Hooper Springs Phase 2 Non-Wires Alternatives Analysis: Final Report

Prepared for:

Bonneville Power Administration

March 12, 2012

Energy+Environmental Economics

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Table of Contents

Acknowledgements **1**

Executive Summary **2**

1 Background **13**

1.1 Organization of this Report 13

1.2 Hooper Springs Transmission Project 14

1.2.1 Hooper Springs Transmission Project Need 15

1.3 Overview of Approach 16

2 Approach **19**

2.1 Updated Hooper Springs Project Cost 19

2.1.1 Financing and Net Present Value of Hooper Springs Project 21

2.2 Updated Local Area Demand Forecast 23

2.2.1 Disagregated Peak Demand For LVE and FREC 24

2.3 Updated Fuel and Power Price Forecasts 26

2.4 Updated Power Flow Analysis 29

2.4.1 Background: Description of Power Flow Analysis 29

2.4.2 Update of Power Flow Scenarios 30

2.4.3 Palisades and Wind Generation 31

2.5 Natural Gas Pipeline Assessment 33

2.6 Assessment of Local Generation 36

2.6.1 Generator Technical Options and Project Site 36

2.6.2 Gas Generator Project Costs 38
2.6.3 Power Plant Financing Options 41
2.6.4 Generator Cost and Benefits Analysis 44
2.6.5 Project Timeline and Permitting 52
3 Demand Side Measures Feasibility Analysis 55
3.1 Energy Efficiency 55
3.1.1 Natural gas fuel switching potential 59
3.2 Demand Response, Direct Load Control & Smart Meters 64
3.2.1 Pacific Northwest Smart Grid Demonstration Project.. 65
3.2.2 Resource Potential Estimate for Demand Response and Direct Load Control 67
3.2.3 Smart Meters and Customer Energy Use Feedback... 68
3.2.4 Summary 69
4 Conclusions and Next Steps 71
Table of Acronyms 74
Appendix A: Lower Valley Energy 6" Gas Pipeline Capacity Study ... 75
Appendix B: Local Generation Development and Construction Plan 76

List of Figures

Figure 1. Comparison of Non-Wires Alternatives Peak Load Reductions with Peak Reduction Requirement for Transmission Deferral, if Distributed Generation were Energized in 2015 7
Figure 2. Bonneville Transmission Facilities and Proposed Project Area... 15
Figure 3. Diagram of Proposed Hooper Springs Project on the transmission system in the LVE/FREC region 16
Figure 4. Comparison of 2010 and 2011 Estimated Winter Peak Demand Forecast for Combined LVE and FREC (excluding Rexburg and Ririe) 23
Figure 5. Comparison of LVE Historical and Forecast Non-Coincident Winter Peak Demand 25
Figure 6. Comparison of FREC (excluding Rexburg and Ririe) Historical and Forecast Non-Coincident Winter Peak Demand 26
Figure 7. Updated Natural Gas Price Forecast 28
Figure 8. Updated Electricity Price Forecast 28
Figure 9. BPA Annual Costs and Savings of Gas Generator assuming Hooper Springs Construction in 2025 46
Figure 10. BPA Annual Costs of Constructing Hooper Springs Line in 2013 47
Figure 11. Comparison of BPA Annual Net Cost of Gas Generator Option (with Hooper Springs Construction in 2025) vs. BPA Annual Net Cost of Constructing Hooper Springs Transmission Project in 2013 48
Figure 12. Winter Peak Load Reduction Potential from Energy Efficiency (MW, 2011 – 2031) 56
Figure 13. First-Year Energy Efficiency Savings: Peak Area Load Reduction: Historical Achievements & NWA Forecast 58
Figure 14. Comparison of Historical and Projected Installations of New Heating and Hot Water Systems 61
Figure 15. Annual Peak Reduction by Fuel-Switching Measure 63

List of Tables

Table 1. Benefit-Cost Ratio of the Full Non-Wires Portfolio: Total Resource Cost 8
Table 2. Six Scenarios of Benefit-Cost Ratios for the Non-Wires Gas Generator 10
Table 3. Detailed Net Present Value of the Cost and Benefits of the Gas Generator, assuming 2013 COD (using lower capital cost scenario and 20-year non-recourse project financing for generator) 10
Table 4. Updated Hooper Springs Project Cost Estimate, 2011 dollars 21
Table 5. BPA Nominal Discount Rate, Annual Inflation Rate & Transmission Financing Assumptions 22
Table 6. Hooper Springs Annual O&M Costs, 2011 dollars 22
Table 7. Cost Estimate for Local Natural Gas Generation Option 39
Table 8. Comparison of Power Plant Financing Options 42
Table 9. Comparison of 20- or 30-year nominal levelized capacity costs of power plant (Lower cost scenario) 43
Table 10. Non-recourse project financing: BPA-perspective benefit-cost calculation of lower cost scenario, 9% discount rate 49
Table 11. Six Scenarios of Benefit-Cost Ratios for the Non-Wires Gas Generator 49
Table 12. Potential costs and benefits to LVE of owning and financing the gas generator 50
Table 13. Comparison of Proposed Hooper Springs Transmission Project Timeline and an Expedited Timeline for Non-Wires Alternative 54
Table 14. Demand Response and Direct Load Control Resource Potential Estimate 68

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Executive Summary

In January 2011, Energy and Environmental Economics (E3) completed a high-level screening study[1] (Phase 1 study) which analyzed whether 'non-wires alternatives'[2] could feasibly defer the proposed Hooper-Springs transmission line. The proposed project is designed to mitigate low-voltages on the transmission system serving parts of Fall River Electric Cooperative (FREC) and Lower Valley Energy (LVE), located in South-Eastern Idaho and Western Wyoming. The Hooper Springs project would be energized by the winter of 2013/2014. The Phase 1 study concluded that the Hooper Springs transmission project could potentially be deferred until 2016 or 2020 with a combined, cost-effective portfolio of energy efficiency, demand response and 20 to 30 MW of new natural gas peaking generation. The Phase 1 study recommended that BPA continue to pursue the Hooper Springs transmission project on its current schedule, while simultaneously investigating a number of questions around the implementation feasibility of the non-wires solution.

The Phase 2 analysis includes updates to key parameters and assumptions, including a revised peak demand forecast for the region, revised electricity and

[1] See: http://transmission.bpa.gov/planproj/non-wires_round_table/NonWireDocs/ScreeningStudy_NonWires_HooperSprings_Jan2011.pdf
[2] For more information about non-wires alternatives, see: http://transmission.bpa.gov/planproj/non-wires_round_table/

fuel price forecasts, and revised power flow model results. Some of the key questions investigated as part of this Phase 2 study included:

- **Timing:** Is it feasible to permit and construct the proposed generator by the winter of 2013/2014, in time to provide a reliable alternative to the Hooper Springs transmission line?

- **Fuel supply:** Is the natural gas supply sufficient to meet the fuel needs of the proposed gas generator?

- **Fuel switching:** To what extent could fuel-switching, from electricity to natural gas, primarily for space and water heating, reduce peak demand in the region?

- **Energy efficiency (EE) and demand response (DR):** What EE and DR options are feasible and cost-effective in the region?

- **Cost effectiveness:** What is the overall cost-effectiveness of the non-wires alternative? How would the proposed gas generator be paid for, and how would the financing of the proposed power plant affect the cost-effectiveness of the non-wires solution?

Timing of the Non-Wires Alternative

The results of this non-wires implementation study conclude that it is unlikely that the proposed generator can be permitted, constructed and commercially on-line in time for the winter of 2013/2014, whereas the Hooper Springs transmission option is currently planned to be energized by that date. In order

to meet a commercial online date for the proposed generator option by the winter of 2013/2014, the permitting process ideally should have already been underway.

There are at least two important sources of risk to the timeline for implementing a successful non-wires alternative to the Hooper Springs transmission project. The first uncertainty is around how long it would take to complete the generator permitting and whether there will be significant public support or opposition to the proposed gas generator. The second important uncertainty is around the timeline for developing the proposed generator telecommunication link.

The timeline for the generator telecommunications link depends on what level of robustness will be required by BPA and PacifiCorp interconnection standards. If a BPA-owned "utility grade" redundant communications link is required by BPA and PacifiCorp, BPA staff has indicated that it would take three years to bring the telecommunication link online. This would mean that the generator would not be available until fiscal year 2015, which is past the reliability need date for the non-wires alternative. If, on the other hand, a leased line communications link is acceptable to both BPA and PacifiCorp, then the communications link would not affect the on-line date for the gas generator.

Fuel Supply for the Gas Generator

There is another risk associated with the non-wires solution due to the fuel supply needs for the proposed generator. While the existing LVE-owned natural gas pipeline has sufficient capacity to supply LVE's existing and forecasted natural gas distribution customer needs, the pipeline does not have sufficient

gas supply to also meet the fuel needs of a new natural gas power plant during the winter peak demand periods. As a result, the natural gas generator would need to use liquefied natural gas (LNG) during winter critical peak periods. Although using LNG as a fuel source appears to be a feasible solution from a cost-effectiveness and siting perspective, Lower Valley Energy has indicated that under current market conditions the supply of LNG and the availability of LNG delivery trucks is relatively constrained compared to demand. As a result, LVE indicates that it could be challenging for them to schedule sufficient LNG deliveries to maintain a reliable fuel supply to the gas generator during the winter critical peak periods.

Fuel Switching

Another potential source of peak demand reductions in the LVE region, beyond the gas generator, is fuel switching from electricity to natural gas. As part of this implementation analysis, we investigated the potential for fuel switching away from electric hot water heaters and electric space heating to natural gas heat. While the resource potential exists, it is limited by the fact that only about 19% of residential customers and 17% of commercial customers in LVE and FREC's combined service territory have access to existing natural gas service but do not already use gas to meet their heating needs. As a result, fuel switching alone cannot provide a sufficient reduction in electricity demand during the critical winter peak hours to provide an alternative to the transmission option. Furthermore, since the use of electricity at current retail rates is relatively cheap compared to the use of natural gas at current retail rates, the cost-effectiveness of fuel-switching measures for customers is limited without significant incentives and/or rebates to encourage fuel-switching.

Given these findings, we conclude that it does not appear feasible at this time to implement a timely non-wires alternative to the Hooper Springs transmission project.

Energy Efficiency, Demand Response and the Non-wires Portfolio

The achievable resource potential for energy efficiency measures that reduce winter peak demand, including residential building shell measures (such as attic, wall and floor insulation), natural gas heating, natural gas water heating measures and ground-source heat pumps, is estimated to be 31 MW by 2025, if the programs begin in 2012. The achievable resource potential demand response and direct load control measures, particularly direct load control hot water heaters and thermal electric storage heating systems, is estimated to provide another 6 MW of flow reductions by 2025.

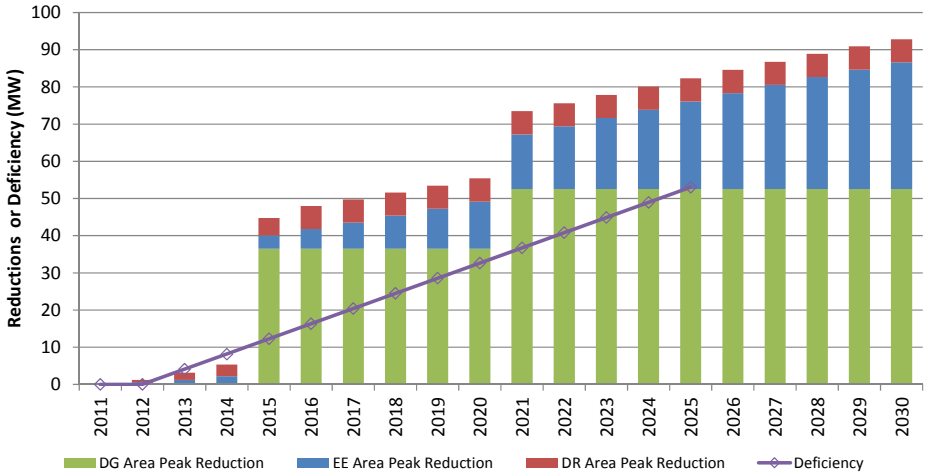
As part of the Phase 2 analysis, BPA performed updated power flow model runs of the transmission constraints in the LVE/FREC region. The results of the power flow model runs find that a 3-unit, 25 MW natural gas generator located at Lower Valley Energy's Rafter J substation (also known as Jackson Yard), would provide the equivalent of approximately 37 MW in flow reductions on the Lower Valley Energy transmission system. Furthermore, the addition of a $2 million capacitor bank at Tincup could provide the equivalent of approximately 16 MW of flow reductions.

However, it does not appear possible at this time to bring the gas generator on-line by the winter 2013/2014. If the generator were brought on-line in 2015, rather than in 2013, then the LVE/FREC region would be at risk of experiencing

low-voltages during the winters of 2013 and 2014, resulting in NERC reliability violations.

Figure 1 shows the results of the non-wires portfolio if the gas generator were brought on-line in 2015 (plus additional capacitors in 2021), along with the savings potential from energy efficiency and demand response/direct load control, compared to the MWs of flow reductions needed in each year to defer the Hooper Springs transmission project, labeled "deficiency" in the figure. Figure 1 shows that in the winters of 2013 and 2014, without the natural gas generator on-line, energy efficiency and demand response are not expected to provide sufficient load reductions to meet the reliability criteria and to defer the Hooper Springs project.

Figure 1. Comparison of Non-Wires Alternatives Peak Load Reductions with Peak Reduction Requirement for Transmission Deferral, if Distributed Generation were Energized in 2015



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

Costs and Benefits of the Non-Wires Portfolio

We test the cost-effectiveness of the non-wires solution under two scenarios: 1) a "lower cost" scenario, which includes lower generator capital costs as well as the cheaper, "leased line" telecommunication link, and 2) a "higher cost" scenario, which includes higher capital costs for the generator and the more expensive "utility grade" telecommunication link.

If the non-wires solution, including energy efficiency and demand response as shown in Figure 1 above, could be implemented by 2013 under the "lower cost scenario" assumptions, then from an overall portfolio perspective, the 2011 present value benefits of the non-wires portfolio would be greater than the costs, resulting in a total resource cost (TRC) benefit-cost ratio of 1.4. This is equivalent to approximately $26.9 million in net present value savings for BPA ratepayers over the course of 30 years. Under the "higher cost" scenario assumptions, if the generator could defer the Hooper Springs project, then the benefit-cost ratio would be 1.3, with net present value savings of approximately $21.9 million over the course of 30 years (Table 1). The non-wires solution would not be cost-effective if the gas generator utilized IPP financing.

Table 1. Benefit-Cost Ratio of the Full Non-Wires Portfolio: Total Resource Cost[3]

2011 Net Present Value of Costs and Benefits of Non-Wires Portfolio (EE, DR & DG)				
Total Resource Cost Test	Total Benefits ($M)	Total Costs ($M)	Net Benefit ($M)	BC Ratio
Lower Cost Scenario	$102.1	$ 75.3	$ 26.9	1.4
Higher Cost Scenario	$102.1	$ 80.3	$ 21.9	1.3

[3] Scenarios assume non-recourse project financing over 20 years for the gas generator.

Costs and Benefits of the Gas Generator

Considering only the capital costs of the gas generator, the potential range of all-in capital costs of the gas generator, including the uncertainty around the communications link cost, is between $48.4 million for the "lower cost scenario" and $60.1 million for the "higher cost scenario" (in 2011 dollars). The deferrable capital cost of the Hooper Springs transmission project, at $56.9 million (in 2011 dollars), falls within the cost range for the gas generator. However, the capital costs are not the full story, project financing impacts and variable costs and benefits should be considered as well to get a complete picture of cost-effectiveness over the non-wires alternative project lifetime.

Assuming that the non-wires solution could defer the construction of the Hooper Springs transmission line until 2025, it would generate ratepayer savings in the early years of the project compared to the transmission solution, but these savings would be partially offset by higher costs after 2025, when the deferred Hooper Springs line is assumed to be constructed. We find that the benefits of the gas generator (energy, capacity and deferred transmission benefits) would slightly outweigh the costs of the gas generator. As part of this analysis, we considered two cost scenarios, a "lower cost" scenario and a "higher cost" scenario, and three financing options. The resulting 20-year net present value benefit-cost ratios for the generator, (excluding for the moment energy efficiency and demand response), vary from 1.1 to 1.3 if LVE finances the power plant. The power plant would not be cost-effective under independent power producer financing (See Table 2).

Table 2. Six Scenarios of Benefit-Cost Ratios for the Non-Wires Gas Generator

			Benefit-Cost Ratio	
Financing scenario	Rate	Term	Lower Cost Scenario	Higher Cost Scenario
Non-Recourse Project Financing (1)	4.66%	20	**1.2**	**1.1**
LVE borrowing rate after discounts (2)	5.80%	30	**1.3**	**1.1**
IPP financing (3)	8.00%	20	**0.9**	**0.9**
(1) Based on BPA FY12 3rd Party Taxable Borrowing Rate, Memorandum: FY 2012 Interest Rate and Inflation Forecast, December 09, 2011				
(2) Based on communication with LVE, 2/3/2012				
(3) Standard industry assumptions				

Table 3 below shows, in more detail, the costs and benefits of the gas generator for a single scenario: the lower-capital cost scenario combined with the non-recourse project financing scenario.

Table 3. Detailed Net Present Value of the Cost and Benefits of the Gas Generator, assuming 2013 COD (using lower capital cost scenario and 20-year non-recourse project financing for generator)

Results			
2011 Present Value Costs (Million $)		**2011 Present Value Benefits (Million $)**	
Generator Capacity & Fixed Costs	$39.7	Generator Capacity Savings	$18.9
Generator Variable O&M Costs	$0.0		
Generator Fuel Costs	$1.2	Generator Energy Savings	$0.5
Tincup Capacitor Bank in 2021	$1.4		
Generator Communications Sys.	$0.8		
Tx Line: Hooper Springs in 2025	$24.7	Tx Deferral: Hooper Springs in 2013	$63.8
Total	**$67.7**	**Total**	**$83.1**

Benefit-Cost Ratio	1.2

Table 3 shows each of the categories of the generator cost, if the generator and the communications link were built in 2013, and if a capacitor bank were installed at Tincup in 2021, resulting in a deferral of the Hooper Springs

transmission line to 2025. The value, or benefits, of the gas generator to BPA customers include capacity savings (starting after 2016 when the General Transfer Agreement with PacifiCorp expires), minimal energy saving for the peak hours during the year when the generator is dispatched, and the deferral value of the Hooper Springs transmission line from 2013 to 2025. The results show that the gas generator could generate about $15.3 million in savings to BPA ratepayers over the 20-year project lifetime in 2011 NPV terms, if it were brought online in 2013.

From LVE's perspective, the costs of the generator could be entirely offset through a power purchase agreement with BPA. However, the complete set of benefits and costs of the gas generator from LVE's perspective are more difficult to quantify. On the one hand, financing the gas generator could introduce unwanted liabilities onto LVE's balance sheet, unless BPA and LVE pursued a non-recourse project financing structure whereby credit rating agencies would not treat the project debt as LVE's. Furthermore, the permitting and construction of the power plant could create inconvenience and risk for LVE, especially if the generator faces unexpected opposition or delays. One the other hand, the gas generator could have a number of benefits for LVE, largely in the form of a local, dispatchable resource which could help to improve power quality and reliability year-round, making LVE less reliant on transmission for all of its power needs.

Conclusions and Recommendations

Based on this updated Phase 2 implementation analysis of the proposed non-wires alternative to the Hooper Springs transmission line, E3 recommends that

BPA construct the Hooper Springs transmission line on its original schedule. The timeline necessary to implement a non-wires alternative by the winter of 2013/2014, which would require permitting and constructing a gas generator at LVE's Rafter J/Jackson Yard site, does not appear to be feasible at this time. Furthermore, LVE's concerns about scheduling deliveries of LNG to the site indicate that there could be some fuel supply risk associated with the project.

If, at some future date, another non-wires analysis is called for in the LVE region, then BPA, in close coordination with LVE, may want to re-consider the gas generator option as a potential solution. The technical feasibility of the project remains sound, and the Jackson Yard site appears to be a beneficial location, electrically, for a power plant. However, given that this analysis found limitations to the natural gas supply into the region, an analysis of non-wires alternatives in the region should first evaluate whether the fuel supply availability and reliability in the LVE region has changed. A gas generator is likely to be a more attractive option in the future if the capacity of the natural gas pipeline serving LVE has been expanded and if the pipeline's natural gas supply has become more reliable.

Finally, we recommend that future non-wires analyses begin at an earlier stage in the transmission planning process, when the transmission need is just beginning to become visible to transmission planners. This would serve the duel benefit of providing more time to investigate and implement innovative non-wires options, and would ensure that the transmission planning effort has not already accrued significant sunk costs and BPA staff-time before an in-depth analysis of alternatives is started.

1 Background

In January 2011, E3 completed a high-level Phase 1 screening study,[4] which determined that non-wires measures had a reasonable potential to cost-effectively defer BPA's proposed Hooper Springs transmission project to 2016 or 2020. The Phase 1 non-wires solution was dependent on the development of a new natural gas peaking facility in Lower Valley Energy's service territory. In addition, energy efficiency and demand response measures were identified as part of the non-wires solution. The Phase 1 study highlighted the need to determine the feasibility of implementing these measures, which is the focus of this Phase 2 study.

1.1 Organization of this Report

Chapter 1 of this report provides background on the Hooper Springs transmission project, including the project need and estimated Hooper Springs project costs. Chapter 2 outlines important updates to the non-wires input assumptions made in the Phase 2 analysis. Chapter 2 also summarizes the results of E3's subcontractors' independent studies of Lower Valley Energy's natural gas pipeline capabilities and the natural gas generator feasibility and siting assessment, and overall costs and benefits. Chapter 3 identifies the

[4] See: http://transmission.bpa.gov/planproj/non-wires_round_table/NonWireDocs/ScreeningStudy_NonWires_HooperSprings_Jan2011.pdf

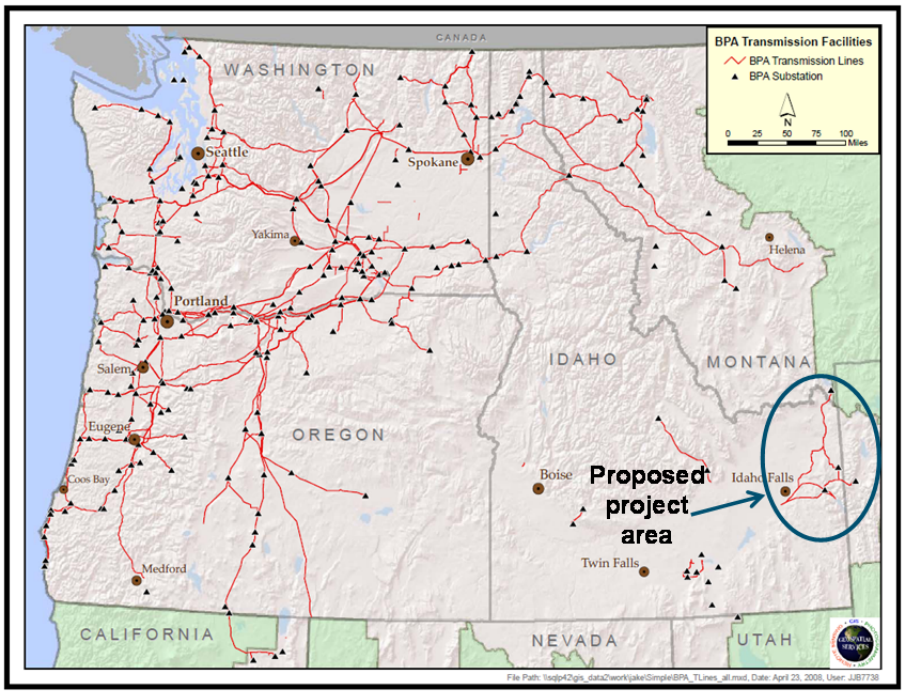
complementary contribution that energy efficiency and smart-grid enabled demand response measures could make (in addition to the contributions from the natural gas generator) to help defer project need. Chapter 4 summarizes the study's conclusions, including recommended next steps.

1.2 Hooper Springs Transmission Project

Lower Valley Energy (LVE) and Fall River Rural Electric Cooperative (FREC), a member of the Pacific Northwest Generation Cooperative (PNGC), are BPA preference customers. Load growth in the LVE/FREC region has increased the risk that an outage of the Palisades-Snake River 115 kV line would cause a NERC single contingency criteria violation during the winter critical peak conditions.

LVE is located on the Western edge of Wyoming, adjacent to Grand Teton and Yellowstone National Parks and includes Jackson Hole, Wyoming. FREC is located to the north and west of LVE, and includes the Idaho towns of Ashton, Victor and Driggs, and the Montana town of West Yellowstone (see Figure 2). FREC's electrical loads in the Idaho towns of Rexburg and Ririe are excluded from this analysis because they are not served out of the Goshen substation.

Figure 2. Bonneville Transmission Facilities and Proposed Project Area



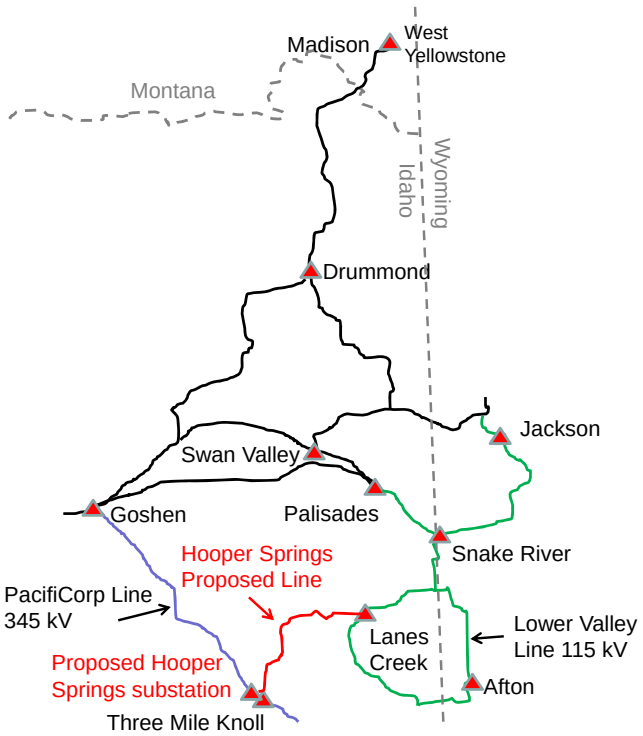
Source: Bonneville Power Administration

1.2.1 HOOPER SPRINGS TRANSMISSION PROJECT NEED

The purpose of the proposed 32-mile Hooper Springs transmission line is to alleviate low-voltage violations caused by an outage of the Palisades-Snake River 115 kV line. Based on updated load forecasts and load flow information, the Hooper Springs line could prevent low-voltage violations caused by a single contingency until the winter of 2029/2030. The proposed line would be located in South-Eastern Idaho and Western Wyoming (See Figure 3). The Hooper Springs line would connect between a proposed BPA-owned Hooper Springs substation, near PacifiCorp's Three Mile Knoll substation, and an expansion of

the existing Lanes Creek substation on Lower Valley Energy's system. Construction would begin in the spring of 2013, and the line would be energized by December of 2013.

Figure 3. Diagram of Proposed Hooper Springs Project on the transmission system in the LVE/FREC region



1.3 Overview of Approach

The Phase 1 Hooper Springs non-wires study provided an initial screening-level assessment of the potential for demand response, energy efficiency and distributed generation to defer the need for the line. This Phase 2 analysis

provides more in-depth analysis of the implications and feasibility of the identified measures, with particular emphasis on the cost, feasibility, timeline and permitting requirements of developing a 25 MW natural gas peaking generator in the LVE service territory.

The following steps were taken, in coordination with BPA staff and E3's subcontractors, to develop the results of this study:

(1) Update Hooper Springs project cost estimate (Chapter 2)
(2) Update local area load forecast (Chapter 2)
(3) Update power flow analysis (Chapter 2)
(4) Update fuel and electricity price forecasts (Chapter 2)
(5) Assess the capabilities of the natural gas pipeline to fuel the natural gas generator (Chapter 2)
(6) Assess the cost, feasibility, timeline and permitting requirements for the natural gas generator (Chapter 2)
(7) Feasibility analysis of demand side measures (Chapter 3)
    a. Analyze energy efficiency measure cost and potential
    b. Analyze fuel-switching measure cost and potential
    c. Analyze demand response measure cost and potential
(8) Summary of business case of non-wires portfolio (Chapter 4)

2 Approach

2.1 Updated Hooper Springs Project Cost

In coordination with BPA transmission planning staff, the cost estimates of the Hooper Spring transmission line have been updated from the Phase 1 analysis to reflect improved assumptions about which costs are deferrable with a non-wires solution, and which costs are non-deferrable. Furthermore, this updated analysis includes assumptions about the annual operations and maintenance (O&M) of the transmission line, as well as financing assumptions for the capitalization of the transmission project.

The estimated direct capital cost (not including overhead) of the Hooper Springs transmission project cost is $47.6 million in 2011 dollars. In addition, the Hooper Springs project, by creating a new point of interconnection to PacifiCorp's system, will incur transmission charges to BPA, which BPA estimates at $8.47 million through 2016. (After June of 2016, the General Transfer Agreement with PacifiCorp will expire, at which point the Hooper Springs line will not contribute any incremental transmission costs.) This brings the total unloaded project cost to approximately $56.1 million.

Of that cost, $7 million has been already been spent on the Hooper Springs transformer which is currently in storage. Due to its relatively specialized

voltages (138/115 kV), BPA cannot readily repurpose the transformer to another project, so this $7 million cost is treated as non-deferrable in the non-wires alternatives analysis. Another $1.2 million will be spent on transmission pre-engineering work before a decision is reached regarding the non-wires solution, and so is also considered a non-deferrable cost. All other Hooper Springs costs are treated as deferrable by a non-wires solution.

To these direct capital costs are added non-direct overhead costs for the transmission capital equipment at 23% based on the BPA memorandum, "Implementation of FY 2012 Construction and Reimbursable Non-Direct Rates."[5] The Hooper Springs total net cost is shown in Table 4, at $56.9 million.

[5] The 23% overhead cost estimate is used by BPA in FY 2012 and include 11% for labor and materials and 12% for corporate overhead costs. Overhead costs are not the same as cost uncertainty, which is often reflected in a separate estimate of contingency costs. The transmission line costs include 15% contingency, while the transformer and substation costs do not include contingencies and reflect quoted prices.

Table 4. Updated Hooper Springs Project Cost Estimate, 2011 dollars

	Yr of Cost	Total Cost ($000)	Excluded cost ($000)	Net Cost ($000)	Non-Direct Rates[4]	Total Net Cost ($000)
Sub. spent costs & transformer	2010	$ 7,000	($ 7,000)	$ -	1.23	$ -
Sub. pre-engineering land survey	2012	$ 2,000		$ 2,000	1.23	$ 2,460
Sub. design materials & associated work	2013	$ 5,000		$ 5,000	1.23	$ 6,150
Substation construction	2013	$ 13,000		$ 13,000	1.23	$ 15,990
Tx - pre-engineering	2012	$ 1,800	($1,200)	$ 600	1.23	$ 738
Tx - land acquisition	2013	$ 3,400		$ 3,400	1.23	$ 4,182
Tx - access road	2013	$ 6,000		$ 6,000	1.23	$ 7,380
Tx line	2013	$ 9,400		$ 9,400	1.23	$11,562
PacifiCorp tx. charges	2013	$ 782		$ 782	-	$ 782
PacifiCorp tx. charges	2014	$ 3,129		$ 3,129	-	$ 3,129
PacifiCorp tx. charges	2015	$ 3,129		$ 3,129	-	$ 3,129
PacifiCorp tx. charges	2016	$ 1,434		$ 1,434	-	$ 1,434
Total		**$ 56,074**	**$ 8,200**	**$ 47,874**		**$ 56,936**

2.1.1 FINANCING AND NET PRESENT VALUE OF HOOPER SPRINGS PROJECT

For the purposes of this analysis, we convert the Hooper Springs nominal project cost into a 2011 net present value (NPV). The present value cost represents the value to BPA of the future transmission investment, in today's dollars. The present value calculation factors in all project costs over 30 years, including the cost of financing the transmission line over 30 years and the annual O&M costs of the line over 40 years, as well as BPA's discount rate and an annual inflation rate assumption. The annual transmission O&M costs and

the PacifiCorp transmission charges are treated as annual costs, these costs are not capitalized. The discount rate, inflation rate, cost of borrowing and financing term assumptions are shown in Table 5 below.

