MSA
MARKET SURVEILLANCE ADMINISTRATOR

Q1/14 Quarterly Report

January – March 2014

April 17, 2014

Wholesale market

		2014	2013	Change
Avg. Pool Price ($/MWH)	Jan.	45.23	58.02	-22.04%
	Feb.	96.33	28.71	235.48%
	Mar.	43.68	105.63	-58.65%
	Q1	60.60	65.28	-7.17%
Avg. Outage (MW)	Jan.	2110	2631	-19.78%
	Feb.	2371	2378	-0.32%
	Mar.	2338	3179	-26.46%
	Q1	2270	2741	-17.19%
Avg. Supply Cushion (MW)	Jan.	1892	1629	16.13%
	Feb.	1464	1928	-24.07%
	Mar.	1803	1336	35.02%
	Q1	1728	1621	6.58%
Avg. Wind (MW)	Jan.	514	518	-0.67%
	Feb.	325	519	-37.48%
	Mar.	306	303	1.02%
	Q1	384	444	-13.47%
Avg. Load (MW)	Jan.	9580	9394	1.98%
	Feb.	9788	9166	6.78%
	Mar.	9456	9025	4.78%
	Q1	9602	9196	4.42%

The average pool price in Q1/14 was 60.60$/MWH (70.42$/MWH on-peak, 40.94$/MWH off-peak), which is 7.17% down from Q1/13 of 65.28$/MWH.

While the average pool price was lower, the off-peak pool price was 7$/MWH higher than that of Q1/13, which represents an increase of almost 21%. This was driven by reduced wind and a large increase in off-peak load: it increased on average by 414 MW. While on-peak load increased by 402 MW in Q1 2014 the on-peak pool price was $10.51 lower as a result of on average 471 MW of less outage and less CDG.

In February, the average temperature in Calgary and Edmonton was more than 10 degree Celsius (°C) colder than last year. Three continuous cold days, Feb. 3 to 5 in combination with several unit outages and little wind, contributed a significant portion to the pool price in the quarter. The average pool price would have been 50.64$/MWH had these three days been excluded from the quarter.

The cold weather also brought less wind generation accompanied with higher load. Notwithstanding this, the average supply cushion level in Q1 2014 was 100 MW higher than the Q1 2013 average due to almost 500 MW less outage in Q1, 2014 (Sundance A units were back in service as of Nov. 2013). Higher supply cushion level usually leads to a lower pool price.

	Average Calgary Temperature, °C		Average Edmonton Temperature, °C	
Year	2014	2013	2014	2013
Jan.	-3.1	-5.4	-6.4	-9.0
Feb.	-12.4	-1.0	-14.8	-3.7
Mar.	-6.7	-3.3	-6.5	-5.8
AVG	-7.2	-3.3	-9.0	-6.2

January

While January 2014 was colder than average (-1°C on average) it was warmer than January 2013. With only about 2110 MW on outage and modest load, this month had one of the highest supply cushion levels since 2008. Three high price periods in excess of 500$/MWH were observed on Jan. 5, Jan. 21 and Jan. 22. On January 5 temperature in most areas of the province dipped to below -20°C. With SD5 on outage, the market became tight in the mid part of the day with three hours of spot prices between 666$/MWH and 816$/MWH. Jan. 21 had one hour ending with pool price at 681$/MWH. Three hours of spot prices around 645$/MWH were observed in the evening peak on Jan 22. In contrast, Jan. 22 was "warm" day and had few outages; the price spike was a result of economic withholding.

Beginning Jan. 1, offer control of two previous PPA units BR3 and BR4 was returned to the units' owner with the expiry of the PPA on Dec. 31, 2013.

