VOLUME 7:

RISK ANALYSIS AND STRATEGY SELECTION

KCP&L GREATER MISSOURI OPERATIONS COMPANY (GMOC)

INTEGRATED RESOURCE PLAN

CASE NO. EE-2009-0237

4 CSR 240-22.070

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VOLUME 7: RISK ANALYSIS AND STRATEGIC SELECTION

PURPOSE: This rule requires the utility to identify the critical uncertain factors that affect the performance of resource plans, establishes minimum standards for the methods used to assess the risks associated with these uncertainties and requires the utility to specify and officially adopt a resource acquisition strategy.

SECTION 1: FORMAL DECISION ANALYSIS

(1) The utility shall use the methods of formal decision analysis to assess the impacts of critical uncertain factors on the expected performance of each of the alternative resource plans developed pursuant to 4 CSR 240-22.060(3), to analyze the risks associated with alternative resource plans, to quantify the value of better information concerning the critical uncertain factors and to explicitly state and document the subjective probabilities that utility decision-makers assign to each of these uncertain factors. This assessment shall include a decision-tree representation of the key decisions and uncertainties associated with each alternative resource plan.

For the August 5, 2009 filing GMO prepared a Risk Analysis testing a number of potential risk factors. The original risk analysis is documented in Volume 7 of that filing. Subsequently, the Company has met with Stakeholders in both the Stakeholder Process and during the Missouri Electric Utility Risk Analysis Summit GMO organized on March 30, 2011. While the Risk Analysis for this filing draws heavily on the results of the initial IRP process from 2009, it has been modified to incorporate changing market conditions and feedback from Stakeholders provided during the Stakeholder Process and Risk Summit.

To perform the Risk Analysis, GMO utilized third-party software programs to study the risks that would impact the alternative resource plans and allowed the Company to judge which risk factors are critical to the relative performance of the alternative plans. These models make use of decision tree risk analysis to calculate alternative plan financial performance under different risk scenarios.

These models and associated processes allowed GMO to quantify these risks and evaluate Critical Uncertain Factors. These models also provide results that allow GMO to quantify the value of better information.

A decision tree of the risks each plan is evaluated under is included in detail in Section 3 of this Volume as Figure 9 and Figure 10.

SECTION 2: PRELIMINARY SENSITIVITY ANALYSIS

(2) Before developing a detailed decision-tree representation of each resource plan, the utility shall conduct a preliminary sensitivity analysis to identify the uncertain factors that are critical to the performance of the resource plan. This analysis shall assess at least the following uncertain factors:

GMO compiled information concerning the risks listed in 22.070 (2) from subject matter experts within the company. The experts were requested to provide mid, high and low scenario forecasts for their particular risk driver. The mid, high and low scenarios were also assigned a subjective probability by the subject matter experts. The values for the mid low and high cases were to be the 10^{th}, 50^{th} and 90^{th} percentile values of the probability distributions of each individual risk factor. These values are chosen to approximate the values of risk factors that meet the guidelines provided in Miller and Rice[1] for a discrete approximation of continuous probability distributions. This information was collected and presented to management in a series of meetings to solicit management input into the drivers of the eventual model process.

The results of the preliminary risk analysis from the August 5, 2009 filing were retained and used for this filing. Two additional risk factors were studied as part of the Stakeholder Process and the results of their risk analysis have been included in this filing.

GMO utilized System Optimizer Model™ [CapEx™] from Ventyx to provide a preliminary test of each sensitivity listed in 22.070 (2) along with additional sensitivities chosen by the Company and input from stakeholders to complete its risk assessment.

[1] "Discrete Approximations of Probability Distributions", Allen C. Miller, III and Thomas R. Rice, Management Science, Vol. 29, No. 3, March 1983. Table 3, page 358.

CapEx™ is a linear program based model that chooses a lowest-cost expansion plan given a single determined load growth pattern and other fixed market factors. Once a load growth forecast and market is defined, the model is allowed to pick from among all supply, DSM and ** [redacted] ** available to arrive at the lowest possible cost expansion plan.

GMO executed test runs for each sensitivity to determine if the resulting lowest cost expansion plan constituted different choices of DSM, supply ** [redacted].** If the model did not materially change its expansion plan due to a change in a sensitivity value, that factor was not deemed to be a Critical Uncertain Factor. However, if the model chose different expansion options, such as different technologies or foregoing DSM programs, then that factor would be deemed a Critical Uncertain Factor and was incorporated within the Integrated Analysis Risk Tree.

The results of the Preliminary CapEx™ studies were included in detail in the working papers attached to the August 5, 2009 filing. The results of the additional risk factors were presented to Stakeholders during the Stakeholder Process. What follows is a summary of each tested risk factor describing the manner in which that factor has been incorporated into this present analysis.

2.1 LOAD GROWTH

(A) The range of future load growth represented by the low-case and high-case load forecasts;

The high, mid and low load growth cases compliant with and described in Rule 22.030 (7) were used in the CapEx™ model. The CapEx™ results demonstrated that load growth is a Critical Uncertain Factor. Load growth sensitivity was passed onto the integrated analysis.

For the Revised filing, the Stakeholders agreed that the Company should update the values of the load forecast from the August 5, 2009 filing to the load growth forecasts developed for the 2010 Corporate Budgeting Process. The Stakeholders requested an update using the 2011 Corporate Budgeting Process, however it was not available in time for the Revised filing in January 18, 2011.

For this filing, the Company has updated the load growth estimate to the forecast used in the 2011 Corporate Budgeting Process detailed in Figure 1 and Figure 2.

