

The Brattle Group

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

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Johannes P. Pfeifenberger
Kathleen Spees

Prepared for



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TABLE OF CONTENTS

I.	Executive Summary	1
II.	Background	4
	A. Market Designs to Address Resource Adequacy	4
	1. Energy-Only Markets.....	5
	2. Market Designs Based on Administrative Capacity Payments.....	7
	3. Market Designs with Resource Adequacy Requirements.....	9
	B. AESO’s Energy-Only Market Design	9
III.	Long-Term System Adequacy Challenges Faced in Alberta	11
	A. Low Natural Gas and Electric Prices	11
	B. Expiration of Power Purchase Arrangements	13
	C. Alberta and Federal Carbon Legislation	16
	1. Alberta Carbon Policy.....	16
	2. Federal Carbon Policy.....	24
	D. Air Quality Emissions Regulation	25
	E. Wind Integration and Ancillary Services.....	27
	F. Expanded Interconnections with Neighboring Markets.....	32
IV.	Supply-Demand Outlook.....	36
	A. Supply Outlook Under Various Retirement Scenarios	36
	1. Reserve Margin and Supply Outlook without Retirements or Additions	36
	2. Supply Outlook with PPA Retirements	38
	3. Supply Outlook with Federal Coal CO ₂ Emissions Standard	40
	B. AESO Projected Future Generation Additions	41
V.	Analysis of Generator Economics.....	43
	A. Historic Trends in Generator Economics.....	43
	1. Energy and Operating Reserves Prices	43
	2. Historic Scarcity Pricing Levels	45
	3. Impact of Price Cap and Administrative Scarcity Pricing	47
	4. Price Impact of Declining Reserve Margins	49
	5. Costs and Operating Parameters of New Generating Plants.....	50
	6. Historic Generator Operating Margins vs. Fixed Costs.....	52
	B. Outlook for Generator Economics	55
	1. Projecting Future Market Prices	55
	2. Projection of Generator Operating Margins vs. Investment Costs	61
	3. Breakeven Future Prices by Technology Type	64
VI.	Findings and Recommendations.....	66
	Bibliography	68
	List of Acronyms	75
	Appendices.....	77
	A. Generator Operating Margins versus Fixed Costs	A-1
	B. Method For Projecting Operating Margins	B-1
	C. Projection of Generator Operating Margins versus Fixed Costs	C-1

I. EXECUTIVE SUMMARY

The Alberta Electric System Operator (“AESO”) asked *The Brattle Group* to review long-term challenges to resource adequacy in Alberta’s electricity market and assess the following four questions:

1. Is the market design sustainable in its current state?
2. Is the energy-only market design sustainable with minor changes?
3. Are major changes required to maintain resource adequacy?
4. What long-term adequacy metrics can be used as milestones for change?

The challenges that Alberta will face over the coming decade include: (1) the potential introduction of new environmental regulations that could force aging plants to retire or incur significant capital expenditures; (2) the expiration of power purchase arrangements, which may trigger accelerated retirement partly due to decommission cost recovery regulations; (3) the addition of wind generation capacity, which suppresses energy prices and increases price volatility; (4) expanded interconnections with neighboring markets, which has the potential to reduce reliability in Alberta if they lead to the province becoming dependent on interties for resource adequacy, and (5) the continued long-term outlook of low natural gas and power prices, which result in low operating margins and limits investment cost recovery particularly for coal and hydro plants.

Individually, each of these challenges may impose a manageable downward pressure on reserve margins and consequently upward pressure on market prices, ultimately resulting in relatively stable levels of market prices and reliability. However, the combined impact of these factors might create a resource adequacy challenge for the Alberta electricity market large enough to result in unacceptably low levels of reliability or higher, more volatile power prices. The overall challenge is amplified to the extent that the market will be exposed to all of these pressures simultaneously over a relatively short period of time.

Most electricity markets around the world face a similar set of challenges, although some of these challenges are unique to Alberta. For example, most US electricity markets do not rely on market mechanisms to determine the desired level of reliability, but instead impose resource adequacy standards that ensure a specific reserve margin. By doing so, reserve capacity becomes valuable and power plants can earn revenues through bilateral or centralized capacity markets. Other power markets offer regulated capacity payments to encourage investment. In contrast, no similar capacity-related revenue sources are available to power plants or demand-side resources in Alberta. Rather, investment costs need to be recovered solely through revenue earned in Alberta’s energy and ancillary service markets. Note that these energy revenues may also be hedged through short-term and long-term bilaterally contracted sales, although the prices agreed upon in these contracts will be ultimately informed and driven by energy spot prices from the centralized wholesale market. This “energy-only” market design creates significant uncertainties about whether the market will maintain resource adequacy in the presence of the identified challenges. In fact, some other energy-only markets, such as in Great Britain, are in the midst of significant market redesign efforts to address these challenges.

We find that the identified challenges will come about gradually and increase the rate of plant retirements and investment needs. However, with the possible exception of accelerated

retirements related to decommissioning cost recovery, the identified challenges should not result in substantial simultaneous retirements of existing plants. The rate of plant retirement will most likely average 220 MW per year over the next two decades, which is 1.5 times the 150 MW of annual retirements experienced during the last decade. Considering both these retirements as well as the anticipated load growth of 3.2% per year and an associated reserve margin requirement increase, this would require the addition of 740 MW per year over the next 20 years. This is almost twice the rate of historic generation additions, which averaged 380 MW over the past decade.

We conclude that the current market design should be able to support this higher and consequently more challenging rate of generation additions. Our analysis shows that the Alberta market design is generally well-functioning, with energy and ancillary service prices that have been relatively *low* when reserve margins were high, but that have increased enough to attract new plant additions when system-wide reserve margins declined.

We also find that the Alberta market design will likely be able to retain existing resources and attract new entry without dramatic price increases or a significant reduction in resource adequacy. Our projections of future energy and ancillary service prices based on recently-experienced market conditions show that only modest increases in market prices, consistent with projected increases in natural gas and carbon emission costs, should be sufficient to avoid premature retirement of existing resources and, importantly, support investments in new generation. We find that projected future market prices based on current fundamentals strongly favor a shift in the resource mix from coal generation to natural-gas-fired power plants, which are more flexible and have lower capital costs. The entry of additional wind turbines and coal plants with carbon capture and storage may be supported by government policies and through the value of “green” attributes.

As a result, and perhaps contrary to our initial expectations, we currently see no compelling need for major changes in Alberta’s electricity market design. However, the outlook for resource adequacy remains uncertain and sensitive to changes in market fundamentals and continued evolution of the identified challenges, which must not be underestimated. It also needs to be recognized that an energy-only market design will not be able to “guarantee” that a certain reserve margin will be maintained. In fact, in a small system such as Alberta’s, the lack of coordination between the retirement and online dates of individual units can cause transitional reliability concerns and price spikes, as has been highlighted by the recently announced, unexpected potential early retirements of Sundance 1 and 2.

Overall, we offer the following recommendations.

- The AESO should carefully monitor market fundamentals in light of the identified challenges. In addition to the already ongoing monitoring of resource adequacy metrics based on a 24-month outlook, we recommend monitoring: (1) trends in market heat rates and the long-term outlook for technology-specific operating margins; (2) retirement schedules and associated system reserve margins; (3) market price impacts of wind generation as more wind power plants come on line; and (4) the impact of interties as they are expanded and market rules related to the use of these interties evolve.
- Alberta policy makers should consider relaxing or revising the existing decommissioning cost recovery rule to reduce the risk of large simultaneous plant retirements in 2020 when most of the existing purchase power arrangements expire. More generally, policy makers

should avoid introducing regulations that could result in large simultaneous retirements, which are difficult to manage in any market or regulated environment.

- We recommend that the AESO consider increasing the current price cap from \$1,000/MWh to the lower end of estimates for the “value of lost load”, which tend to be in the range of approximately \$3,000/MWh. We also recommend reducing the price floor below zero to a level where generators, including wind plants, would have an incentive to shut down when it is economic to do so. These adjustments would also allow for economically efficient prices during reliability events, stimulate demand-response, facilitate entry of resources at lower average annual market prices, and make the level of the price cap more consistent with those in other energy-only markets, such as Texas and Australia.
- Coincidentally with increasing its price cap, the AESO should consider revising its mechanism for setting administrative prices under emergency conditions when out-of-market reliability actions become necessary. Under these conditions, prices should be set to reflect the marginal cost of any out-of-market actions.
- The AESO should carefully consider the long-term resource adequacy implications of its efforts to refine the Alberta market design, which include: (1) the integration of additional wind generation; (2) refining ancillary service markets and market designs for demand response; and (3) the expansion of interconnections with neighboring systems.

Overall we conclude that Alberta’s energy-only market is generally well-functioning and sustainable, although its efficiency and effectiveness can be improved with some design changes. However, we caution that the current positive outlook cannot guarantee resource adequacy long-term for the simple reason that Alberta’s market design, like other energy-only markets, does not include a resource adequacy requirement. For this reason the AESO must continue to monitor potential challenges to resource adequacy over time.

II. BACKGROUND

The Alberta Electric System Operator (“AESO”) asked *The Brattle Group* to review long-term challenges to resource adequacy in Alberta’s electricity market and assess the sustainability of the current energy-only market design from a long-term resource adequacy perspective. This report assesses the possible impact of these challenges to the long-term sustainability of Alberta’s energy-only market and explores options that may help reduce the risk of highly undesirable outcomes. In this context, our report explores four questions:

1. Is the market design sustainable in its current state?
2. Is the energy-only market design sustainable with minor changes?
3. Are major changes required to maintain resource adequacy?
4. What long-term adequacy metrics can be used as milestones for change?

Our evaluation defines a sustainable market design as one that will provide long-term resource adequacy through pricing signals that are sufficient to attract and retain capacity when needed. A sustainable design can provide an efficient level of reliability without reliance on “out-of-market” or “backstop” mechanisms. The scope of our analysis does not include challenges related to transmission planning, system operations, and short-term market design initiatives.

A. MARKET DESIGNS TO ADDRESS RESOURCE ADEQUACY

Alberta’s energy-only market design lies within a spectrum of resource adequacy constructs that have been implemented in North America and around the world, as summarized in Table 1. Table 1 describes four different electricity market design approaches: (1) energy-only markets, which are usually accompanied by a set of ancillary services markets, but without an explicit resource adequacy requirement; (2) markets in which resource adequacy is ensured through administratively determined capacity payments made directly to suppliers; (3) markets with explicit resource adequacy requirements that mandate the procurement of reserve capacity by retail suppliers on a short-term basis (*e.g.*, for the next peak season); and (4) market designs that mandate procurement of reserve capacity by retail suppliers on a forward basis (*e.g.*, one to several years prior to the year when the capacity is needed).

Table 1
Spectrum of Approaches to Resource Adequacy¹

Type of Centralized Capacity Market	Designs <i>without</i> Explicit Resource Adequacy Requirement		Designs <i>With</i> Explicit Resource Adequacy Requirement	
	<i>Energy-Only Markets</i>	<i>With Capacity Payments or PPAs</i>	<i>Short-Term</i>	<i>Forward</i>
<i>None</i>	AESO, Australia's NEM, ERCOT, Great Britain, NordPool	Argentina, Chile, Colombia, Peru, Spain, South Korea, Ontario	SPP, former power pools (NYPP, PJM, NEPOOL)	CAISO
<i>Voluntary</i>			Midwest ISO	
<i>Mandatory</i>			NYISO, former PJM, Australia's SWIS	PJM, ISO- NE, Brazil

The three rows of Table 1 show that in market designs with a resource adequacy requirement for retail suppliers, the procurement of reserve capacity may be based on bilateral contracting or self-supply without a centralized capacity market administered by Independent System Operators ("ISO") (row 1), or they may include ISO-administered capacity markets that are either voluntary (row 2) or mandatory (row 3).

1. Energy-Only Markets

In an energy-only market like Alberta, there is no mandated and no guaranteed level of resource adequacy. Instead, the amount of capacity in the system is determined by the aggregate effect of market-based private investment decisions, which are made in response to the prices and revenues available from the energy and ancillary services markets or through bilateral contracting with retail suppliers.^{2,3} Energy-only markets are usually characterized by moderate

¹ Table 1 is based on a report prepared by *The Brattle Group* for PJM (see Pfeifenberger, *et al.* (2009)). The table refers to the following markets according to their short names: California ISO ("CAISO"), Southwest Power Pool ("SPP"), Electric Reliability Council of Texas ("ERCOT"), Alberta Electric System Operator ("AESO"), Australia's National Electricity Market ("NEM"), Australia's South West Interconnected System ("SWIS"), PJM Interconnection ("PJM"), ISO New England ("ISO-NE"), New York Power Pool ("NYPP"), New England Power Pool ("NEPOOL"), and New York Independent System Operator ("NYISO").

² For a full discussion of the theoretical basis for pure energy-only markets, see Hogan (2005) and Joskow and Tirole (2004).

³ In many "energy-only" markets, there often are market interventions through the system operator or government entities in the case of insufficient resources. Such out-of-market interventions can take the form of backstop procurement mechanisms, government-built generation, or out-of-market cost recovery such as government-supported long-term power purchase arrangements. These out-of-market interventions damage the function of the energy-only market by artificially suppressing energy-market

levels of energy prices punctuated by occasional severe price spikes. This is because sufficient resources are available most of the time, and competitive market forces depress prices towards the production cost of the most expensive unit dispatched. These prices near marginal production costs are below the price levels needed for full investment cost recovery for marginal resources. However, there will also be occasional conditions in which supplies become scarce and energy prices increase (or even spike) to include a “scarcity” premium that provides generators with the “operating margins” needed to recover their investment and other fixed costs. These occasional price spikes must be large enough and frequent enough to allow the full recovery of fixed operations and maintenance and investment costs if capacity resources are to be attracted to and retained in the market. Revenues received from the ancillary services markets, which tend to track with prices in the energy market, also help determine when and which types of new capacity investments are attractive.

While such scarcity-based price spikes are inherent to the design of energy-only markets, they can impose economic impacts on retail customers that create political challenges to maintaining the market design. However, retail suppliers have the option to hedge against the economic impact of this price volatility, a practice that is widespread in some energy-only markets, such as Australia’s National Electricity Market (“NEM”).⁴ For buyers and sellers that are fully hedged with long-term contracts for power, the hourly energy price has no effect other than as a settlement tool, or as a benchmark helping to determine a reasonable price for a new long-term contract.

Occasional high scarcity prices also motivate demand reductions through price-responsive demand (“PRD”) and interruptible retail services. The price during a scarcity event must rise until supply and demand are balanced. If that happens, the scarcity price represents an economically efficient and accurate representation of the value customers place on consuming peak power and avoiding interruptions in service. Energy suppliers, likewise, have an efficient price signal indicating whether or not to invest in capacity without any administratively-determined resource adequacy standard. The ability to rely on customers to choose their own desired level of reliability through the marketplace, rather than relying on administrative determinations, is one of the (at least theoretical) advantages of energy-only markets.

Demand can adequately adjust to balance the system during supply shortages only if: (1) a large enough fraction of the load is exposed to and is responsive to market prices; and (2) prices are allowed to rise to the high value that customers place on reliability. In most real-world energy-only markets, there is not yet sufficient price response or interruptible load to realize the theoretical model of how the market should behave under scarcity conditions. Instead, during a scarcity event, the system administrator may have to rely on out-of-market actions such as expensive off-system power purchases, voluntary emergency load shedding contracts, or resort to involuntary load curtailments. In some markets, the actions of the system operator to increase

prices and tend to be self-perpetuating. A well-functioning energy-only market should not require such interventions. See Pfeifenberger, *et al.* (2009), pp. 19-38. Alberta’s backstop reliability mechanism, instituted as part of its Long-Term Adequacy Rules, allows the market operator to intervene to procure sufficient capacity when the 2-year supply outlook is insufficient to maintain a reliability threshold, see AESO (2008).

⁴ See AER (2007), Ch. 3.

supply through out-of-market actions during emergency events can actually have the undesirable effect of artificially suppressing the market price. Finally, in the extreme event of firm load shed, the market price has to be set to an administratively-determined level because the market clearing price is an undefined quantity during a rationing event. In Alberta the price is set at the price cap under such conditions.

The theoretically efficient price during emergency operations is the marginal cost of the next emergency procedure. For example, if voluntary curtailments are required, the pool price should be set equal to the per-MWh cost of the most expensive load-shed contract called upon during the emergency.⁵ If involuntary curtailments of firm load are required, the most efficient price during the rationing event is the estimated price that the average interrupted customer would have been willing to pay to avoid interruption. This price level is referred to as the Value of Lost Load (“VOLL”).⁶ Estimates of VOLL vary widely depending partly on the makeup of the customer base and partly on uncertainty in estimation methods, but usually are at least in the range of \$3,000-\$10,000/MWh.^{7,8} Administrative scarcity pricing at the VOLL crudely approximates a “demand curve” for energy.⁹ More advanced administrative scarcity pricing schemes, as used by the Midwest ISO for example, gradually increase the price toward the VOLL as the necessity of involuntary curtailments becomes more likely.¹⁰

When the potential for exercise of generator market power is a concern, administrative scarcity pricing can also allow the system operator to maintain a generator bid cap below the VOLL-based price cap, without undermining efficiently high prices during scarcity events. For example, prices can increase to the generator bid cap as the supply stack runs out. At even higher levels of scarcity, a combination of high-priced demand bids (which can be higher than the generator bid cap) and administrative scarcity pricing can tie the prevailing market price directly to the marginal cost of demand interruptions or the marginal cost of out-of-market emergency operations.

2. Market Designs Based on Administrative Capacity Payments

Some energy market designs mitigate or otherwise suppress market prices to levels far below the VOLL, such that they do not include a sufficient scarcity premium. As a result, suppliers are generally unable to recover their fixed costs solely through energy and ancillary services

⁵ For example, if the load-shed contract for a 1 MW reduction costs \$10,000/year and stipulates an expected 5 hours of curtailment per year, then the hourly system-wide price for any hour when the contract is enacted should be \$2,000/MWh.

⁶ See Joskow and Tirole (2004) and Hogan (2005).

⁷ See Centolella and Ott (2009) and Midwest ISO (2006).

⁸ Note that some sectors of industry, such as mining, place an extremely high value on lost load, exceeding \$50,000/MWh, see Midwest ISO (2006). However, a system-wide estimate of average VOLL does not need to include the full VOLL of these customers if they exceed the cost of private investments in back-up generation.

⁹ Note that if there actually *were* sufficient levels of demand response and interruptibility in the market, the outcome during a scarcity event would be much more efficient because customers would self-select reductions from low-value uses of power. Under involuntary curtailments, high and low value applications for power are indiscriminately interrupted.

¹⁰ See Hogan (2005) and Newell, *et al.* (2010), Section IV.A.4.

markets, resulting in “missing money” relative to what is needed to attract and retain sufficient capacity to meet reliability targets.¹¹ In a market design with administrative capacity payments as shown in Table 1, the system operator makes direct payments to suppliers or signs PPAs with suppliers of capacity. The system administrator then recovers the costs associated with these capacity payments via an uplift charge assessed to customers.¹²

There has been great variation in the determination of administrative capacity payments and the designation of eligible suppliers. The most widely-used capacity payment design is similar to the one first implemented in Chile in 1982.¹³ This was an availability-based compensation mechanism under which any supplier bidding into the energy market would receive a capacity payment whether or not the unit was dispatched. These capacity payments would be set such that, over the course of the year, they would cover the annual investment costs of a peaking unit as long as the plant demonstrated sufficient availability during months of peak demand or capacity shortage.¹⁴

The major criticism of capacity payment systems is that they rely on administrative judgment rather than market forces.¹⁵ In a capacity payment system, the system administrator is extensively involved in determining the size of the payments that will be made and the type of capacity resources that would be eligible. However, the quantity that will be supplied in response of such payments can remain uncertain, which can lead to excess capacity or reliability levels that remain below targets despite the administrative payments.

Maintaining target levels of resource adequacy by making administratively-set capacity payments available only to “new” resources is sometimes viewed as a more cost-effective solution than providing capacity payments to all resources. However, attempts to limit payments only to new resources, while implemented in some places such as Spain, will not likely result in lower costs in the long run, particularly in cases where re-investing in existing facilities would have been lower in cost than building new facilities. Such an approach also generally risks higher long-term costs because capacity payments are generally not made available to low-cost capacity supply from demand-side resources, capacity uprates, or postponed retirements. Finally, the cost of these payments is not generally reflected in market prices during peak load conditions, which means that efficient levels of demand-response cannot be achieved even in the absence of other barriers to demand-response.

¹¹ For additional discussion and explanation of the meaning of “missing money” and how baseload, intermediate, and peaking capacity is affected, see Hogan (2005), pp. 2-7.

¹² See Adib, *et al.* (2008), pp. 336-337.

¹³ See Batlle (2007), p. 4547; Larsen (2004); Rudnick (2002).

¹⁴ In Chile, the peak demand months are May-September; in Colombia, the payments are made during the dry season of December-April when hydro capacity is limited, see p. 161, Rudnick (2002). Sometimes the capacity payments are differentiated depending on the type of resource, for example, in order to incent investments in thermal capacity after a period of drought and associated electric shortages, Colombia introduced increased capacity payments for thermal units. However, the units would have to make at least some energy margins to be profitable overall, see Larsen, (2004).

¹⁵ For example, both the South Korean and Colombian systems have been criticized for lack of transparency and predictability. See Park (2007), pp. 5821-22; Larsen, *et al.* (2004), p. 1772.

3. Market Designs with Resource Adequacy Requirements

The approach to ensuring resource adequacy used in most of the United States is based on reserve margin requirements imposed on retail suppliers. Under this market design, the regulator or system administrator determines the amount of capacity each retail supplier must procure to ensure resource adequacy. For example, to ensure a system-wide reserve margin of 15%, each retail supplier would be required to procure capacity amounting to 115% of its projected coincident peak load.

These reserve margin requirements can be imposed on a current or forward basis. As shown in Table 1, the Midwest ISO, SPP, and NYISO require that sufficient capacity commitments are demonstrated immediately prior to each delivery period (*e.g.*, prior to each delivery month). In contrast, PJM, ISO-NE, and CAISO all require capacity procurement on an annual or 3-year forward basis.

Another key difference among these markets is whether the design relies exclusively on bilateral contracting and self-supply, or whether the system operator facilitates procurement through a centralized capacity market. While the creation of a resource adequacy requirement always creates a bilateral market for capacity, centralized capacity markets are not a necessary design element. For example, in SPP, retail suppliers procure capacity through self-supply or bilateral contracting.¹⁶ The Midwest ISO operates in largely the same way, but it also administers a Voluntary Capacity Auction (“VCA”) through which market participants can buy or sell capacity on a voluntary basis.¹⁷ In both Midwest ISO and SPP, retail suppliers are solely responsible for procuring capacity, and the system operator would not intervene to fill deficiencies if any existed. This is unlike California, where the CAISO will bilaterally procure capacity when needed to fill any deficiencies that remain beyond what LSEs have already procured and submitted in their capacity procurement plans. In PJM, NYISO, and ISO-NE, the ISOs procure capacity deficits through their centralized capacity auctions.

Participation in the centralized market for procuring residual capacity is mandatory in PJM, NYISO, and ISO-NE.¹⁸ Under these designs, retail suppliers have the option to self-supply or contract bilaterally, and the RTO will procure any residual capacity requirements through the mandatory centralized auction and assign responsibility for payment to retail providers. Participation in the capacity auction is also mandatory for all existing capacity with competitive bid levels overseen by the market monitor.

B. AESO’S ENERGY-ONLY MARKET DESIGN

Prior to deregulating, Alberta’s electric sector consisted of vertically-integrated regulated investor-owned utilities as well as municipalities and cooperatives. Under this market structure, supply adequacy was ensured by regulator-approved cost recovery for assets needed for

¹⁶ Member utilities in SPP are mandated to fulfill the 12% capacity margin. The RTO oversees but does not enforce this provision, with overall resource adequacy and enforcement handled by state regulators. See NERC (2008), p. 222; SPP (2009), pp. 2.2-2.4.

¹⁷ See Midwest ISO (2009).

¹⁸ See PJM (2009); NYISO (2009).

reliability. In the 1990s, Alberta began a deregulation initiative to create competition in the electric sector. In 1996, Alberta introduced a power pool, creating the wholesale energy market, and over 1998-2001 Alberta deregulated its electric generation fleet.¹⁹ With these reforms, Alberta transitioned to an energy-only market in which new generation investments would not be mandated by regulators but rather would be attracted by market incentives. After the first few years of experience with the energy-only market, the Alberta Department of Energy initiated a market design review to determine whether major market modifications were required for long-term adequacy, including the option of imposing adequacy obligations on retail suppliers. The review concluded that such a redesign was not necessary at the time, noting that the market had attracted more than 3,500 MW of competitive new generation between 1998 and 2005.²⁰ However, the review did recommend an initiative toward the long-term adequacy (“LTA”) rules.

Alberta’s energy-only market design is implemented along with a set of ancillary services markets including operating reserves to ensure sufficient operating flexibility. The energy and ancillary markets are also accompanied by a dispatch down service (“DDS”) settlement mechanism to mitigate against energy price distortions from out-of-market transmission must run (“TMR”) dispatch. Like other energy-only markets such as those in Great Britain, Scandinavia, Texas, and Australia, Alberta’s electricity market design does not offer capacity payments and does not have a mandated resource adequacy requirement.

Also similarly to other market designs, Alberta has out-of-market backstop mechanisms for providing reliability when in-market signals have failed to provide sufficient supply for reliability. One backstop mechanism is the option to sign TMR contracts with generation units that are needed for locational resource adequacy or voltage stability although they are uneconomic to operate as market-based assets. The LTA rule sets out another set of backstop mechanisms that may be implemented if the two-year supply outlook appears insufficient to maintain a reliability threshold. In this case AESO can engage in out-of-market reliability contracts for load shedding, back-up generation, or the temporary installation of emergency portable generation.²¹ The need to rely on out-of-market backstop reliability contracts such as these could be a strong indicator of problems in the market design, which may not be providing sufficient price signals for supply investments. Out-of-market reliability contracts can also add to the reliability problem by suppressing market prices during periods of scarce supply, unless they are managed carefully.

Like other energy-only markets, Alberta takes a carefully restrained approach to mitigation of market power, allowing energy prices to spike sufficiently in response scarcity events to attract and retain generation and demand response investments.²² This differs from the more heavy-handed price mitigation in U.S. and other electricity markets with resource adequacy standards, which mitigate energy market prices to much lower levels but supplement suppliers’ cost recovery with a capacity market or capacity payments.

¹⁹ See AESO (2006), pp. 4, 7-9.

²⁰ See DOE (2005), pp.3-4, 26-35.

²¹ See AESO (2006), pp. 10-11.

²² For example, see MSA (2010a) and (2010b).

However, Alberta's energy-only market design and market fundamentals also differ from other energy-only markets in a number of respects. Alberta's market price limits are more restrictive than in other markets, with a price floor at zero and a \$1,000/MWh price cap that is far below reasonable estimates of VOLL.²³ The relatively low price cap along with a high load factor and other features likely combine to limit the potential for demand response ("DR"), which may only choose to respond at much higher energy prices.²⁴ Alberta's centralized market is an ex-post real time market, with no day-ahead market, hour-ahead market, or centralized generation unit commitment.

Importantly, Alberta is a relatively small market which naturally limits the number of market participants and the extent to which competitive locational submarkets could be maintained. The Alberta energy-only market is also surrounded by non-market-based regions with resource adequacy requirements, which creates some unusual challenges at the market seams. Finally, provincial regulations, the upcoming expiration of power purchase arrangements ("PPA"), and high dependence on coal under a potential federal coal retirement mandate all create challenges unique to Alberta. These unique factors also limit the extent to which experience in other markets can be directly applied in our analysis.

III. LONG-TERM SYSTEM ADEQUACY CHALLENGES FACED IN ALBERTA

Like other electric markets around the world, Alberta faces a series of challenges to resource adequacy over the coming decades. Existing generators will face retirement pressures from a number of directions, including the potential federal coal retirement mandate, Alberta's carbon and air quality emissions standards, the expiration of PPAs for most of the coal generation fleet, and reduced operating margins caused by low electric prices. Low electric prices are driven by the economic turndown, low natural gas prices, the growth of wind power, and the potential expansion of interties with neighboring power markets where generators do not need to rely only on energy market revenues to recover investment costs. In particular, the growth of wind power and increased intertie capacity may reduce energy prices without substantially contributing to dependable capacity available for resource adequacy. We describe each of these challenges here, document the scale of impact that these challenges may have on the Alberta market, and discuss the potential resource adequacy implications.

A. LOW NATURAL GAS AND ELECTRIC PRICES

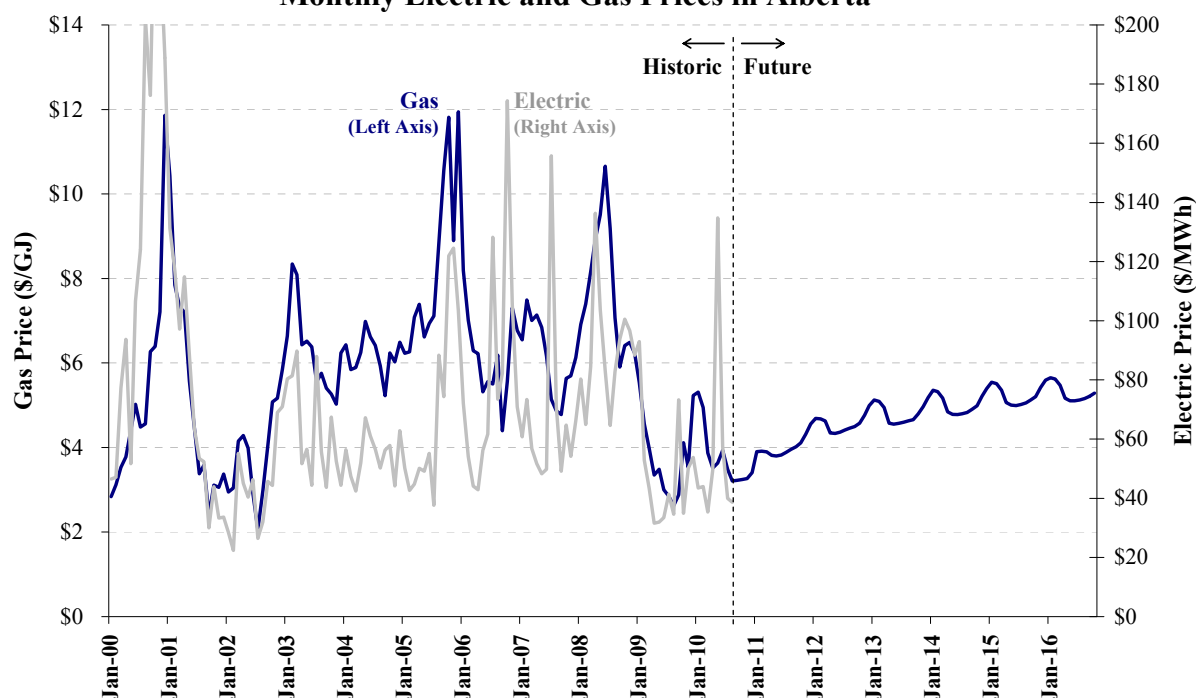
The price of natural gas directly impacts the production cost and offer prices of gas generators in the wholesale electricity market. Because natural gas generators are the price-setting suppliers in many hours, the price of natural gas also has a strong impact on the market clearing price for

²³ For example, Australia's NEM currently has a price floor of -\$1001/MWh (-\$1000 AUD/MWh) and a price cap at their estimated VOLL of \$12,512/MWh (\$12,500 AUD/MWh). See AEMC (2010). Exchange rate of 1.0009 CAD/AUD is the December, 2010 monthly average exchange rate from FRB (2011).

²⁴ For a comprehensive review of these issues, see our review of market design for DR in AESO, Pfeifenberger and Hajos (2011).

electric energy.²⁵ The close relationship between natural gas and electricity prices can be seen in Figure 1. The figure shows historic spot and futures prices for gas at Alberta Energy Company (“AECO”) C Hub, along with the AESO electricity prices over the same period. While the relationship is not one-for-one, the impact of natural gas prices on electric energy prices can be seen clearly during several periods of high gas prices, including early 2003, late 2005, and early 2008.²⁶

Figure 1
Monthly Electric and Gas Prices in Alberta



Sources and Notes:

Historic and Future gas prices from Bloomberg (2010); AESO electric prices from Ventyx (2010).

AECO C basis futures shown through 2010; AECO price in out years estimated by AESO (2010c) based on Henry Hub futures.

More recently, the combination of economic downturn and rapid increases in shale gas production have resulted in lower prices for natural gas and electricity.²⁷ AECO C Hub prices dropped to \$3.82/GJ in 2009-10 from an average of \$6.14/GJ for 2003 through 2008. Coincident with this drop in natural gas prices, electric prices have also dropped to \$50.86/MWh for 2009-2010 from an average of \$70.83/MWh for 2003 through 2008. Given the changed fundamentals of the natural gas industry due to shale gas developments, these low gas prices are expected to

²⁵ For example, in 2009, gas and cogen units submitted price-setting bids in 40% of hours while coal units submitted price-setting bids in 60% of all hours. Note that this means that gas-based generators have a disproportionately large impact on the average price. See AESO (2010e), p. 6.

²⁶ Note however, that gas prices are not the only or necessarily the dominant reason for many of the observed variations in electric prices. For example, the Alberta energy price spike in May 2010 was caused by transmission outages. Note also that while monthly energy and gas prices have a relatively strong correlation, hourly energy prices have a relatively weaker relationship to gas prices, with most of the volatility explained by short-term fluctuations in supply and demand.

²⁷ See, for example, Saur and Wallace (2011).

continue for the foreseeable future, as also indicated by the futures market for gas for the next several years. AECO C gas prices will make only a modest recovery to approximately \$4.90/GJ by 2015 as shown in Figure 1.

These low gas and electric prices have already greatly reduced the operating margins of existing and potential new generators as discussed in Section V.A.6. The impact is particularly pronounced for baseload coal generators that have low operating costs but high fixed costs. These generators require higher operating margins to cover the capital costs of new coal units and fixed costs of existing baseload coal units. Given the additional environmental challenges that coal generators face, and associated environmental upgrades that may be required to keep existing units operating, these low energy margins may not only deter new entry but also force some existing units to retire early. The likely impact that these low gas and electric prices have had on existing coal generators in Alberta are discussed further in Section V.A.6.

