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To What Extent Does Wind Replace Fossil Fuels in Power Generation: Evidence from Alberta

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To What Extent Does Wind Replace Fossil Fuels in Power Generation: Evidence from Alberta

by

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ABSTRACT

To achieve the “Net-Zero” target, Alberta committed to phase out coal power plants before 2030 and facilitate the application of renewable energy to replace fossil fuel electricity generation. This paper investigates the substitution effect on the fossil-fuel generation of electricity produced by renewable wind-generated electricity. We analyze the nature of electricity generated from fossil-fuel power plants and wind farms and study their cyclical and seasonal characteristics. Our study highlights the importance of accounting for the dynamic effect of wind energy. Failing to consider dynamics will lead to either overestimation or underestimation of the impact of wind electricity, depending on the energy source. Contrary to some previous studies, we find that wind electricity has a larger substitution effect on coal-fired electricity compared to natural gas electricity.

Key words: wind energy, electricity market, climate change mitigation

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1. INTRODUCTION

After introducing the 'Pan-Canadian Framework on Clean Growth and Climate Change' (PCF) in 2016, and 'A Healthy Environment and a Healthy Economy' climate plan in 2020, Canada has been working on mitigating climate change and committing to achieving "Net Zero" by 2050. To reduce greenhouse gas (GHG) emissions, Alberta proposed to phase out coal-powered electricity generation by 2030. From 2018 to 2022, 13 coal-powered units have either been retired or transferred to natural gas, leaving three coal plans still in operation, although these are also to transit to natural gas by 2023. Meanwhile, wind and solar generating facilities have experienced rapid growth in Canada, accounting for approximately 68% of all new generation capacity in the country (Canadian Renewable Energy Association, 2022). Alberta is one of the leading provinces of wind energy development, with maximum wind capacity having grown from 24 MW in 2000 to 2178 MW in 2022.

Due to the low marginal cost of wind electricity, when wind farms penetrate into the grid, they will replace output from other generating sources, particularly fossil fuel generation, if wind power is taken as 'must run' (or non-dispatchable) by the system operator. At times, wind will replace power generated by baseload assets, such as coal and combined-cycle gas turbine (CCGT) plants.[1] Assuming that wind electricity would substitute for coal and/or natural gas electricity, we employ an econometric model to examine the offset effect of wind on coal and natural gas generation. Wind is highly intermittent: When it is not windy, there might be no electricity generated from wind; when there is adequate wind, there might be excessive electricity, in which case the grid might seek to export or curtail wind-generated electricity (van Kooten, 2016). While

[1] Baseload refers to "the minimum power that must be delivered to the grid at every moment throughout the year"; peak load is "the maximum power that must be delivered to the grid at some point throughout the year" (van Kooten, 2012, pp 410-411).

increasing and decreasing the output in a short period turns out to be highly expensive for coal and CCGT power plants, peak-load assets such as open-cycle gas turbines (OCGT) can ramp up rapidly in response to the change in the electricity market. When wind electricity declines due to the drop in intermittent wind power, OCGT is able to scale up rapidly to meet the electricity demand, although the marginal cost is high compared to that of baseload assets. In contrast, CCGT and coal baseload plants ramp slowly, although, in situations where ramping must be relatively fast (e.g., in response to large changes in renewable energy output), the costs can be prohibitive.

For this research, wind power is used to represent renewable energies, because (1) wind energy has become the most popular and “likely the most cost-effective” renewable energy source (van Kooten, 2012, pp.410), and (2) the intermittent nature of wind is indicative of the instability of other renewable energy sources, such as solar photovoltaic (PV) and tidal energy sources. Further, (3) we employ electricity market data from Alberta, where wind energy accounts for a comparatively much larger share of overall electricity output than solar and biomass sources, both of which have played a minor role during the years employed in the current research.

There has been a widespread interest in estimating the environmental effect of wind. Previous studies have mostly focused on how wind energy reduces emissions. By simulating the electricity generated from renewable energy and regressing GHG emissions on electricity output, Callaway et al. (2018) estimated the fossil-fuel emissions that renewable energy displaced. Using Electricity Reliability Council of Texas (ERCOT) data and econometric approaches, Cullen (2013), Novan (2015) and Kaffine et al. (2013) studied the fossil-fuel emissions offset by wind energy, as well as the substitution effect of wind energy on specific conventional electricity generation. Extending this research, our study explores whether wind offsets electricity generation from coal and natural gas, and to what extent. This provides insights into Alberta’s policy to phase out coal plants and reduce overall GHG emissions.

To examine these effects, we utilize data on hourly electricity generation, load (demand), imports and exports from the Alberta Electric System Operator (AESO) to estimate whether wind energy offsets coal and gas electricity generation. Considering the operational characteristics of the Alberta electricity system and the potential relationship between coal, gas and wind energy, we establish econometric models to examine the substitution effect of wind for electricity generated from fossil fuels. While Cullen (2013), Novan (2015), and Kaffine et al. (2013) used identical econometric models to examine the relationship between the generation of electricity from wind energy and different types of fossil fuels, we identify different models based on the characteristics of coal and natural gas turbines as well as how wind influences them. Additionally, the ramping up of fossil fuel generators involves an increase in emission rates, whereas the ramping down reduces emissions. When a generator operates steadily, it usually produces the least emission (Cullen, 2013). Therefore, we also examine how the intermittent nature of wind affects the ramping of fossil fuel generators. If the ramping down of wind energy increased the change in coal and natural gas-powered electricity, the ramping up of the fossil-fuel generators might produce unexpected emissions and cause damage to the generating facilities.

The remainder of this study is organized as follows: Section 2 provides background pertaining to the operation of the Alberta electricity system and how the accommodation of wind can change the electricity system. In Section 3, we present a descriptive analysis of the data, followed by a discussion of the empirical method in Section 4, and estimation results in Section 5. Our conclusions ensue in Section 6.

2. BACKGROUND: MODELING THE ALBERTA ELECTRICITY GRID

The Alberta electricity grid consists of electricity generators and transmission facilities.

