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

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Abstract

We evaluate .

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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 observeable 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 we do face a challenge in that Alberta was hit with a major, oil-price-induced recession contemporaneously with some of the changes in carbon policies, and this economic downturn led to record-low prices in the market. Alberta's generation mix is also somewhat unique, with a significant portion of internal load served by combined heat and power (or cogeneration) 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 a unique opportunity to study carbon pricing pass-through to prices and the induced changes in market participation.

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

[1] The 2021 maximum Alberta internal load per AESO 2021 data was 11729MW 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.

ates. We measure and describe facility-level hourly offers of power into the market over nearly 10 full years. We combine these data with plant characteristics compiled from regulatory data, emissions data from Alberta's and Canada's air emissions reporting, weather data, commodity price information, and power market data include hourly renewable generation, imports and exports, import and export capabilities and total and forecast internal loads. Finally, we include observed carbon policy costs 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 or by which entity holds offer control on the units in question. 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 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 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

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

reducing the benchmarks for emissions allocation to 85% and 80% respectively for 2016 and 2017. 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.

COVERED FACILITIES TABLE

3 Data

The core of our 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,

[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

2009 through February 28, 2020 where we cut off the data 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 which we merge with merit order data. Next, we combine 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 metered generation into the merit order and treat renewable generators as having offered 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 units or blocks, we apply these measurements in the same way in our data. As 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 and Calgary, 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 only X hours without at least one observation in each of the three areas.

Finally, we merge daily natural gas prices for the Nova Inventory Transfer hub. We access daily spot prices from NRGStream.

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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). Our raw data set extends to November, 2020.

[6]The offer control identifiers are only published after 2013, so we...

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.

WE MIGHT BE ABLE TO GET PERMISSION TO INCLUDE THE NGX DATA.

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 model 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 ERCOT, for example, with 58,597 MW peak 2021 load.[7] Alberta has seen significant growth in average and peak loads, as shown in Figure **??**, 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 sands generation and load off-line, which explains the markedly-lower spring trough in that year shown in Figure **??**.

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 until 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 **??**. Some of these changes market coincide with policy changes in our experiment - in particular, the changes to the Specified Gas Emitters regulations introduced in June of 2015 which took effect in January of 2016 and 2017 respectively coincide with a period of over-supply, while