Figure 1: Peak Load Growth Forecasts

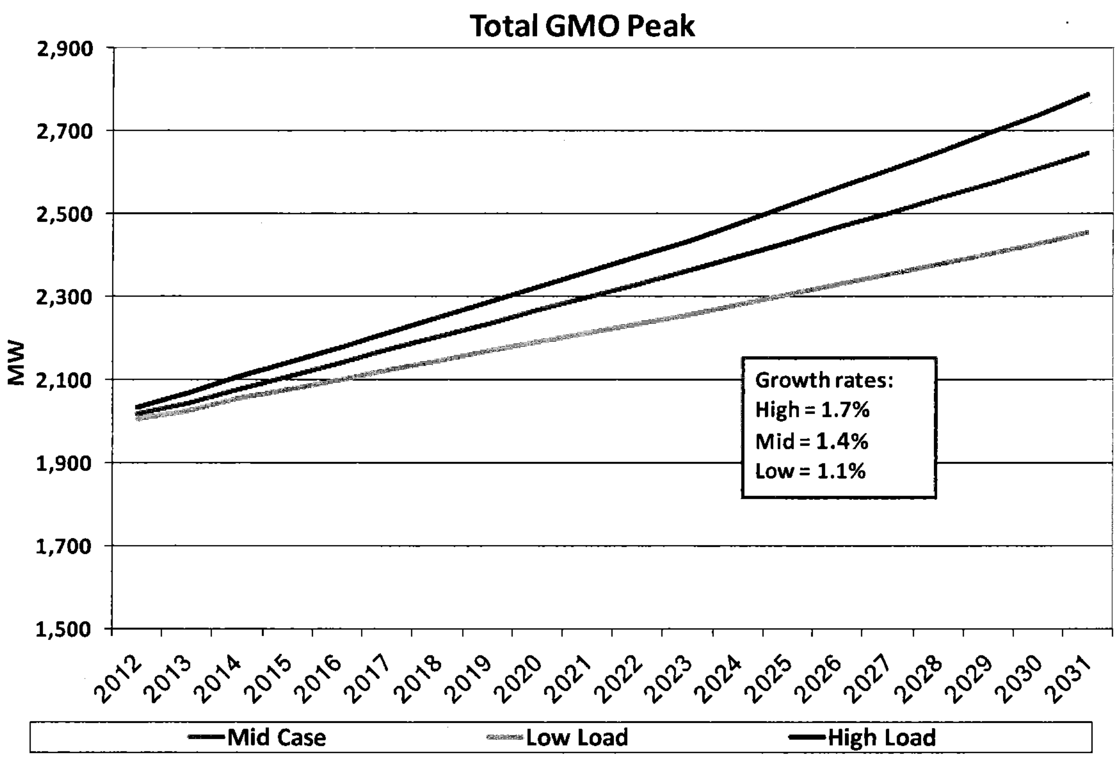

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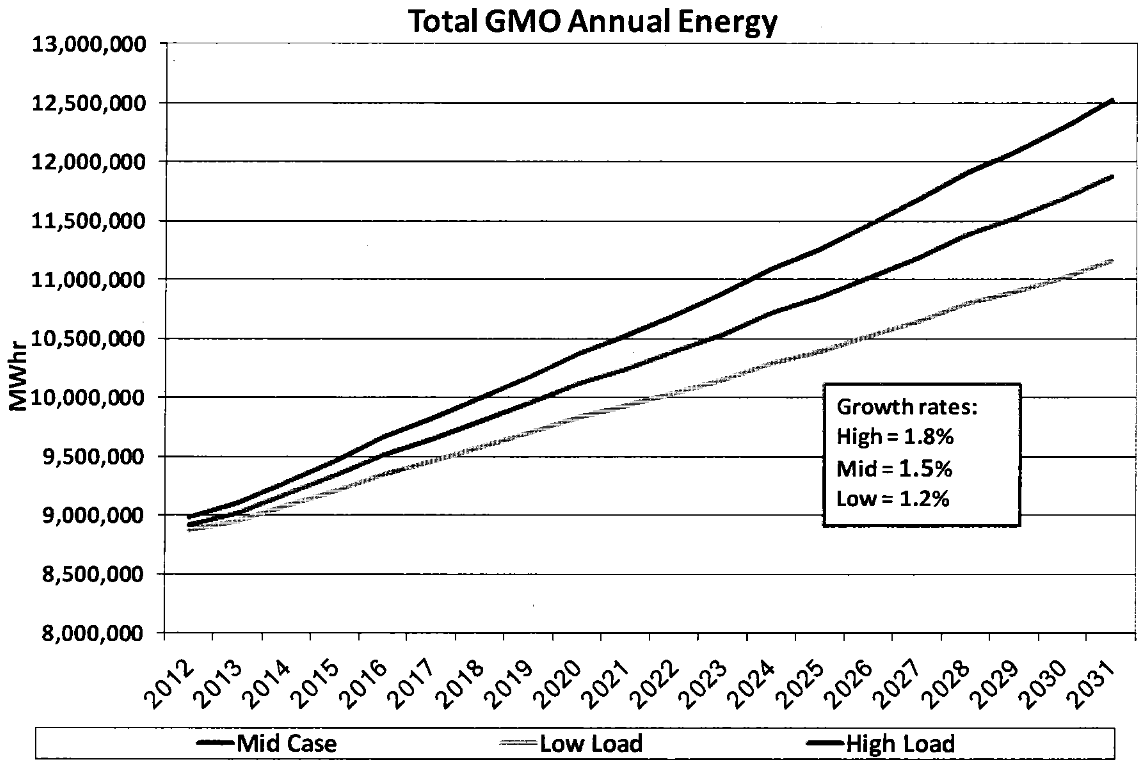
Figure 2: Energy Load Growth Forecasts



Tabular data that created Figure 1: Peak Load Growth Forecasts and Figure 2: Energy Load Growth Forecasts are provided on the work paper disc in an Excel file entitled "Load Forecasts.xlsx".

2.2 INTEREST RATE LEVELS

(B) Future interest rate levels and other credit market conditions that can affect the utility's cost of capital;

GMO compiled a family of interest rate impacted model determinants, such as Return on Ratebase, AFUDC, etc. Two CapEx™ scenarios of these determinants were developed assuming a high and low long term interest rate risk. GMO discovered that the CapEx™ lowest-cost expansion plans were sensitive to the high-interest case but insensitive to the low-interest case. Therefore only a high interest rate risk was forwarded to the Integrated Analysis Risk Tree.

The mid and high cases were updated for this filing to match current market conditions. These determinants are detailed in Table 1 below.

Table 1: Interest Rates and Credit Conditions **Highly Confidential**

Factor	Mid	High
Short-term Rate	[redacted]	
Long-term Rate		
Return on Equity		
Debt Ratio		
Pre-tax Return on Ratebase		
After-tax Return on Ratebase (t=39%)		
AFUDC Equity Rate		
AFUDC Debt Rate		
AFUDC Rate		

Tabular data that created Table 1: Interest Rates and Credit Conditions **Highly Confidential** is provided on the work paper disc in the Excel file entitled "Table240-22.070(2)(B)Interest Rates and Credit Conditions".

2.3 <u>CHANGES IN ENVIRONMENTAL LAWS</u>

(C) Future changes in environmental laws, regulations or standards;

All changes in environmental laws are incorporated into the Integrated Analysis as a capital cost outlay for retrofitting existing units. The only rule change not addressed in this fashion is the Clear Air Transport Rule (CATR). CATR changes the previously promulgated Clean Air Interstate Rule (CAIR) by adjusting the geography of implementation and the levels of emission targets. CATR covers both NO_X and SO2 emissions. Since SO_2 credit risk is detailed later in this section of the rule, only NO_X credit risk is modeled for rule 22.070 (2) (C). NO_X credit forecast development is detailed in the August 5, 2009 filing in Volume 4, Supply-Side Analysis.

In the preliminary Risk analysis performed for the August 5, 2009 filing, high and low NO_X credit scenarios were developed and run in CapEx™. Due to the small changes in optimal plans from CapEx™, GMO determined that future NO_X credit prices do not

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constitute a Critical Uncertain Factor and therefore are not included in the Integrated Analysis Risk Tree.

The mid level of NO_X credits prices are used in the long term forecast of power prices and the calculation of alternative plan revenue requirements. The mid level forecast of NO_X Annual and Seasonal credit prices was updated for this filing and is detailed in Figure 3: Annual NOX Credit Prices and Figure 4: Seasonal NOX Credit Prices below. Tabular data that created Figure 3: Annual NOX Credit Prices and Figure 4: Seasonal NOX Credit Prices is provided on the work paper disc in the Excel file entitled “Emission Credit Price Forecasts.xlsx”.

