Q1/18 Quarterly Report

January - March 2018

April 27, 2018

Taking action to promote effective competition and a culture of compliance and accountability in Alberta's electricity and retail natural gas markets

www.albertamsa.ca

Table of Contents

1. Wholesale Market

1.1 Summary

Pool price in Q1/18 averaged $34.92/MWh ($29.94/MWh ext. off-peak, $37.41/MWh ext. on-peak). This is a 56% increase in pool price compared to the same period last year.

The Carbon Competitiveness Incentive (CCI) Regulation replaced the Specified Gas Emitters Regulation (SGER) on January 1, 2018. This adjustment in carbon pricing substantially increased the variable cost of thermal units based on their carbon emission rates, with coal units being impacted the most. The increase in variable cost for some units was as much as $16/MWh. Coal units set 74.5% of system marginal prices in Q1/18 and consequently a significant proportion of the price increase for the quarter can be attributed to this legislative change.

In Q1/18, total demand was 22.1 TWh, an increase of 3.7% relative to Q1/17.

On January 11, 2018 hour ending (HE) 18, Alberta set a new winter peak load of 11,697 MW, with an associated pool price of $43.64/MWh. This surpassed the previous winter peak load of 11,473 MW set on December 28, 2017 HE 18.

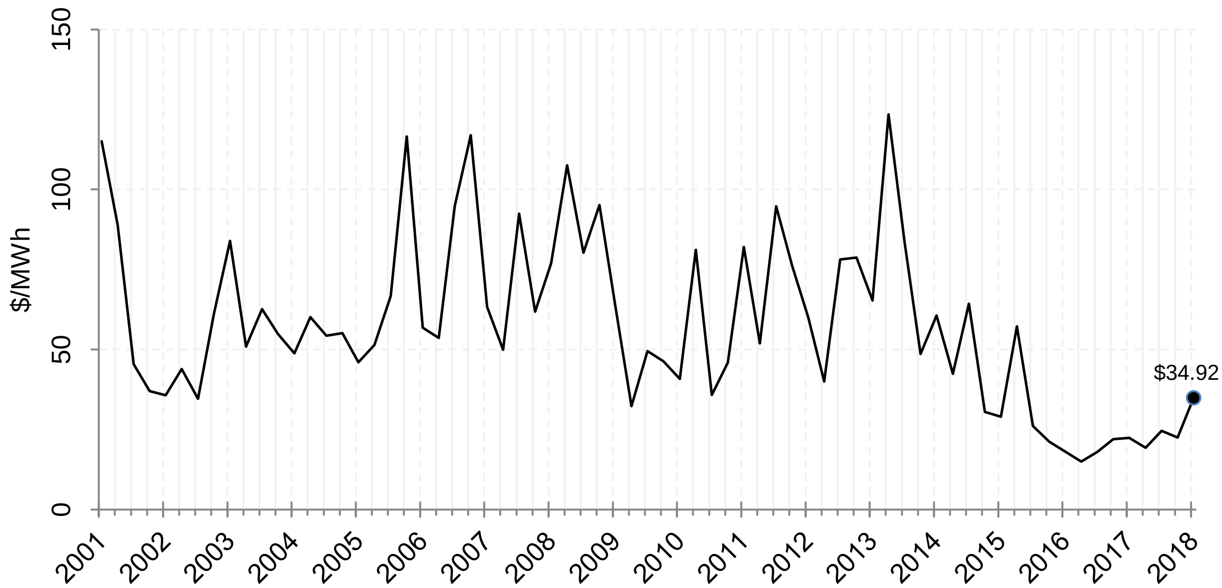
Table 1: Market Summary

		2017	2018	*Change*
Pool Price (Avg $/MWh)	Jan	23.96	40.83	*70.4%*
	Feb	22.18	31.32	*41.2%*
	Mar	21.01	32.27	*53.6%*
	Q1	**22.39**	**34.92**	***56.0%***
Demand (AIL, GWh)	Jan	7,506.3	7,655.6	*2.0%*
	Feb	6,672.1	7,036.0	*5.5%*
	Mar	7,153.6	7,432.0	*3.9%*
	Q1	**21,332.0**	**22,123.7**	***3.7%***
Gas Price (Avg $/GJ)	Jan	2.75	1.98	*-28.2%*
	Feb	2.40	1.91	*-20.4%*
	Mar	2.49	1.92	*-23.0%*
	Q1	**2.55**	**1.94**	***-23.9%***
Wind (GWh)	Jan	436.6	525.6	*20.4%*
	Feb	309.7	358.1	*15.6%*
	Mar	423.5	245.2	*-42.1%*
	Q1	**1,169.8**	**1,128.8**	***-3.5%***
Net Exports (GWh)	Jan	118.6	-191.2	*-261.2%*
	Feb	51.4	-397.5	*-872.8%*
	Mar	-117.4	-312.9	*166.4%*
	Q1	**52.6**	**-901.6**	***-1812.7%***
Supply Cushion (Avg MW)	Jan	1,921	1,901	*-1.0%*
	Feb	2,099	2,317	*10.4%*
	Mar	2,210	2,205	*-0.2%*
	Q1	**2,076**	**2,135**	***2.9%***

1.2 Pool Price Events

Figure 1 shows that the current Q1/18 average price is an extension of the ongoing low-price environment facing generators in Alberta which started in mid-2015.

Figure 1: Quarterly Pool Prices



The high price hours in Q1/18 were concentrated over a short period of time in mid-January. Temperatures during this time were low across the province, driving high demand.

Offer behaviour was not a feature in these events as there were no substantial changes in this period.

On December 31, 2017, Sundance #1 was retired and #2 was mothballed. Sundance #5 was on a forced outage that started December 28. Battle River #5 commenced a planned outage starting on January 12.

Gas supply constraints arose in the evening on January 11 and were slow to resolve. The subsequent derates, along with other outages, resulted in a substantial reduction in available supply from gas generators, including cogeneration. Total gas outages during the period peaked at 2,576 MW, while coal outages reached 1,466 MW (excluding mothballed units).

January 12

On January 12, pool prices were at sustained high levels from HE 08 - HE 19. The highest price during this period was $929.83/MWh in HE 09. Supply cushion reached a minimum of 145 MW at HE 09 and remained relatively low (< 700 MW) until HE 21. In particular, supply cushion was dramatically reduced from 1,797 MW to 832 MW during HE 07. Battle River #5 began its planned outage during HE 06 and some hydro capacity shifted from the energy market to providing operating reserves. Sundance #4 experienced a feeder trip during HE 08 which was resolved quickly. Load in the province was high as it reached 11,344 MW, although it was still 303 MW below the AESO's day-ahead forecast. Temperatures at the time were cold, with Calgary at -23 °C and Edmonton at -29 °C. Wind generation was low during the event, with 69

MW at HE 08 rising to 378 MW at HE 18. During HE 09, 146 MW of price responsive load dispatched off and remained off for most of the day.

January 14

On January 14, pool price reached $354.07/MWh in HE 21. Supply cushion was low throughout the day (< 1,000 MW), and reached a minimum of 255 MW at HE 20. In HE 17 Battle River #3 went on forced outage. The Calgary Energy Centre was designated as long lead time during this event. Load in the province was 80 MW higher than the AESO forecast leading up to the event; however, approximately 104 MW of price responsive load dispatched off, easing demand to 10,681 MW during HE 21. Wind generation was insignificant at 117 MW. Temperatures in the province started mild, but began to fall in the late afternoon, with Edmonton seeing a decrease to -18 °C by HE 19.

January 16

On January 16, pool prices were elevated from HE 08 - HE 10. The highest pool price occurred in HE 08, at $599.79/MWh. During this time, the BC and MATL interties were offline. Battle River #3 remained on forced outage. Sundance #4 had a forced derate that started earlier in the morning, while Sundance #3 experienced a forced derate during HE 08. Supply cushion wasn't drastically reduced during the event but was lower than usual, with levels around 1,000 MW, dipping to 850 MW in HE 08. Load in HE 08 was 10,538 MW which was 123 MW below forecast; however, demand leading up to HE 08 was between 200 and 300 MW above forecast. Wind generation was steady at just over 1,000 MW. Temperatures in Calgary hovered around -5 °C, while Edmonton had temperatures of -16 °C. Some 86 MW of price responsive load was turned off by HE 08.

