N. 2021 IRP MODELING SUMMARY

Hitachi ABB Power Grids (HAPG) completed capacity expansion, production cost, and stochastic modeling for several scenarios for the 2021 IRP. HAPG evaluated nine scenarios for Cheyenne Light, eight scenarios for Black Hills Power, and six scenarios for a joint plan. All scenarios, except one, were run to develop candidate resource portfolios. This process is discussed in detail in Chapter 8.

Modeling and analysis was run through the HAPG Capacity Expansion and Portfolio Optimization modules. Assumptions were derived from the Fall 2020 Reference Case.

This appendix describes the scope, assumptions, modeling and analysis, and results that form the foundation of the 2021 IRP.

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REPORT

2021 Integrated Resource Plan Modelling Summary for Cheyenne Light Fuel & Power, Black Hills Power and a Black Hills Power and Cheyenne Light Fuel & Power Joint System

PREPARED FOR

Black Hills Corporation

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May 2021

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1 Executive Summary

Hitachi ABB Power Grids (HAPG) was retained by Black Hills Corporation (BHC), to provide analytical services in support of Cheyenne Light Fuel & Power's (CLF&P) and Black Hills Power's (BHP) 2021 Integrated Resource Plans (IRP). These services included completing capacity expansion, production cost and stochastic modeling for a variety of scenarios for each utility and a Joint System. HAPG's Energy Market Advisors team (EMA) evaluated ten scenarios for CLF&P's system, nine scenarios for BHP's system and six scenarios for the Joint System. As part of these services, Black Hills' Capacity Expansion (CE) and Portfolio Optimization (PO) databases were updated to include the Fall 2020 Reference Case assumptions and other modeling assumptions provided by BHC. EMA used the updated CE and PO databases to complete capacity expansion modeling for all three IRPs. Table 1 includes a description of the variables that were revised for each scenario and identifies the portfolios that were developed for each utility and the Joint System for the different scenarios[1].

Table 1 Portfolio Descriptions

Scenario	Load Growth	Electric Price	Gas Price	Carbon Cost Adder	Resource Selection	Portfolios
1	Median	Median	Median	None	Economic	C1, B1, J1
2	Median	CO_2 Tax	Median	CO_2 Tax	Economic	C2, B2, J2
3	Median	Low	Low	None	Economic	C3, B3, J3
4	Median	High	High	None	Economic	C4, B4, J4
5	Low	Median	Median	None	Economic	C5, B5, J5
6	High	Median	Median	None	Economic	C6, B6, J6
7	High + Step	Median	Median	None	Economic	C7, B7
8	Median	Median	Median	None	10 MW BESS	C8, B8
9	Median	Median	Median	None	Carbon Capture	C9
10	Median	Median	Median	ACP	C2, B2 Portfolio	C10, B9

EMA then incorporated the portfolios developed by the Capacity Expansion model runs into the PO database and ran PO simulations that included each scenario's portfolio and median assumptions for load growth, electric prices and fuel prices and no carbon cost adder.

[1] CLF&P portfolios are identified as C1 through C10, BHP portfolios are identified as B1 through B9 and the Joint System portfolios are identified as J1 through J6.

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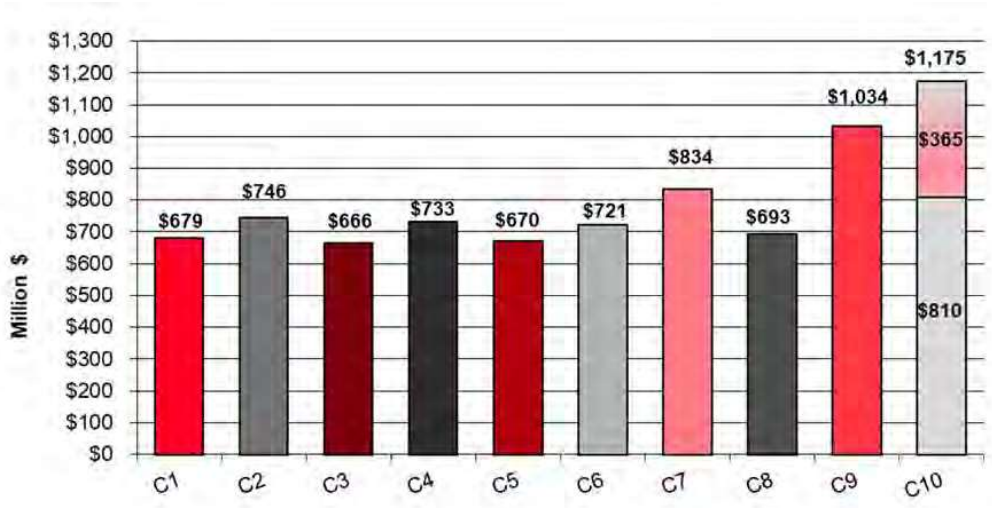
In response to recently proposed regulatory requirements, BHC requested that EMA model a CLEAN Future Scenario (Scenario10). For this scenario EMA completed production cost modelling using the portfolio developed in Capacity Expansion modelling for Portfolios C2 and B2 and applied the market prices and CO_2 Taxes from the Fall 2020 North American Power Reference Case CO_2 Tax Scenario, in lieu of the median assumptions that were used in the other PO simulations. The results from this production cost model were then modified to reflect Alternative Compliance Payments as proposed by BHC's Environmental Department rather than the CO_2 emission costs calculated using the CO_2 Tax forecast included in the Fall 2020 North American Power Reference Case CO_2 Scenario.

Next, EMA performed annual rate making to meet a target return on rate base specified by each utility. CLF&P's target return on rate base was set at 7.98%, BHP's was set at 7.76% and 7.85% was used for the Joint System. The study period for all the modelling was 2021-2040.

Lastly, EMA completed stochastic modeling for seven of BHP's nine portfolios and for seven of CLF&P's ten portfolios. Stochastic modeling was not completed for the Joint System. EMA used its Strategic Planning (SP) Corporate Finance module to complete the financial, rate making and risk simulations.

CLF&P's results, measured by the 20-year PVRR of each portfolio of the production cost, financial and rate making modeling are shown in Figure 1. Portfolio 10 breaks out the ACP revenue requirements of $365 million.

Figure 1 CLF&P Portfolios – Deterministic PVRR (2021-2040)



(Source: Energy Market Advisors)

As mentioned previously, BHP modelling included evaluation of nine portfolios with a target return on rate base of 7.76%. Figure 2 shows the PVRR for the BHP portfolios. Portfolio 10 breaks out the ACP revenue requirements of $91 million.

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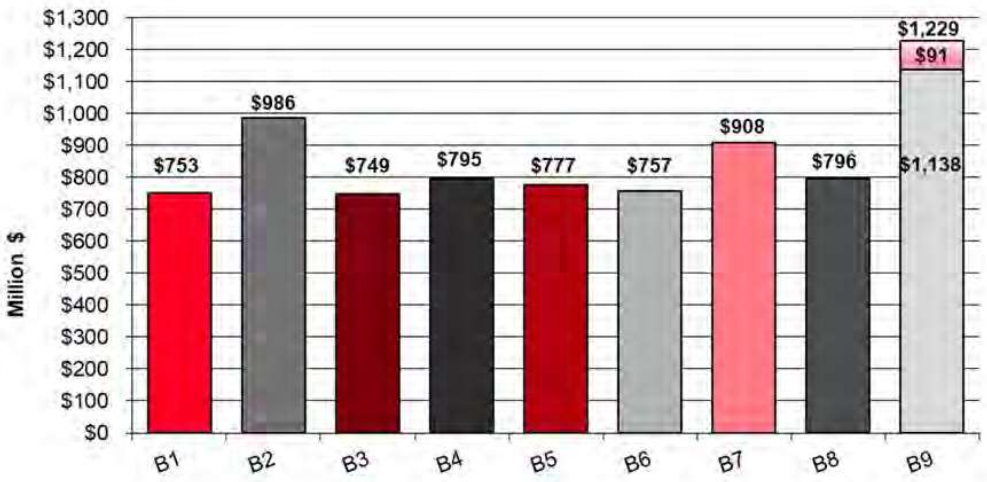
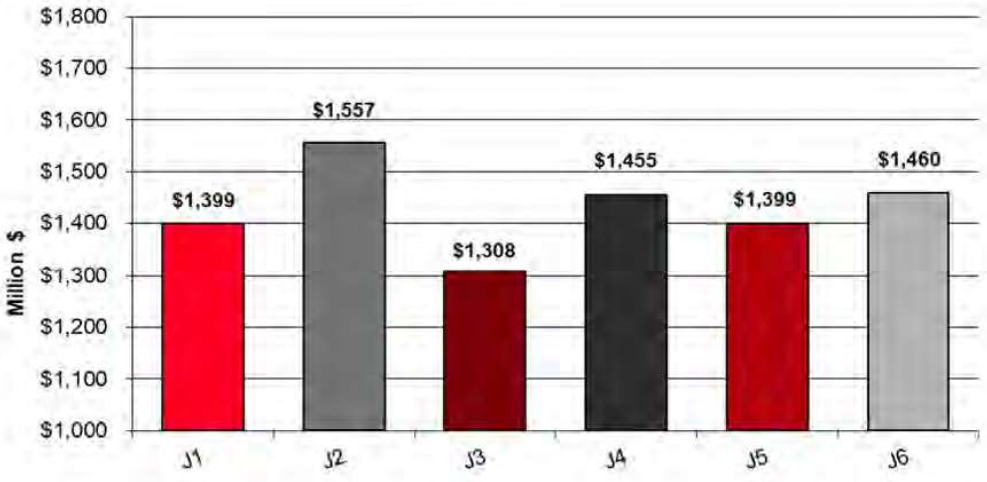
Figure 2 BHP Portfolios – Deterministic PVRR (2021-2040)



(Source: Energy Market Advisors)

Finally, the Joint System modelling included six portfolios with a target return of 7.85% on rate base. Figure 3 shows the PVRR for the six Joint System portfolios.

Figure 3 Joint System Portfolios – Deterministic PVRR (2021-2040)



(Source: Energy Market Advisors)

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2 Scope of Study

EMA was retained by BHC, to provide analytical services in support of CLF&P's, BHP's and the Joint System's 2021 Integrated Resource Plans. As part of these services, EMA updated BHC's CE and PO database to include assumptions necessary to complete capacity expansion and production cost simulations for Base Plans as well as several BHC specified scenarios. Once the databases were updated EMA performed capacity expansion and production cost modelling as well as risk, financial, and rate making simulations using the SP financial model.

2.1 Develop Base Case and Scenario Data Inputs

EMA used data supplied by BHC to model BHP's, CLF&P's and the Joint System's entire portfolio of conventional and renewable resources, both existing and proposed, in Capacity Expansion. BHC also supplied information needed to model loads including demand-side resources that will be implemented during the planning horizon.

EMA updated BHC's database with the natural gas price forecast and electric market price forecast from the Fall 2020 North American Power Reference Case which includes a long-term forecast of the North American power, fuels, and environmental markets. Forecasts of future conditions in these markets are based on fundamentals of demand and supply in the respective markets. Energy Market Advisors examine the interaction between fuel supply and demand, electric demand, electric supply including current thermal and renewable additions and retirements, and environmental regulation, to develop a forecast for all markets. EMA starts with Power Grids' Velocity Suite for load forecasts, generating unit characteristics, new entrants, and proposed retirements. Additional information is based on EMA's research, as well as fuels data from a third-party vendor (Rystad). This information is entered into our proprietary Integrated Model, which helps to develop natural gas prices, coal prices, emission prices, and capacity expansion, based on the interactions between these individual markets. Finally, the quantities are entered in the Power Grids' PROMOD model to determine the final electric energy prices.

BHC selected the CO-W market area Market Clearing Price (MCP) forecast for economy energy market prices and the AZ-PV market area for seasonal firm market prices in all three models. Natural gas pricing was derived from the NG-Rockies and NG-Colorado burnertip forecasts for all three models.

The Fall 2020 North American Power Reference Case assumes CO_2 emission costs for the RGGI states, Alberta, British Columbia and California only. Therefore, no CO_2 emission costs were included in the three systems' median assumptions.

EMA used the Fall 2020 North American Power Reference Case High Gas, Low Gas and CO_2 Tax Scenario forecasts for natural gas prices, market prices and CO_2 emission prices to develop inputs for the IRP Scenario modelling.

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2.2 Capacity Expansion Screening

EMA used the CE model to completely enumerate all possible combinations of resource expansion plans for each scenario run. This powerful screening tool uses a Mixed Integer Linear Programming (MILP) technique to determine the optimal selection of resource expansion plans including sizing and timing while maintaining a 15% reserve margin with a decision criterion of minimizing the present value of revenue requirements (PVRR). The results of the CE plans were passed to the PO and SP models as part of the portfolio, risk, financial, and rate making simulations.

Capacity Expansion plans were created using CE for ten CLF&P portfolios, nine BHP portfolios and six Joint System portfolios. Capacity Expansion was not utilized for the CLEAN Future scenarios.

2.3 Production Cost Modelling (Portfolio Simulation)

Production cost modelling was completed using PO to dispatch the resource portfolios selected from the capacity expansion modelling results and determine the production cost of each expansion plan. This step involved running PO simulations that included each scenario's portfolio and median assumptions for load growth, electric prices and fuel prices and no carbon cost adder. Production costs were calculated using PO for all ten CLF&P portfolios, nine BHP portfolios and six Joint System portfolios. The production cost modelling results were then passed to the financial model.

2.4 Financial Simulation and Rate Making

The production cost results from PO were passed to the financial model where they were used in the portfolio, risk, financial, and rate making simulations. EMA used SP to perform incremental financing. The revenue driver was return on rate base. Financial statements were developed for the deterministic and stochastic runs using PO production cost results. Stochastic results included 50 draws. Capital cost draws were developed in SP and integrated with the production results.

Financial statements were used to calculate Present Value of Revenue Requirements. Risk profiles, trade-off diagrams and Value at Risk charts were produced from the financial results.

EMA performed annual rate making to meet each utility's targeted return on rate base by increasing or decreasing the annual revenue requirements for both deterministic and stochastic results. Annual financial statements were developed for all plans.

