PSE PUGET SOUND ENERGY

energizeEASTSIDE

PSE Screening Study

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Energy+Environmental Economics

Energy and Environmental Economics, Inc.
101 Montgomery Street, Suite 1600
San Francisco, CA 94104
415.391.5100
www.ethree.com

Project Team:
Jack Moore
Lakshmi Alagappan
Katie Pickrell

PO BOX 97034, EST06W
Bellevue, WA 98004
1-800-548-2614

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Executive Summary

Energy and Environmental Economics (E3) was retained to provide a screening-level assessment of the potential for non-wires alternatives to defer the proposed upgrades on the Eastside portion of Puget Sound Energy's (PSE) transmission system.[1] E3's analysis indicates that the cost-effective non-wires potential in the area, including energy efficiency (EE), demand response (DR) and distributed generation (DG) measures[2], does not represent a permanent alternative to avoid the need for the transmission upgrade options. This assessment also indicates that the non-wires potential alone is not sufficient to cost-effectively defer the need date of transmission upgrades while maintaining equivalent reliability levels.

PSE Identified Eastside Project Need

PSE's system currently experiences peak demand during the winter driven by heating loads during cold weather. PSE's Eastside Needs Assessment Report identified a transmission supply need in the Eastside area by Winter 2017-18 to reduce the risk of transmission system criteria violations after outages. In addition, PSE's Needs Assessment indicates that anticipated summer peak demand growth driven by commercial cooling loads in the area could begin to create concern of system criteria violations by Summer 2014, and that continued growth would increase the risk of more severe overloading by Summer 2018.

PSE's Winter 2017-18 transmission need date was based on PSE's load forecast during typical winter peak demand conditions (based on a 23° F temperature), which PSE adjusts downward to account for the impact of 100% of the EE, DR, and DG potential selected by PSE's 2013 Integrated Resource Plan (IRP). Additional powerflow cases included in the Eastside Needs Assessment indicate that the severity of overloads would be greater if higher peak load conditions occur in the area as a result of: (a) extreme cold weather conditions, (b) faster than anticipated load growth due to local economic conditions, (c) slower than anticipated implementation of the target conservation levels assumed in PSE's baseline load forecast, or (d) continued load growth forecasted by PSE beyond 2017.

Energize Eastside ...

... will upgrade approximately 18 miles of electric transmission lines from Renton to Redmond

... will ensure Eastside's power system can continue to support the area's growth

... route identification will occur throughout 2014 with construction starting in 2017

PSE wants to hear from you.

Visit us at:

www.pse.com/energizeeastside

Why We Need Energize Eastside

1. Growth is straining our region's existing transmission system
2. Conservation alone is not enough to meet the challenge
3. We need to act now
4. Upgrades will power Eastside's growth into the future
5. PSE will work with the community to identify solutions to ensure dependable power for businesses and families

Relative to today's system, PSE planning scenarios (without Eastside transmission upgrades) for 2017 would require an increased use of corrective action plan (CAPs) measures during times of outages or high system load levels before transmission upgrades are in place. Activating these CAPs measures can result in over 30,000 customers being served by radial transmission lines, and could result in significant loss of customer load if an outage were to occur on the remaining radial lines serving those customers. PSE operators have indicated a desire to reduce the use of CAPs to mitigate this risk of outage for customers in the area, which they expect a transmission option would do.

PSE's proposed solution to address these issues is to upgrade facilities on its Eastside transmission system by 2017 or 2018, while also implementing the significant levels of planned conservation selected in PSE's IRP. PSE is currently considering a number of alternative routes in Eastern King County, Washington, that could reinforce its transmission system at the 230 kV level. Five transmission alternatives are under study, including include two 230 kV transmission sources and three new transformer sites, with a target in-service date in 2017 or 2018.

Non-wires Assessment Screening Study

In parallel to evaluation of transmission options, PSE retained E3 to evaluate the ability of non-wires alternative options, combining cost-effective EE, DR, and DG, to defer the date when transmission upgrades would be needed beyond 2017. E3's non-wires assessment is a screening analysis rather than an implementation plan, and can be used to identify whether particular non-wires alternatives warrant further study. The methodology of this analysis has been adapted from the approach developed through the Bonneville Power Administration's Non-Wires Solutions Roundtable, which was convened between 2003 and 2006.

E3's non-wires assessment has focused primarily on the winter system issues as an initial set of criteria to evaluate potential impact of non-wires measures. If sufficient non-wires measures were found to be a viable option to defer winter system issues, additional analysis of summer peak would also be needed, as many conservation measures that reduce winter heating end uses do not also provide load reductions during the summer.

[1] PSE's Eastside transmission system includes King County loads located east of lake Washington between Kirkland and Renton.

[2] Energy efficiency, demand response, and distributed generation are collectively referred to as conservation in this report, and can also be described collectively as demand side resources (DSR). The terms "conservation" and "DSR" are used interchangeably in PSE's Integrated Resource Plan (IRP) and Eastside Needs Assessment.

PSE transmission planners used the Winter 2021 transmission powerflow scenarios developed from the Eastside Needs Assessment to identify for E3 the amount of peak load reduction in the area that would be required to defer the transmission project need by four years, from Winter 2017 to Winter 2021, while maintaining equivalent reliability on key transmission system elements such as transformer facilities at Talbot Hill substation. To quantify this load reduction requirement for deferral, PSE planners started with the Winter 2021 powerflow cases used in the Eastside needs assessment, and reduced PSE customer peak demand across King County, until loading under contingencies on key Eastside transmission system elements were reduced to levels equal to those shown in PSE's 2017 powerflow case (which assumed 100% of IRP conservation levels in the baseline load growth forecast).

Assuming typical weather conditions of 23˚ F during PSE's winter peak demand[3], PSE powerflow cases identified that 70 MW of incremental peak demand reduction (beyond the reduction included in the baseline load forecast reflecting 100% of IRP target conservation levels) would be required in King County to defer transmission need until 2021. The powerflow cases also indicated that demand reductions spread across PSE customers outside of King County would not reduce winter peak loading on key Eastside transmission system elements, indicating that targeting King County loads would be the most effective non-wires opportunity[4].

If a higher load growth scenario occurs, such as that represented in an alternative powerflow scenario in which PSE planners reduced conservation to 75% of the IRP target level, PSE would instead require an incremental 160 MW of peak load reduction in King County by 2021 (beyond the reduction included as 75% of selected IRP conservation measures) to defer the need for transmission upgrades by four years.

PSE's planners believe that the transmission options under consideration would address both the summer and winter reliability issues in the Eastside area, as well as remove the need to use CAPs during certain hours, resulting in an improvement to reliability of transmission facilities relative to current level. A non-wires option described above, resulting in the 70 MW of load reduction would not improve reliability relative to 2017 levels and would not remove the need to use CAPs. A 70 MW non-wires option (or an 160 MW non-wires option needed under the higher growth scenario) would instead maintain the 2017 reliability at a constant level for four additional years.

[3] PSE defines this "typical" peak to represents 1-in-2 winter peak load, meaning that PSE anticipates that temperatures will be reach this level or colder approximately 1 out of every 2 years on average.

[4] At E3's request PSE planners also used the powerflow cases to identify whether an more narrowly targeted non-wires approach focused exclusively on the Eastside portion of King County would have a proportionally higher impact on the transmission system flows, thereby reducing the quantity of load reduction required to enable transmission upgrade deferral. These cases, however, showed negligible difference between Eastside-only load reductions versus reductions spread evenly across PSE's King County loads. Thus, E3 focused this analysis on King County-level reductions of PSE loads to maximize the potential customer base from which to obtain potential for non-wires opportunities.

To remove the need to use CAPs would require additional load reductions. Thus, E3's study does not evaluate whether non-wires options represent a complete substitute for the proposed transmission options, but rather a cost-effective opportunity to defer the need for transmission upgrades.

To address this need, E3's study considers all remaining non-wires potential in King County not already selected in PSE's IRP (and incorporated into the baseline load forecast), and includes the economic savings from transmission project deferral to evaluate the cost-effectiveness of these measures as non-wires options. Using the median transmission project cost of $220 million from PSE's Eastside Transmission Solutions report, E3 estimated that a four-year project deferral from Winter 2017 to Winter 2021 would provide PSE approximately $40 million in present-value transmission revenue requirement savings. Assuming PSE requires 70 MW of incremental load reduction to enable a four-year project deferral, the four-year deferral savings would represent $155/kW-year on a levelized basis[5]. Thus, this non-wires analysis assigns available EE, DR, and DG options an additional annual benefit of $155 per kW that they contribute to reducing PSE's winter peak load. To identify the quantity of cost-effective non-wires potential, this benefit is included in the cost-effectiveness screen along with the avoided energy, generation capacity, and other benefits of the EE, DR, and DG measure evaluated.

PSE's Existing Demand-Side Resource Targets and Remaining Supply

PSE's 2013 IRP[6] details the utility's demand-side resource (DSR) goals, which include a system-wide load reduction target of 550 MW during the PSE winter peak as a result of EE and DG implemented between 2014-2021, a distribution system efficiency target of 10 MW, and a DR target of 108 MW . The IRP target selected all EE options expected to cost below $150/MWh, which together represents 75% of the total achievable EE potential for 2021 that had been identified by PSE's consultant the Cadmus Group[7]. The demand response selected by the IRP represents 64% of total achievable system wide potential.