1.3 Alberta Load

Alberta load continues to grow at a fairly healthy pace, largely in step with historical averages.

Figure 2: Growth in Alberta Load (Year-over-year)

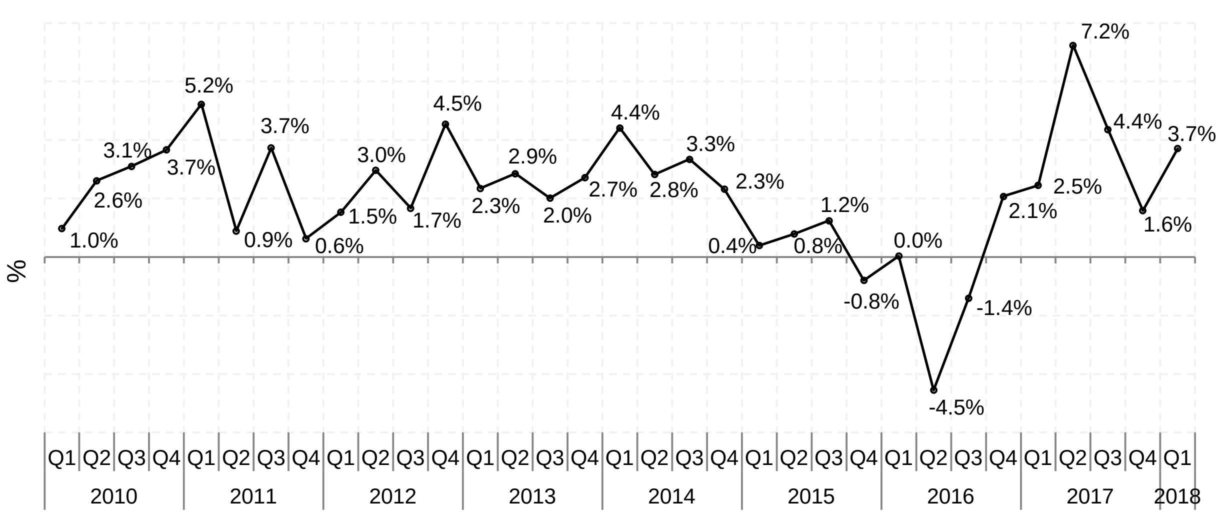
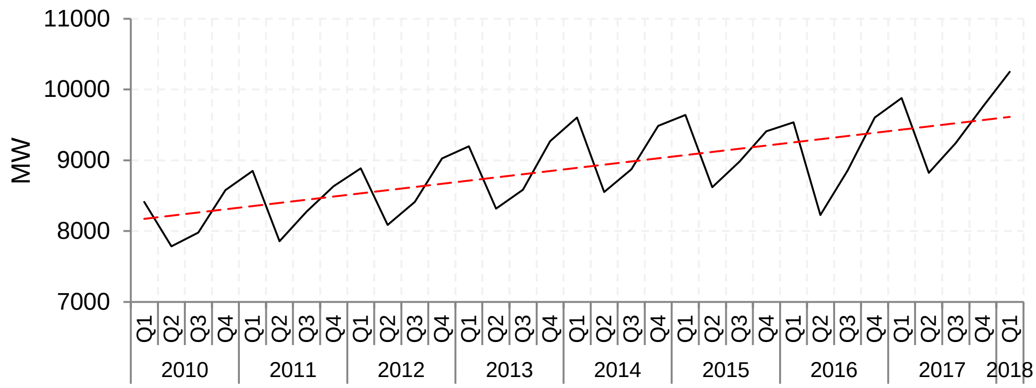


Figure 3: Average Alberta Load (MW)



2. Forward Market

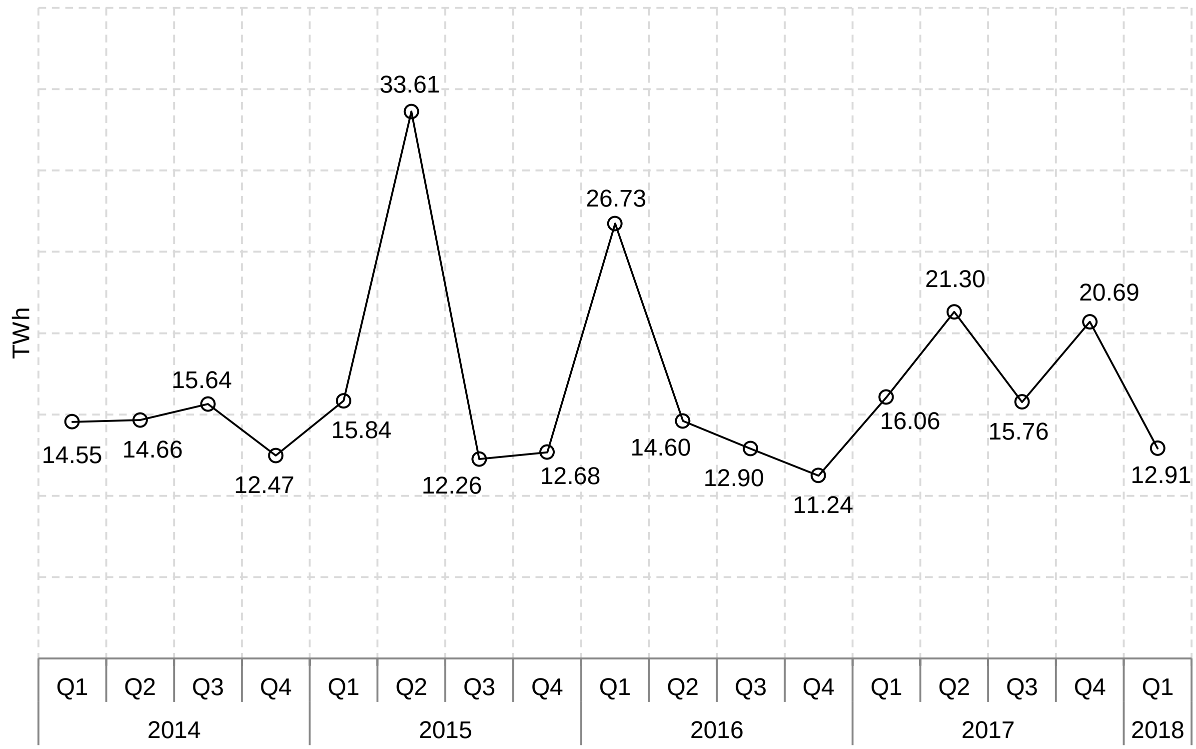
2.1 Trade Volumes

Trade volumes in Q1/18 were moderate being at the lower end of the range seen in recent years. Trade volumes of monthly contracts remained robust, driven in part by RRO-associated trading.

Table 2: Trade Volumes by Contract Term (TWh)

		Daily	Monthly	Quarterly	Annual	Other	Total
2015	Q1	0.10	9.96	0.84	4.17	0.76	15.84
	Q2	0.20	10.46	1.14	16.71	0.66	29.18
	Q3	0.06	6.25	0.50	4.40	0.29	11.51
	Q4	0.06	5.87	0.98	5.74	0.03	12.68
	Year	0.42	32.54	3.46	31.03	1.74	69.20
2016	Q1	0.22	9.36	1.78	12.37	3.01	26.73
	Q2	0.19	8.25	0.58	4.50	1.08	14.60
	Q3	0.07	6.80	1.23	4.56	0.25	12.90
	Q4	0.09	5.44	1.46	3.78	0.47	11.24
	Year	0.57	29.85	5.05	25.20	4.81	65.47
2017	Q1	0.06	6.53	3.03	4.57	1.86	16.05
	Q2	0.13	6.87	2.31	11.13	0.84	21.27
	Q3	0.18	6.77	2.13	5.51	1.17	15.76
	Q4	0.06	8.24	3.51	7.50	1.38	20.69
	Year	0.43	28.40	10.98	28.70	5.26	73.78
2018	Q1	0.15	7.28	0.60	4.47	0.41	12.91