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3 Assumptions

3.1 Introduction

The Energy Market Advisors (EMA) team is part of the HAPG Energy Market Intelligence solution area that provides tools and analysis around market and transmission modeling, analysis, and price forecasting to support investment decisions, regulatory compliance, trading, energy operations, and renewable integration.

The North American Power Reference Case product, published twice a year by the EMA team, is an assessment of conditions and trends in power, fuels, renewables, and environmental markets in North America. The product includes a long-term forecast of future conditions in these markets based on the fundamentals of demand and supply and are developed by utilizing HAPG's widely used data intelligence product called Velocity Suite, HAPG's proprietary capacity expansion model called Integrated Model, and HAPG's long-established production cost model called PROMOD®.

3.2 Natural Gas

The natural gas forecasts used in the BHP and CLF&P modelling were based on EMA's Fall 2020 North American Power Reference Case long-term forecasts. Natural gas pricing was derived from the NG-Rockies and NG-Colorado burnertip forecasts for BHP and CLF&P. Thermal units located in Cheyenne, Wyoming were assigned the NG-Rockies burnertip forecast while the NG-Colorado burnertip forecast was assigned to thermal generation located in Wyoming and South Dakota. Regional gas basis adders that are included in the Reference Case forecasts and CLF&P and BHP specific pipeline and transport costs were added to the EMA natural gas price forecast[2]. The annual Henry Hub gas price forecast is shown in Figure 4, and the monthly price forecast is summarized in Table 2.

[2] The published HAPG natural gas forecasts were converted to nominal dollars using a 1.5% escalation rate.

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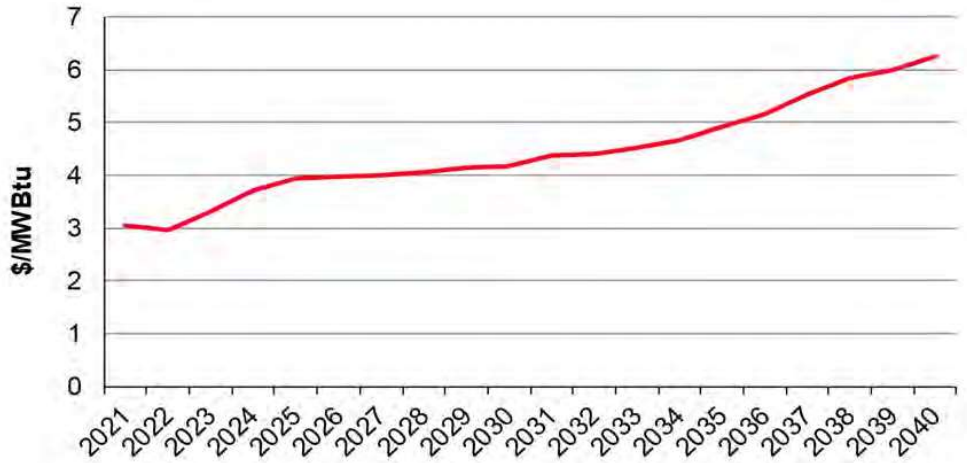
Figure 4 Annual Henry Hub Natural Gas Price



(Source: Energy Market Advisors)

Table 2 Monthly Henry Hub Natural Gas Price ($/MMBtu)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2021	3.42	3.37	3.23	2.87	2.81	2.84	2.88	2.89	2.88	2.91	2.97	3.11
2022	3.22	3.17	3.00	2.62	2.62	2.70	2.78	2.84	2.88	2.94	3.06	3.23
2023	3.32	3.34	3.22	3.10	3.13	3.17	3.22	3.25	3.26	3.29	3.42	3.58
2024	3.70	3.61	3.54	3.63	3.64	3.64	3.67	3.67	3.65	3.65	3.82	3.93
2025	4.03	4.02	3.82	3.83	3.83	3.86	3.89	3.89	3.86	3.85	3.94	4.11
2026	4.12	4.12	3.87	3.84	3.85	3.86	3.90	3.91	3.87	3.87	4.03	4.11
2027	4.14	4.12	3.90	3.85	3.85	3.86	3.88	3.89	3.87	3.88	4.09	4.12
2028	4.14	4.05	3.95	3.93	3.93	3.94	3.96	3.97	3.95	3.96	4.13	4.24
2029	4.26	4.26	4.06	4.01	4.02	4.05	4.06	4.07	4.06	4.04	4.18	4.25
2030	4.31	4.28	4.06	4.05	4.06	4.07	4.07	4.08	4.08	4.08	4.30	4.41
2031	4.49	4.44	4.26	4.23	4.24	4.26	4.29	4.30	4.26	4.27	4.43	4.50
2032	4.54	4.43	4.34	4.27	4.28	4.31	4.31	4.32	4.30	4.31	4.47	4.60
2033	4.67	4.64	4.40	4.38	4.38	4.39	4.41	4.41	4.40	4.41	4.61	4.74
2034	4.79	4.75	4.53	4.50	4.51	4.52	4.54	4.55	4.53	4.54	4.79	4.95
2035	5.09	4.98	4.75	4.77	4.78	4.82	4.84	4.86	4.83	4.81	5.06	5.19
2036	5.34	5.11	4.97	5.01	5.02	5.03	5.07	5.07	5.04	5.05	5.34	5.48
2037	5.67	5.55	5.24	5.39	5.40	5.41	5.48	5.49	5.43	5.43	5.58	5.79
2038	5.97	5.83	5.54	5.67	5.67	5.75	5.82	5.85	5.76	5.71	5.87	6.05
2039	6.27	6.08	5.73	5.79	5.80	5.87	5.96	5.97	5.88	5.83	6.02	6.17
2040	6.48	6.18	5.90	6.08	6.09	6.19	6.27	6.28	6.19	6.13	6.19	6.50

(Source: Energy Market Advisors)

To derive the NG Rockies and NG Colorado burner tip forecasts, EMA first aggregates regional basis prices at major trading hubs. Natural gas prices for the first 12 months of the forecast are driven by Henry Hub futures market prices plus a basis hub differential forward price. For the following 36 months of the forecast period (months 13-48), EMA blends the futures market price expectations with the long-term fundamental forecast, so that by the end of this period the gas price forecasts are consistent. EMA uses a cost-minimization linear program model of gas supply and demand.

3.3 Oil Prices

BHP's fleet includes five, two MW each, diesel units that operate primarily during extreme load hours or when other units in the fleet experience unplanned outages. The No.2 Distillate price forecast from the 2020 Fall Reference Case Base Case was used as the fuel price forecast for these units.

U.S. crude oil prices are based on conditions in the world oil market. Based on extensive prior analysis, EMA believes that the feedback to the world oil market from the markets represented in the North American forecast, i.e., power, natural gas, coal, and emissions, is extremely weak. Moreover, the effects on the world oil market of the types of policies or exogenous events that might be modeled, such as a CO_2 cap-and-trade program, are also very weak. As a result, EMA believes it is appropriate to treat the world oil market—and more specifically U.S. crude oil prices—as an exogenous input, as opposed to modeling it explicitly.

For months 1-12, the deflated New York Mercantile Exchange (NYMEX) Light Sweet Crude Oil (WTI, Symbol CL) futures prices are used. For months 13-48, we use a blend of the NYMEX futures in real money terms and the long-term forecast. Starting with the 49th month onwards we use the long-term forecast. We generate forecasts of region-specific prices for refined oil products burned in power plants, e.g., diesel and residual, based on an analysis of historical relationships between these prices and the West Texas Intermediate price.

3.4 Market Electricity Prices

The Western Electricity Coordinating Council (WECC) covers nearly 1.8 million square miles extending from Canada to Mexico, including the Canadian provinces of Alberta and British Columbia; Northern Baja California, Mexico; and all or portions of 14 Western states. EMA has further divided the WECC into 22 market areas as illustrated in Figure 5. These 22 market areas are within the six NERC Assessment Areas. Although WECC is predominantly a summer peaking region, Alberta, British Columbia, and Northwest loads peak in the winter.

The WECC is highly interconnected, and, with some limitation, generation from any area within WECC can be used to meet load in any other area. The diversity in loads, along with seasonal power exchanges between the hydro-rich Northwest and solar from the southwest and California, results in electricity markets and wholesale electric prices that are highly interdependent.

EMA created a forward view of the Colorado West regional electricity market. EMA is forecasting the actual day-ahead cash price that will occur in spot markets under normal conditions in the future, not the traded price of futures or forward contracts.

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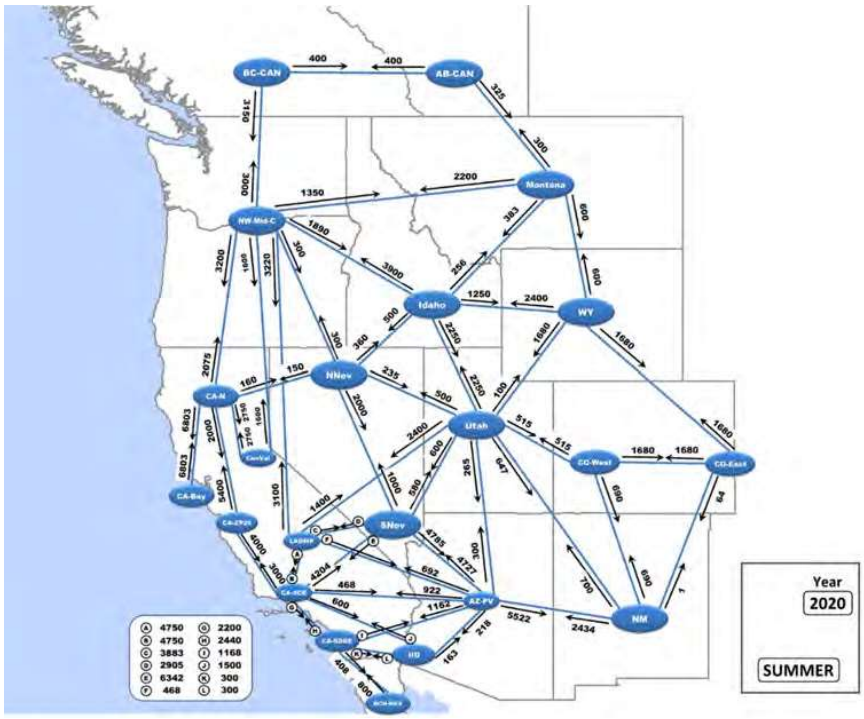
BHP's and CLF&P's models allow for the purchase of hourly economy energy from energy markets and monthly seasonal firm market purchases to cover short-term capacity shortfalls up to 50 MW. For economy energy purchase pricing, both BHP and CLF&P used the CO-West market area MCP forecast. The pricing for SFMP was derived by increasing the AZ-PV market area MCP forecast by 20 percent to emulate the additional cost of providing firm energy.

Figure 5 WECC Market Configuration



(Source: Energy Market Advisors)

Table 3 summarizes the Base annual 6x16 (On-Peak), Wrap (Off-Peak) and 7x24 (Average) electricity prices for the Colorado West region[3].

[3] The published EMA electric price forecasts were converted to nominal dollars using a 1.5% escalation rate.

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Table 3 Base Prices for the CO-West Market Area

	CO-West On-Peak	CO-West Off-Peak	CO-West Average
2021	38.18	23.26	31.79
2022	36.89	22.35	30.67
2023	38.74	24.23	32.50
2024	37.38	24.99	32.08
2025	34.98	26.21	31.22
2026	35.95	28.22	32.64
2027	35.91	30.32	33.51
2028	36.68	30.90	34.19
2029	37.07	31.84	34.83
2030	37.51	31.96	35.13
2031	47.60	38.21	43.58
2032	48.14	38.80	44.14
2033	49.55	39.99	45.45
2034	50.80	40.81	46.50
2035	51.80	42.14	47.66
2036	53.56	43.29	49.16
2037	56.53	46.95	52.42
2038	58.38	49.57	54.61
2039	59.36	51.26	55.89
2040	61.17	52.80	57.57

(Source: Energy Market Advisors)

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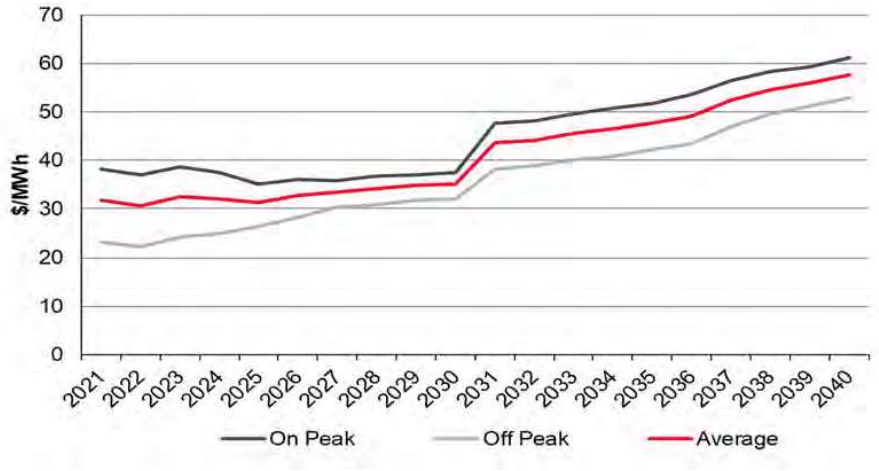
The CO-West market area Base electricity prices for on-peak, off-peak and average are shown in Figure 6.

Figure 6 Reference Case – CO-West Electricity Prices



(Source: Energy Market Advisors)

Figure 7 shows that CO-West average prices increase starting in 2025 with the retirement of Craig Unit 1. From 2025 to 2030 prices trend upward in a similar manner as the natural gas price forecast. The sharp increase in the 2031 forecast is a result of the expected retirement of nearly one GW of coal generation. Craig 3 and Hayden units 1 & 2 are expected to retire in 2030.

