MARKET SURVEILLANCE ADMINISTRATOR

Q4/18 Quarterly Report

October - December 2018

May 24, 2019

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

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1 Wholesale Market

1.1 Summary

The average pool price for Q4/18 settled at $55.52/MWh. This is a $33/MWh (147%) increase over the same period in 2017 and a slight increase ($0.90/MWh) over the average pool price observed during Q3/18. The average annual pool price for 2018 settled at $50.35/MWh which is a substantial increase over the pool prices observed in 2015, 2016 and 2017 (see Table 1). The increase in pool price observed during 2018 was largely the result of higher market demand, increasing carbon costs, changes in offer behaviour, and the retirement and mothballing of coal-fired generating units.

Table 1: Market Summary

		2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Pool Price (Avg $/MWh)	Q1	60.12	65.28	60.60	29.03	18.11	22.39	34.92
	Q2	40.03	123.41	42.43	57.22	15.00	19.29	56.01
	Q3	78.09	83.61	64.34	26.09	17.94	24.57	54.66
	Q4	78.71	48.59	30.47	21.19	22.03	22.46	55.52
	Year	**64.32**	**80.19**	**49.42**	**33.34**	**18.28**	**22.19**	**50.35**
Demand (AIL, GWh)	Q1	19,398	19,854	20,731	20,814	20,821	21,332	22,124
	Q2	17,663	18,168	18,681	18,829	17,972	19,273	20,052
	Q3	18,579	18,953	19,587	19,830	19,551	20,404	20,978
	Q4	19,934	20,475	20,951	20,784	21,216	21,563	22,176
	Year	**75,574**	**77,451**	**79,949**	**80,257**	**79,560**	**82,572**	**85,330**
Gas Price (Avg $/GJ)	Q1	2.06	3.03	5.30	2.62	1.74	2.55	1.96
	Q2	1.80	3.36	4.44	2.52	1.34	2.64	1.14
	Q3	2.16	2.32	3.81	2.75	2.21	1.37	1.18
	Q4	3.05	3.34	3.42	2.35	2.94	1.64	1.49
	Year	**2.27**	**3.01**	**4.24**	**2.56**	**2.06**	**2.05**	**1.44**
Wind (GWh)	Q1	824	970	834	1,285	1,367	1,170	1,154
	Q2	615	697	753	765	1,022	1,082	965
	Q3	432	477	682	822	825	779	674
	Q4	768	945	1,283	1,253	1,245	1,510	1,356
	Year	**2,640**	**3,088**	**3,551**	**4,125**	**4,459**	**4,541**	**4,149**
Total Net Exports (GWh)	Q1	-676	-675	-486	-411	-8	53	-902
	Q2	-1,162	-855	-642	-295	-97	-836	-1,664
	Q3	-866	-460	-276	98	538	370	-312
	Q4	-793	-299	-90	166	-1	141	214
	Year	**-3,497**	**-2,289**	**-1,494**	**-440**	**432**	**-273**	**-2,663**
Supply Cushion (Avg MW)	Q1	1,388	1,621	1,728	2,126	2,445	2,076	2,135
	Q2	1,769	1,276	2,066	1,931	2,339	2,439	1,845
	Q3	1,652	1,323	1,848	2,229	2,200	1,797	1,706
	Q4	1,407	1,643	1,816	2,379	2,098	2,002	1,463
	Year	**1,554**	**1,465**	**1,865**	**2,167**	**2,270**	**2,077**	**1,785**

Figure 1: Quarterly Pool Prices[1]

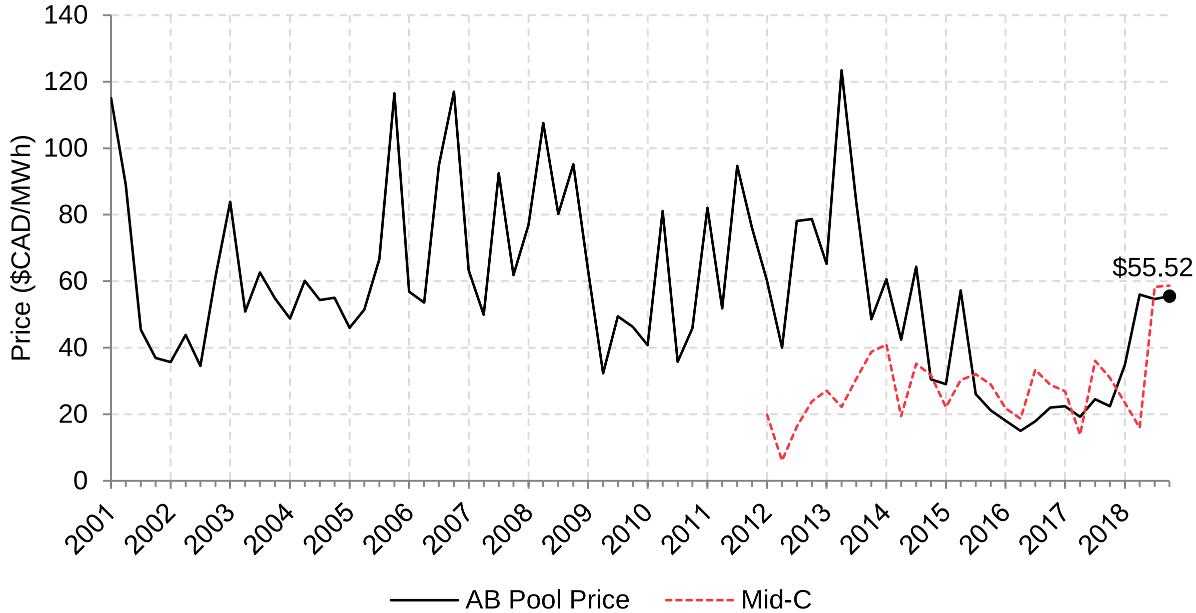
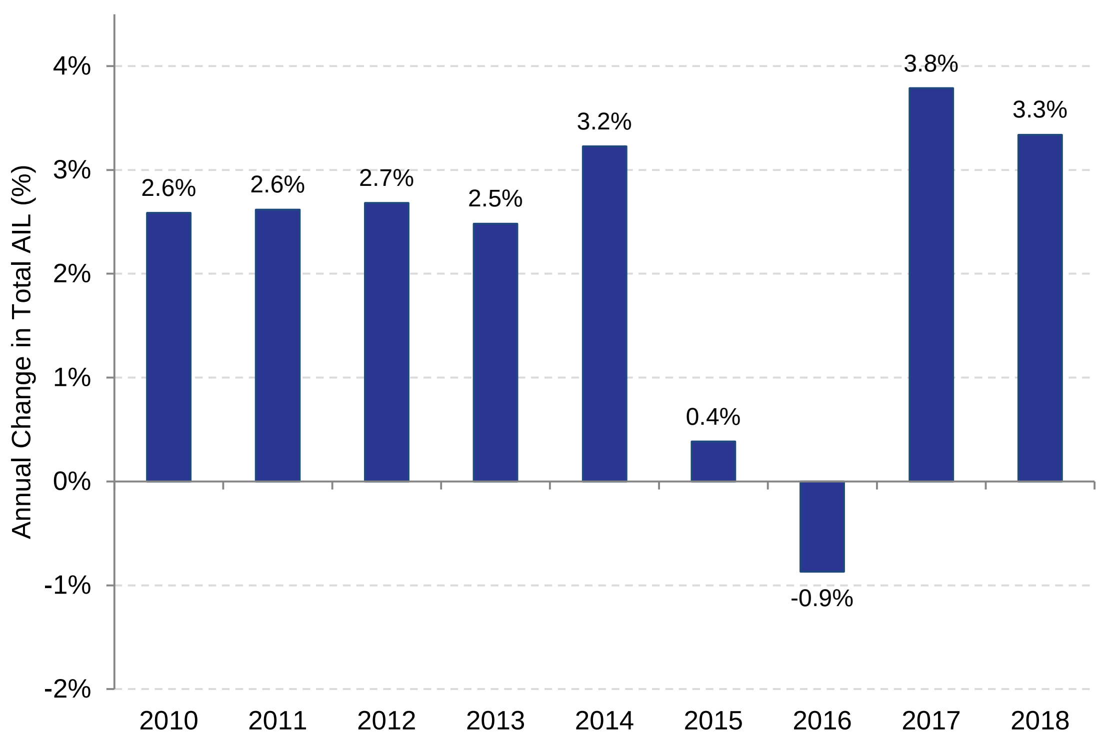


Figure 2: Annual Growth in Alberta's Total Internal Load (Year-over-year)



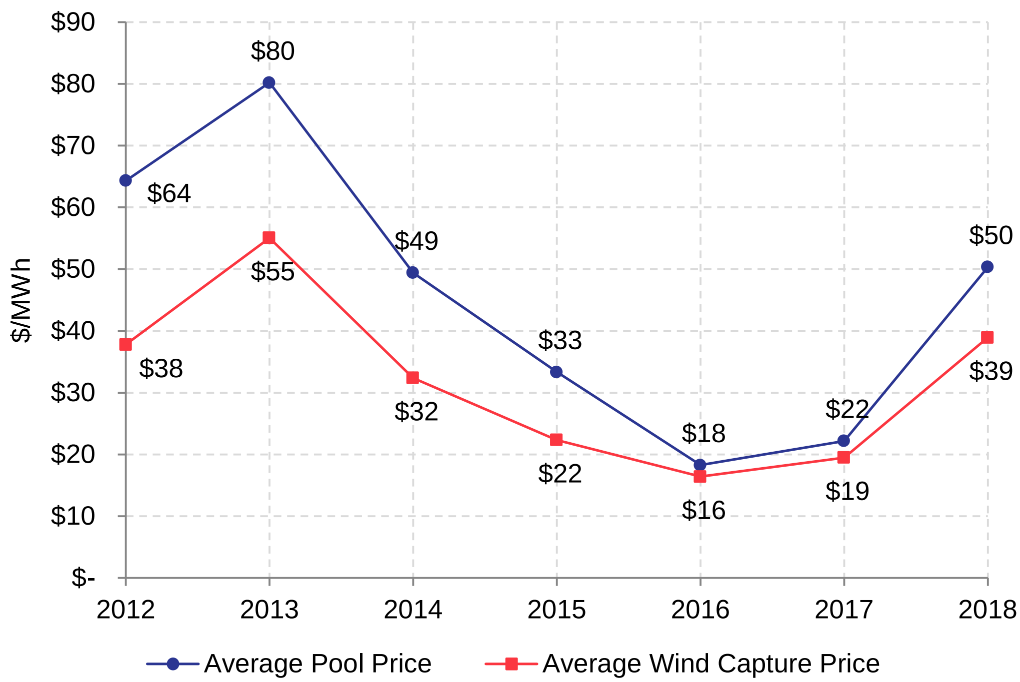
[1] The MSA is missing some Mid-C price data for September 2018.

As shown by Figure 2, Alberta's total internal load in 2018 increased by 3.3% over 2017. This is only down slightly from the 3.8% increase observed between 2016 and 2017. In 2016, we observed a decrease in total Alberta load as compared to 2015, the first time this has happened since 2009. It should be noted that the load observed in 2016 is potentially an outlier because of the Fort McMurray wildfires that were observed in the summer.

On the supply-side, we continue to see low prices in the natural gas markets. In 2018, the annual average of the daily same-day price was \$1.44/GJ, implying a fuel cost of approximately \$14/MWh for a simple cycle gas plant and approximately \$10/MWh for an efficient combined-cycle plant. The annual average of \$1.44/GJ is a decline of \$0.61/GJ (30%) year-over-year. The fall in gas prices in 2018, however, did not lead to lower electricity prices because the fall in gas prices has been more than offset by other changing market fundamentals.

Total wind generation in 2018 was 4,149 GWh (or 474 MWh per hour on average), which is 9% lower than wind output in 2017 and 7% lower than 2016. In 2018, wind generation received an average price of \$39/MWh or 77% of the average annual pool price. Figure 3 below shows how the wind capture price has evolved over time as compared to pool price. As shown, wind generation receives a discount to average pool price; this is because wind generators tend to be correlated with one another and high levels of wind generation tend to suppress pool prices. In addition, wind generation tends to be lower when temperatures in the province are extreme (either hot or cold) and load is higher.

Figure 3: Average Pool Price versus Average Wind Capture Price (\$/MWh)



1.2 Interconnections

Alberta has electrical connections (interties) to three jurisdictions: British Columbia (BC), Saskatchewan (SK), and Montana (MT). During 2018, Alberta saw significantly higher imports into the province compared to the prior three years. For 2018, Alberta had average hourly net imports of 304 MWh. This was primarily the result of higher wholesale prices in Alberta compared to the Pacific NW during the first half of the calendar year.

Figure 4 compares Alberta's pool price to those of the Minnesota Hub and Mid-C markets. From 2015-2017, the wholesale market price of Alberta's electricity has generally been lower than prices in neighbouring markets. However, due to tighter supply cushion levels, economic withholding, greater hydro runoff in the Pacific NW, and increases to Alberta's carbon price starting January 1, 2018, Alberta's pool price has mostly been higher than its neighbouring markets over the past year.

