Alternative Siting Analysis

South Bellevue Segment

LUC 20.20.225.D

September 2017

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1.0 INTRODUCTION

1.1 PROJECT SUMMARY

Puget Sound Energy, Inc. (PSE) proposes the construction of a new substation in Bellevue (the "Richards Creek substation") and the upgrade of 18 miles of two existing 115 kV transmission lines with 230 kV lines (collectively the "Energize Eastside Project" or the "Project"). The new substation and upgraded lines are needed to address electrical system deficiencies identified during federally-required planning studies. Combined with aggressive conservation, the Project significantly improves electric reliability for Eastside communities, including the City of Bellevue (City), and will supply the additional electrical capacity needed for current and anticipated growth.

The existing system is not robust enough to maintain reliable service if the entire facility is taken out of service at one time. Therefore, the Energize Eastside Project will be constructed in two phases. This will allow PSE to keep the existing 115 kV facilities partially in service during construction, which will allow PSE to maintain reliable service to all customers during construction. This approach best ensures that PSE continues to deliver reliable electricity to all of PSE's customers during construction. The first phase (the "South Bellevue Segment") is the focus of this application and includes the following components:

- ***Construction of the Richards Creek substation, a new 230 kV to 115 kV substation in Bellevue.*** The Richards Creek substation will be constructed directly south of PSE's existing Lakeside Switching Station. Situated on parcel 1024059083, the 8.46 acre substation site is currently used as a PSE pole storage yard.

- ***Upgrading 3.3 miles (Bellevue Portion) of existing 115 kV lines with 230 kV lines between the Lakeside and Talbot Hill substations.*** This requires replacing existing wood H-frame poles with steel monopoles. After deliberate review and extensive stakeholder input, PSE proposes to undertake this work in the City's existing transmission line corridor rather than siting a new corridor through Eastside communities. Within the existing utility corridor, the proposed pole locations for the rebuilt lines will generally be in the same locations as the existing poles. Selective tree removal will also be required within the managed corridor to meet federal vegetation management requirements and PSE standards. Use of the existing corridor (which has housed transmission lines since the 1920s and 30s) minimizes environmental impacts and impacts to adjacent uses to the fullest extent feasible.

The Alternative Siting Analysis that follows summarizes the years of study (including dozens of technical studies and two-phases of review under the State Environmental Policy Act (SEPA)) required to reach a decision point on how to best meet growing demand and ensure PSE's compliance with federal performance standards.

1.2 ALTERNATIVE SITING ANALYSIS PURPOSE AND OBJECTIVES (LUC 20.20.255.D)

PSE proposes the Energize Eastside Project--the upgrading of 115 kV transmission lines to 230 kV lines in an existing transmission line corridor and the construction of the Richards Creek substation. In the Bellevue Comprehensive Plan, PSE's proposed route is on a "sensitive site." See Map UT-7. For new or expanded utility facilities on sensitive sites, an Alternative Siting Analysis is required in conjunction with the Conditional Use Permit process. *See* LUC 20.20.255.D.

Under the City's land use code, an Alternative Siting Analysis must: 1) identify, describe and map three alternative site options; 2) analyze whether each alternative site is feasible; 3) describe the technologies considered and how the proposed facilities will improve system reliability; and 4) describe community outreach related to the new or expanded facilities. *See* LUC 20.20.255.D. Where proposed sites are located within a Neighborhood Business or Residential Land Use District, the applicant must 1) describe whether the proposed location is a consequence of demands from customers within the district and 2) describe whether operational need requires locating the proposed facility in the district. *Id.* Using the location selection hierarchy, the applicant must then identify the preferred site alternative. *Id.* Finally, where the preferred site is in a Residential Land Use District, the applicant must demonstrate that the siting causes fewer site compatibility impacts than a nonresidential siting. *Id*.

2.0 ALTERNATIVES ANALYSIS

After extensive study, PSE determined that the most effective solution to meet increased electricity demand and to comply with federal performance requirements is the addition of a 230 kV/115 kV substation in the center of the Eastside load area -- the Richards Creek substation -- and the upgrading of 115 kV transmission lines with 230 kV transmission lines constructed between the Sammamish (Redmond) and Talbot Hill (Renton) substations.[1] These facility upgrades, combined with continued aggressive conservation measures, is the Energize Eastside Project.[2] As confirmed by the City's independent consultants, this Project will improve

[1] The existing transmission lines were last upgraded in the 1960s and are located in PSE's Sammamish – Lakeside – Talbot Hill transmission line corridor, which was established in the late 1920s and early 1930s.

[2] Notably, the City's Phase 2 DEIS concluded that "Under the No Action Alternative, PSE would continue to manage its system in largely the same manner as at present. This includes

reliability for Eastside communities and supply the needed electrical capacity for growth and development on the Eastside.

Siting of electrical transmission infrastructure through urbanized areas presents unique challenges. Finding the best way to route a transmission line is complex, as dozens of elements of both the natural and built environments need to be considered. This is especially true here as the proposed Project traverses the City from north to south.

The Project will be constructed in two phases, with the southern phase of the transmission line traversing 3.3 miles of the City. As a linear project, it necessarily travels through many land use districts. To limit the need to construct new facilities (and the associated environmental impacts), when looking at the entirety of the Energize Eastside Project, all transmission line route alternatives start at PSE's Sammamish substation in Redmond and end at the Talbot Hill substation in Renton. PSE considered various routing options for the entire line, including five route options in the South Bellevue Segment.

2.1 ROUTING ANALYSIS METHODOLOGY (LUC 20.20.255.D.1-2)

PSE determined that the best approach to route selection would be to use a modern tool that employed a graphical information system (GIS)-based Linear Routing Tool (LRT) to conduct a broad evaluation of possible transmission line routes.

To further evaluate the Transformer plus Transmission Line solution, PSE contracted Tetra Tech, a consulting and engineering firm, who has developed an LRT. Details of the LRT assessment can be found in the Eastside 230 kV Project Constraint and Opportunity Study for Linear Site Selection (December 2013) (Attachment C). The LRT is a tool developed by Tetra Tech based on commercially-available geospatial technology and Tetra Tech's linear routing experience. It is a collaborative process that combines powerful analytical software with project experience, system planning, engineering, land use and local knowledge considerations. The LRT's innovative geospatial tool identifies the most suitable route alternatives based on modeled environmental and infrastructure factors and constraints.

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maintenance programs to reduce the likelihood of equipment failure, and stockpiling additional equipment so that in the event of a failure, repairs could be made as quickly as possible. *Implementation of the No Action Alternative would not meet PSE's objectives for the proposed project, which are to maintain a reliable electrical system and to address a deficiency in transmission capacity on the Eastside. Implementation of the No Action Alternative would increase the risk to the Eastside of power outages or system damage during peak power events*." Phase 2 DEIS at 2-3.

PSE and Tetra Tech began this process by identifying an approximately 255 square mile study area (Attachment A, Figure 1) that encompasses the Sammamish substation in the north and Talbot Hill substation in the south. The study area was bounded on the west by the eastern shore of Lake Washington and extending far enough east to include the BPA corridor near Soaring Eagle Regional Park (located north east of the City of Sammamish). Any new transmission line route had to connect to a new one of the potential 230 kV to 115 kV transformation sites (substation) within this area in order to solve the problem. For the study, three possible substation sites were identified.

The LRT combined GIS data layers and created an output file called the suitability grid, which represents a summation of all the constraints and opportunities for every point (grid cell) across the entire study area. The LRT processed and combined the data layers to model preferred corridors across the suitability grid, while still connecting the corridors to one of the transformation site (i.e., substation) options within the study area. The LRT analyzed more than 200 route and substation alternatives. From these, the preferred corridors identified by the LRT were used to develop route alternatives.

2.2 ALTERNATIVE SITES ANALYZED (LUC 20.20.255.D.1-2)

LUC 20.20.255D.1. Alternative Sites Analyzed. Prior to submittal of the application for Conditional Use Permit required pursuant to subsection C of this section, the applicant shall identify not less than three alternative site options to meet the system needs for the proposed new or expanding electrical utility facility. At least one of the alternative sites identified by the applicant shall be located in the land use district to be primarily served by the proposed electrical utility facility.

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LUC 20.20.255D.2b. Map the location of the sites identified in subsection D.1 of this section and depict the proximity of the sites to Neighborhood Business Land Use Districts, Residential Land Use Districts, and Transition Areas.

As set forth in detail below, this Alternative Siting Analysis addresses the requirements of LUC 20.20.255.D for the South Bellevue Segment. First, using nomenclature developed during the 2014 community advisory group process, PSE discusses three siting alternatives considered for the South Bellevue Segment:

1) Willow 1 route (Figure 2, entirely within the existing corridor),
2) Willow 2 route (Figure 3), and
3) Oak 1 route (Figure 4).

The Willow 1, Willow 2, and Oak 1 routes are all feasible; however, based on the information obtained through the EIS process and extensive public outreach, PSE will proceed with the

Willow 1 route to limit environmental impacts and new impacts to adjacent uses. In addition, pipeline safety experts concluded that the Willow 1 route gives PSE the greatest assurance that the Energize Eastside Project will operate safely in the same corridor as BP's Olympic Pipeline.

2.3 ALTERNATIVE SITE DESCRIPTIONS

LUC 20.20.255D.2.a. Describe the sites identified in subsection D.1 of this section and the land use districts within which the sites are located.
[...]

LUC 20.20.255D.2.c. Describe which of the sites analyzed are considered practical or feasible alternatives by the applicant, and which of the sites analyzed are not considered practical or feasible, together with supporting information that justifies that conclusions reached. For sites located within a Neighborhood Business Land Use District, Residential Land Use District, and/or Transition Area (including the Bel-Red Office/Residential Transition (BR-ORT), the applicant shall:

- *i. Describe whether the electrical utility facility location is a consequence of needs or demands from customers located within the district area; and*
- *ii. Describe whether the operational needs of the applicant require location of the electrical utility facility in the district or area.*

The Energize Eastside Project serves all of the potentially impacted land uses as in general, all land uses require electricity. The Energize Eastside Project will provide an upgraded, reliable transmission system serving the Eastside generally and adjacent uses specifically. The Project is needed because cumulatively, demand on the Eastside is increasing, including in areas along the South Bellevue Segment. The transmission line component of the project must run between the Sammamish and Talbot Hill substations. It must also connect with the proposed Richards Creek substation. The location of the substation is not dependent on being sited in a specific district; however, it does need to be situated in a location that the most reliable operation. Based on operational best practices, the ideal location for the new 230 kV substation is located in close proximity to PSE's existing 115 kV Lakeside substation. In addition, operationally, the transmission line must transverse through the City of Bellevue from the north to the south, making it impossible to completely avoid areas of residential zoning. The existing corridor (Willow 1) provides the shortest distance through the city and therefore, crosses the least amount of residential zoning.

As required under LUC 20.20.255.D.1 and LUC 20.20.255.D.2.c.i-.ii, all siting alternatives are located in land use districts served by the South Bellevue Segment. The City of Bellevue's and the Eastside's growing demand for power is a primary driver of the need for the Energize Eastside Project.

This conclusion was confirmed by the City's independent experts. Utility System Efficiencies, Inc. (USE) was engaged by the City in December, 2014 to conduct an independent technical analysis of the purpose, need, and timing of the Energize Eastside Project. In April 2015, USE published a report summarizing its findings. *See* Independent Technical Analysis of Energize Eastside for the City of Bellevue, WA (April 28, 2015) ("USE Report"). The USE Report answered the following questions:

> **IS THE EE PROJECT NEEDED TO ADDRESS THE RELIABILITY OF THE ELECTRIC GRID ON THE EASTSIDE? Yes.**
>
> Although the new 2014 forecast resulted in an 11 MW decrease in the Eastside area's 2017/18 winter forecast, the reduced loading still resulted in several overloaded transmission elements in winter 2017/2018, which drive the project need. ...
>
> Although the corrective action plan (CAP) required in the 2017/18 winter to avoid facility overload doesn't require dropping load (turning off customers' power), by winter 2019/20 approximately 63,200 customers are at risk of losing power. …
>
> **IS THE PROJECT NEEDED TO ADDRESS REGIONAL GRID POWER FLOWS, SPECIFICALLY POWER FLOWS ON THE NORTHERN INTERTIE (TO AND FROM CANADA)? The project is necessary to address local need.**
>
> The Optional Technical Analysis examined this issue by reducing the Northern Intertie flow to zero (no transfers to Canada). Although this scenario is not actually possible due to extant treaties, it was modeled to provide data on the drivers for the EE project, to examine if regional requirements might be driving the need. The results showed that in winter 2017/18, even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230/115 kV transformer #2 would still be overloaded by several contingencies (several different outage scenarios). Again, the projected overloads indicate a project need at the local level to meet reliability regulations.

Use Report at 5-6.

The USE Report went on to confirm PSE's conclusion that, applying federal electrical system planning requirements, transformers serving uses adjacent to the South Bellevue Segment will experience overloads (i.e., reduced reliability) in foreseeable planning scenarios. USE Report at 52 (containing tables summarizing PSE's forecasting results that show overloads at the Talbot and Lakeside substations).

In addition to the USE Report, in 2012, Bellevue retained Exponent to perform an electrical system reliability assessment. Exponents report stated "As a minimum, the following capacity additions have been identified as being needed within the next 5 to 10-year time frame:

- Upgrade of existing 115 kV lines to 230 kV
- Addition of transformer banks to support expected growth in various areas of the City (Downtown, Bel-Red, and Somerset/Eastgate)
- Addition of new 115 kV lines to reinforce the overall electric system."

City of Bellevue Electrical Reliability Study, Phase 2 Report at 140. In sum, following construction, uses adjacent to the proposed transmission line will benefit from improved reliability now, and into the future.

As described above, numerous route alternatives were developed and evaluated in the public review processes described in Section 4.0 of this document.[3] Three of the options for the South Bellevue Segment are described below (LUC 20.20.255.D.1). *See* Attachment A (mapping PSE's proposed alternatives). These include the two existing transmission line corridors and a new corridor. The two existing corridors include Seattle City Light's Eastside 230 kV corridor and PSE's Sammamish-Lakeside-Talbot Hill 115 kV corridor. The third alignment was developed during the LRT work and provides for an alternative located west of the SCL and PSE transmission line corridors. These corridors were chosen as potential alternatives based on the public outreach processes.

2.3.1 Willow 1, Existing PSE 115 kV Transmission Line Corridor

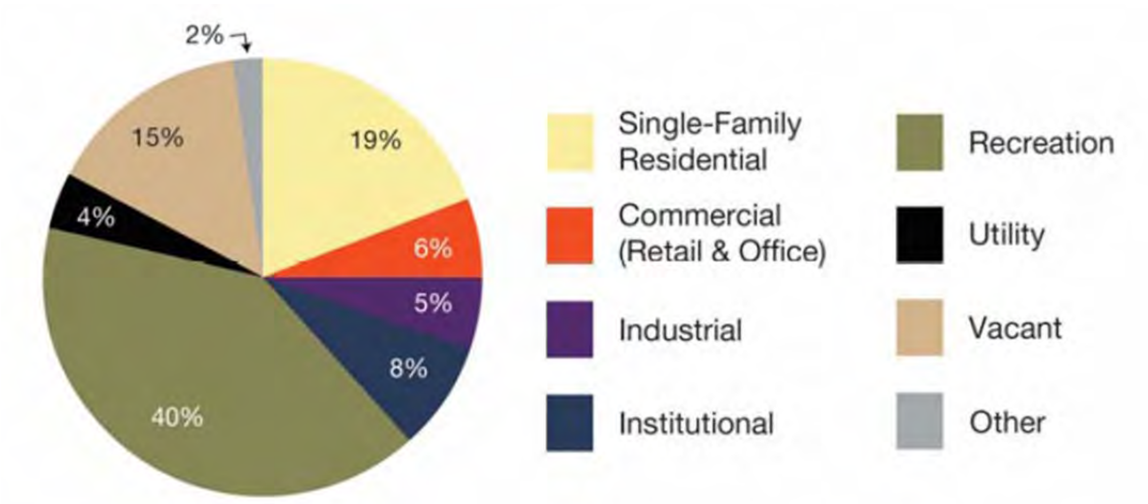
"Willow 1" was one of the original two routes recommended by the community advisory group in 2014. The route utilizes the existing Sammamish-Lakeside-Talbot Hills 115 kV corridor (Attachment A, Figure 2). The corridor was established in the late 1920s and early 1930s. In the 1960s, the line was upgraded from 55 kV to 115 kV, which included replacement of original poles with the existing H-frame poles. As noted in Section 2, PSE identified in the early 1990s

[3] In addition to the three routes evaluated herein, the City's Phase 2 DEIS analyzes two additional routing options in the South Bellevue Segment. *See* Attachment B (comparing environmental impacts of each of the four South Bellevue Segment alternatives). This additional analysis is excluded from the ASA as they go above and beyond what is required under LUC 20.20.255.D, however, the review of the Phase 2 DEIS may also be useful in ensuring PSE's compliance with LUC 20.20.255.D.

that the lines within the same corridor would need to be upgraded to the next higher transmission voltage (230 kV). This 230 kV upgrade has been included in Bellevue Comprehensive Plans since the adoption of the Growth Management Act in 1990. The route crosses through the following land use districts in the South Bellevue Segment: LI, OLB, R-1, R-3.5, R-5, and R-15. *See* LUC 20.20.255.D.2.a. In sum, Willow 1 would be located in six different zoning districts in the City including commercial, industrial, multi-family residential, and single family residential districts. Consistent with the City's Phase 2 DEIS, PSE considers this route to be feasible. *See* LUC 20.20.255.D.2.c.

As described in the City's Phase 2 DEIS:

> Existing land uses are predominantly recreation, single-family residential, and vacant lands (see the chart below for the percentage of the total study area in the Willow 1 route that each land use represents). Approximately 212 parcels are immediately adjacent to the existing corridor. Unique land uses include Tyee Middle School, Forest Hill, King County Solid Waste Division, the I-90 crossing, Somerset Recreation Club, and Sunset Park.



> The route goes through the neighborhoods of Eastgate, Somerset, and Newport Hills. The Eastgate Subarea is characterized by the I-90 business corridor with commercial offices, high-tech industries, and commercial shopping centers. Outside of the commercial center of Eastgate is single-family housing. The Somerset Subarea is a community of hilltop single-family homes. The Newport Hills Subarea is made up of single-family and multi-family neighborhoods with a core commercial district in the center of the community. Several parks (including Sunset Park and Coal Creek Park), a government building, and a school (Tyee Middle School) are along the Willow 1 route.

> The Bellevue Comprehensive Plan designates community business and light industrial in Eastgate, while the Somerset and Newport Hills communities would remain as single-family developments, with a commercial center in Newport Hills. The subarea plan policies of Eastgate, Somerset, and Newport Hills support growth in similar land use patterns as those that currently exist.
>
> There are 180 single-family and 10 multi-family residences within this option.

Phase 2 DEIS at 3.1-15. Approximately 19% of the Willow 1 route would impact Single Family uses. *Id.* All of these residences currently have two 115 kV transmission lines as an adjacent use. The use of an existing corridor does not impose a new transmission line on new areas, does not require the acquisition of new easements, and is specifically identified on Bellevue's Comprehensive Plan UT-7 map as being expanded to 230 kV.

PSE has selected the Willow 1 route as its preferred alternative. All of the proposed routes, including Willow 1, traverse residential land use districts. By constructing the proposed transmission line facilities in the existing 115 kV transmission line corridor, site compatibility impacts are limited by this alternative. *See* LUC 20.20.255.2.d. By using the existing corridor, PSE minimizes tree removal and management within the corridor (see Attachment B) as compared to establishing a new corridor and can better assess and limit potential interactions with a co-located petroleum and natural gas pipeline (*AC Interference Analysis – 230 KV Transmission Line Collocation with Olympic Pipelines OPL16 & OPL20*; DNV-GL 2016). It also avoids the creation of new impacts to adjacent uses, including residential uses. As properties adjacent to the transmission line corridor already have utility facilities in their viewsheds and neighborhoods, Willow 1 significantly limits new impacts.

2.3.2 Willow 2

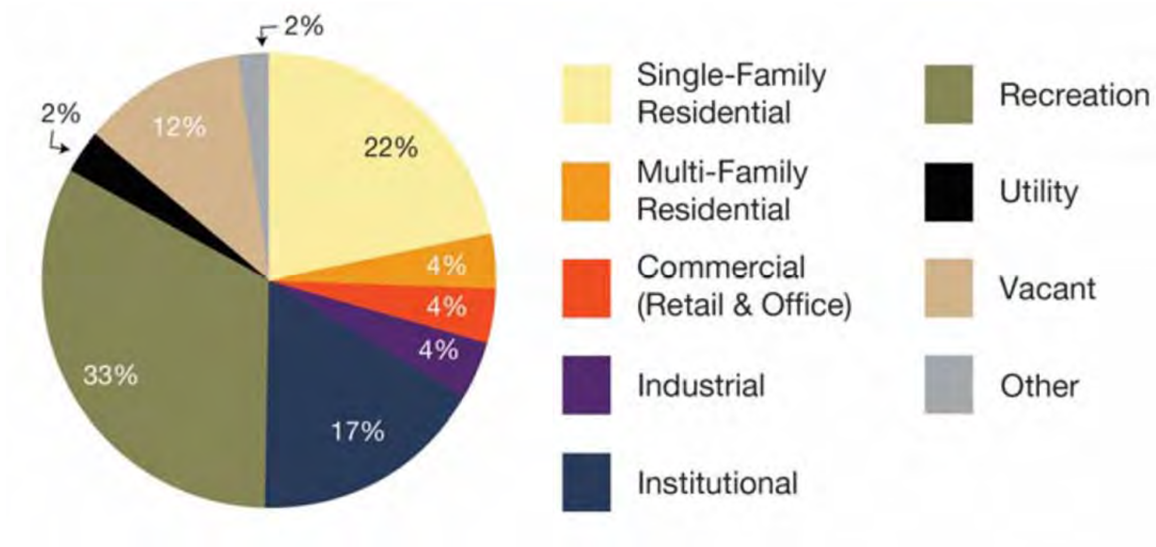
"Willow 2" is a result of one of the original two routes recommended by the community advisory group in 2014. This route was developed to address comments heard during the community advisory group process, primarily to address topographic and visual concerns in the Somerset area. It has also been evaluated as part of the City's SEPA review process. Willow 2 uses PSE's existing Sammamish-Lakeside-Talbot Hill 115 kV corridor; in addition to moving lines to SE Newport Way, Factoria Boulevard SE, and Coal Creek Parkway SE (Attachment A, Figure 3). More specifically, from the new Richards Creek 230 kV substation south to SE Newport Way, the existing two 115 kV lines would be removed and the replaced with two 230 kV lines. In addition, the Somerset substation would need to be rebuilt in order to connect to the 230 kV system.

South of where the existing transmission corridor crosses SE Newport Way, the two existing 115 kV lines would be removed and replaced with a single 230 kV line. From the same crossing at SE Newport Way, the existing double circuit distribution (12.5 kV) and communication lines could be relocated underground because PSE would build a 230 kV line along the road. This new 230 kV line would continue to Factoria Blvd. SE where it would join the existing 115 kV line along Factoria Blvd. SE. The section between SE Newport Way and Coal Creek Parkway SE would be rebuilt to a double circuit line on steel poles. The existing 115 kV line between Coal Creek Parkway SE and PSE's Somerset substation, located at the intersection of Coal Creek Parkway SE and Forest Drive SE, would be rebuilt as a 230 kV line, where it would rejoin with the Sammamish-Lakeside-Talbot Hill corridor.

The Willow 2 route crosses through the following land use districts in the South Bellevue Segment: R-1, R-3.5, R-5, R-15, R-20, R-30, OLB, and LI. See LUC 20.20.255.D.2.a. In sum, Willow 2 would be located in a total of eight different zoning districts in the City of Bellevue.

As described in the City's Phase 2 DEIS:

> Existing land uses mostly include recreation, single-family residential homes, and institutional (see the chart below for the percentage of the total study area in the Willow 2 route that each land use represents). Approximately 309 parcels are immediately adjacent to the corridor (existing and new). Unique land uses include Newport Children's School, Holy Cross Lutheran Church, Newport Covenant Church, King County Solid Waste Division Factoria Transfer Station, Sunset Park, and the I-90 crossing.
>
> The Willow 2 route would go through the same neighborhoods of Eastgate, Somerset, and Newport Hills as in the Willow 1 route. However, at SE Newport Way, the option route would also follow SE Newport Way on the border of Factoria, heading south at Coal Creek Parkway SE. The Factoria/Somerset border is characterized by single-family residential developments and small commercial spaces. Several parks (including Sunset Park and Coal Creek Park), government buildings, and schools (Newport Children's School, and Tyee Middle School) are along the Willow 2 route.



The subarea plan policies of each of the subareas within the Willow 2 route support growth in similar land use patterns as those that currently exist.

There are 257 single-family and 221 multi-family residences within this option. Approximately 26% of the Willow 2 route would impact Single and Multi-Family uses.

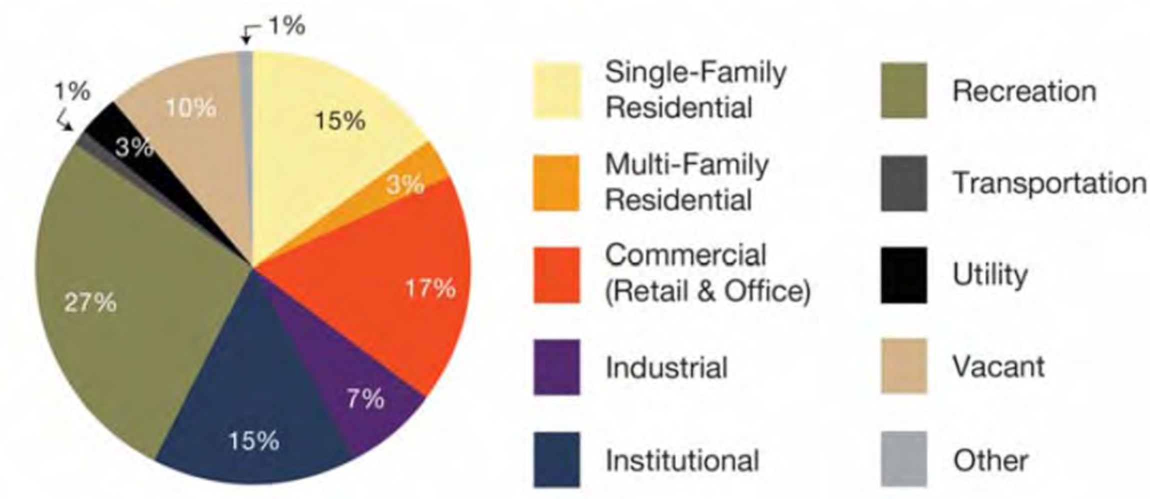
Consistent with the City's Phase 2 DEIS, PSE considers this route to be feasible. See LUC 20.20.255.D.2.c. PSE ultimately eliminated this route from consideration, however, because from a safety perspective, the Willow 1 route has the lowest potential AC interaction with the petroleum pipelines that share the corridor. Additionally, the Willow 1 route requires the fewest number of trees to be removed in order to comply with NERC standards and uses an existing transmission line corridor.

2.3.3 Oak 1

"Oak 1" was also one of the original two routes recommended by the community advisory group in 2014. It has also been evaluated as part of the City's SEPA review process. Oak 1 utilizes portions of the PSE's existing Sammamish-Lakeside-Talbot Hills 115 kV corridor (Attachment A, Figure 4). This alternative departs from the existing corridor just south of PSE's existing Lakeside substation (the proposed Richards Creek substation), which is located on the parcel south of the Lakeside substation, currently used as a pole storage yard. From the Pole Yard, the route heads west along SE 30th Street and then continues south along Factoria Blvd. SE and Coal Creek Parkway, where it converges back with the existing 115 kV corridor. Oak 1 entails maintaining the existing 115 kV transmission lines in the existing corridor through the Somerset area and replacing the existing single 115 kV transmission line circuit with new double circuit 230 kV/115 kV lines on the alignment described above. The new 230 kV route crosses through the following land use districts in the South Bellevue Segment: R-1, R-2.5, R-3.5, R-5, R-20, R-30, O, CB, PO, F-1, F-2, and LI. *See* LUC 20.20.255.D.2.a. In sum, Oak 1 would be located in a total of twelve different zoning districts in the City of Bellevue, including commercial, industrial, mixed use, multi-family residential, and single-family residential districts.

As described in the City's Phase 2 DEIS:

> Existing land uses along Oak 1 mostly include recreation, commercial, and single-family residential homes (see the chart below for the percentage of the total study area in the Oak 1 Option that each land use represents). Approximately 318 parcels are immediately adjacent to the corridor (existing and new). Unique land uses include Sunset Park, King County Solid Waste Division Factoria Transfer Station, the I-90 crossing, Coal Creek Park, Tyee Middle School, Forest Hill Neighborhood Park, a large industrial/commercial area on Factoria Blvd SE, KidsQuest Children's Museum, Bellevue Fire Station 4, St. Margaret's Episcopal Church, Newport High School, Newport Covenant Church, and the Factoria Police Station.



> The option goes through the neighborhoods of Eastgate, Factoria, northwest Somerset, and Newport Hills. The Eastgate Subarea is characterized by the I- 90 business corridor with commercial offices, high-tech industries, and commercial shopping centers. Factoria is characterized by single-family residential developments and small commercial spaces. The northwest Somerset area is a single-family residential development on a hilltop. The Newport Hills Subarea is made up of single-family and multi-family neighborhoods with a core commercial district in the center of the community. Several parks (including Sunset Park and Coal Creek Park), government buildings, and schools (Newport High School and Tyee Middle School) are along the Oak 1 Option.

> The subarea plan policies of each of the subareas within the Oak 1 Option support growth in similar land use patterns as those that currently exist.
>
> There are 212 single-family and 287 multi-family residences within this option.
>
> Phase 2 DEIS at 3.1-13. Approximately 18% of the Oak 1 route would impact Single and Multi-Family uses.

Consistent with the City's Phase 2 DEIS, PSE considers this route to be feasible. *See* LUC 20.20.255.D.2.c. PSE ultimately eliminated this route from consideration, however, because from a safety perspective, the Willow 1 route has the lowest potential AC interaction with the petroleum pipelines that share the corridor. Additionally, the Willow 1 route requires the fewest number of trees to be removed in order to comply with NERC standards and uses an existing transmission line corridor. The use of an existing corridor does not impose a new transmission line on new areas, does not require the acquisition of new easements, and is specifically identified on Bellevue's Comprehensive Plan UT-7 map as being expanded to 230 kV.

2.3.4 Substation Alternatives

The substation yard needs to be large enough to accommodate a new 230 kV-115 kV transformer and associated electrical equipment such as circuit breakers, electrical bus, and connections to the new transmission lines. It is expected that the substation's fenced yard will be approximately 2 acres. The main function of the substation is to step down the 230 kV voltage (bulk power) from the new transmission lines to 115 kV needed for use by the local distribution system. All substation locations are considered to be feasible. LUC 20.20.255.D.2.c.

Three 230-115 kV substation sites were considered for the Energize Eastside Project - referred to as Westminster, Vernell, and Richards Creek. These sites were selected for consideration because they are all owned by PSE; meet the objectives to site the 230 kV transformer at a central location between the existing 230 kV power sources at Sammamish substation in Redmond and Talbot substation in Renton; accommodate the necessary improvements to serve the required 230 kV transmission lines to bring power to the centralized transformer; and distribute power to the existing network of 115 kV transmission lines.. Of the three substation sites, only Richards Creek is located within the Southern Phase; however, since the primary objective of the Energize Eastside Project is to install a new transformation source in the central Bellevue area, their inclusion is relevant.

2.3.4.1 Westminster

The Westminster substation site is on property owned by PSE and located at 13649 NE 24th Street in the City of Bellevue (Parcel 2725059166) in the Bridle Trails Subarea (Attachment A, Figure 5). Currently, the approximately 6 acre site is undeveloped and primarily forested. The north half of the property is zoned for Professional Office (PO) with the southern half zoned Office (O) Surrounding properties to the north and west are zoned as Single-Family Residential Estate (R-1). The properties located to the east is zoned General Commercial (GC) with the properties located south of SR-520 being zoned Bel-Red General Commercial (BR-GC). The Westminster site is mapped as a “sensitive site” in the City’s Comprehensive Plan (Map UT-7). When considering use of the existing corridor, it was determined that since the Westminster site was farther away from the Lakeside 115 kV station, there was no benefit in using the Westminster site over the Richards Creek site. In addition, to make the Westminster site work, additional 115 kV lines would be required between the site and the 115 kV lines located 140th Avenue NE.

2.3.4.2 Vernell

The Vernell substation site comprises two properties located at 2380 116th Avenue NE (Parcels: 2825059278 (1.32 acres) and 5268300010 (0.66 acres) in the Bel-Red Subarea (Attachment A, Figure 6). The site is zoned BR-MO (Bel-Red Medical Office) as are the properties located to the south and the west. The site currently contains an office building, parking areas and a sport court. The site is adjacent to SR-520 to the north and the former BNSF rail corridor the east. The property located to the east across the rail corridor is zone Bel-Red General Commercial (BR-GC). The Vernell site is mapped as a “sensitive site” in the City’s Comprehensive Plan (Map UT-7). The existing 115 kV Sammamish to Lakeside transmission line corridor would not be an option for this substation site. Therefore, since the use of the existing corridor provides a number of benefits, Vernell was not selected as either Westminster or Richards Creek are along the existing PSE corridor and using Vernell would require additional transmission lines between the site and the existing transmission line corridor.

2.3.4.3 Richards Creek

The Richards Creek site is PSE’s selected substation site. It is located adjacent to and south of the PSE’s existing Lakeside substation at 13600 SE 30th Street (parcel 1024059130) (Attachment A, Figure 7). The 8.46 acre property is zoned Light Industrial (LI) as are the properties to the north, west, and south. Properties locate east of the site are zoned Office and Limited Business (OLB) and Multifamily Residential (R-10).

The central portion of the site is currently used as a pole storage yard. It is partially fenced and has a flat storage area consisting of paved driveways and gravel.

The Richards Creek substation is essentially an expansion of the Lakeside substation, which is mapped as a "non-sensitive" site in the City's Comprehensive Plan (Map UT-7). Normal practice is to have the 230 kV station co-located with the adjoining 115 kV station; however, due to topographic and environmental considerations located south of the Lakeside substation, expanding the station in that direction would be challenging. Therefore, placing the two stations on separate parcels was determined to be the most effective approach. Since the two yards have separate access points, they are required to have different names for operational and emergency purposes.

2.4 SELECTED SITE AND ROUTE

LUC 20.20.522D.2.d. Identify a preferred site from the alternative locations considered for the proposed new or expanding electrical utility facility. The following location selection hierarchy shall be considered during identification of the preferred site alternative: (i) nonresidential land use districts not providing transition, (ii) nonresidential Transition Areas (including the Bel-Red Office/Residential Transition (BR-ORT), and (iii) residential areas. The applicant may identify a preferred site alternative in a Residential Land Use District or Transition Area (including the Bel-Red Office/Residential Transition (BR-ORT) upon demonstration that the location has fewer site compatibility impacts than a nonresidential land use district location.

After years of study and extensive community dialogue, PSE selected the Richards Creek substation site and the Willow 1 transmission line corridor as the location for the Energize Eastside Project. Because PSE's project requires reconstruction of miles of transmission lines through the City, all routes evaluated by PSE traverse residential uses. As such, PSE cannot avoid residential uses by selecting a site reflective of the City's selection hierarchy. *See* LUC 20.20.255.D.2.d. The Willow 1 route, however, minimizes compatibility impacts by using an existing utility corridor that has been in operation since the 1920s and 1930s. By doing so, it does not require acquisition of additional easements, it removes the fewest number of trees, and it prioritizes safety by having the lowest potential AC interaction with the two petroleum pipelines that share the corridor. Moreover, the Phase 2 DEIS identified that Willow 1 impacts 309 fewer residences than the Oak 1 route and 288 fewer residences than the Willow 2 route.

Willow 1 is more consistent with the City's selection hierarchy which seeks to limit impacts to residences. When considering the location selection hierarchy (LUC 20.20.225.2.d.), there is no possible way to route a transmission line, between the Richards Creek substation and the Bellevue/Newcastle city border, entirely within nonresidential land use districts not providing transition or non-residential Transition Areas. This is a result of city zoning that does not provide any congruent nonresidential north-south corridors. However, Willow 1 crosses or has adjacency to the least amount of residential and residential transition area. The Willow 1 route was originally established in the late 1920s and early 1930s when little to no development in the area had occurred. The residential areas that exist today have developed around the transmission line corridor. Additionally, the proposed upgrade of the existing 115 kV lines to 230 kV has been incorporated in the City's comprehensive plan since the early 1990s; therefore, using the Willow 1 route is the most compliant with the Comprehensive Plan.

In sum, as Willow 1 upgrades an existing transmission line and follows the existing route, this alternative creates the fewest new impacts (including compatibility impacts) as compared to the Oak 1 route. *See* LUC 20.20.255.D.2.d. These are the key factors that make Willow 1 the preferred alternative for Energize Eastside.

2.4.1 Other Rejected Transmission Line Options

The 2015 Solutions Study and 2014 Solutions Report concluded that the preferred solution to solve the Eastside's transmission deficiencies was aggressive conservation combined with construction of a new 230/115 kV transformer and the development of 230 kV transmission lines to connect existing facilities. Transmission line alternatives evaluated, but rejected, by PSE included the use of the Seattle City Light 230 kV corridor, underwater transmission lines (Phase 1 DEIS), the undergrounding of transmission lines, as well as numerous overhead alternatives. These are discussed below.

2.4.1.1 Seattle City Light 230 kV Corridor

Seattle City Light (SCL) operates a dual 230 kV transmission line through the Energize Eastside Project area. The use of these transmission lines/corridor was evaluated in the Phase 1 DEIS. The SCL corridor traverses approximately 7.3 miles within the city of Bellevue, with about 3 miles in the south phase (excluding the lines necessary to connect to the Richards Creek substation). To connect the SCL lines to the 230 kV Richards Creek substation, two new 230 kV lines would need to be constructed, which would require establishing a new transmission corridor. The exact length of that alignment has not been determined, but the proximity of the Richards Creek and Sammamish substations to the SCL lines suggests that each connection would be approximately 1 mile.

PSE explored the idea of using the SCL lines as an option; however, the SCL facility is not under PSE ownership, and SCL stated that it needs these lines to serve its customers (Gentile et al., 2014). For the foregoing reasons (lack of sufficient capacity, need for new transmission line facilities that will provide sufficient capacity for less than 10 years, and lack of permission from SCL), PSE does not consider this alternative to be feasible. See LUC 20.20.255.D.2.c.

2.4.1.2 Lake Washington Submarine Cable Alternative

The option of using a submerged or underwater transmission line in Lake Washington was also included in the Phase 1 Draft EIS. Additional detail about constructing a submarine cable in

Lake Washington is included in the Eastside 230 kV Project Lake Washington Submarine Cable Alternative Feasibility Report (Power Engineers, 2015). A submerged line would be prohibited by shoreline regulations in two of the communities north of the proposed Richards Creek substation (Beaux Arts Village and Hunts Point), because new utility corridors are prohibited in the aquatic environments of these communities.

South of the Richards Creek substation site, the City of Renton shoreline regulations (RMC 4-10-095) prohibit utilities in some shoreline environments, but it appears technically feasible to avoid prohibited environments if this option were chosen. However, this option would also require the construction of approximately 5 miles of new transmission corridors from the Talbot Hill substation to Lake Washington, and from Lake Washington to the Richards Creek substation, in order to avoid impacts to 8 miles along the existing corridor. As described in the Phase 1 Draft EIS, development of new corridors is expected to have higher environmental impacts than use of existing corridors, including permanent displacement of existing uses, vegetation removal, visual impacts, and construction duration. As such, this alternative was not seen as a reasonable alternative to using the existing corridor as proposed by PSE. For these reasons, an underwater line in Lake Washington was not carried forward as a viable alternative.

2.4.1.3 Underground Alternative

The option of placing the new 230 kV transmission lines entirely underground was evaluated in the Phase 1 Draft EIS. Underground transmission lines involve several technical and economic challenges that would necessitate acquiring a new or expanded right-of-way, including greater restrictions on surface vegetation and uses than are present in PSE’s existing 115 kV right-of-way. Factors contributing to the need for additional right-of-way include the need for heat dissipation from each conductor, and the need for separation from the Olympic Pipeline, which is collocated in much of PSE’s existing 115 kV corridor, in order to prevent corrosion of the pipeline. For heat dissipation, underground transmission lines must be placed approximately 12 to 15 feet apart and 3 feet below the surface (Power Engineers, 2014), which means there can be no trees or large shrubs planted over them. The potential for the electrical line to cause unacceptable corrosion of the pipeline is greater if the electrical line is underground than for overhead lines because soils are more conductive than air. Large access vaults are also required every quarter mile, and must remain unobstructed by surface structures.

While PSE has an easement for their overhead lines, placing a transmission line underground would require permission from both the Olympic Pipe Line Company and each property owner along the route. Gaining such permission would likely require extensive legal action that would delay the project and thus not meet the project objectives regarding timing. A study of potential undergrounding of the transmission lines prepared for PSE by Power Engineers (2014) states that installation adjacent to the pipeline is technically viable, but that the Olympic Pipe Line Company has stated to PSE that they will not consent to other underground facilities being installed longitudinally in their easements. PSE would therefore have to place its transmission lines outside the Olympic Pipeline easement which is, in some places, nearly as wide as the PSE corridor. Even in places where the pipeline easement is substantially narrower than PSE's corridor, PSE generally does not have enough easement area to provide the necessary separation without the pipeline being relocated. As such, an underground line would require a new corridor to avoid colocation with the Olympic Pipeline (Power Engineers, 2014). This would need to be in a street or on other public or private property that PSE would have to obtain rights to use.

The construction costs for an overhead transmission line are about $3 million to $4 million per mile; versus $20 million to $28 million per mile to construct the line underground (PSE, 2016). When a new line is constructed overhead, project costs are distributed evenly between PSE's 1.1 million customers and paid for overtime. If a transmission line were to be constructed underground, PSE can't justify asking customers across its entire service territory to pay the significant cost increases. As a result, per state-approved tariff rules, the requesting party, often the local jurisdiction, must ultimately decide whether to make this investment. The requesting party is then responsible for paying the difference between overhead and underground costs.

Given the high cost of acquiring and developing an entirely new underground corridor, and the likely delays it would entail, this option was not considered reasonable as an alternative for the entire corridor, although it is considered as an option for mitigation in limited areas, should one or more jurisdictions determine that it was necessary to avoid significant impacts. Impacts generally associated with the undergrounding of the transmission lines are addressed in the Phase 1 Draft EIS (in the analysis of Option C).

3.0 TECHNOLOGIES CONSIDERED AND RELIABILITY NEED (LUC 20.20.255.D.3)

LUC 20.20.255D.3.a: Describe the range of technologies considered for the proposed electrical utility facility.

PSE studied a range of potential solutions to resolve the Eastside transmission deficiencies; these included additional conservation, additional generation, demand response (DR), distributed generation (DG), energy storage, expansion of existing transmission substations, transmission line upgrades, and new transmission lines. PSE's analysis of alternative technologies is documented in detail in PSE's Solutions Report (2014), Pre-Screening Study (Feb. 2014), Underground Feasibility Study (2014), Supplemental Eastside Solutions Study

Report (2015) ("Solutions Study"), the Lake Washington Submarine Cable Alternative Feasibility Study (June 2015), and Eastside System Energy Storage Alternatives Screening Study (*Strategen*, 2015). All of these studies can be accessed at https://energizeeastside.com/documents. Non-wire technology solutions are also evaluated in detail in the Phase 1 DEIS (available at http://www.energizeeastsideeis.org/library.html).

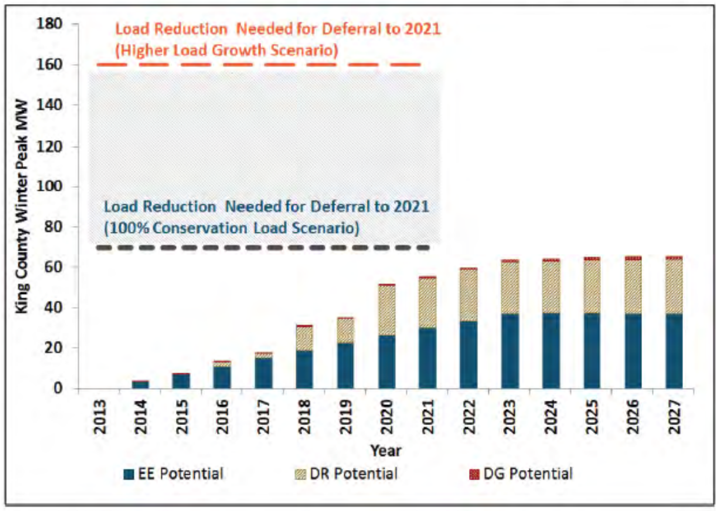
The following section summarizes PSE's analysis with respect to each alternative technology.

3.1 INCREASING CONSERVATION

PSE retained Energy and Environmental Economics, Inc. (E3) to conduct a Non-wires Alternatives Screening Study. E3 included energy efficiency, demand response and distributed generation measures in its evaluation of cost-effective non-wires potential in the Eastside area. The study concluded that the cost-effective non-wires potential for the Eastside is not large enough to provide sufficient load reduction to allow even a 4-year deferral of Eastside transmission upgrade needs (see Figure 8).

Figure 8: King County Non-wires Potential vs. Reduction for Needed Deferral

Figure ES- 1 King County Non-Wires Potential vs. Reduction for Need Deferral



3.2 CONSTRUCTION OF NEW GENERATION FACILITIES

PSE studied both conventional generation and distributed generation (DG) in its 2015 Solutions Study. To be effective, this alternative would require at least 300 MW of generation located in the Eastside. Locating conventional generation of this size on the Eastside has major siting and environmental challenges, as a facility with necessary capacity would require a site of approximately 12 to 15 acres and would have significant supporting infrastructure, noise, emissions, and permitting challenges. For DG to meaningfully impact the identified needs, DG must be installed in the right locations, available when needed and be of significant magnitude. Locating 300 MW or more of distributed renewable generation within the Eastside area by the winter of 2017/2018 or summer of 2018 was not practical and highly impactful to the environment and surrounding communities. Additionally, the Cities' Phase 1 DEIS determined that this alternative did not meet SEPA requirements to provide a reasonable alternative that could feasibly attain or approximate a proposal's objectives at a lower environmental cost or decreased level of environmental degradation (WAC 197-11-440(5)(b)). Phase 2 DEIS at 2-56.

3.3 ENERGY STORAGE AND BATTERY ALTERNATIVES

PSE contracted with Strategen to perform an Eastside System Energy Storage Alternatives Screening Study, which concluded that an energy storage system with power and energy storage ratings comparable to PSE's identified need has not yet been installed anywhere in the world. In addition, Strategen determined that the existing Eastside transmission system does not have sufficient capacity to charge energy storage systems to a level sufficient to meet PSE's operating standards.

Chemical (battery) storage was determined to be potentially the most appropriate and commercially-viable technology for application within the Eastside. Chemical storage technology is rapidly advancing, but the only system of comparable size to what PSE requires is a 100 MW/400 MWh lithium-ion ESS recently procured by Southern California Edison ("SCE"), which is not expected to be operational until 2021. The largest currently deployed and commissioned chemical storage project (by power rating) in the United States is SDG&E's Expedited Energy Storage Project in Escondido, CA, a 37.5 MW/150 MWh lithium ion battery SCE's Tehachapi Wind Energy Storage ESS, an 8 MW/32 MWh lithium ion battery. Confidential interviews with various vendors indicate that the technology and capability exists for batteries to be deployed for this application and at this magnitude exists. However, since no similarly-sized system has ever actually been built or commissioned, it is difficult to estimate the time necessary for development, procurement, construction and deployment. Procurement of battery cells in particular may result in long lead times, especially for the two larger systems contemplated would constitute a significant portion of the global market for batteries.

Based upon the results of the study, Strategen concluded that the existing Eastside transmission system does not have sufficient capacity to charge a large chemical battery to a level sufficient to meet PSE's operating standards. Specifically, the Eastside system has significant constraints during off-peak periods that could prevent an energy storage system from maintaining sufficient charge to eliminate or sufficiently reduce normal overloads over multiple days. In other words, an energy storage system is not capable of meeting Energize Eastside's need, nor does an example of this scale of energy storage exist anywhere in the world. Strategen further estimated that deferring the Eastside transmission system upgrade until 2021 would cost ratepayers approximately $1.44 billion.

3.5 THE ENERGIZE EASTSIDE PROJECT ENSURES A LONG-TERM SOLUTION TO NEAR-TERM RELIABILITY DEFICITS

LUC 20.20.255.D.3.b. Describe how the proposed electricity utility facility provides reliability to customers served.

The Energize Eastside Project is needed to meet local demand growth in the eastside of King County, including Bellevue, Redmond, Kirkland, Renton, Newcastle and Issaquah. It is PSE's responsibility to plan and operate the electrical system while complying with federal standards and guidelines.

Electricity is currently delivered to the Eastside area[4] through two 230 kV/115 kV bulk electric substations – the Sammamish substation in Redmond and the Talbot Hill substation in Renton – and distributed to neighborhood distribution substations using 115 kV transmission lines. No 230 - 115 kV transformer upgrades have been made and the primary 115 kV lines connecting the Sammamish and Talbot Hill substations (the backbones of the Eastside electrical system) have not been upgraded since the 1960s. Since then, the Eastside population has grown from approximately 50,000 to nearly 400,000. This growth is expected to continue. The Puget Sound Regional Council estimates that the Eastside population will likely grow by another third and employment will grow by more than three-quarters over the next 25 years.

The Eastside's rapid growth is also documented in the City's Phase 1 and Phase 2 DEISs:

> 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). 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.

Phase 1 DEIS at 2-13.

As required by federal regulations, PSE performs annual electric transmission planning studies to determine if there are potential system performance violations (transformer and line overloads) under various operational and forecasted electrical use scenarios. These exercises are generally referred to as reliability assessments.

The need for additional 230 kV to 115 kV transmission transformer capacity and 230 kV support in the Eastside was identified in the 1993 reliability assessment, and has been included in PSE's Electrical Facilities Plan for King County ("Plan") since that time.[5] It was first determined

[4] For the purpose of this project, the Eastside is defined as the area between Renton and Redmond, bounded by Lake Washington to the west and Lake Sammamish to the east.

[5] As explained in the Plan, "[t]he 230 kV sources for the 115 kV system in northeast King County are primarily the Sammamish and Talbot Hill substation. The loads on the 230-115 kV transformers in these stations will be high enough to require new sources of transformation." Additionally, the "Lakeside 230 kV Substation project [now the Energize Eastside Project] will rebuild two existing 115 kV lines to 230 kV between Sammamish and Lakeside [where PSE proposes the construction of the Richards Creek substation], and between Lakeside and Talbot Hill."

during PSE's 2009 annual reliability assessment, that if one of the Talbot Hill Substation transformers failed, it would significantly impair reliability on the Eastside. Replacement of a failed 230 kV transformer can take weeks, or even months, to complete depending on the level of failure and other site specific parameters. Since 2009, other reliability deficits have been identified. These include concerns over the projected future loading on the Talbot Hill Substation and increasing use of Corrective Action Plans (CAPs) to manage outage risks to customers in this portion of the PSE system.

In total, since 2009, five separate studies[6] (Attachment C) performed by four separate parties have confirmed the need to address Eastside transmission capacity:

- Electrical Reliability Study by Exponent, 2012 (City of Bellevue)
- Eastside Needs Assessment Report by Quanta Services, 2013 (PSE)
- Supplemental Eastside Needs Assessment Report by Quanta Services, 2015 (PSE)
- Independent Technical Analysis by Utility Systems Efficiencies, Inc., 2015 (City of Bellevue)
- Review Memo by Stantec Consulting Services Inc., 2015 (EIS consultant).[7]

The studies performed by PSE in 2013 and 2015 confirmed that the Eastside's existing grid will not meet federal reliability requirements by the winter of 2017/2018 and the summer of 2018 without the addition of 230 kV to 115 kV transformer capacity in the Eastside area.

3.6 ELECTRICAL UTILITY FACILITY COMPONENTS

LUC 20.20.255.D.3c. Describe components of the proposed electrical utility facility that relate to system reliability.

PSE's proposal is to install and operate a new 230 kV to 115 kV electrical transformer in the center of the Eastside load area. The ideal location for the new transformer is in close proximity to PSE's existing Lakeside 115 kV substation, which provides the connection to the existing 115 kV electrical system that serves the surrounding distribution substations. The new 230 kV to 115 kV transformer is the principal component that will allow the Eastside electrical system to reliably operate and meet Federal Planning standards. To operate the new transformer it must be served by approximately 18 miles of new high-capacity electric transmission lines (230 kV) extending from Redmond in the north and Renton to the south. The transformer would be

[6] These studies provide evidence relevant to the City's review under LUC 20.20.255.E.4 and LUC 20.20.255.D.3.b & c.

[7] The City's consultants evaluation concluded as follows: "...PSE['s] needs assessment was overall very thorough and applied methods considered to be the industry standard for planning of this nature. Based on the information that the needs assessment contains, I concur with the conclusion that there is a transmission capacity deficiency in PSE's system on the Eastside that requires attention in the near future." (DeClerck, Review Memo by Stantec Consulting Services Inc., July 31, 2015).

placed at a new substation site near the center of the Eastside, referred to as the Richards Creek substation. Electrical power would be transmitted to the new substation and the voltage lowered, or “stepped down” (transformed), from 230 kV to 115 kV for distribution to local customers. In sum, and as confirmed by independent experts, all of the proposed Project components will benefit all Bellevue customers by improving reliability of the entire electrical system on the Eastside.

3.7 TECHNOLOGY BEST SUITED TO MITIGATE IMPACTS TO SURROUNDING PROPERTIES

LUC 20.20.255.D.3d. Describe how the proposed facility includes technology best suited to mitigate impacts on surrounding properties.

As proposed, the Energize Eastside Project uses the existing transmission line corridor that was originally established in the late 1920s and early 1930s. By building within the existing corridor, new environmental impacts are avoided. As part of the Energize Eastside Project, PSE has also aggressively sought to mitigate impacts by reducing pole height and moving pole locations where feasible and requested by a stakeholder. Post-construction and consistent with the City’s code, PSE will fully mitigate all vegetation impacts by replanting both on and off-site. PSE is also in the process of obtaining input on pole color to limit contrast with the skyline or adjacent uses.

The Richards Creek substation location itself also gives PSE a significant mitigation opportunity. PSE is planning to replace and upgrade a culvert beneath a driveway that provides access to its existing pole yard site and proposed Richards Creek Substation. A pair of aging and undersized culverts (two side-by-side, 18-inch diameter corrugated metal pipe culverts) have proven inadequate to carry the combined flow and sediment loading along the stream. Construction associated with proposed culvert replacement and stream realignment will result in temporary disturbance to the stream, wetlands, and associated buffers, but will also result in net habitat benefits following project implementation. Significantly, fish passage will be greatly improved following the culvert replacement.

4.0 COMMUNITY OUTREACH CONDUCTED

LUC 20.20.255.D.4: Upon submittal of the Conditional Use Permit application required pursuant to subsection C of this section, the applicant shall provide a description of all methods of community outreach or involvement conducted by the applicant prior to selecting a preferred site for the proposed electrical utility facility.

The Energize Eastside Project was designed specifically to address system reliability deficits identified in multiple PSE and independent review studies. Overall, the Eastside's electrical grid will become less reliable in the near-term during times of peak demand without an upgrade in transmission facilities from 115 kV to 230 kV. Both elements of the South Bellevue Segment (Richards Creek Substation and the associated 3.3 miles of 230 kV transmission line upgrade) are designed to implement this change and improve reliability.

4.1 PSE HAS FULLY ENGAGED THE PUBLIC IN EVALUATING ENERGIZE EASTSIDE PROJECT ALTERNATIVES

Since launching the Energize Eastside Project in December 2013 and consistent with LUC 20.20.255.D.4, PSE has engaged the Eastside community in a robust public involvement process. This process has included mailings, public meetings and direct outreach efforts to ensure that stakeholders are informed about the project and have had plentiful and diverse opportunities to participate. PSE's public involvement process, especially with regards to routing, goes well beyond environmental review and permitting requirements, including a year-long route selection process with a Community Advisory Group (CAG).

To date, public outreach, and involvement has included:

- **22** CAG-related meetings, including **6** public open houses, **2** question and answer sessions, and **2** online open houses at key project milestones
- **500+** briefings with individuals, neighborhoods, cities and other stakeholder groups
- More than **2,900** comments and questions received
- **30+** email updates to more than **1,500** subscribers
- **8** project newsletters to **55,000+** households
- Ongoing outreach to **500+** property owners, including door-to-door and individual meetings
- Participation in **16** EIS-related public meetings

In addition, PSE's Energize Eastside website (https://energizeeastside.com) provides project updates and functions as a repository for project materials, including maps, technical studies, the CAG Final Report, fact sheets, newsletters, meeting summaries and other materials. An overview of the public engagement process is provided in the following sections.

4.1.1 PHASE 1: PUBLIC ROUTE DISCUSSION (2014)

To analyze and narrow the potential route alternatives to a reasonable number to study in detail and remove routes with considerable constraints, PSE engaged the CAG in 2014 to consider community values when evaluating the route options. The advisory group was comprised of representatives from various interests within the study area, including potentially affected neighborhood organizations, cities, schools, social service organizations, major commercial users, economic development groups, and other interests. The advisory group spent a year learning about the Eastside's electrical system, participating in meetings and workshops and evaluating 18 route options identified by PSE using a Linear Routing Tool (see Section 2.2 for discussion).. The advisory group looked at the factors used to develop different route options, narrowed the route options based on values and constraints, and prepared route option recommendations for further consideration.

In addition to the CAG, PSE involved the community through public meetings, neighborhood meetings, briefings and comments, which provided Eastside residents opportunities to share their community values and ask initial questions about the project. The details about the advisory group process can be found in the Community Advisory Group Final Report (2015) (Attachment D).

4.1.2 PHASE 2: FIELDWORK AND ENVIRONMENTAL REVIEW (2015 – 2018)

In 2015, PSE began collecting field information necessary for design and environmental review. PSE kept stakeholders informed about these fieldwork activities to ensure residents knew when crews were expected to perform surveys near their homes and businesses.

In 2015, the City began its review under the State Environmental Policy Act (discussed in greater detail below). The City of Bellevue is leading the EIS process in cooperation with Newcastle, Kirkland, Redmond and Renton.

PSE has provided supplemental EIS notifications about major milestones and comment periods to keep stakeholders informed and to support community engagement in addition to those provided by the City of Bellevue and other jurisdictions. PSE has also participated in eight scoping meetings and eight draft EIS hearings over the two-phased EIS process where input on EIS alternative solutions and route options was solicited from the public.

4.1.3 PHASE 3: PROPERTY-OWNER CONSULTATIONS (2016 – TODAY)

As project design progressed, PSE began reaching out to individual property owners to share information and answer questions. In spring 2016, the project team visited neighborhoods along the existing corridor and Factoria area to talk with residents and business owners about the project. This door-to-door outreach was conducted to help inform customers about the project status and to address questions and concerns from property and business owners.

In September 2016, PSE began meeting with property owners and tenants along the existing corridor to discuss property-specific design and tree replacement plans. We shared our current design for that specific property, including pole locations and how we plan to access those locations during construction. These conversations have helped us refine our project design and better understand customer interests and concerns.

In May 2017, PSE began meeting with property owners to begin developing property-specific landscaping and tree replacement plans with property owners. We are currently reaching out to affected property owners about these efforts.

Input received through the CAG process, neighborhood and stakeholder briefings, the Environmental Impact Statement process, one-on-one property owner meetings, and the nearly 3,000 comments and questions received to date has helped to shape the Energize Eastside Project and PSE's decision making.

4.2 STATE ENVIRONMENTAL POLICY ACT REVIEW

The City rigorously evaluated the Energize Eastside Project, including the South Bellevue Segment, under the State Environmental Policy Act (SEPA). In conjunction with the cities of Redmond, Kirkland, Renton, and Newcastle, the City published a Phase 1 and Phase 2 Draft Environmental Impact Statement (DEIS). These documents can be found online at http://www.energizeeastsideeis.org/.

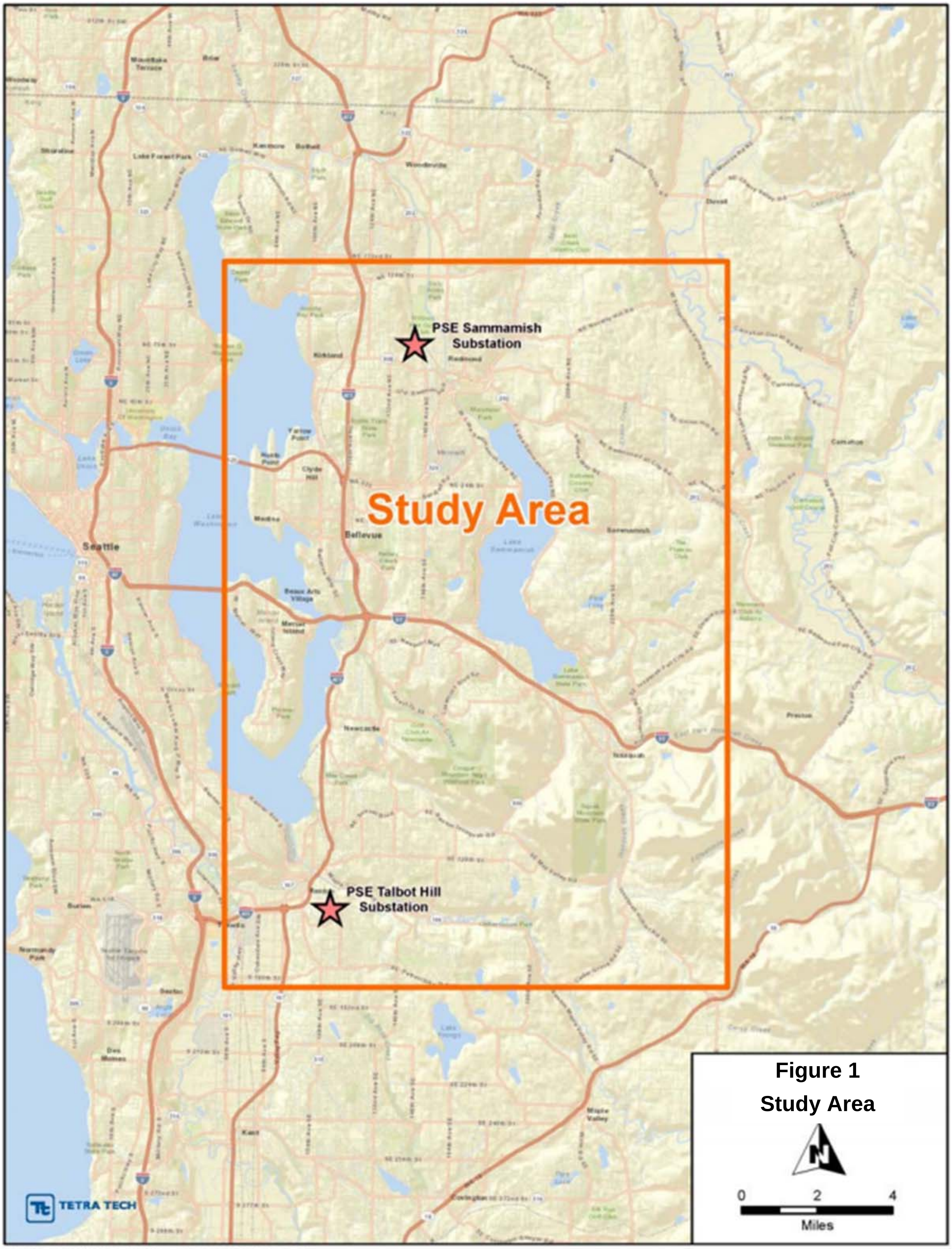
The Phase 1 DEIS contained a programmatic review of project alternatives including analysis of the feasibility of an overhead transmission line (such as the one currently proposed), use of the Seattle City Light transmission system, the construction of underwater transmission lines, and an integrated resource approach (i.e., employing non-transmission line technologies such as additional aggressive conservation and demand response technologies, new distributed generation facilities, and/or energy storage systems). *See Phase 1 DEIS*, Ch. 2. A thorough analysis of all project alternatives relative to defined project objectives (e.g., meeting demand growth and being environmentally acceptable to impacted cities), resulted in a narrowing of reasonable alternatives to an overhead transmission solution.

The Phase 2 DEIS contains the City's focused review of overhead transmission line route alternatives and impacts. It contains a detailed analysis of six route segments and seven route options within those segments. The Phase 2 DEIS analyzes four different routing options in the South Bellevue Segment. *See* Attachment B (comparing environmental impacts of each of the four South Bellevue Segment alternatives). Ultimately, PSE deviated from its originally preferred route in South Bellevue and chose to move forward with a plan to build its proposed system upgrades in the existing transmission line corridor. This route is the least impactful (particularly because it minimizes *new* environmental impacts) and prioritizes safety by limiting the potential for interactions with Olympic's petroleum pipelines.

5.0 CONCLUSION

PSE has selected the Richards Creek substation site and the Willow 1 transmission line corridor as the site for the Energize Eastside Project. The substation site is owned by PSE and is located in an industrial area adjacent to the existing PSE Lakeside 115 kV substation. The Willow 1 route uses an existing transmission line corridor that has been in operation since late 1920s and early 1930s. By using this substation site and corridor, additional easements or properties are not required. Even though the existing vegetation within the corridor is managed, which includes trimming and periodic removal, conversion of the existing transmission lines from 115 kV to 230 kV requires removal of taller growing tree species in order to meet federal vegetation management standards (NERC FAC-003). By using the existing corridor, the fewest number of trees will need to be removed. The use of the Willow 1 route combined with optimized transmission line design and 230/230 kV operation, allows for the lowest potential AC interaction with the two petroleum pipelines that share the corridor. These are the key factors that make Richards Creek substation site and the Willow 1 transmission line route the preferred alternative for Energize Eastside.

ATTACHMENT A
Figures



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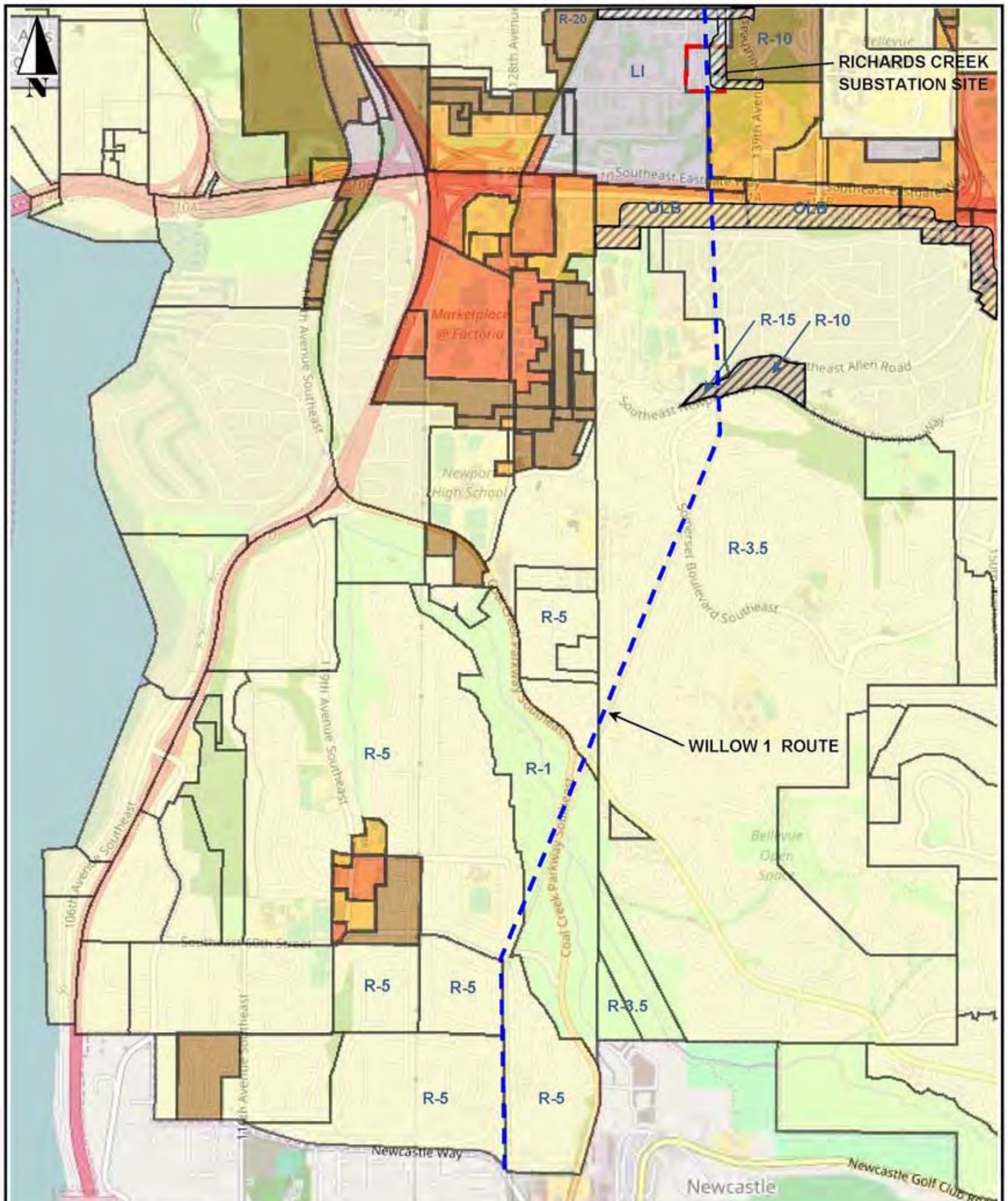
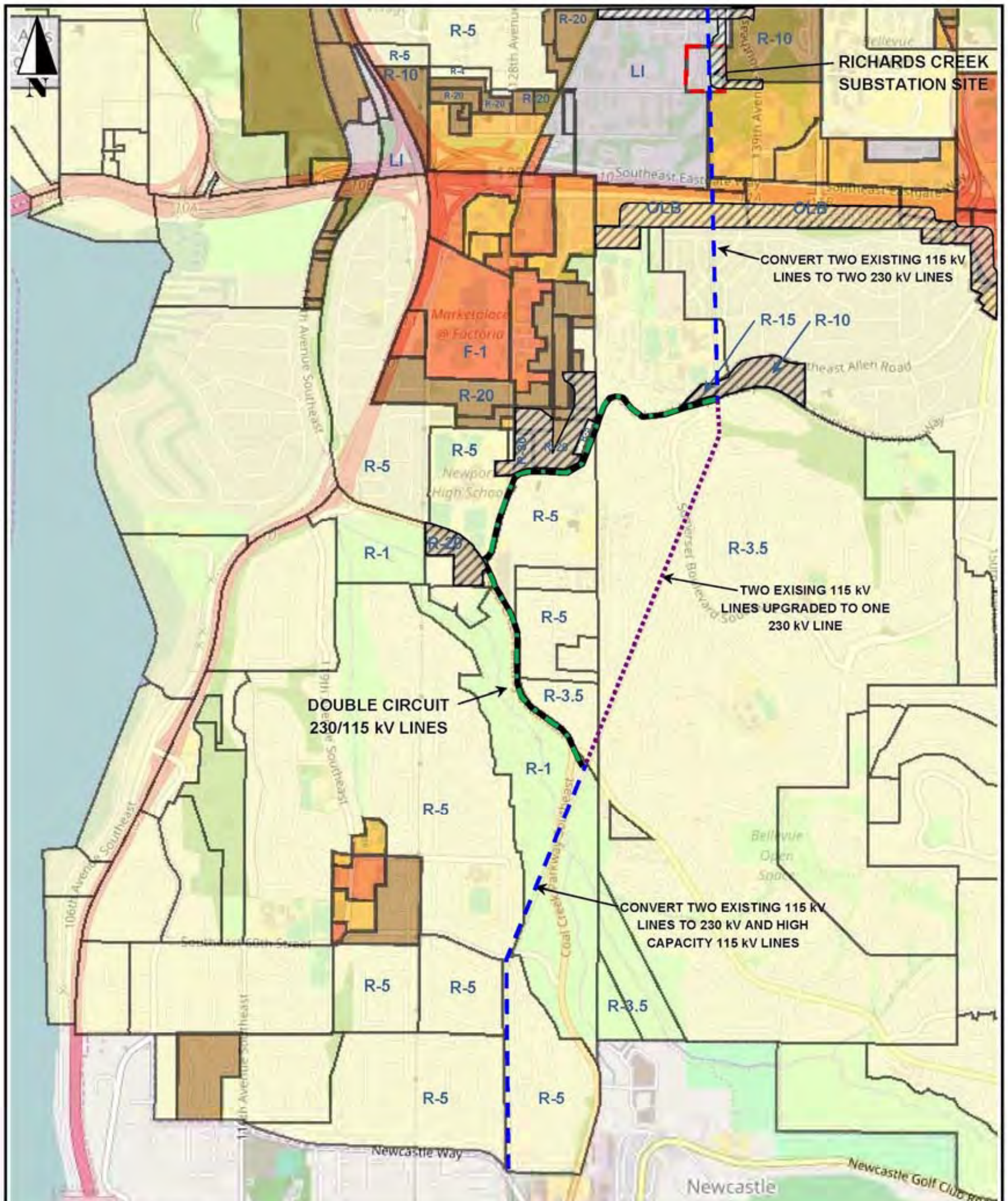


OLB—Office and Limited Business
LI — Light Industrial
R-1 through 7.5—Single Family Residential
R-10 through 15—Multi Family Residential
Transition Area (crossed by route)

FIGURE 2 ZONING

WILLOW 1—SOUTH PHASE

(Bellevue/Newcastle Line to Richards Creek)

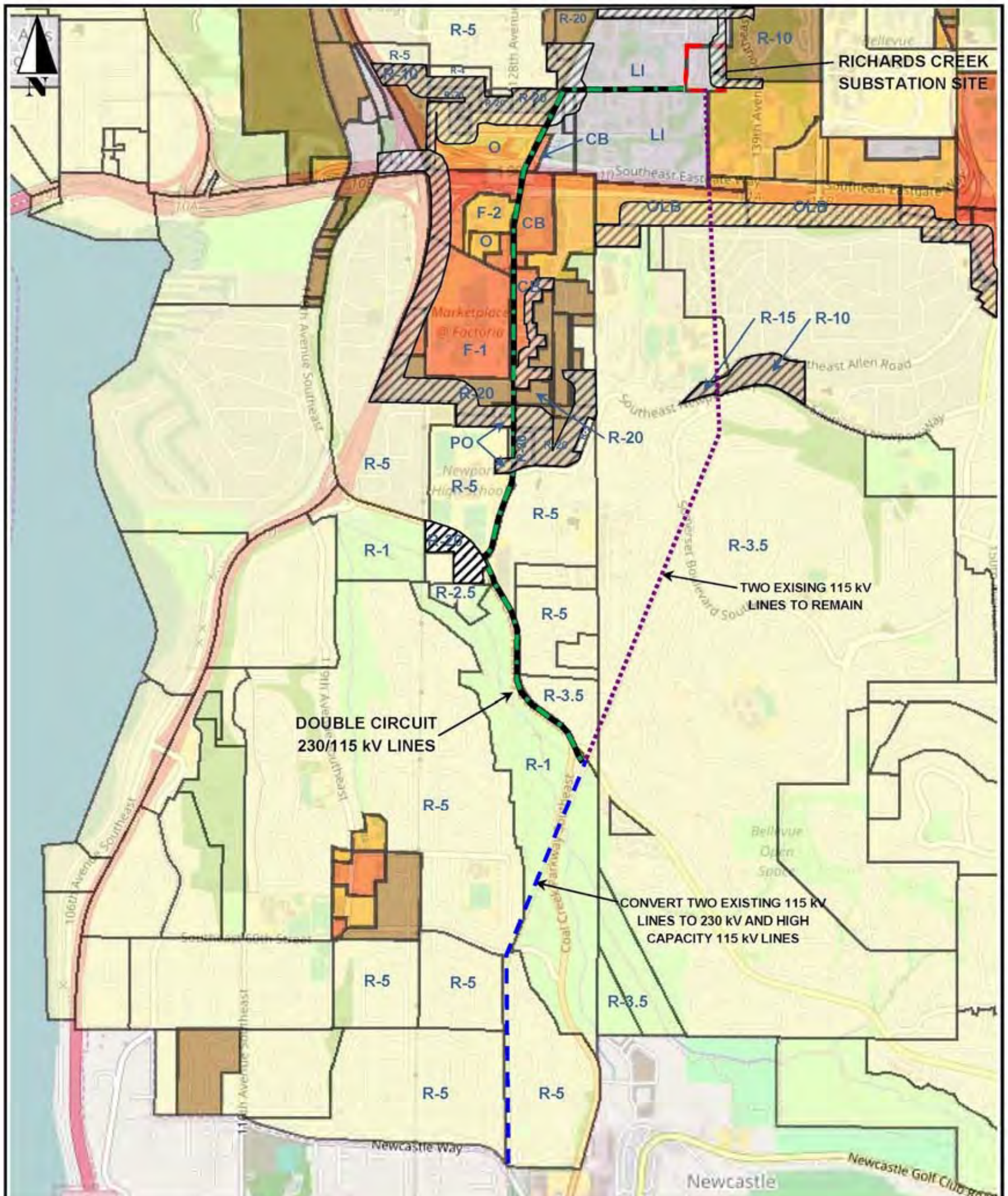


OLB—Office and Limited Business
LI — Light Industrial
R-1 through 7.5—Single Family Residential
R-10 through 15—Multi Family Residential
Transition Area (crossed by route)

FIGURE 3 ZONING

WILLOW 2—SOUTH PHASE

(Bellevue/Newcastle Line to Richards Creek)

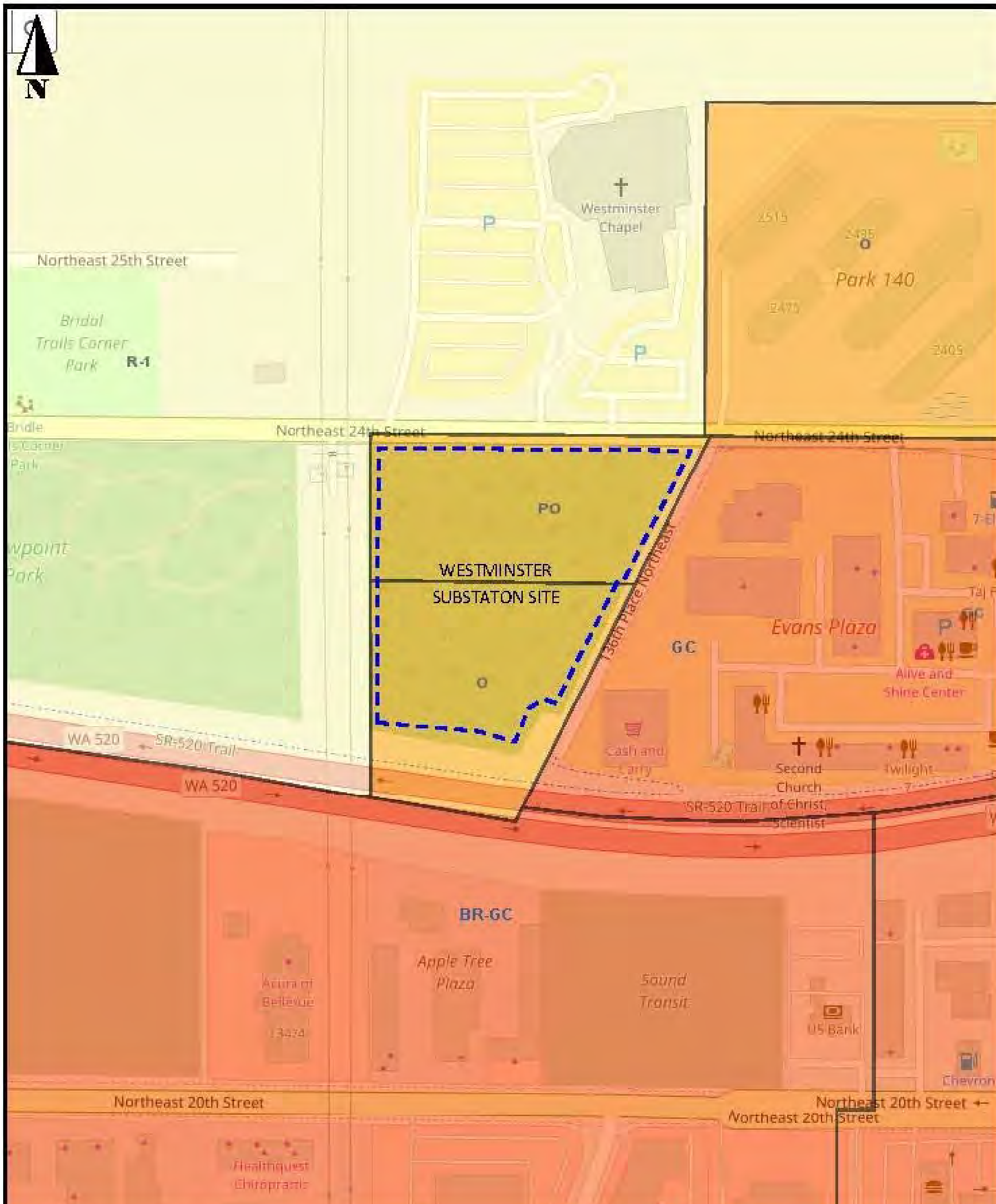


OLB—Office and Limited Business
LI — Light Industrial
R-1 through 7.5—Single Family Residential
R-10 through 15—Multi Family Residential
Transition Area (crossed by route)

FIGURE 4 ZONING

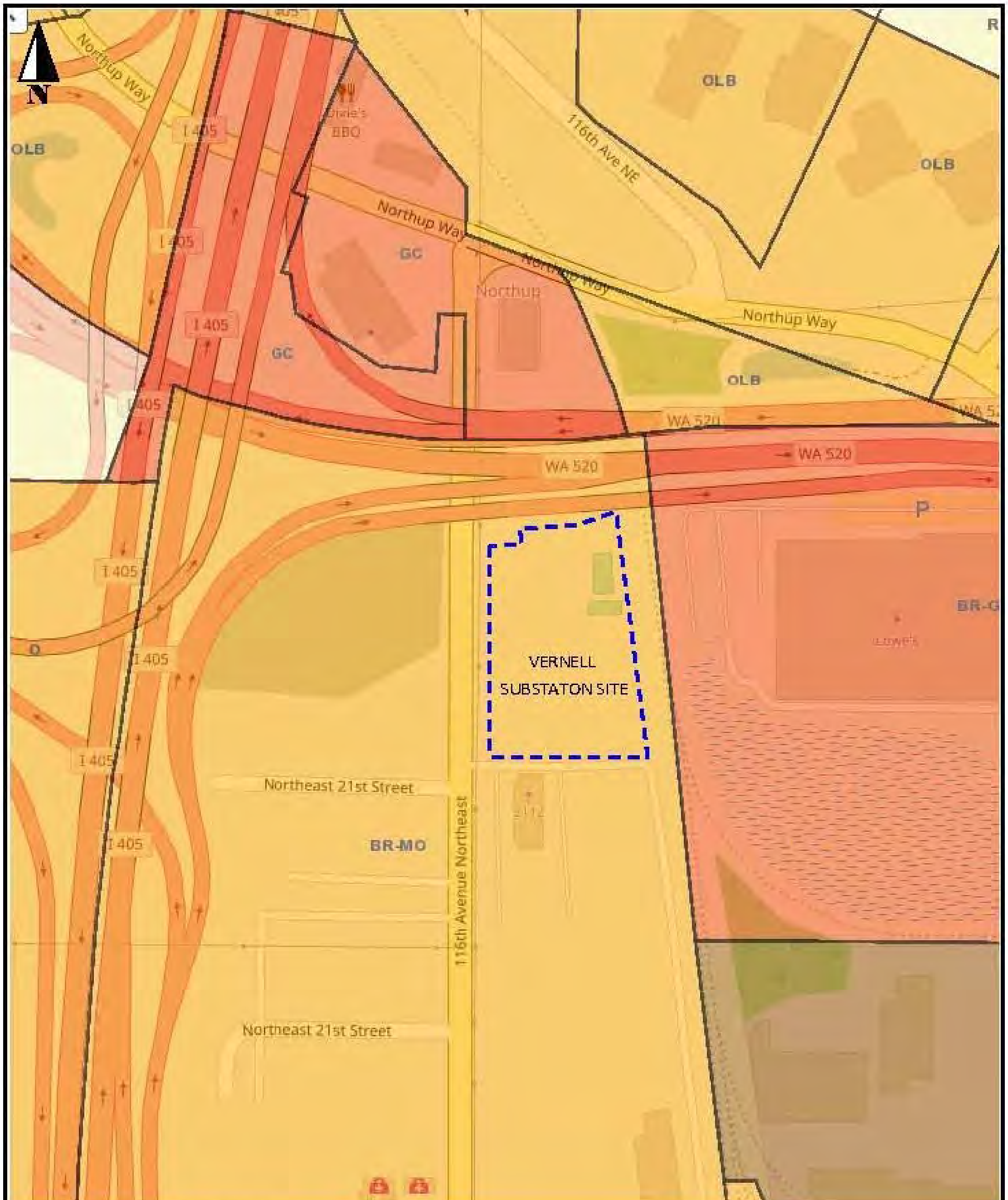
OAK 1—SOUTH PHASE

(Bellevue/Newcastle Line to Richards Creek)



PO—Professional Office
O-Office
BR-GC—Bel-Red General Commercial
GC—General Commercial
R-1—Single Family Residential Estate

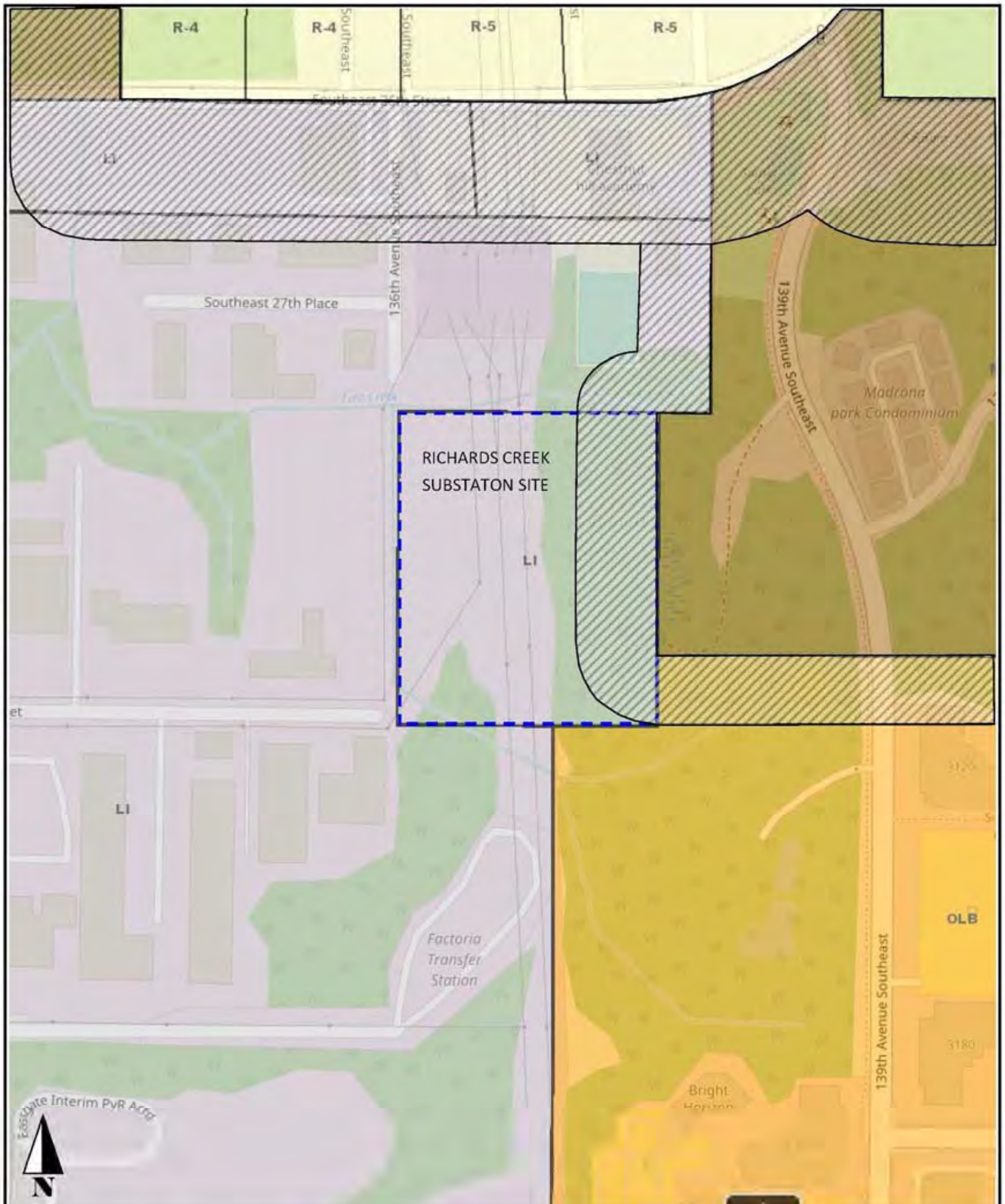
FIGURE 5 ZONING
WESTMINSTER SUBSTATION SITE



BR-MO—Bel-Red Medial Office
BR-GC—Bel-Red General Commercial
GC—General Commercial
O—Office
OLB—Office and Limited Business

FIGURE 6 ZONING

VERNELL SUBSTATION SITE



LI—Light Industrial
OLB—Office and Limited Business
R-4, 5, 10—Single-Family Residential
Transition Area

FIGURE 7 ZONING

RICHARDS CREEK SUBSTATION SITE

ATTACHMENT B
Phase 2 DEIS Impact Table

Potential Impact Table from Phase 2 DEIS

BELLEVUE SOUTH OPTIONS

POTENTIAL IMPACT	OAK 1	OAK 2	WILLOW 1	WILLOW 2 *PSE's Preferred Alignment*
LAND USE				
Potential inconsistencies with plans and policies	Consistent	Inconsistent	Consistent	Inconsistent
New easements needed for new corridor	New Easements Needed	New Easements Needed	No New Easements	New Easements Needed
Shoreline of the state	Not a Shoreline	Not a Shoreline	Not a Shoreline	Not a Shoreline
SCENIC VIEWS & AESTHETIC ENVIRONMENT				
Impacts to visual quality	Low Potential	Low Potential	High Potential	Low Potential
Impacts to scenic views	Low Potential	Low Potential	Moderate Potential	Low Potential
Viewer sensitivity	Moderate	Moderate/High	High	Moderate/High
WATER				
Stream and buffer impacts	Minor Impacts New Stream Crossings	Minor Impacts New Stream Crossings	Minor Impacts No New Stream Crossings	Minor Impacts New Stream Crossings
Wetland and buffer impacts	Minor Impacts New Buffer Impacts	Minor Impacts New Stream Crossings	Minor Impacts No New Stream Crossings	Benefit Fewer Poles in Buffers
Shoreline management impacts	No Impacts	No Impacts	No Impacts	No Impacts
PLANTS AND ANIMALS				
Total trees removed	1,040 Trees	1,610 Trees	1,030 Trees	1,660 Trees
Significant trees removed	670 Trees	1,066 Trees	450 Trees	970 Trees
Trees removed in critical areas	2 Trees	3 Trees	4 Trees	4 Trees
GHG (METRIC TONS OF CO2e/YEAR)				
GHGs from sequestration loss	20 MT	28 MT	14 MT	27 MT
Fugitive loss of SF6 from new gas-insulated substation equipment	75 MT	75 MT	75 MT	75 MT
Total GHG losses	132 MT	140 MT	126 MT	139 MT
RECREATION				
Trees removed at recreation sites	140 Trees	195 Trees	95 Trees	190 Trees
New easements at recreation sites	New Easements Needed	New Easements Needed	No New Easements	New Easements Needed
HISTORIC & CULTURAL RESOURCES				
Sensitivity for unrecorded resources	Very Low Potential	Very Low Potential	Very Low Potential	Very Low Potential
New easements needed (potential for unrecorded resources)	New Easements Needed	New Easements Needed	No New Easements	New Easements Needed
Underground work proposed (potential for unrecorded resources)	Yes	Yes	No	No
ECONOMICS				
Loss of ecosystem services through tree removal (e.g., carbon storage, stormwater runoff, etc.)	1,040 Trees	1,610 Trees	1,030 Trees	1,660 Trees
EMF (MILLIGUASS OR mG)				
Calculated magnetic field levels (maximum)	88-174 mG	27-157 mG	41-88 mG	53-157 mG
Calculated magnetic field levels (edge of right-of-way)	62-127 mG	23-96 mG	38-62 mG	40-92 mG
PIPELINE SAFETY				
Risk to pipeline safety	No Substantial Change in Risk	No Substantial Change in Risk	No Substantial Change in Risk	No Substantial Change in Risk
Miles of co-location	3.2 Miles (20" pipeline) 3.3 Miles (16" pipeline)	5.3 Miles (20" pipeline) 3.3 Miles (16" pipeline)	1.2 Miles (20" pipeline) 3.3 Miles (16" pipeline)	2.1 Miles (20" pipeline) 3.3 Miles (16" pipeline)

- No or Negligible Adverse Impact (in some cases, beneficial)
- Potential Impact but Not Considered Significant (or can be mitigated)
- Potentially Significant Impact

energize EASTSIDE EIS Environmental Impact Statement

ATTACHMENT C
Supporting Studies

Eastside 230 kV Project
Constraint and Opportunity Study
for Linear Site Selection

Prepared for

Puget Sound Energy

Prepared by

Tetra Tech, Inc.
19801 North Creek Parkway
Bothell, WA 98011

December 2013

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1. Executive Summary

PSE's System Planning evaluated a variety of options for addressing the Eastside's growing energy needs including conservation, local generation, and infrastructure improvements (e.g., transmission lines and substations). They found that even with aggressive conservation efforts, demand will outstrip supply in a few years. Additionally, local generation would be difficult to execute in a timely manner and ultimately would not meet long-term needs.

Based on PSE's technical evaluation of potential solutions, the most effective way to ensure the Eastside's power system will meet growing demand is to add a new 230 kV transmission line to connect PSE's Sammamish (Redmond) and Talbot Hill substations (Renton). With these endpoints in mind, PSE contracted with Tetra Tech, Inc. to employ a geographic information system (GIS)-based Linear Routing Tool (LRT) to conduct a broad evaluation of possible transmission line routes.

The LRT is a tool developed by Tetra Tech based on commercially available geospatial technology and Tetra Tech's linear routing experience (see Appendix A). It is a collaborative process that combines powerful analytical software with project experience, system planning, engineering, land use and local knowledge considerations. The LRT is an innovative geospatial tool that identifies the most suitable route alternatives based on modeled environmental and infrastructure factors. PSE and Tetra Tech began this process by identifying a study area of approximately 255 square miles that encompasses the Sammamish Substation in the north and the Talbot Hill Substation in the south. The study area is bounded on the west by the eastern shore of Lake Washington and extends eastward to include the BPA corridor near Soaring Eagle Regional Park (located northeast of the City of Sammamish). Any new transmission line route must connect to a new 230 kV to 115 kV transformation site within this area in order to solve the problem. Potential transformation sites within the study area include Lakeside, Westminster, and Vernell substations, which are all located in the City of Bellevue.

Tetra Tech staff collected existing available data and GIS files for land ownership, land use, public and private rights-of-way (ROW), wildlife, vegetation, threatened and endangered (T&E) species, environmentally critical areas, topography, historical resources, and other factors that would influence the location of the proposed transmission line, such as structure locations. The data collection process was designed to provide geospatial information on criteria that could represent credible baseline opportunities and/or constraints for the location of an above-ground transmission line.

A team of LRT experts, system planners, engineers, land use planners and environmental professionals (Project Team) individually weighted various data layers of the model to reflect the varying degree of constraints or opportunities for each data set. The team assigned values to the data layers using a progressive scale of values ranging from the greatest constraint, such as endangered species, residences and safety hazards, to the greatest opportunity, such as existing PSE transmission lines.

The LRT combined these data layers and created an output file called the suitability grid, which represents a summation of all the constraints and opportunities for every point (grid cell) across the entire study area. The LRT modeled preferred corridors across the suitability grid that pass through the transformation site options within the study area. These preferred corridors were used to develop alternative routes. To provide for more flexibility in the route analysis, each route was partitioned at the crossing points of routes to create unique segments. Each unique LRT segment was validated using professional engineering judgment and available ancillary resources such as aerial photographs, to help assess whether they were feasible options. Once the segments were generated and validated, a composite score was calculated for each segment from the underlying suitability grid. A deterministic model was then used that considered more than 500 combinations of segments and transformation sites. If parallel segments (i.e., typically less than a block apart) were identified during the model evaluation, LRT scores were compared to determine which segment would be used to develop routes.

The LRT scores were used to eliminate from further consideration routes that were not considered viable options. Approximately the top five percent of the positive routes were then mapped to facilitate further discussion and evaluation.

The mapping exercise revealed that there are four general subareas, which when combined, formed a “ladder” of route alternatives. The “leg” components of the ladder comprised the north-south running routes connecting Sammamish, Talbot Hill, and one of the new transformation substations. Moving east to west between the “legs” could be accomplished by using one of the three cross-over segments or “rungs.” The only exception to this being an additional north-south segment situated in the central part of the study area, south of I-90. To simplify future discussion, each of the fourteen legs and rungs were given a unique identifier (Figure 1-1). All of the mapped segment combinations can be used to develop a route that meets the goal of connecting the Sammamish with the Talbot Hill substation, while connecting to any one of the three intermediary substations. Further route refinement will continue during the on-the-ground data collection phase and public process, culminating in the selection of a preferred route.

