Q. Are you the same Rick T. Link that submitted direct testimony in this proceeding?

A. Yes.

<u>Introduction and Summary</u>

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Mr. George W. Evans and Mr. Mark W. Crisp filed on behalf of the Division of Public Utilities ("DPU"), Mr. Randall J. Falkenberg on behalf of the Office of Consumer Services ("OCS"), Ms. Nancy L. Kelly on behalf of Western Resource Advocates ("WRA"), and Dr. Jeremy Fisher on behalf of Sierra Club. I further explain in my testimony corrections and updates to the analysis used by the Company to support its Request for Approval (the "Request") related to the selective catalytic reduction ("SCR") investments planned for Jim Bridger Unit 3 and Jim Bridger Unit 4 that are responsive to the concerns raised by the parties identified above.

Q. Please summarize your rebuttal testimony in this proceeding.

A. My rebuttal testimony specifically addresses concerns raised by the parties in this proceeding that are associated with the financial analysis supporting SCR investments at Jim Bridger Units 3 and 4. Specifically, I am providing testimony on the following:

- Updated base case analysis results that reflect corrections to the Company's original analysis and that incorporate assumption updates responsive to the parties showing a Present Value Revenue Requirement

Differential ("PVRR(d)") of [redacted] favorable to the SCR investments required at Jim Bridger Unit 3 and Unit 4.

- Updated and expanded natural gas and carbon dioxide ("CO_2") price scenario analysis results showing a range of PVRR(d) outcomes that support the SCR investments in six of the nine scenarios studied.
- Updates to base case natural gas price and CO_2 price assumptions that are aligned with the Company's September 2012 official forward price curve ("OFPC").
- Updates to coal cost assumptions.
- Updates to load forecast assumptions.
- Description of a new sensitivity showing that alternative Energy Gateway transmission assumptions and Wyoming wind resource assumptions improve the PVRR(d) results in favor of the SCR investments.
- Description of a new sensitivity showing that the SCR investments are favorable to an early retirement and resource replacement alternative.

<u>Corrections</u>

Q. Did you make any corrections to the PVRR(d) results that were summarized in your direct testimony?

A. Yes. The PVRR(d) is derived by taking the difference in present value revenue requirement ("PVRR") between two System Optimizer ("SO") Model simulations – one simulation in which the SCR equipment required for continued coal-fueled operations is installed at Jim Bridger Units 3 and 4 and another simulation in which the SCR investments are not made. In the simulation where the SCR installations do not occur, the SO Model chooses to convert Jim Bridger Units 3 and 4 to natural gas as the next best, albeit higher cost, alternative.

In the case where Jim Bridger Units 3 and 4 are converted to natural gas, mine capital costs that were assigned pro-rata to these two units were not reported in the PVRR(d) results summarized in my direct testimony, and therefore, mine capital costs were understated. This increases costs in the case where the SCR investments are not made at Jim Bridger Units 3 and 4 and, all else being equal, improves the PVRR(d) favorable to the SCR investment by [redacted]. Also in the case where Jim Bridger Units 3 and 4 are converted to natural gas, the PVRR(d) results summarized in my direct testimony included one year of cost for the SCR equipment on Jim Bridger Unit 4. This overstated costs in the case where the SCR investments are not made, and all else being equal, reduces the PVRR(d) favorable to the SCR investment by [redacted]. These two corrections result in increasing the base case PVRR(d) in my direct testimony from [redacted] to [redacted] favorable to the SCRs, prior to other assumption updates which I will discuss in the next section of my rebuttal testimony.

Q. Are there any other corrections made to the SO Model analysis that you summarized in direct testimony?

A. Yes. The capacity for the Wyodak coal-fired unit located in eastern Wyoming was modeled as a 324 megawatt ("MW") generation resource instead of a 268 MW generation resource. In the Company's updated analysis, which I describe in more detail below, SO Model simulations were updated with the correct capacity for the Wyodak coal unit.

Updated Base Case Assumptions

Q. Did the Company make any updates to its assumptions used in the SO Model for its analysis of the Jim Bridger Unit 3 and Unit 4 SCR equipment?

A. Yes. It is important that the Company update its analysis with new information as it becomes available to ensure that the SCR investments being evaluated in this case are in the best interest of customers. To this end, the following assumptions have been updated in the base case SO Model analysis:

- Natural gas and CO_2 price assumptions;
- Coal cash cost, mine capital and mine reclamation assumptions; and
- Load forecast assumptions.

In addition, in the current proceeding, the Company accepted the adjustment proposed by parties to set the Gadsby peaking units and the Currant Creek combined cycle plant as must-run units.

Q. How have forward natural gas prices and long-term natural gas price forecasts changed since the Company filed its Request?

A. The Company relied upon its December 2011 OFPC in the base case analysis of the Jim Bridger Unit 3 and 4 SCR investments and estimated the PVRR(d) impact of using its June 2012 OFPC in the Request. Average annual natural gas prices at the Opal market hub over the forward period 2016 through 2030 were down approximately nine percent in the June 2012 OFPC as compared to the December 2011 OFPC. The updated base case analysis discussed herein was performed using the September 2012 OFPC. Opal natural gas prices from the September OFPC over the forward period 2020 and beyond are identical to those in the June 2012 OFPC and are four percent higher than average annual prices from June

2012 OFPC over the forward period 2016 through 2019.

Q. Describe how the forward trend in natural gas prices compares to historical prices at the Opal market hub.

A. Figure 1R below shows historical average annual natural gas prices and forward natural gas prices from the December 2011 OFPC, the June 2012 OFPC, and the updated base case September 2012 OFPC at the Opal market hub. Over the eleven-year period 2002 through 2012, prices at Opal averaged $4.38 per mmBtu. The highest annual average price over this period is $7.26 per mmBtu, which occurred in 2005 when hurricanes Katrina, Rita, and Wilma caused significant production losses in the Gulf of Mexico region. Average annual prices were $6.48 per mmBtu in 2008, which coincided with the general rush to commodities in advance of the collapse of the housing bubble later that year.

In the September 2012 OFPC, Opal market prices over the period 2016 through 2020 average $4.98 per mmBtu. Prices over the period 2021 through 2030 average $6.45 per mmBtu, which is 29 percent higher than prices in the 2016 to 2020 timeframe and 47 percent higher than average historical prices over the period 2002 through 2012. While forward prices from the September 2012 OFPC have fallen in relation to forward prices from the December 2011 OFPC, average annual prices over the mid- to long-term are expected to rise above near-term forwards and historical price levels.

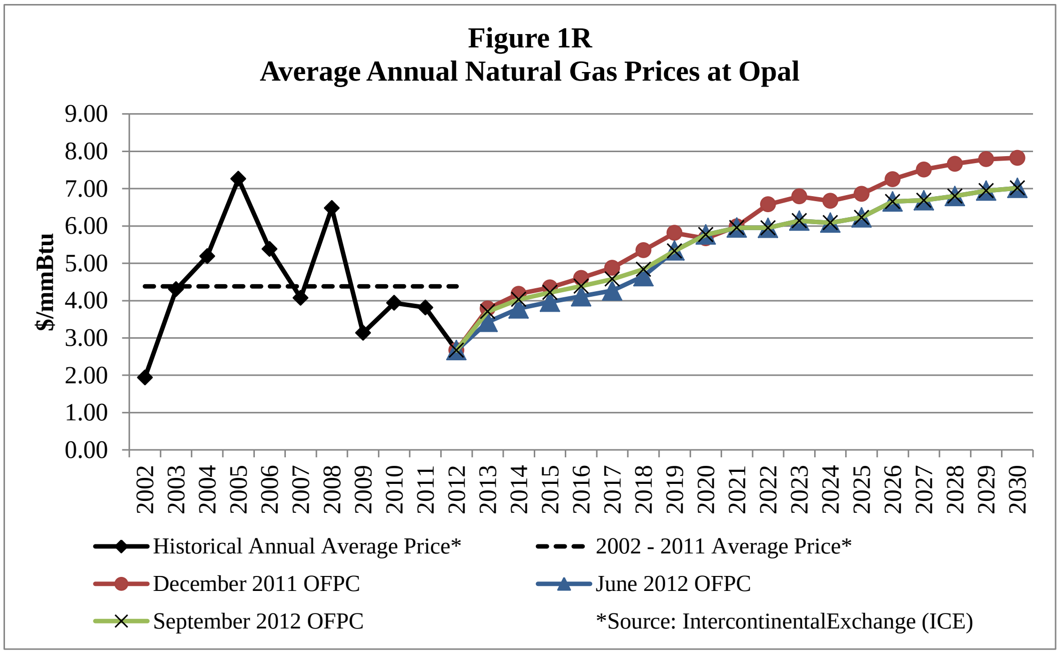


Figure 1R
Average Annual Natural Gas Prices at Opal

Q. Has the Company updated its base case assumptions for CO_2 prices?

A. Yes. The September 2012 OFPC reflects an assumed CO_2 policy that will be implemented in 10 years, and as such, CO_2 prices are assumed to begin in 2022, one year later than assumed in the Company's original base case analysis. The initial price level for CO_2 emissions has not changed, with prices starting at $16 per ton and escalating at three percent plus inflation thereafter. The one-year delay in the assumed start date for CO_2 prices remains consistent with assumptions from third party forecasts, with a one-year delay observed in one third party projection, and is consistent with the lack of legislative activity on developing federal greenhouse gas policies in 2012.