Figure 4: Monthly Prices in Neighbouring Markets (7 X 24)[2]

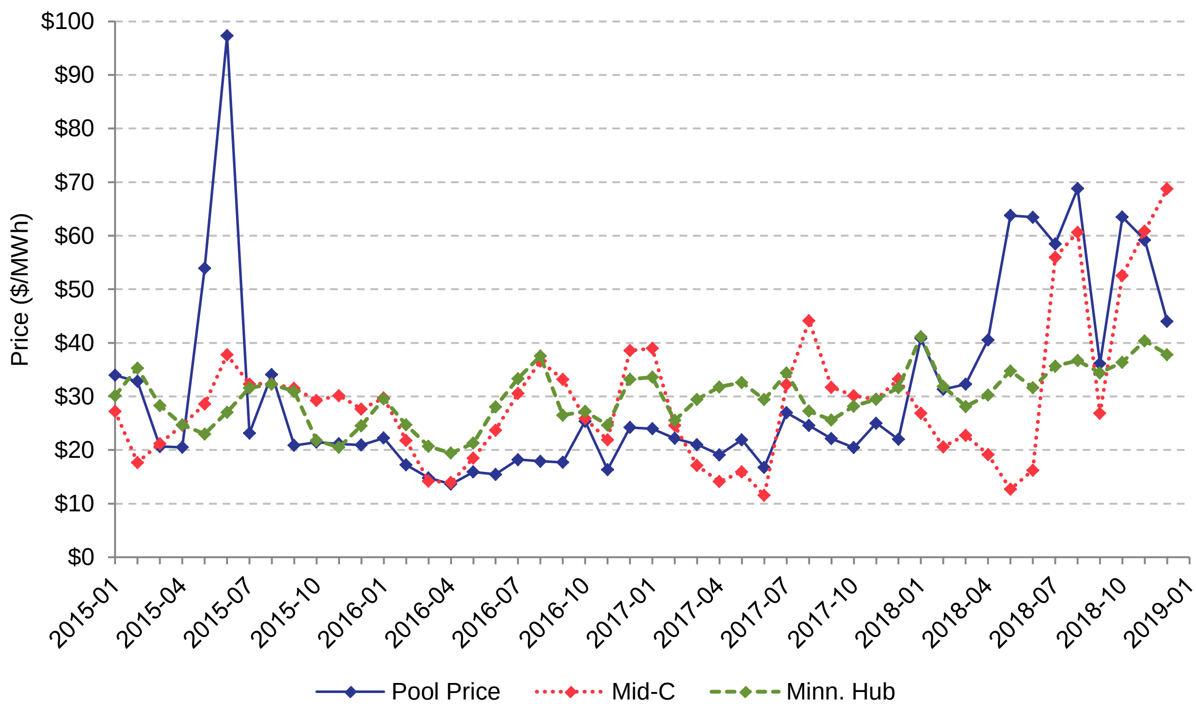
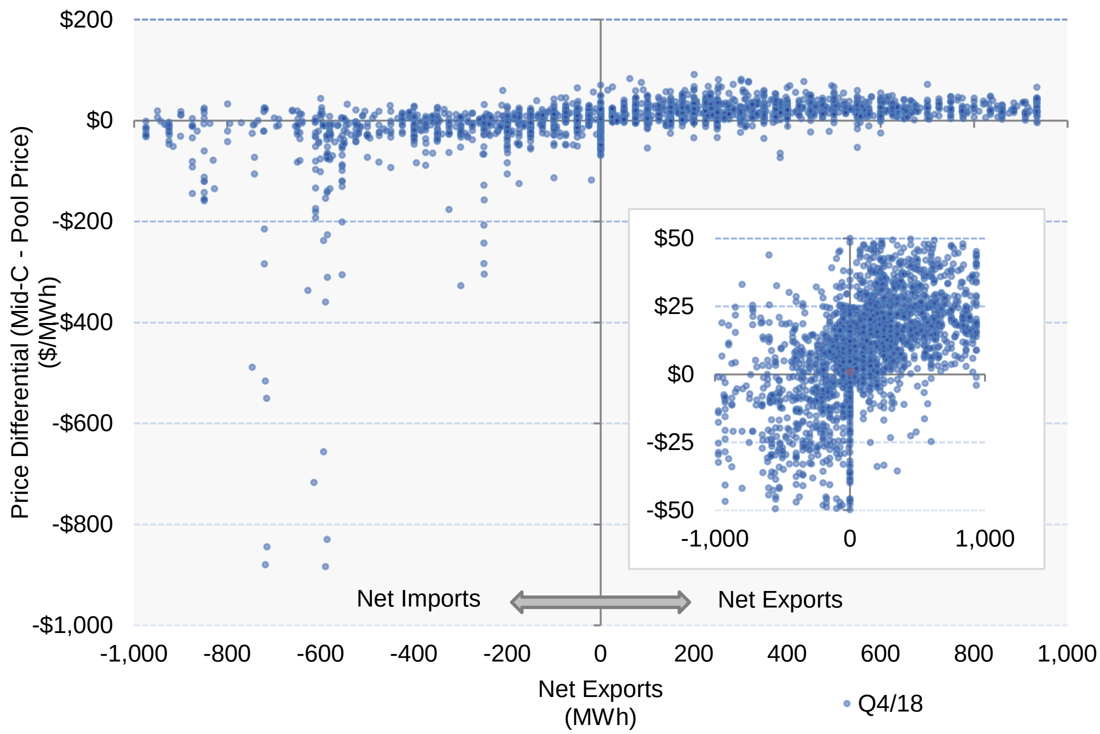


Figure 5 shows a scatterplot of the price differential and scheduled net flow between Alberta and Mid-C using the combined import/export capability on the BC and MT tielines. In efficient markets, energy should flow from regions of low prices to those of high prices. As a result of lower prices relative to Mid-C in Q4/18, Alberta saw net exports to Mid-C during the quarter, particularly overnight.

[2] The MSA is missing some Mid-C price data for September 2018.

It can be seen in the expanded portion of Figure 5 that the majority of the data points are in the lower-left and upper-right quadrants, consistent with the economics of flow. The MSA is continuing to examine the data points in the upper-left or lower-right quadrants. A simple differential between Mid-C and pool price suggests these represent uneconomic flow, but there are a number of reasons why such flows may not be of concern, including but not limited to flows being delivered to other regions, pool price uncertainty and that transactions may not have occurred at the average Mid-C price.

Figure 5: Intertie Price Differential and Net Flow (BC/MT Intertie)



During the first three quarters of 2018, Alberta was a net importer of electricity on the BC-MT tieline, while this trend reversed during the last quarter as Alberta became a net exporter.

Most of these exports occurred during the night, or during off-peak hours, when Mid-C prices were greater than pool prices in Alberta.[3] This would likely have resulted in higher off-peak pool prices within Alberta. Meanwhile during the day, or during on-peak hours, Alberta was a small net importer, which would likely have resulted in downward pressure on pool prices.. A plot of the quarterly intertie flows is illustrated in Figure 6.

It is noteworthy that since 2014, the net exports levels have largely been consistent with the direction and degree to which there has been a price differential between Alberta and Mid-C. This provides some check into the overall efficiency of tieline schedules and whether the collective behaviour of market participants is economic.

[3] “Off-peak” hours are defined as hour-endings 1-7 and 24, while “on-peak” is defined as hour-endings 8-23.

Figure 6: Intertie Flow, by On-Peak/Off-Peak period, based on Market Price Differential (BC/MT Intertie)

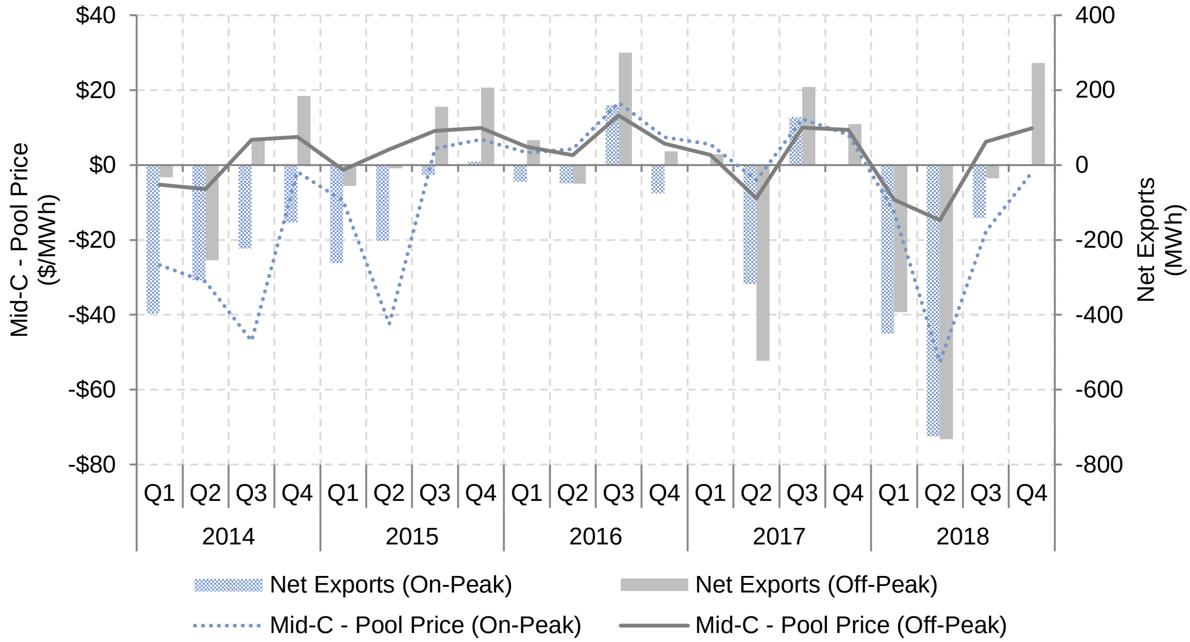
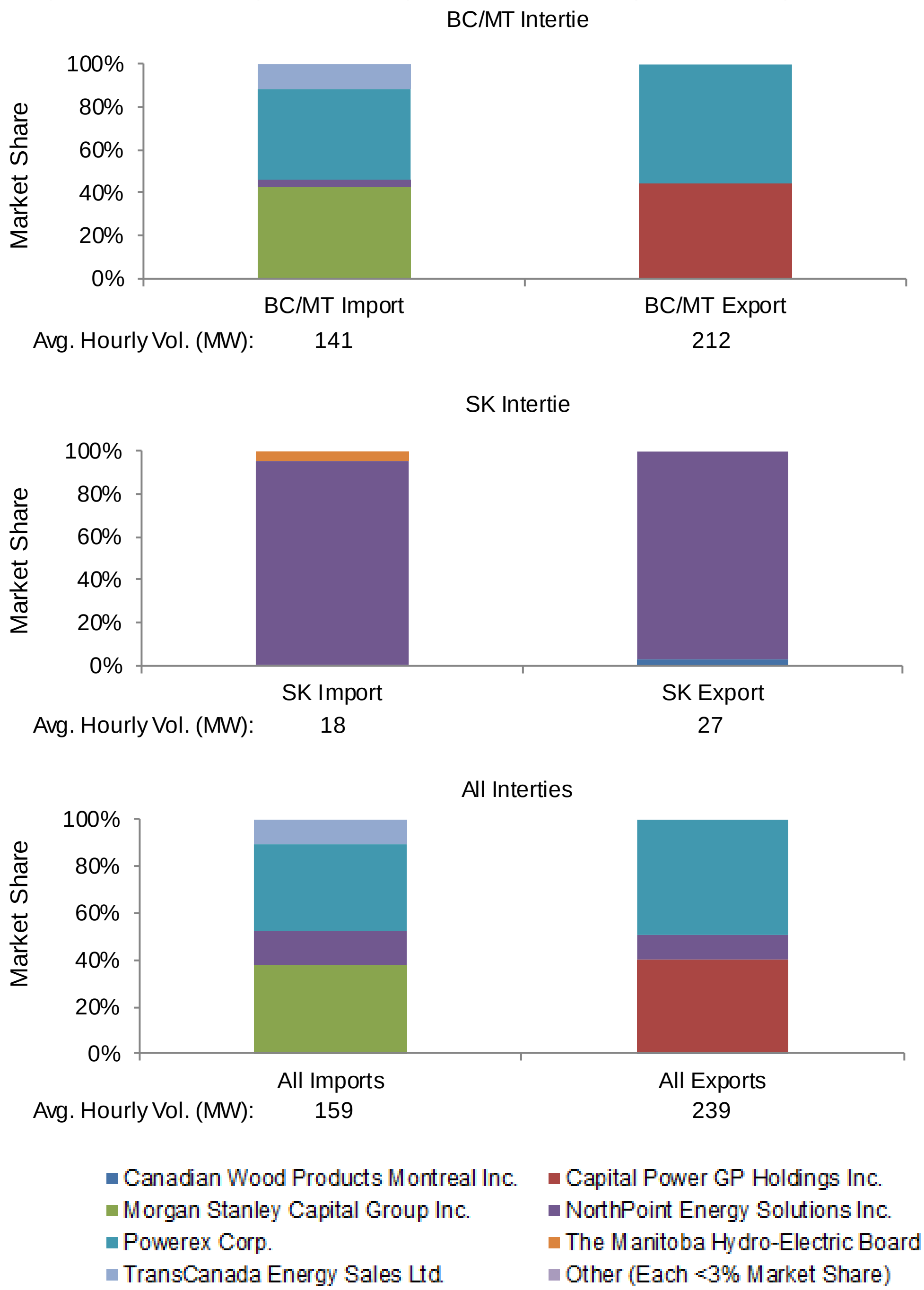


Figure 7 shows the quarterly volumes of imports and exports on Alberta's interties as well as the market share by company. Imports averaged 159 MW per hour compared to exports of 239 MW per hour during Q4/18. Approximately 89% of imports to the province came from the BC and MT interties while 89% of all exports went over the BC and MT interties.

For the western interconnect, the dominant firms were Powerex Corp., Morgan Stanley and Capital Group Inc. Both Powerex Corp. and Morgan Stanley own substantial firm transmission rights on the British Columbia and Montana interties, respectively. For Alberta's eastern interconnect NorthPoint Energy Solutions Inc. was the dominant player for both imports and exports on the Saskatchewan intertie.

