Summary of Integrated Capacity and Energy Revenue Modelling

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1. Summary of Integrated Capacity and Energy Revenue Modelling

The AESO has simulated capacity and energy market conditions for the proposed Alberta capacity market under forecast future scenarios. The purpose of this document is to review various potential future capacity and energy market conditions, and determine the revenue sufficiency of select generating assets under those conditions. This analysis is based on a broad set of assumptions and inputs which test, at a high level, the revenue sufficiency of the capacity market design described in the first draft of the Comprehensive Market Design (CMD 1).

The resulting energy and capacity payment cash flow streams demonstrated sufficient and stable returns for new generators that ensure the reliability of electricity supply during a period of significant supply transition. The results indicated that new combined-cycle and simple-cycle assets could expect returns in line with the weighted average cost of capital for a new entrant, while consumers could expect stable pricing and reliable electricity generation across the scenarios.The results are provided as information and should not be considered to be the AESO's view of future market outcomes.

Energy and Natural Gas Price Scenarios

A significant input into the total capacity and energy market revenue modelling is the hourly energy price. The focus of this document is to provide an explanation of key components and assumptions of the energy price scenarios.

1.1 Modelling Tool

The AURORA market simulation model (AURORA model) was used to develop the energy price scenarios. The AURORA model is a cost-production model that applies economic principles, dispatch simulation and bidding strategies to model the relationships of supply, demand and interconnection to forecast market prices[1]. It produces Monte Carlo stochastic analyses, and forecasts market prices and operation based on key fundamental drivers such as demand, fuel prices and renewable generation profiles. The model incorporates unit characteristics, including startup costs, minimum up time, minimum down time and ramp rate to build an economic dispatch. All operating units in an area receive the hourly market-clearing price for the power they generate.[2]

The AESO analyzed historical data of the entire Alberta generating fleet, researched industry cost information, surveyed potential developers, and set up an AURORA model to reflect the supply and demand fundamentals of the future Alberta power market. The model is a forward-looking tool, subject to continual change as new information becomes available. Results are dependent on individual participant behaviour, which is dynamic and difficult to model within the limitations of the tool.

1.2 Scenario Assumptions

The three scenarios for the energy price scenarios were the *AESO 2017 Long Term Outlook* (2017 LTO) Reference Case Scenario, the 2017 LTO High-Coal-to-gas Conversion Scenario and a low reserve margin case. The 2017 LTO Reference Case Scenario and the 2017 High-Coal-to-gas-Conversion

[1] Source: EPIS AURORA Help Information Document

[2] Source: EPIS AURORA Help Information Document

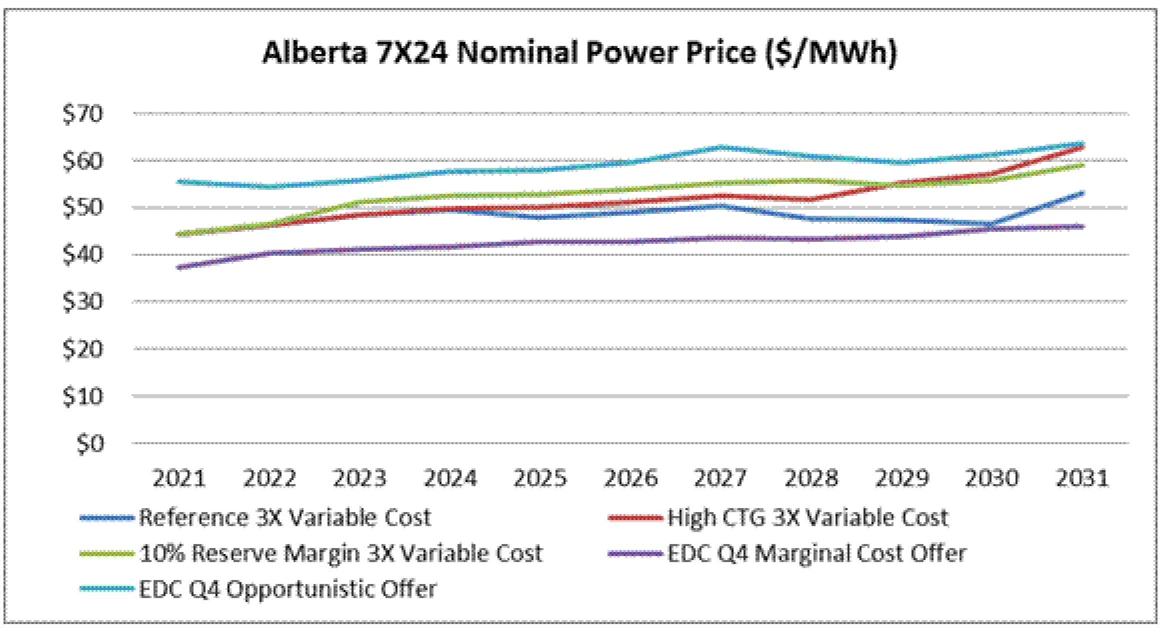
Scenario were predicated upon the 2017 LTO. The low reserve margin case moved from a 15 per cent reserve margin to a 10 per cent reserve margin within the 2017 LTO by reducing future generation development. The lower reserve margin is to test the impacts of a tighter supply mix within the capacity and energy market design being proposed.

To align with the proposed energy market mitigation in CMD 1, participants who failed the residual supply index (RSI) screen were deemed to have market power and subject to offer mitigation at 3x variable cost. Other large participant offers were adjusted from historic behaviour, assuming competition would drive more efficient generating units to shadow bid less efficient, mitigated units.

Due to time constraints, a single iteration was conducted for each scenario.

In addition to the AESO internal price scenarios, the *Marginal Cost* and the *Opportunistic Offer Strategy* energy price forecasts from the *EDC Q4 2017 Quarterly Update: Capacity Market Scenarios* are included for reference. These two EDC forecasts bound the AESO internal scenarios. The price strips are presented in Figure 1.

Figure 1: Alberta Power Prices for Total Revenue Modelling



1.3 Modelling Assumptions

In the reference 3x variable cost case, the offer strategy for the existing assets is based on historical observations, including shadow bidding and coal-to-gas units. New gas assets are also assumed to offer competitively. Offers from those assets that belong to pool participants where the firm fails an RSI screen are deemed to have market power and are mitigated to 3x the estimated variable cost. Bids of large generating portfolios reflect shadow bidding behaviour. A generic variable cost was estimated for each technology, which includes fuel cost, emission cost and variable operating and maintenance (VOM) cost.