[5] As described above, 70MW would be needed under the 100% Conservation Load Growth Scenario. If instead load growth were higher, and a larger incremental load reduction from non-wires measures is required, the deferral savings would need be spread over a larger need, resulting in a lower $/kw-yr levelized savings. For example, if PSE load growth follows the path in the scenario including only 75% of IRP conservation, and 160 MW is required for a four year deferral (rather than 70MW), the deferral savings would instead be $68/kw-yr on a levelized basis. For consistency in this analysis, E3 used $155/kw-yr deferral savings for all scenarios.

[6] E3 assessed non-wires potential and existing DSR targets based on the most recent available data from PSE, which was updated in the 2013 IRP. PSE's Needs Assessment powerflow analysis was conducted before the release of the 2013 IRP, so was based PSE's 2012 load forecast which included the impact of DSR from PSE's 2011 IRP. The Needs Assessment reports a larger amount of selected DSR through 2021 than the 668 MW described here primarily because the Needs Assessment shows 209 MW conservation for 2012 and 2013, which are excluded from these totals. The resulting PSE net winter peak load for 2021 is nearly identical (4923 MW from 2012 PSE load forecast vs. 4920 from 2013 PSE load forecast).

The 550 MW of EE and DG selected in the IRP for 2014 through 2021 includes the impact of Federal EISA-related EE measures. This total selected in the IRP represents 70 MW of peak demand reduction annually for 8 years, which represents 1.45% of peak electric demand for PSE in 2013. On an annual basis, the IRP-selected conservation targets assume approximately 378,000 MWh of incremental energy savings from new conservation for each of the 8 years between 2014 and 2021. This compares to PSE's conservation achievement of 311,000 MWh each year in 2010 and 2011, and 339,500 MWh in 2012, which were 3 of the highest 5 historical years of annual EE achievement for PSE[8]. PSE's target of 378,000 MWh in of annual energy savings represents approximately 1.7% of annual electricity sales to PSE customers in 2013. By comparison, in 2012 the Northwest Power and Conservation Council (NPCC) estimates that the Northwest region as a whole achieved reductions from utility and SBC-funded conservation equal to 1.2% of regional electricity sales, compared to 0.58% on average for the U.S. as a whole[9]. Due to the high level of conservation targets included in PSE's baseline load forecast, the remaining resources available to provide an incremental reduction as non-wires deferral solutions are limited and relatively high-cost.

Non-wires Alternative Potential for Project Deferral

E3's screening analysis identified an estimated 56 MW of winter peak reduction potential by 2021 (above the level included in the IRP) from incremental EE (30 MW), DR (25 MW), and DG (1 MW) in King County. This total non-wires potential includes all remaining cost-effective EE and DR in King County, as well as all remaining achievable DG in the area. This potential is insufficient to reach the 70 MW King County peak load reduction required for four-year transmission need deferral under PSE's 100% Conservation Scenario, and it is over 100 MW short of the 160 MW peak load reduction that PSE would expect to require in King County under a 75% conservation, which is a proxy for the higher load growth scenario or extreme winter conditions.

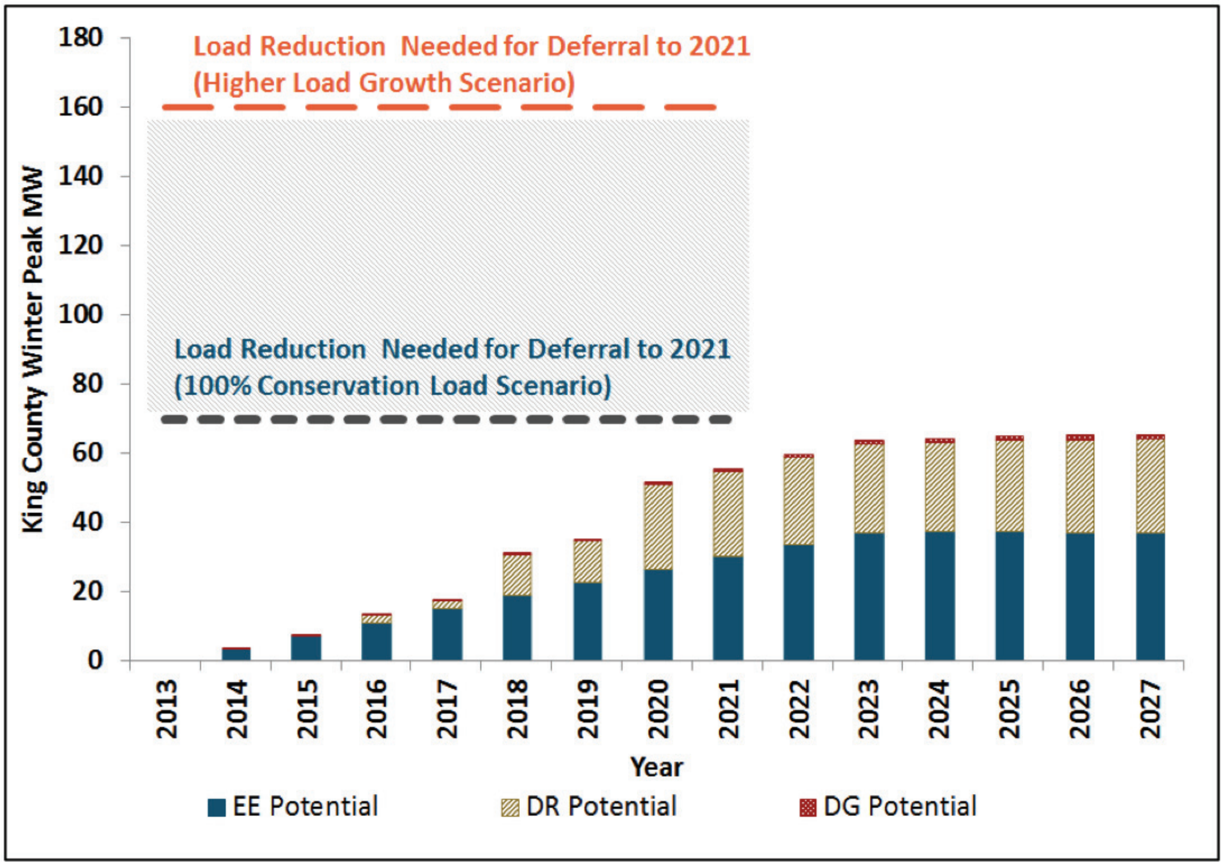
Figure ES- 1 below shows the shortage of available non-wires potential relative to the King County peak load reduction required for a four-year project deferral. The colored bars identify the cost effective incremental EE, DR and DG potential identified beyond the values included in the IRP; the total potential level is cumulative for each year shown. The resource potential estimates include a measure-specific program ramp up rates for 2014 through 2027. A limited amount of additional potential would become available after 2021, as the chart shows. The blue and orange horizontal lines identify the amount of peak load reduction in King County that would be required to defer the transmission project need from 2017 to 2021 under the 100% Conservation Load Scenario and the Higher Load Growth Scenario, respectively.

[7] Consistent with NPCC's 6th Power Plan, the Cadmus analysis assumes "achievable potential" to be equal to 85% of total technical potential for electric EE measures.

[8] Conservation reported in PSE 2013 Integration Resource Plan, Appendix D, Figure D-7.

[9] See NPCC, slide 19 (http://www.nwcouncil.org/media/6914345/8.pdf).

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



The shaded area represents the range of King County load reduction levels required for transmission deferral depending on load growth rate and weather extremity. The level of shortfall could be significant if weather conditions are more extreme than typical winter peak temperatures, if PSE load inside King County growths faster than projected by PSE's corporate load forecast, or if conservation between 2013 and 2021 does not achieve 100% of the target level selected in PSE's IRP.

PSE planners did not study powerflow scenarios after 2021, so the load reduction required for deferral post 2021 is not shown on this chart. PSE's corporate load forecast does estimate that PSE King County loads will grow by approximately 250 MW between 2021 and 2027, an average of over 40 MW annually for this six-year period, after accounting for conservation selected in the IRP for those years. If long-run load growth in King County does follow that forecast after 2021, the load total reduction required to defer transmission upgrades for additional years would quickly grow significantly larger than remaining non-wires potential. Thus, even under a scenario with 100% of conservation selected in PSE's IRP, plus incremental non-wires measures identified in this report, such measures alone would be unlikely to provide a permanent substitute to avoid the need for new transmission facilities.

Summary Implications

The cost-effective non-wires potential identified by E3 is not large enough to provide the load reduction that PSE planners expect would be needed to enable a four-year deferral of Eastside transmission upgrades (from 2017 through 2021), particularly under a higher load growth scenario or in a winter with more severe peak temperatures.

1 About this Report

Puget Sound Energy (PSE) is currently evaluating transmission upgrade options to reinforce its Eastside transmission system. PSE has conducted a Needs Assessment to determine, based on forecasted growth through 2021, what transmission challenges may occur under a range of contingency situations occurring during winter and summer peak load hours that could lead to loss of loads in eastern King County or that could result in NERC contingency violations. PSE has created a report to evaluate the strengths and weaknesses of a range of transmission solutions options to address these challenges. PSE also studied new large-scale generation options in their solutions report but determined generation additions to be infeasible to permit and/or construct in locations that would be able to ameliorate the Eastside transmission issues. In parallel to the evaluation of transmission and large generation options, PSE engaged Energy and Environmental Economics, Inc. (E3) to provide an independent evaluation of the potential feasibility of using a portfolio of cost-effective "non-wires" measures—including energy efficiency (EE), demand response (DR), and distributed generation (DG)—as an alternative option to defer the need for transmission upgrades. This report describes the methodology and results of E3's analysis.

