Quarterly Report for Q2 2022

August 12, 2022

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

THE QUARTER AT A GLANCE

- The average pool price in Q2 2022 was $122.47/MWh, a 17% increase relative to Q2 last year, and the highest quarterly pool price since Q2 2013. Elevated natural gas prices were the principal factor in the increase. The average price of natural gas in Q2 was $6.86/GJ which is 134% higher than in Q2 2021 and is the highest quarterly gas price since 2008. Increased renewable generation, changes in generator offer behaviour, and fewer thermal outages moderated the increase to pool prices.

- Wind and solar generation in Alberta continue to increase. For some hours during Q2 wind generation supplied over 2,000 MW, while solar provided more than 600 MW in some hours and is set to increase further this summer. Wind and solar generation capacity are expected to increase in the coming years as new assets come online. Currently there is 2,450 MW of wind capacity and 1,210 MW of solar capacity under construction.

- Substantial investment in natural gas generation assets is also occurring, including the Cascade combined cycle project (900 MW), the Suncor Base Plant cogeneration project (800 MW), and the repowering of the Genesee 1 and 2 assets (a net capacity increase of 512 MW). Expectations of increased supply are reflected in lower forward power prices for coming years. As of June 30, Calendar 2024 (CAL24) was priced at $69/MWh compared to $95/MWh for CAL23, while CAL22 is expected to settle around $116/MWh.

- The carbon emission intensity of the Alberta grid continued to decrease year-over-year in Q2. A longer-term analysis of carbon emission trends shows that the distribution of hourly average emission intensity has decreased materially since 2014. The analysis indicates that carbon pricing effected a material reduction in coal-fired generation. The findings are consistent with the expectation that market participants respond to carbon price incentives and show that the amount of emissions to which the carbon price applies matters.

- In an assessment of the performance of the energy market, the MSA found that generators' exercise of market power has led to price markups and profits in some years, and that such behaviour is consistent with long-run capital cost recovery.

- The MSA has published various retail market analyses in a Supplemental Retail Market Report for Q2 2022.

- The number of small micro-gen sites continued to increase in 2021. One retailer receives a significant share of micro-gen export compensation, as they control a significant share of micro-gen exports and offer above-market micro-gen retail rates.

- From April 1 to June 30, 2022, the MSA closed 70 ISO rules compliance matters; 19 matters were addressed with notices of specified penalty. For the same period, the MSA closed 12 Alberta Reliability Standards Operations and Planning compliance matters. In addition, the MSA closed 80 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; 11 matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Quarterly summary

The average pool price in Q2 was $122.47/MWh, which is 17% higher than in Q2 2021 when pool prices averaged $104.51/MWh.[1] This increase is largely attributable to materially higher natural gas prices in Q2 this year. Higher wind and solar generation, changes in generator offer behaviour, and fewer thermal outages put some downward pressure on pool prices compared to last year and somewhat offset the higher natural gas prices.

Table 1 shows summary market statistics for Q2. The average price of natural gas increased by 134% year-over-year, settling at $6.86/GJ, the highest quarterly price since 2008. Natural gas fired assets set the System Marginal Price (SMP) 86% of the time in Q2, illustrating that natural gas prices are an important cost-driver for the Alberta power market.

Table 1: Monthly market summary for Q2

		2022	2021	*Change*
Pool price (Avg $/MWh)	Apr	117.14	87.99	33%
	May	121.24	85.39	42%
	Jun	129.08	140.80	-8%
	Q2	**122.47**	**104.51**	**17%**
Demand (AIL) (Avg MW)	Apr	9,559	9,088	5.2%
	May	9,161	8,961	2.2%
	Jun	9,265	9,653	-4.0%
	Q2	**9,326**	**9,231**	**1.0%**
Gas price (Avg $/GJ)	Apr	6.56	2.65	148%
	May	7.19	2.93	145%
	Jun	6.84	3.23	112%
	Q2	**6.86**	**2.94**	**134%**
Wind generation (Avg MW)	Apr	890	621	43%
	May	907	517	76%
	Jun	756	524	44%
	Q2	**852**	**554**	**54%**
Net imports (+) Net exports (–) (Avg MW)	Apr	582	543	7%
	May	470	587	-20%
	Jun	626	479	31%
	Q2	**558**	**537**	**4%**
Thermal outages[2] (Avg MW)	Apr	2,472	2,800	-12%
	May	2,842	3,012	-6%
	Jun	2,585	2,668	-3%
	Q2	**2,635**	**2,829**	**-7%**

Natural gas prices in Alberta have risen along with prices at other major gas trading hubs in North America, such as Henry Hub. Increased demand, in part from power generation and LNG exports, led to relatively low storage levels coming out of winter, which put upward pressure on natural gas prices.

Although the year-over-year increase in natural gas prices was 134%, the year-over-year increase in pool prices was less at 17%. This indicates that the margin between natural gas input costs and pool prices was smaller in Q2 than in Q2 2021.

Increased wind and solar generation were a factor in this outcome. Average wind generation in Q2 was 298 MW higher year-over-year, an increase of 54%, which was driven by increased capacity and favourable weather conditions.

---

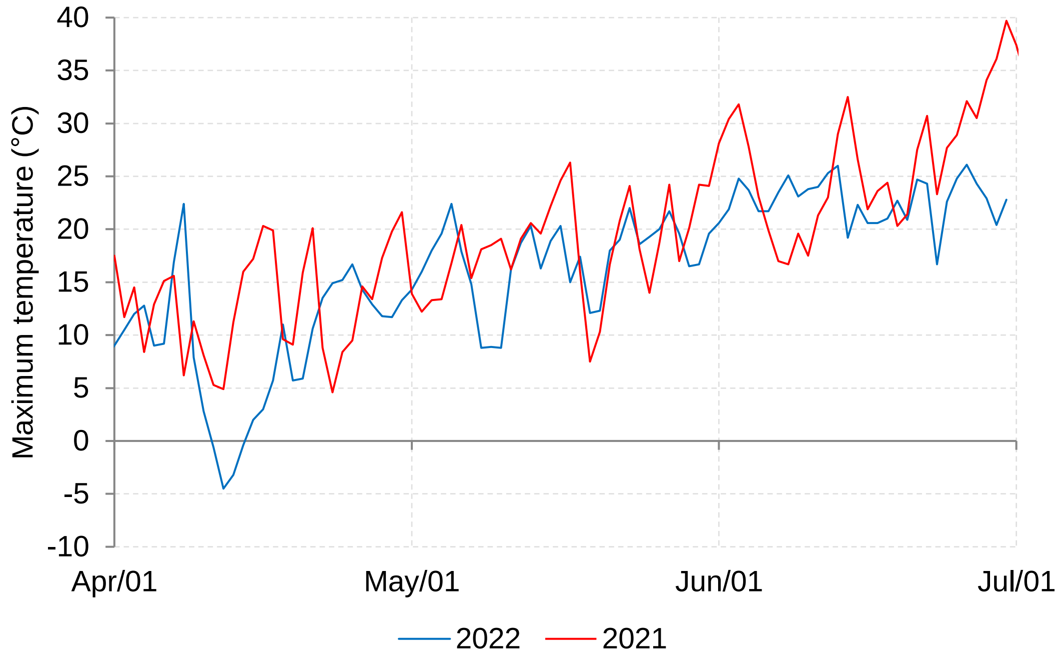
[1] Reference to Q2 means Q2 2022 unless specified otherwise. Reference to a month, or a day in a month, means a month or day in 2022 unless specified otherwise.

[2] These outage figures reflect the difference between maximum capability and total declared energy for coal, dual fuel, and natural gas assets (including cogeneration). The 2021 figures do not include the Sundance 5 mothball outage.

Solar capacity in Alberta has also increased. On June 27 solar generation peaked at 608 MW, compared to a peak of under 300 MW in Q2 2021. Wind and solar generation capacity are set to increase further in the coming years, with 2,450 MW of additional wind capacity and 1,210 MW of additional solar capacity currently under construction.[3]

Weather differences year-over-year were an important factor in the monthly demand differences reported in Table 1. A cold spell in mid-April 2022 (Figure 1) increased heating demand during this period, and April saw demand increase by 5.2% year-over-year, which was a factor in the higher average pool price in April. In contrast, temperatures in June did not reach the same highs seen in June 2021. High temperatures increase cooling demand for electricity, so demand was lower in June this year, which was a factor in the lower average pool price year-over-year.

Figure 1: Maximum daily temperature at Calgary, Edmonton, or Fort McMurray (Q2 2022 and Q2 2021)



Another consideration in the year-over-year demand changes was oil production. In April, total oil production was 10% higher than in April 2021, and in May oil production was 4% higher year-over-year.[4] Alberta oil production has increased in response to higher oil prices and greater export capacity, with the replacement of Line 3 completed in the fall of 2021. WTI oil typically traded between US$100 and $120/bbl in Q2 compared to between US$60 and $70/bbl in Q2 2021.

[3] AESO Long-Term Adequacy Metrics – August 2022 (assets listed on the CSD page as of August 15, 2022, were not included)

[4] AER ST3 report, Oil, Total Production

Electricity is an important input for Alberta oilsands operations and therefore increased oil production can lead to higher electricity demand.

1.2 Market outcomes

Natural gas prices increased materially in early April in response to low storage volumes and forecasts for high air conditioning demand in some regions of the US. The demand for natural gas has increased because of increased power generation demand (including generator coal-to-gas conversions and air conditioning demand), higher levels of LNG exports, and high heating demand over the 2021/22 winter. As a result, natural gas storage levels in the US have been below historical levels this year. In mid-April, EIA natural gas storage estimates were 23% below last year's level and 17% below the five-year average.[5] Consequently, natural gas prices across North America have been higher this year.

Figure 2 illustrates the monthly average price of natural gas in Alberta since January 2013. In Q2, natural gas prices peaked in May, averaging $7.19/GJ, before declining in June. In the latter half of June, natural gas prices fell significantly as an LNG facility in the US was forced out of service until later this year.[6] This outage reduced the export capacity of LNG from North America, which helped to replenish natural gas storage levels. At the end of June, EIA storage levels were 12% lower than the same period last year. This was an improvement over mid-April when storage levels were 23% lower than their 2021 levels. Between June 12 and June 30, the same-day price of natural gas in Alberta fell from $8.11/GJ to $5.23/GJ, a decline of 36%.

Figure 2: Monthly average of same-day AB-NIT natural gas prices (January 2013 to June 2022)

[5] EIA Weekly Natural Gas Storage Report, More Storage Data

[6] Reuters article – June 14, 2022

The average pool price increased by 17% compared to Q2 last year, whereas natural gas prices were 134% higher. Therefore, the margin between pool prices and natural gas input costs was lower in Q2 compared to Q2 2021 (Table 2). The average spark spread in Q2 was $53.83/MWh, a decline of 28% relative to $75.16/MWh in Q2 2021.[7] Increased wind and solar generation, fewer thermal outages, lower demand in June, and changes in the offer behaviour of larger suppliers were all factors in the lower spark spread this quarter.

Table 2: Monthly spark spread figures using a 10 GJ/MWh heat rate (Q2 2022 and Q2 2021)

	2022	2021	% change
April	$51.51	$61.50	-16%
May	$49.39	$56.10	-12%
June	$60.73	$108.53	-44%
Q2	**$53.83**	**$75.16**	**-28%**

Wind and solar generation increased materially in Q2 compared to Q2 2021. On average wind generation was 852 MW in Q2, an increase of 298 MW (54%) year-over-year. Average solar generation during peak hours (HE08 to HE23) was 195 MW in Q2, which is 80 MW (70%) higher than in Q2 last year.

Wind and solar generation typically act as price takers and offer into the energy market at the offer price floor of $0.00/MWh, receiving the prevailing pool price for their generation. In addition, wind and solar assets are eligible for carbon emission offsets, which are an additional source of revenue for these assets. A wind or solar asset brought online in 2022 may be eligible to receive $26.50/MWh in revenue from carbon emission offsets, based on the electricity grid displacement factor of 0.53 t/MWh and the carbon price of $50/MWh.

As of June 30, the total capacity of wind assets in Alberta was 2,269 MW, an increase of 488 MW (27%) year-over-year. In addition to the increase in capacity, the capacity factor of wind assets was also higher in Q2 at 38%, relative to 31% in Q2 last year.

Wind generation is an intermittent resource; during some hours in Q2 total wind supply was over 2,000 MW while in other hours it was close to 0 MW. Figure 3 illustrates hourly wind generation, solar generation, and the pool price in June. Higher pool prices tended to occur when wind generation was low, and pool prices were generally lower during periods of high wind generation. Over Q2, the received price for wind generation was $98.87/MWh, 19% less than the average pool price.

[7] Spark spread is the difference between the price of electricity and the input fuel cost of natural gas. These calculations assume 10 GJ of natural gas are needed to produce a MWh of electricity; a heat rate of 10 GJ/MWh. This heat rate is similar to the efficiency of simple cycle assets and is slightly lower than most gas-fired steam assets. An efficient combined cycle has a lower heat rate of around 7 GJ/MWh.

The received price for solar generation over the quarter was higher at $138.18/MWh, 13% more than the average pool price. Solar generation produces during daylight hours which often overlap with peak demand periods when pool prices are higher, particularly during the summer months.

Solar capacity has increased significantly since the start of the year as the Travers development (465 MW) continues to add capacity, and seven other solar assets have come online, totalling 135 MW in capacity. Towards the end of June, solar generation surpassed 600 MW in some hours, more than double the peak of solar generation in 2021 (Figure 4).

Figure 3: Hourly wind generation, solar generation, and pool price (June 2022)

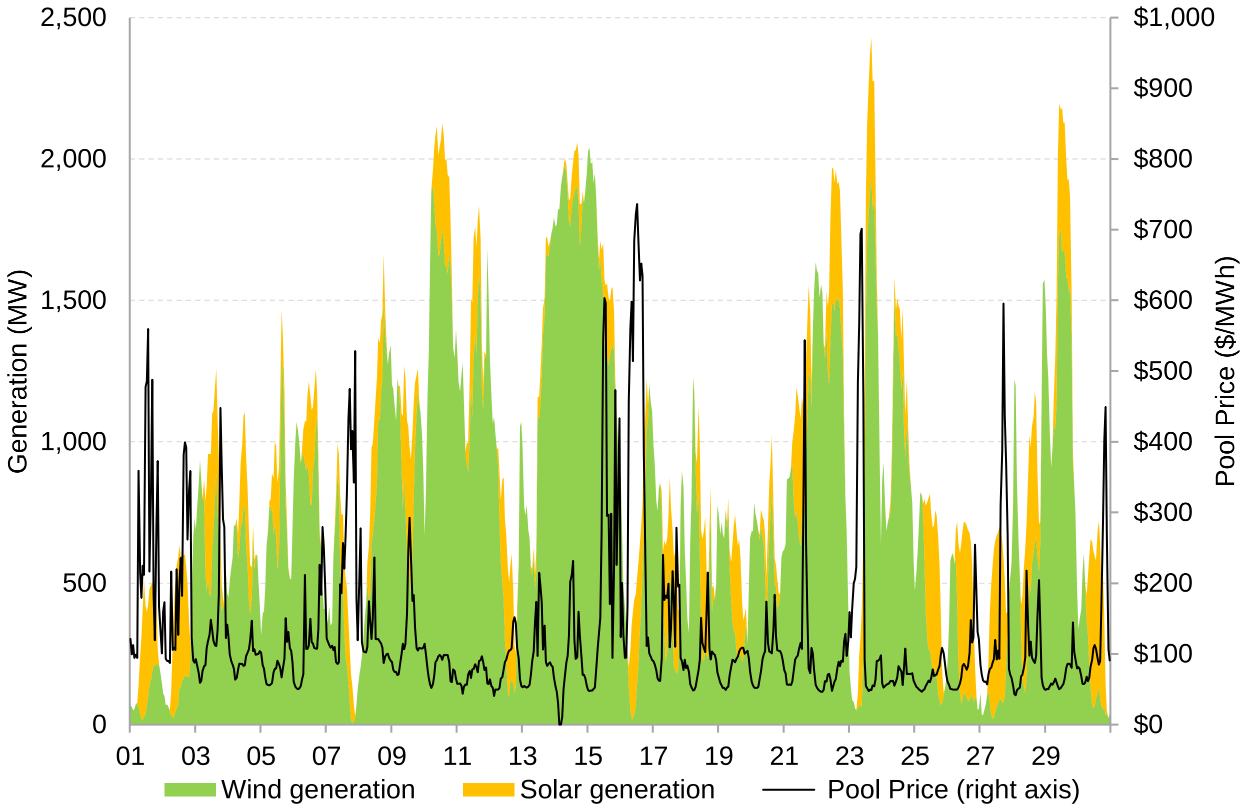
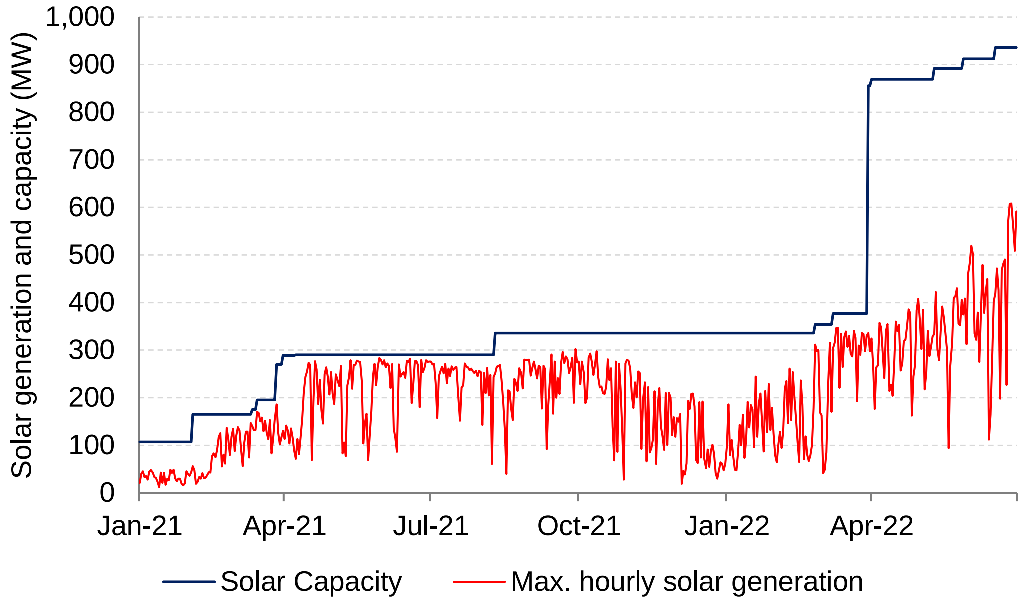


Figure 4: Solar capacity and maximum solar generation by day (January 1, 2021 to June 30, 2022)[8]



During a few off-peak hours in Q2 the System Marginal Price (SMP) was set at the offer price floor of $0.00/MWh. This price reflects a supply surplus situation when the amount of capacity offered into the market at $0.00/MWh exceeds the prevailing demand for electricity. On Tuesday, June 14 the SMP was $0.00/MWh for almost three hours, resulting in the pool prices for HE04 and HE05 being set at $0.00/MWh.

High wind generation was a factor during this event, as wind assets were supplying around 1,900 MW at the time. In addition, importers fully utilized the available transmission capacity on BC/MATL and supplied 554 MW despite the pool price being $0.00/MWh. Prices in the Mid-C market were below zero at the time, at around negative CAD$12/MWh, which incentivized the flow of power into Alberta.

Table 3: Time periods where the SMP was $0.00/MWh in Q2 2022

Date	Begin time	End time	Length of time
May 6, 2022 (Friday)	02:33	03:53	1 hr 20 mins
June 12, 2022 (Sunday)	03:19	03:29	10 mins
June 14, 2022 (Tuesday)	01:54	02:13	19 mins
June 14, 2022 (Tuesday)	02:49	05:37	2 hrs 48 mins

[8] In this chart, the capacity of a new solar asset is added in full once the asset starts to generate to the grid

Despite five gas-fired steam assets being commercially offline during the off-peak hours on June 14, there was still a large amount of thermal capacity offered into the market at $0.00/MWh. In HE04 for example, there was 2,300 MW of cogeneration capacity offered at $0.00/MWh in addition to 1,100 MW of combined cycle, 870 MW of coal, and 510 MW of gas-fired steam. In total this amounted to 4,800 MW of thermal capacity offered into the market at the price floor. These zero-dollar offers often reflect industrial operations at cogeneration facilities, or a minimum level of generation that a thermal asset must run at or above due to operational constraints. The AESO did not have to constrain imports, the first step in addressing a supply surplus event[9], in any of the zero-dollar events in Q2.

As shown in Table 1, thermal outages were about 200 MW lower on average in Q2 compared to Q2 2021. This had the effect of increasing supply and somewhat offsetting the retirements of the Keephills 1 coal asset (395 MW) on January 1 and the Sundance 4 coal asset (406 MW) on April 1.[10] In Q2 2021, a six-week outage at Shepard (868 MW) began in early April, reducing supply materially, while a coal-to-gas conversion outage at Keephills 2 ran from mid-March to the end of May 2021. In Q2 2022, there was a six-week outage at the Calgary Energy Centre (330 MW) beginning in early April, and several cogeneration outages. On April 13, the Genesee 3 conversion outage was moved from May into the fall, and this increased thermal supply in Q2.

1.3 Offer behaviour

Figure 5 shows the distribution of offer prices for coal and converted coal assets in Q2 2022 and Q2 2021. The duration curves indicate that less coal and converted coal capacity was offered at a higher price level in Q2 compared to Q2 2021. For example, in Q2 2021 10% of the available capacity was offered above $615/MWh, whereas in Q2 2022 5% of available capacity was offered above $615/MWh. The reduction in higher-priced offers year-over-year may reflect increased hedging. In financial reporting, some larger suppliers discussed increased hedging levels for 2022 relative to 2021, which would generally reduce the incentive to offer generation capacity at a higher price.

Offer prices in lower percentiles were higher in Q2 compared to Q2 2021, which reflects higher natural gas prices in Q2 this year. The average price of natural gas was $6.86/GJ in Q2, a 134% increase year-over-year. Natural gas is an important input for converted coal assets so higher natural gas prices increase the variable cost of generation. In addition, the carbon price increased from $40 to $50/tCO2e, which increased the carbon costs for most thermal assets, particularly coal.

[9] ISO Rule 202.4 – Supply Surplus

[10] Beginning on January 1, 2022 the Sundance 4 asset was operated using gas-fired capacity only with a reduced capacity of 113 MW.

Figure 5: Offer price duration curves (Q2 2022 and Q2 2021)

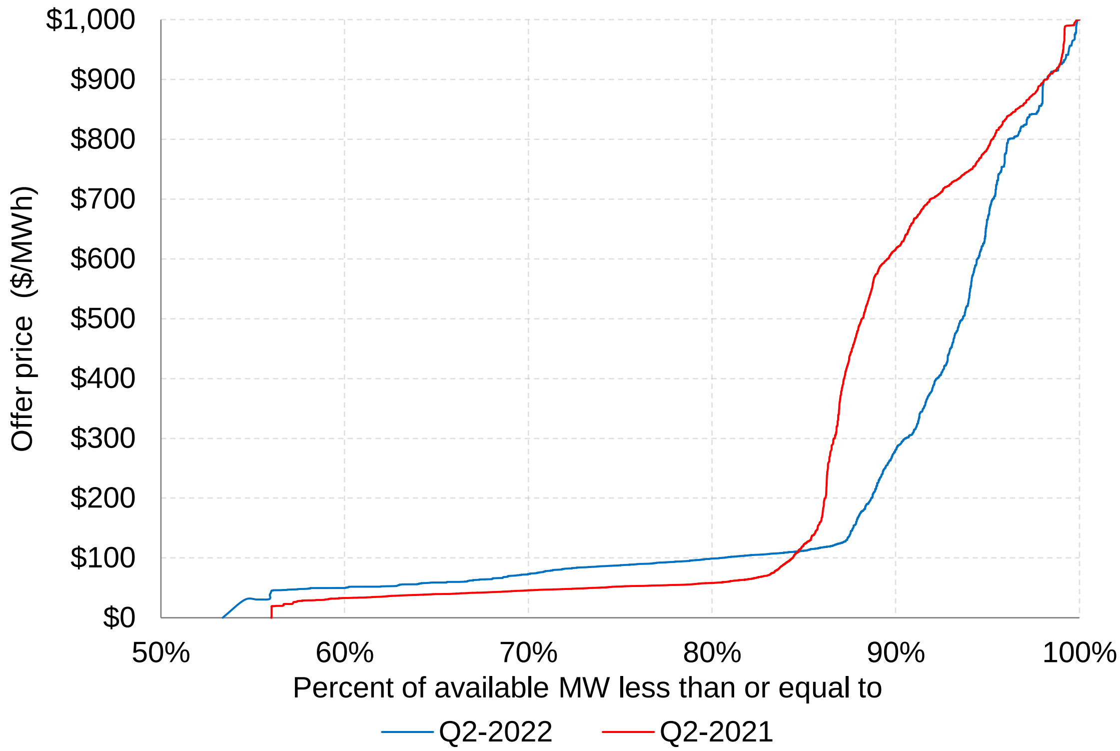


Figure 6 shows the amount of coal and converted coal capacity commercially offline and the amount of coal and converted coal capacity that was offered above $100/MWh during the daily peak in pool price from April 1 to June 30. The average amount of capacity commercially offline during the daily peak in pool price was 711 MW in Q2.

The average amount of capacity commercially offline was highest in June, which was driven in part by a high amount of capacity being offline on June 14 and 15. The reduced capacity was a factor in higher pool prices on June 15, when the daily average was $233/MWh, the fourth highest in the quarter. Pool prices on June 15 were also increased by thermal outages, reduced import capacity, and offer behaviour.

In April, more converted coal was commercially offline around the start of the month when wind generation was typically high. In mid-April, wind generation was much lower and only one small asset was commercially offline from April 14 to 16.

Later in April, there was an increase in the amount of coal and converted coal capacity that was offered above $100/MWh. For example, on April 29, 1,300 MW of coal and converted coal capacity was offered above $100/MWh when the pool price was at its daily peak, the highest year-to-date.

Figure 6: Coal and converted coal capacity commercially offline and offered above $100 (daily peak in pool price, April 1 to June 30)

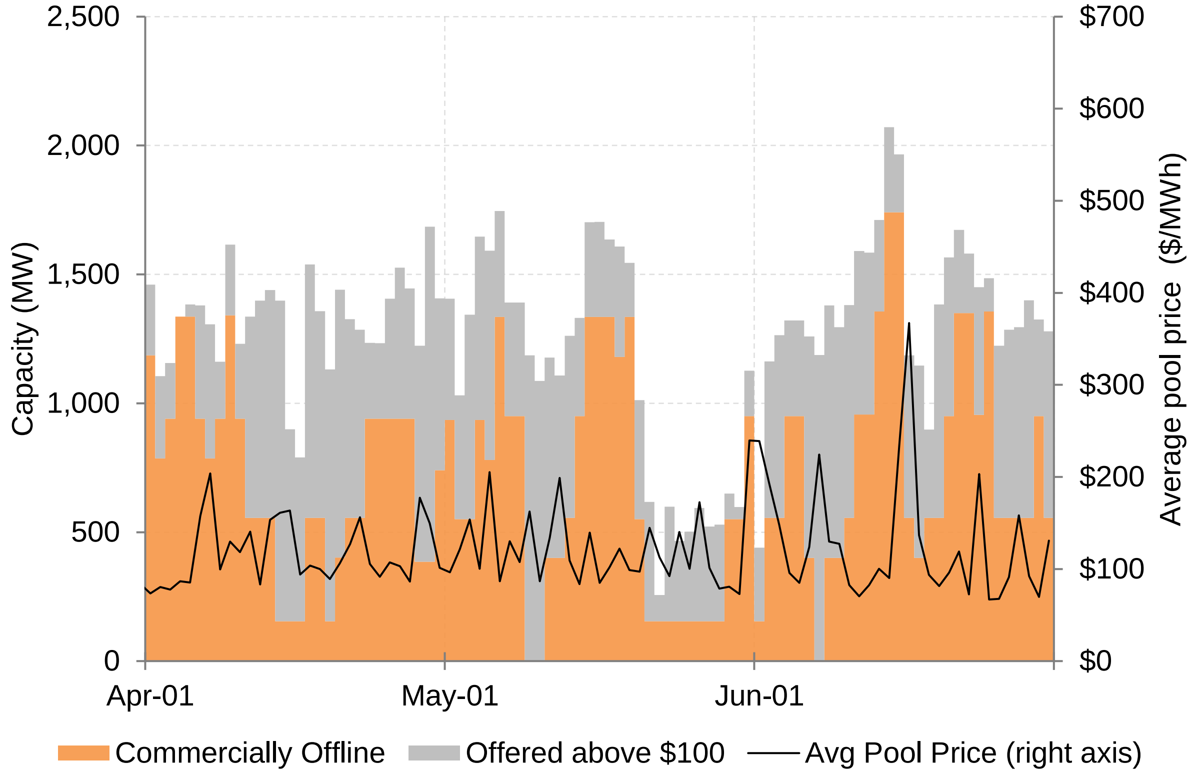


Figure 7 and Figure 8 illustrate the relationship between pool prices and supply cushion in Q2 2022 and Q2 2021. The lines in the figures illustrate the average pool prices in 200 MW supply cushion bins while the markers illustrate hourly data points. At higher supply cushion levels, the average pool price was higher in Q2 2021 relative to Q2 2022. This is consistent with the previous discussion regarding fewer higher-priced offers in Q2 this year.

