Hooper Springs Non-Wires Alternatives Screening Study

Prepared for:

Bonneville Power Administration

January 28, 2011

Energy+Environmental Economics

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

Project Team:
Snuller Price
Amber Mahone
Nick Schlag

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Executive Summary

This report provides a screening-level assessment of the potential for non-wires alternatives to defer the proposed Bonneville Power Administration (BPA) Hooper Springs transmission project. Based on Energy and Environmental Economics' (E3's) analysis of non-wires alternatives, as well as information provided by BPA, the report confirms the need for immediate winter peak demand reductions in the Fall River Rural Electric Cooperative (FREC) and Lower Valley Energy (LVE) region to avoid the risk of a NERC single contingency criteria violation. E3's screening-level assessment indicates that BPA should continue to pursue the Hooper Springs transmission project on its current schedule at this time, while simultaneously investigating the implementation feasibility of reducing winter peak demand in the region through a combination of energy efficiency (~38 MW by 2020), demand response (~4 MW by 2020) and 20 to 30 MW of new distributed generation. If the energy efficiency, demand response and distributed generation measures prove feasible, they have the potential to cost-effectively defer the need for the transmission project until 2016 or 2020, depending on how much new distributed generation can be built, and the load growth in the region.

Key questions which would need to be addressed as part of a Phase 2 implementation study of the non-wires alternative solution include:

- To what extent is LVE, or FREC, interested in collaborating with Bonneville to pursue a non-wires alternative solution in their service territory, including the construction of new distributed generation?
- What is an appropriate implementation strategy for the energy efficiency identified in this report? How can higher levels of energy efficiency targeted towards reductions in winter peak demand best be achieved in the LVE and FREC service territories?
- If the distributed generation option is investigated further in LVE's service territory, what are the natural gas supply constraints and how would these affect the performance and reliability of a new natural gas generator?
- What is the likely timeline and feasibility of permitting a distributed generation option in the LVE, or FREC, service territory?[1]
- How would distributed generation be integrated onto the LVE or FREC system, and what supporting equipment would be needed, such as capacitors and transformers? How long would it take to procure and install the necessary equipment and what would it cost?

We emphasize that given the urgent need for a solution to the winter-time capacity constraints in the region, the timeline for the proposed transmission line should not be slowed down to accommodate additional study of the non-wires alternative. This study describes the analysis and information underpinning the recommendations above.

[1] For example, in BPA's initial discussions with ABB, estimates suggest that it could require 26 months to procure a transformer needed to interconnect a new 20 – 30 MW generator in LVE's service territory. Whether the NWA proves to be feasible will depend in part on how long it takes to interconnect the generator and when procurement of a new transformer begins.

Hooper Springs Project

The proposed 32-mile Hooper Springs transmission line would be located in South-Eastern Idaho and Western Wyoming; construction is proposed to begin in the spring of 2013, and the line would be energized at the end of 2013. The single-circuit 115-kV line would connect between a proposed BPA-owned Hooper Springs substation, connecting to PacifiCorp's Three Mile Knoll substation, and an expansion of the existing Lanes Creek substation on Lower Valley Energy's system. The transmission line and substations are designed to reduce the risk of a single contingency leading to voltage instability and outages across the entire LVE and FREC service territories, spanning from West Yellowstone in Southern Montana to Afton, Wyoming. The consequences of an outage in the LVE/FREC region during the winter would be severe due to the extremely cold temperatures in the region (the 1-in-2 planning temperature is negative 27˚F). During a wintertime outage resulting from a single contingency, restoring power would take several hours at a minimum and up to a week or more under the worst case scenario.

Non-wires Assessment Screening Study

This study builds from an analytical approach developed as part of the Bonneville Power Administration's Non-Wires Solutions Roundtable, which was convened between 2003 and 2006. The study evaluates whether it would be possible to defer the proposed transmission line with different combinations of energy efficiency, demand response, existing generation and new generation, and whether these alternatives are cost-effective from a Regional Cost Perspective, compared to the cost of building the transmission line. The report

is not an implementation plan, rather it describes the results of a screening tool which can be used to identify whether particular non-wires alternatives warrant further study.

Load Growth & Project Need

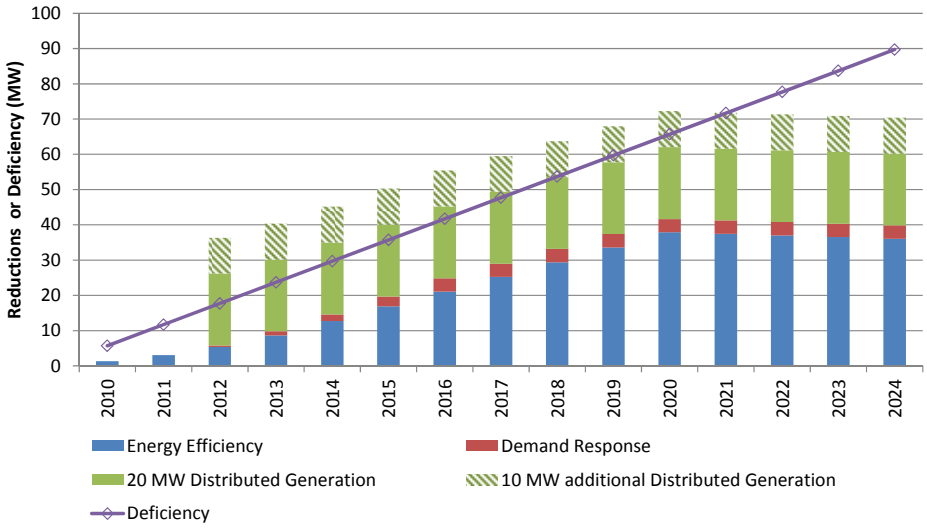
Peak demand in LVE and FREC is highest during the winter, and is precipitated by heating loads during cold weather. Our forecast of peak demand suggests that in the absence of a transmission or non-wires solution, the system operating limit in the region could be exceeded by nearly 6 MW as early as the winter of 2010/11, with an additional 6 MW increase in demand each year thereafter. By 2014, 30 MW of demand reduction are needed to avoid a voltage collapse during a single critical contingency.

Non-wires Alternative Potential for Project Deferral

The Hooper Springs non-wires alternative screening study finds that cost-effective energy efficiency (EE) and demand response (DR) are not sufficient to defer the proposed transmission line on their own. Likewise, it does not appear likely that additional winter time output could be obtained from the existing generation in the region: the Palisades hydroelectric facility. However, combining the cost-effective EE and DR with the addition of 20 to 30 MW of new natural gas distributed generation (DG) in the LVE service territory could defer the proposed line to 2016 or 2020, depending on how much new generation is built. The figure below shows that the combination of EE, DR and 20 to 30 MW of new DG could defer the Hooper Springs transmission line through 2016 or 2020. The solid green bars represent the 20 MW generation

scenario; the shaded green bars represent an additional 10 MW of new generation for the scenario with 30 MWs of new DG.

Figure 1. Comparison of Non-Wires Alternative Program Peak Savings with Annual Requirements for Peak Savings Needed to Defer Line



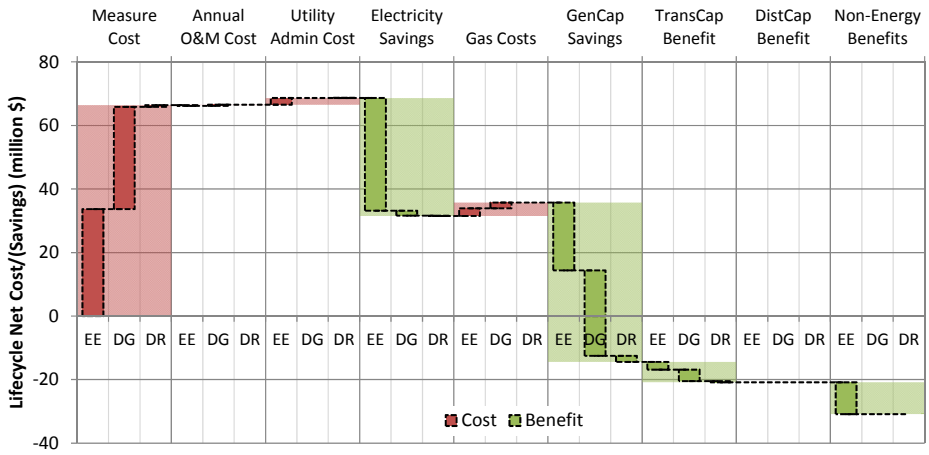
This portfolio solution has a positive benefit-cost ratio for BPA's customers and the region as a whole. The results of this screening study conclude that the line could be deferred cost-effectively from a Regional Cost Perspective with a benefit-cost ratio between 1.4 and 1.5, assuming that the non-wires alternative can be implemented as modeled. The NWA study methodology uses the Regional Cost Test as the basis for the analysis. Other key benefit-cost test perspectives, including the participant cost test and the societal cost test, are calculated as well and also show positive benefits. See Table 1 below.

Table 1. Comparison of Benefit-Cost (BC) Ratios from Three Cost Perspectives for Two Scenarios

Net Present Value of Costs and Benefits of Resource Portfolio				
	Total Benefits ($M)	Total Costs ($M)	Net Benefit ($M)	BC Ratio
Overall Program - 30 MW new generation scenario				
Regional Cost Test	**$103.7**	**$73.1**	**$30.7**	**1.4**
Participant Test	$63.6	$31.7	$32.0	2.0
Societal Test	$138.9	$77.6	$61.3	1.8
Overall Program - 20 MW new generation scenario				
Regional Cost Test	**$91.8**	**$61.6**	**$30.2**	**1.5**
Participant Test	$63.6	$31.6	$32.0	2.0
Societal Test	$123.1	$65.4	$57.7	1.9

The breakdown of the benefits and the costs of the non-wires alternatives by resource type are shown in the figure below. The "waterfall chart" indicates costs with red bars and benefits with green bars. The costs increase, and the benefits reduce, the cumulative net cost of the NWA resource portfolio. When all of the costs and benefits have been accounted for, the lifecycle net cost of the non-wires solution is shown to save approximately $30 million over the 30-year period of analysis. The costs are primarily the upfront costs of the peak reduction measures: the distributed generation (DG) and the energy efficiency (EE) measures. The primary benefits of the non-wires solution include electricity savings (from the EE) and generation capacity savings (from both the EE and the DG). Other, smaller economic benefits of the non-wires solution include the ability to defer the need for new transmission until 2020 (in the case shown below), as well as certain non-energy benefits, such as a reduction in water use from more efficient clothes washers. (Note that the waterfall chart for the scenario with 20 MW of DG looks very similar to Figure 2 shown below but with slightly lower costs and benefits.)

