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 information including fuel source, ownership, nameplate capacity, heat rate, and estimated emissions-intensity based on heat rates and fuel sources. ADD ON-LINE APPENDIX TABLE OF PLANT INFO.

We also use compliance data from the Alberta Specified Gas Emitters Regulations and the Federal Greenhouse Gas Emissions Reporting Program to provide, where available, more precise emissions intensity data for facilities. Since these data are both reported at the facility level, not by generating unit, we apply these measurements in the same way in our data. As

[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.

such, we do not allow emissions intensity to vary with the intensity of use of a particular unit within a facility in a particular hour nor do we account for any ramping rates of units.

We add weather data from Environment Canada weather stations in Edmonton, Fort McMurray, Cold Lake, and Calgary, covering the three 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.

Finally, we merge daily natural gas prices for the Nova Inventory Transfer hub. We access daily spot prices via NRGStream, a commercial data aggregation service.

All data save the natural gas prices 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

Using our dataset, we can provide a statistical portrait of Alberta's power market. 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-structure Energy Reliability Council of Texas (ERCOT) market, for example, which had a 58,597 MW peak 2021 load.[7] Alberta has seen significant growth in average and peak loads, as shown in Figure 1, with X cumulative annual average load growth rate during our sample period, 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

[7]The AESO previous record, reached on January 11, 2018, was 11,697 MW, so peak loads have been quite stable in recent years after a period of rapid growth.

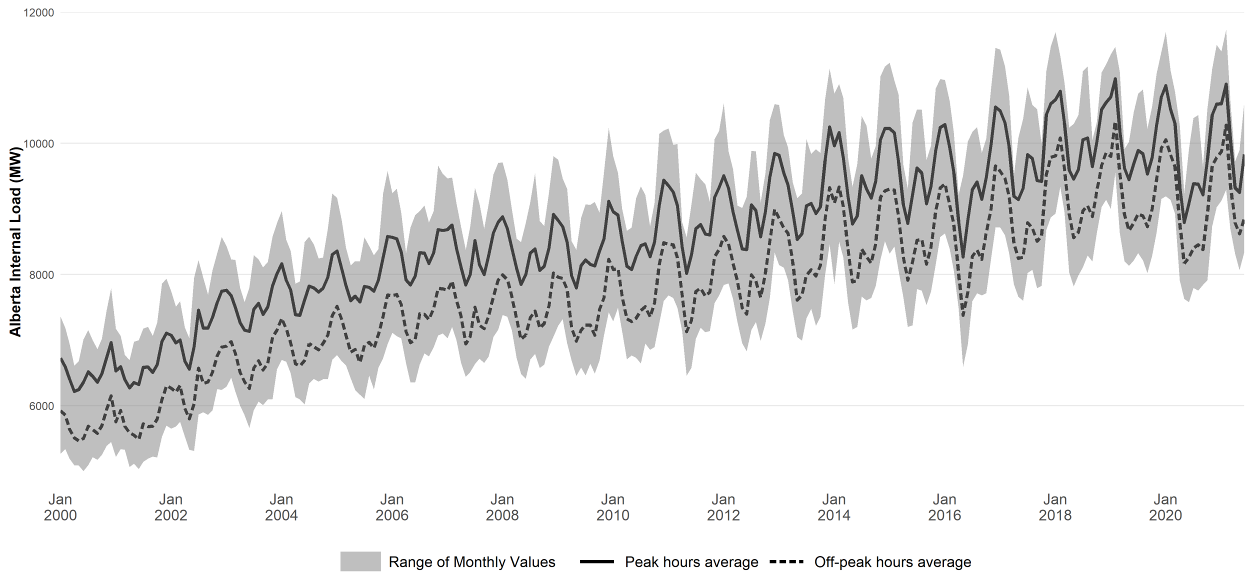

Figure 1: Alberta Internal Load. Source: Alberta Electric System Operator data.

sands generation and load off-line, which explains the markedly-lower spring trough in that year shown in Figure 1. The 2020 COVID-19 demand shock is also evident in this graph, 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 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 in our experiment - in particular, the changes to the *SGER* introduced in June of 2015 which took effect in January of 2016 and 2017 respectively coincide with a period of over-supply, while the introduction of the *CCIR* in 2018 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