Table 5. BPA Nominal Discount Rate, Annual Inflation Rate & Transmission Financing Assumptions

Variable	Input Assumption	Source
BPA nominal discount rate	9%	BPA administratively determined transmission discount rate
Annual inflation rate	1.7%/year	FY 2011 Common Agency Assumptions, Table 11: Projected Change in GDP Price Deflator
3rd Party Taxable Borrowing Rate, 30 yr in 2013	5.43%	FY 2012 Interest Rate and Inflation Forecast, December 09, 2011
Borrowing term	30 yrs	Discussion with BPA staff

The impact of the annual O&M costs adds $2.0 million per year to the Hooper Springs project, as shown in Table 6 below.

Table 6. Hooper Springs Annual O&M Costs, 2011 dollars

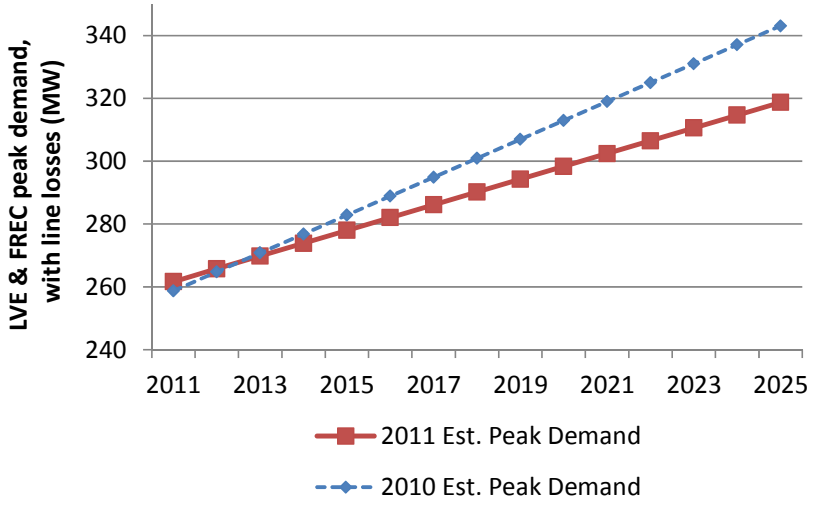
	Total Cost ($000)	Annual O&M % adder (1)	Annual O&M Cost ($000)
Sub. spent costs & transformer	$ 7,000	3.30%	$ 231
Sub. pre-engineering land survey	$ 2,000	3.30%	$ 66
Sub. design materials & associated work	$ 5,000	3.30%	$ 165
Substation construction	$ 13,000	3.30%	$ 429
Tx - pre-engineering	$ 1,800	2.95%	$ 53
Tx - land acquisition	$ 3,400	18.64%	$ 634
Tx - access road	$ 6,000	2.95%	$ 177
Tx line	$ 9,400	2.95%	$ 277
Total	**$ 47,874**		**$ 2,032**
(1) Source: 2010 AIS project submission training manual, provided per BPA staff comment.			

Applying the present value calculation, using the assumptions from Table 5 and the annual O&M costs in Table 6, to the cost schedule shown in Table 4, results in a 2011 net present cost of $63.8 million for the Hooper Springs transmission project.

2.2 Updated Local Area Demand Forecast

A revised winter peak demand forecast for LVE and FREC was developed by BPA and applied to the Phase 2 analysis. The winter peak demand forecast for the region in the Phase 1 analysis was approximately 1.9% per year, or 6 MW per year. The revised peak demand forecast is approximately 1.4% per year, or 4 MW per year. The lower forecast is due to expectations around continued slow economic growth in the region (Figure 4).

Figure 4. Comparison of 2010 and 2011 Estimated Winter Peak Demand Forecast for Combined LVE and FREC (excluding Rexburg and Ririe)



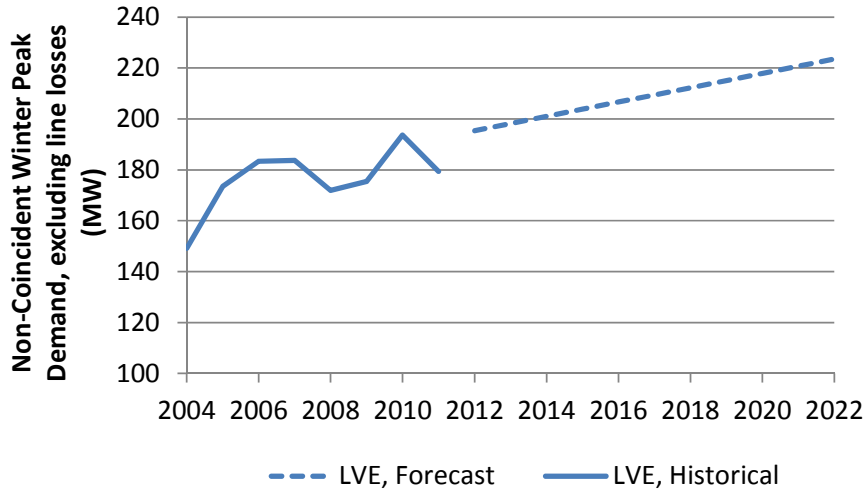
The distribution of load growth has also changed somewhat, with slightly lower growth expected in the Jackson area due to increased cost of living in the region, and slightly higher load growth south of Snake River in LVE's service territory and north of Targhee in FREC's service territory.

2.2.1 DISAGREGATED PEAK DEMAND FOR LVE AND FREC

Lower Valley Energy's position is that the BPA peak demand forecast for their service territory is too low. They state that LVE's winter peak demand in 2010 reached 193.6 MW, while the forecast for the coming winter of 2012 is 195.4 MW (net of the generation at Strawberry hydroelectric generation facility), see Figure 5 below. LVE points out that this increase of only 1.8 MW in peak demand growth over this two year period is inconsistent with their expectation of peak demand growth. LVE notes that fuel switching from propane and fuel oil to electric end uses, and the addition of snow making pumps, is likely to have contributed to a peak demand growth closer to 2.5 MW over the past two years.

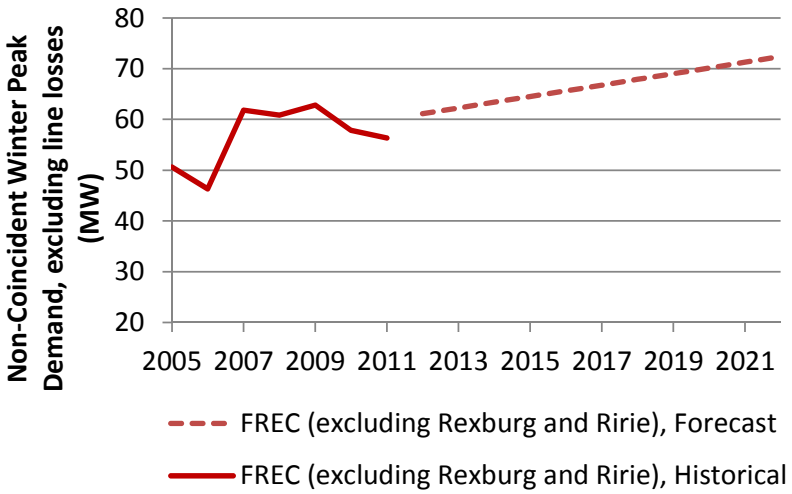
However, BPA staff has stated that the current forecast represents an appropriate planning level forecast covering new customer additions, consumer equipment changes, and the correct weather conditions for the planning criteria of a 1-in-2 forecast (-25˚ F), whereas the LVE suggested changes would not reflect 1-in-2 planning temperatures.

Figure 5. Comparison of LVE Historical and Forecast Non-Coincident Winter Peak Demand



The historical winter peak and the peak demand forecast for Fall River Energy (excluding Rexburg and Ririe), are shown in Figure 6. Just as for the LVE peak demand forecast, the FREC forecast is developed by BPA using statistical analysis techniques which reflect a 1-in-2 planning temperature rather than the absolute peak demand historically seen in the region.

Figure 6. Comparison of FREC (excluding Rexburg and Ririe) Historical and Forecast Non-Coincident Winter Peak Demand



2.3 Updated Fuel and Power Price Forecasts

The Phase 1 analysis used the Northwest Power and Conservation Council's (NWPCC) 6Th Power Plan (February 2010) assumptions for the natural gas and electricity price forecasts. For the Phase 2 analysis, we have updated the gas and electricity price forecasts to reflect more recent market conditions as of October 2011, using natural gas market price forwards data from the New York Mercantile Exchange (NYMEX), scaled from Henry Hub to the Northwest regions. The forecasted ratio between regional gas prices and electricity prices was maintained to be consistent with the NWPCC forecast. In addition, we developed a price forecast for liquefied natural gas (LNG), to approximate the fuel prices that the gas generator located in LVE's service territory would pay.

The updated natural gas and electricity price forecasts are compared to the Phase 1 forecast in Figure 7 and Figure 8 below.

Figure 7. Updated Natural Gas Price Forecast

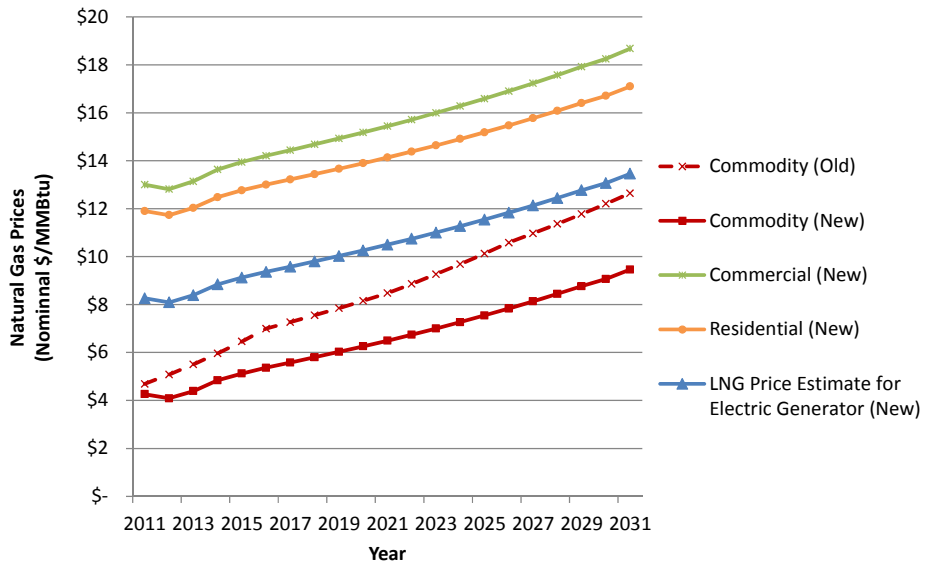
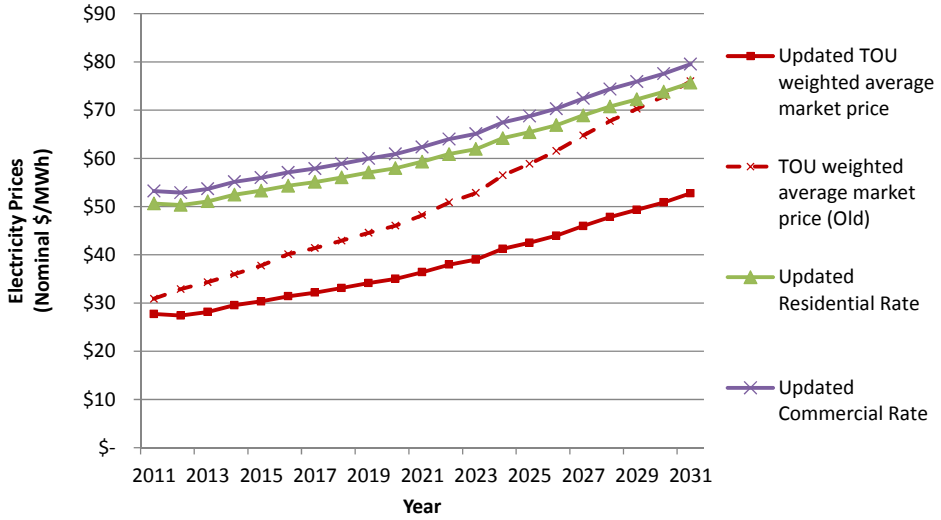


Figure 8. Updated Electricity Price Forecast



2.4 Updated Power Flow Analysis

2.4.1 BACKGROUND: DESCRIPTION OF POWER FLOW ANALYSIS

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

- Transmission network topology and facility ratings
- Electric loads withdrawing defined amounts of power at particular bus locations on the transmission system
- Electric generators injecting defined levels of power into the transmission system at particular bus locations.

Based on these inputs, the power flow model will simulate the loadings on particular transmission facilities (both lines and substations) under a base case with all transmission facilities in service. To find areas of concern, the power flow modeler will run contingency situations such as line or generator outages to determine whether these present a reliability concern on a particular transmission facility. To meet North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability criteria, planners will typically assess contingencies involving the loss of one transmission element (N-1), or at times two elements that are in a common location. After running all the possible contingencies, the transmission engineer then identifies lines that are either near 100% of their thermal load limit or

areas in which voltage may be lower or higher than the planning criteria. The transmission planning study will typically indicate a "project need date" for a new facility needed to avoid thermal load limit or voltage violations, based on the last year before a contingency would cause a system problem.

2.4.2 UPDATE OF POWER FLOW SCENARIOS

Using the updated peak demand forecast for LVE and FREC discussed above, as well as updated load distribution factors for LVE, BPA's Transmission Planning staff created power flow cases simulating summer and winter peak flow levels, and associated voltage levels on all BPA-owned and BPA-leased lines including the Snake River and Tincup substations.

Three cases were developed. The base case analysis, without the Hooper Springs line or the gas generator at Rafter J, demonstrates that voltages are already low in the region during the winter critical peak, under the single critical contingency. A solution to increase voltages in the region, such as with additional transmission capacity, local generation or demand response, would have been beneficial as early as the winter of 2011/2012. The power flow scenarios indicate that the Hooper Springs transmission project, or a non-wires solution, should be designed to address the low voltage violations starting in the winter of 2013/2014. BPA transmission planning staff has indicated that they do not expect low voltages in the region to result in a single contingency violation this winter (2011/2012) or next (2012/2013).

Including the Hooper Springs transmission project in the power flow run, starting in the fall of 2013, demonstrates that the transmission line would avert low voltage violations through the summer of 2035. By 2035, the single

contingency risk would be from an outage of the Goshen-Drummond 161 kV line or the Drummond 161/115 kV transformer. BPA Transmission Planning staff indicates that these low voltage violations in 2035 could be addressed with the addition of a capacitor bank at Madison for a cost of approximately $1.1 million. These findings indicate that the upgrade to the Goshen-Palisades line from 115 to 161 kV, which had been thought to be the next transmission project needed in the region after Hooper Springs, may actually not be needed in the foreseeable future.

The final power flow case included the addition of a 3-unit, 25 MW natural gas reciprocating engine facility at LVE's Rafter J substation in lieu of the Hooper Springs transmission line, starting in the winter of 2013/2014. The addition of the gas generator improves voltages in the region, deferring the need for a transmission solution until the winter of 2021/2022. Furthermore, transmission planning staff identified that the addition of a capacitor bank at the Tincup substation, at a cost of approximately $2 million, would further defer the need for the line until the winter of 2024/2025.

2.4.3 PALISADES AND WIND 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.

Efficiency improvements are planned for the four turbines at the Palisades hydroelectric generator. The refurbishments should improve the efficiency of the turbines by 30%. Under the current configuration, 2 of the 4 turbines are used to produce power during the winter peak period, at approximately 10 MW. During the winter, one of the remaining 4 units is offline for maintenance and the other unit is generally run for voltage support. After the efficiency improvements are completed, only one turbine would be used to produce real power, two units would remain offline, while the fourth turbine would be operated for voltage support.[6] Based on this information, it does not appear that the Palisades efficiency improvements will either increase or decrease the winter peak output or total voltage support available from Palisades. This means that the existing characterization of Palisades in BPA's power flow model adequately reflects the output from the Palisades facility even after the efficiency improvements are complete.

In addition to Palisades, a new 57.6 MW wind farm, Horse Butte Wind, is being developed near Idaho Falls and is expected to be operational by the second quarter of 2012. According to BPA planning practice, the wind farm is not assumed to provide reliable capacity during the winter critical peak, assuming worst case conditions. The Horse Butte Wind farm output is not modeled in the power flow runs, and does not affect the results of the non-wires analysis.

[6] Interview with Bureau of Reclamation staff.

2.5 Natural Gas Pipeline Assessment

The potential for a non-wires alternative to the Hooper Springs transmission line, as identified in the Phase 1 analysis, is contingent upon the ability to develop 20 to 30 MW of new natural gas generation by the winter of 2013/2014. One of the key questions that emerged from the Phase 1 non-wires study was whether LVE's natural gas pipeline supply would be sufficient to meet current and future distribution customer needs as well as the additional loads of a new natural gas peaking facility. To answer these questions, E3 subcontracted with the pipeline engineering firm Audubon Engineering. To read the complete natural gas pipeline assessment report, see Appendix A.

The natural gas pipeline assessment concluded that the existing 6" pipeline flow could be increased, using compression, to meet current and projected LVE flow requirements to the 2020 timeframe, assuming consistent and reliable gas supply from the Williams gathering field. With the addition of compression and a consistent supply of natural gas, LVE should also be able to meet the loads of the planned service area expansion into the Teton Village, Wyoming area in the 2014 timeframe.

However, the pipeline assessment concluded that the flow in the existing pipeline cannot be increased sufficiently to meet the natural gas needs of the proposed new gas generator on LVE's system during critical winter peak periods. As a result, the natural gas generator would need to be fueled during the winter peak periods using supplemental natural gas. The best option to meet the fuel needs of the proposed generation would be an expansion of the existing on-site LVE liquefied natural gas (LNG) storage system.

The cost of adding two additional 60,000 gallon storage tanks and LNG vaporization equipment at the site is estimated to cost between $1.8 and $3 million. This amount of storage would provide sufficient natural gas to run the 25 MW generators at full capacity for 10 consecutive days, for 4 hours per day, without re-filling the LNG storage tanks.[7] This would likely represent a worst-case scenario for the winter critical peak period. This option would allow LVE to continue to use the existing LNG storage to support pipeline operations and would also allow LVE to increase its emergency reserves of LNG should their pipeline supply be curtailed on a short-term basis.

Importantly, the proposed gas power plant, composed of three reciprocating engines, does not consume natural gas while in warm stand-by mode.[8] The engines are kept warm through the winter with an electrical heating unit.

There appears to be sufficient space at LVE's Rafter J/Jackson Yard site to locate two additional LNG storage bullets. However, in preliminary discussions with LVE staff, they have indicated that under current market conditions it can be challenging to schedule on-demand LNG deliveries. For example, Exxon, the largest LNG supplier in the region, requires that LVE schedule deliveries one year in advance, which could be difficult to do for a gas generator if it were only run for reliability purposes during the winter critical peak periods. Furthermore, LVE staff

[7] Each 60,000 LNG tank can be filled about 85% full, to 51,000 gallons. This means each tank holds approximately 4.2 mmscf of gas, and two LNG tanks hold approximately 8.5 mmscf of gas. If the gas generator ran for 4 hours per day for 10 consecutive days, it would consume 8.28 mmscf, representing a 97% draw-down of the tanks.

[8] Unlike a gas turbine, reciprocating engines do not operate in a spinning reserve mode. Rather, in "warm stand-by mode," the generator provides contingency reserves (not spinning reserves) and can synchronize to the grid in two minutes from the start signal, and ramp to full load in less than 10 minutes.

has found it challenging to find certified LNG truck drivers with experience driving flammable liquids to deliver the gas. This means that scheduling unexpected LNG deliveries can be difficult and ideally should be scheduled well in advance.

In quantifying the number of LNG truck deliveries that would be required to meet the gas generator's LNG fuel needs, it appears that it would be possible, but challenging and perhaps inconvenient for LVE to schedule sufficient truckloads of LNG. As a point of reference, if the 25 MW gas generators ran for 4 hours per day during the critical peak hours, this would be equivalent to approximately 1 LNG truck load per day. Or, if the gas generator ran for as many as 8 hours per day, which is unlikely, this would be equivalent to approximately 2 LNG truck loads per day.[9] Alternatively, if the 2 LNG storage tanks were fully-drawn down by the gas generator, it would require approximately 11 truckloads to re-fill the tanks, which would need to occur over the course of several days. To put these numbers into context, the largest LNG supplier in the region, Exxon, is capable of delivering five truckloads of LNG to LVE per day, while the second-largest LNG supplier in the region can supply two loads per day. Under worst case conditions, LVE takes about five loads of LNG per day to meet their existing natural gas distribution customers' end-use needs, which means that up to two additional loads per day could potentially be scheduled to meet the gas generator's fuel supply needs.

[9] A 60,000 LNG tank can be filled 85% full to hold approximately 51,000 gallons of LNG, which is equivalent to 4.2 mmscf of gas. A 25 MW generator, consisting of 3 generating units, consumes 207,000 scf/hour (each unit consumes 69,000 scf/hr. If the gas generator ran for 4 hours per day, it would consume 828,000 scf/day, which is equal to just over one truckload assuming each load holds 9,500 gallons of LNG.

During non-winter, non-peak demand periods, customer demand for pipeline natural gas falls dramatically. It would be possible to operate the natural gas generator using pipeline gas during these lower gas demand periods to provide summer peak electrical supply, including; energy, capacity and system reactive power (MVAR). This ability to use pipeline gas would require some additional valves, regulation and flow control equipment, the costs of which are included in the $1.8 to $3 M estimate for the LNG tanks. This analysis does not include costs or benefits associated with running the gas generator during non-critical peak periods, but it does assume the gas generator is interconnected to the 70-100 psi on-site gas system.

2.6 Assessment of Local Generation

To better understand the feasibility of the gas generator option, as part of the Phase 2 analysis, E3 subcontracted with Ramco Energy Incorporated, a power plant project development firm. To read Ramco Energy Inc.'s complete report of the local generation option, see Appendix B. The following section summarizes Ramco Energy's report and supplements it with additional information provided by Ramco after their report was finalized as well as additional analysis from E3.

2.6.1 GENERATOR TECHNICAL OPTIONS AND PROJECT SITE

Ramco Energy finds that it is technically feasible to locate a 25 MW natural gas generator next to LVE's Rafter J substation, at a site known as Jackson Yard. This site is determined to be the preferred location for such a project for the following reasons:

- Site access to both natural gas and LNG.
- Site access to the LVE 115 kV Rafter J substation.
- Adequate space available for the construction and operation of the generating plant, including construction laydown and parking.
- No identified fatal flaws with respect to air, environmental or engineering issues.
- The site is located more than 10 km from the Teton National Park, a Class 1 area, whereas the two alternate sites are within 10 km and as such would require extensive air modeling.
- While the site does not have access to municipal water or sewage (contrary to the initial assumption), the needs of a natural gas reciprocating engine for both would be minimal. Instead of municipal sewage, any "gray" or contaminated water would be collected in a small sump tank for pump-out and offsite disposal. Water needs would average on the order of roughly 0.1 gallon per minute. Since water is used only for consumptive purposes, mostly to top off engine maintenance water tanks after engine inspection and plant maintenance work, most of the time no water would be needed.

Three Wartsila natural gas reciprocating engines (20V34SG), with predicted gross full load output of 8.439 MW each, are recommended as the preferred power plant type for the site. The three-engine configuration is recommended to avoid the risk of a single engine start failure. Key factors in the recommendation of the Wartsila units over other technology types include a lower delivered cost compared to similar alternatives, superior full and partial load heat rates, the lack of a need for natural gas compression, as well as the engine's robust design and starting integrity.

2.6.2 GAS GENERATOR PROJECT COSTS

The direct project costs of the Warstila 25 MW reciprocating engine gas generator, including 14% - 15% for indirects, overhead, contingency and profit are estimated at between $42.3 and $44.6 million in 2011 dollars, or between $1,713 - $1,806/kW. Additional project costs include a range of $3.2 to $6.0 million to relocate two existing buildings on LVE's property, interest during construction costs, sales tax and between $374,000 and $6.8 million for the generator telecommunication link.

A broad range is estimated for the cost for the communications system into the Rafter J substation, reflecting uncertainty around what level of robustness would be required for the telecommunications link by BPA and PacifiCorp as part of their generation interconnection standards. The "lower cost" scenario assumes $304,000 (unloaded) plus $60,000/year in annual lease payments. These costs reflect the "leased line" telecommunication link option, whereby BPA would lease two existing redundant communication paths with geographic separation.

The "higher cost" scenario assumes a capital cost of $5.5 million (unloaded) and represents a "utility grade" communications link, whereby BPA would construct a new communications path, including a fiber optic cable from Swan Valley Substation to Teton Substation and a radio communication path with a passive reflector, between Teton substation and Rafter J substation. Since BPA would either lease or build and own the communications system, the 23% BPA transmission services non-direct rate is applied to both of options for the

communications system.[10] This brings the estimated range on the capital cost of the communication system to $374,000 to $6.8 million. Thus, the total, all-in capital cost of the generator project is estimated at $48.4 million for the lower cost scenario and $60.1 million for the higher cost scenario (Table 7).

Table 7. Cost Estimate for Local Natural Gas Generation Option

25 MW Local Gas Generation Project Cost (including overhead, 2011$, Millions, except as noted)	**Lower Cost Scenario**	**Higher Cost Scenario**
Wartsila equipment delivered to site (1)	$16.6	same
Balance of plant equipment (except switchyard) (2)	$1.5	same
Switchyard and transmission (3)	$2.0	same
Interconnection costs for 3-breaker protection (4)	-	$1.0
LNG – 2 additional bullets and accessories (5)	$1.8	$3.1
Engineering and permitting services	$5.7	same
Construction directs (6)	$8.1	same
Indirects, overhead, contingency and profit (7)	$6.6	same
Power plant sub-total	**$42.3**	**$44.6**
Direct cost per kW	***$1,713***	***$1,806***
Relocation of existing buildings "A & B" (8)	$3.2	$6.1
Interest during construction (9)	$1.4	$1.5
Sales tax (10)	$1.2	$1.3
BPA communications system (11)	$0.37	$6.8
All-in project cost	**$48.4**	**$60.1**

(1) The Ramco report used Wartsila pricing which assumes a euro exchange rate of 1.42. Current exchange rates are closer 1.3. As a result, the cost of the generator is reduced by $1M from their report, to reflect the current lower exchange rate.
(2) Includes all direct power plant costs not associated with Wartsila equipment, pumps, motors, and internal power plant communications system. No re-conductoring is required.
(3) Includes one generator step-up (GSU) and associated 115 kV breaker, two switches/structures, relays, auxiliary transformers and relocation of existing distribution undergrounds.
(4) Range reflects uncertainty as to whether two additional breakers for added protection will be required. The cost of two additional breakers is

[10] A 2.01% multiplier on the capital cost is used to calculate the communication link's annual O&M costs, based on the BPA 2010 AIS project submission training manual.

estimated at $1 million, incremental to the other switchyard and transmission costs, and is not included in Ramco's original report.

(5) Audubon Engineering estimated the cost of two 60,000 gallon LNG bullets at $3 million, or $1.2 million higher than Ramco Energy's estimate. Ramco's estimate is based on information obtained during a site visit, and reflects the fact that the LNG storage would be located at a site with existing LNG storage equipment, which reduces the cost compared to greenfield development. However, both costs are presented here.

(6) Does not include any cost for re-engineering site fill, or for pilings.

(7) Equivalent to 14% - 15% contingency.

(8) This estimated cost of demolishing, relocating and re-constructing buildings A & B directly west of the proposed site includes the cost of new imported fill and compactions, which Ramco estimates at $3.2 million. LVE has indicated that these costs could be as high as $6 million. Both costs are presented here.

(9) Interest during construction is calculated assuming LVE financing, using USE DOE's FY2011 Common Agency Assumptions of "Third Party Taxable Rates" with a 20-year maturity, at a 4.66%/yr interest rate.

(10) Wyoming state sales tax rate at 4% and a local sales tax rate at 1.38%.

(11) Includes 23% overhead. Lower range reflects costs of leased communication link. Higher range reflects BPA-built option including a fiber optic cable from Swan Valley Substation to Teton Substation and a MW radio between Teton substation and Rafter J substation.

The Hooper Springs deferrable transmission project cost of $56.9 million is similar to the all-in cost of the gas generator at $48.4 - $60.1 million. However, it is more useful to compare the net present value costs and benefits of these projects, in order to incorporate on-going annual O&M costs and other variable costs and benefits into the comparison.

Since BPA is statutorily prohibited from owning the gas generator, another entity would need to own and finance the power plant, either LVE or an independent power producer (IPP). To compensate LVE or the IPP for allowing the power plant to be dispatched by BPA during the winter critical peak periods,

BPA would likely pay the owner of the power plant for the annual energy and capacity value, as well as any associated fuel and variable O&M costs incurred for dispatching the power plant. A full accounting of these costs is described in the next section.

In addition, it is necessary to make a full accounting of the benefits of the generator, including any avoided power purchases and capacity costs. The next section of this report discusses the project financing options, and provides a complete net present value accounting of all costs and benefits.

2.6.3 POWER PLANT FINANCING OPTIONS

As mentioned, BPA is statutorily restricted from owning the proposed gas generator. As a result, there are two principal options to finance the power plant. Either BPA and Lower Valley Energy can work together to structure financing for the power plant, likely using non-recourse debt (i.e., the lender would not have recourse to LVE assets or general revenues), or an independent power producer (IPP) could finance the power plant.

Under the non-recourse project financing structure, or if Lower Valley Energy chose to finance the power plant, the project could access a lower cost of borrowing than it would under IPP financing. Furthermore, as an electric cooperative, LVE's tax status would reduce the financing costs for the project compared to IPP financing. Under non-recourse project financing, the financing transaction could be structured such that the project debt would not be treated as Lower Valley Energy's debt by the rating agencies, nor would existing LVE equity requirements and bond covenants be impaired. Alternatively, LVE could structure the project financing without BPA coordination, which would result in

different borrowing terms. The key assumptions for three financing options are shown in Table 8 below.

Table 8. Comparison of Power Plant Financing Options

Non-recourse project finance	Input Assumption	Source
Non-recourse project financing cost of borrowing	4.66%	FY 2011 Common Agency Assumptions, Table 8, Third-party taxable term rates, 20-year borrowing rate
Financing term	20 yrs	Standard generator financing assumption
Percent debt	100%	100% debt backed by revenue bond
LVE State and federal income tax rate	0%	Electric cooperative tax-exempt status
LVE project financing	**Input Assumption**	**Source**
LVE 30-year cost of borrowing, after discounts,	5.8%	Communications with LVE, 2/3/2012
Financing term	30 yrs	Communications with LVE, 2/3/2012
Percent debt	100%	100% debt backed by revenue bond
LVE State and federal income tax rate	0%	Electric cooperative tax-exempt status
IPP Financing	**Input Assumption**	**Source**
IPP weighted average cost of capital (WACC)	8.0%	California Public Utilities Commission, Market Price Referent, average of 2010 and 2009 WACC.
Financing term	20 yrs	Standard generator financing assumption
Percent debt	80%	Maximize leverage while sustaining acceptable debt-service coverage ratio
Debt interest rate	7.0%	California Public Utilities Commission, Market Price Referent, average of 2010 and 2009 debt interest rate.
IPP Federal income tax rate	35%	Typical federal income tax rate for IPPs
Common assumptions	**Input Assumption**	**Source**
MACRS term	15 years	Modified Accelerated Cost Recovery System, Federal statute
BPA nominal discount rate	9%	BPA administratively determined discount rate
Annual inflation rate	1.7%/yr	FY 2011 Common Agency Assumptions, Table 11: Projected change in GDP Price Deflator

To evaluate the costs of these three different options, we developed a financial pro-forma, which is a tool used for all types of power plant projects to calculate

the all-in cost of building, financing and operating a power plant, including costs associated with sales tax, income tax, insurance, operation and maintenance costs, depreciation tax benefits, and the cost of debt and equity. Annual cash flows, including all costs and revenues, are calculated over a 20-year project life, with the exception of the LVE financing scenario which uses a 30-year project life. This stream of annual cash flows is then converted into an annual payment to cover the capital cost of the power plant, also known as a levelized capacity cost. The levelized capacity cost can be thought of like a mortgage payment – it is the flat, nominal cost that would need to be paid each year for twenty or thirty years in order to cover the total fixed costs of the power plant. Variable costs, such as fuel costs and variable operation and maintenance costs would be paid for separately. Table 9 below shows the 20-year or 30-year nominal levelized capacity cost from the financial pro-forma for the lower cost scenario.

Table 9. Comparison of 20- or 30-year nominal levelized capacity costs of power plant (Lower cost scenario)

Gross Project Costs for Lower Cost Scenario (nominal levelized)	Non-recourse project financing	IPP financing	LVE financing
Project Capacity Cost, fixed costs only ($/kW-yr)	$ 191	$ 310	$ 179
Project Capacity Cost, fixed costs only ($/kW-mo)	$ 16	$ 26	$ 15

These levelized capacity costs are higher than the price that BPA typically assumes for a natural gas peaking power plant (such as GE's LMS100) for a number of reasons. First, since the size of the power plant is relatively small, at 25 MW, the cost per kW is higher because it is harder to achieve economies of scale. Second, the power plant cost estimates include a number of unique features which other generator cost estimates would not, such as the cost of

relocating LVE's existing buildings and adding LNG storage tanks to the site, the fact that the gas generator is being constructed at a high elevation, etc.

