2012 Annual Market Statistics

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Executive Summary

As an independent system operator, the AESO leads the safe, reliable and economic planning and operation of Alberta's interconnected power system. The AESO also facilitates the fair, efficient and openly competitive operation of Alberta's wholesale electricity market. In 2012, the Alberta market had 170 participants and approximately $6.4 billion in annual energy transactions.

The Annual Market Statistics report provides a summary of key market information from 2012 and describes historic trends in Alberta's wholesale electricity market. An accompanying **data file** is provided to give stakeholders access to the information behind the metrics presented in the summary report. The AESO is committed to continuously improving the quality, timeliness and utility of the market data we provide.

In 2012, there was continued strong growth in demand over the previous year. Average Alberta Internal Load (AIL) grew by 2.4 per cent over 2011 values. New peak records for both the winter and summer seasons were set in 2012 of 10,609 MW and 9,885 MW respectively.

The annual average pool price for wholesale electricity fell 16 per cent from previous year values to $64.32/MWh in 2012. The average AECO/NIT natural gas price decreased 34 per cent, averaging $2.27/GJ in 2012. The market heat rate average of 28.1 GJ/MWh was the highest observed in the past decade. The highest monthly average pool price for the year occurred in September 2012, averaging $110.39/MWh.

Imports from Alberta's two interties served almost five per cent of total load in 2012. Total net imports on both interties were fairly consistent year-over-year. Net imports on the B.C. intertie increased by one per cent over the previous year and net imports from the Saskatchewan intertie decreased by one per cent.

In 2012, approximately 720 MW of supply was added to the system, primarily new wind generation and expansions to existing cogeneration units. Two new wind units started operation: the Halkirk wind power facility (150 MW) and the Castle Rock wind power facility (77 MW). Firebag 3 and 4 were added to the Suncor cogeneration facility in 2012, increasing the facilities' maximum capability from 540 MW at the end of 2011 to 901 MW in 2012. Two large coal units, Sundance 1 and 2 were removed from service at the end of 2010 and remained offline throughout 2011 and 2012. These units are expected to return to service in the fall of 2013.

Pool Prices Down 16 Per Cent

Alberta's competitive wholesale market electricity prices fluctuate due to the principles of supply and demand. During instances of supply surplus and low-to-moderate demand, prices are low, while times of supply scarcity and high demand drive prices higher. The wholesale electricity price, known as the pool price, ranges from the price floor of $0/MWh to the offer cap of $999.99/MWh. In 2012, the annual average pool price fell 16 per cent from 2011, averaging $64.32/MWh over the year. This decrease was chiefly driven by the fall in on-peak prices which decreased by 17 per cent, while off-peak prices declined three per cent. Table 1 summarizes the historical price statistics from 2003 to 2012. Also during 2012, a supply shortfall event occurred on July 9, when the system controller issued a directive to curtail firm load. This resulted in the maximum pool price for the year being set at the administrative price cap of $1,000/MWh.[1]

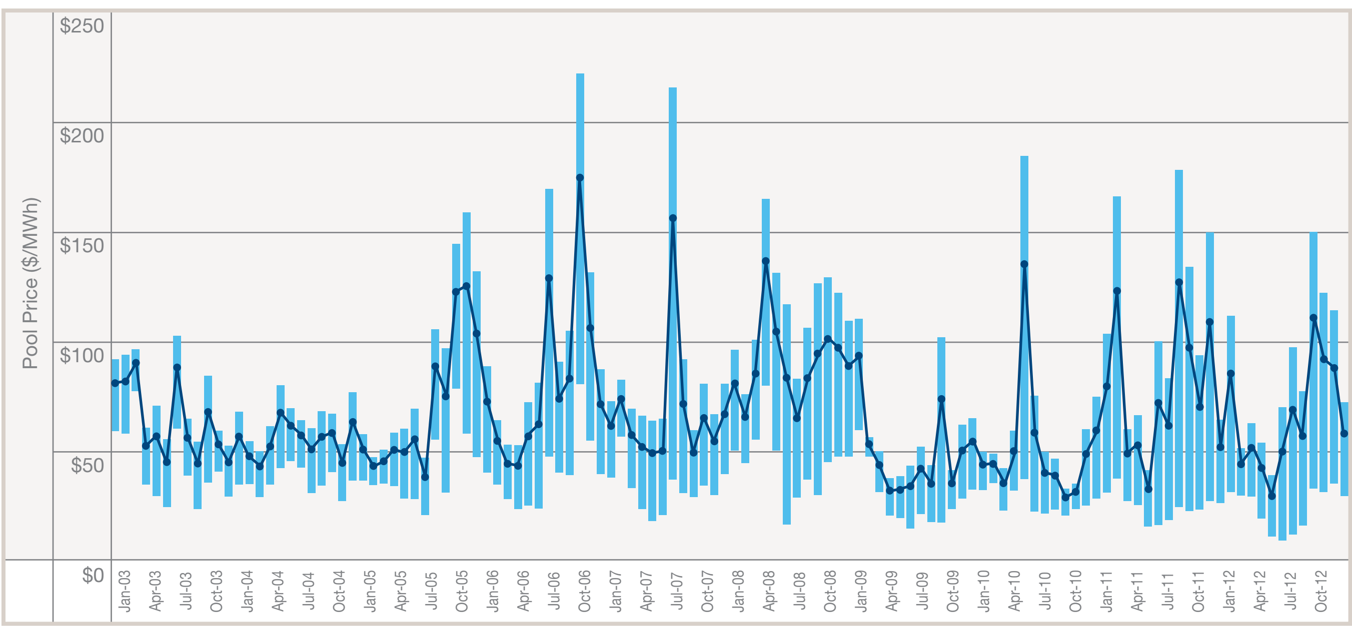
TABLE 1
Annual Pool Price Statistics, 2003 to 2012

Pool Price *($/MWh)*	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Average hourly pool price	62.99	54.59	70.36	80.79	66.95	89.95	47.81	50.88	76.22	**64.32**
Off-peak average pool price	42.15	35.72	40.37	39.54	32.11	43.92	27.36	26.67	24.22	**23.51**
On-peak average pool price	73.41	64.03	85.35	101.41	84.37	112.97	58.04	62.99	102.22	**84.72**
Maximum hourly pool price	999.99	998.01	999.99	999.99	999.99	999.99	999.99	999.99	999.99	**1,000.00**
Minimum hourly pool price	7.07	0.00	4.66	5.42	0.00	0.00	0.10	0.00	0.00	**0.00**

Note: On-peak hours refer to hour ending 08:00 through to hour ending 23:00, Monday through Sunday inclusive. Off-peak hours are all other periods.

Figure 1 shows the monthly distribution of prices over the past ten years.

FIGURE 1
Monthly Average Hourly Pool Price from 2003 to 2012 with On/Off Peak Averages



[1] *As described in market rule 201.6.3(1) Pool Price Determination.*

In 2012 there were six separate supply shortfall events during which the offer cap of $999.99/MWh was reached. A supply shortfall event occurs when there is insufficient generation to meet the total Alberta demand for electricity. In conditions of supply shortfall, system controllers manage the situation using a series of prescribed mitigation steps. This result represents a decrease from 2011, when 11 supply shortfall events occurred. Figure 2 illustrates that there has been a corresponding decrease in the number of hours where system marginal price (SMP) exceeded $990/MWh.

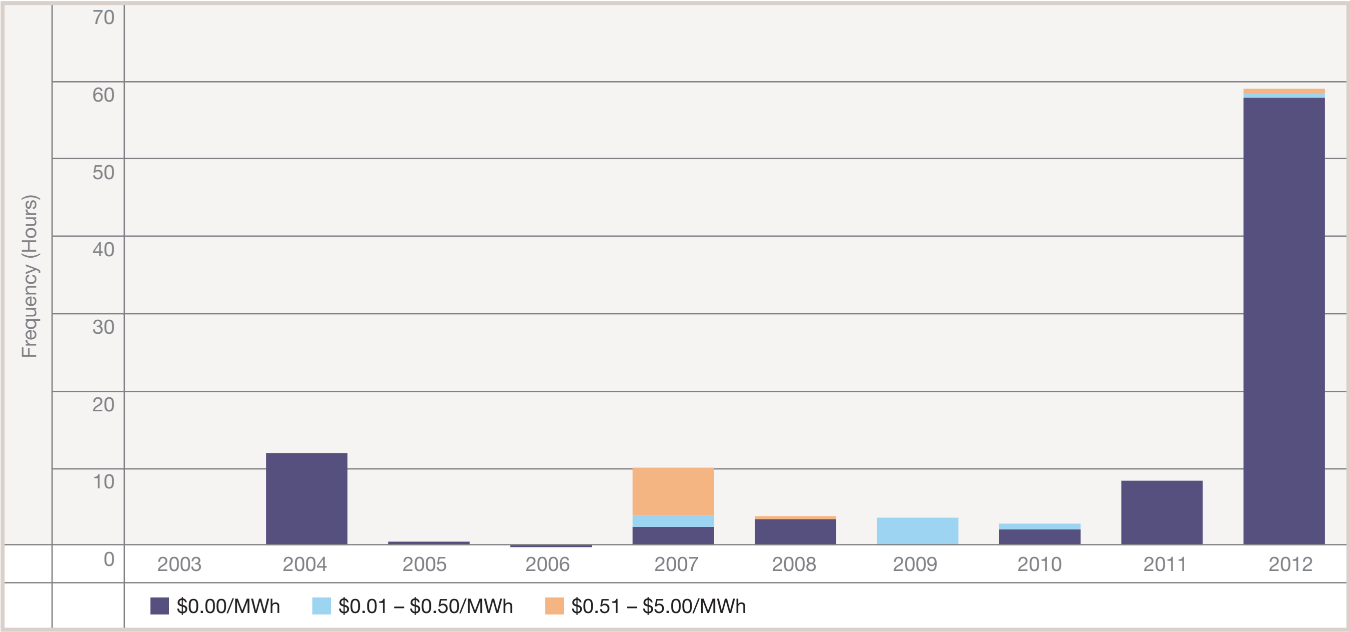
Despite this reduction, the Alberta Interconnected Electric System (AIES) experienced a noteworthy period of supply shortfall on the afternoon of July 9, 2012. During this event, the system controller issued a directive to curtail firm load, and pool price was set at $1,000/MWh for three hours.[2] This event occurred when high temperatures across Alberta drove system demand to a new summer peak value at the same time that various planned and forced generation outages reduced generation capacity at coal and gas-fired generating units. Previous to July 9, 2012, the last time a firm load shed event occurred was on July 24, 2006.

FIGURE 2
Total Time Where SMP Exceeded $990.00/MWh

Also of note in 2012, the number of supply surplus events increased significantly over previous years. A supply surplus event occurs when there is excess zero-dollar supply and low system demand. As seen in Figure 3, there were 58 hours in 2012 where SMP settled at $0/MWh, compared to eight hours in 2011. The substantial increase in zero-dollar price events in 2012 was a result of the simultaneous occurrence of several factors including higher levels of low cost wind production, instances of low demand, high imports, and higher production levels from hydroelectric facilities.

