Ken Nichols
Principal, EQL Energy
3701 SE Milwaukie Ave, Suite A
Portland, OR 97202

Date: February 1, 2016

Via web portal at www.uts.wa.gov/e-filing, and email to Commission's Records Center at records@uts.wa.gov

Steven V. King
Executive Director and Secretary
Washington Utilities and Transportation Commission
P.O. Box 47250
1300 S. Evergreen Park Drive S.W.
Olympia, WA 98504-7250

RE: Comments of EQL Energy, UE-141170, Puget Sound Energy 2015 Integrated Resource Plan.

On December 9, 2015, The Washington Utilities and Transportation Commission (Commission) issued a notice that it would accept written comments on Puget Sound Energy's (PSE or Company) integrated resource plan for electric and natural gas service, with a due date for comments of January 15, 2016. The notice also established a recessed open meeting on March 4, 2016, at which PSE representatives will present the plan to the Commission and the public.

EQL has participated in several PSE IRP advisory group meetings, both in person and via phone, in the past year and was a regular provider of comments on topics related to:

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

EQL has two primary interests in providing these comments.

1. We would like to see distributed energy resources be given more value in IRPs through T&D cost reduction, resiliency, renewable integration, customer preference, etc. and
2. EQL has provided services to CENSE (Coalition of Eastside Neighborhoods for Sensible Energy). They are a local stakeholder group opposing the large transmission projects through eastside neighborhoods, e.g., rebuilding of Sammamish-Lakeside-Talbot 115 kV line to 230 kV (aka Energize Eastside). CENSE asked EQL to review the PSE 2015 IRP and comment on the relationship of the IRP with planning for Energize Eastside. EQL's comments are solely those of EQL, and are meant to promote improved least cost utility planning. These same comments were made to PSE as part of their advisory group

process. We have provided summary comments, specific section comments, and recommendations.

3.

1 Executive Summary 5
1.1.1 Location, Location, Location 7
1.1.2 It's not just a good idea, it's the law 7
1.1.3 DER and DSR can avoid Transmission 8
1.1.4 Defining distribution located resources 9
1.1.5 PSE Consideration of Transmission in the 2015 IRP 10
1.1.6 Western wholesale electricity markets 10

2 Specific Comments 11
2.1 Chapter 1 - Executive Summary 11
2.1.1 Rewrite Opening 11
2.1.2 Load Forecast between system and eastside confusing 11
2.1.3 Electric Action Plan 11
2.2 Chapter 4 – Key Analytical Assumptions 12
2.2.1 Solar Penetration estimates should be changed 12
2.2.2 Cadmus March 2015 memorandum in Appendix M has many errors and conclusions should not be used 12
2.2.3 No explanation as to why DSR impact is reduced from 2025 to 2035 13
2.3 Chapter 5 –Demand Forecast 13
2.3.1 At beginning of chapter provide summary of energy and peak capacity forecast for territory and for eastside, include graphs. 13
2.3.2 2015 IRP Base Scenario Demand Forecasts are different between Exec Summary (1-1) and Ch 5 (Figure 5-21) 13
2.3.3 Load Forecast should include all DER especially in areas with expected load growth... 13
2.4 Chapter 6 – Electric Analysis 13
2.4.1 EQL approves the use EUE and providing details on load curtailment magnitude, duration, and frequency of events. 14
2.4.2 PSE should use Planning Standard A 14
2.4.3 PSE should break out capacity needs (page 14) 14
2.4.4 All Supply-side resources should include cost of Transmission (page 30) 14
2.4.5 Demand Response resources should be described with amounts (MW), and annual hours, both summer and winter. (page 42) 14
2.4.6 Demand Response resources should be described with amounts (MW), and annual hours, both summer and winter. (page 42) 14

3 IRP and DRP Inputs 14
3.1 Load Forecast – Winter Peaks have gone down 15
3.2 DSR and DER Contribution 15
3.2.1 EQL DER adder to DSR 16
3.2.2 Distributed Resource Planning 18
3.2.3 Regional DER Examples 20
3.2.4 Distributed Solar 21
3.2.5 Distribution Efficiency (aka CVR) 22
3.2.6 Demand Response 23
3.2.7 Dispatchable Standby Generation (DSG) 24

3.2.8 Combined Heat and Power (CHP) 26
3.2.9 Energy Storage 27
3.2.10 PSE DER Potential & Interconnection 28
3.2.11 DER Load Shape Chart 28
3.3 Transmission and Resource Planning 30
This section is primarily a critique of PSE's transmission planning process and identifies the disconnect between resource and transmission planning at PSE. 30
3.3.1 Energize Eastside Planning 30
3.3.2 Transmission Planning 31
1. Appendices 35
1.1 Appendix A: Eastside Substations Historical Load 35

Figures

Figure 1: Energize Eastside Problem is Eastside load growth 5
Figure 2: DER potential at PSE above the IRP DSR forecast 9
Figure 3: EQL Categories of Distributed Energy Resources 10
Figure 4: NW Power & Conservation Council Forecast Slide 15
Figure 5: DSR Scenarios, Support data from PSE, Cadmus, E3, and EQL 16
Figure 6: EQL DER Amounts to Study by 2021 18
Figure 7: Distributed Resource Planning Value Analysis 18
Figure 8: DRP locational value components (CPUC DRP Guidance) 19
Figure 9: Bellevue Substation Peak Load Heat Map (2006) 20
Figure 10: WECC DER Estimate 2022 21
Figure 11: Range of Distributed Solar by 2030 22
Figure 12: Eastside Area DR by 2021 24
Figure 13: Potential DSG by 2021 24
Figure 14: Base CHP Quantity 2021 27
Figure 15: Energy Storage Quantity 2021 28
Figure 16: Sample DER Contribution to Winter Peak Day Load Shape 29
Figure 17: Puget Sound Area Generation Levels for Study Request 30
Figure 18: Generation Levels 33
Figure 19: Generation North of the Eastside Area 34
Figure 20: Generation Levels used for previous studies 34
Figure 21: Eastside substations load and forecast 35

1 Executive Summary

PSE ignores costs of T&D in Resource Planning, and ignores resources in T&D planning.

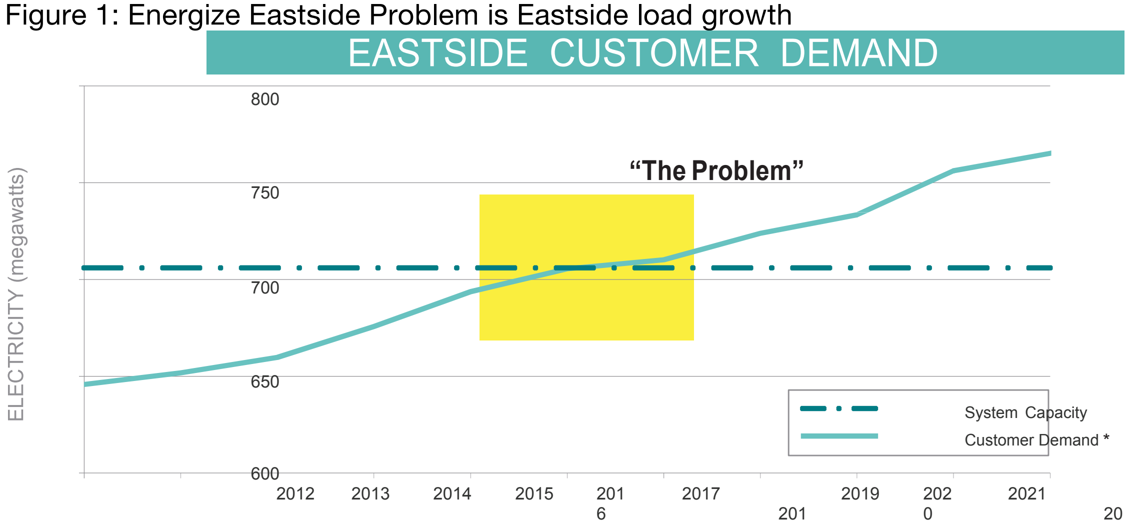
As more demand side energy and capacity resources become available and cost effective, it becomes more important to include transmission and distribution investments and local reliability into the decision making process. EQL has participated in both the review of Energize Eastside and the PSE 2015 IRP. EQL understands there are different reliability metrics, drivers, and analysis in IRP, Transmission, and Distribution planning, but these differences should not lead to the omission of important data and costs from least cost utility planning. We believe these planning processes need to come together in order choose cost effective resources.

Energize Eastside is a transmission project that is addressing load growth on the eastside, see Figure 1 from Eastside Needs Assessment Report. Its cost, estimated $300MM, should be added to all supply-side resources outside this region, and excluded from resources that do not require it.

The PSE IRP has described in detail that peak demand driver in the next decade to be specifically eastside load growth from 65 to 200MW. In fact, it appears that looking at Figure 1-1 in PSE Exec Summary and other data sources, winter peak load in non-eastside territory actually goes down through 2025.