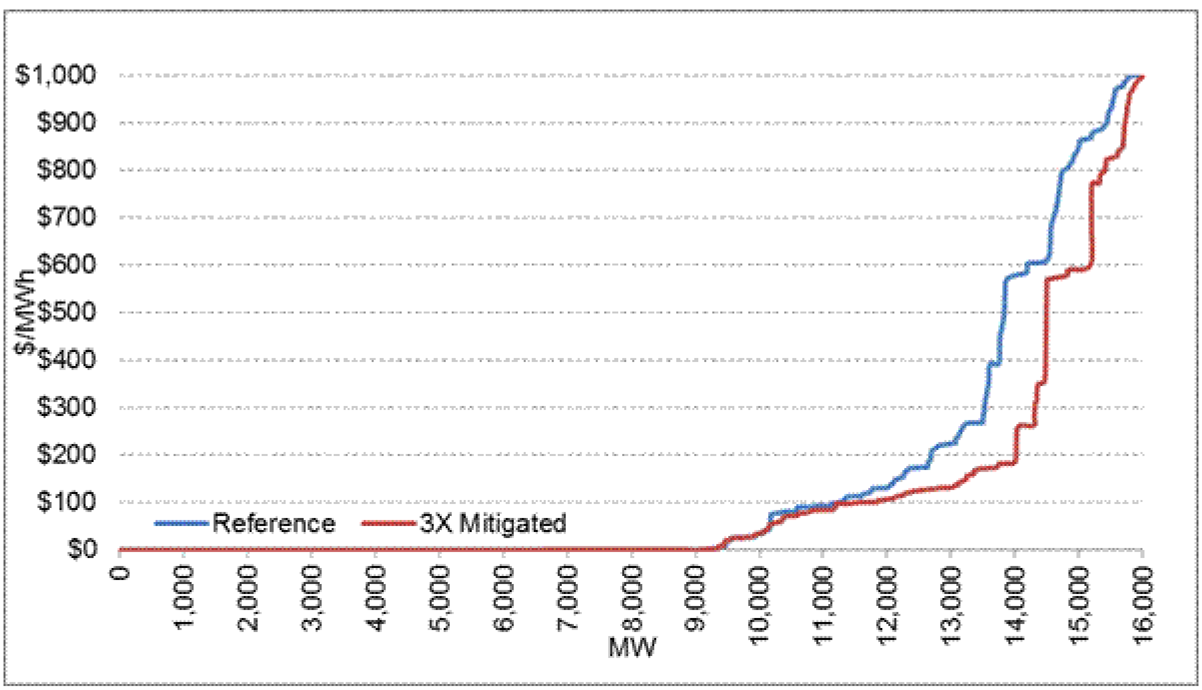
VOM costs were estimated based on Black & Veatch's 2012 study[3] and adjusted to 2017 Canadian dollars by technology. Start-up costs were conducted according to Aptech's 2011 study of cycling costs adjusted to 2017 Canadian dollars by technology[4]. Interties are modelked as pseudo units, which seek the arbitrage opportunities.

Since all scenarios were run before the finalized output-based allocation (OBA), the proposed recommendations in the Government of Alberta's Climate Leadership Plan were assumed in this modelling. The electricity emission standard was based on a baseline of 0.42 tonnes / MWh and a 0.2 per cent annual reduction to the standard.

Resulting merit order and price-setting by fuel type containing the above assumptions are reflected in Figure 2 and Figure 3 respectively, and compared to the unmitigated energy market, titled reference scenario. Figure 2 depicts an indicative snapshot of the annual average energy market merit order in 2021. The upper part of the merit order curve was shifted to the right for the 3x variable cost mitigated scenario compared to the unmitigated reference scenario to account for reduced offers for participants that failed the RSI screen.

Figure 3 shows price setters by fuel type across the two scenarios. Since certain higher offers from coal, combined-cycle and simple-cycle units were mitigated, there is a slight reduction from these units' setting prices. The reduction in price setting was replaced predominantly by dispatchable cogeneration units, and to a lesser extent, by coal-to-gas units.

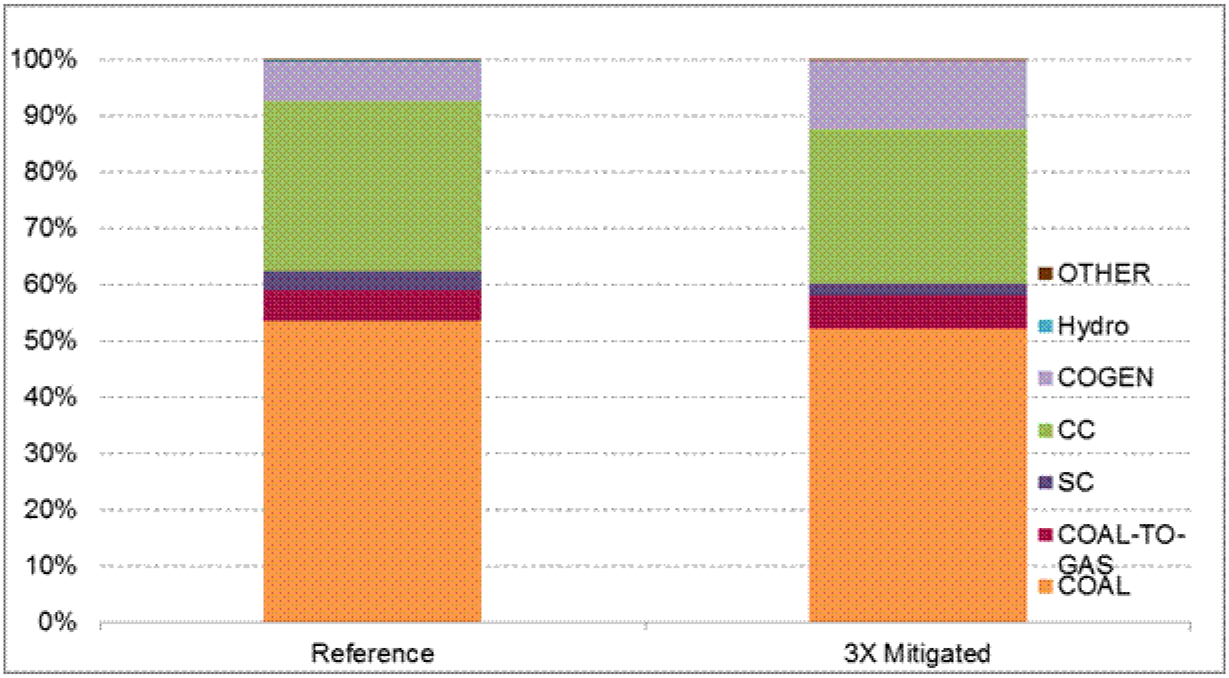
Figure 2: Indicative Snapshot of the 2021 Energy Market Merit Order (Annual Average Offers)



