒Y ☐N   Date of training: 09/2014

HGM Class used for rating: Slope   Wetland has multiple HGM classes? ☐Y ☒N

NOTE: **Form is not complete without the figures requested** *(figures can be combined)*.

Source of base aerial photo/map: King County iMap and Google Earth

OVERALL WETLAND CATEGORY (based on functions ☒ or special characteristics ☐)

1. Category of wetland based on FUNCTIONS

☐ **Category I** – Total score = 23 - 27

☐ **Category II** – Total score = 20 - 22

☒ **Category III** – Total score = 16 - 19

☐ **Category IV** – Total score = 9 - 15

FUNCTION	Improving Water Quality			Hydrologic			Habitat			
									Circle the appropriate ratings	
Site Potential	H	M	L	H	M	L	H	M	L	
Landscape Potential	H	M	L	H	M	L	H	M	L	
Value	H	M	L	H	M	L	H	M	L	**TOTAL**
Score Based on Ratings	5			6			5			16

Score for each function based on three ratings
(order of ratings is not important)

9 = H,H,H
8 = H,H,M
7 = H,H,L
7 = H,M,M
6 = H,M,L
6 = M,M,M
5 = H,L,L
5 = M,M,L
4 = M,L,L
3 = L,L,L

2. Category based on SPECIAL CHARACTERISTICS of wetland

CHARACTERISTIC	CATEGORY
Estuarine	I II
Wetland of High Conservation Value	I
Bog	I
Mature Forest	I
Old Growth Forest	I
Coastal Lagoon	I II
Interdunal	I II III IV
None of the above	☒

Maps and figures required to answer questions correctly for Western Washington

Slope Wetlands

Map of:	To answer questions:	Figure #
Cowardin plant classes	H 1.1, H 1.4	1
Hydroperiods	H 1.2	2
Plant cover of **dense** trees, shrubs, and herbaceous plants	S 1.3	3
Plant cover of **dense, rigid** trees, shrubs, and herbaceous plants (*can be added to figure above)*	S 4.1	3
Boundary of 150 ft buffer (can be added to another figure)	S 2.1, S 5.1	2
1 km Polygon: Area that extends 1 km from entire wetland edge - including polygons for accessible habitat and undisturbed habitat	H 2.1, H 2.2, H 2.3	8
Screen capture of map of 303(d) listed waters in basin (from Ecology website)	S 3.1, S 3.2	9
Screen capture of list of TMDLs for WRIA in which unit is found (from web)	S 3.3	10

HGM Classification of Wetlands in Western Washington

For questions 1-7, the criteria described must apply to the entire unit being rated.

If the hydrologic criteria listed in each question do not apply to the entire unit being rated, you probably have a unit with multiple HGM classes. In this case, identify which hydrologic criteria in questions 1-7 apply, and go to Question 8.

1. Are the water levels in the entire unit usually controlled by tides except during floods?

   ☒NO – go to 2 ☐**YES –** the wetland class is **Tidal Fringe** – go to 1.1

   1.1 Is the salinity of the water during periods of annual low flow below 0.5 ppt (parts per thousand)?

   NO – Saltwater Tidal Fringe (Estuarine) **YES – Freshwater Tidal Fringe**
   *If your wetland can be classified as a Freshwater Tidal Fringe use the forms for **Riverine** wetlands. If it is Saltwater Tidal Fringe it is an **Estuarine** wetland and is not scored. This method **cannot** be used to score functions for estuarine wetlands.*

2. The entire wetland unit is flat and precipitation is the only source (>90%) of water to it. Groundwater and surface water runoff are NOT sources of water to the unit.

   ☒NO – go to 3 ☐**YES –** The wetland class is **Flats**
   *If your wetland can be classified as a Flats wetland, use the form for **Depressional** wetlands.*

3. Does the entire wetland unit **meet all** of the following criteria?
   ☐The vegetated part of the wetland is on the shores of a body of permanent open water (without any plants on the surface at any time of the year) at least 20 ac (8 ha) in size;
   ☐At least 30% of the open water area is deeper than 6.6 ft (2 m).

   ☒NO – go to 4 ☐**YES –** The wetland class is **Lake Fringe** (Lacustrine Fringe)

4. Does the entire wetland unit **meet all** of the following criteria?
   ☒The wetland is on a slope (*slope can be very gradual*),
   ☒The water flows through the wetland in one direction (unidirectional) and usually comes from seeps. It may flow subsurface, as sheetflow, or in a swale without distinct banks,
   ☒The water leaves the wetland **without being impounded.**

   ☐NO – go to 5 ☒**YES –** The wetland class is **Slope**

   NOTE: Surface water does not pond in these type of wetlands except occasionally in very small and shallow depressions or behind hummocks (depressions are usually <3 ft diameter and less than 1 ft deep).

5. Does the entire wetland unit **meet all** of the following criteria?
   ☐The unit is in a valley, or stream channel, where it gets inundated by overbank flooding from that stream or river,
   ☐The overbank flooding occurs at least once every 2 years.

☐NO – go to 6 ☐**YES –** The wetland class is **Riverine**

NOTE: The Riverine unit can contain depressions that are filled with water when the river is not flooding

6. Is the entire wetland unit in a topographic depression in which water ponds, or is saturated to the surface, at some time during the year? *This means that any outlet, if present, is higher than the interior of the wetland.*

   ☐NO – go to 7 ☐**YES –** The wetland class is **Depressional**

7. Is the entire wetland unit located in a very flat area with no obvious depression and no overbank flooding? The unit does not pond surface water more than a few inches. The unit seems to be maintained by high groundwater in the area. The wetland may be ditched, but has no obvious natural outlet.

   ☐NO – go to 8 ☐**YES –** The wetland class is **Depressional**

8. Your wetland unit seems to be difficult to classify and probably contains several different HGM classes. For example, seeps at the base of a slope may grade into a riverine floodplain, or a small stream within a Depressional wetland has a zone of flooding along its sides. GO BACK AND IDENTIFY WHICH OF THE HYDROLOGIC REGIMES DESCRIBED IN QUESTIONS 1-7 APPLY TO DIFFERENT AREAS IN THE UNIT (make a rough sketch to help you decide). Use the following table to identify the appropriate class to use for the rating system if you have several HGM classes present within the wetland unit being scored.

   NOTE: Use this table only if the class that is recommended in the second column represents 10% or more of the total area of the wetland unit being rated. If the area of the HGM class listed in column 2 is less than 10% of the unit; classify the wetland using the class that represents more than 90% of the total area.

HGM classes within the wetland unit being rated	HGM class to use in rating
Slope + Riverine	Riverine
Slope + Depressional	Depressional
Slope + Lake Fringe	Lake Fringe
Depressional + Riverine along stream within boundary of depression	Depressional
Depressional + Lake Fringe	Depressional
Riverine + Lake Fringe	Riverine
Salt Water Tidal Fringe and any other class of freshwater wetland	Treat as ESTUARINE

If you are still unable to determine which of the above criteria apply to your wetland, or if you have ***more than 2 HGM classes*** *within a wetland boundary, classify the wetland as Depressional for the rating.*

SLOPE WETLANDS

Water Quality Functions - Indicators that the site functions to improve water quality

S 1.0. Does the site have the potential to improve water quality?	
S 1.1. Characteristics of the average slope of the wetland: *(a 1% slope has a 1 ft vertical drop in elevation for every 100 ft of horizontal distance)* ☐ Slope is 1% or less — points = 3 ☐ Slope is > 1%-2% — points = 2 ☐ Slope is > 2%-5% — points = 1 ☒ Slope is greater than 5% — points = 0	0
S 1.2. The soil 2 in below the surface (or duff layer) is true clay or true organic *(use NRCS definitions)*: Yes = 3 No = 0	0
S 1.3. Characteristics of the plants in the wetland that trap sediments and pollutants: Choose the points appropriate for the description that best fits the plants in the wetland. *Dense means you have trouble seeing the soil surface (>75% cover), and uncut means not grazed or mowed and plants are higher than 6 in.* ☐ Dense, uncut, herbaceous plants > 90% of the wetland area — points = 6 ☐ Dense, uncut, herbaceous plants > ½ of area — points = 3 ☒ Dense, woody, plants > ½ of area — points = 2 ☐ Dense, uncut, herbaceous plants > ¼ of area — points = 1 ☐ Does not meet any of the criteria above for plants — points = 0	2
Total for S 1 — Add the points in the boxes above	2

Rating of Site Potential If score is: ☐**12 = H** ☐**6-11 = M** ☒**0-5 = L** *Record the rating on the first page*

S 2.0. Does the landscape have the potential to support the water quality function of the site?	
S 2.1. Is > 10% of the area within 150 ft on the uphill side of the wetland in land uses that generate pollutants? ☐Yes = 1 ☒ No = 0	0
S 2.2. Are there other sources of pollutants coming into the wetland that are not listed in question S 2.1? Other sources___________________ ☐Yes = 1 ☒ No = 0	0
Total for S 2 — Add the points in the boxes above	0

Rating of Landscape Potential If score is: ☐**1-2 = M** ☒**0 = L** *Record the rating on the first page*

S 3.0. Is the water quality improvement provided by the site valuable to society?	
S 3.1. Does the wetland discharge directly (i.e., within 1 mi) to a stream, river, lake, or marine water that is on the 303(d) list? ☒Yes = 1 ☐ No = 0	1
S 3.2. Is the wetland in a basin or sub-basin where water quality is an issue? *At least one aquatic resource in the basin is on the 303(d) list.* ☒Yes = 1 ☐ No = 0	1
S 3.3. Has the site been identified in a watershed or local plan as important for maintaining water quality? *Answer YES if there is a TMDL for the basin in which unit is found.* ☐Yes = 2 ☒ No = 0	0
Total for S 3 — Add the points in the boxes above	2

Rating of Value If score is: ☒**2-4 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

SLOPE WETLANDS **Hydrologic Functions** - Indicators that the site functions to reduce flooding and stream erosion	
S 4.0. Does the site have the potential to reduce flooding and stream erosion?	
S 4.1. Characteristics of plants that reduce the velocity of surface flows during storms: Choose the points appropriate for the description that best fits conditions in the wetland. *Stems of plants should be thick enough (usually >1/8₈ in), or dense enough, to remain erect during surface flows.* ☒ Dense, uncut, **rigid** plants cover > 90% of the area of the wetland points = 1 ☐ All other conditions points = 0	1

Rating of Site Potential If score is: ☒**1 = M** ☐**0 = L** *Record the rating on the first page*

S 5.0. Does the landscape have the potential to support the hydrologic functions of the site?	
S 5.1. Is more than 25% of the area within 150 ft upslope of wetland in land uses or cover that generate excess surface runoff? ☐Yes = 1 ☒ No = 0	0

Rating of Landscape Potential If score is: ☐**1 = M** ☒**0 = L** *Record the rating on the first page*

S 6.0. Are the hydrologic functions provided by the site valuable to society?	
S 6.1. Distance to the nearest areas downstream that have flooding problems: ☒ The sub-basin immediately down-gradient of site has flooding problems that result in damage to human or natural resources (e.g., houses or salmon redds) points = 2 ☐ Surface flooding problems are in a sub-basin farther down-gradient points = 1 ☐ No flooding problems anywhere downstream points = 0	2
S 6.2. Has the site been identified as important for flood storage or flood conveyance in a regional flood control plan? ☐Yes = 2 ☒ No = 0	0
Total for S 6 Add the points in the boxes above	2

Rating of Value If score is: ☒**2-4 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

NOTES and FIELD OBSERVATIONS:

These questions apply to wetlands of all HGM classes.

HABITAT FUNCTIONS - Indicators that site functions to provide important habitat

H 1.0. Does the site have the potential to provide habitat?

H 1.1. Structure of plant community: *Indicators are Cowardin classes and strata within the Forested class.* Check the Cowardin plant classes in the wetland. *Up to 10 patches may be combined for each class to meet the threshold of ¼ ac or more than 10% of the unit if it is smaller than 2.5 ac. Add the number of structures checked.*

- ☐ Aquatic bed — 4 structures or more: points = 4
- ☐ Emergent — 3 structures: points = 2
- ☒ Scrub-shrub (areas where shrubs have > 30% cover) — 2 structures: points = 1
- ☒ Forested (areas where trees have > 30% cover) — 1 structure: points = 0

If the unit has a Forested class, check if:

- ☒ The Forested class has 3 out of 5 strata (canopy, sub-canopy, shrubs, herbaceous, moss/ground-cover) that each cover 20% within the Forested polygon

2

H 1.2. Hydroperiods

Check the types of water regimes (hydroperiods) present within the wetland. The water regime has to cover more than 10% of the wetland or ¼ ac to count (*see text for descriptions of hydroperiods*).

- ☐ Permanently flooded or inundated — 4 or more types present: points = 3
- ☐ Seasonally flooded or inundated — 3 types present: points = 2
- ☒ Occasionally flooded or inundated — 2 types present: points = 1
- ☒ Saturated only — 1 type present: points = 0
- ☐ Permanently flowing stream or river in, or adjacent to, the wetland
- ☐ Seasonally flowing stream in, or adjacent to, the wetland
- ☐ **Lake Fringe wetland** — **2 points**
- ☐ **Freshwater tidal wetland** — **2 points**

1

H 1.3. Richness of plant species

Count the number of plant species in the wetland that cover at least 10 ft^2.

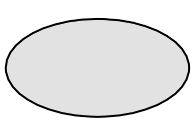
Different patches of the same species can be combined to meet the size threshold and you do not have to name the species. ***Do not include Eurasian milfoil, reed canarygrass, purple loosestrife, Canadian thistle***

If you counted:
- ☐ > 19 species — points = 2
- ☒ 5 - 19 species — points = 1
- ☐ < 5 species — points = 0

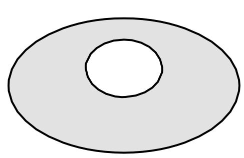
1

H 1.4. Interspersion of habitats

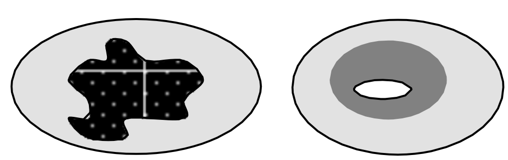
Decide from the diagrams below whether interspersion among Cowardin plants classes (described in H 1.1), or the classes and unvegetated areas (can include open water or mudflats) is high, moderate, low, or none. *If you have four or more plant classes or three classes and open water, the rating is always high.*



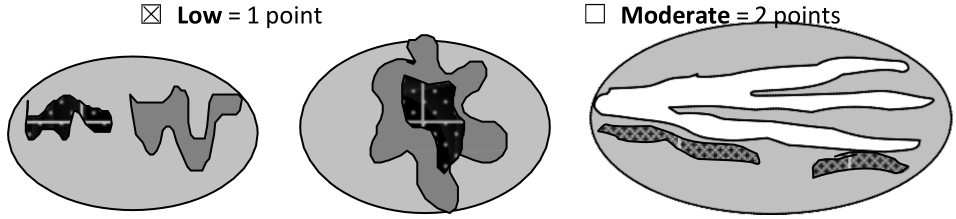
☐ **None** = 0 points



☒ **Low** = 1 point



☐ **Moderate** = 2 points



All three diagrams in this row are ☐ **HIGH** = 3points

1

DSD 010029

H 1.5. Special habitat features: Check the habitat features that are present in the wetland. *The number of checks is the number of points.* ☒ Large, downed, woody debris within the wetland (> 4 in diameter and 6 ft long). ☐ Standing snags (dbh > 4 in) within the wetland. ☐ Undercut banks are present for at least 6.6 ft (2 m) **AND/OR** overhanging plants extends at least 3.3 ft (1 m) over a stream (or ditch) in, or contiguous with the wetland, for at least 33 ft (10 m). ☐ Stable steep banks of fine material that might be used by beaver or muskrat for denning (> 30 degree slope) **OR** signs of recent beaver activity are present *(cut shrubs or trees that have not yet weathered where wood is exposed).* ☐ At least ¼ ac of thin-stemmed persistent plants or woody branches are present in areas that are permanently or seasonally inundated *(structures for egg-laying by amphibians).* ☐ Invasive plants cover less than 25% of the wetland area in every stratum of plants (*see H 1.1 for list of strata*).	1
Total for H 1 Add the points in the boxes above	6

Rating of Site Potential If score is: ☐**15-18 = H** ☐**7-14 = M** ☒**0-6 = L** *Record the rating on the first page*

H 2.0. Does the landscape have the potential to support the habitat functions of the site?	
H 2.1. Accessible habitat (include *only habitat that directly abuts wetland unit*). *Calculate:* % undisturbed habitat + [(%moderate and low intensity land uses)/2] = **3.0% + (0%/2) = 3.0%** If total accessible habitat is: ☐ > 1/3 (33.3%) of 1 km Polygon points = 3 ☐ 20-33% of 1 km Polygon points = 2 ☐ 10-19% of 1 km Polygon points = 1 ☒ < 10% of 1 km Polygon points = 0	0
H 2.2. Undisturbed habitat in 1 km Polygon around the wetland. *Calculate:* % undisturbed habitat + [(%moderate and low intensity land uses)/2 **= 13.8% + (0%/2) = 13.8%** ☐ Undisturbed habitat > 50% of Polygon points = 3 ☐ Undisturbed habitat 10-50% and in 1-3 patches points = 2 ☒ Undisturbed habitat 10-50% and > 3 patches points = 1 ☐ Undisturbed habitat < 10% of 1 km Polygon points = 0	1
H 2.3. Land use intensity in 1 km Polygon: If ☒ > 50% of 1 km Polygon is high intensity land use points = (- 2) ☐ ≤ 50% of 1 km Polygon is high intensity points = 0	-2
Total for H 2 Add the points in the boxes above	-1

Rating of Landscape Potential If score is**:** ☐**4-6 = H** ☐**1-3 = M** ☒**< 1 = L** *Record the rating on the first page*

H 3.0. Is the habitat provided by the site valuable to society?	
H 3.1. Does the site provide habitat for species valued in laws, regulations, or policies? *Choose only the highest score that applies to the wetland being rated.* Site meets ANY of the following criteria: points = 2 ☒ It has 3 or more priority habitats within 100 m (see next page) ☐ It provides habitat for Threatened or Endangered species (any plant or animal on the state or federal lists) ☐ It is mapped as a location for an individual WDFW priority species ☐ It is a Wetland of High Conservation Value as determined by the Department of Natural Resources ☐ It has been categorized as an important habitat site in a local or regional comprehensive plan, in a Shoreline Master Plan, or in a watershed plan ☐ Site has 1 or 2 priority habitats (listed on next page) within 100 m points = 1 ☐ Site does not meet any of the criteria above points = 0	2

Rating of Value If score is: ☒**2 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

WDFW Priority Habitats

Priority habitats listed by WDFW (see complete descriptions of WDFW priority habitats, and the counties in which they can be found, in: Washington Department of Fish and Wildlife. 2008. Priority Habitat and Species List. Olympia, Washington. 177 pp. http://wdfw.wa.gov/publications/00165/wdfw00165.pdf or access the list from here: http://wdfw.wa.gov/conservation/phs/list/)

Count how many of the following priority habitats are within 330 ft (100 m) of the wetland unit: ***NOTE:*** *This question is independent of the land use between the wetland unit and the priority habitat.*

☐ **Aspen Stands:** Pure or mixed stands of aspen greater than 1 ac (0.4 ha).

☐ **Biodiversity Areas and Corridors**: Areas of habitat that are relatively important to various species of native fish and wildlife (*full descriptions in WDFW PHS report*).

☐ **Herbaceous Balds:** Variable size patches of grass and forbs on shallow soils over bedrock.

☐ **Old-growth/Mature forests:** Old-growth west of Cascade crest – Stands of at least 2 tree species, forming a multi- layered canopy with occasional small openings; with at least 8 trees/ac (20 trees/ha) > 32 in (81 cm) dbh or > 200 years of age. Mature forests – Stands with average diameters exceeding 21 in (53 cm) dbh; crown cover may be less than 100%; decay, decadence, numbers of snags, and quantity of large downed material is generally less than that found in old-growth; 80-200 years old west of the Cascade crest.

☐ **Oregon White Oak:** Woodland stands of pure oak or oak/conifer associations where canopy coverage of the oak component is important (*full descriptions in WDFW PHS report p. 158 – see web link above*).

☒ **Riparian**: The area adjacent to aquatic systems with flowing water that contains elements of both aquatic and terrestrial ecosystems which mutually influence each other.

☐ **Westside Prairies:** Herbaceous, non-forested plant communities that can either take the form of a dry prairie or a wet prairie (*full descriptions in WDFW PHS report p. 161 – see web link above*).

☒ **Instream:** The combination of physical, biological, and chemical processes and conditions that interact to provide functional life history requirements for instream fish and wildlife resources.

☐ **Nearshore**: Relatively undisturbed nearshore habitats. These include Coastal Nearshore, Open Coast Nearshore, and Puget Sound Nearshore. (*full descriptions of habitats and the definition of relatively undisturbed are in WDFW report – see web link on previous page).*

☐ **Caves:** A naturally occurring cavity, recess, void, or system of interconnected passages under the earth in soils, rock, ice, or other geological formations and is large enough to contain a human.

☐ **Cliffs:** Greater than 25 ft (7.6 m) high and occurring below 5000 ft elevation.

☐ **Talus:** Homogenous areas of rock rubble ranging in average size 0.5 - 6.5 ft (0.15 - 2.0 m), composed of basalt, andesite, and/or sedimentary rock, including riprap slides and mine tailings. May be associated with cliffs.

☒ **Snags and Logs:** Trees are considered snags if they are dead or dying and exhibit sufficient decay characteristics to enable cavity excavation/use by wildlife. Priority snags have a diameter at breast height of > 20 in (51 cm) in western Washington and are > 6.5 ft (2 m) in height. Priority logs are > 12 in (30 cm) in diameter at the largest end, and > 20 ft (6 m) long.

Note: All vegetated wetlands are by definition a priority habitat but are not included in this list because they are addressed elsewhere.

RATING SUMMARY – Western Washington

Name of wetland (or ID #): Richards Creek Substation – Wetland C Date of site visit: 3/27/2017

Rated by: Katy Crandall Trained by Ecology? ☒Y ☐N Date of training: 09/2014

HGM Class used for rating: Slope Wetland has multiple HGM classes? ☒Y ☐N

NOTE: **Form is not complete without the figures requested** *(figures can be combined)*.
Source of base aerial photo/map: King County iMap and Google Earth

OVERALL WETLAND CATEGORY (based on functions ☒ or special characteristics ☐)

1. Category of wetland based on FUNCTIONS

☐ **Category I** – Total score = 23 - 27

☐ **Category II** – Total score = 20 - 22

☒ **Category III** – Total score = 16 - 19

☐ **Category IV** – Total score = 9 - 15

FUNCTION	Improving Water Quality	Hydrologic	Habitat	
			Circle the appropriate ratings	
Site Potential	H M L	H M L	H M L	
Landscape Potential	H M L	H M L	H M L	
Value	H M L	H M L	H M L	**TOTAL**
Score Based on Ratings	6	6	6	18

Score for each function based on three ratings
(order of ratings is not important)

9 = H,H,H
8 = H,H,M
7 = H,H,L
7 = H,M,M
6 = H,M,L
6 = M,M,M
5 = H,L,L
5 = M,M,L
4 = M,L,L
3 = L,L,L

2. Category based on SPECIAL CHARACTERISTICS of wetland

CHARACTERISTIC	CATEGORY
Estuarine	I II
Wetland of High Conservation Value	I
Bog	I
Mature Forest	I
Old Growth Forest	I
Coastal Lagoon	I II
Interdunal	I II III IV
None of the above	☒

Maps and figures required to answer questions correctly for Western Washington

Slope Wetlands

Map of:	To answer questions:	Figure #
Cowardin plant classes	H 1.1, H 1.4	1
Hydroperiods	H 1.2	2
Plant cover of **dense** trees, shrubs, and herbaceous plants	S 1.3	3
Plant cover of **dense, rigid** trees, shrubs, and herbaceous plants (*can be added to figure above)*	S 4.1	3
Boundary of 150 ft buffer (can be added to another figure)	S 2.1, S 5.1	2
1 km Polygon: Area that extends 1 km from entire wetland edge - including polygons for accessible habitat and undisturbed habitat	H 2.1, H 2.2, H 2.3	8
Screen capture of map of 303(d) listed waters in basin (from Ecology website)	S 3.1, S 3.2	9
Screen capture of list of TMDLs for WRIA in which unit is found (from web)	S 3.3	10

HGM Classification of Wetlands in Western Washington

For questions 1-7, the criteria described must apply to the entire unit being rated.

If the hydrologic criteria listed in each question do not apply to the entire unit being rated, you probably have a unit with multiple HGM classes. In this case, identify which hydrologic criteria in questions 1-7 apply, and go to Question 8.

1. Are the water levels in the entire unit usually controlled by tides except during floods?

   ☒NO – go to 2 ☐**YES** – the wetland class is **Tidal Fringe** – go to 1.1

   1.1 Is the salinity of the water during periods of annual low flow below 0.5 ppt (parts per thousand)?

   NO – Saltwater Tidal Fringe (Estuarine) **YES – Freshwater Tidal Fringe**
   *If your wetland can be classified as a Freshwater Tidal Fringe use the forms for **Riverine** wetlands. If it is Saltwater Tidal Fringe it is an **Estuarine** wetland and is not scored. This method **cannot** be used to score functions for estuarine wetlands.*

2. The entire wetland unit is flat and precipitation is the only source (>90%) of water to it. Groundwater and surface water runoff are NOT sources of water to the unit.

   ☒NO – go to 3 ☐**YES** – The wetland class is **Flats**
   *If your wetland can be classified as a Flats wetland, use the form for **Depressional** wetlands.*

3. Does the entire wetland unit **meet all** of the following criteria?
   ☐The vegetated part of the wetland is on the shores of a body of permanent open water (without any plants on the surface at any time of the year) at least 20 ac (8 ha) in size;
   ☐At least 30% of the open water area is deeper than 6.6 ft (2 m).

   ☒NO – go to 4 ☐**YES –** The wetland class is **Lake Fringe** (Lacustrine Fringe)

4. Does the entire wetland unit **meet all** of the following criteria?
   ☒The wetland is on a slope (*slope can be very gradual*),
   ☒The water flows through the wetland in one direction (unidirectional) and usually comes from seeps. It may flow subsurface, as sheetflow, or in a swale without distinct banks,
   ☒The water leaves the wetland **without being impounded.**

   ☐NO – go to 5 ☒**YES –** The wetland class is **Slope**

   NOTE: Surface water does not pond in these type of wetlands except occasionally in very small and shallow depressions or behind hummocks (depressions are usually <3 ft diameter and less than 1 ft deep).

5. Does the entire wetland unit **meet all** of the following criteria?
   ☐The unit is in a valley, or stream channel, where it gets inundated by overbank flooding from that stream or river,
   ☐The overbank flooding occurs at least once every 2 years.

☐NO – go to 6 ☐**YES –** The wetland class is **Riverine**

NOTE: The Riverine unit can contain depressions that are filled with water when the river is not flooding

6. Is the entire wetland unit in a topographic depression in which water ponds, or is saturated to the surface, at some time during the year? *This means that any outlet, if present, is higher than the interior of the wetland.*

☐NO – go to 7 ☐**YES** – The wetland class is **Depressional**

7. Is the entire wetland unit located in a very flat area with no obvious depression and no overbank flooding? The unit does not pond surface water more than a few inches. The unit seems to be maintained by high groundwater in the area. The wetland may be ditched, but has no obvious natural outlet.

☐NO – go to 8 ☐**YES** – The wetland class is **Depressional**

8. Your wetland unit seems to be difficult to classify and probably contains several different HGM classes. For example, seeps at the base of a slope may grade into a riverine floodplain, or a small stream within a Depressional wetland has a zone of flooding along its sides. GO BACK AND IDENTIFY WHICH OF THE HYDROLOGIC REGIMES DESCRIBED IN QUESTIONS 1-7 APPLY TO DIFFERENT AREAS IN THE UNIT (make a rough sketch to help you decide). Use the following table to identify the appropriate class to use for the rating system if you have several HGM classes present within the wetland unit being scored.

NOTE: Use this table only if the class that is recommended in the second column represents 10% or more of the total area of the wetland unit being rated. If the area of the HGM class listed in column 2 is less than 10% of the unit; classify the wetland using the class that represents more than 90% of the total area.

HGM classes within the wetland unit being rated	HGM class to use in rating
Slope + Riverine	Riverine
Slope + Depressional	Depressional
Slope + Lake Fringe	Lake Fringe
Depressional + Riverine along stream within boundary of depression	Depressional
Depressional + Lake Fringe	Depressional
Riverine + Lake Fringe	Riverine
Salt Water Tidal Fringe and any other class of freshwater wetland	Treat as ESTUARINE

If you are still unable to determine which of the above criteria apply to your wetland, or if you have ***more than 2 HGM classes*** *within a wetland boundary, classify the wetland as Depressional for the rating.*

SLOPE WETLANDS

Water Quality Functions - Indicators that the site functions to improve water quality

S 1.0. Does the site have the potential to improve water quality?	
S 1.1. Characteristics of the average slope of the wetland: *(a 1% slope has a 1 ft vertical drop in elevation for every 100 ft of horizontal distance)* ☐ Slope is 1% or less points = 3 ☐ Slope is > 1%-2% points = 2 ☐ Slope is > 2%-5% points = 1 ☒ Slope is greater than 5% points = 0	0
S 1.2. The soil 2 in below the surface (or duff layer) is true clay or true organic *(use NRCS definitions)*: Yes = 3 No = 0	0
S 1.3. Characteristics of the plants in the wetland that trap sediments and pollutants: Choose the points appropriate for the description that best fits the plants in the wetland. *Dense means you have trouble seeing the soil surface (>75% cover), and uncut means not grazed or mowed and plants are higher than 6 in.* ☐ Dense, uncut, herbaceous plants > 90% of the wetland area points = 6 ☒ Dense, uncut, herbaceous plants > ½ of area points = 3 ☐ Dense, woody, plants > ½ of area points = 2 ☐ Dense, uncut, herbaceous plants > ¼ of area points = 1 ☐ Does not meet any of the criteria above for plants points = 0	3
Total for S 1 Add the points in the boxes above	3

Rating of Site Potential If score is: ☐**12 = H** ☐**6-11 = M** ☒**0-5 = L** *Record the rating on the first page*

S 2.0. Does the landscape have the potential to support the water quality function of the site?	
S 2.1. Is > 10% of the area within 150 ft on the uphill side of the wetland in land uses that generate pollutants? ☐Yes = 1 ☒ No = 0	0
S 2.2. Are there other sources of pollutants coming into the wetland that are not listed in question S 2.1? Other sources Stream conveying roadway and urban runoff ☒Yes = 1 ☐ No = 0	1
Total for S 2 Add the points in the boxes above	1

Rating of Landscape Potential If score is: ☒**1-2 = M** ☐**0 = L** *Record the rating on the first page*

S 3.0. Is the water quality improvement provided by the site valuable to society?	
S 3.1. Does the wetland discharge directly (i.e., within 1 mi) to a stream, river, lake, or marine water that is on the 303(d) list? ☒Yes = 1 ☐ No = 0	1
S 3.2. Is the wetland in a basin or sub-basin where water quality is an issue? *At least one aquatic resource in the basin is on the 303(d) list.* ☒Yes = 1 ☐ No = 0	1
S 3.3. Has the site been identified in a watershed or local plan as important for maintaining water quality? *Answer YES if there is a TMDL for the basin in which unit is found.* ☐Yes = 2 ☒ No = 0	0
Total for S 3 Add the points in the boxes above	2

Rating of Value If score is: ☒**2-4 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

SLOPE WETLANDS

Hydrologic Functions - Indicators that the site functions to reduce flooding and stream erosion

S 4.0. Does the site have the potential to reduce flooding and stream erosion?	
S 4.1. Characteristics of plants that reduce the velocity of surface flows during storms: Choose the points appropriate for the description that best fits conditions in the wetland. *Stems of plants should be thick enough (usually >1/8 in), or dense enough, to remain erect during surface flows.* ☒ Dense, uncut, **rigid** plants cover > 90% of the area of the wetland points = 1 ☐ All other conditions points = 0	1

Rating of Site Potential If score is: ☒**1 = M** ☐**0 = L** *Record the rating on the first page*

S 5.0. Does the landscape have the potential to support the hydrologic functions of the site?	
S 5.1. Is more than 25% of the area within 150 ft upslope of wetland in land uses or cover that generate excess surface runoff? ☐Yes = 1 ☒ No = 0	0

Rating of Landscape Potential If score is: ☐**1 = M** ☒**0 = L** *Record the rating on the first page*

S 6.0. Are the hydrologic functions provided by the site valuable to society?	
S 6.1. Distance to the nearest areas downstream that have flooding problems: ☒ The sub-basin immediately down-gradient of site has flooding problems that result in damage to human or natural resources (e.g., houses or salmon redds) points = 2 ☐ Surface flooding problems are in a sub-basin farther down-gradient points = 1 ☐ No flooding problems anywhere downstream points = 0	2
S 6.2. Has the site been identified as important for flood storage or flood conveyance in a regional flood control plan? ☐Yes = 2 ☒ No = 0	0
Total for S 6 Add the points in the boxes above	2

Rating of Value If score is: ☒**2-4 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

NOTES and FIELD OBSERVATIONS:

These questions apply to wetlands of all HGM classes.

HABITAT FUNCTIONS - Indicators that site functions to provide important habitat

H 1.0. Does the site have the potential to provide habitat?

H 1.1. Structure of plant community: *Indicators are Cowardin classes and strata within the Forested class.* Check the Cowardin plant classes in the wetland. *Up to 10 patches may be combined for each class to meet the threshold of ¼ ac or more than 10% of the unit if it is smaller than 2.5 ac. Add the number of structures checked.*

☐ Aquatic bed	4 structures or more: points = 4
☐ Emergent	3 structures: points = 2
☒ Scrub-shrub (areas where shrubs have > 30% cover)	2 structures: points = 1
☒ Forested (areas where trees have > 30% cover)	1 structure: points = 0

If the unit has a Forested class, check if:

☒ The Forested class has 3 out of 5 strata (canopy, sub-canopy, shrubs, herbaceous, moss/ground-cover) that each cover 20% within the Forested polygon

2

H 1.2. Hydroperiods

Check the types of water regimes (hydroperiods) present within the wetland. The water regime has to cover more than 10% of the wetland or ¼ ac to count (*see text for descriptions of hydroperiods*).

☐ Permanently flooded or inundated	4 or more types present: points = 3
☐ Seasonally flooded or inundated	3 types present: points = 2
☒ Occasionally flooded or inundated	2 types present: points = 1
☒ Saturated only	1 type present: points = 0
☐ Permanently flowing stream or river in, or adjacent to, the wetland	
☐ Seasonally flowing stream in, or adjacent to, the wetland	
☐ **Lake Fringe wetland**	**2 points**
☐ **Freshwater tidal wetland**	**2 points**

1

H 1.3. Richness of plant species

Count the number of plant species in the wetland that cover at least 10 ft^2.

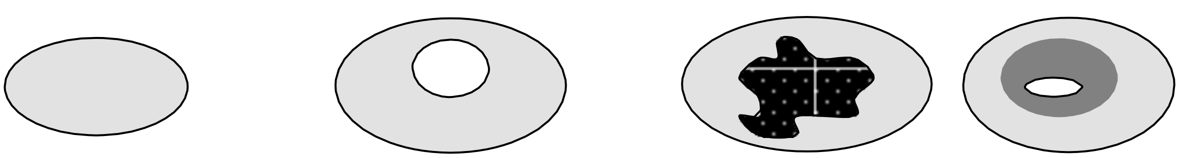
Different patches of the same species can be combined to meet the size threshold and you do not have to name the species. ***Do not include Eurasian milfoil, reed canarygrass, purple loosestrife, Canadian thistle***

If you counted:	☐ > 19 species	points = 2
	☒ 5 - 19 species	points = 1
	☐ < 5 species	points = 0

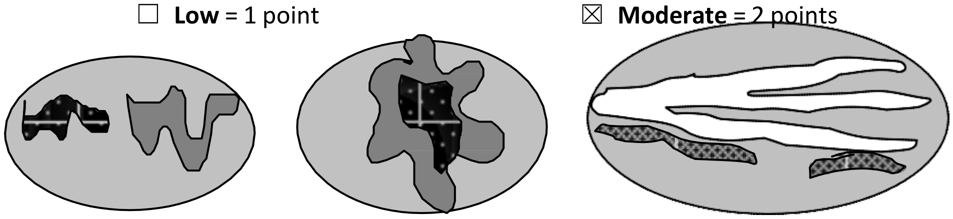
1

H 1.4. Interspersion of habitats

Decide from the diagrams below whether interspersion among Cowardin plants classes (described in H 1.1), or the classes and unvegetated areas (can include open water or mudflats) is high, moderate, low, or none. *If you have four or more plant classes or three classes and open water, the rating is always high.*



☐ **None** = 0 points ☐ **Low** = 1 point ☒ **Moderate** = 2 points



All three diagrams in this row are

☐ **HIGH** = 3points

2

DSD 010038

H 1.5. Special habitat features: Check the habitat features that are present in the wetland. *The number of checks is the number of points.* ☒ Large, downed, woody debris within the wetland (> 4 in diameter and 6 ft long). ☒ Standing snags (dbh > 4 in) within the wetland. ☒ Undercut banks are present for at least 6.6 ft (2 m) **AND/OR** overhanging plants extends at least 3.3 ft (1 m) over a stream (or ditch) in, or contiguous with the wetland, for at least 33 ft (10 m). ☐ Stable steep banks of fine material that might be used by beaver or muskrat for denning (> 30 degree slope) **OR** signs of recent beaver activity are present *(cut shrubs or trees that have not yet weathered where wood is exposed).* ☐ At least ¼ ac of thin-stemmed persistent plants or woody branches are present in areas that are permanently or seasonally inundated *(structures for egg-laying by amphibians).* ☒ Invasive plants cover less than 25% of the wetland area in every stratum of plants (*see H 1.1 for list of strata*).	4
Total for H 1 — Add the points in the boxes above	10

Rating of Site Potential If score is: ☐**15-18 = H** ☒**7-14 = M** ☐**0-6 = L** *Record the rating on the first page*

H 2.0. Does the landscape have the potential to support the habitat functions of the site?	
H 2.1. Accessible habitat (include *only habitat that directly abuts wetland unit*). *Calculate:* % undisturbed habitat + [(%moderate and low intensity land uses)/2] = **3.0% + (0%/2) = 3.0%** If total accessible habitat is: ☐ > 1/3 (33.3%) of 1 km Polygon — points = 3 ☐ 20-33% of 1 km Polygon — points = 2 ☐ 10-19% of 1 km Polygon — points = 1 ☒ < 10% of 1 km Polygon — points = 0	0
H 2.2. Undisturbed habitat in 1 km Polygon around the wetland. *Calculate:* % undisturbed habitat + [(%moderate and low intensity land uses)/2 **= 13.8% + (0%/2) = 13.8%** ☐ Undisturbed habitat > 50% of Polygon — points = 3 ☐ Undisturbed habitat 10-50% and in 1-3 patches — points = 2 ☒ Undisturbed habitat 10-50% and > 3 patches — points = 1 ☐ Undisturbed habitat < 10% of 1 km Polygon — points = 0	1
H 2.3. Land use intensity in 1 km Polygon: If ☒ > 50% of 1 km Polygon is high intensity land use — points = (- 2) ☐ ≤ 50% of 1 km Polygon is high intensity — points = 0	-2
Total for H 2 — Add the points in the boxes above	-1

Rating of Landscape Potential If score is: ☐**4-6 = H** ☐**1-3 = M** ☒**< 1 = L** *Record the rating on the first page*

H 3.0. Is the habitat provided by the site valuable to society?	
H 3.1. Does the site provide habitat for species valued in laws, regulations, or policies? *Choose only the highest score that applies to the wetland being rated.* Site meets ANY of the following criteria: — points = 2 ☒ It has 3 or more priority habitats within 100 m (see next page) ☐ It provides habitat for Threatened or Endangered species (any plant or animal on the state or federal lists) ☐ It is mapped as a location for an individual WDFW priority species ☐ It is a Wetland of High Conservation Value as determined by the Department of Natural Resources ☐ It has been categorized as an important habitat site in a local or regional comprehensive plan, in a Shoreline Master Plan, or in a watershed plan ☐ Site has 1 or 2 priority habitats (listed on next page) within 100 m — points = 1 ☐ Site does not meet any of the criteria above — points = 0	2

Rating of Value If score is: ☒**2 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

WDFW Priority Habitats

Priority habitats listed by WDFW (see complete descriptions of WDFW priority habitats, and the counties in which they can be found, in: Washington Department of Fish and Wildlife. 2008. Priority Habitat and Species List. Olympia, Washington. 177 pp. http://wdfw.wa.gov/publications/00165/wdfw00165.pdf or access the list from here: http://wdfw.wa.gov/conservation/phs/list/)

Count how many of the following priority habitats are within 330 ft (100 m) of the wetland unit: ***NOTE:*** *This question is independent of the land use between the wetland unit and the priority habitat.*

☐ **Aspen Stands:** Pure or mixed stands of aspen greater than 1 ac (0.4 ha).

☐ **Biodiversity Areas and Corridors**: Areas of habitat that are relatively important to various species of native fish and wildlife (*full descriptions in WDFW PHS report*).

☐ **Herbaceous Balds:** Variable size patches of grass and forbs on shallow soils over bedrock.

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☐ **Oregon White Oak:** Woodland stands of pure oak or oak/conifer associations where canopy coverage of the oak component is important (*full descriptions in WDFW PHS report p. 158 – see web link above*).

☒ **Riparian**: The area adjacent to aquatic systems with flowing water that contains elements of both aquatic and terrestrial ecosystems which mutually influence each other.

☐ **Westside Prairies:** Herbaceous, non-forested plant communities that can either take the form of a dry prairie or a wet prairie (*full descriptions in WDFW PHS report p. 161 – see web link above*).

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☐ **Talus:** Homogenous areas of rock rubble ranging in average size 0.5 - 6.5 ft (0.15 - 2.0 m), composed of basalt, andesite, and/or sedimentary rock, including riprap slides and mine tailings. May be associated with cliffs.

☒ **Snags and Logs:** Trees are considered snags if they are dead or dying and exhibit sufficient decay characteristics to enable cavity excavation/use by wildlife. Priority snags have a diameter at breast height of > 20 in (51 cm) in western Washington and are > 6.5 ft (2 m) in height. Priority logs are > 12 in (30 cm) in diameter at the largest end, and > 20 ft (6 m) long.

Note: All vegetated wetlands are by definition a priority habitat but are not included in this list because they are addressed elsewhere.

RATING SUMMARY – Western Washington

Name of wetland: Richards Creek Substation – Wetland D Date of site visit: 10/10/2016, 5/8/2017

Rated by: M. Foster, K. Crandall Trained by Ecology? ☒Y ☐N Date of training: 09/2014

HGM Class used for rating: Riverine Wetland has multiple HGM classes? ☐Y ☒N

NOTE: **Form is not complete without the figures requested** *(figures can be combined)*.
Source of base aerial photo/map: King County iMap and Google Earth

OVERALL WETLAND CATEGORY (based on functions ☒ or special characteristics ☐)

1. Category of wetland based on FUNCTIONS

☐ **Category I** – Total score = 23 - 27
☒ **Category II** – Total score = 20 - 22
☐ **Category III** – Total score = 16 - 19
☐ **Category IV** – Total score = 9 - 15

FUNCTION	Improving Water Quality	Hydrologic	Habitat	
Circle the appropriate ratings				
Site Potential	H M L	H M L	H M L	
Landscape Potential	H M L	H M L	H M L	
Value	H M L	H M L	H M L	TOTAL
Score Based on Ratings	7	7	6	20

Score for each function based on three ratings *(order of ratings is not important)*

9 = H,H,H
8 = H,H,M
7 = H,H,L
7 = H,M,M
6 = H,M,L
6 = M,M,M
5 = H,L,L
5 = M,M,L
4 = M,L,L
3 = L,L,L

2. Category based on SPECIAL CHARACTERISTICS of wetland

CHARACTERISTIC	CATEGORY
Estuarine	I II
Wetland of High Conservation Value	I
Bog	I
Mature Forest	I
Old Growth Forest	I
Coastal Lagoon	I II
Interdunal	I II III IV
None of the above	☒

Maps and figures required to answer questions correctly for Western Washington

Riverine Wetlands

Map of:	To answer questions:	Figure #
Cowardin plant classes	H 1.1, H 1.4	4
Hydroperiods	H 1.2	5
Ponded depressions	R 1.1	5
Boundary of area within 150 ft of the wetland *(can be added to another figure)*	R 2.4	4
Plant cover of trees, shrubs, and herbaceous plants	R 1.2, R 4.2	6
Width of unit vs. width of stream *(can be added to another figure)*	R 4.1	5
Map of the contributing basin	R 2.2, R 2.3, R 5.2	7
1 km Polygon: Area that extends 1 km from entire wetland edge - including polygons for accessible habitat and undisturbed habitat	H 2.1, H 2.2, H 2.3	8
Screen capture of map of 303(d) listed waters in basin (from Ecology website)	R 3.1	9
Screen capture of list of TMDLs for WRIA in which unit is found (from web)	R 3.2, R 3.3	10

HGM Classification of Wetlands in Western Washington

For questions 1-7, the criteria described must apply to the entire unit being rated.

If the hydrologic criteria listed in each question do not apply to the entire unit being rated, you probably have a unit with multiple HGM classes. In this case, identify which hydrologic criteria in questions 1-7 apply, and go to Question 8.

1. Are the water levels in the entire unit usually controlled by tides except during floods?

   ☒NO – go to 2 ☐**YES** – the wetland class is **Tidal Fringe** – go to 1.1

   1.1 Is the salinity of the water during periods of annual low flow below 0.5 ppt (parts per thousand)?

   NO – Saltwater Tidal Fringe (Estuarine) **YES – Freshwater Tidal Fringe**
   *If your wetland can be classified as a Freshwater Tidal Fringe use the forms for **Riverine** wetlands. If it is Saltwater Tidal Fringe it is an **Estuarine** wetland and is not scored. This method **cannot** be used to score functions for estuarine wetlands.*

2. The entire wetland unit is flat and precipitation is the only source (>90%) of water to it. Groundwater and surface water runoff are NOT sources of water to the unit.

   ☒NO – go to 3 ☐**YES** – The wetland class is **Flats**
   *If your wetland can be classified as a Flats wetland, use the form for **Depressional** wetlands.*

3. Does the entire wetland unit **meet all** of the following criteria?
   ☐The vegetated part of the wetland is on the shores of a body of permanent open water (without any plants on the surface at any time of the year) at least 20 ac (8 ha) in size;
   ☐At least 30% of the open water area is deeper than 6.6 ft (2 m).

   ☒NO – go to 4 ☐**YES** – The wetland class is **Lake Fringe** (Lacustrine Fringe)

4. Does the entire wetland unit **meet all** of the following criteria?
   ☐The wetland is on a slope (*slope can be very gradual*),
   ☐The water flows through the wetland in one direction (unidirectional) and usually comes from seeps. It may flow subsurface, as sheetflow, or in a swale without distinct banks,
   ☐The water leaves the wetland **without being impounded.**

   ☒NO – go to 5 ☐**YES** – The wetland class is **Slope**

   NOTE: Surface water does not pond in these type of wetlands except occasionally in very small and shallow depressions or behind hummocks (depressions are usually <3 ft diameter and less than 1 ft deep).

5. Does the entire wetland unit **meet all** of the following criteria?
   ☒The unit is in a valley, or stream channel, where it gets inundated by overbank flooding from that stream or river,
   ☒The overbank flooding occurs at least once every 2 years.

☐NO – go to 6 ☒**YES –** The wetland class is **Riverine**

NOTE: The Riverine unit can contain depressions that are filled with water when the river is not flooding

6. Is the entire wetland unit in a topographic depression in which water ponds, or is saturated to the surface, at some time during the year? *This means that any outlet, if present, is higher than the interior of the wetland.*

☐NO – go to 7 ☐**YES** – The wetland class is **Depressional**

7. Is the entire wetland unit located in a very flat area with no obvious depression and no overbank flooding? The unit does not pond surface water more than a few inches. The unit seems to be maintained by high groundwater in the area. The wetland may be ditched, but has no obvious natural outlet.

☐NO – go to 8 ☐**YES** – The wetland class is **Depressional**

8. Your wetland unit seems to be difficult to classify and probably contains several different HGM classes. For example, seeps at the base of a slope may grade into a riverine floodplain, or a small stream within a Depressional wetland has a zone of flooding along its sides. GO BACK AND IDENTIFY WHICH OF THE HYDROLOGIC REGIMES DESCRIBED IN QUESTIONS 1-7 APPLY TO DIFFERENT AREAS IN THE UNIT (make a rough sketch to help you decide). Use the following table to identify the appropriate class to use for the rating system if you have several HGM classes present within the wetland unit being scored.

NOTE: Use this table only if the class that is recommended in the second column represents 10% or more of the total area of the wetland unit being rated. If the area of the HGM class listed in column 2 is less than 10% of the unit; classify the wetland using the class that represents more than 90% of the total area.

HGM classes within the wetland unit being rated	HGM class to use in rating
Slope + Riverine	Riverine
Slope + Depressional	Depressional
Slope + Lake Fringe	Lake Fringe
Depressional + Riverine along stream within boundary of depression	Depressional
Depressional + Lake Fringe	Depressional
Riverine + Lake Fringe	Riverine
Salt Water Tidal Fringe and any other class of freshwater wetland	Treat as ESTUARINE

If you are still unable to determine which of the above criteria apply to your wetland, or if you have ***more than 2 HGM classes*** *within a wetland boundary, classify the wetland as Depressional for the rating.*

RIVERINE AND FRESHWATER TIDAL FRINGE WETLANDS

Water Quality Functions - Indicators that the site functions to improve water quality

R 1.0. Does the site have the potential to improve water quality?		
R 1.1. Area of surface depressions within the Riverine wetland that can trap sediments during a flooding event: ☐ Depressions cover ≥ 3/4 area of wetland ☐ Depressions cover > 1/2 area of wetland ☒ Depressions present but cover < 1/2 area of wetland ☐ No depressions present	points = 8 points = 4 points = 2 points = 0	2
R 1.2. Structure of plants in the wetland (areas with >90% cover at person height, **not** Cowardin classes) ☒ Trees or shrubs > 2/3 area of the wetland ☐ Trees or shrubs > 1/3 area of the wetland ☐ Herbaceous plants (> 6 in high) > 2/3 area of the wetland ☐ Herbaceous plants (> 6 in high) > 1/3 area of the wetland ☐ Trees, shrubs, and ungrazed herbaceous < 1/3 area of the wetland	points = 8 points = 6 points = 6 points = 3 points = 0	8
Total for R 1	Add the points in the boxes above	10

Rating of Site Potential If score is: ☐**12-16 = H** ☒**6-11 = M** ☐**0-5 = L** *Record the rating on the first page*

R 2.0. Does the landscape have the potential to support the water quality function of the site?		
R 2.1. Is the wetland within an incorporated city or within its UGA?	☒Yes = 2 ☐ No = 0	2
R 2.2. Does the contributing basin to the wetland include a UGA or incorporated area?	☒Yes = 1 ☐ No = 0	1
R 2.3. Does at least 10% of the contributing basin contain tilled fields, pastures, or forests that have been clearcut within the last 5 years?	☐Yes = 1 ☒ No = 0	0
R 2.4. Is > 10% of the area within 150 ft of the wetland in land uses that generate pollutants?	☒Yes = 1 ☐ No = 0	1
R 2.5. Are there other sources of pollutants coming into the wetland that are not listed in questions R 2.1-R 2.4 Other sources:	☐Yes = 1 ☒ No = 0	0
Total for R 2	Add the points in the boxes above	4

Rating of Landscape Potential If score is: ☒**3-6 = H** ☐**1 or 2 = M** ☐**0 = L** *Record the rating on the first page*

R 3.0. Is the water quality improvement provided by the site valuable to society?		
R 3.1. Is the wetland along a stream or river that is on the 303(d) list or on a tributary that drains to one within 1 mi?	☒Yes = 1 ☐ No = 0	1
R 3.2. Is the wetland along a stream or river that has TMDL limits for nutrients, toxics, or pathogens?	☐Yes = 1 ☒ No = 0	0
R 3.3. Has the site been identified in a watershed or local plan as important for maintaining water quality? (*Answer **YES** if there is a TMDL for the drainage in which the unit is found*)	☐Yes = 2 ☒ No = 0	0
Total for R 3	Add the points in the boxes above	1

Rating of Value If score is: ☐**2-4 = H** ☒**1 = M** ☐**0 = L** *Record the rating on the first page*

RIVERINE AND FRESHWATER TIDAL FRINGE WETLANDS

Hydrologic Functions - Indicators that site functions to reduce flooding and stream erosion

R 4.0. Does the site have the potential to reduce flooding and erosion?	
R 4.1. Characteristics of the overbank storage the wetland provides: *Estimate the average width of the wetland perpendicular to the direction of the flow and the width of the stream or river channel (distance between banks). Calculate the ratio: (average width of wetland)/(average width of stream between banks).* ☐ If the ratio is more than 20 points = 9 ☐ If the ratio is 10-20 points = 6 ☒ If the ratio is 5-<10 points = 4 ☐ If the ratio is 1-<5 points = 2 ☐ If the ratio is < 1 points = 1	4
R 4.2. Characteristics of plants that slow down water velocities during floods: *Treat large woody debris as forest or shrub. Choose the points appropriate for the best description (polygons need to have >90% cover at person height. These are NOT Cowardin classes).* ☒ Forest or shrub for > 1/3 area OR emergent plants > 2/3 area points = 7 ☐ Forest or shrub for > 1/10 area OR emergent plants > 1/3 area points = 4 ☐ Plants do not meet above criteria points = 0	7
Total for R 4 Add the points in the boxes above	11

Rating of Site Potential If score is: ☐**12-16 = H** ☒**6-11 = M** ☐**0-5 = L** *Record the rating on the first page*

R 5.0. Does the landscape have the potential to support the hydrologic functions of the site?		
R 5.1. Is the stream or river adjacent to the wetland downcut?	☒Yes = 0 ☐ No = 1	0
R 5.2. Does the up-gradient watershed include a UGA or incorporated area?	☒Yes = 1 ☐ No = 0	1
R 5.3. Is the up-gradient stream or river controlled by dams?	☐Yes = 0 ☒ No = 1	1
Total for R 5	Add the points in the boxes above	2

Rating of Landscape Potential If score is: ☐**3 = H** ☒**1 or 2 = M** ☐**0 = L** *Record the rating on the first page*

R 6.0. Are the hydrologic functions provided by the site valuable to society?	
R 6.1. Distance to the nearest areas downstream that have flooding problems? *Choose the description that best fits the site.* ☒ The sub-basin immediately down-gradient of the wetland has flooding problems that result in damage to human or natural resources (e.g., houses or salmon redds) points = 2 ☐ Surface flooding problems are in a sub-basin farther down-gradient points = 1 ☐ No flooding problems anywhere downstream points = 0	2
R 6.2. Has the site been identified as important for flood storage or flood conveyance in a regional flood control plan? ☐Yes = 2 ☒ No = 0	0
Total for R 6 Add the points in the boxes above	2

Rating of Value If score is: ☒**2-4 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

These questions apply to wetlands of all HGM classes.

HABITAT FUNCTIONS - Indicators that site functions to provide important habitat

H 1.0. Does the site have the potential to provide habitat?

H 1.1. Structure of plant community: *Indicators are Cowardin classes and strata within the Forested class.* Check the Cowardin plant classes in the wetland. *Up to 10 patches may be combined for each class to meet the threshold of ¼ ac or more than 10% of the unit if it is smaller than 2.5 ac. Add the number of structures checked.*

- ☐ Aquatic bed — 4 structures or more: points = 4
- ☒ Emergent — 3 structures: points = 2
- ☒ Scrub-shrub (areas where shrubs have > 30% cover) — 2 structures: points = 1
- ☒ Forested (areas where trees have > 30% cover) — 1 structure: points = 0

If the unit has a Forested class, check if:

- ☒ The Forested class has 3 out of 5 strata (canopy, sub-canopy, shrubs, herbaceous, moss/ground-cover) that each cover 20% within the Forested polygon

4

H 1.2. Hydroperiods

Check the types of water regimes (hydroperiods) present within the wetland. The water regime has to cover more than 10% of the wetland or ¼ ac to count (*see text for descriptions of hydroperiods*).

- ☐ Permanently flooded or inundated — 4 or more types present: points = 3
- ☐ Seasonally flooded or inundated — 3 types present: points = 2
- ☒ Occasionally flooded or inundated — 2 types present: points = 1
- ☒ Saturated only — 1 type present: points = 0
- ☒ Permanently flowing stream or river in, or adjacent to, the wetland
- ☐ Seasonally flowing stream in, or adjacent to, the wetland
- ☐ **Lake Fringe wetland** — **2 points**
- ☐ **Freshwater tidal wetland** — **2 points**

2

H 1.3. Richness of plant species

Count the number of plant species in the wetland that cover at least 10 ft^2.

Different patches of the same species can be combined to meet the size threshold and you do not have to name the species. ***Do not include Eurasian milfoil, reed canarygrass, purple loosestrife, Canadian thistle***

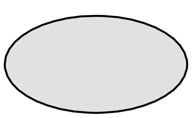
If you counted:

- ☐ > 19 species — points = 2
- ☒ 5 - 19 species — points = 1
- ☐ < 5 species — points = 0

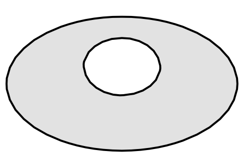
1

H 1.4. Interspersion of habitats

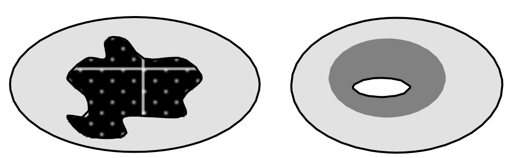
Decide from the diagrams below whether interspersion among Cowardin plants classes (described in H 1.1), or the classes and unvegetated areas (can include open water or mudflats) is high, moderate, low, or none. *If you have four or more plant classes or three classes and open water, the rating is always high.*



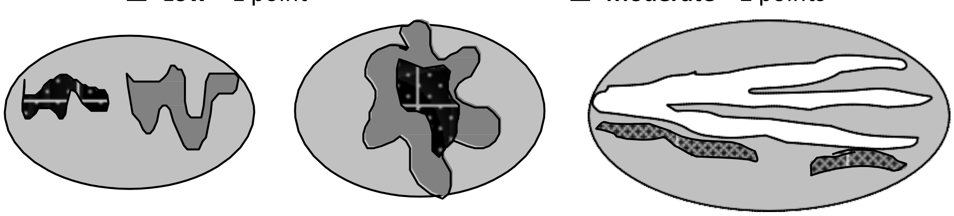
☐ **None** = 0 points



☐ **Low** = 1 point



☐ **Moderate** = 2 points



All three diagrams in this row are

☒ **HIGH** = 3points

3

H 1.5. Special habitat features: Check the habitat features that are present in the wetland. *The number of checks is the number of points.* ☒ Large, downed, woody debris within the wetland (> 4 in diameter and 6 ft long). ☒ Standing snags (dbh > 4 in) within the wetland. ☒ Undercut banks are present for at least 6.6 ft (2 m) **AND/OR** overhanging plants extends at least 3.3 ft (1 m) over a stream (or ditch) in, or contiguous with the wetland, for at least 33 ft (10 m). ☐ Stable steep banks of fine material that might be used by beaver or muskrat for denning (> 30 degree slope) **OR** signs of recent beaver activity are present *(cut shrubs or trees that have not yet weathered where wood is exposed).* ☐ At least ¼ ac of thin-stemmed persistent plants or woody branches are present in areas that are permanently or seasonally inundated *(structures for egg-laying by amphibians).* ☐ Invasive plants cover less than 25% of the wetland area in every stratum of plants (*see H 1.1 for list of strata*).	3
Total for H 1 — Add the points in the boxes above	13

Rating of Site Potential If score is: ☐**15-18 = H** ☒**7-14 = M** ☐**0-6 = L** *Record the rating on the first page*

H 2.0. Does the landscape have the potential to support the habitat functions of the site?	
H 2.1. Accessible habitat (include *only habitat that directly abuts wetland unit*). *Calculate:* % undisturbed habitat + [(%moderate and low intensity land uses)/2] = **3.0% + (0%/2) = 3.0%** If total accessible habitat is: ☐ > 1/3 (33.3%) of 1 km Polygon — points = 3 ☐ 20-33% of 1 km Polygon — points = 2 ☐ 10-19% of 1 km Polygon — points = 1 ☒ < 10% of 1 km Polygon — points = 0	0
H 2.2. Undisturbed habitat in 1 km Polygon around the wetland. *Calculate:* % undisturbed habitat + [(%moderate and low intensity land uses)/2 **= 13.8% + (0%/2) = 13.8%** ☐ Undisturbed habitat > 50% of Polygon — points = 3 ☐ Undisturbed habitat 10-50% and in 1-3 patches — points = 2 ☒ Undisturbed habitat 10-50% and > 3 patches — points = 1 ☐ Undisturbed habitat < 10% of 1 km Polygon — points = 0	1
H 2.3. Land use intensity in 1 km Polygon: If ☒ > 50% of 1 km Polygon is high intensity land use — points = (- 2) ☐ ≤ 50% of 1 km Polygon is high intensity — points = 0	-2
Total for H 2 — Add the points in the boxes above	-1

Rating of Landscape Potential If score is: ☐**4-6 = H** ☐**1-3 = M** ☒**< 1 = L** *Record the rating on the first page*

H 3.0. Is the habitat provided by the site valuable to society?	
H 3.1. Does the site provide habitat for species valued in laws, regulations, or policies? *Choose only the highest score that applies to the wetland being rated.* Site meets ANY of the following criteria: — points = 2 ☒ It has 3 or more priority habitats within 100 m (see next page) ☐ It provides habitat for Threatened or Endangered species (any plant or animal on the state or federal lists) ☐ It is mapped as a location for an individual WDFW priority species ☐ It is a Wetland of High Conservation Value as determined by the Department of Natural Resources ☐ It has been categorized as an important habitat site in a local or regional comprehensive plan, in a Shoreline Master Plan, or in a watershed plan ☐ Site has 1 or 2 priority habitats (listed on next page) within 100 m — points = 1 ☐ Site does not meet any of the criteria above — points = 0	2

Rating of Value If score is: ☒**2 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

WDFW Priority Habitats

Priority habitats listed by WDFW (see complete descriptions of WDFW priority habitats, and the counties in which they can be found, in: Washington Department of Fish and Wildlife. 2008. Priority Habitat and Species List. Olympia, Washington. 177 pp. http://wdfw.wa.gov/publications/00165/wdfw00165.pdf or access the list from here: http://wdfw.wa.gov/conservation/phs/list/)

Count how many of the following priority habitats are within 330 ft (100 m) of the wetland unit: ***NOTE:*** *This question is independent of the land use between the wetland unit and the priority habitat.*

☐ **Aspen Stands:** Pure or mixed stands of aspen greater than 1 ac (0.4 ha).

