

The Brattle Group

Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market: 2013 Update

March 2013

Johannes P. Pfeifenberger
Kathleen Spees
Michael DeLucia

Prepared for



Copyright © 2013 *The Brattle Group, Inc.* This material may be cited subject to inclusion of this copyright notice. Reproduction or modification of materials is prohibited without written permission from the authors.

Acknowledgements and Disclaimer

The authors would like to thank the AESO staff for their cooperation and responsiveness to our many questions and requests. Opinions expressed in this report, as well as any errors or omissions, are the authors' alone.

TABLE OF CONTENTS

Executive Summary	1
I. Background	5
II. Long-Term Supply Adequacy Challenges.....	6
A. Update to Long-Term Resource Adequacy Challenges Analyzed in 2010-11	6
1. Low Natural Gas Prices	6
2. Expiration of Power Purchase Arrangements	7
3. Alberta and Federal Environmental Regulations	8
4. Increased Wind Penetration	9
5. Expanded Interconnections with Neighboring Markets.....	11
B. Financing New Power Generation Projects	13
C. Recent Investment Trends.....	16
D. Supply and Demand Outlook.....	17
1. Investment Levels Required to Sustain Resource Adequacy.....	17
2. AESO Projected Future Generation Additions	19
III. Historical Trends in Generator Economics	20
A. Wholesale Price Levels	21
B. Costs and Operating Parameters of New Generating Plants.....	24
C. Historical Generator Operating Margins vs. Fixed Costs.....	27
IV. Outlook for Generator Economics.....	29
A. Market Prices Projected With Recent Market Heat Rates	29
1. Projected Gas, Coal, and Carbon Prices	29
2. Projected Future Power Prices	30
3. Projections of Generator Operating Margins vs. Fixed Costs	33
4. Sensitivity Analysis of Projected Margins vs. Fixed Costs	38
B. Simulation-Based Estimates of Future Market Prices	40
1. 2013 Reference Case.....	40
2. Market Impacts of Changes to the Reserve Margin.....	43
3. Market Price Cap and Scarcity Pricing Mechanisms	44
V. Findings and Recommendations	49
Bibliography	51
List of Acronyms	53

EXECUTIVE SUMMARY

In 2010, the Alberta Electric System Operator (AESO) asked us to review long-term challenges to resource adequacy in Alberta's electricity market and assess the sustainability of the energy-only market design from a long-term resource adequacy perspective.¹ As we stated in the March 2011 report, we found that the Alberta market was sustainable from a resource adequacy perspective but recommended continued monitoring. We now update our 2011 report by analyzing recent changes to resource adequacy challenges and market fundamentals.

Many of the resource adequacy challenges facing Alberta at the time of our 2010-11 review still play an important role today, although their relative importance has changed. These challenges include:

Low Gas Prices that continue to put downward pressure on mid-peak and off-peak power prices and baseload generators' operating margins. However, this challenge appears less important now than in our previous review because, despite the low gas prices, on-peak wholesale power prices in 2011-12 increased from 2009-10 level, causing a net increase in earnings for natural-gas-fired power plants.

Expiration of Power Purchase Agreements (PPAs). Approximately 5,000 MW of PPAs which were signed upon deregulation are set to expire by 2020. Under the current policies and market fundamentals the favorable economics of existing plants makes it unlikely that PPA expiration would lead to simultaneous retirement of a significant portion of these units.

Environmental Regulations, including existing federal and provincial carbon standards and potential future carbon and air quality regulations. The existing carbon regulations will gradually but only modestly increase the rate of coal plant retirements. The federal mandate will force the retirement of aging coal plants and also prevent the construction of new coal plants unless they are fitted with costly carbon capture and storage (CCS) technology. We anticipate that resource adequacy needs associated with retirements from these regulations will be addressed by market-based investments in gas plants. These factors will increase Alberta's reliance on natural gas as a generation fuel, with natural gas capacity expected to increase from approximately 40% of the fleet in 2013 to 60% by 2032.

Increasing Wind Penetration which suppresses wholesale power prices for baseload and wind generation. We find that this downward pressure on market prices has not been large enough to increase retirements or deter new entry from natural gas plants, which can be switched off when prices are low.

Expanded Interties with neighboring markets. While expanded intertie capacity has the potential to reduce Alberta pool prices in the short term and increase investment risks in the long-term, this does not appear to be a concern at the current level of (or even moderately expanded) intertie capacity.

While similar challenges are faced in a number of power markets throughout Canada and the U.S., maintaining resource adequacy is a particular concern for Alberta and other energy-only

¹ For the full text of our 2011 resource adequacy review, see Pfeifenberger and Spees (2011a).

markets that do not use regulatory mechanisms to ensure a particular level of resource adequacy through planning reserve margin requirements. Unlike in markets with required reserve margins, installed generating capacity in Alberta and other energy-only markets is driven solely by market-based incentives. Suppliers will only construct new plants if they anticipate that prices will be high enough to allow for the recovery of their investment costs and provide a reasonable return on the investment. Ideally, these investment incentives should reflect supply and demand conditions, with prices high enough on average to attract investments when reserve margins are low and prices low enough to discourage investments when reserve margins are high.

Attracting financing for the construction of new power plants requires investors to believe that they will earn returns sufficient to cover their investment costs. While some stakeholders have expressed concerns about the ability of the Alberta market to allow for financing of new power plants, we are more optimistic. The Alberta electricity market, like other deregulated power markets, does not provide for investment cost recovery through long-term power purchase agreements (PPAs) or regulated bundled retail rates. This means that suppliers, rather than customers, must take on the risk that a particular investment may ultimately prove to be uneconomic. It also means that Alberta's market is not a suitable environment for small, undiversified project developers and others that are reliant on significant amounts of project financing (i.e., non-recourse debt) and revenue certainty provided through long-term contracts. Instead, Alberta will likely continue to attract investments primarily from larger, more diversified companies that are able to employ balance-sheet financing for much or all of their projects.

Alberta will require generation investments of approximately 530 MW per year between 2013 and 2029 to keep pace with retirements and load growth, a challenge in a small market like Alberta. Alberta's track record is very promising, however, given that the market has successfully attracted enough merchant investment to sustain resource adequacy for more than a decade. Generation companies have constructed on average approximately 450 MW of power plants per year since the current market design was established in 2000. Also reassuring is that, since the financial crises began in 2008, Alberta has attracted at least one large investment (ENMAX-Capital Power 800 MW Shepard Energy Center) and a number of wind and cogeneration projects.

Despite this promising track record, we note two potential concerns about the market's ability to attract sufficient investments to ensure resource adequacy going forward. First, and consistent with recommendations by Market Surveillance Administrator (MSA), it is important to monitor for potential barriers to new entry, which might inhibit the ability of Alberta's market to attract investments. One such barrier could be related to generator offer behavior. While such offer behavior has increased on-peak market prices to a level that supports new investments, new entrants may discount the long-term value of these prices if they deem them uncertain because of their dependence on incumbent generators' offer behavior rather than underlying market fundamentals. This could lead to reduced new entry even under favorable current levels of market prices. Our second concern relates to the potential impact of Alberta's monthly Regulated Rate Option (RRO) on the level of forward bilateral contracting. While retail customers typically prefer not to sign long-term contracts, the current RRO structure may contribute to inefficiently low levels of forward contracting and increase generation investment risk in Alberta.

Our review of current and projected market conditions documents continued favorable investment conditions for natural-gas-fired power plants. On-peak power prices have increased

since 2010, likely driven primarily by changes in generators' offer behavior in 2011 and 2012. If this offer behavior were to continue, new gas generation investments would be very profitable. However, even when projecting future market prices based the four-year *average* of the (less favorable) 2009-10 and (more favorable) 2011-12 market conditions, our analysis shows that natural-gas-fired power plants are economic. We consequently expect that a sufficient amount of new natural gas generation will be constructed unless, as we noted above, investors heavily discount the projected future prices because of their dependence on generator offer behavior.

Despite the favorable current market conditions for natural gas plants, investments in coal and wind generation would not be profitable without additional (out-of-market) revenues or subsidies. Moreover, the recently-finalized Federal Carbon Standard for Coal Generation will prevent development of new coal plants unless they can be equipped with subsidized carbon capture and storage (CCS) technology.

Overall, we reiterate our conclusion from 2011—our updated analysis confirms that, from a resource adequacy and generation investment perspective, the Alberta electricity market is generally well functioning based on current market conditions and policies. The current market design should be able to address the identified resource adequacy challenges and there is no compelling or immediate need for major design changes to address these challenges. Nevertheless, considering both our 2011 review and this update, we offer the following set of recommendations to safeguard the continued sustainability of Alberta's market from a resource adequacy perspective:

1. *Continue to Monitor Physical Resource Adequacy Metrics* to assure that the AESO, regulators, and market participants have a full understanding of the resource adequacy situation in the Province. In addition to the already ongoing monitoring of the 2-5 year resource adequacy outlook by the AESO,, we recommend evaluating:
 - Physical reliability metrics such as Normalized Expected Unserved Energy (EUE) over a range of possible reserve margins (in addition to the current approach of estimating expected unserved energy at the anticipated reserve margin), which will confirm how many unanticipated retirements or construction delays the system could withstand before experiencing reliability concerns;
 - Retirement schedules and associated system reserve margins; and
 - The actual resource adequacy value of non-traditional resources, *i.e.* the effective reserve margin contribution of resources such as wind, demand response, hydro, and interties.
2. *Continue to Monitor Economic Resource Adequacy Metrics* to identify potential difficulties in attracting needed investments before they arise, including:
 - Trends in market heat rates and the long-term outlook for technology-specific operating margins;
 - The market price impacts of increasing wind generation and potential inertia expansions; and
 - The ability of the market to attract financing of generation investments, including from non-incumbent generators.
3. *Build on the Recent RRO Review to Evaluate the RRO's Impact on Forward Contracting* and determine whether it results in inefficiently low levels of forward contracting. If so,

it may be possible to revise RRO forward procurement or encourage customers to switch to competitive retail suppliers to develop a more efficient portfolio of short, medium, and longer-term contracts.

4. *Avoid Policies that Create Large Simultaneous Retirement Pressures:*

- Continue to monitor the impact of existing and new policies on the economics of continued plant operations, retirement, decommissioning, and the associated risks of simultaneous retirements.
- Evaluate any new regulations to mitigate the risk that they could result in a substantial number of simultaneous retirements (*e.g.* environmental regulations that require many plants to retire or retrofit in a particular year).
- Ensure information on planned retirements is made public with sufficient advance notice to allow for a market response.

5. *Increase the Price Cap, Reduce the Price Floor, and Introduce More Gradual Scarcity Pricing For Operating Reserve Depletions, including:*

- Considering whether to increase the current price cap from \$1,000/MWh up to a level, such as \$3,000 to \$7,500 that is more consistent with customers' value of lost load (VOLL). We do not recommend increasing the generator offer cap of \$999.99/MWh, however, as the higher prices should only be realized during operating reserve depletion and rare load shed events.
- Improve the efficiency of prices during supply surplus events by reducing the price floor below zero. The price floor should be set low enough that generators, including wind plants and importers would have an incentive to curtail when it is economic to do so.
- The increase in the price cap would be combined with a scarcity pricing function that gradually increases prices to the new price cap as operating reserves are depleted during emergency conditions. These adjustments would also allow for economically efficient prices during reliability events, stimulate demand-response, promote generator performance and provide stronger investment signals during periods of low reserve margins. This would make the level of the price cap more consistent with those in other energy-only markets, such as Texas and Australia.

While we reiterate our 2011 conclusions, we also continue to note that Alberta's power market, because it is an energy-only market, cannot guarantee that a specific reserve margin will be maintained in the short-term or long-term. The lack of a reserve margin requirement also means that Alberta must expect to experience periodic shortage events in which the market may experience lower reserves, lower reliability, and higher prices. For these reasons, we reiterate the need for continued monitoring and refinements to the market design that increase its efficiency and effectiveness. Today's relatively high reserve margin and positive outlook for generation investment also presents an unique opportunity to implement market design refinements in a deliberate manner. This is particularly relevant for our price cap and scarcity pricing recommendations, which could be implemented with minimal market impacts but provide significantly improved investment signals should reserve margins decline in the future.

I. BACKGROUND

In 2011, the Alberta Electric System Operator (“AESO”) asked us to review long-term challenges to resource adequacy in Alberta’s electricity market and assess the sustainability of the energy-only market design from a long-term resource adequacy perspective.² We now update that evaluation after considering recent changes to market conditions.

Our 2011 review was spurred by a number of important challenges to resource adequacy in the province, including: (1) low gas and electric prices that put downward pressure on generators’ operating margins; (2) the expiration of power purchase agreements (“PPAs”), which might trigger accelerated retirement partly due to decommissioning cost recovery mechanisms; (3) environmental regulations that could force aging plants to retire or incur major capital expenditures; (4) increasing wind penetration, which suppresses energy prices and increases price volatility; and (5) expanded interconnections with neighboring markets, which have the potential to reduce Alberta pool prices in the short term and increase investment risks in the long-term.

While similar challenges face a number of markets throughout Canada and the U.S., maintaining resource adequacy is a particular concern for Alberta and other energy-only markets that do not use regulatory mechanisms to enforce reserve margin requirements. Instead, installed capacity levels in Alberta are driven solely by market-based incentives, and suppliers will only construct new plants if they anticipate that prices will be high enough to recover their investment costs. Ideally, these investment incentives will mirror supply and demand conditions, with prices high enough to attract investments when reserve margins are low and prices low enough to discourage investments when reserve margins are high.

We concluded in our 2011 review that Alberta’s power market was sustainable from a resource adequacy perspective and that market prices were generally reflective of market conditions. We found that, despite a number of challenges to resource adequacy, market conditions were favorable for attracting investments in gas combined-cycle (CC), combustion-turbine (CT), and cogeneration plants, while conditions are unfavorable for any hydro, coal, and wind projects that were not otherwise subsidized for public policy reasons. However, we also offered a number of recommendations for improving market efficiency and monitoring market sustainability over time.

The AESO has now asked us to update our previous evaluation of market sustainability. This report is a more narrowly-focused effort than our previous review, intended to: (1) evaluate the implications of any major changes to the resource adequacy challenges facing the Province; and (2) update our analysis of generator economics and the attractiveness of investing in Alberta under current market conditions.

² For the full text of our 2011 resource adequacy review, see Pfeifenberger and Spees (2011a).

II. LONG-TERM SUPPLY ADEQUACY CHALLENGES

Alberta's power market can maintain resource adequacy over the long term only if market prices are high enough to attract private investments when those investments are needed. We examine here: (a) challenges to resource adequacy faced by the Alberta power market, including important changes that have occurred since our 2011 study; (b) factors affecting the ability to finance new power plants in Alberta; (c) specific projects that have recently been financed in Alberta; and (d) the supply-demand outlook, which indicates the rate of new investments that will be required to maintain resource adequacy over the coming years.

A. UPDATE TO LONG-TERM RESOURCE ADEQUACY CHALLENGES ANALYZED IN 2010-11

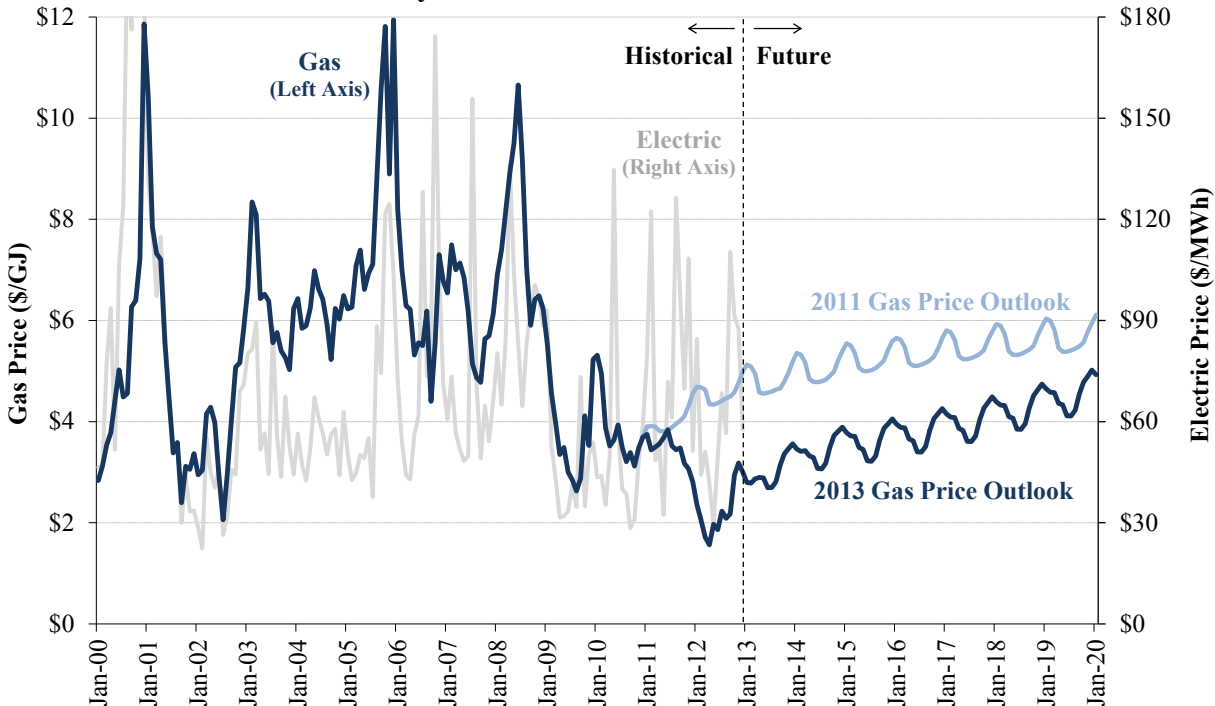
Like other electric markets around the world, Alberta faces a series of challenges to resource adequacy over the coming decades. In this section, we summarize these challenges, with a focus on factors that have changed materially since our 2011 report.

1. Low Natural Gas Prices

In our 2010-11 analysis we noted that the outlook for low natural gas prices posed a potentially serious challenge to resource adequacy due to the strong positive relationship between power prices and natural gas prices. We pointed out that the challenge was particularly pronounced for coal generation due to their baseload operation, high fixed costs, and fuel costs that do not decline with natural gas prices. Since our 2011 report, spot and futures prices for natural gas have declined further, as shown in Figure 1. For example, in our previous outlook futures prices indicated expected Alberta prices of \$5.4/GJ in 2017. They are now projected to be only \$4.0/GJ.

We note, however, that the decline in natural gas prices has not resulted in a resource adequacy challenge because power prices did not decline with gas in 2011 and 2012. Instead, power prices increased since 2010, as also shown in Figure 1. The change in this relationship, if continued, would more than offset the challenge that low natural gas prices would otherwise pose to resource adequacy. The causes and implications of this change are discussed further in Section III.A.

Figure 1
Monthly Electric and Gas Prices in Alberta



Sources and Notes:

Historical AECO C gas prices and hourly energy prices are from Ventyx (2013).

AECO C future prices based on December 2012 Henry Hub futures and average 2009-12 basis discounts.

2. Expiration of Power Purchase Arrangements

As we explained in our 2011 report, as part of Alberta's wholesale restructuring effort, 7,600 MW or approximately 78% of the fleet was placed under PPAs in 2001.³ A potential resource adequacy challenge is created by the possibility that a substantial proportion of the units currently operating under PPAs may retire after the PPAs expire. Particularly of concern is that most of these PPA expirations will occur simultaneously. Of the 5,400 MW of capacity currently still operating under PPAs, 4,300 MW of coal and 780 MW of hydro PPAs will expire on December 31, 2020.⁴

Further, current regulations require legacy asset owners to determine by December 31, 2018 whether or not to decommission the facility within one year of PPA expiration to be eligible for regulated recovery of unfunded decommissioning costs.⁵ This option for regulated recovery of unfunded decommissioning costs could be a deciding factor in the retirement decision of individual generators, particularly if these units (1) faced unexpectedly high decommissioning costs (e.g., due to environmental liabilities) that exceed funded amounts and (2) would be expected to operate only for a few more years beyond PPA expiration. We were concerned in our 2011 report that the then-pending Federal regulations that effectively would have forced 1,170 MW of 45-year old coal plants to retire over the 2020-2025 time frame created the risk of

³ See Pfeifenberger and Spees (2011a), p. 13.

⁴ See Pfeifenberger and Spees (2011a), p. 13.

⁵ See Alberta Government (2007a), Section 7.

large simultaneous retirements in 2018 in order to obtain regulated recovery of decommissioning costs. However, we believe this risk of simultaneous retirements in 2018 is reduced significantly given that Federal legislation was modified to apply only to coal plants more than 50 years old, which extends the operating life of many plants significantly beyond PPA expiration.

Generators' retirement decisions will depend on expected environmental regulations, capital requirements for continued operations, decommissioning costs, and the market outlook at that time. However, the longer 50 year operating life in combination with the favorable economics of continued market-based operations of existing coal plants (as confirmed in our updated analysis) and the likely modest amount of unfunded decommissioning costs,⁶ makes it unlikely that asset owners would decide to retire multiple coal plants in 2018 or immediately after PPA expiration. Thus, unless the plant requires significant capital investment for continued operations, we now find that retirements as a result of PPA expirations are very unlikely under the current policies and market conditions. Nevertheless, to address the significant uncertainties that invariably remain going forward, we recommend continued monitoring of the potential risk of significant simultaneous retirements of existing plants. We also recommend to ensure information on planned retirements is made public with sufficient advance notice (ideally several years) to allow for a market response.

3. Alberta and Federal Environmental Regulations

Both Alberta and the Canadian federal government have existing carbon reduction policies that will affect plant retirement and the operation of the energy-only market over the next 20 years. Most notable among these is the recently finalized Federal Carbon Standard for Coal Generation, which will phase out all coal generation in Canada without CCS.

The federal regulation was passed in September 2012, and requires coal plants to meet a strict performance standard of 420 tonnes of CO₂/GWh, consistent with the emissions rate of natural gas combined cycle units. It will apply to any new units coming online after July 2015, and to existing units after their 50th operating year.⁷ This ensures that no new coal units without CCS will be built in Canada, and that existing units will gradually be forced to retire. The entire Alberta coal fleet will be affected by this regulation, but because of the different ages of Alberta coal plants, the impact of this regulation will be phased in over the next several decades. As a consequence, we believe that there will be sufficient time for additional market-based investments to be built and compensate for any increase in the retirement rate. This regulation contributes to the fact that new coal plants will likely remain uneconomic for the foreseeable future, but does not create a resource adequacy challenge as natural gas-fired generating plants are robustly supported by current market conditions as discussed further in Section IV.

⁶ Based on conversations with Balancing Pool staff at the 19th Annual IPPSA conference, March 11, 2013.