The correlation between natural gas prices and MCP's is also depicted in Figure 7. In 2034, the natural gas price upward trend increases as a result of the year-over-year lack of growth in the total potential gas supply. Gas supply roughly flattens out from 2034-2040 as the potential supply from shale plays, especially tight liquids/shale oil plays, declines (Permian, Midcontinent, and Western Canada). At the same time gas demand continues to slowly increase during this timeframe, pushing the marginal resource up the supply curve more quickly than pre-2034.

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Figure 7 Average CO-West Market Clearing Prices and NG-Colorado burner-tip gas prices

(Source: Energy Market Advisors)

3.5 High Gas Price and Low Gas Price Scenarios

The Fall 2020 Power Reference Case also includes forecasts for three additional scenarios: a Low Gas Price Scenario, High Gas Price Scenario, and Carbon Tax Scenario (CO_2 Tax). For the Fall 2020 Reference Case, EMA utilized a new approach in the development of gas price scenarios by using custom assumptions for supply fundamentals. This methodology isolates the impact of supply expectations on gas prices by holding other natural gas and power assumptions constant. The assumptions reflected in the gas scenarios are highlighted below:

- Low Gas Price scenario – Production costs are set equal to short-run marginal costs over the study period in this scenario. This scenario is intended to reflect pricing that could be sustained over the short-term. Over the long-term, significant technological improvements would be required to sustain the price trajectory in this scenario.

- High Gas Price scenario – Assumed long-run marginal production costs for shale plays are increased to at least the 75th percentile in this scenario. EMA reduced the overall availability of gas resources by approximately eight percent and defined higher costs for each shale play to create a geographically diversified gas price scenario.

The Fall 2020 Reference Case scenario natural gas price forecasts, MCP price forecasts and CO_2 tax forecast were used in the scenarios completed for CLF&P, BHP and the Joint System.

Figure 8 depicts the Henry Hub monthly price forecasts for the 2020 Fall Reference Case Base Case and two gas price scenarios, Low Gas Price and High Gas Price. The scenario prices directly reflect custom assumptions for supply fundamentals and how these would impact the utilization of storage, transmission, and ultimately prices at gas hubs throughout North America. Both cases hold all other assumptions for natural gas and power sector fundamentals constant to isolate the substantial impact of supply expectations on natural gas prices.

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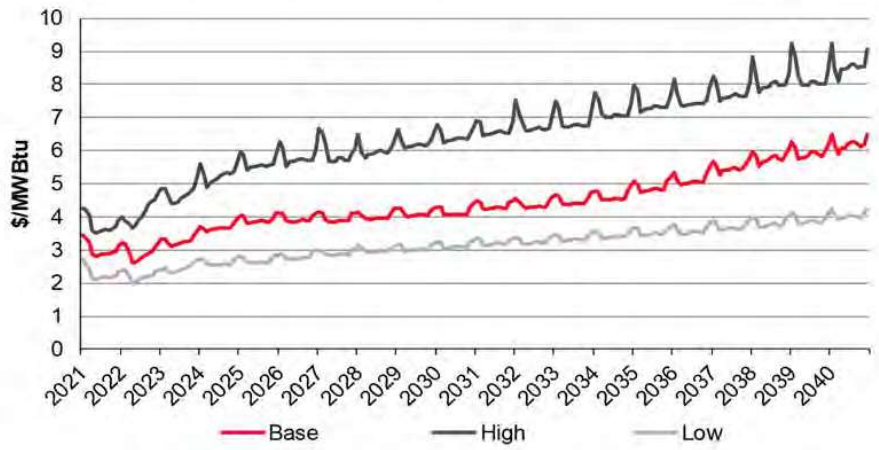
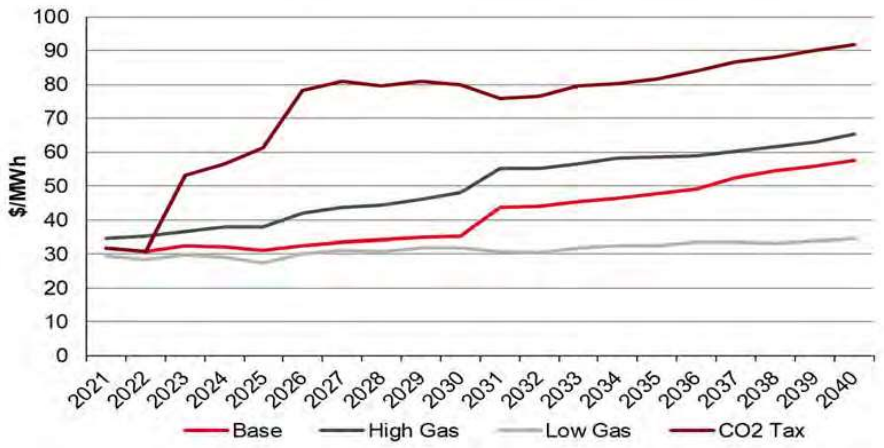
Figure 8 Monthly Henry Hub Natural Gas Prices



(Source: Energy Market Advisors)

Average CO-West electricity prices are shown in Figure 9 for the Fall 2020 Reference Case Base Case and three scenarios.

Figure 9 Average CO-West Base and Scenario Market Clearing Prices



(Source: Energy Market Advisors)

3.6 Carbon Tax Scenario

EMA's CO_2 Tax Scenario is based on the U.S. Government's Social Cost of Carbon (August 2016 update) with a 3 percent discount rate. The carbon tax begins in 2023 and ramps up to the full Social Cost of Carbon in 2026. It is applied across North America and replaces all state or provincial carbon pricing programs. Figure 10 shows the Carbon Tax Scenario CO_2 emission cost annual forecast.

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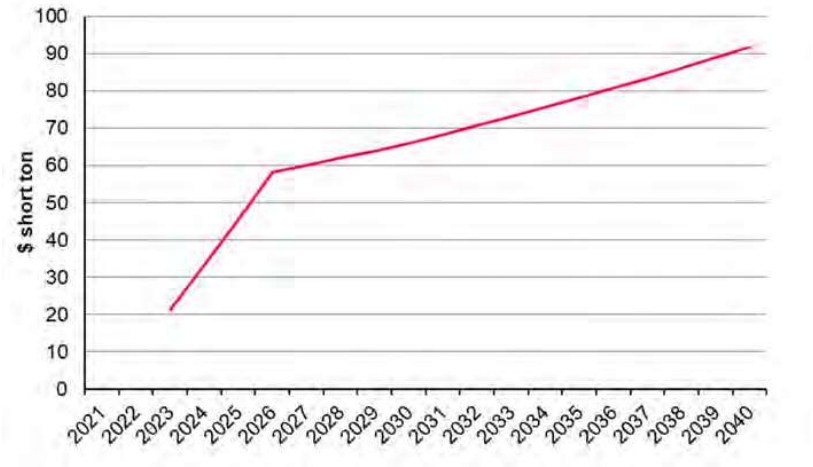
Figure 10 Carbon Tax Scenario CO_2 Emission Cost



(Source: Energy Market Advisors)

3.7 Regulating Reserves

EMA completed an assessment of Black Hills Power's Regulating Reserves, Flexible Capacity Requirement and Effective Load Carrying Capability as part of the Black Hills Power's Variable Energy Resource Integration Study. The study examined renewable and energy storage resource options of varying sizes and locations to assess incremental impacts of the addition of renewable resources on BHP's regulation requirements and costs. The assessment evaluated twelve different renewable and energy storage resource expansion options and five different potential geographic locations for those resources. These resource options and locations were specified by the BHP planning team, based on commercial interest it has seen in developing resources at those locations, and with a goal of capturing impacts of geographic diversity in wind and solar generation profiles within its service territories.

As part of the Variable Energy Resource Integration Study, estimated costs for BHP to carry additional Regulation Up and Regulation Down capacity were calculated. As shown in Table 4 these cost estimates reflect changes in BHP operating cost as the system unit commitment and dispatch is altered to reflect an increased Regulation Up and Down capacity operating reserve requirement. The costs did not reflect any capital related cost needed to procure additional flexible regulation capacity. EMA estimated incremental regulation costs assuming Regulation Up and Down quantities needed to meet the 98 percentile North American Reliability Council (NERC) Control Performance Standard 2 (CPS2). For resource portfolios that include only battery storage projects, EMA did not estimated an incremental regulation requirement or cost, as storage only resources are unlikely to cause incremental ACE deviations.

BHP also has an option to procure regulation from WAPA, through its Open Access Transmission Tariff (OATT) at a lower cost. WAPA's current tariff offers regulation service for a fixed cost of $0.303/kW/Month for wind resources, and $0.205/kW/Month for solar resources. At a 40% annual average wind capacity factor, the WAPA regulation cost is equivalent to $1.04/MWh for

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wind resources, and at a 25% annual average capacity factor for solar, the regulation cost would be equivalent to $1.12/MWh for solar resources. The WAPA tariff rates were used in all three of the resource plan's modelling. Table 4 provides a summary of the renewable and energy storage resource options and projected regulation requirements included in the Variable Energy Resources Study.

Table 4. Incremental BHP Regulating Reserve Cost

Portfolio	Type	Size (MW)	Location	98% CPS2: Incremental Regulation Up (MW)	98% CPS2: Incremental Regulation Down (MW)	Regulation Cost – BHP Generation ($/MWh)	Regulation Cost – WAPA Tariff ($/kW/Mo)
Existing System				55	50		
1	Wind	50	Cheyenne	24	0	$10.17	$0.303
2	Wind	100	S. Gillette	26	22	$6.56	$0.303
3	Wind	200	N. Douglas	50	40	$11.12	$0.303
4	Solar	50	Cheyenne	7	1	$5.38	$0.205
5	Solar	100	Gillette	10	1	$4.63	$0.205
6	Solar	200	Hot Springs	11	1	$1.57	$0.205
7	Solar + Storage	100 + 40	Cheyenne	0	1	$0.02	$0.205
8	Solar + Storage	100 + 20	Gillette	0	1	$0.03	$0.205
9	Solar + Storage	100 + 60	Hot Springs	0	1	$0.02	$0.205
10	Storage	20	Cheyenne	0	1	N/A	
11	Storage	40	Gillette	0	1	N/A	
12	Storage	60	Hot Springs	0	1	N/A	

3.8 Flexible Capacity Requirement

In addition to assessing incremental regulation requirements and costs likely to be incurred due to changes in BHP operating costs, EMA also completed an assessment of whether BHP, CLF&P or the Joint System was likely to require additional flexible capacity to integrate the renewable resources identified in the resource portfolios created for each scenario. EMA used a methodology originally developed by the California Independent System Operator (CAISO) to assess each portfolio system's flexible capacity requirements. The final assessment showed that each system's existing flexible capacity was sufficient when the variable energy resources added in each portfolio were added to their system, with the exception of a few scenarios as shown in Table 5. This was accomplished by modelling multiple capacity expansion iterations. If the

existing flexible capacity was not sufficient for a portfolio, the cost of flexible peaking capacity was added to the portfolio options and a new expansion plan was developed. The cost for a LM6000 combustion turbine, on a $/kW-Yr basis, and any flexible capacity requirements identified for each resource plan were reflected in the expansion plan resource options.

Table 5. Flexible Capacity Requirements

System	Scenario	MW Requirement	Starting in Year
BHP	B2 & B9	41 MW	2025
	B7	38 MW	2024
CLF&P	C1	9 MW	2033
	C8	9 MW	2033
	C2 & C10	29 MW	2029
	C4	9 MW	2033
	C6	9 MW	2033
	C7	9 MW => 57 MW	2026 => 2032
	C9	29 MW	2033
Joint	J2	49 MW	2023
	J4	30 MW	2033
	J6	49 MW	2034

3.9 Effective Load Carrying Capability

EMA also completed an Effective Load Carrying Capability (ELCC) assessment of the wind, solar and battery storage resource portfolio options as part of the Black Hills Power Variable Energy Resource Integration Study. This study was used to assess the level of reserve capacity that each option provides to BHP and the data was also used for their resource portfolio options. The ELCC analysis was used to determine the percentage of the nameplate capacity of each resource type and location that can be counted on for reserve margin planning purposes.

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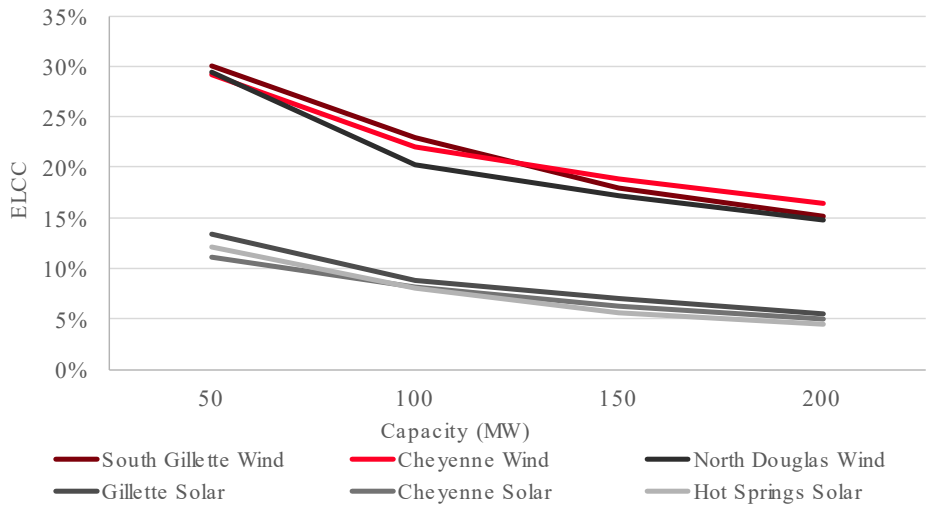
Figure 11. ELCC Capacity of Wind and Solar Resources



As shown in Figure 11, the ELCC values for wind are comparable at all three locations for 50 MW resource additions. For 100 MW wind resource additions, ELCC values are highest at South Gillette, followed by Cheyenne and then North Douglas. Projected ELCC values at South Gillette begin at 30 percent with a 50 MW wind addition and decline with additional wind expansion. The ELCC values for wind at Cheyenne and Douglas begin in the 28 percent range and decline with additional wind expansion. However, for the Cheyenne site, estimated ELCC values see a lesser decline than the other two sites, for wind additions of 150 and 200 MW.