B. EXPIRATION OF POWER PURCHASE ARRANGEMENTS

As part of the transition to a competitive wholesale electricity market, 7,600 MW or approximately 78% of the Alberta electric generating fleet were placed under PPAs in 2001.²⁸ These PPAs were introduced to assure that generation assets built under the previous regulated, rate-of-return regime would be able to recover their costs, while still allowing for a transition to a competitive wholesale market. Under the terms of these PPAs, the original generation suppliers retained ownership of the facilities but were provided with PPAs that ensured full cost recovery through the remainder of the assets' lifetime. The buyer of the PPA was obligated to make the agreed-upon payments to the asset owner and, in return, gained the right to schedule sales and collect revenues from the wholesale market.²⁹ These PPAs expire over the 2003-2020 period.

Rights to 4,460 MW of PPAs covering thermal capacity were sold at a competitive auction in August 2000, with auction proceeds returned to retail customers. An additional 2,350 MW of thermal capacity failed to sell in the auction and 790 MW of hydroelectric capacity were not placed in the auction.³⁰ These unsold PPAs were transferred to the Balancing Pool, an entity created by the Alberta government in 1998, which manages these assets as the PPA buyer and returns any net revenues to retail customers in Alberta.³¹

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. For example, some asset owners may be operating facilities that are recovering their fixed costs under the terms of the PPA even though those units would not be economically viable without the PPA payments. Additionally, asset owners need to make continuous investments into their facilities over time to

²⁸ List of units originally under PPA and their MW ratings are from Appendix D, AESO (2006), AESO (2010c), and Balancing Pool (2004), p. 9. Percentage is based on a total installed fleet of 9,400 MW in 2000 and a hydro derate to 67% of installed capacity value. List of units online in 2000 and MW ratings from Ventyx (2010) and AESO (2010c).

²⁹ See AESO (2006), pp. 12-13, 58-60.

³⁰ List of units sold at auction and their MW ratings are from AESO (2006), Appendix D; AESO (2010c); and Balancing Pool (2004), p. 9.

³¹ See Balancing Pool (2009), p. i.

maintain the assets and extend the operating lives of the plants beyond PPA termination. They may, however, choose not to make these investments if they do not expect to be able to recoup the costs once the PPAs expire. Finally, by December 31, 2018 asset owners need to determine whether or not to decommission the facility within one year of PPA expiration to be eligible for payment of decommissioning costs.³² The payment of these decommissioning costs may be a major factor in the retirement decision for units with large environmental liabilities such as ash or asbestos cleanup, particularly if these units would expect to operate only a few years beyond PPA expiration in any case. For these reasons, the expiration of PPAs is an important factor to consider when assessing long-term resource adequacy in the Alberta electricity market.

Figure 2 shows the historic and future PPA expiration dates and generating capacities by unit type. The figure also shows the PPA capacity that has already retired. The experience to date shows that generation retirement after PPA expiration is a possibility. In fact, among coal units with already expired PPAs, 540 MW out of 680 MW have since retired, and among natural gas-fired steam turbines (“STs”) all 840 MW have since retired.³³ The figure shows some delayed retirement dates for some of the capacity with expired PPAs in light green and light purple for past years. However, several of these retirements may have been delayed not because they were economically viable, but rather because they were awarded temporary (non-market-based) TMR contracts by the AESO to avoid local reliability problems that would have been introduced by their retirement.³⁴ Finally, the figure also shows the potential early retirement and PPA termination of the Sundance 1 and 2 units, which reportedly developed mechanical problems so substantial that they may not be resolved to fulfill the PPA term.³⁵

A key problem introduced by the scheduled PPA expirations is the fact that a large proportion of them occur at the same time. 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, 2020.³⁶ This large quantity of simultaneous PPA expirations represents 41% of the currently-available generation fleet, and may represent 28% of the fleet in 2020.³⁷

Fortunately, the simultaneous retirement of all of these units after their PPAs expire in 2020 is unlikely. As discussed further in Section V.A.6, these units generally earn sufficient returns in

³² Units that apply to the Alberta Utilities Commission (“AUC”) for retirement within one year of PPA expiration are entitled to receive payments for any *decommissioning* costs unrecovered from the PPA or from consumers prior to PPA commencement. See Balancing Pool (2009), pp. 39-40; Alberta Government (2007b), Section 7; and Alberta Government (2003), Section 5.

³³ Retirement dates from Ventyx (2010) and AESO (2010c).

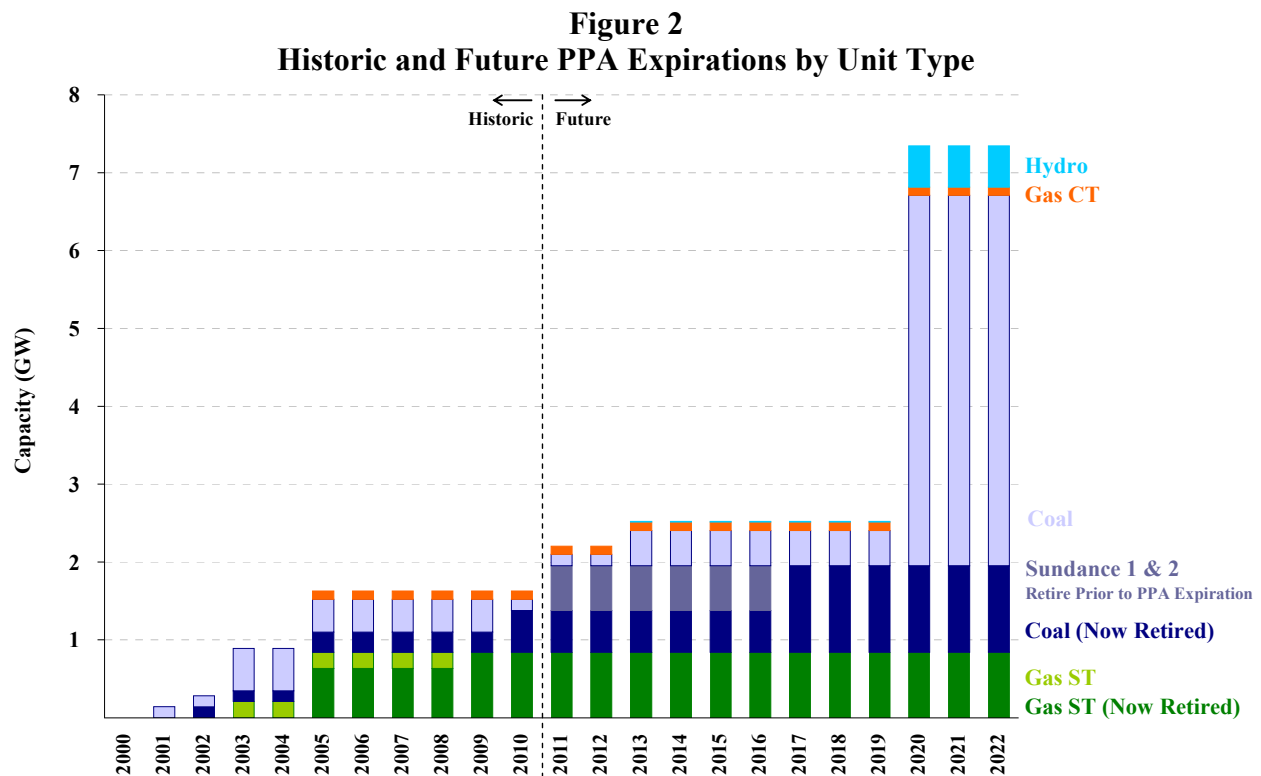
³⁴ For example, the Rainbow gas CTs and Rosedale gas STs received substantial non-market TMR contract payments that may have contributed to their delayed retirement dates, AESO (2010c).

³⁵ See TransAlta (2011).

³⁶ Future PPA expiration dates from AESO (2010c). Current PPA capacity number is after the potential early Sundance 1 and 2 retirement and PPA termination.

³⁷ Dependable capacity value of hydro and wind units derated to 67% and 0% of installed capacity respectively. Calculation is based on a current effective installed capacity of 11,730 MW and an estimated 2020 installed capacity of 17,440 assuming that future capacity will be large enough to meet projected peak load and a 15% reserve margin. List of units online in 2010 and MW ratings from Ventyx (2010) and AESO (2010c). The AESO projection of 2020/21 winter peak Alberta Internal Load is 15,162, see AESO (2010a).

the energy market to cover their ongoing fixed costs even at relatively low market prices. Therefore, unless faced with significant investment needs or near-term decommissioning costs, most units will have sufficient economic incentive to continue operating beyond the PPA expiration for the remainder of the economic life of the plant.



Sources and Notes:

Dependable capacity rating reported above for hydro is 67% of installed capacity.

Unit online and retirement dates, MW rating, and future PPA expiration dates from Ventyx (2010) and AESO (2010c).

Historic PPA expiration dates from Appendix D, AESO (2006).

Clover Bar and HR Milner PPAs originally expired in 2010 and 2012, but are reported above at their early termination dates of 2005 and 2001 respectively, CRA (1999); p.3, Balancing Pool (2001), p.9 (2004), p. 3 (2005).

An additional challenge is that a substantial portion of these coal units likely will be forced into retirement within a few years after 2020 regardless of the PPA expiration. These retirements will be driven by a combination of factors discussed below, chiefly the pending federal coal retirement mandate, large capital expenditures that might be required to life-extend an aging unit, or capital investments that may be required for environmental upgrades. If these units would be forced into retirement within a few years of PPA expiration, there is an increased risk that the owners will opt to accelerate retirement by a few years in order to recover decommissioning costs.³⁸ For example, the federal coal retirement mandate would force 1,170 MW into retirement over the 2020-25 period if enacted, which could lead to large simultaneous retirements if these facilities were to accelerate retirement to recover decommissioning costs.

³⁸ See Balancing Pool (2009), pp. 39-40; Alberta Government (2007b), Section 7.

Overall, these factors combine to introduce a substantial risk of a step change of an unusually large number of retirements in 2020 and 2021. If these retirements were phased in on a more gradual basis, it would be less challenging for market-based investments to replace the units without introducing temporary reliability problems. A large step change in the number of retirements may be too abrupt for the market to absorb without administrative intervention. The number of retirements in 2020 thus should be monitored and the decommissioning cost rule stipulated in the Power Purchase Arrangements Regulation may have to be reexamined and relaxed to spread retirements over several years.³⁹ The AESO's forward-looking supply adequacy review, which summarizes suppliers' announced retirement and online dates, will also be a helpful mitigation factor. However, the AESO cannot modify announced retirements without a resource adequacy requirement or market interventions.

C. ALBERTA AND FEDERAL CARBON LEGISLATION

Both Alberta and the Canadian federal government have greenhouse gas ("GHG") reduction goals that could substantially affect plant retirement, resource adequacy, and the operation of the energy-only market over the next 20 years. The Federal GHG reduction target is a 17% reduction below 2005 levels by 2020. This compares to a less ambitious Alberta reduction target of 21% *above* 2005 levels. Alberta's major carbon policy initiatives are \$2 billion in investments in carbon capture and storage ("CCS") technology and the Specified Gas Emitters Regulation. Both of these efforts as well as the implications of the overall GHG strategy are discussed below. Federal policy on GHG has yet to be codified, although the recently proposed strict carbon emissions standard for coal would effectively require either a CCS retrofit or retirement, and could significantly impact resource adequacy in Alberta as discussed in Subsection III.C.2.

1. Alberta Carbon Policy

The government of Alberta has a Climate Change Strategy for reducing GHG emissions in the province as a whole, which will require large contributions from the electricity sector. The two current initiatives that may have the largest impact on the wholesale electricity market are the carbon capture and sequestration objectives and the Specified Gas Emitters Regulation

a. Alberta Climate Change Strategy

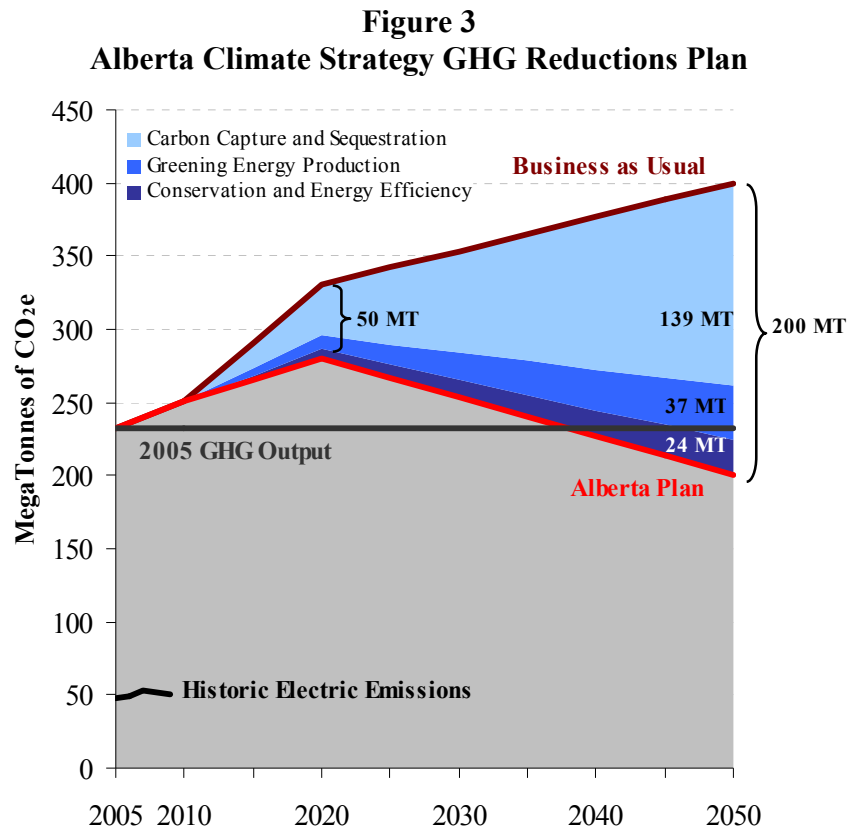
In January 2008, Alberta Environment published its climate change strategy, laying out a policy framework for reducing GHG emissions in the province.⁴⁰ The strategy sets a GHG reduction target of 15% below a business-as-usual ("BAU") case by 2020, and 50% below BAU by 2050. This is equivalent to 21% above 2005 CO₂-equivalent ("CO₂e") output levels in 2020 and 14% below 2005 levels by 2050.⁴¹ Alberta Environment's strategy includes a 139 MT CO₂e

³⁹ See Alberta Government (2007b), Section 7. Note that AESO does not have authority to revise the decommissioning cost recovery rule, which may need to be reviewed by the Department of Energy and the Alberta Utilities Commission.

⁴⁰ See Alberta Environment (2008).

⁴¹ The unit for measuring GHG emissions used by the Alberta government and in this report is tonnes of CO₂e. Under this unit non-CO₂ greenhouse gases are converted into the equivalent global warming potential of CO₂. For the electric sector, the non-CO₂ emissions covered are methane ("CH₄") and nitrous oxide ("N₂O"), which typically contribute approximately 0.6% of the total CO₂e emissions for coal

reduction (70% of total reductions) through CCS, a 37 MT reduction (19%) through greening energy production, and a 24 MT reduction (12%) through conservation and energy efficiency as shown in Figure 3.^{42,43}



Sources and Notes:

Alberta Environment (2008), pp. 23-24. Historic calculated from AESO (2010c)

A large fraction of these emissions reductions will be achieved within the electric sector, which accounted for 44.1% of Alberta's *registered* GHG emissions as of 2008 as shown in Table 2, although only approximately 21% of *total* emissions as shown in Figure 3.⁴⁴ Table 2 shows that the utilities sector contributes more registered emissions than any other sector.⁴⁵ The high

generators and 1.0% for gas generators. Calculation based on emissions rates from Alberta Environment (2010a).

⁴² *Id.*, pp. 23-24. Year 2020 50 MT reduction was explicitly reported, but percentage numbers are estimated from a graphic representation.

⁴³ One MT is equivalent to one million tonnes or one megatonne.

⁴⁴ Total Alberta 2008 emissions of approximately 243 MT from visual inspection of figure in Alberta Environment (2008), pp. 23-24. Total reported and unreported 2008 electric sector emissions were approximately 51.4 MT as explained in footnote 45.

⁴⁵ While the "utilities" sector is almost totally comprised of electric generation plants, emissions from each sector are not strictly separated in all cases. In particular for cogeneration units, the electric-related emissions and industrial process emissions are generally reported together and may be included under either utilities or under another industry such as oil sands mining or petroleum refining. See Alberta Environment (2010a). In an independent calculation of the sector GHG emissions based on AESO data and separating out the cogen emissions attributable to electricity generation, the electric sector emissions

registered proportion from electricity is partly because more than 99% of the GHG emissions in the electricity sector are from large point sources emitting more than 100 kT/yr, while sources from some other sectors, such as transportation, are from diffuse sources and therefore are not covered under the current reporting rules.⁴⁶ Including unregistered emissions, the electric sector accounted for only approximately 21% of Alberta's total GHG output in 2008 as shown in Figure 3.

Table 2
Alberta Registered GHG Emissions by Sector, 2008

Sector	Number of Reporting Facilities	Total Sector Emissions, kT	Percent of Total
Chemical Manufacturing	15	10,270	9.3%
Coal Mining	3	497	0.4%
Conventional Oil and Gas Extraction	29	6,845	6.2%
Mineral Manufacturing	6	2,403	2.2%
Oil Sands In Situ Extraction	13	10,927	9.9%
Oil Sands Mining and Upgrading	5	23,848	21.5%
Paper Manufacturing	4	478	0.4%
Petroleum Refineries	3	3,862	3.5%
Pipeline Transportation	4	2,797	2.5%
Utilities	26	48,903	44.1%
Waste Management	1	90	0.1%
Total	109	110,921	100%

Sources and Notes:

Alberta Environment (2010a), p. 7.

Total Alberta GHG emissions are not represented in this table; only facilities outputting more than 100 kT of CO₂e annually must report their emissions.

Meeting these targets of 15% CO₂e reductions below BAU by 2020 and 50% below BAU by 2050 will have a large impact on Alberta's generation fleet and its energy-only market. Many of the impacts can only be inferred, however, because the measures that will be enacted to meet these goals have not yet been specified. Nevertheless, the most immediate impacts on Alberta wholesale electricity prices and resource adequacy will come from the 2020 goals, toward which the electric sector may have to contribute approximately 15 MT of reductions from CCS, 4 MT from greening production, and 3 MT from efficiency.⁴⁷ These reduction targets may have the following impacts:

were approximately 51.4 MT in 2008, 51.0 MT of which were from units emitting more than 100 kT/yr. This calculation would put electric sector emissions at 45.9% of all registered emissions in Alberta, AESO (2010c).

⁴⁶ One kT is equivalent to one thousand tonnes or one kilotonne. One MT or megatonne is equal to 1,000 kT or one million tonnes.

⁴⁷ Based on approximate BAU emissions estimate, see Footnote 42. Assumes that contributions toward CO₂e reductions by category are the same in 2020 as in 2050, or 35 MT CCS, 9 MT greening production, and 6 MT efficiency over all of Alberta. Electric sector reductions are assumed to be achieved in proportion to

Carbon Capture and Sequestration – Achieving a 15 MT reduction of CO₂e in the electricity sector by 2020 may require approximately 3,620 MW of CCS-enabled coal generation, compared to a coal fleet of 5,780 MW in 2010. The scale and implications of this goal and current large scale CCS projects are discussed in the next subsection.

Greening Energy Production – The largest initiative enacted to date toward achieving 4 MT of CO₂e reductions through greening energy production is Alberta’s Specified Gas Emitters Regulation. This regulation requires GHG reductions below a per-unit historic baseline or else requires payments on excess emissions as discussed further below. Alberta is investing revenue collected under this regulation into carbon-reducing programs and renewable energy sources, the potential AESO impacts of which are discussed further in Section III.E.

Energy Efficiency and Conservation – The Climate Change Strategy’s efficiency goal amounts to approximately 4% consumption reductions below BAU by 2020.⁴⁸ This goal could reduce energy load growth from the forecasted 4.6% to 4.1% annually between 2010 and 2020.⁴⁹ While large efficiency gains would tend to reduce wholesale energy prices and relieve resource adequacy concerns if implemented quickly on a large scale, the gradual introduction planned is unlikely to substantially impact the Alberta energy-only market either in terms of prices or resource adequacy.

Overall, however, Alberta’s climate change strategy may require significant changes to the makeup of the generation fleet, impacting the wholesale electricity prices and resource adequacy.

b. Carbon Capture and Sequestration

The Government of Alberta has awarded \$2 billion in financial commitments to developing four large CCS projects in Alberta, along with \$526 million in federal investments as shown in Table 3. Together, these four projects are expected to achieve 5 MT of annual CO₂ sequestration by 2015.

the electric sector’s share of registered GHG emissions, or 44.1% of the total as shown in Table 2. In reality, the share of reductions required from the electric sector may be greater than from other sectors.

⁴⁸ Percentages assume that efficiency gains in the electric sector will be proportional to its share of the registered Alberta GHG emissions or 3 MT by 2020. From Table 2, the registered CO₂e rate in the electric sector was 48.9 MT in 2008 over 69,947 GWh of AIL from AESO (2010a). At this same emissions rate of 0.70 kT/GWh, a 3 MT reduction by 2020 would require a 4,291 GWh reduction in AIL by 2020 or 3.9% of the current projection of 108,638 GWh.

⁴⁹ Compound annual growth rates calculated from AESO projected Alberta Internal Load (“AIL”) energy of 72,459 GWh in 2010 to 113,652 GWh in 2020 and an alternative 2020 load reduced by 2%. AESO (2010a).

Table 3
Large-Scale CCS Projects under Development in Alberta

Project	Description	Online Date	Generation Capacity	Government Awards, \$M	Annual CO ₂ Sequestration
Swan Hills Synfuels	[1] Underground coal gasification. Above ground separation of syngas from CO ₂ and impurities. Power production from syngas in separate combined cycle facility.	2015	300 MW	\$285 Alberta	1.3 MT
Alberta Carbon Trunk Line	[2] 240 km CO ₂ pipeline from near Fort Saskatchewan south to Clive, to be used for EOR. Initial CO ₂ will come from Agrium Redwater Complex and the North West Upgrading facility once completed.	2012	n/a	\$495 Alberta \$63 Federal	14.6 MT Capacity 1.8 MT Initially
Shell Quest Project	[3] Scotford bitumen upgrader facility.	2015	n/a	\$745 Alberta \$120 Federal	1.2 MT
Project Pioneer on Keephills 3	[4] Carbon capture retrofit to coal plant.	2011 Power Output 2015 Carbon Capture	450 MW	\$436 Alberta \$343 Federal	1 MT

Sources and Notes:

[1 - 4] Alberta Government (2010a); Natural Resources Canada (2010).

[1] Alberta Government (2009).

[2] Enhance Energy, (2010).

Agrium fertilizer plant retrofit is planned to provide 0.25-0.55 MT of CO₂ annually, Agrium (2010).

North West Upgrading will produce 1.3 MT annually from each of 3 identical phases with Phases I and II online 2013 and 2018,

North West Upgrading (2010a-b).

1.8 MT initial output assumes both Agrium and North West Upgrading Phase 1 are operational.

[4] TransAlta (2010).

Two of these planned CCS projects are planned for new coal generation facilities with a total capacity of 750 MW and an expected 2.3 MT of total annual CO₂ sequestration. Once energy consumption of the CCS equipment is accounted for, these projects may contribute approximately 1.7 MT of net avoided CO₂ or 11% of the 2020 GHG reduction target for the electric sector.⁵⁰ If the rate of avoided CO₂ emissions can be improved on future projects to 81% below the emissions rate of a new coal plant without CCS, then an additional 2,880 MW of CCS-enabled coal generation may have to be built or retrofitted by 2020.⁵¹ Combined with the projects currently under way, the potential 3,630 MW of CCS-enabled coal generation by 2020 compares to an existing coal fleet of approximately 5,780 MW as of 2010. This ambitious CCS goal represents a massive build-out of capacity that will likely be too aggressive to achieve. However, if this target is met, CCS-enabled coal will represent two thirds of the current coal fleet

⁵⁰ A fraction of the CO₂ sequestered is not counted toward “net avoided” CO₂ emissions. Net avoided CO₂ emissions are approximately 72%-76% of captured CO₂ emissions for pulverized coal plants because CCS technology consumes power itself, and therefore decreases the net plant capacity rating for power deliverable to the grid. See IPCC (2005), Table 8.3a.

⁵¹ Calculation assumes that 15 MT of the 2020 CCS coal must be met in the electric sector, or a fraction proportional to the currently registered emissions from the utilities sector, of which 1.7 MT will be met by the two electric projects already funded as described in Table 3. Also assumes that 620 kg CO₂/MWh can be avoided and units would operate at 85% capacity factor. See IPCC (2005), Table 8.3a.

and about 21% of the entire Alberta generation fleet by 2020. For comparison, coal currently accounts for 49% of the generation fleet.⁵²

While this estimate of the required CCS-enabled coal generation is only a rough approximation of the investment required to meet the Climate Strategy targets, it can be used to infer the scale of impacts on the AESO electricity market. Large governmental investments in CCS-enabled coal over the coming decade could boost resource adequacy in Alberta by supporting new generation additions or possibly enabling the retrofit and refurbishment of coal units that otherwise would be retired.

These CCS-enabled coal plants may also impact wholesale electricity market prices by operating as “must-run” units to achieve high levels of CO₂ sequestration. If operating as must-run generation, they are likely to bid into the wholesale energy market at or near zero, thereby tending to suppress market prices. During peak hours, this price suppression may not be a problem, especially if peak prices are allowed to rise to levels that can support new entry.

During off-peak hours, however, this addition of must-run units could potentially increase the frequency of surplus supply conditions. At these times, wholesale electricity prices can drop to zero and must-run units will operate at a loss because they are unable to reduce output without incurring even larger shutdown-related costs. During some low-load conditions, the AESO must force these units to ramp down or shut down to maintain system stability, regardless of additional costs. Note that the efficient market price during such events would be negative because generators would rather pay some amount (up to their shut-down-related costs) than be forced to reduce output further, as discussed further in Section III.D. The economics of must-run coal, cogeneration and, increasingly, wind generation already result in occasional surplus supply conditions. Due to the low dispatch flexibility of CCS plants, the frequency and severity of these conditions could increase as CCS generation expands.⁵³

c. Specified Gas Emitters Regulation

Alberta’s Specified Gas Emitters Regulation went into effect July 1, 2007, requiring emissions reductions from all Alberta facilities outputting more than 100 kT of CO₂e annually.⁵⁴ These facilities were assigned a GHG emissions intensity reduction target of 12% below their baseline output established over 2003-2005.⁵⁵ For electric generators, this target is a requirement to reduce the quantity of CO₂e emitted per MWh produced. In order to comply with the regulation, facilities have four options:

- Improve the efficiency of operations to reduce per-unit output by 12%,

⁵² Year 2020 percentage assumes installed capacity will be equal to projected Alberta Internal Load of 15,160 MW plus a 15% reserve margin; current effective installed capacity is 11,730 MW assuming that hydro dependable capacity is 67% of installed capacity and wind dependable capacity is 0%. From AESO (2010a), AESO (2010c).

⁵³ For a full analysis of minimum generation conditions in AESO, see AESO (2010b).

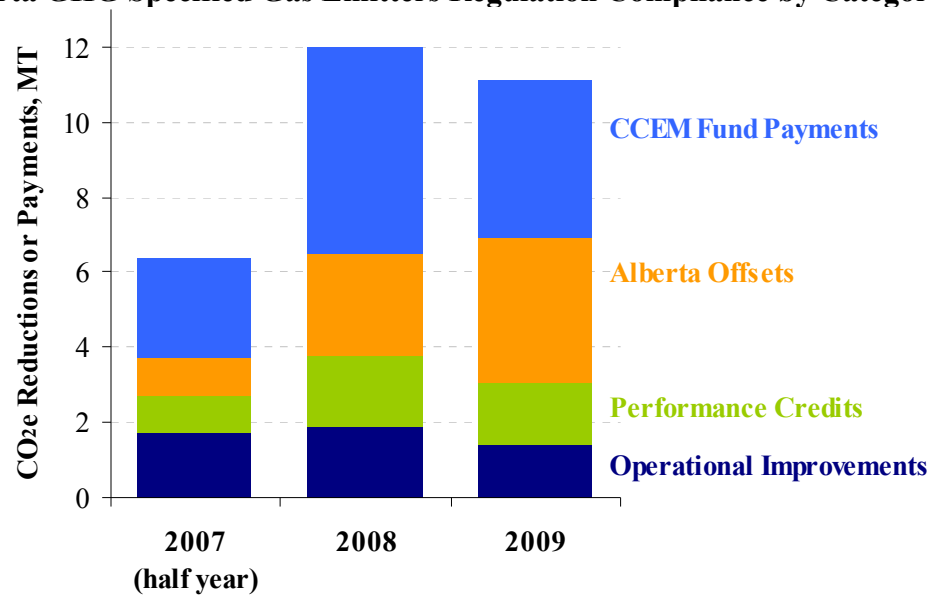
⁵⁴ See Alberta Government (2007a), pp. 5-7.

⁵⁵ 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.

- Contribute \$15/tonne of CO₂e to the Climate Change and Emissions Management (“CCEM”) Fund, which invests these funds in projects to reduce emissions elsewhere,
- Purchase offset credits for CO₂e emissions from Alberta-based projects that reduced output but are not covered by the regulation, or
- Purchase performance credits from other Alberta GHG emitters that exceeded their 12% GHG reduction target.⁵⁶

Year 2009 program results show that Alberta-wide reductions targets were approximately 11 MT in total and approximately 4.9 MT for the electricity generation sector. Of the total from all sectors, 38% or 4.2 MT of the reductions target were met via payments to the CCEM, 28% or 3.1 MT were met by either operational improvements or performance credits to facilities covered by the regulation, and the remaining 34% or 3.8 MT were supplied by Alberta-based CO₂e offsets as shown in Figure 4.

Figure 4
Alberta GHG Specified Gas Emitters Regulation Compliance by Category



Sources and Notes:

Alberta Government (2010c).

These compliance requirements put a cost burden on large GHG emitters participating in the Alberta market. As of 2009, there were approximately 4,090 MW of natural gas and 6,060 MW of coal plants subject to this regulation, representing 85% of Alberta’s generation fleet.⁵⁷

⁵⁶ See Alberta Government (2010b), pp. 2-3.

⁵⁷ Based on 2009 effective installed capacity of 11,920 after accounting for a 67% net dependable capacity rating for hydro and 0% dependable for wind. Determination of units covered by the regulation is based on a calculation of estimated GHG output in 2009 for each unit from AESO internal generation data and estimated heat rates, AESO (2010c), Ventyx (2010).

Covered suppliers are likely to pass these increased production costs through to the wholesale electricity market in the form of increased offer prices to the extent that their offer prices are based on their marginal production cost rather than strategic bidding.

To scale the total impact that this regulatory requirement may have on the market, we can examine a case in which suppliers meet their entire regulated efficiency reduction through \$15/tonne CO₂e payments. Table 4 shows the approximate impact that paying full price for these emissions would have on the production cost for gas and coal units. As the table shows, if the full \$15/tonne compliance cost is paid, then this regulation increases production costs by approximately 2% for natural gas-fired combustion turbine (“CT”) and combined cycle (“CC”) plants, and by approximately 13% for coal plants.

Table 4
Approximate Production Cost Impact of Alberta CO₂ Emissions Regulation

		Gas CC	Gas CT	Coal
Assumptions				
Fuel Cost, \$/GJ	[1]	6	6	1
Heat Rate, GJ/MWh	[2]	7.7	13.2	10.4
GHG Rate, kg/GJ	[3]	56.6	56.6	103.1
CO ₂ e Cost, \$/tonne	[4]	\$15	\$15	\$15
Fraction of CO ₂ e Output Charged	[5]	12%	12%	12%
Costs, \$/MWh				
Fuel	[6]	\$46.29	\$79.43	\$10.37
VOM	[7]	\$2.22	\$3.84	\$4.93
CO₂e	[8]	\$0.79	\$1.35	\$1.92
Total Cost w/o CO ₂ e Charges	[9]	\$48.50	\$83.26	\$15.30
Total Cost w/ CO ₂ e Charges	[10]	\$49.29	\$84.61	\$17.22
% Cost Increase w/ CO₂e Charges	[11]	1.6%	1.6%	12.6%

Sources and Notes

- [1] Mine-mouth coal cost assumption provided by AESO.
- Approximate average AECO C price over 2008-09, Bloomberg (2010).
- [2] AESO class average fully loaded heat rate from Ventyx (2010).
- [3] CO₂ rate from EIA (2010b).
- Ratio of CO₂e to CO₂ calculated from Alberta Government (2010b).
- [4] Alberta Government (2007).
- [5] Alberta Government (2007).
- [6] = [1] * [2]
- [7] See Table 8.2, EIA (2010a). Converted to 2010 CAD.
- [8] = [2] * [3] * [4] * [5] / 1000
- [9] = [6] + [7]
- [10] = [6] + [7] + [8]
- [11] = ([10] - [9]) / [11]

Because the payments apply to only 12% of total plant output, the increase in production costs associated with this regulatory requirement is quite small, amounting to approximately \$0.80/MWh to \$1.90/MWh. The cost impact on natural gas plants is comparable to the impact of a 2% increase in natural gas prices, a minor impact compared to the daily and monthly

volatility of gas prices.⁵⁸ Given the small scale of this impact, it appears that the Specified Gas Emitters Regulation is unlikely to substantially impact retirements or resource adequacy. The cost of emitting CO₂e and the portion of the sector's output that is covered by the regulation would have to be increased substantially before the regulation would have a material impact on the economics of existing units or the wholesale electricity market.

2. Federal Carbon Policy

Federal GHG reduction goals are substantially more ambitious than Alberta's. The Canadian federal government has committed to reducing GHG output to 17% below 2005 levels by 2020, compared to the Alberta goal of 21% *above* 2005 levels by 2020.⁵⁹ The federal government announced this regulatory framework for GHG emissions reductions in 2007, but the framework has not been translated into binding regulation in time to meet the original 2010 reductions goals. Although the Alberta regulation discussed in Section III.C.1.c remains the only binding GHG regulation currently affecting Alberta, the more ambitious federal commitment highlights the possibility of substantial federal mandates.

A federal policy that would have a large impact on Alberta is the coal generation performance standard proposed by the Minister of the Environment on June 23, 2010, for which draft regulations may be published in spring 2011.⁶⁰ The proposed regulation would effectively phase out all coal generation in Canada without CCS. The proposal would require coal plants to meet a strict performance standard based on CCS technology, or else retire after the later of its 45th operating year or PPA expiration. In order to build new coal plants or extend the lives of existing coal plants, operators would have to meet a GHG emissions performance standard of approximately 360 to 420 kg of CO₂e/MWh, putting it in the range of the emissions rate of a natural gas-fired CC or a CCS-enabled coal unit with an overall 50% rate of net avoided CO₂e.⁶¹

The entire Alberta coal fleet would be affected by this regulation, but the impact would be phased in over the next twenty years, as shown in Figure 5. The figure shows Alberta coal capacity that would be subject to retirement under the regulation. These retirements add up to an overall retirement rate of approximately 210 MW per year starting in 2015. This is 1.5 times the retirement rate observed in Alberta over the past decade.⁶² The retirements driven by this

⁵⁸ For example, in 2009 daily AECO C gas prices had a standard deviation of 26% of the average annual value, while monthly gas prices had a standard deviation of 25% of the average. Bloomberg (2010).