Table 1-1. Route Segment Composition

Vernell 248	Vernell 249	Westminster 217	Lakeside 155	Lakeside 160	Lakeside 166
A	A	A	A	A	A
B	B	C	C	C	C
F	F	D	E	E	E
H	H	F	G2	G2	J
K1	L	H	G1	I	M
K2	N	L	H	K1	N
M		N	L	L	
N			N	N	

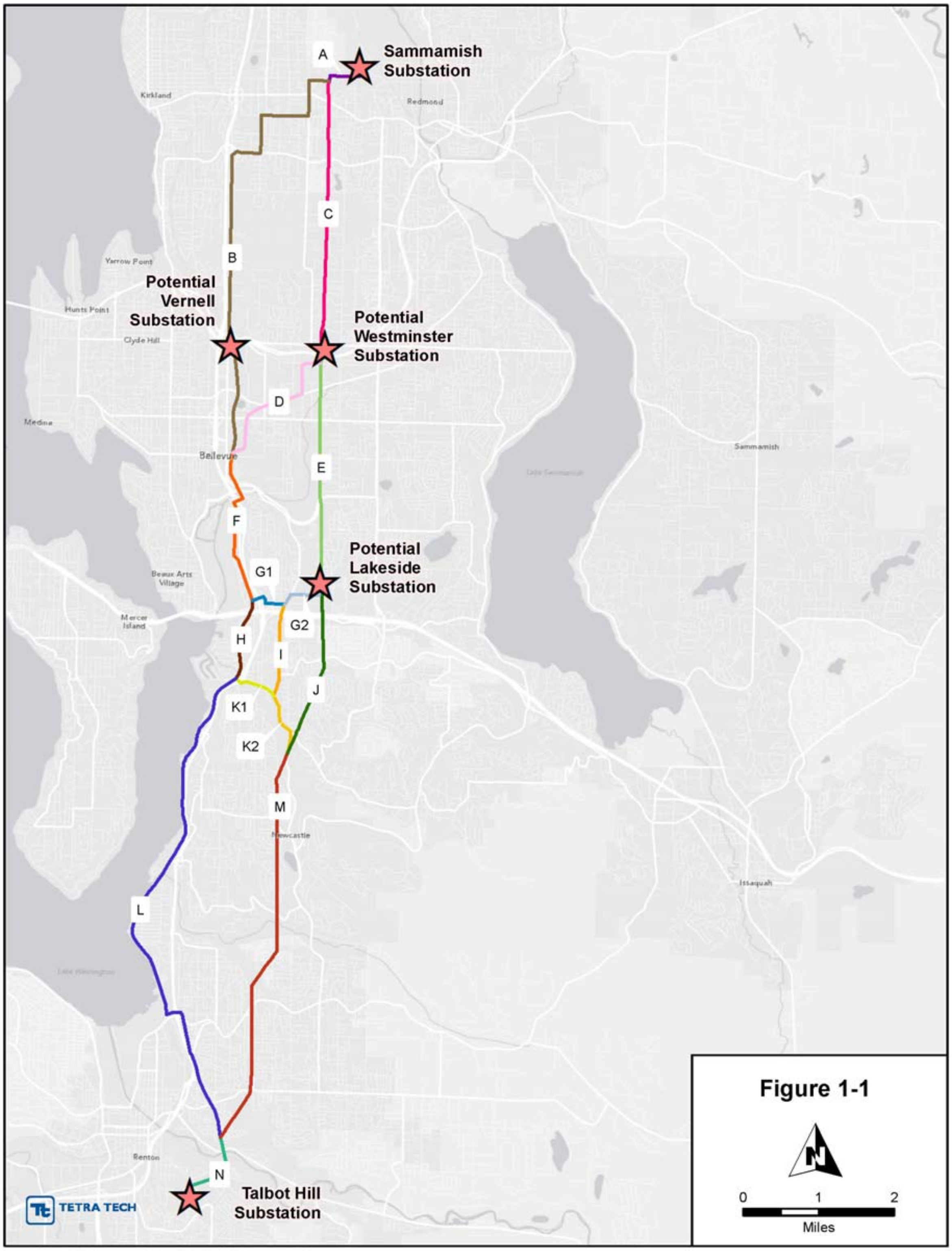

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Figure 1-1. General Corridor for Eastside 230 kV Project

2. Overview

PSE System Planning conducted a needs assessment reviewing population trends, electric load growth, economic development patterns, conservation programs, energy efficiency improvements, and other key trends pertaining to power demand. Studies reveal that different parts of the transmission system will overload, or be close to overloading, within the 10-year study period (2012-2022) and more specifically, by 2017.

PSE's System Planning evaluated a variety of options for addressing the Eastside's growing energy needs including conservation, local generation, and infrastructure improvements (e.g., transmission lines and substations). They found that even with aggressive conservation efforts, demand will outstrip supply in a few years. Additionally, local generation would be difficult to execute in a timely manner and ultimately would not meet long-term needs.

System Planning's review determined that system infrastructure improvements must be made to resolve the deficiency issue. These system infrastructure improvements will address the following issues:

- Overload of PSE electrical facilities in the Eastside Area;
- Small margin of error to manage risks from inherent load forecast uncertainties;
- Increasing use and expansion of Corrective Action Plans;
- Emerging regional impacts identified by the ColumbiaGrid.

To meet the objectives above, PSE had to first identify 230 kV sources and then identify potential transformation sites (to convert 230 kV to 115 kV for distribution) between those sources. The new transformation site will be a 230 kV to 115 kV substation. The next step was to determine a study area between the source endpoints and evaluate the possible routes to make this connection using a 230 kV transmission line (Figure 2-1).

Seeking an objective fact-based evaluation, PSE contracted with Tetra Tech, Inc. to employ a geographic information system (GIS)-based Linear Routing Tool (LRT) to conduct a broad evaluation of possible transmission line routes. The LRT is a collaborative process that combines powerful analytical software with project experience, system planning, engineering, land use and local knowledge considerations. The LRT is an innovative geospatial tool that identifies the most suitable route alternatives based on modeled environmental and infrastructure factors that are available in GIS format. The purpose of this study was to do a high-level review of significant and well known factors that affect route siting using available data in GIS format, to develop possible routes for further study.

The first steps of the LRT process were to define elements that were positive or negative for siting the proposed 230 kV transmission line and to collect the related data. These elements were defined as constraints and opportunities. GIS available data was collected for land ownership, land use, public and private rights-of-way (ROW), wildlife, vegetation, threatened and endangered (T&E) species, environmentally critical areas, topography, historical resources, and other factors that would influence the location of the proposed transmission line, such as structure locations.

With the GIS data compiled, a team of LRT experts, system planners, engineers, land use planners and environmental professionals (Project Team) individually weighted various data layers of the model to reflect the varying degree of constraints or opportunities for each data set. The LRT combined these data layers to create a suitability grid, summarizing all the constraints and opportunities for every point (grid cell) across the entire study area. This grid was used to develop suitable corridors and routes, and in turn those routes were broken down into segments. These segments were individually weighted so that more than 500 routes could be put together and mathematically considered.

The result of all this evaluation and modeling was that the top recommended segments could be combined to form five possible route options for further evaluation through public input, stakeholder review, further land use/zoning and environmental requirements review, and real estate review.

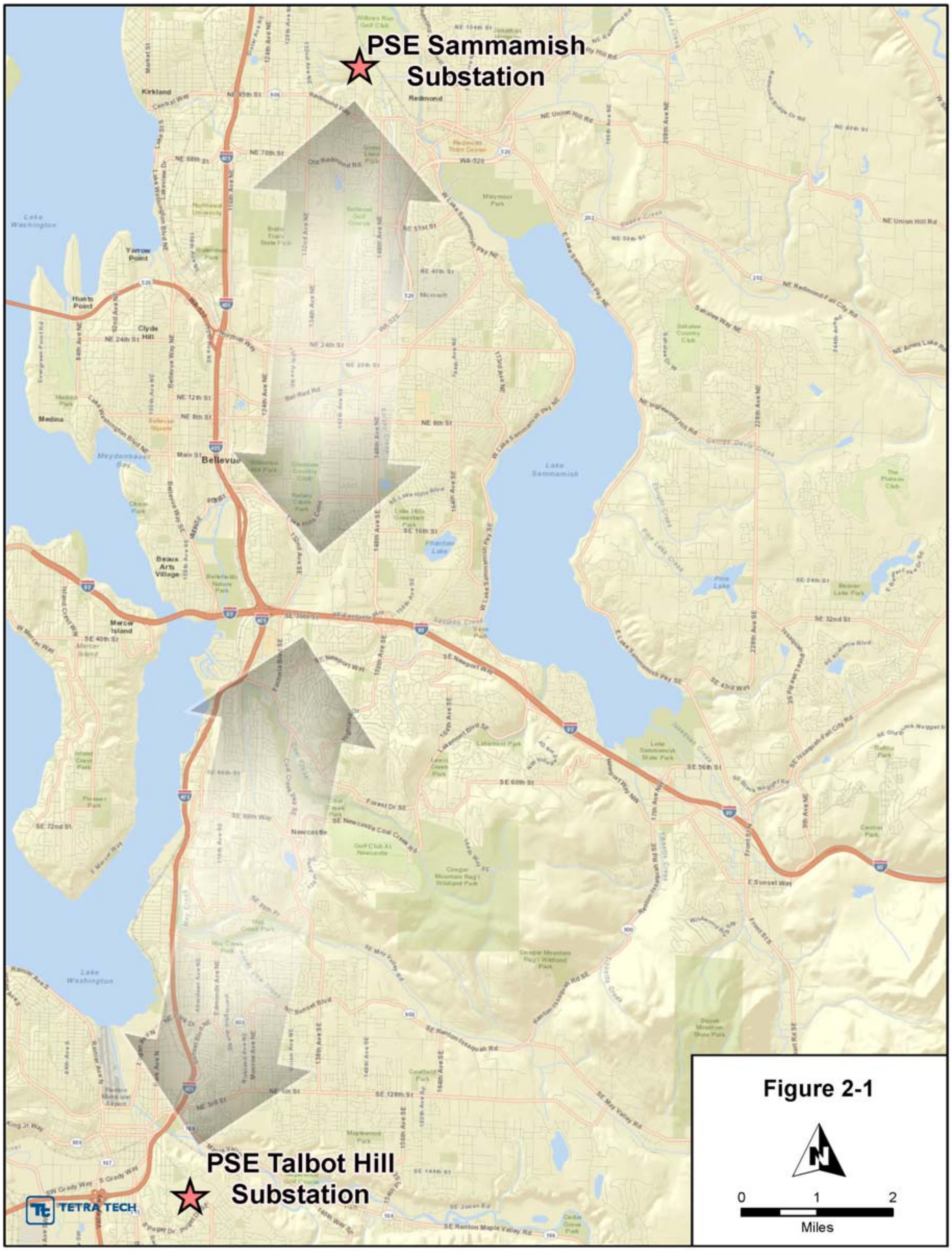

Figure 2-1. General Corridor for Eastside 230 kV Project

3. Process

The development of possible transmission line routes followed a six-step process that culminated in a set of alternatives that could be further evaluated. The steps included:

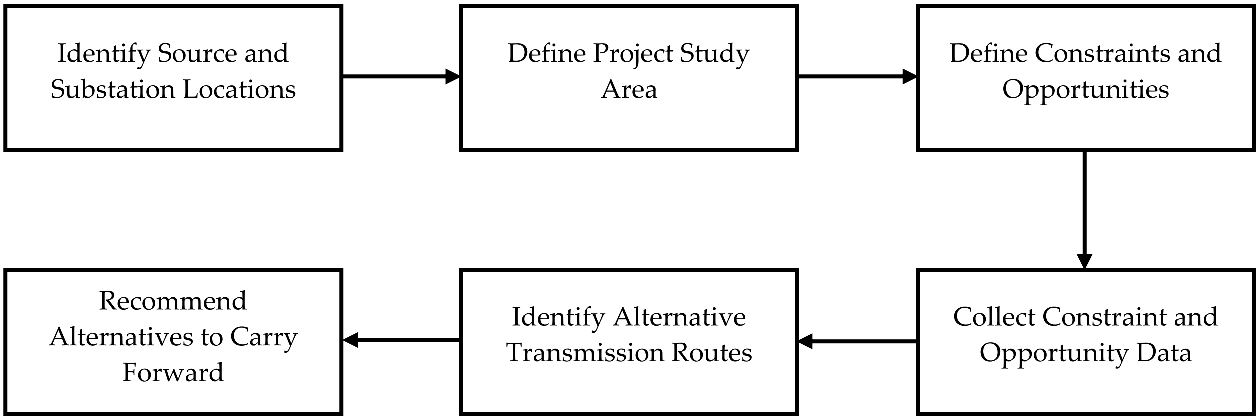

Figure 3-1. Route Development Process

3.1 IDENTIFY 230 KV SOURCE AND SUBSTATION LOCATIONS

At the beginning of the routing effort, the Sammamish and Talbot Hill Substations were defined as the 230 kV source for the project. Potential intermediate transformation (new 230 kV to 115 kV substation) sites between the Sammamish and Talbot Hill Substations were identified by PSE and used to help define the study area. The potential new transformation sites included PSE-owned property at the future Vernell and Westminster substations, and the existing Lakeside Substation. In addition, a new site referred to as Woodridge was considered based on its location. Ultimately the Lakeside, Westminster, and Vernell sites were selected as they meet the necessary minimum dimensions and are owned by PSE.

3.2 DEFINE PROJECT STUDY AREA

The next step was to establish a study area that was defined as a boundary that generally encompassed the 230 kV source substations locations and the potential routes to connect them. Therefore, the study area encompasses the Sammamish Substation in the north, the Talbot Hill Substation in the south, the eastern shore of Lake Washington in the west, and eastward to near Soaring Eagle Regional Park in King County, east of the City of Sammamish. Figure 3-2 shows the extent of the study area used during the constraint and opportunity analysis.

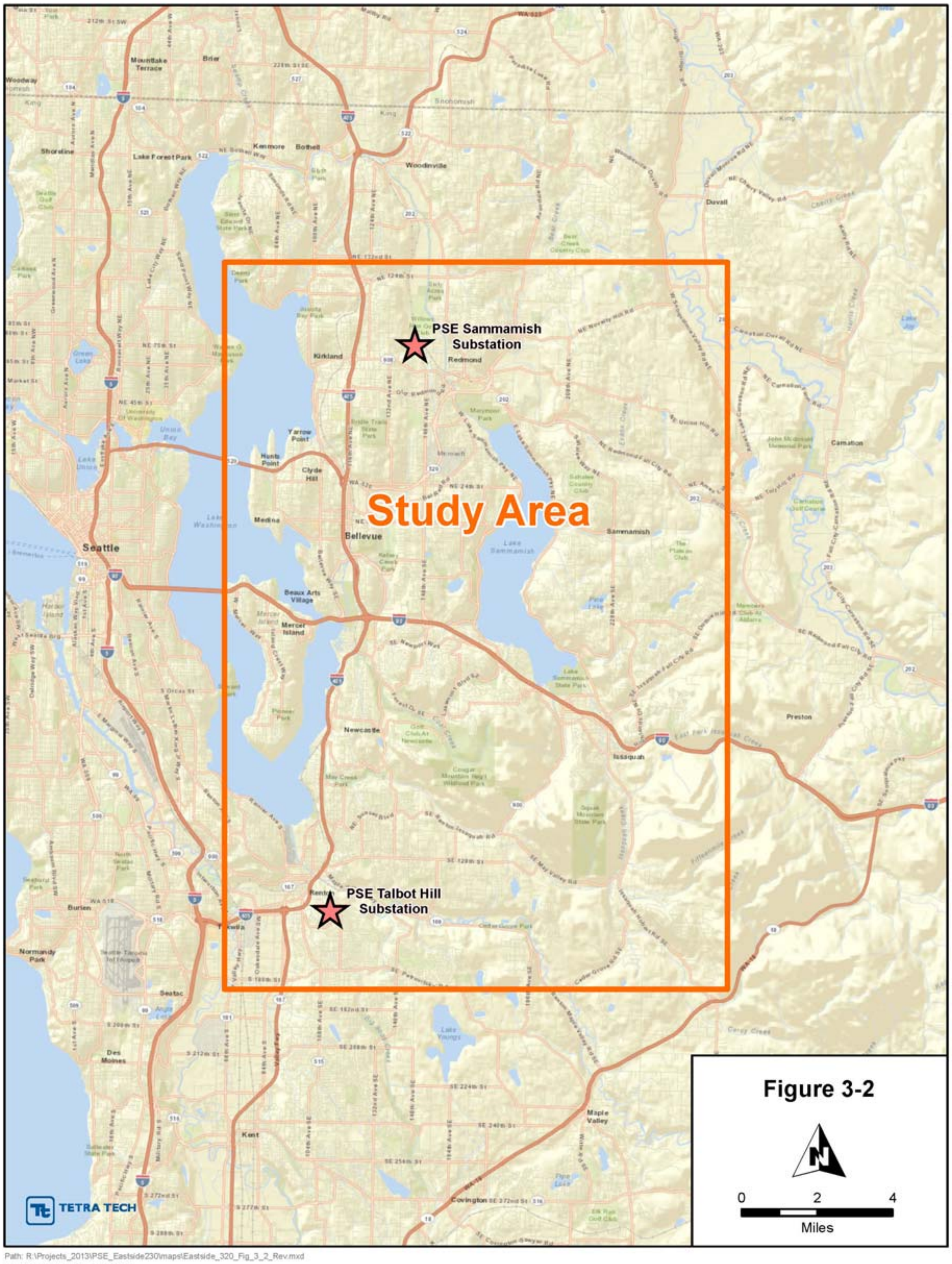

Figure 3-2. Study Area

Once the boundaries of the study area were established, the Project Team identified and delineated constraints and opportunities to siting the transmission line. Constraints are defined as resources or conditions that potentially limit project siting because of regulations or engineering requirements associated with facility construction and operation. Opportunities are defined as resources or conditions that can accommodate facility permitting, construction, or operation. The following sections describe the GIS data sets that were collected to analyze these constraints and opportunities, describe the key categories of constraint and opportunity factors in the study area based on GIS data sets, and summarize how the GIS data were processed in preparation for route development.

3.3 AVAILABLE GIS DATA BASES USED FOR CONSTRAINTS AND OPPORTUNITY ANALYSIS

Based on the defined study area, Tetra Tech collected readily available GIS data sets to use in the LRT model. Data collection was based on the constraint and opportunity factors used in the analysis. The data used in routing were subjected to a defined process of preparation and analysis before being used in the LRT as described below. Preparation of data began with the compilation of multiple layers into a geodatabase. Data layers were then quality checked and evaluated for project usefulness, including reliability and accuracy based on available maps. If the data passed the quality check, the data then went through several additional geoprocessing steps in order to be ready to input into the LRT. Where appropriate, buffer areas were added to the data based on how the feature would impact the transmission line route. These buffers were necessary to ensure line routes would not go over the top of structures, down the center of vehicular travel lanes, as well as allowing for adequate area to physically accommodate a 230 kV line. Buffers added to specific data layers are described in Section 3.6 Existing Conditions and in Table 3-1, below.

Data for the constraint and opportunity analysis were obtained from a variety of county, state, and federal GIS database sources (see Table 3-1). These GIS databases included the Washington Department of Natural Resources (WDNR), Department of Fish and Wildlife (WDFW), Department of Transportation (WSDOT), and State Parks and Recreation Commission (WSPRC); the US Fish and Wildlife Service (USFWS); the King County Assessor’s Office, Department of Development and Environmental Services (DDES), and Department of Natural Resources (DNR); and Tetra Tech. This information was supplemented by the review of aerial photography and local knowledge. The following discussion outlines specific data sets collected for this project and their sources.

Table 3-1. Analysis Attributes and Data Sources

Attribute	Data Source
Existing and Proposed Linear Corridors	
PSE transmission corridors	PSE
PSE 55 kV corridor	PSE
BPA transmission corridors	PSE
Natural gas pipeline	Photo interp. and King County
Highways and roads	King County
Arterial road corridors	Interp. of King County roads
Railroads	ESRI Streetmap, King County, Sound Transit
Abandoned rail corridor	Photo interp. and King County parcels
Land Ownership, Land Use and Special Designated Uses	
Land Ownership	
Rights-of-way	King County
Parcels	King County Assessor
Transfer of development rights	King County Assessor
BNSF Railroad parcel boundaries (active)	King County
Land Use/Future Land Use	
Structures	King County
Coal mine	King County
Renton municipal airport	Photo interp. and King County parcels
Airports clear zone	Photo interp. and analysis
Residential	King County
Special Land Use Designation	
Parks	King County
Recreational trails	King County
Scenic byways	WSDOT
Soils, Topography, and Geology	
Unspanable slope 20 to < 40%	King County LiDAR and analysis
Unspanable slope >= 40%	King County LiDAR and analysis
Slopes 20%+	King County LiDAR and analysis
Slopes 40%+	King County LiDAR and analysis
Landslide potential	WDNR
Elevation – LiDAR	King County
Water Resources	
Lakes	King County
Floodways and floodplains	King County
Wetland Resources	
Wetlands – large	USFWS, National Wetlands Inventory

Attribute	Data Source
Wetlands – SAO	King County
Wildlife	
Chinook salmon streams	USFWS
Waterfowl areas	WDFW
Great blue heron rookeries	WDFW
Bald eagle management areas	WDFW
Natural Heritage locations	WADNR
Historic Resources	
Historic register and districts	WADAHP
Historic property inventory - named	WADAHP
Heritage barns	WADAHP

Various King County agencies maintain extensive GIS databases on natural and built environment conditions within the county. Tetra Tech purchased several King County GIS data sets on DVD for use in the analysis. Many of these GIS data sets were used directly in the analysis, or processed to derive new data to represent constraints and opportunities, including the following:

- Airpark
- Airport clear zone
- Arterial road corridors
- Water pipeline corridors
- BPA substation
- Railroads and railroad corridors
- Public right-of-way
- Parcels
- Structures (based on address points)
- Residential areas
- Coal mine
- Parks
- Recreational trails
- Streams and rivers
- Lakes
- Floodways and floodplains

- Wetlands – SAO
- Historic points
- Contours
- Unspanable slope 20 to < 40%
- Unspanable slope >= 40%
- Slopes 20%+

For the purpose of this process, only data sets that were readily available and in GIS form were used. Constraints of opportunities that were not easily identified in an available GIS data set (such as cultural resources, real estate issues, electric distribution lines, or non-high pressure natural gas pipelines) were not considered for the purposes of this study, but will be evaluated in future steps.

3.4 PRIMARY GIS CATEGORIES CONSIDERED FOR CONSTRAINTS AND OPPORTUNITIES

Study area conditions applicable to the key categories of constraints and opportunities are described below, along with a description of how the data were preprocessed for analysis.

3.4.1 Utilities

3.4.1.1 Transmission

The existing PSE 115 kV corridor runs between the Sammamish substation, the Lakeside substation, and the Talbot Hill substation (Figure 3-3). Transmission line corridors owned by BPA run along the north, east and south boundaries of the study area.

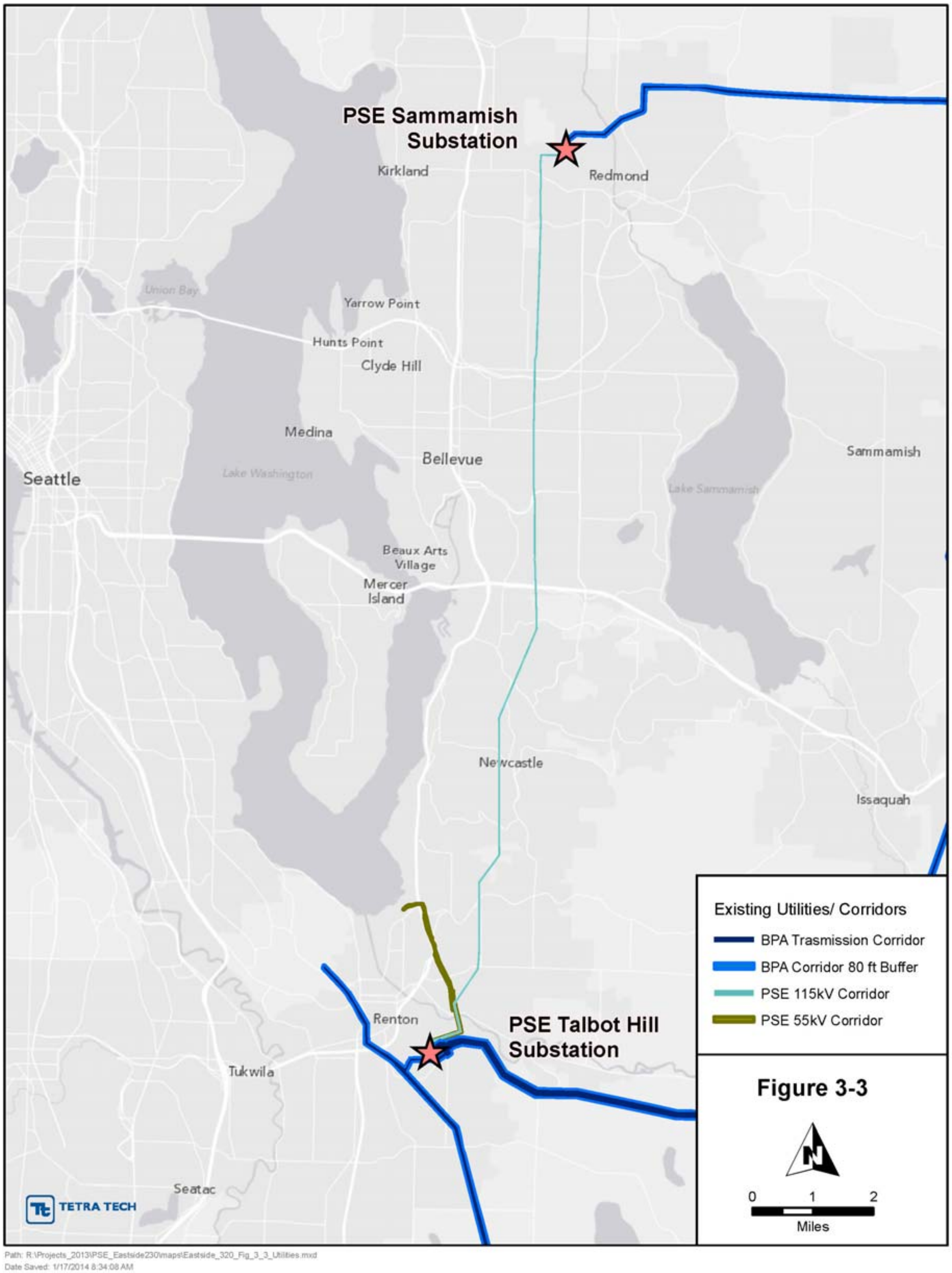

Figure 3-3. Utilities

PSE provided the locations of existing transmission corridors between the Sammamish and Talbot Hill Substations. PSE 115 kV and 55 kV transmission corridor systems were considered opportunities in the analysis. PSE's transmission system is primarily operated at 115 kV; however, a remnant 55 kV corridor still exists in the southern portion of the study area. This corridor can be upgraded to a higher voltage without a change in land use, so it was considered an opportunity. In order to accommodate the space requirements for the proposed 230 kV line, a buffer was applied to the 55 kV line corridor before including it in the analysis.

Based on past experience, BPA does not allow additional third party transmission lines within their corridors; therefore, existing BPA transmission corridors were considered a constraint. However, an 80 ft corridor (minimal area required for a transmission line) was created adjacent to BPA corridors and used in the analysis as an opportunity, since paralleling existing corridors is typically considered favorable during the permitting process.

3.4.1.2 High Pressure Natural Gas Pipeline (Northwest Pipeline)

High-pressure natural gas pipelines run along some arterial roads in the study area. The north-south trending sections potentially provide the most benefit, such as along 148th Ave. NE between NE 70th St. and Bel-Red Rd.; however, these sections are only small opportunities and do not contribute significantly to the siting analysis.

3.4.1.3 Fuel Pipeline (Olympic)

The Olympic Pipeline (fuel products) corridor is co-located with PSE's existing 115 kV corridor (between Sammamish and Talbot Hill) for most of its length in the study area. As a result, it was not included in the analysis so that the existing 115 kV corridor would not be double counted as an opportunity.

3.4.2 Transportation

3.4.2.1 Roads

The major vehicular routes through the study area are Interstate Highway 405 (I-405), I-90 and Washington State Route (SR) 520. Nineteen miles of I-405 runs north-south through the west side of the study area; I-90 runs east-west through roughly the center of the study area; and SR 520 meanders roughly east-west through the northern third of the study area (Figure 3-4). I-405 runs through the study area from Kirkland, through Bellevue, along the east side of Lake Washington, and finally through Renton in the south. I-90 runs across the north end of Mercer Island in the west, through Eastgate (Bellevue), past the southern tip of Lake Sammamish and finally through Issaquah and High Point in the east. SR 520 starts in Hunts

Point alongside Lake Washington, passes through Clyde Hill and Bellevue, and then terminates in Redmond along the northern edge of Marymoor Park. Based on past experience, the Interstate travel routes are considered impedances, as installation of transmission lines within those corridors has not been allowed. Additionally, in some locations spanning of such travel routes is restricted by WSDOT. Throughout the study area, there are several smaller state highways with similar restrictions. However, the study area is dominated with arterial roads, which are typically considered opportunities for transmission line routing. Arterial roads are often paralleled by existing transmission lines or distribution lines that can be overbuilt with transmission line, thereby affording a viable passage route through areas that have existing development.

To prepare arterial road corridors for analysis, King County's Transportation Network layer was buffered by 45 ft on either side of the road centerline. This provided the area necessary to place a 230 kV line along the roadways. A second buffer of 20 ft on both sides of the road centerline was then removed from the 45 ft buffer to create the polygons that roughly represent the buildable opportunity while excluding the paved surface. This approach was used to create an opportunity for routing along paved roadways.

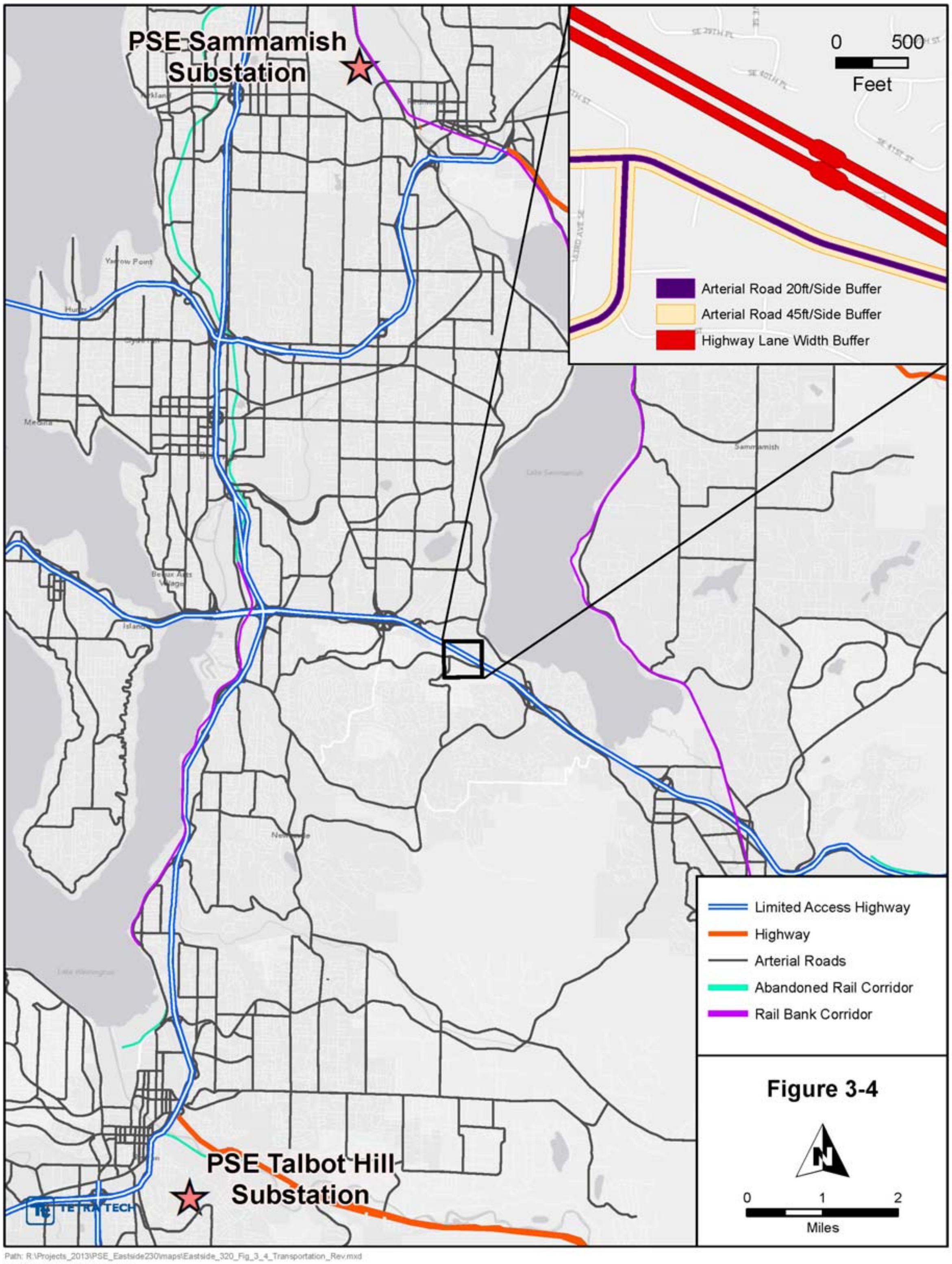

Figure 3-4. Transportation

3.4.2.2 Railroads

The Eastside Rail Corridor, which was formerly the BNSF railroad line, runs parallel to I-405 and Lake Washington in the western part of the study area. Although portions of this corridor have been mapped as "parks" lands, PSE has purchased easement rights along the majority of the corridor. This corridor offers routing opportunities for the proposed line because it is considered abandoned throughout the study area, and it runs in a north-south direction. There are some segments, such as along the southeastern edge of Lake Washington, that are also considered "rail banked," however, since this was considered only a minor impedance, the combined values of abandoned plus rail banked still leave this corridor as a relatively strong opportunity. Rail banks constitute rail corridors that can be converted to trails and other uses, while still preserving the ability to revert back to rail use under certain conditions.

Where active rail corridors existed, a 50-foot buffer was applied to provide an adjacent area of opportunity that would parallel them. For abandoned rail corridors, no buffer was applied because the corridor itself provided the opportunity.

3.4.3 Slope and Slope Stability

3.4.3.1 Slope

The topography of the study area is composed of mostly flat terrain and rolling hills separated by small valleys. The most significant topographic features running east-west are the incised drainages created by the rivers draining into Lake Washington. These include the Cedar River, May Creek, Coal Creek, and Richards Creek.

PSE design standards and experience indicate that transmission line construction on slopes greater than 20 percent is difficult, requiring special engineering measures, while slopes greater than 40 percent should be avoided. Areas with slopes greater than or equal to 20 percent were calculated from the elevation model. All slope areas greater than or equal to 20 percent were not included in the steep slope layer if at least 200 ft per slope was not present to site the transmission line. The remaining high-slope areas are wider than the standard structure span for the project, and were therefore considered "unspanable." The same process was done for slopes greater than or equal to 40 percent (Figure 3-5). If an area with a steep slope can be spanned within standard design limitations, then the slope is not considered an impediment to a specific route. Figure 3-6 explains graphically how the final result was attained.

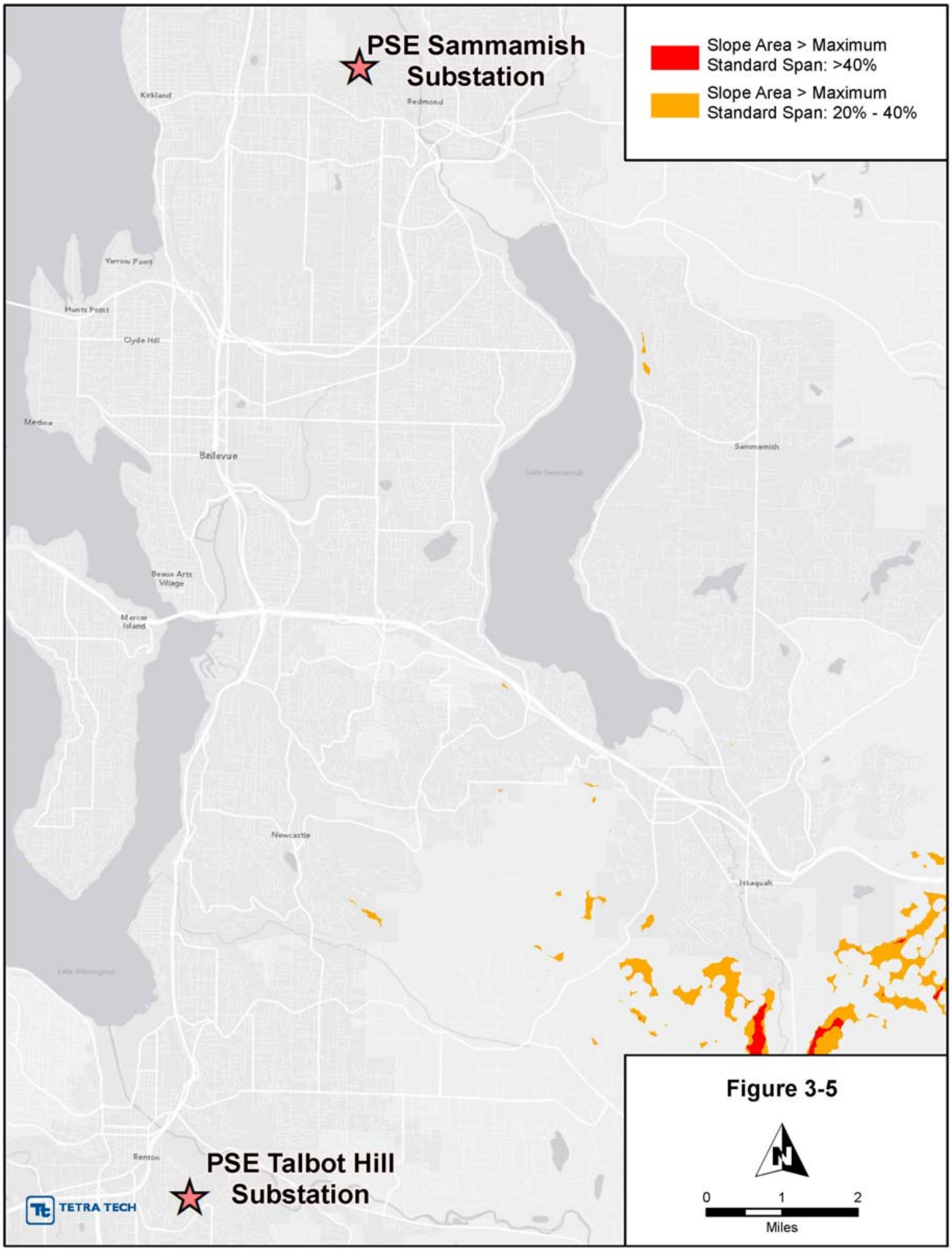

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Figure 3-5. Unspanable Slope

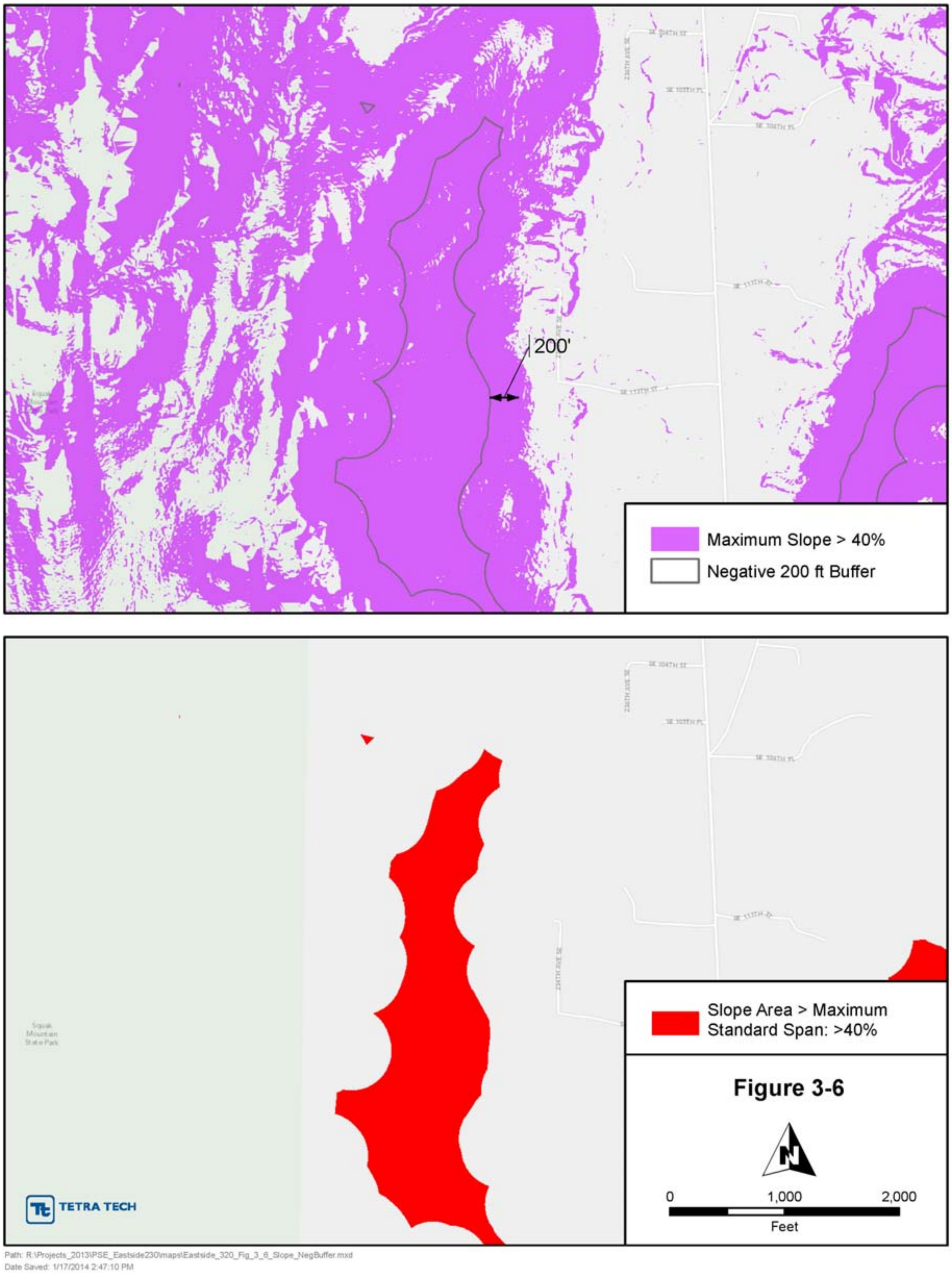

Figure 3-6. How Unspanable Slope Is Derived

3.4.3.2 Slope Stability

Figure 3-7 shows the various levels of slope stability. As shown, the large majority of land has stable slopes, including the existing PSE corridor. Areas of high instability occur mostly along valley walls. To reduce potential impacts, GIS mapped unstable slopes were avoided to the extent possible. This factor is important, especially during construction.

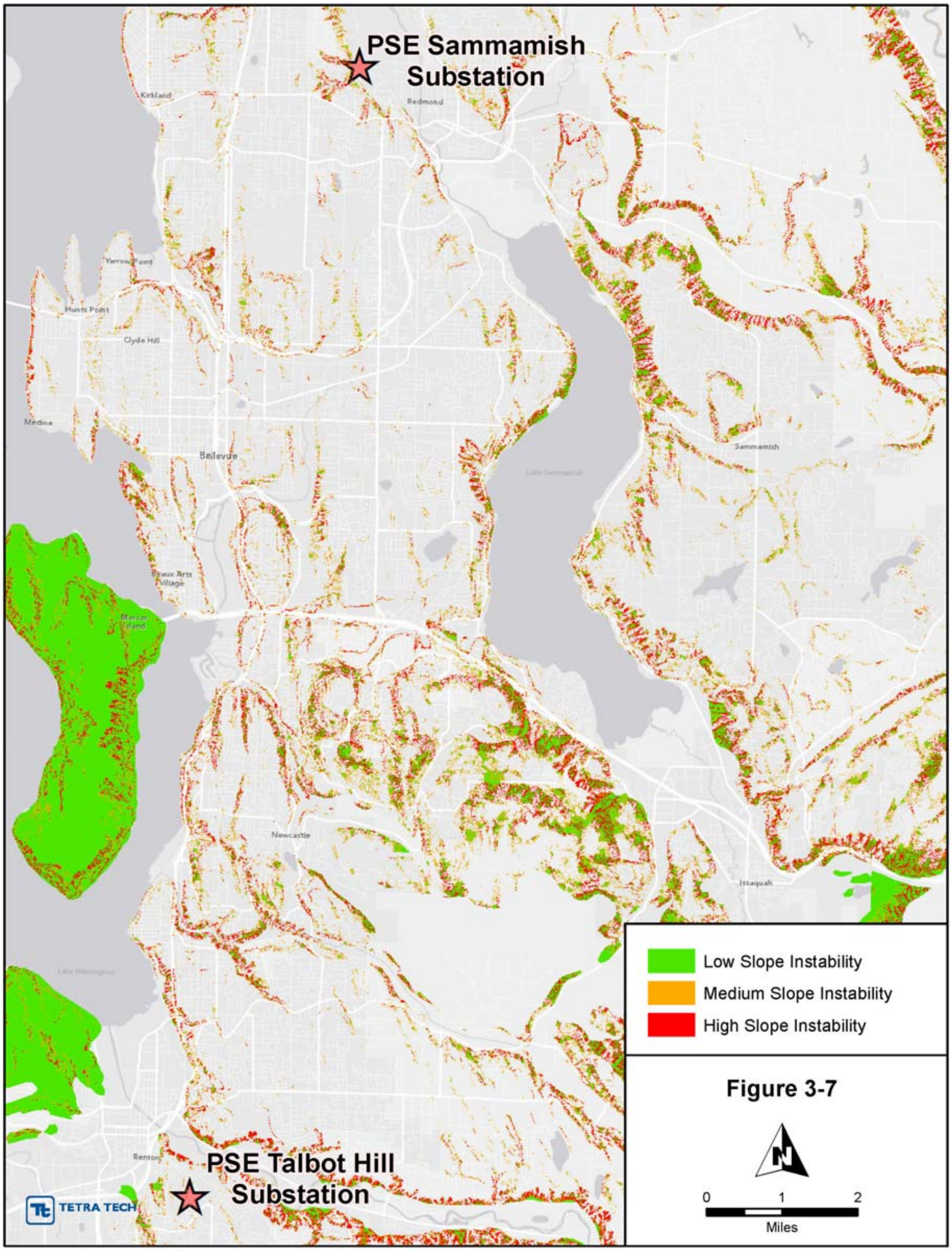

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Figure 3-7. Slope Stability

3.4.4 Habitat

3.4.4.1 Waterfowl, Heron Rookeries and Bald Eagle Management Zones

Locations of priority habitat features were acquired from the WDFW GIS database. The identified priority habitat features in the study area are waterfowl areas, great blue heron rookeries, and bald eagle management zones. WDFW has identified priority waterfowl areas at the north and south ends of Lake Sammamish, Phantom Lake, Juanita Bay (part of Lake Washington), and several smaller lakes in the region that are classified as "Lakes With Waterfowl Use." The transmission line alternatives under consideration do not cross any of these GIS features.

Great blue heron rookeries are scarce within the study area. The nearest GIS mapped rookery to any alternative is 0.3 miles away in the Mercer Slough Nature Park.

Bald eagle management zones are designated by WDFW according to current conservation guidelines, and their locations were used unaltered in the analysis. Development of any transmission line within a bald eagle management zone will be subject to review and regulation by WDFW.

3.4.4.2 Fish and Wildlife Species

Streams in the Puget Sound region that provide Chinook salmon habitat are protected under the federal Endangered Species Act (ESA) and are considered a constraint to be avoided or spanned (Figure 3-8). Data for streams with known Chinook salmon use were acquired from the U.S. Fish and Wildlife Service (USFWS) GIS database. These mapped streams can be typically be avoided or spanned.

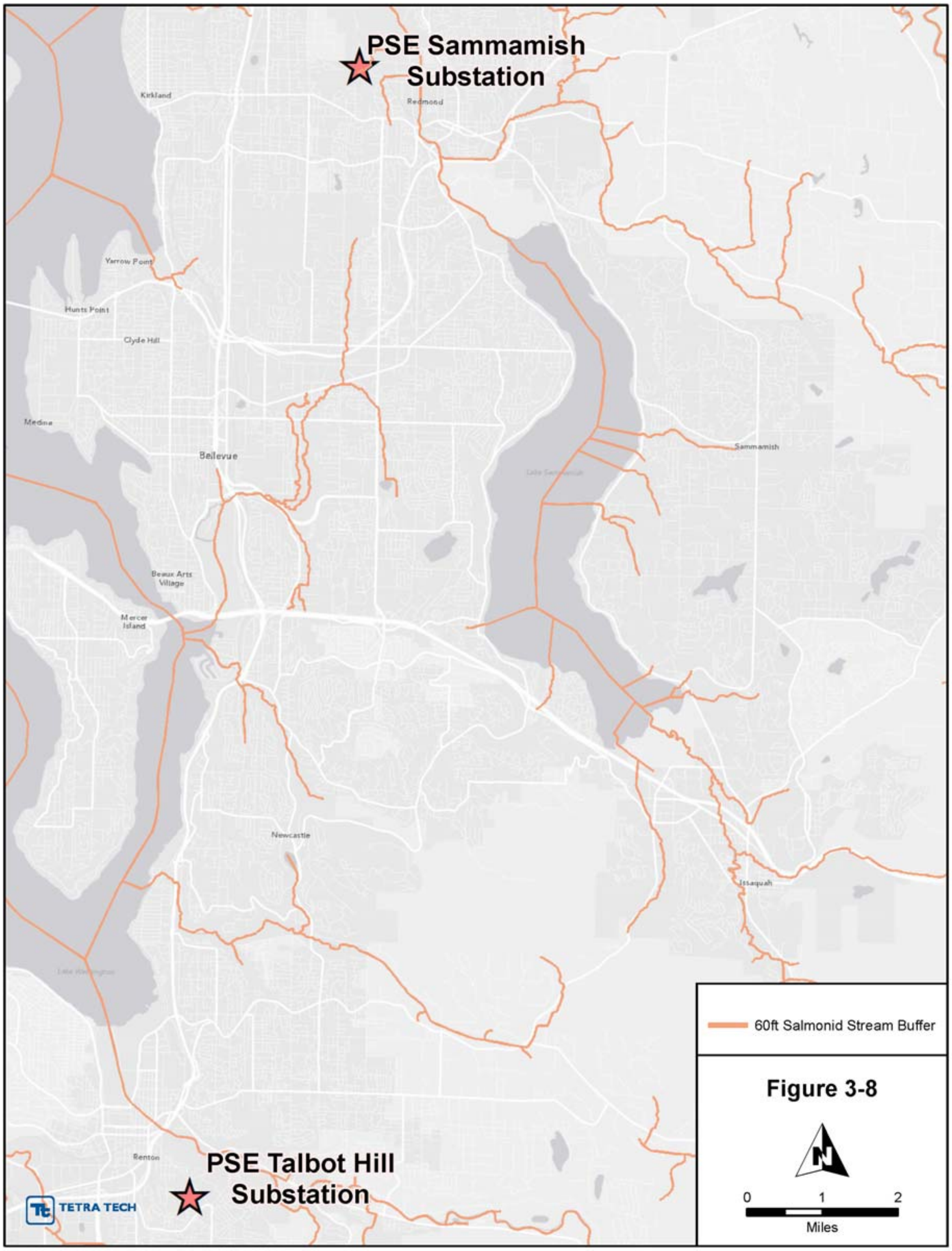

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Figure 3-8. Salmonid Streams

3.4.5 Land Ownership

The optimum location of the transmission line is across land that allows for sufficient access, such as an easement owned by PSE, as this facilitates performance of maintenance and vegetation management in accordance with applicable clearance and safety requirements. As shown on Figure 3-9, private ownership is the predominant land owner type in the study area and would be a constraint if the transmission line had to traverse it. However, it is expected that most of the line can be constructed along existing road/utility corridors or overbuilt at existing overhead electrical line structure locations on PSE easement where the setting already includes both vertical and horizontal linear transmission facilities.

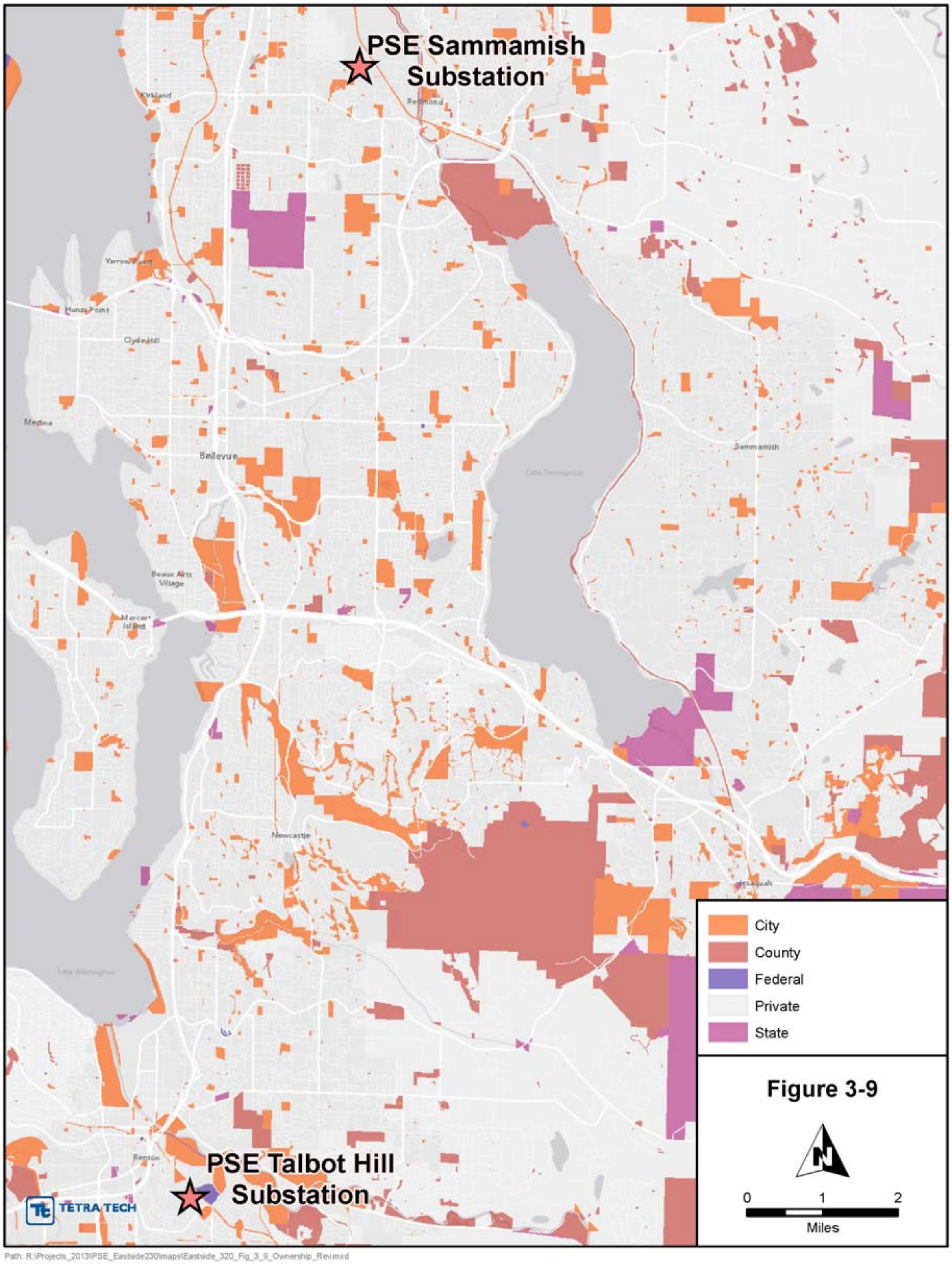

Figure 3-9. Land Ownership

3.4.6 Zoning / Land Use

Zoning and land use patterns were considered for purposes of this study based on two available GIS databases, a GIS database on current zoning (setting forth envisioned land use patterns such as agricultural, residential, commercial, etc.), and the tax assessors database based on current type of land use (commercial, residential, etc.). According to the zoning database, most of the land in the study area is zoned residential (Figure 3-10). More specific zoning and land use patterns and land use policy considerations will be evaluated in the next step of the process.

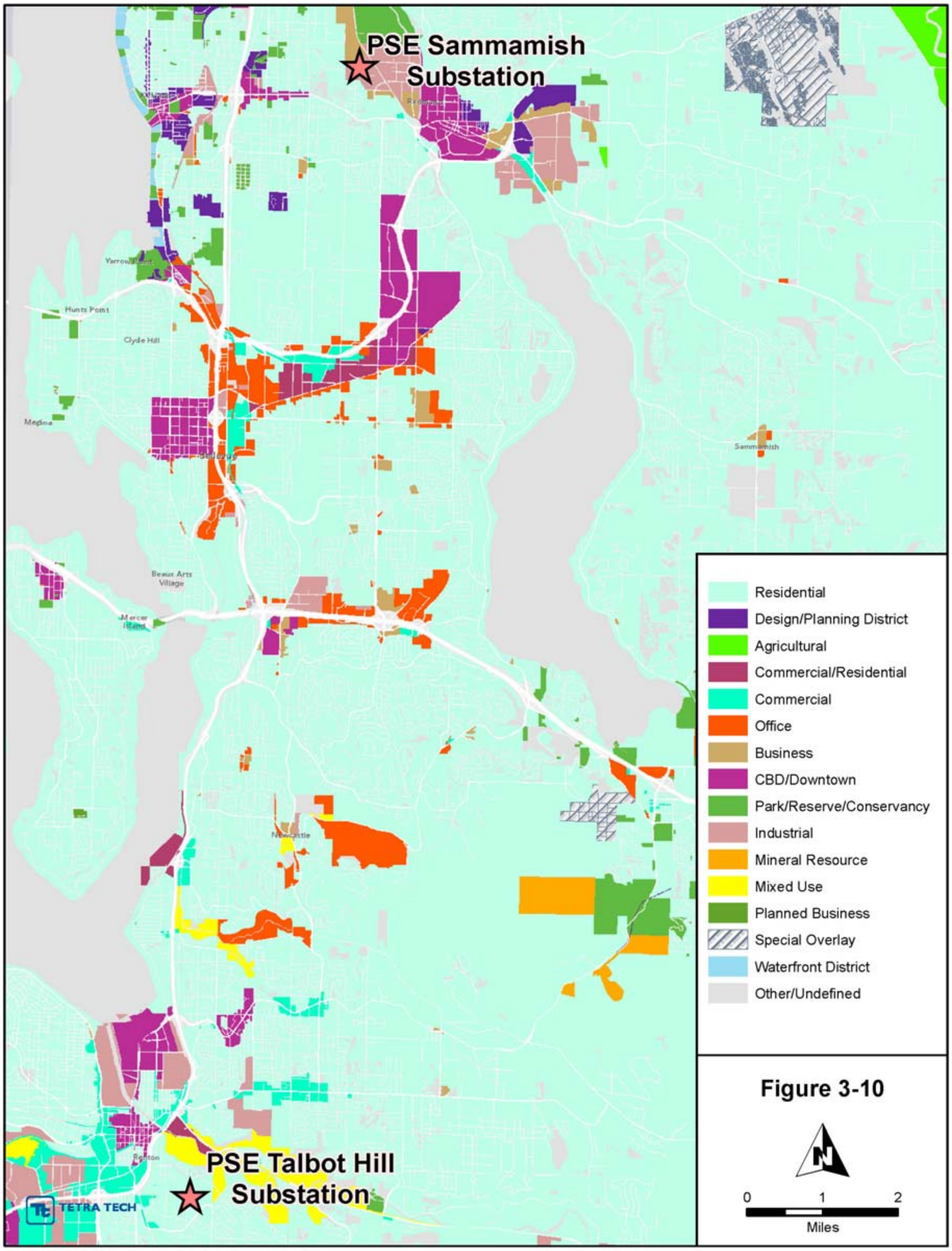

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Figure 3-10. Zoning

3.4.7 Structures

Address point locations obtained from the tax assessor's GIS database were used as a proxy for occupied structure locations. In order to provide adequate avoidance, residential points were buffered by 100 feet, commercial locations were buffered by 160 feet, and trailers were buffered by 60 feet (Figure 3-11). Structure buffer density is high in the study area; therefore, buffers that overlapped onto roadways and existing corridors were removed as the structures would not be located in those areas (Figure 3-12). Additionally, without this modification, the address point layer density was too great to facilitate creation of viable routes.

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Figure 3-11. Structure Buffer Process

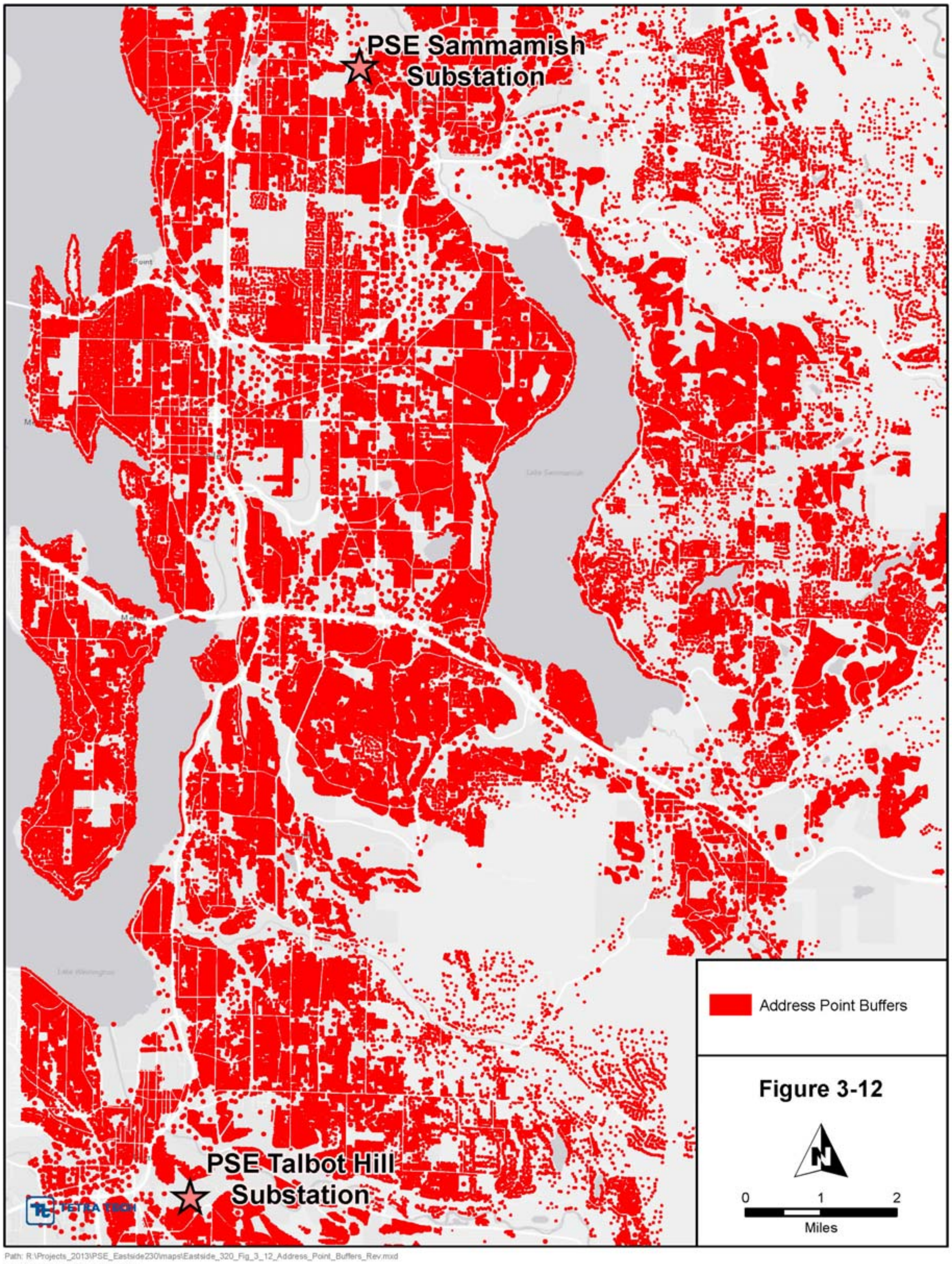

Figure 3-12. Buffered Address Locations

3.4.8 Parks and Recreation

The study area includes public lands designated as parks and recreational trails (Figure 3-13) using a GIS database from King County. While these lands can sometimes represent constraints for transmission line routing (with exception to the Eastside Rail Corridor, as described in section 3.5.2.2 above), they are relatively scarce and widely distributed, and therefore easily avoided.

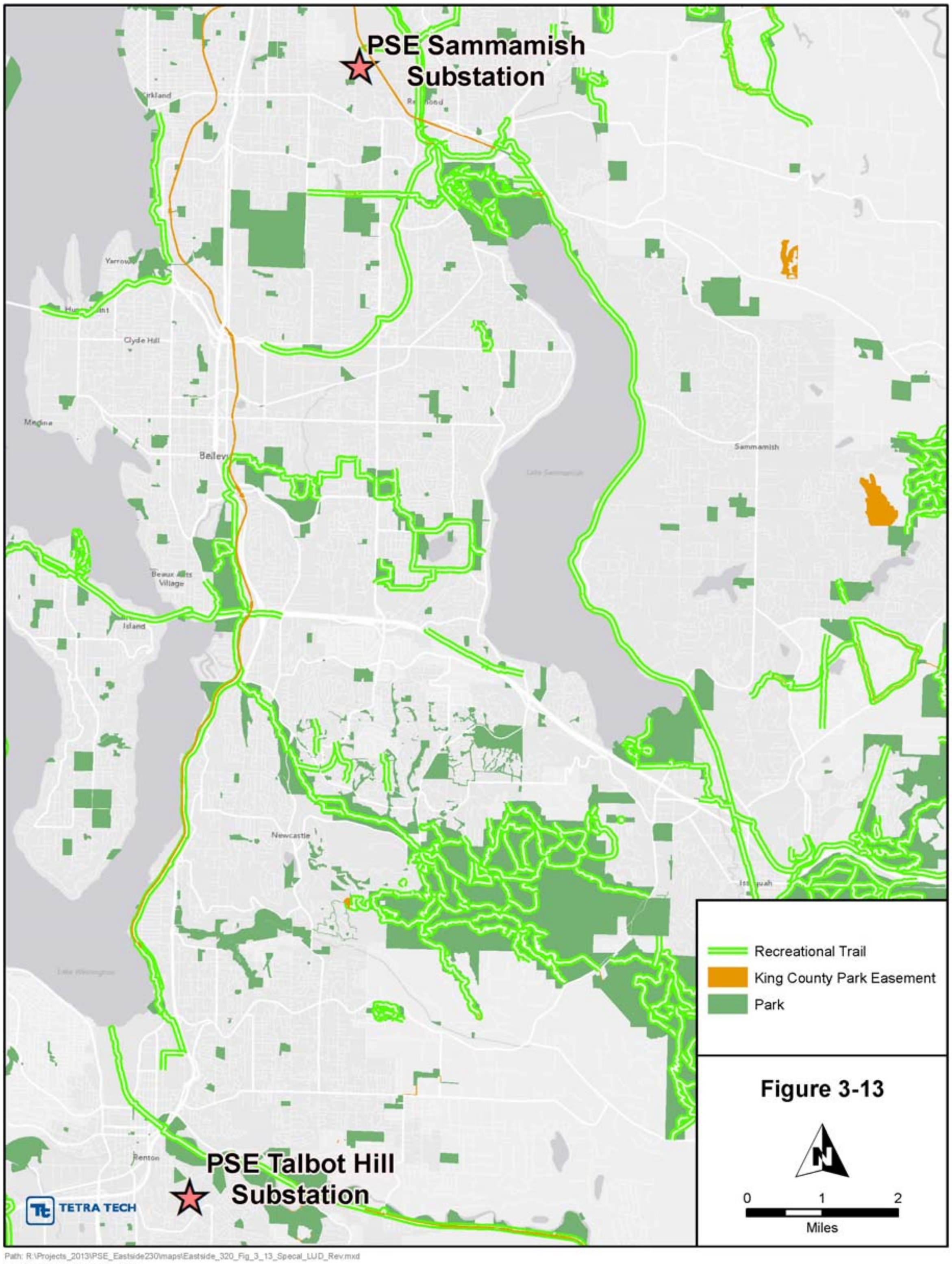

Figure 3-13. Special Land Use Designations

3.4.9 Historic Sites

Historic sites represent constraints, but also tend to be spaced well apart and can be easily avoided (Figure 3-14). For purposes of this analysis, data for Historic Parcels and Points were acquired from the King County GIS database. Cultural site data are classified as sensitive by the Department of Archaeology and Historic Preservation and therefore, were not included in the analysis. A review of cultural and historic sites will be undertaken during further route development, which is the next step of the process.

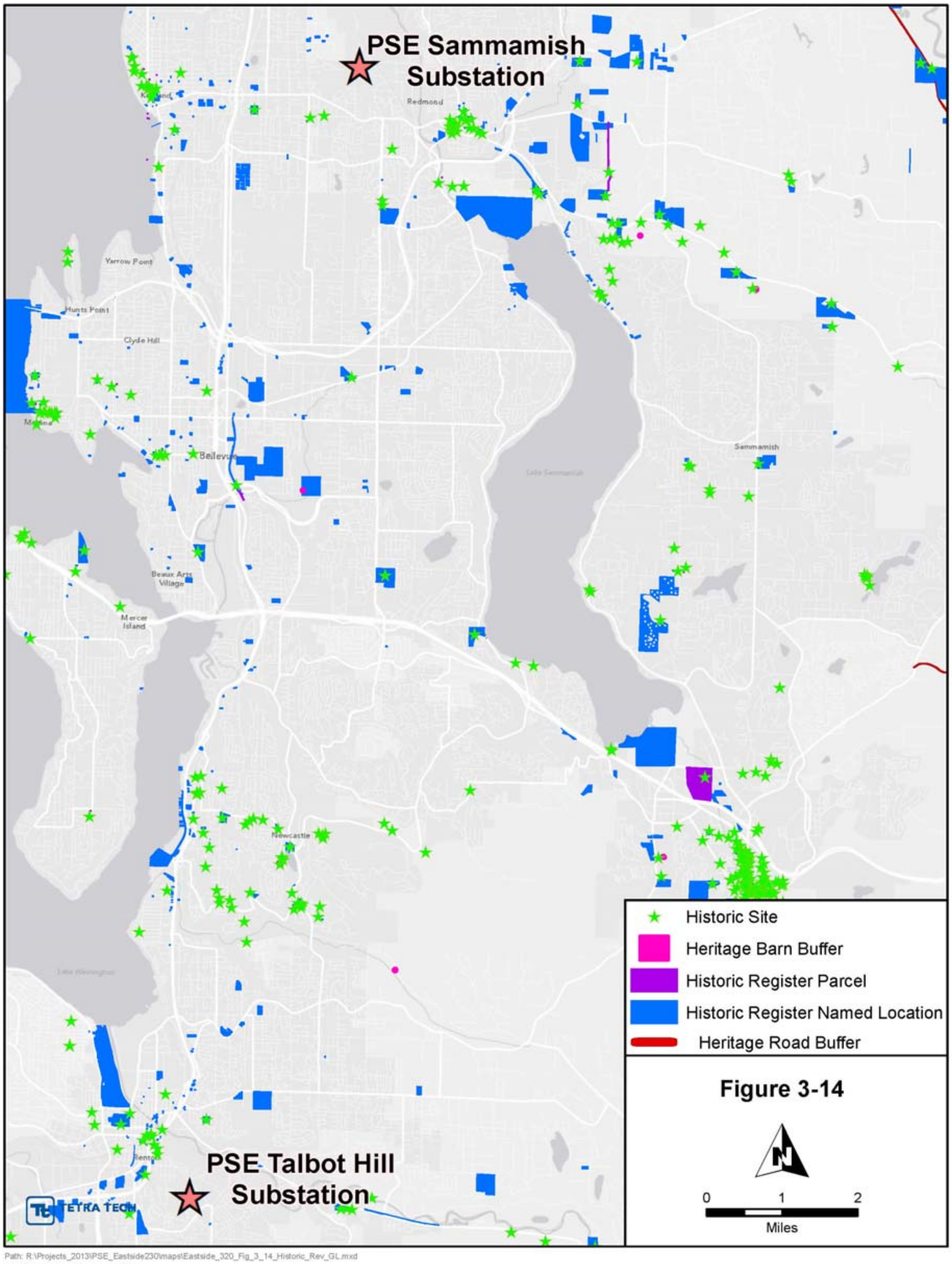

Figure 3-14. Historic Parcels and Points

3.4.10 Visual Resources

There is no GIS data available to effectively represent visual resource considerations in the routing analysis. Nonetheless, using existing corridors or ROW already occupied by existing lines can help minimize new visual impacts.

3.4.11 Waterbodies and Wetlands

There are a number of existing wetlands in the study area that could present constraints to routing a transmission line (Figure 3-15). Large wetlands can be routed around and therefore do not pose a serious problem. The wetlands in the project area occur mostly in river/stream floodways and floodplains, and around shallow lakes. Wetland locations were collected from the National Wetlands Inventory and King County.

Locations of water bodies, such as rivers, streams and lakes were collected from King County, as were the floodways and floodplains. These features can be spanned, except for Lake Sammamish, Lake Washington, Phantom Lake, Larson Lake, and Lake Boren, which can be routed around.

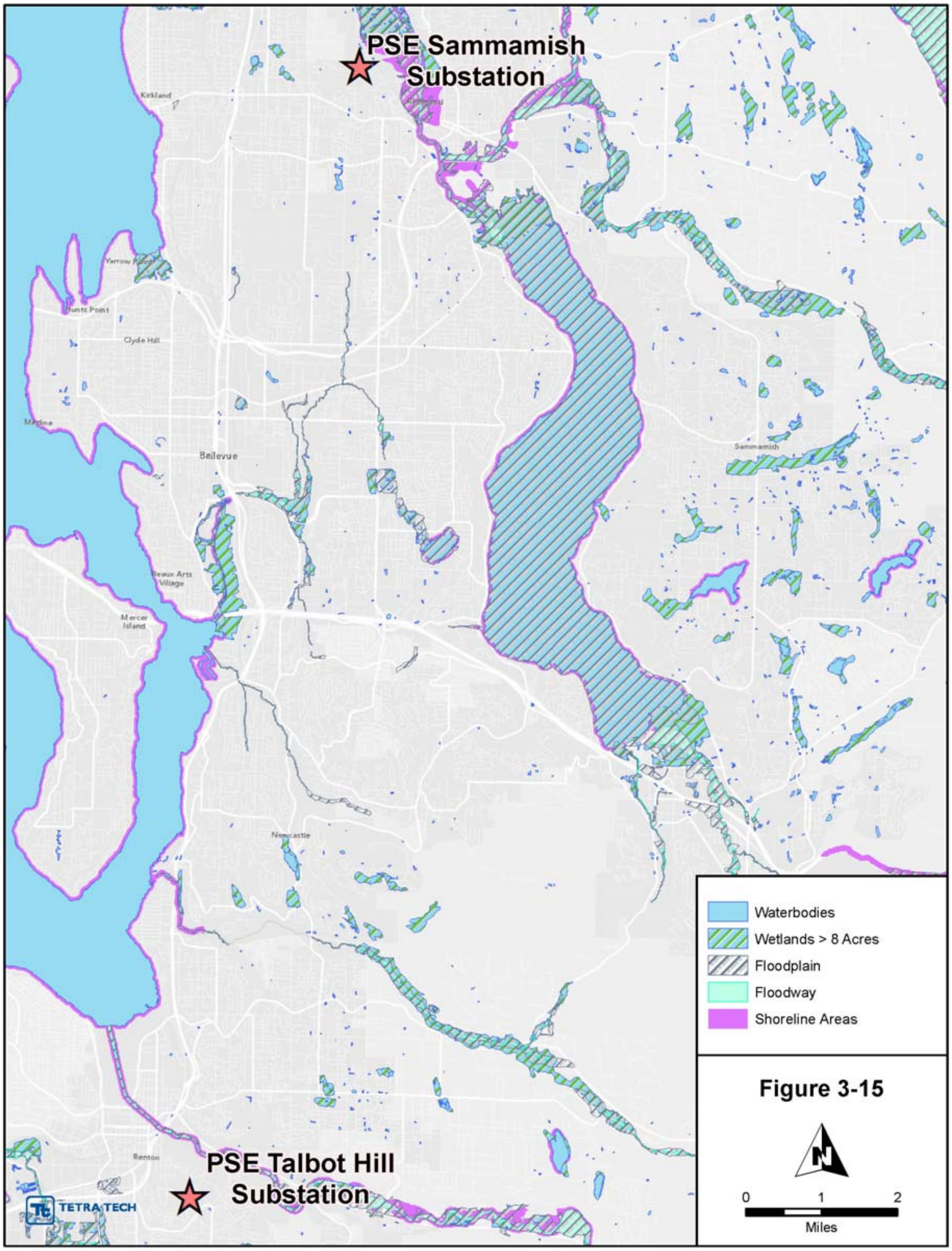

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Figure 3-15. Water and Wetlands

3.4.12 Plants and Vegetation

The selected route must be compatible with PSE's vegetation management obligations, as well as applicable local, state, and federal species designated for enhanced protection. However, for the purposes of this study, only GIS mapped special habitat areas were considered. Washington Natural Heritage Program (WNHP) GIS data indicate that several rare, endangered or sensitive plant species occur in the study area. There is *Boschniakia hookeri* (S3) in Bridle Trails State Park, a *Pseudotsuga menziesii - Arbutus menziesii / Gaultheria Shalloon* Forest (S2) between Squak Mountain and Tiger Mountain, and a Forested Sphagnum Bog PTN (S1). S1 is the most sensitive of these categories, and the bog is over 4 miles east southeast of the Talbot Hill substation, and therefore does not influence the analysis. The S2 forest is over 8 miles east of the Talbot Hill substation, and not pertinent to the analysis. The S3 *Boschniakia hookeri* is 0.6 mile from a route segment; however, it is a small patch and easily avoided. In addition, King County and the local municipalities all have regulations regarding wildlife habitat conservation areas, as well as plant, significant tree, and vegetation disturbance in their jurisdictions that will be evaluated in the next step.

3.5 LRT ANALYSIS OF GIS MAPPED CONSTRAINTS AND OPPORTUNITIES

Following definition of the project study area, collection and processing of GIS data, and assessment constraints and opportunities, the LRT was used to identify transmission corridor options for further evaluation. Refinements to the corridors identified by the LRT were made after considering electric system feasibility and reviewing aerial photography, street maps, U.S. Geological Survey (USGS) topographic maps, and readily available knowledge of local conditions. Other criteria, such as engineering and construction feasibility, were also considered to a certain extent. Route distance minimization is built into the LRT as a standard parameter for route development. The respective steps in the transmission line route selection process are discussed below.

To select the best route options from the large number of possible routes, relevant attributes were evaluated simultaneously. Each of the environmental and engineering data sets identified in Table 3-1 were used to determine preliminary routes. Other criteria, such as total distance, engineering, and construction feasibility were also incorporated.

To enable this process, all of the datasets had to be normalized according to anticipated or potential constraints or opportunities associated with construction or operation of the proposed substation and transmission line(s). For that reason, the Project Team assigned values to each resource according to its relative contribution as an opportunity or constraint.

Tetra Tech staff collected existing available GIS files for land ownership, existing and future land use, public and private ROW, wildlife, vegetation, threatened and endangered (T&E) species, wetlands, topography, historical resources, and other factors that would influence the location of the proposed transmission line. The data collection process was designed to provide geospatial information on criteria that could represent either opportunities or constraints for the location of a transmission line.

Using the team's professional, multi-discipline expertise, the various data layers were individually weighted to reflect the varying degree of constraint or opportunity for each data set. The team's resource and LRT experts assigned values to the data layers (resources) using a progressive scale of values ranging from the most negative or adverse constraint, such as endangered species and residences, to the most positive or greatest opportunity, such as existing PSE ROW. Certain features were considered exclusion areas that could not be crossed under any circumstances because of regulatory, environmental, or engineering limitations. A matrix populated with these resources and their associated values was used as input to the LRT to identify potential transmission line routes. The GIS constraints and opportunities are listed in Appendix B.

The LRT combined these resource layer values and created an output file called the suitability grid, which represents a summation of all the constraints and opportunities for every point (grid cell) across the entire study area. Each grid cell was 10 feet by 10 feet in size, allowing for the model to look at the study area in relative detail. For each grid cell, the scores for each of the attribute layers were summed. The suitability grid can be likened to a landscape of opportunities and constraints that the corridor must traverse. The areas of greatest opportunity are the easiest to cross (valleys), while the areas of highest constraint (hills) are more difficult. The LRT generated multiple corridors across the suitability grid from PSE's Sammamish substation to PSE's Talbot Hill substation connecting via the potential transformation sites. An example of this output is shown in Figure 3-16. This figure depicts the optimal feasible route from the Sammamish to the Vernell substation, and from the Vernell to the Talbot Hill substation. Because all feasible routes include a transformation site between the Sammamish and Talbot Hill substations, all routes were modeled from the Sammamish substation to a potential intermediate transformation site, and then from that site to the Talbot Hill substation.

Multiple corridors, with varying degrees of opportunities and constraints were generated and used to develop alternative routes. To simplify analysis, each route was partitioned at the crossing points of routes to create unique segments. Each LRT segment was validated using professional judgment and ancillary resources such as aerial photographs, to help ensure they were realistic options. Once the segments were generated and validated, a composite score was calculated for each segment from the underlying suitability grid. The composite score for each segment was put into a deterministic model that considered over five hundred combinations of segments and substation sites. If parallel segments (i.e., typically less than a block apart) were identified during the model evaluation, LRT scores were compared to determine which segment would be used to develop routes.

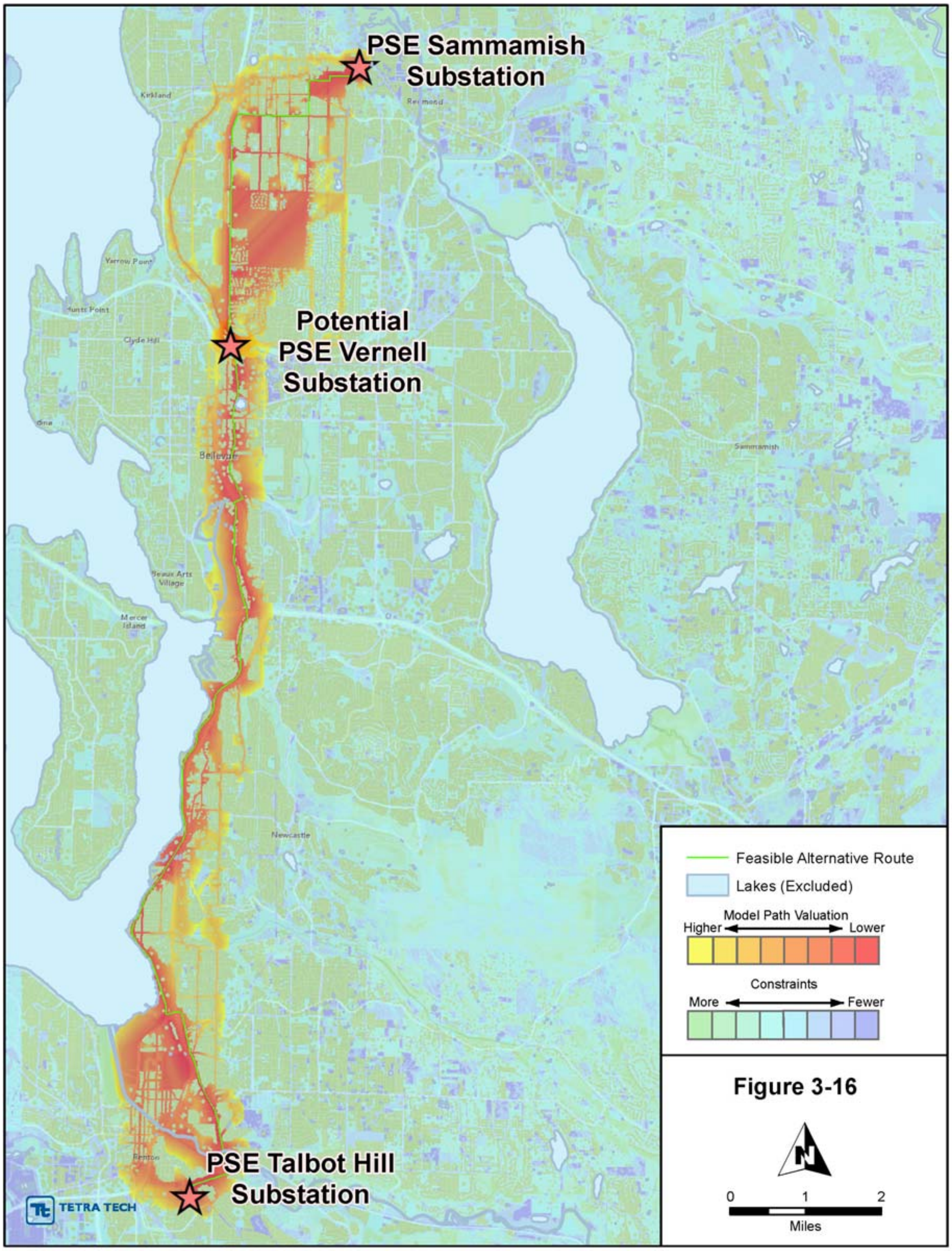

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Figure 3-16. LRT Constraints and Opportunities, Corridor Grid and Route Alternatives

3.6 SELECTION OF ALTERNATIVES TO CARRY FORWARD

Because the Corridor Grid shows variations in the degree of opportunity and constraint, it is used to define route alternatives. Multiple corridors, with varying degrees of opportunities and constraints, were generated and used to develop alternative routes. To simplify analysis, each route was partitioned at the crossing points of routes to create unique segments. Each segment was then analyzed by the Project Team. This process has been used to help identify route options on many linear projects, further refining the professional judgment of the analysts over time. The analysis process also includes review of ancillary resources, such as aerial photographs, that add new and objectively verifiable information to the data sets that generated the corridor grid and route segments. By applying professional judgment to the data sets and ancillary resources, each LRT segment was validated to help ensure that they were feasible options. Once the segments had been identified, the constraint value score was calculated for each one. A constraint value model was developed that considered over 500 segment/route/substation site combinations. If parallel segments (i.e., typically less than a block apart) were identified during the model evaluation, LRT constraint values were used to compare and determine which segment would be used to develop routes.

A deterministic model was used to evaluate the LRT scores for each of the segment/route/site combinations. Negatively scored routes were eliminated from further consideration as they were not considered viable options. The top five percent of the positive routes were then mapped to assist further discussion and evaluation, with the segment combinations for these routes provided in Table 3-2, below. The mapping exercise revealed that there were four general subareas, which when combined, formed a “ladder” of route alternatives. The “leg” components of the ladder comprised the north-south running routes connecting the Sammamish, Talbot Hill, and one of the new transformation substations. Moving east to west between the “legs” could be accomplished by using one of the three cross-over segments or “rungs.” The only exception to this being an additional north-south segment situated in the central part of the study area, south of I-90. To simplify future discussion, each of the fourteen legs and rungs were given a unique identifier (Figure 3-17).

Table 3-2. Route Segment Composition

Vernell 248	Vernell 249	Westminster 217	Lakeside 155	Lakeside 160	Lakeside 166
A	A	A	A	A	A
B	B	C	C	C	C
F	F	D	E	E	E
H	H	F	G2	G2	J
K1	L	H	G1	I	M
K2	N	L	H	K1	N
M		N	L	L	
N			N	N	

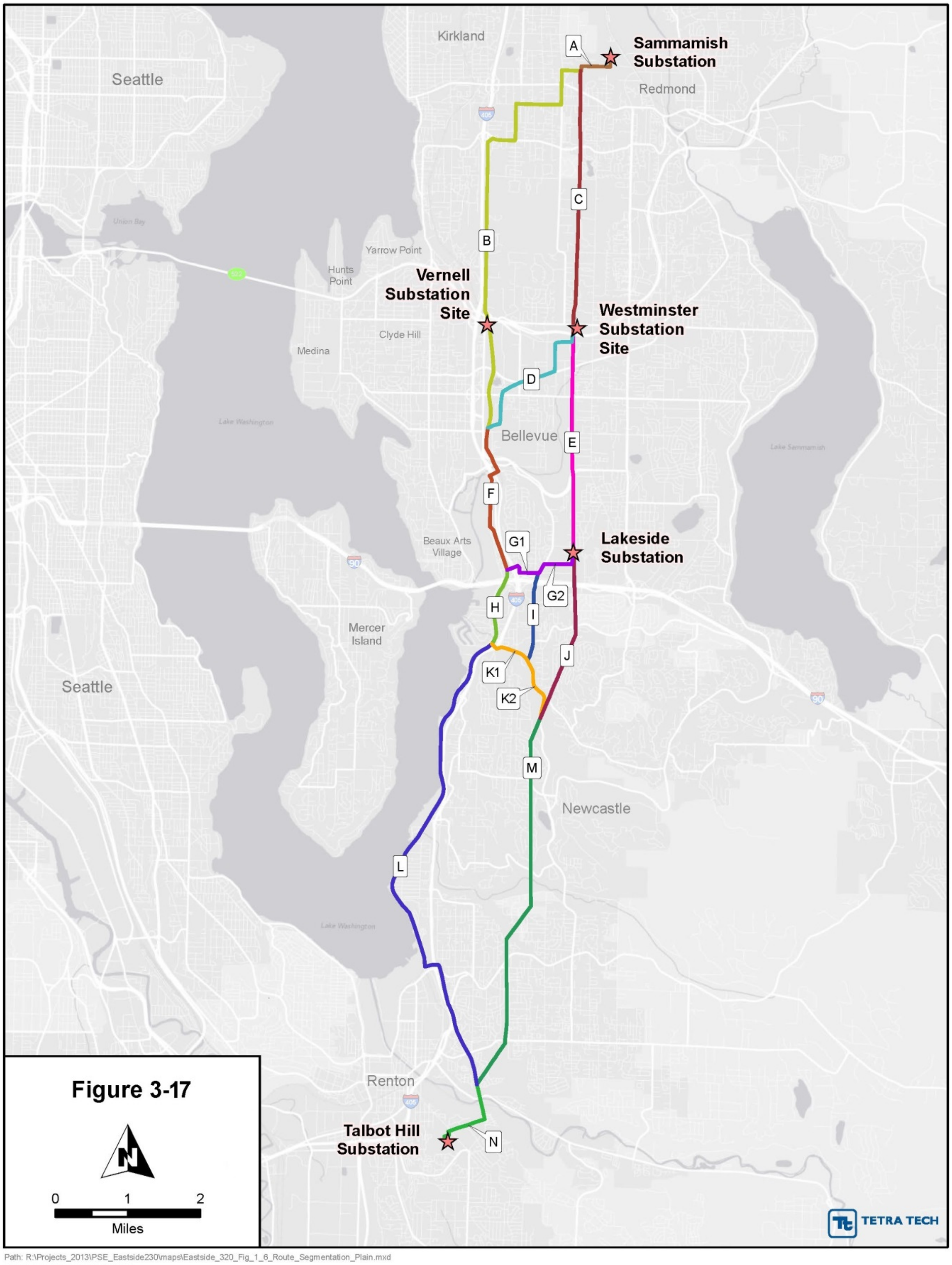

Figure 3-17. Route Alternatives with Unique Identifiers

4. Conclusion and Next Step: Viable Segments and Recommended Routes

Collection and synthesis of the GIS data sets identified throughout this report, analyzed by linear route selection professionals using the processes discussed above, supports the determination that all of the mapped segment combinations shown in Figure 3-17 can be used to develop a route capable of connecting the Sammamish Substation with the Talbot Hill Substation, while connecting to any one of the three new 230 kV intermediary substations.

Additional data collection and evaluation will be conducted in order to further refine the assessment of route segments, which will support a determination that the most viable route is one that is technically feasible and practicable for permitting, construction, and maintenance over time. Following a public review and input process, PSE will select the preferred route, which will then be subjected to project-specific land use and environmental review in support of permits to construct the new transmission facility.

5. Report Limitations

This assessment was developed in conjunction with Puget Sound Energy in an effort to assist in the selection of a feasible 230 kV transmission line route from the Sammamish Substation to the Talbot Hill Substation. The report was developed to describe the evaluation and selection processes. The need for future analysis may also be warranted if specific issues are identified that were outside the intended scope of this assessment.

As with any project that involves an evaluation of environmental and permitting factors, there is a certain degree of dependence upon available information that may not be readily verifiable without the implementation of thorough field programs. Data collected and used within this report were derived primarily from examination of records in the public domain and input from the project team's knowledge about the project area. The passage of time, manifestation of latent conditions, or occurrence of future events may require further study, as well as reevaluation of the findings, observations, and conclusions in the report.

APPENDIX A- Tetra Tech Routing Experience

Tetra Tech, founded in 1966, has provided siting and permitting services for AC and DC electric transmission lines for approximately 40 years in locations from California to Maine, including our current work on the longest contiguous electric transmission project in the nation, the Gateway West Transmission Project.

Listed below is a table of transmission siting projects in the West that Tetra Tech is currently supporting or has supported recently.

Client	Project	Location
Puget Sound Energy	Berrydale to Lake Holm (Krain Corner)	King County
Puget Sound Energy	Eastside 230 kV Project	King County
Idaho Power/ PacifiCorp	Gateway West 230 kV and 500 kV Lines	Wyoming and Idaho
Idaho Power	Boardman to Hemingway 500 kV Line	Oregon and Idaho
NV Energy	Falcon-Gender 345 kV Line	Nevada

APPENDIX B- GIS Constraints and Opportunities

Constrain / Opportunity	Value	Value Definition
Address point buffers (buildings); BPA substation; Large lakes	barrier	Exclusion areas that cannot be crossed under any circumstances due to regulatory, environmental or engineering requirements.
Highway polygons created using lane widths; WSDOT Utility Restrictions – restricted; WA Natural Heritage Project Critically Imperiled Species of Special Concern (S1); Water bodies, Airport; Transfer of development rights – receiving; Convenience Store with Gas; Service Station; Marina; Resort/Lodge/Retreat; 4-Plex; Air Terminal and Hangers; Apartment; Apartment (Co-op); Apartment(Mixed Use); Apartment (Subsidized); Campground; Condominium (Residential); Condominium (Mobile Home Park); Duplex; Fraternity/Sorority House; Retirement Facility; Townhouse Plat; Triplex; Gas Station; Mobile Home Park; Daycare Center; Golf Course; Historic Prop (Misc); Historic Prop (Office); Mobile Home; Reserve/Wilderness Area; Residence Hall/Dorm; Rooming House; School (Private); School (Public); Single Family (C/I Use); Single Family (C/I Zone); Single Family (Res Use/Zone)	-5	Very high impact (duration, regulation). Very difficult or impossible to mitigate (due to technology, sensitivity of resource or cost of mitigation).
Arterial Roads buffered by 20 feet; Landslide potential (class 3); Wetlands, large; Parks; Art Gallery/Museum/Social Service; Auditorium/Assembly Building; Church/Welfare/Religious Service; Club; Condominium Office); Park-Private (Amuse Center); Park- Public (Zoo/Arbor); Condominium (Mixed Use); Group Home; Health Club; Hospital; Hotel/Motel; Medical/Dental Office; Mini Lube; Movie Theater; Nursing Home; Office Building;	-4	High impact. Mitigation would be successful, but would be difficult to implement, very costly, and/or require a long time to complete.

Post Office/Post Service; Rehabilitation Center; Restaurant (Fast Food); Restaurant/Lounge; Skating Rink (Ice/Roller); Tavern/Lounge; Vet/Animal Control Service		
WSDOT Utility Restrictions – with exceptions; WA Historical Register; WA Historical Register Districts; Historic Property Inventory – named; WA Natural Heritage Project Imperiled Species of Special Concern (S2); Slope 20% or greater, unspanable; Slope 40% or greater, unspanable (combined with slope >20% results in a total of -6); Shorelines (200' Buffer); Waterfowl habitat; Heron rookeries; Bald eagle nest buffers; Native growth protection easement; River/Creek/Stream; Water Body- Fresh	-3	Moderate impact. Would not likely result in significant adverse impact. Mitigation, if necessary, would be fairly easy to implement.
WA Natural Heritage Project Rare or Uncommon Species of Special Concern (S3); Floodway; Floodplain; Coal mine hazards; Airport approach notification zone; Landslide potential (class 2); Utility, Private (Radio/T.V.); Retail Store; Shopping Center (Community); Shopping Center (Major Retail); Shopping Center (Neighborhood); Shopping Center (Regional); Shopping Center (Specialty); Retail(Discount); Retail(Line/Strip); Open Space Timber Land/Greenbelt; Open Space (Agriculture-RCW 84.34); Open Space (Current Use-RCW 84.34)	-2	Low impact. Mitigation, if necessary, would be easy to implement.
Scenic Byways buffered by 50 feet; Railroads (rail bank) buffered by 50 feet; BPA transmission corridor; Heritage Barns buffered by 100 feet; Landslide potential (class1); Salmonid streams buffered by 60 feet; Park easements, King County; Tideland, 1st Class; Auto Showroom and Lot, Bank; Bowling Alley; Car Wash; Convenience Store without Gas; Grocery Store; Service Building; Sport Facility	-1	Very low impact. No mitigation required.
Transfer of development rights – sending; Governmental Service;	0	No impact or impact not a concern.