⁷ See Canadian Government (2012).

Alberta's Specified Gas Emitters Regulation went into effect in 2007, requiring emissions reductions from all Alberta facilities outputting more than 100 kT of CO₂e annually.⁸ These facilities were assigned a GHG emissions intensity reduction target of 12% below their baseline output established over 2003–2005.⁹ For electric generators, this target is a requirement to reduce the quantity of CO₂e emitted per MWh produced. To comply with the regulation, facilities can improve the efficiency of operations to reduce per-unit output by 12%, contribute \$15/tonne of CO₂e to the Climate Change Fund, purchase offset credits for CO₂e emissions, purchase performance credits from other Alberta GHG emitters that exceeded their reduction targets.¹⁰ As we discussed in the 2011 report, this regulation does not create a resource adequacy concern. However, a review of the program is expected in 2014.¹¹ The nature of the revised regulation is unknown at this time and its implications will need to be assessed as information becomes available.

We thus confirm our 2011 findings that existing federal and provincial environmental regulations, including carbon policies, are not expected to create a challenge to resource adequacy in the Alberta power market. Beyond these existing regulations, however, there is a potential for new federal policies that, while not currently introducing imminent retirement challenges, could drive incremental retirements and increase construction costs over the coming years. A federal carbon standard for gas-fired generating units and possible SO₂, NO₂, and PM standards under the federal Air Quality Management System are prominent examples of possible future regulations which may affect resource adequacy in Alberta.

4. Increased Wind Penetration

Wind generation capacity in Alberta has increased quickly over the past decade, growing from 30 MW in 2000 to 1087 MW in 2013, as shown in Figure 2. This level materially exceeds the 630 MW of wind capacity which was online at the time of our 2011 report. This increase in wind capacity can be expected to continue, with more than 1000 MW of approved additions and an additional 2000 MW of proposed additions. While only a fraction of these approved and proposed projects will ultimately reach commercial operation, they indicate continued investor interest.

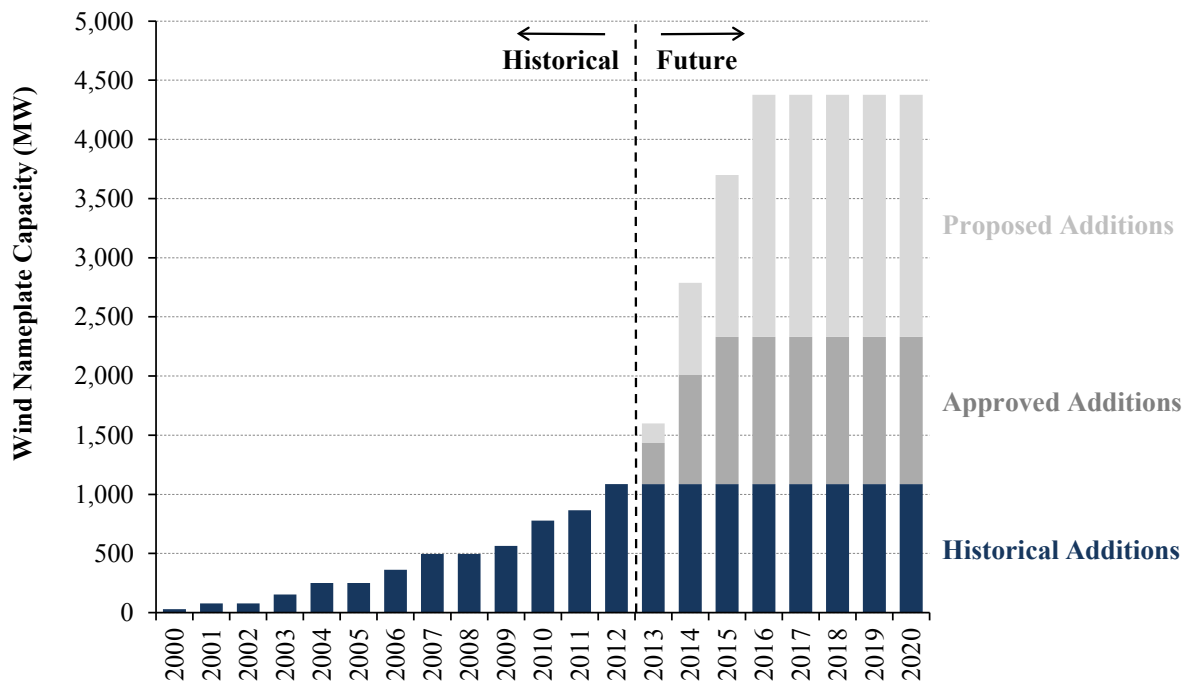
⁸ See Alberta Government (2007b), pp. 5-7.

⁹ A new unit's baseline is determined from the 3rd year of operations, with the efficiency requirement ramped up to the full 12% by the 9th year of operations. See Alberta Government (2007a), pp. 7, 17.

¹⁰ See Alberta Government (2010), pp. 2-3.

¹¹ See Alberta Government (2012), p. 23.

Figure 2
Historical and Potential Future Wind Capacity Growth



Sources and Notes:

Data provided by the AESO, consistent with the February 1, 2013 LTA, See AESO (2013a).

As we noted in our 2011 report, high levels of wind generation can introduce long-term resource adequacy challenges. Due to intermittent output levels, wind resources have very little capacity value during peak load conditions. While not contributing substantially to system adequacy, wind generation tends to reduce energy market prices because it enters the supply stack at zero or negative prices (in markets that allow negative prices). The increased wind generation, particularly during lower-load hours, also means that Alberta must be expected to experience a greater number of supply surplus events in which prices are at the current floor. For this reason we continue to recommend improving the efficiency of prices and generation dispatch during supply surplus events by reducing the price floor below zero. The price floor should be set low enough that generators, including wind plants and importers, have an incentive to curtail when it is economic to do so. Based on preliminary analyses, even reducing the price floor to negative \$50/MWh would allow for price signals that result in market-based curtailments of resources with the lowest curtailment costs during supply surplus events. This would yield a more efficient outcome than administrative pro-rata curtailment.

Regardless of whether it offers at zero or somewhat below zero, increasing wind generation can reduce the net revenues received by other generators, particularly base load units that are online even when wind generation is high, making them more likely to retire and potentially making it less likely that new resources are built. We find, however, that the significant increase of wind generation in the last two years does not appear to have had a sufficient adverse impact to undermine investment signals for new generation and market sustainability. In fact, the margins earned by natural gas-fired generating capacity have increased materially during the top 10% to 20% of all hours in the year. This means that market fundamentals are more supportive to continued generation investment, particularly for natural gas plants that can be shut down during off-peak periods with high wind generation, creating a more positive outlook for market sustainability than what we found in 2011.

5. Expanded Interconnections with Neighboring Markets

The Alberta electric system currently has two interties, one with BC Hydro and the other with Saskatchewan. The BC Hydro intertie is currently operating with available transfer capability (ATC) less than its design capacity due to operational restrictions.¹² The BC Hydro intertie has a WECC path rating of 1,200 MW for imports and 1,000 MW for exports, but currently has a maximum ATC value of only 700 MW for imports and 735 MW for exports.¹³ The Saskatchewan intertie design rating is 153 MW for imports and exports.¹⁴ Under Alberta's *Transmission Regulation* the AESO is required to take steps to restore the capability of the existing interties to near to their WECC path rating. In addition to restoring ATC on the existing interties to their path ratings, there is one intertie project that will further expand Alberta's interconnections with neighboring markets, although it will not initially increase total import ATC into the Alberta market. This new intertie is the 300 MW Montana-Alberta Tie Line ("MATL") that is currently under construction with an estimated online date in mid-2013.

As we explained in our 2011 report, expanding interconnections to neighboring markets introduces risks which must be monitored carefully.¹⁵ These risks include the possibility that expanded interconnections could depress market prices in Alberta and deter needed investment in new internal resources. Because resources in neighboring markets that are imported over the interties are not committed to the Alberta market, their resource adequacy value is limited, which has the potential to erode long-term resource adequacy and system reliability in Alberta. In this respect, interconnection capacity is similar to wind generation in that it reduces pool prices but provides limited resource adequacy value.

The price differential between Alberta and neighboring markets increased substantially in 2011 and 2012, as shown in Figure 3. Neighboring markets in the Pacific Northwest have experienced significant increases in hydro generation during 2011 and 2012, and prices in the western part of MISO have declined with low gas prices and increased wind generation.¹⁶ The combination of a decline in market prices in the neighboring markets and an increase in market prices in Alberta means that, on average across 2011 and 2012, on-peak prices in Alberta were approximately four times the average at Mid-Columbia and three times the average in Northern California and western MISO. The increase in this price differential sharply increased imports over the interties during 2011 and 2012.¹⁷ The price differential highlights concerns expressed by some of Alberta's internal suppliers regarding the potential price suppression risk associated with intertie expansion.

¹² These can include internal Alberta transmission limitations, the ability of the intertie to withstand Alberta contingencies and the ability of the Alberta power system to withstand the sudden loss of the intertie.

¹³ Current value from AESO staff; design rating from AESO (2009a).

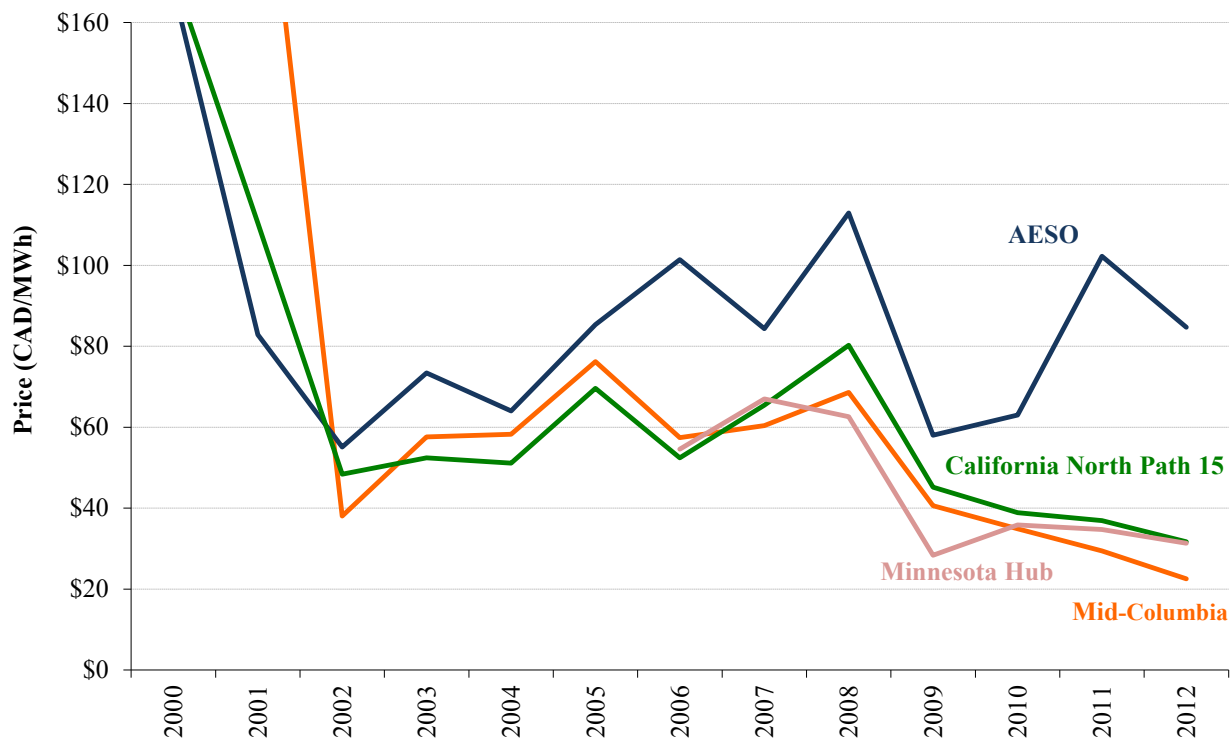
¹⁴ Current value from AESO staff; design rating from AESO (2009a), p. 303.

¹⁵ See Pfeifenberger and Spees (2011a), Section III.F.

¹⁶ See British Columbia River Forecast Center (2011) and (2012).

¹⁷ See AESO (2013c), p.12.

Figure 3
Annual Average On-Peak Energy Prices in Alberta and Neighboring Regions
 (California North Path 15, Mid-Columbia, and MISO's Minnesota Hub)



Sources and Notes:

Energy prices for U.S. markets from Ventyx (2013). Energy prices for AESO from AESO (2013c).

U.S. prices converted to Canadian dollars according to the exchange rate at the time from the Bank of Canada.

While Mid Columbia, California North Path15, and Minnesota Hubs are relatively far from Alberta, we report these prices as indicators of potential purchase prices in neighboring systems where there are no organized wholesale markets or liquid trading hubs.

If expanding intertie capacity were to suppress market clearing prices in Alberta and increase the Alberta market's exposure to unique risks faced in neighboring regions (such as hydro generation risks), expanding interties would likely reduce incentives to invest in new generation assets. This could reduce the sustainability of the Alberta market design from a resource adequacy perspective. It is unclear, however, that modest expansion of intertie capacity would necessarily be associated with adverse impacts. Expanded intertie capacity likely would reduce Alberta pool prices only in the short term (e.g., for a year or two), until the combination of load growth, plant retirements, or reduced generation investment have offset the additional imports. However, these short-term market price impacts and increased exposure to hydro risks of neighboring markets could nevertheless increase Alberta investment risks in the long-term.

Actual imports during the last two years have greatly exceeded the levels in prior years, while the operating margins of Alberta generating plants have increased. While increased intertie capacity may expose the Alberta market to the unique hydro risks of neighboring regions, imports and exports over the interties can also serve to reduce the volatility of market prices and provide assistance during scarcity and emergency conditions in Alberta. In addition, as some

potential generation investors have noted, expanding intertie capacity may increase the liquidity and attractiveness of the Alberta market for non-incumbent investors.¹⁸

Despite concerns over the potentially adverse long-term impact of significant intertie expansion, the recent experience of sharply increased imports has not yet raised resource adequacy concerns. While not raising a concern at this point, given the potential concerns and possible challenges, efforts to expand interconnections should be evaluated and monitored carefully. In particular, it would be beneficial to more fully evaluate the resource adequacy value of the interties considering: (a) the probabilistic availability of intertie capacity; (b) the potential for low-hydro years in BC and other northwestern markets; and (c) the fact that external resources have firm commitments to their host system and will only be available to Alberta on an opportunistic basis during excess supply conditions.

Overall, we conclude that, while expanded intertie capacity has the potential to reduce Alberta pool prices in the short term and increase investment risks in the long-term, this does not appear to be a concern at the current level of (or even moderately expanded) intertie capacity.

B. FINANCING NEW POWER GENERATION PROJECTS

Constructing new generation projects requires significant amounts of capital that will only be invested if suppliers anticipate returns equal to or in excess of their cost of capital. Power plants are funded through a combination of equity investments and debt financing. Debt holders (lenders) have first claim on a company's cash flows (and, if necessary, liquidation value) for the purpose of repaying principal and interest. Lenders have no stake in the residual value of the investment after their principal is repaid, nor any claim to project "upside" in the event of asset appreciation. Financing generation investment with debt conserves equity investors' funds and increases their returns, along with their financial risks. Lenders bear less risk than equity investors, making the required return on debt less than the required return on equity. However, with no upside potential, lenders require that their first claim be substantially insulated from default risk and, therefore, impose corresponding requirements on borrowers.

Debt and equity investors use two general models used to finance power plants: (1) project financing; and (2) balance-sheet financing. As is the case in other deregulated power markets, unless generation developers can find buyers willing to sign long-term contracts, the structure of the Alberta market does not support significant levels of project financing. This means that most of the necessary generation investment may have to come from financially-strong companies who are able to employ balance-sheet financing to build new plants.

Project financing refers to the use of project-specific, "non-recourse" debt, along with a required portion of equity, to finance the construction of a power plant. Non-recourse debt is not backed by a guarantee from the equity investor (likely a larger parent company) beyond the value of the individual power plant. This means that if the project becomes insolvent, the creditors will be unable to recover their investment from any other entity than the project itself. Non-recourse debt is riskier for the lender and consequently more expensive than corporate debt. This is because corporate debt is backed by a guarantee from a larger parent company, which is less likely to default because it has a larger, more diversified set of revenues and assets. Despite its

¹⁸ MPA (2012), p. 22.

higher cost, non-recourse debt is often attractive to developers because: (1) it is often the only form of debt financing available for small generation developers; (2) it may be less expensive than corporate debt for companies with below-investment grade ratings; and (3) it limits the equity investor's risk to the value of the equity originally invested in case the project proves to be a bad investment. If combined with a long-term contract, project financing can also allow high financial leverage (e.g., 70% debt financing), which is attractive to many equity investors who prefer the higher-risk, higher-return investment options the leverage creates.

Project financing will only be available up to a level at which lenders are still highly confident that cash flows from the plant will be sufficient to repay principal plus interest. The most important factor that can provide this confidence is a long-term PPA to sell power at a known revenue stream. Having a PPA reduces project risk to the owner and lender by shifting market risks to the buyer. With a PPA, even relatively small entities with limited borrowing capacity may be able to build a plant through project financing. Without a PPA, the share of a project that lenders are willing to support through project financing drops substantially. For example, some projects supported by PPAs are able to employ non-recourse debt for 70% or more of total project capital. Conversely, the higher volatility and uncertainty in projected cash flows of projects without PPAs may reduce the portion that can be financed with non-recourse debt to 30% or less of total project capital.¹⁹ At such low levels of project financing, many smaller developers without access to corporate debt or sufficient equity will not be able to finance generation developments.

As a recent study conducted for the MSA documented, the deregulated and competitive nature of Alberta's power market creates significant barriers to generation development efforts that would rely heavily on project financing.²⁰ However, this is not necessarily a concern. Similar to other competitive industries, competitive power markets tend to rely less on long-term contracting than regulated power markets, and the prevalence of project financing is likely going to decline as larger, more diversified, and financially strong companies become more active in the industry.²¹

However, while some level of mid- to long-term contracting exists in other competitive power markets, it appears that long-term contracts are available in Alberta only from the steam hosts of co-generation facilities located in Alberta's oil sands region.²² This suggests that an inefficiently low level of mid- to long-term contracting may exist in Alberta. If that were the case, it may be in part due to the design of Alberta's retail regulated rate option (RRO) and the 100% short-term contracting of month-ahead supplies for this option.²³ In contrast to the monthly procurement

¹⁹ A member of a financial institution active in the Alberta power market confirmed in a conversation that project financing of 30% is in fact possible for new generation in Alberta.

²⁰ See MPA (2012).

²¹ The same topics and concerns are discussed in other competitive power markets. See Pfeifenberger and Newell (2011). See also Newell, *et al.* (2012).

²² See MPA (2012), pp. 14, 19, and 25. As noted, cogeneration plants are expected to account for approximately 2,000 MW or one third of needed generation additions over the next 10 years. MPA's survey of investors indicates that financing of these facilities can be assumed to be feasible even on a project financing basis.

²³ In the 2012 State of the Market Report, the MSA stated that "*The Energy Price Setting Plans made in accordance with the Regulated Rate Option Regulation have resulted in procurement of monthly product in a 45 day window prior to the start of the month. This likely has a mixed effect on liquidity – forcing more trades to occur within this period at the expense of less longer term forward contracts being bought.*" See MSA (2012d), p. 37.

under Alberta's RRO, competitive retail service providers would generally secure their supplies through a portfolio of short, medium, and long-term contracts or even the acquisition of generating assets.²⁴ However, even without the RRO, we would not expect a high proportion of long-term contracts, because a competitive retailer's portfolio tends to be reflective of retail customers' risk and long-term contracting preferences. Generally, retail customers are not interested in long-term commitments of more than a few years. This means that, while reform to RRO contracting could increase the quantity and liquidity of forward contracting in Alberta, this increase would not be significant enough to support substantially greater levels of project financing. We thus recommend to build on the Alberta Government's recent RRO review²⁵ to evaluate its impact on forward contracting. It may be possible to revise RRO forward procurement or encourage customers to switch to competitive retail suppliers to develop a more efficient portfolio of short, medium, and longer-term contracts.

Balance-sheet financing avoids many of the barriers that project financing faces in a competitive power market such as Alberta. Balance sheet financing employs debt backed by the project owner itself, which may have significant, diverse resources and assets beyond the individual power plant. Corporate debt provides creditors much greater certainty because repayment is no longer solely reliant on the success of a single project, but is instead tied to the solvency of a large, diversified company. Corporate debt backing means that the loan will not go into default due to transitory periods of cash flow shortfall that may result from merchant generation operations in volatile markets. Therefore, balance sheet financing will tend to increase the amount of debt financing effectively available to a given generation project without a PPA (e.g., to 50% or 60%). To achieve the greater certainty for debt holders, however, this also means that balance sheet financing requires an investor with sufficient scale and diversity to provide this security to the lender.

As the study prepared for the MSA noted, Alberta investors that are able to utilize balance-sheet financing were much more positive about the Alberta market's attractiveness than those reliant on project financing. It also reported that most of Alberta's projects that are recently built or in advanced development stages have relied on balance-sheet financing.²⁶ This confirms that, similar to trends in other deregulated power markets, Alberta generation developers who need to rely on project financing will be at a significant competitive disadvantage. From a market sustainability perspective, this also means that most of the needed new generation investments will have to be developed by larger companies, such as the incumbent generation owners and

²⁴ For example, Constellation's NewEnergy retail supply business obtains energy from a portfolio of various sources, including its own generation assets, contractually-controlled generation assets, exchange-traded bilateral power purchase agreements, unit-contingent power purchases from generation companies, tolling contracts with generation companies, and spot purchases from the regional power markets. This portfolio balances retail sales contracts that are reported to extend from one to ten years and beyond, although these will generally not be exactly matched by long-term capacity procurement contracts. Constellation Energy explicitly stated that its strategic retail-service-operations objective is to buy generation assets in regions where the company does not have a significant generation presence and to enter into longer-term agreements with merchant generators. In fact, this objective was a primary reason for Constellation's purchase of generating plants in Texas as well as its recent acquisition of 2,950 MW of generating plants in New England, which "improved [Constellation's] net load to generation ratio to approximately 55 percent." See Pfeifenberger and Newell (2012).

²⁵ Retail Market Review Committee (2012).

²⁶ MPA (2012).

recent entrants, who are able to employ balance sheet financing to develop the new assets.²⁷ As a result, the financial health of the current generation owners, who are also the predominant investors in new generation, may be a relevant factor in maintaining the sustainability of Alberta's power market.