For solar resources, ELCC values are highest at the Gillette location, followed by Hot Springs and then Cheyenne. Solar ELCC values are considerably lower than those for wind resources, ranging in the 11 to 13 percent range with 50 MW additions, and declining to around 5 percent with 200 MW solar additions. The primary driver for lower solar ELCC values is a lower capacity factor for solar resources, compared to wind.

EMA also calculated the ELCC value of stand-alone battery storage at four capacity levels, 20 MW, 40 MW, 60 MW and 100 MW. The battery charge level was determined in every hour to calculate the amount of capacity that a stand-alone battery storage facility can provide. This capacity ranges between 0 MW and the maximum capacity of the storage facility. Table 6 lists the estimated ELCC values. As the size of the capacity increases from 20 MW to 60 MW, the effective capacity contribution is expected to decrease from 80% to 54%.

Table 6. ELCC of Battery Storage

Type	Capacity (MW)	Incremental Demand (MW)	ELCC (%)
Storage	20	16	80%
Storage	40	27	67%
Storage	60	33	54%
Storage	100	49	49%

3.10 Future Generation Options

As mentioned previously, BHC provided data necessary to model a variety of proposed units including natural gas-fired thermal generation, renewable generation, energy storage and existing generation betterment options. The data BHC supplied included unit characteristics, operating costs and financial criteria for five natural gas-fired thermal options, a biofuel option, six renewable options (wind and solar, four Battery Energy Storage System (BESS) options and three solar paired with BESS options. Betterment options included conversion to natural gas or life extension of the coal-fired Neil Simpson II unit, conversion of the Ben French Diesel units to natural gas and expansion of the CPGS LM6000 to a combined cycle unit.

Battery storage can be modeled in PO purely as an arbitrage opportunity or can be paired with another generating unit that exclusively charges the battery. In both cases the battery attempts to charge during the lowest-priced hours in a day and discharge during the highest-priced hours. In this way batteries can provide peak shaving benefits, as it will generally be the case that the highest-priced hours coincide with the system peak and when the battery is economically incentivized to discharge. The battery options modeled as part of this IRP used an algorithm that estimates marginal costs to determine economic charging and generating schedules. Battery storage options for the BHP and CLFP IRPs were modelled in two ways; as standalone (charged by the system) and paired with proposed solar facilities. In both cases, the BESS stations were not limited to a specific number of cycles per day, maximum energy per charge or daily maximum generation.

3.11 Financial Parameters

Financial assumptions used in the modelling are included in Table 7. In addition, a 21% federal income tax rate was used. Book life and tax life assumptions for various technologies were provided by BHC. They included 35 years for combined cycle and peaking technologies, 25 years for wind and solar, and 20 years for battery storage. Tax lives of 20 years were used for combined cycle, 15 years for peaking technology, 7 years for battery storage and 5-year life for solar and wind. Unless otherwise specified, a 1.5% escalation rate was assumed.

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Table 7. Financial Assumptions

	CLF&P	BHP	Joint System
Discount Rate	6.3	6.13	6.2
Debt (%)	46	47	47
Equity (%)	54	53	53
Cost of Debt (%)	5.72	Global Settlement	5.94
Cost of Equity (%)	9.9	Global Settlement	9.5
Property Tax Rate (%)	.43	.6	.53

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4 Stochastic Analysis

In order to simulate the risk associated with uncertainties in electric prices, fuel prices and load forecasts stochastic analysis was undertaken. The stochastic process involves completing a specified number of independent simulations or "runs", with each run representing a "draw" or iteration that contain variations in the values of the selected uncertainties. The Stochastic Analysis component within PO was used to complete the stochastic analysis. This component includes a Regression Tool that computes stochastic properties for variables and a Draw Generation Tool that generates sample random draws using the distributions calculated by the Regression Tool.

PO's built-in Regression Tool uses user-specified historical data and distribution types and sample settings to calculate the stochastic properties of variables. Stochastic properties that are computed include, among others, volatility, short-term mean-reversion rate, standard deviation and correlations among the random time-series. PO's Draw Generation Task generates sample random draws using the distributions calculated by the Regression Tool. The power simulation model uses these random paths to optimize commitment and dispatch along each random path.

The PO stochastic modelling framework allows the user to specify, for each stochastic entity, a specific distribution type. The options include:

- Continuous – Time
  - Normal and LogNormal Mean-reverting Distributions
- Discrete Time Independent
  - Normal, LogNormal, Uniform and Triangle Distributions

The stochastic distribution typically assumed for price variables such as fuel prices, emission costs or electricity prices is either a Normal or LogNormal Mean-Reverting Distribution. The Mean-Reverting distribution's short-term process features shocks, whose effect through time evaporates as the variable returns to its expected value. While the long-term process shocks expected value with no reversion to mean. The lognormal distribution, particularly in comparison to the normal distribution, is widely used as the stochastic model distribution for prices because it is restricted to positive values. There is an expectation that fuel and energy commodities will always have value and therefore draws for price variables should not include non-positive values. Zero or negative prices cannot be produced by a lognormal distribution.

Load variables are typically characterized by ether a Normal, LogNormal, Uniform or Triangle Distribution. These types of distributions generate draw values for a particular time period and are not directly dependent on the previous period's draw value. These types of distributions are used when modeling uncertainties in escalation and inflation rates and monthly peak and energy for load.

4.1 Stochastic Variables

Based on results from the Capacity Expansion and PO simulations, CLF&P and BHP selected seven scenarios for stochastic evaluation: Scenarios 1, 2, 3, 4, 5, 6 and 8. Stochastic runs were performed for 50 iterations where each utility's load, the Colorado-West Market Price forecast, coal price forecast and the appropriate natural gas price forecast[4] were all varied stochastically.

[4] Stochastic variables for the three natural gas price forecasts, NG_Cheyenne, NG_Gillette, and NG_Rapid City are based on historical Henry Hub price data.

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As discussed above, the model calculated short term volatilities and mean reversion rates shown in Table 8 for the natural gas and coal stochastic variables. Standard deviation and time correlations for the BHP and CLF&P load stochastic values are shown in Table 9. In addition, correlations between the natural gas and electric market price variables were calculated and are shown in Table 10. Load was modelled with a normal distribution while the market prices and natural gas prices were modeled with a lognormal distribution based on the reasoning mentioned earlier.

Table 8 Short Term Volatilities and Mean Reversion Rates

	Short Term Volatility Rate	ST Mean Reversion Rate
Gillette Coal	0.084	0.345
EP_COW	0.199	0.291
NG_Cheyenne	0.112	0.102
NG_Rapid City	0..112	0.102
NG_Gillette	0.112	0.102

(Source: Energy Market Advisors)

Table 9 Standard Deviation and Time Correlations

	Standard Deviation	Time Correlation
CLF&P Load		
June - Sept	12.637	0.945
Oct - May	14.456	0.945
BHP Load		
June - Sept	9.721	0.663
Oct - May	10.921	0.663

(Source: Energy Market Advisors)

Table 10 Commodity Correlations

	NG_Cheyenne	NG_Gillette	NG_Rapid City	EP_COW
EP_COW	0.40	0.40	0.40	1.0

(Source: Energy Market Advisors)

4.2 Capital Cost

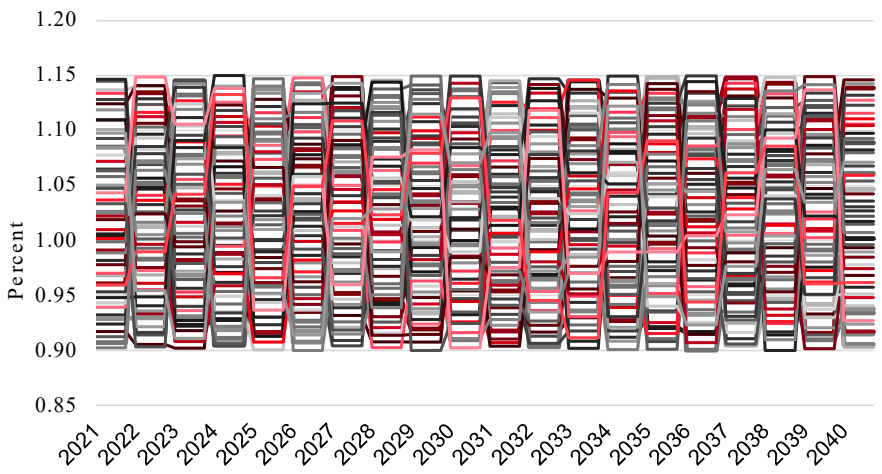
Using Strategic Planning's Stratified Monte Carlo sampling program, EMA created 50 future scenarios for portfolio evaluation. EMA has performed extensive market price trajectory simulations and has determined that 50 trajectories provide a reasonable balance between the number of scenarios to provide a convergent solution balanced with a manageable number of stochastic scenarios to be applied to many resource plan alternatives. Uncertainty draws were

made for the capital cost of the resource additions in the portfolio evaluation. These capital cost draws are combined with the uncertainty draws generated by PO.

4.2.1 Long-Term Capital Cost Uncertainty

Capital cost is a constant variance variable with a uniform distribution. Capital cost ranges were based on forecasts from Lazard, AEO20 and NREL-ATB with final input from BHC's Resource Planning Team. It was assumed that the multipliers for capital cost will range from .9 to 1.15 with an expected value of 1.025. Figure 12 shows the multipliers used for a Simple Cycle. Separate multipliers were used for wind, solar, combined cycles and storage, however graphically the draws remain similar.

Figure 12 Simple Cycle Capital Cost Multiplier



(Source: Energy Market Advisors)

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4.2.2 Summary of Uncertainty Variables

Table 11 is a summary of the uncertainty variables used in the stochastic analysis and their range of multipliers.

Table 11 Uncertainty Variable Range Multipliers

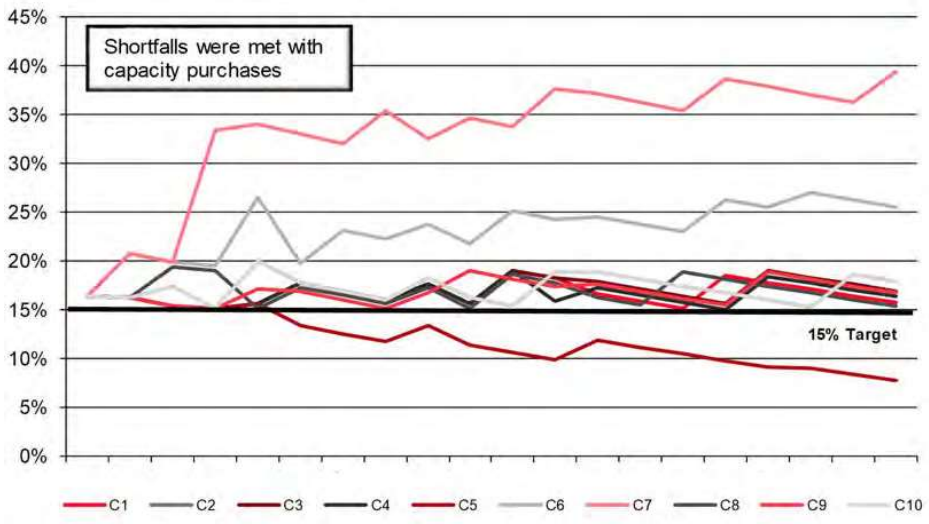
Uncertainty	Uncertainty Range
Simple Cycle Costs	0.9 – 1.15
Combined Cycle Costs	0.9 – 1.15
Wind	0.9 – 1.15
Solar	0.9 – 1.15
Storage	0.9 – 1.15
Load – CLF&P	0.39 – 1.53
Load - BHP	0.39 – 1.53
Market Price	1.12 – 2.05
Natural Gas Price	0.34 – 2.80
Coal Price	0.92 – 1.41

(Source: Energy Market Advisors)

4.3 Regulatory Capacity

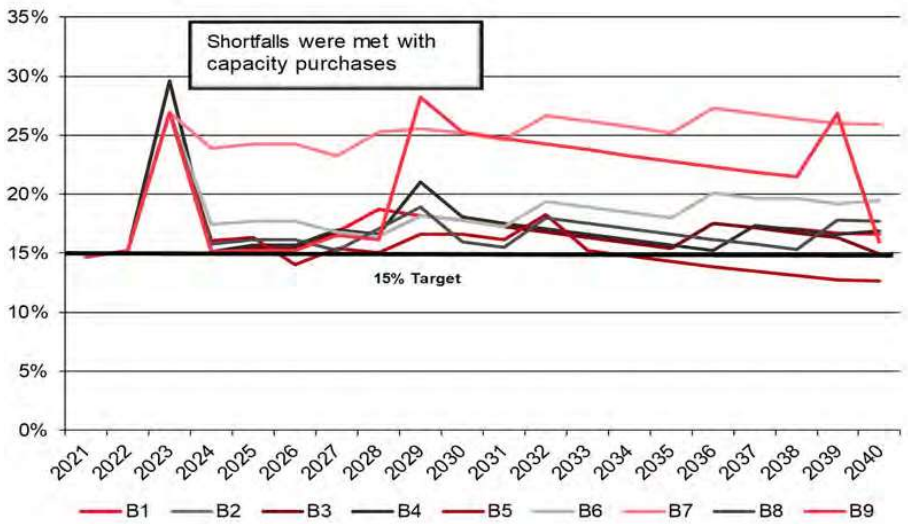
The deterministic simulations in PO were designed, under median assumptions, to maintain a minimum 15% reserve margin, with the exception of the low load scenario as shown in Figure 13, Figure 14 and Figure 15. To address any reserve margin deficits, EMA used the levelized cost of a new LM6000 combustion turbine as a proxy for purchases from a capacity market to meet the reserve margin target.