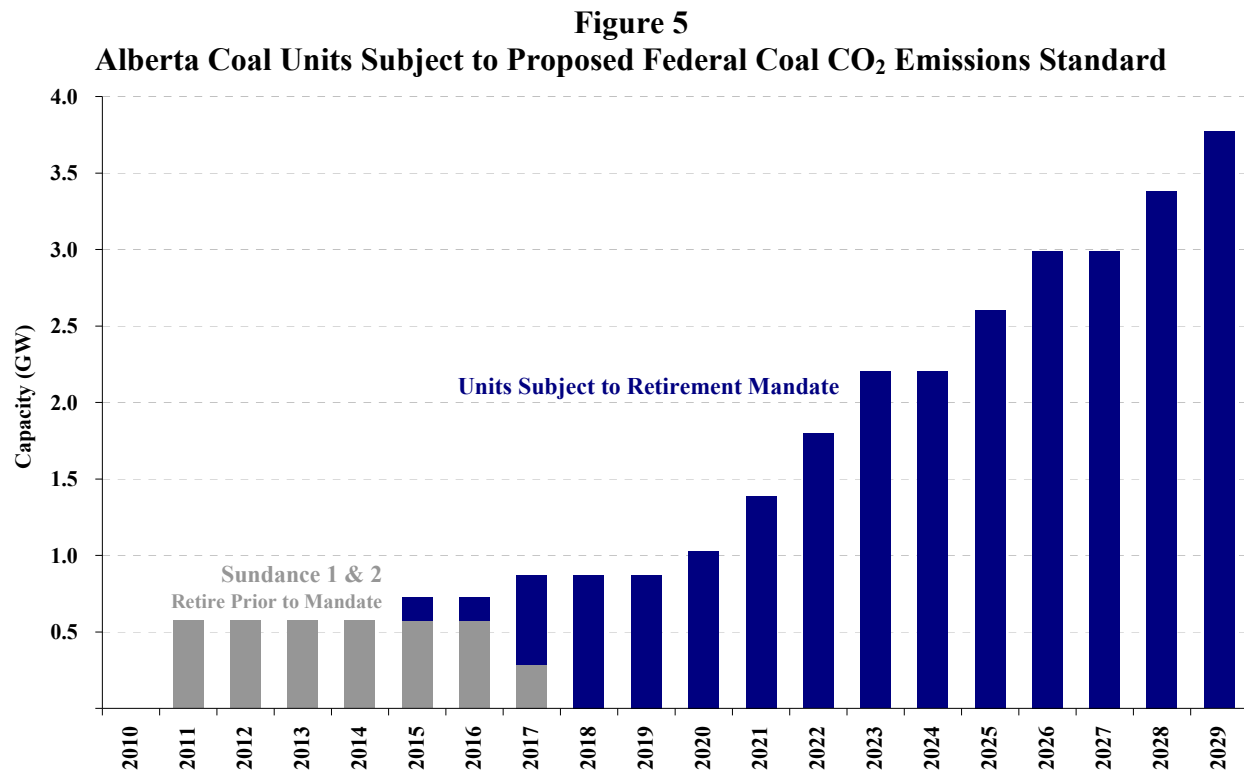
⁵⁹ See Environment Canada (2010a).

⁶⁰ See Environment Canada (2010a-b).

⁶¹ Note that the total rate of avoided CO₂e is lower than the rate of captured CO₂e because of the efficiency losses associated with CCS. For comparison, the emissions rate of a typical gas CCs is approximately 344 to 379 kg/MWh and the emission rate for a new coal unit without CCS is approximately 736 to 811 kg/MWh. See IPCC (2005), Table 8.1.

⁶² Over 2001 through 2010, the annual retirement rate in AESO has been approximately 150 MW per year. AESO (2010c). Note that these numbers are different from those reported on page 2. Page 2 reports the total retirements over 2011-29 projected by AESO in their long-term planning activities, including Sundance 1 and 2 and some adjustments to assumed retirements timing as informed by factors other than just the federal coal mandate. The numbers here cover a shorter time span, exclude Sundance 1 and 2, and include only retirements that would be driven by the federal coal mandate over 2015-29.

potential federal mandate, along with retirements that may occur for other reasons, would noticeably increase the rate of new plant additions required to maintain resource adequacy.



Sources and Notes:

Sundance 1 & 2 retirement mandates would have been in 2017 and 2018 respectively. No units will be under PPA past their 45th year.

Terms of retirement mandate from Environment Canada (2010a-b).

Unit online date and MW rating from Ventyx (2010) and AESO (2010c).

D. AIR QUALITY EMISSIONS REGULATION

In Alberta, air quality emissions from the electric sector are regulated under the Emissions Management Framework for the Alberta Electricity Sector. The framework was developed by the Clean Air Strategic Alliance (“CASA”) stakeholder group and proposed to Alberta Environment in 2003.⁶³ The original framework standards were adopted in 2006, as was the recommendation that the group reconvene each five years to determine whether new substances need to be covered or whether standards need to be tightened.⁶⁴ Currently, the framework is implemented under two sets of emissions standards, one standard covering SO₂, NO_x, and particulate matter (“PM”), and another standard covering mercury.

Emissions of SO₂, NO_x, and PM are covered under the Alberta Air Emissions Standards for Electricity Generation. These standards set out maximum emissions rates for new units, after the 50th operating year for coal units, after the 40th operating year for most natural gas units, and

⁶³ See CASA (2003).

⁶⁴ See CASA (2010), p. 1; Alberta Environment (2010c).

after the 60th operating year for gas peaking units.⁶⁵ The allowed emissions rates are set based on a determination of the best available technology economically achievable (“BATEA”), which may improve over time and will therefore result in more strict emissions standards over time. These emissions standards somewhat increase the costs of building new units by requiring that new generators have pollution controls. For aging units past their design life, these standards are likely to require a retrofit installation of emissions controls for the unit to continue operating. For many units, the costs associated with these upgrades may be too high relative to potential going-forward operating margins to remain viable. For this reason, these control standards could force some aging units to retire before these controls would need to be installed.

Figure 6 shows the timeline over which the existing AESO coal and gas fleet will be subjected to these SO₂, NO_x, and PM standards. This 50-year coal retirement timeline corresponds to a 5-year delay relative to when the federal coal retirement mandate would force coal plants to retire. For this reason, if the federal coal mandate is enacted, the Alberta air quality standard will have no incremental effect on coal retirements or resource adequacy. In either case, the standard *will* have an incremental impact on natural gas units past their 40th operating year or past the 60th operating year for peaking units. Overall, these standards could force 1,630 MW of coal and 460 MW of natural gas plant retirements by 2029.⁶⁶ While the quantity of capacity affected is large, the resource adequacy impact is likely to be very limited because of the gradual timeline and the imposition of standards only on older units that are already past their design life.

Alberta’s Mercury Emissions from Coal-Fired Power Plants Regulation is an additional emissions standard based on output levels under BATEA.⁶⁷ However, the mercury standard is imposed on all existing generators at the same time regardless of the unit age. In order to comply with the mercury standard, coal generators had to meet the following requirements by the first of the year:

- Continuous monitoring equipment installed by January 1, 2010
- 70% mercury capture by January 1, 2011
- 80% mercury capture by January 1, 2013

The mercury standard was implemented with some flexibility that allowed some older units to avoid installing mercury controls as long as they committed to retiring by unit-specific deadlines over the 2012-17 timeframe.⁶⁸ Of these, Sundance 1 and 2 may already be considered retired for unrelated reasons, but all other coal facilities in Alberta will meet the mercury standard.⁶⁹ The recent CASA review contained recommendations for increasing flexibility in meeting the requirement by allowing credits for early reductions that could later be used at the same facility

⁶⁵ Peaking units are regulated based on an annual total emissions limit that assumes approximately 1500 MW of operation per year, see CASA (2010), Sections 3 and 6; Alberta Environment (2005).

⁶⁶ Note that Sundance 1 and 2 are excluded from this total as they may have already retired, pending determination of whether repowering will occur.

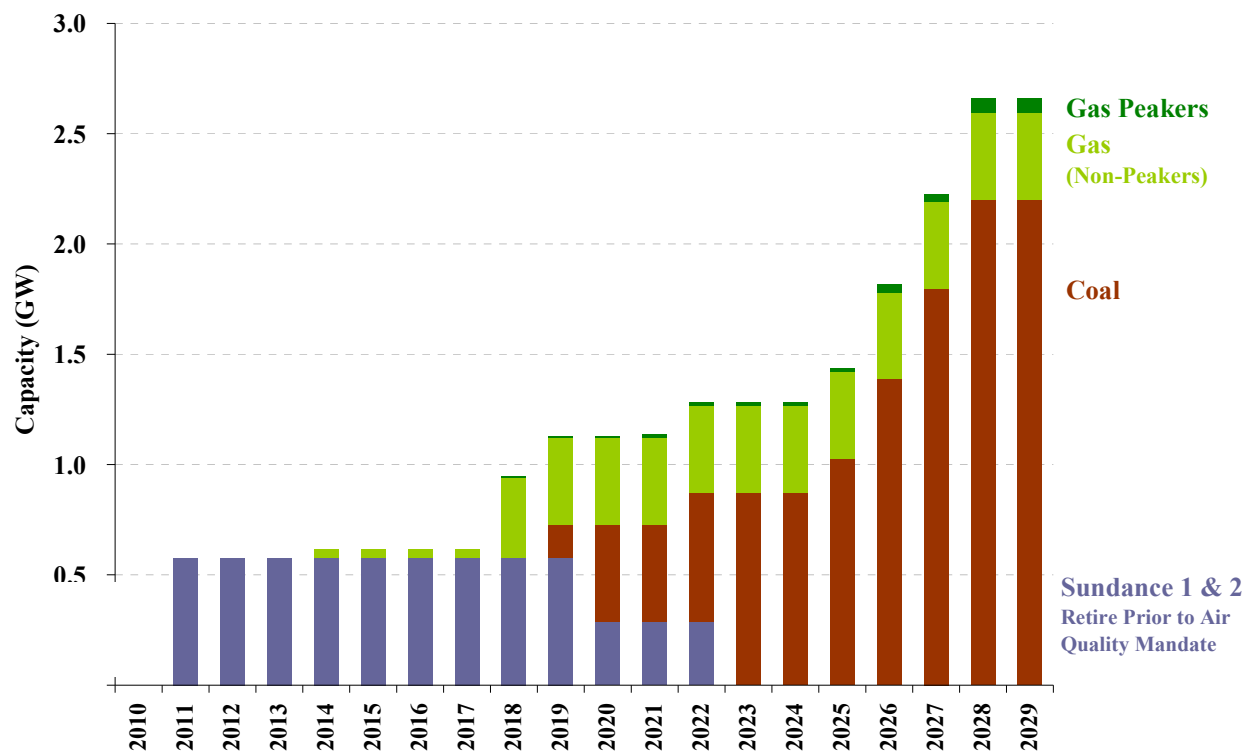
⁶⁷ See Alberta Government (2006).

⁶⁸ Specifically, HR Milner would have had to retire by 2012, Battle River 3 and 4 by 2015, and Sundance 1 and 2 by 2017. See Alberta Government (2006), p. 4.

⁶⁹ Confirmed via personal communication with Alberta Environment staff director of the mercury program. Note that Sundance 1 and 2 will retire early in advance of the air quality mandate because of unrelated large investment costs that would be required for continued operation. See TransAlta (2011).

if it had equipment problems.⁷⁰ Overall, it appears that the mercury standard has been successfully implemented without imposing any resource adequacy concerns and even without imposing any incremental retirements.

Figure 6
Capacity Subject to Provincial Air Quality Emissions Standards



Sources and Notes:

Peaking units identified as units operating at less than 17% capacity factor, see p. 4, Alberta Environment (2005) and AESO (2010c).

Unit online date and MW rating from Ventyx (2010), AESO (2010c), and Alberta Environment (2005).

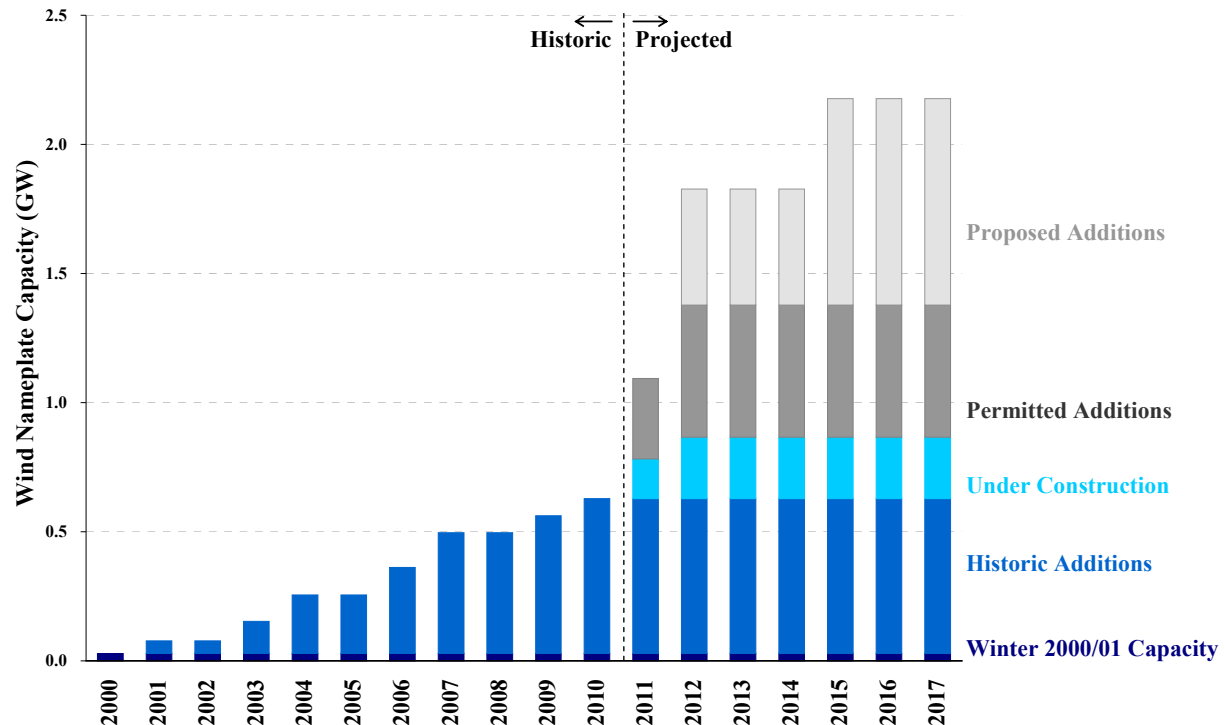
E. WIND INTEGRATION AND ANCILLARY SERVICES

Wind generation capacity in Alberta has increased quickly over the past decade, from 30 MW in 2000 to 630 MW in 2010 as shown in Figure 7. These increases in wind capacity can be expected to continue, with 240 MW of wind currently under construction and another 1300 MW either permitted or proposed. While many of the proposed or even permitted projects may never get built, they do indicate a high level of continued investor interest. The large increases in wind penetration have been driven by a variety of policies subsidizing wind. For example, wind suppliers are eligible to create and sell Alberta-based GHG offsets under the Specified Gas Emitters Regulation discussed in Section III.C.1.c and are now able to sell renewable energy

⁷⁰ Assuming the recommendations are adopted, 50% of the early reductions above 75% capture would earn a credit starting 2011, while 50% of reductions above 80% would earn a credit starting 2013. These credits could not be used to delay controls upgrades or transferred to other facilities, but they could be used to offset excess emissions caused by maintenance or operational issues. All credits would expire by the end of 2015. See CASA (2010), p. 4.

certificates to allow utilities in California to meet the state's ambitious renewable energy standards.⁷¹

Figure 7
Historic and Potential Future Wind Capacity Growth



Sources and Notes:

Unit online and retirement dates and MW rating from Ventyx (2010) and AESO (2010c).

Units under construction, permitted, and proposed from AESO (2010d).

Large wind penetration levels can introduce a variety of operational challenges as the system operator must develop wind forecasting capability and operate the power grid with a highly intermittent generation resource. The risk of sudden drop-off in wind output increases the need for additional operating reserves. Unexpectedly high wind output during low load periods can also create operational challenges by creating minimum generation conditions in which market prices are zero, baseload generators are operating at minimum output, and the system operator must order further involuntary generation reductions or shutdowns. These operational challenges are the subject of ongoing market design effort by AESO and stakeholders to address increasing wind penetration in the near term and longer term.⁷²

High levels of wind generation can also introduce long-term resource adequacy challenges. Due to intermittent output levels, wind resources have very little capacity value during peak load conditions. Alberta's capacity factor during peak times is higher than in many other systems, simply because Alberta's peak load and highest wind season both occur in winter. In fact, the wind capacity factor is about 41% over November-January, which is much higher than the

⁷¹ See Herndon (2011).

⁷² See AESO (2010b); AESO (2010h).

approximate 29% annual capacity factor..⁷³ However, this capacity factor substantially overstates the *capacity value* of wind, because wind is not firm supply and will be unavailable periodically despite relatively high average monthly output. For example, Midwest ISO studies have shown that only 8% of a wind turbine's nameplate capacity can be reliably counted toward the overall system installed capacity although the wind fleet has a 27% average capacity factor.⁷⁴

While not contributing substantially to system adequacy, wind generation does have a large impact on the energy market because it enters the supply stack at zero (or even negative) marginal cost. These negative marginal costs can arise if suppressing power output during high wind conditions causes lost revenues from renewable energy credits (RECs) or if it imposes additional O&M costs to slow turbine speeds. Wind generation consequently tends to depress average energy prices and reduce the net revenues received by other generators, making them more likely to retire and potentially making it less likely that new resources are built. Figure 8 shows the short-term price impact of wind output fluctuations, by separately showing the price duration curves for high-wind and low-wind hours during 2008-10. The figure shows that low-wind hours with less than 100 MW of wind output had an average price of \$77/MWh, while high-wind hours with more than 400 MW of wind had an average price of \$42/MWh. However, this does not mean that 300 MW of wind can suppress average prices by more than \$30/MWh, because the analysis does not control for factors such as natural gas price changes, time of day, or the difference between forecasted and realized wind output. Nevertheless, the figure highlights the importance of monitoring and further analyzing the potential price-suppressing effects of additional wind investments.

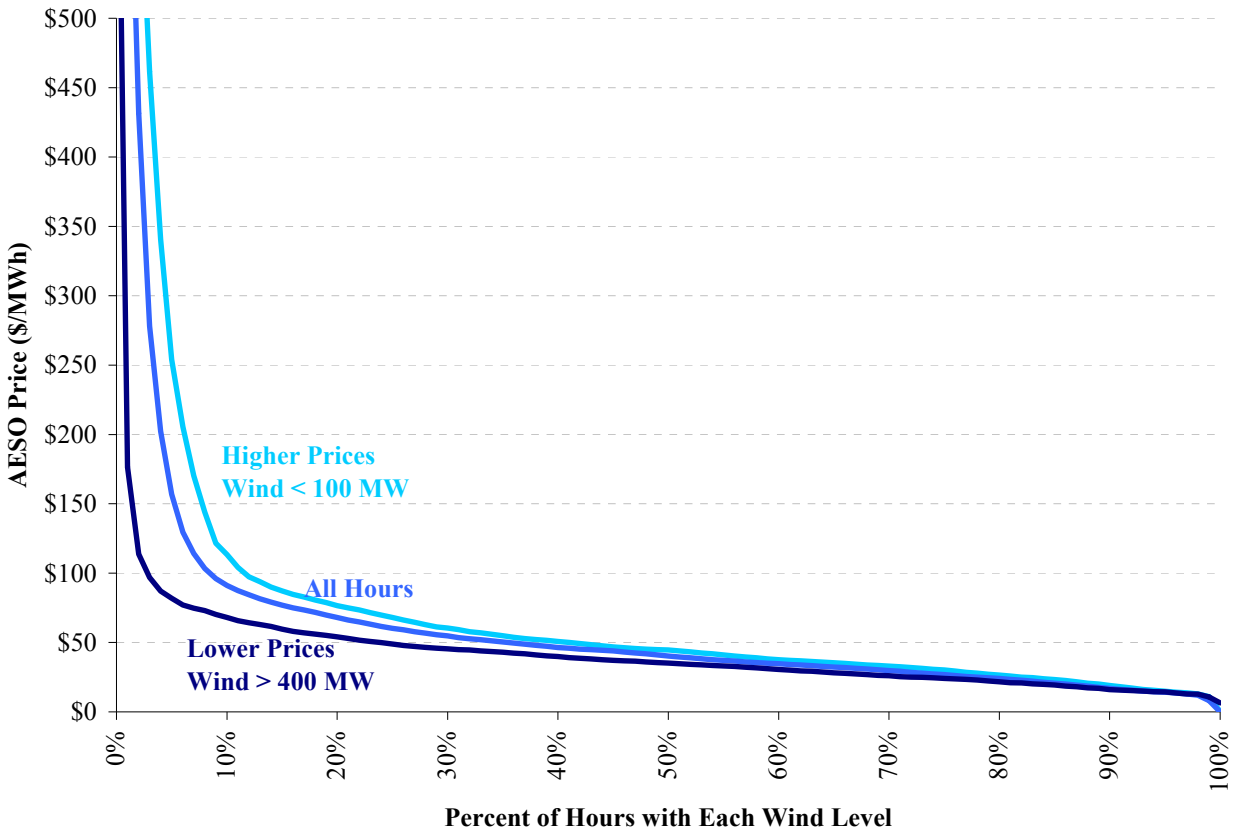
The lower energy prices during high wind events do not mean that energy market prices will need to be artificially propped up or otherwise revised. In fact, low or even negative hourly prices during high wind hours correctly represent the short-run marginal cost of supply at those times, which is the efficient energy price signal at these specific instances in time. In fact, negative prices would enhance market efficiency by creating an additional incentive for wind and other suppliers to ramp down or for load to ramp up during high wind events, making flexibility more valuable. While some market participants may fear that negative prices will undermine overall incentives for conventional generation investment, we believe that this will not be the case as long as ancillary services requirements and operational requirements on wind suppliers are carefully designed. The overall market impact of increased wind integration should be to increase the value of flexible generation and demand response relative to inflexible generation.

The immediate-term effect of wind generation-related price suppression may be to replace more traditional resources that have high capacity value with wind resources that have very little capacity value, reducing the system reserve margin. The lower system reserve margin, however, would increase price spikes in response to low-wind conditions. This will tend to increase average prices and price volatility, but will also prevent further deterioration of reserve margins by making it more attractive to build flexible generating resources that can take advantage of the higher prices and price volatility.

⁷³ Calculated from hourly wind data and wind installed capacity data from AESO (2010c).

⁷⁴ See Midwest ISO (2009), pp. 3, 13.

Figure 8
Price Duration Curve at Different Levels of Wind Output



Sources and Notes:

AESO analysis of hourly wind and price data over Jan. 2008 through Nov. 2010.

Finally, increased wind generation will also increase the need for operating reserves. If additional reserves requirements are instituted, flexible resources will become, again, more valuable because of their ability to provide operating reserves. The Alberta generation fleet may also have some additions from less flexible, new baseload generation sources, such as new cogeneration for the oil sands industry and coal plants fitted with CCS. This means even if resource adequacy can be maintained, the added wind generation may create system operations challenges. This added challenge will require continued close attention to current market design efforts to facilitate the integration of additional wind resources.⁷⁵

The quantity of reserves that are currently required are somewhat variable, but the average level of operating reserves scheduled over 2009 is shown in Table 5. The table also shows the total fleet capability for supplying operating reserves of each type, based on AESO's qualified provider list. Note that the total capability for reserves is less than the sum of the capability for each individual type of reserves because suppliers cannot supply their maximum capability for more than one type of reserves at a time. Overall, the fleet capability is 6 times the currently

⁷⁵ See AESO (2010b); AESO (2010h).

required level of regulating reserves, 9 times the required spinning reserves, 12 times the required supplemental reserves, and 4 times the total simultaneously required reserves.

Table 5
Operating Reserves Need and Fleet-Wide Capability

	Average Scheduled in 2009			Fleet-Wide
	Active	Standby	Total	Capability
	MW	MW	MW	MW
Regulating	160	131	290	1,785
Spinning	243	106	350	3,148
Supplemental	243	37	280	3,502
Total	646	274	920	3,780

Sources and Notes:
AESO (2010c).

AESO has examined the potential for mitigating wind variability by increasing regulating reserves capability, among other options. In a year 2020 scenario with 4,000 MW of installed wind capacity, the AESO analysis found that an additional 300 MW of regulating reserves could mitigate approximately half of the Area Control Error (“ACE”) events, although 2,000 MW of regulating reserves would be required to resolve 98% of the events.⁷⁶ An increase in regulating reserves of this magnitude would be difficult to achieve, since it is higher than the currently installed capability. However, it is likely within a potential feasible range by the time overall growth in the generation fleet by 2020 is accounted for. Further, it is likely that much of the difficulty with wind variability can be mitigated with other options that AESO is considering including acquiring additional operating reserves from demand response and placing additional requirements on wind generators.

Finally, if AESO increases reserves requirements, market prices for reserves are also likely to increase and help attract incremental reserves. If resources that can provide operating reserves become scarce relative to increasing demand for such reserves, then prices for reserves will tend to rise relative to the price of energy. This should support the entry by resources that can provide operating reserves beyond what is reported in Table 5. High reserves prices could even attract additional reserves supply from the existing fleet as some suppliers may choose to invest in upgrading their reserves capability, for example, by adding active generation controls (AGC) that would allow them to supply regulation.

The total system capability for supplying operating reserves can also be increased through the integration of demand-side resources. This could be achieved through market designs that reduce barriers that limit the participation by demand-side resource in energy markets and operating reserves.⁷⁷

⁷⁶ See AESO (2010h), pp. 15-16.

⁷⁷ This option is discussed in a forthcoming *Brattle* study for AESO, *Demand Response Review*, by Johannes Pfeifenberger and Attila Hajos.

F. EXPANDED INTERCONNECTIONS WITH NEIGHBORING MARKETS

Alberta currently is only weakly interconnected with neighboring systems, but the Alberta government, in its Provincial Energy Strategy, has set out a policy objective of expanding interties with neighboring markets. By expanding these interconnections, the government aims to increase reliability, supply adequacy, market competitiveness, and access to wind generation.⁷⁸ However, expanding interconnections to neighboring markets, all of which have resource adequacy requirements, also introduces risks which must be monitored carefully. This includes the possibility that the interaction with external markets could depress Alberta market prices and deter needed investment in new resources, thereby decreasing long-term supply adequacy and reliability.

The Alberta electric system currently has two major 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 Alberta-internal transmission constraints and other operational restrictions.⁷⁹ The BC Hydro intertie has a design rating of 1,200 MW for imports and 1,000 MW for exports, but currently has a maximum ATC value of only 650 MW for imports and 735 MW for exports.⁸⁰ The Saskatchewan intertie design rating is 150 MW for imports and exports and its ATC has recently been restored to its design rating.⁸¹ The ATC on the BC Hydro intertie is also anticipated to be restored to its original design ratings after the creation of intertie restoration products including load shed service and other system enhancements.⁸²

In addition to restoring intertie ATC to design rating, there is one intertie project that will further expand Alberta’s interconnections with neighboring markets, although it will not necessarily increase ATC. This new intertie is the 300 MW Montana-Alberta Tie Limited (“MATL”) line that is currently under construction with an estimated online date in late 2011. In addition, the AESO has begun considering several other potential interconnection options, although specific projects have not yet been determined.⁸³

Expanded interconnections increase market efficiency by allowing more power to flow from locations with lower-priced supplies to locations with higher-priced supplies. These increased transmission flows tend to reduce price differentials between regions by increasing prices and supplier profits in the lower-priced locations while decreasing prices and supplier profits in high-

⁷⁸ See AESO (2009a), pp. 10, 14, 26-27.

⁷⁹ The north-south transmission constraint between Calgary and Edmonton is the primary constraint reducing intertie ATC values to below design ratings. Both the BC Hydro and Saskatchewan interties are connected south of AESO’s north-south transmission cut plane, which places a limit on the total imports and exports that can be scheduled. The loss of an intertie would represent too large a contingency for the system south of the cut plane to absorb by itself. From communication with AESO staff and AESO (2009a), Section 4.3.

⁸⁰ Current value from AESO staff; design rating from AESO (2009a).

⁸¹ Current value from AESO staff; design rating from AESO (2009a), p. 303.

⁸² Based on communication with AESO staff and AESO (2009a), p. 39.

⁸³ The expansion paths being considered include: southern Alberta to Saskatchewan and Manitoba, southern Alberta to the US Pacific Northwest, northern Alberta to northern BC, and northern Alberta to northern Saskatchewan. See AESO (2009a), p. 36 and Section 4.9.3.

priced locations. Because Alberta is typically an exporter at night and an importer during the day, expanded interconnections may increase off-peak prices while decreasing on-peak prices.⁸⁴

The combined impact from both effects is likely to be a suppression of Alberta prices overall, given that Alberta prices are higher on average than are those of its neighbors as shown in Figure 9. Part of the reason for the lower energy prices in neighboring markets is that these other markets are cost-of-service regulated, meaning that suppliers recover the capacity costs of their generation through regulated retail rates or through public ownership as in British Columbia rather than solely through wholesale market prices for energy. Other more distant markets, such as California, have resource adequacy requirements that allow suppliers to earn capacity payments through a bilateral market to supplement their energy market revenues.⁸⁵ As a consequence, the energy prices of neighboring regions typically reflect only short-term generation dispatch costs without sufficient contributions to recover investment costs. This is in contrast to AESO, where suppliers need to recover their investment costs through the wholesale energy and ancillary service markets.⁸⁶

Price suppression in Alberta's energy-only market through expanded interties is likely to be magnified by an increase in imports from zero-marginal-cost technologies, such as new wind generation. For example, the MATL developer has predicted that adding the new transmission line will allow for the development of a large wind farm at its source in Montana.⁸⁷ Similarly, increased intertie capacity with BC Hydro will interconnect Alberta more heavily with a market that is planned to become a large exporter of green power, likely from wind and hydro, which could further depress Alberta energy prices because of lower energy prices in British Columbia.⁸⁸

These low-marginal-cost imports would directly benefit Alberta customers in the near term. However, in the long term, the price suppression would reduce the profitability of generation resources in Alberta, which would make it less likely that new resources would be built while increasing the likelihood that existing generators would retire prematurely. These impacts could tend to reduce the reserve margin within Alberta and make the system more dependent on the interties for resource adequacy.

⁸⁴ See AESO (2009a), p. 50.

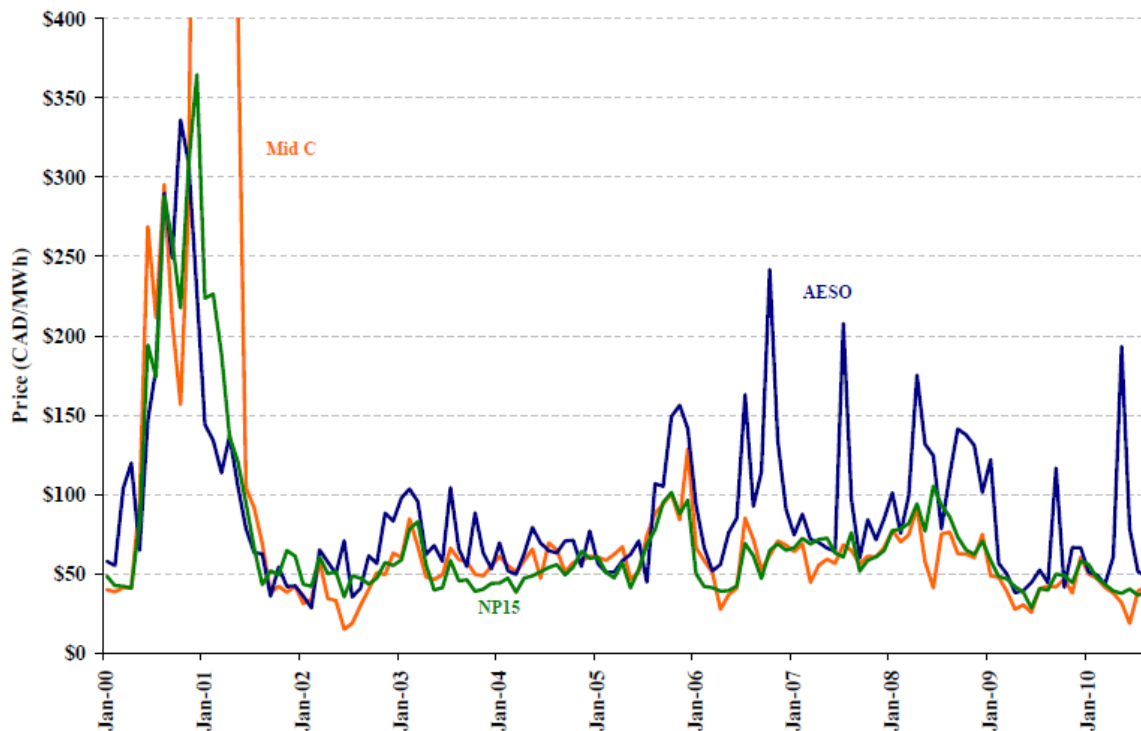
⁸⁵ See CPUC (2006); Blakes (2008), Section VI.

⁸⁶ See Section II.A for more discussion of the difference between energy-only markets and markets with resource adequacy standards.

⁸⁷ See Puckett (2009).

⁸⁸ See BC Government (2010), Section 2.n.

Figure 9
Monthly On-Peak Energy Prices in Alberta, Northern California, and Mid-Columbia



Sources and Notes:

Bloomberg (2010); Ventyx (2010); and UCEI (2003).

Prices for North Path 15 ("NP15") are zonal prices until April 2009, after which NP15 Gen Hub is shown.

NP15 and Mid C prices converted to CAD from USD, Bloomberg (2010).

While expanded interconnections increase the capability for importing power, they do not guarantee that external supplies will be available for import when they are needed most. This is because generators in neighboring markets tend to be obligated to supply their local customers during peak load conditions. If such peak load or emergency conditions occur simultaneously in Alberta and neighboring markets, Alberta will not be able to import the needed supplies no matter how much intertie capacity is available and no matter how high the AESO price. It also means that the resource adequacy value of the increased interties is limited to a probabilistic value that depends on the extent to which neighboring markets are over-built beyond their own resource adequacy requirements and the extent to which those markets experience system peak conditions at times different from Alberta.