Q. Please describe how the Company's coal cost assumptions have been updated for the new base case analysis.

A. Base case coal cost assumptions have been updated for both the four-unit operation and the two-unit operation fueling plans. As I discussed in my direct testimony, the two-unit operation fueling plan takes into consideration how the plant fueling requirements are affected if Jim Bridger Units 3 and 4 stop operating as coal-fueled generation assets. The updated coal cost assumptions are informed by more current mine plans and reclamation plans, which are described in more detail in the rebuttal testimony of Company witness Ms. Cindy Crane.

Updated cash coal cost assumptions, representing all non-capital related costs to fuel the Jim Bridger plant, are included alongside the cash coal costs assumed in the original base case in Confidential Exhibit RMP__(RTL-1R). On average, over the period 2013 through 2030, cash coal costs for the four-unit operation fueling plan have [redacted] per mmBtu (approximately 6.6 percent) as compared to the original base case assumptions. The increase in cash coal costs for the four-unit operation fueling plan reflects updated third party coal prices and transportation costs for Black Butte coal as well as updated cash operating costs for Bridger Coal Company. The increase in cost is primarily attributable to an increase in final reclamation trust contributions and the cost impact of reduced production from the Bridger surface mine in the 2015-2017 timeframe.

Over the period 2013 through 2030, average annual cash coal costs for the two-unit operation fueling plan have [redacted] per mmBtu (approximately 4.3 percent) relative to the original base case assumptions. The decrease in cash coal costs for the two-unit operation fueling plan, which also reflects updated third party coal prices and transportation costs for Black Butte coal and Bridger Coal Company cash operating costs, is principally associated with reduced underground mine operating costs starting in 2017. Company witness Ms. Cindy Crane describes in more detail updated coal cost assumptions.

Q. Did the Company update mine capital cost assumptions given the availability of a more current mine plan?

A. Yes. As informed by an updated mine plan, the mine capital cost assumptions for Bridger Coal Company's surface and underground mining operations have been updated for both a four-unit operation and the two-unit operation fueling plan at the Jim Bridger plant. Updated mine capital cost assumptions are included alongside the mine capital costs assumed in the original base case in Confidential Exhibit RMP__(RTL-2R).

Over the period 2013 through 2030, average annual mine capital cost assumptions for a four-unit operation fueling plan are higher by about [redacted]. Over the same period, average annual mine capital cost assumptions for a two-unit operation fueling plan at the Jim Bridger plant are higher by approximately [redacted]. Relative to the original base case assumptions, mine capital cost increases are most significant from 2021 through 2026, where annual average mine capital costs are higher by [redacted] in the four-unit operation fueling plan and higher by [redacted] in the two-unit operation fueling plan. Beyond 2026, average annual updated mine capital cost assumptions are lower by [redacted] and [redacted] in the four-unit and two-unit operation fueling plans, respectively.

Q. Please summarize the key drivers behind the updated mine capital cost assumptions.

A. As described in the testimony of Company witness Ms. Cindy Crane, the key drivers behind the updated mine capital costs in the cases pertain to additional surface and underground mine reserve acquisition costs as well as additional mine extension costs and longwall system rebuild/replacement costs.

Q. Did the Company update mine reclamation cost assumptions in its updated base case analysis?

A. Yes. Mine reclamation costs are included in the updated cash coal cost assumptions I described above. Cash coal costs drive the fuel cost for Jim Bridger in the SO Model analysis, which has a study horizon extending out through 2030.

Q. Was the Company criticized for its treatment of mine reclamation costs beyond the 2030 study period used in the SO Model analysis?

A. Yes. The DPU requested the Company include in its analysis mine reclamation costs for the four-unit operation fueling plan that are expected to occur beyond 2030. Similarly, the OCS noted that reclamation costs in the continued coal operation case beyond the 2030 study horizon were not factored into the PVRR(d) results originally filed by the Company.

Q. How do you respond?

A. In the updated base case analysis, the Company has factored into its PVRR(d) results contributions to the mine reclamation trust that are not accounted for in the cash coal costs inputs used in the SO Model. This includes contributions to the mine reclamation trust over the period 2031 through 2037 for both the four-unit and two-unit operation fueling plans at the Jim Bridger plant. Over this timeframe, annual contributions to the mine capital trust total [redacted] under a four-unit operation plan and [redacted] under a two-unit operation plan. Assumptions for contributions to the mine reclamation trust are summarized in Confidential Exhibit RMP__(RTL-3R).

Q. In its review of base case assumptions, did the Company include the most current load forecast in its updated SO Model analysis?

A. Yes. The Company included in its updated base case analysis its most current load forecast consistent with the load forecast used in the "Needs Assessment" filed with the Commission through the All Source Request for Proposals for a 2016 Resource (Docket No. 11-035-73).

Q. Please describe how the Company's load forecast has changed.

A. The Company's current load forecast is lower than the load forecast used in the original base case analysis, which was consistent with the load forecast used in the Company's 2011 IRP Update. The lower load forecast is driven by reduced industrial sector loads in Utah and Wyoming that reflect load request cancellations and postponements prompted by prolonged recessionary impacts and permitting issues. The most current load forecast also incorporates projections of increased industrial self-generation driven largely by lower wholesale gas and electricity prices. Finally, the Company's new industrial load forecast uses a regression analysis in place of a probability assessment of customer-provided forecasts.

Figure 2R below compares the updated coincident peak load forecast to the original coincident peak load forecast used in the SO Model analysis. As compared to the original load forecast, the annual coincident peak load projection is on average reduced by 663 megawatts over the period 2015 through 2020, reduced by 934 megawatts over the period 2021 through 2025, and reduced by 1,215 megawatts over the period 2026 through 2030.

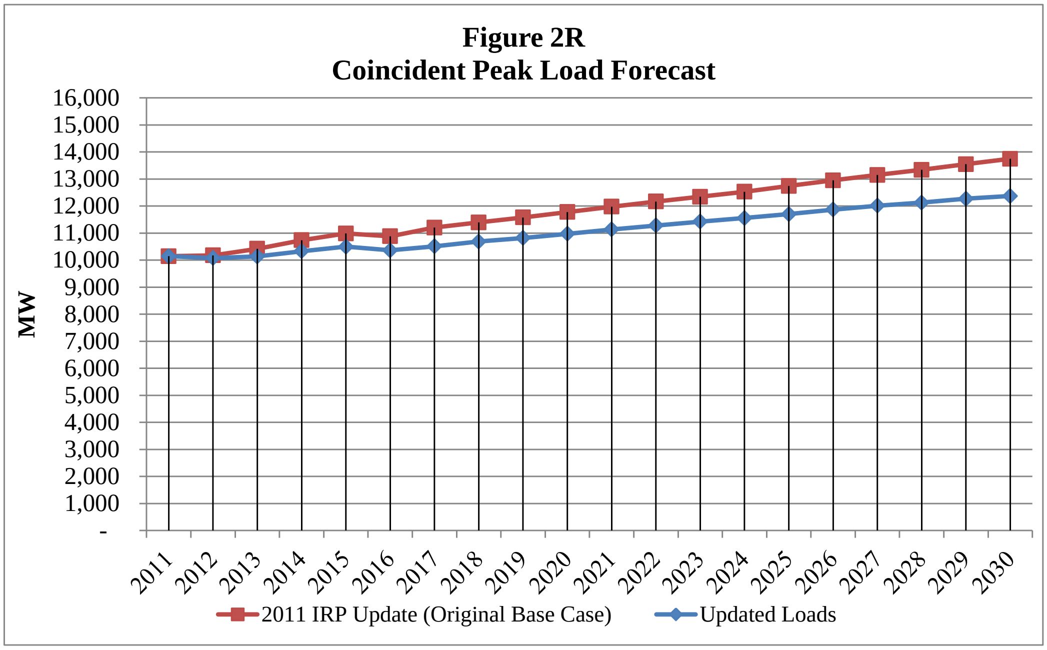


Figure 2R
Coincident Peak Load Forecast

Q. Were any parties to this proceeding critical of how certain assets were dispatched in the Company's SO Model analysis?