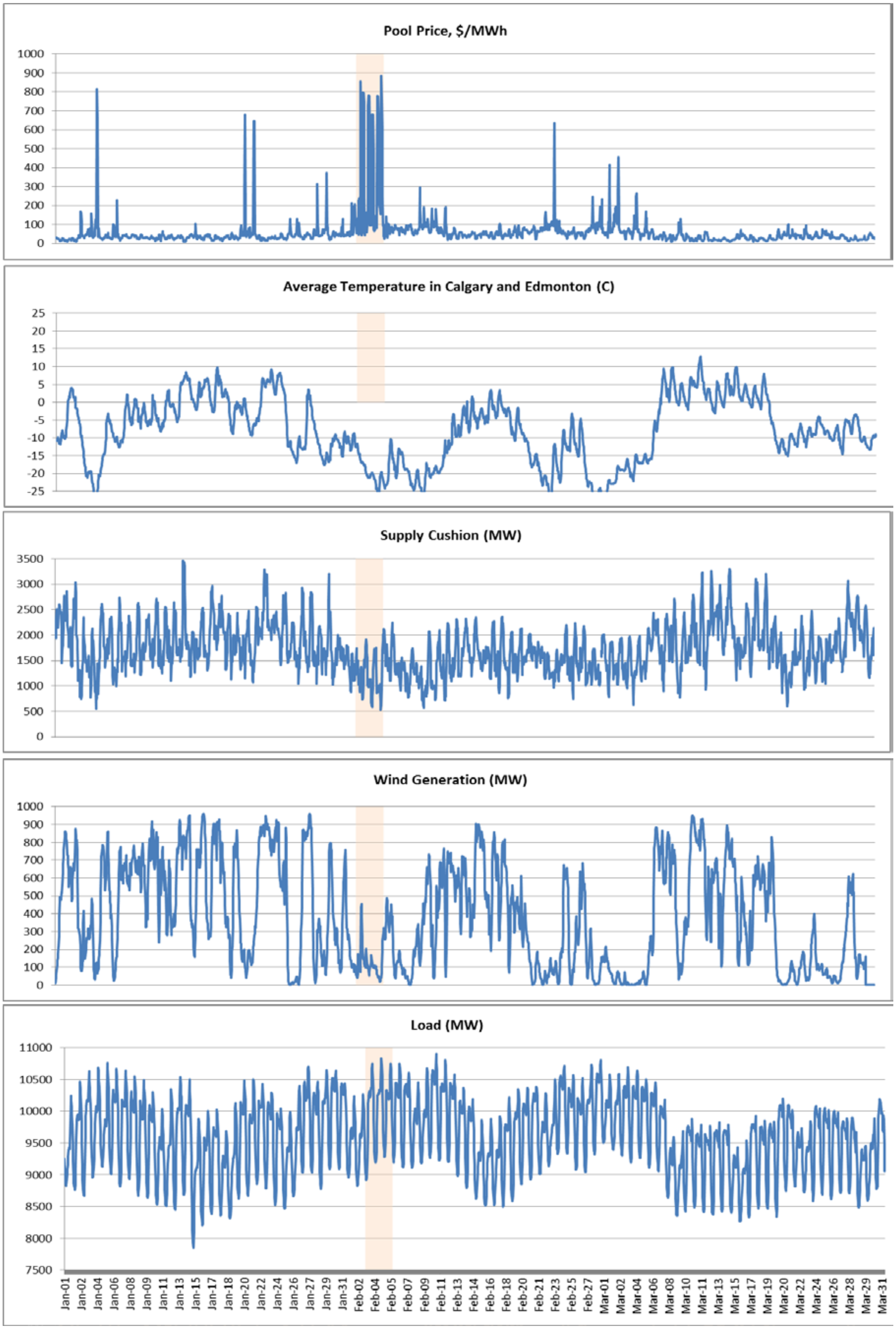
February

February on average was one of the coldest months since 2008. Beginning on Feb. 3, temperature in Calgary and Edmonton steadily dropped to below -20°C, prices were on average the highest in the quarter fundamentally being driven by high demand caused by the cold. The outage of KH2 and SD5 made the market even tighter. As reported below, on Feb. 5, the AECO hub spot gas price peaked at 24.82$/GJ.

March

While load in March moderated from February it still averaged 431 MW higher than Q1 2013. Average generator outages for March were close to 800 MW less than the previous year leading to a high average supply cushion. From previous reports high supply cushion typically leads to lower prices and pool price at 43.68$/MWH was the lowest monthly pool price in the quarter.

The following chart presents the hourly pool price, average temperature in Calgary and Edmonton, merit order supply cushion, wind generation and load from January 1 to March 31, 2014.


Pool Price, $/MWh
Average Temperature in Calgary and Edmonton (C)
Supply Cushion (MW)
Wind Generation (MW)
Load (MW)

Wholesale forwards

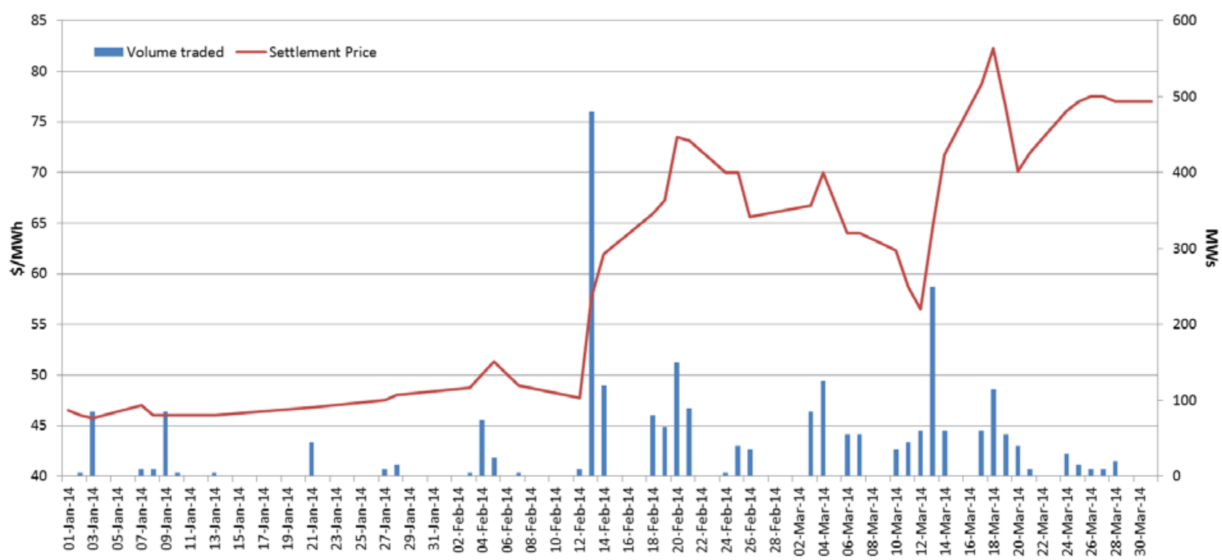
Trading activity

All three months experienced a drop in liquidity over the same period of the previous year: there were approximately 12.34 TWh of forward trades, which was 7.17% lower than in Q1/13.

	TWh Traded		
	2014	2013	% Change
Jan.	4.35	4.8	-9.53%
Feb.	4.53	4.63	-2.22%
Mar.	3.46	3.85	-10.19%
Q1 Total	**12.34**	**13.3**	**-7.17%**

May forward contract

Trading volume of the May 2014 flat contract went against the trend, with significant volume traded and price outcomes 30-40/MWH higher than April or June. The figure below sets out the closing price of the May 2014 flat contract and volume traded between 1 January 2014 and 31 March 2014.