In our 2011 review, we noted that the high investment volume will require companies with sufficient financial strength to make these investments, and recommended monitoring the investment risks and financial capabilities of market participants most likely to finance new plants.²⁸ We still do not see evidence that such companies do not exist or that they are unable or unwilling to make the needed investments in Alberta. However, to identify investment-related challenges to resource adequacy that could emerge over time, we recommend monitoring: (1) the financial health of Alberta's generation owners and developers; and (2) entry by new companies who can utilize balance-sheet financing (or similar other financial structures) to develop new generation in Alberta. We also recommend analyzing: (3) the extent to which exclusive reliance on monthly contracting to supply RRO load results in an inefficiently low level of forward, bilateral contracting; and (4) whether such inefficiencies should be addressed through either phasing out the RRO or introducing longer-term contracting for a portion of RRO supply.

C. RECENT INVESTMENT TRENDS

Recent Alberta investment activity—particularly among projects that have recently been completed or received financing—provides helpful insights into the outlook for investment and resource adequacy. Table 1 examines a subset of recent projects that are particularly relevant from a resource adequacy perspective. The table shows projects completed since 2008, but excludes wind plants and cogeneration because investment decisions for these technologies are less closely linked to wholesale electric market conditions. Wind power investment is typically dependent on supplemental “green” revenues and investment in cogeneration is heavily influenced by the availability of and payments from a suitable steam host. After excluding these generation types, five projects larger than 20 MW have been completed since 2008, and one is currently under construction.

All of these projects have been developed by relatively large companies, which supports our position that Alberta will continue to attract investment primarily from larger, more diversified investors that are able to rely on balance sheet financing of projects. Constellation's investment in the Northern Prairie Power Project, as well as their development plans for the new Harmattan Energy Center, also shows that not all new generation projects are undertaken by incumbent generators.²⁹ Lastly, we note that, besides a number of smaller wind and cogeneration projects, the 800 MW Shepard Energy Center is the first large generation project to be financed and begin construction since the financial crisis and drop in natural gas prices in 2008.

²⁷ For example, Constellation New Energy, who is active in Alberta's competitive retail market has also invested in new generation, with one peaker (93 MW Northern Prairie Power Project) that came online in 2009 and another peaker (95 MW Harmattan Energy Center) proposed to come online in 2013. Another smaller Alberta generator is Maxim Power, which proposed the 90 MW Deerland Peaking Station. See AESO (2013).

²⁸ See Pfeifenberger and Spees (2011b), and Pfeifenberger and Spees (2011a).

²⁹ Constellation Energy merged with Exelon Corporation in 2012, and the merged company operates under the Exelon name.

Table 1
Recently Financed Projects

Project	Developer	Online Date	Unit Type	Capacity
Completed Since 2008				
Keephills 3	TransAlta 50%, Capital Power 50%	2011	Coal	450
Clover Bar	Capital Power	2008 - 2010	Gas CT	245
Crossfield Energy Station	ENMAX	2009	Gas CT	120
Northern Prairie Power Project	Constellation/Exelon	2008	Gas CT	85
Valleyview 2	ATCO	2008	Gas CT	45
Recently Financed and Under Construction				
Shepard Energy Center	ENMAX 50%, Capital Power 50%*	2015	Gas CC	800

Sources and Notes:

Data from Ventyx (2013). Projects larger than 20 MW completed since 2008 are shown. Wind and cogeneration projects are excluded. 1,010 MW of wind, cogeneration, and projects smaller than 20 MW have been completed since 2008, and 680 MW are currently under construction (Ventyx 2013). *Capital Power's 50% stake is a 20 year tolling agreement.

D. SUPPLY AND DEMAND OUTLOOK

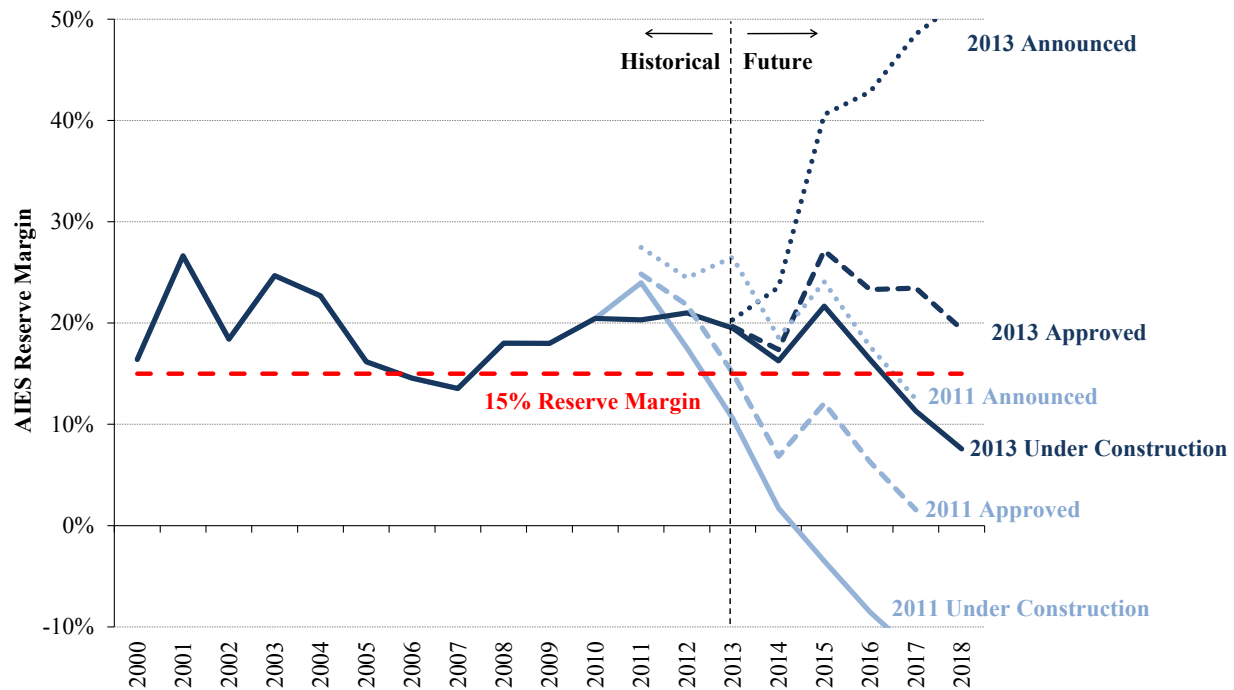
This section of our report documents the long term outlook for supply adequacy given current levels of proposed additions and potential retirements. We find that changes in several factors have driven a modest improvement in the supply-demand outlook since our 2011 analysis.

1. Investment Levels Required to Sustain Resource Adequacy

Figure 4 shows that the reserve margin remained near 20% in 2011 and 2012, and that the outlook for future years has improved since our 2011 analysis.³⁰ Some of the improvement in projected reserve margins can be explained simply by advancements in generation projects along their development timelines. For example, the 800 MW Shepard Energy Center had only received regulatory approval at the time of our 2011 analysis, but construction of the project has since begun. Lastly, there has been an increase in announced projects since 2011, which indicates that investors are evaluating a healthy number of potential projects for economic viability.

³⁰ See AESO (2013). Note that Sundance 1 and 2 are excluded from the 2011 and 2012 reserve margin.

Figure 4
Historical and Projected Reserve Margins



Sources and Notes:

AIES reserve margin data provided by the AESO, consistent with the February 2013 LTA and the February 2011 LTA. See AESO (2013a) and AESO (2011). We note that the reserve margin has been generally above or close to 15%, which we use in this report as an approximate indicator of resource adequacy, although the 15% is not an official target and may exceed the economically efficient reserve margin set by the market.

Figure 5 shows existing supply, projected retirements, and potential additions, along with projected peak Alberta Internal Load (AIL) after including our benchmark 15% reserve margin.³¹ Looking forward, Figure 5 shows that from 2013 to 2029 capacity additions will have to average approximately 530 MW annually to maintain resource adequacy. This rate is lower than the 740 MW annual rate that we projected in 2011. The difference is largely the result of a 1,600 MW reduction in the long-term load projection and a 5-year delay in the compliance date for the Federal Carbon Standard for Coal Generation, which reduced the overall number of projected retirements by the end of the period by approximately 1,600 MW.³² Another factor behind the improvement is the return to service of Sundance units 1 and 2, which was not anticipated in 2011.³³

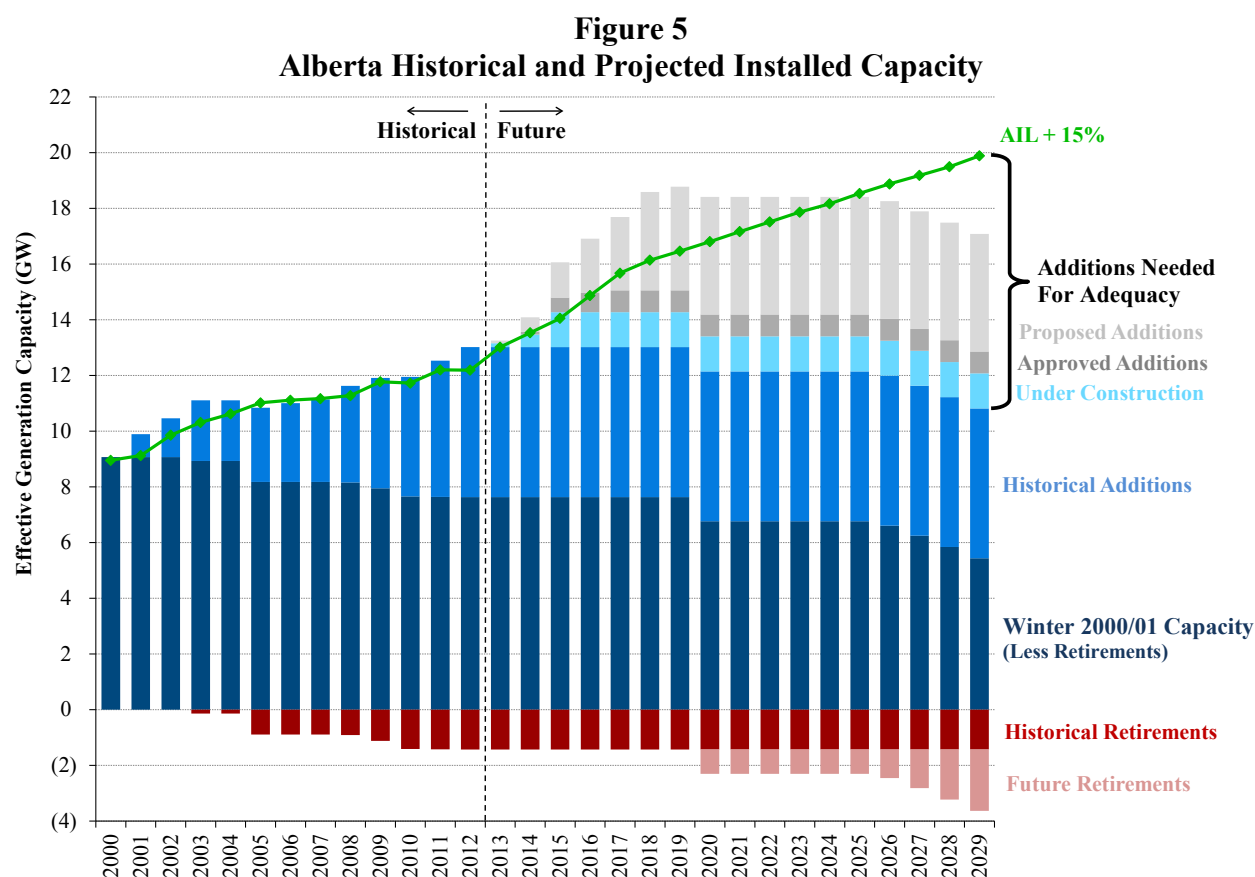
³¹ This is one of two types of load forecasts that AESO conducts, with the other being the Alberta Internal Electric System (AIES) load. The difference between the two is that AIL includes behind-the-meter electric consumption, including that used by cogeneration facilities for their own industrial operations, making AIL the more relevant indicator of resource adequacy.

³² The carbon standard proposed in 2011 required that coal units comply following their 45th operating year, while the final rule required compliance after the 50th operating year.

³³ In July 2012, an arbitration panel directed TransAlta to repair Sundance units 1 and 2 and maintain a PPA with TransCanada through 2017. See Reuters (2012).

Figure 5 also shows already-permitted and other proposed capacity additions currently being tracked by the AESO.³⁴ While the approved additions are in advanced development and have a higher likelihood of coming online than proposed projects, they are still not guaranteed to materialize. If the approved additions met their proposed online dates, they would maintain the benchmark resource adequacy through 2016. The shown “proposed additions” are more speculative projects that may only be in a scoping phase and generally have a smaller potential for materializing. Based on the current load growth projections, a 15% reserve margin would be maintained through 2024 if all plants proposed, approved, and under construction were realized.

The increase in the projected coal retirements after 2025 is driven by the Federal Carbon Standard for Coal Generation.



Sources and Notes:

Data provided by the AESO, generation additions consistent with the February 1, 2013 LTA, See AESO (2013a).
Projected AIL load is consistent with the 2012 Long-term Outlook Update, See AESO (2013b).

2. AESO Projected Future Generation Additions

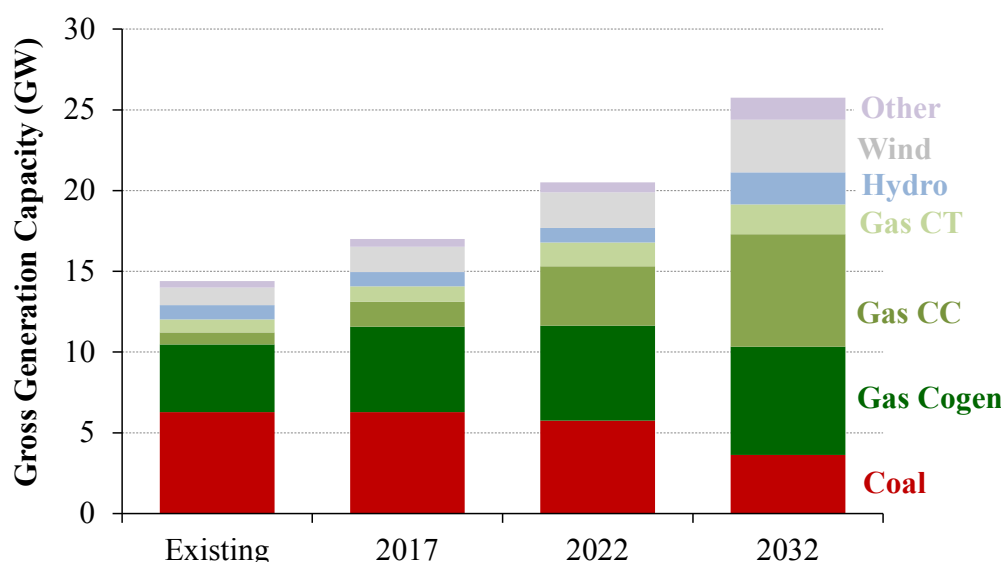
In its 2012 Long-term Outlook, the AESO projected changes in the generation fleet over the next two decades. The projection is based on a combination of factors including known and expected projects under development, the economics of competing generation types, and the outlook for

³⁴ The figure does not reflect potential wind additions because wind is derated to a capacity value of 0% while hydro is derated to 67%.

retirements. A broad shift in fleet composition from coal-fired to gas-fired generation is expected, as shown in Figure 6 below. As noted previously, the projected coal retirements near the end of the period are driven by the Federal Carbon Standard. In contrast, all gas-fired generation types are projected to increase rapidly, driven by relatively low capital, fuel, and carbon costs.³⁵ Gas-fired generation is projected to increase from approximately 40% of the total fleet in 2013 to 60% in 2032.

We use this generation outlook as a reference point for our analysis. In particular, we aim to determine whether private investors are likely to find the assumed generation technologies to be sufficiently economically attractive to make these projected investments.

Figure 6
AESO Generation Outlook



Sources and Notes:

Data provided by the AESO, consistent with the 2012 Long-term Outlook Update, See AESO (2013b).

III. HISTORICAL TRENDS IN GENERATOR ECONOMICS

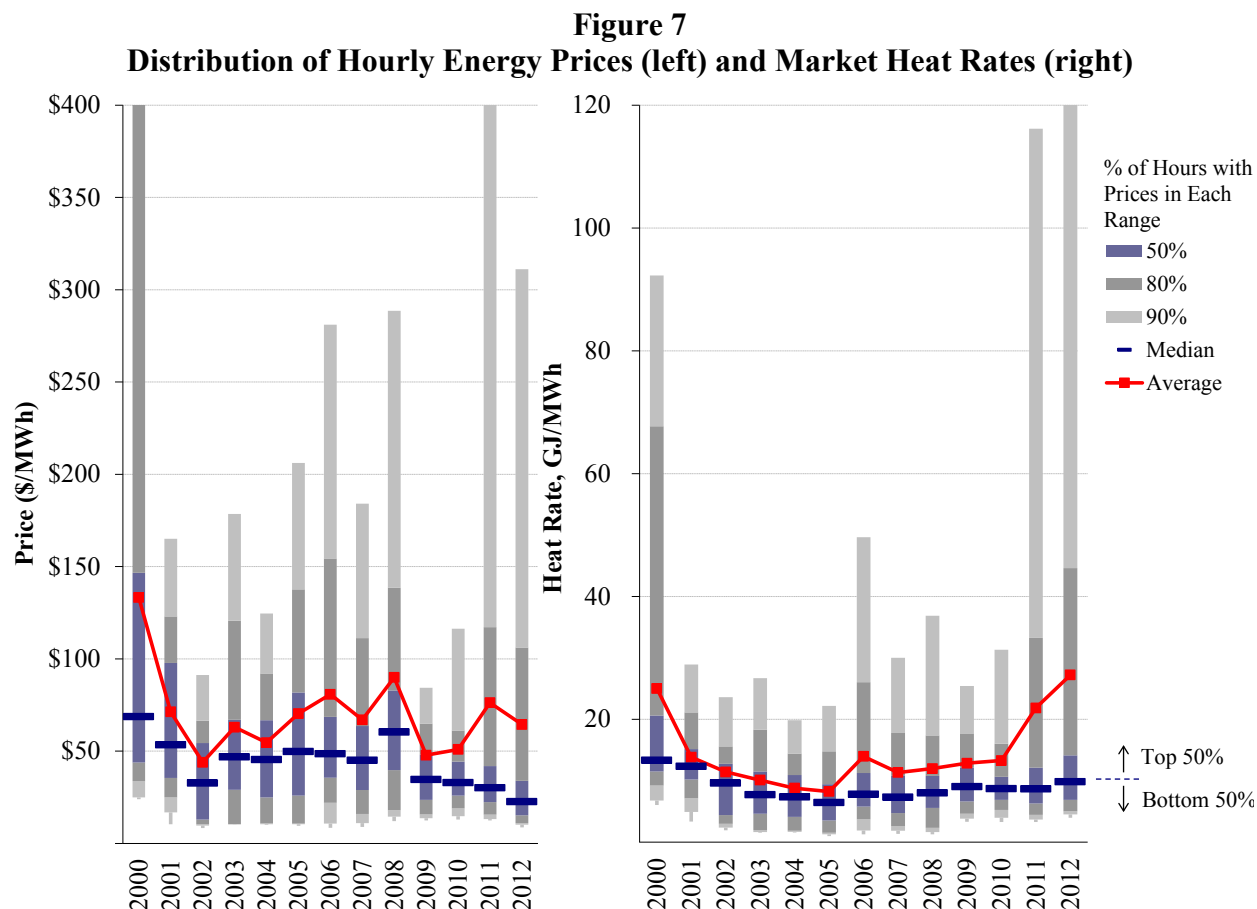
Because the Alberta market is an energy-only market, the challenges to resource adequacy documented in Section II.A must be managed through private investments solely in response to energy market price signals. In a well-functioning energy-only market this means that energy and ancillary service market prices and associated revenues available to potential new entrants must be sufficient to attract and retain generation supplies when needed. This section of our report updates and examines trends in pricing levels, the costs and operating parameters of new generating plants, and the contributions to fixed costs (*i.e.*, the operating margins) earned by suppliers in recent years. Again, this serves as a starting point for assessing the economics of different generation technologies in the Alberta electricity market.

³⁵ See AESO (2012), Section 7.

A. WHOLESALE PRICE LEVELS

Figure 7 shows the historical distribution of hourly energy prices and market heat rates for each of the last 13 years. The market heat rate is the ratio of the hourly energy price to the daily natural gas and emission prices, and can be interpreted as energy prices that are normalized for changes in natural gas and emission costs. The stacked vertical bars document the distribution of market prices and market heat rates, with average and median prices indicated by the red markers and dark blue lines, respectively. For example, the range from the bottom of the lowest bar to the top of the highest bar indicates that 90% of all hourly market prices and market heat rates observed in that year were within that range.

Figure 7 shows an increase in average prices in 2011 and 2012 relative to 2009 and 2010 levels. As shown, average 2011 and 2012 price levels were roughly consistent with those experienced between 2005 and 2008. Once normalized for lower natural gas costs, however, the 2011–2012 increase in market heat rates is much more pronounced, with average market heat rates in 2011 and 2012 at approximately two to three times the levels observed over the past decade. The increase in average prices and heat rates is driven almost entirely by changes in the top end of the price duration curve, representing only 10–20% of all hours. Median prices, on the other hand, have declined with gas prices, as median market heat rates have remained fairly stable.