Figure 7: Intertie Market Shares (Q4/18)

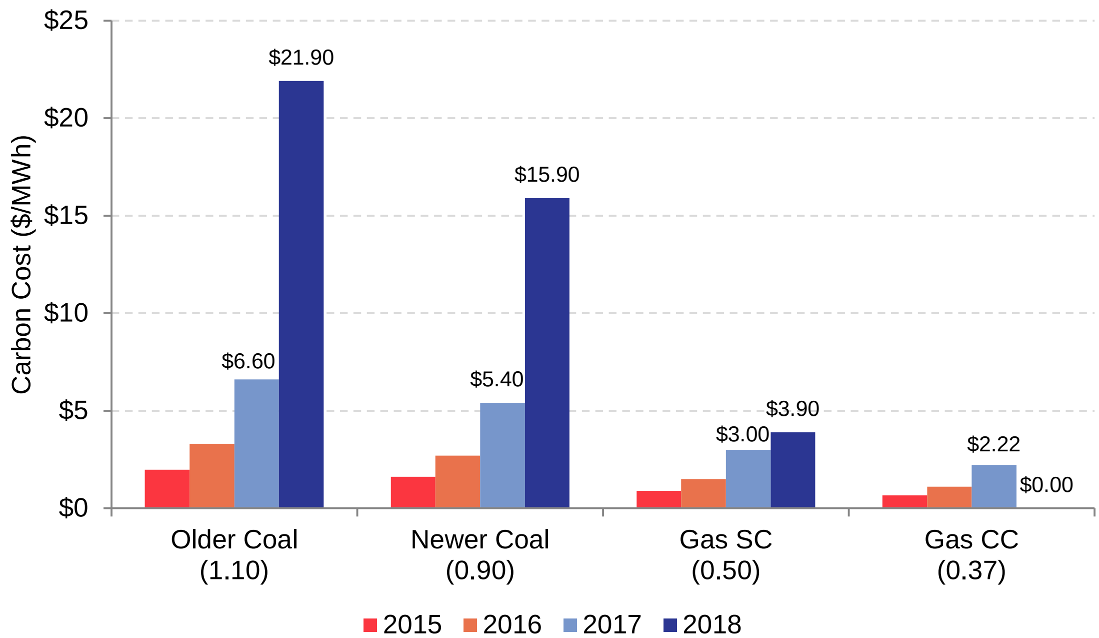


1.3 Alberta Carbon Price

Figure 8 shows the cost of carbon for various generating technologies from 2015 to 2018. As shown by the chart, 2018 saw a substantial increase in carbon costs for some generators as the province transitioned from the *Specified Gas Emitters Regulation* (SGER) to the *Carbon*

Competitiveness Incentive Regulation (CCIR). For example, an older coal unit with an assumed efficiency of 1.10 tCO2e/MWh saw an increase in its carbon cost from $6.60/MWh in 2017 to $21.90/MWh in 2018; an increase of 232%. The impact of the new regulations has been more muted on natural gas facilities. For example, an efficient simple cycle unit with an efficiency of 0.50 tCO2e/MWh saw a carbon cost increase from $3.00/MWh in 2017 to $3.90/MWh in 2018; an increase of 30%.

Figure 8: The Cost of Carbon for Electricity Generators of Various Efficiencies (tCO2e/MWh)



1.4 Retirements, Mothballing and Offer Changes

On December 31, 2017, the term of the Sundance A PPA ended. As a result, the offer control for the Sundance 1 and 2 units went back to the PPA Owner, TransAlta. TransAlta subsequently retired Sundance 1 (280 MW) on January 1, 2018.[4] Sundance 2 (280 MW) was mothballed on January 1, 2018 and was subsequently retired on July 31, 2018.[5]

In September 2017, the Balancing Pool elected to terminate the Sundance B and C PPAs with the offer control for these units (1,431 MW) reverting back to TransAlta on April 1, 2018.[6] On April 1, 2018 TransAlta mothballed Sundance 3 (368 MW) for a period of up to two years and Sundance 5 (406 MW) for a period of up to one year.[7]

[4] TransAlta Board Approves Plan for Accelerating Transition to Clean Power in Alberta April 19, 2017
[5] TransAlta Announced Retirement of Sundance Unit 2 July 18, 2018
[6] Balancing Pool to Terminate Sundance B and C PPAs September 18, 2017
[7] TransAlta Announces Accelerated Transition to Clean Energy December 6, 2017

In March 2018, the Balancing Pool elected to terminate the Battle River 5 PPA with offer control (368MW) reverting back to the PPA Owner, ATCO Power, on October 1, 2018.[8]

Between January 1 and April 1, 2018, we observed a total of 1,334 MW of coal-fired capacity being taken offline, either through retirements or mothballing. In combination with the increased demand this led to a tighter market and lower supply cushion. As shown in Figure 9 the monthly average supply cushion trended downwards for much of 2018, indicating a tighter market and implying upward pressure on pool prices.

Figure 9: Evolution of Supply Cushion

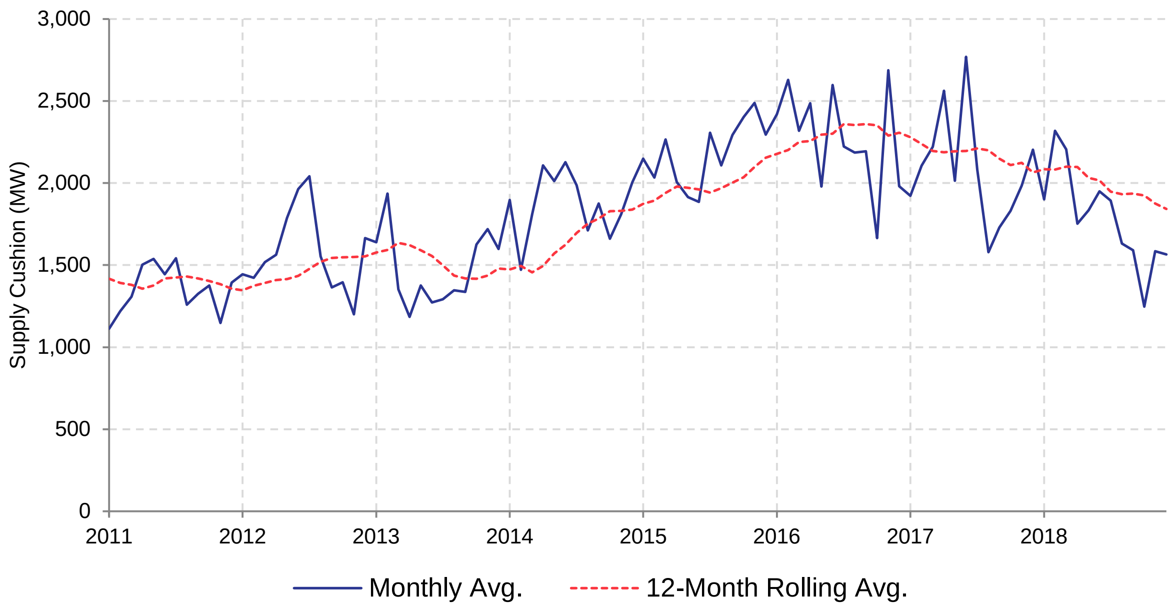
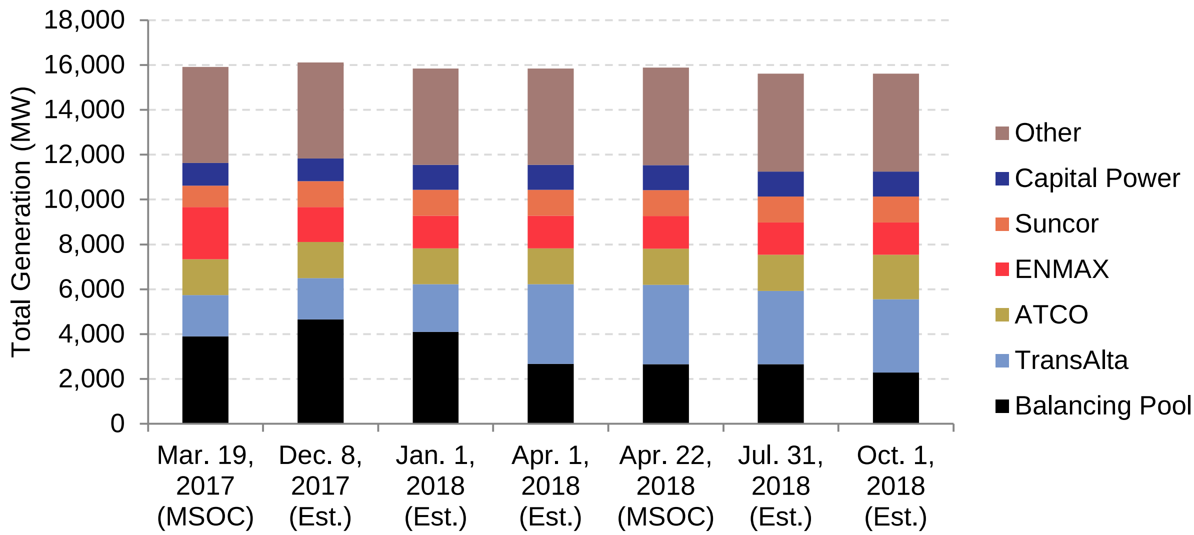


Figure 10 shows the evolution of offer control over 2017-2018, based on the MSA's annual Market Share Offer Control (MSOC) reports. The chart includes market participants who hold five percent MSOC or more during a given calendar year. The MSA intends to update its annual assessment of MSOC in the first half of 2019.

[8] Balancing Pool to Terminate Battle River 5 PPA March 21, 2018

Figure 10: Market Share Offer Control (2017-2018)



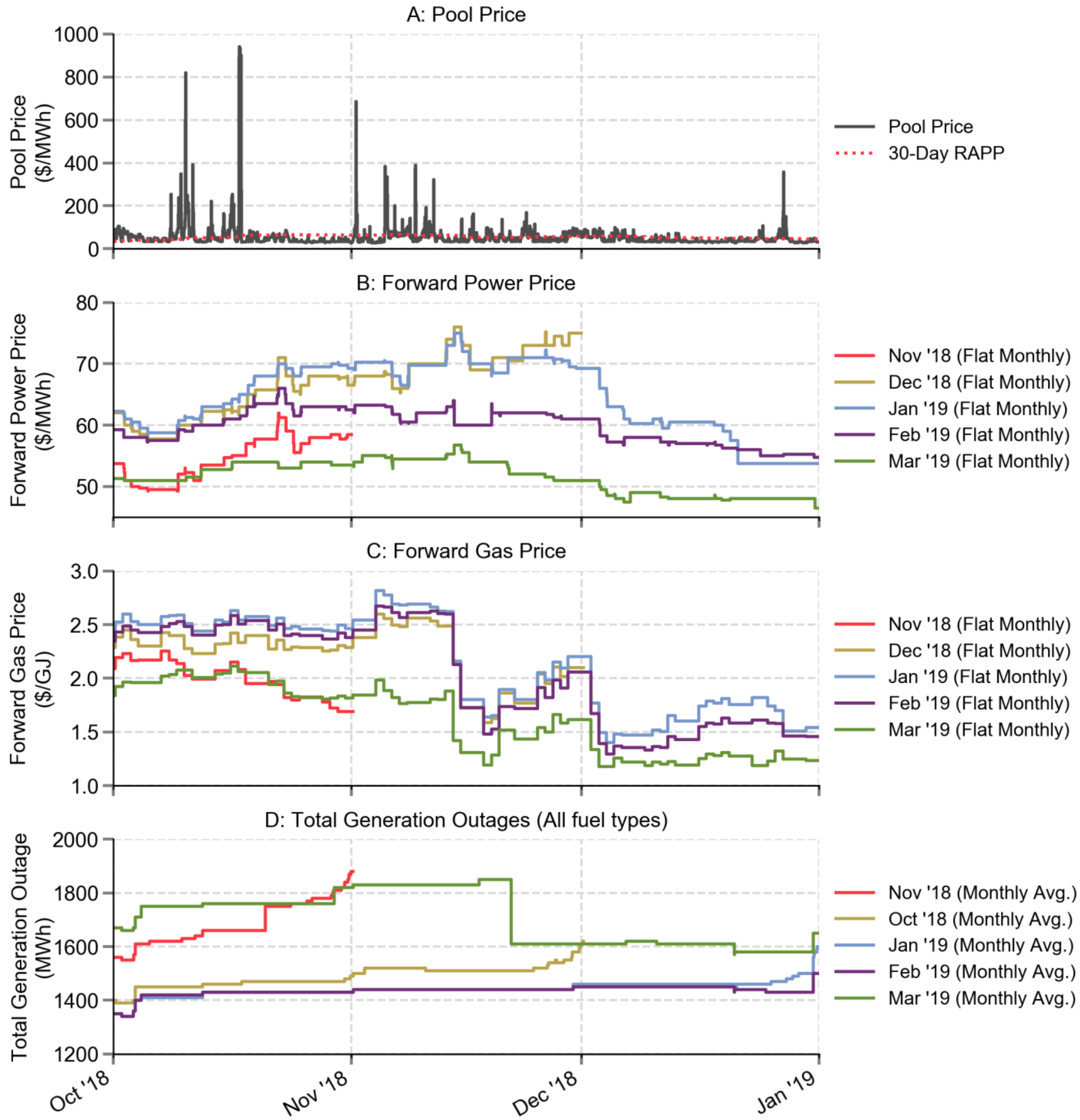
2 Forward Market

2.1 Forward Prices

Figure 11 shows the evolution of flat-monthly forward power prices in relation to several factors which often influence market prices. Overall, monthly prices increased in October, but moved down through the beginning of December.

During the first week of December, the price of January, February, and March flat-monthly contracts decreased. This may be partially attributed to a drop in forward natural gas prices for the same months, also occurring at the beginning of December.

Figure 11: Evolution of Forward Contract Prices



2.2 Trade Volumes

Trade volumes in Q4/18 were close to the historical average level of the past 5 years.. Trade volumes of monthly, quarterly, and annual contracts increased, recovering from a sharp decline in Q3/18 with overall volumes up 80% from Q3/18 but 34% lower than Q4/17.

Total trade volumes fell by 29% in 2018 from the previous three year average, 2015-2017. Most of the declines occurred in the monthly and annual term contract volumes.