PSE explains their exclusion of transmission and distribution costs from the IRP as too specific for a high-level resource analysis, *"the process for planning distribution and local transmission to address the needs of local growth hot spots is part of a different planning process, one that focuses on the specific engineering details of specific solutions to specific issues, which is very different from the high-level generic resource analysis performed in an IRP."* This statement may be accurate in some situations, but not for PSE's situation.

Figure 1: Energize Eastside Problem is Eastside load growth



*

Our summary comments and recommendation on the IRP are the following:

1. **Integrate transmission and distribution into IRP.** EQL believes that PSE 2015 IRP Draft does not address WAC 480-100-238 requirements in 3(d) and (e), of including transmission and distribution costs in resource planning. These costs should be considered when 1) addressing load, and 2) along with supply side energy and capacity resources. Load growth is location specific, and therefore least cost planning should address all costs to support those loads, including transmission, distribution, and resource type. For example, Energize Eastside is a transmission project that is addressing load growth on the eastside, and therefore its cost should be added to all portfolios with supply-side resources outside this region, or included as an avoided cost in determining DSR cost effectiveness.
2. **Distributed Energy Resources (DER).** In addition to DSR, and DR (demand-response) there are other distributed generation (e.g., CHP, storage, dispatchable standby generation, solar, EV load management, etc.). These should be categorized by their qualities (e.g., dispatchable, non-dispatchable, amount of energy/capacity, time of day, etc.. See below for EQL recommendations for DSM categories, and DER resource forecasts for PSE at both system and Eastside. DSR, DR, and DER studies by Cadmus and E3[1] are outdated and do not reflect an accurate representation of cost effective amounts on the eastside, especially when considering cost of T&D to serve eastside.
3. **Acquire demand-response and DER** Develop and implement a DR and DER acquisition process and issue an RFP. Through needs assessment of Energize Eastside, PSE eastside zone needs winter capacity resources to address transmission congestion and reliability by 2018. The IRP analysis supports addition of further distributed energy resources by 2021.
4. **Use Distribution Resources Planning to capture value and forecasted amounts of DER.** PSE should include distribution resources planning as a means to evaluate the capacity and value of distributed energy resources at different portions of PSE system. For instance, storage may be cost effective at one substation but not another. Avista Energy is beginning to use DRP to evaluate DER and infrastructure investments to support system capacity and service quality.
5. **Provide amount (MW) and timing of specific resource requirement types, e.g., operating and contingency reserves.** In the Electric Analysis PSE describes contingency and balancing reserves, but does not discuss amounts. This gets challenging when capacity resources are being asked to provide flexible capacity throughout the year to assist with integration of renewable energy, or emergency capacity required in the event of a line or generator outage. IRPs need to describe the type of resource needs, e.g., energy, peaking capacity, load following, contingency reserves[2], frequency regulation,

[1] http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/attachment_5_-_screening_study.pdf
[2] http://www.nerc.com/files/BAL-002-WECC-2.pdf

VAR support, etc. This detailed description and forecast will allow for PSE to plan resources accordingly.

Recommendation. List and provide detail on all resource requirements, e.g., Contingency reserves, Balancing reserves, panning margin over planning horizon. Separate these from the peak demand forecast.

6. If IRP includes #1 through #5, then comparing all resources become easier and relative cost effectiveness more accurate.

1.1.1 Location, Location, Location

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

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

On March 5, 2015, PSE announced it would participate in the California ISO energy imbalance market that will provide imbalance energy via locational marginal pricing, a paradigm that explicitly recognizes locational value of generating and demand-side resources.

1.1.2 It's not just a good idea, it's the law

As described in Washington Administrative Code (WAC) 480-100-238, planning for new transmission and generation infrastructure are best considered together. It meets the objective of determining *Lowest Reasonable Cost*. Washington State Administrative Code 480-100-238[3] on IRP requires:

> *(3)(d) An assessment of transmission system capability and reliability, to the extent such information can be provided consistent with applicable laws.*
> *(3)(e) A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using the criteria specified in WAC 480-100-238 (2)(b), Lowest reasonable cost.*
>
> *(2)(b), "Lowest reasonable cost" means the lowest cost mix of resources determined through a detailed and consistent analysis of a wide range of commercially available sources. At a minimum, this analysis must consider resource cost, market-volatility risks, demand-side resource uncertainties, resource dispatchability, **resource effect on system operation,** the risks imposed on ratepayers, public policies regarding resource*

[3] http://apps.leg.wa.gov/wac/default.aspx?cite=480-100-238

preference adopted by Washington state or the federal government and the cost of risks associated with environmental effects including emissions of carbon dioxide.

EQL believes that PSE 2015 IRP Draft does not address WAC 480-100-238 requirements in 3(d) and (e).

Separating transmission planning from resource planning, as PSE has done, is not consistent with the unique obligations of a public utility that has been granted monopoly status by the state of Washington and provides bundled service to its customers. PSE's process follows more closely that of other states which have restructured transmission, generation and retail components of the electric power business, where customers no longer can receive bundled service. Due to valid concerns about the viability of this industry organization structure, Washington retained vertical integration for investor owned utilities. Because investor owned utility customers in Washington receive bundled service, they stand to benefit from integration of generation and transmission cost structures such that the lowest reasonable cost service is delivered. If PSE were to build a transmission project that could have been avoided by a targeted resource procurement decision, PSE's bundled retail rates may not be just and reasonable absent such a process to target resource procurement to optimize total transmission, distribution, supply-side, and demand-side resource cost.

PacificCorp's draft 2015 IRP provides a useful example of how modern IRP planning should be done in regards to Transmission costs. For example, see Figure 7.2 on page 134 that shows PacifiCorp's transmission system topology and describes analysis capabilities that consider the locational impact of generation.[4] PacifiCorp began using this transmission modeling approach in its IRP process over 10 years ago. Regarding its transmission planning process, PacificCorp says this on page 135:

> *In developing resource portfolios for the 2015 IRP, PacifiCorp includes estimated transmission integration and transmission reinforcement costs specific to each resource portfolio.* ***These costs are influenced by the type, timing, and location of new resources*** *as well as any assumed resource retirements, as applicable, in any given portfolio.* (emphasis added)

We ask that PSE adopt a similar approach that meets or exceeds this set of planning capabilities. It simply is not prudent to plan any other way.

1.1.3 DER and DSR can avoid Transmission

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

[4] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

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

Figure 2: DER potential at PSE above the IRP DSR forecast

DER Measure	% of winter peak	2018 PSE System Estimate	2018 PSE Eastside DER Capacity Estimate
		MW	
System Winter Peak load		***5385***	***750.0***
Solar	0.0%	0	0.0
Distribution Efficiency (CVR)	2.5%	135	18.8
Combined Heat & Power (CHP)	3.0%	162	45.0
Storage	1.0%	54	7.5
Dispatchable Standby Generation (10 minute)	2.5%	135	18.8
DR Day Ahead	3.0%	162	22.5
DR (10 minute)	1.5%	81	11.3
Total	13.5%	727	123.8

1.1.4 Defining distribution located resources

PSE should move away from current categories of distribution-side resources towards resource descriptions that meet utility requirements (energy, capacity, reserves, etc). As mentioned above these requirements need better descriptions than just MW and aMW. These requirements need amount, duration, time of day/season, etc.. The distribution located resources PSE has used 3 categories of distribution located resources seen in Cadmus report 2014:[5]

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

Figure 3 is a suggestion on a better way to describe all distribution level resources. This categorization allows planners to place different values on a resource based on its

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

quality and location. For instance, getting dispatchable capacity for winter peaks is more valuable ($/kW-year) than non-dispatchable capacity.

Figure 3: EQL Categories of Distributed Energy Resources

Category	Description	Example
Class 1	fully dispatchable or scheduled firm capacity	Virtual Power Plant, dispatched DR, Curtailment, storage, DSG, CVR capacity
Class 2	non-dispatchable, firm energy and capacity	Energy and Capacity Efficiency, permanent load shift, CHP, Solar, CVR energy
Class 3	price responsive energy and capacity	TOU, CPP, PTR: enabled with technology and double savings
Class 4	Non-incented energy and capacity through broad market transformation, customer education and communication	NEEA, Strategic Energy Management, Opower, smart thermostats and information

1.1.5 PSE Consideration of Transmission in the 2015 IRP

PSE considers transmission cost in two narrow aspects:
1. Costs associated with importing Montana wind
2. Gas Plant location – build in eastern Washington instead of inside PSE service territory.

We commend PSE for including transmission cost in the analyses, but PSE has left out cost of Energize Eastside which is being justified by increased load growth on the eastside. Since DSR and DER can address need for Energize Eastside, these resources should be given an RFP chance to meet eastside needs.