Figure 3: Annual NO_X Credit Prices **Highly Confidential**

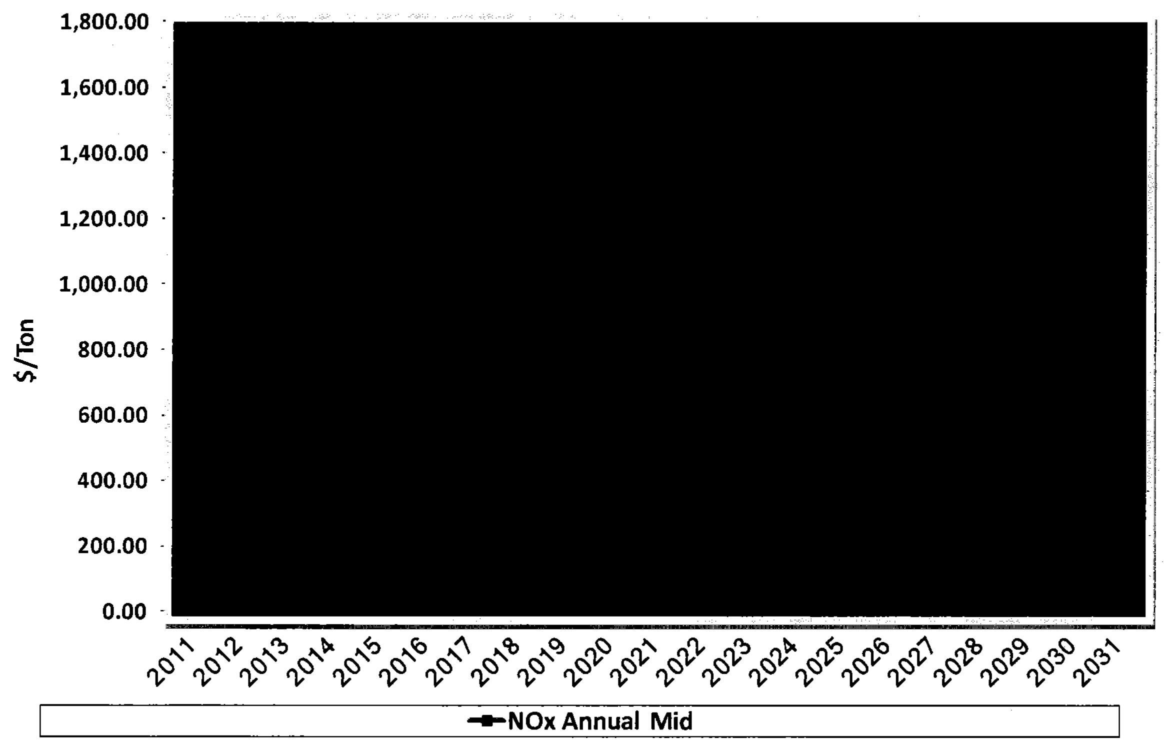

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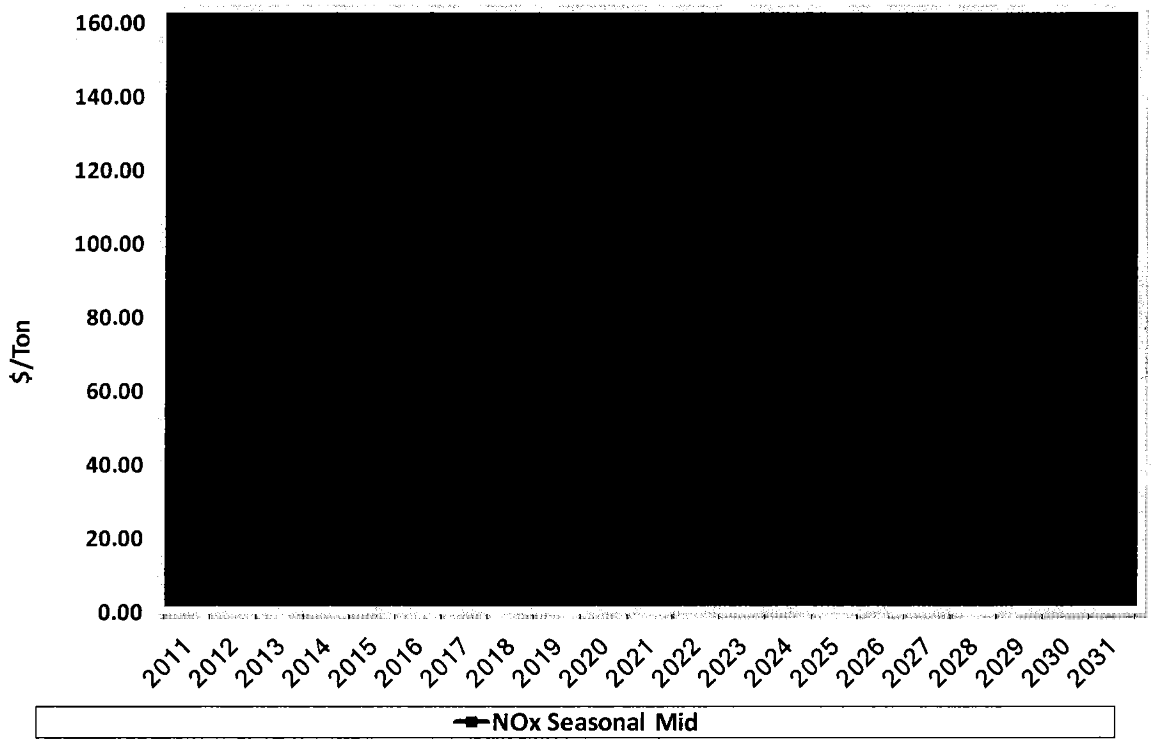
Figure 4: Seasonal NO_X Credit Prices **Highly Confidential**



2.4 REAL FUEL PRICES

(D) Relative real fuel prices;

See each individual fuel price discussion below.

2.4.1 NATURAL GAS

High, mid and low Natural Gas price forecast scenarios were developed as inputs into the CapEx™ model. In the original preliminary risk analysis performed for the August 5, 2009 filing, the optimized expansion plans for the high and low cases are sufficiently different to require adding Natural Gas price risk as a Critical Uncertain Factor. Natural Gas price forecast development is detailed in Volume 4, Supply-Side Analysis of the August 5, 2009 filing.

The Natural Gas price forecasts had been updated for this filing using a March 2011 Company update of fuel prices and are detailed in Figure 5.

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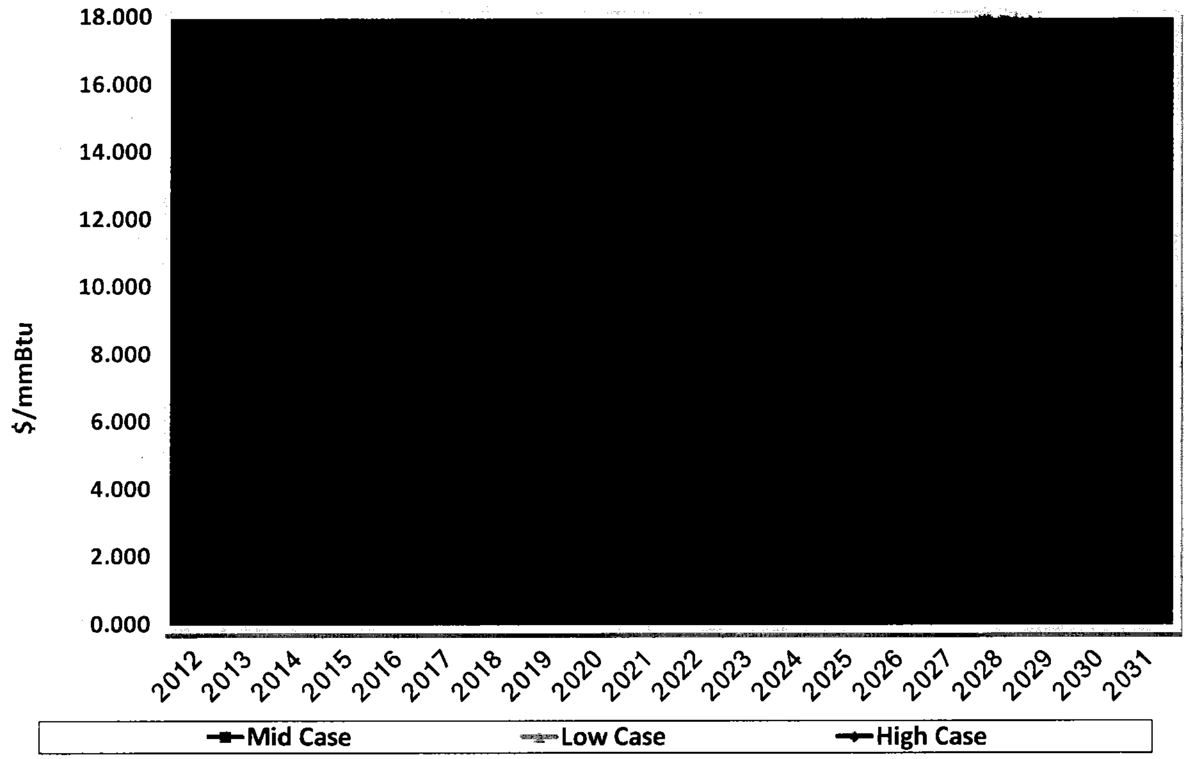
Figure 5: Natural Gas Price Forecasts **Highly Confidential**



Tabular data that created Figure 5: Natural Gas Price Forecasts is provided on the work paper disc in the Excel file entitled "Fuel Price Forecasts.xlsx".

2.4.2 COAL

High and low delivered coal price forecast scenario was modeled in CapEx™. The resulting optimal expansion plans were changed as a response to changes in the forecasted price of coal. Therefore coal price sensitivity was included in the Integrated Analysis Risk Tree as a Critical Uncertain Factor. Coal price forecast development is detailed in Volume 4, Supply-Side Analysis of the August 5, 2009 filing.

The coal price forecasts had been updated for this filing using a March 2011 Company update of fuel prices and are detailed in Figure 6.