Figure 4: Total Trade Volumes over Time

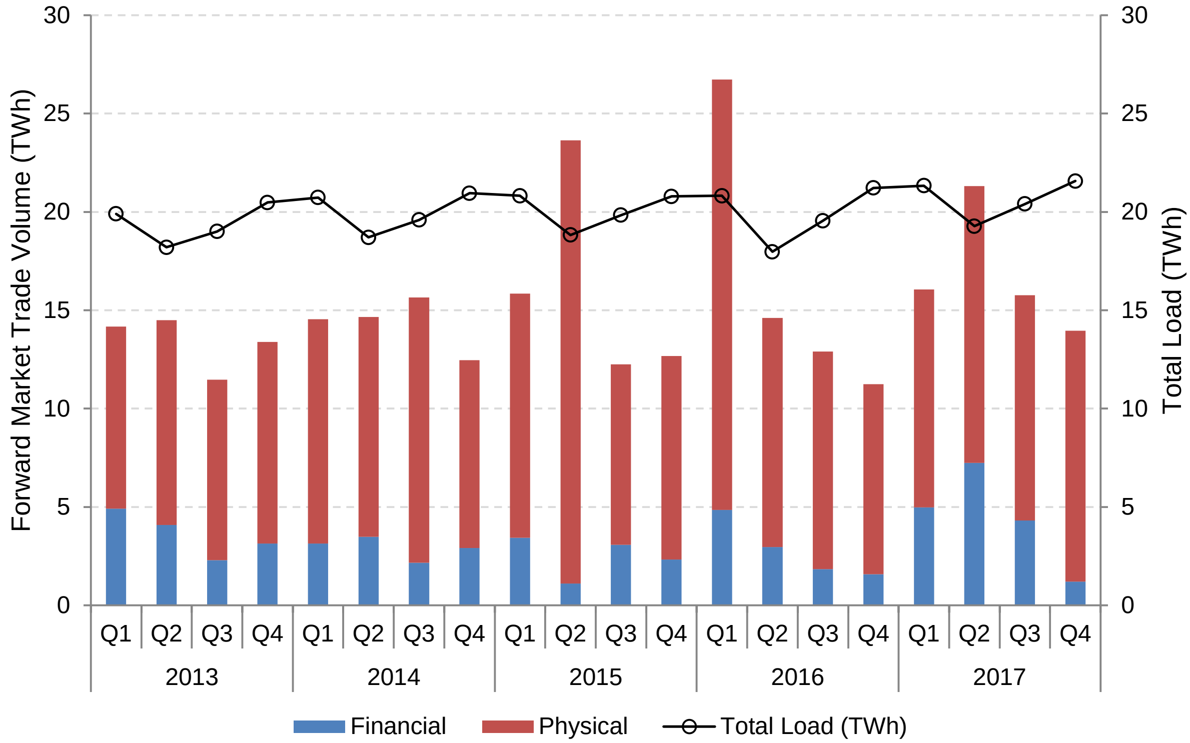


2.2 Participation in the Forward Market

Over the past two and a half years, market volatility (risk) has been much lower than in prior years. As a result, while financial participants can afford to take larger positions, other participants with physical positions to manage may be inclined to take the risk and elect to go to the spot market. Figure 5 shows the trend over time and it is apparent that participation rates of financial and physical market participants have remained fairly consistent over the past several years.

It is also noteworthy that average trade volumes are less than the size of the physical market as it has been for a long time. This contrasts significantly with the natural gas market in Alberta which trades at several multiples of the physical market.

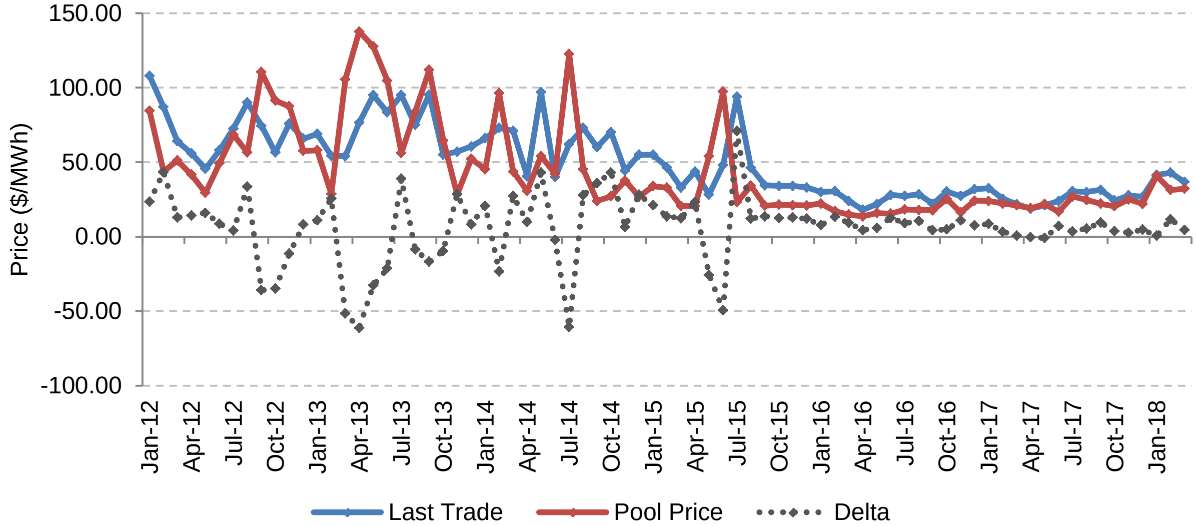
Figure 5: Forward Market Participation Rates



2.3 Forward Market Convergence

The volatility in the wholesale market has been low over the past two years. As a consequence the forward market prices are currently closer to the corresponding pool prices than in the past. The MSA looked at the last traded price for each flat monthly contract and compared it with the average of the corresponding pool prices. The last traded price for a contract contains all information about price expectations except for uncertainties in supply and demand as the month unfolds. Figure 6 shows the results and demonstrates this convergence as the final trade prices have become much better predictors of the relevant pool prices. It is also evident that there is a small, but persistent, premium in the forward price, at least for the flat monthly contract examined herein.

Figure 6: Convergence of Forward and Actual Market Pool Price



2.3 Forward Price Curve

The near-term forward curve, as of late-April, is shown in Figure 7. If these prices persist, the data suggests that the buying necessary for the RRO will result in rates above the Retail Price Cap for regulated customers for several months this summer.

Figure 7: Forward Price Curve for Near-Term Months (7 X 24, April 27, 2018)

Figure 8: Forward Curve for Annual Contracts (7 X 24, April 27, 2018)

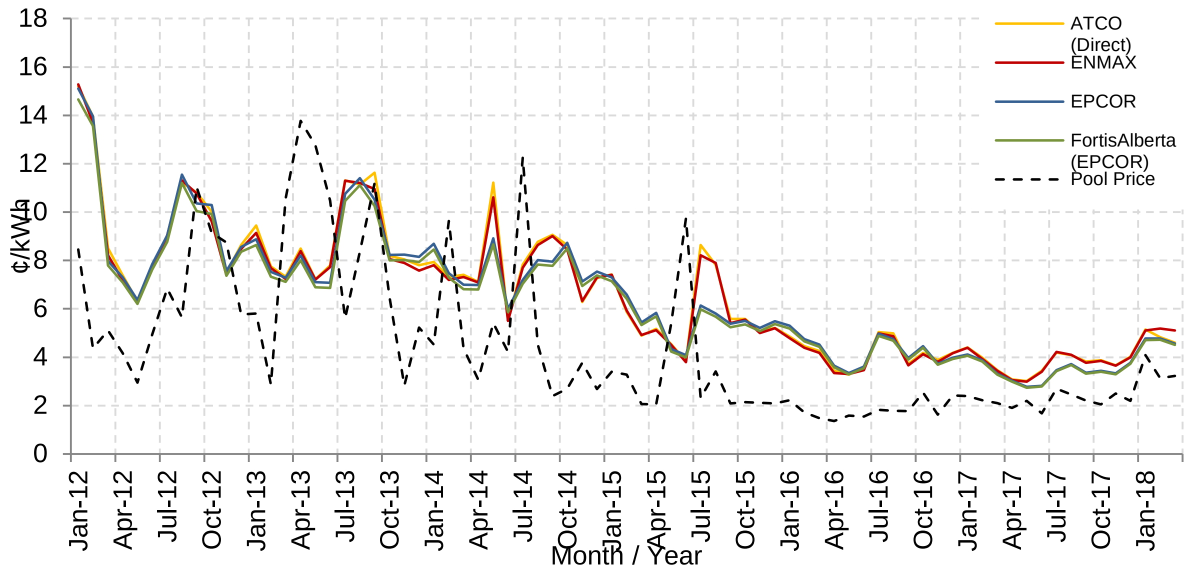
3. Retail Market

3.1 Regulated Retail Market

3.1.1 Regulated Rate Option (RRO)

RRO rates have continued at low levels in line with the corresponding wholesale market prices. The rates of the different providers are generally quite similar after allowing for the different buying protocols of the various Energy Price Setting Plans.