Although the project costs for the gas generator are higher than for a hypothetical "standard" peaking power plant, the relevant comparison is actually the cost of the gas generator compared to the Hooper Springs transmission line, since the project would be developed for reliability reasons within a narrowly-defined, capacity-constrained region.

2.6.4 GENERATOR COST AND BENEFITS ANALYSIS

This section evaluates the costs and benefits of the natural gas generator, in 2011 present value terms, from the perspective of BPA and LVE.

2.6.4.1 Costs and Benefits to BPA

The cost of the gas generator, from BPA's perspective, would be in the form of energy and/or capacity payments to the owner of the gas generator to cover their fixed costs, and any variable costs of running the gas generator to meet peak demand needs in the region. These costs will vary depending on whether non-recourse project financing through a cooperative agreement between BPA and LVE is used, or LVE project financing or IPP project financing is used.

The benefit of the gas generator, from BPA's perspective, would primarily be the value of deferring the construction of the Hooper Springs line to 2025. The power flow modeling shows that if the 25 MW gas generator could be on-line for the winter of 2013/2014, and if a $2 million capacitor bank were built in 2021, these resources could defer the need for the Hooper Springs line until

2025. If additional energy efficiency and demand response/direct load control peak savings are achieved, as described in this report, the Hooper Springs line could be deferred potentially well beyond 2025. As a conservative assumption, we have assumed that no additional energy efficiency or DR/DLC savings are achieved and that construction of the Hooper Springs line is only deferred until 2025, at which point the cost of the line is incurred.

The gas generator will also save BPA energy costs and capacity costs, based on the terms of the General Transfer Agreement with PacifiCorp, given that the gas generator would be located in the PacifiCorp balancing authority. Our current understanding is that under the GTA, if loads in LVE's service territory are reduced, this reduces the amount of power that BPA transfers to PacifiCorp. Therefore, the addition of a gas generator in LVE's service territory should reduce BPA's wholesale power purchases for the hours when the generator is operating.

The story is slightly different for BPA's avoided capacity costs. Currently, the terms of the GTA do not provide BPA with any benefit associated with reducing capacity needs in the LVE region. However, after the GTA expires in 2016, it is likely that BPA would enter into a standard transmission tariff with PacifiCorp, in which case the gas generator in LVE's service territory would save BPA capacity costs after 2016. For the purposes of this analysis, we assume that the gas generator in LVE's service territory avoids wholesale power purchases for the hours that it produces power starting in 2013, and that the generator avoids BPA capacity costs starting only in 2017. Both energy and capacity savings conclude by 2043, at the end of the 30-year project life.

Figure 9 and Figure 10 below compare the annual cash flow for the generator project (including the deferred Hooper Springs transmission project coming on-line in 2025) to the annual cash flow of constructing the Hooper Springs project in 2013.

Figure 9. BPA Annual Costs and Savings of Gas Generator assuming Hooper Springs Construction in 2025

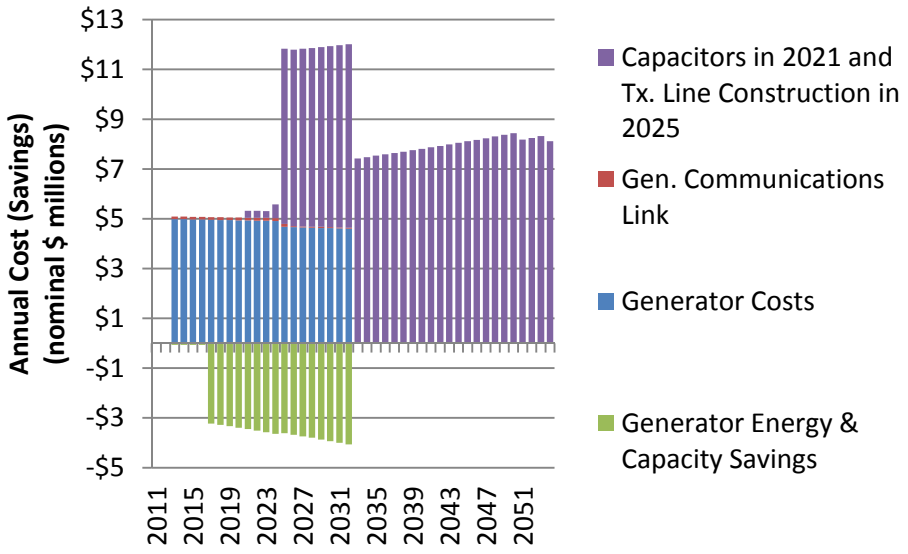


Figure 10. BPA Annual Costs of Constructing Hooper Springs Line in 2013

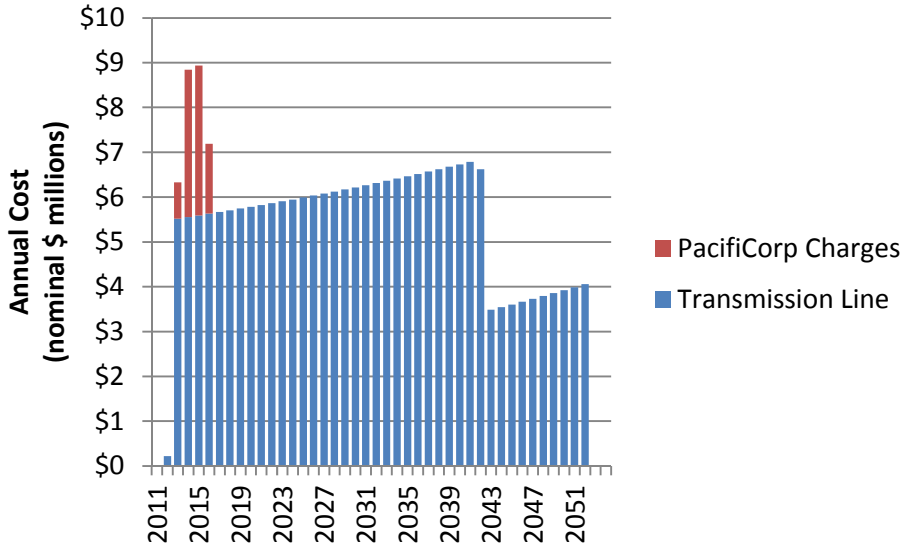
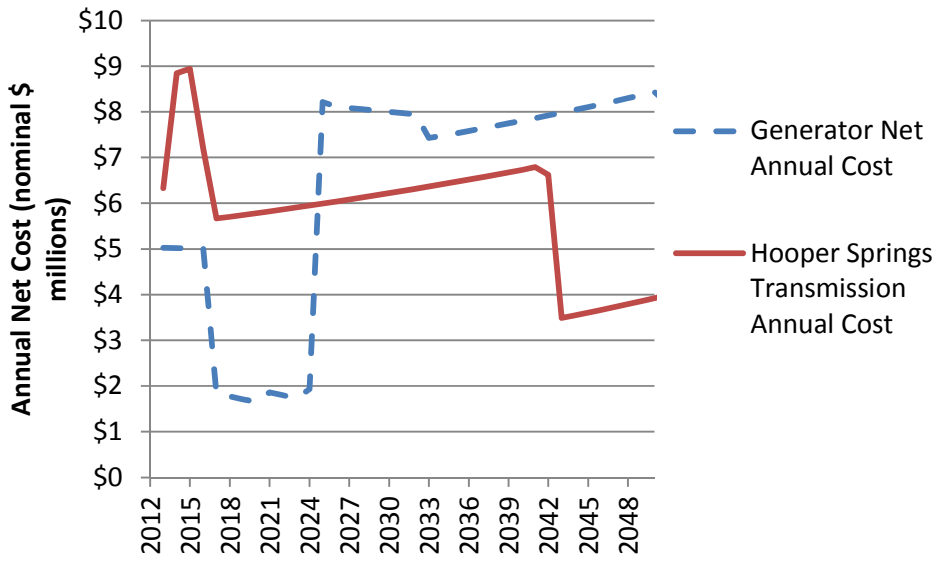


Figure 11 below compares the BPA annual net costs of the two alternatives (summarizing in a single chart the numbers shown in Figure 9 and Figure 10). This figure shows that the non-wires alternative has a lower expected cost in the early years of the project compared to the Hooper Springs project, and a higher expected annual cost starting in 2025, when the deferred Hooper Springs transmission line is expected to be built.

There is some uncertainty regarding whether the deferred Hooper Springs transmission line would be needed in 2025, or if it would be needed earlier or later under the non-wires alternative. The current assumption, that the deferred Hooper Springs transmission line will be needed in 2025, is based on BPA's load growth forecast for the region, which could change over time due to changes in population growth, the rate of economic recovery in the region, as well as changes in energy efficiency or demand response relative to historical

achievements in EE and DR, among other factors. In this analysis, we have made a conservative assumption and have not adjusted the need date for the Hooper Springs transmission project to reflect the impact of potential increases in winter-peak reducing EE or DR measures that could be implemented as part of a non-wires alternative program.

Figure 11. Comparison of BPA Annual Net Cost of Gas Generator Option (with Hooper Springs Construction in 2025) vs. BPA Annual Net Cost of Constructing Hooper Springs Transmission Project in 2013



Another way to look at the annual costs and benefits of the alternatives is through the calculation of a net present value. The table below shows the 2011 net present value benefit-cost results, from BPA's perspective, for the lower capital cost scenario ($48.4 million generator capital cost), assuming non-recourse project financing. The result is a benefit-cost ratio of 1.2. Or put differently, the present value benefits of the gas generator to BPA are $15.3

million higher than the present value costs of building the generator in 2013 and constructing the Hooper Springs line in 2025. Table 10 shows the break-down of the annual costs and benefits of the lower capital cost scenario in net present value terms.

Table 10. Non-recourse project financing: BPA-perspective benefit-cost calculation of lower cost scenario, 9% discount rate

Results			
2011 Present Value Costs (Million $)		**2011 Present Value Benefits (Million $)**	
Generator Capacity & Fixed Costs	$39.7	Generator Capacity Savings	$18.9
Generator Variable O&M Costs	$0.0		
Generator Fuel Costs	$1.2	Generator Energy Savings	$0.5
Tincup Capacitor Bank in 2021	$1.4		
Generator Communications Sys.	$0.8		
Tx Line: Hooper Springs in 2025	$24.7	Tx Deferral: Hooper Springs in 2013	$63.8
Total	**$67.7**	**Total**	**$83.1**

Benefit-Cost Ratio	1.2

Table 11 below shows the benefit-cost ratios for the gas generator under six different scenarios, showing the impacts of varying both the financing assumptions and the capital cost assumptions. While IPP financing is not cost-effective under either capital cost scenario, the other scenarios show that the benefits of the generator slightly outweigh the costs.

Table 11. Six Scenarios of Benefit-Cost Ratios for the Non-Wires Gas Generator

			Benefit-Cost Ratio	
Financing scenario	Rate	Term	Lower Cost Scenario	Higher Cost Scenario
Non-Recourse Project Financing (1)	4.66%	20	**1.2**	**1.1**
LVE borrowing rate after discounts (2)	5.80%	30	**1.3**	**1.1**
IPP financing (3)	8.00%	20	**0.9**	**0.9**

(1) Based on BPA FY12 3rd Party Taxable Borrowing Rate, Memorandum: FY 2012 Interest Rate and Inflation Forecast, December 09, 2011
(2) Based on communication with LVE, 2/3/2012
(3) Standard industry assumptions

The results of these six scenarios indicate that the proposed natural gas generator, if available by the winter of 2013/2014, could be marginally cost-effective to BPA as a non-wires solution, independent of any energy efficiency or demand response savings from a non-wires portfolio, as long as either LVE finances the project or a coordinated effort between BPA and LVE using non-recourse project financing is pursued. Under these circumstances the gas generator could save BPA ratepayers between $6.4 and $18.0 million over the course of the project life, in 2011 present value dollars.

2.6.4.2 Costs and Benefits to LVE

In this section, we evaluate the costs and benefits of the gas generator from Lower Valley Energy's perspective. Perhaps most important are the costs and benefits to LVE from owning and financing the gas generator which are not quantified in this analysis, but which are listed below.

Table 12. Potential costs and benefits to LVE of owning and financing the gas generator

Potential Costs	Potential Benefits
Additional debt on LVE balance sheet. This risk could be mitigated by pursuing non-recourse project financing in coordination with BPA.	Development of local, dispatchable generation could improve power quality, improve reliability with the addition of 3 breaker configuration, reduce dependence on transmission solutions
Increased number of deliveries of LNG to Jackson Yard storage site could raise environmental or safety concerns, and it could be difficult to schedule timely deliveries of LNG.	Increased optionality around use and sales of pipeline natural gas, if gas generator were connected to pipeline, as well as additional LNG storage capabilities

Potential Costs	Potential Benefits
"Hassle factor" of permitting and constructing generator, including relocation of existing buildings on site. Generator would trigger NERC/WECC reporting requirements.	Improvements to existing facilities through relocation of existing buildings
Potential for opposition from local residents due to view shed impacts, emissions, noise, etc.	Potential for support from local residents for developing local, reliable generation and/or avoiding the construction of transmission through national forest land
Risk and uncertainty associated with construction of gas generator on timeline necessary to meet reliability needs	Generator could be operated during the summer peak period for limited hours as an additional source of revenue and reliability

If LVE owned and financed the gas generator, or pursued non-recourse project financing in coordination with BPA as part of a non-wires solution, the cost of the power plant would most likely be paid for by BPA through a power purchase agreement (PPA) or capacity payment arrangement. Under such an agreement, the full cost of building and financing the gas generator would be covered by BPA through a series of payments to cover the fixed costs of the generator, as well as the variable costs of operating the facility.

Under the non-recourse project financing option specifically, the transaction would be structured such that the project debt would not be considered Lower Valley Energy's debt by the rating agencies, nor would existing LVE equity requirements and bond covenants be impaired. The project debt would be secured by the stream of payments to LVE under the PPA, and the cost of borrowing would be based on BPA's credit rating, not LVE's credit rating.

Under this PPA structure, the present value of the direct costs and benefits of the generator, from LVE's perspective would be exactly equal over the project lifetime, resulting in a benefit-cost ratio of 1.0. Given that the present value of the BPA PPA payments would be explicitly designed to offset the costs of paying

for and operating the gas generator, the choice, for LVE, of whether to support the construction of the power plant comes down to the other costs and benefits described qualitatively in Table 12 above.

2.6.5 PROJECT TIMELINE AND PERMITTING

There is significant uncertainty around the project development timeline for two reasons. The first major source of uncertainty in the timeline is around the generator permitting, and what level of public support or opposition the gas generator would face in the permitting process. We estimate that it would require 11.5 months to complete the generator permitting, from the start of the preparation permit package through to the receipt of the permits, assuming that there is no major public opposition to the proposal. The total project development timeline for the gas generator, excluding the interconnection requirements and communication link uncertainty, is estimated to require 24 months.

Approximately 6 months are estimated for site-preparation at the Jackson Yard site, including the relocation of the two existing buildings on the site. The site preparation and building relocation work could begin prior to the completion of the generator permitting and siting requirements, if necessary. The site-preparation work would need to be completed when the area is free of snow cover, i.e. during the spring and summer and potentially early fall months. The actual construction and testing of the generator is expected to require 9 months, and could begin as soon as the Warstila equipment is delivered and the site-preparation work is complete.

The second major source of project timeline risk is due to uncertainty around the level of robustness that will be required by BPA and PacifiCorp for the generator interconnection requirements. If the generator interconnection requires a "utility grade" communication link, it is expected to require 3 years to put in place the new fiber optic cable and microwave communications which would be required by this option. This would push the non-wires alternative implementation beyond the project need date, creating reliability risks in the Lower Valley and Fall River service territories. If a less robust communication link is required, then BPA could lease two existing communications paths along geographically diverse routes to meet the communication link requirement. It is not known exactly how long it would take to implement the "leased line" option, but it would require a minimum of 10 months to complete while BPA and PacifiCorp complete the interconnection studies. Under this option, the communication link would not represent a significant barrier to brining the gas generator on-line by the project need date.

Table 13 below compares an expected project timeline for the Hooper Springs transmission project, with two timeline scenarios for the non-wires alternative, assuming that permitting and pre-engineering can begin as soon as the spring of 2012. Table 13 shows that if the generator pre-engineering work and permitting applications began in the spring of 2012, and if the Wartsila equipment were ordered no later than the fall of 2012, it would be difficult to bring the generator commercially on-line in time for the winter of 2013/2014. However, if the generator communications link requires three years to procure land rights and design and build, then the earliest that the generator could be on-line would be the winter of 2014/2015, which negates the generator as a viable non-wires alternative to the Hooper Springs project.

Table 13. Comparison of Proposed Hooper Springs Transmission Project Timeline and an Expedited Timeline for Non-Wires Alternative

	2011			2012				2013				2014			
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	Summer	Fall	Winter
Hooper Springs Proposed Transmission:															
Initial Scoping/Work on Hooper Springs															
Draft EIS on Hooper Springs					X										
Final EIS Report on Hooper Springs							X								
Construction Hooper Springs Project															
Energization of Hooper Springs Project											X				
Non-Wires Alternative:															
Phase 2 NWA Implementation Study															
Gen. pre-engineering & studies															
EE and DR Implementation															
Gen. permitting, siting & LGI study															
Scenario 1: Leased line communication link									?						
Order Wartsila equipment															
Gen. site prep, relocate buildings															
Gen. plant construction															
Scenario 1: Energization of Generator												?			
Scenario 2: Utility grade communication link															
Scenario 2: Energization of Generator															X

Scenario 1: Timeline requirements if BPA and PacifiCorp interconnection study allows a "leased line" generator communication link.

Scenario 2: Timeline requirements if BPA and PacifiCorp interconnection study requires a "utility grade" generator communication link.

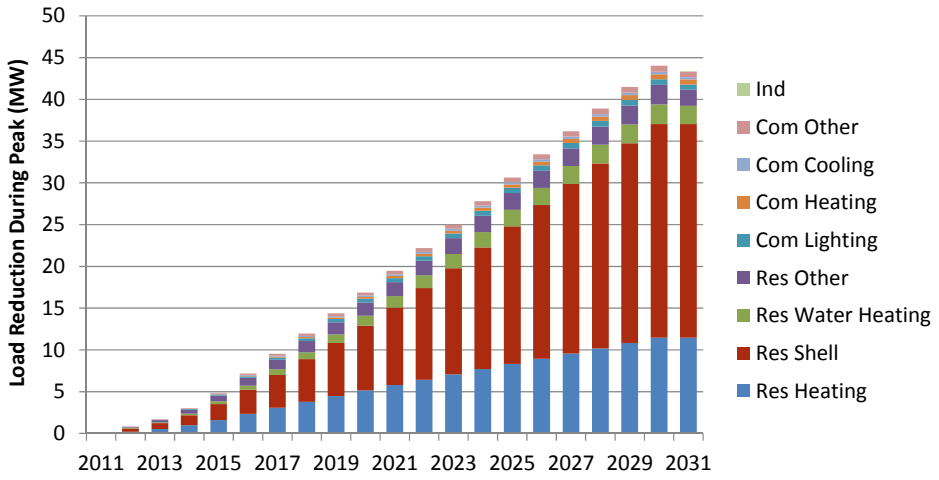
3 Demand Side Measures Feasibility Analysis

3.1 Energy Efficiency

In this section, we discuss the updated assessment of the cost-effective energy efficiency potential for winter peak-reduction measures in the LVE and FREC region. Using a number of revised input assumptions, including the updated natural gas and electricity price forecasts, we estimate a winter peak savings potential of approximately 17 MW by 2020 and nearly 45 MW of peak savings by 2030 (Figure 12).

Nearly 95% of the identified peak savings potential comes from residential measures. Approximately 50% of total peak savings potential is from residential shell measures, mostly through improving attic, wall and floor insulation. Approximately 30% of total peak savings potential is from residential heating measures, mostly in the form of ground-source heat pumps with some fuel-switching potential to natural gas, as discussed below.

Figure 12. Winter Peak Load Reduction Potential from Energy Efficiency (MW, 2011 – 2031)



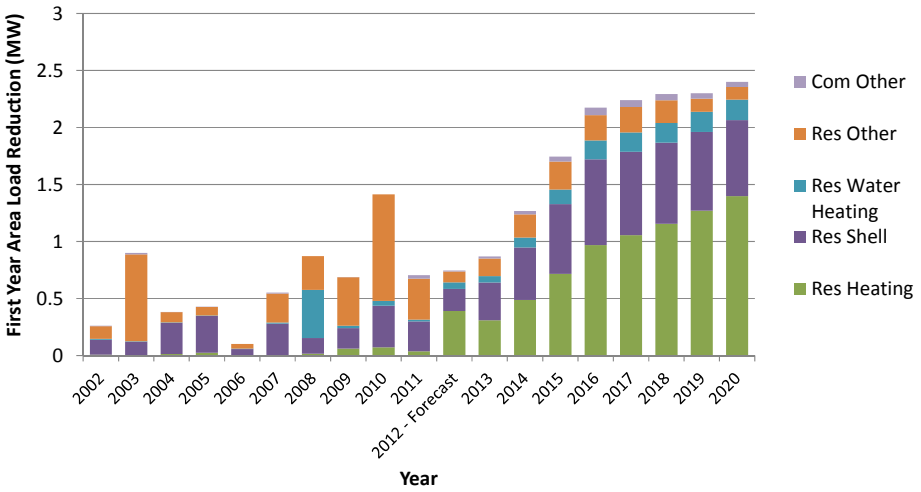
We have made a number of changes and updates to the energy efficiency resource potential estimates compared to the Phase 1 analysis. Overall, these changes have resulted in an approximately 50% lower energy efficiency peak savings estimate in 2020 in the Phase 2 results. One of the biggest drivers of the change between the Phase 1 and Phase 2 energy efficiency potential results is due to the updated (lower) fuel prices and electricity prices. In addition, all air-source heat pumps measures were removed from the energy efficiency potential database, as it was determined that this technology is not appropriate, given the cold winter temperatures. The air source heat pumps were replaced in the energy efficiency database with ground-source heat pumps, which are more expensive and result in slower expected adoption rates. Finally, in the Phase 1 analysis, the energy efficiency program was only designed to extend through 2020. In the Phase 2 analysis, the energy efficiency program is assumed

to be sustained through 2030, to better reflect the longer time-horizon in the Phase 2 analysis and a long-term commitment to energy efficiency in the region.

The non-wires energy efficiency portfolio that would be required to achieve the nearly 45 MW of peak savings by 2030 that is shown in Figure 12 would require adjustments to the emphasis of current energy efficiency programs. An energy efficiency program that was optimized to reduce winter peak demand, rather than total energy savings, would need to place a much higher emphasis on the installation of residential shell measures and residential heating measures (mostly ground source heat pumps).

Figure 13 below illustrates this shift in energy efficiency portfolios by comparing historical first year peak savings from energy efficiency measures to the projected first year savings under a non-wires resource portfolio. The figure shows that a dramatic increase in residential heating measure savings would be needed, as well as a nearly doubling of residential shell measure savings. The category of "residential other" which includes residential appliances, lighting and efficient shower heads, among other measures, could be scaled-back relative to historic levels.

Figure 13. First-Year Energy Efficiency Savings: Peak Area Load Reduction: Historical Achievements & NWA Forecast



Overall, the non-wires energy efficiency portfolio represents a fairly large change relative to historical practices, representing both an increase in annual peak savings from energy efficiency in the region, as well as a different mix of measures for customers and program administrators to implement.

There are a number of implementation challenges associated with achieving higher installation rates of residential heating and shell measures particularly. Both residential heating and shell measures can require fairly extensive renovations in the home, which can be disruptive to residents and which carry fairly high upfront costs, even after taking into consideration energy efficiency incentives. While these energy efficiency measures can increase the comfort in the home and save homeowners money, the other hurdles to implementation may prove challenging to overcome without significant changes to current program design strategies.

One way to increase the penetration of these peak-savings measures would be through higher upfront incentive payments. For example, the current incentive payment for ground source heat pumps within BPA programs is capped at $3,000, on a system which can cost between $15,000 and $25,000 more than a standard heating system.

However, there are also other ways of increasing program participation in energy efficiency programs. Community-targeted energy efficiency outreach efforts can be great motivators for program participation, especially when combined with a specific near-term savings goal and a clear explanation of how the peak savings will benefit the local community. Targeted energy efficiency outreach efforts can be relatively labor-intensive, but represent a proven way to bring a program to scale quickly. Lawrence Berkeley National Laboratory has put together a summary of community-based residential home energy retrofit programs which describes in more detail how these kinds of programs have worked across the country.[11]

3.1.1 NATURAL GAS FUEL SWITCHING POTENTIAL

The energy efficiency resource potential estimate discussed above includes the impact of residential fuel-switching measures. Currently, neither BPA nor LVE are offering customer incentives for fuel-switching as part of an energy efficiency or demand management program. However, there is potential to achieve winter peak savings through switching heating and hot water fuel from electricity to natural gas, if a fuel-switching program were developed.

[11] Fuller, Merrian et. al., Lawrence Berkeley National Laboratory, "Driving Demand for Home Energy Improvements, September 2010, available at: http://drivingdemand.lbl.gov/

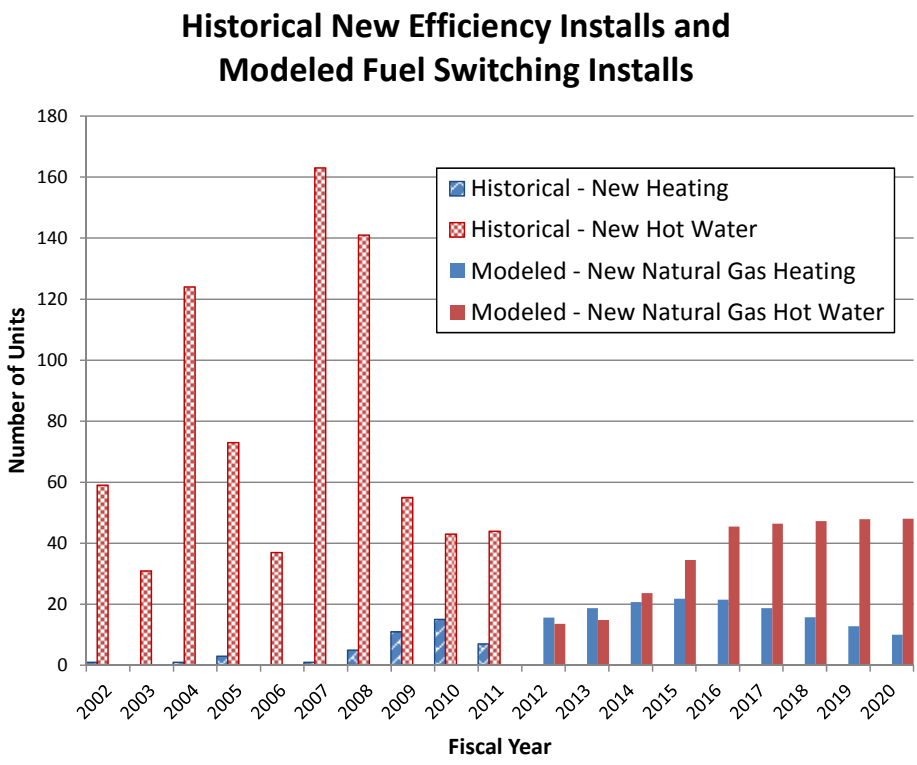
We found that fuel switching measures could reasonably be installed through 2020, at a rate that would yield just over 1 MW of winter peak reductions. While these installations would increase demand for natural gas, this increase would be small compared to already forecasted growth of pipeline gas deliveries in peak demand months. From a total resource cost perspective, fuel switching measures are cost-effective, but from a participant cost perspective, most fuel switching measures are not currently cost-effective, given current electric retail rates and retail gas prices. However, the participant cost-effectiveness of fuel-switching measures is likely to improve over time as Tier 2 power costs increase and begin to be reflected in retail rates.

To estimate the fuel-switching potential in the combined LVE and FREC service territory, we first estimated the percentage of customers with access to the existing natural gas distribution system, but who do not currently use natural gas service. This estimate was developed using three years of monthly billing data for LVE. Approximately 19% of residential customers and 17% of commercial customers in LVE and FREC's combined service territory have access to existing natural gas service but do not use it, and so are candidates for fuel-switching measures.

We developed an estimate of fuel-switching potential, based on an analysis of total resource cost-effectiveness, an estimate of gas availability and customer adoption rates. We then compared the forecast of cost-effective fuel-switching

potential to historical annual rates of installations[12] of heating and hot water systems, as shown in Figure 14.

Figure 14. Comparison of Historical and Projected Installations of New Heating and Hot Water Systems



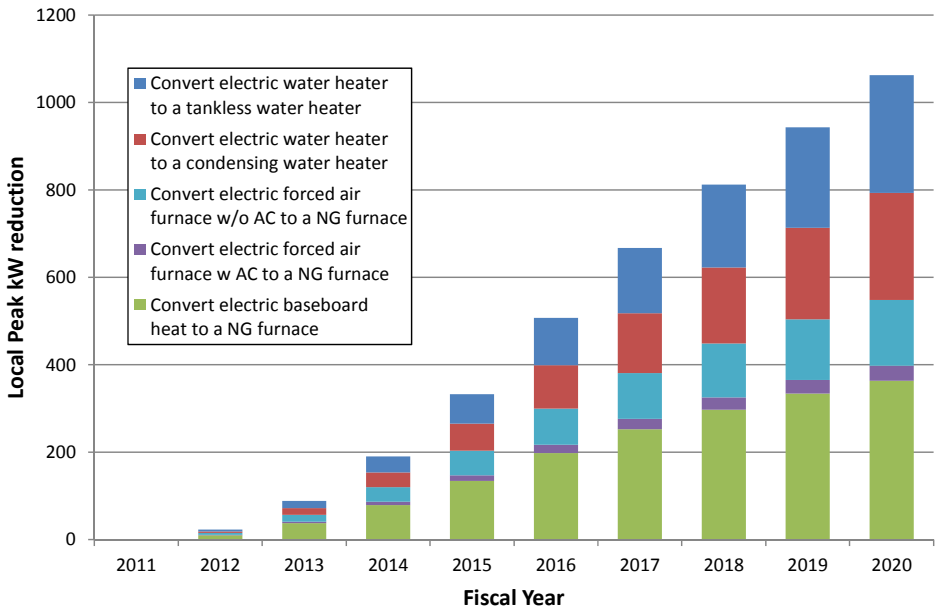
Historical hot water installations represent energy efficient electric hot water heaters; historical heater installations represent a mix of geothermal or zonal systems for heating. Figure 14 illustrates that the rate of fuel-switching in residential hot water heaters would be in-line with historical rate of installations

[12] Historical installations come from BPA utility energy efficiency program implementation data.

of more efficient electric water heaters. However, for residential heating systems, the rate of switching from electric to gas heat would be slightly faster than historic rates of installations of energy efficiency residential heaters. The installation of new gas heating systems is more involved than electric heating systems and would require some acceleration in the historical rate of annual energy efficient heating system installations.

These fuel switching measures are comprised of two different types of natural gas water heaters and three different types of electric heating being replaced by natural gas furnaces. Figure 15 shows persistent local peak reductions from these five fuel switching measures increasing annually to over 1 MW of peak demand savings by 2020. The natural gas heating systems generate more peak reductions per unit than the natural gas hot water heaters, representing just over 50% of fuel-switching peak savings in 2020. Overall, fuel-switching is not expected to represent a large source of peak demand savings in the LVE region.

Figure 15. Annual Peak Reduction by Fuel-Switching Measure



Part of the reason that the total peak savings from fuel switching measures is relatively low is because less than 20% of all customers in the region have access to the natural gas distribution system. In addition, the measures are not currently cost-effective to participants. The cost-effectiveness of fuel switching measures from a TRC perspective are good, hence their inclusion in the non-wires energy efficiency portfolio. The average TRC benefit-cost ratio is 2.1, the least cost-effective measure still has a benefit-cost ratio of 1.5. This is because the benefits associated with transmission savings, capacity savings and electricity savings all outweigh the costs of incentive payments and increased natural gas demand. However from a participant cost perspective, all of the fuel switching measures have a benefit-cost ratio less than 1. Incentives cover a portion of the incremental cost of these measures, but there is a remaining

upfront cost for participants. This upfront cost is never paid off over the lifetime of the measures as the electricity savings participants earn are smaller than the natural gas costs associated with operating new natural gas heating or hot water.[13] In order to achieve higher adoption rates for fuel switching measures in the region, the cost effectiveness of these measures would need to improve for participants. Customers would need to see lower gas prices, higher electricity prices, or larger upfront incentive payments.

