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September 27, 2013

VIA HAND DELIVERY
Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83702

Re: Case No. IPC-E-13-16
Certificate for Public Convenience and Necessity for Jim Bridger Units 3 and 4 – Idaho Power Company's **Redacted** Exhibit 5A

Dear Ms. Jewell:

Enclosed for filing in the above matter are an original and nine (9) copies of Idaho Power Company's **Redacted** Exhibit 5A which was originally filed as Confidential Exhibit 5 to Tom Harvey's Direct Testimony on June 28, 2013.

To facilitate the filing of testimony and cross-examination at hearing, the Snake River Alliance requested that Idaho Power redact the confidential information from Exhibit 5. Idaho Power consulted the operating partners of the Bridger and North Valmy power plants regarding the sensitivity of the inputs they provided for the study in Exhibit 5. To clarify which portions of the study are confidential, Idaho Power redacted the forward-looking financial information included the utilities' business plans and proprietary operating data from the study.

Sincerely,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:evp
Enclosures

1221 W. Idaho St. (83702)
P.O. Box 70
Boise, ID 83707

BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

CASE NO. IPC-E-13-16

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HARVEY, DI TESTIMONY

EXHIBIT NO. 5A

Final Report

Coal Environmental Compliance Upgrade Investment Evaluation

Idaho Power Company

February 8, 2013

SAIC.

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Section 1
BACKGROUND

1.1 Introduction

Like many utilities around the country, Idaho Power Company ("IPC") is facing significant decisions regarding its generation portfolio. Recent and pending Environmental Protection Agency ("EPA") regulations could require substantial capital investment at the Jim Bridger Plant ("Jim Bridger") and North Valmy Generation Station ("North Valmy") coal-fired power plants to remain in environmental compliance. IPC decided to conduct a planning level study of the relative costs and benefits of either making significant environmental investments in additional emissions control equipment, or retiring affected units at the plants and replacing them with alternate generation capacity. IPC engaged SAIC Energy, Environment & Infrastructure, LLC ("SAIC") to conduct this study and identify which options were likely to be the most cost effective and warrant further study.

SAIC has a designated group of economists, engineers, analysts, and other professionals who provide a range of energy resource planning and advisory services. We have a long history of providing independent engineering services to project developers and financiers for hundreds of power plants in the U.S. and around the world; our independent engineering teams are widely acknowledged in the power supply industry as being industry leaders in providing unbiased and technically superior services. SAIC's utilities consulting group has combined financial and planning insights with robust analytical skills to assist hundreds of utilities with planning efforts, spanning from individual project decisions to comprehensive Integrated Resource Plans. SAIC applied our expertise and experience to review and comment on IPC's investment decisions relating to either upgrading its coal units, converting them to burn natural gas, pursuing a retirement and replacement strategy, or some combination of these options.

1.2 Objectives

In its 2011 Integrated Resource Plan ("IRP"), IPC identified a number of pending EPA regulations which may affect the Jim Bridger and North Valmy plants. However, at the time of the development of the IRP, many of those environmental regulations had not yet been issued by the EPA. While several of the applicable environmental regulations have faced legal challenges, IPC desired a study which examines the costs of environmental upgrades required for compliance under the regulations as currently proposed. Specifically, IPC had the following objectives for the study:

- Review IPC's assumptions regarding the capital cost assumptions of the proposed environmental compliance upgrades, including Selective Catalytic Reduction ("SCR"), Dry Sorbent Injection ("DSI"), Wet Flue Gas

Desulfurization ("WFGD"), and other systems, as well as the costs of replacement capacity.

- Review IPC's assumptions regarding the variable cost assumptions of the proposed environmental compliance upgrades and replacement capacity.
- Develop estimates of the costs for each unit going forward, including total costs reflecting environmental compliance upgrade investments as well as total replacement capacity costs.
- Provide conclusions as to the economic feasibility of the environmental compliance upgrades and retirement options.

This Coal Environmental Compliance Upgrade Investment Evaluation Report (the "Report") provides the results of the SAIC study.

1.3 Approach

At this stage of the decision process, SAIC felt that due to the uncertainties involved in the future environmental regulations, capital expenditures, and fuel forecasts, a planning level study was the most appropriate approach. This study examined the likely ranges of costs involved with the relevant options identified for each unit, based on a simplified analysis of the costs of generation for each of those options.

The study identified a total of 21 options involving the six Jim Bridger and North Valmy units, ranging from minimum to enhanced environmental compliance upgrades, fuel switching to natural gas, and retirement of the units. SAIC analyzed the scenarios under a variety of potential fuel and carbon costs, to examine the sensitivity of each option to changes in future assumptions. The following four tasks describe the study approach:

> **Task 1: Scenario and Sensitivity Identification**. SAIC met with IPC staff to discuss the objectives of the study and to identify the appropriate options to analyze for each unit. A number of scenarios were initially identified for each unit, including minimum compliance environmental upgrades for all units, and enhanced compliance upgrades for the North Valmy units. After considering several different types of replacement capacity for both the Jim Bridger and North Valmy units, SAIC and IPC mutually agreed to limit the replacement capacity units to natural gas fired combined cycle units. Further, to increase the analysis to include a wider range of possible outcomes, SAIC and IPC decided to evaluate the potential conversion of all four Jim Bridger Units from coal fired boilers to natural gas fired boilers. Eventually the potential natural gas conversion scenarios were expanded to include the North Valmy 1 & 2 units.
>
> The potential environmental compliance upgrade, fuel switching, and retirement scenarios addressed many of the uncertainties in future environmental regulations. SAIC and IPC also decided to include sensitivities designed to address the uncertainties involved in forecasting natural gas prices as well as possible carbon regulation compliance costs. Ultimately, SAIC

subjected each of the scenarios described above to nine different combinations of low case, planning case, and high case projections for both natural gas prices and carbon compliance costs.

Task 2: Environmental Costs and Performance Review. SAIC examined the emissions profile of each unit, and addressed the adequacy of proposed environmental upgrades to address environmental compliance. Additionally, SAIC reviewed the proposed capital and variable costs for each upgrade to determine whether the identified costs were within the reasonably expected range for such costs.

Task 3: Options Analysis. IPC's primary goal for this study was to obtain specific direction regarding upgrading each of the units at North Valmy and Jim Bridger. SAIC used extensive forecast and operational data provided by IPC for each of the units to compile a comprehensive analysis of each option's total costs for the duration of the appropriate time horizon. These costs were then compared to other options for each unit on a net present value basis.

Task 4: Summary. The results and conclusions of the analysis were compiled in a draft report and reviewed internally by IPC and SAIC for quality assurance. Results were then compiled and provided in this Report. Results also have been communicated in various conversations between SAIC team members and IPC.

The Report contains five Sections:

Section 1 contains an introduction and background.

Section 2 provides the results of the Environmental Cost and Performance Review.

Section 3 addresses the Options Analysis, and describes the methodology and primary assumptions used in the Analysis.

Section 4 provides the results of the Options Analysis.

Section 5 provides the conclusions of the study.

A detailed summary of the assumptions used in the analysis is included in Appendix A.

This Report summarizes the results of our investigations and analyses up to the date of this Report. Changed conditions occurring or becoming known after such date could affect the material presented herein to the extent of such changes. Nothing contained in this Report is intended to indicate conditions with respect to safety or to security regarding the proposed upgrades or to conformance with agreements, codes, permits, rules, or regulations of any party having jurisdiction with respect to the construction, operation, and maintenance of the Jim Bridger and North Valmy plants, which matters are outside the scope and purposes of this Report.

Section 2
ENVIRONMENTAL COST AND PERFORMANCE REVIEW

2.1 Introduction

Coal-fired as well as other electric power generating units must comply with various environmental laws and regulations depending on their size, location, and fuel characteristics. In the case of the Jim Bridger and North Valmy units, these regulations include the Mercury and Air Toxics Rule ("MATS") published by the United States Environmental Protection Agency ("USEPA") February 16, 2012, and the state of Wyoming's regulations addressing USEPA's regional haze rules.

Other proposed or potential environmental regulations that could impact IPC's coal-fired generating plants include the Clean Water Act Section 316(b) regulations, Coal Combustion Residuals ("CCR") environmental regulations, and carbon legislation/regulation. Such proposed or potential regulations could require additional capital expenditures and an increase in the Fixed and Variable Operation and Maintenance ("O&M") costs of affected generating units.. Compliance with these environmental regulatory changes could also impact the efficiency or heat rate of affected units.

SAIC reviewed the projected capital and O&M costs for the retrofit of environmental controls to comply with the MATS and regional haze rules for Jim Bridger and the projected capital and O&M costs for the retrofit of environmental controls to comply with MATS for the North Valmy Unit 1 ("NV1"). Additionally, as a possible enhanced environmental compliance case, we reviewed the projected capital and O&M costs associated with possible SCR and WFGD systems for both North Valmy units.

2.2 Jim Bridger

Based on information provided by IPC, the Jim Bridger units are currently equipped with sulfur dioxide ("SO_2") scrubbers for the control of SO_2 and electrostatic precipitators ("ESPs") for the control of particulates. It is our understanding that the SO_2 emission rate during 2010 and 2011 was below 0.2 pounds per million Btu ("lb/MMBtu"), which is the limit set MATS forth in the rule for compliance with acid gases (0.18 lb/MMBtu for 2010 and 0.15 lb/MMBtu for 2011). SO_2 can be used as a surrogate for meeting acid gas emissions limits.

It is also our understanding that Jim Bridger will require additional controls to comply with mercury limits as well as SCR systems to reduce the emissions of nitrogen oxide ("NO_x"). PacifiCorp, in conjunction with the Wyoming Department of Environmental Quality, agreed to install SCRs on Units 3 and 4 and potentially Units 1 and 2 in order to allow a path for timely submittal of the state's Regional Haze Implementation Plan (RH FIP) in January 2011. For the purposes of this Report, the installation of the

SCRs for Units 3 and 4 are planned for 2015 and 2016, respectively. The EPA announced that it would re-propose the plant-specific NOx control provisions of its RH FIP in March 2013 and would not finalize the RH FIP until September 2013. At the present time, an SCR retrofit for Unit 2 is planned for 2021 and for Unit 1 in 2022.

IPC provided the following estimated retrofit costs for the Jim Bridger SCR retrofits; it is SAIC's understanding that these estimates were originally provided to IPC by PacifiCorp, the majority owner of Jim Bridger. Note that these figures represent the total costs for the Jim Bridger upgrades in nominal dollars; the IPC share of these costs is 33 percent. The total costs including Allowance Funds During Construction ("AFUDC") are discussed below for the purposes of evaluating their reasonableness, while the IPC share of the costs were used in the analysis as described in Section 3 of the Report.

- Unit 1 (2022) - [redacted]
- Unit 2 (2021) - [redacted]
- Unit 3 (2015) - [redacted]
- Unit 4 (2016) - [redacted]

The above costs are in the range of approximately [redacted]. The estimates appear to be adequate for the installation of the SCRs and in fact are in the upper end of the range of retrofit costs for similar units with which we are familiar; without performing detailed, line item engineering reviews of the IPC estimates, SAIC cannot refine that opinion further. Based on SAIC's experience in providing independent and owner's engineering services for a wide variety of similar retrofit installations, SAIC estimates variable O&M costs in the range of [redacted]/megawatt-hour ("MWh") for the operation of the SCRs (inclusive of the catalyst replacement costs every two to three years). The IPC cost estimates for variable O&M associated with the SCRs fall within the range of [redacted]/MWh. Based on the information provided by IPC, in SAIC's opinion the SCR installations for Jim Bridger should be sufficient to control the plant's NOx emissions to a level consistent with Wyoming's regional haze implementation plan.

A control system (scrubber additives with calcium bromide and possibly powder activated carbon) is proposed for the compliance of mercury emissions with MATS regulations. The system is proposed for all four units, to be installed in 2014. An estimate of [redacted] (2015 dollars) retrofit capital cost was presented by PacifiCorp for all four units. This estimate appears adequate for the installation of the systems and is in the upper range of retrofit costs for similar units with which SAIC is familiar. O&M costs for the system are estimated by SAIC at [redacted] The mercury control system contemplated for the Jim Bridger plant should be sufficient to control the plant's mercury emissions to a level consistent with the MATS rule.

In addition to the SCR and mercury control costs, certain other environmental retrofit costs have been identified for the plant site, including costs for landfill closures, catalyst replacements, and new pond construction for solid waste disposal. SAIC did not perform any plant site visits as part of this study, and as such, SAIC does not have enough information to address the adequacy of these costs (approximately [redacted] from 2013 to 2019), or their ability to ensure compliance with their applicable regulation.

2.3 North Valmy

Based on information obtained from IPC, a DSI system is contemplated for NV1 to be installed by 2015 for compliance with MATS. North Valmy Unit 2 ("NV2") is already equipped with a SO_2 scrubber system. No additional controls are contemplated for acid gases, mercury or particulates for either unit. Both units are equipped with baghouses for particulates control. Using hydrated lime as a reagent for use in a DSI system should ensure compliance with the MATS rule on NV1 for controlling hydrochloric acid (HCl) as a surrogate for acid gases.

SAIC estimates approximately $13 million in capital costs (total Unit 1 costs) for the installation of the DSI using hydrated lime as a reagent. This compares favorably with the approximately [redacted] in capital costs estimate provided by IPC. SAIC believes the IPC projections appear to be adequate assuming continued operation at a level similar to recent history; without performing detailed, line item engineering reviews of the IPC estimates, SAIC cannot refine that opinion further.

IPC also provided cost estimates for the possible installation of SCR and WFGD systems on both North Valmy units, for use in examining a possible "Enhanced Compliance" scenario for the North Valmy plant. The figures below represent the total capital costs for the North Valmy upgrades in nominal dollars; the IPC share of these costs would be 50 percent, based on IPC's ownership share.

- Unit 1 SCR (2018) – [redacted]
- Unit 1 WFGD (2018) – [redacted]
- Unit 2 SCR (2018) – [redacted]
- Unit 2 WFGD (2018) – [redacted]

These estimates appear adequate for the installation of the systems and are in the upper range of retrofit costs for similar units with which we are familiar. Because mercury emissions at North Valmy are already below required levels for MATS compliance, no additional controls are required.

