I-5 Corridor Reinforcement Non-Wires Alternatives Screening Study

Prepared for:

Bonneville Power Administration

January 12, 2011

Energy+Environmental Economics

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Executive Summary

This report provides a preliminary screening-level assessment of the potential for non-wires alternatives to defer the proposed Bonneville Power Administration (BPA) I-5 Corridor Reinforcement transmission project (I-5 Project). Based on Energy and Environmental Economics' (E3's) analysis of non-wires alternatives and project details provided by BPA, E3's screening-level assessment indicates that BPA should continue to pursue the transmission project on its current schedule at this time while simultaneously investigating the implementation feasibility of reducing peak summer power flows along I-5 through two interrelated actions: (a) contracting to redispatch generators in the region and (b) pursuing aggressive energy efficiency (EE) and demand response (DR) in the Portland area. If these redispatch and energy efficiency measures prove feasible, they have the potential to defer the need for the transmission project by 5 or more years beyond the currently estimated 2015 need date for the I-5 Project. This screening study describes the analysis and information behind this recommendation.

I-5 Corridor Reinforcement Project

The proposed I-5 Corridor Reinforcement Project (I-5 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 power flow analysis indicates that the line would need to be energized by summer 2015 to avoid the risk of overloads on two critical transmission paths along the I-5 Corridor during summer peak-load conditions. Without the I-5 Project, BPA is concerned that by 2015, increased summer peak load growth in the region could create conditions in which an outage on the high voltage lines along I-5 could damage the parallel lower voltage lines, and raise the risk of voltage collapse and curtailed power delivery to loads in the Portland, Oregon and Vancouver, Washington areas. The I-5 Project could provide the additional benefits of enabling BPA to meet the requests of certain generators in the area for firm transmission service on the BPA system. Planning, permitting, and constructing a transmission project of this size requires a considerable lead time, and to have the I-5 Project operational by summer 2015 would require BPA to engage in numerous activities throughout the next four years.

Non-wires Assessment Screening Study

This preliminary screening study builds on an analytical approach developed as part of the BPA's Non-Wires Solutions Roundtable, which was convened between 2003 and 2006. The current study evaluates whether it would be possible to defer the proposed I-5 Project through a combination of energy efficiency, demand response, existing generation, and new generation. To the extent possible, the analysis also assesses whether these alternatives are cost-effective from a Regional Cost Perspective,[1] by comparing the cost of these non-

[1] 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 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.

wires measures to the cost of building the transmission line. It is important to note that this report is not an implementation plan; rather, it describes the results of a distributed energy resource screening tool and a high-level estimation of the flow impact of generator redispatch to identify whether particular non-wires alternatives warrant further study.

Load Growth & Project Need

BPA emphasizes the importance of forecasted summer peak load growth as a driver of need for the I-5 Project. A forecast of summer peak demand for power in the greater Portland and Vancouver area, given the expected range of a number of key drivers, must consider uncertainty. The key factors include: the intensity and duration of heat waves in the area, the adoption rate of air conditioners, the speed of regional economic recovery, and the level of new construction and population growth over the next 5 to 10 years. How much power will flow on the existing I-5 transmission facilities during future summers is also affected by: Northwest hydro conditions in a given year, whether a heat wave in Portland coincides with high temperatures in California, and the construction and operational conditions of renewable and non-renewable generation and other transmission in the region. Given the long lead time to develop the I-5 Project, as well as the potential negative impact of overloads and outages if the I-5 Project is needed before it can be constructed, BPA planners should rightly approach these uncertainties conservatively. At the same time, they must also seek to avoid constructing a line significantly before it is expected to be needed.

In this screening-level analysis, we address the impact of load growth uncertainty by creating two load growth cases:

- **Case 1**: this load forecast case uses the latest forecasts of summer peak load from BPA's customer utilities, adjusts these forecasts to reflect the response of power demand to summer temperatures at a level expected to occur once in every 10 years (1-in-10), and also sets a floor based on the highest observed historical summer peak, which occurred in July 2009,[2] and
- **Economic Sensitivity Case:** a more conservative sensitivity case in which economic conditions rebound and growth in the area occurs more rapidly than in the utilities' base case forecast.

Figure 1 below compares these two peak load forecasts for 2011 through 2020 for PGE and Clark PUD and shows the historical summer peak data for these utilities.

[2] Clark PUD provided only a summer peak forecast for 1-in-2 temperatures, so E3 adjusted Clark's 1-in-2 forecast upward proportionally based on the size of PGE's 1-in-10 peak relative to its 1-in-2 forecast. Expected conservation savings were removed from (i.e., load was added back to) these forecasts, as EE potential will be addressed directly as a non-wires measure. PacifiCorp did not provide an updated load forecast for its Portland area load, so we used the peak load estimate that the original BPA power flow studies used for PacifiCorp. Finally, we left the load forecast for Cowlitz PUD unchanged from that used in the BPA power flow studies, because we did not have similarly recent data for Cowlitz, and BPA's power flow cases aggregated the load forecast for Cowlitz PUD and a number of other utilities in the region. We do not believe these choices materially affect the results of this analysis.

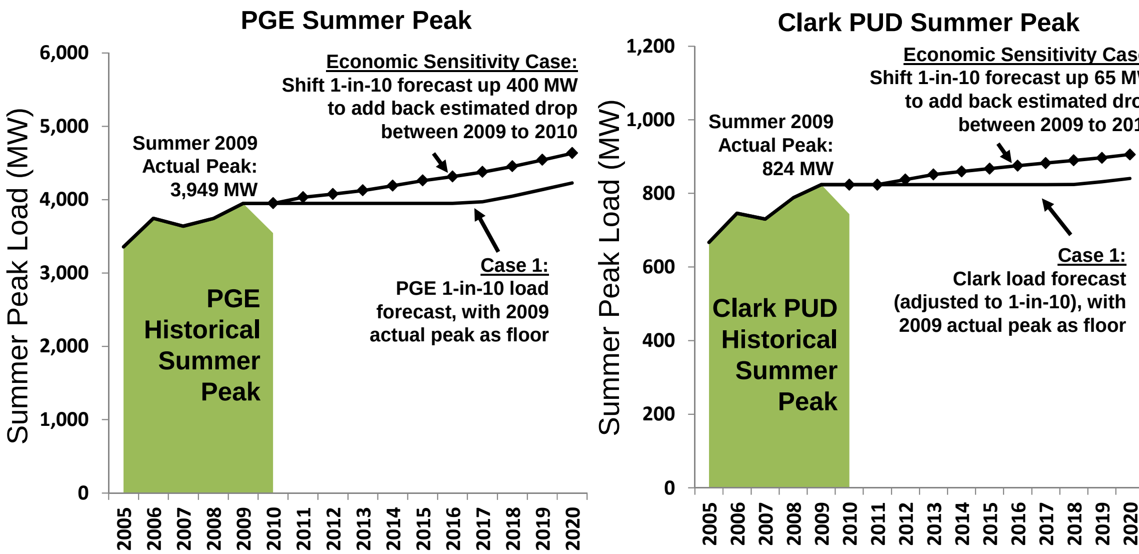


Figure 1: Summer Peak Load Growth Cases for PGE and Clark, 2005-2020.
Actual summer peak loads for PGE and Clark PUD (shown as the shaded areas in the figure) set historical highs during a July 2009 heat wave and then declined in 2010 as a result of weaker economic conditions in the area and lower summer peak temperatures. Both utilities' forecasts (from June 2010 for PGE and November 2010 for Clark) show relatively slow peak growth for the next 5 years. For the non-wires analysis, E3's Case 1 (represented by black lines without markers) uses the utilities' peak forecast expected under 1-in-10 temperatures, but sets the 2009 peak as a minimum level in order to reflect the possibility that customer sites that are still connected to the electric system could rapidly reach this level again under certain conditions. The more conservative Economic Sensitivity Case (shown as black lines with markers) shifts the utility 1-in-10 load forecast upward by the size of the 2009-10 drop to approximate a more rapid economic recovery, as well as weather patterns similar to 2009.

Under the Case 1 load forecast and in the absence of new transmission upgrades or generation interconnections, flows on existing I-5 transmission may exceed system operating limits as early as summer 2014. On the South of Napavine transmission path (which travels from Paul substation near Chehalis, Washington to the Allston substation located southwest of Longview, Washington) flows in 2018 may need to be reduced 343 MW below the forecasted level to remain within safe operating limits. Additionally, 2018 flows on the South of Allston path, which connects the Allston substation to the Keeler substation near Hillsboro, Oregon, may need over 130 MW of flow reduction relative to the forecast. In the Economic Sensitivity Case, the South of Napavine power flows could to exceed the path's total long-term transfer capability of 2250 MW by 2013. In 2018, the South of Napavine path would require total flow reductions of 512 MW, and the South of Allston path would need to reduce flow by 299 MW to stay within its thermal operating limits.

Because of the way that power flows over the network of transmission facilities, each MW of load reduction or additional in-area generation only reduces the flows across the relevant transmission paths by a fraction of a MW. For example, a 100 MW load reduction in downtown Portland will only reduce loadings on the South of Allston and South of Napavine paths by approximately 37 MW. The ratio of the MW change on the transmission path to the MW change at the source is called the load flow distribution factor, or distribution factor. When applying this 37% load flow distribution factor, the 512 MW path flow reduction that is required (in the Economic Sensitivity Case) to bring the peak flows on South of Napavine path in 2018 below the path's operating limit translates to approximately 1,384 MW of needed load reduction or additional generation within the Portland Area.

Non-wires Alternative Potential for Project Deferral

The I-5 non-wires alternative screening finds that cost-effective energy efficiency (EE) and demand response (DR) on their own are not sufficient to defer the proposed transmission line. Additionally, existing local generation, such as Clark's River Road plant, that helps reduce I-5 path flows was already assumed to be running at full capacity in the BPA power flow cases used to determine the need for the I-5 Project. However, if certain generators located to the north of the constrained transmission paths could be contracted to lower their output for a limited number of hours in the summer when high temperatures are driving peak load in the area, *and* if it were feasible to replace this energy by ramping up output from generators located south of Portland (possibly including plants in California), then this "redispatch" approach combined with cost-effective local EE and DR could potentially defer the need for the proposed I-5 Project by five or more years past the 2015 need date established by BPA analysis.

The total number of MW that would be required under this redispatch option to enable I-5 Project deferral for five or more years could range from 500 MW to over 1,500 MW, depending on which combination of generators would participate in the program, the evolution of local load growth, and the effectiveness of EE and DR program implementation in the period. Any viable generator redispatch option must also avoid creating overloads on other transmission facilities, including keeping flows on the Raver-Paul path, located to the north of Napavine, under its 1,450 MW total transfer capacity limit.

For the Case 1 and Economic Sensitivity Case load growth scenarios, respectively, Figures 2 and 3 show the identified non-wires potential and remaining flows (net of the impact of non-wires measures) on the South of Napavine and South of Allston paths.