3 https://www.bv.com/docs/reports-studies/nrel-cost-report.pdf

4 http://wind.nrel.gov/public/wwis/aptechfinalv2.pdf

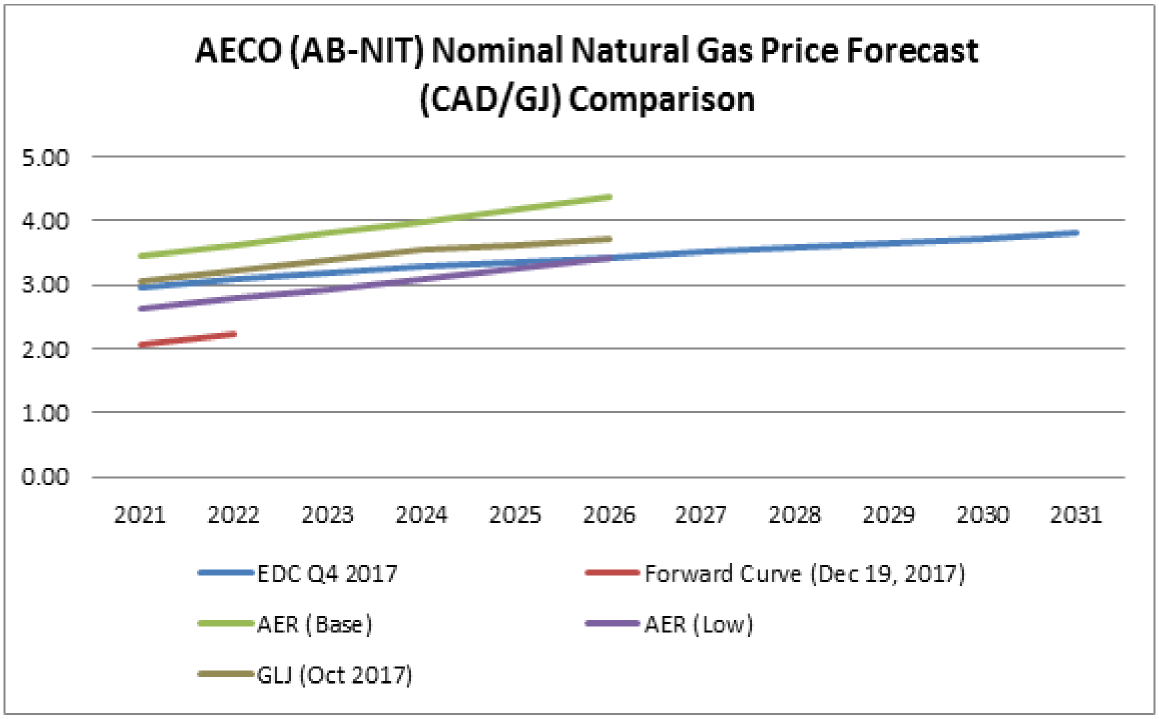
Figure 3: 2021 Price Setters by Fuel Type



1.4 Natural Gas Price Forecast

The natural gas price forecast is an integral input for the simulation modelling as natural gas-fired generation will be at the margin for significant periods of time in the future due to the retirement and/or conversion of coal generation to natural gas. For the total capacity and energy market revenue modelling, the *EDC Q4 Natural Gas Price Forecast* was incorporated into the power price scenarios. For comparative purposes, the *Alberta Energy Regulator (AER) ST98 AECO Natural Gas Price Forecast* updated March 2017 and revised July 2017 was reviewed. The *EDC Q4 Natural Gas Price Forecast* trends toward the AER low case and is below the *October 2017 GLJ Petroleum Consultants October 2017 Natural Gas Price Forecast* highlighted in Figure 4.

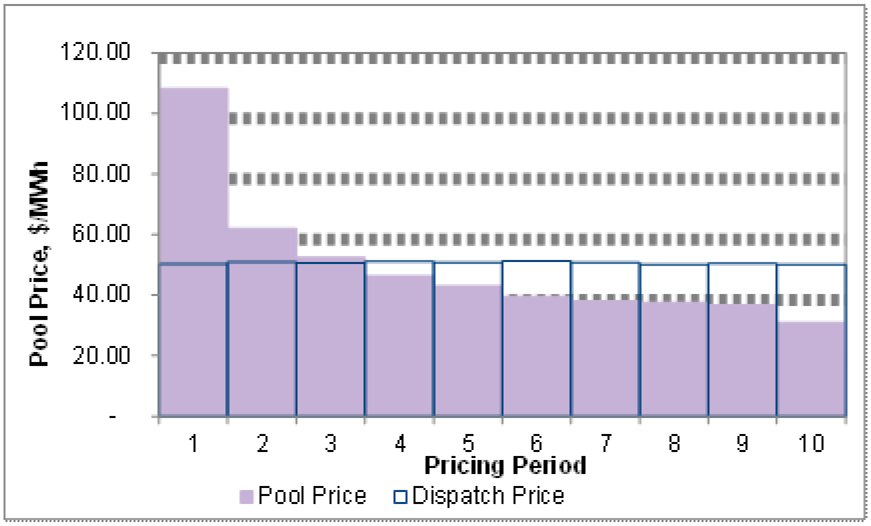
Figure 4: EDC Natural Gas Price Forecast Versus Other Forecasts



1.4.1 Energy Market Revenues for New Assets

These energy price scenarios are used to estimate the energy market revenue for a hypothetical new asset. Energy market revenues for new assets have been estimated by comparing asset variable costs against the energy price scenarios. A simplified dispatch model incorporated the hourly energy pricing, based on the three energy market scenarios, and distilled the prices into 10 pricing periods per year. When the dispatch cost (fuel costs, plus the variable operating costs, plus $10/MWh dispatch premium) was less than the forecast energy price for the period, the asset was deemed to be dispatched, and its unit net revenue was equal to the energy price, less the variable cost (fuel plus VOM costs). The unit net revenue ($/MWh) was multiplied by the number of hours represented by the pricing period, for each pricing period in the year, to determine the annual net revenue for the asset. This dispatch process was performed for each year of useful life for the asset, resulting in a life-cycle forecast energy revenue for the asset. Ancillary services revenues were not modelled in this analysis, but will be considered in future revenue analysis.