Section 3
STUDY DEFINITION AND METHODOLOGY

3.1 Introduction

SAIC applied a structured, consistent approach to analyzing the projected costs for each unit under the various configurations described in Section 2 of this report. The analysis was conducted to provide planning level comparisons of various options IPC is facing for each of the six coal fired units in this analysis. This approach provides IPC with the relative costs of each scenario for each unit, which will guide IPC's management and system planners in their decisions regarding the investment decisions they must make, particularly identifying which investments warrant a further, more detailed analysis.

3.2 Scenarios and Sensitivities

SAIC worked with IPC staff to identify key scenarios and sensitivities to be analyzed. Scenarios involve a particular unit's given situation, and generally include one or more environmental compliance upgrades, as well as a retire and replace option. The retire and replace scenarios examine the relative costs of retiring the given unit and developing a similarly sized, natural gas fired combined cycle combustion turbine ("CCCT") unit in its place. Sensitivity cases involve examining the effects of a change in natural gas pricing, or a change in the assumption regarding possible carbon regulations.

3.2.1 Scenarios

Following is a comprehensive summary of the range of scenarios analyzed:

North Valmy Unit 1 Upgrade (Install DSI)

NV1 requires the installation of DSI for compliance with the acid gases section of the MATS rule. This requires an initial capital expenditure of [redacted] (2015 dollars) IPC share in 2015.

North Valmy Unit 1 Enhanced Upgrade (Installation of DSI, SCR & WFGD)

Although Valmy is not required by any current or proposed environmental regulations to install a SCR and WFGD system, SAIC evaluated the costs and benefits associated with installing these systems on both Valmy units. In addition to the above installation of DSI, the analysis assumed an SCR installed by January 1, 2018 with a projected cost of [redacted] (2018 dollars). The WFGD system was assumed to be installed by January 1, 2018 with a projected capital cost of [redacted] (2018 dollars).

North Valmy Unit 1 2015 Natural Gas Conversion (SCR & WFGD not installed)

SAIC examined the costs and benefits of switching the unit to burn natural gas instead of coal, reducing the amount of investment required for environmental compliance. The fuel conversion was assumed to occur in the same time that the SCR installation would have for NV1, January 1, 2015, and assumed a six-month outage in 2014 to allow for the conversion to burning natural gas. After the conversion, the analysis assumed a natural gas heat rate of 10,904 British thermal units per kilowatt- hour ("Btu/kWh"). The fuel conversion assumed a projected capital cost of [redacted] (2015 dollars) for NV1, and a projected capital cost of [redacted] (2015 dollars) for the associated natural gas pipeline.

North Valmy Unit 1 2018 Natural Gas Conversion (SCR & WFGD not installed)

SAIC examined the costs and benefits of switching the unit to burn natural gas instead of coal, reducing the amount of investment required for environmental compliance. The fuel conversion was assumed to occur in the same time that the SCR installation would have for NV1, January 1, 2018, and assumed a six-month outage in 2017 to allow for the conversion to burning natural gas. After the conversion, the analysis assumed a natural gas heat rate of 10,904 British thermal units per kilowatt- hour ("Btu/kWh"). The fuel conversion assumed a projected capital cost of [redacted] (2018 dollars) for NV1, and a projected capital cost of [redacted] (2018 dollars) for the associated natural gas pipeline.

North Valmy Unit 1 2015 Retire/Replace with CCCT (SCR & WFGD not installed)

The NV1 retirement scenario assumes that the NV1 unit is retired December 31, 2014 and replaced with a similarly sized CCCT beginning operation on January 1, 2015. For the purposes of this analysis, for the NV1 retirement and all other unit retirement analyses, the assumption is that the new CCCT would be sited in a region with access to the Sumas hub natural gas pricing, with additional gas transportation charges and capacity to a generic Idaho City gate. Additionally, the assumption is that the unit would be sized to exactly replace the megawatts ("MW") for the given unit, assumed to be 122 MW in the case of NV1. The data provided for a new CCCT unit assume a size of 300 MW, at a projected capital cost of $1,336/kW (2012 dollars). For this analysis, SAIC assumed that IPC would either construct the full size unit and sell the extra capacity, or possibly purchase the 122 MW of NV1 capacity at the given pricing, which produces a projected capital cost of $178.2 million in 2015 assuming an annual escalation rate of 3 percent. For modeling purposes, the full capital cost was prorated for the fifteen years remaining in the study period, resulting in a cost of $106.9 million (2015 dollars) applied to this scenario in 2015. The new CCCT assumptions include annual capital and O&M costs. Complete details on the assumptions for a new CCCT are provided in the list of assumptions in Appendix A.

North Valmy Unit 1 2018 Retire/Replace with CCCT (SCR & WFGD not installed)

The NV1 retirement scenario assumes that the NV1 unit is retired December 31, 2017 and replaced with a similarly sized CCCT beginning operation on January 1, 2018. For the purposes of this analysis, for the NV1 retirement and all other unit retirement analyses, the assumption is that the new CCCT would be sited in a region with access to the Sumas hub natural gas pricing, with additional gas transportation charges and capacity to a generic Idaho City gate. Additionally, the assumption is that the unit would be sized to exactly replace the megawatts ("MW") for the given unit, assumed to be 122 MW in the case of NV1. The data provided for a new CCCT unit assume a size of 300 MW, at a projected capital cost of $1,336/kW (2012 dollars). For this analysis, SAIC assumed that IPC would either construct the full size unit and sell the extra capacity, or possibly purchase the 122 MW of NV1 capacity at the given pricing, which produces a projected capital cost of $194.72 million in 2018 assuming an annual escalation rate of 3 percent. For modeling purposes, the full capital cost was prorated for the fifteen years remaining in the study period, resulting in a cost of $97.4 million (2018 dollars) applied to this scenario in 2018. The new CCCT assumptions include annual capital and O&M costs. Complete details on the assumptions for a new CCCT are provided in the list of assumptions in Appendix A.

North Valmy Unit 2 Enhanced Upgrade (Installation of SCR & WFGD)

NV2 is not expected to require any additional modifications to be compliant with current environmental regulations. Although Valmy is not required by the current regulations to install a SCR and WFGD system, SAIC and IPC decided to analyze the costs and benefits associated with installing these systems on both Valmy units. The analysis assumed an SCR installed by January 1, 2018 with a projected cost of [redacted] (2018 dollars). The WFGD system was assumed to be installed by January 1, 2018 with a projected capital cost of [redacted] (2018 dollars).

North Valmy Unit 2 Natural Gas Conversion (SCR & WFGD not installed)

SAIC examined the costs and benefits of switching the unit to burn natural gas instead of coal, reducing the amount of investment required for environmental compliance. The fuel conversion was assumed to occur in the same time that the SCR installation would have for NV2, January 1, 2018, and assumed a six-month outage in 2017 to allow for the conversion to burning natural gas. After the conversion, the analysis assumed a natural gas heat rate of [redacted]. The fuel conversion assumed a projected capital cost of [redacted] (2018 dollars) for NV2, and a projected capital cost of [redacted] (2018 dollars) for the associated natural gas pipeline.

North Valmy Unit 2 Retire/Replace with CCCT (SCR & WFGD not installed)

The NV2 retirement scenario assumes that the NV2 unit is retired December 31, 2017 and replaced with a similarly sized CCCT beginning operation on January 1, 2018. The NV2 137 MW replacement capacity was assumed to have a projected capital cost of $218.7 million (2018 dollars), including AFUDC. For modeling purposes, the full capital cost was prorated for the fifteen years remaining in the study period, resulting in a cost of $109.3 million (2018 dollars) applied to this scenario in 2018.

Jim Bridger Unit 1 Upgrade (Install SCR)

To achieve environmental compliance, Jim Bridger Unit 1 ("JB1") requires a variety of pollution control systems. The systems include:

- a mercury control system in 2014, with a projected capital cost of [redacted] (2015 dollars) including AFUDC;
- an SCR system in 2022, with a total projected capital cost of [redacted] (2022 dollars) including AFUDC. For modeling purposes, the full capital cost was prorated for the eleven years remaining in the study period, resulting in a cost of [redacted] (2022 dollars);
- a Clean Water Act compliance system in 2017, with a projected capital cost of [redacted] (2017 dollars) including AFUDC; and
- a CCB compliance system with expenditures in 2014, 2015, 2019, 2023, 2025, and 2031. This system had a total projected capital cost of [redacted] (sum of nominal dollars in 2014-2031) including AFUDC.

Jim Bridger Unit 1 Retire/Replace with CCCT (SCR not installed)

The JB1 retirement scenario assumes that the JB1 unit is retired December 31, 2022 and replaced with a similarly sized CCCT beginning operation on January 1, 2023. The JB1 175 MW replacement capacity was assumed to have a projected capital cost of $323.79 million (2023 dollars), including AFUDC. For modeling purposes, the full capital cost was prorated for the ten years remaining in the study period, resulting in a cost of $107.9 million (2023 dollars) applied to this scenario in 2023.

Jim Bridger Unit 1 Natural Gas Conversion (SCR not installed)

SAIC examined the costs and benefits of switching the unit to burn natural gas instead of coal, reducing the amount of investment required for environmental compliance. The fuel conversion assumed a six-month outage in 2022 to allow for the conversion to burning natural gas, with natural gas operation commencing January 1, 2023. After the conversion, the analysis assumed a natural gas heat rate of [redacted]. The fuel conversion assumed a projected capital cost of [redacted] (2023 dollars) for JB1, and a projected capital cost of [redacted] (2023 dollars) for the associated natural gas pipeline.

Jim Bridger Unit 2 Upgrade (Install SCR)

Similar to JB1, to achieve environmental compliance, Jim Bridger Unit 2 ("JB2") requires a variety of pollution control systems, including:

- a mercury control system in 2014, with a projected capital cost of [redacted] (2015 dollars) including AFUDC;
- an SCR system in 2021, with a projected capital cost of [redacted] (2021 dollars) including AFUDC. For modeling purposes, the full capital cost was prorated for the twelve years remaining in the study period, resulting in a cost of [redacted] (2021 dollars);
- a Clean Water Act compliance system in 2017, with a projected capital cost of [redacted] (2017 dollars) including AFUDC; and

- a CCR compliance system with expenditures in 2014, 2015, 2019, 2023, 2025, and 2031. This system had a total projected capital cost of [redacted] (sum of nominal dollars in 2014-2031) including AFUDC.

Jim Bridger Unit 2 Natural Gas Conversion (SCR not installed)

SAIC examined the costs and benefits of switching the unit to burn natural gas instead of coal, reducing the amount of investment required for environmental compliance. The fuel conversion assumed a six-month outage in 2021 to allow for the conversion to burning natural gas, with natural gas operation commencing January 1, 2022. After the conversion, the analysis assumed a natural gas heat rate of [redacted]. The fuel conversion assumed a projected capital cost of [redacted] (2022 dollars) for JB2, and a projected capital cost of [redacted] (2022 dollars) for the associated natural gas pipeline.

Jim Bridger Unit 2 Retire/Replace with CCCT (SCR not installed)

The JB2 retirement scenario assumed that the JB2 unit is retired December 31, 2021 and replaced with a similarly sized CCCT beginning operation on January 1, 2022. The JB2 175 MW replacement capacity was assumed to have a projected capital cost of $314.36 million (2022 dollars) including AFUDC. For modeling purposes, the full capital cost was prorated for the eleven years remaining in the study period, resulting in a cost of $115.2 million (2022 dollars) applied to this scenario in 2022.

Jim Bridger Unit 3 Upgrade (Install SCR)

All the Jim Bridger units require a variety of pollution control systems to achieve compliance. Jim Bridger Unit 3 ("JB3") upgrades include:

- a mercury control system in 2014, with a projected capital cost of [redacted] (2015 dollars) including AFUDC;
- an SCR system in 2015, with a projected capital cost of [redacted] (2015 dollars) including AFUDC;
- a Clean Water Act compliance system in 2017, with a projected capital cost of [redacted] (2017 dollars) including AFUDC; and
- a CCR compliance system with expenditures in 2014, 2015, 2019, 2023, 2025, and 2031. This system had a total projected capital cost of [redacted] (sum of nominal dollars in 2014-2031) including AFUDC.

Jim Bridger Unit 3 Natural Gas Conversion (SCR not installed)

SAIC examined the costs and benefits of switching the unit to burn natural gas instead of coal, reducing the amount of investment required for environmental compliance. The fuel conversion assumed a six-month outage in 2015 to allow for the conversion to burning natural gas, with natural gas operation commencing January 1, 2016. After the conversion, the analysis assumed a natural gas heat rate of [redacted]. The fuel conversion assumed a projected capital cost of [redacted] (2016 dollars) for JB3, and a projected capital cost of [redacted] (2016 dollars) for the associated natural gas pipeline.

Jim Bridger Unit 3 Retire/Replace with CCCT (SCR not installed)

The JB3 retirement scenario assumes that the JB3 unit is retired December 31, 2015 and replaced with a similarly sized CCCT beginning operation on January 1, 2016. The JB3 175 MW replacement capacity was assumed to have a projected capital cost of $263.3 million (2016 dollars) including AFUDC. For modeling purposes, the full capital cost was prorated for the seventeen years remaining in the study period, resulting in a cost of $149.2 million (2016 dollars) applied to this scenario in 2016.

Jim Bridger Unit 4 Upgrade (Install SCR)

All the Jim Bridger units require a variety of pollution control systems to achieve compliance. Jim Bridger Unit 4 ("JB4") upgrades include:

- a mercury control system in 2014, with a projected capital cost of [redacted] (2015 dollars) including AFUDC;
- an SCR system in 2016, with a projected capital cost of [redacted] (2016 dollars) including AFUDC;
- a Clean Water Act compliance system in 2017, with a projected capital cost of [redacted] (2017 dollars) including AFUDC; and
- a CCR compliance system with expenditures in 2014, 2015, 2019, 2023, 2025, and 2031. This system had a total projected capital cost of [redacted] (sum of nominal dollars in 2014-2031) including AFUDC.