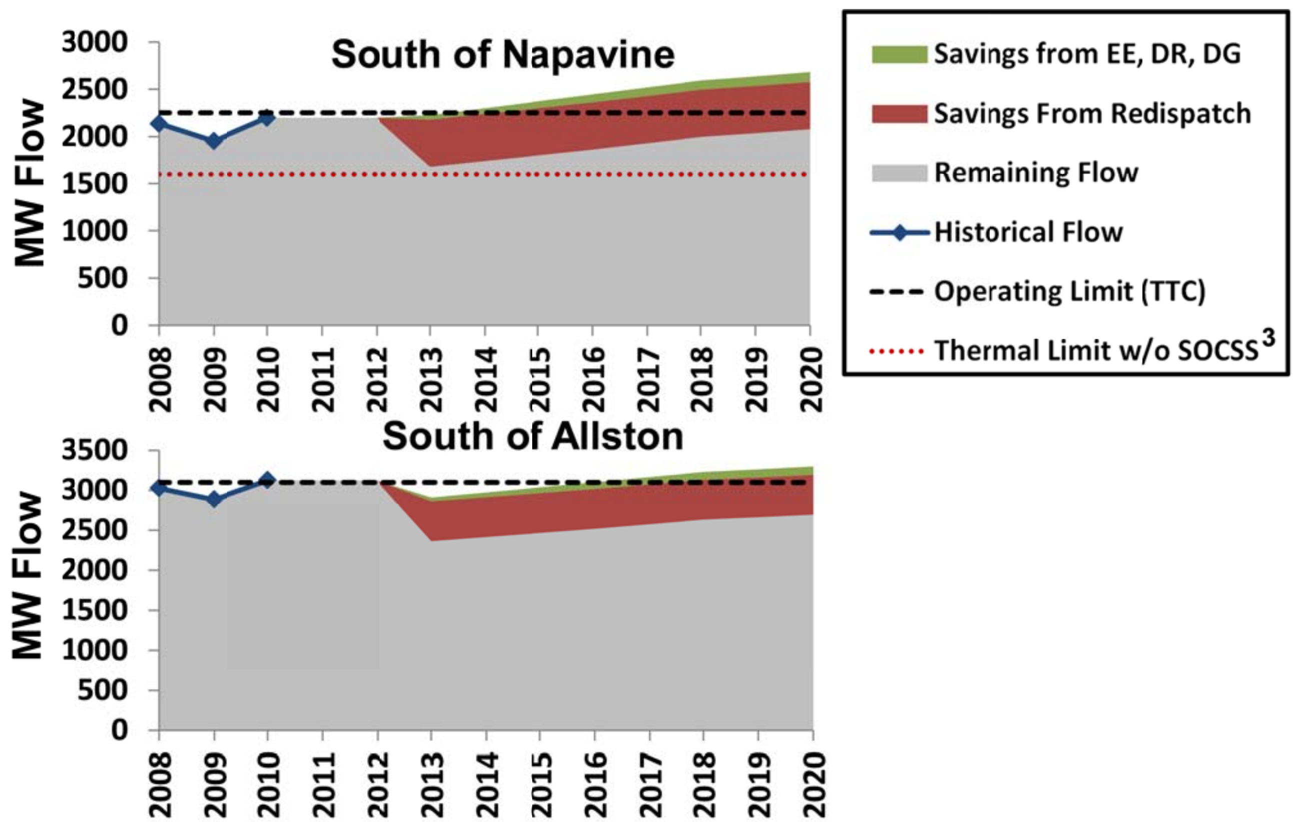


Figure 2. Identified non-wires potential and resulting flows, Case 1 load forecast. Using the Case 1 load forecast (and assuming no non-wires measures are implemented), the South of Napavine path flows would be expected to exceed the path's transmission constraints in 2015 (and remains well above the path's 1,600 MW thermal limit without the South of Chehalis Sectionalizing Scheme, or SOCSS, in place.)[3] If feasible, non-wires potential identified in this study from EE, DR, DG, and generator redispatch could defer

[3] The South of Chehalis Sectionalizing Scheme (or SOCSS) is an operational response that BPA must prepare when South of Napavine path flows exceed 1,600 MW to protect the lower voltage lines on the path during a contingency. SOCSS protects the lower voltage system during an outage of a 500 KV line by opening the circuits of (turning off) the lower voltage lines, effectively severing, or "sectionalizing" the transmission system along I-5 and forcing power to reach the Portland area by a different route.

the I-5 Project's need by 5 or more years beyond the 2015 need date established by BPA. These measures also respect Raver-Paul transmission limits and address forecasted overloads on the South of Allston path.

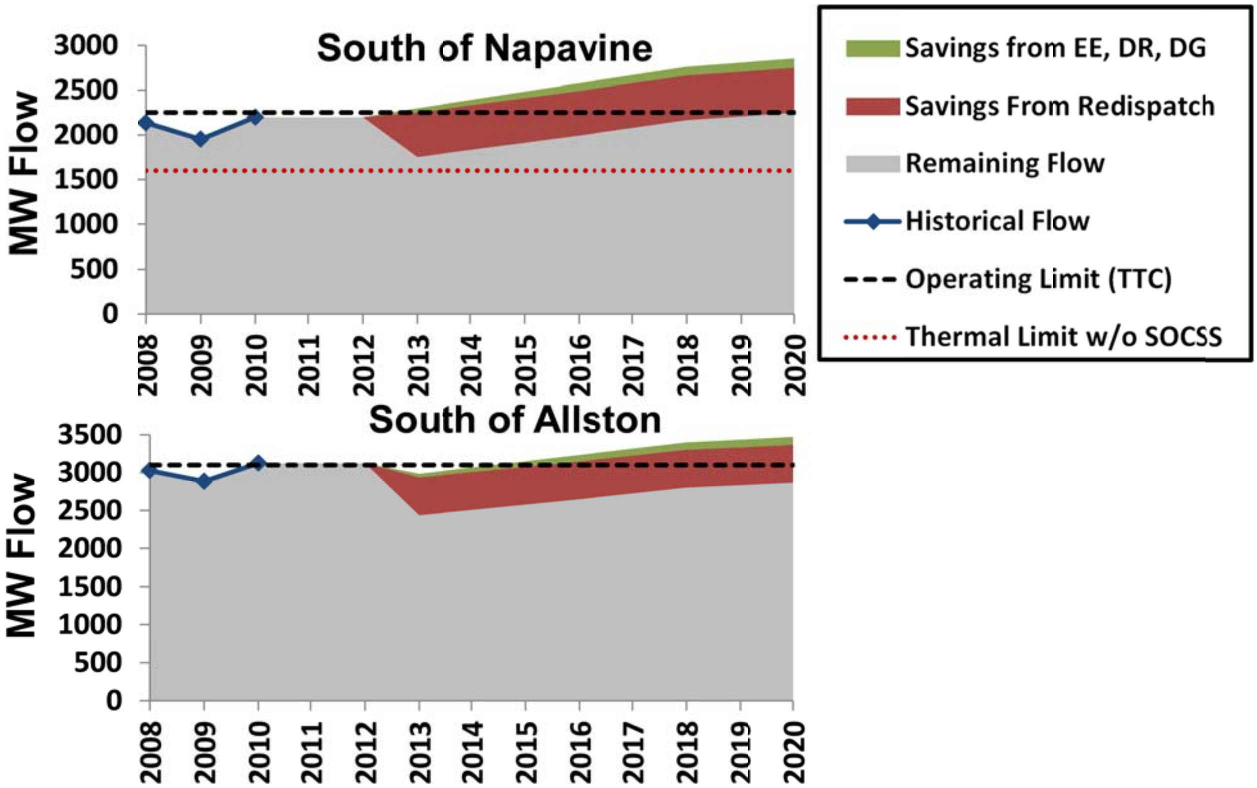


Figure 3. Identified non-wires potential and resulting flows, using Economic Sensitivity Case load forecast.

Under the Economic Sensitivity Case (and assuming no non-wires measures are implemented), expected flows on the South of Napavine path would exceed the path's transmission constraints earlier and more severely than under the Case 1 forecast. Under either load forecast, identified non-wires measures, if feasible, could keep path flows on both the South of Napavine and South of Allston paths below their limits for 5 or more years beyond the currently estimated 2015 need date for the I-5 Project.

Implications & Recommended Next Steps

Based on the potential identified in this screening study, we recommend that BPA explore the feasibility of generator redispatch and accelerated EE and DR measures in greater depth. This report's high-level screening analysis does not assess the implementation feasibility of a generator redispatch contract from an operational or economic perspective, so this feasibility remains uncertain. The price of this option could only be determined through a bilateral negotiation with an interested generator. Also, before signing a long-term agreement, BPA would need to perform operational analysis to confirm that the particular redispatch combination could provide sufficient flow reduction on the I-5 corridor while avoiding overloads on other parts of the transmission system, including the Raver-Paul transmission path. A non-wires implementation plan would also need to incorporate an ongoing review of line flows, load growth, and EE/DR program penetration so BPA can know as quickly as possible whether potential changes such as higher load growth from new industrial plants in the area would overwhelm the expected capabilities of non-wires measures to mitigate key path flows.

If contracting for sufficient redispatch turns out to be an infeasible option, BPA may still face a tight schedule to complete the I-5 Project by the date when it is expected to be needed. Thus, we also recommend that, in parallel to performing a non-wires implementation feasibility analysis, BPA maintain its current schedule for permitting the I-5 Corridor Reinforcement Project.

1 About this Report

The Bonneville Power Administration (BPA) commissioned Energy and Environmental Economics, Inc. (E3) to conduct a preliminary screening assessment of whether 'non-wires alternatives' could feasibly defer the proposed I-5 Corridor Reinforcement Project (I-5 Project) in the Portland, OR, and Southern Washington area. The proposed project, which includes a new 500-KV line from Castle Rock, Washington to Troutdale, Oregon would increase reliability and reduce the risk of voltage collapse or overload of lower voltage transmission facilities in the event of an outage on two critical transmission paths that parallel Interstate 5 between Chehalis, WA and Portland.[4] This study examines non-wires alternative measures that could potentially defer construction of the proposed line, including energy efficiency, demand response, new distributed generation, and changes to the dispatch of existing generation.

The purpose of a non-wires screening study is to provide an independent assessment of whether there appear to be cost-effective measures that could defer the need for a proposed transmission line. The study's high-level cost-effectiveness "screening" methodology considers the economics of non-construction alternatives, highlighting issues that may warrant further study,

[4] For information about the proposed line from BPA, see: http://www.bpa.gov/corporate/i-5-eis/.

but is not a detailed implementation plan. Furthermore, this study complements and does not replace existing transmission planning studies.

The methodology applied in this study was originally developed as part of the BPA regional "Non-Wires Alternative Roundtable" which involved public workshops and stakeholder participation. The non-wires study approach, developed through the Roundtable, has been applied by E3 and others in many non-wires studies for Bonneville, including Kangley-Echo Lake (2002), the Olympic Peninsula (2004) and the Lower Valley Energy transmission upgrade study (2004).[5]

The analytical approach applied in this study consists of several steps, described briefly below, and outlined in more detail in the rest of the report:

1. **Develop base case approximation of constraint**
    - The first step is to adequately define the magnitude and scope of the transmission problem. To do this we develop a total 'path flow' estimate of the constrained path, relying on results from the Bonneville Transmission Services (TS) division's load flow modeling results. We also estimate the number of hours when loads are expected to exceed the path limits on the transmission lines using a load duration curve approach.

2. **Update local area demand forecast**
    - The second step of the analysis is to update the local area peak demand forecast. The peak demand forecast drives the timeline of the need for the proposed transmission line and/or any cost-effective non-wires alternatives.

3. **Determine value of line deferral**

[5] For more information see: http://transmission.bpa.gov/PlanProj/Non-Wires_Round_Table/

- Once the magnitude of the problem is well defined, we evaluate the value of deferring the proposed transmission line. There are two main categories of economic benefits that would accrue from deferring the line: (a) transmission revenue requirement savings of line deferral, as well as (b) any avoided electricity and natural gas purchases from implementing energy efficiency, demand response, etc. as part of a non-wires alternative.

4. **Evaluate cost-effective non-wires alternatives potential**
    - In this step the costs and benefits of non-wires alternatives are compared to the costs and benefits of the proposed transmission line. The non-wires alternatives evaluated here include energy efficiency, demand response, re-dispatch of existing generation and the construction of new generation, including distributed generation. Line benefits include potential reduction in energy losses over the upgraded transmission system, as well as incremental revenue (if any) provided by sales of additional transmission service enabled by the new line.

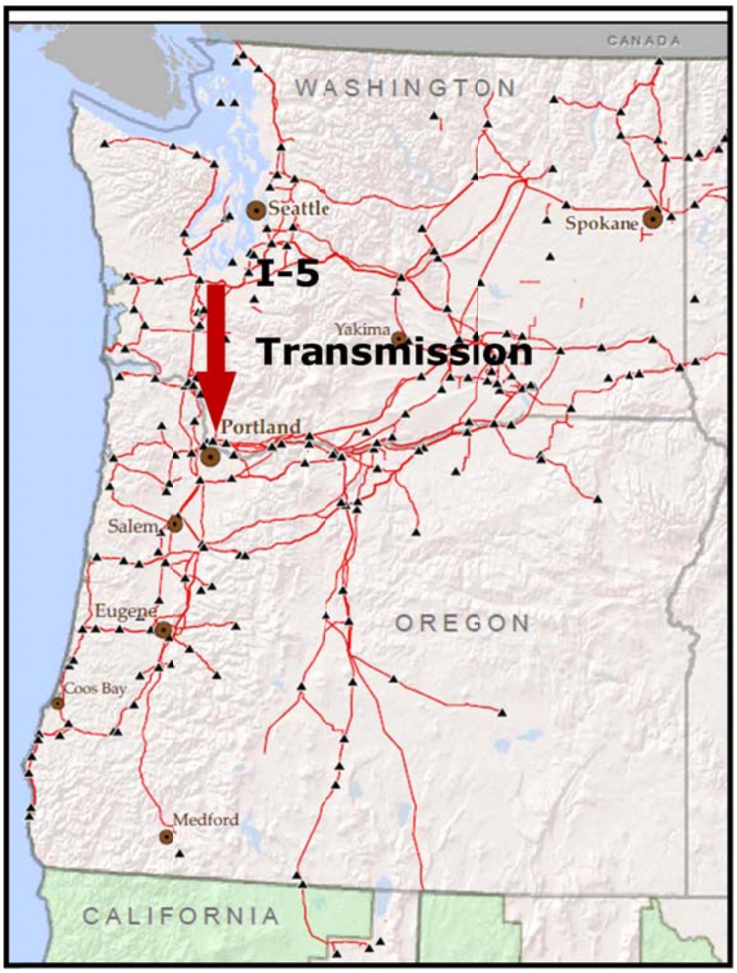
5. **Aggregate results & develop conclusions**
    - The final step is to aggregate the results and develop conclusions and recommendations for next steps. A non-wires screening analysis does not recommend a particular implementation path, but rather highlights the best options which pass the screening test and may warrant further study.