Greenhouse/Nursery/Horticulture Service; High Tech/High Flex; Mining/Quarry/Ore Processing; Office Park; Retail(Big Box); Terminal (Auto/Bus/Other)		
High Pressure Gas Lines buffered by 75 feet; Farm; Mortuary/Cemetery/Crematory	1	Reduces impacts and mitigation requirements, and would facilitate permitting to a very minor extent.
Recreational Trails buffered by 10 feet; BPA transmission corridor buffered by 80 feet; Vacant (Commercial); Vacant (Multi-family); Vacant (Single-family)	2	Reduces impacts and mitigation requirements, and would facilitate permitting to a fairly minor extent.
Industrial Park; Industrial (Gen Purpose); Industrial (Heavy); Industrial (Light); Mini Warehouse; Terminal (Rail); Vacant (Industrial); Warehouse	3	Reduces impacts and mitigation requirements, and would facilitate permitting to a moderate extent.
Arterial Roads buffered by 45 feet; Railroads (abandoned) buffered by 50 feet; PSE 55kV corridor; Easement; Parking (Assoc); Parking (Commercial Lot); Parking (Garage); Right-of-Way/Utility-Road; Utility-Public	4	Reduces impacts and mitigation requirements, and would facilitate permitting to a large extent.
PSE transmission ROW buffered by 50 feet	5	Reduces impacts and mitigation requirements, and would facilitate permitting to a very large extent.

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City of Bellevue
Electrical Reliability Study
Phase 2 Report

EXCERPTS

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City of Bellevue
Electrical Reliability Study
Phase 2 Report

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Executive Summary

Study Results

The City of Bellevue (the City) retained Exponent to perform an electric system reliability assessment to assist the City in meeting its goals to be an informed stakeholder and to work with Puget Sound Energy (PSE) to ensure a reliable electric power supply for the City. The study was performed to answer the following questions from the Electric Reliability Study Plan[1]:

1. *"How does PSE's existing system serving Bellevue perform relative to the Washington Utilities and Transportation Commission (WUTC) expectations, industry standards, and peers relative to reliability?"*

   There are over 90 circuits in Bellevue and while the performance on individual circuits can vary, the overall system in Bellevue is reliable.

   Electric system reliability is measured by the availability of the system to deliver electric power to a customer's meter in accordance with voltage and frequency requirements specified by the WUTC.[2] Reliability is therefore a measure of the probability that electric power is delivered in accordance with those requirements. Electric system reliability is typically measured based on the frequency (System Average Interruption Frequency Index [SAIFI]) and duration (System Average Interruption Duration Index [SAIDI]) of outages relative to the number of customers.

   WUTC has established reliability goals for its regulated utilities (service quality indices). Prior to 2010, the measures included SAIFI (frequency of outages per customer) and SAIDI (duration of outages per customer) goals for PSE of 1.3 and 136 minutes, respectively, excluding major storm events. While PSE has not always met the SAIDI goals system-wide, Bellevue's reliability has met the SAIFI and SAIDI goals over the past 5 years. In 2010, the reliability in Bellevue measured 0.44 and 66 minutes, respectively for SAIFI and SAIDI. In 2010, the measure for SAIDI was changed to include a 5-year average including major storm events and PSE met that goal system-wide. They will report this measure for Bellevue's circuits in 2011.

   PSE participates in an industry reliability survey through the Institute of Electrical and Electronics Engineers. PSE's overall system reliability performance is typically in the 1st or 2nd quartile on SAIFI (frequency of outages) and 2nd or 3rd quartile in SAIDI (duration of outages) (with the 1st quartile being best performance). PSE's 2010 performance for SAIFI and SAIDI was 0.86 and

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1 Reference 10.

2 Washington Administrative Code (WAC)480-100.

129 minutes, respectively, and as shown above, Bellevue had significantly better reliability performance.

2. *“What changes relative to facilities, equipment, planning, and emergency operations will improve electric system reliability, communication, and outage response in Bellevue?”*

   While there has been improvement in the reliability of the Bellevue system over the past several years, the following enhancements are required to ensure continued improvement in reliability for the City:

   - Hardening of the Bellevue system to ensure appropriate redundancy to all substations and circuits.
   - Continued focus on underground cable replacement and remediation as well as replacement of older switches and transformers placed in underground vaults.
   - Review of specific circuits within the City that experience lower reliability to identify improvement actions.
   - Accelerate investments in distribution automation (including a Distribution Management System [e.g., Supervisory Control and Data Acquisition]) to improve reliability and to enable future technologies.
   - Develop strategies to provide greater opportunities for undergrounding lines experiencing lower reliability due to tree and storm impacts.
   - Improvements in the information technology infrastructure for outage management and customer interface to specifically improve communication and outreach to customers during outages on the system.

3. *“Will the City have adequate and reliable power supply to meet future City growth needs?”*

   Based on current plans, the City will have an adequate and reliable power supply to meet the medium-term (5–10 years) and long-term (10–20 years and beyond) growth requirements. The current plan includes:

   - Capacity additions, including upgrade of the 115 kV lines running north-south through Bellevue.
   - Addition of transformer banks to support growth in the Downtown, Bel-Red, and Eastgate/Somerset areas.
   - Upgrade of 115 kV lines to support additional transformer banks.
   - Support of PSE plans to significantly reduce the peak electric power demand through the use of more efficient electric lighting and equipment.

4. *"What opportunities are available to the City to work with PSE, regulators (WUTC,* Federal Energy Regulatory Commission*), and other stakeholders to ensure the needs and expectations of Bellevue's residents and businesses are met relative to the reliability of the power supply?"*

   Bellevue's role as an informed stakeholder requires that the City take an active role in becoming informed on matters affecting the reliability and planning for the electric system in Bellevue. This role includes direct communication with PSE as well as other stakeholders regarding electric service. Specific opportunities for the City to engage as an active stakeholder include:

   - WUTC: The City has a role in informing lawmakers and commissioners regarding matters that affect reliability. The City also has the opportunity to comment or participate in matters directly affecting PSE and its interaction with WUTC. It may be possible for Bellevue to support measures for investment brought forward by PSE that support its overall City goals for electric system reliability and service.
   - PSE: The City has many opportunities to proactively interact with PSE on issues related to system reliability, long-term planning, near-term major project planning, Smart Grid initiatives, and emergency planning.

5. *"How can the City measure and monitor whether improvement in reliability is being achieved?"*

   This reliability assessment includes recommendations for the City to consider moving forward. Proposed reliability improvement metrics have also been included to assist the City in measuring and monitoring the implementation and effectiveness of these recommendations.

This reliability study provides the analyses and recommendations to support the City in meeting its goals to be an informed and active stakeholder and to ensure that the City has an adequate and reliable electric system now and into the future.

Recommendations Summary

The outcome of this reliability assessment is a set of recommendations that will support the City's efforts to meet its stated goals. The recommendations are summarized below:

1. **Conduct Joint City/PSE Reliability Workshops—**The City should conduct an annual reliability workshop with PSE to perform a review of the following topics that relate to reliability in Bellevue:

   - Specific Circuit Reliability: The City should request reliability metrics (SAIDI and SAIFI) on a circuit basis. This will provide the City with information regarding the performance of circuits throughout the City and provide a basis for the City to work with PSE to identify appropriate means to improve performance.

- The City should trend circuit performance over time to identify the effectiveness of completed reliability projects (review number of outages and causes to trend improvement). This assessment provides the City with a means of reviewing the overall Downtown performance and performance for specific neighborhoods that have experienced frequent outages (such as neighborhoods with overhead circuits).

- Equipment Reliability Projects: The City should request a list of the current PSE projects identified for Bellevue (both funded projects in the capital plan and those waiting future funding) to understand the potential reliability improvement efforts for Bellevue.

- Maintenance and Inspection Program Results: PSE should identify to the City any new items likely to significantly affect the electric system reliability from its review of maintenance and inspection programs during the prior year.

- System Redundancy Projects: The City should review the design improvements that are being added to the Bellevue system.

- Automation Installation: The City should review with PSE the automation improvements that are being added in the Bellevue system. The City can monitor the overall upgrades to the system and the degree of system automation.

2. **Joint City/PSE Planning Workshops—**It is recommended that the City engage PSE in an annual planning workshop around future projects. The Comprehensive Plan includes an electric system plan that can serve as the basis for the annual workshop. The workshop should focus on the following items:

   - Current growth projections and electric power use in Bellevue

   - Review and update of current plan

   - Actions for capacity projects required to initiate siting and permitting activities within the next 2 years.

   An outcome of the workshop should be an updated plan for inclusion in the Comprehensive Plan (if required) and an action plan to move designated projects forward into siting analysis and/or planning.

3. **Integrated Resource Planning (IRP)—**The City should remain active in the IRP process and should begin to understand potential long-term impacts of this strategy.

4. **Vegetation Management—**The visual review of overhead circuits indicates that there are many substations and lines located in heavily wooded areas. The only way to significantly improve reliability is to perform more comprehensive tree

trimming. The City should review its vegetation policies, specifically in the areas of substations, to look at alternative vegetation approaches.

5. **Community Communications—**City personnel involved in emergency response should meet with PSE to understand the capabilities of the new outage management system (when completed) to assist in communications with the Bellevue community.

6. **Emergency Response Capability—**The City and PSE should consider the development of a more formal process (procedure) related to response and support activities during an outage. The outcome should be an agreement (or procedure) for communication and coordination during large-scale events affecting Bellevue.

7. **Energy Efficiency Improvements—**The City should lead the energy efficiency effort to assist PSE in reaching its long-term electric energy usage goals to help ensure adequate electric power supply during peak power periods for the City. Electric energy savings programs require active outreach to the customers and citizens to support various efficiency initiatives. The PSE long-term plan has a large reliance on reducing the electric energy demand by installing lower power consuming appliances and lighting systems. The City will have a major role to play in terms of City policy and regulations that support efforts that are alternatives to building additional power plants to supply peak power during high demand periods. The City will also have a major role in community outreach.

8. **Undergrounding of Distribution Lines—**The City should investigate opportunities for additional undergrounding of distribution lines through coordination of multiple utility projects and evaluation of local improvement districts. The City's Comprehensive Plan requires undergrounding of new distribution lines and strategies should be developed to increase opportunities to convert overhead lines to underground circuits.

9. **City Interface with WUTC—**Bellevue's involvement with WUTC should be one of informing lawmakers and commissioners regarding matters that affect reliability. This involvement should include:

   - Assigning a designated individual to electric system matters. This individual should remain informed of electric system activities related to WUTC.

   - Developing "white papers" for submittal to WUTC to inform the Commission of issues affecting electric reliability in the City. This provides a means to provide feedback to WUTC without direct response to hearings.

   - Commenting on or participating in matters directly affecting PSE and their interaction with the WUTC.

There are several additional recommendations that can be incorporated into the recommendations listed above. These include:

10. **Smart Grid Strategies—**PSE has identified a series of Smart Grid technology projects that are being considered over the next 2 years. These projects include a range of programs from the base infrastructure required to enable the Smart Grid to specific customer-related efforts. The City should review the overall PSE plan and determine its level of support for the various customer initiatives. The City needs to define a Smart Grid approach that it would like to see implemented in Bellevue, specifically addressing the level of support for customer interface applications, such as customer energy management, demand response, home automation, etc. The City should work with PSE to develop a Bellevue deployment plan consistent with PSE obligations. (Include with Recommendation #1)

11. **Long-Range Planning—**The City and PSE should synchronize their growth projections for the City by frequent information exchange on expected projects, expected timing of projects, and coordination of actions required by PSE and the City to address these projects. This exchange is meant to assist longer-term planning and should occur well in advance of any specific permitting or development activities. (Include with Recommendation #2)

12. **Multi-Utility Planning—**The City should engage with its utility partners to identify new projects (both large and small) to maximize efficiency for projects in the rights-of-way. The City can take advantage of projects that require trenching to place conduit for potential future use of undergrounding. The existence of conduit may allow for more economic alternatives for undergrounding in the future. (Include with Recommendation #1)

Detailed descriptions of these recommendations are included in this report.

Conclusions

This assessment of the electric system serving the City has shown that electric system reliability is improving and that the programs and projects shown in PSE's planning documents should continue to improve system reliability. However, successful execution of plans, programs, and projects is required to ensure that there is an adequate and reliable electric power system serving the City.

The recommendations offered for consideration by the City are intended to provide a basis for the City to become an informed and active stakeholder relative to decisions and actions required to support continued and improved electric system reliability.

2.2.8 Recommendations

Based on the outage assessment and the current status of PSE's programs to respond to these events, the following recommendations are made to improve the City's ability to be a more proactive participant in improving reliability:

- There are several programs underway to address prevention of outages and to reduce duration of outages. The City can and should proactively monitor the progress and extent of those programs focused on improving the reliability of the City's power distribution system. This will require the City to add staff with power system know-how.
- The City should investigate opportunities for additional undergrounding of distribution lines through coordination of multiple-utility projects and evaluation of funding for conversion of overhead lines to underground cable circuits by forming local improvement districts.
- PSE has ongoing reliability initiatives and performs system-wide and targeted projects to improve system reliability. The City should track the reliability impacts experienced in the various neighborhoods. Since, in the future, PSE will be reporting additional reliability information including storm outages, the City can utilize this information to determine the effectiveness of the various reliability programs and projects, and to work with PSE in identifying circuits requiring attention. A fast track implementation of system improvements is an option for the City to explore with PSE, although accelerated investments might have a negative impact on the power rates.
- The visual review of overhead circuits indicates that there are many substations and lines located in heavily wooded areas and the only way to significantly improve reliability is to perform more comprehensive tree trimming. The City should review its vegetation policies, specifically in the substation areas, to look at alternate vegetation approaches where the risks for large-scale disturbances related to vegetation issues is high.

The remainder of the section provides a discussion of the overall system design and work processes relative to the potential for reliability risk.

2.3 Review of PSE's System Design

2.3.1 Scope

System design has a major impact on electric reliability from the standpoint of limiting outages and reducing the restoration period in response to events. This section provides an assessment of the current PSE system relative to the overall design and layout of the Bellevue distribution system. The review of PSE's system design is intended to identify potential opportunities or vulnerabilities in the overall electric power system relative to reliability within Bellevue.

2.3.2 Approach

The assessment was performed solely through a review of publicly available WUTC documents, publically available PSE and other documents, and limited discussions with PSE's staff. In addition, a walk-through of PSE's substations and control centers was a part of the review in order to obtain an understanding of PSE's design practices. PSE proprietary and confidential documents were not made available for the review. The information reviewed for this assessment is listed below and was discussed with PSE personnel during meetings on these topics:

- Distribution System Design, Loadings, and Operations
- Transmission System Design, Loadings, and Operations
- Capital Project Planning and Prioritization
- Projects and Reliability Initiatives in Bellevue
- Substation and Line Maintenance and Problem Investigations
- PSE Electric Substation Work Practice Standards
- PSE Electric Relay Work Practice Standards.

The WUTC information included in Washington Administrative Code (WAC) 480-100 series was also reviewed as part of this assessment.

2.3.3 State of Washington Requirements

2.3.3.1 Relevant State Codes

WUTC provides oversight of electric utilities through regulations codified in WAC Chapter 480-100. As noted in WAC 480-100-001, the purpose of these regulations is "to administer and enforce chapter 80.28 of Revised Code of Washington (RCW) by establishing rules of general applicability and requirements for consumer protection, financial records and reporting, electric metering, and electric safety and standards". The principal statutes that define WUTC's authority and responsibility with respect to electric utilities are found in RCW Title 80. WUTC regulates electric non-public power utilities, such as PSE[44]. These laws provide the basis for the operations of the electric utilities and how they must conduct business. A more detailed discussion of the regulations and their impact on system reliability is provided in Section 4.2.1.

A brief summary relative to the regulatory impacts on reliability are:

- Requirements for maintaining fair rates subject to rate case hearings: These requirements have an impact on the utility's capital expenditures and projects selected each year.

[44] WUTC does not have jurisdiction over the Public Utility Districts (PUD) or Municipal Utilities.

- Requirements for power quality that define voltage range provided to the customers: This item requires both the utility and end-users (major industrial or power users) to manage their assets to minimize voltage fluctuations on the system.

- Requirements for submitting annual reliability reports: Regulated utilities are required to submit reports on electric system reliability and on actions taken to improve reliability. This requirement also has a major impact on the selection of capital projects and maintenance each year.

- Requirements for interacting with jurisdictions relative to access to rights-of-way in order to maintain a safe and reliable system.

- Guidance on renewable, energy efficiency, and environmental concerns: The State provides requirements and incentives to utilities to promote reductions in power use and the use of environmentally friendly power sources.

2.3.3.2 PSE's Regulatory Environment

Based on this review it was concluded that the state of Washington has codes and requirements similar to other states. However, the code requirements are less detailed than, for example, those of the state of California, which has issued detailed regulations in regard to design, operation, and maintenance of the electric power system.[45] California's key code sections are:

- General Order 95—Rules for Overhead Electric Line Construction

- General Order 128—Rules for Construction of Underground Electric Supply and Communication Systems

- General Order 165— Inspection Cycles for Electric Distribution Facilities.

That is, the state of California has issued detailed rules for design, construction, and maintenance of facilities. No similar rules have been found among WUTC's rules. Thus, it appears as if PSE can design and operate its power system with a higher degree of freedom. However, it still has to meet prevailing standards such as the National Electric Safety Code.[46]

According to information provided by PSE, expenditures and investment costs to be included in the rate base are not reviewed and approved in advance by WUTC but are reviewed after the expenditures and investments have been made. That is, PSE carries the entire risk for investment decisions that it makes until the investments have been made and are presented to WUTC for inclusion in the rate base. If WUTC does not find the investments or expenditures to be prudent it might not allow for these costs to be included in the rate base. In some other states, such investments may have to be preapproved by the regulators prior to initiating the project or starting construction.

[45] See http://docs.cpuc.ca.gov/gos/index.html for information about the California codes.

[46] IEEE Standard C2-2012 National Electric Safety code: ISBN: 9780738165882 (Latest Issue).

2.3.4 Review of PSE's Power Supply

Electric reliability depends on a stable power supply. Relative to the City, the power supply starts with generation and transmission assets feeding the distribution assets in Bellevue. Since the power flows to whatever loads are connected, it is not possible to evaluate the power generation portion specifically related to Bellevue. The Bellevue-specific aspect of the power supply relates to having transmission lines that are capable of supplying the generated power to the City. This section provides a brief synopsis of the current power supply situation for Bellevue.

2.3.4.1 Risk Analysis—Present Generation Capacity

Generation capacity has been sufficient to support the overall PSE electric demand at present, including Bellevue. However, issues have arisen about the ability of wind energy to be delivered through the transmission system in the Northwest from wind power plants in eastern Washington, Idaho, and Oregon.[47] This has not caused power supply problems for Bellevue but indicates that the location of PSE's power supply sources is important and that bottlenecks exists outside of PSE's service territory that can impact how much power PSE will be able to transfer over transmission lines that are not owned by PSE. The risk to Bellevue related to insufficient generation available to PSE cannot be quantified because data are lacking to enable such an analysis. A detailed discussion of generation issues is provided in Section 3 with the review of the Integrated Resource Plan (IRP).

2.3.5 Risk Analysis—Bulk Power Transmission System for Bellevue

2.3.5.1 Scope

PSE operation depends on power wheeling over relatively few transmission lines. This task entailed reviewing the contingencies under which PSE might lose all or a significant amount of the power it needs to keep its customers supplied with electric power in order to assess any potential risks to reliability.

2.3.5.2 Present Transmission System Design

The City receives its electric supply via a 115 kV looped subtransmission system that is connected to primary substations at Sammamish (to the north) and Talbot Hill (to the south). These two stations, in turn, are connected to the high-voltage transmission grid that serves the northwestern states, and receive energy from a mixture of fossil fuel and renewable sources, often located many miles away from Bellevue. The 115 kV lines roughly encircle the City and feed several distribution substations, which step the voltage down to 12.5 kV, a voltage which can more readily be routed through the neighborhoods of the City. It is important to note that most (although not yet all) of these distribution substations are fed from the 115 kV system using two different lines, a method which provides redundancy should one line experience a

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47 See http://www.nytimes.com/2011/11/05/business/energy-environment/as-wind-energy-use-grows-utilities-seek-to-stabilize-power-grid.html for a discussion of wind power issues in the Pacific Northwest.

fault or if maintenance on a line is required. On the 12.5 kV system, the service transformers, whether located on poles, underground, or as ground-level “pad-mounted” units, further reduce the voltage to the familiar ones we all use, such as 120, 240, or 480 VAC, and also provide 3-phase service to commercial and industrial customers.

Figure 30 provides a map of the existing 115 kV system for the City and the surrounding area. The map also shows an existing, double circuit (two 3-phase circuits on one pole) 230 kV line that is owned by Seattle City Light which is not available for power transmission into the City, although the line affects the power flows on other lines owned by other entities in the region. PSE has two 230 to 115 kV, 325 MVA transformers and three 115 kV lines feeding power north up to the City from its Talbot Hill substation. The two lines from Talbot Hill to Lakeside carry about 157 MW each under N-0 conditions (normal winter peak load with all circuits in operation).[48] The map also shows five 115 kV circuits feeding power from the north into the City. These terminate in the Sammamish substation, where there are also two 230/115 kV, 325 MVA transformers installed to feed power into the 115 kV lines.

The Talbot Hill and Sammamish substations receive power from 230 kV lines connected to the Bonneville Power Administration’s (BPA) Maple Valley substation (which is shown in Figure 31) and from its Monroe substation to the northeast of Sammamish. The Maple Valley substation is located a short distance to the east of Talbot Hill. Figure 31 also shows the 230 kV line that comes from BPA’s Monroe substation to PSE’s Novelty Hill substation (not shown on the BPA map) and from there a transmission line extends west where it is terminated in PSE’s Sammamish substation, which has a total of three 230 kV line terminations. One of these is leased from BPA by PSE. This line loops south from Sammamish via Klahanie to BPA’s Maple Valley Substation. This lease expires in 2018 at which time the lease has to be renegotiated or the line reverts to BPA’s control. The third line connects PSE to the Seattle City Light substation at Bothell.

[48] Reference 33 (Section 28, Reliability/Availability of Systems). N is the number of elements in the system and the minus zero designation means that no element is missing or out of service.

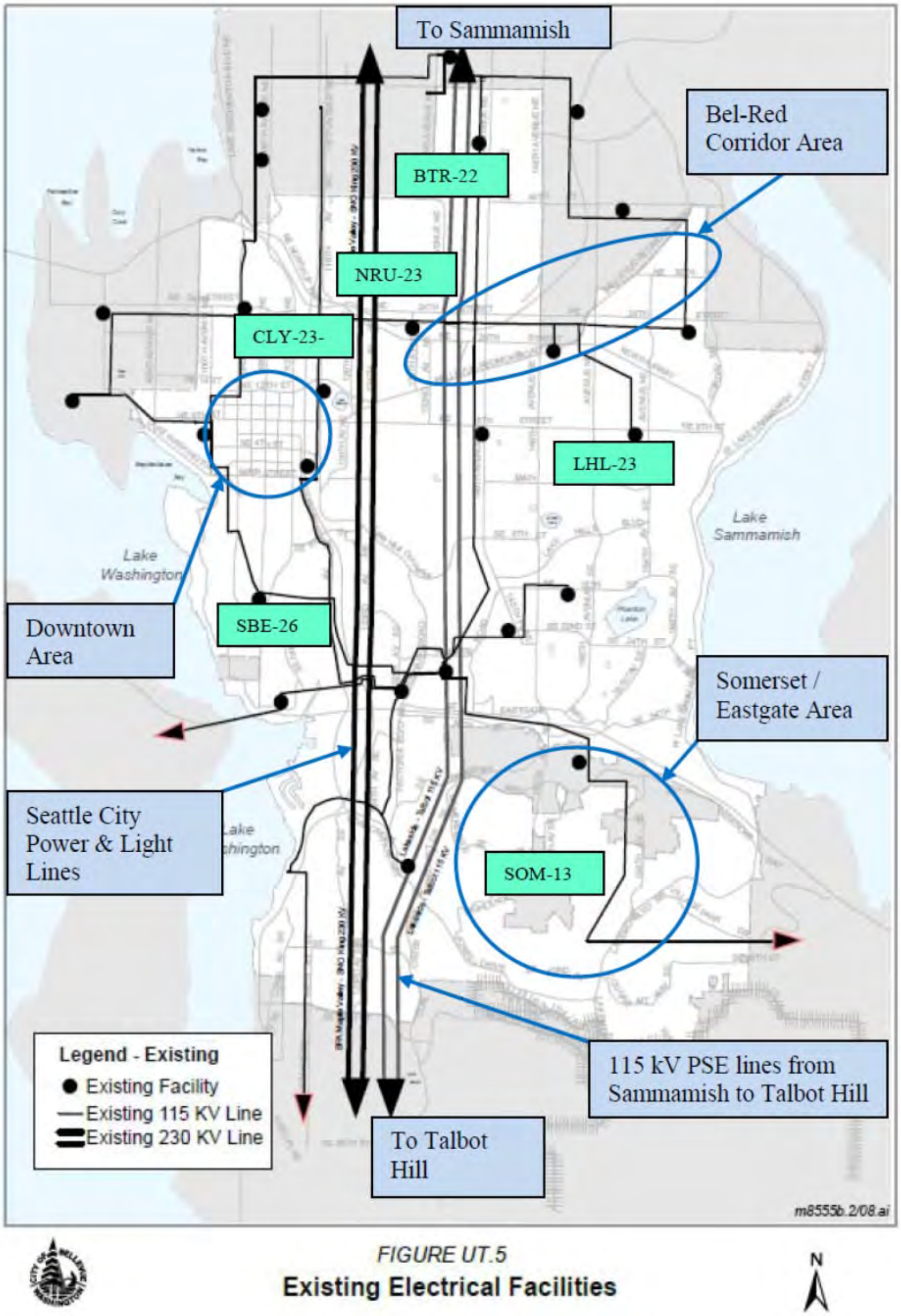

Figure 30. Existing Transmission Facilities around the City of Bellevue

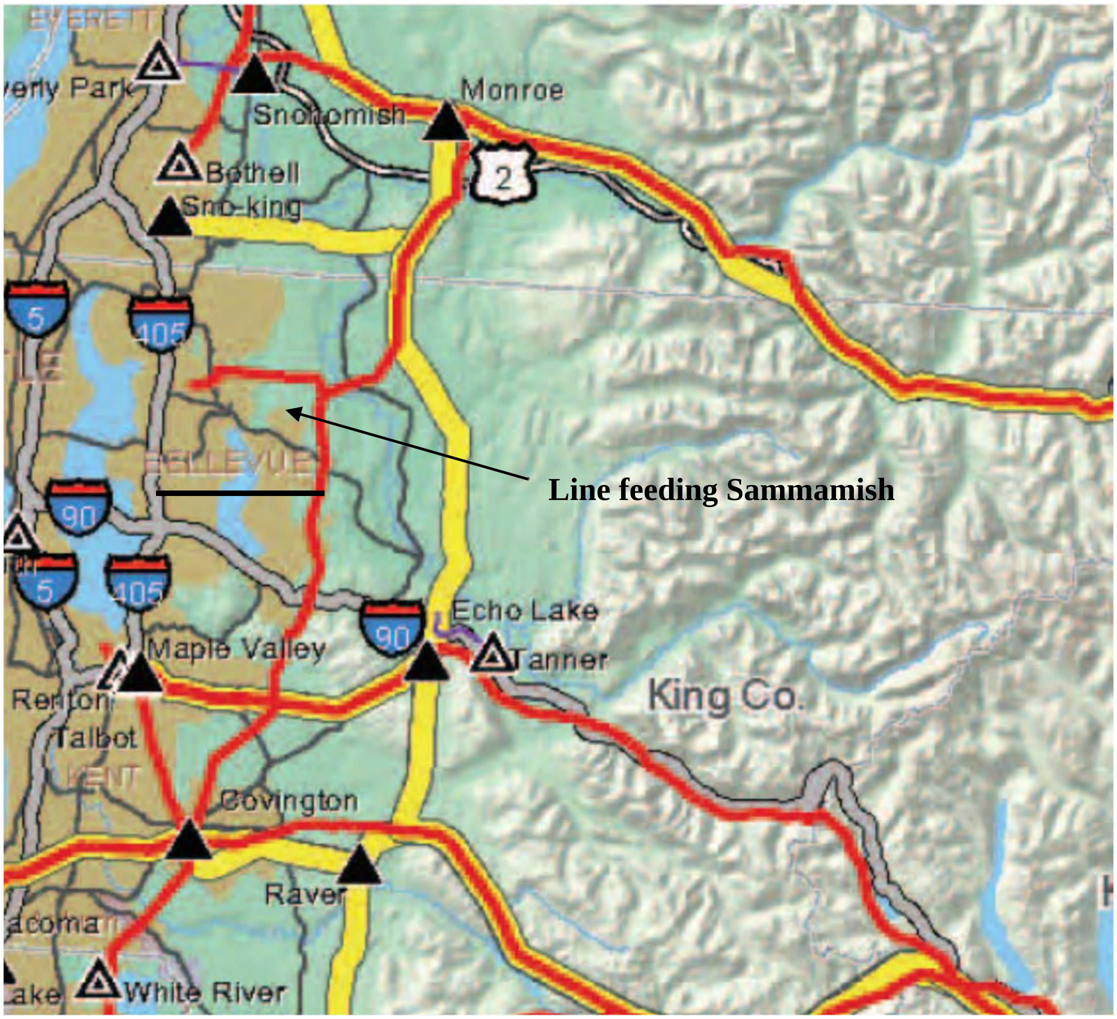

Figure 31. BPA's 500 kV (Yellow) and 230/345 kV (red) lines East and South of Bellevue

2.3.5.3 Bulk Power (230 kV) Transmission System Assessment

BPA's Maple Valley substation is a strong source supplied via 500 kV lines, whereas the Sammamish substation receives its power via longer 230 kV circuits from the Monroe, Bothell, or Maple Valley substations. (PSE also owns a 230 kV line going from Sammamish to the Bothell substation, which is owned by Seattle City Light.)

A loss of the 230 kV line to Monroe or the one to Maple Valley (N-1 contingency) is a serious stress to the City's power supply but should not cause any outages in the City.[49] 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.[50] Conversion of one of the 115 kV lines between Talbot

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[49] Loss of the 230 kV lines from BPA was one of the reasons (but not the only one) for the widespread power outage in 2006. (Based on interview with PSE personnel; see also Reference 34)

[50] Interview with PSE planners.

Hill and Sammamish to 230 kV and installation of a 230/115 kV, 325 MVA transformer in the Lakeside substation will also be needed to support the region’s expected future growth.

2.3.6 115 kV Transmission System Review

2.3.6.1 Scope

PSE’s 115 kV system is considered a subtransmission system with transmission service being provided by BPA. This review consisted of assessing PSE’s 115 kV transmission system, since disturbances on the 115 kV system would be most likely to cause power system disturbances in Bellevue.

2.3.6.2 System Load Scenarios and Planning Assumptions

PSE is a winter peaking utility. Therefore, transmission system outages have a larger impact in the winter than a similar outage during the summer period, since the summer peak load is only about 65% of winter peak.

PSE has not experienced any load growth since 2008. The planned growth has therefore been shifted foreword by a couple of years. The present planning criteria is for 0.5% annual growth for the immediate future and a growth rate of about 1% per year for the next 10 years.

PSE builds its transmission infrastructure to minimize outages and avoid overloads on the 115 kV transmission system on an N-1 basis (N-1 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.

PSE also tries to minimize many so called N-1-1 events. That is, with one outage in the system, planned or unplanned, it tries to be in position to handle a second, unplanned outage. However, this is not possible for some portions of the 115 kV transmission system where a portion of the City is fed via a single 115 kV line. A loss of this line might cause power disruptions to a portion of the power users in the City. For example, as is shown in Figure 32, the loss of the single, radial line to Lake Hills would cause a loss of power to those connected to the substation, unless power can be provided via a looped 12.5 kV distribution circuit that can be fed from another 115 kV substation.

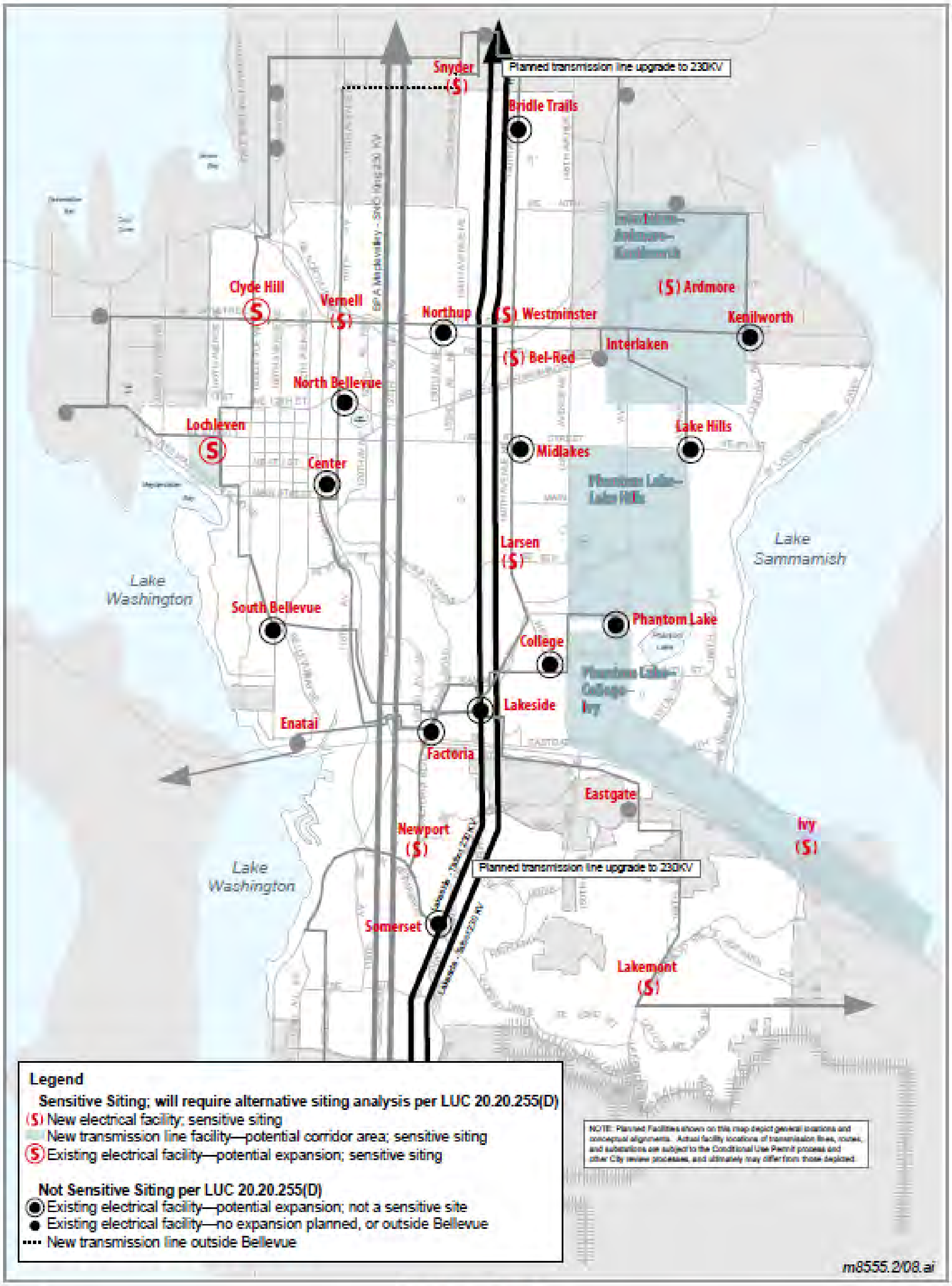


FIGURE UT.5a

New or Expanded Electrical Facilities

N

Figure 32. PSE’s Expansion Plan for Bellevue

While in general, underground systems should have fewer faults per circuit mile than overhead transmission circuits, they are often subjected to flooding of the vaults and workmanship issues related to joints or splices that can affect the reliability of the circuits. That is, underground systems are not as robust and forgiving as overhead circuits are. These issues are reflected in the actual failure statistics as discussed in Section 2.2.3.3.

2.3.7.4 Comparison to Other Utilities

Some older utilities use a low voltage network that typically operates at voltages that can be directly used by the power users. This means voltage levels at 480 V or 120/208 V. The load flows in these types of systems are not easily monitored and faults frequently lead to underground vault explosions since faults in cables of such a system will often burn free. In younger, modern cities, the power distribution is typically handled as it is done in Bellevue using 15 kV or higher class distribution cable systems, often with redundant feeder cables to supply the loads. In modern high rise buildings, 5 to 15 kV class substations are sometimes placed on many of the floors up through the building. Since PSE began to install underground cables a long time ago for the Downtown area, it does not have the redundant feeder cables often used for critical loads in newer cities. PSE has therefore installed a number of unloaded reliability circuits, which can be switched to feed power to customers affected by a cable outage. Thus, PSE's system design compares well with other cities with which Exponent is familiar.

2.3.7.5 Recommendations

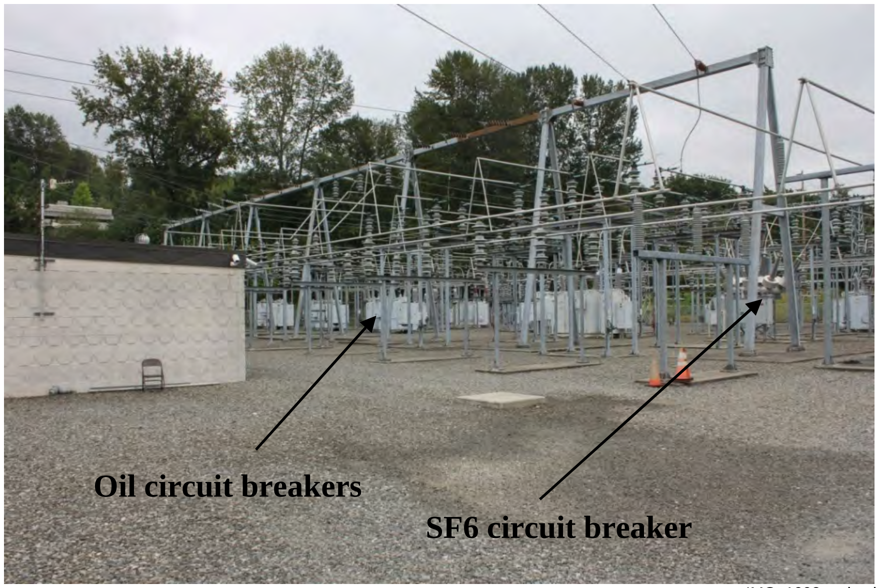
- The City needs to decide how to approach conversion of overhead distribution lines, used primarily in the residential areas, to underground systems, which requires special funding mechanisms.

- PSE needs to continue to reinforce the distribution system to meet the N-1 criteria for the entire City.

2.3.8 PSE's Substation Designs

2.3.8.1 Transmission Substations

PSE has built, owns, and operates transmission substations operating with voltages up to 230 kV for its bulk power supply. These incorporate large power transformers, which are used to reduce the voltage for distribution of power at 115 kV. Most of the substations used for power infeeds to load areas contain transformers rated 25 MW that are used to reduce the voltage from 115 kV to 12.5 kV for power distribution using cables and overhead distribution lines. The power is then stepped down to voltage levels that can be used by PSE's customers by means of underground vault transformers, pad mount transformers placed aboveground, or pole top transformers placed on the distribution power poles close to residences.



IMG_1908 resized.jpg

Figure 37. Lakeside 115 kV switchyard

Figure 38 shows a new 325 MVA transformer that was installed a short time ago to replace a transformer that failed. The installed transformer was a spare that had been procured by PSE in case of a failure of a transformer of this type. Since PSE has established 325 MVA as the rated power for bulk 230/115 kV transformers, PSE is able to have one spare high power transformer to be used in case of any bulk power transformer failure. This enabled PSE to restore the Sammamish substation to normal operation in a short time after removing the failed transformer. It could have taken from 10 to 18 months to obtain a replacement transformer, during which time the station would have had to operate at reduced capacity. PSE demonstrated in this case that it pursues a prudent strategy of spare parts inventory. Figure 39 shows that the new transformer is equipped with an on-line gas-in-oil monitoring device, which should enable early detection of many incipient transformer failures, which should reduce the cost of future transformer repairs.

The Sammamish substation appears to be relatively well designed to survive at least moderate earthquake forces. The transformers are welded to the foundation and if the breakers are also welded or secured to their foundations, they should remain in place during an earthquake. The station for the most part uses equipment placed directly on ground level foundations, which reduces the risk of amplification of earthquake forces. One potentially weak point might be the attachment of the flexible connections shown in Figure 40, since some experience from other earthquakes has demonstrated that flexible conductors attached to the overhead structure by means of suspension insulators have failed and fallen down to the ground. However, in case of a severe earthquake, the power supply is not likely to remain after the event. But such damage would be easy to repair and if the equipment is not seriously damaged, it should be relatively easy to restore the power and to put the system back in operation.[53] An assessment of the dynamic forces on the suspension insulators caused by earthquake forces would possibly reduce the risk of damage to the substation and would be a prudent use of resources.

53 Experience has shown that the transformer breakers will be tripped because of sudden pressure or Buchholtz relay operations from the transformer protections. However, if the transformers are not damaged by the earthquake forces, restoring power is a simple operation.

Table 6. Major Project Roadmap

Capacity Requirement	Action	Potential Need Date	Initiate Early Planning Time Frame
Downtown			
Growth to 125 MVA	Add transformer bank	2016	2012
Growth to 150 MVA	Add transformer bank	2020	2016
Growth to 175 MVA	Add transformer bank	2026	2022
Growth to 200 MVA	Add transformer bank	Post 2026	Unknown
Bel-Red			
Growth to 20 MVA	Add transformer bank	2018	2012
Growth to 40 MVA	Add transformer bank	2026	2022
Somerset/Eastgate			
Growth/Reliability	Add transformer bank	2018	2012
115 kV System			
50 MVA Need Downtown/Regional Growth	Upgrade 115 kV line	2018–2022	2012
Additional 50 MVA Downtown	Add third transmission feed from north	2020–2024	2015

3.4 Future System Assessment Recommendations

The future system status has been reviewed using the future plans for growth in Bellevue, PSE's long-range planning, and potential technology innovations. Based on this review, a set of findings and recommendations is provided to the City of Bellevue for their use as an informed stakeholder.

Recommendation Future 1: Energy Efficiency Programs

Finding: PSE's long-range plans indicate a significant reliance on energy efficiency for management of the peak electric power demand.

Reliability Actions: Support for Long-Term Power Supply

Recommendation Future 1: The City should lead the electric energy efficiency effort to assist PSE in reaching its peak electric power demand goals to avoid using or building new peak electric power plants. Electric energy efficiency programs require active outreach to the customers and citizens to support various energy efficiency initiatives. The PSE long-term plan has a large reliance on electric energy efficiency.

This is a longer-term issue that will be included in future PSE IRPs. The City should remain active in the IRP process and should begin to understand potential long-term impacts of this strategy.

Recommendation Future 2: Smart Grid Initiatives

Finding: PSE is initiating Smart Grid programs to comply with WUTC requirements.

Reliability Actions: Enabling of reliability impacts of Smart Grid technology.

Recommendation Future 2: PSE has identified a series of Smart Grid technology projects that are being considered over the next 2 years. These projects include a range of programs from base infrastructure required to enable the Smart Grid to specific customer-related efforts. Several projects that support development of the infrastructure are currently underway:

- Upgrade of information technology systems
- Upgrade SCADA in transmission substations
- Distribution SCADA on feeder breakers
- Extension of fiber optic cabling through T&D system.

These programs represent upgrades to the PSE infrastructure that are being undertaken on a system-wide basis. Additional programs to enable customer interface applications will be needed. These technologies have been discussed in other recommendations.

An issue with Smart Grid implementation is that PSE must review customer interface applications on a system-wide basis and Bellevue may have different needs and requirements than other parts of the PSE service territory. Security of these communications systems will become a major issue that needs to be resolved before major investments are made in the new technologies.

Therefore, the City should review the overall PSE plan and determine their level of support for the various customer initiatives that would be appropriate for the City to provide. The types of initiatives to be considered are those relating to customer energy management, demand response, and home automation. These technologies are enabled by significant communication system upgrades, but allow for consumers to have greater control over energy usage and expenditure.

Recommendation Future 3: Major Project Planning (see Recommendation Role 2 also)

Finding: PSE maintains a plan for expansion of the system in Bellevue to support growth of the City and the region. However, as the lead time to permit larger projects (required to add capacity or reinforce the City infrastructure) has grown, it requires that the City understand the projects from a more detailed perspective than just a conceptual framework.

Finding: There is the potential for several of the growth-related projects to occur within this decade. The specific projects for consideration are upgrade of the 115 kV lines, additional capacity required for the Bel-Red and Somerset/Eastgate areas, and additional capacity requirements Downtown.

Reliability Actions: Conduct major project discussions well in advance of permit applications to ensure sufficient lead time to permit larger projects (required to add capacity or reinforce the City infrastructure).

Recommendation Future 3: It is recommended that the City engage PSE in an annual planning workshop around future projects with the intent of understanding the requirements from a City perspective. The Comprehensive Plan includes an electric system plan that can serve as the basis for the annual workshop. The workshop should focus on the following items:

- Current growth projections and electric power use in Bellevue
- Review of current plan applicability (Figure UT.5a from the City of Bellevue Comprehensive Plan)
- Update of the current plan
- Develop actions for capacity projects required to initiate siting and permitting activities within the next 2 years.

An outcome of the workshop should be an updated plan for inclusion in the Comprehensive Plan (if required) and an action plan to move designated projects forward into siting analysis and/or planning.

As a minimum, the following capacity additions have been identified as being needed within the next 5 to 10-year time frame. These capacity additions are based on the proposed growth within Bellevue and an assessment of current loadings on the Bellevue substations.

- Upgrade of existing 115 kV lines to 230 kV
- Addition of transformer banks to support expected growth in various areas of the City (Downtown, Bel-Red, and Somerset/Eastgate)
- Addition of new 115 kV lines to reinforce the overall electric system.

Based on recent Exponent staff experience with T&D capital projects, capacity additions of this magnitude typically require the following project execution times:

- Transformer bank additions require 18−24 months to complete from start of engineering to operation. This project time frame is based on the major material long-lead times (which have been increasing), and typical engineering and construction times. This time frame can be different based on difficulty in working at existing stations or permitting new stations. Also, additional time is required for planning and permitting.

- Line projects may require 4–5 years from the start of engineering to completion since permitting of lines typically requires significant engineering to be completed before the formal permitting process proceeds. The time frame for these projects is dependent on the length of the line segment, the number of jurisdictions involved, and the number of permits required (federal, state, and local). Line projects often require engineering to be completed in order to satisfy permit applications so that these projects have a longer time frame than substation projects.

Recommendation Future 4: Long-Range Planning

Finding: Both Bellevue and PSE work with various developers and companies to identify new potential facilities in Bellevue. There is an opportunity to share and communicate the results of these planning activities. This exercise relates to longer-term issues that are expected to be addressed in the future.

Reliability Actions: Coordination of growth planning and major project activities.

Recommendation Future 4: While information is shared for the IRP, and to the extent that information can be shared, it is recommended that a more formal meeting (annually) be held to ensure that all of Bellevue's needs are identified to PSE and that both organizations are coordinated regarding future load demand. This information sharing can also be included in the annual planning meeting.

The City and PSE should synchronize their growth projections for the City by exchanging information on expected projects, expected timing of projects, and coordination actions required by PSE and the City to address these projects. This exchange is meant to be longer-term planning and well in advance of any specific permitting or development activities.

4 Role of the City of Bellevue

4.1 Study

4.1.1 Study Scope

The Role of the City assessment was performed to answer the following question: "what opportunities are available to the City to work with PSE, regulators [WUTC, FERC], and other stakeholders to ensure the needs and expectations of Bellevue's residents and businesses are met relative to the reliability of the power supply?"

4.1.2 Study Approach

The Role of the City assessment was performed in the following steps:

- Evaluation of potential interactions with WUTC and other government agencies as it relates to the City's ability to inform decision-makers or to advocate for policy change
- Evaluation of City's interaction with PSE around planning and permitting relative to influencing electric system reliability in Bellevue
- Review of transparency of operations relative to improvements in communication between PSE and its customers as it relates to reliability.

4.2 Enhance Role of City as an Informed Stakeholder

4.2.1 Regulatory Agencies

4.2.1.1 Study Approach

Prior to discussing the opportunities for Bellevue to interact with regulatory agencies, it is important to understand the regulatory framework under which PSE operates the electric power system and the regulatory framework as it affects the City. A brief summary of the regulatory requirements and their impact on reliability is provided below.

4.2.1.2 Washington Utilities and Transportation Commission

WUTC provides oversight to electric utilities through regulations codified in the WAC Chapter 480-100. As noted in WAC 480-100-001, the purpose of these regulations is "to administer and enforce chapter 80.28 RCW by establishing rules of general applicability and requirements for consumer protection, financial records and reporting, electric metering, and electric safety and standards." The principal statutes that define WUTC's authority and responsibility with respect to electric utilities are found in RCW Title 80.

In determining the opportunity for the City to interact with WUTC, Exponent reviewed the responsibility of the agency to oversee the operation of electric utilities regulated by the agency. These requirements were then reviewed as they relate to PSE activities. Relative to electric system reliability, there are several requirements that are highlighted here:

PSE-Related Activities

- PSE is required to publish and communicate rates for electric power delivery through the filing of tariffs and rate schedules with WUTC (WAC 480-100-028 and WAC 480-100-103). Any changes to these tariffs or rate schedules must be presented at public hearings before WUTC and are subject to public hearings (RCW 80.28.020 and WAC 480-100-194). This requires PSE to present its basis for the proposed increases (for its investments and costs for providing services) to WUTC and to justify these expenditures as prudent since these expenditures are the basis for the increases and the means of PSE recovering their investment. The proposed changes are then reviewed by WUTC staff and a decision regarding the proposed changes is issued. While this process introduces risk to PSE's investment plans, the process is not expected to significantly alter PSE's investment program.

  This process of utility commission oversight is common to regulated utilities in the United States. In the case of PSE, they present their request for rate increases after investments are made so they are recovering expenses after they have been incurred. In other states, the rate case proceeding precedes the investments and the level of investment is approved prior to execution of projects. In the case of PSE, this requires that their investments (e.g., capital projects) be considered as prudent uses of capital across their entire system.

- PSE is required to have a rate structure that provides the same rates for similar services. This requirement is based on RCW 80.28.80. This requirement establishes a basis that a utility cannot provide preferred service and that service must be provided on a non-prejudicial basis except for a few special exemptions provided in the RCW. This requirement means that PSE must select projects to maintain their electric system assets from an overall system perspective.

- PSE is required to submit annual reliability reports that provide the service performance to its customers (WAC 480-100-398). This report highlights the current performance as well as actions that PSE will take to improve performance. This report addresses the entire service area. PSE indicates system circuits of concern (top 50) and identifies specific actions for these circuits. For 2010, there were no circuits identified in the Bellevue area (although Lake Hills-23 was on the list in 2009) (Reference 4).

- Through RCW19.285, the state of Washington has required that utilities meet a portion of their generation requirements through the use of renewable technologies. The state has required that at least 15% of generation come from renewable sources by 2020. The intent of this requirement is to encourage the use of renewable energy sources and energy efficiency in the state of Washington. This requirement affects reliability in the sense that PSE must develop a generation mix that satisfies its load demands and its renewable energy portfolio. In the future, as renewable energy sources and distributed energy sources become a bigger power source and a more local source, there will be a challenge to maintain the T&D system within acceptable voltage levels.

- WUTC (WAC 480-100-238) requires utilities to submit an IRP that is intended to present how a utility will meet its system demand and what the mix of generation sources will be. The IRP is required to examine alternatives that allow for meeting future demand at the "lowest reasonable cost." Utilities are also required to address conservation relative to energy reduction from energy efficiency and other means. The requirement is to submit the IRP on a biannual basis.

  PSE provides an IRP defining its strategy to respond to future load scenarios. The current IRP has been referred to previously in Section 3 in discussing future system status.

- Requirements for delivery of power are specified in WAC 480-100-368 and -373 for system frequency and voltage, respectively. The requirements state that the system must be operated at a frequency of 60 cycles per second under normal conditions and the voltage (depending on service class) must be maintained within ±5% of the standard voltage on the distribution feeder. There are additional requirements related to both utility and customer actions to control voltage fluctuation.

  This requirement directly relates to the issue of power quality. PSE is required to deliver voltage within the specified range. For customers who require a tighter band on voltage fluctuations, there are standard technologies employed by the end user at these sites to maintain the required voltage stability. Typically, information technology and manufacturing plants most often use site-specific technologies to control voltage that may interrupt their operations.

City-Related Activities

- Through RCW 35.96.040, the state of Washington specifies requirements that allow cities or towns to create local improvement districts and to levy and collect special assessments against the real property benefitting from the conversion of overhead facilities to underground facilities. This requirement directly relates to the funding mechanism required to convert existing overhead facilities. Issues regarding the conversion of overhead lines to underground were presented in Section 2.2.6.4.

- Through RCW 36.70A, the state of Washington requires cities and counties to develop comprehensive land use plans to govern growth management in their jurisdictions, if they are required or choose to plan under RCW 36.07A.040.
- Through RCW 80.32, the state of Washington allows cities to establish franchise agreements with utilities relative to use of city rights-of-way (public roads, streets, and highways).

There are additional requirements in the state of Washington statutes and WUTC regulations that govern interconnections to the electric system, requirements for the renewable portfolio, and purchase of power from qualifying facilities.

4.2.1.3 Western Electricity Coordinating Council

The second organization with oversight responsibility is WECC, which is chartered with ensuring the reliability and security of the bulk electric system in the Western Interconnection. Since PSE has limited bulk transmission assets, their involvement with WECC deals with coordination of their transmission lines with the WECC area. PSE interacts with WECC for operations of its transmission lines at 100 kV and above. WECC provides requirements for operations and maintenance of the transmission system to ensure the reliability, stability, and security of the transmission system in the western United States and Canada. PSE involvement with WECC is mostly from an operations, maintenance, and protection standpoint to ensure that its system operates and coordinates planning with other regional entities. WECC develops standards for the western region based on review and application of NERC reliability standards which defines requirements to maintain reliability of the transmission system in the United States. WECC activities are focused only on transmission and do not reach into the distribution system within Bellevue or other parts of the PSE service territory. However, this interface is important from the transmission standpoint where events on the transmission system can result in significant wide-area outages.

4.2.1.4 Analysis

From a WUTC perspective relative to electric power, cities are considered as any other member of the public. This means that Bellevue has access to the published tariffs and rate schedules of PSE and has the ability to participate in public hearings and to offer comments and opinions relative to these hearings. Therefore, Bellevue’s primary interaction with WUTC is one of being an active participant relative to changes in laws and tariffs that may affect electric system reliability in the State of Washington.

From an overall regulatory perspective, the City has the right to execute franchise agreements with companies that provide utility services to the City. These items are discussed in Section 4.2.2.2.

From the perspective of WECC, Bellevue has no real involvement with this group since it deals with issues on the transmission system (and large generation). WECC, however, does provide a source of information relative to electricity planning in the region and provides short- and long-term views of the electric transmission system. Their planning documents identify needs of the system moving forward and will provide Bellevue with an independent assessment of potential transmission needs in the area that may affect assets providing service to Bellevue or that are located in Bellevue.

4.2.1.5 Recommendations

There are potentially two areas of involvement by Bellevue relative to WUTC:

- Since WUTC operates and oversees all regulated utilities, any changes in fundamental requirements must be driven by state law and enforcement by WUTC must be consistent and fair among all regulated companies. Therefore, Bellevue's involvement in this aspect is one of informing lawmakers and commissioners regarding matters that affect reliability. However, matters affecting the electric system must be viewed in a global rather than a local context.
- Bellevue does have the opportunity to comment or participate in matters directly affecting PSE and their interaction with WUTC. The City may choose to support or oppose measures for investment brought forward by PSE that support its overall City goals for electric system reliability and service. Again, PSE has to propose its plans to WUTC on a system-wide basis, but Bellevue has the ability to support and advocate for initiatives that meet its goals and objectives.

From an overall regulatory perspective, interaction with the regulatory agencies provides Bellevue with a means of keeping current on plans for the electric system and advocating for projects that meet Bellevue's objectives.

4.2.2 Puget Sound Energy

4.2.2.1 Study Approach

Bellevue's primary involvement in electric system reliability is through its interaction and collaboration with PSE. There are several areas where Bellevue is actively involved with electric system activities by PSE. The interaction between the City and PSE relative to specific reliability initiatives and outage performance was discussed in Section 2. The major areas of interaction discussed here are planning, permitting, and emergency response.

4.2.2.2 City Policies

Bellevue establishes policies for utilities in the Utilities Element of the Comprehensive Plan[105]. The City provides its long-term vision and plans in its Comprehensive Plan, which provides goals, policies, and plans for all areas and aspects of City operations. The Utilities Element addresses many activities relating to electric reliability, including:

- A high level plan for utility capacity expansion to meet City and regional needs and to guide planning and decision-making
- Coordination of public and private trenching activities (related to the potential for undergrounding opportunities)
- Notification to the City prior to vegetation management in the City rights-of-way
- Required undergrounding of all new electrical distribution facilities
- Encouragement of consolidation of facilities
- Facilitation of conservation and environmentally sensitive energy sources
- Encourage communication with utilities, WUTC, and the City about cost distribution and undergrounding of electric distribution lines.

All of these policies have the potential to impact reliability. Additionally, through the Franchise Agreement between the City and PSE, the City provides requirements for work in the City rights-of-way that are intended to reflect the policies of the Comprehensive Plan. Based on a review of these documents, the City is influencing reliability through its planning and permitting process, its vegetation management policies, the ability to underground new facilities, and coordination of activities to take advantage of joint utility efforts. In the longer term, renewable and alternate energy sources and conservation will factor into the overall electric energy picture in Bellevue.

The recommendations provided in Sections 2 and 3 are consistent with the policies of the Comprehensive Plan. The recommendations are based on focusing the City's efforts on areas that will drive improvements in reliable service to existing and new members (business and residential) of the community, that satisfies the City's goals, and that understands the requirements of PSE as a regulated utility. The recommendations are provided to support City reliability through improved system design (redundancy), expanded use of automation and information technology, and improved communications between the City and PSE on matters affecting reliability and growth.

[105] Reference 26.

4.2.2.3 Planning

Both Bellevue and PSE engage in planning for the City. However, the planning needs for each organization are focused on different areas and concerns. Bellevue planning is required to address services and land use planning across all aspects of city operations, such as impact on land use, rights-of way, roadways, water and sewage, and coordination of projects by other utilities (electric, gas, and telecommunications). Therefore, planning by Bellevue involves the following:

- City growth projections including major facility and capital projects
- Forecast and plans for land use
- Forecast and plans for roadway additions and changes
- Forecast and plans for utility (water, electric, gas, telecommunications) additions and changes
- Forecast and plans for parks and public areas.

PSE focuses on planning for electric and gas system operations. PSE obtains its growth plans and projections from interactions with its various customers including cities, developers, companies, and facility owners. PSE and Bellevue share many of the same customers when it comes to planning for growth in Bellevue.

From the perspective of electric system planning, there are two main elements:

- Overall long-term growth planning to identify the potential for growth in Bellevue and to identify the need for additional electric system capacity.
- Medium-term tactical planning for specific projects that affect the electric distribution system in Bellevue as well as the PSE-owned transmission lines. The long-term plan is based on growth projections in the PSE service territory (Bellevue and surrounding areas) that impact the need for additional service to various areas of the City. The Comprehensive Plan Utilities Element Figures UT.5 and UT.5a present the current view of potential plans for electric expansion in Bellevue to meet future needs.

Discussions with staff in both Bellevue and PSE indicate that the overall growth plan is developed based on individual discussions with prospective developers and then later meetings are held between PSE and Bellevue to ensure that PSE has input from Bellevue relative to preparing their IRP. This level of planning is one of the means that PSE utilizes to project growth and to develop system plans to support growth. Since these are longer-term plans to identify future needs, the major need is to coordinate the results of the planning activities to ensure that PSE is informed by City input relative to growth for inclusion in its long-term planning process.

The medium-term tactical planning is directed at potential projects that may need to be performed in Bellevue on existing or new locations. Typical maintenance or replacement projects are handled through the normal permit process. PSE performs ongoing assessments and studies of its electric system to ensure that the system is capable of handling current and future demands. The PSE plans are based on their projections for future growth in Bellevue and other parts of their system. These medium-term tactical projects are also part of the IRP. The ability to turn the medium-term tactical plans into real projects varies by size and type of project. The projects subject to tactical planning are large expansion projects (substation expansions, new feeders, substation connections) that require significant lead-time to proceed to an actual project. Based on the discussion in Section 3, there will be a need for new facilities as the City grows and reaches its build-out limits.

Bellevue has entered into a Franchise Agreement with PSE[106] that outlines requirements for PSE operation, construction, and support of facilities in Bellevue. The Franchise Agreement outlines the requirements for the various types of projects performed by PSE. The Franchise Agreement and the City Comprehensive Plan Policies include requirements that call for siting reviews of the larger capacity projects. Based on discussions with staff at PSE and Bellevue, the review and update of the utility growth plans in the Comprehensive Plan requires review and update. Since these capacity expansions represent large and complex projects, and given the significant growth expectations of the City, a regular update of the plan is appropriate to ensure that the City and PSE understand the requirements for future growth.

4.2.2.4 Permitting

Once a project is ready to proceed, it then enters the permitting process. For major projects (including those on sensitive site locations per the Comprehensive Plan), the following steps are typically required:

- Pre-application meeting
- Siting analysis that must include three alternatives
- Tentative agreement on an alternative
- Submittal of the application
- City recommendation
- Hearings and appeals, if required
- City Council decision
- Permit issued.

The typical time frame for these types of projects (from initial request to permit) is approximately 3 years and can be longer. Typical smaller projects follow a similar permitting

[106] Reference 27.

process but start with submittal of the application, and the process proceeds in a quicker manner. If the project is on the public right-of-way and is covered by the Franchise Agreement, then issue of the permit is handled through the Franchise Agreement and does not require City Council approval.

4.2.2.5 Analysis

Based on discussions with Bellevue and PSE staff, observations relative to the planning and permitting process are:

- There is good agreement that both parties understand the permitting process and that working relations between the parties is good. However, there is sometimes a need to get new PSE contractors to more quickly understand the process.
- Complete information in the permitting process results in a more routine permit process. Incomplete information tends to slow the process.
- For larger projects, more complete siting analysis information on the alternatives (specifically impacts and mitigation plans) will improve the permitting process.
- There is more public interaction and comment for any large projects, especially for aboveground infrastructure.
- The PSE tariffs are clear and understood by the City relative to services provided under tariff. When multiple non-City utilities are involved in a project, all have Franchise Agreements, and there is some negotiation required to determine who pays for the services depending on the project initiator.
- Future projects are understood at a conceptual level, but the details are not fully appreciated until the permitting process is initiated.
- Coordination between the various utilities requesting right-of-way work could be improved from a planning perspective so that each utility can plan for these opportunities.

4.2.2.6 Recommendations for PSE Interaction

The assessment indicates that there are opportunities to improve the overall knowledge sharing and coordination in the planning and permitting process. While the interactions between the organizations are good due to proximity and history, much of the interaction is based on informal communications. The following recommendations are provided:

- It is recommended that the City engage PSE in an annual planning workshop around large future capital projects. This is the same recommendation that is defined in Section 3. The outcome of these workshops should be an action plan to move projects forward. The intent of this recommendation is to have these major project discussions well in advance of permit applications. PSE has developed and maintains a long-term system planning strategy relative to the electric power system. This plan is generally represented in the IRP. However, as the lead time to permit larger projects (required to add capacity or reinforce the City infrastructure) has grown, it requires that the City understand the projects from a more detailed perspective than just a conceptual framework.

- Both Bellevue and PSE work with various developers and companies to identify new potential facilities in Bellevue. While information is shared for the IRP, and to the extent that information can be shared, it is recommended that a more formal meeting (annually) be held to ensure that all Bellevue needs are identified to PSE and that both organizations are coordinated regarding future load demand. This exercise relates to longer-term issues that are expected to be addressed in the future.

- There are opportunities for multiple utilities to take advantage of projects being performed by one of the utilities. This is a coordination function that is best captured by the City. It is recommended that the City engage their utility partners to identify new projects (both large and small) to attempt to maximize projects in the rights-of-way. This planning activity is intended to take place in advance of permit applications so that the utilities can plan these projects into their annual work. This action also represents a potential means to advance undergrounding of circuits if PSE can take advantage of trenching to add conduits for future use.

4.2.3 Transparency of Operations

The transparency of operations is focused on the communications between PSE and its customers during emergency and outage events. The City has a role to play as a representative of the community. However, PSE has also provided transparency in its operations through the information provided around its various business processes, projects, and plans.

4.2.3.1 Emergency Planning

The emergency response programs are well-defined for the both the City of Bellevue and PSE in their respective policies and procedures. The City of Bellevue maintains its emergency response program in its Emergency Operations Plan.[107] The plan supports and is compatible with King County and state of Washington emergency plans, the National Response Framework, and the Regional Disaster Plan for Public and Private Organizations in King County. Bellevue has adopted the National Incident Management System (NIMS) as the basis for incident management. The plan includes roles and responsibilities for the City departments and also discusses non-governmental agency support. In this case, PSE is identified as an

[107] Reference 28.

organization that will provide support during emergency events when appropriate. When requested, PSE will assign a liaison to the EOC, if available. However, PSE does assign a liaison to the King County Emergency Coordination Center (ECC) if a more regional emergency is called. Bellevue has also implemented programs for first responder “GETS” cards that provide priority access through the phone system. A HAM radio system is employed through the Amateur Radio Emergency Service to address situations where phone towers are down and normal (cell) phone communication cannot be used.

PSE maintains its emergency response program in its Corporate Emergency Response Plan.[108] This document outlines how PSE addresses emergency operations for both its electric and gas systems. Similar to Bellevue, PSE maintains an EOC and is in the process of adopting the NIMS protocol. Some key aspects of the PSE Emergency Response Plan include:

- An electric emergency is defined as:
  - 12 distribution circuits out in one region and escalating
  - 30 distribution circuits out system-wide and escalating
  - Poor weather conditions (wind, snow, ice) predicted
  - Earthquake or other hazardous conditions.
- PSE’s overall response strategy is summarized as:
  - Restoration priorities are assigned for each region.
  - Focus on correcting problems that can be fixed quickly and restore the greatest number of customers.
  - Restore first and then repair (based on conditions of the damage). Damaged sections may be de-energized and service may be restored up to the point of damage.
  - Schedule and complete the repairs.
  - Facilities are generally restored in the following order: transmission, distribution substations, distribution feeders, and individual service. PSE maintains a more detailed list in its Corporate Emergency Response Plan document.
- PSE maintains a list of critical facilities and accepts municipality identification of critical facilities. PSE also maintains a list of locations that require priority for medical reasons (nursing homes, individuals).
- PSE maintains someone onsite at the King County ECC to coordinate on regional events.

108 Reference 29.

- PSE has defined contacts as liaisons with Bellevue even if they do not staff the Bellevue EOC.
- PSE has established agreements with other entities, including their subcontracting partners, to provide resources in an emergency. This includes a Western Region mutual assistance agreement for support from other utilities outside of the area to assist in restoration and repair in a major emergency (such as the 2006 storm event).
- PSE also employs a HAM radio operations system in the event that normal phone service is not available.

The Bellevue and PSE EOCs are similar, but they serve different functions. The PSE plan is related to their service territory and the PSE EOC may be activated without Bellevue needing to activate its own EOC. Similarly, the Bellevue EOC focuses on events in Bellevue, and depending on the emergency conditions, may open without PSE having to activate its center. However, in all cases, there are established interfaces within each organization to provide communication during an emergency. Additionally, both Bellevue and PSE participate in regional emergency planning exercises and have significant information on their websites regarding emergency response.

There are several coordination actions required in order to recover from an electric system emergency outage. Bellevue indicated that they have provided a priority list of critical facilities to PSE so that these are known in advance. Another issue centers on coordination of local city police and fire departments to support PSE crews in getting access to streets and areas to provide assessment, restoration, and repair services. There currently is no formal protocol for handling these interactions in an emergency and they are generally handled informally by requests from PSE to the Bellevue EOC as crews identify needs in the field.

4.2.3.2 Communications with Stakeholders

A major issue during the 2006 winter storm was the lack of communication on the status of the outage and restoration activities. The PSE OMS is currently a manual system as described previously in Section 2.4.6. The system does not currently provide web-based information on specific outage locations and statuses, and the manual process can get overwhelmed in a large outage or emergency.[109] PSE utilizes media outlets to try to communicate during these times; however, this has not been effective in the past at keeping customers at specific locations informed of outage status. Even in a major storm outage (non-emergency), the manual outage management process may be overburdened.

Many utilities are taking lessons learned from major storm events in all parts of the country and are engaging in installation or upgrades to their OMSs. Lessons learned[110] from major storms in

[109] Web-based systems assume that people have access to the Internet, which may not be available during a severe power system outage event.

[110] Reference 35.

the southeast United States indicate the need and the benefits of a fully-integrated computerized system to improve response in major storm events. These integrated systems allow for communication of real-time information to personnel located in multiple locations to facilitate decisions and to update progress. The ability to get visibility into the outage extent and to communicate rapidly with field personnel improves the overall response time. Several other utilities in the Northwest are in the process or have recently upgraded OMSs.

PSE has taken many actions to improve their response to a major event. Some key actions include:

- PSE is currently implementing a major upgrade to its OMS. This upgrade was defined in Section 2.4.6. A key feature of the OMS is that it can automatically locate circuit status visually on a display board that will allow personnel in multiple locations to have access to the data.
- Currently, in a major outage event, where PSE, Bellevue, and King County have activated ECCs and EOCs, communication channels will be strained based on the volume of people needing information. Per their emergency protocols, PSE will communicate from its EOC directly with the King County ECC. The King County ECC communicates with the other governmental entities. Additionally, PSE has liaisons for its various stakeholders and PSE will communicate directly to the City of Bellevue. When completed, the OMS installation should provide a means for faster and more accurate reporting of information.
- The PSE EOC will also issue regular status updates during an emergency. These updates will go to the various EOCs, municipalities, and the news media. The news media (radio) represents a significant distribution channel during major emergency events. PSE also updates its customer call center information to be consistent with releases to the news media. Unfortunately, in a major electric outage, normal communications channels may not be available, and individuals should be equipped with the ability to access the radio news media.

4.2.3.3 Recommendations

The assessment indicates that there are opportunities to improve the communication channel in outage and emergency events. The following recommendations are provided:

- PSE is deploying a new OMS system over the next year that should improve overall outage communications. After deployment, it may be appropriate for selected City personnel involved in emergency response to gain an understanding of the enhanced capabilities in order to better assist in communicating to the Bellevue community.
- There is an opportunity to improve the emergency response and recovery capability between PSE and Bellevue relative to coordination of PSE activities, and Bellevue emergency management, transportation, police, and

fire functions. This opportunity may also include Bellevue staff assisting PSE in identifying damaged areas. It is recommended that the City engage PSE in discussions to develop a formal process for these communications to facilitate response and recovery in the future.

- The improvements in the system over the past 5 years have had a positive impact on reducing outages and duration during normal operation. However, the overall system cannot be hardened sufficiently to prevent major outages for an event similar to the 2006 storm. A storm of this magnitude that impacts the regional transmission system requires significant time to restore power to all customers. It is expected that citizens within the City should be prepared to be without power for up to 3–7 days after this type of event. The City should consider an education campaign to make its citizens aware of the problems and help them to be better prepared to deal with future emergencies.

4.3 Role of the City Recommendations

Bellevue's role as an informed stakeholder requires that the City take an active role in becoming informed on matters affecting the reliability and planning for the electric system in Bellevue. This role includes direct communication with PSE as well as other stakeholders regarding electric service. Based on this review, a set of recommendations were described earlier in this section that focus on planning, permitting, emergency or outage management, and regulatory interface. A summary of the assessment is provided below.

Question:

- "What opportunities are available to the City to work with PSE, regulators (WUTC, FERC), and other stakeholders to ensure the needs and expectations of Bellevue's residents and businesses are met relative to the reliability of the power supply?"

Recommendation 1: WUTC Interaction

Finding: From a WUTC perspective relative to electric power, cities are considered as any other member of the public. Bellevue's primary interaction with WUTC is one of being an active participant relative to changes in laws and tariffs that may affect electric system reliability in the state of Washington.

Reliability Actions: Bellevue's ability to be a knowledgeable stakeholder will require assignment of an engineer knowledgeable in the electric power system to foster the City interaction with stakeholders.

Recommendation 1A: Bellevue's involvement with WUTC may be one of informing lawmakers and commissioners of matters that the City believes affect the City's electric reliability or general electric service. For issues affecting electric reliability that are of interest to the City:

- A designated individual can be assigned to electric system matters. The individual should remain informed of electric system activities related to WUTC.
- On matters of interest to the City, white papers can be developed for submittal to WUTC on issues affecting electric reliability. This provides a means to provide feedback to WUTC without direct response to hearings. Potential policy matters could be advanced using this approach.

Recommendation 1B: Bellevue has the opportunity to comment or participate in matters directly affecting PSE and their interaction with WUTC. Bellevue also has the ability to support and advocate for initiatives that meet its goals and objectives. The recommended actions are:

- The City can support or advocate for PSE positions of interest to Bellevue. As programs and rate discussions take place between WUTC and PSE, the City has the opportunity to advocate for positions that support City goals.
- The City should comment and participate in various programs submitted to WUTC by PSE, where PSE is seeking advisory input from stakeholders including the IRP, Smart Grid plan, and reliability programs.

Recommendation 2: Major Project Planning

Finding: The assessment indicates a need to review and update the utility growth plans in the Comprehensive Plan. The large capacity projects will require significant lead time for siting analysis and permitting.

Reliability Actions: Conduct major project discussions well in advance of permit applications to ensure sufficient lead time to permit larger projects (required to add capacity or reinforce the City infrastructure).

Recommendation 2: It is recommended that the City engage PSE in an annual planning workshop around future capacity and expansion projects. The Comprehensive Plan includes an electric system plan that can serve as the basis for the annual workshop. The workshop should focus on the following items:

- Current growth projections and electric power use in Bellevue (see Recommendation Role 3)
- Review of current plan applicability (Figure UT.5a)
- Update of the current plan
- Develop actions for capacity projects required to initiate siting and permitting activities within the next 2 years.

An outcome of the workshop should be an updated plan for inclusion in the Comprehensive Plan (if required), and an action plan to move designated projects forward into siting analysis and/or planning.

As a minimum, the following capacity additions have been identified as being needed within the next 5–10 year time frame:

- Upgrade of the existing 115 kV lines to 230 kV
- Addition of transformer banks to support expected growth in various areas of the City (Downtown, Bel-Red, and Somerset/Eastgate)
- Addition of new 115 kV lines to reinforce the overall electric system.

As previously stated, based on recent Exponent staff experience with T&D capital projects, typical time frames for projects of this size and complexity are as follows:

- Transformer additions require 18−24 months to complete from start of engineering to operation. Additional time is required for planning and permitting.
- Line projects may require 4−5 years from the start of engineering to completion since permitting of lines typically requires significant engineering to be completed before the formal permitting process proceeds.

Recommendation 3: Long-Range Planning

Finding: Both Bellevue and PSE work with various developers and companies to identify new potential facilities in Bellevue. There is an opportunity to share and communicate the results of these planning activities. This exercise relates to longer-term issues that are expected to be addressed in the future.

Reliability Actions: Coordination of Growth Planning and Major Project Activities

Recommendation 3: While information is shared for the IRP, and to the extent that information can be shared, it is recommended that a more formal meeting (annually) be held to ensure that all of Bellevue’s needs are identified to PSE and that both organizations are coordinated regarding future load demand. This information sharing can also be included in the annual planning meeting.

The City and PSE should synchronize their growth projections for the City by frequent information exchange on expected projects, expected timing of projects, and coordination actions required by PSE and the City to address these projects. This exchange is meant to assist longer-term planning and should occur well in advance of any specific permitting or development activities.

Recommendation 4: Multi-Utility Planning

Finding: There are opportunities for multiple utilities to take advantage of projects being performed by one of the utilities.

Reliability Actions: This action also represents a potential means to advance undergrounding of circuits if PSE can take advantage of trenching to add conduits for future use.

Recommendation 4A: It is recommended that the City engage their utility partners to identify new projects (both large and small) to attempt to maximize projects in the rights-of-way. This planning activity is intended to take place in advance of permit applications so that the utilities can plan these projects into their annual work.

Recommendation 4B: The City can take advantage of projects that require trenching to place conduit for future use of potential undergrounding. The existence of conduit may allow for more economic alternatives for undergrounding in the future. This action requires City planning to identify future projects that require trenching and to discuss with PSE the placement of conduit. This will be an ongoing action as projects are defined, but can be coordinated through the City Planning Department. (This action is associated with Recommendation Current 3A).

Recommendation 5: Emergency Response Capability

Finding: There is an opportunity to improve the emergency response capability between PSE and Bellevue relative to coordination of PSE activities (e.g., Bellevue transportation, police, and fire functions). Currently, the coordination activities are more informal and on an as-needed basis. This opportunity may also include Bellevue staff assisting PSE in identifying damaged areas.

Reliability Actions: The ability to improve recovery time in Bellevue after an outage can be improved by better coordination between City first responders and PSE crews.

Recommendation 5: The City and PSE should consider the development of a more formal process (procedure) related to response and support activities during an outage. The ability to coordinate activities (especially during a major outage) may include the following activities:

- Locating damage
- Coordination of access to areas of damage
- Access to PSE outage information
- Coordination of recovery plans
- Emergency support to people in need.

The outcome should be an agreement (or procedure) for communication and coordination during large scale events affecting Bellevue.

REDACTED

Eastside Needs Assessment Report

Transmission System
King County

Redacted Draft

October 2013

Puget Sound Energy

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Section 1 Executive Summary

The analysis discussed in this report verified that there is a transmission capacity deficiency in the Eastside area of Lake Washington which will develop by the winter of 2017-18. This transmission capacity deficiency is expected to increase beyond that date. Cities in the deficiency area include Redmond, Kirkland, Bellevue, Clyde Hill, Medina, Mercer Island, Newcastle and Renton along with towns of Yarrow Point, Hunts Point, and Beaux Arts.

Assessment Objective

The objective of this needs assessment is to assess the sufficiency of transmission supply within the next 10 years to Puget Sound Energy's customers and communities on the east side of Lake Washington.

As part of the mandatory North American Electric Reliability Corporation (NERC) Compliance Enforcement Program[1], PSE performs an annual comprehensive reliability assessment[2] to determine if any potential adverse impacts to the reliability of delivery of electricity exist on the PSE transmission system. During the 2009 comprehensive reliability assessment[3], PSE determined that there was a transmission reliability supply need developing due to the loss of one of the Talbot Hill Substation[4] transformers.

Since 2009, other issues have also been identified which impact this portion of the PSE system. These issues include concerns over the projected future loading on the Talbot Hill Substation, increasing use of Corrective Action Plans (CAPs) to manage outage risks to customers in this portion of the PSE system, and regional transmission reinforcement needs that were identified by ColumbiaGrid studies to support the movement of power from existing wind generation and hydroelectric generation across the Cascade Mountains to load centers around the Puget Sound.

The study described in this report focused specifically on the central King County portion of the larger PSE system in order to provide a more focused needs assessment. The timing of this study was intended to provide sufficient lead time to implement viable, long term solutions before the issues identified by the study develop. This report discusses the review of the current transmission infrastructure to support the current load and the future load growth in this area.

Method and Criteria

The studies documented by this report are collectively referred to as the "2013 Eastside Needs Assessment." 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. In 2009, as part of

[1] NERC Reliability Standards for the Bulk Electric Systems of North America

[2] PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report

[3] 2009 PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report

[4] Talbot Hill Substation is located in Renton

the TPL-001 through TPL-004 Compliance Report, PSE's analysis showed that there was a potential thermal violation with the loss of one of the two transformers at Talbot Hill Substation. For the 2013 Eastside Needs Assessment, PSE performed an updated analysis to evaluate if this potential thermal violation would still exist with updated load forecasts. The 2013 Eastside Needs Assessment was performed consistent with the mandatory NERC TPL annual comprehensive analysis. Supplemental performance studies were also performed to provide a clear understanding of the location and causation of these potential thermal violations.

For the 2013 Eastside Needs Assessment, PSE used the WECC 2012 series base cases to develop the 2013-14, 2017-18, and 2021-22 heavy winter cases. These cases were set up to account for normal weather with 100% of the forecasted level of conservation and were updated with the current PSE system configuration and load information. To better understand the extent of the need and risks faced by customers in this portion of the PSE system, sensitivity studies were conducted to evaluate performance under different levels of conservation. Sensitivities studies were also conducted to assess system performance under extreme weather conditions that are expected to occur once every twenty years.

This assessment also reviewed the near and long-term summer cases run for the 2012 NERC Transmission Planning (TPL) standard requirements. For the TPL report, cases had been developed for heavy summer of 2014 and 2018 using the 2012 WECC series base cases. These cases were set up to account for normal summer weather with 100% of the forecasted level of conservation and were updated with the current PSE system configuration and load information.

This analysis covered PSE facilities that are part of the Bulk Electric System (BES) and the interconnected system covered by the Western Electricity Coordinating Council (WECC). BES facilities must be studied in accordance with the latest approved versions of the mandatory NERC Reliability Standards and the WECC Reliability Standards[5]. These standards set forth the specific methods for studying the performance of the transmission system – 100 kV and above – and govern how that system is planned, operated and maintained.

In addition to the mandatory reliability standards, PSE has also issued Transmission Planning Guidelines[6] which describe how to plan and operate PSE's electric transmission system. These guidelines are in place to encourage the optimal use of the transmission system for service to loads and generators while complying with the mandatory standards. These guidelines also support transfers between utilities, when applicable, to support economic use of available resources.

Performance criteria are also established to determine if a need exists to improve the system. These performance criteria serve as a baseline to measure performance and to identify where reinforcements may be needed. The needs documented in this report were determined by whether or not the study area would perform such that it satisfied all approved applicable NERC, WECC and PSE transmission performance criteria[7].

Study Assumptions

The following key assumptions were adopted to more fully understand the potential reliability impacts:

- The study horizon selected was the ten year period from 2012 to 2022.
- System load levels used the PSE corporate forecast published in June 2012.

[5] TPL-001-WECC-CRT-2 – System Performance Criterion Under Normal Conditions, Following Loss of a Single BES Element, and Following Extreme BES Events

[6] PSE Transmission Planning Guidelines, November 2012

[7] PSE Transmission Planning Guidelines, pages 3-5 & 7, November 2012

- Area forecasts were adjusted by substation to account for expected community developments as identified by PSE customer relations and distribution planning staff.
- Generation dispatch patterns reflected reasonably stressed conditions to account for generation outages as well as expected power transfers from PSE to its interconnected neighbors.
- Winter peak Northern Intertie transfers were 1,500 MW exported to Canada.
- Summer peak Northern Intertie transfers were 2,850 MW imported from Canada.

Specific Areas of Concern

The 2013 Eastside Needs Assessment was a fresh look at current and future system conditions which did not pre-judge the existence of any specific issues on the PSE system. Since 2009 a variety of concerns have been identified and these were investigated in the analysis. During the course of the analysis, some additional potential problems were identified that also were evaluated. The major issues include:

1. Overload of PSE Facilities in the Eastside Area: Several previous studies had identified potential overloading of transformers at Sammamish and Talbot Hill Substations[8]. These include the 2008 Initial King County Transformation Study, 2009 PSE TPL Planning Studies and Assessment, and the 2012 PSE TPL Planning Studies and Assessment[9]. Those studies indicated that potential thermal violations may occur on facilities from Talbot Hill Substation to Sammamish Substation. The 2013 Eastside Needs Assessment validated those concerns and identified transmission supply needs that focused on two 230-115 kV supply injections into central King County at Sammamish and Talbot Hill Substations. In the 2013 Eastside Needs Assessment the team found:

    - For the winter peak at approximately 5,200 MW (2017-18 in the model) there are two 115 kV elements with loadings above 98% for Category B (N-1) contingencies and five 115 kV elements above 100% for Category C (N-1-1 & N-2) contingencies.

    - For the summer peak at approximately 3500 MW (2018 in the model), there are two 230 kV elements above 100% and two 115 kV elements above 93% loadings for Category B (N-1) Contingencies. Also there are three elements above 100% loading and one above 99% loading for Category C (N-1-1) contingencies.

2. Small Margin of Error to Manage Risks from Inherent Load Forecast Uncertainties: The 2012 Corporate load forecast for winter under normal weather conditions and 100% conservation indicates load increases 138 MW from 2013-14 to 2021-22 (Figure 1-1), or about 17 MW of increased load per year. This annual increase is significantly lower than previous forecasts and is much lower than the 2011 forecast of approximately 22 MW per year[10],

    In extreme weather, system load can be much higher than this forecast. To illustrate, Figure 1-1 shows that the difference in forecast load between normal and extreme winter weather for the year 2014 is actually 497 MW – almost 10 percent of the total PSE load (assuming 100% of the forecast conservation for both). Normal weather represents the projected load at 23° F and extreme weather represents the projected load at 13° F. As the temperature gets close to 13° F, the forecasted load in any given year could easily surpass the entire 138 MW load increase projected for the 10 year study period. This effect has occurred recently on the

[8] Sammamish Substation is located in Redmond. Talbot Hill Substation is located in Renton.

[9] The 2010 and 2011 TPL Planning Studies also identified the Lakeside 230-115 kV transformer as needed and planned for 2016. It did not show up as a deficit in the long term due to being modeled as installed by the long term case year.

[10] 2011 PSE IRP Section H Page H-12 from 2010 to 2017

PSE system. In winter 2009, the system hit an all-time peak of 5038 MW[11] at a temperature of 16° F, which was 194 MW higher than the 2009 forecast for normal weather peak load in 2009 . This 2009 actual peak load level is also higher than the 2012 forecast for normal system peak load in 2021.

The 2013 Eastside Needs Assessment shows a load level of need at approximately 5,200 MW winter peak. To illustrate the importance of conservation in our modeling, the team forecasted PSE load levels under a variety of conditions. If only 75% of forecasted conservation materializes, the 5,200 MW load level would be hit as early as 2015 under normal weather conditions. Even if 100% conservation is achieved, under extreme weather conditions PSE could exceed the 5,200 MW level during the winter 2013-14. These winter peak forecast sensitivities are illustrated in Figure 1-1:

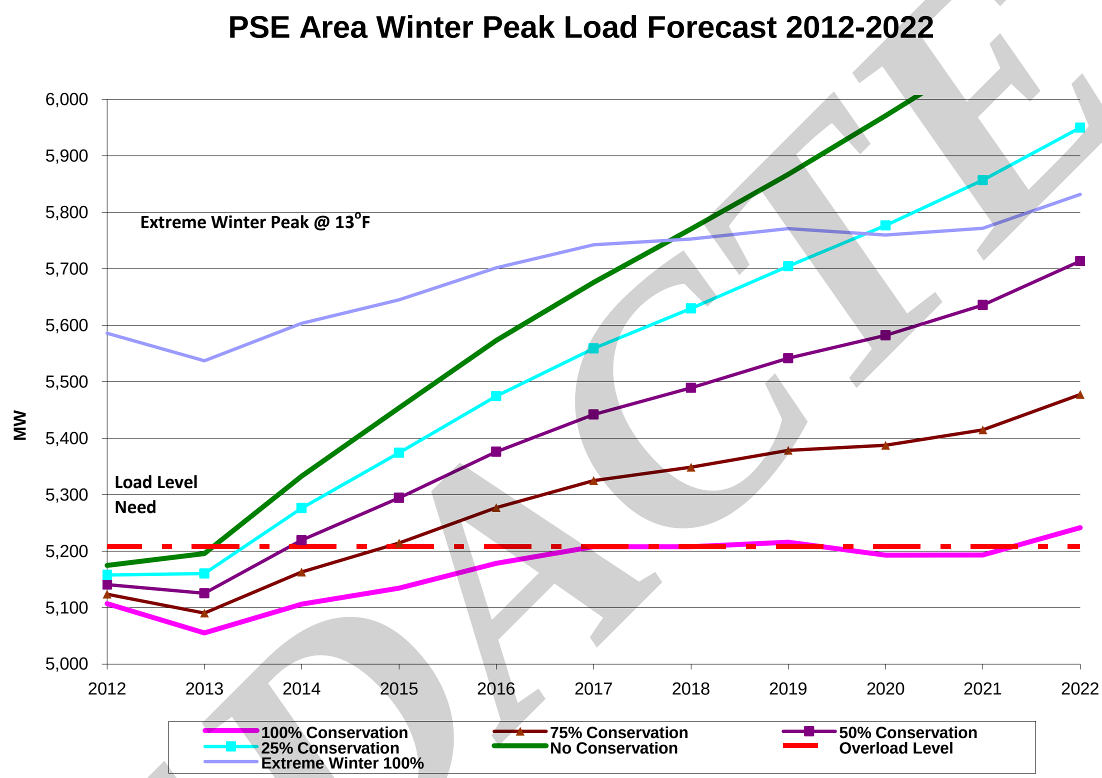

Figure 1-1: Corporate System Load Forecast for Winter 2012 to 2022

The 2013 Eastside Needs Assessment shows a summer load level of need is approximately 3340 MW (Figure 1-2). Summer peak load is calculated for an 86° F peak day. This load level could occur as early as 2014 and becomes more likely with time. While PSE has traditionally been a winter peaking utility, the increase in commercial load has driven summer load growth disproportionately higher than the winter growth in recent years. The projected summer peak growth is on average approximately 37 MW per year. The corporate load forecast does not indicate loading for an "extreme summer" peak, which would be expected to be higher than shown on these projections.

[11] This does not include approximately 270 MW of load on PSE's system served by other transmission providers.

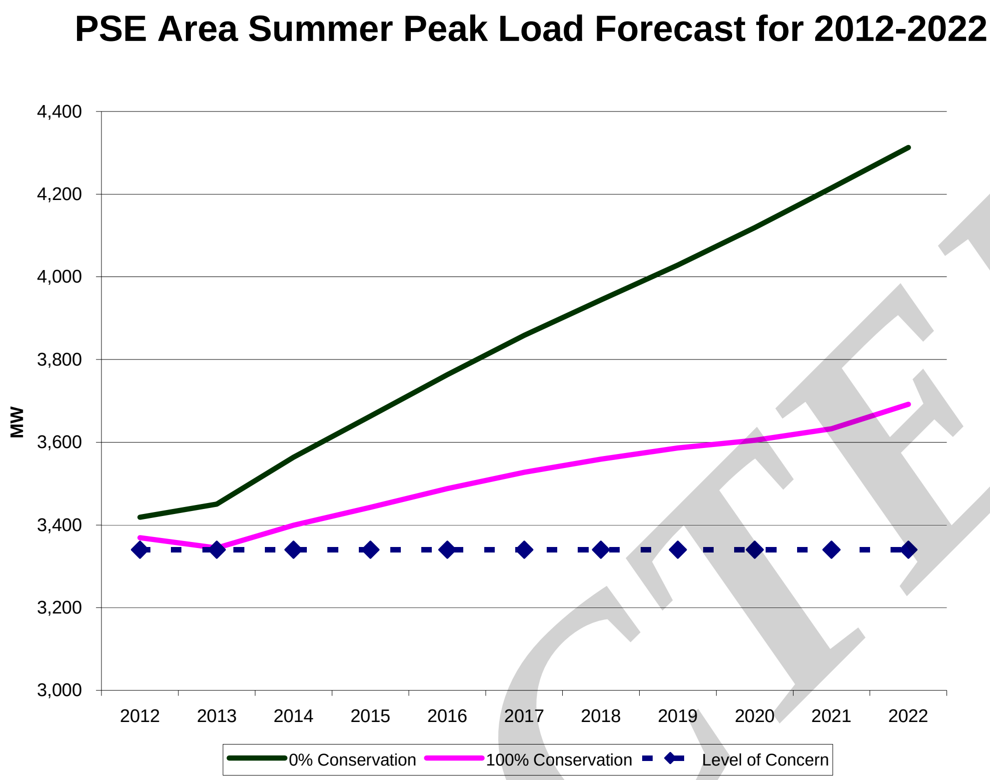

Figure 1-2: Corporate Load Forecast for Summer Peak from 2012 to 2022

3. Increasing Use and Expansion of Corrective Action Plans: An existing CAP in place to prevent overloads in the winter on either of the Talbot Hill transformer banks is increasing outage risk to customers. This CAP is to manually open [redacted], which removes [redacted]. Taking this step reduces the inherent reliability of the network since the transmission system cannot handle as many contingencies without overloads, voltage issues or loss of customers' power.

As the PSE system load grows, the overload of either Talbot Hill transformer at winter peak may not be sufficiently reduced by this CAP. If loading on the overloading transformer is not reduced by use of the existing CAP, then [redacted] and [redacted] will also be opened. In addition to the reduction in reliability discussed above, opening these four 115 kV lines results in splitting northern King County from southern King County and puts approximately 32,400 customers at risk of outage, being served by just 1 transmission line without a backup line available (i.e., "radial supply"). This action also puts an additional 33,000 customers in Bellevue and Kirkland at risk of outage should there be an outage of [redacted] while the north and south systems are operating separately.

There are two contingencies in the north end of King County that would trigger a CAP under summer conditions. These contingencies are (1) the loss of [redacted] along with the loss of the [redacted]; and (2) the loss of the [redacted] along with the loss of [redacted]. This CAP would open [redacted]. Taking this action places 33,000 customers at risk of outage should an additional transmission line outage occur. The 33,000 customers are served from two separate lines, so a single line outage would take out approximately half of the 33,000.

4. Emerging Regional Impacts Identified by ColumbiaGrid: ColumbiaGrid was formed in 2006 by regional utilities to improve the operational efficiency, reliability, and planned expansion of the Northwest transmission grid through an open and transparent process. The ColumbiaGrid produces a Biennial Transmission Expansion Plan that addresses system needs in the Pacific Northwest, including the PSE system. The latest report indicated a need to improve the dependability of the transfer capability through the Puget Sound Area. This need occurs during high load conditions and much of the rest of the year as facilities such as transmission lines are taken out of service to do required maintenance and improvements. ColumbiaGrid indicated that a reduced risk of curtailments is needed to reliably deliver power from regional and renewable generation such as PSE's wind generation in eastern Washington, to King County. Also, there are regional commitments to increase flows across the Northern Intertie to 2300 MW that will show up in the ten-year time frame.

   To significantly reduce regional curtailments, ColumbiaGrid identified six specific projects which include installing inductors on the 115 kV system in Seattle, adding a 500-230 kV transformer at BPA's Raver Substation in south King County, and increasing 230 kV south-north transmission capacity along the Eastside.

Statements of Need

The 2013 Eastside Needs Assessment confirmed that by winter of 2017-18, there is a transmission supply need on the Eastside of Lake Washington which impacts PSE customers and communities in and around Kirkland, Redmond, Bellevue, and Newcastle along with Clyde Hill, Medina, and Mercer Island. The supply need focuses on the two 230 kV supply injections into central King County at Sammamish Substation in the north and Talbot Hill Substation in the south. The transmission supply becomes a need at a PSE load level of approximately 5,200 MW, where overloads will result in operating conditions that will put thousands of Eastside customers at risk of outages. According to PSE projections, demand is expected to exceed this level in winter 2017-18.

The assessment also identified that higher overloads are expected to develop as load grows beyond the 5,208 MW (100% conservation) shown in 2017-18. For example as shown below, if only 75% of the conservation forecast is achieved - equivalent to 5,300 MW load in that same time period, the overloads will have grown. By the end of the 10 year study period, the study indicates that overloads will continue to grow even with all of the projected conservation in effect. These possible overloads will result in more hours operating under conditions that will put thousands of Eastside customers at risk of outages.

Under both load forecast conditions (full conservation and 75% conservation), the overloads occur for both Category B contingencies which are the loss of a single element (i.e., "N-1") and Category C contingencies which are the loss of more than one element, (i.e., "N-1-1" or "N-2"). Table 1-1 shows the overloads expected by 2017-18 for winter peak under normal weather conditions.

