I-5 Corridor Reinforcement Phase 2 Non-Wires Analysis: Feasibility for Line Deferral

Prepared for:

Bonneville Power Administration

December 19, 2011

Energy+Environmental Economics

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Acknowledgements

This study benefitted greatly from collaboration with a number of BPA staff across a range of departments. E3 greatly appreciates the assistance of BPA's transmission planning team, including Anthony Radcliff, Kendall Rydell, and Kyle Kohne. E3 also thanks the following BPA staff for their support and input: Joshua Binus, Ravi Aggarwal, John Anasis, Maryam Asgharian, Larry Bekkendahl, Frank Brown, Sarah Burczak, Tom Coatney, Sean Egusa, Richard Ellison, Anders Johnson, Hardev Juj, Steven Knudsen, Mark Korsness, Stacy Mason, Ottie Nabors, Lauren Nichols-Kinas, Melvin Rodrigues, Brian Silverstein, Mark Symonds, Travis Togo, Joshua Warner, Mike Weedall, Jennifer Williamson, and Nancy Wittpenn.

Executive Summary

In January 2011, Energy and Environmental Economics (E3) completed a high-level screening study[1] (Phase 1 study) which determined that the non-wires measures could not replace the need for Bonneville Power Administration's (BPA's) proposed I-5 Corridor Reinforcement Transmission Project (I-5 transmission project, or I-5 project) but may be able to defer the project's energization date. The primary non-wire measure E3 identified is operational, redispatching certain generators at peak times to reduce transmission flows along the I-5 corridor below the path ratings. In addition, energy efficiency (EE), distributed generation (DG), and demand response (DR) measures were identified. The Phase 1 study highlighted the need to determine the feasibility of implementing these measures, which is the focus of this Phase 2 study.

Phase 2 Findings

With a few specific cautions discussed below, E3, with transmission power flow support from BPA, has confirmed that BPA could defer the I-5 transmission project energization until spring 2022 while maintaining the forecasted summer peak transmission flows below 2015 levels (the year before the I-5 project would need to be energized if no non-wires measures are used) by contracting with certain generators to redispatch. In order to achieve the deferral, BPA

[1] http://www.bpa.gov/corporate/i-5-eis/documents/ScreeningStudy_NonWires_I-5_Corridor_Jan2011.pdf

would also need to make upgrades to the Pearl substation. These Pearl substation upgrades would be redundant once the I-5 transmission project is built. A preliminary analysis of recent energy market prices also indicates that the cost of redispatch contracts, plus the Pearl substation upgrades, could be lower than the present-value savings from deferral of transmission project construction.

The specific cautions that remain include the following:

1. The evaluated non-wires measures could meet the current minimum reliability planning criteria up to spring of 2022[2] while deferring the line, but the measures are not expected to be a full or permanent replacement for the I-5 project. Once energized, the I-5 transmission project would provide more operational flexibility and reliability than the non-wires measures can provide.[3]

2. The primary non-wires measure is an operational solution, actively redispatching generation on a day-ahead or day-of basis when certain conditions are expected to create peak transmission flows. This study provides the operational requirements, but has not evaluated how redispatch could be reliably incorporated into BPA's current real-time transmission operations protocol. BPA is currently evaluating operational challenges related to redispatch, which may create further constraints on feasibility beyond those evaluated at a planning level.

[2] Or up to spring of 2024 under a sensitivity case with one Centralia generation unit retired.
[3] It was not feasible to include a valuation of this additional flexibility in this report; BPA transmission operations staff could separately assess the relative flexibility from redispatch compared to the I-5 transmission project only after establishing basic parameters for how operational protocols for implementing redispatch would function.

These operational issues may include concerns such as redispatch requirements during maintenance outages, identification of proper indicators for when to anticipate the need to implement redispatch, and ability of generators to respond at times when needed.

3. The non-wires option requires participation of certain regional generators. Again, this study provides the requirements, but has not engaged with potential counterparties to determine whether they would be willing to sign a redispatch contract at a cost-effective price to BPA. Counterparties may also be unwilling or unable to provide redispatch in the quantities that BPA would require.

Implications & Next Steps

Since these are outstanding issues that could make the non-wires measures infeasible or uneconomic, BPA should continue the process for completing the I-5 transmission project on its current schedule. Once the operational protocol and contracting processes are finalized, BPA could make a final determination of whether to pursue deferral using the non-wires option.

There are two primary considerations on a longer term basis if BPA chooses to pursue redispatch contracts to defer the I-5 project. First, BPA would need to periodically review ongoing changes in local load growth, transmission project development and generator construction and retirements. Potential developments, such as, for example, the retirement of Centralia units, or the siting of a new gas generator on the Portland side of the South of Allston transmission path, could further adjust the need date for I-5 transmission project energization and the amount of generator redispatch required for deferral. Depending on the location of generator additions or retirements, these changes could bring the I-5 project need date sooner in time or could push it later.

Second, an increased focus on conservation and DR targeting summer peak loads, plus improved coordination with Portland General Electric's (PGE's) own DR programs, could reduce the amount of redispatch required for significant deferral in the longer term. It is important to note that the estimate of DR included in this analysis of non-wires options is conservative. The expected contribution from EE and DR toward transmission project deferral must be evaluated conservatively (resulting in a smaller estimate than the total technical potential) due to the fact that a transmission construction schedule would be difficult to advance if EE and DR were assumed to enable deferral but then created less reduction in peak loads than expected. This analysis is based on a screening tool that identifies measure potential based on high-level aggregated data and applies conservative adoption rates for these measures.

In particular, there are two important areas in which more analysis by BPA staff could be useful for potentially identifying higher levels of DR contributions than have been shown here. First, this screening level analysis was not able to look at specific industrial activities and individual customers in the area. Additional research by BPA in assessing DR potential with specific industrial power users in the greater Portland area may be able to identify additional non-wires opportunities that could be complementary to the measures included in this study. Secondly, PGE has ambitious targets for DR in its own integrated resource plan. Initial discussions with PGE showed that coordination challenges for DR use under current operational arrangements could currently prevent BPA from being able to count on PGE's DR measures for deferring I-5 transmission upgrades; however, in many hours PGE may choose to use this DR for its own needs during hours that would be helpful for relieving power flows on key I-5 transmission paths. Thus, it would be worthwhile for BPA's DR staff to explore in more detail potential opportunities to coordinate DR activities, such as obtaining advanced notice on days when PGE plans to make use of its own DR resources. Common DR software platforms may assist in potentially enabling benefits from shared coordination.

Thus, this analysis indicates that it would be complementary for BPA's DR staff to provide additional analysis of industrial DR options as well as improved coordination of DR activities and procurement between BPA & PGE. Identifying additional DR opportunities would be a particularly beneficial activity if BPA were able to use redispatch contracts to defer I-5 project construction. In that situation, redispatch contracts could serve as an "anchor" or backstop option for reducing flows on key I-5 paths.[4] Any achievement and funding of DR and other demand side non-wires options, such as targeting of EE programs measures that affect summer peak loads, could then be used to reduce the total amount of redispatch that BPA ultimately needs to call on and make payments for during times of high summer paths flows on I-5. To the extent that BPA staff could identify and contract for more DR than the amount shown by the estimates here, that additional DR could help minimize BPA's need to call on redispatch, as well as providing additional margins of safety from an operational perspective.

[4] On their own, conservatively identified estimates of cost-effective local non-wires measures, including EE, DR, and distributed generation (DG) that could be implemented appear unlikely to enable sufficient transmission flow reduction to defer the I-5 project need by more than a year. BPA transmission planners set a target of four years or more as a threshold for deferral options for this project due to the potential for unanticipated changes in load and project scheduled issues. Based on our analysis, however, many demand side= measures are economic on their own and are already included in the longer-term energy plan for the region.

Any incremental DR measures could also be kept in place after their need for I-5 deferral, and thus could potentially serve as long-term assets for addressing other needs.

Finally, using DR to reduce I-5 path flows would need to address similar operational issues to generation redispatch. Therefore, the work that BPA's transmission operational staff has underway to evaluate the feasibility of generator redispatch would also be useful for obtaining maximum benefit of DR resources in relieving transmission flows.

1 Background

In January 2011, E3 completed a high-level Phase 1 screening study,[5] which determined that the non-wires measures could not replace BPA's proposed I-5 transmission project,[6] but may be able to defer the project's needed energization date. The primary non-wire measure E3 identified is operational, redispatching certain generators at peak times to reduce flows below the transmission path ratings along the I-5 corridor. In addition, EE, DR, and DG measures were identified. The Phase 1 study highlighted the need to determine the feasibility of implementing these measures, which is the focus of this Phase 2 study.