Figure 13 CLF&P All Scenarios – Capacity Margin



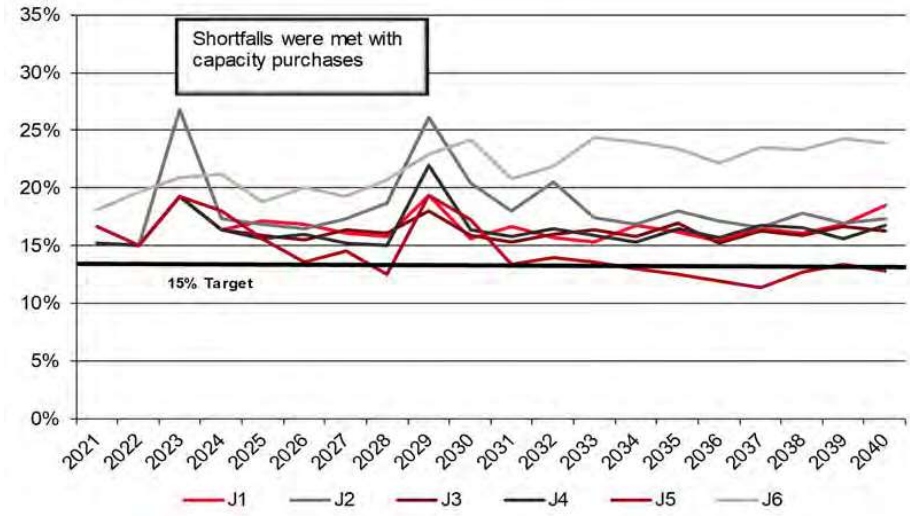
(Source: Energy Market Advisors)

Figure 14 BHP All Scenarios – Capacity Margin



(Source: Energy Market Advisors)

Figure 15 Joint System All Scenarios – Capacity Margin



(Source: Energy Market Advisors)

When exposed to demand uncertainty in the stochastic process, there are certain scenarios where the resource plan would become reserve margin deficit. Again, to address these deficits, EMA used the levelized cost of a new LM6000 combustion turbine as a proxy for purchases from a capacity market to meet the target. Figure 16 illustrates the annual reserve margins for the fifty load draws.

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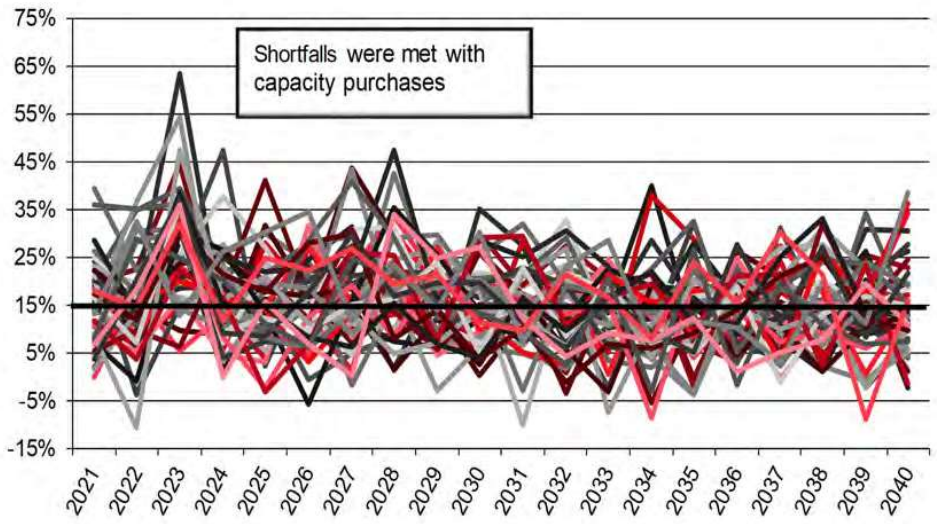
Figure 16 Portfolio B1 Reserve Margins for Fifty Load Draws



(Source: Energy Market Advisors)

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5 Capacity Expansion Results

To produce optimal resource plans under a variety of conditions BHC identified nine scenarios for CLF&P, eight scenarios for BHP and six scenarios for the joint system to optimize in the Capacity Expansion module. Table 12, Table 13 and Table 14 summarize the optimal resource expansion plans for each utility as well as the Joint System for each of their scenarios (the table does not include seasonal firm market purchases). Seasonal firm market purchases are short term purchases that do not have capital costs. The cost of SFMPs are included in the income statements as purchase power. As noted in the Executive Summary Portfolio Description Table, C10 and B9 use the same portfolio as C2 and B2 respectively.

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Table 12 CLF&P Optimal Expansion Plans

YEAR	C1	C2	C3	C4	C5	C6	C7	C8	C9	C1
2021										
2022										
2023		Wind 50 MW						Storage 10 MW		Wir 50 M
2024		Solar 50 MW					Wind 50 MW			Sol 50 M
2025									Solar 50 MW Wygen 2 Carbon Capture	
2026						Wind 50 MW	Storage 10 MW Wind 50 MW		Wind 50 MW	
2027										
2028										
2029		Wind 50 MW								Wir 50 M
2030										
2031										
2032				Wind 50 MW			Wind 50 MW			
2033	LM6000 42 MW Wind 100 MW	LM6000 42 MW	LMS100 91 MW	LM6000 42 MW Wind 100 MW	LM6000 42 MW Wind 50 MW	LMS100 91 MW Wind 50 MW	LMS100 91 MW	LM6000 42 MW Wind 100 MW	LMS100 91 MW Wind 50 MW	LM6 42 M
2034										
2035										
2036										
2037										
2038					Wind 50 MW	Solar 50 MW				
2039							Wind 50 MW			
2040										

2021 Integrated Resource Plans

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Table 13 BHP Optimal Expansion Plans

YEAR	B1	B2	B3	B4	B5	B6	B7	B8	B9
2021									
2022									
2023	Wind 50 MW	Wind 250 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Storage 10 MW Solar 50 MW	Wind 250 MW
2024	Wind 50 MW	Wind 50 MW	Wind 50 MW	Wind 50 MW	Solar 50 MW	Wind 50 MW	Wind 150 MW Solar 50 MW	Wind 50 MW	Wind 50 MW
2025	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW Solar 100 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW Solar 100 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW Solar 100 MW
2026									
2027									
2028									
2029									
2030					Wind 50 MW				
2031									
2032								Wind 50 MW	
2033									
2034									
2035									
2036									
2037									
2038	Wind 50 MW					Wind 50 MW			
2039		Wind 100 MW						Wind 50 MW	Wind 100 MW
2040	Wind 100 MW		Wind 150 MW	Wind 150 MW	Wind 100 MW	Wind 150 MW	Wind 150 MW Storage 10 MW	Wind 100 MW	

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Table 14 Joint System Optimal Expansion Plans

YEAR	J1	J2	J3	J4	J5	J6
2021						
2022						
2023		Wind 200 MW Solar 200 MW				
2024						
2025	NS2 Coal to Gas 79 MW Solar 200 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW	NS2 Coal to Gas 79 MW Solar 200 MW	NS2 Coal to Gas 79 MW Solar 200 MW	NS2 Coal to Gas 79 MW Solar 200 MW
2026				Wind 50 MW		
2027						
2028						
2029						
2030						
2031						Wind 50 MW
2032						Wind 50 MW
2033	Wind 100 MW			Wind 150 MW	Wind 100 MW	Wind 50 MW
2034	Wind 50 MW					Wind 50 MW
2035						
2036			Wind 50 MW			
2037					Wind 50 MW	
2038				Wind 50 MW		Wind 50 MW
2039						
2040	Wind 150 MW	Storage 10 MW	Wind 150 MW	Wind 100 MW	Wind 50 MW	Wind 150 MW

2021 Integrated Resource Plans

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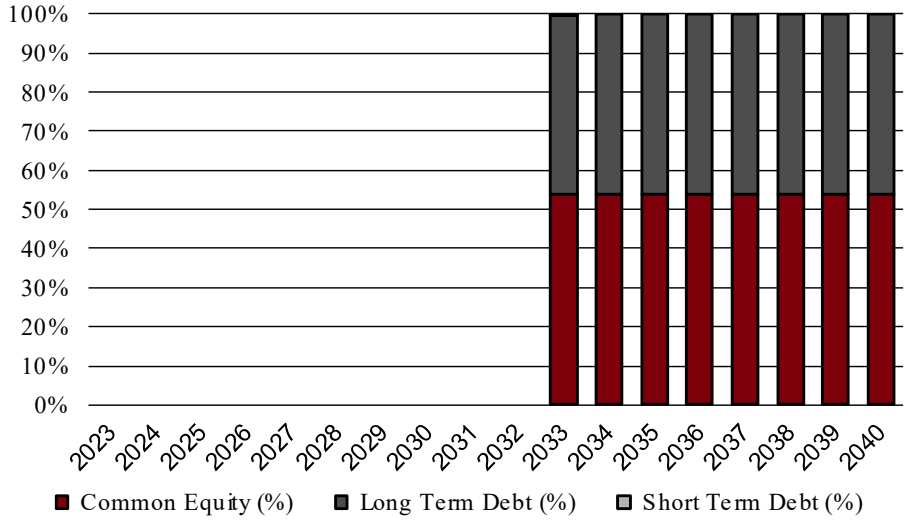
6 Deterministic Portfolio Results

6.1 Portfolio 1 Results

EMA evaluated multiple scenarios with varying inputs to highlight the effect of fuel price, market electricity price and load when determining future resource portfolios. This set of scenarios includes a plan that used price and load forecasts that are considered to most likely represent future prices (median). For CLF&P, portfolio C1 meets the needs of its forecast energy requirements under median assumptions. Figure 17 shows the capitalization ratios for C1. The financial modelling includes only incremental rate base additions with financing beginning in 2033 with the addition of a LM6000 and a 100 MW wind facility. Figure 18 shows the incremental annual rate increase for C1.

Figure 17 Portfolio C1 - Capitalization Ratios



(Source: Energy Market Advisors)

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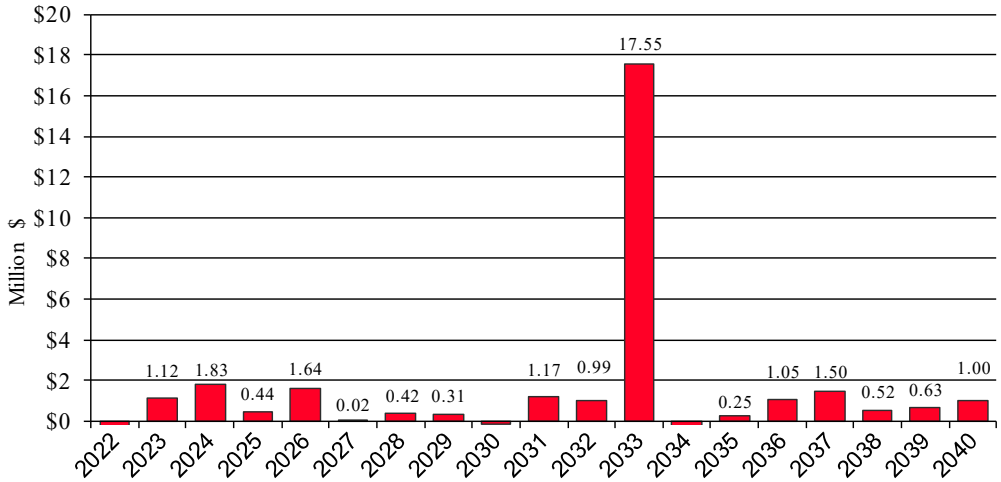
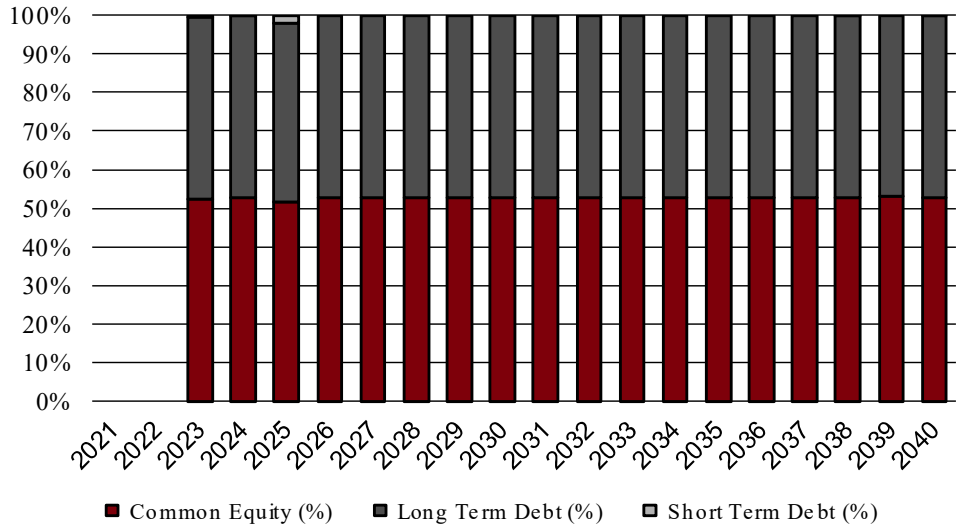
Figure 18 Portfolio C1 – Annual Rate Increases



(Source: Energy Market Advisors)

Portfolio B1 meets the needs of BHP's forecast energy requirements under median assumptions. Figure 19 shows the capitalization ratios for B1. The financial modelling includes only incremental rate base additions, with financing beginning in 2023 when a 50 MW Wind facility is added to BHP's system. Additional builds include a 50 MW Wind facility in 2024, NS2 Coal to Gas conversion in 2025, 50 MW Wind facility in 2038 and 100 MW Wind facility in 2040. Figure 20 shows the incremental annual rate increase for B1.