Table 1-1: Potential Thermal Violations for 2017-18 Winter Peak with Normal Weather

	2017-18 Winter Peak	2017-18 Winter Peak
	5208 MW	5325 MW
Contingency	100% Conservation	75% Conservation
Cat B (N-1)	Talbot Hill - Lakeside #1 115 kV line – 98.6%	Talbot Hill - Lakeside #1 115 kV line – 99.9%
	Talbot Hill - Lakeside #2 115 kV line – 98.4%	Talbot Hill - Lakeside #2 115 kV line – 99.8%
	Talbot Hill 230-115 kV transformer #2 – 90.3%	Talbot Hill 230-115 kV transformer #1 – 90.9%
		Talbot Hill 230-115 kV transformer #2 – 92.4%
Cat C (N-1-1)	Talbot Hill-Lakeside #1 115 kV Line - 127.8%	Talbot Hill-Lakeside #1 115 kV Line - 129.9%
	Talbot Hill-Lakeside #2 115 kV Line - 127.6%	Talbot Hill-Lakeside #2 115 kV Line - 129.7%
	Talbot Hill 230-115 kV transformer #1 - 105.7%	Talbot Hill 230-115 kV transformer #1 - 108.1%
	Talbot Hill 230-115 kV transformer #2 - 105.7%	Talbot Hill 230-115 kV transformer #2 – 107.6%
	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 110.6%	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 112.5%
	Shuffleton – O'Brien 115 kV Line – 97.9%	Shuffleton – O'Brien 115 kV Line – 99.7%
	Shuffleton – Lakeside 115 kV Line – 97.3%	Shuffleton – Lakeside 115 kV Line – 98.9%
Cat C (N-2 or Common Mode)	Talbot Hill-Lakeside #1 115 kV Line - 101.5%	Talbot Hill-Lakeside #1 115 kV Line – 100.5%
	Talbot Hill-Lakeside #2 115 kV Line - 101.1%	Talbot Hill-Lakeside #2 115 kV Line – 103.0%
	Talbot Hill 230-115 kV transformer #1 – 91.8%	Talbot Hill 230-115 kV transformer #1 – 93.8%
	Talbot Hill 230-115 kV transformer #2 – 92.8%	Talbot Hill 230-115 kV transformer #2 – 94.4%

The analysis also identified that overload conditions will occur for Summer Peak conditions under normal weather. These overloads can occur as early as 2014 with a load level of approximately 3,300 MW. These overloads increase by the year 2018 when the load is expected to increase to 3,500 MW. Those issues are listed in Table 1-2.

Table 1-2: Potential Thermal Violations for 2014 and 2018 Summer Peak with Normal Weather

	2014 Summer Peak	2018 Summer Peak
	3343 MW	3554 MW
Contingency	100% Conservation	100% Conservation
Cat B (N-1)	Monroe-Novelty Hill 230 kV line - 132.6%	Monroe-Novelty Hill 230 kV line - 133.0%
	Maple Valley - Sammamish 230 kV line - 111.4%	Maple Valley - Sammamish 230 kV line - 132.3%
		Talbot Hill - Lakeside #1 115 kV line - 93.9%
		Talbot Hill - Lakeside #2 115 kV line - 93.8%
Cat C (N-1-1)	Sammamish 230-115 kV transformer #1 - 95.5%	Sammamish 230-115 kV transformer #1 - 100.7%
	Sammamish 230-115 kV transformer #2 - 100.8%	Sammamish 230-115 kV transformer #2 - 106.4%
		Beverly Park - Cottage Brook 115 kV line - 100.5%
		Sammamish - Lakeside #2 115 kV line - 99.8%

When winter load reaches the point that overloads are possible, PSE or BPA would use CAPs to automatically or manually prevent overloads under the NERC reliability requirements. The CAPs required to prevent N-1-1 overloads would open lines between Sammamish and Talbot Hill. Some of the CAPs place customers at risk of outage due to transmission lines being switched to a radial supply, with no backup transmission line available. Load growth by the end of the 10 year study period will result in additional lines required to be opened, putting over 60,000 customers at risk of resulting outages. Some of the CAPs are set up today as BPA nomograms or PSE manual corrective action plans. If extreme winter weather were to occur today, loading would be high enough that CAPs would be employed to remain NERC compliant.

Future load growth will result in additional lines required to be opened, putting over 60,000 customers at risk of resulting outages. Additional power supply is needed in the central King County area to prevent overloads and outages, see .Figure 1-3.

The diagram below indicates areas at risk of outage if switching is performed to prevent overloads, and then subsequent outages occur on transmission lines that had been switched open. The subsequent outages could be due to radial lines experiencing faults due to car-pole accidents, lightning, or tree limbs. Outages could also occur if PSE dispatchers must drop load to prevent transformer overloads while transmission lines are switched open. In the diagram, green lines indicate a line or transformer whose loss during peak winter load could result in overloads of other system elements. The gold colored lines indicate those lines or transformers at risk of overloading when the green element trips out. The gray shaded areas indicate where customers would be at risk of outage from switching to mitigate the overloads.

This study finds that within the 10 year study period, additional transmission supply to the Eastside is needed to meet future demand growth of the area.

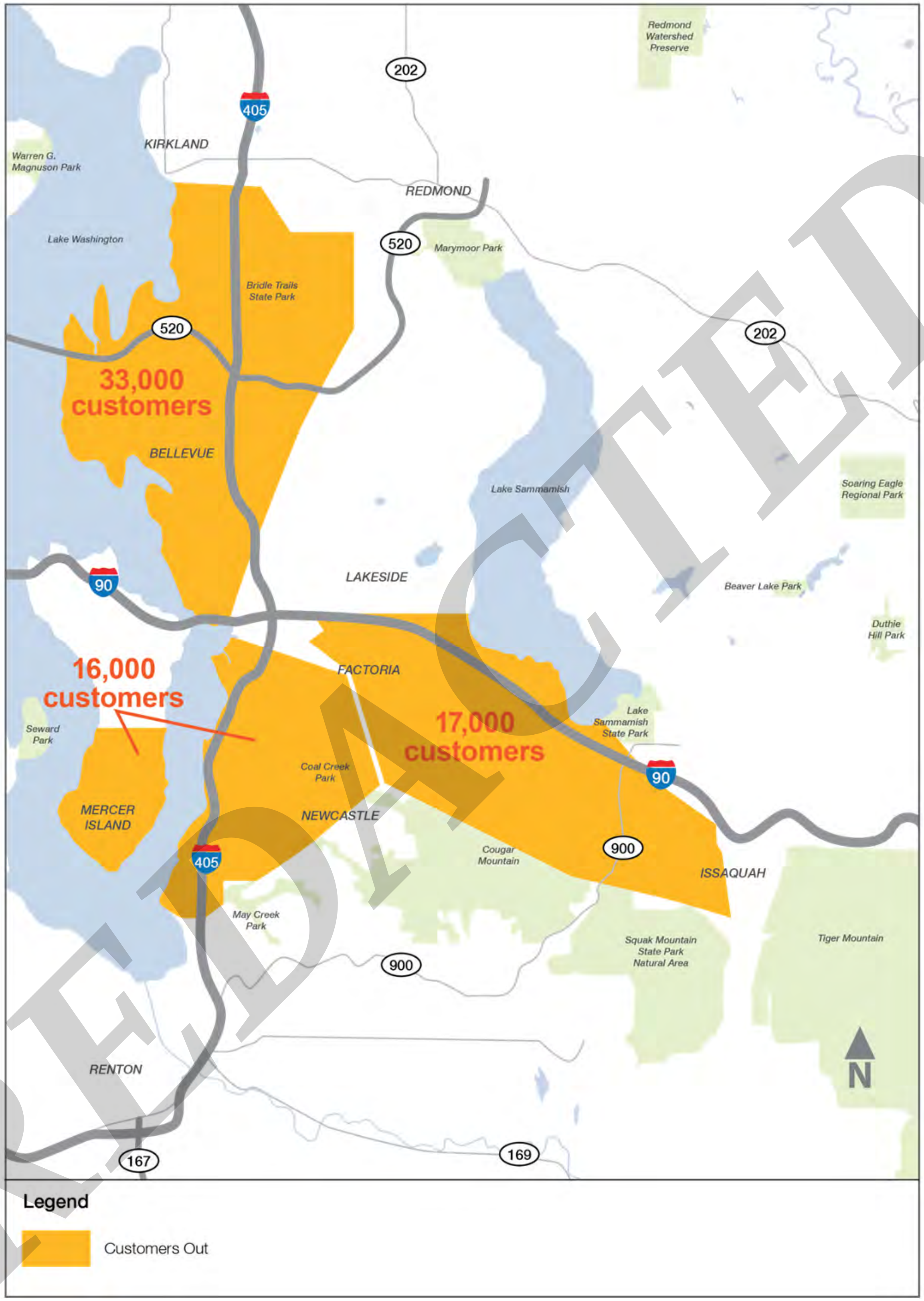

Figure 1-3: Topological View of the Needs Assessment of the Eastside of Lake Washington

Section 2 Introduction and Background Information

2.1 Study Objective

The study objective was to assess the capability of existing transmission infrastructure to supply the communities on the east side of Lake Washington, called the "Eastside", within Puget Sound Energy's (PSE's) central King County area. These communities include Bellevue, Kirkland, Redmond, Mercer Island, and Newcastle as well as the smaller towns along the shore. A review was performed to determine the needs for future transmission supply to the Eastside. This study review was performed due to concerns identified in 2009 TPL studies that were related to the projected future loading on the Talbot Hill Substation, future requirements of the Columbia Grid, and operational issues of PSE's control area. These supply issues were exacerbated by impacts on the PSE system due to Puget Sound Area Northern Intertie (PSANI) related events during winter supply conditions and heavy south to north flows that had been identified in analysis conducted by Columbia Grid.

This present report reviews the entire infrastructure, and design of the transmission system with respect to present and future viability. The following tasks were completed as part of this study review and are discussed in this report: (i) updated the block load forecast of the King County area; (ii) merged this block load forecast into the 2012 PSE system load forecast (iii) conducted future performance simulations of the King County area for the years 2014, 2018 and 2022; (iv) reviewed the Columbia Grid 2013 Biennial Transmission Expansion Plan; and (v) reviewed operational issues with PSE's control area operators; and (vi) aligned the recommendations with the recommendations from the Columbia Grid analysis of PSANI events under heavy south to north flows.

Quanta Technology, LLC., assisted Puget Sound Energy in conducting this study, including research, analysis and documentation.

2.2 Background Information

One of the major drivers in the determination of need for additional transmission facilities is the existing load on the system and the projected load growth that is expected to occur. As early as 2008, PSE had indications that additional transmission supply was needed to support the central King County portion of PSE's service territory. In 2008, PSE conducted a King County Transformation Study that indicated increased loading had occurred at the Talbot Hill Substation, which has two 230-115 kV transformers. Concerns were noted that if load continued to grow in the area, then by 2017-18 one transformer would overload if the other transformer tripped off-line. This study used the F2008 Puget Sound Energy Electric Load Forecast.

The needs for additional transmission sources into central King County were confirmed while performing the mandatory NERC 2009 reliability compliance studies. In that analysis, PSE observed a potential thermal issue when there was a bus fault at Talbot Hill Substation. The bus fault caused the overload of a Talbot Hill transformer for the loss of the other transformer for the 2010-2011 winter peak[12]. Based upon the adjusted 2009 PSE load forecast, the peak load modeled in the 2010-2011 Winter peak case was 5,329 MW[13]. For the 2018-2019 Winter peak case a load of 5,765 MW was modeled.

To resolve this equipment overload, a temporary measure of manually switching out two 115-kV lines from Talbot Hill –Lakeside was identified as a Corrective Action Plan (CAP) that could be used to mitigate the overload[14]. The CAP would be used at a PSE load level of approximately 5,300 MW. At that time, PSE implemented the CAP and has been using it in its operations for managing the reliability of service in that area.

[12] Page 13, 2009 PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report

[13] Page 7, 2009 PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report

[14] Page 22, 2009 PSE Planning Studies and Assessment TPL-001 to TPL-004 Compliance Report

In early 2009, PSE's corporate load forecast group responded to the national economic crisis to re-evaluate the projected load forecast. The resulting revision reduced the forecast 2010-11 winter peak by 3% from the previous year's forecast.

In 2009, PSE set their all-time record loads for both the winter and summer seasons. The 2009 winter peak load was 5,038 MW and the 2009 summer peak was 3,509 MW. This compares with a 2009 forecast of 4,973 MW for winter and 3,086 MW for summer. Neither the forecast number nor the peak load includes the 270 MW of transmission level customers used in the area load. It should be noted that the 2009 winter peak forecast assumed a normal winter temperature of 23° F, while the peak load occurred with a temperature of 16°F. For a discussion of the forecast methodology and the limitations on its use, see Section 4.1.5.

2.3 King County Area Description

King County is a major load center of the Puget Sound Region. The Eastside area is in central King County and includes the cities of Redmond, Kirkland, Bellevue, Mercer Island, Newcastle and Renton, as well as the smaller towns of Yarrow Point, Hunts Point, Medina, Clyde Hill and Beaux Arts. The greater Eastside area also includes towns and cities to the north and east of the core area which are not a focus of this study: Bothell, Woodinville, Duvall, Carnation, Sammamish, Issaquah, Preston, Fall City, Snoqualmie, and North Bend.

Figure 2-1 Street Map of Eastside Area

The load density of north King County is shown below in Figure 2-2. The map shows that the most densely populated areas, shown in red, of King County are Kenmore, Kirkland, Redmond, Bellevue, and Renton.

The easterly border of King County is along the Cascade Mountain Range, which creates a natural obstacle between the densely populated western Washington communities clustered around Seattle and Tacoma, and the sparsely populated arid region of eastern Washington.

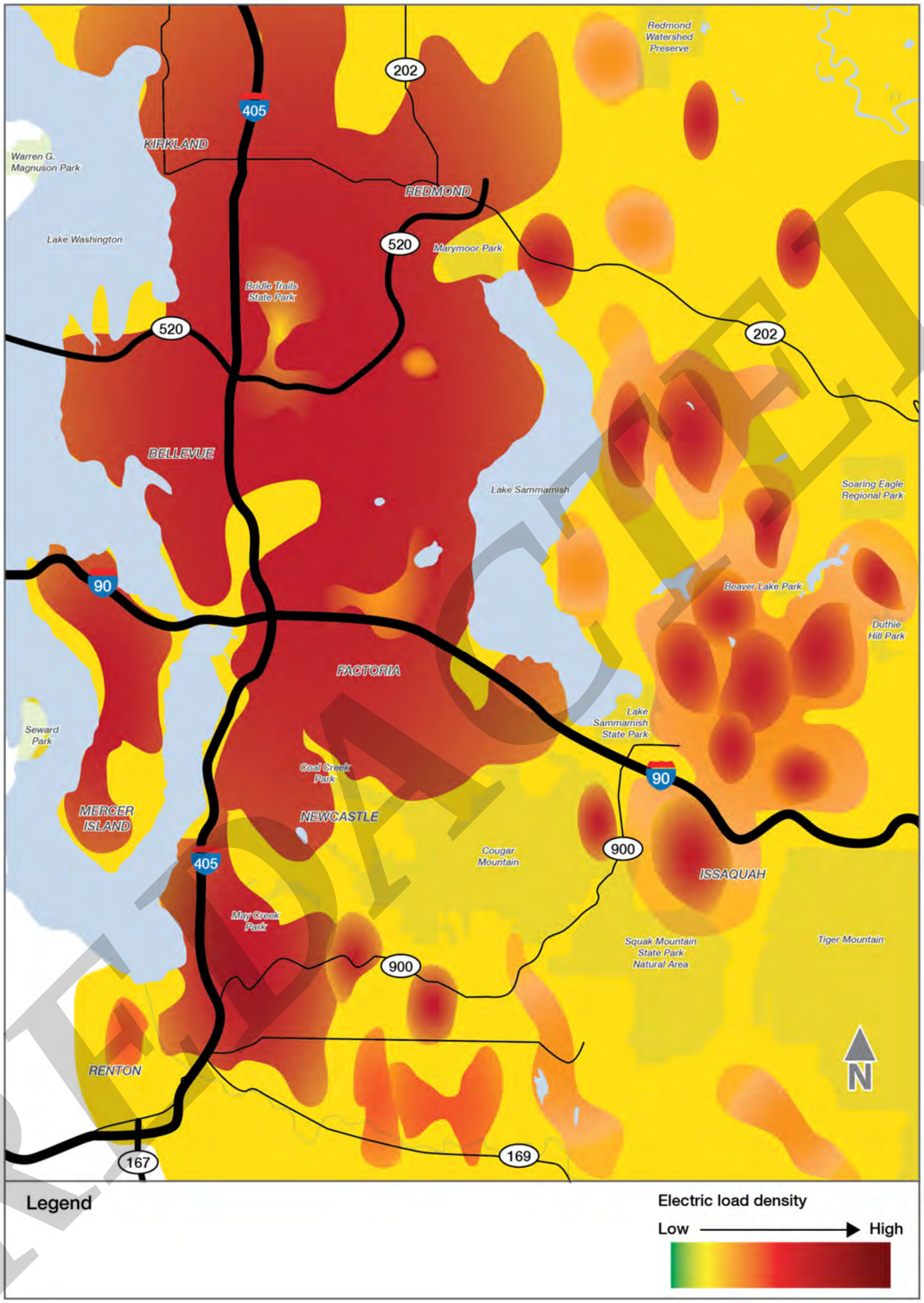

Figure 2-2: King County Load Density Map

The King County load is supplied from Bonneville Power Administration's (BPA) 500 kV sources at Monroe (Monroe), SnoKing (Mill Creek) Maple Valley (Renton), and Covington (Covington) Substations, as well as 500 kV switching stations at Echo Lake (south of Snoqualmie) and Raver (Ravensdale). There is very little generation in King County; a small amount of hydro generation in eastern King County provides less than 5% of the county's peak load requirements. Therefore PSE depends on its transmission system and on transmission interconnections with neighboring utilities to bring power to its load center in King County.

King County also has 230 kV supply from the following substations: Sammamish (Redmond), Novelty Hill (Redmond Ridge), Talbot Hill (Renton), O'Brien (Kent), and Berrydale (Covington). To serve the loads in King County, there are eight 230 kV/115 kV transformers; two at Sammamish, two at Talbot Hill, and one at Novelty Hill, two at O'Brien, and one at Berrydale. North King County load is generally served by Sammamish and Novelty 230 kV sources but due to the interconnecting nature of the system, Talbot Hill transformers serve part of the North King and South King systems. Sammamish and Novelty Hill are both connected to the Monroe-Maple Valley 230 kV line, which is leased from BPA. See Figure 2-3 and Figure 2-4 on the following pages.

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Figure 2-3: Puget Sound Area System Overview One-Line Diagram

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Figure 2-4: Major Electrical Infrastructure Supporting the Eastside Area

The 11 - 115 kV lines out of Lakeside Substation serve 15 substations in Bellevue and 14 substations in Newcastle, Issaquah, Mercer Island, Medina, Kirkland and Redmond, as shown in Figure 2-5. Lakeside Substation is supplied by 230-115 kV transformers at Sammamish and Talbot Hill. Lakeside connects to switching stations at Shuffleton (Renton), Lake Tradition (Issaquah) and Ardmore (Bellevue). In the Eastside area, when regional power flows are from south to north the power serving the Eastside will generally flow from south to north. In this case, power for the Eastside starts at Talbot Hill and flows north to Lakeside and continues to Sammamish Substation. When regional flows are north to south, Talbot Hill will still feed north past Lakeside but power will also flow south out of Sammamish Substation which feeds approximately sixty percent of the load between Sammamish and Lakeside Substations during north-south regional flows. Talbot Hill is a strong source of supply between Lakeside and Sammamish Substations.

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Figure 2-5 One-Line Diagram of Eastside Study Area

All of the 115 kV transmission lines in the Eastside area have been uprated to their maximum capacity ratings, except the two lines to Mercer Island, which operate normally open. PSE has two 115 kV transmission lines on separate structures on a transmission right of way (ROW) between Sammamish and Talbot Hill Substations, which interconnect at Lakeside Substation. There are three 115 kV lines in parallel with this corridor in the north, two lines in parallel in the south, all supplying load to distribution substations.

The Bellevue area is a higher-density load center without a 230 kV bulk transmission source nearby. With 230 kV supplies in the north at Sammamish Substation and the south at Talbot Hill Substation, lower-capacity 115 kV transmission lines bring power to Bellevue from the 230 kV transmission substations in Redmond and Renton.

2.4 Study Horizon

PSE has studied the Eastside area for the near-term (years 1-5) and long-term (years 6-10) horizons. Since PSE peaks during the winter season, the reliability analysis focused on the winter peak for years 2013-14, 2017-18, and 2021-22. Summer peak was also analyzed for years 2014 and 2018 for the annual 2012 NERC TPL analysis; the 2012 NERC TPL summer results were included in this study.

Section 3 Analysis Description

A number of comprehensive reliability analyses were performed to determine the present and future transmission supply to the central King County area. The following detailed studies were performed to assess any adverse conditions to the reliability and operating characteristics of the PSE system or surrounding systems in the context of applicable standards:

2013 Eastside Needs Assessment: Power flow simulations were performed for the near and far-term horizon to determine if there are any thermal or voltage violations to King County's Eastside area. Past studies have shown supply issues to this area. While the recent economic downturn has impacted the future load growth projections of PSE overall, the load within the Eastside continues to grow. This study uses the latest corporate load forecast and adjusts the lumpiness of the load based on PSE's knowledge of future block loads.

2008 Initial King County Transformation Study: Power system simulation studies were performed on the King County system which indicated increased loading at Talbot Hill Substation, pointing to future overloads of either transformer for the loss of the other transformer at Talbot Hill. A bus section fault or loss of one of the lines from BPA Maple Valley Substation could also result in Talbot Hill transformer overloads.

2009 PSE Planning Studies and Assessment-TPL-001 to TPL-004 Compliance Report: As required per the 2009 NERC Compliance Enforcement Program, PSE performed an assessment of the system based on criteria described in NERC Standards TPL-001 through TPL-004. There were a number of potential overloads and voltage violations identified with these studies. The proposed solutions are generally system projects that will mitigate the issues via a topology change, line uprate, or additional transformation. The solutions may also take the form of a Remedial Action Scheme (RAS), as well. PSE demonstrated through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions.

2012 PSE Planning Studies and Assessment-TPL-001 to TPL-004 Compliance Report:
PSE performed an assessment of the system based on criteria described in NERC Standards TPL-001 through TPL-004. There were a number of potential overloads and voltage violations identified with these studies. The proposed solutions are generally system projects that will mitigate the issues via a topology change, line uprate, or additional transformation. The solutions may also take the form of a Remedial Action Scheme (RAS), as well.

BPA Transformation Study: A study was conducted by PSE in 2010 to review the impact of BPA 500-230 kV transformation at Monroe, Maple Valley or Covington which had been identified by BPA as alternative sites for the new transformer. A Covington transformer plus Lakeside 230-115 kV transformation provides better improvements to stressed contingencies than Covington plus Lake Tradition, Berrydale and Christopher 230-115 kV transformers combined. A Maple Valley transformer would stress PSE's system in the Talbot Hill vicinity more than a Covington transformer.

ColumbiaGrid 2013 Biennial Transmission Expansion Plan: ColumbiaGrid 2013 Biennial Transmission Expansion Plan looks out over a ten-year planning horizon (2013 - 2023) 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 load and meet firm transmission service commitments. The Expansion plan still includes the addition of a Lakeside 230-115 kV transformer in the Ten-Year Plan, and the additional 230-115 kV transformation at Lake Tradition in the long term. The new issues in the 2013 Expansion plan include Northern Intertie transfer issues.

A limitation in the 500/230 kV transformation in the Puget Sound area was noted in previous System Assessments. To resolve this issue, The Puget Sound Area Transmission Expansion Plan and the ColumbiaGrid Ten-Year Plan include a new 500-230 kV transformer at Raver which is scheduled to be installed in 2016.

Study Criteria: The following is a list of the criteria, standards and guides which apply to this needs statement:

1. TPL-001- System Performance Under Normal (No Contingency) Conditions (Category A)
2. TPL-001-WECC-CRT-2 – System Performance Criterion Under Normal Conditions, Following Loss of a Single BES Element, and Following Extreme BES Events:
3. TPL-002 - System Performance Following Loss of a Single Bulk Electric System Element (Category B)
4. TPL-003 - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)
5. TPL-004 - System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D)
6. PSE's Transmission Planning Guidelines
7. Northwest Power Pool Coordinated Plan
8. PSE Procedures to Establish and Communicate Operating Limits

Section 4 Study Assumptions

4.1 Steady State Model Assumptions

4.1.1 Study Assumptions

The 230 kV Eastside Area steady state models were developed to be representative of the long term projection of the winter peak system demand level to assess reliability performance under heavy load conditions. The model assumptions included consideration of Puget Sound area generation units' unavailability conditions as well as variations in surrounding area transfer level conditions.

The following assumptions are used in the 2013 Eastside Needs Assessment. The primary focus was on the winter peaks for years 2013-14, 2017-18, and 2021-22 utilizing the latest corporate load forecast modified to reflect the lumpiness of the load by substation. The Eastside load is defined as the sum of the MW flows out of the bus on the Talbot Hill end of the Talbot Hill - Lakeside #1 & #2 115 kV lines, Shuffleton end of the Shuffleton - Lakeside 115 kV line, Lake Tradition end of the Lake Tradition - Goodes Corner - Lakeside 115 kV line, and Sammamish end of the Sammamish - Lakeside #1 & #2, Sammamish - North Bellevue - Lakeside, Sammamish - Lochleven - Lakeside, and Sammamish - Ardmore - Lakeside 115 kV lines.

The difference in winter peak load forecasts with 100% conservation from 2013-14 to 2021-22 is 138 MW, which on average, is only approximately 15 MW per year (see Figure 4-1). Sensitivities on the amount of conservation and weather were run to reflect the inherent risks associated with an essentially flat load growth. Figure 4-1 shows the load levels in the study with various levels of conservation.

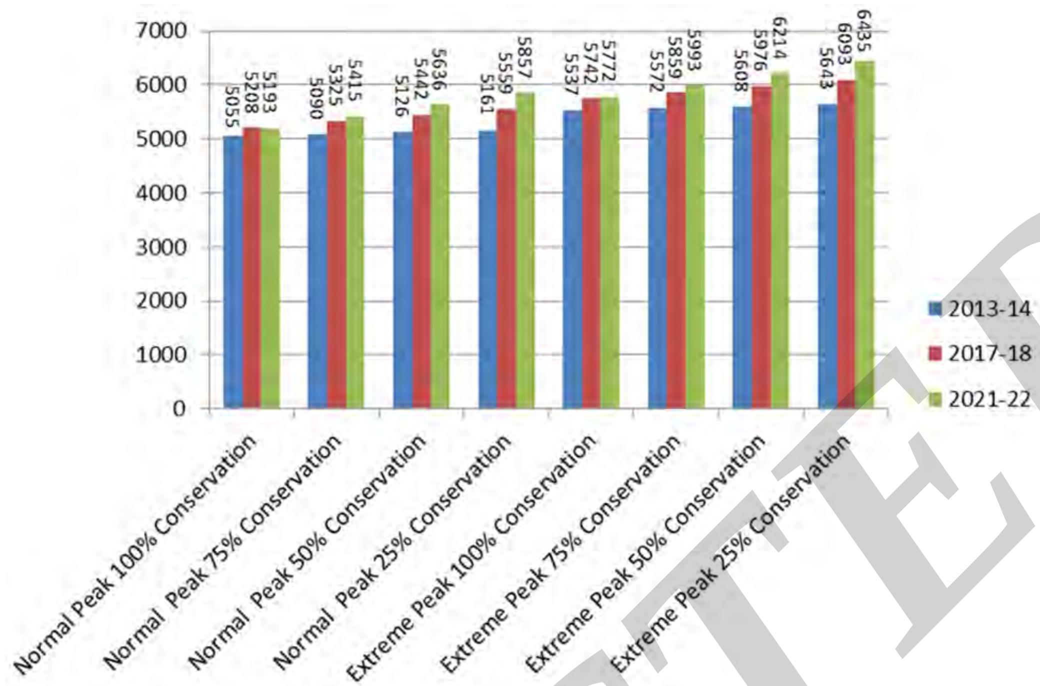


Figure 4-1: Winter Peak Load Growth with Varying Levels of Conservation

The Northern Intertie for the winter peak was modeled with a south to north flow of 1,500 MW into Canada.

The generation dispatches for the winter peak were modeled to reflect the standard way PSE studies the King County area which is to reduce generation in the north of the PSE area to create a greater south to north power flow during contractual flows from the Northwest to Canada. A winter low generation sensitivity case with adjusted Puget Sound area generation was run to identify risks associated with running a no Puget Sound Area generation case.

4.1.2 Source of Power Flow Models

The power flow models used in the study were based on WECC base cases created in 2012 for the winters 2012 -13, 2016 -17 and 2021-22 and for summers 2012 and 2017. These base cases are updated annually by all WECC members to reflect expected load forecasts, planned projects, generation changes and system adjustments. The 2012-13 winter case was modified to model the expected 2013-14 winter, the 2016-17 winter case to 2017-18 winter, the 2012 summer case to 2014 summer, and the 2017 summer case to 2018 summer. The cases were updated to reflect the PSE Corporate load forecast as discussed in Section 4.1.5.

The winter cases were then adjusted to reflect the case where the region sees high south to north power flows with no Puget Sound area generation. In previous studies, this scenario was the one that indicated the greatest problems on the Eastside in the winter. For TPL studies, four other scenarios are also studied:

- High South to North flows on the Northern Intertie with high Puget Sound area generation
- High South to North flows on the Northern Intertie and high south to north flows on the Paul - Raver 500 kV line with no Puget Sound area generation
- High North to South power flows on the Northern Intertie with no Puget Sound area generation
- High North to South power flows on the Northern Intertie with high Puget Sound area generation

The summer cases were run through four generation and Northern Intertie scenarios for PSE's 2012 TPL report; the TPL report summer results were used for this study.

The adjusted cases were then tailored for system improvements. Most improvements had been included already in the WECC cases. Additionally, the Seattle City Light (SCL) inductors and the Raver transformer were modeled. The PSE Lakeside 230 kV project was removed from the 2018 summer and 2021-22 winter cases since this project was proposed for perceived Eastside transmission supply need.

The cases were also adjusted for forecasted load in future years. First a block load adjustment was made where expected load is known for substations in King County. Then the system load for each of the study years was scaled to the level forecasted by PSE's Load Forecast Group in 2012.

4.1.3 Transmission Topology Changes

Projects added to the Eastside Needs Assessment base case are listed in Section 9 - Appendix B Table B-1 and Table B-2.

4.1.4 Generation Additions and Retirements

In addition to the generation increases included in the WECC base case by other utilities, PSE added generation capacity at the Snoqualmie and Lower Baker hydro units in 2013. These increases were modeled in the summer cases. The winter cases used no Puget Sound area generation for low generation scenarios, so the additional hydro generation was not relevant.

4.1.5 Forecasted Load (including assumptions concerning energy efficiency, interruptible loads, etc.)

The 2012 PSE Corporate system load forecast was used as a basis for the demand levels modeled in the study. PSE Corporate Load Forecast Group uses econometric regression models (*not end use models*) to forecast use per customer and customer counts for its electric and gas service area. The regression models are developed by customer class, such as residential, commercial, industrial, and so on.

The use-per-customer and customer equations are driven by a number of regional economic, demographic, weather, binary and other independent variables. The forecasts of the underlying economic and demographic variables are developed using information from Moody's Analytics and other regional sources of economic data.

The use per customer equation is driven primarily by historical data and variables such as unemployment rate, total employment, manufacturing employment, real personal income, retail rates and weather variables like heating and cooling degree days. The base forecast created by the regression model is modified appropriately to account for impacts of conservation programs and any known changes to large customers managed by the major accounts group. The conservation estimates prepared by the Integrated Resource Planning team distribute the implementation of conservation measures based on cost effectiveness analyses. The forecast of conservation savings is a major determinant of the final shape of the load forecast.

Customer count growth is driven by historical data and changes in population, household growth, housing permits, total employment and manufacturing employment in PSE's service area.

A major influence on PSE in the early 1990s was Washington's Growth Management Act (GMA). Elements of the GMA provide direction as to where growth and load will locate. PSE's planning process continues to provide input and updates on future planned transmission and distribution facilities for local jurisdiction Comprehensive Plan revisions to support their growth forecasts. Overall, the GMA and the local Comprehensive Plans coupled with PSE Annual Corporate Customer and Sales Forecasts provide a measure of predictability as to where and when construction of planned facilities will be needed.

PSE Annual Corporate Customer and Sales Forecasts include summer and winter peak load forecasts for a 20 year period. These forecasts include both normal and extreme winter load levels, with and without Demand Side Resources (DSR). Forecasts for Network Loads and other T & D service categories are obtained from customers annually for a 10-year period. Transmission Planning uses the most recent normal peak loads as a starting point and checks sensitivities to forecasted load as set forth in the NERC transmission planning requirements[15].

Table 4-1 shows PSE's 20 year load forecasts for the calendar years of 2010 to 2012 for normal (23° F) and extreme weather (13° F) with 100% conservation. PSE Load Forecast is provided for PSE system load, and does not include the 270 MW of Transmission Customer industrial loads. Transmission Customer loads are included in the area load for the TPL and 2013 Eastside Need Assessment. The load forecasts have decreased from the earlier years. The 2013 Eastside Need Assessment used the latest forecast.

From Table 4-1, the total load growth between 2013 and 2021 for normal weather is 138 MW. The difference in load between normal weather and extreme weather for 2013 is 482 MW. If the temperature on the peak day drops from 23° F to 13° F, the load increase would be approximately 3.5 times the total normal load growth over the study period.

[15] TPL-001-2 R2.1.4: http://www.nerc.com/docs/standards/sar/atfnsdt_recirc_ballot_tpl_001_2_clean_20110711.pdf

Table 4-1: PSE Load Forecasts from 2010 to 2012 for Normal and Extreme Weather

	Forecasted 2010		Forecasted 2011		Forecasted 2012	
Year	Max of Normal Peak w/ DSR	Max of Extreme Peak w/ DSR	Max of Normal Peak w/ DSR	Max of Extreme Peak w/ DSR	Max of Normal Peak w/ DSR	Max of Extreme Peak w/ DSR
2010	4,842	5,260	4,781	5,253		
2011	4,868	5,291	4,878	5,363		
2012	4,913	5,344	4,893	5,388	4,837	5,316
2013	4,947	5,387	4,925	5,433	4,785	5,267
2014	4,961	5,407	4,965	5,487	4,836	5,333
2015	4,947	5,400	4,979	5,513	4,865	5,375
2016	4,954	5,414	5,003	5,548	4,909	5,432
2017	4,967	5,434	5,023	5,579	4,938	5,472
2018	4,989	5,462	5,027	5,593	4,938	5,483
2019	5,017	5,498	5,044	5,622	4,946	5,501
2020	5,063	5,551	5,025	5,615	4,923	5,490
2021	5,141	5,639	5,028	5,630	4,923	5,502
2022	5,222	5,731	5,078	5,693	4,972	5,562
2023	5,302	5,821	5,149	5,775	5,039	5,641
2024	5,383	5,913	5,225	5,865	5,117	5,732
2025	5,466	6,007	5,303	5,955	5,193	5,820
2026	5,547	6,099	5,382	6,047	5,266	5,905
2027	5,629	6,192	5,464	6,142	5,341	5,993
2028	5,711	6,285	5,552	6,244	5,426	6,090
2029	5,795	6,380	5,645	6,351	5,515	6,192
2030			5,490	6,091	5,605	6,296
2031					5,694	6,399
2032					5,785	6,504
2033					5,878	6,610

The conservation in MW, by county, utilized in the 2012 forecast is shown below in Table 4-2.

Table 4-2: Conservation in MW, by County

Conservation Effects by County Normal Peaks (23ºF) 100% Target Conservation (MW)										
Year of Study	King	Thurston	Pierce	Whatcom	Skagit	Island	Kitsap	Kittitas	Jefferson	Total
2012	33.0	7.8	6.9	5.2	3.4	2.1	7.4	0.8	1.3	67.9
2013	69.6	16.5	14.6	10.8	7.2	4.4	15.5	1.7	2.7	142.9
2014	112.3	26.7	23.6	17.5	11.5	7.0	24.8	2.7	4.3	230.5
2015	158.5	37.8	33.2	24.6	16.2	9.9	34.8	3.9	6.1	324.9
2016	196.1	46.8	41.0	30.3	20.0	12.1	42.7	4.8	7.5	401.5
2017	233.0	55.6	48.6	35.9	23.7	14.3	50.3	5.8	8.9	476.2
2018	280.4	66.9	58.3	43.1	28.4	17.2	60.1	7.1	10.7	572.1
2019	325.4	77.6	67.4	49.8	32.9	19.8	69.2	8.3	12.4	662.9
2020	389.5	92.8	80.4	59.5	39.2	23.5	82.2	10.2	14.9	792.1
2021	443.5	105.6	91.2	67.5	44.6	26.6	92.8	11.7	16.9	900.4
2022	474.0	112.9	97.3	72.0	47.6	28.2	98.4	12.7	18.0	961.1
2023	495.6	118.0	101.4	75.1	49.6	29.3	102.1	13.4	18.8	1003.4
2024	514.9	122.6	105.1	77.9	51.5	30.3	105.3	14.1	19.5	1041.2
2025	535.1	127.3	109.0	80.7	53.3	31.3	108.5	14.7	20.3	1080.3

Figure 4-2 shows the twenty year window of PSE's Winter Normal Peak with 0%, 25%, 50%, 75% and 100% conservation. As Figure 4-2 shows, with 100% conservation, the load levels of PSE are relatively flat for the years of study. The difference between 2013 and 2021 is 138 MW.

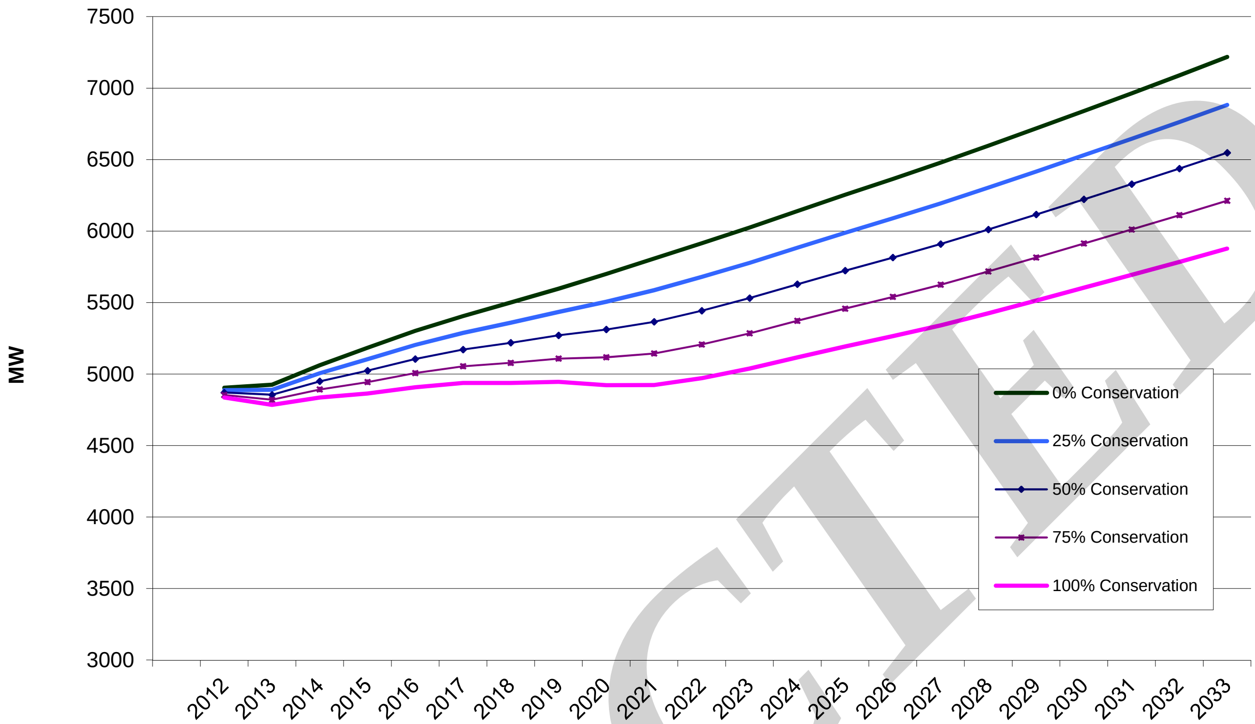


Figure 4-2: Twenty Year Graph of PSE's Forecast Winter Normal Peak with 0%, 25%, 50%, 75% and 100% Conservation

4.1.6 Load Levels Studied

For the power flow studies associated with the 230 kV Eastside Needs Assessment, the heavy winter 2013-14, 2017-18 and 2021-22 cases were used. Substation loading for the PowerWorld cases was developed using the substation loading at the time of the January 18, 2012 system peak as a proxy to the distribution of the load. There were a few substations without Supervisory Control and Data Acquisition (SCADA) load readings. Those substations were assigned values based on manual onsite substation load readings during the same load cycle. Both megawatts (MW) and megavars (MVAR) were determined in this manner.

Small Area Load Forecast: PSE distribution planners keep current on developments planned for their respective planning areas. These anticipated new loads are generally known within a 2-5 year time frame; specific projects are not often known with confidence beyond 5 years in advance. PSE planners reviewed such new loads expected in the King County area within the study period and added those expected loads to the historical load for each substation. These small area load adjustments were included in the substation load spread before the company-wide load was scaled to the corporate load forecast.

Transmission Customer Load: The corporate load forecast together with the interconnected Transmission Customer load, or non PSE load, was used to determine future loads for the power flow studies. 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. For example, in the year 2013-2014 the winter peak load forecast for the PSE area is 5055 MW which comprises the projected forecast of 4785 MW plus 270 MW of Transmission Customer loads. Loads were developed similarly for years 2017-18 and 2021-22. For completeness, this non-PSE load was included in the 2013 Eastside Needs Assessment and is shown in Table 4-3.

Table 4-3: Winter Peak Load levels studied in the Eastside Needs Assessment

Area Load Used for Eastside 230 Study												
Year Studied	Report	Season	Normal Peak 100% Conservation	Normal Peak 75% Conservation	Normal Peak 50% Conservation	Normal Peak 25% Conservation	Normal Peak 0% Conservation	Extreme Peak 100% Conservation	Extreme Peak 75% Conservation	Extreme Peak 50% Conservation	Extreme Peak 25% Conservation	Extreme Peak 0% Conservation
2013-14	2012 E230	Winter	5055	5090	5126	5161	5196	5537	5572	5608	5643	5678
2017-18	2012 E230	Winter	5208	5325	5442	5559	5676	5742	5859	5976	6093	6210
2021-22	2012 E230	Winter	5193	5415	5636	5857	6078	5772	5993	6214	6435	6656

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.

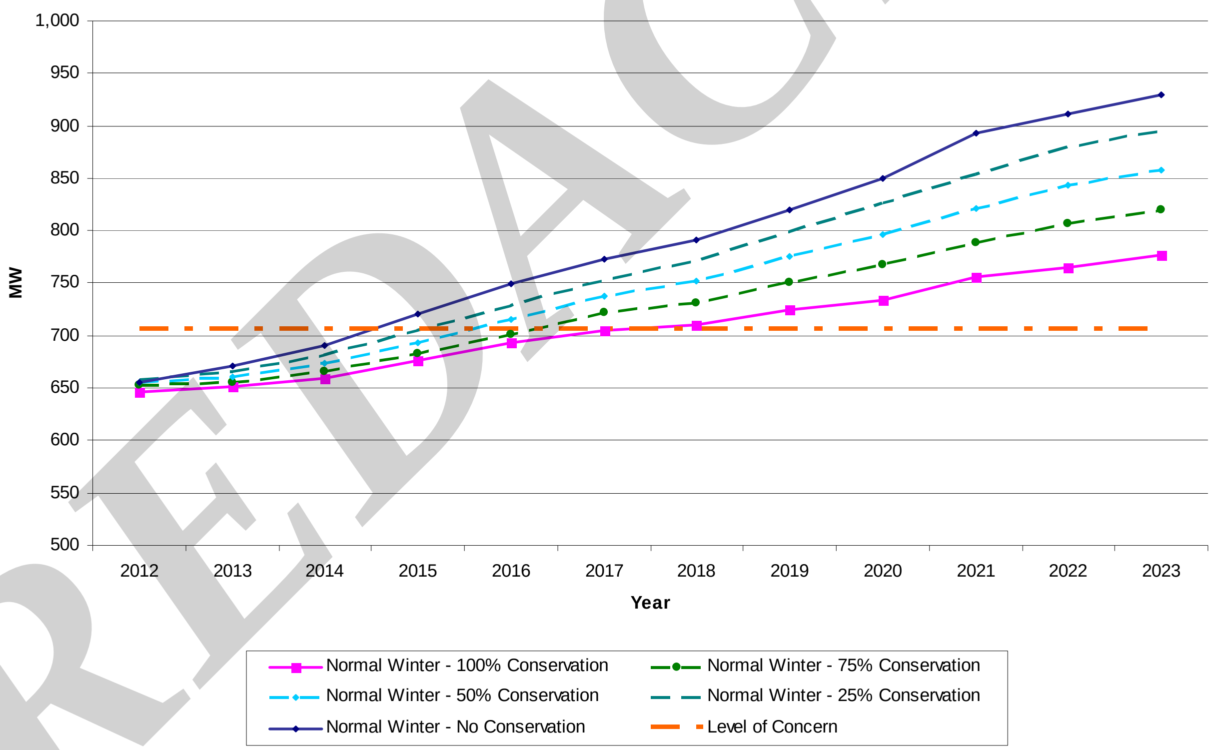


Figure 4-3: Eastside Load Forecast for Normal Winter Load Forecast 2012-2023

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.

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.

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
Frederickson	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.

4.1.10 Reactive Resource and Dispatch Assumptions

All existing and planned area reactive resources were assumed available and dispatched if conditions called for their dispatch. The reactive output of units was constrained to defined limits and shunt reactive resources were dispatched as conditions required.

4.1.11 Conservation Assumptions

PSE employs conservation as a strategic measure to manage energy requirements and provide customer benefits. Conservation programs have been funded for over 20 years and are projected to continue to receive strong funding in the next 20 years. PSE's Energy Efficiency Group has demonstrated the efficacy of its funded programs on a continuing basis. As a result, conservation is included in PSE's Integrated Resource Plan (IRP) as a cost-effective source of new energy.

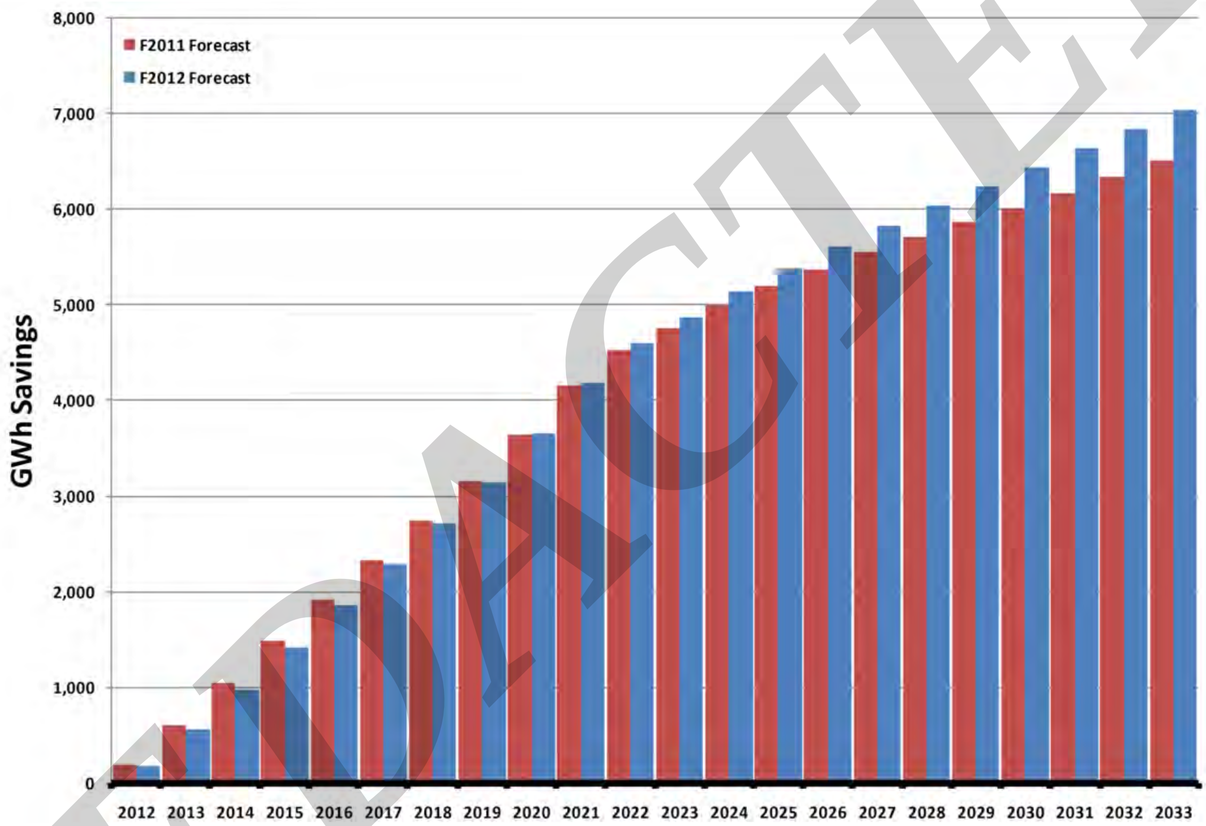


Figure 4-4: PSE Conservation Forecast in 20 year Horizon Measured in Gigawatt-Hours; Comparison of 2012 Forecast to 2011 Forecast

4.1.12 Explanation of Operating Procedures and Other Modeling Assumptions

PSE's Transmission Planning group has prepared a CAP that instructs PSE Transmission Operators to take certain actions in the event of either Talbot Hill 230-115 kV transformers overloading. While the CAP was initiated to address the potential for either transformer to exceed its emergency rating, the CAP can also be used to address the event of either transformer exceeding its operating limit as well.

The CAP instructs the PSE Transmission Operators to open the Talbot Hill – Lakeside #1 & #2 115 kV lines if either Talbot Hill 230-115 kV transformer overloads. The contingency that would cause the transformers to overload would be a double-contingency (N-1-1) loss of a Talbot Hill transformer and the Berrydale transformer during high winter loading.

With future load growth, the CAP may be expanded to state that if the transformer overload is not sufficiently reduced or the Shuffleton – Lakeside 115 kV line overloads as a result of [redacted], then the Transmission operation should open [redacted]

While none of these planned actions would drop load in a system normal configuration, the opening of [redacted] exposes three substations supplying 16,000 customers [redacted] and three substations supplying 17,000 customers on [redacted] to an outage on the lines, as shown in Figure 4-5. Furthermore, if [redacted] are opened, North and Central King County is at risk of manual load shedding for an N-1-1 loss of [redacted]. See Figure 4-5 below that shows areas in jeopardy of outage when transmission lines are opened under the CAP's to prevent overloads of the Talbot Hill and Sammamish transformers.

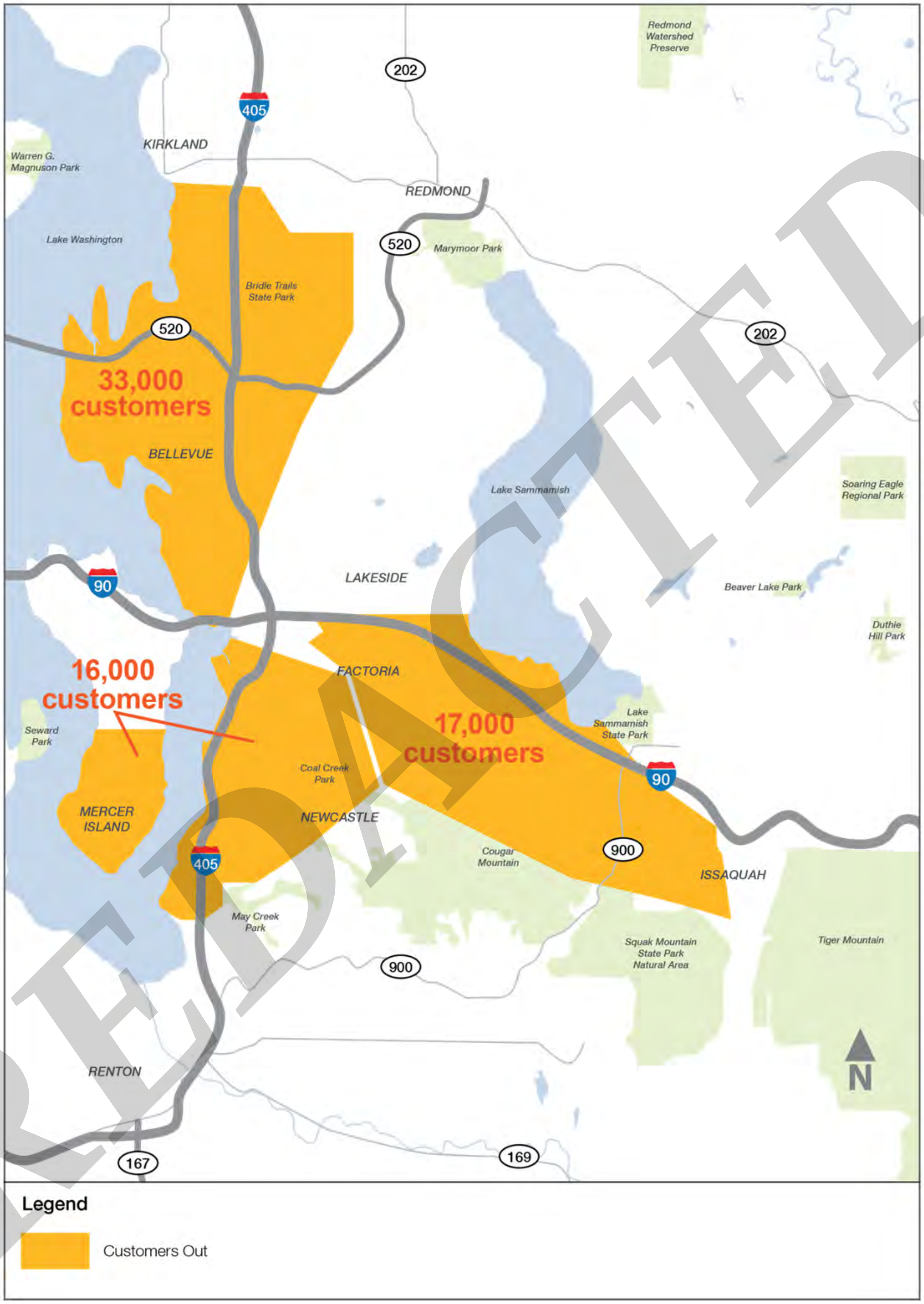


Figure 4-5: Topological View of the Needs Assessment of the Eastside of Lake Washington

If, with future load growth, the Talbot Hill 230-115 kV transformers are at risk of overloading for an N-1 loss of one transformer during Winter peak conditions, then the CAP described above would be implemented as a pre-emptive, pre-contingent measure to ensure that overloads don't materialize. In this case [redacted] would be opened during winter peak conditions, regardless of the loading on the Talbot Hill transformers.

There is also a CAP intended for use during the summer peak in the event of the loss of [redacted]. The CAP instructs the PSE Transmission Operators to open [redacted].

While none of these planned actions would drop load in a system normal configuration, the opening of the transmission lines exposes seven substations supplying 23,000 customers on [redacted] and [redacted] to a subsequent outage on the lines. The total customer impact of 33,000 is shown in Figure 4-5.

With future load growth, the CAP may be expanded to state that if the associated overloads are not sufficiently reduced, then the Transmission Operator should also open [redacted].

While none of these additional actions would drop load in a system normal configuration, the opening of [redacted] exposes one substation supplying 6,000 customers on [redacted] and seven substations supplying 23,000 customers on [redacted] to a subsequent outage on the lines.

In the King County area, PSE has eight transmission transformers, any one of which, when tripped, could trigger a CAP. The customers at risk of outages due to the CAPs described above are supplied by four of the eight transmission transformers, located at Talbot Hill and Sammamish. When a transformer trips, it takes substantial time to test and replace: 18-24 hours typically for testing, and 3-5 weeks to replace the damaged transformer with a spare transformer. This is a long duration of exposure if CAPs must be employed during the transformer outage.

4.2 Changes in Study Assumptions

The Bothell - SnoKing 230 kV #1 & #2 lines, owned by SCL, overloaded for various outages in all cases. These overloads were excluded from the results page, as SCL is planning to upgrade these lines whether or not the Eastside 230 kV project is built. Furthermore, the Eastside 230 kV project scope is not expected to significantly alleviate these line overloads.

SCL's Maple Valley - SnoKing 230 kV #1 & #2 lines overloaded for various outages in all cases; these overloads were observed in the base case and were expected to also occur in the more extreme cases. However, these overloads were caused in large part by the loss of [redacted]. BPA has winter operating procedures in place that will protect against these overloads through use of nomograms.

The [redacted] contingencies did not solve for the majority of the cases, due to the high South to North flows on the Northern Intertie. Therefore, the overloads in more extreme cases were not listed, as the contingency did not solve. The potential issues caused by the high South to North flows are managed through the use of nomograms by BPA.

Certain local 115 kV PSE system overloads within King County were excluded from the listed results, as they were clearly a local system problem that did not contribute to the need for the Eastside 230 kV project. The following systems or lines were excluded: Moorlands three line system, Asbury three line system, Krain Corner 115-55 kV system, and Novelty Hill - Stillwater - Cottage Brook 115 kV lines. These are known system issues with planned projects that are independent in nature from the Eastside 230 kV project.

Section 5 Performance Requirements

5.1 Planning Standards and Criteria

This study examined thermal overloads for Category A (N-0), Category B (N-1) and Category C (N-2 and N-1-1) outages as required by NERC, WECC and PSE Transmission Planning Guidelines. PSE plans for winter and summer peak, such that no thermal or voltage violations result. While the peaks occur for just a few hours per year, there are many more hours each year where operating flexibility is impacted by system capacity. PSE plans for normal summer and winter temperatures, which are 23ºF in winter and 86ºF in summer. PSE also studies extreme winter peak temperature (13ºF) as an indicator of future deficiencies.

> NERC TPL-001- System Performance Under Normal (No Contingency) Conditions (Category A): PSE shall demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table 1[16].
>
> NERC TPL-002 – System Performance Following Loss of a Single Bulk Electric System Element (Category B): PSE shall demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table 1[17].
>
> Category B outages can occur at any time when a single element trips off line. The NERC TPL Standards Table 1 Category B states that there should be no loss of load or curtailed firm transfers with the exception outlined in footnote b of Table 1[18]. Utilities may only shed directly-connected ("consequential") load to stay compliant. Non-consequential load loss is not allowed for Category B events for BES level less than 300 kV. The system shall remain stable. Cascading or uncontrolled islanding shall not occur. Therefore any overloads showing up for a Category B event are very serious.
>
> NERC TPL-003 – System Performance Following Loss of Two or More Bulk Electric System Elements (Category C): PSE shall each demonstrate through a valid assessment that its portion of the interconnected transmission systems is planned such that the network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand

[16] Table 1 TPL-001 - System Performance Under Normal (No Contingency) Conditions (Category A)

[17] Table 1 TPL-002 - System Performance Following Loss of a Single Bulk Electric System Element (Category B)

[18] Footnote b Table 1 - An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. For purposes of this footnote, the following are not counted as Firm Demand: (1) Demand directly served by the Elements removed from service as a result of the Contingency, and (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.

Levels over the range of forecast system demands, under the contingency conditions as defined in Category C of Table 1[19] .

Category C outages have subcategories of N-2 and N-1-1. An N-2 outage is when a single event trips multiple facilities, such as a transmission bus fault tripping all breakers on the bus or a double-circuit transmission line outage. Breaker failure is also included as a Category C outage. For these outages, there is no time allowed for operator response, but the utility is allowed to have automatic processes to shed non-consequential load to stay compliant.

An N-1-1 Category C outage is a Category B outage followed by a period of time to manually adjust the system to a secure state, followed by a second Category B outage. PSE utilizes 30 minutes to make manual system adjustments after the first outage occurs, to prevent overloads upon the second outage event.

TPL-001-WECC-CRT-2: System Performance Criterion Under Normal Conditions, Following Loss of a Single BES Element, and Following Extreme BES Events. System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and that systems continue to be modified or upgraded as necessary to meet present and future system needs.

PSE Transmission Planning Guidelines, November 2012: The Transmission Planning Guidelines explain the criteria and standards used to assess the ability of Puget Sound Energy's existing and future electric transmission system, and how they are applied to provide safe and reliable service at reasonable cost. The guidelines address both specific and general issues the transmission planner needs to consider. There may be issues specific to site, project, region, or customer that will require plans to be developed on a case-by case basis. However, the Transmission Planning Guidelines are structured in a way that will help achieve consistency across the PSE transmission system.

5.2 Performance Criteria

5.2.1 Steady State Thermal and Voltage Limits

PSE has two thermal operating limits; normal and emergency. The normal operating limit is a specific level of electrical loading that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life. The emergency limit is a specific level of electrical loading that a system, facility, or element can support or withstand for a finite period. The emergency rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved. If there is a violation of the emergency limit, a transmission line may not meet applicable clearance, tension and sag criteria. PSE's operating practice is to shift or shed load or dispatch generation to avoid reaching an emergency limit.

System steady state voltages and post contingency voltage deviation shall be within acceptable limits. For PSE system the acceptable limits are: the steady state voltage levels are not above 105% or below 90% for any bus, the voltage deviation for Category B events does not exceed 5%, and the voltage deviation for multiple contingency Category C events does not exceed 10%.[20]

[19] Table 1 TPL-003 - System Performance Following Loss of Two or More Bulk Electric System Elements (Category C)

[20] PSE Transmission Planning Guidelines, November 2012, page 7

5.2.2 Steady State Solution Parameters

Devices with automatic settings were allowed to adjust automatically for base case runs, reflecting manual operation by Transmission Operators where appropriate: LTC's, phase-shifters, and shunt reactive devices. During contingency runs, LTC and phase-shifter operations were disabled. Shunt reactive devices with known fast-acting schemes were allowed to switch. Inter-area AGC was enabled for the analysis since generation or load loss simulations for the Eastside Needs Assessment were all modeled within the Northwest area and AGC response would be expected for those conditions.

Table 5-1: Study Solution Parameters

Case	Area Interchange	Transformer LTCs	Phase Angle Regulators	SVDs & Switched Shunts
Base	Tie Lines Regulating	Stepping	Regulating or Statically Set	Regulating
Contingency	Tie Lines Regulating	Disabled	Disabled	Regulating

REDACTED

5.3 System Testing

5.3.1 System Design Conditions and Sensitivities Tested

Four base scenarios were developed for the additional winter studies run for the 2013 Eastside Needs Assessment. The study plan is shown in Figure 5-1.

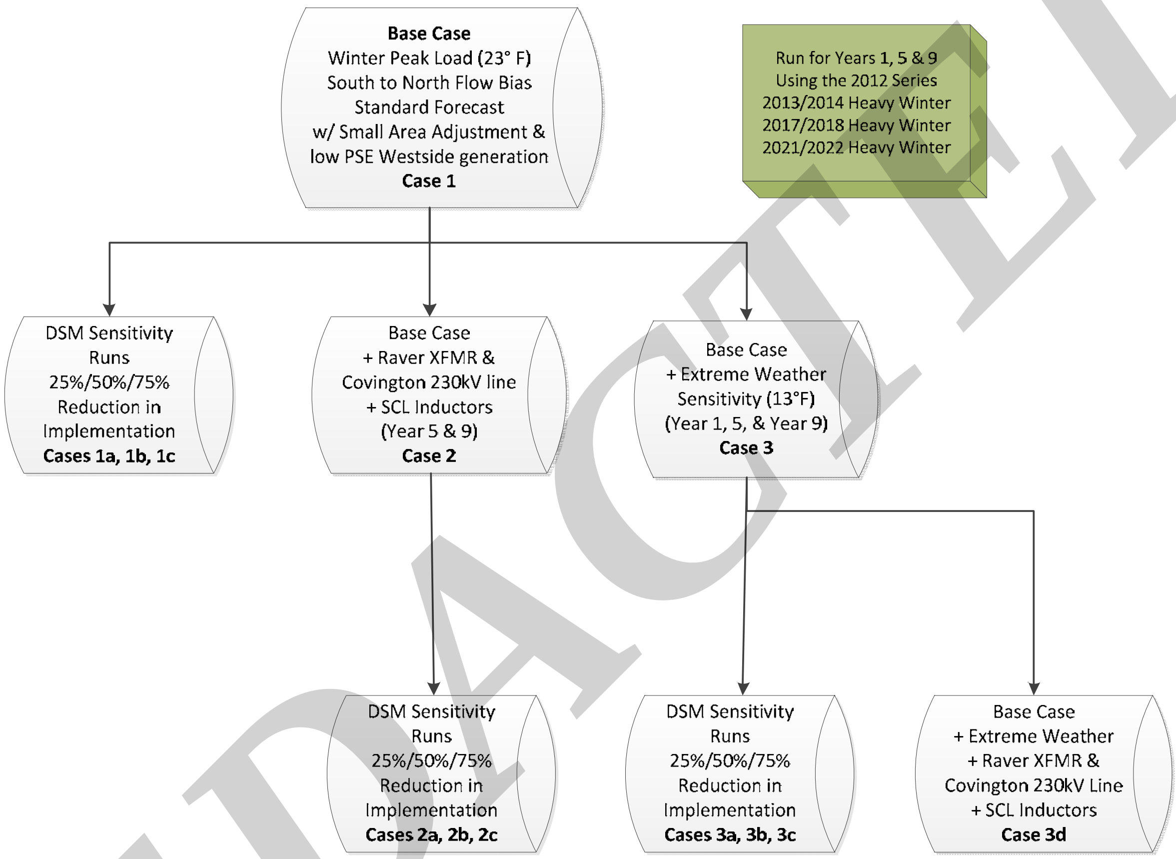


Figure 5-1: Eastside Project Need Validation Study Plan

Case 1 represents base years 2013-14, 2017-18, and 2021-22 winter peaks, normal weather adjusted by substation to reflect the lumpiness of the load. Case 1 includes a south to north bias of 1500 MW with low PSE generation in the Puget Sound area.

Case 2 represents 2017-18 and 2021-22 with additions of a 500 kV/230 kV transformer at Raver, a Raver to Covington 230 kV line, and 115 kV series inductors to the Broad Street - Massachusetts and Broad Street - East Pine 115 kV underground cables in Seattle City Light.

Case 3 represents extreme weather for Case 1.

Case 3d represents extreme weather for Case 2.

The winter cases were run with no generation in the Puget Sound area, a case which PSE normally runs for the annual TPL assessment. However, since it is an extreme case, a low-generation case was run for the 2013 Eastside Needs Assessment as a sensitivity to determine whether some of the violations seen during the power flows could be offset by running generation. The generation levels for the low-generation sensitivity case are shown in Table 4-4, in the column labeled “Expected MW Output during Winter Peak for Low-Generation Sensitivity Case.”

Sensitivities on the amount of conservation realized were performed for each of the cases above, to indicate the possible additional violations that could occur should conservation be achieved at a level below the projection or if economic growth should be higher than forecast. This was done because the 10 year load forecast with full projected conservation had such a flat growth profile. The load levels were adjusted to reflect 75%, 50%, and 25% conservation as a proxy for higher loads. The case assumptions are summarized in Table 5-2.

Table 5-2: Winter and Summer Case Study Assumptions

Winter and Summer Case Study Assumptions						
Case Name	Amount of Conservation	System Load	Eastside Load	Northern Intertie	PSE/SCL Westside Gen	Other Adjustments Modeled
1 100% Conservation 2013-14 Winter	100%	5055 MW	652 MW	1500 MW Export	0 MW	Saint Clair 230-115 kV transformer; Talbot Hill - Berrydale #1 line uprate; Starwood autotransformer removal with Tacoma Power voltage increase
1 75% Conservation 2013-14 Winter	75%	5090 MW	656 MW	1500 MW Export	0 MW	Saint Clair 230-115 kV transformer; Talbot Hill - Berrydale #1 line uprate; Starwood autotransformer removal with Tacoma Power voltage increase
2 100% Conservation 2017-18 Winter	100%	5208 MW	706 MW	1500 MW Export	0 MW	Block load allocated per King Co Dist. Planers; Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; Raver 500-230 kV transformer; SCL series inductors
2 75% Conservation 2017-18 Winter	75%	5325 MW	722 MW	1500 MW Export	0 MW	Block load allocated per King Co Dist. Planers; Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; Raver 500-230 kV transformer; SCL series inductors
2 100% Conservation 2021-22 Winter	100%	5126 MW	756 MW	1500 MW Export	0 MW	Block load allocated per King Co Dist. Planers; Planned improvements include 2017-18 adjustments
2 75% Conservation 2021-22 Winter	75%	5415 MW	789 MW	1500 MW Export	0 MW	Block load allocated per King Co Dist. Planers; Planned improvements include 2017-18 adjustments
3 100% Conservation 2013-14 Extreme Winter	100%	5537 MW	718 MW	1500 MW Export	0 MW	Saint Clair 230-115 kV transformer; Talbot Hill - Berrydale #1 line uprate; Starwood autotransformer removal with Tacoma Power voltage increase
3d 100% Conservation 2017-18 Extreme Winter	100%	5742 MW	782 MW	1500 MW Export	0 MW	Block load allocated per King Co Dist. Planers; Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; Raver 500-230 kV transformer; SCL series inductors
3d 100% Conservation 2021-22 Extreme Winter	100%	5772 MW	845 MW	1500 MW Export	0 MW	Block load allocated per King Co Dist. Planers; Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; Raver 500-230 kV transformer; SCL series inductors
2014 Heavy Summer	100%	3343 MW	516 MW	2850 Import	2171 MW	Saint Clair 230-115 kV transformer; Talbot Hill - Berrydale #1 line uprate; Starwood autotransformer removal with Tacoma Power voltage increase
2018 Heavy Summer	100%	3554 MW	552 MW	2850 Import	2276 MW	Planned improvements include 2013 adjustments + Alderton 230-115 kV transformer; Beverly Park 230-115 kV transformer; White River - Electron Heights 115 kV line re-route into Alderton; White River 2nd bus section breaker; Lake Hills - Phantom Lake 115 kV line; Sammamish-Juanita 115 kV line

5.3.2 Steady State Contingencies / Faults Tested

The above cases were tested based on Category A, B, and C contingencies described in the NERC TPL, and WECC standards and PSE's Transmission Planning Guidelines. Descriptions of the type of contingencies tested are listed in Table 5-3.

Table 5-3: Summary of NERC, WECC and/or PSE Category Contingencies Tested

NERC WECC PSE Categories	Description of Outaged Element(s)	Contingencies Modeled
A	All lines in-service	N/A
B A-2; 6.1 a. PP4; 3.1 a.	Loss of a generator, transmission circuit, transformer or single pole DC line	Category B contingencies included all PSE and interconnected transmission lines and transmission transformers,
C A-2; 6.1 a. PP4; 3.1 a.	Normally loss of a bus or circuit breaker; or loss of any category B element followed by another category B element with system adjustments between events; or loss of any two circuits of a multi circuit tower line or loss of a bipolar DC line; or a stuck breaker with delayed clearing of a generator, transmission circuit, transformer or bus section.	Category C: N-2 contingencies included all common-structure double circuit lines, all transmission buses and bus sections with 3 or more transmission elements, and all stuck transmission breakers. Category C: N-1-1 included a pairwise combination of all Category B elements followed by all other Category B elements.
D A-2; 6.1 a. PP4; 3.1 a.	Loss of a generator, transmission circuit, transformer or bus section; or other transmission planning entity selected critical outage or loss of a category B element followed by loss of any two circuits of a multi circuit tower or a stuck breaker	Category D was not performed in this study

Section 6 Results of Analysis

6.1 Overview of Results

The following sections describe the results of the analysis. The thermal loading percentages described below are based on a percentage of the emergency rating for each facility.

6.1.1 N-0 Thermal and Voltage Violation Summary

For all cases, there are no thermal or voltage violations for the all lines in (N-0) state.

2013-14 – Case 1-Winter Peak, Normal Weather: For all elements in service (N-0) state, there were no thermal or voltage violations for 2013-14 winter peak, normal weather with all levels of conservation modeled (i.e. 100%, 75%, 50%, or 25%)

2013-14 – Case 3-Winter Peak, Extreme Weather: For all elements in service (N-0), there were no thermal or voltage violations for 2013-14 winter peak, extreme weather, with all levels of conservation modeled (i.e. 100%, 75%, 50%, or 25%) conservation.

2017-18 – Case 2-Winter Peak, Normal Weather: For all elements in service (N-0), there were no thermal or voltage violations for 2017-18 winter peak, normal weather, with all levels of conservation modeled (i.e. 100%, 75%, 50%, or 25%) conservation.

2017-18 – Case 3-Winter Peak, Extreme Weather: For all elements in service (N-0), there were no thermal or voltage violations for 2017-18 winter peak, extreme weather, with all levels of conservation modeled (i.e. 100%, 75%, 50%, or 25%) conservation.

2021-22 – Case 2-Winter Peak, Normal Weather: For all elements in service (N-0), there were no thermal or voltage violations for 2021-22 winter peak, normal weather, with all levels of conservation modeled (i.e. 100%, 75%, 50%, or 25%) conservation.

2021-22 – Case 3-Winter Peak, Extreme Weather: For all elements in service (N-0), there were no thermal or voltage violations for 2021-22 winter peak, extreme weather, with all levels of conservation modeled (i.e. 100%, 75%, 50%, or 25%) conservation.

6.1.2 2013-14 Thermal Summaries: Winter Peak, Normal and Extreme Weather & Summer Peak Normal Weather

Table 6-1 shows the summary of results for categories B (N-1) and C (N-1-1 & N-2) for 2013-14 winter and 2014 summer peaks with normal weather. Table 6-1 shows that for the winter peak, normal weather, 100% conservation, (PSE Load 5,055 MW), there are no Category B thermal violations but there are five (5) potential thermal violations in the King County area for Category C contingencies. Those five potential violations are as follows and highlighted in yellow in

Table 6-2.

1. Talbot Hill - Lakeside #1 115 kV Line
2. Talbot Hill - Lakeside #2 115 kV Line
3. Talbot Hill 230-115 kV transformer #1
4. Talbot Hill 230-115 kV transformer #2
5. Talbot Hill - Boeing Renton - Shuffleton 115 kV Line

Those Category C contingencies can be mitigated by operational procedures and re-dispatching. Also, Table 6-1 lists six (6) additional facilities within the King County area, which are operating from 90% to 100% of the emergency operating limits and are above the operating limits. Those facilities are highlighted in gray on

Table 6-2.

1. White River 230-115 kV transformer #2 – 97.4%
2. White River 230-115 kV transformer #1 – 96.9%
3. Talbot Hill - Berrydale #1 115 kV line – 96.0%
4. Berrydale 230-115 kV transformer – 92.4%
5. O'Brien 230-115 kV transformer #2 – 94%
6. O'Brien 230-115 kV transformer #1 – 93.2%

Table 6-2 also shows potential thermal overloads of elements outside of PSE's service area. Two lines of notice include Maple Valley - SnoKing #1 & #2 230 kV lines, which pass through the Eastside of King County.

For the 2014 summer peak normal weather, (PSE load of 3343 MW), high generation in the north and high imports from British Columbia (Table 6-1), there is one (1) potential Category B (N-1) thermal violation (Monroe - Novelty Hill 230 kV line) and for the same case with no generation in the north there is one (1) potential Category B thermal violation (Maple Valley - Sammamish 230 kV line). Those potential over loads are the result of losing [redacted]. Those facilities are owned by BPA. There is also one (1) potential Category C (N-1-1) potential thermal violation (Sammamish 230-115 kV transformer #2).

Table 6-3 show the potential impact of extreme winter weather with 100% and 50% conservation in 2013-14, (PSE load of 5,537 MW and 5,608 MW respectively). There are no potential Category B thermal violations, but there are three (3) elements which are operating at 90% or greater of the emergency limits and are above the operating limits; Talbot Hill 230-115 kV transformer #1, Talbot Hill 230-115 kV transformer #2, and White River 230-115 kV transformer #2.

Table 6-1: Summary of Elements above Emergency and Operating Limits: 2013-14 Winter Peak, Normal Weather & Summer Peak Normal Weather

Year of Study	Normal or Extreme Weather	Case Conditions	Amount of Conservation/ System Load	Type of Contingency	Elements above Emergency Limit	Elements > 90% of Emergency Limit or above Operating Limit
2013-14 Winter	Normal	South-North NI Flow No Western Generation	100% 5055 MW	N-1		
2013-14 Winter	Normal	South-North NI Flow No Western Generation	100% 5055 MW	N-1-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 Talbot Hill-Boeing Renton-Shuffleton 115 kV Line	White River 230-115 kV transformer #2 White River 230-115 kV transformer #1 Talbot Hill-Berrydale #1 115 kV line Berrydale 230-115 kV transformer O'Brien 230-115 kV transformer #2 O'Brien 230-115 kV transformer #1
2013-14 Winter	Normal	South-North NI Flow, No Western Generation	100% 5055 MW	N-2 or Common Mode		Talbot Hill-Lakeside #2 115 kV Line Berrydale 230-115 kV transformer
2013-14 Winter	Normal	South-North NI Flow, No Western Generation	75% 5090 MW	N-1		
2013-14 Winter	Normal	South-North NI Flow No Western Generation	75% 5090 MW	N-1-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2	White River 230-115 kV transformer #2 White River 230-115 kV transformer #1 Talbot Hill-Berrydale #1 115 kV line Berrydale 230-115 kV transformer O'Brien 230-115 kV transformer #2 O'Brien 230-115 kV transformer #1
2013-14 Winter	Normal	South-North NI Flow, No Western Generation	75% 5090 MW	N-2 or Common Mode		Talbot Hill-Lakeside #2 115 kV Line Berrydale 230-115 kV transformer
2013-14 Winter	Normal	South-North NI Flow, No Western Generation	50% 5126 MW	N-1		
2013-14 Winter	Normal	South-North NI Flow, No Western Generation	50% 5126 MW	N-1-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2	White River 230-115 kV transformer #1 White River 230-115 kV transformer #2 Talbot Hill-Berrydale #1 115 kV line Berrydale 230-115 kV transformer O'Brien 230-115 kV transformer #2 O'Brien 230-115 kV transformer #1
2013-14 Winter	Normal	South-North NI Flow, No Western Generation	50% 5126 MW	N-2 or Common Mode		Talbot Hill 230-115 kV transformer #2 Talbot Hill-Lakeside #2 115 kV Line Berrydale 230-115 kV transformer
2014 Heavy Summer	Normal	Hi Gen, Hi Import from BC	100% 3343 MW	N-1	Monroe-Novelty Hill 230 kV line	
2014 Heavy Summer	Normal	No Gen, Hi Export to BC	100% 3343 MW	N-1	Maple Valley - Sammamish 230 kV line	
2014 Heavy Summer	Normal	No Gen, Hi Export to BC	100% 3343 MW	N-1-1	Sammamish 230-115 kV transformer #2	Sammamish 230-115 kV transformer #1

Table 6-2: Elements above Emergency and Operating Limits: 2013-14 Winter Peak, 100% Conservation, Normal Weather, Thermal Loadings (Redacted)

Case	Category	Worst Contingency	Owner of Facilities Out	Element(s)	Owner of Overloaded Facilities	Percent Overload
2013-14 Winter	B	[redacted]	BPA	Maple Valley - SnoKing #1 230 kV line	SCL	110.0%
2013-14 Winter	B	[redacted]	BPA	Maple Valley - SnoKing #2 230 kV line	SCL	107.8%
2013-14 Winter	C	[redacted]	BPA	Maple Valley - SnoKing #1 230 kV line	SCL	124.0%
2013-14 Winter	C	[redacted]	BPA	Maple Valley - SnoKing #2 230 kV line	SCL	123.8%
2013-14 Winter	C	[redacted]	BPA	Talbot Hill - Lakeside #1 115 kV line	PSE	97.1%
2013-14 Winter	C	[redacted]	BPA	Talbot Hill - Lakeside #2 115 kV line	PSE	96.9%
2013-14 Winter	C	[redacted]	PSE	Berrydale 230-115 kV transformer	PSE	96.6%
2013-14 Winter	C	[redacted]	BPA & SCL	Maple Valley - SnoKing #1 230 kV line	SCL	146.7%
2013-14 Winter	C	[redacted]	BPA & SCL	Maple Valley - SnoKing #2 230 kV line	SCL	145.0%
2013-14 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #1	PSE	100.9%
2013-14 Winter	C	[redacted]	BPA & PSE	Talbot Hill - Lakeside #1 115 kV line	PSE	115.2%
2013-14 Winter	C	[redacted]	BPA & PSE	Talbot Hill - Lakeside #2 115 kV line	PSE	115.1%
2013-14 Winter	C	[redacted]	BPA & PSE	Talbot Hill - Boeing Renton - Shuffleton 115 kV line	PSE	101.1%

Table 6-2: Elements above Emergency and Operating Limits: 2013-14 Winter Peak, 100% Conservation, Normal Weather, Thermal Loadings (Redacted) (CONTINUED)

2013-14 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #2	PSE	100.5%
2013-14 Winter	C	[redacted]	PSE	White River 230-115 kV transformer #2	PSE	97.4%
2013-14 Winter	C	[redacted]	PSE	White River 230-115 kV transformer #1	PSE	96.9%
2013-14 Winter	C	[redacted]	PSE	Talbot Hill - Berrydale #1 115 kV line	PSE	96.0%
2013-14 Winter	C	[redacted]	PSE	Berrydale 230-115 kV transformer	PSE	92.4%
2013-14 Winter	C	[redacted]	PSE	O'Brien 230-115 kV transformer #2	PSE	94.0%
2013-14 Winter	C	[redacted]	PSE	O'Brien 230-115 kV transformer #1	PSE	93.2%

Table 6-3: Summary of Elements above Emergency and Operating Limits: 2013-14 Winter Peak, Extreme Weather

Year of Study	Normal or Extreme Weather	Case Conditions	Amount of Conservation/ System Load	Type of Contingency	Elements above Emergency Limit	Elements > 90% of Emergency Limit or above Operating Limit
2013-14 Winter	Extreme	South-North NI Flow No Western Generation	100% 5537 MW	N-1		Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 White River 230-115 kV transformer #2
2013-14 Winter	Extreme	South-North NI Flow No Western Generation	50% 5608 MW	N-1-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 White River - Lea Hill - Berrydale 115 kV line Talbot Hill-Berrydale #1 115 kV line Berrydale 230-115 kV transformer O'Brien 230-115 kV transformer #1 O'Brien 230-115 kV transformer #2 White River 230-115 kV transformer #1 White River 230-115 kV transformer #2	Shuffleton-Lakeside 115 kV line O'Brien 115 kV North bus section breaker O'Brien - Asbury 115 kV line Shuffleton - President Park - Lake Tradition 115 kV line
2013-14 Winter	Extreme	South-North NI Flow No Western Generation	50% 5608 MW	N-2 or Common Mode	Talbot Hill-Lakeside #2 115 kV Line Berrydale 230-115 kV transformer	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2

6.1.3 2017-18 Thermal Summaries: Winter Peak, Normal and Extreme Weather & Summer Peak Normal Weather

Table 6-4 shows the summary of results for categories B (N-1) and C (N-1-1 & N-2) for 2017-18 winter and summer peaks with normal weather.

Table 6-4 shows that for the winter peak, normal weather, 100% conservation, (PSE load of 5,208 MW), there are no potential Category B thermal violations but there are three (3) facilities which are loaded from 90% to 100% of the emergency ratings. These facilities are highlighted in gray in Table 6-5.

1. Talbot Hill - Lakeside #1 115 kV line – 98.6%
2. Talbot Hill - Lakeside #2 115 kV line – 98.4%
3. Talbot Hill 230-115 kV transformer #2 – 90.3%

If 50% of conservation is achieved, (PSE load of 5,442 MW), the number of potential Category B thermal overloads increase to two (2) facilities.

1. Talbot Hill - Lakeside #1 115 kV Line
2. Talbot Hill - Lakeside #2 115 kV Line

There are six (6) potential thermal violations (same as 2013-14) of PSE lines or transformers in the King County area for Category C contingencies. These facilities are highlighted in yellow on Table 6-5, which shows that the potential thermal overloads vary up to a high of 128%. Overloads caused by BPA facility outages which are controlled by BPA generation dispatch are not highlighted.

1. Talbot Hill - Lakeside #1 115 kV Line
2. Talbot Hill - Lakeside #2 115 kV Line
3. Talbot Hill 230-115 kV transformer #1
4. Talbot Hill 230-115 kV transformer #2
5. Talbot Hill - Boeing Renton - Shuffleton 115 kV Line
6. Maple Valley - Sammamish 230 kV Line

If 75% of conservation is achieved, (PSE load of 5,325 MW), the number of potential Category C thermal overloads increase to seven (7) facilities and some occur for more than one Category C contingency.

1. Talbot Hill - Lakeside #1 115 kV Line
2. Talbot Hill - Lakeside #2 115 kV Line
3. Talbot Hill - Boeing Renton - Shuffleton 115 kV Line
4. Talbot Hill 230-115 kV transformer #1
5. Talbot Hill 230-115 kV transformer #2
6. White River - Lea Hill - Berrydale 115 kV line
7. Maple Valley - Sammamish 230 kV line

If 50% of conservation is achieved, (PSE load of 5,442 MW), the number of potential Category C thermal overloads increase to ten (10) facilities and some occur for more than one Category C contingency.

1. Talbot Hill- Lakeside #1 115 kV Line
2. Talbot Hill- Lakeside #2 115 kV Line
3. Talbot Hill - Boeing Renton-Shuffleton 115 kV Line
4. Talbot Hill 230-115 kV transformer #1
5. Talbot Hill 230-115 kV transformer #2
6. Maple Valley - Sammamish 230 kV line
7. White River - Lea Hill - Berrydale 115 kV line
8. Talbot Hill - Berrydale #1 115 kV line
9. Shuffleton - O'Brien 115 kV line
10. Shuffleton - Lakeside 115 kV line

For the 2018 summer peak, normal weather, (PSE load of 3,554 MW), high generation in the north and high imports from British Columbia (Table 6-12), there are two (2) potential Category B (N-1) thermal violations (Monroe - Novelty Hill 230 kV line and Maple Valley - Sammamish 230 kV line) and there are three (3) potential Category C (N-1-1 & N-2) thermal violations (Beverly Park - Cottage Brook 115 kV line, Sammamish 230-115 kV transformer #1, and Sammamish 230-115 kV transformer #2). The sections of the Monroe - Novelty Hill 230 kV line and Maple Valley - Sammamish 230 kV line that may overload are owned by BPA.

Table 6-6 shows the results of the generation sensitivity case for 2017-18, in which 1,031 MW of Puget Sound area generation was turned on. For the winter peak, normal weather, 100% conservation, (PSE load of 5,208 MW), and Puget Sound generation of 1,031 MW, there are no potential Category B thermal violations. There are four (4) potential Category C (N-1-1) violations remaining above the emergency limits (Talbot Hill - Lakeside #1 & #2 115 kV lines, and Talbot Hill 230-115 kV transformers #1 and #2). Running this level of generation also resulted in a new transformer operating above 90% for an N-1-1 contingency; the Sammamish transformer #2 will be above 90% if there are outages of both Sammamish transformer #1 and the Novelty Hill transformer. In general, turning on 1,000 MW of generation in the northern part of the Puget Sound area can have a significant impact in reducing transmission line overloads, but minor impact for transformer overloads.

Table 6-7 shows that for the 2017-18 winter peak, extreme weather, (PSE load of 5,742 MW), no generation in the north and high exports to British Columbia, there are two (2) potential Category B (N-1) thermal violations (Talbot Hill - Lakeside #1 & #2 115 kV lines (99.2% & 98.6%)); and there are twelve (12) potential Category C (N-1-1 & N-2) thermal violations.

The operational solution to temporarily remedy the potential overloads on Talbot Hill #1 transformer for the Category C loss of the North Talbot Hill 230 kV bus during extreme winter weather is to open breakers preemptively [redacted]. When that occurs there is added risk of losing load with the next N-1 contingency.

Table 6-4: Summary of Elements above Emergency and Operating Limits: 2017-18 Winter Peak, Normal Weather & Summer Peak Normal Weather

Year of Study	Normal or Extreme Weather	Case Conditions	Amount of Conservation/ System Load	Type of Contingency	Elements above Emergency Limit	Elements > 90% of Emergency Limit or above Operating Limit
2017-18 Winter	Normal	South-North NI Flow No Western Generation	100% 5208 MW	N-1		Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill 230-115 kV transformer #2
2017-18 Winter	Normal	South-North NI Flow No Western Generation	100% 5208 MW	N-1-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Maple Valley-Sammamish 230 kV line	Talbot Hill-Berrydale #1 115 kV line White River - Lea Hill - Berrydale 115 kV Line Shuffleton-O'Brien 115 kV line Shuffleton-Lakeside 115 kV line Berrydale 230-115 kV transformer O'Brien 230-115 kV transformer #2 O'Brien 230-115 kV transformer #1
2017-18 Winter	Normal	South-North NI Flow No Western Generation	100% 5208 MW	N-2 or Common Mode	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line	Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 Berrydale 230-115 kV transformer
2017-18 Winter	Normal	South-North NI Flow No Western Generation	75% 5325 MW	N-1		Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2
2017-18 Winter	Normal	South-North NI Flow No Western Generation	75% 5325 MW	N-1-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 White River - Lea Hill - Berrydale 115 kV line Maple Valley - Sammamish 230 kV line	Talbot Hill-Berrydale #1 115 kV line Shuffleton-O'Brien 115 kV line Shuffleton-Lakeside 115 kV line Berrydale 230-115 kV transformer O'Brien 230-115 kV transformer #2 O'Brien 230-115 kV transformer #1 O'Brien 115 kV North bus section breaker O'Brien-Asbury 115 kV line
2017-18 Winter	Normal	South-North NI Flow No Western Generation	75% 5325 MW	N-2 or Common Mode	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line	Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 Berrydale 230-115 kV transformer
2017-18 Winter	Normal	South-North NI Flow No Western Generation	50% 5442 MW	N-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line	Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 Talbot Hill-Boeing Renton-Shuffleton 115 kV Line
2017-18 Winter	Normal	South-North NI Flow No Western Generation	50% 5442 MW	N-1-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 Maple Valley-Sammamish 230 kV line White River - Lea Hill - Berrydale 115 kV line Talbot Hill-Berrydale #1 115 kV line Shuffleton - O'Brien 115 kV line Shuffleton-Lakeside 115 kV line	Berrydale 230-115 kV transformer O'Brien 230-115 kV transformer #2 O'Brien 230-115 kV transformer #1 O'Brien 115 kV North bus section breaker O'Brien - Asbury 115 kV line Shuffleton - President Park - Lake Tradition 115 kV line
2017-18 Winter	Normal	South-North NI Flow No Western Generation	50% 5442 MW	N-2 or Common Mode	Talbot Hill-Lakeside #2 115 kV Line	Talbot Hill-Lakeside #1 115 kV Line Berrydale 230-115 kV transformer Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2
2018 Heavy Summer	Normal	Hi Gen, Hi Import from BC	100% 3554 MW	N-1	Monroe-Novelty Hill 230 kV line	

REDACTED

Table 6-4: Summary of Elements above Emergency and Operating Limits: 2017-18 – Winter Peak, Normal Weather & Summer Peak Normal Weather (CONTINUED)

2018 Heavy Summer	Normal	No Gen, Hi Export to BC	100% 3554 MW	N-1	Maple Valley - Sammamish 230 kV line	Talbot Hill-Lakeside #1 115 kV line Talbot Hill-Lakeside #2 115 kV line
2018 Heavy Summer	Normal	Hi Gen, Hi Import from BC	100% 3554 MW	N-1-1	Beverly Park - Cottage Brook 115 kV line Sammamish 230-115 kV transformer #1 Sammamish 230-115 kV transformer #2	Novelty Hill 230-115 kV transformer
2018 Heavy Summer	Normal	Hi Gen, Hi Import from BC	100% 3554 MW	N-2 or Common Mode		Sammamish-Lakeside #2 115 kV line

Table 6-5: Elements above Emergency and Operating Limits: 2017-18 Winter Peak, 100% Conservation, Normal Weather, Thermal Loadings (Redacted)

Case	Category	Worst Contingency	Owner of Facilities Out	Element(s)	Owner of Overloaded Facilities	Percent Overload
2017-18 Winter	B	[redacted]	BPA	Maple Valley - SnoKing #1 230 kV line	SCL	119.3%
2017-18 Winter	B	[redacted]	BPA	Maple Valley - SnoKing #2 230 kV line	SCL	118.2%
2017-18 Winter	B	[redacted]	BPA	Talbot Hill - Lakeside #1 115 kV line	PSE	98.6%
2017-18 Winter	B	[redacted]	BPA	Talbot Hill - Lakeside #2 115 kV line	PSE	98.4%
2017-18 Winter	B	[redacted]	PSE	Talbot Hill 230-115 kV transformer #2	PSE	90.3%
2017-18 Winter	C	[redacted]	BPA	Maple Valley - SnoKing #1 230 kV line	SCL	123.9%
2017-18 Winter	C	[redacted]	BPA	Maple Valley - SnoKing #2 230 kV line	SCL	123.3%
2017-18 Winter	C	[redacted]	PSE	Talbot Hill - Lakeside #2 115 kV line	PSE	101.1%
2017-18 Winter	C	[redacted]	BPA	Talbot Hill - Lakeside #1 115 kV line	PSE	101.5%
2017-18 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #1	PSE	91.8%
2017-18 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #2	PSE	92.8%
2017-18 Winter	C	[redacted]	PSE	Berrydale 230-115 kV transformer	PSE	93.6%
2017-18 Winter	C	[redacted]	BPA & SCL	Maple Valley - SnoKing #1 230 kV line	SCL	176.6%

Table 6-5: Elements above Emergency and Operating Limits: 2017-18 Winter Peak, 100% Conservation, Normal Weather, Thermal Loadings (Redacted) (CONTINUED)

2017-18 Winter	C	[redacted]	BPA & SCL	Maple Valley - SnoKing #2 230 kV line	SCL	157.8%
2017-18 Winter	C	[redacted]	BPA & PSE	Talbot Hill - Lakeside #1 115 kV line (Redispatch not enough)	PSE	127.8%
2017-18 Winter	C	[redacted]	BPA & PSE	Talbot Hill - Lakeside #2 115 kV line (Redispatch not enough)	PSE	127.6%
2017-18 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #1 (Redispatch not enough)	PSE	105.7%
2017-18 Winter	C	[redacted]	BPA & PSE	Talbot Hill - Boeing Renton - Shuffleton 115 kV line (Redispatch not enough)	PSE	110.6%
2017-18 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #2 (Redispatch not enough)	PSE	105.7%
2017-18 Winter	C	[redacted]	PSE	Talbot Hill - Berrydale #1 115 kV line	PSE	97.6%
2017-18 Winter	C	[redacted]	PSE	White River - Lea Hill - Berrydale 115 kV line	PSE	98.0%
2017-18 Winter	C	[redacted]	BPA & PSE	Shuffleton - O'Brien 115 kV line	PSE	97.9%
2017-18 Winter	C	[redacted]	PSE	Berrydale 230-115 kV transformer	PSE	93.8%
2017-18 Winter	C	[redacted]	BPA & SCL	Maple Valley - Sammamish 230 kV line	BPA	104.4%

Table 6-6: Elements above Emergency and Operating Limits: 2017-18 Winter Peak, 100% Conservation, Normal Weather, Low Generation Sensitivity Case, Thermal Loadings (Redacted)

						No Gen	With Gen
Case	Category	Worst Contingency	Owner of Facilities Out	Element(s)	Owner of Overloaded Facilities	% Overload	% Overload
2017-18 Winter	B	[redacted]	PSE	Talbot Hill 230-115 kV transformer #2	PSE	90.3%	87.4%
2017-18 Winter	B	[redacted]	BPA	Maple Valley - SnoKing #1 230 kV line	SCL	119.3%	86.5%
2017-18 Winter	B	[redacted]	BPA	Maple Valley - SnoKing #2 230 kV line	SCL	118.2%	84.2%
2017-18 Winter	B	[redacted]	BPA	Talbot Hill - Lakeside #1 115 kV line	PSE	98.6%	84.1%
2017-18 Winter	B	[redacted]	BPA	Talbot Hill - Lakeside #2 115 kV line	PSE	98.4%	83.9%
2017-18 Winter	C	[redacted]	BPA	Maple Valley - SnoKing #1 230 kV line	SCL	123.9%	89.0%
2017-18 Winter	C	[redacted]	BPA	Maple Valley - SnoKing #2 230 kV line	SCL	123.3%	87.1%
2017-18 Winter	C	[redacted]	PSE	Talbot Hill - Lakeside #2 115 kV line	PSE	101.1%	87.2%
2017-18 Winter	C	[redacted]	BPA	Talbot Hill - Lakeside #1 115 kV line	PSE	101.5%	85.8%
2017-18 Winter	C	[redacted]	PSE	Berrydale 230-115 kV transformer	PSE	93.6%	90.2%
2017-18 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #1	PSE	91.8%	89.3%
2017-18 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #2	PSE	92.8%	90.5%
2017-18 Winter	C	[redacted]	BPA & SCL	Maple Valley - SnoKing #1 230 kV line	SCL	176.6%	112.9%
2017-18 Winter	C	[redacted]	BPA & SCL	Maple Valley - SnoKing #2 230 kV line	SCL	157.8%	110.9%
2017-18 Winter	C	[redacted]	BPA & PSE	Talbot Hill - Lakeside #1 115 kV line	PSE	127.8%	108.7%

Table 6-6: Elements above Emergency and Operating Limits: 2017-18 Winter Peak, 100% Conservation, Normal Weather, Low Generation Sensitivity Case, Thermal Loadings (Redacted) (CONTINUED)

2017-18 Winter	C	[redacted]	BPA & PSE	Talbot Hill - Lakeside #2 115 kV line	PSE	127.6%	108.5%
2017-18 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #2	PSE	105.7%	102.2%
2017-18 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #1	PSE	105.7%	102.0%
2017-18 Winter	C	[redacted]	BPA & PSE	Talbot Hill - Boeing Renton - Shuffleton 115 kV line	PSE	110.6%	98.8%
2017-18 Winter	C	[redacted]	PSE	Talbot Hill - Berrydale #1 115 kV line	PSE	97.6%	96.5%
2017-18 Winter	C	[redacted]	PSE	White River - Lea Hill - Berrydale 115 kV line	PSE	98.0%	94.8%
2017-18 Winter	C	[redacted]	PSE	Berrydale 230-115 kV transformer	PSE	93.8%	93.0%
2017-18 Winter	C	[redacted]	PSE	O'Brien 230-115 kV transformer #2	PSE	93.9%	91.3%
2017-18 Winter	C	[redacted]	PSE	O'Brien 230-115 kV transformer #1	PSE	93.1%	90.5%
2017-18 Winter	C	[redacted]	PSE	Sammamish 230-115 kV transformer #2	PSE	83.8%	90.3%
2017-18 Winter	C	[redacted]	BPA & PSE	Shuffleton - O'Brien 115 kV line	PSE	97.9%	86.4%
2017-18 Winter	C	[redacted]	BPA & PSE	O'Brien 115 kV North bus section breaker	PSE	92.5%	85.0%
2017-18 Winter	C	[redacted]	BPA & PSE	Shuffleton - Lakeside 115 kV line	PSE	97.3%	83.6%
2017-18 Winter	C	[redacted]	BPA & SCL	Maple Valley - Sammamish 230 kV line	BPA	104.4%	76.7%

Table 6-7: Summary of Elements above Emergency and Operating Limits: 2017-18 Winter Peak, Extreme Weather

Year of Study	Normal or Extreme Weather	Case Conditions	Amount of Conservation / System Load	Type of Contingency	Elements above Emergency Limit	Elements > 90% of Emergency Limit or above Operating Limit
2017-18 Winter	Extreme	South-North NI Flow No Western Generation	100% 5742	N-1	Talbot Hill-Lakeside #1 115 kV Line 99.1% Talbot Hill-Lakeside #2 115 kV Line 98.9%	Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 Talbot Hill - Boeing Renton - Shuffleton 115 kV line
2017-18 Winter	Extreme	South-North NI Flow No Western Generation	100% 5742	N-1-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 White River - Lea Hill - Berrydale 115 kV line Shuffleton-Lakeside 115 kV line Talbot Hill-Berrydale #1 115 kV line Berrydale 230-115 kV transformer O'Brien 115 kV North bus section breaker O'Brien 230-115 kV transformer #1 O'Brien 230-115 kV transformer #2	O'Brien - Asbury 115 kV line Shuffleton - President Park - Lake Tradition 115 kV line White River 230-115 kV transformer #1 White River 230-115 kV transformer #2 Sammamish 230-115 kV transformer #2
2017-18 Winter	Extreme	South-North NI Flow No Western Generation	75% 5859	N-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line	Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 Talbot Hill - Boeing Renton - Shuffleton 115 kV line Berrydale 230-115 kV transformer
2017-18 Winter	Extreme	South-North NI Flow No Western Generation	75% 5859	N-1-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 White River - Lea Hill - Berrydale 115 kV line Shuffleton-Lakeside 115 kV line Talbot Hill-Berrydale #1 115 kV line Berrydale 230-115 kV transformer O'Brien 115 kV North bus section breaker O'Brien 230-115 kV transformer #1 O'Brien 230-115 kV transformer #2	O'Brien - Asbury 115 kV line Shuffleton - President Park - Lake Tradition 115 kV line White River 230-115 kV transformer #1 White River 230-115 kV transformer #2 Sammamish 230-115 kV transformer #2 Shuffleton - O'Brien 115 kV line O'Brien - Midway #1 115 kV line Talbot Hill - Lake Tradition #1 115 kV line Sammamish 230-115 kV transformer #1
2017-18 Winter	Extreme	South-North NI Flow No Western Generation	75% 5859	N-2 or Common Mode	Berrydale 230-115 kV transformer Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2	Shuffleton - O'Brien 115 kV line Talbot Hill - Boeing Renton - Shuffleton 115 kV line O'Brien - Midway #1 115 kV line
2017-18 Winter	Extreme	South-North NI Flow No Western Generation	50% 5967 MW	N-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill 230-115 kV transformer #1 (99.6%) Talbot Hill 230-115 kV transformer #2 (99.9%)	Berrydale 230-115 kV transformer Talbot Hill - Boeing Renton - Shuffleton 115 kV line
2017-18 Winter	Extreme	South-North NI Flow No Western Generation	50% 5967 MW	N-1-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 White River - Lea Hill - Berrydale 115 kV line Shuffleton-Lakeside 115 kV line Talbot Hill-Berrydale #1 115 kV line Berrydale 230-115 kV transformer O'Brien 115 kV North bus section breaker O'Brien 230-115 kV transformer #1 O'Brien 230-115 kV transformer #2	Shuffleton-Lakeside 115 kV line O'Brien 115 kV North bus section breaker O'Brien - Asbury 115 kV line Shuffleton - President Park - Lake Tradition 115 kV line White River 230-115 kV transformer #1 White River 230-115 kV transformer #2 Shuffleton-O'Brien 115 kV line Sammamish 230-115 kV transformer #2
2017-18 Winter	Extreme	South-North NI Flow No Western Generation	50% 5967 MW	N-2 or Common Mode	Berrydale 230-115 kV transformer Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2	Talbot Hill 230-115 kV transformer #2 Shuffleton - O'Brien 115 kV line Talbot Hill - Boeing Renton - Shuffleton 115 kV line O'Brien - Midway #1 115 kV line O'Brien 230-115 kV transformer #2

6.1.4 2021-22: Winter Peak, Normal & Extreme Weather Thermal Summaries

Table 6-8 shows the summary of results for categories B (N-1) and C (N-1-1 & N-2) for 2021-22 winter and summer peaks with normal weather.