☐ **Biodiversity Areas and Corridors**: Areas of habitat that are relatively important to various species of native fish and wildlife (*full descriptions in WDFW PHS report*).

☐ **Herbaceous Balds:** Variable size patches of grass and forbs on shallow soils over bedrock.

☐ **Old-growth/Mature forests:** Old-growth west of Cascade crest – Stands of at least 2 tree species, forming a multi- layered canopy with occasional small openings; with at least 8 trees/ac (20 trees/ha) > 32 in (81 cm) dbh or > 200 years of age. Mature forests – Stands with average diameters exceeding 21 in (53 cm) dbh; crown cover may be less than 100%; decay, decadence, numbers of snags, and quantity of large downed material is generally less than that found in old-growth; 80-200 years old west of the Cascade crest.

☐ **Oregon White Oak:** Woodland stands of pure oak or oak/conifer associations where canopy coverage of the oak component is important (*full descriptions in WDFW PHS report p. 158 – see web link above*).

☒ **Riparian**: The area adjacent to aquatic systems with flowing water that contains elements of both aquatic and terrestrial ecosystems which mutually influence each other.

☐ **Westside Prairies:** Herbaceous, non-forested plant communities that can either take the form of a dry prairie or a wet prairie (*full descriptions in WDFW PHS report p. 161 – see web link above*).

☒ **Instream:** The combination of physical, biological, and chemical processes and conditions that interact to provide functional life history requirements for instream fish and wildlife resources.

☐ **Nearshore**: Relatively undisturbed nearshore habitats. These include Coastal Nearshore, Open Coast Nearshore, and Puget Sound Nearshore. (*full descriptions of habitats and the definition of relatively undisturbed are in WDFW report – see web link on previous page).*

☐ **Caves:** A naturally occurring cavity, recess, void, or system of interconnected passages under the earth in soils, rock, ice, or other geological formations and is large enough to contain a human.

☐ **Cliffs:** Greater than 25 ft (7.6 m) high and occurring below 5000 ft elevation.

☐ **Talus:** Homogenous areas of rock rubble ranging in average size 0.5 - 6.5 ft (0.15 - 2.0 m), composed of basalt, andesite, and/or sedimentary rock, including riprap slides and mine tailings. May be associated with cliffs.

☒ **Snags and Logs:** Trees are considered snags if they are dead or dying and exhibit sufficient decay characteristics to enable cavity excavation/use by wildlife. Priority snags have a diameter at breast height of > 20 in (51 cm) in western Washington and are > 6.5 ft (2 m) in height. Priority logs are > 12 in (30 cm) in diameter at the largest end, and > 20 ft (6 m) long.

Note: All vegetated wetlands are by definition a priority habitat but are not included in this list because they are addressed elsewhere.

RATING SUMMARY – Western Washington

Name of wetland: Richards Creek Substation – Wetland H Date of site visit: 7/1/2015, 5/8/2017

Rated by: R. Kahlo, A. Hoenig, K. Crandall Trained by Ecology? ☒Y ☐N Date of training: 09/2014

HGM Class used for rating: Slope Wetland has multiple HGM classes? ☐Y ☒N

NOTE: **Form is not complete without the figures requested** *(figures can be combined)*.
Source of base aerial photo/map: King County iMap and Google Earth

OVERALL WETLAND CATEGORY (based on functions ☒ or special characteristics ☐)

1. Category of wetland based on FUNCTIONS

☐ **Category I** – Total score = 23 - 27

☐ **Category II** – Total score = 20 - 22

☒ **Category III** – Total score = 16 - 19

☐ **Category IV** – Total score = 9 - 15

FUNCTION	Improving Water Quality	Hydrologic	Habitat	
			Circle the appropriate ratings	
Site Potential	H M L (L circled)	H M L (M circled)	H M L (M circled)	
Landscape Potential	H M L (M circled)	H M L (L circled)	H M L (L circled)	
Value	H M L (H circled)	H M L (H circled)	H M L (H circled)	**TOTAL**
Score Based on Ratings	6	6	6	18

Score for each function based on three ratings *(order of ratings is not important)*

9 = H,H,H
8 = H,H,M
7 = H,H,L
7 = H,M,M
6 = H,M,L
6 = M,M,M
5 = H,L,L
5 = M,M,L
4 = M,L,L
3 = L,L,L

2. Category based on SPECIAL CHARACTERISTICS of wetland

CHARACTERISTIC	CATEGORY
Estuarine	I II
Wetland of High Conservation Value	I
Bog	I
Mature Forest	I
Old Growth Forest	I
Coastal Lagoon	I II
Interdunal	I II III IV
None of the above	☒

Maps and figures required to answer questions correctly for Western Washington

Slope Wetlands

Map of:	To answer questions:	Figure #
Cowardin plant classes	H 1.1, H 1.4	4
Hydroperiods	H 1.2	5
Plant cover of **dense** trees, shrubs, and herbaceous plants	S 1.3	6
Plant cover of **dense, rigid** trees, shrubs, and herbaceous plants (*can be added to figure above)*	S 4.1	6
Boundary of 150 ft buffer (can be added to another figure)	S 2.1, S 5.1	4
1 km Polygon: Area that extends 1 km from entire wetland edge - including polygons for accessible habitat and undisturbed habitat	H 2.1, H 2.2, H 2.3	8
Screen capture of map of 303(d) listed waters in basin (from Ecology website)	S 3.1, S 3.2	9
Screen capture of list of TMDLs for WRIA in which unit is found (from web)	S 3.3	10

HGM Classification of Wetlands in Western Washington

For questions 1-7, the criteria described must apply to the entire unit being rated.

If the hydrologic criteria listed in each question do not apply to the entire unit being rated, you probably have a unit with multiple HGM classes. In this case, identify which hydrologic criteria in questions 1-7 apply, and go to Question 8.

1. Are the water levels in the entire unit usually controlled by tides except during floods?

   ☒NO – go to 2 ☐**YES** – the wetland class is **Tidal Fringe** – go to 1.1

   1.1 Is the salinity of the water during periods of annual low flow below 0.5 ppt (parts per thousand)?

   NO – Saltwater Tidal Fringe (Estuarine) **YES – Freshwater Tidal Fringe**
   If your wetland can be classified as a Freshwater Tidal Fringe use the forms for ***Riverine*** *wetlands. If it is Saltwater Tidal Fringe it is an* ***Estuarine*** *wetland and is not scored. This method* ***cannot*** *be used to score functions for estuarine wetlands.*

2. The entire wetland unit is flat and precipitation is the only source (>90%) of water to it. Groundwater and surface water runoff are NOT sources of water to the unit.

   ☒NO – go to 3 ☐**YES –** The wetland class is **Flats**
   If your wetland can be classified as a Flats wetland, use the form for ***Depressional*** *wetlands.*

3. Does the entire wetland unit **meet all** of the following criteria?
   ☐The vegetated part of the wetland is on the shores of a body of permanent open water (without any plants on the surface at any time of the year) at least 20 ac (8 ha) in size;
   ☐At least 30% of the open water area is deeper than 6.6 ft (2 m).

   ☒NO – go to 4 ☐**YES –** The wetland class is **Lake Fringe** (Lacustrine Fringe)

4. Does the entire wetland unit **meet all** of the following criteria?
   ☒The wetland is on a slope (*slope can be very gradual*),
   ☒The water flows through the wetland in one direction (unidirectional) and usually comes from seeps. It may flow subsurface, as sheetflow, or in a swale without distinct banks,
   ☒The water leaves the wetland **without being impounded.**

   ☐NO – go to 5 ☒**YES –** The wetland class is **Slope**

   NOTE: Surface water does not pond in these type of wetlands except occasionally in very small and shallow depressions or behind hummocks (depressions are usually <3 ft diameter and less than 1 ft deep).

5. Does the entire wetland unit **meet all** of the following criteria?
   ☐The unit is in a valley, or stream channel, where it gets inundated by overbank flooding from that stream or river,
   ☐The overbank flooding occurs at least once every 2 years.

☐NO – go to 6 ☐**YES –** The wetland class is **Riverine**

NOTE: The Riverine unit can contain depressions that are filled with water when the river is not flooding

6. Is the entire wetland unit in a topographic depression in which water ponds, or is saturated to the surface, at some time during the year? *This means that any outlet, if present, is higher than the interior of the wetland.*

☐NO – go to 7 ☐**YES** – The wetland class is **Depressional**

7. Is the entire wetland unit located in a very flat area with no obvious depression and no overbank flooding? The unit does not pond surface water more than a few inches. The unit seems to be maintained by high groundwater in the area. The wetland may be ditched, but has no obvious natural outlet.

☐NO – go to 8 ☐**YES** – The wetland class is **Depressional**

8. Your wetland unit seems to be difficult to classify and probably contains several different HGM classes. For example, seeps at the base of a slope may grade into a riverine floodplain, or a small stream within a Depressional wetland has a zone of flooding along its sides. GO BACK AND IDENTIFY WHICH OF THE HYDROLOGIC REGIMES DESCRIBED IN QUESTIONS 1-7 APPLY TO DIFFERENT AREAS IN THE UNIT (make a rough sketch to help you decide). Use the following table to identify the appropriate class to use for the rating system if you have several HGM classes present within the wetland unit being scored.

NOTE: Use this table only if the class that is recommended in the second column represents 10% or more of the total area of the wetland unit being rated. If the area of the HGM class listed in column 2 is less than 10% of the unit; classify the wetland using the class that represents more than 90% of the total area.

HGM classes within the wetland unit being rated	HGM class to use in rating
Slope + Riverine	Riverine
Slope + Depressional	Depressional
Slope + Lake Fringe	Lake Fringe
Depressional + Riverine along stream within boundary of depression	Depressional
Depressional + Lake Fringe	Depressional
Riverine + Lake Fringe	Riverine
Salt Water Tidal Fringe and any other class of freshwater wetland	Treat as ESTUARINE

If you are still unable to determine which of the above criteria apply to your wetland, or if you have ***more than 2 HGM classes*** *within a wetland boundary, classify the wetland as Depressional for the rating.*

SLOPE WETLANDS

Water Quality Functions - Indicators that the site functions to improve water quality

S 1.0. Does the site have the potential to improve water quality?	
S 1.1. Characteristics of the average slope of the wetland: *(a 1% slope has a 1 ft vertical drop in elevation for every 100 ft of horizontal distance)* ☐ Slope is 1% or less — points = 3 ☐ Slope is > 1%-2% — points = 2 ☐ Slope is > 2%-5% — points = 1 ☒ Slope is greater than 5% — points = 0	0
S 1.2. The soil 2 in below the surface (or duff layer) is true clay or true organic *(use NRCS definitions)*: Yes = 3 No = 0	0
S 1.3. Characteristics of the plants in the wetland that trap sediments and pollutants: Choose the points appropriate for the description that best fits the plants in the wetland. *Dense means you have trouble seeing the soil surface (>75% cover), and uncut means not grazed or mowed and plants are higher than 6 in.* ☐ Dense, uncut, herbaceous plants > 90% of the wetland area — points = 6 ☒ Dense, uncut, herbaceous plants > ½ of area — points = 3 ☐ Dense, woody, plants > ½ of area — points = 2 ☐ Dense, uncut, herbaceous plants > ¼ of area — points = 1 ☐ Does not meet any of the criteria above for plants — points = 0	3
Total for S 1 — Add the points in the boxes above	3

Rating of Site Potential If score is: ☐**12 = H** ☐**6-11 = M** ☒**0-5 = L** *Record the rating on the first page*

S 2.0. Does the landscape have the potential to support the water quality function of the site?	
S 2.1. Is > 10% of the area within 150 ft on the uphill side of the wetland in land uses that generate pollutants? ☒Yes = 1 ☐ No = 0	1
S 2.2. Are there other sources of pollutants coming into the wetland that are not listed in question S 2.1? Other sources____________________ ☐Yes = 1 ☒ No = 0	0
Total for S 2 — Add the points in the boxes above	1

Rating of Landscape Potential If score is: ☒**1-2 = M** ☐**0 = L** *Record the rating on the first page*

S 3.0. Is the water quality improvement provided by the site valuable to society?	
S 3.1. Does the wetland discharge directly (i.e., within 1 mi) to a stream, river, lake, or marine water that is on the 303(d) list? ☒Yes = 1 ☐ No = 0	1
S 3.2. Is the wetland in a basin or sub-basin where water quality is an issue? *At least one aquatic resource in the basin is on the 303(d) list.* ☒Yes = 1 ☐ No = 0	1
S 3.3. Has the site been identified in a watershed or local plan as important for maintaining water quality? *Answer YES if there is a TMDL for the basin in which unit is found.* ☐Yes = 2 ☒ No = 0	0
Total for S 3 — Add the points in the boxes above	2

Rating of Value If score is: ☒**2-4 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

SLOPE WETLANDS

Hydrologic Functions - Indicators that the site functions to reduce flooding and stream erosion

S 4.0. Does the site have the potential to reduce flooding and stream erosion?	
S 4.1. Characteristics of plants that reduce the velocity of surface flows during storms: Choose the points appropriate for the description that best fits conditions in the wetland. *Stems of plants should be thick enough (usually >1/8$_8$ in), or dense enough, to remain erect during surface flows.* ☒ Dense, uncut, **rigid** plants cover > 90% of the area of the wetland points = 1 ☐ All other conditions points = 0	1

Rating of Site Potential If score is**:** ☒**1 = M** ☐**0 = L** *Record the rating on the first page*

S 5.0. Does the landscape have the potential to support the hydrologic functions of the site?	
S 5.1. Is more than 25% of the area within 150 ft upslope of wetland in land uses or cover that generate excess surface runoff? ☐Yes = 1 ☒ No = 0	0

Rating of Landscape Potential If score is: ☐**1 = M** ☒**0 = L** *Record the rating on the first page*

S 6.0. Are the hydrologic functions provided by the site valuable to society?	
S 6.1. Distance to the nearest areas downstream that have flooding problems: ☒ The sub-basin immediately down-gradient of site has flooding problems that result in damage to human or natural resources (e.g., houses or salmon redds) points = 2 ☐ Surface flooding problems are in a sub-basin farther down-gradient points = 1 ☐ No flooding problems anywhere downstream points = 0	2
S 6.2. Has the site been identified as important for flood storage or flood conveyance in a regional flood control plan? ☐Yes = 2 ☒ No = 0	0
Total for S 6 Add the points in the boxes above	2

Rating of Value If score is: ☒**2-4 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

NOTES and FIELD OBSERVATIONS:

These questions apply to wetlands of all HGM classes.

HABITAT FUNCTIONS - Indicators that site functions to provide important habitat

H 1.0. Does the site have the potential to provide habitat?

H 1.1. Structure of plant community: *Indicators are Cowardin classes and strata within the Forested class.* Check the Cowardin plant classes in the wetland. *Up to 10 patches may be combined for each class to meet the threshold of ¼ ac or more than 10% of the unit if it is smaller than 2.5 ac. Add the number of structures checked.*

☐ Aquatic bed	4 structures or more: points = 4
☒ Emergent	3 structures: points = 2
☒ Scrub-shrub (areas where shrubs have > 30% cover)	2 structures: points = 1
☒ Forested (areas where trees have > 30% cover)	1 structure: points = 0

If the unit has a Forested class, check if:

☐ The Forested class has 3 out of 5 strata (canopy, sub-canopy, shrubs, herbaceous, moss/ground-cover) that each cover 20% within the Forested polygon

Points: 2

H 1.2. Hydroperiods

Check the types of water regimes (hydroperiods) present within the wetland. The water regime has to cover more than 10% of the wetland or ¼ ac to count (*see text for descriptions of hydroperiods*).

☐ Permanently flooded or inundated	4 or more types present: points = 3
☐ Seasonally flooded or inundated	3 types present: points = 2
☒ Occasionally flooded or inundated	2 types present: points = 1
☒ Saturated only	1 type present: points = 0
☐ Permanently flowing stream or river in, or adjacent to, the wetland	
☐ Seasonally flowing stream in, or adjacent to, the wetland	
☐ **Lake Fringe wetland**	**2 points**
☐ **Freshwater tidal wetland**	**2 points**

Points: 1

H 1.3. Richness of plant species

Count the number of plant species in the wetland that cover at least 10 ft^2.

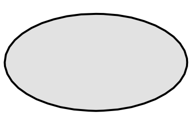
Different patches of the same species can be combined to meet the size threshold and you do not have to name the species. ***Do not include Eurasian milfoil, reed canarygrass, purple loosestrife, Canadian thistle***

If you counted:		
	☒ > 19 species	points = 2
	☐ 5 - 19 species (SASC, TEGR, BUTTERFLY BUSH, EQGI, GAAP, RUAR)	points = 1
	☐ < 5 species	points = 0

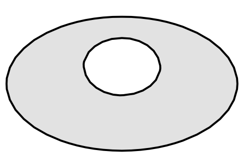
Points: 2

H 1.4. Interspersion of habitats

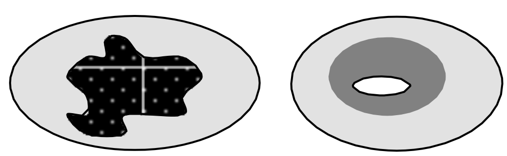
Decide from the diagrams below whether interspersion among Cowardin plants classes (described in H 1.1), or the classes and unvegetated areas (can include open water or mudflats) is high, moderate, low, or none. *If you have four or more plant classes or three classes and open water, the rating is always high.*



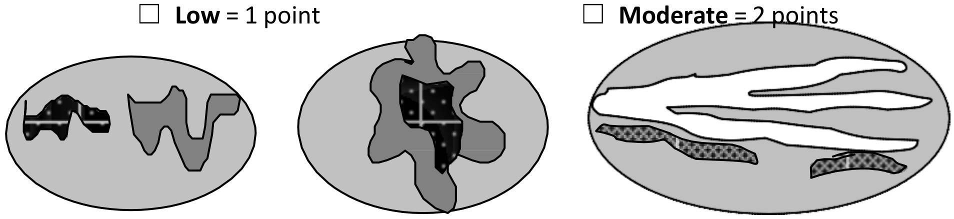
☐ **None** = 0 points



☐ **Low** = 1 point



☐ **Moderate** = 2 points



All three diagrams in this row are

☒ **HIGH** = 3points

Points: 3

DSD 010056

H 1.5. Special habitat features: Check the habitat features that are present in the wetland. *The number of checks is the number of points.* ☒ Large, downed, woody debris within the wetland (> 4 in diameter and 6 ft long). ☒ Standing snags (dbh > 4 in) within the wetland. ☒ Undercut banks are present for at least 6.6 ft (2 m) **AND/OR** overhanging plants extends at least 3.3 ft (1 m) over a stream (or ditch) in, or contiguous with the wetland, for at least 33 ft (10 m). ☐ Stable steep banks of fine material that might be used by beaver or muskrat for denning (> 30 degree slope) **OR** signs of recent beaver activity are present *(cut shrubs or trees that have not yet weathered where wood is exposed).* ☐ At least ¼ ac of thin-stemmed persistent plants or woody branches are present in areas that are permanently or seasonally inundated *(structures for egg-laying by amphibians).* ☐ Invasive plants cover less than 25% of the wetland area in every stratum of plants (*see H 1.1 for list of strata*).	3
Total for H 1 Add the points in the boxes above	11

Rating of Site Potential If score is: ☐**15-18 = H** ☒**7-14 = M** ☐**0-6 = L** *Record the rating on the first page*

H 2.0. Does the landscape have the potential to support the habitat functions of the site?	
H 2.1. Accessible habitat (include *only habitat that directly abuts wetland unit*). *Calculate:* % undisturbed habitat + [(%moderate and low intensity land uses)/2] = **3.0% + (0%/2) = 3%** If total accessible habitat is: ☐ > 1/3 (33.3%) of 1 km Polygon points = 3 ☐ 20-33% of 1 km Polygon points = 2 ☐ 10-19% of 1 km Polygon points = 1 ☒ < 10% of 1 km Polygon points = 0	0
H 2.2. Undisturbed habitat in 1 km Polygon around the wetland. *Calculate:* % undisturbed habitat + [(%moderate and low intensity land uses)/2 **= 13.8% + (0%/2) = 13.8%** ☐ Undisturbed habitat > 50% of Polygon points = 3 ☐ Undisturbed habitat 10-50% and in 1-3 patches points = 2 ☒ Undisturbed habitat 10-50% and > 3 patches points = 1 ☐ Undisturbed habitat < 10% of 1 km Polygon points = 0	1
H 2.3. Land use intensity in 1 km Polygon: If ☒ > 50% of 1 km Polygon is high intensity land use points = (- 2) ☐ ≤ 50% of 1 km Polygon is high intensity points = 0	-2
Total for H 2 Add the points in the boxes above	-1

Rating of Landscape Potential If score is: ☐**4-6 = H** ☐**1-3 = M** ☒**< 1 = L** *Record the rating on the first page*

H 3.0. Is the habitat provided by the site valuable to society?	
H 3.1. Does the site provide habitat for species valued in laws, regulations, or policies? *Choose only the highest score that applies to the wetland being rated.* Site meets ANY of the following criteria: points = 2 ☒ It has 3 or more priority habitats within 100 m (see next page) ☐ It provides habitat for Threatened or Endangered species (any plant or animal on the state or federal lists) ☐ It is mapped as a location for an individual WDFW priority species ☐ It is a Wetland of High Conservation Value as determined by the Department of Natural Resources ☐ It has been categorized as an important habitat site in a local or regional comprehensive plan, in a Shoreline Master Plan, or in a watershed plan ☐ Site has 1 or 2 priority habitats (listed on next page) within 100 m points = 1 ☐ Site does not meet any of the criteria above points = 0	2

Rating of Value If score is: ☒**2 = H** ☐**1 = M** ☐**0 = L** *Record the rating on the first page*

WDFW Priority Habitats

Priority habitats listed by WDFW (see complete descriptions of WDFW priority habitats, and the counties in which they can be found, in: Washington Department of Fish and Wildlife. 2008. Priority Habitat and Species List. Olympia, Washington. 177 pp. http://wdfw.wa.gov/publications/00165/wdfw00165.pdf or access the list from here: http://wdfw.wa.gov/conservation/phs/list/)

Count how many of the following priority habitats are within 330 ft (100 m) of the wetland unit: ***NOTE:*** *This question is independent of the land use between the wetland unit and the priority habitat.*

☐ **Aspen Stands:** Pure or mixed stands of aspen greater than 1 ac (0.4 ha).

☐ **Biodiversity Areas and Corridors**: Areas of habitat that are relatively important to various species of native fish and wildlife (*full descriptions in WDFW PHS report*).

☐ **Herbaceous Balds:** Variable size patches of grass and forbs on shallow soils over bedrock.

☐ **Old-growth/Mature forests:** Old-growth west of Cascade crest – Stands of at least 2 tree species, forming a multi- layered canopy with occasional small openings; with at least 8 trees/ac (20 trees/ha) > 32 in (81 cm) dbh or > 200 years of age. Mature forests – Stands with average diameters exceeding 21 in (53 cm) dbh; crown cover may be less than 100%; decay, decadence, numbers of snags, and quantity of large downed material is generally less than that found in old-growth; 80-200 years old west of the Cascade crest.

☐ **Oregon White Oak:** Woodland stands of pure oak or oak/conifer associations where canopy coverage of the oak component is important (*full descriptions in WDFW PHS report p. 158 – see web link above*).

☒ **Riparian**: The area adjacent to aquatic systems with flowing water that contains elements of both aquatic and terrestrial ecosystems which mutually influence each other.

☐ **Westside Prairies:** Herbaceous, non-forested plant communities that can either take the form of a dry prairie or a wet prairie (*full descriptions in WDFW PHS report p. 161 – see web link above*).

☒ **Instream:** The combination of physical, biological, and chemical processes and conditions that interact to provide functional life history requirements for instream fish and wildlife resources.

☐ **Nearshore**: Relatively undisturbed nearshore habitats. These include Coastal Nearshore, Open Coast Nearshore, and Puget Sound Nearshore. (*full descriptions of habitats and the definition of relatively undisturbed are in WDFW report – see web link on previous page).*

☐ **Caves:** A naturally occurring cavity, recess, void, or system of interconnected passages under the earth in soils, rock, ice, or other geological formations and is large enough to contain a human.

☐ **Cliffs:** Greater than 25 ft (7.6 m) high and occurring below 5000 ft elevation.

☐ **Talus:** Homogenous areas of rock rubble ranging in average size 0.5 - 6.5 ft (0.15 - 2.0 m), composed of basalt, andesite, and/or sedimentary rock, including riprap slides and mine tailings. May be associated with cliffs.

☒ **Snags and Logs:** Trees are considered snags if they are dead or dying and exhibit sufficient decay characteristics to enable cavity excavation/use by wildlife. Priority snags have a diameter at breast height of > 20 in (51 cm) in western Washington and are > 6.5 ft (2 m) in height. Priority logs are > 12 in (30 cm) in diameter at the largest end, and > 20 ft (6 m) long.

Note: All vegetated wetlands are by definition a priority habitat but are not included in this list because they are addressed elsewhere.

2014 Ecology Wetland Rating Form Figures

PSE Richards Creek Substation

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WETLANDS A, B, AND C (SLOPE)

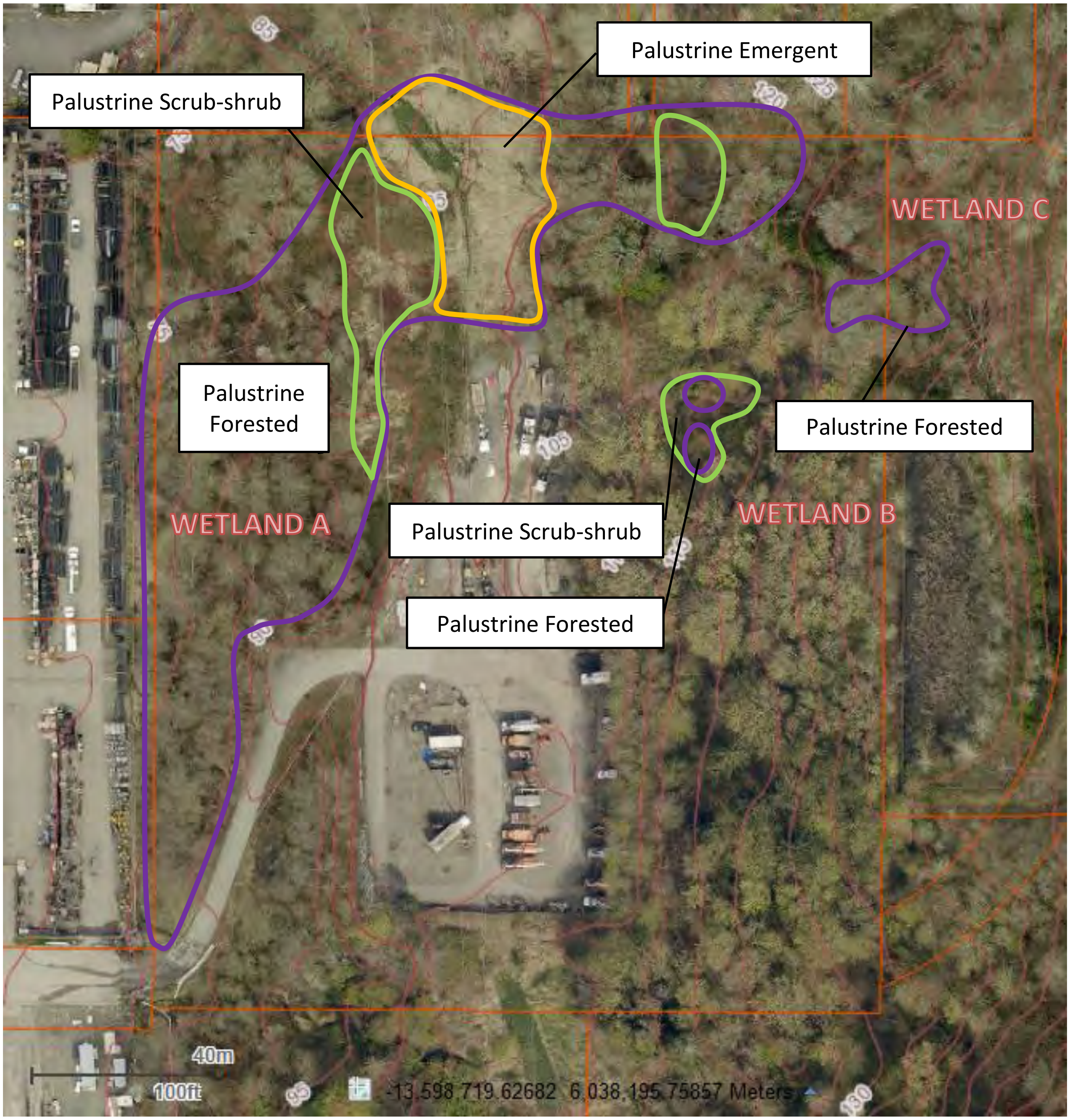


Figure 1. Cowardin plant classes – H1.1, H1.4

Features depicted are not be to scale. Sketches are based on available data and best professional judgment.

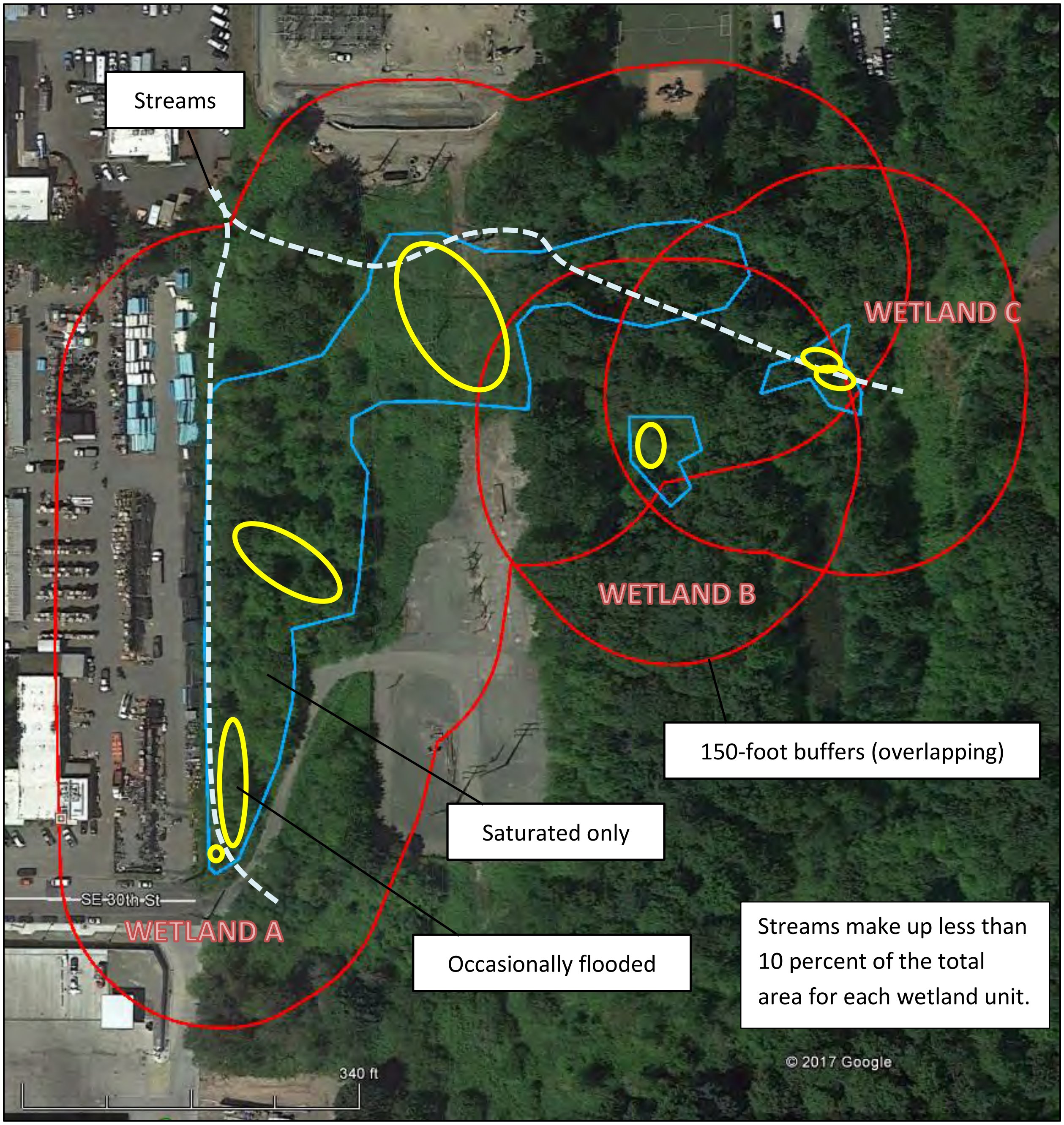


Figure 2. Hydroperiods and 150-foot buffer – H1.2, S2.1, S5.1

Features depicted are not be to scale. Sketches are based on available data and best professional judgment.

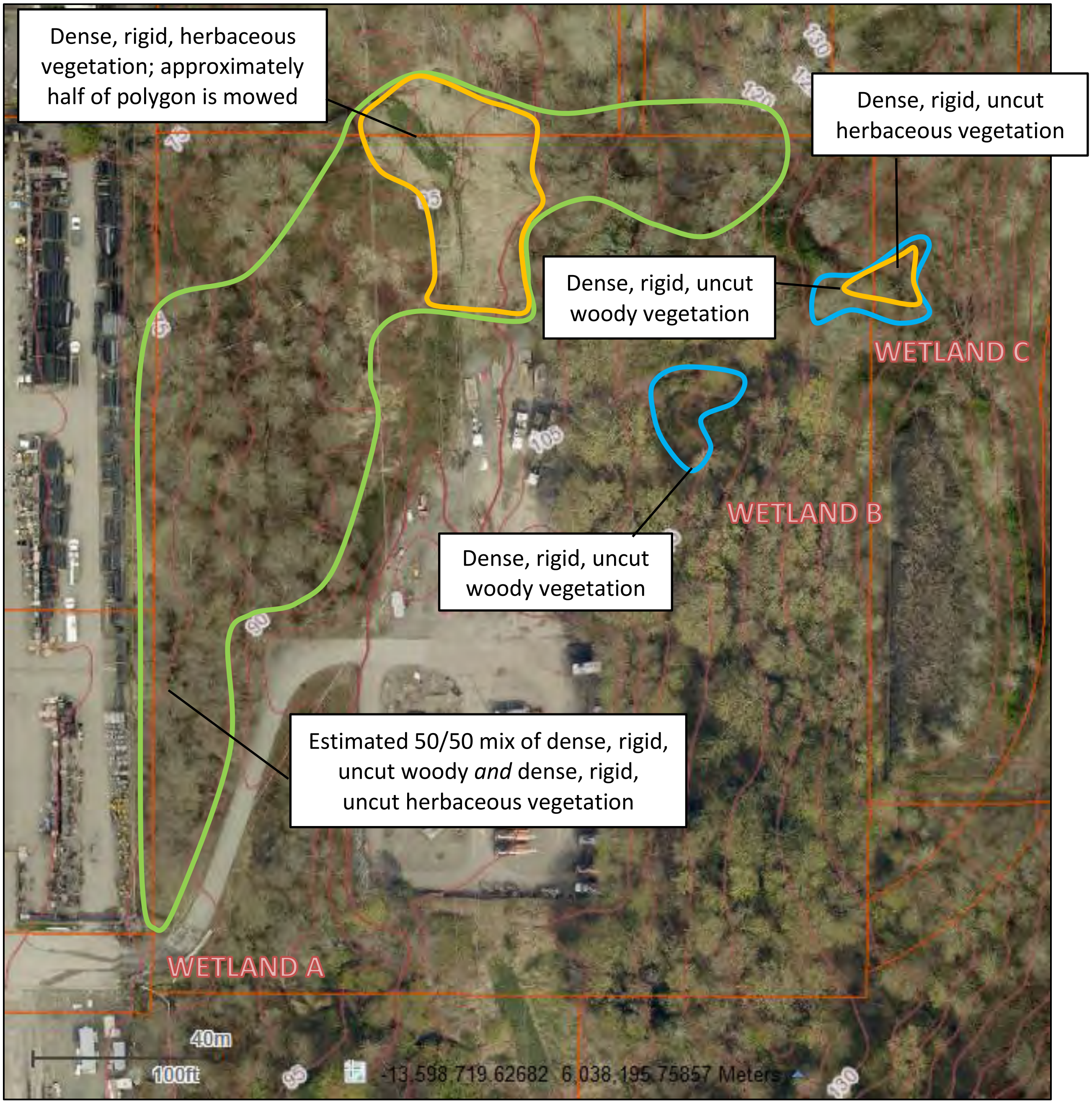


Figure 3. Plant cover of dense and rigid trees, shrubs, and herbaceous plants – S1.3, S4.1

Features depicted are not be to scale. Sketches are based on available data and best professional judgment.

WETLANDS D (RIVERINE) AND H (SLOPE)

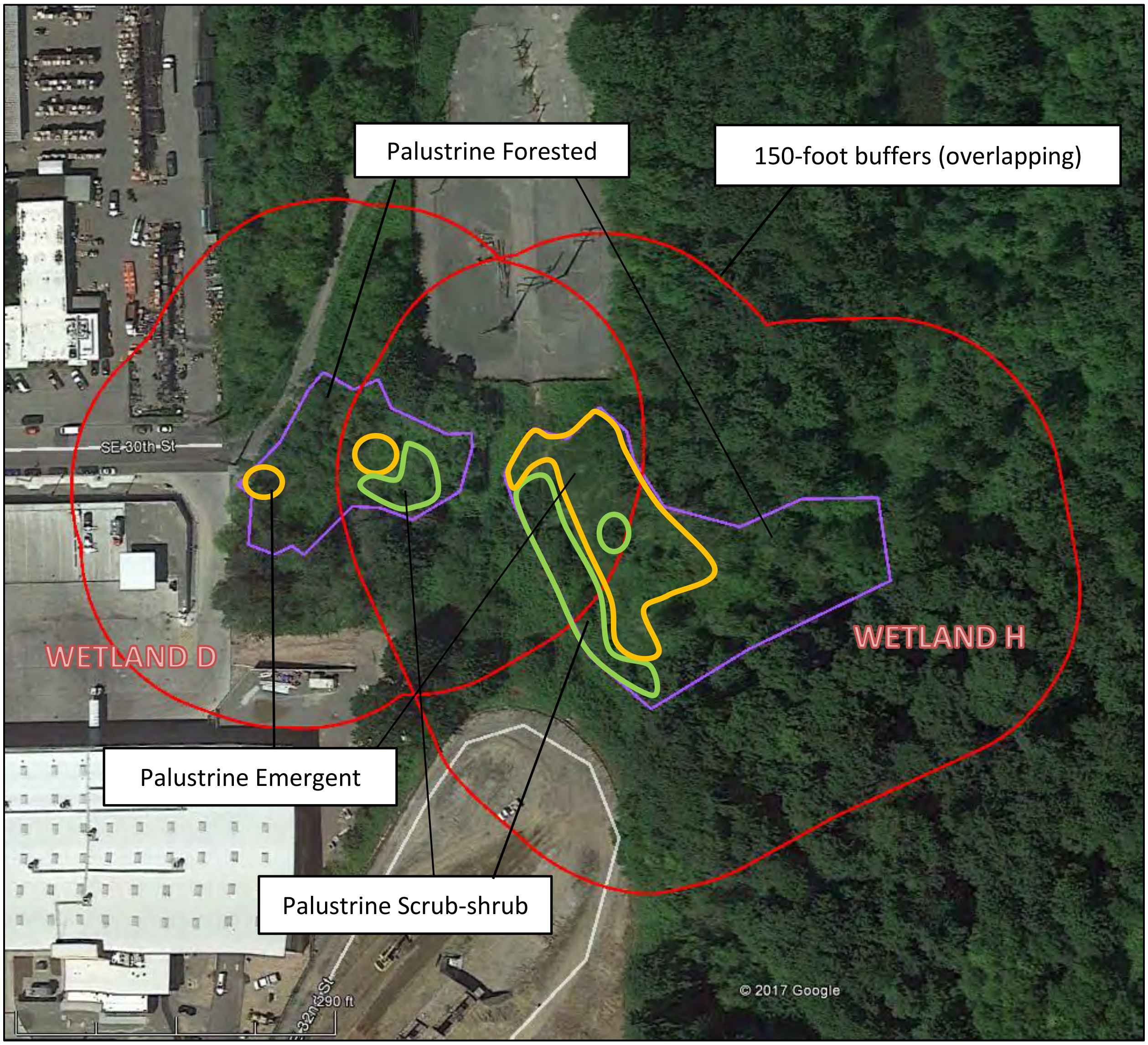


Figure 4. Cowardin plant classes and 150-ft buffer – H1.1, H1.4, R2.4, S2.1, S5.1

Features depicted are not be to scale. Sketches are based on available data and best professional judgment.

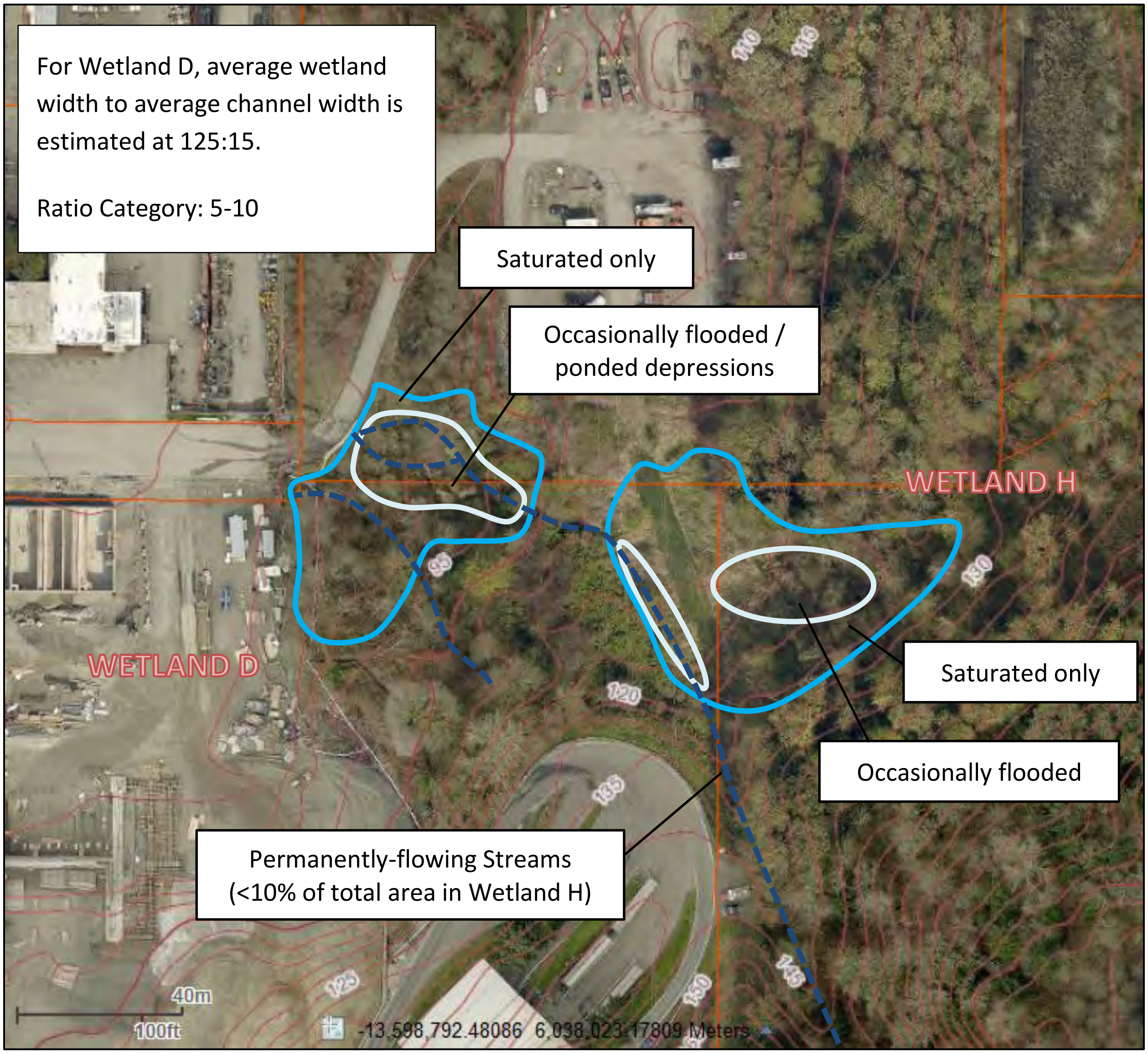


Figure 5. Hydroperiods, ponded depressions, and wetland-width-to-stream-width ratio – H1.2, R1.1, R4.1

Features depicted are not be to scale. Sketches are based on available data and best professional judgment.

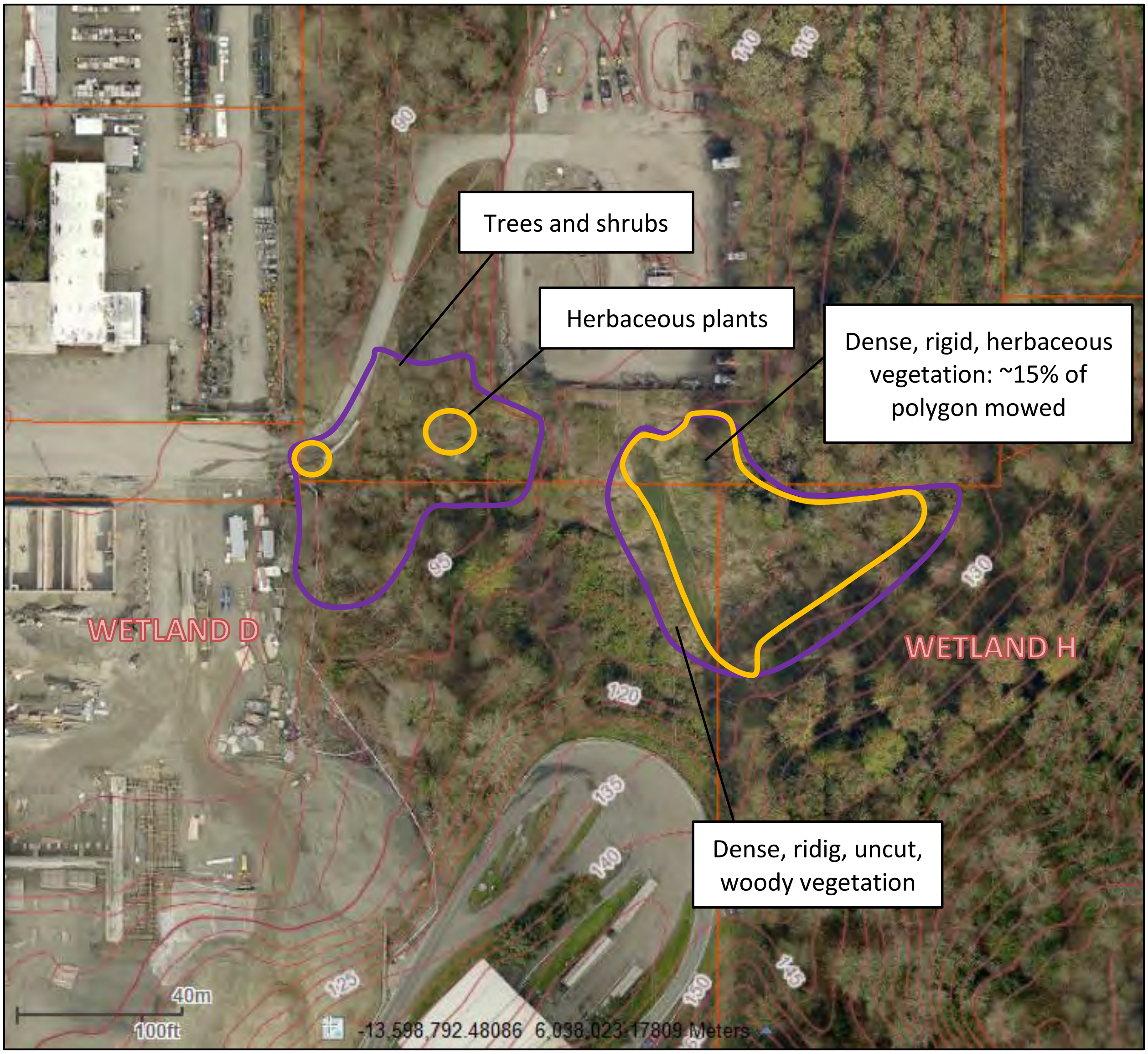


Figure 6. Plant cover of trees, shrubs, and herbaceous plants (not Cowardin) – R1.2, R4.2, S1.3, S4.1

Features depicted are not be to scale. Sketches are based on available data and best professional judgment.

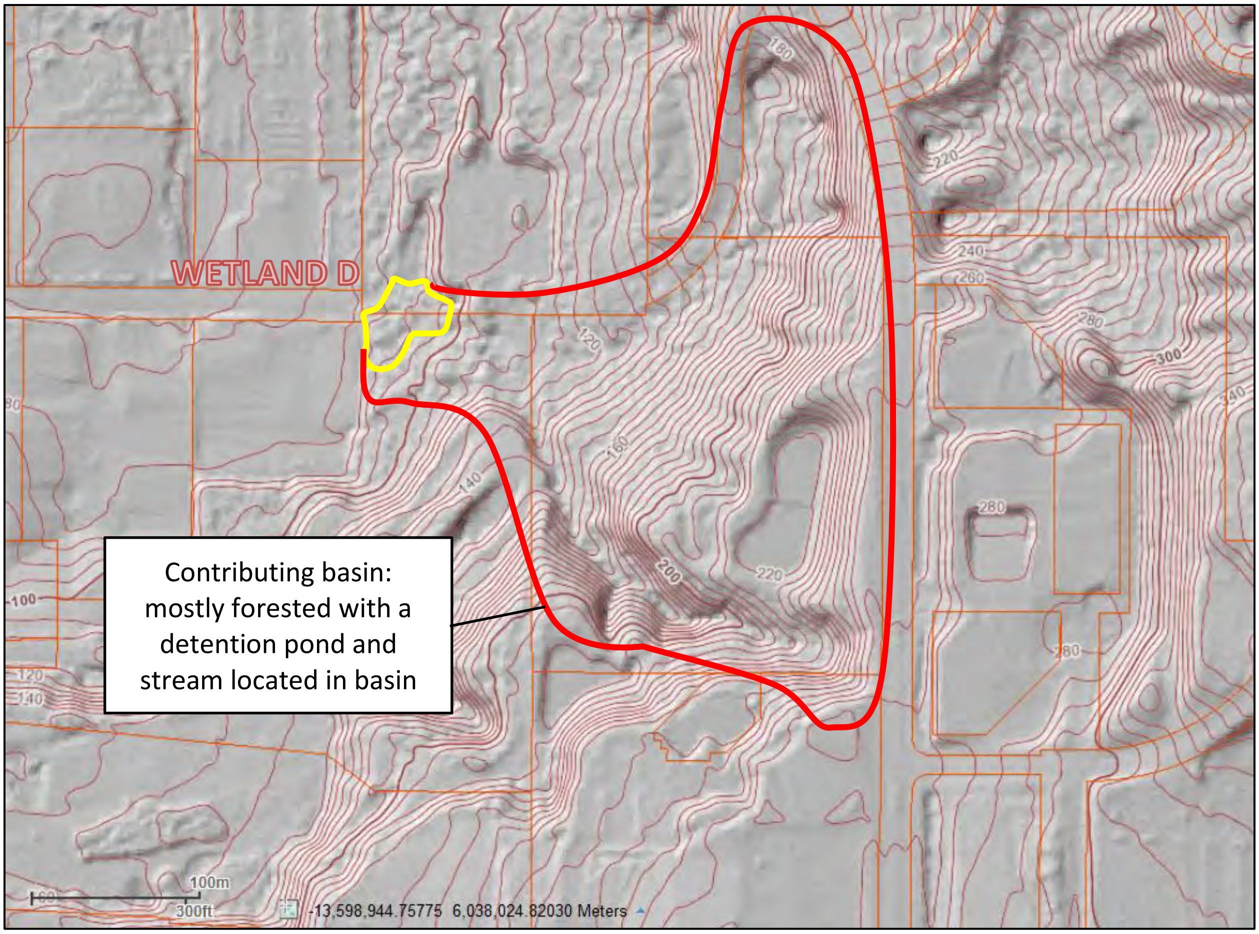


Figure 7. Map of the contributing basin (for Wetland D only) – R2.2, R2.3, R5.2

Features depicted are not be to scale. Sketches are based on available data and best professional judgment.

All Wetlands

Figure 8. Undisturbed habitat and moderate-low intensity land uses within 1 km from wetland edge including polygon for accessible habitat – H2.1, H2.2, H2.3 (move to all).

Features depicted are not be to scale. Sketches are based on available data and best professional judgment.

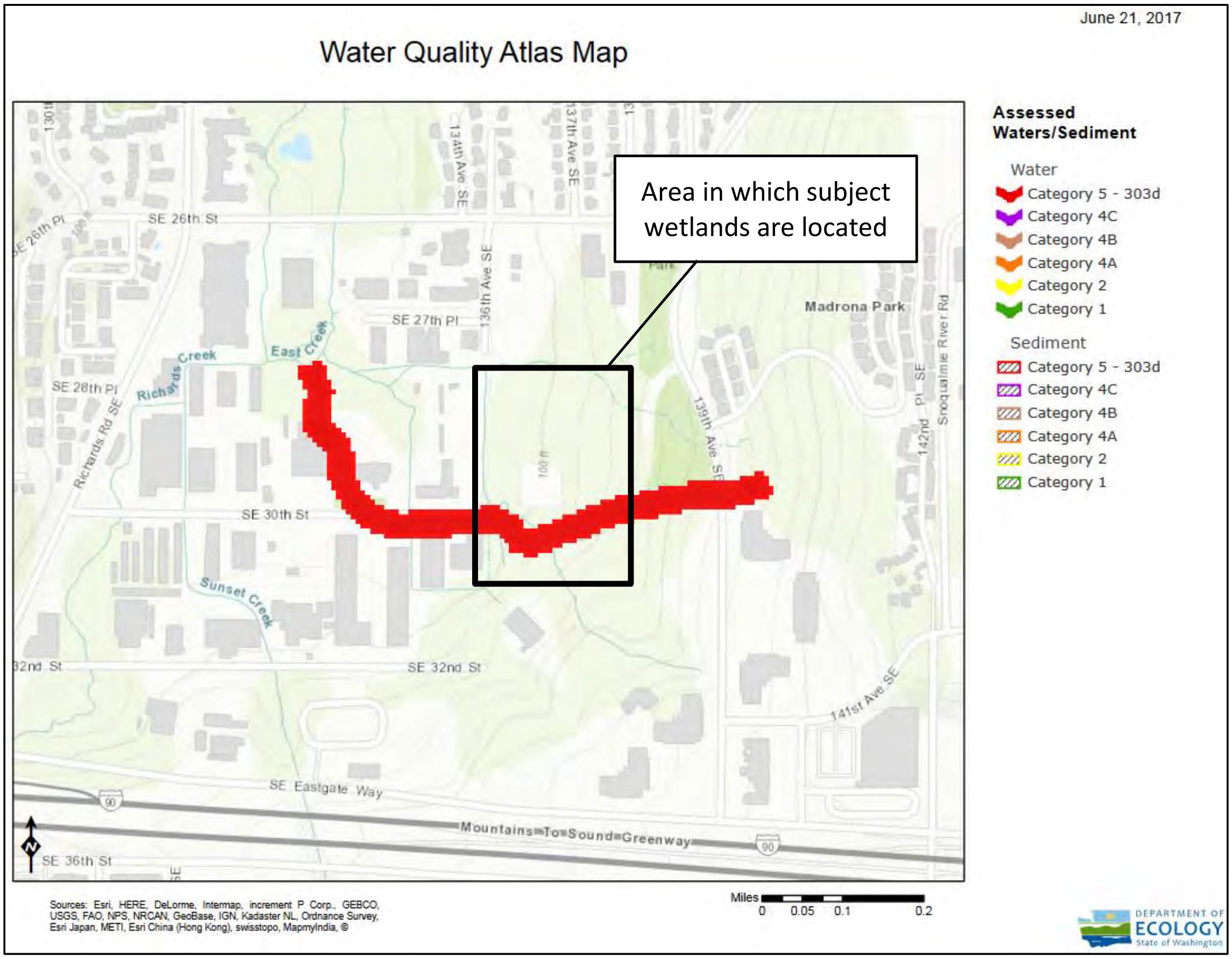


Figure 9. Screen-capture of 303(d) listed waters in basin – S3.1, S3.2

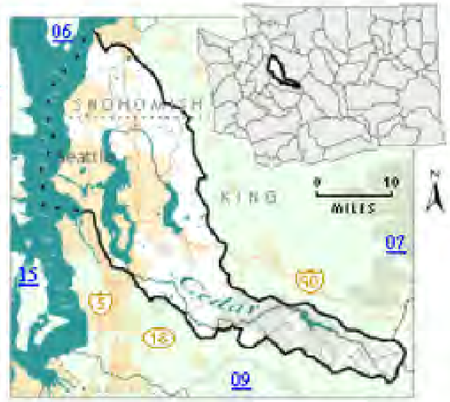
Features depicted are not be to scale. Sketches are based on available data and best professional judgment.

Water Quality Improvement Projects (TMDLs)

Water Quality Improvement > Water Quality Improvement Projects by WRIA > WRIA 8: Cedar-Sammamish

WRIA 8: Cedar-Sammamish

The following table lists overview information for water quality improvement projects (including total maximum daily loads, or TMDLs) for this water resource inventory area (WRIA). Please use links (where available) for more information on a project.



Counties
- King
- Snohomish

All wetlands located in the Kelsey Creek / Mercer Slough Basin of WRIA 8

Waterbody Name	Pollutants	Status**	TMDL Lead
Ballinger Lake	Total Phosphorus	Approved by EPA	Tricia Shoblom 425-649-7288
Bear-Evans Creek Basin	Fecal Coliform	Approved by EPA	Joan Nolan 425-649-4425
	Dissolved Oxygen Temperature	Approved by EPA	
Cottage Lake	Total Phosphorus	Approved by EPA Has an implementation plan	Tricia Shoblom 425-649-7288
Issaquah Creek Basin	Fecal Coliform	Approved by EPA	Joan Nolan 425-649-4425
Little Bear Creek Tributaries: Trout Stream, Great Dane Creek, Cutthroat Creek	Fecal Coliform	Approved by EPA	Ralph Svrjcek 425-649-7036
North Creek	Fecal Coliform	Approved by EPA Has an implementation plan	Ralph Svrjcek 425-649-7036
Pipers Creek	Fecal Coliform	Approved by EPA	Joan Nolan 425-649-4425
Sammamish River	Dissolved Oxygen Temperature	Field work starts summer 2015	Ralph Svrjcek 425-649-7036
Swamp Creek	Fecal Coliform	Approved by EPA Has an implementation plan	Ralph Svrjcek 425-649-7036

*** **Status** will be listed as one of the following: Approved by EPA, Under Development or Implementation*

Figure 10. Screen-capture of TMDL list for WRIA in which unit is found – S3.3, R3.1

Features depicted are not be to scale. Sketches are based on available data and best professional judgment.