This study provides a high-level screening evaluation of the quantity and cost of available non-wires options located within areas that would be effective at reducing loading on critical existing PSE transmission facilities, thereby deferring the date when upgrades are needed. This screening level analysis indicates whether certain non-wires opportunities or other issues are relevant for more detailed further study.

This evaluation involved a number of steps. First, E3 worked with PSE transmission engineers to obtain the quantity of local area load reduction required, relative to the baseline forecast, for a non-wires option to be effective in deferring the need for transmission upgrades. E3 then used this quantity reduction and PSE's projected cost of the transmission project to determine the economic value that a non-wires based deferral of transmission upgrades would create. E3 incorporated this additional transmission deferral value, together with energy value and avoided generation capacity value, into the overall cost-effectiveness assessment of non-wires potential. Finally, E3 compared whether the resulting quantity of non-wires potential determined to be cost effective and available in King County would be sufficient to meet the identified load reduction targets required to defer the need for transmission upgrades.

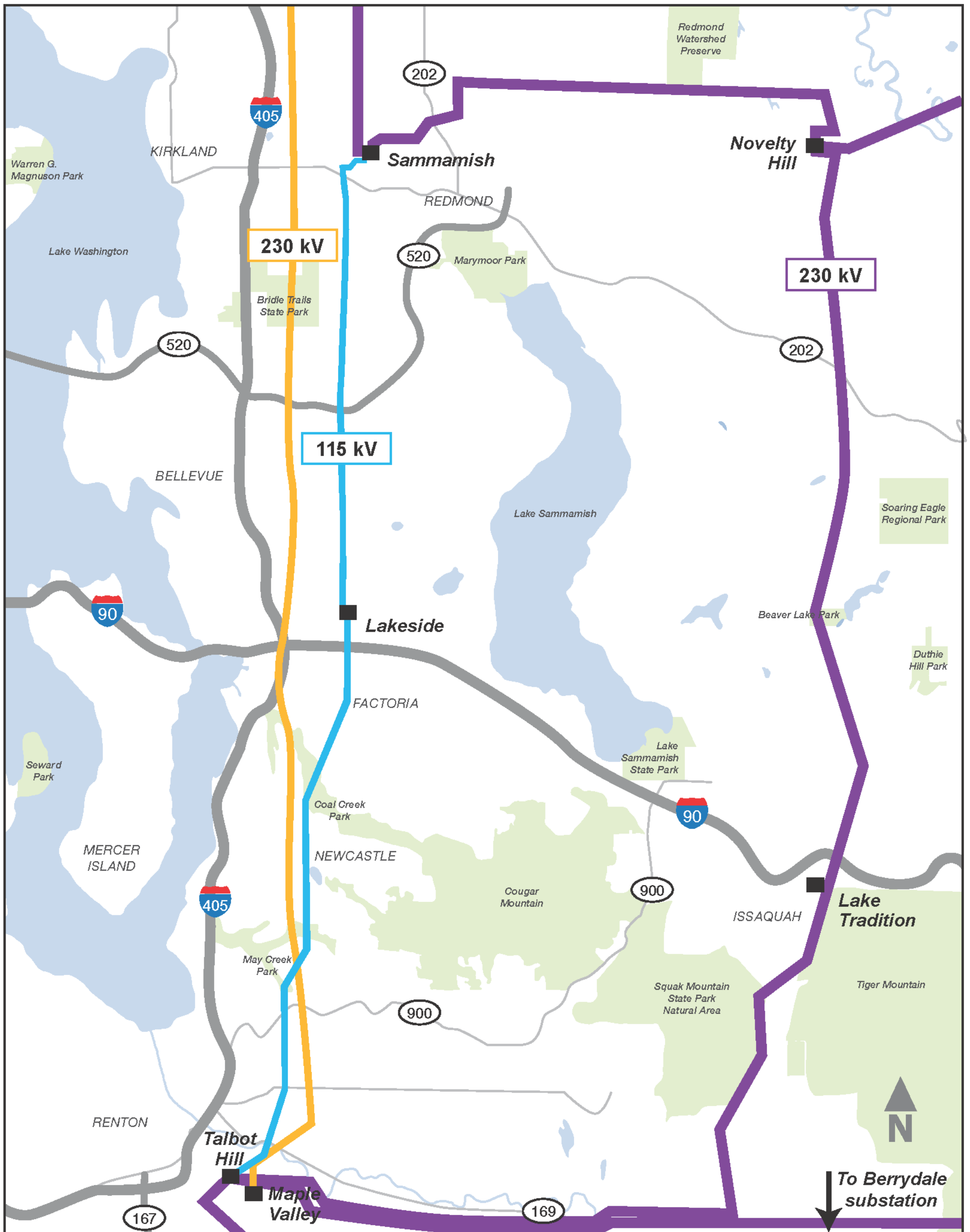
Section 2 of this report summarizes the potential problems PSE identified on the Eastside system that could trigger the need for upgrades. Section 3 describes the proposed Eastside transmission system upgrades and PSE's estimate of their costs. Section 4 summarizes the values used to estimate non-wires cost effectiveness (including the value of line deferral), and then describes the non-wires potential in each of the evaluated categories: EE, DR, and DG. Section 5 summarizes the overall results and provides conclusions.

2 Description of Identified Problem for Eastside System

PSE's Eastside transmission system serves customers located between the Sammamish substation in the north (located northeast of Kirkland) to the Talbot Hill substation in the south (located in southwest Renton).[11] Figure 1 below shows the existing major transmission infrastructure serving the Eastside system. These include 230 kV lines connecting Sammamish and Novelty Hill substations, Novelty Hill to Lake Tradition substations in far north eastern end, and an existing 115 kV line running through Bellevue, Factoria, and Newcastle that connects the Sammamish substation to Lakeside substation and the Lakeside substation to the Talbot Hill Substation. BPA's 500 kV substation at Maple Valley is located nearby the Talbot Hill substation, connecting this area to the region's high-voltage bulk system. BPA's Maple Valley Substation also connects to the Sammamish substation via a 230 kV line that runs along the far eastern side of King County. Seattle City Light (SCL) also operates a north-south 230 kV line that connects at Talbot Hill, and SCL's Bothell (not pictured on the map) substation to the north is connected to PSE by 230 kV line.

[11] PSE defines Eastside system load as the summed MW flow out of the bus on the Talbot Hill end of the Talbot Hill - Lakeside #1 & #2 115 kV lines, Shuffleton end of the Shuffleton - Lakeside 115 kV line, Lake Tradition end of the Lake Tradition - Goodes Corner - Lakeside 115 kV line, and Sammamish end of the Sammamish - Lakeside #1 & #2, Sammamish - North Bellevue - Lakeside, Sammamish - Lochleven - Lakeside, and Sammamish - Ardmore - Lakeside 115 kV lines.

Figure 1: Map of the Eastside area transmission system



Existing Conditions

Legend

- Existing bulk transmission lines (230 kV)
- Existing transmission lines (115 kV)
- Seattle City Light bulk transmission lines (230 kV)

PSE peak customer demand in the winter, both on the Eastside and system-wide, is driven by cold temperatures and generally occurs during the morning and evening hours in December, with a typical "1-in-2" winter planning temperature of 23° F (expected to occur during system peak every 1-in-2 winters on average). The area has also been known to experience more extreme winter temperatures, such as in 2009, where winter low temperatures reached 16° F. PSE also anticipates rapid growth in summer peak loads due to increase in cooling demands by commercial customers. A typical summer peak for the area is 86° F (which is expected to occur during system peak every 1-in-2 summers on average).

The goal of the proposed Eastside transmission upgrades is to avoid the risk of criteria violations or losses of customer load in the area. The non-wires alternatives in this study are evaluated based on their ability to defer the PSE's identified "need date" for Eastside transmission upgrades by maintaining peak load levels below amounts that would produce potential overloads under contingencies and create the need for upgrades.

PSE currently uses corrective action plan (CAPs) measures to prepare the system during times of outages or high system load. These CAPs measures can result in over 30,000 customers being served by radial transmission lines, and could result in loss of customer load if an outage were to occur on the remaining radial lines serving those customers. Load growth above today's levels will require PSE to use CAPs more frequently to avoid criteria violations, raising the risk of outage for customers in the Eastside.

2.1 Description of the Problem

PSE load growth in King County, coupled with high regional south-north flows through the area driven by high winter export levels to Canada, has increased the risk that winter outages on particular lines or substations could lead to customer loss of load or NERC criteria violations by Winter 2017-18. In addition, PSE's Needs Assessment indicates that anticipated summer peak demand growth driven by commercial cooling loads in the area could begin to create concern of system criteria violations by Summer 2014, and that continued growth would increase the risk of more severe overloading by Summer 2018.

In assessing the winter issues, the Eastside Needs Assessment identifies a number of potential contingency criteria violations, and loading very near violation levels, for single line outages (N-1) as well as double line outages (N-1-1 and N-2). These outages include:

- **Contingency:** Talbot Hill 230-115 kV transformer #1 outage
  → **Resulting Overload:** Talbot Hill 230-115 kV transformer #2 (N-1)
- **Contingency:** Talbot Hill 230-115 kV transformer #2 & Berrydale 230-115 kV Transformer out
  → **Resulting Overload:** Talbot Hill 230-115 kV transformer #1 (N-1-1)
- **Contingency:** Talbot Hill 230-115 kV transformer #1 & Berrydale 230-115 kV Transformer out
  → **Resulting Overload:** Talbot Hill 230-115 kV transformer #2 (N-1-1)
- **Contingency:** Berrydale 230-115 kV transformer & White River – Sherwood tap 115 kV line section out → **Resulting Overload:** Talbot Hill 230-115 kV transformer #1 (N-1-1)

For this non-wires analysis, the N-1-1 (Category C) contingency of the Talbot Hill 230-115 kV transformer #2 outage followed by the Berrydale transformer outage was studied as the critical winter problem that the non-wires solution must address. This contingency, which results in overloads on Talbot Hill 230-115 kV transformer #1 by Winter 2017, was chosen for study because PSE transmission planning staff indicated that load reductions mitigating this contingency also would likely resolve many of the other significant winter reliability issues identified in the study.