Jim Bridger Unit 4 Natural Gas Conversion (SCR not installed)

SAIC examined the costs and benefits of switching the unit to burn natural gas instead of coal, reducing the amount of investment required for environmental compliance. The fuel conversion assumed a six-month outage in 2016 to allow for the conversion to burning natural gas, with natural gas operation commencing January 1, 2017. After the conversion, the analysis assumed a natural gas heat rate of [redacted]. The fuel conversion assumed a projected capital cost of [redacted] (2016 dollars) for JB3, and a projected capital cost of [redacted] (2016 dollars) for the associated natural gas pipeline.

Jim Bridger Unit 4 Retire/Replace with CCCT (SCR not installed)

The JB4 retirement scenario assumes that the JB4 unit is retired December 31, 2016 and replaced with a similarly sized CCCT beginning operation on January 1, 2017. The JB4 175 MW replacement capacity was assumed to have a projected capital cost of $271.1 million (2017 dollars) including AFUDC. For modeling purposes, the full capital cost was prorated for the seventeen years remaining in the study period, resulting in a cost of $144.6 million (2017 dollars) applied to this scenario in 2017.

3.2.2 Sensitivities

Each of the unit scenarios were analyzed using a range of inputs pertaining to the cost of natural gas, and possible carbon legislation. By using these ranges of inputs, IPC can gain insight into the drivers behind the costs involved in either upgrading or retiring a given unit, and to what extent the variation of those drivers affects the final results. Following is a description of the nine sensitivities analyzed:

Planning Case Gas, Planning Case Carbon

This sensitivity used the planning case gas price and planning case carbon assumptions. The planning case gas price forecast used in the analysis was provided by IPC, and corresponds to the price forecast IPC used for its 2013 IRP. Details regarding the gas price forecast may be found in the list of assumptions in Appendix A.

The planning case carbon assumption was provided by IPC staff and represents IPC's view of likely carbon legislation. The assumption is that there would be a projected carbon compliance cost, expressed in terms of $/MWh, applied to the coal fired generation. This cost is projected to begin in 2018, at a level of $14.64/MWh, escalating at 3 percent annually.

Low Gas, Planning Case Carbon

This sensitivity used the low gas price and planning case carbon assumptions. The low gas price used was provided by IPC, and corresponds to the price forecast IPC used for its 2013 IRP. Details regarding the gas price forecast may be found in the list of assumptions in Appendix A.

High Gas, Planning Case Carbon

This sensitivity used the high gas price and planning case carbon assumptions. The high gas price used was provided by IPC, and corresponds to the price forecast IPC used for its 2013 IRP. Details regarding the gas price forecast may be found in the list of assumptions in Appendix A.

Planning Case Gas, Low Carbon

This sensitivity used the planning case gas price and low carbon assumptions. The low carbon assumption was provided by IPC, and assumes that no carbon legislation will develop during the study period, and assumes a $0/MWh carbon compliance cost for all years.

Planning Case Gas, High Carbon

This sensitivity used the planning case gas price and high carbon assumptions. The high carbon assumption was provided by IPC, and assumes that carbon regulation will occur earlier and at a higher rate than the base carbon assumption, beginning in 2018 at a level of $35/MWh, escalating at 9 percent annually.

Low Gas, Low Carbon

This sensitivity used the low gas price and low carbon assumptions. The low gas price used was provided by IPC, and corresponds to the price forecast IPC used for its 2013 IRP. Details regarding the gas price forecast may be found in the list of assumptions in Appendix A. The low carbon assumption was provided by IPC, and assumes that no carbon legislation will develop during the study period, and uses a $0/MWh carbon compliance cost for all years.

High Gas, Low Carbon

This sensitivity used the high gas price and low carbon assumptions. The high gas price used was provided by IPC, and corresponds to the price forecast IPC used for its 2013 IRP. Details regarding the gas price forecast may be found in the list of assumptions in Appendix A.

Low Gas, High Carbon

This sensitivity used the high gas price and low carbon assumptions.

High Gas, High Carbon

This sensitivity used the high gas price and high carbon assumptions.

3.3 Analysis Methodology

The study approach examined the costs and benefits of each unit's upgrade or retirement decision separately. This means that the effects of the given unit's scenario was isolated, and considered no interaction with any other units on the IPC system. This methodology, while limited, provides a planning level look at the economics of the upgrade or retirement decision.

For each scenario and for each sensitivity, SAIC used the annual generation amounts for each unit provided by IPC. For purposes of this screening analysis, the same annual generation amount for each unit for each year was used before and after the potential environmental improvements or fuel switching, and for the replacement unit in the case the coal unit was assumed to retire. This has the effect of isolating the costs of the upgrade, allowing IPC to determine the relative benefits of the upgrade or retirement without any effect of an altered dispatch on fuel and O&M expenses. The generation forecasts provided by IPC extended through 2032.

The fuel, O&M, start charges, carbon costs, and SO_2 allowance prices were forecasted for each unit for the duration of the study period. Additionally, the ongoing capital and O&M expenses were included in the analysis, to ultimately forecast the total cost of generation, both fixed and variable, for each unit under each scenario and sensitivity.

The costs of the environmental upgrades applicable to each unit were also included. IPC provided total capital costs including AFUDC for each upgrade required, as well as the ongoing incremental O&M costs associated with each upgrade. The timing of the capital expenditures varied according to the schedule of the given unit's upgrades.

3.3.1 Study Period and Replacement Capacity

The study period used in the analysis was 2013 to 2032.

In the retirement scenarios, SAIC assumed that each unit was replaced with generic CCCT capacity and energy at the end of its life. The generic replacement capacity was, as in the retirement scenarios, assumed to be similar in size to the given coal unit. Section 3.2 above describes the specific costs associated with each NV or JB unit. For the retirement scenarios, the total projected cost is identified above. The analysis used a prorated cost for the replacement CCCT units, based on how many years remained in the study period for a given unit. The proration was calculated based on a 30-year life for the replacement CCCT. For example, the Jim Bridger 1 replacement CCCT was assumed to begin operations in 2023, with ten years remaining in the study period. The full cost of the replacement CCCT was prorated by a factor of 10/30, corresponding to 10 years in the study period out of the 30 year life of the CCCT.

3.3.2 Fuel, Start Charges, and Emissions costs

Each unit's fuel costs were estimated using the average heat rates provided by IPC. The dispatch amount of generation was fixed according to the annual projected generation provided by IPC, allowing SAIC to use the average heat rates to calculate the amount of coal burned and total fuel costs.

Similarly, the starts for each unit were also provided by IPC, as well as costs per start. SAIC calculated the total start charges for each year of the study period.

SO_2 emissions allowance costs were calculated using the total fuel consumption estimates for each year, combined with the lbs/MMBtu data provided by IPC for each unit, to obtain the total tons of SO_2. The SO_2 allowance prices were assumed to be \$0.50/ton in 2012 dollars, and such costs were escalated at 3 percent annually. IPC has sufficient allowances to cover SO2 emissions for these plants, although they were included in the study to be conservative.

Carbon costs were calculated according to the given carbon price for each sensitivity. IPC provided carbon costs in terms of \$/MWh for the coal fired generation. To account for possible carbon costs for the gas fired replacement capacities, SAIC assumed that 50 percent of the \$/MWh price for coal would apply to the gas fired generation. For example, the base carbon scenario calls for coal fired carbon costs of \$16/MWh in 2021 dollars. For the gas-fired generation, SAIC assumed this would be \$8/MWh in 2021 dollars.

3.3.3 Capital and O&M costs

Each unit has ongoing capital expenditures and O&M costs related to the operation of the unit, separate from any capital or O&M costs associated with the environmental upgrades. IPC provided a forecast through 2032 for base capital and O&M expenditures. Based on discussions with IPC, the average base O&M expenses were escalated at 3 percent annually. The average capital expenditures were escalated at 3 percent annually.

The incremental O&M expenses associated with the upgrades were also provided by IPC through 2032.

3.3.4 Net Present Value ("NPV") analysis

The annual and cumulative projected power costs for this Report are presented on a NPV basis for each scenario. Based on discussion with IPC, total annual costs for each year were discounted to 2013 dollars using a discount value of 6.77 percent, which represents IPC's Weighted Average Cost of Capital ("WACC).

Section 4
OPTIONAL ANALYSIS RESULTS

4.1 Introduction

This section presents the results of the analysis for each of the six coal units. Conclusions and recommendations follow in Section 5.

4.2 Summary Results

Table 4-1 contains the summary results for all scenarios. For each unit, the option with the lowest projected cumulative present value power costs is highlighted. Dollars are shown in millions of dollars and discounted to the year 2013. Table 4-2 contains the comparison of the costs of the environmental compliance upgrades to the Retirement scenarios for each unit, both in dollars and percentage.

Table 4-1
Present Value of Power Cost by Scenario ($2013 M)

	Low Gas No Carbon	Low Gas Planning Case Carbon	Low Gas High Carbon	Planning Case Gas No Carbon	Planning Case Gas Planning Case Carbon	Planning Case Gas High Carbon	High Gas No Carbon	High Gas Planning Case Carbon	High Gas High Carbon
North Valmy 1 Upgrade (DSI)	$430	$405	$314	$543	$585	$493	$802	$688	$747
North Valmy 1 2015 NG Conversion	$441	$348	$196	$760	$723	$447	$1,032	$1,052	$897
North Valmy 1 2018 NG Conversion	$445	$353	$200	$735	$698	$422	$961	$980	$825
North Valmy 1 Enhanced Upgrade (DSI+SCR+WFGD)	$604	$569	$466	$728	$764	$663	$789	$873	$920
North Valmy 1 2015 Retire/Replace	$455	$403	$303	$671	$661	$488	$857	$886	$811
North Valmy 1 2018 Retire/Replace	$478	$426	$326	$684	$674	$502	$847	$877	$802
North Valmy 2 NG Conversion	$430	$294	$205	$683	$663	$354	$868	$889	$635
North Valmy 2 Enhanced Upgrade (SCR+WFGD)	$586	$516	$462	$687	$726	$584	$719	$796	$760
North Valmy 2 Retire/Replace	$486	$406	$351	$659	$660	$469	$782	$811	$668
Jim Bridger 1 Upgrade (SCR)	$538	$654	$655	$560	$707	$988	$573	$723	$1,070
Jim Bridger 1 NG Conversion	$797	$842	$636	$973	$1,039	$1,103	$1,136	$1,206	$1,342
Jim Bridger 1 Retire/Replace	$774	$851	$722	$899	$997	$1,127	$1,014	$1,116	$1,311
Jim Bridger 2 Upgrade (SCR)	$540	$650	$610	$571	$708	$929	$592	$740	$1,069
Jim Bridger 1 NG Conversion	$797	$828	$577	$1,003	$1,058	$1,068	$1,195	$1,261	$1,378
Jim Bridger 2 Retire/Replace	$787	$842	$787	$931	$1,013	$1,071	$1,065	$1,158	$1,323
Jim Bridger 3 Upgrade (SCR)	$561	$670	$570	$598	$740	$939	$617	$767	$1,087
Jim Bridger 3 NG Conversion	$822	$836	$506	$1,130	$1,185	$1,120	$1,422	$1,491	$1,568
Jim Bridger 3 Retire/Replace	$835	$861	$787	$1,051	$1,111	$1,100	$1,251	$1,322	$1,426
Jim Bridger 4 Upgrade (SCR)	$542	$628	$511	$597	$715	$798	$620	$761	$1,043
Jim Bridger 4 NG Conversion	$773	$760	$426	$1,105	$1,111	$897	$1,397	$1,439	$1,455
Jim Bridger 4 Retire/Replace	$791	$798	$787	$1,023	$1,047	$920	$1,221	$1,273	$1,332

Table 4-2
Present Value Power Cost Deltas by Scenario ($2013 M and %)

	Low Gas No Carbon	Low Gas Planning Case Carbon	Low Gas High Carbon	Planning Case Gas No Carbon	Planning Case Gas Planning Case Carbon	Planning Case Gas High Carbon	High Gas No Carbon	High Gas Planning Case Carbon	High Gas High Carbon
North Valmy 1: Upgrade (DSI) - 2015 NG Conversion	($11) -2%	$57 16%	$119 61%	($217) -29%	($138) -19%	$46 10%	($430) -42%	($364) -35%	($149) -17%
North Valmy 2: Retire/Replace - NG Conversion	$56 13%	$112 38%	$146 71%	($23) -3%	($2) 0%	$115 32%	($86) -10%	($78) -9%	$33 9%
Jim Bridger 1: Upgrade (SCR) - NG Conversion	($259) -33%	($178) -21%	$19 3%	($413) -42%	($332) -32%	($114) -10%	($563) -50%	($483) -40%	($273) -20%
Jim Bridger 2: Upgrade (SCR) - NG Conversion	($258) -32%	($178) -22%	$33 6%	($432) -43%	($350) -33%	($139) -13%	($602) -50%	($521) -41%	($309) -22%
Jim Bridger 3: Upgrade (SCR) - NG Conversion	($261) -32%	($165) -20%	$64 13%	($532) -47%	($446) -38%	($182) -16%	($806) -57%	($723) -49%	($481) -31%
Jim Bridger 4: Upgrade (SCR) - NG Conversion	($231) -30%	($132) -17%	$86 20%	($508) -46%	($396) -36%	($98) -11%	($777) -56%	($678) -47%	($412) -28%

The analysis for the North Valmy units indicates that under Planning Case assumptions, the projected cumulative present value power costs associated with the Upgrade (Install DSI) scenario is projected to be the least cost option. This holds true for the majority of the various cases for the North Valmy units, with the exception of the Low Gas/Planning and High Carbon cases, and the Planning Gas/High Carbon case. In these instances, the lower fuel costs associated with the low gas prices, and the higher carbon compliance costs associated with the high carbon cost assumption, led to the Natural Gas Conversion cases having the lowest projected cumulative present value power costs.