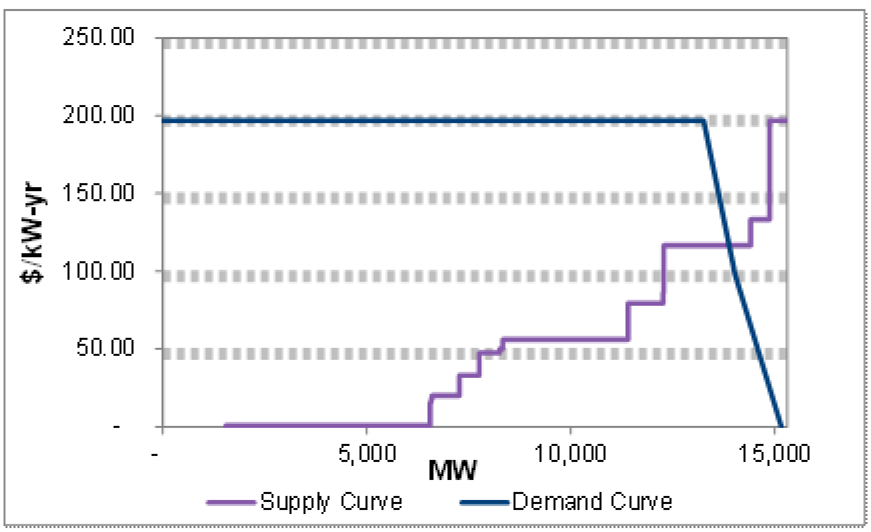
Figure 5: Simple-cycle Natural Gas-fired Generation Dispatch by Pricing Period



1.4.2 Capacity Market Revenue

Based on the design elements in CMD 1, capacity market revenue was modelled in a deterministic equilibrium model using the expected generation supply in each year, and the demand curve described below. The solved clearing price for 2021 was modelled as $116/kw-yr with 13,885 MW of unforced capacity (UCAP) supply clearing.

Figure 6: Reference Case Scenario Capacity Market Supply & Demand Curve – 2021

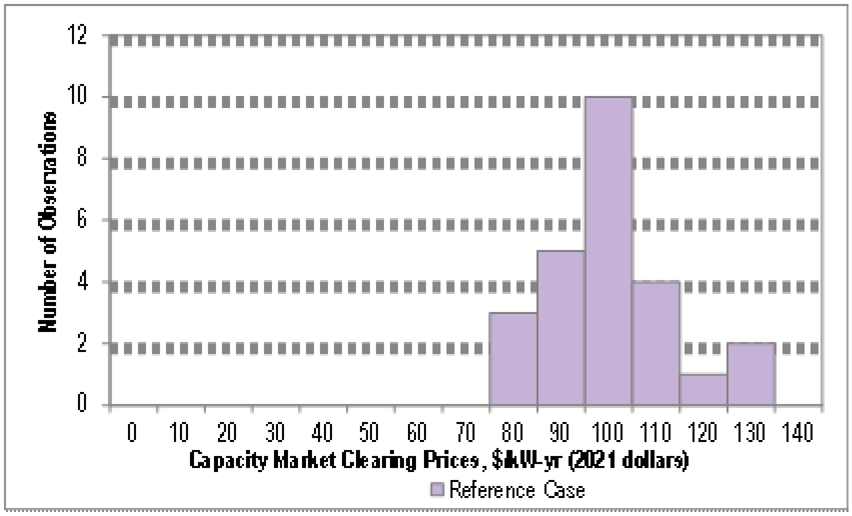


Subsequent years were modelled using the same procedure, with clearing prices and volumes determined for each year by intersecting supply and demand curves. Clearing prices were used to calculate the capacity market revenue that a new generator could expect to receive.

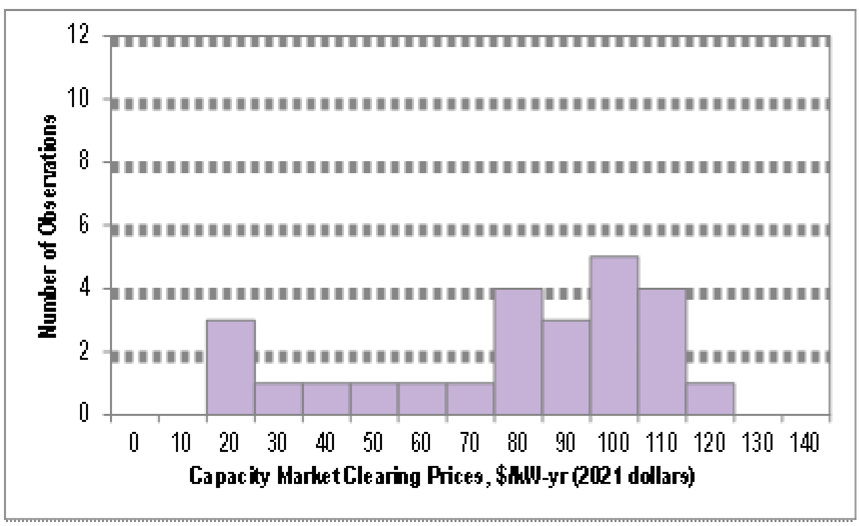
The distribution of annual capacity market clearing prices is depicted in Figure 7. The observations have been separated between the energy price scenarios to depict the range portrayed in each scenario.

Figure 7: Distribution of Capacity Market Clearing Prices

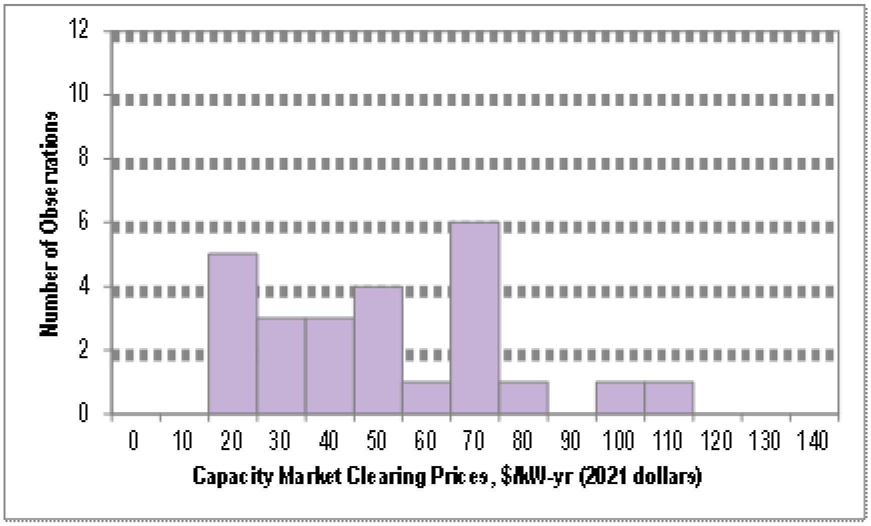
Reference Case



High Coal-to-gas Scenario



Low Reserve Margin Scenario



The capacity market clearing prices ranged between $22/kW-yr to $132/kW-yr (measured in 2021 dollars) in the three energy market scenarios, over the 2021 to 2045 period.