Figure 2. Non-Wires Alternative Program Lifecycle Costs and Benefits Comparison (Regional Cost Perspective, using the 30 MW new generation NWA scenario)



EE = energy efficiency, DG = distributed generation, DR = demand response

Implications & Recommended Next Steps

Based on the potential identified in this screening study, we recommend that BPA explore the feasibility of accelerated EE and DR measures combined with 20 to 30 MW of new distributed generation in greater depth. This analysis shows that ratepayer savings could be achieved from the implementation of the non-wires alternative. A Phase 2 analysis could also prove useful if the Hooper Springs project faces unexpected delays and a backstop solution is needed for reliability in the region.

However, it is important to note that this report's high-level screening analysis does not assess the implementation feasibility of developing new generation in the LVE/FREC region. For example, the interconnection, natural gas supply and

timelines for permitting and construction of the distributed generation are all areas that would need further study as part of a Phase 2 analysis. Likewise, a robust energy efficiency implementation plan, focused on achieving peak demand savings, would need to be designed and implemented to support the non-wires alternative. If it proves infeasible or more costly than expected to develop the EE, DR and new generation needed in the region, BPA will still need to construct the Hooper Springs project. Thus, we recommend that in parallel to performing a non-wires implementation analysis, BPA staff should not delay its current schedule for permitting the Hooper Springs project at this time.

1 About this Report

The Bonneville Power Administration (BPA) commissioned Energy and Environmental Economics, Inc. (E3) to study whether 'non-wires alternatives' could feasibly defer the proposed Hooper-Springs transmission line in South-Eastern Idaho and Western Wyoming. The proposed Hooper Springs line would increase reliability and reduce the risk of a NERC single contingency violation in the Lower Valley Energy (LVE) and Fall River Rural Electric Cooperative (FREC) service territories.[2] The non-wires alternatives to the proposed line that are examined in this study include energy efficiency, demand response, new generation and changes to the dispatch of existing generation.

The purpose of a non-wires alternatives study is to provide an independent assessment of whether there appear to be cost-effective alternatives to construction of a proposed transmission line which could defer the need for the line. The study's high-level cost-effectiveness "screening" methodology considers the economics of non-construction alternatives, highlighting ideas that may warrant further study, but is not a detailed implementation plan. Furthermore, this study complements and does not replace existing transmission planning studies.

[2] For information about the proposed line from BPA, see: http://efw.bpa.gov/environmental_services/Document_Library/HooperSprings/

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).[3]

This Hooper Springs non-wires alternatives report encompasses a similar regional territory as the 2004 non-wires study of the proposed LVE transmission upgrade. The 2004 study evaluated a 5-phase proposed project designed to address the risk that an outage of a source line in the area could cause a voltage collapse, and potentially outages, during the winter critical peak. The 2004 report concluded that it would be difficult to defer the proposed line with existing cost-effective non-wires alternatives. The study also noted that a new natural gas pipeline distribution system was being introduced into LVE's service territory, which once completed would allow the option to encourage fuel switching away from electric heat space heating to natural gas heating. Since the 2004 study, the natural gas pipeline distribution system has been expanded into LVE, allowing some fuel switching to occur. However, no major upgrades to the transmission system have been made into the region. As a result, the risk of a single contingency and subsequent voltage collapse remains of concern, which is why the Hooper Springs proposal is being explored.

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

Since the 2004 study, nearly all of the data inputs for the non-wires alternatives have been updated and improved, including the incorporation of new energy efficiency data from the Northwest Power and Conservation Council, new demand response data from BPA and PacifiCorp, new generation cost and performance data from recent industry reports and new avoided costs of power and natural gas price forecasts. While the overall study approach between the 2004 LVE transmission upgrade study and the current Hooper Springs study remains unchanged, the fact that the proposed transmission lines are different between the two studies, and the key data inputs have been updated makes an 'apples-to-apples' comparison of the two studies difficult.

The analysis approach applied in this study consists of several steps, outlined briefly below, and described 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 load flow modeling results. We also estimate the number of hours when loads are expected to exceed the system operating limits on the substations and/or transmission lines using a load duration curve approach and identifying the typical timing of peak load in the area by time-of-day and season.

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 and energy and capacity benefits

+ Once the magnitude of the problem is well defined, we estimate the value of deferring the proposed transmission line. We use the 'differential revenue requirement' (also known as the 'present worth') method for estimating the value of the avoided line from a revenue requirement perspective. That is, we estimate the benefits based on savings to transmission ratepayers of deferring the expenditures on the line. In addition, we forecast any avoided electricity and natural gas purchases from implementing energy efficiency, demand response, etc. as part of a non-wires alternative and any system capacity value provided by the non-wires alternatives.

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 (including fuel-switching from electricity to natural gas), demand response, re-dispatch of existing generation and the construction of new generation, including distributed generation.

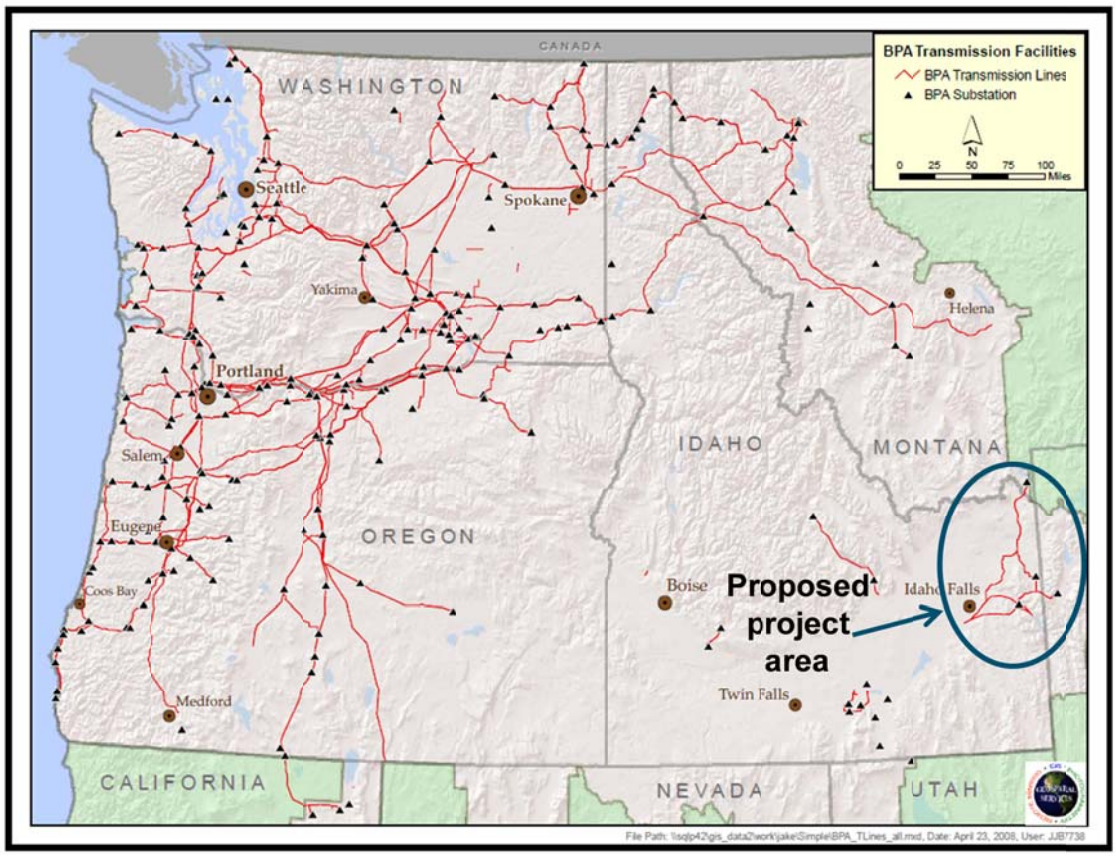
5. Aggregate results & develop conclusions

+ The final step is to aggregate the results and develop conclusions and recommendations for next steps. The report does not recommend a particular implementation path, but rather highlights the best option which passes the cost screening test and may warrant further study.

2 Description of Hooper Springs Project and the Identified Problem

Lower Valley Energy is a full service BPA customer while Fall River Rural Electric Cooperative is a Slice/Block customer served through the Pacific Northwest Generation Cooperative (PNGC). Lower Valley Energy is located on the Western edge of Wyoming (see Figure 3), adjacent to Grand Teton and Yellowstone National Parks and includes Jackson Hole, Wyoming, an international skiing resort during winter months. The loads in the region are served by the Goshen substation south of Idaho Falls, ID.

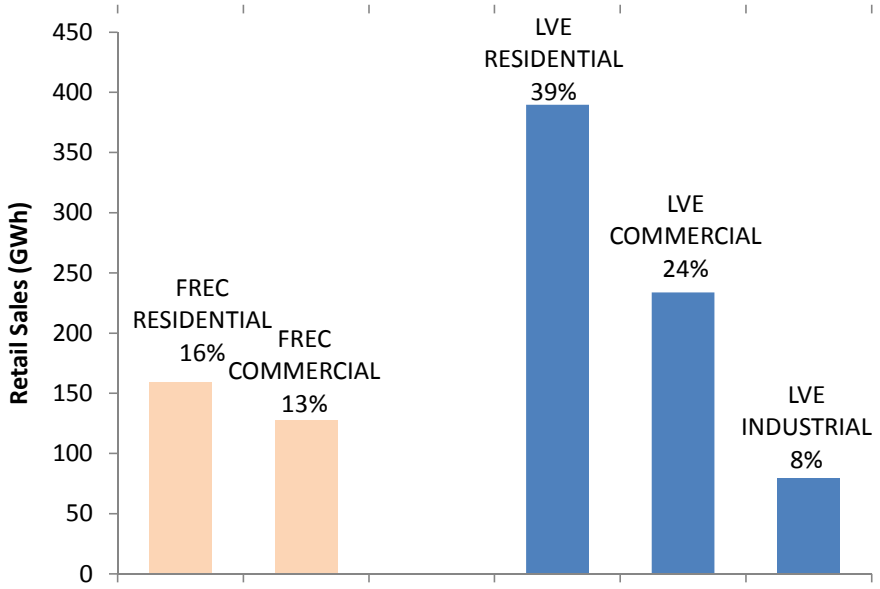
Figure 3. Bonneville Transmission Facilities and Proposed Project Area



Source: Bonneville Power Administration

Combined, LVE and FREC include about 32,000 residential customers, nearly 9,000 commercial customers and 1 industrial customer.[4] LVE's energy demand represents approximately 70 percent of the total demand in the region. Over half of the region's electricity consumption comes from residential loads, with the remainder of the demand coming from commercial loads, and only 8% of total energy demand represented by industrial loads (See Figure 4).