2 Description of Transmission in I-5 Corridor and the Identified Problem

The I-5 Transmission Corridor, which runs approximately from Tacoma, Washington to Portland, Oregon, is an important component of BPA's overall transmission system in the Northwest. Broadly, the bulk of hydro generation with swing capacity in the region is located east of the Cascades on the Upper Columbia River (at Grand Coulee and Chief Joseph dams), and in British Columbia. Significant thermal generation capacity (largely natural gas-fired generators plus the Centralia coal plant) is located near I-5, directly to the north of the critical constrained paths to be addressed by the proposed project. The Northwest's major load centers are located west of the Cascades in the Seattle and Portland areas. During summer peak hours, the Northwest region often also makes power transfers south to serve California loads over the California-Oregon Intertie (COI) & the Pacific Direct Current Intertie (PDCI) lines, located on the Eastern side of the Cascades.

During the summer peak, the I-5 Corridor typically experiences heavy north to south flows. Power in the summer generally will flow from BC and the Upper Columbia dams toward Portland along two separate paths: (1) westward over the West of Cascades North path toward Tacoma, then southward along the I-5 Corridor, and (2) southward towards Boardman, Oregon, then westward along the West of Cascades South Path into Portland. The map below shows the I-5 Transmission Corridor's location in the overall Northwest electric system.

Figure 4. Bonneville Transmission Facilities in Washington and Oregon



BPA provides both power and transmission service to Clark County PUD (serving loads in and around Vancouver, Washington), Cowlitz County, and a number of other smaller public utilities in the area. Bonneville also provides transmission service (including along I-5) to the investor owned utilities Portland General Electric (PGE) and PacifiCorp to help them serve loads in the greater Portland area.

2.1 Description of the Problem

BPA believes that summer peak load growth in and near Portland could soon create an unacceptable level of risk that an outage on one or more of the high-voltage lines could lead to damage on parallel lower voltage lines in the area. Currently, in the event of an outage on one of the 500 kV lines on 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, however, the larger total flows would exceed the capacity of lower voltage lines (in the event of 500 kV system outage), resulting in equipment damage and causing more subsequent line outages.

This unacceptable risk, formally identified as a National Electric Reliability Council (NERC) single contingency criteria violation, or a Western Electric Coordinating Council (WECC) double-line common-corridor contingency criteria violation, could also lead to voltage collapse in the area or could force BPA to drop load customers in the Portland area. The goal of the I-5 Corridor Reinforcement Project is to avoid the risk of outages and overloads on the major I-5 transmission paths by providing an additional high voltage line that would have the capacity to absorb the power flow in the event of an outage on one of the existing 500 kV lines.

Specifically, on the South of Napavine (SoN) path, which extends from Paul Substation near Chehalis, Washington to Allston Substation southwest of Longview, Washington, the limiting outage would be the simultaneous loss of the Paul-Allston #1 and #2 500-kV lines (located in a single corridor), which could cause voltage problems and overloads of the lower-voltage system. BPA's power flow studies found that summer peak flows would likely pass the voltage limits of the SoN path by 2018.

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 shed load after a contingency must occur within seconds to avoid voltage problems on SoN.

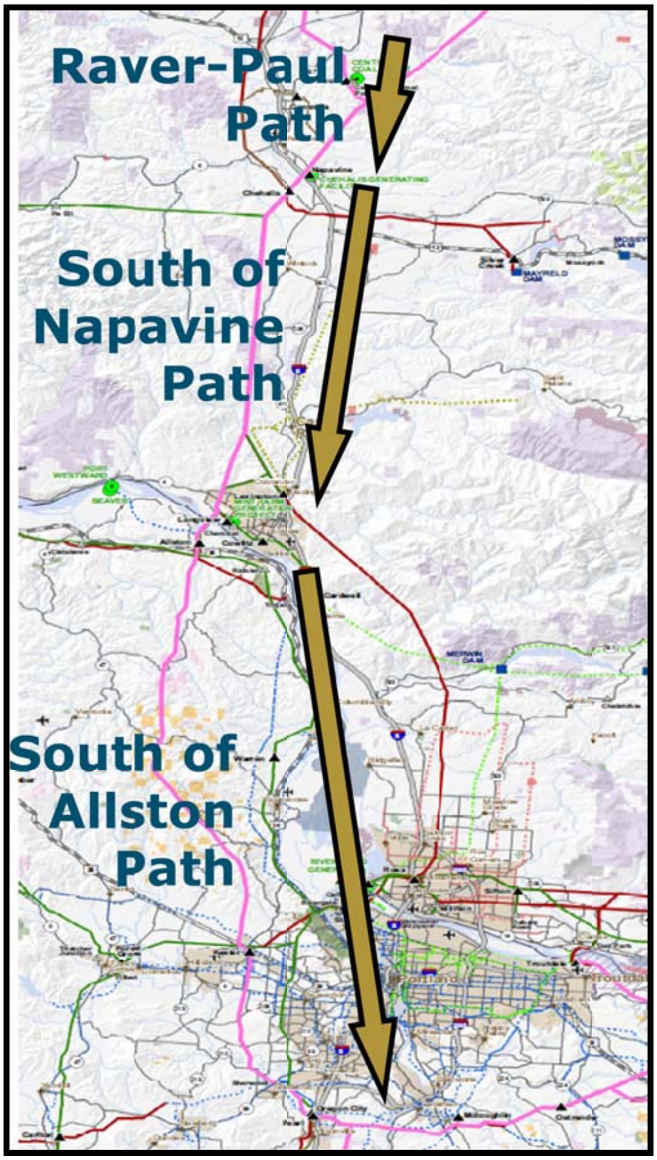
Also, when power flows on SoN are above a certain threshold, BPA readies an operational response called the South of Chehalis Sectionalizing Scheme (or SOCSS) to protect the lower voltage lines on the path during a contingency. SOCSS protects the lower voltage system during a 500 KV outage by opening the circuits (turning off) of the lower voltage lines, effectively severing, or "sectionalizing" the 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 southward to Boardman and then flow 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 voltage problems in the area under certain operating conditions.

On the South of Allston (SoA) Path, the limiting outage would be the loss of the 500 kV Allston-Keeler line, which runs from Allston Substation south to Keeler substation and connects there with an additional 500 kV line that runs from Keeler to Pearl substation, which is located to the southwest of Portland. BPA forecasts thermal overloads on this path by 2015.

For later discussion, it is also important to note that the Raver-Paul path, which runs from near Tacoma, WA to Paul Substation, would also be expected to be near its operating limits in the absence of the I-5 Corridor Reinforcement Project. While flows on this path are not directly identified as a driver of need for the I-5 Project, Raver-Paul's constraints must be considered closely when exploring generator redispatch options to ensure that any proposed solution on SoA and SoN paths do not add to loading on Raver-Paul.

A map of the relevant paths on the I-5 Corridor transmission system is shown in the figure below.

Figure 5. Diagram of I-5 Corridor transmission paths



3 Proposed I-5 Corridor Reinforcement Project

The proposed I-5 Corridor Reinforcement Project ("I-5 Project") evaluated here includes construction of two new substations—in Castle Rock, Washington, and Troutdale, Oregon—as well as a new 500 kV transmission line spanning approximately 70 miles to connect these two substations. The line is proposed to be energized by the beginning of summer of 2015, which would require that construction start in 2013.

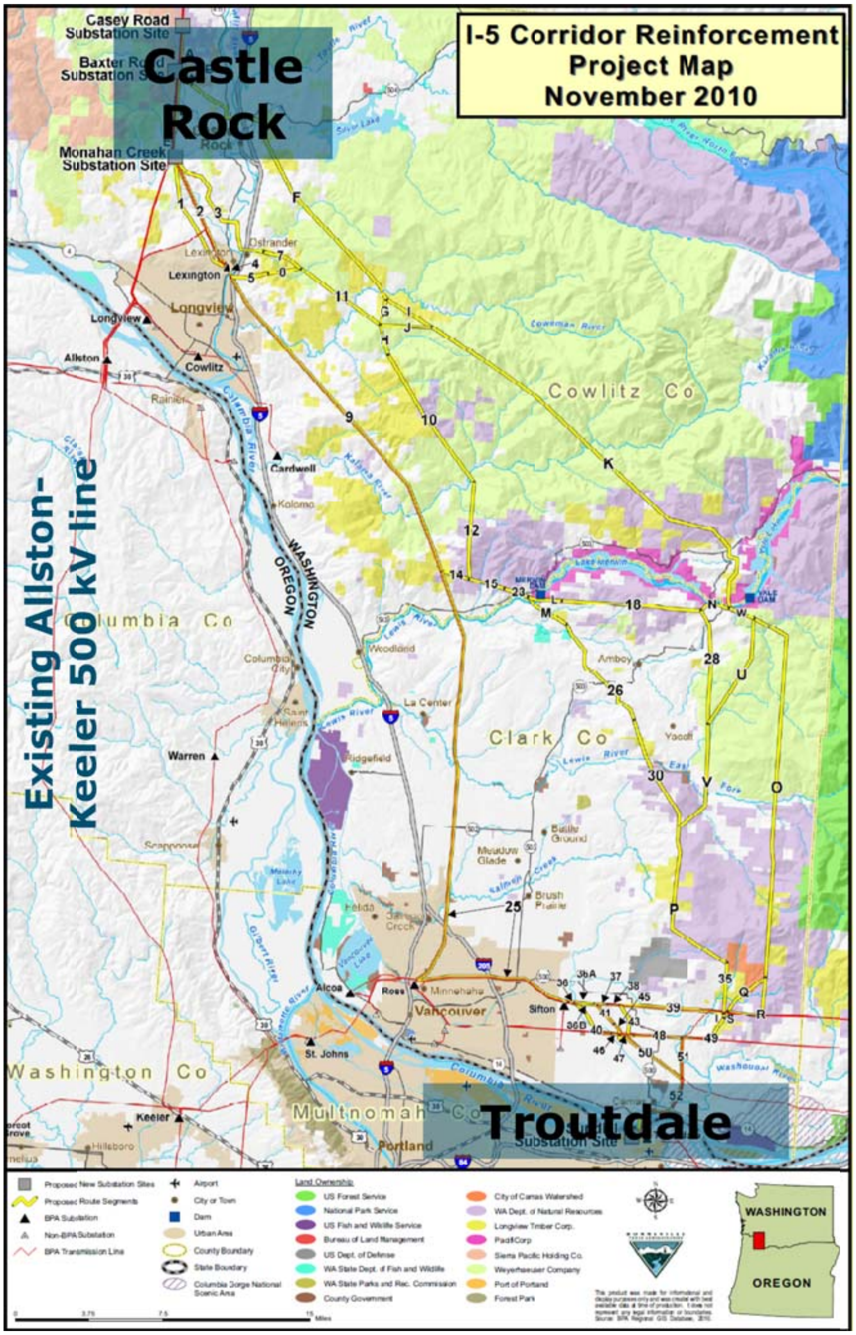
BPA analysis indicates that the I-5 Project would adequately address the identified reliability problems discussed above. Additionally, BPA estimates that the line would increase total transfer capability (TTC) rating for the South of Napavine path by over 700 MW, and would raise South of Allston TTC by over 900 MW. Alternatively, with the I-5 Project in place, BPA could choose instead to increase TTC ratings on the SoN and SoA paths by a smaller amount and instead remove the need for SOCSS.

The direct cost of the line and the two substations is estimated at $342 million dollars (in constant 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.

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.

The exact route for the line has not yet been determined. The figure below depicts the proposed I-5 Project and potential routes under consideration as of November 2010.

