

Assessment of Proposed Energize Eastside Project

Technical review with respect to Section
18.44.052 of the City of Newcastle Municipal
Code

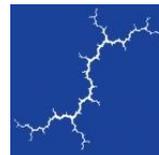
Prepared for City of Newcastle

AUTHORS

MaxETA Energy, PLLC

1032 15th ST NW, Suite 204
Washington, DC 20005

202.794.5015



Synapse
Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

- 1. EXECUTIVE SUMMARY 1**
- 2. INTRODUCTION AND STATUTORY REVIEW 8**
- 3. OVERVIEW OF EASTSIDE NEEDS ASSESSMENT AND EASTSIDE PROJECT..... 9**
 - 3.1. History of Eastside Needs Assessments.....9**
 - 3.2. PSE’s Latest Eastside Contingency Load Threshold Analysis11**
 - 3.3. Description of Proposed Eastside Project.....14**
- 4. REVIEWED MATERIAL 15**
- 5. LOAD FORECASTS AND NEED ASSESSMENT 16**
 - 5.1. PSE Load Forecast Methodology16**
 - 5.2. PSE Evaluation of Conservation and Other Demand Side Resources.....17**
 - 5.3. PSE Winter Peak Load and Need Assessment19**
 - 5.4. PSE Summer Peak Load and Need Assessment.....23**
 - 5.5. Limitations in PSE’s Load Forecasts and Conservation Estimates.....26**
- 6. ASSESSMENT OF THE PROPOSED EASTSIDE PROJECT..... 33**
 - 6.1. The Proposal.....33**
 - 6.2. Operational Need33**
 - 6.3. Reliability Improvement.....34**
- 7. KEY FINDINGS, CONCLUSIONS AND RECOMMENDATIONS 36**
 - 7.1. Key Findings.....36**
 - 7.2. Conclusions37**
 - 7.3. Recommendations38**
 - Transmission solutions 38
 - Non-wires alternatives 38

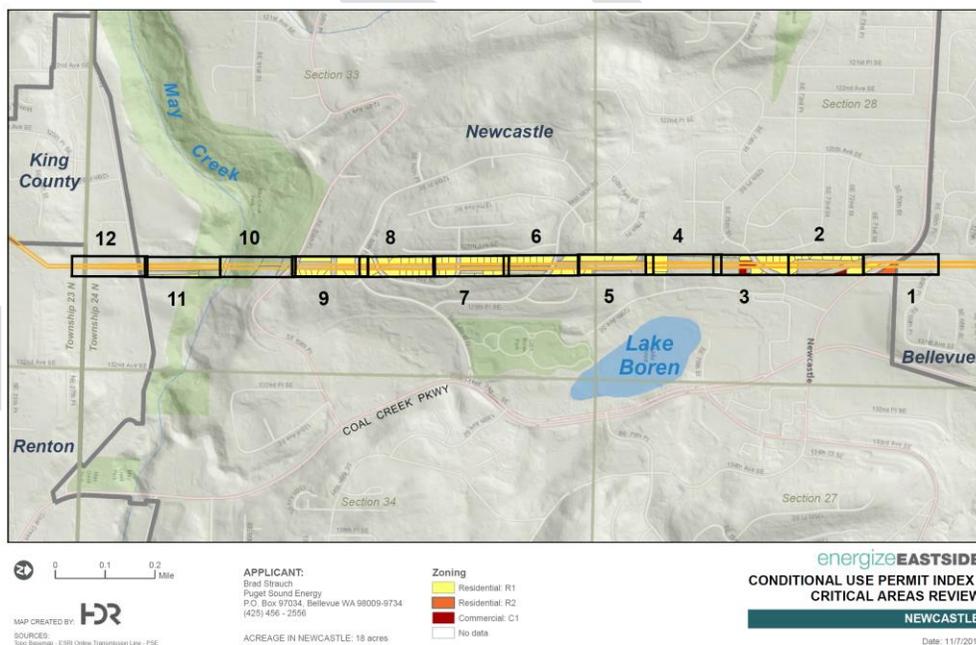
1. EXECUTIVE SUMMARY

Background

Puget Sound Energy (PSE) is projecting rapid load growth in the Eastside area near Lake Washington in Washington State. As a result, the utility identified the need to upgrade its substation and transmission infrastructure as early as 2008. To meet this need PSE proposed the Energize Eastside project in 2013, which entails building a new substation and upgrading transmission lines. PSE also investigated alternatives to building the substation, including energy conservation, batteries, and solar panels. However, the company concluded that such alternatives would not sufficiently address reliability concerns caused by the expected load growth.

As part of the Energize Eastside project, Puget Sound Energy (PSE) applied for a Conditional Use Permit (#CUP17-002) for a Regional Utility Facility with the City of Newcastle to upgrade its electric transmission facilities for approximately 1.5 miles in the existing utility corridor, Willow 1, that spans approximately 1.5 miles in Newcastle; see Figure 1 below.

Figure 1. PSE Proposed Energize Eastside Electric Transmission Route, Newcastle



Source: PSE Site Plans, Energize Eastside Project, November 2017

The upgrades in Newcastle are part of a large transmission project plan¹ that extends from the Sammamish transmission substation in Redmond to the Talbot Hill transmission substation in Renton (Figure 2). This plan was proposed to address several identified contingency² deficiencies in transmission capacity that PSE claims are triggered by Summer and Winter peak demand in King County. The proposed Energize Eastside project would build a new electric substation, the Richards Creek substation in Bellevue, and upgrade existing transmission lines in Redmond, Bellevue, Newcastle and Renton.

In parallel with two other local communities affected by the project, the City of Newcastle is investigating PSE's Eastside filings to assess the need for the Energize Eastside project and to determine whether to provide the utility a city permit to allow PSE to upgrade its transmission infrastructure. MaxETA and Synapse Energy Economics were hired by the City of Newcastle to aid this investigation.

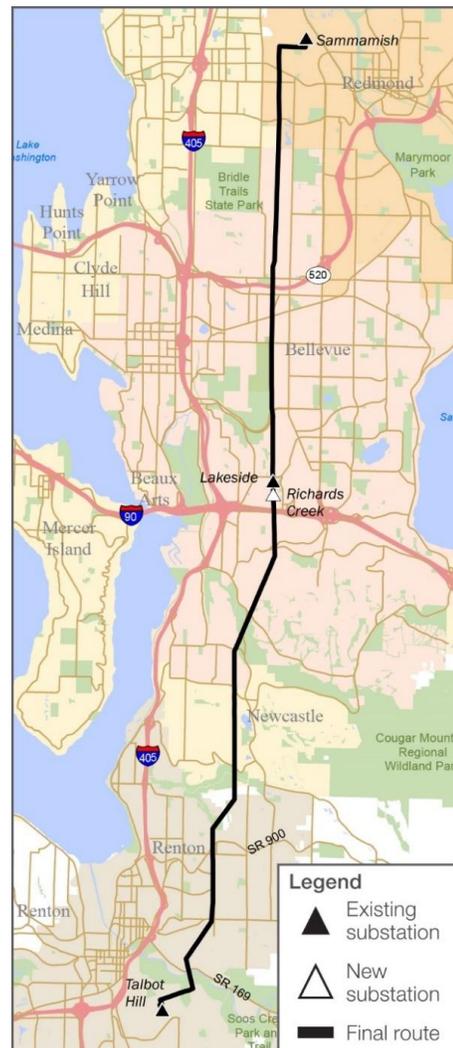
Methodology

As part of this need assessment, MaxETA and Synapse team assessed:

- a) whether PSE's load forecast methodology and assumptions, as well as forecast results, are reasonable and technically sound;
- b) whether there is a regional need for additional transmission capacity to maintain reliability;
- c) whether PSE has taken all necessary and cost-effective measures (including demand-side measures) to prevent an operational need from arising.

MaxETA and Synapse team reviewed various publicly available reports prepared by PSE as well as additional data obtained from PSE regarding historical and updated forecasted loads, conservation, and

Figure 2. PSE Proposed Energize Eastside Electric Transmission Facilities and Route



Source: Energize Eastside Project Newsletter Summer 2017

¹ Energize Eastside, <https://energizeeastside.com/>.

² Contingency – an event where one or more electric facilities suffer an outage.

other demand-side resources.³ The team also carried out a load flow model analysis to evaluate regional load conditions under contingencies, including whether the regional capacity thresholds estimated by PSE are reasonable.

Key Findings

- Our assessment of power flow finds that current or projected electric peak demand within the City of Newcastle does not trigger an operational need for the proposed transmission expansion. However, our analysis shows that the current summer electric peak demand in King County has already triggered an operational need for the proposed transmission expansion under system contingency situations to ensure the security of the Bulk Electric System (BES).
- Our power flow model assessment finds that the regional capacity thresholds in King County estimated by PSE are reasonable.
- The PSE load forecast approach follows a standard industry practice, although it has some limitations regarding the way it incorporates demand-side resources. More specifically, while PSE's forecast includes the energy conservation potential identified in the most recent potential study, it excludes any potential impacts from demand response, distributed generation, behind the meter (BTM) solar PV, and BTM solar plus storage.
- Our review of historical summer peak loads and the capacity thresholds in King County provided by PSE shows that there is a summer transmission capacity deficiency in King County under N-1-1 contingencies even at today's peak load level. We further find that this capacity deficiency has existed for the past 10 years or more for the summer season. The peak load levels in King County have been 13 to 20 percent (or 200 MW to 300 MW) above the area's capacity threshold, putting PSE customers at risk of losing power for the past 10 years.
- Our review of historical winter peak loads and the capacity thresholds in King County shows PSE's winter peak load actually has been declining over the past several years and its current peak load is still below the critical threshold for additional transmission capacity. We cannot conclude based on the evidence we analyzed that there is a winter capacity deficiency or any winter need for transmission capacity expansion, at least in the next several years.
- PSE's transmission planning that seeks to prevent a facilities outage from becoming a customer interruption has been adequately conducted.

³ See Section 4, Reviewed Material

- PSE can be more aggressive identifying targeted demand side management opportunities that could defer the need for additional transmission buildup.⁴

DRAFT

⁴ See Section 7, Conclusions and Recommendations



Conclusions

Even though PSE was not able to demonstrate that an operational need was triggered by electric demand in Newcastle, PSE has demonstrated that the proposed transmission upgrades are needed to safeguard the operational reliability of the electric system as a whole.⁵ To maintain system security, power systems are operated so that overloads do not occur either in real-time or under any statistically likely contingency. Not securing the bulk electric system to operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies could affect the electric supply reliability in Newcastle. This peer review verified that under specific contingencies (N-1-1 and N-2) the as-is bulk electric system serving Newcastle is already at operational risk, and in fact has been in such a condition at least over the past 10 years during the summer season. **This means that PSE's application has met the threshold for approval** Newcastle City Code C-5 under NMC 18.44.052 Utility facilities – Regional: “[t]he applicant shall demonstrate that an operational need exists that requires the location or expansion at the proposed site.”

The current transmission deficiency can be cured by upgrading one of the 115kV transmission lines between the Talbot Hill and Sammamish substations to 230kV and installing an additional 230kV/115kV 325MVA transformer at the proposed Richards Creek substation in Bellevue. Upgrading the second 115kV transmission line that currently travels through the same corridor, Willow 1, to 230kV is consistent with good system planning, noting that the facilities to support these higher voltages will already be deployed.

However, we note that there were various actions and measures PSE could have taken over the past 10 years or more to avoid the current situation. Such actions include actually implementing targeted demand-side resources, rather than just studying them, and also identifying and acting upon summer peak savings opportunities that have been neglected for many years. These actions would have allowed PSE to avoid the current serious condition that could now be jeopardizing its service to customers under transmission contingencies, as well as reduce the need to implement Corrective Action Plans (CAPs), while providing additional net benefits to the area because many demand-side resources are cost-effective on their own.

⁵ Electric system as a whole is also referred to as Bulk Electric System.