To quantify the winter load reduction requirement for transmission deferral, PSE planners started with the Winter 2021 powerflow cases used in the Eastside Needs Assessment, and reduced PSE customer peak demand in King County until loading under contingencies on key Eastside transmission system elements were reduced to levels equal to those shown in PSE's 2017 powerflow case (which assumed 100% of IRP conservation levels in the baseline load growth forecast).

The details of the overload on the Talbot Hill 230-115 kV transformer #1 are outlined in Table 1 below for Winter 2017 and 2021 scenarios that assume 100% of IRP conservation in the baseline load forecast.

Table 1: Contingency Thermal Loading on Talbot Hill 230-115 kV Transformer #1

	2017 Case (100% Conservation)	2021 Case (100% Conservation)
Pre-Contingency Value (MVA)	324.9	331.5
Post Contingency Value (MVA)	490.7	501.5
Operating Limit (MVA)	383.0	383.0
Emergency Limit (MVA)	464.0	464.0
Percent Overload (above operating limit/above emergency limit)	128.1%/ 105.7%	131.0%/ 108.1%

The PSE power flow analysis indicates that under this N-1-1 condition, the Talbot Hill 230-115 kV transformer #2 overloads 128.5% above its normal operating limit and 105.7% above its emergency limit in 2017 under a scenario with heavy south to north flows and 100% of conservation selected in the IRP included in the load growth forecast. By 2021 (assuming 100% of IRP selected conservation is included in the load growth forecast), Talbot Hill transformer overloads under this contingency are expected to grow to 108.1% of the facility's emergency limit. PSE planners, however, were able to bring the 2021 case overload back down to 105.7% of the emergency rating by reducing PSE loads in King County by 70 MW. This implies that a non-wires portfolio creating 70 MW of PSE peak load reduction in King County would be expected to enable PSE to maintain reliability levels in 2021 that are equivalent to the level shown for 2017 (which PSE identified as the first year of winter need for Eastside transmission system upgrades). Thus, the E3 screening analysis was targeted to identify find cost-effective EE, DR and DG measures in King County measures that can reduce King County load by 70 MW during the winter peak for 2021.

The load reduction requirements identified in PSE's power flow analysis are derived from the utility's load forecast, which includes both a gross load growth forecast and annual estimates of projected conservation selected in PSE's integrated resource plan (IRP), which result in lower net load growth for the final PSE load projection. While the utility has successfully met 100% of its conservation targets over the past several years, there is some uncertainty in forecasting future conservation achievement, as well as uncertainty in the underlying load growth driven by local economic conditions, and potential peak demand under extreme weather conditions. For purposes of comparison with respect to these uncertainties, E3 also considered the level of King County load reduction that would be required in a non-wires solution under a higher load case. To identify the impact of this uncertainty, E3 also investigated a Higher Load Growth Scenario, which is based on the powerflow case used in PSE's Eastside Needs Assessment that included only 75% of the IRP planned conservation. These alternate scenarios could reflect either an increase in load growth above what is included in PSE's gross forecast, a shortfall in conservation, or peak winter load due to colder winter peak temperatures than the typical peak 23° F. In this Higher Load Growth Scenario, King County winter peak load would need to be reduced by 160 MW by Winter 2021 (incremental to the load reduction included as a result of 75% of the conservation measures selected by PSE's IRP) to present a viable four-year deferral option. These range of load reduction required for deferral based on PSE's powerflow scenarios are summarized in Table 2 below.

Table 2: Winter peak load reduction required to defer transmission upgrades from 2016 to 2021

Load Scenario	Peak Load Reduction Required by 2021
100% Conservation Scenario	**70 MW** (incremental to 100% of conservation selected in PSE IRP through 2021)
Higher Load Growth Scenario	**160 MW** (incremental to 75% of conservation selected in PSE IRP through 2021)

If sufficient non-wires measures were implemented to provide sufficient winter peak load reduction to defer the winter transmission needs on the Eastside system, summer peak issues could still remain a concern to the transmission system, as many conservation measures that address heating end uses do not reduce loads during the summer. This non-wires report has focused primarily on the winter system issues as an initial set of criteria to evaluate potential impact of non-wires measures. If a non-wires measures were found to be a viable option to defer winter system issues, additional analysis of summer peak would also be needed.

2.2 Critical Peak Period Definition

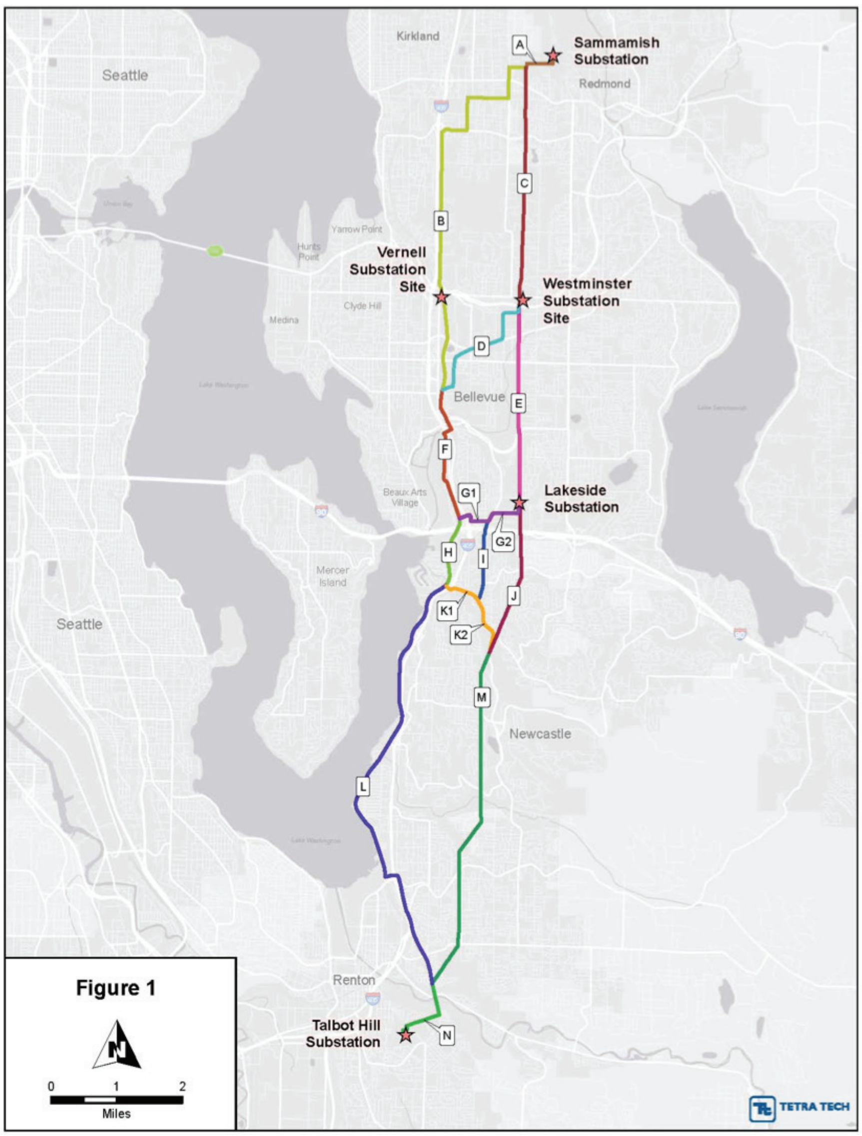
In order to identify non-construction deferral alternatives to Eastside transmission system upgrades, it is necessary to determine when the critical peak period is likely to occur in the region. Only those demand-side resources that reduce load during the peak period have the potential to defer the need for new transmission.

PSE provided E3 with several recent historical years of hourly load data for both the PSE system and the Talbot Hill 230-115 kV transformers. E3 used those load shapes to confirm that the typical peak loading period on the Talbot Hill transformer is typically coincident with the PSE system peak. Because of the coincidence of the peak periods, E3 elected to use PSE's system winter peak definition in our analysis. 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.

3 Eastside Transmission Project

PSE is currently considering a number of alternatives to reinforce the Eastside system. These alternatives are described in PSE's Eastside Transmission Solutions Report, and include five transmission upgrade alternatives. These five solutions include 230 kV transmission sources and three prospective transformer sites. Two of the options include rebuilding the Talbot Hill – Lakeside – Sammamish 115 kV line to 230 kV and looping it through new substations (Westminster or Lakeside). The other three alternatives would build a new Talbot Hill – Sammamish 230 kV line on new rights-of-way and loop the lines through a new substation (Westminster, Vernell, or Lakeside). A map of the alternatives is shown in Figure 2 below.

Figure 2: Eastside 230 kV Transmission Route Alternatives



Among the transmission upgrade options considered, PSE estimates that the total transmission cost would range from $155 million to $288 million, with a median cost of $220 million. For the purposes of the non-wires screening analysis, E3 used the median transmission cost to calculate the potential deferral value that non-wires measures may create.