A. Yes. Both the DPU and the OCS were critical of the SO Model's dispatch for certain generation units in the Company's system. The DPU noted differences in the dispatch of the Wyodak coal unit, the Gadsby peaking units, and the Currant Creek combined cycle plant as compared to historical generation data, and the OCS suggested that the Gadsby peaking units and the Currant Creek combined cycle plant should be modeled as must run assets as implemented in recent rate proceedings.

Q. Did you make any changes to the SO Model in response to these concerns?

A. Yes. As I mentioned earlier in my testimony, the capacity for the Wyodak coal unit located in eastern Wyoming was modeled as a 324 MW generation resource instead of a 268 MW generation resource. In the Company's updated analysis, SO Model simulations were updated with the correct capacity for the Wyodak coal unit. The Company also enforced must run settings on the Gadsby peaking units and the Currant Creek combined cycle plant to be consistent with the must run settings applied to these assets in GRID for recent net power cost filings.

Q. Once these changes were implemented, did you compare how the SO Model's forecasted generation levels compare to historical generation levels from the Wyodak, Gadsby, and the Currant Creek plants?

A. Yes. In direct testimony, the DPU presented three figures, each comparing historical generation levels from FERC Form 1 data to the SO Model's forecast of annual generation from each of these facilities through 2015.[1] The Company updated each of these figures with generation from its updated SO Model base case, extended the historical period back to 2004 for the Wyodak and Gadsby plants, and included updated generation levels from the SO Model through 2030 for each of these facilities.[2]

Figures 3R through 5R below compare historical generation with updated forecasted generation from the Wyodak, Gadsby, and the Currant Creek plants. Implementing the correction to the Wyodak capacity and implementing the must run settings on the Gadsby peaking units and the Currant Creek plant produces forecasted generation that is reasonably consistent with historical generation

[1] Please refer to the Direct Testimony of DPU witness Gorge W. Evans at lines 83, 97, and 112.
[2] Currant Creek did not come online as a combined cycle facility until the spring of 2006, and so the historical period does not go back to 2004.

levels at these facilities.

Figure 3R
Wyodak Annual Generation: Actual vs. Updated SO Model

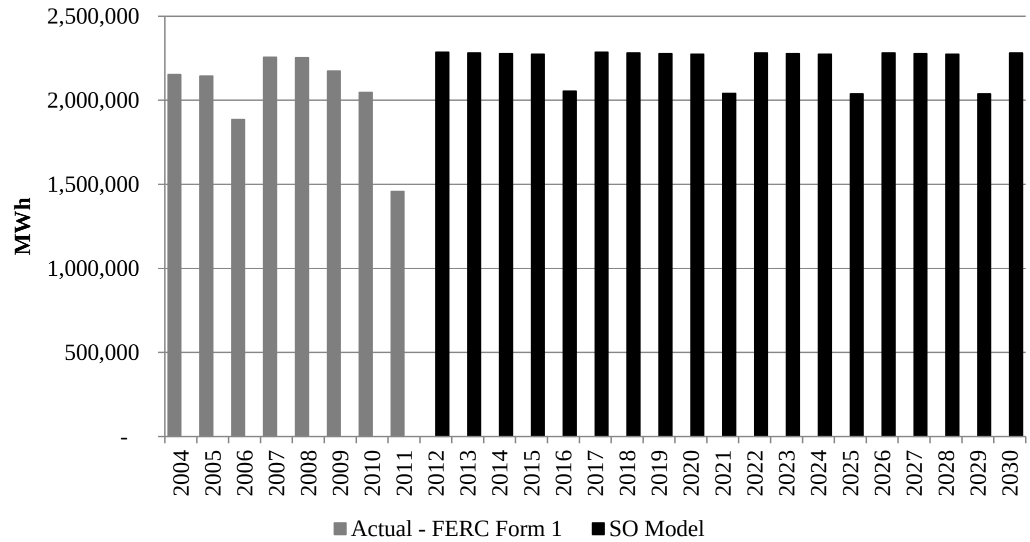
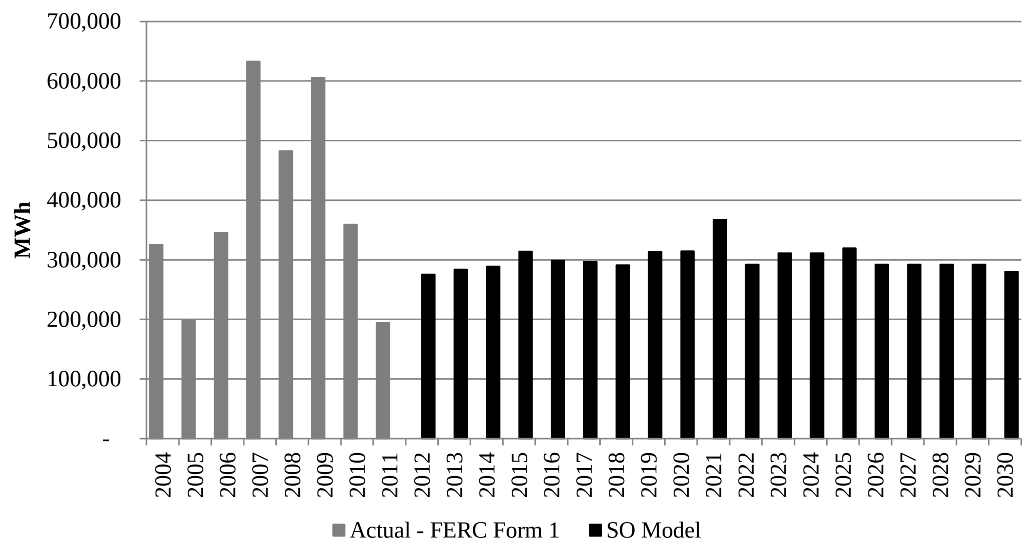
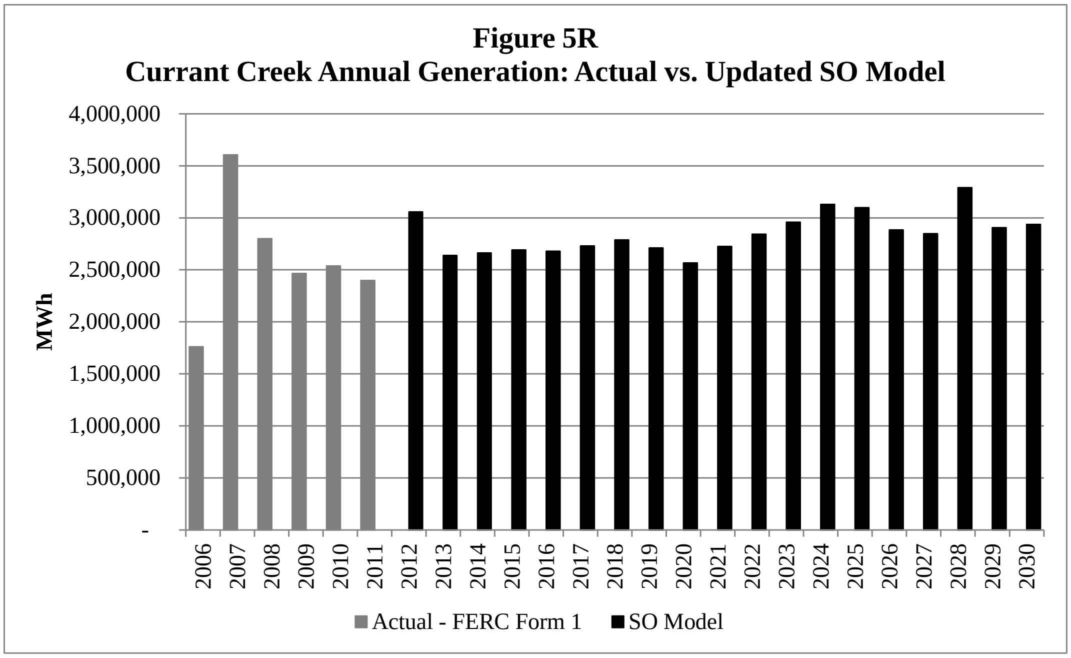


Figure 4R
Gadsby Annual Generation: Actual vs. Updated SO Model





Q. Why is the historical generation from Gadsby in 2007 and 2009 higher than generation levels from other years?

A. The operating costs at Gadsby are higher than operating costs of other generation resources in the Company's system and often higher than the price of power in the market. As a marginal generating facility, Gadsby provides valuable capacity to the system and is often dispatched during peak load and price periods, is used to carry operating reserves, and is used to respond to changes in system conditions such as outages at other generating facilities. As a marginal unit in the Company's dispatch stack, year-to-year generation levels are more likely to fluctuate than year-to-year generation levels from base load assets that operate in most hours of the year.