1.1 I-5 Transmission Project Need

BPA transmission studies show that projected increases in summer power flows over the transmission paths in the I-5 corridor north of Portland could create an unacceptable level of risk as soon as summer 2016. As a result of projected Portland area summer peak load growth, combined with high levels of power transfers over southern interties, I-5 transmission paths flows are expected to increase by summer 2016 to a level at which an outage on one or more of the high-voltage lines during the peak load period could lead to damage on parallel

[5] http://www.bpa.gov/corporate/i-5-eis/documents/ScreeningStudy_NonWires_I-5_Corridor_Jan2011.pdf
[6] For information about the proposed I-5 project from BPA, see: **http://www.bpa.gov/corporate/i-5-eis/**.

lower voltage lines in the area or outages for customers. Currently, in the event of an outage on one of the 500 kV lines on the constrained I-5 transmission paths, power would typically shift to flow over the lower voltage lines that parallel the 500 kV system. As the overall summer peak flow on the I-5 transmission paths increases in response to Portland load growth, flows would exceed the capacity of lower voltage lines, resulting in equipment damage and causing more subsequent line outages if there is an outage on the I-5 500 kV transmission paths.

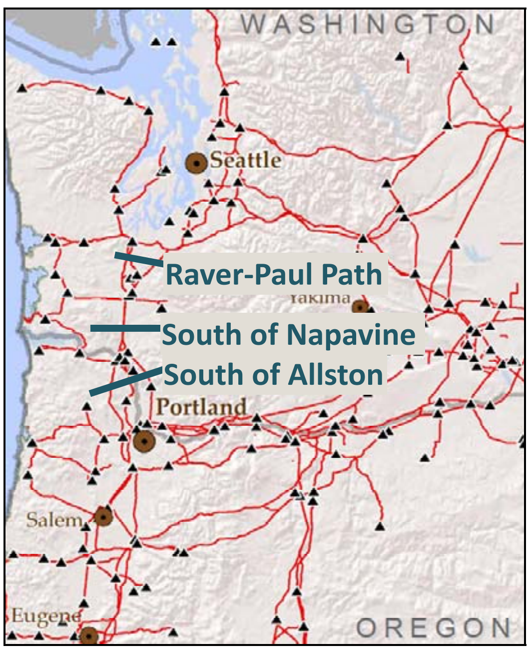
The two 500 kV transmission paths with projected risk of overload are titled South of Allston (SoA) and South of Napavine (SoN). When forecasted peak power flows on the SoA path rise to near the path's operating limit, BPA prepares operational responses to curtail generation and make other system adjustments in the event of an outage. BPA currently employs a remedial action scheme (RAS) that would automatically drop up to 2,700 MW of generation to the north of the constrained transmission path in the event of an outage to reduce flow on the path, but BPA faces limits on the total amount of generation it can drop as part of a RAS. Any response to shut down generation after a contingency must occur within seconds to avoid voltage problems on SoN.

In addition to the RAS, when power flows on SoN are above a certain threshold, BPA readies an operational response called the South of Chehalis Sectionalizing Scheme (SOCSS) to protect the lower voltage lines on the path during a contingency. SOCSS protects the lower voltage system by opening the circuits of the lower voltage lines during a 500 kV outage, effectively disconnecting, or "sectionalizing" the lower voltage system. This causes any power that would typically be flowing south along the I-5 Corridor toward Portland to instead flow over lines located east of the Cascades, going southward to Boardman and then flowing westward to reach Portland via the West of Cascades South path. The large and rapid shift in power flows that would result from implementing SOCSS could increase the risk of local voltage instability problems in the Portland area under certain operating conditions.

BPA transmission studies indicate that the I-5 transmission project would increase the total transfer capability (TTC) ratings on the SoN and SoA paths, allowing higher levels of power flow over these paths without the projected risks to system reliability. The I-5 transmission project could also remove or reduce the need to ready RAS and SOCSS to prepare for an outage on these paths.

A map of the approximate location of the key transmission paths in the I-5 corridor is shown in the figure below. The red lines in the map represent transmission facilities on the BPA system, and the black triangles are high voltage substations. The three horizontal blue lines perpendicular to the I-5 corridor represent the three official transmission "paths", each of which is composed of a group of transmission lines which are collectively subject to a maximum limit on transmission loading (also termed power flow on the path).

Figure 1. Diagram of I-5 Corridor transmission paths



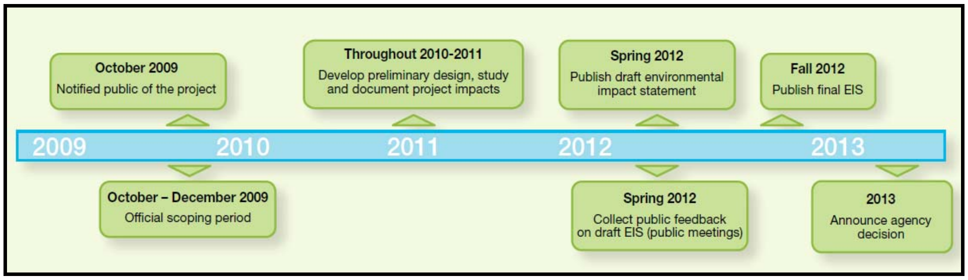
1.2 I-5 Transmission Project Details

The proposed I-5 transmission project includes construction of a new 500 kV line approximately 70 miles in length to connect two new proposed substations in Castle Rock, Washington and Troutdale, Oregon. The exact route of the project is still under consideration. BPA's current power flow analysis indicates that the line would need to be energized by spring 2016 to avoid the risk of overloads on two critical transmission paths along the I-5 Corridor during summer peak-load conditions. Planning, permitting, and constructing a transmission project of this size requires a considerable lead time, and to have the I-5 project operational by spring 2016 would require BPA to engage in numerous activities throughout the next four years.

1.2.1 ASSUMED TIMELINE

BPA's published timeline (as of December 2011) for project study, permitting, and agency evaluation is shown in the figure below. Currently, the draft environmental impact statement (EIS) is expected to be published in spring of 2012. If BPA decides to proceed with the line after the environmental review is complete, construction would require approximately two years for completion.

Figure 2. BPA I-5 Project timeline as of December 2011[7]



[7] http://www.bpa.gov/corporate/i-5-eis/documents/factsheet_I-5_Corridor_Reinforcement_December_2011.pdf

1.2.2 COSTING ASSUMPTIONS

BPA has estimated the direct cost of the I-5 project line and two substations to be $342 million dollars (in 2010 dollars). Of the total cost, an estimated $128 million is related to land purchases required for the transmission line, and we considered these costs non-deferrable, recognizing that it is likely in BPA customers' and the region's best interest for the land to be purchased on the original schedule if the transmission project construction will eventually be required.[8] Excluding the non-deferrable costs from the analysis brings the net cost of the proposed I-5 project to $214 million, which is the cost used in the non-wires alternatives analysis.

1.3 Phase 1 Non-wires Summary

The Phase 1 Study determined that non-wires measures could not replace the need for the proposed I-5 project; the study also provided a preliminary screening-level assessment of the potential for non-wires alternatives to defer the proposed I-5 project. The Phase 1 screening study utilized an analytical approach developed as part of the BPA's Non-Wires Solutions Roundtable to evaluate whether it would be possible to defer the proposed I-5 project through a combination of EE, DR, existing generation, and new generation. To the extent possible, the analysis also assessed whether these alternatives would be cost-effective from a Regional Cost Perspective[9] by comparing the cost of the

[8] Technical analysis indicates the project will eventually be needed, even under the most aggressive use of non-wires deferral options. Since no scenario indicated potential for the I-5 project to be permanently deferred, the economic analysis did not consider potential recovery of this non-deferrable cost portion at a later point in time.

[9] The Regional Cost Perspective, which is similar to the Total Resource Cost perspective, is a method of comparing the costs and benefits of a particular alternative to the costs and benefits of a proposed solution (such as the I-5

non-wires measures to the cost of building the transmission line on its projected schedule.

The Phase 1 screening-level analysis addressed uncertainty regarding load growth in the greater Portland area (and resulting effect on increased loading on I-5 transmission paths that serve Portland) by evaluating non-wires measure potential under two load growth cases to reflect different assumptions of economic recovery and growth in the area.

The Phase 1 study screening analysis indicated that cost-effective EE, DR, and DG, on their own would not reduce I-5 flows sufficiently to defer the proposed transmission line. The Phase 1 study also indicated, however, that if cost effective EE and DR measures could be combined with contracts to "redispatch" generators located to the north and south of the constrained I-5 paths, the actions could potentially defer the need for the proposed I-5 project by five or more years.