Table 6-9 indicates that the PSE load level for the winter peak, normal weather, 100% conservation, for 2021-22 is 5,193 MW. There are no potential Category B (N-1) thermal violations but there are five (5) elements with loadings from 90% to 100% of the emergency ratings. Those facilities are highlighted in gray on Table 6-9.

1. Talbot Hill - Lakeside #1 115 kV Line – 95.2%
2. Talbot Hill - Lakeside #2 115 kV Line – 95.1%
3. Talbot Hill 230-115 kV transformer #1 – 91.0%
4. Talbot Hill 230-115 kV transformer #2 – 91.5%
5. Talbot Hill - Boeing Renton - Shuffleton 115 kV Line – 91.5%

For Category C (N-1-1) contingencies there are six (6) elements above the emergency limits and an additional six (6) elements with loadings above 90% of their emergency limits. Those facilities are highlighted in yellow for overloads.

1. Talbot Hill - Lakeside #1 115 kV Line
2. Talbot Hill - Lakeside #2 115 kV Line
3. Talbot Hill 230-115 kV transformer #1
4. Talbot Hill 230-115 kV transformer #2
5. Talbot Hill - Boeing Renton - Shuffleton 115 kV Line
6. Shuffleton - Lakeside 115 kV Line

The PSE load level for the winter peak, normal weather, 75% conservation, for 2021-22 is 5,415 MW. Table 6-8 indicates that there are no potential Category B (N-1) thermal violations but there are five (5) elements with loadings above 90% of the emergency ratings (Talbot Hill-Lakeside #1 & 2 115 kV Lines, Talbot Hill 230-115 kV transformers #1 & 2, and Talbot Hill-Boeing Renton-Shuffleton 115 kV Line). For Category C (N-1-1) contingencies there are ten (10) elements above the emergency limits and an additional five (5) elements with loadings above 90% of their emergency limits.

Table 6-10 shows that for the 2021-22 winter peak, extreme weather, (PSE load of 5,772 MW), no generation in the north and high exports to British Columbia, there are four (4) potential Category B (N-1) thermal violations (Talbot Hill - Lakeside #1 & #2 115 kV lines, Talbot Hill-Boeing Renton-Shuffleton 115 kV line, and the Talbot Hill 230-115 kV transformer #1). There are fourteen (14) potential Category C (N-1-1 & N-2) thermal violations.

The extreme winter cases are run as an indication of the flexibility and robustness of the electric transmission system in a near or far future year. As shown in Tables 6-7 and 6-10, the increased load to be expected with extremely cold weather could lead to many more overloads than those projected with loads during normal weather, even with reduced conservation effects. While most utilities, including PSE, do not construct facilities on the basis of extreme seasonal temperatures, it does serve as an indicator of system stresses further into the future.

Table 6-8: Summary of Elements above Emergency and Operating Limits: 2021-22 Winter Peak, Normal Weather

Year of Study	Normal or Extreme Weather	Case Conditions	Amount of Conservation/ System Load	Type of Contingency	Elements above Emergency Limit	Elements > 90% of Emergency Limit or above Operating Limit
2021-22 Winter	Normal	South-North NI Flow No Western Generation	100% 5193 MW	N-1		Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 Talbot-Boeing Renton-Shuffleton 115 kV Line
2021-22 Winter	Normal	South-North NI Flow No Western Generation	100% 5193 MW	N-1-1	Talbot Hill-Lakeside #1 115 kV Line Talbot-Lakeside Hill #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 Shuffleton-Lakeside 115 kV line	White River - Lea Hill - Berrydale 115 kV Line Berrydale 230-115 kV transformer O'Brien 230-115 kV transformer #2 O'Brien 230-115 kV transformer #1 O'Brien 115 kV North bus section breaker Talbot Hill-Berrydale #1 115 kV line
2021-22 Winter	Normal	South-North NI Flow No Western Generation	100% 5193 MW	N-2 or Common Mode	Talbot Hill-Lakeside #2 115 kV Line	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 Berrydale 230-115 kV transformer
2021-22 Winter	Normal	South-North NI Flow No Western Generation	75% 5415 MW	N-1		Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2
2021-22 Winter	Normal	South-North NI Flow No Western Generation	75% 5415 MW	N-1-1	Talbot Hill-Berrydale #1 115 kV line Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 White River - Lea Hill - Berrydale 115 kV line Shuffleton-Lakeside 115 kV line Berrydale 230-115 kV transformer O'Brien 230-115 kV transformer #2	O'Brien 230-115 kV transformer #1 O'Brien 115 kV North bus section breaker O'Brien-Asbury 115 kV line Shuffleton-President Park - Lake Tradition 115 kV line Shuffleton-O'Brien 115 kV Line
2021-22 Winter	Normal	South-North NI Flow No Western Generation	75% 5415 MW	N-2 or Common Mode	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Berrydale 230-115 kV transformer	Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 Shuffleton - O'Brien 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line
2021-22 Winter	Normal	South-North NI Flow No Western Generation	50% 5636 MW	N-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line	Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 Berrydale 230-115 kV transformer Talbot Hill - Boeing Renton - Shuffleton 115 kV line
2021-22 Winter	Normal	South-North NI Flow No Western Generation	50% 5636 MW	N-1-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 White River - Lea Hill - Berrydale 115 kV line Talbot Hill-Berrydale #1 115 kV line Shuffleton-Lakeside 115 kV line Berrydale 230-115 kV transformer O'Brien 230-115 kV transformer #1 O'Brien 230-115 kV transformer #2 O'Brien 115 kV North bus section breaker	O'Brien - Asbury 115 kV line Shuffleton - President Park - Lake Tradition 115 kV line Shuffleton-O'Brien 115 kV line Sammamish 230-115 kV transformer #2 White River 230-115 kV transformer #1 White River 230-115 kV transformer #2 O'Brien-Midway #1 115 kV Line
2021-22 Winter	Normal	South-North NI Flow No Western Generation	50% 5636 MW	N-2 or Common Mode	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Berrydale 230-115 kV transformer Talbot Hill 230-115 kV transformer #1	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #2 Shuffleton - O'Brien 115 kV line

Table 6-9: Elements above Emergency and Operating Limits: 2021-22 Winter Peak, 100% Conservation, Normal Weather, Thermal Loadings (Redacted)

Case	Category	Worst Contingency	Owner of Facilities Out	Element(s)	Owner of Overloaded Facilities	Percent Overload
2021-22 Winter	B	[redacted]	PSE	Talbot Hill - Lakeside #1 115 kV line	PSE	95.2%
2021-22 Winter	B	[redacted]	PSE	Talbot Hill - Lakeside #2 115 kV line	PSE	95.1%
2021-22 Winter	B	[redacted]	PSE	Talbot Hill 230-115 kV transformer #1	PSE	91.0%
2021-22 Winter	B	[redacted]	PSE	Talbot Hill 230-115 kV transformer #2	PSE	91.5%
2021-22 Winter	B	[redacted]	PSE	Talbot Hill - Boeing Renton - Shuffleton 115 kV line	PSE	91.5%
2021-22 Winter	C	[redacted]	PSE	Talbot Hill - Lakeside #2 115 kV line	PSE	107.1%
2021-22 Winter	C	[redacted]	PSE	Talbot Hill - Lakeside #1 115 kV line	PSE	96.8%
2021-22 Winter	C	[redacted]	PSE	Berrydale 230-115 kV transformer	PSE	95.5%
2021-22 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #2	PSE	93.2%
2021-22 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #1	PSE	93.6%
2021-22 Winter	C	[redacted]	PSE	Shuffleton - O'Brien 115 kV line	PSE	90.0%
2021-22 Winter	C	[redacted]	PSE	Talbot Hill - Berrydale #1 115 kV line	PSE	97.6%
2021-22 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #1	PSE	108.1%

Table 6-9: Elements above Emergency and Operating Limits: 2021-22 Winter Peak, 100% Conservation, Normal Weather, Thermal Loadings (Redacted) (CONTINUED)

2021-22 Winter	C	[redacted]	PSE	Talbot Hill - Lakeside #1 115 kV line	PSE	117.8%
2021-22 Winter	C	[redacted]	PSE	Talbot Hill - Lakeside #2 115 kV line	PSE	117.7%
2021-22 Winter	C	[redacted]	PSE	Talbot Hill - Boeing Renton - Shuffleton 115 kV line	PSE	107.6%
2021-22 Winter	C	[redacted]	PSE	Talbot Hill 230-115 kV transformer #2	PSE	107.0%
2021-22 Winter	C	[redacted]	PSE	White River - Lea Hill - Berrydale 115 kV line	PSE	99.7%
2021-22 Winter	C	[redacted]	PSE	Shuffleton - Lakeside 115 kV line	PSE	100.8%
2021-22 Winter	C	[redacted]	PSE	Berrydale 230-115 kV transformer	PSE	96.1%
2021-22 Winter	C	[redacted]	PSE	O'Brien 230-115 kV transformer #1	PSE	94.3%
2021-22 Winter	C	[redacted]	PSE	O'Brien 230-115 kV transformer #2	PSE	95.1%
2021-22 Winter	C	[redacted]	PSE	O'Brien 115 kV North bus section breaker	PSE	94.6%
2021-22 Winter	C	[redacted]	PSE	O'Brien - Asbury 115 kV line	PSE	90.9%

Table 6-10: Summary of Elements above Emergency and Operating Limits: 2021-22 Winter Peak, Extreme Weather Thermal Loadings

Year of Study	Normal or Extreme Weather	Case Conditions	Amount of Conservation/ System Load	Type of Contingency	Elements above Emergency Limit	Elements > 90% of Emergency Limit or above Operating Limit
2021-22 Winter	Extreme	South-North NI Flow No Western Generation	100% 5772 MW	N-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1	Berrydale 230-115 kV transformer Talbot Hill 230-115 kV transformer #2
2021-22 Winter	Extreme	South-North NI Flow No Western Generation	100% 5772 MW	N-1-1	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #1 Talbot Hill 230-115 kV transformer #2 White River - Lea Hill - Berrydale 115 kV line Shuffleton-Lakeside 115 kV line Talbot Hill-Berrydale #1 115 kV line Berrydale 230-115 kV transformer O'Brien 115 kV North bus section breaker O'Brien 230-115 kV transformer #1 O'Brien 230-115 kV transformer #2 O'Brien - Asbury 115 kV line Shuffleton-O'Brien 115 kV line	Shuffleton - President Park - Lake Tradition 115 kV line White River 230-115 kV transformer #1 White River 230-115 kV transformer #2 Sammamish 230-115 kV transformer #1 Sammamish 230-115 kV transformer #2 Talbot Hill-Lake Tradition #1 115 kV Line O'Brien-Metro Renton – Talbot Hill 115 kV Line O'Brien – Christopher #1 115 kV Line
2021-22 Winter	Extreme	South-North NI Flow No Western Generation	100% 5772 MW	N-2 or Common Mode	Talbot Hill-Lakeside #1 115 kV Line Talbot Hill-Lakeside #2 115 kV Line Talbot Hill 230-115 kV transformer #1 Shuffleton-O'Brien 115 kV line Berrydale 230-115 kV transformer	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line Talbot Hill 230-115 kV transformer #2 O'Brien 230-115 kV transformer #2 O'Brien - Midway #1 115 kV line

6.1.5 Summary of Potential Thermal Violations

Based on Table 6-11, below, the PSE Winter load level where King County starts to have significant issues is approximately 5200 MW. The elements which are the most susceptible to potential overloads for the winter peak loads are in the Talbot Hill and Lakeside Substation areas.

The sensitivity cases with 75% conservation instead of 100% conservation indicate system performance concerns with higher winter loads. Those sensitivity studies show even higher overloads of the elements already overloaded in the 100% conservation cases. In general, should loads grow faster than forecast, or conservation not provide anticipated peak load relief, the potential overloads will be higher than the results reported. Even when the corporate load does not increase from 2017-18 to 2021-22, the Eastside load has grown, resulting in an increased number of potential violations.

Table 6-11: Summary of Potential Thermal Violations for Winter Peak Load Season

Contingency	2013-14 5055 MW 100% Con	2013-14 5090 MW 75% Con	2017-18 5208 MW 100% Con	2017-18 5325 MW 75% Con	2021-22 5193 MW 100% Con	2021-22 5415 MW 75% Con
Cat B (N-1)			Talbot Hill - Lakeside #1 115 kV line – 98.6%	Talbot Hill - Lakeside #1 115 kV line – 99.9%	Talbot Hill - Lakeside #1 115 kV line – 95.2%	Talbot Hill - Lakeside #1 115 kV line – 99.2%
			Talbot Hill - Lakeside #2 115 kV line – 98.4%	Talbot Hill - Lakeside #2 115 kV line – 99.9%	Talbot Hill - Lakeside #2 115 kV line – 95.1%	Talbot Hill - Lakeside #2 115 kV line – 99.1%
			Talbot Hill 230-115 kV transformer #2 – 90.3%	Talbot Hill 230-115 kV transformer #1 – 90.9%	Talbot Hill 230-115 kV transformer #1 – 91.0%	Talbot Hill 230-115 kV transformer #1 – 94.7%
				Talbot Hill 230-115 kV transformer #2 – 92.4%	Talbot Hill 230-115 kV transformer #2 – 91.5%	Talbot Hill 230-115 kV transformer #2 – 93.6%
						Talbot Hill - Boeing Renton - Shuffleton 115 kV line - 95.4%
Cat C (N-1-1)	Talbot Hill-Lakeside #1 115 kV Line - 115.2%	Talbot Hill-Lakeside #1 115 kV Line - 115.9%	Talbot Hill--Lakeside #1 115 kV Line - 127.8%	Talbot Hill-Lakeside #1 115 kV Line - 129.9%	Talbot Hill--Lakeside #1 115 kV Line - 117.8%	Talbot Hill--Lakeside #1 115 kV Line - 122.9%
	Talbot Hill-Lakeside #2 115 kV Line - 115.1%	Talbot Hill-Lakeside #2 115 kV Line - 115.8%	Talbot Hill--Lakeside #2 115 kV Line - 127.6%	Talbot Hill-Lakeside #2 115 kV Line - 129.7%	Talbot Hill-Lakeside #2 115 kV Line - 117.7%	Talbot Hill-Lakeside #2 115 kV Line - 122.8%
	Talbot Hill 230-115 kV transformer #1 - 100.9%	Talbot Hill 230-115 kV transformer #1 - 101.6%	Talbot Hill 230-115 kV transformer #1 - 105.7%	Talbot Hill 230-115 kV transformer #1 - 108.1%	Talbot Hill 230-115 kV transformer #1 - 108.1%	Talbot Hill 230-115 kV transformer #1 - 112.8%
	Talbot Hill 230-115 kV transformer #2 - 100.5%	Talbot Hill 230-115 kV transformer #2 - 101.6%	Talbot Hill 230-115 kV transformer #2 - 105.7%	Talbot Hill 230-115 kV transformer #2 – 107.6%	Talbot Hill 230-115 kV transformer #2 - 107.0%	Talbot Hill 230-115 kV transformer #2 - 109.8%
	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line -101.1%	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 101.7%	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 110.6%	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 112.5%	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 107.6%	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 112.3%
				White River - Lea Hill - Berrydale 115 kV line - 100.2%	White River - Lea Hill - Berrydale 115 kV line - 99.7%	White River - Lea Hill - Berrydale 115 kV line - 104.0%
				Maple Valley - Sammamish 230 kV line - 100.5%		Talbot Hill-Berrydale #1 115 kV line - 101.9%
						Shuffleton-Lakeside 115 kV line - 105.2%
						Berrydale 230-115 kV transformer - 100.8%
						O'Brien 230-115 kV transformer #2 - 100.2%
						O'Brien 230-115 kV transformer #1 - 99.4%
Cat C (N-2 or Common Mode)			Talbot Hill-Lakeside #1 115 kV Line - 101.5%	Talbot Hill-Lakeside #1 115 kV Line - 103.0%	Talbot Hill - Lakeside #1 115 kV line – 96.8%	Talbot Hill-Lakeside #1 115 kV Line – 100.7%
			Talbot Hill-Lakeside #2 115 kV Line - 101.1%	Talbot Hill-Lakeside #2 115 kV Line - 100.5%	Talbot Hill - Lakeside #2 115 kV line – 107.1%	Talbot Hill-Lakeside #2 115 kV Line - 111.7%
					Talbot Hill 230-115 kV transformer #1 – 93.6%	Talbot Hill 230-115 kV transformer #1 – 97.3%
					Talbot Hill 230-115 kV transformer #2 – 93.2%	Talbot Hill 230-115 kV transformer #2 – 95.1%
					Berrydale 230-115 kV transformer - 95.5%	Berrydale 230-115 kV transformer - 100.2%

Based on Table 6-12 below, the PSE summer load level where King County starts to have significant issues is approximately 3,500 MW. The elements which are the most susceptible to potential overloads for the summer peak loads are in the Sammamish Substation area.

Table 6-12: Summary of Potential Thermal Violations for Summer Peak Load Season

Contingency	2014 3343 MW 100% Con	2018 3554 MW 100% Con
Cat B (N-1)	Monroe-Novelty Hill 230 kV line - 132.6%	Monroe-Novelty Hill 230 kV line - 133.0%
	Maple Valley - Sammamish 230 kV line - 111.4%	Maple Valley - Sammamish 230 kV line - 132.3%
		Talbot Hill - Lakeside #1 115 kV line - 93.9%
		Talbot Hill - Lakeside #2 115 kV line - 93.8%
Cat C (N-1-1)	Sammamish 230-115 kV transformer #2 - 100.8%	Beverly Park - Cottage Brook 115 kV line - 100.5% (Have solution)
	Sammamish 230-115 kV transformer #1 - 95.5%	Sammamish 230-115 kV transformer #1 - 100.7% (Have solution)
		Sammamish 230-115 kV transformer #2 - 106.4% (Have solution)
Cat C (N-2)		Sammamish - Lakeside #2 115 kV line - 99.8%

6.1.6 Temporary Mitigations and Associated Risks

Based on the analysis described above there are a number of system events that require the Transmission Operators to implement operating procedures in place to temporarily reduce or mitigate the potential thermal violations. Table 6-13 indicates mitigation needed for each of the winter overload contingencies identified in 2017-18.

Table 6-13: Mitigations for Worst Winter 2017-18 Contingencies

Contingency	2013-14 Winter Peak 5208 MW 100% Conservation	2017-18 Winter Peak 5208 MW 100% Conservation	2017-18 Winter Peak 5325 MW 75% Conservation	Contingency Causing Overload	Mitigation Plan - Worst Contingency	Customers at Risk
Cat B (N-1)		Talbot Hill - Lakeside #1 115 kV line – 98.6%	Talbot Hill - Lakeside #1 115 kV line – 99.9%	[redacted]	[redacted]	None
		Talbot Hill - Lakeside #2 115 kV line – 98.4%	Talbot Hill - Lakeside #2 115 kV line – 99.9%	[redacted]	[redacted]	None
		Talbot Hill 230-115 kV transformer #2 – 90.3%	Talbot Hill 230-115 kV transformer #2 – 92.4%	[redacted]	[redacted]	None
			Talbot Hill 230-115 kV transformer #1 – 90.9%	[redacted]	[redacted]	None
Cat C (N-1-1)	Talbot-Lakeside #1 115 kV Line - 115.2%	Talbot-Lakeside #1 115 kV Line - 127.8%	Talbot-Lakeside #1 115 kV Line - 129.9%	[redacted]	[redacted]	49,000 for line outage, 33,000 for transformer outage
	Talbot-Lakeside #2 115 kV Line - 115.1%	Talbot-Lakeside #2 115 kV Line - 127.6%	Talbot-Lakeside #2 115 kV Line - 129.7%	[redacted]	[redacted]	49,000 for line outage, 33,000 for transformer outage
	Talbot Hill 230-115 kV transformer #1 - 100.9%	Talbot Hill 230-115 kV transformer #1 - 105.7%	Talbot Hill 230-115 kV transformer #1 - 108.1%	[redacted]	[redacted]	More lines may need to be opened for next N-1-1 contingencies
	Talbot Hill 230-115 kV transformer #2 - 100.5%	Talbot Hill 230-115 kV transformer #2 - 105.7%	Talbot Hill 230-115 kV transformer #2 – 107.6%	[redacted]	[redacted]	More lines may need to be opened for next N-1-1 contingencies
	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 101.1%	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 110.6%	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 112.5%	[redacted]	[redacted]	23,000 for line outage, 33,000 for transformer outage

Table 6-13: Mitigations for Worst Winter 2017-18 Contingencies (CONTINUED)

		O'Brien 230-115 kV transformer #1 - 93.1%	O'Brien 230-115 kV transformer #1 - 94.9%	[redacted]	[redacted]	More lines may need to be opened for next N-1-1 contingencies
		O'Brien 230-115 kV transformer #2 - 93.9%	O'Brien 230-115 kV transformer #2 - 95.7%	[redacted]	[redacted]	More lines may need to be opened for next N-1-1 contingencies
		Berrydale 230-115 kV transformer - 93.8%	Berrydale 230-115 kV transformer - 96.0%	[redacted]	[redacted]	More lines may need to be opened for next N-1-1 contingencies
		Talbot Hill-Berrydale #1 115 kV line - 97.6%	Talbot Hill-Berrydale #1 115 kV line - 99.8%	[redacted]	[redacted]	32,000 for line outage, 50,000 for transformer outage
		Shuffleton - Lakeside 115 kV line - 97.3%	Shuffleton - Lakeside 115 kV line - 98.9%	[redacted]	[redacted]	None
			White River - Lea Hill - Berrydale 115 kV line - 100.2%	[redacted]	[redacted]	32,000 for line outage, 50,000 for transformer outage
			Maple Valley - Sammamish 230 kV line - 100.5%	[redacted]	[redacted]	None
Cat C (N-2 or Common Mode)		Talbot-Lakeside #1 115 kV Line - 101.5%	Talbot-Lakeside #1 115 kV Line - 103.0%	[redacted]	[redacted]	32,000 for line outage, 50,000 for transformer outage
		Talbot-Lakeside #2 115 kV Line - 101.1%	Talbot-Lakeside #2 115 kV Line - 100.5%	[redacted]	[redacted]	None
		Talbot Hill 230-115 kV transformer #1 - 91.8%	Talbot Hill 230-115 kV transformer #1 - 93.8%	[redacted]	[redacted]	None
		Talbot Hill 230-115 kV transformer #2 - 92.8%	Talbot Hill 230-115 kV transformer #2 - 94.4%	[redacted]	[redacted]	None

The following table indicates mitigation needed for each of the summer overload contingencies identified in 2018.

Table 6-14: Mitigation for Worst Summer 2018 Contingencies

Contingency	2014 Summer Peak 3343 MW 100% Conservation	2018 Summer Peak 3554 MW 100% Conservation	Contingency Causing Overload	Mitigation	Customers at Risk
Cat B (N-1)	Monroe-Novelty Hill 230 kV line - 132.6%	Monroe-Novelty Hill 230 kV line - 133.0%	[redacted]	[redacted]	None
	Maple Valley - Sammamish 230 kV line - 111.4%	Maple Valley - Sammamish 230 kV line - 132.3%	[redacted]	[redacted]	None
		Talbot Hill - Lakeside #1 115 kV line - 93.9%	[redacted]	[redacted]	None
		Talbot Hill - Lakeside #2 115 kV line - 93.8%	[redacted]	[redacted]	None
Cat C (N-1-1)	Sammamish 230-115 kV transformer #2 - 100.8%	Sammamish 230-115 kV transformer #2 - 106.4%	[redacted]	[redacted]	33,000
	Sammamish 230-115 kV transformer #1 - 95.5%	Sammamish 230-115 kV transformer #1 - 100.7%	[redacted]	[redacted]	33,000
		Beverly Park - Cottage Brook 115 kV line - 100.5%	[redacted]	[redacted]	27,000
Cat C (N-2)		Sammamish - Lakeside #2 115 kV line - 99.8%	[redacted]	[redacted]	None

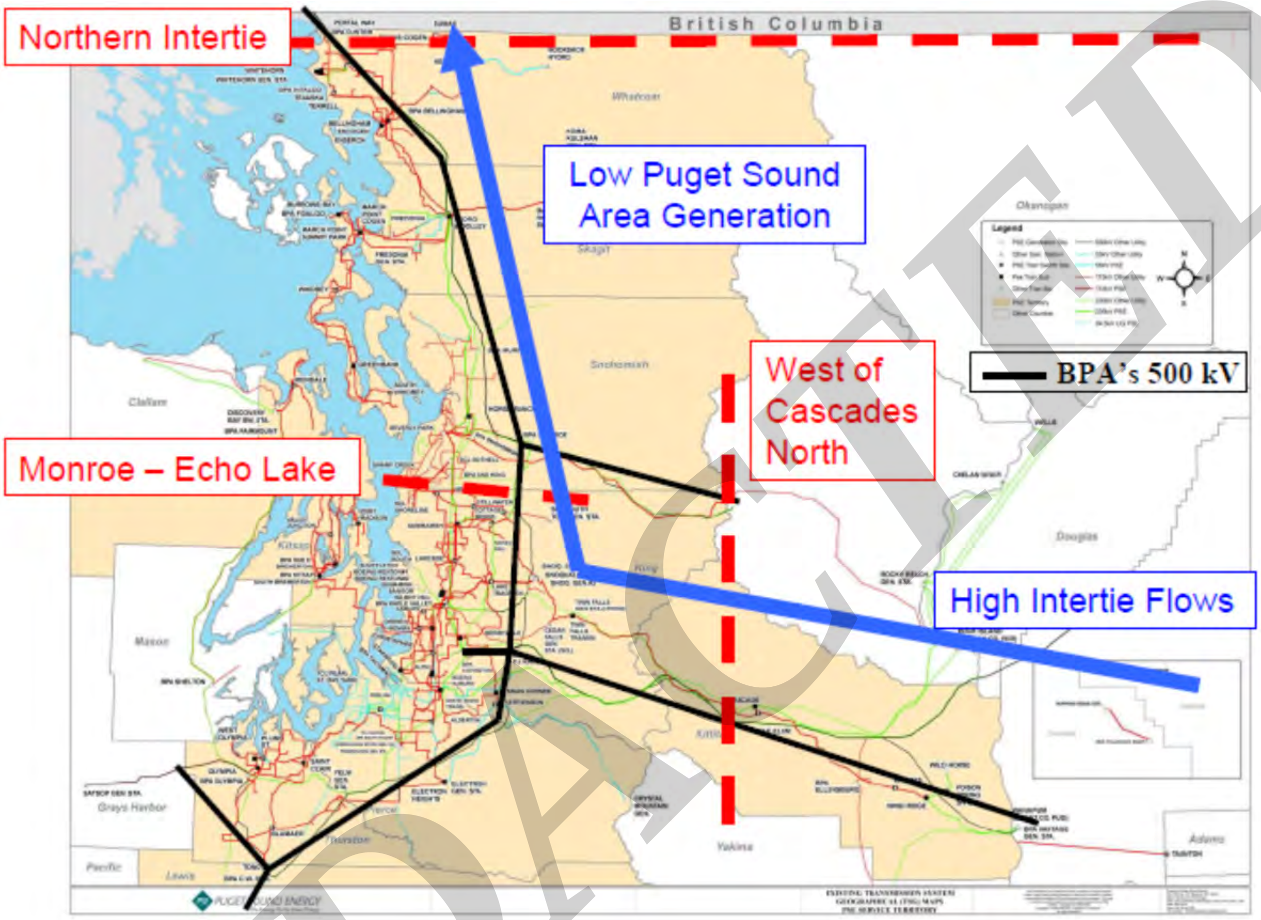
6.2 Other Assessment Criteria Compliance

6.2.1 Columbia Grid

As stated in the ColumbiaGrid 2012 System Assessment[21], ColumbiaGrid was formed with seven founding members in 2006 to improve the operational efficiency, reliability, and planned expansion of the northwest transmission grid. Eleven parties have signed ColumbiaGrid's Planning and Expansion Functional Agreement (PEFA) to support and facilitate multi-system transmission planning through an open and transparent process. ColumbiaGrid's primary grid planning activity is to develop a biennial transmission expansion plan that 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 load and transmission service commitments. A significant feature of the transmission expansion plan is its single-utility planning approach. The plan has been developed as if the region's transmission grid were owned and operated by a single entity. This approach results in a more comprehensive, efficient, and coordinated plan than would otherwise be developed if each transmission owner completed a separate independent analysis.

[21] ColumbiaGrid 2012System Assessment, page 1 – Executive Summary, July 2012

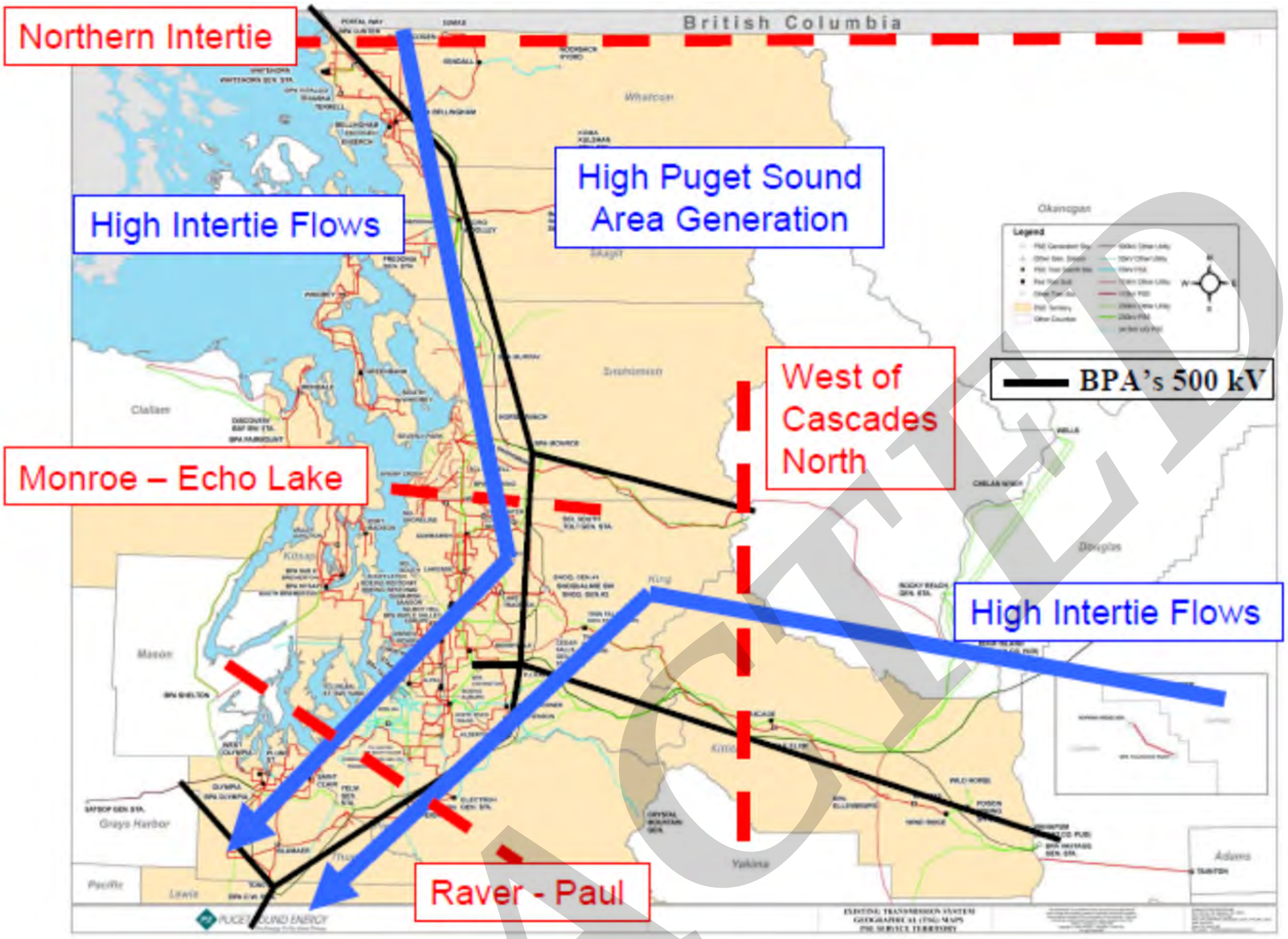
The capacity of the Northern Intertie path in the north to south direction is 2,850 MW on the west- side and 400 MW on the east-side with a combined total transfer capability limit of 3,150 MW (Figure 6-2). The total capacity of the path in the south to north direction is 2,000 MW, with a limit of 400 MW on the east-side (Figure 6-1). Both of these directional flows can impact the ability of the system to serve loads in the Puget Sound area.



22

Figure 6-1: Winter Power Flow resulting from Northern Intertie

[22] PSE Attachment K, Puget Sound Area Transmission Meeting, PSE Presentation Slide #9, Dec 18, 2012



[23]

Figure 6-2: Summer Power Flow Resulting from Northern Intertie

The major issues in the PSE area were identified in the 2012 System Assessment, dated July 2012. The Assessment documented that: BPA is making commitments to increase flows across the Northern Intertie to 2,300 MW through the Network Open Season that will show up in the ten-year time frame. 200 MW of this new commitment is planned to be scheduled on the east side of the Northern Intertie at Nelway. Therefore in the ten- year summer cases this flow will increase to 2,300 MW to cover the additional commitments that are being made on the Northern Intertie including the 200 MW on the east side of the tie at Nelway.

6.2.2 2009 TPL Study Results

Issues associated with loading in the Talbot Hill area under winter conditions and south-north regional transmission flows were first shown in the 2009 TPL study. (The previous year's TPL study had noted high loading on Talbot Hill transformers, although these were not identified as Category B or C overloads in any of the study years used for the 2008 TPL.) As a result, PSE identified short-term mitigation in the form of CAPs and also began studying options for improving the power supply in the central King County area.

Load forecasts used in the 2009 TPL study followed corporate forecasts published in December 2008. There was an updated forecast in June 2009 which projected lower normal peaks. Due to the conservative approach used in the TPL report, it is deemed that the change in the peak loads would not influence any TPL results.

[23] PSE Attachment K, Puget Sound Area Transmission Meeting, PSE Presentation Slide #10, Dec 18, 2012

The 2009 TPL Study assumed no generation in Puget Sound Area as opposed to minimum generation in earlier reports - for the low generation scenarios. Also, the NI (Northern Intertie) flows were assumed realistic based on season and historic flows. This information is tabulated in Table 6-15.

The winter season in years 2010 (2010-11) and 2019 (2018-19) was studied both in Northern Intertie (NI) import and export conditions. Loads used were 1 in 2 year winter peak. The summer season in years 2010 and 2019 was also studied both in Northern Intertie (NI) import and export conditions. Loads used were 1 in 2 year summer peak. PSE's system load peaks during the winter season; summer represents reduced-load conditions. For the near-term cases winter peak load of 5,329 MW and summer peak load of 3,417 MW is modeled. For the long-term cases a winter peak load of 5,765 MW and summer peak load of 3,678 MW is modeled. To cover a broad range of operating conditions, Northern Intertie flows and PSE generation levels were varied in all case studies.

Table 6-15 shows the different scenarios used for the study.

Table 6-15: Scenarios for the 2009 TPL Study

WECC case	Base case	Northern Intertie flows (North-South (N-S) or South –North (S-N)	Puget Sound Area Generation
2009 HS3A APPROVED OPERATING CASE	2010HS-A	N-S 2850/300 MW	Full generation
2009 HS3A APPROVED OPERATING CASE	2010HS-B	N-S 2850/300 MW	No generation
2009 HS3A APPROVED OPERATING CASE	2010HS-C	S-N 2000/0 MW	Full generation
2009 HS3A APPROVED OPERATING CASE	2010HS-D	S-N 2000/0 MW	No generation
2009-10 HW2 OPERATING CASE	2010-11HW-A	S-N 1500/300 MW	No generation
2009-10 HW2 OPERATING CASE	2010-11HW-B	S-N 1500/300 MW	Full generation
2009-10 HW2 OPERATING CASE	2010-11HW-C	N-S 1450/0 MW	No generation
2009-10 HW2 OPERATING CASE	2010-11HW-D	N-S 1450/0 MW	Full generation
2019 HEAVY SUMMER 1 BASE CASE	2019HS-A	N-S 2850/300 MW	Full generation
2019 HEAVY SUMMER 1 BASE CASE	2019HS-B	N-S 2850/300 MW	No generation
2019 HEAVY SUMMER 1 BASE CASE	2019HS-C	S-N 2000/0 MW	Full generation
2019 HEAVY SUMMER 1 BASE CASE	2019HS-D	S-N 2000/0 MW	No generation
2018-19 HW1 BASE CASE	2018-19HW-A	S-N 1500/300 MW	No generation
2018-19 HW1 BASE CASE	2018-19HW-B	S-N 1500/300 MW	Full generation
2018-19 HW1 BASE CASE	2018-19HW-C	N-S 1450/0 MW	No generation
2018-19 HW1 BASE CASE	2018-19HW-D	N-S 1450/0 MW	Full generation

The 2009 TPL study indicated that as soon as the winter of 2010-11, during south-north regional transmission flows with low Puget Sound Area generation, a Category C loss [redacted] or a Category C loss of [redacted] could overload the Talbot Hill transformer #2. The [redacted] outage would load the Talbot Hill transformer to 101% of its emergency limit, which could be mitigated by dispatching generation. The [redacted] outage was shown to result in a 107% load on Talbot Hill transformer #2, which would be mitigated by instituting a CAP to open [redacted]. Installation of 230-115 kV transformation in central King County was identified as a long-term mitigation and studies commenced as to best transformation location and associated system improvements.

Section 7 Conclusions on Needs Assessment

This 2013 Eastside Needs Assessment has shown that PSE is facing a transmission capacity deficiency on the Eastside of Lake Washington. Overloads of Talbot Hill and Sammamish transformers as well as several 115 kV lines point to the need for a new power supply centered in the Eastside area. By the fall of 2017, additional 230-115 kV transformation or generation integrated at the 115 kV level will be required in the Eastside area to relieve the overloads predicted in this study. Depending on the location of a new transformer, additional 115 kV or 230 kV line capacity will also be required.

In multiple contingencies studied, different parts of the transmission system will overload or will be close to overloading within the 10 year study period. When the regional power flows are south to north, as is typical in the winter, there are potential overloads in the Talbot Hill Substation area, on both transformers and transmission lines. When the regional power flows are north to south, as is typical in the summer, there are potential overloads in the Sammamish Substation area. In each case, it is the need to provide power to PSE communities in the Eastside area that is stressing the local power system.

The Eastside area has no utility generation sources. In King County, local generation covers less than 10% of the peak load. Therefore the King County area is quite dependent on transmission interties to Bonneville Power Administration and other neighboring utilities that can transport bulk power from generation located north, south and east of King County, primarily in the east. Bulk power is most often transported at 230 kV or higher voltage. This study has indicated possible overloads of existing 230 kV lines in future years. A 2012 Columbia Grid study has also indicated the need for additional 230 kV capacity in the King County area.

The core area of the Eastside in Bellevue is eight miles from any 230-115 kV source. This has placed a strain on the two nearest substations providing 230-115 kV transformation to the Eastside: Sammamish and Talbot Hill Substations. Continuing load growth in the Eastside area would increase the overload problems being shown in the first 5 years of the study.

This study examined thermal overloads for Category A (N-0), Category B (N-1) and Category C (N-2 and N-1-1) outages as required by NERC, WECC and PSE Transmission Planning Guidelines.

At approximately 5,200 MW PSE system load, as forecast for 2017-18 winter, multiple elements are at risk of overload. If the load growth is higher or conservation goals are not achieved as projected, the overloads will be higher and occur sooner.

PSE uses CAPs to automatically or manually prevent overloads under the NERC reliability requirements. The CAPs required to prevent N-1-1 overloads would open lines between Sammamish and Talbot Hill. Some of the CAPs place customers at risk of outage due to transmission lines being switched into a radial mode, with a feed from just one end. In the future, load growth will result in additional lines required to be opened, putting over 60,000 customers at risk of subsequent outages.

This analysis has shown a transmission capacity deficiency in the Eastside area of Lake Washington will develop by the winter of 2017-18. This transmission capacity deficiency will continue to increase beyond that date.

Appendix A: Load Forecast

Table A-1: 2012 Annual Peak Load Forecast Distribution

Year	100% Conservation		Net of 100% Conservation			Gross of Conservation (0% Conservation)		
	Normal 23°	Extreme 13°	Normal Peak (23°)	Extreme Peak (13°)	ERM Peak (PSO)	Normal Peak (23°)	Extreme Peak (13°)	ERM Peak (PSO)
2012	68	68	4,837	5,316	5,316	4,905	5,384	5,384
2013	140	140	4,785	5,267	5,267	4,926	5,408	5,408
2014	226	226	4,836	5,333	5,333	5,063	5,560	5,560
2015	319	319	4,865	5,375	5,375	5,184	5,694	5,694
2016	394	394	4,909	5,432	5,432	5,303	5,826	5,826
2017	468	468	4,938	5,472	5,472	5,406	5,940	5,940
2018	562	562	4,938	5,483	5,483	5,500	6,045	6,045
2019	651	651	4,946	5,501	5,501	5,597	6,152	6,152
2020	778	778	4,923	5,490	5,490	5,701	6,268	6,268
2021	885	885	4,923	5,502	5,502	5,808	6,386	6,386
2022	944	944	4,972	5,562	5,562	5,916	6,506	6,506
2023	986	986	5,039	5,641	5,641	6,025	6,627	6,627
2024	1,023	1,023	5,117	5,732	5,732	6,140	6,754	6,754
2025	1,061	1,061	5,193	5,820	5,820	6,254	6,881	6,881
2026	1,100	1,100	5,266	5,905	5,905	6,365	7,004	7,004
2027	1,138	1,138	5,341	5,993	5,993	6,479	7,131	7,131
2028	1,172	1,172	5,426	6,090	6,090	6,598	7,262	7,262
2029	1,203	1,203	5,515	6,192	6,192	6,718	7,396	7,396
2030	1,236	1,236	5,605	6,296	6,296	6,840	7,531	7,531
2031	1,270	1,270	5,694	6,399	6,399	6,964	7,668	7,668
2032	1,305	1,305	5,785	6,504	6,504	7,090	7,808	7,808
2033	1,341	1,341	5,878	6,610	6,610	7,219	7,951	7,951

Table A-2: 2012 Annual Peak Load Forecast for Eastside Area

	Normal Peaks (23 ^{0}F) Net of Conservation			Extreme Peaks (13 ^{0}F) Net of Conservation			Normal Peaks (23 ^{0}F) Gross of Conservation		Extreme Peaks (13^{0}F) Gross of Conservation	
Year	Eastside % of King Co	Eastside	King	Eastside % of King Co	Eastside	King	Eastside	King	Eastside	King
2012	27.5	646	2,348	27.4	709	2,586	655	2,381	718	2,619
2013	27.5	652	2,371	27.5	718	2,615	671	2,440	737	2,685
2014	27.5	660	2,399	27.5	729	2,652	691	2,512	760	2,764
2015	28.0	676	2,413	28.0	748	2,672	720	2,572	793	2,831
2016	28.5	694	2,434	28.5	769	2,699	750	2,630	825	2,896
2017	28.8	706	2,448	28.8	782	2,719	773	2,681	849	2,952
2018	29.0	710	2,449	29.0	790	2,725	792	2,729	872	3,006
2019	29.5	724	2,454	29.5	807	2,735	820	2,779	903	3,061
2020	30.0	733	2,445	30.0	820	2,732	850	2,834	937	3,122
2021	30.9	756	2,449	30.8	845	2,742	893	2,892	982	3,187
2022	30.9	765	2,476	31.0	861	2,776	912	2,950	1,008	3,251
2023	30.9	777	2,514	31.0	874	2,821	930	3,010	1,028	3,317
2024	30.9	790	2,558	31.0	890	2,871	949	3,073	1,050	3,387
2025	30.9	804	2,602	31.0	906	2,922	969	3,137	1,072	3,458
2026	30.9	818	2,646	31.0	922	2,973	989	3,201	1,094	3,530

NOTES:

1. Normal and Extreme County Peaks taken from PSE F2012: Electric County Peaks worksheet.
2. Eastside Normal and Extreme Peaks for years 2013, 2017 and 2021 are taken from the E230 Project worksheet: Eastside Load. The King County load was adjusted for expected block loads known to PSE Planning within the 10-year study period.
3. The Eastside load is calculated for years 2013, 2017 and 2021 based on the expected block loads with interpolation being used to calculate the in between years.

Appendix B: Upgrades Included in Base Cases

Table B-1: Projects Added to the Eastside Needs Assessment Winter Base Case

2013-14	2017-18	2021-22
Beverly Park - Cottage Brook breaker replacement	Beverly Park - Cottage Brook breaker replacement	Beverly Park - Cottage Brook breaker replacement
Cottage Brook - Moorlands line reconductor	Cottage Brook - Moorlands line reconductor	Cottage Brook - Moorlands line reconductor
Saint Clair 230-115 kV transformer	Saint Clair 230-115 kV transformer	Saint Clair 230-115 kV transformer
Talbot Hill - Berrydale #1 line uprate	Talbot Hill - Berrydale #1 line uprate	Talbot Hill - Berrydale #1 line uprate
Starwood autotransformer removal / Tacoma Power voltage increase	Starwood autotransformer removal / Tacoma Power voltage increase	Starwood autotransformer removal / Tacoma Power voltage increase
	Alderton 230-115 kV transformer	Alderton 230-115 kV transformer
	Lake Holm Substation (block load)	Lake Holm Substation (block load)
	Beverly Park 230-115 kV transformer	Beverly Park 230-115 kV transformer
	Sensitivity Study 2: Raver 500-230 kV transformer	Sensitivity Study 2: Raver 500-230 kV transformer
	Sensitivity Study 2: SCL series inductors	Sensitivity Study 2: SCL series inductors

Table B-2: Projects Added to the Summer NERC TPL Base Case for the Eastside Area

2014	2018
Beverly Park - Cottage Brook breaker replacement	Beverly Park - Cottage Brook breaker replacement
Cottage Brook - Moorlands line reconductor	Cottage Brook - Moorlands line reconductor
Saint Clair 230-115 kV transformer	Saint Clair 230-115 kV transformer
Talbot Hill - Berrydale #1 line uprate	Talbot Hill - Berrydale #1 line uprate
Starwood autotransformer removal / Tacoma Power voltage increase	Starwood autotransformer removal / Tacoma Power voltage increase
	Alderton 230-115 kV transformer
	White River - Electron Heights 115 kV line re-route into Alderton
	White River 2nd bus section breaker
	Lake Hills - Phantom Lake 115 kV line
	Lake Holm Substation (block load)
	Cumberland Substation 115 conversion (block load)
	Beverly Park 230-115 kV transformer

Appendix C: Quanta Technology and Puget Sound Energy Author Biographies

Quanta Technology assisted Puget Sound Energy in conducting this study, including research, analysis and documentation. Quanta Technology is an expertise-based, independent consulting company providing business and technical expertise to the energy and utility industries. They assist with deploying strategic and practical solutions to improve a company's business performance. Their mission is to provide value to clients in every engagement with the industry-best technical and business expertise, holistic and practical advice, and industry thought leadership.

Thomas J. Gentile, PE, *Quanta Technology Vice President Transmission Strategy,* is based in Massachusetts and has over 36 years of experience and proven leadership with transmission and distribution system planning, analysis, engineering, program/project management and interfacing with RTOs/ISOs and regulatory agencies. Mr. Gentile has participated in various planning, operating and market committees at NERC, NPCC, NYISO and ISO-NE. Tom received MSEE and BSEE degrees from Iowa State University and Northeastern University. He is a registered professional engineer in the State of Massachusetts.

Donald J. Morrow, PE, *Quanta Technology Partner, Senior Vice President of Corporate Strategy and Quanta Technology Expert*, has more than 30 years of utility and consulting experience. During the course of his career, Don has held a wide range of technical and management responsibilities including system planning, control area operations, transmission operations, energy trading, maintenance scheduling, operator training, protection, distribution operations, energy management systems and natural gas dispatch. Don received his BSEE and MBA from the University of Wisconsin, Madison. Don developed the transmission practice at Quanta Technology and he has led several transmission planning projects since 2006, including the SPP EHV Overlay study, the Smartransmission Project (www.smartstudy.biz), and Companhia de Electricidade de Macau in Macua, China. He is a registered professional engineer in the states of Wisconsin and Arkansas.

Carol O. Jaeger, PE, *Puget Sound Energy Consulting Engineer*, *Transmission Planning*, has over 30 years experience in transmission and distribution planning, distribution design, and substation design and operations. She received her BSEE from the University of Washington and is a registered professional engineer in the state of Washington.

Zach Gill Sanford, *Puget Sound Energy Engineer, Transmission Planning*, has over 4 years experience in transmission planning and NERC compliance. He received his BSEE from the University of Washington.

REDACTED

Supplemental Eastside Needs Assessment Report

Transmission System
King County

April 2015

Puget Sound Energy

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Executive Summary

This document summarizes the changes to the Eastside Needs Assessment Report dated October 2013, based upon the recent updates to the Puget Sound Energy (PSE) load forecast, system topology, facility ratings, changes affecting the Northern Intertie as the monitored flowgate for the Puget Sound Area Northern Intertie ("PSANI") issues, and changes to the Seattle City Light (SCL) system. This is a supplemental document that should be read in concert with the 2013 Eastside Needs Assessment Report ("2013 Needs Assessment").

The 2013 Needs Assessment concluded that there is a transmission capacity deficiency in the Eastside area which will develop by the winter of 2017-18. The assessment also concluded that the transmission capacity deficiency will continue to get worse as load grows. The 2013 Needs Assessment identified a number of concerns related to this transmission capacity deficiency, which included:

- Overload of PSE facilities in the Eastside area under certain contingencies
- Increasing use and expansion of Corrective Action Plans ("CAPs") to manage these overloads
- Inherent load forecast uncertainties which leave a small margin for error for the CAPs to be effective

The supplemental studies, utilizing the updated information discussed in this report, verified that there is still a transmission capacity deficiency in the Eastside area that will develop by the winter of 2017-18 and require the expanded use of CAPs to manage overloads for certain contingencies. In addition, the studies continued to show that this transmission capacity deficiency is expected to increase beyond that date. Cities in the deficiency area include: Redmond, Kirkland, Bellevue, Clyde Hill, Medina, Mercer Island, Issaquah, Newcastle, and Renton, along with towns of Yarrow Point, Hunts Point, and Beaux Arts.

The supplemental studies also verified that a transmission capacity deficiency still develops by the summer of 2018. However, the supplemental study showed that transmission capacity deficiency is actually worse than what was identified in the 2013 Needs Assessment. In the 2013 Needs Assessment, CAPs were required to mitigate the transmission capacity deficiency but load shedding was not required. In the supplemental study, both CAPs and load shedding are required to mitigate the transmission deficiency.

1. Introduction

This document summarizes the changes and results to the Eastside Needs Assessment dated October 2013, based upon the recent updates to the PSE load forecast, system topology, facility ratings, changes affecting the use of the Northern Intertie as the monitored flowgate for PSANI issues, and changes to the SCL system. This document also presents a comparison of the results using the updated information. The method, criteria, and key assumptions are the same as utilized in the 2013 Needs Assessment with the exception of those items discussed below.

2. Differences between the 2013 and 2015 Needs Assessments

2.1 Changes to the Power Flow Cases which have Minimal Impact

There are three changes that have minimal impact on the results of the supplemental study.

2.1.1 WECC Base Case Differences

Each year, Western Electric Coordinating Council (WECC), in coordination with its members, develops a set of "base cases" to model the bulk electric system. These base cases include the most up-to-date electrical system information for the entire WECC model including updated loads, generators, transmission lines, etc. All electric providers use these base cases as starting points to study their proposed system improvements and to understand the potential impacts to the regional electric grid, thereby ensuring no adverse impacts to the reliability and operating characteristics of its system or any surrounding system. The 2013 Needs Assessment was based on WECC base cases for the winter peak for years 2013-14, 2017-18, and 2021-22. Summer peak was analyzed for years 2014 and 2018 for the annual 2012 NERC TPL analysis.

For the 2015 Needs Assessment analysis, PSE utilized WECC winter peak base cases for the years 2019-20 and 2023-24. A 2017-18 case was developed from the 2019-20 base case. Summer peak base cases included the 2020 and 2024 WECC base cases. A 2018 summer case was developed from the 2020 base case.

2.1.2 Topology Changes in the Base Case

The studies within the 2015 Needs Assessment included all projects in the 2013 Needs Assessment, which are listed in Section 9 and Appendix B Tables B-1 and B-2 of the 2013 Needs Assessment. Changes in topology between the previous set of study cases and the current study cases are included in Appendix A of this report. Based on our analysis, no topology changes listed in Appendix A significantly impacted the study results. There was one change, the Talbot 230-115 kV transformer #1 replacement, which increased the winter normal and emergency limits from 383 MW and 464 MW to 398 MW and 484 MW respectively.

2.1.3 Northern Intertie vs. North of Echo Lake and South of Custer Flowgates

Prior to 2013, Bonneville Power Administration (BPA) used the West-Side Northern Intertie as the monitored flowgate for electricity transfers between the Puget Sound area and British Columbia. A one-line diagram of this flowgate is included in Appendix D. This flowgate was managed through the use of nomograms that would dictate the amount of capacity available on the Northern Intertie based on varying Puget Sound area generation levels, expected load levels, ambient temperature, and the next worst contingency. Nomograms were published on this Path for flows in both the north-south direction and the south-north direction. The amount of power that could be transferred between the Northwest and BC Hydro's system on the West-Side Northern Intertie was somewhat dependent on generation in the Puget Sound area. Transmission across the Northern Intertie would be curtailed if it was found that conditions would not support transfers, both in real time and in the operations planning timeframe. In February of 2013, BPA moved away from using the Northern Intertie as the basis for determining available transfer capability through the Puget Sound area and instead developed two new flowgates. These flowgates are the South of Custer (SOC) flowgate, used for determining acceptable north-south transfer levels through the Puget Sound area and the North of Echo Lake (NOEL) flowgate, used for determining acceptable south-north transfer levels. The lines that make up these new flowgates are included in Table 2-1. One-line diagrams of these updated flowgates are also included in Appendix D. These changes are used operationally to monitor flows that do not impact the study results but help determine and prevent adverse reliability impacts when power is flowing between the Northwest and BC Hydro's system.

Table 2-1: Definitions of PSANI Flowgates

North of Echo Lake (NOEL) Flowgate Definition:	South of Custer (SOC) Flowgate Definition:
Echo Lake – SnoKing Tap 500 kV	Monroe – Custer #1 & #2 500 kV
Echo Lake – Maple Valley 500 kV	Murray – Custer 230 kV
Covington – Maple Valley 230 kV	Bellingham – Custer 230 kV

2.2 Changes to the Power Flow Cases which had Substantial Impact

There are three changes that have a substantial impact on the results of the 2013 Needs Assessment. They are described below.

2.2.1 PSE has updated the Facility Ratings for all transmission lines in the system

For the 2013 Needs Assessment analysis, PSE used an Electric Power Research Institute (EPRI) tool called DYNAMP to establish transmission line facility ratings. By 2014, DYNAMP was no longer supported and PSE converted to a program called PLS–CADD. As a result of the conversion to this new tool, the transmission line facility ratings increased over the ratings used in the previous assessment. This increase in line ratings had an impact on post-contingency loadings, effectively reducing the percentage of overloads on facilities throughout the PSE system.

For example, the winter Emergency Facility Rating of the Talbot-Lakeside 115 kV line increased from 238.6 MVA to 249 MVA. In the 2017-18 Heavy Winter case, actual post-contingency MVA loading on the line for the worst Category B contingency in the 2013 Needs Assessment was 235.3 MVA or 98% of the 238.6 MVA line rating in the case. Actual post-contingency MVA loading on the line for the worst Category B contingency in the current study case was 218.3 MVA, or 87.6% of the 249 MVA line rating used in the case. If the line rating had not changed, loading in the current case would be 91.5% of the rating. Overloads seen on this line decreased by approximately 4% due to the change in line rating.

2.2.2 Seattle City Light Load Levels Decreased

In 2014, Seattle City Light made some corrections and adjustments to the load levels used in the WECC power flow base cases. These changes resulted in decreased Seattle City Light load levels.

2.2.3 Differences in load forecast levels utilized in the 2013 and 2015 Needs Assessments

The following briefly describes the PSE load forecasting process and the resulting differences between the 2012 and 2014 load forecast that were used in the 2013 and 2015 Needs Assessments.

PSE's service territory is very diverse, and hence, PSE experiences highly variable growth across its service territory. For the 2014 load forecast, PSE prepared a more detailed county-by-county forecast than had been done previously. The 2014 load forecast disaggregated the system wide forecast to county and sub-county regions to examine reasonableness from both system and sub-system perspectives. A small area forecast was also performed to focus on the Eastside study area.

PSE used data from PSE's electric demand and consumption history and federal and local government sources as inputs to develop an econometric load forecast using econometric-time series approach. PSE's electric demand and energy consumption history was also used to forecast future trending. Regional temperature taken at the National Oceanic and Atmospheric Administration (NOAA) station at SeaTac International Airport during the system peak was used to compare peak load reading. The load readings were normalized to 23˚ F, which was used as a 1-in-2 year normal ambient temperature at the time of system peak. Forecasts were also performed for a 1-in-20 year (or extreme temperature) forecast at 13˚ F.

To perform the system and county level forecasts, population data was also taken from the US Census as well as the US Bureau of Economic Analysis (BEA) and WA State Office of Financial Management (OFM). Employment data was taken from BEA, US Bureau of Labor Statistics (BLS), and Washington State Employment Security Department. Additionally, historic and forecasted US level data was from Moody's Analytics. At the sub-county level, population and employment data were obtained from Puget Sound Regional Council (PSRC) and WA State OFM.

PSE used the population and employment forecast evaluated by the PSRC for King, Pierce, and Kittitas counties. Population data was also taken from the US Census as well as the US BEA and WA State OFM. Employment forecast data were taken from the US BLS and PSRC.

To augment the data provided by the government agencies, PSE provided information about expected significant new loads, known as "block loads," over the next few years. This information was used for the first three years of the forecast period at full value, then at 50% value for the next three years. After six years, the forecast block loads were considered to be included in the data available on employment and population provided by the forecasting agencies so no additional load was added to the load forecast after year six.

Once an econometric forecast was developed for each county, or for the company as a whole, the peak demand and energy consumption were reduced by a forecast amount of conservation based on conservation target determined as optimal from the 2013 Integrated Resource Plan (IRP). This conservation target includes energy efficiency programs, Energy Independence and Security Act (EISA), distribution efficiency, and demand response. PSE has not implemented an active demand response program, so the demand response included in this forecast consisted of conservation programs and intrinsic conservation due to measures required by modern building codes.

It should be noted that a segment of PSE's transmission customers were not included in the corporate load forecast. These are interconnection or high voltage customers who connect to PSE for transmission service, but do not purchase energy from PSE. Approximately 250-300 MWs are required by the transmission customers on a nearly continuous basis.

There are some differences between the 2012 and 2014 load forecast worth noting:

a. The 2012 load forecast assumed faster recovery of the US economy from the recession than the 2014 load forecast.
b. The 2014 load forecast used updated US population growth forecast from the US Bureau of Census, which is lower compared to what was used in the 2012 load forecast.
c. Because of slower housing recovery, customer growth and customer counts in the 2014 load forecast are lower than the 2012 load forecast.
d. Peak load growth and peak load levels for the system and for King County are projected to be lower in the 2014 load forecast as compared to the 2012 load forecast.
e. Based on PSRC's population and employment growth forecasts, Eastside peak loads in the 2014 load forecast are projected to grow by 2.4% per year in the next 10 years, which is driven by growth in the commercial sector and high density residential sector. Also, updates to block loads over the study period influenced the load growth in the Eastside area.

The following tables show the comparison between the 2012 and 2014 system corporate load forecast and a breakdown by county of the 2014 corporate load forecast.

Table 2-2: Comparison of PSE's 2012 and 2014 Corporate Load Forecast

PSE Corporate Load Forecast				
	Forecasted 2012		Forecasted 2014	
Year	Max of Normal Peak w/ DSR	Max of Extreme Peak w/ DSR	Max of Normal Peak w/ DSR	Max of Extreme Peak w/ DSR
2012	4,837	5,316		
2013	4,785	5,267		
2014	4,836	5,333	4,803	5,255
2015	4,865	5,375	4,820	5,283
2016	4,909	5,432	4,844	5,317
2017	4,938	5,472	4,891	5,377
2018	4,938	5,483	4,891	5,385
2019	4,946	5,501	4,904	5,406
2020	4,923	5,490	4,856	5,365
2021	4,923	5,502	4,850	5,366
2022	4,972	5,562	4,863	5,388
2023	5,039	5,641	4,888	5,421
2024	5,117	5,732	4,961	5,504
2025	5,193	5,820	5,029	5,581
2026	5,266	5,905	5,085	5,645
2027	5,341	5,993	5,148	5,716
2028	5,426	6,090	5,224	5,802
2029	5,515	6,192	5,302	5,889
2030	5,605	6,296	5,376	5,972
2031	5,694	6,399	5,444	6,049
2032	5,785	6,504	5,512	6,126
2033	5,878	6,610	5,580	6,203
2034			5,649	6,282

Table 2-3: PSE's 2014 Corporate Peak Load Forecast by County

2014 PSE Corporate Peak Load Forecast by County									
Year	King	Thurston	Pierce	Whatcom	Skagit	Island	Kitsap	Kittitas	Total PSE
2014	2391	549	498	374	265	144	524	59	4803
2015	2410	550	500	373	263	143	523	59	4820
2016	2427	552	503	372	262	143	524	61	4844
2017	2458	557	508	375	262	143	526	62	4891
2018	2454	559	510	375	260	143	526	64	4891
2019	2465	561	511	375	259	143	526	65	4904
2020	2445	555	506	371	254	140	518	66	4856
2021	2443	555	505	370	252	140	516	68	4850
2022	2454	557	506	370	251	139	516	70	4863
2023	2472	559	508	371	250	139	517	71	4888
2024	2515	567	515	376	252	141	522	74	4961
2025	2555	574	521	380	253	142	527	76	5029
2026	2590	580	526	384	254	143	531	78	5085
2027	2628	586	531	388	255	144	536	80	5148
2028	2675	594	538	392	256	145	541	82	5224
2029	2723	601	545	397	258	146	547	84	5302
2030	2769	609	551	402	259	147	553	87	5376
2031	2814	615	555	406	260	148	557	88	5444
2032	2859	621	559	410	261	149	562	90	5512

The 2013 Needs Assessment used PSE's 2012 corporate load forecast as the basis for the analyses and adjusted the load based on PSE's knowledge of future block loads and non-PSE customers supplied by PSE. In PSE's 2012 corporate load forecast, the forecast was provided for PSE's system as a whole, and sub-area forecasts were proportionally derived from this overall forecast. For the 2015 Needs Assessment, PSE's 2014 corporate load forecast was used and was also adjusted for non-PSE load supplied by PSE. This 2014 corporate load forecast provided an overall PSE system forecast and it also included bottom-up sub-area load forecasts for the King County and Eastside areas.

Table 2-4 below lists the Eastside and King County load levels for the cases used in the 2013 Needs Assessment and Table 2-5 lists the load levels using the 2014 load forecast. Comparing the results of the load levels for winter 2017-18, the total load level for PSE's system is 46 MW less using the 2014 load forecast (5162 MW) than the 2012 forecast (5208 MW). Using the 2014 load forecast, the King County area, without the Eastside load, is 27 MW higher (1854 MW – 1881 MW) and the Eastside area is 11 MW less than 2012 forecast (699 MW–688 MW). The remaining reduction is distributed over the rest of PSE.

Table 2-4 Eastside and King County Load Levels Using 2012 Load Forecast in MW

Case	King County (excluding Eastside)	Eastside	Remainder of system	Total
17-18HW	1854	699	2654	5208
18HS	1258	550	1744	3552
21-22HW	1862	748	2548	5193

Table 2-5: Eastside and King County Load Levels Using 2014 Load Forecast in MW

Case	King County (excluding Eastside)	Eastside	Remainder of system	Total
17-18HW	1881	688	2592	5162
17-18EHW	2091	728	2828	5647
18HS	1379	538	1707	3625
19-20HW	1858	708	2609	5175
19-20EHW	2084	749	2843	5676
20HS	1373	561	1747	3681
23-24HW	1817	764	2577	5158
23-24EHW	2053	804	2833	5691
24HS	1399	618	1800	3817

2.3 Base Cases Used for Analysis

The WECC base cases are updated annually. The cases available for this update were Heavy Winter 2019-20 and 2023-24 and Heavy Summer 2020 and 2024. All other cases were derived from those WECC cases. Table 2-6 below includes a comparison of the cases utilized in the 2013 Needs Assessment and the 2015 Needs Assessment study cases using 2014 updated data.

Table 2-6: Comparison of the Cases Utilized in the Eastside Needs Assessment

Case	2012	2014
2013-14 Heavy Winter	✓	--
2017-18 HW SN 100% Cons	✓	✓
2017-18 HW SN 75% Cons	✓	--
2017-18 HW SN 50% Cons	✓	--
2019-20 HW SN 100% Cons	--	✓
2021-22 HW SN 100% Cons	✓	--
2021-22 HW SN 75% Cons	✓	--
2021-22 HW SN 50% Cons	✓	--
2021-22 HW SN Extreme 100% Cons	✓	--
2021-22 HW SN Extreme 75% Cons	✓	--
2023-24 HW SN 100% Cons	--	✓
2014 HS NS	✓	--
2018 HS NS	✓	✓
2018 HS SN	✓	--
2024 HS NS	--	✓
2024 HS SN	--	✓

2.4 Points of Clarification from the 2013 Needs Assessment

2.4.1 Use of Corrective Action Plans (CAPs)

PSE uses operating procedures, such as corrective action plans (CAPs), to prevent any loss of firm load, either intentionally or due to a credible outage condition while remaining compliant with mandatory NERC/WECC reliability requirements. CAPs are generally considered temporary in nature with the understanding that permanent solutions are forthcoming. 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.

2.4.2 Use of Load Shedding

While NERC and WECC allow dropping "non-consequential[1]" load for certain contingencies, intentionally dropping firm load for an N-1-1 or N-2 contingency to meet its federal planning requirements is not a practice that PSE endorses. All load modeled in the Needs Assessment studies was firm load and PSE does not consider any of its firm requirements to be non-consequential. This is consistent with the view of most utilities. It is also consistent with the views of virtually all community officials who do not consider intentionally blacking out segments of customers as a responsible way to operate a modern electricity delivery system.

PSE's concern about using load shedding for N-1-1 contingencies is best illustrated by the outage of two 230 kV-115 kV transformers in the Eastside area. Losing two 230 kV-115 kV transformers could result in the other remaining 230 kV-115 kV transformers being overloaded. In this scenario, simply re-dispatching PSE generation does not reduce these transformer overloads below the emergency rating. A transformer outage would require a minimum 24-hour outage to test and re-energize the transformer. Further, if the outaged transformer tests bad, then it must be replaced, and this can take up to another five to seven weeks. This scenario results in a significant amount of time to place PSE customers at risk either with CAPs or with exposure to load shedding.

To illustrate how other utilities in WECC address load shedding, the CAISO Planning Standards indicates in their Section 6, Planning for High Density Urban Load Area:

> *"Increased reliance on load shedding to meet these needs would run counter to historical and current practices, resulting in general deterioration of service levels. For local area long-term planning, the ISO does not allow non-consequential load dropping in high density urban load areas in lieu of expanding transmission or local resource capability to mitigate NERC TPL-001-4 standards P1-P7 contingencies and impacts on the 115 kV or higher voltage systems….In the near-term planning, where allowed by NERC standards, load dropping, including high density urban load, may be used to bridge the gap between real-time operations and the time when system reinforcements are built."*

3. Results of 2015 Needs Assessment

The detailed results of the 2015 Needs Assessment are shown in Appendix A for winter peak conditions and Appendix B for summer peak conditions. The results verified that there is a transmission capacity deficiency in the Eastside area that will develop by the winter of 2017-18. This transmission capacity deficiency in the Eastside area is expected to increase beyond that date.

Using the same methodology as the 2013 Needs Assessment, the supplemental analysis shows that a transmission capacity deficiency develops at a winter Eastside area load of 688 MW, requiring the use of CAPs, and worsens at an Eastside area load of 708 MW, requiring both the use of CAPs and exposing some PSE customers to load shedding. The transmission capacity deficiency also develops at a summer Eastside area load of 538 MW.

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[1] Non-Consequential Load is defined as Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. Consequential Load is defined as all Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Similar to the 2013 results, there were a significant number of overloads that showed up in the results of power flow studies due to outages of high voltage lines owned by other utilities that interconnect to PSE. Most of these are outages in BPA's 230 kV or 500 kV network. BPA and the other interconnected utilities have operating procedures in place to prevent overloads of area facilities, including PSE lines and equipment. For example, the most frequent external contingency that causes PSE overloads is an outage of the [redacted]. BPA operates the interchange flows and generation levels so that this [redacted] line outage does not cause overloads. Therefore, overloads resulting from this [redacted] BPA line were not considered as necessary for PSE to resolve.

In addition, a number of overloads of area transmission lines can be partially mitigated by adjusting PSE generation levels in Western Washington. As such, this type of generation re-dispatch costs more than the optimal generation levels that PSE would elect, thereby driving up customer costs. Therefore, while these system adjustments are not a desirable operating condition, they are acknowledged as an available action to mitigate these types of overloads while remaining NERC compliant.

There are still a number of transmission transformer overloads which cannot be addressed by dispatching generation, similar to the 2013 Needs Assessment. These transformer overloads will require CAPs in the future to shift load; at some point the CAPs will be expanded to include load shedding in order to remain NERC compliant.

3.1 Winter Analysis

Utilizing the 2014 load forecast and the results of the winter analysis, Figure 3-1 shows two system capacity lines for the Eastside area – both of which are reflected on the graph as dashed red lines. These lines highlight the area of concern where the 2015 Needs Assessment indicates violations of the mandatory performance requirements developed for certain contingencies that put customer reliability at risk. The area of concern starts at an Eastside area load of 688 MW in the winter of 2017-18 and continues to 708 MW in the winter of 2019-20. The 2015 Needs Assessment established that a transmission capacity deficiency exists at an Eastside area load level of 688 MW that requires the use of CAPs to manage Category C overloads in winter of 2017-18. The 2015 Needs Assessment also established that the transmission capacity deficiency continues to worsen at an Eastside area load level of 708 MW, which requires the use of additional CAPs by winter of 2019-20. These additional CAPs placed approximately 63,200 customers at risk of losing power due to being served radially. By the winter of 2023-24 the CAPs will require load shedding affecting approximately 16,800 customers to prevent thermal violations under certain conditions.

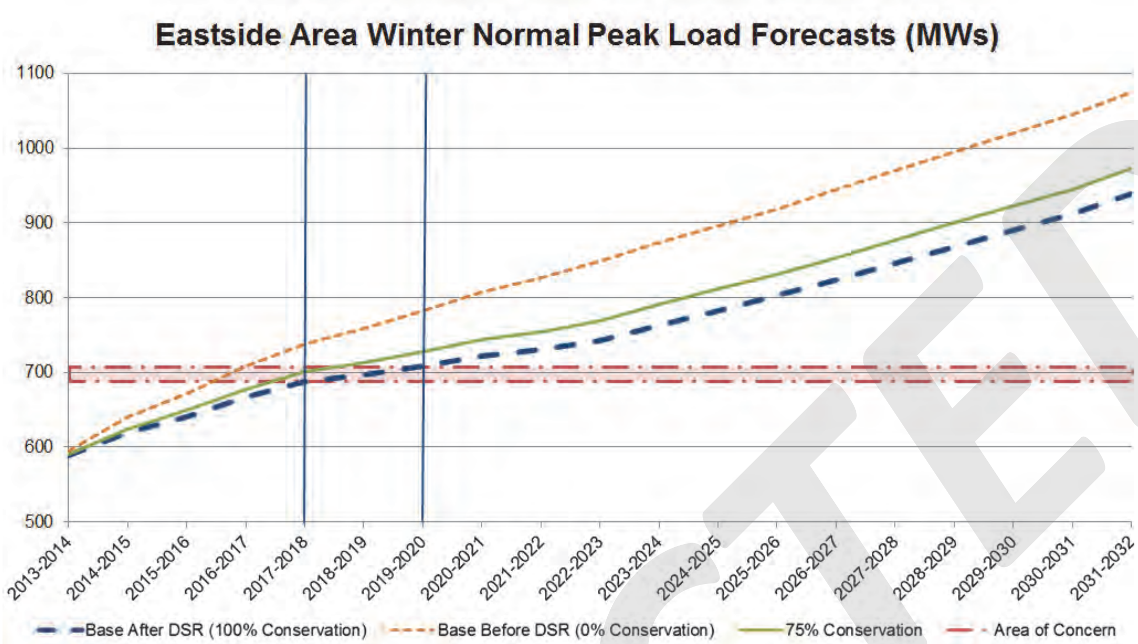

Figure 3-1: Capacity Need Results with 2015 Updated Information

The area of concern shown in Figure 3-1 is consistent with the 706 MVA level of concern identified for the Eastside area in the 2013 Needs Assessment. This value was reflected in the graph shown in Figure 4-3 of the 2013 Needs Assessment (where the units were mislabeled as "MW"). The actual MW value for the level of concern was 699 MW in the 2013 Needs Assessment. The 699 MW value reflected the load level of the Eastside area in the winter of 2017-18 in the previous study where the power flows indicated violations of the mandatory performance requirements that put customer reliability at risk. For ease of reference, this figure is repeated below as Figure 3-2.

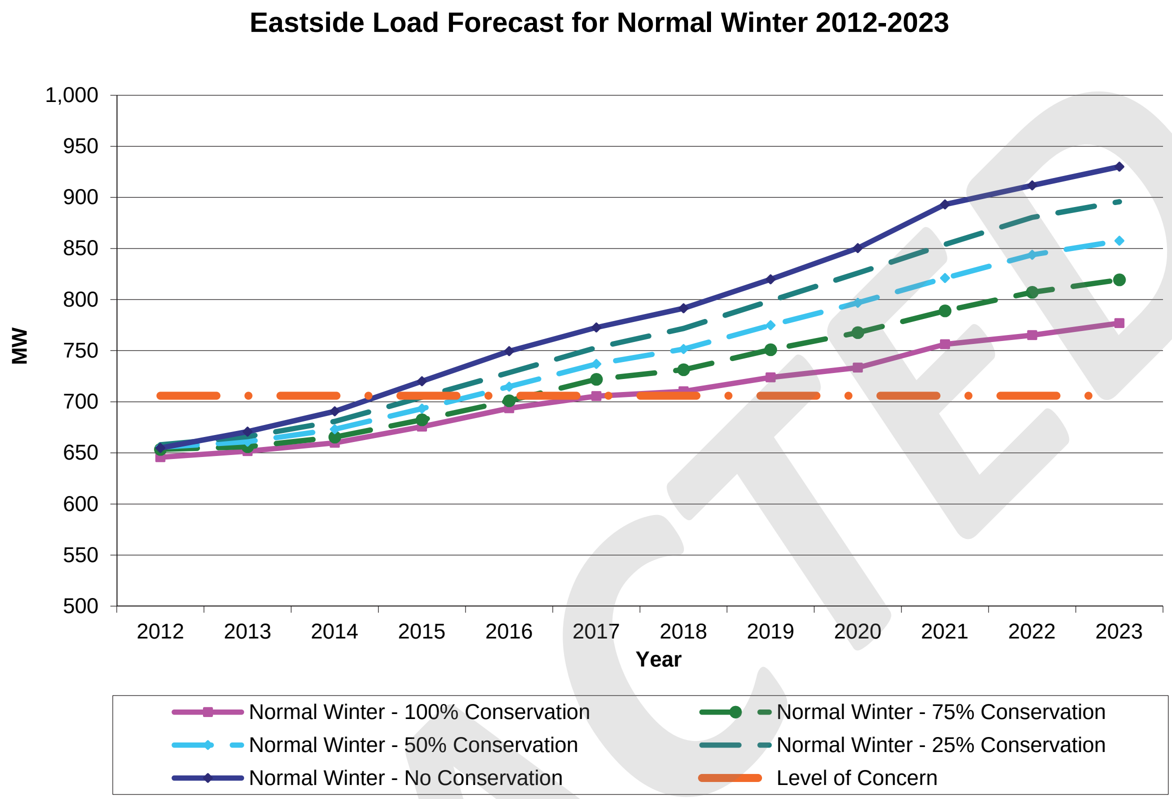

Figure 3-2: Level of Concern for Eastside Area Load in 2013 Needs Assessment

As the winter summary in Table 3-1 shows, CAPs are needed throughout the study period. As noted above, CAPs are required starting in the winter of 2017-18 to manage overloads on five elements from 12 Category C contingencies. By 2019-20, the overloads on these same five elements will be created from 18 Category C contingencies, which require additional CAPs to manage and which place approximately 63,200 customers at risk by placing them on radial feeds. By 2023-24 the overloads on these same five elements will be caused by 40 Category C contingencies, which require the use of even more CAPs and place approximately 68,800 customers at risk. In addition, by 2023-24 load shedding of approximately 133 MW will be needed to maintain a reliable and secure transmission system.

Table 3-1: Winter Power Flow Summary Comparison of 2013 and 2015 Needs Assessment

Winter Power Flow Summary						
	2012 Load Forecast			2014 Load Forecast		
	2013-14 Winter 5055 MW 100% Conserv-ation Eastside Load = 545 MW	2017-18 Winter 5208 MW 100% Conserv-ation Eastside Load = 699 MW	2021-22 Winter 5193 MW 100% Conserv-ation Eastside Load = 748 MW	2017-18 Winter 5162 MW 100% Conserv-ation Eastside Load = 688 MW	2019-20 Winter 5175 MW 100% Conserv-ation Eastside Load = 708 MW	2023-24 Winter 5158 MW 100% Conserv-ation Eastside Load = 764 MW
Elements Above Emergency Limit:						
Category B (N-1)	0	0	2	0	0	0
Category C (N-1-1 & N-2)	5	6	5	5	5	5
Corrective Action Plans Required	Yes	Yes	Yes	Yes	Yes	Yes
Customers at Risk from Corrective Action Plans	0	68,800	76,300	0	63,200	68,800
Customers at Risk from Load Shedding	0	0	4,400	0	0	16,800
Load Shed MW	0	0	22	0	0	133
Elements Above Normal Limit or 90% of Emergency Limit:						
Category B (N-1)	0	4	6	0	3	3
Category C (N-1-1 & N-2)	6	7	8	7	6	5
Contingencies that cause post-contingency loading above 100% of Emergency Limit:						
Category B (N-1)	0	0	1	0	0	0
Category C (N-1-1 & N-2)	13*	23*	37*	12	18	40

* Note: There were additional contingencies in the study using the 2012 Load Forecast that resulted in overloads between 100% and 104%. In the supplemental study, overloads on the PSE lines between 100% and 104% were eliminated to account for the change in line ratings from 2012 to 2014. Those overloads are not included in the 2012 Load Forecast counts provided in this table.

Detailed results of the winter analysis are shown in Appendix A.

3.2 Summer Analysis

The 2013 Needs Assessment showed a PSE area summer load level of need at approximately 3340 MW. This need was illustrated in Figure 1-2 of that document and is included as Figure 3-3 below for ease of reference.

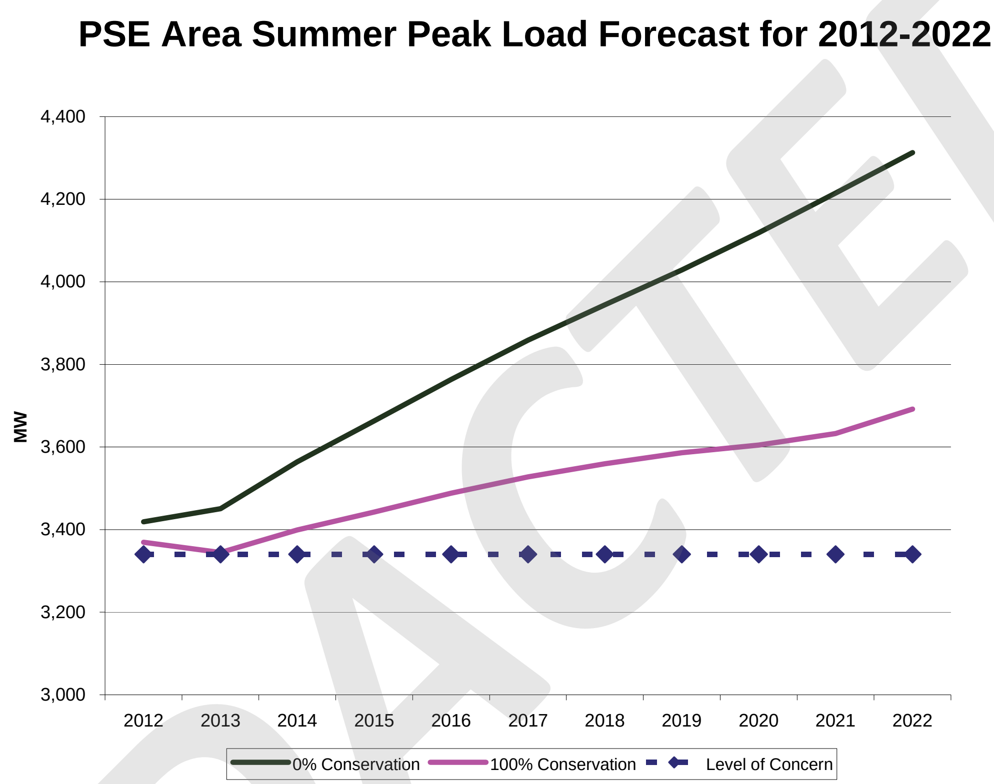

Figure 3-3: PSE Area Summer Peak Load Forecast for 2012-2022

The 2013 Needs Assessment, analyzed the summer of 2018, had a PSE area summer peak of approximately 3,552 MW. That 2013 assessment found there were two 230 kV elements above 100% and two 115 kV elements above 93% loadings for Category B (N-1) contingencies. Also, there were three elements above 100% loading and one above 99% loading for Category C (N-1-1) contingencies. In the 2013 Needs Assessment, the 3,552 MW system load corresponds to an Eastside Area load level of 550 MW. In the 2013 Needs Assessment, we identified that CAPs were needed to manage the Category C (N-1-1) contingencies and that up to 33,000 customers would be put at risk when those CAPs were utilized.

The 2015 Needs Assessment shows an Eastside summer load level of need at approximately 538MW. This need is shown in Figure 3-4 below.

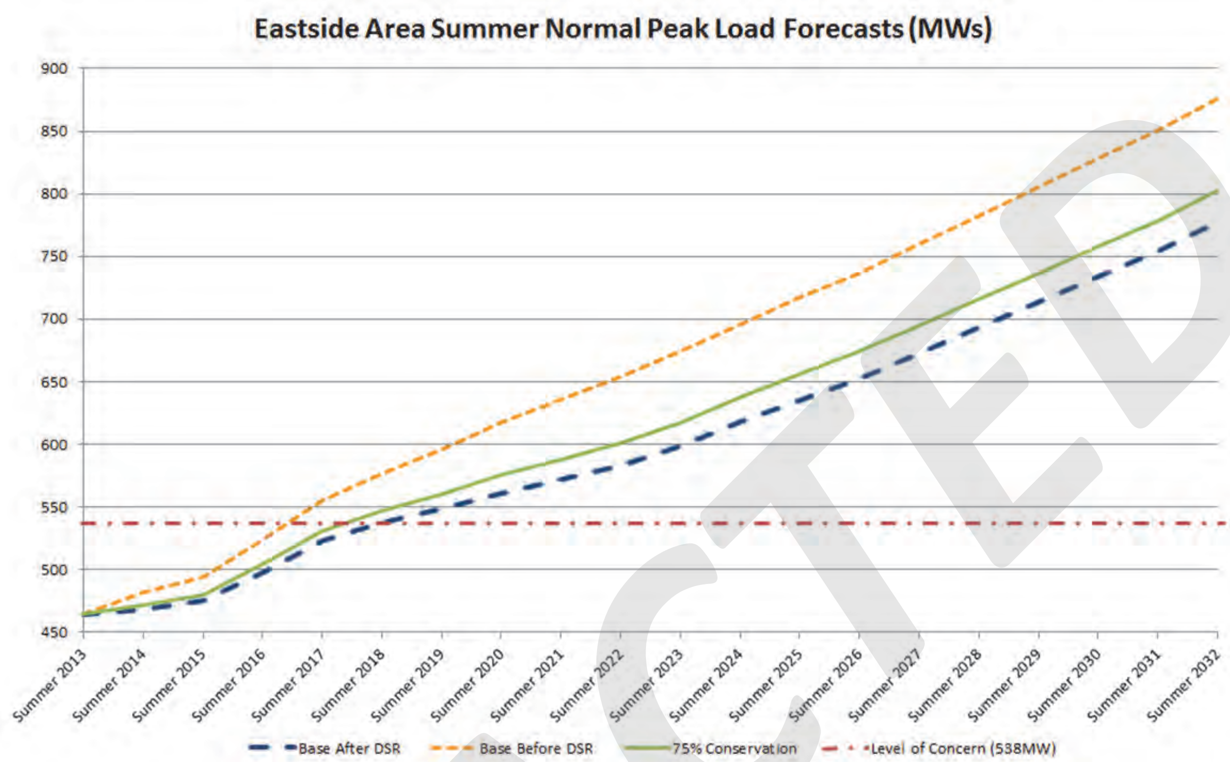

Figure 3-4: Eastside Summer Peak Load Forecast for 2012-2023

Table 3-2 summarizes the results of the 2015 Needs Assessment and it shows that the amount of customers at risk for losing power will increase to approximately 68,800 by the summer of 2018. The 2015 Needs Assessment also shows that load shedding of approximately 74 MW will be needed to maintain a reliable and secure transmission system starting in the summer 2018, increasing to approximately 78 MW in 2020 and approximately 123 MW by 2024. The number of contingencies that cause post-contingency loading above 100% Emergency Limit is six by the summer of 2018 and grows to nine by 2024.

Table 3-2: Summer Power Flow Summary Comparison of October 2013 and 2015 Updated Results

Summer Power Flow Summary				
	2012 Load Forecast	2014 Load Forecast		
	2018 Summer 3552 MW 100% Conservation Eastside Load = 550 MW	2018 Summer 3625 MW 100% Conservation Eastside Load = 538 MW	2020 Summer 3681 MW 100% Conservation Eastside Load = 561 MW	2024 Summer 3817 MW 100% Conservation Eastside Load = 618 MW
Elements Above Emergency Limit:				
Category B (N-1)	2 [1]	1 [1]	2 [1]	2 [1]
Category C (N-1-1 & N-2)	3	5 [2]	5 [2]	5 [2]
Corrective Action Plans Required	Yes	Yes	Yes	Yes
Customers at Risk from Corrective Action Plans	62,800	68,800	68,800	68,800
Customers at Risk from Load Shedding	0	10,900	10,900	12,700
Load Shed MW	0	74	78	123
Elements Above Normal Limit or 90% of Emergency Limit:				
Category B (N-1)	4	1	2	2
Category C (N-1-1 & N-2)	4	6	6	6
Contingencies that cause post-contingency loading above 100% of Emergency Limit:				
Category B (N-1)	2	2	2	2
Category C (N-1-1 & N-2)	8	6	7	9

[1] These elements are BPA transmission lines leased by PSE

[2] These elements include 1 BPA transmission line leased by PSE

Detailed results of the summer analysis are shown in Appendix B.

4. Conclusions of the 2015 Needs Assessment using the 2014 PSE Load Forecast

The project date of need will remain the same at the winter of 2017-18 due to these key risk factors:

- The 2017-18 winter power flow cases still require the use of CAPs to mitigate transmission transformer overloads with load risk beginning between 2017-18 to 2019-20.
- The number of contingencies requiring the use of CAPs steadily increases as load grows.
- The forecast uses a 1-in-2 year weather forecast. Colder weather will result in higher load levels.
- 100% conservation may not be achieved, which would result in a higher load level. Even if 100% conservation is achieved, it may not be in the appropriate locations and magnitudes assumed for this assessment.
- There is only 20 MW difference on the Eastside between the winters of 2017-18 and 2019-20, and in the winter of 2019-20 with over 60,000 customers are at risk.
- By the summer of 2018, studies show that 68,800 customers will be at risk of outages and 10,900 customers at risk of load shedding using CAPs to mitigate transmission transformer overloads.
- Load shedding becomes an increasingly necessary action as load grows.

5. Statement of Need

The 2015 Needs Assessment reconfirmed that, by winter of 2017-18, there is a transmission capacity deficiency on the Eastside that impacts PSE customers and communities in and around Kirkland, Redmond, Bellevue, Issaquah, Newcastle, and Renton along with Clyde Hill, Medina, and Mercer Island. The transmission deficiency focuses on the two 230 kV supply injections into central King County at Sammamish substation in the north and Talbot Hill substation in the south. The transmission capacity becomes a need at an Eastside winter load level of approximately 688 MW, where overloads will result in operating conditions that require CAPs to manage. By winter of 2019-20, at an Eastside load level of approximately 706 MW, additional CAPs are required that will put approximately 63,200 Eastside customers at risk of outages. These results are summarized in Table 3-1 above.

The 2015 Needs Assessment also reconfirmed that by summer of 2018, there will be a transmission capacity deficiency on the Eastside which impacts PSE customers and communities in and around Kirkland, Redmond, Bellevue, Issaquah, and Newcastle along with Clyde Hill, Medina, and Mercer Island. By summer of 2018, CAPs will be required to manage overloads under certain Category C contingencies and the use of these CAPs will place approximately 68,800 customers at risk and will require 74 MW of load shedding, affecting approximately 10,900 customers. These results are summarized in Table 3-2 above.

Appendix A. 2015 Needs Assessment Results for Winter Peak Season

Table A-1: Summary of Potential Thermal Violations for Winter Peak Load Season

2013-14 5055 MW 100% Con Eastside Load = 545 MW		2017-18 5208 MW 100 % Con Eastside Load = 699 MW		2021-22 5193 MW 100% Con Eastside Load = 748 MW		2017-18 5162 MW 100% Conservation Eastside Load = 688 MW		2019-20 5175 MW 100% Conservation Eastside Load = 708 MW		2023-24 5153 MW 100% Conservation Eastside Load = 764 MW		2023-24 Extreme 5690 MW 100% Conservation Eastside Load = 804 MW	
Category B: N-1 Contingency Results													
[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload
		[redacted]	Talbot Hill - Lakeside #1 115 kV line – 98.6%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 97.4%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 87.7%[3]	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 91.1%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 96.1%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 101.0%
		[redacted]	Talbot Hill - Lakeside #2 115 kV line – 98.4%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 97.2%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 87.5%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 90.9%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 92.4%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 97.1%
		[redacted]	Talbot Hill 230-115 kV transformer #1 – 89.0%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 91.0% (see footnote 4)	[redacted]	Talbot Hill 230-115 kV transformer #1 – 85.1%[4]	[redacted]	Talbot Hill 230-115 kV transformer #1 – 85.6%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 87.1%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 95.9%
		[redacted]	Talbot Hill 230-115 kV transformer #2 – 90.3%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 91.5%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 89.3%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 90.2%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 92.8%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 101.9%

[2] All contingencies involving loss of the Monroe – Echo Lake – SnoKing 500 kV three-terminal line are unsolvable in the 21-22HW case without modeling the Intalco load tripping RAS. Study results reflect opening all Intalco loads, totaling about 300 MW, to get the case to a solvable state. Opening these loads slightly changes line flows in the case and may contribute to the decrease in post-contingency line loading.

[3] Decrease in post-contingency line loading can be attributed to lower area load, lower SCL load and increased line ratings between the 2012 study and the current study.

[4] The Talbot 230/115 kV transformer #1 is scheduled to be replaced in 2015 and the new expected ratings and impedance were included in the 2014 cases.