Figure 8 shows the same scatter plot but focuses on pool prices under $140/MWh; most of the hours in Q2 2022 and Q2 2021 are confined to this price range. As shown, pool prices generally settled at a higher value in Q2 2022 compared to Q2 2021 for all supply cushion levels above 1,600 MW. This is largely the result of much higher natural gas prices in Q2 2022 compared to Q2 2021.

Figure 7: The relationship between supply cushion and pool price (year-over-year)

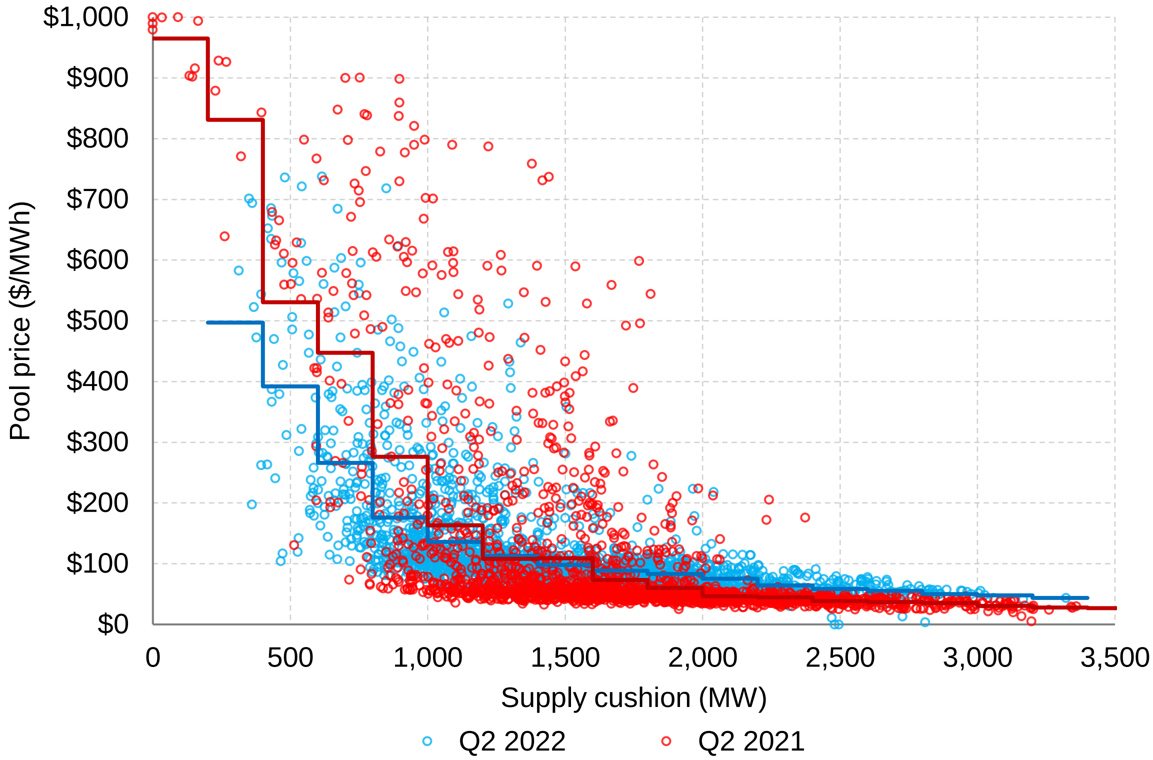
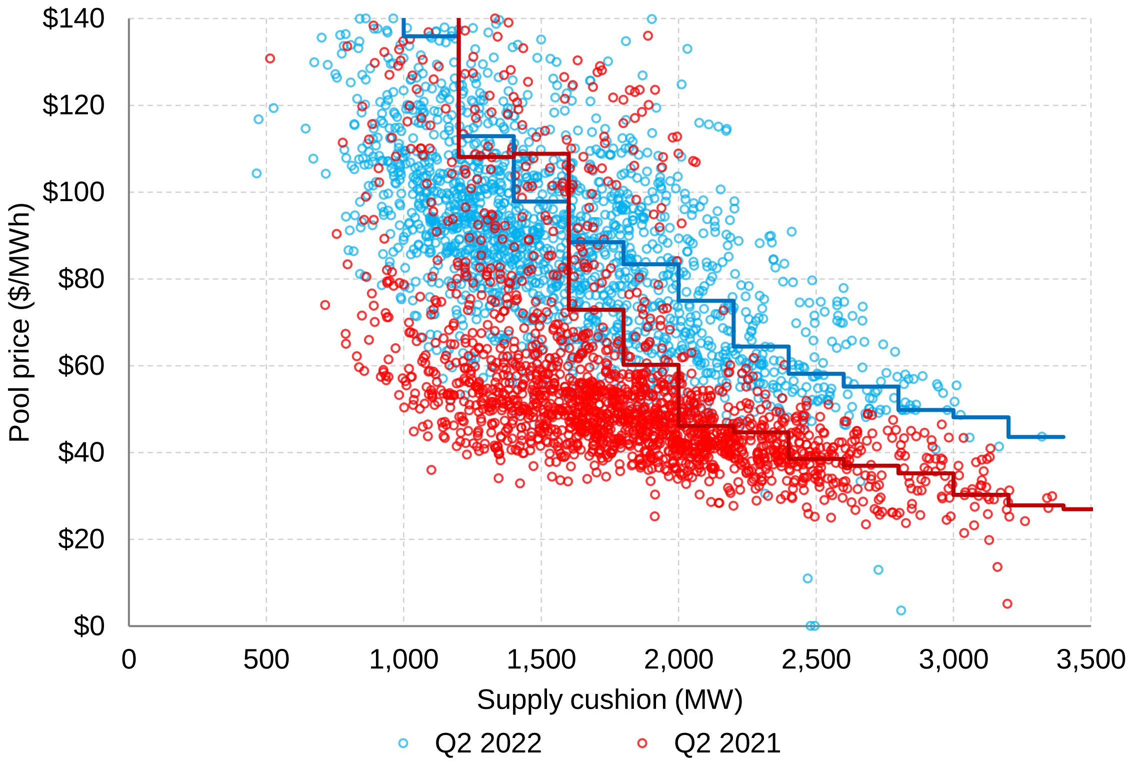


Figure 8: The relationship between supply cushion and pool price (year-over-year, under $140)



1.4 Imports and exports

Interties connect Alberta's electricity grid directly to those in British Columbia (BC), Saskatchewan (SK), and Montana (MATL), with the intertie to BC being the largest. For reliability purposes, the AESO treats BC and MATL as one intertie (BC/MATL) because a trip on the BC intertie would also cause MATL to trip offline. Indirectly, these interties link Alberta's electricity market to markets in Mid-Columbia (Mid-C) and California.

The prevailing price of power in Mid-Columbia (Mid-C) and California are two factors that influence the direction and magnitude of intertie flows to or from Alberta. When the Alberta pool price is above prices in Mid-C and California, increased import and reduced export volumes are typically seen, and the converse is true when pool prices are relatively low.

Figure 9: Daily average prices in Alberta, Mid-C, and California (SP15) (Q2 2022)

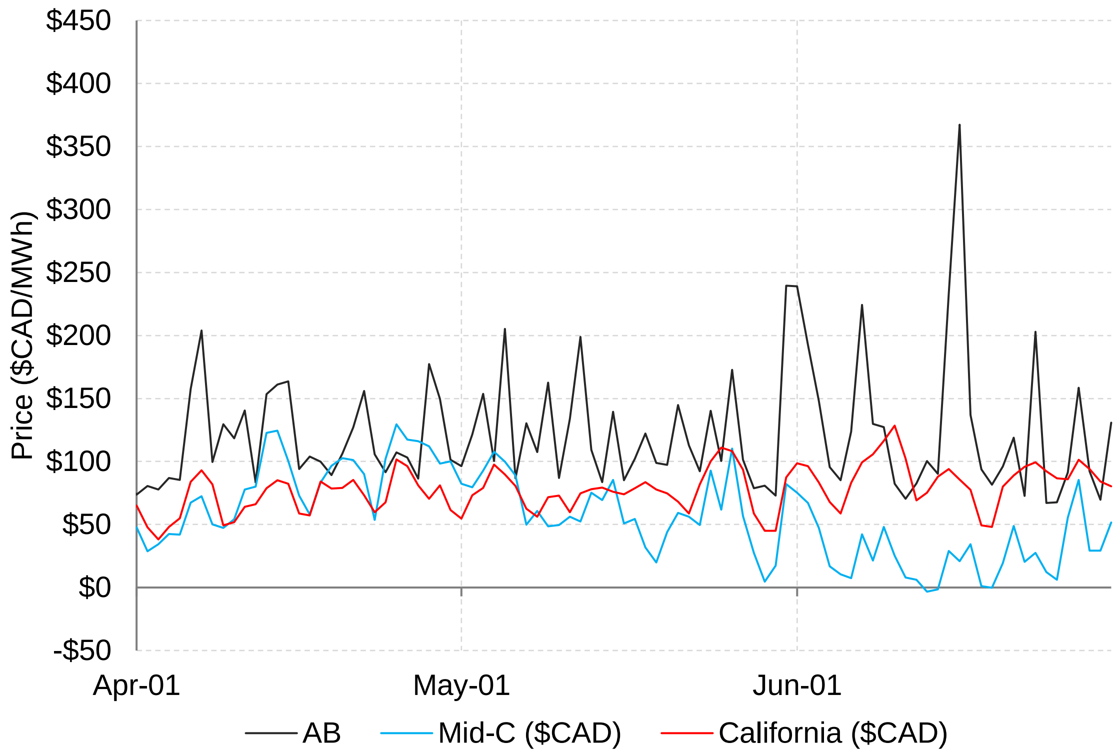


Figure 9 shows daily average power prices in Alberta, Mid-C and California[11] (in $CAD) over Q2. The direction of flow on the BC/MATL interties was largely imports into Alberta since pool prices were often higher than prices in Mid-C and California. As shown, Mid-C prices fell relative to prices in Alberta and California during June, which is likely the result of more realized and expected rainfall.[12]

---

[11] The California prices are from the South of Path 15 (SP15) Day-Ahead Market. SP15 is a major electricity hub in Southern California.

[12] USBR Website: see GCL (Grand Coulee Dam and FDR Lake), Reservoir Water Storage, for example

Figure 10: Daily average imports and exports on BC/MATL and the Pool Price – Mid-C price differential (Q2 2022, peak hours)

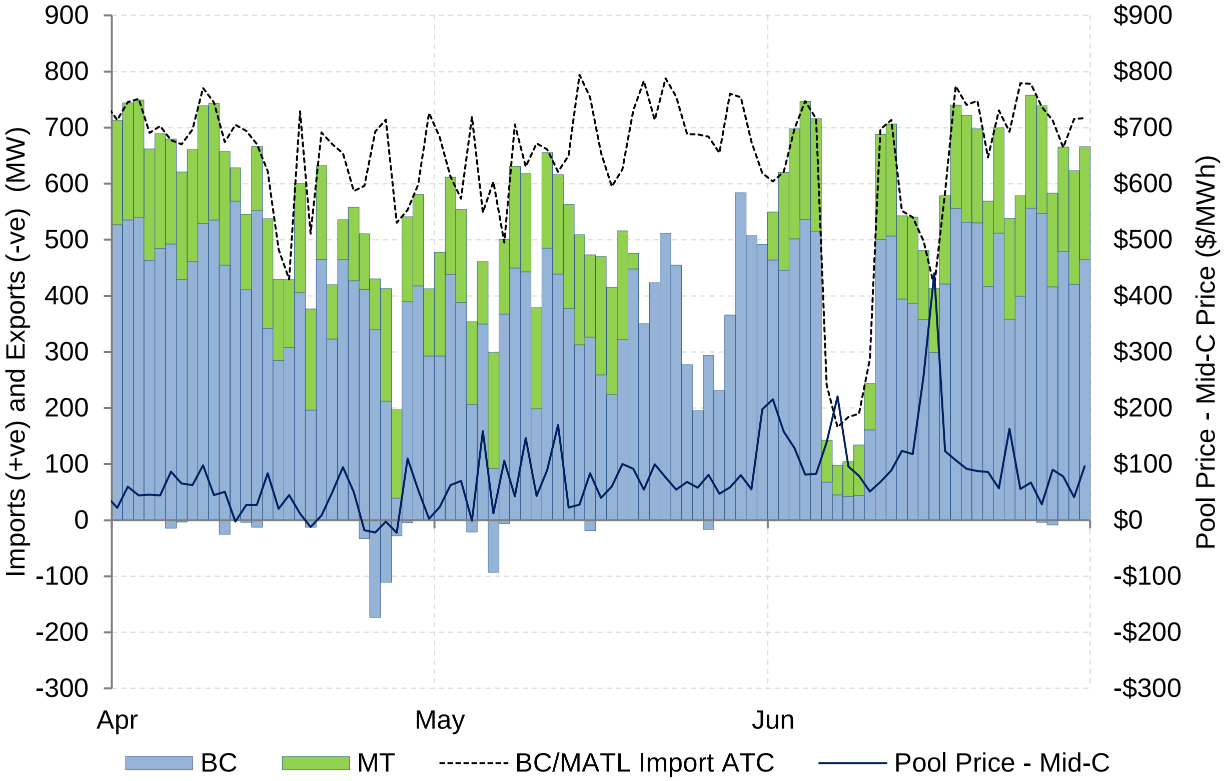


Figure 10 illustrates the daily average import and export volumes on the BC/MATL intertie during peak hours from April 1 to June 30. In mid-April the ATC on BC/MATL was constrained for a few days due to a line outage on 2L294, which reduced import capacity from around 700 MW to 450 MW when the pool price was above prices in Mid-C. From April 24 to April 27 Mid-C prices were often higher than Alberta pool prices during peak hours, which resulted in reduced imports and some exports volumes from Alberta to Mid-C.

In May, the average amount of net imports was 470 MW, a reduction of 19% compared to April. As shown in Figure 10, there was a substantial gap between import volumes and the import ATC in mid-to-late May, which indicates a low utilization of import capacity. Although the MATL line was out of service from May 19 to June 1, this did not significantly impact overall import ATC on BC/MATL because the BC intertie had increased capacity.

The average amount of net imports increased to 626 MW in June as pool price volatility increased and Mid-C prices fell. However, from June 6 to 10 a transmission line outage on 5L92 caused a material derate to the BC/MATL intertie (Figure 10) which reduced imports during this period. A derate on the BC/MATL intertie also occurred in mid-June and was a factor in higher pool prices on June 16, which saw the highest daily average pool price in Q2. Overall import utilization was much higher in June compared to late May, as Mid-C prices decreased materially relative to Alberta pool prices, which provided more incentive for imports into Alberta.

1.5 Carbon emission intensity

The MSA's mandate requires it to conduct surveillance related to the structure and performance of Alberta's electricity market. Consideration of market prices and offer behaviour, among other things, has long been integral to this work. The carbon emissions associated with electricity generation have become more important in recent years and now are essential to consider in any assessment of market performance. The MSA has undertaken to measure this performance in an ongoing, transparent, and consistent manner that is appropriate to the physical reality and fundamental economic principles of Alberta's electricity market.

In the context of power generation, carbon emission intensity is the amount of carbon dioxide equivalent emitted for each unit of electricity produced. Starting with the Q4 2021 report, the MSA has been publishing analysis of the carbon emission intensity of the Alberta electricity grid in its quarterly reports. The results are indicative only, in the sense that the MSA has not sought to collect the precise carbon emission intensities of assets from market participants, but rather relied on information that is publicly available. The methodology that underlies this analysis can be found in the Quarterly Report for Q4 2021.[13] The MSA welcomes any feedback and further suggestions from market participants regarding its approach and analysis in this section.

1.5.1 Quarterly results

The hourly average emission intensity is the volume-weighted average carbon emission intensity of the assets supplying the grid in a given hour. Figure 11 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q2 for the past four years. Figure 11 illustrates a shift of the distribution to the left, indicating a decline in carbon emission intensity over time. The displacement of coal-fired generation with natural gas-fired generation has been the major factor driving this outcome. In addition, increased wind and solar generation have reduced the carbon emission intensity. Mean hourly average emission intensities are reported in Table 4 showing year-over-year and quarter-over-quarter comparisons.

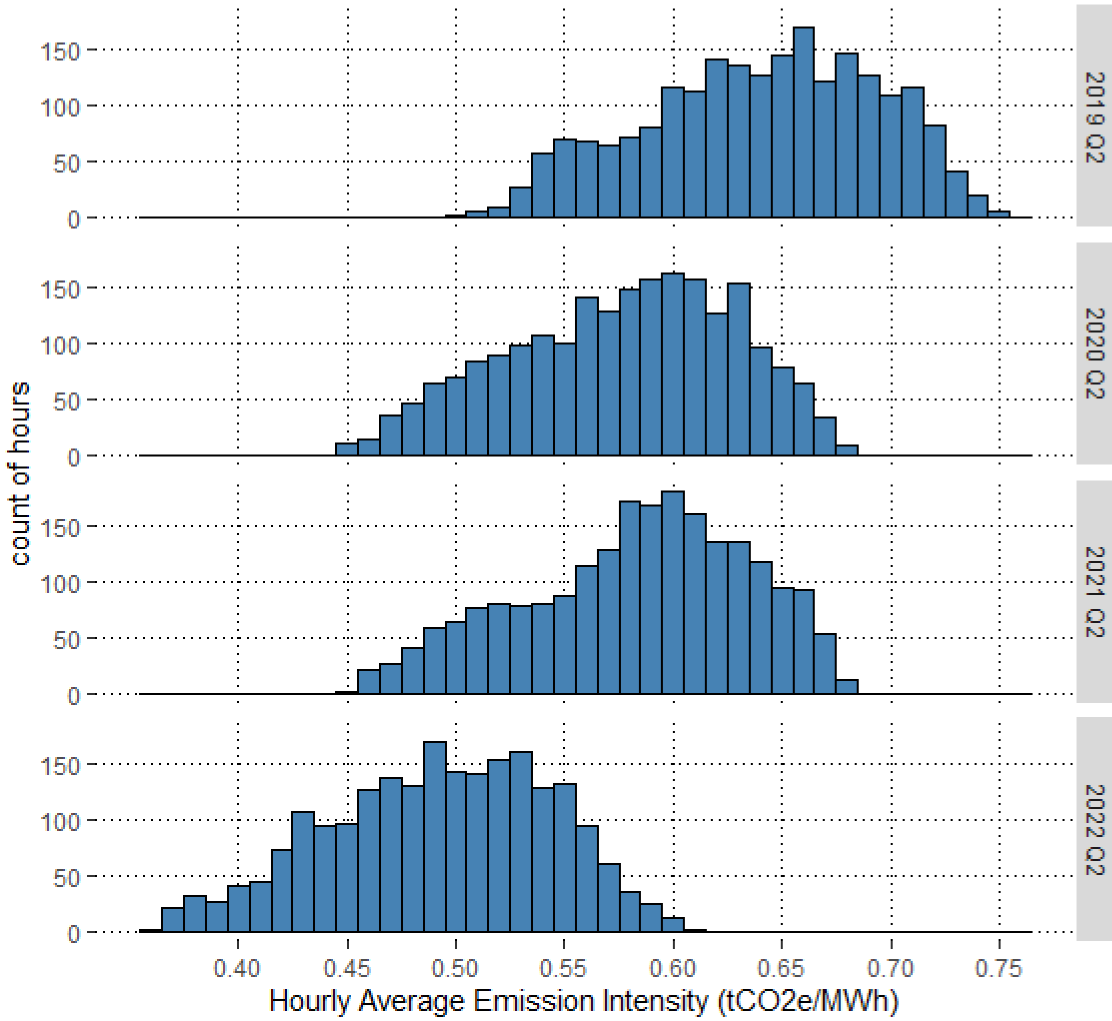
Table 4: The mean of hourly average emission intensities (tCO2e/MWh)

	Mean
2019 Q2	0.64
2020 Q2	0.58
2021 Q2	0.58
2022 Q2	0.49

	Mean
2021 Q3	0.55
2021 Q4	0.52
2022 Q1	0.50
2022 Q2	0.49

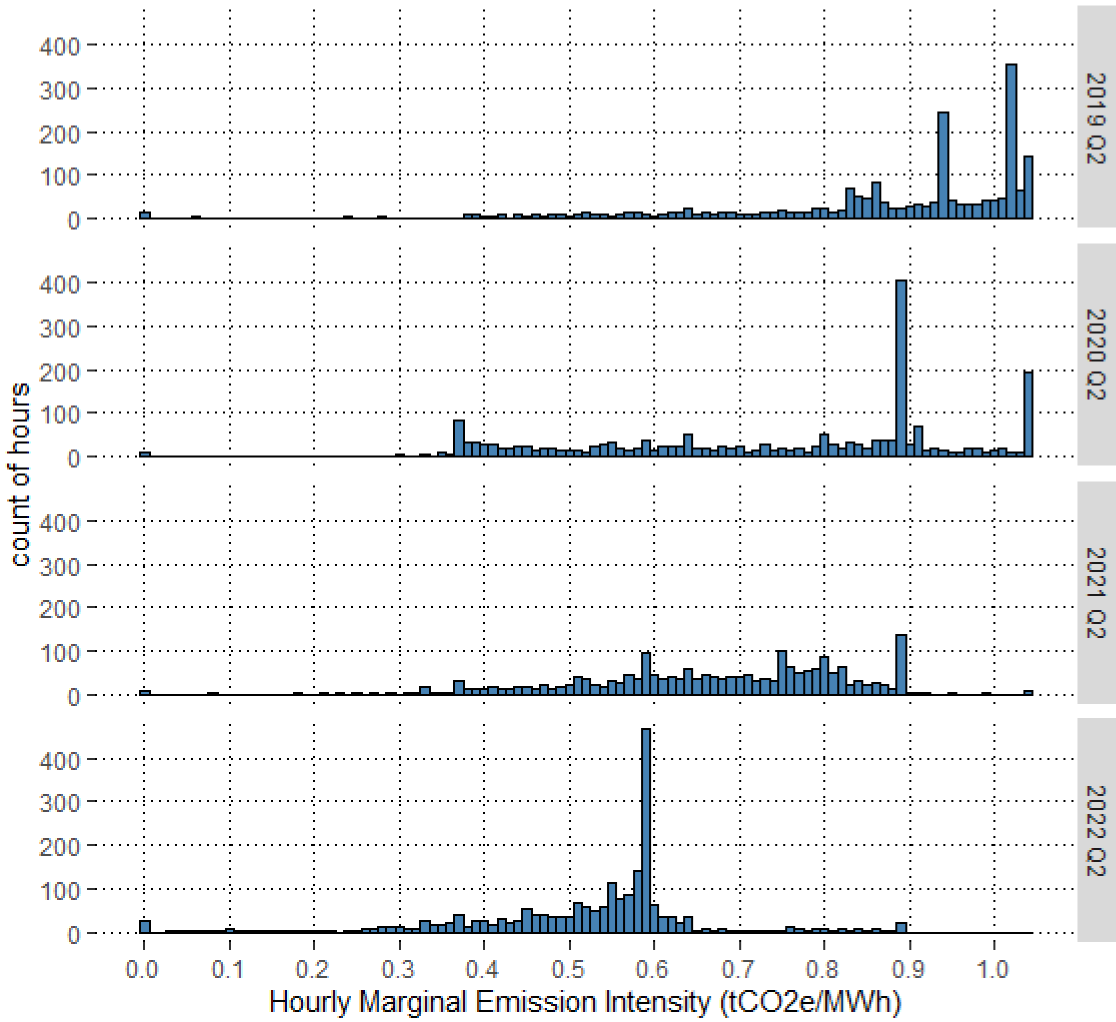
[13] Pages 25-26.

Figure 11: The distribution of hourly average carbon emission intensity in Q2 (2019 to 2022)



The hourly marginal emission intensity of the grid reflects the carbon emission intensity of the asset setting the System Marginal Price (SMP) in a given hour. In hours where there were multiple SMPs and multiple marginal assets, a time-weighted average of the carbon emission intensities of those assets is used. Figure 12 shows the distribution of the hourly marginal emission intensity of the grid in Q2 for the past four years. In Q2 2022, the increase in converted coal capacity, which set the price quite often was a material factor in the spike observed around 0.59 tCO2/MWh.

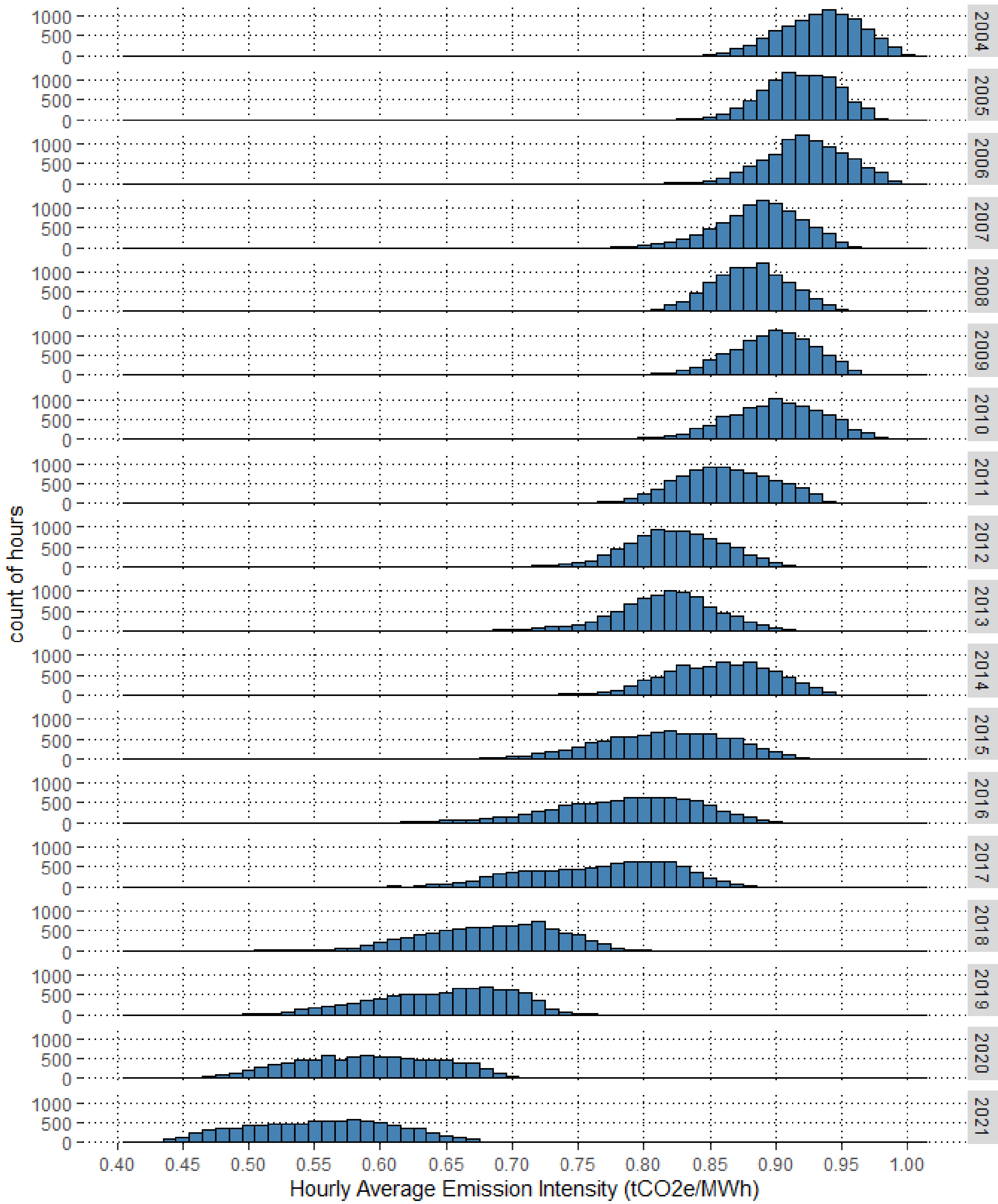
Figure 12: The distribution of hourly marginal carbon emission intensity in Q2 (2019 to 2022)



1.5.2 Long-term trends

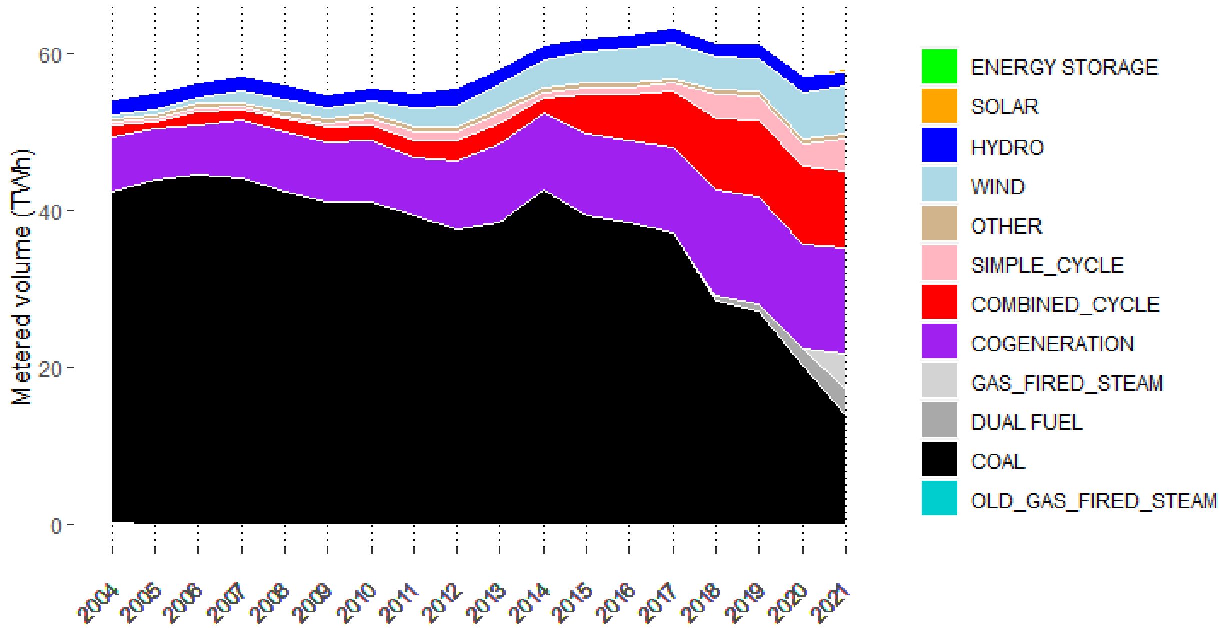
In this section, a longer-term view is taken with respect to the changes in carbon emission intensity. Figure 13 provides yearly distributions of hourly average emission intensity from 2004 to 2021. As shown, the distributions have shifted to the left since 2004 and more drastically since 2014. Concurrent with this change is the increase in the dispersion of the distributions, driven in part by the increase in wind generation.