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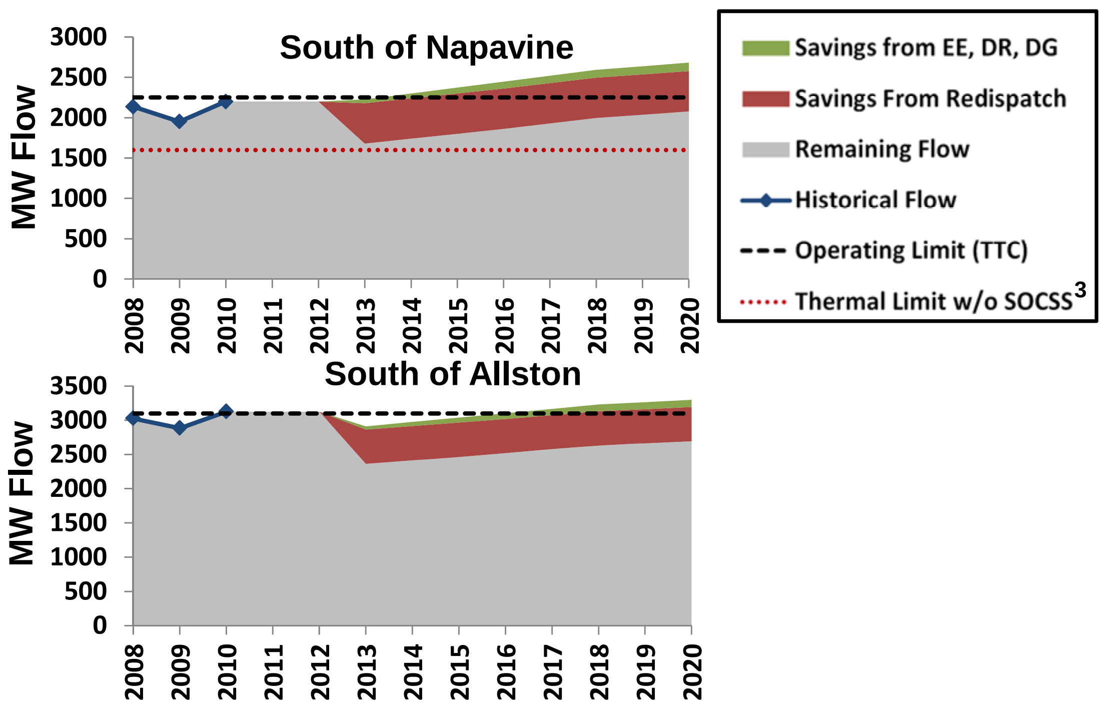
project). Unlike certain other perspectives, the Regional Cost Test does not consider the potential allocation of benefits and costs among stakeholders, such as the utility and participating customers, but rather evaluates the aggregate costs and benefits for the region as a whole. See **http://transmission.bpa.gov/PlanProj/Non-Wires_Round_Table/NonWireDocs/P3.pdf**

The figure below (reproduced from the Phase 1 study) uses the lower load forecast from the Phase 1 analysis, and shows the projected overloads on the SoN and SoA transmission paths, the potential of screened Phase 1 non-wires measures for reducing these flows, and the remaining flow (net of identified non-wires potential) on these paths. The figure indicated that with no non-wires measures implemented, the SoN path flow would be expected to exceed the path's transmission constraints in 2015 and remains well above the path's 1,600 MW thermal limit without the SOCCS in place.[10]

Figure 3. Phase 1 Identified non-wires potential and resulting flows.



[10]When SoN path flow exceeds 1,600 MW, BPA must prepare to implement the SOCCS as an operational response to protect the lower voltage lines on the path during a contingency by opening the circuits of the lower voltage lines.

The Phase 1 study recommended that BPA explore the identified non-wires measures for line deferral in greater depth, with particular focus on the potential economic and technical feasibility of the generator redispatch options. The Phase 1 study also recommended that, in parallel to performing a non-wires implementation feasibility analysis, BPA maintain its current schedule for permitting the I-5 transmission project, in case the non-wires measures prove infeasible for enabling project deferral.

1.4 Organization of this Phase 2 Report

Chapter 2 of this report describes the analytical approach taken to evaluate the feasibility and effect of implementing redispatch measures and local demand side non-wires measures for project deferral. Chapter 3 identifies the study's findings on feasibility of redispatch, the primary source of potential to defer the I-5 project. Chapter 4 identifies the complementary contribution that EE, DR, and DG could make (on top of redispatch) to help defer project need. Chapter 5 summarizes the study's conclusions, cautions, and recommended next steps for determining the viability of the non-wires options.

2 Approach

2.1 Overview of Approach

The Phase 1 I-5 Non-wires study provided an initial screen of the potential of non-wires measure to enable line deferral. This Phase 2 analysis provides more in-depth analysis of the implications and feasibility of the identified measures, with particular emphasis on redispatch, the non-wires option with the highest deferral potential.

This chapter describes our approach to provide a more in-depth assessment of I-5 project deferral. The following six steps were taken:

(1) Update local area load forecast
(2) Update power flow analysis base case (without non-wires measures)
(3) Develop redispatch feasibility assessment
    a. Screen and select potential redispatch cases
    b. Rerun power flow cases with redispatch measures in place
(4) Develop demand side measure (DSM) assessment
    a. Analyze demand side measures cost and potential
    b. Analyze flow impact of DSM
(5) Feasibility analysis of redispatch (Chapter 3)
(6) Feasibility analysis of DSM (Chapter 4)

2.2 Update Load Forecast

In the Phase 2 analysis we update the load growth forecast used to evaluate the need for the I-5 project. While loads for the entire Western Interconnection were updated, we focused on the forecast for the greater Portland area. The expected peak load level in the Portland area, immediately south of the I-5 corridor project, has the greatest impact on project need. This analysis replaces the high and low scenarios developed in Phase 1 with a single base case load forecast.

To develop the updated forecast, we combined the most recent forecasts of the local utilities in Portland and the surrounding region (June 2011), taking care to account for the various methods used by the local utilities, and through use of various benchmarking metrics.

2.2.1 GREATER PORTLAND AREA LOAD FORECAST

The PGE load forecast used for this analysis is PGE's own June 2011 long-term forecast for load growth in its entire control area. This summer peak high growth forecast is based on a temperature level expected to be reached or exceeded once every five years (1-in-5 peak forecast). The 1-in-5 forecast is used by PGE's transmission planners when evaluating reliability issues and the need for capacity expansion projects. The forecast is based on a regression of a number of factors affecting load growth for separate customer classes, including expected economic conditions and population, and estimates of load additions and reductions for specific large industrial customers. The forecast used is PGE's "high" growth rate case, which accounts for a higher level of response of PGE load growth to underlying drivers such as employment and economic conditions.[11] The forecast also incorporates the effect of recent conservation programs from historical data, assuming the net effects of conservation programs (in reducing annual growth) will continue for future years at approximately the historical level.

The load forecast for PacifiCorp service territory in the Portland area was based on the latest 1-in-5 summer peak load forecast (from May 2011), which accounted for load growth through a regression of historical growth and projected economic conditions for the area.

The Clark Public Utilities District (PUD) forecast (from June 2011) is also based on a regression of historical data; however, it is developed as a 1-in-2 summer peak. Therefore, Clark's 1-in-2 summer peak forecast is a lower (less conservative) forecast regarding temperature's effect on peak summer loading than was used for PGE and PacifiCorp's 1-in-5 forecasts. This forecast, however, is reflective of Clark's forecast method and Clark does not produce a 1-in-5 peak forecast.[12]

The forecast used for Clark is identical to the load forecast that Clark submitted to BPA and WECC for typical power flow planning studies. This forecast incorporates the effect of conservation programs on load growth into the historical data trend. A load forecast for Clark was also prepared independently

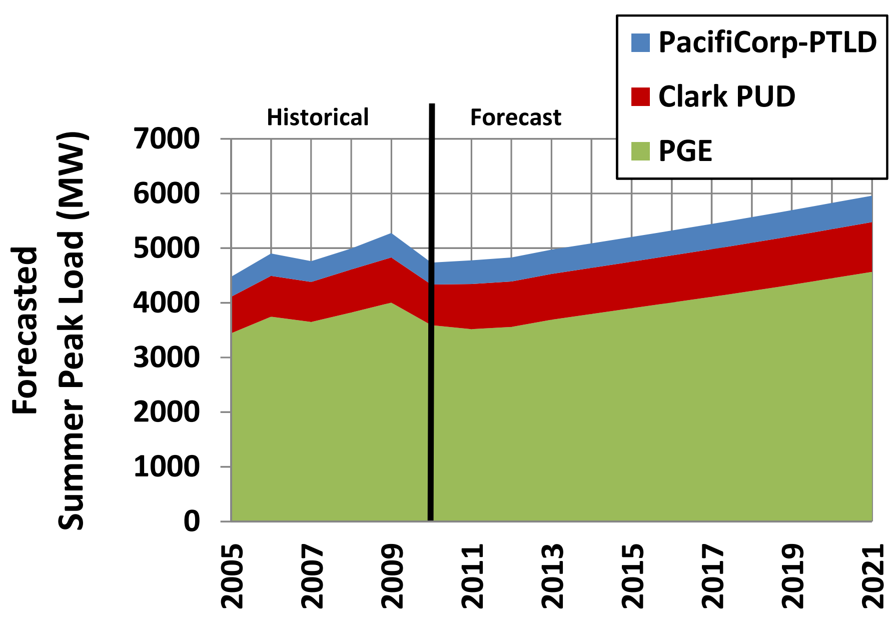
[11] The load growth rate in the PGE high growth case is calculated as the sum of PGE's base case growth rate plus one statistical standard error of the regression estimate used to calculate the growth rate. The regression equation would estimate a 16% chance that the high growth rate could be exceeded. This high case is conservative when used for transmission planning by PGE to reflect the need to have transmission facilities already completed if growth exceeds the central estimate.