2013-14 5055 MW 100% Con Eastside Load = 545 MW		2017-18 5208 MW 100 % Con Eastside Load = 699 MW		2021-22 5193 MW 100% Con Eastside Load = 748 MW		2017-18 5162 MW 100% Conservation Eastside Load = 688 MW		2019-20 5175 MW 100% Conservation Eastside Load = 708 MW		2023-24 5153 MW 100% Conservation Eastside Load = 764 MW		2023-24 Extreme 5690 MW 100% Conservation Eastside Load = 804 MW	
				[redacted]	Sammamish-Lakeside #1 115 kV Line - 104.7%								
				[redacted]	Sammamish-Lakeside #2 115 kV Line - 104.5%								
Category C: N-1-1 Contingency Results													
[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload
[redacted]	Talbot Hill-Lakeside #1 115 kV Line - 115.2%	[redacted]	Talbot Hill--Lakeside #1 115 kV Line - 127.5%	[redacted]	Talbot Hill--Lakeside #1 115 kV Line – 125.9%	[redacted]	Talbot Hill--Lakeside #1 115 kV Line – 113.3%	[redacted]	Talbot Hill-Lakeside #1 115 kV Line – 117.4%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 123.9%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 130.5%
[redacted]	Talbot Hill-Lakeside #2 115 kV Line - 115.1%	[redacted]	Talbot Hill--Lakeside #2 115 kV Line - 127.7%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 125.8%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 113.1%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 117.3%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 120.8%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 127.2%
[redacted]	Talbot Hill 230-115 kV transformer #1 - 100.9%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 105.8%	[redacted]	Talbot Hill 230-115 kV transformer #1 - 108.1%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 101.0%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 101.3%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 103.1%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 113.7%
[redacted]	Talbot Hill 230-115 kV transformer #2 - 100.5%	[redacted]	Talbot Hill 230-115 kV transformer #2 - 105.7%	[redacted]	Talbot Hill 230-115 kV transformer #2 - 107.0%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 104.6%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 105.4 %	[redacted]	Talbot Hill 230-115 kV transformer #2 – 108.1%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 118.5%

2013-14 5055 MW 100% Con Eastside Load = 545 MW		2017-18 5208 MW 100 % Con Eastside Load = 699 MW		2021-22 5193 MW 100% Con Eastside Load = 748 MW		2017-18 5162 MW 100% Conservation Eastside Load = 688 MW		2019-20 5175 MW 100% Conservation Eastside Load = 708 MW		2023-24 5153 MW 100% Conservation Eastside Load = 764 MW		2023-24 Extreme 5690 MW 100% Conservation Eastside Load = 804 MW	
[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 101.1%	[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line - 110.4%	[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 110.5%	[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 101.1%	[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 103.0%	[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 102.9%	[redacted]	Talbot Hill-Boeing Renton-Shuffleton 115 kV Line – 110.2%
[redacted]	White River - Lea Hill - Berrydale 115 kV line - 91.7%	[redacted]	White River - Lea Hill - Berrydale 115 kV line – 98.0%	[redacted]	White River - Lea Hill - Berrydale 115 kV line - 99.7%	[redacted]	White River - Lea Hill - Berrydale 115 kV line – 90.6%	[redacted]	White River - Lea Hill - Berrydale 115 kV line – 92.0%	[redacted]	White River - Lea Hill - Berrydale 115 kV line – 88.4%[4]	[redacted]	White River - Lea Hill - Berrydale 115 kV line – 98.2%
Category C: N-2 and Common Mode Contingency Results													
[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload
		[redacted]	Talbot Hill-Lakeside #1 115 kV Line - 101.5%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 96.8%[5]	[redacted]	Talbot Hill-Lakeside #1 115 kV Line – 89.9%	[redacted]	Talbot Hill-Lakeside #1 115 kV Line – 92.3%	[redacted]	Talbot Hill-Lakeside #1 115 kV Line – 98.9%	[redacted]	Talbot Hill-Lakeside #1 115 kV Line – 102.3%
		[redacted]	Talbot Hill-Lakeside #2 115 kV Line - 102.1%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 107.1%[6]	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 94.5%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 99.4%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 103.4%	[redacted]	Talbot Hill-Lakeside #2 115 kV Line – 107.7%
		[redacted]	Talbot Hill 230-115 kV transformer #1 – 91.8%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 93.6%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 88.1%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 88.2%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 90.1%	[redacted]	Talbot Hill 230-115 kV transformer #1 – 99.6%

[5] Using the 2012 load forecast in the 2021-22 Heavy Winter case, this contingency is unsolvable, even with the Intalco load tripping RAS modeled.

[6] N-2: ADJ Talbot – Lake Tradition #1 & Talbot – Lakeside #1 115 kV was second most limiting contingency and overloaded this element by 106.6%. It is possible that, as load drops, the limiting contingency will change.

2013-14 5055 MW 100% Con Eastside Load = 545 MW		2017-18 5208 MW 100 % Con Eastside Load = 699 MW		2021-22 5193 MW 100% Con Eastside Load = 748 MW		2017-18 5162 MW 100% Conservation Eastside Load = 688 MW		2019-20 5175 MW 100% Conservation Eastside Load = 708 MW		2023-24 5153 MW 100% Conservation Eastside Load = 764 MW		2023-24 Extreme 5690 MW 100% Conservation Eastside Load = 804 MW	
		[redacted]	Talbot Hill 230-115 kV transformer #2 – 92.8%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 93.2%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 93.14%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 92.6%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 95.7%	[redacted]	Talbot Hill 230-115 kV transformer #2 – 104.8%
		[redacted]	Berrydale 230-115 kV transformer – 93.6%	[redacted]	Berrydale 230-115 kV transformer - 95.5%	[redacted]	Berrydale 230-115 kV transformer – 95.6%	[redacted]	Berrydale 230-115 kV transformer – 87.6%	[redacted]	Berrydale 230-115 kV transformer – 88.3%[7]	[redacted]	Berrydale 230-115 kV transformer – 96.7%

[7] BF: White River 115 kV bus section breaker resulted in loading the Berrydale 230/115 kV transformer to 87.3% for this case. As loading shifts off of the Berrydale transformer, the White River BSBF is less critical.

Appendix B. Supplemental Needs Assessment Results for Summer Peak Season

Table B-2: Summary of Potential Thermal Violations for Summer Peak Load Season

2014 3343 MW 100% Con		2018 3554 MW 100% Con Eastside Load = 550 MW		2018 3625 MW 100% Conservation Eastside Load = 538 MW		2020 3681 MW 100% Conservation Eastside Load = 561 MW		2024 3813 MW 100% Conservation Eastside Load = 618 MW	
Category B: N-1 Contingency Results									
[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload
[redacted]	Monroe-Novelty Hill 230 kV line - 132.6%	[redacted]	Monroe-Novelty Hill 230 kV line - 133.0%	[redacted]	Monroe-Novelty Hill 230 kV line – 143.9%	[redacted]	Monroe-Novelty Hill 230 kV line – 143.1%	[redacted]	Monroe-Novelty Hill 230 kV line – 139.8%
[redacted]	Maple Valley - Sammamish 230 kV line - 111.4%	[redacted]	Maple Valley - Sammamish 230 kV line - 132.3%	[redacted]	N/A	[redacted]	Maple Valley - Sammamish 230 kV line – 110.0%[9]	[redacted]	Maple Valley - Sammamish 230 kV line – 116.4%
		[redacted]	Talbot Hill - Lakeside #1 115 kV line - 93.9%	[redacted]	N/A	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 81.5%	[redacted]	Talbot Hill - Lakeside #1 115 kV line – 87.8%
		[redacted]	Talbot Hill - Lakeside #2 115 kV line - 93.8%	[redacted]	N/A	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 81.3%	[redacted]	Talbot Hill - Lakeside #2 115 kV line – 87.6%
Category C: N-1-1 Contingency Results									
[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload

[8] Loading reported on the Maple Valley – Sammamish 230 kV and Talbot Hill – Lakeside #1 & #2 115 kV lines occurred for a Heavy Summer condition with south-to-north transfers through the system. A 2018 Heavy Summer case with south-to-north flows was not available for this study. Due to consistency in the 2020 Heavy Summer and 2024 Heavy Summer with the results encountered in 2012 (see footnote 8 for discrepancies found in this case), the 2018 case was not developed and run.

[9] The 2012 TPL study modeled the Northern Intertie gen tripping scheme which trips Whitehorn and Fredonia generation and runs back Mica and Revelstoke generation in BC. Tripping this generation in a south-to-north condition without tripping the Northern Intertie exacerbates this overload. If the limiting contingency is run without the RAS in place, overloads on the Maple Valley – Klahanie line are only 106%.

[redacted]	Sammamish 230-115 kV transformer #1 - 95.5%	[redacted]	Sammamish 230-115 kV transformer #1 - 100.03%	[redacted]	Sammamish 230-115 kV transformer #1 – 104.2%	[redacted]	Sammamish 230-115 kV transformer #1 – 108.1%	[redacted]	Sammamish 230-115 kV transformer #1 – 109.4%
[redacted]	Sammamish 230-115 kV transformer #2 - 100.8%	[redacted]	Sammamish 230-115 kV transformer #2 - 106.4%	[redacted]	Sammamish 230-115 kV transformer #2 - 110.1%	[redacted]	Sammamish 230-115 kV transformer #2 – 114.3%	[redacted]	Sammamish 230-115 kV transformer #2 – 115.6%
				[redacted]	Novelty Hill 230/115kV Transformer #2 - 102%	[redacted]	Novelty Hill 230/115kV Transformer #2 - 103%	[redacted]	Novelty Hill 230/115kV Transformer #2 - 100%
		[redacted]	Beverly Park - Cottage Brook 115 kV line – 101.4%	[redacted]	Beverly Park - Cottage Brook 115 kV line – 110.5%	[redacted]	Beverly Park - Cottage Brook 115 kV line – 110.2%	[redacted]	Beverly Park - Cottage Brook 115 kV line – 106.4%

Category C: N-2 and Common Mode Contingency Results

[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload	[redacted]	Overload
		[redacted]	Sammamish - Lakeside #2 115 kV line - 99.8%	[redacted]	Sammamish – Lakeside #2 115 kV – 90.8%	[redacted]	Sammamish - Lakeside #2 115 kV line 95.4%	[redacted]	Sammamish - Lakeside #2 115 kV line 99.2%
				[redacted]	Monroe-Novelty Hill 230 kV line – 143.6%	[redacted]	Monroe-Novelty Hill 230 kV line – 143.1%	[redacted]	Monroe-Novelty Hill 230 kV line – 139.9%

Appendix C. Upgrades Included in Base Cases

Table C-3: Projects Added to the Eastside Needs Assessment Winter Base Case

2017-18	2019-20	2023-24
Bothell – SnoKing reconductor	Bothell – SnoKing reconductor	Bothell – SnoKing reconductor
Cumberland substation reconfigured to 115 kV	Cumberland substation reconfigured to 115 kV	Cumberland Substation reconfigured to 115 kV
White River – Electron Heights reroute to Alderton	White River – Electron Heights reroute to Alderton	White River – Electron Heights reroute to Alderton
Talbot 230/115 kV transformer #1 replacement	Talbot 230/115 kV transformer #1 replacement	Talbot 230/115 kV transformer #1 replacement
Spurgeon substation, Similk substation & Maxwelton substation	Spurgeon substation, Similk substation & Maxwelton substation	Spurgeon substation, Similk substation & Maxwelton substation
Carpenter substation removed	Carpenter substation removed	Carpenter substation removed
Bus section breakers at BPA Olympia and BPA Tacoma	Bus section breakers at BPA Olympia and BPA Tacoma	Bus section breakers at BPA Olympia and BPA Tacoma
Switched shunt at Paul 500 kV, Broad St. 115 kV	Switched shunt at Paul 500 kV	Switched shunt at Paul 500 kV

Table C-4: Projects Added to the Summer NERC TPL Base Case for the Eastside Area

2018	2020	2024
Bothell – SnoKing reconductor	Bothell – SnoKing reconductor	Bothell – SnoKing reconductor
Cumberland substation reconfigured to 115 kV	Cumberland substation reconfigured to 115 kV	Cumberland substation reconfigured to 115 kV
Talbot 230/115 kV transformer #1 replacement	Talbot 230/115 kV transformer #1 replacement	Talbot 230/115 kV transformer #1 replacement
White River – Electron Heights reroute to Alderton	White River – Electron Heights reroute to Alderton	White River – Electron Heights reroute to Alderton
Spurgeon substation, Similk substation	Spurgeon substation, Similk substation	Spurgeon substation, Similk substation
Denny Way substation Phase 1	Denny Way substation Phase 1	Denny Way substation Phase 1 & Phase 2
Bus section breakers at BPA Olympia, BPA Tacoma and BPA Covington	Bus section breakers at BPA Olympia, BPA Tacoma and BPA Covington	Bus section breakers at BPA Olympia, BPA Tacoma and BPA Covington
Raver 500-230 kV Transformer	Raver 500-230 kV Transformer	Raver 500-230 kV Transformer
Switched shunt at Paul 500 kV	Switched shunt at Paul 500 kV	Switched shunt at Paul 500 kV
Switched shunt at Lake Tradition 115 kV removed	Switched shunt at Lake Tradition 115 kV removed	Switched shunt at Lake Tradition 115 kV removed

Appendix D. West-side Northern Intertie, North of Echo Lake and South of Custer Flowgate One-Line Diagrams

REDACTED

Figure D-1: One-Line Diagram – West-Side Northern Intertie

REDACTED

Figure D-2: One-Line Diagram - North of Echo Lake

REDACTED

Figure D-3: One-Line Diagram - South of Custer

Independent Technical Analysis of Energize Eastside

for the

City of Bellevue, WA

April 28, 2015
Version 1.3

Prepared by
Utility System Efficiencies, Inc.

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1. Executive Summary

Utility System Efficiencies, Inc. (USE) was engaged by the City of Bellevue in December, 2014 to conduct an independent technical analysis of the purpose, need, and timing of the Energize Eastside project. Energize Eastside (EE) is Puget Sound Energy's (PSE's) proposed project to build a new electric substation and new higher–capacity (230 kilovolt) electric transmission lines in the East King County area, which encompasses Bellevue, Clyde Hill, Medina, Mercer Island, Newcastle, the towns of Yarrow Point, Hunts Point, and Beaux Arts, and portions of Kirkland, Redmond, and Renton (the Eastside). The transmission lines would extend from an existing substation in Redmond to one in Renton (See Figure 3.1).

The goals of the technical analysis were to determine:

- Is there a need for this project to address growth in Bellevue? In answering this question, the analysis included determining if PSE's load forecast is reasonable, and if their studied contingencies were reasonable. Here, reasonable is defined as just, rational, appropriate, ordinary, or usual in the circumstances.[1] If the actions or data are consistent with industry practice, it is deemed reasonable.
- Is the EE project needed to address the reliability of the electric grid on the Eastside? This question assesses the purpose of the project and its timing. In other words, is the need a local issue?
- Is there a need for the project to address regional flows, with imports/exports to Canada (ColumbiaGrid[2])? This question is examined in Appendix B, Optional Technical Analysis.

This independent technical analysis (ITA) included reviewing EE documentation, examining the forecast and growth assumptions, reviewing historical demand (MW load) of the area, reviewing weather volatility, and assessing potential variability from the forecast assumptions used in the EE study. The ITA reviewed PSE's forecasting methodology, the major elements that made up the forecast, and decisions made in the forecasting procedure (including choices on what elements or variables to include). The ITA compared PSE's forecast variables with typical industry forecast variables. The ITA also looked at the assumptions that PSE used in electrically modeling the Energize Eastside area, including generation assumptions, local loads, and regional flows. The ITA reviewed PSE's powerflow cases[3] to determine whether the modeling in the cases was consistent with the forecast, and whether the outage scenarios resulted in PSE's identified transmission deficiency.

The optional technical analysis (OTA) at Appendix B examined several hypothetical scenarios, called sensitivity studies. The OTA looked at the effect of a) reducing load growth in the Eastside area, b) reducing load growth in King County while keeping the Eastside growth the same, c) increasing Puget Sound area generation, and d) reducing the Northern Intertie[4] flow to zero (no transfers to Canada). Reduced Northern Intertie flow was examined only to assess the relative impact of local need

[1] http://www.nolo.com/dictionary/reasonable-term.html
[2] ColumbiaGrid (single word) is a regional transmission planning organization with a footprint encompassing Oregon, Washington, parts of Idaho and Montana.
[3] powerflow case: Computer model of the electric grid representing a snapshot in time with a specific scenario of electric load, generation, and equipment, including what is in service and what isn't.
[4] Northern Intertie - transmission interconnection between Washington and British Columbia (also called Path 3.)

versus regional need and does not reflect a realistic planning scenario. The OTA also looked at the impact of an Extreme Winter forecast.

A key purpose of the ITA and the OTA was to provide an increased level of *understanding* of the purpose, need and timing of the EE project to the City Council and community stakeholders. Over the course of the project, dozens of questions were received from various stakeholders. City staff filtered stakeholder comment through the Task's scope, and submitted the need related questions to USE (Other comments as appropriate were directed to the Environmental Impact Statement (EIS) process, the Integrated Resource Plan[5] (IRP) process, etc.). A Q & A discussion is included at the end of each section of the ITA. All questions analyzed are also set forth in Appendix D.

Disclaimer: This report seeks to describe the findings in terms that a non-expert can understand. Thus, some descriptions or definitions may not be exact, in an effort to make the general concept clear. However, some questions received required a higher level of technical detail. Again, the effort was made to simplify the explanations while still providing a helpful response. A glossary is provided in Appendix A.

Results:

IS THERE A NEED FOR THIS PROJECT TO ADDRESS GROWTH IN BELLEVUE? YES.

The ITA examined the forecasting methodology used by PSE in its 2014 forecast, completed in February 2015. The 2014 forecast methodology provided improved visibility of where growth was occurring within PSE's service area. The PSE forecast shows a growing peak load demand[6] of 2.4% per year for years 2014 – 2024.

The typical utility industry forecast is composed of 1) weather normalization[7], 2) economic and demographic data, 3) application of end-use data[8] including conservation and efficiency measures, and 4) adjustment for large specific load additions (such as for a new building).

The ITA concludes that PSE has followed industry practice in forecasting its demand load, incorporating the four major components of forecasting:

- PSE incorporated weather normalizing. The variables used in the weather normalizing process were typical based on industry practice.
- PSE used typical data set elements and multiple data sources for its economic/demographic data as shown in Table 6.1, acquiring data at the county level, and for the Eastside area at the census track level, in order to differentiate growth rates within the service territory. Data on jobs and

[5] Integrated Resource Plan - A comprehensive and long-range road map for meeting the utility's objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. A process used by utility companies to determine the mix of Supply-Side Resources and Demand-Side Resources that will meet electricity demand at the lowest cost. The IRP is often developed with input from various stakeholder groups.

[6] MW demand

[7] Weather normalization is a process that adjusts actual energy (MWh) or demand (peak MW) values to what would have happened under normal weather conditions. Normal weather conditions are expected on a 50 percent probability basis (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak).

[8] End-use: How is the electricity being used? What appliances are used? What efficiency measures are employed? What load can be controlled or interrupted? Utilities and cities can influence electric end-use through Demand-Side Management technologies and practices, city code changes, efficiency programs or incentives, awareness campaigns, et cetera. The end-use data is generally limited to new DSR measures. Historical end-use data is generally not captured due to the difficulty in acquiring it (surveys, etc.).

employment in the Eastside region were obtained by PSE from the Puget Sound Regional Council and the WA State Office of Financial Management, and included census tract level analysis. PSE employed regression analysis[9] at this step, an industry standard computer analysis technique, to determine the forecast before new conservation measures and block load adjustments. (The computerized regression analysis was not analyzed as part of this study, but the technique is a computerized estimation of the best fit of the variables to the given data.)

- PSE acquired/developed significant end-use data via their IRP process, including over four thousand Demand Side Resources (DSR) measures, incorporated National and State requirements on conservation and RPS, and optimized the achievable, technical measures with a resultant 100% Conservation scenario which projects 135 MW of winter peak DSR by 2031.
- PSE gathered block load data (major projects) and utilized short-term forecast adjustments (1-year ramp in based on certificates of occupancy and 2-year ramp-out) to account for the impact on demand.

No forecast is perfect, but by following industry practice, the ITA concludes that PSE used reasonable methods to develop the forecast. PSE's resultant forecast shows the Eastside area growing at a higher level than at the county and system level, and these growth rates are based on the data it received.

PSE is applying the Northwest US practice (as does Seattle City Light (SCL)) of basing projects on a normal 50/50 forecast (actual load will be more than forecast half the time, and less than forecast half the time). This 50/50 forecast is less conservative than scenarios utilized by many other electric utilities elsewhere in the country. Basing projects on an adverse weather scenario is more conservative, but seeks to ensure that the lights stay on given the adverse weather event.

IS THE EE PROJECT NEEDED TO ADDRESS THE RELIABILITY OF THE ELECTRIC GRID ON THE EASTSIDE? YES.

Although the new 2014 forecast resulted in an 11 MW decrease in the Eastside area's 2017/18 winter forecast, the reduced loading still resulted in several overloaded transmission elements in winter 2017/2018, which drive the project need.

Although the corrective action plan (CAP) required in the 2017/18 winter to avoid facility overload doesn't require dropping load (turning off customers' power), by winter 2019/20 approximately 63,200 customers are at risk of losing power. In addition, by summer 2018, studies show that customers will be at risk of outages and load shedding[10] due to CAPs used to mitigate transmission overloads. Despite the possibility of an in-service date shift to summer 2018 from winter 2017/18, balancing a six month delay in a complex and multi-year EIS process (which can have its own delays) against the risk of an adverse winter and less realized conservation (which could increase 2017/18 winter loading to a point where customers are at risk of load

[9] Regression analysis is a statistical process for estimating the relationships among variables. It seeks to determine the strength of the relationship between one dependent variable (usually denoted by Y) and a series of other changing variables (known as independent variables). It is also known also as curve fitting or line fitting because a regression analysis equation can be used in fitting a curve or line to data points. It includes many techniques for modeling and analyzing variables.

[10] Load shedding - An intentional electrical power shutdown to a portion of the system (customers experience an outage) to protect the network from a greater impact or from potential damage.

shedding), suggests it is reasonable to maintain the schedule for the existing project in-service date.

Several hypothetical scenarios were studied as part of the Optional Technical Analysis (OTA). Each one showed overloads in the 2017/18 timeframe, indicating project need in order for PSE to meet federal regulatory requirements for system reliability. The OTA results showed that reducing the Eastside area growth from 2.4% to 1.5% per year in the period from winter 2013/14 to winter 2017/18 still resulted in project need. Reducing PSE's King County growth while keeping the Eastside growth the same similarly resulted in a project need. Turning on additional generation in the Puget Sound area also resulted in a project need. (See Appendix B.)

IS THE PROJECT NEEDED TO ADDRESS REGIONAL GRID POWER FLOWS, SPECIFICALLY POWER FLOWS ON THE NORTHERN INTERTIE (TO AND FROM CANADA)? The project is necessary to address local need.

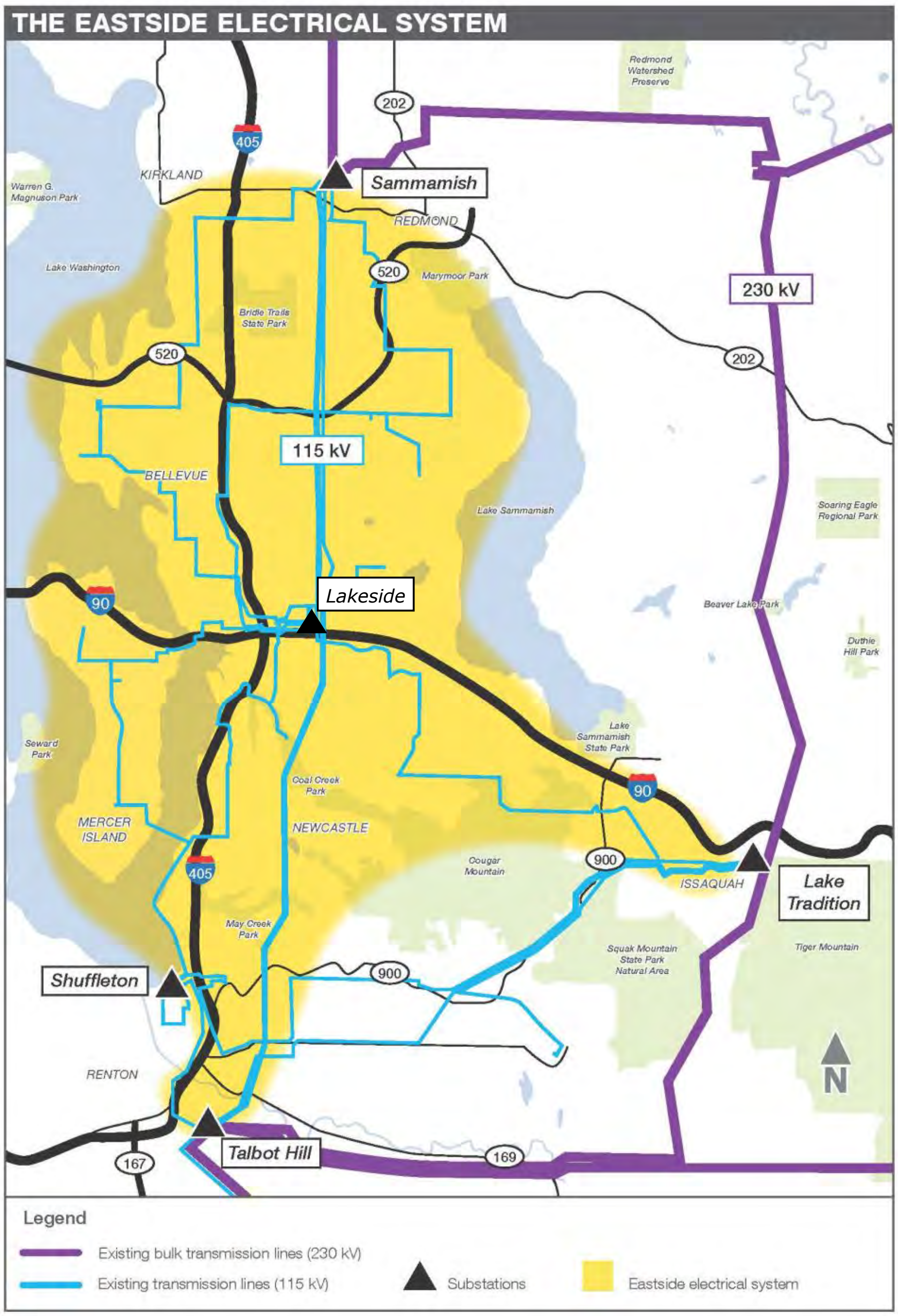
The Optional Technical Analysis examined this issue by reducing the Northern Intertie[11] flow to zero (no transfers to Canada). Although this scenario is not actually possible due to extant treaties, it was modeled to provide data on the drivers for the EE project, to examine if regional requirements might be driving the need. The results showed that in winter 2017/18, even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230/115 kV transformer #2 would still be overloaded by several contingencies (several different outage scenarios). Again, the projected overloads indicate a project need at the local level to meet reliability regulations. (See Appendix B for more details.)

[11] Northern Intertie - transmission interconnection between Washington and British Columbia (Also called Path 3.)

2. Eastside Area

The Eastside area is highlighted in yellow below, and was defined electrically as the area served by the 115 kV transmission lines that connect with the Lakeside Transmission Substation. Geographically it is bounded by Lake Washington and Lake Sammamish. The area is also north of PSE's Talbot Hill Substation and south of PSE's Sammamish Substation.

Figure 3.1: Eastside Area (Figure provided by PSE)



3. 2013 Eastside Needs Assessment Report

This section is included in the ITA report because PSE's 2013 Needs Assessment report is public whereas there is no updated PSE report documenting the 2014 forecast results as of the date of this writing.

The "Eastside Needs Assessment Report", published in October 2013 by PSE, focused on the central King County portion of PSE's service territory. It was based on PSE's corporate forecast which was published in June, 2012. The study determined that there was a transmission capacity deficiency in the Eastside area that would develop by the winter of 2017/2018.

Key Assumptions in PSE's 2013 Study:

- System load levels used the PSE corporate forecast published in June 2012.
- Area forecasts were adjusted by substation to account for expected community developments as identified by PSE customer relations and distribution planning staff.
- Generation dispatch patterns reflected reasonably stressed conditions to account for generation outages as well as expected power transfers from PSE to its interconnected neighbors.
- Winter peak Northern Intertie transfers were 1,500 MW exported to Canada.
- Summer peak westside Northern Intertie transfers were 2,850 MW imported from Canada.

Per PSE's 2013 study report, specific areas of concern for the 2017/2018 winter are shown in Table 4.1 below. The table lists the overloaded elements within each category of contingency.

Each of the three contingency types (N-1, N-1-1, and N-2) shown below are part of the required study process and are defined in the report glossary.

Table 4.1: PSE's 2013 Study Report: 2017/2018 Overloaded Elements

	2017/2018 Normal Winter (23° F) 100% Conservation		
	Type of Contingency		
Transmission Line or Transformer	N-1	N-1-1	N-2
Talbot Hill - Lakeside #1 115 kV line		OL	OL
Talbot Hill - Lakeside #2 115 kV line		OL	OL
Talbot Hill 230-115 kV transformer #1		OL	
Talbot Hill 230-115 kV transformer #2		OL	
Talbot Hill-Boeing Renton-Shuffleton 115 kV line		OL	
Shuffleton – O'Brien 115 kV line			
Shuffleton – Lakeside 115 kV line			

OL = Overload of Emergency Rating.

PSE's 2013 Needs Assessment report drove many need-related Stakeholder questions about the forecast, the weather scenarios, the regional scenarios, exports and imports to Canada, the outage contingencies studied and whether they were needed, the probability of having the issues, etc. PSE develops a new forecast every two years, and in February, 2015, PSE completed their new forecast with actuals through 2014. They have since restudied the situation with the new forecast. The remainder of this ITA report will relate the questions received to the new forecast and the new results.

4. Energy versus Demand

Forecasts are developed for both energy and demand. A useful analogy is to compare energy to a car odometer and demand to a car speedometer.

- Energy (kWh) is analogous to an odometer reading, which is a cumulative measure of total miles traveled over time. Energy is a cumulative measure of total power produced or consumed over time.

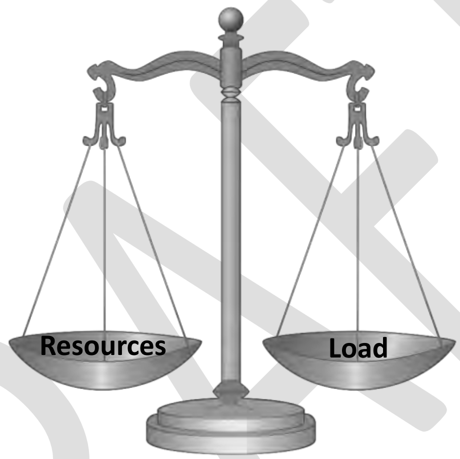
Demand (kW) is analogous to a speedometer reading, which shows a snapshot of the speed at a precise moment. Demand is a snapshot of power required or power used. Peak demand is the highest demand that will be required at any particular moment during a period of time. An odometer doesn't indicate how fast someone drives, but does indicate how much driving has been done. Similarly, an energy forecast (kWh) indicates increases or decreases in the use of electricity, but doesn't indicate peak usage (kW).

Bellevue's Resource Conservation Manager (RCM) program stats on declining energy use are reflecting a decline in the average use per customer. The DSM programs, solar, etc. are showing success with this decline. But, that is one piece of the story - the energy piece on a per customer basis. The number of customers continues to increase, and the aggregate peak usage (peak demand), is continuing to increase. Growth in peak demand drives the size and amount of infrastructure required and drives the issue of grid reliability.

5. Typical Electric Forecast Elements

The typical utility industry forecast is composed of four main parts which will each be further explained later in this section: 1) adjustment for weather, 2) economic and demographic data, 3) application of end-use data, including energy efficiency and conservation effects, and 4) adjustment for large specific load additions (such as for a new building).

Resource planning is a related activity which provides direction on some of the forecasting elements. Resource planning (ensuring there are sufficient generation and conservation/efficiency resources to serve the customer load) requires a load forecast to know how much load one must serve. The resources must balance the load.



National Level

There are NERC Reliability Standards which pertain to the collection of data necessary to analyze the resource needs to serve peak demand while maintaining a sufficient margin to address operating events. One Standard (NERC MOD-021-1) requires that "forecasts shall each clearly document how the Demand and energy effects of DSM programs (such as conservation, time-of-use rates, interruptible Demands, and Direct Control Load Management) are addressed." Another Standard (NERC MOD-019-0.1) requires "forecasts of interruptible demands and Direct Control Load Management (DCLM) data".

State Level

There are state requirements for resource planning, which identifies generation resources and conservation/efficiency measures to serve the customer load. State Law (RCW 19.280.030), identifies the requirements of a resource plan, and states that the integrated resource plan must include:

> "(1)(a) A range of forecasts, for at least the next ten years or longer, of projected customer demand which takes into account econometric data[12] and customer usage;"

[12] Econometrics is the application of mathematics and statistical methods to economics. The data to which it is applied is called econometric data. Econometrics tests hypotheses and forecasts future trends by applying statistical and mathematical theories to economics. It's concerned with setting up mathematical models and testing the validity of economic relationships to measure the strengths of various influences.

> "(1) (b) An assessment of commercially available conservation and efficiency resources. Such assessment may include, as appropriate, high efficiency cogeneration, demand response and load management programs, and currently employed and new policies and programs needed to obtain the conservation and efficiency resources;"

Item 1(a) above requires econometric and end-use data in the forecast. Item 1(b) requires that the forecast account for conservation and efficiency resources. Both are industry practices.

Resources consist of Supply-Side Resources (conventional generation plants, renewables, etc.) and Demand-Side Resources (resources that reduce the demand (load)).

5.1. Simplified Description of the Forecasting Procedure

1) WEATHER NORMALIZING.

The North American Electric Reliability Corporation (NERC[13]) provides direction at the national level for normalizing the demand (MW) forecast to account for weather impact.

> "The fundamental test for determining the adequacy of the Bulk Electric Power System (BEPS) is to determine the amount of resources and the certainty of these resources to be available to serve peak demand while maintaining a sufficient margin to address operating events. This test requires the collection and aggregation of demand forecasts on a normalized basis. This is defined as a forecast that has been adjusted to reflect normal weather conditions and is expected on a 50 percent probability basis, also known as a 50/50 forecast (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak). This forecast can then be used to test against more extreme conditions." [14]

Normalizing the forecast seeks to remove the variation in load due to weather related factors including the temperature at the time of the peak, the temperature on the days prior to the peak, whether the peak occurred on a weekend, a weekday, a holiday, etc. Reactions to these variables vary throughout the United States, yet for a localized area there will be a typical reaction that can be calculated. These are addressed when normalizing the forecast. For example, many office buildings use less power on the weekend or on a holiday. Moreover, some residential customers will put up with a short cold or hot spell, but if it lasts "too long", they will be more likely to increase their use of heating or air conditioning.

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[13] NERC: North American Electric Reliability Corporation. NERC is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards as one of its duties. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico.

[14] NERC, Normalizing "NERC | MOD C White Paper | April 24, 2014", page 5 http://www.nerc.com/pa/Stand/Project%20201004%20Demand%20Data%20MOD%20C/MOD_C_White_Paper_Redline_20140424.pdf

In addition to calculating the normalized peaks, industry also typically calculates an adverse or extreme peak. Many utilities utilize a 90/10 forecast[15] to justify projects, some use an 80/20 forecast to justify projects. Utilities in the Northwest area of the United States typically base their projects on the normal (50/50) forecast, although they develop a 95/05 forecast (1-in-20) for reference.

A typical industry source for the weather data is a National Oceanic and Atmospheric Administration (NOAA) weather station. Some utilities may have their own weather recording data.

Stakeholder Questions on weather adjustment

Q1. Please explain weather adjustment. Is it reasonable/appropriate?

- A *Please see the above discussion.*
- A *Weather adjustment is reasonable and appropriate, and is required by NERC.*

2) DEVELOP A MATHEMATICAL RELATIONSHIP (EQUATION) BETWEEN A) THE ECONOMIC AND DEMOGRAPHIC DATA AND B) EITHER ENERGY USAGE (KWH) OR ELECTRIC DEMAND (KW).

For each customer class (e.g. industrial, commercial and residential), estimate the relationship between electricity consumption (usage) or demand, and the major variables that affect it (e.g. population, price, economic growth, etc.). This relationship is usually developed first, without accounting for new Demand-Side Resources (DSR), in order to show the effect of the DSR on the forecast.

Econometrics utilizes multiple sources of data. Table 5.1 lists examples of data sets that may be used in the econometric modeling.

Table 5.1: Examples of Data Used in Econometric Models

Example Data Sets used in Econometrics
Household Size
Population
Customer Count by Customer Class
Employment (Manufacturing, Non-Manufacturing, by NAICS Code[16], etc.)
GDP (Gross Domestic Product)
GMP (Gross Metropolitan Product) – a measure of the size of the economy of a metropolitan
Personal Income

[15] 90/10 forecast: 90% probability that the weather will be less severe and a 10% probability that the weather will be more severe. This is also called a 1-in-10 forecast.

[16] NAICS - The North American Industry Classification System (NAICS) is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy (Source: Census.gov)

3) <u>ACCOUNT FOR END-USE DATA INCLUDING ENERGY EFFICIENCY AND CONSERVATION EFFECTS (TYPICALLY FROM AN INTEGRATED RESOURCE PLAN (IRP))</u>

End-Use Analysis projects the quantity and use of electricity-using equipment (or a subset of them) to make a forecast or to revise one. *End-use analysis is responsive to consumer changes in kinds of equipment and allows analysis of conservation programs, energy efficiency improvements, building code modifications, increase in household electronics or typical housing square footage, etc. It breaks the data into user sectors and needs an extensive inventory of data. It readily reflects changes in the factors that influence consumption, but requires detailed assumptions on the use going forward.*

Utilities and cities can influence electric end-use through Demand-Side Management technologies and practices, city code changes, efficiency programs or incentives, awareness campaigns, et cetera. Example end-use programs are listed below.

• Residential mass market lighting and appliances
• Residential HVAC replacement
• Residential new construction
• Residential retrofits
• Commercial/Industrial lighting, equipment, HVAC
• Customized programs for larger customers
• Demand Response incentive/enabling programs
• Pricing—interruptible, time of use pricing, real time pricing

Demand-Side Management (DSM) can be broken into two components: energy efficiency and Demand Response. Energy efficiency attempts to permanently reduce the demand for energy in intervals ranging from seasons to years and concentrates on end-use energy solutions. Demand Response is designed to change on-site demand for energy in intervals from minutes to hours, targeting the lowering of electric demand/energy use during peak periods by transmitting changes in prices, load control signals or other incentives to end-users to reflect existing production and delivery costs.

When end-use factors are taken into account in the forecast, there will be multiple variables representing different elements of end-use. Some may offset others. For example, the U.S. Department of Energy noted that "Homes built between 2000 and 2005 used 14% less energy per square foot than homes built in the 1980s and 40% less energy per square foot than homes built before 1950. However, larger home sizes have offset these efficiency improvements."[17]

When utilized, the IRP process is where the end-use data is analyzed. The IRP is a comprehensive and long-range road map and is where a utility examines both Supply-Side and Demand-Side options with the objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. Because energy efficiency is generally a low-cost resource, the IRP tends to incorporate energy efficiency as a utility system resource and reduce the need for additional Supply-Side resources.

The end-use data is generally limited to new DSR measures. Historical end-use data is not usually captured due to the difficulty in acquiring it.

[17] "Buildings Energy Data Book", US Department of Energy

4) ADJUST FOR BLOCK LOADS (MAJOR LOAD ADDITIONS)

Known large load additions would be added to or removed from the forecasted load. This could include new large commercial buildings, major customers leaving the area, etc.

The above forecast discussion represents the system forecast, referring to the forecast for the utility's entire service area. A system forecast may be broken into sub-areas at the utility's discretion, or separate forecasts may be developed for sub-areas. Various scenarios may be modeled, to examine higher or lower conservation levels, adverse weather, et cetera.

5.2. Utilizing the System Forecast in Powerflow Cases

In order to conduct studies on the transmission system, the substation loads are calibrated to the system forecast. Once calibrated, the substation loads are modeled in the transmission planning cases for study. Multiple seasons and years may be studied.

6. PSE's Forecast Methodology

PSE updates their load forecasts every two years. In early February, 2015, PSE completed their 2014 forecast which included historical data through 2014, and thus included the summer 2014 peak and the winter 2013/2014 peak. This new forecast was based on a new methodology. PSE shifted from a predominately system-wide view to a county by county examination. Particular focus was placed on King County, where the Eastside study area was further separated out from King County using census tract data to develop a separate Eastside forecast. This new forecast methodology provided improved visibility of where growth was occurring and where it wasn't. Consequently, after conferring with the City, USE decided to wait for the new forecast, with its improved visibility of the Eastside area, as well as its more recent actual load information.

The review of PSE's forecast methodology in this report is specific to PSE's 2014 forecast.

6.1. Weather Adjustment (Weather Normalizing)

PSE's 2014 system forecast incorporated weather normalizing consistent with industry practice.

PSE's weather normalizing process tests the following major variables via regression analysis. The regression analysis process selects out the variables that result in the best fit to the data.

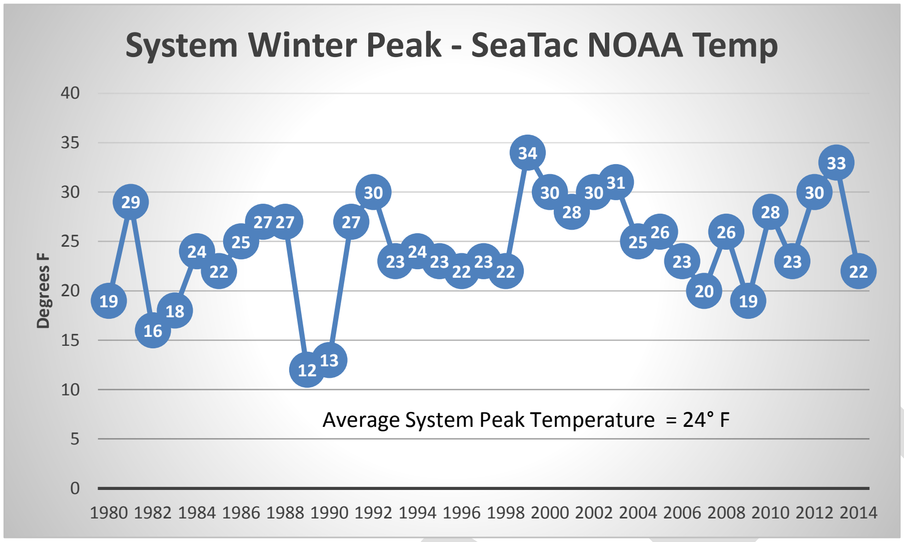
- Peak hourly load for the month
- Maximum hourly load on each of the three days prior to the peak day
- Minimum and maximum temperature on the peak day
- The minimum temperature on each of the three days prior to the peak day
- The average temperature on the peak day
- The average temperature on each of the three days prior to the peak day
- Temperature 1, 2, and 3 hours before the peak
- Temperature at the peak hour
- Total monthly load
- Average monthly temperature
- The season the peak occurred in
- Whether the average temperature on the peak day, or the day before, fell below a certain threshold (cold snap variables)
- Whether it is an El Niño
- Day of the week

The factors PSE uses to normalize the effect of weather are quite typical for electric forecasting. Some utilities use humidity as a variable, PSE does not. PSE stated it did not consider humidity a significant factor. Realistically, humidity is less likely to be a factor in the winter. Heating the cold air lowers the relative humidity[18], so it feels dryer.

[18] Relative humidity is the amount of water vapor present in air. It is expressed as a percentage of the amount needed for saturation at the same temperature. Thus relative humidity varies with temperature.

PSE utilizes the SeaTac NOAA weather station for weather data. Figure 6.1 shows the historic winter system peak[19] actual temperatures through winter 2013/2014.

Figure 6.1: Historical Temperature Data



PSE has defined their winter season as November 1 – February 28, and the normal temperature at which PSE's winter load peaks is 23° F (normal peak load temperature). PSE also defines an extreme winter peak load that has a probability of occurring once every twenty years and occurs at a temperature of 13° F. Although PSE develops the extreme winter forecast and models the effect, they only use it as an indicator of future deficiencies. PSE does not use the extreme winter forecast to justify transmission projects, they only use the normal forecast to justify projects. (Utilities in the Northwest area, including Seattle City Light (SCL), use the normal forecast for justifying projects. Many utilities outside this area use an adverse forecast to justify projects.)

Comments:

PSE uses a normal peak load temperature of 23° F. The average winter peak load temperature since 2008 is 24°F, though examining a longer span of time may show that it is 23° F. It is likely that a 1° shift upwards in temperature would reduce the normal winter forecast, but it may not be significant. One could say the normal forecast is a bit conservative. On the other hand, PSE does not use any type of adverse weather (anything worse than a 50/50 forecast) to justify a project. Many utilities design their system based on adverse weather, such as a 90/10 or 80/20 scenario where the forecast is exceeded 10% or 20% of the time. Per the Western Electricity Coordinating Council (WECC) Data Collection Manual (2014), NERC has requested that each Balancing Authority provide a 90/10 forecast. In NERC's 2014-2015 Winter Reliability Assessment, it recommends that scenarios should be assessed that reflect severe winter conditions, such as a "... higher-than-normal peak load (e.g. 90/10 forecast)." PSE does study a 95/5 (1 in 20) extreme winter, but does not use it to justify projects

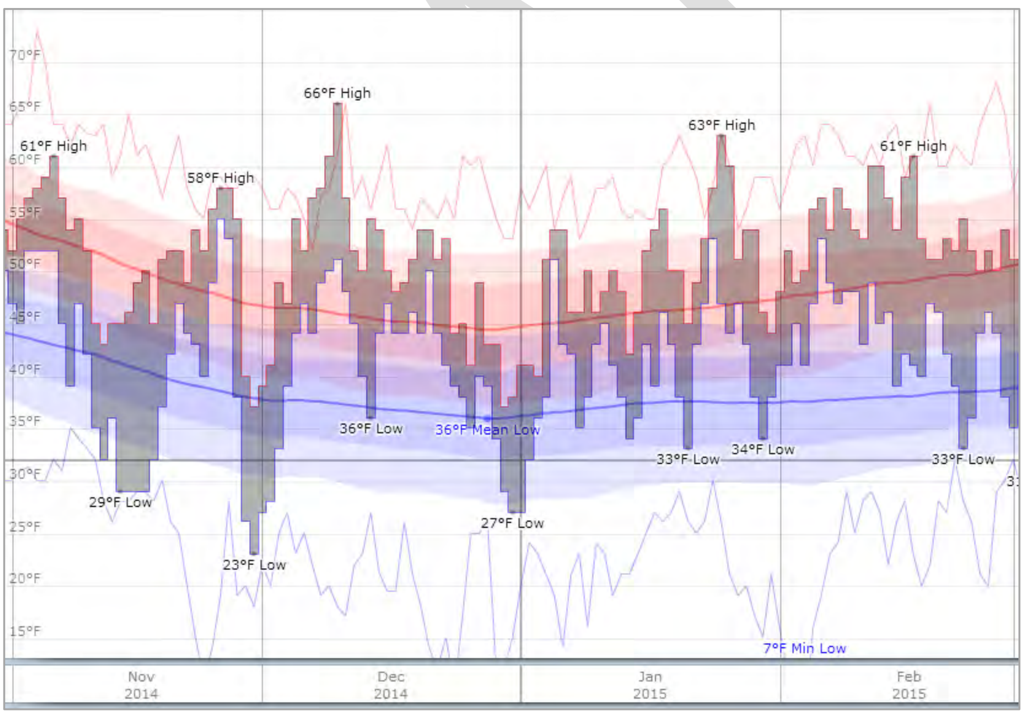
PSE uses one weather station for their service area. Some utilities use more than one weather station to reflect significant weather differences in their service territory.

[19] A system peak refers to the peak demand. In winter, this would be driven by low temperatures.

PSE feels there is not enough weather variation within their service territory to require using more than one weather station. In addition, they expressed concern that the while the SeaTac weather station is very reliable, not all the weather stations are maintained as well and there might be data reliability issues.

Although the 2014/2015 winter peak period ended February 28th, the winter peak data is not yet available. The data verification and normalizing process is not complete and typically occurs mid-year, but it is known that the 2014/15 winter peak was an unusually warm one. Figure 6.2 is taken from Weatherspark.com, and simply shows the highs and lows for each day during the winter season. The very lowest temperature for the entire season was 23°F on November 30th at 2am, per Weatherspark.com. PSE's winter peak (demand) typically occurs either in the morning between 7am and 9am or in the late afternoon/early evening between 4:30pm and 7pm. In either case the winter system peak would have occurred at a warmer temperature. Does this drive any change? At this point, no. It is expected that actual temperatures will not be the same as the defined "normal" temperature. A single data point is unlikely to change a trend. When PSE revises their forecast in two years, they will have two more data points and will recheck the trends through a new regression analysis.

Figure 6.2: Historical Temperature Data 2014/15 Winter Season – Weatherspark.com



6.2. *PSE's Econometric Modeling*

PSE incorporates economic and demographic data into their forecast, subdivided by customer class, using typical data set elements. See Table 6.1 for the sources of data used in their model.

Table 6.1: Data used in PSE's Economic/Demographic Model

Data Set	Historical Data Frequency	Source of Historical Data	Source of Forecasted Data
County Level Employment			
Labor Force, Employment, Unemployment Rate	Quarterly	US Bureau of Labor Statistics (BLS)	PSE's Economic/Demographic Model
Total Non-Farm Employment Goods Producing & Service Providing Sectors	Monthly	WA State Employment Security Department (ESD), using data from Quarterly Census of Employment & Wages	
County Level Personal Income			
Personal Income, Wages and Salaries	Yearly	US Bureau of Economic Analysis (BEA)	PSE's Economic/Demographic Model
County Level Population and Households			
Population (thousands)	Yearly	US BEA/ WA State Office of Financial Management (OFM)	PSE's Economic/Demographic Model
Households, Single-family & Multi-Family (thousands.)	Annual forecasts	US Census	
Household size, Single- and Multi-family (number)	Quarterly	Building Industry Association of Washington	
Eastside Area by Census Tracts			
Population	Yearly	WA State Office of Financial Management (OFM), 9/28/14	PSRC data, April 2014
Employment	Yearly	PSRC, June 2014	PSRC data, April 2014
US Level Macroeconomy			
GDP ($ x Billions, in year 2000 $), Industrial Production Index	Quarterly	Moody's	Moody's
Employment (mils.), Unemployment Rate (%)			
Personal Income ($ x Billions) Wages & salary disbursements, Other Income			
CPI (82-84=1.00[20]), consumer expenditures deflator (2000=1.0)			
Housing Starts (millions)			
Population (millions)			
T-bill rate, 3 months (%), Conventional mortgage rage (%)			

The Puget Sound Regional Council (PSRC) intends for the City of Bellevue to be a hub for regional growth. In their Vision 2040 Regional Growth Strategy report, PSRC designated five Metropolitan Cities to serve as the focal point for accommodating population and employment growth. These are Bellevue, Bremerton, Everett, Seattle, and Tacoma. The strategy is for the Metropolitan Cities "… to accommodate 32 percent of regional population growth and 42 percent of regional employment growth by the year 2040." It was also noted that it would be in the spirit of the strategy for them to accommodate an even higher percentage.

In addition, the City of Bellevue provided the following information on expected population and employment growth. "Currently there are an estimated 11,000 residents living in Downtown, and that number is expected to grow to 19,000 by 2030. Currently there are about 45,000 jobs within Downtown and that number is expected to increase to 70,300 by 2030."

Given the above, one could expect a higher growth in the Eastside area than in some of the other areas served by PSE.

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[20] The average of the 1982-1984 data is set to 1.00

The following graphs display the historic and forecasted data for population, employment, and customer count, provided by PSE. Data is shown for the PSE service territory, PSE's portion of King County, and Eastside. The graphs for Eastside were developed from data sets at the census tract level. Graphs for these data sets are provided for comparison of growth rates between Eastside, King County and the PSE service territory.

The historic graph data for the PSE system goes back to 2000, and includes Jefferson County up until March 2013. The historic graph data for King County and Eastside only goes back to 2006. The Eastside customer count graphs are missing the actual data for year-end 2013; PSE recently updated their billing system with a new IT company, and not all of their customer reports were available at the time of the 2014 forecast.

Because the system graph data goes back to 2000, it shows the trend prior to the recession. The King County and Eastside graph data only goes back to 2006, so the historical trend is obscured by the recession.

Employment and population are increasing. (Data provided by PSE. See Table 6.1 for original data sources.)

Figure 6.3: Population and Employment - PSE Service Territory

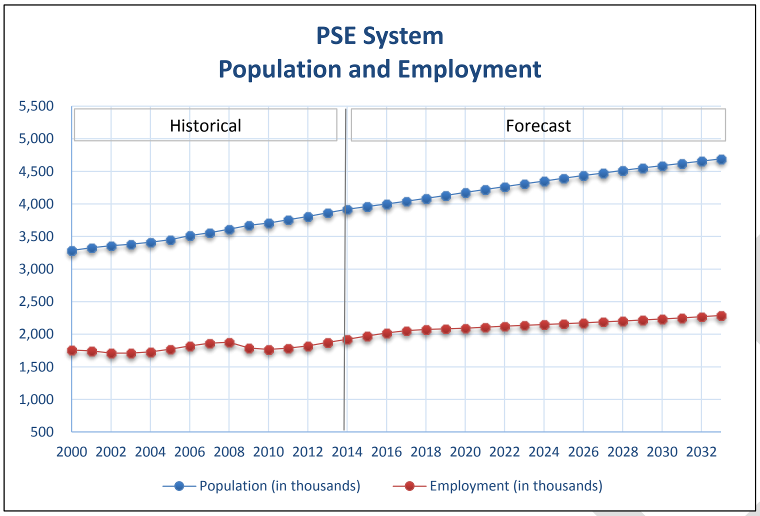


Figure 6.4: Population and Employment – King County

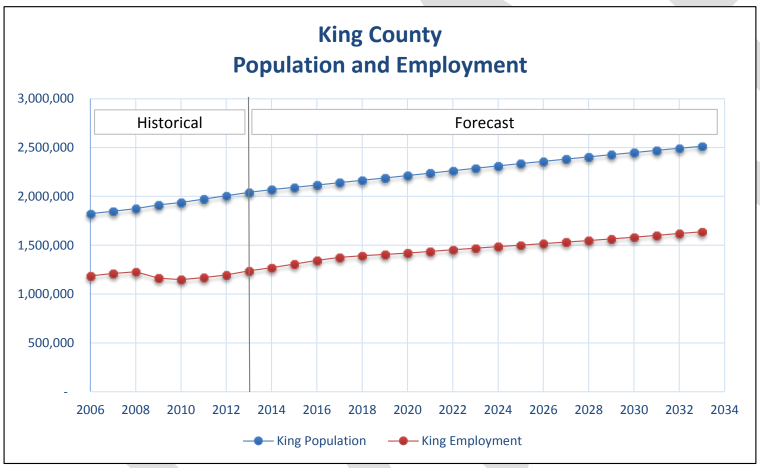
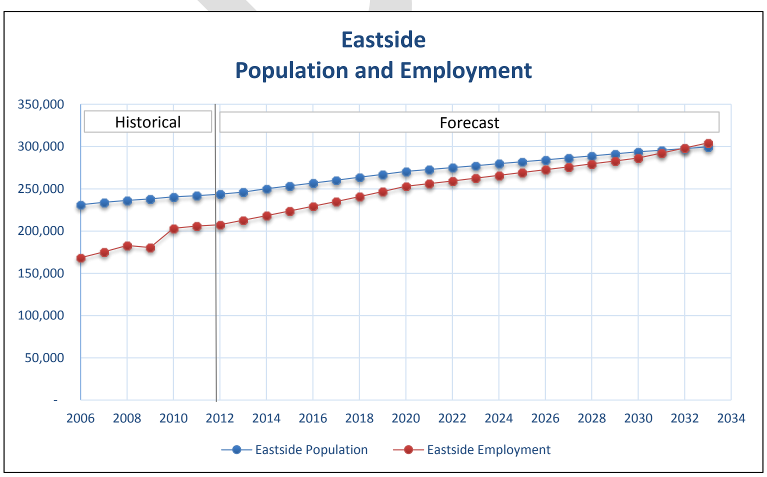
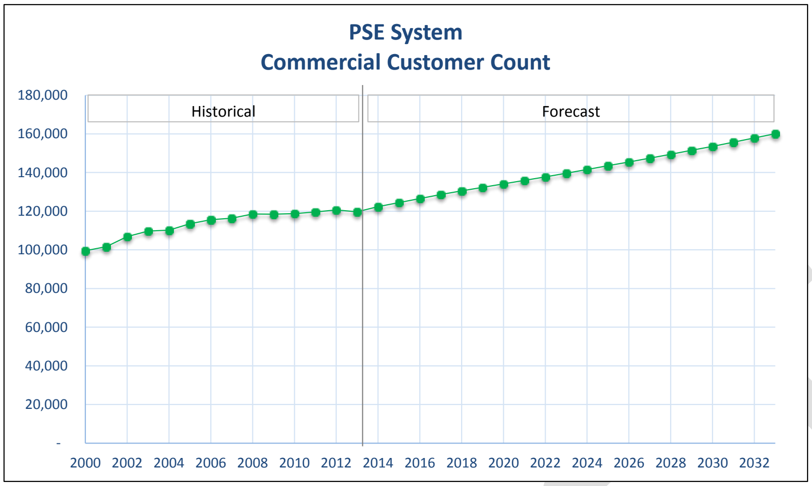


Figure 6.5: Population and Employment – Eastside



Forecasts for the commercial customer counts are increasing.

Figure 6.6: Commercial Customer Count - PSE Service Territory



The PSE system data goes back to 2000 and shows the trend prior to the recession. The King County and Eastside data only goes back to 2006, so the historical trend is obscured by the recession.

Figure 6.7: Commercial Customer Count – King County

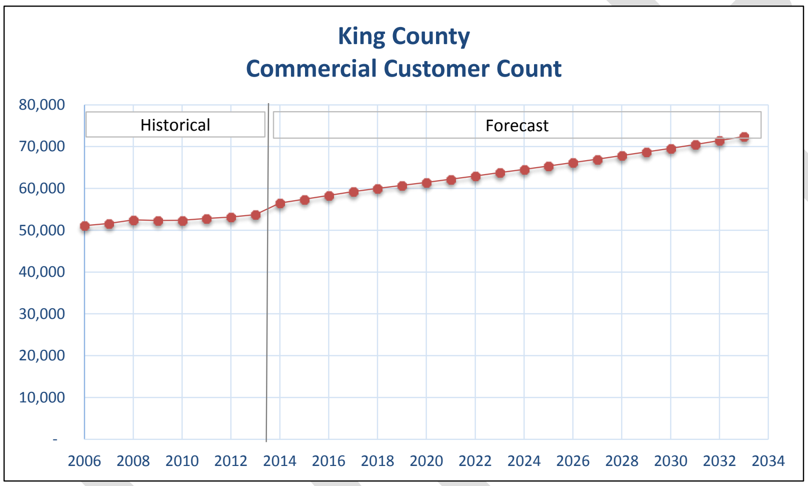
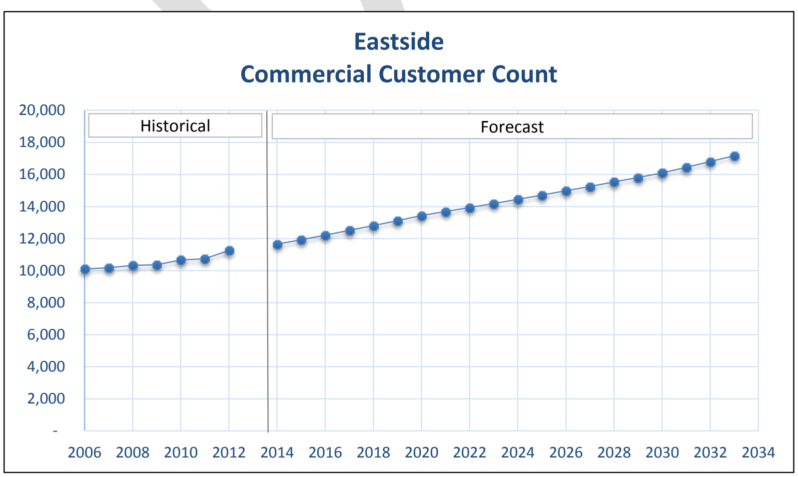
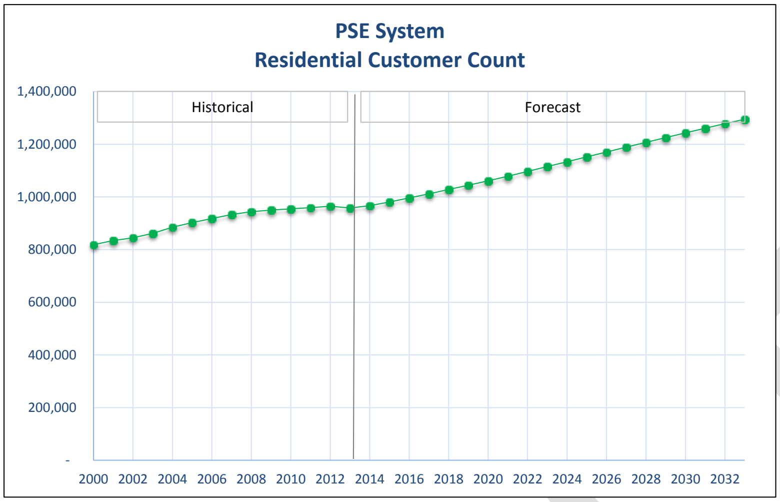


Figure 6.8: Commercial Customer Count – Eastside



Forecasts for the residential customer counts are increasing.

Figure 6.9: Residential Customer Count - PSE Service Territory



The PSE system data goes back to 2000 and shows the trend prior to the recession. The King County and Eastside data only goes back to 2006, so the historical trend is obscured by the recession.

Figure 6.10: Residential Customer Count – King County

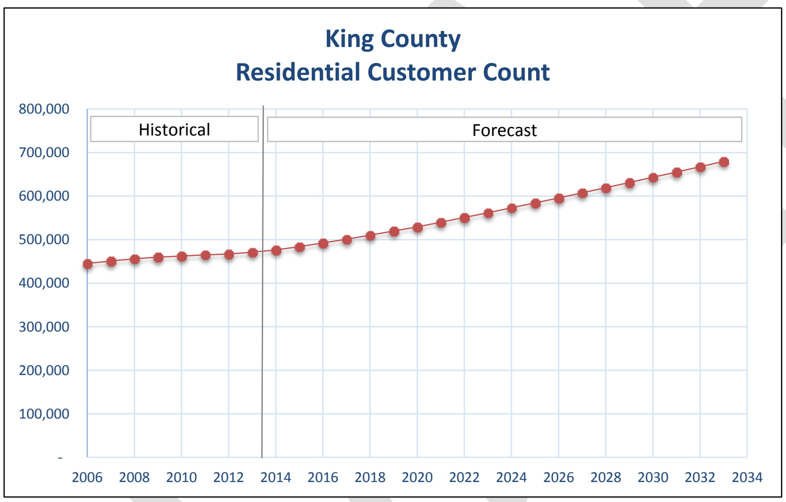
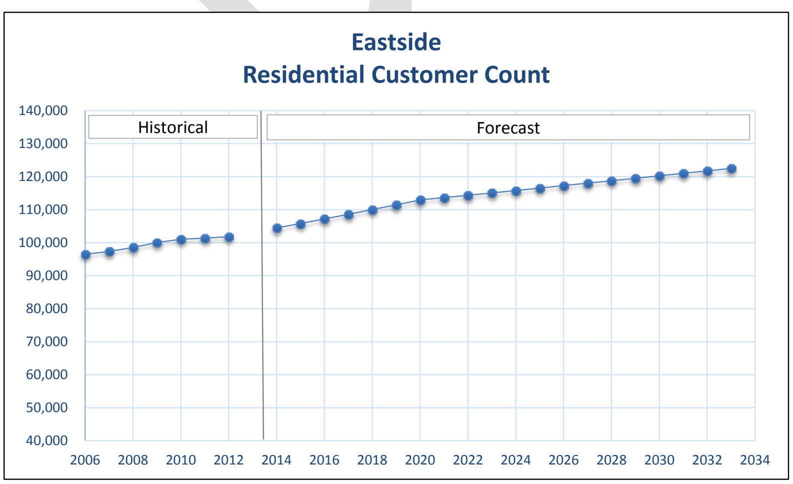
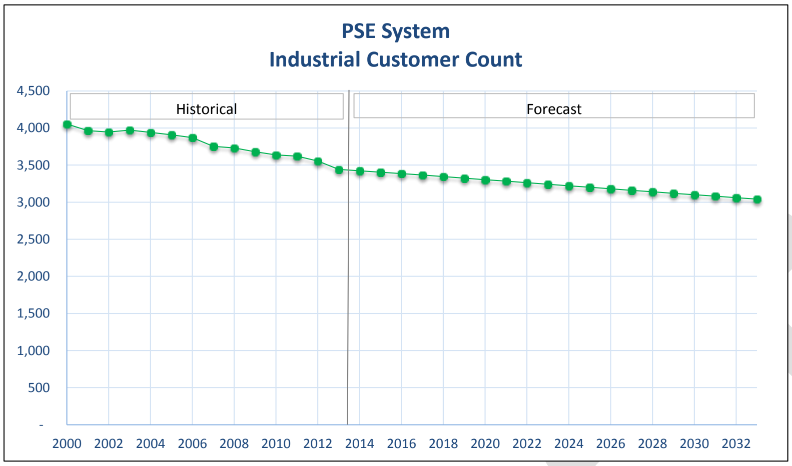


Figure 6.11: Residential Customer Count – Eastside



The industrial customer count is continuing to decline as more industrial customers move out of the area and more commercial moves in.

Figure 6.12: Industrial Customer Count - PSE Service Territory



Industrial customers include warehousing.

Figure 6.13: Industrial Customer Count – King County

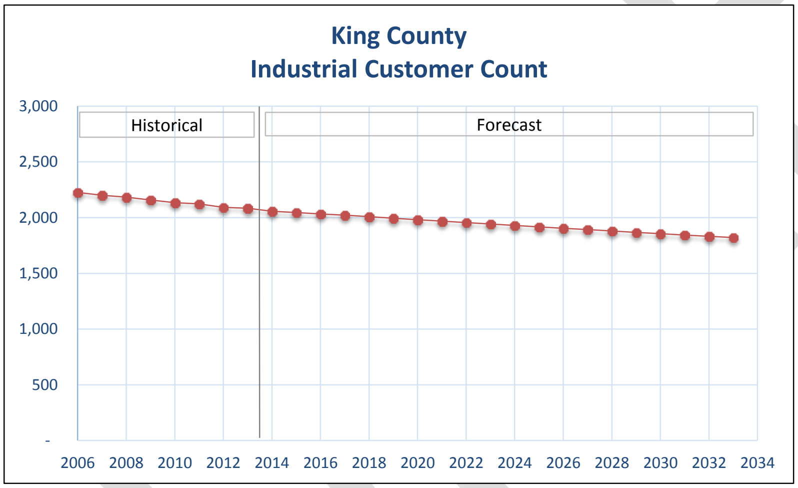
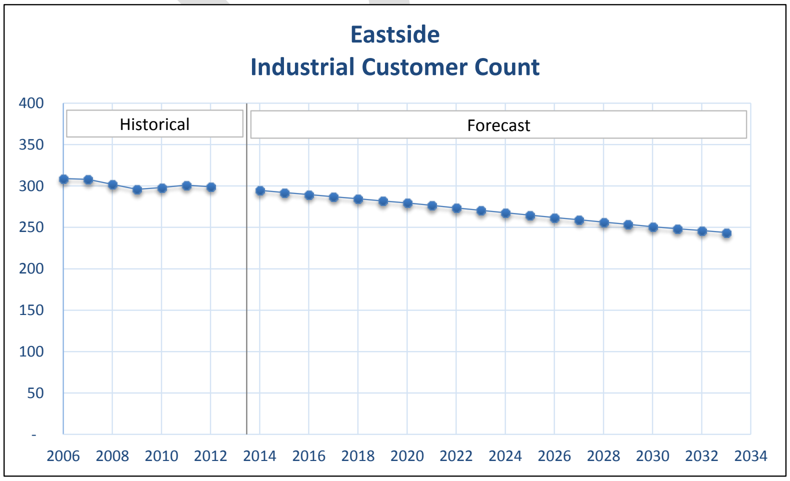


Figure 6.14: Industrial Customer Count – Eastside



6.3. End-Use Data, Including Demand-Side Response and Energy Efficiency

End-use data is evaluated in Integrated Resource Planning. The IRP is where a utility examines both Supply-Side and Demand-Side options with the objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. Because energy efficiency is generally a low-cost resource, the IRP tends to incorporate energy efficiency as a utility system resource and reduce the need for additional Supply-Side resources.

Washington State's Renewable Portfolio Standard (RPS) law requires conservation potential be developed using Northwest Power & Conservation Council (NWPCC) methodology, and conservation targets are based on IRP with penalties for not achieving them. It requires PSE to meet specific percentages of its load with renewable resources or renewable energy credits (RECs) by specific dates.

The Energy Independence and Security Act (EISA, 2007) provides for minimum federal standards for lighting and other appliances beginning in 2012. It also sets standards for increasing the production of clean renewable fuels, increasing the efficiency of buildings and vehicles, and more.

PSE commissioned The Cadmus Group, Inc. (Cadmus) to conduct an independent study of Demand-Side Resources (DSR) in the PSE service territory as part of its biennial integrated resource planning (IRP) process. The study considered energy efficiency, fuel conversion, Demand Response, and distributed generation, totaling over four thousand measures. PSE also considered distribution efficiency. The achievable, technically feasibly Demand-Side measures were combined into bundles[21] based on levelized cost[22] for inclusion in the generation optimization analysis. The optimization model developed and tested different portfolios, combining Supply-Side Resources with Demand-Side bundles, to find the lowest cost combination of resources that: a) met capacity need; b) met renewable resources/RECs need; and c) included as much conservation as was cost effective. (Once the capacity and renewable resources/RECs needs are met, the decision to include additional conservation bundles is simply whether that next bundle of measures increases the cost or decreases it.) The final set of cost effective measures is identified as the "100% conservation" set. By 2033, the 100% conservation scenario is projected to reduce PSE's winter system peak by 1226 MW, 209 MW from the EISA programs and 1017 MW from all the other Demand-Side Resources. Only new opportunities are captured.

The table below breaks out the 100% conservation DSR at the King County and Eastside area level. The MW column shows the impact (reduction) to the demand forecast. For the Eastside area, 51 MW of peak DSR is projected by 2017, and 135 MW by 2031. These reductions are incorporated into the 100% Conservation forecast, which is what is being reviewed in this report.

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[21] All the bundles are cost bundles, with the exception of a standards bundle (expected effects of codes and standards such as EISA) and a distribution efficiency bundle. An example bundle is the set of measures that cost between $28/MWh and $55/MWh.

[22] Levelized Cost - An economic assessment of the cost to build and operate a power-generating asset over its lifetime divided by the total power output of the asset over that lifetime. It is also used to compare different methods of electricity generation in cost terms on a comparable basis.

Table 6.2: Cumulative DSR Impact (2013 IRP)

King County		
year	Annual DSR (MWh)	Peak DSR (MW)
2014	112,730	45
2015	348,463	88
2016	557,863	131
2017	756,295	171
2018	951,360	213
2019	1,147,137	246
2020	1,393,906	309
2021	1,668,547	350
2022	1,902,423	387
2023	2,112,925	421
2024	2,274,243	432
2025	2,351,296	444
2026	2,431,870	457
2027	2,508,352	471
2028	2,589,821	483
2029	2,658,889	494
2030	2,731,640	505
2031	2,798,219	517
2032	2,875,530	532
2033	2,931,133	533

Eastside Area		
year	Annual DSR (MWh)	Peak DSR (MW)
2014	94,667	21
2015	152,559	31
2016	207,980	41
2017	262,563	51
2018	317,493	61
2019	386,767	74
2020	464,427	86
2021	529,013	96
2022	585,484	107
2023	629,201	110
2024	650,086	113
2025	672,152	116
2026	693,168	120
2027	715,397	123
2028	734,411	127
2029	754,139	130
2030	771,869	134
2031	793,300	135

Source: PSE

Stakeholder Questions on Demand-Side Response:

Q2. What is the effect of the LED street light program on load?

- A *The Eastside load is forecasted at 641 MW under normal conditions (Winter 15/16). The funded street light conversion program would reduce this load by 282 kW and the full conversion would reduce the load by 798 kW. On a percentage basis, the funded conversion would reduce Eastside load by 0.044% and the full conversion would reduce Eastside load by 0.12%. Though not evaluated in the 2013 IRP and thus not part of the 100% conservation measures, there will be limited impact to the overall load in any given year.*

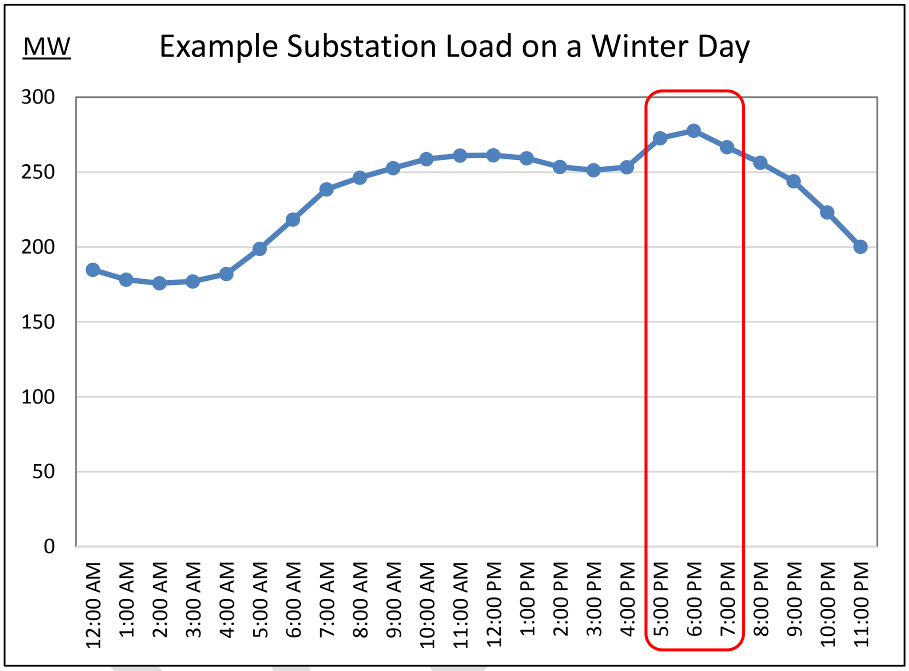
Q3. Does the load forecast take into account local government actions, such as Bellevue's street light and traffic light initiatives?

- A *The LED programs were not specifically identified in the 2013 IRP. The LED technology and availability is different today than it was when the 2013 IRP study began. PSE is planning on including LED lighting in the 2015 IRP.*

Q4. What is the effect of the planned 289 kW of renewable generation (including Solarize Bellevue, the Bellevue College and the Bellevue Service Center), to the grid?

- A *The Eastside load is forecasted at 641 MW under normal conditions (Winter 15/16). The planned 289 kW of renewable generation is nameplate rating, so actual output may be 80-85% of that on a sunny day. For a summer* *peak, the Eastside load could be reduced by 0.04%. For a winter peak, solar output would be significantly less or non-existent. PSE assumes that solar will not be available for the winter peak, since the winter peak usually occurs when it is dark out. The sample graph below reflects a mixed commercial/residential area, with the peak driven by the residential load. (A substation with the peak driven by commercial load could have a different load profile (different peaking curve).)*

Figure 6.15: Sample Winter Load Profile



Q5.Is PSE using all the available Demand Response initiatives/opportunities?

A *Available Demand Response initiatives/opportunities were evaluated as to whether they were achievable and technically feasible. Then PSE used a generation optimization tool to identify the lowest cost combination of resources that a) meet capacity need b) meet renewable resources/RECs need, and c) included as much conservation as was cost effective. (Once the capacity and renewable resources/RECs needs are met, the decision to include additional conservation bundles is simply whether that next bundle of measures increases the cost or decreases it. The IRP has the objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. For example, Pacificorp states that the objective of the IRP is "…providing reliable and least-cost electric service to all of our customers while addressing the substantial risks and uncertainties inherent in the electric utility business." Energy Efficient West Virginia states that IRP is a process used by utility companies to determine the mix of resources that will meet electricity demand at the lowest cost.*

Q6.How does efficiency affect energy usage?

- *Energy efficiency elements were described above. The 2013 IRP identified 521 aMW[23] of market achievable, technically feasible electric energy-efficiency potential by the end of 2033. To gauge achievability, Cadmus relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs, and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment. For the 2013 IRP, PSE assumed achievable electric energy efficiency potentials of 85 percent in existing buildings and 65 percent in new construction. If this potential proves cost-effective and realizable, it would result in a 16% reduction in 2033 forecast retail sales. (Note: this is an energy usage question, not a demand (MW) question. That said, the forecast and need are based on incorporating all of the cost-effective conservation measures (100% Conservation).)*

Q7. Provide details on cost-effective energy efficiency and Demand Response (DR) elements included in the forecast, and how "cost-effective" is determined.

- *See Tables B-2-1, B-2-2, and B-2-3 (pages 156 – 265) of IRP Appendix N (2013) for a list of the thousands of electric measures studied. Table 13, page 20 provides a summary of the number of energy efficiency measures by customer class. The energy efficiency measures make up the majority of the DSR measures.*
- *Cost-effective: The short answer is that PSE has an optimization tool that ensures that the capacity needs are met, ensures that the renewable resources/RECs requirements are met, then minimizes total revenue requirements for both Supply-Side and Demand-Side. Those measures it selects are "cost effective". Longer answer: The measures are bundled into similar levelized costs and the optimization tool evaluates the measures in bundles rather than each individually, then the model determines which bundles are cost effective. See IRP Chapter 5 Figure 5-17 for the DSR bundles by cost group and Appendix N Figure 15 for the DSR supply curve. Out of an identified 1226 winter peak MW of achievable, technical potential in the PSE system (*1017 MW + 209 MW EISA), 1007 MW *were identified as cost effective.*

Q8. Do the growth projections account for increased electrical efficiency? What assumptions are made, and do these represent the low, high, or average model outputs?

- *Yes, the growth projections account for the cost effective efficiency measures.*
- *See answers to the preceding two questions.*
- *The forecast represents the base model.*

Q9. Concern expressed with PSE's forecast when considering energy efficiency, renewables, and Demand Response incentives.

- *Please see above discussion and answers.*

6.4. Major Loads

PSE adjusts its forecast to incorporate major load additions, also called block load additions. The adjustment is a temporary adjustment, as they assume that within a few years the growth built into the load forecast will "catch up" and include the block load additions.

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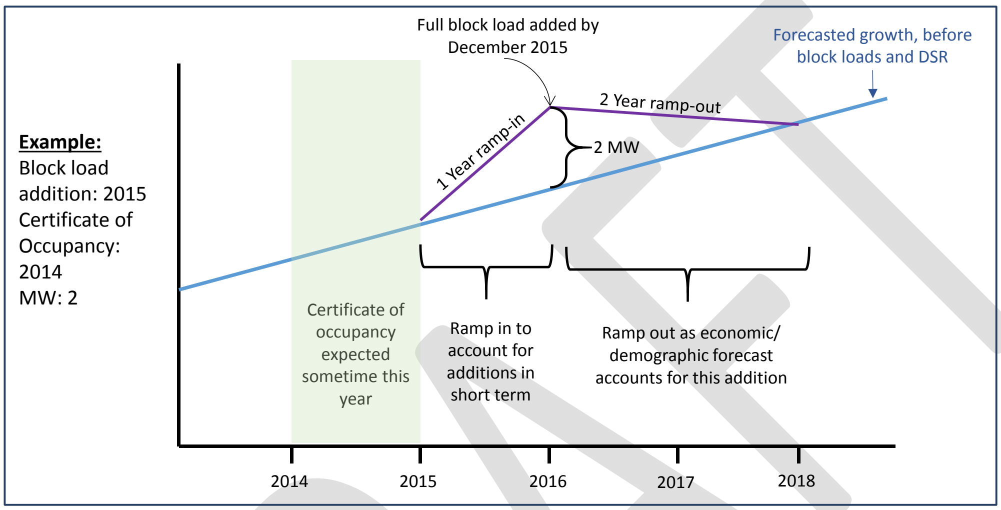
[23] aMW - The average number of megawatt-hours (MWh) over a specified time period; for example, 295,650 MWh generated over the course of one year equals 810 aMW (295,650/8,760 hours). (Source: PSE's 2013 IRP Definitions)

Example: A building has a certificate of occupancy in 2014, with an expected diversified load of 2 MW. PSE will assume it takes a year for the load to fully appear and will add it to the forecast using a one year ramp-in. PSE then ramps the adjustment out over two years, assuming that the growth built into the forecast will take two years to catch up to the block load addition. The block load additions are like bumps on the forecast; they don't change the overall trend, but do create short term changes. See the figure below.

Figure 6.16: Block Load Addition Methodology (from PSE)



PSE acquires data on major load additions from cities as well as directly from developers; some of this data is considered confidential and was not shared. PSE did provide a list of over fifty Eastside Block Load projects (unnamed) with estimated MW load and the expected year when the load would be fully realized. The table below provides a summary by year of this information. The square footage and number of units are reported where known. PSE's Planning group projects a probability of occurrence of 100% for loads anticipated through 2017, 50% for loads anticipated between 2018 and 2020, and 0% for projects after 2020. This probability is multiplied by the expected load before adding into the forecast. The probability factor is a way of addressing the increasing uncertainty of projects in future years.

Table 6.3 does include the City of Bellevue Projects (individually listed in Table 6.4). The Sound Transit East Link project is included in the forecast and accounts for a small portion of the load (approximately 3.5 MW) beginning in the year 2020. Although the East Link web site indicates a 2023 in-service date, PSE's initial expectation is that a small portion of the load will be needed in 2020 and as the project grows they anticipate that Sound Transit's impact on the peak demand will increase. This particular load may be forecasted in advance of need, but it would not impact the 2017/18 HW need for the Energize Eastside project.

Table 6.3: Eastside Total Block Loads by Year

Estimated Completion Year	Assigned Probability	# of Projects	Commercial Sq Footage	# of Multi-family units	MW fully energized this year	MW added to forecast
2014	100%	3	100,000	642	4.4	4.4
2015	100%	9	n/a	1231	5.3	5.3
2016	100%	6	263,000	493	7.0	7
2017	100%	7	2,157,000	1566	25.0	25
2018	50%	4	820,362	n/a	1.0	0.5
2019	50%	6	1,989,340	n/a	21.5	10.75
2020	50%	18	1,316,000	234	16.3	8.15
2021	0%	4	2,010,000	n/a	14.8	0
2022	0%	0	0	0	0.0	0
2023	0%	0	0	0	0.0	0
2024	0%	3	928,000	n/a	8.5	0
2025 and beyond	0%	9	602,000	150	17.8	0

* Square footage and number of units are reported where known.

Table 6.4 lists the thirty-nine major projects identified on the City of Bellevue's website, and is provided to show the significant growth expected in the City of Bellevue. Twelve of the Projects include data on the number of stories (building floors), and seven of these are planning fifteen stories or more.

Table 6.4: City of Bellevue Major Projects (website)

#	Name
Downtown - In Review	
1	Bellevue Square SE Corner Expansion
2	Washington Square Hilton garden Inn
3	Goldsmith Plaza 305
4	Bellevue Center, Phase II
5	415 Office Building
6	Rockefeller Bellevue Tower Phase I
7	Marriott AC Hotel
8	AMCUT
Downtown - Under Construction	
1	Alamo Manhattan Main Street
2	Main Street Gateway / Bellevue Gateway, LLC
3	Marriott Hotel
4	Bellevue at Main / SRM
5	Bellevue Apartments / LIHI
6	Alley 111
7	Bellevue Office Tower
8	Bellevue Park II Apartments
9	Lincoln Square Expansion
10	SOMA Phase II
Downtown - Issued Land Use & Building	
1	The Summit Building C / Bentall
2	103rd Avenue Apartments / HSL Properties
3	Bellevue Center, Phase I
4	Pacific Regent of Bellevue, Phase II
Downtown - In the Pipeline	
1	Evergreen Development Bellevue Tower
2	EROS Properties
3	Fana CBD Master Development Plan
4	Metro 112 Apartment, Phase II
5	17-102nd Avenue NE
6	Eastlink Bellevue Transit Center Station
7	10625 Main Street
8	846 108th Avenue NE
9	Habib Properties
10	Bellevue Plaza
Bel-Red - In Review	
1	Spring District Residential (Land Use Approval)
2	Spring District Office, Bldgs. 16&24 (Building Permit)
3	East Link 130th Station
Bel-Red - Under Construction	
1	GRE Phase I and Phase II
Bel-Red - In the Pipeline	
1	Aegis at Overlake
2	Sherwood Center
3	East Link 120th Station

Projects can shift, developers can change their schedule, but PSE's projected timing of the block loads falls within a realistic range based on current construction schedules and plans, with the possible exception of the East Link project in 2020. However, the East Link timing wouldn't affect the EE timing. PSE's 1-year ramp-in is based on having certificates of occupancy; as long as certificates of occupancy and visual confirmation of both construction and occupancy rates are utilized, the forecast can be updated each time with the best available information. In addition, some of the block load project information is still limited and doesn't provide a complete picture of the electric load requirements, so assumptions must be made. These situations are also typical and another reason for the need to regularly update block load information which is a typical industry practice. In summary, PSE's block load data appears to fall within a realistic range. Construction is happening. Developers have indicated interest in future projects. Also, PSE applies a probability factor to the estimated loads to try to address the uncertainty of projects with later in-service dates, and all the forecasted impacts of the block loads on the forecast are only temporary bumps, and are ramped out of the forecast so that they don't affect the overall growth trend.

Stakeholder Questions on Major Projects

Q10. Is development like Bellevue's Spring District factored in? Are there numbers that account for the impact of individual projects in downtown Bellevue? What numbers are used to predict the load impact for these projects?

- A *Yes. See Table 6.3 for the summary.*

Q11. A scenario was posed that data centers were consolidating and moving out of the Eastside area, and a question was asked whether PSE had accounted for that in their forecast.

- A *PSE does account for large loads leaving the system or moving from one substation to another, but is not aware of any major changes in data centers. Data centers can be relatively small or quite large. Per PSE, the large data centers generally locate outside the PSE service area, where it is cheaper. PSE's planners have seen no indication of large data center changes. A short, independent web search did not turn up any large data center moves out of the Eastside area.*

6.5. PSE's Forecast

Figures 6.17 – 6.21 depict energy and demand (MWh and MW) forecasts, and growth rates. The peak forecast is affected by conservation programs, and all the graphs assume 100% conservation and a normal winter. PSE's conservation programs are heavily weighted toward the first 10 years of the forecast (2014-2023), with less aggressive conservation occurring in the second 10 years of the forecast (2024-2033). This can result in a slower growth rate in the load forecast for the first 10 years.

PSE reached several key conclusions in comparing the new 2014 forecast (F14) with the prior 2012 forecast (F12), which affects some of the information that PSE had publicly shared showing demand and need for the project. PSE's F14 system forecast assumed a more gradual recovery of the US economy from recession than the prior F12 forecast. The F14 system forecast also used an updated US population growth forecast from the US Bureau of Census which is lower than what was used in F12.

In addition, customer growth and customer counts in the F14 system forecast are lower than in F12 because of slower housing recovery. Finally, peak load growth and peak load levels at the system and King County level are also projected to be lower in F14 versus F12.

The Eastside area is where the load projections increased. Eastside peak loads in the new forecast, based on PSRC's population and employment growth forecasts, are projected to grow by 2.4% per year[24] in the next 10 years driven by growth in commercial sector and high density residential sector.

Although the F14 forecasted Eastside growth rate increased over the 2012 forecast (F12), the resultant F14 forecast for Eastside reduced the projected 2017/18 normal winter loading by 11 MW. The new F14 forecast, based on census tract level demographic data for the Eastside area, had normalized actual peak loads for winter 2012/13 and 2013/14 which were less than the forecasted peak loads from the F12 forecast, which in turn resulted in lower forecasted peaks for winter 2017/18. Section 8 of the report discusses the impact on the Energize Eastside project need.

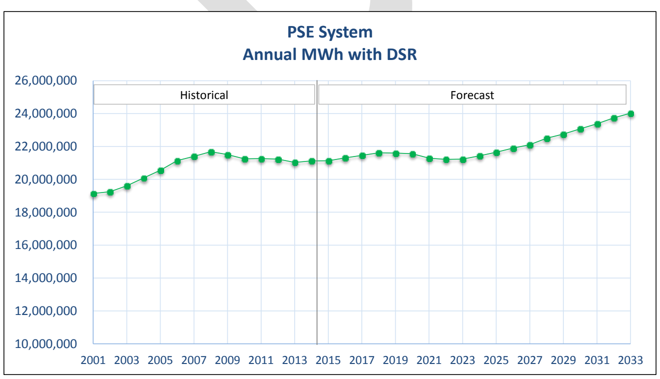
Table 6.5: PSE's Eastside 2017/18 Forecast Comparison

Forecast Development Year	2017/18 Winter Peak
2012	699 MW
2014	688 MW

Figures 6.17 – 6.20 show MWh and MW forecasts for the PSE system, King County, and the Eastside area. The EE project need is based on the MW graph for Eastside. The MWh forecasts do not drive the need, but are shown because of the number of Stakeholder questions received and the uncertainty and/or misconception of what MWh indicate. The MWh forecasts show *usage*, like the odometer, not *peak.* They reflect growth and conservation, but are not directly tied to the peak. The typical behavior or response of a household may be different on the one or two very cold days in a year, as one is getting ready in the morning or coming back from work to a cold house.

Figure 6.17 shows the energy forecast for the PSE system. The forecasted dip in energy is due in part to the aggressive conservation programs that are weighted toward the first 10 years of the forecast (2014-2023). In addition, the block loads are phased in and then phased out over time. Any block loads that come in after 2017 are only given half of the MWh since these projects are less certain to be completed. After 2020 no block loads would be phased in, with a few more years of earlier block loads phasing out.

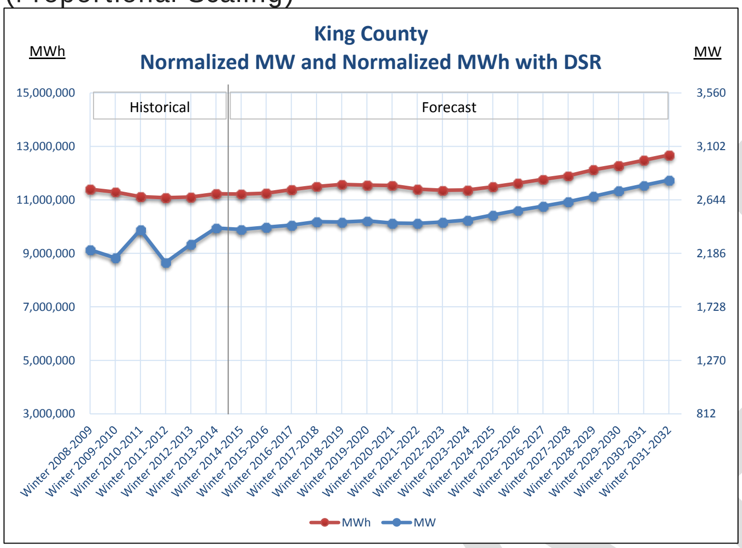
Figure 6.17: PSE's Energy Forecast (MWh) – PSE System



[24] The growth rate is a peak load growth rate and is developed through a regression analysis.

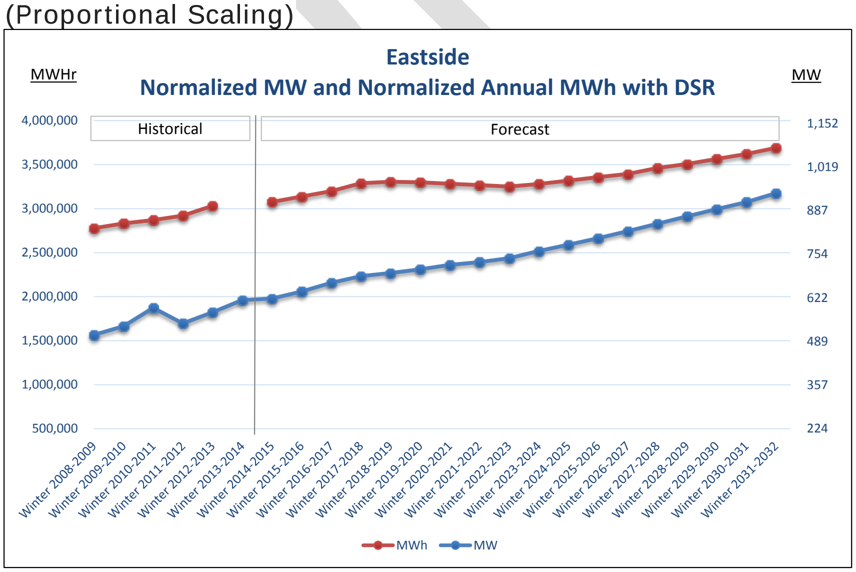
Figure 6.18 shows the energy forecast and demand forecast for King County. King County is forecasted to have a relatively flat energy and demand forecast until approximately winter 2023/2024, at which point both forecasts are increasing. The energy and demand forecasts track fairly closely in King County, but this doesn't mean the same response is expected in other areas.

Figure 6.18: PSE's Energy (MWh) and Demand (MW) Forecasts - King County
(Proportional Scaling)



In the Eastside area, the energy forecast appears to show a stronger impact from conservation compared to the demand forecast. As mentioned previously, the forecasted dip in energy is due in part to the aggressive conservation programs that are weighted toward the first 10 years of the forecast (2014-2023). It is also impacted by the block loads which are phased in and then phased out over time. After 2020 no block loads would be phased in, with a few more years of earlier block loads phasing out.

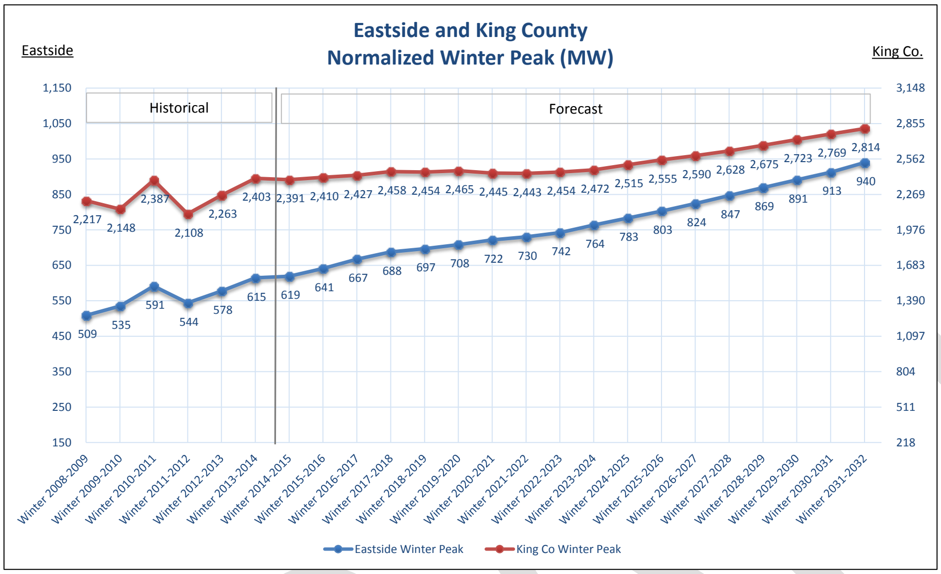
Figure 6.19: PSE's Winter Energy (MWh) and Demand (MW) Forecasts – Eastside
(Proportional Scaling)



The dip is due to a cold snap that lasted several days. Per PSE their weather adjustment does not fully account for the lag effects of longer cold snaps.