In addition, shortage conditions in neighboring markets can introduce supply shortages in Alberta. Because Alberta generators do not have the *obligation* to serve Alberta load, they have the option to export power to neighboring systems even during peak conditions and would rationally choose to do so any time external power prices are higher.⁸⁹ The converse is not true, however. Because generators in neighboring markets will typically not be able to sell power into

⁸⁹ This impact applies to peak conditions only prior to the initiation of emergency procedures, as AESO will intervene to curtail exports to zero during peak load conditions. See AESO (2010f).

Alberta during emergencies, this means that neighboring markets are largely insulated from any resource adequacy challenges in Alberta.⁹⁰

The scale of the impact that shortages in external markets may have on Alberta can be gauged to some extent by examining the level of correlation that already exists between prices in Alberta and those in neighboring markets. Figure 9 shows electricity prices in Alberta compared with electricity prices in Northern California and Mid-Columbia in Washington, the two closest liquid power trading hubs with transparent market prices. While the figure shows a strong correlation among the electric prices in the three locations, this is somewhat misleading since a significant portion of the common price movements starting in 2001 have been driven by changes in the regional price for natural gas.⁹¹

The extreme high prices in the year 2000 affecting all three locations were caused by the California power crisis.⁹² These extreme price conditions during 2000 were driven partly by tight supply conditions and partly by market power abuses. The market power abuses have been the subject of substantial litigation, investigation, and damages settlements before the Federal Energy Regulatory Commission (“FERC”) in the United States, and also have been investigated for their impact on Alberta by the Market Surveillance Administrator (“MSA”).⁹³ The experience does highlight the point that real *and even manipulated* shortages in neighboring markets can substantially impact Alberta. Expanding interconnections will further increase AESO’s exposure to the market fundamentals and potential shortages in neighboring markets in the future. At the same time, as Figure 9 also shows, the price spikes that occurred in the Alberta energy market since 2006, with proximate causes often related to short-term supply adequacy problems, had virtually no impact on the market prices in these neighboring regions.

These factors mean that the expansion of interconnections with neighboring markets will require the AESO to increase the extent to which it monitors for potential shortage conditions, including assigning a realistically low capacity value to total import capability. It also means that the AESO should maintain its procedures for limiting exports during scarcity conditions, and not introduce firm export transmission service without careful consideration of the potential resource adequacy consequences.⁹⁴

⁹⁰ If Alberta had the potential to become a large net exporter of power, then increased interties would have the potential to increase reliability in Alberta by incenting generation build-out in excess of supply needs to meet export demand. This scenario would only materialize if Alberta had structural potential for lower-cost energy market prices over the long run, even after accounting for the capital cost recovery required through Alberta’s energy market (compared to Alberta’s neighbors which award cost recovery outside the energy market).

⁹¹ Excluding the year 2000, the R^2 values of predicting AESO prices from Mid-Columbia and Northern California power prices are 0.122 and 0.221 respectively, while AESO, Mid-Columbia, and Northern California power prices have R^2 values of 0.227, 0.119, and 0.302 when predicted by gas prices.

⁹² Natural gas prices were also high during the year 2000, but no higher than in other years with moderately high electric prices such as 2005.

⁹³ While the investigation into the bidding strategies and intertie conduct of Enron Canada Corporation and Powerex Corporation did not uncover prohibited behaviors, it did result in the revision of rules governing intertie conduct that would prevent those behaviors in the future. See MSA (2005); FERC (2010).

⁹⁴ No similar concern would be introduced by allowing for firm import capability, which would allow for the possibility that suppliers would have the firm option to sell into Alberta. However, only external suppliers

IV. SUPPLY-DEMAND OUTLOOK

This section of our report reviews historic levels of capacity additions, retirements, and reserve margin, and documents the long term outlook for supply adequacy given current levels of proposed additions and potential retirements.

A. SUPPLY OUTLOOK UNDER VARIOUS RETIREMENT SCENARIOS

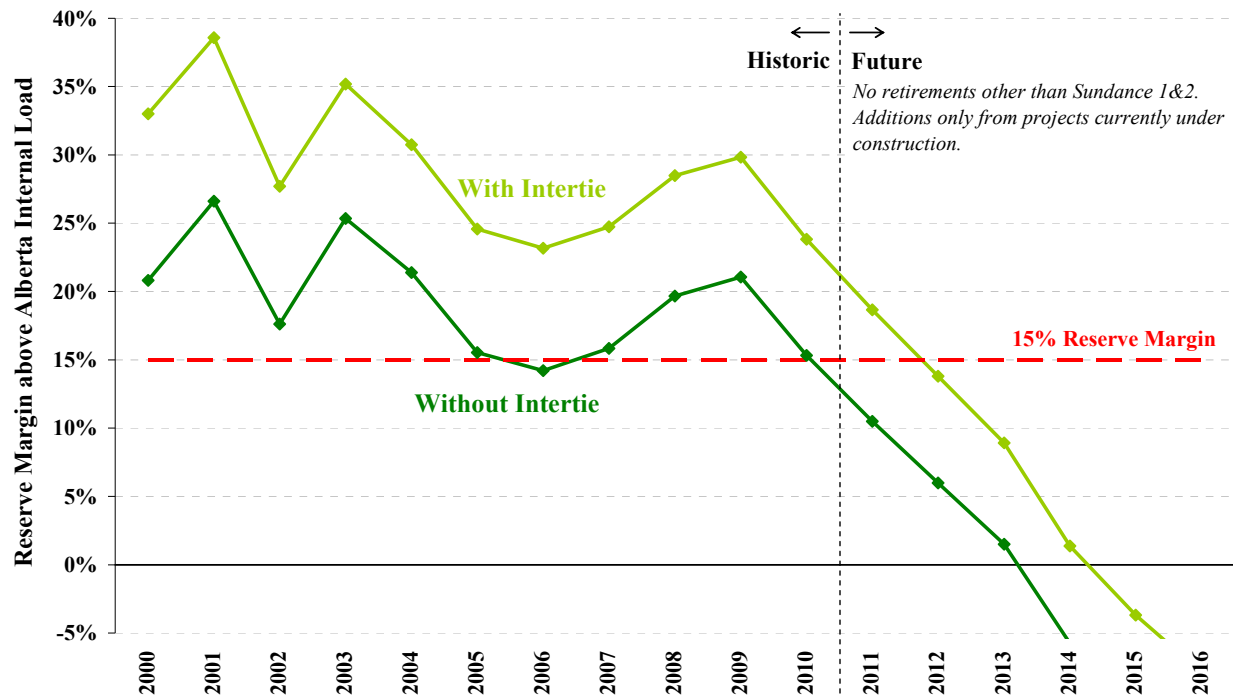
After considering the long-term resource adequacy challenges discussed in Section III, it appears that retirement rates over the coming decade will likely be almost twice the rate of the past decade. The timing and scale of these retirements will determine how much new capacity will be required for resource adequacy. To assess the timing and range of necessary supply additions, we examine the quantity of replacement capacity that would be required under: (1) no retirements; (2) if all PPA units retired upon PPA expiration; and (3) under the federal coal retirement mandate, which we believe represents the most likely retirement scenario. As discussed previously, if the federal coal retirement mandate is not implemented, Alberta emission regulations would likely result in five-year delayed but otherwise nearly identical retirement pattern.

1. Reserve Margin and Supply Outlook without Retirements or Additions

Since 2000, reserve margins in Alberta have ranged from 14% to 27% over Alberta Internal Load without the interties, and from 23% to 39% with the interties as shown in Figure 10. This reserve margin range has been generally above or close to the 15% reserve margin benchmark that 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. The figure shows that reserve margins have been lower during the past several years than they were at the beginning of the decade. Figure 10 also shows that if a 15% reserve margin is viewed as a resource adequacy target, the system has been close to dependent on import capability for resource adequacy during the winters of 2005/06 through 2007/08 and 2010/11. Even without additional retirements other than Sundance 1 and 2, the currently projected load growth would quickly erode reserve margins over the next several years in the absence of resource additions.

that are not subject to capacity obligations in their home territory would be able to sell into Alberta when both regions were experiencing shortages.

Figure 10
Historic and Projected Reserve Margins above Alberta Internal Load



Sources and Notes:

Dependable capacity ratings reported above are 0% of installed capacity for wind and 67% for hydro.
 Alberta Internal Load (AIL) winter peak projections for end of each calendar year are from AESO (2010a).
 Unit online and retirement dates and MW rating from Ventyx (2010) and AESO (2010c); units under construction from AESO (2010d).
 Projected margins represent the case in which only units currently under construction will get built and no units retire.

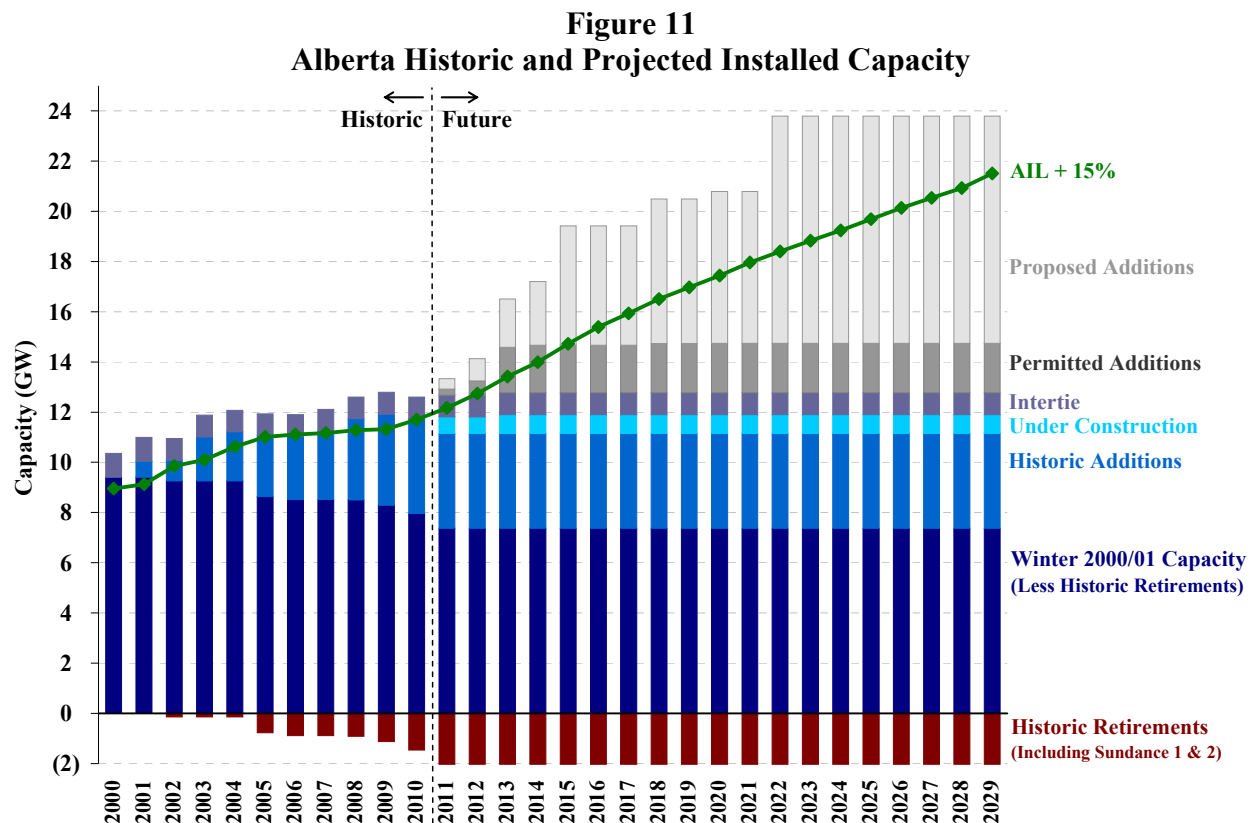
Effective installed generating capacity in Alberta (derated for hydro and wind availability) increased from 9,400 MW in 2000 to 11,730 MW by 2010, representing 230 MW of net capacity additions annually, as shown in Figure 11.⁹⁵ These potential additions are shown along with projected peak Alberta Internal Load (“AIL”) after including our benchmark 15% reserve margin.⁹⁶ Looking forward, Figure 11 shows that from 2010 to 2020 even without retirements beyond Sundance 1 and 2, net capacity additions will have to average approximately 630 MW annually.⁹⁷ This indicates that at the projected rate of load growth, higher levels of new investment will be required to maintain resource adequacy than average annual investments in the past. This need for resource additions will be even more pronounced because of likely retirements as discussed in Section III.C.2.

⁹⁵ Net additions of 230 MW are after 380 MW of average annual additions and 150 MW of average annual retirements. The reported numbers are based on a 67% capacity rating for hydro and a 0% capacity rating for wind.

⁹⁶ 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.

⁹⁷ Based on effective installed capacity of 11,730 MW in 2010, less 580 after the Sundance retirements, and a projected requirement of 17,440 MW in 2020, AESO (2010c). Wind is assigned 0% capacity value, hydro is assigned 67%.

Figure 11 also shows already-permitted and other proposed capacity additions currently being tracked by the AESO.⁹⁸ While the “permitted additions” are further along in development and have a higher likelihood of coming online, these potential additions are not guaranteed to materialize. If the permitted additions met their proposed online dates, they would maintain resource adequacy through 2015. The shown “proposed additions” are more speculative projects that may only be in a scoping phase and generally have a smaller potential for materializing. However, the large number of these proposed additions, which would maintain resource adequacy through at least 2029 if they all came online and none of the existing capacity retired, indicates that investors are evaluating a healthy number of potential projects for economic viability.



Sources and Notes:

Dependable capacity ratings reported above are 0% of installed capacity for wind and 67% for hydro.

Alberta Internal Load (AIL) projection from AESO (2010a).

Unit online and retirement dates and MW rating from Ventyx (2010), AESO (2010c), and AESO (2010d).

Totals represent winter peak load and capacity totals for the end of the calendar year.

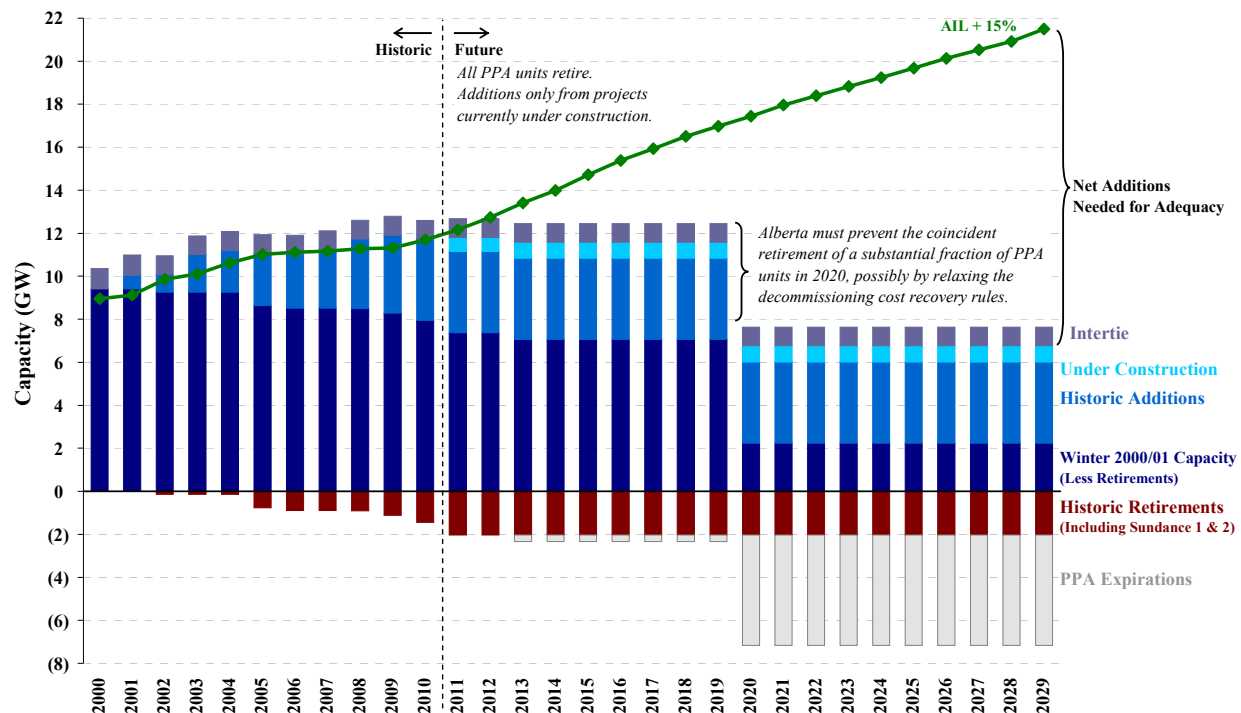
2. Supply Outlook with PPA Retirements

As discussed in Section III.B, one of the potential resource adequacy challenges that will be faced over the coming decade is the coincident expiration of 4,300 MW of coal and 780 MW of

⁹⁸ The figure does not reflect potential wind additions because wind is derated to a capacity value of 0% while hydro is derated to 67%. See Section III.E on the potential increases in wind, reported and the wind nameplate capacity.

hydro PPAs in 2020. Figure 12 shows what the supply-demand outlook would look like in the unlikely scenario that all units would retire upon the expiration of their PPAs and no incremental capacity would be built beyond what is currently under construction. As discussed in Section III.B, the most likely retirement pattern will be much less of a step function than suggested by the PPA expiration illustrated below. However, we note that the combination of these PPA expirations, the decommissioning cost rule, and the potential acceleration of five years' worth of federally-driven coal retirements could result in significant retirements in 2020 and 2021.

Figure 12
Installed Capacity Outlook with All PPA Units Retiring



Sources and Notes:

Dependable capacity ratings reported above are 0% of installed capacity for wind and 67% for hydro.

Alberta Internal Load (AIL) projection from AESO (2010a).

Unit online and retirement dates, MW rating, and PPA expiration dates from Ventyx (2010) and AESO (2010c); units under construction from AESO (2010d).

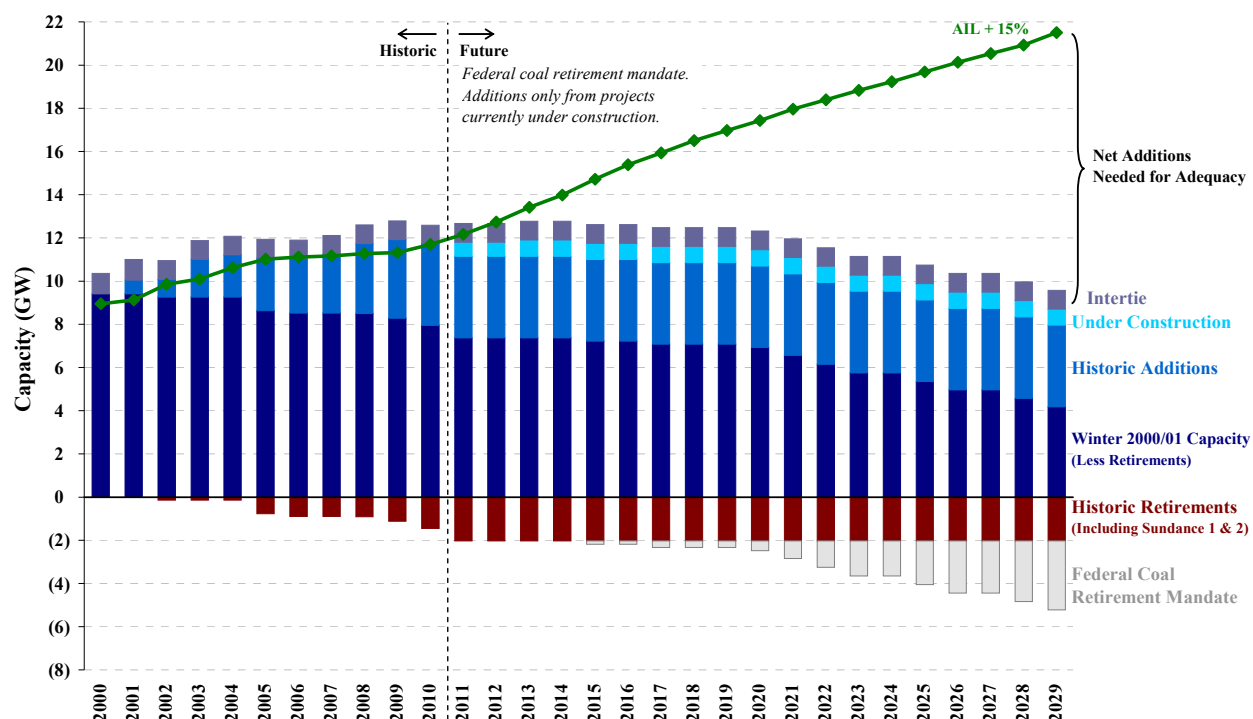
Totals represent winter peak load and capacity totals for the end of the calendar year.

More generally, this figure highlights the importance of avoiding public policies that could induce many retirements at once, as opposed to more gradually. Step changes in the economics of existing units can be quite problematic and difficult to absorb in any market environment, but the risk is more pronounced in energy-only markets. This is because energy-only markets have no mechanism to ensure that retirements are only scheduled to occur when there are sufficient new replacement resources. For this reason, large simultaneous retirements would result in high prices and low reliability for a few years until the high prices are able to attract enough capacity additions that allow the market to revert back to supply-demand equilibrium. By comparison, markets with multi-year forward resource adequacy standards, for example, would not be as seriously affected by a step-change in policy because the forward requirement would help smooth out new entry and retirement decisions.

3. Supply Outlook with Federal Coal CO₂ Emissions Standard

Another challenge discussed in Section III.C.2 is the federal coal CO₂ emissions standard. Figure 13 shows the supply outlook if retirements are only driven by the federal mandate and only generating units already currently under construction would be added. The figure shows a steadily growing supply gap over the next two decades. This means that new capacity will have to be added at a fairly rapid pace over the next two decades in order to balance projected load growth and retirements.

Figure 13
Installed Capacity Outlook with Federal Coal Retirement Mandate



Sources and Notes:

Dependable capacity ratings reported above are 0% of installed capacity for wind and 67% for hydro.

Alberta Internal Load (AIL) projection from AESO (2010a).

Unit online and retirement dates and MW rating from Ventyx (2010) and AESO (2010c); units under construction from AESO (2010d).

Proposed federal coal retirements are for units past the 45th year operating and not under PPA, Environment Canada (2010a-b).

Totals represent winter peak load and capacity totals for the end of the calendar year.

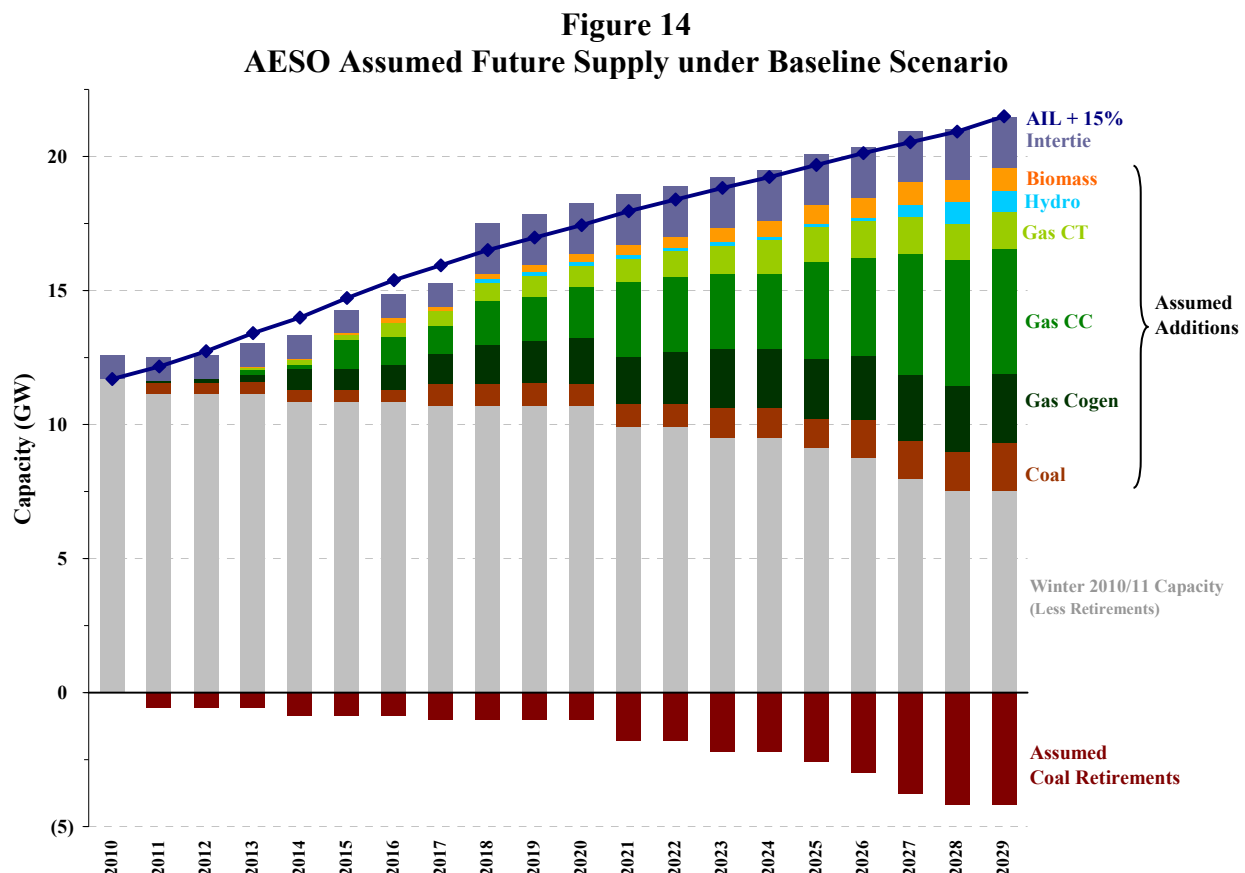
At the projected load growth, this amounts to 710 MW per year of gross capacity additions required from 2011 to 2029, compared to 380 MW of gross additions per year since 2000.⁹⁹ This means that the investment rate in Alberta must be 1.9 times higher in the coming decades than in the past decade. This large investment rate will require that investors are able to expect sufficient operating margins from their energy and ancillary services markets participation to

⁹⁹ Note that this number is somewhat lower than the “most likely” net additions level that we report in the introduction and conclusion as 740. This is because the 710 MW number reported here represents only retirements that could be caused by the federal coal CO₂ emissions standard, while the 740 MW number is based on the AESO planning study projection which includes somewhat higher retirement levels as reported in Section IV.B.

recover the needed investment, including their required returns on investments. The high investment volume will also require companies with sufficient financial strength to make these investments.

B. AESO PROJECTED FUTURE GENERATION ADDITIONS

For its internal planning efforts, AESO projects load growth and the total generation supply that could be used to fill the resource gap over the next two decades. Figure 14 shows the AESO's baseline scenario for future additions, while several alternative scenarios are summarized in Figure 15. These projections are based on a combination of factors including the retirement outlook and known projects under development. Because these supply scenarios are done for transmission planning purposes, they are intended to reflect a range of possible development paths, but they do not reflect an official view of projected future generation investment decisions. Even so, for the purposes of our analysis we will use these generation addition projections 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.



Sources and Notes:

Dependable capacity ratings reported above are 0% of installed capacity for wind and 67% for hydro.

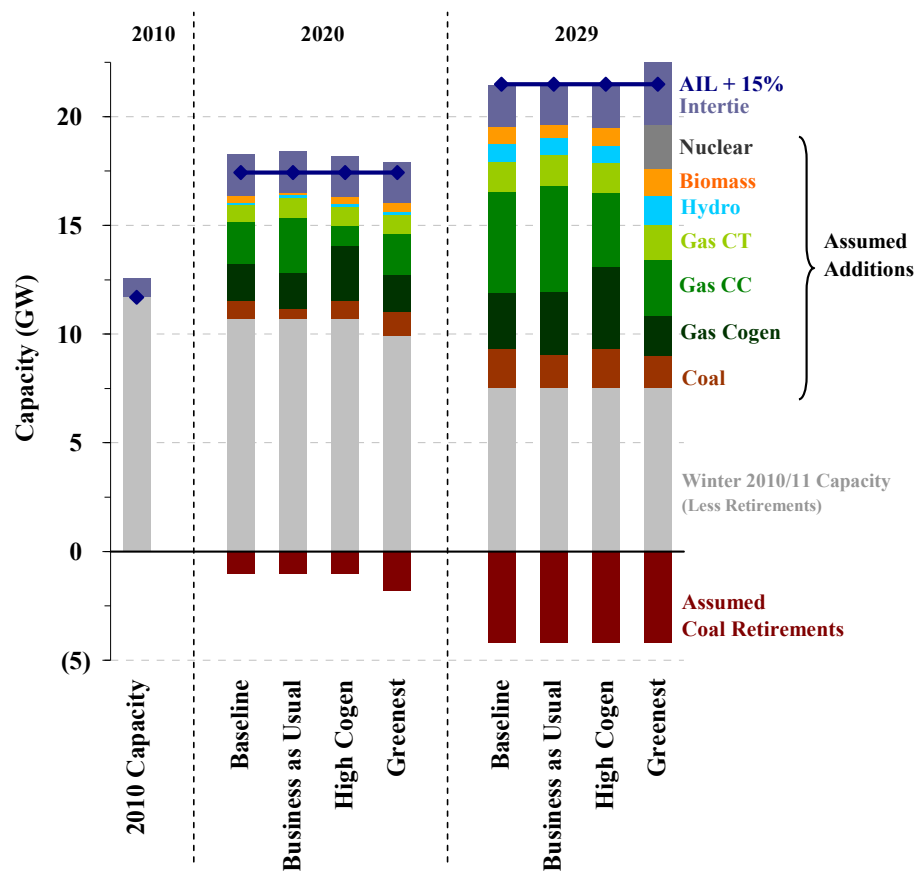
Currently operating unit list and MW rating from Ventyx (2010) and AESO (2010c).

UPLAN Baseline Scenario additions and retirements from AESO (2010c).

The generation retirements assumed in the baseline scenario shown in Figure 14 as well as the alternative supply scenarios shown in Figure 15 vary slightly from those observed under the

federal coal retirement mandate as shown in Figure 13. This is because the planning scenario retirement dates also consider the timing of PPA expirations including the forfeiture of decommissioning cost recovery, units retiring as pairs, and resource availability. In all these scenarios, future supply approximately meets projected AIL growth plus a 15% reserve margin, though the intertie capacity needs to be counted as available supply to achieve this reserve margin.¹⁰⁰ In all of these scenarios the AESO projects substantially more coal retirements than coal additions, with the overall supply portfolio moving toward gas-fired generation.¹⁰¹

Figure 15
AESO Assumed Future Supply under Alternative Scenarios



Sources and Notes:

Dependable capacity ratings reported above are 0% of installed capacity for wind and 67% for hydro.
Currently operating unit list and MW rating from Ventyx (2010) and AESO (2010c).
UPLAN Baseline Scenario additions and retirements from AESO (2010c).

¹⁰⁰ Note that the figure shows an adequacy gap until 2017 because AESO originally developed the scenario assuming that Sundance 1 and 2 would retire in 2017 rather than 2011. The scenario has been updated for the sensitivity of an early Sundance retirement date, but has not been otherwise updated.

¹⁰¹ Note that the supply additions shown have not been updated for the retirement of Sundance 1 and 2, which is the reason behind the small shortfall between 2012 and 2018.

The four alternative scenarios shown in Figure 15 represent different resource addition paths and different future CO₂e prices as shown in Section V.B.1.b as well as different assumed supply additions:

Baseline Case - The Baseline case is a middle-of-the-road scenario for generation additions, recognizing increased reliance on natural gas generation with increasing but modest carbon restrictions;

Business as Usual Case - The Business as Usual scenario has a similar supply outlook to the Baseline scenario, but is modeled with lower carbon prices;

High Cogen Case - The High Cogen case represents a future with high cogeneration supply primarily from the oil sands sector; and

Greenest Case - The Greenest case has more supply from low-GHG sources such as biomass, nuclear, and hydro and assumes higher carbon prices.

In Section V.B we examine the economic outlook for the major generation technologies assumed to be added to ensure resource adequacy in the Alberta market. However, we do not examine which supply mix shown in these cases would be optimal or most likely.

V. ANALYSIS OF GENERATOR ECONOMICS

Because the Alberta wholesale electricity market is an energy-only market, the challenges to resource adequacy documented in Section III must be met through private investments solely in response to energy market 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 examines the recent trends and long-term outlook for prices, revenues, and contributions to fixed costs for different generating technologies to determine prospects for new entry and the magnitude of price increases that may be required to ensure resource adequacy.

A. HISTORIC TRENDS IN GENERATOR ECONOMICS

The contributions to fixed costs (*i.e.*, the operating margins) earned by suppliers in recent years is a helpful starting point for assessing the economics of different generation technologies in the Alberta electricity market. To assess the economic drivers for retirements and new entry, we reviewed energy and ancillary service prices, evaluated the scale of scarcity prices during peak times, and estimated energy margins for specific unit types over recent years.