[12] The effect on I-5 transmission flows from each MW of load growth in Clark PUD is approximately equal to the effect for load growth in the PGE service, so using the combination 1-in-5 peak for PGE with 1-in-2 peak for Clark should not cause problems in the power flow analysis. In effect, the loads forecast for the aggregate area (PGE, Clark, and PacifiCorp Portland) reflect a summer peak slightly less extreme than 1-in-5.

by BPA's internal load forecast staff; the results matched closely with Clark's own analysis so Clark's data was used.

The chart below shows the aggregated load forecast for the three utilities in the Portland area that create the greatest direct impact on I-5 path flow. PGE's summer peak load is projected for this analysis to grow by 2.2% annually between 2010 and 2021, from 3,591 MW to 4,566 MW. Collectively, the modeled summer peak for utilities in the area (PGE, Clark PUD, and PacifiCorp's Portland-area loads) is projected to increase 1,225 MW between 2011 and 2021 (from 4,735 MW to 5,960 MW), a 2.1% annual growth rate. For the purposes of this analysis we assume that the utility's peak demand is coincident which is a conservative forecast assumption.

Figure 4. Summer Peak MW Forecast used for Phase 2 Analysis - Greater Portland Area



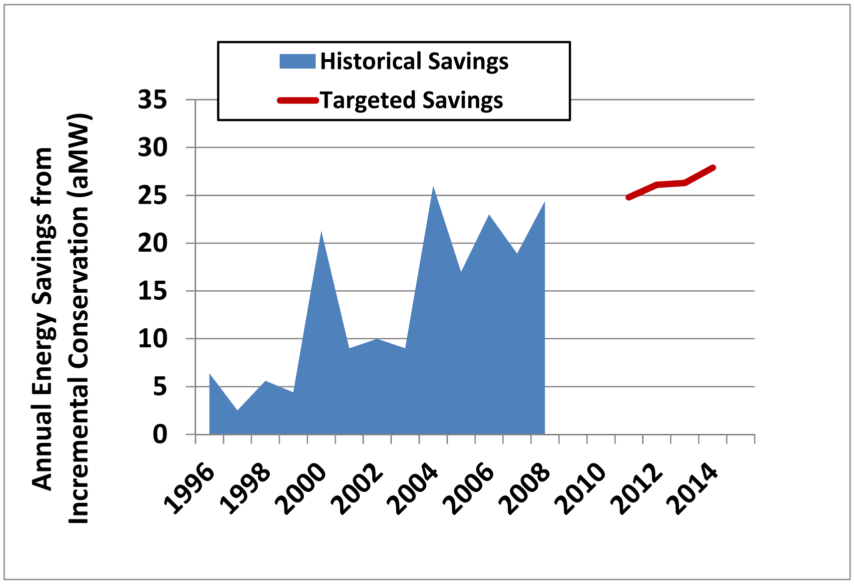
2.2.2 EMBEDDED CONSERVATION IN FORECAST GROWTH RATES

For Clark, PGE, and the Portland area portion of PacifiCorp territory, the levels of conservation in recent years is embedded as a trend into the forecasted rate of growth for Clark, PGE, and PacifiCorp, meaning that the baseline forecasts assume that the programs will continue to achieve additional conservation at similar rates to those achieved in recent years. That is, the baseline load forecasts described in this chapter are net of the assumed effect of the bulk of recent years' current annual levels of conservation achievement and assumed continuation at similar levels for future years. To the extent that the utilities increase conservation programs beyond the levels achieved in recent years, the incremental effect of that larger amount of conservation would reduce loads relative to the baseline forecast.

For example, PGE's load forecast is created using an auto-regressive (AR) econometric model that effectively uses economic forecast data, as well as historical growth rates, to project the annual change in PGE loads. The historical growth rates used in PGE's forecasting analysis reflect the effect of efficiency programs funded under Oregon Senate Bill (SB) 1149 as well as more recent additions as part of Oregon Senate Bill 838. The annual conservation savings achieved in PGE territory is higher over the last 5 years than it had been during the 2000 to 2004 period. PGE's AR econometric model, however, places a greater weighting on historical load growth data from recent years, so the forecast more closely reflects ongoing annual new conservation savings at levels similar to the last five years of data than to the level in earlier years of the historical period.[13] Future conservation targets for the PGE service territory by the Energy Trust of Oregon (ETO) are larger than those achieved in the most recent years; PGE's load model does not account for this incremental increase in efficiency program targets over and above current levels. Overall, PGE staff estimate that the current model using historical data incorporates approximately 75 to 85% of the anticipated conservation target.

The table below compares historical load reductions in PGE territory to annual conservation targets under both SB 1149 and SB 838 funding.

Figure 5. PGE Historical and Targeted Annual Energy Savings from Incremental Conservation, =1996-2020



[13] The full PGE regression analysis incorporates historical data back to 1990.

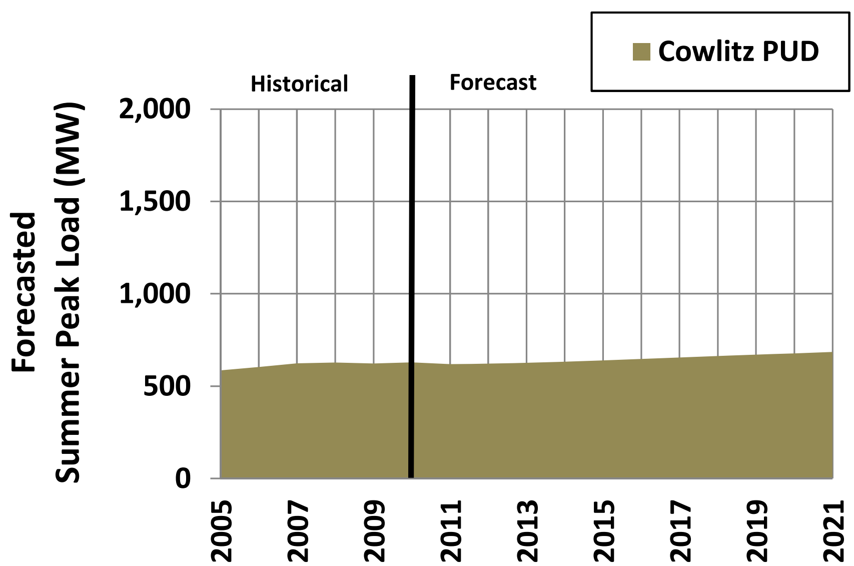
The conservation potential for use as a non-wires option that focuses on summer peak demand reduction is assumed to be incremental to the efficiency embedded in the baseline forecasts. This assumption has been made because of the uncertainty in the amount of energy efficiency in the baseline forecast and provides an optimistic estimate of the total impact of energy efficiency as a non-wires alternative for the purposes of this study. As shown in the results of this study, energy efficiency has a relatively small impact on the need date for the line even with the optimistic assumption. In other non-wires studies where energy efficiency may play a bigger role (such as the Hooper Springs Transmission study) it may be more appropriate to estimate the embedded efficiency in the forecast and apply only the net energy efficiency savings to the baseline forecast.

2.2.3 COWLITZ PUD LOAD FORECAST

The Phase 2 analysis also used an updated summer peak load forecast for the Cowlitz PUD service territory. The forecast, from June 2011, was produced by BPA's load forecasting staff, but BPA verified that the results match closely with Cowlitz's own internal forecast. The forecast is based on a regression of historical data and represents a 1-in-2 summer peak, similar to the forecast used for Clark PUD. The effect of ongoing annual conservations efforts at current levels on annual load growth is embedded into the Cowlitz load forecast. The forecast is also adjusted to subtract the effect of two large industrial customer conservation projects expected to be fully in place by 2015.

The Cowlitz summer peak forecast is shown in the figure below and is displayed separately from the forecasts for Clark, PGE, and PacifiCorp because Cowlitz is located to the north of the SoA path. As a result, summer peak load growth in the Cowlitz service territory typically has a downward effect on north-to-south flows over the SoA path.[14] By contrast, load growth in Greater Portland area for PGE, Clark, and PacifiCorp leads to an increase in summer peak path flow on SoA.

Figure 6. Summer Peak MW Forecast used for Phase 2 Analysis – Cowlitz PUD



[14] Similarly, load growth in the Puget Sound area, over and above the level forecasted in the WECC heavy summer powerflow case used for this analysis for that area, would reduce flows on both the SoA and SoN transmission paths because the Puget area is located north of both paths. Load forecasts used in the model are of a similar vintage, but many are provided independently by different utilities which use a range of forecasting methodologies. In the long-term it could be beneficial for future non-wires analysis for a regional entity to create a single load forecast for the region based on a common methodology and set of assumptions.

For loads outside of the focus area of this analysis, peak load forecasts are based on forecasts provided by individual load serving entities to the Western Electricity Coordinating Council (WECC) in 2010, and incorporated into WECC's Heavy Summer (HS) power flow cases for 2016 and 2021 (HS2016, HS2021).

While the study is based on the latest load forecasts available at the time of the analysis, expected growth may continue to change in response to a number of conditions. If BPA chooses to pursue non-wires measures, it will be important to periodically monitor and update load growth forecasts to know as quickly as possible whether loading limits are expected to be reached sooner or later than first modeled.