PSE should supplement the Gas Plant Location sensitivity with additional alternatives that evaluate transmission requirements for plants are sited within PSE's service territory. Questions that need to be addressed include:
1. Does it matter if the gas plants are sited in different locations of PSE's service territory?
2. Do different siting locations or zones cause different transmission costs?
3. Do different siting locations or zones cause reliability-driven transmission requirements to increase or decrease?

1.1.6 Western wholesale electricity markets

PSE should consider impacts on resource procurement of ongoing rapid development of wholesale electricity markets in Western North America. During the course of PSE's IRP process, numerous developments have occurred that stand to affect resource procurement in a variety of ways.

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

Utilities such as PacifiCorp, that decide to pursue full integration with the CAISO likely will have an impact on regional capacity procurement practices and quantities. For this reason, PSE should immediately begin analysis on impacts of ISO market expansion on resource procurement requirements and plans. For example, if Portland General Electric were to follow PacifiCorp and pursue CAISO full integration, it is likely that cost/benefit analysis would consider capacity requirement reductions. A potential direct impact on PSE's IRP is a change to PGE's plan regarding Carty 2.

2 Specific Comments

Below are comments directed at specific sections of the IRP document.

2.1 Chapter 1 - Executive Summary

2.1.1 Rewrite Opening

"The purpose of the Integrated Resource Plan is to examine resource and system investments to support reliable electric service for PSE customers, including capacity, energy and renewable resources; transmission and distribution infrastructure: allocation of resource needs between demand-side and supply-side resources; and to identify important issues to examine further. The primary value of the IRP is to learn from the opportunity to do three things: develop key analytical tools to aid in prudent decision making, create and manage expectations about the near future, and think broadly about the next two decades."

2.1.2 Load Forecast between system and eastside confusing

It is confusing to see PSE system peak flat through 2025, yet adding 200MW on eastside in same time frame. Is it true that PSE forecasts winter peak load for non-eastside territory is planned to decrease? If this is true then PSE should focus all its capacity resources on addressing eastside peak load growth.

- Figure 1-1 2015 IRP Base Peak Demand Forecast Net of 2015 IRP DSR is very different than Figure 1-4 Electric Peak Hours Capacity.

Recommendation: add expected DER to eastside load forecast. See
Recommendation: Include battery storage to Eastside DSR forecast

2.1.3 Electric Action Plan

Recommendations for Actions

a. **Modify energy efficiency design and programs to also target specific capacity requirements (DR-like).** For example, smart thermostats, building management systems, VFD and controls, etc.
b. **Acquire Distributed Energy Resources (including demand response) through RFP process.** Develop and implement a distributed energy resource acquisition process and issue an RFP. Through needs assessment of Energize Eastside, PSE eastside zone needs winter capacity resources to address transmission congestion and reliability by 2018. The IRP analysis supports addition of further distributed energy resources by 2021.
c. **Actively investigate emerging resources.**
    i. Pilot price responsive demand response programs
    ii. Invest in Smart EV Charging infrastructure and programs that do not contribute to system or distribution peaks. Smart means capable of communication and control.
    iii. Participate in market transformation projects, e.g., Water Heater communication/control, Smart Thermostats, Building Management Systems for small/medium commercial, etc.

d. **Gas-Electric Convergence**
    i. Hold RFP for CHP projects

2.2 Chapter 4 – Key Analytical Assumptions

2.2.1 Solar Penetration estimates should be changed

- PSE has 2,800 customers with 17.4 MW of capacity and 2aMW of supply
- Base demand forecast is 1.7%/yr. Using 1.7% as a minimum add to solar capacity you get 5MW addition by 2030.

Recommendation: See section on distributed solar

2.2.2 Cadmus March 2015 memorandum in Appendix M has many errors and conclusions should not be used

- For instance on Page 1 of Cadmus Memo they write, "Declining costs of PV will begin to encourage some growth after 2030 but, in the interim, the PV industry in Washington will likely experience substantial decline compared to present levels."
- Cadmus argues that because of increasing payback periods that penetration for solar will decrease. They may wish to consider solar companies with leasing and financing programs take on the payback challenge have aggressively entered the US market.
- Out of a technical potential of 14,037 MW, Cadmus basecase is 3 MW by 2030. This is ridiculous.

2.2.3 No explanation as to why DSR impact is reduced from 2025 to 2035

DSR keeps both energy and peaks almost flat through 2025, and then it suddenly goes up. Why?

2.3 Chapter 5 –Demand Forecast

2.3.1 At beginning of chapter provide summary of energy and peak capacity forecast for territory and for eastside, include graphs.

In Executive Summary there is some summary of demand forecasts. Should add these also to Chapter 5.

2.3.2 2015 IRP Base Scenario Demand Forecasts are different between Exec Summary (1-1) and Ch 5 (Figure 5-21)

2.3.3 Load Forecast should include all DER especially in areas with expected load growth

This Draft has DSR as only conservation. PSE has missed opportunity to evaluate hundreds of Megawatts of energy and capacity focused resources. Draft has some narrative discussion on solar and storage in Appendix K and L. Talking about cost effective resources does not address the purpose of an IRP. L-6 provides examples of value of storage in grid services, yet IRP has not provided any analysis on how these resources provide cost-effective alternatives to Transmission, Distribution, or Supply-side resources, e.g., "Transmission Congestion Relief"

Recommendation: Add all DER to IRP analysis.

a. Cadmus 2013 IRP, (datapoint: 22% winter peak reduction reached by 2033)
b. E3 adder, 2.3% of King Count peak load reduction (datapoint; 56MW of winter peak by 2021)
c. EQL Eastside targeted DER – Add 8% of Eastside peak load reduction through DER deployment by 2021 to PSE load forecast

2.4 Chapter 6 – Electric Analysis

2.4.1 EQL approves the use EUE and providing details on load curtailment magnitude, duration, and frequency of events.

2.4.2 PSE should use Planning Standard A

2.4.3 PSE should break out capacity needs (page 14)

Load Demand, Planning Margin, Operating Reserves (Contingency and Balancing Reserves). Each one of these have different characteristics that will better match a resource.

2.4.4 All Supply-side resources should include cost of Transmission (page 30)

None of the resources were assumed located in Eastside load area, therefore Energize Eastside and other infrastructure would be required to meet load requirement.

2.4.5 Demand Response resources should be described with amounts (MW), and annual hours, both summer and winter. (page 42)

See recommendations below for amounts to use

2.4.6 Demand Response resources should be described with amounts (MW), and annual hours, both summer and winter. (page 42)

See recommendations below for amounts to use

3 IRP and DRP Inputs

EQL Energy expects PSE could add over 160MW of capacity to Eastside DSR forecast by 2021. See Figure 5 below. Using an Avoided Cost analysis that includes avoiding cost of Transmission, Distribution, and supply-side generation should include:

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

PSE can provide better estimates based on cost estimates for Energize Eastside and generation (e.g., Figure D-17 in IRP)

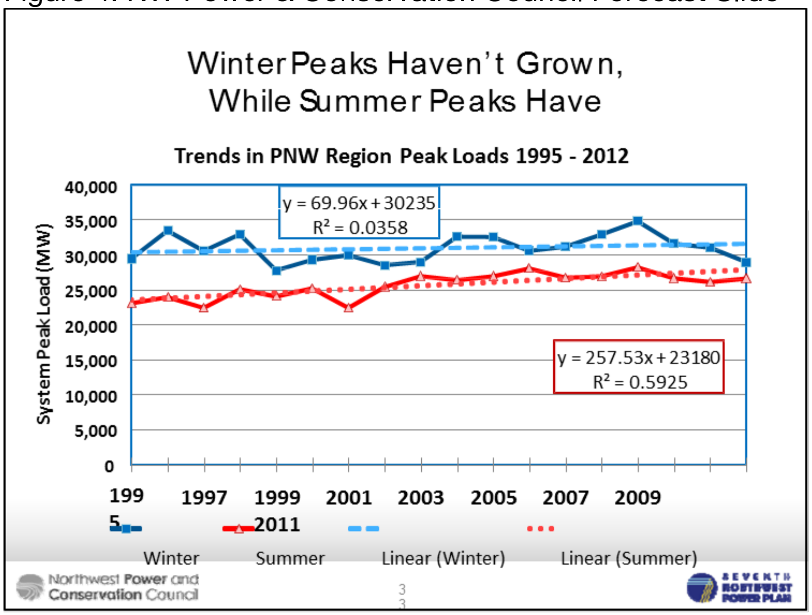
3.1 Load Forecast – Winter Peaks have gone down

Winter peaks have gone down in the Pacific Northwest in the last 5 years, and growth in the winter peak will continue to be less than the increase in growth in energy use. PSE's winter peak decreased by 11 MW from 2013 to 2014. NPCC explains this low growth in winter peak through:

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

The NPCC winter peak load forecast uses a low to high range of 0.4 to 0.9% growth, and high range forecasts are not expected to reach the historical peak set in 2009 again until 2026.[6]

Figure 4: NW Power & Conservation Council Forecast Slide[7]



3.2 DSR and DER Contribution

The terminology around resources on the distribution side can be confusing. PSE uses DSR or demand side resources, which includes energy efficiency, demand response, and distributed generation. The EE Documents we reviewed focus on energy efficiency and do not fully address DSR and its impact on peak capacity (MW). Analysis that is

6 NW Power & Conservation Council load forecast for use in draft 7th plan. Dec 02, 2014 http://www.nwcouncil.org/media/7148586/p1.pdf
7 Ibid

reported in Annual Average Megawatts (aMW) provides limited useful information for analyzing for transmission and distribution infrastructure needs.