Figure 13: Hourly average emission intensity distribution by year



The trends observed in Figure 13 can be traced in Figure 14, which shows net-to-grid generation volumes by generation type.[14]

Figure 14: Yearly total net-to-grid generation volumes by generation type[15]



An extended force majeure outage period declared for the SD1 and SD2 units from 2011 to 2013 contributed to a reduction in coal generation and the corresponding leftward shift in Figure 13 during this period. The more recent substantive reductions in emissions from 2015 onwards are largely reflective of the changes in carbon policy that have taken place over this period. Specifically, the carbon policy in the 2018-2019 period was directed by the Carbon Competitiveness Incentive Regulation (CCIR), which was then replaced by the Technology Innovation and Emissions Reduction (TIER) Regulation. These developments have resulted in changes to hourly dispatch dynamics as well as longer term changes in coal unit retirement and conversion decisions. Table 5 provides a summary of changes in the carbon pricing policy in Alberta.

---

[14] In our understanding, assets RG8-10 (Rossdale) and CG1-4 (Clover Bar Generating Station) that appear at the beginning of our study period can be described as gas fired steam assets. To distinguish them from the more recent gas fired steam assets they are categorized as old gas fired steam. These assets have small but positive metered volumes in 2004-2006.

[15] The chart includes assets greater than 5MW in size.

Table 5: Summary of changes in the carbon pricing policy

Year	Policy	Carbon price
2007	SGER (12% reduction from baseline)	$15/tCO2e
2016	SGER (15% reduction from baseline)	$20/tCO2e
2017	SGER (20% reduction from baseline)	$30/tCO2e
2018	CCIR (applied on emissions above 0.37tCO2e/MWh)	$30/tCO2e
2019	CCIR (applied on emissions above 0.37tCO2e/MWh)	$30/tCO2e
2020	TIER (applied on emissions above 0.37tCO2e/MWh)	$30/tCO2e
2021	TIER (applied on emissions above 0.37tCO2e/MWh)	$40/tCO2e
2022	TIER (applied on emissions above 0.37tCO2e/MWh)	$50/tCO2e

Figure 15 shows the yearly change in mean, median, maximum, and minimum hourly average emission intensity observed since 2004. A significant reduction is visible in all measures since 2014.

Figure 15: Hourly average emission intensity: descriptive statistics by year

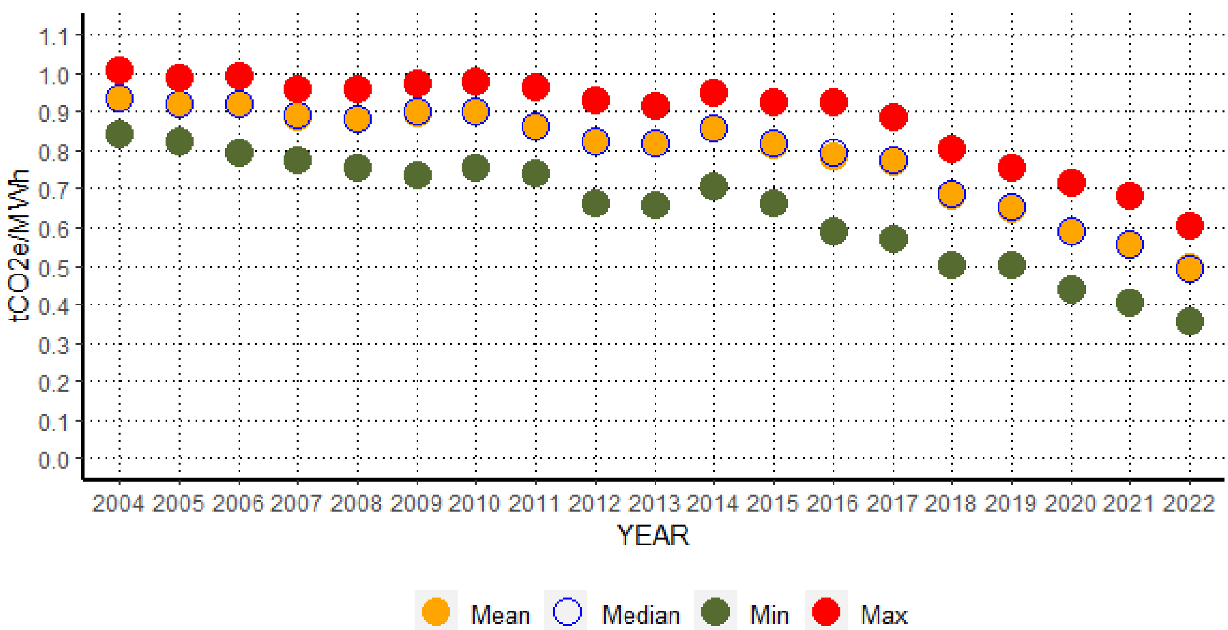


Figure 16 shows the same descriptive statistics for the hourly marginal emission intensity. As the marginal emission intensity is driven by one or a small number of assets in a given hour, it is expected that these descriptive statistics do not exhibit the same gradual patterns observed for the average emission intensities.

Figure 16: Hourly marginal emission intensity: descriptive statistics by year

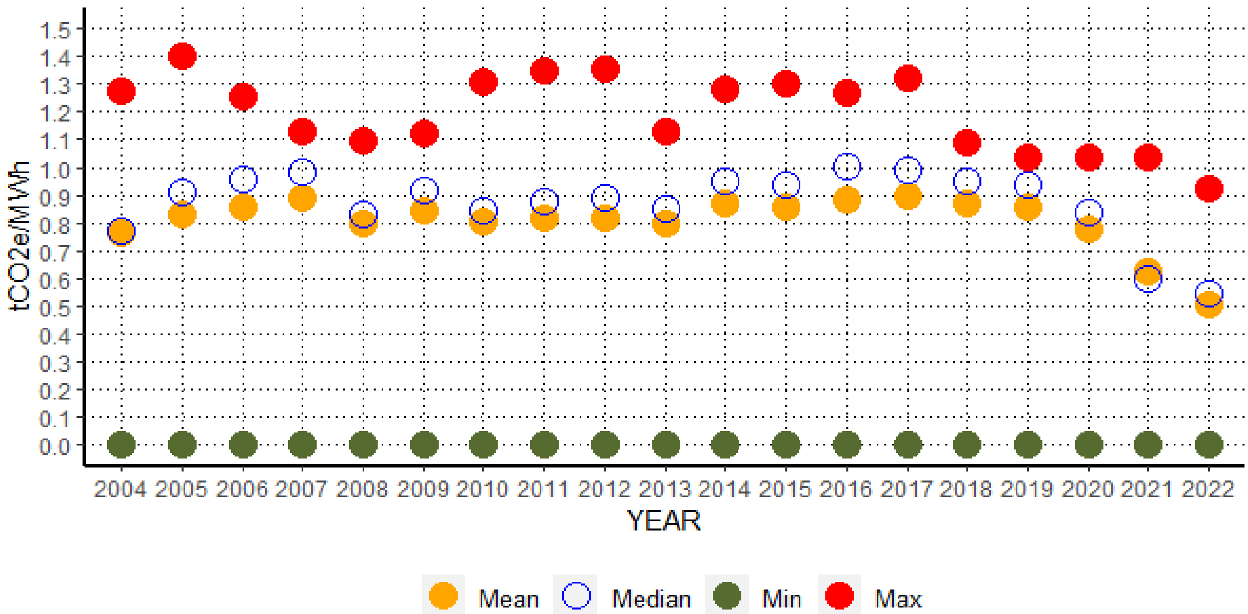
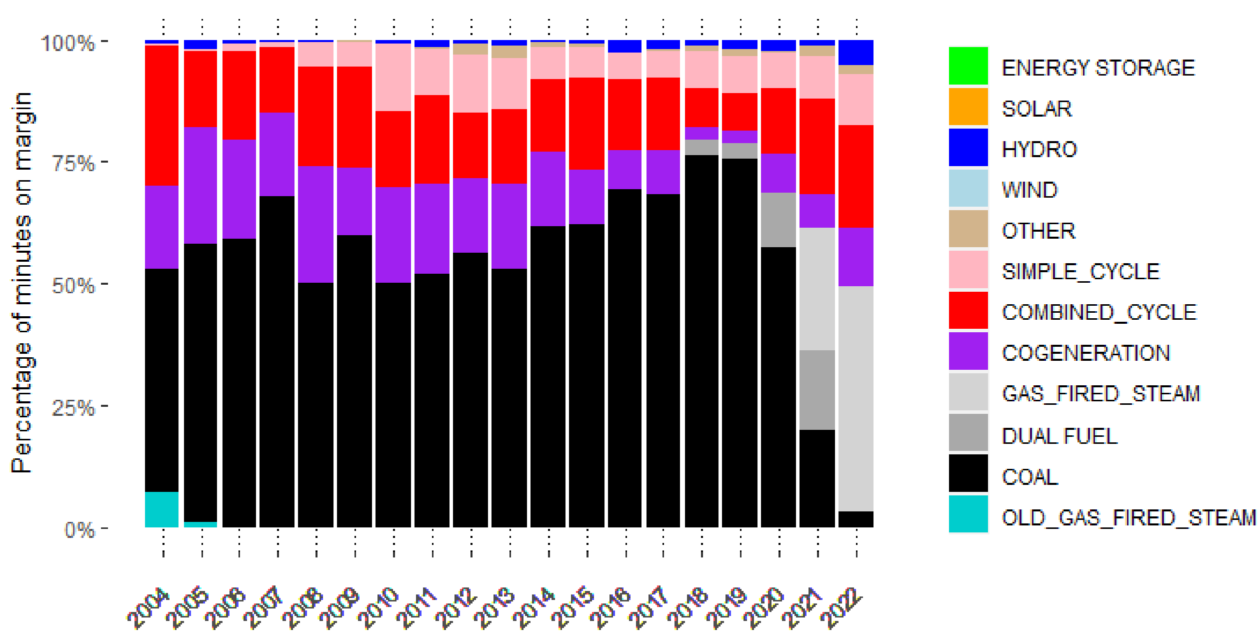


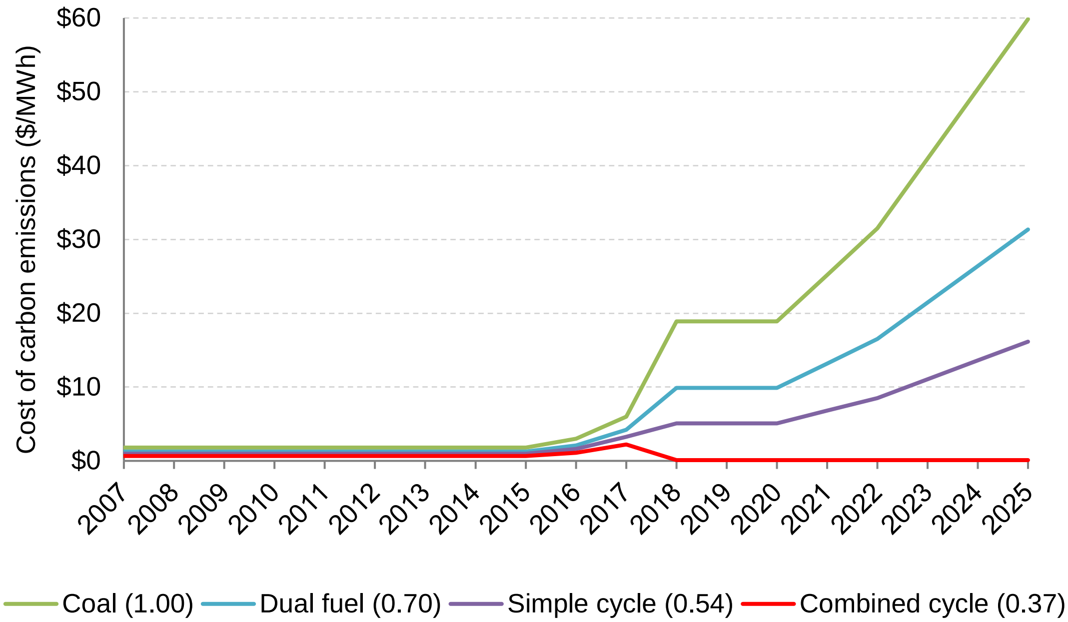
Figure 17 shows the drastic change in assets setting the SMP since 2019, which is behind the decline in mean and median marginal emission intensities observed in Figure 16. The increase in the percentage of time coal-fired assets were on the margin reflects the changes in the merit order resulting from the increase in carbon costs incurred by this type of asset. This increase has been reversed since 2020 with the conversion of most of these plants to burn gas instead of coal, as well as retirements.

Figure 17: Marginal assets by fuel type and year



The preceding figures illustrate the changes in average and marginal emission intensities over the years without necessarily establishing the driving force behind the changes. As the most the prominent influence, impacts of carbon pricing policy on different types of generic assets over time are shown in Figure 18. The impact on coal generation is large and, as discussed below, consequential.

Figure 18: Cost of carbon emissions for generic assets



1.5.3 Econometric examination of the impact of carbon price on coal-fired generation

To examine the impacts of the changes in carbon pricing policy, the MSA analyzed the data using a regression analysis. The results confirm that coal-fired generation has responded to the carbon price policy, where the impact of the carbon price under the CCIR/TIER framework has been significantly larger than that of under the SGER framework as shown in Figure 18. This is consistent with the expectation that market participants respond to incentives in the form of carbon prices, and the amount of emissions to which the carbon price applies matters.

A simple ordinary least squares regression shows that about 97% of the variation in the hourly average emissions intensity over the January 2005 to June 2022 period can be explained by the variation in the hourly share of coal-fired generation.[16] This is not surprising given that carbon emission intensities for coal-fired assets are significantly higher than those of other types of generation assets. This observation leads to the question of how coal-fired generation might have

[16] That is, the R-squared from the following regression is 0.97, with $\beta_0 = 0.360$ and $\beta_1 = 0.701$.

$$HourlyAverageEmissionIntensity_h = \beta_0 + \beta_1 * PercentageOfCoalGeneration_h + \epsilon_h$$

been impacted by the carbon pricing policies. Table 6 shows the coefficients estimated for the following regression:

$$CoalGen_h = \alpha_0 + \alpha_1 NetToGridDemand_h + \alpha_2 RenewableGen_h + \alpha_3 Imports_h + \alpha_4 Exports_h$$
$$+\alpha_5 CoalMaximumCapability_h + \alpha_6 CoalAvailableCapability_h$$
$$+ \alpha_7 CostofCarbon_h + \sum_{m=2}^{12} \alpha_{m+6} MonthDummy_m + \varepsilon_h$$

The data used in estimating this regression covers the period from January 2005 to the end of June 2022. Net-to-grid demand and renewable generation are estimated from metered generation volumes. Coal generation is expected to increase with demand and decrease with renewable generation (hydro, wind and solar). Imports and exports cover scheduled imports and exports on the BC, MATL, and Saskatchewan interties. As imports mean more supply, it is expected to have a negative impact on coal generation, whereas exports mean more demand and it is expected to have a positive impact on coal generation. Coal available (maximum) capability is the sum of available (maximum) capabilities across coal-fired assets in Alberta and is expected to have a positive impact on generation. Cost of carbon reflects the cost of carbon for a generic coal asset that has an emission intensity of 1tCO2e/MWh as shown in Figure 18 above. The regression includes month dummies to capture any monthly fixed effects.

Table 6: Coal-fired generation regression coefficient estimates

Net to Grid Demand	0.441*** (0.022)
Renewable Generation	-0.663*** (0.049)
Imports	-0.106 (0.067)
Exports	0.112 (0.092)
Total coal available capability	0.237*** (0.034)
Total coal maximum capability	0.041 (0.035)
Cost of carbon for coal generation	-77.162*** (3.150)
Constant	811.733*** (220.456)
Number of observations	153,359
Adjusted R-squared	0.930

*(Newey-West) Standard errors in brackets. *** indicate statistical significance at the 1% level.*

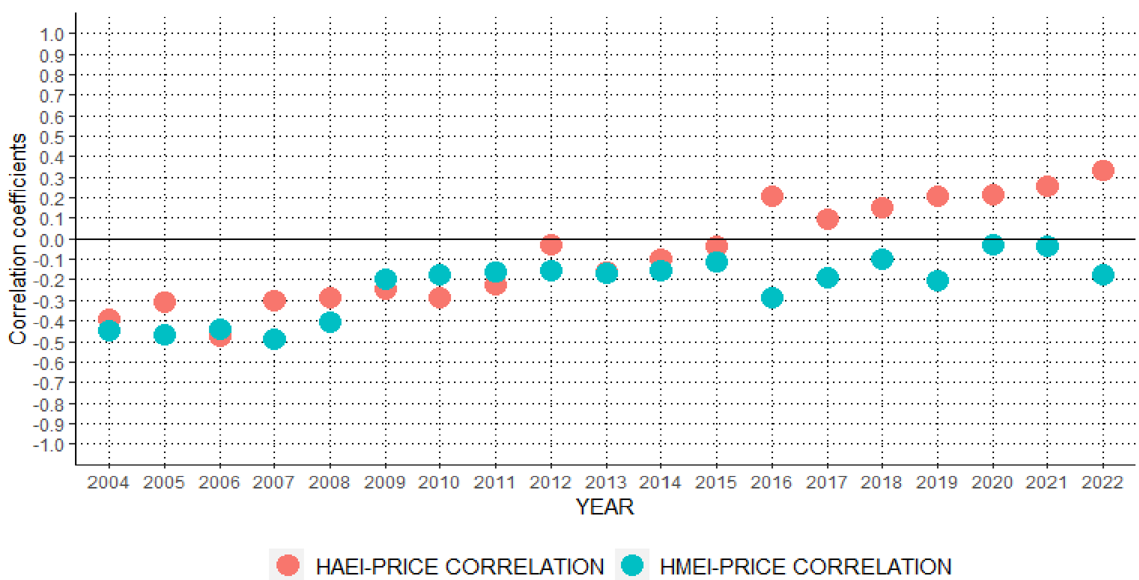
All the coefficient estimates in this regression have the expected signs. The impact of maximum capability on coal-fired generation is not statistically significant; however, this is not surprising given that available capability is highly correlated with maximum capability. Most notably, the results confirm that coal-fired generation has responded to the carbon price policy. Specifically, a one dollar increase in the carbon price increases the cost of carbon for generic coal generation by $0.63/MWh, given the 0.37tCO2e/MWh benchmark. The model implies that, for a $10/MWh increase in the carbon price, an average of 486 MW (0.63*10*77.162) decrease in coal-fired generation is expected over the sample period.

1.5.4 Relationship between pool price and average and marginal emission intensities

Given the impacts of policy on the generation mix and the consequent change in emission intensities, the MSA also looked at the co-evolution of these changes with the pool price. While a fulsome investigation of the relationship between the pool price and emission intensities or the causal impact of policy changes on pool prices is beyond the scope of this analysis, an examination of the annual correlation coefficients between pool price and emission intensities sheds some light on how this relationship evolved over time. However, it should be noted that this analysis focuses on the within-year, relatively short-term correlation. The relationship between the pool price and the emission intensity is also influenced by longer term decisions involving investments.

Figure 19 illustrates that the correlation between pool price and the hourly average emission intensity evolved gradually from a moderately strong negative to a moderately strong positive over time. The negative correlation in the past is consistent with the fact that high levels of coal-fired generation tended to be associated with lower pool prices. However, this relationship was never very strong and in fact it has reversed since 2016. The reversal is consistent with the increase in carbon prices, which was reflected in the offer prices of coal-fired assets.

Figure 19: Correlation of pool price with hourly average emission intensity (HAEI) and hourly marginal emission intensity (HMEI)



The within-year correlation between the hourly marginal emission intensity and pool price has never been strong and remained negative throughout the sample period. The moderately strong negative correlation observed until 2008 indicates that whenever coal-fired assets set the price, the price tended to be relatively low. The relationship between hourly pool price and marginal emission intensity has become less negatively correlated over time, with increasing carbon prices reflected in the offer prices, which then set the system marginal price. The within-year relationship, however, remains weak.

1.6 Assessment of market performance

1.6.1 Overview

In December 2012, the MSA released State of the Market Report 2012[17] and its Assessment of Static Efficiency in Alberta's Energy-Only Electricity Market.[18] In these reports, the MSA assessed the competitiveness of the Alberta electricity market, paying particular attention to market power and the efficiency of the market over the 2008 to 2011 period.

The Alberta electricity market has experienced significant changes since the release of these reports, including substantial changes to the nature of carbon pricing, the expiry of the power purchase arrangements, and recently, a large increase in natural gas prices. As a result, the MSA is revisiting several aspects of its earlier work. Of particular interest are the following questions:

1. Over a lengthy period, for a range of generation types that are present in the Alberta electricity market, how has the market revenue associated with electricity production and, if applicable, environmental attributes compared to the total cost of production? How has this comparison evolved over time?

2. Is there evidence that profit-seeking firms have or are responding to profitable opportunities to invest in the Alberta electricity market?

3. The exercise of market power generally occurs through supply being offered to the market at prices above marginal cost. In Alberta's competitive electricity market, the exercise of market power is expected to be disciplined by competition.

    a. How much market power has there been in the market and what have the trends been over time?

    b. To the extent that the exercise of market power is associated with high marginal cost supply being utilized in place of lower marginal cost supply, the total cost of production will not be minimized and there is a productive inefficiency. By how much has the observed exercise of market power raised production costs and what have the trends been over time?

    c. To the extent that the exercise of market power raises the pool price above the marginal cost of production, there may be consumers who forego consumption

[17] MSA State of the Market Report 2012, December 10, 2012.

[18] Assessment of Static Efficiency in Alberta's Energy-Only Electricity Market, December 21, 2012.

(compared to if the pool price was equal to the marginal cost of consumption) and there is a loss of allocative efficiency. By how much has the observed exercise of market power resulted in allocative inefficiency and what have the trends been over time?

4. Consider a hypothetical alternative market with no market power and therefore the pool price equal to the marginal cost of electricity production. How much lower would generator revenues have been for a range of generation types that are used in the Alberta electricity market? How may generation investment have been different had the counterfactual prices prevailed?

5. Is there reason to believe that the inefficiencies identified were necessary for the market to provide revenue sufficient to result in the observed investment?

6. What can we conclude about the performance of the Alberta electricity market from this analysis?

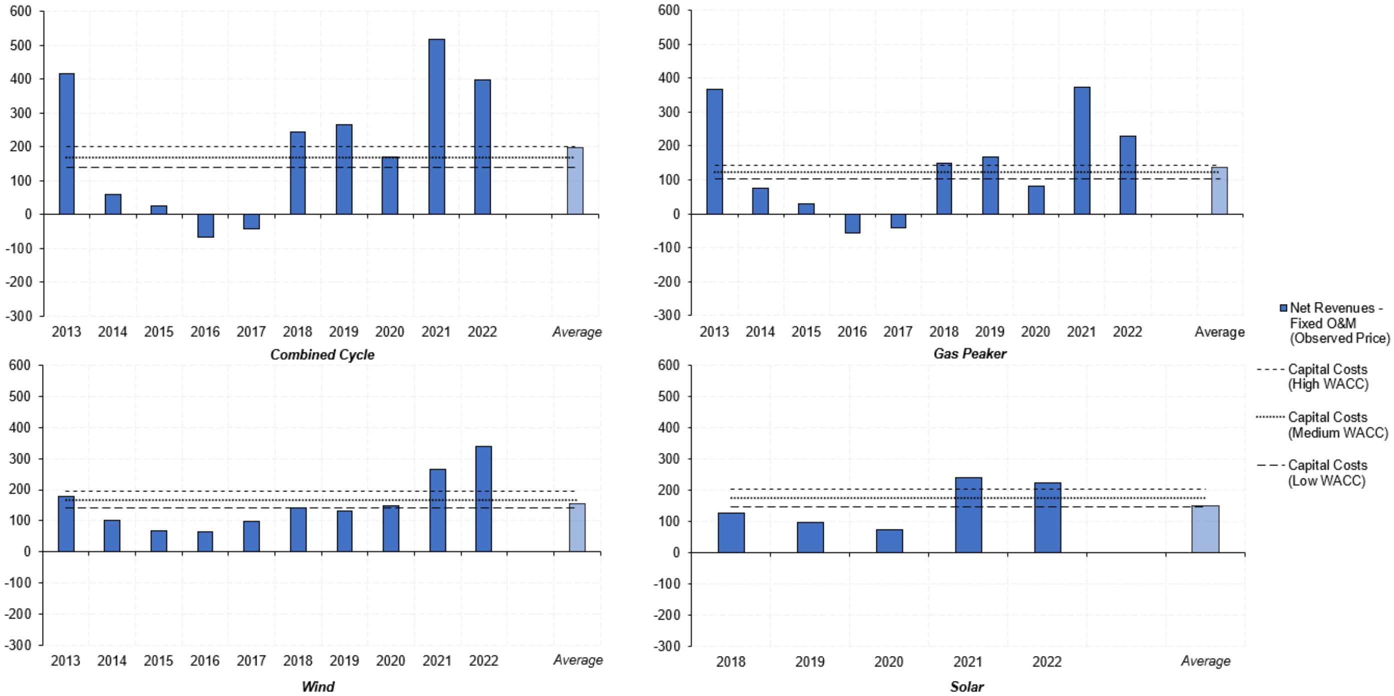
The MSA has considered these questions by looking at market outcomes spanning the period from January 2013 to June 2022. It is the MSA's view that this period is sufficiently long and characterized by a sufficiently varied set of market outcomes to draw preliminary conclusions on these questions.

A preliminary summary of the answers to these questions is below, with additional detail provided in the following sections.

1. The MSA conducted a net revenue analysis to assess the market revenues associated with electricity production and environmental attributes (where applicable) and how they compared with the total cost of production over time. Figure 20 illustrates the estimated annual net revenue less fixed operation and maintenance costs for a selection of generation technologies that are used in the Alberta electricity market (the vertical bars) and simple estimates of the annualized capital cost of generation capacity, including a return on and of capital for different weighted average costs of capital (WACC) (the dashed lines). The results indicate that generators have, on average, been able to earn sufficient net revenues in the energy market to recover their capital costs, indicating that investment in the Alberta market has been profitable for generators over time.

   It is also clear that there is substantial variation in this comparison across years. While generators earned robust net revenues in 2021 and 2022 (results for 2022 have been assumed to reflect the first six months of the year), this was not the case in many of the previous years. Variation in input costs and operating characteristics between technology types creates different investment incentives for different types of generators.

Figure 20: Comparison of net revenues (less fixed operations & maintenance cost) and capital costs by technology (2022$ thousands/MW-year), observed prices, 2013 to 2022



2. Generators have responded to these capital cost recovery signals by investing further in the Alberta market (Figure 21). Such investments have included the construction of new generation capacity (including significant amounts of non-emitting technologies), capacity additions to existing generators, and the refurbishment of over 2,800 MW of previously coal-fired generation to natural gas-fired. With limited exceptions, these investments were not financed or backstopped by ratepayers. All the while, as discussed in section 1.5, the carbon emission performance of electricity generation in Alberta has improved dramatically.

   Looking forward, 7,054 MW of generation capacity is currently under construction, all of which has in-service dates before the end of 2024 (Figure 22).