2 *Refer to market rule 202.7 Market Suspension or Limited Market Operations rule.*

FIGURE 3
Total Time Where SMP Settled Below $5.00/MWh

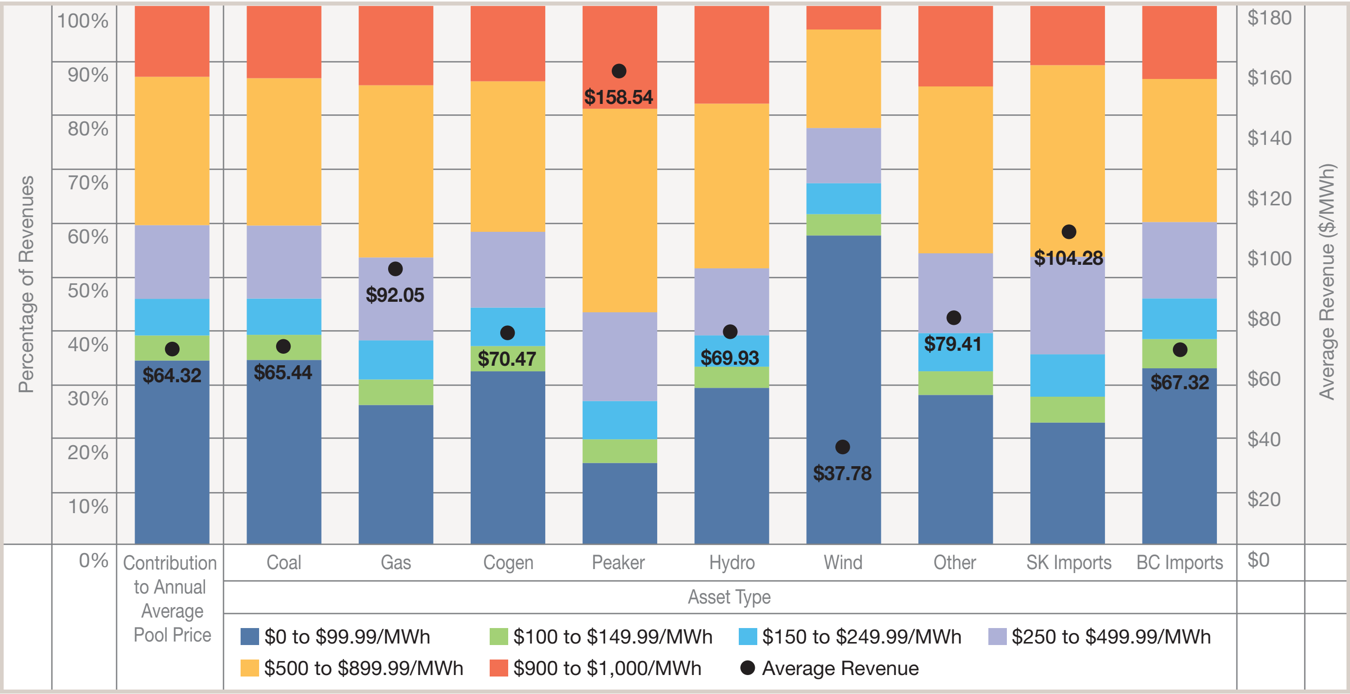


The Alberta pool price is determined by the highest priced generator dispatched to meet the demand for electricity. Generators submit hourly offers to the AESO that include the amount of energy they will provide at a specific price. The AESO's automated Energy Trading System arranges all the hourly offers from generators from the lowest to the highest price. The AESO system controller dispatches generating units in ascending order of price until the demand requirement is satisfied. The highest priced unit dispatched is the marginal unit and its offer price sets the system marginal price for that minute. The hourly pool price is the simple average of all system marginal prices in the hour.

Figure 4 presents the breakdown of revenue by pool price range for different asset types. As seen in the graph, the percentage contribution to the annual average pool price was highest in the $0/MWh to $100/MWh range.

The numbers shown within the bars represent the average revenues by asset type. For example, gas-fired generators received $92.05/MWh on average over all hours, a 43 per cent premium to the annual average pool price. This is because gas-fired generators typically offer to run at higher prices than baseload coal-fired generation. Figure 4 shows that in 2012, all asset types except wind received a premium to the annual average price. Wind generation tends to receive lower prices per megawatt hour because it displaces higher cost generation and reduces the pool price. In 2012, wind generators on average received $37.78/MWh, a 41 per cent discount to the annual average price.

FIGURE 4
Pool Price Contribution to Total Revenue by Asset Type and Pool Price Range
Average Revenues = 2012 Hourly Pool Price Multiplied by Metered Volumes



In 2012, natural gas prices averaged $2.27/GJ, a decrease of 34 per cent from the 2011 average of $3.44/GJ. Figure 5 shows the historic relationship between natural gas prices and the pool price. The market heat rate refers to the market price of electricity expressed as a ratio of the annual average pool price to the annual average natural gas price. The market heat rate is generally an indication of supply scarcity; however, in the past four years, high heat rates have been mainly caused by historically low natural gas prices. The annual market heat rate increased from 22.39 GJ/MWh in 2011 to 28.10 GJ/MWh in 2012, as natural gas prices decreased at a greater rate than pool prices.

FIGURE 5
Annual Average Pool Price, AECO Natural Gas Price and Market Heat Rate

Strong Load Growth in 2012

Hourly Alberta Internal Load (AIL) grew 2.4 per cent in 2012, continuing the strong growth trend seen in the previous year. Increased demand in major urban centres such as Calgary and Edmonton, oilsands demand growth in northeastern Alberta and increased industrial demand throughout the province were the primary contributors to this growth.

TABLE 2
Annual System Demand Statistics

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Total energy *(GWh)*	62,714	65,260	66,267	69,371	69,661	69,947	69,914	71,723	73,600	**75,574**
Average hourly load *(MW)*	7,159	7,429	7,565	7,919	7,952	7,963	7,981	8,188	8,402	**8,604**
Maximum hourly load *(MW)*	8,786	9,236	9,580	9,661	9,701	9,806	10,236	10,196	10,226	**10,609**
Minimum hourly load *(MW)*	5,658	6,017	6,104	6,351	6,440	6,411	6,454	6,641	6,459	**6,828**
Year-over-year growth in total energy *(%)*	5.5	4.1	1.5	4.7	0.4	0.4	0.0	2.6	2.6	**2.7**
Year-over-year average load growth (adjusted for leap year effect) *(%)*	5.5	3.8	1.8	4.7	0.4	0.1	0.2	2.6	2.6	**2.4**
Load factor *(%)*	81.5	80.4	79.0	82.0	82.0	81.2	78.0	80.3	82.2	**81.1**

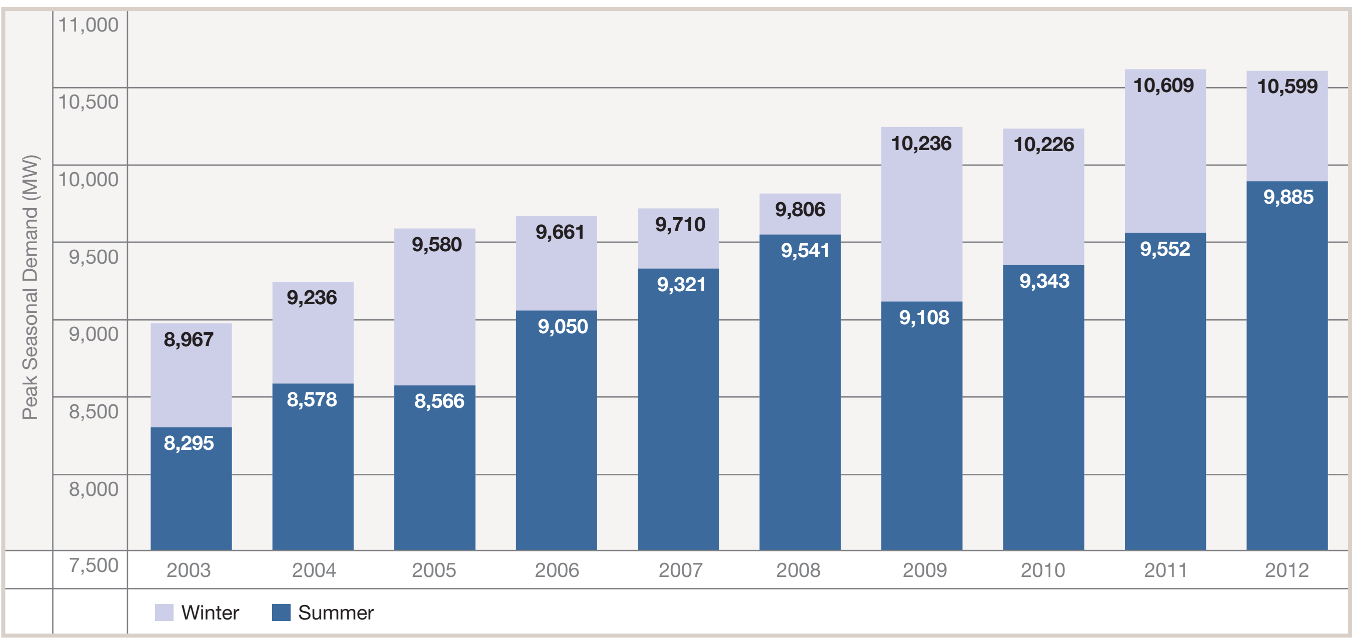
The minimum load in 2012 was nearly 400 MW higher than the 2011 minimum load, and nearly 200 MW higher than the 2010 minimum load. This is an indication of the strong baseload growth observed in 2012. In addition, there has been a substantial increase in the number of hours where demand has exceeded 10,000 MW. In 2012, demand exceeded this threshold in two per cent of total hours, whereas in 2011, demand exceeded 10,000 MW in approximately 0.3 per cent of total hours during the year.

New Records for Peak Demand Set in 2012

2012 set new records for demand in both the winter and summer months.[3] Figure 6 illustrates the winter and summer peak demands for the past ten years. In the winter months, demand typically peaks between 5 p.m. and 6 p.m. The winter 2011 season occurred from November 2011 through April 2012, and January 2012 saw a new all-time peak record for winter of 10,609 MW on January 16, 2012. The new peak was driven by cold temperatures with the Alberta temperature averaging -28 degrees Celsius during the hour in which the peak demand occurred. The previous highest peak recorded was 10,236 MW in winter 2009, with temperatures averaging -30 degrees Celsius during the hour of the peak.

Peak demand during the summer months is driven by sustained periods of high temperatures. In 2012, high temperatures drove a new peak in summer demand of 9,885 MW on July 9, 2012 between 2 p.m. and 3 p.m. Temperatures across Alberta averaged 29 degrees Celsius during that hour.