These fuel switching measures increase demand for natural gas in the region, on a system which is already limited in terms of natural gas distribution potential. However, based on forecasted flows of gas on the pipeline, the growth in gas demand from the fuel switching measures is not expected to strain the existing capacity of the gas pipeline. Assuming gas deliveries have a baseline growth rate of 1% per year, during peak heating demand months fuel switching measures would represent no more than 3% of total gas deliveries in 2020.

3.2 Demand Response, Direct Load Control & Smart Meters

A number of smart-grid enabled direct load control (DLC) pilot programs are currently underway in LVE and FREC's service territories. LVE and BPA have been jointly evaluating localized non-wires options to cost-effectively defer a needed transformer upgrade. Other pilot programs are underway with support

[13] Natural gas heating is less efficient than electric heating. Assuming a natural gas water heater is 85% efficient, and an electric water heater is 100% efficient, electricity would need to be 18% more expensive than natural gas for an equivalent unit of energy in order for a gas water heater to be cheaper to operate than an electric water heater.

from the Department of Energy. These pilots are already helping to contribute to reductions in winter peak demand in the region as discussed below.

3.2.1 PACIFIC NORTHWEST SMART GRID DEMONSTRATION PROJECT

The Pacific Northwest Smart Grid Demonstration Project (PNW-SGDP) is funded by the Department of Energy, Battelle Northwest Laboratory and BPA, and is demonstrating and testing new combinations of technology and software to manage the electric grid in 12 Pacific Northwest communities. LVE is a participant in the program. Through this program, in 2009, LVE has installed 50 hot water heater controls, 49 of which are still in place. The control program disconnects the hot water heater from its power source from 6:30 am to 9:30 am every day. LVE plans to install another 400 control systems in 2011, or early 2012. As of October 2011, 100 additional hot water heater controls had been installed, with 250 customers signed-up for the program. In order to achieve maximum benefits from the program, residents that do not spend the winter in the region are ineligible for the program.

According to LVE, the magnitude of the winter peak demand reduction from the hot water heater program has not yet been definitively measured. LVE has estimated that as many of 2/3^{rds} of hot water heaters are in use during the winter critical peak in the region. This could imply that the hot water heater cycling program could achieve up to 3 kW of peak demand reductions on average per water heater. Hot water heaters typically represent a 4 kW load. However, other estimates suggest that hot water heater cycling programs in the region would result in much lower peak demand reductions. The PNPCC 6th Power Plan makes the more conservative estimate of 0.6 kW of peak savings per

hot water heater, which is equivalent to 15% of all hot water heaters operating during the critical peak period. Here we assume a 1 kW reduction per hot water heater, implying that 25% of hot water heaters would normally be in use during the critical peak. Ideally, the data collected from this smart grid demonstration pilot will generate a more precise estimate of the peak demand savings resulting from the program.

The cost of the hot water control technology is approximately $200 for a single-switch control, and an additional $250 to install, for a total installed cost of $450 per control device. Participating customers are currently offered a $15 bill credit per month for participating in the program. Program participation has been relatively strong to date, and has been met with customer acceptance. However, without new drivers of adoption, LVE may be approaching a saturation point of customer interest in the program. To date, LVE has engaged in a significant advertising push, including bill stuffers, radio and print ads and targeted letters to potential customers.

Lower Valley Energy is also participating in a test of electric furnaces using Steffes thermal storage technology. Five residential furnaces, most in conjunction with air-source heat pumps, are being installed in existing homes, with two commercial pilots underway as well. As of October 2011, two installations had been completed, with another 3 installations underway. Ultimately, the pilot installations should represent about 300 kW of dispatchable load. The utility will study the effects of their approach on energy savings and shaving peak loads. The thermal storage technologies could ultimately be controlled to assist with integration of variable resources such as wind generation. The cost of the thermal storage technology is modeled at

$7,742 per unit, although early pilot program costs appear to be higher, with an estimated winter peak savings of 13 kW per unit. Like the other pilot programs, the installation of the Steffes units will provide LVE with improved information about actual peak saving and more realistic cost information.

3.2.2 RESOURCE POTENTIAL ESTIMATE FOR DEMAND RESPONSE AND DIRECT LOAD CONTROL

In this analysis, the estimate of cost-effective demand response potential has been updated from the Phase 1 results. We learned that LVE and FREC are unlikely to institute, at least in the near-term, the kinds of price-based demand response measures that were included in the Phase 1 study, such as capacity market demand response, peak time rebates or critical peak pricing. On the other hand, some forms of direct-load control are already being piloted in the region and are being met with positive customer satisfaction, as reflected in the new estimate of demand response potential for the LVE/FREC region. In the Phase 2 analysis, three measures pass the cost-effectiveness screening assessment: large commercial emergency demand response, direct load control of residential hot water heaters, and Steffes thermal electric storage for residential heating. Adoption potential is limited to 30% of residential customers and 50% of large commercial customers. The total cost-effective peak reduction savings from DR and DLC measures are estimated at 5.8 MW by 2017, as shown in Table 14.

Table 14. Demand Response and Direct Load Control Resource Potential Estimate

DR-DLC Program Name	Winter peak impact (kW/customer)	Total Resource Cost-Benefit Ratio	MW Savings in 2017
Emergency DR - Large Commercial (>200kW)	186	12	0.1
Direct load control – residential water heater retrofit	1	2.3	0.5
Direct load control – residential heating, Steffes thermal electric storage	13	3.0	5.2
Total Portfolio Selected			**5.8**

3.2.3 SMART METERS AND CUSTOMER ENERGY USE FEEDBACK

Through a grant from the Pacific Northwest National Laboratory (PNNL), LVE is investigating the potential to achieve greater energy conservation through improved customer energy use feedback information. The demonstration project will provide approximately 400 residential customers with home energy monitors. These devices, either the TED 5000 from The Energy Detective, or the PowerCost Monitor from Blue Line Innovations, cost between $125 and $150. They will be paired with LVE's smart meters to provide customers with greater detail regarding their energy use.

LVE is providing the home energy monitor devices free of charge to their customers, and plans to monitor customer acceptance and responses to the technology. In addition, LVE is developing an on-line portal which will allow customers to compare their current energy usage to their historical electricity bill. Both of these efforts have the potential to generate energy efficiency

savings in the LVE region, however, the impacts on winter peak demand are highly uncertain and are not modeled as part of the non-wires portfolio.

Fall River Electric Cooperative is also installing advanced metering infrastructure with a grant from DOE. These meters are expected to help customers better control their energy use through improved customer information and feedback. In the future, the smart meters could be used as part of direct load control or demand response programs to reduce peak demand.

3.2.4 SUMMARY

The pilot programs underway in LVE's service territory are generating important data regarding the feasibility of using direct load control and smart meter technology to reduce winter peak demand in the region. However, the relatively limited scale of planned deployments of these pilot programs means that these pilots are not expected to have a significant impact on the non-wires portfolio. Until the results of the pilot programs have been collected and interpreted for cost-effectiveness and efficacy, it is likely premature to consider rapidly expanding the deployment of these technologies in order to achieve peak demand reductions at scale. However, our analysis indicates that if and when these programs are deemed ready to be scaled up, significant peak savings potential exists, especially from the thermal electric storage devices for residential heating, which is the largest contributor to winter peak demand in the region.

4 Conclusions and Next Steps

The conclusion of this implementation feasibility analysis of the proposed non-wires alternative to the Hooper Springs transmission project is that it is unlikely that a non-wires solution can be implemented in time to defer the need for the Hooper Springs project by the winter of 2013/2014. With a longer lead time for implementing a non-wires alternative it may have been cost-effective and technically feasible to defer the Hooper Springs transmission line to 2025. Deferring the transmission option would require close collaboration between BPA and LVE to complete the development of a 25 MW natural gas generator in Lower Valley Energy's service territory, at the Rafter J/Jackson Yard site. At this stage, it is not known whether LVE would be supportive of building and operating a gas generator at their facilities.

The proposed generator would run on liquefied natural gas (LNG) during the winter critical peak period, given that the existing natural gas pipeline does not have sufficient capacity to support the power plant's fuel needs in addition to existing customer distribution fuel needs.

From a cost-effectiveness perspective, the net cost of the non-wires solution would be less than the Hooper Springs transmission option over the project lifetime – but only if the generator could be brought online in time to defer the Hooper Springs project, and only if relatively low-cost financing were obtained

for the project in the form of LVE financing or BPA-secured non-recourse project financing; independent power producer financing would not be cost-effective. The direct costs to LVE of financing and operating the power plant could be entirely offset by a power purchase agreement (PPA) from BPA.

If additional energy efficiency and demand response, focused on achieving winter peak reductions, could be implemented in LVE and FREC's service territories, the cost-effectiveness of the overall non-wires portfolio would improve, with a benefit-cost ratio between 1.3 and 1.4, and the Hooper Springs transmission project could likely be deferred beyond 2025.

Our recommendation is that BPA continue to pursue construction of the Hooper Springs transmission line on its original schedule. The timeline to implement a non-wires alternative by the winter of 2013/2014, which would require permitting and constructing a gas generator at LVE's Rafter J/Jackson Yard site, does not appear to be feasible at this time. Furthermore, LVE's concerns about scheduling deliveries of LNG to the site indicate that there could be some fuel supply risk associated with the project.

If, at some future date, another non-wires analysis is called for in the LVE region, then BPA, in close coordination with LVE, may want to re-consider the gas generator option as a potential solution. The technical feasibility of the project remains sound, and the Jackson Yard site appears to be a beneficial location, electrically, for a power plant.

Given that this analysis found some limitations to the natural gas supply into the region, an analysis of the fuel supply availability and reliability in the LVE region should be a key component of any future consideration of the generator option.

A gas generator is likely to be a more attractive option in the future if the capacity of the natural gas pipeline serving LVE has been expanded and if the pipeline's natural gas supply has become more reliable.

Finally, we recommend that future non-wires analyses begin at an earlier stage in the transmission planning process, when the transmission need is just beginning to become visible to transmission planners. This would serve the duel benefit of providing more time to investigate and implement innovative non-wires options, and would ensure that the transmission planning effort has not already accrued significant sunk costs and BPA staff-time before an in-depth analysis of alternatives is started.

Table of Acronyms

Acronym	Definition
aMW	Average Megawatt
BC ratio	Benefit Cost ratio
BPA	Bonneville Power Administration
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
WECC	Western Electricity Coordinating Council

Appendix A: Lower Valley Energy 6” Gas Pipeline Capacity Study

Appendix B: Local Generation Development and Construction Plan

Appendix A:

for

Lower Valley Energy 6" Gas Pipeline Capacity Study

Prepared for Energy and Environmental Economics

Audubon Project No.: 007384

Engineering Seal

P.E. Name: _____

Registration No.: _____

Approvals (Initial Release)

	By:	Date:
Initiator:		
Checker:		
Mechanical:		
Structural:		
Electrical:		
Instrument:		
Proj. Mgr.:		
Other:		
Client:		

Energy+Environmental Economics

Revisions

Rev.	Date	By	App'd	Purpose

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Table of Contents

1. Study Overview and Key Conclusions 3
2. LVE Pipeline System and Gas Source Summary 4
3. LVE Gas Demand Profile and Growth Forecast without Generation Expansion 5
4. Proposed Gas Fired Generator Facilities and Fuel Requirements 8
5. Expansion Options to Meet Forecasted Loads 10
6. Gas Pipeline Throughput Calculations 13
7. Attachments 13

1. STUDY OVERVIEW AND KEY CONCLUSIONS

This document summarizes the results of a gas capacity and expansion option study for Lower Valley Energy's (LVE) existing 6" gas pipeline serving its distribution system in the vicinity of Jackson, Wyoming. The objective of the study is to evaluate LVE's current system capabilities in view of its future load growth and planned expansions and to assess the effect of adding 25 MW to 42 MW of natural gas fired generation to the system.

Current system and projected system loads are evaluated and presented during the years 2011 through 2025.

Facility expansion options, order of magnitude facility expansion costs, and timing are identified.

Since LVE's source gas stream is from unprocessed gathering operations there is reliability risk with upstream operations. These reliability risks include pressure variation, gas quality variation, receipt of hydrocarbon condensate liquid slugs, excessive water, and unscheduled/unplanned gas flow outages. There is also operating reliability risks associated with the operation of existing equipment on LVE's system like the compressor and dehydration unit. This study acknowledges these risks but it is not the intent of this study to specifically address these issues.

The study and its results are conceptual in nature and primarily based on conversations with LVE personnel. Since peak load demands and peak throughput capacity are the main concern of the study only peak requirements have been evaluated.

Fuel gas requirements and run times for the proposed generator units were supplied to Audubon.

This study is limited to the 50 miles of pipeline detailed below and appurtenances thereto and does not extend to upstream or downstream facilities owned and operated by others or LVE.

Key conclusions from the study are:

1. LVE's current pipeline and LNG augmentation capabilities are adequate for near term loads and growth projections.
2. Planned service area expansion in 2014 to the Teton Village, Wyoming area will likely require increased flow capability on the 6" diameter pipeline.
3. The 6" pipeline flow can be increased to meet LVE's projected flow requirements to the 2020 time frame but pipeline flow cannot be increased enough to meet proposed generation additions to LVE's system.
4. Compression expansion at Rim Station could free up existing LNG capabilities to service proposed generation fuel requirements. However, LVE's gas system reliability will be diminished.
5. The best option to fuel the proposed generation is to expand existing LNG facilities should LVE decide that current LNG capabilities are needed to support pipeline operations reliability.

2. LVE PIPELINE SYSTEM AND GAS SOURCE SUMMARY

2.1 PIPELINE SYSTEM PHYSICAL CHARACTERISTICS (Refer to LVE-Pipeline System Schematic)

LVE's pipeline system consists of approximately 50 miles of pipeline and associated equipment as detailed below. The pipeline originates at an interconnection (Williams Interconnect) with Williams Field Services (WFS) gathering system in the Big Piney area of Wyoming and terminates just south of Jackson, Wyoming at a location LVE refers to as Jackson Yard. The 50 miles of pipeline is made up of 3 miles of 8" diameter pipe and 47 miles of 6" diameter pipe.

The source gas is metered through a WFS owned and operated custody transfer meter at the Williams Interconnect.

The 8" pipeline then traverses approximately 3 miles from the Williams Interconnect to a site LVE refers to as Rim Station where it owns and operates a glycol dehydration (dehy) unit and is currently installing a leased 425 HP compressor unit. For the purposes of this study the compressor unit will be considered as existing. The compressor unit is rated to deliver 3 mmscf/d of gas at a suction pressure of 100 psi and discharge pressure of 300 psi. The pipeline diameter reduces to a 6" diameter at Rim Station.

The 6" diameter pipeline then traverses approximately 47 miles to the Jackson Yard site. LVE owns and operates a filter separator, air injection and an 180,000 gallon LNG storage and injection facility at Jackson Yard. LNG storage consists of 3-60,000 gallon horizontal tanks. LNG is trucked to the site. LNG injection is used for peak shaving and to mitigate reliability risks with its upstream gas supply. The LNG system is configured to inject up to 300,000 scf/hr gas in to the distribution system when pipeline pressure falls below 80 psi. LVE shuts in the pipeline when LNG injections commence and the downstream distribution system operates exclusively on LNG until pipeline pressure recovers above 80 psi. LVE replenishes LNG stocks at a 25% drawdown.

Air injection will be discussed later in this report.

There are a couple of farm taps off of the pipeline but LVE considers the use at these taps as negligible. Gas flows off the LVE system at these farm taps are not included in this study.

The pipeline system when installed was designed and tested to a maximum allowable operating pressure (MAOP) of 1000 psi but LVE has informed us that nameplate data on some pipeline components (e.g. dehydration unit name plate indicates a 5 mmscf/d capacity at 800 psi.) may limit the operating pressure to a value less than 1000 psi. For the purposes of this study the pipeline MAOP will be taken as 800 psi.

2.2 GAS SOURCE and QUALITY

LVE's service contract with WFS is not firm. The exact terms of the service contract are not known to Audubon but these types of contracts normally do not carry a guarantee of gas quantity, service reliability, gas pressure or gas quality. While these types of contracts do not guarantee much they also don't restrict the taking of gas. In other words, LVE is probably not restricted from taking whatever gas is available at its interconnect with WFS. This study will assume that no restriction exists and expansion gas volumes are available.

LVE has experienced source gas pressure swings (300 psi-100 psi) and BTU content variations (1210 BTU/cf-1140 BTU/cf). This is typical for gathering system operations upstream of gas processing facilities.

The pressure variation is the primary driver in LVE's decision to install compression at the Rim Station.

The BTU content of this gas stream is considered "rich" as most commercial quality natural gas ranges from 1030 BTU/cf to 1060 BTU/cf. High BTU content is most likely the result of heavier hydrocarbons in the gas stream like ethane, propane and butane. These hydrocarbons are usually stripped out of the wellhead produced gas at processing plants leaving methane which is the primary constituent in commercial grade natural gas. Heavier hydrocarbons like propanes and butanes have a tendency to condensate out of the gas stream at usual natural gas pipeline operating pressures and temperatures and many times exist as liquids in the pipeline. These liquids collect at low points in the pipeline and can affect pipeline operations in several ways. This study will not consider any pipeline flow inefficiency due to possible liquid hold up in the pipeline. However, the study will limit gas flowing velocity to 45 ft/sec. as an upper bound because pipe wall thickness can be eroded by the impingement of liquid droplets on the pipe wall especially at elbows and sharp turns in the pipeline when the flowing velocity reaches approximately 60 ft/sec or higher.

LVE injects 10% to 15% air by volume in the pipeline at Jackson Yard to reduce the BTU content of the "rich" gas stream. The air/gas mixture yields a lower and more consistent BTU content around 1030 BTU/cf. Gas supply calculations are increased by 10% above the pipeline gas content to account for the air injection at Jackson Yard.

Another constituent in wellhead produced gas that can affect pipeline operations and performance is water. LVE's facilities include a glycol dehydration unit at Rim Station. The Dehydration Unit serves to reduce water content in the gas stream to acceptable levels.

Audubon was not supplied with a gas chromatograph analysis of the gas stream consequently no other wellhead produced constituents will be considered in this study.

3. LVE GAS DEMAND PROFILE AND GROWTH FORECAST WITHOUT GENERATION EXPANSION

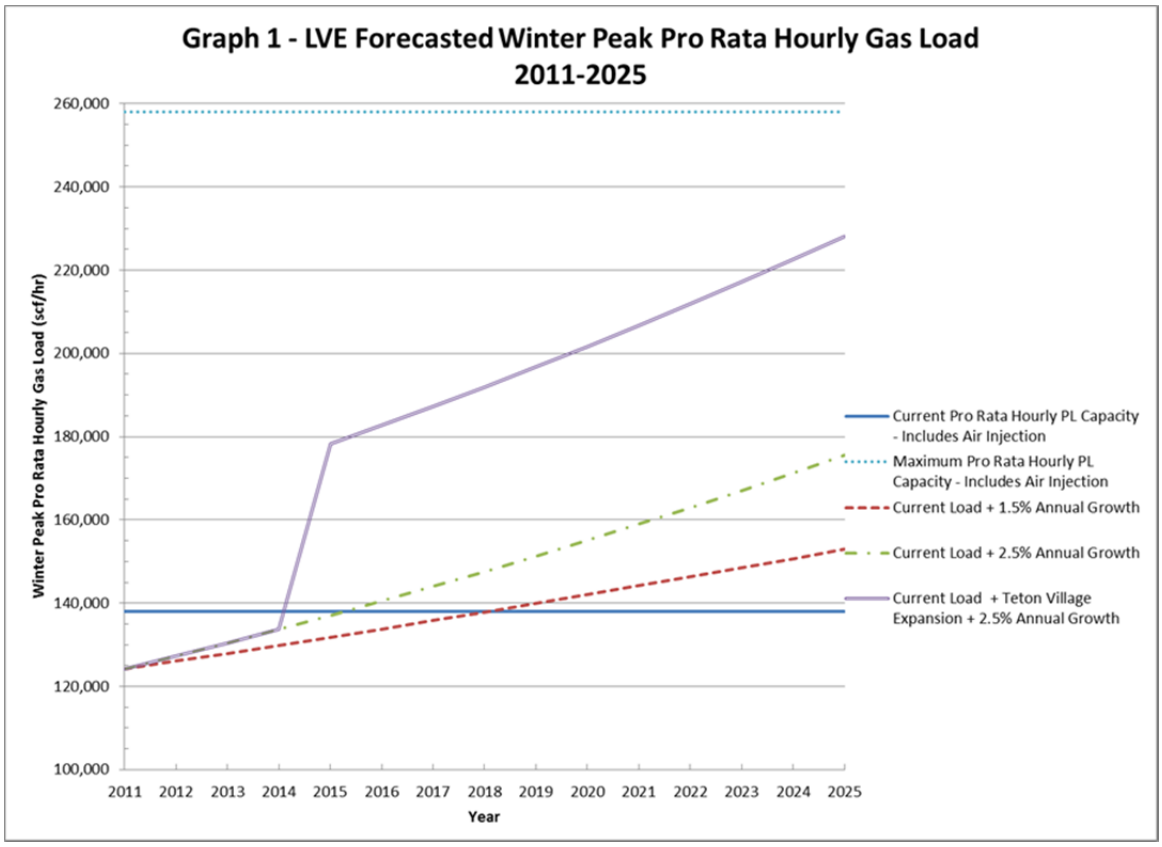
LVE's peak seasonal gas demand occurs during the months December through February. Peak daily demand during this period can total 3 mmscf/d. Peak hourly demand on the coldest days can be 170 mscf/hr for the morning hours between 6:00 am and 11:00 am but averages 155 mcf/hr over the 5 hour period. The 155 mcf/hr value will be used in this report as the winter peak hourly load. Gas demand also increases slightly over average hourly values in the evening between 6:00 pm and 8:00 pm.

LVE is experiencing an annual gas demand growth a rate of between 1.5% and 2.5% although gas demand has grown faster in the past. LVE is also considering expansion by pipeline to the Teton Village, Wyoming area in the 2014 time frame which it estimates could increase gas demand by 30%. Teton Village is currently being served with propane fuel. This study assumes that Teton Village's propane to natural gas switch over would happen at a very rapid pace in 2014.

Graph 1 presents a family of curves that represent LVE's Forecasted Winter Peak Pro Rata Hourly Gas Load growth in different scenarios in the years 2011 through 2025 without proposed generation loads. These load curves are superimposed on LVE's current pro rata hourly pipeline capacity (including air injection) and maximum pro rata hourly pipeline capacity (including air injection). The maximum curve has been derived by Audubon and will be discussed later in this report.

Pro rata means that total daily gas usage is averaged over the day such that each hour sees 1/24 of the daily volume.

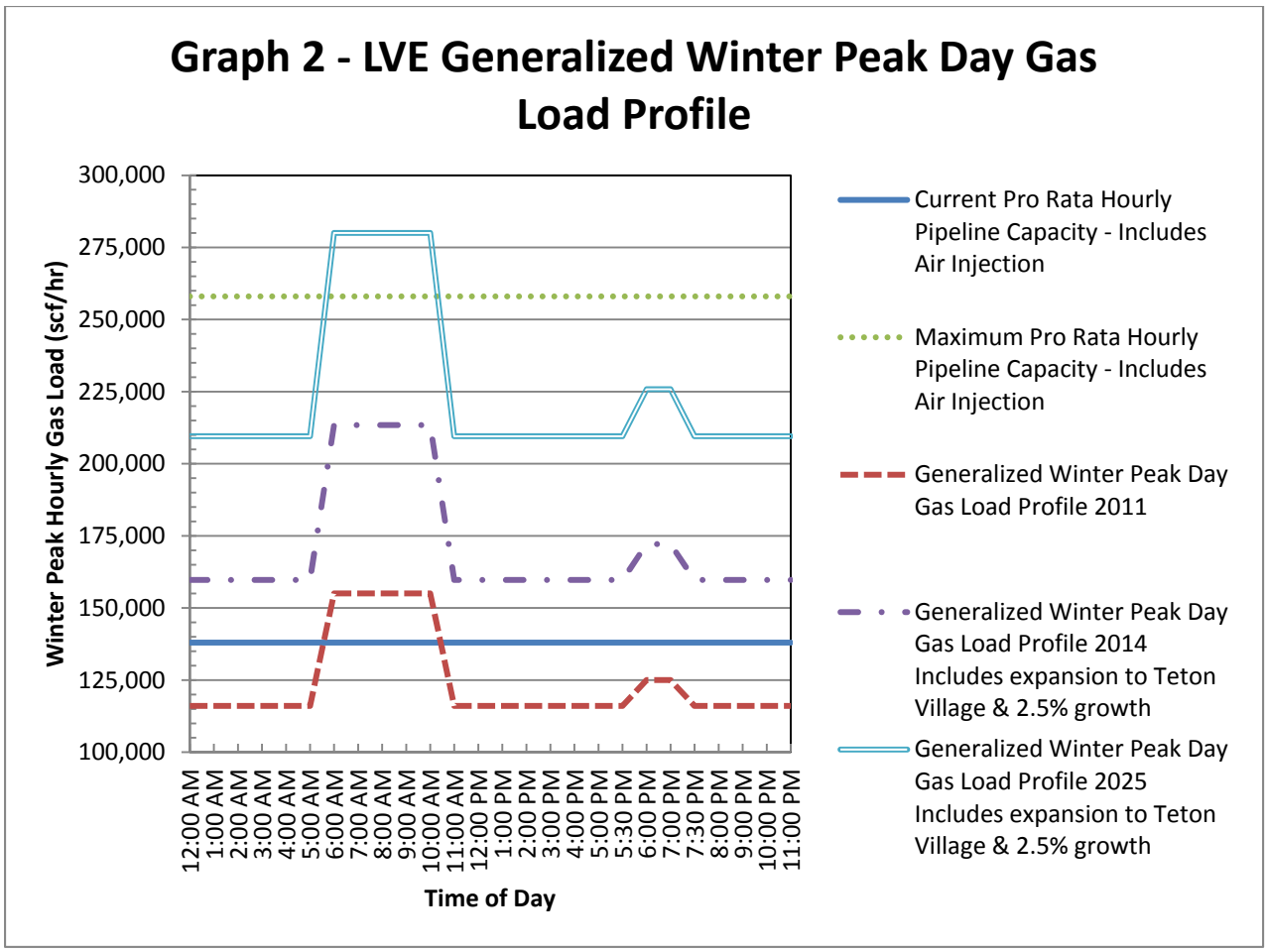
This graph shows that on a pro rata hourly flow basis (i.e. not a peak hour load basis) the current LVE pipeline configuration is sufficient for near term daily loads but more importantly it shows that there is significant enhancement opportunity to increase pipeline flows.



Graph 2 shows winter peak hourly flows on an actual hourly rather than a pro rata basis. The current pipeline capacity while sufficient for total daily loads as shown in Graph 1 is insufficient for the morning peak hours (155,000 scf/hr) even on a current pipeline configuration basis. This indicates that LNG augmentation and or line packing is required to meet these morning peaks. The graph also indicates that the maximum pipeline capacity (258,000 scf/hr) is sufficient to meet not only current peak hour and current daily loads but projected hourly and daily loads well in to the future.

Line packing refers to building pressure in the pipeline over normal operating pressures in order to build gas supply to be used during peak daily hours. LVE's pipeline system does present some line packing ability since its MAOP is in the 800 psi range while its normal operating pressures are in the 100 psi to 300 psi range.

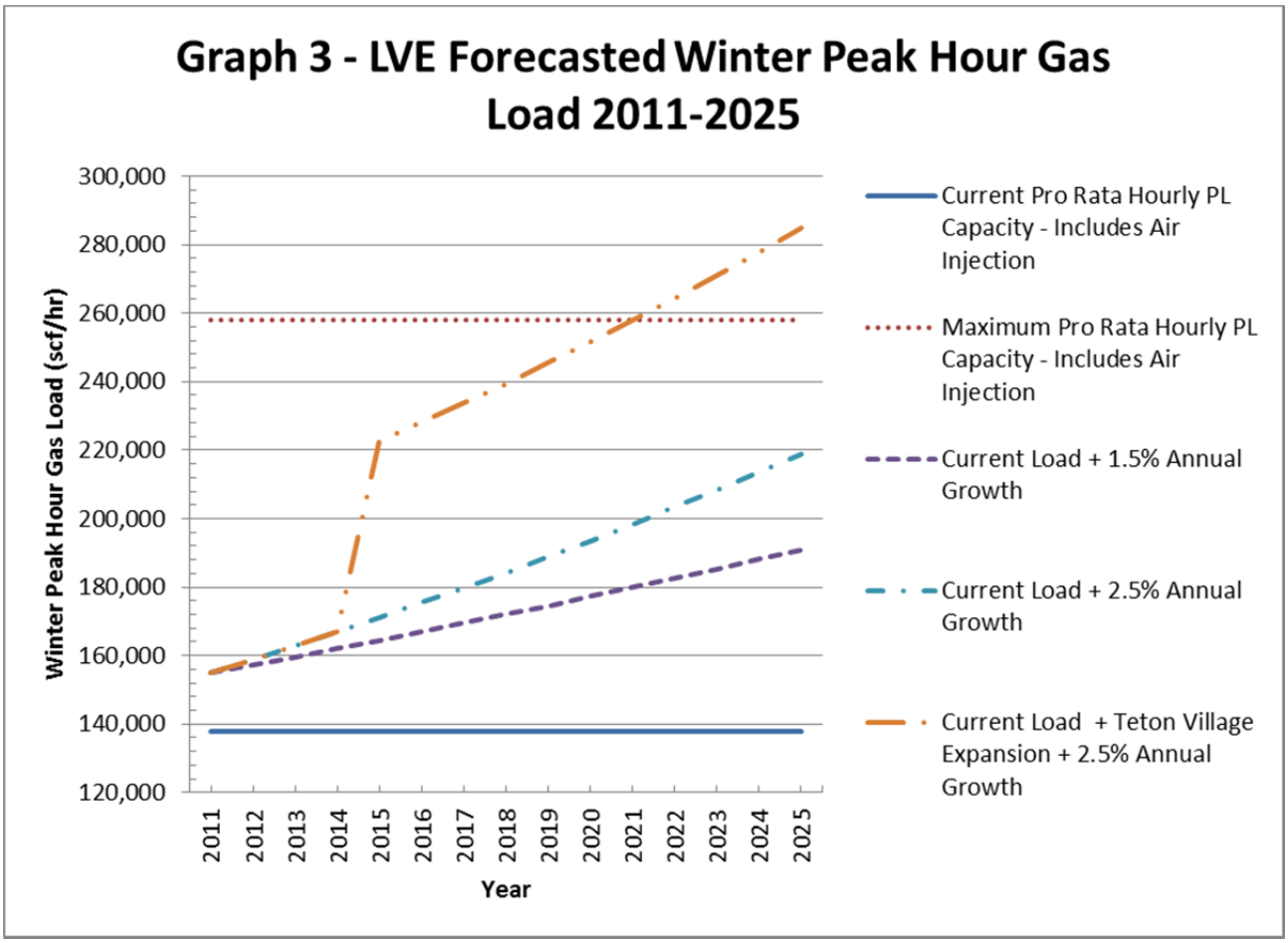
LVE has significant LNG storage and injection capabilities. The ability to inject 300,000 scf/hr exceeds its current peak hourly load of 155,000 scf/hr and with 180,000 gallons of storage it can supply morning peak hour volumes over several days. However, as Graph 2 shows with the addition of the Teton Village load in 2014 the current pipeline capacity will run an hourly throughput shortfall during all hours of the day which will make LNG augmentation impractical over the full winter season.



Graph 3 shows the peak hour (non-pro rata) load growth over the study period again relative to LVE's current and maximum pipeline capacity. This graph emphasizes that in the near term LVE's current combined pipeline and LNG system capabilities are adequate but expansion to the Teton Village area in 2014 will, from a practical standpoint, require capability enhancements to LVE's system. The graph also

indicates that the pipeline can be enhanced to meet LVE's peak hourly loads without the need for LNG augmentation until the 2020 time frame.

Pipeline system enhancement options will be presented later in this report.