Q. Did you review the DPU's claim that Company's SO Model does not produce reasonable fuel costs?

A. Yes. The DPU compared coal and natural gas costs for 2011 as output by the SO

Model with the Company's FERC Form 1 data for the same 2011 period. This comparison shows that the SO Model fuel costs are lower than actual costs reported in FERC Form 1.

Q. Does this comparison demonstrate that the SO Model has not been properly tuned for the analysis?

A. No. The comparison is not valid. Inputs to the SO Model for calendar year 2011 were not populated with actual cost data as a means to benchmark the model outputs to actual reported cost information. SO Model outputs for 2011 are entirely ignored and not in any way used in the Company's evaluation of the SCR investments being evaluated in this case.

Q. Did the Company update its forced outage assumptions applied to Jim Bridger Units 3 and 4?

A. No. The OCS explains how the Company's forced outage rate assumptions for Jim Bridger Units 3 and 4 are lower than forced outage rate assumptions used in GRID for net power cost filings. WRA also expressed concern that the Company's unit availability assumptions are optimistic. The assumptions used in the SO Model analysis do not explicitly separate forced outage rates from planned outage rate assumptions. Rather, the SO Model assumptions are configured to represent projected availability, taking into consideration both planned and unplanned outage events on a forecast basis. The Company believes that forecasted unit availability data are appropriate for use in analyzing the forecasted PVRR(d) benefits or costs associated with SCR equipment required on Jim Bridger Unit 3 and Unit 4.

Q. How are forced outages modeled in GRID for regulatory net power cost filings?

A. The Company uses the average of the most recent four-year historical outage data for each unit. This outage amount is used in GRID to de-rate the maximum capacity of each unit by a fixed percentage.

Q. Why does the Company use a four-year historical average to model forced outages for net power cost studies?

A. There are two primary reasons. First, use of a rolling four-year average reflects the current operation of each unit and smoothes the data to limit the magnitude of changes from year to year. Second, using actual data to determine a normalized outage rate allows forecast net power costs to reflect the availability that was historically experienced by the Company.

Q. How are planned outages modeled in GRID for regulatory net power cost filings?

A. Planned outages are based on the same four-year average as forced outages. They are placed throughout the forecast period to best match the timing of the historical outages and are modeled by setting the unit that is on planned outage to zero.

Q. Why does the Company use a four-year historical average to model planned outages for purposes of net power cost filings?

A. For the same reasons stated above for forced outages.

Q. Please explain why use of forecasted unit availability (planned and unplanned outages) is applied in the SO Model analysis supporting this case.

A. Unlike a typical net power cost study, which often covers a one-year normalized forward test period, the SO Model simulates PacifiCorp's system over a study horizon extending through 2030. Use of forecasted availability rates allows the SO Model to factor into its optimization routine the anticipated timing of major maintenance activities, which are aligned with the installation of environmental equipment such as the SCR equipment required on Jim Bridger Units 3 and 4. Forecasted availability rates also allow the SO Model to reflect expected year-to-year availability changes identified by plant staff in anticipation of operational changes or regulatory requirements identified during the Company's planning processes. The availability forecasts generated by plant staff are informed by prior operating history and experience, recognized industry best practices, and original equipment manufacturer recommendations, where applicable.

Q. Did you review the DPU's claim that it is not reasonable to apply manual adjustments to the SO Model results?

A. Yes. In the original analysis supporting the Request, the Company performed a series of cost adjustments to the SO Model results to reflect assumption updates made after the original SO Model simulations were completed to ensure PVRR(d) results would reflect current information. In updating its analysis, the Company has incorporated into the SO Model all current assumptions, which alleviates the need for manual adjustments.[3]

<u>**Updated Base Case Results**</u>

Q. How has the base case PVRR(d) result changed with the updated assumptions that were applied in the SO Model?

[3] Note, the PVRR(d) impact of mine reclamation funds over the period 2031 through 2037, which was requested by several parties, are calculated outside of the SO Model because this period extends beyond the SO Model study horizon.

A. As originally described in my direct testimony, the base case developed off of the December 2011 OFPC produced a PVRR(d) that was [redacted] favorable to the SCR investment required at Jim Bridger Units 3 and 4. The updated base case that has been developed off of the September 2012 OFPC, and that incorporates corrections and assumption updates as I described above, produces a PVRR(d) that is [redacted] favorable to the SCR investment required at Jim Bridger Units 3 and 4.

Q. With the updated assumptions, did the SO Model continue to select gas conversion as the next best, albeit higher cost, alternative to the SCR investments at Jim Bridger Units 3 and 4?

A. Yes.

Q. Please explain how the updated assumptions contribute to the change in base case PVRR(d) results.

A. Confidential Table 1R below summarizes how the corrections and assumption updates applied in the base case analysis affect the base case PVRR(d) results as compared to what was summarized in my direct testimony. The table shows that after accounting for the correction to mine capital and SCR costs reported in the original two-unit operation case, updated natural gas price assumptions, and updated coal cost assumptions are most influential to the change in PVRR(d) results.

Confidential Table 1R Change in Base Case PVRR(d) (Benefit)/Cost of SCRs $ Million		
Description of Update/Correction	**Incremental Change in PVRR(d)**	**Accumulated Change in PVRR(d)**
Original Base Case in Request (December 2011 OFPC)	n/a	[redacted]
Correction to Mine Capital/SCR Costs	[redacted]	[redacted]
Correction to Wyodak capacity, application of Gadsby& Currant Creek Must Run	[redacted]	[redacted]
Update to September 2012 OFPC	[redacted]	[redacted]
Updated Coal Cost & Bridger Coal Mine Capital	[redacted]	[redacted]
Updated Load Forecast	[redacted]	[redacted]
Mine Reclamation Fund Contributions beyond 2030	[redacted]	[redacted]

Q. Please explain why the updated forward price curve assumptions make the PVRR(d) results less favorable to the SCR investments.

A. Nominal levelized natural gas prices at the Opal market hub over the period 2016 through 2030 in the December 2011 OFPC were $6.18 per mmBtu. Nominal levelized natural gas prices at the Opal market hub from the September 2012 OFPC over the same term are $5.72 per mmBtu, which is approximately eight percent below levelized prices from December 2011. The assumed price for natural gas directly affects the cost for a gas-fueled replacement alternative, which is directionally favorable to gas conversion as an alternative to the SCR investments. Natural gas prices are also a key factor in setting wholesale power prices. As gas prices fall, the market value of energy is reduced. In this way, gas prices disproportionately affect the value of energy net of operating costs from Jim Bridger Units 3 and 4 when operating as coal-fueled resources versus the value of reduced energy output net of operating costs from a gas conversion alternative.

Q. Did you identify in your direct testimony how falling natural gas prices might affect the PVRR(d) of the SCR investments?

A. Yes. Based upon the relationship between natural gas price assumptions and PVRR(d) results described in my direct testimony, I described that the June 2012 OFPC would erode the base case PVRR(d) results favorable to the Jim Bridger Unit 3 and Unit 4 SCR equipment by approximately [redacted]. Considering that natural gas prices from the September 2012 OFPC are slightly higher than the natural gas prices from the June 2012 OFPC through 2018 and that prices between the two price curves are aligned from 2019 and beyond, the [redacted] incremental impact of updating forward price curve assumptions is consistent with the estimate in my direct testimony.[4]

Q. Please explain why the updated coal costs make the PVRR(d) results less favorable to the SCR investments.

A. As I discussed earlier in my testimony, cash coal costs were updated consistent with more current mine plans and reclamation plans for Bridger Coal Company. The updated average annual cash coal cost assumptions for the continued coal operation case have increased by approximately 6.6 percent, and the average annual cash coal costs for Jim Bridger Units 1 and 2 in the Jim Bridger Unit 3 and Unit 4 gas conversion case have decreased by approximately 4.3 percent. Higher cash coal costs in the continued coal operation case and lower cash coal costs in the gas conversion case reduces the benefits of the SCR investments. Nonetheless, while the updated PVRR(d) results are directionally less favorable to

[4] Nominal levelized prices at the Opal market hub over the period 2016 through 2030 were $5.65 per mmBtu in the June 2012 OFPC, which is just $0.07 per mmBtu lower than levelized prices from the September 2012 OFPC.

the SCR investments, the updated base case analysis continues to support the SCR investments required at Jim Bridger Units 3 and 4.