4 Non-Construction Alternatives to Defer Transmission Line

E3's screening analysis of non-wires measures, described in this section, evaluated whether there is enough cost-effective non-wires potential in King County to provide the identified magnitude of load reductions required to defer Eastside transmission upgrades (as described in Section 2). As discussed in the remainder in this section, E3 incorporated the value of deferring the Eastside transmission upgrades into the analysis when evaluating the cost-effectiveness of non-wires resource potential. In this way, the analysis highlights what additional quantities of EE, DR, and DG (incremental to the quantities already selected in PSE's IRP) would become cost effective the transmission project deferral value is also incorporated into the avoided costs created by the non-wires measures.

E3's screening analysis focused specifically on King County, as opposed to PSE's full service territory. This is because power flow scenarios evaluated by PSE's transmission planners have indicated that load reductions outside of King County do not have a significant impact on reducing peak loading on key transmission existing facilities of the Eastside transmission system.

4.1 Value of Line Deferral

4.1.1 REVENUE REQUIREMENT SAVINGS OF LINE DEFERRAL

To evaluate the potential transmission savings for PSE customers if the proposed Eastside project were deferred, we estimate the transmission revenue requirement (TRR) savings from the line deferral using the "differential revenue requirement" method. This method includes all of the costs the transmission upgrades that could be deferred.[13] Other key input assumptions to the TRR savings include a 2.5% per year inflation rate and a utility nominal weighted average cost of capital (WACC) of 7.8%. We also include the value of avoided O&M over the duration of the deferral period.

[13] Non-wires studies often exclude land costs components from deferrable costs of the wires project because it is generally prudent to purchase land for a transmission line even if the line will not be built immediately, since land costs rarely decrease over time and purchased rights of way provide more certainty for regional land use planning. For this analysis, PSE was not able to provide the separate land cost component of the total Eastside upgrades to E3, since a number of different transmission options are still under consideration. Thus, for this analysis, E3 used the total transmission project cost--including land--for estimating transmission deferral savings from a non-wires option. If PSE had identified the land cost component separately from other costs, and E3 had removed this "non-deferrable" component from the total project cost, the resulting transmission deferral value would have been lower than the value used here, resulting in a lower quantity of cost-effective non-wires potential.

The results of this savings calculation are shown in the table below. If the transmission upgrades could be deferred from the planned online date of Winter 2017 to Winter 2021, this four year deferral would create total present value savings for PSE ratepayers of $40.24 million in transmission project costs. Assuming that PSE would require 70 MW of incremental load reduction to enable a four-year project deferral, this savings is equivalent to a capacity payment of $575/kW for the four-year period, or annual savings of $155/kW-year.

Table 3: Transmission Revenue Requirement Savings of Deferring Eastside Transmission Upgrades

	Winter 2021
Transmission Revenue Requirement Savings ($ million)	$40.24
$/kW (contracted)	$575
$/kW-year (levelized)	$155

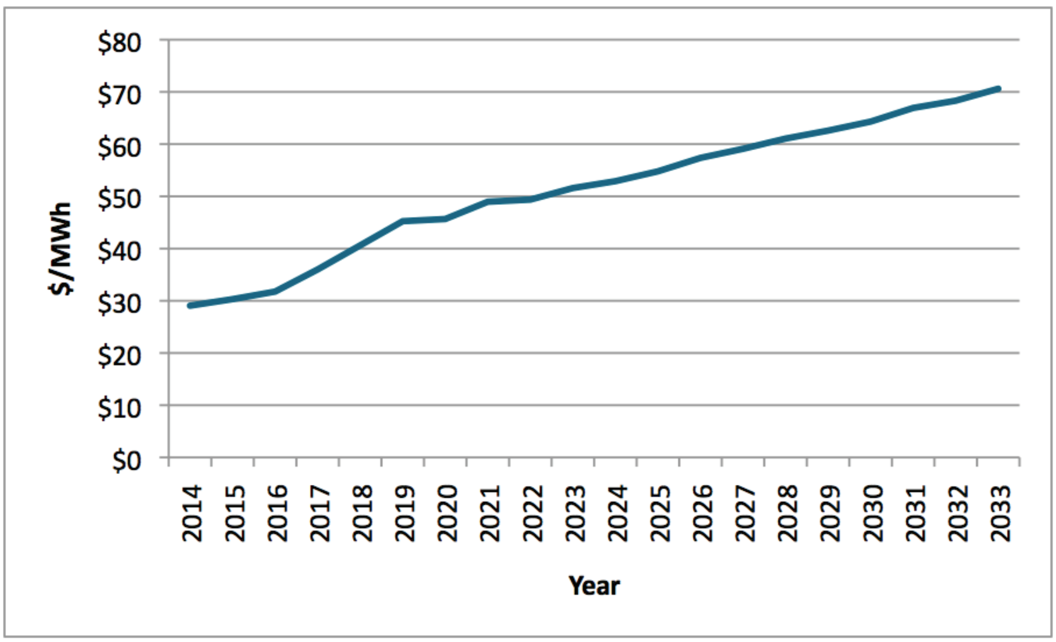
4.1.2 ADDITIONAL AVOIDED COSTS

In addition to the value from deferring the Eastside transmission project, the non-wires options considered would also provide other value streams, including the avoided cost of energy that would otherwise need to be purchased or generated on behalf of customers. EE, DR, and DG can also generate savings by deferring the need for new distribution system upgrades, by reducing generation capacity costs, and by enabling additional non-energy benefits such as water savings for customers whom adopt EE measures that impact efficient end-use of hot water. These components of energy and capacity savings must be aggregated for assessing non-wires measure cost effectiveness.

[14] As described earlier in this report, 70MW would be needed under the 100% Conservation Load Growth Scenario. If instead load growth were higher, and a larger incremental load reduction from non-wires measures is required, the deferral savings would need be spread over a larger need, resulting in a lower $/kw-yr levelized savings. For example, if PSE load growth follows the path in the scenario including only 75% of IRP conservation, and 160 MW is required for a four year deferral (rather than 70MW), the deferral savings would instead be $68/kw-yr on a levelized basis. For consistency in this analysis, E3 used $155/kw-yr deferral savings for all scenarios.

PSE provided E3 with utility-specific values for avoided costs of energy, generation capacity, and generic transmission and distribution (T&D) capacity for the PSE system. PSE's avoided energy costs are the hourly energy prices used in the 2013 IRP base scenario, forecast for the years 2014 through 2033. The average annual energy price by year is shown in Figure 3 below.[15]

Figure 3: Average Avoided Cost of Energy (Nominal Dollars)



PSE's energy avoided costs also include a flat cost adder representing the avoided cost of renewable energy procurement. The value of this adder is $6.85/MWh in 2014 dollars; this value was escalated for annual inflation during future years. PSE's IRP team also provided avoided generation capacity cost of $184/kW-year and an avoided generic T&D cost of $23/kW-year, which are both represented in 2014 dollars.[16] For this analysis, E3 assumed that PSE's generic T&D avoided cost and the specific transmission line deferral value related to PSE upgrades are additive. This additive assumption presumes that load reductions in King County can defer the need for more general planned distribution system upgrades, in addition to deferring the construction of the specific Eastside upgrades.[17]

[15] The average price is shown for confidentiality purposes; E3's analysis relied on hourly energy efficiency savings shapes and hourly avoided energy prices.

[16] PSE's $23/kw-year value for generic T&D avoided costs is taken from the 6th Power Plan of the Northwest Power and Conservation Council, http://www.nwcouncil.org/media/6305/SixthPowerPlan_Appendix_E.pdf, p.13.

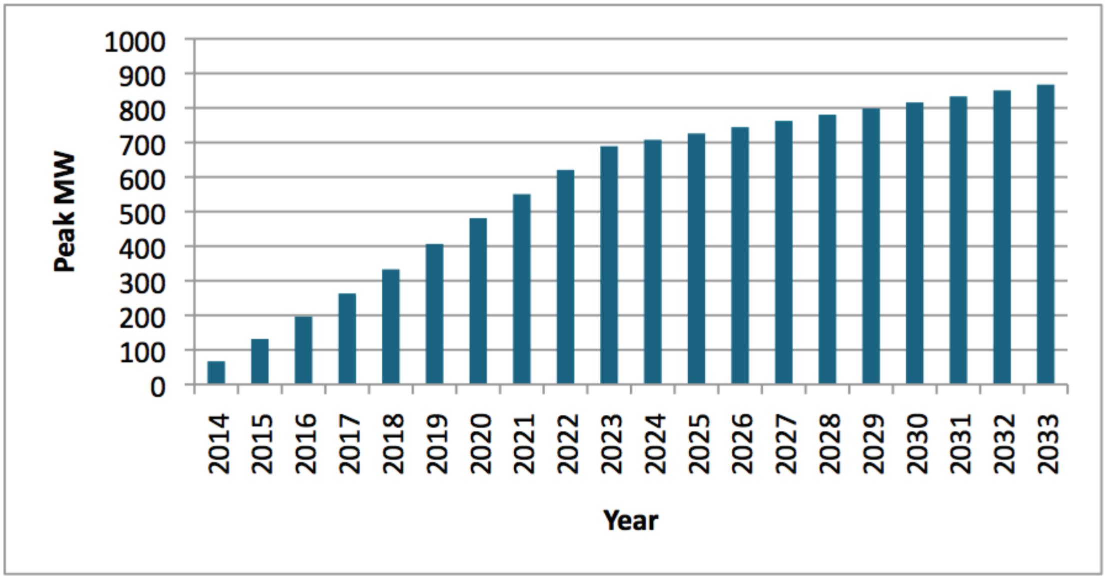
[17] If, in practice, these avoided cost items are not fully additive and there is partial overlap between the $23/kw-year deferral value for generic PSE T&D upgrades, and the $155/kw-yr deferral value specific to Eastside transmission upgrades, then the combined total avoided cost for non-wires measures would be reduced to remove double counting this overlap, resulting in a potential reduction to the quantity of non-wires potential deemed to be cost-effective.