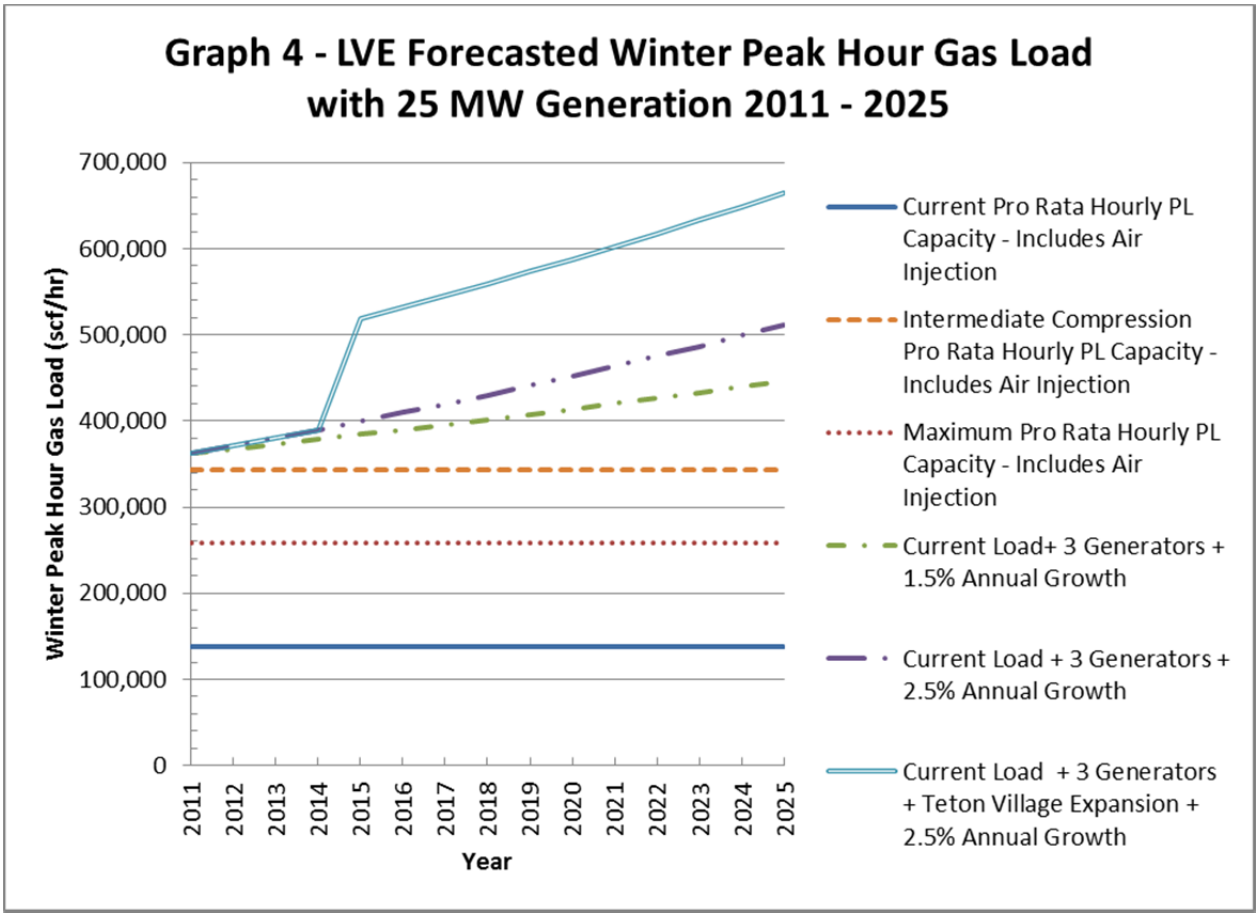


4. PROPOSED GAS FIRED GENERATOR FACILITIES AND FUEL REQUIREMENTS

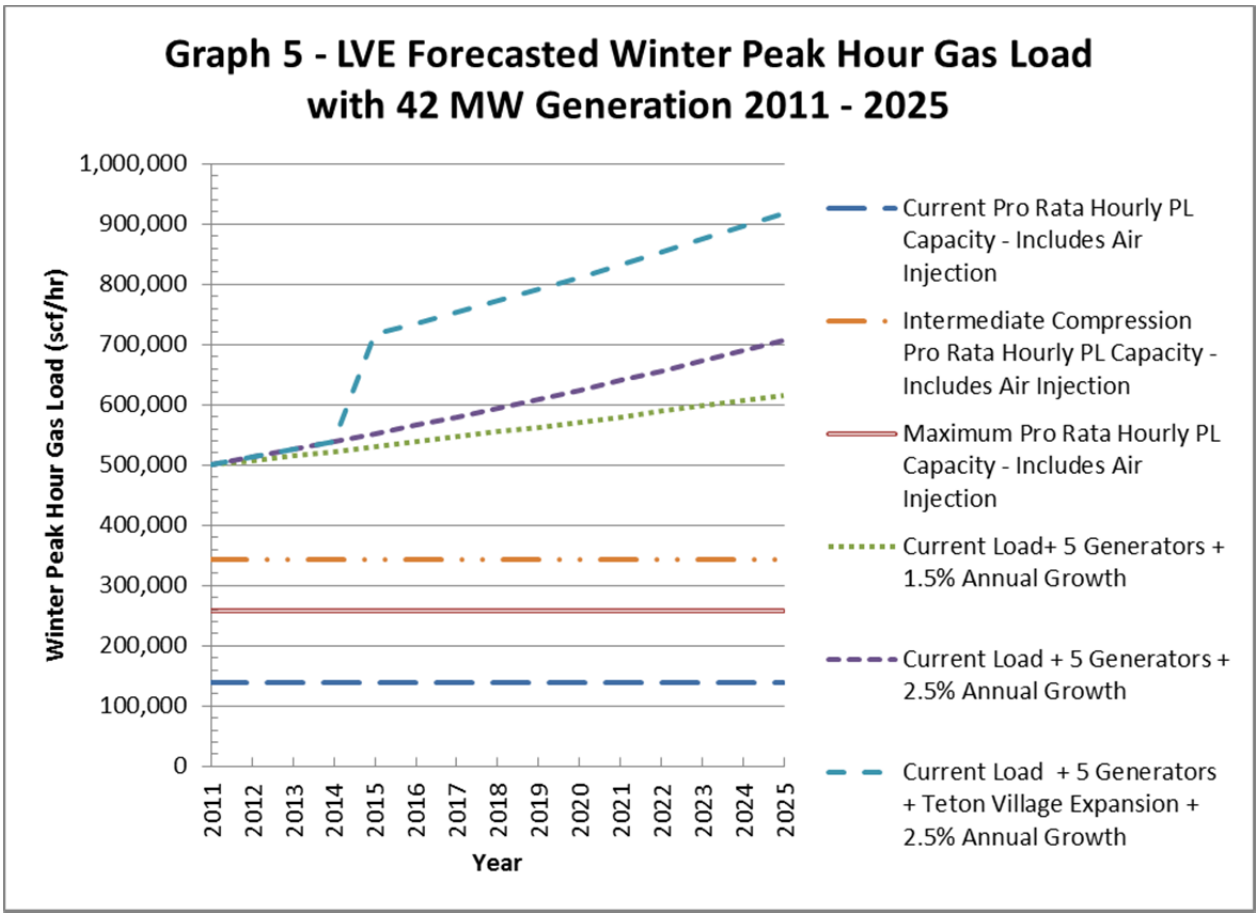
The installation of 3 (25MW) to 5 (42MW) natural gas fired electric generators are being analyzed as part of the broader "non-wires" study by Ramco Engineering at or near the Jackson Yard site. The generators as analyzed here are assumed to run during electricity peak demand periods only. These electricity peak periods are expected to be concurrent with peak gas demand. Run times for the generators are analyzed using the conservative assumption of 10 hours/day over 4 consecutive winter peak days.

The generator drivers are proposed to be natural gas fired reciprocating engines and fuel gas requirements to each generator driver is expected to be 69,000 scf/hr at 100 psi. Fuel requirements for the proposed generators based on run times of 10 hours/day over 4 consecutive days total 8.28 mmscf for the 25 MW case and 13.8 mmscf for the 42 MW case.

Graph 4 and Graph 5 show the cumulative generation and LVE system peak hourly loads for both the 25 MW and 42 MW cases. Peak hourly loads far exceed the pipelines capability even at its maximum capacity.



An additional line has been added to these graphs showing the increased pipeline throughput should an intermediate compressor be installed midway between Rim Station and Jackson Yard. This option as well as other options to fuel the generators will be discussed in more depth below.



5. EXPANSION OPTIONS TO MEET FORECASTED LOADS

LVE on its present course will need to enhance its system capabilities in the near term and certainly before the Teton Village expansion with or without generation expansion. There are several options available which are detailed below:

1. Compression Enhancement at Rim Station

   LVE is currently installing a 425 hp compressor at Rim Station to increase pipeline capacity to 3 mmsf/d. A compressor in the 550 hp to 600 hp range would be sufficient to increase the pipeline throughput to approximately 5.63 mmscf/d. Air Injection at 10% brings this value up to 6.19 mmscf/d. On a pro rata hourly basis this becomes 258 mscf/hr. This value has been represented on Graphs 1, 2 and 3 as the maximum pipeline capacity.

   This probably represents the best option to meet LVE's current and future load requirements. As shown in Graph 3 this option can meet all of LVE's projected loads without LNG augmentation through 2020. This option also suggests that current LNG capabilities could be repurposed to serve generation loads. The use of LNG storage options are discussed below. The downside to

repurposing the existing LNG for this option is that LVE potentially loses the reliability risk mitigation capability that it now has.

Greenfield horsepower additions can be roughly estimated at $2500/hp on a total installed cost (TIC) basis. Since the Rim Station site is already developed the cost should be less. Actual maximum operating capacities of appurtenant facilities like the dehydration unit, filter separator and air injection systems are unknown. It is likely that these systems would need to be upgraded to accommodate the increased flow rates.

2. Line Packing

The differential between LVE's normal operating pressures and the pipelines MAOP at 800 psi provides an opportunity for line packing. More operational and physical data on LVE's system are needed to quantify the opportunity exactly but theoretically the 6 " diameter pipeline could store up to 1 mmscf of gas over its normal flowing inventory if the pressure were raised to MAOP levels. LVE's normal cumulative morning peak requirement amounts to 775,000 scf which suggests that the morning peak could be served in this manner on a day over day basis without LNG augmentation. Line packing is available to LVE in the current or enhanced compression configurations because the normal operating maximum pressure of the pipeline is little changed.

Line packing should be viewed only as a pipeline optimization item. While line packing could lessen LVE's need for LNG augmentation in the near term it will not meet LVE's increased flow needs with the addition of the Teton Village load. Line Packing does little to help meet generation loads at the 25MW or 42MW level.

This option would more than likely require a second compressor at Rim Station in the 300 hp to 400 hp range that would be specifically devoted to line packing operations and operate only in low gas demand hours.

3. Intermediate Compressor Station

Gas flow on the 6" diameter pipeline could be boosted to 8.34 mmscf/d (including air injection) with the addition of an intermediate compressor station at a point midway between Rim Station and Jackson Yard.

An intermediate compressor is not required to meet any of LVE's current or projected system loads so this option would only be considered to meet the proposed generation loads. While the intermediate compressor does close the peak hourly shortfall it does not fully alleviate LNG augmentation when the generators are running. Pipeline pressure at Jackson Yard would be in the 140 psi range so much of the energy spent in compressing the gas stream at the intermediate compressor would be wasted in regulating the gas stream down to pressures that the distribution system and generator drivers could use.

This would require another compressor installation similar to the enhanced compression case and further upgrades to dehydration, filter separator and air injection systems.

Increasing pipeline throughput in this way for such an infrequent and short duration load is probably not cost effective from a capital or operations standpoint.

4. Pipeline Looping

As indicated previously LVE does not need anything more than a modest compression enhancement at Rim Station to meet its current and future system loads not including the proposed generation loads. Therefore looping would only be considered to feed the generator loads.

Loops can be of any size or diameter so the solution set is nearly infinite. Loops can also be looked at to inherently meet the generator hourly fuel loads on a 24 hour basis or as storage bottles akin to line packing to meet generator run time demands only.

It would require a full 47 mile 6" pipeline loop to inherently meet the hourly fuel requirements of the 25 MW case or a full 47 mile 8" pipeline loop to meet the hourly fuel requirements of the 42 MW case.

Total installed pipeline costs can be roughly evaluated at $100,000/diameter inch-mile. This makes capital cost requirements approximately $28 mm for the 6" loop and $38 mm for the 8" loop. These costs reflect pipeline costs only and do not include upgrade costs for dehydration, separation, etc.

In the storage bottle case and using 36" diameter pipe at 800 psi it would take 4 miles of pipe to store the 8 mmscf of fuel gas for the 25 MW case and 7 miles of pipe at 800 psi to store the 14 mmscf of fuel gas for the 42 MW case.

Neither of these options appears to be attractive from a cost standpoint and LNG storage is a more effective way to store gas than a pipeline bottle.

5. LNG Storage

As mentioned, fuel requirements for the proposed generators based on run times of 10 hours/day over 4 consecutive days total 8.28 mmscf for the 25 MW case and 13.8 mmscf for the 42 MW case.

LVE's existing LNG storage and delivery system could supply these requirements as indicated in the enhanced compression case. Each of the three existing 60,000 gallon LNG tanks holds approximately 5 mmscf of gas. Assuming a 90% LNG drawdown potential in each tank and considering no LNG replenishment over the 4 day cycle it would take two tanks to meet the 25 MW case and all three tanks to meet the 42 MW case.

This option comes at increased gas system reliability risk for LVE as discussed previously.

Alternatively, generation loads could be met by adding new LNG capabilities at the proposed generator site specifically dedicated to generation operation. LNG tanks can be designed and installed in various sizes but as a reference point each 60,000 gallon tank installation, including

truck offloading and LNG evaporation equipment would cost roughly $1.5 mm on a total installed cost basis.

6. GAS PIPELINE THROUGHPUT CALCULATIONS

Pipeline throughput capacity calculations were generated using the Panhandle A gas pipeline flow equation. The limiting segment on the pipeline system is the 47 miles of 6" pipeline and all calculations were performed on this segment.

Gas flowing velocity was limited to 45 ft/sec.

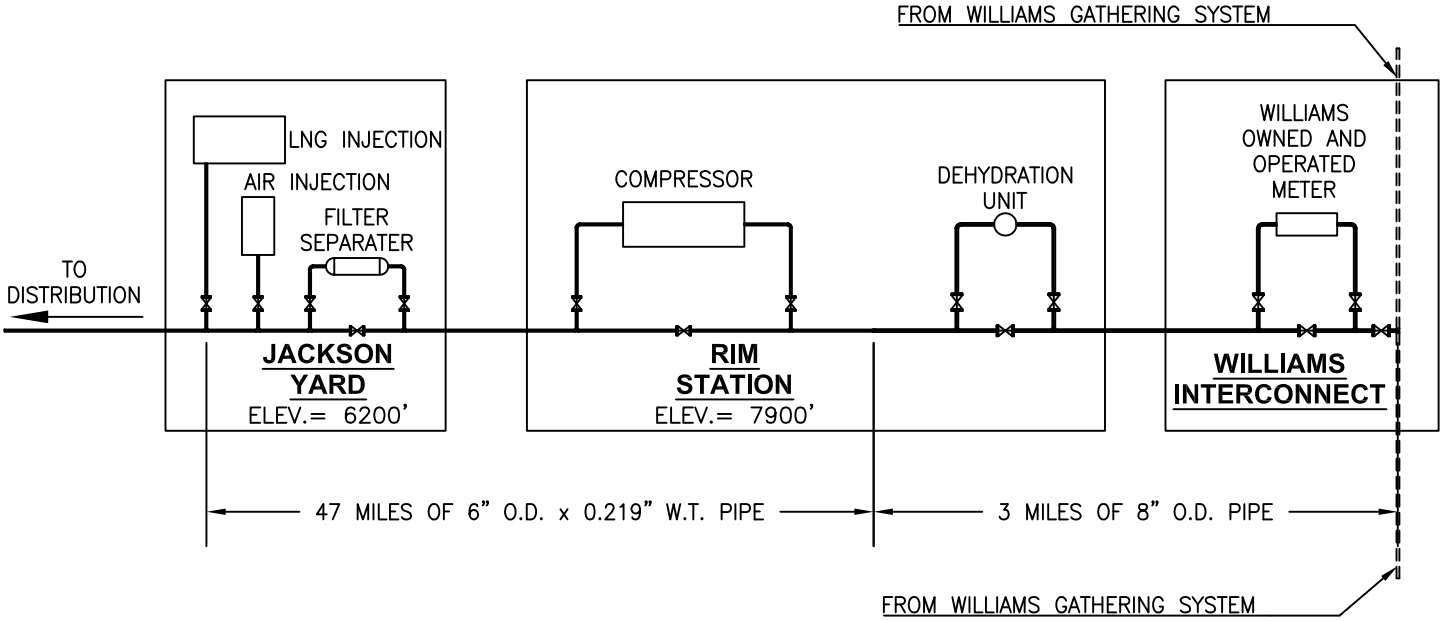
Pipeline flowing efficiency is considered to be 95% which is appropriate for a new pipeline. LVE's pipeline was placed in service in 2008.

Other physical input values are shown on the LVE Pipeline System Schematic.

7. ATTACHMENTS

LVE Pipeline System Schematic

LVE PIPELINE SYSTEM SCHEMATIC



ISSUED PRELIMINARY

PIPELINE, STATION, OR ACCOUNT NUMBER	SCALE N.T.S.	CONST. YR. –		PROJECT NO. 007384
FILENUMBER / CADD FILENAME	DRAWN	DATE 09/23/11		

REV. NO. – DESCRIPTION		BY	DATE	APP.
A	ISSUED FOR PRELIMINARY	RJL	09/23/11	MH

audubon Engineering
10205 WESTHEIMER ROAD
SUITE 600
HOUSTON, TEXAS 77042
PHONE: (281) 669-0590
TX. REG. NO. 8696
RENEWAL DATE: 5/31/2011

LVE PIPELINE SYSTEM
EXISTING 8" & 6" PIPELINE

PREVIOUS DWG. NO.
SHT. OF

DWG. NO.
SHT. 1 OF 1
A

Plotted by: Rlanclos on: Sep 23, 2011 – 10:36am

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Hooper Springs Non-Wires Alternatives Implementation Study

Appendix B:

Local Generation Development and Construction Plan

Prepared By

Ramco Energy, Inc.

For

Energy & Environmental Economics, Inc.

Ramco

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Table of Contents

	Page
1. Executive Summary	1
2. Introduction, Scope and Assumptions	2
3. Rafter J site Information and Development Viability	2
3.1. Site Information	3
3.2. Viability of site for Peaking Plant Development	6
3.3. Development Viability Criteria	7
3.3.1. Confirming Maximum site Development	7
3.3.1.1. Site Area	7
3.3.1.2. Electrical Interconnection	8
3.3.1.3. Gas Interconnection, Availability, and Pressure	10
3.4. Infrastructure and Sensitive Receptors	10
3.4.1. Site Infrastructure	10
3.4.2. Sensitive Receptors	11
3.5. Special Requirements Criteria	11
3.5.1. Community and Political Support	11
3.5.2. Permitting	11
3.5.2.1 Local Permitting: Zoning	12
3.5.2.2 State Permitting: Wyoming Public Service Commission	13
3.5.2.3 State Permitting: Wetlands and Cultural Resources	13
3.5.2.4 State Permitting: Air Permitting	13
3.5.3. Taxes	13
4. Technical Assessment and Options Evaluation Summary	14
5. Project Schedule	19
6. Other Power Related Benefits and Costs Not Related to Winter Peak Demand	23
7. Development of Criteria for Selection of Contractor for Project Development	23

Figures and Tables

Figures	Page
1 – General Project Location	3
2 – Site Location on LVE Parcel	4
3 – Proposed Rafter J Generation Site	4
4 – Rafter J and Alternate Sites	5
5 – Jackson Substation	5
6 – East Jackson Substation	6
7 – Aerial Photo of LVE Rafter J Parcel	8
8 – Proposed Plant Site at Rafter J	8

Tables	Page
4.0 – Equipment Comparison	16
4.1 – Expected Budgetary Cost; 3 Engine Plant	18
5.0 – LVE Rafter J Site Project Milestone Draft	19
5.1 – Permit Matrix	21

Appendices

Appendix No.	Title
1	Rafter J Site Recreational and Visual Assessment
2	Air Quality Assessment of Project Feasibility
3	Engine Brochures
4	Conceptual Layout

1. Executive Summary

In January 2011, Energy+Environmental Economics ("E3") completed the Hooper Springs Non-Wires Alternatives Screening Study for the Bonneville Power Administration ("BPA"). Based on the results of that Study, BPA commissioned E3 to perform an in-depth evaluation of the non-wires alternatives. E3 retained Ramco Energy, Inc. ("Ramco") to support this effort by performing the following tasks:

- Assess the viability of the Rafter J site for a nominal 25 to 41MW natural gas fueled peaking plant, and determine if there is a more suitable site in the Jackson area.
- Evaluate the technical options for natural gas fueled peaking generation at the preferred site.
- Identify all local, state and federal approvals and permits required to construct and operate the generating plant, including timelines for contested and uncontested permit approvals.
- Update cost estimates and development schedule to aid in the evaluation of the cost effectiveness of local generation to defer transmission expansion.
- Work with BPA staff to evaluate and document other power related benefits and costs not related to transmission alternatives.
- Work with BPA and Lower Valley Energy ("LVE") staff on the process, procedures and criteria for competitive selection of contractors to permit, develop and construct the generating plant.

Key assumptions that underlay our evaluation include the following:

- The proposed project is a nominal 25 to 41 MW peaking resource needing to be in service by fourth quarter 2013.
- The Plant will be limited to operating up to 1000 hours per year to cover winter peak emergency use.
- Natural gas is the preferred fuel.
- Key economic assumptions include:

    1. Construction costs are stated in 2011 dollars.
    2. Permitting is completed and major equipment Purchase Contracts are signed and fabrication authorized on or before September 14, 2012.
    3. Kick-off for local and State air permits will occur by November 1, 2011.

This report presents the results of the development and technology assessment of the Rafter J site and a preliminary review of alternative sites, conducted by Ramco in August, 2011. The key highlights of the assessment are:

1. The Rafter J site is the preferred site for a natural gas-fueled peaking generation plant given the following desirable characteristics:

    - Site access to both natural gas and liquid natural gas ("LNG") on the site.
    - Site access to the LVE 115 kV substation on the site.
    - Adequate space available for the construction and operation of the generating plant, including construction laydown and parking.
    - No identified fatal flaws with respect to air, environmental or engineering issues.

- The site is located more than 10 km from the Teton National Park, a Class 1 area, whereas the two alternate sites are within 10 km and as such would require extensive air modeling.

2. Natural gas fueled reciprocating engines are preferable over gas turbines for the intended use because of superior performance at the site elevation (6,150 feet).

3. The estimated cost for a nominal 25 MW reciprocating engine peaking plant with a commercial operation date (COD) of no later than November 30, 2013 is $43.25 mm, or $1,730/kw (2011$). In addition to the estimated cost to remove, provide new clean fill to the new location and rebuild the two existing buildings on the new building site would be about $3.2 mm. To meet the 2013 COD, BPA should commence detailed development and permitting activities by October 31, 2011. This would also allow BPA/LVE to determine if the proposed 3 engine generating project is viable while waiting for final approval of the transmission alternative. The November 2011 to July 2012 development cost to meet this schedule are estimated to be $700,000.00 for permitting/engineering.

4. The timeline for the permitting of the Rafter J site is estimated at between 6 and 12 months depending on the level of public scrutiny of the project.

2. Introduction, Scope and Assumptions

Key assumptions that underlay our evaluation include the following:

- The proposed project is an nominal 25 to 41 MW peaking resource needing to be in service by the fourth quarter of 2013
- Natural gas is the preferred fuel and will be available at the site at 100 PSI.
- LVE will provide adequate space for the construction of the proposed plant, construction trailers and lay-down area as discussed with their technical staff in August 2011.
- Key economic assumptions include:
  - Construction costs are stated in 2011 dollars
  - Major Equipment Purchase Contracts are signed the end of August, 2012.
  - Sufficient craft labor can be provided, but will largely come from outside the region.
  - Project contingency of 15%. This contingency level may be reduced as project scope and duration become more precisely defined.

3. Site Information and Development Viability

3.1 Site Information

Ramco made two site visits to Jackson to perform due diligence on the viability of the proposed project. During those site visits, Ramco meet with officials of LVE to discuss the nature of the

proposed project and the specific location of the proposed project on LVE'S property. Ramco reviewed alternate site locations and natural gas supply options with LVE staff. Ramco also met with staff of the Teton County Planning Department to discuss the proposed project and the local permitting process.

Proposed Site – Rafter J

The 4 acre Rafter J site is located on the approximately 14 acre utility yard that is owned by LVE. The LVE parcel is located at 4000 S. Highway 89 about four miles southwest of the city of Jackson in

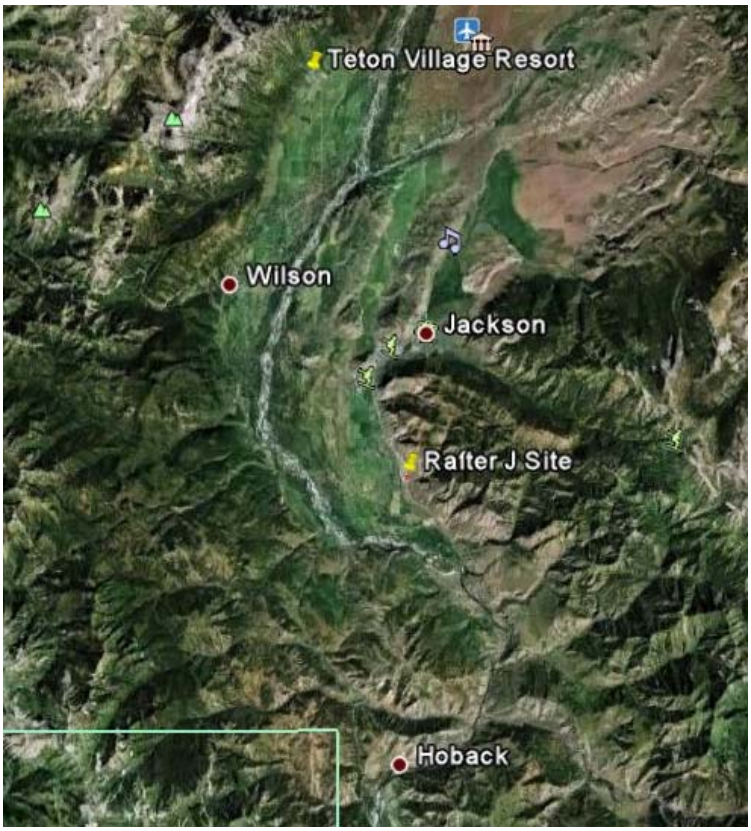


Figure 1 – General Project Location

Teton County, Wyoming. It is in the electric and gas service territory of LVE. See Figure 1 - 3 for a general site location map, the LVE parcel and the proposed location of the plant on the LVE parcel.

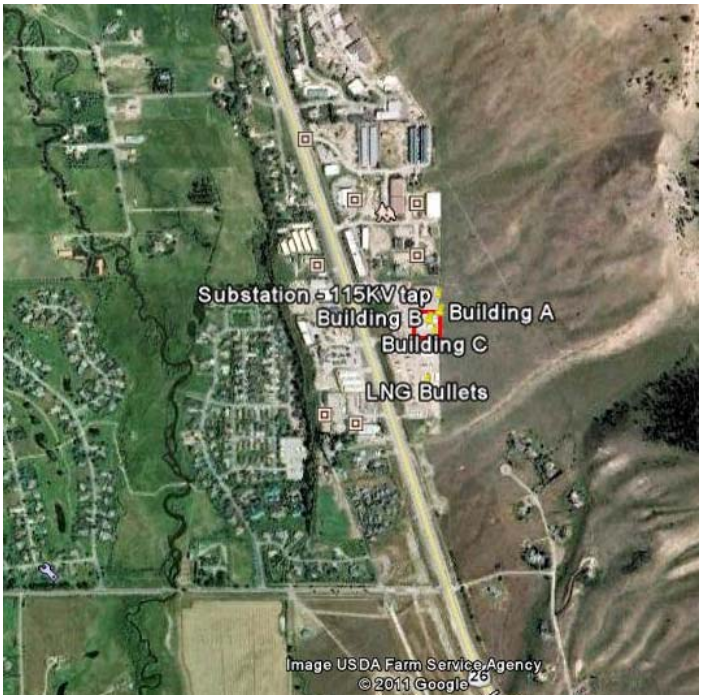


Figure 2 – Site Location on LVE Parcel

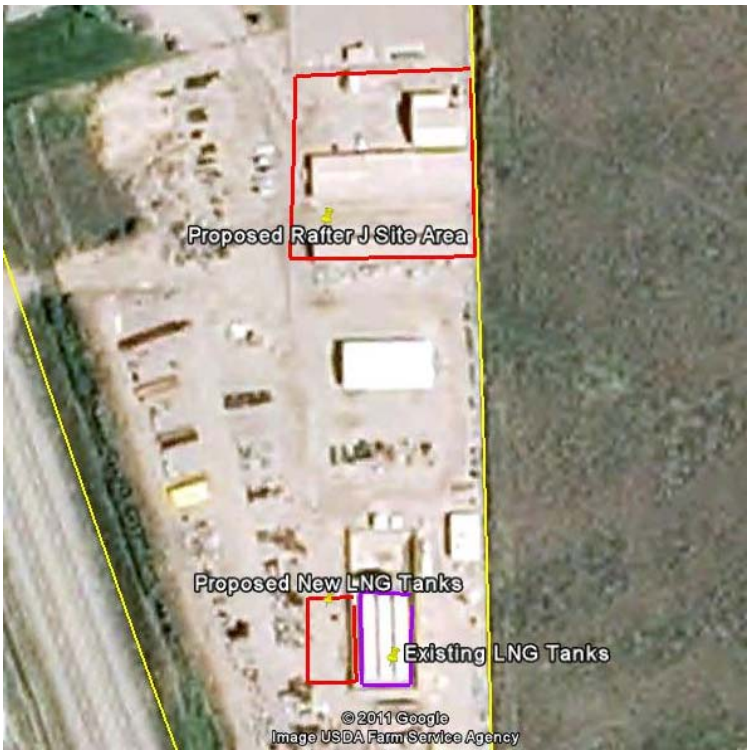


Figure 3 – Proposed Rafter J Generation Site

Ramco also looked at two other locations, where LVE has electric substations, as alternative sites (see Figure 4). These sites are the East Jackson Substation and the Jackson Substation.

Figure 4 – Rafter J and Alternate Sites

Alternate Site 1 – Jackson Substation

The Jackson 115 kV Substation is owned by LVE and is located on the north side of W. Snow King Ave. about 600 feet east of the intersection of W. Snow King Ave and Virginian Lane in the city of Jackson in Teton County, Wyoming (See Figure 5). While this site provides acceptable electrical interconnection capabilities and has adjacent undeveloped land that might

Figure 5 – Jackson Substation

allow for a new small peaking plant to be constructed, the large riparian natural area directly to the east of the site, along with both the adjacent seasonal residential trailer park and lack of access to sufficient natural gas volumes makes permitting this site problematic.

The Jackson Substation site could be used for the short-term emergency placement of stand-by generators to cover winter contingency generation over the next two winters.

Alternate Site 2 - East Jackson Substation

The East Jackson 115 kV Substation is owned by LVE and is located along the north side of E. Kelly Ave. between Vine and Oak Streets in the city of Jackson in Teton County, Wyoming (See Figure 6).

Figure 6 – East Jackson Substation

While this site provides acceptable electrical interconnection capabilities, the lack of both available undeveloped land and ready access to sufficient natural gas volumes, along with the predominant residential character of the surrounding land uses makes this site ill-suited for a generating plant.

Given the location and land use of both these sites, it is not feasible to build and operate the proposed facility at either location. Given the critical schedule needed to meet a winter of 2013 COD, it would be difficult to acquire the necessary land and approvals and complete construction by November 2013. Last, both alternate sites are within 10 km of the Teton national Park Class 1 area, which could potentially constrain development at these locations. For these reasons no further evaluation was done at either of these alternative sites.

3.2 Viability of Rafter J site for Peaking Power Plant Development

Based on previous experience, Ramco has developed a methodology for evaluating any prospective site for power plant development. This process focuses on three groups of development criteria:

1. Those critical to *confirming maximum site development* (site area, electric interconnect potential and access to natural gas in adequate quantities and pressure).

2. Those that, depending on the site location, may require significant amounts of capital (dollars and political) to resolve a potential constraint (*infrastructure and sensitive receptors*). Examples are roads, water and sewer, rights of way for electric and gas transmission and local sensitive receptors to noise and industrial operations (houses, schools and hospitals).
3. Finally, those criteria that do not prevent development, but may require special attention and/or mitigation that need to be accounted for in the project budget (*special requirements criteria*). Air quality, wetlands and cultural resources are examples of these types of criteria.

Based on the results of its review and subject to successfully obtaining local zoning approval and a Certificate of Public Convenience and Necessity from the Wyoming Public Service Commission, Ramco concludes that from constructability and operating perspectives, the Rafter J site is excellent for a peaking plant given the current use of the site. The biggest question is the local permitting process and the reaction of local stakeholders (discussed further in Section 3.5). At the present time both the local community and the local government officials are generally unaware of the potential project. Given the overall characteristics of the local population and the emphasis on local land use and environmental concerns, it should be expected that even this clean and important local infrastructure project could attract significant attention and potentially well funded and organized opposition.