FIGURE 6
Peak Demand during the Winter and Summer Periods[4]



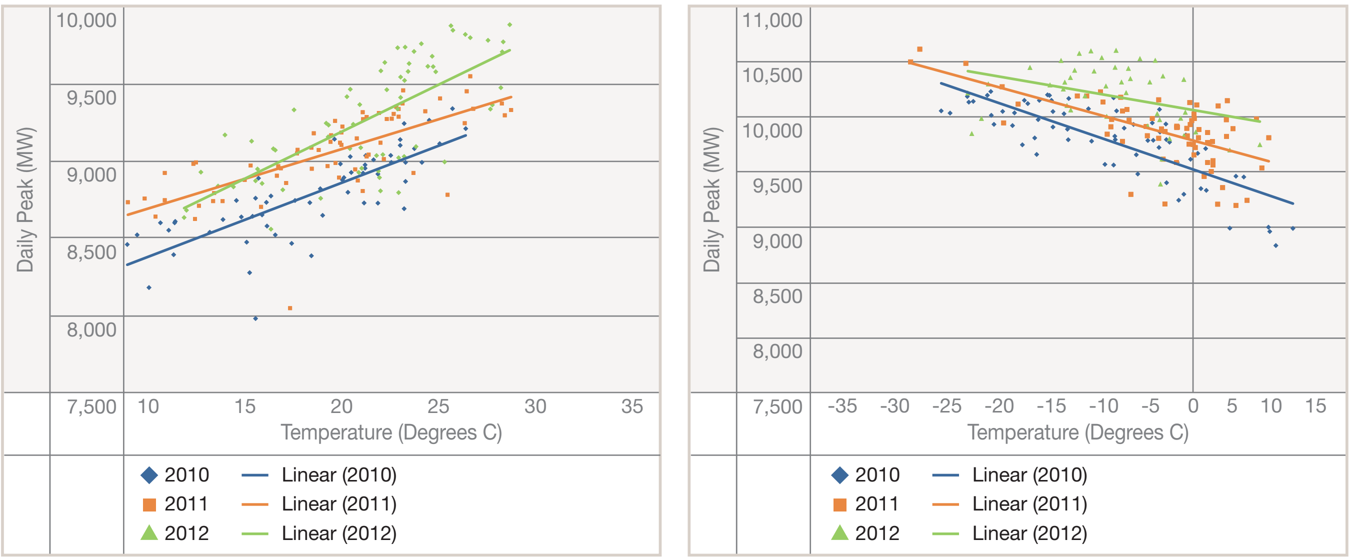
[3] *Winter is defined as November through April and Summer is defined as May through October. For example, Winter 2011 refers to the period from November 2011 through April 2012.*

[4] *For Winter 2012, year-to-date data from November 2012 to December 2012 was used in the determination of winter peak demand.*

Figure 7 illustrates the relationship between temperature and daily peak demand in summer and winter respectively. On average, an increase of one degree Celsius results in an increase in the daily AIL peak of 50 MW during the summer months. In the winter months, a decrease of one degree Celsius will see AIL peak increase by 23 MW.

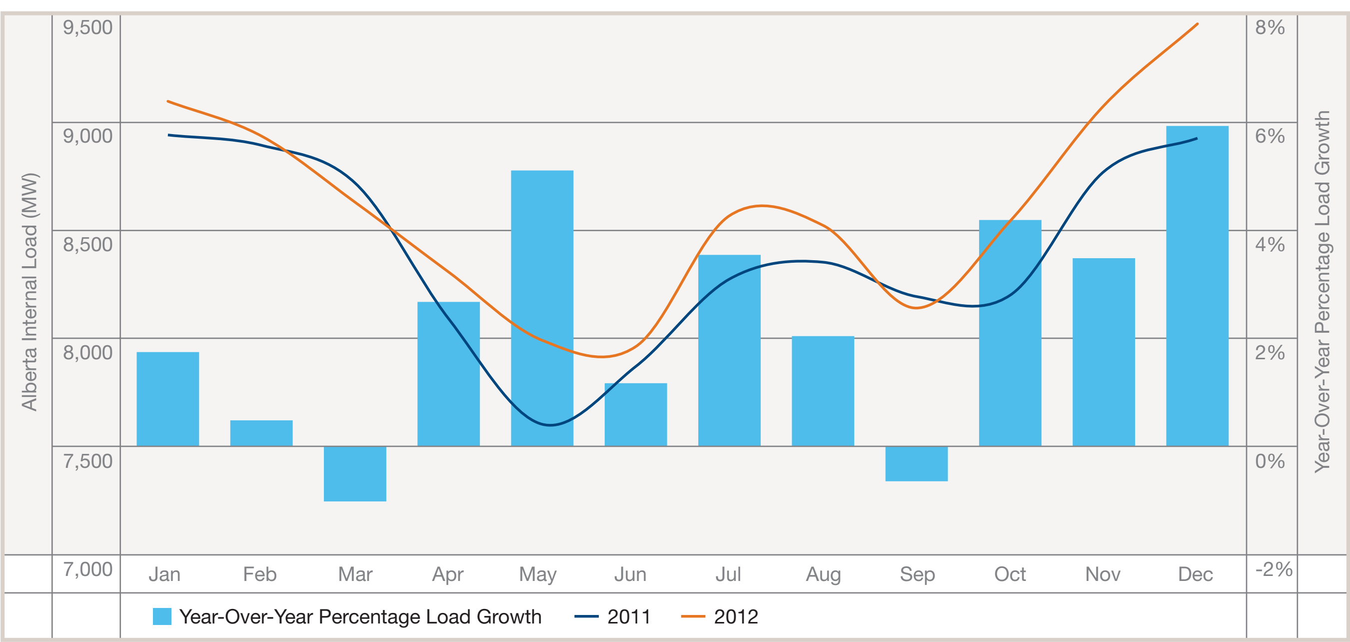
FIGURE 7
Summer and Winter Peak Demand and Temperature

Daily Weekday Summer Peaks vs. Mean AB Temperature at Time of Peak **Daily Weekday Winter Peaks vs. Mean AB Temperature at Time of Peak**



As seen in Figure 8, load growth for 2012 was highest in the month of December. Temperatures during December 2012 averaged nine degrees colder than during December 2011, driving the year-over-year increase in demand. In all months of 2012 except March and September, average monthly demand increased from 2011 values.

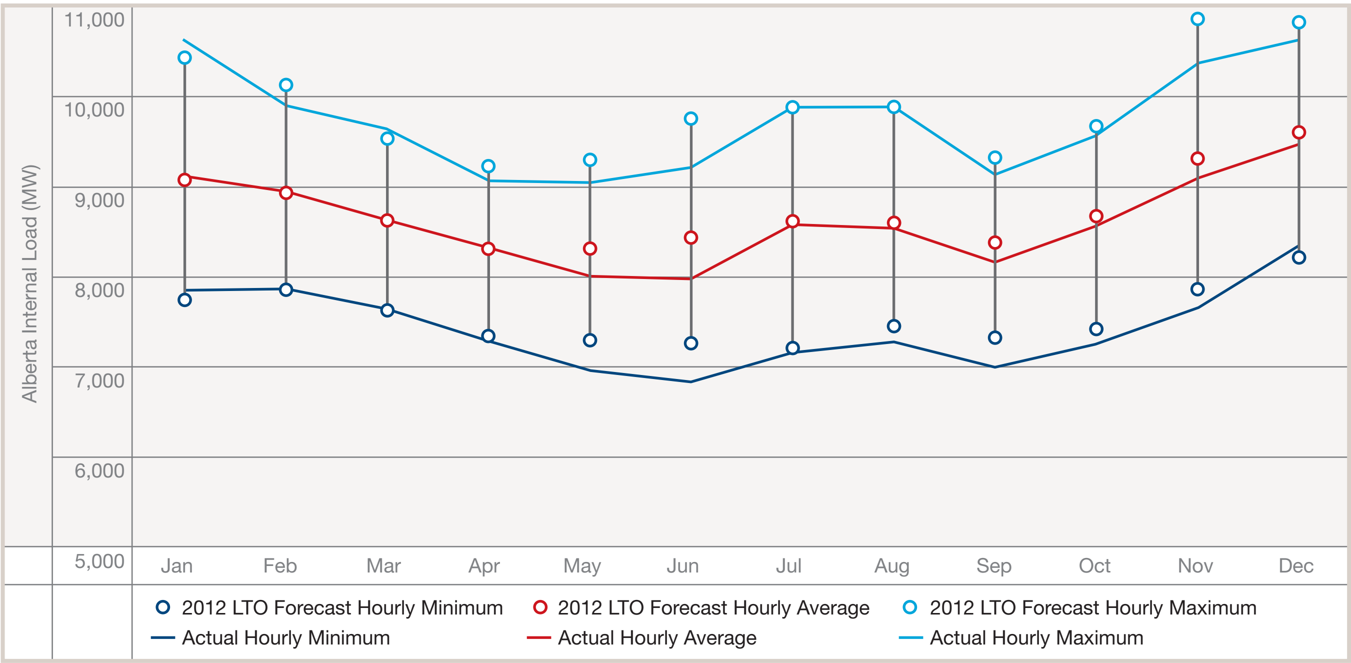
FIGURE 8
Monthly Average AIL and Load Growth



The AESO produces long-term load forecasts for the transmission planning process. These forecasts are continuously assessed against Alberta's actual demand and sector-by-sector electricity usage to verify methodology and identify variances that could impact the forecast. The latest long-term load forecast is the *2012 Long-term Outlook* (2012 LTO).

Figure 9 compares monthly forecast to actuals for hourly minimum, peak and average demand. The forecast of monthly average demand was within 1.5 per cent of actuals for 2012.

FIGURE 9
Forecast Versus Actual System Demand Based on the 2012 Long-term Outlook



Imports Serve Almost Five Per Cent of Total Load in 2012

Alberta imports energy from and exports energy to its provincial neighbours across electrical interties. During the course of the year the amount of imports and exports varies depending on the limitations of the interties, market prices for electricity in other jurisdictions, and other factors. As seen in Table 3, total net imports were fairly consistent year-over-year, increasing by one per cent on the British Columbia intertie, and decreasing by one per cent on the Saskatchewan intertie.

TABLE 3
Annual Intertie Statistics

Intertie Statistics *(GWh)*	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Total Scheduled Imports										
Imports on B.C. intertie	903	1,073	1,071	1,101	927	1,574	1,344	1,846	3,047	**3,064**
Imports on Saskatchewan intertie	429	418	464	416	540	674	675	358	544	**515**
Total imports	1,332	1,492	1,535	1,517	1,467	2,248	2,019	2,205	3,591	**3,579**
Total imports as a per cent of total AIL *(%)*	2.1	2.3	2.3	2.2	2.1	3.2	2.9	3.1	4.9	**4.7**
Total Scheduled Exports										
Exports on B.C. intertie	1,194	968	988	460	886	518	488	411	71	**59**
Exports on Saskatchewan intertie	34	93	50	29	88	40	25	48	48	**23**
Total exports	1,228	1,061	1,038	489	973	559	513	459	119	**82**
Total exports as a per cent of total AIL *(%)*	2.0	1.6	1.6	0.7	1.4	0.8	0.7	0.6	0.2	**0.1**
Net Imports (Imports Minus Exports)										
Net B.C. Imports	-291	105	83	641	42	1,056	856	1,435	2,976	**3,006**
Net Saskatchewan Imports	395	325	413	386	452	633	649	310	496	**492**
Total net imports	104	430	497	1,028	494	1,689	1,505	1,745	3,473	**3,497**
Total net imports as a per cent of total AIL *(%)*	0.2	0.7	0.7	1.5	0.7	2.4	2.2	2.4	4.7	**4.6**
Market Size (Total Demand)										
Alberta Internal Load (AIL)	62,714	65,260	66,267	69,371	69,661	69,947	69,914	71,723	73,600	**75,574**

The available transfer capability (ATC) is the amount of electricity that can flow on the interties. Table 4 provides annual intertie ATC statistics for the past five years. In 2012, the average import ATC on the B.C. intertie increased by three MW over 2011, while the maximum import ATC increased by 75 MW. This increase to the maximum import ATC was made possible by the introduction of the Load Shed Service for imports (LSSi), which was implemented in late 2011. The average Saskatchewan import ATC increased six MW and the maximum import ATC remained unchanged over 2011. The maximum export ATC remained unchanged and the average export ATC decreased by 108 MW on the B.C. intertie and increased by 11 MW on the Saskatchewan intertie. The B.C. export ATC decrease occurred due to an increase in transmission element outages in 2012 impacting the B.C. export limit.