Table 2: Trade Volumes by Trade Date (TWh)[9]

		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
	Q2	0.16	6.06	1.20	5.75	0.32	13.49
	Q3	0.10	4.59	0.22	3.60	0.53	9.04
	Q4	0.10	6.54	2.33	6.88	0.43	16.28
	Year	0.52	24.46	4.35	20.71	1.70	51.72

Table 3 provides a summary of forward market liquidity by the time to maturity for flat annual contracts. The table includes flat annual trades that cleared on NGX. As expected, the market is typically most liquid in the year prior to delivery and is generally less liquid the further back in time you go.

Prices and volumes in Table 3 are current as of December 31, 2018. Cumulative volumes show the total traded volumes (MW) that were traded prior to a particular date. For example, for the 2022 contract there were 55 MW of traded volumes prior to 3 years out (January 1, 2019); this includes the 10 MW which was traded prior to 4 years out (January 1, 2018).

[9] Excludes all NGX transactions after 3:00 PM for a given calendar day.

Table 3: Forward Market Liquidity by Time to Maturity (Flat Annual Contracts, NGX-cleared only)[10]

	4 years out		3 years out		2 years out		1 year out		Final Trade	
Calendar Contract	**Price ($/MWh)**	**Cum. Vol. (MW)**	**Price ($/MWh)**	**Cum. Vol. (MW)**	**Price ($/MWh)**	**Cum. Vol. (MW)**	**Price ($/MWh)**	**Cum. Vol. (MW)**	**Price ($/MWh)**	**Cum. Vol. (MW)**
2013	-	0	$57.00	120	$53.02	150	$72.25	300	$59.50	535
2014	-	0	-	0	$63.00	15	$51.00	410	$53.50	752
2015	-	0	$66.00	50	$47.50	265	$48.50	590	$49.00	1,359
2016	-	0	$52.00	70	$52.25	215	$48.50	463	$34.50	1,414
2017	$53.50	30	$52.50	100	$52.00	173	$40.00	1,031	$31.40	1,836
2018	$57.50	23	$52.00	78	$51.00	513	$39.00	1,133	$52.50	2,263
2019	$58.75	15	$56.00	195	$41.00	465	$53.25	1,525	$54.75	2,351
2020	$58.00	60	$45.00	190	$46.50	785	$47.50	1,660	-	-
2021	$58.00	85	$43.50	110	$45.00	340	-	-	-	-
2022	$50.00	10	$43.50	55	-	-	-	-	-	-
2023	$45.00	20	-	-	-	-	-	-	-	-

2.3 Forward Price Curves

The forward price curve for monthly contracts is provided in Figure 12 while annual contracts are provided in Figure 13. The prices shown in each figure are for a flat (7x24) contract term.

As of late January, with the exception of July 2019, monthly forward contract prices largely hover around the $50/MWh until October 2019. There are currently no trades for August 2019. Annual forward contract prices, meanwhile, hover around $45/MWh until 2024, at which point prices increase to $62.50/MWh.

It should be noted that there is generally low liquidity outside the prompt calendar year.

[10] Excludes all transactions after 3:00 PM for a given calendar day.

Figure 12: Forward Price Curve for Monthly Contracts (7x24, January 18, 2019)

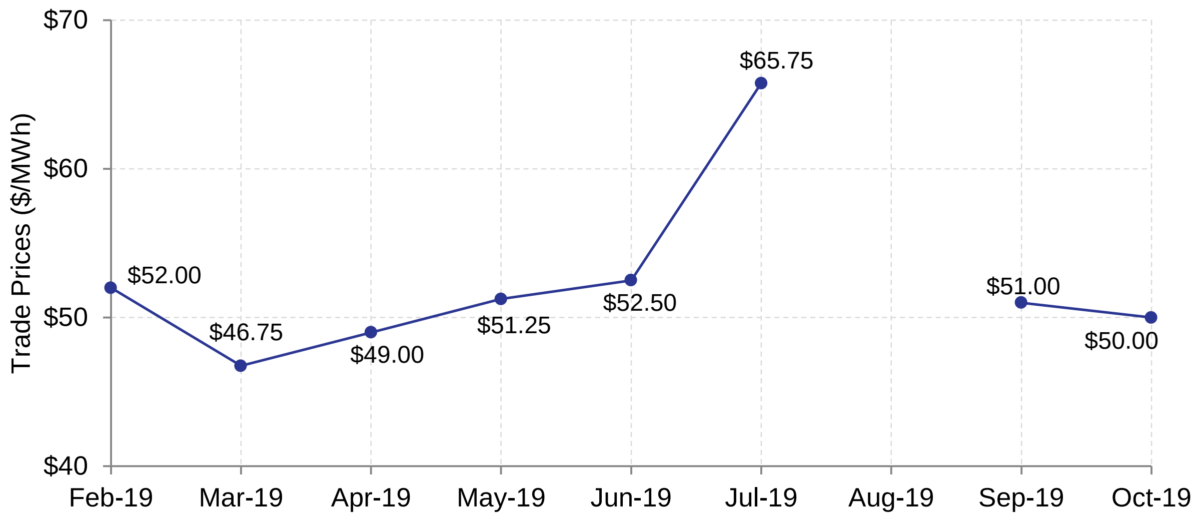


Figure 13: Forward Price Curve for Annual Contracts (7x24, January 18, 2019)

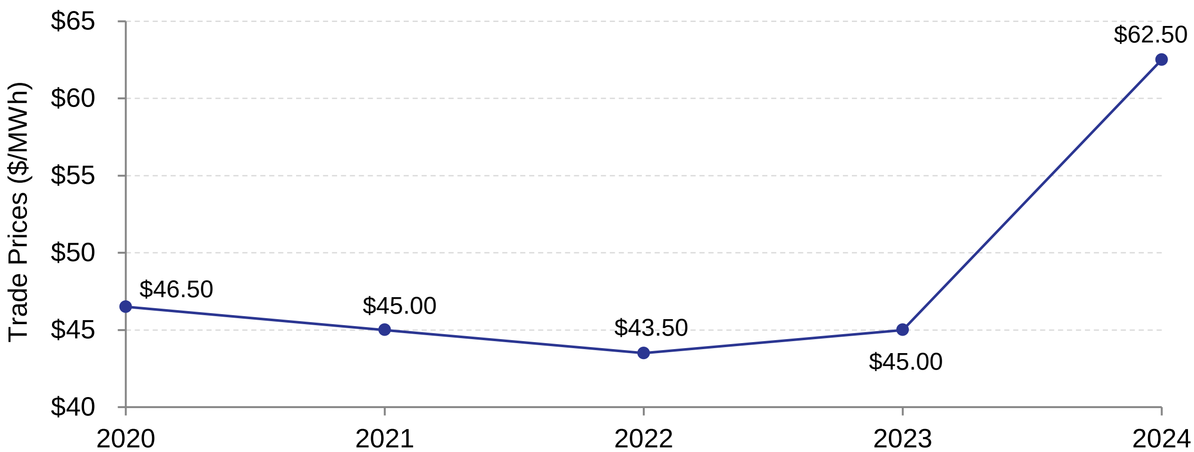
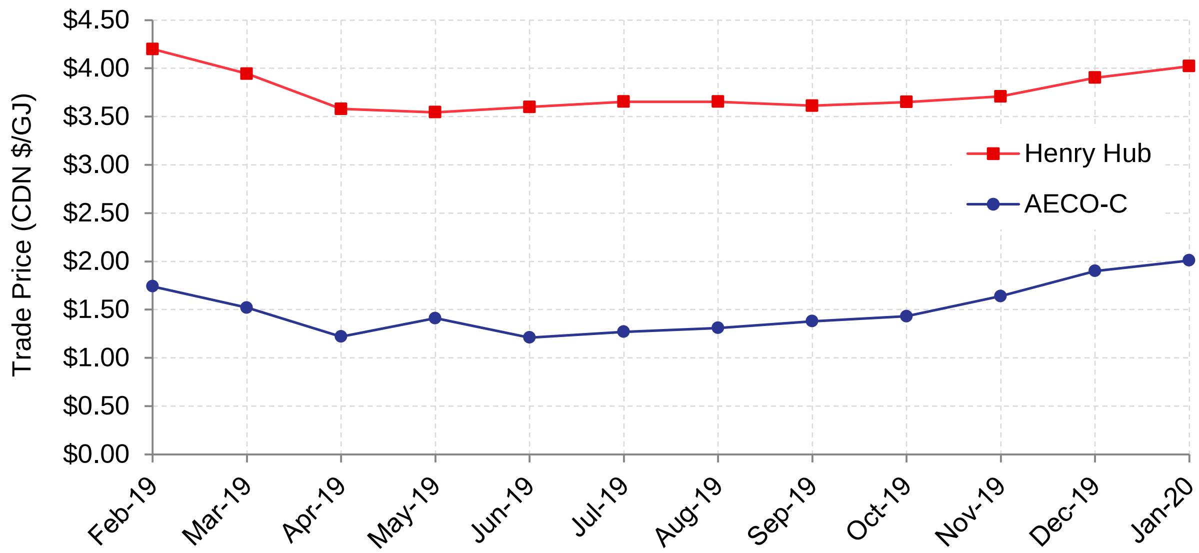


Figure 14 shows the forward curve for natural gas at the AECO-C Hub in Alberta, as well as at the Henry Hub in Louisiana, as of January 18th, 2019. The price of natural gas in Alberta for February 2019 was trading below $1.75/GJ. Forward prices decrease to below $1.50/GJ and remain low until autumn. As shown, prices for April 2019 onward are significantly lower than the forward prices over the next few months. Comparatively, AECO-C is trading at an approximate average discount of $1.50/GJ to Henry Hub for calendar year 2019. This is primarily due to high supply relative to demand within Alberta, pipeline constraints which limit the amount of natural gas that can be exported from the province, and the cost of pipeline transport to other markets. This results in inexpensive natural gas for Alberta consumers, but reduced income for Alberta's natural gas producers and the provincial government.

Figure 14: Forward Curve for Natural Gas, AECO-C Hub and Henry Hub (January 18, 2019)



3 Ancillary Services

3.1 Operating Reserves

Total operating reserves costs were $239.8 million in 2018. This is 5% of the costs of the energy market. It reflects a 196% increase in the cost of operating reserves compared to 2017. Most of this increase was due to increases in costs in the active operating reserves markets. Since the cost of active operating reserves is indexed to pool price, higher pool prices seen over the year was a contributor to higher costs in the active operating reserves markets. Pool price and active operating reserves costs have a positive correlation as shown in Figure 15. Comparing total active operating reserves costs and average pool price in Figure 15 suggests that the increase in active operating reserves costs is similar to cost increases observed in previous years at similar pool price levels. The volume of active operating reserves procured did not materially change from year-to-year.

Figure 15: Total Active Operating Reserves Cost Compared to Average Pool Price

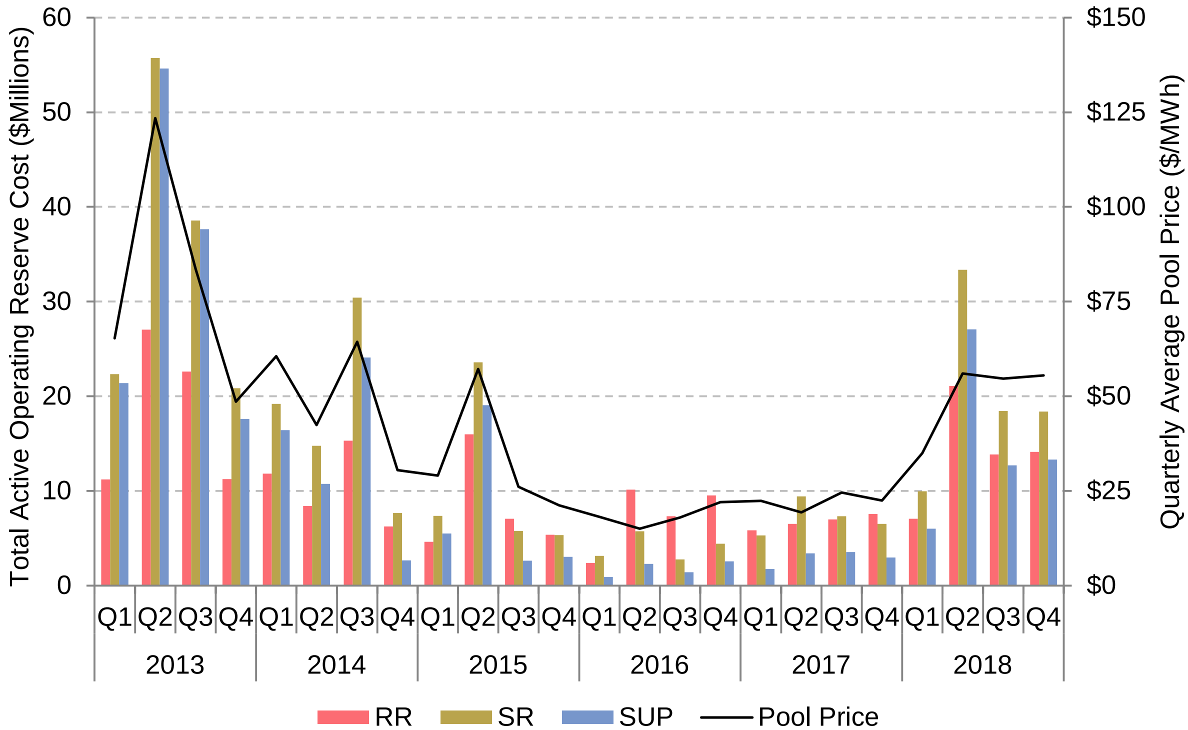


Table 4: Operating Reserve Summary

	Total Cost ($ Millions)					
	2013	**2014**	**2015**	**2016**	**2017**	**2018**
Active Procured	**340.8**	**167.8**	**105.2**	**52.6**	**67.2**	**195.4**
RR	72.1	41.8	33.0	29.4	26.9	56.1
SR	137.5	72.0	42.0	16.1	28.6	80.2
SUP	131.3	54.0	30.2	7.2	11.7	59.1
Standby Procured	**18.8**	**13.8**	**13.0**	**12.1**	**7.6**	**8.1**
RR	6.4	4.4	4.6	7.8	3.1	5.8
SR	9.2	7.1	6.5	3.5	3.6	1.8
SUP	3.2	2.2	1.9	0.8	0.9	0.5
Standby Activated	**9.7**	**3.0**	**20.1**	**2.0**	**6.3**	**36.4**
RR	3.0	0.8	0.4	0.3	0.2	0.4
SR	5.7	1.7	13.3	1.3	4.2	26.5
SUP	1.1	0.5	6.4	0.4	1.8	9.5
Total	**369.3**	**184.5**	**138.3**	**66.7**	**81.0**	**239.8**