Questions for Puget Sound Energy
Submitted to City of Bellevue June 5th, 2014 & to PSE on June 30th 2014
by

Todd Andersen – MSEE, former gigawatt device engineer US Dept of Defense 425-449-8889,
Bellevue resident and home owner at 4419 138th Ave SE.
Co-Chair of the Technical Committee for CENSE. All errors, omissions and other issues are mine alone.

Reviewed and updated by the technical members of CENSE's Technical Committee, including Bellevue residents Dr. Philip Malte, Professor of Engineering and a senior utility power engineer with 35 years of experience all of it in the Seattle, Eastside, Puget Sound and Pacific North West.

1. Please define what "the Eastside area" is for PSE's chart on page 31 of PSE's Eastside Needs Assessment document[2] in terms of cities and counties spanned, geographical area covered (by zip code if easier) and the population. That document is vague on the definition of what the Eastside area is with page 6 just saying *"Eastside area of Lake Washington"* and *"To assess area supply needs, comprehensive reliability analyses were performed to determine the present and future transmission supply to PSE's* ***Eastside area in King County*** *and the Puget Sound area as a whole".* What exactly is the Eastside area?

2. Page 6 of PSE's Eastside Needs Assessment document[1] says *"The studies documented by this report are collectively referred to as the "2013 Eastside Needs Assessment."* We are unable to locate the documents referenced, collectively called *2009 PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report* in footnote 3 of that document. Can we get a copy of that report(s) and the updated reports noted in footnote 2 called *"PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report"*? And any others that make up the *"Eastside Needs Assessment."*

3. PSE's Corporate Load Forecast Group provides forecasts via econometric regression models (not end use models) per page 6 of the Needs Assessment[1]. That document leaves out any actual details of data used in those models other than broad descriptions which can not be used to evaluate the validity of those assumptions/data. Please provide the detailed data and assumptions going into those models. Please describe end use models and how they differ from PSE's econometric regression model.

4. PSE's Corporate Load Forecast Group only provides forecasts via econometric regression models with no sanity check of actual historical peaks to compare against.

A. What are the actual historical peak winter and summer power loads in Mega Watts for the "Eastside" as used in PSE's chart on page 31 of 78 of the Eastside Needs Assessment[2]?
B. What are the actual historical peak winter and summer power loads in Mega Watts for the broader area PSE references in the same doc on page 30?

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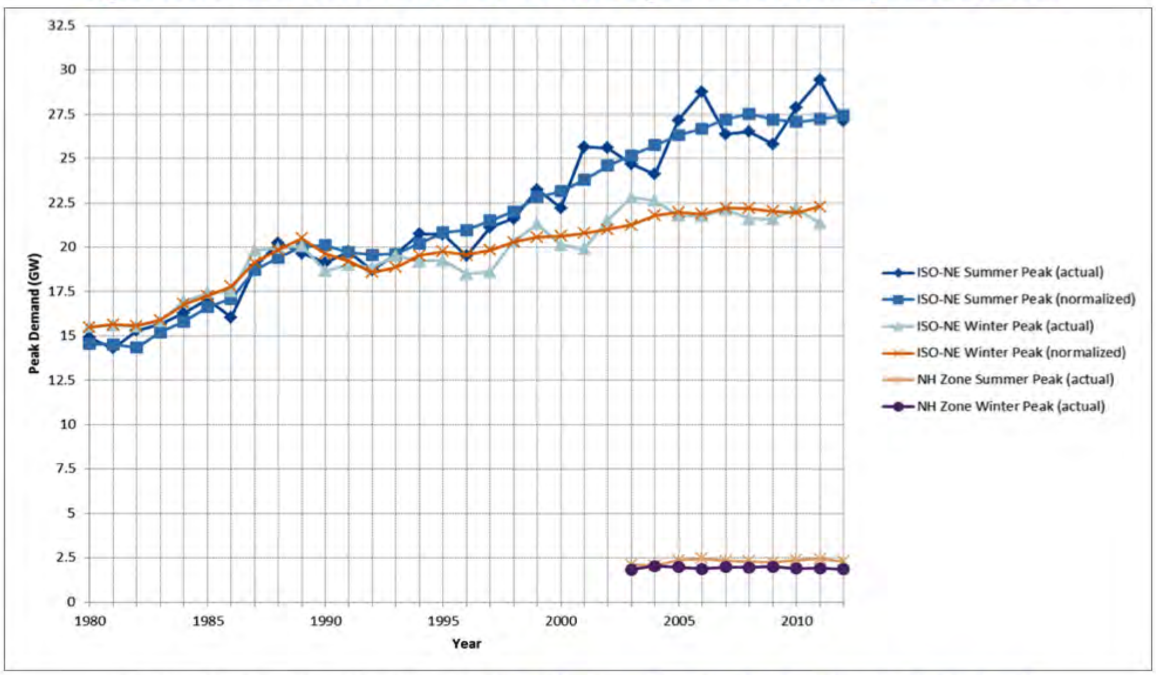
[1] Eastside_Needs_Assessment_Final_Draft_10-31-2013v2%20REDACTED%20R1.pdf
http://energizeeastside.com/Media/Default/Library/Reports/Eastside_Needs_Assessment_Final_Draft_10-31-2013v2%20REDACTED%20R1.pdf

Questions to uncover the true **current** Canada- California power flow for non BPA failover

C. What are the actual historical peak winter and summer power loads in Mega Watts for non Eastside PSE customers Canada/California etc transmission (i.e. North/South flow) moving through the eastside.
D. And if different, the same for the broader PSE area (i.e all PSE area, not just the Eastside) for non local customers of PSE?
E. Can we get these above data sets going back to 1980 in spreadsheet form?

These charts should look like those PSE's contractor Cadmus did for New Hampshire (see chart below) but I did not see this in the PSE documents. We have reviewed over 2000 pages so it is possible we missed it.

Figure 1. Historical Seasonal Peaks for ISO New England and New Hampshire Load Zone



Source: ISO-NE historical market data (http://www.iso-ne.com/markets/hstdata/index.html)

5. If the non Eastside power is different than what PSE calls "*Transmission Customer load*" on pg30/78 of the Eastside Needs Assessment doc, then can PSE please detail what the difference is?

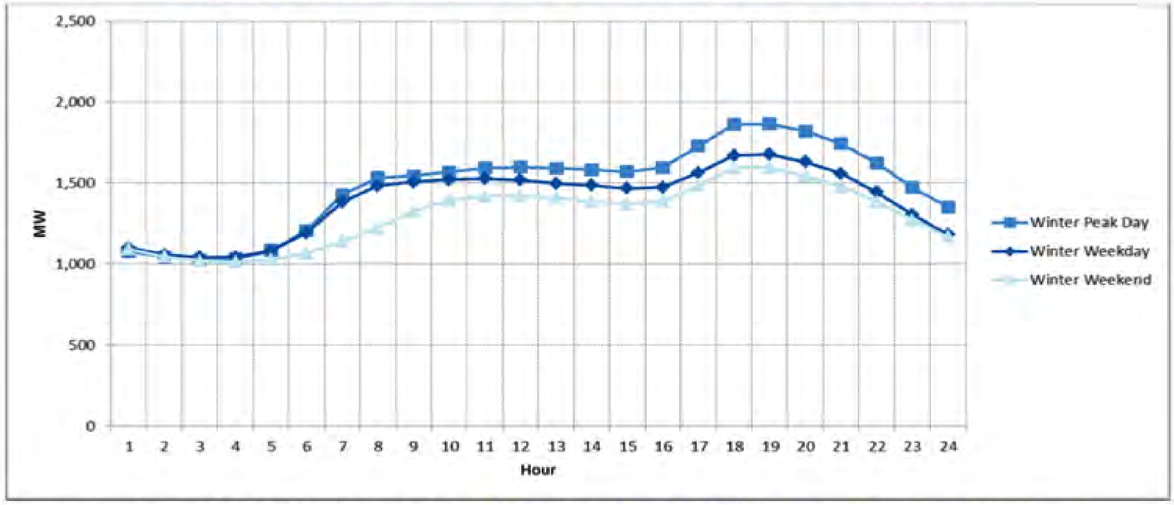
6. How much of the non-Eastside load "*Transmission Customer load*" in Mega Watts is for Canada and how much for USA endpoints?

Questions to uncover the true **current** Eastside power flow

7. Please provide 24-hour graphs and the raw data for actual historical peak, and typical weekday and weekend for the winter and summer as is typically done at other utilities. If this could be done for the last 5 winters and all time peak year that would be outstanding for the Eastside and PSE's broader area. Please provide the associated temperature(s) and humidity for the maximum load points during the day. See sample below of PSE's contractor Cadmus did for New Hampshire

Questions to uncover the Eastside true power needs vs non failover power flow to from Canada/California

Figure 4. Winter Load Profile for New Hampshire Load Zone, 2012



Source: ISO-NE historical market data (http://www.iso-ne.com/markets/hstdata/index.html)

8. During PSE's May 19th presentation to Bellevue City Council member Lynne Robinson asked the question of *"what percent of power going to Canada."*(45:25 25 City of Bellevue onlineVideo) **PSE's stated it was about 5% power to Canada.** (48:25 onlineVideo) **Per PSE's data in the Eastside Needs Assessment document the percent of Eastside power going to Canada is 38% minimum. Can PSE explain the discrepancy and in detail how they get *"about 5%"?*** Per page 31 of PSE's Eastside Needs Assessment doc[2] it is at peak 400/650 =62% or if the 650 load number does not include power to Canada then 400/(400+650)=~38%. Hard to pin down as PSE technical documents have little descriptions of the technical details.

9. PSE says on page 30 of Eastside Needs Assessment doc *"The Transmission Customer load typically runs between 250 MW and 300 MW. For purposes of this study, 270 MW was used for a typical value".* When the purpose of the effort is to size the peak winter load, using non-peak load is inaccurate. Why is the "typical" fixed value of 270 MW used and not the peak (400 MW) Transmission Customer load? What are the actual historical peak Transmission Customer loads for winter and summer in MW going back 10 years? Do these loads peak at the same hour in the 24hr cycle as Eastside peaks?

10. Page 71 of PSE's Eastside Needs Assessment[2] report says the limit to/from Canada is 400 MW with 200 MWs of new commitment to Canada planned per page 72 of 78. What sets the limit? Treaty obligation or technical constraint? Who had made that commitment and by what authority? Whose responsibility is it to fill that commitment?

Questions on actual generation availability

11. Page 32 of PSE's Eastside Needs Assessment doc[2] says *"For the winter peak load cases,* ***no PSE and SCL generation west of the Cascades were run"*** How is this a valid assumption to shut off ALL PSE and Seattle City Light generation west of the Cascades, yet Tacoma left on? Please explain why this condition, which appears to not to be a real world case, could even rationally happen? What are the

[2] Eastside_Needs_Assessment_Final_Draft_10-31-2013v2%20REDACTED%20R1.pdf http://energizeeastside.com/Media/Default/Library/Reports/Eastside_Needs_Assessment_Final_Draft_10-31-2013v2%20REDACTED%20R1.pdf

actual historical generation levels for PSE, SCL Shell (oil) and private owners listed in Table 4-4, west of the cascades for peak winter and summer? Of particular interest is the generation at all-time winter peak and summer peaks. Table 4-4 has "*Expected MW Output during Winter Peak for Low- Generation Sensitivity Case*" but we would like to see <u>actual historical generation</u> for all PSE, SCL, Tacoma Power and private owners at the all-time high winter peak load, and the last 5 years. See the below page 32 of PSE's document.

What does "*Sensitivity Case"* mean in the context used by PSE?

Questions on actual generation power availability

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.

Hey Eastside – we at PSE shut off all our generators and Seattle City Lights' west of the Cascades, thus our computer simulations show we need to build more powerlines!!

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 Tacoma Power left on and PSE & SCL left off? Answer = how to fake Eastside power needs

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.

Table 4-4: List of Puget Sound Area Generators Adjusted in the 2013 Eastside Needs Assessment

Generation Plant	Winter MW Rating	Expected MW Output during Winter Peak for Low-Generation Sensitivity Case	Type	Owner	Transmission Delivery Area
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
Fredrickson	162.2	0	Natural Gas, Simple Cycle	PSE	Pierce County
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

Low Generation = 1031 MW

Peak Winter Case generation assumed by PSE = ZERO!!! If PSE just uses the low generation case of 1.031 GW no new powerlines are needed. If transformers are over loading then add a third transformer at both Sammamish and Talbot Hill

32

Questions on actual generation availability

12. Also on page 32 of PSE's Eastside Needs Assessment doc states "*Tacoma Power generation was left on, due certain internal system constraints.*" Can PSE please explain what the certain internal system constrains are and why those constraints or others are not applicable to PSE and SCL forcing them to be left on? How does the Eastside load needs change if PSE and SCL and Shell and private owner generation west of cascades is left on at actual historical peak generation? Namely what would the results be in the new increased load ceiling (in megawatts) and increase in the years of extra capacity before the new ceiling is reached?

PSE's Own plan to delay the project until 2021, likely to 2030 But by then Grid batteries, home based Co-gen and Solar will rule.

13. The non wires options screened in PSE Screening Study[3] state on page 6 that *"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"* Please detail how this 70 MW was arrived at, preferably by providing the reports / powerflow cases with detailed description and math. Please include details of why 70 MW would only last 4 years until 2021.

14. Page 7 of PSE's Screening Study[3] written by PSE contractor E3 states that *"Using the median transmission project cost of $220 million from PSE's Eastside Transmission Solutions report, E3 estimated that a four-year project deferral from Winter 2017 to Winter 2021 would provide PSE approximately $40 million in present-value transmission revenue requirement savings."* Please provide the details of the math and assumptions to arrive at that $40 million.

15. On the same topic of <u>cost effectively deferring PSE's power line until 2021</u> PSE's contractor E3 stated on page 8 of the Screening Study[3] that *"E3's screening analysis identified an estimated 56 MW of winter peak reduction potential by 2021 (above the level included in the IRP) from incremental EE (30 MW), DR (25 MW), and DG (1 MW) in King County. This total non-wires potential includes all remaining cost-effective EE and DR in King County, as well as all remaining achievable DG in the area."* Please detail the power found in each of the three categories: energy efficiency (EE), demand response (DR) and distributed generation (DG) measures that make up the 56 MW E3 found. Why was PSE/SCL/private generation capacity of +80 MW in East King County left out?

16. Please provide the above spread sheets used to determined the above referenced 56 MW of incremental peak demand reduction.

Grid batteries use in California

17. Why has PSE not studied and reported the results of grid storage batteries as California's Public Utility Commission as determined they are the best technical, environmental and financial solution to growth driving up peak power and requiring additional capacity[4]? Batteries solve exactly the problem claimed by PSE of the Eastside growth driving up the <u>peak power</u> and eliminatie the need to add additional transmission capacity. A need which would only occur only a few days of the year. California's top three for profit electric utilities are deploying 1,325 megawatts Grid storage batteries by 2020. **On Oct 2013 California PUC <u>unanimously</u> approved Commissioner Carla Peterman's ground breaking proposal that requires the for-profits** (PG&E, Southern California Edison and San Diego Gas & Electric) **to add 1,325 megawatts of electric storage by 2020**.

[3] www.energizeeastside.com/Media/Default/Library/Reports/PSE Screening Study February 2014.pdf
[4] www.energy.ca.gov/research/integration/storage.html
www.mercurynews.com/business/ci_24331470/california-adopts-first-nation-energy-storage-plan

18. PSE's Project Engineer Jens Nedrud stated at the May 29th 2014 South Bellevue Community Center PSE Q & A, that batteries were reviewed in the 33pg PSE non wires solution report[3] done for PSE by the San Francisco consulting company E3. Contrary to Jens Nedrud's statement, not one word about batteries or storage in that report. In fact, the only reference to grid batteries was in the document that Mr Nedrud co-authored. Here is the entirety of battery storage mentioned in all of PSE's publicly available "Energize Eastside" reports. On page 34 of 118 of the *Transmission Solution Study Report* [5]

> At this time, biomass, batteries, pumped storage hydro, solar, fuel cells, geothermal, tidal, and wind were not modeled. PSE has observed some recent activity in biomass generation development plans, both for cogeneration and standalone facilities. The typical plant size is approximately 25 MW, but plants up to 50 MW are being proposed. The majority of the plants that have been proposed in this region would interconnect with BPA. Pumped storage hydro, tidal, geothermal, and wind are locational and would require additional transmission to get the supply to the load center of the Eastside area. Fuel cells and batteries have been growing in both number and scale, but are not yet operating at a gross generation scale. Fuel cells operate or are being developed at scales from several hundred watts, such as those to power portable electric equipment, up through several MW to power equipment, buildings, or provide backup power.

Given dozens of non-profit utilities are using/deploying at least 1000 Megawatts of batteries, ten times greater than the scale of growth PSE claims the Eastside requires, can PSE detail why those utilities see the batteries ready to deploy while PSE sees the batteries as not ready?

19. In 2013 PSE published their Integrated Resource Plan (IRP). The plan addressed the utility level electrical energy storage and compared its installed cost with that of combustion turbine peaking generators using 2011 pricing. Would PSE please clarify why its utility level energy storage in the IRP is so much greater than the US DOE's September 2013 report on the same subject that also has 2011 pricing?

The US Department of Energy's Sept 2013 report on energy storage is called "*National Assessment of Energy Storage for Grid Balancing and Arbitrage Phase II*[6]" PSE's IRP quotes "*utility- scale battery storage costs remain above $2,000 per kW with up to four hours of discharge capacity …*"[7] while the US Department of Energy report states that 2011 prices (in pages 36 & 45) for vanadium redox flow batteries, all inclusive 5-hour system capital costs were between $942 and $1280/kW. Furthermore, with prices expected to fall to as low as $608/kW by 2020. PSE's peaker prices will only climb. If one desizes to 4 hour capacity the price is $889/kW. PSE's price level for this critical next generation utility infrastructure is

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[5] www.mercurynews.com/business/ci_24331470/california-adopts-first-nation-energy-storage-plan
www.energy.ca.gov/research/integration/storage.html

014%20REDACTED%20v2.pdf
[6] http://energyenvironment.pnnl.gov/pdf/National_Assessment_Storage_PHASE_II_vol_2_final.pdf
[7] Page 107/245 of IRP chap1-7,
http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_Chapters.pdf

off more than 125%. How does PSE account for the discrepancy between PSE's numbers and the US Dept of Energy's?

20. If one uses PSE's old data in PSE's 2013 IRP of $2000/kW for Grid storage, then a Grid storage system is still cheaper at $200 Million for storing 100 MW peak power for 4 hours than the median cost of the proposed new powerline used in PSE's alternatives Screen Study report [3](page 7) of $220 million. And significantly cheaper than the $300 million dollar price PSE has stated numerous times in the community forums. Why was this alternative not offered and discussed in detail in the alternatives report[3]? If PSE determines this solution not viable then please detail why.

21. Would PSE please explain how its load forecast might be significantly lowered given that new technology and price reductions will encourage businesses and individuals to install battery storage devices, home based co-generation, solar PV and/or wind? Would PSE please explain what would prevent cheaper and more ecologically friendly "distributed generation" from unfolding?

<u>Discussion:</u>

If one reads the managing owner of PSE[8], (Macquarie) and the Edison Electric Institute's, (the lobbying group for the utilities) 2013 report *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business.*[9] on page 11 is the following statement from that report "***one can imagine a day when battery storage technology or micro turbines could allow customers to be electric grid independent. To put this into perspective, who would have believed 10 years ago that traditional wire line telephone customers could economically "*****cut the cord**?" " Given Macquarie/EEI's urgent call to political action in that report then PSE's graph shown on page 32 of PSE's Needs Assessment[2] would look different.

Furthermore, the CEO of NRG Energy, David Crane, also has a significantly different view of the near & far term electric energy growth, than PSE. He generates more than 10 times the electricity as PSE (53,000 MW) and sees the future as local distributed generation, largely home. A quote from him "*Distributed generation will win because,* ***in the very near term****, it will perform the central function of our industry — the delivery of safe, affordable, reliable and sustainable energy — better than the grid operated by regulated utilities.*"[10] See his full open letter to the utility industry in the reference. Why is his future not the cheapest and most environmentally friendly one to solve the Eastside's growth needs?

The below chart is a mocked up of PSE's own chart to show what reality PSE's owners and the CEO of an electric company ten times the size of PSE think is going to actually going to happen, nearterm.

[8] www.macquarie.com/mgl/com/us/about/news/2007/20071026
[9] The for-profit electric utility trade association Edison Electric Institute's 2013 report www.eei.org/ourissues/finance/documents/disruptivechallenges.pdf
[10] http://www.energybiz.com/magazine/article/340139/keep-digging

The future Bellevue and the Eastside should be building so we look like a City in a park and not further delay clean energy and not have dirty power turn the neighbors into an industrial war zone.

Note: PSE Load Forecast is provided for PSE system load, not including the 270 MW of Transmission Customer industrial load. Transmission Customer load is included in the area load for the TPL and Eastside Needs Assessment studies.

Conservation Sensitivities: The winter forecast was adjusted for sensitivities regarding the amount of expected conservation at peak load. PSE's corporate load forecast assumes 100% of the targeted conservation levels are achieved. To understand the reliability risk due to higher than expected load, PSE ran load sensitivity studies which adjusted conservation levels as a proxy for the higher loads. For the load sensitivity studies, conservation was adjusted to 75%, 50%, and 25% of expected values.

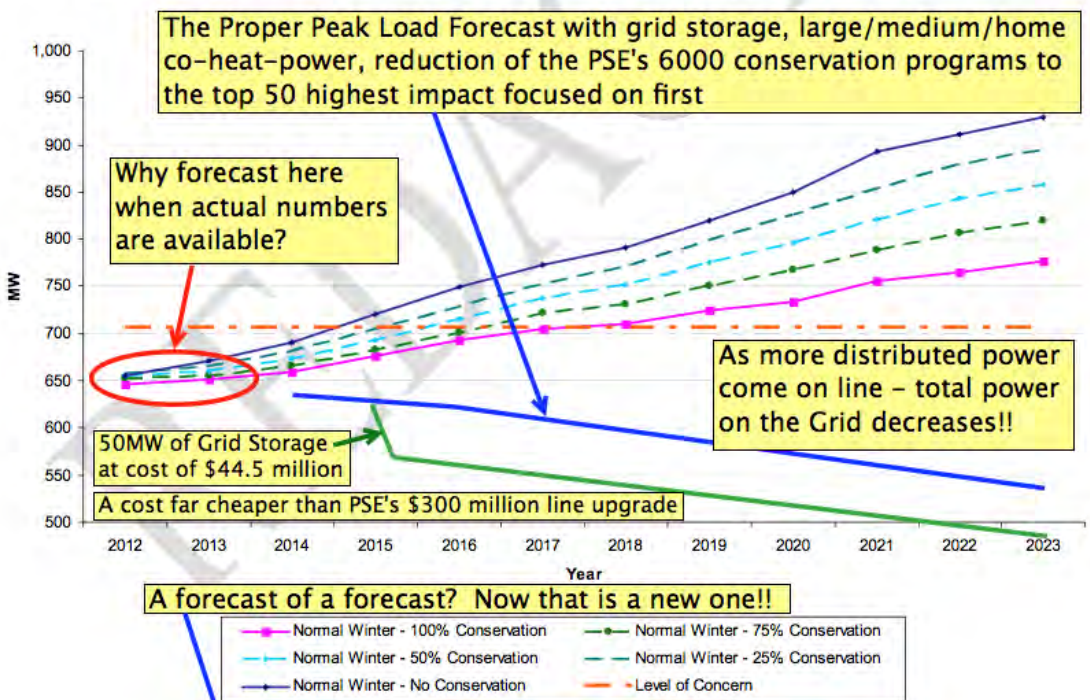

Figure 4-3: Eastside Load Forecast for Normal Winter Load Forecast 2012-2023

31

The Eastside power usage <u>from PSE</u> will go down because of all the distributed generation made possible from far more cost effective and less polluting technologies (mini & micro co-generation, solar PV, wind, Solar pavers etc).

Grid batteries deployments by a Bellevue sized city

22. The Imperial Irrigation District (IID), a municipal utility that provides power and water services to about 150,000 residential, commercial, and industrial customers launched a solicitation in January 2014 for 20 megawatts to 40 megawatts of battery storage. This Bellevue sized entity in California wants "respondents to design, engineer, procure and construct a utility-scale energy storage project" and specifies that it is a "battery" storage project[11]. What plans

[11]. http://energystorage.org/news/esa-news/grid-scale-energy-storage-rfqs-lessons-imperial-irrigation-district
http://www.greentechmedia.com/articles/read/Grid-Scale-Energy-Storage-RFQs-Lessons-From-the-Imperial-Irrigation-Distri

does PSE have for the Eastside service area similar to IID battery storage project?[12] For additional information on grid scale energy storage see the many footnotes

23. Has PSE evaluated these grid battery storage companies for the purposes of solving the Eastside's power growth? If so please provide the details. The following were selected by California's Imperial Irrigation District[13]:

1. AES Energy Storage
2. Black & Veatch
3. Coachella Energy Storage
4. Duke Energy Business Services
5. Invenergy Storage Development
6. PMCCA, dba Performance Mechanical Contractors
7. S&C Electric Company
8. UC Synergetic (Hitachi)
9. ZBB Energy Corporation

More Grid batteries deployments by California , NY Hawaii and Bill Gates

24. What flaws does PSE find in the California Public Utility Commission's 95 page detailed policy and technical report on Grid storage that prevents PSE from solving the Eastside's power growth with a battery solution that is cheaper and more environmentally friendly than PSE proposed power line expansion[14]?

25. New York City's Metropolitan Transport Authority (MTA) will be installing three vanadium-flow batteries in a downtown Manhattan building to solve peak power issues[15]. PSE is requested to comment on why this solution would not solve the Eastside's power growth.

26. Hawaii Electric Co. launched one of the biggest energy storage proposals in the country in May 2014, quietly opening up requests for proposals of 60 to 200 megawatts of storage project[16]. PSE is requested to comment on why this battery solution would not solve the Eastside's power growth.

27. Does PSE think Bill Gates investment into grid storage to be unwise[17]?

Conservation

28. Page 8 of PSE's 2013 Integrated Resource Plan Appendix N[18] discusses a key document to understanding how well PSE is tackling energy conservation called the *2010 Residential Characteristic Survey* (RCS). Please forward the 2010 Residential Characteristic Survey as well as any similar studies or updates that detail the size and types of loads characteristic for PSE operating areas. Please provide in

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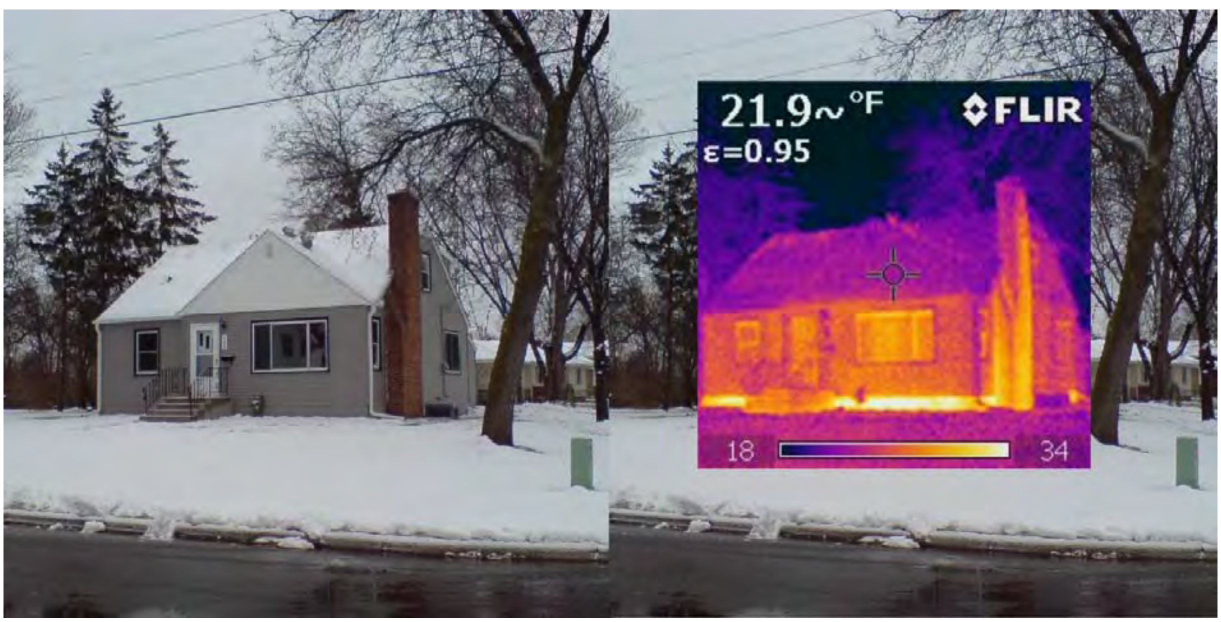
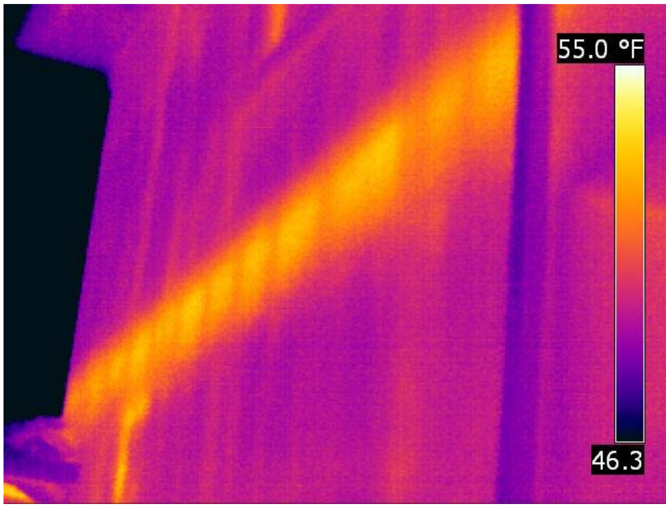
[12] http://www.greentechmedia.com/articles/read/Another-40-MW-of-Grid-Scale-Energy-Storage-in-the-California-Pipeline
13 http://energystorage.org/news/esa-news/grid-scale-energy-storage-rfqs-lessons-imperial-irrigation-district
[14] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M078/K912/78912194.PDF.
[15] www.resourceinvestingnews.com/70106-a-giant-leap-for-energy-storage.html
[16] www.greentechmedia.com/articles/read/hawaii-wants-200mw-of-energy-storage-for-solar-wind-grid-challenges wants-200mw-of-energy-storage-for-solar-wind-grid-challenges.
[17] www.smartgridnews.com/artman/publish/Technologies_Storage/Even-Bill-Gates-is-betting-on-energy-storage-6292.html
[18] http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppN.pdf

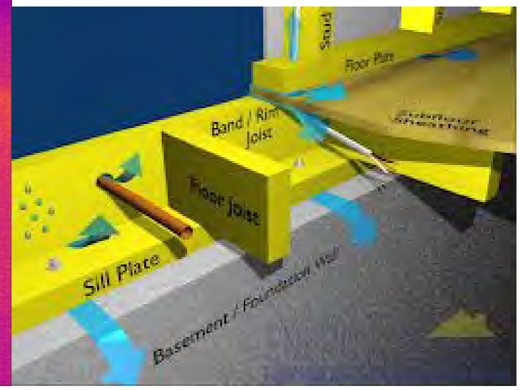
spreadsheet format so that the user can the rank order based on deferring parameters so that the work of E3 and PSE can be independently verified. Please describe any limitations of the reports and data set(s) accurately describing the characteristics of PSE's load. For example margin of error, undocumented assumptions and major missing load type(s) particularly during peak load conditions.

29. Has PSE measured energy savings by insulating RIM joists in residential and non-residential structures? This is likely to be a major cause of peak winter loading. What is PSE's count/estimate of the structures with uninsulated RIM joists? No RIM joist insulation is mentioned in any of the Cadmus Groups works for PSE - why? Cadmus might use a terminology that is not self evident, if so please tell us how uninsulated RIM joists are delineated. Or this info may be reported in non Cadmus documents, if so please identify.

These are huge energy wasters at low temperatures as almost all heating ducts run in those spaces with very little separating those ducts and the outside air. In most cases it is just 1.5 inches of wood and siding. About an R1.6 insulation value, less if air leaks. Most non remodeled homes in Bellevue's Somerset region are like this. The heat lost gradient of this confined space is ~50F higher than room temp, making it a major if not the major energy loss of most structures. Many of these homes will use electric space heaters to heat just a portion of the house on cold days to save $$ and driving electric peak load and unneeded infrastructure/pollution. **<u>There are large number of "Humvee houses" who will do this fix on their nickel if informed.</u>**







Above is a two story home on a typical Bellevue day of 46 degF

30. If a statistically valid survey is not available for the Eastside and the broader area for uninsulated RIM joists, then can PSE provide a count of pre 1980 (or prior to the date which code enforcement changed) of one, two and three story residential structures and what percent the residential is of total structures? Also, what is the count/survey of insulated vs uninsulated heating ducts?

31. Can PSE's Geographical Information System/data system(s) (or contractor, OnPower, Cadmus etc) map the above counts' addresses to income brackets? At the house level (high energy bill with high income)? If not, why? Any legal code restricting? If so please note. If restricted, will you turn this over this info to city officials? **<u>This data is needed to prompt the large number of "Humvee houses" who will fix their uninsulated RIM joist on their nickel if informed.</u>** If the reason was cost what was the dataset quote cost for income per address by which data bureau? Can PSE provide a data set of home addresses per grouping, 1 story, 2 story, 3 story (all per income bracket)? We do not need the actual data at this time but might require it if RIM joist prove to be the cost effective solution.

32. Please provide a count of when structures on the Eastside were originally built per year (manufactured, single family, multifamily/commercial) vs **<u>all-time</u>** **<u>peak</u>** month energy use in spreadsheet form. And again for the last two years of peak winter just for the peak month. This allow us to determine how much waste is built in that can be fixed and verify PSE and contractors assessments.

33. Inefficient heating is likely another major cause of the peak load during the 23°F temperature that PSE is using for its forecasts. Can PSE provide a count (or <u>statistically valid</u> sample, including methodology of how/when they were conducted) of residential homes (manufactured, single, multifamily etc), commercial and industrial with in the eastside and the broader area for the following:

A) Electric heat count at highest granularity you have (furnace, base board etc) and what percent each of these are of the total stock of electrical heating,
B) count of natural gas heat,
C) count of those not electric nor natural gas (i.e. propane, wood burning etc).

D) count of electric water heaters.
E) count of heat pumps (If you have numbers of pure electric heat pumps vs duel fuel that is natural gas backed up that would be excellent)

34. How many pure electric heat pumps (i.e not dual fuel electric and gas) are in PSE's overall area and specifically in the Eastside? Heat pumps are great 90% of the time. BUT on cold days or cool humid days they are very inefficient. On those days they are a major driver of peak load as electric heat pumps convert to pure electric restive heat in the Northwest due to humidity ice-over/lockup from 40°F to 34°F . And while generally not in ice-over/lock up at below 34°F they are generally still switched to pure restive heat by their users at temperatures below freezing. This is why great utilities track their use and effects on peak load and great municipalities require dual fuel heat pumps. PSE's new grid design temperature is 23°F. Attached is a graph from Dept. of Defense's August 2013 Air Source Cold Climate Heat Pump Final Report depicting energy consumption for 12 months [19]. But it is far worst than graphed for 15 to 20 days in Puget Sound due to our humidity. Does PSE agree with this analysis of lockup and actual efficiency under real operational use? If not please detail.

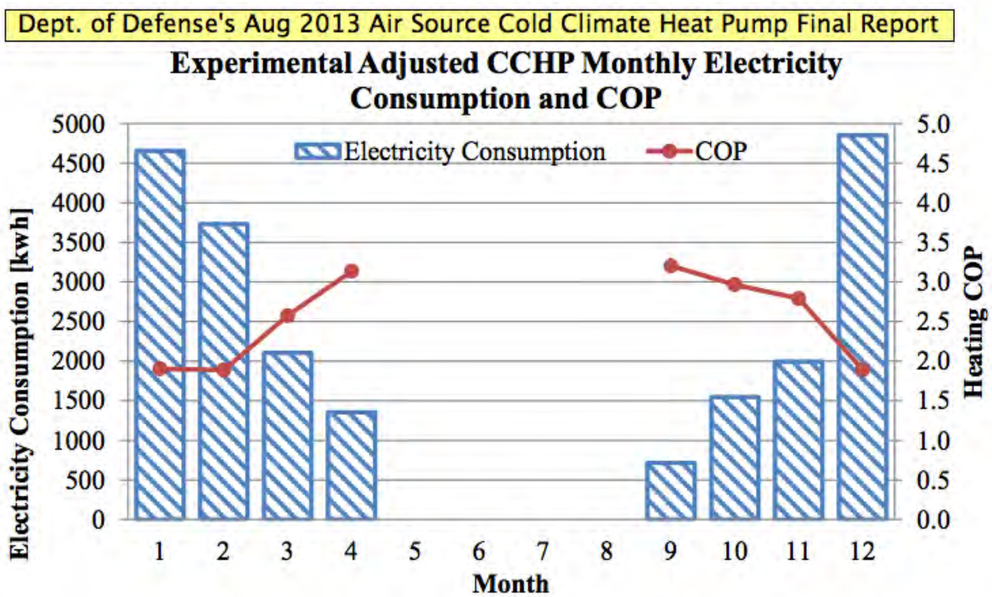


Figure 13. Experimentally adjusted TRNSYS model – monthly CCHP electric consumption and heating COP.

35. Has PSE made a dollar estimate to convert existing electric heat pumps to dual fuel heat pumps? What is the estimated peak load reduction for converting these residential and commercial heating devices? Lets say we convert/replace 5000 electric only heat pumps to dual fuel. Assuming a 5kW coil, (many have 10 kW coils) then 5000 times 5kW gives 25 MW of peak load reduction at $20 million assuming $4k per fix.

[19] page 37 of 50 DOD.2013Cold Climate Heat PumpEW-201136-CP.pdf http://www.serdp.org/Program-Areas/Energy-and-Water/Energy/Conservation-and-Efficiency/EW-201136/EW-201136/%28language%29/eng-US

36. What financial incentives do regulators provide to PSE to reduce energy consumption? Please detail and provide code and/or regulations supporting.

X-IP-SPAM: Suspect
To: todd@matadortech.com, sdofour@aol.com
Subject: Re: CEII paperwork like meant to silence given PSE broke so many CEII rulles Re: PSE's Jens might actually send answers or just more delay Fwd: RE: "Need" response to PSE invite RE: PSE CEII Tariff Language, Procedure, Request Form & Nondisclosure Agreement
X-MB-Message-Source: WebUI
From: CV <cvchung@aol.com>
X-MB-Message-Type: User
X-Mailer: AOL Webmail STANDARD
Cc: don.m.marsh@gmail.com, hansennp@aol.com, whalvrsn1@frontier.com, rborgmann@hotmail.com, keithc@seanet.com, malte@u.washington.edu, larry.ede@gmail.com, markhancock@hotmail.com
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bh=mLA2fCHzUwt/DzShOh8NGLmqLwIBFIVDRoISRh2+drY=;
h=From:To:Subject:Message-Id:Date:MIME-Version:Content-Type;
b=k+cP66c0mS5ImHVEMSqTaSVQXqF/yP4raO/11y+s2s1VgFAybjrmIscZQg6ZkuYFZ
EujXOIsBfYfYuljwcSSWBd4Rm3+nAAehif9TFPgFGEHI02M3vMXY7Hqm/mIw0zTvJY
CffzgiaQ6mG5Y+qQjM5mUBZYPJfYNxEbNk0Ob9+s=
x-aol-sid: 3039ac1afe9053ec65b11d77
X-Nonspam: None

Hi Todd,

Thanks for thinking of the request I made from ColumbiaGrid.

Wonder if we should include Columbia Grid in those complaints given they are not answering CV's question there as well. I think UTC would want to know given they want the info on PSE.

I wonder whether we should list all the requests and not swamp Steve who has many things going on all at the same time.

I'll take a look to see if I have a copy of the questions with me. I may not have downloaded all the EE stuff in my "net-book PC". Perhaps I could send it to you for compiling a complete list to include all that we wish PSE to respond to.

I read in the news that it is "kinda warm in Seattle" = 81 degrees F. Stay cool.

Best wishes,

CV

-----Original Message-----
From: Todd Andersen <todd@matadortech.com>
To: sdofour <sdofour@aol.com>
Cc: don.m.marsh <don.m.marsh@gmail.com>; Norm Hansenn <hansennp@aol.com>; Warren Halvrson <whalvrsn1@frontier.com>; russell borgmann <rborgmann@hotmail.com>; ""kc\" <keithc" <kc" <keithc"@seanet.com; philip C Malte <malte@u.washington.edu>; Larry Johnson

<larry.ede@gmail.com>; cvchung <cvchung@aol.com>; markhancock <markhancock@hotmail.com>
Sent: Thu, Aug 14, 2014 7:17 am
Subject: CEII paperwork like meant to silence given PSE broke so many CEII rulles Re: PSE's Jens might actually send answers or just more delay Fwd: RE: "Need" response to PSE invite RE: PSE CEII Tariff Language, Procedure, Request Form & Nondisclosure Agreement

Steve - I have been holding off as CEII paperwork(critical energy infrastructure information) likely meant to silence and given Russ B's good work with UTC. UTC is sounding like they will pressure PSE to answer questions that are non CEII. The stronger way to kill EE is with the 36 questions, all are non CEII. Thus I am holding off visiting the death star. PSE broke so many CEII rules that PSE lawyers likely want an easy way shut up anyone using CEII info that PSE incompetently sent out to the public already. Surely there is a FERC fine waiting for them on that.

UTC sent Russ complaint forms via snail mail that KC scanned and folks that have not gotten their questions answered by PSE are sending back to UTC with paper trail of requests of PSE. That info@energizeeastside.com email is an official record that PSE has to send all to UTC.

Wonder if we should include Columbia Grid in those complaints given they are not answering CV's question there as well. I think UTC would want to know given they want the info on PSE.

Todd

At 07:48 AM 8/11/2014, sdofour@aol.com wrote:

> Todd,
> Have you had an opportunity yet to go in and sit down and look at what they won't show us in public?
> Steve O.
> PS:CV is in Prague and tomorrow gets on a Viking river boat for two week in Budapest...he said he boards on the PEST side of the river and that suits him.
>
> -----Original Message-----
> From: Todd Andersen <todd@matadortech.com>
> To: Norm Hansenn <hansennp@aol.com>; Warren Halvrson <whalvrsn1@frontier.com>; KC <keithc@seanet.com>; russell borgmann <rborgmann@hotmail.com>; don.m.marsh <don.m.marsh@gmail.com>; sdofour <sdofour@aol.com>; Larry Johnson <larry.ede@gmail.com>; pamagnani <pamagnani@gmail.com>; markhancock <markhancock@hotmail.com>; lisa Taylor <14lisat@gmail.com>; 747rwmorris <747rwmorris@msn.com>; Barry Zimmerman <Baz@starboarddev.com>; drkaner <drkaner@live.com>
> Sent: Mon, Aug 11, 2014 7:14 am
> Subject: PSE's Jens might actually send answers or just more delay Fwd: RE: "Need" response to PSE invite RE: PSE CEII Tariff Language, Procedure, Request Form & Nondisclosure Agreement
>
> PSE's Energize Eastside co project manager Jens might actually send answers or just more delay.
>
> Todd
>
> >From: "Nedrud, Jens V" <jens.nedrud@pse.com>
> >To: Todd Andersen <todd@matadortech.com>, 'CV' <cvchung@aol.com>
> >CC: "Kostek, Leann" <leann.kostek@pse.com>

>Subject: RE: "Need" response to PSE invite RE: PSE CEII Tariff Language,
>   Procedure, Request Form & Nondisclosure Agreement
>Thread-Topic: "Need" response to PSE invite RE: PSE CEII Tariff
Language,
>   Procedure, Request Form & Nondisclosure Agreement
>Thread-Index: AQHPrb00nFihrzXwNUiiBodx45SUApvHm8DT
>Date: Sat, 9 Aug 2014 02:42:52 +0000
>
>Todd,
>
>I just wanted to confirm that I received your
>earlier email. I will be on vacation now through
>next week, but will send you more information
>when I return. Thank you for your patience.
>
>
>Jens
>________________________________
>From: Todd Andersen< mailto:todd@matadortech.com>
>Sent: Fri, 01 Aug 2014 12:14:52 -0700
>To: Nedrud, Jens V<mailto:jens.nedrud@pse.com >;
'CV'<mailto:cvchung@aol.com >
>Cc: Kostek, Leann< mailto:leann.kostek@pse.com>
>Subject: "Need" response to PSE invite RE: PSE
>CEII Tariff Language, Procedure, Request Form & Nondisclosure Agreement
>
>Jens,
>
>While reading all the paperwork you sent to get
>cleared for critical energy infrastructure
>information (CEII) it got me thinking that the
>need & alternatives for Energize Eastside do not
>require CEII. We sent a list of 36 questions to
>you June 30th and all are Non CEII and we have
>not yet received any answers. I suggest we
>first focus on those first so that when we do
>sit down to review CEII information we won't
>waste time on the basic "need" as that will be
>documented. Re-attached for your convenience.
>
>As was reported to the Bellevue City Council,
>the CEOs two of utilities, each more than 10x
>the size of PSE (NRG Energy & Duke Energy), made
>statements that electric load growth is
>shrinking not growing and no longer correlated
>with economic growth as in the past. Given
>PSE's total electrical energy sales are down
>from where they were 6 years ago, the
>communities are going to need answers to the
>basic questions if PSE wants to regain the
>community's trust. Add to this a front page

>Wall Street Journal Article July 29th, that
>electricity sales across the country peaked in
>2008 and have been down ever since, see attached.
>
>Also, PSE's non-wire solution report said there
>was not enough achievable conservation or
>distributed generation to avoid the project but
>that also has not been proven to many of us
>engineers and the WUTC. This includes some
>professors at UW that you might know. Not sure
>PSE wants to hang their hat on the analysis as
>that report is littered with holes. Most who
>have read that report or the source material for
>it are not convinced including the WUTC.
>
>Thus to help PSE make its case I suggest we
>focus on 36 questions sent previously as they do
>not require any CEII and are foundation to any need for CEII:
>1. Answering questions 1-16 related to the
>"need" , 17-27 as they relate to grid batteries and 28-36 on
conservation. .
>
>2. PSE states only 1 MW of distributed
>generation is available in King County, (pg 8 of
>the PSE Screen Study, see attached question
>13-16 for full reference). Yet the WA Utilities
>and Transportation Commission says PSE is not
>correctly accounting for distributed generation
>for both existing DG and potential DG growth.
>
>"Currently, distributed generation (DG) on or
>interconnected with PSEÃƒÂ¢Ã‚Â€Ã‚Â™s distribution system
>has a cumulative capacity of approximately 39 MW
>(per Docket UE-131883, Puget Sound Energy
>Comments filed November 6, 2013) and the net
>metering cap will increase by another 11.2 MW
>starting January 1, 2014. As mentioned above,
>PSEÃƒÂ¢Ã‚Â€Ã‚Â™s IRP identifies a capacity deficit of 12
>MW in 2017, growing to 100 MW by 2020, and yet
>PSE did not explicitly include potential impacts
>from distributed generation in its load
>forecasts. Existing DG capacity, let alone
>expected DG growth, could significantly affect
>the timing of resource acquisition in the first
>half of the planning horizon. Similar to
>modeling DG, PSE should also include in its load
>forecasts the capacity available from customers
>on interruptible schedules." per page three of
>Attachment A
>
www.wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/4b0c052bf4e679f

e88257c7700773244!OpenDocument
><
http://www.wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/4b0c052bf4e679fe88257c7700773244!OpenDocument >
www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=131883
>
>< http://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=131883 >3.
>PSE's non-wires screening assessment report to
>review non wire alternatives to Energize
>Eastside. see attached questions 13-16;
>
>3a. This report uses a decade old framework that
>is surely missing many new developments
>including grid storage. "The methodology of
>this analysis has been adapted from the approach
>developed through the Bonneville Power
>AdministrationÃƒÂ¢Ã‚Â€Ã‚Â™s Non-Wires Solutions
>Roundtable, which was convened between 2003 and
>2006." pg5 of PSE Screening Study. Can you
>point me to written documentation of that
>methodology and what changes PSE's contractor E3
>made to it? It is quite obvious PSE's
>contractor E3 knew better but yet did so anyway, see below.
>
>3b. PSE's 2013 Screening Study does not mention
>one word of grid storage nor grid batteries,
>even though you stated it did at the May 29th
>Q&A session. It is very stark that E3, the
>author of that report, did not analyze any grid
>storage to solve a problem which PSE says will
>be "for just a few hours per year" per pg 38 of
>Eastside needs assessment. PSE's contractor for
>that work is overflowing in grid battery skills
>and was significantly skilled in analyzing use
>of grid batteries from at least three years
>prior to writing that report per E3's own
>comments to the WUTC and work done for the State
>of California. (
>
www.wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/65ac2f7ac329f4b888257c390003b91d!OpenDocument<http://www.wutc.wa.gov/rms2.nsf/177d98baa5918c7388256a550064a61e/65ac2f7ac329f4b888257c390003b91d!OpenDocument >

>) E3 has analyzed grid storage from at least
>when California's Energy Storage Bill AB 2514
>was signed into law in 2010 per E3 own
>statements to the WUTC and from being on The
>Project Advisory Committee for the California
>Energy Commission's massive 2011 report ÃƒÂ¢Ã‚Â€Ã‚Âœ2020
>Strategic Analysis of Energy Storage (
> www.energy.ca.gov/2011publications/CEC-500-2011-047/CEC-500-2011-

047.pdf<http://www.energy.ca.gov/2011publications/CEC-500-2011-047/CEC-500-2011-047.pdf >

> www.greentechmedia.com/articles/read/vc-cmeas-gunderson-on-utility-scale-storage < http://www.greentechmedia.com/articles/read/vc-cmeas-gunderson-on-utility-scale-storage >)

>Here is the opportunity for PSE to correct that
>error by answering those June 30th questions 17
>to 27 related to grid storage for the Energize Eastside.
>
>3c. The WUTC first asked PSE to analyze grid
>storage (batteries) in 2011 for their "the
>cost-effectiveness, commercial availability, and
>proper classification compared to other forms of
>generation.ÃƒÂ¢Ã‚Â€Ã‚Â per pg6 the above Attachment A
>review of PSE's work by the WUTC. Yet the WUTC
>had to call out PSE for not studying grid
>batteries in 2013 when the "Commission questions
>whether the use of 2010 data for the 2013 IRP
>gave energy storage a fair opportunity to
>compete with other resource options. PSE
>received multiple storage bids in a recent RFP
>solicitation process, which PSE could have used
>to update cost and operational assumptions for
>those storage technologies. Further, PSE does
>not explain its method for quantifying energy
>storage costs and benefits." Could PSE please
>provide the missing information and explanations
>the WUTC is asking as that info also applies to Energize Eastside?
>
>3d. California's grid operator, CA-ISO, has had
>more than 2,000 megawatts of energy storage
>projects applying to interconnect with the
>stateÃƒÂ¢Ã‚Â€Ã‚Â™s grid to date. The full spreadsheet is
>here
> www.caiso.com/Documents/ISOGeneratorInterconnectionQueue.pdf
>< http://www.caiso.com/Documents/ISOGeneratorInterconnectionQueue.pdf%A0
>
>The list includes 1,669 megawatts of standalone
>battery storage, 44 megawatts of other
>standalone storage, 255 megawatts of batteries
>combined with generation projects, and a
>90-megawatt project combining solar and
>batteries. Furthermore, CAISO only tracks
>projects seeking interconnection to the
>high-voltage transmission grid, that leaves out
>all the distribution-grid-connected and
>customer-sited storage systems, which make up a
>combined 875 megawatts. Thus use of grid
>batteries to solve Energize Eastside "for just a

>few hours per year" (pg 38 of PSE's Eastside
>Needs Assessment report) is not only ready for
>prime-time but is likely the best solution
>across the domains of cost effectiveness,
>environmental friendly impact not to mention the
>not having 18 miles of industrial plight. If
>PSE disagrees could PSE please provide its analysis?
>
>Best Regards,
>Todd Andersen
>425-449-8889
>c415-412-3878
>
>
>
>At 10:43 AM 7/22/2014, Nedrud, Jens V wrote:
>CV and Todd,
>As we move forward identifying a date to meet,
>can you please get the CEII request form and NDA
>sent to me. A scanned signed PDF via e-mail
>will work for that. This way we can get that process started.
>
>Thanks,
>Jens
>
>Jens Nedrud, P.E.
>Sr. Project Manager Â– Easstside 230
>[cid: image003.jpg@01CEC8EA.CFADA810]
>< http://pse.com/inyourcommunity/king/Pages/Planning-for-Growth.aspx >
>
>Puget Sound Energy
>355 110th Ave NE, EST06W
>Bellevue, WA 98004
>(425) 462-3818 - desk
>(425) 533-5307 - cell
>
>From: CV [mailto:cvchung@aol.com]
>Sent: Friday, July 18, 2014 4:44 PM
>To: Nedrud, Jens V; todd@matadortech.com
>Subject: Re: PSE CEII Tariff Language,
>Procedure, Request Form & Nondisclosure Agreement
>
>Jens,
>
>Thanks. I will leave it up to Todd to make the
>decision. There is no reason for me to hold
>things up just because I am out of town.
>
>CV
>
>-----Original Message-----

>From: Nedrud, Jens V <jens.nedrud@pse.com < mailto:jens.nedrud@pse.com>>
>To: 'CV'
><cvchung@aol.com < mailto:cvchung@aol.com>>; todd
><todd@matadortech.com < mailto:todd@matadortech.com>>
>Sent: Fri, Jul 18, 2014 2:40 pm
>Subject: RE: PSE CEII Tariff Language,
>Procedure, Request Form & Nondisclosure Agreement
>Guys,
>Schedules are definitely busy during the summer
>season. It would be great to have both of you in
>attendance during the material review and based
>on your availability in August, letÃƒÂƒÃ‚Â¢Ã‚Â€Ã‚Â™s set up
>this review for after Cr CV returns. In
>addition, our technical experts will already be
>in town Sept 3-5, so that will work out well.
>
>How does Sept 3rd work for you both, or as an alternate Sept 5th?
>
>Thanks,
>Jens
>
>
>Jens Nedrud, P.E.
>Sr. Project Manager Â- Eastside 230
>[cid: image003.jpg@01CEC8EA.CFFADA810]
>< http://pse.com/inyourcommunity/king/Pages/Planning-for-Growth.aspx >
>
>Puget Sound Energy
>355 110th Ave NE, EST06W
>Bellevue, WA 98004
>(425) 462-3818 - desk
>(425) 533-5307 - cell
>
>From: CV [mailto:cvchung@aol.com<mailto:cvchung@aol.com?>]
>Sent: Wednesday, July 16, 2014 7:46 PM
>To: Nedrud, Jens V; todd@matadortech.com < mailto:todd@matadortech.com>
>Subject: Re: PSE CEII Tariff Language,
>Procedure, Request Form & Nondisclosure Agreement
>
>Jens,
>
>I think Todd is anxious to review un-redacted
>studies. I will not be back until August 27. I
>will be jet lagged for next 2 days.
>
>I would let Todd speak for himself. If I cannot
>make it, and the window is open just for that
>week, I am prepared to forfeit he opportunity.
>
>CV
>-----Original Message-----

>From: Nedrud, Jens V <jens.nedrud@pse.com < mailto:jens.nedrud@pse.com>>
>To: 'CV'
><cvchung@aol.com < mailto:cvchung@aol.com>>; todd
><todd@matadortech.com < mailto:todd@matadortech.com>>
>Sent: Wed, Jul 16, 2014 9:32 am
>Subject: RE: PSE CEII Tariff Language,
>Procedure, Request Form & Nondisclosure Agreement
>CV,
>If possible, it would be great to have both you
>and Todd at the meeting. What does your
>availability look like on the week of Aug 25 or the following week?
>
>Thanks,
>Jens
>
>Jens Nedrud, P.E.
>Sr. Project Manager Â– Eastsidee 230
>[cid: image003.jpg@01CEC8EA.CFADA810]
>< http://pse.com/inyourcommunity/king/Pages/Planning-for-Growth.aspx >
>
>Puget Sound Energy
>355 110th Ave NE, EST06W
>Bellevue, WA 98004
>(425) 462-3818 - desk
>(425) 533-5307 - cell
>
>From: CV [mailto:cvchung@aol.com<mailto:cvchung@aol.com?>]
>Sent: Wednesday, July 16, 2014 12:33 AM
>To: Nedrud, Jens V; todd@matadortech.com < mailto:todd@matadortech.com>
>Subject: Re: PSE CEII Tariff Language,
>Procedure, Request Form & Nondisclosure Agreement
>
>Jens,
>
>Thank you for the attachments and the proposed
>visit of PSE facilities ÃƒÂƒÃ‚Â¢Ã‚Â€Ã‚Âœto review complete
>copies of the Eastside Needsds Assessment and
>Eastside Transmission Solutions Report at a
>meeting with the Energize Eastside technical
staff.ÃƒÂƒÃ‚Â¢ÃƒÂ¢Ã‚Â‚Ã‚Â¬ÃƒÂ‚Ã‚Â□.
>
>Unfortunately, I shall be out of the country on
>week of Aug 18. I have asked Todd if he would
>please obtain relevant information if he could make it on week of Aug
18.
>
>Best wishes,
>CV
>
>
>-----Original Message-----

>From: Nedrud, Jens V <jens.nedrud@pse.com < mailto:jens.nedrud@pse.com>>
>To: 'cvchung@aol.com<
><cvchung@aol.com <mailto:cvchung@aol.com>>; Todd
>Andersen
>(todd@matadortech.com < mailto:todd@matadortech.com>)
><todd@matadortech.com < mailto:todd@matadortech.com>>
>Sent: Tue, Jul 15, 2014 3:29 pm
>Subject: PSE CEII Tariff Language, Procedure,
>Request Form & Nondisclosure Agreement
>CV,
>It was nice talking to you last week. As we
>discussed, PSE would be happy to have you and
>Todd come in to go through a more detailed
>discussion of our Needs Assessment and Solutions
>reports. Based on your request to review the
>complete, non-redacted reports at the meeting,
>some additional documentation is needed.
>
>Please see the attached documents that are also
>found on PSEÃƒÂƒÃ‚Â¢Ã‚Â€Ã‚Â™s OATTATT website. They include:
>ÃƒÂƒÃ‚Â‚ÃƒÂ‚Ã‚Â·   A copy of PSEÃƒÂƒÃ‚Â¢Ã‚Â€ÃƒÂ¢ÃƒÂ¢Ã‚Â„Ã‚Â¢s tariff with
>specific language regarding CEII information,
>including the reference to 18 C.F.R 388.113
>ÃƒÂƒÃ‚Â‚ÃƒÂ‚Ã‚Â·   PSEÃƒÂƒÃ‚Â¢Ã‚Â€Ã‚Â™s CEII procedures
>ÃƒÂƒÃ‚Â‚ÃƒÂ‚Ã‚Â·   PSEÃƒÂƒÃ‚Â¢Ã‚Â€ÃƒÂƒÃ‚Â¢ÃƒÂ¢Ã‚Â‚Ã‚Â¬Ã‚Â™s CEII request form
>ÃƒÂƒÃ‚Â‚ÃƒÂ‚Ã‚Â·   PSEÃƒÂƒÃ‚Â¢Ã‚Â€Ã‚Â™s CEII noII non-disclosure agreement
>
>The CEII request form and CEII nondisclosure
>agreement need to be filled out separately by
>each individual (you and Todd). Once completed,
>please send it back to me and I will expedite
>the review. The requested information would be
>ÃƒÂƒÃ‚Â¢Ã‚Â€Ã‚Âœto review complete c copies of the Eastside
>Needs Assessment and Eastside Transmission
>Solutions Report at a meeting with the Energize Eastside technical staff.ÃƒÂƒÃ‚Â¢Ã‚Â€ÃƒÂ‚Ã‚Â
>
>Based on our teamÃƒÂƒÃ‚Â¢Ã‚Â€ÃƒÂ¢Ã‚Â‚Ã‚Â¬Ã‚Â™s availability during
>this busy summer season, the earrliest we can
>get together to sit down with you is the week of August 18th.
>
>If you have any questions, please let me know.
>
>Thanks,
>Jens
>
>Jens Nedrud, P.E.
>Sr. Project Manager Â– Eastside 230

>[cid: image003.jpg@01CEC8EAA.CFADA810]
>< http://pse.com/inyourcommunity/king/Pages/Planning-for-Growth.aspx >
>
>Puget Sound Energy
>355 110th Ave NE, EST06W
>Bellevue, WA 98004
>(425) 462-3818 - desk
>(425) 533-5307 - cell
>
>
>

Questions from Utility Power Engineers To Puget Sound Energy on "Energize Eastside"

1. Question on Lake Tradition Substation:

a) According to PSE planning documents, there was a plan to add a transformer at Lake Tradition and bring a 115 kV line into Bellevue along a route parallel to I-90. This plan would be less expensive and would cause less impact to neighborhoods on the Eastside, but it was abandoned in 2011. Could PSE please explain why? What specific criteria was not met that resulted in it being abandoned.

b) We also request to review non-redacted studies and the power flow printouts and line flows through the Lake Tradition transformer if it had been installed at that station.

c) From 2007 to 2010, PSE sent annual reports to WECC stating that their intention was to install a 230-115 kV transformer at Lake Tradition. In 2011, PSE changed its plans and no longer wished to supply Eastside load growth by installing a transformer in Lakeside. Would PSE please explain if previous to 2011, whether the power flows supported the proposal to install a 230-115 kV transformer at Lake Tradition Substation.