2.3 Update Power Flow Analysis Base Case

2.3.1 BACKGROUND: DESCRIPTION OF POWER FLOW ANALYSIS

Power flow analysis is an industry standard methodology used by transmission planners for a variety of evaluations, including the need assessment for new transmission facilities. A number of commercial software tools are available to transmission planners for running power flow cases. A power flow case models a snapshot of how electricity would flow over a transmission system as a function of a given set of inputs consisting of:

1. Transmission network topology and facility ratings

2. Electric loads withdrawing defined amounts of power at particular bus locations on the transmission system

3. Electric generators injecting defined levels of power into the transmission system at particular bus locations.

Based on these inputs, the power flow model will simulate the loadings on particular transmission facilities (both lines and substations) under a base case with all transmission facilities in service. To find areas of concern, the power flow modeler will run contingency situations such as line or generator outages to determine whether these present a reliability concern on a particular transmission facility. To meet North American Electric Reliability Corporation (NERC) and WECC reliability criteria, planners will typically assess contingencies involving the loss of one transmission element (N-1), or at times two elements that are in a common location. After running all the possible contingencies, the transmission engineer then identifies lines that are either near 100% of their thermal load limit or areas in which voltage may be lower or higher than acceptable. The transmission planning study will typically indicate a "project need date" for a new facility based on the last year before a contingency would cause a system problem.

2.3.2 UPDATE OF BASE CASE POWER FLOW SCENARIO

Using the updated greater Portland area load growth forecast, plus the WECC heavy summer base case data for the rest of the WECC, E3 worked with BPA's Transmission Planning staff to create updated power flow cases simulating summer peak flows on key I-5 paths for summer snapshots in two years: 2016 and 2021.

This updated power flow analysis modeled generation on-line with a mixture of firm and non-firm transmission access. The generation patterns modeled are intended to simulate stressed, but realistic, summer conditions. The updated case maximized California power exports to the rated path limits to reflect contractual obligations and associated upgrades on the California-Oregon Intertie (COI) transmission facilities.

Compared to the original I-5 Corridor Reinforcement power flow cases, which were completed in 2007 and indicated a 2015 need date for the I-5 project, the updated results model a slightly reduced load growth rate for PGE and Clark PUD. The updated study also reflects two transmission system changes:

(a) West of McNary Reinforcement (WOMR) transmission upgrades including the new McNary-John Day and Big Eddy-Knight 500 KV lines, which alone would push the need date for the I-5 project by one year,

(b) Increased flows over interties to California to reflect upgrades that have recently been completed on the COI. This 600 MW intertie flow increase would speed up the I-5 need date by approximately one year, offsetting the effect of WOMR.

The power flow analysis, implemented by BPA staff, models line loading on all major transmission facilities in the WECC to analyze the risk of thermal and voltage criteria violations under a wide range of facility outage conditions.

Without non-wires measures in place, updated base case power flow analysis indicates the potential for transmission planning criteria violations by the summer of 2016, which implies the need to energize the I-5 project transmission upgrades by the spring of 2016. The limiting outage on the SoA path would be the loss of either the Keeler-Pearl or Allston-Keeler 500 KV transmission line, which would cause the parallel lower voltage facilities to overload. The limiting thermal outage on the SoN path is the double line loss of the Paul-Allston #1 and #2 500 kV lines, which would cause the parallel lower voltage facilities to overload and could cause local voltage instability.

2.3.3 CENTRALIA SENSITIVITY

The 1,400 MW Centralia coal plant, immediately north of the I-5 project, is a key driver to the loads on the I-5 transmission path. Washington state legislation passed in 2011 has mandated the retirement of one Centralia unit by the end of 2020 and the second by 2025. To evaluate the non-wires alternatives through 2021, an updated transmission power flow case for 2021 models both Centralia units as online so that years 2017 to 2020 can be evaluated through interpolation of the 2016 and 2021 load flow cases. An additional case has been run for 2021 which reflects the planned retirement of one Centralia unit in 2020 to reflect the Washington state legislation. The non-wires measures studied would need to defer I-5 project through the end of 2020 (with both Centralia units online) to reach the retirement of the first Centralia unit. The 2021 case with retirement of one Centralia unit assumes that the generation from that unit is replaced by a mix of additional output from natural gas generators in the I-5 corridor as well as additional production from hydroelectric units on the upper Columbia.

2.3.4 OUTAGE CRITERIA & PEARL SUBSTATION SENSITIVITY

The power flow analysis assesses project need both for thermal and voltage-related issues on the SoA and SoN paths under a variety of N-1 contingencies, as well as critical common-mode failure such as breaker failure outages at substations.

The base case power flow analysis shows the limiting condition to be thermal overload issues triggered by the loss of either the Keeler-Pearl or Allston-Keller 500 kV lines anticipated to occur by summer 2016. A series of upgrades to the Pearl substation could potentially mitigate this issue and defer the project need date up to two years (requiring energization by spring of 2018). The need date is estimated by interpolating expected line flows between the 2016 and 2021 cases based on the load growth level for PGE. These Pearl substation upgrades were not envisioned in the original analysis of transmission options for the I-5 corridor because they could not enable long-term project deferral on their own, and they would become redundant in the long-term once the I-5 transmission project is in place. Thus, the economic comparison of deferral options includes the full cost of the Pearl upgrades as additive to the total cost of other non-wires measures, because the substation would not be needed if the full I-5 project is not deferred.

2.4 Screen and Select Potential Redispatch Cases

After creating the updated power flow base case, E3 worked closely with BPA to create a set of plausible generator redispatch scenarios, each of which involved making increases in output to one generator and a comparable reduction in output at another generator.

Prior to evaluating the redispatch power flow cases, E3 screened the options to exclude obviously infeasible or ineffective options. For each combination of generators evaluated, we verified the following:

(1) The generator increasing its output during redispatch had sufficient unloaded capacity in the power flow base case.

(2) The generator reducing its output during the redispatch had at least the amount of generation online to be decreased.

(3) The location of the increasing and decreasing generators would be effective at reducing the flow on the critical I-5 SoA path.

(4) E3 and BPA staff did not identify any other obvious constraints on changing dispatch (operational limitations, environmental constraints on hydro flow, existing long-term contracts, RAS commitments, etc.).

BPA's staff indicates that Federal hydroelectric units would be unable to provide significant summer redispatch capability on a long-term basis due to environmental constraints on output, existing ramping obligations, and uncertainty about hydro availability in future years. For example, in certain years with heavy rainfall (high water years), the hydro units could potentially be unable to reduce output when needed for redispatch due to environmental constraints on the dam's ability spill water flow (instead of using it to generate power). By contrast, during low water years, there may be insufficient hydro energy available to ramp up production during hours that it would be needed for redispatch.

E3's redispatch list included 17 redispatch options, some of which included thermal generators in the I-5 corridor, hydro generation in the Northwest, and intertie flows in and out of the BPA system. The capacity of generators and interties considered for redispatch ranged from 300 MW to 1,400 MW.

2.5 Run Power Flow Cases with Redispatch

BPA analyzed each of the 17 redispatch cases by re-running the 2016 and 2021 power flow cases with the adjustment to the individual generators identified as feasible combinations. The redispatch power flow cases resulted in new I-5 transmission project need dates for each case, and represent a more robust screening of redispatch measures possible in Phase 1. For example, redispatch may relieve I-5 flows on South of Alston but increase flows on other transmission paths (such as Raver-Paul, in the northern portion of the I-5 corridor), resulting in another condition limiting or affecting the need date for I-5 upgrades.

The updated cases were simulated with and without Pearl substation upgrades in place. Additionally, redispatch options that enabled deferral until the end of 2020 were also analyzed to identify if they would enable additional years of deferral if one Centralia unit is retired at the end of 2020.

In assessing the potential effect of redispatch options, the power flow analysis identified generators in the I-5 corridor that may be expected to be curtailed as part of a RAS in the event of an outage. If these generators are redispatched (to reduce their output), then the units would have less remaining online generation that could be curtailed under a RAS if a transmission outage occurred. This change would reduce the effectiveness of the RAS. Therefore, the analysis carefully avoids double-counting potential flow reductions that would result from redispatch of these generators and curtailment under RAS.

2.6 Develop Demand Side Measures Assessment

In addition to redispatch, E3 also provided a high level assessment of the feasibility of implementing demand side measures including EE, DR, and DG to enable project deferral.

This analysis involved application of the following feasibility screens:

1. Updated screening tool used in E3's Phase 1 study to reflect updated estimates of transmission project need, load levels, and measure adoption rates. The methodology of this tool is described in detail in Chapter 4 and 5 of E3's Phase 1 study.[15]

[15] Available at:
http://www.bpa.gov/corporate/i-5-eis/documents/ScreeningStudy_NonWires_I-5_Corridor_Jan2011.pdf

2. Compared screening level results to historical conservation and DR program achievement levels for utilities serving the Greater Portland Area (as well as the Energy Trust of Oregon), and the targeted conservation and DR goals for those entities.