Figure 21: Additions in generation capacity, coal unit conversions by market share offer control year[19]

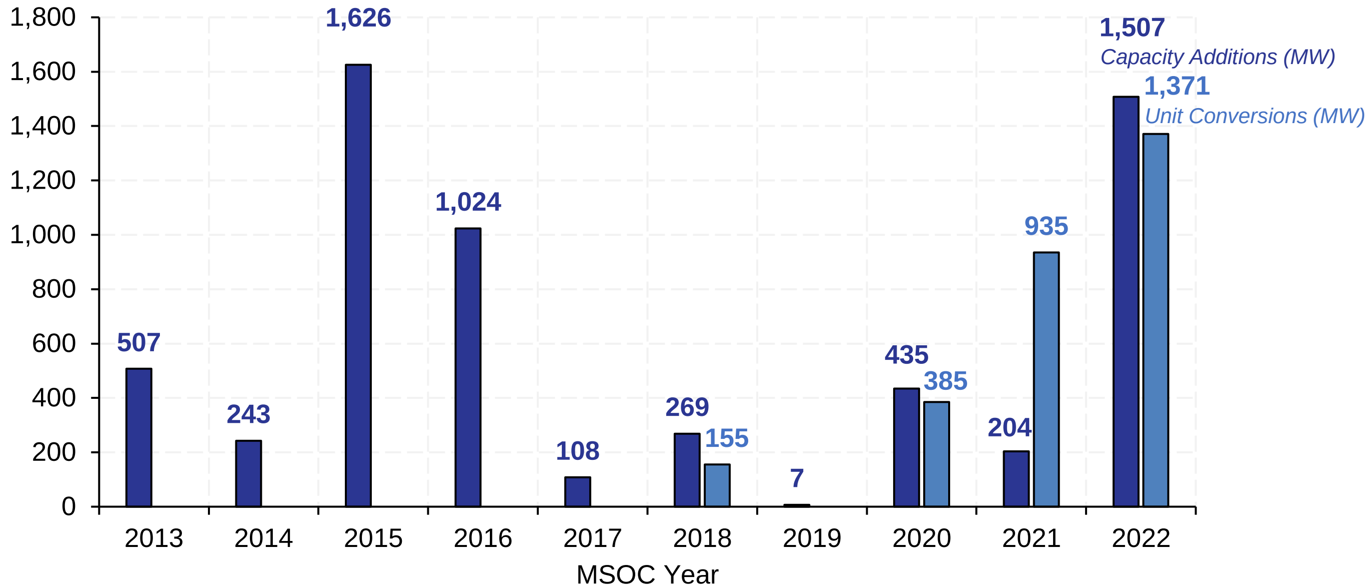
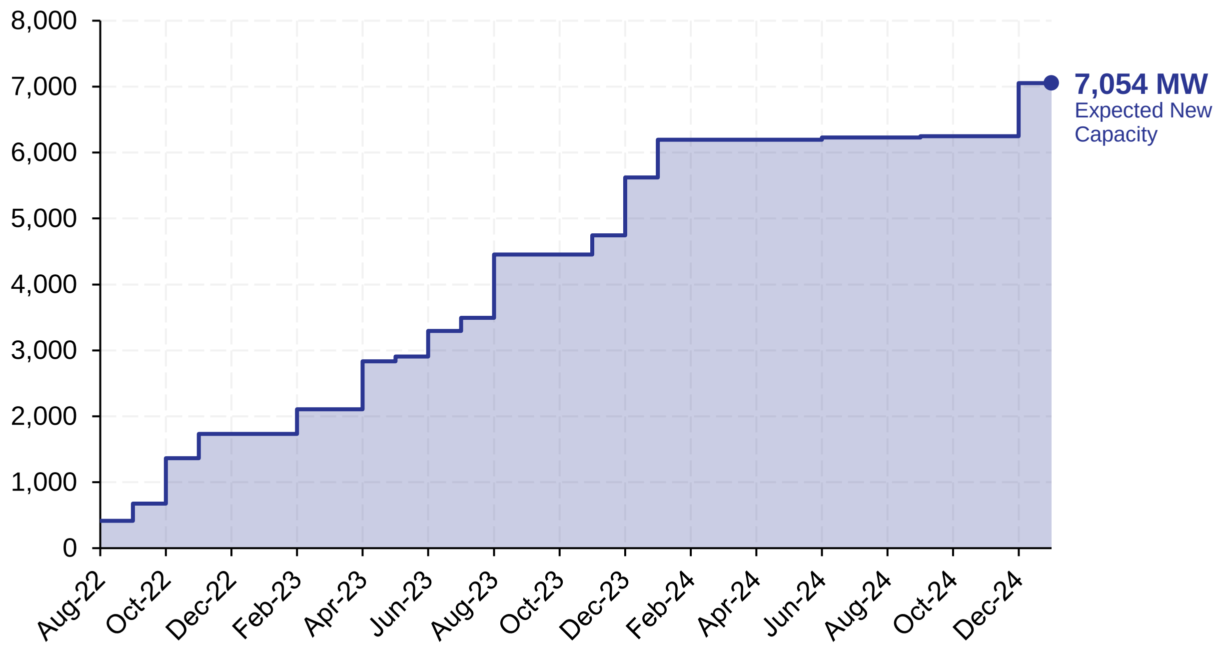


Figure 22: Cumulative capacity of generation projects under construction by expected in-service month, July 2022 to December 2024[20]



---

[19] Excludes retired capacity and reductions in capacity. Values representative of changes between market share offer control (MSOC) dates. For example, the 1,626 MW of capacity additions between the 2014 and 2015 MSOC dates are reflected as capacity additions in the 2015 MSOC year.

[20] AESO Long-Term Adequacy Metrics – August 2022 (assets listed on the CSD page as of August 3, 2022 were not included).

3. To assess market power in the Alberta market, the MSA estimated counterfactual energy market outcomes where generators offered their supply at short-run marginal cost. The MSA's key findings are:

    a. Price markups over marginal cost vary significantly between and within years, with market conditions determining the ability and incentive for market participants to exercise market power. Between 2013 and June 2022, price markups expressed as a percentage of pool prices were as high as 44% (in 2014) or as low as 6% (in 2017). While markups hit seven-year highs in 2021 (averaging 37% of pool price), they have subsequently fallen with input costs increasing and new capacity entering the market.

    b. The exercise of market power can change the order of generator dispatch at any given time. This can result in situations where demand is not met at the lowest feasible production cost. In these situations, there is productive inefficiency. Between 2013 and June 2022 productive inefficiency averaged $0.60/MWh in 2022$ (around 1% of average pool price), with some variation between years due to changes in the configurations of generator portfolios and input costs.

    c. The exercise of market power can result in pool price rising above marginal cost. To the extent that electricity consumption is foregone as a result, there is an allocative inefficiency. The MSA estimates allocative inefficiency averaged $0.71/MWh (in 2022$) between 2013 and June 2022 (around 1% of average pool price). While these allocative inefficiencies are higher than previous estimates released by the MSA, this reflects improvements to the MSA's demand estimation methodology that has found demand to be more price elastic than previously thought.

       The MSA has observed that, while some years exhibit significant allocative inefficiency (for example, 2013 and 2021), this is often followed by a decline in allocative inefficiency. This is consistent with the incentive of market participants to build new generation capacity to take advantage of relatively high markups, increasing generation supply in the process.

4. A counterfactual market where generators offer their supply at short-run marginal cost would have resulted in lower pool prices in all years, significantly so in some years (Figure 23).

   Associated with the lower counterfactual pool prices is lower counterfactual net revenue for all generators, though the impact on natural gas-fired generators is greater than on renewable generators (Figure 24). It is likely that there would have been less generation investment in the counterfactual than was observed. The extent of this effect is unclear because, in the market's long-run equilibrium, lower investment would result in higher market prices.

Figure 23: Observed and counterfactual pool prices, 2013 to June 2022

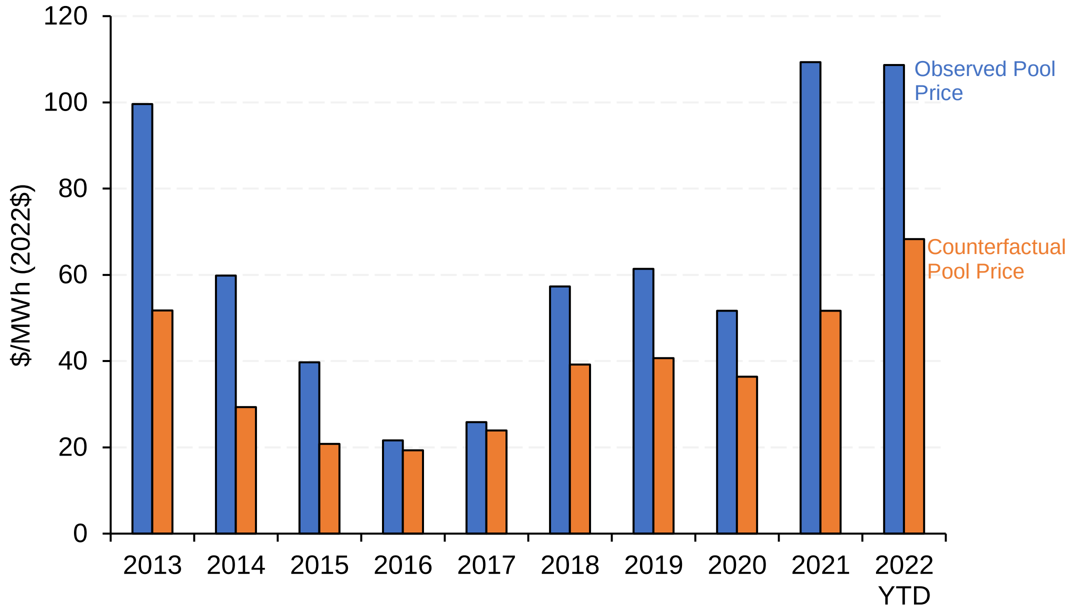
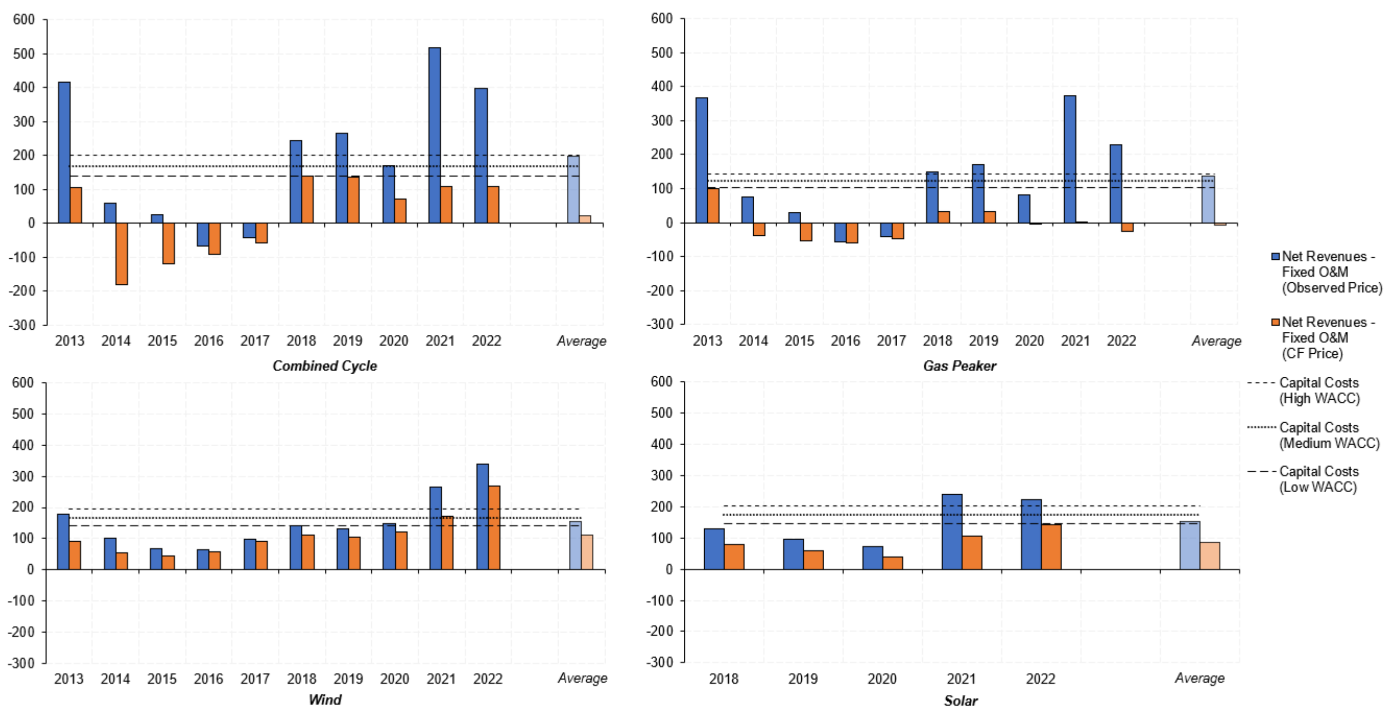


Figure 24: Comparison of net revenues (less fixed operations & maintenance cost) and annualized capital costs by technology (2022$ thousands/MW-year), observed and counterfactual prices, 2013 to 2022



5. It is likely that some degree of allocative inefficiency must occur for the market to provide generators with sufficient revenue to cover the full cost of investment in generation capacity that Alberta needs. Consistent with this view, the MSA has stated that it "believes that in an energy-only electricity market, the pool price must sometimes exceed short-run marginal cost, if the cost of generation capacity is to be recovered from the market" and that "market efficiency does not require that the pool price equal short-run marginal cost in each settlement interval."[21]

   Regarding productive inefficiency, the analysis does not indicate that investment is contingent on any amount of it. This does not mean that conduct which may result in productive inefficiency should be prohibited but that opportunities to improve the market design to reduce productive inefficiency should be considered whenever feasible. The MSA considers that market design improvements to minimize productive inefficiency will become increasingly important as, among other things, the electricity market continues to decarbonize, issues with unit commitment arise in the context of growing intermittent supply, and technology allows for increasing responsiveness from the demand-side participants in the market.

   For greater clarity, it is not the view of the MSA that allocative inefficiency is irrelevant; it should be reduced or avoided whenever possible. For example, the recovery of regulated sunk costs through charges that reduce consumption is inefficient for this reason.[22] The difference in the power pool is that the pool price is the only available source of revenue (setting aside payments for ancillary services) to fund generation investment that Alberta needs.

6. While market power and inefficiency exist in the Alberta market, this has enabled sufficient investment in generation capacity to reliably meet demand without the need for direct funding by ratepayers or taxpayers, or unnecessarily increasing risks for investors. The same cannot be said of many other markets.

   The MSA is satisfied that periods of relatively high markups resulting from the exercise of market power are not generally sustainable for significant periods of time under the prevailing market design as such periods incentivize the construction of new capacity and may encourage forward hedging behaviour that incentivizes lower offer prices in the

[21] MSA Enforcement Statement: Economic Withholding, June 29, 2020.

[22] For example, regarding the recovery of sunk transmission and distribution network costs from residential consumers, the MSA's Supplemental Retail Market Report for Q1 2022 stated that "variable charges that correspond to costs that increase when a consumer consumes more energy are economically efficient. However, to the extent that variable charges are used to recover fixed costs, they may result in economic inefficiency by causing a consumer to avoid consumption that they value in excess of cost. The magnitude of this inefficiency depends on how responsive consumers are to price changes (i.e., the own-price elasticity of demand)." The inefficiency referred to here was allocative inefficiency. The report went on to say that "in the past, consumers may have been sufficiently non-responsive to price changes (price inelastic) that this inefficiency was negligible. However, technological change is likely to result in consumers or intermediaries acting on their behalf being more responsive to price changes, which would increase the inefficiency associated with using variable charges to recover fixed costs. By virtue of being fixed, fixed charges do not result in economic inefficiency."

energy market. Additionally, complementary markets exist to mitigate the impacts of high or volatile pool prices. Large consumers and generators can trade hedges in the forward market, locking-in a price. Likewise, retail customers have access to a wide variety of fixed-rate contracts (addressed elsewhere in the MSA's quarterly reporting).

The analysis and conclusions in this section are consistent with the MSA's Enforcement Statement regarding economic withholding: the MSA does not consider economic withholding by a market participant, in and of itself, to qualify as conduct that does not support the fair, efficient and openly competitive operation of the electricity market.[23]

The MSA routinely monitors the performance of the Alberta market and expects to revisit questions around performance in subsequent reporting.

For greater clarity, these findings do not imply that the MSA has no concerns about Alberta's electricity market going forward. Among other things, the MSA has identified concerns related to (i) the price floor in light of substantial out-of-market value for the environmental attributes of some generation[24] and (ii) generator commitment through the interaction of generator cycling (including use of long lead time status) and sudden decreases in renewable generation.[25]

1.6.2 Net revenue

Net revenue analyses can add context to observed pool prices as they can be used to compare prices to a set of assumed costs for hypothetical assets to examine the profitability of the energy market for different asset types. This section provides an overview of the net revenue analysis used in part to construct Figure 24 above. Additional detail regarding assumptions and data sources used in the MSA's analysis can be found in Appendix A.

By analysing unit net revenues using both observed and counterfactual pool prices, meaningful conclusions about the state of Alberta's energy market can be drawn. Generators may choose to invest in the Alberta market if they believe they will be able to recover their capital costs. The Alberta electricity market allows economic withholding to encourage such investment, enabling generators to price their assets above marginal cost. As such, the MSA would expect generators to offer such that some degree of capital cost recovery is possible in individual years, subject to market conditions. The degree of capital cost recovery would be expected to vary for different unit types, with relatively low-marginal cost units being expected to recover their capital costs sooner than other units, all else equal.

The MSA's net revenue analysis assesses the revenues different generating technologies could have earned in the energy market less their variable costs of production. Generators incur fixed

---

[23] *Ibid*, Page 2.

[24] MSA's Quarterly Report for Q1 2021 at section 1.5

[25] MSA's Quarterly Report for Q1 2022, PDF page 12.

operating and maintenance (O&M) costs on an annual basis; these were subtracted from the annual net revenues.

For ease of annual comparisons, results from the first six months of 2022 have been scaled to enable year-over-year comparisons; as a result, 2022 results may not be representative of actual net revenues received throughout the remainder of the year.

In the case of natural gas generating units (combined cycle and peaker technologies), the MSA incorporated carbon compliance costs into the variable costs of production. Carbon credit sales were accounted for in the revenues of renewable generating units (wind and solar technologies).

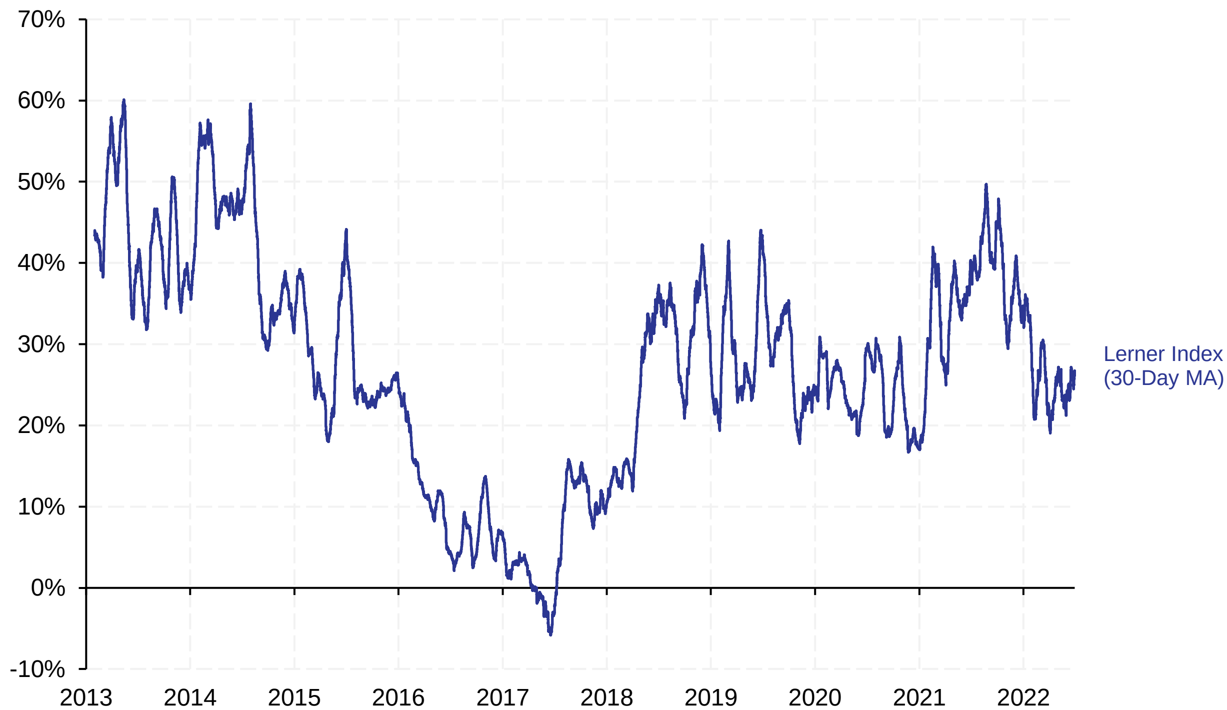
1.6.3 Price markups

Generators exercise market power by offering their capacity above marginal cost. The Lerner index measures the market markup (price less marginal cost) expressed as a percentage of the price and is used as a proxy measure of the exercise of market power. Where measures of allocative inefficiency capture the impact of such market markups on foregone net demand, the Lerner index is a measure of the magnitude of such markups.

The Lerner index has fluctuated dramatically since 2013 (Figure 25); reaching sustained highs in 2013 to 2014, followed by significant declines until 2017 with the entry of new thermal assets and marginal cost pricing by a significant market participant. The Lerner index subsequently stabilized at around 20 to 40% between 2018 and 2019, fell during the first year of the COVID-19 pandemic, and rose over the first half of 2021 in response to changes in offer behaviour and the return of PPA units to the unit owners. Despite similar year-over-year pool prices in the first half of 2022, the Lerner index fell significantly year-over-year with the increase in input costs in the first half of the year (particularly natural gas prices), despite significant thermal asset retirements in January and April.

Although market markups reached highs in 2021 not seen since 2014, their lack of persistence into 2022 is indicative that unusually high markups do not easily persist in Alberta’s energy market. Additionally, such periods encourage generators to invest in the Alberta market with new generation projects. The MSA believes such dynamic efficiency benefits are reflected in the current slate of planned generation projects.

Figure 25: Lerner index (30-day moving average), 2013 to June 2022



1.6.4 Market efficiency

The same counterfactual price data used to estimate price markups was used to assess market efficiency. To generate this counterfactual price data and market efficiency analysis, the MSA relied on several assumptions listed in Appendix A.

In its assessment of the market efficiency, the MSA examined both static efficiency losses and the state of dynamic efficiency in the market. Static efficiency losses represent the societal loss that occurs from deviating away from a set of efficient outcomes at a single (short-run) point in time. Dynamic efficiency refers to the long-run state wherein production processes may be improved and continuous investment in required generation capacity is possible.

The MSA examined two types of short-run efficiencies: allocative efficiency and productive efficiency. Allocative efficiency refers to the state where the net benefit to consumers or producers attained using the market's resources are maximized. Productive efficiency refers to the state where the production costs needed to serve the observed level of demand are minimized. Additional discussion regarding allocative and productive efficiencies can be found in Appendix A.

In its 2012 static efficiency assessment, the MSA estimated the average energy market static inefficiency was $0.72/MWh (nominal dollars) between 2008 and 2011, or 1.1% of the average pool price.[26] In its update to this static efficiency assessment, the MSA finds the average energy

[26] Assessment of Static Efficiency in Alberta's Energy-Only Electricity Market, December 21, 2012, PDF Page 7.

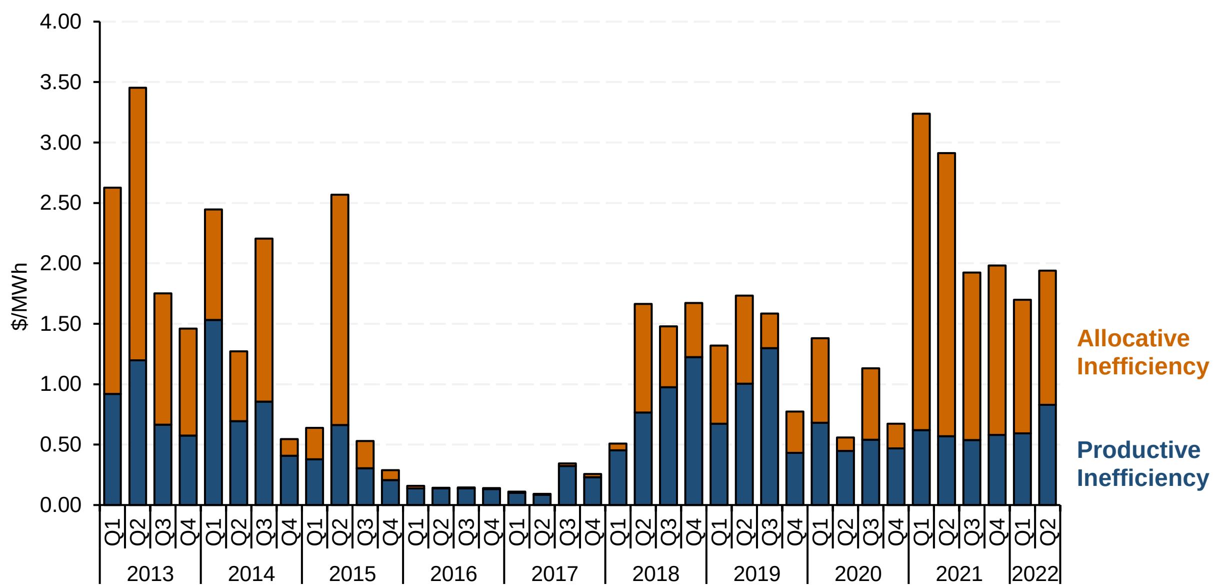
market static inefficiency was $1.16/MWh (nominal dollars) between 2013 and June 2022, or 2.1% of the average pool price. In real dollars,[27] the average 2013 to June 2022 static inefficiency was $1.32/MWh, compared with $0.94/MWh between 2008 and 2011. Despite changes to the MSA's model that would tend to increase estimates of static inefficiency,[28] the MSA's 2013 to 2022 estimates are comparable with estimates of static inefficiency between 2008 and 2011.

Static inefficiency varied significantly over the 2013 to 2022 period examined by the MSA (Figure 26). Relatively high static inefficiency occurred throughout 2013 and most of 2014, but generally declined in 2015 following the commissioning of the Shepard Energy Centre, a large low-cost combined cycle generator. The termination of various coal PPAs in 2016 and 2017, and the subsequent offering of these coal assets at short-run marginal cost, further reduced static inefficiency.

These low static inefficiencies persisted until 2018, when tighter market conditions in some hours, coal asset mothballing and retirements, and changes in participant offer behaviour pushed up pool prices despite low prevailing natural gas prices, increasing static inefficiency. The changes in offer behaviour and the declining cost of natural gas played key roles in the significant increases in productive inefficiency.

Following a similar year in 2019, static inefficiency generally declined in 2020, primarily as a result of the COVID-19 pandemic's impact on demand, increased renewable capabilities, and more competitive offer behaviour compared to the previous two years.

Figure 26: Average static inefficiency by quarter, Q1 2013 to Q2 2022 (2022$)



[27] References to real dollars reflect prices as of June 2022.

[28] In contrast to the 2012 analysis, the MSA did not assume a perfectly inelastic demand curve at prices below $75, an assumption that would otherwise reduce estimates of allocative inefficiencies.

The return of the PPA units to the unit owners in 2021, with corresponding changes in offer behaviour, as well as tightening supply conditions led to a significant increase in static inefficiency in the first half of 2021. These inefficiencies declined alongside significant increases in natural gas prices in the second half of 2021 and have generally stabilized at a quarterly average of around $2/MWh since then. Notably, the highest quarterly static inefficiency experienced in 2021 was less than the inflation-adjusted static inefficiencies at their peak in 2013.

The magnitude of allocative inefficiencies over the last year and a half are not typical for the Alberta market. However, during this period the MSA has observed an increase in new and planned generation projects commensurate with the relatively high prices. Such new and planned generation is consistent with the design of the Alberta market: inefficiency in the short-run is acceptable to incentivize investment and promote dynamic efficiency in the long-run.

One prominent feature of the Alberta market evident in Figure 26 is the relative persistence of productive inefficiency over time. A market participant only has significant incentive to offer its own units in order of their respective marginal costs to avoid incurring more costs than needed for a given level of revenue. Similarly, since offers are typically not marginal cost based, the merit order does not necessarily reflect the order of assets that would have been used if the sole purpose was to reduce total dispatch cost. It would do so only if market power exercise would manifest in offer prices that does not change the ordering of assets based on costs. As such, productive inefficiency is not surprising. In periods where productive inefficiencies are low (such as 2016-17), coal units were more often offered close to marginal cost, often by a single participant, leading to fewer opportunities for market power exercise and thereby increasing productive efficiency. Such circumstances are unusual in the Alberta market, where generators typically control units of varying marginal costs offered as a portfolio into the energy market.

2 THE MARKETS FOR OPERATING RESERVES

There are three types of operating reserves (OR) that the AESO system controllers use when there is an unexpected imbalance or lagged response between supply and demand: regulating reserve, spinning reserve, and supplemental reserve. Regulating reserve (RR) provides an instantaneous response to an imbalance of supply and demand. Spinning reserve (SR) is synchronized to the grid and provides capacity that the system controller can call upon in a short amount of time when there is a sudden drop in supply, for example. Supplemental reserve (SUP) is not required to be synchronized but must be able to synchronize quickly if called upon by the system controller.[29] These products are all bought by the AESO through day-ahead auctions.

2.1 Costs and volumes

In Q2 2022, both total and average OR costs were lower than in Q2 2021. Total OR costs in Q2 2022 were $69 million, compared to $90 million in Q2 2021. Table 7 shows the year-over-year average cost changes for active OR products in Q2. As shown, average active OR costs decreased while average pool price increased. Generally, active OR costs and pool price are expected to be correlated because the opportunity cost of providing active OR is often forgoing the sale of energy in the power pool. Moreover, active prices are directly indexed to pool price. Decreasing active OR costs concurrent with increasing pool prices are the result of increased competition in the OR market and higher natural gas prices.