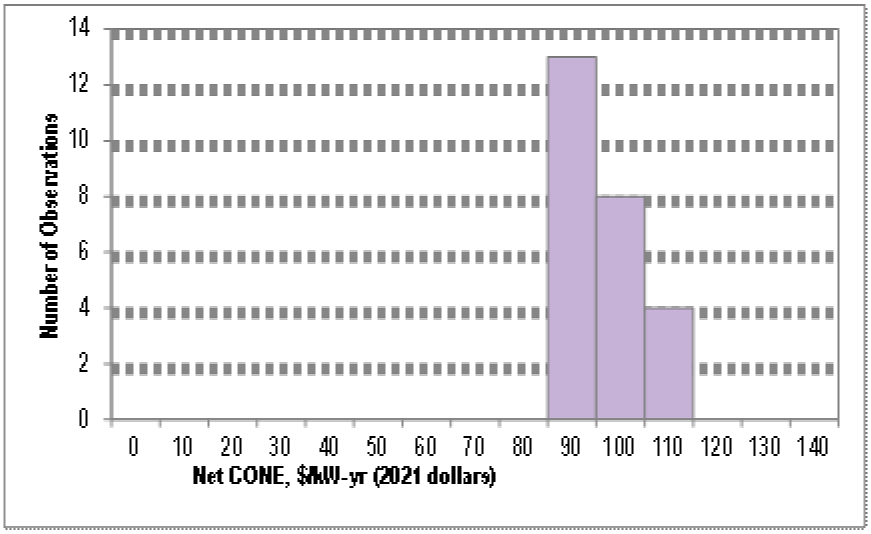
The Reference Case energy price forecast resulted in a concentration of prices near the net-CONE range, while prices in the High Coal-to-gas Conversion Scenario resulted in a wider dispersion of prices skewed to the left. The low reserve margin scenario had a wide range of distribution skewed to the right. This scenario resulted in the highest energy margins, and as a result, the capacity market was typically small compared to the other energy price scenarios.

Figure 8 illustrates the distribution of annual net-CONE values across the three energy price scenarios. The distribution has been divided such that the frequency of net-CONE values for each energy scenario can be observed.

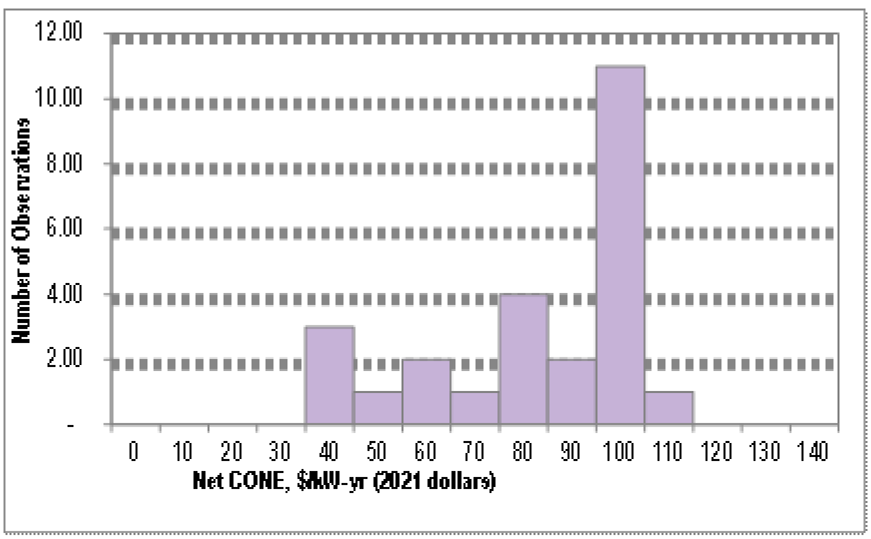
The net-CONE range was significant between scenarios. The Reference Case Scenario resulted in a tight range of net-CONE values between $91/kW-yr and $116/kW-yr, while the High Coal-to-gas and low reserve margin scenarios exhibited a much wider range of net-CONE values. The distribution of net-CONE values significantly influences the clearing prices in each scenario, since the demand curve is indexed to this variable.

Figure 8: Distribution of net-CONE Values

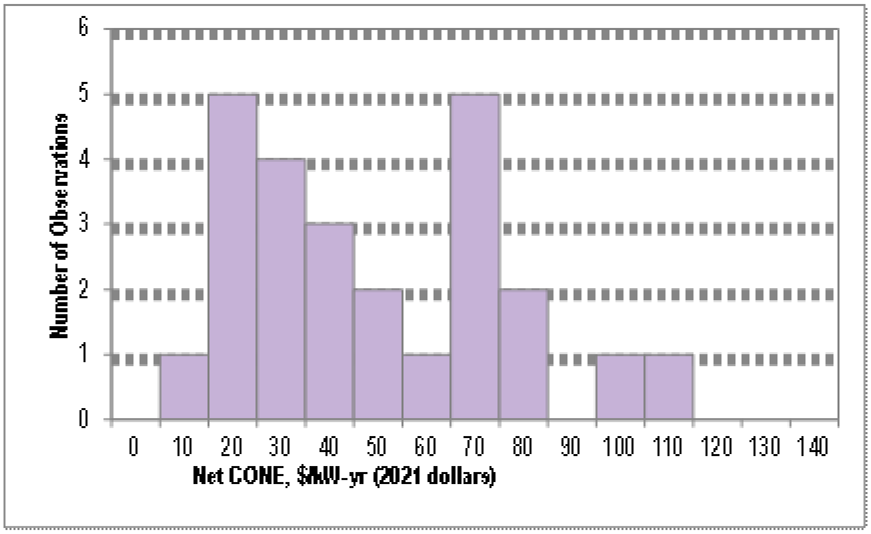
Reference Case



High Coal-to-gas Conversion Scenario



Low Reserve Margin Scenario



1.4.3 Supply Curve

A high-level supply curve was simulated by the AESO, based on the supply projected in each of the scenarios and priced based on the net go-forward cost of generation. For most plants, the net go-forward cost was deemed to be the annualized capital costs, plus annual fixed O&M costs, less the expected net energy revenue received by the facility. For this analysis, performance and availability payment adjustment costs were not included in the net go-forward cost estimates, it is expected that offers may include such costs. Plants with large maintenance capital requirements were bid higher to reflect the required reinvestment capital. Portfolios representing more than 15 per cent of the capacity market UCAP target were deemed to have market share, and all of the generators belonging to those portfolios were subject to mitigation via a bid cap at 0.5 x net-CONE. The UCAP of each unit was approximated as a proportion of its installed capacity. For thermal capacity the proportion was 100 per cent and for intermittent assets a range of 5–50 per cent was used, dependent on the resource type. This simplified approximation is a reasonable approach for this indicative assessment, noting that the actual offers will depend on more detailed assessment and data by owners, and actual UCAP calculation for each asset is dependent on design proposed in CMD 1.