Figure 9: RRO Rates



3.1.2 Energy Price Setting Plans – Recent Developments

On March 16, 2018, the Alberta Utilities Commission (AUC) released its decision regarding EPCOR Energy Alberta GP Inc.'s (EPCOR) 2018–2021 Energy Price Setting Plan (EPSP).[1] The AUC approved EPCOR's EPSP with a few minor directions. EPCOR's 2018–2021 EPSP proposed some significant changes from its current 2016–2018 EPSP.

In its 2018–2021 EPSP application, EPCOR proposed an alternate procurement and risk compensation calculation methodology. The auction format would be changed from one with six random-close auctions over the procurement period to one with four descending clock auctions over the procurement period (plus two contingency auctions). EPCOR proposed that it will procure monthly full-load energy contracts for 50% of its actual RRO customer load as well as 7x24 and 7x16 block hedges for the remaining 50% of its actual RRO customer load. EPCOR will set the rate for its entire RRO customer load at the volume-weighted average price of the full-load energy contracts. In changing to this procurement methodology, EPCOR's proposed RRO rate will not include Commodity Risk Compensation or an energy return margin as the risk from the procurement of the RRO will be incorporated into the procurement auction.

[1] See: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2018/22357-D01-2018.pdf

While EPCOR's proposed overall procurement methodology has been approved by the AUC, a compliance filing is required by EPCOR to address other elements of its application. EPCOR's compliance filing for its 2018–2021 EPSP application was filed on April 10, 2018.[2] In its April 11, 2018 Notice of Application, the AUC stated that it considers the application to be routine in nature and thus will issue a decision on the matter without intervention by other parties unless challenged by an intervener.[3] The first auction under the new procurement methodology is expected to occur in September 2018.

Direct Energy Regulated Services is currently operating under its 2016–2018 EPSP and ENMAX Energy Corporation's 2016–2018 EPSP is pending AUC approval.

EPCOR's existing auction format is different from the RRO procurement protocols of ENMAX and Direct. ENMAX and Direct both buy block products in the forward market, buying small amounts at relatively frequent intervals. With the change in EPCOR's EPSP, the difference is more marked. EPCOR's RRO prices will incorporate a forward looking market-based commodity risk premium. The plans for ENMAX and Direct use commodity risk premiums that are based on historical values. The MSA will continue to monitor the RRO and any developments in the EPSPs.

3.1.3 Rate Cap Regulation

The Government of Alberta's cap on regulated retail rates bound for the first time in April 2018, since taking effect in June 2017. The Alberta Utilities Commission is responsible for approving reimbursements for the large distribution systems for which it has oversight of the regulated rates (Direct, ENMAX, EPCOR and Fortis). The regulated rates charged to customers of these entities are capped at 6.8 ¢/kWh.

The MSA is responsible for approving reimbursements for areas with board or council approved regulated rates (rural electrification associations (REAs) and certain municipalities) as well as the City of Medicine Hat. For these entities, the AUC calculates a monthly reference rate (one for the board and council entities and one for the City of Medicine Hat). For a month when the AUC reference rate is above 6.8 ¢/kWh and these entities approve a rate below the AUC reference rate (but above 6.8 ¢/kWh), they are reimbursed at a rate equal to the difference between their approved rate and 6.8 ¢/kWh. For a month when the AUC reference rate is above 6.8 ¢/kWh and these entities approve a rate above the AUC reference rate, they are reimbursed at a rate equal to the difference between the AUC reference rate and 6.8 ¢/kWh. Therefore, customers on the regulated rate charged by these entities may not be capped at 6.8 ¢/kWh in all cases.

The reference rate board or council approved providers for April 2018 was 9.030 ¢/kWh and for Medicine Hat it was 8.210 ¢/kWh.

On April 16, the MSA approved all of the deferral account statements that it received for April. The City of Medicine Hat follows an alternative process with a delayed timeline and has

[2] See Exhibit 23492-X0001, AUC Proceeding 23492 (available through the AUC eFiling System)
[3] See: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2018/23492.pdf

therefore not yet submitted its deferral account statement for April 2018. Table 3 summarizes the approved and maximum possible rates for April 2018, along with the reimbursement amounts to date, which total $8.33 million dollars (not including the City of Medicine Hat).

Table 3: April 2018 Rate Cap Summary

	Consumption Weighted Average RRO Rate/AUC Reference Rate (¢/kWh)[4]	Reimbursement Rate (¢/kWh)[5]	Reimbursement Amount (Thousands)
Direct[6]	7.89	1.09	$979.9
ENMAX[7]	9.28	2.48	$2,615.2
EPCOR[8]	7.87	1.07	$1,635.7
Fortis[9]	7.79	0.99	$2,234.1
Board or Council Approved[10]	9.03	2.23	$865.3
City of Medicine Hat	8.21	1.41	Not Yet Available
Total			$8,330.2

3.1.4 ATCO Energy Code of Conduct Regulation Compliance Plan

On March 12, 2018, ATCO Energy Ltd. (ATCO Energy) filed an application with the AUC to amend its *Code of Conduct Regulation* Compliance Plan.[11] ATCO Energy's main proposed changes are: 1) changes to the definition of advertising, 2) the introduction of the definition of branding and generic messaging, 3) the removal of the Fair Competition Statement from calls to its call centre, and 4) a new mechanism to clarify that radio spots are not advertisements.

On December 14, 2017, the MSA provided notice to stakeholders outlining its view that an affiliated distributor or regulated rate provider that have a similar name or logo of their obligation to strictly adhere to section 7 of the *Code of Conduct Regulation* (Code) and their AUC

[4] Direct, EPCOR, and Fortis have rate classes with varying rates, which were weighted by forecast consumption to produce an average. The AUC Reference Rate is calculated by the AUC for the board or council approved regulated rate tariff entities and the City of Medicine Hat. See: http://www.auc.ab.ca/Pages/regulated-rate-option-price-cap.aspx.

[5] For Direct, ENMAX, EPCOR, and Fortis, the reimbursement rate is the difference between the calculated weighted RRO Rate and 6.8 ¢/kWh, while for the board or council approved regulated rate tariff entities and the City of Medicine Hat, the values reported are the maximum possible reimbursement rate (the reimbursement rate may be lower if these entities approve a monthly rate that is below the AUC Reference Rate).

[6] See http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2018/23445-D01-2018.pdf.

[7] See: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2018/23442-D01-2018.pdf.

[8] See: http://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2018/23449-D01-2018.pdf.

[9] Ibid.

[10] See: https://albertamsa.ca/index.php?page=approved-das.

[11] See Exhibit 23407-X0004, AUC Proceeding 23407 (available through the AUC eFiling System)

approved compliance plans.[12] Section 7 of the Code states that the Fair Competition Statement must be included “in any advertising that markets energy services”. On March 26, 2018, the MSA submitted a statement of intent to participate to the AUC reiterating its views and that it would not be appropriate to define “advertising”, “branding” or “generic messaging” as suggested by ATCO Energy in its compliance plan without an amendment to the Code.[13]

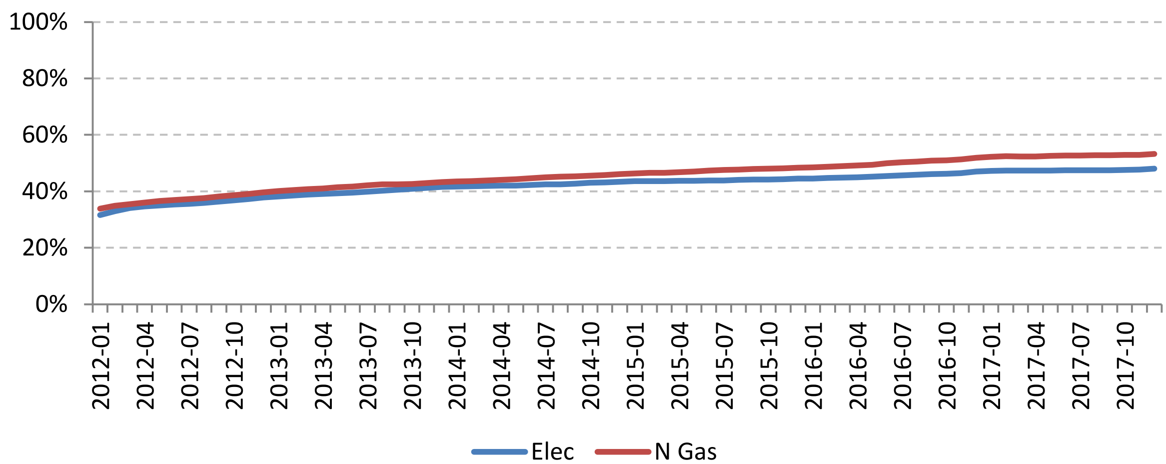
3.2 Competitive Retail Market

Readers are reminded that the MSA publishes retail statistics on its web site under the ‘Market Reporting’ tab. Early in April the data was updated to the end of 2017 per our normal publishing protocols.

