Carbon Price Pass-Through in Alberta's Electricity Market*

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Abstract

We evaluate the response of wholesale power market participants in Alberta to a series of changes in greenhouse gas (GHG) emissions policies. Between 2015 and 2019, legislative changes have affected carbon price levels, the rates of output-based allocations of emissions credits, and the coverage of carbon pricing across facilities of different sizes, creating variation in average and marginal carbon prices both across and within facility types and across and within portfolios held by major players in Alberta's wholesale power market. We exploit this variance in treatment to provide unique evidence of offer response to carbon pricing in power markets. We show that even after adjusting for costs imposed by carbon policies at the facility level, statistically significant changes in portfolio-level offer curves were induced leading to a shift in the merit order toward gas and away from coal which exceeded that which would have been predicted by carbon prices alone.

Keywords: climate change, carbon pricing, electricity, coal

JEL classification: Q3, Q4, Q54

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1 Introduction

We evaluate the response of wholesale power market participants in Alberta to a series of changes in greenhouse gas (GHG) emissions policies. Between 2015 and 2019, legislative changes have affected carbon price levels, the rates of output-based allocations of emissions credits, and the coverage of carbon pricing across facilities of different sizes, creating variation in average and marginal carbon prices both across and within facility types and across and within portfolios held by major players in Alberta's wholesale power market. We exploit this variance in treatment to provide unique evidence of offer response to carbon pricing in power markets. We show that even after adjusting for costs imposed by carbon policies at the facility level, statistically significant changes in portfolio-level offer curves were induced leading to a shift in the merit order toward gas and away from coal which exceeded that which would have been predicted by carbon prices alone.

The Alberta wholesale power market provides an excellent laboratory for our study because it is small, isolated, and the market is settled on a real-time, energy-only basis, so there are limited confounding factors beyond what is observable in our data. Alberta's market is winter-peaking, with peak 2021 load of just under 12,000 MW.[1] Alberta has only three small interconnections to British Columbia, Montana, and Saskatchewan, with total capacity of less than 15% of peak internal load.[2] The relative isolation of Alberta's market means that local prices and generation will be more affected by Alberta's policies than would be the case if traded power had a more important market share, and implies that extra-jurisdictional confounding factors are less likely to influence our results. The downside to this is that Alberta, a major oil-producing jurisdiction, was hit with a major, oil-price-induced recession contemporaneously with some of the changes in carbon policies, and this economic downturn led to a period of low prices in the power market. Alberta's generation mix is also somewhat unique, with a significant portion of internal load served by combined heat and power (or co-generation) plants associated with industrial facilities, primarily located in the oil sands region in Northern Alberta. Despite these anomalies, the transparency and isolation of Alberta's market provide us with a unique opportunity to study carbon price pass-through to prices as well as the induced changes in market participation.

We compile data describing market offer behaviour and a wide range of relevant co-

[1]The 2021 maximum Alberta internal load per AESO 2021 data was 11,729 MW at time of writing, which is also the peak value ever recorded in Alberta.

[2]The British Columbia and Montana tie lines have a joint capacity of 1500 MW for imports and 1325 MW for export, while the Saskatchewan tie line has a path rating of 150 MW.

variates. We measure and describe facility-level hourly offers of power into the market over slightly more than 10 years preceding the COVID-19 pandemic. We combine these data with detailed plant characteristics compiled from regulatory data, emissions compliance data from Alberta's and Canada's air emissions reporting, weather data, commodity price information, and power market data including hourly renewable generation, imports and exports, import and export capabilities and total and forecast internal loads. Finally, we include both observed carbon policy costs and the value of output-based allocations at the facility level.

In order to isolate the impact of the changes in policies on offer behaviour, we develop a unique empirical strategy based on synthetic power plants and synthetic power portfolios. For each hour of each day, we create synthetic power portfolios either by plant type . We are then able to examine, for example, how changes in policies affected the offer of power across all coal- or gas-fired plants in the province.

or by which entity holds offer control on the units in question , or across all facilities owned by particular actors in the market. We normalize these portfolios by percentile, so we are able to compare behaviour across portfolios of different sizes without loss of generality.

Results preview...

2 Alberta's GHG Policy Changes

Alberta has had carbon pricing in place since the *Specified Gas Emitters Regulation* (*SGER*) took effect on July 1, 2007. That regulation, the first industrial carbon price in North America, implemented a price of \$15/tonne, and allocated emissions credits to covered facilities at a rate equal to 88% of an individual facility's historic (2003-2005) emissions intensity. For new facilities built after 2005, they were allocated emissions credits per unit output at a rate equal to 88% of their average year 3 emissions intensity. In addition to carbon pricing on industrial emissions, the *SGER* also included an offset protocol which provided emissions credits for deemed emissions reductions due to certain activities. In the case of combined heat and power plants, facilities received an allocation of credits which amounted to 0.418t/MWh for net-to-grid electricity. New renewable power facilities were also eligible for offset credits under the SGER, with a deemed emissions reduction rate of 0.65t/MWh.[3]

This system remained in place until June, 2015 when the government of Premier Rachel

[3]Cite. Subsequently reduced to 0.59t/MWh (2015) and 0.53t/MWh (2019)