Recommendations

We recommend that the Conditional Use Permit to PSE to upgrade the identified approximately 1.5 miles of existing 115kV lines with 230kV lines be conditioned on conducting an independent design assessment of the overhead transmission facilities traversing Newcastle that verifies compliance with the clearance safety rules for the installation and maintenance of overhead electric supply of the 2017 National Electrical Safety Code, ANSI C2 Part 2. We also recommend that the City of Newcastle send field inspectors during the transmission line upgrades to ensure compliance with the 2017 NESC.

We also have a number of recommendations on demand-side measures as follows:

- Although our assessment confirmed that PSE does need to build and increase its transmission capacity for the Eastside and King County, it takes several years to complete any substantial transmission and substation construction project. Until such a project is complete, PSE should strive to minimize the risk of forced outages as much as possible. The best approach for minimizing the risk is likely to involve implementing cost-effective demand-side resource (DSR) programs as non-wires alternatives (NWA) with a focus on reducing the summer peak load.
- Second, PSE should seek to procure as much demand response (DR) as possible along with energy efficiency, solar PV, and combined heat and power because DR has some advantages over other resources: (a) DR is an untapped resource in the region; (b) DR can be quickly procured; (c) DR can be dispatched by PSE; and (d) DR has the potential to deliver a large amount of summer peaking reduction within a short time frame. PSE's current efforts to secure DR capacity seem lukewarm at best.⁶ As mentioned in our report, Portland General Electric (PGE), PSE's nearby peer utility which has a similar level of peak loads, has implemented about 160 MW of Summer DR including dispatchable generators (32 MW of conventional DR and 130 MW of dispatchable backup generators) since 2016 and is on track to meet its 2020 DR goals of about 200 MW, or close to 6 percent of the summer peak load.⁷ We believe PSE could do the same while cost-effectively reducing risk for its customers.
- Third, PSE should assess the potential of energy efficiency measures that can reduce summer peak loads. Historically PSE's conservation studies have been focusing on winter peak periods. While PSE's 2017 IRP assessed summer peak reduction potential from demand response for the first time, it did not analyze summer peak potential from energy efficiency measures despite the fact that PSE identified by-then-serious transmission constraints during the summer peak time. We recommend PSE

⁶ <https://www.pse.com/pages/grid-modernization/demand-response>

⁷ PGE. 2019. Integrated Resource Plan DRAFT, p. 15-16. Available at <https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning>; 3,436 MW of summer peak expected for 2020 per page 233 of PGE's 2019 IRP Draft.



immediately undertake a study to evaluate summer peak reduction from energy efficiency measures if this scope is not included in the ongoing 2019 IRP process.

- Fourth, PSE should take a serious look at the expected impacts of BTM solar PV and incorporate the impact in its summer peak load forecast by following other leading utilities (including PGE) and regional system operators. This will modify PSE's summer peak load forecasts downward.
- Fifth, PSE should modernize its transmission planning process by formally incorporating the process of including and implementing targeted demand-side resource programs as non-wires alternatives (NWAs). Implementation of NWA in King County will be a valuable experience for transforming the transmission planning process for PSE. PSE may be able to identify more achievable demand-side resource potential in targeted areas than identified in PSE's potential studies or assumed in PSE's Energize Eastside studies because targeted approaches accompany area specific, enhanced customer outreach, marketing, and incentives that are outside of the scope of the traditional potential studies.
- Finally, PSE or the Washington Utilities and Transportation Commission (WUTC) should consider developing an independent third-party model for evaluating and/or procuring NWA as part of the transformation of the transmission planning process. Other states have such processes. For example, the Vermont System Planning Committee was formed more than a decade ago after a large transmission project was approved but regulators identified that it could have been avoided had utilities begun pursuit of non-wires solutions sooner.

While the City of Newcastle does not have the regulatory authority to require the actions we recommend above regarding demand-side measures, we believe they would be prudent utility actions that the utility should undertake of its own volition, and that the WUTC should give them due consideration and support for rate recovery if pursued in a prudent manner. We believe that PSE should take proactive actions to implement our recommendations and reach out to WUTC as it reforms its current transmission planning process and load forecast.

2. INTRODUCTION AND STATUTORY REVIEW

Puget Sound Energy (PSE) is projecting rapid load growth in the Eastside area near Lake Washington in Washington State. As a result, the utility identified the need to upgrade its substation and transmission infrastructure as early as 2008. To meet this need PSE proposed the Energize Eastside project in 2013, which entails building a new substation and upgrading transmission lines. PSE also investigated alternatives to building the substation, including energy conservation, batteries, and solar panels. However, the company concluded that such alternatives would not sufficiently address reliability concerns caused by the expected load growth.

In parallel with two other local communities affected by the project, the City of Newcastle is investigating PSE's Eastside filings to assess the need for the Energize Eastside project and to determine whether to provide the utility a city permit to allow PSE to upgrade its transmission infrastructure. MaxETA and Synapse Energy Economics were hired by the City of Newcastle to aid this investigation.

The City of Newcastle requires that “[p]roposals that include new or expansions to existing utility facility – regional shall demonstrate compliance with” several criteria under NMC 18.44.052 (“Utility facilities – Regional”) in addition to the conditional use permit criteria listed in NMC 18.44.050. For the purposes of NMC 18.44.052, expansions include “a modification of an existing regional utility facility by an increase in the size, height, impervious coverage, floor area, or parking area of the facility by greater than 10 percent.”

Among others, our review specifically investigates whether PSE as an applicant to the City of Newcastle has complied with the following criteria under NMC 18.44.052:

C-5. The applicant shall demonstrate that an operational need exists that requires the location or expansion at the proposed site;

C-6. The applicant shall demonstrate that the proposed utility facility – regional improves reliability to the customers served and reliability of the system as a whole, as certified by the applicant's licensed engineer;

To find answers to these statutory requirements, this independent consultant report assesses

- a) whether PSE's load forecast methodology and assumptions, as well as forecast results, are reasonable;
- b) whether there is a regional need for additional transmission capacity to maintain reliability; and
- c) whether PSE has taken all necessary and cost-effective measures (including demand-side measures) to prevent an operational need from arising.



3. OVERVIEW OF EASTSIDE NEEDS ASSESSMENT AND EASTSIDE PROJECT

3.1. History of Eastside Needs Assessments

Since 2008, PSE has conducted numerous studies to examine the reliability of its transmission facilities to meet future peak load conditions and needs for transmission facility expansion. These studies identified a variety of concerns and the studies conducted in recent years identified and examined solutions to the concerns in detail.

Earlier studies include the 2008 Initial King County Transformation Study, 2009 PSE TPL Planning Studies and Assessment, and the 2012 PSE TPL Planning Studies and Assessment.⁸ These studies found that “potential thermal violations may occur on facilities from Talbot Hill Substation to Sammamish Substation,” as noted in a 2013 study commissioned by PSE called the “2013 Eastside Needs Assessment.”⁹

More recent studies focused on transmission facilities in the Eastside area and examined both the transmission needs as well as solutions. The studies that focused on the need for the transmission facilities are:

- 2013 Eastside Needs Assessment Report (“2013 Needs Assessment”), prepared by Quanta Technology
- 2015 Supplemental Eastside Needs Assessment Report (“2015 Supplemental Needs Assessment” or “2015 Needs Assessment”), prepared by Quanta Technology

Notably the 2013 Eastside Needs Assessment found that there would be a transmission deficiency in the winter of 2017-2018 and in the summer of 2018. More specifically, these key findings are as follows:

- “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 3,500 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. There are also three elements above 100% loading and one above 99% loading for Category C (N-1-1) contingencies.”¹⁰

⁸ Descriptions of these studies are provided on page 23 of the 2013 Eastside Needs Assessment.

⁹ Quanta Technology 2013. Eastside Needs Assessment Report – Transmission System King County.

¹⁰ Quanta Technology 2013. Page 8.



The 2013 Needs Assessment also found that a summer load level of need (3,340 MW) could occur as early as 2014. However, the study emphasizes that the PSE summer load level where King County starts to have significant issues is about 3,500 MW projected for 2018.¹¹

The 2013 Eastside Needs Assessment report also indicated the need to expand the use of Corrective Action Plans (“CAPs”) to manage these overloads. CAPs are implemented according to the regional entity’s procedures to remedy a specific system problem using a list of actions and an associated timetable for implementation. These actions include:¹²

- Installation, modification, retirement, or removal of transmission and generation facilities and any associated equipment
- Installation, modification, or removal of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violation
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan
- Use of rate applications, Demand Side Management (DSM), new technologies, or other initiatives
- If situations arise that are beyond the Transmission Planner or Planning coordinator that prevent CAP implementation in the required timeframe:
 - Non-Consequential Load Loss
 - Curtailment of Firm Transmission Service

PSE does not advocate for the use of CAPs as a solution to an identified need.¹³ However, we note that targeted deployment of demand-side measures is an acceptable long-term solution to identified constraints. In fact, many independent system operators rely on demand response as a valuable resource under system capacity contingencies.¹⁴ NERC Standard TPL-001-4 allows curtailment and loss of load for specific contingencies as a temporary remedy to meet performance requirements, however it is best practice to avoid the use of these operating procedures.

¹¹ Quanta Technology. 2013. 2013 Eastside Needs Assessment, page 8, 9, 13 and 70; Quanta technology. 2015. 2015 Supplemental Eastside Needs Assessment Report, page 18.

¹² NERC Standard TPL-001-4 R2.7

¹³ 2015 Supplemental Eastside Solutions Study Report

¹⁴ For example, see ISO New England’s Operating Procedure No. 4 – Action During a Capacity Deficiency, available at https://www.iso-ne.com/static-assets/documents/rules_proceeds/operating/isone/op4/op4_rto_final.pdf

The 2013 Needs Assessment also indicated the overloads could be more severe if peak loads were higher as a result of other factors, such as extreme cold weather conditions, higher load growth due to local economic conditions, or lower conservation achievements relative to PSE's conservation targets.

The 2015 Supplemental Needs Assessment verified that there was still an expected transmission capacity deficiency in the Eastside area in the Winter of 2017-2018 and in the Summer of 2018. This study further identified that the Summer capacity deficit is worse than what was identified in the 2013 Needs Assessment. The 2015 study found expected needs to use CAPs and load shedding to mitigate the system deficiency while the 2013 study found CAPs would be required, but not load shedding.¹⁵

To address these potential transmission deficiency problems, PSE carried out numerous studies to examine potential solutions including traditional supply side solutions and non-wires solutions such as energy efficiency, demand response and batteries:¹⁶

- 2013 Eastside Solutions Study Report (Updated February 2014), prepared by Quanta Technology
- 2014 PSE Screening Study, prepared by E3
- 2014 Eastside 230 kV Project Underground Feasibility Study, prepared by Power Engineers
- 2015 Supplemental Eastside Solutions Study Report, prepared by Quanta Technology
- 2015 Eastside System Energy Storage Alternatives Study, prepared by Strategen
- 2015 Lake Washington Submarine Cable Alternative Feasibility Study, prepared by Power Engineers
- 2018 Eastside System Energy Storage Alternatives Assessment Update, prepared by Strategen.

3.2. PSE's Latest Eastside Contingency Load Threshold Analysis

The 2013 Eastside Needs Assessment Report includes a heat map that PSE claimed to depict electric load density. However, we note that this map shows the most densely populated areas in and around the Eastside (see Figure 3) which do not necessarily coincide with electric demand. We conducted power flow models in the Northwest area serving the South King county zone using historical and projected peak demand for King County.¹⁷ The models were run employing the base cases provided by the Western Electricity Coordinating Council (WECC) and varying key sensitivities while maintaining the projected peak demand constant to evaluate regional grid conditions under various contingency events.