Updated Natural Gas and CO_2 Price Scenario Assumptions

Q. Has the Company updated its natural gas price and CO_2 price scenario analysis?

A. Yes. The DPU testified that the Company should consider completing a revised SO Model analysis that incorporates a more current base case forecast and updated low and high price projections. Concurrent with the update to base case forward price curve assumptions as discussed above, the Company reviewed the range of updated natural gas and CO_2 price forecasts from third parties to establish updated low and high projections.

Q. Did you use the same approach to establish low and high projections for your updated analysis?

A. Yes. The fundamental approach of reviewing the range of third party price forecasts in relation to the base case price projections is identical to the approach used to develop natural gas and CO_2 price scenarios in the Company's original analysis. We simply included in our review more recent third party forecast data.

Q. Did the Company expand the number of natural gas and CO_2 price scenarios used to evaluate the Jim Bridger Unit 3 and Unit 4 SCR investments?

A. Yes. The DPU testified that updated SO Model natural gas price and CO_2 price scenario analysis be expanded to include additional scenarios that pair low natural gas price with low CO_2 price assumptions and that pair high natural gas price with high CO_2 price assumptions. The Company has incorporated these two additional scenarios in its updated SO Model analysis. Table 2R below summarizes the directional changes to base case natural gas and CO_2 price assumptions among the nine different scenarios included in the updated analysis. Confidential Exhibit RMP__(RTL-4R) to my testimony shows how the low and high price assumptions used in the Company's updated scenarios compare to current third party forecasts.

Table 2R
Natural Gas and CO_2 Price Scenarios

Description	Natural Gas Prices	CO_2 Prices
Base Case	September 2012 OFPC	$16/ton in 2022 rising to $23/ton by 2030
Low Gas, Base CO_2	Low	$16/ton in 2022 rising to $23/ton by 2030
High Gas, Base CO_2	High	$16/ton in 2022 rising to $23/ton by 2030
Base Gas, $0 CO_2	Base Case Adjusted for Price Response	No CO_2 Costs
Base Gas, High CO_2	Base Case Adjusted for Price Response	$14/ton in 2020 rising to $65/ton by 2030
Low Gas, High CO_2	Low Case Adjusted for Price Response	$14/ton in 2020 rising to $65/ton by 2030
High Gas, $0 CO_2	High Case Adjusted for Price Response	No CO_2 Costs
Low Gas, $0 CO_2 (New Scenario)	Low Case Adjusted for Price Response	No CO_2 Costs
High Gas, High CO_2 (New Scenario)	High Case Adjusted for Price Response	$14/ton in 2020 rising to $65/ton by 2030

Q. How do your updated CO_2 price scenarios compare to those used in your original analysis?

A. As noted earlier, base CO_2 price assumptions begin in 2022 as opposed to 2021. For the low case, the Company continues to assume that there is no CO_2 price imputed on emissions. The high case assumes there is a tax on CO_2 emissions beginning 2020, two years later than in the original high case assumptions and two years earlier than in the updated base case assumptions. Relative to the original high case assumptions, CO_2 prices in the updated high case start at a lower price level, but escalate rapidly through 2025 and reach $65 per ton by 2030. The change in the high case CO_2 prices better aligns with a current high price forecast from a reputable third party source.

Q. How do your updated natural gas price scenarios compare to those used in your original analysis?

A. Consistent with the drop in base case natural gas prices, third party forecasters have lowered their long-term natural gas price projections, which supports a drop in the Company's low and high natural gas price assumptions. At base CO_2 price levels, average annual prices in the low natural gas price forecast and the high natural gas price forecast are down by 15 percent and 13 percent, respectively, over the period 2016 through 2030.

Q. Why do you adjust natural gas price assumptions in those scenarios where CO_2 price assumptions vary from the base case?

A. As discussed in my direct testimony, we assume that different levels of CO_2 prices will affect the demand for natural gas in the electric sector of the U.S. economy and that any change in natural gas demand would be balanced with a change in supply and subsequent movement in the market price for natural gas. In effect, we assume that as the intersection of supply and demand for natural gas changes, the price for natural gas will change accordingly.

Q. Have any of the parties in this case identified concerns with this assumption?

A. Yes. Sierra Club testifies that there is currently no definitive evidence that such a trend would occur and that it is not appropriate to assume natural gas prices will increase in the presence of a CO_2 price.

Q. Does the Company only apply upward adjustments to natural gas prices in response to changes in CO_2 price level?

A. No. The assumed interaction between natural gas prices and CO_2 prices is bi-directional. That is, the Company not only assumes natural gas prices rise in the presence of a CO_2 price (or with increased CO_2 price levels), but also incorporates downward natural gas price pressures when CO_2 prices are removed or lowered.

Q. Is this the first time that the Company has made assumptions regarding the interaction between natural gas and CO_2 prices?

A. No. The Company has assumed a dynamic interaction between natural gas price and CO_2 price assumptions in developing market price scenarios for the 2008 IRP, the 2011 IRP, and in developing market price scenarios in the evaluation of bids submitted into recent all source request for proposals.

Q. Are you aware of other forecasts that account for the interaction between natural gas prices and CO_2 prices?

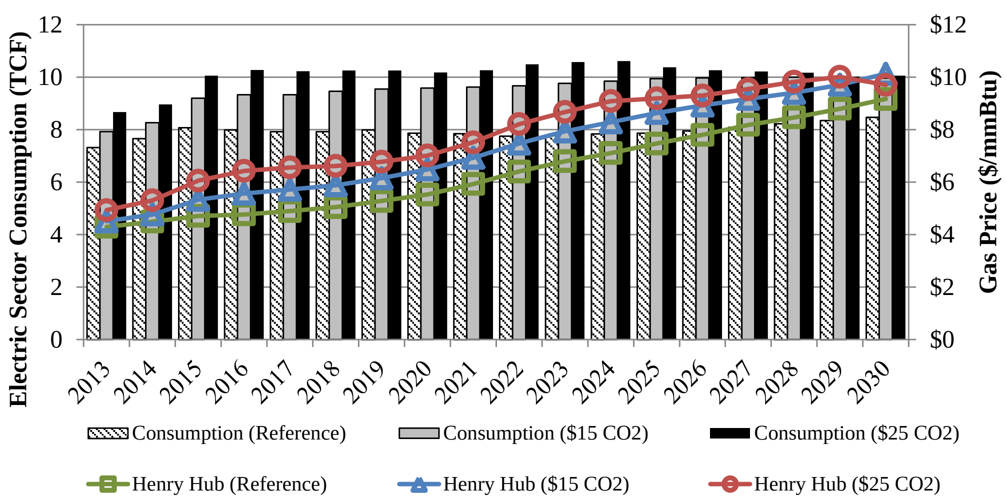
A. Yes. The U.S. Energy Information Administration's ("EIA") 2012 Annual Energy Outlook ("AEO") includes a reference case Henry Hub natural gas price forecast and a broad range of forecast scenarios.[5] In one of these scenarios, EIA applies a $15 CO_2 emissions fee to the U.S. economy beginning 2013. In another scenario, EIA applies a $25 CO_2 emissions fee.[6] Under the AEO reference case and in the two CO_2 emission fee scenarios, EIA reports natural gas consumption by sector of the U.S. economy, including a line item for the electric sector, and a

[5] The U.S. Energy Information Administration is the statistical and analytical agency within the U.S. Department of Energy.
[6] In each CO_2 scenario, prices are assumed to escalate at five percent per year.

forecast of Henry Hub natural gas prices.

Figure R6 below shows EIA's annual electric sector natural gas consumption and the accompanying Henry Hub natural gas price forecast for the AEO 2012 reference case and the two CO_2 emission fee scenarios. The left horizontal axis reports electric sector gas consumption in trillion cubic feet ("TCF") and the right horizontal axis reports nominal Henry Hub natural gas prices. The figure clearly shows that electric sector natural gas consumption increases from the reference case when a \$15 CO_2 emissions fee is assumed, and increases further when a \$25 CO_2 emissions fee is assumed. Moreover, the figure shows that the presence of a CO_2 emissions fee drives higher natural gas prices consistent with a rise in natural gas consumption, and that the magnitude of the impact increases with a higher CO_2 emissions fee assumption.