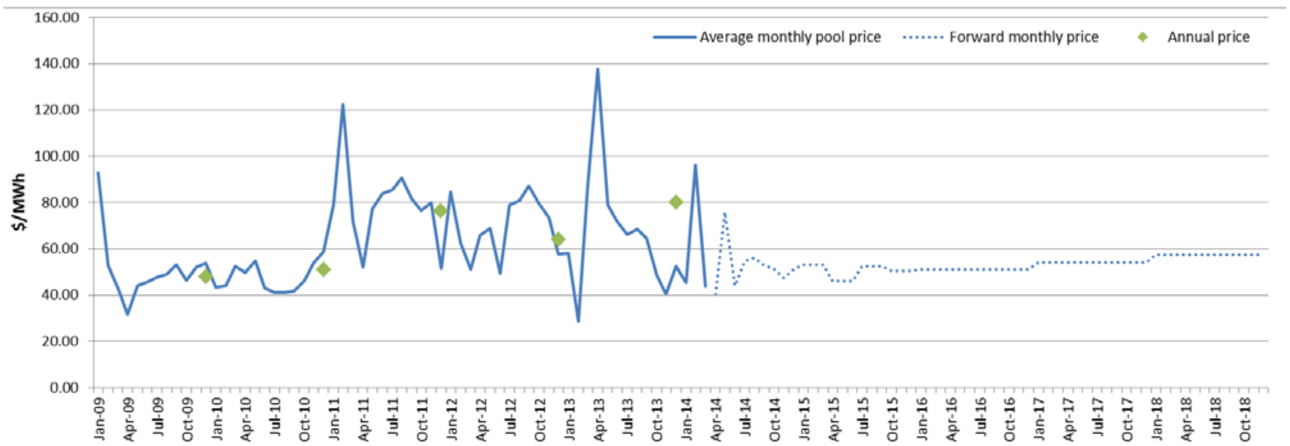
May flat contracts predominantly traded between 45-50/MWH until a significant upturn in price in mid February 2014. The price jumped 8$/MWH on February 13, with 480 MW traded on the day, the highest single day trading of a product observed during the quarter. Price has remained firm during the remainder of February and March, with price peaking at 80$/MWH at the end of the quarter.

A number of participants began trading significant volumes of the May flat contract on the opening of the market on February 13. The increase in the May flat contract coincides with the publication of a revision to the Long Term Critical Transmission Outages report by AESO at approximately 5 pm the previous day. The update included the announcement of a 12 day outage during May 2014 of the 500kV 1209L transmission line between the Genesee and Ellerslie substations in the Keephills-Ellerslie-Genesee (KEG) area. The outage of the 1209L line places the Genesee plant on a single line, making the loss of the Genesee plant the most severe single contingency event. It is our understanding that to manage system security in this situation, AESO may reduce imports across the Alberta-BC intertie and, if required, output levels at Genesee.[1] In line with AESO's Available Transfer Capability and Transfer Path Management Information Document #2011-001R,[2] imports across the MATL are also reduced. Previous outages of elements in the KEG cut plane have seen curtailment of Alberta-BC imports and corresponding high spot prices.[3] Prices rose over the next few days as the market began to integrate the possibility of a limited inter-tie tightening supply and reducing competition in Alberta.

There is no indication that there was any untoward behaviour in the event. This is an example of how forward prices move in response to news affecting the supply-demand balance.

Long term forward price trends

Notwithstanding a cold winter and record monthly peak demand levels, average monthly prices have remained relatively low this quarter. The February average price of 96$/MWH was an outlier against the moderate prices in the mid-40$/MWH range observed during December, January and March. The figure below graphs average monthly pool prices since January 2009 and the forward monthly flat contract prices to end of 2018 (as at 31 March 2014).

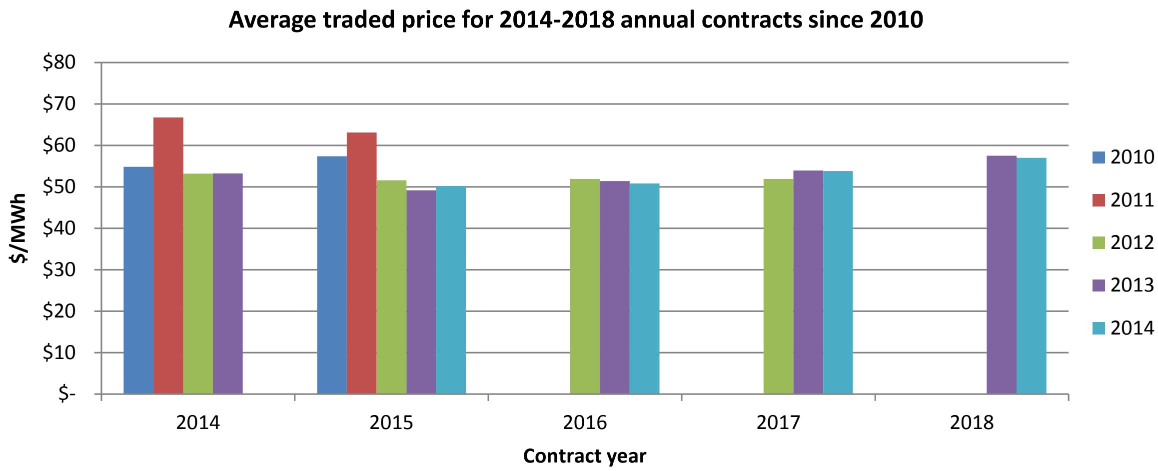


The chart below shows the average price at which flat contracts have traded for the 2014 to 2018 period. Although these contracts have been thinly traded, the chart illustrates how market expectations about wholesale price outcomes have changed since 2010. Notably the highest prices for the 2014 and 2015 annual contracts occurred in 2011. The MSA released its *Offer Behaviour Enforcement Guidelines* in January 2011. In this period Sundance 1 and 2 were under force majeure, tightening the market but subsequently returning. Market expectations have moderated downwards by 10$/MWH in subsequent years. As with monthly flat contracts, expectations are for low average spot prices during 2015 and 2016, with prices trading upwards from 2017.