The AESO is responsible for planning and operating electricity generation, transmission, distribution and retailing. The fundamental principle of the operation of the electricity system is to perfectly match electricity generation and load at every instant in time (Alberta Electric System Operator, AESO, 2018a). To realize this, the AESO predicts the hourly demand and matches the supply offer provided by generators with the electricity buyers. On the supply side, generators submit their supply bids and price offers a day prior to delivery, although asset owners are permitted to modify their bids up to two hours beforehand. The selection of suppliers is determined by "merit order", whereby they are ranked by their bidding price from the lowest to the highest. At the delivery hour, the system operator will begin with the lowest price offer and move to the highest until the electricity demand is met (AESO, 2018b).

The lowest price bids are usually offered by baseload facilities, such as coal, CCGT and nuclear assets, and the highest price bids are usually offered by peak load generators, such as OCGT, diesel and hydroelectric generators with reservoirs. Baseload plants generally ramp up and down at significant expense in response to a real-time change in load; hence, they tend to submit low bids to maintain their place in the merit order, knowing that they will receive the market-clearing price. Whereas OCGT and hydroelectric assets are able to react promptly to changes in load and useful for meeting peak load demand, they tend to bid high due to their higher fuel cost (van Kooten, 2012).

The cost of wind electricity is primarily incurred during the construction period. When wind farms start to operate, they generate electricity at near-zero marginal cost. Further, the government often offers subsidies or feed-in tariffs for wind turbines. However, the intermittency nature of wind prevents it from providing power reliably; when there is no wind, no electricity is generated from wind farms. When there is plentiful wind, excess electricity is sometimes generated; the excess power requires either that wind energy is curtailed, causing waste of renewable energy, or the output of one or more existing fossil-fuel generators must be reduced. There is typically higher wind output at midnight when the electricity demand is lower than in the daytime. Wind farms either generate much more than their supply bids or are unable to satisfy the supply bid. As a result, an electrical system with large-scale wind farms needs a lot more generators that can react quickly to changes in both demand and wind electricity output, such as OCGT and hydroelectric reservoirs. Fortunately, Alberta can trade with British Columbia (BC) through the transmission lines that connect the two provinces. About 87% of electricity in BC is provided by hydro reservoirs ("Provincial and Territorial Energy Profiles – British Columbia", 2022). The transmission line that links BC and Alberta enables Alberta to export extra wind electricity at night within the intertie capacity constraints to support the operation of those reservoirs and to store the wind energy, which forms the basis for the electricity trade between these two jurisdictions.

3. DATA AND DESCRIPTIVE ANALYSIS

To investigate the substitution effect of wind electricity on coal and natural gas electricity in Alberta, we utilize Alberta's electricity market data that include the hourly electricity generation from coal, CCGT, OCGT, wind, biomass, solar and hydro assets, and cover five years from 2015 to 2020. The wholesale price of electricity, imports from and exports to British Columbia (BC), Saskatchewan (SK) and Montana (MT) are also included. There are 52,068 observations in total. Since there is not much solar and hydroelectric capacity in Alberta, we do not consider hydroelectric and solar sources of power in our analysis. In addition, electricity generated from biomass, and trade with Saskatchewan and Montana, are not in the scope of our analysis because they only take very small portions of the total electricity supply and demand.

Table 1: Summary Statistics (MW)

Statistic	Mean	St. Dev.	Min	Max
Wind	518.553	395.882	0.000	1,704.036
Coal	3,708.707	896.514	1,366.933	5,884.367
Open-cycle gas turbine	243.097	190.193	0.331	930.799
Combined-cycle gas turbine	896.234	321.328	1.198	1,526.110
Load	9,423.530	839.083	6,594.692	11,698.010
Import from BC	147.296	208.557	0	875

Table 1 presents summary statistics for wind, coal, CCGT and OCGT power generation, as well as load and electricity imports from BC. Coal still ranks first in terms of mean, minimum and maximum values due to its large share in the generation mix. However, the share of coal in Alberta's total generation has declined from 63% in 2015 to around 40% in 2020, reflecting the phasing out process of coal power plants. The share of wind to total generation increased from 6.6% to 10%, together with an increase in CCGT generation from 8% to 17%, and OCGT generation from 1.7% to 4.8%. Solar joined the generation mix in 2017 and still takes a small percentage of less than 1% until 2020. Although as a baseload asset coal generation has a larger standard deviation than OCGT (Table 1), how much a generating facility can increase or decrease the electricity output in a certain time period is more of a concern. Coal takes a larger percentage of total electricity production than natural gas throughout our study period, which implies that the difference between its maximum and minimum generation is supposed to be large. However, it usually takes 10-12 hours for a coal plant to ramp up from 0 to its full capacity, while CCGT assets can ramp up in a few hours and OCGT assets can ramp almost instantaneously.

Figure 2 - 4 show the scatter plots of coal, CCGT and OCGT from 2015 to 2020, as well as their two-week moving average. In 2017, Alberta set up a carbon tax of $20, which increased to $30 in January 2018 (Murphy, 2019). The Carbon Competitiveness Incentive Regulation established an industry-wide benchmark for all electricity producers at the emissions level of a

productive CCGT plant. These events changed the landscape of the Alberta electricity market, which is why we can see the downward shift in the first panel of Figure 1 in the year 2018. At the same time, coal began to be phased out, so that, by 2022, there were only three coal-fired plants left in Alberta (see Table 2).