PSE interconnection to SCL Maple Valley-Snoking 230 kV lines:

d) PSE says Seattle City Light rejected PSE's inquiries to upgrade lines currently running along the SCL corridor. Did PSE ever make a formal interconnection request with Seattle City Light? Why not?

e) We request PSE submit a formal request for interconnection with SCL. We request that PSE mention in the SCL letter that FERC encourages open access for transmission systems and SCL should have a policy to perform interconnection studies.

2. **PSE proposed project to rebuild Sammamish-Lakeside-Talbot Hill 115 kV lines to 230 kV.**

Please provide detailed technical study on need to rebuild the Talbot-Lakeside #1 & #2 and Sammamish-Lakeside #1 & #2 lines. Please provide in a short paragraph defining the problem clearly why those have to be rebuild for 230 kV."

3. Please verify that the following are the only system contingencies (PSE, BPA & SCL) that the PSE proposed project is supposed to resolve:

a) Summarizing from the Eastside ~~Alternative~~ Transmission Solutions Report (pp 30-54, including Tables 4-2 and 4-11), and the City of Bellevue, Electrical Reliability Study, Phase 2 Report (dated February 2012), commonly known as the Exponent report, please verify that the

Commented [I1]: Need to number to make it easy to refer to in future communication with PSE, WUTC, Simon fittch etc. xxx

Commented [I2]: Added to xxx

Commented [I3]: Do you mean Lake Tradition?

Commented [I4]: xxxx "See Eastside Needs Assessment Study and Transmission Solution Study" PSE published Those two reports were missing key info. See table 4-1 pg 39of118 of Transmission Study, which is inadequate and tables 6-1 through 6-14 Eastside Needs Assessment are inadequate.

Commented [I5]: Confusing please verify Seems like the "Needs report " has this information but tables 4-2 to 4-11 are only in the "Transmission" report

Commented [I6]: My copy has these table 4-3 and on to xxx are completely blank. IF you have a copy that is not then can you fw to me Russ, KC, Don , phil, Lisa? This question is related to question 6b

DSD 010096

following is the complete list of the system overloads and/or future voltage problems:

b) Loss of Talbot Hill 230-115 kV transformer would overload the adjacent transformer – winter condition

c) Loss of Sammamish 230-115 kV transformer would be close to overloading the adjacent transformer – winter condition

d) Loss of both the Monroe-Novelty Hill 230 kV line and the Bothell-Sammamish 230 kV line – summer condition

e) Loss of the Novelty Hill 230 kV transformer and the loss of one of the Sammamish 230 kV transformers may overload the remaining Sammamish transformer – summer condition.

f) There will be a future need for better voltage support to the Sammamish substation in order to support growth in the City and the surrounding areas. The contingency is loss of the Bothell-Sammamish and the Monroe-Novelty 230 kV lines.

Would PSE please confirm the above?

4. Previous PSE transformer fire and other transformer failures Information required to evaluate possible solutions to PSE transformer "overheating issues"

Commented [I7]: xxx add "Information required to evaluate possible solutions to PSE transformer "overheating issues"

a) PSE stated previously that they had a transformer fire at their Sammamish Substation in 2011. We would like to know the date when the fire occurred. Would PSE also please state when their system peak occurred in 2013 – date, time, system peak load and the loading on the Sammamish transformer during peak.

b) Please state the dates it took to replace the faulted transformer. Would PSE please submit the daily work schedule at Sammamish Substation for the duration of when the transformer was taken out of service until the spare was made operational?

c) In PSE service territory, how many transformer failures occurred during the last 20 years and what time of the year did they occur? Would you please give specific dates when failures occurred and when the spares were put in service?

d) How many total transformers did PSE have in operation during the last 20 years not including the spare transformers and those not serving load? Please provide annual numbers.

e) In order to reduce transportation of heavy and bulky transformers, would PSE be willing to relocate their spare transformers inside the fenced properties of Sammamish and Talbot Hill Substations?

f) In addition to moving the spare transformers inside the fenced substation properties, would PSE consider energizing these spare transformers to make sure that when they are needed, the spares are in good working condition?

g) To minimize the down time after loss of one transformer, would PSE considered making temporary line connection normally known as "shoofly" to the spare transformer? Please provide CENSE (Coalition of Eastside Neighborhoods for Sane Energy) the engineering sketches that PSE had previously prepared for "shoofly" connections in order to re-energize the spare transformer in the shortest possible time.

Definition of shoofly: A conductor or conductors strung as a temporary substitute for a more permanent installation; can be in a substation as a substitute for a section of bus or a short section of transmission line.

h) Has PSE revised their transformer overload policy to allow for "loss of life loading" of the transformer above its nameplate rating during an emergency? Would PSE please submit such policy to CENSE for comment and additional questions? Please submit previous policies and present policies. Would PSE please comment on the overload capabilities of their 230-115 kV transformers and whether they conform to NEMA standards? Would PSE please submit the loss of life tables for overloading the 230-115 kV transformers?

i) Would PSE please provide us a target date to relocate the spare transformers inside Sammamish and Talbot Hill Substations and provide CENSE a short report upon completion of the relocation?

j) Does PSE own a "lowboy trailer" (photo – click here) or other trailers for transporting spare transformers? Would PSE please comment on where it is situated?

5. PSE system planning criteria submitted to the WUTC

a) Please provide a copy of PSE "system planning criteria that is used in the technical studies. This is the same criteria that PSE filed with the WUTC. We wish to see the technical study that is performed in accordance with the planning criteria."

b) PSE builds its transmission infrastructure to minimize outages and avoid overloads on the 115 kV transmission system on an N-1 basis (N-1

Commented [I8]: Spell out acronym for future paper trail purposes

Commented [I9]: xxxx.

Commented [I10]: xxxxxx

Commented [I11]: PSE *Needs Assessment doc* page27of81 says the criteria is based on 8 items including NERC Standards TPL-001 to TPL-0004. and PSE transmission Guidelines.

is the first contingency). This is defined as a Category B event by the North American Electric Reliability Corporation (NERC). NERC defines a Category C event as an N-2 contingency case (two simultaneous events). An example of this is a breaker failure (the first event) that would lead to clearing all circuits connected to a substation bus (the second event). For this contingency, according to the NERC rules, PSE is allowed to drop non-consequential load. Please define non-consequential load.

Please verify.

6. Documents, supporting data, maps and one-line schematics requested but not supplied by PSE:

a) Please provide all transmission line maps 525kV & below in N & S King County. Please provide one-line diagrams of N & S King County facilities including those of PSE, SCL and BPA. Please list normally open breakers, switchers and existing PSE Remedial Action Schemes.

b) Please provide historical load growth of all PSE substations in N & S King County. The annual substation loads for last 10 years for N & S King County have to be "coincidental loads" (measured at the same time) and the ambient temperature for the loads should be based on PSE's "normal" 23ºF winter design temperature and not for an "extreme" 13ºF winter. Please provide temperature-adjusted loads for each station and the SeaTac temperature when the loads were adjusted for normal winter.

c) Please provide the annual transformer loadings for the 230-115 kV transformers in Sammamish, Talbot and Novelty Hill substations for the last 10 years with the coincidental transformer loads when the distribution substation loads were measured.

d) Please provide transmission line rating tables, one-lines, or any lists showing the lines that PSE said would be overloaded. The lines are Talbot-Lakeside #1 & #2 and the Sammamish-Lakeside #1 & #2. We also need the one-line diagram to include the 115 & 230 kV line ratings and proposed new 230 kV lines "normal" ratings. Please specify line rating at what ambient temperature and at what wind speed.

e) Please provide the calculated "through flow" on the proposed new 230 kV lines when BPA's Monroe-Echo Lake 500 kV line is faulted. Please provide technical analysis of the fault and computer models showing the "through flows" during Spring. Please show maximum imports from BC Hydro and maximum export to California. Please show maximum generation from Columbia River dams. Please show imports to Pacific NW from Idaho and/or Montana. Please provide base cases that were verified by ColumbiaGrid as the appropriate base cases used in the ColumbiaGrid

Commented [I12]: xxxxxx

Commented [I13]: xxxx. Are these all peaks per given year. thus 10 years times # of substations = total number of points. The key data will be 2008/09 the all time winter peak which PSE reported to Joint Operation Committee June 13, 2013 at 25F. And the 2013/14 peak.. Define Normal as Deg F and whose normal

Commented [I14]: Add to show xxx

Commented [I15]: xxxx Also why are these not included already in the N & S KC substation info from above

Commented [I16]: This must be substantial as statement below table 1-2 of the PSE Eastside Needs Assessment report say line over heat in Summer with 3500 MW of "load" when in winter the load is 5208MW per pg 11of78.

April 25, 2011, study #4 and study #11. Please provide "bubble diagrams" of the studies. Also please provide base cases that are verified by ColumbiaGrid as the true base cases that were used to complete the October 28, 2011, study #4 and #11.

~~e)~~f)PSE states on page 11 of 78 of the Eastside Needs Assessment document that regional commitments to increase flows across to the Northern Intertie (the power grid connection British Columbia Canada) to 2300 MW that will show up in the 10 year time frame. Whose commitments are those specifically (PSE, or BPA etc) and what requirements, legal or otherwise, require PSE to shoulder that load through heavily populated areas.

7. CENSE also requested on June 17, 2014, for ColumbiaGrid studies but the detailed studies were unavailable:

a) ColumbiaGrid study dated Apr 25, 2011, request study #4 and study #11

b) ColumbiaGrid study dated Oct 28, 2011, request study #4 and study #11

Can PSE provide the above studies and if not explain why not?

Things missing but may be in your other questions. You may have sent them to me but I don't remember seeing/getting, can you resend?

c) Please detail the other Columbia Grid solutions that had higher capacity and lower reliability risk (higher grid reliability improvement) including but not limited to the "SCL" lines that the City of Bellevue asked SCL about and SCL replied "we prefer that PSE does not use" yet when PSE forwards they change that "prefer" to cannot. The letter was sent by Bellevue City employee Nicolas Matz to Seattle City Lights.
~~c)~~d)

DSD 010100

From: "Kostek, Leann" <leann.kostek@pse.com>
To: "'todd@matadortech.com'" <todd@matadortech.com>
CC: "Nedrud, Jens V" <jens.nedrud@pse.com>, "Aliabadi, Gretchen" <gretchen.aliabadi@pse.com>, "'cvchung@aol.com'" <cvchung@aol.com>
Subject: RE: "Need" response to PSE invite RE: PSE CEII Tariff Language, Procedure, Request Form & Nondisclosure Agreement
Thread-Topic: "Need" response to PSE invite RE: PSE CEII Tariff Language, Procedure, Request Form & Nondisclosure Agreement
Thread-Index:
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AAJFVA=
Date: Wed, 13 Aug 2014 22:12:17 +0000
Accept-Language: en-US
X-MS-Has-Attach: yes
X-MS-TNEF-Correlator:
x-originating-ip: [170.192.215.182]
X-Nonspam: None

Todd –

Hazardous Combination of Risks in South Bellevue: The Seattle Fault, The Olympic Pipeline, and PSE's "Energize Eastside" Power Transmission Line

Rev. 1, 6/2/2015

SUMMARY

The two powerline routes now being considered for PSE's "Energize Eastside" power transmission line ("Oak" and "Willow") share a potentially serious flaw that could increase risk to the public in an already-risky location. Both routes follow the Olympic Pipeline where it crosses the Seattle Fault near I-90 in South Bellevue. The Seattle Fault is an active earthquake fault zone that lies relatively close to the earth's surface. Surface ruptures have occurred in past quakes along the Fault Zone, with the south side of the fault displaced upwards as high as 22 feet relative to the north side. Visual evidence of past surface ruptures has been found within 2 miles of Energize Eastside's proposed route, with indirect evidence even closer.

If surface faulting and ground displacement occur where the Olympic Pipeline crosses the Fault, there is a reasonable likelihood that the pipeline will rupture at that point. With the pipeline moving up to 13 million gallons of gasoline/jet fuel per day at pressures above 1000 PSI, any sizeable break will result in a large fuel spill and probably a major fire. Utility industry guidelines warn against large fires beneath high voltage transmission lines, as the consequences often include line damage, line breakage, and/or "flashover" of current from the pipeline to the ground. Since the Olympic Pipeline is made of steel, a flashover from a 230,000 volt / 1 gigawatt powerline to a 300-mile-long metal pipeline full of gasoline could have catastrophic consequences far beyond Bellevue's city limits.

One mystery remains regarding the routing of the Olympic Pipeline: why does it take two different routes through South Bellevue? The designers of the original pipeline (completed 1965) routed it through Eastgate and Somerset ("Route Segment J"). A second pipeline was completed in 1973, primarily using the same route as the original pipeline. <u>However, for some reason this second line bypassed the original 3-mile pipeline section that passes through Eastgate, Somerset, and the Seattle Fault. Instead, this section of the new line was routed to the west, through Factoria and along Coal Creek Parkway, re-joining the original pipeline route south of Somerset near Coal Creek.</u> As the first indications of the Seattle Fault were noticed in late 1965, the author wonders if the second phase of the pipeline was re-routed to avoid possible fault issues discovered in the Eastgate/Somerset area.

The author recommends that the Energize Eastside EIS study group retain independent consultants with experience in liquid fuel pipelines and seismic zone evaluation to study the following issues in detail:

- **Evaluate the likelihood of a surface rupture of the Seattle Fault where it crosses the Olympic Pipeline(s) in Bellevue.**
- **Determine the vulnerability of the Olympic Pipeline(s) to a surface rupture where it crosses the Fault. This should include a determination of whether the pipeline meets seismic design**

criteria for pipelines that cross surface earthquake faults where surface displacement is known to occur.

- **Engage the Olympic Pipeline Company to determine if they can shed light on why the 1973 pipeline was not co-located with the 1965 pipeline as it passes through the Seattle Fault Zone in Bellevue.**
- **Determine if there are existing regulations that direct utilities to avoid building powerlines in locations where significant risks exist from the presence of existing utilities and/or hazardous geological features.**

BACKGROUND: OLYMPIC PIPELINE

The Olympic Pipeline is operated by BP Pipelines, and is designed to transport up to 13 million gallons of gasoline and jet fuel every day from Blaine and Anacortes, WA, towards Portland, OR[1] (with several delivery points in between). The pipeline consists of two parallel pipes (16" and 20") operating at pressures of around 1000 PSI. The pipeline was completed in 1965 (16" line) and 1973 (20"line)[2], and is buried along most of its route. Where the Olympic Pipeline crosses the Seattle Earthquake Fault Zone in south Bellevue, these two pipelines split to follow separate routes: one crossing Eastgate/Somerset from north to south ("Route Segment J"), and the other diverging from the original pipeline north of I-90, traveling down Factoria Boulevard and Coal Creek Parkway to re-join the main pipeline route near Coal Creek (Route Segments G2, I, K2). **The first phase of the Olympic Pipeline was designed in the early 1960's before the Seattle Fault was discovered.** The author has been unable to determine if any seismic design criteria were incorporated in the design of either of the two Olympic lines.

BACKGROUND: THE SEATTLE FAULT

The Seattle Fault is actually a network of several earthquake fault lines that run east to west, from Hood Canal, WA to around Fall City, WA. The first modern indications that the Seattle Fault exists were noticed in 1965, but it was not determined to be a major seismic danger until 1992[3]. In the Bellevue/Issaquah area, the fault zone runs roughly along Interstate 90, then crosses Lake Sammamish. The Seattle Fault is considered by many to be a particularly hazardous earthquake zone due to the fact that it is a shallow, crustal fault, unlike many other local earthquake faults that are located 30+ miles underground. A map of the Seattle Fault Zone can be found in Attachment A.

Geologists estimate the recurrence rate of the Seattle Fault at approximately 1000 years. The last major quake along this fault occurred approximately 1100 years ago, and resulted in several major landslides into Lake Washington[3]. One of these landslides, which occurred at the south end of Mercer Island, carried an entire hillside covered with large fir trees into the lake, which divers can still see today[4].

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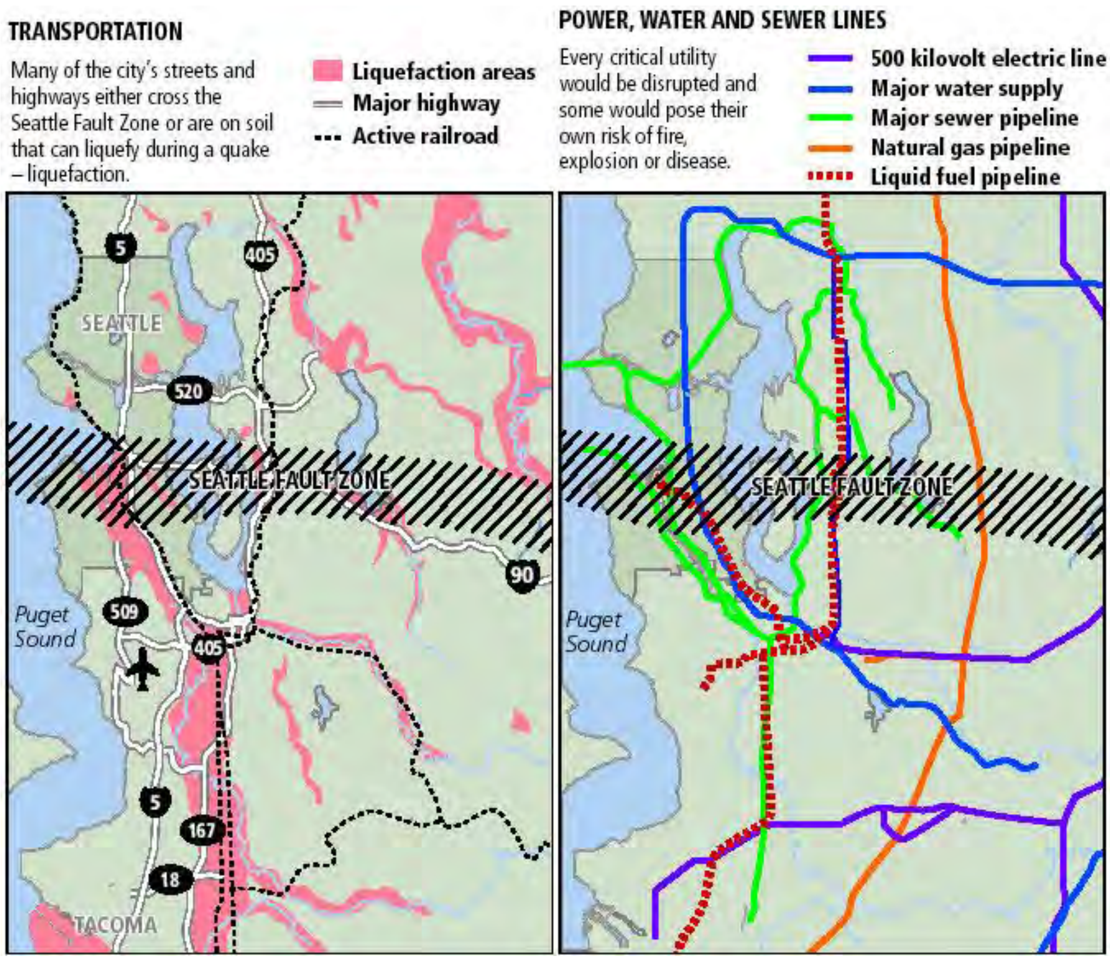
1 http://www.olympicpipeline.com/
2 Bellingham pipeline hearing minutes 3/13/2000
3 Wikipedia article Seattle Fault
4 Underwater forest video

Past earthquakes along the Seattle Fault have caused the earth to rupture at the surface in multiple locations. One such rupture can be seen today near Bainbridge Island, where an uplift 22' high was created in the last earthquake 1100 years ago[5]. Another surface rupture can be found in West Seattle. In South Bellevue, **yet another rupture occurred, near Southeast 38th Street in Vasa Park – less than 2 miles away from the pipeline**.[6] Other surface ruptures have likely occurred, but have been obscured over centuries of erosion and vegetation growth.

The US Geological Survey has stated that future earthquakes on the Seattle Fault will occur: "It's a matter of not if, but when." The Fault has been active for an estimated 40 million years, and has an estimated recurrence interval of approximately 1000 years.[7] Due to its location in a heavily urbanized area with major traffic corridors, many geologists believe the Seattle Fault is a candidate for enhanced real-time seismic monitoring to attempt to quantify the risk to the public.



5 Scenario for a 6.7 magnitude quake on the Seattle Fault
6 Scenario for a 6.7 magnitude quake on the Seattle Fault
7 Scenario for a 6.7 magnitude quake on the Seattle Fault

COMBINING RISKS: THE OLYMPIC PIPELINE, THE SEATTLE FAULT, AND POWER TRANSMISSION LINES

Pipelines located over surface earthquake faults have experienced major failures in other locations. Several examples of pipeline ruptures during earthquakes can be found. "On Jan. 17, 1994, the (magnitude 6.7) Northridge earthquake struck the San Fernando Valley in southern California. The shaking began at 4:31 in the morning. Freeways and apartment buildings collapsed, killing 57 people and injuring thousands. Buried out of sight, an old pipeline operated by the Atlantic Richfield Company tore apart at the seams. Welds failed at nine different points along a 56km stretch, including at a pumping station on the banks of the Santa Clara (River).[8]" One could easily envision this scenario unfolding in Bellevue where the Olympic Pipeline crosses the Seattle Fault, particularly if the earth's surface ruptures during a quake.

According to City of Bellevue testimony in a 1998 hearing: "Our consulting engineer with extensive expertise in pipelines tells us that the locations where Olympic pipeline crosses under SR 520 and I-90 are, in fact, the two most vulnerable points of the pipeline within Bellevue. This is because they are the lowest topographical points where gravity exerts the most pressure on the pipe."[9]

According to the Washington State Military Department: "The (Olympic) pipeline crosses the Seattle Fault in an area where the scenario earthquake will create several feet of displacement and where liquefiable soils exist. …If significant ground displacement occurs, pipeline rupture is expected. Consequences could be devastating – a 1999 rupture of the pipeline in Bellingham released nearly a quarter-million gallons of fuel that subsequently caught fire and killed three people."[10]

Many Washington residents remember the disaster that struck in Bellingham, WA, caused by a breach in the Olympic Pipeline which resulted in deaths. On June 10, 1999, a valve failure caused the Olympic Pipeline to rupture, allowing 229,000 gallons of gasoline from the pipeline to flow into Whatcom Creek. The gasoline traveled down the creek for 1.5 miles, ignited, and created a 1.5-mile-long wall of fire 200' high. Three boys playing near the creek were incinerated. The flames from the gasoline reached a temperature of 2000 degrees, with the smoke from the conflagration reaching 30,000 feet.[11]

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[8] Frazer River spill article
[9] Bellingham pipeline hearing minutes 3/13/2000
[10] Scenario for a 6.7 magnitude quake on the Seattle Fault
[11] Historylink.org Bellingham Pipeline fire

Olympic Pipeline fire, Bellingham, June 10, 1999
Photo by Bill Pifer

HYPOTHETICAL DISASTER SCENARIO (for illustration purposes only)

In South Bellevue, not only does the Olympic Pipeline pose risks, but the combination of the Seattle Fault (a shallow earthquake fault), the 50-year-old Olympic Pipeline, and an older 115,000 volt PSE transmission line have the potential to compound tragedy (even before considering PSE's proposed Energize Eastside new 1 GW transmission line). For example: At the northern base of Somerset hill, the following can be found in close proximity: the Seattle Fault, the Olympic Pipeline, PSE's existing 115,000 volt transmission line (which uses the same route as the pipeline), Sunset Creek (which runs east-west at the base of Somerset Hill), Tyee Middle School, and Edgebrook Swim and Tennis Club. (See Exhibit B for a map of this area.)

Consider the following scenario at this location:

- During a swim meet at Edgebrook, an earthquake along the Seattle Fault ruptures the Olympic pipeline at the base of Somerset Hill, spilling 250,000 gallons of gasoline into Sunset Creek.
- The old PSE 115,000 volt transmission line breaks due to the earthquake, and falls to the ground near the creek.
- The power line ignites the gasoline, causing a wall of flame to travel down the creek.
- Edgebrook Swim and Tennis Club (which is next to the creek) is engulfed in flames, trapping those inside.
- Another break in the pipeline 100 yards north is ignited directly adjacent to Tyee Middle School, trapping 400 children and their teachers inside.
- A third rupture occurs where the pipeline crosses beneath I-90 (about ¼ mile north of Tyee Middle School) and also ignites, engulfing the freeway in flames, blocking all traffic (including emergency responders). All accesses from Seattle to points east of Bellevue via I-90 are blocked.

"ENERGIZE EASTSIDE" ADDS MORE RISKS

None of the above scenarios involve PSE's proposed "Energize Eastside" transmission line. As currently proposed, this line will be a 1 gigawatt (1,000,000 KW), 230,000 volt line running from Woodinville to Renton, WA. (1 gigawatt is approximately the amount of power produced by a large nuclear power plant, and is roughly equivalent to Seattle City Light's entire average demand.[12] The average home uses 2 to 5 KW.)

Both of the proposed routes for the new Energize Eastside project are routed above the Olympic Pipeline where it crosses the Seattle Fault. The Olympic Pipeline actually consists of two pipelines. These two pipelines follow two different routes through South Bellevue where they cross the Seattle Fault. By coincidence, PSE has chosen these very two routes as their finalists for Energize Eastside, exposing both of them to the risk of fire from a burning pipeline fractured during a seismic event.

There are at least four potential disaster scenarios that this new Energize Eastside PSE 1,000,000 KW transmission line could add at this already dangerous location:

1.) Scenario #1: The new electrical transmission line breaks during an earthquake and falls to the ground, causing damage and/or injury. (This is probably the least likely of these events.)
2.) Scenario #2: The Olympic Pipeline ruptures during an earthquake. The existing PSE 115,000 volt transmission falls and ignites the spilled fuel. A 200' wall of smoke and 2000 degree flames from the burning pipeline rises to engulf the new Energize Eastside PSE 1,000,000 KW power lines, causing the conductors to heat up, weaken, and break. The falling power line wires land on trees and buildings below, causing damage and/or injury. (A variant of this scenario would involve the powerline becoming damaged but not breaking, which could require deactivation and replacement of the powerline.)
3.) Scenario #3: The 200' wall of smoke and flames from the burning Olympic Pipeline rises to engulf the new Energize Eastside power line and causes it to "flash-over", delivering a massive short circuit to the earth below. "Flashover" is a known phenomenon in the utility industry, and has been known to occur where wildfires cause large amounts of smoke to billow up to overhead high voltage transmission lines. In a flashover incident, the electric current flowing in the power line finds a new path to ground through the smoke and flames, using it to conduct electricity.[13] If anywhere near the 1 gigawatt capacity of the proposed PSE line was delivered to the earth below via flashover, anything in its path could be destroyed. **It may also be possible that this surge of electricity would strike the metal pipeline and travel along it, igniting even more gasoline and jet fuel along the pipeline route.**

According to the Bonneville Power Authority, one of the nations' largest operators of high-voltage transmission lines: "Smoke and hot gases from a large fire can create a conductive path for electricity. When a fire is burning under a power line, electricity could arc from the wire, through the smoke and to the ground, endangering people and objects near the arc……large fires near or around power lines can damages the lines and cause power outages."[14]

[12] Seattle City Light Wikipedia article
[13] BPA Document DOE/BP–3804
[14] BPA Document DOE/BP–3804

Scenario #4: The Olympic Pipeline is damaged during installation of the new Energize Eastside power transmission line, resulting in a leak and fire. (Damage caused by third party construction is by far the leading cause of pipeline leaks.[15]) The fire damages the powerline and causes a flashover event, resulting in damage on the ground.

Perhaps these kind of potential events demonstrate why the Olympic Pipeline Company has expressed their preference for Energize Eastside transmission line routes that do not follow the pipeline route.

A 50-YEAR-OLD MYSTERY

One mystery remains regarding the routing of the Olympic Pipeline: why does it take two different routes through South Bellevue? The designers of the original pipeline (completed in 1965) routed it through Eastgate and Somerset ("Route Segment J"). A second pipeline was completed in 1973, which for most of its length used the same route as the original pipeline. However, this second pipeline for some reason bypassed the 3-mile section that passes through Eastgate, Somerset, and the Seattle Fault. Instead, the new line was routed to the west, through Factoria and along Coal Creek Parkway, re-joining the original pipeline route south of Somerset near Coal Creek. Since the first indications of the Seattle Fault came to light in late 1965, the author wonders if the second phase of the pipeline was re-routed to avoid faults in the Eastgate/Somerset area. The author recommends that the EIS study group engage Olympic Pipeline to determine if their records show why this route choice was made for the second pipeline (which still crosses the Seattle Fault). This information could influence the final selection of the Energize Eastside powerline route.

RISKS TO THE UTILITY

PSE has a vested interest in the reliability of this proposed new powerline, which is being built to add redundancy to the grid in an area where power demand is projected to increase. One event that could threaten the grid in this region is a large regional earthquake that causes local PSE generation assets in the area to trip offline. However, if studies determine that the new powerline is also threatened by this same type of event, it is debatable whether it accomplishes the goal of increasing redundancy in the aftermath of an earthquake.

POTENTIAL REGULATORY ISSUES

It is possible that Federal guidelines or industry regulations exist that would direct the designers of the Energize Eastside transmission line to avoid hazardous locations such as this one. While the author was unable to determine if such rules exist when this document was written, these should be fully explored before a permit is issued.

[15] Bellingham pipeline hearing minutes 3/13/2000

RECOMMENDED ACTIONS

The author recommends that a moratorium on the Olympic Pipeline route be established until the EIS study group is able to retain independent consultants with pipeline and seismic experience to study the following issues in detail:

- **Evaluate the likelihood of a surface rupture of the Seattle Fault where it crosses the Olympic Pipeline(s) in Bellevue when the next quake occurs along the Fault.**
- **Ascertain the vulnerability of the Olympic Pipeline(s) to a surface rupture where it crosses the Fault. This should include a determination of whether the pipeline meets seismic design criteria for pipelines that cross surface earthquake faults where surface displacement is known to occur.**
- **Engage the Olympic Pipeline Company to determine if they can shed light on why the 1973 pipeline was not co-located with the 1965 pipeline as it passes through the Seattle Fault Zone in Bellevue**
- **Determine if there are existing regulations that direct utilities to avoid building powerlines in locations where significant risks exist from the presence of existing utilities and/or hazardous geological features.**

CONCLUSION

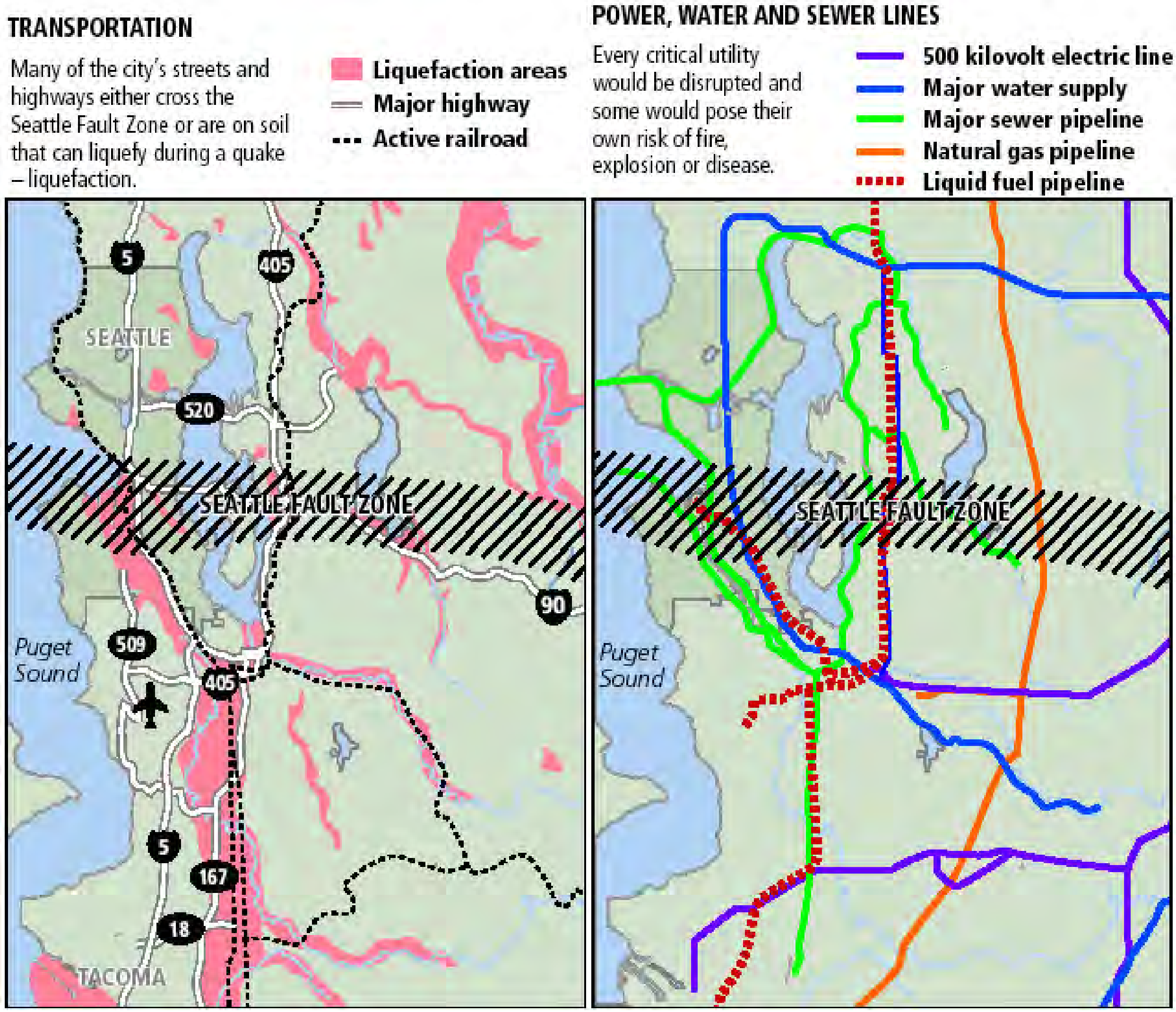
South Bellevue already faces multiple catastrophic risk scenarios due to the presence of the Seattle Fault, the Olympic Pipeline, PSE's existing 115 KV power line, Interstate 90, and other thoroughfares, schools, and creeks in the fault zone. **Locating a new 1 gigawatt power line above an older gasoline pipeline where it crosses a known surface earthquake fault seems like a poor decision when other route options exist.** Prudent disaster mitigation suggests that a different powerline route be used that does not increase the risk to the public, as these routes do. A moratorium on this route should be established until appropriate engineering evaluations are completed to quantify the risk to the public.

The author also encourages the reader to learn more about the Seattle Fault, with the goal of developing a personal disaster survival plan. The State of Washington document titled "Scenario for a Magnitude 6.7 earthquake on the Seattle Fault" provides an excellent overview of the scope of such an event.

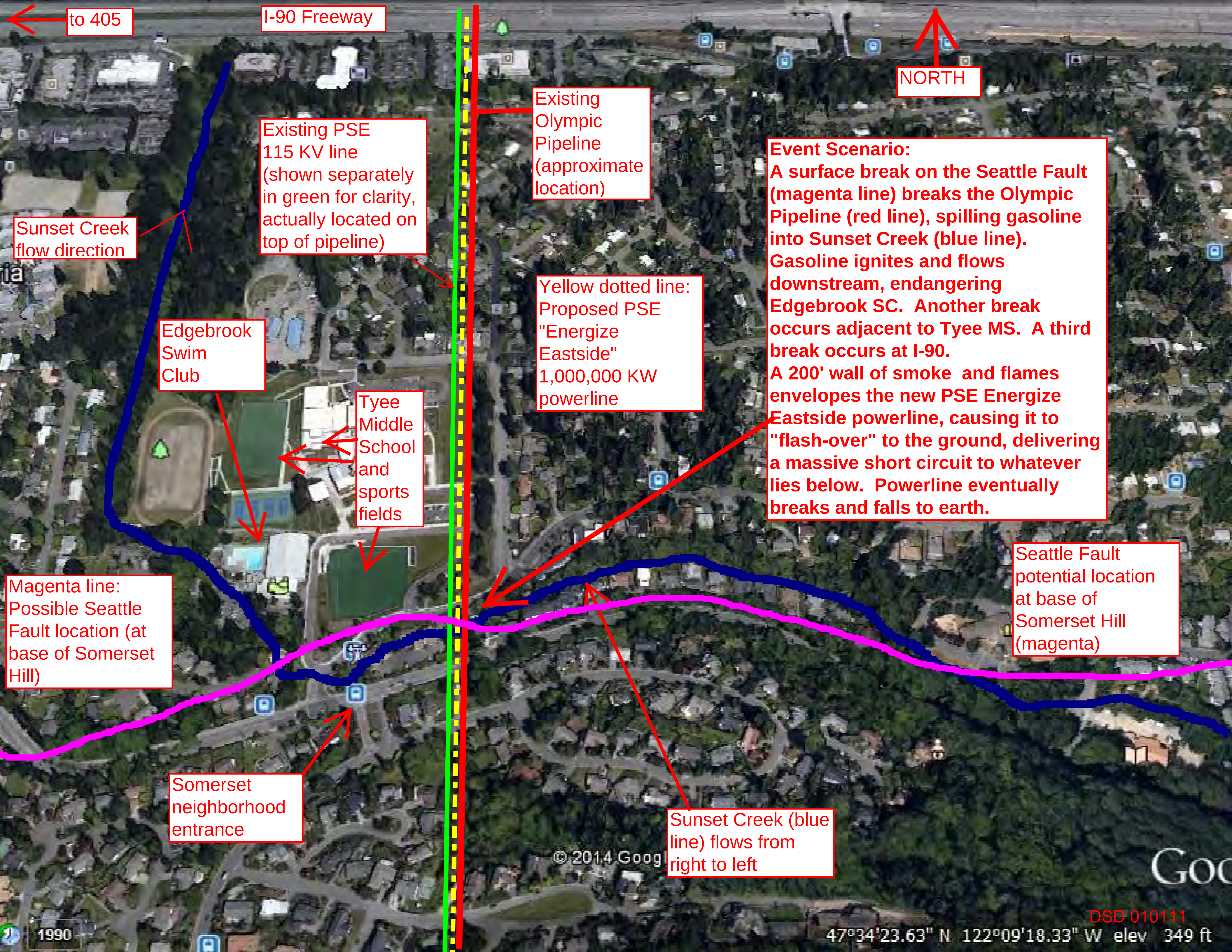
ABOUT THE AUTHOR

James Sweet, PE is a retired engineer who moved to South Bellevue with his family in 1960. Jim grew up in Newport Hills, and attended Newport Hills Elementary, Tyee Middle School, Ringdall Middle School, Newport High School, and the University of Washington, graduating with a degree in Mechanical Engineering. Jim presently lives in South Bellevue, has many friends in the area, and wants them to be aware of the risks lying beneath our feet.

Attachment A - Seattle Fault map (with utilities shown)



Source: "Scenario for a Magnitude 6.7 Earthquake on the Seattle Fault", by Earthquake Engineering Research Institute and Washington Military Department Emergency Management Division, June 2005


to 405
I-90 Freeway
NORTH
Existing Olympic Pipeline (approximate location)
Existing PSE 115 KV line (shown separately in green for clarity, actually located on top of pipeline)
Sunset Creek flow direction
Event Scenario:
A surface break on the Seattle Fault (magenta line) breaks the Olympic Pipeline (red line), spilling gasoline into Sunset Creek (blue line). Gasoline ignites and flows downstream, endangering Edgebrook SC. Another break occurs adjacent to Tyee MS. A third break occurs at I-90.
A 200' wall of smoke and flames envelopes the new PSE Energize Eastside powerline, causing it to "flash-over" to the ground, delivering a massive short circuit to whatever lies below. Powerline eventually breaks and falls to earth.
Yellow dotted line: Proposed PSE "Energize Eastside" 1,000,000 KW powerline
Edgebrook Swim Club
Tyee Middle School and sports fields
Magenta line: Possible Seattle Fault location (at base of Somerset Hill)
Seattle Fault potential location at base of Somerset Hill (magenta)
Somerset neighborhood entrance
Sunset Creek (blue line) flows from right to left
© 2014 Googl
1990
DSD 010111
47°34'23.63" N 122°09'18.33" W elev 349 ft

STRATEGY FOR ELIMINATING RISKS OF CORROSION AND OVERPROTECTION FOR BURIED MODERN PIPELINES

MAIN author

Fumio Kajiyama

TOKYO GAS CO., LTD
Transmission Section
Supply Control and Disaster Management Department
5-20, Kaigan, 1-Chome, Minato-ku,
Tokyo, 105-8527

JAPAN

ABSTRACT

The driving force that causes metals to corrode is a natural consequence of their temporary existence in metallic form. Application of cathodic protection (CP) as measures to stop corrosion has a very long history. The first application of impressed current system for protection of underground structures took place in England and in the United States, about 1910-1912. The first criterion for CP of steel pipelines, that is, −0.850V (vs. copper sulfate electrode) with the CP applied, was proposed by Kuhn in 1933 and has since been accepted and used worldwide on steel pipelines and structures in various soils and water. Kuhn’s criterion has facilitated the application of CP for extending buried pipelines with the economic growth. Kuhn’s criterion is referred to the protection potential criterion and in the scope of direct current (DC) corrosion protection.

In the early 1900s, the effect of AC interference current on a metallic structure was known and to some degree had been quantified. In 1906, Hayden investigated to determine whether, and to what extent, AC currents passing between any metallic conductors (gas and water pipes, lead cables, etc.) and the ground would produce AC corrosion, due to the introduction of grounded AC systems using the developed single-phase railway motor. Hayden concluded iron is attacked less than lead. Up until the mid-1980s, the prevailing opinion was that, although AC current could cause corrosion of steel, the corrosion rate was a small percentage of an equivalent amount of DC and furthermore could be controlled by the application of CP in accordance with the protection potential criterion. Up to the mid-1980s, corrosion failure on a pipeline was not attributed to AC corrosion, probably because the pipelines were bare or less well coated having sufficient grounding, such that induced voltages were not a practical problem.

In 1986, corrosion failure on a polyethylene coated pipeline caused by induced AC interference currents resulting from AC powered rail transit system was first reported in Europe despite satisfying the protection potential criterion. Since then, pipeline failures caused by AC corrosion have been reported not only in Europe but in North America. Factors that contribute to AC corrosion include (1) high resistivity of pipe coating, and (2) the increased tendency to locate pipelines paralleling high voltage (HV) AC electric power lines and/or AC powered rail transit systems. It has been definitely shown by the occurrence of AC corrosion on a cathodically protected pipeline that AC corrosion cannot be prevented by CP in the presence of very high AC voltage of a pipeline.

The necessity for establishment of criterion for AC corrosion protection has been realized ever since. However, there are no agreed-on criteria for AC corrosion protection.

Recently, pipelines are being constructed in parallel with HVAC electric power lines and/or AC powered rail transit systems with thinner, high strength steel-walls, high resistivity coating with little or no corrosion allowance. This means that more attention must be paid to new threats, that is, AC corrosion and overprotection on modern pipelines.

The authors have developed an advanced instrumentation for assessing the AC corrosion risk of buried pipelines, and established the new CP criterion based on coupon DC and AC current densities (coupon current density-based criterion). The most distinguished feature of the instrumentation is the simultaneous computation in a measuring unit of 20 ms regarding coupon DC current density and coupon AC current density corresponding to the commercial frequency of 50 Hz. The criterion eliminates all corrosion risks such as AC corrosion, DC stray current corrosion, microbiologically influenced corrosion etc., and overprotection risk.

This paper details how the developed instrumentation enabled understanding of AC corrosion or protection level of a cathodically protected pipeline, and establishment of the new CP criterion. Particular emphasis in the presence of AC is placed on the necessity for understanding of (1) limitations of the protection potential criterion and CP, and (2) adverse effects leading to possible AC corrosion and hydrogen embrittlement under overprotection circumstances caused by increasing the CP level as protection measures against AC corrosion. Furthermore, the features of an advanced instrumentation for assessing the AC corrosion risk of buried pipelines are also described with an example of measured data.

1. PREAMBLE

Pipeline operators were shocked at the first occurrence of AC corrosion in 1986 and subsequent AC corrosion failures of modern pipelines in Europe and North America despite satisfying the protection potential criterion. It was proven that AC corrosion was attributed to induced AC voltage on a pipeline caused by (1) application of high resistivity coatings, and (2) the increased tendency to locate pipelines paralleling HVAC electric power lines and/or AC powered rail transit systems. To prevent a recurrence of AC corrosion, corrosion engineers have urged the necessity of a new cathodic protection (CP) criterion for AC corrosion protection. However, there are no agreed-on criteria for AC corrosion protection.

Recently, because of limitations of land, minimization of environmental effects and cathodic currents demand, high transportation efficiency, and cost reduction in pipeline construction, natural gas transmission pipelines (modern pipelines) are being constructed in parallel with HVAC electric power lines and/or AC powered rail transit systems with high resistivity coating, and thinner, high strength steel-walls.

Today it is acknowledged that, the AC corrosion risk of pipelines with high resistivity coating can be evaluated by installing steel coupons at pipe depth and measuring the DC and AC current densities when the coupon is connected to the pipe. However, there are still not concrete techniques for measuring coupon DC and AC current densities in the field.

Furthermore, special regard shall be paid to the fact that modern pipelines made of high strength steels are susceptible for hydrogen embrittlement. Thus particular care shall be excised to avoid overprotection leading to two possible adverse effects on modern pipelines. The first is hydrogen embrittlement due to hydrogen production at the pipe surface by excessive cathodic reaction. The second is stabilization of significant corrosion due to the formation of dissolved dihypoferite ions ($HFeO_2^-$) by very high levels of cathodic reaction.

Therefore, a new cathodic protection criterion must cover the eliminations of the overprotection risk as well as the AC corrosion risk, in addition to the protection potential criterion.

This paper describes strategy for eliminating risks of corrosion and overprotection for buried modern pipelines with two key points:

1) Establishment of a new cathodic protection criterion in which the elimination of the risks of overprotection as well as AC corrosion are taken into account, in addition to the protection potential criterion
2) Development of an advanced instrumentation for assessing the AC corrosion risk in the field

2. HISTORY OF CATHODIC PROTECTION

2.1 APPLICATION OF CATHODIC PROTECTION

The definition of corrosion is the degradation of a material that results from the interaction of a material and its environment. The spontaneous process by which metals convert to the lower-energy oxides is referred to corrosion. Application of cathodic protection (CP) as measures to stop corrosion has a very long history. The practice of zinc coating on steel was described in France as early as 1742. This method is application of the conception of CP. Contributions of Sir Humphry Davy to CP are very famous. The rapid failure of the copper sheathing on the hulls of ships of the British Navy provided Davy with the opportunity to apply his discoveries of the galvanic effects of dissimilar metals to the prevention of corrosion electrolytically. At that time, copper sheathing was used to protect the wooden hulls from destruction by worms and prevent the adhesion of barnacles. In 1824, Davy reported that copper is protected by zinc or iron coupled by copper in sea water. The problem regarding a balance between ‘corrosion prevention’ of copper by CP and ‘fouling development’ was not entirely solved. This led Davy to realize the necessity for control of the current required for corrosion prevention.

The first application of impressed current system for protection of underground structures took place in England and in the United States, about 1910-1912.Nowadays it is widely recognized among corrosion engineers that the most reliable methods of protecting buried pipelines from corrosion are external coatings and CP. The external coatings can degrade over time; enabling corrosion to initiate in a holiday provided that insufficient current flowing through electrolyte to the holiday. Therefore combination coating with CP is prerequisite.

2.2 PROTECTION POTENTIAL CRITERION WITH THE CATHODIC PROTECTION APPLIED

The first criterion for cathodic protection (CP) of steel pipelines, that is, −0.850V (vs. copper sulfate electrode, CSE) with the CP applied, was proposed by Kuhn in 1933 and has since been accepted and used worldwide on steel pipelines and structures in various soils and water. Kuhn's criterion has facilitated the application of CP for extending buried pipelines in order to cope with the rapid economic growth.

3. RECOGNITION OF AC CORROSION

In the early 1900s, the effect of alternating currents on metallic structures was known and to some degree had been quantified. In 1906, Hayden investigated to determine whether, and to what extent, alternating currents passing between any metallic conductors (gas and water pipes, lead cables, etc.) and the ground would produce electrolytic corrosion, due to the introduction of grounded alternating-current systems using the developed single-phase railway motor. Hayden concluded iron is attacked less than lead.

More than 50 years ago, AC corrosion on pipelines was perceived in the gas industry. Kulman cited an American Gas Association (AGA) corrosion committee survey in 1955 wherein seven of 27 pipeline respondents who had experienced induced AC also had suspected that AC current was a contributing cause of corrosion in their facilities.

Up until the mid-1980s, the prevailing opinion was that, although AC current could cause corrosion of steel, the corrosion rate was a small percentage of an equivalent amount of direct current (DC) and furthermore could be controlled by the application of cathodic protection (CP) in accordance with the protection potential criterion.

At length, in 1967, Dévay et al. have disproved the prevailing opinion indicating the combined effect of 50 Hz AC and DC current densities on the polarization behavior of 1 cm^2 steel electrodes in a 5 % KCl solution that residual corrosion rate exceeded 0.1 mm/y despite a substantial cathodic current density of 10 A/m^2 and corresponding polarized potentials more negative than $-0.90\ V_{CSE}$. However, at that time, pipeline engineers did not consider the experimental results obtained by Dévay et al. very important, probably because the pipelines were bare or less well coated pipelines having sufficient grounding, such that induced voltages were not a practical problem.

4. UNDERSTANDING OF AC CORROSION WITH THE CATHODIC PROTECTION APPLIED

4.1 UNDERSTANDING OF AC CORROSION

AC corrosion was not well understood for two reasons: (1) the interaction of AC and DC currents affecting the electrochemical phenomenon of corrosion is very complicated, and (2) the instrumentations used to measure the electric parameters in DC and AC with frequencies between 50 and 100 Hz were not available.

Although some investigators have attempted to explain mechanisms of AC corrosion, there is a lack of technical consensus on the mechanism and extent of the effect of AC on underground metallic structures. However, the AC corrosion on a cathodically protected pipeline is understood conceptually as follows. Figure 1 illustrates induced AC voltage on a pipeline with and without cathodic protection (CP) for a single period of a 50 Hz-sinewave. In Figure 1, the period of induced AC voltage is 20 ms corresponding to the commercial frequency of 50Hz. AC corrosion can occur on a cathodically protected pipeline only when the peak of the positive part of AC wave form is more positive than the protection potential. For the positive part of AC wave form, simultaneous reactions could occur in addition to the dissolution of steel, that is, corrosion reaction.

Probable simultaneous reactions for the positive part of AC wave form:
$Fe^{2+} \rightarrow Fe^{3+} + e^-$
$1/2H_2O \rightarrow 1/4O_2 + H^+ + e^-$
$1/2H_2 \rightarrow H^+ + e^-$
Principal anodic reaction is thought to be the dissolution of steel. Consequently, the dark shading on the AC wave form in Figure 1 refers to a strong likelihood of AC corrosion.

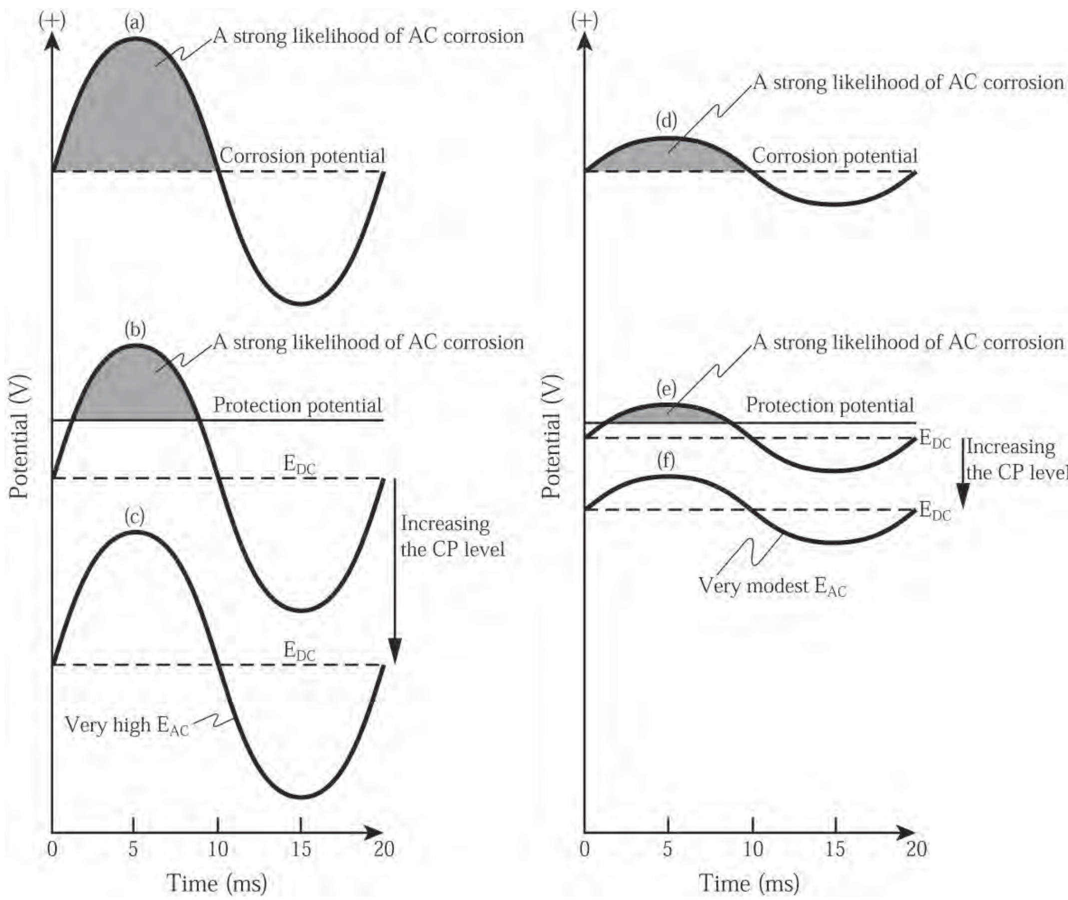


Figure 1 AC corrosion and its control by increasing the cathodic protection (CP) level.

Although increasing in the cathodic protection level so that the peak of the positive part of AC wave form can be brought below the protection potential is thought to eliminate the AC corrosion risk on a cathodically protected pipeline, AC corrosion can remain significant due to the formation of dissolved dihypoferrite ions ($HFeO_2^-$) which may stabilize corrosion at a very high rate at very high pH, even when the protection potential criterion is being met. This method can produce excess hydroxide ions (OH^-) and hydrogen produced by CP current ($1/2O_2 + H_2O + 2e^- \rightarrow 2OH^-$, $2H_2O + 2e^- \rightarrow 2H(H_2) + 2OH^-$), that is, overprotection conditions. Furthermore, overprotection may promote hydrogen damage of modern pipelines. ISO 15589-1 requires that, for high strength steels (specified minimum yield strength greater than 550 MPa), the limiting critical potential shall be determined with respect to the detrimental effects in the material due to hydrogen formation at the metal surface.

4.2 FACTORS CONTRIBUTING TO AC CORROSION

Because AC corrosion rate is related to AC current density, and then whether or not AC corrosion will occur depends primarily on the surface area of holiday and electrolyte resistivity under induced AC voltage. Assuming a circular holiday, the AC current density I_{AC} is given by equation (1) and proportional to parallel length between pipelines and HVAC electrical power lines or AC powered rail transit systems.

$$I_{AC} = \frac{8V_{AC}}{\rho \ \pi \, d} \quad \propto \quad \frac{I \cdot L}{\rho \, d} \tag{1}$$

where:

V_{AC} = Induced AC voltage of pipeline to remote earth (V)
ρ = Electrolyte resistivity (ohm-m)
d= Diameter of a circular holiday (m)
I = Current in HVAC electric power lines or trolley wires
L = Parallel length between pipelines and HVAC electrical power lines or AC powered rail transit systems

The formula is applicable to cases when the holiday size is greater than the thickness of the coating and resistance to earth of the holiday is ρ / (2d).

Equation (1) suggests that AC current density, that is, AC corrosion rates;

- Increase with increasing currents in HVAC electric power lines/trolley wires I;
- Increase with increasing the parallel length between pipelines and HVAC electric power lines/trolley wires;
- Increase with decreasing electrolyte resistivity; and
- Increase with decreasing holiday surface area.

5. OCCURRENCE OF AC CORROSION ON A CATHODICALLY PROTECTED PIPELINE

Rapidly growing demand for energy requires the construction of an increasing number of high voltage AC (HVAC) electric power lines and the laying of high-pressure pipelines of large diameters. In congested areas as well as rural districts, the possibilities of using different routes for HVAC electric power lines and transmission pipelines are very limited. This suggests that these lines will run parallel to each other, sometimes for long distances.

In 1986, corrosion failure on a pipeline caused by induced AC interference currents was first reported in Europe despite satisfying the protection potential criterion. Since then, AC corrosion has occurred in North America as well as in Europe.

The primary conclusion stemming from the literature survey on AC corrosion with the CP applied is as follows: (1) Short-term perforation or severe corrosion has been observed, (2) The pipelines had high resistivity coatings such as fusion bonded epoxy, (3) The pipelines were laid paralleling HVAC electric power lines and/or AC powered rail transit systems for a long distance, (4) The AC corrosion protection has not been taken into account in the stage of design for cathodic protection.

External pipe coatings are intended to form a continuous film of electrical insulating material over the metallic surface to be protected. The function of such a coating is to isolate the metal from direct contact with the electrolyte, interposing a high electrical resistivity so that electrochemical reactions cannot occur. Pipe coatings are not perfect forever, natural and third party degradation of pipe coating could occur. Therefore, combination of pipe coatings and cathodic protection is prerequisite. Pipe coating industries have endeavored to develop coatings with high resistivity and a high level of damage resistance.

Since its first use in New Mexico in 1960, fusion bonded epoxy (FBE) coating has remained the external pipe coating of choice in North America. The 1980s saw the introduction of three-layer polyethylene or polypropylene coatings in Europe. Both the fusion bonded epoxy coatings and three-layer polyethylene coatings have raised induced AC voltages on pipelines.

The AC corrosion risk of modern pipelines is increasing, due to the technological advancements in pipe coating materials which provide increased pipe coating resistance values and furthermore the increased tendency to locate pipelines paralleling HVAC electric power lines and/or AC powered rail transit systems.

6. LIMITATIONS OF THE PROTECTION POTENTIAL CRITERION

As illustrated earlier in Figure 1, if induced AC voltage is very high, the AC corrosion can occur even the protection potential criterion is being met. In other words, despite satisfying the protection potential criterion, coupon DC potential E_{DC} cannot indicate whether the AC corrosion occurs or not. This suggests that a coupon DC potential satisfying existing protection potential criterion does not necessarily eliminate the likelihood of AC corrosion.

A 1992 report by Funk, Prinz and Schöneich described the test results of steel coupons with respect to corrosion versus AC and DC (cathodic protection) current densities as follows:

- For AC current densities greater than 30 A/m^2
  The maximum corrosion rate is in excess of 0.1 mm/y despite a constant cathodic protection current density of 2 A/m^2. In this case, the protection potential criterion is not applicable.
- For AC current densities less than 30 A/m^2
  There is no AC induced corrosion at cathodic protection current density of about 1 A/m^2.