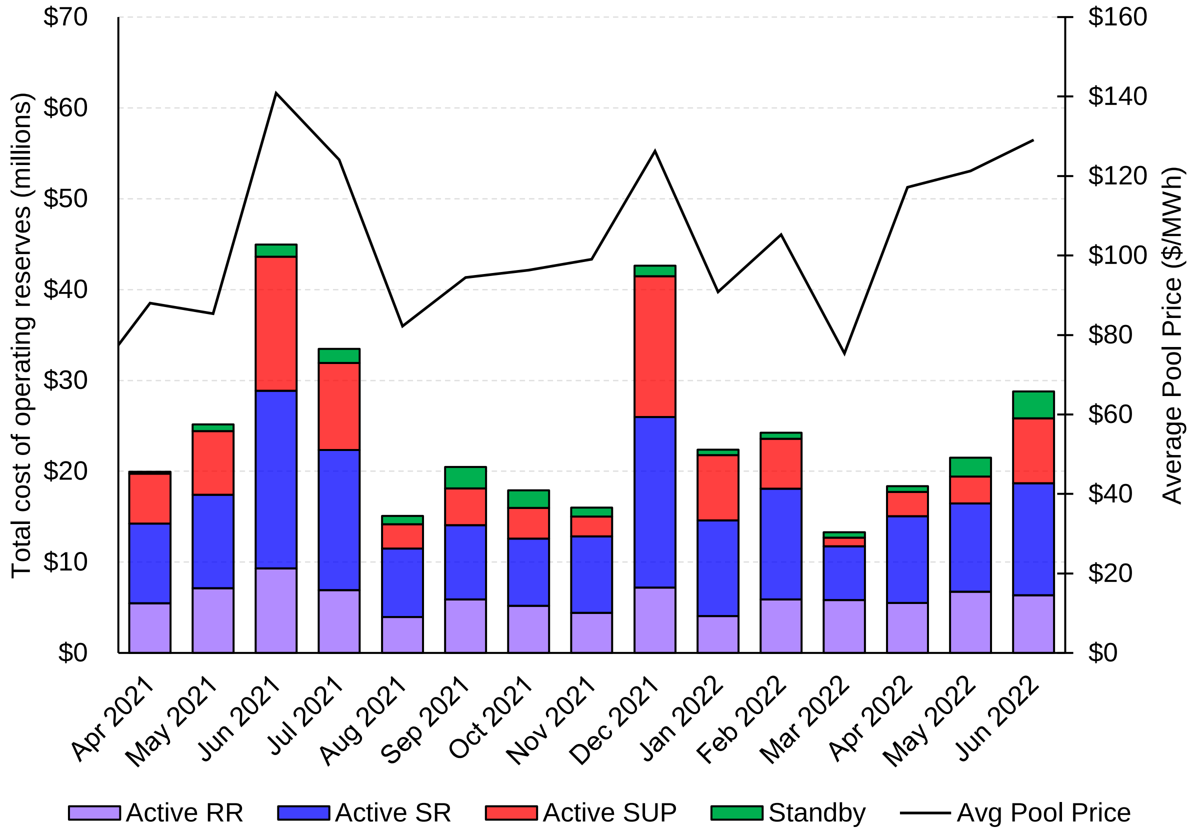
Table 7: Average cost ($/MWh) of active OR products

Product	Q2 2022	Q2 2021	Q2 2022 less Q2 2021
Spinning	$55.89	$68.64	($12.75)
Supplemental	$22.57	$48.49	($25.92)
Regulating	$63.11	$74.36	($11.25)
Avg. Pool Price	$122.47	$104.51	$17.96

Figure 27 shows total OR costs by month. Compared to Q2 2021, supplemental and spinning reserve costs were significantly lower in Q2 2022, reflecting lower average costs especially for supplemental reserve. Among the different types of OR costs, only standby costs were higher in Q2 2022 than in the previous year. In addition, standby costs increased from $0.6 million in April to $2.9 million in June, mainly driven by increased standby regulating reserve activations.

[29] For more detailed information, see AESO: Operating Reserve

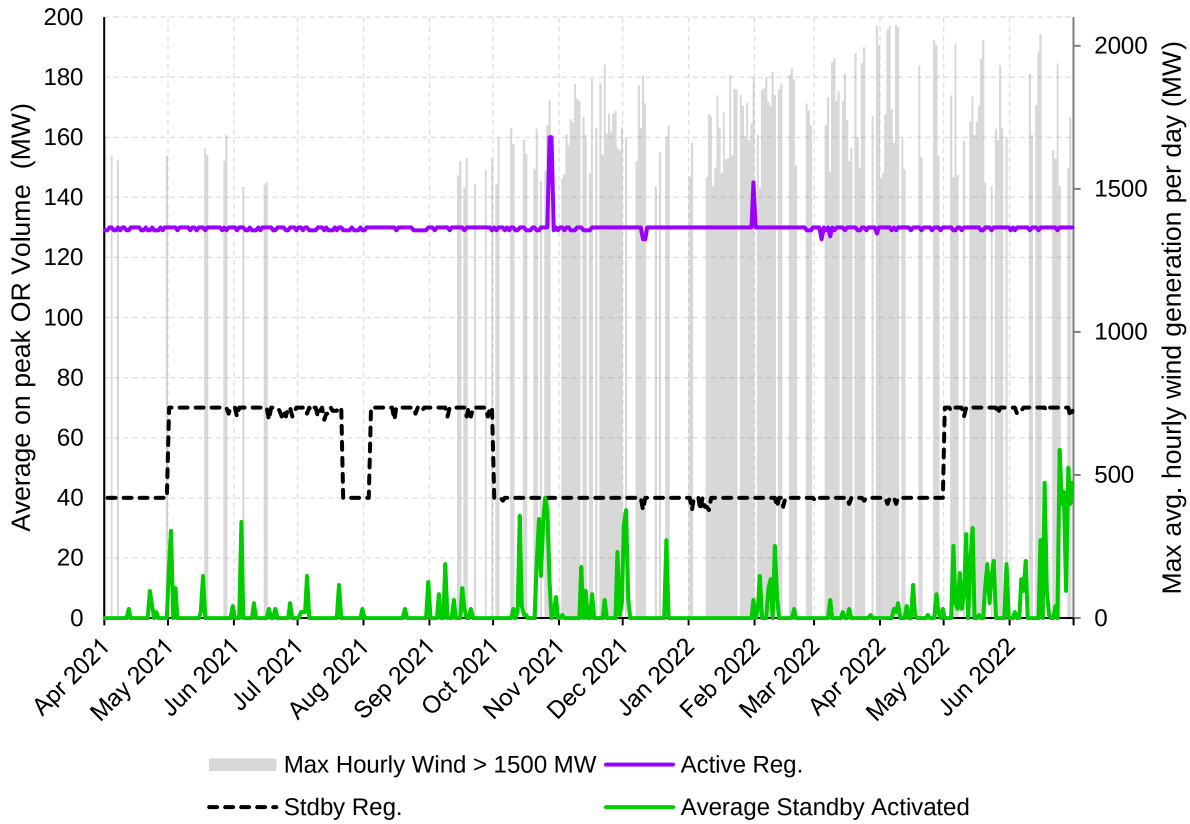
Figure 27: Total cost of active and standby reserves and average pool price by month



Daily active on-peak volumes of spinning and supplemental reserves procured in Q2 2022 were just below 270 MW per day, a slight decrease from about 280 MW per day in Q1 2022, but about the same as Q2 2021. Similarly, procured regulating reserve volumes were almost the same in Q2 2022 and Q2 2021. Figure 28 shows daily on-peak regulating reserve volumes from April 2021 to June 2022. Also plotted as grey columns is the maximum hourly average wind generation observed per day, showing only those days with over 1,500 MW of maximum hourly average wind. While procured active and standby levels are comparable year-over-year, standby activations increased significantly in May and June 2022.

Standby regulating activations are primarily driven by active restatements but are also driven by a combination of renewable resource volatility, merit order shuffles at the beginning of an hour, and price responsive load volatility. Standby regulating activations peaked at a daily on-peak average of 56 MW activated on June 24.

Figure 28: Active and standby on-peak regulating volumes, on-peak (April 2021 to June 2022)



2.2 Active on-peak equilibrium prices

The prices of active reserve OR products are indexed to pool price. Specifically, OR sellers are paid the sum of the pool price and the equilibrium price,[30] which is a discount or premium. However, in cases where pool price plus the equilibrium price is negative, the seller is not required to pay the AESO.

From 2017 through Q2 2022, on-peak pool prices have generally increased, and on-peak OR equilibrium prices have generally fallen. In other words, the on-peak discount to pool price has generally increased in absolute value for active reserve OR products.

Figure 29 shows daily average on-peak pool price versus the active on-peak spinning reserve equilibrium price, between $40 and -$100. This scatter plot also shows a linear trendline of the data, by year, from 2017 to 2022, up to Q2. The horizontal range of each trendline covers the range of observed on-peak pool prices that year; longer trendlines indicate that a greater range of on-peak pool prices were observed that year. From 2017 to 2022, the pool price-equilibrium price pairs during each on-peak period, plotted as circles, have drifted down and to the right. This

[30] AESO defines the equilibrium price as the average of the AESO's bid price and the marginal offer. (ID #2013-005R, p.6)

illustrates that on average, active spinning reserve price premiums have decreased, and average on-peak pool prices increased from 2017 to Q2 2022.

Declining OR equilibrium prices were partially driven by increasing natural gas and carbon prices. A thermal generator expects to earn the difference between expected pool price and its variable cost of generation, per unit of energy sold in the power pool. Forgoing the sale of energy is often the opportunity cost of selling OR. Holding all else constant, an increase in variable costs decreases the profitability of selling energy, thus decreasing the opportunity cost of selling OR. As a result, increasing natural gas prices have put downward pressure on OR equilibrium prices.

The downward sloping yearly trendlines for 2019 to Q2 2022 suggest a slight negative correlation between active on-peak equilibrium prices and on-peak pool price within each year. One might expect OR equilibrium prices to be negatively correlated with energy prices because a market participant's OR offer prices may decrease with expected pool prices. That is, as expectations of pool prices increase, some OR providers are willing to offer active OR at a greater discount to pool price.

Figure 29: Average on-peak pool price versus active on-peak spinning reserve equilibrium price, between $40 and -$100 (2017 to 2022 up to Q2)

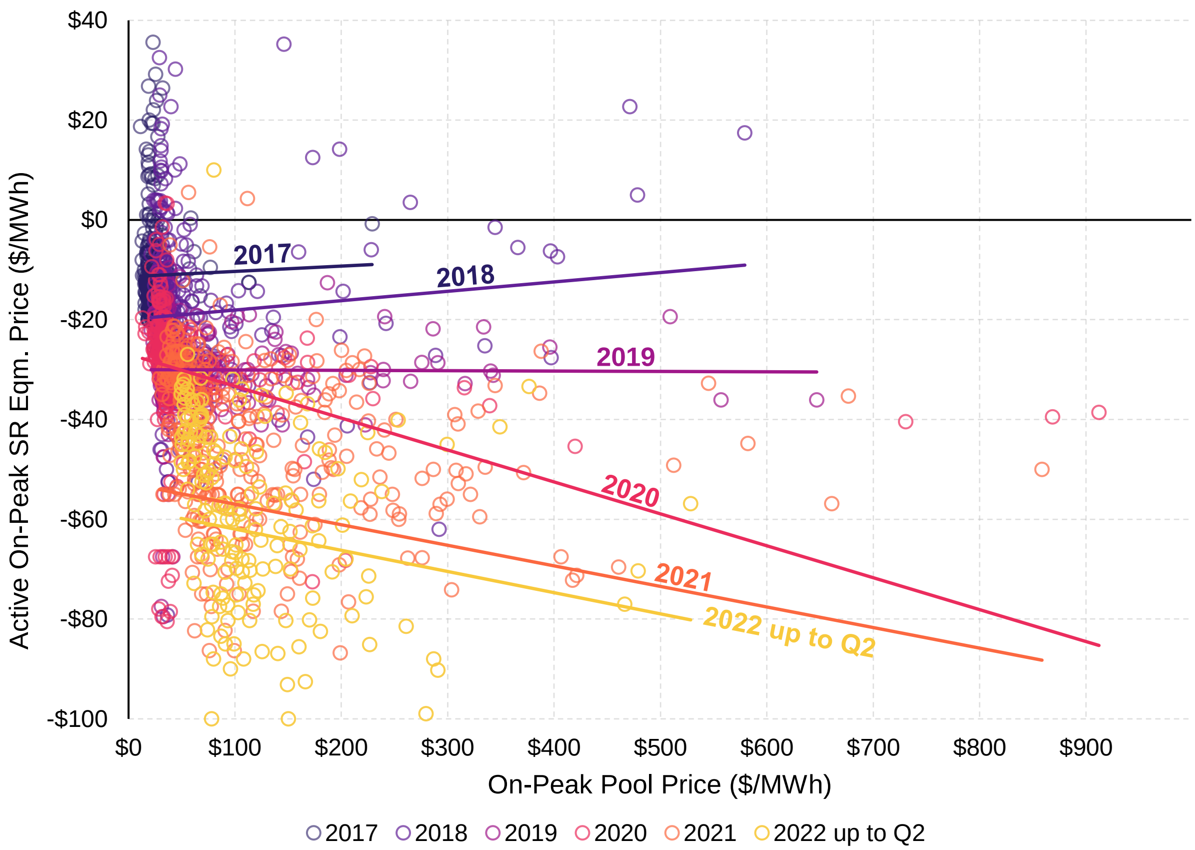
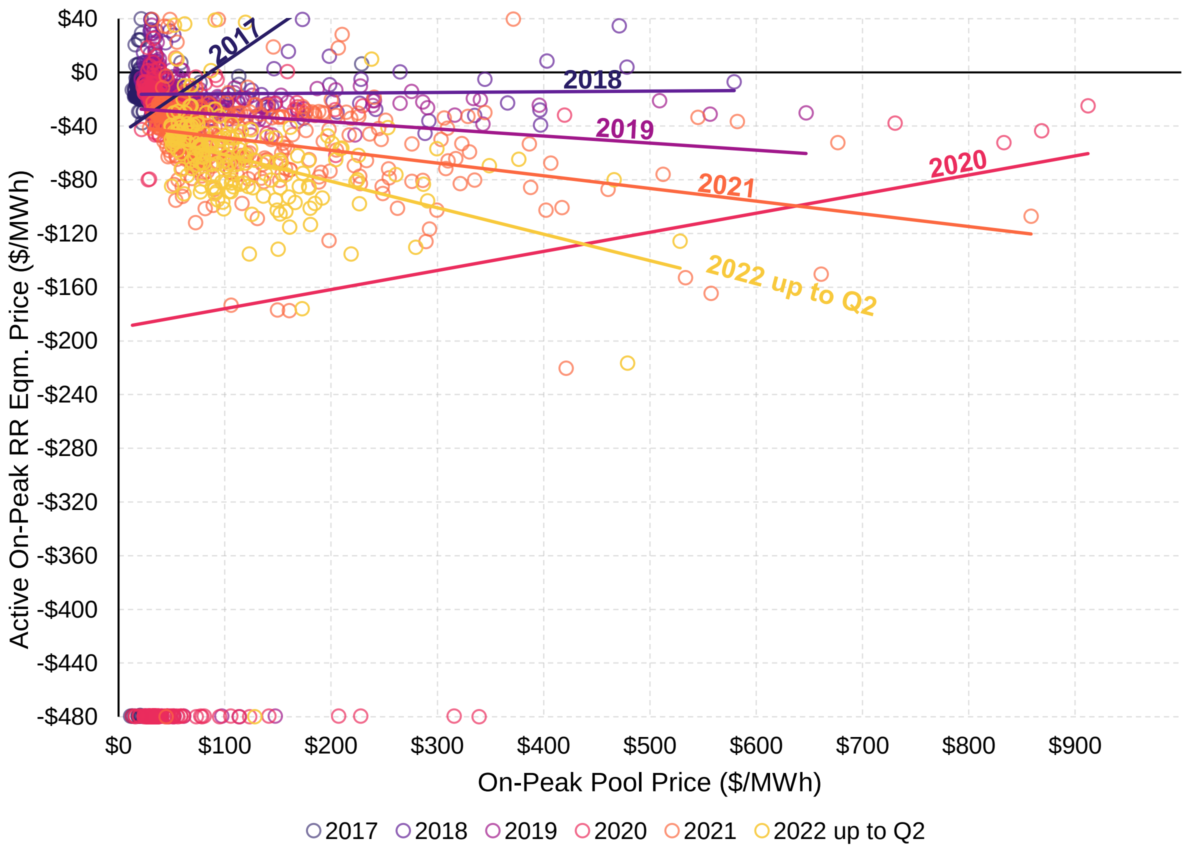


Figure 30 shows average on-peak pool price, versus active on-peak regulating reserve equilibrium price, between $40 and -$480, the price cap and floor of equilibrium prices. Similar to the spinning reserve market, the plot of pool price-equilibrium price pairs in the regulating reserve market have generally drifted down and right, towards lower equilibrium prices and higher pool prices over time.

Equilibrium prices for regulating reserves during some periods of 2020 were significantly lower than in other years. This was driven by numerous factors, including a reduction in the typical volume of active regulating reserve procured by the AESO. In May 2020, procured active on-peak regulating reserve volumes fell from 150 MW to 130 MW, while several OR providers continued to offer at low prices. Additionally, electricity demand in 2020 was softened by effects of COVID-19. The MSA reported on a period of low on-peak regulating reserve index prices occurring in 2020 in its Quarterly Report for Q3 2020.[31]

Figure 30: Average on-peak pool price versus active on-peak regulating reserve equilibrium price, between $40 and -$480 (2017 to 2022 up to Q2)



Average spinning, supplemental, and regulating equilibrium prices so far in 2022 were lower, on average, than in any other year since 2017, except for regulating index prices in 2020. On-peak pool prices averaged over the first and second quarter of the year from 2017 to 2022, were the

[31] MSA Quarterly Report for Q3 2020, Section 2.1.2 On-peak regulating reserves: https://www.albertamsa.ca/assets/Documents/Q3+2020+Quarterly+Report.pdf

highest in 2021, followed by 2022. The energy price-equilibrium price relationship appears to exhibit a loose negative correlation, both within years, and across years, from 2017 to Q2 2022.

2.3 Standby activations and directives

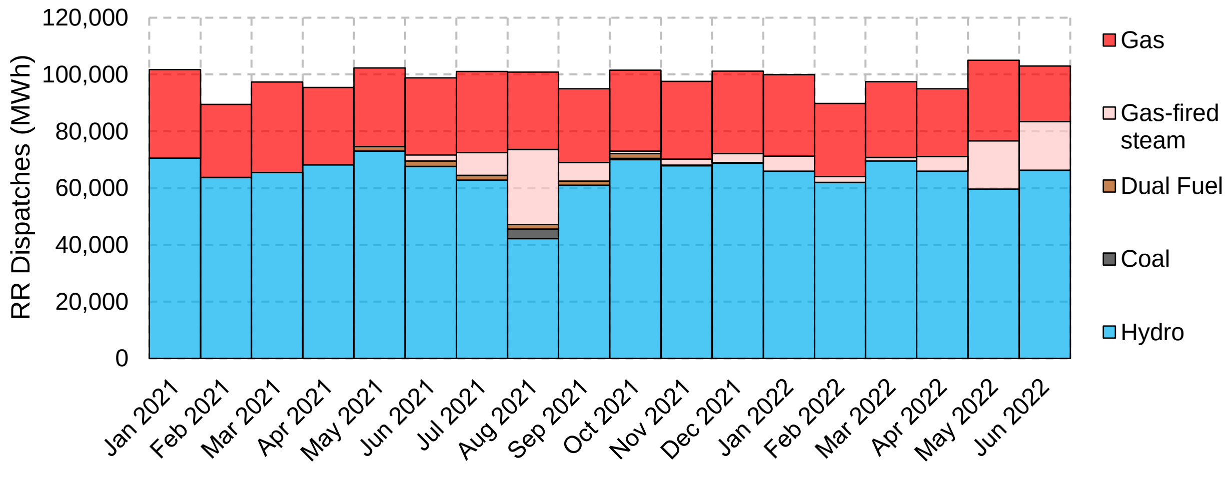
As previously mentioned, standby regulating reserve activations increased significantly in May and June 2022 (Figure 28), driving higher standby OR costs in Q2 2022 (Figure 27). While standby spinning and supplemental reserve activations decreased slightly from Q1 2022 to Q2, regulating activations increased approximately seven-fold (Table 8). The difference in activation increases was driven in part by higher wind generation and greater volatility in wind generation in Q2, which increased the need for regulating reserve, but not contingency reserve.

Table 8: Quarterly standby activations (MW)

Quarter	SR	SUP	RR
Q2 2021	6,611	2,445	3,514
Q3 2021	12,826	5,168	2,395
Q4 2021	14,972	6,984	10,875
Q1 2022	15,522	6,281	2,004
Q2 2022	14,939	5,098	14,518

Figure 31 shows that the volume of gas-fired steam assets dispatched for regulating reserve increased in May and June 2022. The overall increase in regulating reserve dispatches in the last two months of Q2 reflects the increase in standby activations.

Figure 31: Volume of regulating reserve dispatches by fuel type (January 2021 to June 2022)[32]

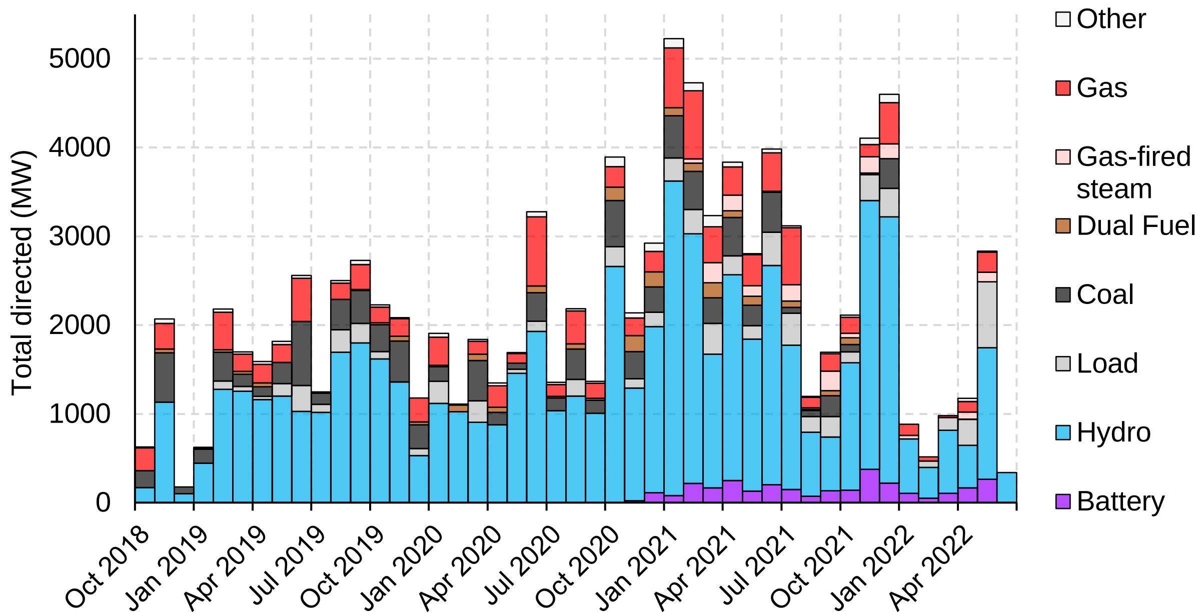


[32] The fuel type charts in the OR Markets section of this report group simple cycle, cogeneration, and combined cycle together as "gas", shown in red.

Figure 32 shows the total quantity of directed contingency reserves per month, plotting the sum of spinning and supplemental reserve directive instructions.[33] In the first half of 2022, 6,700 MW were directed, significantly less than the first half of 2021, when 23,800 MW were directed.

In June 2022, only 340 MW of contingency reserves were directed. This is the lowest monthly quantity of directives issued since December 2018, when 175 MW were directed, and is one tenth the 2021 monthly average of about 3,400 MW directed per month.

Figure 32: Total directed MW by fuel type (October 2018 to June 2022)



2.4 Energy storage assets

The Summerview (SUM1) energy storage asset entered service in October 2020 and was the first battery asset to enter service in Alberta. Since then, eReserve1 Rycroft (ERV1) and eReserve2 Buffalo Creek (ERV2) entered service in December 2020 and October 2021, respectively. This analysis looks at how battery assets have participated in Alberta's OR markets from January 2021 to June 2022.

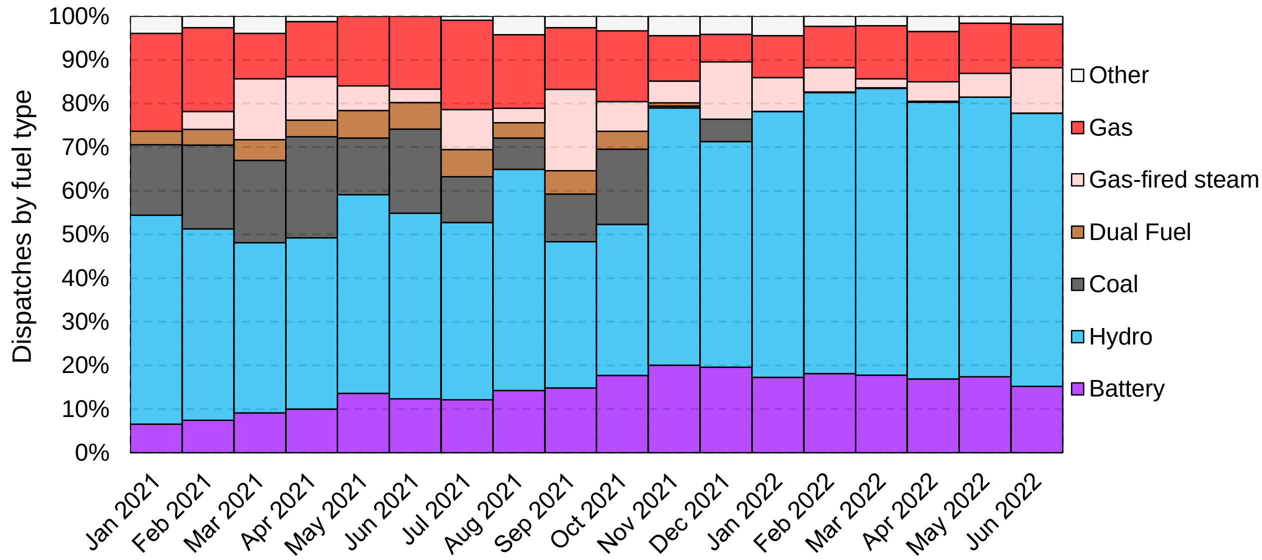
Battery assets primarily sell spinning reserve. Approximately 96% of battery OR dispatch volumes were for spinning reserve, while 4% were for supplemental reserve. Figure 33 shows spinning reserve dispatches by fuel type and illustrates the increasing role of battery assets in the spinning reserve market throughout 2021.[34] Battery assets provided 15% of spinning reserve dispatch

[33] This figure sums the MW values of directive instructions that were issued, excluding instructions that timed out or were invalid. This measure would count a 10 MW directive as 10 MW, regardless if the duration of the directive was 10 minutes or an hour.

[34] The battery category includes Crossfield 3 (CRS3), a hybrid battery-gas asset, beginning in May 2021.

volumes in June 2022. This is the second largest share by fuel type. Hydro assets maintain the largest share, accounting for roughly 65% of dispatched spinning reserve volume.

Figure 33: Spinning reserve dispatches by fuel type (January 2021 to June 2022)



The directive rate, which indicates how frequently an asset is directed to provide power in response to a contingency, varies across asset fuel types. Figure 34 shows the directive rate of spinning reserves; the percent of dispatched spinning volumes that were directed to provide power.[35] Hydro assets were directed most frequently, while battery assets were directed least. During this period, battery assets had a directive rate of just under 0.6%, which is almost half of the directive rate of the hydro assets.

Figure 35 shows the distribution of spinning directives by minute-duration and fuel type. The distribution of directives with respect to fuel type appears largely unaffected by directive length; as shown, battery assets received both long and short directives. The mean directive length during this period was approximately 15 minutes. The longest directive during this period occurred on August 13, 2021 in HE18, and lasted for 73 minutes. During this event, directives were issued to battery, natural gas, and hydro assets.

Looking forward, battery capacity is expected to increase in the province, with ERV3 scheduled to begin operations in August 2022 and with other projects under development.[36] As energy storage capacity continues to increase, it is likely that their relative contribution to spinning reserve dispatches will continue to grow.

---

[35] Calculated as the sum of spinning reserve directed, MW, divided by the volume of spinning reserve dispatch, MWh.