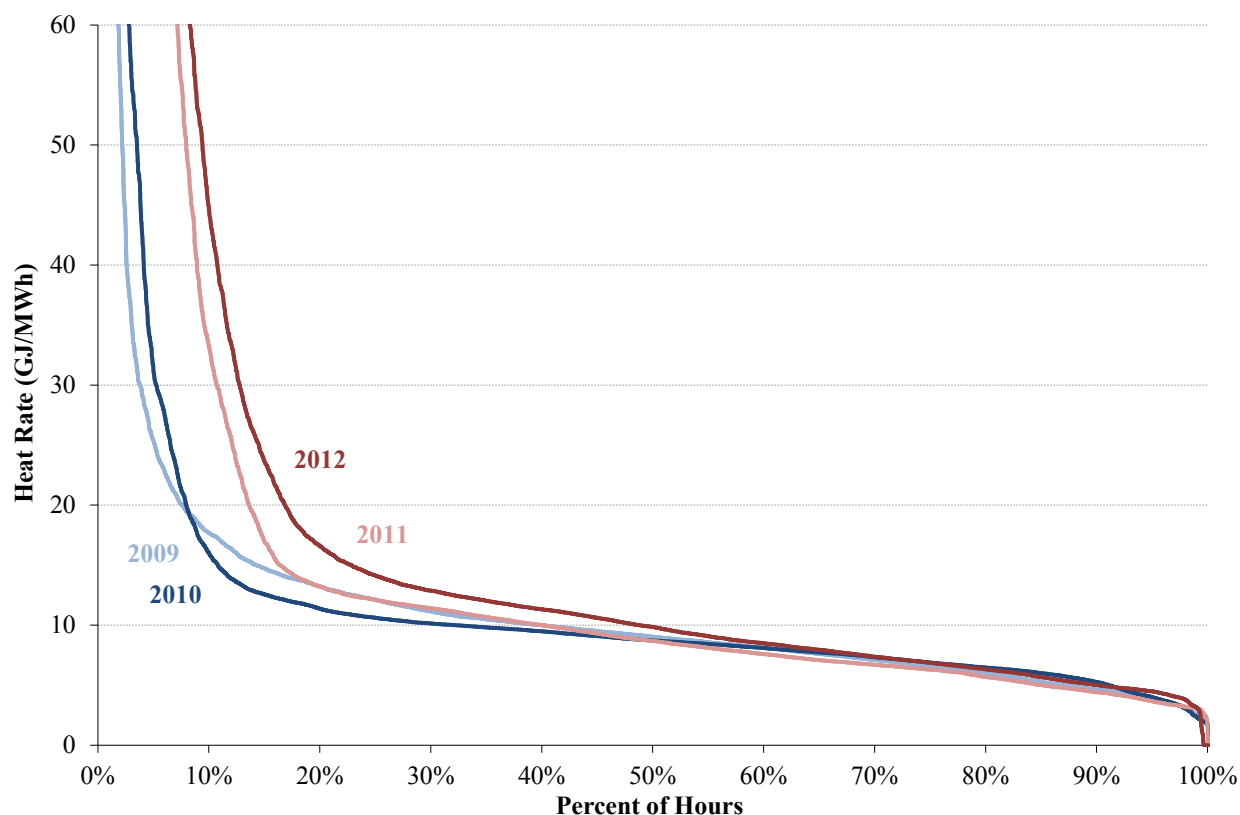
Sources and Notes:

Daily historical AECO C gas prices and hourly energy prices are from Ventyx (2013).

Figure 8 shows market heat rate duration curves for the years 2009 through 2012. These duration curves confirm that the increase in market heat rates in 2011 and 2012 was concentrated

in the top 10% to 20% of all hours. This change in the top 10–20% of all hours was large enough to drive the significant increase in average annual prices and market heat rates shown in Figure 7. If prices in the top 15% of hours had been equal to the 2009–2010 average, annual average prices would have dropped from \$76/MWh to \$47/MWh in 2011 and from \$64/MWh to \$41/MWh in 2012.

Figure 8
Historical Market Heat Rate Duration Curves



Sources and Notes:

Daily historical AECO C gas prices and hourly energy prices are from Ventyx (2013).

The MSA recently examined the cause of the much higher peak-period prices over the last two years, and tentatively concluded that it was driven primarily by a shift in generator offer behavior, rather than an increase in the frequency or severity of scarcity conditions.³⁶ Specifically, the MSA tentatively found in its third quarter 2011 report that “*the change in behaviour commented upon in the past several quarterly reports is mostly a shift in market participant behaviour from 2010 to 2011. Also, it appears that the change is a significant contributor to the overall level of pool price.*”³⁷ The MSA had already noted in its second quarter report that the change in the relationship between price and scarcity was driven by a shift in offer behavior with an increase in economic withholding, stating that the data suggested that “*there has been a shift in offer behavior in the past two or three quarters. The output analysis indicated that in the majority of these hours, economic withholding through increasing the offer prices of large volumes of energy, particularly by Participant C, was an important driver.*”³⁸

³⁶ See MSA (2011b), p. 34.

³⁷ See MSA (2011b), p. 34.

³⁸ See MSA (2011a), p. 17.

This change in generator offer behavior roughly coincided with the MSA's issuance of Offer Behavior Enforcement Guidelines in January 2011.³⁹

The MSA based its conclusion on an analysis of the relationship between the pool price and the hourly 'supply cushion', which is measured as the quantity of available but undispached supply in the merit order.⁴⁰ Table 2 summarizes the frequency of scarcity conditions as measured by the supply cushion, and reports mean prices in several supply cushion ranges. Table 2 shows that low-supply cushion events were no more common in 2011 than over 2008–2010, despite the loss of Sundance 1 and 2 in December 2010.⁴¹ However, there was a pronounced increase in the mean price during scarcity conditions, particularly when the supply cushion dropped below 750 MW.

Table 2
Mean Prices at Varying Levels of Scarcity

Supply Cushion Range (MW)	0 - 250	250 - 500	500 - 750	750 - 1000	1000+
Percent of Hours in Range					
2008 - 2010	1.4%	6.1%	12.5%	18.7%	61.3%
2011	1.5%	4.4%	10.9%	17.0%	66.1%
Mean Price in Range					
2008 - 2010	\$542	\$199	\$88	\$58	\$32
2011	\$828	\$348	\$177	\$70	\$26

Sources and Notes:

Supply cushion data from MSA (2012e). Table style from MSA (2011b), Table 2.2.

Figure 9 similarly shows this change in the relationship between the hourly supply cushion and price, demonstrating that prices reached much higher levels in 2011 compared to 2008–2010 under similarly tight market conditions. As the figure shows, during 2008–2010 prices above \$400/MWh were reached mostly when the supply cushion was less than 500 MW. In contrast, in 2011 prices started to exceed \$400/MWh when the supply cushion fell below 1000 MW. When the supply cushion was below 500 MW, market prices in 2011 were often above \$800/MW. Complete data for 2012 has not been released, but the MSA remarked that the patterns in the first, second, and third quarters of 2012 are in line with those observed in 2011.⁴²

As we show below in Section III.C, this increase in market heat rates and market prices during the top 10–20% of all hours in 2011–2012 significantly increased generator margins in

³⁹ MSA (2011c).

⁴⁰ See MSA (2012f) for a detailed definition of the supply cushion.

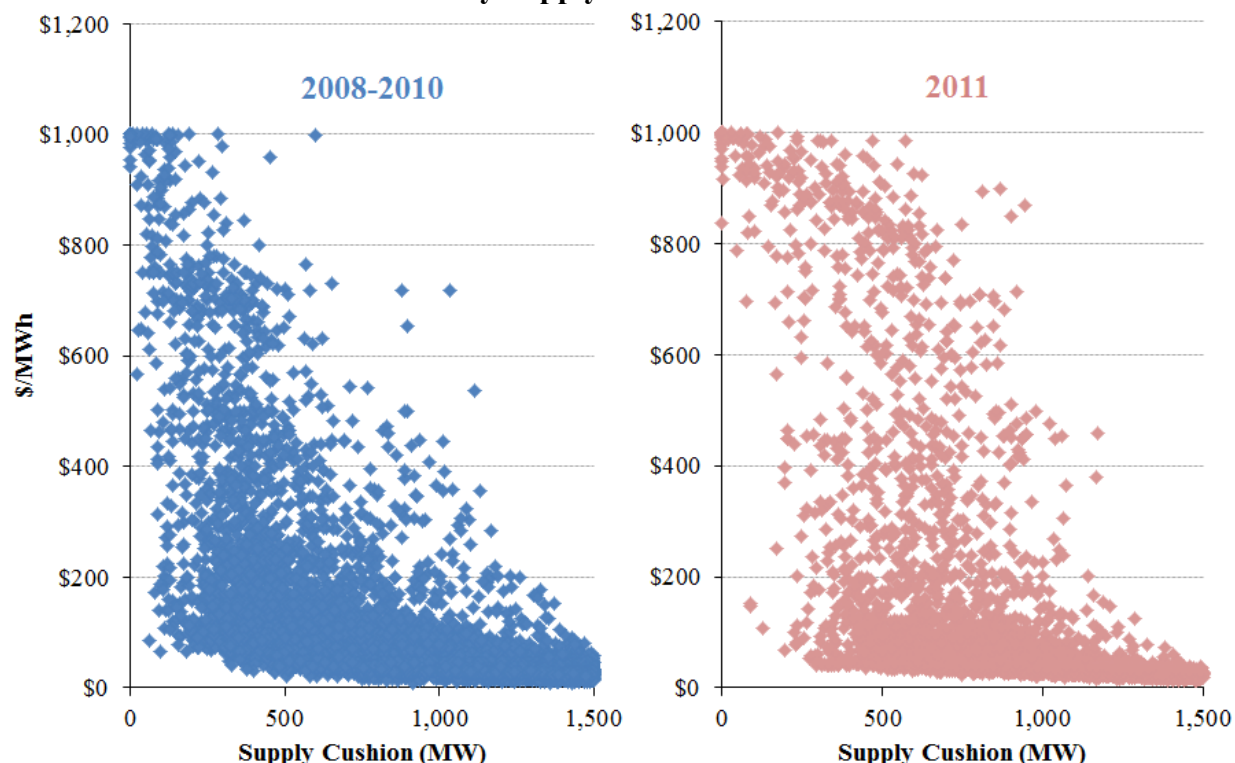
⁴¹ See MSA (2011b), p.33.

⁴² See MSA (2012a), p. 8, MSA (2012b), p. 9, MSA (2012c), p. 5

⁴³ The charts in Section IV.A.3 show the cost of a new plant in each year compared with operating margins expected for the same years. To evaluate the attractiveness of an investment made in a particular year, one has to determine the operating margins above or below the assumed annual payment schedule. For a constant *real* payment schedule, the levelized cost increases with inflation similar to how the costs of new plants increase over time. For a constant *nominal* payment schedule, each vintage of new power plant would require a different horizontal line for capital costs, which would make it more difficult to compare capital costs and operating margins over time.

comparison to generation-related costs, with margins exceeding the all-in cost of new natural gas plants. If investors anticipate similarly high margins looking forward, these market conditions will provide a strong signal to invest in new generating plants, which will not only ensure resource adequacy but also increase competition during high-priced hours, thereby putting downward pressure on market prices. However, if new entrants discount the long-term value of the high current prices because they are driven mostly by incumbent generators' offer behavior rather than by underlying market fundamentals, this could nevertheless lead to insufficient new entry even under apparently favorable investment conditions. This potential concern is discussed in more detail in Section IV.B.2 below.

Figure 9
Hourly Supply Cushion vs. Price



Sources and Notes:
Supply cushion data from MSA (2012e).

B. COSTS AND OPERATING PARAMETERS OF NEW GENERATING PLANTS

To examine the attractiveness of new generation investments, our 2011 report compared the investment and fixed operating costs of new resources against the operating margins available to these resources from the energy and ancillary service markets. We update this analysis with two years of additional data and new cost information.

Table 3 shows the updated capital costs and operating parameters for different types of new generating technologies used in this evaluation. We relied on AESO estimates of overnight costs, fixed and variable operations and maintenance (O&M) costs, and heat rates for these generation technologies in Alberta. In an effort to produce more conservative estimates of annualized fixed costs, we reduced the AESO estimates of the useful life of these plants

(operating lifetime). The annualized fixed costs are calculated based on an after-tax weighted average cost of capital (ATWACC) of 8.0% and an inflation rate of 2.4%, as discussed further below.

Table 3
Updated Fixed Costs and Operating Parameters for New Generating Plants

Generating Technology	Overnight Costs	Operating Lifetime	Fixed O&M	Variable O&M	Heat Rate	Annualized Fixed Costs (Constant Nominal)	Annualized Fixed Costs (Constant Real)
	2012\$/kW	years	2012\$/kW-y	2012\$/MWh	GJ/MWh	2012\$/kW-y	2012\$/kW-y
Gas CT	\$1,196	20	\$14.0	\$4.3	9.8	\$148	\$126
Gas CC	\$1,689	25	\$9.0	\$3.3	7.2	\$186	\$153
Gas Cogen*	\$1,241	25	\$14.0	\$3.7	6.6	\$135	\$112
Wind	\$2,100	20	\$50.0	\$2.0	n/a	\$265	\$230
Coal	\$4,003	30	\$33.0	\$6.3	9.4	\$438	\$353

Sources and Notes:

Overnight costs, FOM, VOM, and heat rate estimates provided by AESO. Operating lifetimes reflect *Brattle* assumptions.

*These costs represent the electric portion of a cogen unit.

To support investment in new generation, the present value of a generating plant's anticipated operating margins must be equal or greater than its total fixed costs, which are its capital costs plus the fixed operations and maintenance ("FOM") costs incurred over the operating life of the plant. To assess the overall attractiveness of market conditions on a year-by-year basis, we estimated the annualized fixed costs of different types of new generation technologies. These annualized fixed costs of new generation are shown in the last two columns of Table 3 based on two approaches to cost levelization: one with annual payments that remain constant in *nominal* terms over the operating life of the plant, and another with annual payments that increase with inflation over time (*i.e.*, are constant in *real* dollar terms). These two annualized capital costs could represent the pricing structures of two different PPAs, both of which would result in full recovery of capital and fixed costs. For the purposes of our analysis of projected generation margins and costs in Section III.B and Section IV, we use the "constant real" approach, which allows for a more intuitive comparison of annual margins and levelized capital costs over time.⁴³

A comparison to the updated annualized costs with those from our 2011 report is shown below in Table 4. As shown, the levelized cost estimates increased for all generation types since our 2011 report, with the exception of wind generation. The increases are largely driven by higher estimates of overnight costs, which are only partly offset by a decline in financing costs.

⁴³ The charts in Section IV.A.3 show the cost of a new plant in each year compared with operating margins expected for the same years. To evaluate the attractiveness of an investment made in a particular year, one has to determine the operating margins above or below the assumed annual payment schedule. For a constant *real* payment schedule, the levelized cost increases with inflation similar to how the costs of new plants increase over time. For a constant *nominal* payment schedule, each vintage of new power plant would require a different horizontal line for capital costs, which would make it more difficult to compare capital costs and operating margins over time.

Table 4
Annualized Fixed Costs for New Generating Plants
Comparison to 2011 Estimates

Generating Technology	2011 Estimate <i>2012\$/kW-y</i>	Updated <i>2012\$/kW-y</i>
Gas CT	\$108	\$126
Gas CC	\$135	\$153
Gas Cogen (Electric)	\$112	\$112
Wind	\$272	\$230
Coal	\$312	\$353

Sources and Notes:

2011 estimates from Pfeifenberger and Spees (2011a).

One of the main inputs needed to estimate the annualized cost of new generation is the required return on investment, which is measured as a project's ATWACC. The project's cost of capital is the opportunity cost for a marginal investor—the rate of return that capital could be expected to earn with an alternative, equally risky investment. Because investment risks differ, investors will have a different required return for each type of project they consider. In other words, the cost of capital varies by the type of generation project. For example, a project built with a long-term PPA that provides a stable revenue stream will have a relatively low cost of capital. Alternatively, a merchant project that is fully exposed to market risks will have a higher cost of capital.

The financing assumptions used in our 2011 review of the Alberta market yielded an ATWACC of 8.59% for merchant generation investments. Changes in financial market conditions since 2011, in particular a 2 percentage point drop in the government's borrowing cost, have significantly reduced these financing costs. Our updated analysis of Canadian financial market conditions and the financial risks of a sample of large merchant generation companies shows that the ATWACC for merchant generating companies currently is between 7.5% and 8.0%.⁴⁴ It is possible, however, that some generation developments might face after-tax financing costs as low as 7.0% or as high as 9.0% to 9.5%—particularly if the project is developed by smaller companies with less experience, less favorable access to capital markets, and partial reliance on project financing. We thus assess the annualized costs of generation investments for an ATWACC of 8.0% (the high end of our estimate for merchant generation companies), with a 150 basis point sensitivity range from a low of 7.5% to a high of 9.0%.⁴⁵

⁴⁴ This ATWACC of 7.5% to 8.0% for merchant generation companies compares to an ATWACC for cost-of-service regulated utilities of 6% or less. The updated ATWACC estimates also reflect changes in the cost of debt and financial leverage of the sample companies (if any) as well as a reduction in the corporate tax rate from 28% to 25%.

⁴⁵ This range is also consistent with the range of “unlevered” discount rates (equivalent to ATWACC) as disclosed in the July 20, 2012 fairness opinions that investment banks (Credit Suisse, Morgan Stanley, and J.P. Morgan) prepared for NRG's merger with GenOn, two merchant generating companies in the U.S. (NRG Energy, U.S. Securities and Exchange Commission Form S-4, dated October 5, 2012). In that analysis, the unlevered discount was estimated to range from 7.0% to 8.5% for NRG, from 8.5% to 9.5% for GenOn, and from 7.4% to 8.8% for the newly-combined company. (Note, while the Canadian cost of

Continued on next page

C. HISTORICAL GENERATOR OPERATING MARGINS VS. FIXED COSTS

To determine the overall attractiveness of the Alberta electric market to potential new entrants from a historical perspective, we first examine historical generator margins for each technology type and compare those against the cost of new generating plants estimated in Section III.B. We calculated energy and ancillary services revenue from unit-specific AESO data, although operating reserves data are unavailable for years prior to 2004. We estimated generator costs based on historical market fuel and GHG prices, a public database on individual units' heat rates, and generic unit assumptions for variable O&M from Table 3 above. We included as many AESO generators as possible in our aggregation of historical generator margins for each technology, but eliminated some units because of uneconomic dispatch under Transmission Must Run (TMR) contracts or because of data quality problems. We did not account for supplemental "green" revenue streams such as carbon offsets for wind generation.

Figure 10 shows the historical operating margins compared to fixed costs over the past decade for gas CTs, gas CCs, gas cogen, wind, and coal units. The figure shows that operating margins for all gas-fired generation types increased significantly in 2011 and 2012, and exceeded their fixed costs by a substantial amount. In fact, realized operating margins for natural gas units in 2011 and 2012 were more than twice as high as the baseline projections we had made in our 2011 report for those years. Realized margins in 2011 and 2012 also exceeded the high end of the range of margins we projected in our 2011 report. The largest driver of this increase in natural gas units' margins was an increase in peak prices caused by a shift in generators' offer behavior, as discussed in Section III.A.

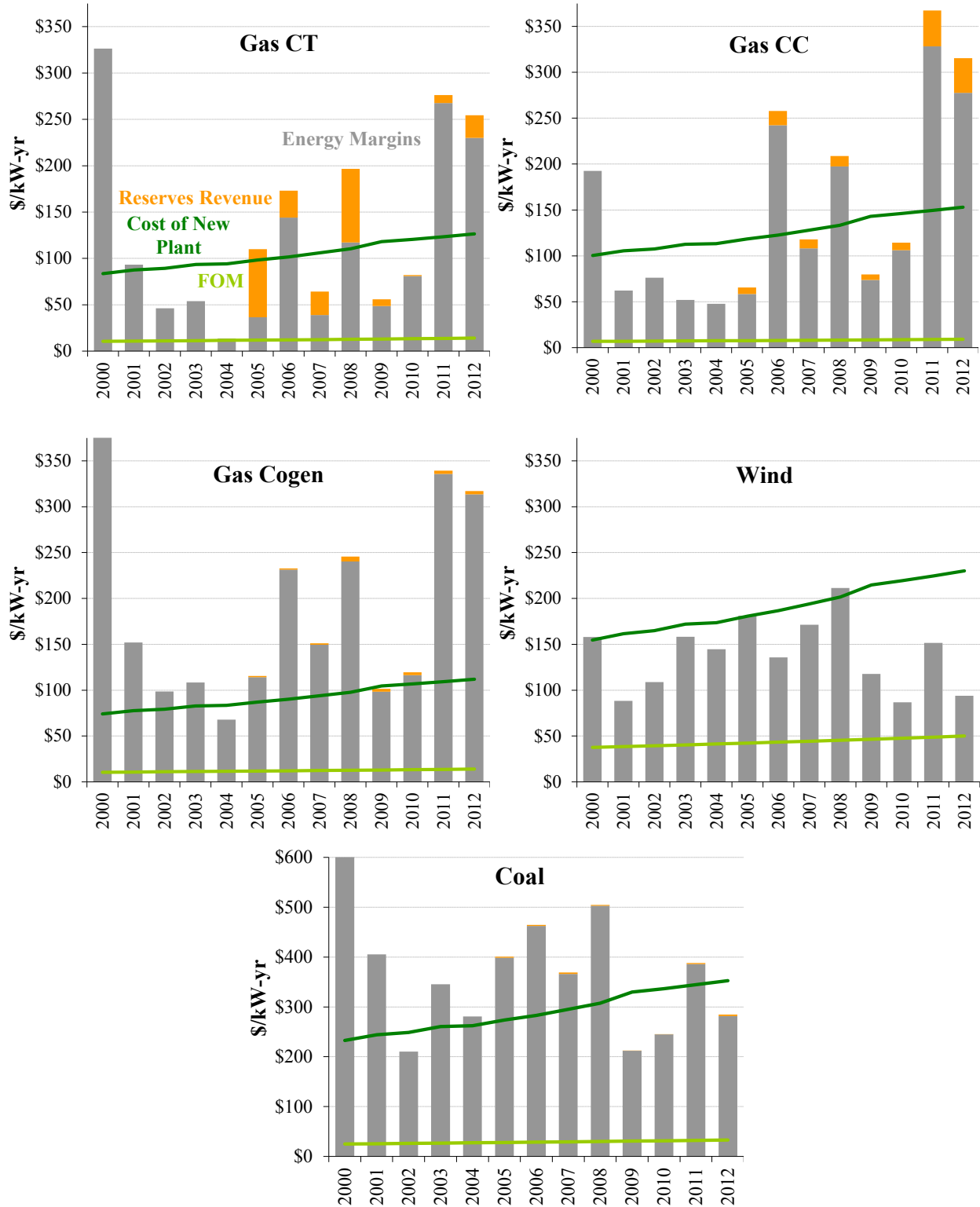
As shown in Figure 10, operating margins for wind and coal units also increased in 2011 and 2012 relative to 2009 and 2010. However, the increase in operating margins was much smaller than those of natural gas units because these generation types operate more during off-peak hours and thus benefit less from peak-period prices. They also did not benefit from the lower natural gas prices during 2011 and 2012. As shown, annual operating margins for coal units exceeded the annualized costs of new coal plants in 2011 and fell short in 2012, while wind generator' operating margins were less than their annualized costs of new plants in both years. At the same time, however, operating margins for both coal and wind generators continue to significantly exceeded estimates of their fixed operating costs—which means existing plants will not retire unless they faced the need for substantial capital additions.

These data show that the market conditions during 2011–2012 were very favorable for natural gas fired generating plants, with operating margins that significantly exceeded the annualized cost of new plants. If investors anticipate that these market conditions prevail going forward, they would provide strong investment signals for natural gas plants. At the same time, the realized energy market prices during 2011–2012 are still insufficient to cover the annualized costs of other generation technologies, including coal and wind.