Funk et al. also reported that measurement of AC current density on steel coupons provides information on the risk of corrosion and corrosion prevention for AC current densities greater than 30 A/m^2.

Kajiyama and Nakamura have carried out a field study, with coupons in monitoring stations, on a 6.6 km length of polyethylene coated 323.9 mm outside diameter pipeline that paralleled a 66 kV, 50 Hz electric power transmission line. They have reported that, despite a substantial coupon DC (cathodic protection) current of 10.8 A/m^2 and showing polarized potential of $-1.12\ V_{CSE}$, coupon AC current density was 184 A/m^2. This indicates that AC corrosion on a holiday is very likely to occur despite high level of cathodic protection.

ISO 15589-1 prescribes for the AC corrosion risk and CP as follows: If the a.c.current density on a 100 mm^2 bare surface (e.g. an external test probe) is higher than 3 A/m^2 (or less, in certain conditions), there is a high risk of corrosion. Risk of corrosion is mainly related to the level of a.c.current density compared to the level of CP current density. If the a.c.current density is too high, the a.c. corrosion cannot be prevented by CP.

7. OVERPROTECTION AS THREAT TO PIPELINE INTEGRITY

In Figure 1, E_{DC} indicates polarized potential. If induced AC voltage on a cathodically protected pipeline is very high as shown (b), the method of increasing the CP level ((b) $\rightarrow$ (c)) may be thought so that the positive part of AC wave form can be neglected; Thereby satisfaction with the protection potential criterion is achieved. The aim of increasing the CP level is not to mitigate induced AC voltage but to lower the peak of the positive half cycle of the sinusoidal AC wave form more negative than the protection potential. However, particular care shall be exercised to avoid overprotection, which can result in two adverse effects on modern pipelines. In overprotection conditions, excess hydroxide ions (OH^-) and hydrogen are produced by excess CP current ($1/2O_2 + H_2O + 2e^- \rightarrow 2OH^-$, $2H_2O + 2e^- \rightarrow 2H(H_2) + 2OH^-$). The first possible adverse effect is hydrogen embrittlement due to hydrogen production at the pipe surface by excess cathodic reaction. The second possible adverse effect is stabilization of significant corrosion due to the formation of dissolved dihypoferrite ions ($HFeO_2^-$) at the alkalized steel interface as a result of accumulation of hydroxide ions (OH^-) by very high levels of cathodic reaction as illustrated in Figure 2 showing Pourbaix diagram. In Figure 2, potential E is expressed in terms of standard hydrogen electrode (SHE). In the domain of $HFeO_2^-$, potentials are shown between about $-1115mV_{CSE}$ and $-1345mV_{CSE}$ at pH above about 13.5. ISO 15589-1 stipulates that the limiting critical potential should not be more negative than -1200 mV referred to CSE, to avoid the detrimental effects of hydrogen production and/or a high pH at the metal surface.

Therefore, in the case of high induced AC voltage, increasing the CP level shall be prohibited. It should be noted that overprotection is regarded as threat to pipeline integrity.

In the case of very modest induced AC voltage, increasing the CP level (f) is probably effective.

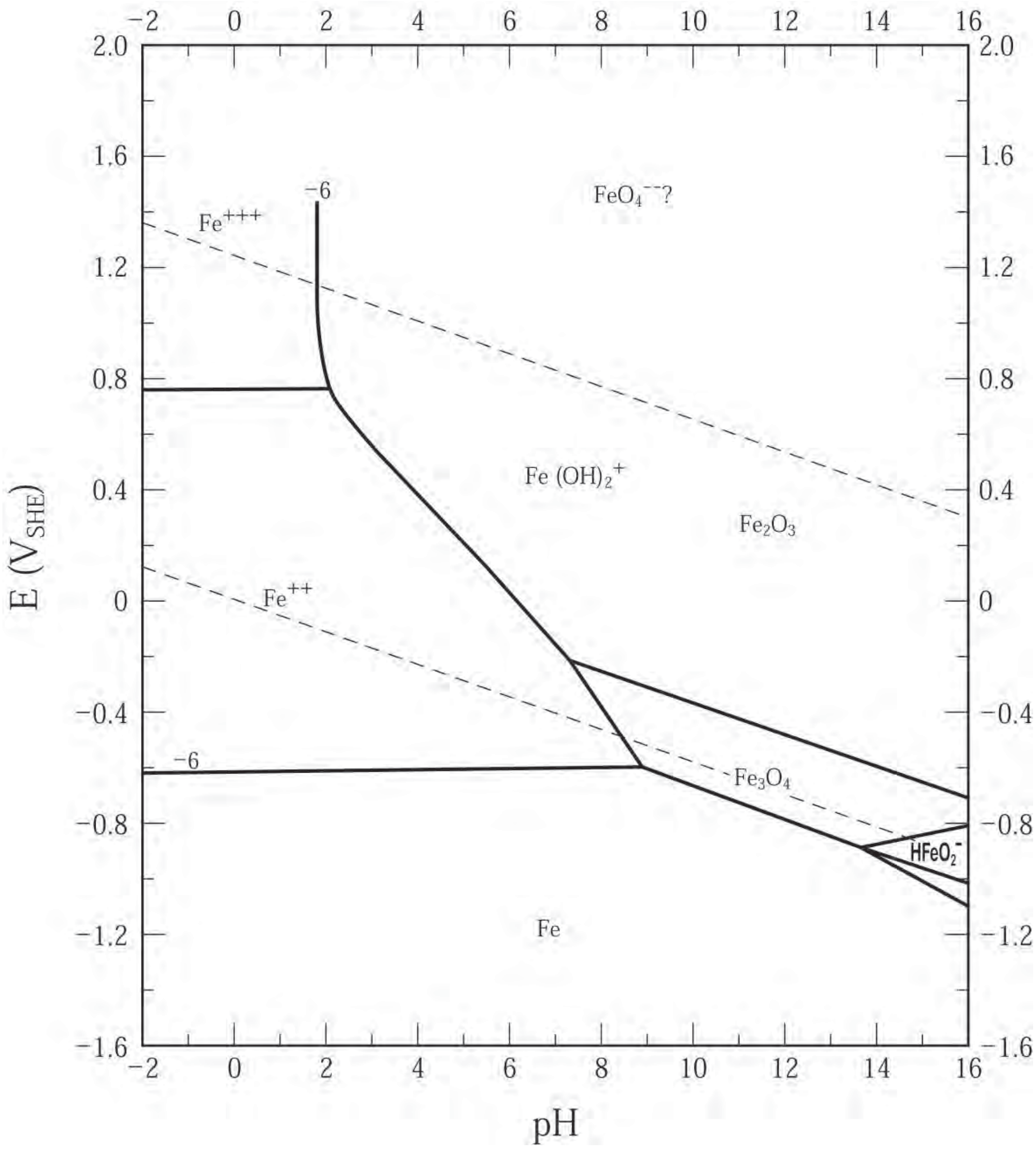


Figure 2 Pourbaix diagram showing $HFeO_2^-$ region with respect to AC corrosion at very high pH.

8. EVALUATION METHOD OF THE AC CORROSION RISK

Because the AC current density at a holiday on a pipeline cannot be measured directly, the current density and therefore the risk of AC corrosion must be evaluated indirectly. The AC current density can be determined by installing steel coupons at pipe depth and measuring the AC current when the coupon is connected to the pipe. A coupon and reference electrode are placed as close to the pipe as possible to minimize the IR drop. Thereby coupon DC potentials E_{DC} can be considered as polarized potential. Figure 3 shows measuring systems for the coupon current densities (I_{DC}, I_{AC}) and coupon potentials (E_{DC}, E_{AC}). In Figure 3, the dark shading on the coupon is a bare steel surface simulating a holiday.

Nowadays there appears to be a tacit agreement that the AC corrosion can be evaluated by coupon DC and AC current densities, I_{DC} and I_{AC}, respectively.

Coupon currents can be measured by the voltage drop across an internal shunt resistor between a coupon and a pipe. For coupon current measurements the value of the internal shunt resistor should sufficient low to avoid significant disturbance of the system.

Though coupon DC and AC potentials, E_{DC} and E_{AC}, are not adopted for determining the CP level. However, these values are very useful to understand the CP condition of buried pipelines. Plotted data taken from over-the-line coupon DC potentials, tops (the most positive direction) in the plot indicate locations to be suspected as holidays and/or metallic connections. Using the reference electrode instead of remote earth, coupon AC potentials E_{AC} are used to determine the levels of AC interference roughly.

The method for acquisition of data on coupon current densities (I_{DC}, I_{AC}) and coupon potentials (E_{DC}, E_{AC}) is detailed in **12**.

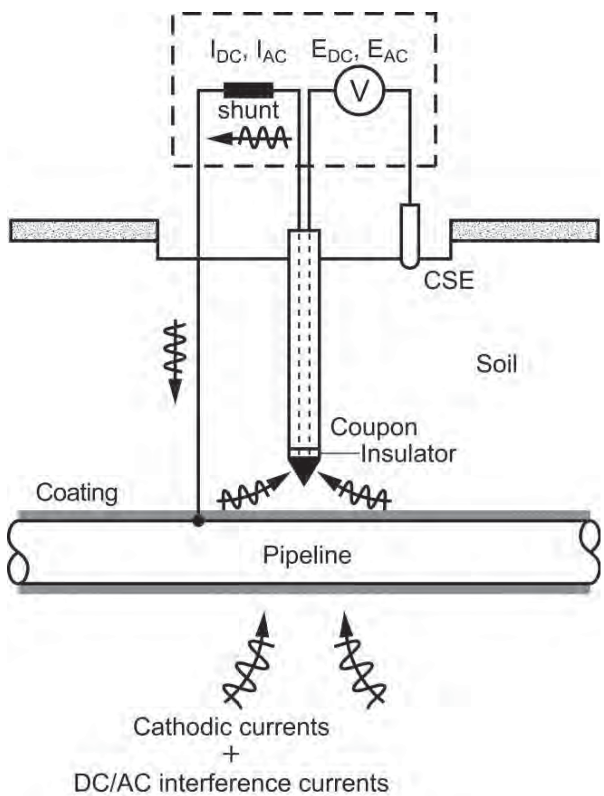


Figure 3 Measuring systems for the coupon current densities (I_{DC}, I_{AC}) and coupon potentials (E_{DC}, E_{AC}).

9. AC CORROSION PROTECTION CRITERION

After the first corrosion perforation on a polyethylene coated gas pipeline in Germany, attributed to AC corrosion despite satisfying the protection potential criterion, in 1986, the AC corrosion protection criterion DIN 50 925 as described as below was established, in 1992.

The AC corrosion protection criterion was established on the concepts as follows:

At present, there are two criteria related to the control of AC corrosion. These can be applied after coupon DC and AC current densities are measured.

Equation (1) suggests that, even with very modest induced AC voltage, AC corrosion rate would be very high at very small holidays in contact with the electrolyte with very low resistivity. Therefore AC corrosion rate is affected not by induced AC voltage but by AC current density. This is the reason why CP criteria related to the control of AC corrosion are prescribed based on coupon current densities (coupon DC current densities and AC current densities).

The two criteria defined are:

- DIN 50 925 (in the year 1992)
  AC current densities less than about 30 A/m^2, when cathodic protection current densities shall be maintained at about 1 A/m^2
- ISO 15589-1 (in the year 2003)
  AC current densities less than 30 A/m^2 (or less, in certain condition)

The two CP criteria, however, do not document how coupon AC current density can be measured in the field, and the frequency at which AC corrosion shall be prevented.

There are no agreed-on criteria for AC corrosion protection.

10. NEW CATHODIC PROTECTION CRITERION FOR THE ELIMINATION OF ALL CORROSION RISKS AND OVERPROTECTION RISK

Kasahara has presented that the minimum coupon DC current density of 0.1 A/m^2 should be adopted.

According to BS 7361 : Part 1, for thick film coatings, such as reinforced coal tar enamel in high resistivity soil, an instant-off potential more negative than −3.0 V_{CSE} could be acceptable. Kajiyama et al. have reported that, in the case of thick polyethylene coatings (coating thickness > 5 mm) without holidays with an average coating resistance of higher than 10^5 ohms-m^2, the maximum coupon DC current density of 40 A/m^2 corresponding to instant-off potential more positive than −2.5 V_{CSE} should be adopted.

Nakamura and Kajiyama have assessed the relationship between DC and AC current densities and corrosion rate by performing laboratory studies using 10 cm^2 steel specimens with constant DC and AC currents. Laboratory results are shown in Figure 4. Corrosion rate obtained from weight loss was reduced to less than 0.01 mm/y as long as the data was plotted inside the protection area designated by thick solid lines.

Kajiyama and Okamura have stated that, the cathodic current density, required to achieve CP of pipelines buried in microbially active soils containing sulfate-reducing bacteria or iron bacteria in Tokyo metropolitan areas in Japan, is greater than 0.1 A/m^2 corresponding to the residual uniform corrosion rate less than 0.1 mm/y. Therefore the above-mentioned CP criterion is effective to control microbiologically influenced corrosion (MIC).

Kajiyama has carried out field observations to assess the above-mentioned criterion established by laboratory studies using the coupons buried for 2～3 years in various environments having potential corrosion risks. After removing the coupons from the soils followed by cleaning and weight loss measurements, corrosion rates were obtained to be less than 0.01 mm/y. The final values of coupon current densities are shown by square symbols in Figure 4. Therefore the new CP criterion is also verified by field observations.

Taking the above-mentioned discussions into account, the authors have established the new CP criterion based on coupon DC and AC current densities (coupon current density-based criterion) as follows:

Ⅰ. 0.1 A/m^2 $\leqq I_{DC} <$ 1.0 A/m^2, $I_{AC} < 25\, I_{DC}$

Ⅱ. $1.0\ A/m^2 \leqq I_{DC} \leqq 40\ A/m^2,\ I_{AC} < 70\ A/m^2$
where:
I_{DC} = time-averaged coupon DC current density
I_{AC} = time-averaged coupon AC current density

Positive values in DC current density indicate the current flowing through electrolyte to the coupon (i.e. cathodic current flowing).

Graphic expressions of the new CP criterion (Ⅰ and Ⅱ) established by the authors together with DIN 50 925 and ISO 15589-1 are illustrated by Figure 5. The criterion eliminated all corrosion risks such as AC corrosion, DC stray current corrosion, microbiologically influenced corrosion etc. and overprotection risk.

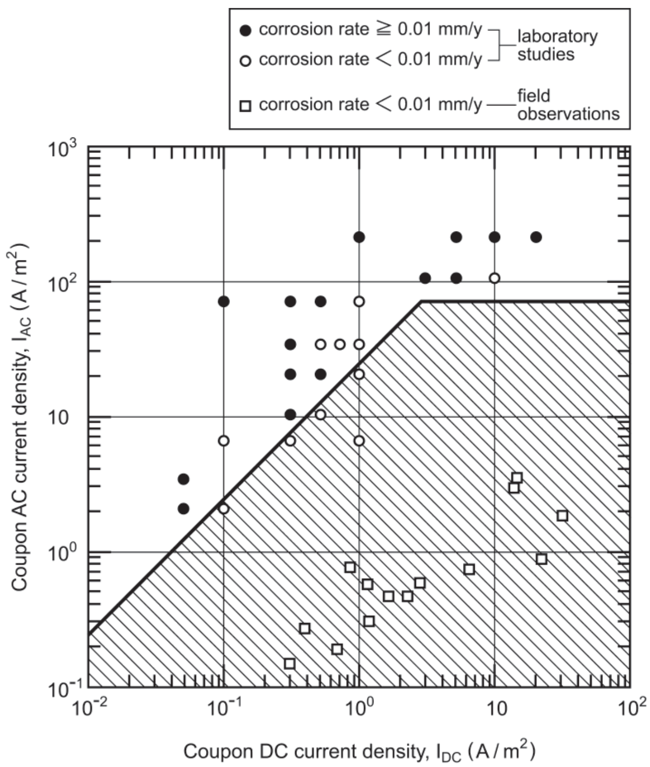


Figure 4 The data on DC and AC current densities on test specimens and coupons in consideration of corrosion rate obtained from laboratory studies and field observations.

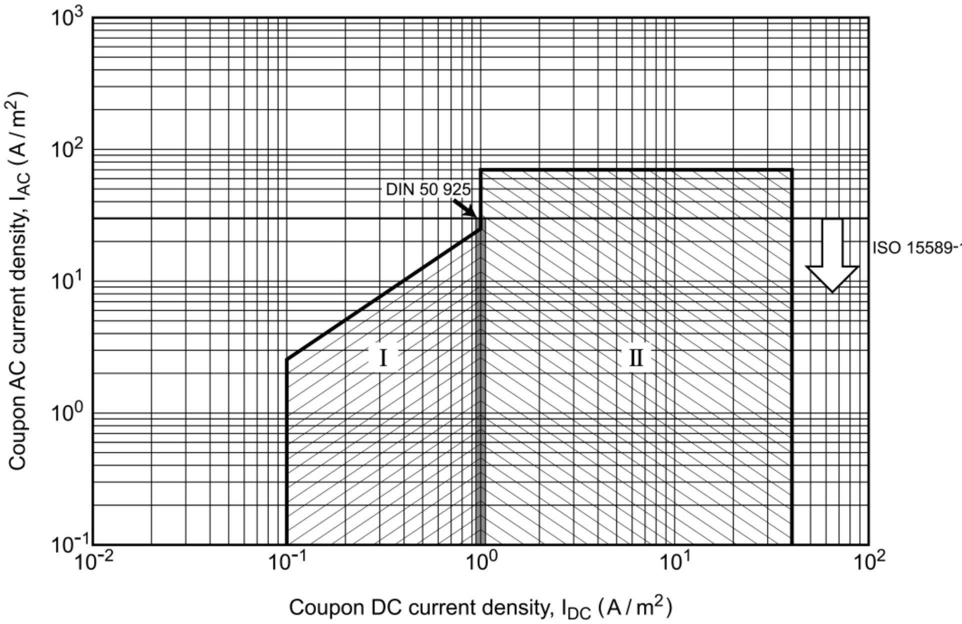


Figure 5 Graphitic expressions of the new CP criterion (Ⅰ and Ⅱ) established by the authors together with DIN 50 925 and ISO 15589-1.

11. AC VOLTAGE OF PIPELINE

So far AC mitigation is mostly driven by safety considerations. According to NACE SP0177, the AC voltage should need to be mitigated below 15 V with respect to local earth for steady-state conditions on above-grade portions, where personnel could readily come in contact with the pipeline or appurtenance. On the other hand, in Germany, the same threshold is 65 V.

European Standard CEN/TS 15280 explains that reducing the AC corrosion likelihood on a buried pipeline means that pipeline AC voltage does not at any time exceed 10 V over the entire pipelines, or 4 V where the local soil resistivity measured along the pipeline is less than 2,500 ohm-cm. Kajiyama has suggested that, for the case of a 100 mm^2 holiday on a pipe in 1000 ohm-cm soil, the AC corrosion risk on a pipeline presents if pipeline AC voltage is in excess of 3.0 V.

Induced AC voltage is well below the safety potential. Mitigating the induced AC voltage on pipelines to the recognized maximum safe AC voltage of 15 V used in NACE SP0177, does not necessarily eliminate the likelihood of AC corrosion.

Many commercially available voltmeters that can measure both DC and AC voltage are hand-held, battery-powered, and well suited for field applications. Measurement of voltage between a pipeline and a reference electrode is probably the most frequently made for determination in corrosion and CP testing works. If the AC corrosion risk can be evaluated based on induced AC voltage, it is very simple and prompt to detect the location where AC corrosion likelihood is present using hand-held voltmeter in the field. As has been previously indicated, though assessment of AC corrosion likelihood based on AC voltage can be misleading, it is effective to measure AC voltage to evaluate AC corrosion likelihood roughly.

12. PROTECTION MEASURES AGAINST AC CORROSION

As has previously been mentioned, recently, concern for AC corrosion mitigation has been increasing.

Protection measures against AC corrosion should be achieved through the following measures:
- Reduce the induced AC voltage

To reduce induced AC voltage, the following methods should be considered.
1) Install pipeline grounding equipped with suitable devices in order to let AC current, but not DC current, flow.
2) Add grounding systems to provide potential equalization at local areas.
These grounding systems can be constructed using a wide variety of electrodes (galvanized steel, zinc, magnesium, etc.). To reduce induced AC voltage, the method of adding grounding systems is widely used to discharge the induced AC current resulting in reduction of the potential on the pipeline. If grounding systems are used, they can have an adverse effect on the effectiveness of the CP due to a load to the pipeline's CP systems. To avoid adverse effects on the CP, (1) the electrode (e.g. magnesium) whose potential is close to the CP potential of the pipeline should be used, or (2) the grounding systems should be connected to the pipeline via appropriate devices (e.g. DC decoupling devices in order to let AC current, but DC current, flow).
3) Increase the CP level so that the peak of the positive part of AC wave form can be brought below the protection potential.
This method is previously described with special regard in **4**.

13. AN ADVANCED INSTRUMENTATION USING INNOVATED MEASURING TECHNIQUES

13.1 CONCEPTS FOR THE DESIGN

The authors named an advanced instrumentation "CP MONITOR" in this paper. "CP MONITOR" with a coupon was designed on the concepts as follows:

1. Surface Area and Shape of a Coupon

Literature suggests that the most severe corrosion occurs at holiday surface area of 1 cm^2, and then a 1 cm^2 coupon is recommended to be installed at the pipe depth for the purpose of measuring AC current density. In the present field observations, however, conical shaped coupons having a surface area of 10 cm^2 were used in order to ensure good contact of the coupon with electrolyte. From the extensive field observations, no possibility of significant non-uniformity of the current distribution (i.e., the current density is higher at the edge of the coupon where current lines emerge or arrive from a greater range than at the middle of the coupon) was confirmed. A bare steel coupon permitting accurate weighing to judge whether or not CP level is acceptable was installed in a monitoring station. The monitoring stations were installed above the pipeline at intervals not greater than 1 km along the pipeline.

2. Simultaneous Measurements on Coupon Current Densities and DC potentials with High Rate Data Sampling Rate

As shown in Figure 3, measuring systems for coupon DC and AC current densities, and coupon DC and AC potentials are illustrated. I_{DC} stands for coupon DC current density, I_{AC} coupon AC current density, E_{DC} coupon DC potential (polarized potential), and E_{AC} coupon AC potential, respectively. The measurement was typically performed during a period of 24 hours in each monitoring station installed in Tokyo metropolitan areas in Japan. In areas frequency of electric power transmission lines is 50 Hz, AC powered rail transit system is operated at frequency of 50 or 60 Hz. The measurement of coupon current densities should be carried out for a period of at least 24 hours, to assess the level of permanent or short-term interference on a pipeline. Figure 6 shows that block diagram for an advanced instrumentation "CP MONITOR" developed by the authors. The data on coupon current densities and coupon potentials were continuously measured with resolution of 16 bit at the interval of 0.1 ms in each monitoring station. In areas where DC/AC interference currents induced by the passing of a high speed DC/AC train are suspected, this measuring technique with high data sampling rate of 0.1 ms enables an engineer to asses the corrosion risk. Coupon DC current density I_{DC}, coupon AC current density I_{AC}, coupon DC potential E_{DC}, and coupon AC potential E_{AC} were obtained, every sub-units of 20 ms corresponding to the frequency of 50 Hz, from equations (2), (3), and (4), respectively using a low pass filter with a cut-off frequency of 73 Hz to avoid abnormal electrical spikes and harmonic currents.

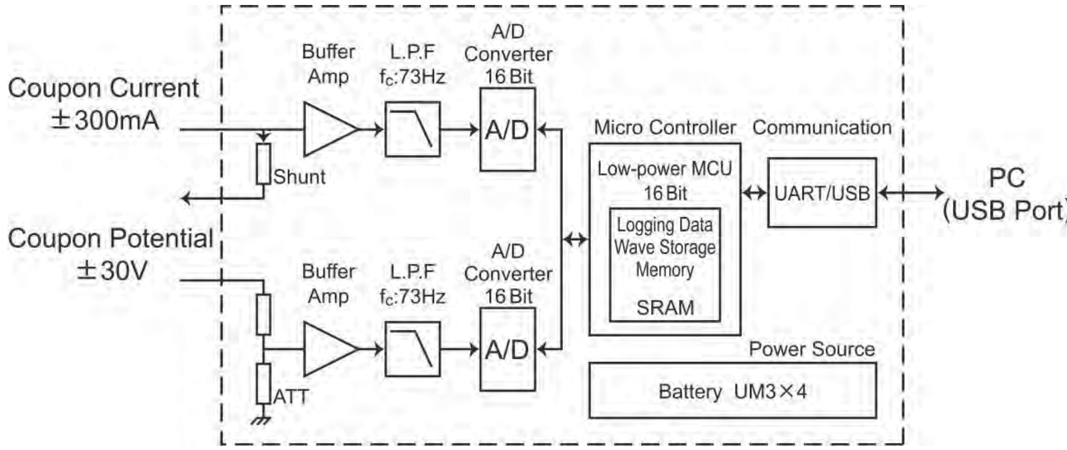


Figure 6 Block diagram for an advanced instrumentation.

Coupon current measurements must be made using a data logging device programmed to acquire the precise coupon DC current in a period.

$$I_{DC} = \frac{1}{A} \cdot \frac{1}{200} \sum_{t=1}^{200} I(t) \tag{2}$$

$$I_{AC} = \frac{1}{A} \cdot \sqrt{\frac{1}{200} \sum_{t=1}^{200} \{I(t) - I_{DC}\}^2} \tag{3}$$

$$E_{DC} = \frac{1}{200} \sum_{t=1}^{200} E(t) \tag{4}$$

$$E_{AC} = \sqrt{\frac{1}{200} \sum_{t=1}^{200} \{E(t) - E_{DC}\}^2} \tag{5}$$

where:

A = Surface area of a coupon (= 10cm^2)
I(t) = Instantaneous coupon current at t ms in each sub-unit of 20 ms
I_{DC} = Time-averaged instantaneous coupon current in each sub-unit of 20 ms
I_{AC} = Coupon AC current in each sub-unit of 20 ms
E(t) = Instantaneous coupon potential at t ms in each sub-unit of 20 ms
E_{DC} = Time-averaged instantaneous coupon potential in each sub-unit of 20 ms, that is, polarized potential
E_{AC} = Coupon AC potential in each sub-unit of 20 ms

Higher the data sampling rate, higher the accuracy of obtained I_{DC}, I_{AC}, E_{DC}, and E_{AC}. By taking the transference rate of measured data from “CP MONITOR” to a client PC and consumption of battery for measurement into consideration, data sampling interval of 0.1 ms was determined. Even if E_{DC} satisfies the protection potential criterion, the positive part of AC wave form more positive than the protection potential which indicates a strong likelihood of AC corrosion cannot be recognized without high rate data sampling measurement techniques as mentioned above.

Each unit containing 500 sub-units was set to 10 s. The average, maximum, and minimum values of I_{DC}, I_{AC}, and E_{ON} were obtained every units by analyzing 500 sub-unit data. The schematic representation of the measurement for I_{DC}, I_{AC}, and E_{ON} is shown in Figure 7.

For field measurements, the value of 0.1 ohm was determined as shunt resistor. Coupon current measurements must be made using a data logging device programmed to acquire the precise coupon DC current in a period. Coupon DC current is acquired as an average of coupon currents over a period according to equation (2). Based on equation (3), coupon AC current in a period can be obtained. By using a low pass filter with a cut-off frequency of 73 Hz and equation (3), the frequency of coupon AC current densities can be regarded as 50 Hz or less.

Instantaneous coupon potential at t ms in each sub-unit of 20 ms, E(t), is measured by placing a copper sulfate electrode (CSE) as close to the pipe as possible to minimize IR drop. So time-averaged E(t) in each sub-unit of 20 ms, E_{DC}, can be considered as polarized potential. By using E_{DC}, E_{AC} in each sub-unit of 20 ms is obtained according to equation (5).

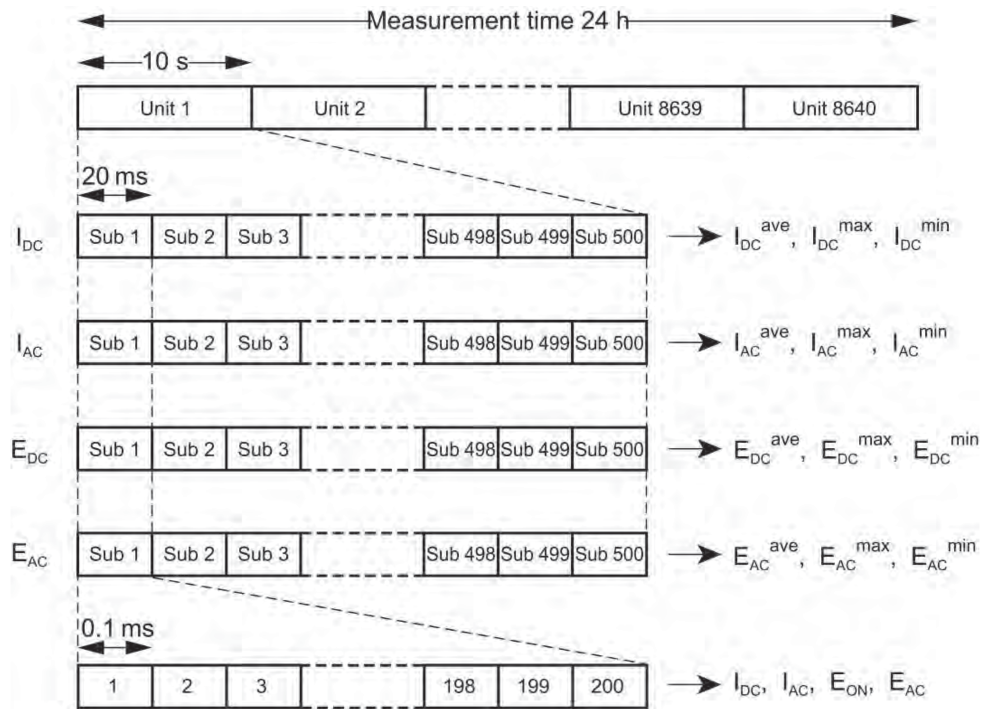


Figure 7 The schematic representation of measurement for coupon DC current density I_{DC}, coupon AC current density I_{AC}, coupon DC potential E_{DC}, and coupon AC potential E_{AC}.

3. Controlled by the "CP Management System"

The schematic representation of the procedures of periodic inspection using a developed instrumentation "CP MONITOR" controlled by the "CP MANAGEMENT SYSTEM" is illustrated in Figure 8. The authors named cathodic protection management system "CP MANAGEMENT SYSTEM" in this paper. Information on CP maintenance activities of pipelines and monitoring facilities is centralized in "CP MANAGEMENT SYSTEM".

Measurement conditions such as start time, measuring time, weather are set from the client PC to the "CP MONITOR" using USB (Universal Serial Bus). The client PC has the same information as web server via an internet.

The measurement of coupon current densities, coupon on potentials, and coupon AC potentials are carried out using "CP MONITOR" installed in a monitoring station. After ascertaining that the remaining capacity of battery is enough to measure coupon current densities and on potentials throughout the measuring time, the measurement starts up. The average, maximum and minimum of coupon DC and AC current densities and on potentials are obtained through computation every units. The data on every units together with the waveform of the maximum coupon AC current density in the measurement time are then stored in the SRAM (Static Random Access Memory) with high-speed access and low battery consumption.

The measured data are transferred from the “CP MONITOR” to the client PC.

Immediately after the transference, the CP level is assessed by comparing the obtained time-averaged coupon DC and AC current densities to the new CP criterion based on the coupon current densities using the client PC in the field. When the CP level is not met the CP criterion, the detailed investigations shall be performed based on the inspection results and pipeline history. A benefit of CP MANAGEMENT SYSTEM-based inspection is to certainly and efficiently implement periodic inspection of the CP system with large quantity information, resulting in minimizing human errors.

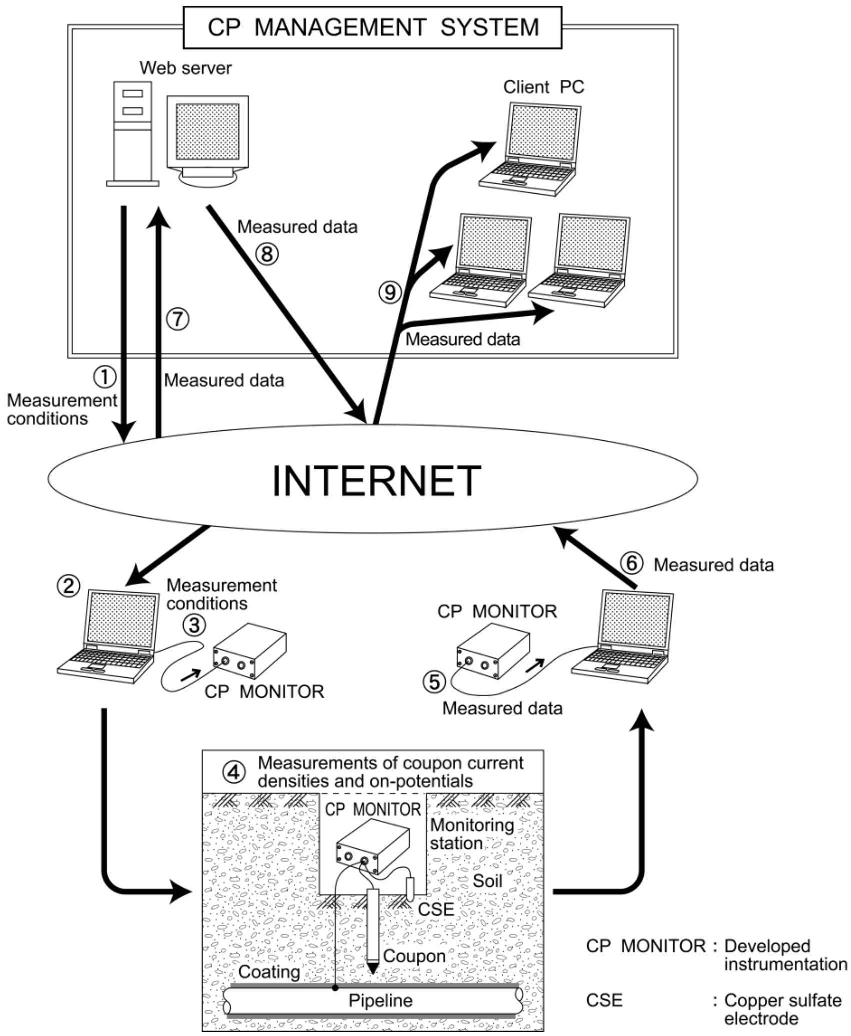


Figure 8 The schematic representation of the procedures of periodic inspection using a developed instrumentation “CP MONITOR” controlled by “CP MANAGEMENT SYSTEM”.

4. Identification of I_{AC} (50Hz)

In this paper I_{AC} (50Hz) is defined as the coupon AC current densities, corresponding to the frequency of 50 Hz. The frequency of 50 Hz is regarded as coupon AC current density having the difference within 10 ms $\pm$ 1 ms (i.e. 45.5 Hz − 55.6 Hz) in appearance time between and minimum value in a sub-unit (a single period of 20 ms).

5. Display of the waveform of the maximum coupon AC current density

After the measurement, the waveform of the maximum coupon AC current density in a sub-unit is displayed. Thereby the frequency and current level can be confirmed visually.

13.2 AN EXAMPLE OF MEASURED DATA

Figure 9 demonstrates the data on coupon DC potentials E_{DC} and coupon DC and AC current densities, I_{DC} and I_{AC}, respectively, measured during a period of 24 hours for the polyethylene coated 300 mm diameter pipeline paralleling two 66 kV, 50Hz overhead electric power lines and neighboring a 1500 V DC powered rail transit system. The environment in which the pipeline is laid suggests that there is the possibility of AC corrosion and DC stray current corrosion. The DC powered rail transit system was not operated after midnight until early morning (1:30 – 4:00). The fluctuation of coupon DC potentials and coupon DC and AC current densities varied corresponding to the demand for electric power and the operation condition of the DC powered rail transit system. During no operation of DC powered rail transit system, stable and more positive coupon on potentials were observed, together with stable and lower DC current densities, indicating no DC interference currents induced by the passing of DC powered train. Variations in coupon AC current density between 1.06 – 5.00 A/m^2 were measured, the most severe effect occurring at 9:57. From 3:00 through 5:30, lower coupon AC current densities were observed, suggesting the decrease in electric power transmission currents due to the lower electric power consumption. The AC level was satisfactorily mitigated using Mg electrodes as earthing electrodes.

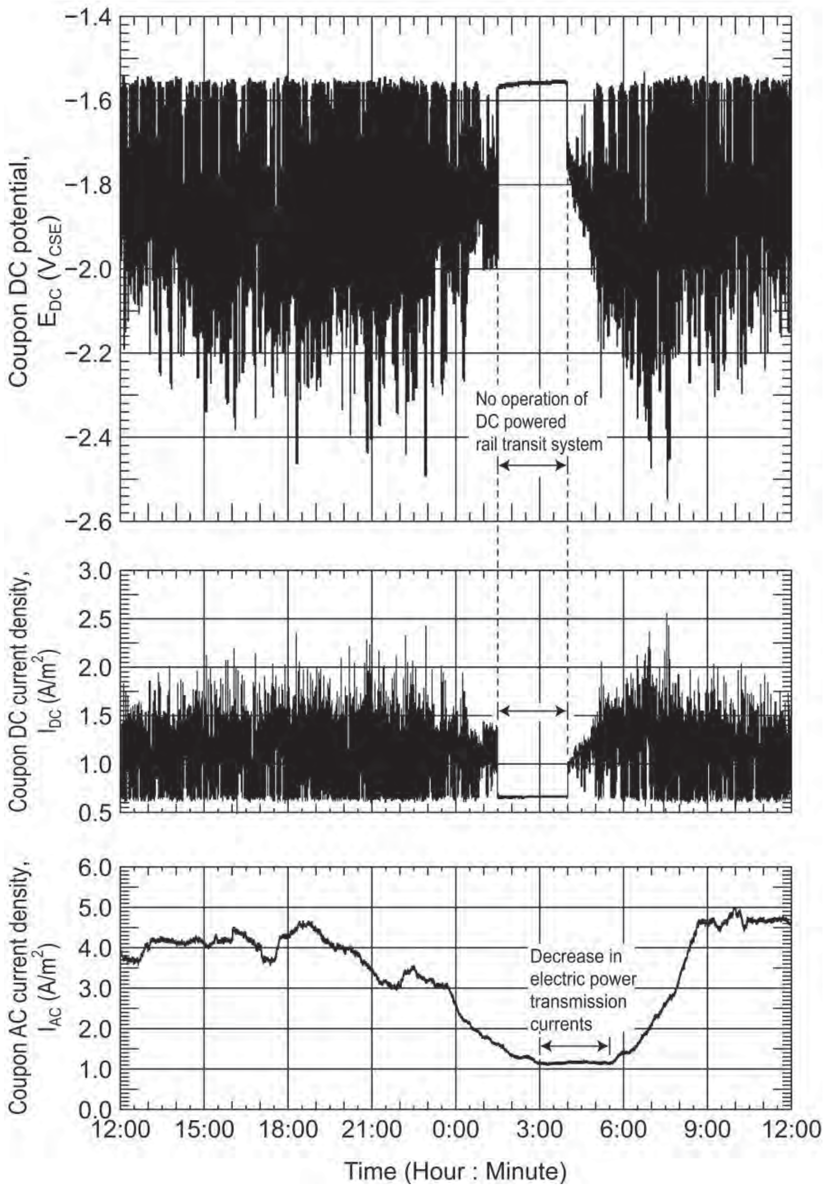


Figure 9 The data on coupon DC potentials, and coupon DC and AC current densities measured during a period of 24 hours for the polyethylene coated 300 mm diameter pipeline paralleling two 66 kV, 50 Hz overhead electric power lines and neighboring a 1500 V DC powered rail transit system.

The original waveform of the maximum coupon AC current density is demonstrated in Figure 10. The difference in appearance time between the maximum and minimum values exhibited 10 ms (3.2 ms − 13.2 ms), therefore the frequency of coupon AC current density was regarded as 50 Hz corresponding to the power-line frequency. As a result, the maximum I_{AC}^{max} was considered as I_{AC} (50 Hz).

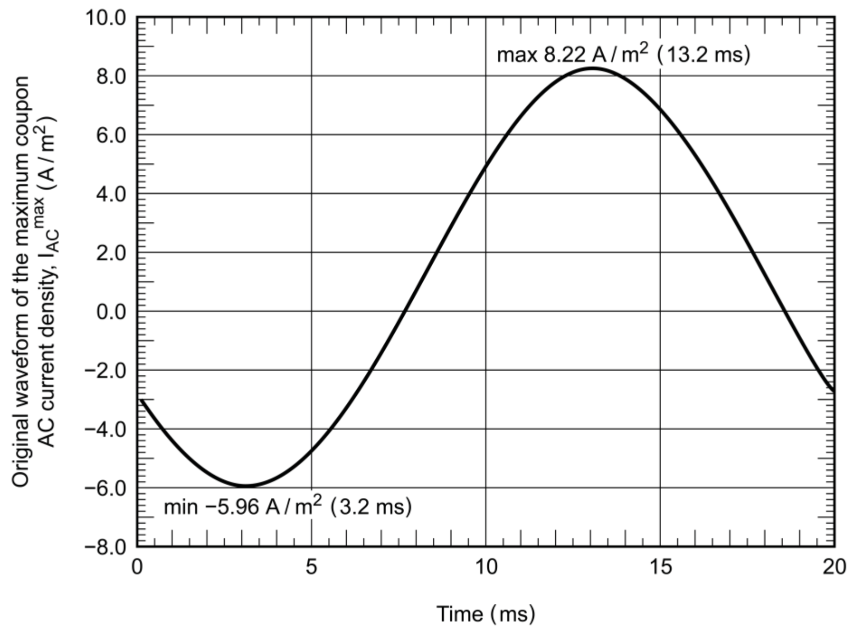


Figure 10 Original waveform of the maximum coupon AC current density in the measurement time.

Average values of coupon DC and AC current densities were assessed with respect to the new CP criterion as shown in Figure 11. The result satisfied the CP criterion.

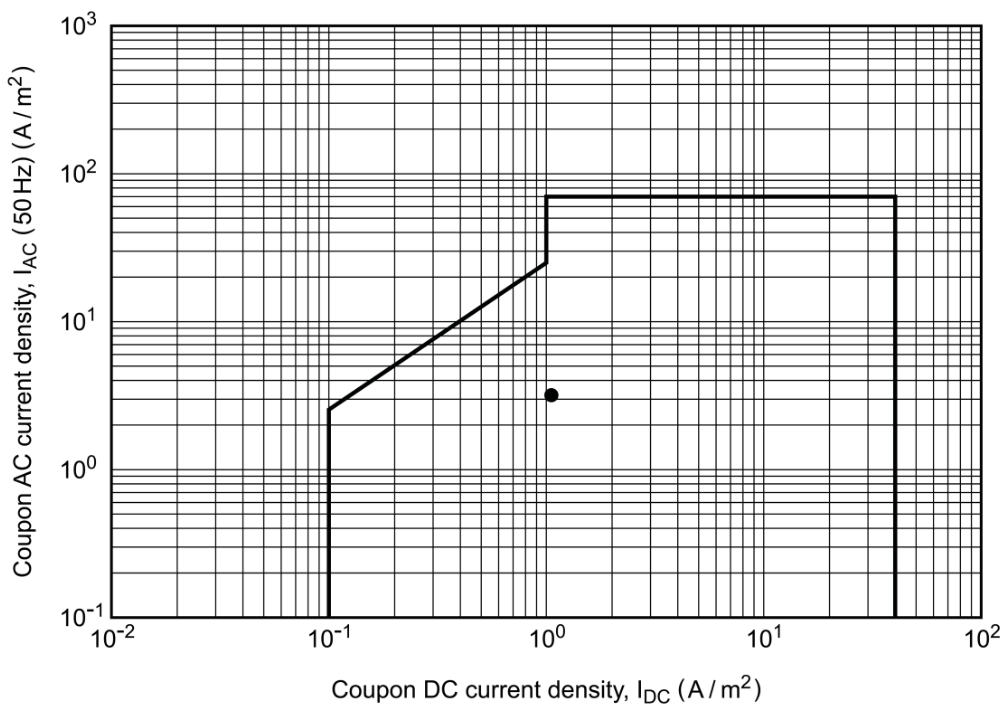


Figure 11 Result of the measured average values of coupon DC and AC current densities.

14. CONCLUSIONS

In this paper, modern pipeline is defined as high strength steel pipeline (specified minimum yield strength greater than 550 MPa) with high resistivity coating. Recently, modern pipelines have been used worldwide in response to the growing energy demand.

Modern pipeline is thought to be susceptible for hydrogen embrittlement induced by cathodically-formed excess hydrogen under overprotection condition. The technological advancements in pipe coating materials which provide increased pipe coating resistivity values and the increased tendency to locate pipelines paralleling high voltage AC (HVAC) electric power lines and/or AC powered rail transit systems have made the AC corrosion risk more severe. This means that more attention must be paid to new threats, that is, AC corrosion and overprotection on modern pipelines.

Conclusions can be drawn as follows:

1. Even if coupon DC potential (polarized potential) satisfies the protection potential criterion, the positive part of AC wave form more positive than the protection potential which indicates a strong likelihood of AC corrosion cannot be recognized without high rate data sampling measurement techniques.

2. AC corrosion can occur in high alkaline environment produced by cathodic protection that is perfectly passivating if AC currents are absent. This is a special feature of AC corrosion.

3. There is a lack of technical consensus on the mechanism and the extent of the effect of AC densities on cathodically protected underground metallic structures, particularly AC corrosion in soils. There are no agreed-on criteria for AC corrosion protection. Furthermore, the effect of hydrogen formed by cathodic protection on a modern pipeline is not well understood. In spite of these situations, pipeline corrosion engineers shall struggle to eliminate risks.

4. Based on accumulated-experience and knowledge for many years, the authors have developed an innovated instrumentation for assessing the AC corrosion risk of buried pipelines, and established the new CP criterion based on coupon DC and AC current densities (coupon current density-based criterion). The most distinguished feature is the simultaneous computation in a measuring unit of 20 ms regarding coupon DC current density and coupon AC current density corresponding to a period of the commercial frequency of 50 Hz. The criterion eliminates all corrosion risks such as AC corrosion, DC stray current corrosion, microbiologically influenced corrosion etc. and overprotection risk.

5. The new CP criterion established by the authors is the second revolutionary criterion following the protection potential criterion proposed by Kuhn in 1933. From now on, for the case of no AC interference, the protection potential criterion continues to be accepted and used on steel pipelines and structures in various soils and water.

6. Pipeline corrosion engineers shall be aware of the changes in materials (pipe and coating) and conditions of environments where the pipeline is laid (AC interference current), then eliminate predictable risks of all corrosion including AC corrosion and overprotection to manage and maintain the integrity of their pipelines; thereby engineer's primary responsibility is achieved.

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Welcome
Message from the editor

Dr. Klaus Ritter

The Pipeline Technology Journal (ptj) is published for the fifth time. Its design as well as its internal structure clearly sharpened in comparison with the first issues. What remain are the close ties to the Pipeline Technology Conference (ptc) in Berlin and the occupation with research and development at an early stadium. It thus offers the possibility to support discussions among the pipeline community on new developments considering experiences worldwide.

Unlike the Poster-show that establishes a selective professional public during the annual ptc conference, the journal ptj will be thus published four times a year to intensively report about research and development helping to optimize the construction, operation and life support of pipelines.

The triggers for this promotion were the requirements of many operators who are participants of the Pipeline Technology Conference (ptc) to speed in dealing with issues of pipeline safety and longevity.

Help us to meet these demands and provide us Your new solutions.

Our ptc Editorial and ptc Advisory Board are available to further encourage the development of Pipeline technologies from the point of view of safety and durability.

Yours sincerely

> Dr. Klaus RItter, Editor in Chief

ptc ADVISORY COMMITTEE / ptj EDITORIAL BOARD

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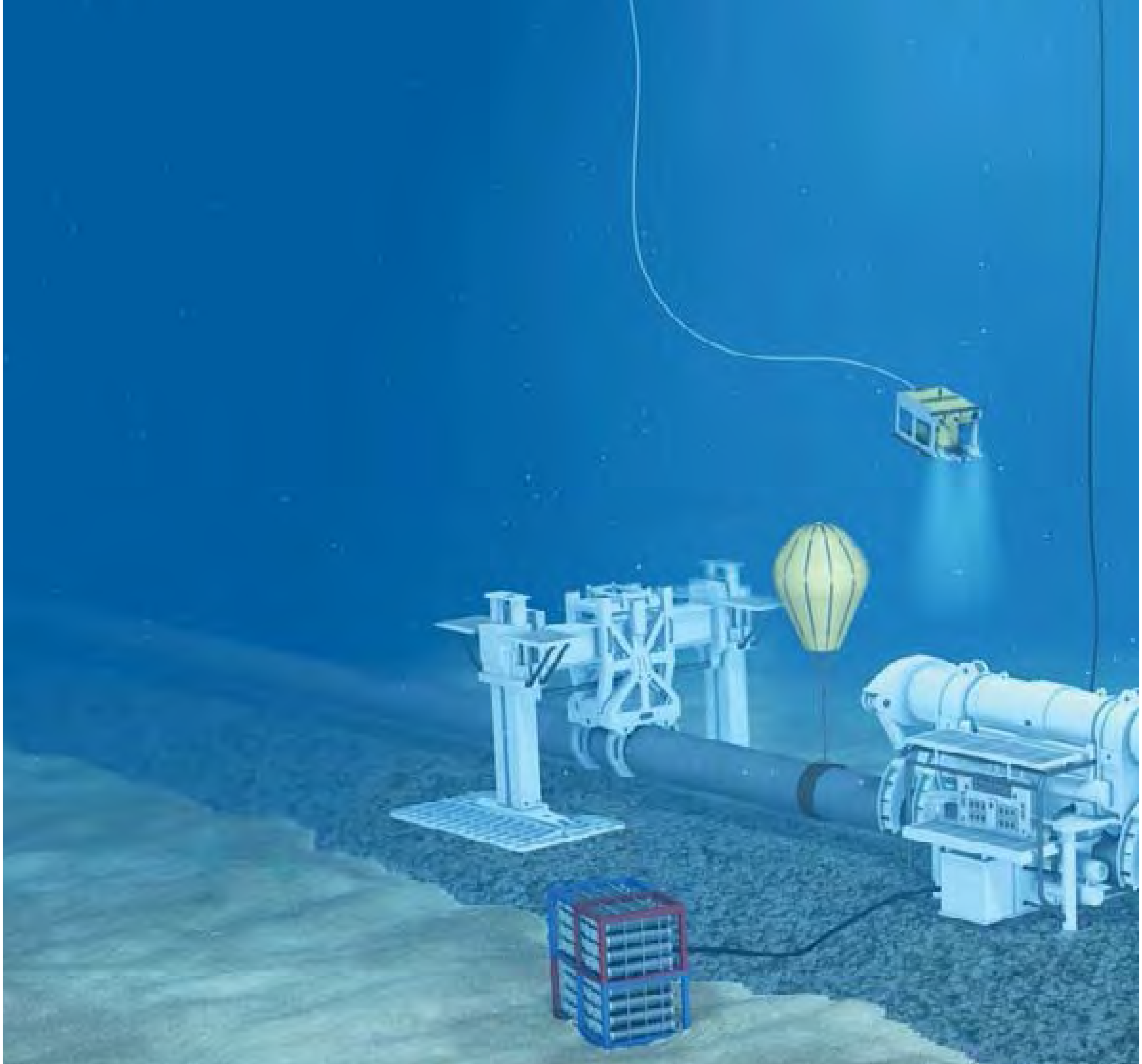

NORD STREAM UNDERWATER TIE-IN BACKGROUND

Each of the two Nord Stream Pipelines is built in three sections. Once completed, the sections must be welded together to form the 1,224 kilometre pipelines. This "tie-in" process takes place on the seabed in an underwater welding habitat. Welding operations are remotely controlled from a support vessel, and divers assist and monitor the subsea construction work.


Andrey Voronov
(Offshore Manager,
Nord Stream AG) will
report about The Nord Stream
Offshore Pipeline Repair Strategy during
the 10th Pipeline Technology
Conference, 8-10 June 2015
Berlin, Germany
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PIPELINE TECHNOLOGY CONFERENCE (ptc)

PIPELINE TECHNOLOGY JOURNAL

RESEARCH / DEVELOPMENT / TECHNOLOGY

PIPELINE TECHNOLOGY JOURNAL

CONFERENCES / SEMINARS / EXHIBITIONS

NORTH AMERICA

Enbridge Pipelines, TransCanada Corporation and Kinder Morgan Canada have signed a Joint Industry Partnership agreement to conduct research into aerial-based leak detection technologies with the aim of enhancing pipeline safety throughout North America.

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SEATTLE / U.S.A

Quest Integritiy Group announces flow loop simulation capabilities, including client-specific pipeline configurations, to validate its InVista™ ultrasonic in-line inspection (ILI) technology in demanding environments. Visit Quest Integrity Group at ptc 2015 stand 41.

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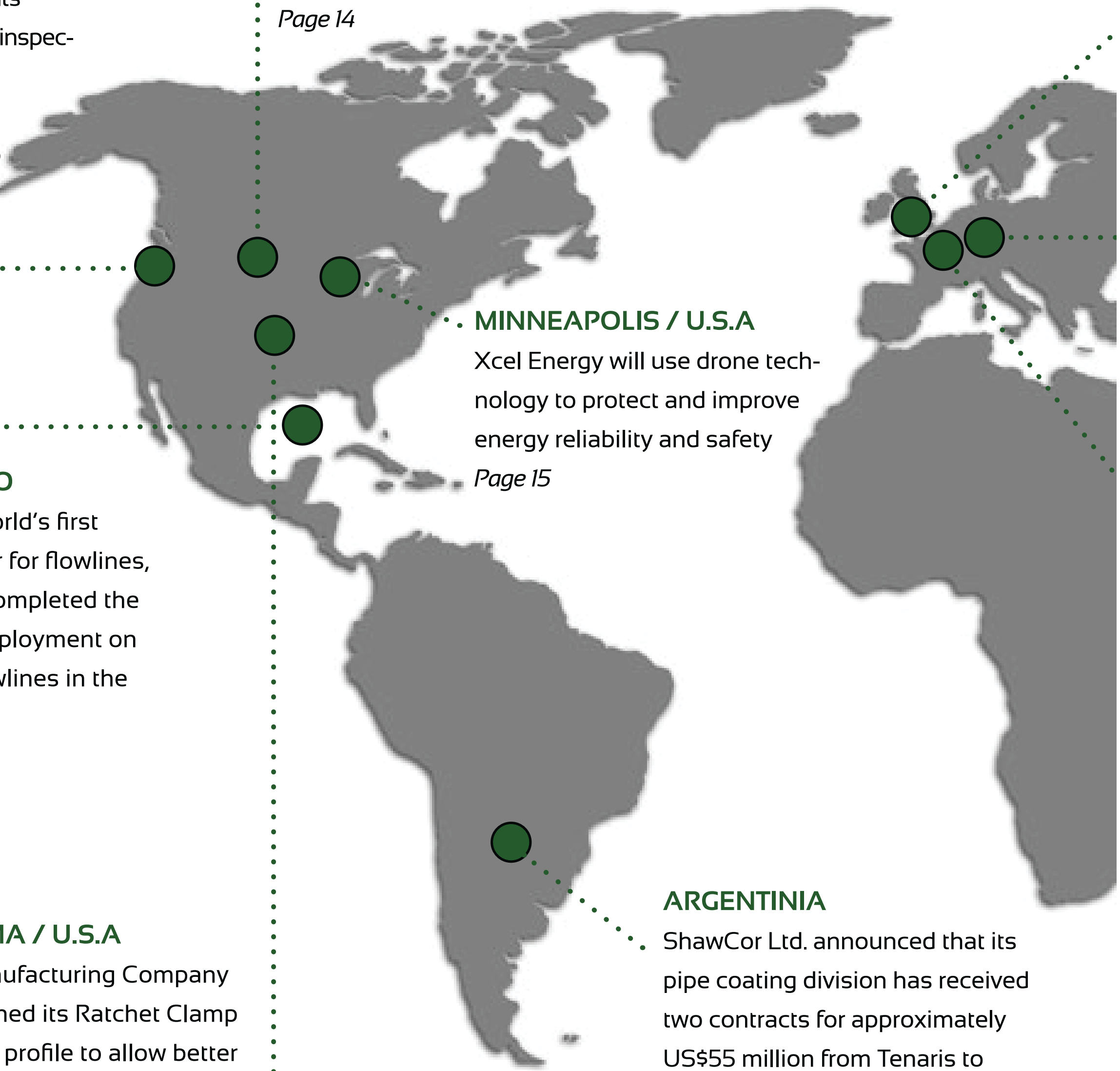

MINNEAPOLIS / U.S.A

Xcel Energy will use drone technology to protect and improve energy reliability and safety

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GULF OF MEXICO

Discovery™, the world's first subsea CT scanner for flowlines, has successfully completed the first deep-water deployment on Shell-operated flowlines in the Gulf of Mexico.

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ARGENTINIA

ShawCor Ltd. announced that its pipe coating division has received two contracts for approximately US$55 million from Tenaris to provide three layer polyethylene anti-corrosion pipeline coatings for the first and second phase of the Argentina Northeast Gas Pipeline (GNEA) project.

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OKLAHOMA / U.S.A

Sawyer Manufacturing Company has redesigned its Ratchet Clamp with a lower profile to allow better access to the butt join, helping welders effectively and quickly align and weld pipe.

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MANCHESTER / GREAT BRITAIN

Atmos International (Atmos) will celebrate 20 years in the pipeline industry by exhibiting new theft detection solutions at Pipeline Technology Conference 2015 (stand 52).

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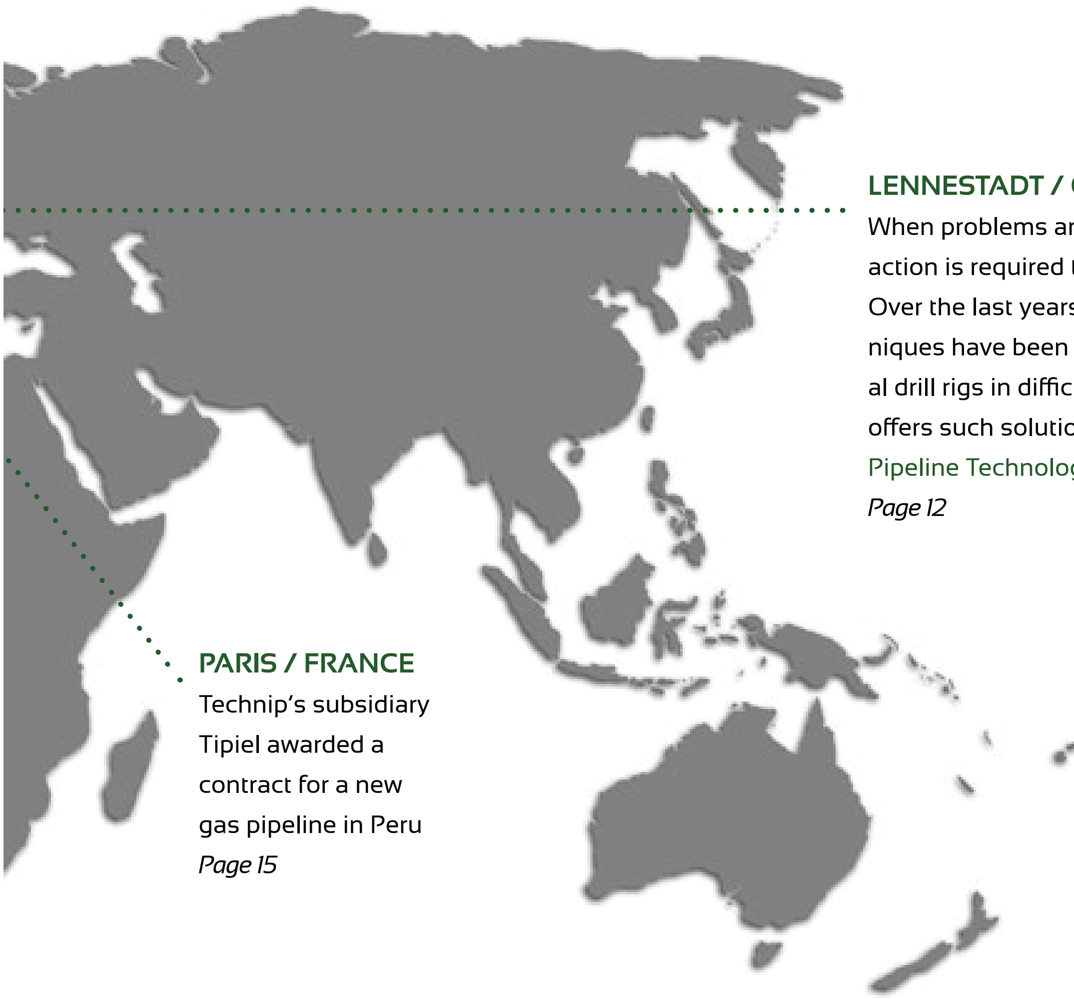

LENNESTADT / GERMANY

When problems arise on an HDD project, quick action is required to avoid a costly situation. Over the last years, several pipe ramming techniques have been developed to assist directional drill rigs in difficult situations. Tracto Technik offers such solutions for HDD projects during Pipeline Technology Conference (ptc) 2015

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PARIS / FRANCE

Technip's subsidiary Tipiel awarded a contract for a new gas pipeline in Peru

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WORLD NEWS

IN-LINE INSPECTION OF CHALLENGING PIPELINES VALIDATED WITH FLOW LOOP SIMULATIONS

Quest Integrity Group announces flow loop simulation capabilities, including client-specific pipeline configurations, to validate its InVista™ ultrasonic in-line inspection (ILI) technology in demanding environments. Visit Quest Integrity Group at ptc 2015 stand 41.