Figure 4. Fall River Electric Cooperative and Lower Valley Energy Retail Sales in 2008, by Sector



Source: DOE EIA Form 861, 2008

[4] U.S. Department of Energy, Energy Information Agency Form 861, 2008. Note that as of 2001, the EIA definition for industrial loads includes irrigation. Approximately 500 irrigation accounts exist but have not been classified as industrial loads in the EIA data.

Peak demand in the LVE/FREC region is driven by heating loads during the coldest winter days, with 1-in-2 winter planning temperatures at -27˚F (-33˚C). The cold temperatures are accompanied by mountainous terrain and high elevations across most of the region: the elevation of Jackson, Wyoming is over 6,000 feet. The cold winter temperatures and difficult terrain make the risk of a power outage in the area of particular concern because of the difficulties of restoring power under those conditions.

Parts of LVE's service territory are served by a natural gas pipeline distribution system, allowing some customers the opportunity to switch from electric heat to natural gas heat. However, most heat in the region remains electric. We estimate that nearly 80% of the region's homes are heated by electric heat, with a remaining 15% using propane or natural gas fuel and 5% using wood fuel.[5]

2.1 Description of the Problem

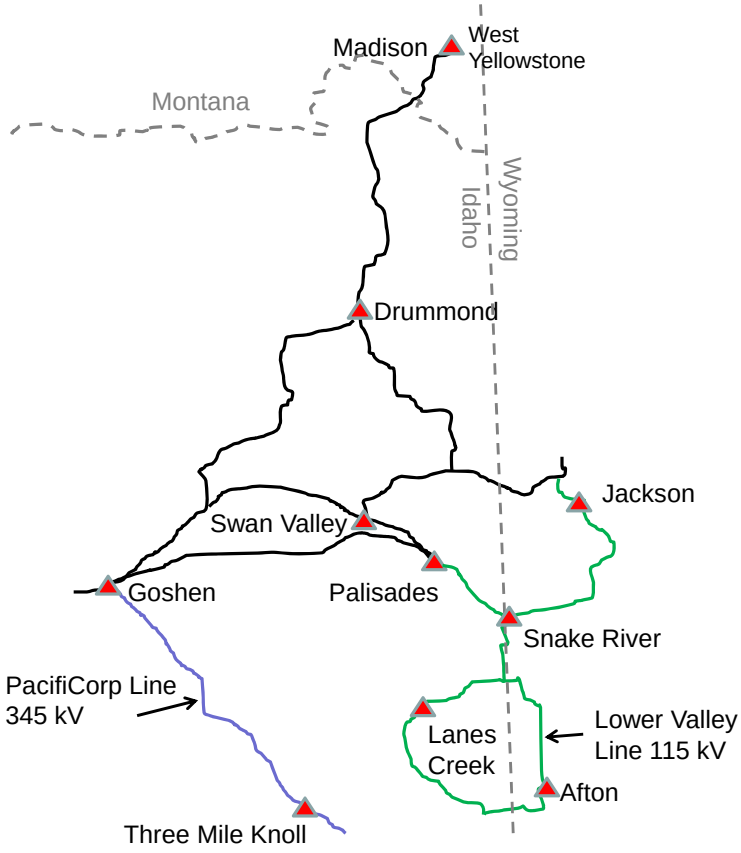
Load growth in the LVE/FREC region has increased the risk that an outage along one of three paths or substations would cause a NERC single contingency criteria violation during the winter critical peak conditions. Three single contingencies are identified:

- Swan Valley 161/115 kV Tx or Goshen-Swan Valley 161 kV line
- Drummond 161/115 kV Tx or Goshen-Drummond 161 kV line
- Palisades-Snake River 115 kV line

[5] Estimate is based on the number of natural gas accounts in LVE in 2010, from LVE staff, DOE EIA form 861, 2008 data and U.S. Census Bureau American Community Survey (ACS) data.

A diagram of the region's transmission system is shown in the figure below.

Figure 5. Diagram of transmission system in the Lower Valley Energy / Fall River region



A critical contingency in this area could cause a voltage collapse and cascading outages across parts of Southern Idaho, Western Wyoming and Southern Montana. This would mean that residents and businesses in the area would lose power in the winter during the coldest hours of the year, with

temperatures likely to be in the range of -27˚F. This represents a safety risk for residents in the region, especially given that BPA staff estimate that re-establishing power to the region could require several hours, and up to a week or more under worst-case conditions.

The goal of the Hooper Springs proposed transmission line is to avoid the risk of a voltage stability collapse in the LVE/FREC region. The non-wires alternatives evaluated in this study must also be capable of delaying the risk of voltage collapse in the region.

3 Hooper Springs Project

The proposed Hooper Springs project evaluated here is a 32-mile single circuit 115-kV transmission line, and includes a new Hooper Springs substation on the PacifiCorp system and an expansion of the existing Lanes Creek substation on the Lower Valley Energy system. The line is proposed to be energized by the end of 2013, which would require that construction begin in the spring of 2013.

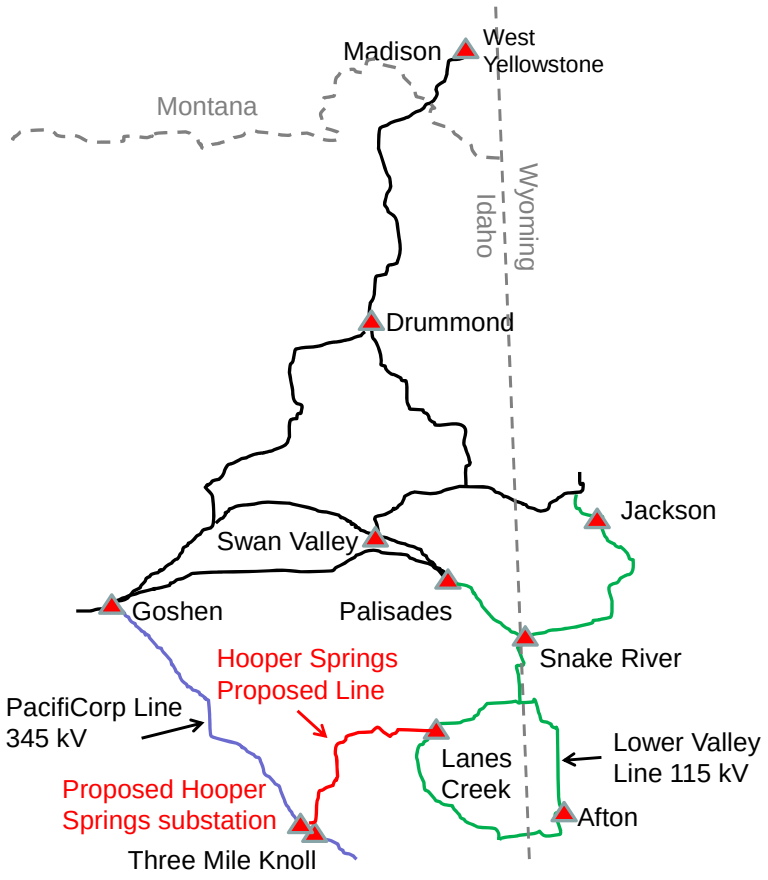
The total cost of the line and the two substations is estimated at $47.8 million dollars (in constant 2010 dollars). Of the total cost, an estimated $23.75 million is non-deferrable, either because the cost has already been outlaid or is otherwise expected to be committed before 2013, or Bonneville customers are unlikely to benefit from a deferral of the cost, such as the cost of purchasing land for the transmission line. Excluding the non-deferrable costs from the analysis brings the net cost of the proposed Hooper-Springs projects to $24.05 million, which is the cost used in the non-wires alternatives analysis.

Table 2. Estimated Total Cost and Net Cost of Hooper Springs Project

Expense Item	Year	Total cost ($million)	Excluded cost ($million)	Notes	Net cost ($million)
Hooper-Springs & Lanes Creek Substation	2010	$7.0	$7.0	Purchased transformer	-
	2011	$2.0	$2.0	Committed payments for substations	-
	2012	$5.0	$5.0	Non-deferrable preliminary assessments	-
	2013	$10.5	-	-	$10.5
Hooper-Springs transmission line	2011	$1.45	$1.45	Non-deferrable preliminary engineering	-
	2012	$1.0	$1.0	Non-deferrable preliminary assessments	-
	2013	$20.85	$7.3	Excluded cost includes estimate of land purchase costs	$13.55
TOTAL	-	$47.8	$23.75		$24.05

A diagram of the proposed Hooper Springs project is shown in the Figure below.

Figure 6. Diagram of Proposed Hooper Springs Project on the transmission system in the LVE/FREC region



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 and energy and capacity benefits
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 which the proposed transmission line would solve. The winter thermal operating limits of each of the three single contingencies are shown in the table below. For the purposes of this analysis, we must simplify the complex interrelationships between these transmission lines and the associated facilities, since it would be inefficient to run new power flow models for every scenario considered. To simplify the transmission problem, we rely on the load flow analysis of the Bonneville Transmission Services staff which simulates the conditions under which a single contingency would lead to voltage instability on the system.

Table 3. Winter thermal limits on the three single contingency lines in LVE/FREC region

Line	Winter thermal limit
Goshen – Swan Valley 161 kV	268 MVA
Goshen – Palisades 115 kV	201 MVA
Goshen – Drummond 161 kV	360 MVA

The BPA TBL load flow model shows that the measured flows on the three lines (Goshen-Drummond 161 kV, Goshen-Swan Valley 161 kV, and Goshen-Palisades 115 kV) prior to the critical contingency are 244 MW. Assuming that the Palisades hydroelectric facility in the region is operating at 10 MW, this puts the total path load limit at 253 MW, including distribution losses.