	Total Volume (GWh)					
	2013	**2014**	**2015**	**2016**	**2017**	**2018**
Active Procured	**6,019.2**	**6,005.9**	**5,333.3**	**5,262.0**	**5,449.2**	**5,802.4**
RR	1,400.8	1,400.0	1,399.4	1,405.6	1,405.3	1,404.5
SR	2,310.2	2,303.3	1,967.1	1,927.8	2,022.0	2,200.4
SUP	2,308.2	2,302.6	1,966.7	1,928.6	2,022.0	2,197.5
Standby Procured	**2,144.5**	**2,142.4**	**2,140.3**	**2,048.6**	**2,058.2**	**1,971.3**
RR	871.5	871.0	873.0	823.1	697.8	698.3
SR	915.1	916.0	938.7	918.3	985.2	941.7
SUP	357.9	355.4	328.6	307.2	375.1	331.3
Standby Activated	**76.8**	**64.8**	**135.7**	**85.1**	**236.0**	**343.5**
RR	12.9	9.0	7.6	7.9	5.9	7.3
SR	50.2	39.3	86.2	54.1	141.4	230.8
SUP	13.8	16.5	41.9	23.2	88.7	105.4
Total	**8,240.5**	**8,213.2**	**7,609.3**	**7,395.8**	**7,743.4**	**8,117.3**
	Average Cost ($/MWh)					
	2013	**2014**	**2015**	**2016**	**2017**	**2018**
Active Procured	**56.62**	**27.93**	**19.73**	**10.00**	**12.32**	**33.67**
RR	51.46	29.85	23.58	20.90	19.13	39.95
SR	59.50	31.27	21.37	8.34	14.14	36.44
SUP	56.87	23.43	15.36	3.73	5.78	26.89
Standby Procured	**8.76**	**6.42**	**6.07**	**5.89**	**3.69**	**4.09**
RR	7.35	5.08	5.25	9.49	4.43	8.24
SR	10.04	7.78	6.93	3.83	3.66	1.90
SUP	8.93	6.22	5.77	2.44	2.39	1.57
Standby Activated	**126.50**	**46.49**	**148.03**	**23.71**	**26.58**	**105.85**
RR	230.71	86.63	54.39	36.89	33.74	60.43
SR	113.51	43.42	154.29	24.16	29.95	114.66
SUP	76.50	31.97	152.20	18.21	20.71	89.70
Total	**44.82**	**22.47**	**18.18**	**9.02**	**10.46**	**29.54**

The cost of procuring standby operating reserves at $44.5 million in 2018 is the highest in the past six years. There was a marked increase in the cost of activating standby reserves while the cost of procuring standby reserves remained moderate and even decreased with respect to standby contingency reserves. This is driven by increases in both volume of standby contingency reserves activated to enable imports and higher activation prices offered by market participants in anticipation of being activated to provide contingency reserves. The cost of procuring standby contingency reserves decreased in part because, in order to remain competitive in the market while offering a higher activation price, a market participant must decrease the premium price offered to provide standby contingency reserves. When a seller believes that the chances of being activated the next day are high, much higher than the 10% long term average, $1/MWh of premium price can be converted to $10/MWh of activation price for the same combined price used to compete in the market.

To illustrate this observation, Figure 16 and Figure 17 show the average on- and off-peak activation prices and pool prices for each month in 2018. In the on-peak period from April to August and in the off-peak period from April to June, the average activation prices for spinning and supplemental reserves were much higher than the average pool price for the month. When activating standby operating reserves, the opportunity cost of activation is the pool price a provider would have received in the energy market instead of providing operating reserves. Given that the operating reserves market clears day-ahead, it is not expected that pool prices and activation prices will be equal. However, where activation prices diverge significantly from pool price market participants are likely seeing higher returns from providing standby operating reserves than energy.

Figure 16: Average On-Peak Pool Price and Activation Price in 2018

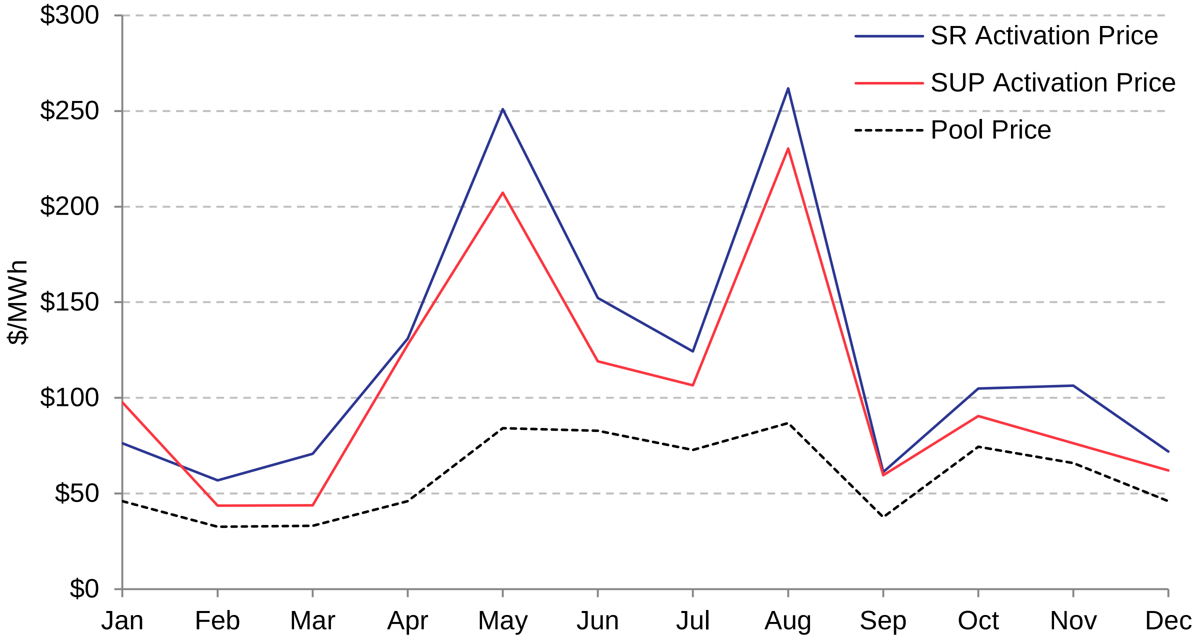
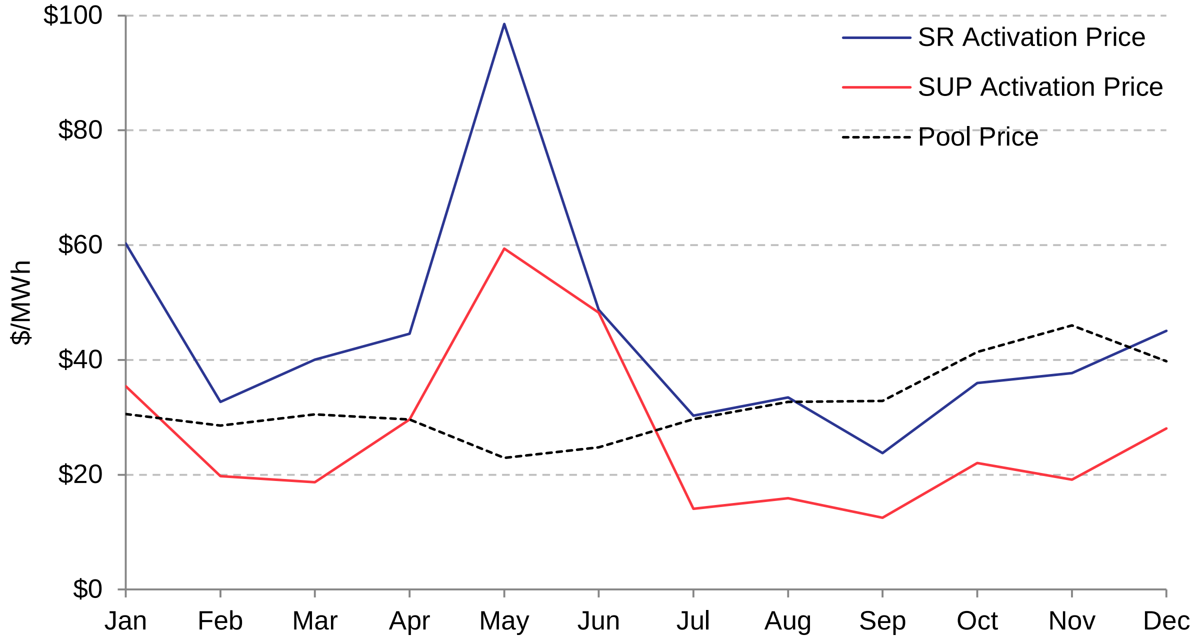


Figure 17: Average Off-Peak Pool Price and Activation Price



The MSA has commented on the effects on the standby operating reserves markets of their use (in conjunction with LSSi) to enable imports in previous quarterly reports. The MSA is of the view that changes can be made to the standby operating reserves market to avoid sharp increases in total operating reserves costs in the future. In particular, the activation price for standby reserves should be set at that of the active reserves (which is the value of active reserves for the day) and standby providers should then compete, based on the premium that they require to provide the service.

3.2 Load Shed Service for imports

In December 2018, the AESO announced the results of its Request for Proposals (RFP) to provide Load Shed Service for imports (LSSi) from January 1, 2019 to December 31, 2021. Through the RFP, the AESO procured 330 MW of LSSi which is a decrease from the previously contracted volume of 425 MW. All of the successful proponents of the RFP have provided LSSi in the past. Changes to the new LSSi contracts include removal of the minimum arming guarantee payments and a new availability payment structure based on the availability price offered by each provider multiplied by a ratio between LSSi offered in a given hour and the provider's contract volume instead of a flat $5/MWh rate that was in effect previously. The MSA will continue to monitor the conduct and performance of the LSSi program in light of these changes.

3.3 Net Revenue Analysis

The MSA has undertaken a net revenue analysis to examine the potential profitability of a hypothetical gas peaking plant in the Alberta energy and operating reserves markets. The analysis calculates the net revenues and returns that were available across the energy and operating reserves markets. The time period analyzed is January 1, 2016 through December

31, 2018. The hypothetical new entrant analyzed is a 93 MW peaking plant consisting of two GE LM6000PF Sprint Turbines. The assumed plant characteristics and development costs are provided below[11]:

Table 5: Net Revenue Plant Characteristics (2 x GE LM6000PF Sprint)

	Winter	Summer
Capacity (MW)	93	78
Heat Rate (GJ/MWh)	9.526	9.954
CO_2 Emissions (t/MWh)	0.477	0.499
Forced Outage Factor	3%	3%

Table 6: Net Revenue Plant Development Cost Assumptions ($2018)

Overnight Capital Costs ($/MW)	$	1,452,000
Fixed O&M ($/MW-year)	$	48,400
Variable O&M ($/MWh)	$	4.36

To analyze the potential profitability of the hypothetical plant in the energy market the plant is assumed to act as a price-taker and offer at variable cost. Therefore, in hours where the pool price (less transmission losses of 3.17%) is greater than the plant's total variable cost, the plant is dispatched and earns net revenue. In hours when pool price (less transmission losses) is less than total variable cost, the plant is not dispatched. To calculate total variable cost the MSA considered fuel cost, carbon cost, variable O&M and the AESO trading charge.

To analyze the potential profitability of the hypothetical plant in the active supplemental reserve market the MSA assumed the plant offers into the market such that it is dispatched for supplemental reserves whenever the supplemental market index is greater than (-1 x Total Variable Cost). This way the unit will be only dispatched for supplemental when the margin in supplemental is greater than the margin available in the energy market. When the plant does not get dispatched in supplemental reserves in the on- or off-peak period it is assumed to participate in the energy market as a price-taker for the period, as described above.

To examine the potential profitability of the spinning reserve market the same procedure as the supplemental reserve market was used for the hypothetical plant (i.e. the plant is fully dispatched for spinning reserve whenever the margin for spinning reserve is greater than energy, and when the plant is not providing spinning reserve it is assumed to participate as a price-taker in energy).

For regulating reserve, the hypothetical plant was assumed to be fully dispatched for regulating reserve in all hours. When dispatched for regulating reserve the unit was assumed to be called

[11] The plant characteristics and cost numbers are taken from the AESO's work on the Capacity Market:
AESO Presentation: Cost of New Entry June 14, 2018
AESO Draft Net CONE and EAS Offset Methodology August 16, 2018

on to generate energy for half of its regulating reserve dispatch, and to earn a margin of pool price (less transmission loss factors) less variable costs on this dispatch.

For regulating reserves super peak, the plant is assumed to be fully dispatched in regulating reserves for AM/PM super peak periods and in the remainder of the hours the hypothetical plant is assumed to be dispatched in the energy market as a price taker.