Quest Integrity conducts flow test loop demonstrations in various locations worldwide and can custom build flow loops for clients to include their real-world ILI challenges such as heavy wall piping, dual-diameters, reduced port valves, 1D bends, risers, unbarred tees and wyes. By simulating multiple ILI obstacles in a test environment, the company effectively demonstrates the navigational proficiency of the InVista tool, and pipeline operators gain first-hand knowledge of the tool's capabilities for their pipelines.

The company recently constructed a 6-inch custom flow loop for a large, international oil and gas client in Houston, Texas. The client needs integrity management data for a high-profile, heavy wall sour gas pipeline asset in the United States, but wanted to avoid failed run or stuck tool situations. Quest Integrity's flow loop simulations included running the tool at varying speeds and bi-directionally to validate data collection and operational capabilities. InVista successfully overcame the operational trials presented and collected accurate data for both known and unknown defects in the line.

"As an added value to our clients, we build flow test loops to their specifications to simulate an in-service challenging ILI run in a test environment," said Stefan Papenfuss, Vice President - Pipeline Resources, at Quest Integrity. "This provides our clients with procedural information and project confidence while demonstrating the many benefits of the InVista technology for their critical pipeline assets – without the potential risks associated with testing an in-service pipeline."

For further information:
http://www.questintegrity.com/services/inspection-services/pipeline-in-line-inspection

SAWYER MFG. CO. IMPROVES THE RATCHET CLAMP-MODEL 255

Sawyer Manufacturing Company has redesigned its Ratchet Clamp with a lower profile to allow better access to the butt join, helping welders effectively and quickly align and weld pipe.

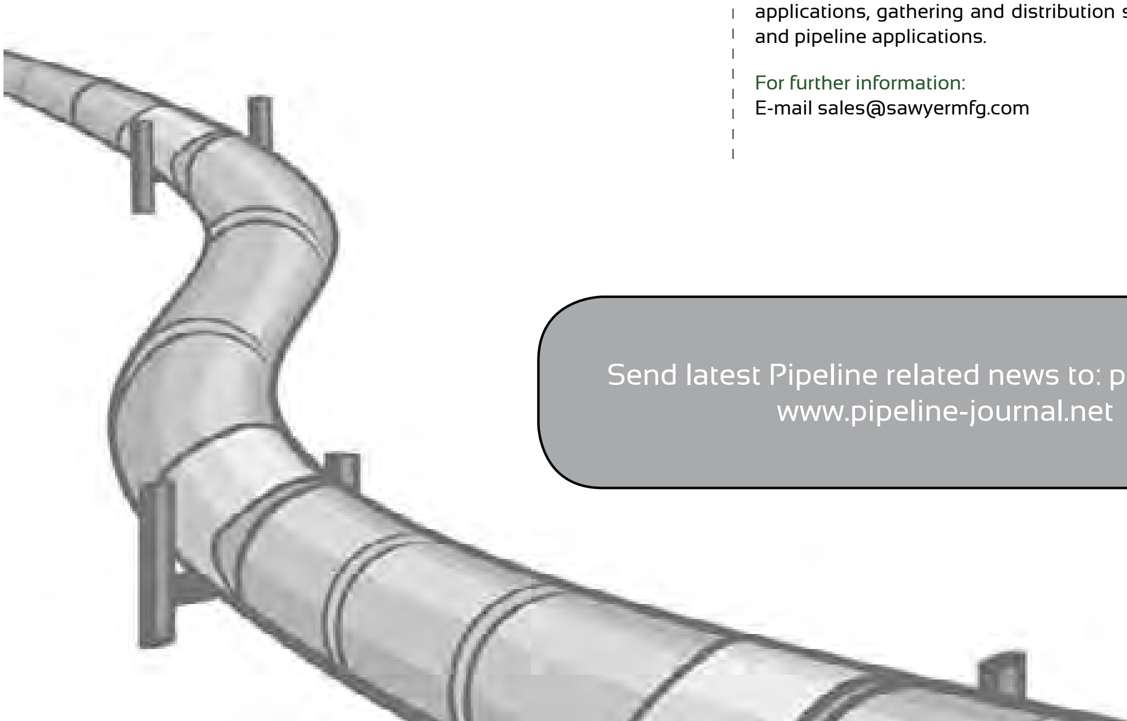
The ratchet mechanism was also improved with a built-in handle and enclosed threads to protect against dirt and weld splatter, all while retaining the true double ratchet feature that allows for quicker closure on the pipe to increase speed and performance. This mechanism permits the clamp to align pipe quicker than any other ratchet clamp on the market.

The Ratchet Clamp is built with a focus on speed and accuracy. This 10-ton ratchet will deliver precision and rugged durability with ease. The clamp is designed with an open bridgework to allow full 360-degree welding, ensuring a quality weld, and the machined headrings are precision bored for consistent and accurate fit up. Also, the Ratchet Clamp's new yellow color provides high visibility and improved safety.

Improvements in the manufacturing process have allowed Sawyer Mfg. Co. to offer a price that is even more competitive. "There are a lot of clamps out there," said Dave Hembree, Sawyer Manufacturing Vice President. "I believe our customers will be pleasantly surprised by the small but important changes we made with this clamp."

Sawyer equipment is used worldwide in the construction and maintenance of pipeline, waste water and sewer lines, marine and offshore applications, gathering and distribution systems, and other welding and pipeline applications.

For further information:
E-mail sales@sawyermfg.com



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ATMOS INTERNATIONAL'S NEW THEFT SOLUTIONS AT PTC

Atmos International (Atmos) will celebrate 20 years in the pipeline industry by exhibiting new theft detection solutions at Pipeline Technology Conference (stand 52).

Atmos already offers Atmos Wave, which detects theft valve movement; and Atmos Wave Flow which, with sensitivity to 0.1% of the flow rate, can potentially detect theft within two minutes. However, Jun Zhang, Managing Director, Atmos, explained, 'We're seeing meticulously planned, near-invisible taps by well-organized gangs that significantly impact a pipeline user's profits. Rapid detection is essential for minimizing financial, environmental, and reputational damage.'

'Our powerful new detection solutions enable clients to react instantly and catch criminals red-handed.'

ATMOS THEFT NET

As illicit connections have become smaller, more intermittent and harder to detect, so detection systems must become more sensitive. This increases the rate of false alarms, which can be costly but also dangerous if they result in genuine alarms being ignored. Atmos experts are trained in the latest techniques for spotting theft in action – and offer this unique analysis service to save clients time and loss, and help them prosecute. To collect data, Atmos has developed:

ATMOS PORTABLE DATA LOGGER FOR LEAK AND THEFT DETECTION

This case-based autonomous data logging solution can be rapidly deployed – either by your staff or Atmos - to collect the pressure and flow data where taps are suspected. Data can be collected on site or remotely.

ATMOS HYDROSTATIC TESTER

This portable kit takes hydrostatic testing to unprecedented levels. It uses both pressure and acoustic sensors to identify even tiny leaks or intermittent tapping, with location accuracy to 2 meters. It is ideal for where pipeline integrity testing is mandatory, and negates the need for costly yet limited options with dyed or odorized water.

ODIN

This revolutionary battery-based theft detection solution has been designed for pipelines previously in a detection 'black hole' – for example, in areas without power or communications, or where standard detection units are undesirable for aesthetic reasons (as in National Parks.) Small and unobtrusive, it can be hidden near suspected tapping points, yet has the sensitivity of permanent detection systems.

For further information:
Georgina Amica-Carpenter, Marketing Associate
Tel: +44 161 445 8080
E-mail: georgina@atmosi.com

Atmos Portable Data Logger for Leak and Theft Detection

Battery-based theft detection solution ODIN has been designed for pipelines previously in a detection 'black hole'.

DSD 010143

TRACTO TECHNIK OFFERS SOLUTIONS FOR HDD PROJECTS DURING PIPELINE TECHNOLOGY CONFERENCE (STAND 47)

When problems arise on an HDD project, quick action is required to avoid a costly situation. Over the last years, several pipe ramming techniques have been developed to assist directional drill rigs in difficult situations. Having a ramming hammer on site during HDD projects ensures a trouble free installation as the combination of the HDD technique's static pulling force with the ramming technique's dynamic impact offers proven solutions for tough drilling problems.

CONDUCTOR BARREL: INSTALLATION OF CASING PIPES FOR HDD CROSSINGS

The concept behind the Conductor Barrel is creating a clear pathway through poor soil conditions so that drilling can begin in more favourable soil conditions. The success of a drilling operation can often be determined right from the outset. Loose, unsupported soils are prime candidates for this method. During the Conductor Barrel process, casings are rammed into the ground, at a predetermined angle, until desirable soil conditions are encountered. The spoil is removed from the casing prior to the drilling operation. Drilling starts within the casing in the favourable soil conditions. The conductor barrel can also serve as a friction-free section during the pullback operation or prevent situations in unstable soils acting in a similar fashion to containment cells.

PULLBACK ASSIST

The pullback assist technique incorporates the use of both a pipe rammer and an HDD rig working in tandem to get a problematic product pipe installed. When drilling underwater or in loose flowing soil conditions, hydrolock can occur. This happens when the external pressure being put on the product pipe from ground water pressure, drilling fluid pressure and/or soil conditions exceeds the drill rig's pullback capacity, or the product pipe's tensile strength. The percussive action of a pipe rammer in this situation is used to help free the jammed pipe.

DRILL ROD RECOVERY: LOOSENING OF JAMMED HDD DRILL ROD

The principal is the same during drill rod recovery, as it is during bore salvage, however, there are two possible tooling configurations. Depending on the situation, contractors can remove the drill rod from the ground or, if the rod is still attached to the drill rig, push on the rod while the drill rig pulls back.

BORE SALVAGE: RESCUING / REMOVING JAMMED PRODUCT PIPES

This simple yet highly effective technique is used to remove jammed product pipes. During the bore salvage operation the Grundoram pipe rammer is attached to the end of the partially installed product pipe. The pipe rammer is attached to the product pipe so that it pulls the pipe from the ground. This can be accomplished through a fabricated sleeve. A winch or some form of pulling device is used to assist the rammer during operation. In many cases, the percussive power of the pipe rammer is enough to free the jammed product pipe and allow it to be removed from the ground.

For further information:
TRACTO-TECHNIK GmbH & Co. KG
Tel. (+49) 2723 808-0
Fax (+49) 2723 / 808-180
E-Mail: info@tracto-technik.de
Internet: www.tracto-technik.de

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Editors in Chief
Dr. Klaus Ritter
E-Mail: ritter@eitep.de
Tel: +49 (0)511 90992-10

Editorial Board
Advisory Committee of the Pipeline Technology Conference (ptc)

Editorial Management & Advertising
Rana Alnasir-Boulos
E-Mail: alnasir-boulos@eitep.de
Tel: +49 (0)511 90992-20

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Admir Celovic

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DSD 010145

NEW RESEARCH INTO AERIAL VEHICLE TECHNOLOGIES TO ENHANCE PIPELINE MONITORING

The pipeline infrastructure in Canada and the United States is showing growing signs of wear and tear. In the past few months a series of leaks and explosions from Mississippi to Calgary have led to a number of deaths, damaged property and polluted the local environment. Against this background Enbridge Pipelines, TransCanada Corporation and Kinder Morgan Canada have signed a Joint Industry Partnership agreement to conduct research into aerial-based leak detection technologies with the aim of enhancing pipeline safety throughout North America.The partnership suggests an interest in cutting-edge aerial vehicle technology to bolster pipeline safety and reliability. It is also an attempt to answer a chorus of public demands for responsible pipeline development and maintenance.

"We are committed to identify, develop and test new technologies to further progress key areas of pipeline safety, such as leak detection. Through collaboration with committed industry partners, we continue to make important advancements with leak detection technology," says Kirk Byrtus, Enbridge's Vice President of Pipeline Control. "This extension to the Joint Industry Partnership is another great example of the pipeline industry connecting to make important advancements with leak detection technology, and we look forward to closely working with our partners, TransCanada and Kinder Morgan."

Enbridge, TransCanada, Kinder Morgan working together to evaluate aerial-based pipeline safety technologies (© 2015, Enbridge Inc.)

DISCOVERY™ COMPLETES SUCCESSFUL DEPLOYMENT ON SHELL ASSETS IN THE GULF OF MEXICO

Discovery™, the world's first subsea CT scanner for flowlines, has successfully completed the first deep-water deployment on Shell-operated flowlines in the Gulf of Mexico.

Discovery™ was developed by Tracerco, part of the FTSE100 Johnson Matthey Plc, in response to an industry need for a non-invasive method of scanning subsea flowlines. The technology is used to establish the integrity of subsea pipeline assets.

In total, Discovery™ scanned ten flowlines including jumpers, steel catenary risers, and pipe in pipe flowlines all of varying diameters. Over 250 CT scan images over a pipeline length of 50,000 feet, at depths down to 4,200 feet, were generated. In the Gulf of Mexico, based on such data, Shell was able to build a complete profile of their pipeline, which helped to confirm the condition of the asset.

Shell undertook a comprehensive technology review to select an inspection solution to support safe, efficient, and competitive operations. Discovery™ offers three key advantages over alternative inspection technologies:

- The device attaches to the outside of the flowline, allowing the inspection campaign to be conducted while production continues;

- There is no need to remove the insulation coating on the flowline, minimising the risk of flowline damage or of the build-up of hydrates;

- Scan image data is available in real time, allowing engineers to rapidly evaluate and respond to any integrity and flow assurance problems.

Jim Bramlett, Business Development Manager for Tracerco's Subsea Technologies division, said: "Using Discovery™ we were able to quickly deliver data, drip feeding the scans through to Shell engineers then providing an in-depth analysis once we had all the information. We understand that for each day a pipeline is out of action, or not performing at peak, there are significant financial implications"

The planning, preparation and execution of the inspection campaign was a joint effort which provided access to the Discovery™ CT scan images, and Tracerco's expert interpretation, within the same day. Discovery™ scans pipelines from the outside to gain an accurate picture of the condition of the pipe and the flow, with no need to remove the protective coating and no interruption to production. It is a highly accurate, rapid and low risk solution to gaining information on flowlines including pipe-in-pipe and bundle systems. Discovery™ provides a 360 degree, high resolution scan of pipeline contents and pipe walls in real time, with defect resolution of 1mm.

Tracerco Shell deployment in Gulf of Mexico

DSD 010146

TECHNIP'S SUBSIDIARY TIPIEL AWARDED A CONTRACT FOR A NEW GAS PIPELINE IN PERU

Tipiel(1) S.A., Technip's subsidiary in Colombia, was awarded by the Consorcio Constructor Ductos del Sur(2), a front-end engineering design and detailed engineering design contract, on a lumpsum basis. This covers the development of a new gas pipeline to transport gas from the Camisea field to Southern Peru.

Launched by the Peruvian government, the project consists of more than 1,700 kilometers of 32" gas pipeline. It aims to improve the existing Peruvian Energy Network, contributing to the development of an Energy Node and Petrochemical Hub in Southern Peru.

The overall work will be performed by Tipiel's offices in Bogota, Colombia. Marco Villa, Technip's Region B(3) President, commented: "This award reflects the importance to accompany the client since the very early stage of an initiative to help design an optimized project execution scheme."

Riccardo Nicoletti, Tipiel General Manager, stated: "This contract, which is related to one of the most important projects for the development of energy infrastructure in Peru, serves our objective to make Tipiel a leading engineering company outside Colombia as well".

SHAWCOR ANNOUNCES CONTRACT TO PROVIDE PIPE COATING SERVICES FOR THE GNEA PROJECT IN ARGENTINA

ShawCor Ltd. (TSX:SCL) today announced that its pipe coating division has received two contracts for approximately US$55 million from Tenaris to provide three layer polyethylene anti-corrosion pipeline coatings for the first and second phase of the Argentina Northeast Gas Pipeline (GNEA) project.

This project is owned by ENARSA, an Argentine state-run energy company, and it includes the construction of a gas pipeline that will transport up to 11,200,000 m³/day of natural gas to locations in northeast Argentina.

The execution of these contracts has commenced in ShawCor's coating facilities in Argentina and is expected to be completed by Q1 2016.

For further information:
ShawCor Ltd.Gary Love
Vice President, Finance and CFO
Tel: 416-744-5818
E-mail: glove@shawcor.com
Website: www.shawcor.com

XCEL ENERGY WILL USE DRONE TECHNOLOGY TO PROTECT AND IMPROVE ENERGY RELIABILITY AND SAFETY

FAA approves company's request to use unmanned aircraft for energy infrastructure inspections

Xcel Energy inspects more than 320,000 miles of electricity and natural gas infrastructure to ensure the safety and reliability of its energy system. Now with approval of the Federal Aviation Administration, Xcel Energy will be able to more efficiently, effectively and safely monitor its systems using drone technology.

The FAA on May 11 approved Xcel Energy's request to operate small unmanned aircraft systems or drones commercially. Xcel Energy sought the approval so it can inspect its critical energy infrastructure.

Xcel Energy will use drones to visually inspect electricity transmission and distribution lines, power plants, renewable energy facilities, substations and natural gas transmission and distribution pipelines.

"We are pleased with the FAA decision as we study how this new technology can best be used to enhance employee and public safety at our operations," said Kent Larson, Xcel Energy's executive vice president and group president of operations.

The use of small unmanned aircraft systems will allow Xcel Energy employees to safely inspect hard to reach areas, keeping the workers out of danger. Employees will also use drones to observe environmentally sensitive areas without the use of trucks, helicopters or other utility equipment, minimizing the environmental impact.

"We believe these measures will increase electricity and gas system reliability, reduce customer costs and improve our emergency response times," said Larson. He added that the company's current plan is to use drones only over utility property or utility rights of way and away from populated areas and airports. The drones will be flown at low altitudes and in the operator's line of sight.

The XCEL Drone

DSD 010147

PIPELINE TECHNOLOGY CONFERENCE

500+ DELEGATES | **50+** EXHIBITORS | **55+** DIFFERENT NATIONS

The Pipeline Technology Conference (ptc),

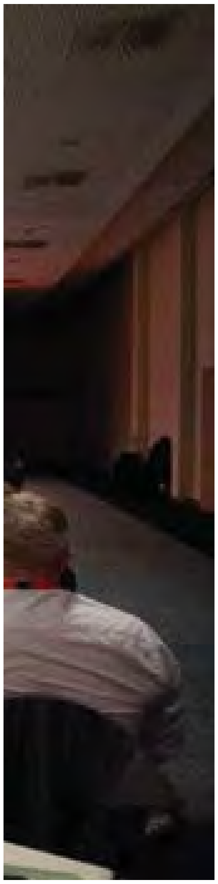
europe's leading pipeline conference and exhibition, the Pipeline Technology Conference (ptc), will take place for the 10th time offering again opportunities for operators as well as technology and service providers to exchange latest technologies and new developments supporting the energy strategies world-wide.

The conference will provide panel discussions and special focus sessions on "Pipeline Safety", "German Energy Turnaround", "Challenging Pipelines" and "Offshore Technologies". For the first time the conference will also feature an "Scientific Advances Poster Session" with latest updates on present and upcoming research activities.

ptc will feature lectures and presentations on all aspects surrounding oil, gas, water and product pipeline systems. The exhibition with more than 50 exhibitors will show latest pipeline technologies and products.

For more information kindly visit: www.pipeline-conference.com

"63% of the PTC Delegates are coming from abroad (Europe, Middle East, North America, South America, Asia, etc.)"



10th ANNIVERSARY ptc

EUROPE'S BIGGEST PIPELINE EVENT

THE ANNUAL GATHERING OF THE INTERNATIONAL PIPELINE COMMUNITY IN THE HEART OF EUROPE

After starting as a small side event of the huge HANNOVER MESSE trade show in 2006 in Hannover, the Pipeline Technology Conference developed into Europe's largest pipeline conference and exhibition. Since 2012 the EITEP Institute organizes the ptc on its own and moved the event to Berlin in 2014. The 10th anniversary will again be a record breaking event.

35+ SUPPORTERS

13 Technical Sessions at ptc 2015

- Integrity Management
- Geohazards
- Construction
- Materials
- Challenging Pipelines
- Inline Inspection
- Repair / Rehabilitation
- Management
- Pump & Compressor Stations
- Leak Detection
- Monitoring
- Coating
- Offshore Technologies

PIPELINE TECHNOLOGY CONFERENCE

ptc

Play Video

One of the world's major pipeline conferences will be held from June 8-10, 2015 in Berlin. With 500 to 600 participants from about 50 countries, the international Pipeline Technology Conference (ptc) is already among the largest and most important conferences of its kind in the world just 10 years after being initiated.

This "German" international conference is organized by EITEP (Euro Institute for Information and Technology Transfer in Environmental Protection), based in Hanover. It is especially supported by the major gas network operators (as to content) and by producers and service providers from Europe (exhibitors).

Content-related matters are managed by the internationally staffed 32-member Advisory Committee, AdCo. The AdCo is particularly active when it comes to putting together the conference program. AdCo members submit the received presentation proposals to a quality check, in which both the content (abstracts) and the potential speakers (CVs) are evaluated according to such criteria as relevance and topicality.

Over 150 proposals for 50 "free" presentations for the PTC 2015 were received by the EITEP following a "Call for Papers". The "Call for Papers" was sent out to about 22,000 verified addresses from the international pipeline community in July 2014. The returns were then examined together with the AdCo in the manner described.

This process ensures that participants are offered a high-quality program that addresses and presents for discussion all current and ongoing developments throughout the world.

Pipeline construction is booming worldwide – except in Europe. Instead, Europe can offer a lot of experience and technology for operations and maintenance as well as on issues of safety and long service life. That is ostensibly what participants from Asia, Africa, Australia and North and South America are looking for in Europe at the ptc.

For the ptc 2015, the presentation selection procedure for the 50 free presentations, which is supplemented by about 10 invited speakers, has resulted in one plenary session and 13 technical sessions with 3 to 5 individual presentations. They cover all important, complex current issues related to the technology of onshore and offshore pipelines. Due to high demand, the topics of "Inline Inspection", "Geohazards" and "Microbiologically Influenced Corrosion" will be offered as two-day seminars for additional information following the conference.

15 research institutes from academia and industry are taking advantage of the opportunity to present their latest research results in a structured poster show.

Two particularly topical issues will be addressed in discussion forums. This year, the topics will be: 1. "Pipeline safety" and 2. "The German Energy Transition". Both topics will be moderated by the former CEO of Open Grid Europe, Heinz Watzka, who has invited experts from North America and Europe to participate in the discussion. DVGW Vice President Dr. Hüwener will be involved in discussion round 1 and DVGW Chairman Dr. Linke in discussion round 2. This will ensure that there will be plenty of input into various aspects of the German gas industry.

The papers from the past 9 years of ptc are made freely available in a central abstract/paper database for research purposes at:

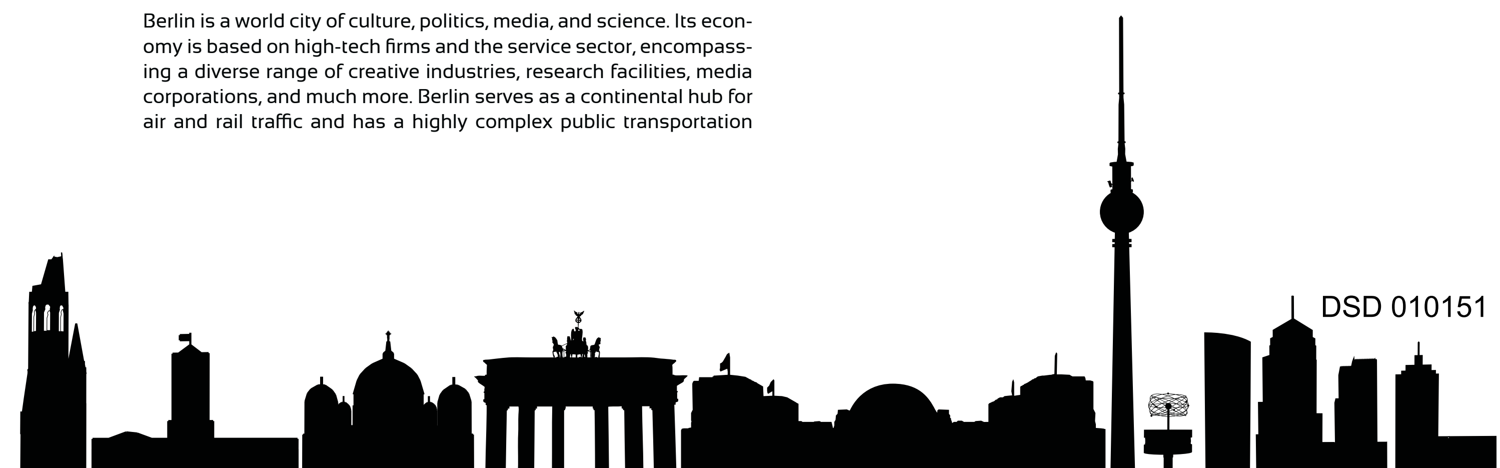
www.pipeline-conference.com.

Combine your ptc visit with Berlin sightseeing

THE INTERNATIONAL PTC COMMUNITY MEETS IN BERLIN

Berlin is more than 775 years old and over the decades, all generations have left their monuments and landmarks in town.The capital is a centre for international conventions and trade fairs and the number one among German cities for conventions. Berlin offers excellent infrastructure, the most up-to-date locations in Europe, a diverse range of services and a great shopping mile and night-life.

Berlin is a world city of culture, politics, media, and science. Its economy is based on high-tech firms and the service sector, encompassing a diverse range of creative industries, research facilities, media corporations, and much more. Berlin serves as a continental hub for air and rail traffic and has a highly complex public transportation network. The metropolis is a popular tourist destination. Significant industries also include IT, pharmaceuticals, biomedical engineering, clean tech, biotechnology, construction, and electronics. Berlin is one of the 16 states of Germany with a population of 3.5 million people. It is also the country's largest city.



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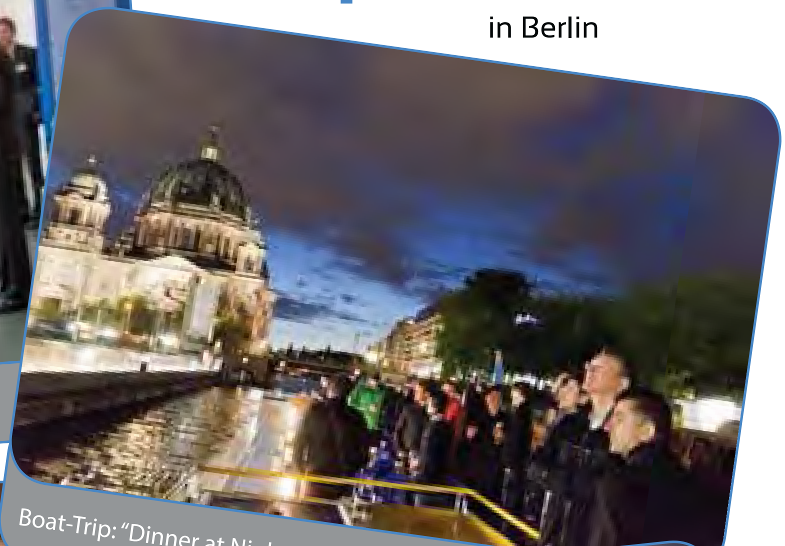
PIPELINE TECHNOLOGY CONFERENCE

Impressions from ptc 2014 in Berlin

Attendees networking at the exhibition



Boat-Trip: "Dinner at Night"

Lively and interesting discussions

Over 400 Attendees visited ptc 2014 in Berlin

Plenary sessions during ptc

See you at ptc 2015

www.pipeline-conference.com

DSD 010153


HIGH
INDUCTIVE
interference on pipelines
due to nearby high voltage
overhead lines
PTC-POSTERSHOW
This paper will be presented during the
"Scientific Advances Poster Session" at
10th Pipeline Technology Conference

DSD 010154

PIPELINE VOLTAGE

POSSIBLE REASONS WHY CALCULATIONS OF INDUCTIVE INTERFERENCE PIPELINE VOLTAGES ARE HIGHER THAN CONDUCTED MEASUREMENTS

> by: Christian Wahl

> and: Ernst Schmautzer

*> Graz University of Technology
Institute of Electrical Power Systems*

Abstract

Due to bundled energy routes, high voltage energy systems (HVESs), e.g. overhead lines or AC traction power supply systems, are often located near buried isolated metallic pipelines. Thus, a possible high inductive interference from energy systems may produce hazardous AC pipeline interference voltages (PIVs). High induced voltage levels can cause dangerous high touch voltages (personal injuries) and damages to pipeline system components (overvoltage, AC material corrosion). Therefore, for minimizing the risk of personal injuries and material corrosion, European standards and guidelines (EN 50443 [1], EN 15280 [2]) exist which limit the maximum voltage for long term and short term interference If the PIV is within given limits, the risk for personnel and material is acceptable and no further measures, e.g. AC earthing systems, special working methods or additional isolating joints along the pipeline are required and no further mitigation costs are generated.

For this reason it is necessary to calculate the induced PIVs already in the planning stage or in the case of significant changes in the pipeline or HVESs to specify necessary protection measures, particularly in areas where the PIV is already near the given limit.

Unfortunately, the results of these – standardized – calculations are often up to 7 times higher than conducted measurements on pipelines, despite using state of the art calculation parameters. Research on this discrepancy is needed to bring calculations and measurement data closer together to avoid excessive measures.

INDUCTIVE INTERFERENCE ON PIPELINES

Inductive coupling appears when a magnetic field between an interfered buried isolated metallic pipeline system and an interfering HVES exists. The inductive coupling impedances z_gkL are affected by all of the below-described parameters and can be calculated with e.g. the formula of Dubanton [3].

These HVES parameters are load current or phase conductor arrangement as well as pipeline parameters such as the pipeline diameter, material or coating. Another parameter is the ambience soil resistivity which varies within a large spectrum. The final important parameter is the influence of several known and unknown grounded conductors, located near influenced or influencing systems. These conductors produce a voltage reduction on the induced pipeline and can be e.g. the PEN conductor of low voltage power lines, metal rails and compensation conductors of AC traction power supplies, conducting pipelines, foundation earth electrodes and global earthing systems.

The induced voltage $\underline{U}_i$ can be calculated by formula (1).

$$\underline{U}_i = \sum_{k=1}^{n} \underline{I}_k \cdot \underline{Z}_{gkL} \cdot \ell$$

If all currents and inductive coupling impedances $\underline{z}_{gkL}$ for one segment l are known, the induced voltage $\underline{U}_i$ can be calculated for a segment. Segmenting is needed because the geographical closeness and other parameters are not constant over the whole interfering distance and therefore the value of $\underline{z}_{gkL}$ is always changing see Figure 1. Also, other segments are not influenced as shown in Figure 1. When all induced voltages $\underline{U}_i$ have been determined, the induced PIV over the whole interfering distance is calculated with the lattice network model. As a requirement for using this model, all parameters must be (approximately) homogenous within one segment.

The parameters in this network model represent the longitudinal impedance (RL, LL), which stands for the pipeline material characteristics and the shunt admittance (CQ, RQ), which is a combination of the pipeline coating value, ambience soil resistivity, reduction conductors and reducing earthing systems. The PIV alongside the pipeline can be calculated with the node admittance matrix [4].

DIFFERENT POSSIBLE IMPACT FACTORS ON PIPELINE VOLTAGES

The following factors are suspected of having different degrees of impact on the induced voltages and the discrepancy between calculated and measured PIVs and has to be considered individually and in combination with each other:

- Load current instead of using the maximum operational currents
- Reduction effect of global earthing systems
- Reduction effect of practically achievable pipeline earthing systems
- Reduction effect of pipelines, running in parallel
- Reduction effect of parallel high voltage power systems with grounding conductors
- Reduction effect of local earthing systems
- Incorrect or inadequate pipeline coating parameter
- The influence of the model-conform specific soil resistivity

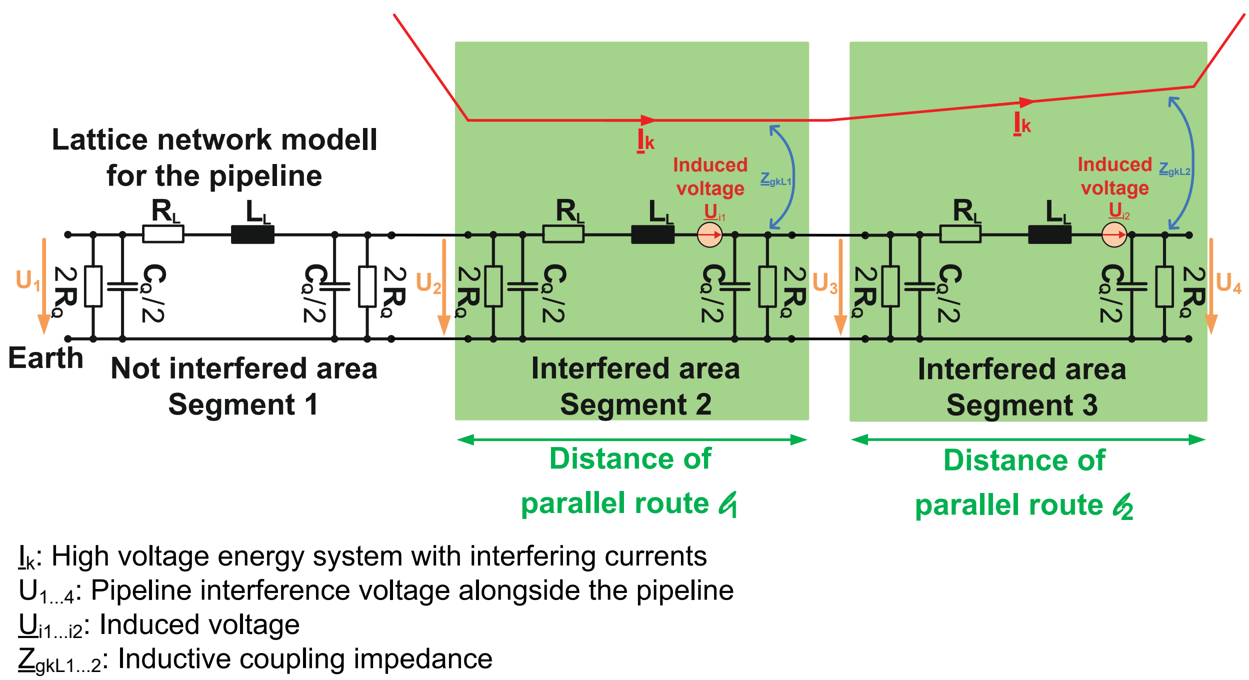


Figure 1: Pipeline subdivided into segments because of changing parameters

IMPACT OF THE LOAD CURRENT

As stated above, the value of the load current is a direct proportionality factor in the voltage calculation formula (I). Normally it is common practice to use the maximum operational currents in order to cover worst case scenarios for touch voltages or, depending on the type of the influencing system, 60 to 95 percent of this maximum load current for AC corrosion.

In reality, these operational currents rarely occur. For the comparison of a one week lasting measurement and its associated calculations on the same pipeline locations it is indispensable to use the correct actually used load currents to get comparable results. The difference between such currents and maximum operational currents is illustrated for an overhead line and a railroad system in Figure 2 [5].

POSSIBLE VOLTAGE REDUCTION EFFECT OF GESS, HVESS AND PIPELINES - GLOBAL EARTHING SYSTEMS (GESS)

In short, GESs consist of connected foundation electrodes and other conductive material buried in the soil within a (sub-) urban area. This connection can be realised intentionally or unintentionally either directly via conductive materials or in the common sense via the electric flow field. If an HVES is located near a pipeline and a GES, a configuration arises as depicted in Figure 3.

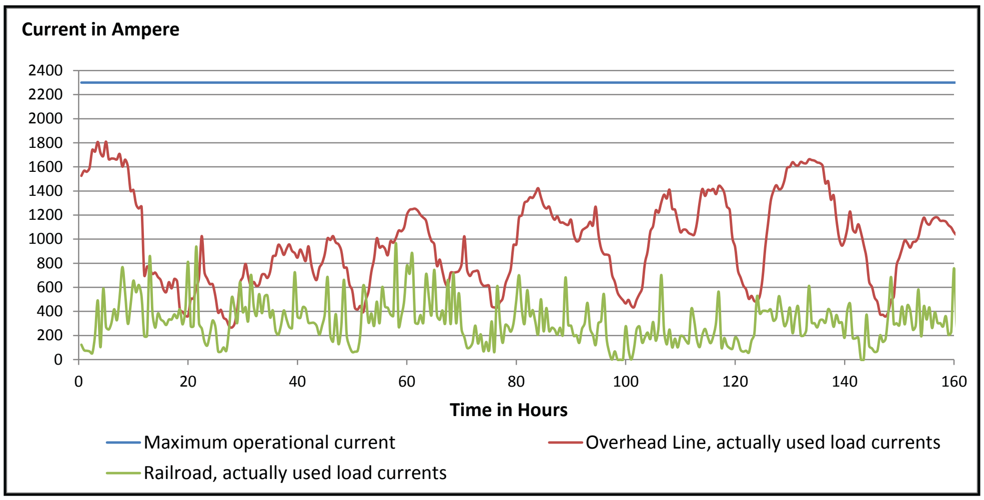


Figure 2: Difference between maximum operational currents and load currents for overhead lines

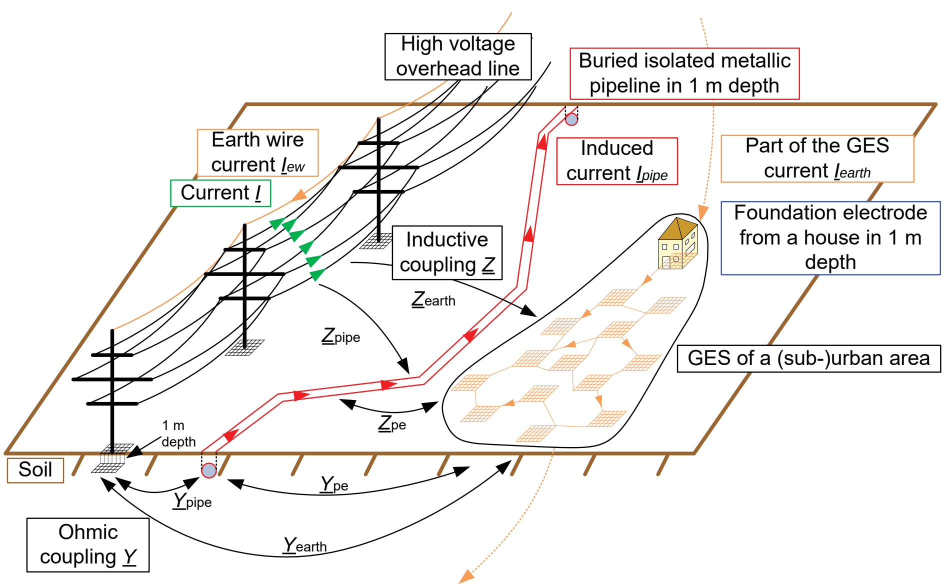


Figure 3: The complex interference and reduction situation between high voltage power line, GES and pipeline system

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In these cases, pipeline and GES are more or less parallel metallic conductors due to their similar conductive material. The inductive coupling impedances $\underline{Z}_{gkl.}$ from the energy system turn into a parallel connection of the pipeline coupling $\underline{Z}_{pipe.}$ and the GES coupling $\underline{Z}_{earth.}$ Consequently, the coupling impedance to the pipeline is reduced with the effect of a lower PIV. Thus, GESs have a reduction effect. How great it is depends on the expansion, grid structure as well as the material- and soil-conductivity. As a result of the inductive coupling, the pipeline voltage $\underline{U}_i$ is induced with consideration of this reduction effect. This leads to the currents $\underline{I}_{pipe}$ and $\underline{I}_{earth}$. These currents result in an additional inductive coupling $\underline{Z}_{pe.}$, additionally increasing or reducing the current $\underline{I}_{pipe}$ and thus the PIV [5].

The following calculation example shows the impact of such interference between an HVES, a pipeline and three differently sized GESs. GES 1 and 2 represents a village with a low and GES 3 a small city with a medium density of conducting grounded material. The size and the amount of buried conducted metal leads to an accordingly high voltage reduction effect. Also, the general geographical alignment, e.g. distance between the systems or position along the pipeline, is important.

As depicted in Figure 4 the PIV calculation shows different reduction effects from the differently sized GESs. Since GES 1 (red line) and 3 (purple line) have a similar reduction effect, it can be seen that the geographical alignment is important. GES 1 is in the middle of the pipeline and the reduction effect evenly distributed over the entire PIV. Because GES 3 lies on the end of the pipeline, it has a notable PIV reduction effect especially in this area. Due to of the bigger size of the GES 2 (green line), a remarkable voltage reduction effect can be seen which shows that GESs has to be considered in calculations.

OTHER PIPELINES

Because of bundled energy routes, transport pipelines are built near other pipelines. Therefore two or more pipelines can run parallel over a long distance. If an HVES is located near a configuration with two pipelines, a setup appears as can be seen in Figure 5 and two interference effects have to be noted.

The first effect is due to the inductive coupling between the HV power line and the pipeline causing currents in both pipelines. Depending on the current flow direction, the current $\underline{I}_{pipe2}$ can increase or reduce the current $\underline{I}_{pipe1}$ and vice versa. Figure 5 shows an example, where both currents flow in the same direction.

The second effect is based on the fact that the second pipeline (blue) works as a reduction conductor (see Chapter 2.2.1) on the regarding pipeline (red). This means that both factors have to be considered to be able to state whether the pipeline current and interference voltage is increased or reduced.

Figure 6 illustrate how this reduction or increasing factor from a parallel pipeline works. It shows three different calculations which depict the influence of the current directions on the regarding PIV. The blue line shows the calculation of the PIV of the regarding pipeline without any other parallel pipeline; the other two lines already include the parallel pipeline reduction effect. This shows that when both pipeline currents flow in the same direction, the regarding pipeline current and therefore, the PIV, are increased (green line). Furthermore, it is clearly shown that a reduction effect is present when the currents flow in opposite directions (red line).

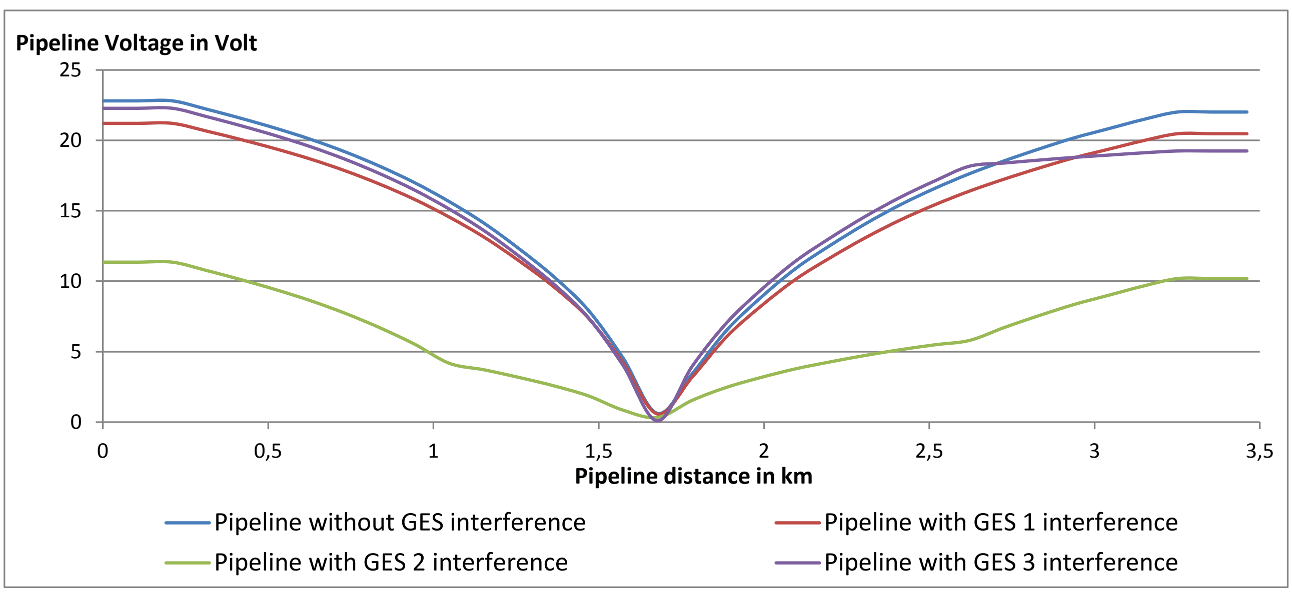

Figure 4: PIV reduction effect from differently sized GESs

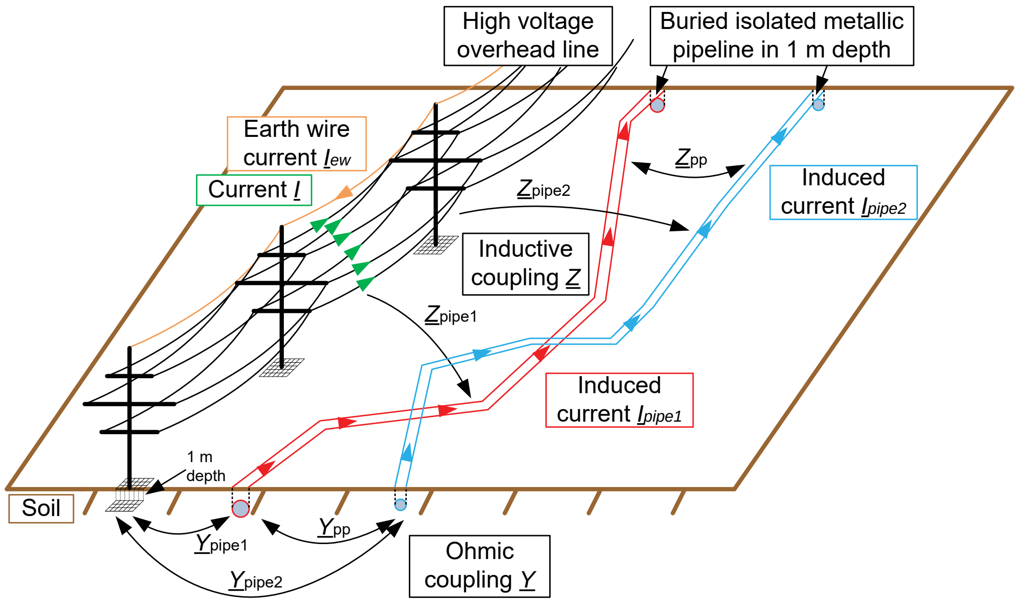

Figure 5: The complex interference and reduction situation between high voltage power line and two pipeline systems

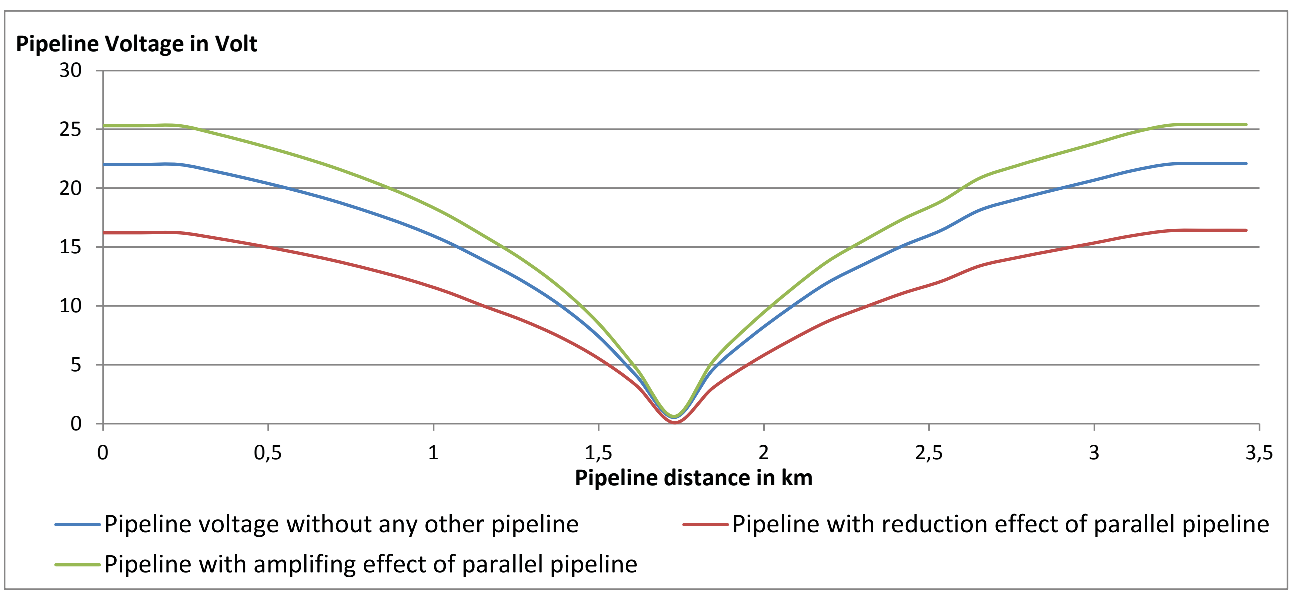

Figure 6: PIV with a second parallel pipeline

PARALLEL HIGH VOLTAGE ENERGY SYSTEMS

Especially, high voltage power lines but also railway systems are bundled on energy routes and therefore often have a long parallel routing. This leads to potentially high inductive interference. Besides the geographical alignment and HVES parameters, the load flow current situation is crucial. In case of the same load flow current in parallel HVESs, the pipeline inductive interference voltage rises dramatically. If the load currents flow in different directions, the PIV is massively lower. The overall load flow situation should always be reviewed when comparing measurement data with calculation results.

LOCAL EARTHING SYSTEMS

Local earthing systems are conducted materials, e.g. connecting water pipelines or earthed cable shields, buried in the soil. They are difficult to detect and usually not considered in calculations but can still act as reduction systems in the vicinity of HVESs and pipelines. This can lead to unexplainable reduced PIVs since the physical effects and the calculations are very similar to the above-mentioned cases.

OHMIC-INDUCTIVE COUPLING

An ohmic coupling $\underline{Y}$ exists between all interfered and interfering systems due to their earthing systems. In normal and fault operation conditions of HVESs, earth currents can flow through their earthing systems (e.g. pylons or transformer stations) into their ambience soil and, in the vicinity of a GES, pipeline or other conductive material, they can catch these currents and spread them to other regions. This results in a higher $\underline{I}_{earth}$ component with the effect of a higher influence on the current $\underline{I}_{pipe}$ and the resulting PIV.

INCORRECT OR INADEQUATE PIPELINE COATING PARAMETER

It is generally known that the pipeline coating is crucial to avoid material corrosion. It is problematic that the value of the coating resistance can vary within a wide range. On the one hand, the material has been changed from bitumen with a low value (1 MΩm) to polyethylene with a high value (100 MΩm). One the other hand, with time, the resistance value can fall to 10 kΩm (bitumen) or 50 kΩm (polyethylene) due to coating holidays. To summarise, with a lower coating resistance value, a lower PIV can be expected which one should bear in mind when comparing measurements and calculations [6].

VARYING THE SPECIFIC SOIL RESISTIVITY

The soil resistivity has a very strong influence on the PIV (as is shown in the paper of 2014 [6]). In areas with lower values, lower PIVs can be expected. However, weather and time of the year also influence the soil resistivity, changing the soil moisture and the soil temperature. The soil resistivity is lower when the soil moisture is high (e.g. due to high precipitation) and/or the soil temperature is high (e.g. during the summer). Therefore it is difficult to find the correct value of the soil resistivity along a pipeline.

Generally, the specific soil resistivity ranges between 25 Ωm and 10000 Ωm. Based on this wide range of values and the fragmenting of the different types of soil, the value for the representative respective ambient soil resistivity along the pipeline can be very diverse. Considering this variation is essential, both for calculations and measurements. Especially where measurements are conducted a detailed soil analysis is indispensable.

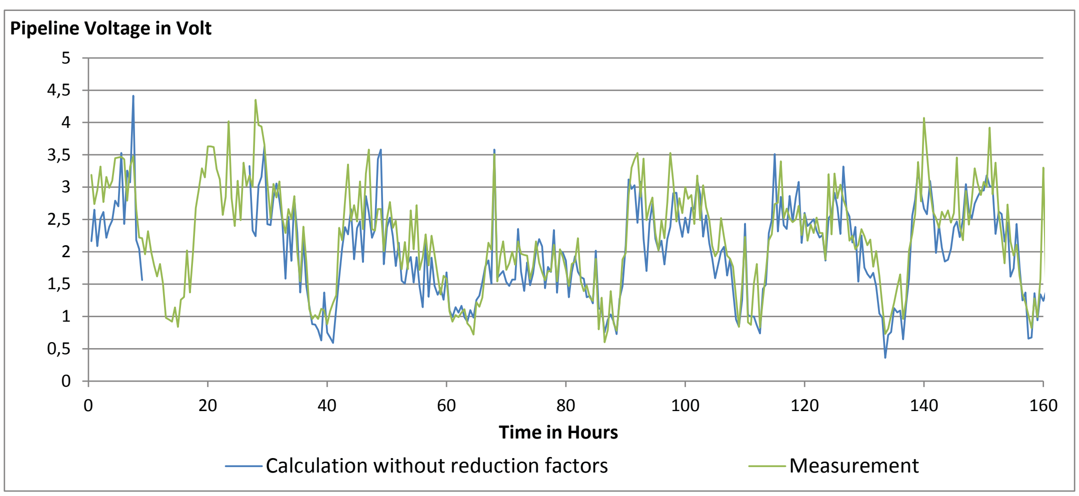

Figure 7: PIV calculation versus measurement, location 1, perfect example

PRACTICAL RESULTS

The following figures show different examples of calculations using the actually used load currents and comparing them to measurements during a measurement period of 140 to 160 hours at different pipeline locations. Figure 7 shows a nearly identical voltage characteristic between measurement and calculation since the model parameters reflect the real conditions very well.

The calculations in Figures 8 and 9 (which represent two different locations) without reduction effects show results higher by a factor of up to 7, compared to calculations considering conductive material nearby. These two figures show an intense voltage reduction, based on the geographical closeness of two different things: in location 2, another pipeline in combination with the reduction factor of two parallel high voltage overhead lines and in location 3, a rural area with a well-developed and extended GES.

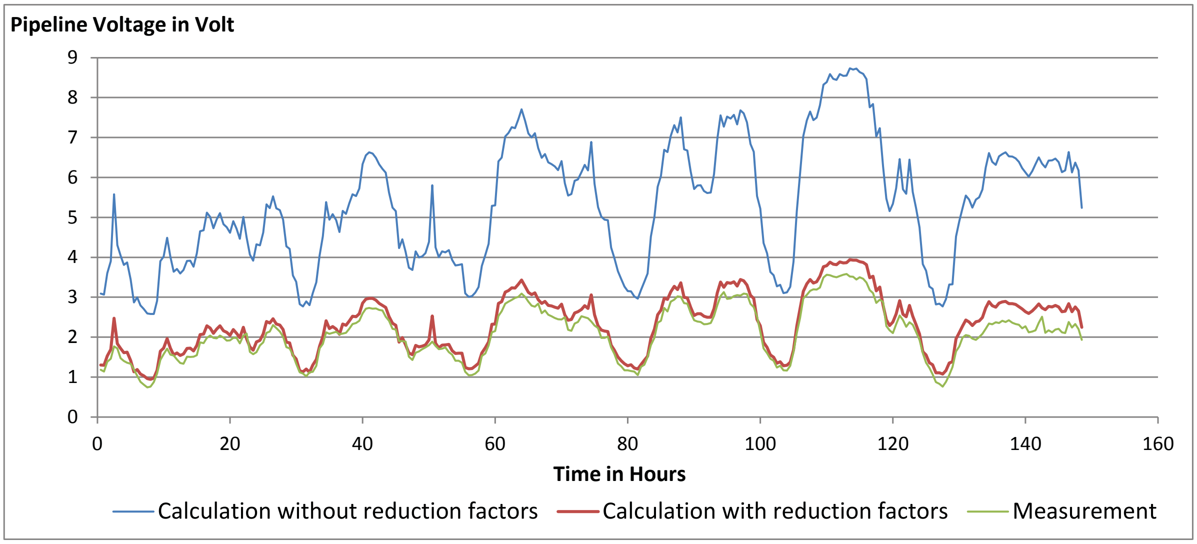

Figure 8: PIV calculation versus measurement, location 2, HVES

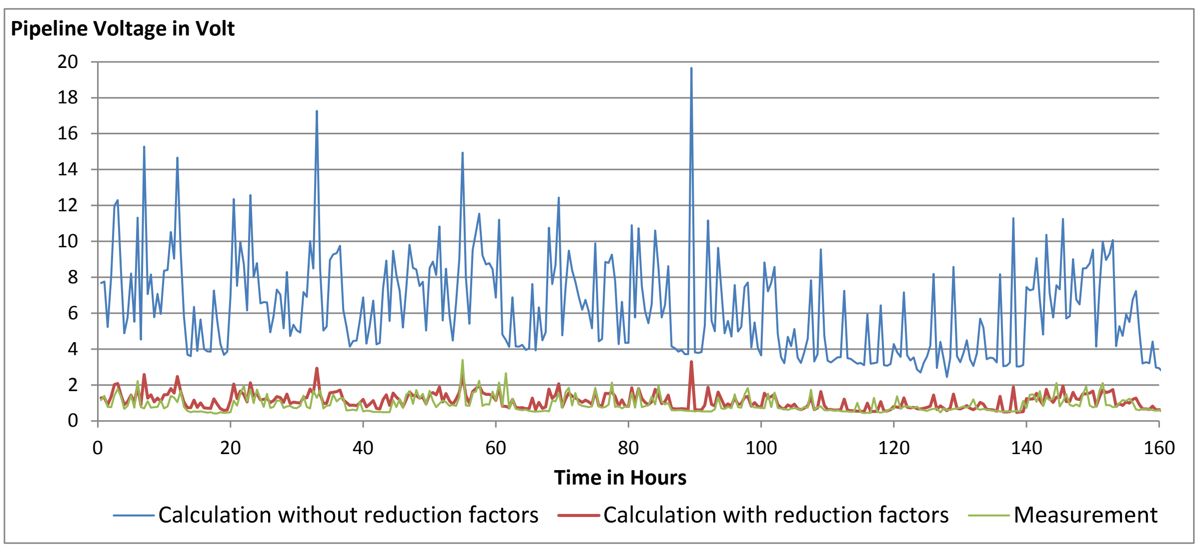

Figure 9: PIV calculation versus measurement, location 3, railway

Figures 10 and 11 show a combination of two reduction effects: the voltage reduction effect due to a parallel pipeline and also a voltage shift due to inadequate soil resistivity. Apart from the reduction effect, in location 4 the specific soil resistivity was essentially lower than expected while in location 5, the value was higher. Figure 10 because the calculation result is massively lower than before while in Figure 11, the average value is still remaining on the same level with consideration of the parallel pipeline reduction effect.