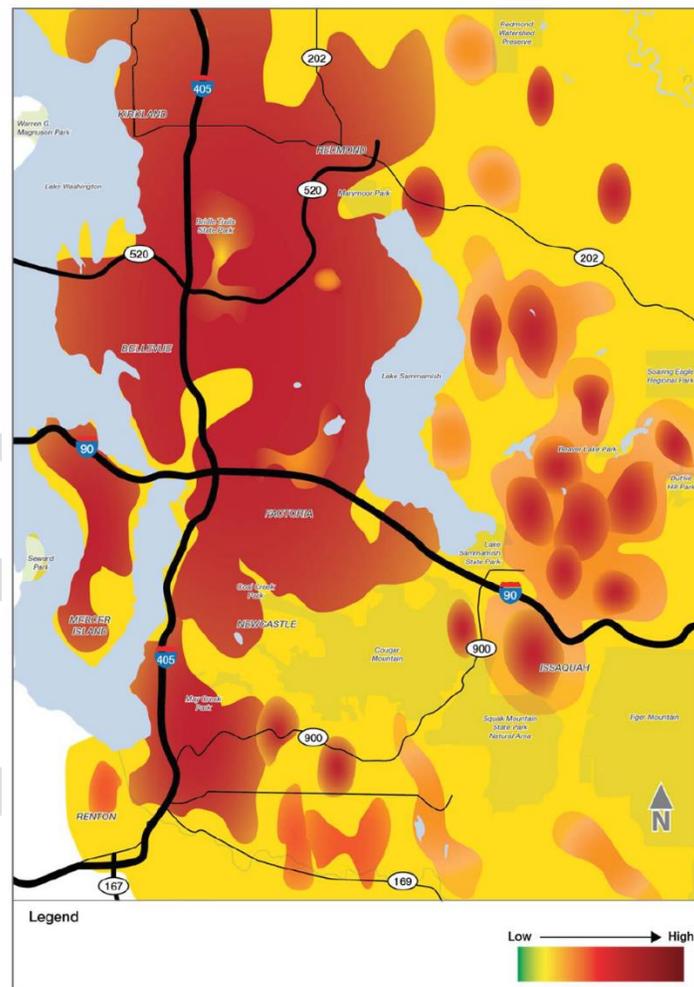
¹⁵ Quanta Technology. 2015, page 4.

¹⁶ These studies are available at <https://energizeeastside.com/>

¹⁷ An assessment of historical and projected peak demand is discussed in Section 5, for summer peak loads, see Figure 10 in Section 5.

For the Summer 2018 our load flow analysis verified that under N-1-1 contingencies the 230/115kV transformers at the Sammamish substation will overload when modeled using reasonable transformer series resistances and reactances and MVA operational limits. However, we also found that any increases in peak demand within the City of Newcastle, primarily served by the Hazelwood substation in the South King County zone, have little to no effect in the thermal transformer overloads identified for the Sammamish substation. In actuality, we were unable to identify one single occurrence while running different sensitivity scenarios during modeling (base case, primary contingency, secondary contingency) where realistic increases in peak demand in Newcastle would have triggered a non-existing overload in the bulk electric system serving the region.

Figure 3. Modified Heat Map



Source: 2013 Eastside Needs Assessment Report depicts population density

However, we were able to verify that under several contingencies certain facilities of the bulk electric system (BES) serving Newcastle will overload. The operational need arises from having to comply with NERC reliability standards that safeguard the security of the BES and not due to historical and/or

projected electric peak demand in Newcastle. We want to highlight that Newcastle will experience electric supply reliability issues if the BES is not secured.

On page 18 of the 2015 Supplemental Needs Assessment, 3,340 MW of area summer load is referenced as a level of need. Table 6-12 from the 2013 Eastside Needs Assessment further justifies the 3,340 MW as a level of concern by demonstrating equipment is overloaded to 100% of emergency rating during N-1-1 contingency at 3,340 MW of area summer load. In 2016, PSE switched to EPRI’s PTLOAD program to calculate load limits for transformers because the existing in-house software was unmaintainable. PTLOAD program is a widely accepted tool in the industry for rating transformers. With the new software, PSE adjusted its level of concern to 3,125 MW in the summer. The level of concern load level difference between 2013 and 2019 is mainly due to a change to a more widely accepted method of determining the individual transformer ratings. The latest estimate of the level of concerns by PSE is provided in Table 1 below for the PSE’s entire service territory and for King County. Our load flow analysis confirmed that these load thresholds are reasonable.

Table 1. PSE’s Revised Load Thresholds

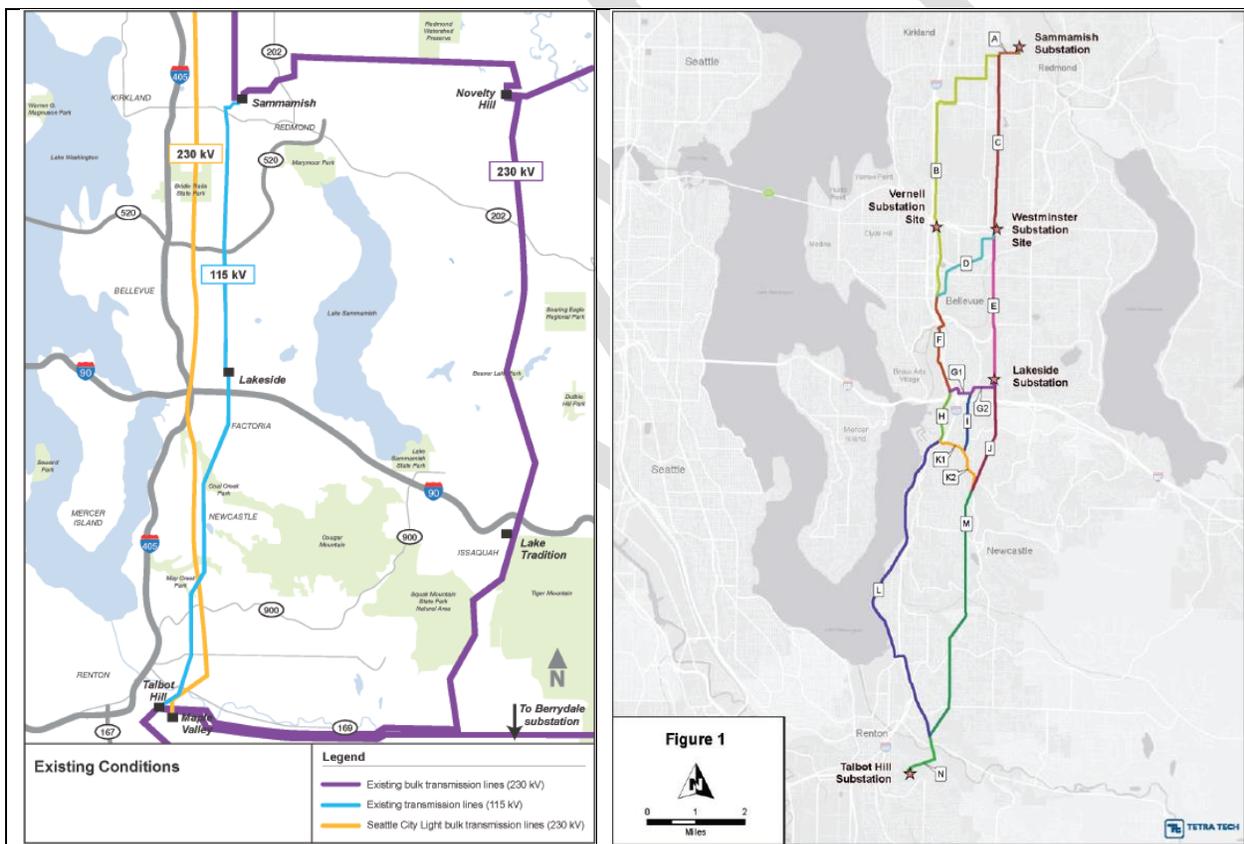
	Summer	Winter
PSE Area Load (Native + Transportation)	3125	5000
King County (Native + Transportation)	1594	2436

Source: PSE Data Request Response – September 9, 2019; Note: These load levels were calculated by scaling 2018 TPL seasonal caseloads until the emergency rating exceeded 100% during N-1-1 contingency.

3.3. Description of Proposed Eastside Project

PSE identified several contingency¹⁸ deficiencies in its transmission capacity that are triggered by summer peak demand in King County. To address these deficiencies, PSE proposes a transmission buildup plan¹⁹ that extends from the Sammamish transmission substation in Redmond to the Talbot Hill transmission substation in Renton (Figure 4). The proposed Energize Eastside project will also build a new electric substation, the Richards Creek substation in Bellevue, and upgrade existing transmission lines in Redmond, Bellevue, Newcastle and Renton. PSE claims that these upgrades and new facilities are needed to ensure the bulk electric system continues to perform reliably under several contingencies.

Figure 4. The Energize Eastside project proposes to upgrade the Sammamish-Talbot Hill 115kV transmission line (blue line left) to 230kV and build a new substation, the Richards Creek substation, in Bellevue.



Source: Tetra Tech (December 2013) Eastside 230kV Project Constraint and Opportunity Study for Linear Site Selection

¹⁸ Contingency – an event where one or more electric facilities suffer an outage.

¹⁹ Energize Eastside, <https://energizeeastside.com/>.

4. REVIEWED MATERIAL

The following materials were reviewed in order to evaluate PSE's filings against the City of Newcastle's code requirements.

- Quanta Technology (2013) Eastside Needs Assessment
- Quanta Technology (2013) Eastside Solutions Study Report
- Quanta Technology (2015) Supplemental Eastside Needs Assessment
- Quanta Technology (2015) Supplemental Eastside Solutions Study Report
- Energy and Environmental Economics (2014) PSE Screening Study
- Strategen (2015) Eastside System Energy Storage Alternatives Screening Study
- Strategen (2018) Eastside System Energy Storage Alternatives Assessment – Report Update.
- PSE (2017) 2017 PSE Integrated Resource Plan
- PSE's Annual Report of Energy Conservation Accomplishments
- PSE (2019) Overview of Integrated Resource Plans and Cost-Effective Conservation in Washington
- Portland General Electric 2019 Draft Integrated Resource Plan
- Navigant (2017) 2017 IRP Demand-Side Resource Conservation Potential Assessment Report, Appendix J to PSE's 2017 Integrated Resource Plan
- Utility System Efficiencies, Inc. (2015) Independent Technical Analysis of Energize Eastside for the City of Bellevue, WA
- CADMUS Group (2013) Comprehensive Assessment of Demand-Side Resource Potentials (2014-2033)
- November 2017 Newcastle Site Plans, Variance and Non-Variance
- Tetra Tech (December 2013) Eastside 230kV Project Constraint and Opportunity Study for Linear Site Selection
- PSE (2017) Newcastle Alternative Siting Analysis

5. LOAD FORECASTS AND NEED ASSESSMENT

5.1. PSE Load Forecast Methodology

The PSE load forecast approach follows a standard industry practice, although it has some limitations regarding the way it incorporates demand-side resources. PSE uses typical econometric models to forecast energy and peak loads over a 20-year time period. PSE's forecasting approach mainly consists of a regional economic and demographic model and a billed sales and customers model. The former uses both national and county-level data to produce a forecast of various economic and demographic factors (e.g., employment, types of employment, unemployment, personal income, population, households, building permit, etc.). The latter model takes the outputs from the former model and projects the number of customers by class as well as the energy use per customer (UPC) by class. This model then multiplies the number of customers and UPC to arrive at the billed sales forecast by class.

PSE uses another regression model to estimate electric peak loads based on observed monthly peak system demand and monthly weather normalized delivered demand.²⁰ It is not clear how much historical data are used in PSE's load forecast models, but one report produced by a consultant for Bellevue ("Bellevue Consultant report") stated that key historical statistics are available for the entire system from 2000 and for King County and Eastside area from 2006.²¹

PSE's current forecasts are produced for each county. However, PSE also produced a forecast specific to the Eastside area in the 2013 and 2015 Eastside Needs Assessment studies. The Bellevue Consultant report noted that PSE started to produce county by county forecasts starting in 2015. The report also noted that for the 2013 and 2015 Eastside Needs Assessment studies PSE produced the Eastside specific forecast from the King County forecast using census tract data.²²

PSE also makes some further adjustments to its load forecasts. Most notably, PSE reduces annual energy and peak load demands to account for the cost-effective amount of energy conservation (also called demand-side resource or DSR) identified in PSE's IRP process.²³ The 2013 and 2015 Eastside Needs Assessment studies included several conservation scenarios, including one scenario called 100% conservation (including 100% of the conservation potential estimated in the most recent IRP) and a 75% conservation scenario. PSE has been including the impacts of electric vehicles in its load forecast since its 2017 IRP.²⁴ PSE also includes the impacts of specific new construction projects in its near-term load forecasts, but correctly transitions those projects out of the forecast over several years to reflect the

²⁰ PSE. 2017. 2017 PSE Integrated Resource Plan, Chapter 5.