[1] See AESO's previous Transmission Operating Policies and Procedures # 517: http://www.aeso.ca/downloads/OPP_517.pdf and http://www.aeso.ca/downloads/2013-004R_Keephills_Ellerslie_Genesee_Area_(TCM).pdf

[2] http://www.aeso.ca/downloads/2011-001R_ATC_and_Transfer_Path_Management.pdf

[3] The CDG report provides a detailed analysis, see http://albertamsa.ca/uploads/pdf/Archive/00-2014/Q4_2013%20140131%20Final.pdf



Forward prices reflect the market's expectation of future wholesale pool prices, adjusted for a risk premium. The risk premium built into the price increases as contracts go further out, reflecting greater levels of uncertainty. Factoring in risk premiums, current forward prices for monthly flats on the NGX indicate soft wholesale market conditions for the next two to three years. With the exception of the May 2014 monthly flat, monthly flats are being traded in the range 42$/MWH to 52$/MWH until the end of 2016. This is well below most wholesale monthly prices over the last three years and is below the cost of new entry for open cycle or combined cycle gas plant. While Alberta Internal Load is forecast by the AESO to grow at an annual average of 4.2% until 2017,[4] approximately 1550 MW of new capacity is scheduled to come online over the next eighteen months, most notably the 850 MW CCGT Shepard plant in early 2015 and 350 MW of new wind farms.[5] The forward market is anticipating that this capacity is likely to have a suppressing effect on pool prices.

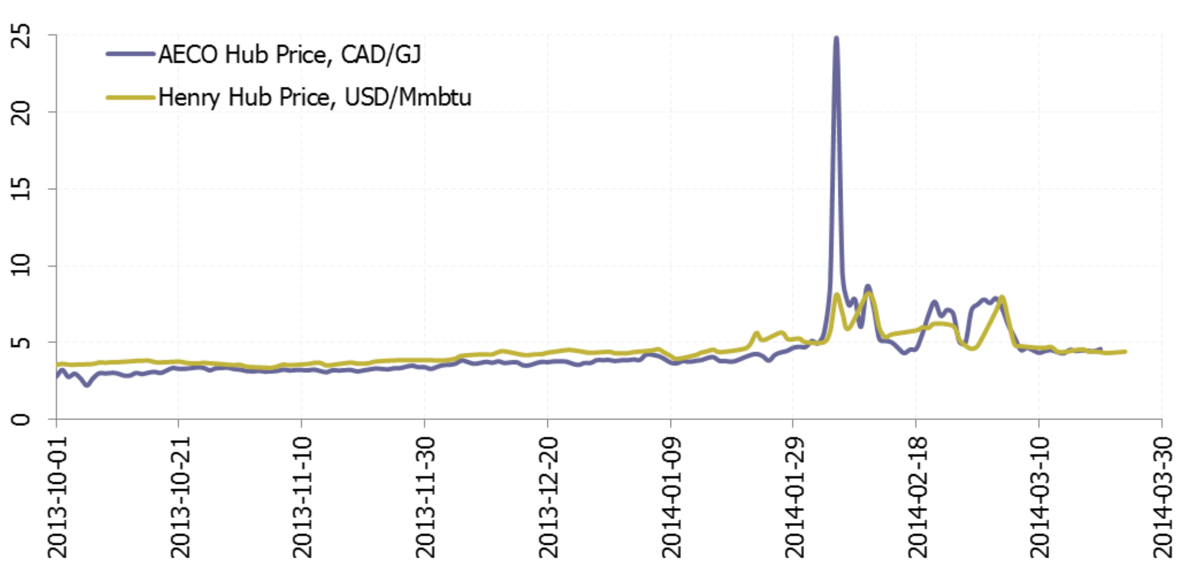
[4] AESO, *AESO 2012 Long-term Outlook Update*, http://www.aeso.ca/downloads/AESO_LTO_Update_Final.pdf

[5] AESO, *Long Term Adequacy Metrics – February 2014*, http://www.aeso.ca/downloads/2014_02_LTA.pdf

Natural Gas Price Spike

The price of natural gas as a feedstock to over 40% of installed capacity in the Alberta electricity market has an impact on gas fueled generators' short run marginal cost. A majority of Albertan residential consumers also use natural gas to heat their homes.

In the past few years natural gas prices in Alberta, typically priced at the AECO hub, have been low due to an abundance of supply. In this past quarter natural gas prices have spiked across North America including at the AECO hub. The chart below illustrates the price of natural gas over the past two quarters at the AECO and Henry hub.[6]



The natural gas price is a market-based price determined as an equilibrium outcome of market supply and demand. Due to limited alternatives for its consumption or production in the short run, even small changes in supply or demand over a short period can result in large price movements. The peak AECO hub price reached 24.82$/GJ on Feb. 5, almost triple that on the previous trading day, though the trading volume increased only about 30%.