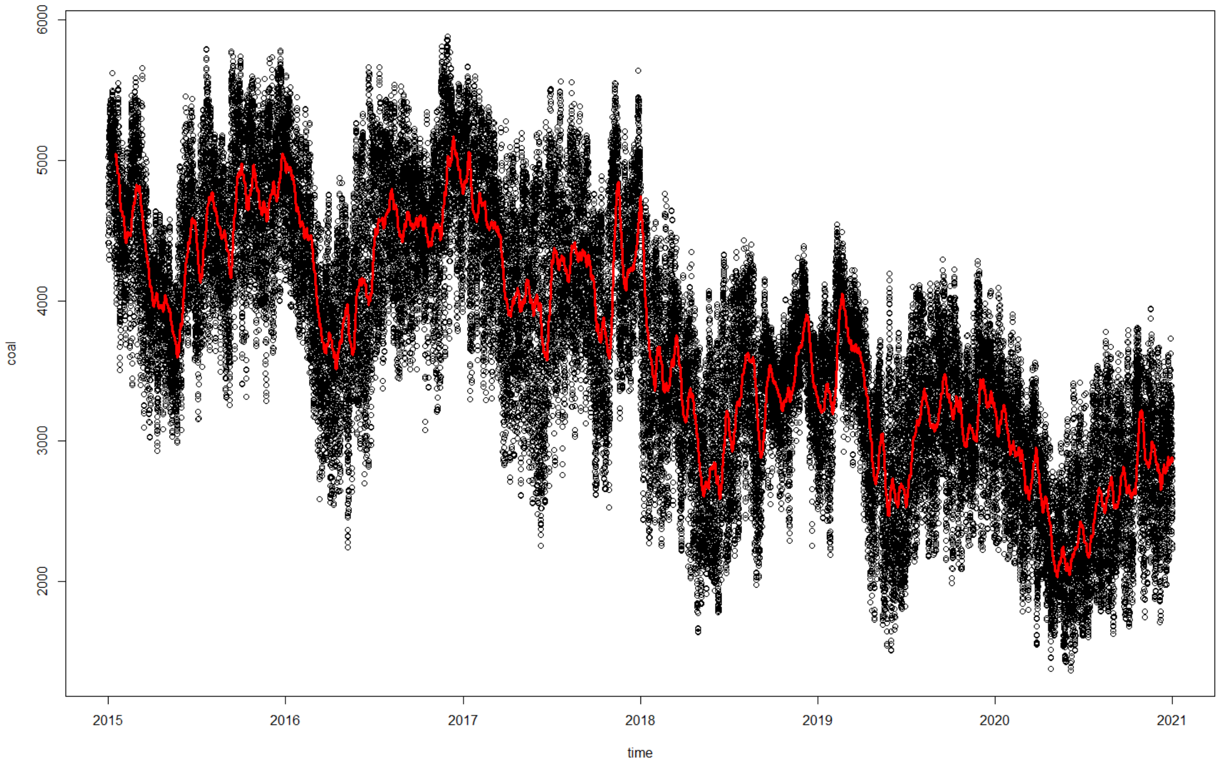

Figure 1: Electricity Produced from Coal and Two–Week Moving Average in Alberta, 2015-2020

Note: red line represents the two-week moving average of coal electricity

In 2018, two coal-powered units were retired and one coal unit shifted to a co-fired plant. In 2019 and 2020, there are one retired and one transited to co-fired plant for each year, corresponding to the decreasing trend of coal-fired electricity generation after 2018. However, there were no re-purposed or retired coal power plants prior to 2018, implying that the electricity production from 2015 to 2017 was relatively steady, which is also demonstrated in Figure 1.

Table 2: Phasing out Progress of the Coal-fired Electricity Plants in Alberta

		Capacity	Phasing out Progress
Keephills	Unit 1	403 MW	Converted to gas in December 2021
	Unit 2	403 MW	Converted to gas in July 2021
	Unit 3	463 MW	Converted to gas in December 2021
Battle River	Unit 3	149 MW	Retired in December 2019
	Unit 4	155 MW	Converted to co-firing, 50% coal and 50% natural gas in 2018
	Unit 5	385 MW	Start to shift to co-fired plant in April 2020
Genesee	Unit 1	400 MW	In the transition to gas power plant.
	Unit 2	400 MW	In the transition to gas power plant.
	Unit 3	466 MW	In the transition to gas power plant.
Sundance	Unit 1, unit 2	280 MW each	Retired in 2018
	Unit 3	380 MW	Retired in 2020
	Unit 4	433 MW	Retired in 2022
	Unit 6	422 MW	Converted to natural gas plant in 2021
H.R. Milner	Unit 1	150 MW	Converted to co-fired plant, 50% coal and 50% gas in December 2019
Sheerness	Unit 1	400 MW	Converted to gas-fired plant in March 2021
	Unit 2	400 MW	Converted to gas-fired plant in July 2021

Source: synthesized from Global Energy Monitor (2022)

As coal plants were retired or transitioned to burn natural gas, the amount of electricity produced by natural gas, particularly that produced by CCGT, increased. OCGT capacity also increased to the end of 2018, but then began to decline beginning in 2019. OCGT exhibited larger variations near the end of 2019. This phenomenon was accompanied by an increase in wind turbine construction starting from the end of 2019.

At the end of 2019, the construction of Whitla Wind 1 was completed, with a capacity of 353 MW. Castle Rock Ridge II and Riverview Wind Farm started operating in May 2020, with capacities of 29.4 MW and 105 MW, respectively. No other wind farms joined the generation mix during the period under investigation except, starting from 2015, the Bull Creek wind farm with a capacity of 29 MW.