[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

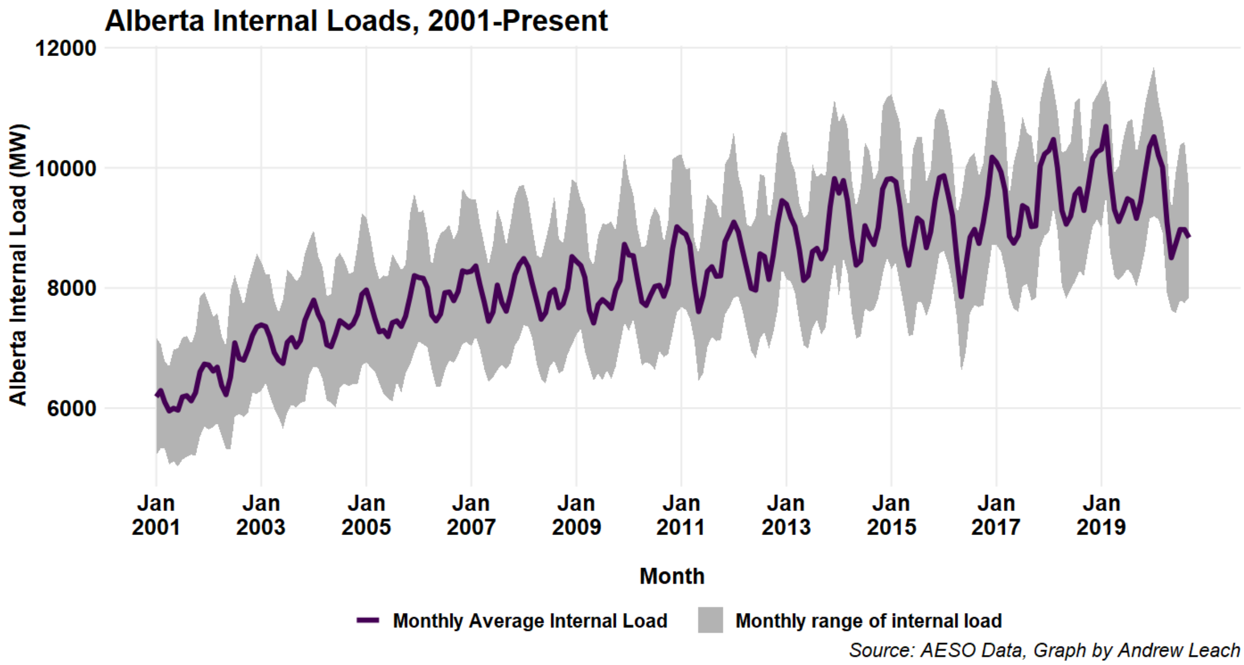

Figure 1: Alberta Internal Load. Source: Alberta Electric System Operator data.

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 **??**, the dominant fossil fuel has change from coal to natural gas. Within natural gas generation, the mix of plant types is also relevant to our study. X% are combined cycle plants, y% are simple-cycle plants, and Z% are combined heat and power facilities which tend to be price-takers in the market, with very little flexibility at the margin since the industrial processes with which they are associated relay on them for process heat. As will be discussed below, any net-to-grid power from these facilities is primarily offered into the market at a $0 offer and accepts market price.

Consumption in Alberta is relatively stable due to the large industrial base. For example, here's AB load compared to ERCOT...what does this mean?

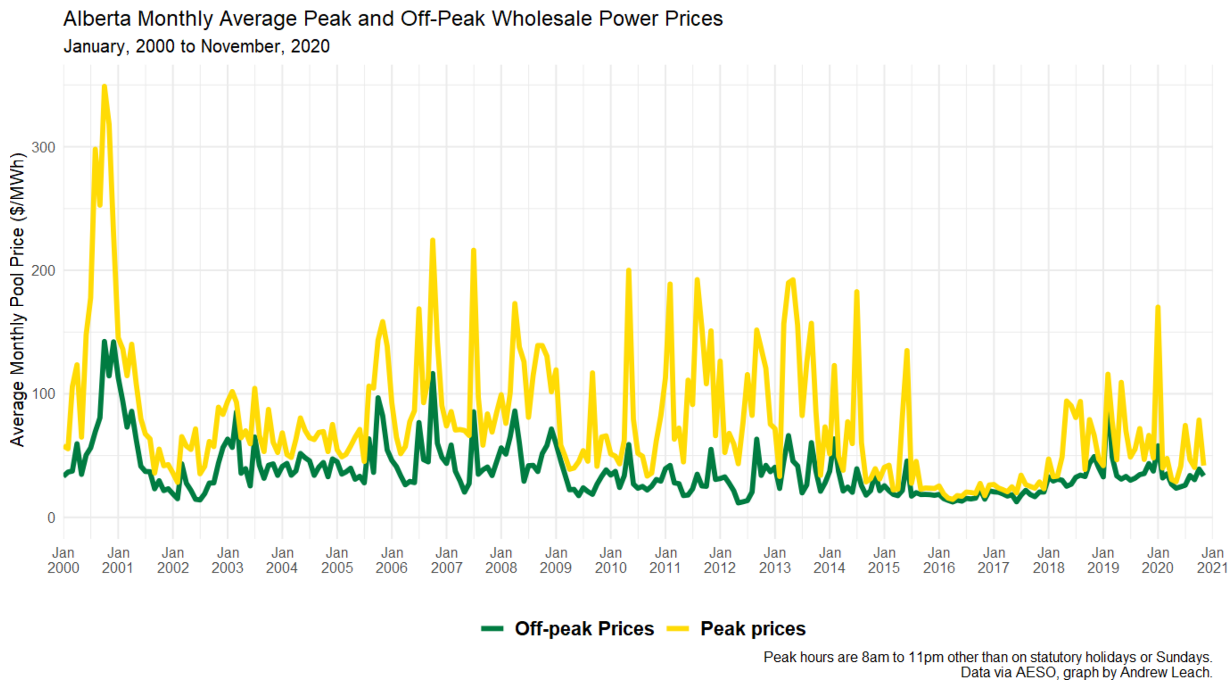

Figure 2: Wholesale power prices, peak and off-peak hours. Source: Alberta Electric System Operator data.