Figure 18: Net Revenues ($000s/MW)

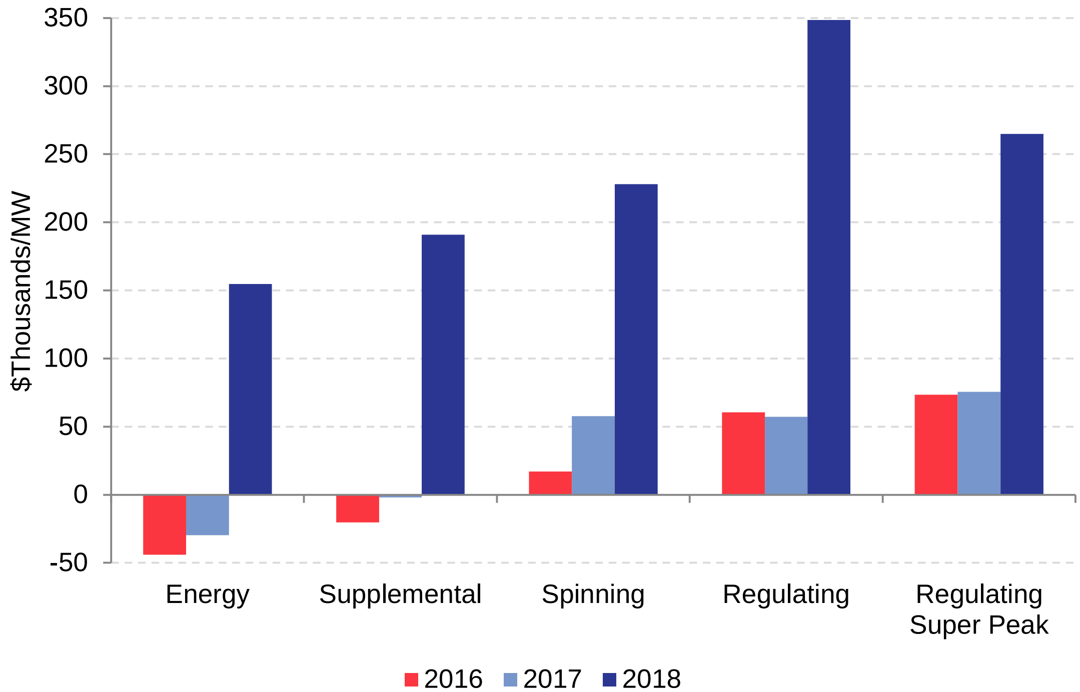


Table 7: Net Revenues – Fixed O&M (% of Capital Costs)

	2016	2017	2018
Energy	-3%	-2%	11%
Supplemental Reserve	-1%	0%	13%
Spinning Reserve	1%	4%	16%
Regulating Reserve	4%	4%	24%
Regulating Reserve (Super Peak)	5%	5%	18%

The results of the net revenue analysis are shown in Figure 18 and Table 7. Figure 18 illustrates net revenue, which accounts for fixed O&M costs of $48,400/MW, by market and year. As shown, 2018 provided a marked increase in revenues across all markets when compared with 2016 and 2017. In addition the analysis shows there is a consistent premium in the operating reserves markets compared to energy, with spinning reserve, regulating reserve and super-peak regulating reserve being the superior markets. Table 7 reports the net revenues less fixed O&M costs as a percentage of overnight capital costs ($1,452,000/MW).

The figures in Table 7 need some care in interpretation. They do not necessarily imply that a new peaking plant would be able to achieve on average the rates of return for reserves, given the small size of these markets. They do, however, suggest that increased participation in reserve markets could at least at the margin be highly profitable. A persistent profitable opportunity that is not taken by market participants suggests there may be significant barriers to participation in operating reserves markets and that is of concern to the MSA.

4 Retail Market

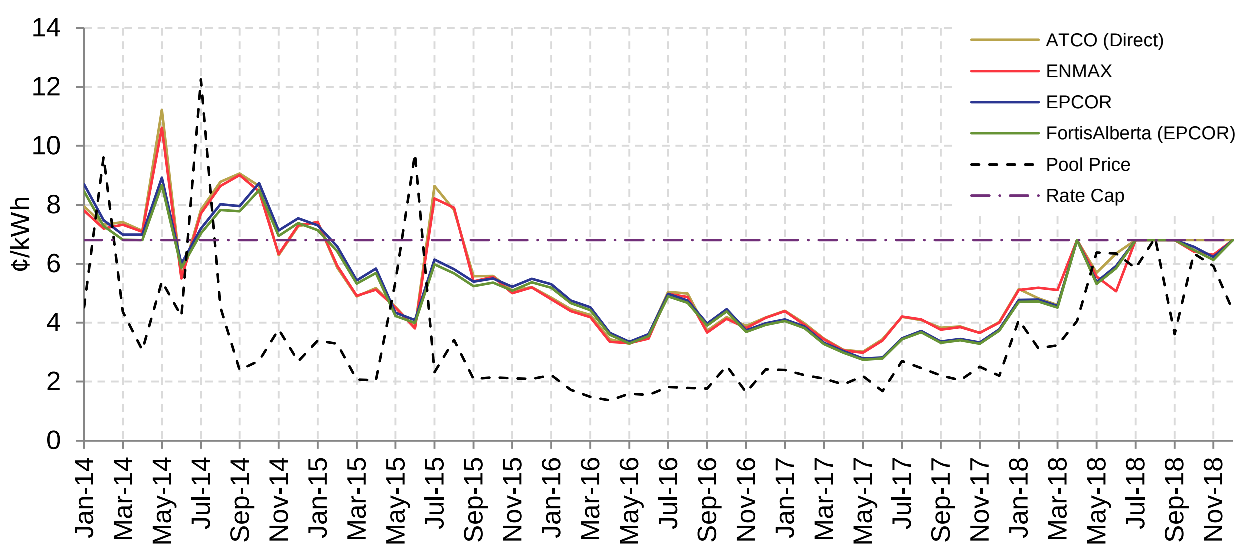
The retail market is comprised of regulated and competitive components. All customers who do not select a competitive retailer for electricity or natural gas services are on some form of default rate. The electricity regulated rate for smaller customers is called the Regulated Rate Option (RRO) and the mechanism for pricing this option is regulated, not the actual prices. For larger electricity customers, the default tariff is at the discretion of the wires service provider. Natural gas customers who have not chosen a competitive retailer are on the Default Rate Tariff (DRT).

4.1 Regulated Retail Market

4.1.1 Regulated Rate Option (RRO)

In Q4/2018, residential RRO billing rates averaged 6.58 ¢/kWh across the four largest distribution service areas, with rates only reaching the Government of Alberta's 6.8 ¢/kWh cap in all four service areas in December 2018 (see Figure 19).[12] This is a decline from Q3/2018, when billing rates bound at the rate cap across all four service areas across the quarter.

Figure 19: Residential RRO Billing Rates, January 2014 – December 2018

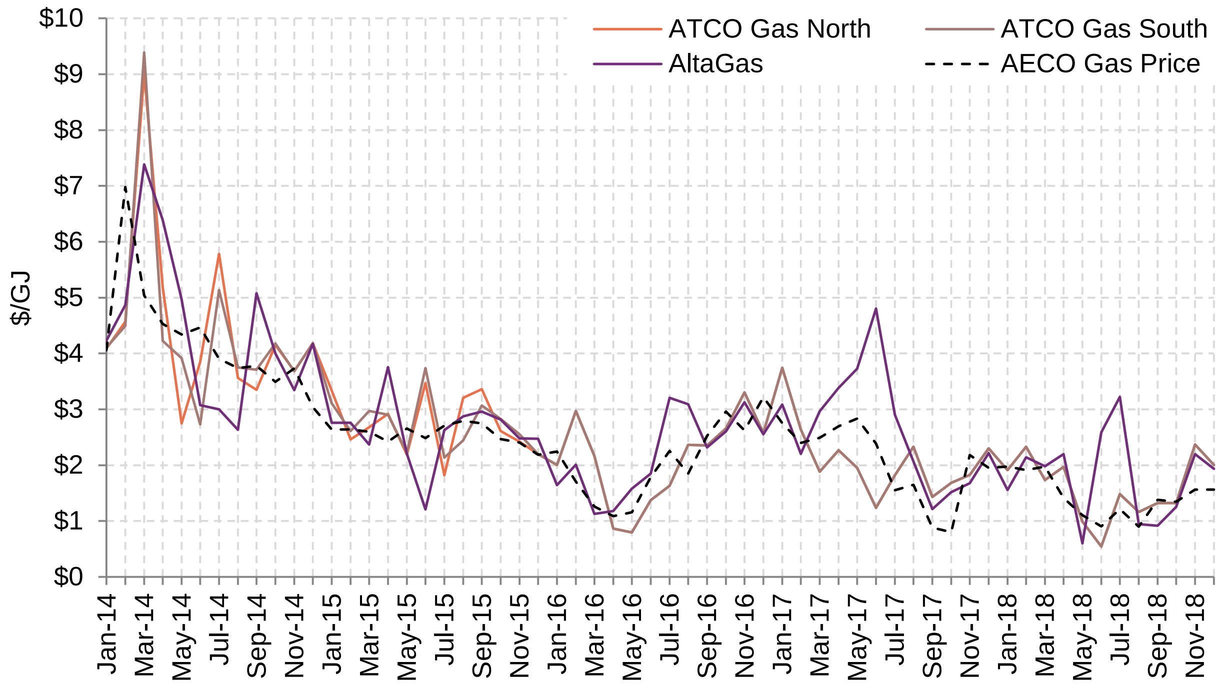


[12] RRO billing rates here refers to the RRO energy rate charged to retail electricity customers after accounting for the effect of the rate cap.

4.1.2 Default Rate Tariff (DRT)

Default Rate Tariff rates increased modestly in Q4/18 to around 2 $/GJ by December 2018 (Figure 20). DRT rates typically increase in the colder months of the year in response to increased withdrawals of natural gas.

Figure 20: DRT Rates, January 2014 – December 2018



4.1.3 Energy Price Setting Plans – Recent Developments

On December 4, 2018, EPCOR held its first descending clock auction for the April 2019 delivery month under its 2018-2021 EPSP methodology.[13] In this auction format, three hedge products (flat, extended peak, full load) are auctioned simultaneously over a series of rounds, with the price of each product decreasing between rounds if it is over-supplied. Full load strips are a new product in the EPCOR RRO auction, with sellers obliged to serve a fixed percentage of EPCOR's hourly load over the delivery period. In its observation of the first few auctions in December 2018 and January 2019, the MSA notes that the auctions have been successful in attracting the required volumes. The MSA also notes that in Proceeding 24284 EPCOR is seeking to reduce the length of the auction sessions having received feedback from participants that auction sessions are too long.[14] The MSA will continue to monitor the EPCOR RRO auctions given the limited experience to date with this procurement method.

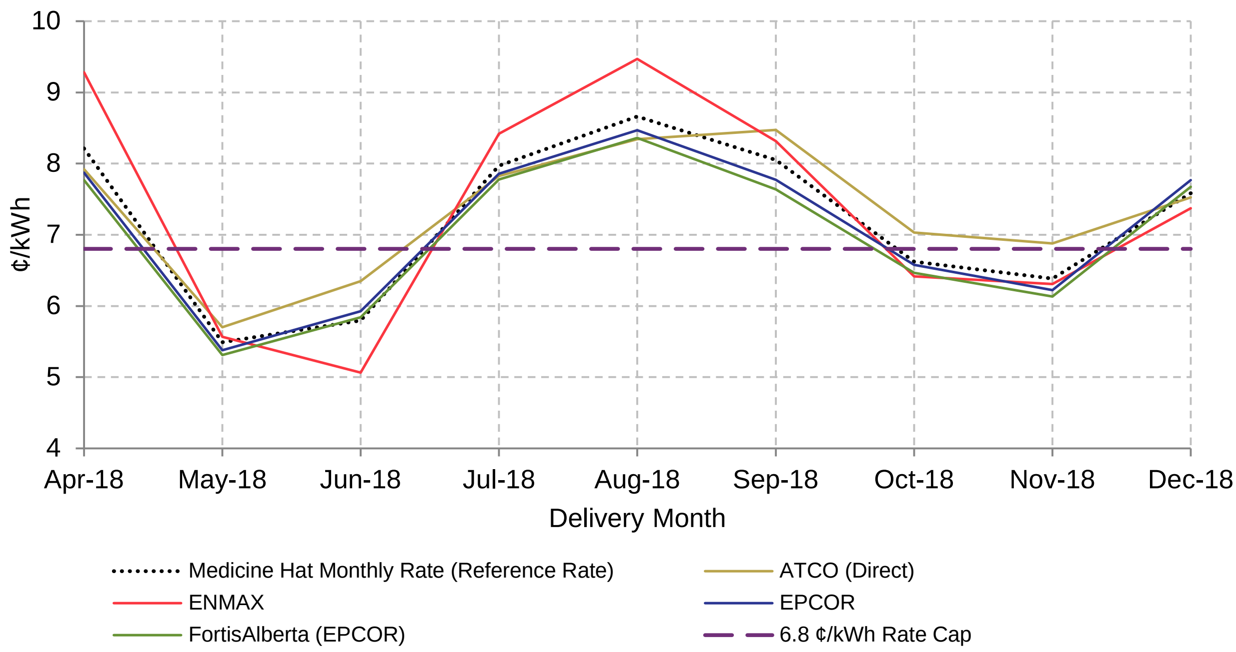
[13] EPCOR's 2018-2021 EPSP was approved by the Commission in Decision 22357-D01-2018 with subsequent amendments approved in Decision 23916-D01-2018.
[14] AUC Proceeding 24284 - EPCOR Energy Alberta GP Inc. 2018-2021 Energy Price Setting Plan Amendment Application (Exhibit X0002), January 28, 2018.