3.2.1 Switching Rates

Prices in both the wholesale electricity and natural gas markets have been exceptionally low and this in turn has caused the default rates for both commodities to exhibit little, if any, volatility. Accordingly the switching rates away from the default rate to competitive contracts have slowed as shown in Figure 10.

Figure 10: Percentage of Residential Customers on Competitive Retail Contracts



Looking more closely at the chart it can be seen that the percentage of residential customers on competitive contracts has continued to climb in the case of natural gas, but the rate of increase has slowed down considerably in the case of electricity.

The switching rate varies across the province as summarized in Table 4. In recent years the switching in the Fortis Zone has increased substantially; in January 2012 it stood at 26.6%, less than half that in December 2017.

[12] See: https://albertamsa.ca/uploads/pdf/Archive/00000-2017/2017-12-14%20Notice%20re%20Conclusion%20of%20MSA%20Affiliated%20Retailer%20Advertising%20Investigation.pdf

[13] See Exhibit 23407-X0017, AUC Proceeding 23407 (available through the AUC eFiling System)

Table 4: Regional Switching Statistics (December 2017)

Electricity	
Province	48.0%
Zone:	
ATCO	46.6%
ENMAX	64.4%
Epcor	32.8%
Fortis	59.7%
Other	53.3%
Natural Gas	
Province	53.3%
Zone:	
ATCO -N	23.2%
ATCO-S	47.7%
AltaGas	62.7%

3.2.2 Market Shares

Figures 11 and 12 show the market shares of the larger retailers in the residential customer segment. The figures are quite similar with the same ordering in size of the largest retailers.

Figure 11: Residential Customers – Electricity Market Shares

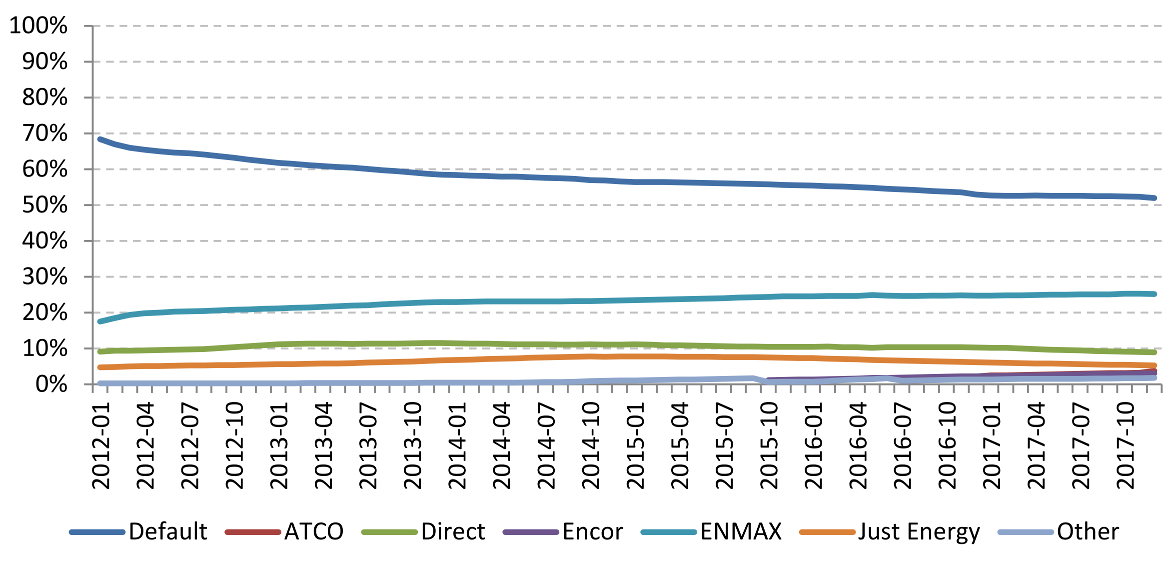
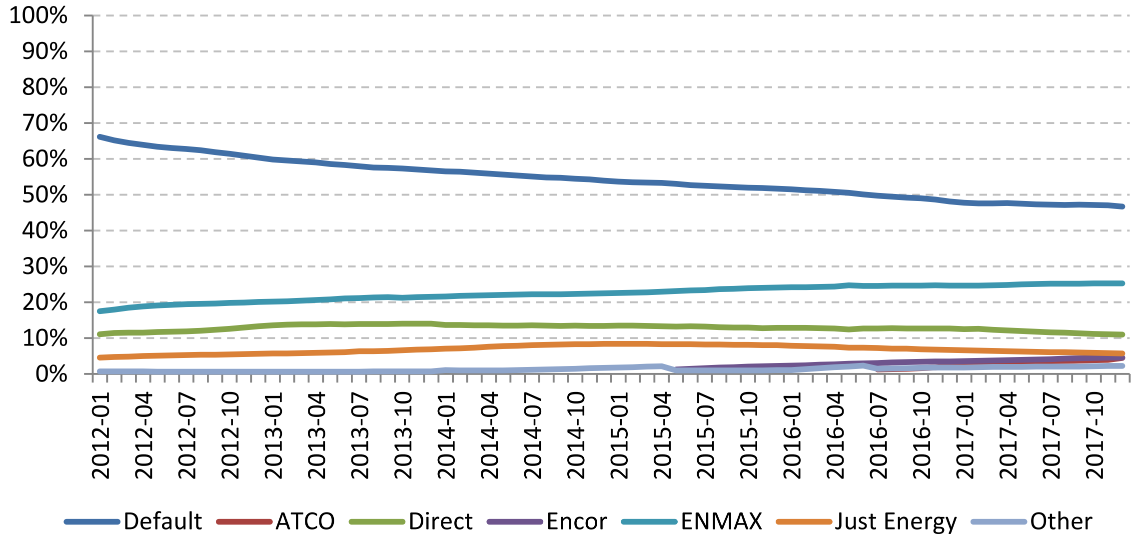


Figure 12: Residential Customers – Natural Gas Market Shares



The market shares as of the end of 2017 are shown in Table 5.

Table 5: Market Shares (December 2017)

Company	Electricity	Natural Gas
	%	%
Default	52.0	46.7
ENMAX	25.2	25.2
Direct	8.9	11.0
Just Energy	5.3	5.7
Encor	3.1	4.6
ATCO	3.8	4.5
Other	1.8	2.3

Drilling down into the numbers for calendar year 2017, the number of residential sites increased by 22,484 and the number of customers that switched away from the RRO was 2,251. This means that competitive retailers in total gained 24,735 customers in 2017. Similarly, in natural gas, the number of sites that moved into the competitive market was 21,990. The resulting gains across retailers were as shown in Table 5.

Table 5: Change in Number of Residential Customers Over 2017

	Electricity	Natural Gas
New Sites	22484	10559
Default	-2251	-11431
ATCO	23466	23426
Encor	13927	13141
ENMAX	11609	9795
Other	5954	5943
Just Energy	-12544	-11446
Direct	-17677	-18869
TOTAL	24735	21990

The newer retailers, ATCO and Encor, have clearly gained new customers at the expense of Just Energy and Direct. All the retailers named in Table 5 sell both electricity and natural gas contracts and the changes in number of customers are very similar for both commodities. This suggests that many customers are signing dual fuel contracts with their retailers. In 2014, the MSA canvassed competitive retailers about contract types and found that about 78% were on dual fuel at that time. The above data strongly suggests that the customer preference for dual fuel contracts still exists.