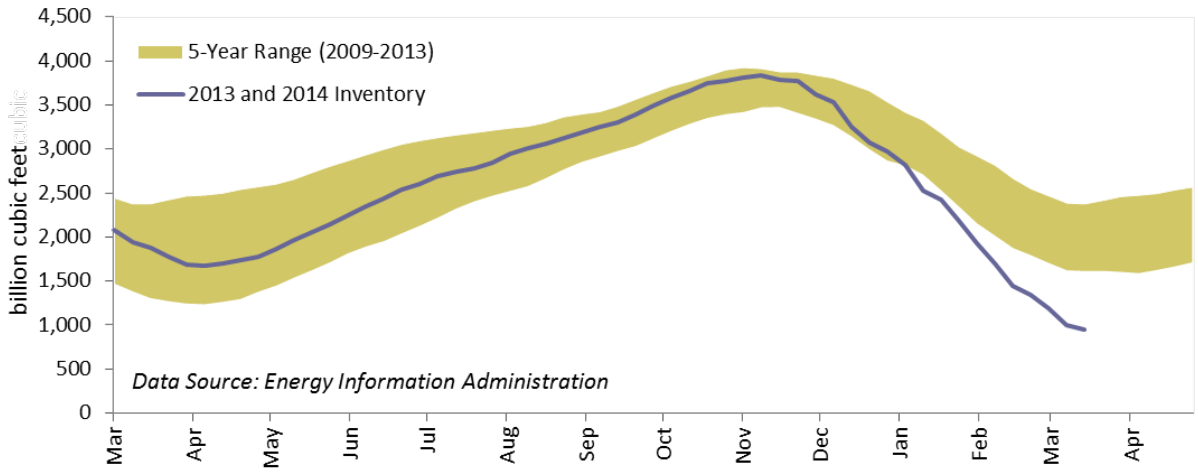
In the short run weather is the most prominent factor that dictates residential and commercial demand for natural gas. As noted in the electricity section, much of Canada and the Northeast USA[7] experienced the coldest winter in decades during Q1/14. The cold weather put upward pressure on natural gas prices as demand increased. In some parts of the Northeast USA the price was exacerbated by gas pipeline congestion due to coincidence high demand from both electricity generators and residential consumers.

While cold weather can reduce natural gas supply due to equipment freezing, much of North America relies on gas in storage to help satisfy demand during peak periods. This natural gas is held in underground storage fields, typically geological formations such as salt caverns or geological reefs or depleted oil wells. These natural gas underground storage facilities are refilled from April through

[6] 1 GJ=0.947817 Mmbtu
[7] A note on the cold wave can be found at http://en.wikipedia.org/wiki/Early_2014_North_American_cold_wave.

October when demand is low (due to no little to no residential heating demand) and release gas to pipelines from November through March when demand is high.

According to the U.S. Energy Information Agency (EIA), the natural gas working inventories in the lower 48 states on January 31was almost 30% below the level at the same time a year ago and 22% below the previous five-year average (2009-13). The next figure shows the inventory and compares it with the 5-year range from 2009-2013 based on the EIA lower 48 states data.

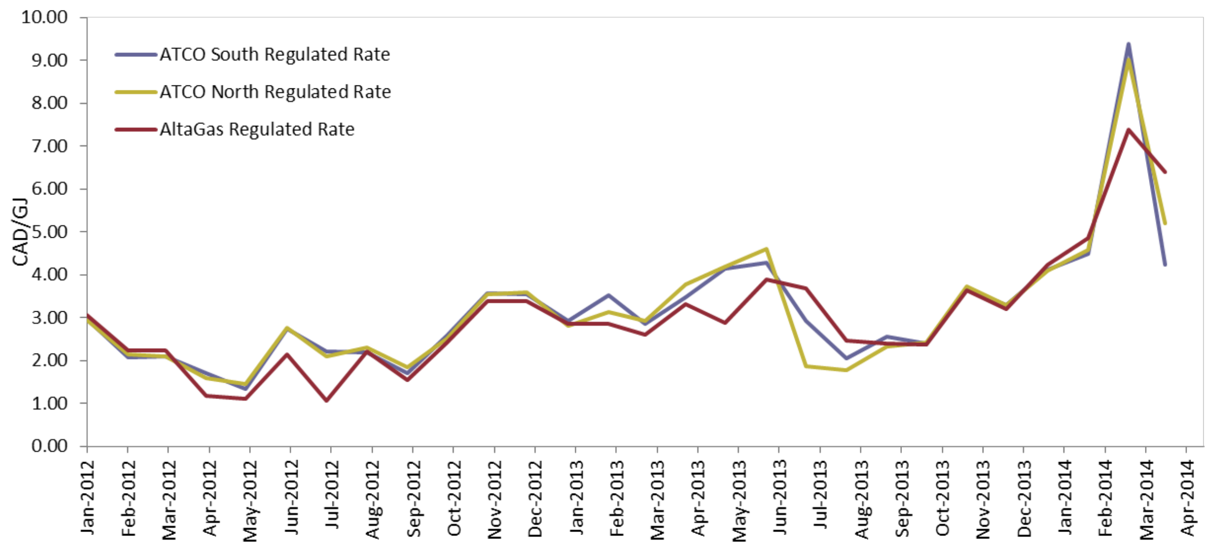


While the run-up in gas prices over the past quarter can be attributed to high demand caused by the severe winter, there will be a flow-on impact as larger amounts of gas will be required to re-fill storages by November. With abundant installed coal capacity and 1388 MW wind, its impact on Alberta's pool price is anticipated to be modest.