The analysis for the Jim Bridger units indicates that for all four Jim Bridger units, the projected cumulative present value power costs associated with the environmental upgrades represent the least cost option. For all four units, similar to the North Valmy analysis, there was one case in which the projected cumulative present value power costs associated with the Natural Gas Conversion option represented the least cost: the Low Gas, High Carbon scenario.

4.2.1 Jim Bridger Unit 1

The JB1 unit was examined for three scenarios: Upgrade (Install SCR), Natural Gas Conversion (SCR not installed), and Retire/Replace with CCCT (SCR not installed).

The planning case results indicate that the projected cumulative present value power costs associated with the Upgrade option is the least cost option. The projected cumulative present value power costs associated with the Upgrade option is lower by $291 million when compared to the Retire/Replace option, and lower by $332 million when compared to the Natural Gas Conversion option.

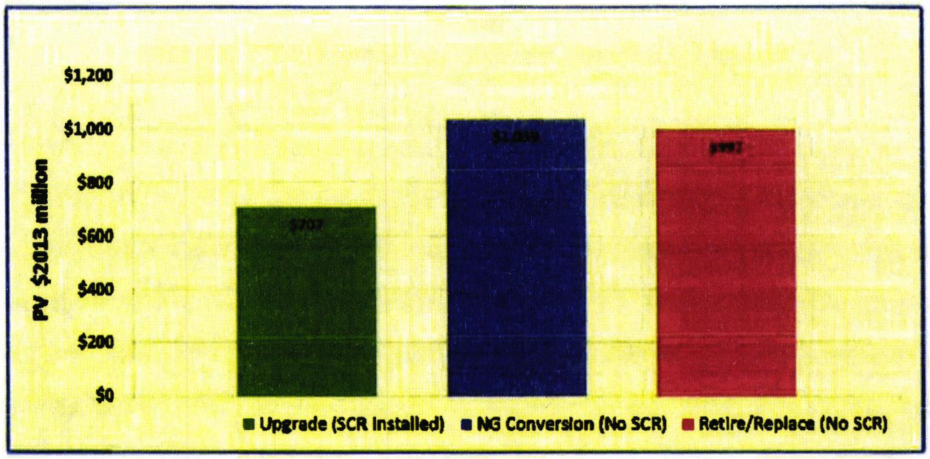

Figure 4-1. Jim Bridger Unit 1 Planning Case – Total Costs

As with all the Jim Bridger units, the projected cumulative present value power costs associated with the cases were generally higher as carbon compliance costs increased. There was a similar trend with regards to gas prices. The NG Conversion option was similar to the Retire/Replace option. With one exception, the cumulative present value power costs associated with the Upgrade option were projected to be lower when compared to the projected cumulative present value power costs associated with the NG Conversion and Retire/Replace options.

Table 4-3 and Figure 4-2 contain the results for the nine JB1 cases:

Table 4-3
Jim Bridger Unit 1 – Total Costs NPV ($2013M)

	Low Gas No Carbon	Low Gas Planning Case Carbon	Low Gas High Carbon	Planning Case Gas No Carbon	Planning Case Gas Planning Case Carbon	Planning Case Gas High Carbon	High Gas No Carbon	High Gas Planning Case Carbon	High Gas High Carbon
Upgrade (SCR Installed)	$538	$664	$655	$560	$707	$988	$573	$723	$1,070
NG Conversion (No SCR)	$797	$842	$636	$973	$1,039	$1,103	$1,136	$1,206	$1,342
Retire/Replace (No SCR)	$774	$851	$722	$899	$997	$1,127	$1,014	$1,116	$1,311
NG Conversion - Upgrade	$259	$178	($19)	$413	$332	$114	$563	$483	$273

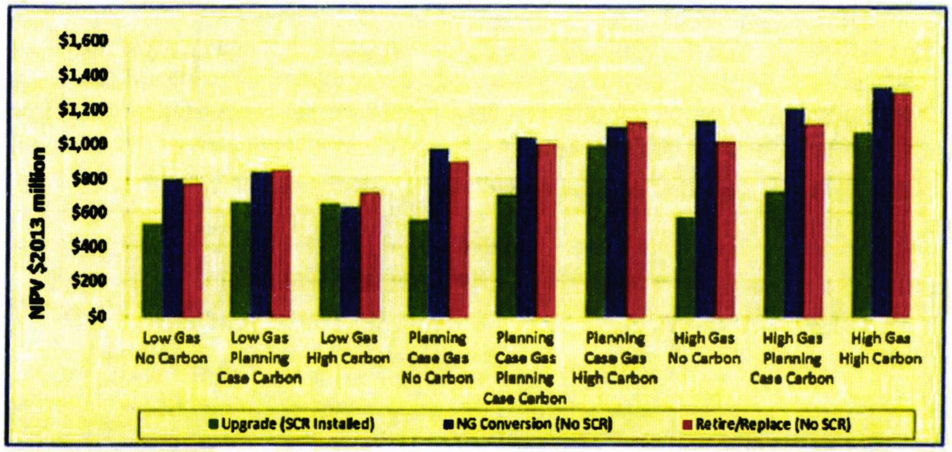

Figure 4-2. Jim Bridger Unit 1 All Cases – Total Costs

4.2.2 Jim Bridger Unit 2

The JB2 unit was examined for the same three scenarios as Unit 1: Upgrade (Install SCR), Natural Gas Conversion (SCR not installed), and Retire/Replace with CCCT (SCR not installed).

The planning case results indicate that the Upgrade option is the least cost option. The cumulative present value power cost for the Upgrade option is projected to be $305 million lower than the Retire/Replace scenario, and $350 million lower than the Natural Gas Conversion option. -

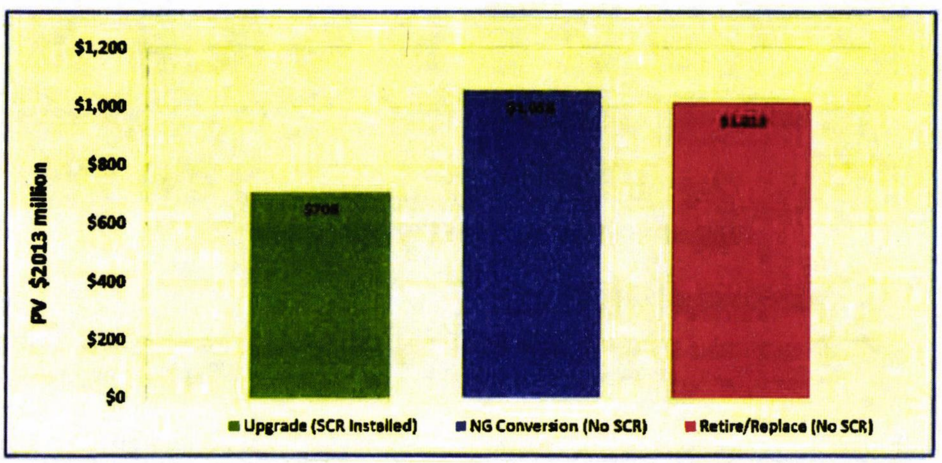

Figure 4-3. Jim Bridger Unit 2 Planning Case – Total Costs

As with all the Jim Bridger units, the projected cumulative present value power costs associated with the cases were generally higher as carbon compliance cost increased, and a similar trend is projected with regards to higher gas prices. The projected cumulative present value power costs associated with the Retire/Replace option were generally lower than the projected cumulative present value power costs associated with the Natural Gas Conversion option, with the exception of two Low Gas cases. The Upgrade option was forecasted to have the lowest projected cumulative present value power costs in all but one case, the Low Gas/High Carbon case.

Table 4-4 and Figure 4-4 contain the results for the JB2 cases:

Table 4-4
Jim Bridger Unit 2 – Total Costs NPV ($2013 M)

	Low Gas No Carbon	Low Gas Planning Case Carbon	Low Gas High Carbon	Planning Case Gas No Carbon	Planning Case Gas Planning Case Carbon	Planning Case Gas High Carbon	High Gas No Carbon	High Gas Planning Case Carbon	High Gas High Carbon
Upgrade (SCR Installed)	$540	$650	$610	$571	$708	$929	$592	$740	$1,069
NG Conversion (No SCR)	$797	$828	$577	$1,003	$1,058	$1,068	$1,195	$1,261	$1,378
Retire/Replace (No SCR)	$787	$842	$787	$931	$1,013	$1,071	$1,065	$1,158	$1,323
NG Conversion - Upgrade	$258	$178	($33)	$432	$350	$139	$602	$521	$309

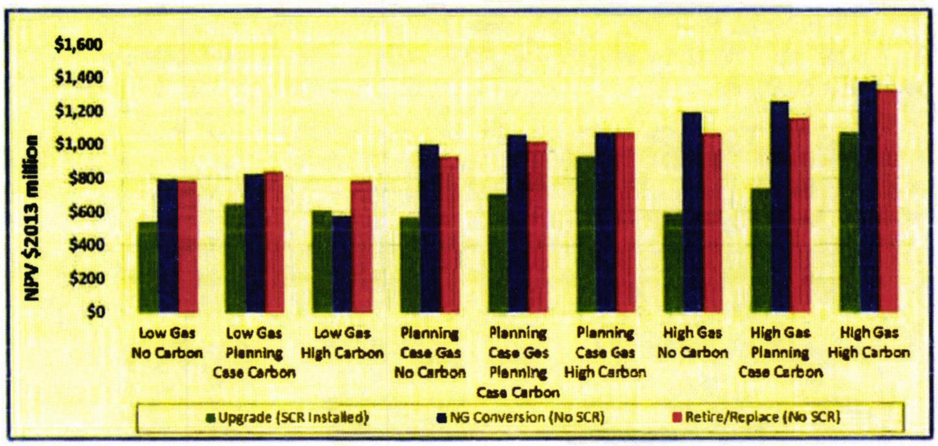

Figure 4-4. Jim Bridger Unit 2 All Cases – Total Costs

4.2.3 Jim Bridger Unit 3

All Jim Bridger units were examined for the same three scenarios: Upgrade (Install SCR), Natural Gas Conversion (SCR not installed), and Retire/Replace with CCCT (SCR not installed).

The planning case results for JB3 indicate that the projected cumulative present value power costs associated with the Upgrade option is the least cost option. The projected cumulative present value power costs associated with the Upgrade option is $446 million lower than the projected cumulative present value power costs associated with the Natural Gas Conversion scenario, and $371 million lower than the Retire/Replace option.

The projected cumulative present value power costs associated with the Retire/Replace option indicate this is the most expensive option for the majority of the cases, more so even than the Natural Gas Conversion option. This is primarily due to the construction costs for the Replacement CCCT being significantly higher than the capital costs associated with the fuel conversion.

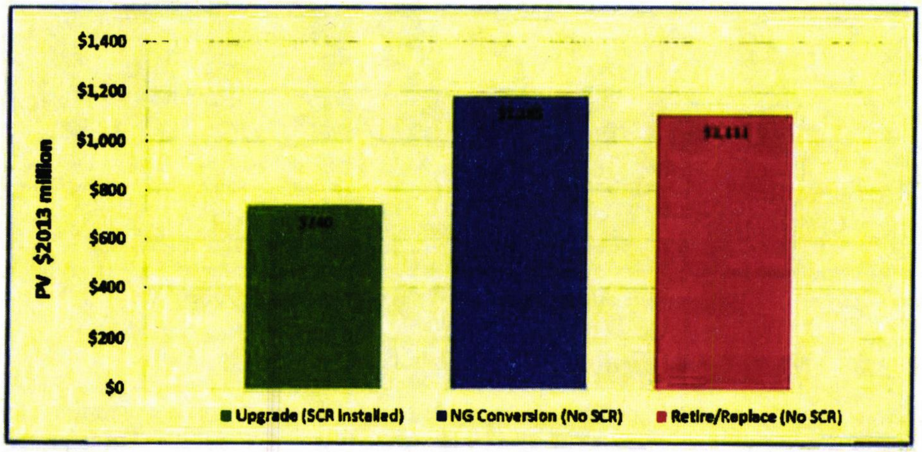

Figure 4-5. Jim Bridger Unit 3 Planning Case – Total Costs

Table 4-5 and Figure 4-6 contain the results for the JB3 cases:

Table 4-5
Jim Bridger Unit 3 – Total Costs NPV ($2013 M)

	Low Gas No Carbon	Low Gas Planning Case Carbon	Low Gas High Carbon	Planning Case Gas No Carbon	Planning Case Gas Planning Case Carbon	Planning Case Gas High Carbon	High Gas No Carbon	High Gas Planning Case Carbon	High Gas High Carbon
Upgrade (SCR Installed)	$561	$670	$570	$598	$740	$939	$617	$767	$1,087
NG Conversion (No SCR)	$822	$836	$506	$1,130	$1,185	$1,120	$1,422	$1,491	$1,568
Retire/Replace (No SCR)	$835	$861	$787	$1,051	$1,111	$1,100	$1,251	$1,322	$1,426
NG Conversion - Upgrade	$261	$165	($64)	$532	$446	$182	$806	$723	$481

The general trend of higher carbon and higher gas prices making the Upgrade option the most economical option occurs also with JB3 and JB4.