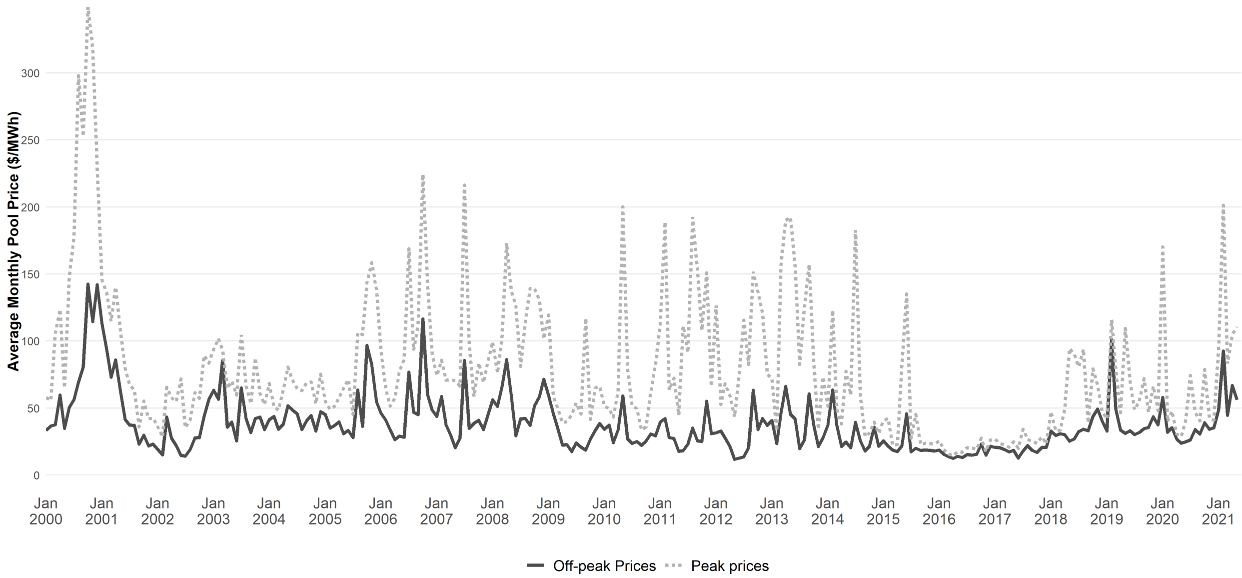

Figure 2: Wholesale power prices, peak and off-peak hours. Peak hours are 8am to 11pm other than on statutory holidays or Sundays. Source: Alberta Electric System Operator data.

our sample period, X% of installed natural gas capacity comes from combined cycle (NGCC) plants, while y% is from simple-cycle (NGSC) plants, and the remaining Z% of capacity is from combined heat and power (COGEN) facilities. Combined heat and power plants 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 these 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 for most of the power offered by these facilities.

ADJUST FIGURE TO SHOW SAMPLE PERIOD

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 the 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