The Palisades hydroelectric facility is located on the Palisades Reservoir on the South Fork of the Snake River, to the southwest of Jackson, WY. Palisades is operated by the Bureau of Reclamation, and is used primarily for water storage in the winter and for irrigation in the summer, although other considerations include fish and wildlife, flood control and power production. There is little variation in the power output of Palisades during winter months; for the purposes of this analysis we assume that the plant operates at 10 MW during the winter critical peak, which is consistent with historical patterns. For more discussion of the power output of Palisades during the winter critical peak see Section 5.3.

The regional analysis is also simplified by the fact that the LVE/FREC region is an isolated transmission spur from much of the Eastern Idaho transmission network. Therefore, we can assume that the load flow distribution factor is one. In other words, a 1 MW reduction in load anywhere in the LVE/FREC

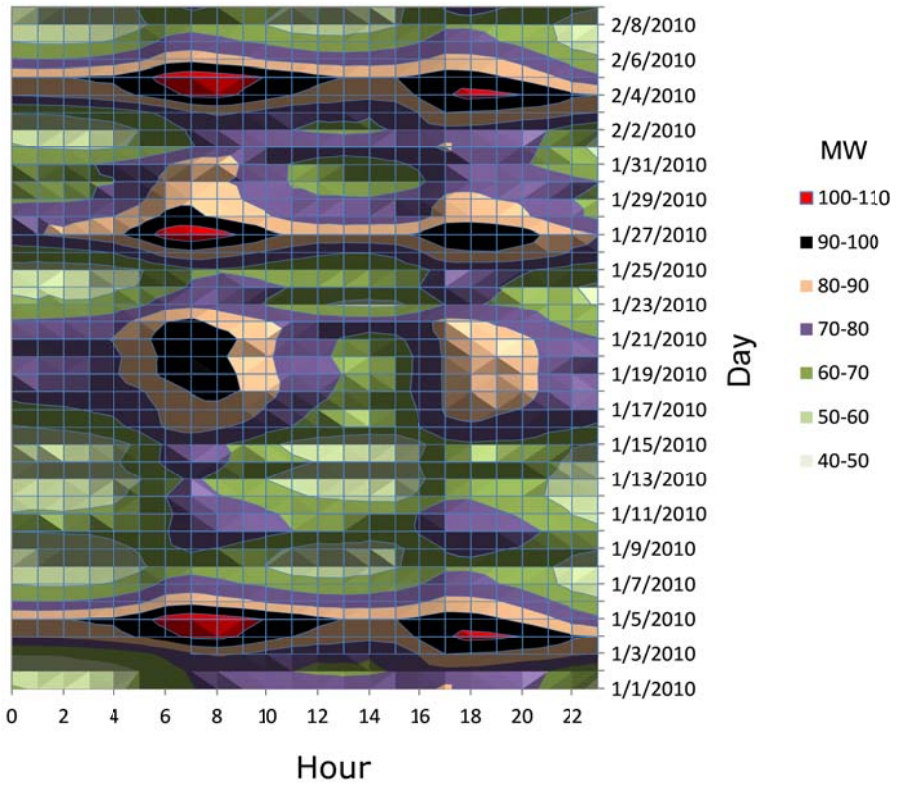
system contributes a 1 MW, plus losses, reduction in flows along the constrained path. Based on all of this information, we use a total path load limit in the LVE/FREC region of 253 MW in this analysis.

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 occurs during the winter, air conditioner energy efficiency measures will not help to alleviate peak demand (for treatment of direct load control demand response options for space heating see Section 5.2). 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 Goshen-Swan Valley path during the high demand period between January 1, 2010 and February 8, 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 Goshen-Swan Valley path are shown across the third dimension, the z-axis. The hours shown in red represent the highest demand hours on the constrained path.

Figure 7. Goshen-Swan Valley Winter Peak Flows in 2010 – Topographic Representation



Critical Peak Defined as:

6am – 9am (weighted at 100%)

5pm – 7pm (weighted at 50%)

Figure 7 shows that the periods of highest demand tend to occur during the morning hours between 6am and 9am, when people generally wake-up turning on lights, heaters, hot water and other end-uses. A second, less dramatic peak period also tends to occur in the evenings, when people return to their homes, but when commercial loads are still in use, between 5pm and 7pm. Since the afternoon peak is not as

pronounced as the morning peak, energy efficiency or demand response measures that occur during the afternoon peak are weighted 50% less than demand reductions that occur during the morning peak. Based on the historical hourly flow data, we define the critical peak period as 6am to 9am, with a secondary peak weighted at 50% between 5pm and 7pm.

4.2 Update local area demand forecast

In order to determine when and by how much the system operating limit in the region would likely be exceeded in the absence of the proposed Hooper Springs transmission line or the deployment of other non-wires alternatives, E3 developed a peak demand forecast for LVE and FREC. The E3 peak demand forecast is also compared to historical peak demand growth rates and the BPA and LVE forecasts to check for consistency.

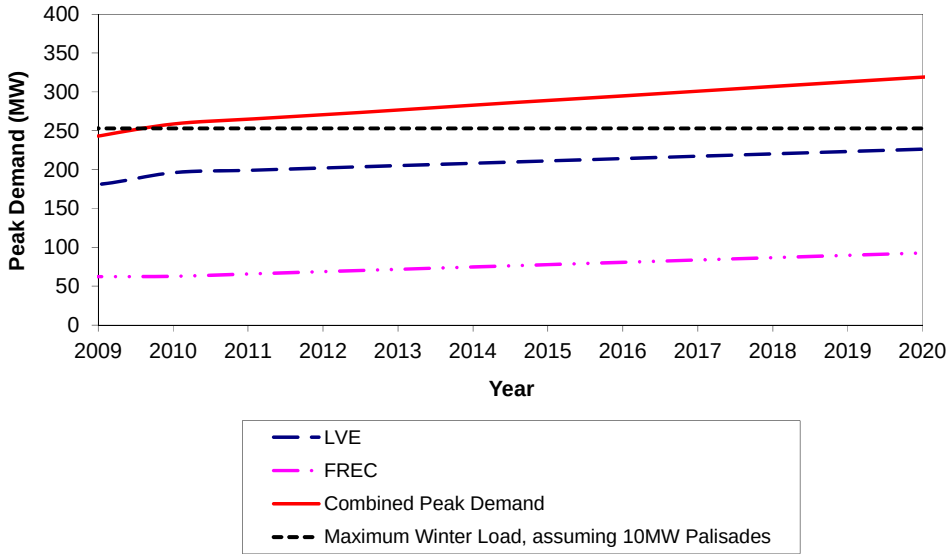
The E3 peak demand forecast is based on a temperature-adjusted regression forecast, using historical hourly demands for LVE and FREC, combined with historical hourly maximum temperatures in the region, reported by the National Oceanographic and Atmospheric Administration (NOAA). The regression is temperature adjusted to the 1-in-2 planning temperature of -27˚ Fahrenheit (-33°C).

To combine the LVE and FREC peak demand forecasts, we make the assumption that there is a 100% coincidence factor between the two service territories. In other words, we make the conservative assumption that the peak demand periods for LVE and FREC occur at the same time. Given that the regions experience similar weather patterns and have similar loads, this is a reasonable

assumption. Furthermore, historical data show that the peak periods for these two regions tend to occur together. Finally, we assume distribution loss factors of 3.59% for transmission peak losses and 6.35% for distribution losses, based on information from BPA.

The results of E3's temperature adjusted forecast show the combined LVE/FREC peak demand forecast growing at an average of 2.1% per year. Comparing this peak demand forecast to the system operating limit of 253 MW (assuming Palisades generates at 10 MW), shows that the region's peak demand forecast could exceed the system operating limit by 5.7 MW (including losses) as early as the winter of 2010/11. Peak demand is expected to grow by approximately 6 MW (including losses) each year thereafter. Without the transmission line or other non-wires alternatives, this will lead to the region likely exceeding the system operating limit by approximately 30 MW in 2014. The results of the E3 temperature-adjusted peak demand forecasts are shown in Figure 8 below compared to the system operating limit in the region of 253 MW.

Figure 8. Combined FREC and LVE Peak Demand Forecast (2009 – 2020)

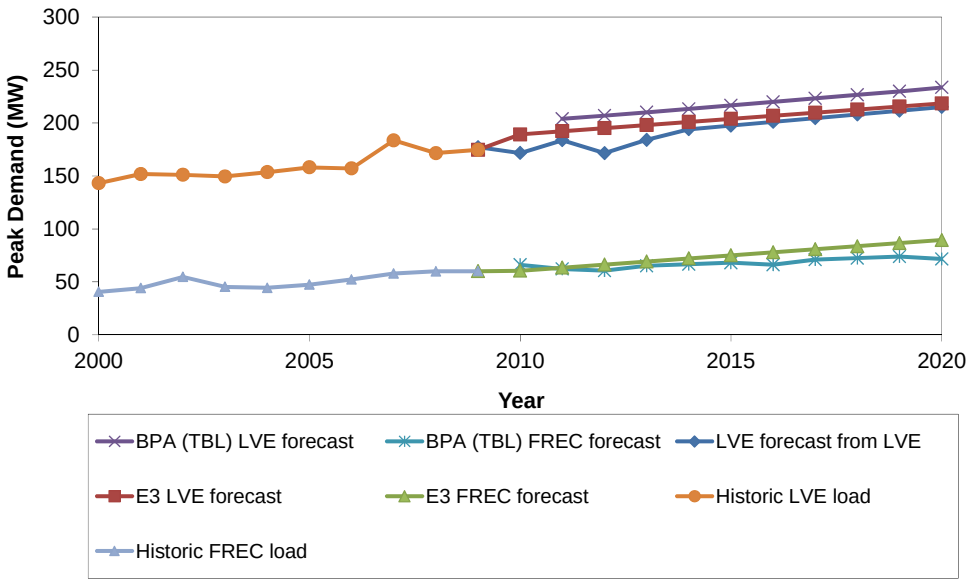


The peak demand forecast highlights the fact that even if the proposed Hooper Spring transmission line is built as planned, the region will still need some stop-gap measures through 2012 until the line can be energized in 2013, or other non-wires solutions can be implemented.