²¹ Utility System Efficiencies, Inc. 2015. Independent Technical Analysis of Energize Eastside, prepared for the City of Bellevue, Page 19.

²² Utility System Efficiencies, Inc. 2015. Page 15.

²³ PSE. 2017. 2017 PSE Integrated Resource Plan, Chapter 5, page 5-2.

²⁴ PSE. 2017. 2017 PSE Integrated Resource Plan, Chapter 5, page 5-37.

fact that new construction is included in the econometric projections of the base load forecast. As will be discussed in detail in Section 5.5, we found that PSE's current conservation/DSR estimates in the load forecast exclude or do not adequately include impacts of distributed solar PV, demand response, and combustion-based distributed generation (e.g., combined heat and power).

5.2. PSE Evaluation of Conservation and Other Demand Side Resources

As mentioned in the Overview section above, PSE commissioned several studies to examine the potential of energy conservation and other demand-side resources as non-wires alternatives to the Energize Eastside project. These studies specifically examined whether there are sufficient demand-side resources available to reduce peak loads to the levels below critical thresholds under transmission contingency events (e.g., N-1-1 conditions). Below we briefly summarize each of the key studies.

- **2013 Eastside Needs Assessment by Quanta Technology:** As mentioned above, in order to examine the need for transmission expansion, this study analyzed the impact of energy conservation measures on peak load forecasts based on the most recent IRP. The study assessed the capacity overloads for the entire PSE system and for the Eastside area with various conservation levels including a "100 percent conservation" scenario. The study identified system overloads by 2017-2018 for winter peak and as early as 2014 for summer peak under normal weather conditions, assuming 100 percent of the energy conservation estimated in the recent IRP. The study is not clear regarding which version of the IRP was used to develop conservation estimates, but it is likely that the study used PSE's 2013 IRP given the timing of the study.
- **2015 Supplemental Eastside Needs Assessment by Quanta Technology:** This report updated the load forecasts and reassessed the need for transmission capacity expansion in the Eastside area. The report indicates no changes to its energy conservation assumptions or methodologies. Unlike the 2013 study, this report clearly indicates that it used conservation targets from the 2013 IRP, although Quanta did not include the active demand response from that IRP because PSE did not implement active DR following the IRP's publication.²⁵
- **E3 study:** In early 2014, E3 assessed the potential for non-wires alternatives in King County to defer the proposed transmission upgrades in the Eastside area, including energy efficiency (EE), demand response (DR), and distributed generation (DG).²⁶ Using additional avoided benefits of deferring the transmission upgrades, the study assessed incremental amounts of cost-effective demand-side resources (DSRs) beyond the level of resources selected in PSE's 2013 IRP as non-wires alternatives. The study found a total of 56 MW of incremental DSR potential (30 MW from energy efficiency, 25 MW from demand response, and 1 MW from distributed generation) in King County. The study concluded that these DSRs are not sufficient to defer the transmission need

²⁵ Quanta Technology. 2015. Page 7.

²⁶ E3. 2014. 2014 PSE Screening Study.

because the region will be 75 MW short with PSE's 100-percent-conservation scenario or 100 MW short with a 75-percent-conservation scenario (which also acts a proxy for the higher load growth scenario or extreme winter conditions). The study focused on winter peak loads, apparently because winter peak is the main focus of the 2013 Needs Assessment. Detailed examination of this study is outside of the scope of our analysis. However, it is not clear to us whether the amount of DSRs identified in this study is still valid today, mainly because the study is more than 4 years old and because potential amounts likely have changed since then. For example, PSE's 2017 IRP found 522 MW of achievable potential for distributed generation while PSE's 2013 IRP used in the E3 study found only 33 MW of achievable potential for this resource.²⁷ Further, the required winter capacity gap used in this study is highly likely to be not applicable to today's conditions. (As will be discussed in the following section, we found that the winter peak loads have been substantially less than projected.)

- **Strategen 2015:** PSE commissioned Strategen to evaluate the feasibility of electric battery storage as an incremental measure to the additional DSR identified by the E3 study.²⁸ The study examined annual hourly load data and determined that Talbot Hill substation was the substation with the most significant normal and emergency overloads that occur during the winter period. Assuming the DSR results from the E3 study, the study examined load flows of the network transmission system and determined the battery sizes necessary to resolve normal overload reductions in the short-term (Baseline), emergency overload elimination (Alternative #1), and normal overload elimination in the long-term (Alternative #2). The resulting battery sizes are 328 MW, 121 MW, and 544 MW respectively.²⁹ The study also examined the technical feasibility and cost-effectiveness of large-scale batteries and concluded that batteries are not technically feasible under the Baseline and the Alternative #2 scenarios due to the excessive size of the batteries, siting limitations, long project timeline, and limited transmission system capacity to charge the batteries. The study then found that while the Alternative #1 (121 MW battery for resolving 34 MW of emergency overload) is technically feasible and cost-effective with a benefit-cost ratio of 1.13 and a \$264 million NPV cost estimate, this scenario does not meet the reliability requirements identified by PSE. However, we note it is likely that the estimated battery sizes are overestimated for addressing winter peak loads because the historical winter peak loads have been substantially lower than projected in the past. However, the study's results for addressing the summer peak overloads are likely to be still applicable.
- **Strategen 2018:** PSE commissioned Strategen to conduct a new study updating the Strategen 2015 study to consider changes to substation equipment ratings, PSE's updated load forecasts in 2017, and recent advancements in the energy storage

²⁷ PSE. 2017. 2017 PSE Integrated Resource Plan, Appendix J; PSE. 2013. 2013 PSE Integrated Resource Plan, Appendix N.

²⁸ Strategen. 2015. Eastside System Energy Storage Alternatives Screening Study.

²⁹ These estimates takes into account battery degradation factors and the study's finding that only 20 percent of the battery capacity is effective in reducing load at the substation and the rest of the battery outputs are expected to affect loads in other substations due to the interconnected nature of the network transmission system.

market.³⁰ This study analyzed the feasibility of two scenarios: (a) the Interim Solutions that meet the Winter 2018/2019 and Summer 2019 overload constraints and (b) the Complete Solution that meets PSE's 2027 forecasted need. The conclusions of this study are mostly consistent with the findings of the Strategen 2015 study. The 2018 Strategen Study found that energy storage is still not a practical solution to meet the expected Eastside transmission overloads. The study found that required battery systems would be substantially more expensive than the proposed transmission upgrades and would require considerably large land areas (e.g., 19 times the size of Tesla's Hornsdale facility in Australia, the world's largest currently installed system). On the other hand, the study found that the largest system constraints have shifted from Talbot Hill substation for the winter peak period to Sammamish substation for the summer peak period.

- **Latest conservation estimate:** PSE's latest load forecasts include the impacts of the 100 percent conservation scenario that is consistent with the latest Conservation Potential Assessment included as Appendix J to the 2017 Integrated Resource Plan with the exception of demand response and distributed generation. This conservation energy efficiency includes PSE's energy efficiency programs, distribution efficiency (e.g., conservation voltage reduction or CVR) and savings from codes and standards. Based on the data we obtained from PSE, we found that PSE assumes 361 MW of winter conservation potential for 2023 (224 MW from energy efficiency programs, 132 MW from codes and standards, and 4 MW from distribution efficiency) while PSE's IRP selected 374 MW of conservation for the same year.³¹

5.3. PSE Winter Peak Load and Need Assessment

We conducted a review of historical winter and summer peak loads and the winter and summer peak load forecasts that PSE has made over the last several years. We obtained PSE's latest historical load data and load forecast through the data request process and compared them with PSE's previous analyses provided in the 2013 and 2015 Needs Assessment report. This sub-section focuses on our assessment of PSE's winter peak load estimates.

Figure 5 presents PSE's load forecasts for its service territory made in 2012, 2014, and 2019 along with weather-normalized actual winter peak loads (i.e., loads adjusted for the specific weather impacts seen each year). These loads represent loads including the demand-side resource potential estimated in PSE's integrated resource plans (IRPs), with some exceptions. These load data are also adjusted for PSE's transmission level customers that are not included in PSE's corporate load forecasts.³² This figure shows that the historical winter peak loads have been lower than what PSE's load forecasts have projected in the past. It is also important to note that the load for the first year of each forecast has been

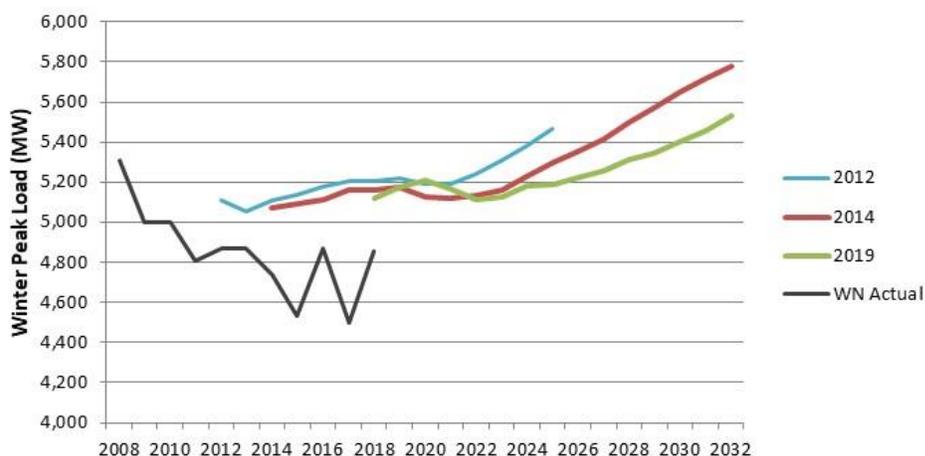
³⁰ Strategen. 2018. Eastside System Energy Storage Alternatives Assessment - Report Update.

³¹ PSE. 2017. 2017 PSE Integrated Resource Plan, Chapter 1, Figure 1-4; File "Newcastle DR Q1 partG.xlsx" obtained from PSE data response on September 10, 2019 to Newcastle Consultants' data request on August 8, 2019.

³² We assume 270 MW of peak load for transmission service customers per page 8 in the 2015 Supplemental Needs Assessment.

substantially higher than actual, weather normalized loads. The causes of these results, particularly the first-year discrepancy, are not clear to us. Further, as shown in the figure, there has been a decreasing trend in the historical weather-normalized peak loads over the past 10 years (although recent reductions in winter peak loads are not as large as the reductions in the early years). Historical peak loads started at about 5,300 MW in 2008 in this figure, reduced to about 4,500 MW in 2015 and increased to about 4,850 MW in 2018 (460 MW or 9 percent lower than the load in 2008). PSE did not project this decline. In fact, PSE’s forecasts show increasing loads into the future years, as well as increasing load during the time period when actual loads have declined. In addition, newer forecasts show lower peak loads than previous forecasts, and the time at which peak loads are projected to rise substantially appears to be shifting into the future with each forecast.