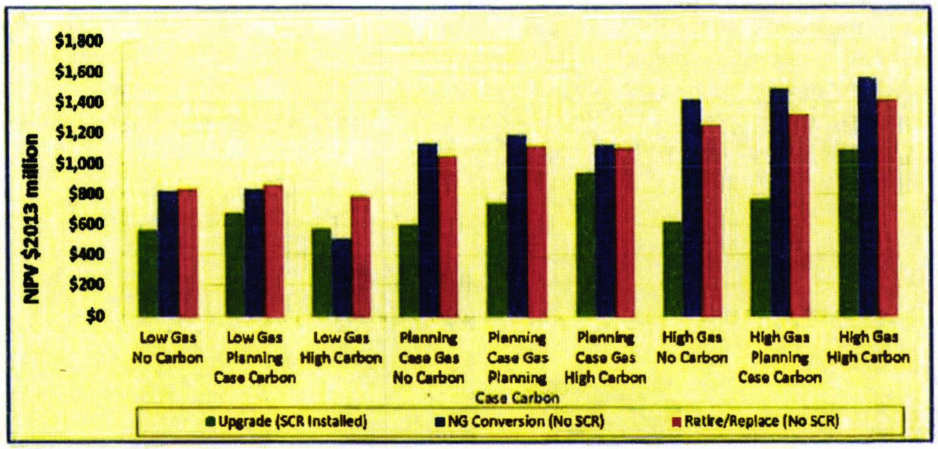

Figure 4-6. Jim Bridger Unit 3 All Cases – Total Costs

4.2.4 Jim Bridger Unit 4

The projected cumulative present value power costs associated with the planning case results for JB4 indicate similar results as with JB 3. The projected cumulative present value power costs associated with the Upgrade option is the least cost option. The projected cumulative present value power costs associated with the Upgrade option is $393 million lower than the projected cumulative present value power costs associated with the Natural Gas Conversion option, and $332 million less than the Retire/Replace option. The projected relative results of the sensitivities scenarios for JB4 are similar to the relative results for the JB3 sensitivity scenarios.

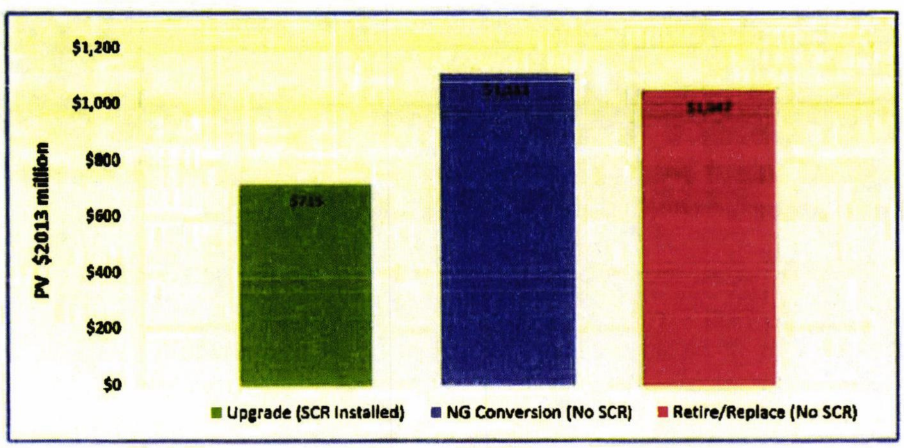

Figure 4-7. Jim Bridger Unit 4 Planning Case – Total Costs

As with JB3, the projected cumulative present value power costs associated with the Retire/Replace option indicate this is the most expensive option for the majority of the cases for JB4, more so even than the Natural Gas Conversion option. This is primarily due to the construction costs for the Replacement CCCT being significantly higher than the capital costs associated with the fuel conversion.

Table 4-6
Jim Bridger Unit 4 – Total Costs NPV ($2013 M)

	Low Gas No Carbon	Low Gas Planning Case Carbon	Low Gas High Carbon	Planning Case Gas No Carbon	Planning Case Gas Planning Case Carbon	Planning Case Gas High Carbon	High Gas No Carbon	High Gas Planning Case Carbon	High Gas High Carbon
Upgrade (SCR Installed)	$542	$628	$511	$597	$715	$798	$620	$761	$1,043
NG Conversion (No SCR)	$773	$760	$426	$1,105	$1,111	$897	$1,397	$1,439	$1,455
Retire/Replace (No SCR)	$791	$796	$787	$1,023	$1,047	$920	$1,221	$1,273	$1,332
NG Conversion - Upgrade	$231	$132	($86)	$508	$396	$98	$777	$678	$412

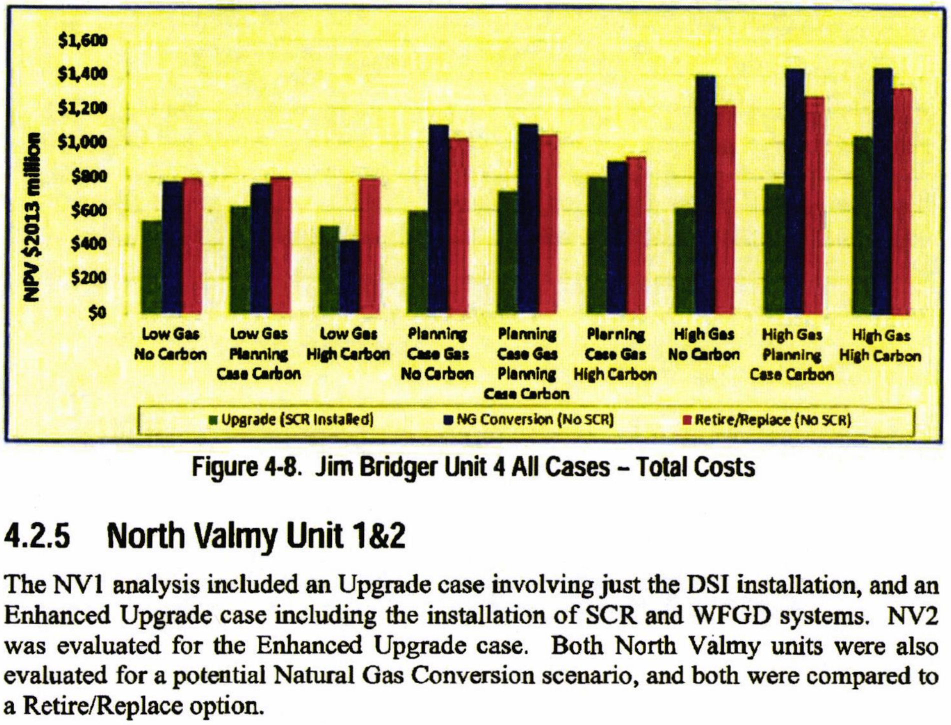

Figure 4-8. Jim Bridger Unit 4 All Cases – Total Costs

4.2.5 North Valmy Unit 1&2

The NV1 analysis included an Upgrade case involving just the DSI installation, and an Enhanced Upgrade case including the installation of SCR and WFGD systems. NV2 was evaluated for the Enhanced Upgrade case. Both North Valmy units were also evaluated for a potential Natural Gas Conversion scenario, and both were compared to a Retire/Replace option.

4.2.6 North Valmy Unit 1

The planning case results for NV1 indicate that the projected cumulative present value power costs associated with the Upgrade (DSI Installed) option is the least cost option. The projected cumulative present value power costs associated with the Retirement option is lower by $138 million when compared to the 2015 Natural Gas Conversion option, and lower by $76 million when compared to the 2015 Retire/Replace option.

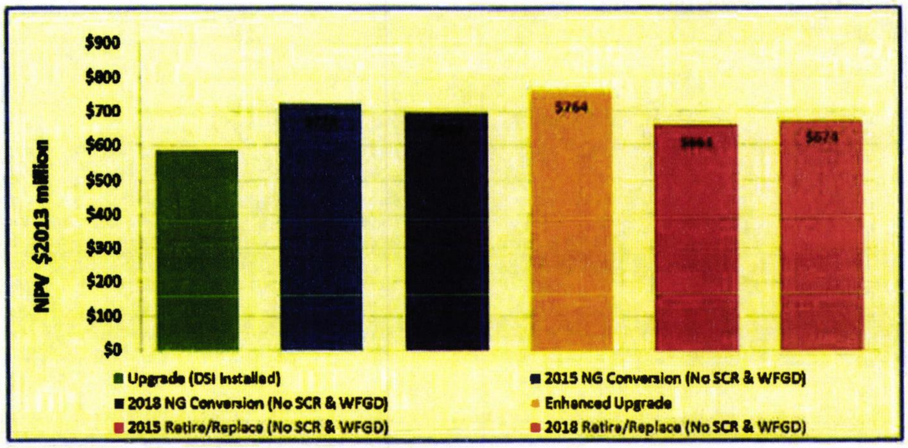

Figure 4-9. North Valmy Unit 1 Planning Case – Total Costs

The NV1 analysis results indicate that for the majority of cases, the Upgrade (DSI Installed) case is the least cost option. The Low Gas/Planning Case Carbon, Low Gas/High Carbon, and Planning Case Gas/High Carbon cases indicate that under low fuel cost conditions, or a high carbon compliance cost condition, the Natural Gas Conversion options would likely result in the lowest cumulative present value power costs.

Table 4-7.
North Valmy Unit 1 – Total Costs NPV ($2013 M)

	Low Gas No Carbon	Low Gas Planning Case Carbon	Low Gas High Carbon	Planning Case Gas No Carbon	Planning Case Gas Planning Case Carbon	Planning Case Gas High Carbon	High Gas No Carbon	High Gas Planning Case Carbon	High Gas High Carbon
Upgrade (DSI Installed)	$430	$405	$314	$541	$585	$493	$602	$688	$747
2015 NG Conversion (No SCR & WFGD)	$441	$348	$196	$760	$723	$447	$1,032	$1,052	$897
2018 NG Conversion (No SCR & WFGD)	$445	$353	$200	$735	$698	$422	$961	$980	$825
Enhanced Upgrade (DSI, SCR, and WFGD Installed)	$604	$569	$466	$728	$764	$653	$789	$873	$920
2015 Retire/Replace (No SCR & WFGD)	$455	$403	$303	$671	$661	$488	$857	$886	$811
2018 Retire/Replace (No SCR & WFGD)	$478	$426	$326	$684	$674	$502	$847	$877	$802
NG Conversion - Upgrade	($11)	$57	$119	($217)	($138)	$46	($430)	($364)	($149)

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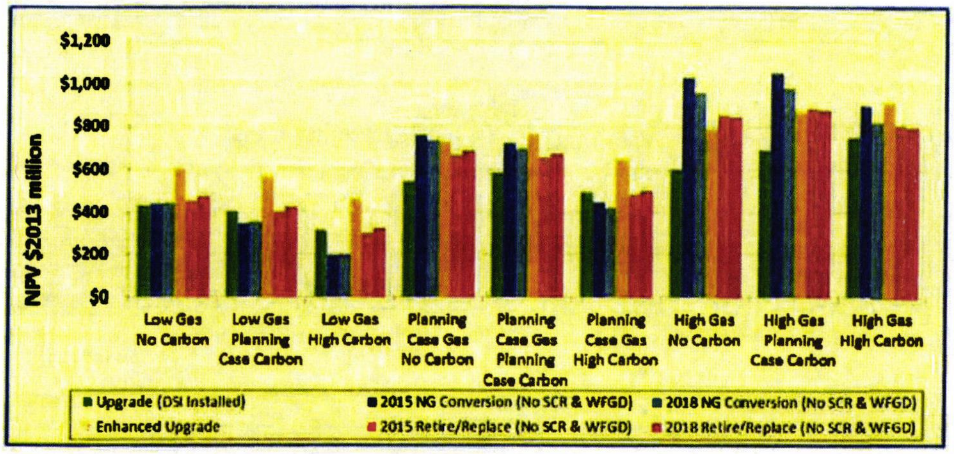

Figure 4-10. North Valmy Unit 1 All Cases – Total Costs

4.2.7 North Valmy Unit 2

The planning case results for NV2 indicate that the projected cumulative present value power costs associated with the Retire/Replace option is the least cost option, though the costs associated with the Natural Gas Conversion option are very similar. The projected cumulative present value power costs associated with the Retire/Replace option are lower by $2 million when compared to the Natural Gas Conversion option, and lower by $66 million when compared to the Enhanced Upgrade option.

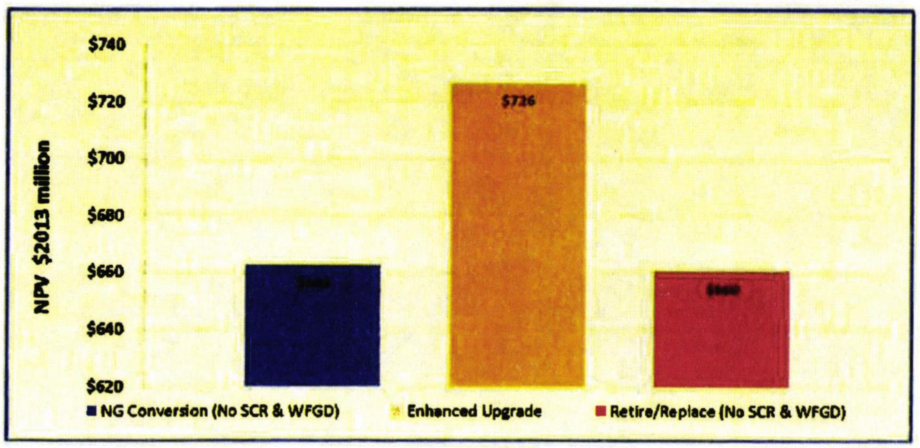

Figure 4-11. North Valmy Unit 2 Planning Case – Total Costs

The NV2 analysis results indicate that for the majority of cases, the Natural Gas Conversion case is the least cost option. The Planning Case Gas/Low Carbon, and Planning Case Gas/Planning Case Carbon cases indicate that under planning case fuel cost conditions and low and planning case carbon compliance cost conditions, the

Retire/Replace option would likely result in the lowest cumulative present value power costs.