TABLE 4
Annual Intertie ATC Statistics

	B.C. Export ATC (MW)		B.C. Import ATC (MW)		Saskatchewan Export ATC (MW)		Saskatchewan Import ATC (MW)	
Year	Maximum	Average	Maximum	Average	Maximum	Average	Maximum	Average
2008	735	387	625	468	60	35	153	148
2009	735	322	600	449	61	37	153	146
2010	735	389	650	507	153	88	153	114
2011	735	421	625	525	153	134	153	137
2012	**735**	**313**	**700**	**528**	**153**	**145**	**153**	**143**

Utilization of the import ATC on the B.C. intertie is defined as the import amount net of any exports for each hour, plus any operating reserve being provided over the intertie, divided by the ATC:

$$\textbf{Import utilization} = \frac{(\text{import}_h - \text{export}_h) + \text{reserves}_h}{\text{ATC}_h}$$

The export utilization is the export amount net of any imports divided by the export ATC:

$$\textbf{Export utilization} = \frac{(\text{export}_h - \text{import}_h)}{\text{ATC}_h}$$

Figures 10 and 11 illustrate the amount of time the B.C. intertie and the Saskatchewan intertie were utilized over the past five years. During 2012 the B.C. intertie was fully utilized 47 per cent of the time, and imports on the B.C. intertie occurred 89 per cent of the time. Exports on the B.C. intertie occurred nearly six per cent of the time, with the highest export utilization value only reaching 65 per cent utilization of the B.C. export ATC. On the Saskatchewan intertie, the amount of time the intertie was fully utilized for import was 10 per cent of the time, and imports occurred 73 percent of the time. Exports on the Saskatchewan intertie occurred four per cent of the time and the Saskatchewan intertie was fully utilized for export in only one hour.

FIGURE 10

Import and Export Utilization on the B.C. Intertie, 2008 to 2012

Import Utilization Adjusted to Account for Reserve on the Intertie

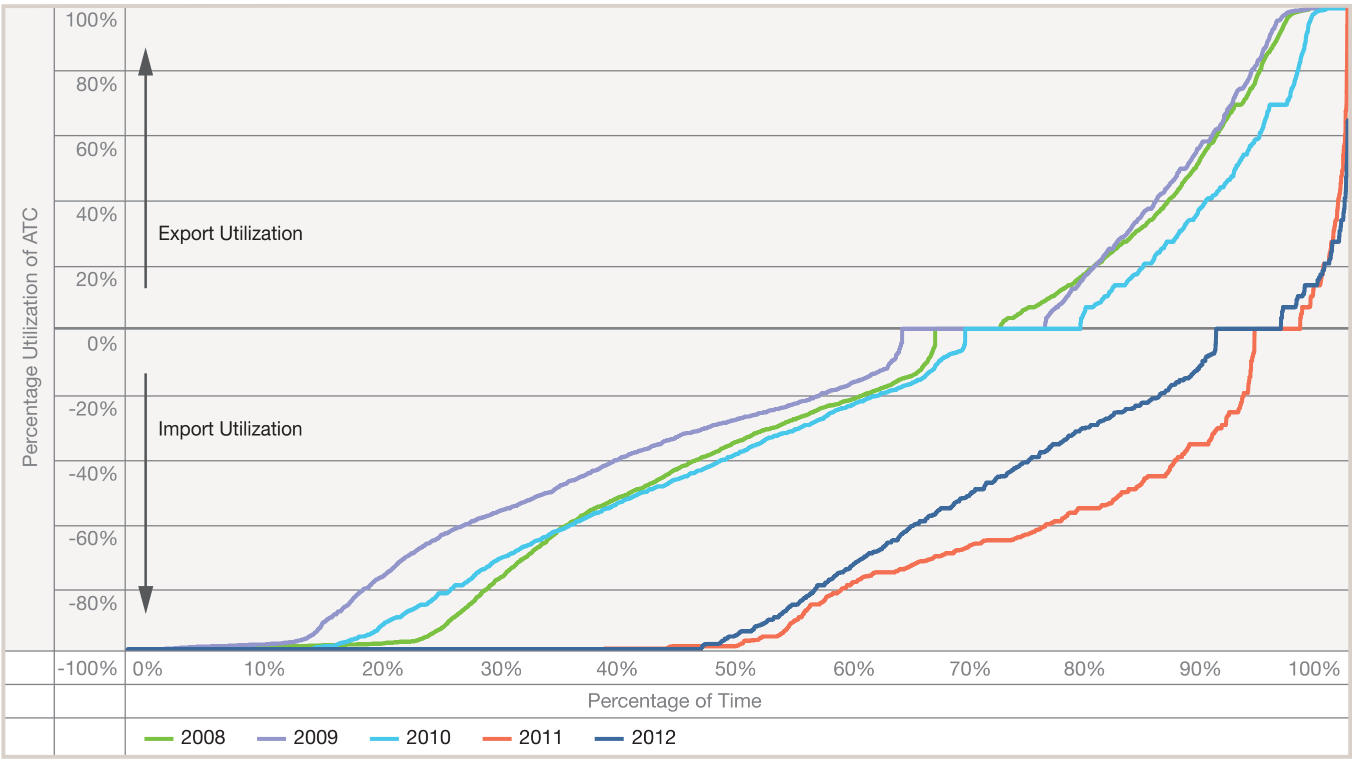
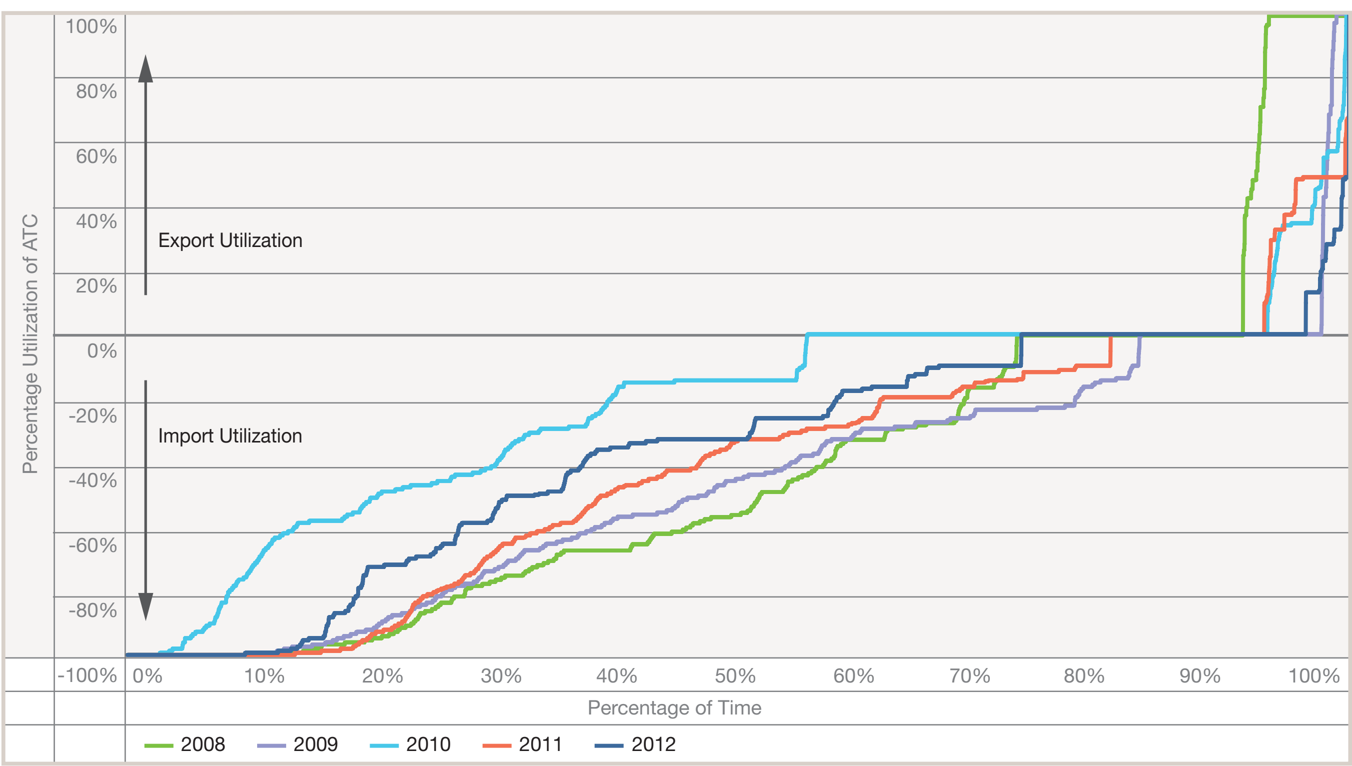


FIGURE 11

Import and Export Utilization on the Saskatchewan Intertie, 2008 to 2012



Supply Adequacy

Supply Cushion

In a well-functioning energy-only electricity market, supply adequacy is the key driver of market price and a motivator of investment decisions. During instances of supply surplus, prices are typically low while times of supply scarcity tend to drive prices higher.

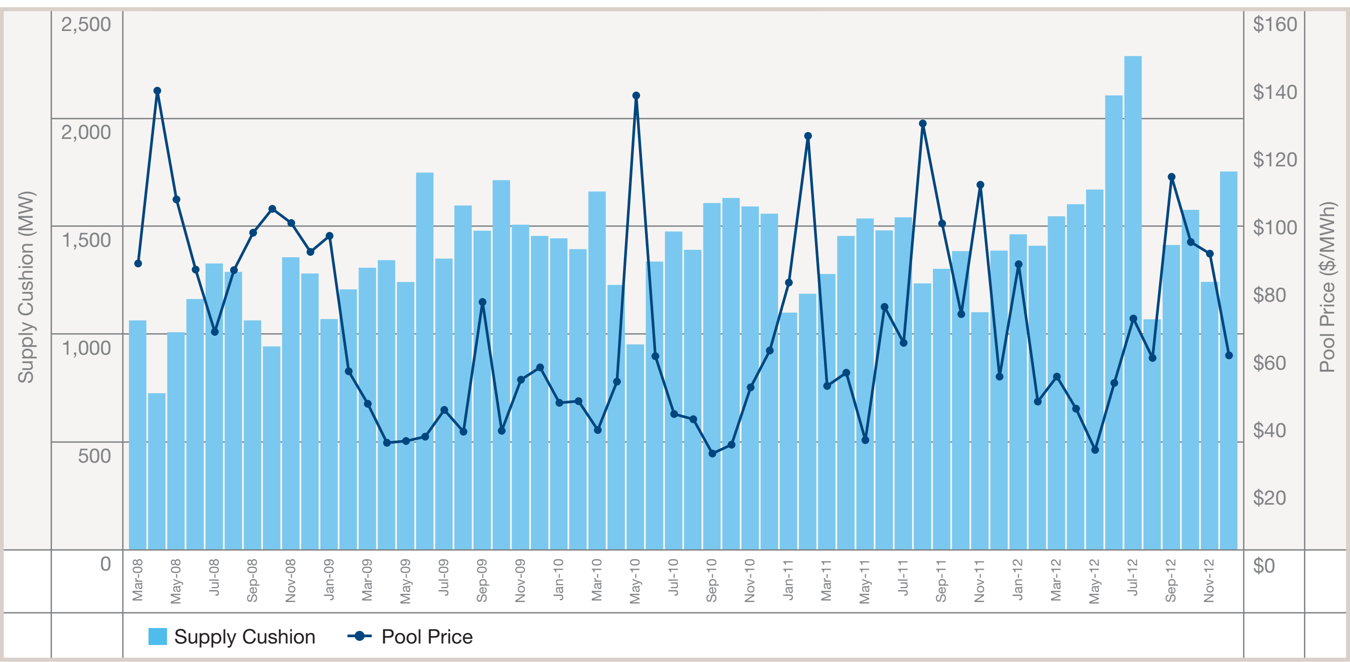
The supply cushion is an indicator of supply adequacy and the market's ability to meet demand. The supply cushion measures the undispatched energy in the energy market merit order using merit order snapshots at the midpoint of the hour. The detailed calculation of supply cushion is as follows:

$$\text{Supply Cushion} = \sum_{1}^{n} (\text{Available MW} - \text{Dispatched MW}) + \text{DDS Dispatched} - \text{TMR Dispatched}$$

Note: In the equation, DDS stands for Dispatch Down Service and TMR stands for transmission must-run. Both concepts are explained in the Dispatch Down Service section on page 21 of this report.