3. Analyzed potential impact of conservation program end-use mix if existing conservation programs could increase focus on end-uses that most greatly affect summer peak load growth (such as cooling loads).

4. Explored the potential of BPA to coordinate use of DR with local utilities in Portland area to call on DR resources in times of high loading on key I-5 transmission paths.

2.7 Analyze Flow Impact of Demand Side Measures

The power flow base case identified a project need date of 2015, implying that the I-5 project must be energized by the spring of 2016 to avoid projected overloads under a contingency for the summer of 2016). Thus, assuming no change in generation patterns from redispatch, to defer the project need date one year (requiring energization in spring 2017), the combined reduction from DSM would need to reduce load in the Greater Portland Area in 2016 to the level it is projected to reach in 2015, or lower. In order to achieve additional years of deferral, demand side measures would need to be sizable enough to maintain the Portland area peak load at or below the projected 2015 peak.

Table 1. Summer Peak Load forecast for Greater Portland Area (MW), 2012-2021

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Greater Portland Area Combined Load (MW)	4,829	4,972	5,088	**5,205**	5,323	5,441	5,567	5,696	5,827	5,960
MW above 2015 Level				0	118	236	362	491	622	755
MW above 2015 as a % of Forecast				0%	2%	4%	7%	9%	11%	13%

Based on the utility forecasts used in this study, the table above shows that combined Portland area summer peak load is expected to increase from 5,205 MW in 2015 to 5,323 MW in 2016, an 118 MW increase, implying that demand side measures would need to supply a 118 MW reduction in addition to the energy efficiency in the baseline summer peak load forecast to enable the first year of deferral of the I-5 project. Deferral each year thereafter would require an additional load reduction relative to forecasted levels of between 120 and 130 MW annually. Deferral of project energization until 2021 using demand side measures alone would require a 622 MW summer peak load reduction, or 11% of the forecasted peak load for 2021. Alternatively, demand side measures that provide only a portion of this required load reduction relative to forecast could potentially be combined with generator redispatch measures to enable project deferral. See Section 4 ("Feasibility Analysis of Demand Side Measures") for more information regarding the ability of demand side measures to reduce summer peak load in the Greater Portland area (and resulting I-5 transmission flows).

It should be emphasized that forecast shown in Table 1 represent a summer peak forecast, and do not indicate that powerflows will exceed transmission limits in every hour. E3's Phase 1 study indicated (based on historical path flow data) that potential overloads would likely be concentrated in the 12pm to 7pm time window on weekdays in July and August when Portland temperatures rise to high levels. Observation of the number of summer hours in which SoA RAS was at the fully armed level in recent years indicates that path flow typically nears the peak limits in 200 or fewer hours, though the number of hours of need could potentially increase as overall summer load levels in the Portland area increase. The SoA path limits for each hour can vary depending on the level of output from particular in-area generators so estimation of the duration required for flow reduction can be imprecise, but it is clear that the total need hours of need is relatively modest.

3 Redispatch Feasibility Analysis

3.1 Redispatch Description

The Phase 1 non-wires report identified generator redispatch as the non-wires measure with the greatest potential for enabling transmission project deferral. At a high level, generator redispatch would involve an arrangement similar to the following:

(1) BPA would identify two or more generators in the region that have operational flexibility to increase or decrease their output and have a combined effect large enough on flows over the SoA and SoN transmission paths due to their size and location to reduce path flow to an acceptable level.

(2) BPA would negotiate a "redispatch contact" with these generators, allowing BPA to pay the generator located to the north of the SoA path to reduce output by a certain MW amount when requested, and with a generator located to south of the SoA path to increase output when requested. The contract would likely specify a maximum number of times and season in which BPA could call on the generators to redispatch. The redispatch contract could be structured a number of

ways, but would likely include a combination of a fixed annual payment and a “pay per use” charge dependent on prevailing market conditions at the time of redispatch. Before deferring the transmission project, BPA would need to have a redispatch contract or a combination of redispatch contracts that could cover the years over which BPA would be expecting to defer the transmission project. While it would not be necessary for a single redispatch contract with the same generator to cover the full deferral period, BPA would need to have signed contracts for the full period before beginning deferral, rather than waiting to sign new single-year contracts on an annual basis.

(3) During a limited number of hours in the summer when high temperatures are expected to cause peak load in the Portland area, or other factors that are likely causing north to south flows on SoA to near the path’s limit, BPA would call on the pair of generator to “inc” and “dec” respectively, thereby reducing the amount of loading on the critical I-5 transmission paths. BPA would need to specify in the contract a length of notice that the generators would receive before needing to redispatch, and the process would need to be well tested and integrated into BPA’s operational protocols.

3.2 Redispatch Study Results

The updated power flow cases with redispatch in place indicate that contracting for generator redispatch (in a number of combinations evaluated) could enable BPA to defer the I-5 transmission project energization until spring 2022 while maintaining the expected peak path flow below 2015 levels (the year before the transmission project's needed energization date without non-wires measures in place). In order to achieve a deferral of this length, BPA would also need to make upgrades to the Pearl substation. This result includes a few specific cautions which are summarized in the next section.

Of the redispatch cases assessed some enabled only one year of deferral, while the larger redispatch options enabled deferral up to spring 2022 (assuming both Centralia units are online) or spring 2024 (with one Centralia unit online). No redispatch option analyzed (even those involving the redispatch of 1400 MW of generation) were anticipated to defer the project need beyond 2023. It should be noted that the years after 2021 were assessed by extrapolation beyond the 2021 case results, rather than by comparison of growth between two end-point cases which is more accurate, and that the uncertainty in load growth forecasts and other factors increase with longer periods. Therefore, there is uncertainty in the 2024 estimate. In addition, the redispatch cases evaluated were assumed to implement the redispatch non-wires measures alone, rather than in conjunction with local demand-side measures. If combined with redispatch, aggressive local non-wires measures implementation could potentially provide a partial substitute, slightly reducing the quantity of redispatch that would be required for a particular length of deferral, or potentially increasing the deferral period.

3.2.1 REDISPATCH ECONOMIC EVALUATION

For the redispatch options that appear to achieve significant deferral, E3 analyzed whether the redispatch contract costs based on forecasted market prices would be expected to be less than the benefits of deferral the I-5 project.

In this case, the non-wires alternative would be cost-effective using the Regional Cost Test. This analysis indicates that the expected costs of redispatch contracts, plus the Pearl substation upgrades, could be lower than the present-value savings from deferral of transmission project construction. However, details of the pricing could be affected by any changes to the specific redispatch quantity requirements of BPA, as well as potential constraints to generator counterparties such as long-term power sales or capacity contracts. Actual pricing for redispatch would need to be determined through bilateral negotiations with BPA, and evaluated as to whether pricing could be made at a suitably economic level for BPA ratepayers.

3.3 Cautions

The specific cautions that remain regarding the evaluated redispatch options include the following:

1. The non-wires measures identified could meet the current minimum reliability planning criteria through summer 2021 (or 2023 with one Centralia unit retired) while deferring the line, but is not expected to be a full or permanent replacement for the I-5 project. TheI-5 transmission project would provide more operational flexibility and reliability once energized than the non-wires alternative can provide.

2. The primary non-wires measure is an operational solution, actively redispatching generation on a day-ahead or day-of basis when certain conditions are expected to create peak flows. This study provides the operational requirements, but has not evaluated how redispatch could

be reliably incorporated into BPA's current real-time transmission operations protocol. BPA is currently evaluating operational challenges related to redispatch, which may create further constraints on feasibility beyond those evaluated at a planning level. These operational issues may include concerns such as redispatch requirements during maintenance outages, identification of proper indicators for when to anticipate the need to implement redispatch, and ability of generators to respond at times when needed.

3. The non-wires option requires participation of certain regional generators. Again, this study provides the requirements, but has not engaged with potential counterparties to determine whether they would be willing to sign a redispatch contract at a cost-effective price to BPA. Counterparties may also be unwilling or unable to provide redispatch in the quantities that BPA would require.

4 Feasibility Analysis of Demand Side Measures

4.1 Demand-Side Non-Wires Measure Description

Loading on I-5 transmission paths could be reduced relative to expected levels through three demand side measures: EE, DR, and DG. Applying one or a combination of these measures to loads located directly south of the constrained I-5 paths (in the PGE, Clark PUD, or Portland area portion of PacfiCorp service territory), would reduce the need for power to be sent over the I-5 transmission path. EE measures could be deployed by increasing funding for conservation measures in the relevant service area, and directing EE programs to focus on measures that affect summer loads during peak hours in particular (such as air conditioning, commercial lighting and other end uses that consume energy during the summer peak). DR could be deployed by contracting (directly or in a partnership arrangement local utility) with customers in the greater Portland area. These measures would then enable BPA to request or directly reduce the customer load (likely on a day-of or day-ahead basis) during hours when loading on I-5 paths is expected to near the path limits. BPA could also contract with the customers or the local utility to use in-area generators, including behind-the-meter backup generators, to produce power that would otherwise be brought over the constrained I-5 transmission paths. That said, we are concerned with the potential local air quality impacts of operating backup diesel generators and consider that when developing the demand side resource options.