Continued from previous page

equity tends to be below U.S. levels because of a lower Canadian market risk premium, this effect is offset in the ATWACC calculations by a lower Canadian corporate tax rate.) Estimates of the ATWACC for Canadian merchant generation companies (TransAlta and Capital Power) are lower than this range, which likely is due to the risk-mitigation effect of restructuring-related long-term PPAs.

Figure 10
Historical Operating Margins vs. Fixed Costs



Sources and Notes:

Energy margins represent revenues minus estimated operating costs in the energy market. Cost of new plant includes capital costs and FOM, levelized on a constant real basis as shown in Table 3.

IV. OUTLOOK FOR GENERATOR ECONOMICS

As explained in our 2011 market review and Section II.C above, Alberta will require significant investments to keep pace with load growth and coal plant retirements over the next two decades. In this section, we examine the attractiveness of new generation investments in Alberta based on a projection of market prices that are consistent with updated market fundamentals.

We use two separate approaches to project future market prices and generator returns. First, we update the analysis from our previous market review by projecting prices based on recently-observed market heat rates, scarcity pricing patterns, and expected future gas and carbon prices. This approach provides a baseline outlook from 2013 to 2029. Second, we report the results of market simulations conducted by the AESO for the purposes of this study. The market simulation was performed for 2013 only, but allows us to examine the effects of changes to the reserve margin, as well as providing an informative comparison to the first approach.

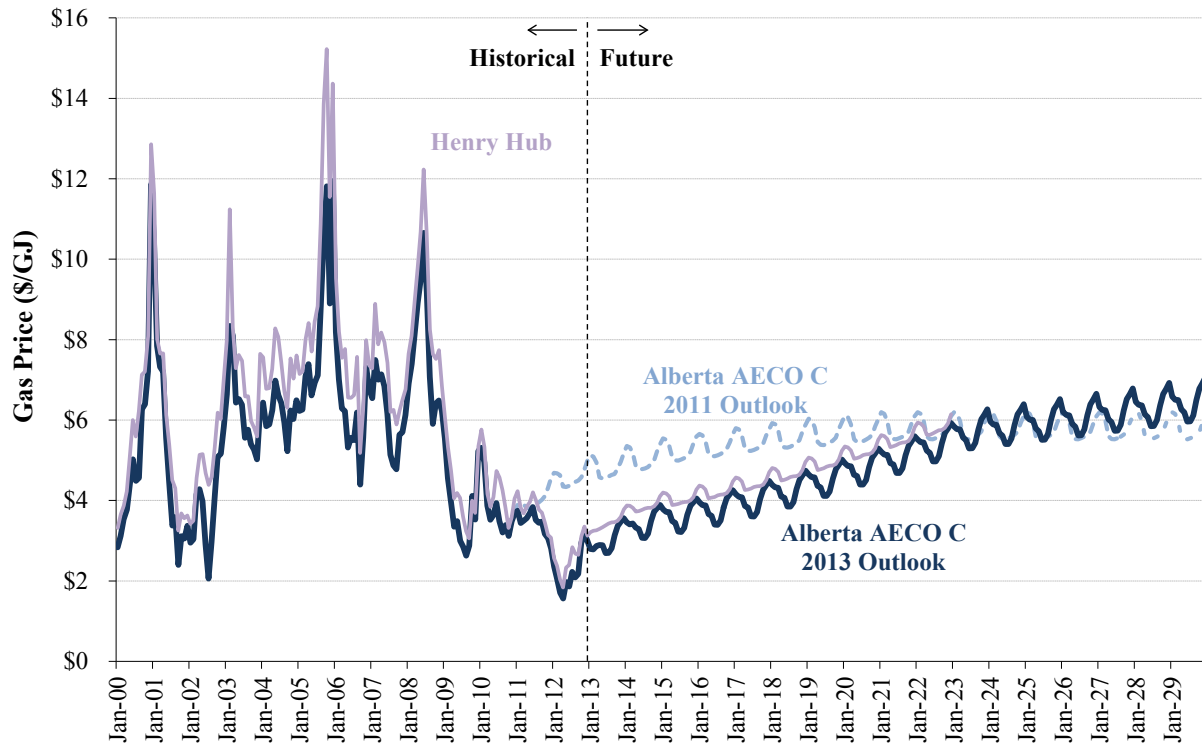
A. MARKET PRICES PROJECTED WITH RECENT MARKET HEAT RATES

Our first approach to projecting market prices is based on recent market heat rates, scarcity pricing patterns, and projected gas and carbon prices. Because we do not forecast changes in market heat rates or the frequency of scarcity pricing under this approach, these projections represent only a reference point. They do not represent price forecasts that reflect potential changes in market fundamentals, such as the impacts of changes in fleet composition, expanded intertie capacities with neighboring markets, increasing wind penetration levels, or other factors. This approach is the same we used in our 2011 market review.

1. Projected Gas, Coal, and Carbon Prices

Figure 11 shows the Alberta natural gas price that we use to project future power prices and plant operating costs. We project gas prices through 2023 based current on Henry Hub futures, after subtracting the monthly average AECO C basis differential observed between 2009 and 2012. We assume that prices increase with inflation after 2023. Forecast natural gas prices have declined since 2011, as already discussed in Section II.A.1

Figure 11
Projected Gas Prices



Sources and Notes:

Historical gas prices from Ventyx (2013). Exchange rates from Bank of Canada (2013).

AECO C outlook estimated based on December 2012 Henry Hub futures and monthly average 2009–2012 basis discounts; increased with inflation after 2023.

The current cost of emitting greenhouse gases in Alberta under the Specified Gas Emitters Regulation is at most \$15/tonne of CO₂e for 12% of output for large emitters. To project power prices and forecast generator operating costs, the AESO has asked us to assume that the price will remain at the current level of \$15/tonne until 2018, and then increase to \$20/tonne thereafter.

We assume coal prices consistent with an AESO estimate of current mining costs at \$1.56/GJ, increasing with inflation.⁴⁶

2. Projected Future Power Prices

To assess the market's ability to attract new generation investments over the coming decades, we project energy prices based on expected future natural gas and carbon prices consistent with recently-observed market conditions. As in our previous market review, our approach is to calculate the hourly heat rate duration curve for historical years and use these historical market-heat rate duration curves to project market prices consistent with forecasts of future natural gas and emissions prices. To understand the sensitivity of this projection to prevailing market conditions, we project prices based on a range of conditions from historical years.

⁴⁶ We note that mining costs vary widely between locations and coal quality and tend to increase with the maturity of the field as extraction becomes more difficult.

To project a baseline of future prices in Alberta's energy market, we multiply the 2009–2012 average market heat rates by the forecasted sum of future natural gas and carbon prices.⁴⁷ During scarcity, however, when prices are set by generator offers that are well above their variable costs, power prices are largely unaffected by the gas and carbon prices that determine variable costs. Therefore, we have decoupled our power price projections for these peak hours from gas and carbon prices, and simply rely on the 2009–2012 price duration curve to project future prices during peak hours (rather than the market heat rate duration curve). We assume that prices in hours with a market heat rate greater than 25GJ/MWh are set by offers above marginal costs, and this is used as the cutoff point between the two price projection methodologies. This assumption is based on the fact that generators' heat rates generally do not exceed this level.⁴⁸ The scarcity prices are assumed to increase with inflation in future years.

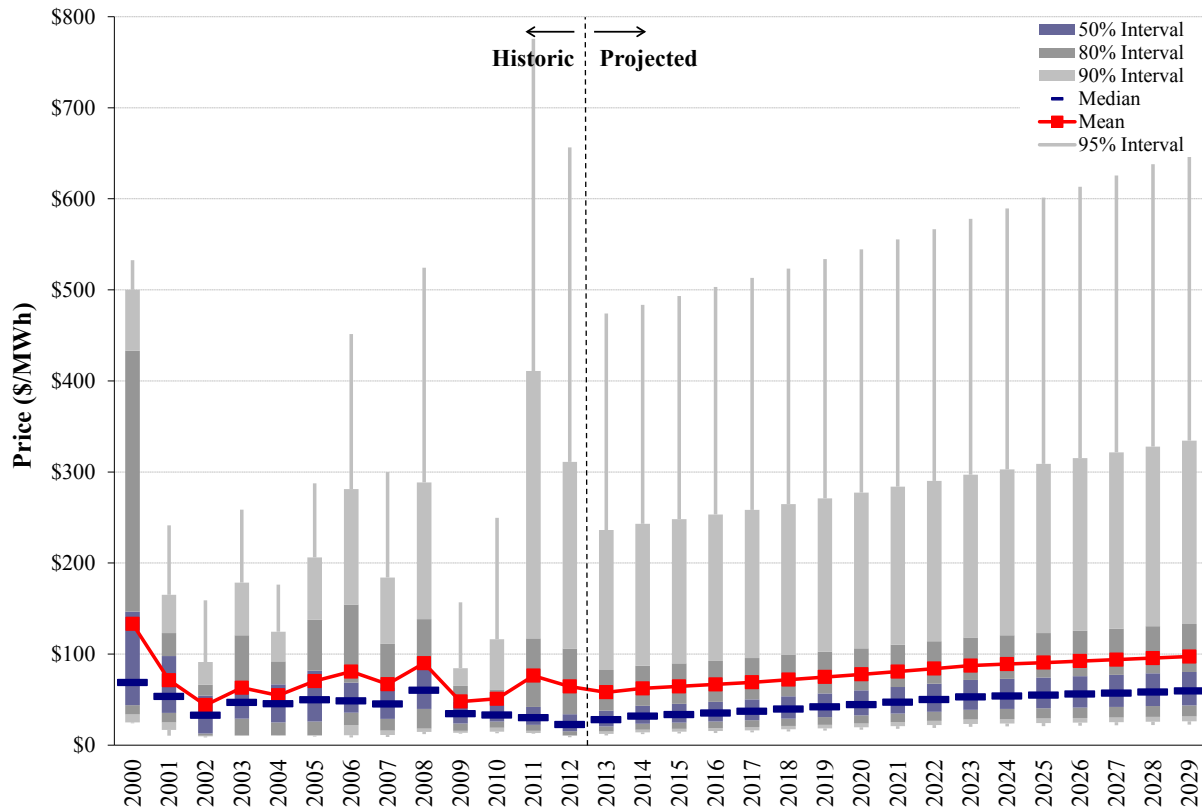
In light of the uncertainty regarding generators' offer behavior and other factors affecting market prices, we use the 2011–2012 and 2009–2010 average heat rate duration curves to project a high and a low range of future prices and operating margins.

Figure 12 shows the resulting prices for each year through 2029, including the average, median, and percentiles. The figure shows that if average market heat rate duration curve for the four year period from 2009 to 2012 is maintained going forward, average electricity prices can be expected to rise only slowly over the coming two decades, driven by increases in natural gas and carbon prices. We note that this projection yields peak-period prices that reflect the average of the lower peak-period prices observed in 2009–2010 and the much higher peak-period prices observed during 2011–2012. As noted, this projection does not account for potential long-term changes in fleet composition, dispatch patterns, or other potential changes in future market fundamentals.

⁴⁷ This is the reverse of the calculation used to determine historical market heat rates discussed in Section III.A. The calculation assumes a carbon content of natural gas of 0.0508 tonnes of CO₂e/GJ of gas. See Alberta Government (2007b).

⁴⁸ Furthermore, we examined a range of cutoffs above and below 25GJ/MWh and found that price and operating margin outcomes exhibit a low sensitivity to variation in this cutoff parameter between 15GJ/MWh and 30GJ/MWh.

Figure 12
Historical and Projected Market Prices
 (Projection Based on 2009–2012 Market Heat Rates and Scarcity Conditions)

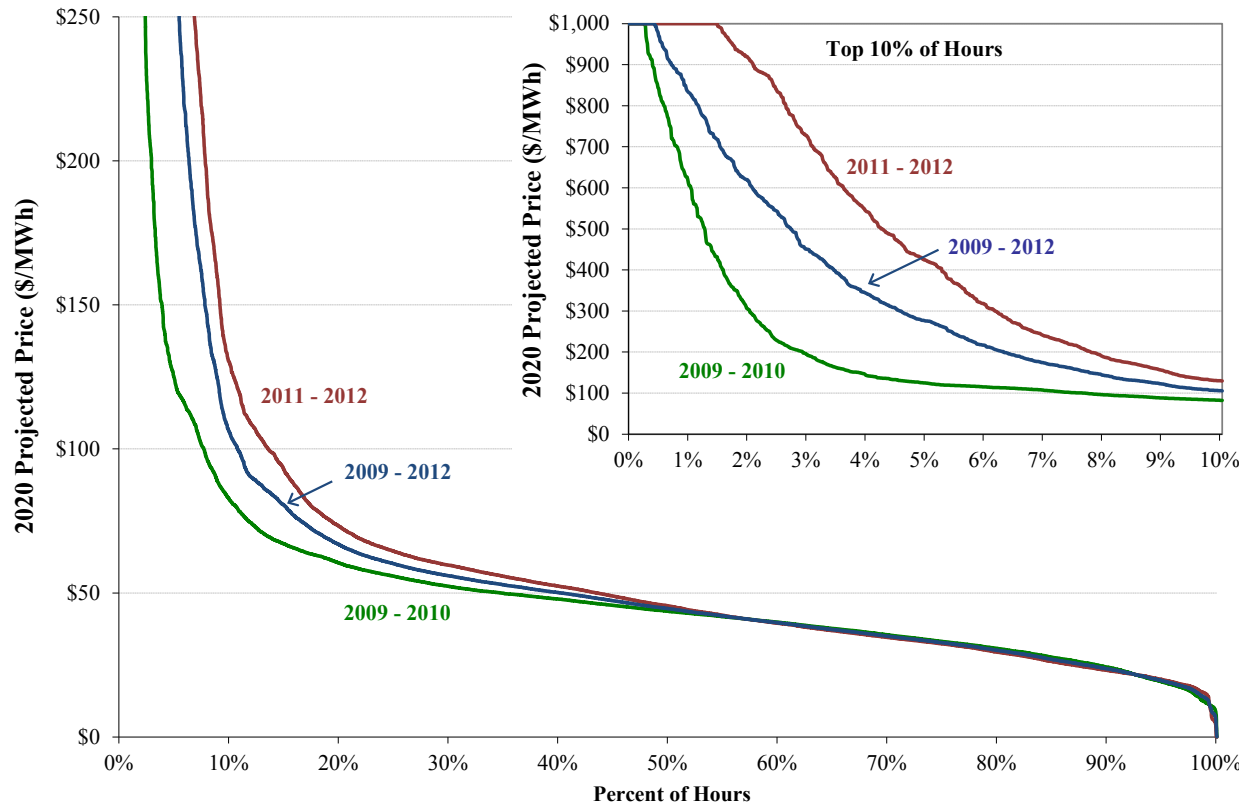


Sources and Notes:

Calculated based on 2009–2012 average heat rates and baseline natural gas and carbon prices.

The projected price duration curve for 2020 based on 2009–2012 average heat rates and scarcity pricing patterns is shown in Figure 13. The figure also shows projected prices based on the 2011–2012 and 2009–2010 market heat rates as high and low ranges, respectively. We believe this range reasonably reflects uncertainty about generators’ future offer behavior, load conditions, reserve margins, and system conditions. The range shows that using the high 2011–2012 market heat rates and scarcity prices results in higher projected prices at the top end of the duration curve, while prices at the lower end of the curve are very similar. Average projected prices in 2020 are \$78/MWh in the base case using 2009–2012 heat rates, while the projection based on 2011–2012 heat rates yields an average price of \$93/MWh and the 2009–2010 based projection yields an average price of \$61/MWh.

Figure 13
Year 2020 Projected Price Duration Curves
 (Projection Based on Historical Market Heat Rates and Scarcity Conditions)



Sources and Notes:

Projected prices based on historical heat rates and scarcity prices.

3. Projections of Generator Operating Margins vs. Fixed Costs

We use the projected price duration curves developed in Section IV.A.2 to project operating margins for each type of generating technology with the costs and operating characteristics described in Section III.B. As documented in Appendix B of our 2011 report, we make these projections in two steps. First, we determine the theoretical “perfect dispatch” margins for each type of generating plant by assuming that the unit generates energy during all hours when energy prices are above its variable operating costs (including fuel, emission prices, and variable operating and maintenance costs). Second, because generating units will not be dispatched perfectly against hourly energy prices due to startup costs, dispatch constraints, forced and planned outages, and imperfect price foresight, we apply a discount factor to translate the calculated perfect dispatch margins into realistic energy margins. These discounted energy margins are calculated as a linear function of perfect dispatch margins based on actual historical operating margins for each unit type. This calculation also takes into account periods during which generators provided operating reserves and were therefore unavailable to participate in the energy market. Projected operating reserves revenues are similarly estimated as a linear function of projected “perfect dispatch” margins, based on the historical relationship between the two for

each unit type.⁴⁹ Operating margins are then calculated by subtracting variable operating costs from the projected market revenues.

In the following figures, we compare these projected operating margins from the energy and ancillary service markets to the annualized fixed (capital investment and fixed operating) costs for gas CTs, gas CCs, gas cogen, wind, and coal plants. The stacked bars in the charts represent the total operating margins that a unit would receive based on projected future prices using 2009–2012 market heat rates and scarcity pricing patterns. The uncertainty range shows the range of margins under a projection of future market prices based on 2011–2012 heat rates at the high end and 2009–2010 heat rates at the low end. The format of these figures is similar to those presented in Section III.B. If projected operating margins on average exceed the annualized fixed cost of a new plant, the investment would be profitable. If projected operating margins on average are below the cost of a new plant, that would discourage new entry.

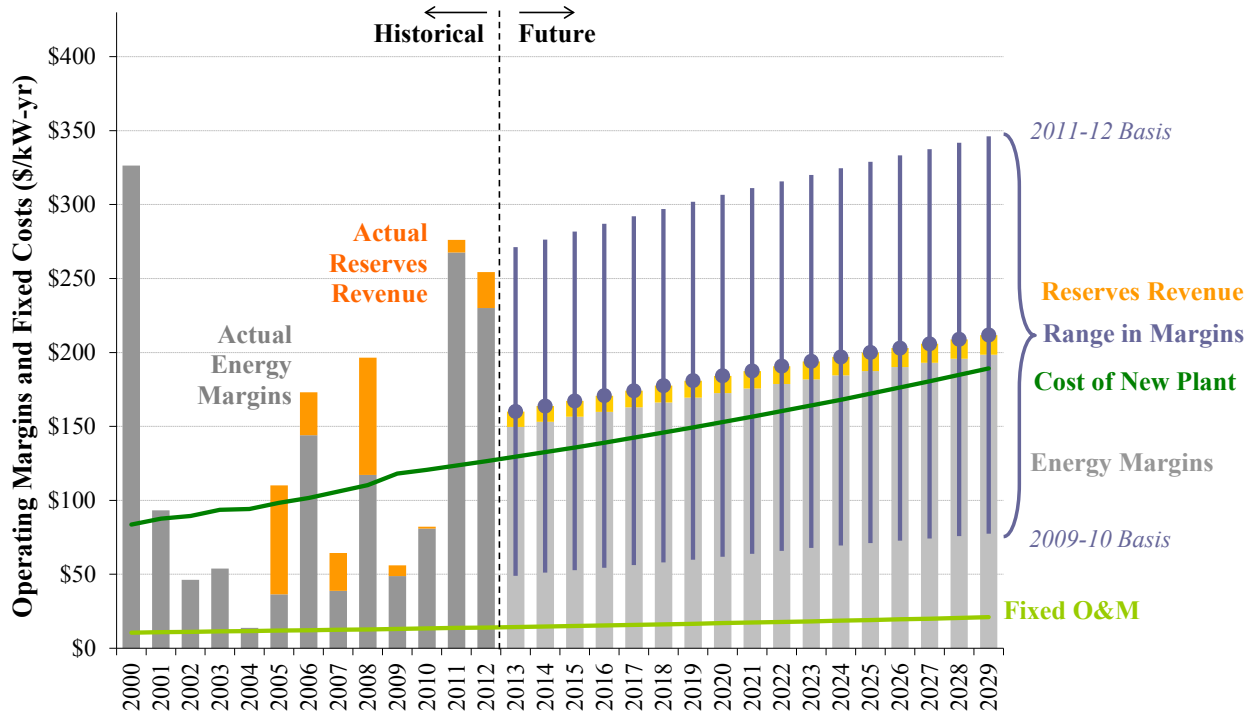
The projected operating margins indicate that the prospects for new entry are promising for all natural gas technologies (CTs, CCs, and cogen). On the other hand, wind and coal plants are unlikely to be attractive investments when projecting current market conditions into the foreseeable future. For natural gas plants, operating margins are likely to exceed their annualized fixed costs if recent market conditions persist on average going forward. Only a sustained return to the low market heat rates and scarcity pricing patterns observed during 2009 and 2010 would make investment in plants uneconomic. On the other hand, if the more recent pricing patterns of 2011 and 2012 were to continue, the operating margins for new gas plants would exceed their annualized costs by a considerable margin. As we noted in our 2011 report, it appears that natural gas cogen investments are the most attractive new generation investments, assuming sufficient steam demand exists in oil sands and other sectors.

Consistent with our 2011 market review, we continue to project that even conventional coal generation is unlikely to be an attractive investment in the future. Coal generation is even less attractive, given the recently approved federal legislation that effectively prevents coal without carbon capture and storage (CCS) from being built. However, future operating margins are still projected to be many times higher than the fixed operating and maintenance costs of existing coal plants. As a result, existing coal units are unlikely to retire absent mandated large capital expenditures or the forfeiture of substantial amounts of regulated decommissioning cost recovery.

⁴⁹ For more detail, see Pfeifenberger and Spees (2011a), Appendix B.