As a check on the E3 peak demand forecast, Figure 9 below compares the historical peak demands for LVE and FREC with three different forecasts: the E3-developed peak demand forecasts for LVE and FREC (used in this analysis), a peak demand forecast for LVE supplied by LVE staff, and peak demand forecasts for LVE and FREC supplied by BPA TBL staff. Overall, these results show that the E3-developed peak demand forecast is both consistent with historical patterns, and in-line with other peak demand forecasts for the region. Historical peak demand growth rates are consistent with the E3 forecast peak demand growth

rate of 2.1% per year. The E3 peak forecast is a bit lower than the BPA TBL forecast for LVE and slightly higher than the BPA TBL forecast for FREC. The E3 forecast for LVE is slightly higher than the LVE-developed forecast. Note that the BPA Power Services also develops a demand forecast for LVE and FREC. However, this forecast is based on an extrapolation of an energy demand forecast, rather than being an explicit peak demand forecast, so is not used in this analysis.

Figure 9. Historical Peak Demand for FREC and LVE and a Comparison of Peak Demand Forecasts (2000 – 2020)



We also estimate the number of hours per year that peak demand is expected to exceed the system operating limit in each year, if the proposed Hooper Springs transmission line is not built and if no alternative solutions are in place. This information is useful in evaluating non-wires alternatives. For example, if a

demand response measure is expected to be available for fewer hours per year than the number of hours which exceed the system operating limit, we will know that demand response options on their own are unlikely to present a feasible non-wires solution.

In order to estimate the number of hours that the system operating limit may be exceeded in any given year, we apply the historical load shape for the LVE/FREC region to the peak demand forecast for each year. Sorting the peak demand hours from highest to lowest produces a load duration curve. The highest demand hours for the combined LVE/FREC region in 2013 and 2014 respectively are shown in Figure 10 below. The figure shows that in 2013, the system operating limit could be exceeded in 19 hours of the year, while by 2014 peak demands could exceed the operating limit for 35 hours of the year.

It is worth noting that if the system operating limit is exceeded for even just one hour or less, this could lead to voltage instability and potential outages. The winters in Southern Idaho and Western Wyoming are a dangerous time to experience a power outage, when temperatures are at their coldest and people rely on electric heat to keep warm. This is especially true since it may take several hours, and up to a week or more under a worst case scenario, to reestablish power to the region once an outage has occurred.

Figure 10. Load Duration Curve Showing the Number of Hours Peak Demand is Likely to Exceed the LVE/FREC System Operating Limit in 2013, 2014

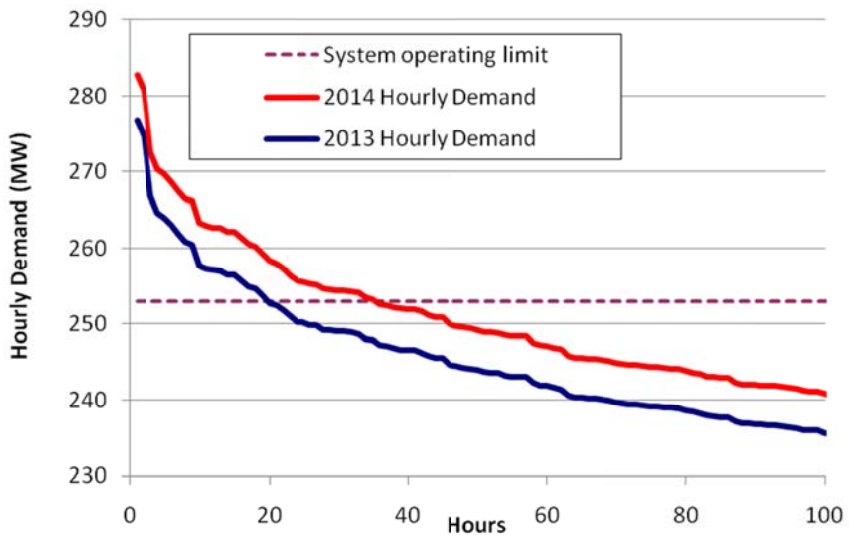


Table 4. Maximum MW Forecast to Exceed System Operating Limit (SOL) and Number of Hours Forecast to Exceed SOL (2012 – 2014)

Year	Max MW exceeding SOL	Number of Hours Exceeding System Operating Limit
2012	18	9
2013	24	19
2014	30	35

4.3 Value of Line Deferral

4.3.1 REVENUE REQUIREMENT SAVINGS OF LINE DEFERRAL

To evaluate the savings which BPA customers would accrue if the proposed Hooper Springs line were deferred, we estimate the transmission revenue

requirement savings from the line deferral. We use the "differential revenue requirement" method. This method includes all of the avoidable costs of the line and excludes any costs which have already been spent and the cost of land. Land costs are excluded from the analysis because it is generally prudent to purchase land for a transmission line even if the line will not be built immediately, since land costs rarely decrease over time and purchased rights of way provide more certainty for regional land use planning.

Other key input assumptions to the transmission revenue requirement (TRR) savings include a 2.2% per year inflation rate and a utility nominal weighted average cost of capital (WACC) at 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 variable costs that could also be deferred.

The results of the differential revenue requirement method are shown in the table below. If the transmission line could be deferred to the end of 2020, this could save Bonneville ratepayers $9.2 million in transmission costs alone, which is equivalent to a capacity payment of $141/kW or $23/kW-yr. Deferring the line also comes with other costs and energy savings as described in Section 5.

Table 5. Transmission Revenue Requirement Savings of Deferring Hooper Springs (2014 – 2020)

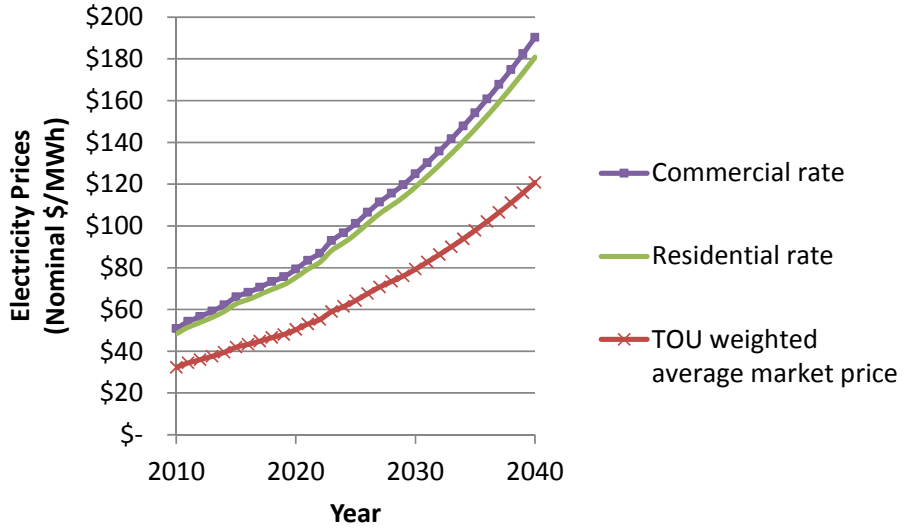
	2014	2016	2018	2020
Transmission Revenue Requirement Savings ($M)	$1.5	$4.4	$6.9	$9.2
$/kW (contracted)	$52	$105	$129	$141
$/kW-year (levelized)	$52	$37	$29	$23

4.3.2 AVOIDED COSTS OF ELECTRICITY AND NATURAL GAS

The other component of the transmission line deferral value is the avoided cost of energy from the non-wires alternatives that may be implemented. Energy efficiency can generate savings by deferring the need for new transmission, reducing capacity procurement costs and by reducing energy procurement costs. Fuel switching measures reduce electricity demand but increase demand for natural gas. These changes to energy and capacity costs must be accounted for in our analysis.

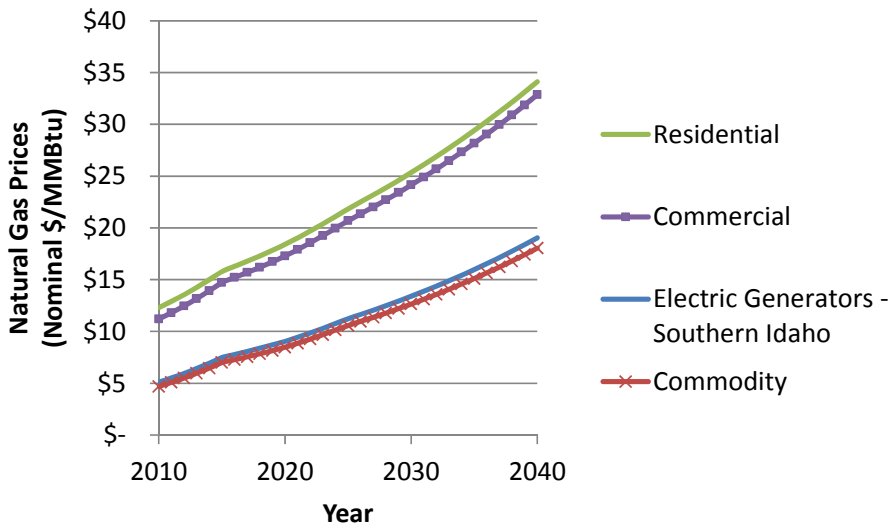
To calculate the avoided cost of electricity and natural gas we use the Northwest Power and Conservation Council's (NWPCC's) Sixth Power Plan forecast of the cost of energy. Wholesale electricity costs are forecast over a 30-year horizon for 48 time periods per year, which are averaged to six time-of-use (TOU) periods. (For purposes of the screening analysis, the six TOU periods include peak, off-peak and shoulder prices for summer and winter). The cost of wholesale power in each time period is compared to the shape of the energy savings by period for energy efficiency measures to determine whether the measure is cost-effective. Figure 11 below shows the TOU weighted average forecast of wholesale power prices in the BPA region, as well as the retail rate forecasts for the region. The retail rates in 2010 are based on LVE's current rates, and the forecasted escalation rate is tied to the wholesale market price changes.

Figure 11. NWPCC Sixth Power Plan Forecast of Wholesale Electricity Prices, TOU weighted average, and Forecast of LVE Retail Rates (2010 – 2040)



For the avoided cost of natural gas purchases, we use the NWPCC Sixth Power Plan's forecast of Southern Idaho natural gas commodity prices for the Total Resource Cost test evaluation. For the Participant Cost Test analysis, we use a natural gas price forecast for residential, commercial, industrial and electric generator customers based on LVE's current retail gas prices.