4.2 Demand-Side Non-Wires Measure Feasibility Results

4.2.1 UPDATE TO PHASE 1 SCREENING TOOL RESULTS FOR EFFICIENCY

The Phase 1 non-wires screening analysis tool estimated the potential of cost-effective conservation measures in the greater Portland Area (after applying filters for expected adoption levels) to provide up to 143 MW of summer peak load reduction by 2020. As described in the Phase 1 study, this estimate of conservation potential applied conservative assumptions on customer adoption rates, and screened for cost effectiveness.[16]

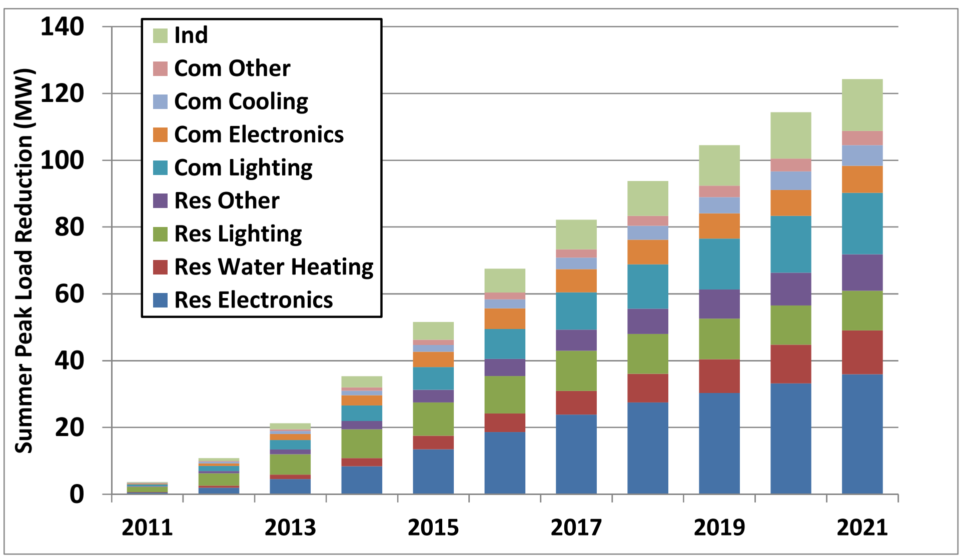
The economic analysis established for non-wires alternatives evaluates whether the net cost of the non-wires measures is positive on a Regional Cost Test basis as defined by the Non-wires Roundtable in 2003.[17] When applying a cost effectiveness screen for conservation measures, this economic analysis explicitly includes the benefit of transmission line deferral, calculated based on the present value revenue requirement savings that project deferral would create, divided by the MW of summer peak load reduction that would be needed to enable deferral. This transmission deferral benefit is then added to other existing types of project benefit, including the avoided cost of electric energy

[16] http://www.bpa.gov/corporate/i-5-eis/documents/ScreeningStudy_NonWires_I-5_Corridor_Jan2011.pdf, Section 4.4.
[17] See http://transmission.bpa.gov/PlanProj/Non-Wires_Round_Table/NonWireDocs/P3.pdf for details.

and avoided generation capacity requirements. Thus, the benefits of cost-effectiveness are larger than if the transmission deferral benefit were not considered. This benefit is relatively small on a per-MW basis, however, due to the large number of MW of load reduction that would be needed for project deferral (622 MW by 2020, as shown in Table 1 above).

The updated non-wires screening tool used for the Phase 2 analysis applied slightly more conservative adoption rate estimates for local conservation measures to account for a dependable expectation of program implementation feasibility and the fact that this conservation is in effect added to the energy efficiency already embedded in the baseline forecast. Using these updated estimates, cost effective conservation would be projected to provide up to 74 MW of incremental summer peak load reduction by 2016 and 124 MW of summer peak load reduction by 2021. The categories of measures included in this total are shown in the figure below.

Figure 7. Greater Portland Area Cost-Effective Incremental Summer Peak Demand Reduction Potential from Conservation (2011 – 2021)



It is important to reiterate from Section 2.2.3 that the conservation potential shown here is incremental to the majority of the effect of current conservation programs on net load growth. The baseline utility forecasts for the Portland area used regression-based trending of conservation, which implicitly is calculated net of the effect of conservation programs' annual achievements in recent years. Therefore, to the extent that the summer peak demand programs evaluated as a non-wires alternative are already implicitly included in the forecast, the incremental forecast of energy efficiency is too high. However, given the methodology to develop the baseline peak load forecast (regression from historical data) it is not possible to exactly what energy efficiency is included in the forecast. Additionally, PGE's efficiency goals for the next few years will seek to expand annual conservation savings beyond the pace achieved in recent years (which is largely embedded in the baseline load forecast). Therefore, for the purposes of this study, we assume the identified summer peak load reduction is incremental to the baseline. For this non-wires evaluation we think this is an appropriate treatment since even with this optimistic assumption, we find that energy efficiency has a relatively small impact on the need for I-5 Transmission Project. A more precise accounting of embedded energy efficiency may be necessary in other non-wires alternative studies.

4.2.2 UPDATE TO DISTRIBUTED GENERATION ESTIMATE

In the Phase 1 economic analysis, no DG measures that would construct new generation passed the Regional Cost Test screen. However, research as part of the Phase 1 work did indentify that PGE had the ability to control approximately 60 MW of existing DG based on the current level of dispatchable standby generation in the PGE service territory participating in PGE's DG program at the time of the Phase 1 analysis. More recent discussions with PGE for this Phase 2 work indicate the utility now has increased its total dispatchable standby generation to control approximately 80 MW of located at customer sites in the

Portland area that can serve as peaking capacity. PGE staff indicate an expectation that this total will likely increase to 125 MW of dispatchable standby generation by 2016. In addition to the coordination issues with the PGE program, the extent to which diesel generation is among the mix of generators in the PGE DG program, the local environmental impact of operating these generators to defer I-5 transmission would have to be considered.

4.2.3 UPDATE TO DEMAND RESPONSE ESTIMATE

The Phase 1 screening analysis indicated cost effective DR potential in the area would be able to provide up to 55 MW of summer peak load reduction by 2020.

The updated screening tool showed no change in the estimate of cost-effective DR in the service areas considered from the Phase 1 results – identifying the availability of 55 MW of summer peak load reduction potential. This screening-level estimate is intentionally conservative to reflect constraints on customer participation, measure cost-effectiveness, and time required to ramp up programs. The technical potential for DR and DG in the area may be significantly higher than these estimates indicate. A conservative estimate must be used for this non-wires assessment since deferring the I-5 project could have regional reliability impacts if transmission project were deferred and the DR and DG programs provided less peak load than anticipated. In this situation there may not be sufficient time to construct the necessary transmission upgrades.

The DR estimates used here are incremental to (and do not incorporate) the resources in PGE's existing programs and planned future procurement. PGE currently has approximately 20 MW of commercial and industrial DR in its current programs. In its 2009 Integrated Resource Plan, PGE anticipates expanding its DR program to approximately 130 MW by 2020. In terms of build out, PGE staff indicated an expected target of approximately 90-95 MW total of industrial, commercial, and residential DR by the 2016.

E3 explored at a high level the feasibility of coordinating the use of these DR and DG resources during times of high loading on the I-5 transmission paths through some form of contracting with PGE. This option, however, does not appear to be a feasible option for deferral under current operational structures.

PGE currently plans to use the DR and DG resources acquired through its programs for its own requirements, which could include avoiding generation capacity shortages, spikes in market prices, or issues on PGE's own transmission facilities. Contracts with participating customers, however, limit the total number of hours in which PGE can call on (or dispatch) this DR and DG. As a result, PGE does not anticipating being able to make it's DR and DG resources available for BPA's use on a long-term basis because letting BPA call on these resources could potential restrict the remaining number of hours in which PGE can call on these resources for its own use.