Notley introduced a series of changes to the existing regulation. The first set of changes increased the carbon price to $20/tonne for 2016 and to $30/tonne for 2017, while also reducing the benchmarks for the output-based allocation of emissions credits to 85% and 80% of historic facility level emissions intensity for 2016 and 2017 respectively. Combined, these changes implied a material increase in the average cost of carbon in each of the years 2016 and 2017. The government subsequently adopted, in November of 2015, a more comprehensive change to GHG emissions policies. Two changes in this iteration of policies affected power markets. Most importantly, the *Carbon Competitiveness Incentive Regulation (CCIR)* replaced the *SGER* and these regulations levelized the output-based allocation of emissions credits across all power generators at 0.37t/MWh, the emissions intensity of the best-in-class combined cycle natural gas generation facility in the province. This implied that coal producers saw a steep increase in their average costs of carbon, while impacts on gas power plants varied depending on the heat rates of the facility. Both combined heat and power plants and existing renewable generation facilities saw the value of their emissions credits issued per MWh generated decrease under the *CCIR*. The second important change was that an economy-wide carbon price was introduced for facilities not covered under the *CCIR* - those without historic emissions in any previous year greater than 100,000 tonnes. These facilities did not, by default, receive output-based allocations of emissions credits to offset the cost of the carbon price, so their average costs of carbon could be much higher than their larger competitors. An opt-in provision allowing these smaller firms to be covered under the *CCIR* was available, should facilities wish to undertake the more comprehensive emissions reporting. While not directly material to our sample period, the government also announced an accelerated coal phase-out which would see all coal-fired generation shut-down, equipped with carbon capture and storage, or re-fired with natural gas by December 31, 2030.

The *CCIR* remained in place until it was replaced by the *Technology Innovation and Emissions Reduction Regulation* (*TIER*) on January 1, 2020, outside of our sample period. However, it's important to not that while *TIER* altered the design of output-based allocations in most sectors, it did not impose material changes in the electricity industry and so we should not expect any changes late in our sample period which abuts the implementation of *TIER*.

3 Data

The majority of data for this paper comes from the Alberta Electricity System Operator (AESO). The AESO provides, with a 60-day lag, information on the offers made by power plant owners or controlling entities into the pool on an hourly basis. Facilities offer their power in up to 7 increasing-price blocks, with a price cap of $1000/MWh and a floor of $0/MWh. Plants are dispatched according the merit order of these offer blocks, from lowest to highest offered prices.[4] We have hourly merit order and dispatch data from September 1, 2009 through May 31, 2021, but we truncate the data at December 31, 2019 to avoid impacts of the COVID-19 pandemic.[5] The data also allows us to identify, by block, which entity had offer control in the market for that block of power in each hour.[6]

We also use three other AESO data sets to build our analysis sample. First, the AESO issues hourly price and load data, including 3-hour ahead forecast and actual prices and loads, which we merge with merit order data. Next, we include intertie capability rating data which allow us to account for hours of limited import or export capacity. Finally, and most importantly, we use metered volumes data at the facility level to incorporate renewable generation into the merit order. The AESO treats non-dispatchable renewables (wind and solar power in our case) as negative load, but lists them in the merit order data as $0 offers at full nameplate capacity. For each facility-hour pair in our data set, we merge actual metered generation into the merit order and treat renewable generators as having offered exactly their metered volumes each hour, still at a $0MWh offer.

We supplement these data with a variety of other information. Most importantly, we add facility-level compliance data from Alberta's greenhouse gas emissions pricing policies, the *SGER* (2009-2017) and the *CCIR* (2018-2019). These data were provided for this analysis by the Government of Alberta, with some portions of the data also available publicly. We supplement these data with information from the Federal Greenhouse Gas Emissions Reporting Program to provide, where available, more precise emissions intensity data for smaller facilities.[7]

[4]Blocks may be either flexible or not, and non-flexible blocks will only be dispatched when demand allows the entire block to be used for the hour. If what would otherwise be the marginal block is not a flexible block, the next-highest-priced offer block will be dispatched.

[5]For a discussion of Alberta market responses to the COVID-19 pandemic, see Leach et al. (2020).

[6]The offer control identifiers are only published after 2013, so our analysis on these data takes place over a smaller sample.

[7]The federal data are useful since the reporting threshold of 10kt CO_2e per annum is lower than the provincial threshold for coverage under the emissions pricing policies of 100ktCO_2e per annum.

There are three sources of incompleteness in our emissions data. First, we have no emissions data for smaller facilities, since provincial and federal reporting is not required below a minimum threshold. We have data on all facilities that fell under Alberta's industrial carbon pricing programs, but for smaller facilities which would have been subject only to the economy-wide carbon pricing program imposed in 2018, we have limited information. Federal reporting thresholds decreased to 10,000 tonnes per year which translates to an exemption from reporting for most natural gas generators with installed capacity of less than 20MW. Because reporting thresholds have changed over time, in some cases we have partial information on emissions intensities for smaller facilities, while in other cases we have no information at all. We use emissions-intensities from provincial reporting data as our first option, since the provincial reporting includes both verified production and emissions. Where we don't have provincial data, we use generation data aggregated by facility and federally-reported emissions to calculate an emissions intensity. Where we have partial information, we complete our dataset by filling first backward in time and then forward in time by plant by year such that, for example, a plant for which we only have 2019 data would see their 2019 emissions intensity used for every previous year. Where we have no information at all, we assume an emissions-intensity of 0.55 tonnes per MWh for simple cycle natural gas plants, the only type of plant for which we lack information of this type, based on facilities for which we do have information in our sample. The second source of incompleteness comes from the fact that data are reported at the facility level, not by generating unit. We apply the same emissions intensity to multiple generating units within a facility.[8] Since we have only annual data at the facility level, we do not allow emissions intensity to vary with the intensity of use of a particular unit within a facility, nor do we allow emissions intensities to vary with ramping of units. Finally, combined heat and power units present a challenge since many units report their emissions for the entire production facility, not simply for the power plant. There are some stand-alone units, but these also vary in terms of the emissions-intensity of net-to-grid electricity depending on the design of the specific unit and what share of the produced heat is used to generate electricity vs process steam. The emissions reporting data tell us the total electricity and heat produced in these facilities, and the emissions attributed to them, but do not tell us what the emissions intensity of an incremental unit of electricity would be. The output-based allocations for cogeneration facilities are determined by the carbon pricing policies, so we know the value of these for each regulated entity. For the