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

DSR – Demand Side Resources: efficiency, demand response, and distributed generation (detail and types are unknown in PSE EE analysis). Cadmus 2013 IRP DSR assessment does not include kW or peak contribution, nor do they provide DR assessments.
DER – Distributed Energy Resources: EQL uses this term to refer to all resources on the distribution system, including distribution efficiency (CVR and power factor correction), demand response, combined heat and power, dispatchable standby generation, and storage.[8]

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

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

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

3.2.1 EQL DER adder to DSR

a. Cadmus 2013 IRP, (datapoint 22% winter peak by 2033)
b. E3 adder, 2.3% of King County peak load (datapoint 56MW of winter peak by 2021)
c. EQL Eastside targeted DER – additional 8% of Eastside peak load reduction through DER deployment by 2021 beyond PSE forecast with DSR (100% conservation)

Figure 5: DSR Scenarios, Support data from PSE, Cadmus, E3, and EQL

5/19/2015 Cadmus IRP presentation	Cadmus 2013 IRP (DSR 22% of winter peak by 2033)	E3 2014 adds 56 MW DSR by 2021[9]	EQL - Target DER in Eastside (8% of Eastside load adder by 2021)

[8] In California Distribution Resources Planning they include energy efficiency into their DER analysis.
[9] Quanta 2015 Needs Assessment

Year	DSR per year[10]	DSR Total	DR per year[11]	DR Total	2015 DSR	Cadmus 2013 IRP	E3 adder	EQL DER adder
2016	75	75	18	18	93	93	93	96
2017	64	139	12	30	169	184	196	209
2018	67	206	42	72	278	278	298	320
2019	64	270	14	86	356	369	401	437
2020	79	349	44	130	479	479	503	556
2021	62	411	2	132	543	550	606	666
2022	66	477	13	145	622	622	678	678
2023	56	533	2	147	680	680	750	750
2024	55	588	3	150	738	738	823	823
2025	53	641	2	152	793	793	895	895
2026	27	668	2	154	822	845	967	967
2027	27	695	2	156	851	897	1,039	1,039
2028	27	722	3	159	881	949	1,112	1,112
2029	23	745	2	161	906	1,001	1,184	1,184
2030	23	768	2	163	931	1,017	1,256	1,256

Notes:

Highlight cell indicates fixed data taken from previous reports

- From a review of EE Documents, it appears PSE is expecting DR to make up 2.7%, of peak load, with a ramp period of 6 years.
- Cadmus 2013 IRP report suggested PSE could expect 22% of winter peak load to be addressed with DSR.
- E3 Non-Wire Alternative Report (2014) has suggested PSE could achieve an addition 56 MW of cost effective DSR across King County by 2021. (represents approximately 2.3 % of King County peak load)
- EQL suggests a targeted DER program in the Eastside area could reduce winter peak load for the Eastside area by **an additional 8%** below the 100% conservation load forecast by 2021.

In transmission planning these peak load reductions should be used for N-1 and N-1-1 analysis. These measures not only address peak load reduction, but also enhance grid resiliency, and improves reliability at customer sites.

[10] DSR and DR estimate from PSE IRP Advisory Group presentation 05.19.2015, pages 50 and 58
[11] Ibid

Figure 6: EQL DER Amounts to Study by 2021

DER Measure	% of winter peak
System Winter Peak load	
Solar	0.0%
Distribution Efficiency (CVR)	2.5%
Combined Heat & Power (CHP)	3.0%
Storage	1.0%
DR Day Ahead	3.0%
Dispatchable Standby Generation (10 minute)	2.5%
DR (10 minute)	1.5%
Total	**13.5%**

Note:
Percentages sum to 13.5%, but PSE has indicated its DSR forecast includes a nearly 2.7% peak load contribution from DR, and E3 findings included an additional 2.3%.

3.2.2 Distributed Resource Planning

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

Figure 9 below shows substation locations in the Eastside area that have historically recorded higher load and may be more likely to serve larger customers sites with high DER potential such as commercial/industrial, multifamily residential, institutional, government, campus and hospital loads.

Distributed Resource Planning is a process

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

Figure 7: Distributed Resource Planning Value Analysis

	Locational Value Component
1	Avoided Sub-transmission, Substation and Feeder Capital and Operating Expenditures: DER ability to avoid Utility costs incurred to increase capacity to ensure the system can accommodate forecasted load growth
2	Avoided Distribution Voltage and Power Quality Capital and Operating Expenditures: DERs ability to avoid Utility costs incurred to ensure power is delivered within required operating specifications, including transient and steady-state voltage, reactive power and harmonics

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

3	Avoided Distribution Reliability and Resiliency Capital and Operating Expenditures: DERs ability to avoid Utility reliability related costs incurred to prevent, mitigate and respond to routine outages (Utilities shall identify specific reliability metrics DERs could improve), and resiliency related costs incurred to prevent, mitigate, or respond to major or catastrophic events (Utilities shall identify specific resiliency metrics DERs could improve)
4	Avoided Transmission Capital and Operating Expenditures: DERs ability to avoid need for system and local area transmission capacity
5	Avoided Flexible Resource Adequacy (RA) Procurement: DERs ability to reduce Utility flexible RA requirements
6	Avoided Renewables Integration Costs: DERs ability to reduce Utility costs associated with renewable integration (for this line item, the Utilities shall attempt to coordinate their efforts with the development of the updated RPS Calculator and the Renewables Integration Charge)
7	Any societal avoided costs which can be clearly linked to the deployment of DERs
8	Any avoided public safety costs which can be clearly linked to the deployment of DERs
9	Definition for each of the value components included in the locational benefits analysis
10	Definition of methodology used to assess benefits and costs of each value component explicitly outlined above, irrespective of its treatment in the E3 Cost-Effectiveness Calculator
11	Description of how a locational benefits methodology can be a into long-term planning initiatives like the Independent System Operator's (ISO) Transmission Planning Process (TPP), the Commission's Long Term Procurement Plan (LTPP), and the California Energy Commission's (CEC) Independent Energy Policy Report (IEPR), including any changes that could be made to these planning process to facilitate more integrated analysis[13]

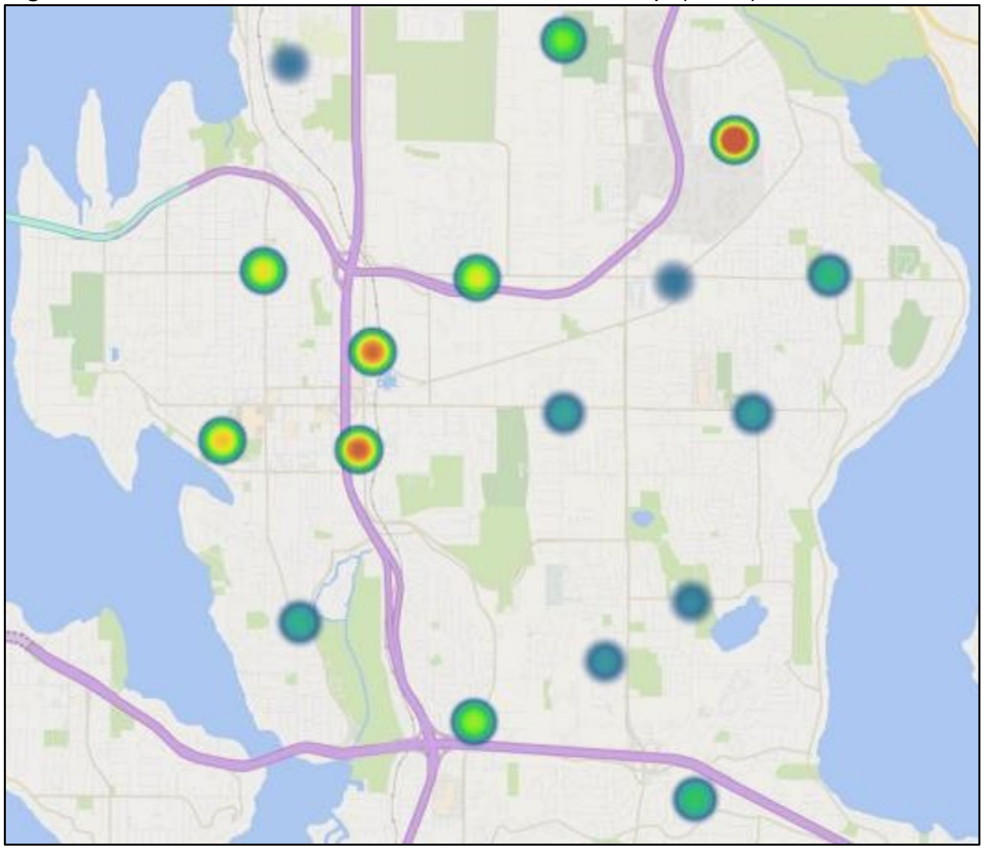
Figure 8: DRP locational value components (CPUC DRP Guidance)