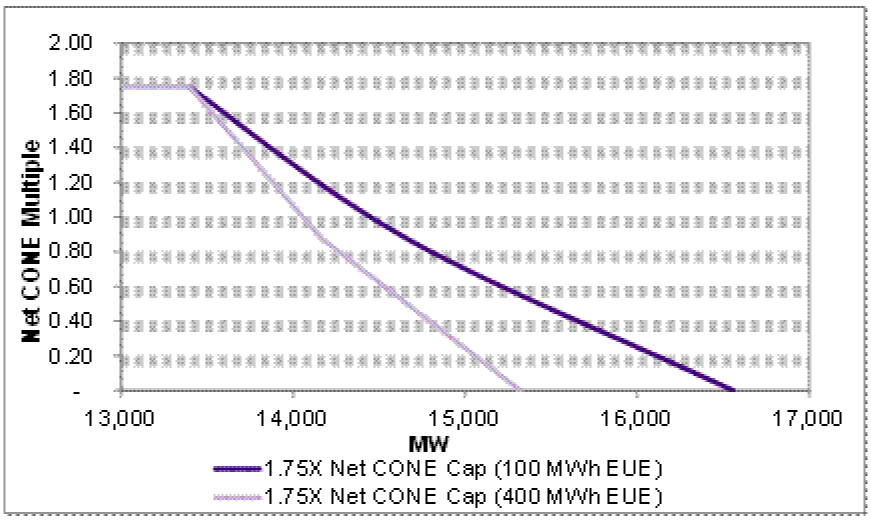
Table 1: 2021 Illustrative Net Go-forward Costs for Select Technologies

Technology	2021 Net Go-Forward Costs $/kW-yr
Conventional Coal	$116
Coal-to-gas Conversion	$39
Combined-cycle Natural Gas	$3
Simple-cycle Natural Gas	$34
Cogeneration	$0

1.4.4 Demand Curve

The 2021 modelling incorporated a demand curve that performs to the 400 MWh expected unserved energy (EUE) resource adequacy level. For subsequent years, the demand curve shape was held constant, but indexed to load growth to reflect the expansion of the market over time. The SAM 3.0 process tested the performance of three demand curves, capped at 1.9 x net-CONE, 1.75 x net-CONE, and 1.6 x net-CONE. For the purpose of this illustrative analysis, the 1.75 x net-CONE curve was selected, with an inflection point at 0.875 x net-CONE. Feedback from stakeholders included concerns regarding the width of curves which perform to the 100 MWh EUE level. The initial 100 MWh curve presented to stakeholders in the SAM 3.0 process for the year 2021 was 3,163 MW wide, from foot to cap, whereas the 400 MWh EUE curve was 1,924 MW wide.

Figure 9: Comparison of Capacity Market Demand Curves for 2021



1.4.5 Cost of New Entry

As a modelling input, the gross cost of new entry (gross-CONE) was modelled based on the development cost of a new simple-cycle gas turbine reference plant, with a Jan. 1, 2021 commissioning date. The estimated 2017 overnight capital cost for this facility was $1,250/kW. A net operating heat rate of 10.5 GJ/MWh is expected for this facility with $18/kW-yr fixed costs and $4/MWh variable costs, based on a two-LM6000 simple-cycle facility. The emissions intensity of the unit was 0.59 t/MWh. A 2 per cent annual price escalation was assumed for all capital and operating costs throughout the analysis.

Using an after-tax weighted average cost of capital (ATWACC) of 8.2 per cent, 45 per cent debt / 55 per cent equity leverage ratio, and a 25-year asset useful life, the overnight gross-CONE was determined to be $148/kW-yr in 2021.

In 2021, the estimated net electricity revenue for the reference unit was $66/kW-yr, leaving the net-CONE calculation at $82/kW-yr.

While these values are considered valid and reasonable for this analysis, they do not represent the net-CONE calculation that will be used for the actual demand curve development. The net-CONE values to be used in the demand curve are being developed with the support of a third party expert and through the ongoing stakeholder engagement process.

1.4.6 Generator Revenue Sufficiency

Through this analysis, revenues between Alberta's energy and capacity markets have demonstrated sufficient returns to generators, slightly above the forecast weighted-average cost of capital for a new entrant. Since the capacity market is indexed to the net cost of new entry, shortfalls from annual energy and ancillary service revenue markets are expected to be recovered in the capacity market. When energy and ancillary services revenues are relatively high, the capacity market is generally small, and when energy and ancillary services revenues are relatively low, the capacity market is generally large. Hence, the capacity market acts as a buffer against low energy and ancillary service revenues, providing long-term electricity market price stability.

Generator net revenue was calculated as the sum of energy and capacity market revenues, less capital costs, fixed operating costs, and variable operating costs. Using the stream of cash flows, the internal rate of return and payback period for the generator were determined.

Combined-cycle Economics

The combined-cycle power plant was simulated as a 455 MW 1-on-1 natural gas-fired facility with a net operational heat rate of 7.20 GJ/MWh. The corresponding emissions rate for this facility was 0.40 t/MWh. A three-year construction cycle was required to initiate operations in 2021, and the capital costs of $1,867/kW-yr were evenly spread over this three-year period.

The power plant was projected to operate at an average 60 per cent capacity factor, dispatching when energy market revenues exceed variable costs. The variable costs include natural gas ($2.84/GJ in 2021), variable O&M ($8.66/MWh in 2021), and carbon costs (estimated at $30/tonne for all emissions above a 0.37 GJ/MWh baseline).

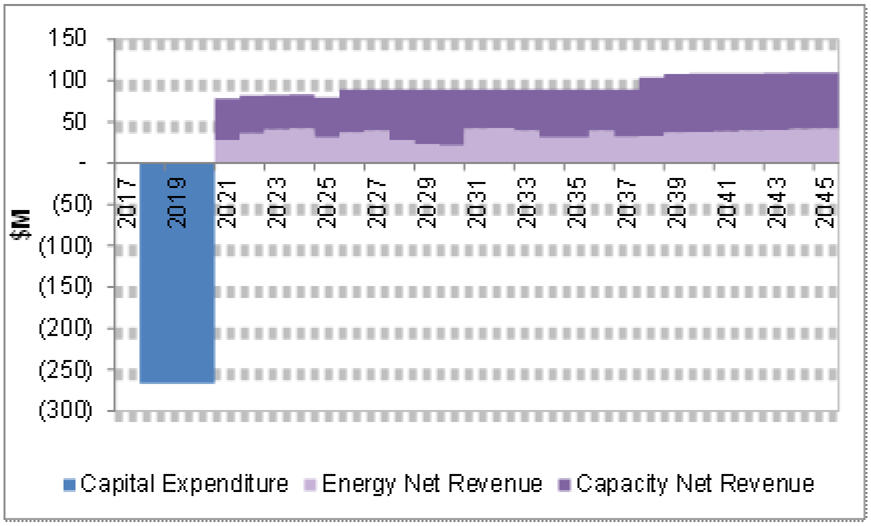
Facility fixed costs include fixed O&M of $29.23/kW-yr in 2021. Estimated fixed O&M costs were extracted from the *AESO 2017 Long-term Outlook* for combined-cycle plants, and escalated at 2 per cent per annum to 2021.