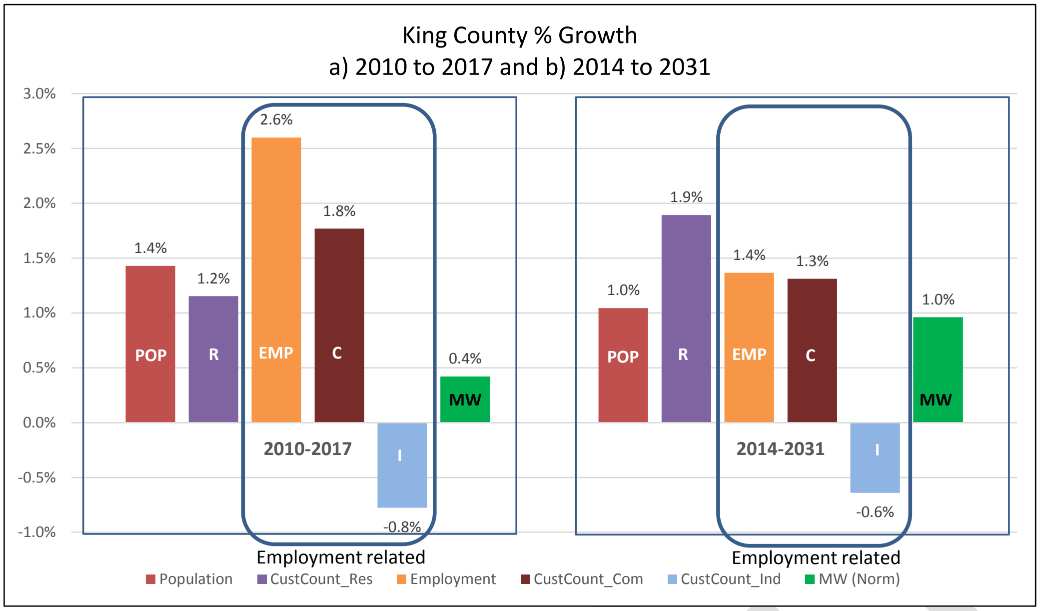
Figure 6.20 compares the Eastside and King County winter peak demand forecasts. The Eastside area is forecasted to grow at a faster rate than King County. This is in line with the Vision 2040 Regional Growth Strategy

Figure 6.20: PSE's Winter Demand Forecasts – Eastside and King County, 100% Conservation
(Proportional Scaling)



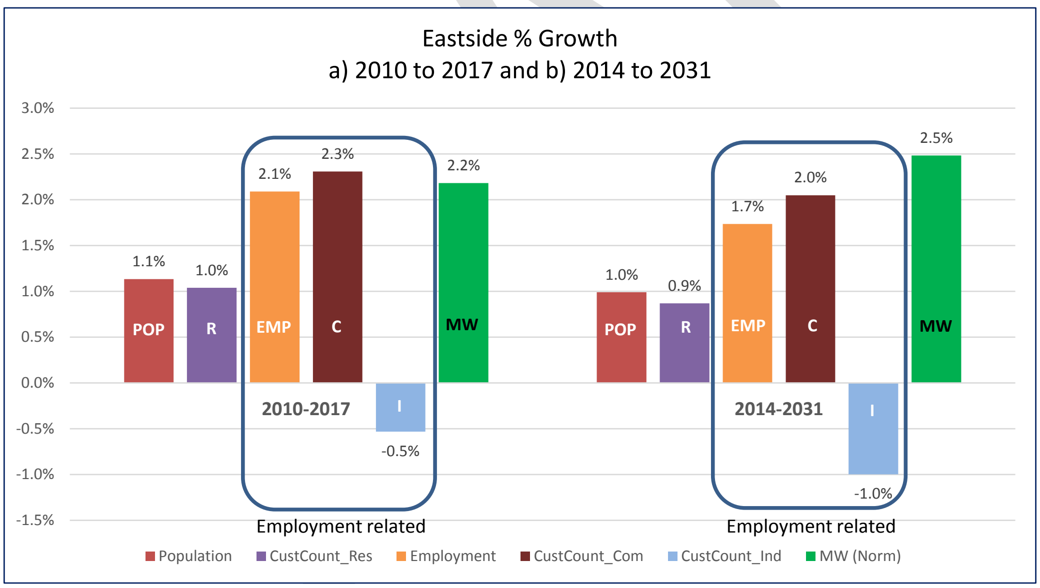
The 2014 forecast shows a 2.4% growth rate for the Eastside area from 2014-2024 and a 2.5% growth for Eastside between 2014 and 2031. In comparison, the forecast shows a 1% growth rate for King County between 2014 and 2031. The Eastside area is projected to grow significantly faster than King County as a whole, which is in line with the Vision 2040 Regional Growth Strategy report. Whether this growth will be sustained through 2031 is unknown. Note: if the growth rate is calculated from the 2010 actuals through 2017, the growth rate is 2.2% for Eastside and 0.4% for King County. See Figure 6.21 and Figure 6.22.

Figure 6.21: Growth Rates – King County



See Table 6.1 for original data sources. Numbers provided by PSE.

Figure 6.22: Growth Rates – Eastside Area



See Table 6.1 for original data sources. Numbers provided by PSE.

<u>Stakeholder Questions related to Actuals (Historical Data)</u>

Q12. What are the ACTUAL numbers for 2012, 2013 and 2014?

A *Actual numbers for employment, population and customer count are shown in Section 6.2. Actual numbers (normalized) for MWh and MW are shown in Section 6.5.*

Q13. Please show historical loads.

A *See preceding question.*

Q14. What is the source of the actuals?

- A *See Table 6.1*

Q15. Would like graph showing load history (back to 2000) and forecast.
- A *See Section 6.5*

Q16. Please include 2014/15 winter peak data.
- A *The data is not yet available for the 2014/15 winter peak. See Figure 6.2 and the paragraph above it.*

Q17. Please provide the unadjusted and temperature adjusted historical peaks.
- A *Temperature adjusted historical peaks are shown in Section 6.5. See the beginning of Section 5 and Section 5.1 for why unadjusted peaks are not used.*

Q18. What have been the highest actual aggregate winter peak loads on Eastside feeders and distribution lines …? How would they relate to PSE's forecast of future loads?
- A *The aggregate peaks for the Eastside area are captured in the historical data shown in Figure 6.19.*
- A *The historic loads are included in the regression analysis which results in the forecast of future loads.*

6.6. Summary Analysis of PSE's Forecasting

PSE has followed industry practice in forecasting their demand load.

- PSE included the major components of a typical system forecast: weather normalizing, use of econometric data, incorporating end-use data (including conservation and DSR measures), and making adjustments for block (major) loads.
- The variables used in the weather normalizing process were typical based on industry practice.
- PSE used typical data set elements and multiple data sources for economic/demographic data as shown in Table 6.1, acquiring data at the county level, and for the Eastside area at the census track level, in order to differentiate growth rates within its service territory.
- PSE employed regression analysis at this step, an industry standard computer analysis technique, to determine the forecast before Demand Side Resources (DSR) and block load adjustments. (The computerized regression analysis was not analyzed as part of this study, but the technique is a computerize estimation of the best fit of the variables to the given data. The equations are considered proprietary by PSE.)
- PSE acquired/developed significant end-use data via their IRP process on over four thousand DSR measures, incorporated National and State requirements on conservation and RPS, and optimized the achievable, technical measures with a resultant 100% Conservation scenario which projects 135 MW of Eastside winter peak DSR by 2031.
- PSE gathered block load data (major projects) and utilized short-term forecast adjustments (1-year ramp in based on certificates of occupancy and 2-year ramp-out) to account for the impact. The block load impact was further adjusted by applying a probability factor based on the projected block load in-service date, with 100% through 2017, 50% from 2018 to 2020, and 0% after 2020. The in-service date accuracy and the ramp-in timing of one year is harder to evaluate. Projects can shift, developers can change their schedule, but PSE's projected timing of the block loads falls within a realistic range based

on current construction schedules and plans, with the possible exception of the East Link project in 2020 which wouldn't affect the EE timing. PSE's 1-year ramp-in is based on having certificates of occupancy; as long as certificates of occupancy and visual confirmation of both construction and occupancy rates are utilized, the forecast can be updated each time with the best available information. In addition, some of the block load project information is still limited and doesn't provide a complete picture of the electric load requirements, so assumptions must be made. This is also typical and another reason for the need to regularly update block load information which is a typical industry practice. In summary, PSE's block load data appears to fall within a realistic range. Construction is happening. Developers have indicated interest in future projects. Also, PSE applies a probability factor to the estimated loads to try to address the uncertainty of projects with later in-service dates, and all the forecasted impacts of the block loads on the forecast are only temporary bumps, and are ramped out such that they don't affect the overall growth trend.

No forecast is perfect, but by following industry practice, PSE used reasonable methods to develop the forecast. PSE's resultant forecast shows the Eastside area growing at a higher level than at the county and system level, and that is based on the data PSE received.

<u>Comments on weather adjustment:</u>

PSE is applying the Northwest US practice (as does SCL) of basing projects on a normal 50/50 forecast, which by definition should be exceeded half the time, and using a 95/5 (1-in-20) extreme weather scenario for reference (but not for developing projects). Although a regional industry standard, many other US utilities base projects on an adverse weather scenario, such as a 90/10 or 80/20. Basing projects on an adverse weather scenario is more conservative, but seeks to ensure that the lights stay on given the adverse weather event. These statistically less frequent assumptions would result in a higher load forecast, and if adopted as a policy on which to base projects, would require the system to be designed to withstand it.

Based on historical temperature data, one could suggest that PSE's forecast use a normal temperature of 24°F rather than 23°F for winter normalizing (see Figure 6.1), but: a) the 24°F average is based on a relatively short span of time, and b) the forecast used to propose projects is a normal 50/50 forecast and is expected to be exceeded given an adverse weather event. If PSE were to adopt an adverse weather policy on which to base projects, then it could make sense to re-evaluate the "normal" winter peak temperature; however, since the system demand is based on the less conservative 50/50 load forecast, using 23°F for the normal temperature is a reasonable assumption because it results in a slightly higher system demand than using 24°F.

<u>*Stakeholder* Questions related to Forecast Methodology</u>

Q19. Questions on heat map. Request to create a more accurate map.

A *USE attempted to make a replacement heat map. One can obtain usage (kWh) data at a detailed level, but that doesn't show the peak demand which drives the project need - analogy of the odometer and speedometer. USE created a map of substation peak demand, using spatial interpolation* *between the substations, but the accuracy wasn't sufficient for the granularity of detail that is desired. The substations aren't necessarily located right where the heaviest load is. USE didn't feel the result gave a sufficiently clear representation of the area load and so did not include it.*

Q20. What are the industry standards for forecasting? Compare to PSE forecast.

- A *See Sections 5 & 6 for standard industry practice.*

Q21. There appear to be no industry wide standards for the development of utility load forecasts, but there do appear to be standards for Integrated Resource Plans. RCW 19.280 State IRP, WAC 480-100-238. Clarify term "conservation" and why it is used for customer load reductions.

- A *Yes, the industry standards have concentrated on the IRP process, but within that are requirements relating to some of the forecast elements. There are typical industry practices.*
- A *100% Conservation is defined as the cost-effective, achievable, technical DSR measures. See the Section 5 introduction and Section 6.3.*

Q22. Is PSE using population growth as a parameter? If so, at what granularity are the growth projections made? In other words, are growth projections used for individual cities, or is the Eastside treated as a whole, with one forecast governing the whole area?

- A *Population is used as a parameter.*
- A *Forecasts were developed at the system level, at the county level, and for the Eastside area. The Eastside forecast was developed using census tract data.*

Q23. We would like to understand economic projections as well. Is economic growth projected for each city, or only for the whole Eastside? What numbers were used?

- A *Economic projections were made at the system level, at the county level, and for the Eastside area. Graphs were provided for some of the major elements (Section 6.2 and 6.5).*

Q24. Does the load forecast anticipate changes in regional transmission flow, such as south-north transmissions to Canada?

- A *The load forecast is based on load. Transmission flows are irrelevant to the forecast. The link between forecast and transmission flows comes from modeling the substation load data, which was correlated to the load forecast, into a powerflow case. The powerflow case is where regional flow scenarios can be modeled. (See Appendix B, Optional Technical Analysis for study results of this scenario. It showed that even with no power flowing to Canada on the Northern Intertie (which is an unrealistic hypothetical scenario but modeled to answer the local vs. regional question), there is still a project need.*

Q25. What other factors governing the regional grid is the load forecast taking into account?

- A *See preceding answer.*

Q26. Is it possible that the industry-standard methodology which PSE uses to forecast load growth has not evolved to reflect the realities of the current electricity marketplace? Are there any newer methodologies, or modifications to existing methodologies, which better reflect the realities of the modern electricity marketplace?

- A *This question is outside the scope of this study; however, the IRP process continues to get attention, and frequently includes input from stakeholders, which is where Demand-Side Resources are evaluated and feed into the forecast process.*

Q27. Is PSE's load projection reasonable? Are they the needs of Eastside or the needs or BPA, etc.? Are the loads PSE is projecting based on a farfetched combination of circumstances that are unlikely to actually happen?

- A *The load projections and need determination are based on a normal weather forecast with 100% conservation. The 2014 forecast methodology and inputs are reasonable. See Section 6.6. See Section 7 for discussion on standards.*

Q28. Is PSE's forecast based on good data, independently verified?

- A *Yes, PSE has followed industry practice in forecasting their demand load. See section 6.6.*

Q29. Why is PSE projecting load growth when their public documents (e.g. 10k) show they are selling less electricity?

- A *The referenced 10k report is based on energy, which like an odometer reading shows usage, not peak demand. As noted previously, average use behavior is not necessarily winter peak behavior; the trends don't have to match. In addition, the data in the report is not adjusted for weather. See figures in Section 6.5 for current forecasts.*

Q30. Provide justification/rational/definition for the System Capacity line on PSE's "Customer Demand Forecast".

- A *System Capacity: Occurs when the load (Eastside Area) just hits the rating limit of the critical contingency condition(s). The System Capacity line can shift depending on where load grows (if not homogenous). The contingency analysis is dictated by national standards. Using the same methodology as the 2013 report, a winter Eastside system capacity range of 688-708 MW has been identified based on the 2014 load forecast powerflow results (see Figure 8.1).*

Q31. How does PSE justify an Eastside growth rate of 1.7% to 2%?

- A *PSE used reasonable methods to develop the 2014 forecast by following industry practice (see Section 6.6). The forecast is built from the data inputs via regression analysis. The 2014 demand forecast shows a 2.4% growth rate for the Eastside area from 2014-2024 and a 2.5% growth for Eastside between 2014 and 2031. In comparison, the forecast shows a 1% growth rate for King County between 2014 and 2031. The Eastside area demand is projected to grow significantly faster than King County as a whole, which is in line with the land use* Vision 2040 Regional Growth Strategy *report. Whether the forecasted demand growth will be sustained through 2031 is unknown. Note: if the growth rate is calculated from the 2010 actuals through 2017, the growth rate is 2.2% for Eastside and 0.4% for King County. See Figure 6.18 and Figure 6.19.*
- A *Note: SCL's "demand" forecast growth of 0.5% noted in their latest IRP update is actually an energy forecast. SCL's actual demand forecast from December 2013 to December 2034 has an estimated compound annual growth rate (CAGR) of 1.2%, based on an estimated 1180 MW in December 2013 and using their IRP demand graph as reference. PSE has a CAGR of 2.4% from winter 2013/14 to winter 2031/32 based on an estimated 615 MW in winter 2013/14.*

Q32. What is the magnitude and timing of the need for EE? An updated peak load forecast is needed to resolve serious questions about the load forecast used by PSE to justify the project as now proposed.

- A *In early February, 2015, PSE completed their 2014 forecast which included historical data through 2014, and thus included the summer 2014 peak and the winter 2013/2014 peak. See the top of Section 6 for discussion on the new forecast methodology.*

Q33. Please explain PSE's "Eastside Customer Demand Forecast" chart. A detailed quantitative analysis for the years is needed on this chart. There have been several credible articles stating electrical usage is not growing but is flat, even declining in the United States. This trend is apparent over several years and is due to conservation and technological changes in production, usage and storage. How does Energize Eastside explain this disparity? Also, solar energy has been increasing on the Eastside.

- A *Please see discussions in Section 6.2 on the economic and demographic data sources, the Vision 2040 Regional Growth Strategy, and Section 6.4 on Major Loads. Please see Section 4 on Energy vs. Demand and Q4 on potential impact of solar on a winter peak.*

Q34. PSE's energy use (MWh) trend and # of customer trend is similar to SCL, yet PSE's load forecast (MW) shows a significantly higher growth % than SCL. Explain. National electricity use is declining as is regional (Pacific Northwest Utilities Conference Committee (PNUCC)). Why is PSE's forecast increasing? Explain why electricity use in Bellevue is so different from other cities.

- A *Please see Q31 and Q33 answers.*

Q35. Please explain PSE's "Eastside Customer Demand Forecast" chart. Show peak demand for Bellevue. Show retail sales to customers, off-system sales and electricity delivered to transmission only customers. Concern over accuracy of trend.

- A *See preceding answer. See Figures in Section 6.5.*
- A *There are no off-system sales within the Eastside area; this would not affect the Eastside forecast. There are transmission only customers in King County outside of the Eastside area, but since the off-system sales customers are not PSE's customers, they wouldn't affect that forecast either.*

Q36. Is it true that PSE's "Eastside Customer Demand Forecast" graph is based on a hypothetical "grid-flow modeling scenario" … rare winter peak …

- A *No. It is based on normal winter weather. The hypothetical outage scenarios are part of the industry mandated contingency analysis. Please see the weather normalizing discussion in Section 5 and see Section 7 on Standards, regarding the required contingency analysis.*

7. Electric Utility Reliability Standards

7.1. EPAct 2005

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The outage affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, New Jersey and the Canadian province of Ontario. The blackout began a few minutes after 4:00 pm Eastern Daylight Time (16:00 EDT), and power was not restored for 4 days in some parts of the United States. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored. Estimates of total costs in the United States range between $4 billion and $10 billion (U.S. dollars). In Canada, gross domestic product was down 0.7% that August, there was a net loss of 18.9 million work hours, and manufacturing shipments in Ontario were down $2.3 billion (Canadian dollars).[25]

Partially in response to this blackout, Section 1211 was added to the Energy Policy Act of 2005 (EPAct 2005). EPAct 2005 became law on August 8, 2005. Section 1211 of the EPAct 2005 requires that the Federal Energy Regulatory Commission (FERC) certify an Electric Reliability Organization (ERO) to establish and enforce reliability standards for the bulk-power system[26], subject to FERC review. On July 20, 2006, FERC certified the North American Electric Reliability Corporation (NERC) as the ERO for the continental U.S. under the Federal Power Act Section 215.

From the NERC website (www.nerc.com):

> "NERC is a not-for-profit international regulatory authority whose mission is to assure the reliability of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization for North America, subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people."

Because of changes brought about by EPAct 2005, the NERC standards that were previously voluntary are now mandatory and all users of the Bulk Power System (BPS) must comply with these standards. There are currently 1426 requirements in 143 reliability standards either subject to enforcement or subject to future enforcement.

[25] http://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/BlackoutFinal-Web.pdf, pg. 1

[26] In this report, the terms Bulk Power System (BPS) and Bulk Electric System (BES) will be used interchangeably. While the definitions are slightly different, for the purposes of this report and for determining the need for the Energize Eastside Project, these two terms can be treated as the same.

7.2. Reliability Standards Applicable to Energize Eastside[27]

NERC Reliability Standard TPL-001-4[28] (Transmission System Planning Performance Requirements) is the Reliability Standard most relevant to the need for the Energize Eastside Project. TPL-001-4 Requirement 1 and Requirement 7 are currently subject to enforcement. Requirements 2-6 and 8 are not currently subject to enforcement but will be subject to enforcement on January 1, 2016. The enforcement date for Requirements 2-6 and 8 is before the planned in-service date of the Energize Eastside Project. Therefore, the Energize Eastside Project will be subject to the newer requirements before the project goes into service. In addition, the newer requirements are in many cases more stringent than the existing requirements. For the above reasons, this report will limit its discussion to the newer TPL-00104 Requirements and will not discuss the currently enforceable requirements of TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a[29].

Another Reliability Standard that can have an impact on the need for the Energize Eastside Project is FAC-008-3[30] (Facility Ratings). TPL-001-4 and FAC-008-3 are discussed in more detail below.

TPL-001-4 requires that each Planning Coordinator and Transmission Planner[31] perform an annual transmission assessment of its portion of the Bulk Electric System[32] (BES). This assessment must model, among other things, system peak load, known commitments for Firm Transmission Service and Interchange, and the planning events (contingencies) listed in Table 1 of TPL-001-4[33].

TPL-001-4 requires the development of a Corrective Action Plan (CAP)[34] whenever the transmission assessment determines that the system cannot meet the performance requirements listed in Table 1. In other words, once a performance requirement specified in TPL-001-4 cannot be met (e.g., an overload is found), a need has been determined.

FAC-008-3 is applicable to both Transmission Owners and Generation Owners[35]. FAC-008-3 requires each Transmission Owner and Generation Owner to have a facility[36]

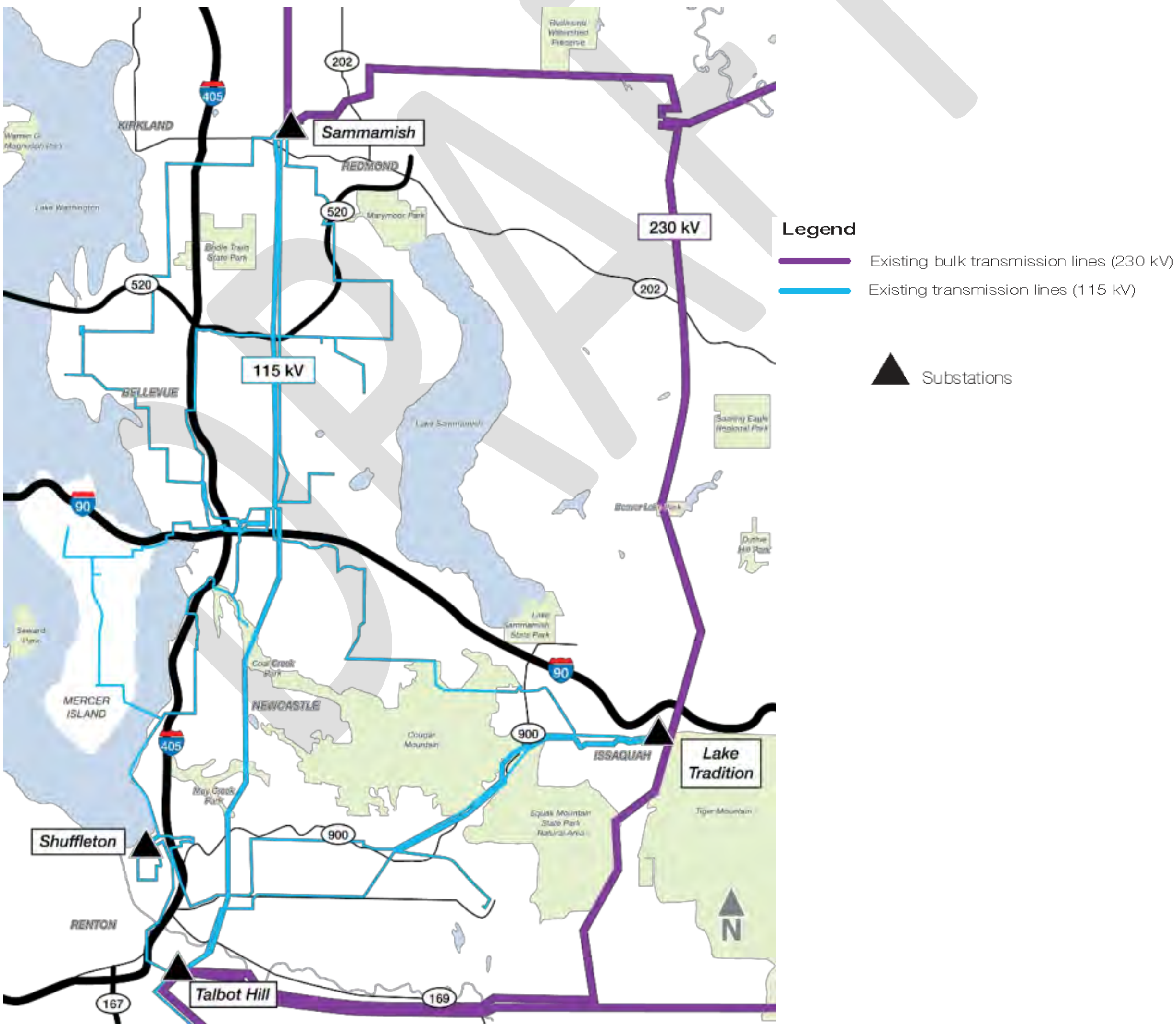
[27] capitalized terms in this section refer to terms that are defined in the NERC Glossary
[28] http://www.nerc.com/files/TPL-001-4.pdf
[29] Reliability Standards TPL-001-0.1, TPL-002-0b, TPL-003-0b, and TPL-004-0a are being replaced by TPL-001-4.
[30] http://www.nerc.com/files/FAC-008-3.pdf
[31] Puget Sound Energy is registered with NERC as both a Planning Coordinator and a Transmission Planner.
[32] The Bulk Electric System (BES) definition is fairly long and involved (see http://www.nerc.com/pa/RAPA/BES%20DL/BES%20Definition%20Approved%20by%20FERC%203-20-14.pdf), but for the purposes of this report, the BES can be considered to be all networked transmission elements with an operating voltage of 100 kV or higher. Radial facilities are generally not considered to be part of the BES even if they are operated at voltages of 100 kV or higher.
[33] Table 1 is provided in Appendix RPM-1 of this report.
[34] Corrective Action Plans as used in the TPL-001-4 Reliability Standard are not the same as the Corrective Action Plans described by PSE in the Eastside Needs Assessment Report (October 2013). In TPL-001-4, a Corrective Action Plan may include operational measures (such as switching existing facilities in or out) and/or the addition of new facilities. In the Eastside Needs Assessment Report, Corrective Action Plans only refer to operational measures.
[35] Puget Sound Energy is registered with NERC as both a Transmission Owner and a Generation Owner.
[36] A facility is a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

rating[37] methodology[38] that is consistent with manufacturer ratings, standards developed through an open process, or a practice that has been verified by testing, performance history, or engineering analysis. The intent of this Reliability Standard is to ensure that facility ratings are based upon sound engineering practices and are consistent across a utility's service area.

7.3. Critical Contingencies for the Energize Eastside Project

Figure 7.1 below is a sketch of the Eastside area transmission network[39]. The area between Sammamish and Talbot Hill is the area of where a number of overloads have been seen in planning studies.

Figure 7.1: Eastside Area Transmission Sketch



[37] A facility rating is the maximum or minimum voltage, current, frequency, or power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
[38] A facility rating methodology is a procedure that is used to establish the facility ratings for all of a utilities facilities.
[39] From the Energize Eastside website: energizeeastside.com

The specific contingencies that cause facility rating violations on specific elements of the power system are CEII[40] and cannot be disclosed in a public document. However, the general types of contingencies that cause overloads on various facilities can be disclosed. Below is a list of the general types of contingencies that are causing overloads on the PSE eastside transmission system.

- Overlapping outages of two transformers (N-1-1) (P6),
- Overlapping outages of two transmission lines (N-1-1) (P6),
- Overlapping outages of one transmission line and one transformer (N-1-1) (P6), and
- Simultaneous outage of two transmission lines (N-2) (P7).

As discussed above, the NERC TPL-001-4 Reliability Standard requires that a Corrective Action Plan (CAP) be developed whenever the system does not meet the performance requirements specified in the standard. A CAP can include: new facilities such as transmission lines; adjustments to operating procedures (such as opening a switch at the end of a transmission line); or a combination of both new facilities and operating procedures.

7.4. Normal vs. Emergency Ratings

A "*normal rating*" is the limit at which a transmission facility can operate indefinitely (i.e., 24/7/365 for the life of the project, which in some cases could be over 50 years). An "*emergency rating*" is only available for use for a short period of time and using an emergency rating usually involves a loss of usable life for the facility. This loss of usable life is caused by the increased temperatures that the facility is subject to when loaded to its emergency limit. The higher temperatures can cause insulation in transformer banks to degrade or overhead conductors to weaken and/or sag. In some cases an emergency rating may have a lifetime limit on the number of hours it can be used (e.g., 100 hours). Once that lifetime limit is reached, a facility will not be able to exceed its normal rating or it may need to be replaced. An emergency rating cannot be used for normal overloads that might occur due to load growth or a sudden increase in load due to extreme weather. Given a typical lifetime limit of 100 hours, an emergency rating would only be good for a little over 4 days under normal (non-contingency) conditions. Therefore, an emergency rating can only be used under contingency (outage/equipment failure) conditions.

In addition to the differences between normal and emergency ratings, there are typically different ratings for summer and winter conditions. Because equipment ratings are based in part on thermal limits of the equipment (as noted above) and the ambient temperatures expected during winter are less than the ambient temperatures seen during summer, normal and emergency winter ratings are almost always higher than the respective normal and emergency ratings for summer.

PSE utilizes different normal and emergency facility ratings for summer and winter conditions, consistent with industry practice.

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[40] CEII - Critical Energy Infrastructure Information CEII is protected information whose release could compromise the reliability of the BES. Each individual utility decides what information they deem to be CEII. The specific contingencies that cause overloads on the elements documented in the public Energize Eastside study reports are considered to be CEII by PSE. Other utilities also consider information such as this to be CEII.

7.5. *Transmission Reliability vs. Distribution Reliability*

Transmission outages currently cause about 5% of the customer outage duration on PSE's system in the Energize Eastside area. The remaining 95% of the customer outage duration are caused by distribution outages (see Table 7.1) below[41]. As can be seen from Table 7.1, the City of Bellevue's transmission related customer outage performance is much better than the rest of the Energize Eastside area (less than 1% of the customer outage minutes were due to transmission outages).

Table 7.1: Transmission and Distribution Outage Data (from PSE)

2014 Total Outages					
Energize Eastside Area (includes City of Bellevue)					
	# of Outages	# of Customers Impacted	Total Customer Minutes	Customers Impacted Per Outage	Outage Minutes Per Customer Per Outage
Transmission outages	6	35,614	2,521,995	5936	11
All other outages	1182	120,074	47,481,181	102	0.33
Total outages for EE	1188	155,688	50,003,176		
Transmission outage percentage of total	0.5%	22.9%	5.0%		
City of Bellevue					
	# of Outages	# of Customers Impacted	Total Customer Minutes	Customers Impacted Per Outage	Outage Minutes Per Customer Per Outage
Transmission outages	3	18,939	224,327	6313	4
All other outages	745	61,963	29,964,379	83	0.65
Total outages for COB	748	80,902	30,188,706		
Transmission outage percentage of total	0.4%	23.4%	0.7%		

Table 7.1 also shows some additional pertinent information regarding the relative severity of transmission outages versus distribution outages. The number of customers affected by a transmission outage in this example is over 50 times greater than the number affected by a distribution outage. In addition, the outage duration per customer per outage is much longer for transmission outages than for distribution outages. This difference is one reason why transmission reliability is required to be so high. While the risk of an outage is low, the consequences of that outage can be quite large.

[41] This data from PSE indicates that the Energize Eastside area has fewer customer outage minutes due to transmission outages (as a fraction of the total outage minutes) than other utilities in the U.S.

The reason mentioned above is the same reason why the nuclear industry designs back-up systems for the reactor core cooling system with multiple layers of redundancy. Nuclear plants are typically designed with two sources of off-site (grid) power. If one source fails, the other can be used to supply the plant cooling load. In addition, just in case both off-site power sources are out, the plant has backup diesel generators that are capable of supplying the cooling system load. Just in case the primary diesel generators fail, there is a redundant set of diesel generators to step in if necessary. Then for additional protection, battery backup is provided in case the offsite grid power and both sets of diesel generators fail. The reason for this extreme level of redundancy is because even though the risk of a failure of four levels of cooling system power supply is incredibly small, the consequence of a failure is extremely large.

In addition to the Northeast blackout discussed above, two other major blackouts have occurred in the Western Interconnection in the last two decades. These two blackouts are discussed below.

On July 2, 1996 at 1424 MDT a disturbance occurred that ultimately resulted in the Western Systems Coordinating Council (WSCC) system (the Western Interconnection) separating into five unconnected load and generation subsystems. This disturbance resulted in the loss of 11,850 MW of load and affected 2 million people in the West. Customers were affected in Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming in the United States; Alberta and British Columbia in Canada; and Baja California Norte in Mexico. Outages lasted from a few minutes to several hours. Electric service was restored to most customers within 30 minutes, except on the Idaho Power Company (IPC) system, a portion of the Public Service Company of Colorado (PSC), and the Platte River Power Authority (PRPA) systems in Colorado, where some customers were out of service for up to six hours. On portions of the Sierra Pacific Power Company (SPP) system in northern Nevada, service restoration required up to three hours.

On August 10, 1996 a major disturbance occurred in the Western Interconnection (Western Systems Coordinating Council, WSCC) at 1548 PDT resulting in the Interconnection separating into four unconnected load and generation subsystems. Conditions prior to the disturbance were marked by high summer temperatures (near or above 100 degrees Fahrenheit) in most of the Region, by heavy exports (well within known limits) from the Pacific Northwest into California and from Canada into the Pacific Northwest, and by the loss of several 500 kV lines in Oregon. The California−Oregon Intertie (COI) (Pacific Northwest to California) north to south electricity flow was within parameters established by recent studies initiated as a result of the July 2-3, 1996 disturbance (see above). The flow on the AC system between the Pacific Northwest and California was about 4,350 MW and the flow on the Pacific DC Intertie (PDCI) (a DC system) was 2,848 MW. This disturbance resulted in the loss of over 28,000 MW of load and affected 7.5 million people in the West. Customers were affected in Arizona, California, Colorado, Idaho, Montana, Nebraska, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington, and Wyoming in the United States; Alberta and British Columbia in Canada; and Baja California Norte in Mexico. Outages lasted from a few minutes to as long as nine hours.

Both of the above outages occurred prior to the implementation of mandatory Reliability Standards. The purpose of the mandatory Reliability Standards is to maintain the reliability of the BES and to help prevent major outages like these from happening again. As previously noted, even though the probability of outages like these is very small, the consequences of this type of outage are very large. Therefore, the Reliability Standards require the examination of contingencies that to a lay person seem to be highly unlikely.

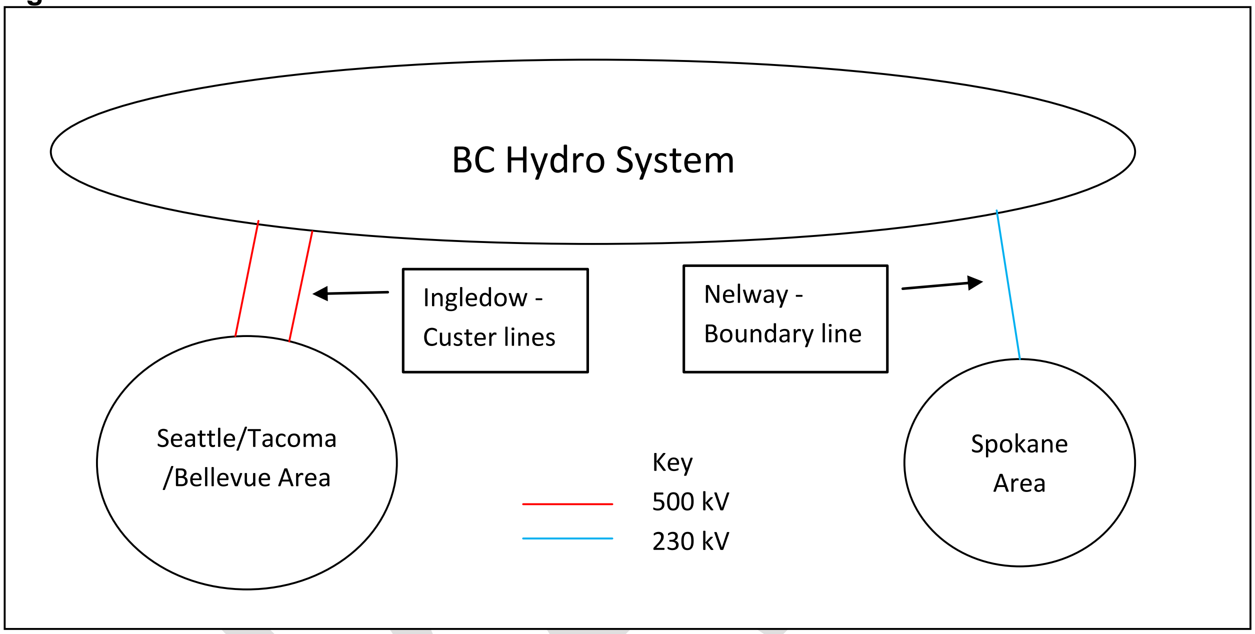
In general, the probability of a single contingency (N-1) is at least once every three years. The probability of multiple contingencies such as N-1-1 or N-2 is somewhere between once every three years and once every 30 years. (See Section 8 and Appendix B for analysis of this subject.)

7.6. Path 3 Issues

Path 3 is the transmission interconnection between Washington and British Columbia. Path 3 consists of three transmission circuits (see Figure P3-1):

1. Ingledow - Custer 500 kV #1,
2. Ingledow - Custer 500 kV #2, and
3. Nelway - Boundary 230 kV #1.

Figure P3-1: Path 3 Transmission Elements



It should be noted when discussing Path 3 that sometimes the Nelway - Boundary 230 kV line is referred to as the Path 3 eastside intertie. This term should not be confused with eastside as it is used in the context of the Energize Eastside project. The Path 3 eastside intertie is located near Spokane, WA and is over 250 miles away from the area under consideration for the Energize Eastside project.

Path 3 has a non-simultaneous rating of 3150 MW north to south and 3000 MW south to north. Known commitments for Firm Transmission Service and Interchange on Path 3 are 2300 MW north to south and 1500 MW south to north.

The planning cases PSE used to study the need for the Energize Eastside project had Path 3 flow at 3150 MW north to south in the summer base cases and 1500 MW south to north in the winter base cases.

<u>Stakeholder Questions related to Standards and Reliability</u>

Q37. 2013 Needs Assessment report, page 43. The "3d" sensitivity, modeling 2021-2022 extreme Weather with 100% conservation. Explain why this scenario, which had 845 MW predicted Eastside load, showed no overload for N-0 yet 845 MW is above PSE's "current system capacity" line in their 2013 report. Clarify what PSE's capacity line represents.

- A *PSE's capacity line is the load level at which overloads will just begin to occur under contingency situations. Because the scenario being referred to in this question is "N-0" (or no contingency), there are no overloads. The reason for there being no overloads is that up to two additional pieces of equipment are in service to carry power to the load.*

Q38. Too much transmission reliability?

- A *The requirement for transmission reliability is discussed in the section on NERC Reliability Standards. Because the Reliability Standards are mandatory, meeting these standards provides just adequate reliability.*

Q39. How are EE "need" and "reliability" related? How many outages in the next 10 years (2017-2027) are anticipated to be avoided by implementation of EE, due to transformer limitations or otherwise stressing system capacity due to local Eastside growth (excluding unpredictable weather events)?

- A *EE need is related to reliability by the requirement that when overloads occur during a planning assessment under the contingencies that are required to be run (see the discussion of TPL-001-4 in the Independent Technical Analysis), there is by definition a need. This need is not necessarily EE, but something must be done to mitigate the overloads seen in the planning assessment. The question of how many outages may be avoided by implementation of EE is not relevant to the question of need. The Reliability Standards require that a defined set of contingencies be run on the system model. If overloads or other violations are found, then a Corrective Action Plan must be produced. The fact that a Corrective Action Plan is needed demonstrates that there is a need.*

Q40. What is the probability of an N-1-1?

- A *The probability of an N-1-1 is not a factor that is considered in determining if there is a need for a project. However, typically the probability of an N-1-1 is between 0.33 and 0.033 outages per year or once in 3 years to once in 30 years.*

Q41. One of the rationales advanced by PSE for the new transmission lines was to increase the 'reliability' of PSE's transmission system and/or the reliability of PSE's "system" that supplies electricity to Bellevue and other east side communities.

- A *Energize Eastside is a project designed to mitigate overloads found in planning studies that used projected future load growth. Therefore, a better way to look at EE is that it will maintain the current reliability that exists today and prevent it from getting worse.*

Q42. Task 8 of USE's 'scope of services' states that USE will develop a formal, written evaluation of the need for PSE's Energize Eastside (EE) project, including an assessment of the " … impacts to electrical system reliability …" Please describe (or provide in the report) a schematic/line-diagram of the "electrical system" that USE evaluated to assess the "reliability" of the "electrical system"; and describe the quantitative reliability measures/metrics that were used in performing the evaluation of the impact of PSE's EE project on the "electrical system" reliability.

- A *The electrical system modeled was the entire Western Interconnection that extends from the Pacific Ocean on the west east to Colorado and from British Columbia and Alberta in the north south to Arizona and a portion of northern Mexico. The studies concentrated on the Puget Sound area, but included all facilities in the entire Western Interconnection. USE did not assess the impacts of PSE's EE project on electric system reliability. Our work scope was limited to investigating the need for EE. Therefore, we investigated the accuracy of PSE's latest load forecast (2014) and ran studies using the system model without EE in it to see if problems occurred that would require a project like EE to solve. In performing this* *investigation, we addressed the impacts of PSE's assumptions regarding load growth and regional transfers on the system without EE to determine if there was a need for a project like EE. The Optional Technical Assessment (OTA) (Appendix B) looked at the sensitivity of modified assumptions regarding load growth, westside generation levels, and regional transfers on the need for a project like EE. Determining the preferred project to mitigate the problems found in the studies of the system without EE is one of the purposes of the EIS process, but this determination is beyond the scope of the ITA and the OTA.*

Q43. Why is an N-1-1 outage scenario (rare) used to determine need?

A *Because N-1-1 contingencies must be simulated in the planning assessments required by the mandatory NERC TPL-001-4 Reliability Standard.*

Q44. Questions about reliability, outages, contingency analysis.

A *As noted in responses to other questions, probability of an outage is not considered in determining need using the NERC TPL-001-4 Reliability Standard. When performing a planning assessment all outages need to be simulated and if there are any overloads or other violations, then a Corrective Action Plan must be developed. What is included in this Corrective Action Plan will vary depending on the type of outage and what sort of mitigation is allowed for that outage in the TPL-001-4 Reliability Standard. However, need is established as soon as a Corrective Action Plan needs to be developed.*

Q45. We ask the consultant to forecast how many outages in the next five years (2016 – 2020) would be avoided by implementation of Energize Eastside.

A *Please see the responses above.*

Q46. Is it true that PSE's "Eastside Customer Demand Forecast" graph is based on a hypothetical "grid-flow modelling scenario" in which a rare winter peak electricity demand event occurs on the Eastside at exactly the same time that there are two major and simultaneous equipment outages on nearby transmission lines?

A *The demand forecast is independent of any equipment outages. The current system capacity line is determined by studies of system performance under multiple contingency scenarios with models that incorporated forecasted peak load. These studies are required to be run in this manner by the Requirements in the NERC TPL-001-4 Reliability Standard.*

Q47. Are PSE's conclusions reasonable?

A *See the conclusions section of the Independent Technical Analysis and the Executive Summary of the OTA (Appendix B).*

8. Assessment of PSE's Identified Drivers for the Eastside Project (PSE's Results)

This section addresses PSE's findings based on their new 2014 normal winter forecast, with 100% conservation.

Table 8.1 shows the new forecasted loads for Eastside that were utilized in the powerflow cases; three normal winter and three normal summer cases were studied by PSE. The winter forecasts between 2017/18 and 2023/24 show Eastside growing, while King County otherwise declines. The ITA confirmed that the load values in Table 1 matched the new forecast and were modeled[42] in the cases.

Table 8.1: PSE's King County and Eastside Forecasted Loads in Studied Years

Forecast Development Year	King County (excluding Eastside)	Eastside
Normal Winter		
2017/18	1881	688
2019/20	1867	708
2023/24	1817	764
Normal Summer		
2018	1379	538
2020	1385	561
2024	1399	618

The ITA also confirmed the Northern Intertie (Path 3) transfers matched PSE's modeling plan (Table 8.2), and that PSE's winter generation dispatch scenario of "no PSE and SCL generation west of the Cascades" was modeled in the winter cases, as per Table 4.4 in the October 2013 Eastside Needs Assessment Report.

Table 8.2: Northern Intertie Flows

Northern Intertie	Flow Direction
Normal Winter	
3150 MW	South to North
Normal Summer	
1500 MW	North to South

Source: PSE. Verified by ITA.

Tables 8.3 and 8.4 list the overloaded elements that PSE identified based on the new 2014 forecast. The ITA confirmed these overloaded elements drive the need for an Eastside project by simulating the contingencies (outages) in the powerflow cases provided by PSE.

[42] The aggregate Eastside load matched the numbers in Table 8.1.

Table 8.3: PSE Projected Normal Winter, 100% Conservation – Overloaded Elements

South to North Flow	Type of Contingency and Season								
	2017/18 Winter (23°F) 100% Conservation			2019/20 Winter (23°F) 100% Conservation			2023/24 Winter (23°F) 100% Conservation		
Transmission Line or Transformer	N-1	N-1-1	N-2	N-1	N-1-1	N-2	N-1	N-1-1	N-2
Talbot Hill - Lakeside #1 115 kV line		OL			OL			OL	
Talbot Hill - Lakeside #2 115 kV line		OL			OL			OL	
Talbot Hill 230-115 kV transformer #1		OL			OL			OL	
Talbot Hill 230-115 kV transformer #2		OL			OL			OL	
Talbot Hill-Boeing Renton-Shuffleton 115 kV line		OL			OL			OL	

OL= Overload of Emergency Rating. Source: PSE Results. ITA verified overloaded elements driving project need.

Table 8.4: PSE Projected Normal Summer, 100% Conservation - Overloaded Elements

North to South Flow	Type of Contingency and Season								
	2018 Summer (86°F) 100% Conservation			2020 Summer (86° F) 100% Conservation			2024 Summer (86° F) 100% Conservation		
Transmission Line or Transformer	N-1	N-1-1	N-2	N-1	N-1-1	N-2	N-1	N-1-1	N-2
Sammamish 230/115 kV Xfmr[43] #1		OL			OL			OL	
Sammamish 230/115 kV Xfmr #2		OL			OL			OL	
Novelty Hill 230/115 kV Xfmr #2		OL			OL			OL	
BPA Monroe – Novelty Hill 230 kV	OL		OL	OL		OL	OL		OL
Beverly Park - Cottage Brook 115 kV line		OL			OL			OL	
Sammamish – BPA Maple Valley 230 kV line				OL			OL		

OL= Overload of Emergency Rating. Source: PSE Results. ITA verified overloaded elements driving project need.

Figure 8.1 utilizes the 2014 load forecast and was supplied by PSE. Two system capacity lines for the Eastside area reflect where the powerflow results indicated violations of the mandatory performance requirements that put customer's reliability at risk. The powerflow results show a range of need for the Eastside area between <u>688 MW</u> in winter 2017/18 and <u>708 MW</u> in winter 2019/20. These levels were chosen by PSE because at 688 MW system elements are overloaded, and by 708 MW they are not only overloaded but 63,200 customers are at risk of losing power, which is a more severe situation. Further detail is noted below.

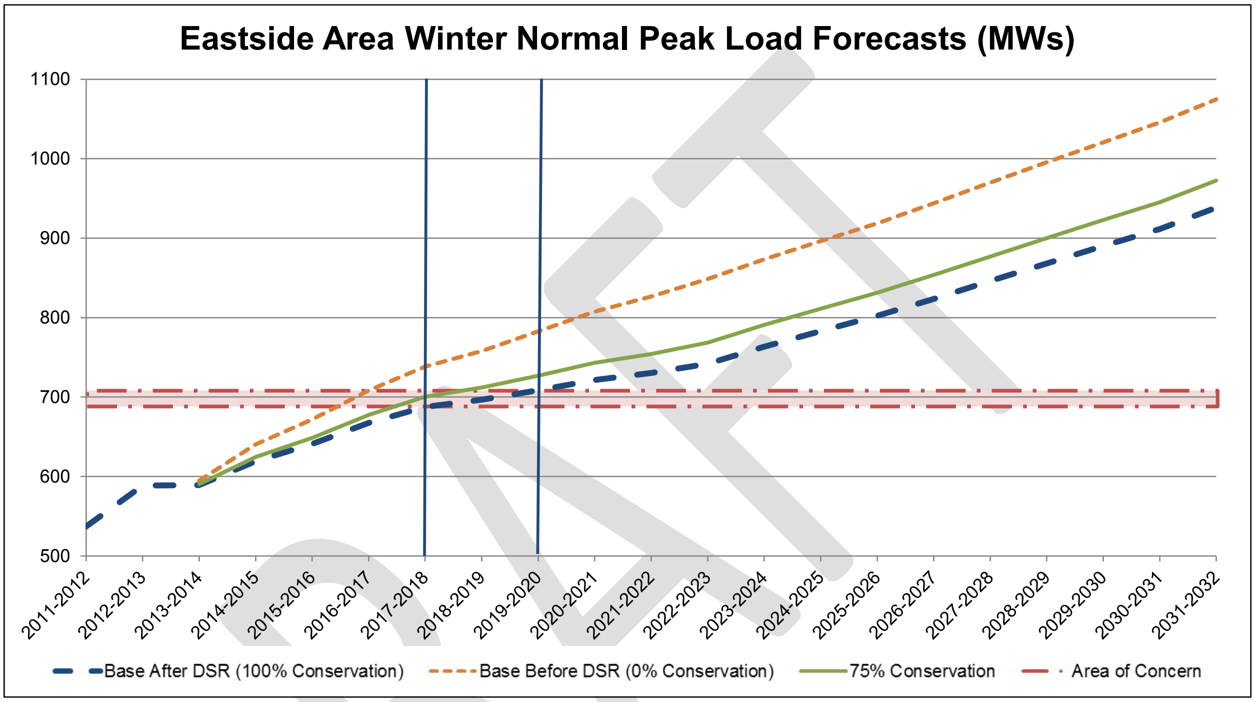
- In winter 2017/18 system elements would be overloaded requiring Corrective Action Plans (CAPs) for the Category C overloads. Zero customers are at risk of losing power by the CAPs[44].

[43] Xfmr = Transformer

[44] CAPs are implemented to protect system equipment from overload and resulting loss of equipment life or damage. CAPs can result in the forced reduction of load (intentionally causing customer outages) to bring

- By winter 2019/20, the CAPs radialize[45] existing loop service such that approximately 63,200 customers are at risk of losing power.
- By winter 2023/24, 16,800 customers are at risk from load shedding (intentional outage to customers to protect the system equipment), with another 52,000 customers at risk of losing power.

Figure 8.1: PSE's Graph of System Capacity, 2014 Forecast, 100% Conservation



In sum, PSE's need date for the Energize Eastside project remains as winter 2017/18. The following issues were identified by PSE and forecast levels and overloads were confirmed by the ITA:

- Transmission system elements will be over their capacity, and will require the use of CAPS to mitigate transmission overloads.
- Although the CAPS do not drop customer load in winter 2017/18, by winter 2019/20 approximately 63,200 customers are at risk of losing power. Intentionally dropping firm load for an N-1-1 or N-2 contingency to meet its federal planning requirements is not a practice that PSE endorses. This view is not unique amongst utilities. The CAISO Planning Standards states that "Increased reliance on load shedding … would run counter to historical and current practices, resulting in general deterioration of service levels."
- The forecast uses a 1 in 2 year weather forecast. Colder weather will result in higher load levels in winter 2017/18.
- 100% conservation may not be achieved which would result in a higher load level in winter 2017/18. Even if 100% conservation is achieved, it may not be in the appropriate locations and correct magnitudes.

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the equipment loading below the emergency rating. This would only be used as a stopgap measure until system reinforcements (new equipment, etc.) are completed. CAPs as used here is a subset of CAPs defined in the NERC Reliability Standards. See Section 7 on Standards.

[45] Radialize: Convert from loop service to radial service (only one source).

- By the summer of 2018, studies show that customers will be at risk of outages and load shedding using CAPS to mitigate transmission overloads.

9. Regional Issues related to EE

Note: All ColumbiaGrid regional documentation of Energize Eastside refers to the project by its terminals: Sammamish-Lakeside-Talbot. The following text refers to Energize Eastside as the Project.

Background

ColumbiaGrid is a regional transmission planning organization with a footprint encompassing Oregon, Washington, parts of Idaho and Montana. A planning team was formed with all Puget Sound area transmission owners and operators as planning participants within a year after the creation of ColumbiaGrid in 2007 to address the beginning curtailments of firm service in the Puget Sound area. Since 1997 and prior to the formation of this team, BPA had been planning to address these needs with a major 500kV line project from Monroe to Echo Lake, but construction had not started. The study team was able to identify a collection of projects to achieve the planning objectives with a cumulative scope less than the 500kV project.

The ColumbiaGrid Puget Sound Area transmission planning activity created 150 document postings on the team website that provide a detailed history of the work that led up to the regional plan. Of the 150 postings, three postings provide the information sufficient to describe the Project's role in regional objectives. The three postings are final reports and are all publicly available. These documents are:

- Transmission Expansion Plan for the Puget Sound Area (October 20,2010)
- Updated Recommended Transmission Expansion Plan for the Puget Sound Area to Support Winter South-to-North Transfers (October 28, 2011)
- Updated Transmission Expansion Plan for the Puget Sound Area to Support Summer North-to-South Transfers (February 21, 2013)

Project Specific Information

The following Project specific regional information was obtained from the above documentation.

1. Either the Project or reconductoring BPA's and SCL's Maple Valley-SnoKing 230kV lines is needed, but not both.
2. The Project or rebuilding SCL's Bothell-SnoKing 230kV lines is needed, but not both. The Bothell-SnoKing lines still need to be reconductored with the Project, but rebuilding is avoided.
3. If the Project voltage level is 115kV, the Project does not achieve the regional objectives. With that scenario, the regional objectives will be achieved by reconductoring the Maple Valley-SnoKing 230kV lines and the Bothell-SnoKing 230kV lines will need to be rebuilt.
4. The Project at 230kV is identified as the preferred alternative because of its dual purpose for regional objectives and local load service. If the Maple Valley-SnoKing 230kV lines had been reconductored prior to development of the Project, there would have been unnecessary redundancy developed in the transmission infrastructure, assuming that the Project voltage level needed to be 230kV.

ColumbiaGrid determined that the Energize Eastside project at 230 kV is the preferred alternative of all the options studied because of its dual purpose for regional objectives and local load service.

Stakeholder Questions related to Regional vs. Local Need

Q49. What is the connection between the need for EE and Columbia Grid (CG) technical objectives?

- A *The CG technical objective is to identify effects of multiple systems that prevent fulfillment of firm transmission commitments. Mitigating transmission effects that do not involve multiple systems is not within the CG mandate. After the effects are identified, the multiple system owners are convened as a team facilitated by CG to identify mitigating alternatives and select the preferred alternative. The proposed 230kV scope of EE is identified by the CG facilitated team as a preferred alternative to reconductoring SCL's Maple Valley-SnoKing 230kV lines. EE at 230kV also changes the SCL scope of rebuilding the Bothell-SnoKing 230kV lines to reconductoring these lines.*

Q50. How are the technical needs of Columbia Grid prioritized and what criteria are used for evaluation and prioritization?

- A *CG performs system assessments to determine forecasted transmission constraints to serving firm transmission commitments. A constraint that affects more than one member is the criteria for creating a study team, facilitated by CG, composed of the affected members. The study team mandate is to determine the mitigating alternatives and select the preferred alternative. Each study team determines their own evaluation and prioritization criteria. In the Puget Sound Area Study Team (PSAST), the criteria is a qualitative combination of cost and a planning metric (i.e. Transmission Curtailment Risk Measure or TCRM).*

Q51. Who has regulatory oversight of Columbia Grid?

- A *There is no government regulatory oversight of CG. The oversight is by CG members, who have their own government regulatory oversight at state and federal levels. CG has no construction authority. The only CG authority is determining cost allocation, but this authority is only used if members do not agree on the cost allocation for a project they agree to implement.*

Q52. Is EE an "OPEN ACCESS" project?

- A *No. An "Open Access" project provides new requested transmission service. This project provides service for existing firm obligations. (The longer answer is as follows: This answer assumes that "Open Access" refers to a transmission service request under a transmission provider's Open Access Transmission Tariff (OATT). These transmission service requests are for new transmission service that involve study requirements, facility addition determinations, and FERC pricing policies. Since EE is for load growth that falls under existing transmission service, it isn't "open access" because it is not new transmission service. .*

Q53. How are the merits of each need evaluated independently and which need takes priority?

- A *The CG PSAST team evaluated the regional, multi-system needs for bulk power transfers independent of local load service needs. The local load service need is evaluated by the single systems. If a single system project (e.g. EE at 230kV) affects multi-system power transfer needs, then it is included in the multi-system evaluation. Firm commitments, regardless of bulk power transfers or local load service, are equal priority to be addressed and issues mitigated.*

Q54. Please describe how the need for EE and Power Wheeling are connected. What are PSE's power wheeling objectives for EE, and how much of the EE need is based on the ability to participate in additional power wheeling?

- A *Wheeling is the transportation of electric power over transmission lines by an entity that does not own or directly use the power it is transmitting.*
- A *(from PSE's Energize Eastside website, based on 2012 forecast) "PSE makes no profit on wheeling power. All revenue obtained from wheeling contracts is passed directly back to our customers in the form of lower rates. PSE does have contracts to wheel power across the region; those contracts bring in revenue of roughly $28 million a year. One hundred percent of this revenue is returned to our customers in the form of a rate reduction. As we stated in our presentation, 92-97% of the power flows on the Energize Eastside line will deliver electricity to local Eastside customers. The power flow studies show that the power used for regional purposes on the Energize Eastside project is 3 to 8% - not 38% (as was incorrectly stated at the meeting). This is the natural consequence of connecting a transmission line into an interconnected system."* June, 2014 http://energizeeastside.com/Media/Default/CAG/Meeting3/2014_0609_CAGLetter_SCL.pdf

Q55. Is any of the capacity of the planned EE 230 kV line, or the existing 115 kV lines between Sammamish and Talbot Hill, allocated for transmission contracts to BC Hydro or CA? If so, what %? What are PSE's power wheeling objectives for Energize Eastside? Does existing or planned/potential wheeling affect the Project capacity?

- A *No/None. PSE makes no profit from wheeling contracts. See Q56.*
- A *Per PSE, Project capacity is not affected by existing or planned/potential wheeling.*

10. Conclusion

The independent technical analysis (ITA) determined that PSE used reasonable methods to develop the 2014 forecast by following industry practice (See section 6.6.). The ITA reviewed PSE's powerflow cases and verified PSE's modeling of the updated load forecast, the Northern Intertie transfers, and the identified winter generation dispatch.

The ITA verified the following key result:
Although the new 2014 forecast resulted in an 11 MW decrease in the Eastside area's 2017/18 winter forecast, the reduced loading still resulted in overloaded transmission elements that drive the project need to address Eastside system reliability issues.

Although the CAP required in the 2017/18 winter to avoid facility overload doesn't drop load, by winter 2019/20 approximately 63,200 customers are at risk of losing power. In addition, by summer 2018, studies show that customers will be at risk of outages and load shedding due to CAPs used to mitigate transmission overloads. One might argue to delay the Energize Eastside project six months until summer 2018 when PSE studies show that customers will be at risk of outages and load shedding. However, balancing a six month delay in a complex and multi-year EIS process, which can have its own delays, against the risk of an adverse winter or less realized conservation (which could increase 2017/18 winter loading to a point where customers are at risk of load shedding) suggests it is reasonable to maintain the schedule for the existing project in-service date.

Appendix A – Glossary

AC	Alternating Current
aMW	aMW - The average number of megawatt-hours (MWh) over a specified time period; for example, 295,650 MWh generated over the course of one year equals 810 aMW (295,650/8,760 hours). (Source: PSE's 2013 IRP Definitions)
Balancing Authority (BA)	Balancing Authority (BA) -- an entity that manages generation, transmission, and load; it maintains load-interchange-generation balance within a geographic or electrically interconnected Balancing Authority area, and it supports frequency in real time. The responsibility of the PSE Balancing Authority is to maintain frequency on its system and support frequency on the greater interconnection. To accomplish this, the PSE BA must balance load with generation on the system at all times. When load is greater than generation, a negative frequency error occurs. When generation is greater than load, a positive frequency error occurs. Small positive or negative frequency deviations are acceptable and occur commonly during the course of normal operations, but moderate to high deviations require corrective action by the BA. Large frequency deviations can severely damage electrical generating equipment and ultimately result in large-scale cascading power outages. Therefore, the primary responsibility of the BA is to do everything it can to maintain frequency so that load will be served reliably. (Source: PSE 2013 IRP)
BES	BES - Bulk Electric System - Unless modified by the inclusion and exclusion lists in the full definition that is available in the NERC Glossary of Terms (http://www.nerc.com/files/glossary_of_terms.pdf), all Transmission Elements operated at 100 kV or higher and resources connected at 100 kV or higher. The BES does not include facilities used in the local distribution of electric energy. (Source: NERC Glossary of Terms)
BPS	BPS - Bulk Power System - A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. (Source: NERC Glossary of Terms)
CAP	CAP - Corrective Action Plan - A list of actions and an associated timetable for implementation to remedy a specific problem. (Source: NERC Glossary of Terms)
COI	COI - California–Oregon Intertie - The three 500 kV AC electric transmission lines between southern Oregon and northern California.
CPI	Consumer Price Index (CPI) – A measure that examines the weighted average of prices of a basket of consumer goods and services, such as transportation, food and medical care. The CPI is calculated by taking price changes for each item in the predetermined basket of goods and averaging them; the goods are weighted according to their importance. (Source: Investopedia)
Critical Energy Infrastructure Information (CEII)	Critical Energy Infrastructure Information (CEII) Regulations –- Established by the Federal Energy Regulatory Commission (FERC). "CEII is specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that: Relates details about the production, generation, transmission, or distribution of energy; Could be useful to a person planning an attack on critical infrastructure; Is

	exempt from mandatory disclosure under the Freedom of Information Act; and Gives strategic information beyond the location of the critical infrastructure." (Source: FERC)
DC	Direct Current
Demand (Utility)	Demand (Utility) – The level at which electricity or natural gas is delivered to users at a given point in time. Electric demand is expressed in kilowatts. (Source: CEC Glossary)
Demand-Side Resources (DSR)	Demand-Side Resources (DSR) - Resources that reduce the demand. (As opposed to Supply-Side Resources)
Demographic	Demographics - Studies of a population based on factors such as age, race, sex, economic status, level of education, income level and employment, among others. Demographics are used by governments, corporations and non-government organizations to learn more about a population's characteristics for many purposes, including policy development and economic market research. (Source: Investopedia.com)
Direct Control Load Management (DCLM)	Direct Control Load Management (DCLM) - Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand. (Source: NERC Glossary)
Distribution System	Distribution System - An electric power distribution system is the final stage in the delivery of electric power; it carries electricity from the transmission system to individual consumers. (Source: Wikipedia)
Econometric Data	Econometric Data – Data sets to which econometric analyses are applied.
Econometrics	Econometrics – The application of mathematics and statistical methods to economics. Econometrics tests hypotheses and forecasts future trends by applying statistical and mathematical theories to economics. It's concerned with setting up mathematical models and testing the validity of economic relationships to measure the strengths of various influences.
EPAct 2005	EPAct 2005 – The federal Energy Policy Act of 2005
ERO	ERO - Electric Reliability Organization
Firm Transmission Service	Firm Transmission Service – 1) Transmission service available at all times during a period covered by an agreement. 2) The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption. (Source: NERC)
GO	GO - Generator Owner
Interruptible Load or Interruptible Demand	Interruptible Load or Interruptible Demand - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment. (Source: NERC Glossary)
IRP	Integrated Resource Plan - A comprehensive and long-range road map for meeting the utility's objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. A process used by utility companies to determine the mix of Supply-Side Resources and Demand-Side Resources that will meet electricity demand at the lowest cost. The IRP is often developed with input from various stakeholder groups. Also Integrated Resource Planning.

Levelized Cost	Levelized Cost - An economic assessment of the cost to build and operate a power-generating asset over its lifetime divided by the total power output of the asset over that lifetime. It is also used to compare different methods of electricity generation in cost terms on a comparable basis.
MW	MW - Megawatt - A unit of power equal to one million watts or one thousand kilowatts.
N-1	N-1 - Loss of a single element such as a generator, a transmission line, or a transformer (P2)
N-2	N-2 - Simultaneous loss of two elements due to a single event. For example, loss of two transmission lines on a common tower due to failure of the tower (P6)
N-1-1	N-1-1 - Loss of a single element such as a generator, a transmission line, or a transformer followed by a system readjustment such as generation redispatch, then loss of a second element such as a generator, a transmission line, or a transformer (P7)
Native load	Native load – 1. The cumulative load (power requirement) of a utility's retail customer base. 2. The end-use customers that the Load-Serving Entity is obligated to serve. (NERC Glossary) http://www.energy.ca.gov/glossary/glossary-d.html
NAICS	NAICS - The North American Industry Classification System (NAICS) is the standard used by Federal statistical agencies in classifying business establishments for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. business economy (Source: Census.gov)
NERC	NERC - North American Electric Reliability Corporation
Northern Intertie	Northern Intertie - transmission interconnection between Washington and British Columbia (Also called Path 3.)
Off-system sales	Off-system sales – Sales by a utility to a customer outside of its current traditional market.
PC	PC - Planning Coordinator
PDCI	PDCI - Pacific Direct Current Intertie
PJM	PJM – PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.
Personal Consumption Expenditure Deflator (PCE Deflator)	Personal Consumption Expenditure Deflator (PCE Deflator) - Measures the average change over time in the price paid for all consumer purchases, thus measures changes in the cost of living. (Source: Investopedia)
Powerflow	Powerflow - a numerical analysis of the flow of electric power in an interconnected system. It can refer to the analysis program, or to a simulation
RE	RE - Regional Entity.
Regression Analysis	Regression analysis is a statistical process for estimating the relationships among variables. It seeks to determine the strength of the relationship between one dependent variable (usually denoted by Y) and a series of other changing variables (known as independent variables). It is also known also as curve fitting or line fitting because a regression analysis equation can be used in fitting a curve or line to data points. It includes many techniques for modeling and analyzing variables.

Renewable energy credits (RECs)	Renewable energy credits (RECs) - A REC represents the property rights to the non-power qualities of renewable electricity generation, such as environmental and social qualities. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source. At the point of generation, both product components can be sold together or separately, as a bundled or unbundled product. (Source: US EPA)
Renewable Portfolio Standard (RPS)	Renewable Portfolio Standard (RPS) – A regulatory mandate to increase production of energy from renewable sources such as wind, solar, biomass and other alternatives to fossil and nuclear electric generation. It's also known as a renewable electricity standard. (Source: National Renewable Energy Laboratory - NREL)
Substation	Substation – Substations transform voltage from high to low or from low to high. They also perform other functions, such as limiting outages, protecting equipment, et cetera.
Supply-Side Resources	Supply-Side Resources – Conventional generation plants, renewable generation, etc. (as opposed to Demand-Side Resources).
TO	TO - Transmission Owner
TP	TP - Transmission Planner
Weather Normalizing	Weather normalization is a process that adjusts actual energy or peak outcomes to what would have happened under normal weather conditions. Normal weather conditions are expected on a 50 percent probability basis, also known as a 50/50 forecast (i.e., there is a 50 percent probability that the actual peak realized will be either under or over the projected peak).
WECC	WECC - Western Electricity Coordinating Council. WECC has been approved by the Federal Energy Regulatory Commission (FERC) as the Regional Entity for the Western Interconnection. The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement.
Western Interconnection	Western Interconnection - North America is comprised of two major and three minor alternating current (AC) power grids, also called "interconnections." The Western Interconnection stretches from the Pacific Ocean eastward over the Rockies to the Great Plains, and from Baja California, Mexico in the South into Western Canada. (Source: Energy.gov)
Wheeling	Wheeling -- The transmission of electricity by an entity that does not own or directly use the power it is transmitting. Wholesale wheeling is used to indicate bulk transactions in the wholesale market, whereas retail wheeling allows power producers direct access to retail customers. This term is often used colloquially as meaning transmission.
WSCC	WSCC - Western Systems Coordinating Council. The predecessor to WECC.

Appendix B – Optional Technical Analysis

Executive Summary

Utility System Efficiencies, Inc. (USE) was engaged by the City of Bellevue in February, 2014 to conduct an Optional Technical Analysis (OTA) of the purpose, need, and timing of the Energize Eastside project. Energize Eastside (EE) is Puget Sound Energy's (PSE's) proposed project to build a new electric substation and new higher–capacity (230 kilovolt) electric transmission lines in the East King County area, which encompasses Bellevue, Clyde Hill, Medina, Mercer Island, Newcastle, the towns of Yarrow Point, Hunts Point, and Beaux Arts, and portions of Kirkland, Redmond, and Renton (the Eastside). The transmission lines would extend from an existing substation in Redmond to one in Renton (See Figure 3.1).

The scope of the OTA was to perform an analysis on PSE's study cases to determine the impact of potential forecast variability on the timing of improvements, and was later expanded to evaluate whether regional requirements rather than local requirements might be driving the project need. The OTA examined several hypothetical scenarios by conducting analysis on PSE's study cases. It looked at the effect of a) reducing load growth in the *Eastside* area to 1.5%, b) reducing load growth in *PSE's portion of King County* to 0.25% while keeping the Eastside growth the same, c) increasing power output of existing Puget Sound area generation, and d) reducing the Northern Intertie[46] flow to zero (no transfers to Canada). Although d) is not actually possible due to extant treaties, it was modeled to examine if regional requirements might be driving the need. In the winter cases, the OTA also combined scenarios c) and d). Finally, the OTA looked at the impact of an Extreme Winter forecast.

IF THE LOAD GROWTH RATE WAS REDUCED, WOULD THE PROJECT STILL BE NEEDED? YES

The OTA results showed that reducing the Eastside average load growth from an average of 2.4%/year to an average of 1.5%/year from winter 2013/14 to winter 2017/18 did not eliminate any overloaded elements; there is still project need. Similarly, reducing PSE's *King County growth rate* (less Eastside) from an average of 0.5 %/year to an average of 0.25%/year from winter 2013/14 to winter 2017/18 did not eliminate any overloaded elements; there is still project need.

IF GENERATION WAS INCREASED IN THE PUGET SOUND AREA, WOULD THE PROJECT STILL BE NEEDED? YES

Results showed that increasing the power output of existing Puget Sound area generation to the levels specified in ColumbiaGrid's July 2010 "Puget Sound Area Generation Modeling Guideline" eliminated one of five overloads in the 2017/18 normal winter, but did not eliminate project need. (This study increased the amount of PSE and SCL generation west of the Cascades from zero to the level identified in the above document. Since the document is confidential (CEII) the generation output is not provided in this report.)

[46] Northern Intertie - transmission interconnection between Washington and British Columbia (Also called Path 3.)

IS THERE A NEED FOR THE PROJECT TO ADDRESS REGIONAL FLOWS, WITH IMPORTS/EXPORTS TO CANADA (COLUMBIAGRID[47])? Modeling zero flow to Canada, the project is still necessary to address local need.

The Optional Technical Analysis examined this issue by analyzing a reduction in the Northern Intertie flow to zero (no transfers to Canada). Although this scenario is not actually possible due to extant treaties, it was modeled to provide data on the drivers for the EE project, to examine if regional requirements might be driving the need. The results showed that in winter 2017/18, even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230/115 kV transformer #2 is still overloaded by several contingencies. This indicates there is a project need at the local level.

The OTA results showed that all studied scenarios resulted in at least one equipment overload in normal winter 2017/18 with 100% conservation, indicating project need.

Analysis and Findings

The OTA studied five normal winter scenarios and three extreme winter scenarios for winter 2017/18 and winter 2019/20. The OTA also studied five normal summer scenarios for 2018 and 2020. The scenarios were modeled in the powerflow cases. Details on the modeling are not provided due to Critical Energy Infrastructure Information (CEII) restrictions.

Table B.1 lists the overloaded elements for winter 2017/18 for each studied scenario. The scenarios are listed in the second blue row in Table B.1 (the vertically oriented text). The normal winter scenarios are numbered 1-6 (with #1 representing the original PSE case). The extreme weather scenarios are numbered E1-E3.

Normal winter results showed:

- Reducing the Eastside average load growth to 1.5% did not eliminate any overloaded elements; there is still project need.
- Reducing PSE's King County growth rate (less Eastside) to 0.25% did not eliminate any overloaded elements; there is still project need.
- Increasing the power output of existing Puget Sound area generation to the levels specified in ColumbiaGrid's July 2010 "Puget Sound Area Generation Modeling Guideline"[48] eliminated one of five overloads, but did not eliminate project need.
- Reducing the Northern Intertie flow to zero (no transfers to Canada) eliminated all but one overload; there is still local project need.
- Reducing the Northern Intertie flow to zero (no transfers to Canada) AND Increasing the Puget Sound area generation to ColumbiaGrid's July 2010 "Puget Sound Area Generation Modeling Guideline" eliminated all but one overload; there is still project need.

Extreme winter results increased the overload levels and/or caused overloads on additional elements. Although the normal winter results showed only one overload when the Northern Intertie flow was reduced to zero, the extreme winter case showed four overloads.

[47] ColumbiaGrid (single word) is a regional transmission planning organization with a footprint encompassing Oregon, Washington, parts of Idaho and Montana.
[48] Confidential (CEII) document that provides modeling values (MW levels of generation) for applicable generators.

Table B.1: Winter 2017/18, 100% Conservation - Overloaded Elements

Northern Intertie: South to North Overloaded Element (Transmission Line or Transformer)	2017/18 Normal Winter 100% Conservation						2017/18 Extreme Winter, 100% Cons.		
	1) Original PSE Case	2) Reduce Eastside load growth to 1.5%	3) Reduce PSE's King County growth to 0.25%[49]	4) Increase Puget Sound area generation	5) Set Load transfers to Canada = 0 (North. Intertie = 0)	6) Combination of Scenario 4 and & 5	E1) Original PSE Case adjusted for extreme weather	E2) Set Load transfers to Canada = 0 (North. Intertie = 0)	E3) Scenario E2 + Increase Puget Sound area generation
Talbot Hill - Lakeside #1 115 kV line	OL	OL	OL	OL			OL		
Talbot Hill - Lakeside #2 115 kV line	OL	OL	OL	OL			OL		
Talbot Hill 230-115 kV transformer #1	OL	OL	OL	OL			OL	OL	OL
Talbot Hill 230-115 kV transformer #2	OL	OL	OL	OL	OL	OL	OL	OL	OL
Talbot Hill-Boeing Renton-Shuffleton 115 kV line	OL	OL	OL				OL		
Sammamish 230/115 kV transformer #1								OL	OL
Sammamish 230/115 kV transformer #2								OL	OL

OL = Overload of Emergency Rating. Source: OTA Results

Table B.2 lists the overloaded elements for winter 2019/20 for each studied scenario. The scenarios are listed in the second blue row (the vertically oriented text).

The 2019/20 winter results showed the same overloaded elements as 2017/18. The overloads in the base cases and in the load reduction cases were more severe in 2019/20. The overload levels in the generation dispatch and Northern Intertie=0 scenarios were mixed; some overloads were more severe in 2019/20, but some were slightly less. Nevertheless, project need was shown in all cases. Extreme winter results increased the overload levels over normal winter and/or caused overloads on additional elements.

Table B.2: Winter 2019/20, 100% Conservation - Overloaded Elements

Northern Intertie: South to North Overloaded Element (Transmission Line or Transformer)	2019/20 Normal Winter 100% Conservation						2019/20 Extreme Winter, 100% Cons.		
	1) Original PSE Case	2) Reduce Eastside load growth to 1.5%	3) Reduce PSE's King County growth to 0.25%[50]	4) Increase Puget Sound area generation	5) Set Load transfers to Canada = 0 (North. Intertie = 0)	6) Combination of Scenario 4 and & 5	E1) Original PSE Case adjusted for extreme weather	E2) Set Load transfers to Canada = 0 (North. Intertie = 0)	E3) Scenario E2 + Increase Puget Sound area generation
Talbot Hill - Lakeside #1 115 kV line	OL	OL	OL	OL			OL		
Talbot Hill - Lakeside #2 115 kV line	OL	OL	OL	OL			OL		
Talbot Hill 230-115 kV transformer #1	OL	OL	OL				OL	OL	OL
Talbot Hill 230-115 kV transformer #2	OL	OL	OL	OL	OL	OL	OL	OL	OL
Talbot Hill-Boeing Renton-Shuffleton 115 kV line	OL	OL	OL				OL		
Sammamish 230/115 kV transformer #1									OL
Sammamish 230/115 kV transformer #2								OL	OL

OL = Overload of Emergency Rating. Source: OTA Results

[49] Excluding Eastside load
[50] Excluding Eastside load

Table B.3 lists the overloaded elements for summer 2018 for each studied scenario. The scenarios are listed in the second green row. The normal summer scenarios are numbered 1-5 (with #1 representing the original PSE case). There is no extreme weather summer forecast.

The 2018 normal summer results showed:

- Reducing the Eastside average load growth did not eliminate any overloaded elements; there is still project need.
- Reducing PSE's King County growth rate (less Eastside) did not eliminate any overloaded elements; there is still project need.
- Increasing the Puget Sound area generation to ColumbiaGrid's July 2010 "Puget Sound Area Generation Modeling Guideline" eliminated one of six overloads, but did not eliminate project need.
- Reducing the Northern Intertie flow to zero (no transfers to Canada) eliminated all the summer overloads; however, there is still a winter overload which means there is still local project need.

Table B.3: Summer 2018, 100% Conservation - Overloaded Elements

Northern Intertie: North to South Overloaded Element (Transmission Line or Transformer)	2018 Summer (86°F) 100% Conservation 1) Original PSE Case	2) Reduce Eastside load growth	3) Reduce PSE's King County growth	4) Increase Puget Sound area generation	5) Set Load transfers to Canada = 0 (Northern Intertie = 0)
Sammamish 230/115 kV Xfmr #1	OL	OL	OL	OL	
Sammamish 230/115 kV Xfmr #2	OL	OL	OL	OL	
Novelty Hill 230/115 kV Xfmr #2	OL	OL	OL		
BPA Monroe – Novelty Hill 230 kV	OL	OL	OL	OL	
Beverly Park - Cottage Brook 115 kV line	OL	OL	OL	OL	
Sammamish – BPA Maple Valley 230 kV line	OL	OL	OL	OL	

OL = Overload of Emergency Rating. Source: OTA Results

The 2020 summer results (Table B.4) showed the same overloaded elements as 2018. The overloads were more severe in 2020, with the exception of the Beverly Park – Cottage Brook 115 kV line which was either unchanged or reduced by less than 0.1%.

Table B.4: Summer 2020, 100% Conservation - Overloaded Elements

Northern Intertie: North to South Overloaded Element (Transmission Line or Transformer)	2020 Summer (86°F) 100% Conservation				
	1) Original PSE Case	2) Reduce Eastside load growth	3) Reduce PSE's King County growth	4) Increase Puget Sound area generation	5) Set Load transfers to Canada = 0 (Northern Intertie = 0)
Sammamish 230/115 kV Xfmr #1	OL	OL	OL	OL	
Sammamish 230/115 kV Xfmr #2	OL	OL	OL	OL	
Novelty Hill 230/115 kV Xfmr #2	OL	OL	OL		
BPA Monroe – Novelty Hill 230 kV	OL	OL	OL	OL	
Beverly Park - Cottage Brook 115 kV line	OL	OL	OL	OL	
Sammamish – BPA Maple Valley 230 kV line	OL	OL	OL	OL	

OL = Overload of Emergency Rating. Source: OTA Results

<u>Stakeholder Questions related to the OTA</u>

Q56. The study must as clearly, but non-technically as possible, define will happens regarding power flow to and from Canada.

- A *See the OTA in Appendix B. Sensitivities were performed where power flow to and from Canada were reduced to zero. These cases still showed overloads so there is clearly a local need. Some overloads were eliminated when flows were reduced to zero, which indicates that flows to and from Canada also have an impact on the need.*

Q57. Clarify Eastside vs. regional needs. What load is causing the problem? Local or regional?

- A *Local. The Optional Technical Analysis results showed that in winter 2017/18, even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230/115 kV transformer #2 is still overloaded by several contingencies. This indicates there is a project need at the local level. See the full Appendix B for further detail.*

Q58. I am concerned that the need is not just for Bellevue and the Eastside but more for Bonneville Power, Snohomish Power, Seattle City Light -- the Columbia Grid. I would ask the consultants to provide a simple quantitative and pie chart breakout of the need that each stakeholder has in "Energize Eastside".

- A *See Q56.*

Q59. Provide a quantitative analysis and pie charts (both historical and futuristic) showing a breakout of the need (demand and reliability) for each of the members of the Columbia Grid.

- A *The Optional Technical Analysis results showed that in winter 2017/18, even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230/115 kV transformer #2 is still overloaded by several contingencies. These results indicate there is a project need at the local level.*

Q60. Given the scenario and contingency driving the EE project, how much regional load will flow through the line?

- A *See Q61 below.*

Q61. What percentage of North-South flow-through load (to Canada/California) will be carried on EE during an N-1-1 event (failure of BPA bulk main PLUS a second transmission line failure?

A *The OTA studied a scenario with flows to Canada at 1500 MW and a scenario with flows to Canada set to 0 MW. Under the worst contingency condition (N-1-1), the reduction in flow on the Talbot Hill - Lakeside lines was 22.5%. Under the worst contingency condition (again N-1-1), the reduction in flow on the Talbot Hill 230/115 kV transformer was 2.6%. These results are before EE and reflect the effects on the current transmission system serving the EE area. As you can see from these results, the impact of flows to Canada on the Talbot Hill 230/115 kV transformer (the main driver of the need for EE) is almost insignificant.*

Q62. Was the system studied with generation on the west side?

A *Yes, the OTA studied a scenario with generation on the west side.*

Q63. Is EE a "BLENDED PROJECT" to satisfy the needs of Columbia Grid, BPA grid reinforcement (Monroe-Echo Lake bottleneck), Columbia River treaty "Canadian Entitlement" curtailments, Seattle City Light load needs, as well as PSE load growth?

A *The term "Blended Project" is not clear. However, the OTA results do show that there is a need for a project to satisfy local needs. A review of ColumbiaGrid documentation indicates that EE will also help satisfy a regional need which is why EE was included in the recommended transmission solution from ColumbiaGrid Puget Sound Area transmission planning activity.*

Appendix C – End-Use Data and IRP

End-use data is evaluated in Integrated Resource Planning, where a utility examines both Supply-Side and Demand-Side options with the objective of providing reliable and least-cost electric service to its customers while addressing applicable environmental, conservation and renewable energy requirements. Because energy efficiency is generally a low-cost resource, the IRP tends to incorporate energy efficiency as a utility system resource and reduce the need for additional Supply-Side resources.

PSE commissioned The Cadmus Group, Inc. (Cadmus) to conduct an independent study of Demand-Side Resources (DSR) in the PSE service territory as part of its biennial integrated resource planning (IRP) process. The study considered energy efficiency, fuel conversion, Demand Response, and distributed generation. PSE also considered distribution efficiency.

Energy efficiency looked at naturally occurring conservation, which occurs due to normal market forces such as technological change, energy prices, improved energy codes and standards, and efforts to change or transform the market. This includes gradual efficiency increases due to replacing or retiring old equipment in existing buildings and replacing it with units that meet minimum standards at that time. It also includes new construction which reflects current state specific building codes, and improvements to equipment efficiency standards that are pending and will take effect during the planning horizon.

Fuel Conversion considered opportunities to substitute natural gas for electricity through replacements of space heating systems, water heating equipment, and appliances.

Demand Response options seek to reduce peak demand during system emergencies or conditions of extreme market prices. It may also be used to improve system reliability and could potentially help to balance variable-load resources such as wind energy.

Washington State's Renewable Portfolio Standard (RPS) law requires conservation potential be developed using Northwest Power & Conservation Council (NWPCC) methodology, and conservation targets are based on IRP with penalties for not achieving them. It requires PSE to meet specific percentages of its load with renewable resources or renewable energy credits (RECs) by specific dates.

The Energy Independence and Security Act (EISA, 2007) provides for minimum federal standards for lighting and other appliances beginning in 2012. It also sets standards for increasing the production of clean renewable fuels, increasing the efficiency of buildings and vehicles, and more.

Cadmus compiled technical, economic, and market data from the following sources:

- PSE Internal Data: Historical and projected sales and customers, historic and projected DSR accomplishments, and hourly load profiles
- 2010 Residential Characteristic Survey (PSE Service Territory)
- 2008 Fuel Conversion Survey (PSE Service Territory)

- 2007 Puget Sound-Area Regional Compact Fluorescent Light (CFL) Saturation Study
- NEEA's 2009 Commercial Building Stock Assessment (CBSA)
- Building Simulations for the residential sector, employing separate models for customer segments and construction vintage
- Pacific Northwest Sources. Technical information included on hourly end-use load shapes (to supplement building simulations), commercial building and energy characteristics. Information on measure savings, costs, and lives
    - The Northwest Power and Conservation Council (Council)
    - The Regional Technical Forum (RTF)
    - The Northwest Energy Efficiency Alliance (NEEA)
- Sources to characterize measures, assess baseline conditions, and benchmark results against other utilities' experiences
    - The California Energy Commission's Database of Energy Efficiency Resources (DEER)
    - ENERGY STAR
    - The Energy Information Administration
    - Annual and evaluation reports on energy-efficiency and Demand Response programs from various utilities

Only new opportunities for conservation are captured in the DSR value and thousands of measures were evaluated. Conservation programs included Energy Efficiency, Fuel Conversion, Distributed Generation, Demand Response and Distribution Efficiency (voltage reduction and phase balancing[51]). Lighting savings in the 2013 IRP assume the availability of a technology meeting the minimum requirements of EISA, and that savings from Compact Fluorescent Lamp (CFL) installations will remain available[52]. (Cadmus estimated that 33% of sockets have CFLs before the 2013 IRP measures are selected.) EISA accounts for 31% of residential DSR and 26% of commercial DSR. DSR targets are reviewed by the Conservation Resource Advisory Group and the Integrated Resource Plan Advisory Group.

The 2013 IRP identified market achievable, technically feasible Demand-Side measures. These measures (over four thousand) were combined into bundles[53] based on levelized cost[54] for inclusion in the generation optimization analysis. The effect of the bundles is to reduce load, so the costs to achieve the savings must be added to the cost of the electric portfolios.

The optimization analysis identifies the economic potential (cost-effective level) of DSR bundles that would work well in planning for generation requirements. (For example, solar energy has a different impact on the summer peak than on a winter peak.) The optimization model developed and tested different portfolios, combining Supply-Side Resources with Demand-Side bundles, to find the lowest cost combination of resources that a) met capacity need b) met renewable resources/RECs need, and c) included as much conservation as was cost effective. (Once the capacity and renewable resources/RECs needs are met, the decision to include additional

[51] Phase balancing: Balancing the single-phase load among the three phases so that unbalanced load isn't driving the peak load value.
[52] LED lighting: The LED programs were not specifically identified in the 2013 IRP. The LED technology and availability is different today than it was when the 2013 IRP study began. PSE is planning on including LED lighting in the 2015 IRP.
[53] An example bundle is the set of measures that cost between $28/MWh and $55/MWh.
[54] Levelized Cost - An economic assessment of the cost to build and operate a power-generating asset over its lifetime divided by the total power output of the asset over that lifetime. It is also used to compare different methods of electricity generation in cost terms on a comparable basis.

conservation bundles is simply whether that next bundle of measures increases the cost or decreases it.)

The optimization analysis results in the final set of cost effective measures, which are identified as the "100% conservation" set.

Appendix D – Ask the Consultant

A key purpose of the ITA and the OTA was to provide an increased level of understanding of the purpose, need and timing of the EE project to the City Council and to community stakeholders. Over the course of the project, dozens of questions were received from various stakeholders. The City engaged such comments through an online outreach feature called 'Ask the Consultant.' In addition to this outreach the City initiated separate interviews with key stakeholders and USE staff. City staff filtered all Ask the Consultant stakeholder comment through the various Tasks in the Scope of Services and submitted the need-related comments to USE for report inclusion. Other comments were directed as appropriate to other comment venues including for example to the scoping process for the Environmental Impact Statement (EIS) the Integrated Resource Plan (IRP) process. That filtering is documented in the chart below.

A Q&A discussion is documented at the end of each section of the ITA.

See Attached Table 1.

Date	Name	Question or Comment	Directed to:
1/27	Plummer	Industry standards, IRP, average yearly loads	Extensive reference to lack of industry wide standards; paragraph 4 and 5 to ITA
1/22	Marsh	Questions for ITA consultant: Overview, Real need, distribution of peak use, Eastside vs regional needs, reliability	Skype session
1/28	Marsh	Questions for ITA consultant: extreme winter study case, other adjustments modeled, System Cap.	Role of Case Study Assumption, clarify reference to Needs Assessment Section 6, connection between CSA and CDF to ITA
1/30	Sweet	Data center consolidation comment	ITA
2/6	Plummer	Quantitative reliability metrics	ITA
2/9	Lander	Choice of USE and communications	Communications response
1/15	Osterberg/ Laughlin	E3 and Cadmus Study, declining revenue, blended project	EIS
2/3	Borgmann	12 questions: forecast, growth rates, Columbia Grid role, used and useful comparison, alternatives	1, 2, 7, 8, 12 to ITA 3 ? to ITA, comments to EIS 5 ? to ITA, comments to EIS 6 ? to ITA, comments to EIS 7- 2nd set? to EIS 4, 9, 10, 11 to EIS
2/9	Kim	2 comments on tech study and CDF chart; 2 questions on growth forecast disparity, show project stakeholder pie chart	1 and 2 to EIS 3 and 4 to ITA

2/10	McCray	4 questions: Load projection, options, trend down, Chang proposal	1 and 3 to ITA 2 and 4 (Chang) to EIS
2/10	Marsh	Circumstances of all-time peak usage occurrence	EIS
2/10	Marsh	PSE and SCL electricity trends	EIS
2/11	Alford	comment on tech study and CDF chart; questions on growth forecast disparity, show project stakeholder pie chart	See Kim comment
2/11	Mozer	Magnitude and timing of EE, alternatives, Canada powerflow	ITA (1) and EIS (2)
2/12	Andersen	4 questions: SCL capacity, Peak load information, use of temperature in modelling, distributed generation, use of peaking turbine generation	New Q1 to EIS Add 1 Q4 not in ITA scope Add 2 Q7 not in ITA scope Add 3 Q15 DSR and DG in ITA modelling, cost info not in scope Add 4 Q19 to EIS
2/12	Merrill	7 questions: Reasonableness of PSE conclusions, rational look, Eastside Customer demand, use of actual data, replacement, outages	1, 3, 5, 6 to ITA 2, 4, 7 to EIS
2/12	Hansen	Bridle Trails Subarea infrastructure reliability	EIS or ERS implementation
2/12	Halvorson	Customer Demand Forecast and Columbia Grid need pie chart	ITA
2/12	Marsh	7 questions: Top assumptions and parameters of the load forecast, economic projections, Spring District, increased efficiency, local government actions, regional transmission flow, regional grid	ITA

Appendix E – Transmission Planning Standards TPL-001-4

See attached Table 1.

Appendix F – Utility System Efficiency, Inc. (USE) Qualifications

Utility System Efficiencies, Inc.

R. Peter Mackin, P.E.
Vice President of Analytical Services

ACADEMIC BACKGROUND
M.S., Electrical Engineering, Montana State University, 1982
B.S., Civil Engineering, Montana State University, 1981

PROFESSIONAL EXPERIENCE
Peter Mackin has over 33 years of power system planning and computer application development experience and has been involved in WSCC/WECC planning and operating activities since 1985. In April of 2006, Mr. Mackin joined Utility System Efficiencies, Inc. (USE) as Vice President of Analytical Services. At USE, among other duties, Mr. Mackin has directed and performed system studies to meet the requirements of the WECC Project Rating Review Process, assisted developer clients with interconnection applications, and supervised a wind integration study for FERC.

While employed at Navigant Consulting, Inc., Mr. Mackin performed several transmission and resource integration studies for the Alberta Electric System Operator (AESO) as well as generation interconnection studies and transmission feasibility analyses for other clients. Mr. Mackin was a member of the NERC Version 0 and Phase III/IV Standards drafting teams. In addition, Mr. Mackin provided expert witness testimony at FERC in Docket No. ER01-1639-006.

While employed by the California Independent System Operator (CAISO), Mr. Mackin performed or reviewed system planning studies for Reliability Must Run generation requirements, new generator interconnection studies, as well as Participating Transmission Owner annual Transmission Assessments. In addition, Mr. Mackin helped develop the CAISO's New Facility Interconnection Policy and Long-Term Grid Planning Policy. Mr. Mackin provided expert witness testimony regarding six new generation projects before the California Energy Commission.

While employed by Pacific Gas and Electric Company (PG&E), Mr. Mackin was the lead transmission planning engineer performing transient stability simulations for the 500 kV California – Oregon Transmission Project. In addition, Mr. Mackin performed, supervised or reviewed studies to determine simultaneous import capabilities into California from the Pacific Northwest and the Desert Southwest. For two years, he served as chairman of the work group that undertook these studies. This work group was comprised of utilities from California, the Northwest, and the Desert Southwest.

Jennifer Geer, P.E.
Principal Power Systems Engineer

ACADEMIC BACKGROUND

B.S., Electrical Engineering, University of New Mexico, 1985

PROFESSIONAL EXPERIENCE

Ms. Geer has over 25 years of electric utility industry experience and has extensive background in the transmission and distribution areas, including transmission planning and generation interconnection studies, distribution planning and forecast development and approval, outage analysis, reliability analysis, project development, and project management. Ms. Geer has also provided training in many of these areas. Ms. Geer joined Utility System Efficiencies, Inc. (USE) in 2009. At USE, Ms. Geer's focus has been on generation interconnection studies, transmission planning and project development.

Prior to joining USE, Ms. Geer was a member of San Diego Gas and Electric's Transmission Planning Department. Though part of their generation interconnection team, she was also involved in studies to determine the need and benefit of new transmission projects on the existing system, examining different route and voltage options.

While running Geer and Geer Engineering, Ms. Geer developed a procedure to determine if a new substation was needed; part of this procedure involved developing long term forecasts for the relevant areas. She also led teams to optimize substation site selection based on both engineering and non-engineering issues, and provided project management for a long term transmission study that was used to determine client company strategy. In addition, Ms. Geer developed or reviewed many distribution projects, trained engineers and leads on distribution planning, developed a training manual, conducted process mapping of distribution functions, and analyzed visibility and accuracy of distribution accounting.

While employed by San Diego Gas & Electric (SDG&E), Ms. Geer forecasted distribution loads, identified issues and alternatives, and developed circuit and substation projects. Ms. Geer also conducted distribution reliability studies to improve performance indices and developed training documents on multiple topics. She reviewed the entire set of distribution circuit forecasts and proposed distribution capital projects for San Diego Gas & Electric in later years, and provided feedback and/or modification as needed. Ms. Geer also developed checklists and forms to assist in forecasting, project development and new business engineering review, and trained engineering personnel on distribution planning procedures.

City of
Bellevue

DATE: 07/31/2015

TO: Energize Eastside EIS File – 14-139122-LE

FROM: David Pyle, Senior Environmental Planner – 425-452-2973

SUBJECT: Energize Eastside EIS Team Review of Project Need

PSE has represented that there is a need to construct a new 230 kV bulk electrical transmission corridor and associated electrical substations on the eastside of Lake Washington to supply future electrical capacity and improve eastside electrical grid reliability. Preliminary discussion between potentially affected jurisdictions and PSE indicated that the proposal is likely to have probable significant adverse environmental impacts, and issuance of a Washington State Environmental Policy Act (State Environmental Policy Act (SEPA) Threshold Determination of Significance was deemed appropriate as outlined in Chapter 197-11-360 WAC.

Following PSE's identification of this essential electrical infrastructure link, and to address the potential for significant environmental impacts, the utility submitted application for processing of an Environmental Impact Statement (EIS) with the City of Bellevue, who assumed the role of lead agency. Subsequent to this initiating action, several steps have been taken to begin processing the required EIS. The EIS is now underway and the EIS project team has been in review of information provided by PSE and collected during the process.

To better understand PSE's project proposal, the EIS project team has obtained clearance to access un-redacted sensitive (protected in accordance with industry security protocol) utility planning and operations information used by PSE in developing the Energize Eastside project proposal. The EIS project team, represented by Stantec (electrical system planning and engineering sub-consultant working in support of the Energize Eastside EIS effort), has reviewed this background information and studied the process used by PSE to establish a need for the proposed Energize Eastside project. A report from Stantec summarizing the findings is attached.

Although validation of the need for the proposed Energize Eastside project is not considered as a component of the EIS process under the requirements of SEPA, review of the need for the project is important in developing a thorough understanding of the project objectives and technical requirements to accurately identify feasible and reasonable project alternatives[1]. The EIS process is not to be used to reject or validate the need for a proposal. Rather, the EIS process is intended to identify and disclose potential significant adverse environmental impacts associated with a specific proposal.

[1] WAC 197-11-786 - Reasonable alternative.
"Reasonable alternative" means an action that could feasibly attain or approximate a proposal's objectives, but at a lower environmental cost or decreased level of environmental degradation. Reasonable alternatives may be those over which an agency with jurisdiction has authority to control impacts, either directly, or indirectly through requirement of mitigation measures.

Stantec Memo

To:	Mark Johnson Program Manager ESA | NW Community Development Director	From:	Keith DeClerck Tucson, ArizonaTucson, Arizona
File:	Energize Eastside	Date:	July 31, 2015

Reference: Energize Eastside Project

The purpose of this memorandum is to summarize my findings regarding Puget Sound Energy's (PSE) electrical system needs that support the purpose and need for PSE's proposed Energize Eastside project. It memorializes the issues we have discussed in depth with the principal jurisdictions reviewing the project (the Cities) as we examined PSE's project criteria and possible alternatives to the 230 kV transmission system improvements that PSE has proposed for consideration in the Phase 1 Draft Environmental Impact Statement (EIS). I have prepared this memo at ESA's request to support a plain-language description of the purpose and need for the Energize Eastside project that can be used in the EIS that ESA is preparing. I understand that ESA and the Cities also want to understand the purpose and need for the project and the constraints PSE is working with so that you can make informed choices about what alternatives to evaluate in the EIS.

<u>My Background</u>
As an electrical engineer with more than 25 years of experience in both Industrial and utility environments, I understand the concerns on both sides of the meter. Specific to this project I have over 14 years of experience in transmission and distribution power flow simulations and have conducted and published extensive power flow studies in several of the states included in the Western Electricity Coordinating Council (WECC) region. I have critical infrastructure security clearance for viewing FERC data, and have experience reviewing such data. In addition, I have conducted transmission adequacy studies and renewable generation interconnection studies in several other North American Electric Reliability Corporation (NERC) regions across the United States. My experience in load forecasting and transmission planning, coupled with the fact that I have never worked for or have been under contract to PSE, allows me to provide a knowledgeable, independent view of the project purpose and need.

<u>Documents Reviewed</u>
In preparing this memo, I reviewed the unredacted versions of the following documents prepared by PSE and Quanta Technology (Quanta):

- *Eastside Needs Assessment Report, Transmission System, King County,* dated October 2013;
- *Supplemental Eastside Needs Assessment Report, Transmission System, King County,* dated April 2015;
- *Eastside Transmission Solutions Report, King County Area,* dated October 2013; and
- *Supplemental Eastside Transmission Solutions Report, King County Area,* dated April 2015.