Since energy efficiency savings occur behind the meter, EE avoided cost benefits must be scaled up to account for line losses. PSE assumes line losses of 6.9%; that loss factor was applied to the avoided costs of energy, generation capacity, generic T&D, and Eastside transmission deferral. Additionally, to measure cost-effectiveness, E3 used the Regional Cost Test benefit-cost ratio, which includes a 10% credit for EE resources.

4.2 Energy Efficiency (EE)

The EE measures included in this study were drawn from data gather to create PSE's 2013 Integrated Resource Plan (IRP). As part of its 2013 IRP process, PSE had commissioned an independent EE resource potential study, which was performed by Cadmus Group using practices compatible with the Northwest 6th Plan.[18] Cadmus's EE potential study is focused specifically on measure potentials within PSE's territory from 2014 through 2033. PSE provided E3 with a catalog of over 5,000 energy efficiency and fuel switching measures used in the Cadmus study. Data provided for each measure included annual technical and achievable potentials, as well as each measure's energy savings impact during PSE's winter peak period. Figure 4 below shows the PSE-wide achievable cumulative EE potential identified in the Cadmus study for each year through 2033, in terms of impact on winter peak MW demand. E3 compared PSE's EE potential from the Cadmus study to the potential published in the 6th Power Plan and found a comparable quantity of EE identified in PSE's territory.

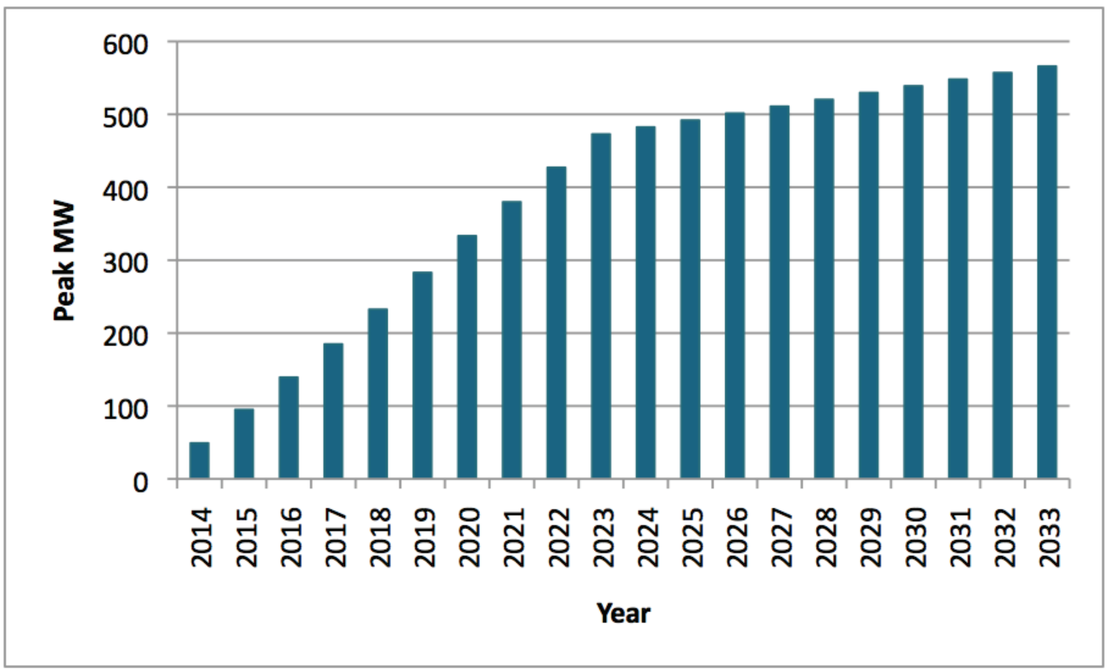
Figure 4: Cumulative EE Potential in PSE Territory



[18] Cadmus Group's report is found in Appendix N of PSE's 2013 IRP, available at the following link: http://pse.com/aboutpse/EnergySupply/Documents/IRP_2013_AppN.pdf

Because PSE's measure catalog was developed for the 2013 IRP, it includes many measures that were identified as cost-effective in the IRP and were selected in PSE's integrated resource planning solution. EE selected in the IRP is also included in PSE's corporate load forecast, meaning that any additional EE that could be called upon to defer transmission must not be already selected in the IRP. Figure 5 below shows the quantity of EE selected in PSE's 2013 IRP and the quantity of remaining available EE in PSE's territory. Because of PSE's aggressive EE targets, a very large share of the total EE potential is already included in the utility's resource plan. Furthermore, because the utility selects the most cost-effective measures in their resource planning process, the remaining measures generally represent higher cost EE options.

Figure 5: EE Measures Selected in 2013 IRP



After eliminating the EE measures already selected in the IRP from the catalog of available EE, E3 next apportioned the remaining EE resources to King County. The annual achievable potential for each measure was determined on a PSE system-wide basis. PSE's corporate load forecast includes annual sales forecasts (MWh) for the full utility territory as well as for each county. The sales forecasts are further divided by customer class (commercial, industrial, or residential). E3 calculated the King County share of sales within each class for each year from 2012 to 2033, and then calculated the average share for each class over that time period.

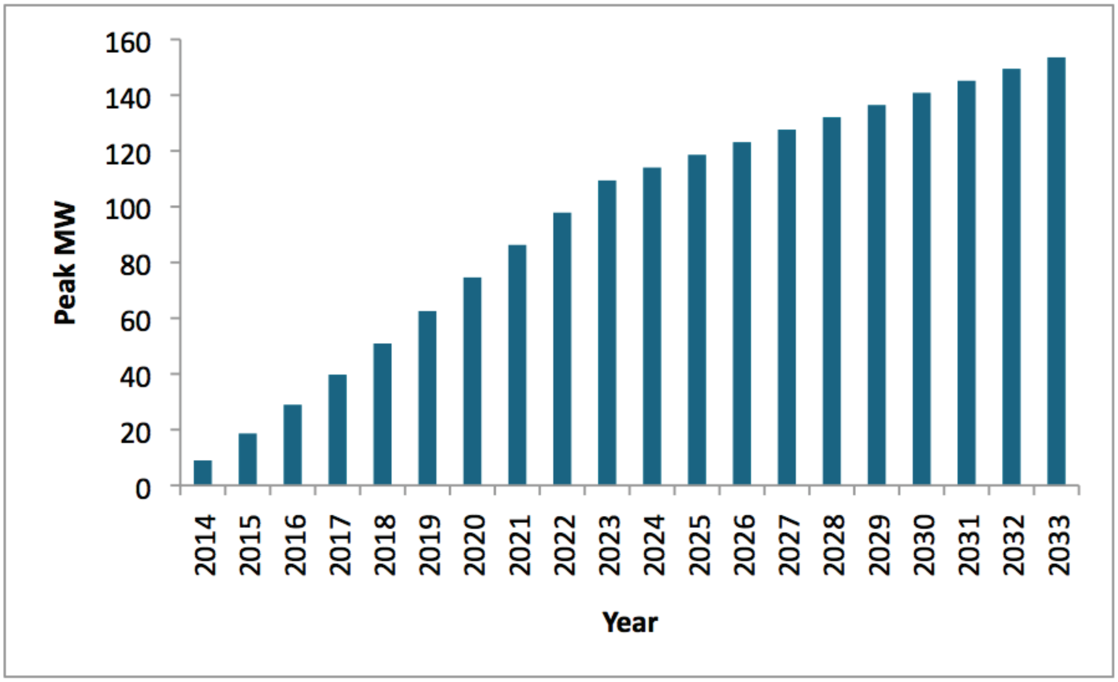
Table shows the resulting King County allocation factors by class.

Table 4: King County EE Allocation Factors by Customer Class

Customer Class	Share of Class Load in King County
Residential	47%
Commercial	58%
Industrial	62%

Since each item in the EE measure database is identified as a residential, commercial, or industrial measure, E3 applied the appropriate county allocation factor to each individual measure to determine King County's remaining achievable EE potential. The resulting annual achievable EE potential in King County is shown in Figure 6 below.