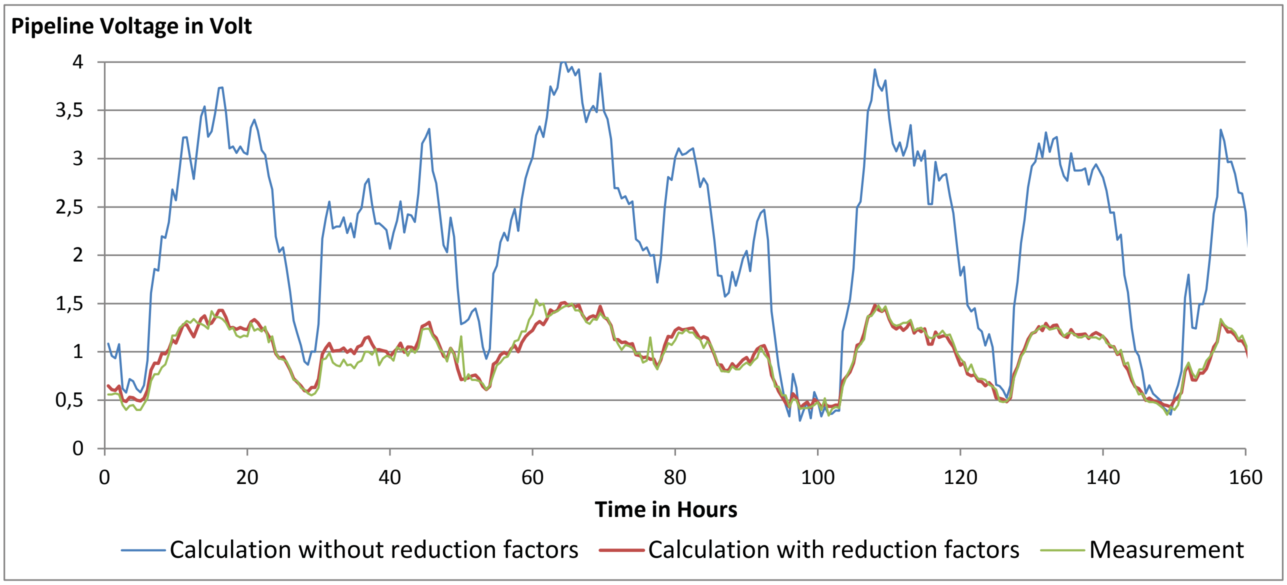

Figure 10: PIV calculation versus measurement, location 4, parallel pipeline with low soil resistivity

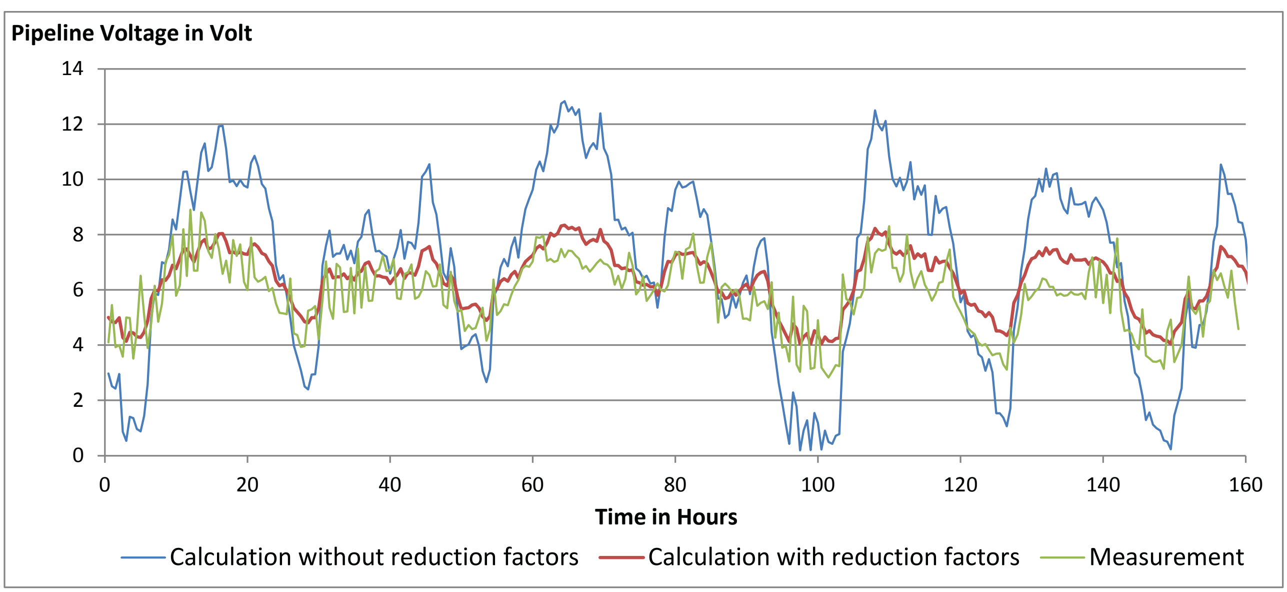

Figure 11: PIV calculation versus measurement, location 5, parallel pipeline with high soil resistivity

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SUMMARY

Even if calculations are done very carefully with established and generally agreed calculation methods, conducted measurements show mostly lower voltage levels than the calculated ones for the same pipelines and pipeline locations. With the consideration of the reduction – or even increasing – effects presented in this paper, most of the discrepancies between measurement and calculation can be explained when all important parameters are known.

Knowledge of the correct specific soil resistivity and pipeline coating resistance is a precondition since both parameters can influence the PIV in the measuring position. The value of the load currents during the measurement period must be known, as it is essential to correctly interpret the measurement data. Much more complicated are conducted materials within the interference area because they can act as a reduction factor, decreasing PIVs. They can also produce influencing voltages and in an unfavourable case, may even increase PIVs too.

The examples show that with consideration of all presented effects, most of the conducted measurements can be explained and even better, they can help to calibrate the calculation. With this research it is possible to reduce or avoid unnecessary measures while necessary actions, e.g. AC earthing systems or special safety working methods along the pipeline, can be used more effectively and efficiently.

Authors

Christian Wahl

Graz University of Technology

Institute of Electrical

Power Systems

Graz, Austria

christian.wahl@tugraz.at

Ernst Schmautzer

Graz University of Technology

Institute of Electrical

Power Systems

Graz, Austria

schmautzer@tugraz.at

BURIED STEEL

SEISMIC ANALYSIS OF BURIED STEEL PIPELINE SUBJECTED TO GROUND DEFORMATION WITH EMPHASIS ON THE NUMERICAL MODELLING OPTIMIZATION

> by: Gersena Banushi, Technische Universität Braunschweig, Germany and Università di Firenze, Italy

Abstract

Steel pipeline systems traverse large geographical areas characterized by a wide variety of soil conditions and environmental hazards such as earthquakes which can threaten the pipeline integrity undergoing large deformations associated with widespread yielding, leading to fracture with consequent material leakage.

Buried pipelines installed in seismic regions are susceptible to the effects of transient ground deformation (TGD) due to seismic wave propagation and permanent ground deformation (PGD) resulting from earthquake induced soil liquefaction, surface faulting and landslides [1].

Post-earthquake investigations have shown that almost all seismic damages to buried pipelines were due to permanent ground deformation and there were very few reported cases of pipelines damaged only by wave propagation [2].

In fact, buried pipelines are primarily affected by large permanent ground deformations (PGD) which may produce pipe wall rupture due to excessive tension as well as buckling by either excessive imposed bending or uniaxial compression loading.

Therefore it is necessary to perform accurate finite element analysis taking into account the nonlinear soil and pipe interaction as well as the constitutive behavior of the pipe material subjected to extreme seismic loading.

At the state of art, detailed finite element analysis of the soil-pipeline system subjected to large ground deformations are computationally expensive resulting in extremely large numerical models that may require days to run using the normally available computational resources [3]. Within the present work, in order to reduce the needed memory and computation time of the calculator, the part of the soil-pipe system away from the fault is suitably modeled as a single equivalent axial spring, connected to the pipe shell elements through appropriate constraints. Furthermore, the seismic performance of the buried pipeline has been investigated through a series of parametric studies that permit to assess the structural response of the pipe components in function of various configurations of the soil-pipeline system. The obtained numerical analysis results allow to evaluate accurately the limit ground displacement inducing global failure on the pipeline components due to loss of strength capacity following large scale seismic loading, with the advantage of being computationally efficient.

"POST-EARTHQUAKE INVESTIGATIONS HAVE SHOWN THAT ALMOST ALL SEISMIC DAMAGES TO BURIED PIPELINES WERE DUE TO PERMANENT GROUND DEFORMATION"

> Gersena Banushi

PTC-POSTERSHOW

This paper will be presented during the "Scientific Advances Poster Session" at 10th Pipeline Technology Conference

NUMERICAL MODELING

Within the present study the seismic performance of a straight 36" x 9.53 mm X65 steel grade pipeline subjected to strike-slip faulting has been assessed through accurate finite element analysis taking into account the nonlinearities of the pipe-soil system, with emphasis on identifying the pipeline structural failure.

The buried steel pipeline is modeled a cylindrical shell using four-node reduced integration shell elements (S4R) available in ABAQUS (2014) [4] which account for finite membrane strains and arbitrarily large rotations, resulting suitable for large strain analysis. The soil surrounding the pipeline is discretized through eight-node linear brick continuum elements with reduced integration (C3D8R). The steel pipe material model is defined within the von Mises plasticity theory with nonlinear hardening. Instead, the soil material is described within the Mohr–Coulomb constitutive model, characterized by different parameters, like the cohesion, the friction and dilatation angle, the elastic modulus E, and Poisson's ratio v, as indicated in the table 1. The soil-pipeline interaction is assumed as frictional allowing for sliding and separation at the soil-pipe interface.

As schematically illustrated in the figure 1, the vertical plane containing the fault trace divides the soil in two equal antisymmetric parts. The fault movement is applied as a horizontal displacement of the lateral external faces of the moving soil part whereas the lateral external faces of the fixed part are restrained in the horizontal direction. Instead the faces of the bottom boundary of both soil parts are restrained to move in the vertical direction.

Moreover, it is noted that each of the ends of the shell pipeline is connected through appropriate constraints to an equivalent boundary spring, which represent the reaction of the part of the soil-pipeline system away from the fault to the pipeline displacement, as described in detail in the following paragraph.

The mesh of both the soil and pipeline components is refined in the central region, close to the fault trace, in order to better capture the large deformation behaviour of the system.

The numerical simulations for assessing the pipeline performance subjected to strike-slip fault movement are conducted in two steps. At first, a geostatic analysis is performed to establish the initial stress and strain state of the soil-pipeline system, which equilibrates the gravity loading and satisfies the boundary conditions. In the second step, a uniform horizontal displacement is applied at the lateral external faces of the moving soil part and the free end of the corresponding equivalent boundary spring, whereas the lateral external faces of the fixed soil part, as well as the free end of the corresponding equivalent boundary spring remain restrained in the horizontal direction.

	Clay Soil
Soil Cohesion	50 kPa
Friction angle ϕ	0
Young's Modulus E	25 mPa
Poissson's ratio v	0.48
Soil density y	20 kN/m^3

Table 1. Mechanical characteristics of the soil analysed.

CALIBRATION OF THE EQUIVALENT BOUNDARY SPRING.

Observing that the relative transverse displacement between the soil and the pipe segment away from the fault trace is negligible, this part is suitably modelled as a single equivalent axial spring connected to the pipe shell elements through appropriate constraints, assuring the deformation continuity of the system, as schematically illustrated in the figure 2. The force displacement relationship of the equivalent axial spring is obtained analytically taking into account the axial constitutive behaviour of the pipeline as well as of the axial soil-pipeline interaction. The latter is obtained by subjecting the pipeline statically to a uniform axial displacement, after establishing the initial geostatic stress-strain state in the system, as schematically illustrated in the figure 3.

The obtained axial spring constitutive behavior is subsequently implemented in ABAQUS [4] finite element software for the numerical analysis purposes. This modeling procedure permits to largely reduce the memory and computation time of the calculator, compared to the one where the entire length of the pipeline is modelled with nonlinear shell elements and the surrounding soil with solid elements.

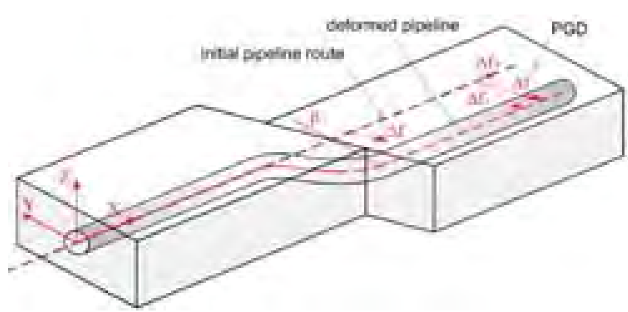

Figure 1. Schematic representation of the soil pipeline system subjected to strike-slip faulting.

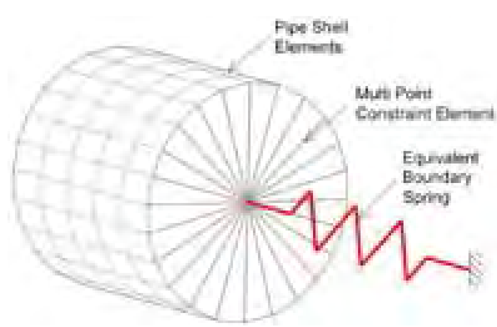

Figure 2. Schematic representation of the equivalent-boundary spring model

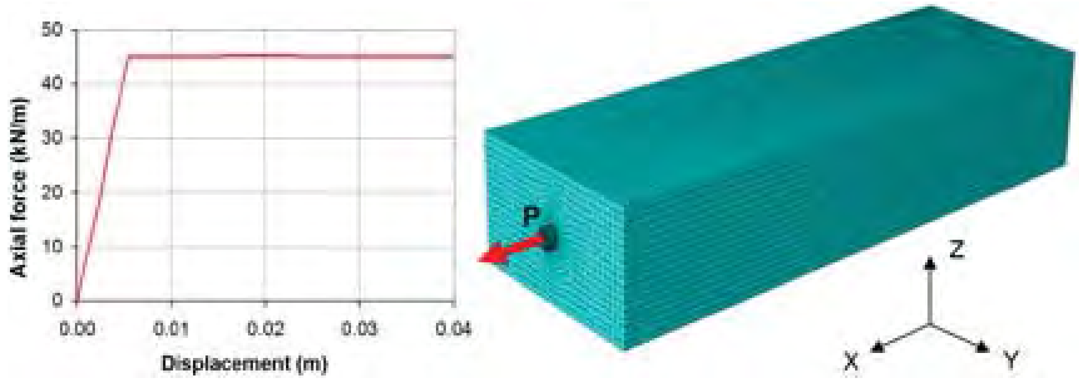

Figure 3. Schematic representation of the procedure for determining the soil reaction to the pipeline movement in the axial direction.

Considering the axial constitutive behaviour of the pipeline, as well as the axial soil-pipeline interaction, as schematically illustrated in the figure 4, the relationship between the equivalent spring axial force F and its elongation ΔL is expressed by the following formula:

$$\Delta L = \begin{cases} \dfrac{F}{\sqrt{kAE_1}} & , F \le F_0 = \sqrt{AE_1 f_s u_0} \\ \dfrac{u_0}{2} + \dfrac{F^2}{2AE_1 f_s} & , F_0 \le F \le F_1 \\ \Delta L_{i-1} + \dfrac{1}{2AE_i f_s}\left[F^2 + 2(AE_i \varepsilon_{i-1} - F_{i-1})F + F_{i-1}^2 - 2AE_i \varepsilon_{i-1} F_{i-1}\right] & , F_1 < F_{i-1} \le F \le F_i \end{cases} \quad (1)$$

where ε_i, σ_i are the *i*-th strain and stress value respectively defining the steel pipeline material constitutive relationship, *A* is the cross section area of the pipe, $F_i = A \cdot \sigma_i$ is axial force in the pipe corresponding to an axial stress equal to σ_i, $E_i = (\sigma_i - \sigma_{i-1})/(\varepsilon_i - \varepsilon_{i-1})$ is the slope of the i-th segment defining the pipe multi-linear stress-strain relationship and ΔL_i is the pipeline elongation corresponding to the axial force F_i. In particular, E_1 and σ_1 are respectively the elastic stiffness of the steel pipeline and its yield stress.

Instead, f_s is the maximum soil friction force per unit length of the pipeline, u_0 the relative displacement between the soil and the pipeline when sliding occurs, $k = f_s/u_0$ is the rigidity of friction interaction at the soil pipeline interface and F_0 is the force in the buried pipeline when sliding occurs at the soil-pipe interface, as schematically illustrated in the figure 5.

Figure 5. Schematic representation of the axial forces and elongations acting in the pipeline segment away from the fault.

Moreover, it is observed that in the case where the pipeline ends connected to the equivalent-boundary spring remain in the elastic range ($i=1$, $F<F_1$), the expression (1) is similar to the approximated formula proposed by Liu et al. [5].

In the figure 6 is illustrated the relationship between the elongation ΔL and the axial force F for the equivalent-axial spring corresponding to the clay soil conditions and pipeline characteristics considered in the present study, calculated using the expression (1).

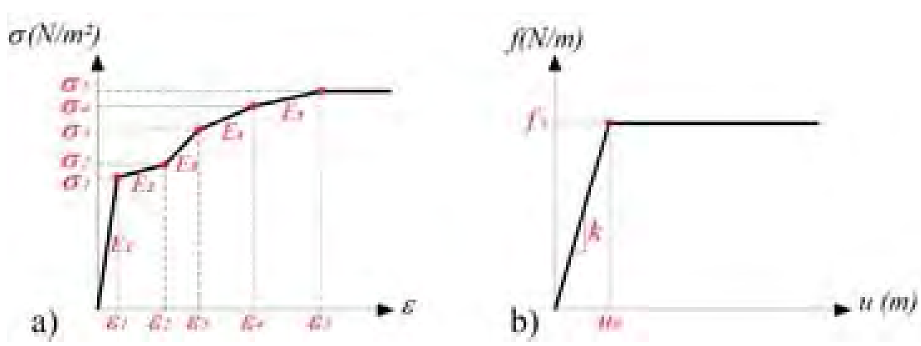

Figure 4. Schematic representation of the axial constitutive behaviour of the: a) Steel Pipeline; b) Pipe-Soil Interaction

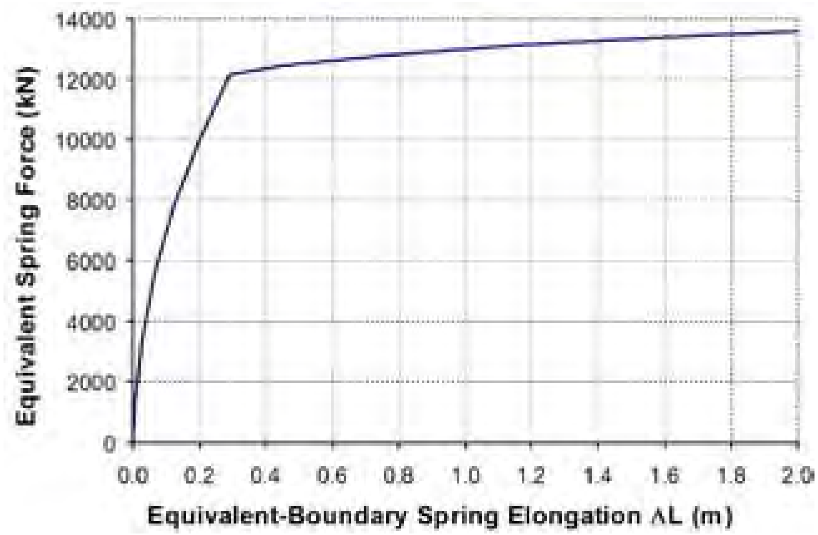

Figure 6. Relationship between F and ΔL for the equivalent-boundary springs corresponding to the soil condition considered, calculated using the formula (1).

ANALYSIS RESULTS

Similarly to the procedure followed within recent European Research Projects [6, 7] three principal modes of structural failure are considered for evaluating the pipeline seismic performance:

1. Tensile strain limit of 3%, as indicated in the Eurocode 8 - Part 4 [8] which can lead to consequent rupture of the pipe wall due to loss of strength capacity in the pipe material.
2. Local buckling of the pipeline caused by an abrupt increase of compressive strains at the compressive side of the pipe cross section.
3. Excessive ovalization of the pipeline cross section. Following the indications contained in Gresnigt, 1986 [9], the critical ovalization parameter, intended as the ratio of the minimum pipe diameter to its initial diameter, is assumed equal to 15%.

The variation of the plastic axial strain at the most stressed generator of the pipe wall, in the case of pipeline oriented perpendicularly to the fault trace (ß=0°), for different values of fault displacement Δf is indicated in the figure 7. It can be observed that the onset of local buckling occurs for a fault displacement equal to 41 cm, at a distance of about 4.3 m away from the fault trace, where the maximum compressive plastic strain in the pipeline reaches 0.45%. Beyond this plastic deformation region, the pipeline remains essentially elastic. In the figure 8 are illustrated the displacement contours for the pipeline and the fixed part of the soil close to the fault trace where the onset of local buckling occurs, whereas in the figure 9 is illustrated the evolution of the deformed shape of the pipeline and axial strain contour at the region of local buckling for different values of the fault displacement Δf.

In the case of the fault trace forming a negative angle ß=-10° with the normal to the pipeline axis, the onset of local buckling is observed earlier, for a fault displacement value equal to 23 cm, at a distance of about 3.75 m away from the fault, as illustrated in the figure 10.

Instead for positive values of the angle ß formed by the fault trace with the normal to the pipeline axis, the predominant limit state is the elevated section deformation. It is observed that the 15% performance limit of section ovalization is reached in the pipeline for values of the fault displacement varying from 85 cm to 1.09 cm, in function of the inclination angle ß. As schematically illustrated in the figure 11, the excessive section ovalization region in the pipeline is localized close to the fault trace which is also the area where maximum pipe axial forces occur.

CONCLUSIONS.

In order to evaluate the seismic performance of a buried pipeline subjected to strike-slip faulting, a detailed numerical procedure has been adopted that considers the pipe-soil system as a three dimensional continuum model, accounting for contact and friction interaction at the soil-pipe interface.

Being the continuum modelling computationally expensive, the region of the pipe soil system away from the fault is modelled as a single equivalent axial spring connected to the pipe shell elements through appropriate constraints. The force displacement relationship of the equivalent axial spring is obtained analytically taking into account the axial constitutive behaviour of the pipeline as well as the axial soil-pipeline interaction. The obtained axial spring constitutive behavior is subsequently implemented in ABAQUS finite element software [4] for the numerical analysis purposes. This modeling procedure permits to largely reduce the needed memory and computation time of the calculator, compared to the one where the entire length of the pipeline is modelled with nonlinear shell elements, and the surrounding soil with solid elements.

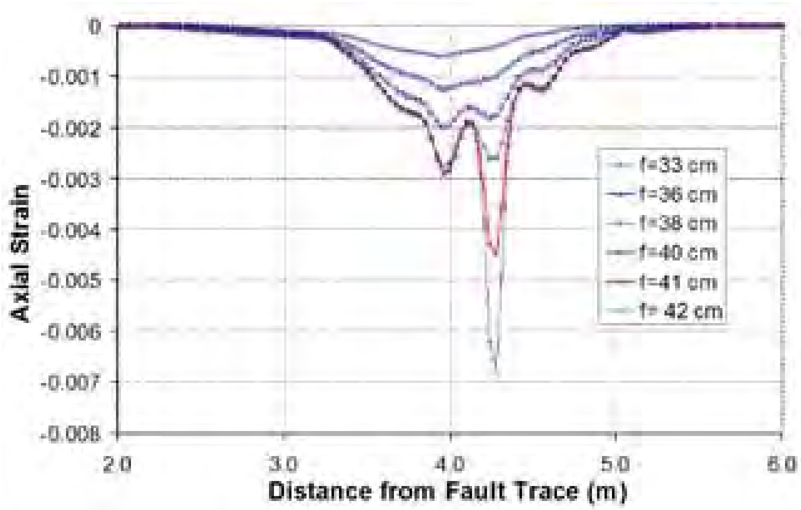

Figure 7. Variation of the plastic axial strain at the most stressed generator of the pipeline wall for different values of fault displacement, in case of ß=O°

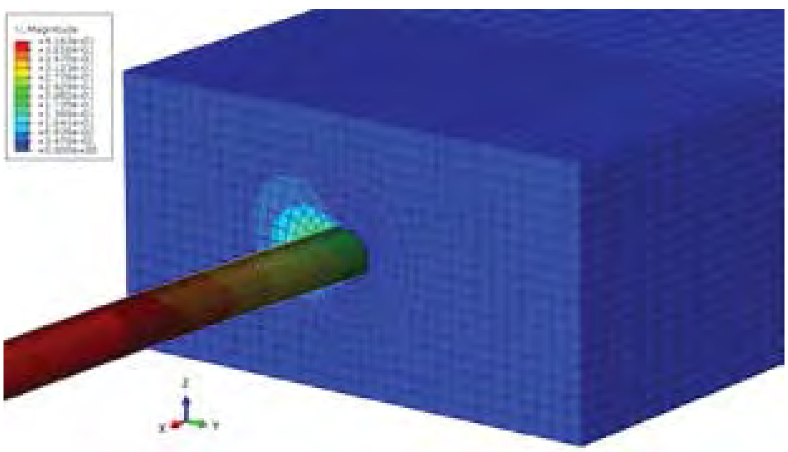

Figure 8. Displacement contours for the fixed soil part (ß=O°) close to the fault trace where the onset of local buckling occurs.

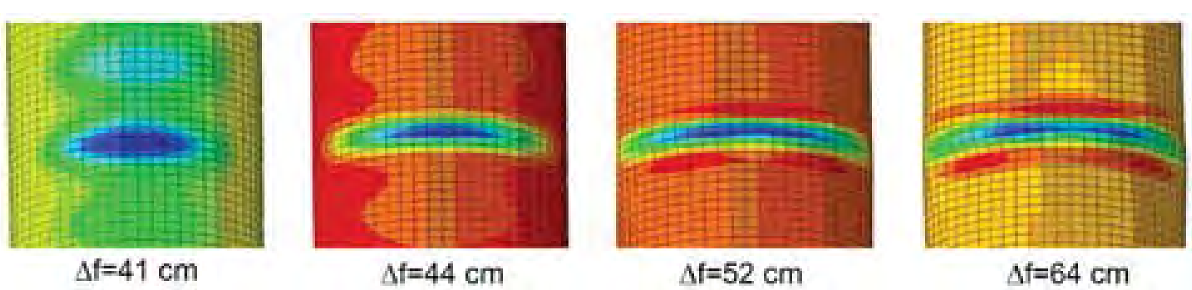

Figure 9. Evolution of the plastic axial strain contour and deformed shape of pipeline at the region of local buckling for different values of the fault displacement Δf, in the case of ß=O°.

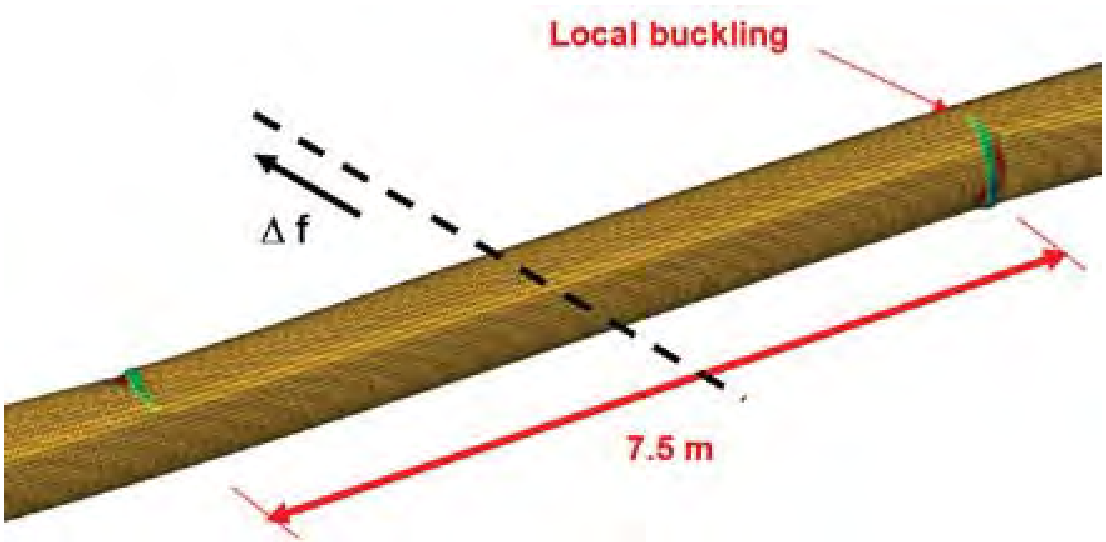

Figure 10.
Deformed shaped and localization of local buckling for the case of fault trace inclined at an angle ß= -10° with respect to the pipeline normal, and a fault displacement value Δf=23cm.

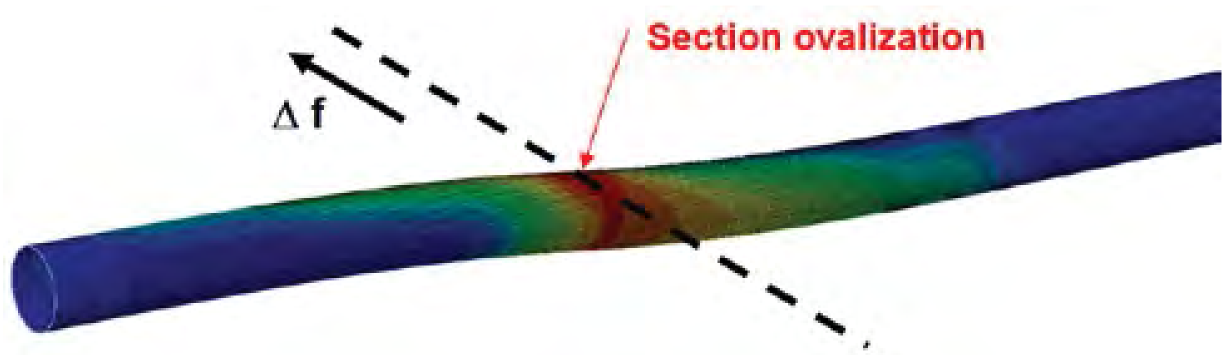

Figure 11. Deformed shape with indicated the localization of excessive section localisation close to the fault trace, in the case of ß = 40°

Author

Gersena Banushi

PhD Student

Technische Universität Braunschweig, Germany & Università di Firence, Italy

g.banushi@ing.unipi.it

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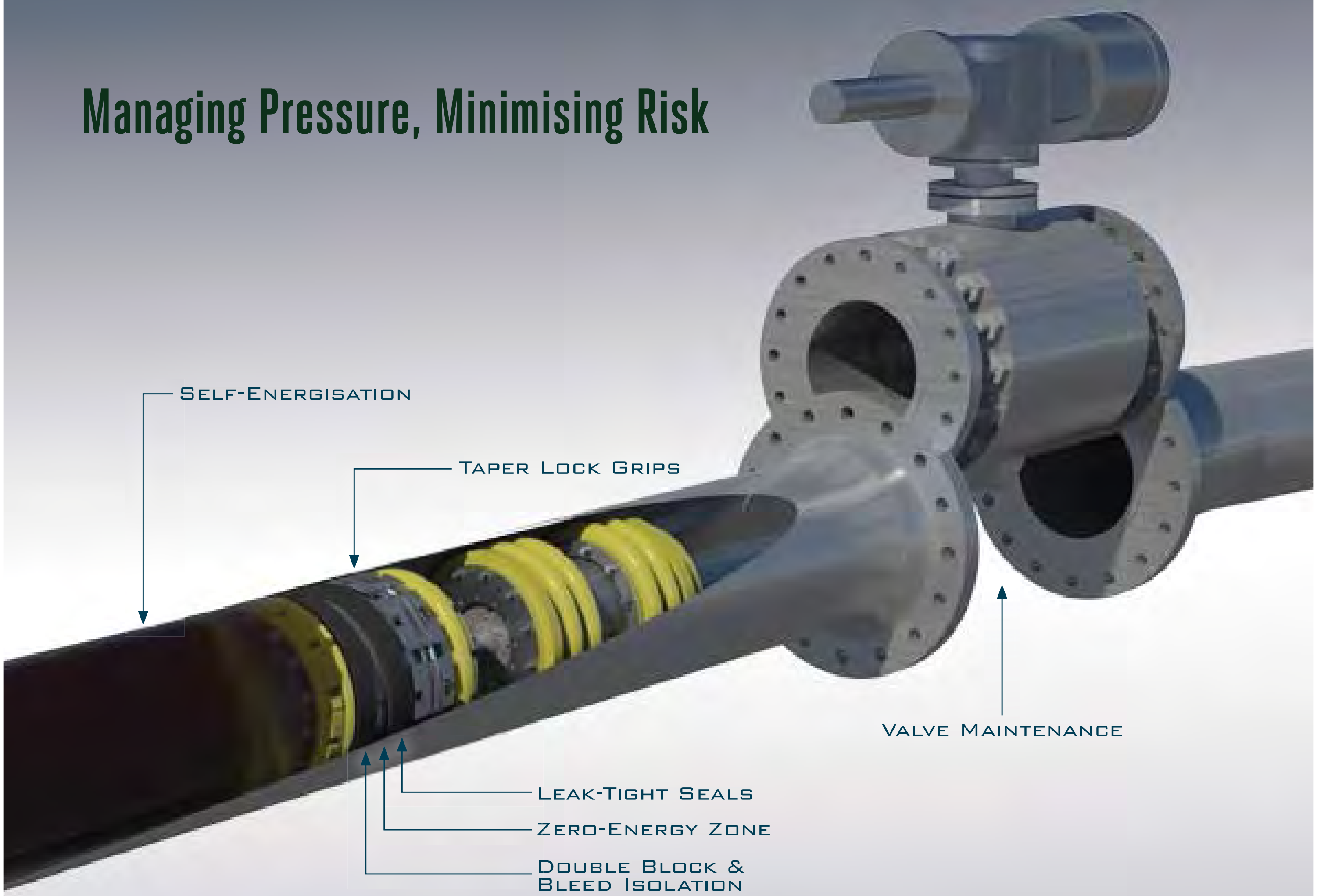

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GRAND THEFT PIPELINE

Finite element simulation of guided waves to detect product theft from pipelines

> by: Salisu El-Hussein, University of Aberdeen, UK / Dr. John Harrigan, Amec Foster Wheeler, UK / Dr. Andrew Starkey, University of Aberdeen, UK

DSD 010172

Abstract

Product theft (hot tap) and intentional attack (vandalism) are among the major causes of reported pipeline failures. The existing pipeline inspection techniques are mainly reactive measures to detect damage/defect. Guided waves (GWs) have potential for the real time structural health monitoring (SHM) of pipelines and other structures. GW offers the advantages of long range examination of a structure and rapid detection of damage. As an example stress waves generated through physical attack on a pipeline propagate in the form of GWs. These signals can be detected to provide information about the source and location of the interference. Deliberately excited GWs can be used to detect the presence of additional features such as small branch introduced to initiate a product theft. Finite element (FE) analysis is conducted on a 12 in (305 mm) diameter steel pipe with 12 mm wall thickness to investigate the potential of longitudinal L(0,1) and torsional T(0,1) GW modes for long distance propagation. The results show that a low frequency tone burst excitation modified by a Hanning window produces a GW with low attenuation and dispersion. For example, at 2.5 kHz centre frequency, the attenuation coefficient is 0.00034 m-1. At this attenuation, the signal would theoretically retain more than 10 % of its original energy after a propagation distance of 8 km. The sensitivity of GW at this frequency was tested with detection of 2 in (50 mm) branch pipe attached along the 12 in pipeline.

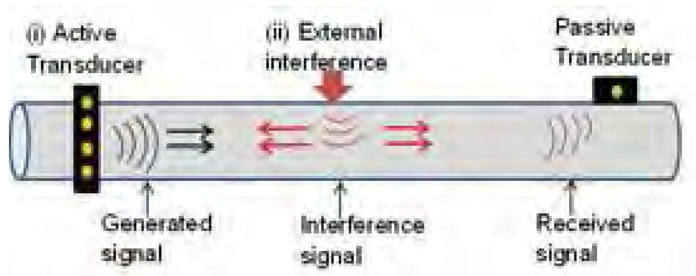

Figure 1 Illustration of guided waves generated by (i) an active transducer; (ii) external interference

"IN THE AREA OF THIRD PARTY RELATED DAMAGES, COST-EFFECTIVE PIPELINE MONITORING IS STILL REQUIRED"

> Salisu El-Hussein, Dr. John Harrigan; Dr. Andrew Starkey

INTRODUCTION AND BACKGROUND

Third party activities constitute about 60 per cent of the reported pipeline failures [1]. Intentional pipeline damage and oil theft are also sources of concern even in developed countries like United States [2], United Kingdom [3] and more especially developing countries like Nigeria [4]. In Nigeria for example, a total of 15,796 cases of pipeline vandalism was recorded between 2000 and 2010. These resulted in estimated 2,800 fatalities, $1.2bn cost of repairs and daily revenue loss to the government of $10.4 million [5]. The damages to the environment and ecosystem are unquantifiable in monetary value. There are many pipeline inspection and monitoring techniques in the literature. However, in the area of third party related damages, cost-effective pipeline monitoring is still required. At selected frequencies, GWs have the potential to meet this requirement. The stress waves generated during physical attack on a pipeline can provide a signal that is transmitted along the pipeline. Fig. 1 illustrates the stress waves generated either deliberately by a transducer or accidentally as a result of an attack on a pipeline. For an attack on the line, the signal generated can be detected to serve as an early warning for the occurrence of vandalism/theft. Alternatively, a GW can be generated deliberately for inspection of the line. The difficulties associated with interpreting signals recorded at a remote location are associated with: energy dissipation; dispersion; and formation of multiple GW modes.

EXISTING PIPELINE INSPECTION AND MONITORING TECHNIQUES

There are many pipeline inspection and monitoring techniques in the literature. They range from visual inspection, wireless sensor networks (WSN) to fibre optic, acoustic, electromagnetic, ultrasonic methods and magnetic flux leakage (MFL). The last two are the most common pipeline inspection and monitoring techniques [6]. Most of these techniques are reactive in nature or require point-to-point transducer movement. In addition, WSN and fibre optic methods are difficult to retrofit. Table 1 summarises the advantages and disadvantages of common pipeline monitoring techniques.

Methods	Advantages	Disadvantages
Visual Inspection	- Effective in a relativley small area	- Labour intensive - Accessability limitation
Electromagnetic method	- Cost-effective in surface and near surface defects	- Requires probe movement
Acoustic emission method	- can operate in passive and active modes	- High cost of sensors - Requires densely spaced sensors
Fibre optic method	- Sensitivity along the entire length - Dual function of communication and monitoring	- Susceptible to damage during installation - High installation cost
Wireless sensor network	- Little inteference with structure operation	- Large multi-hop network required
Ultrasonic methods	- Good sensitivity to the presence of defects	- Requires probe movement
Guides waves	- In-Service Monitoring - Long distance coverage - Cost effectiveness	- Multiple modes formation - Complicated signal processing

Table 1 Comparison of common pipeline inspection and monitoring techniques

BASIC GUIDED WAVE THEORY

GW forms as a result of superposition of longitudinal and shear waves reflecting between structural boundaries. The possible constructive interferences which result from these reflections represent the number of GW modes which will propagate along the length of the waveguide. Unlike longitudinal and shear bulk waves, their velocity is not only dependent on the material properties but also on the thickness of the material and the wave frequency. GWs experience energy leakage when in contact with a surrounding medium (e.g. soil) or internal fluid. Cylindrical waveguides (e.g. pipes) support 3 modes of GW vibrations: longitudinal, torsional and flexural. According to the convention by Silk and Bainton [7] they are labelled as L(0,m), T(0,m) and F(n,m) for longitudinal, torsional and flexural modes respectively. The letter 'n' represents the harmonic order of the circumferential variation within the wall thickness while 'm' describes the sequential number of modes of the same family. For example, L(0,1) is the first longitudinal wave mode to exist with zero cycles of particles' displacement variation around the circumference. GWs in cylindrical structures are governed by Navier's equation, which in vector form can be seen below [8]:

$$\rho \frac{\delta^2 u}{\delta . t^2} = (\lambda + 2\mu)\nabla(\nabla . u) + \mu\nabla \times (\nabla \times u)$$

where u represents displacement, λ and μ are Lamés constants, ∇ is the 3-dimensional differential operator $\delta / \delta x + \delta / \delta y + \delta / \delta z$ and p is the material density. For detailed derivation of GW equations, the reader is referred to reference [8].

GUIDED WAVE STRUCTURAL HEALTH MONITORING

SHM is a technique employed for the maintenance of large structures such as rail-track and pipeline networks. SHM seeks to replace scheduled maintenance with condition based maintenance. In passive mode, SHM consists of measuring the operational parameters of a structure and indirectly assessing its state. Acoustic emission and thermal sensors are commonly used in passive SHM. Active SHM assessed the structure directly in order to detect the presence of defects. Permanent sensors and relevant monitoring techniques are used to provide information on the state of the structure. Resonant frequency measurements, WSN and GW sensors are commonly used for active SHM. T(0,1) and L(0,1) are the common GW modes used in NDT for defect detection. The T(0,1) mode has the advantage of being more sensitive to longitudinal defects while L(0,1) has more potential for long distance propagation. In most SHM techniques, there is a trade-off between resolution and spatial coverage. GWs combine long distance propagation with a good resolution for defect location and identification [9]. Due to these advantages, many studies have been carried out on the inspection of pipes and other structures using GWs.

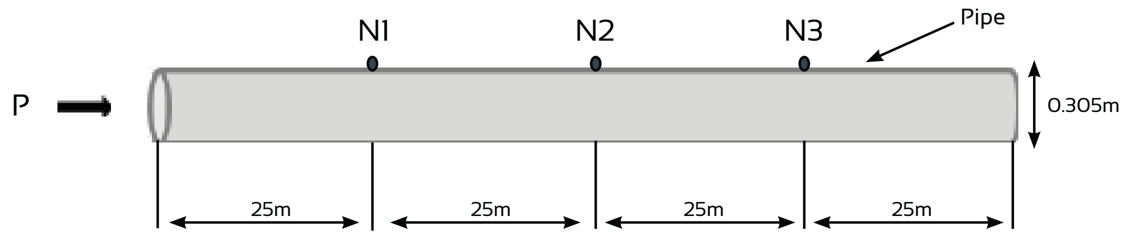

Figure 2: Configuration of model pipe showing nodal locations

FINITE ELEMENT SIMULATION OF GUIDED WAVES

The mathematical solution of GW has been obtained for simple geometries such as a circular cylinder [9]. For complicated geometries no mathematical solution is available. Numerical modelling such as boundary element and FE are used for the analysis of complicated geometries. FE analysis has been successfully employed as a tool for GW propagation analysis in plates and pipes [10]. The use of FE modelling can provide the required understanding of stress waves propagating along a pipeline for application against product theft and vandalism.

FE MODEL

The model was generated with ABAQUS/explicit version 6.12. The simulation was conducted on a 12 in (305 mm) outer diameter, 12 mm wall thickness and 100 m long pipe. Fig. 2 shows the configuration of the model pipe and three nodal locations (N1, N2 and N3) defined along the pipe. The pipe material was made from mild steel with a Young modulus $E = 209$ GPa, Poisson's ratio $v = 0.3$ and density $p = 7850\ kgm^{-3}$. A 3-dimensional linear brick, 8 node solid elements with reduced integration (C3D8R) was chosen for this analysis. A sweep meshing technique was adopted with a 24 mm mesh size in the longitudinal direction. ABAQUS automatic time step (Δt) which stabilised at 0.676 μs was adopted and was sufficient to avoid numerical instability. The element length chosen met the requirement of 20 nodes per smallest wavelength in the model. The excitation signal was a 5-cycle tone burst modified by a Hanning window with a centre frequency of 2.5 kHz.

LONGITUDINAL EXCITATION

L(0,1) mode was excited by applying a uniform pressure pulse load at one end of the pipe as shown in Fig. 3. Stresses and displacements were monitored at the three nodal locations shown in Fig. 2. Time domain displacement signals recorded at these locations and their corresponding frequency spectra are shown in Fig. 4. From Fig. 4 (a) there is no appreciable change in signal shape as the wave propagates from N1 to N3 (low dispersion). Fig. 4 (b) also shows little decrease in magnitude of the frequency content (low attenuation). Using the signals at N1 and N2, the attenuation coefficient of the L(0,1) mode at this centre frequency was calculated as 0.00034 m-1. From this attenuation, the signal can theoretically propagate 8 km and retain more than 10 per cent of its original energy.

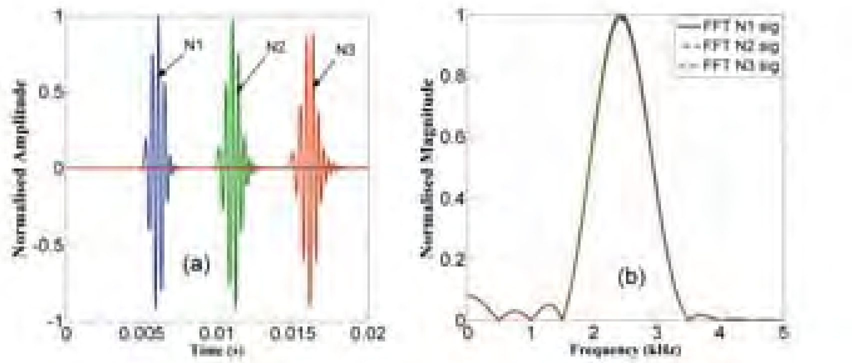

Figure 4 Longitudinal displacement signals recorded at 3 nodal positions: (a) Time domain and (b) frequency spectrum

TORSIONAL EXCITATION

T(0,1) modes were generated by assigning a displacement rotation to the edge nodes. The edge nodes were coupled to a master node as shown in Fig. 5. All other parameters remain the same as for the longitudinal wave simulations. Fig. 6 shows the rotational displacements at the three nodal locations and their corresponding frequency spectra. Compared to the L(0,1) modes, the change in shape as the signal propagates from N1 to N3 is more noticeable (higher dispersion) and the decrease in magnitude of the frequency spectrum is higher (higher attenuation) as shown in Fig. 6 (a, b). At a centre frequency of 2.5 kHz, the attenuation coefficient of the T(0,1) mode was calculated as 0.0083 m-1. From this attenuation, the potential propagation distance at this frequency is less than 1.5 km. This shows that the L(0,1) mode has more potential for long distance propagation than T(0,1) mode.

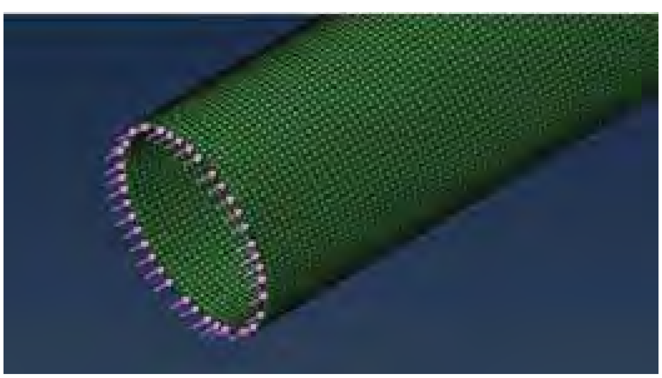

Figure 3 Longitudinal guided wave excitation

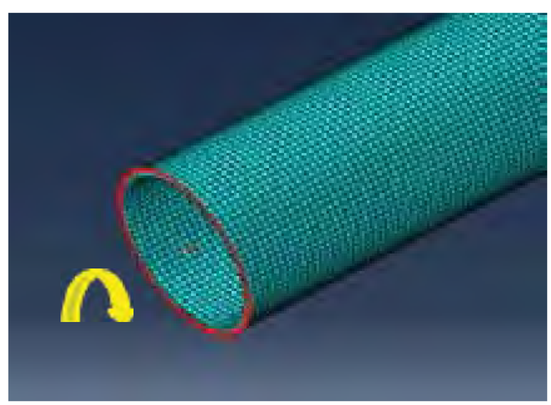

Figure 5 Torsional guided wave excitation

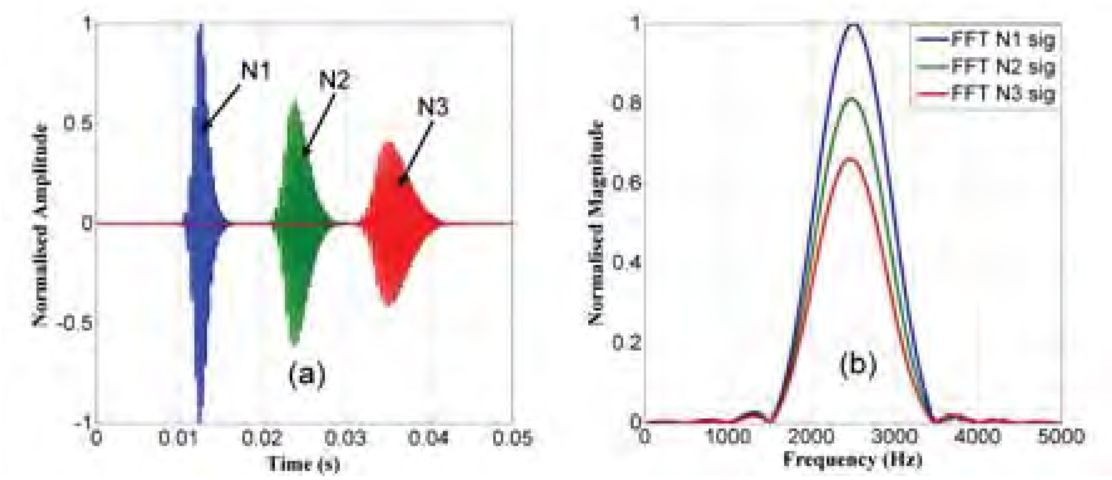

Figure 6 Torsional displacement signals recorded at 3 nodal positions: (a) Time domain and (b) frequency spectrum

INTERACTION OF LOW FREQUENCY GUIDED WAVE WITH A BRANCH PIPE

Oil theft is often carried out by attaching a branch pipe to siphon petroleum products. The model pipe was simulated with a 2 in. branch pipe attached at the N2 location and the stresses and displacements were recorded at N1 and N3. Fig. 7 shows a snapshot of the stresses as the wave propagates along the pipe and up the branch. Fig. 8 (a) shows the displacement history at node N1. The first pulse recorded is the incident signal, I, that travels from left to right in Fig. 2. Sometime later there is a similar pulse but of much lower amplitude. This is the reflection from the branch, termed RB in Fig. 8. The last pulse, termed RE, is similar in magnitude to the incident wave. This is the part of the wave that was transmitted across the branch and reached the far end of the pipeline before being reflected back towards node N1. Fig. 8 (b-d) shows the frequency spectra for the pulses termed I, RB and RE. The reflection from the branch was quantified in terms of reflection coefficient (RB/I) in the frequency domain. Comparing Figs. 8 (b) and (c), there is similarity between the frequency spectra of the incident and branch reflected pulses. This allows the reflected signal to be detected by cross-correlation with the incident signal. A time-shift of approximately 5 ms was observed from the cross-correlated signal. From this time-shift and phase velocity of the wave at 2.5 kHz the distance of the branch from the sensor location (N1) was calculated as 25.5 m. This shows the potential of GW at this frequency to detect and locate a small branch attachment to a pipeline.

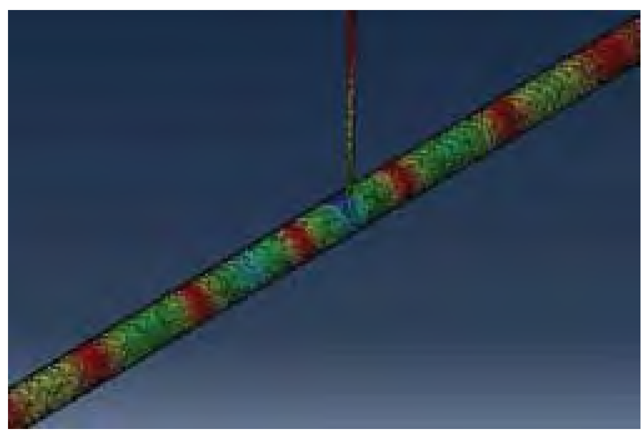

Figure 7 Snapshot of the stress contours along the model with a branch attachment

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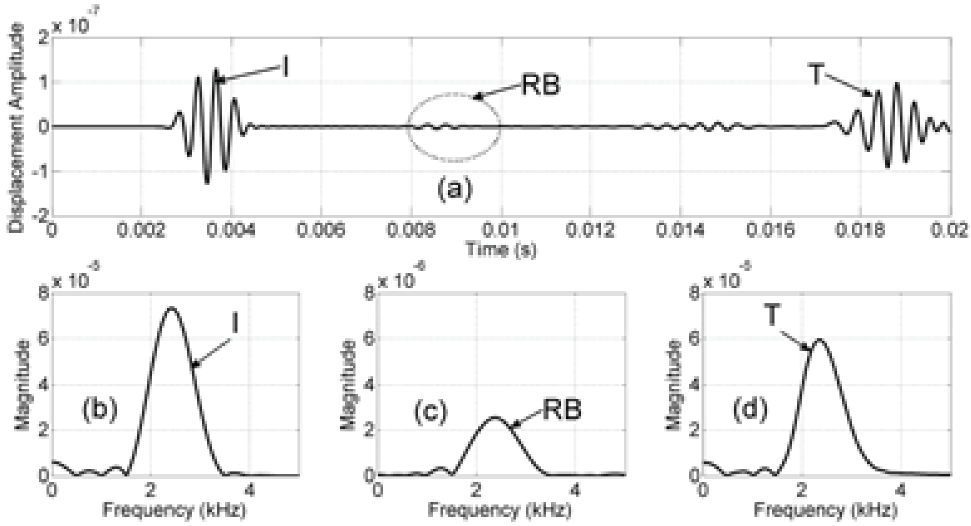

Figure 8 (a) Strain history at N1 showing Incident, branch reflection and end reflection pulses and (b-d) their corresponding frequency spectra

CONCLUSIONS

The results show that the longitudinal GW mode can propagate long distances without appreciable change in shape. In contrast, the torsional mode shows higher dispersion within the same propagation distance. It is shown that at low frequency (2.5 kHz) the L(0,1) mode can be used to detect a 2 inch branch in a 12 inch pipeline. The reflection coefficient for the case considered is approximately 4 % of the incident signal and the reflection will decay with distance. However, the reflected signal from the branch was observed to have the same frequency content as the incident signal. As the reflected signal therefore has a known frequency, it is more easily detected by e.g. cross-correlation. The reflected signal can be used to detect the presence and the location of a small branch on a pipeline.

ACKNOWLEDGEMENT

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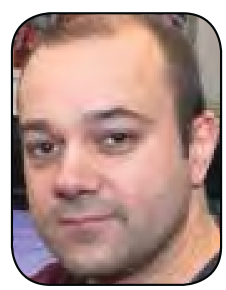
Authors

Salisu El-Hussein
University of Aberdeen
School of Engineering
Aberdeen, UK
r02se13@abdn.ac.uk
+44 (0) 1224 272801

Dr John Harrigan
Amec Foster Wheeler
Aberdeen, UK
john.harrigan@amecfw.com
+44(0)1224 294198

Dr Andrew Starkey
University of Aberdeen
School of Engineering
Aberdeen, UK
a.starkey@abdn.ac.uk
+44 (0) 1224 272801



> Representative ILF Design, Major Water Pipeline, Middle East

> by: Tobias Walk , ILF Consulting Engineers

CSSP

COMMON SEAWATER SUPPLY PROJECT

Enabling one of the world's top oil producing regions

As the second largest oil producer of OPEC nations, Iraq's economy fully depends on the stability and growth of the national oil industry. It is therefore of paramount importance to keep the oil production at target level. To achieve this goal it is necessary to apply secondary oil recovery methods.

The method selected for the oil fields in Southern Iraq is to inject water into the reservoir in order to maintain the reservoir pressure and to increase the percentage of oil extraction

Water Source for Oil Field Pressure Maintenance

The amount of water required in Southern Iraqi oil fields for this purpose is in the range of 12.5 million barrels of water per day, which is equal to 24 m3/second.

Such quantities of water are not available in the project provinces of Al-Basrah and Missan, where temperatures regularly exceed 40 degrees Celsius and where the annual precipitation rate is less than 155 mm. Sourcing water from the famous Euphrates and Tigris rivers would only amount to 10% of the quantities required in the oil fields. Furthermore, use of these local water sources would significantly detract from the life sustaining water for the local population and community needs.

The only source available in sufficient quantity for the needs of the Project is seawater. In consequence it is logical to take this seawater from a single point, treat it and supply it via a common system to the various oil fields. The evolving Project is called the Common Seawater Supply Project CSSP.

ORGANISATIONAL SET UP OF THE OWNER

The South Oil Company (SOC) received a mandate from the Iraq Ministry of Oil and International Oil Companies (IOCs) to develop and operate the CSSP.

SOC's key stakeholders in development of the project include major global operators in the oil and gas industry such as BP, CNOOC, ENI, ExxonMobil, Lukoil, PetroChina, Petronas, and Shell.

In order to support SOC, the consultant CH2M Hill has been contracted as PMC (Project Management Consultant) to manage and coordinate the execution of this project.

ILF's CHALLENGING TASK

ILF identified this project as early as 2010 and presented preliminary technical concepts to ExxonMobil, who developed this project in the initial phase. Subsequently, as SOC took over the mandate for implementation of the project from ExxonMobil, ILF kept a strong focus on the developments. In 2013, ILF was pre-qualified as the only engineering company for both FEED packages (Front End Engineering Design) - i.e. for the STF (Seawater Treating Facilities) and the pipelines. Both proposals were submitted in January 2014. During the following five months, technical and commercial details were negotiated and at the end of June 2014, ILF received a Letter of Award to perform the FEED package for the CSSP pipelines. The contract between SOC and ILF was signed in Abu Dhabi on 20 August 2014.

ILF has since developed an execution plan to deliver the Tender Documents within one year, which is extremely challenging. It will require taking full advantage of ILF's broad know-how and experience in designing and managing the construction of large water transmission pipelines in the Middle East.

To provide the best value for SOC, ILF is leveraging the expertise of multiple offices. The project management team resides in Abu Dhabi, engineering is executed from the ILF Center of Excellence in Munich and the Basrah office handles all local project requirements.

FEED execution is split into two distinct phases: Optimization and Design Development, each within a 6 month schedule.

The project is currently in the optimization phase, which is a specialty of ILF. As a result of these studies a diameter of 56" has been selected for the multiple pipelines running from the Seawater Treatment Facility to the various delivery stations in the oilfields.

The route verification is nearly complete and has identified six major water course crossings including the Euphrates, the Tigris and the Shatt Al-Arab.

System design is well on its way including the simulation of transient flow conditions (another specialty of ILF) and the design of the pressure control and surge protection facilities at the delivery stations.

> Iraq Area Map showing CSSP location within Basrah province

> CSSP Pipeline Routing Overlay onto the Iraq Satellite Image

PROJECT SUMMARY

The Common Seawater Supply Project (CSSP) will supply seawater to the oil fields Zubair, Tuba, Rumaila, West Qurna, Majnoon, Gharraf, Halfaya and Missan in the south of Iraq.

The intake and the Seawater Treatment Facility (STF) will be approximately 40 km south of Basrah at the west bank of the Khor Al Zubair river.

Phase one of the project shall have a capacity of 7.5 million barrels of water per day allocated to the various oil fields in South Iraq. After completion, the full built out design capacity of the CSSP amounts to 12.5 million barrels of water per day which is equal to 24 m3/sec.

From the Shipping Pump Station (SPS), the water will be pumped via two pipeline corridors through multiple 56" steel pipelines to the oil fields over distances of up to 270 km.

The discharge pressure of the shipping pump station will be in the range of 45 bar.

At the delivery stations the water will flow into the tanks of the oilfield facilities, thereby providing hydraulic separation between these facilities and the CSSP.

The estimated cost of the project is in the order of magnitude of 12 billion U$ and it is envisioned that this megaproject will require 3 years for completion.

With an ultimate capacity of 12.5 million barrels of water per day, the CSSP will be one of the biggest plants of its kind in the world.

Author

Tobias Walk
Director of Projects - Pipeline Systems
ILF Consulting Engineers
Munich, Germany
Tobias.Walk@ilf.com
+49 / 89 / 25 55 94 - 244

> Representative ILF Design, Major Water Pipeline, Middle East

DENT HUNTING

using high resolution in-line inspection technologies and finite element analysis

> by: Thomas Walther, ROSEN Group

Abstract

For pipeline integrity management detailed feature assessments based on finite element analysis (FEA) are getting more and more important. Considering dents as one of the major integrity threads of pipelines, the finite element analysis helps to differentiate between severe and benign dents.

Usually, the severity of dents is assessed by using standards and methods, which refer to depth, length and width as main criteria. In many cases, these methods turn out to be over-conservative and lead unnecessary pipe repairs or replacements, resulting in unnecessary costs for pipeline operators.

A more accurate differentiation between severe and un-severe dents can be provided on basis of strain and stress values. This type of information can be derived from high resolution geometry data, which captures a high accurate contour of the pipeline. This type of assessment is not only limited to plain dent conditions any longer. While high resolution geometry tools reliably identify dents associated with girth weld or long seams, dents associated with metal loss corrosion, mechanical damage or crack can be identified by additional ILI technologies, namely MFL, Dual Field MFL, UT and EMAT. An adequate categorization of dent conditions is key for the selection of the right measure.

For plain dent conditions the ROSEN Group developed an automated streamlined process, which allows to rapidly generate and provide stress concentration factors, using the established ABAQUS code. Based on this information, the remaining life can be concluded by taking additional information, coming from the SCADA System into account.