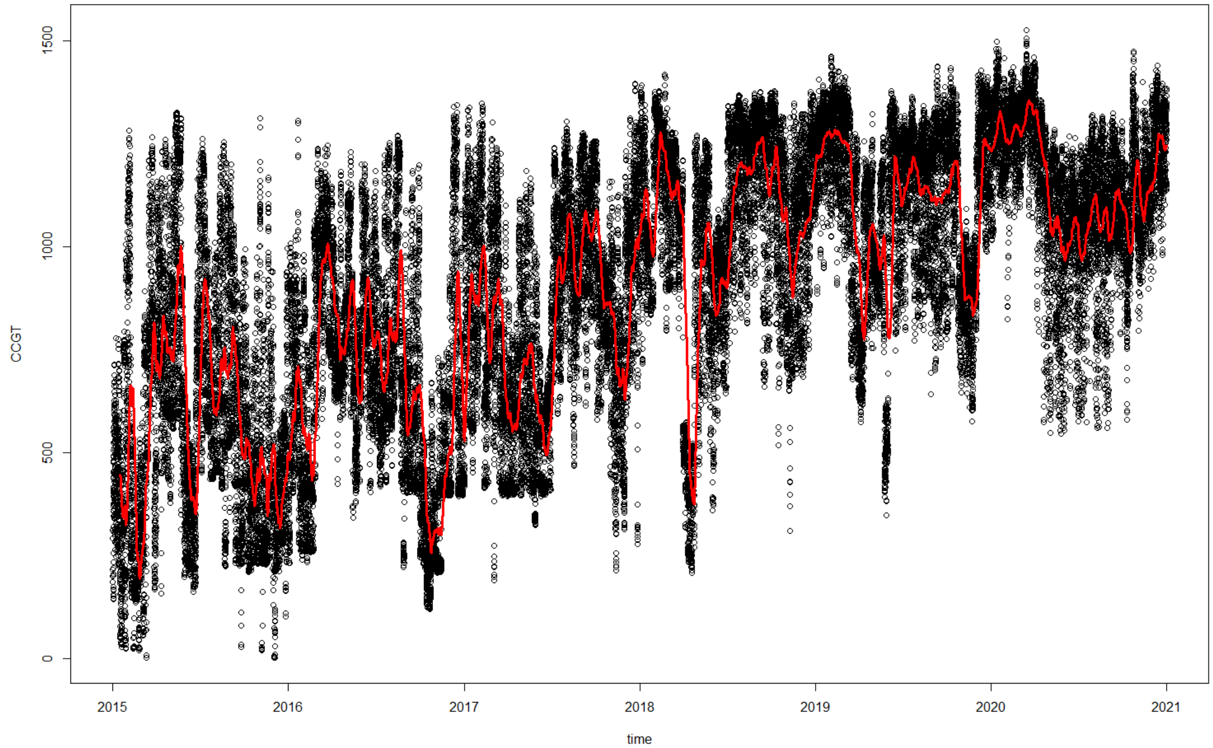

Figure 2: Electricity Produced from CCGT and Two–Week Moving Average in Alberta, 2015-2020

Note: red line represents the two-week moving average of CCGT

The participation of wind farms increases the volatility of the electricity system due to the intermittency nature of wind. Though AESO forecasts energy demand and wind speed, it is likely that the wind may abruptly cease, and the demand would not be met. Therefore, the grid requires greater investment in OCGT to meet fluctuations in demand, as OCGT assets can quickly ramp up and down.

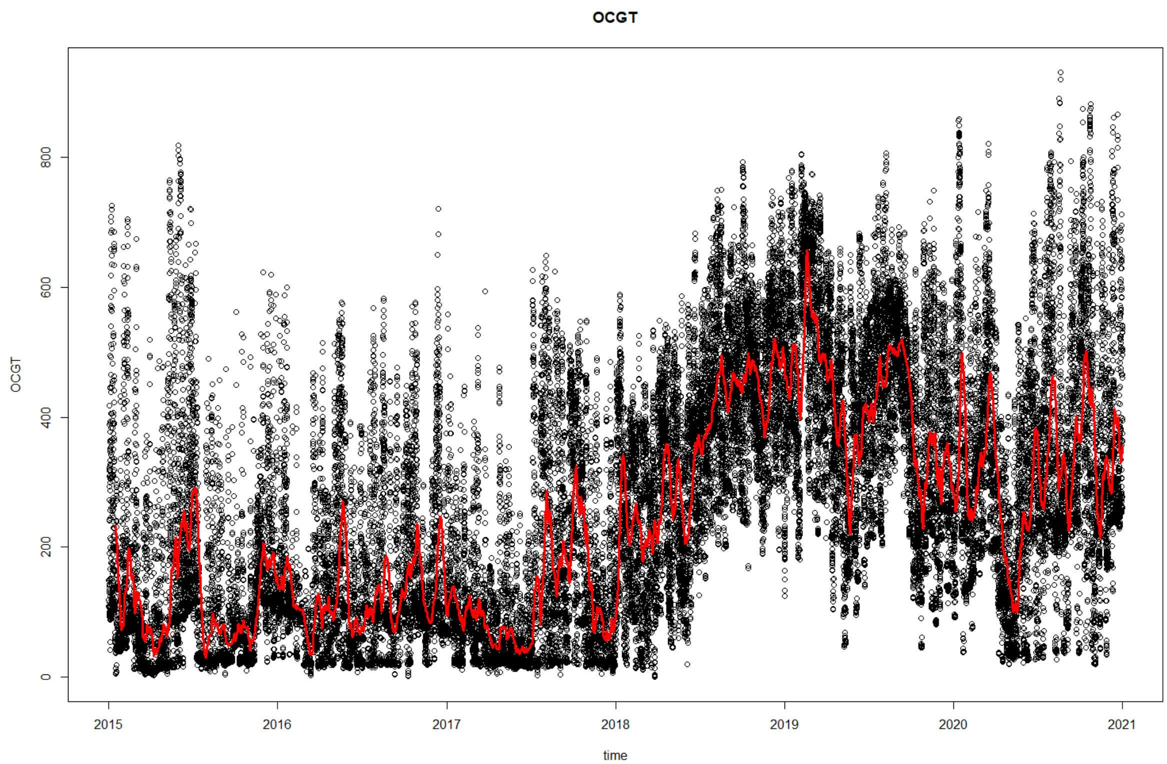

Figure 3: Electricity Produced from OCGT and Two–Week Moving Average in Alberta, 2015-2020

Note: red line represents the two-week moving average of OCGT

Despite the trend described above, the series we investigate shows a strong cyclical pattern. Figure 5 displays electricity generation from coal, CCGT and OCGT, as well as load, wind electricity production, and imports from BC from January 1 to January 15, 2018. Coal, CCGT and OCGT outputs as well as load all exhibit similar trends, decreasing after midnight and increasing in the morning. In contrast, wind energy produces more electricity at night and is more unpredictable.

It is important to note that imports of power from BC increased significantly between January 10 and January 12, 2018, when wind energy production fell sharply. This corresponds to the fact that, when there is excess electricity from wind, Alberta exports it to BC. When wind electricity suddenly drops, Alberta increases the import of electricity from BC. Since over 80% of electricity from BC was produced from hydropower, it can adjust electricity output rapidly and export electricity to Alberta.