Figure 12. Natural Gas Commodity and Retail Price Forecasts (2010 – 2040)



The analysis also incorporates the value of avoided 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 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 gas-fired combustion turbine (the GE LM6000).
- **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 a new gas-fired CT. 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—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 LVE/FREC region to present a credible non-wires alternative to the Hooper Springs proposed line. We evaluate resource potential and costs of energy efficiency, demand response, existing generation and new distributed generation, discussed below.

5.1 Energy Efficiency

The energy efficiency measures evaluated in the Hooper Springs non-wires alternatives study are adapted primarily from the NWPCC's Sixth Power Plan. The energy efficiency resource potential is scaled down to represent the FREC/LVE region using a number of techniques:

Residential measures are screened for the appropriate climate zone. FREC/LVE are located in heating zone 3 and cooling zone 1, so only measures that are applicable to these climate zones are used.

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.

Measures estimating the residential fuel switching potential (from electric heat to natural gas heat) are derived from Puget Sound Energy's 2010 Integrated Resource Plan.[6] The total resource potential is estimated based on the share of residential customers in the region that have access to the natural gas distribution network but currently use only electric heat. The estimate of the share of residential customers with access to natural gas is based on data supplied by LVE showing the number of natural gas and electric meters by region in their service territory.

The total commercial energy efficiency resource potential is scaled based on an estimate of the commercial square footage, by business type, of the FREC/LVE region. The estimate of commercial square footage in the region is based on a number of data sources including Idaho state commercial square footage data, scaled based on the number of commercial establishments in LVE and FREC counties.

The total industrial energy efficiency resource potential is scaled based on the total industrial demand in the region, as reported in EIA form 861 data. For the LVE/FREC region, very little total demand comes from industrial loads, and the

[6] Cadmus Group, "Comprehensive Assessment of Demand-Side Resource Potentials (2010 – 2029) , Volume II, Appendix D, July 2009. Available at: http://www.pse.com/SiteCollectionDocuments/2009IRP/AppL2_IRP09.pdf

largest industrial load in the territory has already undertaken significant energy efficiency efforts. As a result, we have excluded industrial energy efficiency from the non-wires analysis.

We then apply fairly conservative adoption schedules for LVE/FREC energy efficiency resource potential to develop a likely deployment schedule for energy efficiency in the region. 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: replace-on-burnout, retrofit, or new installations.

- **Retrofit:** The adoption of retrofit measures is based on an assumption of logistic growth.
- **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.
- **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. Since the customer's retail rate is one of the factors in the participant payback, the retail rates influence the EE resource potential for the NWA portfolio.

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."[7] The Regional Cost Test is similar to the Total Resource Cost (TRC) cost test, but includes all energy efficiency measures with a benefit-cost ration greater than 0.9, and a few other adjustments for the Bonneville region.[8] 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.

5.1.1 NATURAL GAS FUEL SWITCHING POTENTIAL

Natural gas fuel switching potential (away from electric heat) is included as an energy efficiency option in the Hooper Springs analysis. However, few of LVE's customers and none of FREC's customers have access to the natural gas pipeline distribution network. The natural gas pipeline distribution network is currently available in Jackson, WY and south in Rafter J. The pipeline terminus is currently south of Jackson, near the liquefied natural gas (LNG) storage facility. The LNG facility is used to provide back-up supply in case of disruptions on the gas pipeline, helping to ensure reliable natural gas supply.

Based on information provided by LVE staff, we estimate that approximately 5% of the total combined LVE/FREC residential customers use natural gas. We further estimate that approximately 13% of the combined LVE/FREC residential customers, and 28% of commercial customers, have *access* to the natural gas

[7] 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

[8] The Northwest Power Act of 1980 requires a 10% increase in benefits for energy efficiency, which is implemented in the screening tool as a requirement for only a 0.9 benefit-cost ratio for energy efficiency. See Northwest Power Act of 1980, §3(4)(D), 94 Stat. 2699.

pipeline network but currently use only electricity. We have restricted the fuel switching potential in this analysis to those residential customers with access to the gas pipeline network but who don't currently use it.

The Hooper Springs analysis only includes fuel switching measures for residential measures. If good data on commercial fuel switching measures were available, this aspect of the analysis could be expanded in the future. For now, the natural gas fuel switching analysis represents a conservative estimate of potential.

Over the longer-run, it may be possible to expand the opportunities for fuel switching in the region by increasing the reach of the LVE natural gas pipeline distribution network. Options that may be worth considering in the future, but which are not analyzed here, include running the pipeline network up to Teton Village, the Jackson Hole Airport in the Grand Teton National Park and into the National Park itself in Moose, WY. Teton Village includes a number of luxury lodging resorts with large electrical loads, for which it may make sense to promote the use of combined heat and power applications as a fuel switching measure.

However, there are a number of challenges associated with the expansion of the natural gas pipeline network, making it infeasible as a short-term solution to the load growth problem in the LVE/FREC region. First of all, the environmental permitting and construction of a pipeline network expansion would likely require 3 to 4 years to complete.[9] Furthermore, an engineering analysis may be required to ensure that sufficient gas could be supplied to reliably meet an

[9] Estimate based on interview with LVE staff.

expanded base of customer demand. Current estimates from BPA and LVE suggest that the existing LVE natural gas pipeline could supply approximately 20 to 30 MW of new natural gas generation, in addition to the region's existing natural gas demands. However, these estimates have not been independently verified by the study authors, and a more in-depth study of the natural gas supply issues is needed before moving ahead with a new generator option.

5.1.2 DISTRIBUTION SYSTEM EFFICIENCY IMPROVEMENTS

The NWPCC energy efficiency 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 0.2 MW by 2020. Even these savings may be difficult to achieve given the voltage stability challenges in the LVE/FREC region during the winter critical peak. Although there is some uncertainty about the reliability of the DEI savings, we have included these resources in the analysis even though the overall effect on the results is negligible.

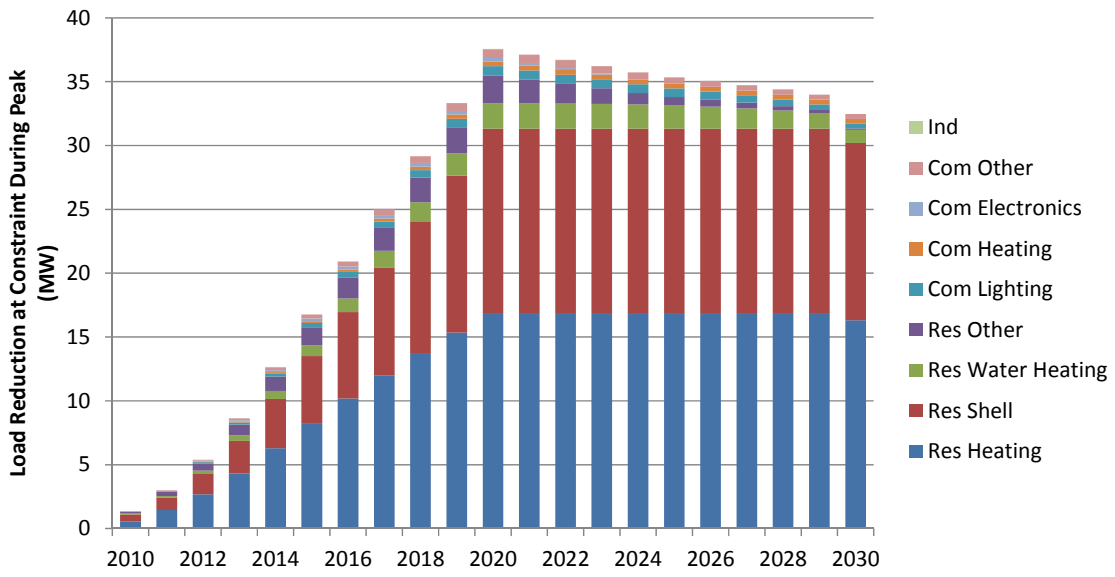
5.1.3 ENERGY EFFICIENCY COST-EFFECTIVE POTENTIAL RESULTS

The figure below illustrates the energy efficiency potential which passes the cost-effectiveness screen, using a 0.9 benefit-cost ratio. By 2020, nearly 40 MW of peak reductions and 10 aMW of energy savings could be achieved using an aggressive energy efficiency deployment strategy in the region.

The vast majority of the winter peak demand reductions in the non-wires energy efficiency analysis come from the residential sector, specifically from residential heating and building shell measures. The reason that commercial sector peak reductions are so small is two-fold. First, the share of total energy use by the commercial sector is smaller than the residential sector in the LVE/FREC region. Second, the commercial energy efficiency measures included in this analysis do not include many measures that result in winter peak savings. For example, the 6th Power Plan data, from which much of the energy efficiency potential information in this analysis is derived, do not appear to include commercial heating efficiency measures, nor does our analysis include commercial fuel switching measures (electric to natural gas space heating or water heating), which could result in significant winter peak savings.

In a Phase 2 study of the NWA, a regionally-specific study of the LVE/FREC energy efficiency potential in needed, including a more in-depth study of the potential for achieving winter peak savings from the commercial sector. What is clear from the current analysis is that significant winter peak savings potential exists in residential heating and building shell energy efficiency measures.

Figure 13. LVE/FREC Cost-Effective Energy Efficiency Peak Demand Reductions (2010 – 2030)



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. However, for practical purposes, and safety concerns, many of these programs are not applicable to the winter-time critical peak periods during extremely cold temperatures that are seen in the LVE/FREC region.