Notes:

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

13 Image of California planning and DRP. http://greentechleadership.org/wp-content/uploads/2014/12/141209-DRP-alignment-with-IEPR-LTPP-TPP-Draft-2.pdf

Figure 9: Bellevue Substation Peak Load Heat Map (2006)



Sources:
Data: City of Bellevue substation peak load for 2002 and 2005[14]
See Appendix A for data table
Map: EQL (using Microsoft Excel/Bing Maps)
Note: PSE's transmission topology in this area has changed and is expected to continue to change to serve changing load patterns, therefore this rendering is for sample purposes only.

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

3.2.3 Regional DER Examples

Figure 10 below shows an estimate of 43 GW of DER among a forecasted peak of 178GW, or **23%** of the peak. Solar may not be a contributor to winter peak events but the other DERs are relevant. Distributed energy resources and load management can often make substantial contributions to reducing peak loads and have demonstrated in

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

many examples that these technologies and strategies can be relied upon for fast dispatch to mitigate contingency events.

Figure 10: WECC DER Estimate 2022

DER	2022 DER WECC Estimate (GW)	Source
Solar	25	2013 E3 TEPPC study on High DG[15]
CHP	9	2013 E3 TEPPC study on High DG[16]
DR Load Following	2.6	2013 WIEB VER Integration[17]
DR Other	4.7	2013 LBNL 6381, Incorporating Demand Response into Western Interconnection Transmission Planning[18]
Storage	1.8	AB2514 California 2020 mandate, plus 500 MW
Total	**43**	178GW WECC peak forecast (23%)

The 2013 LBNL report, identified 144 MW of direct load control programs that were forecasted in PSE's 2011 IRP.

Customer Driven DER

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

Customer desire for self-reliance is increasing

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

3.2.4 Distributed Solar

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

---

[15] http://westernenergyboard.org/spsc/dsm-wg/
[16] http://westernenergyboard.org/spsc/dsm-wg/
[17] http://wiebver.org/wp-content/uploads/2015/03/12-20-13SPSC_EnerNOC.pdf
[18] http://emp.lbl.gov/sites/all/files/lbnl-6381e_0.pdf

Figure 11: Range of Distributed Solar by 2030

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

3.2.5 Distribution Efficiency (aka CVR)

In 2007 Puget Sound and 12 other Pacific Northwest Utilities participated in a Northwest Energy Efficiency Alliance (NEEA) pilot to evaluate the energy and capacity savings from operating Conservation Voltage Reduction. [19] The study tested and found a 2 to 4 percent capacity reduction through distribution efficiency projects. An updated 2014 NEEA study found that over half the CVR projects operating in the United States are used for peak demand reductions versus energy efficiency. [20]

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

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

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

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

CVR Target: 2.5% of peak load

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

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

3.2.6 Demand Response

By 2021 NPCC estimates the Pacific Northwest states will obtain between 960 and 1,080 MW (or 3%) of winter peak through demand response. At present, only a fraction of that quantity is operational. The Council is currently preparing their 7th power plan and has been working with regional utilities and industry stakeholders. [21]

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

> *The estimated cumulative DR market potential for capacity programs represents nearly 9% of winter peak load by 2030. This estimate is in line with estimates of other DR potential studies conducted both in the Northwest and other parts of the country.*[22]

Cadmus 2013 DSR report for PSE IRP (page 7) suggests that by 2033 PSE could expect **4.7% of winter peak** to be reduced by Demand Response. Cadmus (2013) is approximately half of Navigant (2015) winter peak reduction forecast.

Two types of DR are likely to be beneficial for eastside areas:

1. Day-Ahead notification peak load reduction DR
2. Emergency 10-minute response DR

Because PSE identifies a peak load resource requirement for the Eastside, we have identified a need to study a demand response program to operate during these times, when PSE's most expensive resources will likely be supplying power. DR programs are often cost effective when displacing this expensive generation, such as PSE's peaking units in Whatcom County. When combined with the additional value of providing an infrastructure alternative, the cost effectiveness of such a DR program is improved. Many utilities have implemented day-ahead notification DR programs that call upon enrolled customer or 3rd party resources to reduce their demand for a specified duration, typically 2-4 hours.

In addition, emergency DR programs have successfully been implemented that are capable of fast response for contingency reserve purposes. An example is a 10-minute response program run by Southern California Edison.[23] These programs are typically of higher value due to the short notice time and reliability service provided. SCE's program pays customers $240/kW-year for capacity that successfully participates.

For purposes of the EIS analysis, we have requested conservative DR quantities, shown in Figure 12, for the eastside area that are reflective of percentages of peak

[21] https://www.nwcouncil.org/news/meetings/2015/06/
[22] http://www.nwcouncil.org/media/7148943/npcc_assessing-dr-potential-for-seventh-power-plan_updated-report_1-19-15.pdf
[23] https://www.sce.com/NR/rdonlyres/7A1BC024-698D-44A0-98D1-ABD8DEE9E451/0/NR572V20810_BIP.pdf

load that have been achieved in other areas and below those estimated by Navigant (2015).

Figure 12: Eastside Area DR by 2021

	Eastside DR Estimate
Day-Ahead DR quantity	3%
10-minute DR quantity	1.5%

Because PSE has indicated it may include DR at a level of approximately 2.7% of load by 2020, the 3% DR estimate above for day-ahead programs is incorporated into the 100% conservation forecast used by PSE.[24]

3.2.7 Dispatchable Standby Generation (DSG)

Portland General Electric's DSG program can be used as an example for one designed to provide enhanced reliability in the Eastside area. The DSG program connects customer backup generators to the distribution grid using parallel switchgear at sites such as hospitals, commercial/industrial, and government buildings. PGE remotely dispatches the generators, which are capable of providing uninterrupted service to customers in the event of a grid outage. As part of the program, PGE invests in and owns some of the interconnection equipment, pays for fuel, and performs ongoing testing – required for units at many sites such as hospitals.

DSG potential is determined by using a simple proportion of peak load to DSG capacity installed at PGE and applying it to PSE, as shown in Figure 13 below.

Figure 13: Potential DSG by 2021

DSG Potential	MW
2018 PGE System Peak	4000
Current PGE DSG Capacity[25]	94
DSG MW per System MW	2.5%
2018 PSE System Peak	6000
2018 Eastside Peak Load Forecast	750
PSE System DSG Potential	141
PSE Eastside Area DSG Potential	**17.6**

Note that the size of PGE's DSG program is growing and has plans to increase the program capacity to 125 MW in the next 5 years. Using the proportion method described above, Eastside DSG potential would increase to 22.7 MW.

[24] May 19 PSE IRP Advisory Group meeting materials
[25] 2015 PGE Smart Grid Report, May 28, 2015. Oregon PUC Docket UM1657 http://edocs.puc.state.or.us/efdocs/HAQ/um1657haq103857.pdf

While the simple DSG potential figures provided here are adequate to inform planning at this stage, additional detailed analysis of DSG capacity will be valuable to PSE and eastside reliability regardless which transmission projects are built. PSCleanAir has suggested that a DSG program like PGE would follow EPA NESHAP RICE rules. Developer of DSG program would have to go through air permitting compliance, but it is a permittable use.

PSE evaluated using DSG as part of a stipulation in Washington Utilities and Transportation Commission (WUTC) Order 06 in docket UE-130617, in which both parties agreed that PSE should perform an evaluation. Specifically, the Settlement agreement states: PSE agrees to evaluate the PGE Dispatchable Standby Generation (DSG) program, described in the testimony of staff witness Juliana Williams, and either provide a report to the Commission of PSE's conclusions and recommendations by December 1, 2014, regarding the financial and technical feasibility of PSE implementing a similar DSG program in its territory, or file a tariff implementing DSG service by December 1, 2014.

EQL evaluated this work and finds it evasive, inconclusive, and provides the following feedback.