[8]There are two exceptions to this. The Keephills 3 and Genessee 3 coal-fired generating units report separately under Alberta's carbon pricing rules, and so we have separate emissions-intensity data for them.

purposes of our analysis, we adopt an assumed emissions intensity of electricity of 0.418 tonnes per MWh for combined heat and power units. Biomass plants, as well as wind, solar and hydroelectric plants are assigned a deemed emissions intensity of zero.

The compliance data also identifies two other attributes of importance to our analysis. First, under the *SGER* , facilities only faced compliance costs after their third full year of operations. Because facilities had to report federally during these periods, we can identify emissions intensities for some large facilities for 3 or 4 years before they face carbon pricing, and then for the remaining years in the sample when they are subject to carbon pricing. This is confounded slightly by the fact that the output-based allocations in future years are a function of the emissions intensity in the first years of operation. We account for this with an indicator variable in our analysis for the pre-compliance period. The data also provide the facility-specific rate at which output-based allocations were provided in each year, and the carbon price faced on emissions net of output-based allocations. The carbon price is constant for all Alberta-based facilities, but the combined-cycle plant in Fort Nelson, BC faces the BC carbon tax while being connected to the Alberta electricity grid, and so receives no output-based allocations and faced higher carbon prices in many years of the sample than comparable plants in Alberta.

We add weather data from Environment Canada weather stations in Edmonton, Fort McMurray, Cold Lake, and Calgary, covering the major demand centers in Alberta. We take the average of available measurements in each area in order to maximize the number of hours we can cover with weather data. With this approach, we lose fewer hours from our data set than if we allow unavailable weather data from one station to remove an hour from our sample. There is also no reason to believe that weather data availability is correlated with our variables of interest, and so the lost observations should have no leverage on the results. We convert temperature data to heating and cooling degree days for each region, which we then use in our model.

Finally, we supplement our publicly-available data with several series from NRGStream, a commercial data aggregation service. Most importantly, this service provides daily natural gas prices for the Nova Inventory Transfer hub which are a better proxy for Alberta natural gas prices than publicly-available series for Henry Hub. NRGStream also scrapes the real-time data from the AESO, and thus provides slightly different data from the aggregate, publicly-available historic metered volumes provided by the grid operator. We use NRGStream real-time data to compile real-time intertie flows between Alberta and British

Columbia, Saskatchewan, and Montana and to source real-time generation (as opposed to net-to-grid metered volumes) from all generating units in the province where needed. These data are generally the same as metered volumes with the exception of cases where an industrial production facility is co-located with the power generation facility, in which case only the net-to-grid volumes from the facility are measured in the metered volumes data while the NRGStream scraped data captures actual production by hour for the generating facility.

All data save the natural gas prices and NRGStream generation and trade data which we are not authorized to redistribute are available HERE and can be replicated using code for the paper which is available at GITHUB LINK. For the publicly available code, we substitute Henry Hub gas prices as a placeholder, to which we apply the average discount observed between Henry Hub and NIT to adjust the values so that regression results may be more closely replicated.

4 Alberta's Power Market

A statistical portrait of Alberta's power market provides context for our study. Alberta's wholesale market is a single price, energy-only market. There is no day-ahead energy market, but there is a separate ancillary services market which we do not address beyond a couple of tangential references in this paper. Alberta's record internal load, reached on February 9, 2021, is 11,729MW, so Alberta's is a relatively small power market compared to the similarly-structured Energy Reliability Council of Texas (ERCOT) market, for example, which had a 58,597 MW peak 2021 load. Alberta has seen significant growth in average and peak loads, as shown in Figure 1, although growth has been substantially slower since 2014-2015 due to the effects of depressed oil prices on the Alberta economy discussed further below. There was also a major, short-term market event with a wildfire in Fort McMurray in 2016 which took a lot of oil sands generation and load off-line, which explains the markedly-lower spring trough in that year's load profile as shown in Figure 1. The 2020 COVID-19 demand shock is also evident in Figure 1, but lies outside the sample period for our analysis.