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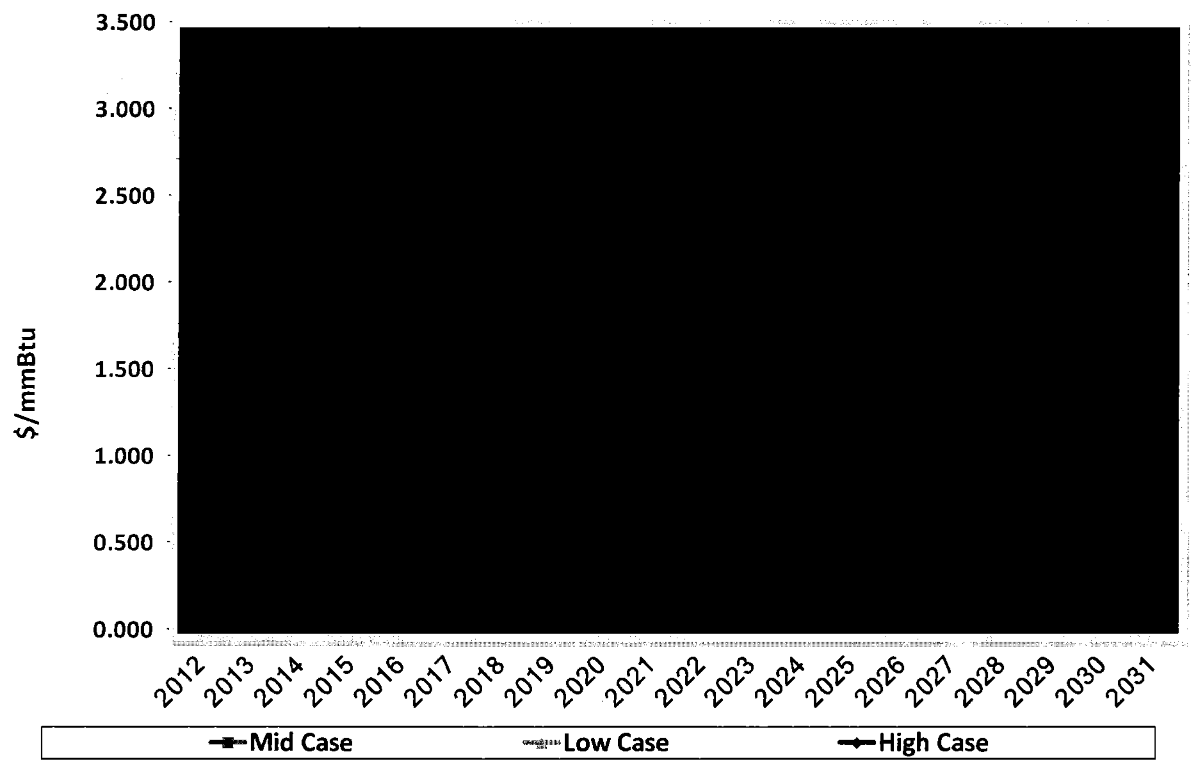
Figure 6: PRB Delivered Coal Price Forecast **Highly Confidential**



Tabular data that created Figure 6: PRB Delivered Coal Price Forecast is provided on the work paper disc in the Excel file entitled "Fuel Price Forecasts.xlsx".

2.5 SITING AND PERMITTING COSTS

(E) Siting and permitting costs and schedules for new generation and generation-related transmission facilities;

Siting and permitting costs are incorporated into the cost of construction risk detailed in 22.070 (2) (F).

2.6 CONSTRUCTION COSTS

(F) Construction costs and schedules for new generation and transmission facilities;

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GMO determined high and low construction cost estimates for each supply technology evaluated. The supply options forwarded from the preliminary screen conducted in compliance with Rule 22.040 (2). High and low construction costs scenarios were modeled in CapEx™. The resulting optimal expansion plans displayed material changes over the range of construction costs. Therefore, construction cost risk was incorporated as a Critical Uncertain Factor in the Integrated Analysis Risk Tree.

Construction costs risks vary by technology. Detailed information for each of the resource options identified can be viewed in Volume 4, Appendix 4E of the August 5, 2009 filing.

The mid point construction cost of some types of technology had been revised after studying the responses to RFPs placed by the company. Construction costs that have been modified since the August 5, 2009 filing are detailed in Table 2: Capital Construction Costs. Tabular data that created Table 2: Capital Construction Costs is provided on the work paper disc in the Excel file entitled "Table240-22.070(2)(F)Capital Construction Costs.xlsx".

Table 2: Capital Construction Costs ** Highly Confidential **

Capital Construction Costs	
Type	**$/kw**
Solar	[redacted]
Wind	[redacted]
Combined Cycle	[redacted]
Combustion Turbine	[redacted]

2.7 PURCHASE POWER AVAILABILITY

(G) Purchased power availability, terms and cost;

High and low purchased power availability was simulated with a high and low cost for the capacity terms of the contracts. High and low purchased power availability scenarios were modeled in CapEx™. No material changes were identified in the

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model's optimal expansion plans. Purchased power availability was not identified as a Critical Uncertain Factor. This risk was not included in the Integrated Analysis Risk Tree.

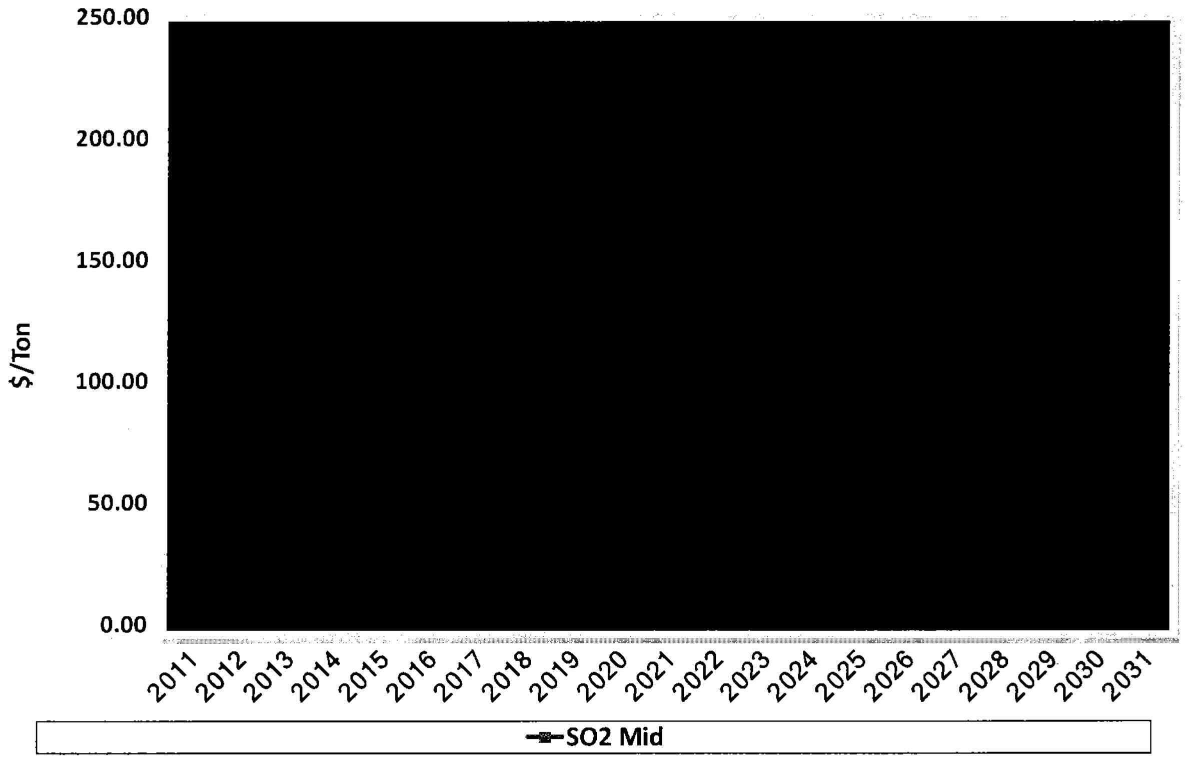
2.8 SULFUR DIOXIDE

(H) Sulfur dioxide emission allowance prices;

SO_2 credit price forecast development is detailed in Volume 4, Supply-Side Analysis. High and low SO_2 credit price forecasts were simulated in the CapEx™ model. Resulting optimal expansion plans did not change as this cost was varied. SO_2 credit prices are not considered a Critical Uncertain Factor and were not used as part of the Risk Tree used in the Integrated Analysis.

The mid level of SO_2 credit prices are used in the long term forecast of power prices and the calculation of alternative plan revenue requirements. The mid level forecast of SO_2 credit prices was updated for this filing and is detailed in Figure 7 below. Tabular data that created Figure 7: SO2 Credit Price Forecast is provided on the work paper disc in the Excel file entitled "Emission Credit Price Forecasts.xlsx".