Figure 5. PSE Entire Service Territory: Winter Peak Load Forecasts and Weather-Normalized (WN) Actual Peak Load



Source: Compiled from PSE load forecast documents and discovery responses

PSE’s load forecasts have historically over-projected loads relative to actual loads. This was noted by Washington Utilities and Transportation Commission (WUTC) in “its Acknowledgement letter attachment” to PSE’s 2017 IRP. In this letter UTC noted “historically, PSE’s load forecasts have been overly optimistic” and included an assessment of PSE’s load forecasts by the Lawrence Berkeley National Laboratory in terms of average annual growth rate of energy (AAGR) as shown in Table 2 below.³³ WUTC further noted one critical factor that makes PSE’s long-term load forecast overly high. According to WUTC’s acknowledgement letter, the majority of conservation potential is assumed to be achievable

³³ Washington Utilities and Transportation Commission (WUTC). *2018 (check). Acknowledgement letter attachment: Puget Sound Energy’s 2017 Electric and Natural Gas Integrated Resource Plan, Dockets UE-160918 and UG-160919. Page 11. Available at <https://www.utc.wa.gov/layouts/15/CasesPublicWebsite/GetDocument.aspx?docID=1743&year=2016&docketNumber=160918>

mainly for the first 10 years, which “significantly affects the energy demand and therefore the projected need for new resources beyond year 10.”³⁴ We can observe this critical limitation of PSE’s load forecast in Figure 5, where forecasted peak loads start to escalate upward around 10 years in the future for each forecast. In the acknowledgement letter, the WUTC agrees with Staff’s comments that “PSE should assume in years 11 through 20 that a reasonable level of emerging retrofit conservation measures will be available in the market at cost-effective rates even though they cannot be accurately identified or predicted now.”³⁵ While the long-term forecast beyond 10 years is not directly relevant for our needs assessment of the Eastside project, we believe this point is worth noting and should be addressed by PSE in its future load forecasts.

Table 2. PSE’s projected and actual average annual growth rate of electric energy

Period	LSE-Projected AAGR	Actual AAGR
2006-2014	1.75%	-0.19%
2012-2014	1.90%	-1.19%

Source: WUTC Acknowledgement letter to PSE’s 2017 IRP.

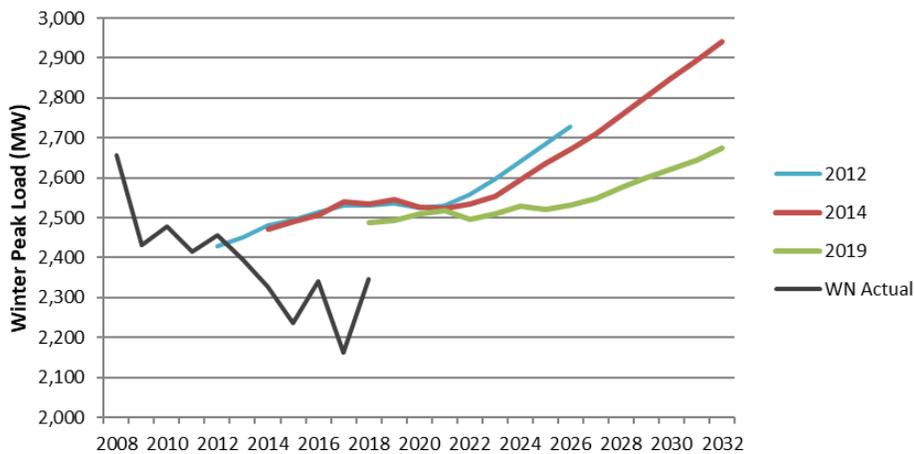
Historical loads and PSE’s peak load forecasts for King County also show similar trends what we have observed in PSE’s entire jurisdiction, as shown in Figure 6. Both the historical loads and projected loads in this figure include additional peak loads expected from transmission level customers.³⁶ Historical loads have been lower than forecasted loads (except in 2013). This comparison also shows that the forecasted peak loads for the first year for PSE’s 2014 and 2019 forecasts are substantially higher—over 140 MW or 8 percent higher—than weather-normalized (WN), actual winter peak loads.

³⁴ WUTC. *2018. Page 11.

³⁵ WUTC. *2018. Page 11.

³⁶ We assumed 81 MW of peak loads from those customers per PSE’s data response on September 9, 2019 to our data request on August 8, 2019.

Figure 6. PSE King County: Winter Peak Load Forecasts and Weather-Normalized (WN) Actual Peak Load



Source: Compiled from PSE load forecast documents and discovery responses.

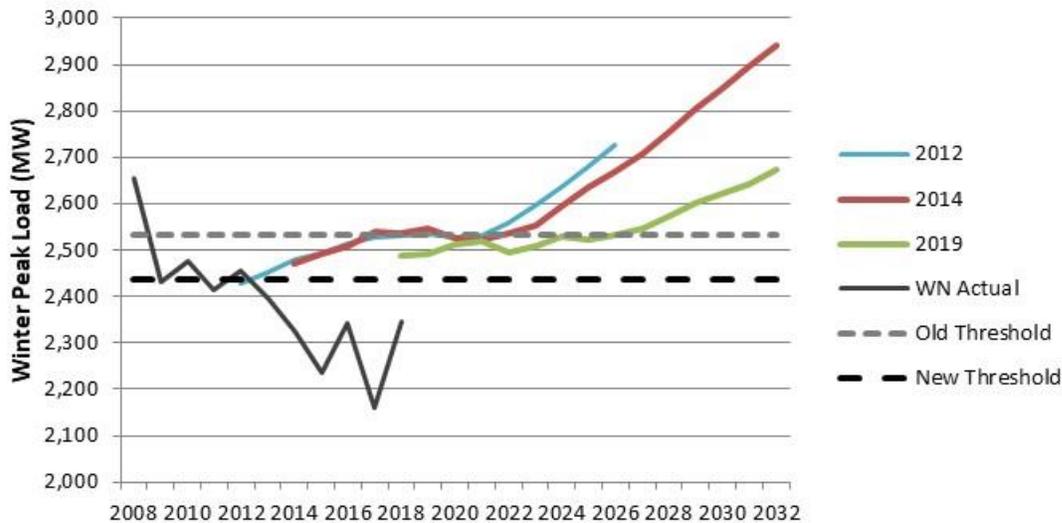
Finally, we examined the potential for winter transmission capacity constraints in King County – that is, whether and to what extent King County currently has or is expected to have any transmission capacity deficiency based on PSE’s projections. We compared King County’s current and projected winter peak loads with PSE’s estimates for peak load thresholds—that is, the load levels of concern above which PSE’s transmission facilities (i.e., Talbot substation for the winter peak) are expected to experience capacity deficiency under extreme contingency events (i.e., N-1-1 conditions). This analysis is presented in Figure 7 below. Our analysis focuses on King County because load constraints were identified in the Eastside area and because PSE has not produced any updated historical loads or forecasts for the Eastside area since the 2015 Supplemental Needs Assessment.

Figure 7 includes two separate estimates for load thresholds, labeled as “Old Threshold” and “New Threshold.” The “Old Threshold” represents a load threshold (or a level of concern) that was estimated in the 2013 and 2015 Eastside Needs Assessment report, scaled from the full PSE service territory to King County. During our investigation of the needs for the Eastside, we learned that PSE made a major change in the way it analyzes load flows in 2016 by changing to a new load flow model (EPRI’s PTLOAD). This change resulted in a significant reduction in the MW threshold, primarily due to different assumptions regarding the performance of grid components that are built into the PTLOAD model. The “New Threshold” in Figure 7 reflects this new estimate. For the PSE service territory, the thresholds were reduced from 5,200 MW to 5,000 MW for the winter period (representing a 4 percent reduction) and from 3,340 MW to 3,125 MW for the summer period (representing a 6 percent reduction).³⁷ For King County, the new peak load thresholds are 2,436 MW for the winter and 1,594 MW for the summer. Because the 2013 and 2015 Needs Assessment reports did not provide any load threshold for King

³⁷ PSE data response on September 10th to Newcastle’s August 8th data request 4(b).

County, we estimated the “Old Threshold” for King County by taking the ratio of load threshold changes at the level of PSE’s service territory.

Figure 7. PSE King County: Winter Peak Load Estimates vs. Peak Load Thresholds



Source: Compiled from PSE load forecast documents and discovery responses.

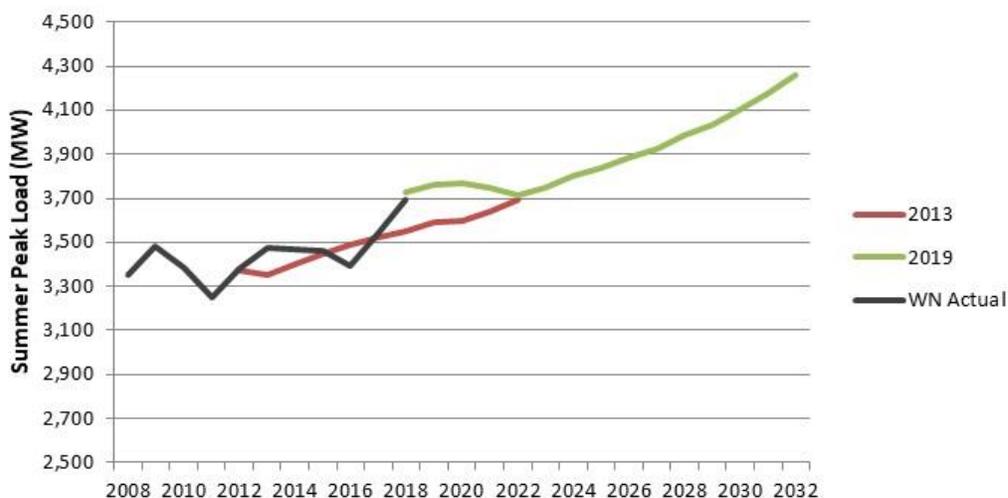
A comparison of the loads in Figure 7 reveals that the recent actual winter peak loads have been under the load thresholds. This is partly because King County’s Winter peak loads have been declining overall over the past several years, as discussed above. However, PSE’s latest load forecast developed in 2019 shows projected load levels above the new load threshold starting in 2018, although only by about 50 to 80 MW (or 2 to 3 percent) over the next few years. The result of this review provides us two conclusions. First, despite a number of claims made by PSE and its consultants about winter reliability issues and the need for capacity expansion by the winter of 2017-2018, our analysis reveals that this need actually has been deferred to at least 2019 because the load has been declining. Second, we have not obtained enough evidence to confirm that PSE’s winter peak load forecasts are reasonable. It is not clear if there is any potential capacity deficiency or any need for transmission capacity expansion, at least in the next several years. The starting point of the latest load forecast for 2018 is not plausible because the forecasted load is substantially higher than the weather-normalized actual load for the same year (by over 140 MW or 6 percent), and PSE has not accurately forecasted the declining winter peak load.

5.4. PSE Summer Peak Load and Need Assessment

PSE’s summer peak loads present a very different story than the winter peak loads. Figure 8 presents PSE’s load forecasts for its entire service territory made in 2013 and 2019, along with weather-normalized actual, historical summer peak loads through 2018 (i.e., loads adjusted for annual specific weather impacts). As with the winter peak load estimates, the summer peak load estimates include

loads for PSE’s transmission level customers.³⁸ The load forecasts also represent loads adjusted for 100 percent of the demand-side resource potential estimated in PSE’s IRPs, although the 2019 forecast excludes a number of resource types (e.g., demand response, solar PV, and other distributed generation). This figure shows that unlike the historical winter peak loads, the historical summer peak loads have been increasing over the past several years, as forecast by PSE in 2013. Further, unlike PSE’s winter peak forecast, the load for the first year for each forecast matches closely with the weather-normalized actual, historical loads (i.e., year 2012 and 2018).

Figure 8. PSE Service Territory: Summer Peak Load Forecasts and Weather-Normalized (WN) Actual Peak



Source: Compiled from PSE load forecast documents and discovery responses.