Our sample period covers ten years with no major regulatory changes in the power market design. Alberta briefly considered an addition of a capacity market, but this was never implemented. However, market conditions have varied over the sample period. There are three distinct periods during our sample - relatively high load growth and tight market conditions from 2009 through 2013, followed by sharply constrained growth and high reserve

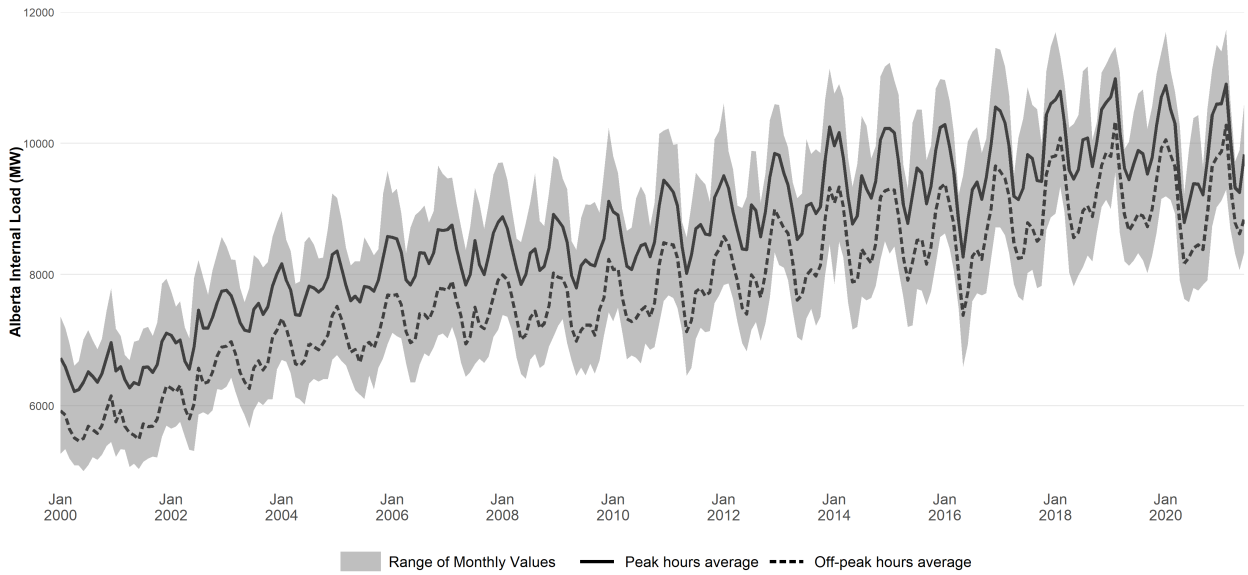

Figure 1: Alberta Internal Load. Source: Alberta Electric System Operator data.

margins after 2014 through most of 2018, followed by a return to tighter market conditions after the spring of 2018. These conditions are reflected in peak and off-peak prices shown in Figure 2. Some of these market changes coincide with policy changes of interest in our paper, in particular the changes to the *SGER* introduced in June of 2015 which took effect in January of 2016 and 2017 respectively and are coincidental with a period of over-supply, and the introduction of the *CCIR* in 2018 which occurred during a period of tightening reserve margins and lingering uncertainty over market structure. From 2018 through pre-COVID 2020, both GHG policy and the wholesale electricity market were tightening, and so we need to be careful to disentangle these impacts.

The generation mix in Alberta's power market is dominated by fossil fuels although, as shown in Figure 3, the dominant fossil fuel has changed from coal to natural gas. Within natural gas generation, the mix of plant types is also relevant to our study. By the end of our sample period, a significant increase in generating capacity from combined cycle (NGCC) plants had been installed, and this is reflected in higher generation from those sources. The installed capacity of combined heat and power (COGEN) facilities also grew during the sample period, and these plants tend to operate with high capacity factors but also tend to be price-takers in the market, with very little flexibility at the margin since the industrial processes with which they are associated rely on them for process heat. As will be discussed below, net-to-grid power from COGEN facilities is primarily offered into the market at a $0 offer and accepts market price, and so we see limited evidence of carbon price pass-through

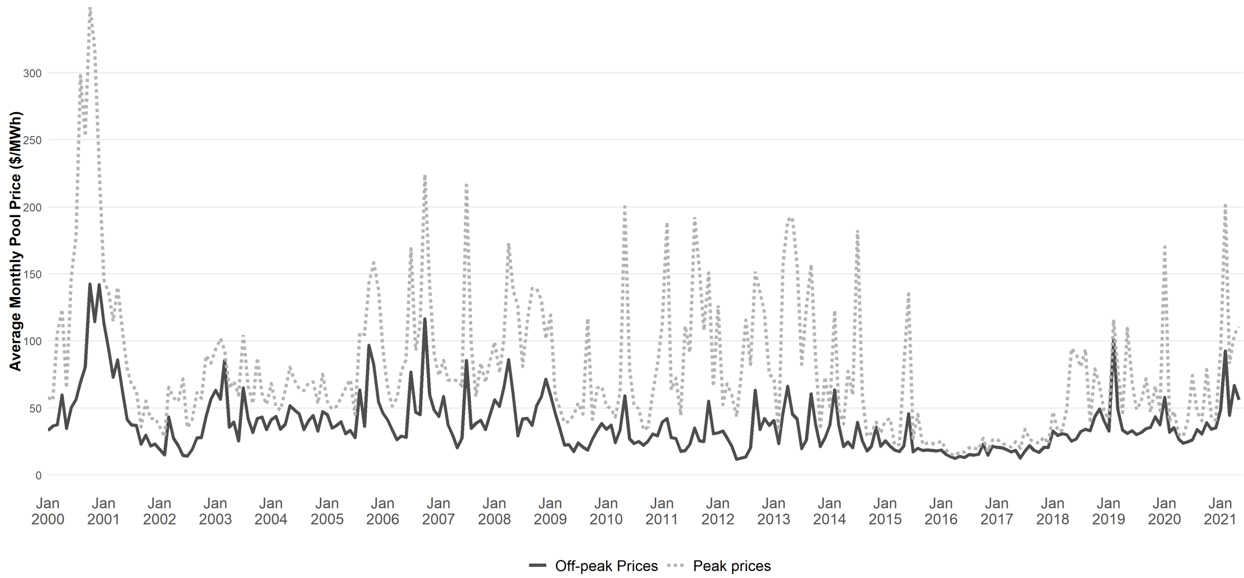

Figure 2: Wholesale power prices, peak and off-peak hours. Peak hours are 8am to 11pm other than on statutory holidays or Sundays. Source: AESO data, authors' graph.

for most of the power offered by these facilities. On the other hand, peaking capacity in the market during our sample period was largely met through ramping of coal and combined-cycle plants, as well as simple cycle (SCGT) natural gas turbines. Each of these would be exposed to carbon pricing, and so we expect to see pass through affect offers of power from these facilities into the market.