Figure 6R
Annual Energy Outlook 2012: Gas Consumption & Gas Price Changes with Varying CO_2 Price Assumptions

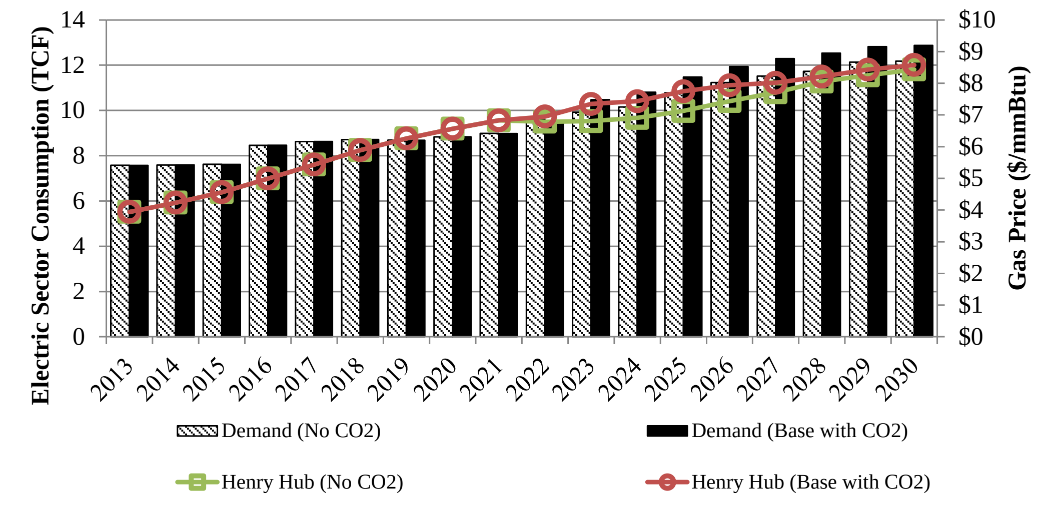


Q. Do any other third party forecast providers included in your review of natural gas and CO_2 price forecasts assume that there is a relationship

between natural gas and CO_2 prices?

A. Yes. [redacted] produces a variant to their base case natural gas price forecast that removes the CO_2 price assumptions included in their base case projection. [redacted] assumes in their base case forecast that there is a nominal CO_2 price of $15.59 per ton beginning in 2023 escalating to $26.77 per ton by 2030. Figure R7 below shows [redacted] annual electric sector natural gas consumption and the accompanying Henry Hub natural gas price forecast for their base case forecast inclusive of CO_2 price assumptions and their scenario forecast the removes the base case CO_2 price assumptions. When CO_2 price assumptions are removed, [redacted] forecasts a drop in electric sector demand for natural gas and a corresponding drop in natural gas price. This interaction between CO_2 price, electric sector demand for natural gas, and natural gas prices is consistent with forecasts produced by EIA in the 2012 AEO and consistent with the adjustments the Company applies to natural gas prices in the scenarios used to evaluate the SCR investments required for Jim Bridger Unit 3 and Unit 4.

Figure 7R
Third Party Forecast: Gas Consumption & Gas Price Changes with Varying CO_2 Price Assumptions



Q. What types of third party CO_2 price forecasts do you evaluate in developing a reasonable range of CO_2 price trajectories?

A. When reviewing third party CO_2 price forecasts, we focus on recent projections from reputable forecast services such as [redacted]. As a point of reference, we often compare these forecasts with U.S. EPA's analysis of past policy proposals, focusing on then current baseline projections and any CO_2 price ceilings and floors that may have been included in those proposals. The intent is to provide context for how current price forecasts that take into consideration current market conditions and the current policy landscape, compare with well-known policy proposals that have been debated in the past.

Q. Have any of the parties to this case suggested the Company review additional CO_2 price forecasts?

A. Yes. Sierra Club describes how Synapse Energy Economics, Inc., the consulting firm that employs Sierra Club witness Dr. Jeremy Fisher, has reviewed a wide range of CO_2 price assumptions used in IRP and utility dockets over the 2009 – 2012 timeframe and further reviewed government and "other" forecasts to arrive at a range of base, low and high CO_2 price assumptions.[7] Sierra Club suggests that these data show the Company's CO_2 price assumptions are too low. Moreover, Sierra Club testifies that U.S. EPA's analysis of these past policy proposals produced a range of CO_2 price trajectories and that a valid mechanism of evaluating the high and low estimates of a particular bill would be to look at a range of models and range of scenarios.

Q. How do you respond?

A. As noted earlier, the Company has focused its review on *recent* third party forecasts. Reviewing price forecasts used by others for planning purposes dating back to 2009 is not a reasonable means to establish a range of CO_2 price assumptions that take into consideration current market conditions and policy developments. Natural gas prices have a significant impact on prospective CO_2 price levels that would be required to achieve an emissions target. Higher natural gas prices increase the cost of reducing emissions because it increases the cost of transitioning away from coal-fired generation to natural gas-fired generation. Conversely, lower natural gas prices reduce the cost of achieving emission reductions by reducing the cost of transitioning to natural gas-fired generation, which is more efficient and produces lower CO_2 emissions. Consequently, the CO_2 price required to achieve an emissions target is correlated with the price of natural gas, where, for a given emissions reduction target, high natural gas prices

[7] Please refer to the Direct Testimony of Sierra Club witness Dr. Jeremy Fisher at page 10, line 3.

yield a higher CO_2 price and low natural gas prices yield a lower CO_2 price. Given long-term forecasts for natural gas prices have dropped significantly since 2009, CO_2 price assumptions developed as much as four years ago are antiquated and not relevant to current market conditions. Moreover, it is not reasonable to review the range of CO_2 price trajectories developed by U.S. EPA's analysis of past legislative proposals, which are similarly dated.

Updated Natural Gas and CO_2 Price Scenario Results

Q. Please describe the results from the updated natural gas and CO_2 price scenarios.

A. The natural gas and CO_2 price scenario results show that the investment in SCRs at Jim Bridger Unit 3 and Jim Bridger Unit 4 remains favorable to the next best, albeit higher cost natural gas conversion alternative under all base and high natural gas price scenarios at all assumed CO_2 price levels. In these scenarios, the PVRR(d) ranges between [redacted] favorable to the SCRs (base gas, high CO_2) and [redacted] favorable to the SCRs (high gas, zero CO_2). The PVRR(d) results are unfavorable to the SCRs only in those scenarios where low natural gas prices are assumed.

When low natural gas price assumptions are paired with base CO_2 price assumptions, the nominal levelized price of natural gas at Opal over the period 2016 to 2030 is \$3.70 per mmBtu and the PVRR(d) is [redacted] unfavorable to the SCR investments required at Jim Bridger Units 3 and 4. In the low gas zero CO_2 scenario, the nominal levelized price of natural gas at Opal is \$3.41 per mmBtu over the 2016 to 2030 timeframe, and the PVRR(d) is [redacted]

[redacted] unfavorable to the SCRs. When low natural gas prices are paired with high CO_2 price assumptions, the nominal levelized price at Opal over the period 2016 to 2030 is $3.78 per mmBtu, and the PVRR(d) is [redacted] unfavorable to the SCRs. The PVRR(d) results from the updated natural gas and CO_2 price scenarios are summarized alongside the base case results in Confidential Exhibit RMP___(RTL-5R) to my testimony.

Q. How do the PVRR(d) results trend among the different updated natural gas price assumptions?

A. As demonstrated in the Company's original analysis, the updated scenario results show that there is a strong trend between natural gas price assumptions and the PVRR(d) benefit/cost associated with the incremental pollution control investments required for continued operation of Jim Bridger Units 3 and 4 as coal-fueled assets. With higher natural gas price assumptions, the incremental SCR investments become more favorable to the Jim Bridger Unit 3 and Unit 4 gas conversion alternatives. Conversely, lower natural gas prices improve the PVRR(d) results in favor of the gas conversion alternative. Lower natural gas prices lower the fuel cost of the gas conversion alternative, lowers the fuel cost of the other natural gas-fueled system resources that partially offset the generation lost from the coal-fueled Jim Bridger units, and lowers the opportunity cost of reduced off system sales when Jim Bridger Units 3 and/or 4 operate as a gas-fueled generation assets.