Figure 14

Projected Natural Gas CT Operating Margins vs. Fixed Costs

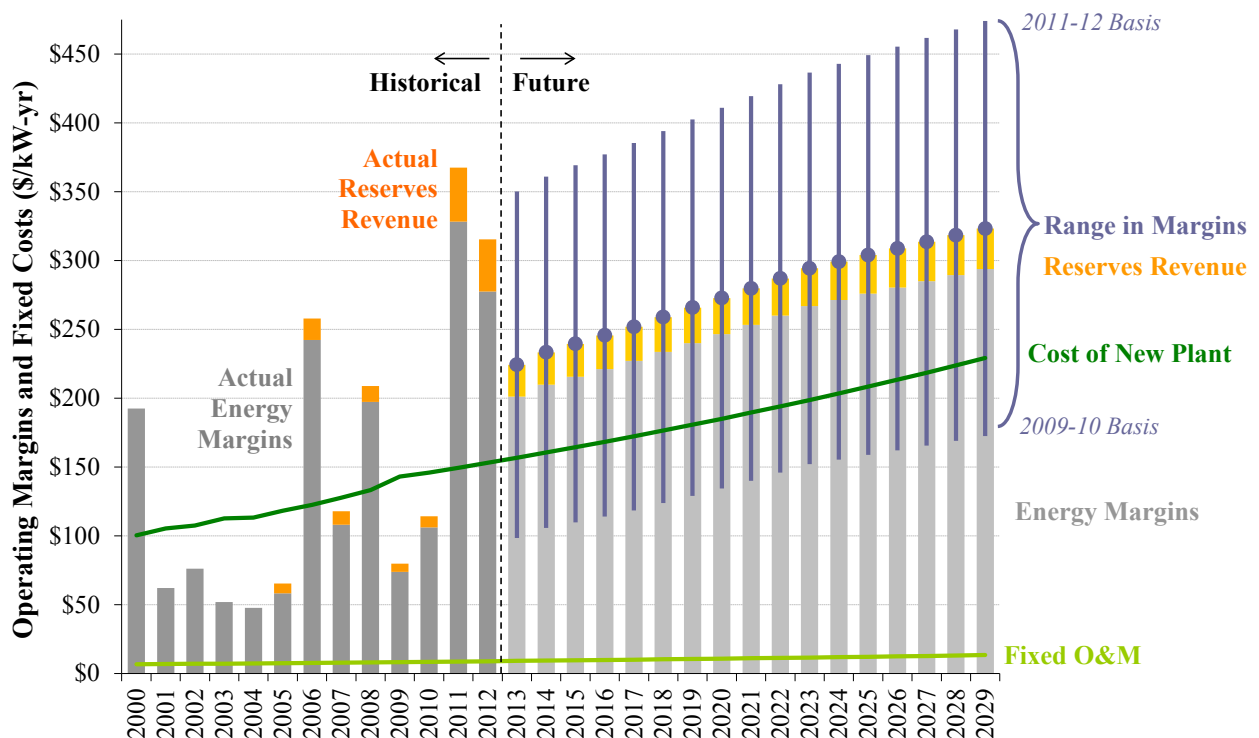


Sources and Notes:

Reference projected margins based on 2009–2012 heat rates. Cost of new plant includes FOM, and is escalated at 2.4%.

Figure 15

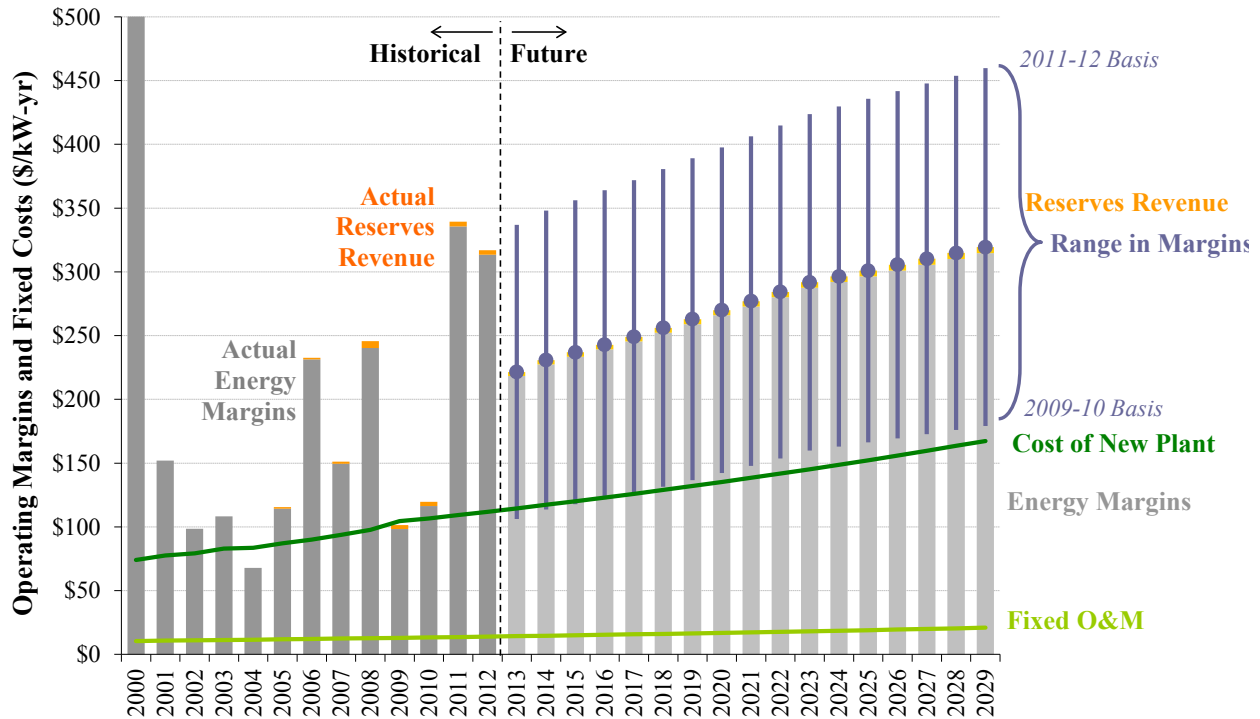
Projected Gas CC Operating Margins vs. Fixed Costs



Sources and Notes:

Reference projected margins based on 2009–2012 heat rates. Cost of new plant includes FOM, and is escalated at 2.4%.

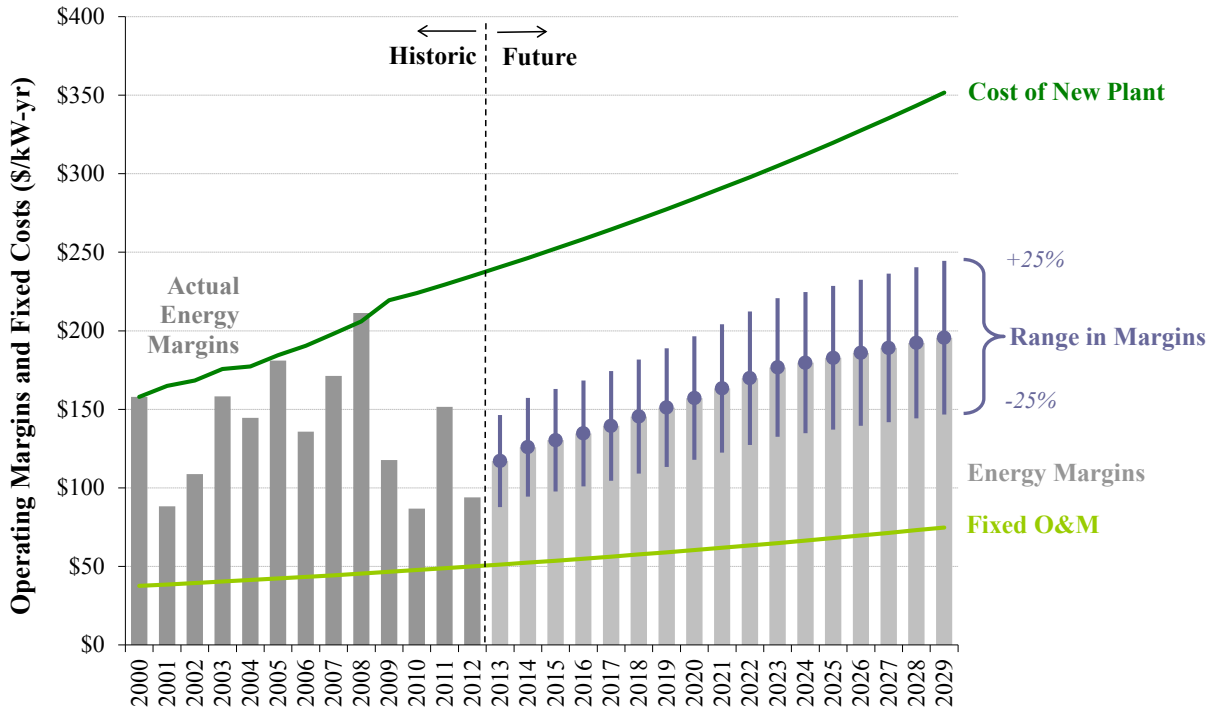
Figure 16
Projected Gas Cogen Operating Margins vs. Fixed Costs



Sources and Notes:

Reference projected margins based on 2009–2012 heat rates. Cost of new plant includes FOM, and is escalated at 2.4%.

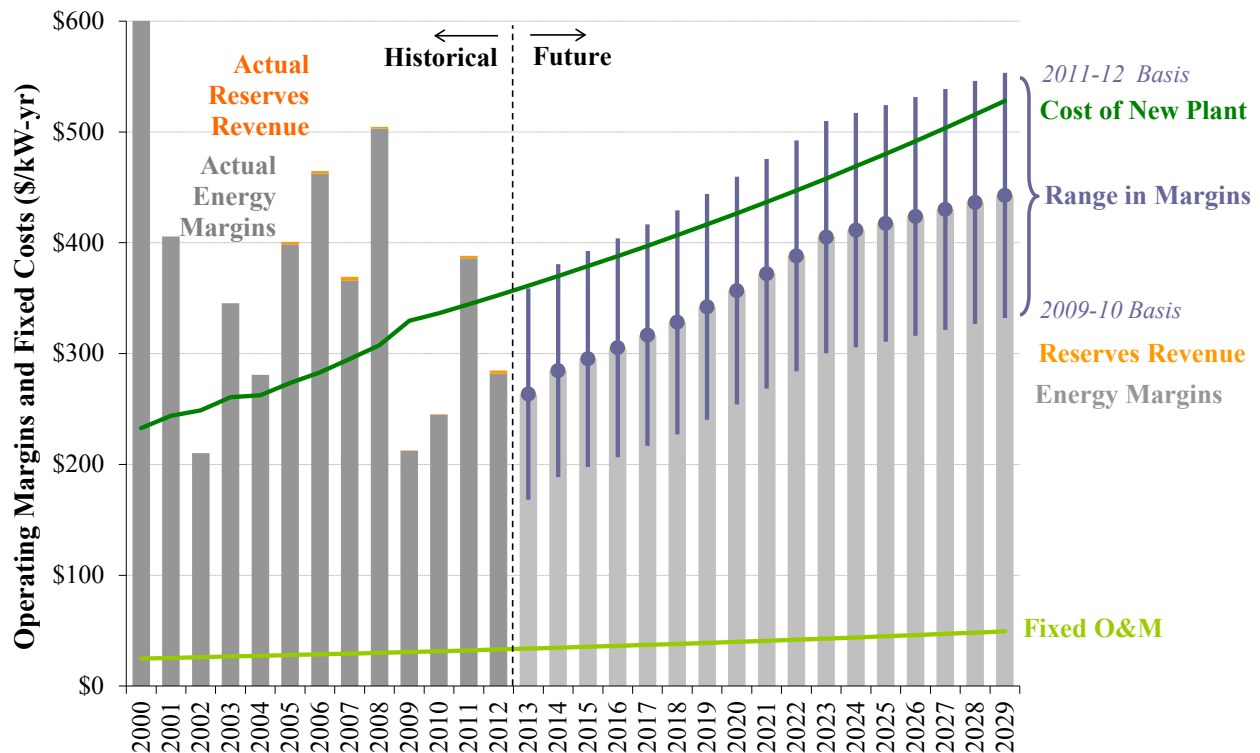
Figure 17
Projected Wind Operating Margins vs. Fixed Costs



Sources and Notes:

Reference projected margins based on 2009–2012 heat rates. Range in margins is assumed to be 25%, based on approximate variation in historical margins.

Figure 18
Projected Coal Operating Margins vs. Fixed Costs



Sources and Notes:

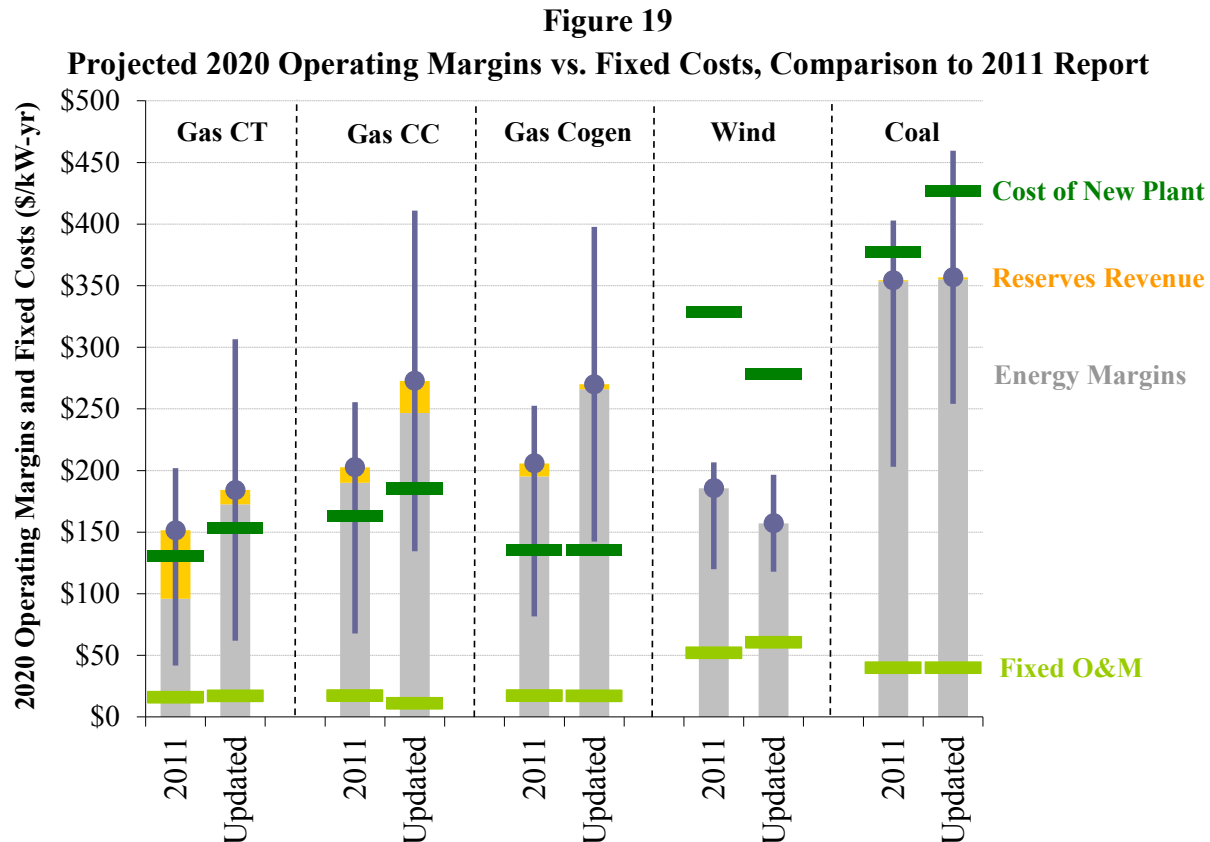
Reference projected margins based on 2009–2012 heat rates. Cost of new plant includes FOM, and is escalated at 2.4%.

Figure 19 compares these updated projections of generator margins for 2020 to those from our 2011 analysis. This comparison shows that projected operating margins have improved for natural gas plants despite the fact that plant costs have increased. The increase in projected margins is primarily driven by the higher market heat rates and scarcity prices for the 2009–2012 baseline we use in our current analysis, relative to the 2006–2010 baseline we used previously.

For coal generation, however, investment prospects have declined somewhat compared to our previous analysis, because estimated plant costs have increased while projected margins are nearly unchanged. The impact of increased market heat rates was almost entirely offset by the negative effect an approximate \$1/GJ drop in the projected 2020 natural gas prices, resulting in a nearly constant projection for operating margins for coal plants.⁵⁰ Changes in projected coal and carbon prices had a minor impact on projected coal operating margins. Operating margins also decreased for wind plants, but that decline is more than offset by lower plant costs.

Lastly, we note that the high end of the projected range of operating margins has increased substantially. This reflects the fact that projected operating margins for gas-fired technology types would exceed their annualized fixed costs by a considerable margin if the higher peak-period prices observed in 2011 and 2012 were to continue.

⁵⁰ The projected annual average 2020 gas price at AECO C in the 2011 report was \$5.71/GJ, compared to \$4.80/GJ currently.



Sources and Notes:

Reference projected margins based on 2009–2012 heat rates. Cost of new plant includes FOM and is escalated at 2.4%. 2011 projections from Pfeifenberger and Spees (2011a) reference projections for 2020. The high and low ranges in the 2011 projections represent the minimum and maximum projections based on individual years from 2001–2010. Range in wind margins is assumed to be 25%, based on approximate variation in historical margins.

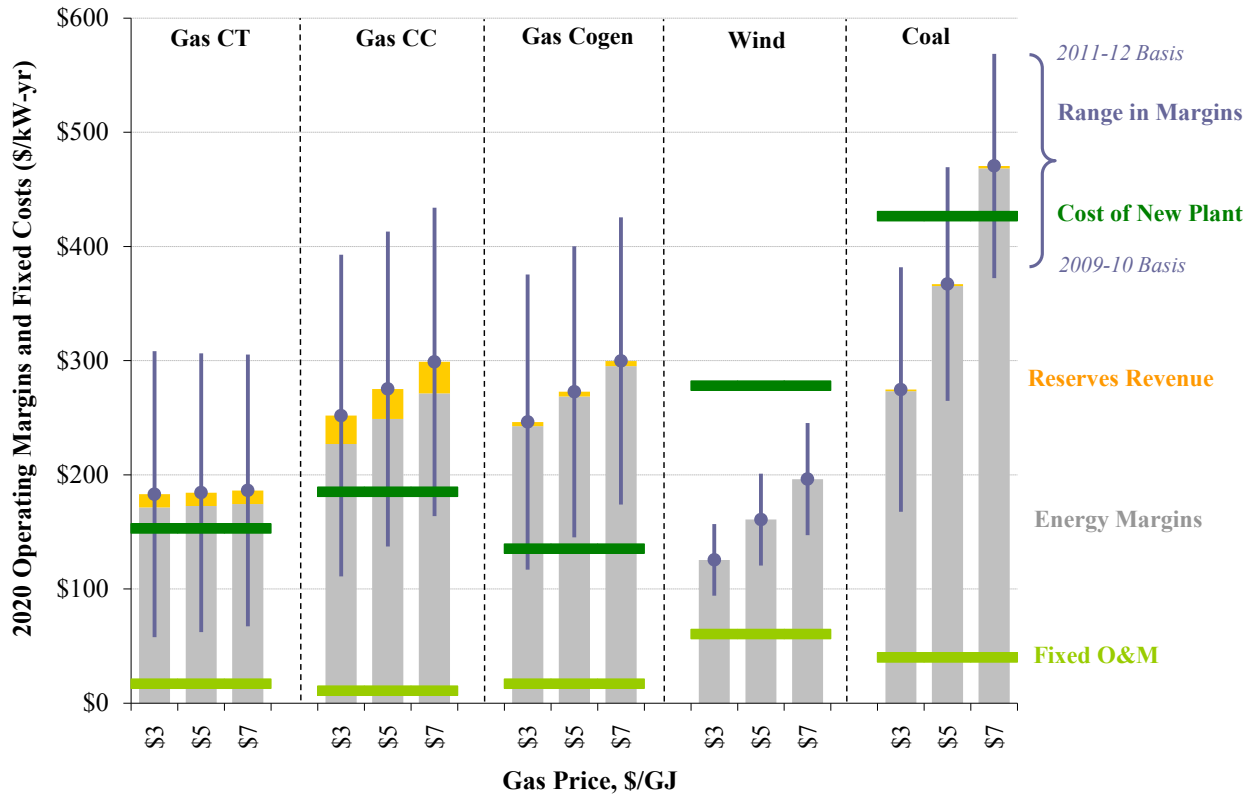
4. Sensitivity Analysis of Projected Margins vs. Fixed Costs

The results presented in Section IV.A.3 indicate that current Alberta market conditions make investments in natural gas plants attractive. We now evaluate the robustness of this conclusion under sensitivities for natural gas prices, plant costs, and the required return on investment.

Figure 20 summarizes the sensitivity of projected margins to variation in natural gas prices. The figure shows projected operating margins by technology type for the year 2020 for gas prices ranging from \$3/GJ to \$7/GJ. Based on future prices projected with 2009–2012 market heat rates, new natural gas plants are all projected to be attractive investments under a wide range of prices, irrespective of technology. New coal generation, in contrast, is likely to be attractive only at gas prices at or above approximately \$6/GJ (before considering costs for mandated carbon capture and storage). These results also show that operating margins for coal generation are (1) significantly above the fixed operating and maintenance costs of existing coal plants at any level of natural gas prices; and (2) the most sensitive to changes in the gas price. Finally, Figure 20 shows that in the absence of other revenue sources—such as tax credits, carbon offsets, and renewable energy credits—wind generation is not financially attractive in Alberta even at natural gas prices of \$7/GJ.

Figure 20

Projected 2020 Operating Margins vs. Fixed Costs, Gas Sensitivity



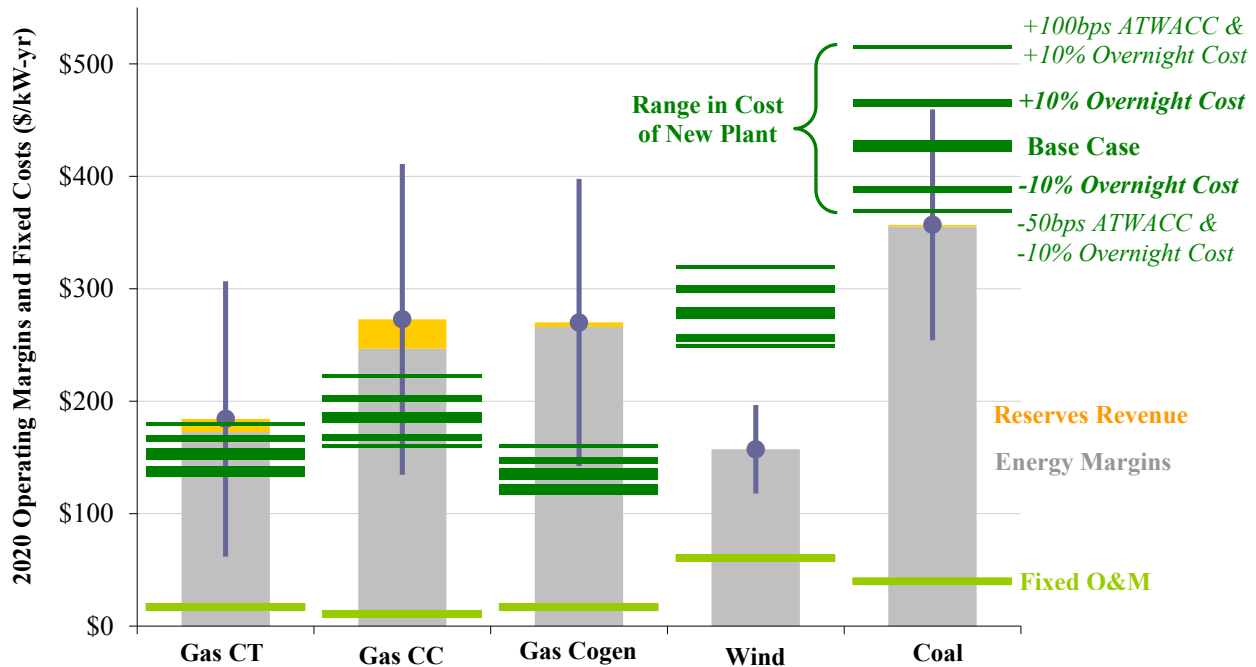
Sources and Notes:

Reference projected margins based on 2009-12 heat rates. Cost of new plant includes FOM, escalated at 2.4% annually.
Range in wind margins is assumed to be 25%, based on approximate variation in historical margins.