Figure 7: SO_2 Credit Price Forecast **Highly Confidential**



2.9 FIXED O&M COSTS

(I) Fixed operation and maintenance costs for existing generation facilities;

High and low Fixed O&M costs were simulated in the CapEx™ model. Resulting optimal expansion plans did not change as this cost was varied. Therefore, fixed O&M costs were not considered a Critical Uncertain Factor and were not used as part of the Risk Tree in the Integrated Analysis.

2.10 EQUIVALENT FORCED OUTAGE RATES

(J) Equivalent or full- and partial-forced outage rates for new and existing generation facilities;

High and low equivalent forced outage rates were simulated in the CapEx™ model. Resulting optimal expansion plans did not change as this factor was varied.

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Therefore, equivalent forced outage rates were not considered a Critical Uncertain Factor and were not used as part of the Risk Tree in the Integrated Analysis.

2.11 LOAD IMPACT OF DSM

(K) Future load impacts of demand-side programs; and

High and low load impacts of DSM were simulated in the CapEx™ model. Resulting optimal expansion plans did not change as this factor was varied. Therefore, load impacts of DSM were not considered a Critical Uncertain Factor and were not used as part of the Risk Tree in the Integrated Analysis.

2.12 MARKETING COSTS OF DSM

(L) Utility marketing and delivery costs for demand-side programs.

High and low marketing costs of DSM were simulated in the CapEx™ model. Resulting optimal expansion plans did not change as this factor was varied. Therefore, marketing costs of DSM were not considered a Critical Uncertain Factor and were not used as part of the Risk Tree in the Integrated Analysis.

2.13 ADDITIONAL RISK MEASURES REVIEWED

GMO considered three other risks not specifically listed in 22.070 (2).

2.13.1 CO_2 CREDIT PRICES

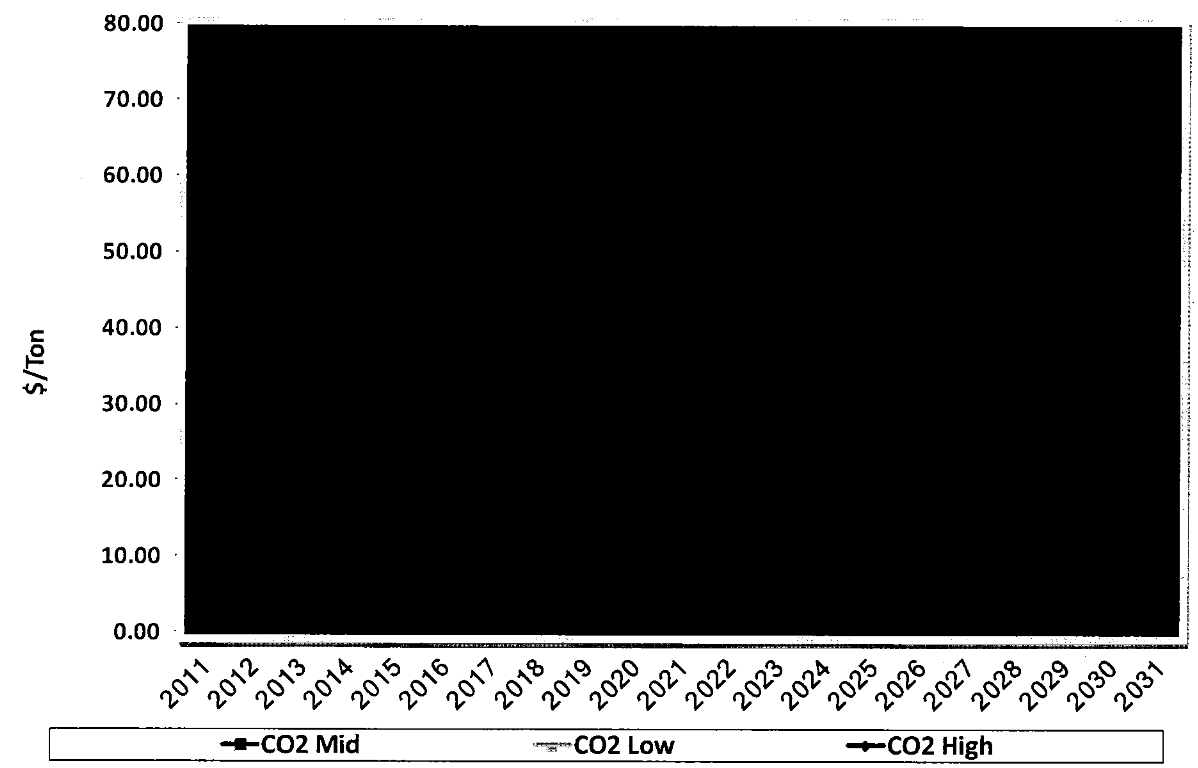
GMO assumed a market for CO_2 emission credits will form. The costs of this market were not planned to be included as a part of the Integrated Analysis Probable Environmental Costs but instead handled as a sensitivity which may of may not become a Critical Uncertain Factor.

High, mid and low CO_2 credit price forecasts were developed, and their effects modeled in CapEx™. The resulting optimal expansion plans showed sensitivity to CO_2 prices. Therefore, CO_2 credit prices were included in the Integrated Analysis

Risk Tree as a Critical Uncertain Factor. CO_2 credit price forecast development is detailed in Volume 4, Supply-Side Analysis of the August 5, 2009 filing.

The CO_2 credit price forecasts had been updated for this filing using a March 2011 Company update and are detailed in Figure 8. Tabular data that created Figure 8: CO2 Credit Price Forecasts is provided on the work paper disc in the Excel file entitled “Emission Credit Price Forecasts.xlsx”.

Figure 8: CO_2 Credit Price Forecasts **Highly Confidential**



2.13.2 PRODUCTION TAX CREDIT

The extension of the Production Tax Credit associated with the emergency funding bill and the stimulus package pushed the time frame of the risk associated with the potential loss of renewable PTC well past the time frame of either the implementation plan or the resource acquisition time frame of the August 5, 2009 filing. When the

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remaining years of the test period were simulated with and without continuing the PTC, the resulting expansion plans did not change. Therefore the PTC is not a Critical Uncertain Factor for the IRP and was not included in the Risk Tree of the Integrated Analysis.

2.13.3 FEDERAL RENEWABLE PORTFOLIO STANDARD

The Company simulated a risk associated with a potential Federal Renewable Portfolio Standard. The Federal Renewable Standard bill that was modeled was the Bingaman bill. The requirements of the proposed bill were similar to the Missouri standard requirements except that they were on a national level and not on a state only level. The Federal standard would not require GMO to acquire additional renewable resources beyond the requirements of the Missouri rules. However, the entire country will be required to acquire additional renewable resources causing an adjustment to power market prices. When adjusted market prices were input into the CapEx™ model, no change to the optimal expansion plan occurred. Therefore the Federal renewable standard was not deemed to be a Critical Uncertain Factor and not included in the Risk Tree of the Integrated Analysis.

2.14 RISK FACTORS FROM STAKEHOLDER PROCESS

The settlement agreement of Case EO-2209-0237 stipulated that the Company will study the impact of two additional risk factors: a Federal Energy Efficiency Standard and Smart Grid. Results of the analysis performed on these two sensitivities were shared with the Stakeholders during the Stakeholder Process. This paper documents the method used to analyze these two factors to determine if they are a Critical Uncertain Factors as defined in 240-22.070 (2) and reviews the results of the evaluation.

2.14.1 FEDERAL ENERGY EFFICIENCY STANDARD

2.14.1.1 Proposed Rule by the company

At the June 2010 Stakeholder Meeting, the Company proposed using Title II of The American Clean Energy and Security Act of 2009 (Waxman-Markey Bill) this comprehensive climate and energy legislation would establish an economy-wide, greenhouse gas (GHG) cap-and-trade system. Title II of the Act sets national targets for energy efficiency by customer class. These and other complementary measures are meant to address climate change and build a clean energy economy. The House Energy and Commerce Committee voted 33-25 to approve the ACES Act on May 21, 2009. The Act passed the House on June 26, 2009 by a vote of 219 to 212.

Using the definition of the targets for energy efficiency in Title II, the Company proposed a level of national energy reduction to be used in the national power price forecasting model. These targets were shared with the Stakeholder parties.