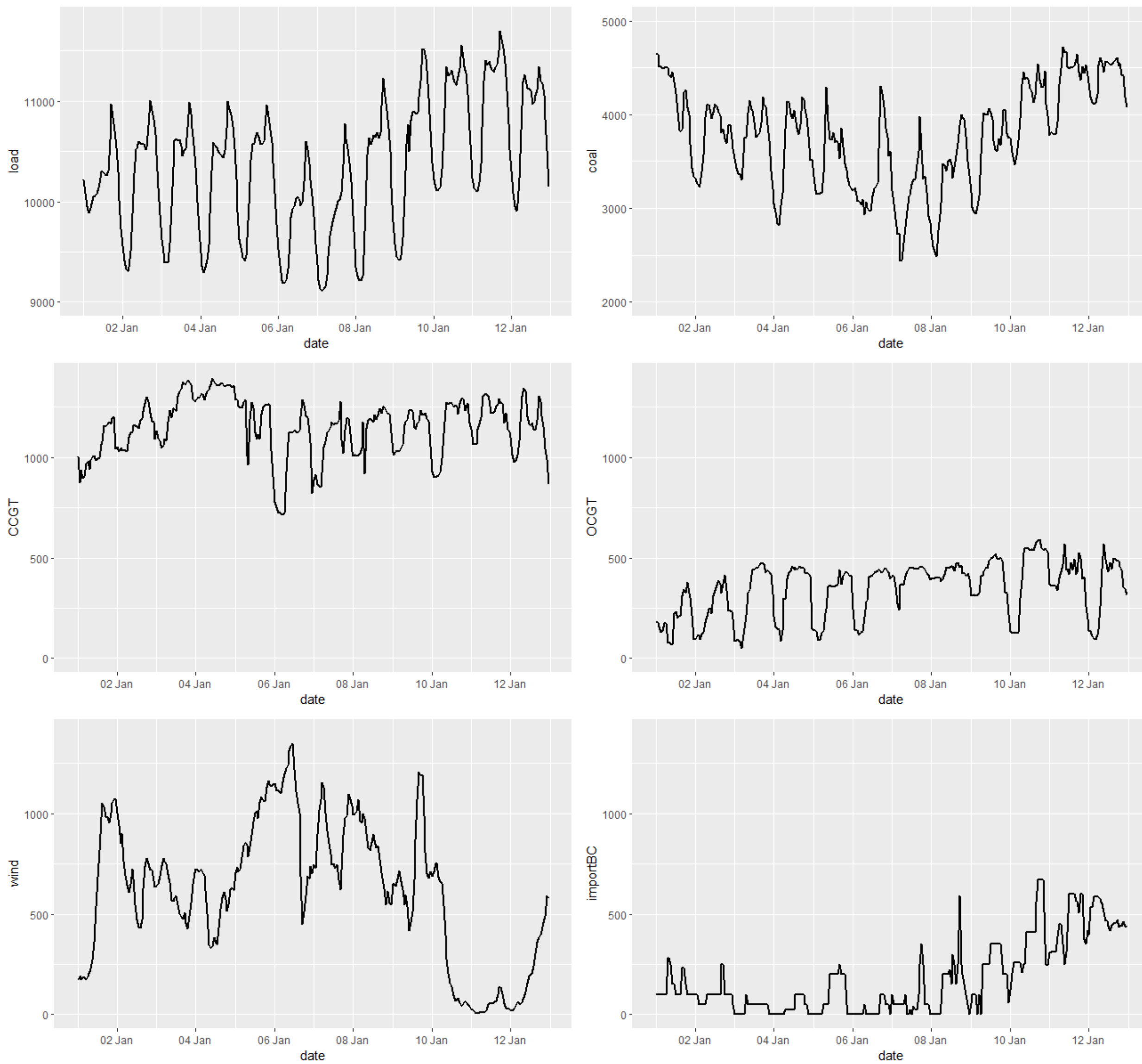

Figure 4: Load, Coal, CCGT, OCGT, Wind and Imports from BC, January 1, 2018 to January 15, 2018

4. EMPIRICAL METHOD

This section provides econometric models for coal, CCGT and OCGT respectively and discussed the offset effect of wind energy on coal and natural gas electricity. From the last section, we can see that electricity generated from coal, CCGT and OCGT show different trends. They also differ from one another in terms of how the wind electricity affects them: while open-cycle gas turbines can make up for the instantaneous reduction in wind generation, coal plants and combined-cycle gas turbines are unable to do so because it is too expensive to ramp up and down promptly. As a result, the effect of wind electricity on coal and combined-cycle gas is represented by a long-term trend, whereas electricity from open-cycle gas turbines is impacted by wind energy in the short run.

In addition, we highlighted the dynamic effect of wind. Cullen (2013) has shown that if the dynamic of wind was not considered, its impact would be overestimated. By using different models for coal, CCGT and OCGT, we showed that it is not necessarily the case: the static model tends to overestimate the impact of wind on coal-fired electricity but underestimates its effect on natural gas.

Coal Model

Our dynamic model for coal is as follows:

$$y_t = \beta_0 + \beta_1 MAwind_t + \beta_2 X_t + \beta_3 D + \beta_4 D \cdot t + \phi Z_t + \epsilon_t$$

y_t denotes the electricity production from coal; X_t are set of control variables. $MAwind_t$ denotes the Moving Average (MA) process of wind electricity generation. D is a dummy variable, where D=0 for the time before 2018 and D=1 after 2018. $D \cdot t$ is an interaction term of D and time trend t. Z_t are set of fixed effect variables.

As we have discussed in the last section, there were not any retired or transformed coal power plants before 2018. The downward shift of coal electricity in 2018 results from the retirement or transition of three coal plants. In 2019 and 2020, there were 2 coal plants either retired or transformed into natural gas-fired plants each year. Hence, we use a linear time trend to approximate this change. In addition, while we assume that wind electricity offsets coal-fired electricity, coal plants have been phasing out due to the climate policies of Alberta. Therefore, we use this time trend term also for filtering out this policy effect.

We also include hour-of-day, day-of-week, and month-fixed effect Z_t to control for the seasonal characteristics. Electricity produced by coal displays strong cyclical characteristics and seasonality. For electricity generated from coal, CCGT, OCGT and wind, as well as import from BC, we approximate the autocorrelation function (ACF) and partial correlation (PACF) of each series. We also detrend and take the first difference of the above series and approximate their autocorrelation function. Details are presented in the Appendix. For coal, the ACF function of its original series, and that of its detrended and first differenced series all exhibit 24-hour cycles. This effect does not extinct after 200 lags, meaning that current electricity production from coal is strongly correlated with its past values, especially every 24 hours. The PACF of coal reveals that coal electricity might be an autoregressive (AR) process whose order number might be unbelievably large, even approaching infinity. The ACF and PACF for CCGT, OCGT, load and import from BC show a similar pattern as coal. Given that generators submit their supply bid 7 to 1 day ahead and that AESO provides the prediction of electricity demand as precise as possible, it is very likely that the load at time t might be close to that at time t–24, t–48, t–72, …, t–168 (a week), which is also demonstrated by the ACF and PACF. Therefore, we included hour and day-of-week fixed effects. To control for the monthly variation of coal electricity generation, we also considered month-fixed effects. However, wind electricity exhibits different characteristics. Although it also shows 24-hour cycles, the PACF function indicates that wind is more likely an AR process with order 3.