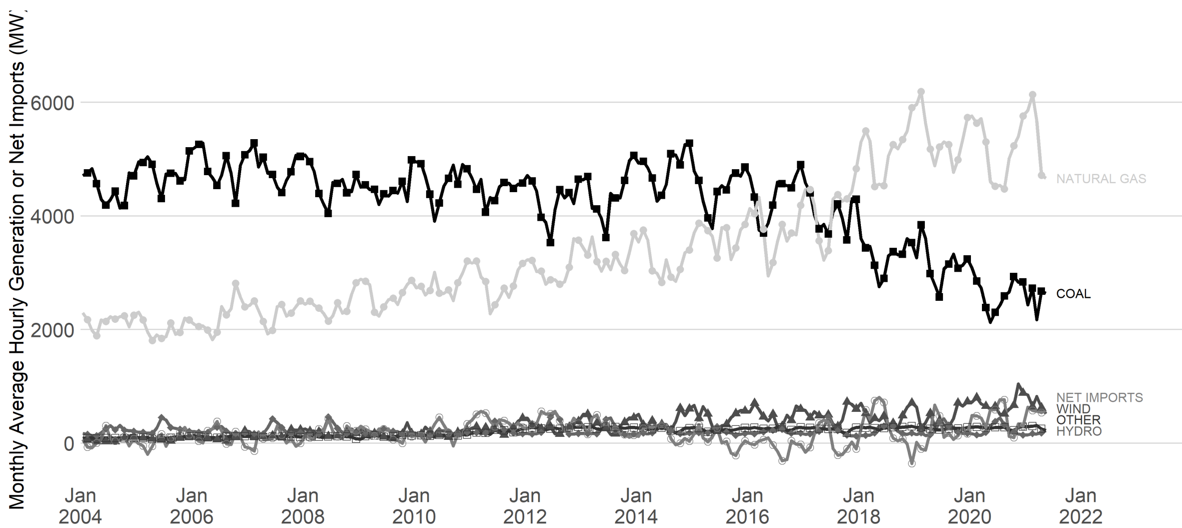

Figure 3: Generation mix in Alberta. Source: Alberta Electric System Operator data.

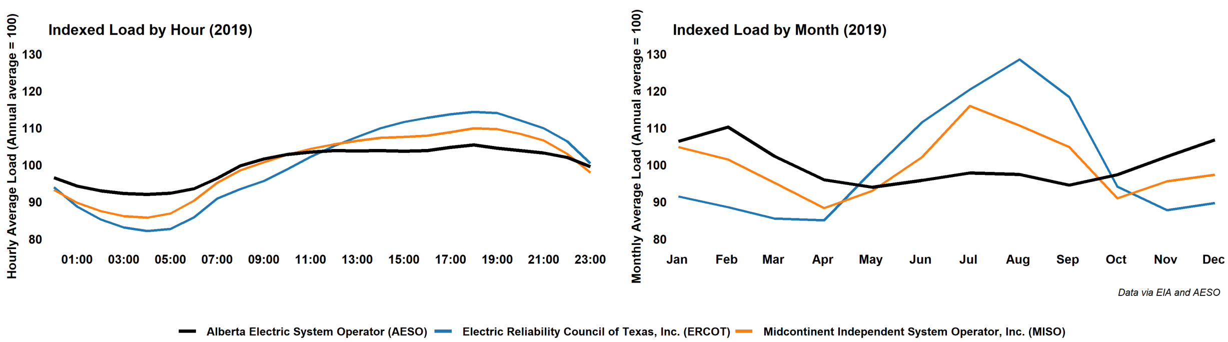

Figure 4: Monthly and hourly load patterns in Alberta compared to ERCOT and MISO.

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 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 the *duck curve* effects take hold over time.

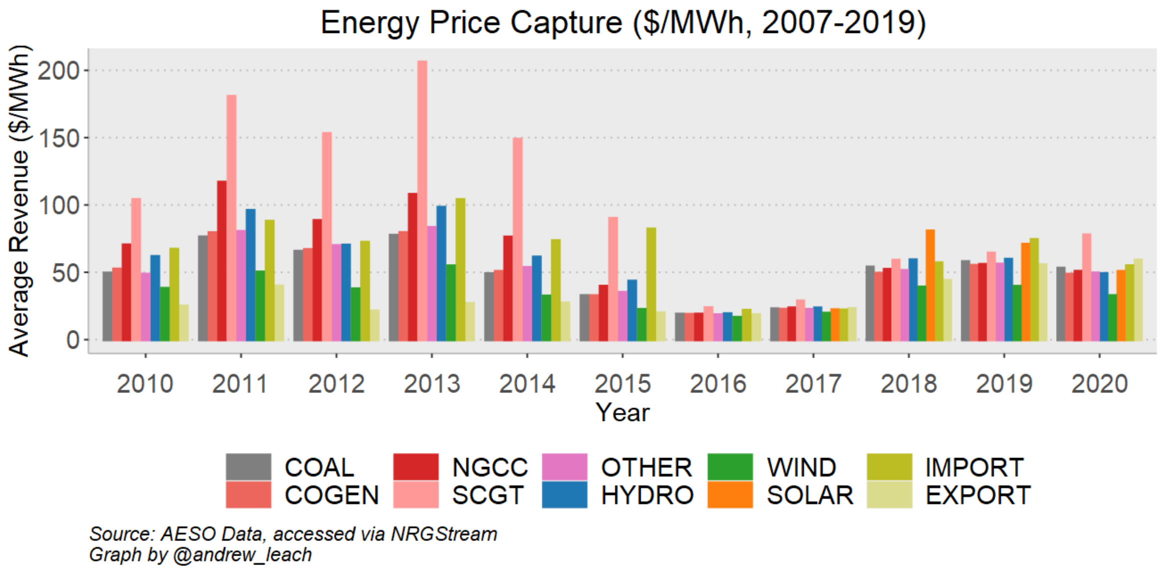

Figure 5: Annual average revenue by plant type

5 The Impact of Carbon Pricing Policy Changes

Alberta's three carbon pricing regimes affect 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 facility types 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.[8]

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 in 2018-2019 rather than the initial increase carbon prices from \$15 to \$30 per tonne CO_2e between 2016 and 2018.