Figure 19 Portfolio B1 - Capitalization Ratios



(Source: Energy Market Advisors)

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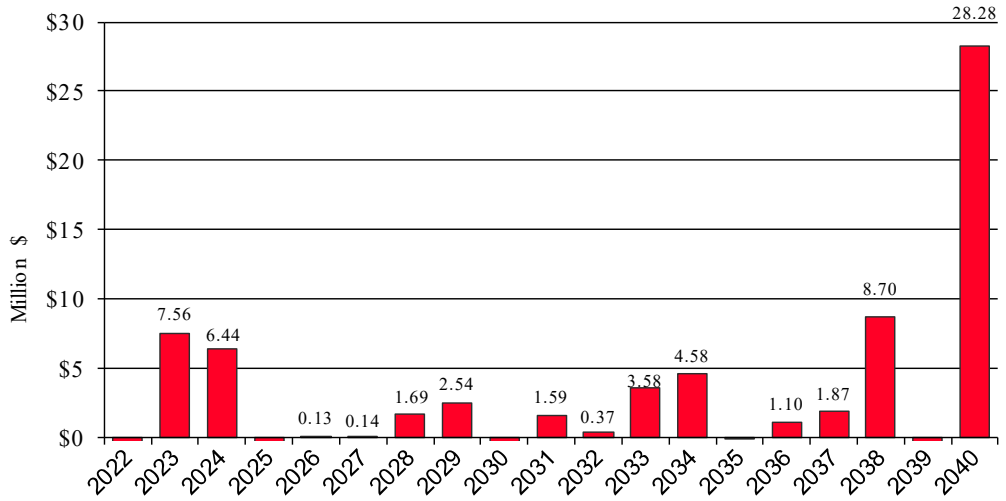
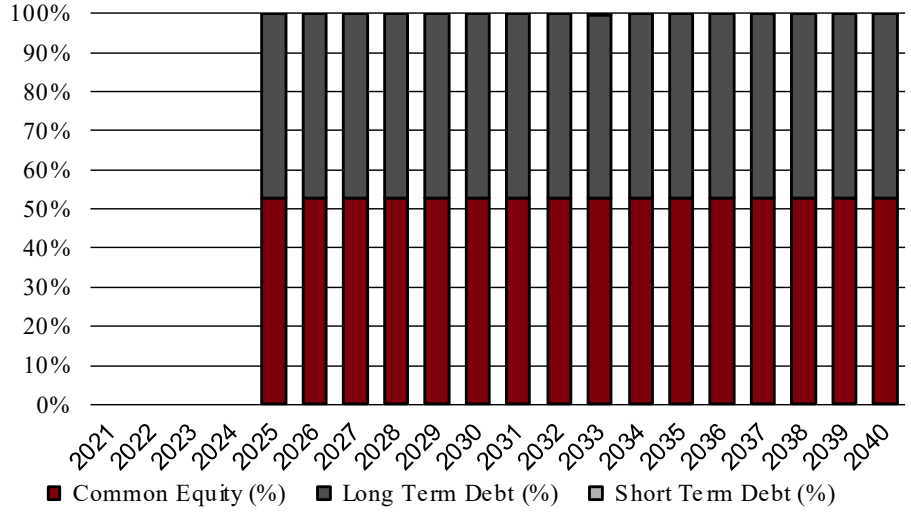
Figure 20 Portfolio B1 – Annual Rate Increases



(Source: Energy Market Advisors)

Portfolio J1 meets the needs of the Joint System's forecast energy requirements under median assumptions. Figure 21 shows the capitalization ratios for portfolio J1. The financial modelling includes only incremental rate base additions. Financing for the Joint System begins in 2025 with the NS2 Coal to Gas conversion and a 200 MW Solar facility. Additional builds include a 100 MW Wind facility in 2033, 50 MW Wind facility in 2034 and 150 MW Wind facility in 2040. Figure 22 shows the incremental annual rate increase for portfolio J1.

Figure 21 Portfolio J1 - Capitalization Ratios



(Source: Energy Market Advisors)

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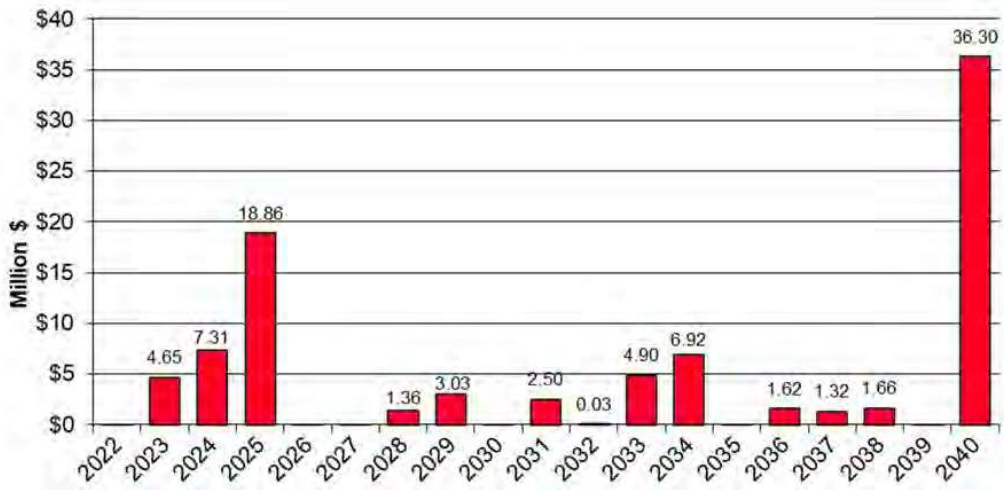
Figure 22 Portfolio J1 – Annual Rate Increases



(Source: Energy Market Advisors)

6.2 All Scenarios Results

The following series of tables and graphs compares the deterministic results for each IRP Portfolio over the twenty-year planning period (2021 through 2040). Table 15 and Figure 23 shows the PVRR for the ten CLF&P Portfolios.

Table 15 CLF&P Portfolios - 20 Year Deterministic PVRR (million $)

Scenario/ Portfolio	Load Growth	Electric Price	Gas Price	Carbon Cost Adder	Resource Selection	PVRR
C1	Median	Median	Median	None	Economic	$679.02
C2	Median	CO_2 Tax	Median	CO_2 Tax	Economic	$745.72
C3	Median	Low	Low	None	Economic	$665.54
C4	Median	High	High	None	Economic	$733.09
C5	Low	Median	Median	None	Economic	$670.01
C6	High	Median	Median	None	Economic	$720.83
C7	High + Step	Median	Median	None	Economic	$833.54
C8	Median	Median	Median	None	10 MW BESS	$693.36
C9	Median	Median	Median	None	Carbon Capture	$1,034.20
10	Median	Median	Median	ACP	Portfolio C2	$1,175.20

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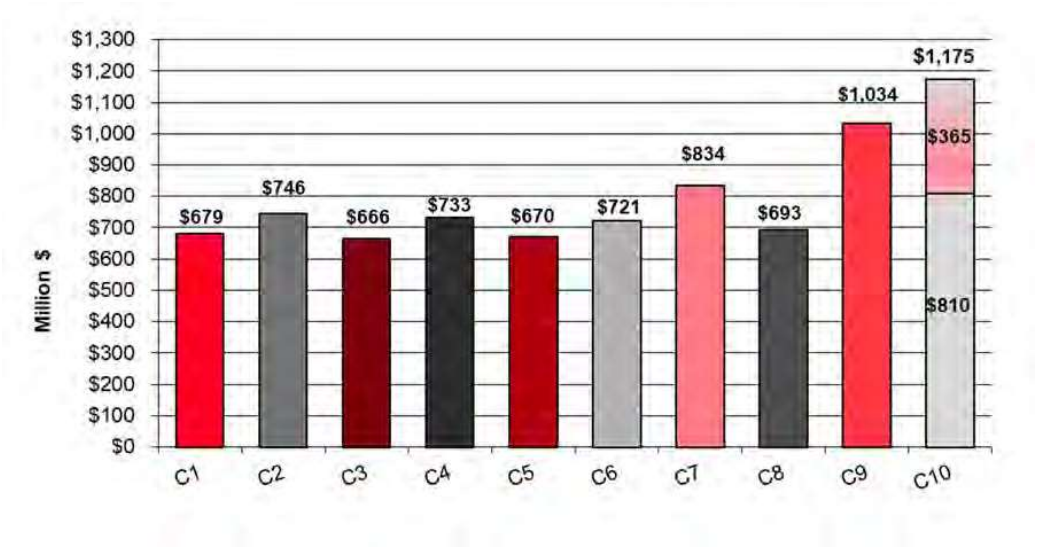
Figure 23 CLF&P Portfolios – Deterministic PVRR (2021-2040)



(Source: Energy Market Advisors)

BHP production costs modelling included nine portfolios. Table 16 and Figure 24 shows the deterministic PVRRs for the nine BHP Portfolios for the years 2021-2040.

Table 16 BHP Portfolios - 20 Year Deterministic PVRR (million $)

Scenario/ Portfolio	Load Growth	Electric Price	Gas Price	Carbon Cost Adder	Resource Selection	PVRR
B1	Median	Median	Median	None	Economic	$752.54
B2	Median	CO_2 Tax	Median	CO_2 Tax	Economic	$985.65
B3	Median	Low	Low	None	Economic	$748.69
B4	Median	High	High	None	Economic	$795.04
B5	Low	Median	Median	None	Economic	$777.24
B6	High	Median	Median	None	Economic	$757.23
B7	High + Step	Median	Median	None	Economic	$908.43
B8	Median	Median	Median	None	10 MW BESS	$795.60
B9	Median	Median	Median	ACP	Portfolio B2	$1,228.60

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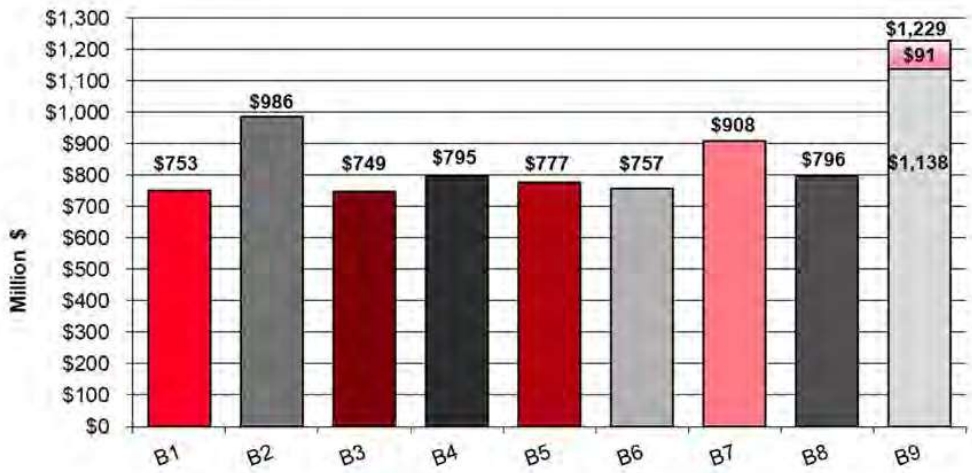
Figure 24 BHP Portfolios – Deterministic PVRR (2021-2040)



(Source: Energy Market Advisors)

Last, the Joint System production cost modelling included six portfolios. Table 17 and Figure 25 shows the PVRR for six Joint System portfolios for the years 2021-2040.

Table 17 Joint System Portfolios - 20 Year Deterministic PVRR (million $)

Scenario/ Portfolio	Load Growth	Electric Price	Gas Price	Carbon Cost Adder	Resource Selection	PVRR
J1	Median	Median	Median	None	Economic	$1,398.97
J2	Median	CO_2 Tax	Median	CO_2 Tax	Economic	$1,556.60
J3	Median	Low	Low	None	Economic	$1,307.51
J4	Median	High	High	None	Economic	$1,454.92
J5	Low	Median	Median	None	Economic	$1,398.81
J6	High	Median	Median	None	Economic	$1,459.74

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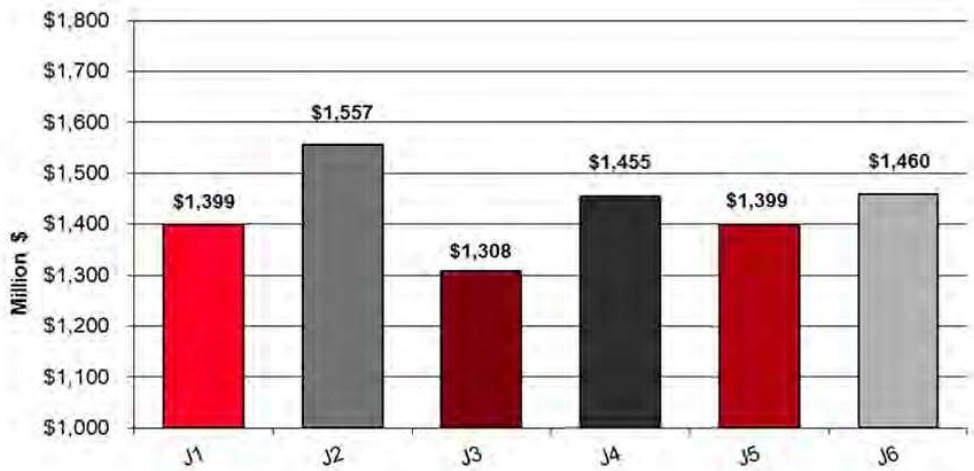
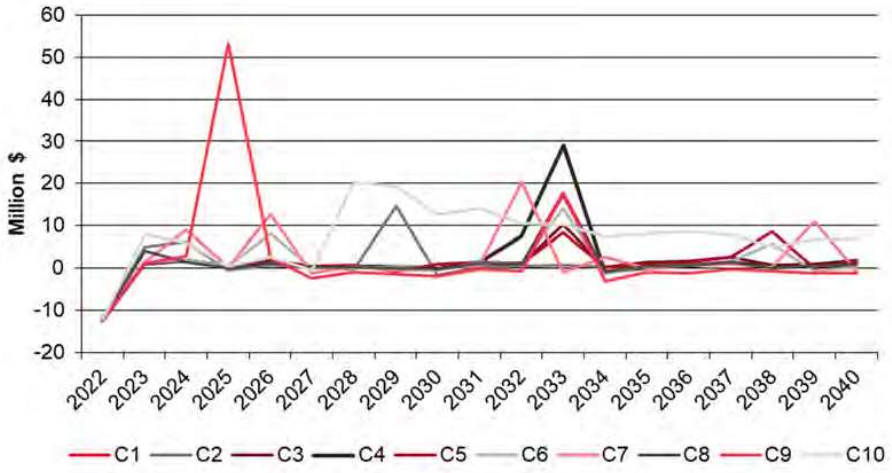
Figure 25 Joint System Portfolios – Deterministic PVRR (2021-2040)



(Source: Energy Market Advisors)

The following series of graphs compares the Incremental Annual Rate Increases for BHP's, CLF&P's and the Joint System's portfolios.