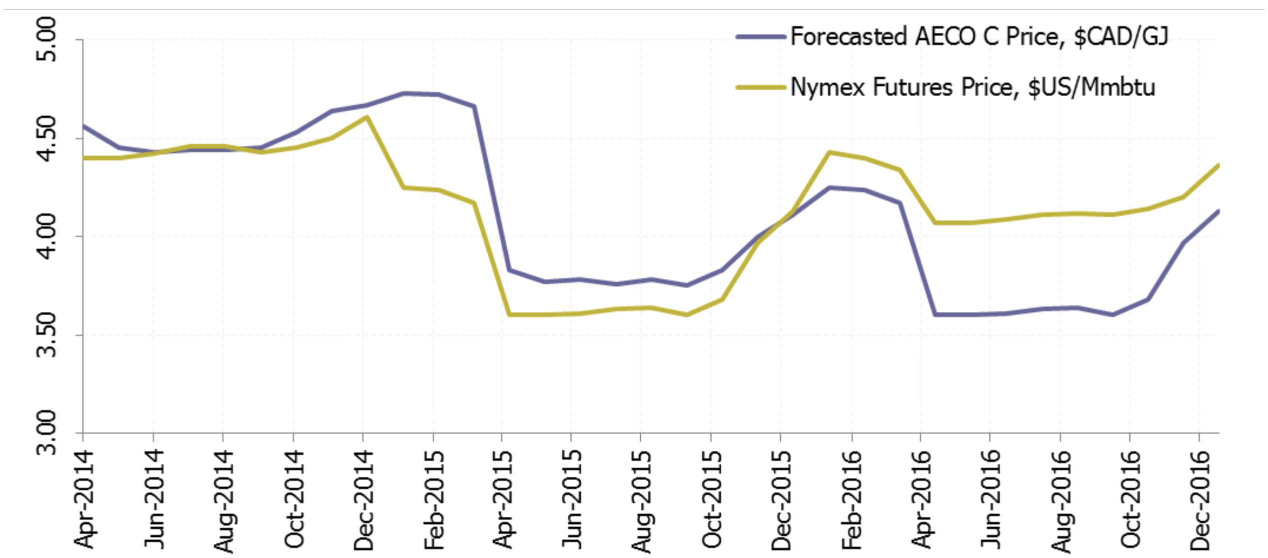
As reported in the recent MSA report on retail statistics, most natural gas consumers in Alberta, over 50% by volume, purchase natural gas on the default tariff rate which is based on wholesale price flow through.[8] Since natural gas is priced ahead of the month a deferral mechanism is set to account for changes in gas price across the month. As a result of the price spike, consumers on default natural gas prices will be noticing a significant rate increase in March 2014 to account for the deferral accounts. Our colleagues at the Utilities Consumer Advocate have already highlighted this issue for consumers.[9]

The figure below shows the regulated rates for the three main areas: ATCO North, ATCO South and AltaGas Utilities. In all cases the March rates stand out as being very high. The monthly rates have two main components: the cost of gas for the upcoming month and the deferral account adjustment. For March the deferral amounts are substantial, over $3 for the rates in ATCO North and ATCO South. The high deferral amounts are due to the real time costs that the regulated service provider encountered in buying for the regulated customers when the AECO hub spot prices were very high.

[8] See Retail Statistics at www.albertamsa.ca
[9] UCA "Default Natural Gas Price Increase March 1, 2014", http://ucahelps.alberta.ca/let's-connect.aspx



Despite the short run price spikes, long term natural gas prices are not forecast to increase over the next three years. Though almost 60 gigawatts of coal fueled capacity is projected to retire before 2020[10] in the USA alone (with most of that capacity replaced by gas fueled generators), the market is signalling that the growth of shale gas production across North America will outpace increasing demand and keep supply and demand in balance over the long-term.



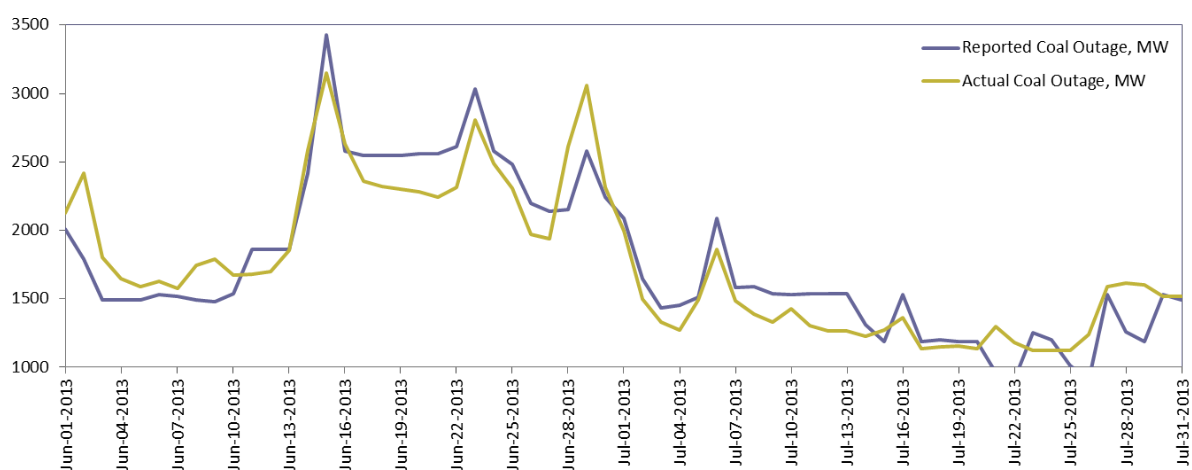
[10] See EIA http://www.eia.gov/todayinenergy/detail.cfm?id=15491&src=email.

Treatment of Coal Outages

Market participants frequently use AESO's daily and monthly generation outage reports when trading in the forward market. The forecast supply/demand balance for an upcoming month influences market expectations about likely pool price outcomes and the consequential value of holding a forward contract for that period.