Figure 12 gives the monthly average supply cushion as compared to average pool price. Typically the supply cushion will decrease when there are planned and unplanned outages that affect supply. In 2012 there was an 18 per cent increase in the annual average supply cushion over 2011.

FIGURE 12
Monthly Average Supply Cushion

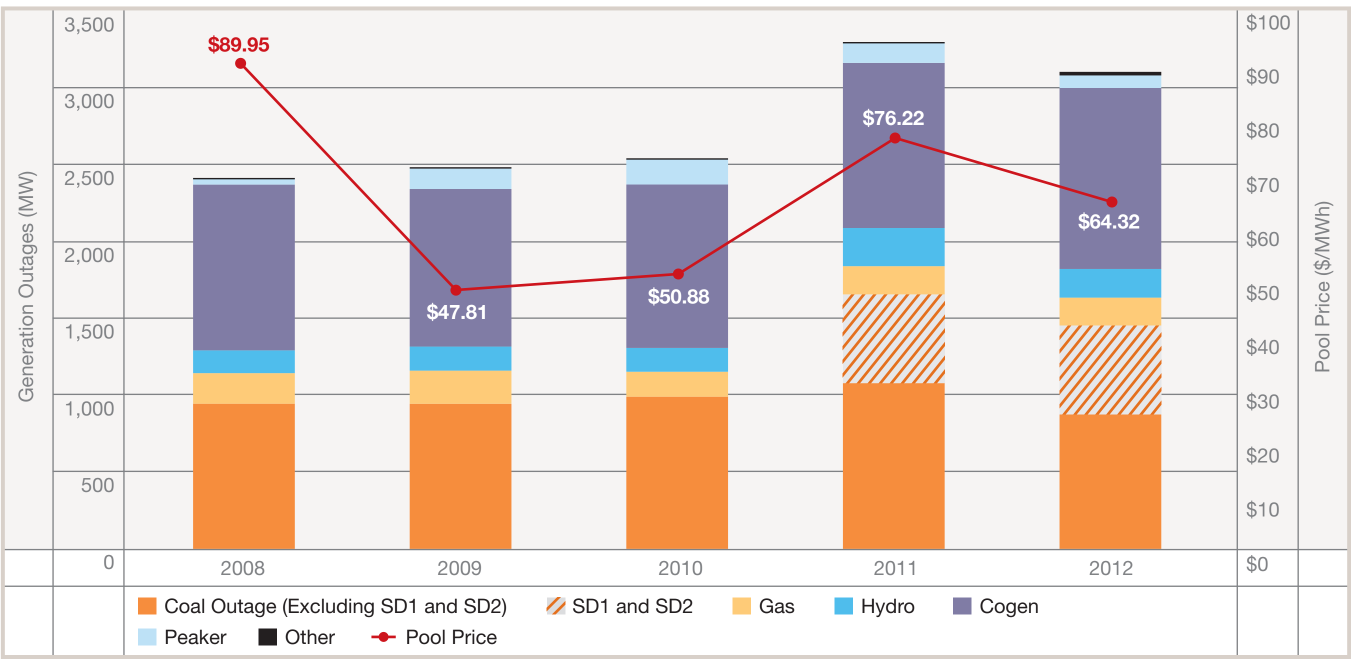


Generation Outages

All generating assets submit a maximum capability (MC) representing the maximum quantity of megawatts the generating asset is physically capable of generating under optimal operating conditions. The available capability (AC) is set to the MC. Each asset must offer its entire MC to the market unless there is an acceptable operational reason (AOR) for reducing AC to a level lower than the MC. The majority of supply in the market is from baseload generating assets that run nearly all the time. Most baseload generators are coal-fired units, which offer the majority of their energy into the market at $0/MWh to ensure that they are dispatched and because they do not have the operational flexibility to be dispatched below a unit's minimum stable generation level. When these baseload generators are unavailable due to planned or unplanned outages, prices tend to increase as generation from gas-fired units and hydroelectric facilities, which tend to have a higher offer price, is required to meet demand.

Figure 13 illustrates the relationship between outages (defined as the difference between the MC and AC) by fuel type and the pool price. Decreased supply availability drives higher pool prices as seen in Figure 13. The exception to this is 2008, which saw higher gas prices coupled with periods of high demand and supply scarcity. As seen in the figure, 2012 saw a 19 per cent decrease in the levels of coal-fired generation on outage or derates over 2011 (excluding the Sundance 1 and Sundance 2 outages).

FIGURE 13
Annual Average Generation on Outage and Derates Versus the Pool Price



Strong Development of Cogeneration and Wind Power in 2012

The Alberta electric system added approximately 720 MW of supply in 2012, including new additions and changes to the capacity of existing units. Two new wind power facilities started operation: the Halkirk wind power facility (150 MW) and the Castle Rock wind power facility (77 MW). Firebag 3 and 4 were added to the Suncor cogeneration facility in 2012, increasing the facilities' maximum capability from 540 MW at the end of 2011 to 901 MW in 2012.

Figure 14 shows the annual generation additions and retirements and Figure 15 gives the annual installed capacity at the end of each year for the past ten years.

FIGURE 14
Generation Additions and Retirements, 2003 to 2012

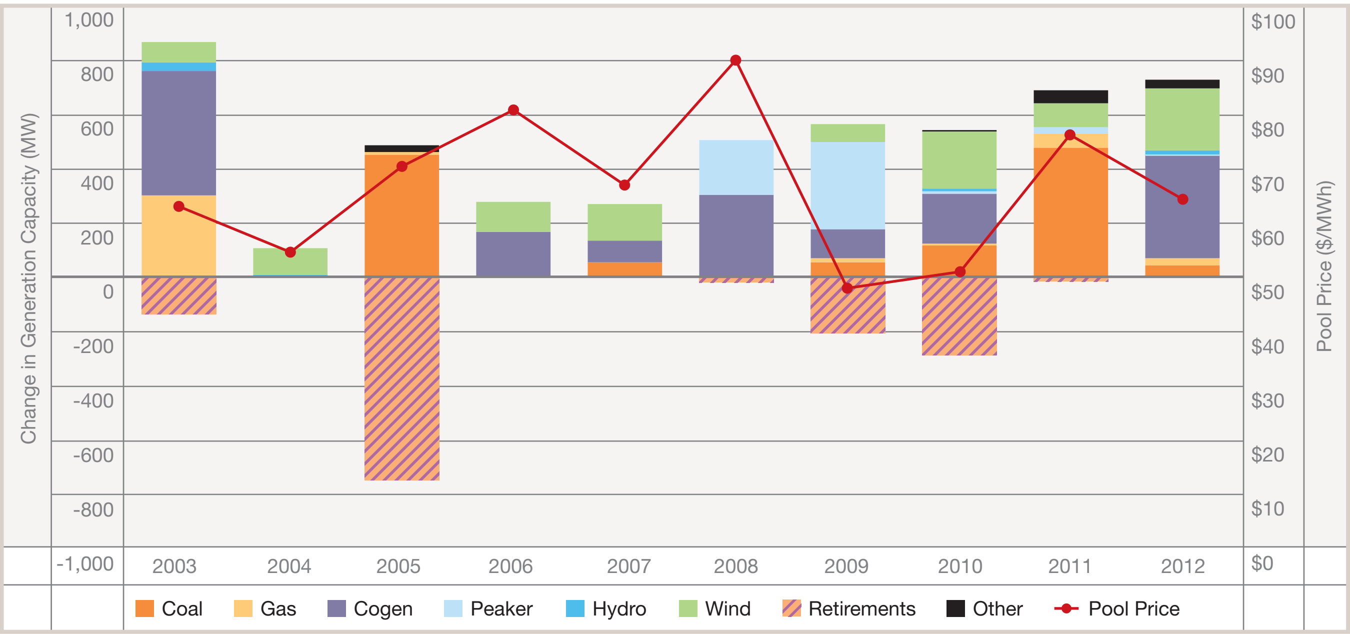
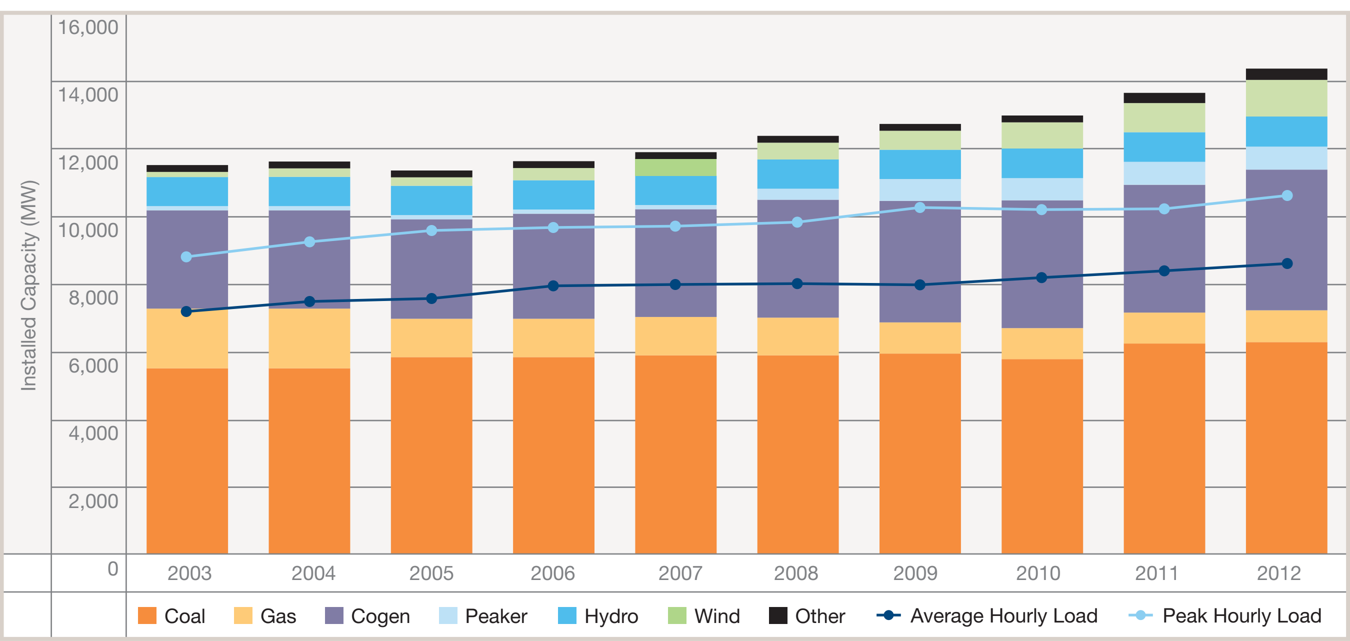