Figure 6: King County EE Potential

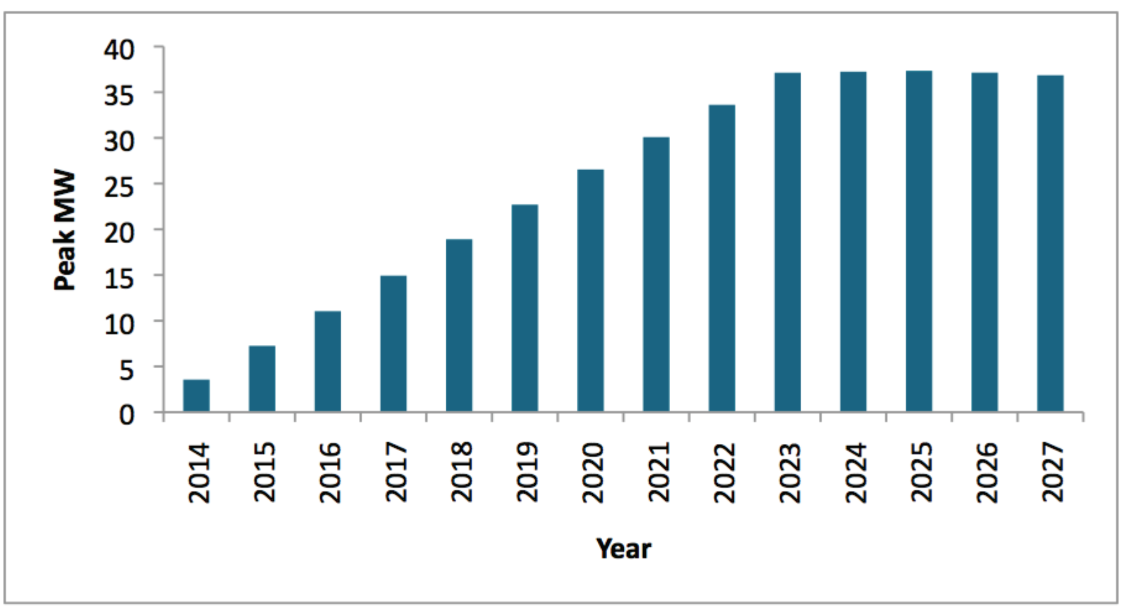


4.2.1 EE COST-EFFECTIVE POTENTIAL RESULTS

After identifying the quantity of achievable EE in King County through 2033, E3 performed a cost-effectiveness analysis to determine the quantity of economic EE available as an option to defer transmission construction. To measure cost-effectiveness, E3 used the Regional Cost Test benefit-cost ratio. The Regional Cost Test is similar to the Total Resource Cost Test (TRC), but also incorporates non-energy benefits and a 10% conservation credit. The 10% conservation credit effectively means that EE measures must have a benefit-cost ratio of 0.9 to be considered cost-effective, instead of a ratio of 1.0, which is required for demand side resources to be cost-effective under a TRC test.

E3 used the Regional Cost Test to determine the quantity of cost-effective EE potential available in the Eastside area from 2014 through 2027, which would represent the time horizon for a 10-year project deferral. Figure 7 below shows the total amount of cost-effective EE available in the area over that time frame, scaled up to account for losses. Because of PSE's aggressive EE goals included in the 2013 IRP, much of the remaining EE potential is not cost-effective even with accounting for the large additional value of deferring Eastside transmission upgrades. As a result, EE can contribute a maximum incremental peak reduction of 30 MW of in King County by 2021 (above the EE selected in PSE's IRP and included in the baseline load forecast).

Figure 7: Available Cost-Effective EE Potential in the King County (Adjusted Upward for Distribution System Losses)



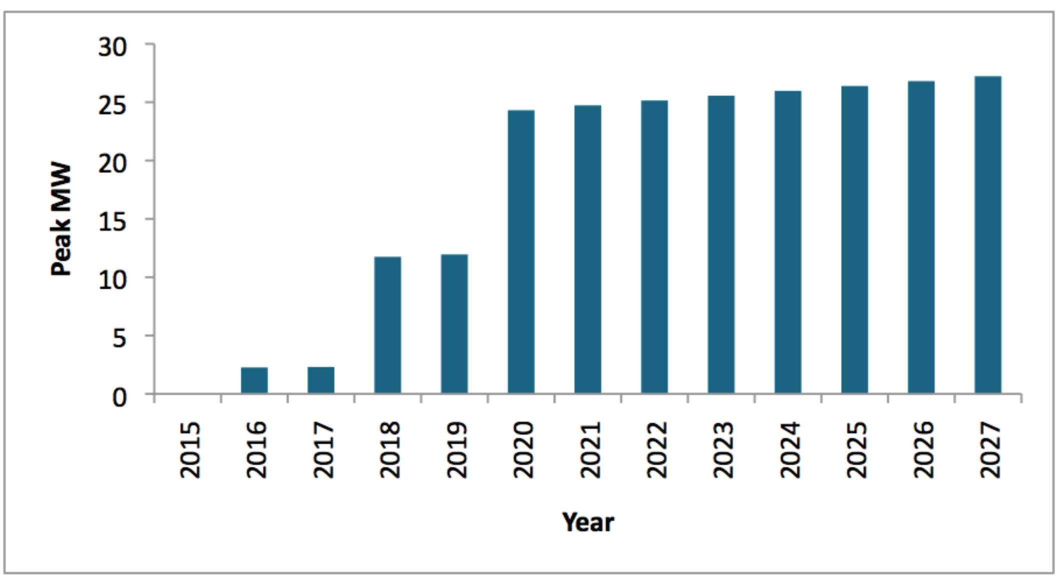
4.3 Demand Response Potential

PSE provided E3 with data on all demand response (DR) programs considered in the utility's 2013 IRP portfolio analysis. The IRP identified five possible DR programs: 1) residential space heating and water heating direct load control (DLC), 2) residential room heating and water heating DLC, 3) residential critical peak pricing, 4) commercial and industrial critical peak pricing, and 5) commercial and industrial load curtailment. Of those five programs, three are already included in PSE's resource plan. The remaining programs not selected by the IRP were residential room and water heating DLC and residential critical peak pricing.

Critical peak pricing programs rely on customers' response to higher energy prices during certain hours. For this analysis, E3 did not consider such programs to provide sufficient certainty as a reliable option for deferring transmission line construction. Thus, E3's DR analysis focuses on residential room heating and water heating DLC potential (referred to in the PSE 2013 IRP and this report as DR-2).

PSE provided an annual forecast of potential of DR-2 potential for the period from 2014 through 2033. Since this forecast was calculated on a system-wide basis, E3 used the same allocation factors described above in the EE section to approximate the share of DR potential located in King County. The resulting DR potential was also scaled up to account for distribution system losses, again using the same loss factor that was applied to EE resources (6.9%). Figure 8 shows the resulting DR potential in King County through 2027, with 24.7 MW of DR incremental potential in King County by 2021. We assume that since the DR program addresses room and water heating end-uses, the potential is fully coincident with the winter system peak.

Figure 8: King County Demand Response Potential



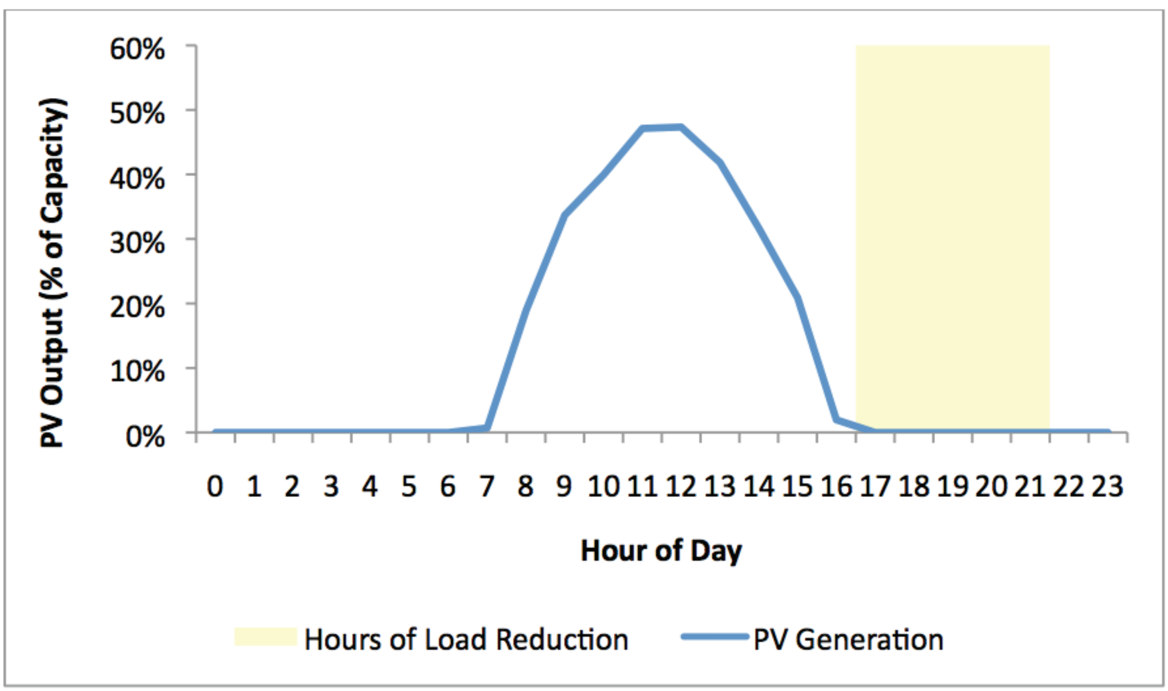
4.4 Distributed Generation

E3's examination of construction alternatives reviewed three distributed generation (DG) technologies: solar photovoltaic (PV) generation, customer-sited backup generators, and combined heat and power resources (CHP).

4.4.1 SOLAR PV

While PSE's 2013 IRP identified potential for distributed solar PV installations in the utility's territory, the shape of solar PV hourly energy output is not effective for deferring transmission upgrades in the Eastside area. Figure 9 below shows the limited coincidence between PV production in December and the PSE December evening critical peak period. To create this comparison, E3 used the National Renewable Energy Laboratory's (NREL's) System Advisor Model to simulate hourly annual solar PV production based on typical meteorological year weather data for Bellevue, Washington. The hourly solar PV output shape for a typical December day in that region does not generate any electricity after 4 PM, meaning that solar PV cannot effectively reduce December evening loads in King County.

Figure 9: Average December PV Output, Bellevue, WA



[19] See EPA National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE) (http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&sid=59a90b3aa02f6d8a04e860a0354600d5&tpl=/ecfrbrowse/Title40/40cfr63e_main_02.tpl). These regulations due allow certain exiting backup generators to be utilized for emergency outage conditions in a limited number of hours, but may hinder their use from being assumed for capacity planning purposes.