Q. Can you infer from this trend how far natural gas prices would need to fall for gas conversion to become favorable to making the incremental

environmental investments in Jim Bridger Units 3 and 4?

A. Yes. Confidential Exhibit RMP___(RTL-6R) to my testimony graphically displays the updated relationship between the nominal levelized natural gas price at the Opal market hub over the period 2016 through 2030 and the PVRR(d) benefit/cost of the incremental investments required for continued coal operation of Jim Bridger Units 3 and 4. To isolate the effects of CO_2 prices, which as I described earlier are assumed to elicit a natural gas price response due to changes in demand for natural gas in the electric sector, the natural gas price relationship with PVRR(d) results is shown for the natural gas price scenarios in which the base case CO_2 price assumption is used. Based upon this trend, levelized natural gas prices over the period 2016 through 2030 would need to decrease by 15 percent, from $5.72 per mmBtu to $4.86 per mmBtu, to achieve a breakeven PVRR(d).

Q. Has the Company's natural gas price curve for Opal changed since September 2012?

A. Yes. The nominal levelized natural gas price at Opal from the Company's December 2012 OFPC is $5.54 per mmBtu, which is approximately three percent lower than the updated base case. Based upon the relationship above, the predicted PVRR(d) with the most recent gas prices would be [redacted] and remain favorable to the SCR investments required at Jim Bridger Units 3 and 4.

Q. What CO_2 price would be required to change the PVRR(d) results in favor of converting Jim Bridger Units 3 and 4 to natural gas?

A. Confidential Exhibit RMP___(RTL-7R) to my testimony includes an updated graphical representation of the relationship between the nominal levelized CO_2 price over the period 2016 to 2030 and the PVRR(d) benefit/cost of the incremental investments required for continued coal operation of Jim Bridger Units 3 and 4. To isolate the effects of fundamental shifts in the natural gas price assumptions, the CO_2 price relationship with the PVRR(d) results is shown for the two CO_2 price scenarios that are paired with the same underlying base case natural gas price assumption. Based upon the trend between PVRR(d) and nominal levelized CO_2 price assumptions, the levelized CO_2 prices over the period 2016 through 2030 would need to exceed $30 per ton, more than three times the base case nominal levelized CO_2 price assumption, to achieve a breakeven PVRR(d) for the Jim Bridger Unit 3 and Unit 4 SCR investments.

Q. Have you assigned probabilities to each of these scenarios to arrive at a weighted PVRR(d) result?

A. No. The DPU has taken the position that the PVRR(d) results from the Company's natural gas and CO_2 price scenarios should be weighted by a scenario specific probability representing the likelihood that each case will actually occur. While such an approach would as a matter of convenience produce a single PVRR(d) outcome, it is problematic in that there is no way to develop empirically derived probability assumptions. Rather, assigning probability assumptions would be a highly subjective exercise largely informed by individual opinion.

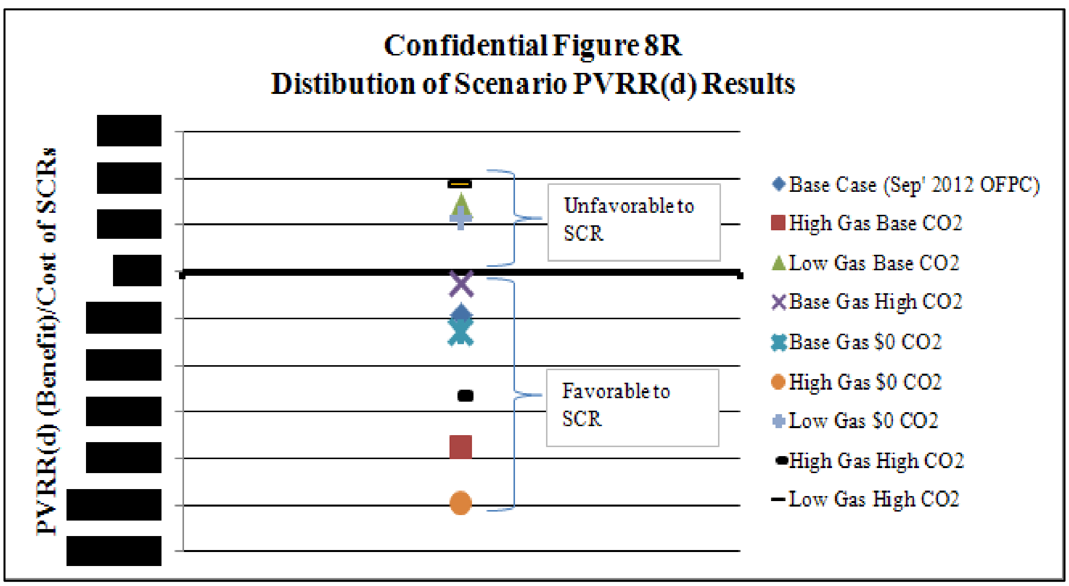
Q. How does the Company use the natural gas and CO_2 price scenario results to inform the Company's decision to pursue the Jim Bridger Unit 3 and Unit 4 SCR investments?

A. We first evaluate the magnitude of the PVRR(d) results from the base case, which is defined by assumptions representing the Company's best estimate of forward looking assumptions at any given point in time. The base case results provide an initial look at how favorable or unfavorable the SCR investments are in relation to the next best alternative and provides useful context when reviewing scenario results. The updated base case results summarized earlier in my testimony yield a PVRR(d) that is [redacted] favorable to the Jim Bridger Unit 3 and Unit 4 SCRs. This outcome also indicates that when the Company's best estimate of forward looking assumptions are used, there is a reasonably sized "cushion" in the PVRR(d) results allowing for some erosion of the favorable economics should long term natural gas prices or CO_2 prices change from what was assumed in the base case analysis. The natural gas and CO_2 price scenarios are then used to quantify how sensitive the PVRR(d) results are to these key assumptions and provide the foundation for judging risk.

Q. Can you describe how the Company has evaluated risk in the context of the updated results from the natural gas and CO_2 price scenarios?

A. Yes. Confidential Figure 8R below shows the distribution of PVRR(d) results for the base case and the eight natural gas and CO_2 price scenarios. The figure shows that of the nine cases analyzed, six scenarios produce a PVRR(d) favorable to the SCR investments and the three scenarios with low gas price assumptions produce a PVRR(d) that is unfavorable to the SCR investments. The figure further illustrates the range of potential PVRR(d) outcomes among the scenarios analyzed. At one end of the spectrum, the PVRR(d) for the high gas zero

CO_2 scenario is [redacted] favorable to the SCRs. On the other end of the spectrum, the PVRR(d) for the low gas high CO_2 scenario is [redacted] unfavorable to the Jim Bridger Unit 3 and Unit 4 SCRs. Among the scenarios analyzed, the distribution of PVRR(d) outcomes indicate a disproportionate risk profile. While there is a possibility evolution of future natural gas prices could render the decision to invest in SCRs to be higher cost than a gas conversion alternative, the cost impacts to customers of such an outcome are higher under a gas conversion alternative should future natural gas prices rise relative to the base case.

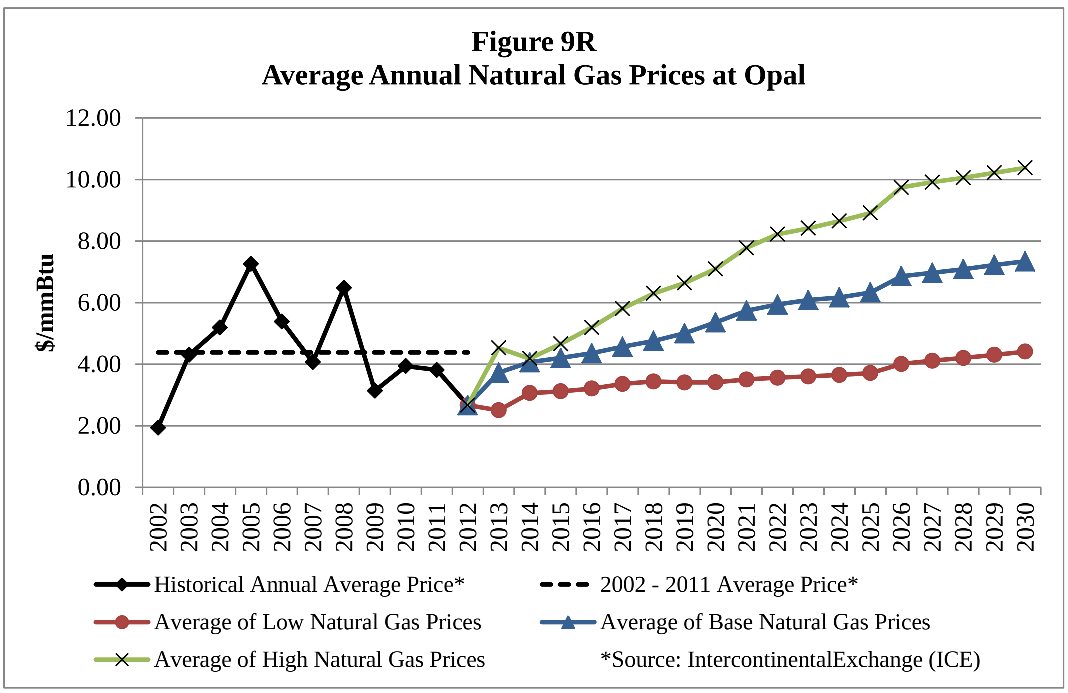


Confidential Figure 8R
Distibution of Scenario PVRR(d) Results

Q. Absent assigning probabilities to each scenario, how does the Company consider the uncertainty of future natural gas prices?