[36] AESO Market Updates – July 7, 2022

AESO Long-Term Adequacy Metrics

Figure 34: Spinning reserve directive rate, by fuel type (January 2021 to June 2022)

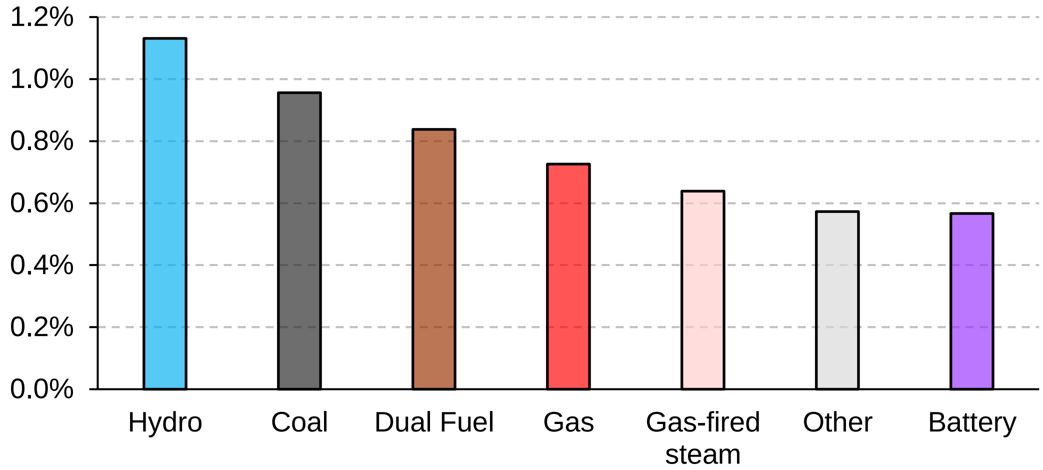
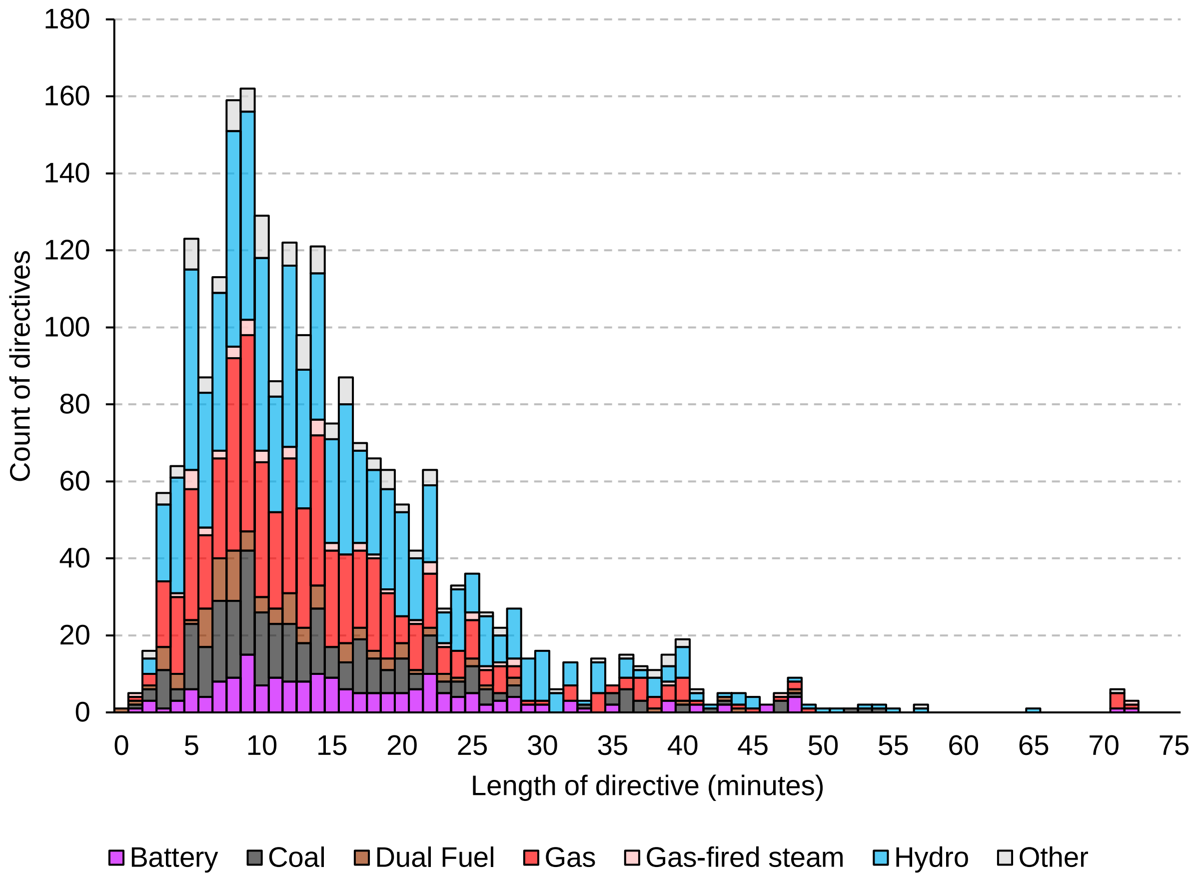


Figure 35: Spinning reserve directives by length and fuel type (January 2021 to June 2022)



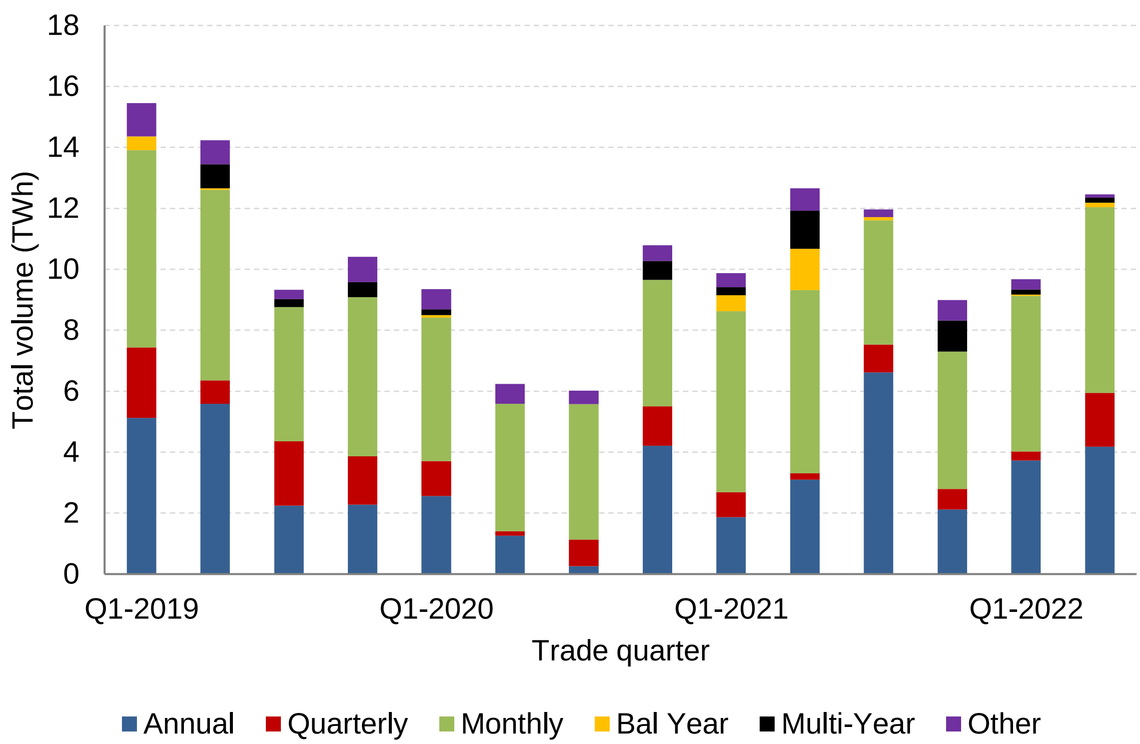
3 THE FORWARD MARKET

3.1 Forward trade volumes

The financial forward market is an important component of Alberta's energy-only market design. In particular, it allows generators and larger loads to hedge themselves from pool price volatility. Hedging involves reducing exposure to pool prices by buying or selling in the forward market for a fixed price, to diversify the buy/sell price and reduce risk. Similarly, the forward market enables retailers to reduce the volatility associated with purchasing electricity to sell to retail customers. Given that electricity is sold to some customers at a fixed price, managing costs through forward market purchases will generally reduce risk and therefore tend to lower the fixed prices available to retail customers.

The MSA's analysis in this section incorporates trade data from ICE NGX and Canax, an over-the-counter (OTC) broker, which are routinely collected by the MSA as part of our surveillance and monitoring functions. Data on direct bilateral trades up to a trade date of December 31, 2021 are also included. These bilateral trades occur directly between two trading parties, not via ICE NGX or through a broker, and the MSA generally collects information on these transactions once a year.

Figure 36: Total volumes by trade quarter (Q1 2019 to Q2 2022)[37]



[37] Includes bilateral trades up to Q4 2021. The monthly volumes include full-load RRO trades based on the expected 4 MW traded volume.

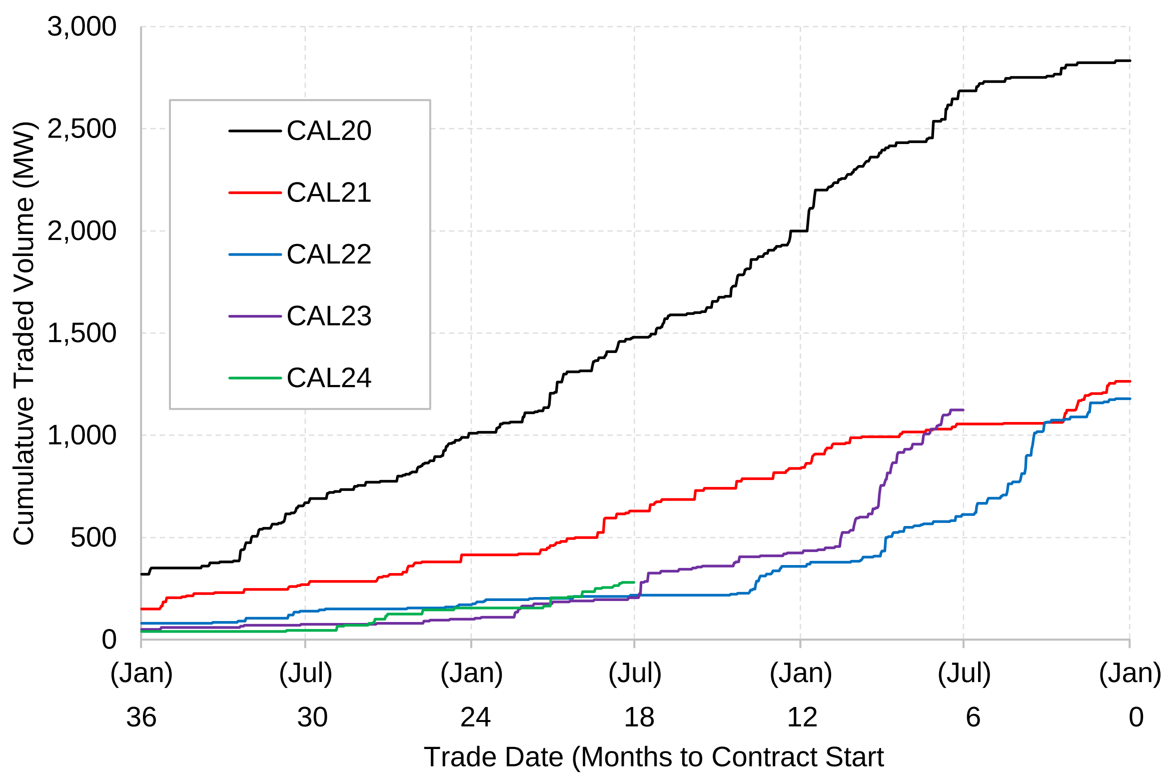
Figure 36 shows the total volume of power that has been traded since 2019 by the quarter in which the trades took place. Total volume is the total amount of power traded financially over the duration of a contract. The total volume of trades in Q2 2022 was 12.46 TWh, which is 29% higher than the volumes traded in Q1 2022, and is the highest quarterly volume traded on ICE NGX and Canax since Q2 2019. A year-over-year comparison shows that there was a 30% increase in the volumes traded on ICE NGX and Canax in Q2 2022 relative to Q2 2021.

The increase in total volumes traded in Q2 was partly the result of more trading of quarterly contracts. Compared to Q1 2022, quarterly trade volumes increased by 1.47 TWh, representing a six-fold increase. Almost all the quarterly volumes traded in Q2 were for delivery in a quarter of 2023. The total volume of monthly trades in Q2 increased as well, by 19% compared to Q1. September 2022, July 2022, and October 2022 were the most traded monthly contracts.

The total volume of annual trades in Q2 was 4.18 TWh, a 12% increase compared to annual volumes traded in Q1. Most of the annual volume (80%) traded in Q2 was for CAL23, while 16% was for CAL24, and 4% was for CAL25.

Figure 37 shows traded volumes for the CAL23 and CAL24 flat contracts compared to those of CAL20, CAL21 and CAL22. For the sake of comparison, this figure only includes trades completed through ICE NGX or Canax. Traded volume is the hourly volume of power being exchanged financially within a given trade. For instance, a trade may specify a traded volume of 5 MW per hour for the duration of the contract.

Figure 37: Cumulative traded volumes for CAL20 to CAL24 flats (up to June 30, 2022)

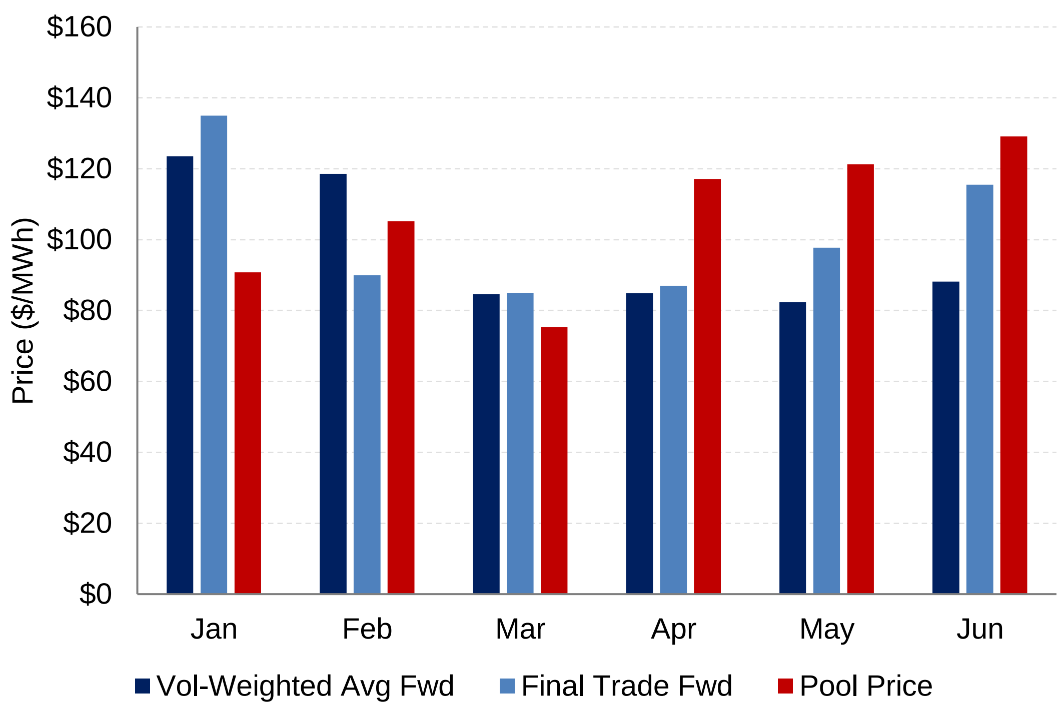


The traded volumes for CAL23 are higher than the traded volumes were for CAL22 and CAL21 at comparable points in time, i.e., with 6 months of trading left. Increased volatility in the natural gas market has potentially been a driver for power trading over recent months. However, the traded volumes for CAL23 are much lower than the traded volumes seen for some historical contracts, such as CAL20. The volume of trades so far for CAL24 is comparable with CAL22 and CAL23 at this point in time, with 18 months of trading remaining for that contract.

3.2 Forward prices

Figure 38 shows the comparison between monthly flat forward prices and the realized pool prices for January through June 2022. Contrary to the months in Q1, the forward monthly prices for April, May, and June traded at a discount to the realized pool price. In June, the weighted average forward price was $88.15/MWh compared to the realized average pool price of $129.08/MWh, a discount of $40.93/MWh. April and May saw forward discounts of $32.27/MWh and $38.86/MWh, respectively, using the volume-weighted average forward price.

Figure 38: Forward prices and realized pool prices for monthly flat contracts (January to June 2022)



Increasing natural gas prices were a major contributor to the forward market discounts seen in the power market for Q2. Table 9 shows the traded and realized market heat rates for April, May, and June. The market heat rate divides the power price by the price of natural gas to illustrate how power prices compare to natural gas input costs, yielding the implied Gigajoules (GJ) of natural gas per Megawatt hour (MWh) of electricity.

As shown in Table 9, the realized heat rates for April and May came in below average forward market expectations, which are estimated using daily forward prices over the final five months of trading. For June the realized heat rate of 18.7 GJ/MWh was very comparable with average forward market expectations of 18.1 GJ/MWh. The fact that realized heat rate figures came in at or below forward expectations illustrates that higher-than-expected natural gas prices were a major factor in pool prices coming in above forward power prices.

Table 9: Forward market and realized heat rates (GJ/MWh) for April, May, and June

Month	**Avg fwd. heat rate** (Settlement prices during the last 5 months)	**Final fwd. heat rate** (Settlement prices on the final day of trading)	**Realized heat rate** (Pool prices and sameday gas prices)
April	23.3	16.8	17.9
May	20.0	15.2	16.9
June	18.1	17.0	18.7

3.3 Trading of monthly products

Figure 39 illustrates the evolution of forward prices for the monthly contracts of April to October 2022. In April, the forward prices for all these power contracts increased largely due to rising natural gas prices. Q2 witnessed a highly volatile natural gas market, both in spot and futures prices. Coming out of the 2021/22 winter, natural gas storage volumes in North America have been low relative to historical levels, reflecting a higher demand for natural gas: for heating and cooling, for exports, and for power generation.

Volatility in natural gas markets can have significant impacts on Alberta forward power prices because the price of electricity in Alberta is predominantly set by natural gas generation assets. For example, the forward natural gas price for July increased from $6.24/GJ on April 11 to $7.30/GJ on April 18, and in response, the forward power price for July increased from $104.00/MWh to $115.00/MWh over the same period. After a continuous period of increases, natural gas forward prices fell significantly on April 19 and 20 (Figure 40), though in this instance, power prices were largely unaffected.

On April 13 the Genesee 3 conversion outage, initially scheduled to begin in late April, was moved into the fall. As a result of this change, the forward power price for May decreased from $102.50/MWh to $94.50/MWh, and the October price increased from $91.00/MWh to $100.00/MWh.

Figure 39: Forward electricity prices for flat monthly contracts (March 1 to June 30)

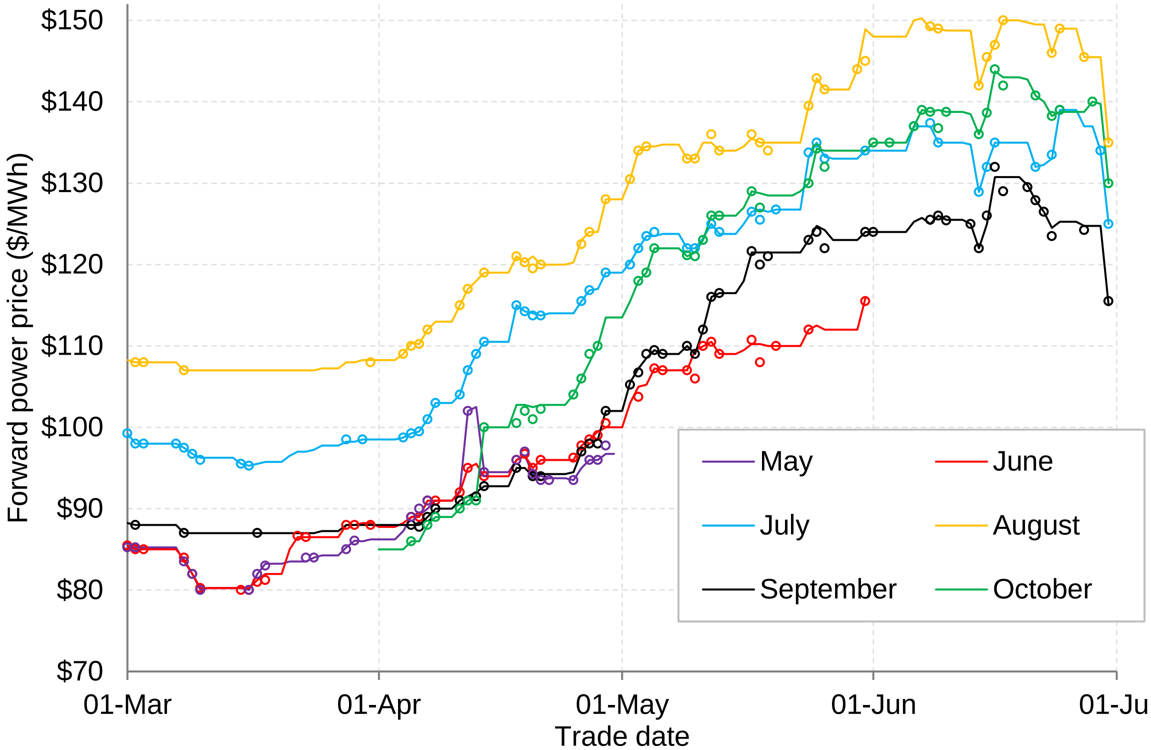
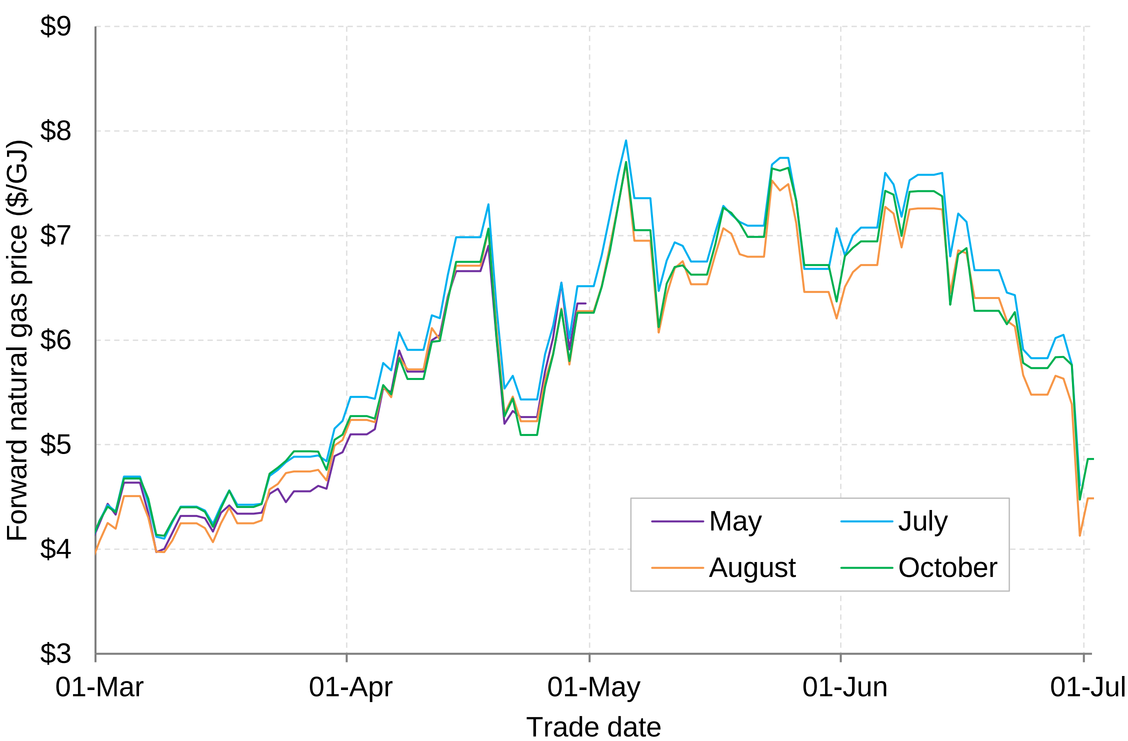


Figure 40: Forward natural gas prices for flat monthly contracts (March 1 to June 30)



The rise in forward monthly power prices continued in May, largely on the back of rising and volatile natural gas prices (Figure 40). In addition to natural gas futures, the August contract was also trading on forward prices in Mid-Columbia (Mid-C). In May and early June, the Mid-C peak price for August was trading around US$200/MWh, reflecting the potential for hot weather and reduced hydro supplies in that region. This put some upward pressure on the Alberta forward price for August due to the possibility of reduced imports.

The peak Mid-C price for August reached US$216/MWh on June 6 but fell materially over a few weeks to US$140/MWh on June 17. In addition to this, natural gas prices fell in mid-June and the Alberta power contract for August fell from $149.00/MWh to $142.00/MWh from June 9 to 14. However, the August price subsequently increased, along with other monthly power contracts, to trade at $150/MWh on June 17, partly in response to pool price volatility in the energy market.

Beginning in mid-June, natural gas prices began to fall significantly (Figure 40). On June 9, a large LNG export facility in the US experienced an operational issue, and on June 14 the operator declared the plant would be shut down until later in the year.[38] This lowered LNG export capacity and effectively landlocked some natural gas in North America, which helped to replenish storage levels. As a result, on June 14 Alberta natural gas prices for July and August fell by 11%, while the gas prices for September and October fell by 14%.

Natural gas futures continued to decline later in June, before falling materially on June 30 when EIA storage volumes came in above market expectations. Alberta natural gas futures for the remaining months of 2022 all fell by between 20% to 23% on June 30. As shown by Figure 39, there was also a meaningful decline in Alberta power forwards. For example, the August contract fell from $145.50/MWh to $135.00/MWh while October fell from $139.75/MWh to $130.00/MWh, a 7% decline for each.

3.4 Trading of annual products

Figure 41 shows forward prices for the CAL22 to CAL25 annual contracts over the trade dates of November 1, 2021 to June 30, 2022. There was a significant rise in annual forward prices over April and May, in part due to increasing natural gas prices. Over the course of Q2, the marked price of CAL22 increased by 27% from $91.19/MWh to $115.64/MWh, and the CAL23 price increased by 22% from $78.00/MWh to $95.09/MWh.

In addition, the forward power price for CAL24 increased by $6.25/MWh (10%) over Q2 while the price of CAL25 increased by $6.50/MWh (11%). These contracts are still trading at much lower levels relative to CAL22 and CAL23 (Figure 41), which is largely due to the expected increase in generation capacity over the coming years.

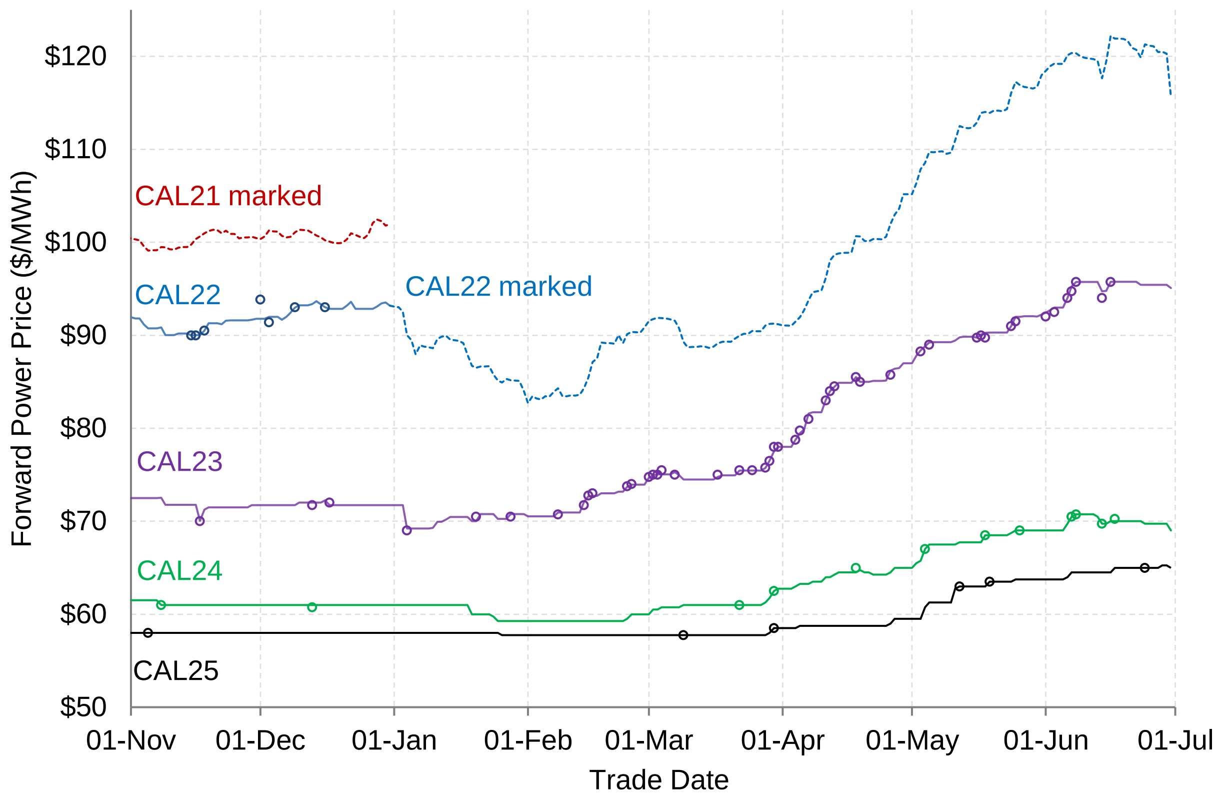
The Cascade combined cycle asset (900 MW) is scheduled to be in service in the fall of 2023, Genesee 1 and 2 are scheduled to be repowered in early 2024 (increasing net capacity by 512

---

[38] Reuters articles June 9 and June 14

MW), the Suncor Base Plant cogeneration project (800 MW) is expected to be online by 2025, and there is expected to be a material increase in wind and solar capacity in the coming years.[39]

Figure 41: Annual forward prices for CAL21 to CAL25 (November 1, 2021 to June 30, 2022)[40]



In addition, forward natural gas prices for CAL24 and CAL25 are trading below prices for CAL23. As of June 30, natural gas prices for CAL24 and CAL25 were priced at $4.10/GJ and $4.08/GJ, respectively, whereas CAL23 was priced at $4.36/GJ and CAL22 is expected to average $5.12/GJ (Table 10).