4. Interconnections

Alberta has electrical connections to three jurisdictions: British Columbia, Saskatchewan and Montana. The lines to British Columbia and Montana are synchronous and all three entities are part of Western Electricity Coordinating Council, commonly termed WECC. The connection to Saskatchewan is an AC-DC-AC connection since Saskatchewan is at the western edge of the Eastern Interconnection and Alberta is not connected synchronously with the Eastern Interconnection. These lines provide reliability benefits to all parties and also provide opportunities for commercial transactions. The MSA's interest is usually focused on the economic performance of the lines, including how imports and exports interact with Alberta's energy and ancillary service markets.

Figure 13 compares Alberta's pool price to those of the Minnesota Hub and Mid-C markets. Over the past few years, the wholesale market price of Alberta's electricity has generally been lower than prices in neighbouring markets. However, in part due to increases in Alberta's carbon price starting January 1, 2018, Alberta's Q1/18 pool price was higher than Mid-C for the first time since June 2017.

Figure 13: Flat Monthly Prices in Neighbouring Markets

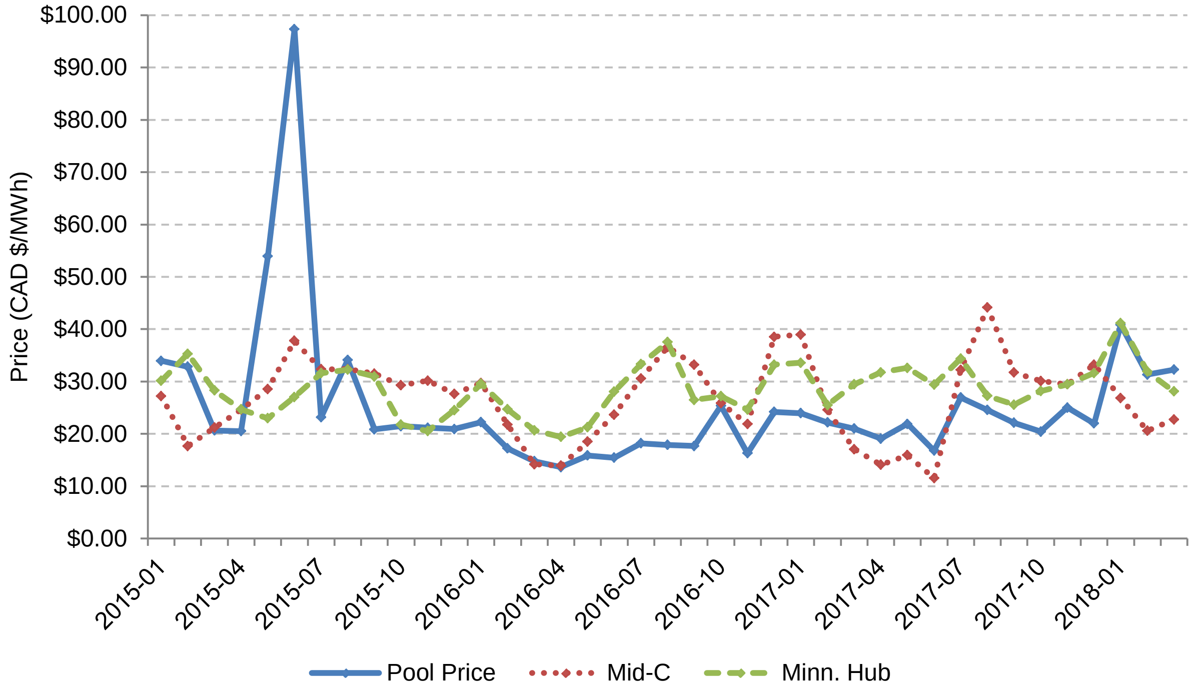


Figure 14 shows a scatterplot of the price differential and scheduled net flow between Alberta and Mid-C using the combined import/export capability on the BC and MATL lines. In efficient markets, energy should flow from regions of low prices to those of high prices. As a result of higher prices relative to Mid-C in Q1/18, Alberta saw an increase in imports from Mid-C during the quarter.

It can be seen in the expanded part of Figure 14 that the majority of the data points are in the upper-left and lower-right quadrants, consistent with the economics of flow. Further, it is apparent that in Q1/18 Alberta imported significantly whereas in Q4/17 the flow was more export-oriented.

Figure 14: Intertie Price Differential and Net Flow (BC/MT Intertie)

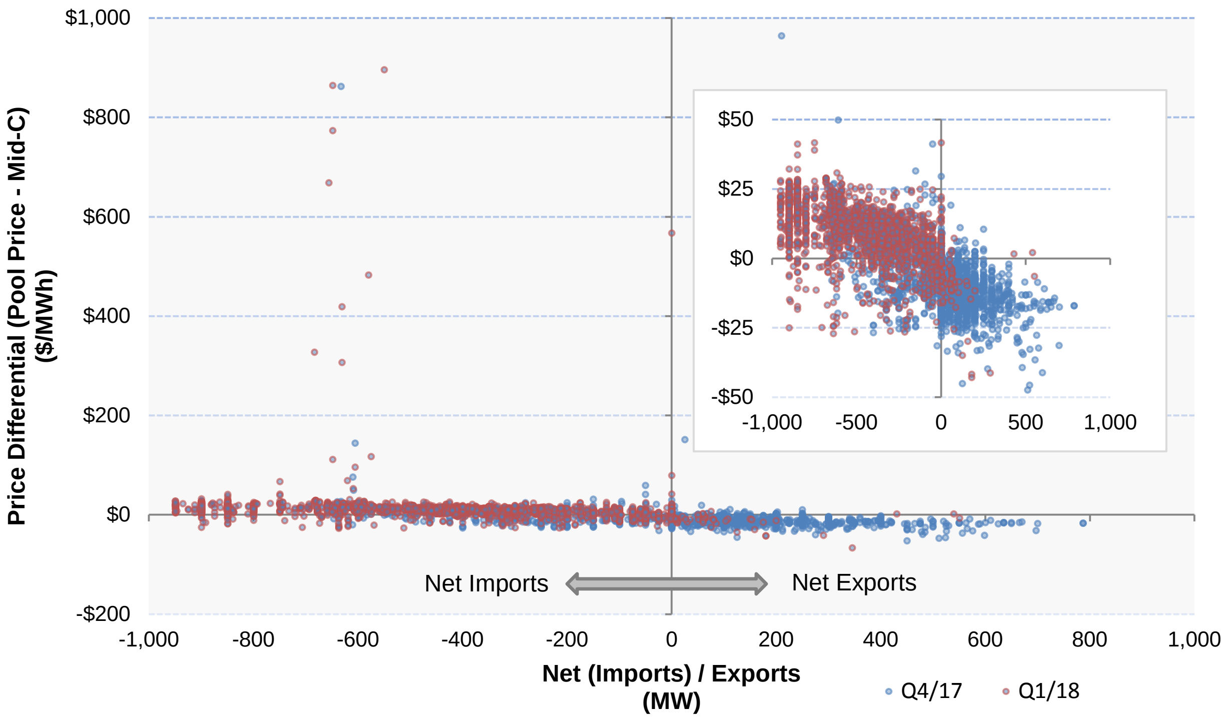
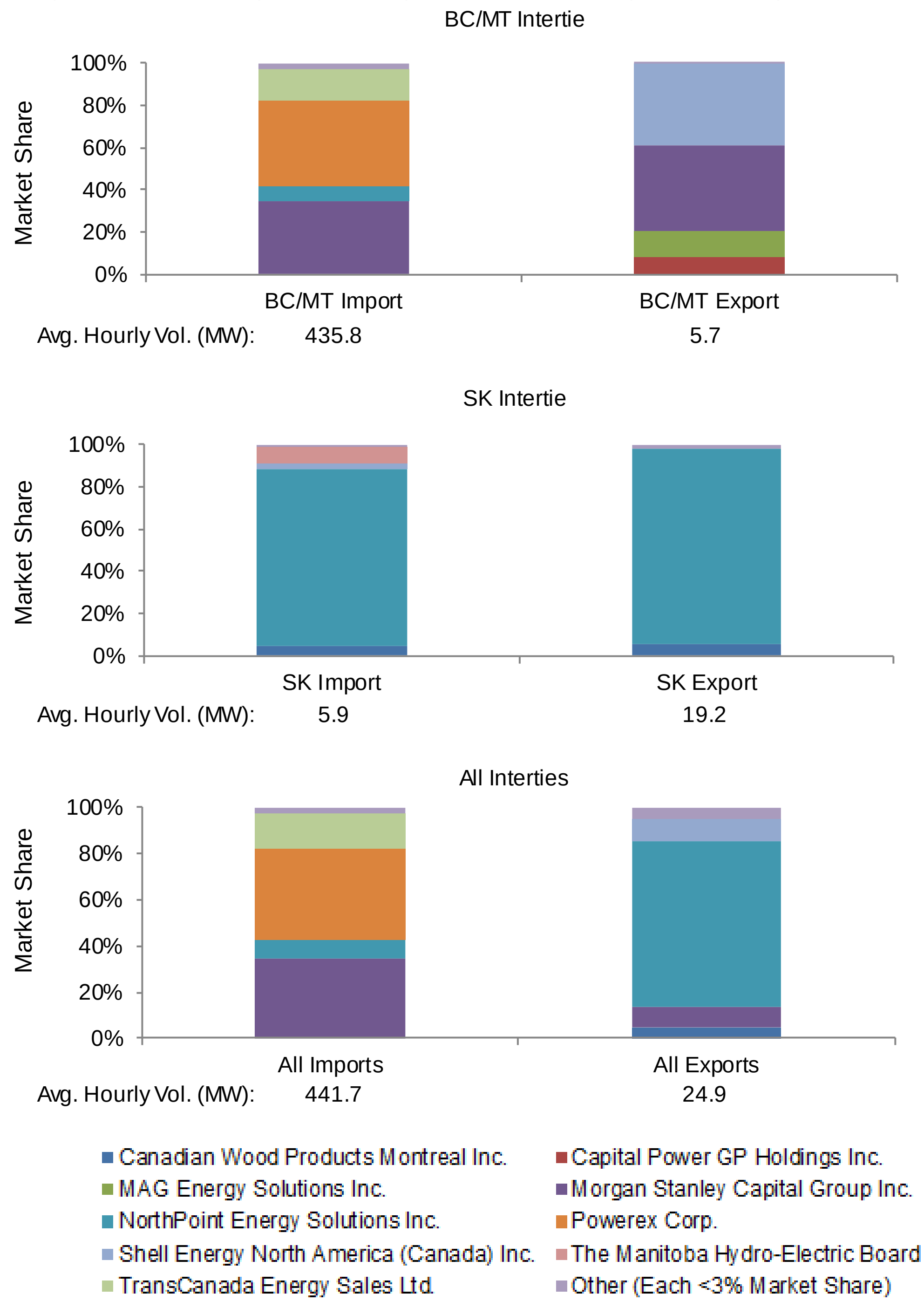