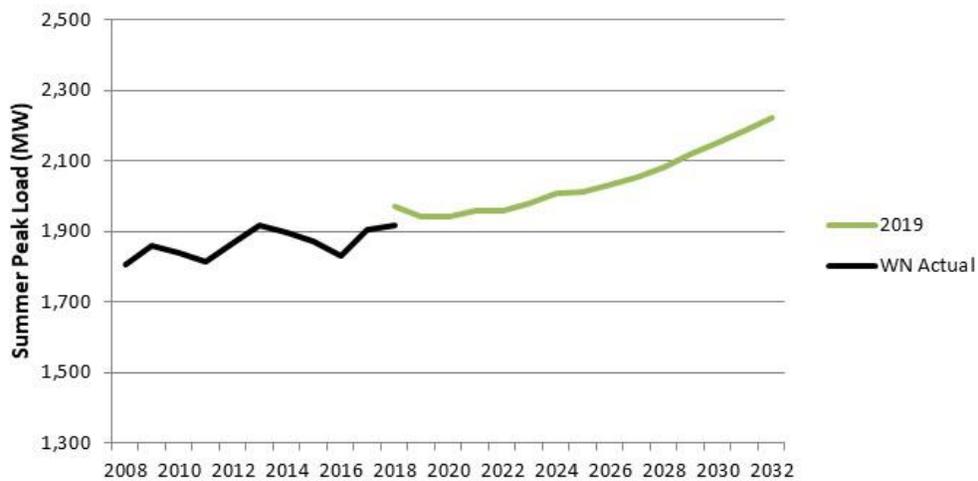
Historical and forecasted summer peak loads for King County show similar trends to the loads for PSE’s entire service area, as shown in Figure 9.³⁹ Summer peak loads have been gradually increasing over the past several years, and PSE’s forecast shows a growing peak load trend into the future. This figure includes just one forecast (made in 2019) because PSE’s Eastside Needs Assessment studies did not analyze summer peak loads at the King County level, but instead focused on winter peak loads for the Eastside area as well as for the entire service territory.⁴⁰

³⁸ We assume 270 MW of peak load for transmission service customers per page 8 in the 2015 Supplemental Needs Assessment.

³⁹ We assumed 81 MW of peak loads from transmission service customers based on PSE’s data response on September 9, 2019 to our data request on August 8, 2019.

⁴⁰ As we mentioned in a few other places, our analysis focuses on King County because PSE has not produced any updated historical or forecasted load estimates for the Eastside area despite the focus of its Needs Assessment reports being on the Eastside area.

Figure 9. PSE King County: Summer Peak Load Forecasts and Weather-Normalized (WN) Actual Peak Load



Source: Compiled from PSE load forecast documents and discovery responses.

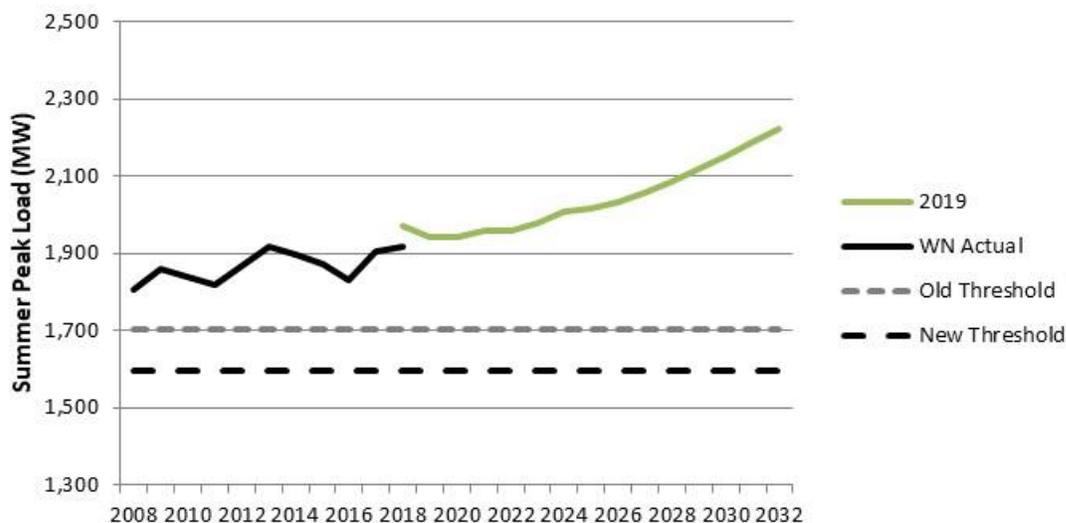
Finally, we examined the potential of summer capacity constraints in King County. Figure 10 presents this review by providing a comparison of the summer peak loads with peak load thresholds (the load levels of concern in King County at which key transmission facilities will be overloaded under extreme contingencies (i.e., N-1-1)). As mentioned above in the winter peak load discussion, PSE revised its previous load threshold calculation methodology. Its new estimate is shown as “New Threshold” (1,594 MW) in Figure 10. Because the 2013 and 2015 Needs Assessment reports did not provide any load threshold for King County, we estimated the “Old Threshold” for King County based on the ratio of load threshold changes at the PSE’s service territory level. At the total system level, the 2013 and 2015 Needs Assessment reports found system overloads could occur as early as 2014 and become more serious by summer 2018.⁴¹

A comparison of the load thresholds in Figure 10 reveals a more severe situation than found in the 2013 and 2015 Needs Assessment for the Summer peak period: King County’s summer peak loads have been exceeding the level of load concerns under N-1-1 contingencies both at the old and new threshold levels since at least 2008. More specifically the peak load levels in King County have been 13 to 20 percent (or 200 MW to 300 MW) above the new threshold (assuming PSE’s latest threshold is accurate). This means that PSE customers have been at risk of losing power each summer for the past 10 years, and this condition would continue unless the load were reduced by 20 percent (new threshold). Given this current severe condition, we do not need to rely on load forecasts to determine the capacity needs because it would be infeasible to acquire sufficient demand-side resources to reduce this substantial gap

⁴¹ Quanta Technology. 2013, pages 8, 9, 13 and 70; Quanta Technology. 2015, pages 18 to 19.

within just a few years. At the current load levels, we have to conclude that there is an operational need to expand the transmission capacity in the region.

Figure 10. PSE King County: Summer Peak Load Estimates vs. Peak Load Thresholds



Source: Compiled from PSE load forecast documents and discovery responses.

Although our determination of need does not rely upon the load forecast, we note that the forecasted summer peak load is likely to be overestimated because PSE’s load forecast does not take into account potential load impacts from distributed PV, demand response, and combustion-based distributed generation that PSE’s own 2017 IRP estimated. Nonetheless, including these resources in the context of a rising base load forecast would likely not reduce the load by 20 percent or more in the next few years and thereby eliminate the need for a transmission solution, and would expose PSE customers to continued risk of outages while the demand-side resources were developed.

5.5. Limitations in PSE’s Load Forecasts and Conservation Estimates

As stated elsewhere, PSE’s load forecasts include conservation potential impacts. As mentioned in previous sections, the 2013 and 2015 Needs Assessment studies assessed various conservation scenarios including the 100 percent conservation scenario. While our review of the latest forecast found that savings estimates from energy efficiency resources are close to 100 percent of the savings estimates selected in the 2017 IRP study, we found PSE’s conservation estimates contain a number of limitations which indicate that the current load forecast is likely to be overestimated, especially after accounting for the utility’s obligation to provide least cost service through demand-side measures.

More specifically, PSE’s load forecast omits certain resources identified in the IRP as achievable technical potential.⁴² For example, the conservation potential study in PSE’s 2017 IRP identified a large amount of demand response and distributed generation potential. Table 3 below shows achievable technical potential estimates from PSE’s 2017 conservation potential study, indicating that PSE has winter peak reduction potential estimates of about 190 MW and 522 MW by 2037 from demand response and distributed generation – combustion (e.g., natural gas turbines and combined heat and power), respectively. Note that distributed or behind-the-meter solar is analyzed separately in PSE’s scenario modeling process.⁴³ The potential study included in the IRP also indicates 140 to 160 MW of summer peak reduction from demand response.⁴⁴ Further, the 2017 IRP selected about 150 MW of winter demand response potential as part of the least cost resources, as shown in Table 4 below.

Table 3. PSE 2017 Potential Study Summary in 2037

	Energy (aMW / MMtherms)		Winter Coincident Peak Capacity (MW)	
	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Electric Resources				
Energy Efficiency	836	598	1,305	975
Fuel Conversion	55	29	125	72
Demand Response	N/A	N/A	N/A	188
Distributed Generation - Combustion	4,280	933	N/A	522
Electric Resources Total	5,172	1,560	1,430	1,757
Natural Gas Resources				
Energy Efficiency	240	164	N/A	N/A

Source: PSE. 2017. 2017 PSE Integrated Resource Plan. Appendix J, Table 22.

⁴² This is also applicable to PSE’s previous load forecasts in the 2013 and 2015 Needs Assessment studies.

⁴³ PSE. 2017 IRP, page 5-37.

⁴⁴ PSE. 2017. IRP, Appendix J, Figure E-1, Figure E-4.

Table 4. PSE 2017 IRP Results: Electric Resource Plan Forecast, Cumulative Nameplate Capacity of Resource Additions

	2023	2027	2037
Conservation (MW)	374	521	714
Demand Response (MW)	103	139	148
Solar (MW)	266	378	486
Energy Storage (MW)	50	75	75
Redirected Transmission (MW)	188	188	188
Baseload Gas (MW)	0	0	0
Peaker (MW)	0	717	1,912

Source: PSE. 2017. 2017 PSE Integrated Resource Plan, Chapter 1, Figure 1-4.

Despite these resource potential estimates, PSE’s latest load forecasts do not include any impacts of such resources. For demand response, PSE stated that “PSE does not include impacts of demand response **because PSE does not have any meaningful demand response** [emphasis added]” in its response to our data request dated May 9, 2019.⁴⁵ Further, PSE implied that PSE does not include demand response because the company found DR was not cost-competitive against other resource bids submitted to a 2018 RFP, as follows:

“PSE put out an “all source” RFP in 2018, which included requests for DR proposals. PSE received six DR proposals along with close to 100 renewable and capacity contract proposals. PSE evaluated all of these proposals, and **the DR proposals were not found to be cost competitive against the other proposals** [emphasis added].”⁴⁶

These responses by PSE do not justify PSE’s exclusion of demand response for future “transmission system capacity” needs. First of all, the fact that PSE does not have any meaningful demand response now does not mean that PSE will not or cannot have any demand response in the future or justify that PSE can exclude demand response for mitigating future peak loads. In fact, PSE is expecting to implement demand response in the near future or is possibly required by legislation to implement demand response as stated by PSE as follows:

“PSE and the Commission continue to engage in conversations about how PSE can engage customers in the near-term through potential demonstrations and pilot projects for demand response for several use cases. PSE is also closely following implementation of recently enacted

⁴⁵ PSE data response on May 9, 2019 to Newcastle’s consultants’ data request on April 16, 2019.

⁴⁶ PSE data response on September 10, 2019 to Newcastle’s consultants’ data request on August 8, 2019.

legislation, including E2SSB 5116, which may require the Commission to set interim targets for demand response by 2022.”⁴⁷

Secondly, the fact that demand response was not competitive against other resources for “energy” supply purposes does not mean that demand response is not cost-effective. In fact, the 2017 IRP selected about 150 MW of demand response as a least cost resource, as shown in Table 4 above. Further, the purpose of the all resource RFP is to procure new “energy” supply.⁴⁸ This RFP was not intended and designed for procuring resources to mitigate transmission constraints. If the value of avoiding new transmission infrastructure (which was not included in the “all source” RFP) were included, the cost-effectiveness and cost-competitiveness of demand response would likely be improved substantially.