As discussed above, natural gas prices decreased materially in mid-to-late June, which put some downward pressure on annual power forwards. However, power prices for CAL22 and CAL23 did not fall to the same extent as natural gas futures in this period. As a result, the market heat rates for these contracts increased to finish the quarter higher than they started (Table 10).

---

[39] AESO Long-Term Adequacy Metrics – Aug 2022

Cascade Power Project

Capital Power Investor Presentation – June 2022 at slide 18

Suncor Coke Boiler Replacement Project

[40] The lines in this chart show settlement prices while the markers indicate the last trade price on a given day.

As of June 30, the marked heat rate for CAL22 was 22.6 GJ/MWh, which is lower than the realized heat rate of 30.1 GJ/MWh in CAL21. Nevertheless, the forward market is expecting that average pool prices in 2022 will be higher than in 2021 (Figure 41). The lower heat rate for CAL22 indicates that higher natural gas prices are the main reason for this expected increase.

Table 10: Power prices, natural gas prices, and market heat rates for annual contracts

Contract	Power price ($/MWh)			Gas price ($/GJ)			Heat rate (GJ/MWh)		
	Mar 31	**Jun 30**	**% chg**	**Mar 31**	**Jun 30**	**% chg**	**Mar 31**	**Jun 30**	**% chg**
CAL22	$91.19	$115.64	27%	$5.04	$5.12	2%	18.1	22.6	25%
CAL23	$78.00	$95.09	22%	$4.14	$4.36	5%	18.9	21.8	16%
CAL24	$62.75	$69.00	10%	$3.50	$4.10	17%	17.9	16.8	-6%
CAL25	$58.50	$65.00	11%	$3.63	$4.08	12%	16.1	15.9	-1%

4 THE RETAIL MARKET

The MSA has published a standalone retail market update for Q2 2022. This update includes various analyses, including a quarterly update, regulated rate outlook, historical retail billing analyses and regulated switching analyses.

5 ENFORCEMENT AND REGULATORY MATTERS

5.1 Trading on non-public outage records and publication timing of AESO Outage Reports

In May 2022, the MSA identified an electricity forward market trade that may have been transacted seconds before relevant outage records were made public. The MSA did not pursue enforcement action because there was no evidence of market impact or financial gain and the trade did not appear to be part of a recurring pattern. The timing of outage record publication was an important component of the MSA's assessment.

The AESO has advised that generation outage reports[41] are updated every 5 to 10 minutes on average but may be delayed by up to 20 minutes.[42] The MSA has observed that the exact update time is difficult to predict with seconds-level precision. Some market participants use automated tools that rely on a fixed time lag before releasing submitted outage records to traders. Given the variability in time intervals between updates, the MSA is concerned that these tools may not capture all instances where outage records are made public on a delayed basis.

The MSA reminds market participants that section 4(1) of the *Fair, Efficient and Open Competition Regulation* prohibits market participants from using non-public outage records to trade, directly or indirectly, unless an exemption applies.[43] It is incumbent on market participants to ensure that their submitted outage records have been made public through the AESO's public generation outage reports before trading on this information. As traders are considered market participants, a robust compliance framework should be designed to protect traders from receiving non-public outage records and subsequently trading on them. The AESO's Information Document on Outages (ID #2013-003R) provides guidance on how market participants can verify whether their outage records have been made public.

5.2 AESO Transmission Must-Run service procurement competition

In June 2022, the AESO awarded a three-year contract for Transmission Must-Run (TMR) service in the Grande Prairie planning area. The three-year service term began on July 1, 2022, which suggests a similar process may be required in 2025 if a foreseeable need for TMR service persists. TMR service is used by the AESO to ensure reliability in parts of the province with insufficient local transmission infrastructure relative to local demand.[44] If there is a foreseeable need for TMR service the AESO will make arrangements for its provision according to Appendix B of the ISO Tariff.[45] The ISO Tariff sets out the process for procuring foreseeable TMR service, the stages of which include Expression of Interest (EOI) and Request for Proposal (RFP). The

---

[41] Daily Outage Report and Monthly Outage Report

[42] AESO Information Document 2013-003R, page 6

[43] *Fair Efficient and Open Competition Regulation*, AR 159/2009, at s. 4(1)

[44] AESO TMR Procurement Competition Backgrounder

[45] ISO Tariff Section 8.5.

ISO Tariff requires the AESO to seek the "advice and direction" of the MSA regarding whether each of the EOI and RFP are contestable. In each instance in the 2022 procurement competition, the MSA provided the AESO with the view that the process step was contestable.

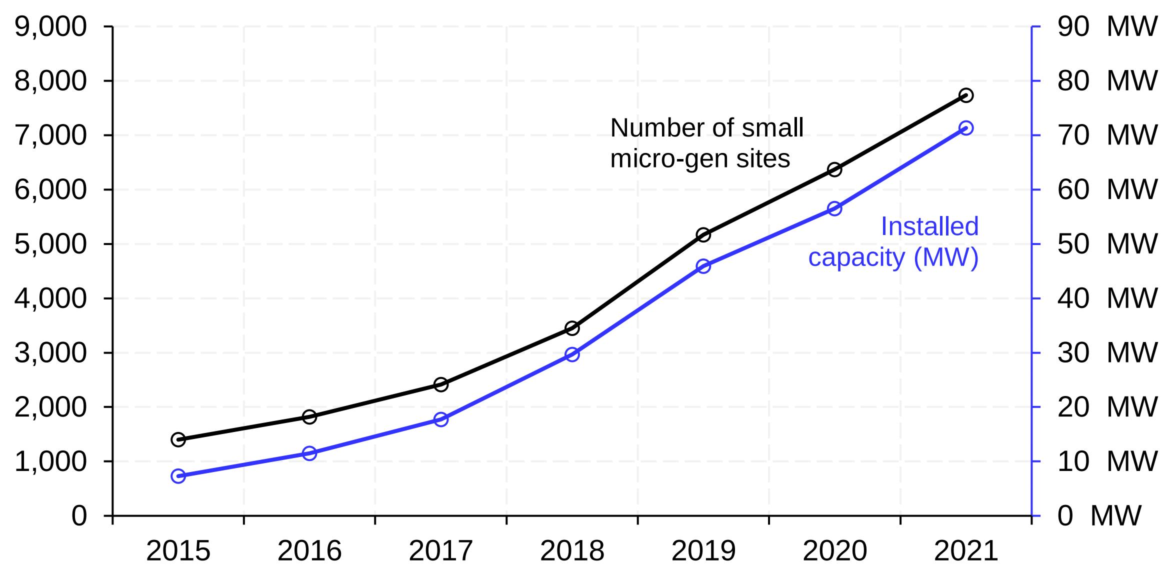
5.3 Microgeneration update

The *Micro-generation Regulation* (MGR) sets out a framework allowing electricity consumers to connect renewable or alternative energy generation to the grid. The MGR outlines how micro-generation ("micro-gen") units are qualified, sized, and compensated.

A micro-gen unit exclusively uses renewable or alternative energy sources to generate electricity. A small micro-gen unit must be less than 150 kW of installed capacity and have a bi-directional cumulative meter. Bi-directional cumulative meters measure the net flow of energy imported into the site (when consumption is greater than generation) and exported to the grid (when generation is greater than consumption).

The number of small micro-gen sites has continued to increase (Figure 42).[46] In 2021, just under 1,400 new small micro-gen sites were commissioned, more than the 1,200 commissioned the previous year. At the end of 2021, the cumulative number of small micro-gen sites connected to the grid was 7,700, totaling about 70 MW of installed capacity.

Figure 42: Number of small micro-gen sites and installed capacity (December 31, 2015 to December 31, 2021)

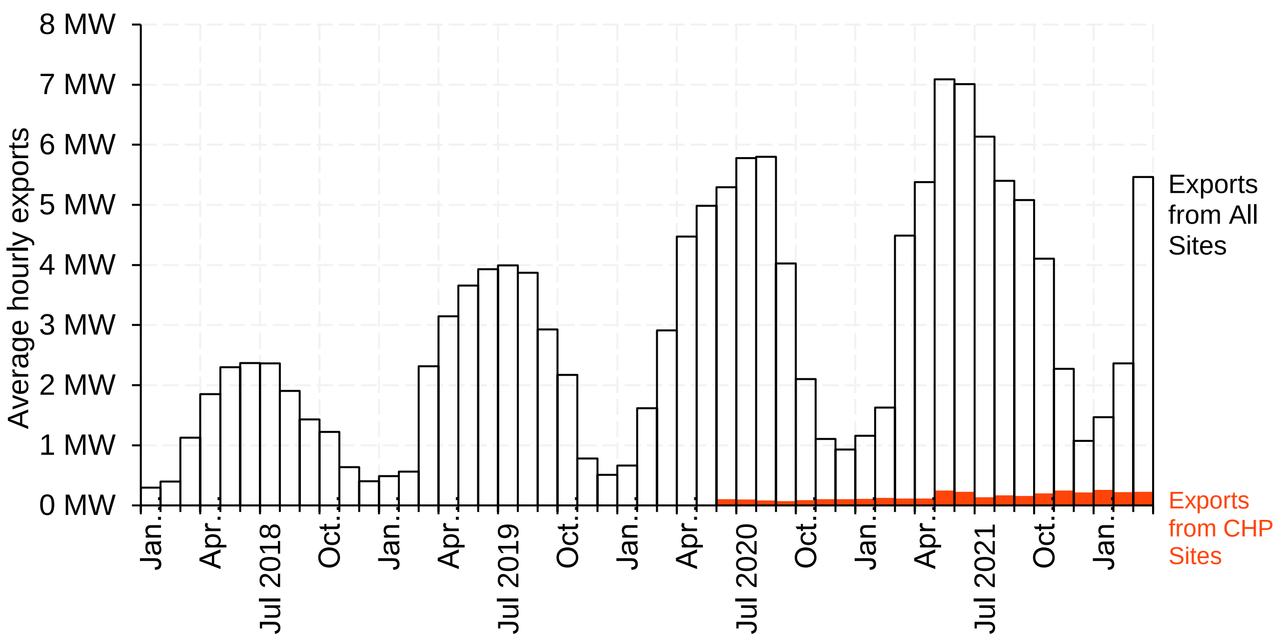


[46] The MSA counts the number of small micro-gen sites based on AESO site commissioning data. The count looks at the number of commissioned sites on December 31 each year. This differs from the approach taken by the MSA in its [Quarterly Report for Q1 2021], where site count was based on the number of unique sites that had received micro-gen payments in a particular year. These count methodologies differ because a site may not produce enough energy to export to the grid, and would not appear in micro-gen payment data, but nonetheless was commissioned.

Approximately 99% of small micro-gen sites generate power using solar photovoltaic panels. The balance use wind, gas-fired combined heat and power (CHP), waste heat, or other renewable or alternative sources of energy. Energy production from solar sources varies seasonally, which has resulted in significant intra-year variation in micro-gen exports (Figure 43). Exports peak in the summer months and fall to their lowest levels in December. Total micro-gen exports have increased over the years, reflecting the addition of new sites.

After solar, CHP is the largest small micro-gen export type, and exhibits a distinct export profile. Unlike solar sites, exports from CHP sites exhibit less seasonal variation, and peak slightly during the winter months. Preliminary data available for Q1 2022 suggests that, although there were over a dozen CHP small micro-gen sites that exported to the grid and received compensation, most CHP exports were associated with two sites.[47]

Figure 43: Hourly micro-gen exports, average by month (January 2018 to March 2022)



When an electricity customer with a small micro-gen unit imports energy into their site, they are charged a retail rate based on an agreement with an energy retailer. When a small micro-gen customer exports energy from their site to the grid, their retailer must compensate the customer for the exported energy at the same retail rate the customer pays to import energy. The retailer submits the amount of compensation it paid to the small micro-gen customer to the AESO and receives reimbursement. The AESO fully reimburses the retailer for the compensation and recovers the compensation costs through the ISO tariff as part of losses charges or credits, and associated Rider E calibration factor adjustments.

[47] Micro-gen data is typically available to the MSA with a one quarter lag. Data for Q1 2022 is still preliminary and subject to change.

An issue concerning retail rates for small micro-gen customers is discussed in detail in the MSA's Quarterly Report for Q1 2021.[48] As a result of the increasing number of small micro-gen sites, the volume of exported energy and total compensation paid has increased year-over-year (Table 11).

Table 11: Annual exports to the grid and compensation paid to small micro-gen

Year	Exports (MWh)	Small micro-gen compensation	
2018	12,000	$	820,000
2019	21,000	$	1,650,000
2020	29,000	$	2,580,000
2021	37,000	$	4,900,000

Figure 44 shows a scatter plot of site-level small micro-gen exports and compensation in 2021; each small micro-gen site is plotted as a blue circle. The rays from the origin at different slopes represent different retail rates. For example, any sites compensated at a rate of 25¢/kWh would be plotted along the steep solid black line representing the 25¢/kWh rate. Sites below the solid line were compensated at rates less than 25¢/kWh. As shown, compensation and exports varied significantly from site to site.

Notably, two extreme outliers received approximately $150,000 in compensation in 2021, vastly more than the next highest compensated site which received approximately $40,000. These outliers are associated with two CHP sites. While there are multiple sites with installed capacities close to the 150 kW limit for small micro-gen, the large difference in exports illustrated by the two outliers is driven by capacity factor. Solar micro-gen sites typically have capacity factors between 5% and 25%, while the outlier CHP sites have capacity factors around 50%.

Figure 45 shows site-level small micro-gen exports and compensation in 2021; only plotting exports up to 10 MWh and compensation up to $1,000. As the median site exported less than 5 MWh in 2021, this range captures most of the data. Almost all sites were compensated at a rate between 3¢/kWh and 25¢/kWh. The diagonal banding illustrates that most sites were compensated at rates around 6¢/kWh, 9¢/kWh, and 20¢/kWh.

[48] MSA Quarterly Report for Q1 2021

Figure 44: Site-level small micro-gen exports and compensation in 2021

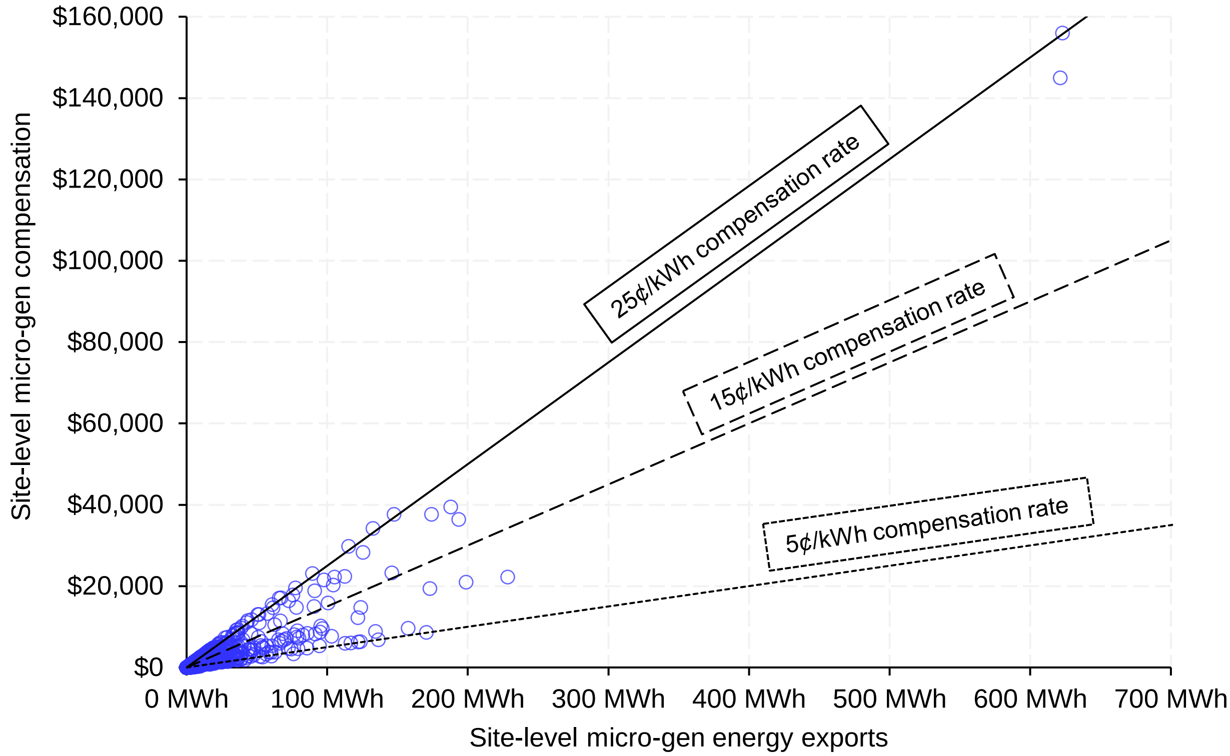


Figure 45: Site-level small micro-gen exports and compensation in 2021 up to 10 MWh and $1,000

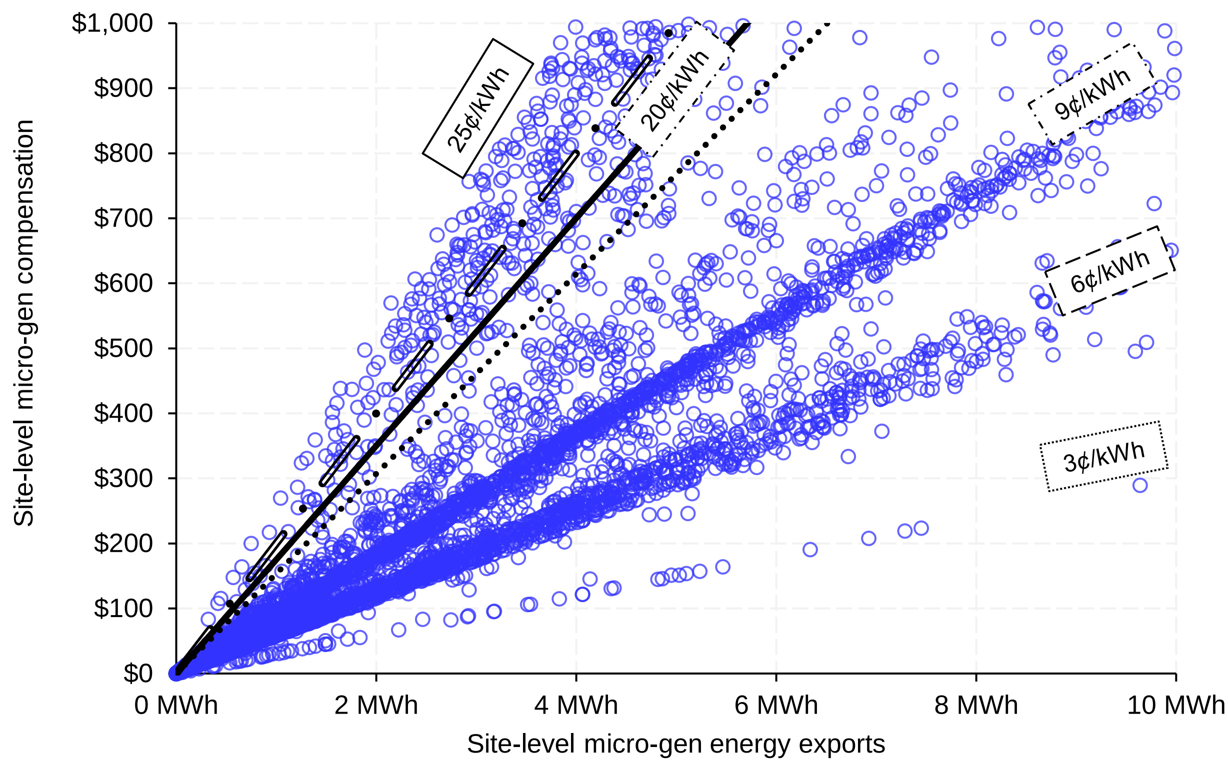


Figure 46 shows the percent of small micro-gen exports corresponding to four select retailers. The majority of small micro-gen export volumes were produced by customers that have signed retail contracts with one of these retailers. The export volume share of Retailer A, shown in light blue, grew significantly from an annual average of 10% in 2018, to 31% in 2021, to 45% for Q1, 2022. Retailer A's monthly volume share reached a peak in January 2022, when 55% of exports were generated by Retailer A's customers. Retailer A has signed several CHP sites which export large volumes during the winter. As a result, Retailer A's volume share typically peaks in the winter, when solar production is lower, and CHP exports account for a larger share of total exports.

Figure 46: Percent of small micro-gen exports submitted by retailer, by month (January 2018 to March 2022)

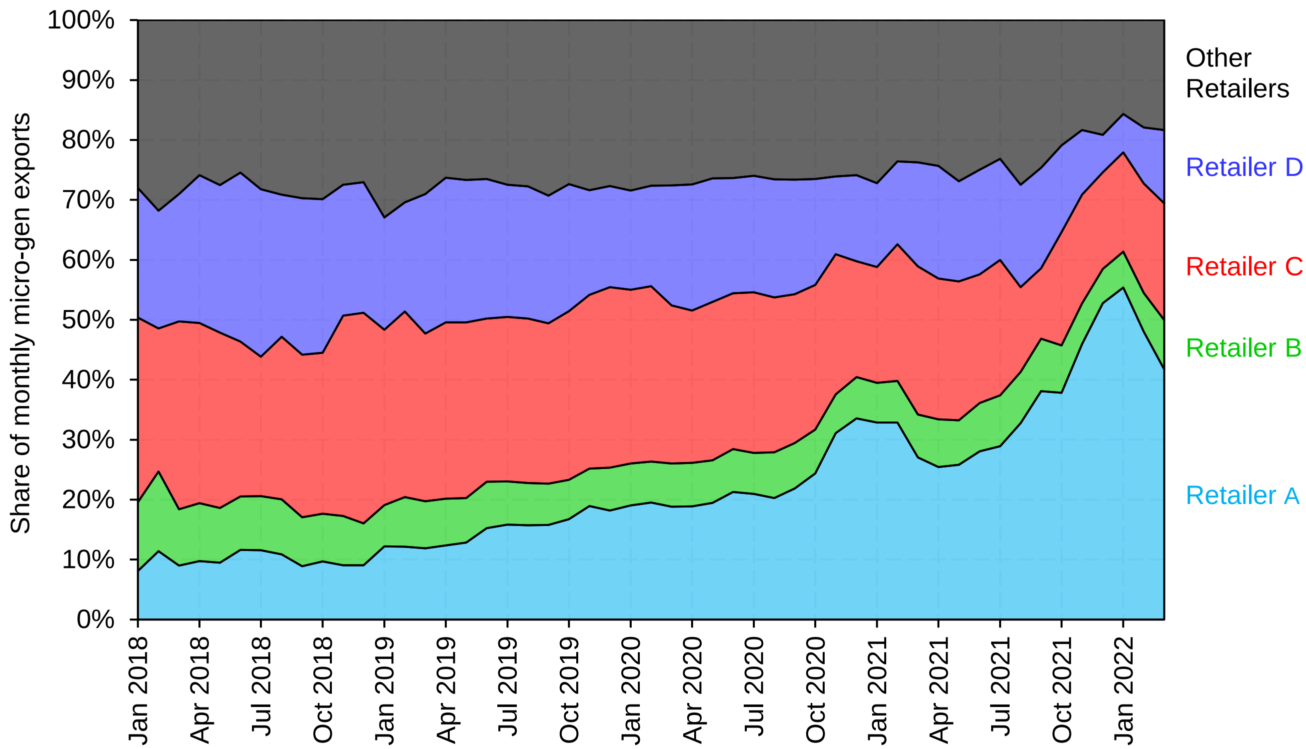


Figure 47 shows the amount of small micro-gen compensation that retailers paid to their customers, for which they were reimbursed by the AESO. Retailer A paid and received significantly more compensation than any other retailer. Although Retailer A was responsible for 31% of export volumes in 2021, it paid and received 49% of all compensation, about 3.8 times more than the next highest retailer. Retailer B, shown in green, paid and received more than either Retailer C or D, despite its customers producing less than half the volume of exports that the customers of either Retailer C or D produced. The differences in the levels of compensation and export volumes for retailers was driven by significantly different retail rates.

Figure 47: Small micro-gen compensation by retailer, by month (January 2018 to March 2022)

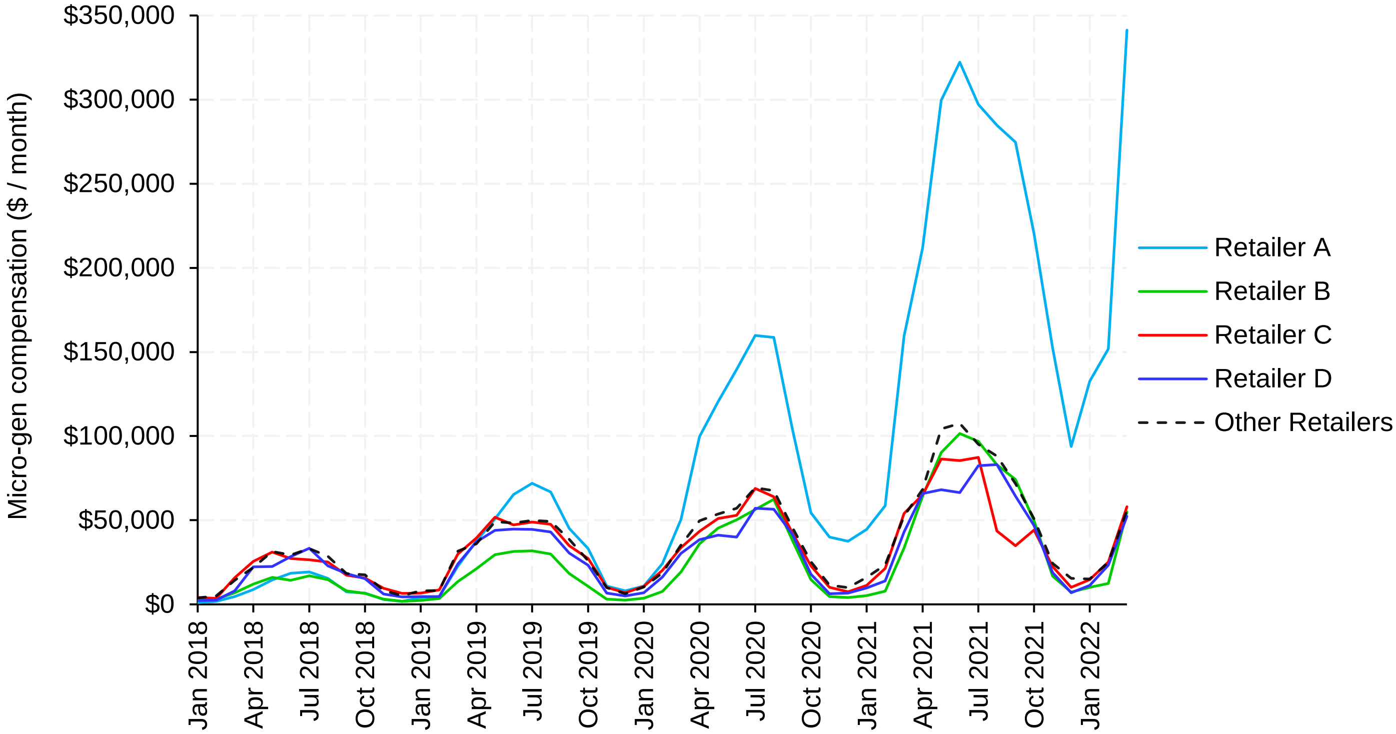
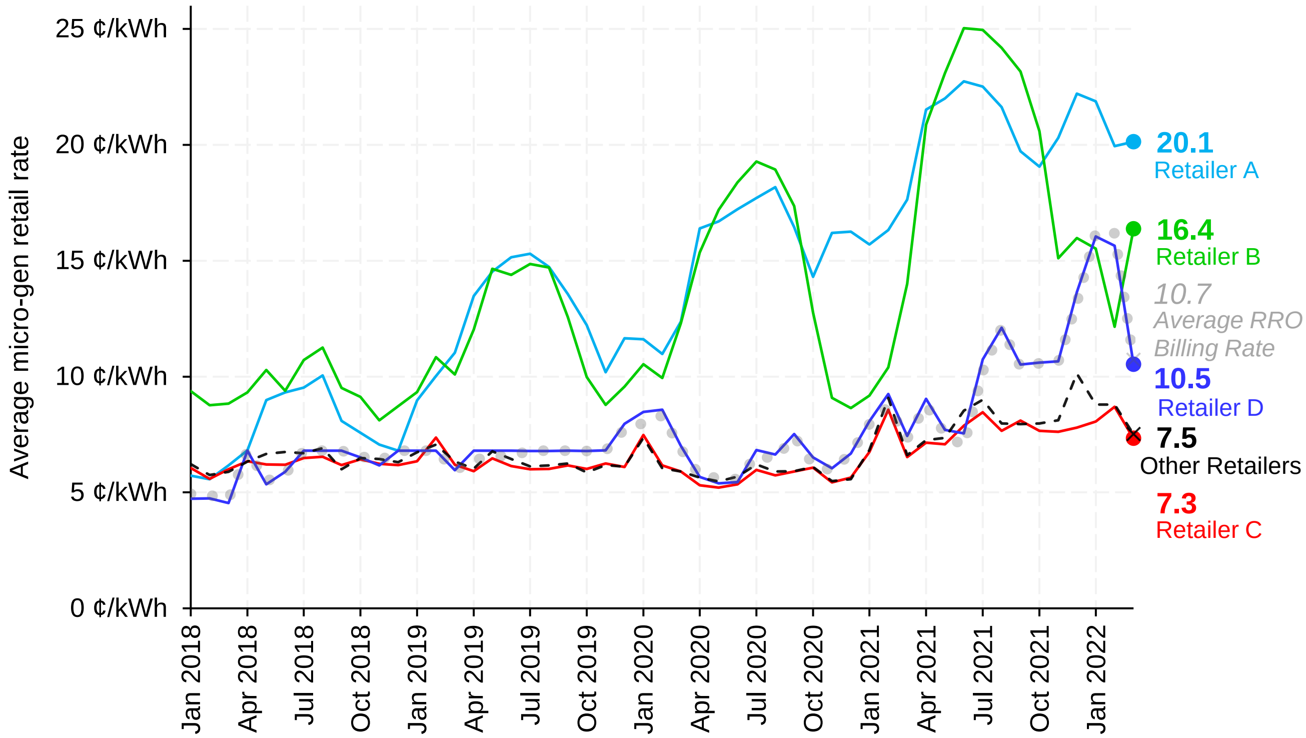


Figure 48 shows the volume weighted average micro-gen retail rate charged and paid by retailers. Also plotted in grey dots is the average residential RRO billing rate of the four RRO zones. On average, micro-gen rates across retailers have increased, but the magnitude of change has varied retailer to retailer. The average rates of Retailer A and B have increased substantially more and exhibit noticeable seasonal variation.