Figure 6. Potential Routes under consideration for the proposed I-5 Corridor Reinforcement Project



4 Study Methodology

The study methodology consists of four key steps, each of which is described below:

1. Develop base case proxy of problem
2. Update local area demand forecast
3. Determine value of line deferral
4. Evaluate cost-effectiveness and potential of non-wires alternatives

4.1 Develop base case proxy of problem

The first step in the analysis is to clearly define the problem that the proposed transmission line would solve. In assessing the potential need for additional transmission on the I-5 Corridor, BPA's transmission engineers used power flow models to simulate loading on critical transmission facilities with various combinations of generators in the area online and under a wide range of transmission contingency (or outage) conditions.

For this analysis, we must simplify the complex interrelationships between load, generators and these transmission facilities, since it would be inefficient to run new power flow simulations for each scenario considered. Thus, in this report, we rely on the power flow analysis of the Bonneville Transmission Services (TS) staff which was used to determine the need date for the I-5 Project.

Our base case proxy consists of two key components: **(a)** **path limits** which characterize the maximum MW level that path flows must remain below to keep system risks within a acceptable range, and **(b)** **a base case forecast of path flows** under a base set of generation and load growth assumptions. Our base case proxy includes both of these components for all three major I-5 paths: South of Allston (SoA), South of Napavine (SoN), and Raver-Paul. The aim of the non-wires screening analysis will be to estimate whether cost-effective non-wires potential could possibly bring the path flows (b) below the path limits (a) for a number of years, which would indicate a potential ability to defer the need for proposed transmission upgrades.

We simplify this analysis by using **load flow distribution factors**. These values approximate the effect that a 1 MW change in load or generation would have on the power flow over a particular transmission path. For example, a load flow distribution factor of 0.37 for the South of Allston transmission path and Portland area load indicates that a 100 MW increase in Portland load and a corresponding 100 MW increase, plus losses, in generation would result in a 37 MW increase in flow on the South of Allston path. Load flow distribution factors are highly useful for estimating the effect that various non-wires measures would have on critical facilities.

At the direction of Bonneville Transmission Services staff, we used the summer Total Transfer Capability (TTC) as a proxy for the maximum path limit for each path. The TTC for a given path typically represents the maximum amount of power flow for which a transmission operator can sign long-term contracts with its customers to send power over that path while remaining within relevant reliability criteria. In any given hour, the actual operating limit on a transmission path may vary based on the expected dispatch of generators in the area, because these generators will affect how the electric system can respond in the event of a line outage. For example, the flow limit on the SoA path will be higher in a given hour if Clark PUD's River Road Plant (located west of Vancouver, WA) is generating in that hour. This hourly limit depends on the generation pattern and is known as the Operating Transfer Capability (OTC).

TTC is a more conservative limit than OTC because TTC represents a firm obligation by BPA to provide transmission service, regardless of generator pattern, so BPA must determine the amount of transmission service it can provide on a given path even in the event that certain generators that would favorably affect the path rating are not operating. TTC is appropriate to use for this screening analysis, because one of the major non-wires measures that will be considered here is generator redispatch. By using TTC, we can know that a particular redispatch of generators to reduce line flows will not result in a moving target by simultaneously affecting the path limit.

The table below contains the proxy path limits which were used for this analysis, as well as the base case path flows during the summer peak. These were provided by BPA Transmission Services from its 2013 and 2018 power flow simulations used to determine the need date of the I-5 Project. The far right column shows the difference between the 2018 base case flow and proxy path limit. It is important to note that the path limit shown for South of Napavine (2,250 MW) assumes that BPA continues to operate the SOCSS scheme. The I-5 Project could allow BPA to discontinue use of SOCSS, resulting in an improvement in reliability on the SoN path. Without the I-5 project, in order to avoid the need for SOCSS, SoN flows would have to be below the path's thermal limit of 1,600 MW.

Table 1. Proxy Path Limit and Base Case Flows from BPA.

Path	Proxy Path Limit	Base Case Flow in 2013 (BPA TS)	Base Case Flow in 2018 (BPA TS)	2018 Flow in Excess of Limit
Raver-Paul	1,450 MW	1,088 MW	1,481 MW	**31 MW**
South of Napavine (SoN)	2,250 MW	2,258 MW	2,760 MW	**510 MW**
South of Allston (SoA)	3,100 MW	2,943 MW	3,397 MW	**297 MW**

In determining the 2015 need date for the I-5 Project, BPA modeled a number of scenarios with different generation patterns and outage conditions. Among the assumptions included in those cases, it is important to highlight three in particular. First, the BPA power flow analysis was conducted in 2009 using load forecast data from WECC regional summer base cases, which were created in 2008.[6] The WECC load data for the cases were provided at the time of the analysis by utilities in the region, including PGE, Clark PUD, and other utility customers of BPA.

Second, while BPA's analysis indicates that the I-5 Project can provide additional firm transmission capacity to serve new and existing generator requests, the need determination studies did not include the additional flow impact from those new projects; rather, only generators with existing firm transmission rights were assumed to be generating pwer during the peak period. Thus, the

[6] BPA's 2013 and 2018 simulations were based on the WECC 2013HS1A base case (created in October 2008) and the 2018HS1A base case (created in July 2008), respectively.

incremental growth in estimated summer path flows for 2013 versus those for 2018 can be interpreted as attributable exclusively to load growth changes.

Third, these cases assume that Grand Coulee Dam on the Upper Columbia River is the "swing plant", or "swing bus", meaning the cases assume that increases in load growth in the region are met by increased energy output from Grand Coulee. The generator used as the "swing plant" is important to such analysis because 1 MW of load growth can cause a larger or smaller flow impact on critical transmission paths, and thus have a larger or smaller load flow distribution factor, depending on the relative location of the generator that responds to meet the load growth. For this non-wires screening analysis, we have chosen to remain consistent with BPA's power flow modeling framework by assuming that Grand Coulee Dam is the swing-plant that ramps up or down production in response to changes in load near Portland.

Based on its simulation results, BPA Transmission Services provided load flow distribution factors to characterize how changes in load at major bulk transmission busses in the greater Portland area would affect flows on the critical paths. For computational efficiency and clarity, we have aggregated these bus-specific factors by using the average value for busses within the PGE, Clark PUD, or Cowlitz PUD service territory. The table below summarizes these factors based on the assumption that Grand Coulee dam is the swing bus. For example, the lower right value, 0.37, indicates that a 100 MW increase in load on the PGE system (and a corresponding 100 MW increase, plus losses, in Grand Coulee output to meet that load growth) would result in a 37 MW (=100 MW * 0.37) increase in flow on the South of Allston path.

Table 2. Load Flow Distribution Factors with Grand Coulee as Swing Plant

Path	Cowlitz PUD	Clark PUD	PGE
Raver-Paul	0.302	0.226	0.228
South of Napavine (SoN)	0.506	0.367	0.370
South of Allston (SoA)	-0.490	0.367	0.370

In actual daily operations of the power system, a change in load for one of these utilities could result in changes in generation at a variety of generators. By choosing to use Grand Coulee Dam as the swing bus, however, BPA's base case flow forecast likely estimates flows lower than they would have been if another set of generators with potential capacity to increase output, such as gas-fired generation located along the I-5 Corridor's northern section, were instead assumed to increase output to serve Portland area load growth. For comparison, the table below characterizes what the load flow distribution factors would have been if northern I-5 generators were assumed to respond to Portland area load growth instead of Grand Coulee Dam. In this case, 100 MW of load growth in would result in nearly twice as large an increase in flows on the SoN path compared to using our base case load flow distribution factors.

Table 3: Load Flow Distribution Factors with Northern I-5 Thermal Generation as Swing Plant

Path	Cowlitz PUD	Clark PUD	PGE
Raver-Paul	0.302	0.226	0.228
South of Napavine (SoN)	0.864	0.726	0.729
South of Allston (SoA)	-0.136	0.726	0.729

While other loads, including those in southern Oregon, such as the cities of Eugene and Salem, do have some impact on I-5 path flows, the relationship is weaker than it is for Portland area loads because the Portland area is located most directly south of the critical I-5 paths, so Portland receives the highest percentage of its power from flows along this corridor. We have chosen to restrict the focus of this screening-level non-wires study to loads in the Portland General Electric (PGE), Cowlitz County PUD, and Clark County PUD service territories to improve the accuracy of the non-wires potential estimates for this analytically manageable area.

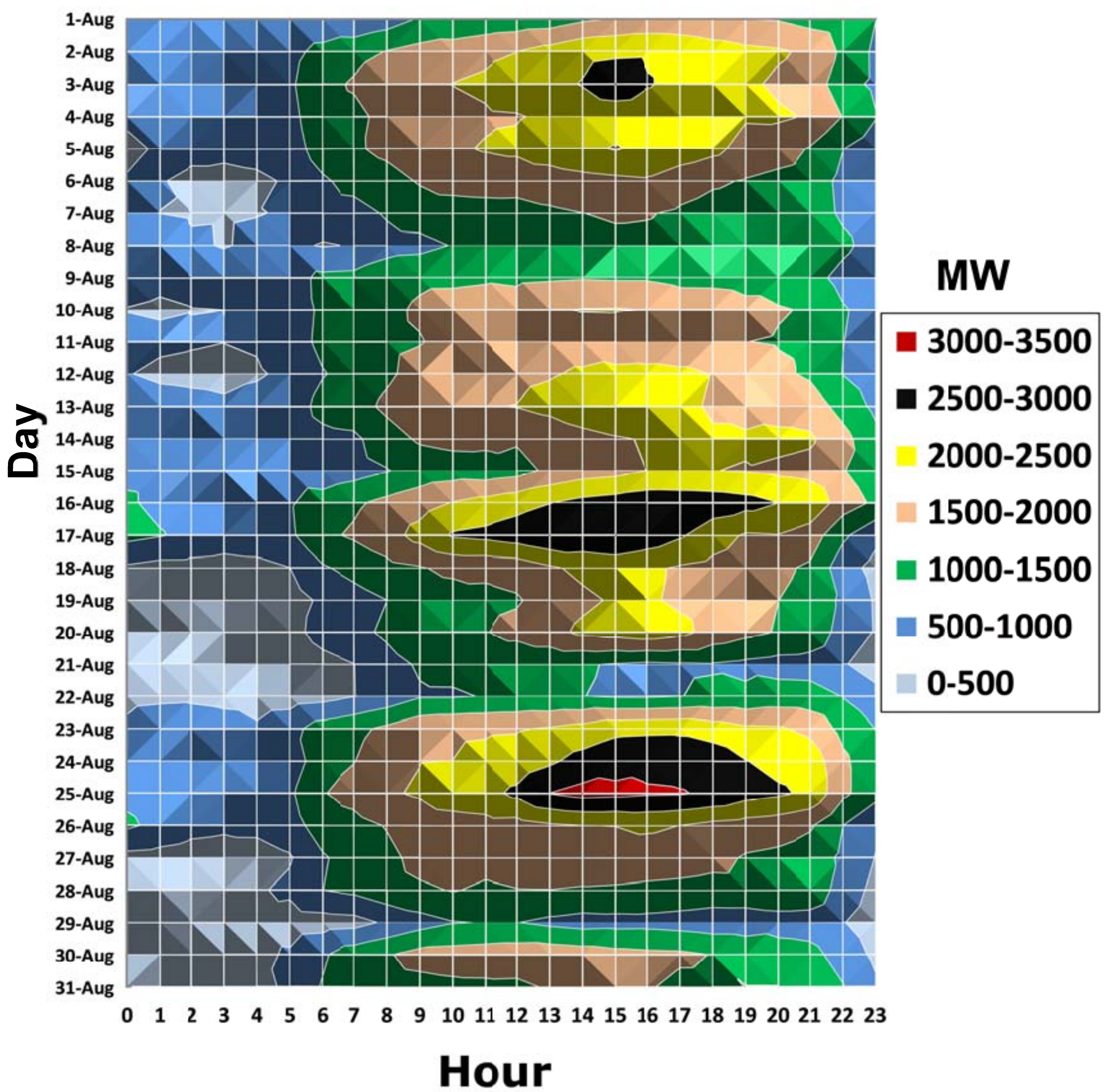
4.1.1 CRITICAL PEAK PERIOD DEFINITION

In addition to defining the maximum total path load limits on the system, it is also necessary to understand when the system critical peak hours are likely to occur. The definition of the critical peak period determines what types of load reduction measures will contribute to peak demand reductions. For example, since the critical peak period for flows on the I-5 paths occurs during the summer, energy efficiency measures targeted at use in the winter, such as space heating, will not help to alleviate peak demand. We compare the load profile of a given energy efficiency or demand response measure to the hours of peak demand to determine how much peak savings to attribute to that measure.