Our control variables include import from BC and load. Coal serves as an important baseload but it cannot meet the peak load, so Alberta imports electricity from BC during peak hours. When Alberta produces excessive electricity, BC imports electricity from Alberta. As a result, import and electricity produced from coal are likely to be substitutes and we expect their relationship to be negative. Since AESO is responsible for making predictions on future demand, we assume that their predictions are accurate and that their prediction takes into account the load in previous hours. When generators make their supply offers, load, or the predicted load, is an important consideration. Instead of using the original load series, we separate load into volatile load and relatively stable load and used stable load in our regression. Volatile load represents the part of the load that fluctuates significantly; stable load means the opposite. Coal plants typically cannot change the output dramatically since it is exceedingly expensive for them to increase or decrease their electricity production in a short time. As a result, the purpose of coal is to meet the "essential demand", which is the stable part of the load, rather than the volatile part of the load. If we fail to consider this, although the sign of load coefficient is expected to be positive, the extremely high or low volatile load might offset the positive effect of stable load, leading to a negative estimate.

We use two methods to approximate the relatively stable part of the load. First, we subtract the OCGT and CCGT production from the total load. OCGT supplies peak load. CCGT supplies baseload most of the time, but it can also ramp up very quickly to meet the peak demand. The electricity generated from solar, biomass and hydropower take a relatively small share of the total load, so we do not consider them. Stable load approximated by this approach is denoted as "RevisedLoad". Second, we estimate stable load using the fitted value of the following regression:

$$load_t = \beta_0 + \beta_1 hour + \beta_2 day + \beta_3 month + \epsilon_t$$

Hour, day and month denote the time fixed effect, or dummies for the hour of day, day of a week and month of a year. The changes in load that can be explained by time of a day, day of a week, or month of a year represents stable load, which denotes the natural variation of load with time. And they are represented by the fitted value of this model. Correspondingly, the residual of this model represents volatile load, which we will use later for the OCGT model. By regressing load on hour, day and month and taking its fitted value, we can get the load that naturally varies with hour, day and month and ruling out the extreme cases caused by wind and other unexpected events. The stable load generated from this approach is denoted as "StableLoad".

We take the moving average (MA) process of wind, stable load and import from BC. Through stepwise regression, we find out that their effect on coal electricity production does not diminish with time. As it is indicated from the ACF and PACF in the Appendix, the extent to which importBC and load are affected by their past lags does not decay over time. We have also approximated ACF and PACF for RevisedLoad and StableLoad, which are presented in the Appendix. They also display characteristics of AR (∞). Therefore, not only they are AR (∞), but their effect on coal electricity also likely does not decay over time. Since AR process and MA process are revertible, we can approximate the AR (∞) process by an MA process with a small order number to avoid using unwieldy large lag numbers. Although wind itself is likely an AR (3) process, its effect on coal is a rather long-term one, so we also take its MA process. In addition, the MA process can also act as a smoother to filter out the short-term variation so that we can focus on the trend.

For comparison, we also estimated the static model

$$y = \beta_0 + \beta_1 wind_t + \beta_2 load + \beta_3 importBC + \epsilon_t$$

For this static model, we use the original series of wind, load and import from BC and do not employ their MA process. The 2018 dummy D and its interact term with time t are not included as well.

CCGT Model

Our model for CCGT follows the same intuition as the coal model:

$$y_t = \beta_0 + \beta_1 MAwind_t + \beta_2 X_t + \beta_3 t + \phi Z_t + \epsilon_t$$

y_t represents electricity generated from CCGT; $wind_t$ denotes the electricity produced from wind; X_t represents control variable MA of load. We still employ the MA process of wind and load, because through stepwise regression, we find that wind and load still affect the response variable through MA process. t is a linear time trend. As we can see in the last section, the electricity produced by CCGT steadily increases throughout the period we study. Z_t denotes hour, day-of-week and month fixed effects. Here we use load itself, not volatile load nor stable load because CCGT can satisfy both. Similarly, we estimated a static model

$$y_t = \beta_0 + \beta_1 wind_t + \beta_2 load_t + \epsilon_t$$

where the time trend and time fixed effect are not included, and we use the original series of wind and load.

OCGT Model

Our model for OCGT is slightly different from that for coal and CCGT:

$$y_t = \beta_0 + \beta_1 wind_t + \beta_2 wind_{t-1} + \beta_4 X_t + \beta_5 D + \beta_6 D \cdot t + \beta_7 D \cdot t^2 + \beta_8 t^3 + \phi Z_t + \epsilon_t$$

y_t denotes electricity generated from OCGT. $wind_t, wind_{t-1}$ denotes wind electricity generated from time t, t-1 respectively. X_t represents control variable MA of load or MA of volatile load. We also take into account the volatile load since OCGT is more frequently employed to meet the peak demand. The volatile load is approximated by the residual of regression $load_t = \beta_0 + \beta_1 hour + \beta_1 week + \beta_2 month + \epsilon_t$. We also consider a dummy D that represents the year after 2018, as well as an interaction term between time t, squared t and cubic t. Z_t are set of time fixed effects, including hour, day of a week and month fixed effects.

Instead of taking the MA process of wind, we use contemporaneous wind electricity and its first lag. Since OCGT can ramp up and down quickly, it can react to changes in the wind and serve as a backup generator for wind energy. Therefore, it is not necessary to make a precise forecast of wind power generation many hours in advance. Wind has a short-term impact on OCGT rather than a long-term one. A 2018 dummy and its interact terms with a linear time trend, a quadratic time trend and a cubic time trend are included in the OCGT model, because, from Figure 4, we can see that the electricity produced by OCGT experienced an increase, followed by a decrease and then again an increase.

Our static model for OCGT is

$$y_t = \beta_0 + \beta_1 wind_t + \beta X_t + \epsilon_t$$

Where X_t represents original load series and $wind_t$ also represents the original wind series. We do not consider the time fixed effect and time trend.

5. EMPIRICAL RESULTS

Table 3 presents the estimation results for the coal equation. The first column displays the estimation result for the static model. The second to fifth column shows the estimation results of the dynamic models. For the second and third columns, we regress the original coal electricity series on StableLoad and RevisedLoad respectively. For the fourth and fifth columns, we first detrend coal with respect to the 2018 dummy D and its interact term with linear time trend (D × t), then regress detrended coal electricity on the MA process of wind, import from BC and StableLoad/ RevisedLoad.