Consumption in Alberta is relatively stable on daily and annual bases due to the large industrial base. For example, in Figure 4, we compare Alberta's hourly load pattern to ERCOT and MISO equivalents. In the left-hand panel, we see that there is less variability through the day in Alberta as industrial load dominates cycles in residential and commercial load. Seasonal patterns are also both less pronounced and exhibit a winter peak, compare to summer-peaking ERCOT and MISO systems.

The nature of Alberta's wholesale market is such that different generators will derive different levels of average revenue from the sale of their power. Those that dispatch only in high-price times will have higher revenues on average than plants without dispatch control, or plants which run most hours of the day. Since prices have varied substantially over time, as shown above in Figure 2, captured average prices at the plant level have varied as well, as shown in Figure 5. We can see evidence here of how plants of different types offer their power into the market: hydro and combined- and simple-cycle gas turbines follow prices, and dispatch more capacity in higher-priced hours, just as imports tend to occur when prices are

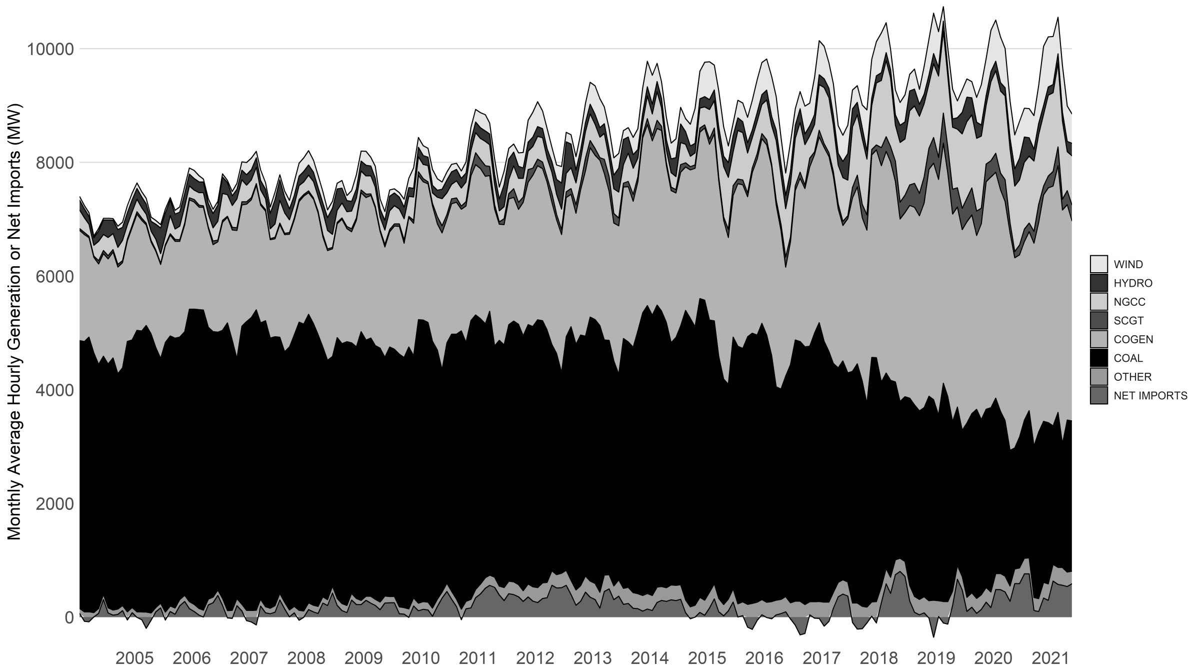

Figure 3: Generation mix in Alberta. Source: AESO data provided by NRGStream, authors' graph.

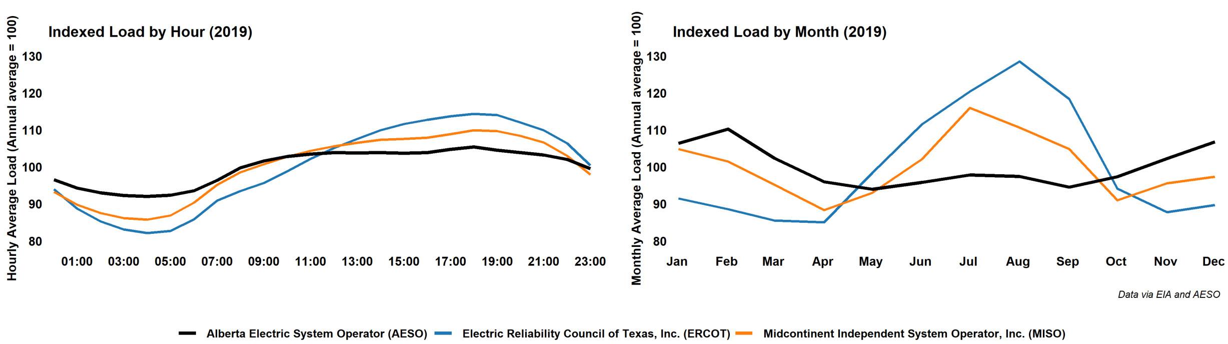

Figure 4: Monthly and hourly load patterns in Alberta compared to ERCOT and MISO.

higher. Lower prices tend to prevail when wind generation is highest, and so captured prices for wind power facilities are lower than other forms of generation, and exports tend to be scheduled when prices are expected to be low. Solar, a relatively new entrant in the Alberta market, has captured higher prices than other variable renewable sources since its generation pattern coincides with daily and seasonal peak prices, although we would expect this to change as *duck curve* effects take hold over time.