FIGURE 15
Installed Capacity, 2003 to 2012

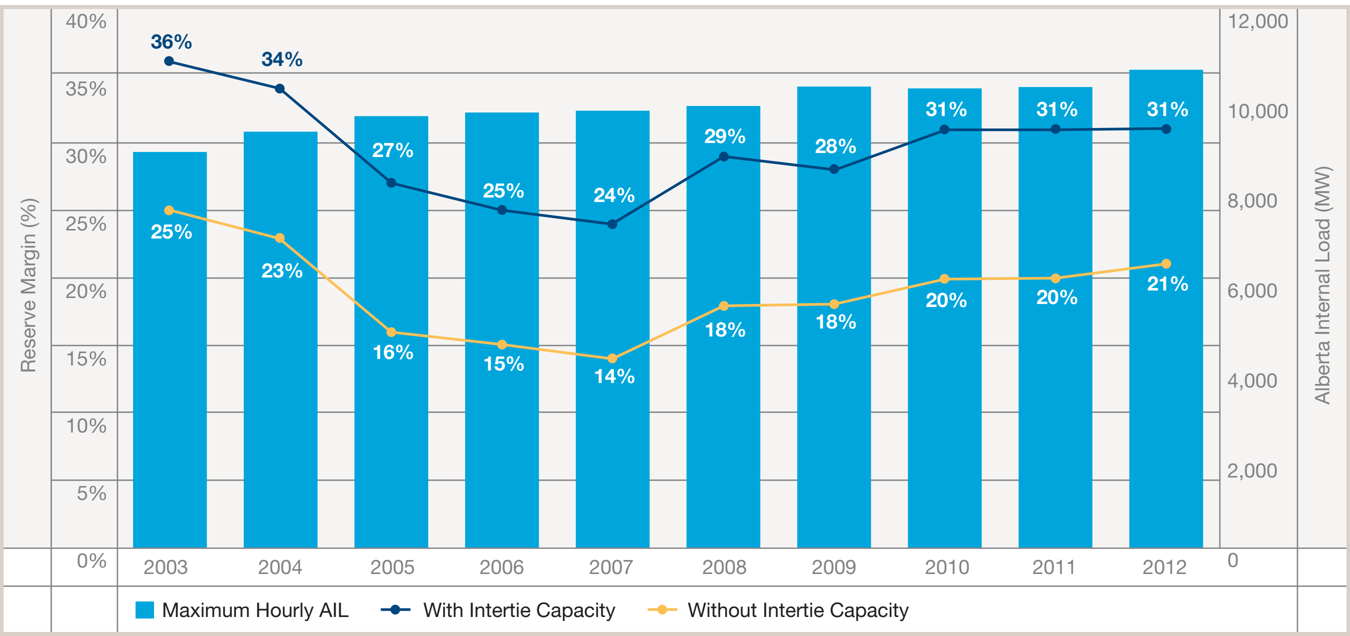


Reserve Margin Indicates Adequate Supply

The reserve margin is a metric that can be used to assess whether supply has been adequate in meeting demand. The reserve margin estimates the amount of firm generation capacity at the time of system peak that is in excess of annual peak demand, expressed as a percentage of the system peak. Firm generation is defined as installed generation capacity, adjusting for seasonal hydro capacity and behind-the-fence demand and generation, excluding wind capacity. Figure 16 gives the annual reserve margin with and without intertie capacity since full import capacity may not always be available at the time of system peak demand.[5]

The 2012 reserve margins had small growth over the previous year with growth in both load and generation development. Also, two large wind generation additions, Halkirk and Castle Rock Ridge wind power facilities, are not included in the reserve margin calculation. Note that Sundance 1 and 2 are not included in the 2011 and 2012 reserve margin calculation, as capacity from these units was not available during those years. Indications are that the Sundance 1 and 2 assets will return to service in late 2013.

FIGURE 16
Annual Reserve Margin and Peak Alberta Internal Load (AIL)



[5] *The reserve margin statistics here are based on the quarterly* **Long Term Adequacy (LTA) Metrics** *that include the annual reserve margin with a five year forecast period.*

Wind Installed Capacity Reaches 1,087 MW

In 2012, two new wind power facilities were added to Alberta's electric system: Halkirk (150 MW) and Castle Rock (77 MW). The aggregate capacity factor compares the actual energy production over a period of time with the amount of power that would have been produced by operating at full capacity. The average capacity factor for wind generation in Alberta decreased two percent from 33 percent in 2011 to 31 percent in 2012. Figure 17 illustrates the monthly average wind capacity factor over the past five years. The highest monthly average capacity factor of 51 per cent occurred in January 2012—close to the previous year's peak reached in December 2011.

Table 5 summarizes the annual performance statistics for wind generation. Demand peaked at 10,609 MW on January 16, 2012. Wind generation is typically low during the annual winter peak demand due to persistent cold weather, which coincides with low wind speeds. In 2012, however, a mid-winter cold front drove temperatures down, spiking system load and spurring wind generation upward. The hourly wind capacity factor during the 2012 demand peak averaged 66 per cent—almost double the 2012 average.

FIGURE 17
Average Hourly Wind Capacity Factor

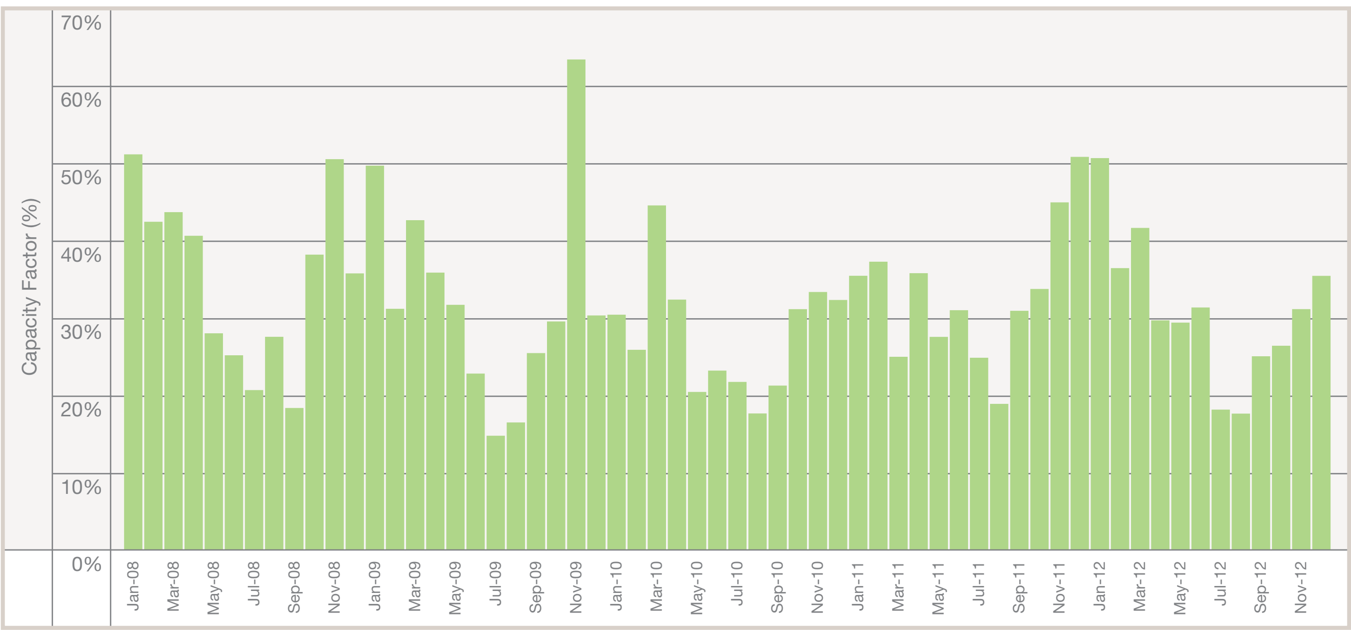


TABLE 5
Wind Generation Statistics

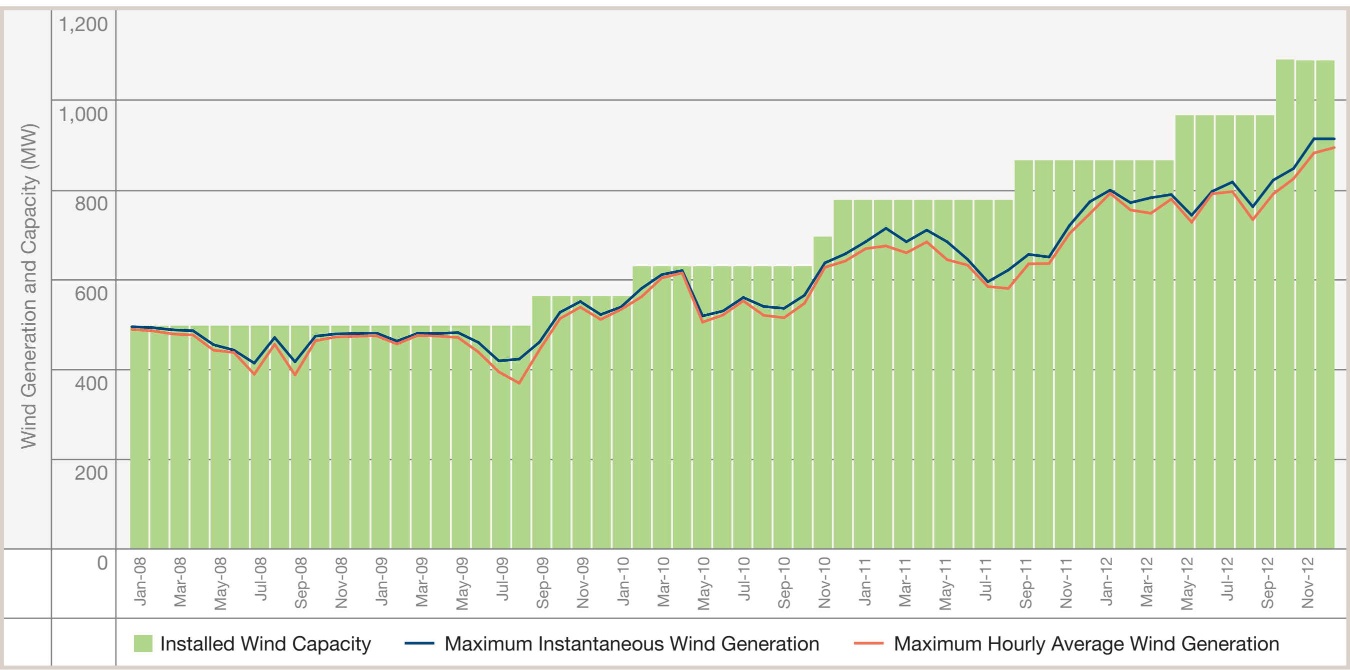
Year	2008	2009	2010	2011	2012
Average Hourly Capacity Factor *(%)*	35.3	32.9	27.9	33.0	**31.2**
Maximum Hourly Capacity Factor *(%)*	97.8	95.1	97.3	87.6	**91.2**
Installed Wind Capacity (at year end) *(MW)*	497	563	777	865	**1,087**
Total Wind Generation *(GWh)*	1,539	1,503	1,552	2,323	**2,574**
Wind Generation as a per cent of Total Energy (AIL) *(%)*	2.20	2.15	2.16	3.16	**3.41**
Wind Capacity Factor during Annual Peak Demand *(%)*	12	3	0	13	**66**

Alberta wind generation can be divided into two general regions: South and Central. The Central region includes three wind power facilities located north of Calgary. The South region includes all other Alberta wind power facilities in the areas of Fort Macleod, Pincher Creek, around the town of Taber and Magrath.