2.14.1.2 <u>Staff proposed rule</u>

At the June Stakeholder Meeting, Staff proposed using the Save American Energy Act, HR 889 bill to use as a basis for analysis. The bill proposes to amend Title VI of the Public Utility Regulatory Policies Act of 1978 to establish a Federal energy efficiency resource standard for retail electricity and natural gas distributors.

This bill is in the first step in the legislative process. Introduced bills and resolutions first go to committees that deliberate, investigate, and revise them before they go to general debate. It was introduced on February 4, 2009 and referred to the House Energy and Commerce Committee.

The Company agreed to use H.R.889 and its energy efficiency targets and alternative payment structure to simulate the effect of a Federal Energy Standard on the IRP alternative plan selection.

2.14.1.3 <u>Salient Features of HR 889</u>

HR 889 introduced a federal energy efficiency mandate upon all utilities based on retail energy load.

2.14.1.4 <u>Base Quantity</u>

A Base Quantity is determined for each utility and required energy reduction mandates are set as percent targets from this quantity. The complete definition of Base Quantity is given in Section 610 (b) (3) of the bill as follows:

> (3) BASE QUANTITY- The term 'base quantity', with respect to a retail electricity distributor or retail natural gas distributor, means, for each year for which a performance standard is established under subsection (d), the average annual quantity of electricity or natural gas delivered by the retail electricity distributor or retail natural gas distributor to retail customers during the 2 calendar years immediately preceding such year. In determining the base quantity of a retail natural gas distributor, natural gas delivered for purposes of electricity generation shall be excluded.

Since the Base Quantity is set in the future from recent actual retail energy sales, a forecast needs to be selected for use as a future Base Quantity. For the risk analysis, the Base Quantity forecast was the load forecast from the GMO 2010 Corporate Budget.

2.14.1.5 Annual Energy Efficiency Targets

Energy efficiency targets were listed in Section 610 (d) (2) of the bill. The percentages applicable to retail electric distributors are detailed in Table 3: Annual Energy Efficiency Targets. Tabular data that created Table 3: Annual Energy Efficiency Targets is provided on the work paper disc in the Excel file entitled "Table240-22.070(2)(M)Fed EE Conditions.xlsx".

Table 3: Annual Energy Efficiency Targets

National Annual Energy Reduction From Baseline			
Year	Percent	Year	Percent
2012	1.00%	2022	15.00%
2013	2.00%	2023	15.00%
2014	3.25%	2024	15.00%
2015	4.50%	2025	15.00%
2016	6.00%	2026	15.00%
2017	7.50%	2027	15.00%
2018	10.00%	2028	15.00%
2019	12.50%	2029	15.00%
2020	15.00%	2030	15.00%
2021	15.00%	2031	15.00%

2.14.1.6 Alternative Compliance payments

The bill proposed a federal alternative compliance payment in Section 610 (g) (2) (A) as follows:

> (A) $100 per megawatt-hour of electricity savings or alternative compliance payment that the retail electricity distributor failed to achieve or make, respectively;

A similar proposal for a state-based alternative compliance payment would equal $50 per megawatt-hour in addition to the Federal compliance payment above. Since the bill did not specifically declare the alternative compliance payment as a fixed price instrument, it was assumed that this compliance payment would increase over time with the rate of inflation. The $150 total cost for both State and Federal alternative compliance prices were set for 2012, the first year of required reductions, but increased at the rate of inflation for subsequent years. Tabular data that created Table 4: Alternative Compliance Payments is provided on the work paper disc in the Excel file entitled "Table240-22.070(2)(M)Fed EE Conditions.xlsx".

Table 4: Alternative Compliance Payments

Alternative Compliance Payment per MWhr			
Year	Cost	Year	Cost
2012	$ 150.00	2022	$ 192.01
2013	$ 153.75	2023	$ 196.81
2014	$ 157.59	2024	$ 201.73
2015	$ 161.53	2025	$ 206.78
2016	$ 165.57	2026	$ 211.95
2017	$ 169.71	2027	$ 217.24
2018	$ 173.95	2028	$ 222.68
2019	$ 178.30	2029	$ 228.24
2020	$ 182.76	2030	$ 233.95
2021	$ 187.33	2031	$ 239.80

2.14.1.7 Method of Analysis

The sensitivity analysis was methodologically identical to the analysis used in the 2009 GMO IRP filing of August 5, 2009. It used the CapEx Model to determine the impact of the bill should it become law. A base and a test scenario were defined to perform this analysis.

2.14.1.8 Base Scenario - Federal EE Standard risk

The Base Scenario used all the mid-level risk values from the GMO IRP filing of August 5, 2009. The only adjustments was an update of the load forecast to the GMO 2010 corporate budget forecast and update of the cost of construction for wind generation.

A new set of Eastern Interconnect wholesale market power prices were developed to incorporate the most recent Ventyx Reference Case national long-term load forecasts. This wholesale market power price forecast was identical to the wholesale price forecast used in the Base Scenario-Smart Grid Risk Analysis described later.

One last adjustment was assumed respecting available level and price of energy efficiency. In order to fairly compare the base scenario with the test scenario, both had the same option of available energy efficiency. Since the Test Scenario had mandated efficiency that was no higher that the alternative compliance price, The DSM option available in the Base Scenario allowed for energy efficiency programs that cost as much as the alternative compliance penalty.

2.14.1.9 Test Scenario - Federal EE Standard Risk

The Test Scenario for the Federal Energy Efficiency Standard was different from the Base Scenario for Federal Energy Efficiency in two regards.

First, the Test Scenario forced the CapEx Model to select the DSM option in its final expansion plan. Secondly, the wholesale power market price forecast had an assumption that all retail load across the Eastern Interconnect has complied with the Standard, and reduced total loads from the original Eastern Interconnect energy forecast by the percentages listed inTable 3.

2.14.1.10 Test results

Results shared with the Stakeholders showed that the planning process is sensitive to a future Federal EE Standard configured like HR889. Due to the large upheavals this law makes to the power markets, a separate Integrated Analysis was built to analyze the best plan under this risk. The separate analysis assumes the same Risk Tree, yet the wholesale market prices and system load forecasts are adjusted to accommodate the reductions in native load that will accompany the new law. The results of those runs are detailed in Section 7 of Volume 6.

2.14.2 SMART GRID

2.14.2.1 Basis of analysis

To begin this study, the Company referred to the July 2009 "Smart Grid System Report" published by the U.S. Department of Energy. The study appendix lists 20 metrics that are used to determine the effectiveness of Smart Grid activities.

Many of these metrics do not lend themselves to production cost based analysis. Others have no direct cost but provide indirect benefit such as consumer acceptance, data sharing measures or reductions in customer complaints. Only one metric can be modeled in such a way to demonstrate an impact on system production costs.

2.14.2.2 Dynamic Line Ratings

Metric #16, Dynamic Line Ratings, has a direct impact on the assumptions used to develop national market clearing prices for wholesale power. The MIDAS ™ Model assumes interregional transfers of power are possible and power is allowed to flow in the model to help lower overall system costs and reduce the resultant market clearing price for wholesale power.

The DOE Report estimates that a 10 – 15% increase in transmission power flow would be capable over 95% of all operating hours. The Company used an increase in the assumed level of power flow capability nationally to simulate in the power price model the impact of Smart Grid technology. Tabular data that created Table 5: Interregional Power Flow Improvement from Smart Grid is provided on the work paper disc in the Excel file entitled "Table240-22.070(2)(M)Smart Grid.xlsx".

Table 5: Interregional Power Flow Improvement from Smart Grid

Interregional Power Flow Improvement Multipliers			
Year	Multiplier	Year	Multiplier
2012	1.01	2022	1.11
2013	1.02	2023	1.12
2014	1.03	2024	1.13
2015	1.04	2025	1.14
2016	1.05	2026	1.15
2017	1.06	2027	1.15
2018	1.07	2028	1.15
2019	1.08	2029	1.15
2020	1.09	2030	1.15
2021	1.10	2031	1.15

2.14.2.3 Method of Analysis

The sensitivity analysis was methodologically identical to the analysis used in the 2009 GMO IRP. It utilized the CapEx Model to determine the impact of the Smart Grid should it increase inter-regional power flows. A base and a test scenario were defined to perform this analysis.