On December 21, 2018, the Alberta Utilities Commission released its decision regarding Direct Energy's 2018-2020 Energy Price Setting Plan (EPSP).[15] The Commission found that Direct Energy failed to show that the Beblow method of commodity risk compensation (CRC) would undercompensate Direct Energy for risks relating to its provision of the RRO.[16] In its application, Direct Energy applied for CRC in the form of a $7.97/MWh monthly RRO component.[17] The Commission rejected this proposal and directed Direct Energy to update its 2018-2020 EPSP to instead include the Beblow method of CRC and the quarterly risk cycle adder.[18] Direct Energy is expected to submit a compliance filing to reflect the Commission's findings and directives by January 31, 2019.[19]

4.1.4 Rate Cap Regulation

The regulated retail electricity rate cap bound for the three largest RRO providers in December 2018, with residential monthly rates averaging 7.585 ¢/kWh in that month.[20] October and November 2018 saw lower rates among these providers, with residential monthly rates averaging 6.621 ¢/kWh and 6.385 ¢/kWh in each month, respectively. The City of Medicine Hat sets its residential energy rate as the average of the four monthly rates in the largest service areas or 6.8 ¢/kWh, whichever is lowest. Figure 21 below shows monthly rates in the City of Medicine Hat and the four largest service areas since the rate cap first bound in April 2018.

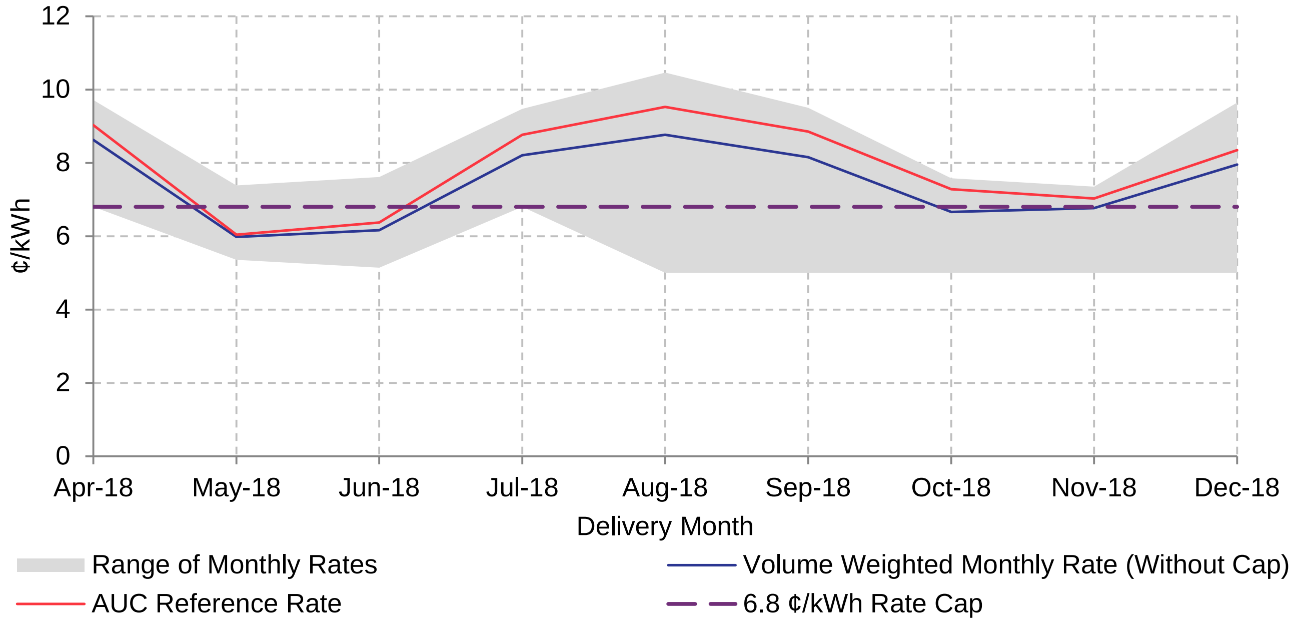
Figure 21: Monthly Rates for Medicine Hat and AUC-Regulated RRO Providers



[15] AUC Decision 22635-D01-2018 Direct Energy Regulated Services 2018-2020 Energy Price Setting Plan, December 21, 2018.
[16] Ibid, PDF Page 37.
[17] Ibid, PDF Page 5.
[18] Ibid, PDF Page 24, 37.
[19] Ibid, PDF Page 47.
[20] Monthly rate here refers to an RRO energy rate that has not been adjusted for the effect of the rate cap.

Among REAs and wire owning municipalities,[21] the reference rate was above 6.8 ¢/kWh across the quarter, enabling RRO providers for these REAs and municipalities to reimburse a portion of their RRO costs if their monthly rates are greater than 6.8 ¢/kWh. The reference rate ranged from 7.024 ¢/kWh to 8.344 ¢/kWh between October and December 2018.[22] Figure 22 illustrates the range of monthly rates submitted to the MSA since April 2018 by 37 RRO providers for REAs and municipalities as part of the Deferral Account Statement (DAS) process.

Figure 22: Monthly Rates for REAs and Municipalities[23]



As of January 2019, the Government of Alberta has paid $44.5 million in compensation to RRO providers (Table 8) for their RRO energy costs incurred between April 2018 and December 2018. RRO providers for the four largest service areas receive approval for reimbursement from the Alberta Utilities Commission, while REAs, wire-owning municipalities and the City of Medicine Hat receive reimbursement approval from the MSA.

Table 8: Rate Cap Compensation[24]

Delivery Month	Reimbursement (Commission Approved DASs)	Reimbursement (MSA Approved DASs - REA and Municipalities)	Reimbursement (MSA Approved DASs - Medicine Hat)	**Total Reimbursement**
Apr-18	$ 7,909,578.53	$ 941,035.38	$ 314,610.78	**$ 9,165,224.69**
May-18	$ -	$ -	$ -	**$ -**

[21] Not including the City of Medicine Hat.
[22] The AUC determines these reference rates as ten percent greater than the average of approved residential RRO rates submitted by the three RRO providers it regulates. See MSA Q2/2018 Quarterly Report for more information.
[23] Does not include data from the City of Medicine Hat.
[24] For deferral account true-ups, reimbursement values are reported by delivery month rather than the month in which the reimbursement was paid. For example, the true-up for April 2018 MSA approved deferral accounts was paid in October 2018 but has been included as part of the April 2018 reimbursement. This methodology differs from that used by the MSA in Table 4 of its Q3/2018 Quarterly Report. An asterisk (*) indicates that compensation values are non-final as true-ups have not been accounted for.

Jun-18	$ -	$ -	$ -	**$ -**
Jul-18	$ 7,087,019.48	$ 751,899.43	$ 378,125.51	**$ 8,217,044.42**
Aug-18	$ 10,811,784.04 *	$ 954,938.81 *	$ 547,761.17	**$ 12,314,484.02 ***
Sep-18	$ 6,362,440.33 *	$ 636,039.17 *	$ 271,050.87	**$ 7,269,530.37 ***
Oct-18	$ 203,505.86 *	$ 70,240.40 *	$ -	**$ 273,746.26 ***
Nov-18	$ 70,788.58 *	$ 53,033.20 *	$ -	**$ 123,821.78 ***
Dec-18	$ 6,370,359.36 *	$ 778,489.79 *	*TBD*	**$ 7,148,849.15 ***
Total	**$ 38,815,476.16**	**$ 4,185,676.19**	**$ 1,511,548.33**	**$ 44,512,700.68**

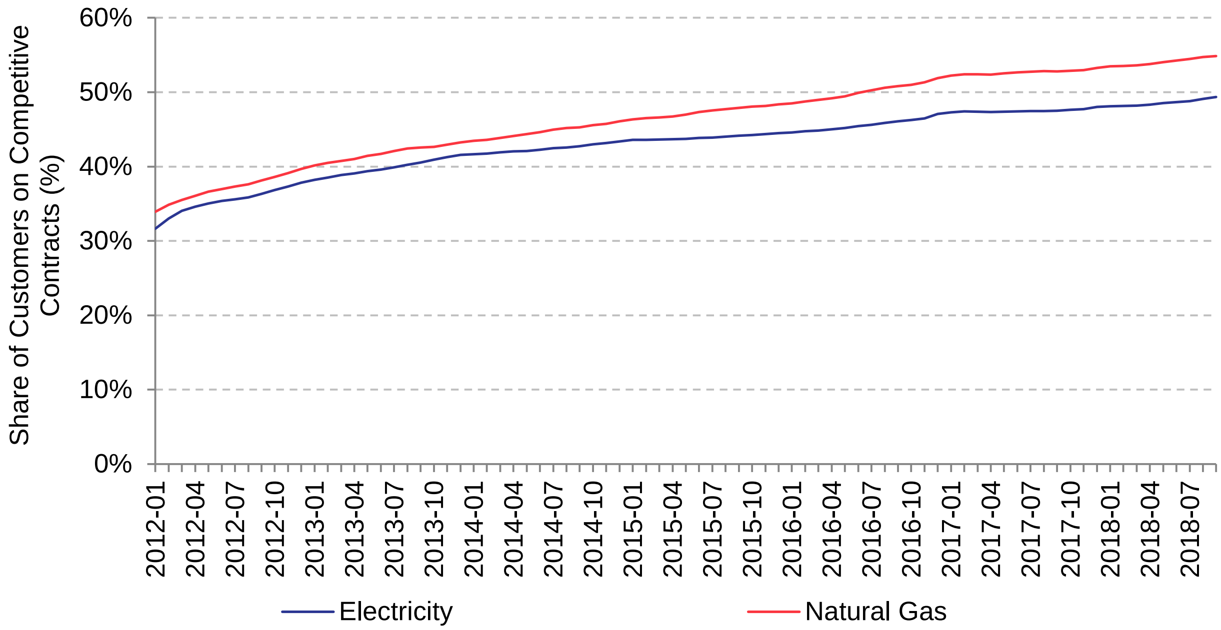
4.2 Competitive Retail Market

4.2.1 Competitive Contract Market Share

Over Q3/18, competitive contract market shares for residential electricity customers grew by 0.7%, reaching a total competitive share of 49.4% (Figure 23). If present trends continue, the MSA anticipates this market share will surpass 50% in 2019.

Competitive natural gas contract shares for residential customers grew by 0.6% over Q3/18, reaching a total competitive share of 54.9%.

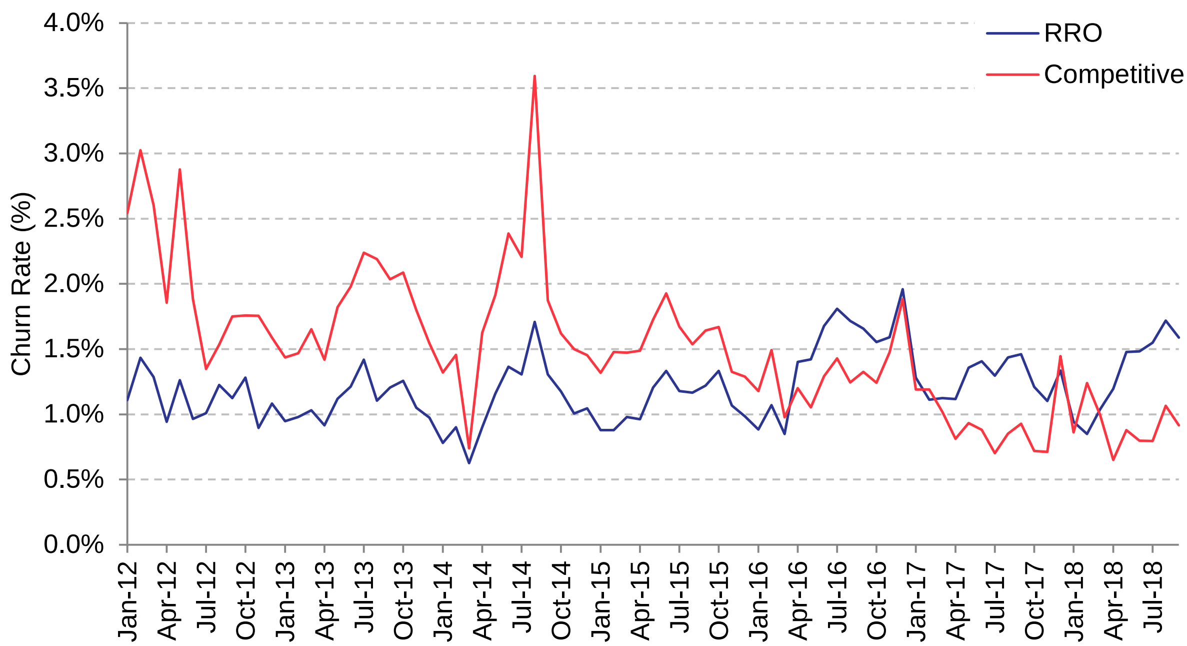
Figure 23: Share of Residential Customers on Competitive Retail Contracts, January 2012 – September 2018



4.2.2 Churn

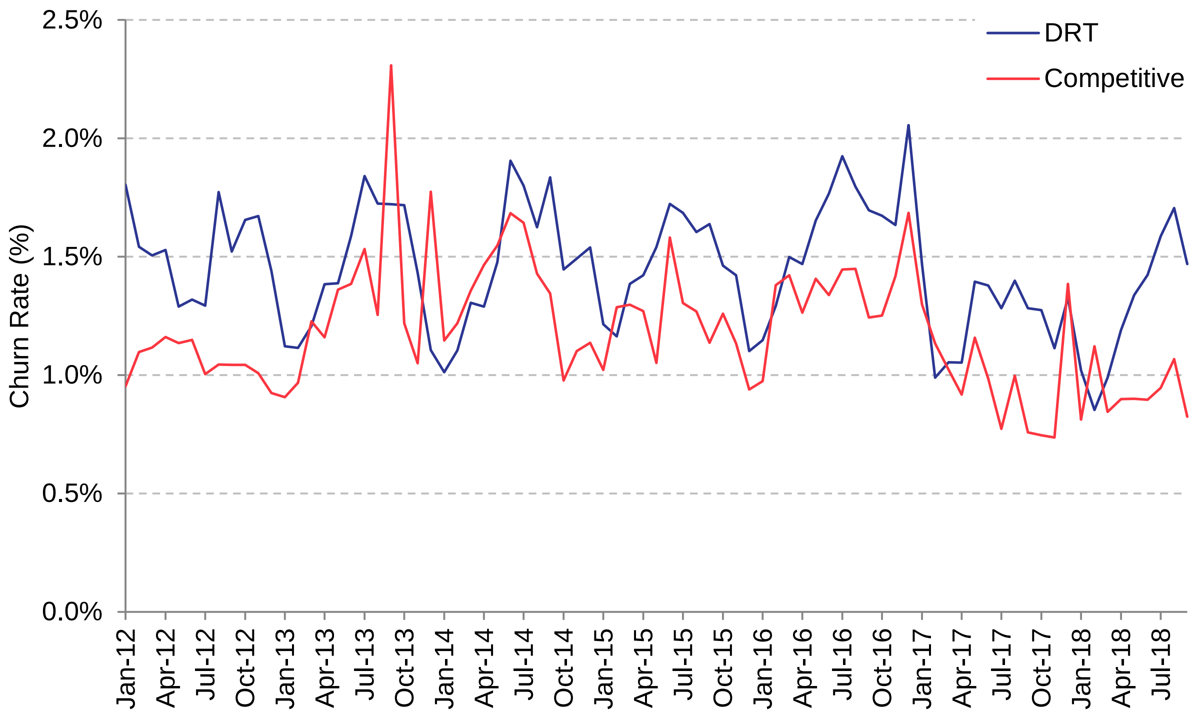
Churn rates represent the loss of customers over a given period, expressed as a percentage of the existing customer base. The monthly churn rates for competitive and regulated electricity retailers are shown in Figure 24. Churn rates for both competitive and regulated electricity retailers increased modestly over Q3/18, but have largely remained within historic norms.