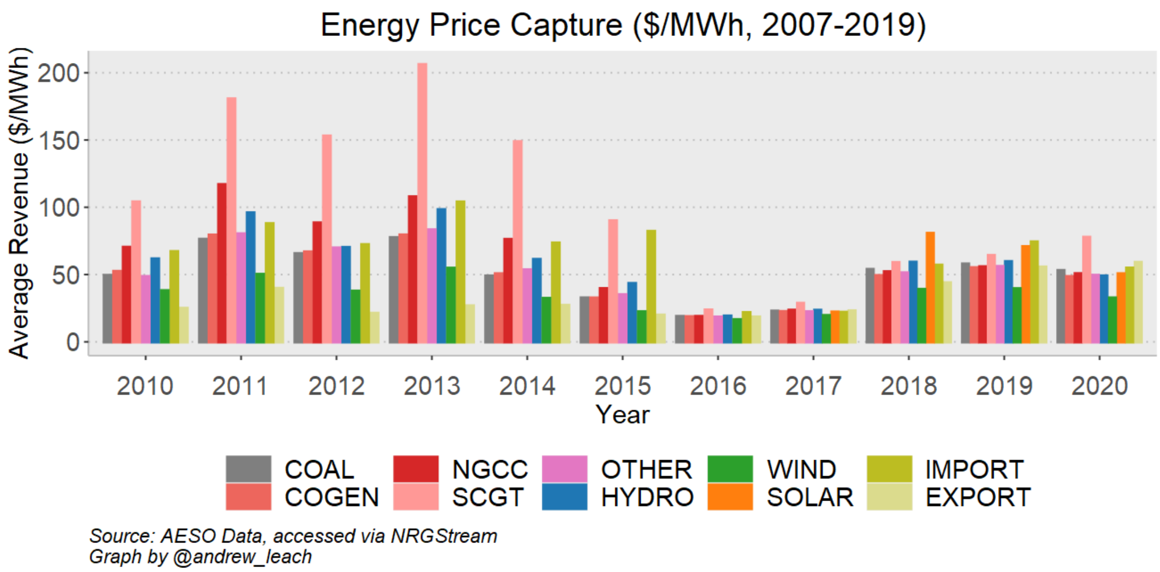

Figure 5: Annual average revenue by plant type. source: AESO data provided by NRGStream, authors' graph.

5 The Impact of Carbon Pricing Policy Changes

Alberta's three carbon pricing regimes each affected generating facilities in two ways. First, each of three (*SGER*, *CCIR*, and *TIER*) regimes imposes a price on emissions. Second, each regime allocates emissions credits based on output or deemed avoided emissions. The net effect of these policies creates variation within and across facilities and facility types and over time. Consider, for example, Figure 6 which shows the mean value and range of annual compliance costs for larger generators in Alberta's fleet over the sample period.[9]

As Figure 6 shows, changes in facility compliance costs were not all coincident with increased marginal carbon prices, but are actually dominated by the changes in output-based allocations which occurred subsequent to the adoption of the CCIR in 2018 rather than the initial increase carbon prices from \$15 to \$30 per tonne CO_2e in 2016 and 2017. The largest cost increases affect coal-fired power plants and some simple-cycle generators, while limited effects were felt by combined heat and power plants. Compliance costs for natural gas combined-cycle plants dropped between 2017 and 2019 as a result of a change

[9]Plants were only included in the sample for this figure if their annual emissions were sufficiently large ($\geq$100kt CO_2e per year) such that we have specific compliance cost data. For our estimation results, we impute compliance costs for a wider set of facilities using emissions intensities from the compliance cost data.