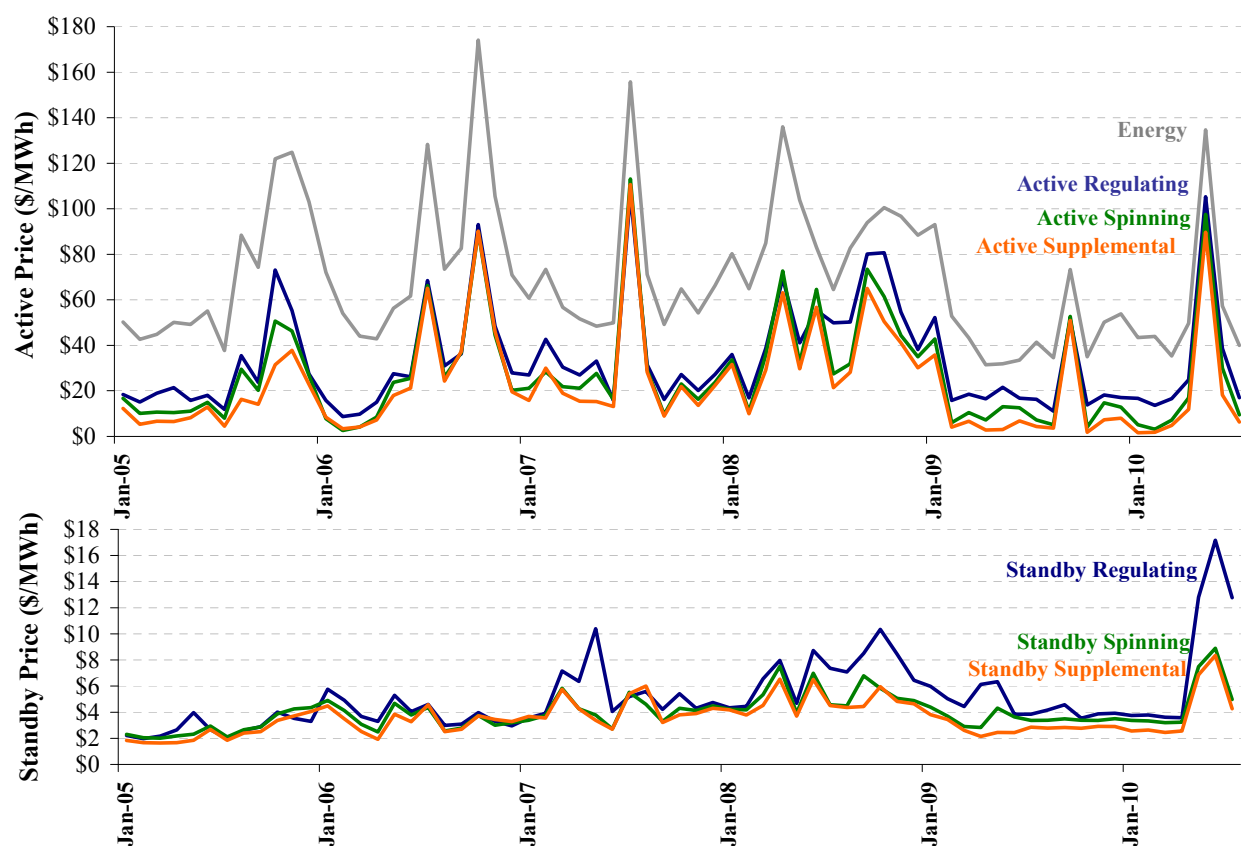
1. Energy and Operating Reserves Prices

Figure 16 shows the average monthly prices paid for energy and ancillary services (*i.e.*, operating reserves) since 2005. As the figure shows, the prices paid for active reserves services track closely with the price for energy; the less valuable standby reserves prices only have a

small positive correlation with energy prices.¹⁰² The reason for this relationship is that suppliers providing active reserves are unable to sell energy and consequently do not benefit from associated operating margins. Therefore, when energy prices are higher, generators will be less willing to supply reserves unless reserves prices rise commensurately with lost margins from not participating in the energy market. Similarly, when energy prices fall, reserves prices fall as well. In fact, most payments for supplying these services are indexed to the energy price.

This relationship between energy prices and operating reserves prices means that the recent history and outlook of low energy prices discussed in Section III.A will impact all types of generating technologies, even those that disproportionally supply reserves with limited energy sales. In particular, the margins of natural gas CTs and hydro units are greatly impacted by operating reserves price levels as discussed further in subsection V.A.5.

Figure 16
Alberta Average Monthly Energy and Reserves Prices



Sources and Notes:

Reserves prices from AESO (2010c); energy prices from Ventyx (2010).

¹⁰² Over the period shown, the monthly average energy and active reserves prices are highly correlated with R^2 values of 0.80, 0.80, and 0.79 for regulating, spinning, and supplemental reserves respectively. Standby reserves are less correlated with R^2 values of 0.03, 0.20, and 0.26 for regulating, spinning, and supplemental reserves.

2. Historic Scarcity Pricing Levels

As discussed in subsection II.A.1, energy-only markets are characterized by occasional severe price spikes caused by scarcity conditions. In order to maintain resource adequacy, these scarcity pricing events must be frequent enough and severe enough to attract new entrants when additional capacity is needed. As a first indicator as to whether the Alberta energy-only market will be able to produce the needed price levels, we examine scarcity pricing observed in the market to date.

While there is no one definition of what constitutes scarcity pricing, one way to define scarcity prices is relative to “market heat rates.” The market heat rate in any given hour is the electric price divided by the natural gas price and CO₂ costs embodied in gas.¹⁰³ Market heat rates above a certain level indicate that either generation with higher heat rates or fuel costs are setting the price or that market prices have simply risen above the marginal costs of generation as is desirable during scarcity conditions. Scarcity pricing provides operating margins to cover the fixed costs of generating units, but whether these prices are sufficient to attract new investments depends on the severity and frequency of the shortage events.

The influence of scarcity prices on average prices and operating margins is shown in Figure 17. This stacked area graph shows what fraction of the monthly average Alberta energy price has been above various levels of market heat rates over the past decade. In this figure, the black line on top of the gray and blue areas represents the average monthly energy price. The individual colored layers show what the average price would have been if market prices had been capped at the selected market heat rate levels: 10 GJ/MWh (top of gray range), 15 GJ/MWh (top of dark blue range), and 25 GJ/MWh (top of medium blue, bottom of light blue range). For comparison, the fuel and emission cost of a new natural gas-fired single-cycle combustion turbine is approximately 9.8 GJ/MWh.

The figure also indicates the operating margins of a generating unit with a given heat rate. The gray area represents prices below the operating cost of a 10 GJ/MWh heat-rate natural gas-fired generator, when that unit presumably would not operate. This means the blue ranges represent the average operating margins of that 10 GJ/MWh gas unit during higher-priced hours when it presumably would choose to operate. For example, in May 2008 the average price was approximately \$100/MWh (top of light blue range), while the fuel and emission cost of 10 GJ/MWh heat rate natural gas generators were approximately \$50/MWh (top of gray range). This means that as long as a 10 GJ/MWh natural gas unit was able to generate whenever it was profitable to do so, it would have earned an average operating margin of approximately \$50/MWh in the energy market over that month.

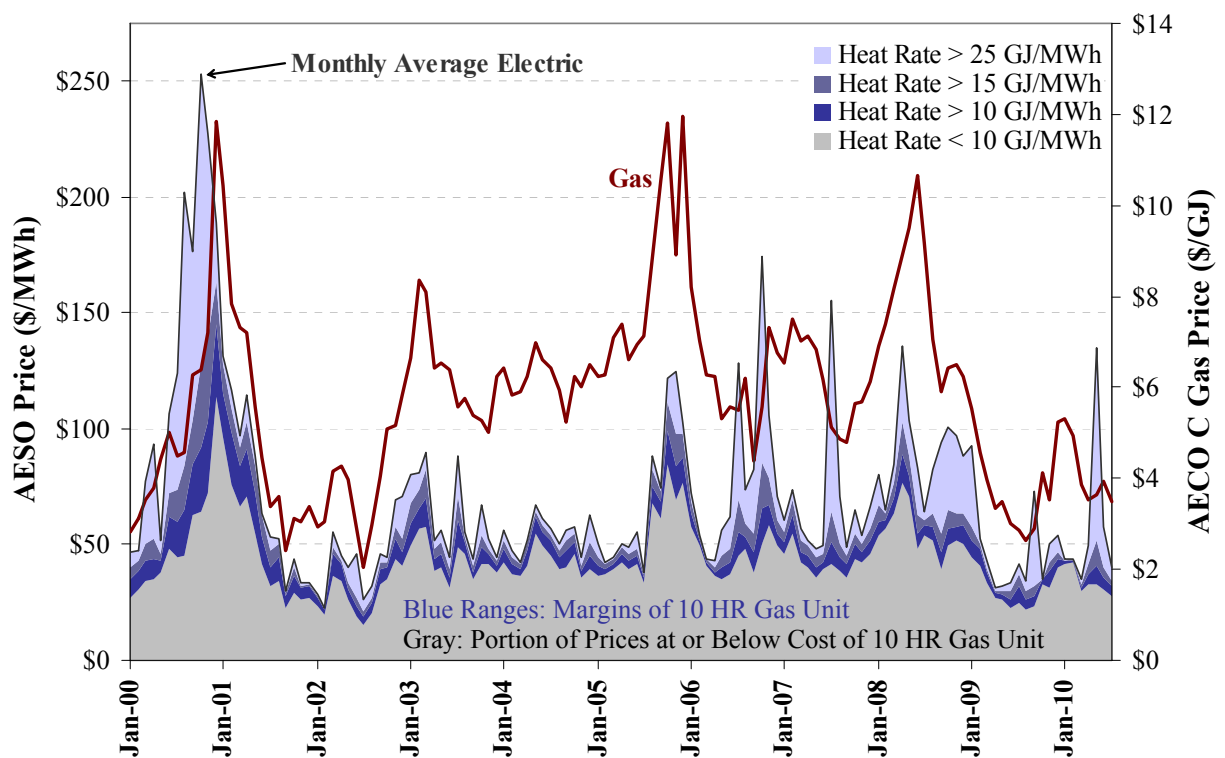
Figure 17 shows that the Alberta energy market has indeed produced occasional price spikes as is necessary in an energy-only market. Over some historic periods, such as in late 2005, the

¹⁰³ Throughout this report, we use daily gas prices and hourly energy market prices to determine the hourly market heat rate, see Bloomberg (2010) and Ventyx (2010). For dates past the enacted date of the Specified Gas Emitters Regulation, an embedded CO₂e cost of \$0.09/GJ is added to the price of gas. This is calculated from a GHG cost \$15/tonne over 12% of emissions or \$1.80/tonne, and a GHG emissions rate of 0.0508 tonnes of CO₂e/GJ of gas, see Alberta Government (2007a); EIA (2010b).

relatively high energy prices appear to have been caused primarily by higher natural gas prices, and would not have contributed as substantially to the fixed costs of natural gas generators. However, there were several months of high prices over the 2006 to 2008 period that appear to have been driven primarily by scarcity.

Importantly, the figure shows that even in the most recent period of low natural gas and electric prices, scarcity premiums have not disappeared, which is important given that new generating capacity additions will be required by 2012. Also note that, while the immediate cause of a price spike may be the simultaneous outage of several coal plants or the scheduling of transmission outages (as was the case during the May 2010 price spike), the ultimate underlying cause is the overall level of installed capacity relative to demand. When reserve margins are very high, simultaneous baseload and transmission outages would still cause some price increases, but would *not* tend to result in extreme price spikes because generation supply would still be sufficient to meet demand.

Figure 17
Fraction of Average Monthly AESO Prices Attributable to Scarcity Pricing



Sources and Notes:

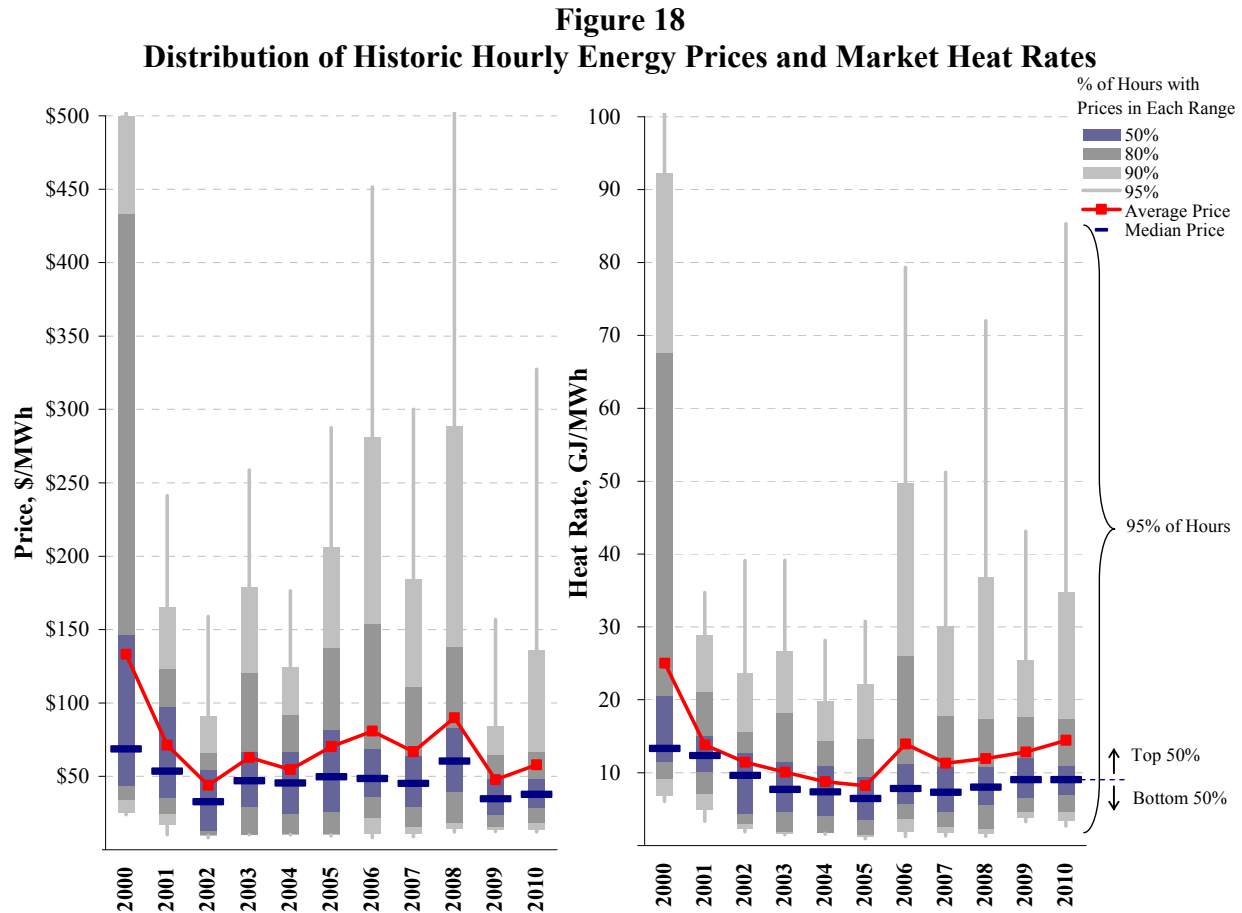
AECO C Gas price from Bloomberg (2010).

Top of stacked graph indicates historic monthly AESO electric prices from Ventyx (2010).

Stacked components indicate the fraction of AESO price attributable to scarcity pricing where scarcity prices are those above the indicated market heat rate threshold.

Figure 18 shows the historic ranges of hourly energy prices and market heat rates. The left-hand plot shows the range of hourly energy prices for each of the last 11 years, while the right-hand plot shows the distribution of hourly market heat rates. As noted earlier, the market heat rate is calculated as the ratio of the AESO energy price to natural gas and emission prices. In other

words, market heat rates can be interpreted as power prices that are normalized for changes in natural gas and emission costs. The price ranges represented by the vertical bars indicate that 95% of all hourly market prices observed in that year were within the range from the bottom of the lowest bar to the top of the highest bar, with average prices and median prices indicated by the red markers and dark blue lines. Figure 18 shows that during the last decade energy prices were among the lowest in 2009 and 2010. However, once normalized for lower natural gas costs during 2009 and 2010, those two years offered some of the higher average market heat rates of the last decade.



Sources and Notes:

Daily historic AECO C gas prices are from Bloomberg (2010), hourly energy prices are from Ventyx (2010).

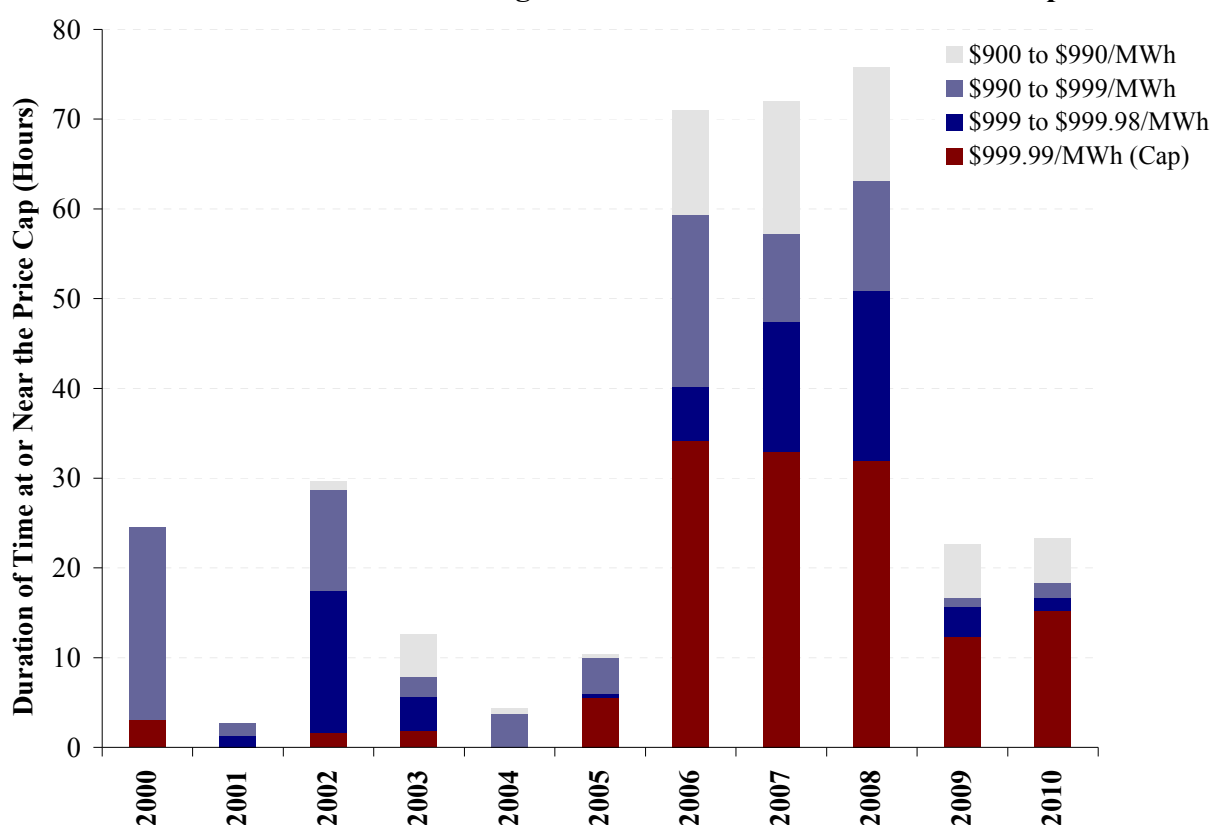
Overall, it appears that the Alberta energy market has demonstrated a history of scarcity pricing as expected and required in energy-only markets. However, the mere existence of scarcity prices is not the most important factor. The more important question is whether these market prices are high enough to attract and retain generation when needed. It is promising that the timing of the highest scarcity prices starting in 2006 appears generally consistent with the lower reserve margins experienced since then as previously shown in Figure 10.

3. Impact of Price Cap and Administrative Scarcity Pricing

Energy prices in Alberta are constrained below an administrative price cap. Since the power pool was created in 1996, the market has operated with a generator bid cap of \$999.99/MWh and

a price cap of \$1,000/MWh.¹⁰⁴ The price is set to the marginal generator bid under all normal operating conditions. Under emergency conditions, with insufficient incremental supply, the AESO sets the price at the highest bid and implements out-of-market measures to maintain system stability, including calling upon emergency imports and voluntary load shedding agreements.¹⁰⁵ Finally, when firm load must be shed, AESO sets the market price at the price cap. The frequency, causes, and implications of these price cap events have been carefully documented in a discussion paper by the AESO.¹⁰⁶ As noted by AESO and shown in Figure 19, the duration of time spent at price cap events was higher during 2006-08 than in previous years, likely a result of higher natural gas prices, lower reserve margins, and the need for new entry during this time period.

Figure 19
Duration of Time the Marginal Price was at or Near the Price Cap



Sources and Notes:

Minute-level system marginal price data were used to compile these data, from AESO (2010c).

A similar figure appears in the AESO price cap discussion paper, which represents the same data as updated here for 2010.

The current \$1,000/MWh AESO price cap is below estimates of VOLL, meaning that it prevents prices from rising to efficiently high levels during scarcity events. Additional inefficiency is

¹⁰⁴ See pp. 3-4, AESO (2009b).

¹⁰⁵ These out-of-market actions correspond to steps 5 through 30 of the Supply Shortfall procedures, while step 31 is the final step of shedding firm load. See AESO (2010f).

¹⁰⁶ See AESO (2009b).

caused by the absence of a more nuanced scarcity pricing mechanism which would tie the market price to the marginal cost of out-of-market emergency procedures. We recommend that AESO consider correcting these inefficiencies by increasing the price cap to a level commensurate with estimates of VOLL and refining its approach to scarcity pricing. It will take careful study to determine how to most appropriately introduce these mechanisms without opening the market to the potential exercise of market power, but one option is to maintain generator bid caps at their existing levels while allowing administrative scarcity prices to rise to higher levels. The urgency of these potential revisions, however, partly depends on whether the current price cap could prevent new capacity from being built when needed, a potential concern that we analyze in the remainder of this report.

4. Price Impact of Declining Reserve Margins

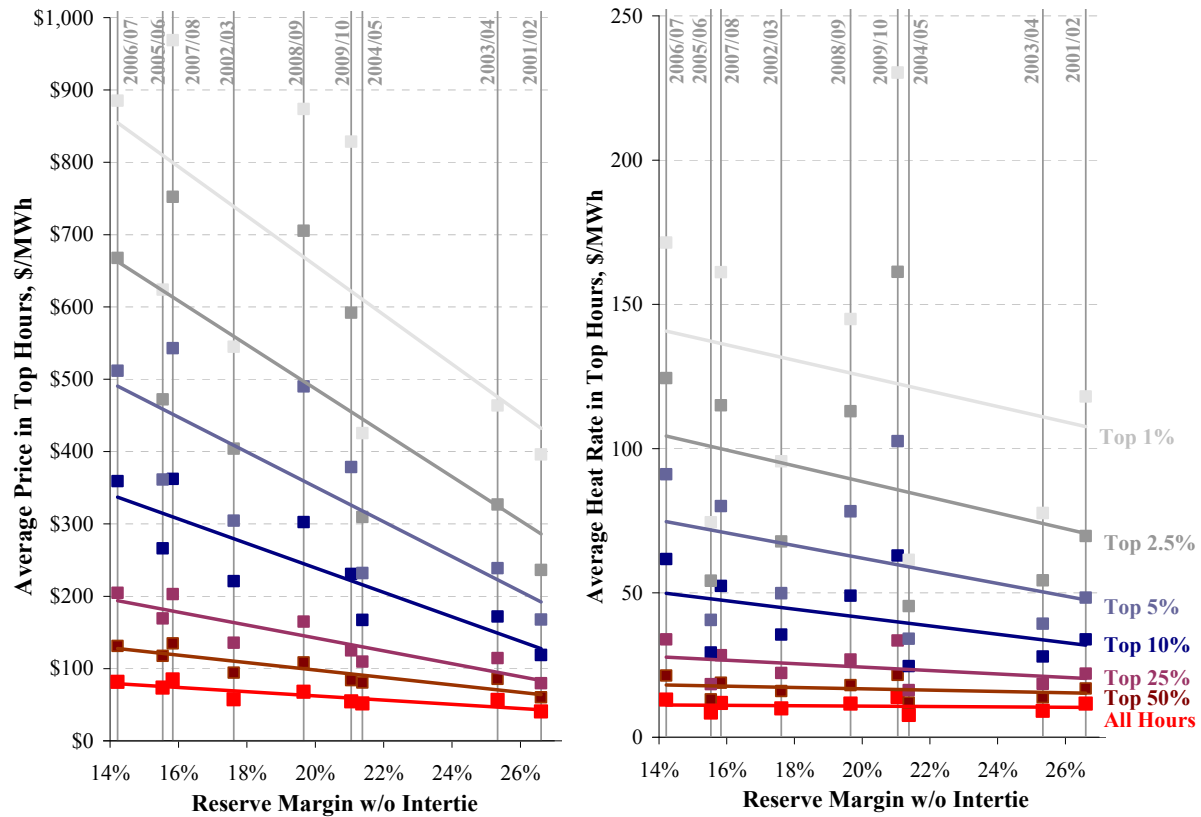
An important feature of an efficient and well-functioning energy-only market is its ability to produce prices consistent with overall supply and demand conditions. This means that when reserve margins are tight and new generation is needed, price levels must be high enough to retain existing supply and attract new construction. 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.

A first step to determining whether the AESO energy-only market is producing prices consistent with market fundamentals is to examine whether declining reserve margins have indeed resulted in higher market prices. Figure 20 shows the relationship between historic reserve margins and market prices (left plot) and market heat rates (right plot) during peak hours. The figure shows the average market prices and heat rates observed during the highest-priced hours of the year, including the top 1% and 2.5% of all hours (in gray), the top 5% and 10% of all hours (in blue), the top 25% and 50% of hours (in maroon), the average price over *all* hours (in red), along with the line of best fit for each.

The left plot shows that there has been a strong relationship between declining reserve margins and increasing market prices over the past decade. The relationship exists over all hours, but the most substantial price impacts are during hours with the highest prices as shown by the steeper slope for the top percentiles of all hours. The right plot shows a similar relationship of increasing heat rates associated with declining reserve margins. The two plots demonstrate the Alberta energy-only market is indeed producing higher prices and market heat rates as reserve margins decline. This strongly suggests that if current prices are not sufficient to attract new capacity, reserve margins will drop and prices will rise until these prices are high enough to attract new investment. Whether current prices are high enough to support new investment or whether the reserve margin may have to drop further before new investments become financially viable is examined in the remainder of Section V.

Figure 20

Hourly Prices and Market Heat Rates vs. Reserve Margins during Peak Hours



Sources and Notes:

Annual prices and heat rates over July-June are examined and compared to the relevant winter reserve margin.
 Winter reserve margin is from Figure 10, hourly market heat rates are as calculated for Figure 18.
 Daily historic AECO C gas prices are from Bloomberg (2010), hourly energy prices are from Ventyx (2010).

5. Costs and Operating Parameters of New Generating Plants

To examine attractiveness of new generation investments, we compare the investment and fixed operating costs of new resources against the operating margins available to these resources from the energy and ancillary service markets. Table 6 shows the capital cost and operating parameter assumptions for different types of new generating technologies used in this evaluation.

Table 6
Fixed Costs and Operating Parameters Assumed for New Generating Plants

Generating Technology	Overnight Costs	Project Lead Time	Operating Lifetime	Fixed O&M	Variable O&M	Heat Rate	Depreciation Schedule	Annualized Capital Costs (Constant Nominal)	Annualized Capital Costs (Constant Real)
	2010\$/kW [1]	years [2]	years [3]	2010\$/kW-yr [4]	2010\$/MWh [5]	GJ/MWh [6]	%/yr [7]	\$/kW [8]	2010\$/kW [9]
Coal	\$3,500	4	35	\$31.52	\$6.30	9.4	15%	\$342.07	\$265.91
Gas CT	\$1,050	3	25	\$12.61	\$4.20	9.8	15%	\$111.03	\$90.38
Gas CC	\$1,435	3	30	\$13.66	\$4.20	7.1	15%	\$144.61	\$114.78
Gas Cogen (Electric Portion)	\$1,160	3	30	\$13.66	\$4.20	6.6	50%	\$116.92	\$92.79
Entire Plant	\$1,800							\$184.13	\$146.13
Hydro	\$3,670	4	40	\$15.78	\$3.72	n/a	15%	\$340.07	\$259.92
Wind	\$2,500	2	25	\$41.00	\$2.00	n/a	50%	\$268.34	\$218.43

Sources and Notes:

- [1] Provided by AESO (2010c).
Electric portion of Cogen capital cost is 64.5%, EEA (2008).
- [2] AESO (2010c). Hydro from EIA (2010a).
- [3] AESO (2010c). Hydro assumed.
- [4] Provided for non-hydro technologies by AESO (2010c).
Hydro FOM from EIA (2010a), inflated by the ratio for other technologies.
- [5] Provided for non-hydro technologies by AESO (2010c).
Hydro FOM from EIA (2010a), inflated by the ratio for other technologies.
- [6] AESO (2010c).
Cogen heat rates calculated based on steam, fuel, and electric data for 5 sample units in Alberta, from Alberta Environment (2010b).
- [7] AESO (2010c).
- [8] Annuity payment over project lifetime required to recover capital costs, annuity constant in nominal terms.
- [9] Annuity payment over project lifetime required to recover capital costs, annuity growing at 2.4% in nominal terms.

To support investment, the present value of a generating plant's operating margins must be equal or greater than 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 annualize the capital costs of new generation based on the financing assumptions summarized in Table 7. These annualized capital costs of new generation are listed in Table 6 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.*, that are constant in *real* terms). These two annualized capital cost numbers 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 in Sections V.A.6 and V.B.2, we use the "constant real" approach, which allows for a more intuitive comparison of levelized capital costs and annual operating margins over time.¹⁰⁷

¹⁰⁷ The charts in Section V.B.2 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 7
Financing Assumptions for New Generating Plants

Debt Fraction	[1]	60%
Debt Rate	[2]	6.0%
Equity Rate	[3]	15.0%
ATWACC	[4]	8.59%
Tax Rate	[5]	28.0%
Inflation Rate	[6]	2.0%
Capital Cost Escalation Rate	[7]	2.40%

Sources and Notes:

[1,3,5-7] AESO (2010c).

[2,4] Brattle Analysis.

6. Historic Generator Operating Margins vs. Fixed Costs

To determine the overall historic attractiveness of the Alberta electric market to potential new entrants, we first examine historic generator margins for each technology and compare those against the cost of new generating plants estimated in Section V.A.5. 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 historic market fuel prices, a GHG price on specified emitters, a public database on individual units' heat rates, and generic unit assumptions for variable O&M from Table 6 above.¹⁰⁸ We included as many AESO generators as possible in our aggregation of historic generator margins for each technology, but eliminated some units because of uneconomic dispatch under TMR contracts or because of data quality problems. The annualized cost of a new plant includes new generation capital costs levelized on a constant real basis as well as annual FOM costs from Table 6. The costs of a new plant for 2010 are adjusted with the Handy-Whitman Index for previous years.¹⁰⁹

Figure 21 and Figure 22 show the historic operating margins against fixed costs over the past decade for natural gas CTs and coal units. Operating margins that are higher than the costs of a new plant on average over time indicate that new generation of this type would be profitable investments while margins below that line indicate that new investments would not recover their costs. For existing plants, the decision to continue operating depends only on going-forward costs and not on capital investments that have already been made. For this reason, units will not retire unless their operating margins are below the fixed operations and maintenance ("O&M") line over time or unless they must make major capital expenditures beyond regular maintenance to continue operating. Appendix A shows these figures for natural gas CCs, gas cogen, hydro,

¹⁰⁸ Coal prices were based on an AESO assumed at a mining cost of \$1/GJ in 2010, tied to inflation. Natural gas prices are the AECO C index price, see Bloomberg (2010). The GHG price is \$15/tonne of CO₂e, or \$1.80/tonne on specified emitters starting on July 1, 2007 as discussed in Section V.B.1.b. Unit heat rates were taken from the Ventyx Energy Velocity database, and supplemented with the generic unit assumptions from Table 6 for units with missing data, see Ventyx (2010).

¹⁰⁹ Historic CONE and FOM numbers are inflated according to the Handy-Whitman Index (converted from USD to CAD) between 2000 and 2009 from Whitman, et al. (2008) and PJM (2009); and by inflation between 2009 and 2010 from Bank of Canada (2010).

wind, and natural gas CTs including TMR units. Our analysis shows different trends for each type of generating technology.

Gas CTs – New combustion turbine plants would have been uneconomic to build during 2002-04 (without considering any potential ancillary services revenues for that period due to data limitations). This technology has become economic to build since 2005 although low prices in 2009-10 have reduced the attractiveness. Operating reserves are also an extremely important source of revenue for CTs, which, in some years, have contributed more than half of their operating margins. There is a substantial quantity of CT capacity that under TMR contracts, which have relied heavily on out-of-market payments for their operating margins.

Gas CCs – Natural gas CCs would have been uneconomic to build during 2002-05, but have become attractive investments since 2006. Lower prices in 2009-10 have had an adverse impact on CCs, but the impact is not as large as the impact on CTs. Gas CCs receive a relatively small portion of their revenues from operating reserves.

Gas Cogen – Natural gas cogen is an attractive investment in Alberta and has been over the past decade. Once accounting for the fuel costs and boiler capital costs that would have been incurred to create steam even without any electricity generation, the incremental capital and fuel cost for electric generation is low compared to other generation technologies. However, the opportunities for cogeneration development and the economic value of these investments are highly dependent on the specifics of the steam demand for particular projects. Operating reserves are not an important revenue source for most cogen.

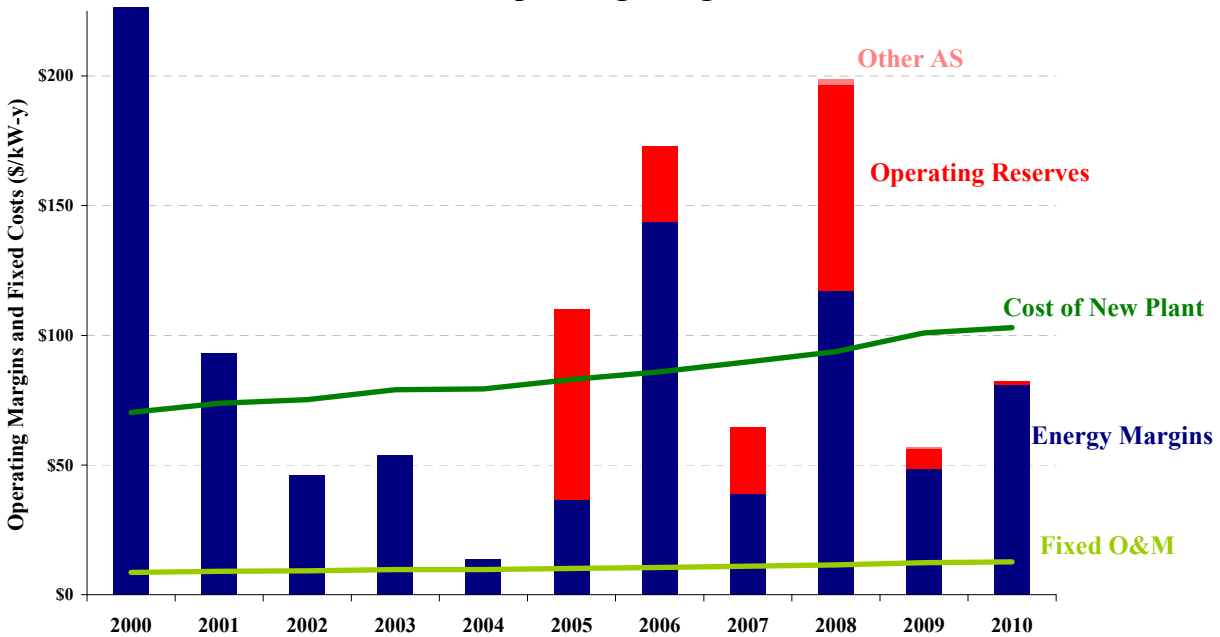
Coal – Coal generation was a consistently profitable investment through 2008, when natural gas prices started to drop. Even since then, coal generators' operating margins are many times higher than their fixed O&M costs, indicating a low likelihood for retirements unless the unit is facing a large capital expenditure or the loss of decommissioning cost recovery if it continued operating. Operating reserves are a minimal source of revenues for coal.