The AESO publishes planned generation outages by fuel-type on an aggregate basis. For gas, hydro and other fuel types, the aggregate is the sum of the maximum capability (MC) of each unit on outage, pro-rated where an outage crosses time periods. Coal units are treated differently; with the outage of any one unit represented as 350 MW (a derate is calculated by the reduction in percentage of the generating unit's MC multiplied by 350 MW). This approach is based on an earlier recommendation of the MSA to the AESO. The genesis of this recommendation was the concern using the actual MC of a coal unit would enable participants to identify which units were going on outage by monitoring outage graphs and determining the MW change in aggregate figures between updates, causing detriment to the market participant taking the outage. This concern was justified when coal units dominated installed capacity in Alberta and were easily identifiable. Shortly two major gas-fired generators will be coming to market which will further reduce the need to mask coal generators.

The MSA considers it is timely to reconsider this approach on an efficiency basis. With the smallest coal unit being 144 MW and the largest 463 MW, using 350 MW as a representative figure can under or overestimate the amount of capacity that will be unavailable to the market. The following graph plots the actual coal outage and the reported coal outage after the aforementioned normalization procedure from June 1 2013 to July 31 2013. Though these two lines generally follow the same pattern, the difference can be as high as almost 400 MW on some days. Where conditions are tight, this can have a material impact on forward prices and volume traded for the relevant period. Price movements or volume traded may have been higher or lower than would have occurred if the true outage figure was known. This creates inefficiencies as the price has moved away from the true equilibrium price and participants may have traded different quantities than what they otherwise would have.



A recent example of the potential inefficiency of masking coal generators influence on forward prices is reflected in the evolution of May 2014 forward contract prices. A "small" coal unit, less than 160 MW, had scheduled an outage from mid-May through to mid-June. This outage was in the AESO coal outage tables normalised as a 350 MW generator, its impact on supply over estimated by close to 200 MW. We interpret a portion of the "run-up" in the forward market for May was due to over 760 MW of coal fired generator outages scheduled for the latter two-thirds of May. On April 15, the small generator canceled its planned outage. Forward market prices for May, immediately after the change in the AESO outage tables, fell 11$/MWH; across the course of the next day the price fell a further 8$/MWH.

The MSA has discussed the treatment of coal outages with the AESO. We understand the change to the AESO's coal outage reporting is a relatively simple change. The MSA is seeking feedback from market participants on this issue.

Potential MSA role in the new EPSP's

The Alberta Utilities Commission has a proceeding underway (ID #2941) which will examine a number of matters of broad interest to the three applicants and to consumers:

1. The return margin to the providers for undertaking the responsibility of providing the Regulated Rate Option.
2. The three company-specific proposals for Energy Price Setting Plans (EPSP) for 2014-18 that have been submitted.
3. Whether all three providers should procure energy through auctions similar to what EPCOR does now (Retail Market Review Committee Recommendation #40).

Of particular interest to the MSA is that two of the proposed EPSPs include a proposed role for the MSA.

In the case of the EPCOR EPSP the proposed role is primarily to monitor the auctions to ensure that the results are competitive. If issues arise, the MSA would have the latitude to work with EPCOR on a very limited number of items that could be adjusted to improve the competitiveness of the process.

In the case of the ENMAX EPSP the role is more complex in that their proposal involves auctioning 'shape risk', something that has not been done before in Alberta. The expectation is that some changes will need to be done as experience in conducting the auctions is gained. The MSA would have a role to monitor the performance of the auctions and work with ENMAX to make improvements in the event that it becomes clear that they are needed to produce competitive outcomes.

Ultimately it will be the decision of the Commission that will define any role that the MSA has in these EPSPS.

Section 3 of FEOC

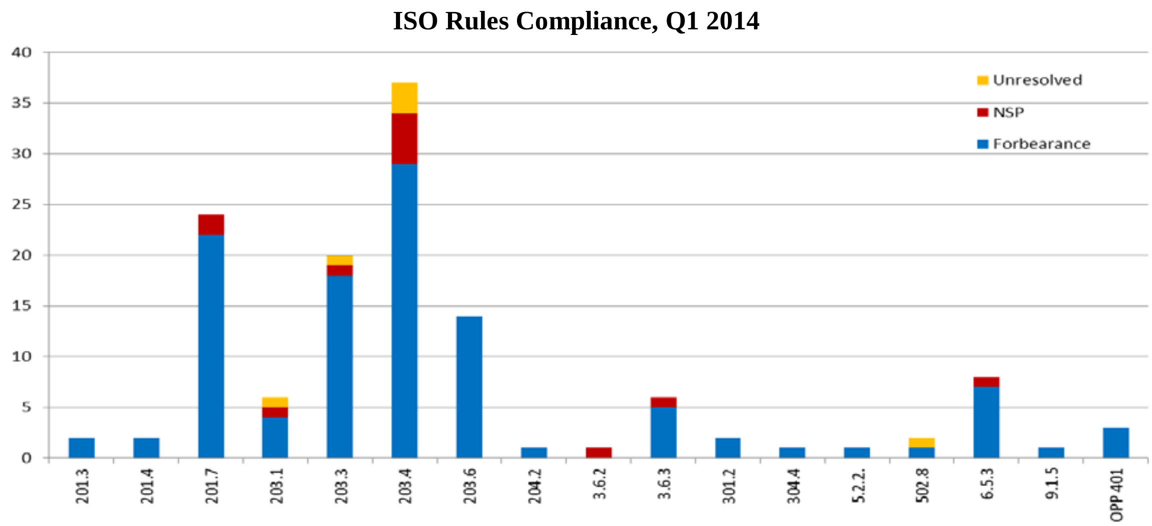
In mid-January 2014 the MSA received a self-report regarding a possible contravention of Section 3 of the *Fair, Efficient and Open Competition Regulation* that occurred when a market participant obtained access to the AESO's Energy Trading System. This section of the Regulation deals with a prohibition on the sharing of certain information between market participants.