The figure below shows a topographical map of hourly peak demands along the South of Allston path during the high demand period of August 2010. The hours in each day are shown across the x-axis, the days are shown on the y-axis, and the peak flows along the South of Allston path are shown across the third dimension, the z-axis. The hours shown in red represent the highest demand hours on the constrained path, and the hours shown in black are when South of

Allston flows are within approximately 20% of the path's 3100 MW summer total transfer capability.

Figure 7. South of Allston Peak Flows in August 2010 - Topographic Representation



Critical Peak Defined as:
Mon-Fri 12pm – 7pm

The figure indicates that the periods of highest flows in the summer tend to occur during afternoon hours on weekdays, with a maximum peak around 2pm-4pm. These are the hottest hours of the day, so they likely coincide with the hours of peak demand for cooling of homes and commercial buildings in the greater Portland area. On some days, the high demand stretches through 7pm, likely reflecting extended need to cool homes, as well as the effect of simultaneous high residential and commercial electric needs at this time of day.

4.2 Update local area demand forecast

In order to determine when and by how much the relevant path limit in the region would likely be exceeded in the absence of the proposed I-5 Corridor Reinforcement project or the deployment of other non-wires alternatives, E3 obtained the latest summer peak load forecasts for utilities in the greater Portland area and estimated the effect of this update on flows along the SoA and SoN paths.

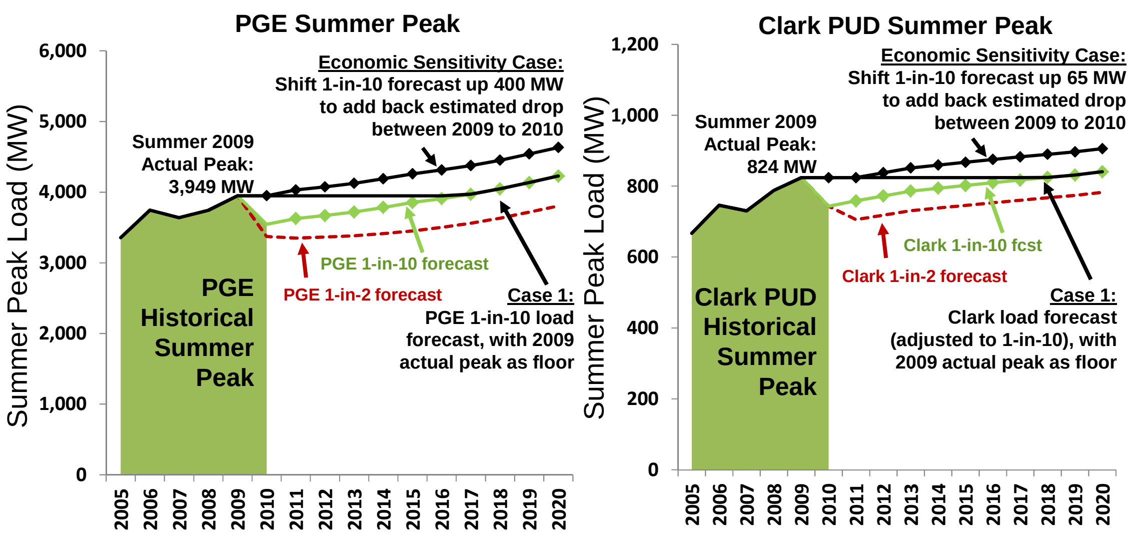
BPA emphasizes the importance of forecasted summer peak load growth as a driver of need for the I-5 Project. A forecast of summer peak demand for power in the greater Portland and Vancouver area, given the expected range of a number of key drivers, must consider uncertainty. The key factors will include: the intensity and duration of heat waves in the area, the adoption rate of air conditioners, the speed of regional economic recovery, and the level of new construction and population growth over the next 5 to 10 years. How much power will flow on the existing I-5 transmission facilities during future summers is also affected by: hydro conditions in a given year, whether a heat wave in Portland coincides with high temperatures in California, and the construction and operational conditions of renewable and non-renewable generation and other transmission in the region. Given the long lead time to develop the I-5 Project, as well as the potential negative impact of overloads and outages if the I-5 Project is needed before it can be constructed, BPA planners should rightly approach these uncertainties conservatively. At the same time, they must also seek to avoid constructing a line significantly before it is expected to be needed.

In this screening-level analysis, we address the impact of this load growth uncertainty by creating two load growth cases:

- **Case 1**: This case which uses the latest forecasts of summer peak load from BPA's customer utilities, adjusts these forecasts to reflect the response of power demand to summer temperatures at a level expected to occur once in every 10 years (1-in-10), and also sets a floor at the highest observed historical summer peak (from July 2009), and
- **Economic Sensitivity Case**: A more conservative sensitivity case in which economic conditions rebound and growth occurs more rapidly than in the utilities' base case forecast.

The figure below characterizes the load growth forecast used for each case, and compares this to the 2005 through 2010 historical summer peaks in PGE and Clark PUD service territories.

Figure 8. Load Growth Cases for PGE and Clark PUD



Actual summer peak power demand for PGE and Clark PUD (shown as the shaded area above) set historical records during a July 2009 heat wave and then declined in 2010 due to a combination of weaker economic conditions in the area and lower summer peak temperatures. Both utilities' forecasts (completed in June 2010 for PGE and November 2010 for Clark) show relatively slow peak growth for the next 5 years. For the non-wires analysis, E3's Case 1 (shown as the black line without markers) uses the utilities' peak forecast expected under 1-in-10 temperatures, but sets the 2009 peak as a minimum level—reflecting the potential of connected power loads to rapidly reach the 2009 peak level again under certain conditions. The more conservative Economic Sensitivity Case (shown as the black line with markers) shifts the utility 1-in-10 load forecast upward by the size of the 2009-10 drop to reflect more rapid economic recovery and weather effects similar to 2009.

Clark PUD provided only a summer peak forecast for 1-in-2 temperatures, so E3 adjusted Clark's 1-in-2 forecast upward proportionally based on the relative size of PGE's 1-in-10 peak versus its 1-in-2 forecast. Expected conservation savings were removed from (i.e., load was added back to) these forecasts, as EE potential will be addressed directly as a non-wires measure. PacifiCorp did not provide an updated load forecast specific to its Portland area load, so our analysis used the same peak load estimate that original BPA power flow studies used for PacifiCorp. We have also chosen to leave Cowlitz PUD load growth unchanged from loads used in the base case BPA load flow analysis because we were unable to obtain as recent data for Cowlitz load as we used for PGE and Clark PUD. We do not believe these choices materially affect the results of this analysis.

4.3 Assess impact of updated load forecast on critical path flows

To assess the effect of these updated load forecast scenarios on expected path flows along I-5, we first must calculate the difference between the updated load forecast and the loads assumed in BPA's original 2013 and 2018 power flow cases. We can then multiply this difference by the relevant load flow distribution factors to estimate the resulting change in path flows under the new load forecast assumptions for this screening analysis.

The load forecast in the Economic Sensitivity Case is quite close to the loads that were used at the time BPA created its 2018 power flow cases for determining the need for the I-5 line, and is approximately 115 MW higher for Clark and PGE in 2013 than the load forecast in BPA's 2013 power flow analysis.

The Case 1 load forecast for Clark and PGE is approximately 90 MW lower in 2013 than the load assumed in BPA's 2013 analysis, and is approximately 460 MW lower in 2018 than the load in BPA's 2018 power flow analysis.

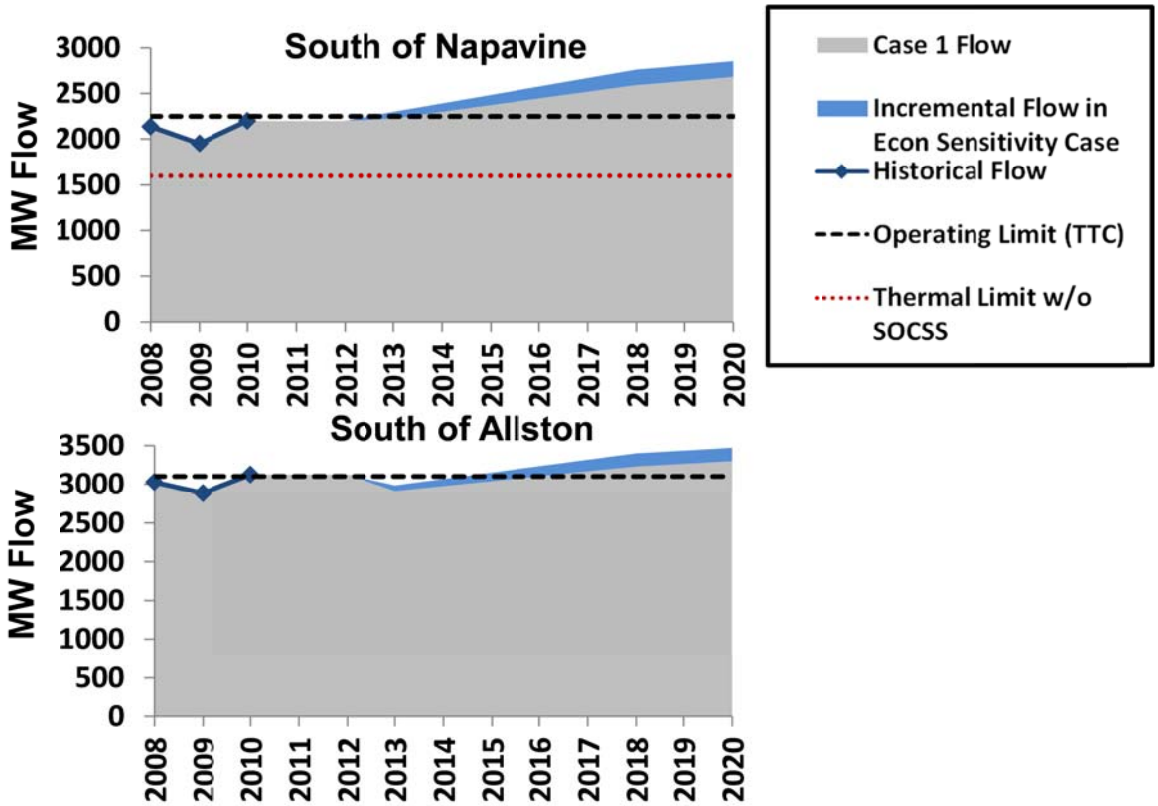
The table below compares the path flow results from the BPA 2018 simulation of critical I-5 paths to the updated 2018 flows after adjusting the load forecast and applying the relevant load flow distribution factors to the differences. The Economic Sensitivity Case load forecast results in flows quite similar to the BPA simulation because the updated load for 2018 is only slightly different. The Case 1 load forecast, by contrast, results in flows that are approximately 170 MW lower than BPA's simulation on SoN and SoA paths, and 105 MW lower on the Raver-Paul path.

Table 4. 2018 Path Flow Forecast using Updated Load Growth Cases

Path	Proxy Path Limit	Modeled Flow in 2018 (BPA TS)	Economic Sensitivity Case: 2018 Flow Result	Case 1 Load Forecast: 2018 Flow Result
Raver-Paul	**1,450 MW**	1,481 MW	1,482 MW	1,375 MW
South of Napavine (SoN)	**2,250 MW**	2,760 MW	2,762 MW	2,593 MW
South of Allston (SoA)	**3,100 MW**	3,397 MW	3,399 MW	3,230 MW

We use similar calculations to update flows from BPA's 2013 power flow analysis. In the chart below, we compare the annual SoA and SoN flows under the two load growth assumptions. For 2014-2017, we interpolate flows from the 2013 and 2018 cases. For 2019 and 2020, we apply load flow distribution factors to the forecasted load growth above 2018 levels.

Figure 9. I-5 Path Flow under Updated Load Growth Cases, 2008-2020



4.4 Value of Line Deferral

4.4.1 REVENUE REQUIREMENT SAVINGS OF LINE DEFERRAL

To evaluate the cost savings that BPA customers would realize if the proposed I-5 Corridor Reinforcement Project were deferred, we estimate the present value of transmission revenue requirement savings from the line deferral. This calculation uses the "differential revenue requirement" method, which includes all of the avoidable costs of the line and excludes the cost of land, which we considered non-deferrable for this analysis.

Other key input assumptions for calculating the transmission revenue requirement (TRR) savings include an assumed 2.2% per year inflation rate and a utility nominal weighted average cost of capital (WACC) of 7.69%. We use a 1.19 scalar to gross up the net cost of the project to TRR levels, which accounts for operation and maintenance and other costs of the project not specifically captured in the capital budget.