In order to determine if it is possible to permit the facility locally, Ramco recommends the immediate preparation and submittal of the applicable zoning permit applications and the application for the Certificate of Public Convenience and Necessity. Initiating that effort by November of 2011 would allow for a final permit approval to be completed by July, 2012 and critical lead time equipment to be ordered in August 2012 to support a November 2013 COD should BPA decide to proceed with a generation project alternative. This recommendation is discussed further in Section 3.5. A timely decision on this matter is critical to maintaining the viability of achieving COD in time for the winter 2013 peak operational season.

3.3 Development Viability Criteria

3.3.1 Confirming Maximum Site Development

3.3.1.1 Site Area

The Rafter J parcel is owned by LVE, and currently contains office building for LVE, a parking lot for staff, a large gas and electric utility yard, storage sheds used by LVE as maintenance and storage facilities, and a liquid natural gas ("LNG") storage and distribution facility, including 3 LNG storage tanks and accompanying vaporization equipment. See Figure 7 for an aerial photo of the existing LVE parcel. The LVE site is currently zoned Business Park Special District.

Figure 8 shows the specific location on the LVE parcel where the 3-engine generating plant would be located. Appendix 4 shows a conceptual 3 engine layout. The proposed site is located in the northeast potion of the LVE parcel and is bordered on the east by the Greater Snow King Recreation Area and on all other sides by the LVE parcel. The LVE parcel is bordered on the east by Highway 89, on the south by Melody Ranch, a single family home development with approximately 15 ranchetts, on the east by the Greater Snow King recreation Area and on the north by a commercial/light industrial park. On the west side of Highway 89, across from the

LVE parcel, is a strip of commercial and light industrial properties. Behind and below those properties is primarily residential development.

Figure 7 – Aerial Photo of LVE Rafter J Parcel

3.3.1.2 Electrical Interconnection

LVE has a 115 kV substation located adjacent to the Rafter J site. (See Figure 8). The proposed

Figure 8 Proposed Plant Site at Rafter J

plant would be directly interconnected into this substation. The general scope of equipment required for this interconnection includes one generator step-up transformer (GSU) and associated switches and main breaker, one auxiliary transformer and switches, switchgear, and required protective/interconnect relays.

3.3.1.3 Gas Interconnection, Availability, Quality and Pressure

The LVE gas system has an exisitng 6 inch line that enters the LVE Rafter J parcel at the south end and interconnects to the exisitng LNG storage and vaporization system on site.

While LVE is currently working on long-term pipeline gas supply options for their standard service, for purposes of this report we have assumed the use of either pipeline or LNG natural gas supplied at 80-100 psi to the proposed power plant's gas point of interconnection, and that sufficient volumes are available to support winter peaking operation. As a pricing option, we have included a separate line item for the cost of adding 2 additional 60,000 gallon LNG storage tanks and a standby aux boiler for vaporizing the gas for use by the plant should long-term pipeline gas supplies not be available. The proposed location for these new LNG facilities can be seen on Figure 11. Note that an attractive feature of the reciprocating engines proposed for

this project (see Section 4) is that they can operate on 80-100 psig natural gas without any compression.

Sample gas quality data provided by LVE was reviewed for both the LNG and pipeline gas sources. Based on that review there does not appear to be any significant concern about the gas quality for the long-term operation of the plant.

3.4 Infrastructure and Sensitive Receptors

3.4.1 Site Infrastructure

Ramco evaluated the proximity, accessibility and capacity of the infrastructure necessary to build and operate the proposed facility.

Water and wastewater infrastructure necessary to serve the Project can be supplied to the Rafter J site at minimal cost.

Water for process use can be supplied to the site at minimal cost. Because of the closed loop radiator system used for cooling the reciprocating engines, the annual water consumption is minimal.

Instead of municipal sewage, any “gray” or contaminated water would be collected in a small sump tank for pump-out and off-site disposal.

Phone and internet facilities are currently available to LVE on site; this infrastructure would be utilized and expanded for use by the power plant.

Major equipment, including permit loads, can be delivered via US 89/Wyoming 26. The existing site is expected to be of adequate size for delivery and temporary storage/laydown of major equipment and materials; for construction worker parking; and for all temporary construction facilities (e.g. trailers).

3.4.2 Sensitive Receptors

The general land use of the industrial park where the LVE Rafter J property is located is primarily light industrial. None of the existing businesses in the area or on adjacent lands to the site has any sensitive receptor characteristics.

The nearest office/light industrial building is 350 feet to the north of the plant site. The closest residential receptor is about 1,200 feet to the south and significantly below grade, with a minimal view of the site (a portion of the exhaust stacks may be visible).

Property line noise requirements of 65 dba can be met with either one or a combination of equipment layout, low noise equipment or noise mitigation structures.

The Wilson Canyon Trailhead for the Snow King Recreation Area originates on the north side of the LVE parcel about 500 feet north of the proposed plant site.

Appendix 1 provides a detailed assessment on the potential recreational and visual impacts from the proposed plant. Based on that assessment, the development of a 25-41 MW reciprocating engine power plant at the Rafter J site should not have a significant impact on the local recreation or visual resources. Nothing at or near the site should prevent or impede the Project from complying with all local, state and federal health and safety criteria.

3.5 Special Requirements Criteria

3.5.1 Community and Political Support

Given the location of the proposed facility at the Rafter J site and the economic, environmental and reliability benefits of the proposed facility, it is possible to permit, construct and operate the proposed facility in this location. At the present time both the local community and the local government officials are generally unaware of the proposed project. Given the overall characteristics of the local population and the emphasis on local land use and environmental concerns, it should be expected that this project would attract attention and potentially well funded and organized opposition. Therefore, a well organized and proactive approach to development and permitting of this project, working closely with LVE to validate the need for and broader benefits to the local community from a reliable local source of power generation, is critical.

3.5.2 Permitting

The major permitting activities for the proposed project include the local zoning permits, the state certification process and the state air permit, all of which are described in more detail below. No federal permits are required. Since the information and preliminary engineering work required for preparing all three permit applications is similar, all permitting activities can take place concurrently. The preliminary engineering work to layout the plant, the ancillary facilities and outbuildings would be used for all three permitting activities. It is anticipated that the permit applications for these three activities would each take 2 to 3 months to prepare and could be done simultaneously. Each permit would require, among other things, a complete description of the project, including major equipment and infrastructure.

3.5.2.1 Local Permitting: Zoning

Local permitting is governed by the Teton County Land Development Regulations (“LDR”). The Rafter J site is located within the Business Park (“BP”) special district that allows for “Utilities, Central Facilities” and “Utilities, Distribution & Collection” but does not provide specifically for electric generating facilities.

Because generating plants are not specifically provided for in the zoning ordinance, the Teton County Planning Director must determine that this proposed use is similar to one of the uses listed in the ordinance. Once that determination is made, an application for a Development Plan Permit can be commenced.

The Rafter J site is located within the Natural Resource Overlay District ("NROD"). As a result it will have to comply with the appropriate review requirements. This review process can occur concurrently with the Development Plan Permit Process. Given the current condition and use of the site meeting the requirements of the NROD should not be an impediment to the permitting of the site. Additionally the project will have to file a Landscaping Plan, a Storm water Management Plan, a Grading and Erosion Control Plan and several variance applications.

A height variance will be required for the stack, which will exceed the 35 ft maximum height restriction in the BP special district. A floor area variance will also be required because the main building will exceed the maximum square footage for a single building (25,000 sq/ft) in the BP special district. Other variances may be required, based on the results of the Pre-Application meeting with the County Planning Department Staff.

The timetable for getting through the permitting process is between 90 and 180 days depending on the nature of the project and level of stakeholder interest.

The first step in the process is the Pre-Application Conference between the Applicant and the Staff. At that meeting the applicant will present the scope of the entire project so that the Staff can provide direction on all the necessary applications. In the case of the proposed project, the applicant would show the location of the engine building, all outbuildings, and infrastructure such the tie-in to the existing electrical substation and the location of and tie-in to the proposed LNG storage tanks. It is anticipated that 2 new storage tanks would be installed adjacent to the existing LNG storage tanks so that LVE's existing storage and supply would not used by the proposed plant. Based on the Staff's input in that meeting, the Applicant finalizes and submits the required applications and variance requests.

Staff has 14 days from submittal to make a sufficiency determination. Once the application is deemed sufficient, Staff has up to 120 days to complete its review, get applicable agency reviews and schedule the first public hearing at a Planning Commission Hearing. A second public hearing is held within 30 to 45 days of the first public hearing. The Application then goes to the County Board of Commissioners for a final determination at least 28 days after the second Planning Commission Hearing.

Depending on the ownership structure of the proposed project, an alternative to obtaining a Development Plan Permit and variances under the existing Business Park special district would be to apply for a rezoning, changing from the BP special district to the Public/Semi-Public special district. By doing so, no variance(s) would be required. However, the Development Plan Permit would still be required. The time frame using this approach is the same as above, 90 to 180 days depending on the level of public intervention and Planning Board concern.

3.5.2.2 State Permitting: Wyoming Public Service Commission ("WPSC")

Pursuant to Title 37 – Public Utilities - of the laws of the state of Wyoming, A Certificate of Public Convenience and Necessity ("CPCN") is required for the construction of a power plant by any "Public utility".

The process for obtaining a CPCN is set forth in the rules and regulations of the WPSC. There are no formal timelines for the completion of the process. Generally speaking, the process is estimated to take between 6 and 12 months, from the time a complete application is submitted, depending on whether the application is contested. An uncontested application for a power plant is estimated to take about 6 months. A contested application for a power plant is estimated to take up to a year.

The process is started by the filing of an application. Generally within 2 weeks of the filing of the application, WPSC issues a public notice identifying the proposed project and allowing 30 days for any interested party to intervene in the proceeding.

If there is no intervention, the WSPC staff will review the application and make a recommendation to the Commission. The Commission may, but is not required to, conduct a public hearing even if the application is uncontested.

If the application is contested then a public hearing is scheduled at the Commission's convenience and other proceedings for discovery and testimony may be scheduled depending on the nature of the intervention.

3.5.2.3 State Permitting: Wetlands and Cultural Resources on site

No visible wetlands or cultural resources requiring agency review were observed during the site visit. Given that the site is wholly contained within an existing disturbed and heavily utilized area consisting of fill materiel, the presence of cultural resources would be very unlikely.

3.5.2.4 State Permitting: Air Permitting

Appendix 2 outlines the screening level air assessment conducted for this project evaluation. Based on that assessment there appear to be no significant constraints to permitting the plant for up to 1000 hours of operation a year using natural gas as the primary fuel.

3.5.3 Taxes

The Project is subject to all applicable real and personal property taxes. Ramco's initial review of applicable taxes determined that the Project would be subject to the following such taxes:

Property taxes (real and personal) - are determined by special assessment because the Project is utility property.

4. Technical Assessment and Options Evaluation

This project presents a somewhat unique combination of requirements and/or operational attributes:

1. A site elevation of 6,150' ASL;
2. Limited annual operating hours (expected to be $\leq$100, but with a recommended annual permit limit of 1000);

3. Winter peaking operation at -20 to -40F, but also capable of operating during expected summer-time ambient conditions of up to about 90F;
4. The requirement of overall high start reliability, regardless of weather conditions (e.g. degree of cloudiness, wind, ambient conditions, etc.);
5. A requirement of rapid progression from the initial start request to operation under load;
6. A requirement to be able to tailor plant operating MWs to conform to what will likely be a variable demand, while maintaining relatively good partial plant load efficiency; and
7. A requirement of relatively rapid plant response to load set point changes.

While the first three items are self-explanatory, some explanation and discussion of the last four is appropriate.

Consider the following hypothetical (but very realistic) operating scenario: BPA and LVE, in monitoring weather patterns, associated overall expected transmission system demands and local LVE load requirements, determine that within 24 hours a cold weather event is likely to happen that will require some level of local LVE-area generation. In such a situation, it is possible that there will be both uncertainty as to the exact quantity of needed local generation, and the timing and duration of such operation. It is certainly conceivable that operational uncertainty will persist until the operating day.

Given this scenario, plant dispatch and operating reliability and flexibility are key aspects of plant design. These argue for the following plant design attributes:

1. Equipment modularity – a plant owner/operator does not want all of its MW "eggs" in a single prime mover "basket";
2. High overall start reliability: the plant will only operate a few hours a year, but when it is needed, it is critical that it starts and operates when called on. This characteristic again argues for multiple prime movers;
3. Good fuel efficiency, i.e. low fuel consumption, when operating over a large range from full to partial output;
4. The ability to be ready for dispatch with minimal prior notification (assuming no more than 24 hour prior notification); and
5. The ability to change load relatively rapidly in order to follow actual local demand requirements.

Two types of prime movers are best designed to meet the above design/ operating attributes, while also being relatively immune (with respect to start reliability and dispatch capability) to unpredictable and variable weather conditions:

1. Smaller simple cycle gas-fueled gas turbines; and
2. Smaller gas-fueled reciprocating engines.

For either option, Ramco assumes that a base plant configuration would employ 3 engines in order to minimize the impact of single engine start failure; provide relatively small dispatch increments; and improve overall plant part load heat rates. For the gas turbine option, several suppliers provide competitive products. Ramco selected as representative for its review the Solar Taurus 70 gas turbine (a nominal 8 MW (ISO) machine). Solar has many of these units in operation and a strong commercial track record. For the reciprocating engine category, Ramco

selected Wartsila as the representative supplier - Wartsila has far and away the largest number of commercially operating reciprocating engine power plants, both in the US and internationally, of any engine vendor. The Wartsila machine that best fits this potential application is the 20V34SG, rated at a nominal 8.4 MW. Product brochures for both engine types are included with this report in Appendix 3.

Both suppliers provided Ramco with budgetary cost, scope, and schedule information. A summary of that information is provided in the following Table 4.0.

Supplier:	**Wartsila**	**Solar**
Engine model	20V34SG	Taurus 70
Engine count	3	3
Predicted gross full load output/engine (Mw)	8.439	7.606
Predicted gross full load heat rate (Btu/kW-hr)	8,490	10,960
Plant gross full load rating (Mw)	25.3	22.8
Predicted engine ½ load rating (Mw)	4,198	3,803
Predicted engine ½ load heat rate (Btu/kW-hr)	9,140	14,062
Plant full load rating (Mw net)[3]	24.7	22.2
Plant full load heat rate (Btu/kW-hr net)[3]	8,708	10,275
Delivered price (3 engines – k$)[1]	17,645	19,375
Delivery lead-time (order to ship)	10 mos.	12 mos.
Features added for cold climate operation	See below	See below
Gas compression required	No	Yes
Duration from start request to synch (min)	~2	≤2
Duration from start request to full load (min)	~13	≤10
Ramp rate (Mw/min)[2]	2	3-36
Average water consumption rate (gpm)	<0.1	<0.1

Notes:

1 Wartsila budgetary price is delivered to site inclusive of all exhaust gas treatment equipment (e.g. selective catalytic reduction and CO_2 oxidation systems (SCR/CO; Solar is free on board (FOB) shipping point and is exclusive of any back end SCR/CO systems –Ramco added $1M to the Solar price for shipping, and $1.5M for backend treatment equipment. Both options include commissioning support and associated initial startup parts. Wartsila pricing assumes a euro exchange rate of $1.42.
2. Wartsila ramp rate applies once engine is at normal operating temperature; during initial startup, ramping is limited to 0.65 MW/min. For Solar, ramp rate is dependent on a number of operating variables.
3. Assumes total plant auxiliary losses, up to the high side of the GSU, of 2.5%.

Table 4.0 Equipment Comparison

Several items identified in the prior table merit discussion:

1. The Solar option currently includes a triple-redundant (for reliability purposes) gas compression system, to compress the supplied natural gas from its assumed delivery pressure of about 100 psig to that required for at the Taurus combustor (~250 psig). Should LVE implement its own gas compression system and thus be able to assure gas delivery to the engine combustor at 250 psig or greater, these compressors could be removed from Solar's scope, at a savings of about $1.3M. For the purposes of this assessment, this scope (and its associated price) is assumed to be required and is included in the estimated cost for this option.
2. No gas compression is required for the Wartsila engines.
3. Both options require scope modifications from normal base to address the cold operating conditions that exist at this site:
   a. For the Taurus engines, inlet air anti-ice is required to prevent ingestion of ice into the compressors. In addition, either the engines would need to be housed in an engine hall so as to protect the engine/generator/auxiliaries package from the cold, or Solar would need to modify its standard package housing to beef up insulation and add components such as space heaters, heat tracing, etc. No added cost for such Solar package modifications are included in the total cost noted in Table 4.0.
   b. For Wartsila, the engines are assumed to be housed in a pre-engineered engine hall. In addition, engine suction (combustion) air must be maintained at or above +5°C/41°F for an engine start, and at or above -20°C/-4°F for normal operation. As a result, suction air heating is needed. This heat can be provided by external power or heat for starting, and from the engine cooling water circuits when running. Another possible solution would be to draw combustion air from within the engine hall, and design the hall/insulation/HVAC system so as to maintain a temperature of at least 41°F at all times. A final design would optimize the solution to minimize lifecycle cost.
   c. Also for Wartsila, engine jacket pre-heating is needed to raise jacket temperature to 50°C/122 ^{o}F (which allows an engine to reach full load from a start request within about 15 minutes). Depending on the dispatch lead time criteria set by the project (e.g. time allowed from issuance of a dispatch notice to when an engine start must be initiated), this preheating would either be provided by standard electric pre-heaters, or by a small package boiler fed with city water treated using normal chemical injection means, and generating saturated steam at 95 psig. As with item b, the final approach would be selected during the detailed design process so as to minimize lifecycle cost.
4. The Wartsila reciprocating engine option provides far better heat rates – both at full and ½ loads – compared to Solar, with the full load heat rate for Wartsila about 2,470 points better than for Solar and the ½ load heat rate roughly 4,920 points lower. This translates to significant fuel cost savings over the turbines and, as a result, a predicted superior life cycle cost for the owner (since O&M costs tend to be roughly comparable for equal sized turbine and engine plants).
5. Gas turbines tend to be more susceptible to initial start problems; reciprocating engines are very reliable starters.
6. Start times are relatively comparable for both engine types; gas turbines can ramp up/down on load quicker than reciprocating engines. (Note that Ramco assumed a 15

minute ramp to full load would be acceptable for this application, given the very limited operating hours. If, however, BPA/LVE should desire a faster ramp, a 10 minute start can be provided at the expense of either upsizing the engine pre-heating system (to more quickly attain higher pre-start jacket and lube oil temperatures) and/or longer notification periods prior to dispatch.)

7. Neither option requires significant water for operation or cooling.

Based on the above, it is Ramco's judgment that the Wartsila reciprocating engine option would provide the best overall value and application fit for LVE, based on its lower delivered cost (and expected lower installed cost), relative simplicity, superior full and part load heat rates, lack of need for gas compression, robust design, and starting integrity.

In addition and as a relatively minor consideration, should black start capability be included, a Solar plant would require a small stand-alone generator (typically diesel) rated at about 367 kW for black plant startup of the turbine/generator sets; depending on when in the startup sequence the gas compressors are required to be operating, this value may increase. For the Wartsila option, this generator size reduces to about 250 kW.

With this judgment in mind, Ramco prepared a preliminary and simplistic general arrangement of a 3 engine plant, situated so as to simplify potential expansion to 4 or 5 engines if needed at a future date (Figure 9). The main features are:

1. The three engines are currently situated west-east, with their cooling radiators lined up parallel to the east fence-line. During final design, this lineup would need to be verified with respect to meeting area noise limits. The use of low-low noise radiators is assumed.
2. All engines are equipped with SCR and CO catalyst; the SCRs use 40% urea injection systems.
3. Buildings A and B (but not C) will require relocation to accommodate this plant.
4. Although not included in our assumed base scope, we have shown a black start generator in the event that BPA/LVE desire that capability.
5. Assumed construction lay-down and trailer areas are denoted. These locations are based on conversations between Ramco and LVE.
6. Some equipment has been placed in LVE's switchyard. Location for the hypothetical placement of this equipment was discussed and coordinated with LVE.

The following Table 4.1 summarizes the budgetary capital costs Ramco anticipates for a three engine 20V34SG Wartsila project at the Rafter J site, stated in 2011 dollars:

Item	Description	Cost ($M)
1.	Wartsila equipment – delivered to site	17.6[1]
2.	BOP equipment except switchyard	1.5
3.	Switchyard and Transmission[2]	1.95
4.	LNG – 2 additional bullets and accessories	1.8

5.	Engineering and permitting services	5.7
6.	Construction directs	8.1[3]
7.	Indirects, overheads, contingency and profit	6.6
8.	**Total Installed Cost – 3 Engine Plant**	**43.25**

Notes:

1. Wartsila pricing assumes a euro exchange rate of 1.42. Should the rate reduce to 1.30, this pricing would be lowered by slightly over $1M.
2. Includes one (1) GSU and associated 115 kV breaker, 2 switches/structures, relays, auxiliary transformers and relocation of existing distribution undergrounds.
3. Does not include any cost for re-engineering site fill, or for pilings.

Table 4.1: Expected Budgetary Cost – 3 Engine Plant

For a four engine plant the price would increase about $ 9 M and for a five engine plant the price would increase about $18 M from the numbers shown in Table 4.1.

Ramco has also prepared a rough estimate of the costs (not included in Table 4.1) for the relocation of Building A & B to a location directly west of the proposed site (see Figure 8). The location for rebuilding the existing buildings will require new imported fill and compaction. The estimate to perform this work is $3.2 M. LVE has indicated that they would want $6M to bring in fill, compact the new location and build new buildings. We have left the resolution of that final budget number to BPA and LVE.

We would note however, that if asked to incorporate “new replacement offices, warehouse and shops” into the final design of the plant, there may be some opportunity to optimize the total layout and provide LVE with the square footage they desire to replace Building A & B.

Ramco has assumed that LVE/BPA would perform all of this work (other than the site geotechnical evaluation and any related rework). If the results of that geotech evaluation require it, the EPC contractor would perform site fill re-engineering.

Should LVE/BPA so desire, all of this work scope could easily be included in the Engineering, Procurement, Construction (EPC) contractor’s scope.

5. Project Schedule

This schedule, set out in Table 5.0 below, consists of two main components: a) Development (the permitting portion of the schedule plan, with the electric interconnection activities occurring in parallel), and b) final Engineering, Procurement, and Construction. Both are discussed below. In addition, the types of and estimated costs for various development/permitting activities follow this schedule discussion. Note that the accelerated nature of this schedule would require capital outlays for major equipment (with cancellation off ramps) by August of 2012 in order to meet a November 1, 2013 COD.

Table 5.0 - LVE Rafter J Site
Project Milestones Draft

Item	Task	Start	End	Duration
1.	EPC phase 1 contract – limited to permitting, related support work, & preliminary engineering	10/31/11	6/4/12	7 mo.
2.	Prepare permit packages – air & local building	10/31/11	1/6/12	2 mo.
3.	Submit permit applications to agencies	1/9/12	1/13/12	1 week
4.	EPC support of permit process	1/16/12	9/14/12	8 mo.
5.	Scope, bid, and negotiate Wartsila contract	4/2/12	8/31/12	5 mo.
6.	Preliminary engineering; site geotech.; BOP bid/eval	5/14/12	8/31/12	3 ½ mo.
7.	EPC phase 2 release	6/4/12	6/8/12	1 week
8.	1st mobilization (mob) (phase 1): site prep; relocate buildings[1]	6/11/12	9/14/12	3 mo.
9.	Permits in hand; Wartsila released to fabricate	9/14/12	9/14/12	1 day
10.	Final engineering	9/17/12	3/11/13	6 mo.
11.	1st mob (phase 2): undergrounds; prep & pour engine hall slab	9/17/12	12/7/12	2 ½ mo.
12.	1st mob complete; demobilization	12/10/12	12/14/12	1 week
13.	2nd mob: plant erection	3/4/13	3/8/13	1 week
14.	Mechanical Completion	9/27/13	9/27/13	1 day
15.	Perform checkouts; ready for witnessed tests	9/30/13	10/25/13	1 mo.
16.	Commercial Operating Date (COD)	11/15/13	11/15/13	1 day

Permitting and Development Activities

As indicated in Table 5, the total duration to complete development for the following (which covers 10 ½ months from the start of the preparation of permit package thru to receipt of the permits) provides an estimate of the time required to secure the necessary permits to construct the project.

Table 5.1 is a permitting matrix by category which details the permits required to construct the plant and the estimated time to obtain them. It is divided into several categories.

- *Land Use/Zoning Permits* – Local permitting is governed by the Teton County Land Development Regulations. ("LDR"). The Rafter J site is located within the BP special district that allows for "Utilities, Central Facilities" and "Utilities, Distribution & Collection" but does not provide specifically for electric generating facilities.

- *State Certificate of Public Convenience and Necessity* – The proposed project may require certification from the Wyoming Public Service Commission pursuant to Title 37 – Public Utilities of the laws of Wyoming.

- *Permitting and Related* – This category itemizes the air permit and other environmental permits/assessments that the project will require prior to commencement of construction.

- *Electric Transmission Interconnect Application – Because the proposed project is interconnecting directly to LVE's distribution system, there is no formal interconnection application required.*

Permit Matrix

Land Use/ZoningPermits	**Start Month**	**Finish Month**
Zoning Permits		
Pre-Application Conference(prep and meeting)	1	2
Prepare Site Development Plan and Submit	1	3
Completeness Determination (1 month)	3	4
Planning Commission Review/Public hearings	4	8
County Commissioner Determination/Permit Approved	9	9
Building Plan Review	9	11
Certificate of Public Convenience & Necessity		
Prepare/Submit Application	1	3
Public Notice	3	4
Public Hearing(s)	5	6
Staff Review and Recommendation	3	9
Commission Decision	9	11
Air Permit		

Pre-Application Meeting	1	1
Prepare/File Application	1	3
Determination of Completeness	3	5
Notice and Public Hearing	6	6
Permit Issued	9	9
Appeal Period	9	11

Table 5.1 - Permit Matrix

Engineering, Procurement, and Construction Activities

In order to achieve a November 30, 2013 COD, the EPC phase 2 release must occur by June 4, 2012. This would be followed by Full Notices to Proceed (FNTP) to both the EPC contractor and to Wartsila by September 14, 2012. For initial permitting and related engineering efforts, authorization to proceed must be issued no later than October 31, 2011. This release would authorize several activities: a) all necessary permitting activities required to achieve the targeted COD, inclusive of interconnect activities; b) the preliminary engineering work needed to support the permitting effort (mainly initial design), and c) the preparation, bidding, and awarding (but not release to fabricate) of the Wartsila equipment. Major BOP equipment orders would occur during the 4th quarter of 2012.

The overall 25 month schedule we prepared (development start through COD) includes the following major activities and assumptions:

- Release to proceed with Phase 1 (permit/Development) on October 31, 2011.
- 10½ months is required to prepare, apply for and receive the air permit, assuming no significant opposition.
- Phase 2 EPC release is provided in June 2012, allowing the relocation of site buildings A&B to begin. The remainder of 2012 construction work would not be released until all permits are in hand. This includes all underground work, and forming and pouring of the engine hall slab.
- Full Notice to Proceed is issued in September 2012.
- The Wartsila engine package is awarded and released for fabrication no later than September 2012.
- No winter construction would be performed.
- Construction resumes in March 2013.
- COD is achieved in November 15 2013, or a little over 17 months after the start of building relocation

Pre Construction Budget Estimates (Development, Permitting, Engineering and Major Equipment Procurement)

With this schedule, there is a risk for potential cancellation costs associated with the major equipment and for investing in site specific initial engineering and permitting activities that may be lost. The 2011/12 investments to maintain the 2013 COD schedule include the following costs:

Development and Permitting Activities:

Land Use Zoning	
Electric Transmission and Interconnection Process	
Conceptual design and project definition	
Technical Permitting Support	
Air Permit Application and Process	
Project and Development Management	
Development Contingency	
Total:	$700,000

This budget covers all activities required both to support the permitting effort, and to maintain the overall project schedule during the permitting effort. The development budget estimate does not include any major engineered equipment or construction costs, BOP equipment procurement, project management costs or fees, all of which are included in the larger total project cost.

While the cumulative project cost up to the point of obtaining the local land use and state air permits is about $700,000, there will be off-ramps available all along the way should it become apparent at any time that obtaining a timely permit is not achievable.

In order to achieve the November 30, 2013 COD, the required development actions are:

- Release start of development activities (Project Management, local community process and implementation and all permit applications including air).
- File for electric interconnection with BPA for up to 43 MW generated by up to 5 Wartsila 20V34SG reciprocating engines, located at the LVE Rafter J Substation.
- Proceed to prepare and file an air permit application including a GHG BACT analysis if deemed needed.
- Release all preliminary engineering activities needed to support this work. The major types of work to be performed are: a) engineering support of for preparation, submittal, and review of the project permits; b) basic and conceptual plant design; and c) bidding, negotiating, and awarding of major equipment.

6. Power Related Benefits and Costs For Non-Winter Peak Demand

Projects like this one typically provide the following benefits to electrical system operations, most of which would be attributed to this project in the non-winter peak periods:

- Spin Reserve - Quick start capability with power to grid in less than 2.5 minutes.
- Local Voltage Support - MVAR reactive capability – MVAR rating = 31.5 MVA; reactive injection 18.9 MVar, reactive absorption = 9.8 MVar.
- Efficient heat rates and full outputs at high ambient temperatures and elevation.
- Summer peak demand – excellent peaking plant with low simple cycle heat rate (8500 kw/mmbtu HHV)

7. Process and Criteria for Selection of Contractor(s) for Generation Options Development

There are two continuing programs outlined for going forward in this Report. They are; proceeding to prepare and file local and state air permits for the generation project, and if selected as the project option to proceed with, initiating the negotiation of a contract and release of an EPC Contractor to design, procure and build the Project.

Local Land Use and Air Permit Process for Permanent Power Plant

If BPA desires to confirm project viability and keeping the generation option available for a November 2013 operations date, then the recommendation of this report is to proceed immediately to prepare and file both local and State permits. Since this process is on the critical path for keeping the generation option available for consideration, Ramco would propose to proceed under a not-to-exceed, time and materials basis for the local land use, state air and any other permits needed.

Selection, Negotiation and Release of an EPC Contractor to Design, Procure and Build the Project.

The process for selecting an EPC contractor usually falls into two steps:

1. Selecting a pool of qualified candidates who will be allowed to bid on the project; and
2. Bidding the work to the selected pool, selecting the winning bidder, and negotiating and awarding a final EPC contract.

If BPA/LVE already have pre-qualified candidates that have specific experience working on small generation projects and more specifically Wartsila reciprocating engine projects, the formality of selecting qualified bidders may already be completed. However, given the limited number of fossil generation projects proposed by BPA and LVE recently, it is likely that an initial screening is appropriate.

In this case, a list of qualification criteria of importance to the Owner (usually associated with eliciting information on the experience level, staffing/ "bench strength", safety record, commercial qualifications, suggested project execution approach, and feedback on commercial considerations of special significance to the Owner) is prepared and issued to – usually – 5-10 prospective bidders. The information provided back by the prospective bidders will then form the basis for the Owner's selection of a short list of qualified bidders.

The types of documents that are generally prepared and issued to the short listed candidates for the purpose of selecting an EPC contractor include the following:

1. A document describing the scope of services to be provided (a "Scope Book"), inclusive of all engineering, materials supply, construction, startup, testing, commissioning, and post-commissioning support services (if any), and the proposed schedule (usually milestone) for same;
2. Alternates and Options (if any) that bidder needs to provide separate quotations on;
3. A document or documents (usually appended to the Scope Book) describing the technical criteria (including site annual meteorology/extremes), procedures, and standards that will be the basis for the plant and must be adhered to by the successful bidder while designing, constructing, starting up, and commissioning the project;
4. Scope assumptions that should be made by bidder, usually in the area of site conditions (including available geotechnical information if any), the nature and types of all interconnects (including battery limits), and the quality and supply conditions of all commodities required for plant operation (most importantly fuel);
5. Proposed commercial conditions, including Owner's proposed payment terms;
6. Pricing data sheets;
7. Required bid document organization;
8. How exceptions to Owner's documents are to be formatted and provided by bidder in its bid; and
9. General bases that Owner will use to select the winning bidder, and also upon which Owner may eliminate bidder(s) from consideration.

BPA/LVE would prepare these documents if a decision should be made to proceed with bidding a project. If assistance is needed, any of a number of qualified companies (including Ramco) are available to provide support in this effort.

Appendix 1

Rafter J Site Recreational and Visual Assessment

A site visit was conducted on August 31, 2011 to assess the potential for any significant visual impacts from the proposed project. The site is located inside the 15-20 acre LVE utility yard that is part of a larger industrial/commercial development lining the west side of Highway 89. The entire industrial park fronts the Snow King Recreational Area on the east.