Only four DR measures pass the safety and cost-effectiveness screen for the Hooper Springs analysis. These measures include emergency DR for large commercial customers, peak time rebates for residential and small commercial customers and critical peak pricing for large commercial customers. Combined, the overall peak reductions from these programs are expected to be relatively small compared to the peak reductions needed to defer the Hooper Springs project. By 2014, cost-effective DR programs could supply 1.7 MW, and by 2020 DR programs could supply 3.8 MW of peak reductions, most of which would be achieved by interruption of non-critical commercial loads. The table below shows the DR measures selected in this analysis:

Table 6. LVE/FREC Demand Response and Direct Load Control Measures

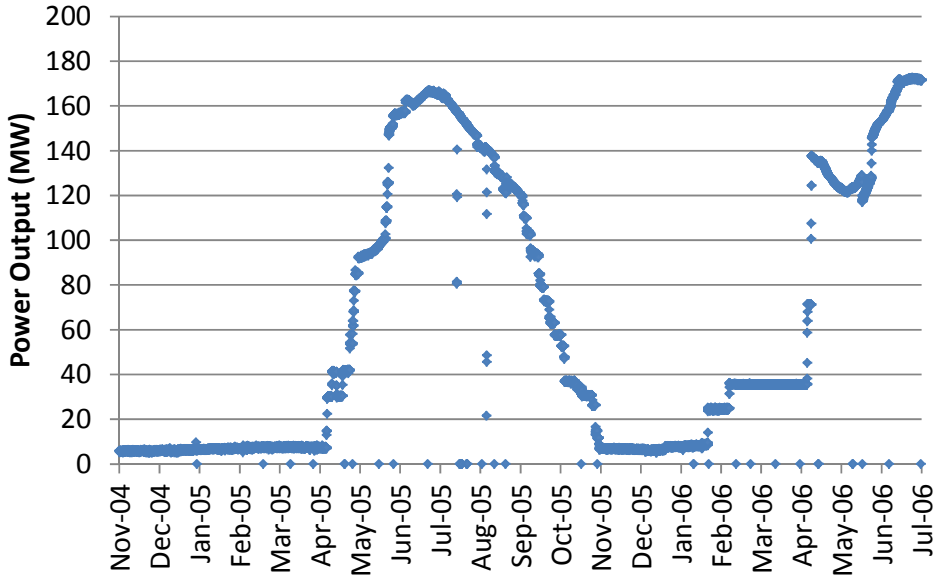
DR-DLC Program Name	Sector	Winter Peak Impact (kW/ customer)	Total Resource Cost Benefit-Cost Ratio	DR/DLC MW Savings in 2014 (un-adjusted for losses)
Emergency DR - Large Commercial (>200kW)	Commercial	186	4.9	.05
Capacity Market DR - Large Commercial (>200kW)	Commercial	186	3.8	.96
Peak Time Rebate - Residential	Residential	0.79	4.4	.14
Peak Time Rebate - Small & Med Commercial (<200kW)	Commercial	13	7.0	.53
Critical Peak Pricing - Large Commercial (>200kW)	Commercial	13	7.0	.03
Total Portfolio Selected				**1.72**

5.3 Existing Generation

Existing generation is another important component of the non-wires alternative analysis since changes to the dispatch pattern of existing generation can sometimes help to alleviate transmission constraints. The only large source of existing generation in the LVE/FREC region is the Palisades hydroelectric facility, located on the South Fork of the Snake River. The 176 MW facility includes four turbines. During the winter, one unit is typically off-line for maintenance, one unit is employed in a condensing mode to provide voltage support to the grid, and two units operate at low flows, producing, on average, about 10 MW of power.[10] Figure 14 shows the historical hourly output of Palisades between November 2004 and July 2006.

[10] Interview with Bureau of Reclamation staff.

Figure 14. Hourly Power Production at Palisades Hydroelectric Facility (Nov. 2004 – July 2006)



From a transmission perspective, if the Bureau of Reclamation increased the power output of the Palisades facility during the critical peak hours of the winter, the risk of voltage instability created by a single contingency in the area could be averted. However, there are a number of contractual and operational challenges associated with increasing the power output of Palisades during the winter. As a result, we have eliminated the option of using existing generation as part of a non-wires alternative to the proposed Hooper Springs project.

Some of the issues associated with increasing the winter-time generation from Palisades include:

- The plant is operated by the Bureau of Reclamation, not by Bonneville, so interagency coordination would need to be arranged.
- The water in the Palisades reservoir is a non-recoverable, annual resource. Once the water is used for power generation during winter months that water is no longer available in the summer for irrigation or other purposes. If power generation were to be increased, even for a few hours in the winter, downstream water rights would likely need to be negotiated with stakeholders.
- The environmental and safety impacts of increasing water flows for a relatively short period during the winter would need to be assessed, including the potential for causing fish stranding and ice jamming risks.
- Currently the turbines in Palisades do not operate efficiently at mid-flow water levels. When operated in the 9 to 17 MW range the turbines vibrate in what is known as the "rough spot." The existing turbines limit the operational flexibility of Palisades. The turbine runners will be replaced over a seven year timeline, meaning that the full benefits of the refurbishment will not likely be available until 2018.[11] Until the turbines are re-furbished, it is unlikely that the winter output of Palisades could be increased, even if all of the other concerns associated with re-dispatching Palisades in the winter were addressed.

We have not done an in-depth analysis of any of these potential constraints associated with increasing the Palisades winter-critical peak output. However, the operational and contractual challenges associated with increasing the output of Palisades during the winter critical peak hours are significant and do

[11] Bureau of Reclamation, Budget Justifications and Performance Information, Fiscal Year 2011, available at: http://www.usbr.gov/budget/2011/2011Budget.pdf

not appear likely to be overcome before 2013, as would be needed to defer the Hooper Springs transmission proposal.

5.4 New Generation

Another option considered in the non-wires alternatives approach is the possibility of developing new generation in the LVE/FREC region. 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 winter critical peak demand. 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, such as during the summer peak 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. Furthermore, running the new generator for additional hours could complicate the permitting of the power plant. For these reasons we assume that new generation is only used to meet the winter critical peak demand period.

The fact that new winter-peaking resources in the LVE or FREC region need to operate at high elevations, likely above 6,000 feet, is also factored into the

analysis based on available industry publications. For this analysis, the capital cost per delivered kW of new combustion turbines is increased by approximately 20% to reflect their reduced performance at high elevations.

Two scenarios of LVE gas pipeline capability are evaluated: a scenario with 30 MW of new natural gas generation, and a scenario with 20 MW of new natural gas generation. This is in part because the Lower Valley Energy natural gas pipeline is operated at relatively low pressures (60 – 300 pounds per square inch).[12] Preliminary engineering assessments suggest that the LVE natural gas pipeline could support no more than 20 to 30 MW of natural gas generation capacity in South Jackson at the current level of supply.[13] The natural gas pipeline terminus is located close to a liquefied natural gas storage facility, which could provide a limited amount of back-up natural gas supply in the event of a supply disruption on the pipeline. However, to implement a natural gas generation solution in LVE, a more detailed engineering study is necessary to evaluate the potential for the existing gas pipeline system to support new generation and maintain customer reliability. For additional generation capacity in the region, it may be possible to locate diesel generation in the LVE and/or FREC service territories.

The table below summarizes the distributed generation technologies considered in this analysis. Based on the analysis, small natural gas reciprocating engines appear to be the most attractive new generation option. The 5,000 kW reciprocating engine does not pass the benefit-cost (BC) test on it own, with a

[12] Lower Valley Energy Natural Gas Pipeline Project, Final Environmental Impact Statement, January 2008. Available at: http://www.fs.fed.us/r4/btnf/projects/
[13] Interviews with BPA and LVE staff.

BC ratio of 0.93. However, it is included in the non-wires alternative portfolio anyway, because even with this resource included, *the portfolio as a whole* still passes the cost-effectiveness text. There are a few different models in this size class, and more analysis in a Phase 2 analysis is needed to select the specific model and configuration that would be most appropriate for the location. Note that the most cost-effective new generation resource of those analyzed here (the 81 MW Microfin GE 7EA gas turbine with a benefit-cost ratio of 1.12) is not selected as part of the portfolio because it is too large of a resource to be supported by the region's limited natural gas supply.

Table 7. New Generation Characteristics

Generation Type	Total Installed Cost ($/kW Installed)	Assumed # hours operating per year	Total Resource Cost Test (30 MW scenario)	Resources Selected (MW)
Reciprocating Engines - 100kW Rich Burn with 3 Way Catalyst	$ 2,252	88	0.49	-
Reciprocating Engines - 800kW - Lean Burn	$ 1,656	88	0.65	-
Reciprocating Engines - 3000kW - Lean Burn	$ 1,141	88	0.93	-
Reciprocating Engines - 5000kW - Lean Burn	$ 1,141	88	0.93	20 - 30
Microturbine - 65 kW	$ 2,766	88	0.39	-
Microturbine - 250 kW multiple units	$ 2,711	88	0.40	-
Fuel Cell - 200/400kW PAFC	$ 6,374	88	0.17	-
Fuel Cell - 300 kW MCFC	$ 5,637	88	0.20	-
Fuel Cell - 1500 kW MCFC	$ 5,303	88	0.21	-
Gas Turbine - 3000 kW	$ 2,161	88	0.50	-
Gas Turbine - 10 MW	$ 1,660	88	0.65	-
Reciprocating Engine - 8MW (Microfin Wartsila 20V34SG)	$ 1,095	88	0.84	-

Generation Type	Total Installed Cost ($/kW Installed)	Assumed # hours operating per year	Total Resource Cost Test (30 MW scenario)	Resources Selected (MW)
Gas Turbine - 42MW (Microfin GE LM6000PD SPRINT)	$ 1,265	88	0.72	-
Gas Turbine - 81MW (Microfin GE 7EA)	$ 735	88	1.12	-
Gas Turbine - 95MW (Microfin GE LM100)	$ 1,361	88	0.71	-
PV - 5kW (Res)	$ 7,053	1,489	0.14	-
PV - 10kW (Com)	$ 7,053	1,489	0.14	-
Wind - 10kW	$ 1,999	2,278	0.66	-
Total Resources Selected	**$1,141**	**88**	**0.93**	**20 - 30**

We assume that a new reciprocating engine natural gas generator could be brought on-line by the end of 2012 under optimistic assumption, or by early 2013, if there are no major barriers to permitting and constructing the unit. However, there may be significant barriers to constructing and operating a new natural gas facility in LVE which are beyond the scope of this screening study, and which would need to be addressed as part of a more detailed implementation study.[14]

[14] For example, in BPA's initial discussions with ABB, estimates suggest that it could require 26 months to procure a transformer needed to interconnect a new 20 – 30 MW generator in LVE's service territory. Whether the NWA proves to be feasible will depend in part on how long it takes to interconnect the generator and when procurement of a new transformer begins.

6 Summary of Results

Overall, we find that it may be possible to cost-effectively defer the Hooper Springs proposed transmission line with a suite of non-wires alternatives until 2016 or 2020, depending on how many megawatts of new generation can be developed in the region. The potential implementation challenges of both the NWA and the proposed transmission line mean that the non-wires alternative should be studied in parallel with the deployment of the Hooper Springs proposal to avoid any delays to either proposed solution. The NWA portfolio could act as a backstop solution if the proposed Hooper Springs transmission line faces any delays.