We note again that this analysis is based on market prices projected based on the recently-observed market conditions. It does not account for any regulatory or policy changes, nor potential long-term changes in market fundamentals due to changes in generation mix, dispatch patterns, intertie capacity, or the bidding behavior of market participants in response to changes in gas prices.

Figure 21 shows the sensitivity of these results to variation in the levelized cost of a new plant. We examined a 10% range in overnight costs, and a wider range which reflects an incremental 100 basis point increase and 50 basis point decrease in the ATWACC, in addition to the variation in overnight costs. This range in the ATWACC reflects possible variation from a low of 7.5% to a high of 9.0%, as explained in Section III.B. The figure shows that variation in plant costs would not change our reference case projection that the prospects for new entry are promising for all natural gas technologies.

Figure 21
Projected 2020 Operating Margins vs. Fixed Costs, Plant Costs Sensitivity



Sources and Notes:

Reference projected margins based on 2009–2012 heat rates. Cost of new plant includes FOM, escalated at 2.4% annually. Range in wind margins is assumed to be 25%, based on approximate variation in historical margins.

B. SIMULATION-BASED ESTIMATES OF FUTURE MARKET PRICES

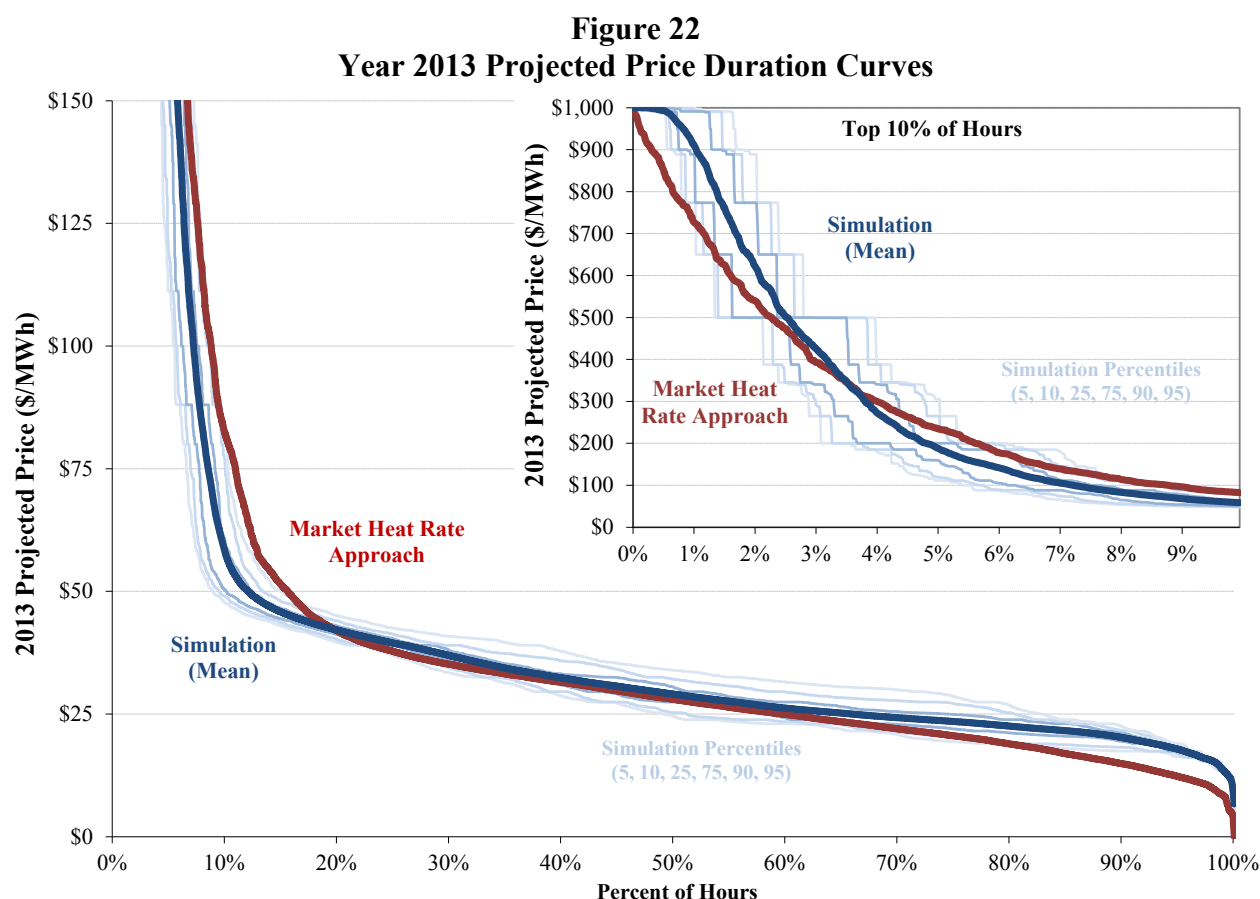
Our second approach to projecting market prices is based on simulation results produced by the AESO for the purposes of this study using a market simulation model. The simulations were performed for the year 2013. A reference case was modeled to provide a comparison to the results of our market heat rate-based projections for 2013 (which reflects recent market conditions adjusted for 2013 projected natural gas prices), and a range of reserve margins was then modeled to examine the impact of changes to the reserve margin on market outcomes and generator investment cost recovery. The simulation modeling also allowed us to examine the market impacts of increasing the price cap and implementing scarcity pricing reforms.

1. 2013 Reference Case

The year 2013 was modeled as a reference case, with load, generation capacity, fuel prices, and other inputs from the AESO. The simulations were performed for 101 full-year iterations, with random variation in inputs such as load, forced generation outages, and natural gas prices. Realistic hourly wind generation profiles and their contributions to scarcity and surplus events were modeled as well.

Figure 22 shows the price duration curve projected by the simulations for 2013, as well as the 2013 price duration curve projected with the market heat rate-based approach. The price projections are similar across the duration curves, and annual average prices in the simulation-based projection are \$60/MWh, compared to \$58/MWh in the market heat rate-based projection. Peak-period prices were also quite similar—in the top 15% of hours, average prices are \$241/MWh in the simulations and \$238 in the market heat rate projection.

The 101 annual iterations for the 2013 base case also provide insights into the likely variability of market prices caused by uncertainties in load, forced generation outages, and fuel prices. This variability is shown by the light blue duration curves in Figure 22, which represent the prices at several intervals from the 5th percentile to the 95th percentile of the 101 model iterations. Annual average prices range from \$49/MWh for the 5th percentile to \$73/MWh for the 95th percentile.



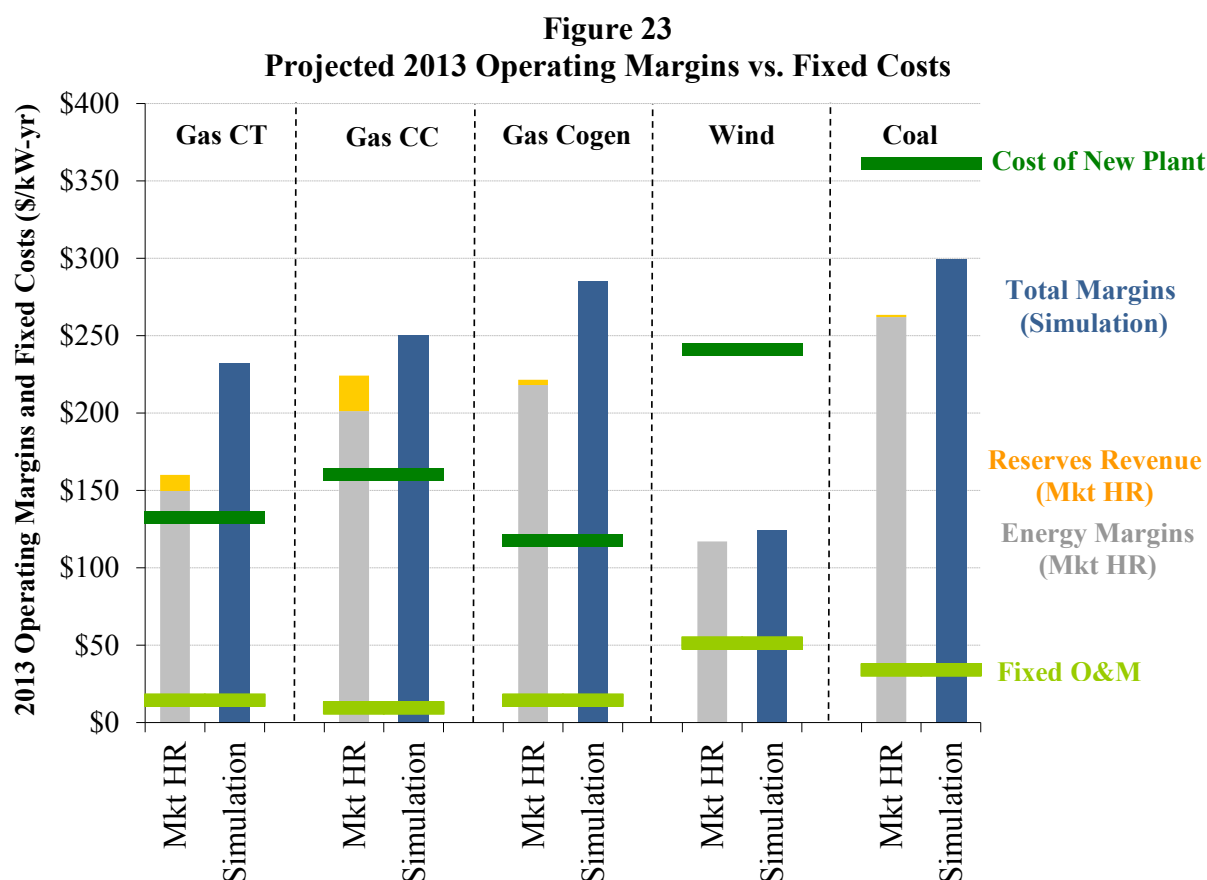
Sources and Notes:

Model results from AESO (2013). Note that fewer hours at the price cap are projected in 2013 than in 2020, as shown in Figure 13.

Generator operating margins in the simulations were calculated based on the simulated generation patterns of recently-built units with characteristics similar to those of likely new builds. For simplicity, all units were modeled to sell their entire output into the energy market rather than withholding a portion of their capacity to sell operating reserves. The resulting operating margins should therefore be compared to the total margins estimated in the market heat rate approach, rather than just to the energy margins.

Figure 23 compares the projected 2013 operating margins from both approaches against the levelized fixed costs of a new plant. Results are shown for each of the five generation types. The simulated operating margins exceed levelized fixed costs for the three gas-fired generation types, which supports our conclusion that investment conditions are favorable for gas-fired generation. The simulated operating margins for wind and coal generation are less than the levelized costs of these plants, which is also consistent with the results of our market heat rate-based approach.

We note that the simulated operating margins are somewhat higher than the corresponding market-heat-rate-based projections. As explained in Section IV.A.3, generating units are not dispatched perfectly against hourly energy prices due to startup costs, dispatch constraints, forced and planned outages, and imperfect price foresight. A comparison of the hourly generating patterns of these units in the simulations against historical generation patterns suggests that the simulated operating margins may be somewhat overstated due to dispatch patterns that are unrealistically optimal. While we do not fully address this issue in this report, it is likely that the projected operating margins calculated in the market heat rate-based approach—which were calibrated based on the operating margins of historical units—are more representative than the operating margins based on the simulation modeling.^{51,52}



Sources and Notes:

Model results from AESO (2013), with further analysis. Results are averaged across 101 annual simulations.

⁵¹ See Appendix B in Pfeifenberger and Spees (2011a) for a full description of our method of calculating operating margins in the market heat rate-based approach.

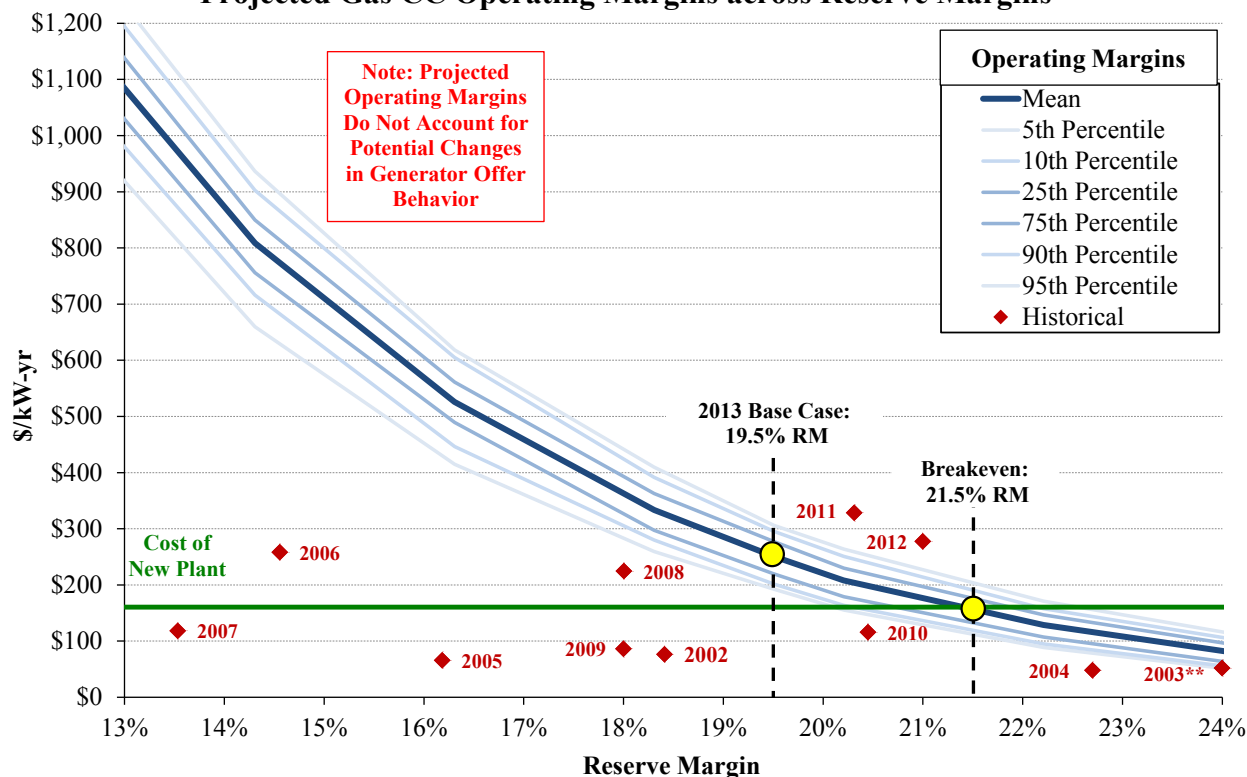
⁵² The range in margins from each of these approaches is not shown in Figure 23 because they are largely not comparable. The range across iterations in the simulations represents random variation in inputs such as load, forced outages, and fuel prices. In contrast, the range from the market heat rate approach represents the difference between 2009-2010 historical market conditions and 2011-2012 historical market conditions, which was largely driven by a change in generators' offer behavior, as explained in Section III.A.

2. Market Impacts of Changes to the Reserve Margin

As explained in our 2011 report, an important feature of an efficient and well-functioning energy-only market is its ability to produce prices consistent with overall supply and demand conditions. This means that when reserve margins are tight and new generation is needed, price levels must be high enough to retain existing supply and attract new investment. It also means that when reserve margins are high and no new capacity is needed, prices should be low enough to discourage new investments and prevent over-building the system.⁵³

To examine the relationship between generator earnings and the system reserve margin, the AESO simulated a range of reserve margins, holding generator offer behavior constant at the average observed behavior of the last four years. The resulting operating margins for a gas CC are shown in Figure 24, along with the estimated levelized fixed cost of a new gas CC. The variability in operating margins between the 5th and 95th percentiles from the 101 simulated iterations are shown in light blue, while the mean is shown in dark blue. Figure 24 also shows historical reserve margins and annual generator operating margins for gas CCs in red.

Figure 24
Projected Gas CC Operating Margins across Reserve Margins



Sources and Notes:

Model results from AESO (2013), with further analysis. AIES reserve margin data provided by the AESO, consistent with the February 2013 LTA. ** The reserve margin in 2003 was 24.7%.

The simulation results indicate that generators' operating margins would increase substantially at lower reserve margins and decrease at higher system reserve margins. The relationship between

⁵³ See Pfeifenberger and Spees (2011a), p. 49.

actual historical operating margins and actual system reserve margins, however, is strikingly different. There are several years with low historic reserve margins and relatively low operating margins (such as 2007 and 2005), while there are also other years with high reserve margins and relatively high operating margins (such as 2011 and 2012). The primary reason that the simulation results are inconsistent with the historical data likely is that generators' offer behavior was held constant in the simulation.⁵⁴ Specifically, generators' offer behavior was simulated to be approximately equal to the average behavior observed across the four year period from 2009 to 2012. This is consistent with the market heat rate-based approach, where average heat rates from 2009 to 2012 were used as the basis for the reference case projected margins. We note that projected operating margins in the simulations would be higher if the offer behavior observed in 2011 and 2012 were simulated, and would be lower if the 2009 and 2010 offer behavior were simulated.

While we believe it is unlikely that the high operating margins projected by the model would actually materialize for the lower reserve margins, future offer behavior is quite uncertain and we did not attempt to model future changes in offer behavior. Nevertheless, historical changes in the offer behavior of incumbent generators have substantially affected historical operating margins. This means that future changes may substantially affect future operating margins, which may cause non-incumbents to discount future operating margins when making investment decisions. If this were the case, the high observed generator operating margins would not necessarily provide clear investment signals and unambiguously support new entry.

In its 2012 State of the Market Report, the MSA noted it that if new entrants were dissuaded from investing because they believe prices are only high temporarily due to market participant control, it would constitute a strategic barrier to new entry. While the MSA concluded that past investments indicate that barriers to new entry have not rendered the market uncompetitive, the MSA also recommended continued monitoring of the issue.⁵⁵ Further, the MSA noted in December 2012 that it would initiate further inquiry into barriers to new entry if prices remain high enough to support new entry but investment does not occur.⁵⁶ We concur and recommend monitoring of new generation investments in response to the observed price signals.

3. Market Price Cap and Scarcity Pricing Mechanisms

As we explained in our 2011 study, we recommend increasing Alberta's energy market price cap to a level consistent with the value of lost load (VOLL), implementing a formal administrative scarcity pricing mechanism during shortage periods, and reducing the price floor below zero.

The current market price cap of \$1,000/MWh is substantially below the average VOLL in Alberta. The VOLL reflects the price that curtailed customers would have been willing to pay on average to avoid being interrupted. It consequently also is the efficient market price during involuntary load-shed events. If energy market prices are allowed to rise to VOLL, it is likely that some market participants will be willing to reduce a portion of their load voluntarily at prices below VOLL. Mobilizing such price-based "demand response" would mean that involuntary load shedding would not be needed during severe scarcity events. The higher

⁵⁴ Other factors including changes in gas prices and fleet composition likely also explain some of the difference.

⁵⁵ See MSA (2012d), pp. 21-22.

⁵⁶ See MSA (2012g), p. 25.

possible market prices would also provide increased incentives for generator operational performance during scarcity events.

Additionally, an administrative scarcity pricing mechanism which gradually increases energy prices above \$1,000/MWh during Energy Emergency Alert (EEA) events when contingency reserves are depleted would better reflect the marginal system costs of depleting reserves and would ensure that prices during scarcity increase gradually. This would also be helpful for the successful integration of demand response into price formation. A number of other markets have recognized the importance of high prices at or near VOLL during scarcity, and have increased their price caps and implemented administrative pricing mechanisms for contingency reserves depletion.⁵⁷

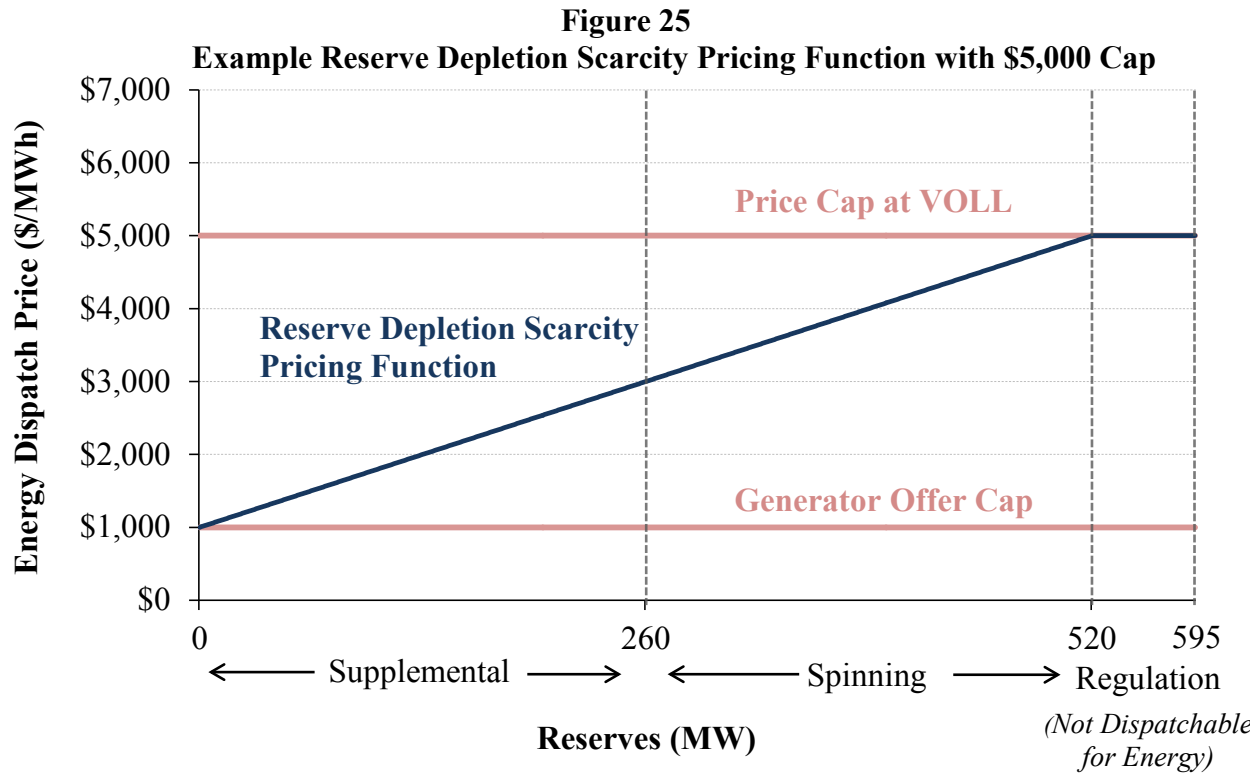
To illustrate the potential market impacts of such scarcity pricing reforms, we analyzed the impact of a \$5,000/MWh price cap in combination with a simple administrative scarcity pricing mechanism.⁵⁸ Under most conditions Alberta pool prices would not change, with prices set by generator offers and rising up as high as the generator offer cap of \$999.99/MWh if supply becomes short, but is not fully exhausted. In the unusual events that the available supply *is* exhausted and AESO must begin depleting operating reserves, prices would be set administratively according to a reserves depletion price shown schematically in Figure 25. The pool price would gradually rise from the generator offer cap of \$999.99/MWh as supplemental and spinning reserves are depleted, and would reach \$5,000/MWh after all contingency reserves are depleted and load is shed. While we do not explicitly model additional demand response penetration in this analysis, incremental price response would likely materialize if such high prices were possible. In that case, prices would be set at the equilibrium level determined jointly by the administrative scarcity pricing function and price responsive demand.