Figure 26 CLF&P All Scenarios – Incremental Annual Rate Increases



(Source: Energy Market Advisors)

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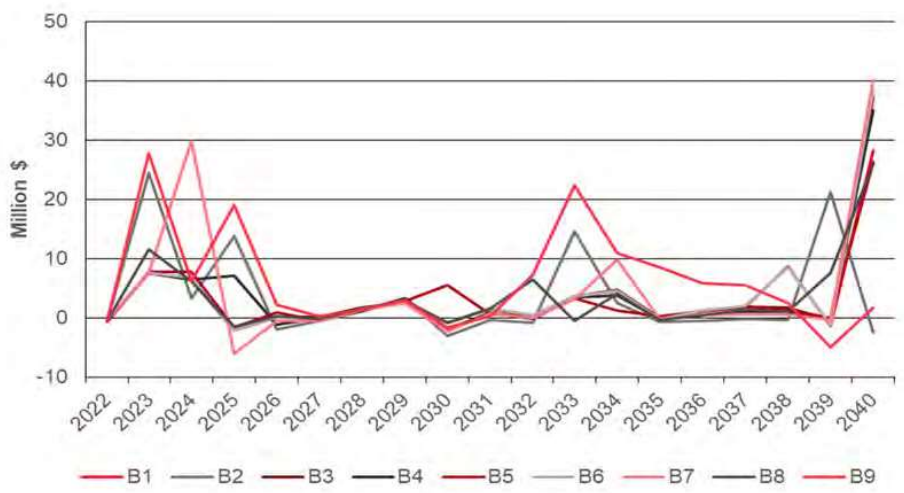
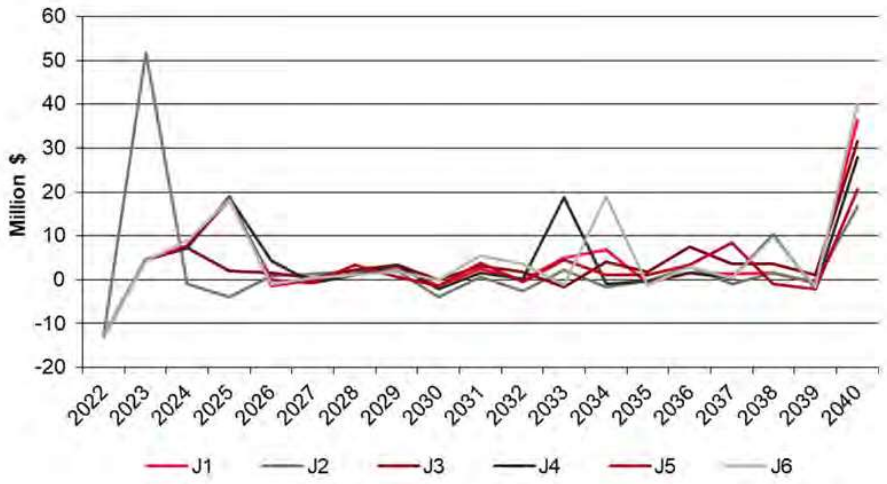
Figure 27 BHP All Scenarios – Incremental Annual Rate Increases



(Source: Energy Market Advisors)

Figure 28 Joint System All Scenarios – Incremental Annual Rate Increases



(Source: Energy Market Advisors)

The following series of graphs compares the Cumulative Capital Expenditures for BHP's, CLF&P's and the Joint System's portfolios.

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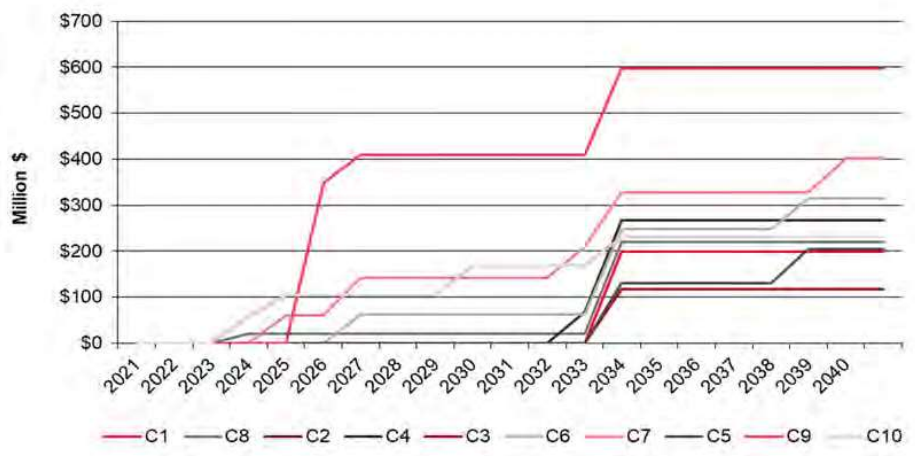
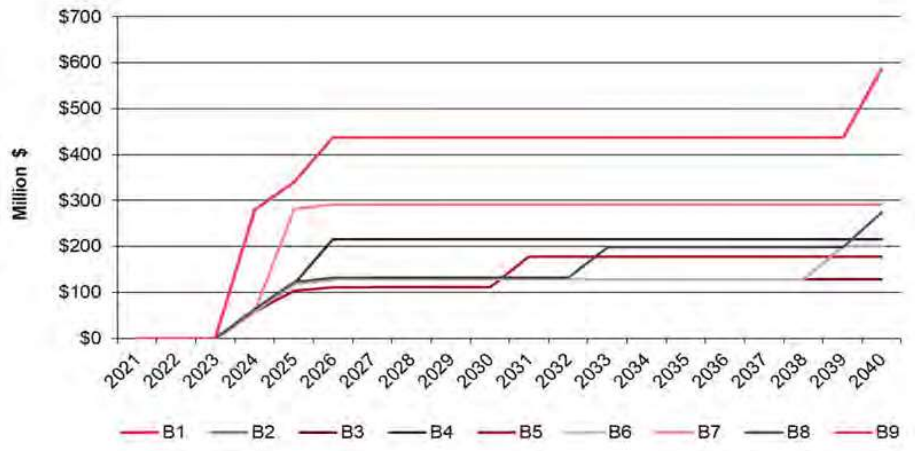
Figure 29 CLF&P All Scenarios – Cumulative Capital Expenditures



(Source: Energy Market Advisors)

Figure 30 BHP All Scenarios – Cumulative Capital Expenditures



(Source: Energy Market Advisors)

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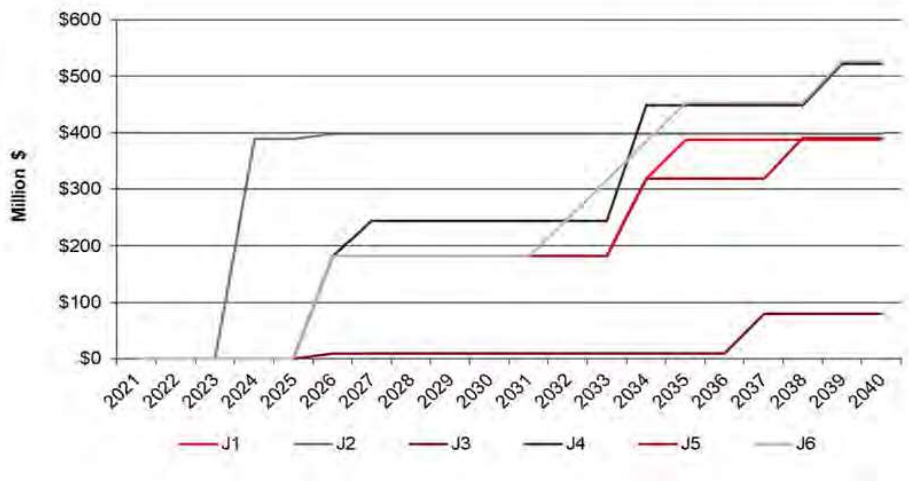
Figure 31 Joint System All Scenarios – Cumulative Capital Expenditures



(Source: Energy Market Advisors)

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7 Risk Analysis

7.1 Introduction

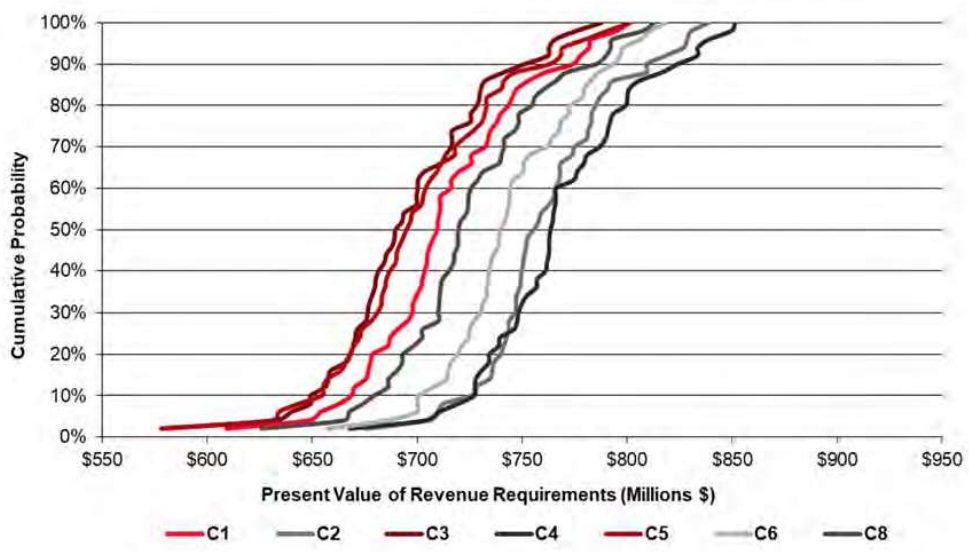
EMA utilized the Strategic Planning Risk Module to develop cumulative probability distributions which are also known as Risk Profiles.

7.2 Risk Profiles

Risk Profiles provide the ability to visually assess the risks associated with a decision under uncertainty. For this study, EMA combined the production cost model results with the financial results. Figure 32 and Figure 33 show the risk profiles for the CLF&P combined scenarios and portfolio C1. In Figure 32, Portfolios C3 & C5 are the closest to the left and therefore have the lowest PVRR in all years.

One can view the risk profile to determine the probability that PVRR will be a particular value. Using Portfolio C1 as an example, in Figure 33, there is a 90% probability that PVRR could be as much as $773.99 million with an expected value, or probably utility costs of $714.19 million. From the prior deterministic simulation, the PVRR value was $679.02 under direct utility costs or "median" conditions. The $35.17 million difference between the expected value and the deterministic value is "real option value" or extrinsic value. This reflects the risk of Portfolio C1 with future uncertainty.

Figure 32 CLF&P - Risk Profiles (2021-2040)



(Source: Energy Market Advisors)

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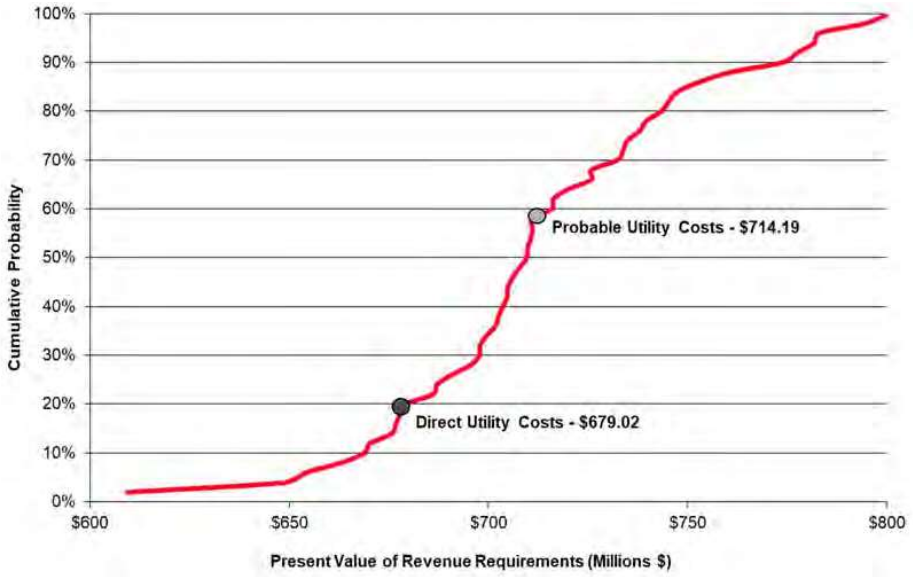
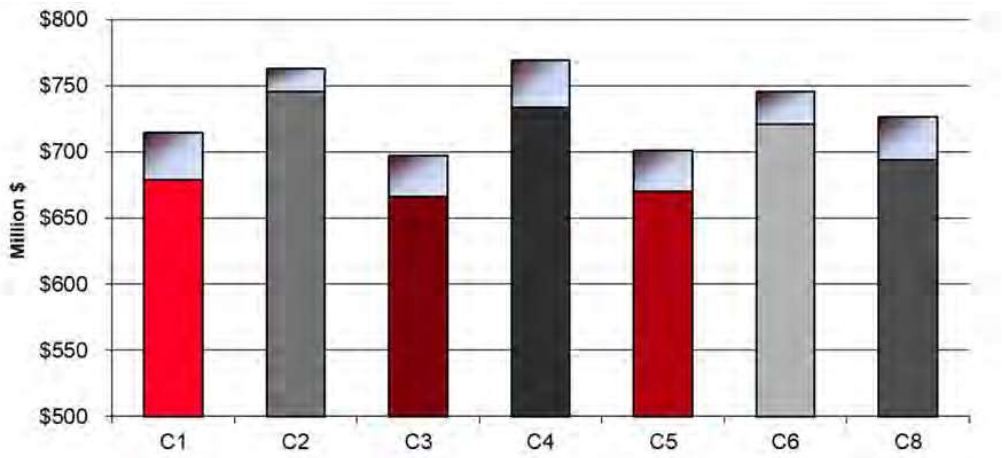
Figure 33 CLF&P C1 - Risk Profile (2021-2040)



(Source: Energy Market Advisors)

Figure 34 shows the "real option value" in table format. The extrinsic value is shaded in grey.