For dents, associated with metal loss or welds, an extended engineering assessment based on FEA allows an adequate assessment of these types of dents.

The article introduces ILI technologies and methods. It presents the results from large scale testing and case studies to underline the usage of finite element analysis as instrument to assess the pipeline integrity. The accuracy of the stress concentration factor, derived from high resolution geometry data, is validated in multiple test comparing the measurements with laser scans, taken with established optical devices.

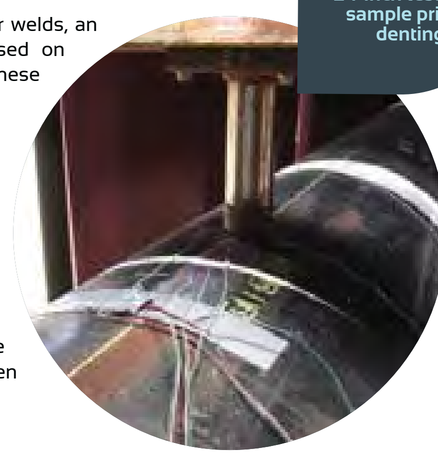
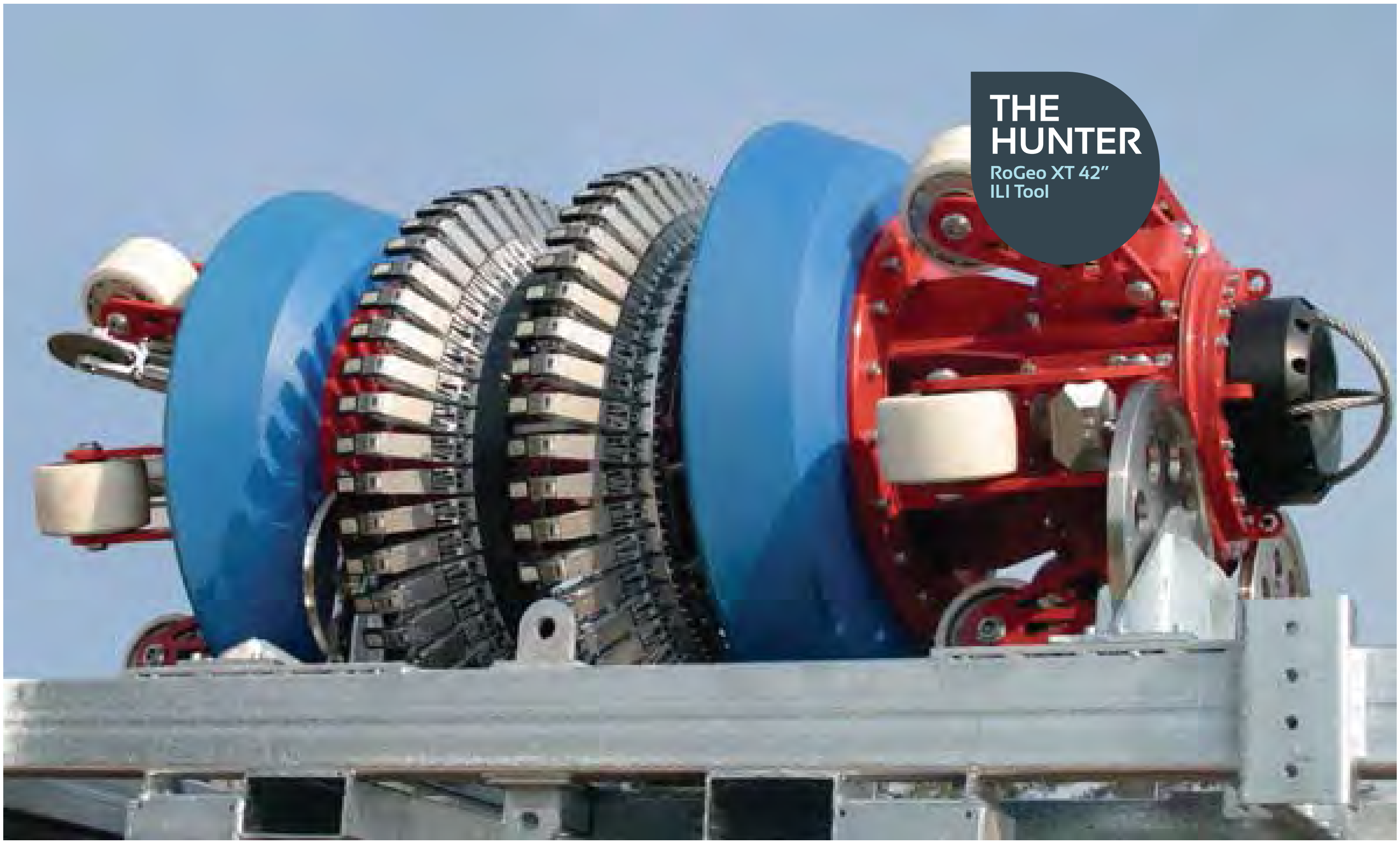


figure 1: 24-Inch test sample prior to denting

"A SET OF DENT ANALYSES THAT MAY HAVE PREVIOUSLY TAKEN WEEKS CAN NOW BE REDUCED TO A FEW HOURS"

> Thomas Walther, Rosen Group



INTRODUCTION

ID anomalies, especially dents, are a significant threat for pipeline integrity. They often fail due to fatigue, caused by varying pressure cycles within a pipeline over lifetime. But commonly dent severity is not assessed considering dynamic loads. Historically, regulations regarding the severity of dents have been governed by one of two metrics: dent depth or strain.

However, the technology and the inspection devices improved over the years, but still dents are assessed using the depth or the strain criteria. The dent depth criteria permits dents with a depth up to 6% of the nominal diameter in both, gas and liquid pipelines, although many operators already use stricter limits and targeting those above a depth of 2% for evaluation.

Using the strain-approach plain dents of any depth are considered acceptable, if the strain does not exceed 6%. The method becomes more common, as strain calculations have become readily available. Therefore, the strain in the hoop and axial planes of the dent is calculated based on the radii of curvature in each plane and the extensional strain based on the length of the dent. An approach is outlined in Appendix R of ASME B31.8. Both, the strain-based and dent depth approaches have similar shortcomings. First, neither approach is adequate for complex dents or in cases, where interacting dents may be present. In the case of depth, the shape of a dent is completely neglected. A long, deep dent is not distinguished from a shorter, steeper dent. While strain-based approaches improve on this shortcoming and can be useful for well-behaved dents, applying the methodology where varying curvatures may exist in a complex dent becomes significantly more difficult. To overcome these shortcomings Finite Element Analysis (FEA) can be used to analyze dents in a more adequate way. Complex dents and well-behaved dents are both suitable for FEA, and the results are not sensitive to small undulations in data. The severity is calculated directly based on the response of the dent to the applied loading, regardless of shape or size. In order to use FEA for detailed assessment of dents, a highly accurate recorded counter of those is required.

Confirmed effectiveness

The case study and additional investigations on more than 113 dents demonstrated that FE-DAT in combination with the RoGeo XT data provides reliable and repeatable stress concentration factors to assess the severity of dents.

Unique sensor array

The RoGeo XT has an unique combination of caliper and eddy current sensors, called the mechatronic measurement system, which can precisely measure the profile and contour of geometric features.

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HIGH RESOLUTION GEOMETRY INSPECTION DEVICE (ROGEO XT)

In order to enable FEA of dents, an in-line inspection system needs to capture the shape of the dent with the utmost precision. Traditional caliper devices do not provide the required resolution to use the recorded data for FEA. Common caliper devices do not have full surface coverage. The majority of them is equipped with one senor plane, not covering the whole circumference of the pipeline. The resulting lower resolution compared to two sensor plane devices and the existing coverage gabs result into misinterpretations and less accurate measurements of the dent shape. But not only the amount of sensor planes guarantees a high accurate measurement of the counter. Even two sensor plane devices will be influenced under certain run conditions. Especially during high inspection velocities, caliper devices, independent of the coverage, will have an increased movement while passing ID reductions. This causes a loss of continuous contact with the internal surface, leading to inaccuracies and misrepresentations of the dent shape. But also at low speed abrupt changes along the pipe wall, like diameter changes may not be captured correctly.

The RoGeo XT has an unique combination of caliper and eddy current sensors, called the mechatronic measurement system, which can precisely measure the profile and contour of geometric features. With both information, coming from the eddy current and the caliper sensor, even movement on ID reduction and abrupt changes at the internal pipe surface can be compensated and will be precisely measured, even in the presence of wax or debris. The device is equipped with two sensor planes, resulting in an 100% circumferential coverage of the inner surface of the pipeline. This device fulfills the perquisite described above for highly accurate measurements to be used for FEA. The RoGeo XT tool fleet today covers pipeline sizes ranging from 6" to 48". Figure 1 shows a 42inch inspection device.

FINITE ELEMENT ANALYSIS, STRESS CONCENTRATION FACTORS AND REMAINING LIFE ANALYSIS

To characterize the severity of discontinuities in uniform load bearing objects, the stress concentration factor (SCF) is often taken into account. The SCF describes the ratio of the peak stress in a body to the calculated nominal stress. The local stresses within an object depend on the cross-sectional area of it. If the area contains a discontinuity, such as a hole, the local stresses around the discontinuity may be several times higher than the nominal stress. This relationship is characterized by the SCF. For simple shapes, such as holes, analytical SCFs are widely available. However, for more complex shapes the SCF is derived from finite element models. This approach is used in offshore structural analysis, where SCFs are combined with published S-N curves when determining fatigue lives for structural connections. In this case the SCFs is used to calculate the peak stresses, which is required for fatigue calculations.

It is straightforward to expand the SCF methodology to the assessment of dents in pipelines. The nominal stress state in a pipeline is easily classified as a function of the internal pressure according to Barlow's equation. The SCF can be derived from a precise model of the dent within a finite element program. The model can be directly constructed from the RoGeo XT data. Once the model is built, the SCF is calculated by the finite element program, considering an applied internal pressure and the maximum principle stresses.

Historically, finite element analyses have been cost intensive and time-consuming for operators, but advances in technology have removed both of these limitations. Improved inline inspection technology (ILI) as well as improved data processing power enable the effective usage of FEA for dents in pipelines and permitted the creation of a streamlined process, referred to as the Finite Element Dent Analysis Tool (FE-DAT). The FE-DAT is not limited to single dents only. It is developed to analyze a large number of dents precisely and accurate. It works by taking data directly from a high-resolution ILI tool, building a finite element model, and post-processing the results. A set of dent analyses that may have previously taken weeks can now be reduced to a few hours. The results from the analysis provide the SCF for each dent, which is directly proportional to the severity of each dent and indirectly proportional to the life. In addition, the stress profile in the region surrounding the dent is also provided in the form of stress contours.

Using the SCF a fatigue analysis can be done, if the operator provides pressure history data. Based on that a rain-flow analysis can be performed in order to calculate an equivalent number of cycles a particular dent experiences. This equivalent number of pressure cycles can be combined with the calculated SCF to determine the remaining life of a dent. Due to the fact that the relationship between stress and fatigue life is highly nonlinear, a fatigue analyses typically carry large factors of safety.

"THE SCF IS PROPORTIONAL TO THE SEVERITY OF THE DENT AND CAN BE USED TO CALCULATE THE REMAINING LIFE OF AN ANOMALY"

> Thomas Walther, Rosen Group

figure 2: Pressure cycled to failure

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CASE STUDY

In order to illustrate the effectiveness of the SCF method and provide a comparison between test data and analytical methods, a case study was performed. Therefore, a dent was generated in a 24-inch OD, 0.25-inch wall thickness, Grade X52 pipe sample. Figure 2 shows the test set-up, the indenter and the applied strain gages. The dent was generated by pressing a 2-inch diameter indenter into the pipe to a depth of 3.61-inches (15% OD) in an unpressurized configuration. Afterwards, the shape of the dent was recorded by an optical scanner and by the RoGeo XT inspection device.

Next, the pipe was subjected to target pressure cycles ranging from 100 – 780 psi (9% - 72% SMYS) until failure occurred. The strains were recorded at intermittent points during cycling. The sample failed after 39,800 cycles when a longitudinally oriented thru-wall crack developed in the shoulder of the dent as shown in Figure 3. The related SCF was calculated out of the recorded stresses from the strain gages and the nominal stress from the recorded pressure range of 690 psi. The SCF from the experimental data was 3.16.

In comparison to the experimental data, the analysis was performed using the FE-DAT and the finite element code ABAQUS. An internal pressure of 208.3 psi was applied to the model corresponding to a 10,000 psi hoop stress. The analysis completed by the FE-DAT showed a maximum principal stress of 32,784 psi on the OD of the pipe resulting in an SCF of 3.28. In addition the data from the optical scan was provided and analyzed using ABAQUS in order to maintain consistency with the FE-DAT. The same internal pressure of 208.3 psi was applied to the finite element model. The calculated maximum principal stress on the OD of the pipe was 38,014 psi yielding a SCF of 3.80.

In general, the calculated SCFs and depths compare well, particularly between the FE-DAT and the test data. The slightly higher SCF shown in the optical scan can be explained by the fact that the optical scan was recorded from the outside, while the RoGeo XT recorded the inner surface. Possible ovailities might not be recorded in the same way as the RoGeo XT does. However, the FE-DAT and the test data showed closer agreement for the dent depths and the resulting SCFs.

For the sample used for the case study, pressure history data was not available, but as it was ultimately destructively pressure cycled in the lab, comparisons can also be made between the predicted cycles to failure and the actual cycles to failure. Using the calculated SCF of 3.28 and a nominal stress of 33.1 ksi, the predicted number of cycles using the design S-N curve is 3674. The calculated number of cycles is significantly lower than the actual number of cycles (39,800). This was expected, as the usage of a standard S-N design curves provide more conservative results and laboratory testing has usually a higher scatter influencing the remaining life analysis. As previously mentioned, the relationship between stress and remaining live is highly nonlinear, so that even small variations in stress lead to high deviations in the predicted life.

CONCLUSION

The case study and additional investigations on more than 113 dents demonstrated that FE-DAT in combination with the RoGeo XT data provides reliable and repeatable stress concentration factors to assess the severity of dents. In comparison to the strain calculation the SCF correlates very well with depth. Furthermore there is also a slight correlation between the results using the strain approach and the SCF method. Therefore, the B31.8 strain assessment provide valid results for a momentarily situation, but not for a fatigue assessment.

The SCF is proportional to the severity of the dent and can be used to calculate the remaining life of an anomaly. The advances in computing and ILI caliper tools have allowed the process of analyzing dents to be streamlined to the point where hundreds of dents can be analyzed quickly and the data be made available as part of ILI reports. This approach has been validated through physical testing and represents an advanced metric that can be used to prioritize dents.

Author

Thomas Walther
International Service Manager
ROSEN Technology & Research Center GmbH
Lingen, Germany
twalther@rosen-group.com
+49-591-9136-121

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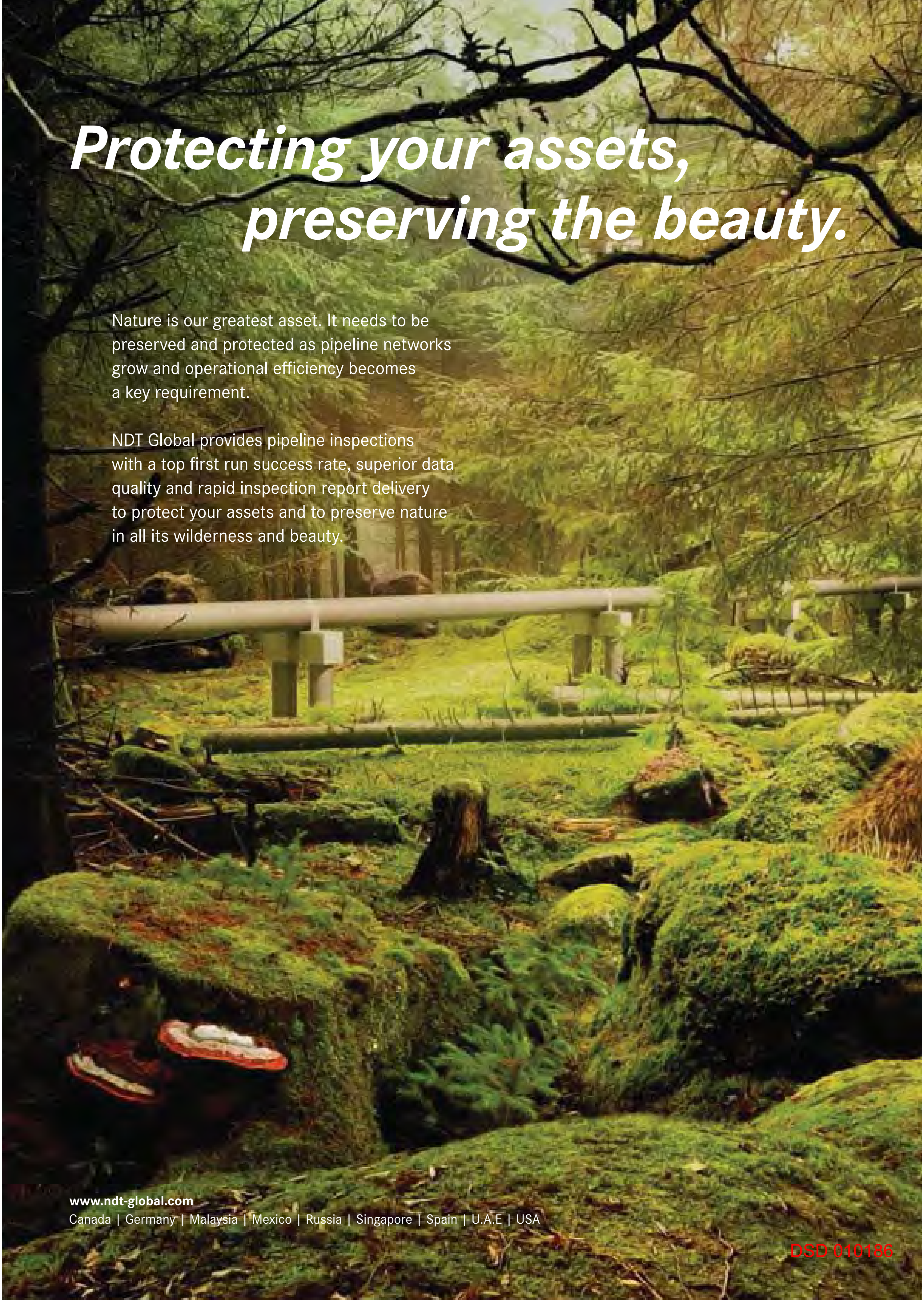
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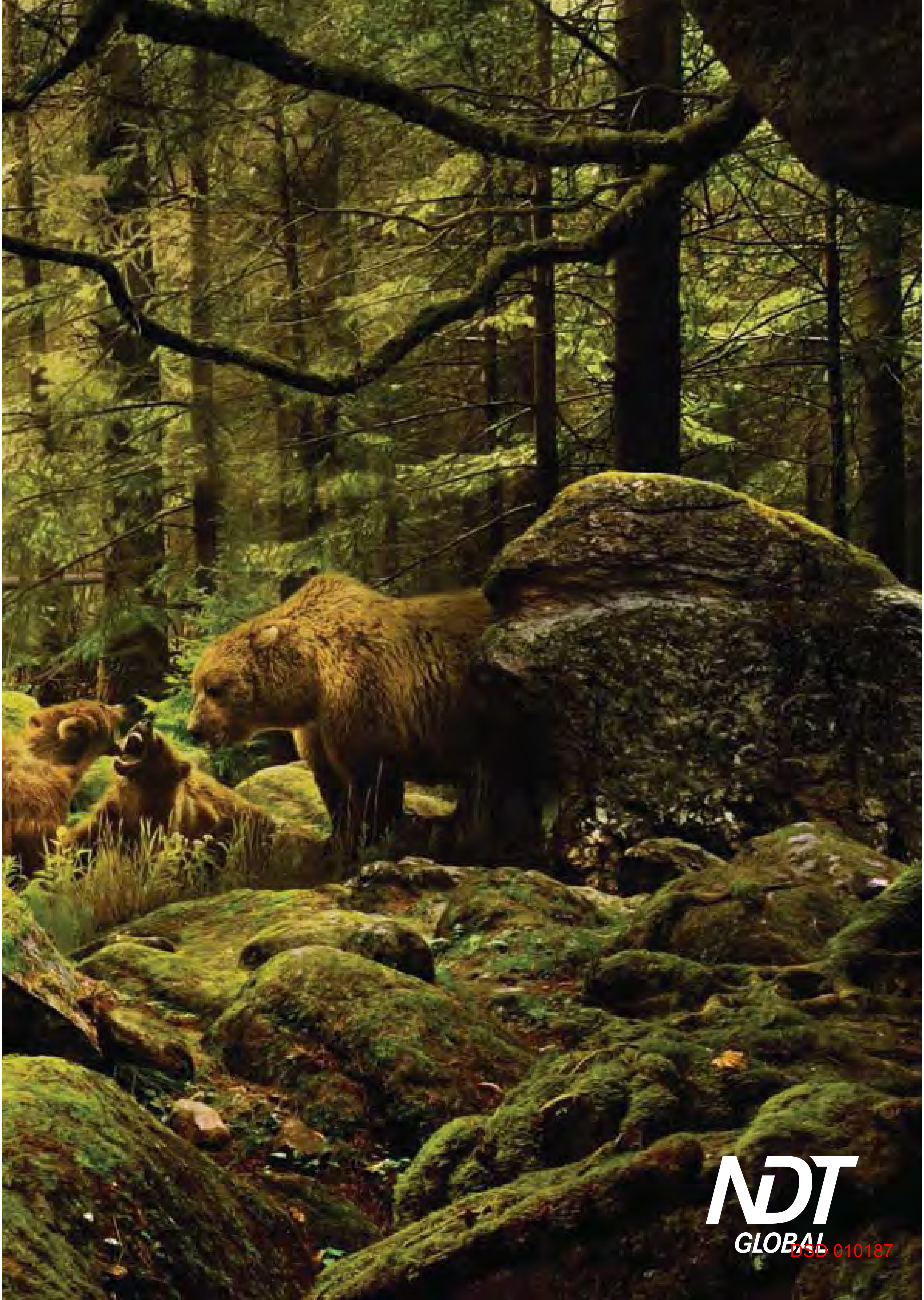
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REMOTE **WELDING**

THE HABITAT

RWS relies on the habitat, the systems foundation. It creates reference to the pipe and spool and provide a platform for the welding tool

> by: Jan Helge Johannessen, Technip-DeepOcean PRS JV

Remote Welding System (RWS)

New fully remote hyperbarbic welding system rated to 1000msw

Statoil have, after several years of testing and technical qualification work, developed a Remote Welding System that was qualified for contingency in the Pipeline Repair System pool services in December 2014. The system is rated for operation down to 1000msw and covers pipelines which are in depths exceeding the limit for diver assisted operations, which is currently 180msw.

The new fully remote hyperbaric welding system is mainly for subsea repair of pipelines and covers pipe dimensions from 30" up to 42". However, the equipment is a huge technical milestone for the subsea business and opens new opportunities in the industry when it comes to planned expansions of infrastructure, bypass of old installations and tie-ins.

Different from the diver habitat that operates with pipe ends, butt welding, the remote system involves installation of a pipe spool with pre-welded sleeves, threaded over both pipeline ends, before welding them together by a fillet weld.

CONCEPT DESCRIPTION – THREE MAIN MODULES

The Remote Welding System consists of three main modules; a habitat, a power & control module (POCO) and the welding tool. In short terms; the habitat is landed over the pipeline, before the pipe and spool are aligned. The habitat is then filled with welding gas (Argon) and dehumidified. The POCO carries the welding tool, and lands onto the habitat. A special designed sealing between the habitat and the POCO provides dry transfer of the welding tool into the habitat. When the welding tool is in position, the pipe and sleeve is preheated before welding operation starts.

The habitat main functions are to act as a foundation of the system, creating reference to the pipe and spool and provide a platform for the POCO and the welding tool. It is equipped with 4 individually operated legs, and longitudinal movement for accurately positioning of the habitat in reference to the welding position. The habitat functions are also to provide a dry and Argon filled hyperbaric welding environment before the welding tool enters. The operation is remotely operated from a topside control container on the vessel deck. All three modules are equipped with a wide range of cameras, LVDTs, pressure, temperature and proximity sensors for feedback and monitoring.

The POCO's main function is to house the welding tool and to provide services for the tool during operations. The POCO enclosure consists of two separate compartments:

- Electronic compartment containing most of the electronics and power distribution components required for operating the POCO and the welding tool.

- Tool compartment, containing equipment and systems required to transport the tool in and out of the habitat

Both compartments are pressurized with Argon whenever submerged and will have a maximum operating differential pressure towards the outside of about 0.5bar. Power communication and gas is supplied through an umbilical from surface.

In addition, power sources for welding and preheating is located in 1 bar containers outside the POCO enclosure.

When the welding area is dry and acceptable welding conditions are reached inside the habitat, the POCO is launched. After landing on the habitat, the interface (between habitat door and POCO door) is blown down. The doors are opened and the welding tool can engage around the pipe. After doing a path capturing +/-180□ and inspection of the welding area by cameras, 2 pre-heat bands are engaged around the pipe. The welding can start when pipe and sleeve temperatures are above 50□C.

For support and feedback the welding tool is among others equipped with welding torch tip changer, welding camera, a grinder and various sensors.

Play Video

TECHNOLOGY QUALIFICATION PROGRAM (TQP)

After going through various system and subsystem testing throughout the project such as Factory Acceptance Testing, Site Integration Test, Welding Robustness Testing and a Shallow Water Test, the last part to fulfill the TQP was the Deep Water Test. This test was to validate the system and to show that the equipment could produce acceptable welds offshore.

The test was twofold with depths on 400msw in Nedstrandsfjorden and 1000msw in Sognefjorden. Two weld sections on a pre-installed pipe spool in the habitat were done on both depths and all the tests were successful.

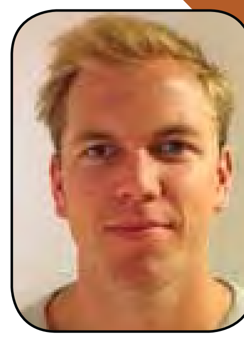
THE WAY FORWARD

The deep water test was the final milestone and completion of the project. Now the Remote Welding System is in contingency in the PRS pool, operated by PRS JV on behalf of Statoil. It is being evaluated to expand its limits with deeper depths, smaller pipes and welding of other pipe materials.

PRS Joint Venture

- Joint Venture between Technip Norge AS and DeepOcean ASA
- Contract awarded in December 2014, 5 years with 3 x 2 years option.
- Includes operation, maintenance, engineering and development of the Pipeline Repair System at Killingøy in Haugesund.

Author



Jan Helge Johannessen
Planning Engineer,
PRS Pool services
Technip-DeepOcean PRS JV
Haugesund, Norway
jhjohannessen@technip.com
+47 67 80 54 48

POCO MODUL
The Power and Control Moduls main function is to house the welding tool and to provide services for the tool during operations.

WELDING TOOL
The three moduls of RWS succeeded in all tests and are fully operational. The System can operate in areas down to 1000msw.

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NEW ERA of In-Line Inspection (ILI)

JUBAIL SAUDI ARABIA
Pipeline corridors at King Fahad Industrial Port.

> by: Hamad Almostaneer, SABIC

Intelligent Pigs for Internal Inspection & Repair Welding of Cross-Country Pipelines

Abstract

Oil and gas are an important transport method of the energy sources products worldwide nowadays and in the near future. However, the major reserves of the oil and gas are mostly located in remote areas. For this reason, pipelines have become the most efficient attractive method for oil and gas transportation. Pipelines are also the most economical method used nowadays for transporting any type of fluid. However, the capital cost for crude trunk pipelines is very high, depending on the pipeline steel grade, the design wall-thickness, and the length of the pipeline. These factors often force the product owners to construct most of the cross-country pipeline network in a single channel, making it difficult to shutdown for inspection, maintenance, or repair. In addition, the major part of the cross-country pipelines are buried and excavation is precluded. Likewise, offshore pipelines are extremely difficult to inspect, maintain, or repair due to deep-water factors and low-density environment. Inspection for integrity of pipelines is often conducted from the inside using an intelligent pigs with the capability of measuring any losses in the pipe wall thickness in the form of flaws, cracks, or corrosion damages while traveling inside the pipeline. Nowadays, new era of smart pigs for both; out-of-service and in-service pipelines have been developed/invented to perform an in-situ repair of these defects on the internal pipe surface before they reach a critical size and become hazardous to operation & safety. This paper will discuss the new era of the intelligent pigs and the benefits of carrying more developments in such tools.

Figure 1: Pig station
A pig launcher/receiver, for Natural Gas Pipeline in Switzerland

INTRODUCTION

Pigging of a pipeline refers to the use of a Pipeline Inspection Gauge or "PIG" to perform various maintenance operations on a transmission, onshore, and offshore pipeline. This usually is done without stopping the flow of production in the pipeline. These maintenance operations include but are not limited to either cleaning, or inspection, or both of a pipeline. This practice is achieved by inserting a pig into a "pig launcher" or a launching station. It is a funnel shaped Y in both end-sections of the pipeline. The launcher is then closed and the pressure-driven flow of the product in the pipeline is then used to push it along down the pipeline length until it reaches the "receiving trap" or a receiving station as shown in Figure 1 [1,2,3].

One of the most crucial aspects of pipeline operation is ensuring the pipeline integrity. For this reason, in-line inspection (ILI) pigs have become important. The Intelligent Pigs "smart pigs" are important tools for assessing the integrity conditions of a pipeline, and is set to become more integral part of the pipeline maintenance. Nowadays, more developments are made towards solving the integrity issues of Unpiggable pipelines [2,3].

PIPELINE PIGGING SYSTEMS

A Pipeline Inspection Gauge or "PIG" in the industry is a tool that sent through a pipeline and propelled by the internal pressure of the product in the pipeline itself. Therefore, pigging operations are mostly performed for in-service pipelines. There are four main uses for pigs: 1) Physical separation, 2) Internal cleaning, 3) Inspection of the internal condition, also known as an Inline Inspection (ILI) operations, and 4) Capturing and recording geometric information related to the pipelines (i.e. size, position, thickness loss, corrosion, etc.).

Depending on the type of pig, it can perform one or a number of specific tasks including [3,4]: 1) Cleaning debris from the pipeline, 2) Removing the residual products that accumulate with time, 3) Gauging the internal wall of a pipe to locate defects, 4) Assessing the condition and location. However, pipeline pigs can also be used for other purposes. These include but not limited to: 1) Hydrostatic testing, 2) Air/nitrogen removal from the pipeline, 3) Batch separation in case of using the same cross-country pipeline to batch multi-products, 4) Pre-inspection and certification of newly constructed pipeline, 5) Integrity assessment of an in-service pipeline, 6) Decommissioning unsafe pipeline for environment purposes. Nonetheless, the pigs can only be one of two main types: 1) Utility pigs, or 2) Intelligent pigs, also called smart pigs as mapped in Figure 2 [1,3]. However, since the utility pigging technology is relatively old and simple to deal with, this paper will focus more on the intelligent pigs.

THE ORIGINS OF INTELLIGENT PIGS INDUSTRY

In 1959 five decades ago, T.D. Williamson introduced the first "caliper tool" for detecting dents in pipelines. Pan-American Petroleum was developing a "Cooley tool" around the same time, which used the Magnetic Flux Leakage (MFL) technique. In 1961, Shell Oil Research developed a technique for detecting pitting corrosion in down-hole casings based on a "MacLean tool", which worked with a Remote Field Eddy Current (RFEC) [1,2,3].

In 1962, Tuboscope obtained a licence from Shell Oil Research for the MacLean tool and started developing a smart pig to carry an array of remote field eddy current sensors through a pipeline. Early test runs with the MacLean tool were unsuccessful, as they could not detect known pits in the test spools. Tuboscope then approached Pan-American Petroleum and purchased the Cooley tool patent. The MacLean tool was discarded and the smart pigging developments switched to Cooley tool or as known today as MFL technique. The new tool was branded LINALOG® [1,2,3].

In 1964 Tuboscope ran the first commercial instrument for the new LINALOG 90° tool. It used MFL technology to inspect the bottom portion of the pipeline. The system used a black box to record the information, a highly customized analog tape recorder. This first commercial job was for Shell company [1,2,3].

> *"INTELLIGENT PIGS INDUSTRY CONTINUED TO GROW"*
>
> *> Hamad Almostaneer*

DSD 010193

Figure 2: An overview map of the available tools for both 1) Utility pigs, and 2) Intelligent pigs.

THEORIES OF INTELLIGENT PIG TOOLS

Intelligent pigs are highly specialized tools for in-line inspection (ILI) which can detect, locate, and size flows in pipelines. There is no tool that can be used for all inspection purposes as each tool uses different physics and principles. However, each inspection tool must be selected accordingly and the ability of the used tool must correspond to the inspection requirements [4,5,6].

However, the difference between different tools can be identified due to the measurement accuracies and the detection threshold. The following tools will focus on in-line inspection (ILI) tools and techniques that are used within intelligent pigs to detect, size, and locate flaws that are reached subcritical sizes [7,8,9].

MAGNETIC-FLUX LEAKAGE TOOL

The magnetic-flux leakage (MFL) method can be used to measure and locate cracks and metal-loss in both circumferential and axial directions. It is a popular method for inspecting pipelines for both stress sensitivity or levels and corrosion defects and characterization. The magnetic-flux leakage (MFL) work principle is shown in Figure 3 [10,11,12].

AXIAL MAGNETIC-FLUX LEAKAGE TOOL

This type of tool usually consists of a central body of mild steel around which is mounted an annular arrangement of magnets. These magnets spread from center outwards in a radial arrangement to give opposing poles on either end of the body (north or south) as shown in Figure 4. There are steel bristles which create contact with the pipeline wall, to complete the magnetic circuit and allow the inspected pipe section to be uniformly magnetized in the axial direction as the tool passes down the line. If the pipe is not corroded, the magnetic flux will be locked-up within the steel pipe wall. However, corrosion or any other feature such as flaw will cause flux to leak out of the pipe wall which then can be detected by the circular array of the magnetic sensors [13]. This type of tools is directly related to the crack detection where axial MFL tool can detect crack geometries at right angles to the induced magnetic field such as cracks in girth welds [14,15].

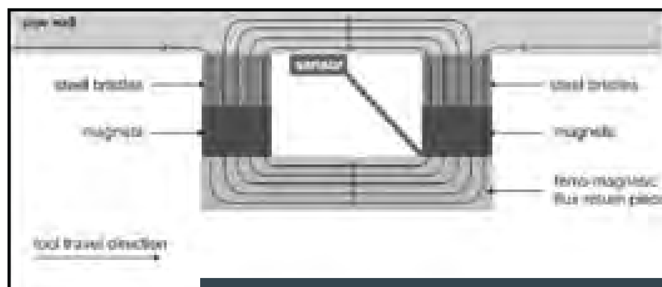


Figure 3: Magnetic-flux leakage working principle: a pipeline with a perfect wall.

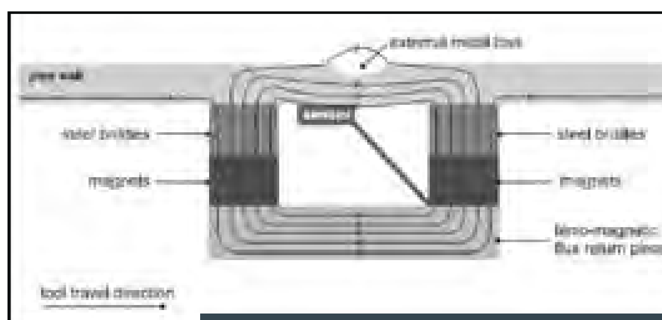


Figure 4: Axial magnetic-flux leakage system.

TRANSVERSE-FIELD MFL TOOL

MFL tools are good to detect flaws which are located at the angles to the induced magnetic field. Axially-oriented narrow flaws are hard be detected by the axial MFL. However, these narrow, long defects are serious threat to the transfer pipelines integrity especially metal-loss flaws and cracks in longitudinal seam welds of a pipeline. They can cause failures during operation to in-service pipelines. The occurrence of the long axial defects led to the development of MFL system incorporating transverse magnetic field. The schematic of such system is shown in Figure 5A. In theory, applying magnetic field in a transverse direction around a pipeline makes it easier to differentiate and characterize defects orthogonal to the field (long axial defect) [14,15,16,17].

ULTRASONIC TOOL

The major advantage of ultrasonic technique is the ability to provide quantitative measurements of a wall of a pipeline. The high accuracy levels make it an ideal ILI tool. UT inspection tools are fitted with sufficient number of ultrasonic transducers to ensure full circumferential coverage of a pipeline. The transducers operate in an impulse-echo mode. This means that they switch from being emitters of an acoustic signal in the ultrasonic sound range to being receivers [17,18,19].

It is often done by determining the pulse repetition frequency. The sensor emits an ultrasonic signal that is partly reflected at the internal wall surface and partly at the external wall surface of a pipeline. The first reflection provides a measurement of the stand-off distance and the second value for the wall thickness as shown in Figure 6. As the tool travel through pipeline, the sensor takes measurements at regular intervals, set by the traveling speed of the tool which later analyzes the whole pipeline length [17,20].

ANGLE-BEAM ULTRASONIC TOOL

An ultrasonic crack-detection tool utilizes angled-beam probes. The tool is designed to detect and size axial crack in a pipeline wall and long-seam weld joints. It also detects stress-corrosion cracking (SCC). The ultrasonic sensors are fixed at an angle to the wall at under a 45° angle which is optimum for crack detection. Depending on the tool size, this tool can have up to above one thousand ultrasonic transducers. Minimum detection threshold for this tool is 30 mm crack length and 1 mm crack depth. Circumferential cracks can also be detected but it would require modified sensor carrier which have to be turned by 90° angle. However, this tool as shown in Figure 7 successfully detected stress-corrosion cracks (SCC) [17].

The lower part of the picture shows the actual flaws and the upper-part are the displayed data by the UT tool. Nonetheless, detection accuracies, high confidence levels of detection, sizing, and repeatability are the main characteristics of ultrasonic ILI tools [17].

WALL-THICKNESS-MEASUREMENT ULTRASONIC TOOL

This type of ultrasonic tools is used for metal-loss measurements. It can be identified by the alignment of the ultrasonic sensors that are mounted at 90° angle to the wall. Figure 8 shows the physical principle for this tool. Ultrasonic transducers emit a signal directed to the internal surface of a pipeline wall and part of the signal is reflected and received by transducers. The other part of the signal that travels through the pipe wall is reflected back by the external surface of the wall. The signals of this part are also received back by the transducers and provide wall-thickness measurement. This ultrasonic tool besides the function of wall-thickness measurements is ideal for flaws that are present inside the pipeline wall such as hydrogen-induced cracks and inclusions [17].

EDDY-CURRENT TOOL

Eddy current inspection tool is another ILI-NDT tool that uses the principle of electromagnetism as the basis for conducting measurements. Eddy currents are created through a process called electromagnetic induction by applying an alternating to a conductor, such as a copper wire, a magnetic field will develop in and around the conductor. This magnetic field expands as the alternating current rises to maximum and collapses as the current is reduced to zero [21].

Figure 9 shows the principle of the Eddy Current sensor inducing a primary field, according to Lenz Law, 90° angle to the original field lines of the coil. Due to further induction of the Eddy Current in the primary field of the electric conductive material, a secondary field is induced which will effect the coil impedance. In case of a defect in the tube wall, the secondary field is changed in comparison to its origin. The change of the Eddy Current field lines causes a change of the impedance of the Eddy Current probe coil, which is related to the defects [22]. A remote field eddy current (RFEC) that uses a low frequency AC and relatively large exciter coils has become an excellent NDT technique to detect cracks of internal wall of pipes and tubes as shown in Figure 10 [23].

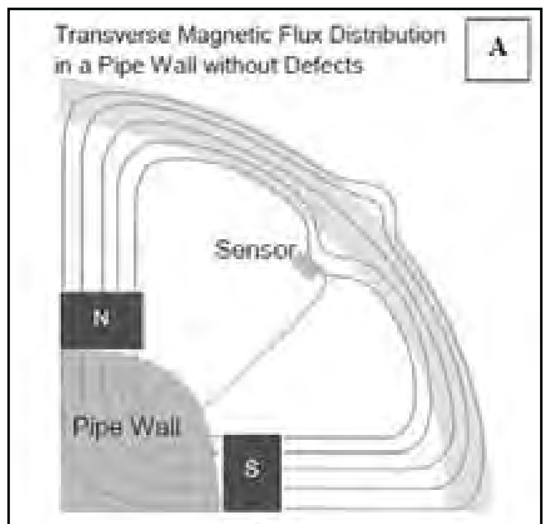
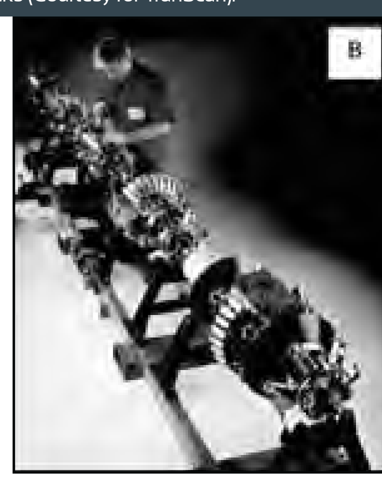


Figure 5: Transverse MFL tool: A) Schematic of the magnetization arrangement for transverse-field, and B) Transverse field tool capable of detecting cracks (Courtesy for TranScan).



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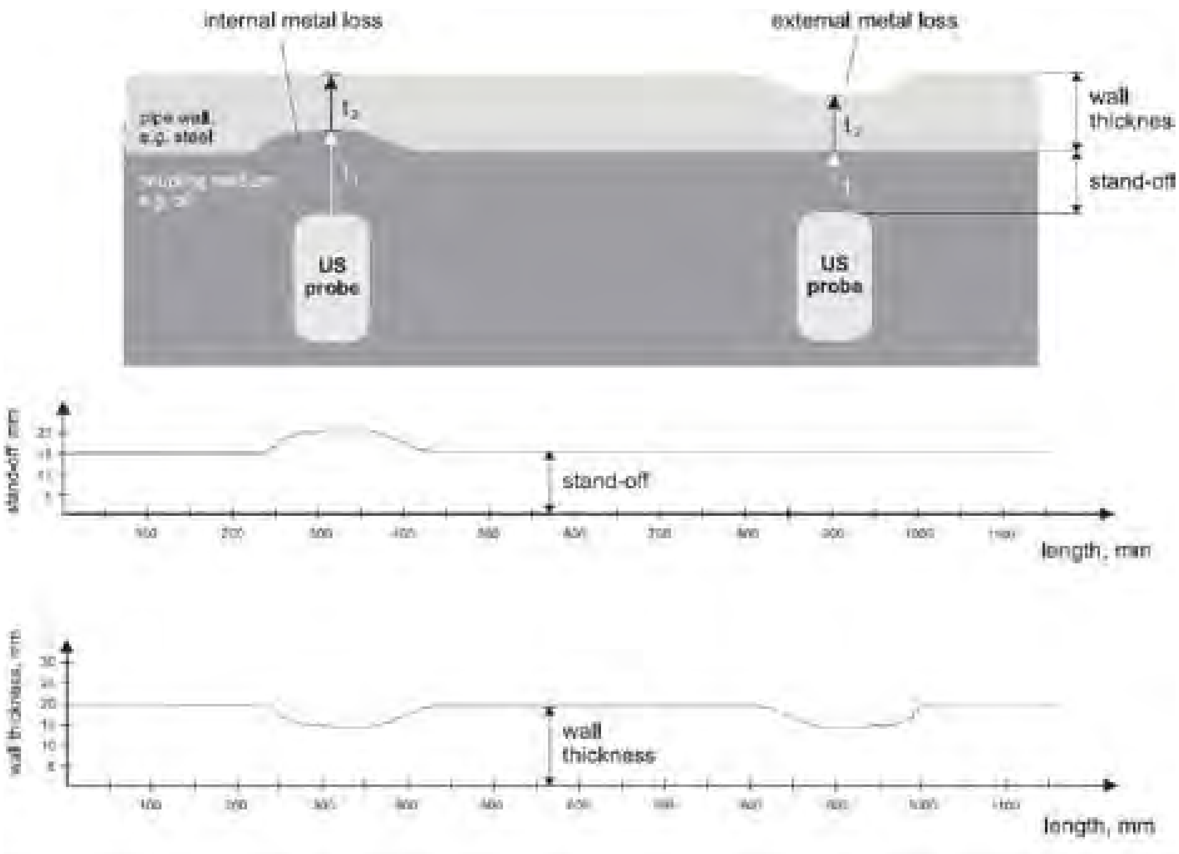


Figure 6: The principle of ultrasonic technique measurements.

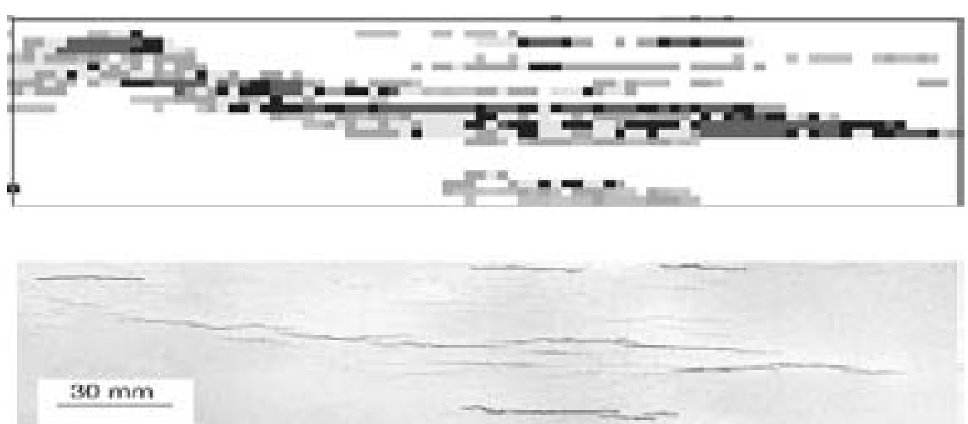


Figure 7: Stress-corrosion cracks (SCC) detected by angled-beam ultrasonic tool.

NEW ERA OF ADVANCED ILI INTELLIGENT PIGS

Intelligent pigs industry continued to grow due to the demands of increasing safety and reduce costs in maintaining transmission, onshore, and offshore pipelines. Osaka Gas studied various types of robots capable of inspecting and repair welding pipelines from inside, and have succeeded in developing automatic welding robots to reinforce welds from the inside of a steel pipeline. The configuration of one of Osaka Gas systems is shown schematically in Figure 11 [24].

The principle of the welding monitor, however, is all welding work is remote-controlled above ground. The torch is controlled with four axes, whose movement is programmed in a specified sequence. The welding conditions can be monitored via two TV cameras. If excessive spatter is deposited on the torch nozzle, the nozzle then can be automatically cleaned with a spatter remover as shown in Figure 12. However, application of this repair method to the inside of an in-service pipeline would require that welding be performed in a hyperbaric environment or to take the pipeline from service/operation [24].

Colorado School of Mines (CSM) invented a method that can be developed within an intelligent pig system to perform in-situ crack detection and repair welding internally, using the MAW-UO process on the internal pipe surface of in-service pipeline. Likewise, the system configuration module of the welding unit that carries the torch of MAW-UO process, NDE tool, grinding, and finishing tools connected to other controlling units on board to travel inside a defective pipeline that has flaws, cracks, or corrosion damage to be repaired is shown schematically in Figure 13 [25].

The concept of the MAWUO welding unit is to have an integrated robot to remotely locate of some widely dispersed perforations in the pipeline using remote laser profillometry (precision laser surface mapping followed by analytical form fitting). Then, eddy-current characterization of the defected areas and a remote positioning and repair welding of a patch, followed by inspection. The weld metal buildup or overlay and finally the inspection all should be remotely controlled with full vision and laser positioning as shown in Figure 14 [25].

There are no technical limitations to these repair methods to the inside of either an out-of- or in-service pipeline. It is direct, inexpensive to apply, and requires no additional materials beyond welding consumables. Typical system can be as schematically shown in Figure 15 [24].

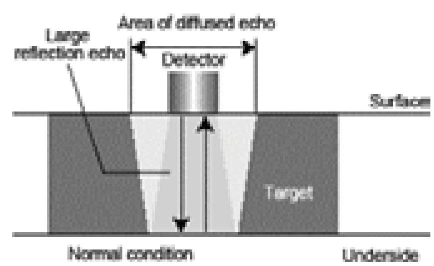


Figure 8:
Wall-thickness-measurement ultrasonic tool working principle.

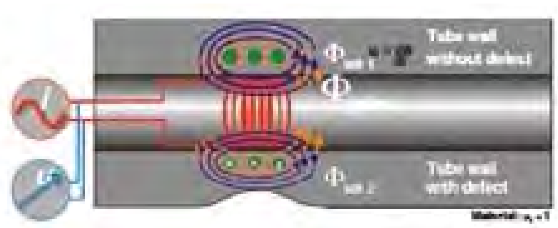


Figure 9: Principle of Eddy Current.

SUMMARY

The in-line inspection intelligent pigging of pipelines have grown tremendously in the last five decades and progressed from utility pigs that are used for cleaning, to smart pigs that are used for inspection purposes, and today to in-situ repair smart pigs.

The inspection/repair of pipelines using intelligent pigs is now well established, and interests are growing in the use of this versatile technique. Intelligent pigging tools offers a viable alternative to traditional, manual inspection techniques with several significant advantages.

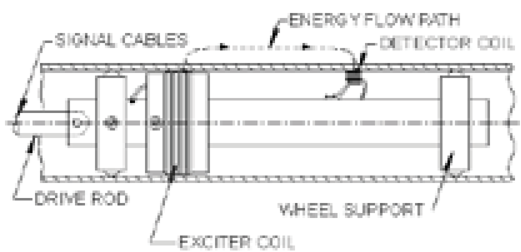


Figure 10:
Remote Field Eddy Current (RFEC) inspection technique.

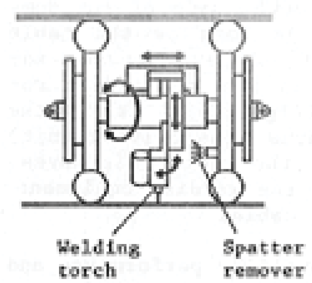


Figure 12:
Schematic of the welding unit.

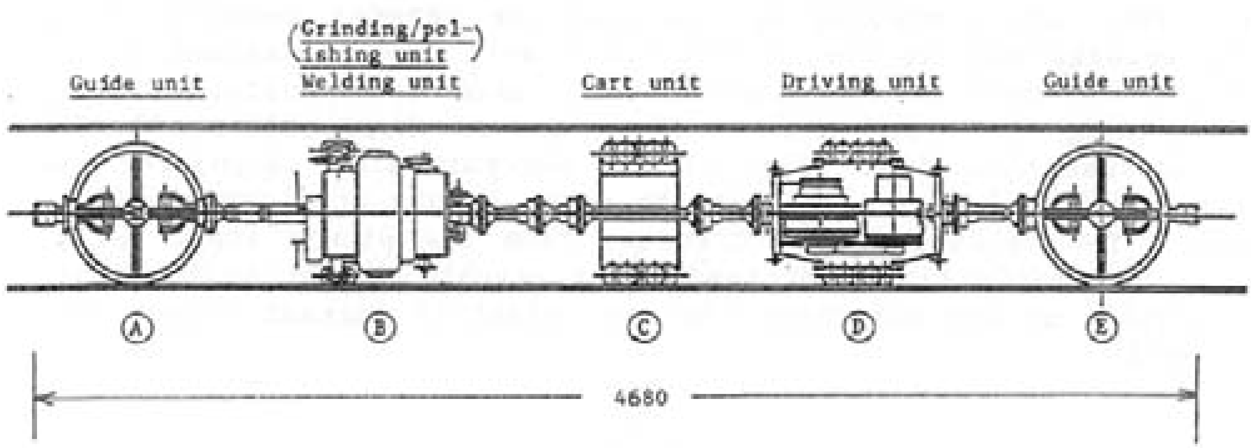


Figure 11: Osaka Gas Co./Sumitomo Metal Model; Internal Welding Robot system.

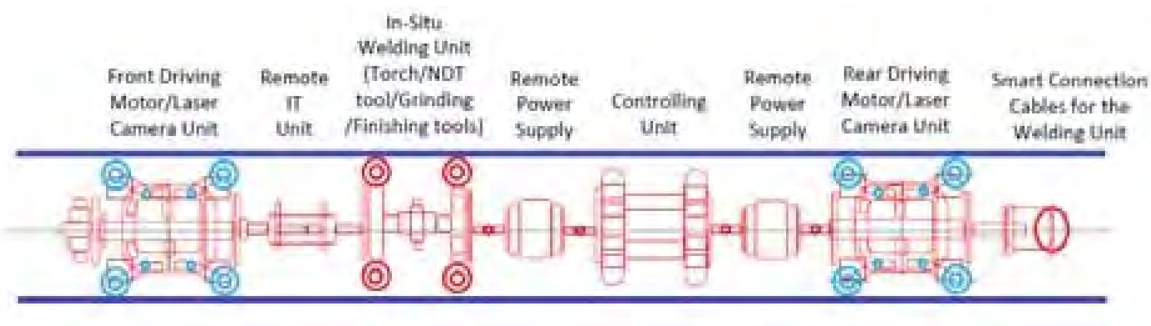


Figure 13: Colorado School of Mines Module; In-Situ Repair Welding Robot.

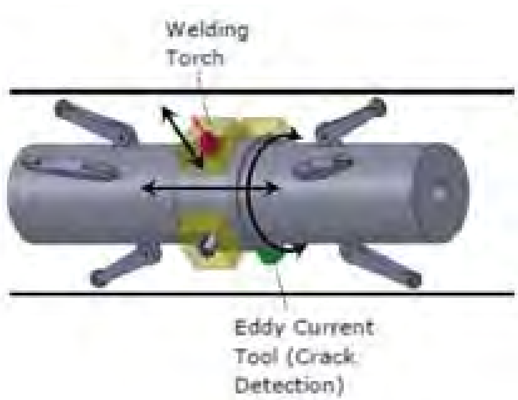


Figure 14: 3D view of MAWUO process welding unit.

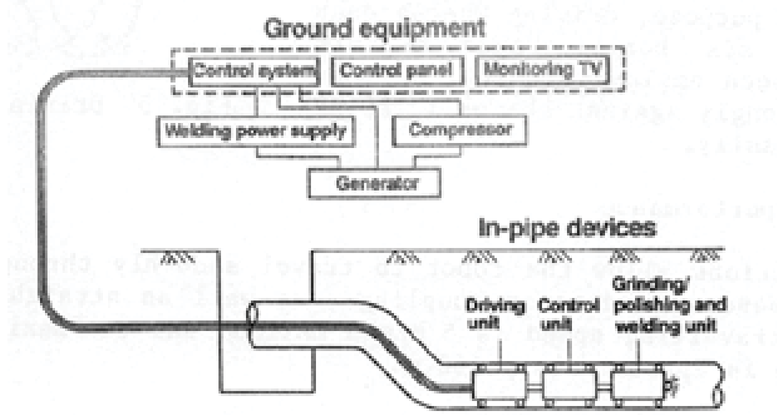


Figure 15: System configuration of intelligent pig for repair welding.

Author

Dr. Hamad H Almostaneer

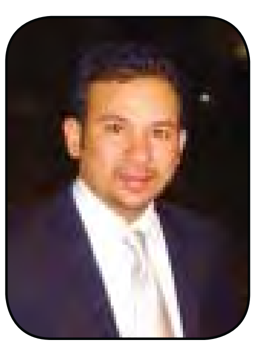
Scientist, Materials, Corrosion & Static Equipment Domain

MCC SABIC, Saudi Basic Industries Corporation

Jubail, Saudi Arabia

mostaneerhh@SABIC.com

+966 (13) 359 9129



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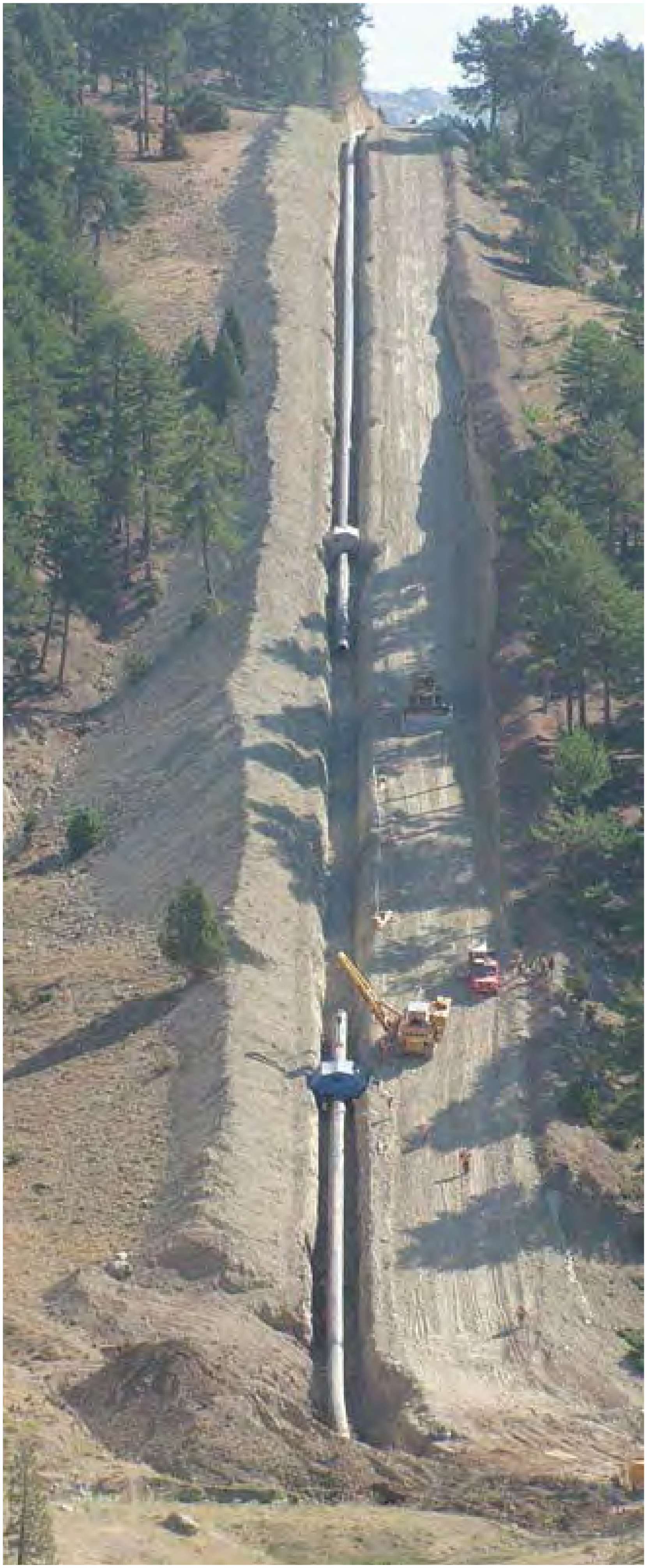

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In-Line Inspection of Onshore and Offshore Pipelines

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The course will introduce the flaws and anomalies observed in pipelines. Suitable external and internal inspection technologies will be introduced including the strength and weaknesses of the non-destructive testing principles applied.

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Geohazards and Geotechnics in Pipeline Engineering

The course will provide an in-depth introduction into the subject and importance of Geohazards and Geotechnics during the stages of evaluation, design, construction and operation of a pipeline.

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The main disciplines that will be presented during the course are Engineering Geology, Soil Mechanics, and Rock Mechanics, while special emphasis will be given on Slope Instabilities and Stabilization Methods.

Since many countries worldwide are characterized by moderate or high seismicity, the course will also introduce the topics of Geotechnical Earthquake Engineering and Pipeline Seismic Design.

Microbiologically influenced Corrosion (MIC) and its impact on pipeline corrosion management

Engineering importance is a function of cost and risk. Cost of corrosion is about 5% of the GDP of a country and microbial corrosion (MIC) accounts for about 1/5 of the corrosion cost. In addition to cost, what makes it even worse is that a great number of MIC cases are mistakenly attributed to corrosion phenomena other than microbial corrosion. In engineering terms, "Risk" is defined as the product of "likelihood" and "consequences": no matter how low the likelihood, as the consequences could always be critical, the risk of MIC is classified as "extremely high". Almost all engineering materials are susceptible to microbial corrosion. Corrosion- related bacteria can tolerate a wide range of pH and temperatures. A combination of the above factors makes MIC a very dangerous factor that must be dealt with meticulously. MIC can be observed in a wide range of industries from mining, oil & gas, power generation to marine industry, chemical industry and even in ships and in systems such as hydrants and pipelines.

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