The unlevered cash flows from the combined-cycle plant operation include energy market net revenue, capacity market revenue, and capital costs. These cash flows produce internal rates of return between 8.9 per cent and 9.6 per cent (depending on the energy and capacity market price forecasts) with a 12 to 13 year payback period, suggesting that combined-cycle economics support sufficient revenue to incent development.

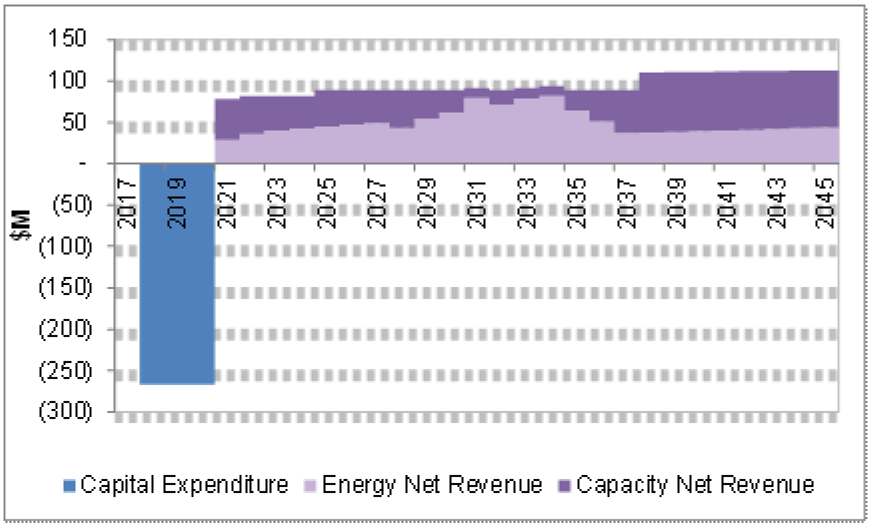
The combined-cycle facility received a large portion of its revenue from the energy market, as the facility operated at a relatively high capacity factor. The low reserve margin scenario derived most of the combined-cycle revenue from the energy market, leaving a smaller capacity market, while the reference case had more “missing money” in the energy market, which was compensated by a larger capacity market.

Figure 10: Generator Cash Flow – Combined-cycle

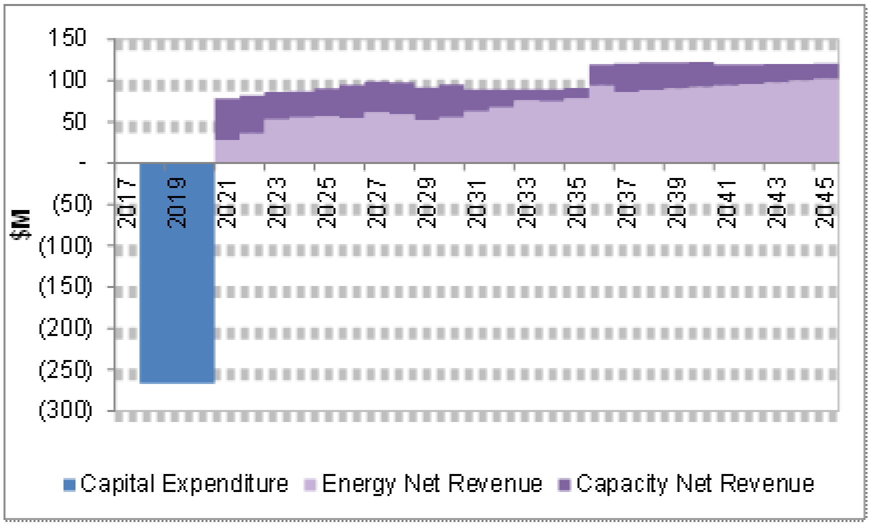
Reference Case Scenario



High Coal-to-gas Conversion Scenario



Low Reserve Margin Scenario



1.4.7 Simple-cycle Economics

The forecast simple-cycle power plant was a 100 MW two-turbine, open-cycle, natural gas-fired facility with a net operational heat rate of 10.5 GJ/MWh. The corresponding emissions rate for this facility was 0.59 t/MWh. A two-year construction cycle was required to initiate operations in 2021, and the capital costs were evenly spread over this two-year period.

The power plant was projected to operate at an average 38 per cent capacity factor, dispatching when energy market revenues exceed variable costs. The variable costs include natural gas ($2.84/GJ in 2021), variable O&M ($4.33/MWh in 2021), and carbon costs (estimated at $30/tonne for all emissions above a 0.37 GJ/MWh baseline).

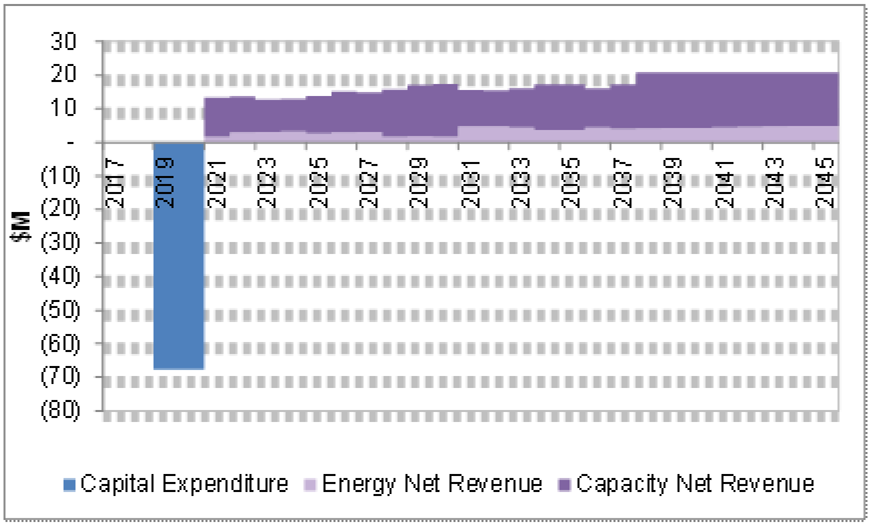
Facility fixed costs included fixed O&M of $19.48/kW-yr in 2021, escalated at 2 per cent per annum from the AESO's *2017 Long-term Outlook* estimate. The capital cost of the facility was $1,353/kW-yr in 2021.

The unlevered cash flows from the simple-cycle plant operation include energy market net revenue, capacity market revenue, and capital costs. These cash flows produce a 9.3 per cent to 9.8 per cent internal rate of return with a 13 year payback period, suggesting that simple-cycle economics support sufficient revenue to incent development of these assets.