A. A useful metric is to compare the potential range of future natural gas price scenarios in the context of historical natural gas price levels. Figure 9R below plots historical natural gas prices alongside the average annual natural gas price at the Opal hub among the three low natural gas price scenarios, the three base natural gas price scenarios, and the three high natural gas price scenarios.

Opal natural gas prices among the low natural gas price scenarios never reach 2002 to 2012 historical average price levels over the course of the next 18 years. Among the low natural gas price scenarios, the average annual price for natural gas at Opal over the period 2013 through 2030 is $3.59 per mmBtu, which is 18 percent below 2002 to 2012 historical price levels. Among the base natural gas price scenarios, which are representative of the best estimate of forward looking assumptions, the average annual price for Opal natural gas is $5.66 per mmBtu, or 29% above 2002 – 2012 historical price levels. Among the high natural gas price scenarios, Opal natural gas prices average $7.60 per mmBtu, representing a 73% increase relative to 2002 to 2012 historical prices.



<u>**Additional Sensitivities**</u>

Q. Were there any other criticisms of the Company's analysis raised by parties in this case?

A. Yes. The OCS, WRA, and Sierra Club have taken the position that the Company's analysis does not consider long term planning uncertainties associated with Energy Gateway transmission investments. The OCS also raises concerns with wind resource additions that are included in the Company's analysis and criticizes the Company for not taking into consideration potential gas conversions at other coal units. WRA further suggests that the Company should capture potential transmission benefits by evaluating early retirement and resource replacement as an alternative to the SCR and/or gas conversion alternatives.

Q. What assumptions for Energy Gateway transmission are included in the Company's analysis?

A. The base case and scenario analyses performed by the Company assume that all segments of the Energy Gateway project will be implemented, including Gateway West, which connects Windstar to Populus and Populus to Hemmingway.

Q. Are any of the Energy Gateway transmission segments driven by the decision to install SCR equipment on Jim Bridger Units 3 and 4?

A. No. The decision to install SCR equipment at the Jim Bridger plant is not influential to the decision-making process for Energy Gateway transmission investments. Independent of the decision to install SCRs at the Jim Bridger facility, the Gateway West segment will provide reliability benefits, increase access to low cost generation resources, and allow for a more efficient use of system resources.

Q. Did the OCS attempt to analyze the impact of Energy Gateway on the SCR investment decisions at Jim Bridger Units 3 and 4?

A. Yes. The OCS described a GRID study in which Gateway West and South Segments were removed.

Q. What were the OCS findings from this analysis?

A. The OCS found that the Gateway Project does not materially affect the value of Jim Bridger Units 3 and 4 whether operating as coal- or gas-fueled assets. The OCS summarizes these findings in its testimony, suggesting that it provides evidence that the Energy Gateway investments should not be completed.

Q. Has the Company included in its Request approval for any funds related to the Energy Gateway project?

A. No.

Q. Did the OCS raise any additional concerns with the Company's analysis related to long-term planning uncertainties?

A. Yes. The OCS questions the Company's assumptions for projected incremental wind resource additions located in Wyoming that would be used to satisfy known state and potential federal renewable portfolio standard requirements. In particular, the OCS recommends that additional sensitivities be performed that evaluate the impact of the renewable resource assumptions on the Jim Bridger Unit 3 and Unit 4 SCR analysis.

Q. Has the Company performed additional sensitivities?

A. Yes. As a variant of the updated base case analysis, the Company performed a PVRR(d) sensitivity that removes Gateway West and South transmission and all incremental wind from Wyoming.

Q. What are the results of this sensitivity analysis?

A. As compared to the updated base case, this sensitivity improves the economics of the continued coal-fueled operation case resulting in a PVRR(d) that is [redacted] favorable to the Jim Bridger Unit 3 and Unit 4 SCR investments. The sensitivity shows that the Energy Gateway assumptions and Wyoming wind resource assumptions do not adversely affect base case results supporting the SCR investments.

Q. Does the Company's base case and scenario analyses allow for early retirement as an alternative to the SCR investments?

A. Yes. The PVRR(d) is calculated by taking the difference in system costs between two SO Model simulations. One simulation assumes the SCR investments are made and Jim Bridger Unit 3 and Unit 4 continue operating as coal-fueled assets. The second simulation forces Jim Bridger Unit 3 and Unit 4 to stop operating as coal-fueled assets, allowing the model to choose among the most economical alternative to the SCR investments, which includes gas conversion and early retirement. In all of our simulations, the SO Model chose gas conversion over early retirement when it is assumed the SCR investments are not made.

Q. Has the Company performed an additional sensitivity that shows gas conversion is a lower cost SCR alternative than early retirement as an SCR alternative?

A. Yes. For this sensitivity, in the case where Jim Bridger Unit 3 and Unit 4 stop operating as coal-fueled assets, we forced each unit to retire (not allowing it to choose gas conversion) for purposes of calculating the PVRR(d).

Q. What are the results of this sensitivity analysis?

A. When Jim Bridger Unit 3 and Unit 4 are forced to retire early the SO Model adds a 597 MW combined cycle unit located in southern Utah in 2017.[8] As compared to an early retirement alternative, the PVRR(d) is [redacted] in favor of the Jim Bridger Unit 3 and Unit 4 SCR investments. The sensitivity also shows that gas conversion, while unfavorable to the SCR investments, has a PVRR(d) that is [redacted] favorable to early retirement.

Q. Does the Company's base case and scenario analyses allow for early retirement and gas conversion alternatives for other coal units beyond Jim Bridger Unit 3 and Unit 4.

A. Yes. The Company's original analysis and updated analysis described herein has allowed for early retirement and natural gas conversion as potential alternatives to major clean air investments at other coal units in the fleet. The effects of these outcomes are included in the PVRR(d) results for all SO Model simulations performed in support of this proceeding. The OCS provides a lengthy discussion on this topic and criticizes the Company for not factoring into its analysis potential early retirement and/or gas conversion outcomes at other coal resources. It is not clear why the OCS criticized the Company for this aspect of its analysis.

<u>Conclusion</u>

Q. Please summarize the conclusions of your testimony.

A. The conclusions of my testimony are as follows:

- The updated base case analysis results in PVRR(d) that is [redacted] favorable to the Jim Bridger Unit 3 and Unit 4 SCR

[8] Incremental FOTs are also included in the portfolio when Jim Bridger Unit 3 and 4 are forced to retire early.

investments as compared to a gas conversion alternative.

- Additional sensitivity analysis shows a PVRR(d) that is [redacted] favorable to the Jim Bridger Unit 3 and Unit 4 SCR investments as compared to an early retirement and resource replacement alternative.
- Updated natural gas and CO_2 price scenario results continue to support the SCR investments, with all scenarios but those with low natural gas price assumptions that do not reach historical price levels for the next 18 years.
- The Company's analysis has been updated to correct for errors and to reflect current assumptions that do not require manual adjustments to SO Model results, better align with assumptions used in net power cost filings, improve comparisons of forecasted unit generation levels with historical data, and incorporate contributions to the mine reclamation trust through 2037.
- Additional sensitivity analysis shows that alternative Energy Gateway transmission assumptions and Wyoming wind resource assumptions improve the PVRR(d) results in favor of the SCR investments.

Q. What do you recommend?

A. I recommend that the Commission approve the Request based on the information and analyses presented in the case.

Q. Does this conclude your rebuttal testimony?

A. Yes.