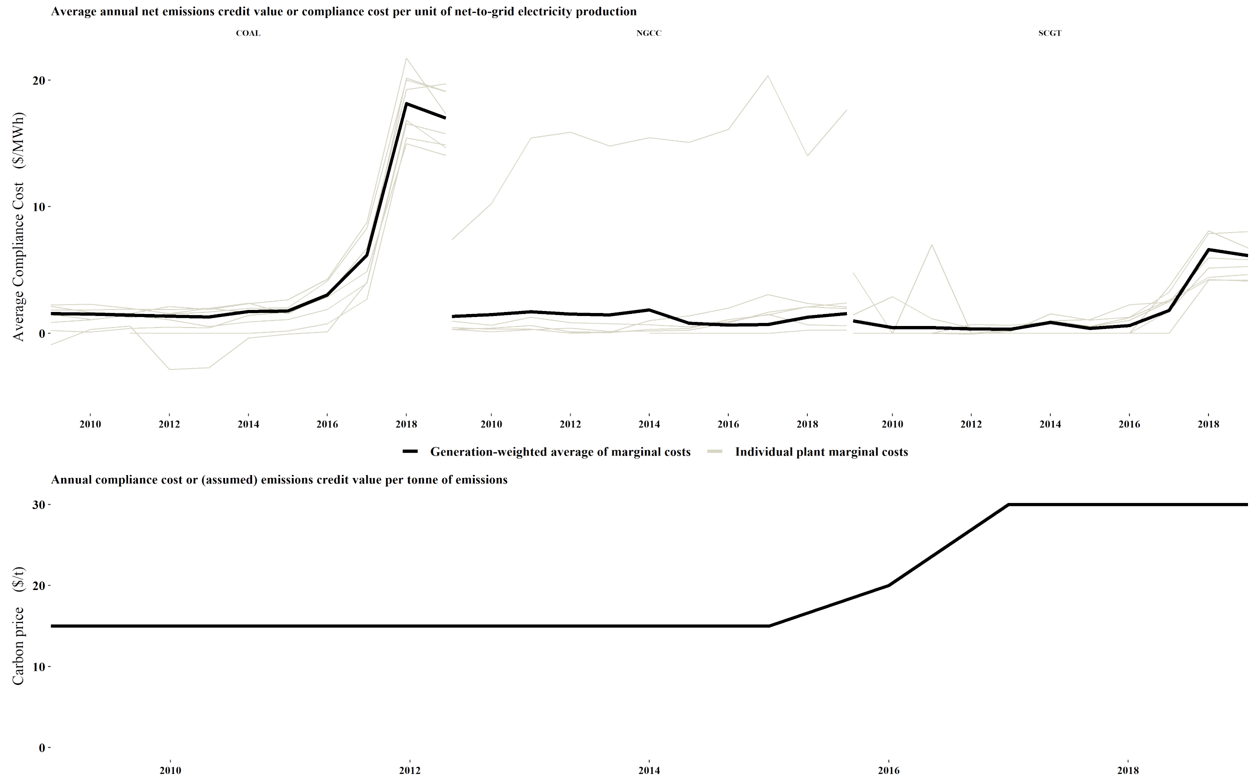

Figure 6: Upper: Annual average compliance cost (line) and range (shaded area) by plant type. Lower: Price charged on excess net annual emissions under Alberta's carbon pricing programs. Source: Alberta Environment compliance cost data

in the formula by which output-based allocations were calculated.

6 Estimation Strategy

There are two factors which confound our ability to draw inference from the merit order data. The first is that plants of the same type (e.g. coal or combined-cycle natural gas plants) may be of different sizes (e.g. a 350MW plant vs a 200MW plant) while facing similar optimization constraints, and they may be jointly dispatched by the same operator. In particular for coal plants, plant-level minimum-must-run constraints imply that facilities will always offer some portion of their generation into the market at a $0/MWh price, effectively acting as price takers for that hour for that block of power. They will offer marginal blocks of power, for capacity above their minimum-must-run level, at higher prices. However, given that plants are of different sizes, and blocks are endogenously determined, it's challenging to identify a change in offers looking only at block offers. The second issue is that the strategy space for each facility is very large, given that they may decide both on the break-points for each of up to 7 blocks of power, and then decide on a price for the first block and an adder for each subsequent block offered into the market. For each hour, then, the optimization problem consists of 12 choice variables and we have data on these choices for almost 20 million facility-hour-block pairs. Finally, since multiple plants may be controlled by a single entity, the observed data are the product of a complex portfolio optimization problem and the offers of any individual plant may not reveal an overall portfolio-level attempt to pass through the costs of carbon prices to wholesale prices. We avoid these problems by constructing synthetic offer curves either by plant-type or by controlling entity, thus estimating the impact of policy changes on the supply behaviour of the aggregate fleet rather than on any individual plant. We can then use the synthetic merit order data we construct to examine how power has been offered into the system over time as climate policies have varied.

Our empirical strategy is best understood visually through a series of figures. Consider Figure 7. In the left-hand panel, we show the merit order for a particular hour for all of the coal facilities in the province, with offers from multi-unit facilities combined for ease of visualization. We see facilities bidding some of their power at $0, ensuring they are in the market, with marginal generation blocks offered at increasing marginal prices. In this particular hour, the price was such that most of the offered coal generation was dispatched, with only blocks offered above the $802/MWh market clearing price not being dispatched. In the right hand panel, we show our synthetic merit order which summarizes all of the coal power offered into the market in a given hour using the 15 points shown in the Figure, which correspond to the value of the merit order at prescribed percentiles of the total offered power in that hour.[10] Summarizing the data this way reduces our stored information by a factor of three, but more importantly it allows us to answer the relevant question in our study - by how much did the supply curve shift in response to changes in the value of carbon pricing costs and output-based allocation revenue - by looking at changes in the value of our sampling points across the portfolio of offered power. Or, visually, we want to ask how, on average, each of the points in the right-hand panel of Figure 7 change when carbon prices are increased or when output-based allocations of emissions credits change.

There is a lot of day-to-day and hour-to-hour variability in how coal are offered into the market. Figure 8, which shows all of the 7pm merit orders (left panel), their synthetic

[10]We store the 10th through 40th percentiles in 10% intervals and the 50th percentile and above in 5% intervals to better capture the curvature of the merit order.