The non-wires screening study finds insufficient energy efficiency and demand response potential to defer the Hooper Springs line. Furthermore, it does not appear feasible to increase the existing generation from the Palisades facility. In terms of new generation, 20 to 30 MW of new natural gas reciprocating engines could be installed to defer the line, but the new generation does not pass the cost-effectiveness test on its own. However, major elements of the portfolio, including the new generation, would have to be implemented by the fall of 2012 or by 2013 at the latest. When new generation is combined with energy efficiency and demand response as part of an integrated non-wires portfolio, the suite of measures is cost-effective as a whole and provides sufficient peak demand reductions to defer the line for several years. The Regional Cost Test of the portfolio with 30 MW of new generation plus EE and DR, achieves a Regional

benefit-cost ratio of 1.4 and could defer the need for the Hooper Springs line until 2020. If only 20 MW of new natural gas generation could be installed along with EE and DR, the proposed line could be deferred until 2016, with a Regional benefit-cost ratio of 1.5 (the benefit-cost ratio is higher in this case because the smaller generator would cost less.) These results are illustrated in the figure and table below.

Figure 15. Comparison of Non-Wires Alternative Program Peak Savings with Annual Requirements for Peak Savings

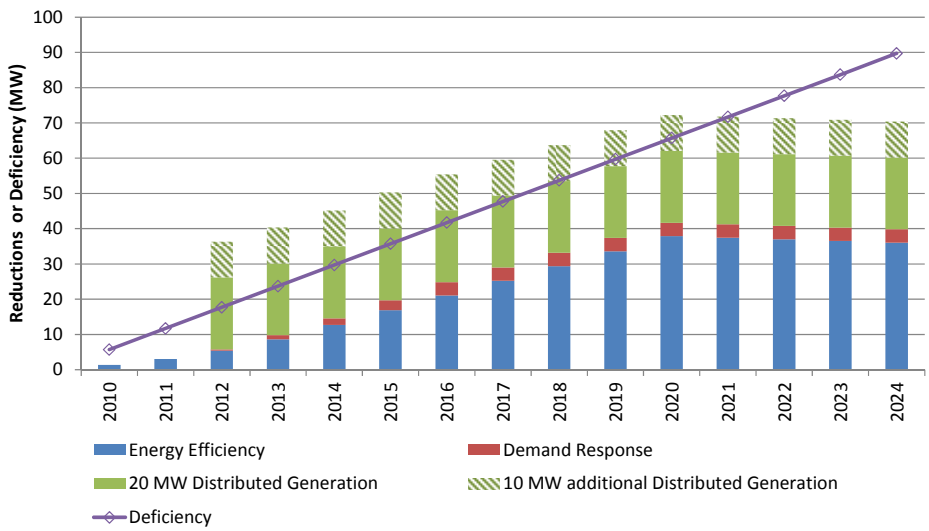


Table 8. Comparison of Benefit-Cost (BC) Ratios from Three Cost Perspectives for Two Scenarios

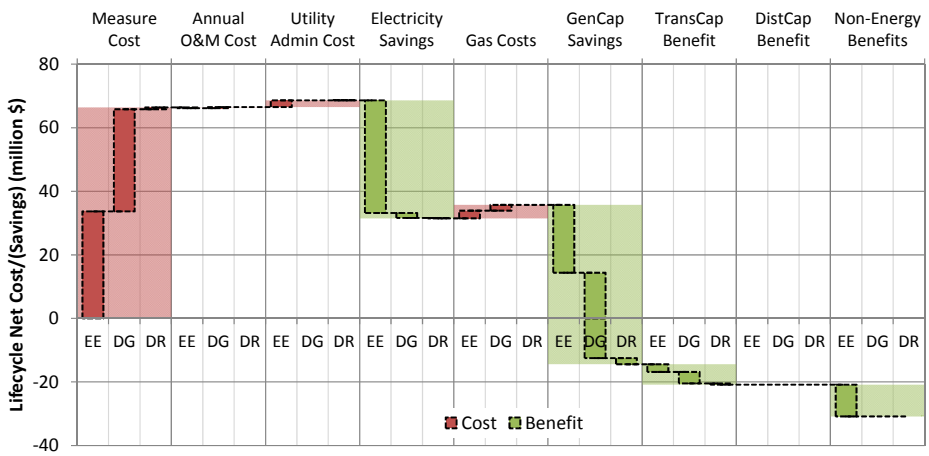
Net Present Value of Costs and Benefits of Resource Portfolio	Total Benefits ($M)	Total Costs ($M)	Net Benefit ($M)	BC Ratio
Overall Program - 30 MW new generation scenario				
Regional Cost Test	**$103.7**	**$73.1**	**$30.7**	**1.4**
Participant Test	$63.6	$31.7	$32.0	2.0
Societal Test	$138.9	$77.6	$61.3	1.8
Overall Program - 20 MW new generation scenario				
Regional Cost Test	**$91.8**	**$61.6**	**$30.2**	**1.5**
Participant Test	$63.6	$31.6	$32.0	2.0
Societal Test	$123.1	$65.4	$57.7	1.9

Another way of looking at the benefit-cost results of the non-wires alternative is to consider each of the components of the costs and benefits separately using the Regional Cost Test perspective. The "waterfall" chart below shows the costs of the non-wires alternative in red, the largest of which include the lifecycle measure costs of new energy efficiency and installing a new natural gas fired power plant. There are also smaller costs associated with the operation and maintenance (O&M) and utility administration cost of the measures. Finally, the fuel switching measures, whereby electric end-uses are replaced with natural gas end-uses, show a slight increase in natural gas procurement costs.

The chart below (Figure 16) shows that the lifecycle costs of the non-wires alternative program are outweighed by the lifecycle benefits of the program, shown in green. The two largest sources of benefits from the non-wires program come from avoided electricity purchases (electricity savings) from the energy efficiency measures installed, as well as the generation capacity savings from the on-peak energy efficiency measures and the on-peak generation from the new natural gas power plant. Other, relatively smaller benefits of the

program include the savings of deferring the transmission line until 2020 (in the case shown below) and the non-energy benefits of energy efficiency, including water savings.

Figure 16. Non-Wires Alternative Program Lifecycle Costs and Benefits Comparison (Regional Cost Perspective)



6.1 Uncertainties

While the basic findings of this analysis are robust, there are a number of critical uncertainties that are worth noting. First, the peak demand load forecast for the LVE and FREC region is uncertain. The peak demand forecast used in this analysis is based on a temperature-adjusted regression-based methodology. The forecast captures historical demand growth and correlations between temperature and peak demand, but does not try to predict how future energy efficiency programs in the region, or changing growth patterns could affect peak demand growth.

BPA is currently ramping up funding for energy efficiency programs among its customers. Both FREC and LVE are likely to significantly increase their EE efforts in response to BPA's post-2011 energy efficiency funding to help meet the NWPCC's Sixth Power Plan EE target for the region. It is uncertain to what extent planned efficiency efforts will target peak demand reductions, especially if the LVE and FREC energy efficiency programs are not designed specifically with winter peak reductions in mind.

A related area of uncertainty is the potential for commercial fuel-switching (from electric to natural gas) in the LVE region and the potential for winter peak reductions from other commercial measures, including traditional commercial heating and building shell measures. If a more detailed implementation study of commercial energy efficiency potential is undertaken, we recommend focusing particular attention on this area which seems to be under-represented in the 6th Power Plan efficiency potential studies.

Other key uncertainties, including the optimal capacity for new generation in the region and the permitting and siting costs and risks of new generation, would ideally be addressed through a more thorough implementation analysis of the non-wires alternative. An implementation study would investigate how an energy efficiency program focused on winter peak-demand savings might be developed and deployed. An implementation could also address:

- To what extent is LVE, or FREC, interested in collaborating with Bonneville to pursue a non-wires alternative solution in their service territory, including the construction of new distributed generation?
- If the distributed generation option is investigated further in LVE's service territory, what are the natural gas supply constraints and how

would these affect the performance and reliability of a new natural gas generator?

- What is the likely timeline and feasibility of permitting a distributed generation option in the LVE, or FREC, service territory?
- How would distributed generation be integrated onto the LVE or FREC system, and what supporting equipment would be needed, such as capacitors and transformers? How long would it take to procure and install the necessary equipment and what would it cost?

7 Conclusions and Recommendations

Based on the findings of this analysis, it is clear that additional transmission or new generation is needed in the LVE/FREC region as quickly as possible to avert the risk of a dangerous and potentially protracted outage in the region. A non-wires approach appears to be feasible, and could defer the need for the Hooper Springs line until at least 2016, if not to 2020, and would be slightly more cost-effective than the Hooper Springs proposal, if implemented as modeled. However, there are risks associated with both the Hooper Springs proposal as well as the non-wires alternative which should not be understated.

The non-wires alternatives analysis suggests that a combination of aggressive energy efficiency, demand response and the construction of 20 to 30 MW of new natural gas generation in LVE would have a Total Resource Cost benefit-cost ratio between 1.4 and 1.5. However, a more in depth study of the natural gas supply constraints in LVE is needed, as well as a more detailed assessment of potential risks or roadblocks to implementation of a new natural gas facility in LVE. This analysis has not made an assessment of the permitting challenges which may be associated with building a new natural gas generation facility in the Jackson area. An aggressive energy efficiency program would also need to

be developed in the LVE and FREC service territories to implement the non-wires alternative.

Given the large risks associated with any delay to a solution to the voltage stability challenge in the region, we recommend that BPA continue to pursue the Hooper Springs transmission project on its current schedule while studying the implementation feasibility of the non-wires option.

Table of Acronyms

Acronym	Definition
aMW	Average Megawatt
BC ratio	Benefit Cost ratio
BPA	Bonneville Power Administration
DEI	Distribution System Efficiency Improvements
DG	Distributed generation
DR	Demand response
E3	Energy and Environmental Economics, Inc.
EE	Energy efficiency
FREC	Fall River Rural Electric Cooperative
kV	Kilovolt
LNG	Liquefied Natural Gas
LVE	Lower Valley Energy
MW	Megawatt
MVA	Megavolt-ampere
NERC	North American Electric Reliability Corporation
NWPCC	Northwest Power and Conservation Council
SOL	System Operating Limit
TOU	Time of Use
TRC	Total Resource Cost
TRR	Transmission Revenue Requirement
WACC	Weighted Average Cost of Capital