Hydro – Hydro generation may have appeared to be an attractive investment during 2005-08, but has otherwise been uneconomic for new generation investments over the past decade. Operating reserves are very important for hydro, representing approximately one third of total operating margins.

Wind – Without considering any revenues from monetizing its green attributes, wind generation investments have been consistently uneconomic for the past decade. In fact operating margins have not even exceeded the annual fixed cost requirement for wind generators in one year during the past decade. Wind generators are unable to sell reserves services in Alberta.

Overall, these trends show that new generation investments were unprofitable for all investments other than cogen during the early part of the decade when reserve margins were high, but new investments, in particular natural gas generation, have become more attractive since 2005 when reserve margins began to drop. These results are promising because they indicate that the market has sent the appropriate investment signals that are in line with the need for new generation capacity. However, the drop in operating margins over the past two years raises the concern that the outlook of low gas prices may depress investments over the coming years despite the current need, a concern which we investigate further in Section V.B.

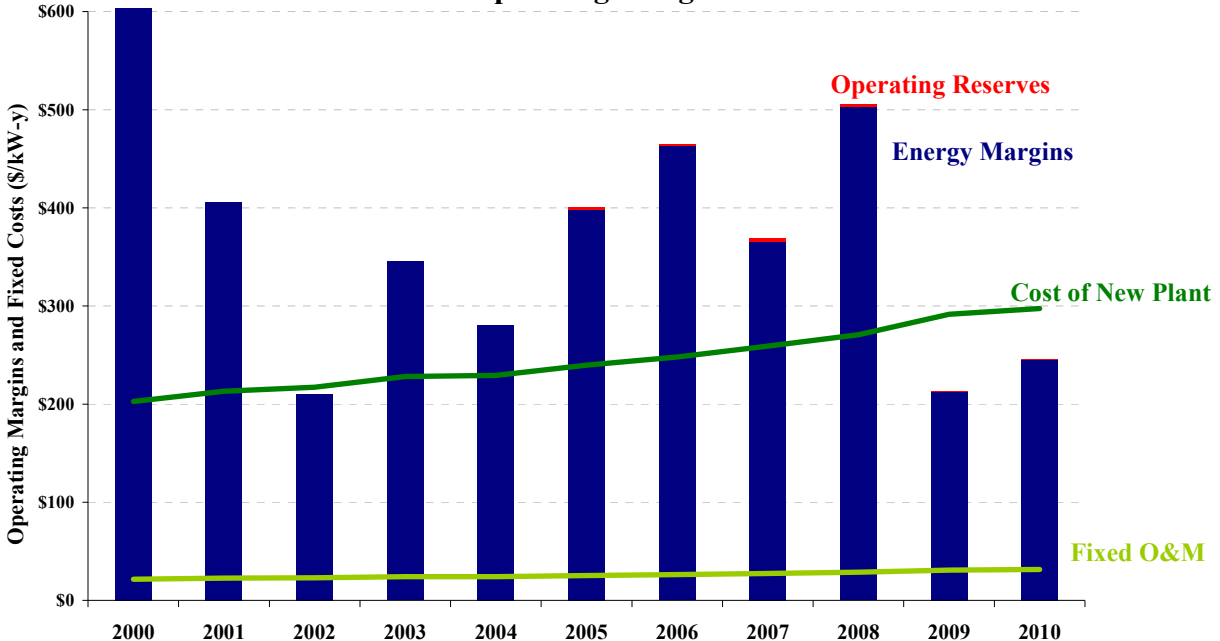
Figure 21
Historic Gas CT Operating Margins vs. Fixed Costs



Sources and Notes:

Energy margins represent revenues minus estimated operating costs in energy market. Cost of New Plant includes capital costs and FOM. Unit-specific volumes and revenues as well as 2010 VOM, CONE, and FOM by unit type are from AESO (2010c). Gas prices and exchange rates from Bloomberg (2010). Heat rates estimated from Ventyx (2010), AESO (2010c), Alberta Environment (2010a-b). Historic CONE and FOM numbers are inflated according to the Handy-Whitman Index (converted from USD to CAD) between 2000 and 2009 from Whitman, et al. (2008) and PJM (2009); and by inflation between 2009 and 2010 from Bank of Canada (2010).

Figure 22
Historic Coal Operating Margins vs. Fixed Costs



Sources and Notes:

Energy margins represent revenues minus estimated operating costs in energy market. Cost of New Plant includes capital costs and FOM. Unit-specific volumes and revenues as well as 2010 VOM, CONE, and FOM by unit type are from AESO (2010c). Gas prices and exchange rates from Bloomberg (2010). Historic CONE and FOM numbers are inflated according to the Handy-Whitman Index (converted from USD to CAD) between 2000 and 2009 from Whitman, et al. (2008) and PJM (2009); and by inflation between 2009 and 2010 from Bank of Canada (2010).

B. OUTLOOK FOR GENERATOR ECONOMICS

As shown earlier, Alberta will require significant investments to keep pace with load growth and coal plant retirements over the next two decades. It is encouraging that a significant number of projects are already under construction, permitted, or at initial planning stages. However, without a resource adequacy requirement these planned or proposed generating resources will move forward only if investors expect market prices that allow for full cost recovery. As we have documented in Section V.A, historic prices in Alberta's energy market were sufficient to attract new capacity when needed. In this section, we examine the outlook for future prices to inform the prospects for new entry. To determine whether Alberta's energy-only market appears to support the addition of new resources, we project future price levels based on current market conditions and evaluate whether they would be sufficient to cover investment costs for different types of generation technologies.

1. Projecting Future Market Prices

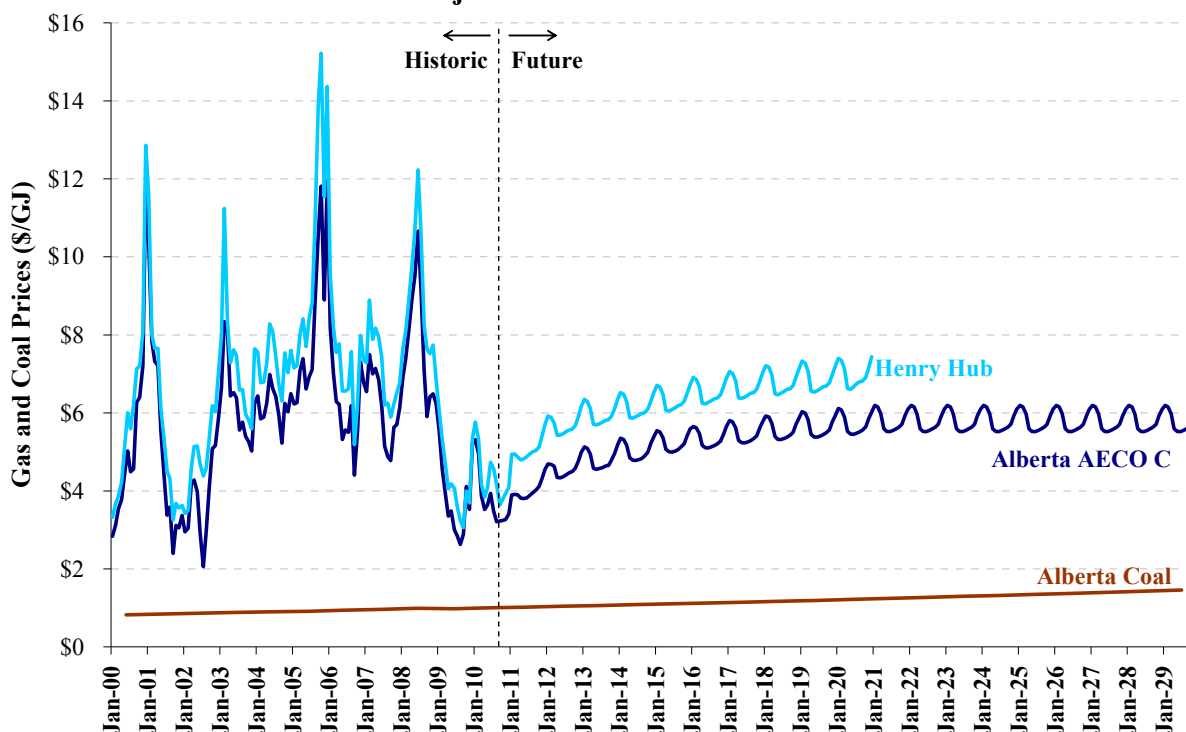
We rely on recent market heat rates and forecasts for natural gas and carbon prices to project future power prices. This allows us to assess the prospects for new entry based on current conditions and determine by how much energy prices would have to increase before investment in new resources would become attractive. Because we do not forecast changes in market heat rates and the frequency of scarcity pricing, these energy price projections present only a reference point. They do not represent price forecasts that reflect the impacts of increased penetration of wind generation, the associated potential increased ancillary services requirements, and several other factors, such as increased intertie capacities with neighboring markets.

a. Projected Gas and Coal Prices

Figure 23 shows the Alberta gas and coal prices that we use to project future power prices and future plant operating costs. Coal prices are from an AESO estimate of current mining costs of \$1/GJ and are assumed to increase with inflation.¹¹⁰ Forecasts of natural gas prices are based on monthly gas price futures for Alberta's AECO C pricing point, with more distant future prices for AECO C estimated based on a basis discount to Henry Hub futures and are held constant in nominal terms after 2021.

¹¹⁰ Note that mining costs vary widely between locations and tend to increase with the maturity of the field as extraction becomes more difficult.

Figure 23
Projected Gas and Coal Prices



Sources and Notes:

Historic gas prices and exchange rates for Henry Hub conversion to CAD/GJ from Bloomberg (2010).

Coal price is \$1/GJ in 2010, tied to inflation. Historic inflation from Bank of Canada (2010), 2% future inflation from AESO (2010c).

AECO C is Alberta the gas market point; Henry Hub prices converted to CAD/GJ using exchange rates from Bloomberg (2010).

b. Future GHG Price Scenarios

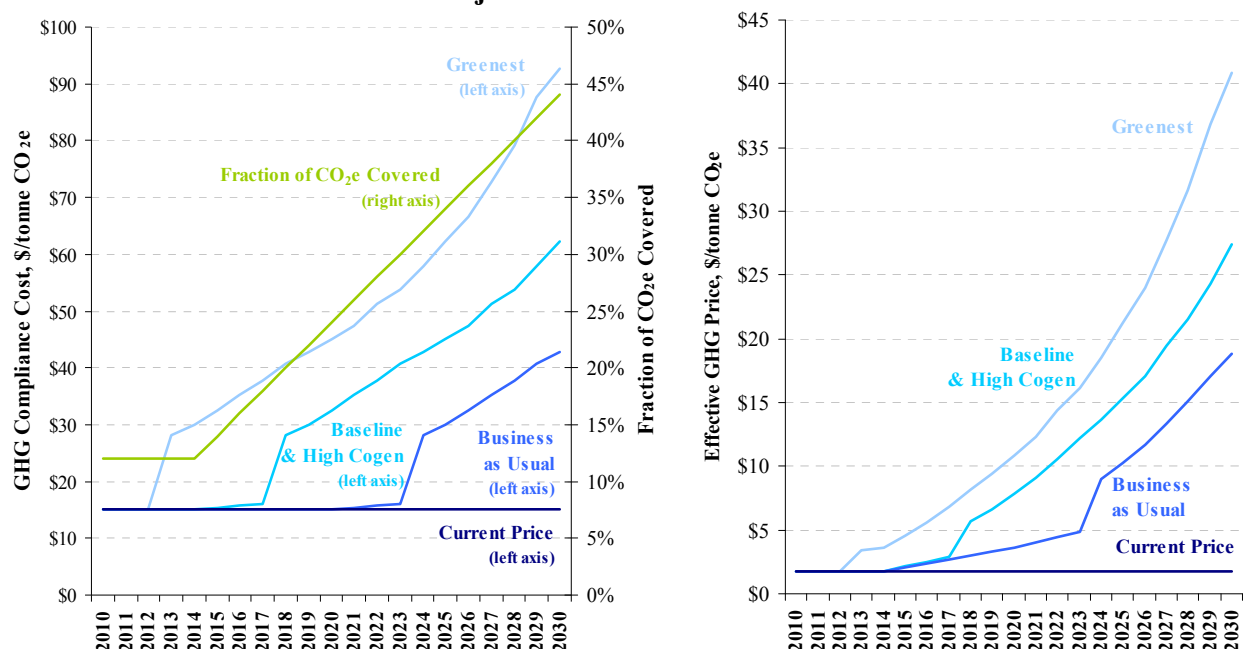
As described in Section III.C.1.c, the current cost of emitting greenhouse gases in Alberta under the Specified Gas Emitters Regulation is at most \$15/tonne of CO₂e for 12% of output for large emitters. This amounts to an effective current CO₂e price of \$1.80/tonne.¹¹¹ In the future, the costs of emitting GHG may increase as Alberta raises the cost of compliance with the GHG rule or it increases the fraction of emissions covered under the regulation. At this time, no schedule has been announced for any increases to the effective GHG price in Alberta, and the potential for national GHG prices is also uncertain. In light of these uncertainties, we use a range of estimates for potential future GHG prices in our outlook of power prices and generation costs.

Figure 24 summarizes the GHG price scenarios used in our projections. These scenarios were developed by AESO and are consistent with the numbers used in their transmission planning scenarios discussed in Section IV.B. The plot on the left shows the projected compliance costs for emitting GHG as well as the fraction of CO₂e emissions assumed to be covered in each of four scenarios. The right-hand plot shows the *effective* GHG price (after accounting for both the

¹¹¹ On average the overall GHG price may be a bit lower if lower-cost emissions reductions or offsets are available. Specifically, emitters may comply with the regulation by reducing per-unit GHG output by 12%, procuring offsets from emitters that reduced per-unit GHG output by more than 12%, or purchasing Alberta-based GHG offsets. See Section III.C.1.c for more details.

GHG compliance cost and the fraction covered), which we use to project power prices and forecast generator operating costs in the remainder of our analysis.

Figure 24
Projected Future GHG Prices



Sources and Notes:

Current GHG price from pp. 2-3, Alberta Government (2010b).

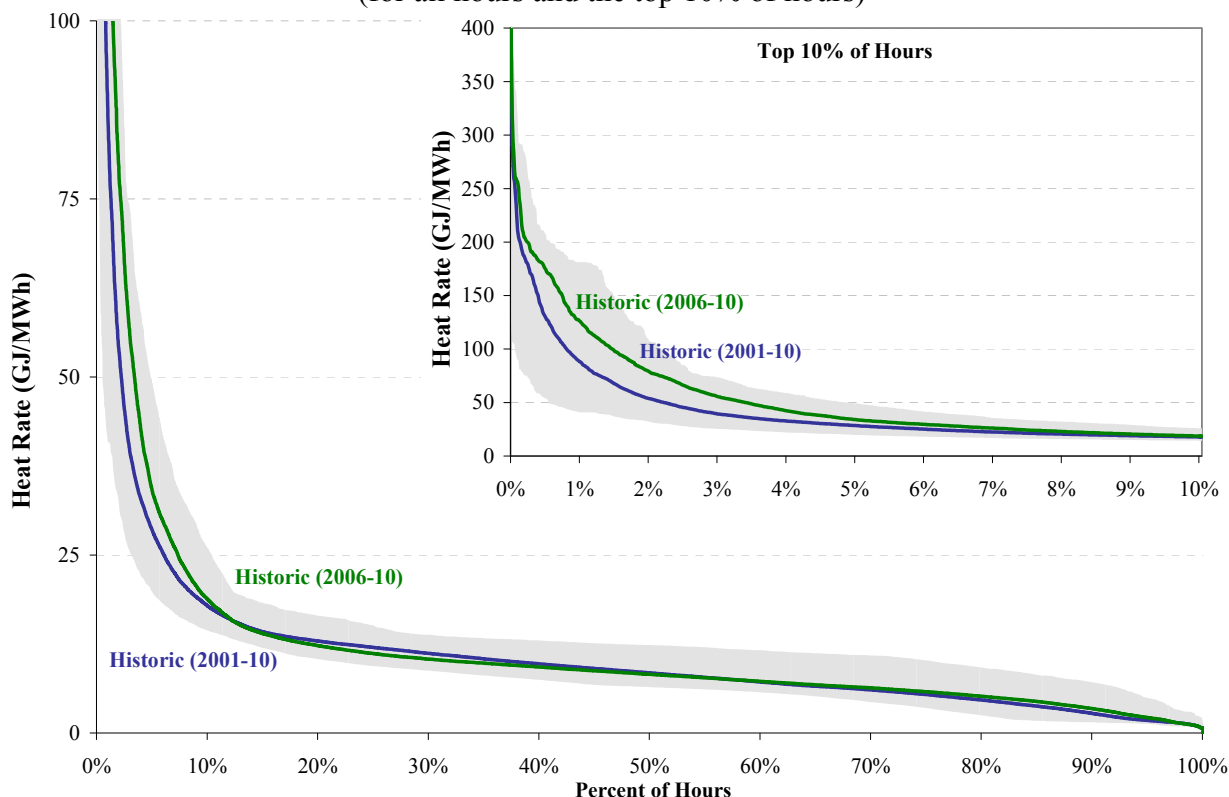
Future GHG price scenarios projected by AESO (2010c).

c. Potential Future Power Prices

To assess the Alberta energy-only market's ability to attract new generation investments over the coming decades, we developed energy price projections based on current market conditions and expected future natural gas and carbon prices. Figure 25 summarizes annual market heat rate duration curves for the years 2001 through 2010. The heat-rate duration curve for the entire 2001-10 period is shown in blue, while the heat rate duration curve for the last five years, 2006 through 2010, is shown in green. The range of heat rate duration curves for the individual years during the past decade is shown in gray.

These duration curves show that market heat rates were below 25 GJ/MWh during most hours of the year. However, they exceed that level during 5-10% of all hours, consistent with occasional scarcity pricing. The inset figure shows the market heat rates for the top 10% of all hours. The kink in these curves above a market heat rate of 150 GJ/MWh for approximately the top 1% of hours is a distortion introduced by the \$1000/MWh price cap as discussed in Section V.A.3. This distortion of the heat rate duration curve for the top 1% of all hours is important to keep in mind for the following analyses.

Figure 25
Historic Market Heat Rate Duration Curves
 (for all hours and the top 10% of hours)



Sources and Notes:

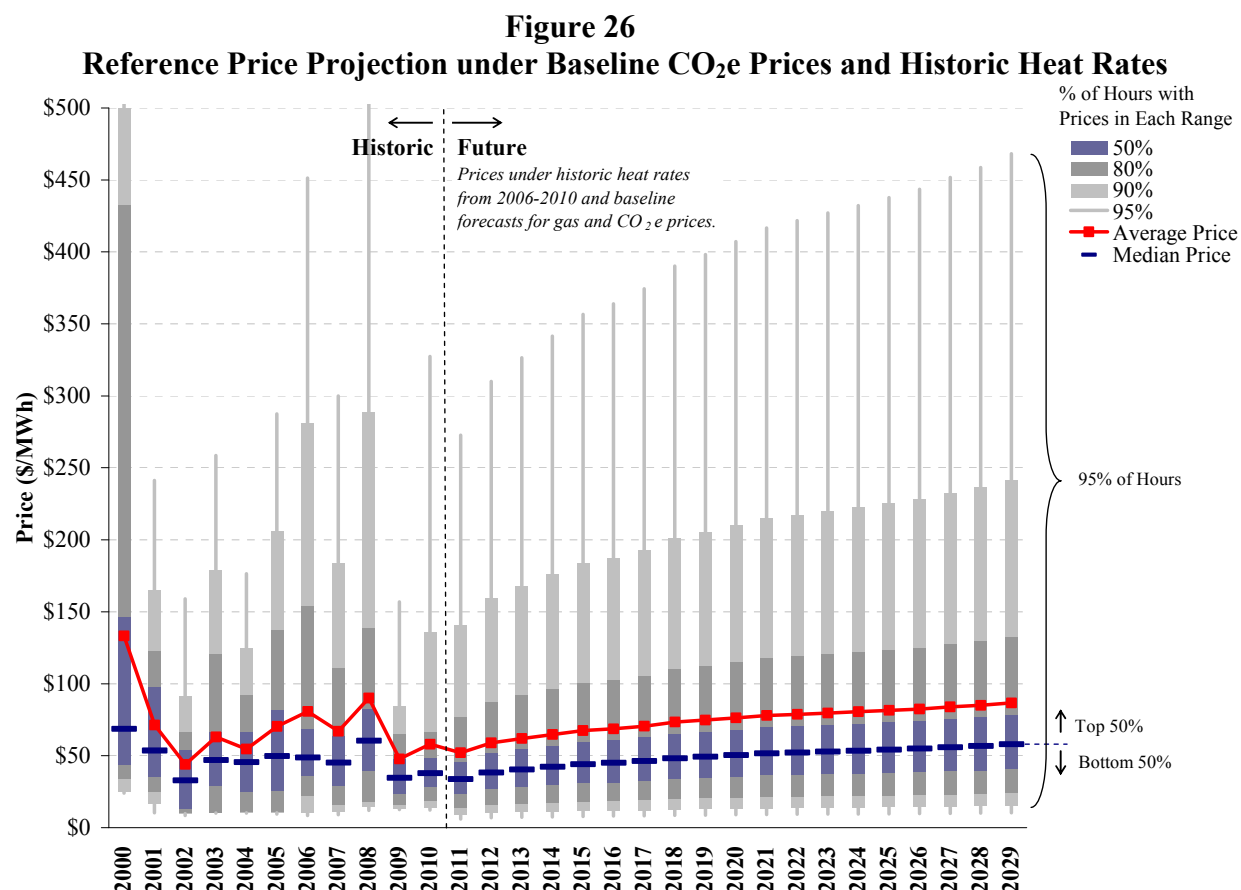
Calculated based on daily historic AECO C natural gas and hourly energy prices, Bloomberg (2010) and Ventyx (2010).
 Blue and green lines reflect heat rate duration curves for years 2001-10 and 2006-10 respectively.
 Gray range indicates maximum and minimum heat rate duration curves for individual years during 2001-10.

As discussed earlier and illustrated by the difference between the green and blue lines in Figure 25, market heat rates during the past 5 years have been higher than the average over the past 10 years. This appears to be directly related to lower reserve margins during the recent past as discussed in Section V.A.4. Because reserve margins of the last 5 years are roughly in line with the 15% reserve margin we use as a rough benchmark for resource adequacy, we use the market heat rate duration curve from this 5-year period to project future power prices and analyze whether the projected prices likely would be sufficient to support investment in new generating plants.

To project future prices in Alberta's energy market, we multiplied the 2006-2010 market heat rates by the forecasted sum of future natural gas and carbon price.¹¹² This results in projected price duration curves for each year through 2029. The average and range of projected energy prices in each of these years are shown in Figure 26. Figure 26 shows that if the 2006-2010 level of market heat rate curve is maintained, electric prices can be expected to rise only slowly over

¹¹² This is the reverse of the calculation used to determine historic market heat rates discussed in Section V.A.2. The calculation assumes a carbon content of natural gas of 0.0508 tonnes of CO₂e/GJ of gas. See Alberta Government (2007a) and EIA (2010b).

the coming two decades, driven by increases in gas and carbon prices. We show here the price projection for the baseline carbon price case, but explore the impacts of the different GHG price scenarios in subsections V.B.2 and V.B.3 below.



Sources and Notes:

Calculated based on historic heat rates (Figure 25) and natural gas and baseline carbon prices (Sections V.B.1.a-b).

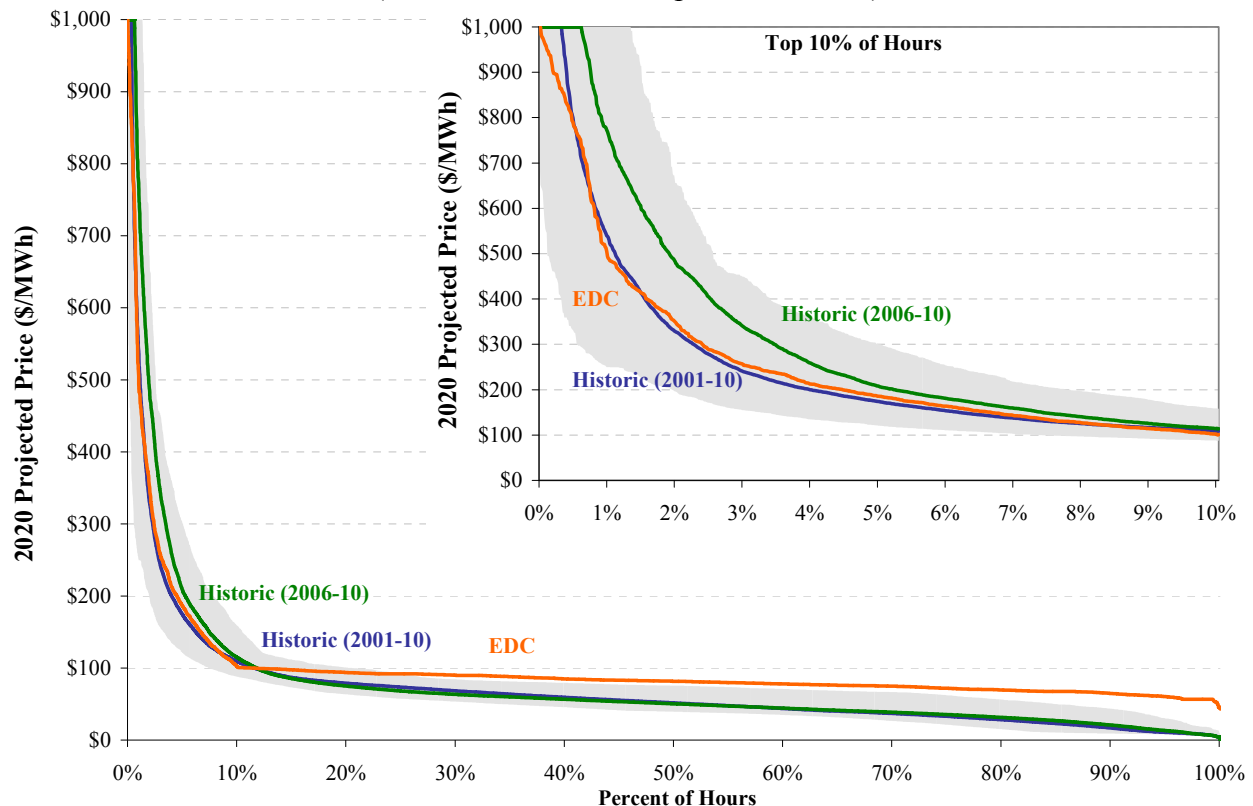
The projected price duration curve for 2020 based on 2006-2010 heat rates is shown as the green line in Figure 27. The figure also shows the projected prices based on 2001-2010 average market heat rates (blue line). This comparison shows that using the most recent 5 years average market heat rates results in higher prices during the top 10% of all hours although prices during the rest of the year are very similar. The gray area represents the range of 2020 projected price duration curves that would be obtained by using the market heat rate duration curves of individual years from the 2001-2010 period. This range is useful for assessing year-to-year uncertainty of prices above and below the baseline projection.

Figure 27 also includes the 2020 price forecast from EDC (orange line).¹¹³ The comparison shows that EDC's forecast exceeds our projections during 70% of the lowest-priced hours, but falls short of our 2006-2010 heat-rate-based projections (green line) during the top 10% of all hours. The likely reason for this discrepancy is that EDC's model is a fundamentals-based model that projects the disproportionately larger off-peak impact that increases in CO₂e prices

¹¹³ See EDC (2010).

will have on coal units, an effect that is not captured in the heat rate curve approach used in our projections. Overall, the 2006-2010 heat-rate-based projection yields an average power price for 2020 of \$73.6/MWh. This is significantly below the average EDC forecast of \$97.6/MWh, and will yield a conservatively low price projection to assess the economics of new generation investments, particularly for baseload units that would benefit from higher off-peak prices.

Figure 27
Year 2020 Reference Price Duration Curve under Baseline GHG Price
 (for all hours and the top 10% of hours)



Sources and Notes:

Blue and green lines are based on heat rates for 2001-10 and 2006-10 respectively; calculated based on historic heat rates (Figure 25) and natural gas and baseline carbon prices (Sections V.B.1.a-b.)

Orange line is a forecast done by EDC (2010).

Gray range indicates maximum and minimum prices calculated with heat rates for individual historic years 2001-10.

Figure 27 shows that approximately 1% of all hours are constrained by the price cap at the full-hour price granularity, curtailing the price duration curve on the high end.¹¹⁴ The current \$1,000/MWh cap has impacted a larger number of hours during the last five years than in the first half of the last decade and its impact has been most substantial during the years with the highest natural gas prices. A price cap tends to distort the free functioning of the market and reduces operating margins available to recover investments; its impact is greater when it

¹¹⁴ Note that this approach and the 1% number under-estimate the impact of the price cap because these data and projections are based on an hourly price granularity. Because Alberta's system marginal price can be constrained at the price cap at a minute-level granularity, the overall duration of time that would be affected is greater than what is presented here.

constrains prices in more hours. The impact of the price cap is highest on peaking resources that are most impacted by changes in peak prices. Also heavily impacted are demand resources which may require very high payments for each interruption. Both peaking generating resources and demand response play a pivotal role in supporting long-term resource adequacy cost effectively.

As the cost of production increases over the coming decade along with upward trending natural gas and carbon prices, the current \$1000/MWh price cap will become an even greater constraint and reduce investment returns during peak hours. This will tend to reduce peaking capacity and demand response and decrease reserve margins until market prices outside the price-capped periods increase enough to attract other investment. This combination of constrained price cap hours and higher prices in non-capped hours could result in lower reliability and possibly higher average system costs at the same time.

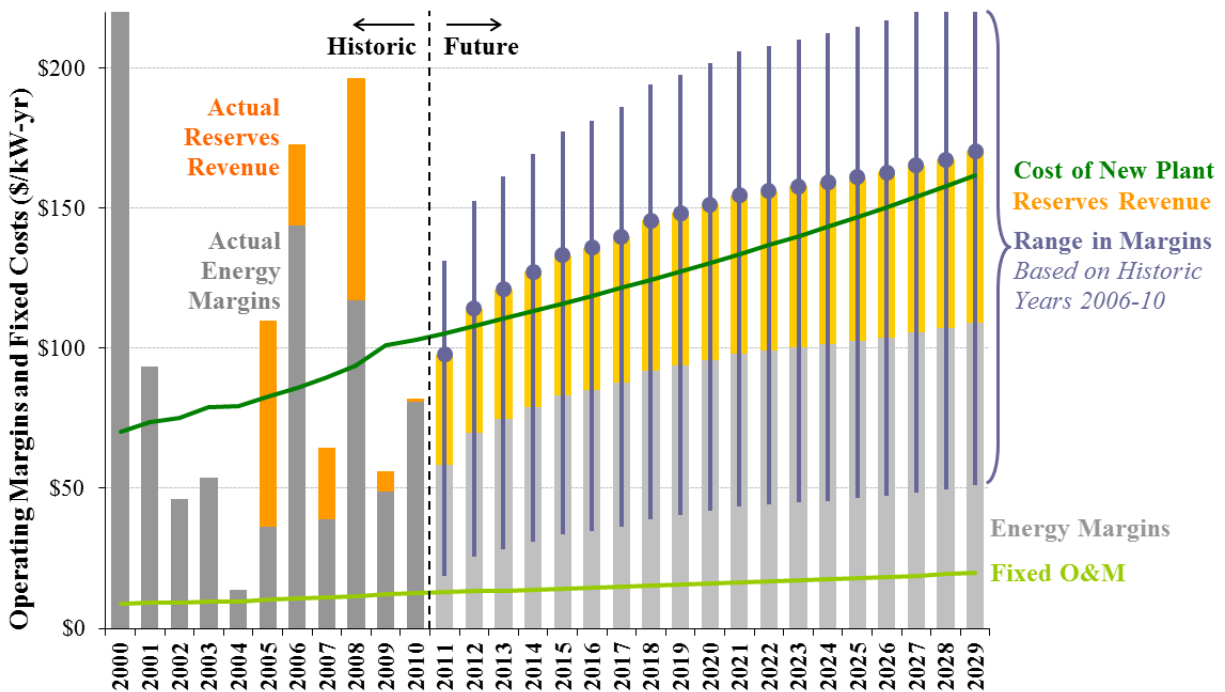
2. Projection of Generator Operating Margins vs. Investment Costs

From the future price duration curve developed in Section V.B.1.c, we are able to project operating margins for each type of generating technology described in Section V.A.5. As documented more fully in Appendix B, we make these projections in two steps. First, we determine the theoretical “perfect dispatch” margins for each generating unit type by assuming that the unit generates energy during all hours when energy prices are above variable operating costs, including fuel, emission prices, and variable operating and maintenance costs.¹¹⁵ Second, because generating units will not be dispatched perfectly into 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 historic operating data for each unit type. This calculation also takes into account periods during which generators provided operating reserves and, thus, were not available to participate in the energy markets. Projected operating reserves revenue is similarly estimated as a linear function of projected “perfect dispatch” margins, based on the historic relationship between the two for each unit type. Appendix B provides more detail about these calculations.

The projected operating margins from energy and operating reserves markets for each generating technology, calculated as revenues less variable operating costs, can now be compared to fixed operating costs and investment-related costs. Figure 28 and Figure 29 show how the projected future operating margins in energy and reserves markets compare to the fixed costs of new gas CTs and new coal units. The figures are similar to those presented in Section V.A.6 in that total projected operating margins that are above the levelized cost of a new plant on average would indicate a profitable investment, while operating margins below the cost of a new plant would discourage new entry.

¹¹⁵ With the exception of wind, which is treated as if it ran every hour; a capacity availability factor has been applied after the fact.