Figure 15 shows the quarterly volumes imports and exports on Alberta's interties as well as the market share by company. Imports averaged 442 MW per hour compared to exports of 25 MW per hour during Q1/18. Over 98 percent of imports to the province came from the BC and MATL interties while 77 percent of all exports went over the SK intertie.

For Alberta's western interconnect, the dominant firms were POWEREX and Morgan Stanley, both of whom own substantial firm transmission rights on the BC and MATL tielines, respectively. For Alberta's eastern interconnect NorthPoint Energy was the dominant player for both imports and exports on the SK tieline.

Figure 15: Intertie Market Shares (Q1/18)



5. Operating Reserves

Overall, the cost of operating reserves in Q1/18 was double that of Q1/17. The majority of the increase was in the cost of active reserves which are indexed to pool price. Most of the increase in active reserve can be attributed to the increase in pool price.

The volume of active contingency reserves procured was up 8.3% year-over-year due in part to increased load in Alberta and also in part to support increased import levels.

The volume of standby activations of contingency reserves rose by 140% and correspondingly the cost of these activations increased from $0.8 million to $6.0 million.

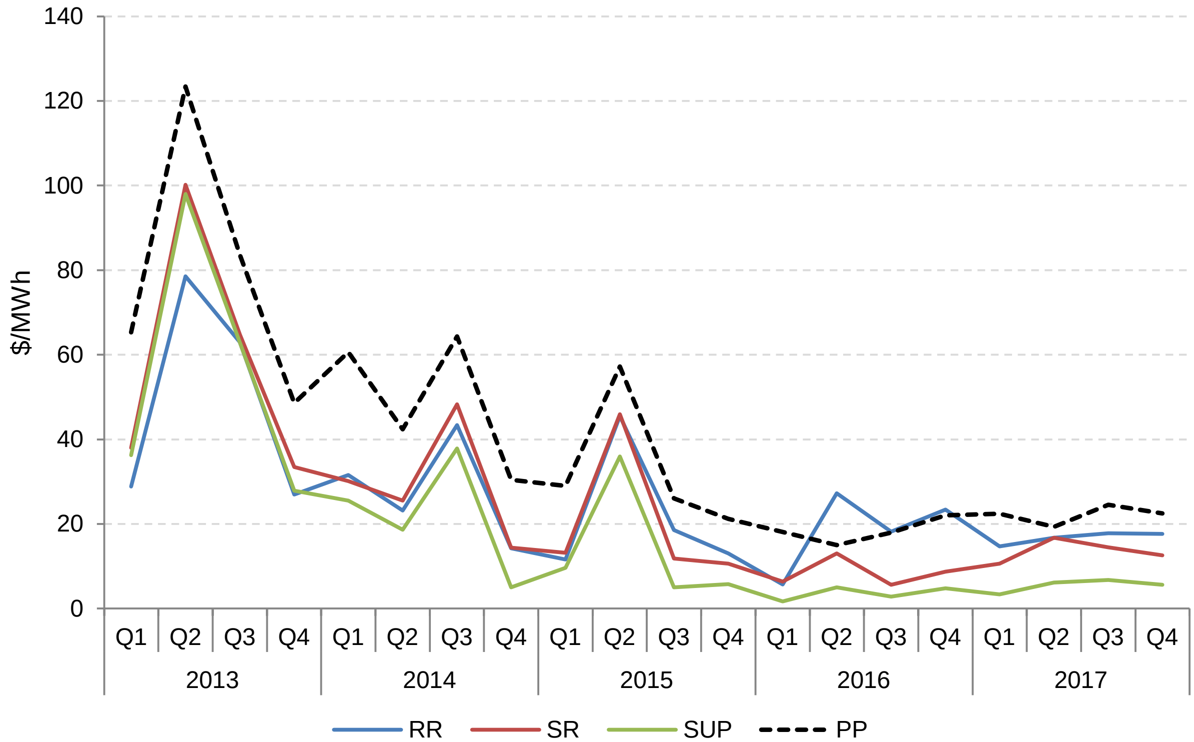
The average cost of activating standby contingency reserves in Q1/18 was $70/MWh which is double the average pool price for the quarter. This illustrates the effect of a weakness in the market design that some sellers continue to exploit on a frequent basis. The situation is further exacerbated on those occasions when the standby reserves are activated to support increased imports and some sellers need to exit the energy market. At such times, AESO is paying (generally) above pool price to contingency reserve providers who then must exit the energy market (where they were receiving pool price) to enable an equivalent volume of imports to flow that also receive pool price.