Following the same methodology, Table 4 presents the estimation results of the static model, dynamic model with CCGT original series and with detrended CCGT. Table 5 displays the

OCGT offset by wind, where the first column still shows the estimation of the static model, the second and third column displays the estimation using the original OCGT series as dependent variable, and the fourth and fifth column presents the results of using detrended OCGT. We detrend OCGT with respect to a 2018 dummy, and its interact terms with a linear time trend, a quadratic time trend and a cubic time trend respectively, because, from Figure 3, we can see that the electricity produced by OCGT experienced an increase, followed by a decrease and then again an increase. While we use the original load series for the model for the second and fourth models, we consider the volatile load for the third and fifth models.

The detrended coal, CCGT and OCGT series are presented in Figure 5, Figure 6 and Figure 7 respectively, from where we can see that the mean of detrended coal, CCGT and OCGT are relatively constant.

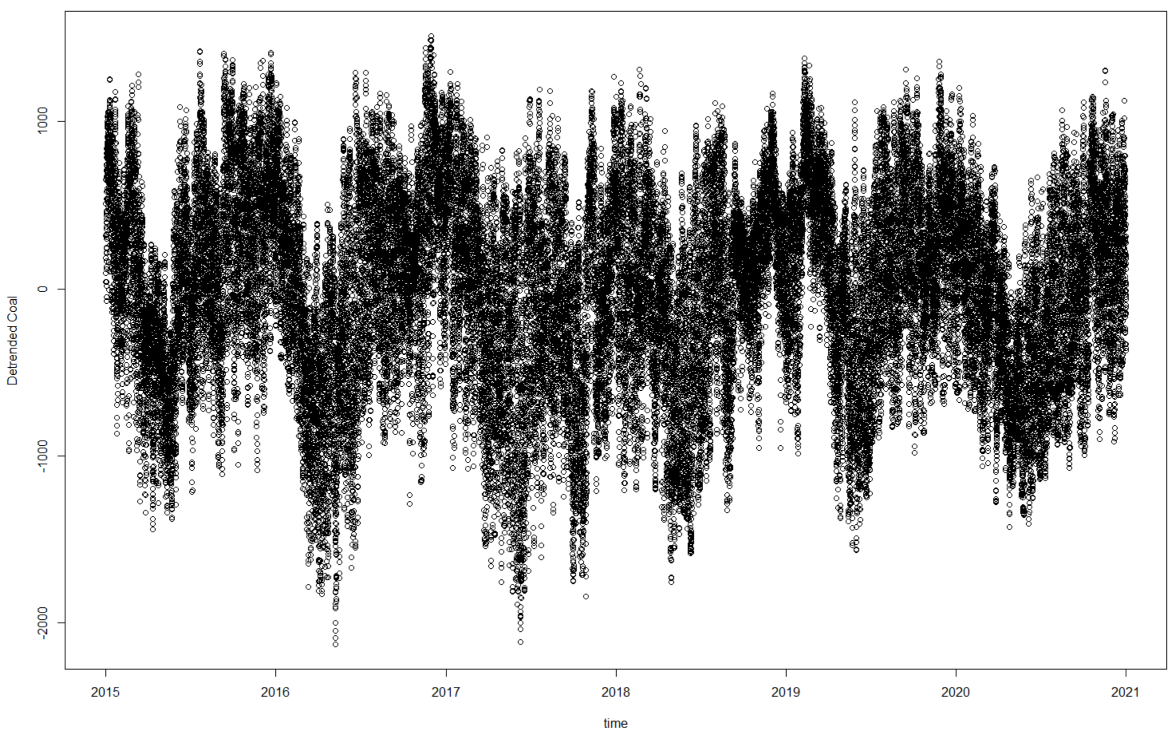

Figure 5: Detrended Coal, 2015-2020

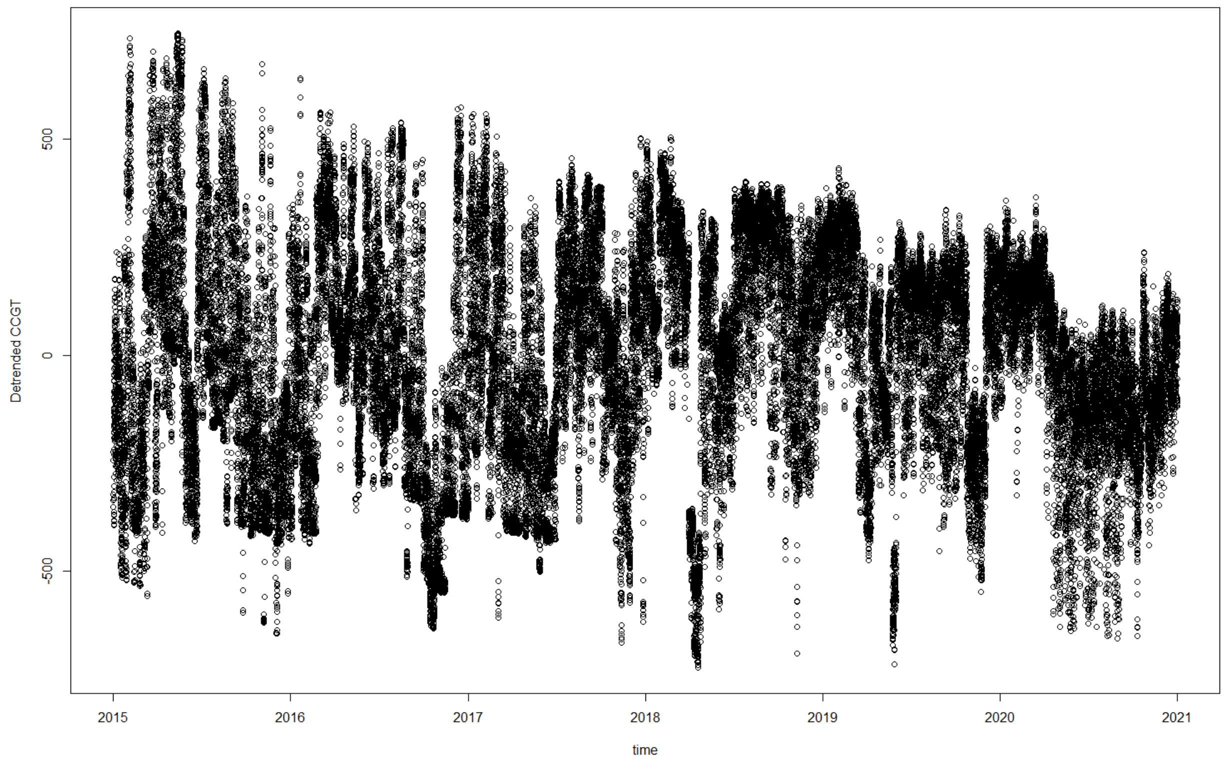

Figure 6: Detrended CCGT, 2015-2020

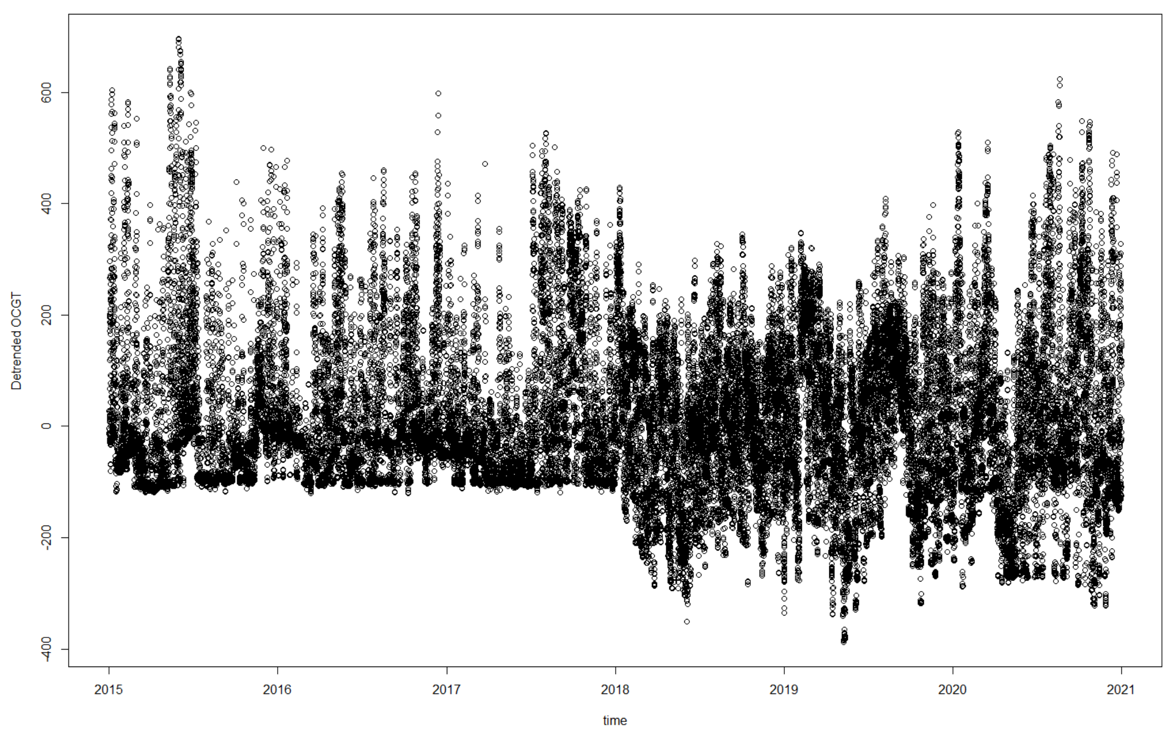

Figure 7: Detrended OCGT, 2015-2020

Table 3: Coal Generation Offset: Static and Dynamic

		Coal		Detrended Coal	
	Static	StableLoad	RevisedLoad	StableLoad	RevisedLoad
wind[a]	-0.977***	-0.718***	-0.788***	-0.686***	-0.690***
	(0.008)	(0.004)	(0.003)	(0.004)	(0.004)
load[b]	-0.287***	0.668***	0.654***	0.661***	0.433***