Table 4-8.
North Valmy Unit 2 – Total Costs NPV ($2013 M)

	Low Gas No Carbon	Low Gas Planning Case Carbon	Low Gas High Carbon	Planning Case Gas No Carbon	Planning Case Gas Planning Case Carbon	Planning Case Gas High Carbon	High Gas No Carbon	High Gas Planning Case Carbon	High Gas High Carbon
NG Conversion (No SCR & WFGD)	$430	$294	$205	$683	$663	$354	$868	$889	$635
Enhanced Upgrade (SCR and WFGD Installed)	$586	$516	$462	$687	$726	$584	$719	$795	$760
Retire/Replace (No SCR & WFGD)	$486	$406	$351	$659	$660	$469	$782	$811	$668
Retire/Replace - NG Conversion	$56	$112	$146	($23)	($2)	$115	($86)	($78)	$33

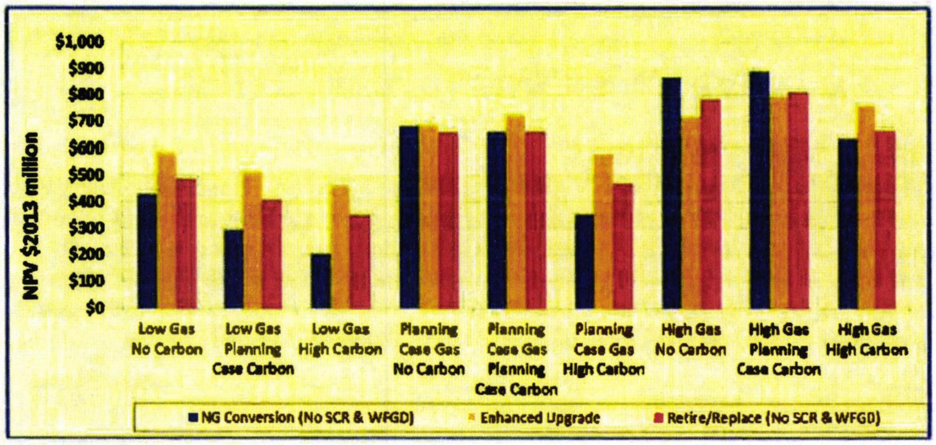

Figure 4-12. North Valmy Unit 2 All Cases – Total Costs

Section 5
CONCLUSIONS

There are a variety of factors causing the increasing number of coal-fired generation retirement studies and actual retirements, including a significant decrease in natural gas prices, increasingly stringent environmental restrictions, and steadily increasing amounts of renewable generation. In IPC's case, the potential environmental restrictions and their associated significant investments required for compliance are of particular concern. Complicating factors for the total system and especially for the North Valmy units is the combination of recent wind installations and the traditionally heavy spring hydro generation; these two factors have combined to result in a significant decrease of North Valmy generation in the March to June months of recent years.

Another challenge facing coal generation owners is the possibility of some form of carbon/greenhouse gas ("GHG") regulation in the future. This possibility leads to substantial uncertainty when attempting to forecast the future of any asset, and coal-fired assets in particular. A recent study[1] by the Deutsche Bank Group identified that, even though natural gas is widely viewed as a less-carbon intensive alternative to coal as a power sector fuel, when considering the entire life cycles of both coal and natural gas, it is possible that the natural gas GHG advantage would either be reduced or eliminated. The study discusses how shale gas production, with its associated hydraulic fracturing, leads to increased GHG emissions relative to conventional natural gas production. The Deutsche Bank Group report ultimately concluded that, on average, natural gas-fired electricity generation does in fact emit significantly less GHGs than coal, on a source to use basis. However, the Report highlights the fact that methane is still a concern as a GHG, and requires further attention. For IPC's purposes, this is significant as it underscores the importance of considering the issues of carbon and GHG when evaluating coal-fired resources, even though the momentum for some form of national carbon/GHG legislation has cooled recently.

SAIC was retained by IPC to conduct this study which addresses these concerns when evaluating the upgrade investments required to keep the North Valmy and Jim Bridger plants in environmental compliance with recent and pending EPA environmental requirements. In collaboration with IPC, we identified a methodology which incorporates the uncertainties IPC is facing, particularly with respect to natural gas pricing and possible GHG regulations. This section provides SAIC's planning level conclusions regarding the economics of those upgrade investments relative to simply retiring the plants and replacing them with natural gas-fired generation. IPC should consider conducting additional detailed analysis to evaluate the most promising alternatives considered in this preliminary study. Such studies should consider both annual and cumulative projected present value power costs, production costing simulation with and without the various proposed alternative conversions/retirement scenarios and sensitivity cases and a review of the O&M expenses under scenarios and

[1] Comparing Life-Cycle Greenhouse Gas Emissions from Natural Gas and Coal

sensitivity cases where a major shift in the operation of generation resources might be expected.

5.1.1 North Valmy

The planning case results for NV1 indicate that the projected cumulative present value power costs associated with the Upgrade (DSI Installed) option is the least cost option. The Upgrade option has the lowest projected present value power costs, with the difference between the Upgrade option and the Natural Gas Conversion and Retire/Replace options ranging between $76 and $138 million.

The NV2 analysis indicated that the Natural Gas Conversion option is projected to have the lowest projected cumulative present value power costs. In the case of NV2, the Natural Gas Conversion option and the Retire/Replace options are both very similar in terms of present value power costs.

The North Valmy analysis also indicated that the Upgrade option for NV1 and the Enhanced Upgrade option for NV2 have the lowest projected cumulative present value power costs in nearly all of the High Gas scenarios, the exception being the High Gas/High Carbon case for NV2.

The potential for some type of carbon compliance regulations have a lesser impact on the relative costs and benefits between the various North Valmy scenarios, due to the lower generation dispatch forecasts used in the analysis. The lowest projected cumulative present value power costs over the Study Period for all the scenarios and cases are the Natural Gas Conversion options under the Low Gas, High Carbon cases. These results indicate that the economic decisions regarding North Valmy 1 are more sensitive to gas price increases than potential carbon compliance costs.

The differences between the Upgrade and Natural Gas Conversion options relative to the Retire/Replace option in the Planning Case, and the lower projected cumulative present value power costs for those options in the High Gas cases indicates that IPC should carefully consider its options regarding North Valmy. Natural gas prices are currently so low that in many areas of the U.S., gas-fired generation is economically displacing coal-fired generation for increasing periods of time. These low prices, combined with the current and pending environmental compliance regulations, make many coal-fired generating plants less cost effective relative to gas-fired generation.

However, SAIC believes that IPC should consider the High Gas cases when making any decisions regarding the North Valmy plant. This study indicates that under Planning Case conditions, upgrading NV1 and retiring NV2 and replacing it with a combined-cycle plant are the most cost effective options; these results also hold in the event that gas prices rise, although the NV2 Enhanced Upgrade case is cost effective under high gas prices as well. These indications offer an opportunity to IPC to consider retaining the North Valmy units as coal-fired to help IPC mitigate potential future gas price increases. The potential value of these units would decrease in the event of significant carbon compliance costs, however.

Because the relative differences between the projected cumulative present value power costs for the Upgrade, Retire/Replace, and Natural Gas Conversion options for North

Valmy are relatively small, in SAIC's opinion IPC should consider further analysis on North Valmy before making a final decision. SAIC has identified that the North Valmy options are materially sensitive to possible carbon compliance costs.

5.1.2 Jim Bridger

The analysis of the cost effectiveness of the Upgrade options for the Jim Bridger units results in more definitive conclusions than with the North Valmy units.

Under the Planning Case assumptions regarding natural gas pricing and potential carbon compliance costs, the Jim Bridger Upgrade options have the lowest projected cumulative present value power costs over the Study Period for all four units. For all Jim Bridger options and for all the gas and carbon cost assumptions, the Natural Gas Conversion options and the Retire/Replace options are relatively similar to each other, differing mainly by the increased fuel costs in the Natural Gas Conversion cases due to a higher heat rate than the generic CCCT in the Retire/Replace option. This is offset by the increased capital expenditures associated with constructing the new CCCT.

5.1.3 Conclusions

IPC decided to conduct a study which examines the costs of environmental upgrades required for compliance as currently proposed, and to provide conclusions regarding the economic feasibility of the environmental compliance upgrades and the retirement options for the six units at the North Valmy Generating Station and the Jim Bridger Plant.

Based upon the principal considerations and assumptions summarized in Appendix A, and upon the studies and analyses as summarized and discussed in this Report, which Report should be read in its entirety in conjunction with the following, we provide the following conclusions:

The North Valmy Upgrade and Retire/Replace options for NV1 and NV2, respectively, are projected to have the lowest projected cumulative present value power costs over the Study Period of the options studied herein for the North Valmy units, but the costs for the Natural Gas Conversion case for NV2 are extremely close to the Retire/Replace option. Furthermore, the High Gas case is projected to indicate that maintaining the North Valmy on coal fuel offers a potential opportunity for IPC to mitigate potential gas price increases. In SAIC's opinion, the difference between the projected costs of retirement and replacing the North Valmy units, combined with the potential benefit of continuing to burn coal at the North Valmy plant in the event of higher natural gas prices, result in the need for further analysis of the North Valmy options.

The Jim Bridger upgrade options are projected to have the lowest projected cumulative present value power costs over the Study Period, of the Jim Bridger alternatives studied herein, including the Retire/Replace alternative. SAIC examined the Jim Bridger upgrade, natural gas conversion, and retirement and replacement alternatives under a variety of market conditions, and with the limited exceptions noted, the upgrade options are projected to be the most cost effective. Based on our results and the assumptions described above, in SAIC's opinion the investment in environmental compliance upgrades are reasonable and prudent. Should any material change occur to the upgrade capital costs or fuel price projections prior to installing the upgrades, SAIC believes that IPC should reevaluate the upgrades at that time.

Appendix A
Idaho Power Company Principle Considerations and Assumptions

In the preparation of the preliminary projected power plant costs, we have made certain assumptions with respect to conditions that may occur in the future. While we believe these assumptions are reasonable for the purpose of this analysis, they are dependent upon future events and actual conditions may differ from those assumed. In addition, we have used and relied upon certain information and assumptions provided to us by others including Idaho Power Company ("IPC"). While we believe the sources to be reliable, we have not independently verified the information and offer no assurances with respect thereto. To the extent that actual future conditions differ from those assumed herein or provided to us by others, the actual results will vary from those forecast. The principal considerations and assumptions made by us in preparing the preliminary projected power plant costs over the study period beginning on January 1, 2013 are summarized below.

A.1 Global Assumptions

1. The study period for the analysis is the 20-year period from January 1, 2013 to December 31, 2032 ("Study Period").
2. Annual inflation rate of 3.0 percent over the Study Period.
3. Present value power cost were discounted to the year 2013 at an annual discount factor of 6.77 percent which is equivalent to IPC's weighted average cost of capital
4. We have assumed that the IPC generation units will operate and be available over the Study Period as projected by IPC.
5. SO2 emissions allowances were assumed at a cost of $0.50 per ton in 2012, escalating annually at 2.5%.

A.2 Generation Unit Assumptions

1. IPC provided the projected annual energy generation dispatch (MWh) for each of the six North Valmy and Jim Bridger generation units, which was modified by IPC for each sensitivity case (High and Low Gas and High and Low Carbon Costs). The generation dispatch was not modified for the scenarios assuming (i) environmental upgrades, (iii) fuel switching or (iii) unit retirement/replacement.
2. Each generation unit was considered independently, without consideration of the IPC system impacts or interactions.

3. Table A-1 below provides assumptions for each unit including size, heat rate, SO_2 emissions rate and start costs.

Table A-1
Generating Unit Assumptions

Unit	Size (MW)	Average Heat Rate (mmBtu/kWh)	SO2 Emission Rate (lbs/mmBtu)	Start Cost ($)
North Valmy Unit 1	122	[redacted]	0.0015	12,610
North Valmy Unit 2	137	[redacted]	0.1541	12,610
Jim Bridger Unit 1	175	[redacted]	0.15	15,760
Jim Bridger Unit 2	175	[redacted]	0.2705	15,760
Jim Bridger Unit 3	175	[redacted]	0.2903	15,760
Jim Bridger Unit 4	175	[redacted]	0.001	15,760

4. For each scenario and for each sensitivity, SAIC used the annual generation forecast for each unit provided by IPC. Table A26 provides the annual generation forecast for each unit and each sensitivity. Note: The fuel switching scenarios included a 6 month outage in the year that the fuel switching occurred; for those scenarios, the generation forecast was decreased by 50% for those units in the given year.

5. Projected fixed costs for the North Valmy and Jim Bridger units were provided by IPC and assume the following:

   a. Base fixed O&M and capital improvements costs, inclusive of AFUDC, for each of the units was based on each unit's current configuration.

   b. Incremental environmental upgrade O&M and capital costs, inclusive of AFUDC, for each of the units were expenses in the year of installation.

   c. Projected costs included in the analysis reflected IPC's share of the total costs, and do not reflect the total costs projected for each unit. IPC is responsible for 33 percent of Jim Bridger costs, and 50 percent of North Valmy costs.

   d. Tables A3 through A22 provide the assumed Fixed O&M, Variable O&M, and Capital Cost projections for all scenarios.

6. The Retirement and Replacement scenarios assume the given unit would be retired on December 31 of the indicated retirement year, and replaced with a natural gas fired combined cycle combustion turbine unit. For the purposes of this analysis, the assumption is that the new CCCT would be sited in a region with access to the Sumas hub natural gas pricing, with additional gas transportation charges and capacity to a generic Idaho City gate. Additionally, the assumption is that the unit would be sized to exactly replace the megawatts ("MW") for the given unit. The replacement

CCCT units have an assumed heat rate of 6,990 Btu/kWh, an assumed 2,616 mmBtu start fuel requirement, and an assumed SO_2 emission rate of .001 lBs/mmBtu. Replacement unit capital costs, inclusive of AFUDC, were amortized at an annual rate of 6.77 percent over the remaining years of the Study Period beginning one year prior to the assumed replacement. Table A1 below provides the retirement years for each unit of the study, and their replacement units' size and total capital costs. Annual O&M and capital costs are provided in the Retire and Replace scenario tables for each unit in Tables A-3 through A-22.

Table A-2
Replacement Unit Capital Costs and Size

Unit	Retirement Date	Replacement Capital Cost (Nominal $/kW)	Size (MW)
North Valmy Unit 1	2015	1,461	122
North Valmy Unit 1	2018	1,596	122
North Valmy Unit 2	2018	1,596	137
Jim Bridger Unit 1	2022	1,796	175
Jim Bridger Unit 2	2021	1,744	175
Jim Bridger Unit 3	2015	1,461	175
Jim Bridger Unit 4	2016	1,504	175

7. No transmission costs and losses were assumed.

A.3 Fuel Assumptions

We have assumed projected coal and natural gas costs in $/MMBTu and over the Study Period based on information provided by IPC. Table A-23 provides projected coal prices by unit, and Table A-24 provides projected natural gas prices.