Figure 34 CLF&P - PVRR with Risk Value (2021-2040)



(Source: Energy Market Advisors)

Figure 35 shows the risk profiles for BHP portfolios B1 through B9. In Figure 35, Portfolios B1, B3 & B6 are the closest to the left and therefore have the lowest PVRR in all years. These portfolios also have deterministic values within $8.5 million of each other.

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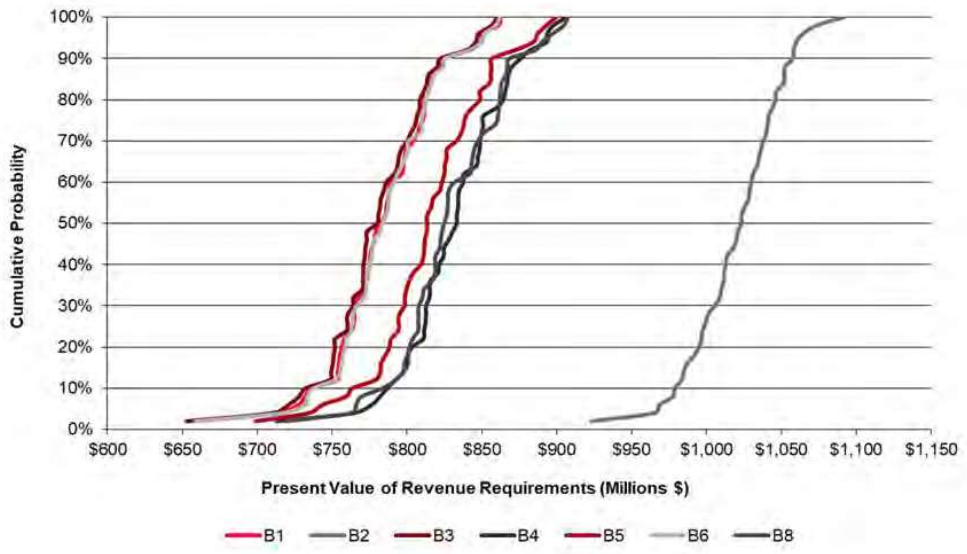
Figure 35 BHP - Risk Profiles (2021-2040)



(Source: Energy Market Advisors)

Again, one can view the risk profile to determine the probability that PVRR will be a particular value. Using Portfolio B1 as an example, as shown in Figure 36, there is a 90% probability that PVRR could be as much as $825.74 million with an expected value of $785.21 million. From the prior deterministic simulation, the PVRR value was $752.54 under "median" conditions. The $32.67 million difference between the expected value and the deterministic value is "real option value" or extrinsic value. This reflects the risk of Portfolio B1 with future uncertainty.

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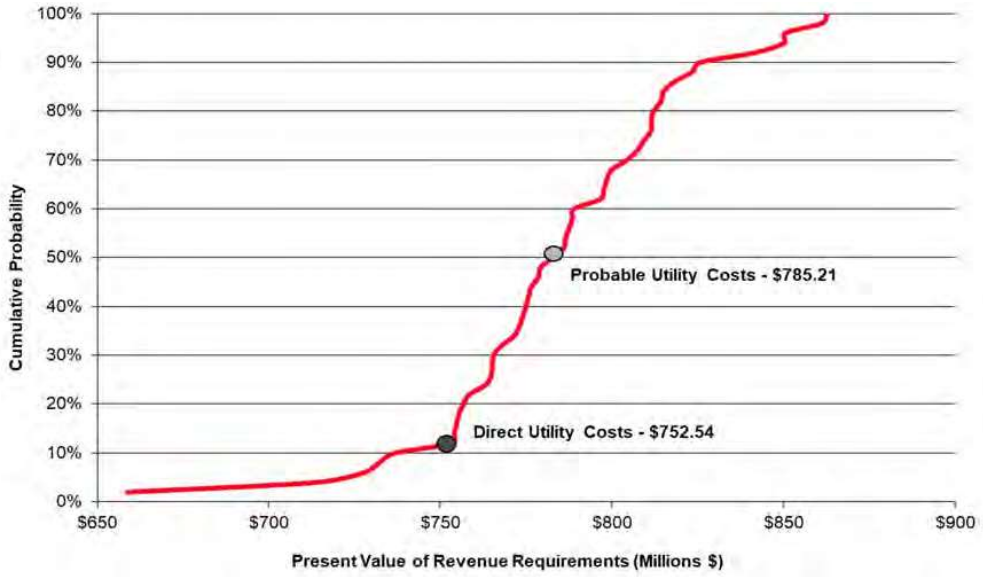
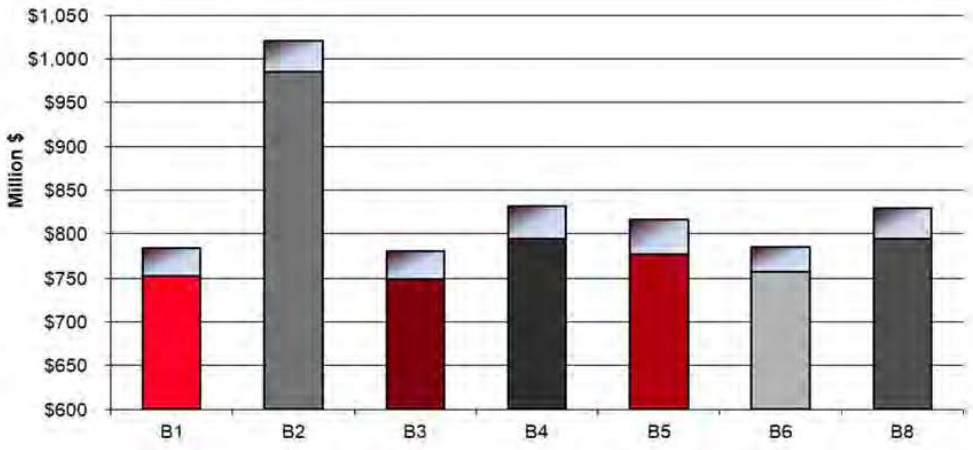
Figure 36 BHP B1 - Risk Profile (2021-2040)



(Source: Energy Market Advisors)

Figure 37 shows the "real option value" in a table format. The extrinsic value is shaded in grey.

Figure 37 BHP - PVRR with Risk Value (2021 - 2040)



(Source: Energy Market Advisors)

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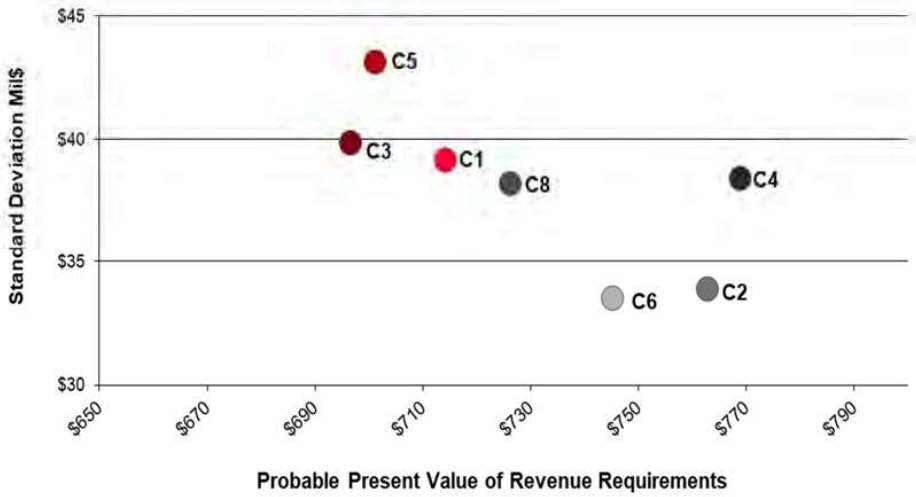
7.3 Trade-Off Diagram

EMA developed trade-off diagrams to evaluate the plans against CLF&P's and BHP's level of risk tolerance. Trade-off diagrams provide a means to quickly compare many plans using two measures such as least cost PVRR versus lowest risk (lowest volatility). In essence, a trade-off diagram summarizes the cost and risk measures of a Risk Profile. Figure 38 shows that for CLF&P, Portfolio C3 has the lowest PVRR whereas Portfolio C6 has the lowest standard deviation.

Figure 38 CLF&P - Trade-Off Diagram



(Source: Energy Market Advisors)

For BHP, Figure 39 shows that, like the Risk Profiles, there is little difference between Portfolios B1, B3 & B6 PVRRs and standard deviations.

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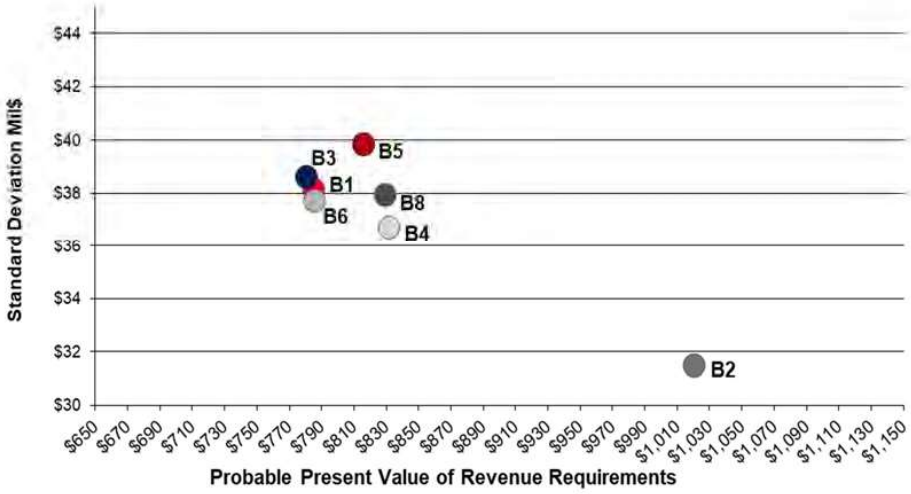
Figure 39 BHP - Trade-Off Diagram



(Source: Energy Market Advisors)

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Appendix A Software Used for Analysis

The Company uses Capacity Expansion to produce unique resource portfolios across a range of different planning assumptions. Capacity Expansion's core logic handles both Capacity Expansion and Emissions Compliance decisions. The primary feature of Capacity Expansion is its ability to analyze renewable portfolio standards and emissions regulations. Renewable portfolio standards can be modeled for the entire portfolio or for multiple jurisdictions. In addition, Capacity Expansion will also consider a wide range of emissions constraints for multiple emissions. Capacity Expansion is used in conjunction with other e7 solutions, such as Portfolio Optimization, when more detailed modeling is preferred. The e7 system allows resource plans to be saved and used in Portfolio Optimization and PROMOD® solutions to provide full hourly chronological simulations to provide operation level detail.

The Capacity Expansion model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability and other constraints. Over the 20-year planning horizon, it optimizes resource additions subject to resource costs and capacity constraints (summer peak loads plus a planning reserve margin). In the event that the retirement of an existing generating resource or contract expiration is assumed for a given planning scenario Capacity Expansion will select additional resources as required to meet summer peak loads inclusive of a target planning reserve margin. To accomplish these optimization objectives, Capacity Expansion performs a time-of-day least cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts within a transmission system. Resource dispatch is based on a representative-week method. Dispatch determines optimal electricity flows between zones and includes spot market transactions for system balancing. The model minimizes the system PVRR, which includes the net present value cost of existing contracts, spot market purchase costs, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), and amortized capital costs for potential new resources.

Portfolio Optimization (PO) software was used to analyze, report, and estimate the optimal dispatch of the Capacity Expansion generation portfolios against either a market price or a load requirement. PO produces optimal operating schedules for the entire portfolio of generation assets and transactions. The solution optimizes a portfolio's operation by modeling detailed unit operating constraints and market conditions to provide a generation schedule for energy and ancillary services, fuel nominations, support the evaluation and pricing of potential short-term transactions, and facilitate the analysis and simulation of deterministic and stochastic scenarios. The mixed-integer linear programming (MILP) based solution optimizes a variety of thermal units, such as simple cycle and combined cycle units, combined heat and power stations, independent and pump storage hydro units, complex cascaded hydro systems, and renewables including battery storage in a single solution. PO also optimizes a combined portfolio of supply resources (traditional generation) and demand response/distributed generation assets modeled as virtual power plants (VPPs).

e7 Portfolio Optimization Stochastic Analysis component was used to simulate uncertainties in electric and fuel prices, loads, energy availability as well as other factors that could contribute results. The component is a shared e7 service that is incorporates a Regression Tool, Draw Generation, and Stochastic Analysis.

Strategic Planning powered by MIDAS Gold® was utilized for the financial and risk modelling. Strategic Planning includes multiple modules for an enterprise-wide strategic solution. These modules are: Markets, Capacity Expansion, Portfolio, Financial, and Risk. The financial and risk modules were the only modules used for the 2021 IRP.

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The financial module allows the user the ability to model other financial aspects regarding costs exterior to the operation of units and other valuable information that is necessary to properly evaluate the economics of a generation fleet. The financial module produces bottom-line financial statements to evaluate profitability and earnings impacts.

The Risk module provides users the capability to perform stochastic analyses on all other modules and review results numerically and graphically. Stochastics may be performed on both production and financial variables.

Strategic Planning uses a Latin Hypercube-based stratified sampling program which takes into account statistical distributions, correlations, and volatilities for three time periods (i.e. Short-Term hourly, Mid-Term monthly, and Long-Term annual) for each transact group. Stratified sampling can be thought of as "smart" Monte Carlo sampling. Instead of drawing each sample from the entire distribution – as in Monte Carlo sampling – the sample space is divided into equal probability ranges and then a sample is taken from each range.