Specific Comments on PSE DSG Findings and select sections. (Dec. 1, 2014)

PSE Findings and Issues	Comment
The primary benefit of the PGE DSG program has been the ability to use the standby generators as a cost-effective resource to meet **non-spin operating reserve** obligations.	True
PSE does not have a near-term need for non-spin operating reserves and has maintained more than adequate operating reserves during peak events	According to IRP, PSE will have need for further operating reserves.
While originally established as peaking resource, PGE's use of its distributed standby generator fleet as a peaking resource has been *de minimis* during the life of the program	True. Program is not used as peaking resource.
New Environmental Protection Agency (EPA) emissions requirements that limit operation and testing on diesel-fired emergency standby generators create uncertainty and potential operational constraints during times of peak need	True that EPA rules are in flux for legal reasons. Current laws to watch are state and local air permits. PSCleanAir has suggested that a DSG program like PGE would follow EPA NESHAP RICE rules
Under normal conditions, PGE's standby generator fleet is not economic compared to other alternatives during dispatch decisions	DSG resources are not part of normal dispatched resources
PSE lacks sufficient market research of its customers that would justify investment in a DSG program including potential participation rates and standby generator inventory	Getting this information would be very easy
It is unlikely PSE would be able to implement a DSG program to meet any near-term capacity needs given time, resources, and current systems capability	PSE has time to develop DSG
Section 4.6 Compliance	
Section 5.2 Constraints and Opportunities	

Market Barrier. The 2011 CBRE market search led to no customers expressing interest in further engagement with PSE to interconnect a standby generation system to the grid.	PGE Customers are not that different than PSE Customers. It takes a clear customer value proposition and a few key customers to get it started.
Monitoring and dispatch. PSE does not own software that allows for monitoring and dispatch. PSE need operational and technical knowledge to operate new software.	EQL can assist.
Interconnection. PSE needs specifications for interconnecting standby generators. PSE does not have interconnection agreement	EQL Team can assist
PSE has several low-cost resources to meet non-spin reserve obligations.	**Contradicted in IRP**
Operating reserves exceed need by 200-400MW in most peak hours.	**Contradiction with IRP forecasts**

The NERC contingency reserves standard (BAL-002-WECC-2[26]) applies to the NW Power Pool Reserve Sharing Group (RSG), and requires the RSG to carry the larger of: 3% of load + 3% of generation OR the **Most Severe Single Contingency (what is this for PSE?).** Contingency reserves can be comprised of any combination of seven types defined in the standard. DSG is categorized as the Operating Reserve – Supplemental subcategory of Contingency Reserve. This reserve type was formerly defined as Non-Spin reserve, but was changed to supplemental in the current standard to be inclusive of demand side management pursuant to FERC Order 740.[27]

E3 incorrectly ruled out DSG in their 2014 non-wires study for Energize Eastside. They wrote,

> "The US Environmental Protection Agency (EPA) prohibits PSE from relying on customer-sited backup generation for peak shaving of utility loads for resource planning purposes, which PSE planners believe would prevent them from planning grid conditions that rely on backup generation to defer transmission upgrades. This regulation exists primarily to protect local air quality. Therefore, customer-sited backup generation was excluded from the DG non-wires potential estimates."

3.2.8 Combined Heat and Power (CHP)

CHP is the simultaneous use of a fuel, primarily natural gas, to generate electricity and provide heat. When properly designed, CHP is capable of operating at higher efficiency than typical central station power plants.

PSE's Non-Wires Screening Study[28] CHP analysis, performed by E3 and informed by earlier work by Cadmus, found approximately 1 MW of peak CHP resource by 2023 across all of PSE's King County service area. Because this quantity can reasonably be achieved in a single building, the previous estimate is likely not reflective of actual potential. In order to determine this potential, a new study is warranted, especially in

[26] http://www.nerc.com/files/BAL-002-WECC-2.pdf
[27] http://www.ferc.gov/whats-new/comm-meet/2010/102110/E-6.pdf
[28] http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/attachment_5_-_screening_study.pdf

light of the amount of growth expected to occur in Bellevue and PSE's need for peak capacity resources.

With the cost of capacity to utilities often exceeding $100/kW-year, infrastructure deferral benefits and electricity sales revenue are components that contribute to cost effectiveness determination and would inform the ultimate potential of this resource. PSE needs over 1000 MW of new capacity by 2025, according to recent IRP development information.[29]

150 MW of load growth could occur in the Bellevue downtown and Bel-Red areas in the next 20 years.[30] The new development represents a large opportunity because many DER technologies such as CHP make the most sense when incorporated during the design phase and provide further benefits when central utility plants serve multiple buildings. But such a strategy requires deliberate planning and clear leadership to become successful.

Because Downtown and Bel-Red will consume significant quantities of natural gas regardless of PSE's electricity infrastructure decisions, the extent to which this gas can be put to use generating electricity should be studied. Additionally, the civil construction work to occur in these areas in future years points toward investigation of co-locating energy infrastructure and potentially common use infrastructure such as district energy where central utility plants supply heating, cooling and electricity to a potentially large development, such as the Spring District.

Recommendation: Explore 3rd party or PSE owned central utility plants with CHP in parts of the Eastside that will experience the most new construction.

Figure 14: Base CHP Quantity 2021

	Eastside CHP Estimate
CHP	3.5% of peak load

Note:
Transmission topology alternative D adds Eastside generation. Because a larger central plant CHP project should be considered for this option, selection of this alternative could result in a substantially higher CHP penetration.

3.2.9 Energy Storage

Energy Storage is receiving a great deal of attention right now due to the cost declines seen in recent years and an increasing number of predictions for continuing storage cost reduction.[31] PSE, Avista, and Snohomish PUD have received $15MM to study use of energy storage.

[29] May 19 PSE IRP Advisory Group meeting materials
[30] Exponent Reliability Study
[31] Sample media story addressing storage:
http://cleantechnica.com/2015/03/04/energy-storage-could-reach-cost-holy-grail-within-5-years/

Figure 15: Energy Storage Quantity 2021

	Eastside Storage Estimate
Storage	1% of peak load

3.2.10 PSE DER Potential & Interconnection

Many existing and future commercial, multifamily residential, institutional and corporate campus sites are centered near downtown Bellevue, Bel-Red and South Redmond– areas that are driving the need for new transmission and distribution infrastructure. Cost effectiveness of DER investments in these areas stands to be influenced to the extent they can substantively contribute to load service and reliability needs. In other words, a next-generation energy system, which is being pursued by leading utilities, will make full use of DERs by integrating their capabilities into utility planning and operations, a step that may well deliver cost reductions to PSE ratepayers – and one that will require developing appropriate compensation mechanisms to DER owners. In addition, PSE or 3rd parties could own DERs that may be designed to provide benefits directly to specific customers (i.e. storage installed behind-the-meter), while simultaneously providing infrastructure deferral benefits enjoyed by all ratepayers.

DER interconnection and operations practices will become more important as these resources grow in quantity and take on additional performance obligations related to reliability and system resiliency. Should PSE and Eastside communities decide to move to make full use of DER options as part of a strategy to support and enhance regional growth, appropriate technical interconnection and operations procedures and standards will be needed. DER best practices are emerging from California, New York, and Hawaii, states that have taken the lead. The standards by which PSE designs and operates the 12.5 kV distribution system will be important for DERs so as to ensure maximum utilization of the system, including supporting 2-way power flows.

Most distribution systems move electricity in one direction – from power plants to substations to customers. But when customers interconnect generation resources, their power will flow the other direction, serving other customers and in some cases flowing power back to the substation itself and serving load further upstream, possibly at higher voltages. While there is no fundamental reason why these new flows of electricity cannot occur, investments in additional monitoring equipment and advanced control technologies will be needed.

These types of investments, involving software, communications, controls, and switching equipment, are also likely to provide reliability benefits by enhancing the ability of utilities to automatically switch customers to alternate feeds in the event of an outage on a given distribution circuit.