Local weather systems drive wind generation in each region. As a result, wind generation between these regions is only weakly related, but wind generation within each of these regions is strongly related. Because the majority of wind capacity in the province is located in the South region, the effect of wind generation on pool price in this region is much greater than the effect of wind generation on pool price in the Central region. This difference occurs because wind generation is priced at $0/MWh, and a sudden influx of low-priced wind generation offsets higher-priced generation, driving pool price downward.

Over the past five years, installed wind generation capacity in Alberta has more than doubled. Figure 18 shows the installed wind capacity and the maximum instantaneous and hourly wind generation levels in each month. Wind generation in the province was located solely in southern Alberta until early 2011. Since that time, the addition of three wind power facilities in the Central region increased the geographic diversification of wind generation across the province. At the end of 2012, the three wind facilities in the Central region of the province totaled 320 MW of generation capacity. The rest of Alberta's wind generation (767 MW) is located in the South region.

FIGURE 18
Installed Wind Capacity with Instantaneous and Hourly Maximums



AESO Launches the Wind Dispatch Pilot Project

At the end of 2012, generating capacity from wind power facilities totaled 1,087 MW and constituted 7.5 per cent of Alberta's total installed generating capacity. The unpredictable nature of wind generation, combined with keen developer interest, has spurred discussion about how best to integrate the technology into the electric system. One option considered was to require wind to participate in the energy market merit order. In May 2012, the AESO implemented a pilot project to permit wind generation market participants to offer energy to the energy market at non-zero prices. The opportunity to participate in the pilot project was offered to all existing wind generating facilities. TransAlta Corporation volunteered to take part in the dispatch pilot that commenced on May 8, 2012, with two wind power facilities involved in the pilot.

Price Setting and Generation Share

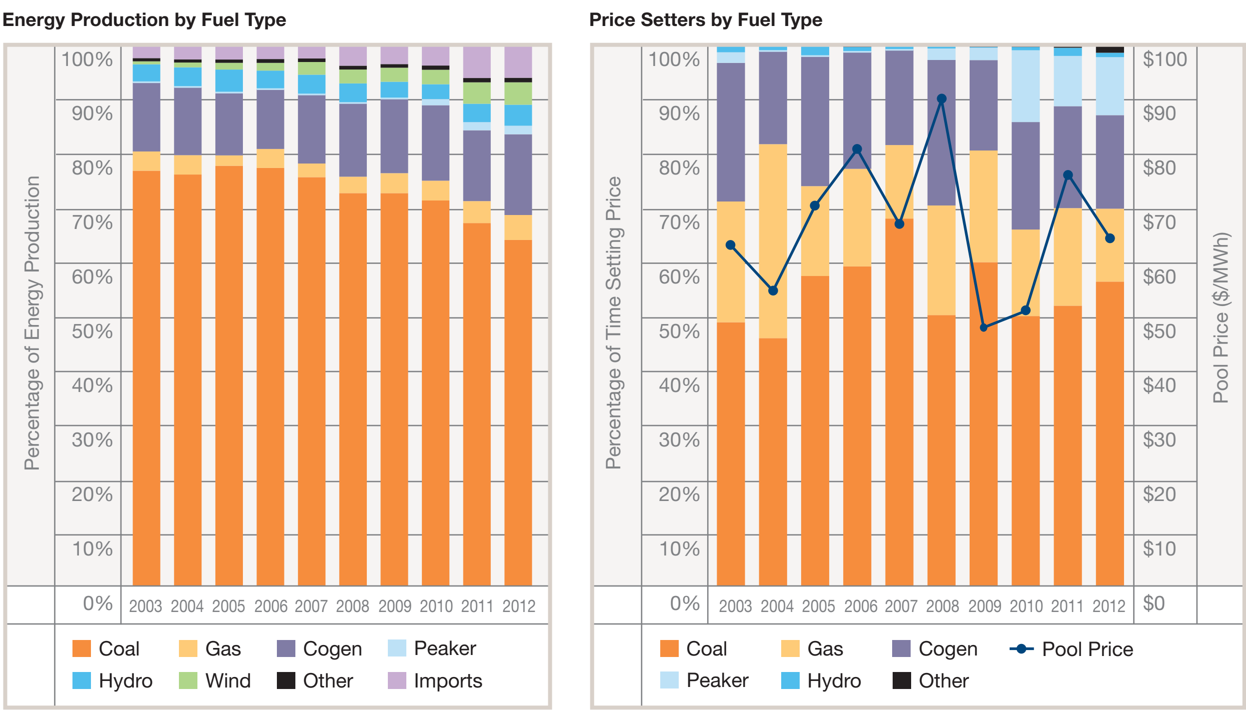
Coal-fired generation provides the majority of the energy consumed in Alberta. In 2012, coal-fired generators provided 64 per cent of the energy consumed—a three per cent reduction from 2011 values. This reduction continues the decreasing trend in coal generation that has persisted over the past six years. The reduction in coal generation was largely offset by increased generation at gas and cogeneration units. Gas and cogeneration units provided 21 per cent of total generation in 2012, an increase of 2.5 per cent from 2011 values. Both wind and hydroelectric generation increased slightly year-over-year: wind generation increased 0.2 per cent to 4.1 percent in 2012; and hydroelectric generation increased 0.5 per cent to 3.9 per cent in 2012.

Coal-fired generating units set price 56 per cent of the time in 2012, a four percent increase from 2011. The amount of time that natural gas-fired units set price decreased from 46 per cent in 2011 to 42 per cent in 2012. Hydroelectric generation set price 0.8 per cent of time, and other generation set price 1.4 per cent of time.

During brief periods of time in 2012, two special events set price: wind generation and administrative price caps. These are included in the "Other" category of the Price Setters by Fuel Type graph in Figure 19. The wind dispatch pilot project enabled wind units to offer generation to the system at specified prices, and for the first time, to potentially set the SMP. In 2012, wind generation set the SMP for just over eight hours. Administrative price caps occur when electricity demand exceeds system capacity, and the system controller must curtail load to maintain system stability. In 2012, firm load curtailment set price for three hours during the supply shortfall event of July 9.

Figure 19 shows the annual production and price-setting share by fuel type from 2003 to 2012.

FIGURE 19
Production and Price Setting Share



Operating Reserve

The AESO procures active and standby operating reserve from a competitive market. Active operating reserve provides flexible energy to the AIES to maintain system reliability. Standby reserve provides replacement energy or additional reserve capability as required. The prices paid to providers of operating reserve (OR) are indexed to the pool price. Therefore, prices in the operating reserve market trend closely to changes in the pool price. All active reserve is priced based on an index to pool price. Standby pricing involves both a premium and activation price. The premium price paid to the OR provider gives the AESO the option to call on the reserve if required. The activation price is the price paid to the provider if the option is called upon.

Table 6 provides a historical summary of prices in both the active and standby markets. Regulating reserve (RR) is used for real-time balancing of supply and demand and requires automatic control of generation levels. Spinning reserve (SR) and supplemental reserve (SUP) are used to maintain the balance of supply and demand when an unexpected system event occurs. SR must be synchronized to the grid.

TABLE 6
Annual Average Operating Reserve Prices

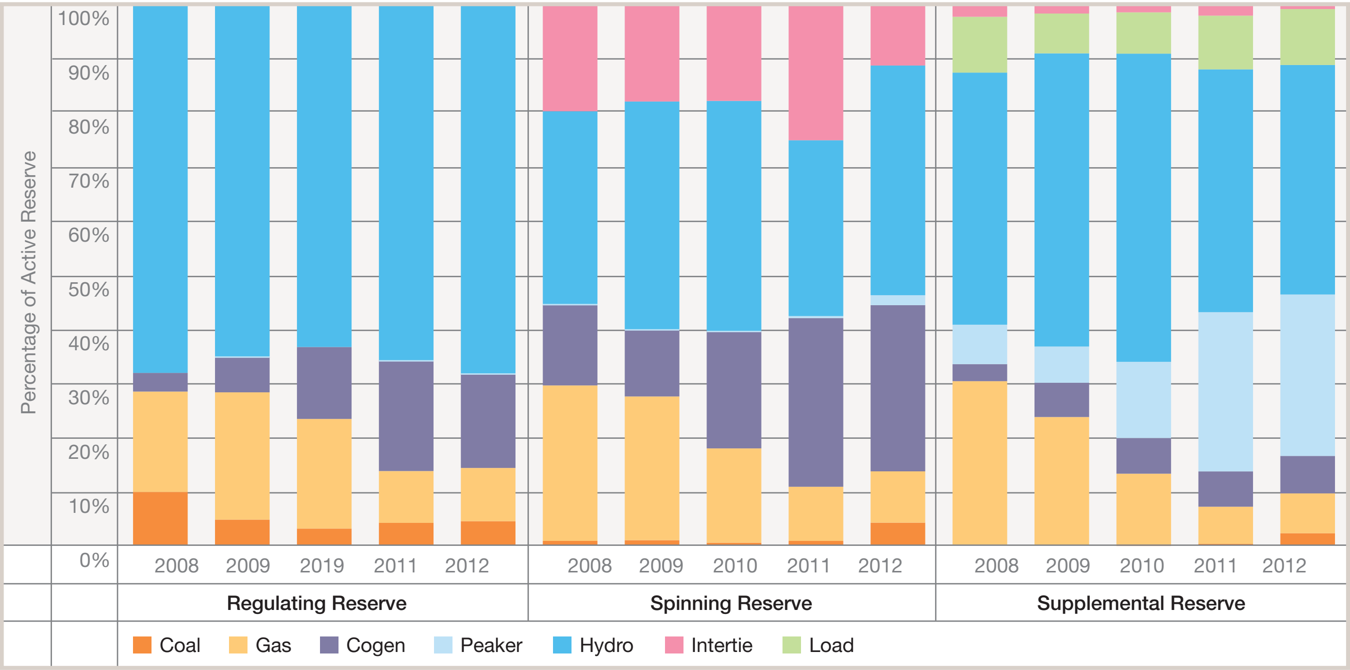
	Active *($/MWh)*			**Standby premiums** *($/MWh)*			**Standby activation** *($/MWh)*			**Total OR Cost** *($ millions)*	**Average hourly pool price** *($/MWh)*
	RR	**SR**	**SUP**	**RR**	**SR**	**SUP**	**RR**	**SR**	**SUP**		
2008	51	43	38	7	5	5	163	151	133	270	89.95
2009	23	16	11	5	4	3	96	85	69	104	47.81
2010	27	21	16	7	4	4	141	115	91	137	50.88
2011	55	57	51	6	8	7	98	121	95	328	76.22
2012	**50**	**52**	**48**	**11**	**13**	**12**	**133**	**80**	**50**	**326**	**64.32**

Note: OR costs and prices are preliminary and may change.