2.14.2.4 BASE Scenario-SMART Grid

The Base Scenario for Smart Grid Risk was identical to the Base Scenario for the Federal Energy Efficiency Standard with the exception that the DSM option is now returned to the level and cost used in the GMO IRP. This Base Scenario utilized all mid-level risks from the GMO IRP. It updated the load forecast to the GMO 2010 Corporate budget load forecast and used updated costs of wind construction. The wholesale market power price forecast were also updated to the Ventyx Reference Case Eastern Interconnect national energy consumption forecast. This power price forecast was identical to the price forecast used in the Base Scenario for the Federal Energy Efficiency Standard risk analysis.

2.14.2.5 Test Scenario-SMART Grid

The Test Scenario used identical inputs to the Base Scenario except for the wholesale power price forecast. The power price model was run assuming an increased interregional power flows. This allows the market to dispatch generation more efficiently, lowering wholesale power prices.

2.14.2.6 Test Results

The results determined that the plan would not be sensitive to the SMART Grid. Therefore is does not constitute a Critical Uncertain Factor for planning purposes and was not included in the Risk Tree used in the Integrated Analysis.

SECTION 3: DECISION TREE DIAGRAM

(3) For each alternative resource plan, the utility shall construct a decision-tree diagram that appropriately represents the key resource decisions and critical uncertain factors that affect the performance of the resource plan.

Using the results of the preliminary sensitivity analysis, the Critical Uncertain Factors were incorporated into a decision tree representation of the risks that will impact the performance of the alternative resource plans. A preliminary tree of 486 scenarios was developed using every possible combination of risks factors weighted by their joint probability. To limit the number of scenarios to use in the final risk decision tree, all scenarios whose joint probability was less than 0.5% were excluded. The number of scenarios was reduced to 62 with two additional scenarios for extreme conditions retained, for a total of 64.

After consulting with Stakeholders in both the Stakeholder Process and the Utility Risk Analysis Summit, a change has been implemented to the Risk Tree to attempt to capture a wider range of effects than the precise definition given above. The proposal was to include additional scenarios chosen at random from the scenarios discarded in the previous method. The Company has implemented this by randomly selecting 34 additional scenarios from those that remain. For this Integrated Analysis a 100 Scenario Risk Tree has been used.

A graphical representation of the 100 Scenario Risk Tree is given in Figure 9: 100 Scenario Risk Tree with Probabilities and Figure 10: 100 Scenario Risk Tree with Probabilities cont. below. Tabular data that created Figure 9 and Figure 10 is provided on the work paper disc in the Excel file entitled "Figure240-22.070(3)100Scenario Risk Tree.xlsx".

Figure 9: 100 Scenario Risk Tree with Probabilities

Scenario	Load_Growth	Construction_Costs	Interest_Finances	CO2	Natural_Gas	Coal	Scenario Probability	Cumulative Probability
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.0723%	0.0723%
2	[redacted]	[redacted]	[redacted]	[redacted]	Low	[redacted]	0.0723%	0.1446%
3	[redacted]	[redacted]	[redacted]	[redacted]	Low	Low	0.0723%	0.2170%
4	[redacted]	[redacted]	Mid	Mid	Mid	Mid	1.1746%	1.3916%
5	[redacted]	[redacted]	Mid	Low	[redacted]	Low	0.1468%	1.5384%
6	[redacted]	[redacted]	[redacted]	Low	Low	[redacted]	0.0723%	1.6107%
7	[redacted]	[redacted]	[redacted]	Low	Low	Mid	0.1446%	1.7553%
8	[redacted]	Mid	[redacted]	[redacted]	Mid	[redacted]	0.2893%	2.0446%
9	[redacted]	Mid	[redacted]	[redacted]	Mid	Mid	0.5785%	2.6232%
10	[redacted]	Mid	Mid	[redacted]	Mid	Mid	1.1746%	3.7978%
11	[redacted]	Mid	Mid	Mid	[redacted]	Mid	1.1746%	4.9724%
12	[redacted]	Mid	Mid	Mid	Mid	[redacted]	1.1746%	6.1470%
13	[redacted]	Mid	[redacted]	Mid	Mid	Mid	1.1571%	7.3041%
14	[redacted]	Mid	Mid	Mid	Mid	Mid	2.3492%	9.6533%
15	[redacted]	Mid	Mid	Mid	Mid	Low	1.1746%	10.8279%
16	[redacted]	Mid	Mid	Mid	Low	Mid	1.1746%	12.0025%
17	[redacted]	Mid	Mid	Low	[redacted]	Low	0.2937%	12.2962%
18	[redacted]	Mid	Mid	Low	Mid	Mid	1.1746%	13.4708%
19	[redacted]	Mid	Mid	Low	Low	Mid	0.5873%	14.0581%
20	[redacted]	Low	[redacted]	[redacted]	Mid	Mid	0.2893%	14.3474%
21	[redacted]	Low	[redacted]	Mid	[redacted]	Low	0.1446%	14.4920%
22	[redacted]	Low	Mid	Mid	Mid	[redacted]	0.5873%	15.0793%
23	[redacted]	Low	Mid	Mid	Mid	Mid	1.1746%	16.2539%
24	[redacted]	Low	Mid	Low	[redacted]	[redacted]	0.1468%	16.4008%
25	[redacted]	Low	Mid	Low	Mid	Mid	0.5873%	16.9881%
26	[redacted]	Low	Mid	Low	Low	[redacted]	0.1468%	17.1349%
27	[redacted]	Low	[redacted]	Low	Low	Mid	0.1446%	17.2795%
28	Mid	[redacted]	Mid	[redacted]	Mid	Mid	1.1746%	18.4542%
29	Mid	[redacted]	[redacted]	[redacted]	Low	Low	0.1446%	18.5988%
30	Mid	[redacted]	Mid	Mid	[redacted]	Mid	1.1746%	19.7734%
31	Mid	[redacted]	Mid	Mid	Low	Mid	1.1746%	20.9480%
32	Mid	[redacted]	Mid	Mid	Mid	[redacted]	1.1746%	22.1226%
33	Mid	[redacted]	[redacted]	Mid	Mid	Mid	1.1571%	23.2797%
34	Mid	[redacted]	Mid	Mid	Mid	Mid	2.3492%	25.6289%
35	Mid	[redacted]	Mid	Mid	Mid	Low	1.1746%	26.8036%
36	Mid	[redacted]	Mid	Low	Mid	Mid	1.1746%	27.9782%
37	Mid	Mid	Mid	[redacted]	[redacted]	Mid	1.1746%	29.1528%
38	Mid	Mid	Mid	[redacted]	Mid	[redacted]	1.1746%	30.3274%
39	Mid	Mid	[redacted]	[redacted]	Mid	Mid	1.1571%	31.4845%
40	Mid	Mid	Mid	[redacted]	Mid	Mid	2.3492%	33.8337%
41	Mid	Mid	Mid	[redacted]	Mid	Low	1.1746%	35.0083%
42	Mid	Mid	Mid	[redacted]	Low	Mid	1.1746%	36.1829%
43	Mid	Mid	Mid	Mid	[redacted]	[redacted]	1.1746%	37.3576%
44	Mid	Mid	[redacted]	Mid	[redacted]	Mid	1.1571%	38.5146%
45	Mid	Mid	Mid	Mid	[redacted]	Mid	2.3492%	40.8639%
46	Mid	Mid	Mid	Mid	[redacted]	Low	1.1746%	42.0385%
47	Mid	Mid	[redacted]	Mid	Mid	[redacted]	1.1571%	43.1956%
48	Mid	Mid	Mid	Mid	Mid	[redacted]	2.3492%	45.5448%
49	Mid	Mid	[redacted]	Mid	Mid	Mid	2.3142%	47.8590%
50	Mid	Mid	Mid	Mid	Mid	Mid	4.6985%	52.5574%

Figure 10: 100 Scenario Risk Tree with Probabilities cont.