I also reviewed the *Independent Technical Analysis of Energize Eastside for the City of Bellevue, WA (Version 1.3)* dated April 28, 2015 by Utility System Efficiencies, Inc. (USE). Although PSE's findings are the focus of this assessment, I found the USE report to be helpful in exploring other facets of the proposed need and verifying my own conclusions.

Reference: Energize Eastside Project

In the process of reviewing these documents I also referred to many other documents prepared by federal and regional agencies and by PSE.

Findings

Based on my expertise, I found that the PSE needs assessment was overall very thorough and applied methods considered to be the industry standard for planning of this nature. Based on the information that the needs assessment contains, I concur with the conclusion that there is a transmission capacity deficiency in PSE's system on the Eastside that requires attention in the near future. For purposes of this memo, "Eastside" refers to the central portion of King County roughly located between the cities of Redmond to the north and Renton to the south.

The transmission capacity deficiency is complex. It arises from growing population and employment, changing consumption patterns, and a changing regulatory structure that requires a higher level of reliability than what was required in the past. PSE has concluded that the only effective and cost-efficient solution is to site a new 230 kV transformer in the center of the Eastside, fed by new 230 kV transmission lines from the north and south. While that conclusion seems simple and straightforward, it is the product of an analysis that considered dozens of options and thousands of potential scenarios that the power system could encounter.

The population of the Eastside is expected to grow at a rate of approximately 1.2% annually over the next decade, and employment is expected to grow at an annual rate of approximately 2.1%. Because of the nature of expected development, PSE projects that electrical demand will grow at a rate of 2.4% annually. Without adding at least 74 MW of transmission capacity or local peak period generation to the Eastside, a deficiency could develop as early as winter of 2017 - 2018 or summer of 2018, putting customers at risk of load shedding (power outages). It is impossible to place a single number on the projected deficiency because it varies by season (winter vs. summer) and by other assumptions that are made in the planning process. However, as the load continues to grow, the risk and extent of the load shedding required increases.

Four components must be understood in order to have a basic understanding of the nature of this expected capacity deficiency:

- Study Parameters
- Load Forecast
- Corrective Action Plans
- Regional Compliance

Study Parameters

PSE started with the WECC database model for load forecasting, distribution, and transmission. The model encompasses all utilities in the western United States, western Canada, and northern Mexico. This model is updated yearly by all entities in the WECC region and reflects the overall system configuration and load forecasts for each utility. This overall model does not always reflect the specific details of a utility's transmission and distribution system. Therefore, PSE added specific details about its system configuration on the Eastside to enhance the accuracy of the results. This includes PSE's 115 kV substations and transmission lines, and other equipment operating at lower voltage. In the model, forecasted electrical load is distributed by substation, based on historical load data for those locations. This model was used for most of the study results.

Reference: Energize Eastside Project

In addition, system sensitivity cases (i.e. scenarios) were conducted using various levels of energy conservation, extreme weather temperatures, power generation patterns, and expected "intertie" flows between PSE and its interconnected neighbors. These scenarios were used to evaluate stresses on the system that can reasonably be expected. The scenarios generally involve trying to operate the system during these extreme weather periods with one or two system components taken offline either because of planned maintenance, or because of an emergency such as damage caused by a storm or vandalism. Scenarios provide insight as to the strengths and weaknesses of the system. Because weaknesses represent vulnerable aspects of the system, specific information about them is not released to the general public.

This procedure is a typical method of study and consistent with standard accepted practice for the industry. Extreme weather conditions examined are relatively high likelihood events, that is, conditions expected in one out of every two years.

Results from both summer and winter conditions were reported. This is because although the Eastside has historically had its highest electrical demand during the winter, recent trends show that summer usage is growing rapidly and will eventually lead to similar or even greater levels of demand as peak winter days. This is discussed further under Load Forecast.

Load Forecast

The load forecast is central to determining the need for the project. The primary contributing factors to the growth in load are as follows:

- Local residential consumption due to population growth; and
- Local growth in commercial and industrial electrical consumption due to both the quantity and types of local businesses that are growing.

PSE prepared a Needs Assessment in 2013 and a Supplemental Needs Assessment in 2015. The methodology used in the Supplemental Needs Assessment increased the accuracy of the results by breaking down the systemwide forecast into county-by-county forecasts and a sub-county area forecast for the Eastside. Both the 2013 and the 2015 reports show that Eastside growth is expected to be relatively strong, with peak loads projected to grow by approximately 2.4% per year over the next 10 years (2014 - 2024) driven mainly by new development in the commercial and high-density residential sectors.

Table 2-2 in the Supplemental Needs Assessment compares the load growth forecast from the 2013 assessment and the 2015 assessment. The 2015 supplemental forecast showed a slight reduction in PSE's overall peak load projections for winter 2017 - 2018 of 46 MW (0.9% of total) as compared to the 2013 projections, which is due to a slower than expected recovery in the housing sector. Similarly, Eastside load projections for winter 2017 - 2018 decreased by 11 MW (1.6% of total) as compared to the previous forecast. Although the new forecast slightly extends the time before system components on the Eastside will have reached capacity, the conclusion regarding the need in the long run has not changed.

PSE has traditionally been a winter-peaking utility, meaning that the highest demand periods typically have occurred in winter when cold weather drives the demand for heating. Both Needs Assessment reports indicate that, in addition to growing winter peak load demand, summer loads on the Eastside are growing even more rapidly, to a point where they also pose transmission capacity deficiency issues.

In the 2015 Supplemental Needs Assessment report, the 2018 summer load projections for the Eastside were 12 MW (2.2% of total) lower than the previous forecast. However, by 2018 the supplemental assessment shows that approximately 74 MW of customer load is at risk of load shedding (shutting off or limiting power to customers) in order to maintain a reliable and secure transmission system. Ultimately, the result of having both a winter and summer peak deficiency leads to more hours of the year when the system is vulnerable to excess loading.

As with the previous forecast, PSE's supplemental forecast was based on historical data that were modified for such variables as energy conservation programs, economic data, population growth trends, and population and employment growth forecasts from the Puget Sound Regional Council (PSRC). Also included into the final shape of the forecast were any expected community development increases in load that have been identified by PSE customer relations and/or PSE local area distribution planning staff as being of significant size. These would be considered block loads and their addition is a typical practice in utility forecasting. In the model, block loads were added to the forecast for the substation that would serve those loads at 100% for the first three years, 50% for the next three years, and 0% after six years. Even though there are no standards for adding block loads of this type, this staged approach allows the forecast to capture any immediate sizable increases while tapering off and allowing the data available on employment and population provided by the other forecasting agencies to shape the outer years. This approach is a reasonable way to capture any significant near-term load increases without skewing the entire forecast.

In my opinion, the one area where PSE used an approach to load growth that was not typical of most utilities was in looking at the effect of its conservation programs. PSE used a conservation level of 100% in its load forecast, which assumes PSE will be able to achieve all of its planned conservation goals. Although PSE has a highly successful conservation program at present, this is more optimistic than most utilities are when making load forecasts, since conservation programs are typically voluntary. Using this as an expectation, anything short of that level of conservation would increase load levels and accelerate the timeframe for the deficiency to develop. The demand-side reduction program is described in PSE's *Integrated Resource Plan* (2013) including the methods used in determining the achievable levels of conservation. My review did not include a review of the methodology or results used in that analysis, although it appears to consider a wide range of factors that should be considered when establishing conservation goals.

In summary, PSE's load forecasting analysis applied methods and assumptions that are standard practice for the utility industry. My only concern is that the approach taken on conservation could result in understating the potential capacity deficiency if PSE were to fall short of its conservation goals.

Corrective Action Plans (CAPs)

An unwanted side effect from transforming power or transmitting power across power lines is the effect of thermal heating. Similar to water encountering friction in a hose, electrons face resistance in the conductor or transformer. Many individuals have felt this phenomenon when attempting to change a light bulb after it has been on for a period of time. Electrical transformation and delivery can cause extreme heat. As electrical system components heat up due to these thermal stresses, they reach a point where physical damage can occur if the temperatures are too high.

System operators monitor the load, which is in direct correlation to the heating of equipment. If the load gets too high, operators must reduce (shed) load, either automatically or manually, from the equipment. This reduces the loading and allows the destructive temperatures to decrease to a safe level. This heating can occur in any system component (transformers, conductors, generators etc.). If the operator does not shed load the equipment will eventually fail due to the excess heat, and no load will be able to be served by that system component until it is replaced. For some components this could take weeks or months to accomplish due to equipment availability, shipment requirements and the time it takes to install and test the component.

Corrective action plans (CAPs) are instructions to PSE transmission operators to take particular actions during certain events to prevent destruction of system components and maintain appropriate voltage levels to all customers. Equipment overheating mainly triggers those actions. Overheating is typically due to high "steady state" load levels during peak load times (i.e., running the system near full capacity for several hours or days, such as during a cold snap or hot spell), or increases in load on a particular piece of equipment due to an outage of another transmission system component. Outages can occur due to unforeseen events such as storms, or during routine maintenance, when pieces of equipment need to be isolated from the system for personnel safety. CAPs are used by all electrical utilities as temporary fixes that can be implemented for short periods in lieu of increasing the capacity of the system.

The electrical transmission system is basically a link between generation (supply of electrical power) and load (demand for electricity). Unless the load is turned off or generation is unavailable, the transmission system will continue to try to deliver electricity to the load even if certain parts of the system are overheating. Operators must be constantly aware of system loading parameters to prevent components of the system from being destroyed by overheating. Once destroyed, the component may be out of service for weeks or months while being repaired, and customers may be adversely affected for the duration. CAPs are sometimes administered manually by the operator, or automatically by control systems in more critical cases where immediate action is deemed appropriate.

CAPs limit the adverse effects to equipment, but during the period that a CAP is being implemented, the electrical supply system is left in a more vulnerable state with fewer components to carry the load. Regardless of whether a CAP has been initiated by normal load levels, an unexpected outage, or a maintenance outage, there is a higher probability during a CAP that any further system upset could leave large areas of the Eastside and thousands of customers without power. As the load for the Eastside increases, and as the problem becomes not only a winter but summer peak issue, the number of hours per year when CAPs must be implemented will increase, meaning the length of time that the system is vulnerable also increases. Therefore, from a functional standpoint the system becomes less reliable in regard to normal load and unexpected system outages. From a maintenance standpoint the system becomes harder to operate and maintain its components in good condition. For example, PSE currently uses CAPs at the Talbot Hill substation to avoid load shedding in winter months.

Reference: Energize Eastside Project

PSE considered CAPs in its Needs Assessment for the Energize Eastside project, recognizing that with growing demand CAPs alone would not be a sustainable solution. CAPs allow PSE transmission operators to temporarily mitigate system problems on the Eastside in order to keep the system operational during certain outages and maintenance procedures. However, each CAP increases the exposure to more widespread customer power outages if any further system upset occurs while the CAP is implemented. As load increases over time, more CAPs are needed for more hours of the year and system reliability decreases. Therefore, CAPs should not be regarded as a long-term solution.

Regional Compliance

Like all major electrical utilities, PSE's electrical supply system does not operate independently of other power providers in the region. The interconnected power system, or bulk electric system (BES) as it is commonly referred to, is intended to be cost and resource effective by allowing excess power generation in one part of the region to supply load in another. In addition, because of the characteristics of electricity, increased system reliability, voltage stability, and performance are achieved by employing an interconnected system.

Several regional agencies in the Northwest oversee the operation of the BES to ensure that it is capable of delivering electricity. These regional agencies are ultimately responsible on a national level to the Federal Energy Regulatory Commission (FERC) and NERC. Among other duties, these regional entities identify additions to the transmission system needed to ensure service to load and meet firm transmission service commitments into the future, while complying with national reliability standards. In order to participate in the benefits of the regional grid, PSE must adhere to these transmission reliability standards.

These standards have become more stringent in recent years, after lessons learned in the cascading blackout that struck the northeastern portion of North America in 2003. Particularly relevant to planning for the Energize Eastside project, the current standards require that the system must be capable of operating safely and reliably with two components being disabled (referred to as N-2 and N-1-1 scenarios), whereas past standards only required that the system operate reliably with one component disabled (referred to as N-1 scenarios).

The Eastside Needs Assessment Report and the Supplemental Eastside Needs Assessment Report mention several other reports prepared by regional agencies, or that PSE prepared in order to comply with these agencies' standards. Each of these reports investigated a range of solutions to meet a particular regional electric system need. Being regional, these studies often encompass several utilities in order to address a particular issue or range of issues.

The Energize Eastside project was discussed as one of the possible solutions in some reports, and it was found to help address regional transmission issues. This should not lead to the conclusion that Energize Eastside was conceived as a means to address these regional needs. It only means that PSE's proposed Energize Eastside 230 kV transmission line would benefit the reliability of the regional grid in addition to addressing the local capacity deficiency on the Eastside. Conversely, other regional solutions these reports investigated would address the regional issue but would not be effective for solving the local transmission capacity deficiency on the Eastside. This is because they were designed only to address the regional issue. Providing support for the electrical needs of the region should not be equated with support for the need identified for the Energize Eastside project.

Reference: Energize Eastside Project

For instance, in the past PSE has utilized various CAPs as mentioned above to meet some of its regional compliance issues for reliability. Yet, as was also indicated above, the enforcement of a CAP is a temporary solution that puts large numbers of Eastside customers at higher risk of a power failure, and the hours of exposure per year continue to increase.

Regional compliance is part of operating an electric utility. There is a tension between what is best for the region and what is best for the local utility.

<u>Summary</u>

Due to increasing load demand, the Eastside is quickly approaching a transmission capacity deficiency. If and when this deficiency develops, PSE's electrical supply system will reach a point where it cannot ensure the level of reliability that it is mandated to provide. Assuming projected growth occurs, the Supplemental Needs Assessment indicates this capacity will be reached as early as winter 2017 - 2018. This is not a prediction that weather conditions and load demand will converge in this time period and require load shedding. Rather, it is a projection that load demand will increase to a point where, if adverse weather conditions occur and one or more components of the system is not operating for any reason, load shedding would be required. Once the threshold is crossed, the physical limitations of the system are such that even the slightest overload will produce overheating that can damage equipment, and larger overloads will produce overheating more quickly. Once equipment is in an overload condition, the options are to let it fail or take it out of service. Both conditions leave the Eastside in a vulnerable state where the system is incapable of reliably serving customer load. At that point further actions may be needed such as load shedding in order to keep the system intact. By the end of the 10-year forecast period, a large number of customers would be at risk, and the load shedding requirement could be as high as 133 MW.

The deficiency is caused by load growth, which is a byproduct of economic growth and population increases in the Eastside area. Addressing the deficiency is difficult because the needed generation to supply this load growth is outside the service area and the available existing pathways to bring that power to the load have reached capacity. The load area in question is situated between two sources: Sammamish substation on the north end (Redmond/Kirkland area) and Talbot Hill substation on the south end (Renton area). These are the only two sites that effectively support this geographical area. Increases or decreases in load that are not directly supplied by these two substations, or power flow to other parts of the system outside the service area, have minimal effect on the ability of these substations to supply load. Only a direct interruption of supply power to or power fed from these two substations will affect the Eastside area. Once the higher voltage (230 kV) is transformed down to a lower voltage (115 kV) at these two substations, the system is limited by the physical capacity of the conductors and transformers that connect those two sources to the load and feed the area.

A simple analogy for the transmission problem on the Eastside would be the water pressure at a residence with a vegetable garden located at the back of the property. In the summer months the vegetable garden needs more water but there isn't enough pressure to deliver an adequate supply. Even if the homeowner increases the size of the hoses or adds more sprinklers, the pressure is divided among them and the flow at each sprinkler reduces to a trickle. To solve the problem the homeowner must either increase the pressure at the main, or develop another water source (such as a well) near the garden.

For the Eastside the highest load densities are north of I-90 and west of Lake Sammamish. In electrical systems, voltage is the pressure. As with the hoses and sprinklers, the physical limitations of the transformers and conductors dictate that the transformation sites closest to the load center will have best performance. Bringing a higher voltage source into the area and making the transformation to a lower voltage closer to the load increases the pressure at the source (comparable to the analogy of bringing a larger water main with plenty of pressure) and adequate power can flow to all parts of the area. The other solution is to produce a new source of power close to the load center. This would be some type of electrical generation (similar to adding a new well in the garden hose analogy). Other solutions would be less effective.

Energy conservation, technological advancements, and system operational improvements can and will slow the need for these infrastructure improvements. In its planning for Energize Eastside, PSE has assumed that a relatively high level of voluntary energy efficiency measures will be adopted within the Eastside over the coming decade, approximately 110 MW by 2024. The analysis PSE provided shows that even with these measures, the economic and population growth expected by planning agencies and businesses on the Eastside equates to the need for either more energy infrastructure, or at least 163 MW of additional conservation, over and above conservation already planned for the Eastside.

Energy conservation is one way of reducing load. But when increasing load has eclipsed increases in energy conservation and the electrical system is reaching capacity, the only other method is to open transmission lines. That is the purpose of CAPs: to reduce load, and therefore heating, by opening transmission lines. CAPs are temporary measures to help the system supply load. However, CAPs do not solve the long-term capacity issue, and when implemented they leave the system vulnerable to increased outages.

To understand this, the garden example can again be used. The homeowner has two sources of water to the garden, one from a faucet on the north side and one from the south much as Sammamish and Talbot Hill substations feed the Eastside load. It is a particularly hot mid-summer day, and the garden needs extra water. The homeowner connects more hoses to each faucet but realizes that even with the additional hoses and the faucets wide open, there is not enough water pressure to effectively water the garden. The only option is to disconnect a hose or two so that the others will have enough pressure to operate the sprinklers. Only now some of the garden is going without water (similar to load shedding in an electrical system). Also, depending on what is disconnected, large portions of the garden would be vulnerable to losing their water supply if the remaining hoses were damaged. In a garden, it may be possible to keep plants alive by rotating areas where the water is turned off, but in an electrical system, instead of plants it is people who will not have the electricity they need for a period of the day.

This is a simple analogy, but the situation with the Eastside power system is similar, except that instead of sprinklers that won't operate, an overloaded electrical system overheats. During peak load periods, operators use CAPs to turn off (referred to as opening) lines from either Sammamish or Talbot Hill substation to reduce heating on certain system transformers and lines so that they will not be destroyed. They may be able to keep the Eastside area supplied with electricity, but in doing so large areas of the Eastside may only be fed from one source. If something happens to that source, such as a tree falling into a line, or a car accidentally taking out a pole, or a piece of equipment fails due to fatigue, at that moment the last viable connection to a power source is gone and the lights go out. Even worse, as load continues to grow, or the area hits the coldest winter or hottest summer on record, the operator will be left with a decision: who will have power and who will not. Until the peak period is over, in order to reduce overloads to an acceptable level, large portions of the Eastside area could be left without power. A further possible consequence would be that hospitals, nursing homes, fire departments, police stations and other critical support services must run on emergency power or are without power. In this situation the event has become not just an inconvenience but a hazard.

There are a lot of questions surrounding the probability of these events occurring on the Eastside. Most people are likely unaware of how many times an outage is imminent or narrowly avoided. Attempting to specifically predict these events is nearly impossible because of the number of potential scenarios and permutations. Is it an extreme peak? Are 100% conservation levels being met? Is there a system component out for repair? Has an accident removed a piece of equipment from service? Has a natural or man-made disaster occurred that no one thought would ever happen? Was the forecast wrong and loads grew faster than expected? The permutations are endless.

Regional electrical reliability is important to local communities. Without a reliable regional backbone, energy generated by a wide variety of sources could not be efficiently delivered to the population areas that need it. All the utilities in the Northwest bear some responsibility to keep the transmission system in working order. However, a local utility's main role is its customers and each has a legal duty to provide electricity to customers in its service area.

The local utility has two roles to play. On the community level, it needs to provide an adequate infrastructure of facilities and equipment that can reliably deliver energy to its local customers. As a regional player, the utility provides its customers access to the larger interconnected system while making sure its system is as reliable as its regional neighbors' systems and not a detriment to the whole.

The Energize Eastside project is designed to bring the needed infrastructure to supply the local need. Any regional benefits that it provides would be added benefits of a stronger regional source, but these are not the primary reasons why the project has been proposed. The transmission capacity deficiency is driven primarily by local rather than regional growth. If the entire region surrounding the Eastside was eliminated or disconnected from Sammamish and Talbot Hill substations, and replaced with an independent 230 kV source of power at both ends, the result would be the same. The Eastside 230 -115 kV system as it exists cannot supply the projected load under all circumstances, with the required levels of reliability that the community and neighboring utilities expect.

STANTEC CONSULTING SERVICES INC.STANTEC CONSULTING SERVICES INC.

Reference: Energize Eastside Project

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ATTACHMENT D
Community Advisory Group Report

PUGET SOUND ENERGY

energizeEASTSIDE

community advisory group FINAL REPORT

January 2015

prepared by: enviroissues

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January-February 2014: Learned about the electric system, project need and routing

March-May 2014: Sub-area process and route segment input

June-July 2014: Narrowed the route options

October 2014: Evaluated the narrowed route options

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The Community Advisory Group reviewed and provided feedback on this report.

Executive summary

The Energize Eastside project will build a new electric substation and higher capacity (230 kV) transmission lines on the Eastside. In order to provide a forum that would generate robust input from diverse community stakeholders, Puget Sound Energy (PSE) convened a Community Advisory Group comprised of 24 representatives from various interests across the Eastside.

The Community Advisory Group's goals were to help identify and assess community values in the context of evaluating which route the new transmission lines should follow, and to develop a route recommendation for PSE's consideration.

Meeting schedule

The Community Advisory Group met eight times between Jan. 22 and Dec. 10, 2014. The advisory group discussed the following topics at each meeting:

- **Jan. 22:** Role of the advisory group and introduction to the project
- **Feb. 12:** Solution selection process and project routing
- **June 4:** Review key findings from the sub-area workshops and Sub-Area Committee meetings
- **June 25:** Review potential route options
- **July 9:** Narrow potential route options and finalize evaluation factors
- **Oct. 1:** Review key findings from the open houses and prepare for route evaluation
- **Oct. 8:** Develop a preliminary route recommendation
- **Dec. 10:** Finalize a route recommendation for PSE's consideration

Additional meeting details are included in section IV (Community Advisory Group activities).

Community outreach

The Community Advisory Group process was supplemented by broad and ongoing community outreach, including public events at key milestones. At outreach events, the community learned about outcomes of the advisory group process to date and submitted feedback that the advisory group considered in their discussions. Key outreach events included:

- **Jan. 29 and 30:** Open House #1
- **March - May:** Six sub-area workshops and three Sub-Area Committee meetings
- **April 21:** Question and Answer Meeting #1
- **July 7:** Question and Answer Meeting #2
- **Sept. 10 and 11:** Open House #2
- **Nov. 12 and 13:** Open House #3

Along with feedback collected at these outreach events, members of the public could also submit input and ask questions via email, voicemail and an online comment form on the project website. To help inform their discussion, the advisory group received monthly public comment summaries of more than 2,300 comments and questions received from the public, as well as summaries of comments received at open houses. Additional activities are detailed in section V (Community involvement).

Recommendation

On Dec. 10, the Energize Eastside Community Advisory Group selected route options Oak and Willow as their final route recommendation for PSE's consideration. Of the 22 advisory group members and four residential association alternates participating in the recommendation discussion, 20 supported the final recommendation.[1]

1 The above count includes the advisory group members and residential association alternates present at the Dec. 10, 2014 meeting, as well as six members and residential association alternates who did not attend the meeting but later provided feedback on the recommendation.

The final recommendation was based on the advisory group's work throughout 2014, including discussion of community feedback collected throughout the year. Six advisory group members and residential association alternates dissented from the recommendation and supported none of the routes.

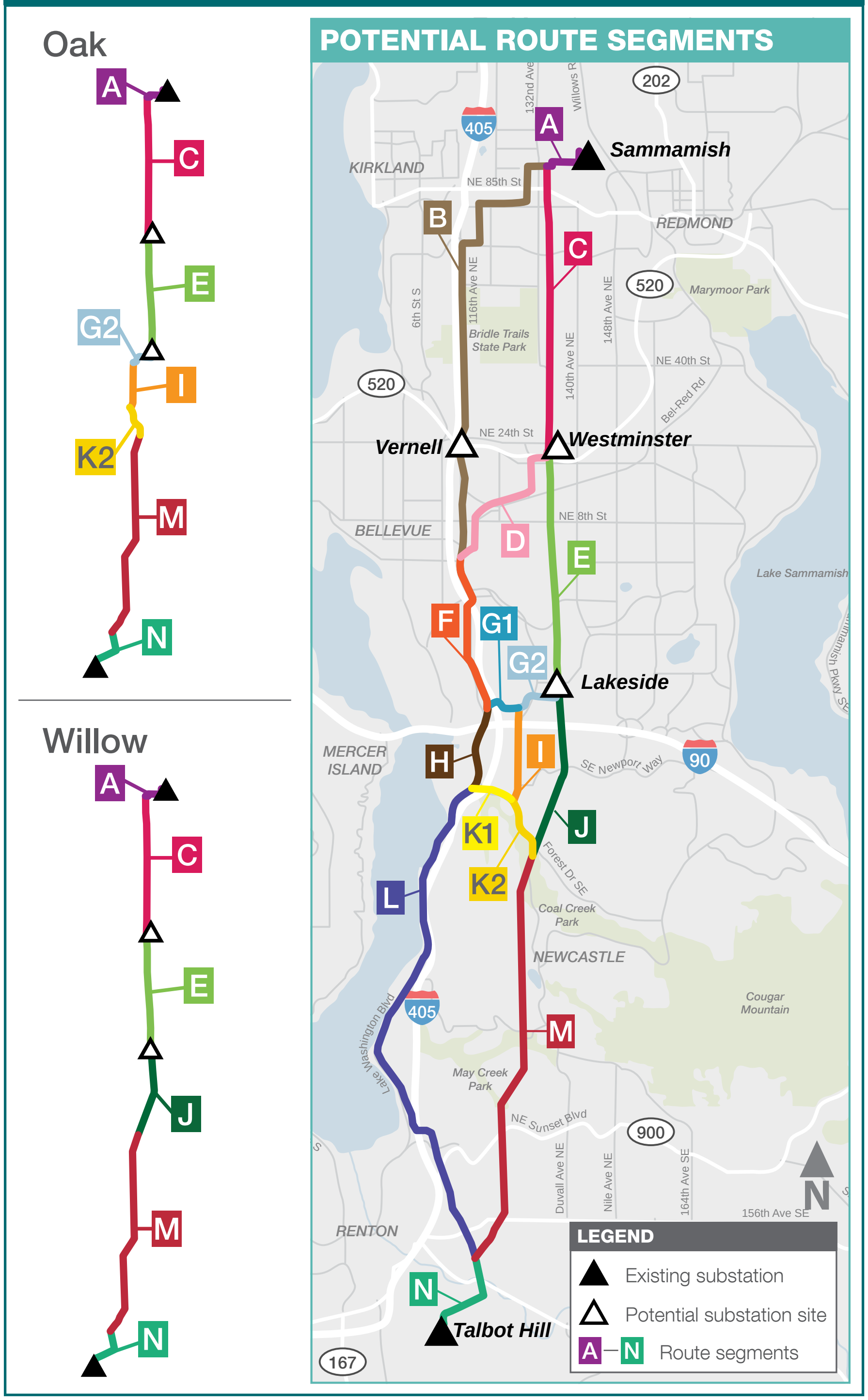
Next steps

Following the completion of the Community Advisory Group's process, PSE's next steps in 2015 are to:

- Take the Community Advisory Group's recommendation under consideration and make an announcement about routing that balances the needs of customers, the local community, property owners and PSE
- Work directly with property owners and tenants to begin detailed fieldwork to inform environmental review, design and permitting
- Ask for community input on project design, which may include pole height, finish and other design considerations
- Work with the City of Bellevue and other affected jurisdictions and agencies on the project's Environmental Impact Statement (EIS) process

Once these steps are complete, PSE will apply for necessary permits from appropriate agencies and jurisdictions. The project design and permitting phase is expected to run through early 2017. Once fully designed and permitted, project construction is expected to begin in 2017, with project completion planned for 2018.

COMMUNITY ADVISORY GROUP FINAL ROUTE RECOMMENDATION



I. Introduction

Growth studies presented by Puget Sound Energy (PSE) and third-party experts project that demand for reliable power on the Eastside will exceed capacity as early as the winter of 2017/2018.[1] These studies indicate that without substantial electrical infrastructure upgrades and aggressive conservation efforts, the Eastside's power system will lose redundancy, increasing the risk of more disruptive and longer outages for as many as 60,000 customers.

The Energize Eastside project will build a new electric substation and higher capacity (230 kV) transmission lines on the Eastside. The new 230 kV transmission lines will extend from the existing Sammamish substation in Redmond to the existing Talbot Hill substation in Renton, connecting with a new substation site in between. These upgrades will provide dependable power for Eastside communities for many years to come.

In January 2014, PSE convened a Community Advisory Group comprised of 24 representatives[2] from various interests across the Eastside. The purpose of the advisory group was to provide a forum that would generate robust input from diverse community stakeholders in compliance with comprehensive plan goals and policies, which promote public participation and/or coordinated utility siting. The Community Advisory Group's goals were to help identify and assess community values in the context of evaluating which route the new transmission lines should follow and to develop a final route recommendation for PSE's consideration.

1 Quanta Technology and Puget Sound Energy, *Eastside Needs Assessment Report*, 2013.

2 The Community Advisory Group consisted of 24 members at the beginning of the process; however, two member organizations (King County and Renton Technical College) withdrew without replacement.

Project Manager Jens Nedrud leads Community Advisory Group members on a tour of the project area.

Purpose of report

The purpose of this report is to document the work and summarize the recommendations of the Community Advisory Group convened by PSE to explore community preferences, priorities and concerns and to assess segments that could be combined to form a final route for the Energize Eastside 230kV transmission lines.

II. Project background

PSE's existing Eastside electric system had its last major upgrade in the 1960s. The electric system serves communities between Redmond to the north, Renton to the south, Lake Washington to the west and Lake Sammamish to the east. Power is currently delivered throughout the Eastside region using 115 kV transmission lines that run between two 230 kV substations – one in Redmond and one in Renton (see Figure 1).

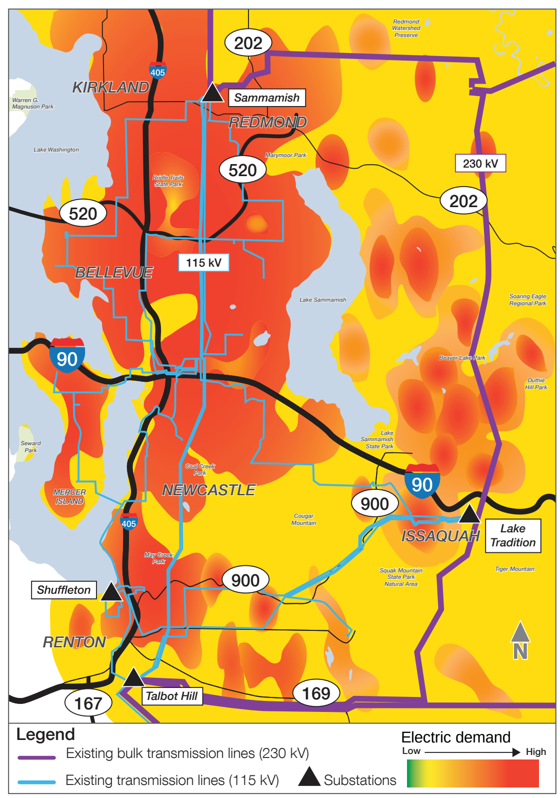
Since the system's last upgrade, the Eastside population has grown from approximately 50,000 to nearly 400,000 people, and this growth trend is expected to continue. Puget Sound Regional Council projections indicate that the Eastside population will grow by more than a third between 2010 and 2040.[1] Not only have Eastside communities grown and prospered, but the way Eastside residents use electricity has changed. Home square footage has increased, requiring more energy for lighting, heating and air conditioning. Additionally, most devices and appliances plugged in today did not exist years ago. Despite improvements in energy efficiency and aggressive conservation efforts, demand for electricity has grown dramatically.

Federal standards require PSE to plan for future forecasted loads and upgrade the system accordingly. Forecasted loads for transmission purposes are based on historical load data as well as a variety of other inputs, including information about weather, regional and national economic growth, demographic changes, conservation, and other customer usage and behavior factors. In 2013, PSE published the *Eastside Needs Assessment*. Prepared with assistance from independent experts, the study demonstrated that the increased demand is already placing a strain on the electric system. As growth continues, the existing system will only become more stressed, increasing the possibility of widespread outages, especially during peak winter loads when customer electricity use is greatest.

To determine a solution, PSE and independent experts conducted multiple independent analyses of the existing system and studied a variety of options to address the growing need on the Eastside, including further reducing demand through conservation, increasing the capacity of existing electric transmission lines, generating energy locally, and building new infrastructure.

After a comprehensive review, PSE determined that a combination of continued conservation and infrastructure upgrades – a new substation and higher capacity 230 kV transmission lines – will meet growing demand on the Eastside and ensure reliable electricity for years to come. [2,3]

Figure 1. The Eastside's electric system and demand



1 Puget Sound Regional Council 2013 Land Use Baseline: Maintenance Release 1 (MR1), update April 2014.

2 Energy + Environmental Economics, *Non-wire Solutions Analysis*, 2014.

3 Quanta Technology and Puget Sound Energy, *Eastside Transmission Solutions Report*, 2013.

III. About the Community Advisory Group

Purpose

The purpose of the Community Advisory Group was to evaluate the potential route options identified by PSE and independent experts, help PSE better understand community and property owner values and concerns, and determine a route recommendation for PSE's consideration. The Community Advisory Group process and final route recommendation will help PSE evaluate and consider routes that balance the needs of its customers, the local community, property owners and PSE.

Throughout the community outreach process, the Community Advisory Group:

- Developed an understanding of the Energize Eastside project and project need
- Reported back to the constituents they represented on project details, gathered feedback from the interests they represented, and provided ongoing communication between PSE and their constituents throughout the process
- As community representatives, provided advice on ways to address community concerns
- Participated in geographic Sub-Area Committee meetings to identify local concerns and values
- Worked collaboratively and constructively to help consider community and property owner values
- Engaged in a process to evaluate route options
- Determined a final route recommendation for PSE's consideration

The Community Advisory Group codified its purpose, process and guidelines in its Charter (Appendix A), agreed upon by consensus.

Membership

The Community Advisory Group was made up of representatives from various interests, including neighborhood organizations, cities, schools, social service organizations, major commercial users, economic development groups, an environmental organization and a property developer. See Table 1 for members, including which interests each member represented and their specific organization or affiliation.

Learning about the project need and advisory group process at Community Advisory Group Meeting #1 in Bellevue.

Table 1: Community Advisory Group members

Interest	Organization or affiliation	Name
City	City of Bellevue	Nicholas Matz
	City of Kirkland	Rob Jammerman
	City of Newcastle	Tim McHarg
	City of Redmond[1]	Pete Sullivan (primary) Lori Peckol (alternate) Cathy Beam (alternate)
	City of Renton	Gregg Zimmerman
Economic development organization	OneRedmond	Bart Phillips
	Renton Chamber of Commerce	Brent Camann
Environmental organization	Mountains to Sound Greenway	Floyd Rogers
Jurisdiction	King County[2]	David St. John (primary) Mary Bourguignon (alternate)
Major commercial/ industrial user	Overlake Hospital Medical Center	Sam Baxter (primary) Jeff Fleming (alternate)
	Renton Technical College[3]	Steve Hanson
Property developer	Master Builders Association	David Hoffman
Puget Sound Energy	Puget Sound Energy	Andy Swayne
Residential organization (Bellevue)	Somerset Community Association	Steve O'Donnell
	Wilburton Community Association	Robert Shay
	Bridle Trails Community Club	Norm Hansen
Residential organization (Kirkland)	South Rose Hill/Bridle Trails Neighborhood Association	Deirdre Johnson (primary) Jim McElwee (alternate)
Residential organization (Newcastle)	Olympus Neighborhood Association	David Edmonds (primary) Sean McNamara (alternate) Sue Stronk (alternate)
Residential organization (Redmond)	Redmond Neighborhoods	David Chicks
Residential organization (Renton)	Kennydale Neighborhood Association	Darius Richards
School district	Bellevue School District	Jack McLeod (primary) Kyle McLeod (alternate)
	Lake Washington School District	Brian Buck
Social service organization	Coal Creek Family YMCA	Marcia Isenberger (primary) Paul Lwali (alternate)
	Hopelink	Nicola Barnes

1 In October 2014, Pete Sullivan relocated and was unable to attend meetings thereafter, but remained involved in the process.

2 King County was invited to have a staff representative serve on the advisory group. King County staff attended two introductory meetings but then withdrew from the process.

3 In October 2014, Steve Hanson of the Renton Technical College resigned due to lack of availability to participate fully in the process.

Residential association alternates

To provide an opportunity for additional input and representation from the residential community, four residential association alternates were appointed. These alternates were appointed from different neighborhood associations than the advisory group members representing residential interests. The four residential association alternates included:

- **Scott Kaseburg**, Lake Lanes Community Association (Bellevue)
- **Bill Taylor**, Liberty Ridge Homeowners Association (Renton)
- **Lindy Bruce**, Sunset Community Association (Bellevue)
- **Barbara Sauerbrey**, Woodridge Community Association (Bellevue)

Past members and residential association alternates

Over the course of the advisory group's work, the following membership changed due to varying circumstances:

- **Mark Rigos**, City of Newcastle (replaced by Tim McHarg)
- **Jules Dickerson**, Lake Lanes Community Association (replaced by Scott Kaseburg)
- **Lynn Wallace**, Renton Chamber of Commerce (replaced by Brent Camann)
- **Debra Grant**, Hopelink (replaced by Nicola Barnes)

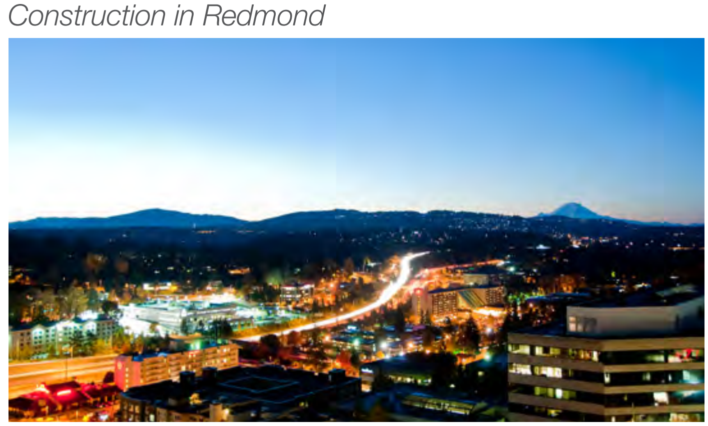
Invited

The following entities were invited and chose not to participate in the Community Advisory Group process, but were informed of project milestones and meetings through postcards and newsletters:

- Muckleshoot Tribe
- Yakama Nation

Aerial view of downtown Renton

Construction in Redmond



Downtown Bellevue at night

IV. Community Advisory Group activities

Meeting schedule

The Community Advisory Group met eight times from January to December 2014. All Community Advisory Group meetings were open to the public and included a period for public comment. For links to advisory group meeting materials, presentations and summaries, see Appendix C.

During this process, PSE hosted three series of public open houses, during which the public could learn about major advisory group milestones and consult with PSE and advisory group representatives. The advisory group used community input from these open houses as well as from sub-area workshops and Sub-Area Committee meetings, community surveys, public comment periods, monthly public comment summaries, and personal communications with constituents to inform their discussions. See Table 2 for a list of advisory group and community meetings held in 2014.

Table 2: 2014 Community Advisory Group and public outreach meeting schedule

Date	Meeting type	Purpose
Jan. 22	Community Advisory Group meeting	Learned about project need and Community Advisory Group process
Jan. 29 & 30	Open House	Broader community learned about the project need, the Community Advisory Group process, and opportunities to get involved
Feb. 12	Community Advisory Group meeting	Learned about PSE's solution selection process and project routing
February – May	Project area tours and sub-area process	Learned about the potential route segments via project area tours provided by PSE; attended sub-area workshops to identify local community values and concerns; determined key findings from sub-areas (See Table 3 for more details)
June 4	Community Advisory Group meeting	Reviewed key findings about the segments gathered at sub-area workshops and Sub-Area Committee meetings; developed community values-based evaluation factors to be used to evaluate the route options
June 25	Community Advisory Group meeting	Reviewed qualitative and quantitative information about the 18 potential route options made by combining route segments
July 9	Community Advisory Group meeting	Narrowed potential route options and finalized evaluation factors
Sept. 10 & 11	Open House	Broader community provided feedback on narrowed route options and weighting of evaluation factors via survey
Oct. 1	Community Advisory Group meeting	Reviewed key findings from September open houses and prepared for a Multi-Objective Decision Analysis evaluation of the routes
Oct. 8	Community Advisory Group meeting	Determined preliminary route recommendation for public review at November open houses
Nov. 12 & 13	Open House	Broader community provided feedback on advisory group's preliminary route recommendation
Dec. 10	Community Advisory Group meeting	Reviewed key findings from the November open houses; finalized route recommendation for PSE's consideration

Key Community Advisory Group discussion topics

The Community Advisory Group discussed many topics over the course of the process. The following topics were most commonly addressed. Descriptions include the advisory group's expressed concerns and PSE's response shared over the course of the advisory group process.

Scope confined to an overhead solution

Some members of the advisory group asked whether PSE would consider other alternatives besides an overhead solution. Those members also asked if considering other alternatives could fall under the advisory group's purview. Before launching the Energize Eastside, PSE studied several different solutions in addition to building the new overhead transmission lines. Those alternatives included reducing demand through conservation, increasing the capacity of PSE's existing electric transmission lines, generating energy locally, and building new infrastructure. However, PSE concluded other solutions were inadequate to solve the problem, and the advisory group was formed to gather feedback on an overhead transmission line solution.

Underground transmission lines

Among the most discussed alternatives to an overhead solution was underground transmission lines. PSE explained that overhead transmission lines are PSE's first option for service due to reliability and affordability. The biggest challenge to underground transmission lines is cost. The construction costs for an overhead transmission line are about $3 million to $4 million per mile, versus $20 million to $28 million per mile to construct the line underground. Per state-approved tariff schedule 80, section 34, the local jurisdiction or customer group requesting underground transmission lines must pay the difference between overhead and underground costs. PSE explained they are willing to sit down with interested communities to discuss undergrounding as an option; however, those communities must decide how to pay for the difference in costs, which must be provided up front.

Submarine cables

Some advisory group members expressed interest in PSE pursuing transmission lines submerged under Lake Washington, and pointed to other submerged transmission projects, such as one in San Francisco. PSE presented research on that project, and noted that it costs an average of $56.2 million per mile, compared to the $3 million to $4 million per mile of overhead transmission. As with undergrounding, according to tariff schedule 80, section 34, the local jurisdiction or customer group requesting submerged transmission lines must pay the difference between overhead and submarine costs.

Batteries

Some advisory group members were interested in learning more about battery technology and local energy storage as an alternative to the project. PSE explained that using batteries instead of building a new substation was considered during the solutions identification process, but the technology has not been used for the type and scale of problem facing the Eastside. Additionally, new transmission lines would still be required to distribute electricity from the battery site to PSE's customers.

Seattle City Light corridor

Some advisory group members also asked PSE about using the Seattle City Light (SCL) utility corridor as an alternative to site the new transmission lines. Early on in the solution identification process, PSE identified the SCL transmission corridor as a potential solution to meet the Eastside's energy needs. PSE asked SCL for permission to use their transmission corridor. However, SCL has told PSE that their corridor is a key component of Seattle City Light's transmission system and not available for PSE's use. A letter from SCL articulating this position is available on the Energize Eastside project website. See Appendix D.

Olympic Pipeline safety

Some advisory group members expressed concern over the safety of building the project near the Olympic Pipeline. PSE explained that building 230 kV lines along the Olympic Pipeline (owned and operated by British Petroleum (BP)) would be safe. The Olympic Pipeline has coexisted with PSE transmission lines in the Eastside corridor for over fifty years. PSE also has a long history of working closely with BP and is a natural gas pipeline operator itself. PSE and its contractors are very familiar with concerns regarding pipeline safety and employ safe construction practices when performing work in the vicinity of pipelines. If a selected route is comprised of segments that include the Olympic Pipeline, PSE will continue to work with BP to ensure safety during and after construction.

Property values

Some advisory group members expressed concern about the effects on property values as a result of the Energize Eastside project and asked whether property values could be considered as a factor for evaluating route options. Property values are comprised of many factors, including economic outlook and location, as well as proximity to jobs, schools, transportation, parks and other amenities. PSE explained that it does not use property values as a factor when selecting routes out of fairness to and in consideration for customers of all income levels, noting that it is socially inequitable to site infrastructure based on income-related considerations. Similarly, a project's potential effects on surrounding property values are excluded from consideration of impacts to the environment under Washington's State Environmental Policy Act (SEPA).

Electric and magnetic fields

Several advisory group members asked whether exposure to electric and magnetic fields (EMF) had any effect on health. A third-party, board-certified health physicist explained that over the past 45 years, there have been many scientific studies conducted to determine whether EMF from transmission lines (called "power frequency EMF") has any effect on human health. To date, this large body of research does not show that exposure to power frequency EMF causes adverse health effects.

January-February 2014: Learned about the electric system, project need and routing

The Community Advisory Group began their process by learning about the current electrical system, the need for the project and the solution selection process. During this learning period, the advisory group asked PSE questions on a variety of topics, including transmission line siting, other options considered for the project (e.g., battery technology and conservation), and how a solution was determined. PSE's real estate, engineering and system planning staff provided detailed responses to these questions.

Communications Manager Gretchen Aliabadi explains the undergrounding tariff at Community Advisory Group Meeting #3 in Redmond.

PSE explained in detail its process to identify a solution and route options, which included the following steps:

1. **Determine the potential approaches to meet the Eastside's electricity needs:** PSE evaluated the potential of several approaches – conservation, local generation and new infrastructure – to meet the Eastside's electricity needs.
2. **Review approaches to provide enough electricity to meet the Eastside's needs:** Engineers reviewed alternatives to each approach, and found that only new generation on the Eastside or new infrastructure located near the center of high electricity demand could meet the Eastside's needs. Additionally, aggressive conservation goals would need to continue.
3. **Review solutions that best deliver electricity to the Eastside:** Engineers reviewed different generation and electric infrastructure alternatives based on system performance, flexibility and longevity. A new generation facility on the Eastside was eliminated from consideration due to difficulties related to siting and operational limitations. It was determined that the best solution to meet the Eastside's electricity needs was to 1) construct a new 230 kV substation and 2) construct new 230 kV transmission lines connecting the new substation with the two existing substations in Redmond and Renton.
4. **Determine which solutions PSE can move forward with:** PSE eliminated the Seattle City Light Corridor and one of the potential Bellevue substation sites as possible new infrastructure locations. Neither the corridor nor the proposed substation property is owned by PSE and other viable sites for new infrastructure were available.
5. **Review where PSE could build a solution:** Engineers used a computer-based modeling tool to analyze key criteria like geographic barriers, land uses and impacts to the environment. Based on this analysis, route segments were identified that could be combined into various complete route options that connect to potential substations (see Figure 2).[1]
6. **Ask what the public thinks:** PSE asked the public to provide input on the combination of route segments that best serves the Eastside's needs. The Community Advisory Group process was part of a larger public outreach process that also included neighborhood briefings, community meetings at key milestones, question and answer sessions, and an interactive project website.

Figure 2. Potential route segments

March-May 2014: Sub-area process and route segment input

In spring 2014, members of the Community Advisory Group participated in one or more of three Sub-Area Committees focused on the following geographic areas:

- North: Kirkland, Redmond and North Bellevue
- Central: Bellevue
- South: Newcastle and Renton

Sub-Area Committee membership included advisory group members and residential association alternates from the geographic

1 TetraTech, *Eastside 230 kV Project Opportunity and Constraints Study for Linear Site Selection*, 2013.

sub-areas. Invitations to serve on the committees were also extended to a representative from each potentially affected neighborhood association (i.e., those who lived near a potential segment) that did not have a member or residential association alternate on the advisory group.

PSE hosted six sub-area workshops and three Sub-Area Committee meetings across the project area. The three Sub-Area Committees developed findings on specific sub-area values, concerns and considerations about route segments from the workshops conducted in each of the sub-areas. The committees' findings served as a source of information that the Community Advisory Group considered in developing evaluation factors and narrowing the route options. See Table 3 for details on schedule and objectives of the sub-area workshops and Sub-Area Committees.

Discussion about route segments at a Central sub-area workshop in Bellevue.

Discussion about route segments at a South sub-area workshop in Renton.

Table 3: Sub-area workshops schedule and objectives

Dates	Meeting type	Purpose
North: March 19, 2014 Central: March 26, 2014 South: March 27, 2014	Sub-Area Workshop #1	Community members: • Identified key issues and considerations for segments in the sub-area • Brainstormed community values • Requested data that would be helpful to compare segments
North: April 16, 2014 Central: April 23, 2014 South: April 24, 2014	Sub-Area Workshop #2	Community members: • Reviewed data and photo simulations PSE prepared based on requests from Workshop #1 • Used data to score all the route segments individually and as a group • As a group, wrote key messages to the Sub-Area Committee
North: May 7, 2014 Central: May 14, 2014 South: May 15, 2014	Sub-Area Committee meeting	Sub-Area Committees determined key findings from sub-areas to share with the Community Advisory Group

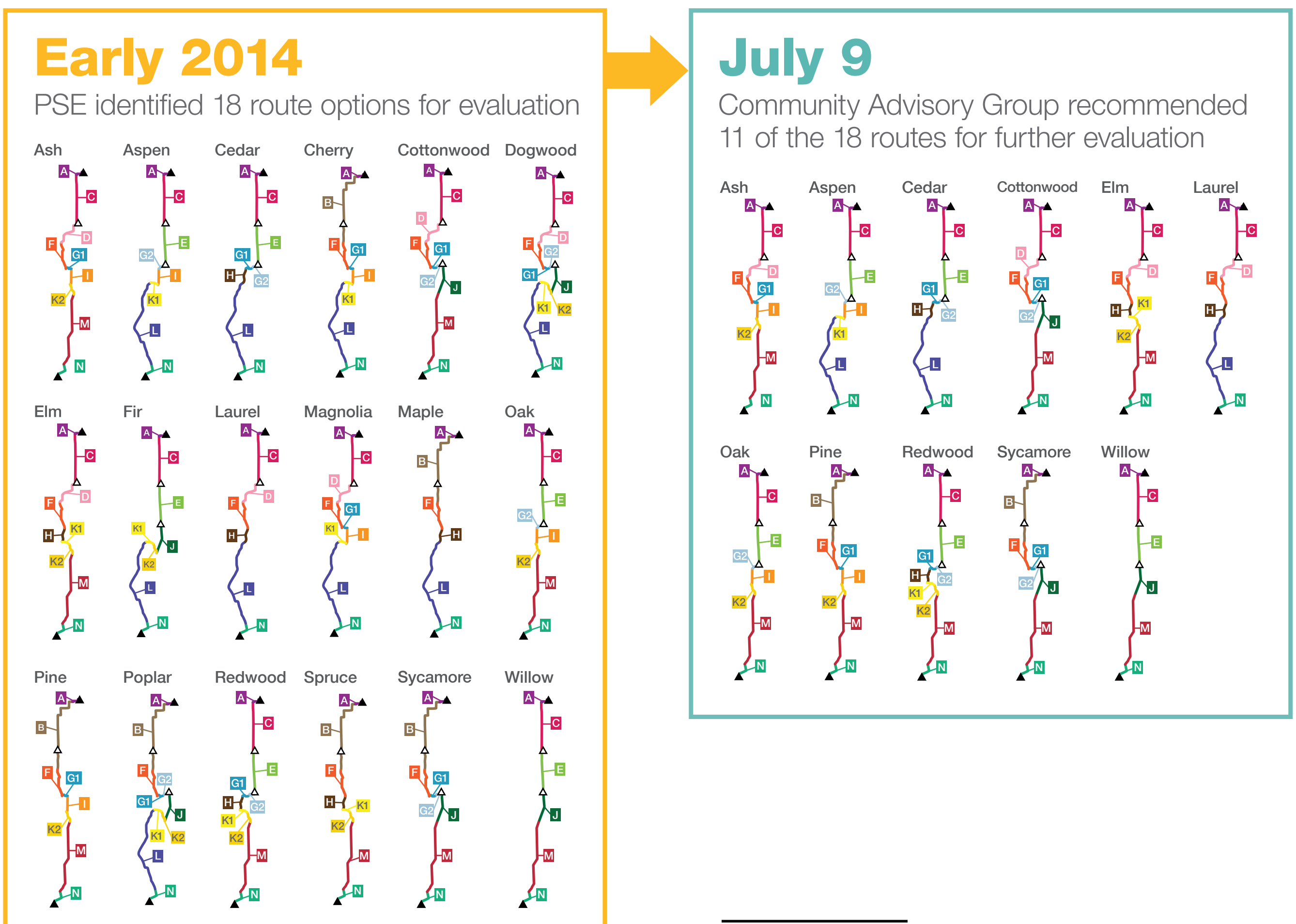
June-July 2014: Narrowed the route options

After segment-specific input was collected through the sub-area process, the Community Advisory Group considered 18 route options made from combining the route segments. (These route options were assigned tree names, such as “Ash,” “Aspen,” and “Cedar,” for easier reference.) The advisory group also identified community values-based evaluation factors.

At their meeting on July 9, the advisory group reviewed the 18 route options and recommended 11 route options for further evaluation.[2] (See Figure 3.) Information that aided their discussion included:

- Feedback from sub-area workshops and Sub-Area Committee meetings, as well as other community input
- Quantifiable data on route options, photo simulations, and information from PSE on route cost, constructability and maintainability
- Results from a blind evaluation of the 18 route options completed by 23 advisory group members
- Initial recommendations submitted before the meeting by eight advisory group members on which route options to remove from further evaluation[3]
- Discussion of route segments and the 18 route options at advisory group meetings

Figure 3: Narrowed route options in July 2014



2 Four advisory group members initially recommended that all or a majority of the 18 routes should move forward for further evaluation.

3 While eight advisory group members provided their initial input before the meeting, all members present at the meeting on July 9 discussed what route options to remove from further evaluation.

October 2014: Evaluated the narrowed route options

The Community Advisory Group used nine evaluation factors (see Table 4), as well as specific route option data, to evaluate the narrowed route options through a process called Multi-Objective Decision Analysis (MODA). MODA is a process for making decisions when there are complex issues involving multiple criteria and multiple parties who may have an interest in the outcome.

Using MODA allows individuals to consider and weight factors and trade-offs while evaluating each alternative (in this case, each route option). Evaluation factors were weighted to reflect the relative importance ascribed to each factor. After scoring each route option for each evaluation factor, the advisory group then discussed the combined group results to help decide on a recommendation. See Figure 4 for a description of the MODA steps and how the advisory group used MODA.

Between Oct. 2 and Oct. 6, 2014, 19 of 24 advisory group members completed individual evaluations of the 11 route options recommended for further evaluation as part of the MODA process. Using online software called Transparent Choice, advisory group members individually scored each route option using each of the nine evaluation factors on a five-point scale. The software then applied two sets of weightings – one determined by the advisory group and another determined by community members who participated in a summer 2014 feedback survey – to the group's averaged scores. See Table 4 for descriptions of the evaluation factors and the two weighting schemes.

Figure 4: Multi-Objective Decision Analysis (MODA)

MODA steps

1. **Factors** - Discuss and agree on evaluation factors
2. **Weighting** - Determine relative importance of each factor and assign corresponding weights
3. **Route options** - Determine route options to evaluate
4. **Scoring** - Score each route option for each weighted factor
5. **Decision** - Discuss results and determine decision

How the Community Advisory Group used MODA

1. **Selected nine evaluation factors** based on community values
2. **Used two sets of weightings** - one determined by the advisory group and a second determined by a community survey
3. **Selected 11 route options** out of 18 to include in the evaluation
4. **Scored** the 11 route options for how well they each met the nine evaluation factors using an online software called Transparent Choice
5. **Considered MODA results** along with community feedback and other sources of information to select four routes as their preliminary route recommendation

Table 4: Evaluation factors and their weightings determined by the advisory group and a community survey

Evaluation factor	Advisory group weighting	Community survey weighting
Avoids impacts to aesthetics (Pole design and views)	5%	14%
Avoids residential areas (Number of residences)	24%	31%
Avoids sensitive community land uses (Parks and other recreational areas, schools, religious institutions, etc.)	13%	10%
Avoids sensitive environmental areas (Wetlands, wildlife habitat, steep slopes, fault lines, etc.)	7%	12.5%
Least cost to the rate payer (Estimated monthly increase to average residential customer; calculation based on total cost)	14%	7%
Maximizes longevity (When in the future additional 230 kV infrastructure is anticipated based on current technology and growth projections)	9%	4%
Maximizes opportunity areas (Runs along existing utility corridors, railroad right of way, public right of way, etc.)	15%	6%
Protects health and safety (Electric and magnetic fields, Olympic Pipeline, etc.)	9%	9%
Protects mature vegetation (Number of trees greater than four inches impacted)	4%	6.5%
Total	100%	100%

On the following page, Figures 5 and 6 present the MODA results for each route option, first using the advisory group weighting and second the community survey weighting. Within the results bar for each route option, colors represent the evaluation factors and show the advisory group's averaged and weighted score for each factor. A higher number equals a better score. Weighting percentages are shown in the weighting keys.

Figure 5: MODA results - Advisory group weighting

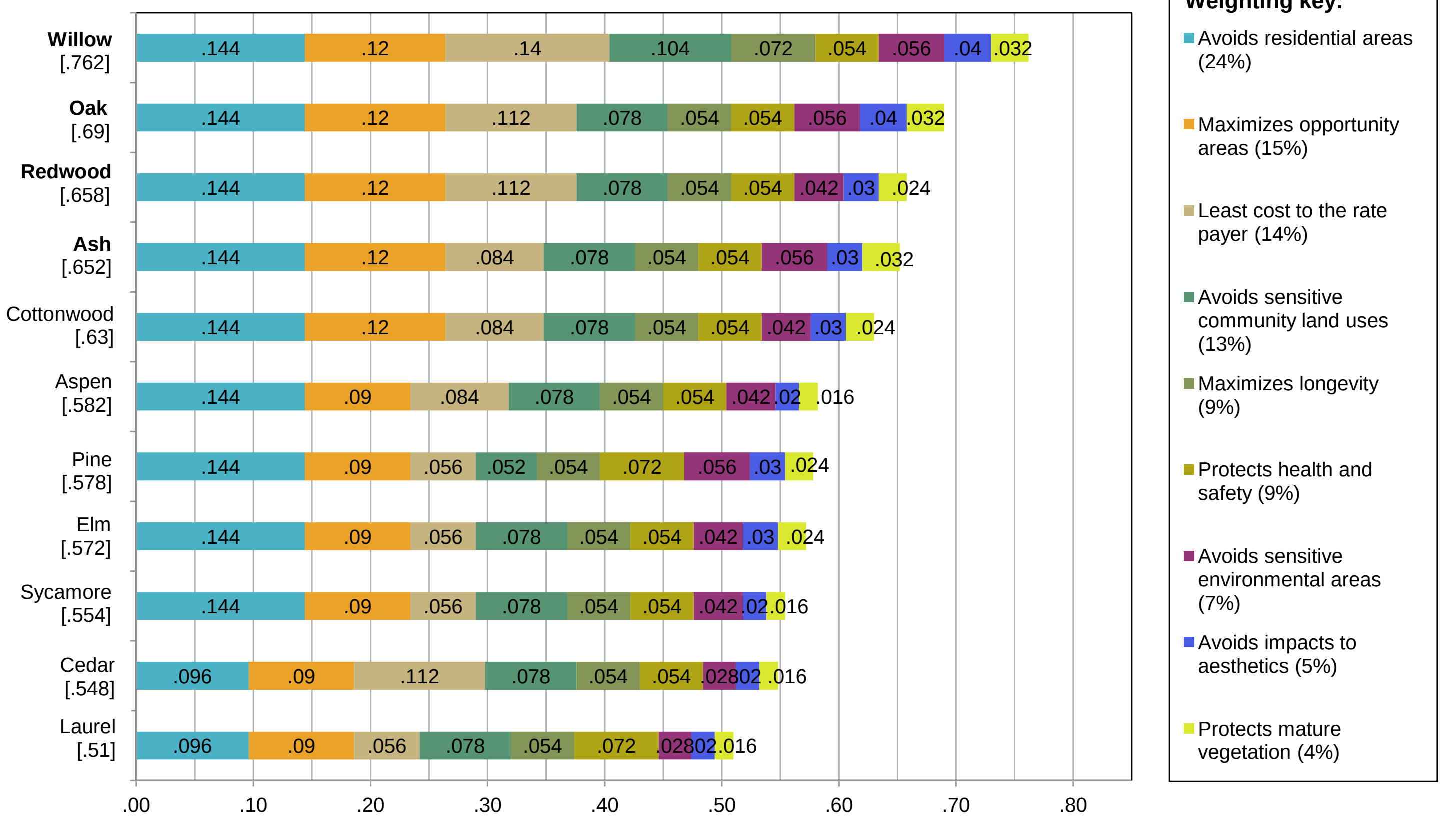
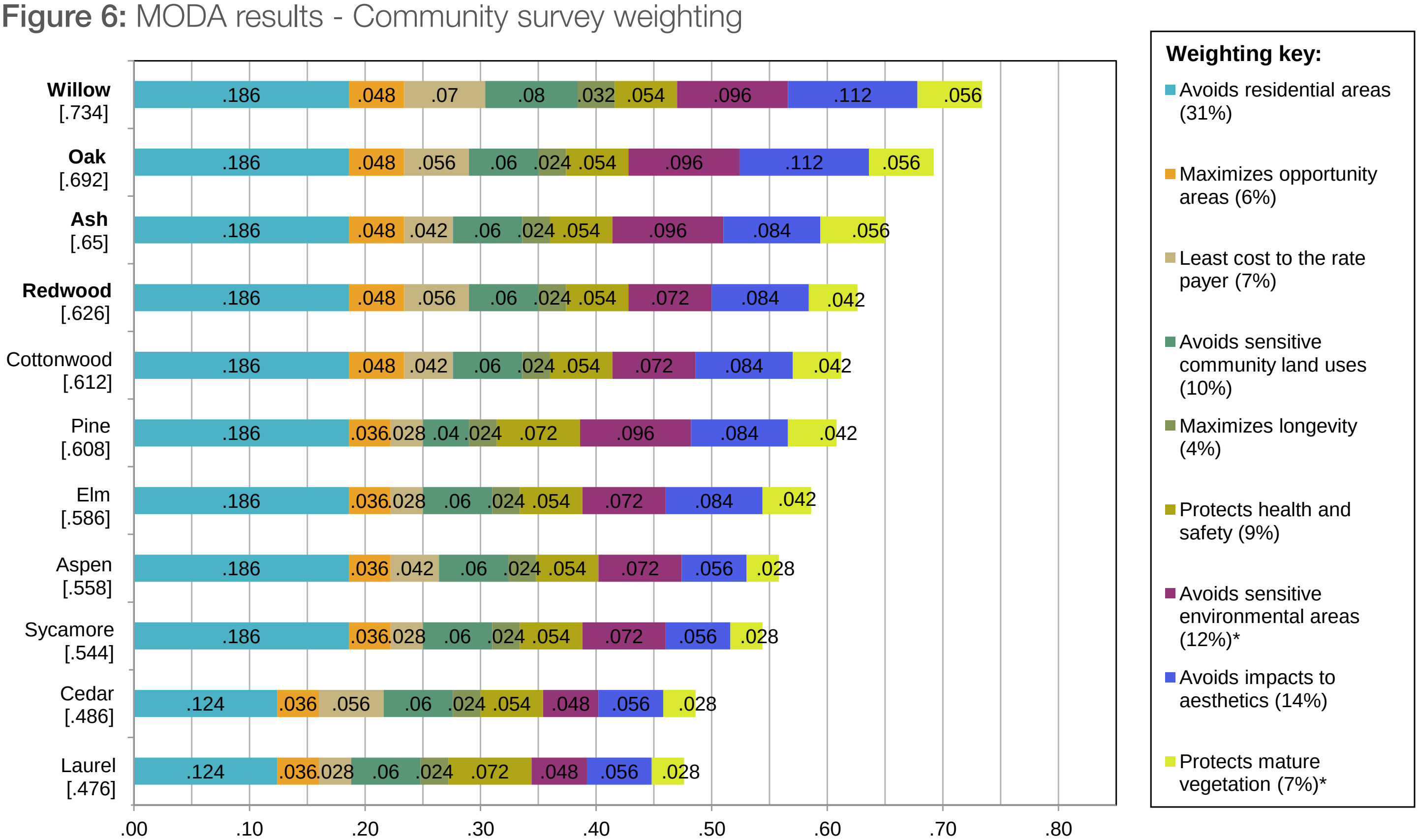


Figure 6: MODA results - Community survey weighting



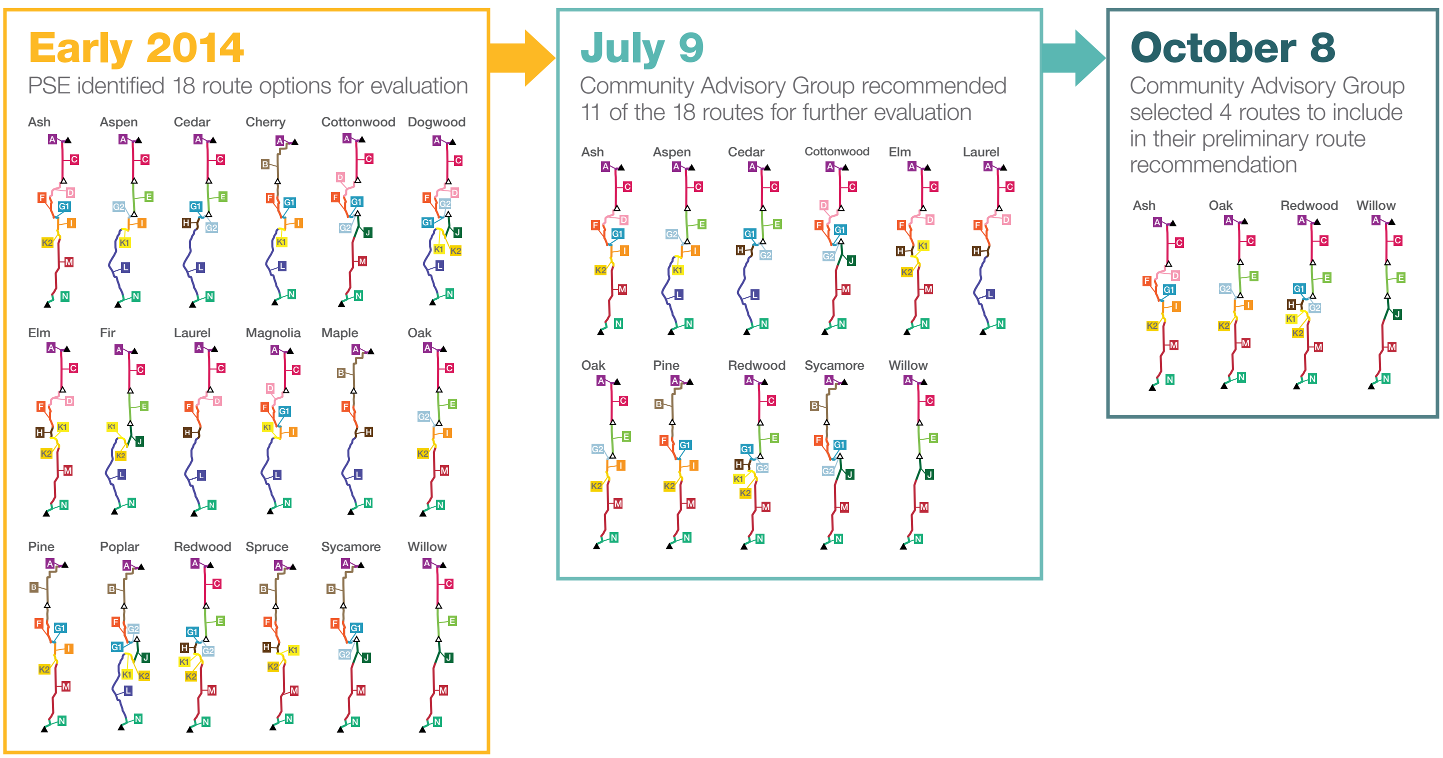
* Note: Transparent Choice, the online MODA software used to compile and calculate results, can only use weighting values that are whole numbers. As a result, the evaluation factors “Avoids sensitive environmental areas” and “Protects mature vegetation” were rounded to the nearest whole number.

October 2014: Preliminary route recommendation

At their Oct. 8 meeting, the advisory group selected four route options – Ash, Oak, Redwood and Willow – as their preliminary route recommendation (see Figure 7).[4] Information sources that helped the group determine their recommendation included:

- Results of the Multi-Objective Decision Analysis (MODA) using evaluation factor weightings from both the advisory group and community survey results
- Feedback from the summer community survey and other community input
- Discussion of the 11 route options at advisory group meetings

Figure 7. Narrowed route options and the preliminary route recommendation in October 2014



4 Of the 18 members present, 15 supported the recommendation, two members abstained and one had a dissenting opinion to include only three routes.

Reviewing results from the blind evaluation at Community Advisory Group Meeting #4b in Renton.

V. Community involvement

In addition to convening the Community Advisory Group, PSE involved the community in the public routing discussion from announcement of the project (December 2013) through the completion of the advisory group process (December 2014) by hosting community meetings, briefing organizations and gathering and responding to comments about the project.

PSE community involvement included:

- More than 240 briefings with individuals, neighborhoods, cities and other stakeholder groups
- 6 public open houses at key project milestones
- 2 online open houses
- 2 question and answer community meetings
- 1 webinar on undergrounding and electric and magnetic fields

Additional project outreach included:

- More than 2,300 comments and questions received from the public, summarized in monthly public comment and open house summaries made available to the advisory group
- 6 project newsletters and postcards sent to more than 50,000 residents and business owners
- Attendance at more than 60 community events
- A traveling kiosk displaying project updates throughout the Eastside
- Project update emails to distribution list, community organizations and elected officials
- Targeted outreach to traditionally underrepresented populations

Reviewing route option maps at Open House #1 in Renton.

Community Projects Manager Jackson Taylor providing project background at the Bellevue Strawberry Festival.

Public comment at Question and Answer Meeting #1 in Renton.

VI. Recommendation of the Community Advisory Group

On Dec. 10, 2014, the Community Advisory Group selected routes Oak and Willow as their final route recommendation for PSE's consideration (see Figure 8).

With this recommendation, the Community Advisory Group fulfilled their purpose as outlined in their charter:

"Work collaboratively, creatively and constructively to help determine community/property owner values and engage in a process to evaluate route segments and select a recommended route option."

Twenty-two advisory group members and four residential association alternates participated in the recommendation discussion. Twenty supported the final recommendation as follows:[1]

- Ten expressed preference for the Oak route
- Five expressed preference for the Willow route
- Five did not express a preference

Figure 8. The Community Advisory Group final route recommendation

Four advisory group members and two residential association alternates[2] – representing Bridle Trails Community Club, City of Newcastle, Liberty Ridge Homeowners Association, Olympus Neighborhood Association, Somerset Community Association, and Sunset Community Association – dissented from the recommendation and supported none of the routes. Refer to Appendix B for the dissenting opinion.

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1 The above count includes the advisory group members and residential association alternates present at the Dec. 10, 2014 meeting, as well as six members and residential association alternates who did not attend the meeting but later provided feedback on the recommendation.

2 Darius Richards (Kennydale Neighborhood Association) and Scott Kaseburg (Lake Lanes Community Association), who supported the final recommendation in the meeting, signed the dissenting report after the meeting.

At the Dec. 10 meeting, advisory group members and residential association alternates who expressed a preference for Oak or Willow discussed several benefits and tradeoffs of each. See Table 4.

Table 4. Route benefits and tradeoffs noted by Community Advisory Group members and residential association alternates with a route preference expressed at the Dec. 10 meeting[3]

Routes	Benefits	Tradeoffs
Oak (Segments: A-C-E-G2-I-K2-M-N)	• Has fewer adjacent residential parcels (524) of the two routes • Has one quarter of adjacent residential parcels (31 in segments G2, I, K2) compared to same portion in Willow (123 in Segment J) and less than half the residences within 600 feet (289 vs. 721) • Avoids residential areas by using Segment I, which is a largely commercial corridor	• Estimated cost is $22 million more than Willow ($176 million total cost; $1.03 estimated monthly increase to an average residential customer) • Requires building infrastructure in new areas (83% of the route is within the existing corridor) • Has a larger number of adjacent residential tax accounts (1,425)
Willow (Segments: A-C-E-J-M-N)	• Has fewer adjacent residential tax accounts (1,422) of the two routes (One advisory group member noted that the difference in residences between Oak and Willow was minor.) • Is the most direct route • Has the highest percentage of route within the existing corridor (100%) • Is the least expensive ($154 million total cost; $0.90 estimated monthly increase to an average residential customer) • Has the greatest longevity (2038)	• Has a larger number of adjacent residential parcels (616) of the two routes • Uses Segment J, which is a view neighborhood

3 For more data on Oak, Willow, and all route options considered by the Community Advisory Group, refer to the complete route options data table on the Energize Eastside project website.

Discussing the final route recommendation at Community Advisory Group Meeting #6 in Bellevue.

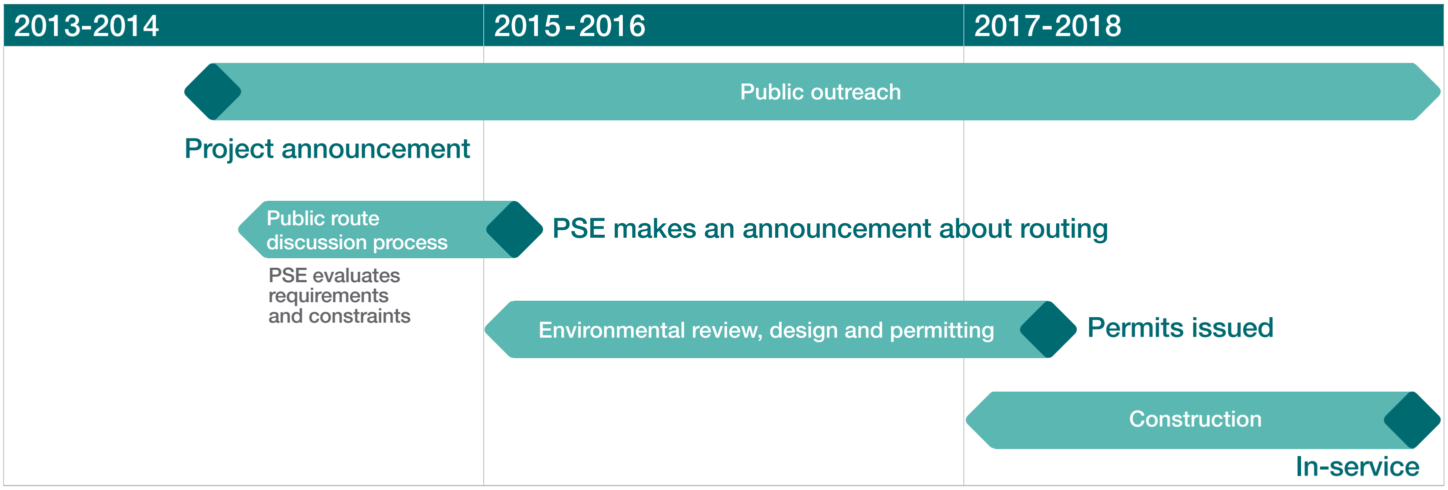
VII. Puget Sound Energy's next steps

Following the completion of the Community Advisory Group's process, PSE's next steps in 2015 are to:

- Take the Community Advisory Group's recommendation under consideration and make an announcement about routing that balances the needs of customers, the local community, property owners and PSE
- Work directly with property owners and tenants to begin detailed fieldwork to inform environmental review, design and permitting
- Ask for community input on project design, which may include pole height, finish and other design considerations
- Work with the City of Bellevue and other affected jurisdictions and agencies on the project's Environmental Impact Statement (EIS) process

Once these steps are complete, PSE will apply for necessary permits from appropriate agencies and jurisdictions. The project design and permitting phase is expected to run through early 2017. Once fully designed and permitted, project construction is expected to begin in 2017, with project completion planned for 2018. See Figure 9.

Figure 9: Project schedule and next steps



Appendices

Appendix A: Community Advisory Group Charter

Appendix B: Minority Report

Appendix C: Community Advisory Group meeting materials, presentations and summaries

Appendix D: Bibliography

Community Advisory Group Charter

Revised:3/24/14

Purpose

The main purposes of the Community Advisory Group are to:

- Learn about PSE's proposed route segments, PSE's route analysis work to date, and the complexity of identifying the route segments, and to work with PSE to combine segments to develop a Community Advisory Group-recommend route to inform PSE as PSE selects a final route.
- Collaborate with PSE to decide on a community values-based evaluation process that will be used by the Community Advisory Group to consider PSE's various route segments, combine into possible route options, and narrow route options down to a Community Advisory Group-recommended route.
- Provide a forum for the community to give meaningful input on route segments and route options.
- Help PSE better understand community/property owner values as PSE selects the preferred route that balances the needs of their customers, the local community, property owners and PSE.

The Community Advisory Group will:

- Develop an understanding of the Energize Eastside project and project need.
- Report back to the people/groups they represent on project details, gather feedback from the interests they represent and provide ongoing communications between PSE and the group they represent throughout the process.
- Provide advice, as community representatives, on ways to address community concerns.
- Participate in geographic Community Advisory Group Sub-Area Committee meetings to determine recommended route segments.
- Work collaboratively, creatively and constructively to help determine community/property owner values and engage in a process to evaluate route segments and select a recommended route option.
- Partner with PSE to combine route segments into one Community Advisory Group recommended route.

Community Advisory Group Sub-Area Committees

- Sub-Area Committees will consist of Community Advisory Group members and their residential association alternates from each of the geographic sub-areas (North – Kirkland, Redmond and North Bellevue; Central – Bellevue; and South – Newcastle and Renton), as well as a representative from each potentially affected neighborhood association that does not have a member or residential association alternate on the advisory group. Additional community representatives will be invited as needed to ensure comprehensive discussion of issues.
- Community Advisory Group members are expected to attend the Sub-Area Committee meetings for their geographic sub-area. In order to participate in the Sub-Area Committees, members should attend the first two advisory group meetings to ensure they have an understanding of the project.
- Residential association alternates are required to attend the Sub-Area Committees to ensure balanced representation from neighborhoods. Alternates representing other interests are recommended to attend, but it is not required.
- The purpose of the Sub-Area Committees is to have an interest-based conversation on route segments and preferred sub-area options. The outcome of the Sub-Area Committee meetings will

be to develop sub-area segment combination recommendations for the full Community Advisory Group discussion.

PSE staff will:

- Provide information on the area’s growth, the need for the project and the factors involved in developing route segments.
- Provide draft materials to Community Advisory Group members one week before meetings.
- Provide technical experts to provide a greater understanding of the topics at hand and inform Community Advisory Group dialogue.
- Consult with the Community Advisory Group, listen carefully and consider advisory group input prior to making final decisions on key technical issues, and explain all decisions made.
- Listen and take into consideration recommendations from the advisory group with regards to providing data and requests for analysis and research to support advisory group deliberations.

Norms for individual work as members of the Community Advisory Group

- We acknowledge our group's diversity and value different points of view. We will respect each other's opinions and will operate in consistently constructive ways.
- We will make every effort to attend meetings, to participate actively, to read and be prepared to discuss information and issues, and to be available for work between formal meetings.
- We will keep an open mind and come to meetings with interests, not entrenched positions. We will share our interests and objectives with all Community Advisory Group members. We will openly explain and discuss the reasons behind our statements, questions and actions.
- We will be responsible for representing the interests and concerns of the community we represent at the table. We will consult with our constituencies on a regular basis concerning the discussions and preferences of the Community Advisory Group.
- We will listen carefully to the views expressed by others, avoid interruptions, and seek ways to reconcile others' views with our own. We will represent information accurately and appropriately.
- We will adhere to the ground rules and respect the procedural guidance and procedural recommendations of the facilitator.

Norms for our work together

Use of time

- We will respect each other’s time by being on time. Meetings will begin and end on time, unless otherwise agreed to by the Community Advisory Group members.
- When making our comments, we will consider the time needed for others to share their perspectives.

Recommending a route

- Community Advisory Group members will strive to collectively make reasonable requests and suggestions through a cooperative and collaborative discussion process with PSE. PSE will inform the Community Advisory Group of any areas of flexibility in the route recommendation development process.
- In discussions, suggestions may not represent unanimity. The facilitator is responsible for seeking and probing for group preferences. It is the responsibility of each stakeholder group member to voice dissent if s/he cannot live with any particular suggestion.
- Any recommendations from the Community Advisory Group and sub-area committees will be considered by PSE. PSE will evaluate requirements and constraints, and select a preferred route. PSE is the final decision maker regarding selecting a preferred route.
- If PSE chooses not to move forward with the recommended route as PSE’s preferred route for permitting, PSE will explain the reason for its decision.

Facilitator

- We give the facilitator permission to keep the group on track and “table” discussions to keep the group moving.
- We expect the facilitator to help the Community Advisory Group accomplish our purpose in a completely neutral, balanced and fair manner.
- We want the facilitator to:
    - Develop draft meeting agendas.
    - Manage Community Advisory Group meetings and discussions.
    - Consult with Community Advisory Group members between meetings about how to manage the process and address issues of concern.
    - Prepare meeting summaries.

Role of alternates

- Each Community Advisory Group member may have one alternate who will be available to stand in for Community Advisory Group members who are unable to attend meetings. Alternates are encouraged to attend all meetings but will not be asked to participate unless called upon.
- Alternates can participate in the Sub-Area Committee meetings if they have attended both of the initial Community Advisory Group meetings.
- Community Advisory Group members are expected to update alternates between meetings so they can replace members on a moment’s notice.

Role of residential association alternates

- Each Community Advisory Group member representing a residential organization may have an appointed residential association alternate that represents a different neighborhood within their city. Residential association alternates are intended to help balance representation from neighborhoods along the route segments.
- Residential association alternates can ask Community Advisory Group members to yield their seat to ask a question or make a comment during Community Advisory Group meetings.
- Residential association alternates serve as members of their geographic Sub-Area Committee and are expected to attend Sub-Area Committee meetings.

Proposed meeting ground rules

- Start / end on time
- Silence cell phones
- Come prepared
- Listen respectfully
- Speak from interests, not positions
- Participate in the process

Norms for our work with others outside the Community Advisory Group

External communications

- All Community Advisory Group meetings shall be open to the public.
- The public will be given the opportunity to comment during each Community Advisory Group meeting. Those wishing to provide public comment to the advisory group will be strongly encouraged to direct their comments towards the issues and topics of focus on the advisory group’s agenda.

- We will avoid characterizing the views or opinions of other Community Advisory Group members outside of any advisory group meeting or activity.
- We will accurately describe Community Advisory Group preferences that are conveyed to PSE.
- Community Advisory Group meetings will be announced on the Energize Eastside website, and meeting announcements with date, time and location, will be provided to local blogs and other media outlets for distribution to the broader community.
- Community Advisory Group meeting products, such as agendas, summaries, and PowerPoint presentations will be posted at pse.com/energizeeastside and will be available to advisory group members for distribution to their constituents. Note: Community Advisory Group member names and affiliations will be included in these materials and will be listed on the project website.

Appendix B: Minority Report

Some Community Advisory Group members did not concur with the consensus recommendation. The report of the minority is provided here in the interest of inclusiveness. The Community Advisory Group majority has not reviewed this report; consequently, it has not been verified by the Community Advisory Group majority for consistency with the Community Advisory Group charter or for technical accuracy, either independently or in conjunction with engineering support from Puget Sound Energy. This report reflects only the opinion of its signatories.

Appendix B: Minority Report

Dissenting Report

We, the undersigned members of the "Community Advisory Group" (CAG) for PSE's Energize Eastside project, declare our dissent from the recommendations included in the Final Report of the CAG.

The CAG did not truly represent the wishes of the community for the following reasons:

1. CAG members were selected by PSE, not the community.
2. PSE misrepresented the full purpose of Energize Eastside.
3. PSE did not provide real data establishing the need for the project.
4. PSE did not provide a complete list of alternative solutions, and CAG members weren't allowed to discuss alternatives.
5. The CAG was not given real choices, because some of the route segments were never viable.
6. Few CAG members participated in critical evaluations.
7. The CAG facilitator was not impartial and frequently pressured members to support the group's conclusions.
8. CAG members were not asked to officially endorse the outcome of the CAG process.

The remainder of this report will provide additional detail regarding these eight objections.

1. CAG selection

Composition of the CAG was determined by PSE, not the community. PSE diluted the votes of residential neighborhoods that had the most at stake. Only one quarter of the voting members represented neighborhoods, and many affected neighborhoods had no representative. Some members represented organizations which receive generous donations from the PSE Foundation.

2. The full purpose of Energize Eastside

Documents available from ColumbiaGrid, Seattle City Light, and the Bonneville Power Administration make it clear that Energize Eastside solves three simultaneous problems: 1) load for PSE, 2) load for Seattle City Light, and 3) regional grid reliability for Bonneville Power Administration (a federal agency). According to a 2012 Memorandum of Agreement signed by PSE, SCL, and BPA, transmission lines in the Puget Sound region can become congested when high local needs coincide with high flows of electricity to British Columbia, especially when there are faults on BPA's trunk lines. This is a concern because the United States is obligated to provide electricity to Canada through the Columbia River Treaty. The large scale of the Energize Eastside project addresses both local and international electricity needs. However, Energize Eastside is not the only solution that can do this. It might not even be the most economical solution, when the project's impact on the community is considered. Reduced property values along the entire 18-mile length of the line cause declines in economic activity and tax receipts, which must be compensated by increasing tax rates on other residents, or decreasing support to people who need tax-funded services.

PSE never disclosed the whole purpose of the project to CAG members. The company sought to minimize regional questions by claiming only 3-8% of power flow serves Canada. While this might be true on a normal day, Energize Eastside is designed to handle extraordinary power flows that occur in rare emergency conditions. Without a full disclosure of the scope and purpose of the project, CAG members were not able to accurately represent the views of their constituents regarding the project.

3. Eastside need

PSE illustrates the need for Energize Eastside using a graph titled "Eastside Customer Demand Forecast."[1] This graph has been simplified so it can be easily grasped by the public. It shows demand growing at an average rate of 1.9% per year, crossing the "System Capacity" line in 2017. According to PSE, electricity outages will become more likely after that.

CAG members are well-informed individuals who had months to understand the issues. Therefore, we expected PSE would provide CAG members with more detailed information regarding the need for the project. There are many questions that members had. How has the Eastside's electricity demand grown over time? Why is demand supposedly growing at a much faster rate than population or economic growth? Why is PSE's projection of Eastside's demand growth more than double that of Seattle's or Portland's? Would programs such as Demand Response help mitigate our demand growth?

PSE did not answer these questions, saying that they were outside the scope of the CAG's stated mission. The CAG was formed only to provide recommendations on which route the overhead lines should take through the five Eastside cities. PSE said that community input was not needed regarding any other aspect of the project.

4. Alternative solutions

CAG members also raised questions about alternative solutions. They wondered why alternatives were eliminated from consideration and further discussion of alternatives was not allowed.

We believe it is important to list reasonable and viable alternatives to Energize Eastside here, since these ideas do not appear in the limited Final Report. The alternatives described below address only the Eastside's local need. BPA would have to build its own project to solve Canadian reliability issues, at a lower cost to PSE's customers.

The issue of cost is of critical importance to many CAG members, especially organizations representing low-income residents like Hopelink and the YMCA. It is also of interest to businesses that are sensitive to the cost of electricity. Adding 1-2% to electricity costs for the next 40 years may affect their profitability. Many CAG members would have supported lower-cost alternatives if PSE had allowed them to be explored by the CAG.

a. **Demand-side Resources.** Demand-side Resource (DSR) programs are used by utilities in almost every state to reduce the stresses of peak load service and avoid construction of new generation and transmission infrastructure. In the Northwest, Portland General Electric devotes 14 pages of its latest Integrated Resource Plan to descriptions of various programs, including a curtailment tariff, residential direct load control, critical peak pricing, and conservation voltage reduction. Similar programs were studied in a detailed report created by the Cadmus Group for PSE's most recent IRP[2]. Which of these programs is PSE planning to implement? The IRP says, "Demand response program costs are higher than supply-side alternatives at this time, and PSE does not currently have a program in place." Translation: it's cheaper to burn coal in a plant located in Colstrip, Montana (one of the dirtiest coal plants in the nation) that provides nearly 1/3 of the Eastside's electricity. The economics of cheap coal

[1] http://energizeeastside.com/Media/Default/AbouttheProject/2013_1030_Single_Line_Load_Chart_v3.png
[2] https://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppN.pdf

and guaranteed returns for capital improvements like Energize Eastside provide little financial incentive for PSE to pursue DSR programs.

b. **Lake Tradition transformer.** For several years before Energize Eastside was conceived, PSE proposed to meet Eastside demand by adding a new 230/115 kV transformer located at Lake Tradition (near Issaquah). Additional power would be delivered on existing 115 kV lines to the Lakeside substation. PSE now claims that this solution causes other transformers to overload in power flow simulations conducted by the company. However, these simulations include the surge of electricity caused by faults in BPA's trunk lines. If BPA were to solve those problems with their own project, Lake Tradition might become a viable solution with much lower costs and community impacts than Energize Eastside.

c. **Upgrade 115 kV lines.** It's possible to use thicker wire and higher capacity transformers on existing lines to increase capacity by approximately 29%. That is enough to delay further action for at least a decade. During that time, it's likely that technologies such as grid batteries, distributed generation, and increasing efficiency will make other solutions possible. This will be cheaper than Energize Eastside, and better for the environment. Upgrading the lines at their current voltage will spare nearly 8000 mature trees that must be cut or removed along the Oak or Willow routes to accommodate a 230 kV line (according to PSE's counts). There is no record that PSE studied this option. It was never mentioned during CAG meetings.

d. **Gas powered plant.** PSE studied the possibility of meeting Eastside needs using a gas-powered generation plant. They dismissed this option in 3 sentences in their Solutions Study. Two of the potential sites for the plant were judged to be too difficult to permit, although this determination was made solely by the company without input from city officials. A third site was dismissed because it would require construction of transmission lines. Neither the CAG nor the cities were given further details about the costs of such a plant, where the transmission lines would be located, how reliability of local generation compares to remote generation, how it impacts the community, or how it might help reduce use of coal that creates much higher emissions of atmospheric carbon, mercury, and sulfur.

e. **Micro-grids and small turbines.** A national expert says that the Puget Sound area is an ideal place to use small gas turbines to inexpensively and incrementally serve peak loads. There is no record that PSE studied this option.

f. **Grid batteries.** PSE says grid batteries are likely to play an important role in the future. The company already has a pilot battery project in Bainbridge. But according to PSE, batteries are too expensive and too risky to use at this time. The company says it can forecast future demand, but it can't forecast the viability of technology solutions that might address that demand.

We believe that one or more of the above solutions would address Eastside's demand and reliability needs for many years at a lower cost than Energize Eastside, allowing us time to develop clean, sustainable solutions rather than rushing a project that is out of scale for our needs as well as our beautiful scenery.

For completeness, we will mention two other alternatives that CAG members were interested in. Both of these would solve Canadian reliability issues as well as Eastside need, but for a considerably higher price tag:

g. **Underground lines.** We list this alternative because it is the most frequently asked question by the public: "In this day and age, why can't we bury our transmission lines?" PSE has made this option politically impossible, due to a tariff the company proposed to the Washington Utilities and Transportation Commission (and which the UTC subsequently adopted). The tariff requires each community who requests an underground line to bear the high cost of underground infrastructure on their own. With the exorbitant costs estimated by PSE, this is not a realistic option for any community. While this tariff seems reasonable for local distribution lines, we hope its application to regional transmission lines will be revisited by the UTC.

h. **Underwater lines.** There are many examples in the U.S. of high-voltage transmission lines being placed in lakes, rivers, and bays. This technology is maturing rapidly. PSE said they would write a white paper on this alternative. The white paper was not released in time for consideration by the CAG.

5. No real choices

It should be no surprise that the final routes selected by the CAG mostly follow the existing transmission corridor. This is the result PSE expected from the beginning, and was confirmed by a senior PSE engineer who said the process of route selection was needed to help the public feel like they were involved in the project.

In particular, the choice between the L and M segments was a false choice. The L segment was never a legally viable option due to well-known conflicts and impacts. PSE should have known this. It is also highly questionable that the B segment was viable, due to the large amount of new right-of-way that would need to be acquired to construct that segment.

We believe the CAG process was more about PR for PSE than real choices for the community.

6. CAG participation

In several cases, only a few CAG members participated in important evaluations. For example, at the July 9th meeting, it was revealed that only 8 CAG members (less than a third of the CAG membership) participated in an evaluation process to eliminate potential routes. These low participation rates didn't occur because CAG members were lazy or on vacation. Many of the residential representatives refused to participate because they objected to the process.

7. CAG process

The facilitator for the CAG was a contractor hired by PSE, harming the appearance of impartiality. The facilitator appeared to have two goals: 1) produce a route recommendation that isn't too onerous to PSE, and 2) achieve this result using "consensus building" techniques.

Unfortunately, these goals were achieved by pressuring or cajoling CAG members to abandon their preferences and join the consensus view. For example, the facilitator would often say to a reluctant member, "Could you live with the emerging consensus of the group?" Or, "Do you want your name to be listed as the dissenting vote?" There were many times when a dissenting member would reluctantly give up significant objections to avoid appearing obstinate or going against the other members. An anonymous ballot would have produced a different result than the facilitated outcome.

Do decisions made in this manner truly represent community values? One need only observe the audience at the final CAG meeting to answer that question. At least 90% of the 400-member audience enthusiastically supported dissenting remarks made by members of the CAG. We conclude the recommendations of the CAG do not represent the desires of the community.

This is also evident in the routes that were finally selected. Both the CAG and hundreds of residents voting online agreed that the top factor to be used to judge routes was "Avoids residential areas." For both the CAG and the community, this factor rated significantly higher than any other. However, in the rush to consensus, the CAG ignored the criterion they previously agreed was the most important and focused instead on cost. All of the routes inequitably burden residential neighborhoods with poles as high as 135 feet that are out of scale with residential land use codes.

8. No endorsements

As of December 15, CAG members were not asked to endorse the Final Report with their signatures. We note a stark contrast with the outcome of a different advisory group for a previous PSE project:

> *"We, the members of the Sammamish-Juanita 115 kV Project Stakeholder Advisory Group, affirm and support this recommendations report to Puget Sound Energy. We believe PSE's community-involved siting process for this project has been transparent and reflects community input."*

Why aren't members of our CAG signing a similar statement in support of their recommendations for Energize Eastside? Could members of this CAG sign a positive statement like this in good faith?

Conclusion

Energize Eastside is one possible step towards our energy future. This is a decision that should be made by citizens and their elected representatives, taking into account values such as community impact, environmental impact, cost, reliability, and safety. This decision should not be made by a utility company or an advisory group with little community support.

The undersigned members of the CAG declare our dissent with the CAG's Final Report.

(By signing this document, we are not rescinding the opinions we expressed or votes we cast during CAG meetings, but simply stating our dissent with the overall project and process.)

Norman Hansen CAG, BELLEVUE BRIDLE TRAILS COMMUNITY

L Kaseburg

TIM McHARG, CITY OF NEWCASTLE

Darius F. Richards

Steven D. O'Donnell

David T. Evans

Lindy Bruce Sunset Community Assn.

Appendix C: Community Advisory Group Meeting Materials, Presentations, and Summaries

The following links provide all Community Advisory Group meeting materials, presentations and meeting summaries:

Jan. 22, 2014 - Community Advisory Group Meeting #1
Convened the advisory group

Feb. 12, 2014 - Community Advisory Group Meeting #2
Learned about the solution selection process and project routing

June 4, 2014 - Community Advisory Group Meeting #3
Reviewed key findings from the Sub-Area Workshops and Committee Meetings

June 25, 2014 - Community Advisory Group Meeting #4a
Reviewed potential route options

July 9, 2014 - Community Advisory Group Meeting #4b
Narrowied potential route options and finalizing evaluation factors

Oct. 1, 2014 - Community Advisory Group Meeting #5a
Reviewed key findings from the open houses and preparing for route evaluation

Oct. 8, 2014 - Community Advisory Group Meeting #5b
Developed preliminary route recommendation

Dec. 10, 2014 - Community Advisory Group Meeting #6
Finalized route recommendation for PSE to consider

Appendix D: Bibliography

The list below includes key reports developed by PSE and/or third-party experts, the findings of which were shared with the Community Advisory Group. All linked documents are available on the Energize Eastside project website at pse.com/energizeeastside.

Quanta Technology and Puget Sound Energy, *Eastside Needs Assessment Report*, 2013.

- Executive Summary
- Full Report

Quanta Technology and Puget Sound Energy, *Eastside Transmission Solutions Report,* 2013.

- Executive Summary
- Full Report

TetraTech, *Eastside 230 kV Project Opportunity and Constraints Study for Linear Site Selection,* 2013.

- Executive Summary
- Full Report

Energy + Environmental Economics, *Non-wire Solutions Analysis*, 2014.

- Full report

Power Engineers, *Underground Feasibility Study,* 2014.

- Full report
- Appendix A - Aerial Route Drawings (part 1)
- Appendix A - Aerial Route Drawings (part 2)
- Appendix B - Typical Detail Drawings

Additional documents referenced throughout the Final Report:

Puget Sound Regional Council 2013 Land Use Baseline: Maintenance Release 1 (MR1), update April 2014.

Letter from Seattle City Light, June 2, 2014.

Tariff schedule 80, section 34, 2006