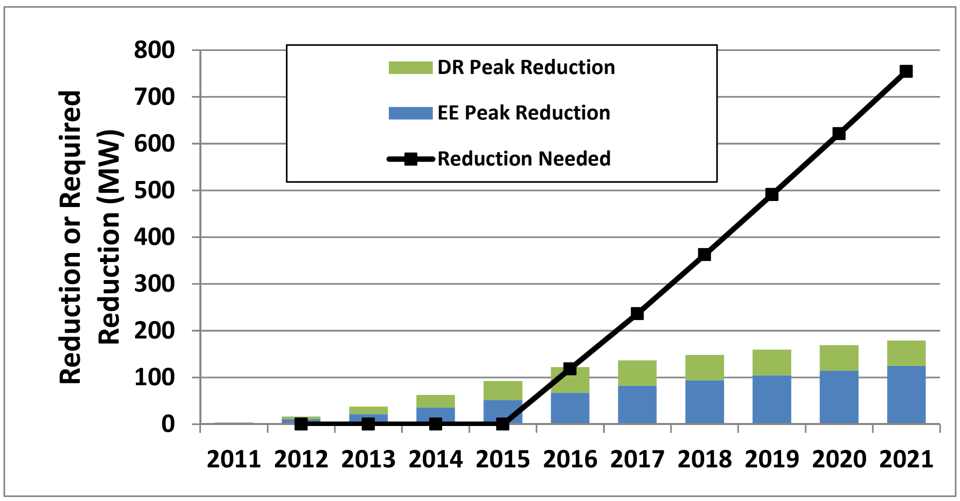
It is important to note that many of the hours in which summer loading is high on BPA's I-5 transmission facilities are also hours in which market prices and generation constraints may prompt PGE to call on its DR resources for its own purposes, which could have a likely downward effect on flows. If BPA were to have advanced confirmation that PGE plans to call on its own DR resources during specific instances of overlapping times of need, that knowledge would reduce the number of hours that BPA would need to call on other non-wires options (such as redispatch), or could reduce the number of MW of redispatch that BPA would need to call (potentially reducing the cost of such options to BPA). Without contractual authority to control the PGE DR resources, however, BPA transmission operators cannot include those PGE DR resources in the I-5 project deferral analysis because of the potential for a scenario to occur (even if rarely) in which BPA needed to reduce I-5 transmission loading, but PGE was not independently planning to use its own DR resources.

At a minimum, PGE does not anticipate having any DR capability available that it could “export” out of the PGE balancing authority (BA) until at least 2013. Thus, for evaluating the resources that BPA could rely on with certainty to defer the need for I-5 transmission upgrades, PGE’s DR and dispatchable standby generation must be excluded from this analysis. This also implies that if BPA would seek to procure DR in the PGE service territory that is incremental to the DR participating in PGE’s own programs, some of the most cost-effective options and willing customers may already be participating in PGE’s program and not able to contract with BPA to provide additional DR.

4.2.4 EXPECTED FEASIBLE ENERGY EFFICIENCY AND DEMAND RESPONSE VS. NEED

The figure below compares the identified potential for summer peak load reduction from cost effective EE and DR to the required peak reduction in the greater Portland area that would be needed to defer the I-5 project (assuming no redispatch).

Figure 8. Comparison of Non-Wires Alternative Program Peak Savings with Annual Requirements for Peak Savings



Collectively, the screened level from energy efficiency and demand response are approximately sufficient to provide one year of deferral of project need. The screened levels of peak reduction from efficiency and DR potential by 2017 (137 MW total) is approximately 60% of the quantity that would be required for a two year project deferral (through 2017), and a lower percentage of the expected MW reduction needed for each year thereafter.

4.2.5 CONSERVATION PROGRAM END USE MIX

The mix of conservation measures identified is selected based on their cost-effectiveness and potential from a broad database compiled from savings estimates developed by the Northwest Power and Conservation Council. The mix of conservation measure types selected (shown in Figure 5) has a relatively low share of cooling loads or other energy end-uses that would be particular concentrated during the summer peak. E3 evaluated the potential to increase the summer peak load reductions in the Portland area. However, high-level discussion with industry exports at the Energy Trust of Oregon indicate there does not appear to be potential to boost the summer peak reduction beyond reductions forecasted for existing Portland-area EE programs to levels that would be required for project deferral. Current levels of penetration of air conditioning in the area partially constrain the ability to significantly boost conservation programs focused on summer cooling. Additionally, the relatively low number of hours of use of air conditioners limits the energy savings and may prevent some high efficiency options from passing a cost-effectiveness test.

4.2.6 POTENTIAL FOR DR AND DG PROGRAM COORDINATION

While BPA is unlikely to be able to contract with PGE to directly control use of PGE's DR resources, it could still be beneficial for BPA to explore coordination on the program dispatch. Knowing whether PGE intends to dispatch the programs could help BPA more accurately predict peak load in the PGE territory, and potentially affect the decision of BPA to call on a certain level of generator redispatch if BPA is to contract for generator redispatch options. This possibility would have economic value to BPA, even though PGE's use of its own DR may not be sufficiently certain to allow BPA to count it on a year-ahead basis towards BPA's total potential for deferring the I-5 transmission project.

5 Conclusions & Next Steps

Since there are outstanding issues that could make the non-wires measures infeasible or uneconomic, BPA should continue the process for completing the I-5 transmission project on its current schedule. Once the operational protocol and contracting processes are finalized for redispatch, BPA could make a final determination of whether to pursue deferral using the non-wires option.

There are two primary considerations on a longer term basis if BPA chooses to pursue redispatch contracts to defer the I-5 project. First, BPA would need to periodically review ongoing changes in local load growth, transmission project development and generator construction and retirements. Potential developments, such as the retirement of Centralia units, other transmission system upgrades, or the siting of a new gas generator on the Portland side of the SoA transmission path, could further adjust the need date for I-5 transmission project construction and the quantity of generator redispatch required for deferral.

Second, an increased focus on conservation and DR targeting summer peak loads, plus improved coordination with Portland General Electric's (PGE's) own DR programs, could reduce the amount of redispatch required for significant deferral in the longer term. It is important to note that the estimate of DR included in this analysis of non-wires options is conservative. The expected contribution from EE toward transmission project deferral is also conservative in the assumed adoption rates, but assumed to reduce peak loads incrementally to the embedded energy efficiency in the baseline load forecast. Even so, the EE and DR impact estimates are intentionally conservative since the transmission construction schedule would be difficult to advance if EE and DR were assumed to enable deferral but then created less reduction in peak loads than expected. If the line is deferred through generation redispatch, then summer peak targeted energy efficiency and demand response should be pursued to provide further deferral, increase operational flexibility in the transmission system and/or reduce the capacity requirements of the redispatch option.

In particular, there are two important areas in which more analysis by BPA staff could be useful for potentially identifying higher levels of DR contributions than have been shown here. First, this screening level analysis was not able to not look at specific industrial activities and individual customers in the area. Additional research by BPA in assessing DR potential with specific industrial power users in the greater Portland area may be able to identify additional non-wires opportunities that could be complementary to the measures included in this study. Secondly, PGE has ambitious targets for DR in its own integrated resource plan. Initial discussions with PGE showed that coordination challenges for DR use under current operational arrangements could currently prevent BPA from being able to count on PGE's DR measures for deferring I-5 transmission upgrades; however, in many hours PGE may choose to use this DR for its own needs during hours that would be helpful for relieving power flows on key I-5 transmission paths. Thus, it would be worthwhile for BPA's DR staff to explore in more detail potential opportunities to coordinate DR activities, such as obtaining notice about when PGE plans to make use of its own DR resources.

Common DR software platforms may assist in potentially enabling benefits from shared coordination.

Thus, this analysis indicates that it would be complementary for BPA's DR staff to provide additional analysis of industrial DR options as well as improved coordination of DR activities and procurement between BPA & PGE. Identifying additional DR opportunities would be a particularly beneficial activity if BPA were able to use redispatch contracts to defer I-5 project construction. In that situation, redispatch contracts could serve as an "anchor" or backstop option for reducing flows on key I-5 paths.[18] Any achievement and funding of DR and other demand side non-wires options, such as targeting of EE programs measures that affect summer peak loads, could then be used to reduce the total amount of redispatch that BPA ultimately needs to call on and make payments for during times of high summer paths flows on I-5. To the extent that BPA staff could identify and contract for more DR than the amount shown by the estimates here, that additional DR could help minimize BPA's need to call on redispatch, as well as providing additional margins of safety from an operational perspective. Any incremental DR measures could also be kept in place after their need for I-5 deferral, and thus could potentially serve as long-term assets for addressing other needs.

[18] On their own, conservatively identified estimates of cost-effective local non-wires measures, including EE, DR, and distributed generation (DG) that could be implemented appear unlikely to enable sufficient transmission flow reduction to defer the I-5 project need by more than a year. BPA transmission planners set a target of 4 years or more of threshold for deferral options for this project due to the potential for unanticipated changes in load and project scheduled issues. Based on our analysis, however, many demand side= measures are economic on their own and are already included in the longer-term energy plan for the region.

List of Acronyms

Acronym	Definition
aMW	Average Megawatt
BA	Balancing Authority
BC ratio	Benefit Cost Ratio
BPA	Bonneville Power Administration
COI	California-Oregon Intertie
DEI	Distribution System Efficiency Improvements
DG	Distributed Generation
DR	Demand Response
E3	Energy and Environmental Economics, Inc.
EE	Energy Efficiency
EIS	Environmental Impact Statement
HS	Heavy Summer
MW	Megawatt
NERC	North American Electric Reliability Corporation
NWPCC	Northwest Power and Conservation Council
OTC	Operating Transfer Capability
PBL	Power Business Line
PGE	Pacific General Electric
PUD	Public Utilities District
RAS	Remedial Action Scheme
SoA	South of Allston Path
SOCSS	South of Chehalis Sectionalizing Scheme
SOL	System Operating Limit
SoN	South of Napavine Path
TRC	Total Resource Cost
TRR	Transmission Revenue Requirement

TTC	Total Transfer Capability
WACC	Weighted Average Cost of Capital
WECC	Western Electricity Coordinating Council
WOMR	West of McNary Reinforcement