3.2.11 DER Load Shape Chart

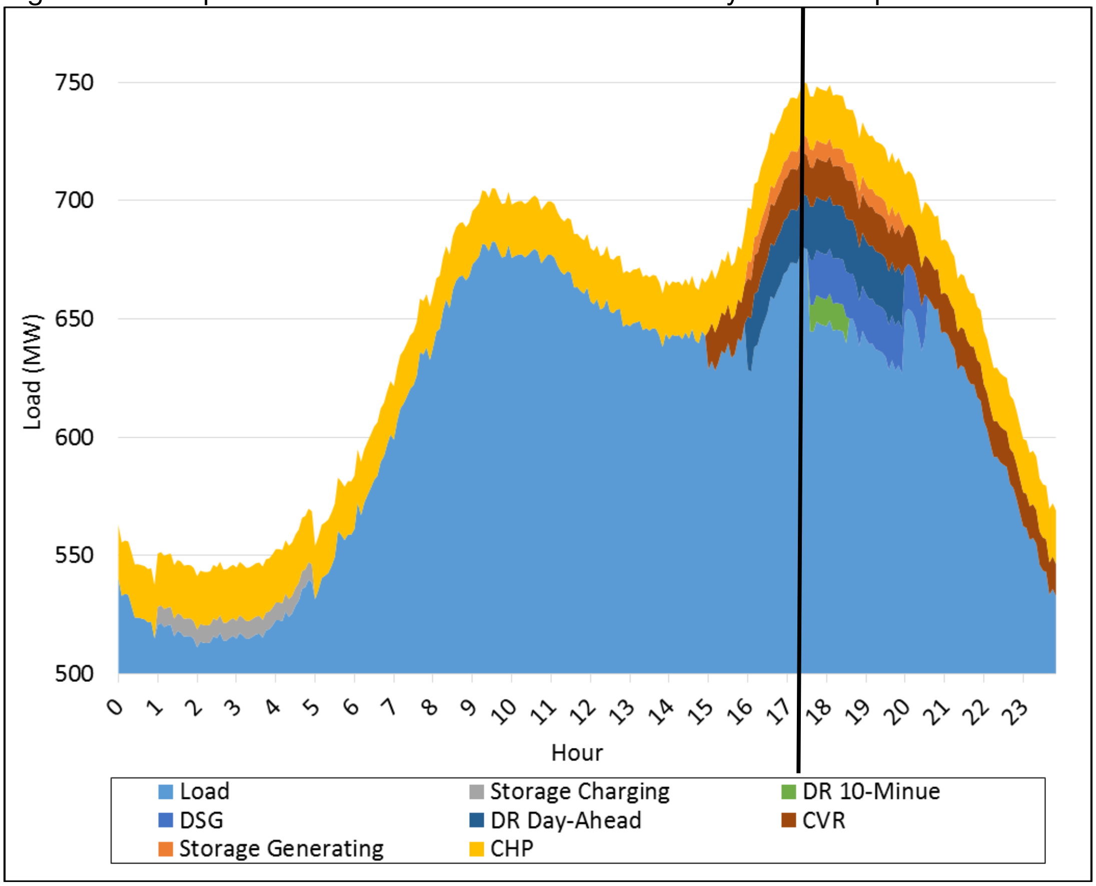
E3 2014 report discusses time of day and critical hours but does not provide a load shape. Report states:

> *PSE's winter peak definition is on December weekdays from the hour ending 7 AM to the hour ending 11 AM and from the hour ending 6 PM to the hour*

ending 10 PM. For estimating each non-wires measure's contribution to reducing winter load, E3 awarded equal weight to the morning and evening portions of the peak period.

Figure 16 shows a sample peak day load shape for the Puget Sound area with a stack of resources deployed both throughout the day and during a dispatch at 5:30PM during the peak to depict what could happen in the event of an outage. Note the duration of DER response required after dispatch as load decreases into nighttime hours.

Figure 16: Sample DER Contribution to Winter Peak Day Load Shape[32]



32 Data source for load shape:
Puget Area Net Load for 12.20.2008
http://transmission.bpa.gov/Business/Operations/Misc/default.aspx
This is not an Eastside area load shape, but is representative of typical winter peak load patterns for NW utilities. A chart with actual Eastside loads requires additional PSE data.

3.3 Transmission and Resource Planning

This section is primarily a critique of PSE's transmission planning process and identifies the disconnect between resource and transmission planning at PSE.

3.3.1 Energize Eastside Planning

Needs assessment for Energize Eastside, PSE has not used all existing resources. It is important to use all resources and transmission and carefully choose certain key resources as contingent forced outages. In evaluating need for Energize Eastside, PSE has turned off most of their thermal resources, which is way beyond NERC contingency planning.

PSE should use all their resources when doing both Transmission and Resource Planning. The figure below lists the MW generation level by resource suggested for Transmission study for N-1 and N-1-1 analysis. For generators that we request should be dispatched, use the maximum seasonal rating if that rating is different from the figures shown below.

Figure 17: Puget Sound Area Generation Levels for Study Request

Unit Name	Owner	December rating (MW)
Fredonia 1	PSE	223
Fredonia 2	PSE	223
Fredonia 3	PSE	118
Fredonia 4	PSE	118
Burlington	SPI	28
March Point	Shell	145
Encogen	PSE	169
Ferndale	PSE	270
Whitehorn 2	PSE	80
Whitehorn 3	PSE	80
Sumas	PSE	131
Upper Baker	PSE	80
Lower Baker	PSE	54
Ross	SCL	295
Gorge	SCL	157
Diablo	SCL	160
Totals		**2496**

Source: 2014 Pacific Northwest Loads & Resources Study (BPA)[33]

Of the generation in Figure 17, PSE owns **1565 MW**.

All of the above generation should be dispatched as close as possible to maximum winter ratings during analysis of contingency events. The hydro units above are listed at levels used in the Quanta 2014 solutions report.

3.3.2 Transmission Planning

WECC base cases are used by utilities and consultants as a starting point that describes key operational details such as generation and reactive power levels from every power plant in the western interconnection. When studies are performed in different regions and for particular projects, these base cases are modified with details specific to those projects.

The modeling sequence for the heavy winter south-north power flow base case is intended to determine if PSE's system can continue to operate in a safe state following a single outage, meaning load service will not be interrupted in the event of another outage. We have included PDR generation levels that should be studied in analysis conducted for compliance with NERC transmission planning (TPL) standards that are applied to the bulk electric system (BES[34]) such as:

- TPL-001-4 (transmission planning performance requirements)
- TPL-002-0b (N-1 or Category B)
- TPL-003-0b (N-1-1 or Category C)

TPL-001-4 allows for generation redispatch in response to an outage, called planned system adjustments, so long as these are "executable within the time duration applicable to the Facility Ratings." Facility Ratings, as applied by PSE pursuant to NERC FAC standards, for the facilities that are most limiting following a category B or C contingency will govern the required response time of the DER products, which is discussed below. Our working assumption is 10-minute response for fast-response DER products, which is a potential response following either a category B or C contingency event.

Generation Levels

Energize Eastside studies conducted by Quanta and USE made limited use of PSE-owned generation when evaluating transformer and line loadings in the Eastside area. This is a substantial oversight because of the system stability benefits of running Puget Sound area generation – instead of relying exclusively on transfers from the south and

[33] https://www.bpa.gov/power/pgp/whitebook/2014/2014WBK-TechnicalAppendixVolume2-CapacityAnalysis-1302015.pdf

[34] NERC standards apply to the BES, which is generally comprised of facilities above 100 kV. Distribution voltage levels (12.5 kV) are generally not included.

from FCRPS generation east of the Cascades – during peak load hours or during times of system stress.

Other regions that rely on heavy generation imports from other areas have developed formalized restrictions to promote reliability by addressing local generation. For example, the Southern California Import Transmission (SCIT) constraint relates LA Basin generation levels to imports from the North and East, according to Southern California Edison:[35]

> *Import limits into southern California on the interconnected transmission system depend on the amount of inertia in southern California. At higher levels of inertia, it is feasible to import more power and vice versa.*