Assessment of Potential Project Impacts to Local Recreational Activities

Figure A-1 shows the location of the proposed site as it relates to the Teton National Park, National Elk Refuge (both to the north) and the Jackson Wilderness Area to the east. Primary tourist traffic enters the Jackson/Teton/Yellowstone area from either the west via Highway 22, the east via Highway 29 (at Moran Junction to the north), or form the north and south via Highway 89 that runs along the western side of the LVE property. A number of RVs were observed using Highway 89 going both north to Jackson and south towards Hoback Junction (about 7 miles to the south of the site).

Operation of the plant will not have any significant impact on the majority of these travelers since their destinations are either in Jackson, Teton and Yellowstone National Parks. Some minor traffic impacts may occur during construction as large equipment and construction supplies are brought into the site. But those will be limited and given the existing industrial activities and corresponding traffic on the site and adjacent industrial park, the proposed project will not significantly add to the exisitng conditions.

Figure A-2 shows the Snow King Recreation Area which is immediately east of the existing industrial park and the Rafter J Site. Skiers use the northern slope areas next to Jackson during the winter. During the spring, summer and fall, mountain bikers and hikers use the trails for active and passive recreation. The trail head for the Wilson Canyon Trail starts immediately north of the site and local hikers sometimes use the LVE parking lot as a location to park their cars while they hike (Figure A-3). The trail is lightly used given it is not close to any major residential areas and requires walking or bike riding across Highway 89 to access the LVE parking lot and trail head. There is a bike and hiking trail running along the west side of Highway 89.

The operation of the plant will not have any significant impact on the recreational use of the Snow King Recreation Area. The trails and area adjacent to the site are closed from December 1 through April 30 each year to allow wintering wildlife (primarily Elk) to forage along the slopes and mountain. The primary usage period for the plant is during winter periods (December through mid February). Even during the spring, summer and fall periods, the operation of the plant will not have any significant impact on local hikers and bikers given the existing business activities already operating along the Recreation Area.

During construction of the plant, the use of the LVE parking lot and Wilson Canyon trail head by local hikers and bikers could be impacted and therefore mitigation, such as temporary/modified access and temporary parking arrangements, may need to be provided to local recreationists to avoid any conflicts.

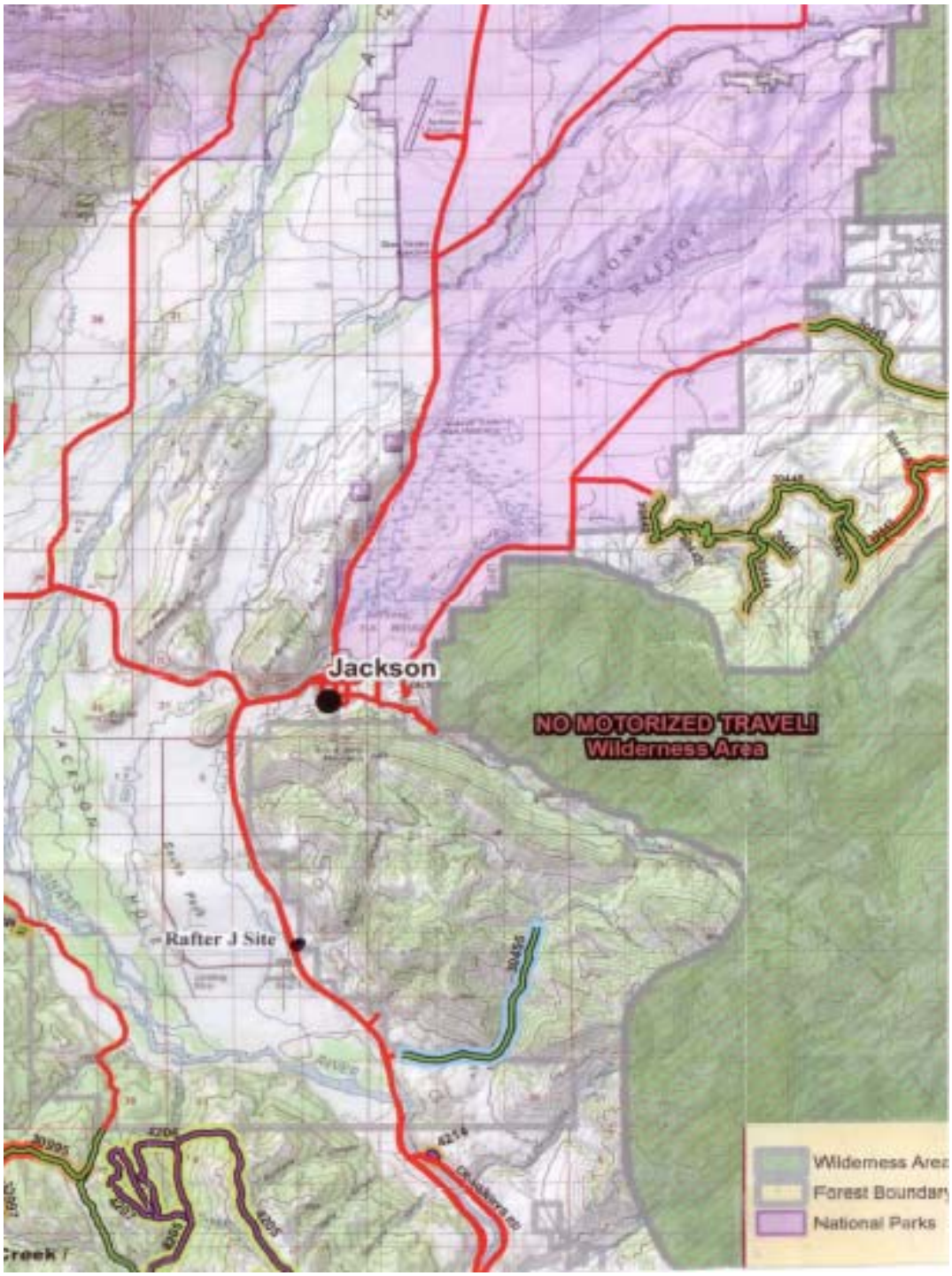


Figure A-1

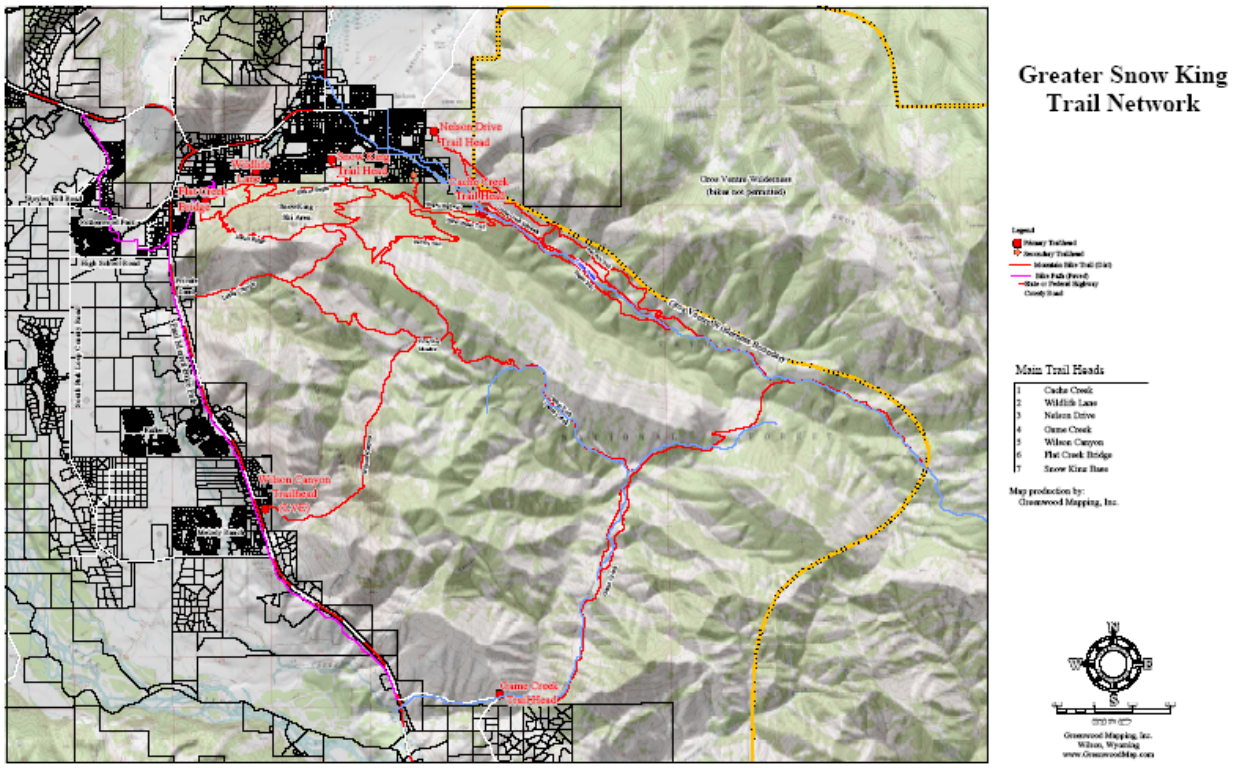


Figure A-2

Figure A-3

Visual Assessment

A review of potential visual impacts, with an emphasis on the Wilson Canyon Trail in the Snow King recreation Area, was conducted on September 1, 2011. Figure A-4 shows the various locations used for the assessment. The impact assessments were focused on three primary areas:

1. Potential visual affects from Highway 89 and the industrial/commercial uses – Photo 1
2. Potential visual affects from local homes that might be able to see the plant site – Photo 2
3. Potential visual affects on the down hill approach to the site area along Wilson Trail – Photos 3-9

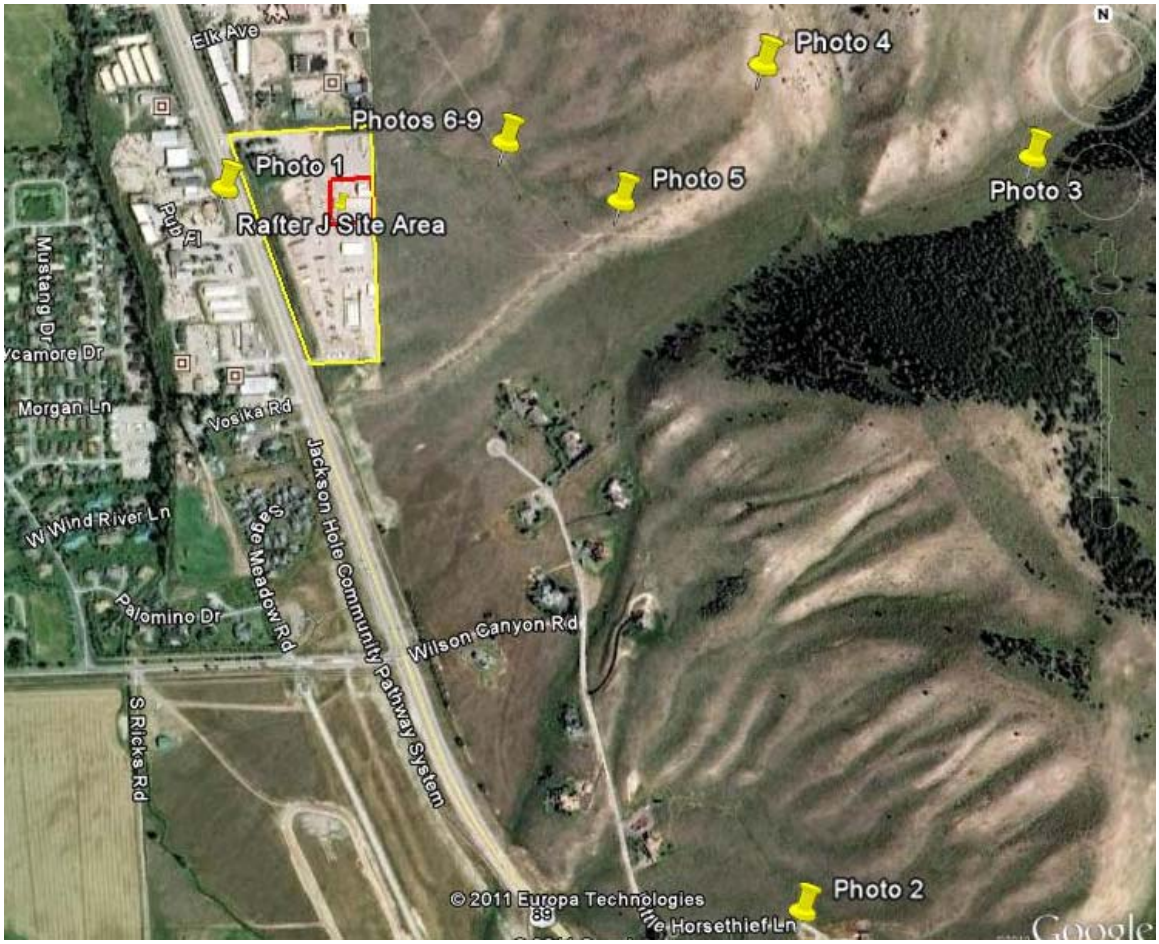


Figure A-4

Photo 1 was taken on the west side of Highway 89 looking up towards the site area. The existing LVE buildings that will be moved can be seen where the proposed plant will be built. The primary visual affect after the project will be that the LVE property across the

road on the right side of the photo will be filled and brought up to grade with the rest of the site. Once that is completed new buildings similar to those located on the proposed site will be constructed on the new fill area. This will significantly block any view of the plant from this location, except for maybe the top few feet of the three 85 foot stacks.

Photo 1

Photo 2 was taken from the front yard of a home located about 4000 feet south of the site. The home is currently on the market for $3.4 mm and is located in the Little Horse Thief Lane Development. This house was selected for a visual assessment because it is the only home in the Little Horse Thief and Melody Ranch Developments with an elevation high enough to possibly see the proposed project.

The project site is currently at an elevation of 6,150'. The current LVE buildings on the site vary from 15 to 30 feet in height. The southern most part of the LVE property has an at grade elevation of 6,165'. The existing structures (aux boiler building, LNG bullets and storage and parking buildings) create an additional 15-20 foot visual barrier to the proposed site. The home located at Photo 2 is at an elevation of 6,200', which is about 20 feet above the LVE site and structures.

The proposed project location is indicated with a small red line in the middle of the photo. As can be seen, the proposed project will blend into the current visual pattern of the industrial and commercial business surrounding the proposed site and therefore not have any significant visual impact to neighbors view sheds.

The Melody Ranch, which is located 1,200 feet west and down slope from the proposed site, has average at grade elevations about 100 feet below the proposed site grade. The

homes in this area are blocked from any direct views of the site by the 15-30 foot buildings located on the ridge (at grade elevation of 6,135'-6,145') on the west side of

Photo 2

Highway 89 across from the LVE property. As a result there will be no significant visual impact to Melody Ranch neighbors view sheds.

Photos 3-9 were taken while hiking down Wilson Canyon Trail in the Snow King Recreation Area. These photos are intended to provide an indication of the current view shed for hikers and bikers using the trail. Perhaps the most visually sensitive members of the public near the proposed site, as can be seen, the current view shed already has homes, offices, industrial and commercial land uses as a baseline prior to the proposed project. Please refer to Figure A-4 for photo reference locations relative to the site.

Photo 3 shows the Wilson Canyon Trail coming out of the Canyon west of the proposed site. Any views of local homes or industrial and commercial properties can not be seen from this location on the Trail.

Photo 3

Photo 4 shows the view from above the Wilson Canyon Trail (Trail goes through Wilson Canyon to the left in this photo). Site area is marked in red. Little Horse Thief homes

Photo 4

are seen at the end of the Canyon below Proposed Site grade.

Photo 5 shows the trail just as it comes out of the lower Canyon. The LVE 115 Kv poles and line can be seen in the foreground.

Photo 5

The proposed plant will not be seen from this point on the trail; however, the three 85 foot stacks may start to be seen over the horizon between the LVE pole line and the Blue Spruce to the right.

Photo 6 shows the first point on the Trail where the site and proposed project will come into full view. The possible location of the proposed plant is shown in red to give some sense of how the plant might look from this point in the trail.

Photo 6

Photo 7 shows the trail about 1000 feet from the LVE trailhead. A rough estimate of the three engine plant has been added in red outline. The metal power pole on the right is about 75 feet high and is about half way between the photo 7 location and the trail head.

Photo 7

Photo 8 and 9 shows where the proposed plant might appear in the last 500 feet of the Trail (red line).

Photo 8

While prominent for the last quarter mile of the trail, the basic profile other than the three

Photo 9

Stack heights would be consistent with the heights and architectural style of the buildings and structures currently located at the site and surrounding industrial and commercial area. In addition, building coloring and architectural enhancements can be used to soften the visual aesthetics of the plant and stacks.

Conclusion

There will be some minor impact to recreation and visual aesthetics near the LVE trailhead for the Wilson Canyon Trail, but they will not be significant in the context of the current surrounding land uses. Therefore there will not be any recreational or visual constraints to full development of the project.

Appendix 2

Air Quality Assessment of Project Feasibility

Existing Background

- The project will require a New Source Review construction permit from the State of Wyoming, Department of Environmental Quality (WDEQ) before any actual work is begun on the project.
- The project is located in Teton County, Wyoming and is currently attainment for all pollutants.
- No Class I Areas are within 10 km of the project site. Grand Teton National Park is approximately 12 kilometers north. Class I modeling requirements are triggered if project is within 10 km of a Class I area. See figure on page 2.
- The nearest air quality monitoring station is located four (4) miles toward the north in Jackson, Wyoming. The monitoring station measures PM10 and PM2.5. It does not collect meteorology.
- The nearest source of meteorology would be Jackson Hole Airport, located approximately 12 miles north of the project site, within the boundary of the Grand Teton National Park.

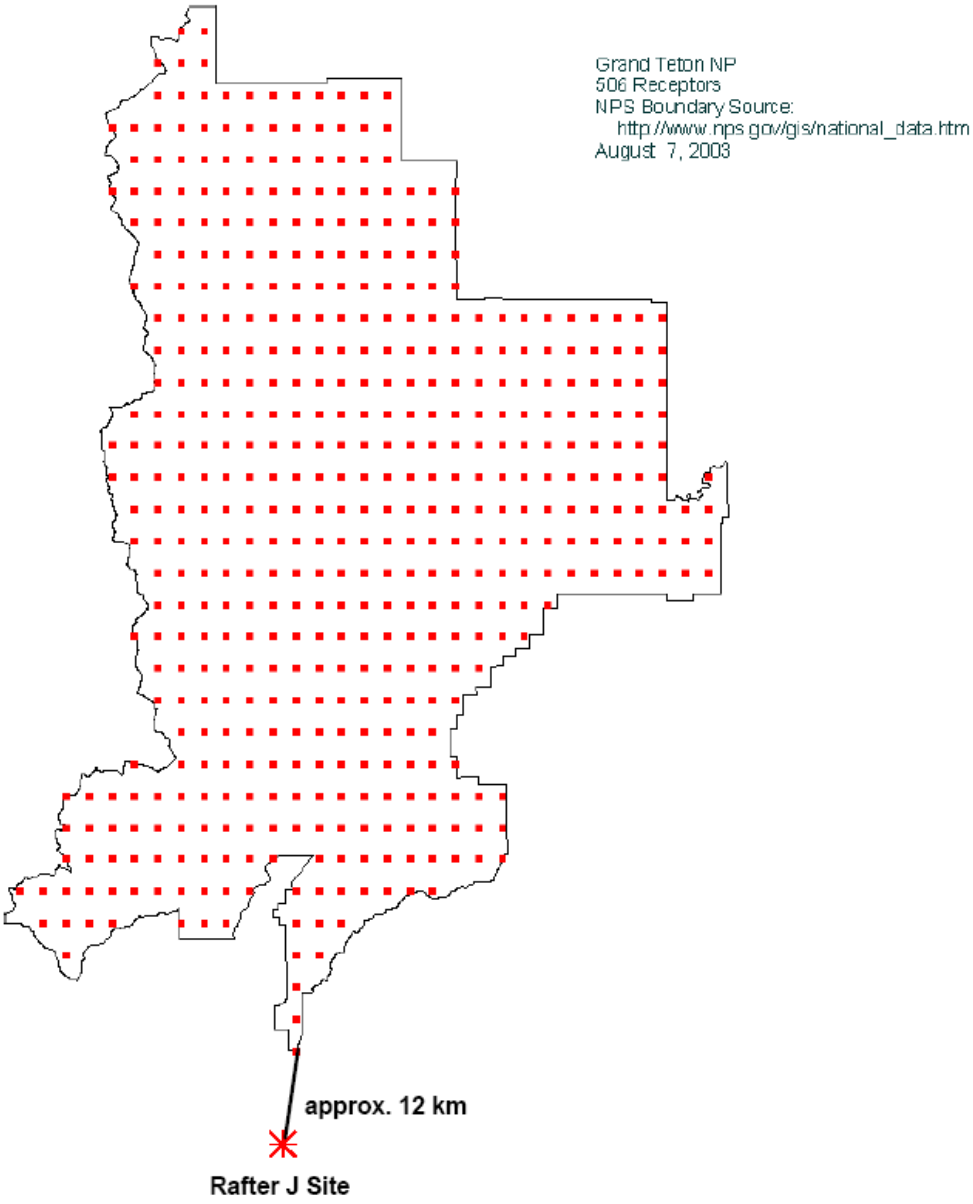
WDEQ Requirements

- The project is not expected to trigger the Prevention of Significant Deterioration for GHG emissions nor is it expected to trigger the requirements based on the distance to Grand Teton National Park.
- Based on the attainment status, the air quality permit will not require offsets.
- The Department of Environmental Quality considers SO_x, NO_x, and VOC as precursors to PM2.5.
- The project will be subject to a BACT analysis
- The project will require an air quality analysis which includes increment consumption and compliance with Wyoming Ambient Air Quality Standards and Toxics Standards.

Conclusion

- Project will not require offsets
- Project will require BACT and modeling, including increment

The following shows that the proposed site is more than 10 km from the Teton National Park based on the 2003 Boundary Source Data.


Grand Teton NP
506 Receptors
NPS Boundary Source:
http://www.nps.gov/gis/national_data.htm
August 7, 2003
approx. 12 km
Rafter J Site

WÄRTSILÄ 34SG

Engine technology 16 and 20V34SG

WÄRTSILÄ

Engine technology

Introduction 4

Design philosophy 5

The lean-burn concept 6

Low emissions 6

Gas admission system 7

Gas supply system 7

Prechamber 8

Ignition system 8

Air-fuel ratio 8

Cooling system 9

Lubricating oil system 9

Starting system 10

Piston 10

Piston ring set 10

Cylinder head 10

Connecting rod and big-end bearings 11

Engine block 11

Crankshaft and bearings 12

Cylinder liner and anti-polishing ring 12

Turbocharging system 12

Multiduct 13

Automation system 13

Easy maintenance 14

Main technical data 15

Ringköping, Denmark
Engine type: 1 x Wärtsilä 20V34SG
Total electrical output: 7.9 MW
Total heat output: 9.7 MW
Total efficiency: >95%.

In 1992, Wärtsilä started the development of lean-burn, spark-ignited Otto gas engines. The first 34SG engine was released in 1995 and now the product range of lean-burn gas engines has been expanded by introducing the new WÄRTSILÄ® 34SG. These engines take the power output of the 34SG series up to 9 MW.

The Wärtsilä 34SG is a four-stroke, spark-ignited gas engine that works according to the Otto process and the lean-burn principle. The engine has ported gas admission and a prechamber with a spark plug for ignition.

The engine runs at 720 or 750 rpm for 60 or 50 Hz applications and produces 6950 to 9000 kW of mechanical power, respectively. The efficiency of the Wärtsilä 34SG is the highest of any spark-ignited gas engines today. The natural gas fuelled, lean-burn, medium-speed engine is a reliable, high-efficiency and low-pollution power source for co-generation plants.

Design philosophy

The Wärtsilä 34SG was developed in response to the market need for bigger gas engines. Its design principles are based on the well-proven technology of the 18V version but with substantial improvements. The Wärtsilä 34SG lean-burn gas engine utilizes the frame of the new Wärtsilä 32 diesel/heavy fuel engine with its advanced integrated lube oil and cooling water channels. The bore has been increased to 340 mm to fully utilize the power potential of this engine block.

The Wärtsilä 34SG meets current and future requirements for overall cost of ownership. It is designed for flexible manufacturing methods and long maintenance-free operating periods. The engine is fully equipped with all essential ancillaries and a thoroughly planned interface to external systems.

The Wärtsilä 34SG combines high efficiency with low emissions. This is achieved applying state-of-the-art technology with features including:

- use of a lean gas mixture for clean combustion
- individual combustion control and monitoring, providing even load on all cylinders
- stable combustion, ensured by a high-energy ignition system and pre-combustion chamber
- self-learning and self-adjustable functions in the control system
- efficient heat recovery design
- minimal consumables.

The lean-burn concept

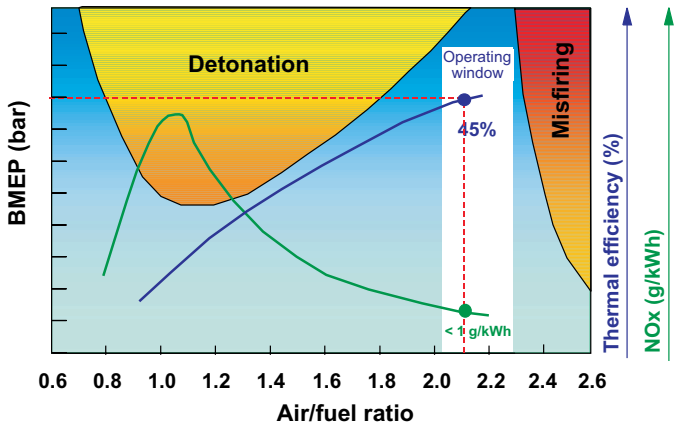
In a lean-burn gas engine, the mixture of air and gas in the cylinder is lean, i.e. more air is present in the cylinder than is needed for complete combustion. With leaner combustion, the peak temperature is reduced and less NO_X is produced. Higher output can be reached while avoiding knocking and the efficiency is increased as well, although a too lean mixture will cause misfiring.

Ignition of the lean air-fuel mixture is initiated with a spark plug located in the prechamber, giving a high-energy ignition source for the main fuel charge in the cylinder. To obtain the best efficiency and lowest emissions, every cylinder is individually controlled to ensure operation at the correct air-fuel ratio and with the correct timing of the ignition.

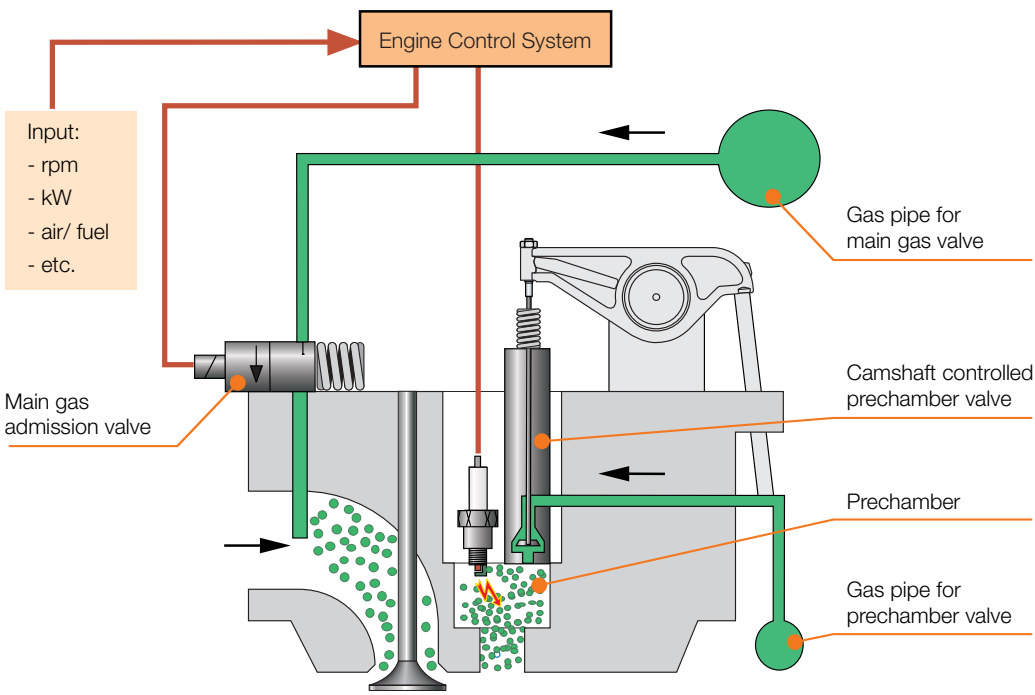
Stable and well-controlled combustion also contributes to less mechanical and thermal load on engine components. The specially developed Engine Control System is designed to control the combustion process in each cylinder, and to keep the engine within the operating window, by optimizing the efficiency and emissions level of each cylinder under all conditions.

Low emissions

The main parameters governing the rate of NO_X formation in internal combustion engines are peak temperature and residence time. The temperature is reduced by the combustion chamber air-fuel ratios: the higher the air-fuel ratio the lower the temperature and consequently the lower the NO_X emissions.



In the Wärtsilä 34SG engine, the air-fuel ratio is very high and is uniform throughout the cylinder, due to premixing of the fuel and air before introduction into the cylinders. Maximum temperatures and subsequent NO_X formation are therefore low, since the same specific heat quantity released by combustion is used to heat up a larger



mass of air. Benefiting from this unique feature of the lean-burn principle, the NO_X emissions from the Wärtsilä 34SG are extremely low, and comply with the most stringent existing NO_X legislation.

Gas admission system

The Wärtsilä 34SG engine fully controls the combustion process in each cylinder. The "brain" for controlling the combustion process and the whole engine is the Engine Control System.

The gas admission valves located immediately upstream of the inlet valve are electronically actuated and controlled to feed the correct amount of gas to each cylinder. Since the gas valve is timed independently of the inlet valve, the cylinder can be scavenged without risk of the gas escaping directly from the inlet to the exhaust. Various parameters like engine load, speed and cylinder exhaust temperatures are monitored and work as inputs to the Engine Control System. With this arrangement, each cylinder always works within the operating window for the best efficiency at the lowest emission levels.

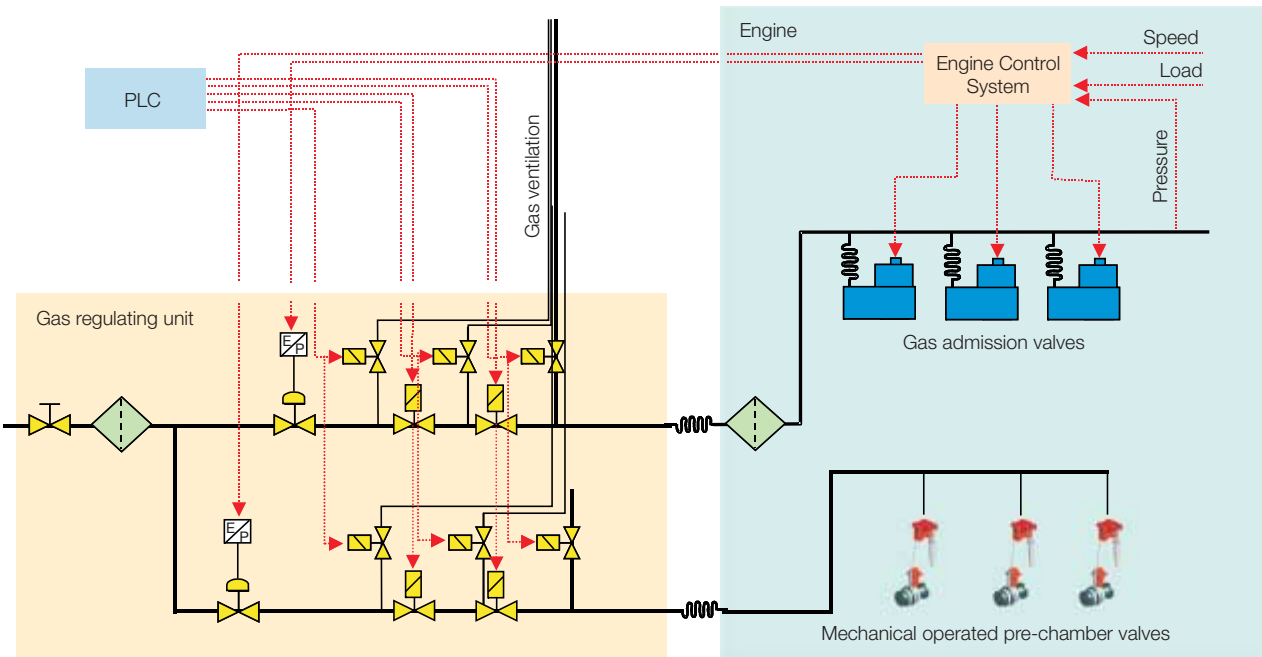
The ported gas admission concept gives:

- high efficiency
- good load response
- lower thermal loading of engine components
- no risk of backfire to the air inlet manifold.