Table 6: Operating Reserve Summary

Total Cost ($ Millions)			
	Q1 2017	**Q1 2018**	***% Change***
Active Procured	**12.9**	**23.1**	***78.6***
RR	5.9	7.1	*20.8*
SR	5.3	10.0	*87.8*
SUP	1.8	6.0	*243.8*
Standby Procured	**1.4**	**1.9**	***39.1***
RR	0.6	0.7	*13.5*
SR	0.6	0.8	*35.6*
SUP	0.1	0.4	*174.6*
Standby Activated	**0.8**	**6.0**	***669.4***
RR	0.0	0.0	*-22.9*
SR	0.6	4.0	*563.3*
SUP	0.2	2.1	*1,265.1*
Total	**15.1**	**31.0**	***105.8***
Total Volume (GWh)			
	Q1 2017	**Q1 2018**	***% Change***
Active Procured	**1,355.5**	**1,439.0**	***6.2***
RR	351.8	352.0	*0.1*
SR	501.9	543.5	*8.3*
SUP	501.8	543.5	*8.3*
Standby Procured	**480.1**	**491.5**	***2.4***
RR	172.1	172.2	*0.1*
SR	230.2	233.9	*1.6*
SUP	77.9	85.4	*9.6*
Standby Activated	**36.6**	**86.2**	***135.8***
RR	1.1	0.6	*-43.1*
SR	23.9	58.9	*146.7*
SUP	11.6	26.7	*130.6*
Total	**1,872.2**	**2,016.8**	***7.7***
Average Cost ($/MWh)			
	Q1 2017	**Q1 2018**	***% Change***
Active Procured	**9.53**	**16.04**	***68.24***
RR	16.64	20.09	*20.72*
SR	10.59	18.36	*73.43*
SUP	3.49	11.08	*217.48*
Standby Procured	**2.86**	**3.89**	***35.88***
RR	3.72	4.22	*13.39*
SR	2.60	3.46	*33.43*
SUP	1.75	4.39	*150.60*
Standby Activated	**21.46**	**70.02**	***226.29***
RR	33.78	45.79	*35.53*
SR	24.98	67.18	*168.89*
SUP	12.99	76.87	*491.92*
Total	**8.05**	**15.38**	***91.01***

Looking at costs of active operating reserves over a longer period (see Figure 16) it can be seen that prior to 2016 the costs of operating reserves were a discount to pool price. In 2016 and 2017, the costs of regulating reserves have been much closer to average pool price. When pool prices are low, sellers of regulating reserves face the risk of generating at a pool price that is below their cost of production. This risk is factored into the selling price and off-peak regulating reserve often sells at a premium to pool price, rather than at a discount. The AM super-peak regulating reserve product is relatively specialized and routinely sells at a premium to pool price.

Figure 16: Operating Reserve Costs



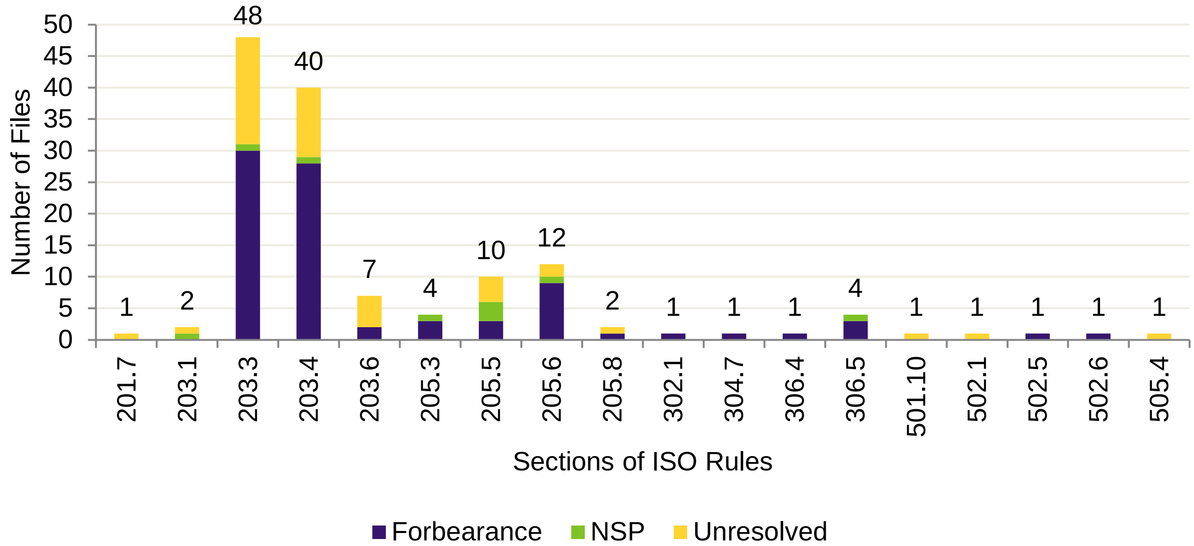
6. Compliance

Through enforcement of ISO rules and Alberta Reliability Standards the MSA contributes to the reliability and competitiveness of the Alberta electric system and promotes a culture of compliance and accountability among market participants.

6.1 ISO Rules

The purpose of ISO rules is to promote orderly and predictable actions on the part of market participants and to support the role of the AESO in coordinating those actions. From January 1 to March 31, 2018, the MSA addressed 93 ISO rules compliance matters, while 45 were carried forward to the next quarter. The MSA issued 9 notices of specified penalty, totalling $7,000 in financial penalties.

Figure 17: Overview of ISO Rules Matters Addressed During or Unresolved at the End of Q1/18



The sections of ISO rules listed in Figure 17 fall into the following categories:

201	General (Markets)
203	Energy Market
205	Ancillary Services Market
302	Transmission Constraint Management
304	Routine Operations
306	Outages and Disturbances
501	General (Facilities)
502	Technical Requirements
505	Legal Owners of Generating Facilities

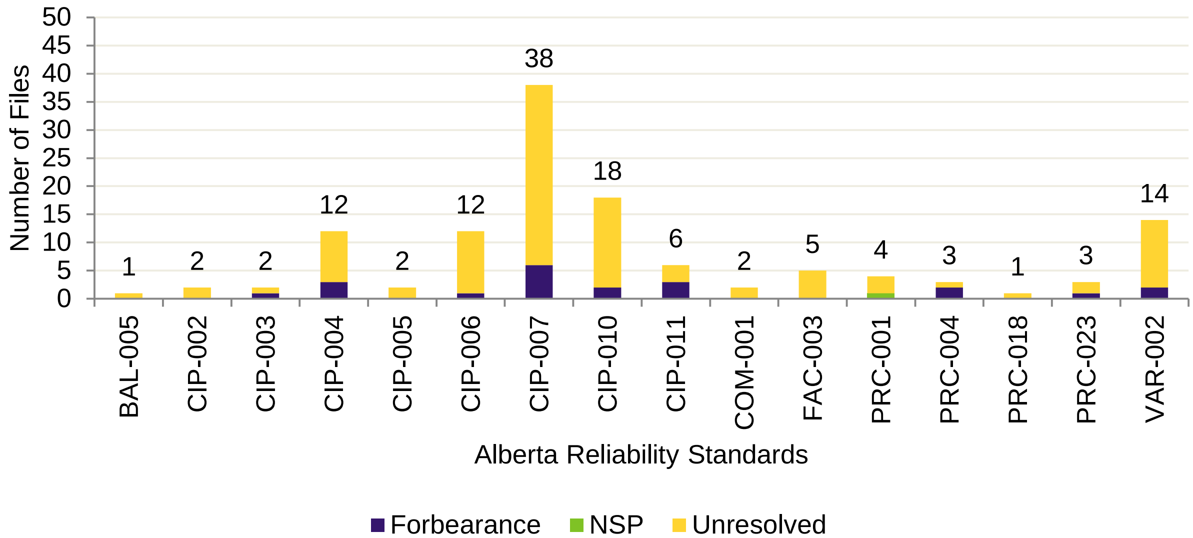
6.2 Alberta Reliability Standards

The purpose of Alberta Reliability Standards is to ensure the various entities involved in grid operations (e.g., generators, transmission operators and the AESO) are doing their part by way of procedures, communication, coordination, training, and maintenance, among other practices, to support the reliability of the interconnected electric system. For Alberta Reliability Standards, the MSA closed 22 matters since the start of 2018, while 103 remained unresolved. One notice of specified penalty was issued in 2017, but the matter was closed in 2018 after certification of completion of a mitigation plan was received.

6.3 MSA Complaint

On March 16, 2018, the MSA filed a complaint to the AUC concerning ISO Rule 306.7, *Mothball Outage Reporting*. This is known as the mothball rule and the MSA expressed some serious reservations about the rule as written. A total of 11 parties registered to the proceeding. On April 24th, the AESO and MSA co-hosted a meeting with the interveners to explore the possibility of a potential settlement outside of the proceeding. At the time of writing, the explorations are still in progress.

Figure 18: Overview of Alberta Reliability Standards Matters Addressed During or Unresolved at the End of Q1/18



The Alberta Reliability Standards listed in Figure 18 fall into the following categories:

BAL	Resource and Demand Balancing
CIP	Critical Infrastructure Protection
COM	Communications
FAC	Facilities Design, Connections and Maintenance
PRC	Protection and Control
VAR	Voltage and Reactive