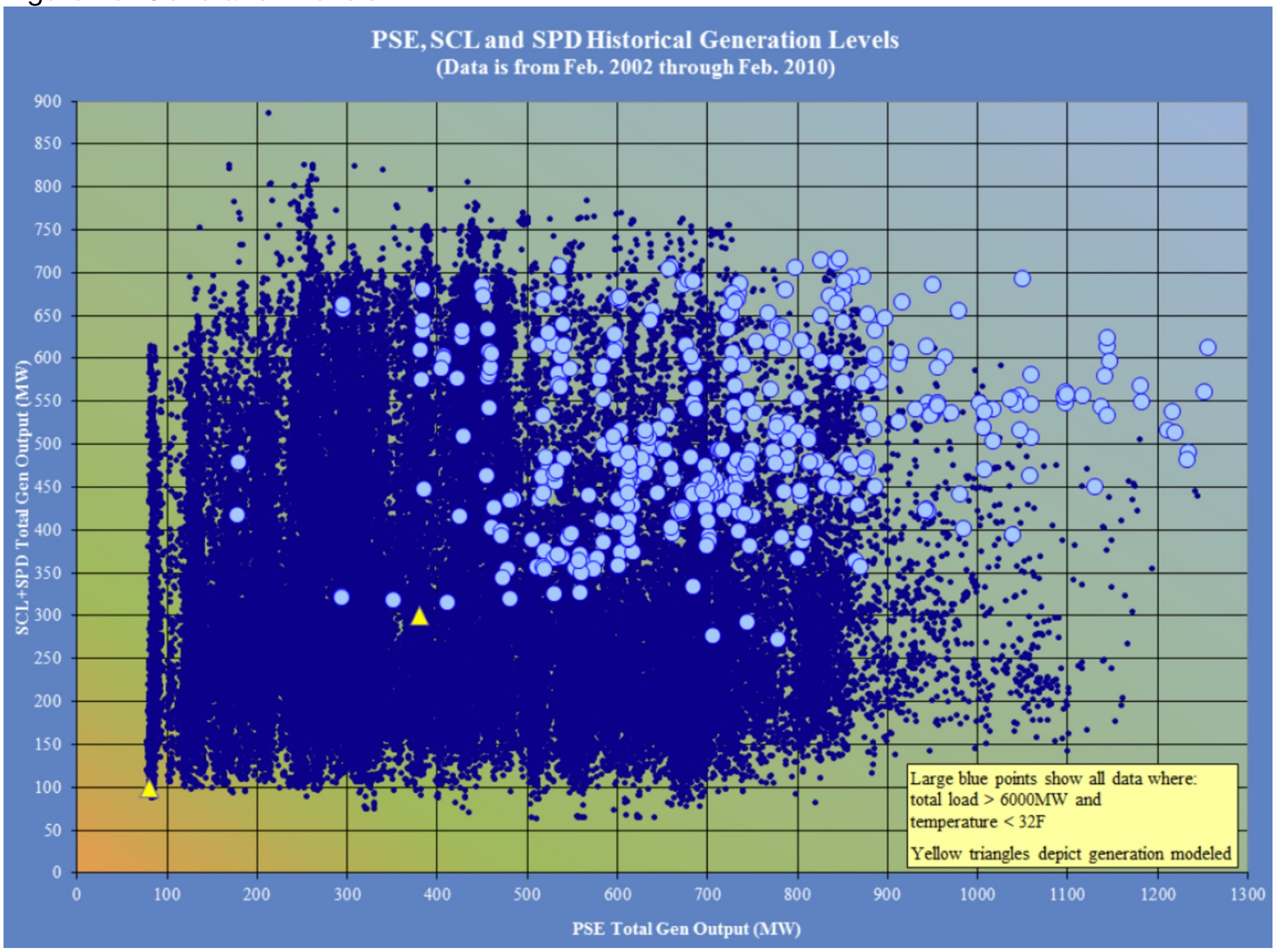
Because generation dispatch was insufficiently studied, and was not clearly communicated, we include suggestions for Puget Sound area generation that is located north of Sammamish substation and is likely to relieve loading at areas to the south during S to N flow such as at Talbot Hill.

Regardless of a contingency event, PSE's generation may already be dispatched to a higher level than was assumed in any of the previous studies because the peak loads used for transmission planning purposes by PSE may require PSE to dispatch its thermal generation portfolio, much of which is located electrically north of the constrained area and is likely to relieve some or all of this congestion.

The Quanta studies assumed low PSE generation, and have provided insufficient detail about which generation was running or was redispatched for sensitivity analysis. The USE study assumed low PSE generation but conducted an optional analysis with some level turned on. The USE report did not disclose the generation quantity assumed for the dispatch level, but we have determined it is likely to be 680 MW.[36]

[35] http://www.energy.ca.gov/2009_energypolicy/documents/2009-09-24_workshop/presentations/02_SCE-Minick_Sept_24_workshop_final.pdf
36 Peter Mackin of USE told the audience this at the Bellevue City Council's May 04, 2015 Study Session

Figure 18: Generation Levels[37]



Source: ColumbiaGrid 2010

Figure 18 shows historical generation levels for PSE, Seattle City Light, and Snohomish PUD, and distinguishes levels that occurred when temperatures were below 32°F and loads were likely to be high. One of the yellow triangles is positioned at approximately 680 MW of total generation, used for a number of ColumbiaGrid studies that were assessing regional transfer capability and did not address local load service. One key conclusion to be drawn from this chart is that historical data shows 680 MW is on the low side for generation assumed to be running during cold winter weather and supports the study request for higher levels described below.

Puget Sound Area Generation

The table below shows generating units that are likely able to relieve Puget Sound area transmission congestion when flow is S to N. These units are all located electrically north of Sammamish substation.

37 Source: ColumbiaGrid draft 2010 Puget Sound Transmission Expansion Plan
Retrieved from:
http://www.bpa.gov/Doing%20Business/TechnologyInnovation/ConferencesGridTransformationWorkshop/Planning_for_Operational_Flexibility_by_Gordon_Dobson_Mack.pdf

Figure 19: Generation North of the Eastside Area

Unit Name	Winter MW	In service Date	Primary Fuel	Plant Type	Firm Gas Supply	Backup Fuel	Backup Type	Owner
Fredonia 1	223	1984	NG	SCCT	YES	YES	Tank	PSE
Fredonia 2	223	1984	NG	SCCT	YES	YES	Tank	PSE
Fredonia 3	118	2001	NG	SCCT	YES	YES	Tank	PSE
Fredonia 4	118	2001	NG	SCCT	YES	YES	Tank	PSE
Burlington	28	2007	Bio	Bio	NO	NO	-	SPI
March Point	145	1991	NG	CCCT	NO	YES	Pipe	Shell
Encogen	169	1993	NG	CCCT	NO	YES	Pipe	PSE
Ferndale	270	1994	NG	CCCT	YES	YES	Tank	PSE
Whitehorn 2	80	1981	NG	SCCT	YES	YES	Tank	PSE
Whitehorn 3	80	1981	NG	SCCT	YES	YES	Tank	PSE
Sumas	131	1993	NG	CCCT	YES	NO	-	PSE
Upper Baker	90	-	Hydro	Dam	-	-	-	PSE
Lower Baker	63	-	Hydro	Dam	-	-	-	PSE
Ross	408	-	Hydro	Dam	-	-	-	SCL
Gorge	178	-	Hydro	Dam	-	-	-	SCL
Diablo	172	-	Hydro	Dam	-	-	-	SCL
Total	**2496**							

Of these units, Figure 20 below shows the quantities of generation that were assumed to be running in previous studies performed by Quanta and USE. Quanta and USE performed sensitivity analyses with some generation running, as noted below.

Figure 20: Generation Levels used for previous studies

<table>
<tr><th>Unit Name</th><th>Winter MW rating</th><th>Quanta 2014 No Gen</th><th>Quanta 2014 Low Gen</th><th>USE 2015</th><th>Quanta 2015</th></tr>
<tr><td>Fredonia 1</td><td>223</td><td>0</td><td>0</td><td rowspan="13">Columbia Grid Generation Guideline</td><td rowspan="13">Unknown</td></tr>
<tr><td>Fredonia 2</td><td>223</td><td>0</td><td>0</td></tr>
<tr><td>Fredonia 3</td><td>118</td><td>0</td><td>0</td></tr>
<tr><td>Fredonia 4</td><td>118</td><td>0</td><td>0</td></tr>
<tr><td>Burlington</td><td>28</td><td>0</td><td>22</td></tr>
<tr><td>March Point</td><td>145</td><td>0</td><td>134</td></tr>
<tr><td>Encogen</td><td>169</td><td>0</td><td>125</td></tr>
<tr><td>Ferndale</td><td>270</td><td>0</td><td>0</td></tr>
<tr><td>Whitehorn 2</td><td>80</td><td>0</td><td>0</td></tr>
<tr><td>Whitehorn 3</td><td>80</td><td>0</td><td>0</td></tr>
<tr><td>Sumas</td><td>131</td><td>0</td><td>0</td></tr>
<tr><td>Upper Baker</td><td>90</td><td>0</td><td>80</td></tr>
<tr><td>Lower Baker</td><td>63</td><td>0</td><td>54</td></tr>
</table>

Ross	408	0	295		
Gorge	178	0	157		
Diablo	172	0	160		
Total	**2496**	**0**	**1027**	**680**	**?**

Additional Generation Dispatch Concerns

Generation levels at other resources in the region can have a significant impact on flows through the eastside, especially Federal Columbia River Power System (FCRPS) generation levels that impact BPA's Cross Cascades North and Raver-Paul flowgates. FCRPS hydro units that influence flows through the Puget Sound area such as Chief Joseph and Grand Coulee need to be modeled at reasonable generation levels for peak load conditions.

1. Appendices

1.1 Appendix A: Eastside Substations Historical Load

Figure 21: Eastside substations load and forecast[38]

Substation Name	2005 Peak Load	2020 Projected Peak Load
	MW	MW
Ardmore	-	20
Bridle Trails	25.7	32.4
Center	24.7	49.3
Clyde Hill	23.4	38.3
College	20.2	21.8
Eastgate	32	27.1
Evergreen	54.1	57.6
Factoria	28.9	33.8
Houghton	22.8	19.9
Kenilworth	24.6	25.3
Lake Hills	22.4	22.6
Lochleven	19.2	41.1
Midlakes	20.7	22.9
North Bellevue	43.9	48.2
Northrup	26.5	37.5
Phantom Lake	19.3	21

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

South Bellevue	22.8	24.3
Somerset	18.3	19.6
Totals	**449.5**	**562.7**