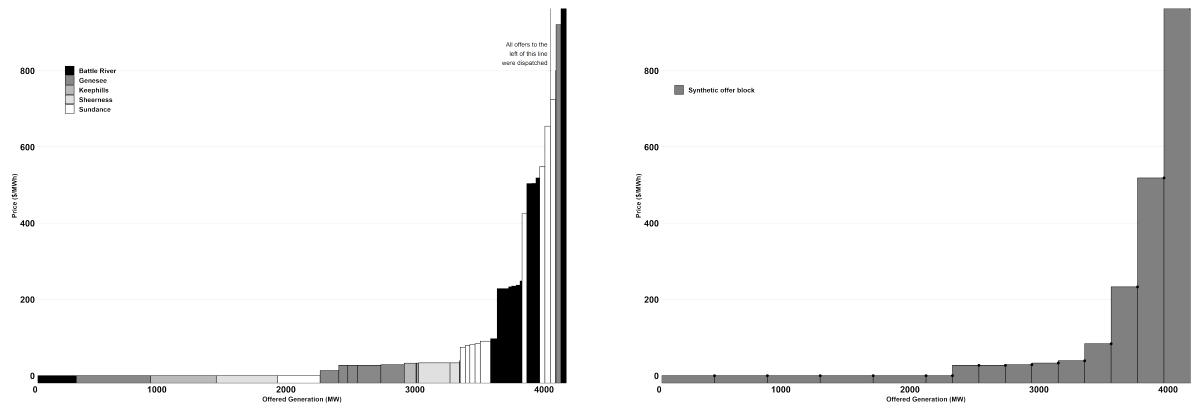

Figure 7: Observed coal facility merit order (left panel) and synthetic coal merit order (right panel) for February 4, 2019 at 7pm. For each hour, we convert the empirical merit order to a step function, and then extract the y-intercept as at 14 unique percentiles of total offered power in that hour, using 5% increments in the upper half of the merit order.

equivalents, and the average synthetic merit order for the last year of our sample, provides a sense of the degree of variability in our sample. Similar variability exists in the offers of generation from other dispatchable sources.[11] Figure 8 shows the degree to which changes in total offered capacity would skew our results if we attempted to base our analysis on offered megawatts. Instead, ny using percentiles of offered capacity as our units of measure, we can more cleanly ask how different segments of the supply curve shift vertically in response to different events, while implicitly assuming that the total offered power available in the market in a given hour is independent of the carbon pricing policy on offer at the time.

The next stage in our analysis is to transfer our information on facility compliance costs to the synthetic merit orders. Recall that, for the major emitters, we have facility-year-specific information on their emissions-intensity and their output-based allocations of emissions credits which determines their net emissions pricing liabilities. Since we are interested in the separate effects of both components of emissions policies, and since both vary at the facility level through our sample, we can separately identify the impacts of each on price pass-through behaviour. As such, for each of the synthetic merit orders we create for analysis purposes, we also capture and store both the marginal emissions charge and the marginal output-based allocation at each percentile support point.

For our analysis sample, we create three other types of synthetic merit orders. First, for

[11]See online graphical appendix, Figure A1, for a similar Figure for all dispatchable generating source types.

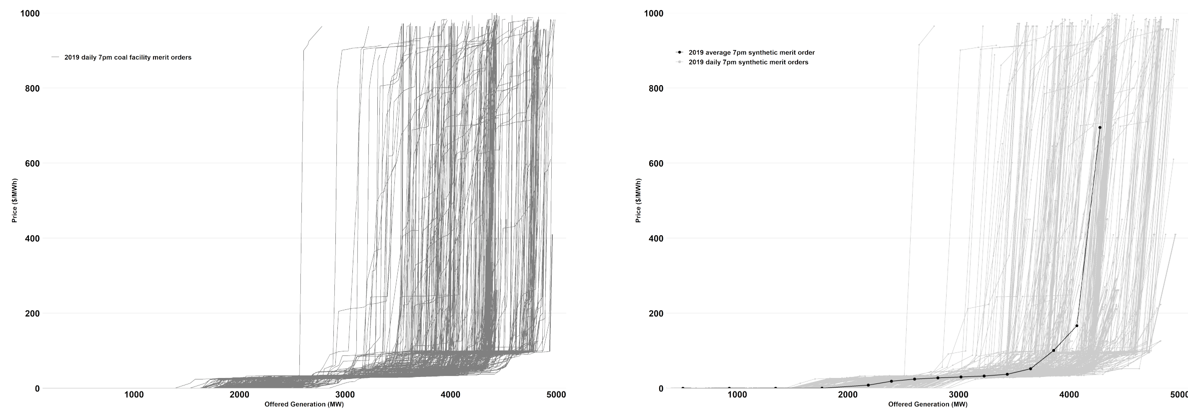

Figure 8: Observed coal facility merit order (left panel) and synthetic coal merit order (right panel) for all of the 7pm hours of 2019.

very general results, we characterize the entire merit order using the methodology outlined above. We also use the fact that, from 2013 through 2019, the AESO provides offer control by unit as part of their merit order releases. We use this information to construct synthetic supply curves for each of the major participants in the Alberta power market. This means that we have facility-level, generator-class-level and market-level synthetic merit orders to analyze.

To these, synthetic merit orders, we add our hourly data on market status, weather, and fuel prices specified above. This then allows us to build regression equations for each percentile support point of each synthetic merit order, asking the degree to which carbon price and output-based allocation changes impact the level of each step of the supply curves by facility, plant-type, by owner, or for the complete market.

7 Results and Discussion

7.1 Facility-level impacts

7.2 Impacts By Generator Type

7.3 Impacts By Generator Type

7.4 Market-wide impacts

8 Conclusion

References