Numerous utilities and independent system operators (ISOs) have implemented or incorporated demand response as a cost-effective capacity resource across the county. For example, the Federal Energy Regulatory Commission (FERC) has reported that ISOs across the county currently have demand response capacities that range from 1.5 percent to about 11 percent of peak demand.⁴⁹ Further, Portland General Electric (PGE) in Oregon (whose electric system has a comparable size to PSE’s system) identified the need to procure DR in its last IRP three years ago and has procured 21 MW of winter DR (of the 77 MW target for 2020) and 32 MW of summer DR (of the 69 MW target) as of July 2019 as well as about 129 MW of dispatchable backup generators (of the 135 MW target for 2020). PGE’s latest IRP stated it is on track to meet the 2020 targets for these resources.⁵⁰ Furthermore, PGE has just implemented its SmartGrid test bed pilot program under which the company intends to recruit more than 20,000 customers, or two-thirds of customers, in three towns for their demand response resources through 2022. These customers will install a range of smart connected devices to control thermostats, water heaters, electric vehicle chargers, and batteries will be eligible to receive a \$1 per kWh incentive for peak reduction. Further, PGE aims to integrate even more renewable energy resources into its power supply with this program without compromising grid safety, security or reliability.⁵¹

⁴⁷ PSE data response on May 9, 2019 to Newcastle’s consultants’ data request on April 16, 2019

⁴⁸ For details about the RFP, see <https://www.pse.com/pages/energy-supply/acquiring-energy?srce=rfp>

⁴⁹ FERC. 2019 Assessment of Demand Response and Advanced Metering, Table 3-3. Available at <https://www.ferc.gov/legal/staff-reports/2019/DR-AM-Report2019.pdf>

⁵⁰ PGE. 2019. Integrated Resource Plan DRAFT, p. 15-16. Available at <https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning>

⁵¹ PGE. 2019. “Portland General Electric’s ambitious Smart Grid Test Bed launches”, July 15, 2019. Available at <https://www.portlandgeneral.com/our-company/news-room/news-releases/2019/07-15-2019-portland-general-electrics-ambitious-smart-grid-test-bed-launches>; UtilityDive. 2019. “PGE demand response pilot offers \$1/kWh incentive, targets 10X customer participation rate,” January 16, 2019. Available at <https://www.utilitydive.com/news/portland-general-pilot-proposes-reward-to-customers-for-reducing-energy-use/546095/>.

For distributed generation (DG)—combustion, PSE stated that it excluded this resource because all of the achievable technical potential was above the cost-effective threshold.⁵² The 2017 PSE IRP found 933 MW of potential in DG combustion resource, a substantial increase from its previous estimate of only 22 MW in the 2015 IRP. This is mainly due to the fact that the 2017 IRP and conservation potential study (a) took into account actual CHP installation data and (b) included natural gas-driven engines without heat recovery (which was omitted in the 2015 IRP).⁵³ Given these new findings and new potential estimates for DG combustion, it is hard to believe that the cost-effective DG—combustion potential is zero from the consumer’s perspective.

For behind-the-meter (BTM) solar PV, PSE states in its response to our data request that solar “is accounted for in the load forecast in that solar trends are embedded in historical data used to develop the forecast”.⁵⁴ However, increase in solar PV installations is a recent trend in response to the significant drop in solar PV prices in the past few years. We do not believe that PSE’s load forecast adequately captures this new trend. In addition, the industry is expecting further growth in solar PV installations. The 2017 potential study included in the IRP indicates there is 122 MW of BTM solar PV potential in PSE territory over the next 20 years.⁵⁵ Further, in its 2019 Annual Energy Outlook, the U.S. Department of Energy (DOE)’s Energy Information Administration (EIA) estimates that solar PV generation grows by three-fold over the next 10 years (from 10 GW to 30 GW for residential systems, for example) under a current-policy baseline.⁵⁶ Given this potential growth, other regions have started to incorporate solar PV forecasts in their load forecasts.

For example, ISO-New England now develops a forecast of BTM solar PV and explicitly includes its impact on Summer peak load forecasts in addition to energy efficiency. In its latest load forecast, ISO-New England projects that the region’s distributed solar resources increase from 630 MW in 2018 to about 1050 MW in 2028 in terms of summer peak reduction impacts.⁵⁷ PSE’s nearby utility PGE is also projecting a rapidly growing BTM solar and battery trend in its 2019 IRP as shown in Figure 11, Figure 12, and Figure 13.

⁵² Email communication with PSE staff on October 29, 2019.

⁵³ PSE. 2017. 2017 PSE Integrated Resource Plan, Appendix J, page xxii.

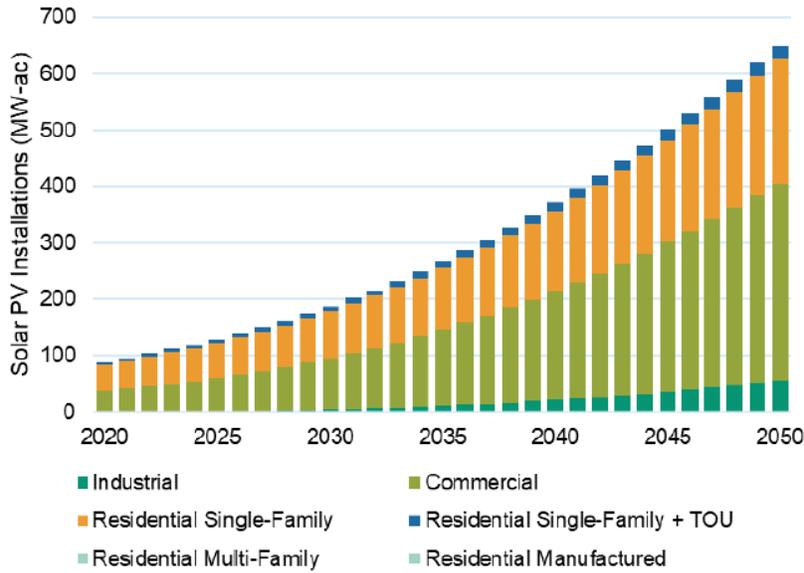
⁵⁴ PSE data response on September 10, 2019 to Newcastle’s consultants’ data request on August 8, 2019, Question 1(f).

⁵⁵ PSE. 2017. 2017 PSE Integrated Resource Plan, Appendix J, Table 7.

⁵⁶ EIA. 2019. Annual Energy Outlook 2019. “Rooftop solar PV adoption grows between 2018 and 2050.” Available at <https://www.eia.gov/outlooks/aeo/pdf/aeo2019.pdf>

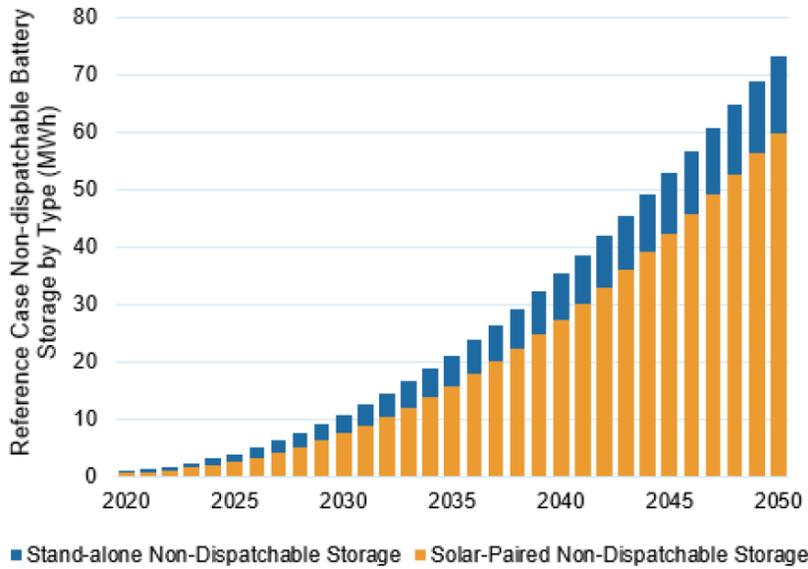
⁵⁷ ISO-New England. 2019. CELT Report – 2019-2028 Forecast Report of Capacity, Energy, Loads, and Transmission. Section 1.1 and 3.2, available at <https://www.iso-ne.com/system-planning/system-plans-studies/celt/?document-type=CELT%20Reports>

Figure 11. PGE’s projection of BTM solar adoption by customer segment in its 2019 IRP Reference Case



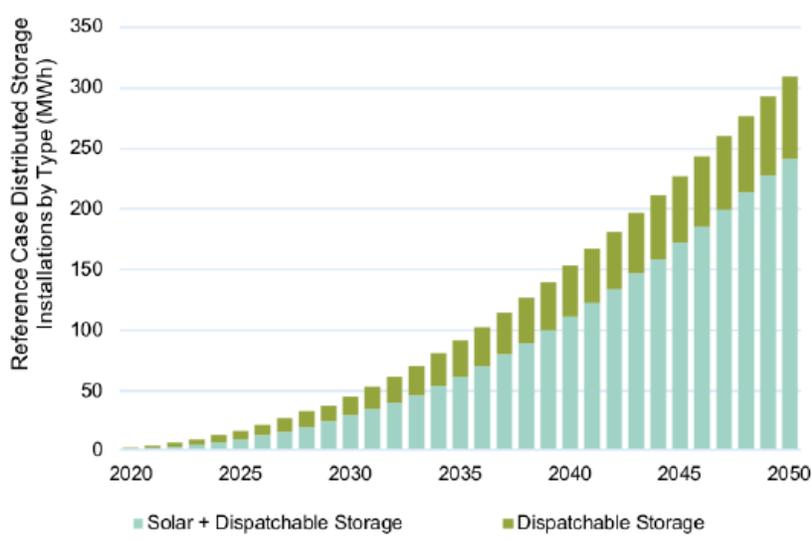
Source: PGE. 2019. Integrated Resource Plan - DRAFT. Figure 4-5

Figure 12. PGE’s projection of Non-dispatchable customer battery storage in its 2019 IRP Reference Case



Source: PGE. 2019. Integrated Resource Plan - DRAFT. Figure 4-7

Figure 13. PGE’s projection of dispatchable customer battery storage in its 2019 IRP Reference Case



Source: PGE. 2019. *Integrated Resource Plan - DRAFT*. Figure 5-2.

Further, the Northwest Power and Conservation Council (NWPCC) is currently examining the impact of BTM solar PV on the summer peak load in the Northwest region as a whole. NWPCC explains this effort as follows:

“The Council closely tracks trends in energy advances and consumer use to improve its long-term load forecast, which is used in the Council’s regional power plan, currently under development. In our planning, we developed a model simulation to gauge the impact of aggregating installations of behind-the-meter solar+battery systems to smooth out the regional electricity load and, as a result, reduce peaks.”⁵⁸

PSE has evaluated the ability of storage to eliminate the need for the Energize Eastside project. However, despite the growing inclusion of BTM storage in utility planning, PSE has not included this resource in the resource assessment in its IRPs, or in the load forecasts presented to us in this evaluation.

⁵⁸ NWPCC. 2019. “What’s Next for Solar Generation? How Solar+Battery Could Help Meet Peak Loads in the Northwest.” May 16, 2019. Available at <https://www.nwcouncil.org/news/what-s-next-solar-generation>.

6. ASSESSMENT OF THE PROPOSED EASTSIDE PROJECT

6.1. The Proposal

PSE proposed the Energize Eastside project that consists of upgrading the 115kV transmission lines to 230kV lines in the existing Willow 1 transmission line corridor and the construction of the Richards Creek substation in Bellevue. Our assessment finds that the upgraded transmission facilities proposed to traverse approximately 1.5 miles through Newcastle serve an operational need to safeguard the security of the bulk electric system.

6.2. Operational Need

We conducted a power flow analysis of PSE's transmission system with a focus on the Eastside project using the PowerWorld power flow model. Our analysis found that the facilities supplying the Eastside are currently experiencing a transmission capacity constraint that is especially pronounced during the summer in the Northwest area serving the South King County zone. Part of PSE's transmission planning responsibilities is to ensure the reliability of the transmission system it operates. This includes no long-term reliance on operating procedure corrective action plans.

Power systems are operated so that overloads do not occur either in real-time or under any statistically likely contingency. Contingencies can consist of several actions or elements, such as an outage of a single transmission line or an outage of several lines, a number of generators, and the closure of a normally open transmission line. The North American Electric Reliability Corporation (NERC) develops and enforces standards to ensure the reliability of power systems in North America. The Transmission Planning Standard (TPL) defines system performance requirements under both normal and various contingency conditions. The NERC transmission planning standards that are currently subject to enforcement are NERC TPL-001-4 and TPL-007-3.⁵⁹ These requirements are used to analyze PSE's transmission system that is part of the Bulk Electric System of the Western Interconnection. The analyzed contingencies included (1) no contingencies, (2) events resulting in loss of a single system element, and (3) events resulting in loss of two or more system elements.