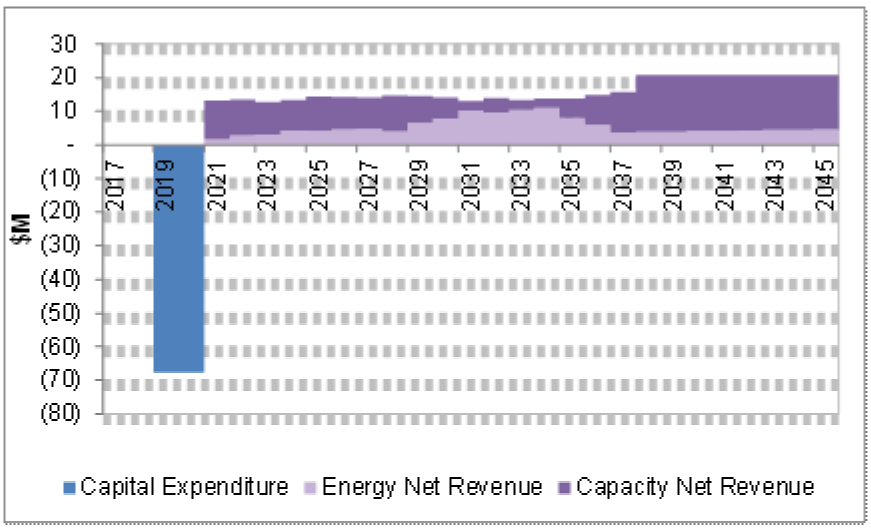
Simple-cycle cash flows were generally more dependent on capacity market revenues than combined-cycle plants, as the facilities operate less frequently in the energy market. The scenarios presented a wide range in the breakdown of capacity and energy market revenues, but in all three energy market scenarios, the simple-cycle cash flows supported development of the reference unit.

Figure 11: Generator Cash Flow – Simple-cycle

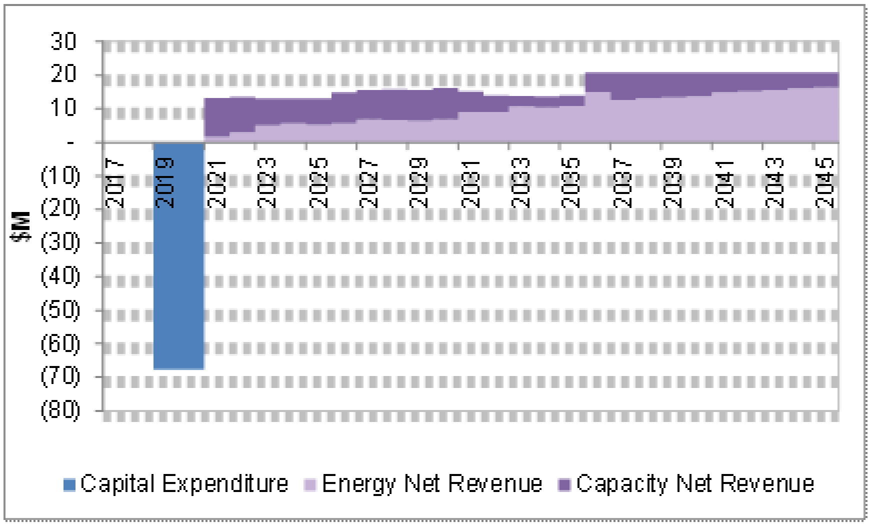
Reference Case Scenario



High Coal-to-Gas Scenario



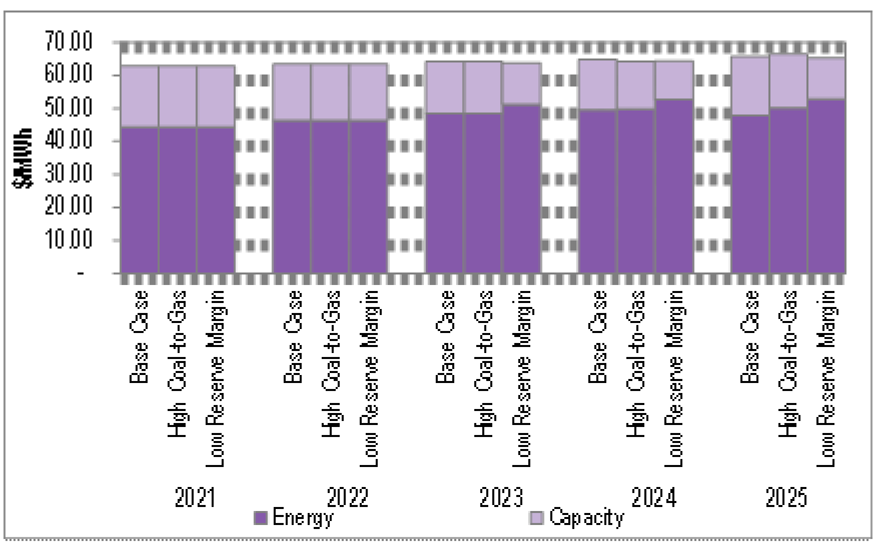
Low Reserve Margin Scenario



1.4.8 Consumer Prices

Although a tariff for capacity market payments has yet to be designed for system users, the revenues paid to generators will ultimately be paid by system users. On aggregate, the estimated capacity costs for consumers range between $12/MWh and $19/MWh in the 2021–2025 timeframe. Generally, these capacity market consumer costs will change inversely to the energy market prices, creating a more stable pricing environment for consumers than an energy-only market.

Figure12: Simulated Consumer Capacity & Energy Prices



1.4.9 Market Price Volatility

The revenue sufficiency analysis indicated that consumer market prices will be generally more stable under capacity market conditions than under Alberta's energy-only market. While the energy-only market exhibited a relatively large standard deviation of prices, the standard deviation of combined capacity and energy market price volatility is expected to be lower. This result reflects that the capacity market price tends to provide the "missing money" associated with the reference unit, and therefore acts a buffer in times of low energy market prices. Although the average price for the historical energy only was $62.04 / MWh, the market exhibited high volatility with a range of prices from $133.21 / MWh in 2001 to $18.28 / MWh in 2016.

Table 2: Energy & Capacity Price Volatility

Scenario	Standard Deviation of Annual Consumer Prices, $/MWh	Average Consumer Energy Plus Capacity Prices, $/MWh
High Coal-to-gas (2021-2031)	$2.42	$66.24
Reference Case	$3.81	$67.46
Low Reserve Margin	$2.91	$66.85
Historical Energy Only Market (2000-2017)	$23.51	$62.04

[1],2 Source: EPIS AURORA Help Information Document

[3] https://www.bv.com/docs/reports-studies/nrel-cost-report.pdf

[4] http://wind.nrel.gov/public/wwis/aptechfinalv2.pdf