The AESO also undertook market simulations to model scarcity events consistent with the AESO's operating procedures, allowing us to examine the potential impacts of scarcity pricing reform. When load exceeds available capacity in the simulation, supplemental reserves are depleted first; spinning reserves are depleted next; and firm load is shed as a last resort.⁵⁹ Table 5 summarizes the frequency of EEA events estimated in these simulations for year 2013 compared to historical averages. The projected frequency of events in 2013 is similar to the past, with somewhat fewer supplemental reserves depletion events, somewhat more spinning reserve events, and a very similar frequency of load shed events.

⁵⁷ ERCOT, CAISO, MISO, ISO-NE, PJM, and NYISO have recently implemented reserve depletion pricing. Several of these RTOs implemented scarcity pricing reforms in response to the U.S. Federal Energy Regulatory Commission's Order 719, which required system operators to examine price formation during scarcity conditions, including assuring that sufficient incentives for demand response are provided and that prices accurately reflected high system-related costs during reserves depletion.

⁵⁸ This modeling work was implemented by the AESO in collaboration with us, using the same modeling techniques described in the previous two sections.

⁵⁹ In evaluating this, 260 MW of both supplemental and spinning reserves were modeled. Reserves and firm load shed were modeled as pseudo-generators. Emergency imports were not modeled.



Sources and Notes:

Typical reserves quantities from AESO (2013).

Table 5
Frequency of Simulated and Actual Historical Emergency Events

Reserves Depletion Events	2000 - 2012 Historic Avg. (hrs/yr)	2006 - 2012 Historic Avg. (hrs/yr)	2013 Model Output (hrs/yr)
Supplemental (EEA1)	6.3	10.5	4.1
Spinning (EEA2)	0.5	0.9	0.9
Firm Load Shed (EEA3)	0.3	0.5	0.4

Sources and Notes:

Historical and model data from AESO for model year 2013. Results averaged across 101 iterations.

EEA1 corresponds to depleting supplemental reserves; EEA2 corresponds to depleting spinning reserves; and EEA3 corresponds to shedding firm load, from AESO (2012a).

Table 6 shows the simulated energy price impact of increasing the price cap to \$5,000/MWh and introducing a linear reserve depletion pricing function on annual average market prices, relative to the current \$1,000/MWh price cap with no reserve depletion pricing. With these changes, annual average prices would increase by less than \$1/MWh because higher prices would only be realized during reserve depletion events, which occur for only a few hours per year as shown in Table 5 above.

Table 6
Estimated Average Annual Price Increase
From Increasing Price Cap and Introducing Administrative Scarcity Pricing

Market Price Cap (\$/MWh)	Reserves Shortage Pricing Function	Annual Average Price (\$/MWh)	Price Increase (\$/MWh)
\$1,000	None	\$60.24	n/a
\$5,000	Linear	\$61.04	\$0.80

Sources and Notes:

AESO model results, AESO (2013). Results are averaged across 101 model iterations.

Table 7 shows the frequency of emergency events projected by 101 annual simulations runs for each of the shown reserve margins. The simulated frequency of emergency events is more than ten times greater at a 12% reserve margin than at the current 19% reserve margin.

Table 7
Frequency of EEA Events across Reserve Margins

		Reserve Margin							
		12%	14%	16%	18%	19% (2013)	20%	22%	24%
Reserves Depletion Events									
Supplemental (EEA1)	(hrs/yr)	50.3	25.3	12.8	6.3	4.1	3.3	1.3	0.6
Spinning (EEA2)	(hrs/yr)	18.4	9.0	4.3	1.7	0.9	0.6	0.3	0.1
Firm Load Shed (EEA3)	(hrs/yr)	8.7	3.8	1.6	0.5	0.4	0.3	0.2	0.1

Sources and Notes:

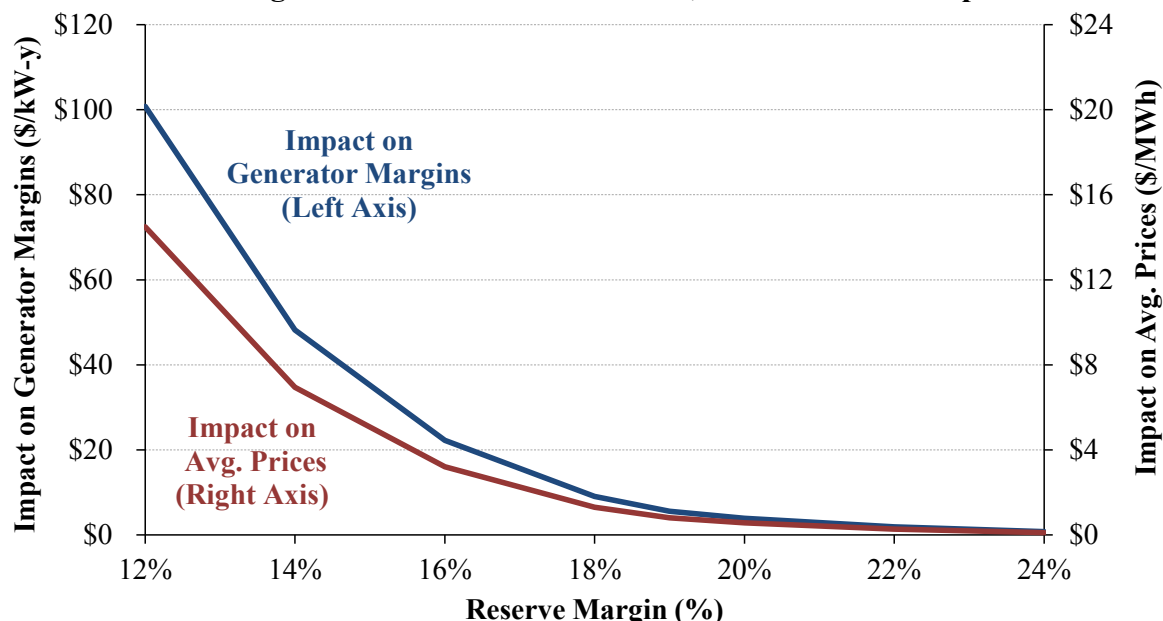
Model results from AESO (2013). Results averaged across 101 model iterations at each reserve margin.

Figure 26 shows the estimated impact of a \$5,000/MWh price cap and linear reserves depletion function on generators' operating margins and annual average prices across reserve margins, relative to the current price cap. This scarcity pricing reform would increase generators' operating margins by approximately \$6/kW-year compared to the current cap at the anticipated 19% reserve margin in 2013.⁶⁰ More importantly, however, the scarcity pricing reform would help ensure that investment returns rise as reserve margins decline, because scarcity events and associated scarcity prices are more frequent at low reserve margins. The impacts are moderate at high reserve margins, but begin to increase significantly below a reserve margin of approximately 15%. The pronounced increase in additional operating margins for generation

⁶⁰ Due to forced outages, generators are unable to operate in all scarcity events. We estimate the impact of scarcity pricing on operating margins by assuming that generators are only able to operate during 80% of scarcity event-hours. This assumption is generally consistent with the historical generation patterns of several coal and combined-cycle gas plants that operated in approximately 80% of historical EEA event-hours. The implied outage rate of approximately 20% is likely higher than annual average forced outage rates due to the causal link between generator outages and EEA events. Generation data from Ventyx (2012), EEA event data from AESO (2012a).

resources at low reserve margins would substantially increase the incentive to construct new generation when reserve margins are tight, especially for combined-cycle and peaking units which have lower fixed costs and earn a greater fraction of their total operating margins and associated investment returns during scarcity periods. Importantly, this increase in operating margins at low reserve margins would not be sensitive to any changes in generators' offer behavior, which would create a stable investment signal.

Figure 26
Average Impacts of a \$5,000/MWh Price Cap and Linear Reserve Function across Reserve Margins Relative to the Current \$1,000/MWh Price Cap



Sources and Notes:

Model results from AESO (2013).

We estimated the impact on generator margins based on simulated prices, but assumed that generators would operate in 80% of emergency conditions, consistent with historical generation patterns of several coal and combined-cycle gas units.

The simulation results provide a valuable insight into the severity of load shed events and the amount of incremental demand response or other supply that would be needed to avoid them. The results indicate that an incremental 200 MW of demand response or other supply would be sufficient to avoid 60% of all firm load shed events, and that an incremental 500 MW would be sufficient to avoid 95% of events, at a 19% reserve margin. These quantities are in addition to 200 MW of existing price-responsive load already included in the model. We emphasize that scarcity prices greater than \$1,000/MWh would provide significant additional incentives for demand response and increased imports. It would also provide additional incentives to increase plant availability (with reduced forced outage rates) during scarcity periods.

Today's relatively high reserve margin and positive outlook for generation investment presents an unique opportunity to implement price cap and scarcity pricing refinements in a deliberate manner. These reforms could be implemented with minimal market impacts at the current high reserve margins when scarcity events are rare, but provide significantly improved investment and performance signals should reserve margins decline in the future.

V. FINDINGS AND RECOMMENDATIONS

Overall, we reiterate our conclusion from 2011—our updated analysis confirms that, from a resource adequacy and generation investment perspective, the Alberta electricity market is generally well functioning based on current market conditions and policies. The current market design should be able to address the identified resource adequacy challenges and there is no compelling or immediate need for major design changes to address these challenges. Nevertheless, considering both our 2011 review and this update, we offer the following set of recommendations to safeguard the continued sustainability of Alberta’s market from a resource adequacy perspective:

1. *Continue to Monitor Physical Resource Adequacy Metrics* to assure that the AESO, regulators, and market participants have a full understanding of the resource adequacy situation in the Province. In addition to the already ongoing monitoring of the 2-5 year resource adequacy outlook by the AESO,, we recommend evaluating:
 - Physical reliability metrics such as Normalized Expected Unserved Energy (EUE) over a range of possible reserve margins (in addition to the current approach of estimating expected unserved energy at the anticipated reserve margin), which will confirm how many unanticipated retirements or construction delays the system could withstand before experiencing reliability concerns;
 - Retirement schedules and associated system reserve margins; and
 - The actual resource adequacy value of non-traditional resources, *i.e.* the effective reserve margin contribution of resources such as wind, demand response, hydro, and interties.
2. *Continue to Monitor Economic Resource Adequacy Metrics* to identify potential difficulties in attracting needed investments before they arise, including:
 - Trends in market heat rates and the long-term outlook for technology-specific operating margins;
 - The market price impacts of increasing wind generation and potential inertia expansions; and
 - The ability of the market to attract financing of generation investments, including from non-incumbent generators.
3. *Build on the Recent RRO Review to Evaluate the RRO’s Impact on Forward Contracting* and determine whether it results in inefficiently low levels of forward contracting. If so, it may be possible to revise RRO forward procurement or encourage customers to switch to competitive retail suppliers to develop a more efficient portfolio of short, medium, and longer-term contracts.
4. *Avoid Policies that Create Large Simultaneous Retirement Pressures:*
 - Continue to monitor the impact of existing policies on the economics of continued plant operations, retirement, decommissioning, and the associated risks of simultaneous retirements.
 - Evaluate any new regulations to mitigate the risk that they could result in a substantial number of simultaneous retirements (*e.g.* environmental regulations that require many plants to retire or retrofit in a particular year).

- Ensure information on planned retirements is made public with sufficient advance notice to allow for a market response.
5. *Increase the Price Cap, Reduce the Price Floor, and Introduce More Gradual Scarcity Pricing For Operating Reserve Depletions*, including:
- Considering whether to increase the current price cap from \$1,000/MWh up to a level, such as \$3,000 to \$7,500 that is more consistent with customers' value of lost load (VOLL). We do not recommend increasing the generator offer cap of \$999.99/MWh, however, as the higher prices should only be realized during operating reserve depletion and rare load shed events.
 - Improve the efficiency of prices during supply surplus events by reducing the price floor below zero. The price floor should be set low enough that generators, including wind plants and importers would have an incentive to curtail when it is economic to do so.
 - The increase in the price cap would be combined with a scarcity pricing function that gradually increases prices to the new price cap as operating reserves are depleted during emergency conditions. These adjustments would also allow for economically efficient prices during reliability events, stimulate demand-response, promote generator performance, and provide stronger investment signals during periods of low reserve margins. This would make the level of the price cap more consistent with those in other energy-only markets, such as Texas and Australia.

While we reiterate our 2011 conclusions, we also continue to note that Alberta's power market, because it is an energy-only market, cannot guarantee that a specific reserve margin will be maintained in the short-term or long-term. The lack of a reserve margin requirement also means that Alberta must expect to experience periodic shortage events in which the market may experience lower reserves, lower reliability, and higher prices. For these reasons, we reiterate the need for continued monitoring and refinements to the market design that increase its efficiency and effectiveness. Today's relatively high reserve margin and positive outlook for generation investment also presents an unique opportunity to implement market design refinements in a deliberate manner. This is particularly relevant for our price cap and scarcity pricing recommendations, which could be implemented with minimal market impacts but provide significantly improved investment signals should reserve margins decline in the future.

BIBLIOGRAPHY

- Adib, P., Schubert, E., and Oren, S. (2008). "Chapter 9: Resource Adequacy: Alternate Perspectives and Divergent Paths." In F. P. Sioshansi (Ed.), *Competitive Electricity Markets: Design, Implementation, Performance*. Oxford: Elsevier.
- Alberta Government (2007a). *Power Purchase Arrangements Regulation*. Retrieved from http://www.qp.alberta.ca/574.cfm?page=2003_167.cfm&leg_type=Regs&isbncln=9780779728787
- Alberta Government (2007b). *Specified Gas Emitters Regulation*. Retrieved from http://www.qp.alberta.ca/574.cfm?page=2007_139.cfm&leg_type=Regs&isbncln=9780779728619
- Alberta Government (2010). *Alberta Environment: Report on 2008 Greenhouse Gas Emissions*. April 2010. Retrieved from <http://www.environment.alberta.ca/02166.html>
- Alberta Government (2012). *Alberta Climate Change Policy Approach Updated December 2012*. Retrieved from <http://www.environment.gov.ab.ca/info/library/8735.pdf>
- Alberta Electric System Operator (2009a). *AESO Long-term Transmission System Plan*. July 2009. Retrieved from http://www.aeso.ca/downloads/AESO_LTTSP_Final_July_2009.pdf
- Alberta Electric System Operator (2011). *Long Term Adequacy Metrics*. February 2011. Retrieved from http://www.aeso.ca/downloads/2011_02_LTA.pdf
- Alberta Electric System Operator (2013a). *Long Term Adequacy Metrics*. February 2013. Retrieved from http://www.aeso.ca/downloads/2013_02_LTA.pdf
- Alberta Electric System Operator (2013b). *2012 Long Term Outlook Update*. February 2013. http://www.aeso.ca/downloads/AESO_LTO_Update_Final.pdf
- Alberta Electric System Operator (2013c). *2012 Annual Market Statistics*. February 2013. http://www.aeso.ca/downloads/AESO_2012_Market_Stats.pdf
- British Columbia River Forecast Center (2011) *Snow Survey and Water Supply Bulletin – June 1st, 2011*. Retrieved from http://bcRFC.env.gov.bc.ca/bulletins/watersupply/archive/2011/2011_Jun1.pdf
- British Columbia River Forecast Center (2012) *Snow Survey and Water Supply Bulletin – June 1st, 2012*. Retrieved from http://bcRFC.env.gov.bc.ca/bulletins/watersupply/archive/2012/2012_Jun1_SnowBulletin.pdf
- Canadian Government (2012). *Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations*. 2012. Retrieved from <http://www.gazette.gc.ca/rp-pr/p2/2012/2012-09-12/html/sor-dors167-eng.html>
- Market Surveillance Administrator (2011a) *MSA 2011 Second Quarter Report*. Retrieved from <http://albertamsa.ca/index.php?page=quarterly-reports>
- Market Surveillance Administrator (2011b) *MSA 2011 Third Quarter Report*. Retrieved from <http://albertamsa.ca/index.php?page=quarterly-reports>
- Market Surveillance Administrator (2011c) *Offer Behaviour Enforcement Guidelines For Alberta's Wholesale Electricity Market*. January 14, 2011. Retrieved from

<http://albertamsa.ca/uploads/pdf/Consultations/Market%20Participant%20Offer%20Behaviour/Decide%20-%20Step%205/Offer%20Behaviour%20Enforcement%20Guidelines%20011411.pdf>

Market Surveillance Administrator (2012a) *MSA 2012 First Quarter Report*. Retrieved from <http://albertamsa.ca/index.php?page=quarterly-reports>

Market Surveillance Administrator (2012b) *MSA 2012 Second Quarter Report*. Retrieved from <http://albertamsa.ca/index.php?page=quarterly-reports>

Market Surveillance Administrator (2012c) *MSA 2012 Third Quarter Report*. Retrieved from <http://albertamsa.ca/index.php?page=quarterly-reports>

Market Surveillance Administrator (2012d) *2012 State of the Market Report*. Retrieved from <http://albertamsa.ca/uploads/pdf/Archive/2012/SOTM%20Final%20Report%2020121210.pdf>

Market Surveillance Administrator (2012e) *Supply Cushion Data*. Retrieved from http://albertamsa.ca/uploads/pdf/Archive/2012/Supply_Cushion_Data.rar

Market Surveillance Administrator (2012f) *Supply Cushion Methodology and Detection of Events of Interest*. Retrieved from http://albertamsa.ca/uploads/Supply_Cushion_Data/Supply_Cushion_and_Outliers_120604.pdf

Market Surveillance Administrator (2012g) *A Comparison of the Long-Run Marginal Cost and Price of Electricity in Alberta*. Retrieved from <http://albertamsa.ca/uploads/pdf/Archive/2012/SOTM%20LRMC%20121012.pdf>

Morrison Park Advisors (MPA) (2012), *Investor Perspectives on the Attractiveness of Alberta's Electricity Generation Market*, prepared for the Alberta MSA, August 2012. Retrieved from <http://albertamsa.ca/uploads/pdf/Archive/2012/Investor%20Perspectives%20Report%20to%20MSA%20-%202017%20August.pdf>

Newell, Samuel, Kathleen Spees, Johannes Pfeifenberger, Robert Mudge, Michael DeLucia, and Robert Carlton (2012) *ERCOT Investment Incentives and Resource Adequacy*. June 1, 2012. Retrieved from <http://www.brattle.com/documents/UploadLibrary/Upload1047.pdf>

Pfeifenberger, Johannes P. and Kathleen Spees (2011a) *Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market*. April 2011. Retrieved from <http://www.brattle.com/documents/UploadLibrary/Upload943.pdf>

Pfeifenberger, Johannes P. and Kathleen Spees (2011b) *Evaluation of Market Fundamentals and Challenges to Long-Term System Adequacy in Alberta's Electricity Market*. March 2011. IPPSA 17th Annual Conference

Pfeifenberger, Johannes P. and Samuel Newell (2011) *Trusting Capacity Markets: Does the lack of long-term contracting undermine the financing of new plants*. December 2011, *Public Utilities Fortnightly*

Retail Market Review Committee, *Power for the People*, Report and Recommendations for the Minister of Energy, Government of Alberta, September 2012. Retrieved from: <http://www.energy.alberta.ca/Electricity/3406.asp>

Reuters (2012) *TransCanada Receives Favorable Ruling with Sundance A Power Purchase Arrangement Arbitration Decision*. July 2012. Retrieved from <http://www.reuters.com/article/2012/07/23/idUS100620+23-Jul-2012+MW20120723>

LIST OF ACRONYMS

ACE	Area Control Error
AESO	Alberta Electric System Operator
AIES	Alberta Internal Electric System
AIL	Alberta Internal Load
ATC	Available Transfer Capability
ATWACC	After-Tax Weighted Average Cost of Capital
BC	British Columbia
CAISO	California Independent System Operator
CC	Combined Cycle
CCS	Carbon Capture and Storage
CO ₂	Carbon Dioxide
CO ₂ e	Carbon Dioxide Equivalent
Cogen	Cogeneration
CT	Combustion Turbine
EEA	Energy Emergency Alert
ERCOT	Electric Reliability Council of Texas, Inc.
EUE	Expected Unserved Energy
FOM	Fixed Operations And Maintenance
GHG	Greenhouse Gas
GJ	Gigajoule
GWh	Gigawatt Hour
ISO-NE	ISO New England, Inc.
kT	Kilotonne
kW	Kilowatt
kW-y	Kilowatt-year

LTA	Long Term Adequacy
MATL	Montana-Alberta Tie Line
MISO	Midwest Independent System Operator
MPA	Morrison Park Advisors
MSA	Market Surveillance Administrator
MW	Megawatt
NYISO	New York Independent System Operator
NO ₂	Nitrogen Dioxide
NO _x	Nitrogen Oxides
NRG	NRG Energy, Inc.
O&M	Operations and Maintenance
PJM	PJM Interconnection
PM	Particulate Matter
PPA	Power Purchase Agreement
RRO	Regulated Rate Option
SO ₂	Sulfur Dioxide
TMR	Transmission Must Run
VOLL	Value Of Lost Load
VOM	Variable Operations and Maintenance
WECC	Western Electricity Coordinating Council