The results of the differential revenue requirement calculations are shown in the table below. If the transmission line could be deferred by one year, to summer of 2016, this could save Bonneville ratepayers $17.8 million, which is equivalent to a payment of $52/kW or $52/kW-year. Note that the $/kW and $/kW-yr values are based on the kW of reduction needed at the load center to enable deferral of the I-5 Project, so the values have been adjusted downward to reflect the load flow distribution factors. The $/kW-year deferral value declines for longer deferrals primarily because deferring the project to later years require acquiring an increasingly large number of kW of load reduction, but the value is also affected by time-value discounting over a larger number of years.

Table 5. Transmission Revenue Requirement Savings of Deferring I-5 Reinforcement (2015 – 2020)

	2015	2016	2018	2020
Transmission Revenue Requirement Savings ($M)	$17.8	$34.6	$65.8	$93.9
$/kW of reduction at load center (contracted)	$52	$63	$69	$78
$/kW-year (levelized)	$52	$32	$18	$14

One issue important to consider is that the I-5 Reinforcement Project could also possibly provide incremental revenue in the form of increased sales of firm transmission service to generators and other BPA transmission customers. BPA currently estimates that 970 MW of firm services requests from the 2008 and 2009 Network Open Season process could be enabled through the construction of the I-5 Project and additional projects in other parts of BPA's transmission system. The exact incremental value will depend on what type and quantity of non-firm service that customers making requests may already be taking from BPA. However, serving the additional requests by constructing I-5 would potentially provide incremental revenues for BPA, which could have a downward effect on overall transmission rates and partially offset the cost of the line.

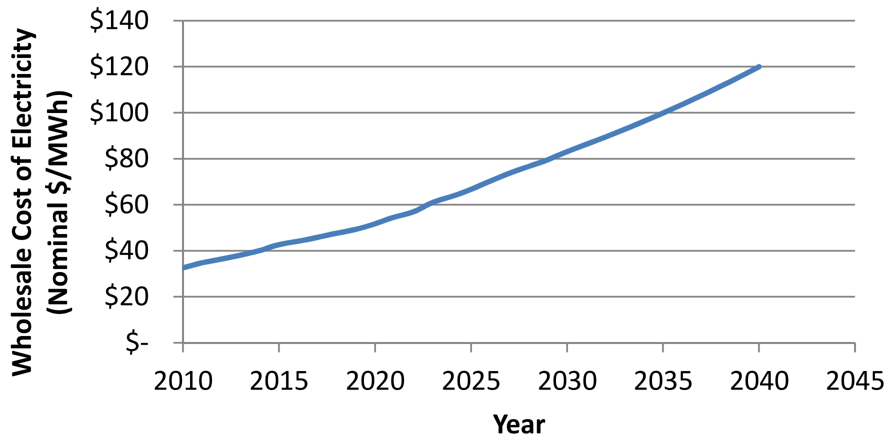
Because details regarding the parties making these firm service requests was not available for this screening-level analysis, we were unable incorporate data on these incremental revenues into our analysis and were hesitant to speculate on their size. To the extent, however, that actual incremental revenues could be enabled by the I-5 Project, these revenues would partially offset the incremental revenue requirement for the I-5 Project and would create a commensurate reduction in the expected savings from deferring the line.

4.4.2 AVOIDED COSTS OF ELECTRICITY AND NATURAL GAS

The other value component of the non-wires measures such as energy efficiency is the avoided cost of energy and generation capacity. Energy efficiency can create economic savings by deferring the need for new transmission, as well as reducing capacity procurement costs and energy procurement costs. These changes to energy and capacity costs must be accounted for in our analysis.

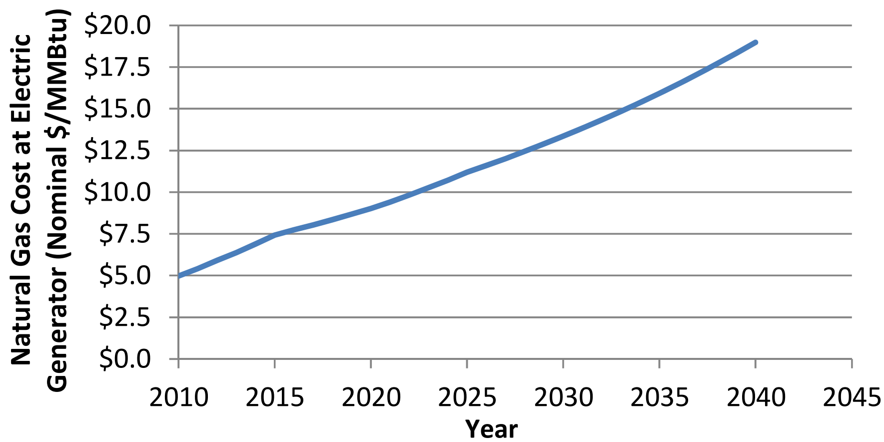
To calculate the avoided cost of electricity and natural gas, we use the Northwest Power and Conservation Council's (NWPCC's) Sixth Power Plan forecast of the cost of energy. Wholesale electricity costs are forecast over a 30-year horizon for each of nine time-of-use (TOU) periods (The nine TOU periods include peak, off-peak and shoulder prices for summer, winter and spring). The cost of wholesale power in each time period is compared to the shape of the energy savings in that period for energy efficiency measures to determine whether the measure is cost-effective. Figure 9 below shows the TOU weighted average forecast of wholesale power prices in the BPA region.

Figure 10. NWPCC Sixth Power Plan Forecast of Wholesale Electricity Prices, TOU weighted average (2010 – 2040)



For the forecast of natural gas purchases, we also use the NWPCC Sixth Power Plan's forecast of West-side (West of the Cascades) natural gas commodity prices, as well as the retail forecast for residential, commercial, industrial and electric generator customers.

Figure 11. NWPCC Sixth Power Plan Forecast of Natural Gas Prices for an Electric Generator, West Side (2010 – 2040)



The analysis also incorporates the value of avoided generation capacity costs from non-wires alternatives like energy efficiency. To maintain resource adequacy, each control area must maintain sufficient generation capacity to meet its peak load plus any reliability reserve margin. Distributed generation, demand response, and energy efficiency can each reduce the need for investments in new generation capacity by reducing the magnitude of the system peak.

The most common proxy value used for the cost of generation capacity is the residual cost of a new combustion turbine (CT). The CT's annualized fixed costs, less any revenues that the unit could earn through operations in local energy markets, is also known as the Cost of New Entry (CONE).

The Northwest currently has a large surplus of generating capacity—enough to maintain resource adequacy during the winter peak until approximately 2024.

Under such conditions, the value of capacity is diminished. Accordingly, the non-wires alternatives analysis uses a two-part forecast for the valuation of capacity:

- **Long Run Value (post 2024):** the long-run value of generation capacity is calculated as the residual capacity cost of a new GE LM6000 gas-fired combustion turbine.
- **Short Run Value (2010-2024):** in the near term, 2010, the value of capacity is set equal to the annual Fixed O&M cost of the LM6000. In 2024, the value of capacity reaches the long-run value of a new CT, as described above. The capacity values in each year between 2010 and 2024 are calculated by linear interpolation between these two values.

The fraction of capacity value captured by each resource depends on its production profile: resources that result in larger reductions in load at the time of the system peak receive larger credits for generation capacity value. Flexible resources—including most demand response programs and distributed generation resources—receive full capacity value for each kilowatt installed, as the full amount of installed capacity is assumed to be available during the system peak. For energy efficiency resources, the allocation of capacity value is based on representative end-use load shapes, which are used to determine each measure’s peak impact.

5 Non-Construction Alternatives to Defer Transmission Line

The final step in the analysis is to evaluate whether there are sufficient cost-effective resources available within the greater Portland area (and the area for generation redispatch options) to present a credible portfolio of non-wires measures that would allow BPA to defer construction of the proposed I-5 Project. In this section, we summarize our evaluation of the potential and costs of energy efficiency, demand response, and distributed generation, as well as redispatch of existing generators on the BPA and neighboring systems.

5.1 Energy Efficiency

For energy efficiency and other load-reduction measures, we have excluded Cowlitz PUD from our target area because load reductions in Cowlitz reduce flows on the SoN path but increases SoA path flows. Load reductions for PGE and Clark PUD, on the other hand, reduce flows on both SoN and SoA; these reductions are more unambiguously beneficial as non-wires measures for helping defer the project.

The energy efficiency measures evaluated in this study are adapted primarily from the NWPCC's Sixth Power Plan.[7] Details such as expected energy savings for the EE measures included in the Sixth Power Plan have been reviewed and validated through the NWPCC's Regional Technical Forum.[8] The energy efficiency resource potential is scaled down to represent the Portland General Electric and Clark County PUD service territory using a number of techniques:

1. Residential measures are screened for the appropriate climate zone. PGE and Clark are located in heating zone 1 and cooling zone 1, so only measures that are applicable to these climate zones are used.

2. The total residential energy efficiency resource potential is scaled based on the number of residential customers in the region (from EIA Form 861 filings) and based on estimates of the vintages and types of residential buildings, adapted from the U.S. Census Bureau's American Community Survey of residential buildings.

3. The total commercial energy efficiency resource potential is scaled based on an estimate of the commercial square footage, by business type, in the Portland area. The estimate of commercial square footage in the area is based on a number of data sources including Washington and Oregon state commercial square footage data, adjusted based on the number of commercial establishments in Clark, WA, and Multnomah counties.

4. The total industrial energy efficiency resource potential is scaled based on the total industrial electric demand in the area, as reported in EIA Form

[7] http://www.nwcouncil.org/energy/powerplan/6/default.htm
[8] http://www.nwcouncil.org/energy/rtf/

861 data.

We then apply fairly conservative adoption schedules for PGE/Clark PUD energy efficiency resource potential to develop a likely deployment schedule for energy efficiency in the area. For each potential energy efficiency measure, we calculate the maximum possible number of installations in the study area. However, the actual rates of adoption modeled for each measure depends upon a number of factors. First, the adoption curves differ depending upon the mode of replacement: retrofit, replace-on-burnout, or new installations.

1. **Retrofit:** The adoption of retrofit measures is based on an assumption of logistic growth.
2. **Replace-on-burnout:** The adoption of replace-on-burnout measures assumes that the number of measures adopted each year is inversely proportional to the measure's lifetime.
3. **New installations:** The adoption of new measures is based on forecasts of growth within each sector.

Each measure's potential is further limited by a participant payback function, which reduces the adoption of measures with extended participant payback periods under the assumption that such measures would be less likely to be adopted by consumers within the study area.

Finally, the Regional Cost Test screen is applied, consistent with the recommendations of the Non-Wires Solutions Roundtable Sub-Committee on

"Defining the Cost Test."[9] The Regional Cost Test is similar to the Total Resource Cost (TRC) cost test, but includes all energy efficiency measures with a benefit-cost ratio greater than 0.9,[10] and a few other adjustments for the Bonneville region. We also include the NWPCC's estimate of "non-energy" benefits of energy efficiency measures, such as the avoided water and avoided detergent cost of more efficient clothes washers.

The Regional Cost Perspective and Total Resource Cost perspectives are similar methods used to comparing the costs and benefits of a particular alternative to the costs and benefits of a proposed solution (such as the I-5 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.

The relatively conservative assumptions used here regarding EE adoption schedules and the participant payback function result in lower overall levels of EE achievement than the those identified in the NWPCC's 6th Power Plan and the Energy Trust of Oregon's EE resource assessment developed for PGE and PacifiCorp.[11] While the 6th Power Plan outlines aggressive EE targets based on achievement of a high percentage of the total EE technical potential, it is appropriate to use more conservative assumptions in this analysis so that we

[9] Non-Wires Alternative Roundtable, sub-committee on "Defining the Cost Test," recommendations available at: http://transmission.bpa.gov/PlanProj/Non-Wires_Round_Table/NonWireDocs/P3.pdf

[10] This is the equivalent of comparing the incremental system cost of conservation to 110 percent of the incremental system cost of any non-conservation measure, as specified by the Northwest Power Act of 1980, §3(4)(D), 94 Stat. 2699 (Available at: **http://www.nwcouncil.org/library/poweract/poweract.pdf**).

[11] Stellar Processes and Ecotape (Prepared for the Energy Trust of Oregon), "Energy Efficiency and Conservation Measure Resource Assessment for the Years 2008-2027", February 2009. (Available at: **http://energytrust.org/library/reports/090226_ee_conservmeasure_resourceasses.pdf**)

can estimate the achievable EE and resulting summer peak load reductions that could be confidently relied upon when deciding whether or not to defer the I-5 Transmission project.