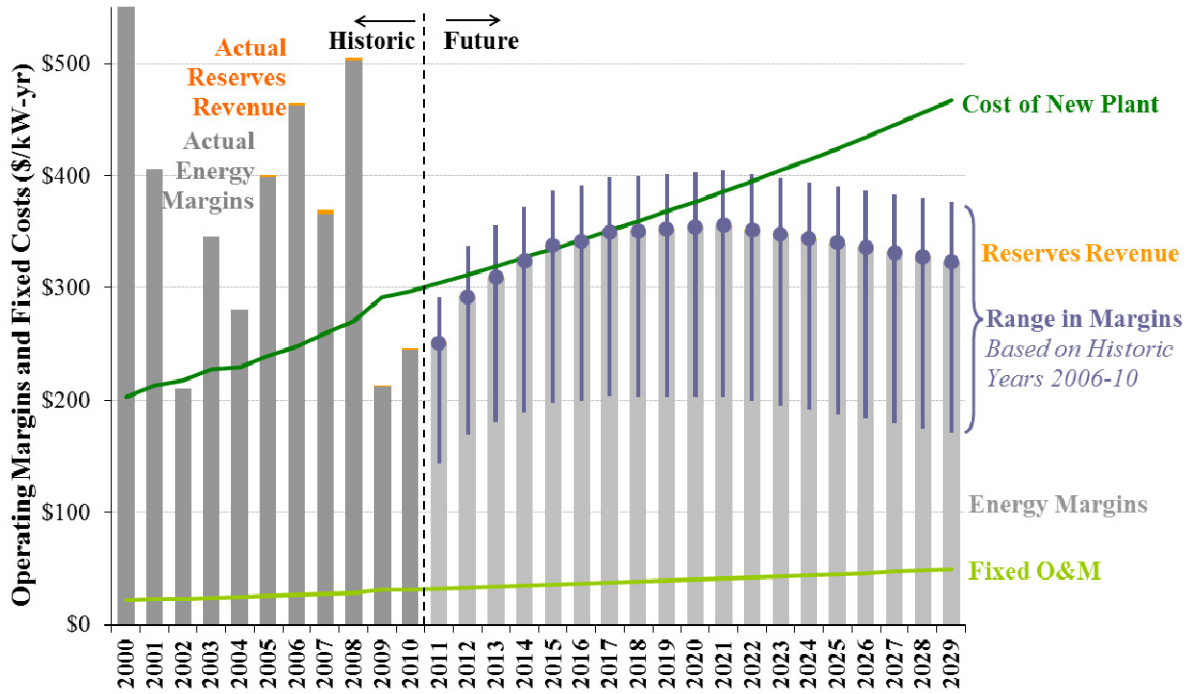
Figure 28
Projected Gas CT Operating Margins vs. Fixed Costs



Sources and Notes:

Future price duration curve is calculated based on heat rates from 2006-10 and baseline gas and CO₂e price forecasts.
 Cost of new plant includes FOM and real levelized capital costs from Section V.A.5, future escalation at 2.4% annually.

Figure 29
Projected Coal Operating Margins vs. Fixed Costs



Sources and Notes:

Future price duration curve is calculated based on heat rates from 2006-10 and baseline gas and CO₂e price forecasts.
 Cost of new plant includes FOM and real levelized capital costs from Section V.A.5, future escalation at 2.4% annually.

The stacked bars in the above charts represent the total operating margins that a unit would receive based on future prices projected with market heat rates from the past five years, while the uncertainty range shows the range of margins that would be obtained from the projection of future market prices with heat rates from individual years since 2001. The range is an indicator of the year-on-year volatility that one could expect in future operating margins based on the experience of the last 10 years.

Appendix C shows the same charts for four other generating technologies: new gas CCs, natural gas cogen, hydro, and wind generators. The difference between levelized costs and projected operating margins provides an indication of whether market conditions would support entry of each of these generation types:

Gas CTs – The projected operating margins support the viability of new CT investments, although the year-to-year volatility of revenues is likely to be high. Revenues from operating reserves substantially contribute to the potential returns, although building more CTs may reduce reserves prices and reduce this value. On the other hand, factors such as additional amounts of intermittent wind generation will increase operating reserve requirements and enhance the viability of CT investments.

Gas CCs – The outlook is similarly positive for future investments in CCs although, based on experience to date, CCs are not likely to be substantial providers of operating reserves.

Gas Cogen – As in the past decade, gas cogen investments appear to remain attractive investments in the future, provided that sufficient demand for steam exists in oil sands and other sectors.

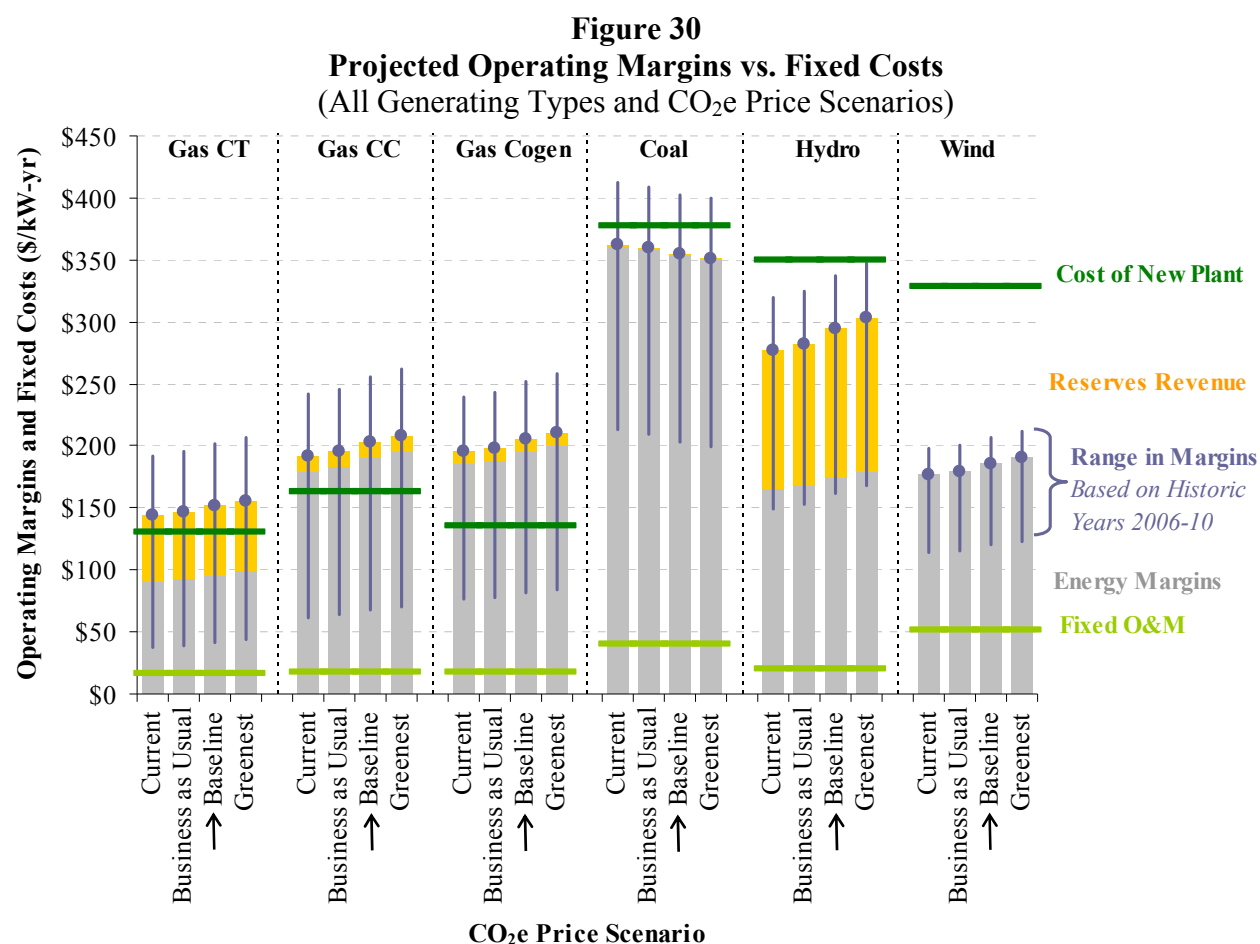
Coal – Our projections strongly suggest that coal generation will become a less attractive investment in the future, as natural gas prices remain low and increases in CO₂e prices will escalate their costs more than they will escalate prices. The continuation of low natural gas prices, combined with other environmental regulations that may prevent coal without CCS from being built, make new market-based coal generation investments unattractive in the foreseeable future. However, future operating margins are still projected to be many times higher than ongoing fixed O&M costs, meaning that existing coal units are unlikely to retire absent mandated large capital expenditures, or the forfeiture of decommissioning cost recovery.

Hydro – The outlook is similarly poor for new market-based hydroelectric generation. While energy and reserves revenues for hydro are projected to increase and substantially benefit existing facilities, the large capital costs associated with these projects appear to make them cost-prohibitive absent governmental subsidy.

Wind – As in the historic operating margins analysis, wind generation is an uneconomic investment if the monetization of green power attributes is not considered. While we have not analyzed the potential future value of such green power attributes (e.g., renewable energy credits), substantial recent growth in wind generation is likely to continue in order to meet corporate, federal, and other environmental policy goals.

Overall, the prospects for new entry appear promising for incremental capacity investments, although it appears that economics have shifted away from favoring coal and toward favoring gas CCs and CTs.

A summary of the projected operating margins by technology type for the year 2020 is shown in Figure 30. This figure shows that gas CCs, CTs, and cogen technology are all projected to be attractive investments under each of the four CO₂e price scenarios discussed in Section V.B.1.b, including a scenario in which the current low carbon price is maintained. The difference in CO₂e prices among these scenarios does not change the determination of whether the investment is attractive for any of these technology types, although the range of CO₂e prices we examine may be more limited than what federal policy could dictate in the coming decades.



Sources and Notes:

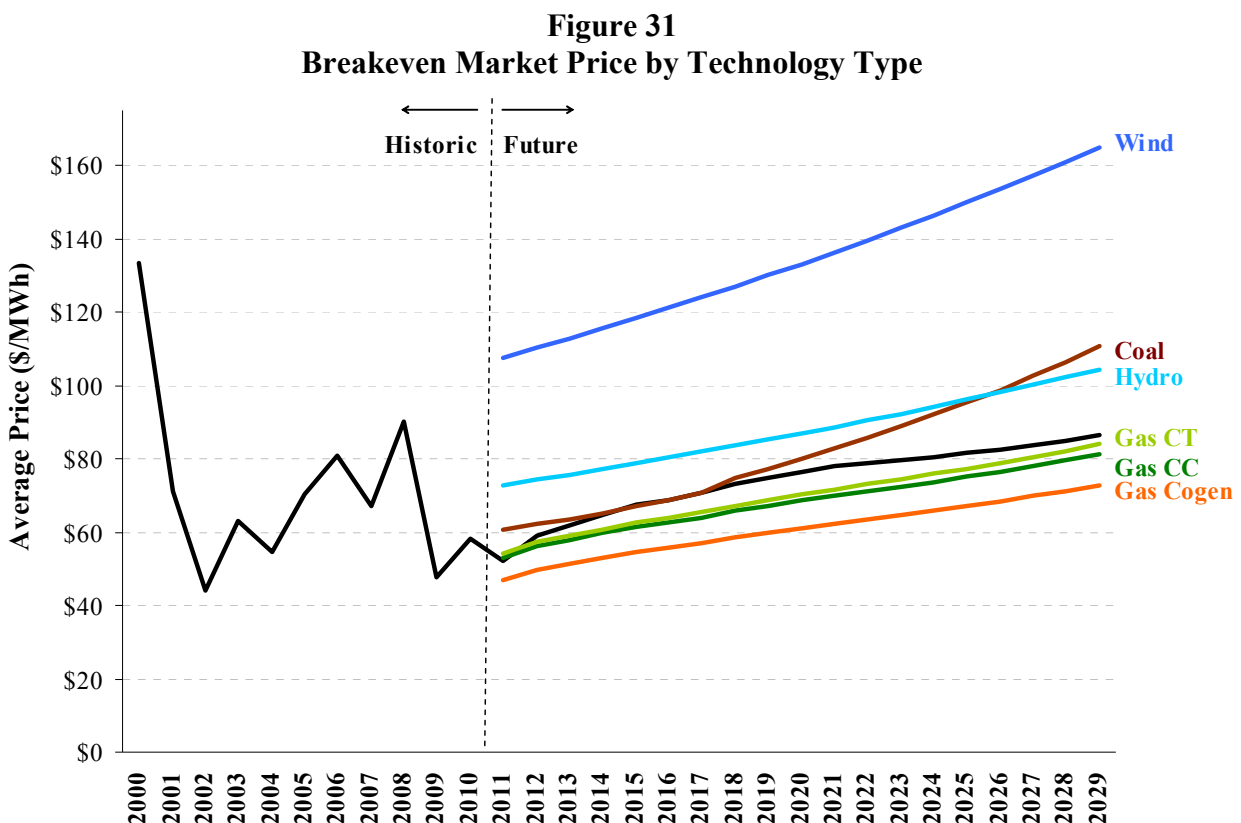
Future price duration curve is calculated based on heat rates from 2006-10 and baseline gas and CO₂e price forecasts.
Cost of new plant includes FOM and real levelized capital costs from Section V.A.5, future escalation at 2.4% annually.

3. Breakeven Future Prices by Technology Type

Another question is how high average annual energy prices would have to be before each type of generation technology could recover its investment costs. This is a somewhat simplistic question because the entire price duration curve (*i.e.*, peak and non-peak hours) must be considered to determine whether a specific technology is economically viable. For example, a natural gas peaking unit requires that prices be sufficiently high during peak hours when it is dispatched, while prices in off-peak hours have no impact. For this reason, the breakeven average annual price for a specific technology will also depend on the shape of the future price duration curve.

To avoid this complexity, we assume that the future heat rate duration curve will be the same as it has been over the past five years, although we increase or decrease the curve by a multiplier that is equally applied to all hours of the year.¹¹⁶ For each future year, we adjust the heat rate duration curve until market prices are just sufficient to yield operating margins that cover the levelized cost of a new plant. The result is a breakeven price trajectory for each technology as shown in Figure 31, along with historic average prices and the baseline price projection shown in black.

As we have already noted, the projection of future prices based on current market conditions suggests that incremental investments in natural gas CTs, CCs, and cogen will be attractive over the coming years while purely market-based coal, hydro, and wind plants are not. The figure also demonstrates that prices would not have to increase substantially to make new coal investments economically viable, unless the cost of carbon emissions would increase beyond the assumed levels or federal mandates prohibit these investments. This result is reassuring in that, even without natural gas generation investments, future prices would not have to increase vastly beyond current price levels to attract incremental capacity for resource adequacy.



Sources and Notes:

Breakeven costs by technology type are calculated by inflating the heat rate duration curve until the margins earned by that technology type are sufficient to cover the fixed O&M and levelized constant real capital costs.

¹¹⁶ Note that this approach does not consider any market fundamentals that might work to increase prices disproportionately only in off-peak or on-peak hours. For this reason the results are illustrative but by no means definitive.

VI. FINDINGS AND RECOMMENDATIONS

The challenges examined in this study will come about gradually and increase the rate of plant retirements and investment needs. However, with the possible exception of accelerated retirements related to decommission cost recovery, these challenges should not result in substantial simultaneous retirements of existing plants. The plant retirement rate will most likely average 220 MW per year over the next two decades, which is 1.5 times the 150 MW of annual retirements experienced during the last decade. Considering both these retirements as well as the anticipated load growth of 3.2% per year and an associated reserve margin requirement increase, this would require the addition of 740 MW per year over the next 20 years. This is almost twice the rate of historic gross generation additions, which averaged 380 MW over the past decade.

The current market design should be able to support this higher and consequently more challenging rate of generation additions. Our analysis shows that the Alberta market design is generally well-functioning, with energy and ancillary service prices that have been relatively *low* when reserve margins were high, but that have increased enough to attract new plant additions when system-wide reserve margins declined.

We also find that the Alberta market design will likely be able to retain existing resources and attract new entry without dramatic price increases or a significant reduction in resource adequacy. Our projections show that only modest increases in market prices, consistent with projected increases in natural gas and carbon emission costs, should be sufficient to avoid premature retirement of existing resources and, importantly, support investments in new generation. We find that projected future market prices based on current fundamentals strongly favor natural gas-fired generation, meaning that the Alberta resource mix is likely to shift from coal generation to natural-gas-fired power plants. The entry of additional wind turbines and coal plants with carbon capture and storage may be supported by government policies and through the value of “green” attributes.

As a result, and perhaps contrary to our initial expectations, we currently see no compelling need for major changes in Alberta’s electricity market design. However, the outlook for resource adequacy remains uncertain and sensitive to changes in market fundamentals and continued evolution of the identified challenges, which must not be underestimated. It also needs to be recognized that an energy-only market design will not be able to “guarantee” that a certain reserve margin will be maintained. In fact, in a small system such as Alberta’s, the lack of coordination between the retirement and online dates of individual units can cause transitional reliability concerns and price spikes, as has been highlighted by the recently announced unexpected potential early retirements of Sundance 1 and 2.

Overall, we offer the following recommendations.

- The AESO should carefully monitor market fundamentals in light of the identified challenges. In addition to the already ongoing monitoring of resource adequacy metrics based on a 24-month outlook, we recommend monitoring: (1) trends in market heat rates and the long-term outlook for technology-specific operating margins; (2) retirement schedules and associated system reserve margins; (3) market price impacts of wind generation as more wind power plants come on line; and (4) the impact of interties as they are expanded and market rules related to the use of these interties evolve.

- Alberta policy makers should consider relaxing or revising the existing decommissioning cost recovery rule to reduce the risk of large simultaneous plant retirements in 2020 when most of the existing purchase power agreements expire. More generally, policy makers should avoid introducing regulations that could result in large simultaneous retirements, which are difficult to manage in any market or regulated environment.
- We recommend that the AESO consider increasing the current price cap from \$1,000/MWh to the lower end of estimates for the “value of lost load”, which tend to be in the range of approximately \$3,000/MWh. We also recommend reducing the price floor below zero to a level where generators, including wind plants, would have an incentive to shut down when it is economic to do so. These adjustments would also allow for economically efficient prices during reliability events, stimulate demand response facilitate entry of resources at lower average annual market prices, and make the level of the price cap more consistent with those in other energy-only markets, such as Texas and Australia.
- Coincidentally with increasing its price cap, the AESO should consider revising its mechanism for setting administrative prices under emergency conditions when out-of-market reliability actions become necessary. Under these conditions, prices should be set to reflect the marginal cost of any out-of-market actions.
- The AESO should carefully consider the long-term resource adequacy implications of its efforts to refine the Alberta market design, which include: (1) the integration of additional wind generation; (2) refining ancillary service markets and market designs for demand response; (3) the expansion of interconnections with neighboring systems.

Overall, we conclude that Alberta’s energy-only market is generally well-functioning and sustainable, although its efficiency and effectiveness can be improved with some design changes. However, we caution that the current positive outlook cannot guarantee long-term for the simple reason that Alberta’s market design, like other energy-only markets, does not include a resource adequacy requirement. For this reason the AESO must continue to monitor potential challenges to resource adequacy over time.

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LIST OF ACRONYMS

ACE	Area Control Error
AECO	Alberta Energy Company
AESO	Alberta Electric System Operator
AEMC	Australian Energy Market Commission
AIES	Alberta Internal Electric System
AIL	Alberta Internal Load
ATC	Available Transfer Capability
AUC	Alberta Utilities Commission
AUD	Australian Dollars
BATEA	Best Available Technology Economically Achievable
BAU	Business as Usual
CAD	Canadian Dollars
CAISO	California Independent System Operator
CASA	Clean Air Strategic Alliance
CC	Combined Cycle
CCEM	Climate Change Emissions Management
CCS	Carbon Capture and Sequestration
CH ₄	Methane
CO ₂	Carbon Dioxide
CO ₂ e	Carbon Dioxide Equivalent
CONE	Cost of New Entry
CPUC	California Public Utilities Commission
CT	Combustion Turbine
DDS	Dispatch Down Service
DR	Demand Response
EDC	EDC Associates, Ltd.
EIA	Energy Information Administration
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FOM	Fixed Operations and Maintenance
FRB	Federal Reserve Board
GHG	Greenhouse Gas

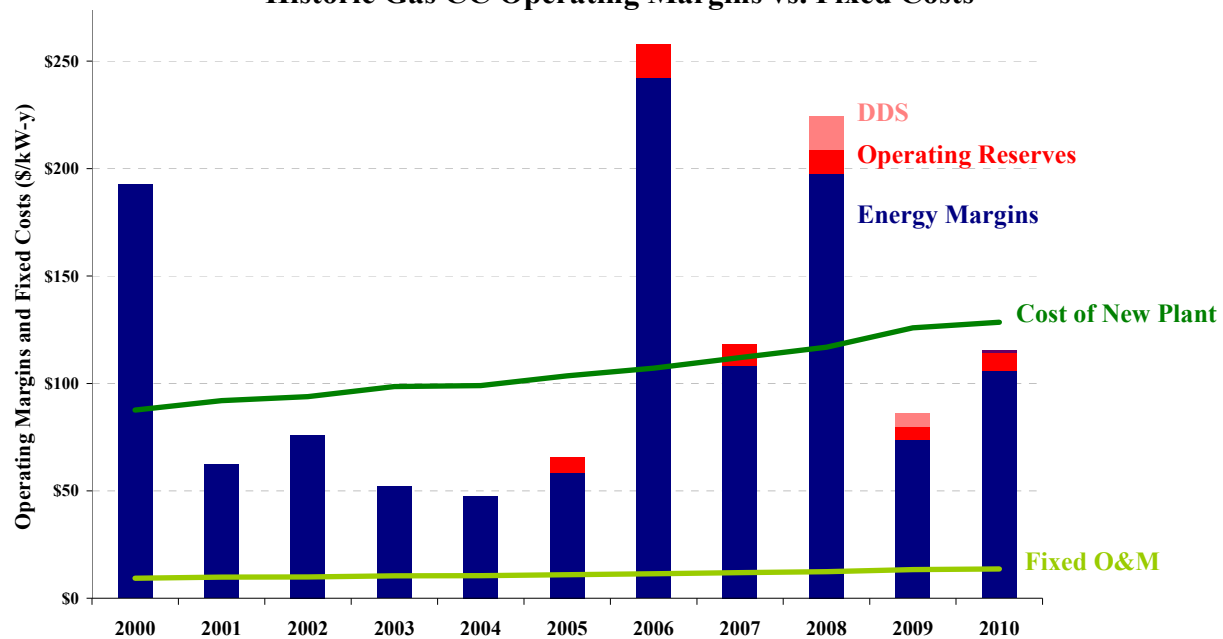
GJ	Gigajoules
GW	Gigawatts
GWh	Gigawatt-hours
IPCC	Intergovernmental Panel on Climate Change
ISO	Independent System Operator
ISO-NE	ISO New England
kT	Kilotonnes
MATL	Montana-Alberta Tie Limited
MT	Megatonnes
MW	Megawatts
MWh	Megawatt-hours
MSA	Market Surveillance Administrator
N ₂ O	Nitrous Oxide
NO _x	Mono-nitrogen Oxides
NEM	National Electricity Market
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NP15	North Path 15
NYPP	New York Power Pool
O&M	Operations and Maintenance
PJM	PJM Interconnection, LLC
PM	Particulate Matter
PPA	Power Purchase Arrangement
PRD	Price-Responsive Demand
SO ₂	Sulfur Dioxide
SPP	Southwest Power Pool
SWIS	South West Interconnected System
TMR	Transmission Must Run
VCA	Voluntary Capacity Auction
VOLL	Value of Lost Load

APPENDICES

A. GENERATOR OPERATING MARGINS VERSUS FIXED COSTS

Figure 32 through Figure 36 show the estimated generator operating margins and fixed costs over the past decade for natural gas CCs, natural gas cogen, hydro, wind, and natural gas CTs including TMR units. A discussion of the implications of this information is in Section V.A.6, along with similar figures for coal units and gas CTs without TMR units.

Figure 32
Historic Gas CC Operating Margins vs. Fixed Costs



Sources and Notes:

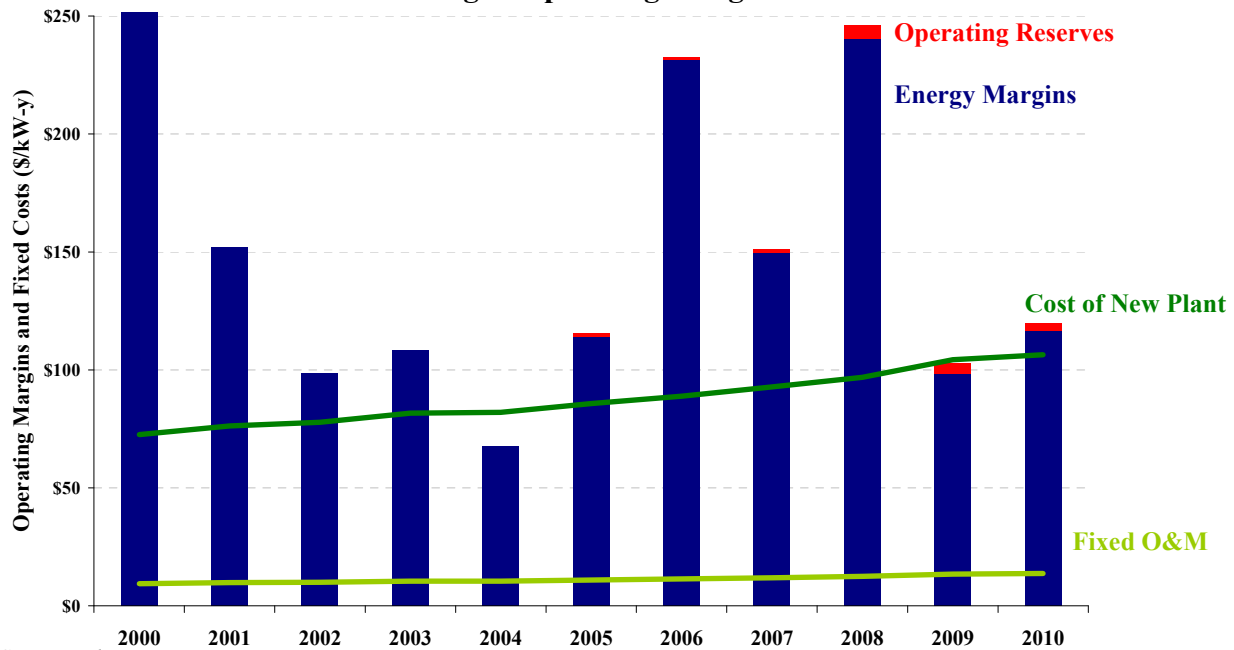
Energy margins represent revenues minus estimated operating costs in energy market. Cost of New Plant includes capital costs and FOM.

Unit-specific volumes and revenues as well as 2010 VOM, CONE, and FOM by unit type are from AESO (2010c).

Gas prices and exchange rates from Bloomberg (2010). Heat rates estimated from Ventyx (2010), AESO (2010c), Alberta Environment (2010a-b).

Historic CONE and FOM numbers are inflated according to the Handy-Whitman Index (converted from USD to CAD) between 2000 and 2009 from Whitman, et al. (2008) and PJM (2009); and by inflation between 2009 and 2010 from Bank of Canada (2010).

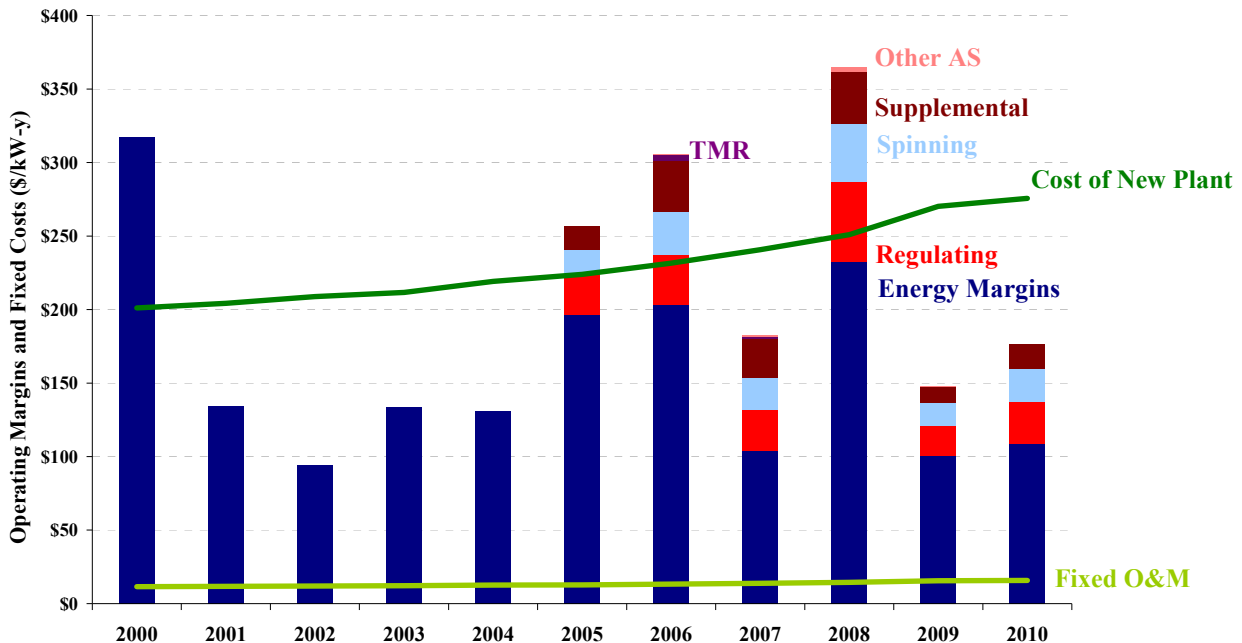
Figure 33
Historic Gas Cogen Operating Margins vs. Fixed Costs



Sources and Notes:

Energy margins represent revenues minus estimated operating costs in energy market. Cost of New Plant includes capital costs and FOM. Unit-specific volumes and revenues as well as 2010 VOM, CONE, and FOM by unit type are from AESO (2010c). Gas prices and exchange rates from Bloomberg (2010). Heat rates estimated from Ventyx (2010), AESO (2010c), Alberta Environment (2010a-b). Historic CONE and FOM numbers are inflated according to the Handy-Whitman Index (converted from USD to CAD) between 2000 and 2009 from Whitman, et al. (2008) and PJM (2009); and by inflation between 2009 and 2010 from Bank of Canada (2010).

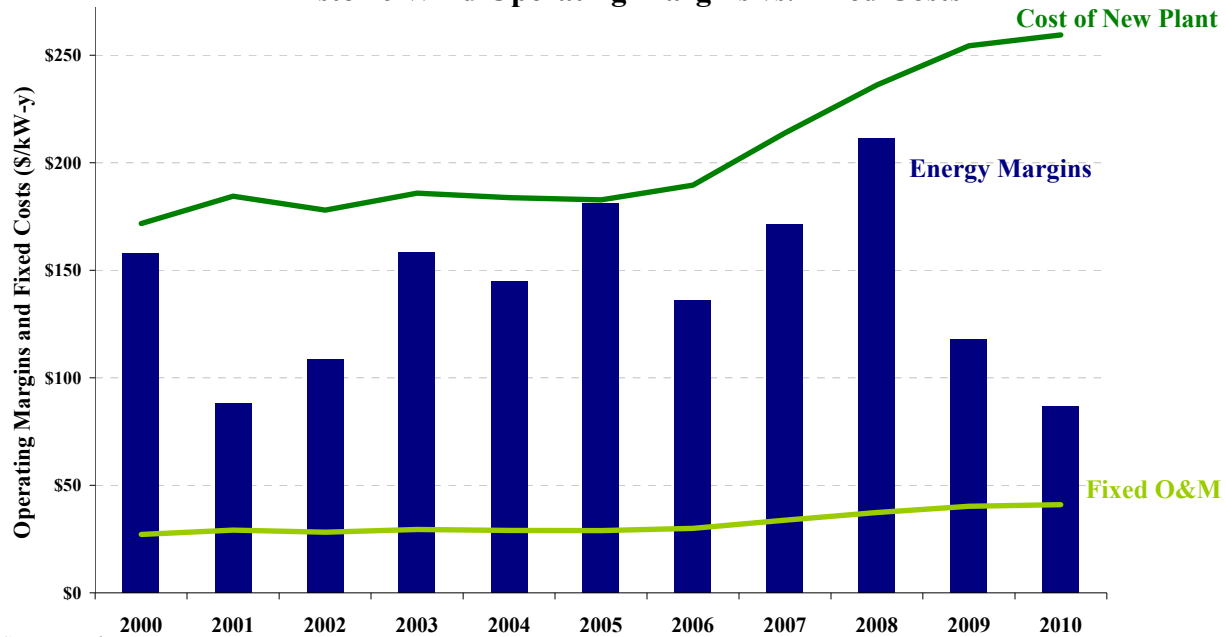
Figure 34
Historic Hydro Operating Margins vs. Fixed Costs



Sources and Notes:

Energy margins represent revenues minus estimated operating costs in energy market. Cost of New Plant includes capital costs and FOM. Unit-specific volumes and revenues as well as 2010 VOM, CONE, and FOM by unit type are from AESO (2010c). Gas prices and exchange rates from Bloomberg (2010). Historic CONE and FOM numbers are inflated according to the Handy-Whitman Index (converted from USD to CAD) between 2000 and 2009 from Whitman, et al. (2008) and PJM (2009); and by inflation between 2009 and 2010 from Bank of Canada (2010).

Figure 35
Historic Wind Operating Margins vs. Fixed Costs



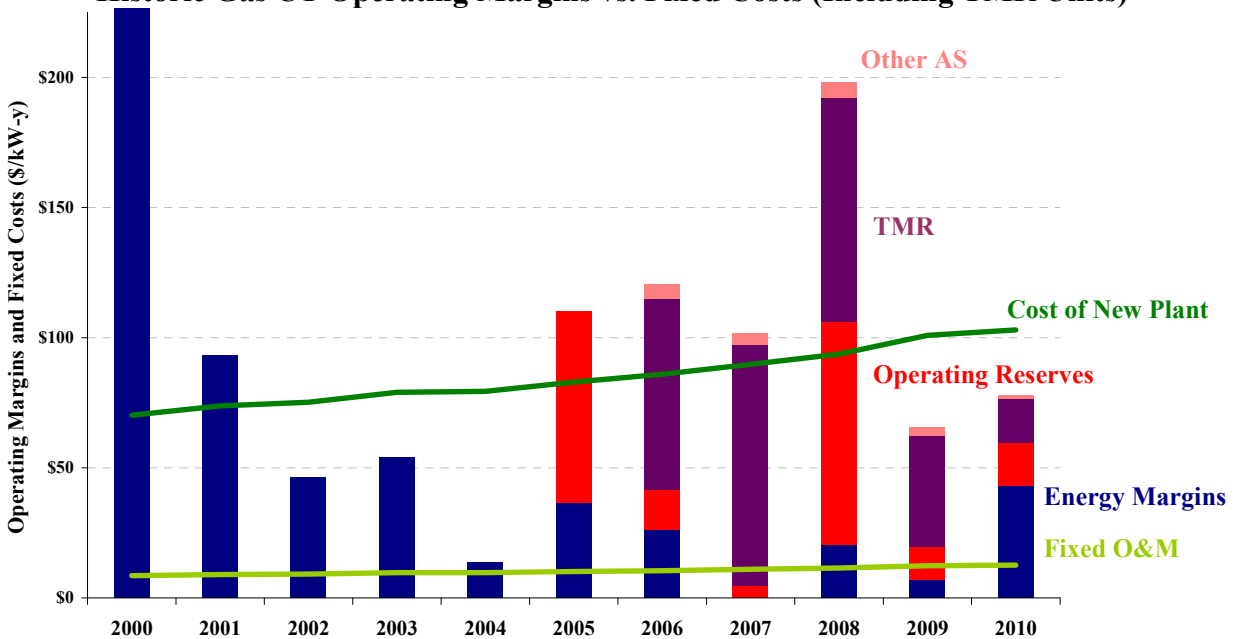
Sources and Notes:

Energy margins represent revenues minus estimated operating costs in energy market. Cost of New Plant includes capital costs and FOM. Unit-specific volumes and revenues as well as 2010 VOM, CONE, and FOM by unit type are from AESO (2010c).