Gas supply system

Before the natural gas is supplied to the engine it passes through a gas-regulating unit, including filter, pressure regulators, shut off valves and ventilating valves. The external pressure regulator regulates the gas pressure to the correct value under different loads; however, the maximum pressure needed is not more than 4.5 bar(a) under full load.

In the engine, the gas is supplied through common pipes running along the engine, continuing with individual feed pipes to each main gas admission valve located on each cylinder head. There are two common pipes per bank, one for the main and one for the prechamber gas supply. A filter is placed before every gas admission valve to prevent particles from entering the valve.

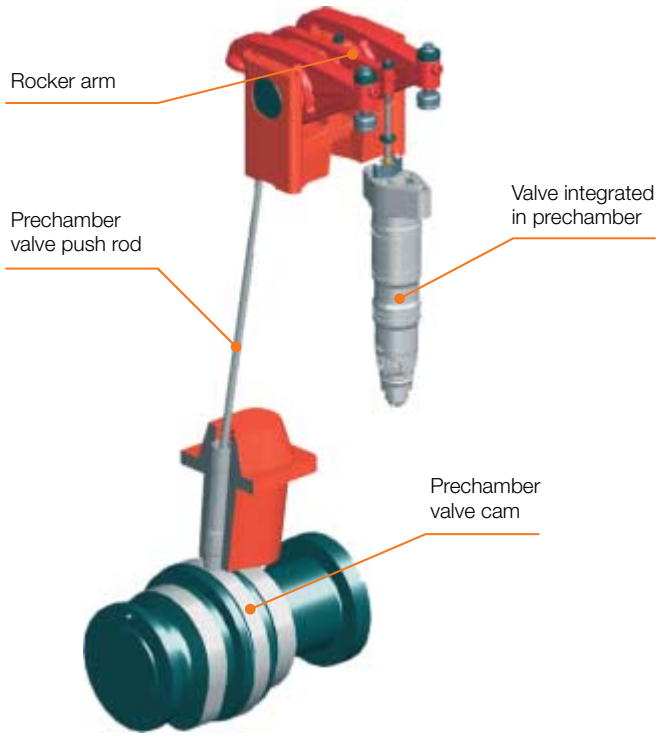


Prechamber

The prechamber is the ignition source for the main fuel charge and is one of the essential components of a lean-burn spark-ignited gas engine.

The prechamber should be as small as possible to give low NO_X values, but big enough to give rapid and reliable combustion. Some of the design parameters considered are:

- shape and size
- mixing of air and fuel
- gas velocities and turbulence at the spark plug
- cooling of the prechamber and the spark plug
- choice of material.



The prechamber of the Wärtsilä 34SG is already optimized at the design stage using advanced three-dimensional, computerized fluid dynamics. In practice, the results can be seen as:

- reliable and powerful ignition
- high combustion efficiency and stability
- extended spark plug life
- very low NO_X levels.

Gas is admitted to the prechamber through a mechanical, camshaft-driven valve. This solution has proved to be extremely reliable and gives an excellent mixture into the prechamber.

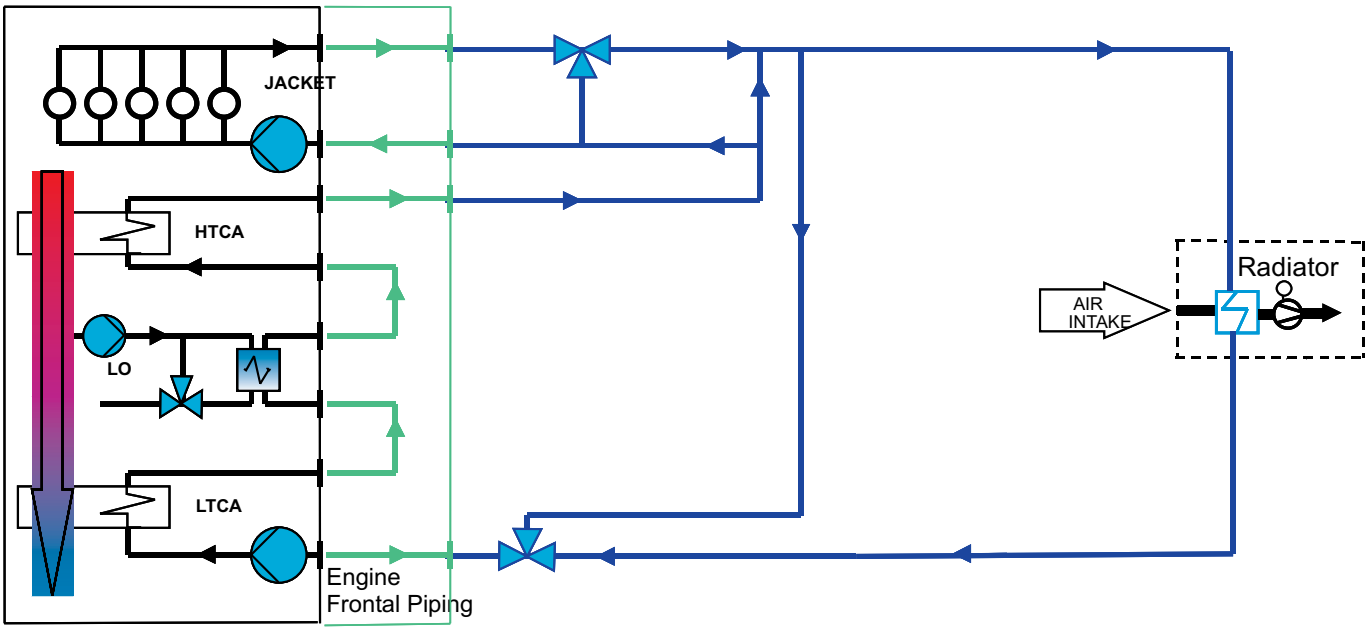
Ignition system

The Wärtsilä 34SG ignition system is tailor-made for the engine type and integrated in the Engine Control System. The ignition module communicates with the main control module, which determines the global ignition timing. The ignition module controls the cylinder-specific ignition timing based on the combustion quality. The cylinder-specific control ensures the optimum combustion in every cylinder with respect to reliability and efficiency.

The ignition coil is located in the cylinder cover and is integrated in the spark plug extension. The coil-on-plug design ensures a reliable solution with a minimum of joints between the spark plug and the ignition coil. The spark plug has been especially developed for long lifetime and to withstand the high cylinder pressure and temperature related to the high engine output.

Air-fuel ratio

To always ensure correct performance of the engine, it is essential to have the correct air-fuel ratio under all types of conditions. The Wärtsilä 34SG uses an exhaust gas wastegate valve to adjust the air-fuel ratio. Part of the exhaust gases bypasses the turbocharger through the waste-gate valve. This valve adjusts the air-fuel ratio to the correct value regardless of varying site conditions under any load.



Cooling system

The Wärtsilä 34SG engine is designed with a Wärtsilä open-interface cooling system for optimal cooling and heat recovery. The system has four cooling circuits: the cylinder cooling circuit (Jacket), the charge air low-temperature (LTCA) and high-temperature (HTCA) cooling circuits, and the circuit for the lube oil cooler (LO) built on the engine.

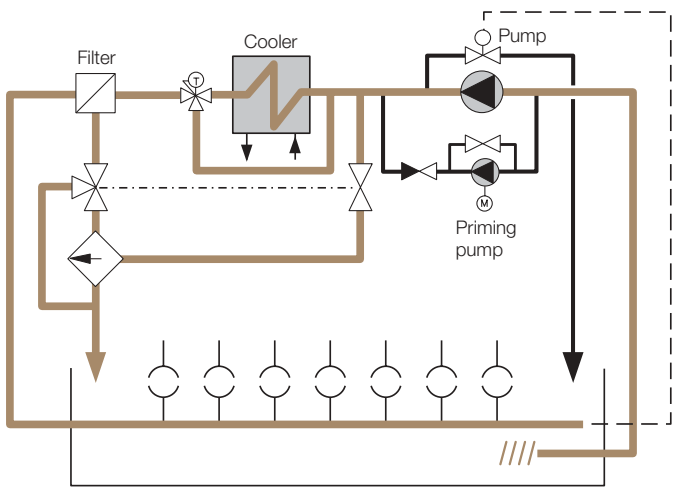
The LTCA cooling circuit and Jacket cooling circuit have water pumps integrated in the cover module at the free end of the engine. The LO circuit has its own thermostatic valve built on the engine. The water temperature into the LTCA cooler and the water temperature out from the Jacket cooling circuit are controlled by external thermostatic valves.

The default cooling system is a single-circuit radiator cooling system where the cooling circuits on the engine are connected in series. For heat recovery applications each cooler can be individually connected to an external cooling system. The open interface allows full freedom in cooling and heat recovery system design.

Lubricating oil system

The Wärtsilä 34SG is equipped with a wet oil sump, an engine-driven main pump, electrically driven pre-lubricating pump, cooler, full flow filter and centrifugal filter. The pumps, pressure regulation valves and safety valves are integrated into one module fitted at the free end of the engine. Filter, cooler and thermostatic valves make up another module.

The lube oil filtration is based on an automatic back-flushing filter requiring a minimum of maintenance. The filter elements are made of a seamless sleeve fabric with high temperature resistance. A centrifugal filter is mounted in the back-flushing line, acting as an indicator for excessive dirt in the lube oil. The engine uses a pre-lubricating system before starting to avoid wear of engine parts. For running in, provision has been made for mounting special running-in filters in front of each main bearing.



Starting system

The Wärtsilä 34SG engine is provided with pneumatic starting valves in the cylinder heads of one bank. The valves are operated by air from a distributor at the end of the camshaft. A starting limiter valve prevents the engine from starting if the turning gear is engaged.

Piston

Pistons are of the low-friction, composite type with forged steel top and aluminium skirt. The design itself is tailored for an engine of this size and includes a number of innovative approaches. Long lifetime is obtained through the use of Wärtsilä's patented skirt-lubrication system, a piston crown cooled by "cocktail-shaker" cooling, induction hardened piston ring grooves and the low-friction piston ring.

Cylinder head

Wärtsilä successfully employs four-screw cylinder head technology. At high cylinder pressure it has proved its superiority, especially when liner roundness and dynamic behaviour are considered. In addition to easier maintenance and reliability, it provides freedom to employ the most efficient air inlet and exhaust outlet channel port configuration.

A distributed water flow pattern is used for proper cooling of the exhaust valves, cylinder head flame plate and the prechamber. This minimizes thermal stress levels and guarantees a sufficiently low exhaust valve temperature. Both inlet and exhaust valves are fitted with rotators for even thermal and mechanical loading.

Piston ring set

The two compression rings and the oil control ring are located in the piston crown. This three-ring concept has proved its efficiency in all Wärtsilä engines. In a three-pack, every ring is dimensioned and profiled for the task it must perform. Most of the frictional loss in a reciprocating combustion engine originates from the piston rings. A three-ring pack is thus optimal with respect to both function and efficiency.

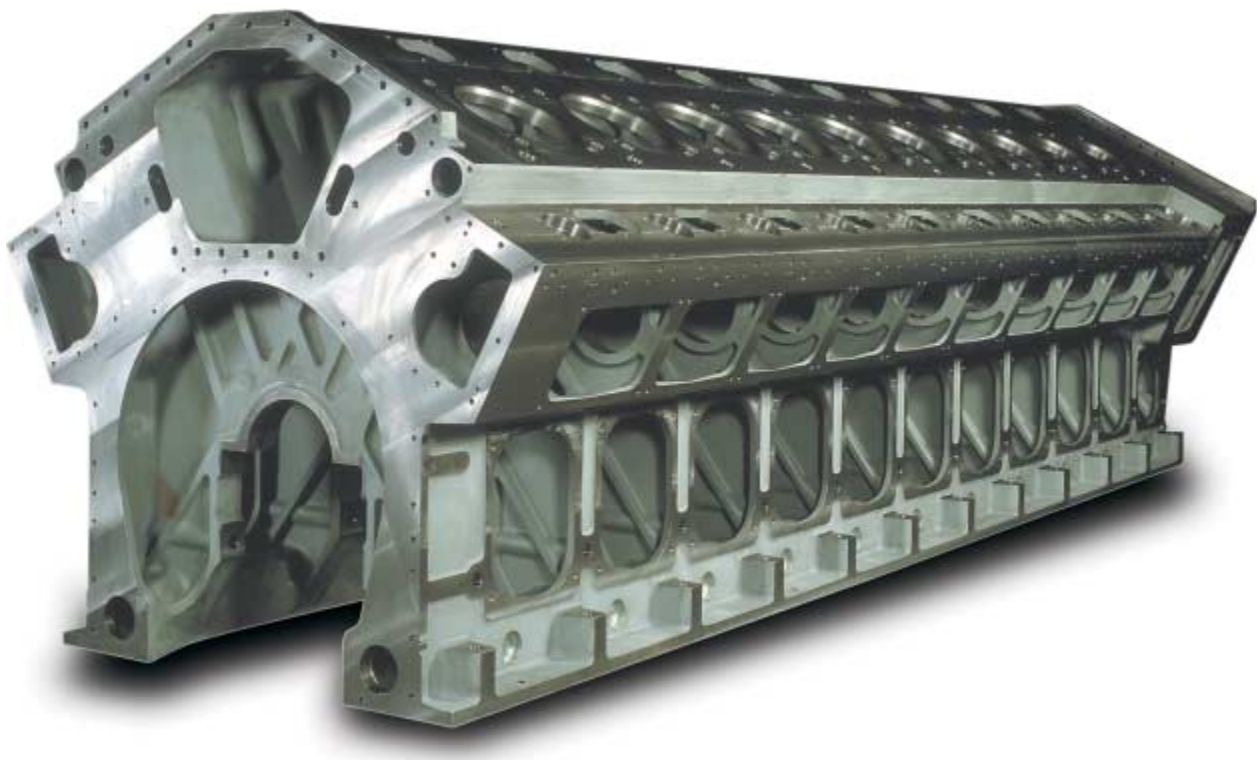
Connecting rod and big-end bearings

The connecting rod is designed for optimum bearing performance. It is a three-piece design, in which combustion forces are distributed over a maximum bearing area and relative movements between mating surfaces are minimized. Piston overhaul is possible without touching the big-end bearing and the big-end bearing can be inspected without removing the piston.

The three-piece design also reduces the height required for piston overhauling. The big-end bearing housing is hydraulically tightened, resulting in a distortion-free bore for the corrosion-resistant precision bearing. The three-piece connecting rod design allows variation of the compression ratio to suit gases with different knocking resistance.

Engine block

Nodular cast iron is the natural choice for engine blocks today due to its strength and stiffness properties. The Wärtsilä 34SG makes optimum use of modern foundry technology to integrate most oil and water channels. The result is a virtually pipe-free engine with a clean outer exterior. The engine has an underslung crankshaft, which imparts very high stiffness to the engine block, providing excellent conditions for main bearing performance. The engine block has large crankcase doors allowing easy maintenance.



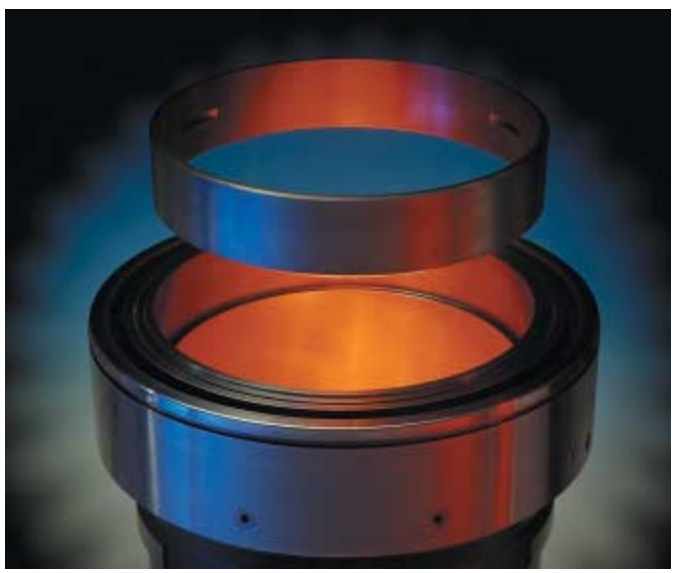
Crankshaft and bearings

The latest advance in combustion development requires a crank gear that can operate reliably at high cylinder pressures. The crankshaft must be robust and the specific bearing loads maintained at acceptable levels. Careful optimization of crankthrow dimensions and fillets achieve this.

The specific bearing loads are conservative, and the cylinder spacing, which is important for the overall length of the engine, is minimized. In addition to low bearing loads, the other crucial factor for safe bearing operation is oil film thickness. Ample oil film thickness in the main bearings is ensured by optimal balancing of rotational masses and, in the big-end bearing, by ungrooved bearing surfaces in the critical areas.

Cylinder liner and anti-polishing ring

The cylinder liner and piston designs are based on Wärtsilä's extensive expertise in tribology and wear resistance acquired over many years of pioneering work in heavy-duty diesel engine design. An integral feature is the anti-polishing ring, which reduces lube oil consumption and wear. The bore-cooled collar design of the liner ensures minimum deformation and efficient cooling. Each cylinder liner is equipped with two temperature sensors for continuous monitoring of piston and cylinder liner behaviour.



Turbocharging system

Every Wärtsilä 34SG is equipped with the Spex turbocharging system. The system is designed for minimum flow losses on both the exhaust and air sides. The interface between the engine and turbocharger is streamlined to avoid all the adaptation pieces and piping frequently used in the past. The Wärtsilä 34SG engine uses high-efficiency turbochargers with inboard plain bearings, and the engine lube oil is used for the turbocharger.

Multiduct

The multiduct replaces a number of individual components in traditional engine designs. These include:

- air transfer from the air receiver to the cylinder head
- exhaust transfer to the exhaust system
- cooling water outlet after the cylinder head
- cooling water return channel from the engine
- gas fuel mixing into the combustion air.

  Additional functions are:
- introduction of an initial swirl to the inlet air for optimal part-load combustion
- insulation / cooling of the exhaust transfer duct
- support for the exhaust system and its insulation.

Automation system

The Engine Control System is an engine-mounted distributed system. The various electronic modules are dedicated to different functions and communicate with each other via a CAN databus. All parameters handled by the Engine Control System are transferred to the operator interface and the plant control system. Its features are:

- easy maintenance and high reliability due to rugged engine-dedicated connectors, CIB´s (cabling interface boxes) and high quality cables
- less cabling on and around the engine
- easy interfacing with external system via a databus
- digitized signals giving immunity from electromagnetic disturbance
- built-in diagnosis for easy troubleshooting.

Main control module

The main control module, the core of the Engine Control System, reads the information sent by all the other modules. Using this information it determines reference values for the main gas admission to control the engine's speed and load.

The main control module also uses the information sent from the different distributed modules to control the global air-fuel ratio and global ignition timing in order to obtain the best performance and reliable operation in different site conditions, such as varying ambient temperature and methane number.

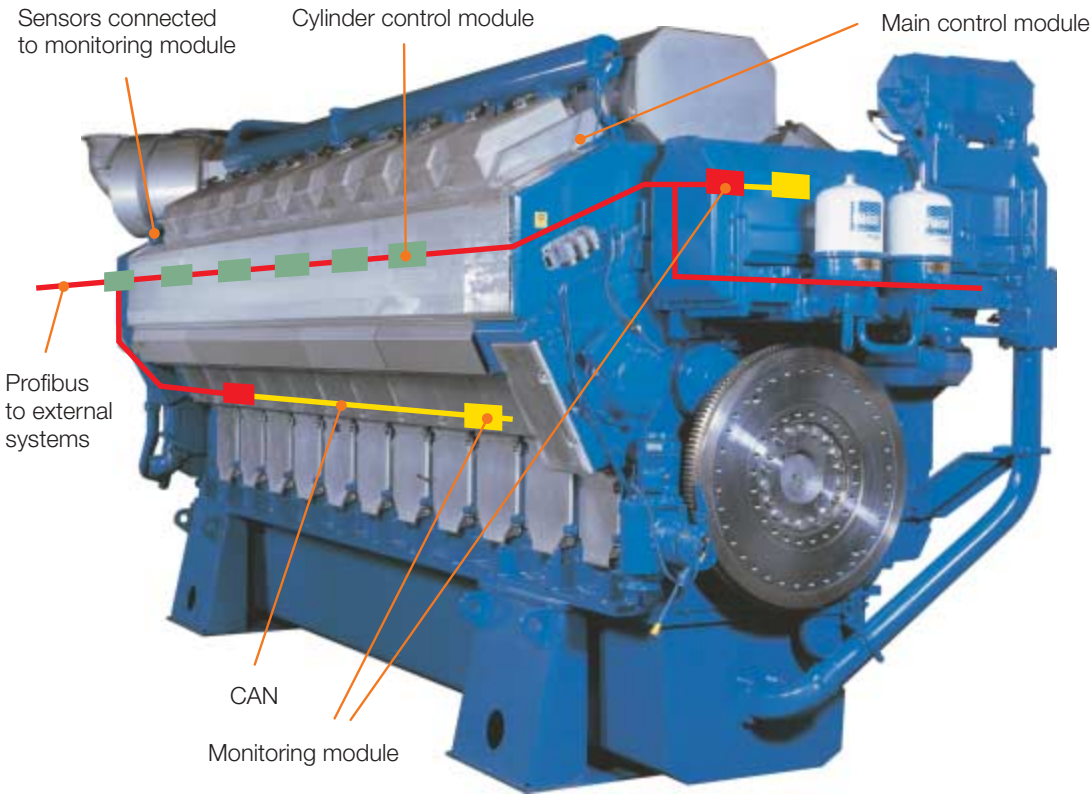
The main control module automatically controls the start and stop sequences of the engine and the engine safety. It also communicates with the plant control system (PLC).

The cylinder control module also monitors the exhaust gas and cylinder liner temperatures of all cylinders.

Cylinder control module

Each cylinder control module monitors and controls three cylinders. The cylinder control module controls the cylinder-specific air-fuel ratio by adjusting the gas admission individually for all cylinders. This ensures optimal combustion in all cylinders.

The cylinder control module also measures the knock intensity i.e. uncontrolled combustion in all cylinders. Information on knock intensity is used to adjust the cylinder-specific ignition timing by the cylinder control module. Light knocking leads to automatic adjustment of the ignition timing and air-fuel ratio. Heavy knocking leads to load reduction and ultimately to shut-down of the engine if heavy knocking does not disappear.



Monitoring modules

Several monitoring modules are located close to groups of sensors, which reduces cabling harness on the engine. The monitored signals are transmitted to the main control module and used for the engine control or safety system. The monitored values are also transferred to the operator interface and the plant control system. The cylinder control module also monitors the exhaust gas and cylinder liner temperatures of all cylinders.

Easy maintenance

The service life of Wärtsilä 34SG engine components and the time between overhauls are very long due to the purity of the gas. The design incorporates efficient and easy maintenance. In combination with the long intervals between overhauls, the hours spent on maintenance are reduced to a minimum. There is greater accessibility to all the components because the number of pipes is minimized and the components are ergonomically designed.

For ease of maintenance, the engine block has large openings to the crankcase and camshaft. All bolts requiring high tension are hydraulically tightened. Hydraulics is extensively used for many other operations as well. Since the main bearing caps are relatively heavy, each bearing cap is equipped with a permanently fitted hydraulic jack for easy manoeuvring of the cap. During delivery test runs, a running-in filter is installed to prevent the bearings from being scratched by any particles left in the oil system.

- The multiduct arrangement allows the cylinder head to be lifted without having to remove gas pipes or water pipes. The slide-in connections allow lifting of the cylinder head without the need to remove oil or air pipes.

- The water pumps are easy to replace thanks to the cassette design principle and water channel arrangement in the pump cover at the free end of the engine.
- A rigid and tight but easily removable insulating box surrounds the exhaust system.
- Easy access to the piping system is obtained by removing the insulating panels.
- The camshaft is built of identical cylinder segments bolted to intermediate bearing pieces.
- A wide range of special tools and measuring equipment specifically designed to facilitate service work are also available.
- Access to and maintenance of the spark plug and prechamber gas valve in the prechamber is easy. The prechamber does not need to be removed. For spark plug replacement, the valve cover does not need to be removed.
- Use of electrically controlled gas admission valves means few mechanical parts and less need for periodic adjustments.
- The three-piece connecting rod allows inspection of the big-end bearing without removal of the piston, and piston overhaul without dismantling the big-end bearing.

Main technical data

Cylinder bore	340 mm
Piston stroke	400 mm
Speed	720 / 750 rpm
Mean effective pressure	20.0 / 19.8 bar
Piston speed	9.6 / 10 m/s
Natural gas specification for nominal load	
Lower heating value	≥ 28 MJ/m^3_N

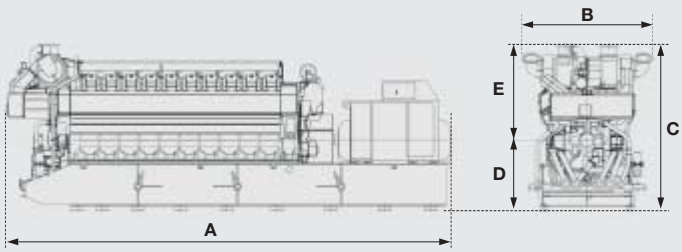
Technical data Compression ratio 12		Unit	16V34SG		20V34SG	
Speed/Hz	NO_X	mg/Nm^3 at 5 % O_2	500	250	500	250
	Methane number		>80	>70	>80	>70
720 rpm 60 Hz	Electrical power	kW	6751	6751	8439	8439
	Electrical efficiency	%	46.5	45.1	46.5	45.1
750 rpm 50 Hz	Electrical power	kW	6984	6984	8730	8730
	Electrical efficiency	%	46.5	45.1	46.5	45.1

Technical data Compression ratio 11		Unit	16V34SG		20V34SG	
Speed/Hz	NO_X	mg/Nm^3 at 5 % O_2	500	250	500	250
	Methane number		>65	>55	>65	>55
720 rpm 60 Hz	Electrical power	kW	6751	6751	8439	8439
	Electrical efficiency	%	45.5	44.1	45.5	44.1
750 rpm 50 Hz	Electrical power	kW	6984	6984	8730	8730
	Electrical efficiency	%	45.5	44.1	45.5	44.1

Electrical power at generator terminals, including engine-driven pumps, ISO 3046 conditions and LHV. Tolerance + 5%. Power factor 0.8.

Principal genset dimensions (mm) and weights (tonnes)

Engine type	A	B	C	D	E	Engine weight	Genset weight
16V34SG	11692	3233	4348	1998	2648	66.5	115
20V34SG	12466	3233	4348	1998	2648	76.4	137.5



For more specific information, please contact Wärtsilä.

06.2005 / Bock's office / Waasa Graphics

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Wärtsilä is The Ship Power Supplier for builders, owners and operators of vessels and offshore installations. Our own global service network takes complete care of customers' ship machinery at every lifecycle stage.

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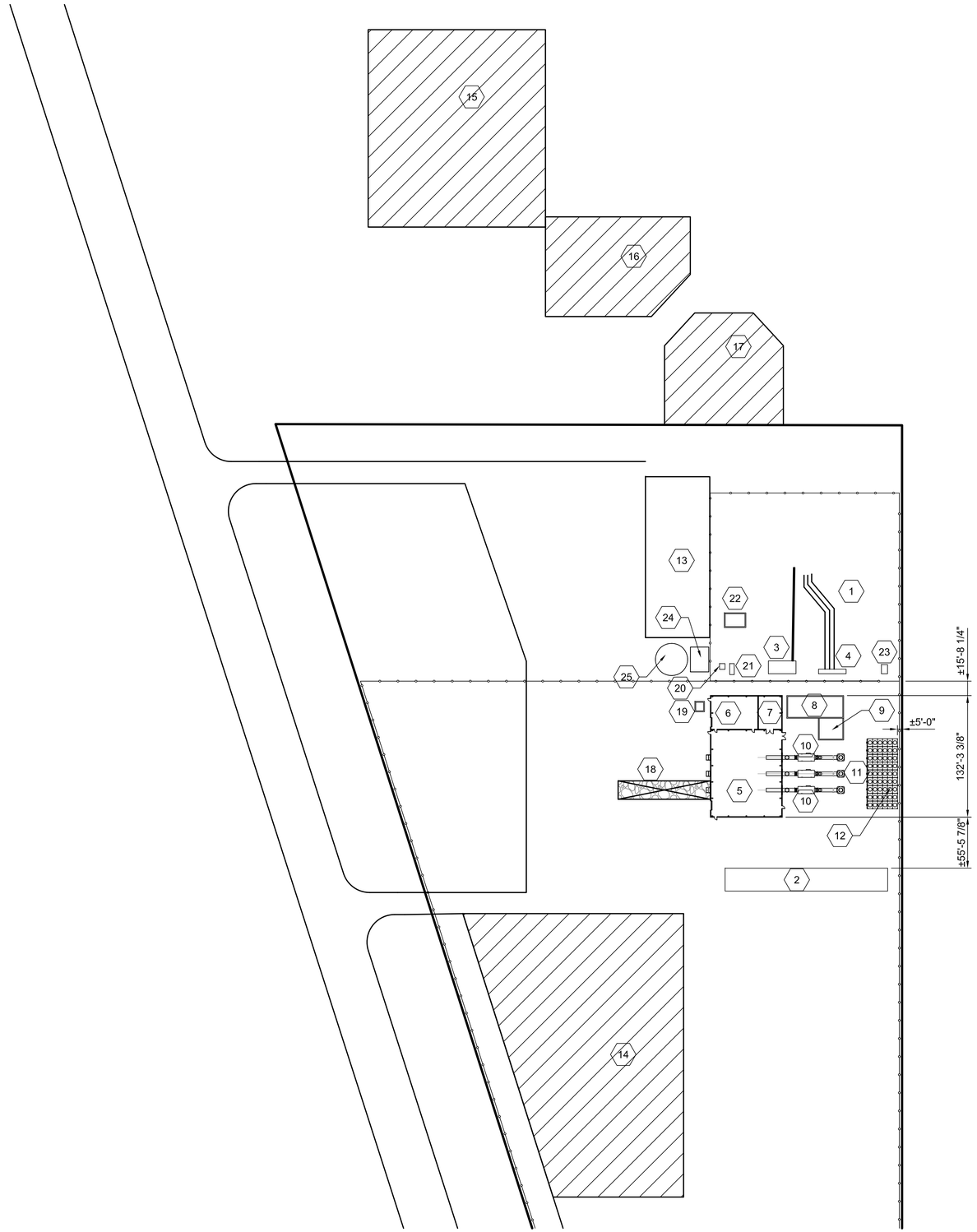

GENERAL ARRANGEMENT PLAN

0 32' 64' 128'

SCALE IN FEET

no.	date	by	ckd	description
A	08/22/11	WRL	CMS	PRELIMINARY
B	09/07/11	WRL	CMS	ADDED LAYDOWN AREAS
C	09/19/11	CJM	WRL	UPDATED BACKGROUND

SITE KEY

1	EXISTING SWITCHYARD
2	EXISTING BUILDING C
3	EXISTING SWITCHYARD BUILDING
4	EXISTING DISTRIBUTION ENCLOSURE
5	ENGINE HALL
6	SWITCHGEAR ROOM
7	MECHANICAL ROOM
8	LUBE OIL CONTAINMENT
9	UREA TANK CONTAINMENT
10	SCR
11	STACK
12	RADIATORS
13	CONSTRUCTION (TRAILERS) (12250 SF)
14	LAYDOWN AREA 1 (58870 SF)
15	LAYDOWN AREA 2 (41384 SF)
16	LAYDOWN AREA 3 (16108 SF)
17	LAYDOWN AREA 4 (14607 SF)
18	ENGINE DELIVERY ACCESS
19	AUX TRANSFORMER
20	STAND-BY TRANSFORMER
21	BLACK START (OPTIONAL)
22	GSU TRANSFORMER
23	RELOCATED FIBER OPTIC ENCLOSURE
24	FIRE PUMPHOUSE
25	FIRE WATER TANK

Burns & McDonnell
SINCE 1898
9400 WARD PARKWAY
KANSAS CITY, MO 64114

date AUGUST 22, 2011	detailed W. LESNIAK
designed	checked C. MARKS

LOWER VALLEY ENERGY

LVE GENERATING STATION

COMPOSITE BUILDING PLAN
OF 3-ENGINE LAYOUT

project 56513	contract C4310
drawing **GA100**	rev. **C**
sheet - of - sheets	
file 3-ENGINE_GA100.DWG	

Scale For Microfilming
Millimeters
Inches

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J:\ENR PRACTICE\RAMCO\JACKSON HOLE\CADD\ARCH\3-ENGINE_GA100.DWG CMARKS September 19, 2011