4.4.2 CUSTOMER-SITED BACKUP GENERATION

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.

4.4.3 COMBINED HEAT AND POWER

Customer-sited combined heat and power (CHP) generation represents a potential non-wires opportunity because it conserves energy during periods of high heating demand, which are coincident with PSE's December critical peak period. Much of this generation potential, however, has already been selected by PSE's 2013 IRP, and the impact of selected CHP on net customer loads has already been incorporated into the PSE baseline load forecast. PSE's 2013 IRP includes an assessment of available CHP potential in the utility's territory, which is drawn from a 2009 report on demand-side resource potentials performed by The Cadmus Group. The report identifies achievable potential in PSE's territory for several different CHP technologies: industrial biomass, small anaerobic digesters, large anaerobic digesters, and non-renewable reciprocating engines, gas turbines, micro-turbines, and fuel cells. The Cadmus report estimates potential achievable by 2029 in average MW.

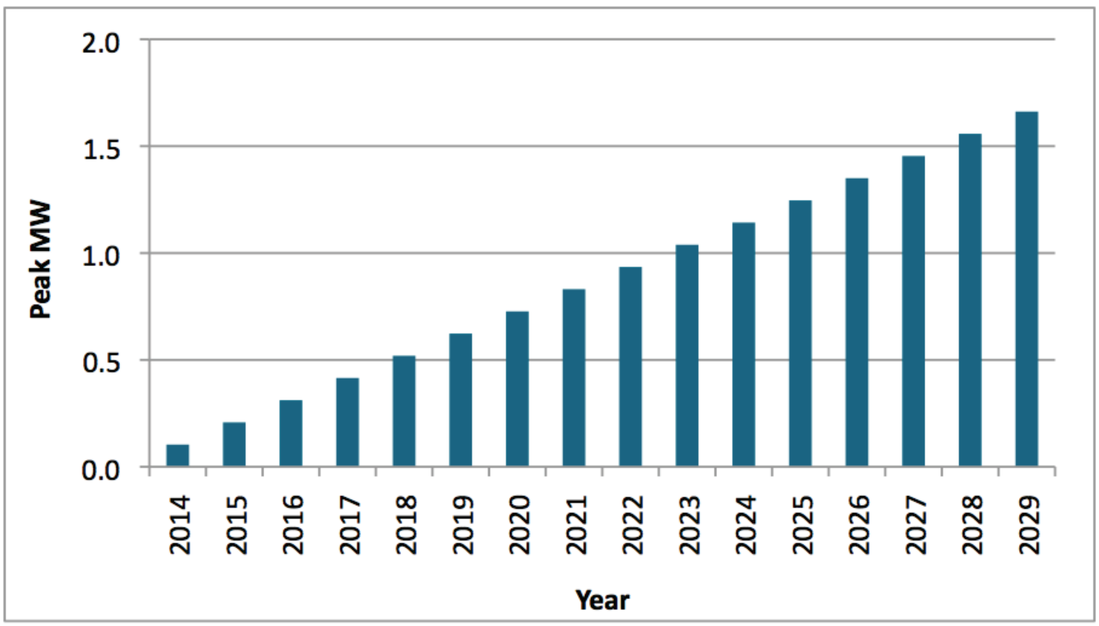
In the 2013 IRP, PSE selected all CHP resources with a levelized cost less than or equal to 15 cents per kWh. Of the CHP technologies listed above, only micro-turbines were above that price threshold, and was the only CHP resource potential not selected by the IRP. The Cadmus Group's 2009 report estimated 2.6 MW of micro-turbine CHP potential in PSE territory through 2029; E3 scaled this potential to King County based on the county's share of total PSE load.

Table 5: Eastside CHP Achievable Potential

Customer Class	Achievable CHP Potential by2029 (aMW)	King County Load Share	Eastside Achievable Potential by 2029 (aMW)
Industrial	1.3	62%	0.80
Commercial	1.3	58%	0.75

Cadmus' study estimated CHP achievable potential for 2029 only, and did not include an adoption schedule for interim years. For the purposes of this non-wires analysis, E3 assumes that CHP adoption is linear from 2014 through 2029. The 2009 Cadmus report also does not include hourly output shapes for CHP; however, the report assumes that CHP units operate as baseload resources with high capacity factors (90% or greater). As a result, E3 assumes that CHP operates with a flat profile, meaning that average MW potentials can be equated to peak MW potentials. Finally, behind-the-meter CHP potentials were scaled up to include 6.9% line losses, consistent with the assumptions used for EE and DR analysis discussed in the previous sections. Figure 10 below shows the resulting loss-adjusted Eastside CHP peak MW potential forecast for 2014 through 2029.

Figure 10: King County CHP Potential



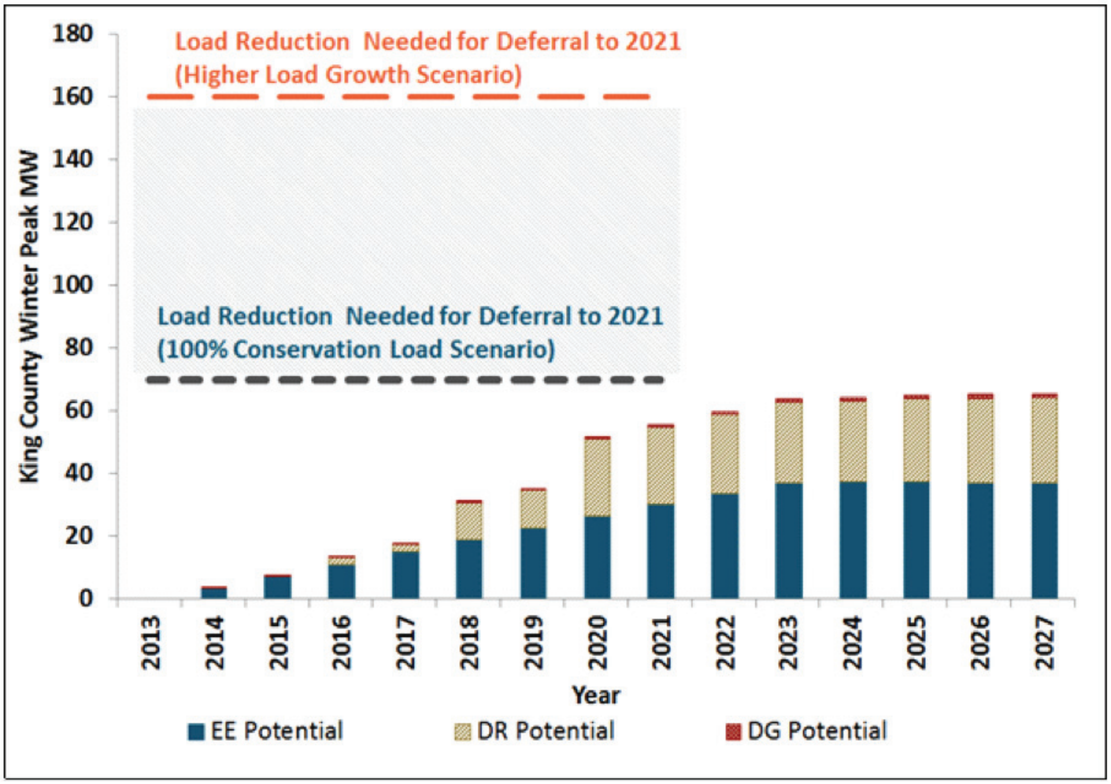
5 Summary of Results and Conclusions

This non-wires screening study identified insufficient load reduction potential in King County to defer the need for Eastside transmission system upgrades. The combination of cost-effective EE, DR, and DG potential (not already selected by the IRP and incorporated into PSE's baseline load forecast) does not meet the threshold necessary to defer the need for the transmission upgrades beyond 2017.

Figure 11 shows the annual aggregated potential for EE, DR, and DG in King County, including all cost-effective EE and DR and all achievable DG. The colored bars identify the cost-effective incremental EE, DR and DG potential identified beyond the values included in the IRP. The potential quantities are shown cumulatively for each year. The resource potential estimates include a measure-specific ramp up rates for 2014 through 2027; a limited amount of incremental potential would become available after 2021. Collectively from these sources, E3's non-wires analysis finds a total potential of 56 MW of peak load reduction in the Eastside through 2021.

The blue and orange horizontal lines identify the amount of peak load reduction in King County that would be required to defer the transmission project need from 2017 to 2021 under the 100% Conservation Load Scenario and Higher Load Growth Scenario, respectively.

Figure 11: Total Non-Construction Alternatives Potential in King County



The shaded area represents the range of King County load reduction levels required for transmission deferral depending on load growth rate and weather extremity. The level of shortfall could be significant if weather conditions are more extreme than typical winter peak temperatures, if PSE load inside King County growths faster than expected under PSE's corporate load forecast, or if conservation between 2013 and 2021 does not achieve 100% of the target level selected by PSE's IRP.

PSE planners did not study powerflow scenarios after 2021, so the load required for deferral post 2021 is not shown on this chart. PSE's corporate load forecast does estimate that PSE loads in King County will grow by approximately 250 MW from 2021 to 2027, an average of over 40 MW annually for this six year period, after accounting for 100% of the conservation selected in the IRP for those years. If long-run load growth in King County closely follows this forecast after 2021, then the total load reduction required to defer transmission upgrades for additional years would quickly grow significantly larger than remaining non-wires potential. Thus, even under a scenario with 100% of conservation selected in PSE's IRP, plus incremental non-wires measures identified in this report, such measures alone would be unlikely to provide a permanent substitute to avoid the need for new transmission facilities.