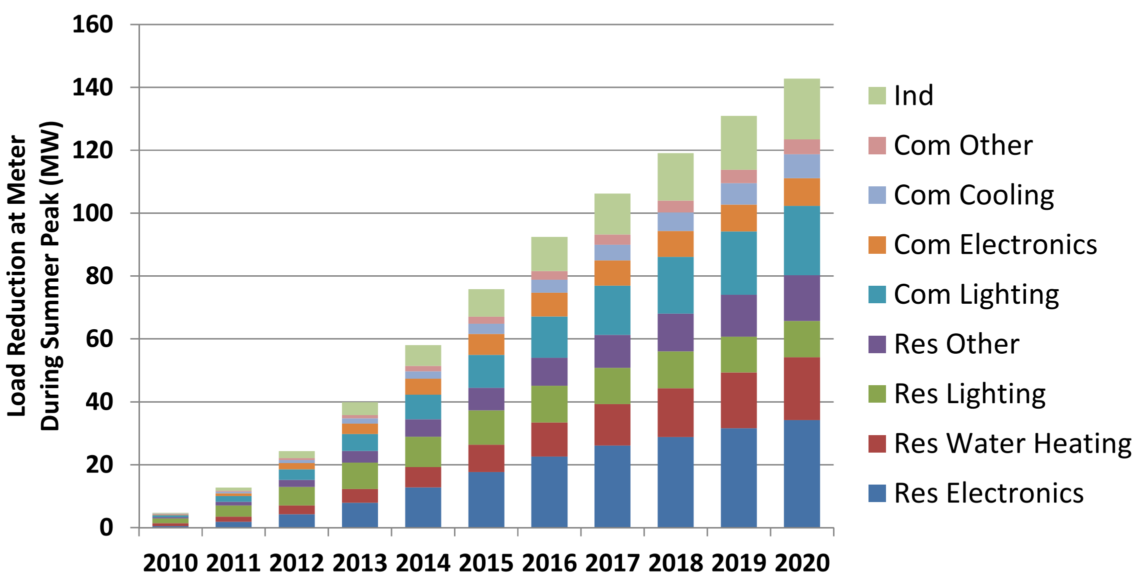
5.1.1 DISTRIBUTION SYSTEM EFFICIENCY IMPROVEMENTS

The NWPCC 6th Power Plan includes four new energy efficiency measures which are collectively termed "distribution system efficiency improvements" (DEI). While the 6th Power Plan notes that these measures may have the potential to save a significant amount of energy, their potential impact on peak demand is extremely limited. We find an estimated combined impact of cost-effective DEI of only 15.8 MW by 2020. We have included these measures in the analysis although the overall effect on the results is negligible.

5.1.2 ENERGY EFFICIENCY COST-EFFECTIVE POTENTIAL RESULTS

The figure below illustrates the energy efficiency potential which passes the cost-effectiveness screen, using a 0.9 benefit-cost ratio. By 2020, nearly 143 MW of summer peak load reductions and 133 aMW of energy savings could be achieved using an aggressive energy efficiency deployment strategy in the region. Summer peak savings largely come from a balance of residential (56%) and commercial measures (30%), with a small about of savings provided by the industrial sector (14%). The small difference between the peak load reduction and the aMW energy savings reflects the limited availability of efficiency measures that target loads in summer peak hours. Commercial cooling is identified as cost effective and included in the analysis, as is residential cooling (grouped into the "Res Other" category in the figure below), but the overall size of reduction from these measures is relatively small, due in part to the lower current level of penetration for air conditioners in the Portland area compared to certain other cities. The majority of savings indentified by the screen comes from measures that reduce energy use by lighting and electronics, both of which have relatively flat hourly load reductions profiles.

Figure 12. PGE/Clark Cost-Effective Energy Efficiency Peak Demand Reductions (2010 – 2020)



Since the savings shown in the figure from theses measures is estimated at the customer meter, they would provide substantially smaller summer peak flow reductions on the SoA and SoN paths. After adjusting for losses between the meter and the transmission constraints, and applying the 0.37 load flow distribution factor, we estimate that identified energy efficiency measures could reduce flows on SoA and SoN by 57 MW in 2020.

5.2 Demand Response and Direct Load Control

In the screening tool for the non-wires alternatives analysis, we consider 17 different types of demand response (DR) measures for commercial, residential and industrial customers. The input assumptions for DR measures' cost and peak savings impacts are from BPA program data, supplied by BPA staff. The Direct Load Control (DLC) measures come from the BPA demand response team and from the PacifiCorp 2009 Integrated Resource Plan.

Eight of the 17 DR measures pass the cost effectiveness screen for the I-5 non-wires analysis. These measures include emergency and capacity market DR for large commercial and industrial customers, peak time rebates for residential and small commercial customers and critical peak pricing for large commercial customers.

It is important to note that many of the DR measures evaluated here are assumed to operate both in the summer as well as the winter months. This operational pattern enables the measures to provide both (a) transmission capacity deferral savings by addressing local summer peak power flows on the I-5 Corridor, as well (b) generation capacity savings by addressing the winter system peak for the overall Northwest region. The combination of both types of capacity savings–especially the avoided cost of generation capacity, which grows to over $100/kW-yr by 2020–results in relatively high benefits-cost ratios for the DR measures evaluated.[12]

[12] See Section 4.4.2 for a full description of the assumptions used in this analysis to estimate the avoided cost of generation capacity for the Northwest region.

Combined, the overall peak reductions from these programs are expected to be relatively small compared to the peak reductions needed to defer the I-5 Project. By 2013, cost-effective DR programs could supply approximately 16.3 MW, and by 2020, DR programs could supply 54.5 MW of peak reductions (at the customer meter level). The table below shows some of the key assumptions for the DR measures that were identified to be cost-effective options for reducing summer peak demand in this screening analysis.

Table 6. PGE/Clark Cost-Effective Demand Response and Direct Load Control Measures

DR-DLC Program Name	Sector	DR/DLC Savings in 2020 (MW)	Total Resource Cost (TRC) Benefit-Cost Ratio
Emergency DR - Large Commercial (>200kW)	Commercial	1.25	4.50
Emergency DR - Industrial	Industrial	0.52	8.27
Capacity Market DR - Large Commercial (>200kW)	Commercial	21.59	3.47
Capacity Market DR - Industrial	Industrial	9.08	3.64
Peak Time Rebate - Residential	Residential	3.93	3.90
Peak Time Rebate - Small & Med Commercial (<200kW)	Commercial	15.33	6.49
Critical Peak Pricing - Large Commercial (>200kW)	Commercial	0.60	6.49
Critical Peak Pricing - Industrial	Industrial	2.17	3.30
Total Portfolio Selected		**54.5**	**3.92**

5.3 New Distributed Generation

Another option considered in the non-wires alternatives approach is the possibility of developing new local generation in the greater Portland area. The cost-effectiveness analysis evaluated 18 types of new generation. The cost effectiveness test for new generation accounts for both the capital cost of the new generation, as well as the variable costs of operating the plant, any revenue associated with sales of the power generated, and avoided capacity costs and avoided electricity procurement costs.

We assume that dispatchable peak generation resources are only operated during the few hours per year needed to meet the critical peak demand for generation capacity on the system and for reducing peak transmission loading on the I-5 corridor. We use a capacity factor of 1% for new dispatchable resources. This is a conservative assumption if the generator could cost-effectively run for additional hours to recoup additional revenues from the electricity markets. However, it is uncertain how much additional revenues a peaking generator could realistically earn from the electricity markets. Based on the assumed technology characteristics, none of the generator technologies considered in our screening tool (other than gas turbines larger than 80 MW in size, which could potentially be difficult to site in the Portland area) currently has a benefit-cost ratio greater than 1.0.

The Portland area does have over 60 MW of existing distributed generation, including small generators located at customer sites in the PGE service territory. It would be useful to explore whether BPA could partner with PGE to be able to have this generation available to respond during times of peak loading on the critical I-5 transmission paths.

5.4 Redispatch of Existing Generation

Existing generation could be an important component of this non-wires analysis since changes to the dispatch pattern of existing generation may help to alleviate transmission constraints. If certain generators located to the north of the constrained SoA and SoN transmission paths could be contracted to lower their output for a limited number of hours in the summer when high temperatures are driving peak load in the Portland area, and if it were feasible to replace this energy by ramping up output from generators located the south of Portland (possibly including plants in California), then this "redispatch" approach could provide a sizeable reduction to the flows on critical I-5 paths.

To assess the non-wires potential of possible redispatch opportunities, we identified generators to the north of the SoN and SoA paths that were running in BPA's 2013 and 2018 power flow cases and applied a reduction (or "dec") to the output of some of these generators, while simultaneously making an output increase (or "inc") for certain generators located to the south of the constrained I-5 paths. BPA provided a set of load flow distribution factors to indicate what effect the combination of a 1 MW increase and 1 MW decrease from particular pairs of generators would have on power flows on the Raver-Paul, South of Napavine, and South of Allston lines.

Our analysis indicates that certain redispatch combinations ranging in size from 500 MW to over 1,500 MW would be required to enable deferral of the I-5 Project for five or more years, assuming that this redispatch were implemented in combination with the EE, DR, and DG programs discussed earlier in this section. The total amount of generator redispatch required would depend on which combination of generators would participate in the program, and on which load growth scenario is assumed.

At the time of this screening study, we are unable to fully identify the economic or operational viability of these redispatch options, in part because the details and pricing of such options would need to be determined through bilateral negotiations between BPA and potential participating generators. Such contracts could potentially take the form of an option through which BPA would pay to be able to instruct the generator not to operate during critical peak hours for a limited number of days each summer.

Any generators that redispatch down would need to have operational flexibility to reduce output at the time the path flow reduction is needed, as well as the contractual flexibility with its existing customers so that the generator could not deliver during a particular hour, or could arrange with a separate arrangement located south of the constrained transmission to replace the energy it would have generated. Additionally, any redispatch option would have to be evaluated by BPA Transmission Services to confirm that it would not cause technical problems on other parts of the transmission system. For example, flows on the Raver-Paul path to the north of Napavine would need to remain under the path's 1,450 MW total transfer capacity limit.

The cost effectiveness of any redispatch option would depend on both the contracted price that BPA could negotiate with relevant generators, as well as the total quantity of generation that BPA would require to be redispatched. We do not speculate on this issue in this screening analysis because such information could be commercially sensitive as an input to future negotiations with generators.

Further analysis is required to fully investigate the implementation feasibility and cost-effectiveness of redispatch-based non-wires measures.

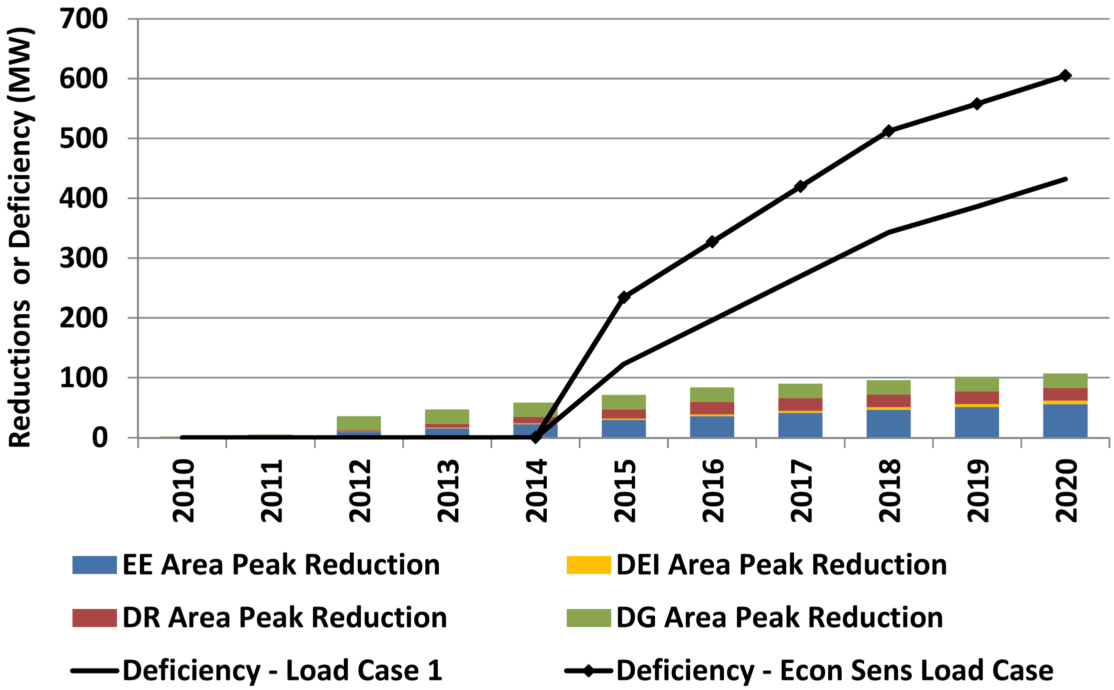
6 Summary of Results

The I-5 non-wires alternative screening study finds that the identified cost-effective energy efficiency (EE) and demand response (DR) measures, as well as contracted distributed generation (DG), would not be sufficient to defer the proposed transmission line on their own.