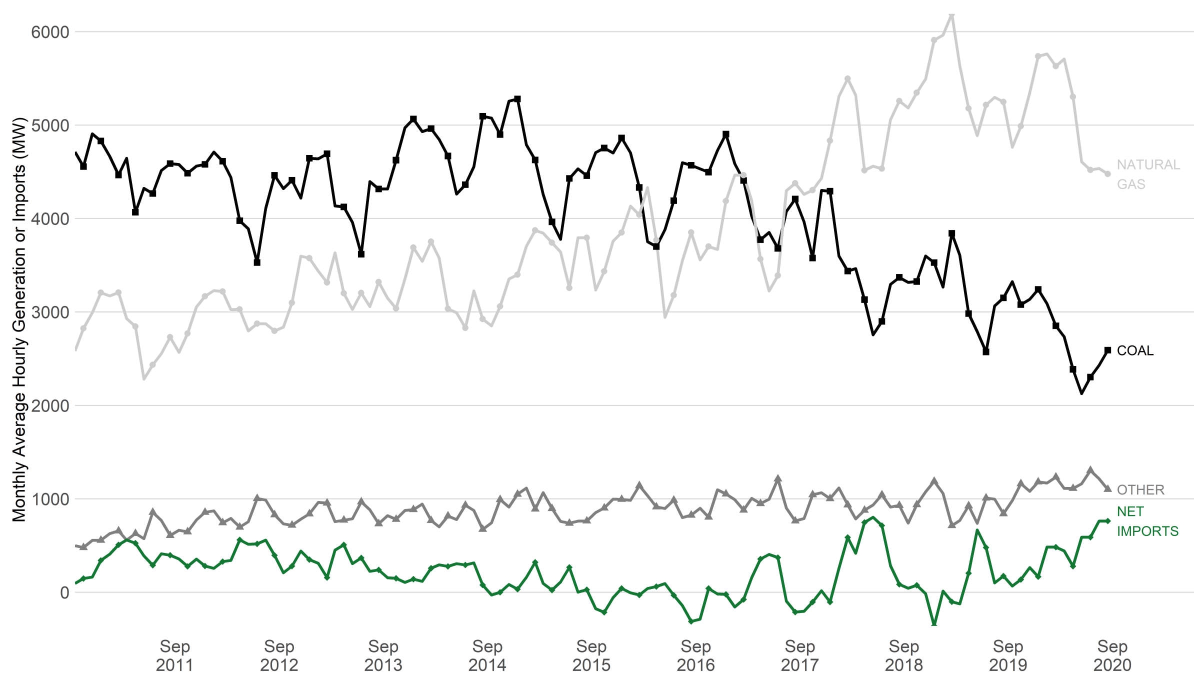

Figure 3: Generation mix in Alberta. Source: Alberta Electric System Operator data.

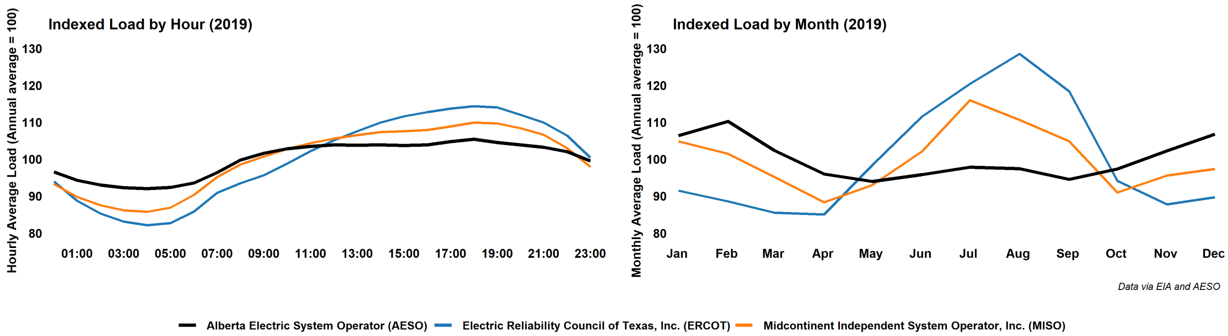

Figure 4: Monthly and hourly load patterns in Alberta compared to ERCOT and MISO.

5 Estimation

6 Results and Discussion

7 Analysis and Results

8 Conclusion

References