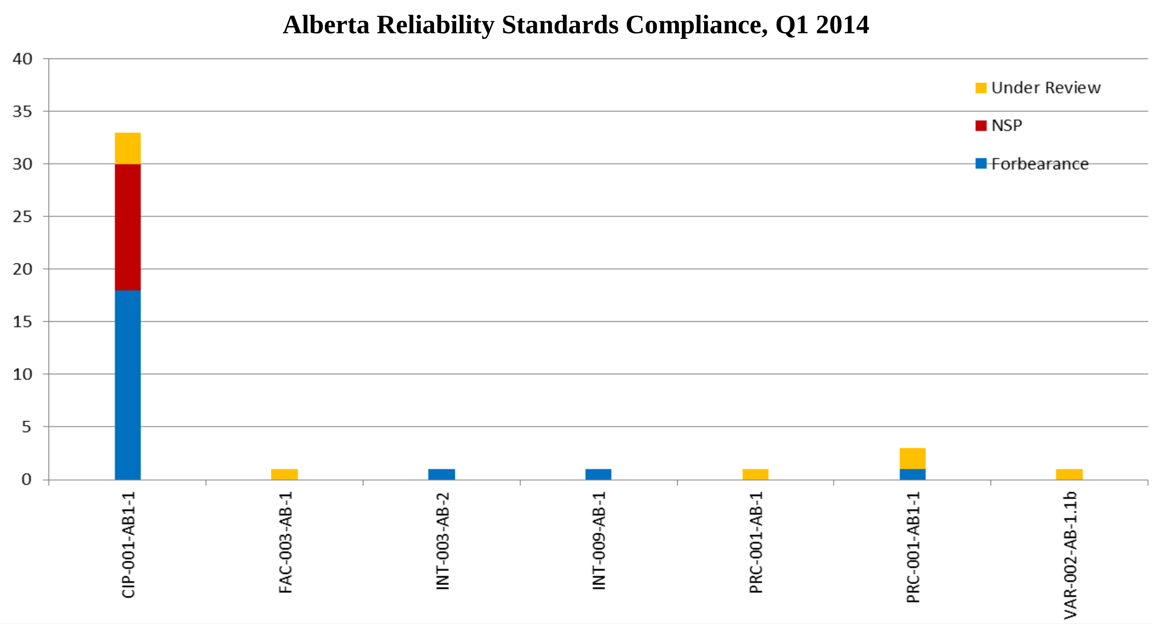
The MSA assessed the self-report and has concluded that the conduct did not cause harm to competition or other market participants; there was no benefit derived from the conduct; and the MSA does not believe an order from the Alberta Utilities Commission to alter compliance processes would result, or be likely to result, in the prevention of future contraventions. As a result the MSA declined to investigate the matter and has informed the market participant that reported the conduct of this decision.

The MSA is discussing this issue with the AESO to understand whether improvements in screening applications could be made that would reduce the likelihood of future issues arising. The MSA would also like to remind all market participants, particularly those with joint ventures or Power Purchase Arrangements, that sharing of certain information may be prohibited under Regulation or might otherwise be viewed by the MSA as inconsistent with supporting a fair, efficient and openly competitive market.

Compliance

- During Q1/14, the MSA issued 12 notices of specified penalty in relation to ISO rules contraventions for a total of $12,000 in financial penalties. File volume with respect to ISO rules was similar to that seen in the same period last year.
- Offer Control Information matters – a prominent issue in the same period a year ago, contributed minimally to compliance events addressed in Q1/14.
- During Q1/14, the MSA issued 2 notices of specified penalty in relation to Alberta Reliability Standards matters for a total of $15,000 in financial penalties. In addition to these two notices, also captured in the metrics shown is the last NSP issued in late 2013 as this matter was considered closed in January 2014.
- The volume of CIP-001 related matters this quarter is a function of the referrals received during Q1/14 based upon AESO compliance audit activities as well as the MSA's practice of tracking each referred contravention individually.





MSA activities and releases

Market reporting

MSA 2013 Fourth Quarter Report (01/31/14)

Compliance Review 2013 (02/06/14)

MSA Co-Branding Impact Research Report - February 2014 (03/25/14)

Notice re Leger Market Survey (03/25/14)

Notice

Notice re Historical Trading Report - Next Steps (03/24/14)

Notice re Application Brought to the Alberta Utilities Commission (03/24/14)

Notice re Court of Queen's Bench Proceedings - TransAlta Corporation and the Market Surveillance Administrator (03/14/14)

Notice re Assessment of Market Harm (03/13/14)

0630 Privilege Decision (03/11/14)

Notice re MOUs with the Competition Bureau and FERC (03/03/14)

Notice of Request for Hearing (02/26/14)

Other

Notice re Forbearance re AESO Compliance per ISO Rule Section 203.6 (01/15/14)

MSA Annual Report to the Minister, 2013 (03/14/14)

MSA Staff Changes (04/04/14)

The Market Surveillance Administrator is an independent enforcement agency that protects and promotes the fair, efficient and openly competitive operation of Alberta's wholesale electricity markets and its retail electricity and natural gas markets. The MSA also works to ensure that market participants comply with the Alberta Reliability Standards and the Independent System Operator's rules.