Gas prices and exchange rates from Bloomberg (2010).

Historic CONE and FOM numbers are inflated according to the Handy-Whitman Index (converted from USD to CAD) between 2000 and 2009 from Whitman, et al. (2008) and PJM (2009); and by inflation between 2009 and 2010 from Bank of Canada (2010).

Figure 36
Historic Gas CT Operating Margins vs. Fixed Costs (Including TMR Units)



Sources and Notes:

Energy margins represent revenues minus estimated operating costs in energy market. Cost of New Plant includes capital costs and FOM.

Unit-specific volumes and revenues as well as 2010 VOM, CONE, and FOM by unit type are from AESO (2010c).

Gas prices and exchange rates from Bloomberg (2010). Heat rates estimated from Ventyx (2010), AESO (2010c), Alberta Environment (2010a-b).

Historic CONE and FOM numbers are inflated according to the Handy-Whitman Index (converted from USD to CAD) between 2000 and 2009 from Whitman, et al. (2008) and PJM (2009); and by inflation between 2009 and 2010 from Bank of Canada (2010).

B. METHOD FOR PROJECTING OPERATING MARGINS

Section V.A.6 describes our approach to projecting future operating reserves revenues and energy margins as a linear function of “perfect dispatch” margins that could be achieved by a plant with no startup costs, outages, or dispatch constraints. The parameters of these linear relationships are shown in Table 8.

Table 8
Energy Margins and Operating Reserves Revenue versus “Perfect Dispatch” Margins
 (Linear Relationships Based on Historic Monthly Data)

Energy Margins vs. Perfect Dispatch Margins				Reserves Revenues vs. Perfect Dispatch Margins			
a * (perfect energy margins) + b = (actual energy margins)				a * (perfect energy margins) + b = (OR revenues)			
	a	b (\$/kW-yr)	R ²		a	b (\$/kW-yr)	R ²
Coal	0.726	19.86	0.710	Coal	0.001	0.219	0.030
Gas Cogen	0.667	-21.68	0.817	Gas Cogen	0.033	-0.076	0.081
Gas CC	0.748	-42.91	0.918	Gas CC	0.031	2.877	0.104
Gas CT	0.484	-26.91	0.655	Gas CT	0.209	2.500	0.167
Hydro	0.295	-10.81	0.440	Hydro	0.290	-60.828	0.628
Wind	0.287	n/a	n/a	Wind	0.000	0.000	n/a

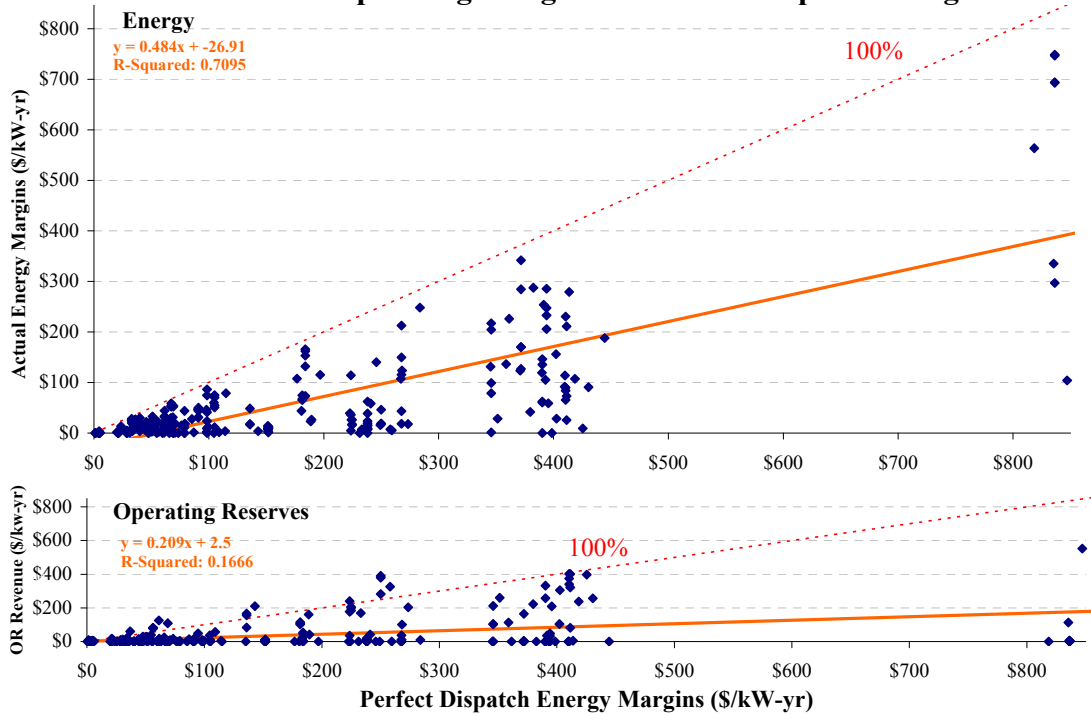
Sources and Notes:

Calculated from historic monthly unit-level data over January 2008 through October 2010 from AESO (2010c).

Wind is calculated as a simple percentage.

These relationships were developed based on the historic relationship between historic energy margins and operating reserves revenue calculated from AESO internal data as described in Section V.A.6 and a theoretical back-cast of perfect dispatch margins. These data are represented at the unit level for each month from January 2008 through October 2010. Figure 37 through Figure 42 are scatter plots of the data used to determine these linear relationships. Note that some data points show zero historic energy margins, which is an indication that the unit was on outage during that month.

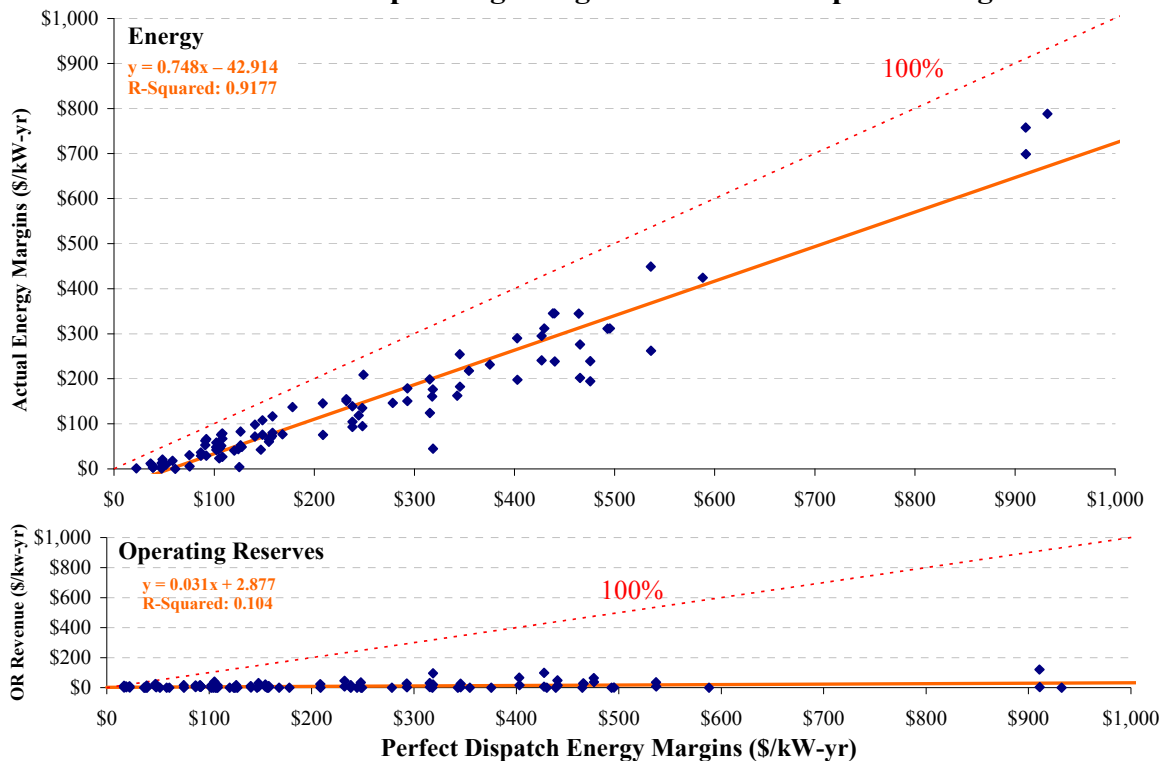
Figure 37
Historic Gas CT Operating Margins vs. Perfect Dispatch Margins



Sources and Notes:

Calculated from historic monthly unit-level data over January 2008 through October 2010 from AESO (2010c).

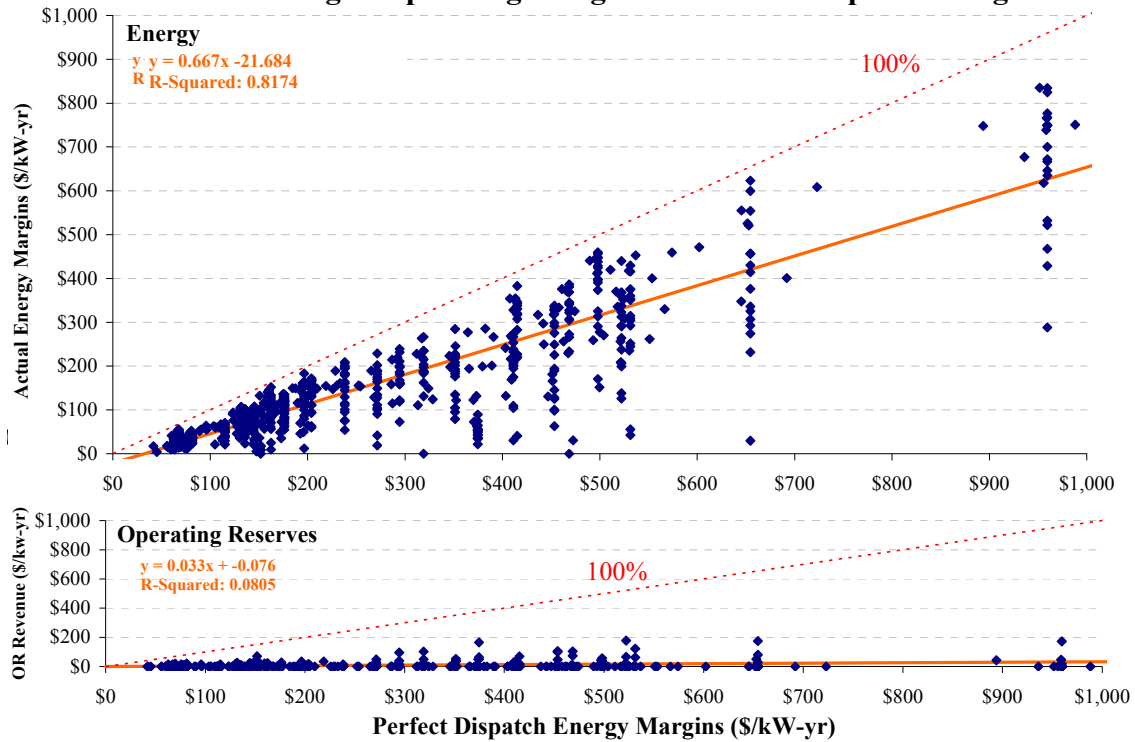
Figure 38
Historic Gas CC Operating Margins vs. Perfect Dispatch Margins



Sources and Notes:

Calculated from historic monthly unit-level data over January 2008 through October 2010 from AESO (2010c).

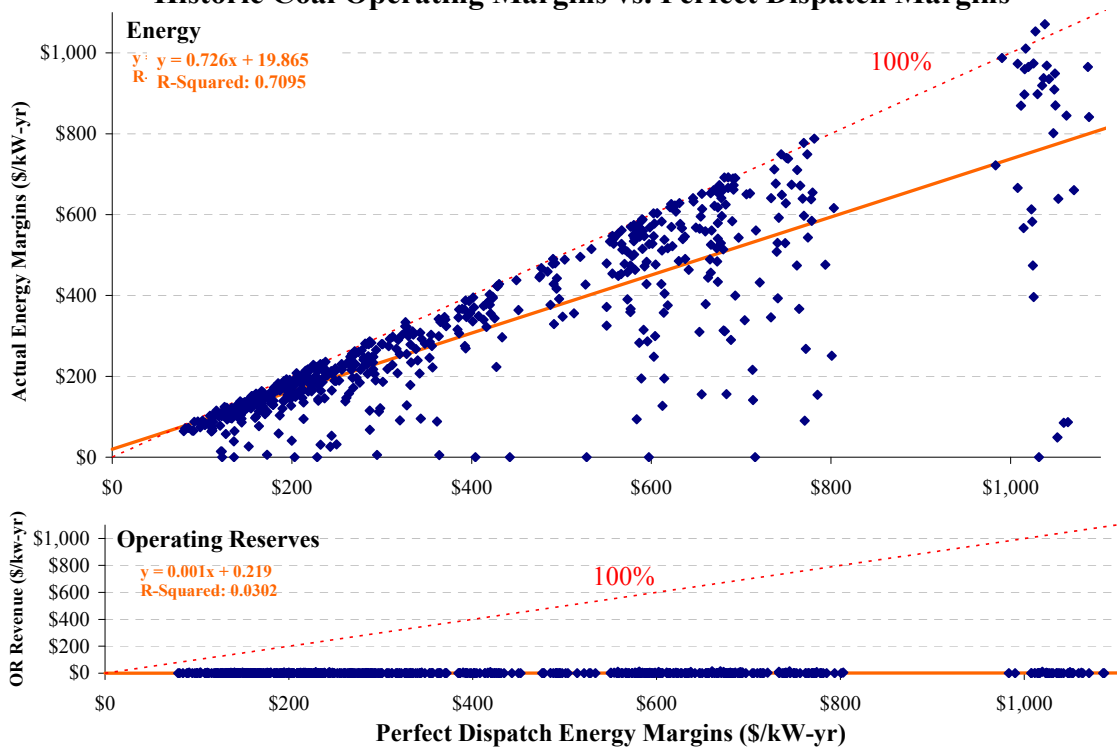
Figure 39
Historic Gas Cogen Operating Margins vs. Perfect Dispatch Margins



Sources and Notes:

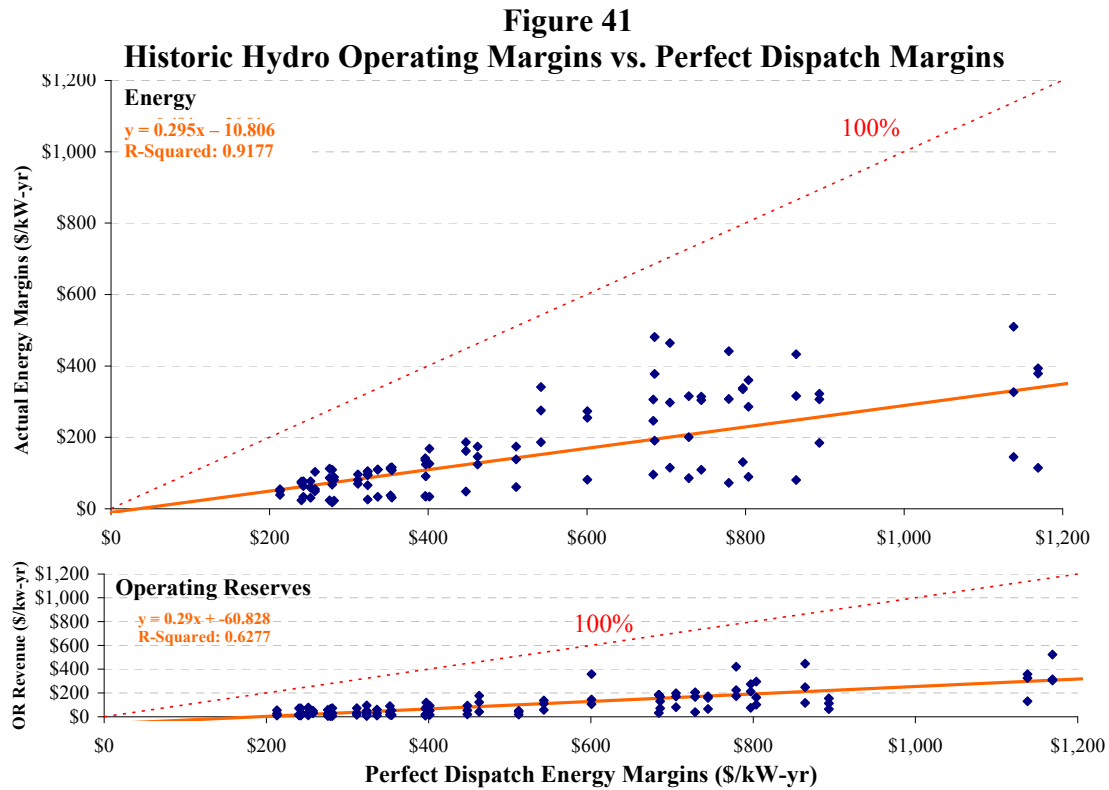
Calculated from historic monthly unit-level data over January 2008 through October 2010 from AESO (2010c).

Figure 40
Historic Coal Operating Margins vs. Perfect Dispatch Margins



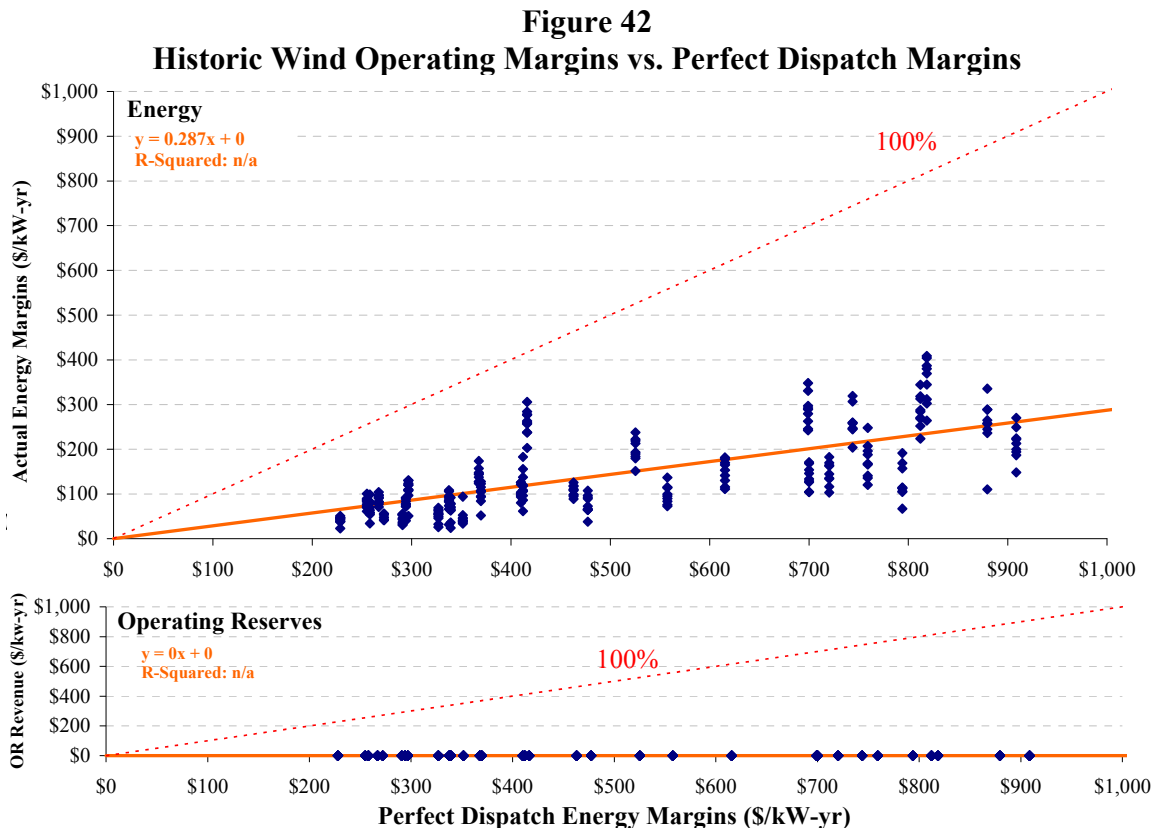
Sources and Notes:

Calculated from historic monthly unit-level data over January 2008 through October 2010 from AESO (2010c).



Sources and Notes:

Calculated from historic monthly unit-level data over January 2008 through October 2010 from AESO (2010c).

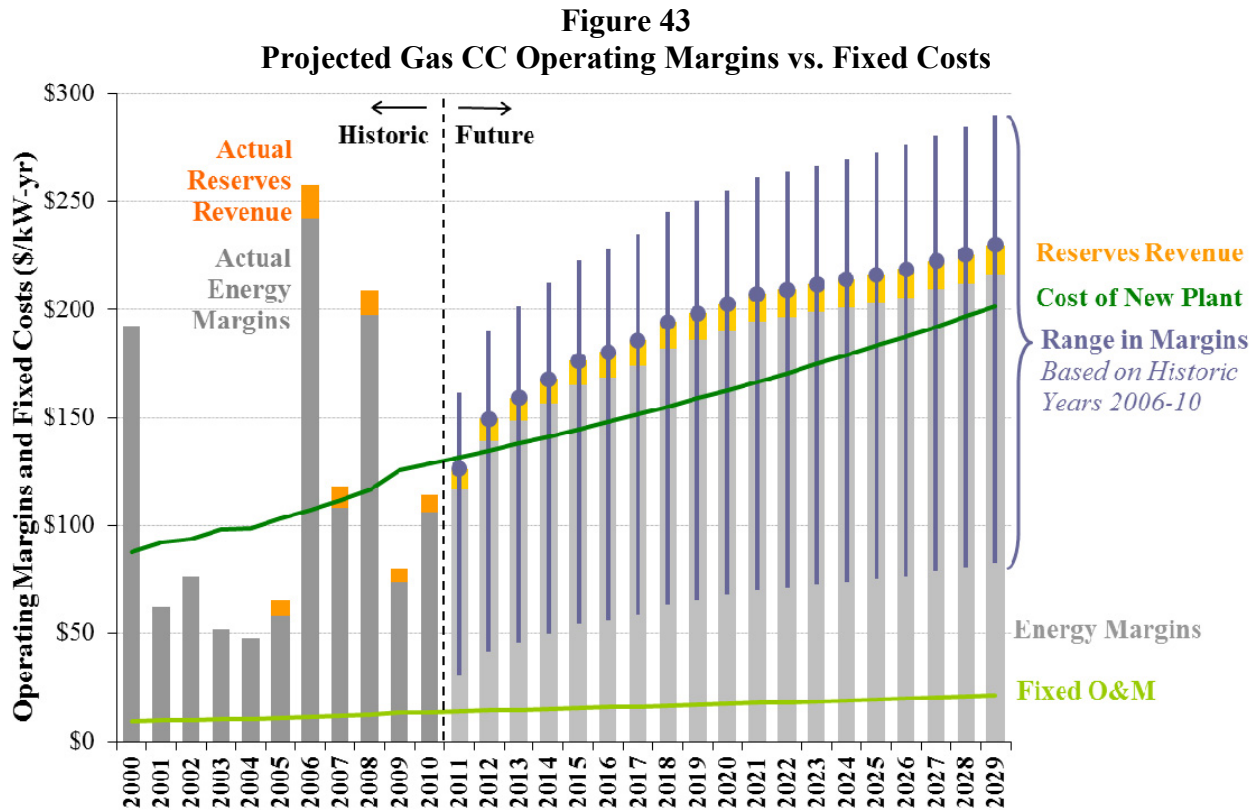


Sources and Notes:

Calculated from historic monthly unit-level data over January 2008 through October 2010 from AESO (2010c).

C. PROJECTION OF GENERATOR OPERATING MARGINS VERSUS FIXED COSTS

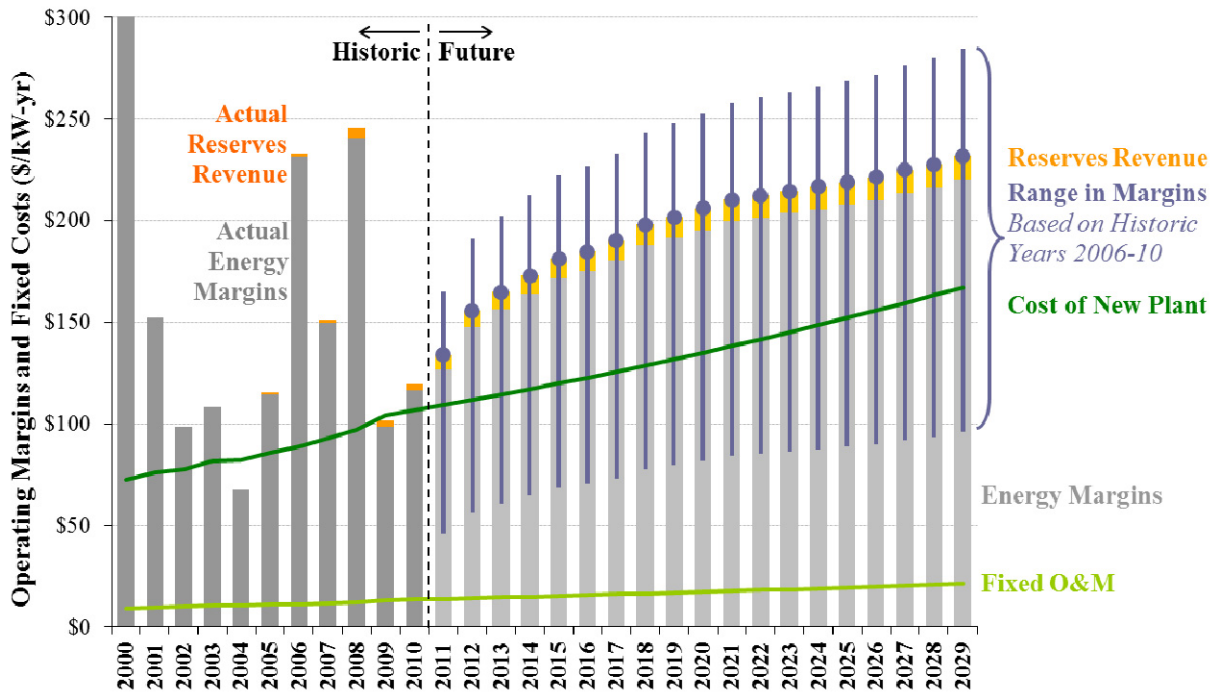
Figure 43 through Figure 46 show a projection of future generator operating margins and fixed costs under baseline CO₂e and gas assumptions using historic heat rates from 2006-10. The figures show results for natural gas CCs, natural gas cogen, hydro, and wind power plants. A discussion of the implications of this information is in Section V.B.2, along with similar figures for coal units and gas CTs.



Sources and Notes:

Future price duration curve is calculated based on heat rates from 2006-10 and baseline gas and CO₂e price forecasts.
Cost of new plant includes FOM and real levelized capital costs from Section V.A.5, future escalation at 2.4% annually.

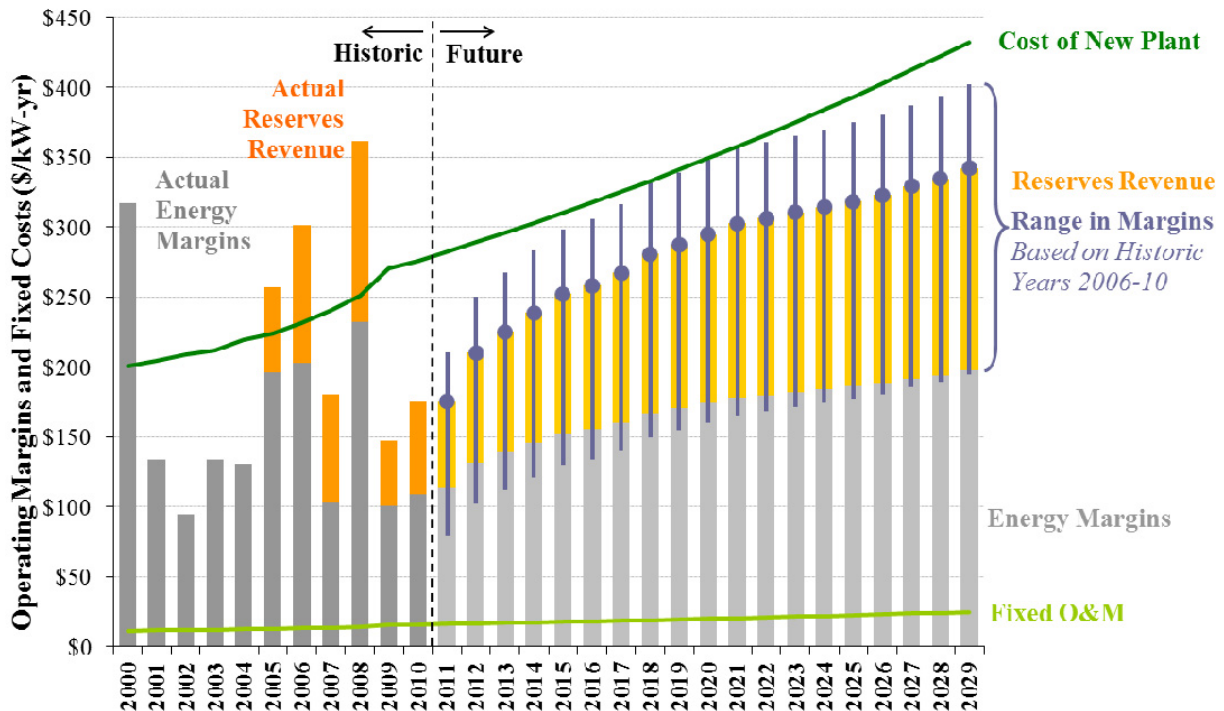
Figure 44
Projected Gas Cogen Operating Margins vs. Fixed Costs



Sources and Notes:

Future price duration curve is calculated based on heat rates from 2006-10 and baseline gas and CO₂e price forecasts.
 Cost of new plant includes FOM and real levelized capital costs from Section V.A.5, future escalation at 2.4% annually.

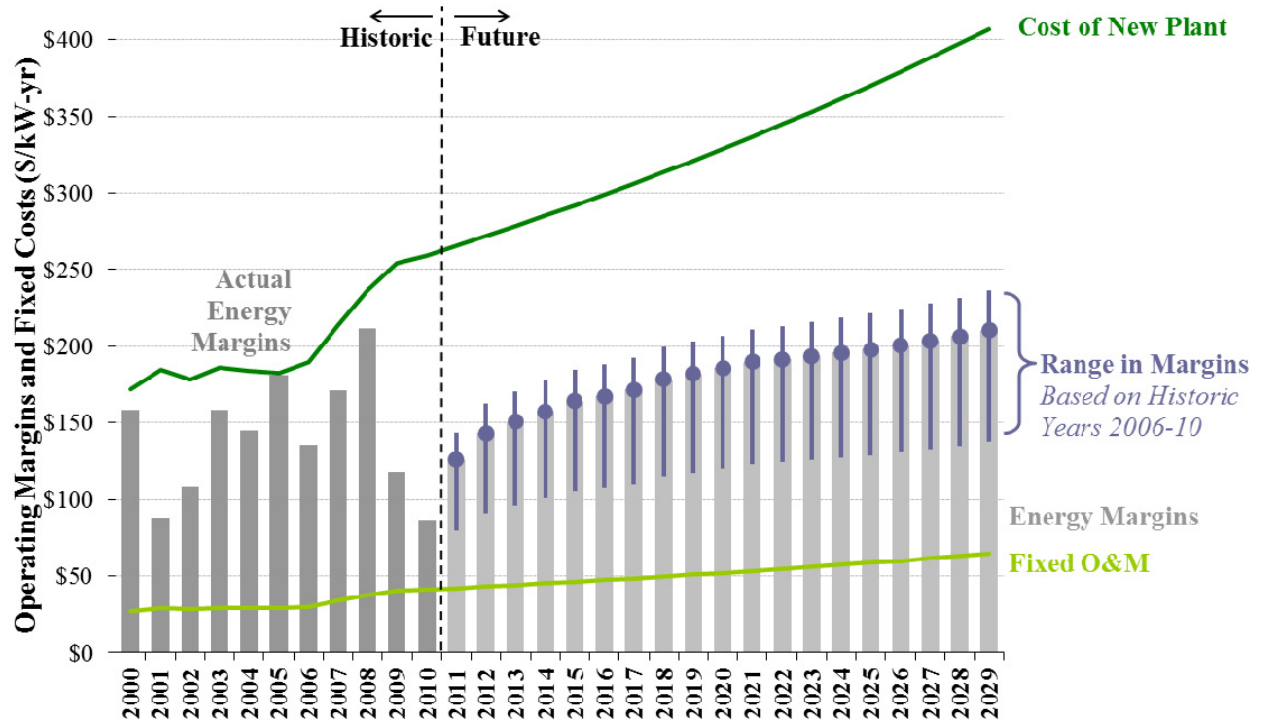
Figure 45
Projected Hydro Operating Margins vs. Fixed Costs



Sources and Notes:

Future price duration curve is calculated based on heat rates from 2006-10 and baseline gas and CO₂e price forecasts.
 Cost of new plant includes FOM and real levelized capital costs from Section V.A.5, future escalation at 2.4% annually.

Figure 46
Projected Wind Operating Margins vs. Fixed Costs



Sources and Notes:

Future price duration curve is calculated based on heat rates from 2006-10 and baseline gas and CO₂e price forecasts.

Cost of new plant includes FOM and real levelized capital costs from Section V.A.5, future escalation at 2.4% annually.