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

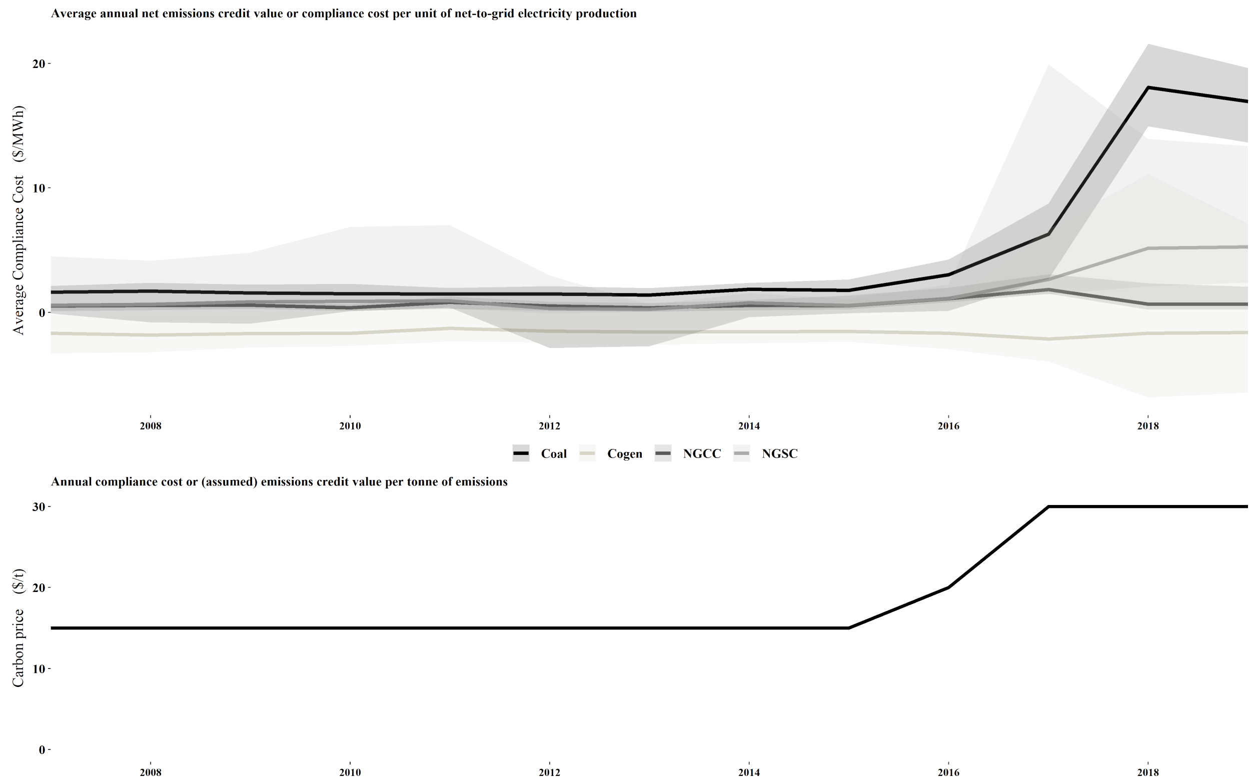

Figure 6: Annual average revenue by plant type

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 individual operators. 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 over 18.5 million facility-hour-block pairs. We render our problem more parsimonious, and at the same time overcome the portfolio bidding issue, both how the overall merit order and how power from a particular type of plant has been offered into the market over time.

This is best understood with a series of figures, and for this we will again use one coal plant (Capital Power's Genessee 3 facility) as well as Alberta's overall coal fleet to demonstrate the approach we take here.

7 Results and Discussion

8 Analysis and Results

9 Conclusion

References