A.4 Carbon Compliance Cost Assumptions

The base carbon compliance cost assumption was provided by IPC staff and represents IPC's view of likely carbon legislation. The assumption is that there would be a projected carbon compliance cost, expressed in terms of $/MWh, applied to the coal fired generation. Table A-25 provides projected carbon compliance costs in $/MWh for both coal fired generation and gas fired generation.

Appendix A

The projections of electric power and energy requirements are based on the assumptions that the State of Idaho will continue to experience economic conditions comparable to those of recent years and that no significant changes will occur in the electric utility industry through the year 2032. Due to uncertainties caused by variable factors, such as changes in costs, technology, legislation and regulation, the considerations and assumptions set forth herein could be affected. For instance, the considerations and assumptions could be affected by regulatory, technological and fuel cost changes leading to significant changes in the costs of electric power and energy. In part because of evolving changes affecting the electric utility industry, potential adverse developments in these, and potentially other, areas cannot be predicted or determined at this time.

Table A-3
North Valmy 1 Upgrade Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M																				
Fixed O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade O&M																				
Variable O&M ($/MWh)			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Capital ($)			[redacted]			[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table A-4
North Valmy 1 Enhanced Upgrade Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M																				
Fixed O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade O&M																				
Fixed O&M ($)						[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Capital ($)	-	-	[redacted]	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table A-5
North Valmy 1 2015 Fuel Switch Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M																				
Fixed O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Capital ($)			[redacted]																	

Table A-6
North Valmy 1 2018 Fuel Switch Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M																				
Fixed O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Capital ($)						[redacted]														

Table A-7
North Valmy 1 2015 Retire and Replace Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M																				
Fixed O&M ($)	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M ($/MWh)	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Base Capital ($)	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT Fixed O&M ($)	-	-	2,001,266	2,061,304	2,123,143	2,186,838	2,252,443	2,320,016	2,389,616	2,461,305	2,535,144	2,611,198	2,689,534	2,770,220	2,853,327	2,938,927	3,027,095	3,117,907	3,211,445	3,307,788
CCCT Capital ($)	-	-	106,916,787	2,389,621	691,333	4,406,636	1,145,333	1,220,000	0	5,713,894	813,333	1,862,533	691,333	2,389,621	691,333	4,406,636	1,145,333	1,220,000	0	5,713,894

Table A-8
North Valmy 1 2018 Retire and Replace Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M																				
Fixed O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT Fixed O&M ($)	-	-	-	-	-	2,186,838	2,252,443	2,320,016	2,389,616	2,461,305	2,535,144	2,611,198	2,689,534	2,770,220	2,853,327	2,938,927	3,027,095	3,117,907	3,211,445	3,307,788
CCCT Capital ($)	-	-	-	-	-	97,359,044	2,389,621	691,333	4,406,636	1,145,333	1,220,000	0	5,713,894	813,333	1,862,533	691,333	2,389,621	691,333	4,406,636	1,145,333

Table A-9
North Valmy 2 Fuel Switch Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M																				
Fixed O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Capital ($)	-	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table A-10
North Valmy 2 Retire and Replace Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M																				
Fixed O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Variable O&M ($/MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT Fixed O&M ($)	-	-	-	-	-	2,455,711	2,529,382	2,605,264	2,683,422	2,763,924	2,846,842	2,932,247	3,020,215	3,110,821	3,204,146	3,300,270	3,399,278	3,501,257	3,606,294	3,714,483
CCCT Capital ($)	-	-	-	-	-	109,329,418	2,683,426	776,333	4,948,435	1,286,153	1,370,000	0	6,416,422	913,333	2,091,533	776,333	2,683,426	776,333	4,948,435	1,286,153

Table A-11
Jim Bridger 1 Upgrade Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade O&M																				
MER Projects ($)		-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NOX Projects ($)	-	-	-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Capital																				
SCR/SNCR/NOX Projects ($)	-			-	-	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-
MER Projects ($)			[redacted]																	
CWA Projects ($)	-	[redacted]	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCB Projects ($)	-	[redacted]	[redacted]	-	-	-	[redacted]	-	-	-	[redacted]	-	[redacted]	-	-	-	-	-	[redacted]	-

Table A-12
Jim Bridger 1 Fuel Switch Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Capital ($)	########	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Capital																				
Fuel Switching ($)		-	-	-	-	-	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-

Table A-13
Jim Bridger 1 Retire and Replace Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-
CCCT Fixed O&M ($)	-	-	-	-	-	-	-	-	-	-	3,636,477	3,745,572	3,857,939	3,973,677	4,092,887	4,215,674	4,342,144	4,472,408	4,606,581	4,744,778
CCCT Capital ($)	-	-	-	-	-	-	-	-	-	-	107,931,791	3,427,734	991,667	6,320,994	1,642,896	1,750,000	0	8,196,160	1,166,667	2,671,667

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Table A-14
Jim Bridger 2 Upgrade Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade O&M																				
MER Projects ($)			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NOX Projects ($)		-	-	-	-	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Capital																				
SCR/SNCR/NOX Projects ($)	-	-	-	-	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-
MER Projects ($)	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CWA Projects ($)	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCB Projects ($)	-	[redacted]	[redacted]	-	-	-	[redacted]	-	-	-	[redacted]	-	[redacted]	-	-	-	-	-	[redacted]	-

Table A-15
Jim Bridger 2 Fuel Switch Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Capital																				
Fuel Switching ($)	-	-	-	-	-	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-

Table A-16
Jim Bridger 2 Retire and Replace Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-
CCCT Fixed O&M ($)	-	-	-	-	-	-	-	-	-	3,530,560	3,636,477	3,745,572	3,857,939	3,973,677	4,092,887	4,215,674	4,342,144	4,472,408	4,606,581	4,744,778
CCCT Capital ($)	-	-	-	-	-	-	-	-	-	115,266,961	3,427,734	991,667	6,320,994	1,642,896	1,750,000	0	8,196,160	1,166,667	3,671,667	0

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Table A-17
Jim Bridger 3 Upgrade Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade O&M																				
MER Projects ($)	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NOX Projects ($)	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Capital																				
SCR/SNCR/NOX Projects ($)	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MER Projects ($)	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CWA Projects ($)	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCB Projects ($)	-	[redacted]	[redacted]	-	-	-	[redacted]	-	-	-	[redacted]	-	[redacted]	-	-	-	-	-	[redacted]	-

Table A-18
Jim Bridger 3 Fuel Switch Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Capital ($)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Capital																				
Fuel Switching ($)	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table A-19
Jim Bridger 3 Retire and Replace Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M ($)	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Base Capital ($)	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT Fixed O&M ($)	-	-	-	2,956,789	3,045,492	3,136,857	3,230,963	3,327,892	3,427,729	3,530,560	3,636,477	3,745,572	3,857,939	3,973,677	4,092,887	4,215,674	4,342,144	4,472,408	4,606,581	4,744,778
CCCT Capital	-	-	-	149,189,319	3,427,734	991,657	6,320,994	1,642,896	1,750,000	0	8,196,160	1,166,667	2,671,667	991,667	3,427,734	991,667	6,320,994	1,642,896	3,427,734	991,667

Table A-20
Jim Bridger 4 Upgrade Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade O&M																				
MER Projects	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NOX Projects	-	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Capital																				
SCR/SNCR/NOX Projects	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MER Projects	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CWA Projects	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCB Projects	-	[redacted]	[redacted]	-	-	-	[redacted]	-	-	-	[redacted]	-	[redacted]	-	-	-	-	-	[redacted]	-

Table A-21
Jim Bridger 4 Fuel Switch Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base O&M	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Base Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Upgrade Capital																				
Fuel Switching	-	-	-	-	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table A-22
Jim Bridger 4 Retire and Replace Scenario O&M and Capital Costs ($Nominal)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CCCT Fixed O&M ($)	-	-	-	-	3,045,492	3,136,857	3,230,963	3,327,892	3,427,729	3,530,560	3,636,477	3,745,572	3,857,939	3,973,677	4,092,887	4,215,674	4,342,144	4,472,408	4,606,581	4,744,778
CCCT Capital	-	-	-	-	144,625,881	3,427,734	991,667	6,320,994	1,642,896	1,750,000	0	8,196,160	1,166,667	2,671,667	991,667	3,427,734	991,667	6,320,994	1,642,896	3,427,734

Table A-23
Projected Coal Prices by Unit ($Nominal)

Coal Pricing		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
North Valmy 1	$/mmBtu	2.85	2.95	3.04	3.05	3.15	3.25	3.36	3.47	3.59	3.70	3.83	3.95	4.08	4.22	4.36	4.50	4.65	4.80	4.94	5.09
North Valmy 2	$/mmBtu	2.85	2.95	3.04	3.05	3.15	3.25	3.36	3.47	3.59	3.70	3.83	3.95	4.08	4.22	4.36	4.50	4.65	4.80	4.94	5.09
Jim Bridger 1	$/mmBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jim Bridger 2	$/mmBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jim Bridger 3	$/mmBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jim Bridger 4	$/mmBtu	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table A-24
Projected Natural Gas Prices by Case ($Nominal)

		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
$/mmBtu	Low	3.73	3.92	4.12	4.24	4.40	4.59	4.86	5.14	5.54	6.02	6.44	6.80	7.22	7.62	8.06	8.45	8.87	9.33	9.82	10.22
$/mmBtu	Base	5.06	5.33	5.61	5.77	5.99	6.24	6.61	6.98	7.54	8.21	8.78	9.28	9.85	10.39	11.01	11.52	12.10	12.74	13.40	14.01
$/mmBtu	High	6.39	6.74	7.10	7.29	7.57	7.89	8.35	8.83	9.54	10.39	11.13	11.76	12.48	13.17	13.95	14.60	15.34	16.15	16.99	17.79

Table A-25
Projected Carbon Compliance Costs by Case and Fuel ($Nominal)

			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Carbon Compliance (Coal)	$/MWh	Low	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	$/MWh	Base	0.00	0.00	0.00	0.00	0.00	14.64	15.08	15.53	16.00	16.48	16.97	17.48	18.01	18.55	19.10	19.68	20.27	20.88	21.50	22.15
	$/MWh	High	0.00	0.00	0.00	0.00	0.00	35.00	38.15	41.58	45.33	49.41	53.85	58.70	63.98	69.74	76.02	82.86	90.31	98.44	107.30	116.96
Carbon Compliance (Gas)	$/MWh	Low	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	$/MWh	Base	0.00	0.00	0.00	0.00	0.00	7.32	7.54	7.77	8.00	8.24	8.49	8.74	9.00	9.27	9.55	9.84	10.13	10.44	10.75	11.07
	$/MWh	High	0.00	0.00	0.00	0.00	0.00	17.50	19.08	20.79	22.66	24.70	26.93	29.35	31.99	34.87	38.01	41.43	45.16	49.22	53.65	58.48

Table A-26
Projected Generation Forecast by Unit by Sensitivity

North Valmy 1	Valmy 1 IPCO	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Low Gas Low Carbon	MWH	48,640	71,979	97,937	138,099	209,042	235,656	286,959	334,242	398,113	528,425	638,607	700,907	735,681	717,797	810,261	832,093	796,683	824,011	799,028	874,411
Low Gas Base Carbon	MWH	48,640	71,979	97,937	138,099	209,042	139,838	167,070	167,453	206,109	279,377	333,802	399,426	401,593	446,453	495,921	558,118	548,789	632,598	631,513	662,593
Low Gas High Carbon	MWH	48,640	71,979	97,937	138,099	209,042	74,741	69,689	64,965	74,734	106,726	108,662	101,607	100,721	85,501	104,395	113,782	98,704	103,279	114,003	123,702
Base Gas Low Carbon	MWH	347,456	382,188	446,751	510,526	572,612	679,248	718,294	752,515	770,087	860,461	864,643	859,583	832,820	798,549	892,943	897,466	865,276	869,726	840,740	927,215
Base Gas Base Carbon	MWH	347,456	382,188	446,751	510,526	572,612	305,111	401,161	463,834	591,830	707,622	755,261	778,483	814,497	768,139	869,198	873,831	854,763	850,266	813,463	908,529
Base Gas High Carbon	MWH	347,456	382,188	446,751	510,526	572,612	228,880	248,178	211,669	277,284	336,542	346,294	345,946	325,240	297,985	294,912	294,749	248,391	246,797	223,079	237,534
High Gas Low Carbon	MWH	717,399	772,035	775,200	752,340	826,809	841,886	854,671	827,433	806,836	890,486	888,869	880,124	860,219	822,440	917,565	911,061	905,799	884,221	845,123	933,899
High Gas Base Carbon	MWH	717,399	772,035	775,200	752,340	826,809	680,986	733,137	764,316	776,931	867,796	867,892	866,144	847,528	806,926	904,516	903,510	897,146	878,645	843,547	932,533
High Gas High Carbon	MWH	717,399	772,035	775,200	752,340	826,809	313,969	375,482	400,401	439,986	586,018	613,113	667,406	660,322	651,642	663,775	703,679	642,869	669,689	602,225	606,942