Scenario	Load_Growth	Construction_Costs	Interest_Finances	CO2	Natural_Gas	Coal	Scenario Probability	Cumulative Probability
51	Mid	Mid	[redacted]	Mid	Mid	Low	1.1571%	53.7145%
52	Mid	Mid	Mid	Mid	Mid	Low	2.3492%	56.0637%
53	Mid	Mid	[redacted]	Mid	Low	[redacted]	0.5785%	56.6423%
54	Mid	Mid	Mid	Mid	Low	[redacted]	1.1746%	57.8169%
55	Mid	Mid	[redacted]	Mid	Low	Mid	1.1571%	58.9740%
56	Mid	Mid	Mid	Mid	Low	Mid	2.3492%	61.3232%
57	Mid	Mid	Mid	Mid	Low	Low	1.1746%	62.4978%
58	Mid	Mid	Mid	Low	[redacted]	Mid	1.1746%	63.6724%
59	Mid	Mid	Mid	Low	Mid	[redacted]	1.1746%	64.8470%
60	Mid	Mid	[redacted]	Low	Mid	Mid	1.1571%	66.0041%
61	Mid	Mid	Mid	Low	Mid	Mid	2.3492%	68.3533%
62	Mid	Mid	Mid	Low	Mid	Low	1.1746%	69.5280%
63	Mid	Mid	[redacted]	Low	Low	[redacted]	0.2893%	69.8172%
64	Mid	Mid	Mid	Low	Low	Mid	1.1746%	70.9918%
65	Mid	Low	[redacted]	[redacted]	[redacted]	[redacted]	0.1446%	71.1365%
66	Mid	Low	Mid	[redacted]	[redacted]	Mid	0.5873%	71.7238%
67	Mid	Low	[redacted]	[redacted]	Mid	[redacted]	0.2893%	72.0131%
68	Mid	Low	Mid	[redacted]	Mid	Mid	1.1746%	73.1877%
69	Mid	Low	Mid	Mid	[redacted]	Mid	1.1746%	74.3623%
70	Mid	Low	Mid	Mid	Mid	[redacted]	1.1746%	75.5369%
71	Mid	Low	[redacted]	Mid	Mid	Mid	1.1571%	76.6940%
72	Mid	Low	Mid	Mid	Mid	Mid	2.3492%	79.0432%
73	Mid	Low	[redacted]	Mid	Mid	Low	0.5785%	79.6218%
74	Mid	Low	Mid	Mid	Mid	Low	1.1746%	80.7964%
75	Mid	Low	Mid	Mid	Low	Mid	1.1746%	81.9710%
76	Mid	Low	Mid	Low	Mid	Mid	1.1746%	83.1456%
77	Mid	Low	[redacted]	Low	Low	Low	0.1446%	83.2902%
78	Low	[redacted]	Mid	[redacted]	[redacted]	Mid	0.2937%	83.5839%
79	Low	[redacted]	[redacted]	[redacted]	Low	Low	0.0723%	83.6562%
80	Low	[redacted]	Mid	Mid	[redacted]	Mid	0.5873%	84.2435%
81	Low	[redacted]	Mid	Mid	[redacted]	Low	0.2937%	84.5372%
82	Low	[redacted]	Mid	Mid	Mid	Mid	1.1746%	85.7118%
83	Low	[redacted]	[redacted]	Low	[redacted]	[redacted]	0.0723%	85.7841%
84	Low	[redacted]	Mid	Low	[redacted]	Mid	0.2937%	86.0778%
85	Low	[redacted]	Mid	Low	Mid	Low	0.2937%	86.3714%
86	Low	Mid	Mid	[redacted]	Mid	[redacted]	0.5873%	86.9587%
87	Low	Mid	Mid	[redacted]	Mid	Mid	1.1746%	88.1333%
88	Low	Mid	Mid	[redacted]	Low	Low	0.2937%	88.4270%
89	Low	Mid	Mid	Mid	[redacted]	Mid	1.1746%	89.6016%
90	Low	Mid	Mid	Mid	Mid	[redacted]	1.1746%	90.7762%
91	Low	Mid	[redacted]	Mid	Mid	Mid	1.1571%	91.9333%
92	Low	Mid	Mid	Mid	Mid	Mid	2.3492%	94.2825%
93	Low	Mid	Mid	Mid	Mid	Low	1.1746%	95.4571%
94	Low	Mid	Mid	Mid	Low	Mid	1.1746%	96.6317%
95	Low	Mid	Mid	Low	Mid	Mid	1.1746%	97.8064%
96	Low	Low	Mid	Mid	Mid	Mid	1.1746%	98.9810%
97	Low	Low	[redacted]	Mid	Low	Mid	0.2893%	99.2702%
98	Low	Low	Mid	Low	Mid	[redacted]	0.2937%	99.5639%
99	Low	Low	[redacted]	Low	Mid	Mid	0.2893%	99.8532%
100	Low	Low	Mid	Low	Low	Low	0.1468%	100.0000%

SECTION 4: CHANCE NODES OVER CONSECUTIVE SUBINTERVALS

(4) The decision-tree diagram for all alternative resource plans shall include at least two (2) chance nodes for load growth uncertainty over consecutive subintervals of the planning horizon. The first of these subintervals shall be not more than ten (10) years long.

GMO requested and received a full waiver of this section of the Rule.

SECTION 5: DISTRIBUTION OF PERFORMANCE MEASURES

(5) The utility shall use the decision-tree formulation to compute the cumulative probability distribution of the values of each performance measure specified pursuant to 4 CSR 240-22.060(2), contingent upon the identified uncertain factors and associated subjective probabilities assigned by utility decision makers pursuant to section (1) of this rule. Both the expected performance and the risks of each alternative resource plan shall be quantified.

GMO used the decision tree risks to compute probabilistic and expected values of each of the performance measures. The results of this analysis are detailed in this section.

5.1 EXPECTED VALUES

(A) The expected performance of each resource plan shall be measured by the statistical expectation of the value of each performance measure.

GMO calculated the expected value of the five performance measures listed in Rule 22.060 (2) for each alternative expansion plan. These results are shown in Table 6 below. Tabular data that created Table 6: Performance Measures is provided on the work paper disc in the Excel file entitled "Table240-22.070(5)(A)Plan Performance Measures.xlsx".

Table 6: Performance Measures

Plan	NPVRR ($MM)	DSM Costs ($MM)	Levelized Annual Rates ($/kw-hr)	Maximum Rate Increase
CAA00	12,677	153.50	0.1417	17.84%
CAA01	12,773	153.50	0.1432	19.09%
CAB00	12,603	153.50	0.1413	12.42%
CAB01	12,695	153.50	0.1427	12.42%
CAB04	12,670	153.50	0.1419	14.63%
CAB05	12,661	153.50	0.1420	12.42%
CBB00	12,754	153.50	0.1432	14.09%
CCB00	12,689	153.50	0.1422	13.82%
CCB01	12,778	153.50	0.1434	14.32%
CXX00	12,752	153.50	0.1430	14.46%
XAB00	13,066	-	0.1402	11.87%

5.2 PROBABILITY DISTRIBUTIONS

(B) The risk associated with each resource plan shall be characterized by some measure of the dispersion of the probability distribution for each performance measure, such as the standard deviation or the values associated with specified percentiles of the distribution.

GMO calculated the standard deviation of each performance measure for each alternative resource plan analyzed over 100 scenarios. The result of these calculations is detailed in Table 7 below. DSM expenses have no risk dispersion as they are a fixed assumption input within the integrated analysis. Probable Environmental Costs are included in the total NPVRR value. Tabular data that created Table 7: Performance Measure Standard Deviations is provided on the work paper disc in the Excel file entitled "Table240-22.070(5)(B)Plan Performance Standard Deviations.xlsx".

Table 7: Performance Measure Standard Deviations

Plan	NPVRR ($MM)	DSM Costs ($MM)	Levelized Annual Rates ($/kw-hr)	Maximum Rate Increase
CAA00	1,031	-	0.0134	5.480%
CAA01	977	-	0.0127	5.253%
CAB00	1,040	-	0.0135	3.508%
CAB01	999	-	0.0129	2.645%
CAB04	1,017	-	0.0132	4.312%
CAB05	1,022	-	0.0132	3.526%
CBB00	1,096	-	0.0143	4.309%
CCB00	1,083	-	0.0141	4.167%
CCB01	1,079	-	0.0141	4.340%
CXX00	1,132	-	0.0148	4.517%
XAB00	1,113	-	0.0137	2.876%

GMO analyzed the risks on each of these plans by ranking their individual performance under each of the 100 endpoint scenarios listed in Figure 9. Table 8 through Table 18 given below are risk tables summarizing these results.