Operating reserve is provided mainly by hydroelectric and natural gas generators. In 2012, hydroelectric generation provided the majority of active regulating reserve (68.2 per cent), with gas-fired generators (gas, cogeneration and peaking units) providing most of the remainder (27.3 per cent). Hydroelectric and gas-fired generation evenly split the provision of active spinning (42.5 per cent and 42.1 per cent respectively) and supplemental reserve (42.4 per cent and 44.1 per cent respectively). Imports from neighbouring jurisdictions provided a small percentage of spinning reserve (11.3 per cent), while load provided the rest of supplemental reserve (10.3 per cent). Load is only permitted to provide supplemental reserve.

Figure 20 illustrates the annual market share of operating reserve by fuel type.

FIGURE 20
Market Share of Operating Reserve by Fuel Type



Dispatch Down Service

Transmission must-run (TMR) dispatches occur when a generator is constrained on to operate at a minimum specified MW output level in order to maintain system reliability. Dispatching TMR displaces in-merit energy and results in a downward impact on the pool price. The Dispatch Down Service (DDS) is a price adjustment mechanism that negates the downward effect that TMR dispatches have on the pool price. This service was introduced in December 2007 with the intention of improving the pool price signal.

As seen in Table 7, DDS payments in 2012 totaled $1.75 million for 137 GWh of DDS dispatched. This was used to offset 260 GWh of TMR dispatches. The total DDS payment in 2012 was 73 per cent lower than in 2011 ($6 million). Total TMR dispatched in 2012 decreased 68 per cent over 2011, while total DDS dispatched decreased by 74 per cent.

TABLE 7
Annual Dispatch Down Service (DDS) Statistics

Year	TMR Dispatched *(GWh)*[6]	DDS Dispatched *(GWh)*	Average DDS Charge per MWh *($/MWh)*	Total DDS Payments *($ millions)*
2008	983	731	0.46	$27.57
2009	1,018	810	0.23	$13.29
2010	792	538	0.13	$7.71
2011	801	537	0.11	$6.48
2012	**260**	**137**	**0.03**	**$1.75**

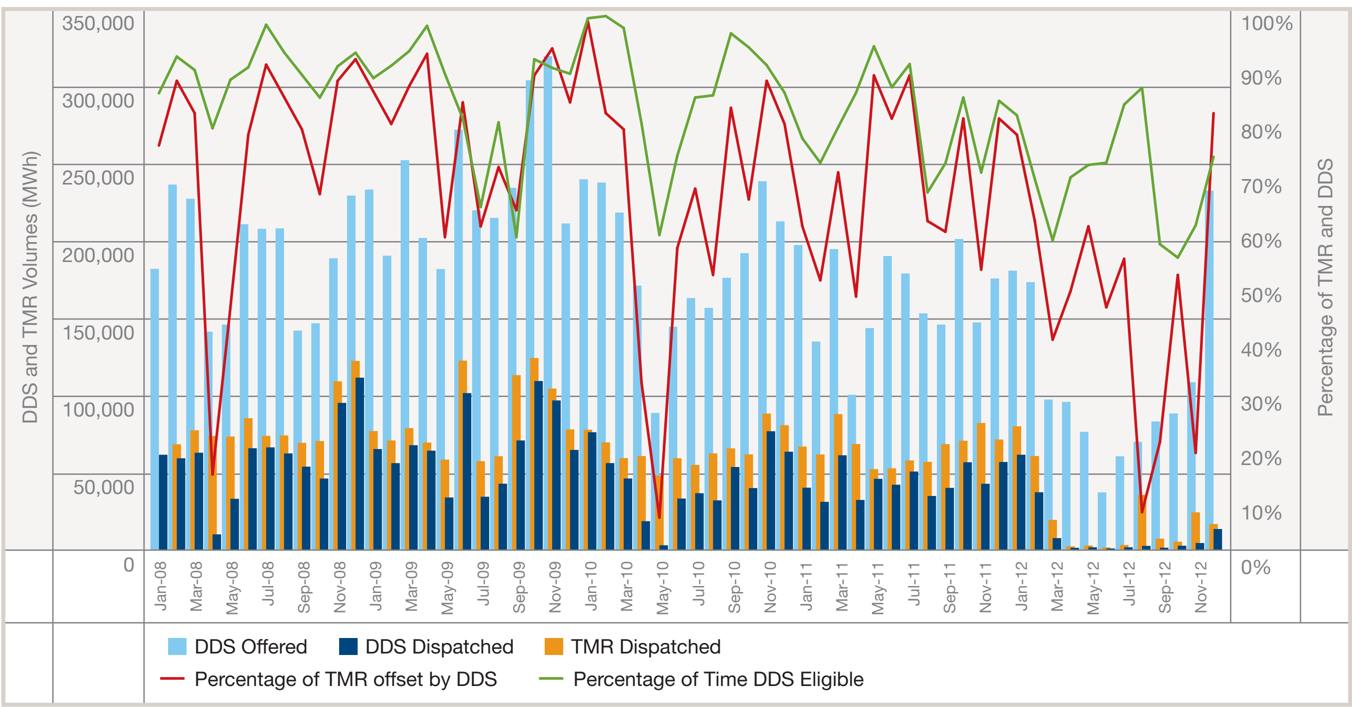
6 *TMR volumes may not be final as conscripted volumes remain to be settled under Article 11 of the AESO tariff.*

The cost of providing DDS service is allocated to suppliers (generators and imports) by metered volumes in a manner that is effectively a "financial pro-rata" among suppliers who generated during a settlement interval. In 2012, the average DDS charge was $0.03/MWh, down eight cents from 2011.

The amount of DDS required is directly related to the amount of TMR on the system. Eligibility for dispatching DDS is also determined by the system marginal price. If the system marginal price is greater than the TMR reference price, then no DDS is dispatched. Furthermore, any system constraints that result in generation being constrained down offset the need for DDS.

As seen in Figure 21, there were more instances where the SMP exceeded the TMR reference price, resulting in a lower DDS eligibility in comparison to the previous year. The system marginal price was less than the TMR reference price 69 per cent of the time in 2012 and 80 per cent of the time in 2011. In addition, TMR dispatches declined 68 per cent from 2011 to 2012. The combined effect of the amount of time the DDS was eligible and the reduction in TMR dispatches resulted in 53 per cent of TMR dispatches being offset by DDS dispatches.

FIGURE 21
Total DDS and TMR Dispatched with Total DDS Offers



Payments to Suppliers on the Margin

Payments to suppliers on the margin, also known as uplift, is a settlement rule intended to address the discrepancy between the dispatch and settlement intervals. Generators on the margin may receive an uplift payment based on their offer prices, in addition to the payment based on the settled hourly pool price, which may have settled lower than their offer that received a dispatch in a particular settlement interval. Table 8 gives annual payments to suppliers on the margin statistics for the past five years.

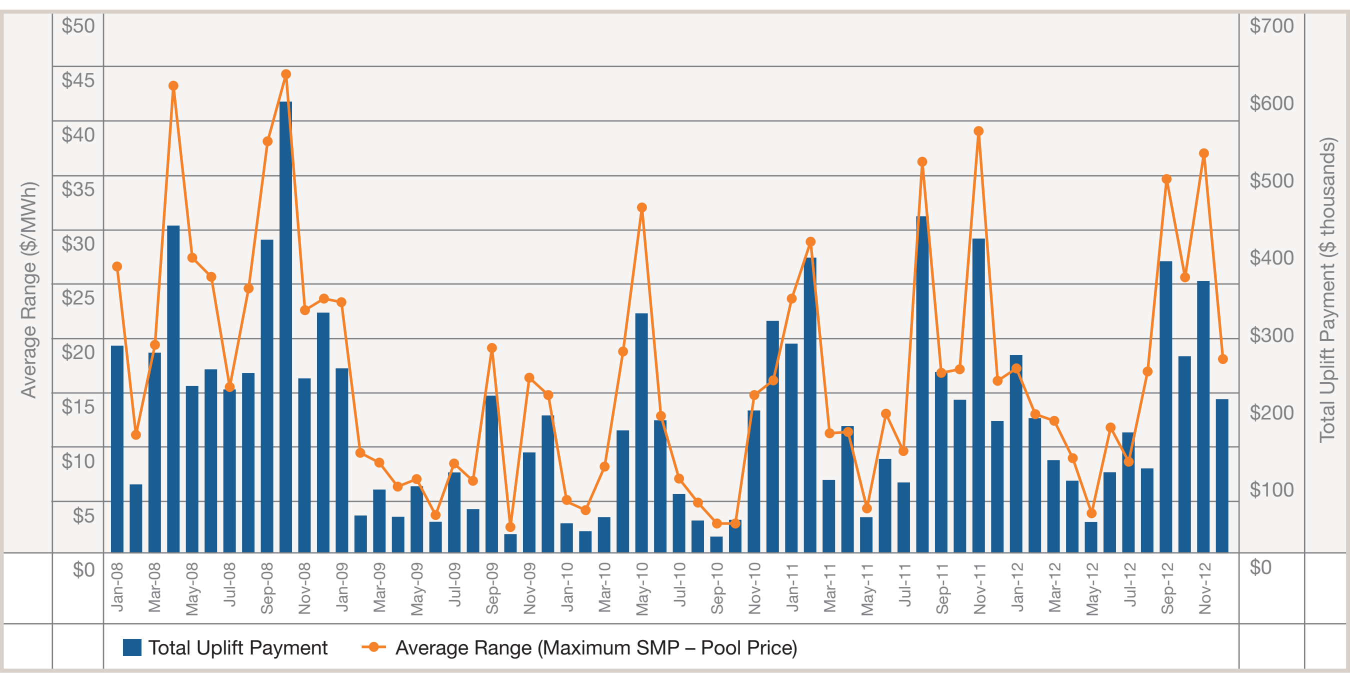
TABLE 8
Annual Payments to Suppliers on the Margin Statistics

Year	Total Uplift Payment *($ millions)*	Average Range between the Maximum SMP and the Pool Price *($/MWh)*	Average Charge *($/MWh)*	Market Value *($ millions)*	% of Market Value
2008	3.5	26.81	0.06	5,178	0.07
2009	1.2	10.29	0.02	2,734	0.05
2010	1.4	10.60	0.02	2,896	0.05
2011	2.6	18.72	0.04	4,580	0.06
2012	**2.2**	**17.11**	**0.04**	**3,903**	**0.06**

** Market value is determined by the pool price multiplied by the AIES load in the hour*

In 2012, uplift payments totaled $2.2 million, a 15 per cent decrease over the 2011 total of $2.6 million. The average range between the maximum SMP and the pool price is a measure of intra-hour volatility and a driver of uplift payments. In 2012, the average range decreased from $18.72/MWh to $17.11/MWh. As seen in Figure 22, the total uplift payment closely tracks the trend in average range between the maximum SMP and the pool price. Uplift continues to hold a small share of overall market value, representing 0.06 per cent of the total market value in 2012.

FIGURE 22
Total Uplift Payments and the Average Range Between Maximum SMP and the Pool Price



Final Notes and Market Monitoring in 2013

As the market evolves throughout 2013 and into the future, the AESO will continue to monitor, analyze, and report on market outcomes. As part of this monitoring process, the AESO provides real-time, historical and forecast reports and metrics on the market. These include daily and weekly reports outlining energy and operating reserve market statistics and a broad selection of historical datasets. The AESO encourages stakeholders to send any comments or questions on this report, or any other market analysis questions to **market.analysis@aeso.ca** Your input is appreciated.

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