North Valmy 2	Valmy 2 IPCO	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Low Gas Low Carbon	MWH	29,968	54,260	78,834	107,972	154,734	174,580	194,944	216,346	279,817	447,144	525,271	635,075	686,869	702,524	737,670	736,013	785,955	756,255	821,377	798,945
Low Gas Base Carbon	MWH	29,968	54,260	78,834	107,972	154,734	105,706	136,662	126,711	138,788	197,665	222,797	237,933	242,463	280,610	266,681	342,601	351,003	428,456	418,677	591,619
Low Gas High Carbon	MWH	29,968	54,260	78,834	107,972	154,734	59,881	57,661	59,997	68,337	95,487	93,639	88,621	86,371	82,894	94,777	101,964	98,043	102,370	113,283	123,638
Base Gas Low Carbon	MWH	224,189	268,214	349,195	404,101	425,018	493,913	537,189	530,984	626,955	675,946	753,048	761,077	783,556	816,286	837,019	803,059	849,825	789,696	867,279	838,564
Base Gas Base Carbon	MWH	224,189	268,214	349,195	404,101	425,018	218,696	249,100	354,316	430,421	622,102	692,444	698,162	740,857	804,765	821,801	800,424	846,446	787,844	866,001	844,269
Base Gas High Carbon	MWH	224,189	268,214	349,195	404,101	425,018	177,129	180,504	164,793	190,504	231,876	231,545	223,026	227,316	211,784	210,079	206,165	173,427	176,448	179,555	192,085
High Gas Low Carbon	MWH	386,891	440,558	438,151	481,494	507,404	545,306	627,305	590,216	693,611	750,564	796,786	791,606	810,282	835,172	856,483	815,511	862,945	806,526	896,235	866,822
High Gas Base Carbon	MWH	386,891	440,558	438,151	481,494	507,404	509,762	551,999	542,663	651,962	703,616	766,477	774,538	796,917	829,164	850,777	811,161	858,278	796,735	892,863	861,511
High Gas High Carbon	MWH	386,891	440,558	438,151	481,494	507,404	223,873	241,376	272,563	292,329	483,721	508,925	535,348	559,161	582,516	582,800	594,384	443,470	409,932	367,342	0

Jim Bridger 1	Jim Bridger 1 IPCO	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Low Gas Low Carbon	MWH	1,045,307	1,059,071	1,103,374	1,134,111	1,056,176	1,121,305	1,321,881	1,338,096	1,343,477	1,059,933	1,306,137	1,205,143	1,376,233	1,367,689	1,391,106	1,204,122	1,403,262	1,397,574	1,400,681	1,095,088
Low Gas Base Carbon	MWH	1,045,307	1,059,071	1,103,374	1,134,111	1,056,176	910,970	1,164,285	1,195,524	1,192,263	1,056,312	1,197,147	1,161,845	1,329,088	1,331,644	1,342,669	1,177,384	1,380,172	1,346,466	1,360,191	1,092,331
Low Gas High Carbon	MWH	1,045,307	1,059,071	1,103,374	1,134,111	1,056,176	423,229	708,609	698,223	581,762	504,310	445,908	699,959	680,693	559,868	623,248	673,182	609,404	531,283	489,787	620,723
Base Gas Low Carbon	MWH	1,227,701	1,171,695	1,281,875	1,315,022	1,302,144	1,136,901	1,371,167	1,388,252	1,402,688	1,083,316	1,385,812	1,258,655	1,394,017	1,389,705	1,401,638	1,204,122	1,403,573	1,398,483	1,406,598	1,095,088
Base Gas Base Carbon	MWH	1,227,701	1,171,695	1,281,875	1,315,022	1,302,144	1,117,188	1,318,000	1,341,463	1,344,552	1,061,029	1,331,786	1,221,150	1,397,179	1,383,907	1,398,926	1,204,122	1,406,614	1,398,452	1,403,572	1,095,088
Base Gas High Carbon	MWH	1,227,701	1,171,695	1,281,875	1,315,022	1,302,144	870,656	1,135,844	1,169,846	1,147,749	1,017,372	1,085,065	1,119,739	1,202,696	1,200,145	1,184,754	1,122,956	1,195,254	1,178,392	1,135,074	1,068,740
High Gas Low Carbon	MWH	1,386,911	1,247,803	1,395,110	1,401,884	1,397,287	1,182,966	1,403,688	1,396,531	1,407,391	1,090,825	1,404,973	1,254,721	1,402,313	1,393,587	1,406,316	1,204,122	1,403,572	1,398,034	1,406,614	1,095,088
High Gas Base Carbon	MWH	1,386,911	1,247,803	1,395,110	1,401,884	1,397,287	1,143,724	1,375,748	1,384,423	1,383,058	1,081,348	1,378,941	1,245,093	1,395,988	1,389,993	1,401,225	1,204,122	1,406,614	1,398,826	1,406,614	1,095,088
High Gas High Carbon	MWH	1,386,911	1,247,803	1,395,110	1,401,884	1,397,287	1,094,913	1,228,453	1,258,494	1,279,182	1,059,857	1,260,742	1,186,343	1,338,243	1,318,730	1,334,894	1,153,777	1,347,629	1,331,539	1,342,117	1,091,614

Jim Bridger 2	Jim Bridger 2 IPCO	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Low Gas Low Carbon	MWH	581,907	675,304	947,917	1,036,730	813,488	1,159,583	1,245,453	1,323,947	1,024,528	1,268,047	1,153,791	1,323,998	1,324,209	1,373,779	1,182,468	1,397,862	1,384,872	1,395,953	1,082,931	1,395,880
Low Gas Base Carbon	MWH	581,907	675,304	947,917	1,036,730	813,488	592,852	1,061,991	1,144,238	929,167	1,054,411	1,103,989	1,257,379	1,293,446	1,335,140	1,163,068	1,342,540	1,327,133	1,387,358	1,079,745	1,382,480
Low Gas High Carbon	MWH	581,907	675,304	947,917	1,036,730	813,488	328,089	441,967	452,121	331,810	317,843	558,766	545,200	555,010	681,908	505,925	571,680	501,358	667,300	598,299	536,989
Base Gas Low Carbon	MWH	817,671	927,733	1,115,830	1,239,682	1,126,429	1,291,461	1,329,562	1,363,976	1,054,251	1,344,891	1,217,933	1,389,996	1,369,402	1,389,981	1,191,136	1,399,817	1,384,992	1,395,953	1,082,931	1,396,831
Base Gas Base Carbon	MWH	817,671	927,733	1,115,830	1,239,682	1,126,429	1,142,881	1,223,155	1,235,658	1,019,795	1,273,846	1,164,294	1,336,692	1,344,107	1,388,300	1,189,062	1,396,474	1,388,084	1,395,953	1,082,931	1,396,831
Base Gas High Carbon	MWH	817,671	927,733	1,115,830	1,239,682	1,126,429	535,530	895,295	964,624	570,581	614,513	1,067,758	1,144,416	1,143,862	1,225,985	1,097,602	1,184,170	1,170,655	1,220,891	1,046,496	1,182,116
High Gas Low Carbon	MWH	1,098,537	1,224,261	1,289,417	1,384,267	1,176,117	1,345,955	1,368,642	1,377,639	1,069,979	1,368,341	1,229,780	1,382,180	1,372,826	1,392,967	1,191,136	1,399,817	1,385,198	1,395,953	1,082,931	1,399,817
High Gas Base Carbon	MWH	1,098,537	1,224,261	1,289,417	1,384,267	1,176,117	1,301,173	1,335,047	1,305,848	1,055,997	1,324,050	1,216,527	1,373,108	1,363,182	1,388,373	1,188,150	1,396,831	1,388,224	1,395,953	1,082,931	1,399,817
High Gas High Carbon	MWH	1,098,537	1,224,261	1,289,417	1,384,267	1,176,117	1,061,732	1,160,051	1,183,609	968,648	1,105,389	1,136,242	1,294,952	1,300,882	1,337,325	1,161,892	1,334,780	1,315,373	1,344,280	1,074,241	1,348,222

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Table A-26 (cont.)
Projected Generation Forecast by Unit by Sensitivity

Jim Bridger 3	Jim Bridger 3 IPCO	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Low Gas Low Carbon	MWH	904,095	979,550	631,461	880,149	912,873	1,159,713	1,118,612	1,203,983	1,254,295	1,296,319	1,131,550	1,302,709	1,055,925	1,272,387	1,344,568	1,376,668	1,215,815	1,372,007	1,370,909	1,383,721
Low Gas Base Carbon	MWH	904,095	979,550	631,461	880,149	912,873	718,157	925,921	1,136,406	1,116,400	1,112,614	1,113,273	1,177,884	1,048,053	1,195,416	1,294,563	1,306,971	1,180,407	1,264,815	1,314,410	1,343,429
Low Gas High Carbon	MWH	904,095	979,550	631,461	880,149	912,873	346,648	487,715	507,794	443,614	413,619	362,703	430,926	410,524	424,799	389,304	413,792	392,841	373,445	350,753	379,749
Base Gas Low Carbon	MWH	1,170,858	1,212,693	872,002	1,107,351	1,216,244	1,285,256	1,178,216	1,304,260	1,339,422	1,355,580	1,277,195	1,371,675	1,066,337	1,366,415	1,368,490	1,388,937	1,216,556	1,381,685	1,374,636	1,386,130
Base Gas Base Carbon	MWH	1,170,858	1,212,693	872,002	1,107,351	1,216,244	1,168,214	1,080,355	1,305,933	1,300,854	1,300,060	1,272,023	1,312,749	1,055,386	1,343,389	1,356,325	1,380,559	1,215,366	1,376,225	1,373,673	1,384,283
Base Gas High Carbon	MWH	1,170,858	1,212,693	872,002	1,107,351	1,216,244	693,169	960,373	1,047,108	984,049	965,264	908,082	1,036,185	955,734	1,067,029	1,032,125	1,086,263	1,077,610	1,044,430	902,402	929,685
High Gas Low Carbon	MWH	1,323,739	1,341,453	1,037,628	1,317,185	1,328,719	1,331,369	1,192,992	1,338,840	1,352,768	1,366,857	1,353,982	1,368,890	1,072,136	1,375,876	1,372,491	1,389,125	1,216,556	1,382,354	1,377,620	1,386,803
High Gas Base Carbon	MWH	1,323,739	1,341,453	1,037,628	1,317,185	1,328,719	1,303,299	1,172,283	1,339,029	1,330,253	1,340,937	1,329,832	1,352,931	1,069,027	1,371,158	1,370,571	1,385,982	1,216,556	1,385,290	1,377,620	1,389,125
High Gas High Carbon	MWH	1,323,739	1,341,453	1,037,628	1,317,185	1,328,719	1,104,066	1,095,702	1,192,960	1,183,875	1,189,303	1,168,746	1,241,273	1,046,856	1,206,579	1,283,401	1,307,893	1,172,454	1,256,915	1,276,980	1,285,620

Jim Bridger 4	Jim Bridger 4 IPCO	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Low Gas Low Carbon	MWH	828,708	914,194	1,003,494	660,373	575,034	995,056	1,099,480	1,067,070	1,161,143	1,125,483	1,260,093	1,164,958	1,188,384	1,022,933	1,261,175	1,300,253	1,279,644	1,186,552	1,333,503	1,353,521
Low Gas Base Carbon	MWH	828,708	914,194	1,003,494	660,373	575,034	397,399	672,426	920,856	1,091,097	915,585	1,113,952	1,105,560	1,158,784	993,351	1,179,115	1,169,046	1,217,430	1,144,402	1,232,476	1,235,541
Low Gas High Carbon	MWH	828,708	914,194	1,003,494	660,373	575,034	272,374	337,062	348,786	387,297	372,548	314,244	331,949	328,811	323,554	306,317	312,196	289,409	289,742	289,486	309,009
Base Gas Low Carbon	MWH	1,129,686	1,172,867	1,206,835	918,819	1,096,965	1,175,610	1,220,917	1,171,274	1,318,710	1,306,206	1,372,574	1,317,867	1,331,698	1,067,209	1,383,067	1,391,741	1,406,299	1,252,930	1,398,204	1,396,886
Base Gas Base Carbon	MWH	1,129,686	1,172,867	1,206,835	918,819	1,096,965	950,569	1,057,841	1,068,412	1,174,738	1,162,854	1,184,066	1,201,061	1,264,930	1,025,398	1,334,348	1,339,961	1,351,107	1,220,974	1,371,182	1,385,315
Base Gas High Carbon	MWH	1,129,686	1,172,867	1,206,835	918,819	1,096,965	437,905	620,108	639,064	841,043	837,330	690,748	901,673	950,989	836,010	815,856	841,930	858,543	757,669	592,517	559,372
High Gas Low Carbon	MWH	1,265,905	1,305,718	1,360,514	1,021,410	1,287,940	1,313,691	1,336,754	1,207,574	1,360,642	1,355,130	1,397,298	1,369,550	1,366,967	1,084,219	1,393,508	1,398,193	1,408,561	1,256,252	1,403,619	1,393,960
High Gas Base Carbon	MWH	1,265,905	1,305,718	1,360,514	1,021,410	1,287,940	1,176,685	1,220,925	1,175,664	1,307,026	1,297,730	1,310,726	1,325,421	1,350,110	1,066,361	1,384,479	1,385,494	1,411,050	1,255,901	1,403,897	1,399,870
High Gas High Carbon	MWH	1,265,905	1,305,718	1,360,514	1,021,410	1,287,940	849,428	1,043,768	1,021,939	1,170,530	1,166,664	1,135,418	1,166,679	1,170,370	1,014,076	1,191,926	1,208,490	1,218,641	1,144,544	1,217,927	1,186,032

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 27th day of September 2013 I served a true and correct copy of the within and foregoing **Redacted** Exhibit 5A, upon the following named parties by the method indicated below, and addressed to the following:

Commission Staff Kristine A. Sasser Deputy Attorney General Idaho Public Utilities Commission 472 West Washington (83702) P.O. Box 83720 Boise, Idaho 83720-0074	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email kris.sasser@puc.idaho.gov
Industrial Customers of Idaho Power Peter J. Richardson Gregory M. Adams RICHARDSON ADAMS, PLLC 515 North 27th Street (83702) P.O. Box 7218 Boise, Idaho 83707	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email peter@richardsonadams.com greg@richardsonadams.com
Dr. Don Reading 6070 Hill Road Boise, Idaho 83703	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email dreading@mindspring.com
Idaho Conservation League Benjamin J. Otto Idaho Conservation League 710 North Sixth Street Boise, Idaho 83702	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email botto@idahoconservation.org
Snake River Alliance Dean J. Miller McDEVITT & MILLER LLP 420 West Bannock Street (83702) P.O. Box 2564 Boise, Idaho 83701	____Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email joe@mcdevitt-miller.com

Ken Miller, Clean Energy Program Director
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Elizabeth Paynter, Legal Assistant