However, if these measures could be implemented up to their cost-effective levels ***and*** if feasible and cost-effective generator redispatch option contracts could be implemented, then the combination of these actions could potentially defer the need for the proposed I-5 Project for five or more years past the 2015 need date established by BPA's power flow analysis.

The figure below compares the identified non-wires measure potential, excluding generator redispatch options, to the required peak savings that would be needed to keep path flows below their acceptable limits and potentially to defer the I-5 Project. The reductions are shown as reductions to MW path flows at the transmission constraint, and the deficiency is based on forecasted overloads on the South of Napavine path under each load growth scenarios.

Figure 13. Comparison of Non-Wires Alternative Program Peak Savings with Annual Requirements for Peak Savings



While these measures are inadequate on their own to provide the full reduction required to defer the I-5 Project, the measures identified do appear to be quite cost effective. As Table 7 illustrates below, the total resource cost test (i.e. regional cost test) of the portfolio of identified EE and DR measures has a benefit-cost (BC) ratio of 1.94,[13] and would produce an estimated net benefit of $423 million in present value over the lifecycle of the measures. The total benefits shown in the table under the total resource cost test include the

[13] Note that the table excludes the costs and benefits of non-wires measures related to contracting with existing DG and large generators for redispatch because further analysis would be needed to determine the costs of those measures.

avoided costs of energy procurement, as well as avoided transmission and generation capacity costs enabled by the EE and DR measures. The lifecycle costs include any equipment installation cost for the measures, as well maintenance and program administrative costs.

Table 7. Net Present Value of Costs and Benefits of Non-Wires Portfolio from Three Cost Perspectives

Cost Test	Total Benefits ($M)	Total Costs ($M)	Net Benefits ($M)	Benefit-Cost (BC) Ratio
Total Resource Cost Test	$871.2	$448.2	$423.0	1.94
Participant Cost Test	$991.3	$325.3	$666.1	3.05
Societal Cost Test	$1,123.8	$456.1	$667.7	2.46

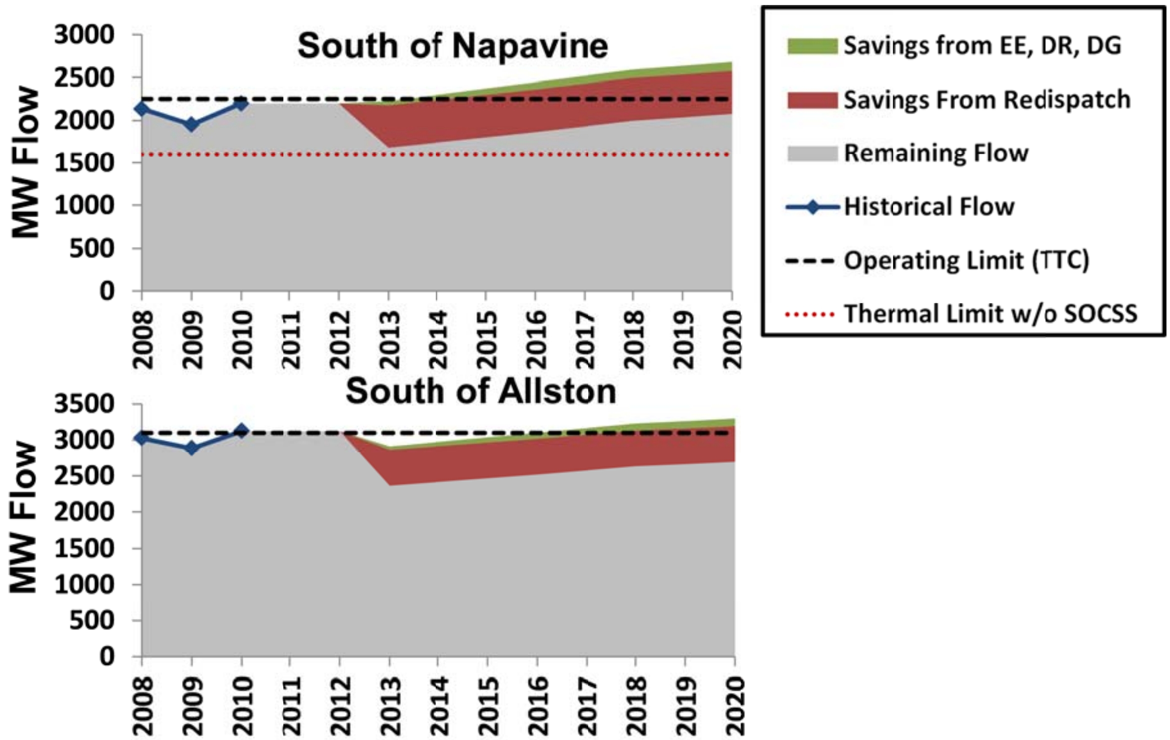
Table 7 also presents the costs and benefits of the identified non-wires portfolio from additional cost test perspectives. The participant cost test measures the lifecycle net benefits for a participating customer who installs the EE, or curtails load as part of a DR program. This test includes benefits such as the incentives paid to the customer and the customer's bill savings due to the measures, as well as the life-cycle costs of the measures to the participant. The high benefit-cost ratio of the identified portfolio under this cost test is a good indicator of how acceptable the portfolio of measures might be to individual customers who could participate in the program.

Finally, the societal cost test considers any environmental externalities, such as reduced air emissions, in addition to all of the direct cash costs evaluated under the total resource cost test. For the identified portfolio of EE and DR measures, these additional benefits related to reduced externalities result in higher net benefits than those estimated under the total resource cost test.

Overall, this cost effectiveness analysis indicates that, though the identified EE and DR measures provide insufficient load reductions on their own to defer the need for I-5 transmission upgrades, these measures could serve as a quite economically attractive component of a larger portfolio of non-wires measures that includes generation redispatch.

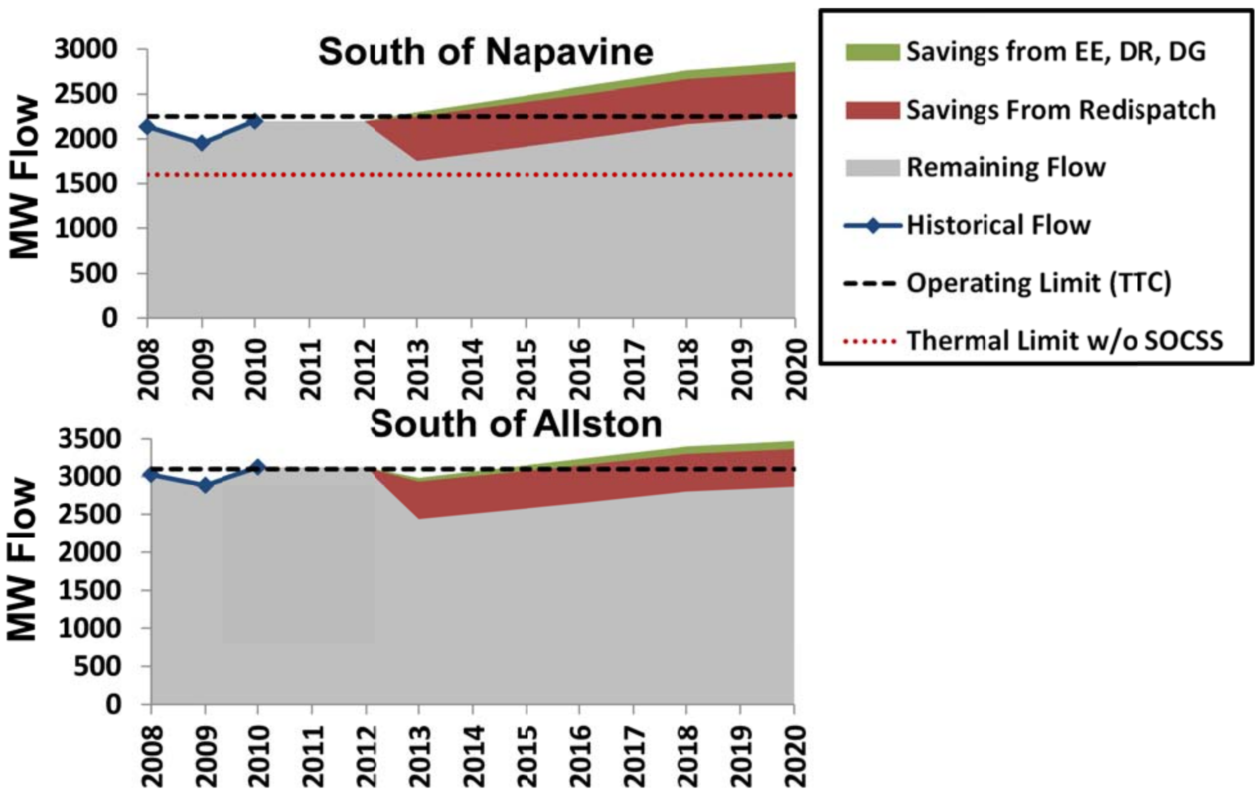
Using the Case 1 load forecast, the figure below shows the identified non-wires potential from combining a portfolio of EE, DR, and DG with generator redispatch of up to 1,500 MW. If feasible, these non-wires measures could defer the transmission project's need date by 5 or more years beyond the 2015 time frame identified in BPA's analysis. These non-wires measures would keep path flows on the Raver-Paul, South of Allston, and South of Napavine paths below their identified limits.

Figure 14. Identified non-wires potential and resulting flows, using Case 1 load forecast



As the figure below shows, under the higher Economic Sensitivity Load Growth Case, flows on the South of Napavine path would exceed its transmission constraints sooner than in the Case 1 load growth scenario, and the total flow reduction required in each year to remain below path limits and defer the need for the I-5 Project would be larger in size. Up to 1,500 MW of generator redispatch combined with local EE, DR, and DG again appear to have the potential to reduce loading on both the SoA and SoN paths below their path limits for the years examined. Thus, these measures, if feasible, could potentially enable BPA to defer the need for the I-5 Project by five or more years beyond the identified 2015 need date under the Economic Sensitivity Load Growth Case as well.

Figure 15. Identified non-wires potential and resulting flows, using Economic Sensitivity Load Growth Case.



These screening-level results indicate that it would be useful to investigate further the operational and economic feasibility of implementing these measures, especially the generator redispatch options.

7 Conclusions and Recommendations

Based on the potential identified in this screening study, we recommend that BPA explore the feasibility of generator redispatch and accelerated EE and DR program implementation in greater depth. This report's high-level screening analysis has not assessed the implementation feasibility of a generator redispatch contract from an operational or economic perspective, so the feasibility of this approach remains uncertain. The price to BPA of this option could only be determined through a bilateral negotiation with an interested generator. Also, before signing a long-term agreement, BPA would need to perform operational analysis to confirm that the particular redispatch arrangement could provide sufficient flow reduction on the I-5 corridor while avoiding overloads on other parts of the transmission system, including the Raver-Paul transmission path. An implementation feasibility study would be useful to define more specific details of possible EE, DR, and DG programs, as well as identifying customers with a high probability of providing useful generator redispatch.

If non-wires options were pursued to defer the I-5 Project, BPA would need to monitor and regularly update its regional load growth forecasts to ensure that the changes in expected I-5 path flows that result from these load forecasts remain within the range that the non-wires measures are capable of mitigating.

If contracting for sufficient generator redispatch turns out to be an infeasible option, however, BPA may still face a tight schedule to complete the I-5 Project by the date when it is expected to be needed for the system. Thus, we also recommend that, in parallel to performing a non-wires implementation feasibility analysis, BPA maintain its current schedule for permitting the I-5 Corridor Reinforcement Project.

List of Acronyms

Acronym	Definition
aMW	Average Megawatt
BC ratio	Benefit Cost ratio
BPA	Bonneville Power Administration
DEI	Distribution System Efficiency Improvements
DG	Distributed generation
DLC	Direct Load Control
DR	Demand response
E3	Energy and Environmental Economics, Inc.
EE	Energy efficiency
MW	Megawatt
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
TS	Transmission Services (part of BPA)
TOU	Time of Use
TRC	Total Resource Cost
TRR	Transmission Revenue Requirement
TTC	Total Transfer Capability
WACC	Weighted Average Cost of Capital