Under several contingencies, our power flow analysis verified that transformers at the Sammamish and Talbot Hill substations experience overloads when modeled using reasonable zero sequence fault impedances, line losses, voltages/angles, per unit impedance parameters, line flows, and MVA limits for normal and emergency operations. If these overloads are left unaddressed, Newcastle can experience reliability issues with its electric supply. However, our analysis also found that the historical and

⁵⁹ <https://www.nerc.net/standardsreports/standardssummary.aspx>

projected peak demand in Newcastle itself will not pose a reliability issue in the bulk electric system serving the region.

Electricity is primarily served to customers through substations that are closer to the loads. The city of Newcastle is primarily served by the Hazelwood Substation in the South King zone of the Northwest area. Based on our power flow analysis conducted to verify the claims of transmission constraints used to justify the proposed facility upgrades, we found that increasing the load served by the Hazelwood switching station had little effect in the flows through the Sammamish transmission substation. We conclude that the operational need claimed by the utility is not triggered by increased demand in Newcastle but instead the operational need results from the requirement to secure the system at a regional level and comply with NERC reliability standards for the Bulk Electric System (BES). We note that if the BES fails, Newcastle will be without electric supply unless island-able distributed generation, i.e., generation closer to load centers, is available. Our review did not identify significant distributed generation capacity in the Newcastle area.

There is a possibility that the power flow through the Northern Intertie to PSE's territory is affecting the summer peak situation in King County. Our power flow models verify that even with the Northern Intertie adjusted to zero flow, the Talbot Hill 230kV/115kV transformer on circuit #2 would still be overloaded when accounting for secondary contingencies. Note that the Northwest system that serves King County has interchange schedules with several other systems including BC Hydro, and during the summertime most of the interchanges are power imports into the Northwest area. The Northwest – BC Hydro interchange transfers take place through the High Voltage Northwest transmission system. Our assessment found that these transfers have minimal impact on the transmission power flows that supply the distribution facilities that feed the load centers of the Eastside.

6.3. Reliability Improvement

Electric utilities commonly experience facilities outages, either planned or unplanned. A well-planned system will feature redundancy and absorb these outages to maintain continuity of supply to customers and ensure service reliability in the Eastside.

In order for Newcastle to benefit from this level of reliability, PSE proposed to upgrade the existing 115kV line in the Willow 1 transmission line corridor (Figure 14 and Figure 15 below) to 230kV lines. Under this proposal, residents in Newcastle would see higher transmission towers needed to comply with the 2017 National Electrical Safety Code.

Figure 14. Existing two 115kV electric transmission facilities on H-frame poles travel in existing transmission corridor through Newcastle around SE 80th Way, Newcastle, WA 98056



Source: Google Earth, retrieved September 2019; Note: City of Newcastle Public Notice of Proposed Land Use Action can be seen.

Figure 15. Current 115kV electric transmission facilities around 12828 SE 80th Way, Newcastle, WA 98056.



Source: Google Earth, retrieved September 2019.

We highlight that a dual 230kV transmission line operated by Seattle City Light (SCL) already travels through Newcastle (Figure 16 below).

Figure 16. Seattle City Light 230kV Transmission Line at Donegal Park [SE 74th ST, Newcastle, WA 98056



Source: Google Earth, retrieved September 2019.

7. KEY FINDINGS, CONCLUSIONS AND RECOMMENDATIONS

7.1. Key Findings

Our assessment of power flow finds that current or projected electric peak demand in Newcastle itself does not trigger an operational need for the proposed transmission expansion. However, our power flow cases analysis shows that the current summer electric peak demand in King County has already triggered an operational need for the proposed transmission expansion under system contingency situations

Our power flow model assessment finds that the regional capacity thresholds in King County estimated by PSE are reasonable.

Our assessment of PSE's load forecasting methodology finds that the PSE load forecast approach follows a standard industry practice, although it has some limitations regarding the way it incorporates demand-side resources. More specifically, while PSE's latest load forecasts include the impacts of the 100 percent conservation scenario that is consistent with PSE's latest Conservation Potential Assessment, it excluded certain resources as follows.

- PSE’s load forecast excludes demand response and distributed generation resources (about 190 MW and 522 MW by 2037) identified in a conservation potential study prepared for PSE’s 2017 IRP. The IRP itself selected about 150 MW of winter demand response potential as part of the least cost resources. But this was not included in PSE’s forecast as discussed in Section 5.5.
- PSE did not adjust its load forecast for behind-the-meter (BTM) solar PV because it believes that the solar PV trends are embedded in historical load data. This assumption is not appropriate because the industry is expecting a significantly larger growth in solar PV installations over the coming decade than experienced in the last decade.
- PSE does not incorporate BTM solar plus storage systems in its forecast or in its IRP process while the Northwest Power and Conservation Council (NWPPCC) is now examining the impacts of such resources on system peak loads.

Our assessment PSE’s historical peak loads found that PSE’s winter peak load actually has been declining over the past several years and its current peak load is still below the critical threshold for additional transmission capacity. While PSE’s studies (the 2013 and 2015 Quanta studies) found that there would be a need for additional capacity by the winter of 2017-2018, in fact that need has been deferred to date, at least during the winter peak periods.

While we found that PSE’s own winter load forecast is above the load threshold for concern in King County, we cannot conclude based on the evidence we analyzed whether there is any potential winter capacity deficiency or any need for transmission capacity expansion at least in the next several years. This is mainly because the starting point of the PSE load forecast for 2018 is implausible: the forecasted 2018 load is over 140 MW (or 6 percent) higher than the weather-normalized actual historical load in King County.

On the other hand, based on PSE’s latest estimate for load thresholds in King County, which our power flow analysis verified, we found there is a summer transmission capacity deficiency in King County under N-1-1 contingencies even at today’s peak load level. We further found that the capacity deficiency in fact has existed for the past 10 years or more for the summer season. More specifically, the peak load levels in King County have been 13 to 20 percent (or 200 MW to 300 MW) above the area’s capacity threshold, putting PSE customers at risk of losing power for the past 10 years.

7.2. Conclusions

Even though PSE was not able to demonstrate that an operational need was triggered by electric demand in Newcastle, PSE demonstrated that the proposed transmission upgrades are needed to safeguard the operational reliability of the electric system as a whole.⁶⁰ To maintain system security,

⁶⁰ Electric system as a whole is also referred to as the Bulk Electric System.

power systems are operated so that overloads do not occur either in real-time or under any statistically likely contingency. Not securing the bulk electric system to operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies can affect the electric supply reliability in Newcastle. This peer review verified that under specific contingencies (N-1-1 and N-2) the as-is bulk electric system serving Newcastle is already at operational risk and in fact has been in such a condition at least over the past 10 years during the summer season. This means that PSE's application has met the threshold for approval Newcastle City Code C-5 under NMC 18.44.052 Utility facilities – Regional: “[t]he applicant shall demonstrate that an operational need exists that requires the location or expansion at the proposed site.”

The current transmission deficiency can be resolved by upgrading one of the 115kV transmission lines between the Talbot Hill and Sammamish substations to 230kV and installing an additional 230kV/115kV 325MVA transformer at the proposed Richards Creek substation in Bellevue. Upgrading the second 115kV transmission line that currently travels through the same corridor, Willow 1, to 230kV is consistent with good system planning, noting that the facilities to support these higher voltages will already be deployed.

However, we note that there were various actions and measures PSE could have taken over the past 10 years or more to avoid the current situation. Such actions include actually implementing targeted demand-side resources rather than just studying them and also identifying and acting upon summer peak savings opportunities that have been neglected for many years. These actions would have allowed PSE to avoid the current serious condition that now could jeopardize its own customers under transmission contingencies and reduce the need to implement CAPs, while likely providing additional net benefits to the area because many demand-side resources are cost-effective on their own.

7.3. Recommendations

Transmission solutions

We recommend that the Conditional Use Permit to PSE to upgrade the identified approximately 1.5 miles of existing 115kV lines with 230kV lines be conditioned on Conducting an independent design assessment of the overhead transmission facilities traversing Newcastle that verifies compliance with the clearance safety rules for the installation and maintenance of overhead electric supply of the 2017 National Electrical Safety Code, ANSI C2 Part 2.

We also recommend that the city of Newcastle sends field inspectors during the transmission line upgrades to ensure compliance with the 2017 NESC.

Non-wires alternatives

The best time to begin implementation of summer demand-side measures would have been many years ago—potentially as early as 2008 when the region's transmission challenges were identified. However, PSE hasn't missed the best remaining opportunity to implement such programs. That time is now.

While the City of Newcastle does not have the regulatory authority to require the actions we recommend below, we believe they would be prudent utility actions that the utility should undertake of its own volition, and that the WUTC should give them due consideration and support for rate recovery if pursued in a prudent manner. We believe that PSE should take proactive actions to implement our recommendations and reach out to WUTC as it reforms its current transmission planning process and load forecast.

Although our assessment confirmed that PSE does need to build and increase its transmission capacity for the Eastside and King County, it takes several years to complete any substantial transmission and substation construction project. Until such a project is complete, PSE should strive to minimize the risk of forced outages as much as possible. The best approach for minimizing the risk is to actually implement cost-effective demand-side resource programs as non-wires alternatives (NWA), with a focus on reducing the summer peak load.

Second, PSE should also seek to procure as much demand response (DR) as possible along with energy efficiency, solar PV, and combined heat and power because DR has some advantages over other resources: (a) DR is an untapped resource in the region; (b) DR can be quickly procured; (c) DR can be dispatched by PSE; and (d) DR has a potential to deliver a large amount of summer peaking reduction within a short time frame. Current efforts to secure DR capacity seem lukewarm at best.⁶¹

As mentioned in our report, Portland General Electric (PGE), PSE's nearby peer utility which has a similar level of peak loads, has implemented about 160 MW of summer DR including dispatchable generators (32 MW of conventional DR and 130 MW of dispatchable backup generators) since 2016 and is on track to meet its 2020 DR goals of about 200 MW, or close to 6 percent of the summer peak load.⁶² We believe PSE could do the same while cost-effectively reducing risk for its customers.

Third, PSE should assess the potential of energy efficiency measures that can reduce summer peak loads. Historically PSE's conservation studies have been focusing on winter peak periods. While PSE's 2017 IRP assessed summer peak reduction potential from demand response for the first time, it did not analyze summer peak potential from energy efficiency measures despite the fact that PSE identified by-then-serious transmission constraints during the summer peak time. We recommend PSE immediately undertake a study to evaluate summer peak reduction from energy efficiency measures if this scope is not included in the ongoing 2019 IRP process.

⁶¹ <https://www.pse.com/pages/grid-modernization/demand-response>

⁶² PGE. 2019. Integrated Resource Plan DRAFT, p. 15-16. Available at <https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning>; 3,436 MW of summer peak expected for 2020 per page 233 of PGE's 2019 IRP Draft.

Fourth, PSE should take a serious look at the expected impacts of BTM solar PV and incorporate the impact in its summer peak load forecast by following other leading utilities (including PGE) and regional system operators. This will modify PSE's summer peak load forecasts downward.

Fifth, PSE should modernize its transmission planning process by formally incorporating the process of including and implementing targeted DSR programs as non-wires alternatives (NWAs). Implementation of NWA in King County will be a valuable experience for transforming the transmission planning process for PSE. PSE may be able to identify more achievable demand-side resource potential in targeted areas than identified in PSE's potential studies or assumed in PSE's Energize Eastside studies because targeted approaches accompany area specific, enhanced customer outreach, marketing, and incentives that are outside of the scope of the traditional potential studies.

Finally, PSE or the WUTC should consider developing an independent third-party model for evaluating and/or procuring NWA as part of the transformation of the transmission planning process. Other states have such processes. For example, the Vermont System Planning Committee was formed more than a decade ago after a large transmission project was approved but regulators identified that it could have been avoided had utilities begun pursuit of non-wires solutions sooner.

The VSPC brings together transmission and distribution utilities, along with appointed stakeholder representatives, every quarter to assess load forecasts and potential future transmission and distribution investments driven by load growth. The VSPC has developed screening criteria and processes to transparently identify NWA opportunities in time to be able to implement targeted load reduction. More recently The State of Maine has charged the state's consumer advocate with hosting a third-party non-wires alternative coordinator, which will analyze the load and reliability data provided by utilities to identify opportunities for cost-effective NWAs.