The seasonal variation in average rates reflects the fact that these retailers provide their small micro-gen customers the option to switch between high and low rates. Typically, a customer would choose a higher rate in the summer when, on average, their micro-gen site is a net-exporter of energy, resulting in a larger payment. A customer could choose a lower rate in the winter, when solar energy production is lower, and their site is a net importer of energy, resulting in a lower energy bill. Retailer A and B's average retail rates exceed 20 ¢/kWh in some months, far surpassing the rates commonly offered to residential competitive retail customers.

The average micro-gen rates of retailers other than Retailer A and B have also increased from 2018 to 2021 but have generally remained at levels similar to or below the RRO or other competitive retail contracts. The large difference in micro-gen retail rates between certain retailers has driven the disproportionately large compensation paid and received by Retailers A and B versus their competitors.

Figure 48: Volume-weighted average small micro-gen retail rate by retailer, by month (January 2018 to March 2022)



5.4 *Technology Innovation and Emissions Reduction* (TIER) *Regulation* Review

On July 24, 2022, Alberta Environment and Parks (AEP) provided notice to stakeholders that it was conducting engagement regarding the TIER Regulation, to inform decisions in fall 2022. AEP stated that the TIER Regulation specifies that a review is required by December 31, 2022, that the federal benchmark criteria for the assessment of provincial carbon pricing systems for 2023 to 2030 is updated, and that Alberta intends to meet the federal benchmark requirements and maintain the TIER system. The MSA submitted comments to AEP on August 5, 2022.

6 ISO RULES COMPLIANCE

The purpose of the ISO rules is to promote orderly and predictable actions by market participants and to facilitate the operation of the Alberta Interconnected Electric System (AIES). The MSA is responsible for the enforcement of the ISO rules and endeavours to promote a culture of compliance and accountability among market participants, thereby contributing to the reliability and competitiveness of the Alberta electric system. If the MSA is satisfied that a contravention has occurred and has determined that a notice of specified penalty (NSP) is appropriate, then AUC Rule 019 guides the MSA on how to issue an NSP.

From January 1 to June 30, 2022, the MSA closed 154 ISO rules compliance matters, as reported in Table 12.[49] An additional 102 matters were carried forward to next quarter. During this period 43 matters were addressed with NSPs, totalling $67,750 in financial penalties, with details provided in Table 13.

Table 12: ISO rules compliance outcomes from January 1, 2022 to June 30, 2022

ISO rule	Forbearance	Notice of specified penalty	No contravention
103.1	1	-	-
201.7	10	7	-
202.4	2	-	-
203.3	46	5	-
203.4	11	7	2
203.6	5	1	-
205.3	3	1	-
205.4	2	-	-
205.5	-	5	-
205.6	1	9	-
304.3	5	-	-
306.4	4	-	-
306.5	10	3	-
502.10	1	-	-
502.4	1	-	-
502.5	-	2	-
502.6	2	-	-
502.8	-	2	-
505.4	3	1	-
9.1.3	1	-	-
9.1.5	-	-	-
Total	**108**	**43**	**2**

[49] An ISO rules compliance matter is considered to be closed once a disposition has been issued. Of the 154 closed matters, one matter was referred by the MSA to another body.

Table 13: Specified penalties issued between January 1 and June 30, 2022 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)											Total ($)	Matters
	201.7	203.3	203.4	203.6	205.3	205.5	205.6	306.5	502.5	502.8	505.4		
Air Liquide Canada Inc.						2,000	500					2,500	3
Alberta Pacific Forest Industries Inc.							2,000					2,000	2
AltaGas Ltd.	500											500	1
ATCO Power (2010) Ltd.		1,500										1,500	1
Calgary Energy Centre No. 2 Inc.									250			250	1
Capital Power (G3) Limited Partnership								500				500	1
Capital Power (Genesee) L.P.								1,000				1,000	2
Claresholm Solar LP										1,000		1,000	2
DAPP Power L.P.			1,500									1,500	1
Enel X Canada Ltd.							15,000					15,000	3
Enfinite Generation Corporation (formerly WCSB Power Generation GP Inc.)			500									500	1
ENMAX Cavalier LP									250			250	1
Imperial Oil Limited	500											500	1
Mercer Peace River Pulp Ltd.		2,000				750						2,750	3
Milner Power II Limited Partnership by its General Partner, Milner Power II Inc	500										250	750	2
Northstone Power Corp.			500									500	1
Powerex Corp.	250											250	1
Suncor Energy Inc.		250										250	1
TA Alberta Hydro LP			3,000		5,000							8,000	3
Tourmaline Oil Corp.	500		500									1,000	2
TransAlta Generation Partnership			1,500			5,500						7,000	3
TransCanada Energy Sales Ltd.				750								750	1
Voltus Energy Canada Ltd.							15,000					15,000	3
West Fraser Mills Ltd.	500	1,500										2,000	2
Whitecourt Power Ltd.	500											500	1
Total	3,250	5,250	7,500	750	5,000	8,250	32,500	1,500	500	1,000	250	65,750	43

7 ARS COMPLIANCE

The MSA has the jurisdiction to assess whether or not a market participant has complied with Alberta Reliability Standards (ARS) and apply a specified penalty where appropriate.

The purpose of ARS is to ensure the various entities involved in grid operation (legal owners and operators of generators, transmission facilities, distribution systems, as well as the independent system operator) are doing their part by way of procedures, communications, coordination, training and maintenance, among other practices, to support the reliability of the AIES. ARS apply to both market participants and the AESO. ARS are divided into two categories: Operations and Planning (O&P) and Critical Infrastructure Protection (CIP). The MSA's approach with respect to compliance with ARS is focused on promoting awareness of obligations and a proactive compliance stance. The MSA has established a process that, in conjunction with AUC rules, provides incentives for robust internal compliance programs, and self-reporting.

In accordance with AUC Rule 027, NSPs for CIP ARS contraventions are not made public, as well as any information related to the nonpayment or dispute of a CIP ARS NSP. CIP matters often deal with cyber security issues and there is concern that granular public reporting may itself create a security risk. As such, the MSA will only report aggregated statistics regarding CIP ARS outcomes.

From January 1 to June 30, 2022, the MSA addressed 51 O&P ARS compliance matters, as reported in Table 14.[50] An additional 11 matters were carried forward to next quarter. During this period, five matters were addressed with NSPs, totalling $27,375 in financial penalties, with details provided in Table 15. For the same period, the MSA addressed 129 CIP ARS compliance matters, as reported in Table 16, and 19 matters were addressed with NSPs, totalling $42,875 in financial penalties. An additional 67 matters were carried forward to next quarter.

[50] An ARS matter is considered closed once a disposition has been issued.

Table 14: O&P ARS compliance outcomes from January 1 to June 30, 2022

Reliability standard	Forbearance	Notice of specified penalty
COM-001	1	-
COM-002	1	-
EOP-001	1	-
EOP-005	1	-
FAC-008	13	1
IRO-008	1	-
MOD-010&012	1	-
PRC-001	2	-
PRC-002	1	1
PRC-005	16	2
PRC-023	-	1
VAR-002	1	-
VAR-501-WECC	1	-
VAR-002	1	-
PRC-019	4	-
PRC-006	1	-
Total	46	5

Table 15: Specified penalties issued between January 1 and June 30, 2022 for contraventions of O&P ARS

Market participant	Total specified penalty amounts by ARS ($)				Total ($)	Matters
	FAC-008	PRC-002	PRC-005	PRC-023		
Imperial Oil Resources Limited	2,250	375	2,250		4,875	3
Suncor Energy Inc.			3,750	18,750	22,500	2
Total	2,250	375	6,000	18,750	27,375	5

The ARS outcomes listed in Table 14 and Table 15 are contained within the following categories:

COM	Communications
EOP	Emergency Preparedness and Operations
FAC	Facilities Design, Connections, and Maintenance
IRO	Interconnection Reliability Operations and Coordination
MOD	Modeling, Data, and Analysis
PRC	Protection and Control
VAR	Voltage and Reactive

Table 16: CIP ARS compliance outcomes from January 1 to June 30, 2022

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-002	9	1	-
CIP-003	6	3	-
CIP-004	20	8	1
CIP-005	5	-	-
CIP-006	13	1	-
CIP-007	26	3	-
CIP-008	3	-	-
CIP-009	2	1	1
CIP-010	14	1	-
CIP-011	6	1	-
CIP-014	3	-	1
Total	107	19	3

The ARS outcomes listed in Table 16 are contained within the following categories:

CIP-002 BES Cyber System Categorization
CIP-003 Security Measurement Controls
CIP-004 Personnel & Training
CIP-005 Electronic Security Perimeter(s)
CIP-006 Physical Security of BES Cyber Systems
CIP-007 System Security Management
CIP-008 Incident Reporting and Response
CIP-009 Recovery Plans for BES Cyber Systems
CIP-010 Configuration Change Management and Vulnerability Assessments
CIP-011 Information Protection
CIP-014 Physical Security

APPENDIX A: ASSESEMENT OF MARKET PERFORMANCE

Net revenue

Natural gas peaker and combined cycle assets

The net revenues for a hypothetical peaking plant and combined cycle asset are examined using cost estimates published in the AESO's 2021 Long Term Outlook. These costs are reported in Table 17.

Table 17: Cost estimates for natural gas assets (2022$ CAD)[51]

	Peaker (simple cycle)	Combined cycle
Overnight capital cost ($/kW)	1,253	1,803
Fixed O&M ($/kW-year)	61.96	58.28
Variable O&M ($/MWh)	4.97	2.92

The assumed parameters of the natural gas assets analyzed are reported in Table 18. As shown, the peaking asset considered has a capacity of 93 MW while the combined cycle asset is 479 MW. The combined cycle asset is more efficient with a heat rate of around 7 GJ/MWh compared with around 10 GJ/MWh for the peaker.

Table 18: Physical parameters assumed for natural gas assets[52]

	Peaker (simple cycle)	Combined cycle
Winter capacity (MW)	93	479
Summer capacity (MW)	78	438
Winter heat rate (GJ/MWh)	9.526	7.163
Summer heat rate (GJ/MWh)	9.954	7.047
Outage rate (%)	10%	10%
Economic life (years)	25	30

Given the lower heat rate, the combined cycle asset has lower carbon costs per MWh, with the carbon emissions rate assumed to be around 0.5 tCO2e/MWh for the peaker and 0.37 tCO2e/MWh for the combined cycle. The carbon costs changed over the duration of the analysis as different carbon regimes were put into place.

[51] AESO: Long Term Outlook 2021, June 2021, Figures have been converted to 2022$ using CPI inflation data.

[52] AESO: Long Term Outlook 2021, June 2021 and AESO: Cost of New Entry Analysis, September 4, 2018

In addition to carbon costs, the net revenue analysis considers several cost components for the natural gas assets. To calculate fuel costs the sameday AB-NIT 2A gas price is used in combination with the assumed heat rate, and the natural gas commodity fuel charge is also included as a component of the assets' fuel costs.[53]

An hourly variable cost figure is calculated by summing fuel costs, carbon costs, variable O&M, and the AESO trading charge. Transmission losses are estimated using the average loss factor in the Fort Saskatchewan area in combination with applicable calibration factors. The average loss factor over the six years is estimated at 4.15%.

In terms of dispatch, the peaking gas plant is assumed to offer into the energy market at its variable cost, such that it generates whenever pool price less transmission losses is above its variable cost. Given its efficiency, the combined cycle asset is assumed to generate at capacity during all hours, regardless of prevailing pool prices.

For generator availability, the analysis uses a 10% outage rate for both the peaker and the combined cycle asset. This is reflected by reducing the available capacity of each asset by 10% in all hours of the analysis.

Wind and solar assets

To estimate the net revenues for hypothetical wind and solar assets the net revenue analysis uses cost estimates published by the AESO in the 2021 Long Term Outlook. The resulting cost figures are reported in 2022$ in Table 19.

Table 19: Parameters and cost estimates for wind and solar assets (2022$)[54]

	Wind	**Solar**
Capacity (MW)	100	50
Overnight capital cost ($/kW)	1,715	1,777
Fixed O&M ($/kW-year)	35.14	34.44
Variable O&M ($/MWh)	0.00	0.00
Economic life (Years)	25	25

In addition to energy revenues, wind and solar assets can also earn revenues from selling carbon emission offsets. Under the current carbon regime, carbon credits are based on the estimated electric grid displacement factor and the prevailing price of carbon. In 2013 the electric grid displacement factor was calculated as 0.65 tCO_2e/MWh, meaning that every MWh of renewable

[53] TransCanada Energy NGTL Fuel Usage and Measurement Variance.

[54] AESO: Long Term Outlook 2021, June 2021, Figures have been converted to 2022$ using CPI inflation data.

generation would displace around 0.65 tCO2e based on the estimated methodology. The grid displacement factor has since fallen as the emissions intensity of the Alberta grid has lowered.

Table 20: Carbon emission offsets by year

Year	Carbon price ($/tCO2)	Electricity Grid Displacement Factor (tCO2/MWh)	Carbon offset credits value ($/MWh)
2013	$15	0.65	$9.75
2014	$15	0.65	$9.75
2015	$15	0.59	$8.85
2016	$20	0.59	$11.80
2017	$30	0.59	$17.70
2018	$30	0.59	$17.70
2019	$30	0.59	$17.70
2020	$30	0.53	$15.90
2021	$40	0.53	$21.20
2022	$50	0.53	$26.50

A new wind or solar asset can lock-in at the prevailing displacement factor for up to 13 years, and carbon offsets may trade bilaterally at different prices. For the purpose this net revenue analysis, carbon credits are changed over time as per Table 20, as the displacement factor has fallen, and the carbon price has increased. In addition, the assets are assumed to fully utilize carbon emissions offsets in the year they are created. Under these assumptions, the net revenue analysis can indicate how changes in the carbon offset parameters impact carbon revenues.

Both the wind and solar assets are assumed to offer into the market at $0/MWh and act as price takers, such that all generation is supplied and receives the prevailing pool price. To estimate the hourly capacity factor of wind and solar assets actual generation data for Alberta wind and solar assets is used. Wind generation data is available for the duration of the 2013 to Q2 2022 period, and new wind assets are added into the capacity factor calculation once they have generated above a 30% capacity factor.

The first large-scale solar asset was added to the Alberta grid in December 2017. Therefore, data on solar generation is available from 2018 to Q2 2022. Additional solar assets were added to the capacity factor calculation once they generated above a capacity factor of 90% in an hour.

For the hypothetical wind farm, the analysis calculates transmission losses using a generation-weighted average of annual loss factors for wind assets. Transmission losses for wind assets in southern Alberta have increased in recent years, with some assets seeing loss factors of close to

10% for 2022.[55] The estimated losses averaged 4.39% for the hypothetical wind asset from 2013 to Q2 2022, and in Q2 2022 weighted-average losses for wind assets were calculated at 6.7%.[56]

The hypothetical solar farm transmission losses have been estimated using the average annual loss factor published by the AESO. This yields average losses of 3.27% over the duration of 2018 to Q2 2022.

Capital cost assumptions

The MSA has assumed generators finance the overnight capital cost of assets with payments amortized over the lifetime of the asset. For comparison purposes, the MSA used the weighted average cost of capital (WACC) values listed in Table 21 below. Capital cost repayments are assumed to be made annually.

Table 21: Annual capital costs under assumed WACC values by technology (2022$/MW-year)

Weighted Average Cost of Capital (WACC)	**Annual capital cost (2022$/MW-year)**			
	Combined cycle	***Gas peaker***	***Wind***	***Solar***
Low (6.5%)	$ 138,069	$ 102,723	$ 140,598	$ 145,681
Medium (8.5%)	$ 167,770	$ 122,433	$ 167,576	$ 173,634
High (10.5%)	$ 199,283	$ 143,380	$ 196,246	$ 203,341

Counterfactual assumptions

The MSA's updated static efficiency assessment incorporates several assumptions. To assess static inefficiency and markups in the Alberta market, the MSA constructed counterfactual energy market merit orders for each hour between 2013 and June 2022. In this counterfactual, market participants are assumed to price a unit at the marginal cost applicable to that unit in that hour. While marginal cost pricing might incent some units to withdraw from the energy market, mothball or not enter the market entirely, the MSA's analysis assumes no change in the capacity or availability of units in the energy market.

The MSA utilized several techniques to estimate unit marginal costs. Notwithstanding the cost assumptions described below, all blocks priced at $0/MWh in observed merit orders were assumed to have zero marginal costs. While this assumption may not be an accurate representation of actual marginal costs – particularly for thermal assets – it reflects physical limitations of most assets priced at $0/MWh.

[55] AESO Loss Factors

[56] These estimates are volume weighted by generation in each year and include the relevant calibration factors.

Coal and biomass marginal costs were estimated for each unit based on the 5th percentile of ordered non-zero offers priced between $1 and $100 in each year in hours where supply cushion exceeds 1,500 MW. Unlike coal assets, which often source their fuel from generator-owned sources, natural gas units are more exposed to daily fluctuations in fuel prices, meaning a single annual marginal cost would not reflect intra-year changes in unit marginal costs. Additionally, some peaking natural gas units only seek to generate under high pool price conditions, making any price-based estimation of marginal cost biased towards excessively high marginal cost estimates for such units. To resolve these issues, marginal costs for non-cogeneration natural gas units were estimated in each hour using publicly available unit heat rate information, same day natural gas index prices and carbon cost data. Cogeneration units were assumed to offer at marginal cost in observed merit orders, as electricity can be considered a biproduct of the primary steam product generated by cogeneration assets.

Market efficiency

Allocative efficiency

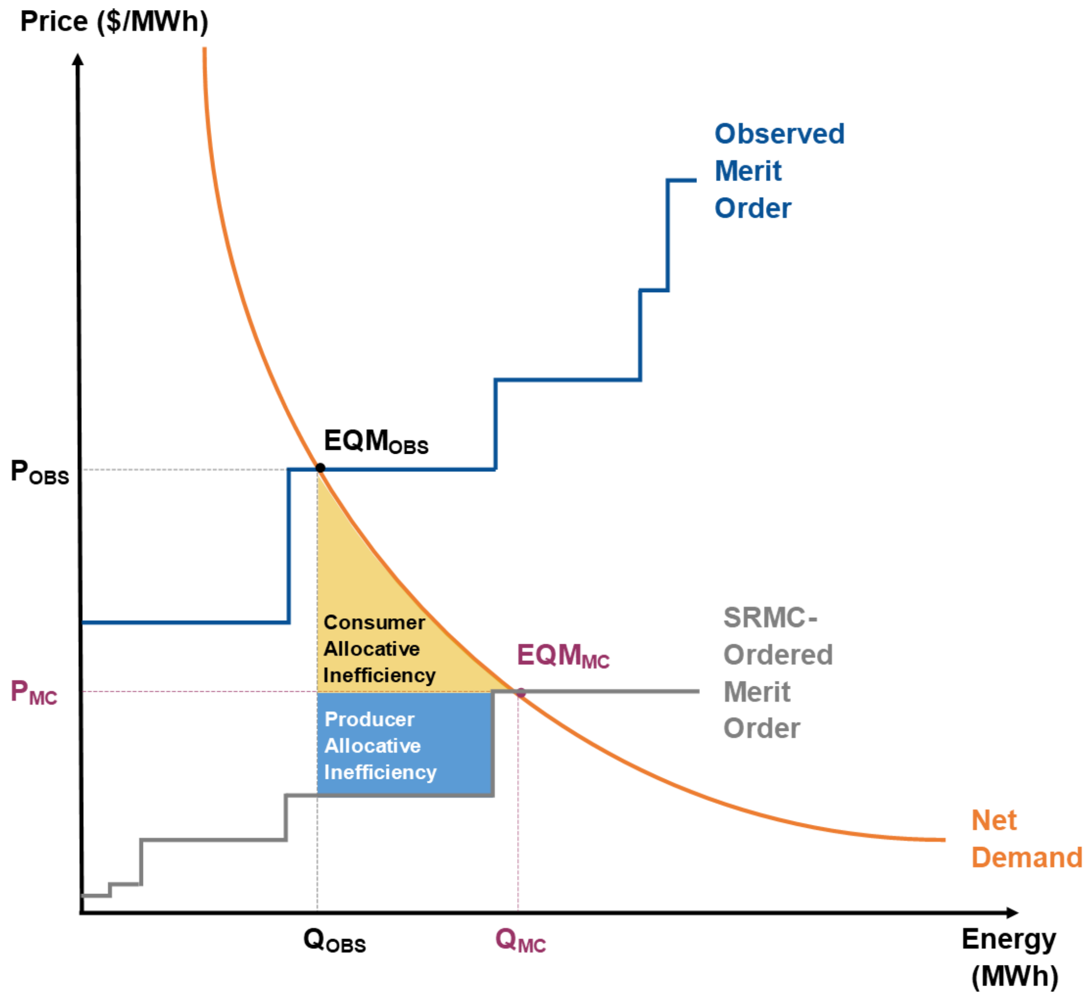
Allocative efficiency refers to a short-run state where the gains from trade are maximized by the market's choice of prices and quantities; at an allocatively efficient outcome the combined net benefit to consumers and producers attained using the market's resources are maximized.

For a given unit of energy transacted at a market price, the net benefit earned by consumers (often referred to as consumers' surplus) is equivalent to the difference between the price paid by consumers and the maximum price consumers would be willing to pay for that unit of energy, represented as the area below the demand curve and above the market price. Meanwhile, the net benefit earned by producers for a given unit of energy in the short-run is the difference between the price earned from selling that unit and the cost expended to produce the additional unit (often referred to as the producers' surplus).

Where producers economically withhold, offering their energy at prices above their short-run marginal cost (SRMC), allocative inefficiency will occur so long as the traded quantity declines (Figure 49). Where at least some producers offer their energy above their SRMC (leading to the observed equilibrium EQM_{OBS} with price P_{OBS} and traded quantity Q_{OBS}) rather than at SRMC (EQM_{MC} with P_{MC} and Q_{MC}), consumers forgo the surplus they would have gained on each additional unit of energy that would have been consumed at the lower price. This is labelled Consumer Allocative Inefficiency in Figure 49.

While most producers gain revenues over and above their SRMC when the market price settles at the higher P_{OBS} as opposed to the cost-based P_{MC}, a sufficiently large reduction in traded quantities *may* result in a loss of relatively low-cost generation with costs below P_{MC}. While the higher revenues earned by the remaining generation at P_{OBS} represents a transfer from consumers to producers – therefore not impacting the net benefit gained by producers and consumers collectively – the foregone producer surplus from the loss of any relatively low-cost generation represents an additional allocative inefficiency, labelled Producer Allocative Inefficiency in Figure 49.

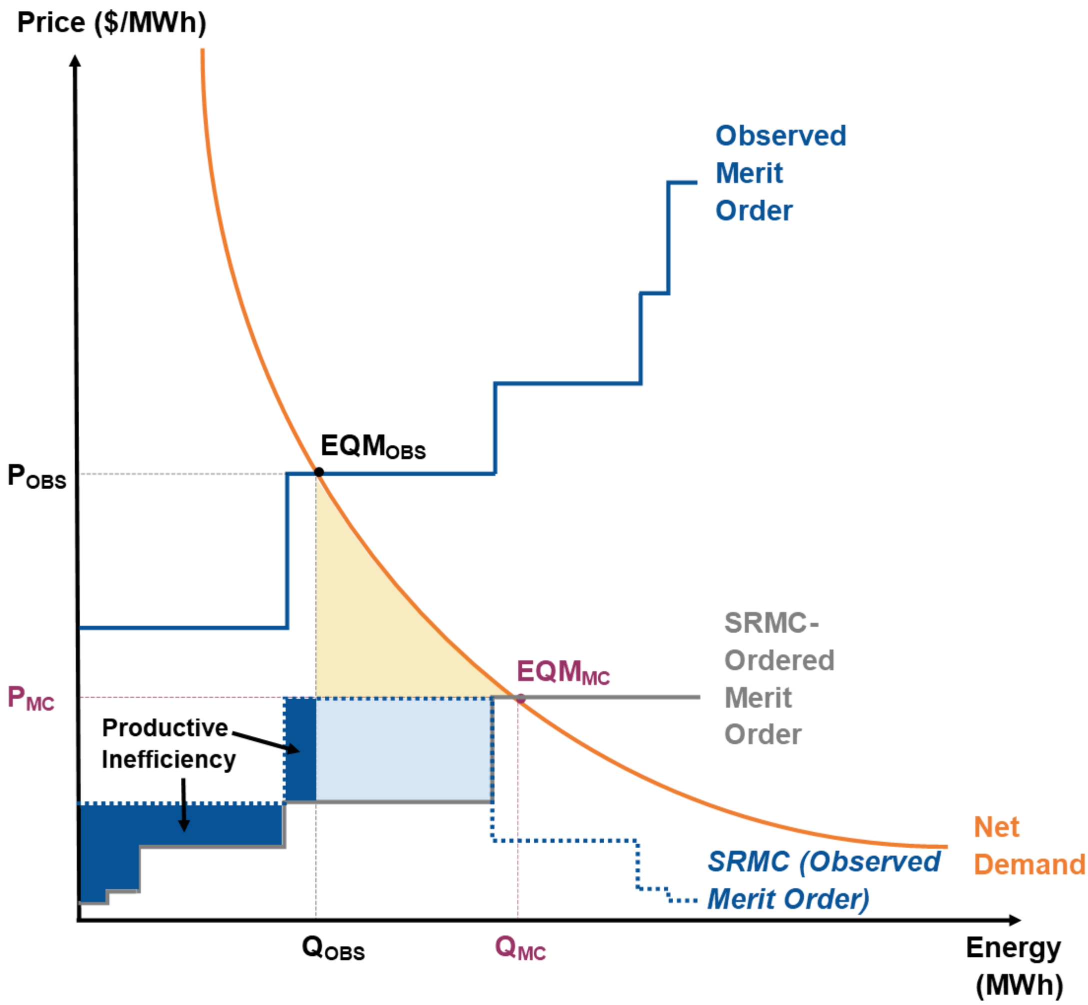
Figure 49: Allocative inefficiency



<u>Productive efficiency</u>

Productive efficiency refers to a state where the costs of inputs used to produce a given level of energy are minimized. In instances where the market could have produced the same level of energy (Q_{OBS}) at a lower input cost to producers, the additional incurred cost is referred to as the productive inefficiency (Figure 50). Quantitatively, productive inefficiency is represented as the difference between the costs incurred to produce the observed level of energy and the lowest possible costs incurred to produce that energy if generators were dispatched in a cost-ordered manner. While it is reasonable to expect that generators would not offer their energy at prices below their input cost, the ability of generators to economically withhold can lead to instances where higher-cost generators may be dispatched to generate energy instead of lower-cost generators if these lower-cost generators have offered their energy at sufficiently high prices.

Figure 50: Productive inefficiency



Unlike allocative inefficiencies, productive inefficiencies are not necessary for long-run cost recovery in an energy-only market, as productive inefficiencies only occur when input resources are used inefficiently, and do not impact the price faced by consumers or the price received by generators.

Static efficiency estimation assumptions

The MSA estimated allocative inefficiency using the observed merit order, counterfactual merit order (where units price their capacity at short-run marginal cost) and the foregone net demand associated with the observed prices relative to net demand at counterfactual prices. Allocative inefficiency necessarily occurs in each hour examined by the MSA where the observed price differs from the counterfactual price by virtue of the estimated net demand curve: even small changes in price are associated with different values of net demand.

Productive inefficiency was estimated using the total variable costs observed merit order and the total variable costs of the optimal SRMC-ordered merit order. [57] The incremental total variable cost incurred by generators to generate the observed level of energy compared to the lower total variable cost of generating the same amount in the optimal dispatched merit order is the productive efficiency loss.

In assessing static inefficiency, the MSA excluded any incremental inefficiency resulting from unit constraints in the energy market. As such, the MSA's static inefficiency estimates should be interpreted as inefficiencies resulting from the exercise of market power in the Alberta energy market, notwithstanding the possibility that the exercise of market power may itself affect constraints.

[57] For the purposes of the MSA's analysis, it is assumed that a generating unit has constant variable costs in production, i.e., the short-run marginal cost is equal to the unit's variable cost of generating a single unit of energy.