Figure 24: Monthly Churn Rates for Residential Electricity Retailers, January 2012 – September 2018



Churn rates for regulated natural gas retailers have been increasing since Q1/18, peaking at 1.7% in August 2018 before decreasing the following month (Figure 25). While competitive natural gas churn rates exhibited a similar pattern in Q3/18, they remained significantly lower than regulated churn rates over the quarter.

Figure 25: Monthly Churn Rates for Residential Natural Gas Retailers, January 2012 – September 2018



4.2.3 Natural Gas Market Shares

Retail natural gas market shares vary significantly across distribution service area and customer types. Some retailers enjoy significant market share among a number of customer types, while others have performed better among a specific customer type.

Among residential customers, natural gas market shares are broadly similar to electricity market shares in comparable service areas (Figure 26 and Figure 27). This may be due to the popularity of dual-fuel contracts among residential customers.

Figure 26: Natural Gas Retailer Market Shares, Residential Customers, September 2018

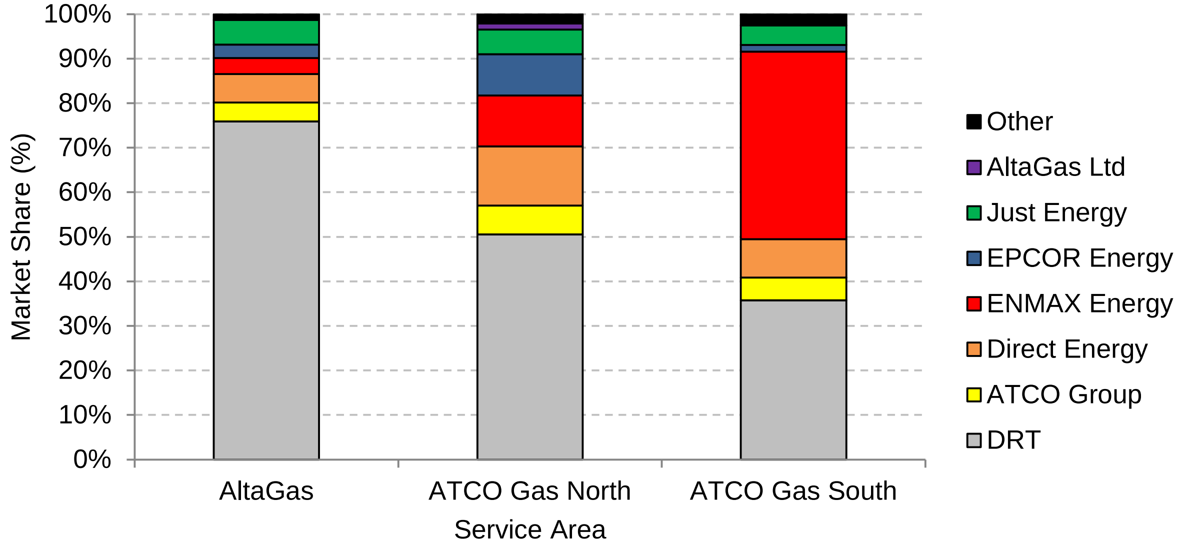
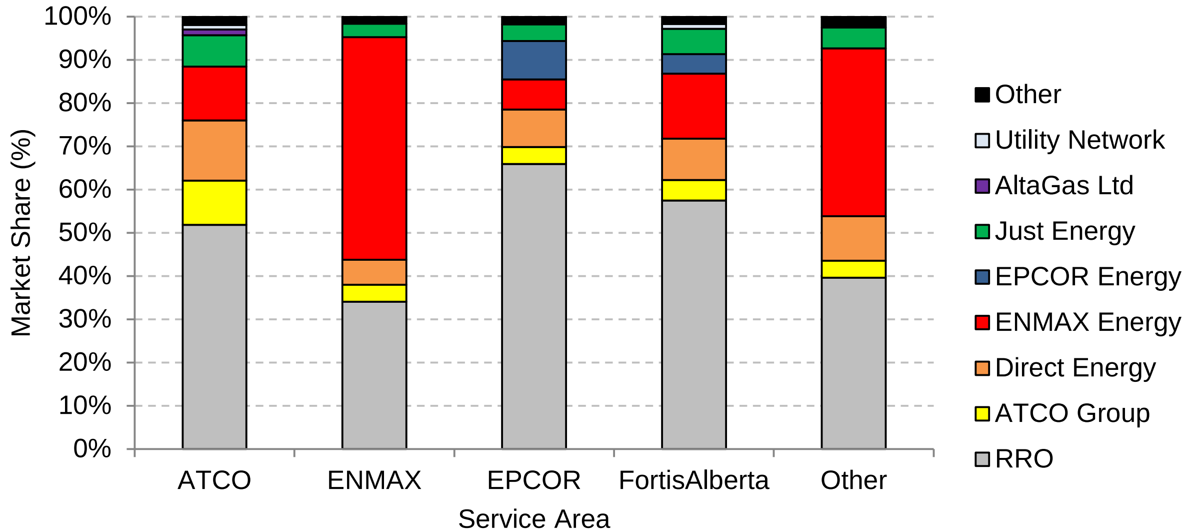


Figure 27: Electricity Retailer Market Shares, Residential Customers, September 2018



A large portion of commercial customers still receive natural gas on the Default Rate Tariff (Figure 28). Few industrial customers still receive natural gas from this default rate, with many opting for other gas retailers with lower market penetration among other customers (Figure 29). These retailers offer products tailored to the needs of larger gas consumers.

Gas Alberta Inc. is one retailer with significant market share among industrial customers, particularly in northern Alberta. This retailer is the exclusive supplier of natural gas to 74 natural gas distribution utilities in Alberta.[25] These utilities serve municipalities, natural gas cooperatives, counties and First Nations utilities.[26]

Figure 28: Natural Gas Retailer Market Shares, Commercial Customers, September 2018

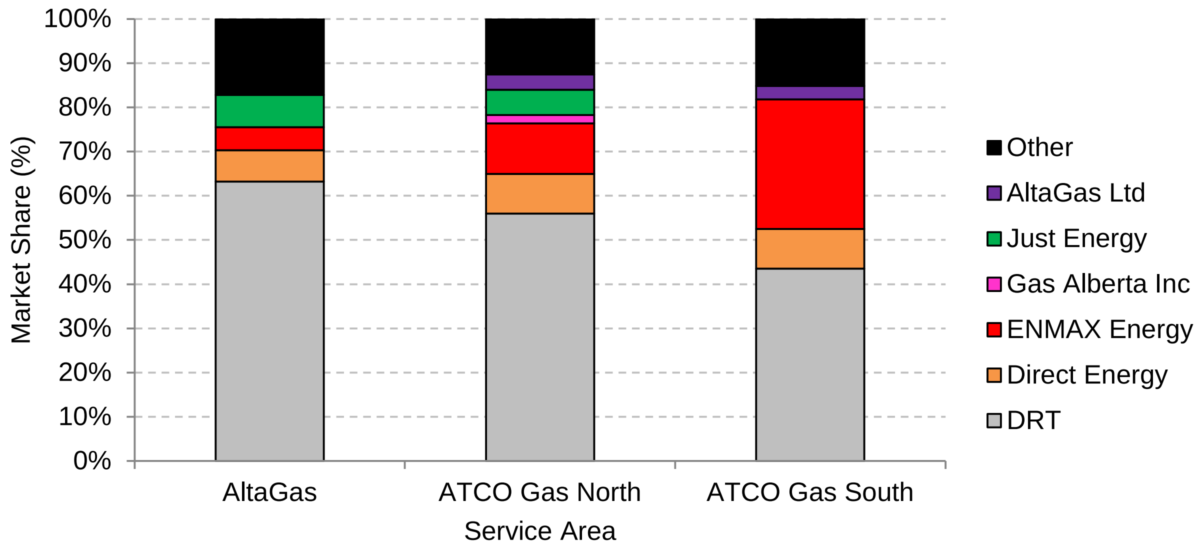
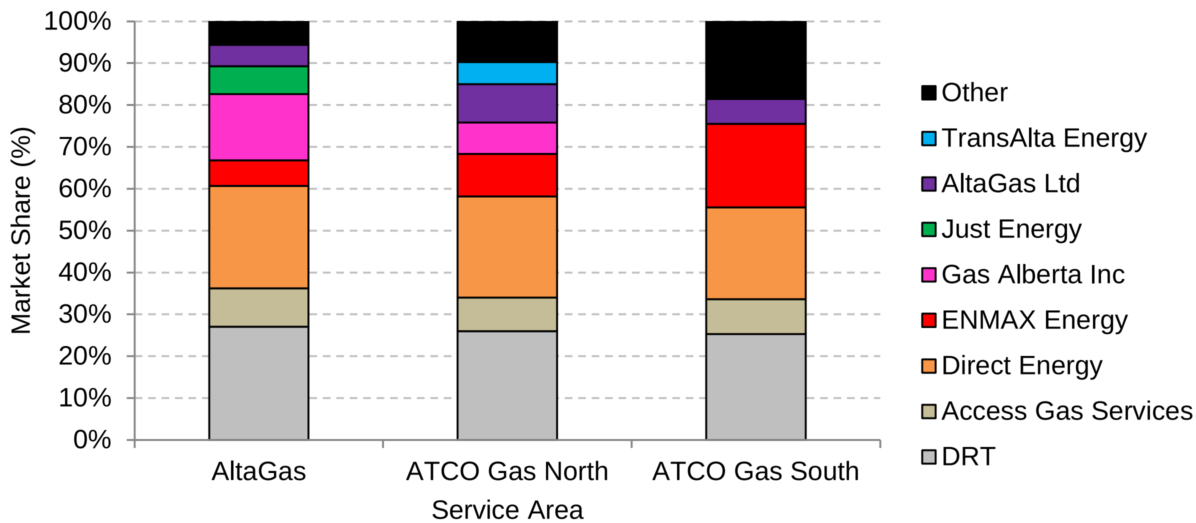


Figure 29: Natural Gas Retailer Market Shares, Industrial Customers, September 2018



[25] Gas Alberta – Our Company.
[26] Gas Alberta – Our Customers.

5 Compliance

A compliance review is not included in this Quarterly Report as an annual compliance report will be published shortly.

6 Highlights

The following points summarize key takeaways from the quarter:

- The average annual pool price for 2018 settled at $50.35/MWh which is a substantial increase over the average pool prices observed for 2015 through 2017 ($24.60/MWh).
- The increase in pool price observed during 2018 was largely the result of higher market demand, increasing carbon costs, changes in offer behaviour, and the retirement and mothballing of coal-fired generating units.
- Alberta's total demand in 2018 increased by 3.3% over 2017. This is approximately in line with growth rates seen since 2010, with the exception of 2015 and 2016 when Alberta was in the midst of a recession.
- During 2018, Alberta had average hourly net imports of 304 MWh a significant increase over the three prior years. This is primarily attributable to higher wholesale prices in Alberta compared to the Pacific NW during the first half of the calendar year.
- Due to the return of PPAs for Sundance A, B and C, the Balancing Pool has seen its Market Share Offer Control (MSOC) decline since 2017. The subsequent retirement and mothballing of several units have seen supply cushion levels in 2018 levels drop off from the recent highs in 2016 and 2017.
- Overall, total forward market trade volumes fell by 29% in 2018 from the previous three year average, 2015-2017. Most of the declines occurred in the monthly and annual term contract volumes.
- Total operating reserves costs were $239.8 million in 2018. This is 5% of the costs of the energy market and reflects a 196% increase in the cost of operating reserves compared to 2017. Most of this increase was due to increases in costs in the active operating reserves markets. Since the cost of active operating reserves is indexed to pool price, higher pool prices seen over the year was a contributor to higher costs in the active operating reserves markets.
- In Q4/18, residential RRO billing rates averaged 6.58 ¢/kWh across the four largest distribution service areas, with rates only reaching the Government of Alberta's 6.8 ¢/kWh cap in all four service areas in December 2018. This is a decline from Q3/2018, when billing rates bound at the rate cap across all four service areas across the quarter.

The MSA continues to monitor market activities with regards to competition and efficiency as per its mandate.