	(0.007)	(0.062)	(0.003)	(0.063)	(0.003)
importBC[c]	-1.723***	-0.670***	-0.980***	-0.531***	-0.590***
	(0.016)	(0.009)	(0.007)	(0.008)	(0.007)
D		-90.718***	-479.127***		
		(11.802)	(9.203)		
D × t		-0.028***	-0.013***		
		(0.0003)	(0.0002)		
Constant	7,395.129***	-1,734.088***	-889.053***	-6,014.365***	-3,282.198***
	(71.551)	(611.327)	(30.554)	(622.609)	(31.999)

Note: *p<0.1; **p<0.05; ***p<0.01
[a, b, c] in the static model we use the original series of wind, load (not "StableLoad" nor "RevisedLoad") and importBC; in the dynamic model, we use the MA process of wind, StableLoad/ RevisedLoad and importBC.

Table 4: CCGT Generation Offset: Static and Dynamic

	CCGT		Detrended CCGT
	Static	Dynamic	Dynamic
Wind[d]	-0.014***	-0.116***	-0.124***
	(0.003)	(0.002)	(0.002)
Load[e]	0.361***	0.148***	0.132***
	(0.003)	(0.002)	(0.002)
T		0.013***	
		(0.0001)	
Constant	-2,654.251***	-842.454***	-1,242.559***
	(27.775)	(24.107)	(21.968)

Note: *p<0.1; **p<0.05; ***p<0.01
[d, e]: in dynamic models, we use the MA process of wind and load. In the static model, we use their original series

Table 5: OCGT Generation Offset: Static and Dynamic

	OCGT			Detrended OCGT	
	Static	Load	Volatile load	Load	Volatile load
Wind[f]	-0.069***	-0.039***	-0.039***	-0.035***	-0.035***
	(0.002)	(0.006)	(0.006)	(0.006)	(0.006)
Wind lag 1		-0.068***	-0.067***	-0.070***	-0.068***
		(0.006)	(0.006)	(0.006)	(0.006)
Load[g]	0.204***	0.059***	0.109***	0.040***	0.079***
	(0.002)	(0.001)	(0.002)	(0.001)	(0.002)
D		-8,710.667***	-8,468.219***		
		(123.243)	(123.208)		
D × t		0.680***	0.660***		
		(0.010)	(0.010)		
D × t^2		-0.00002***	-0.00002***		
		(0.00000)	(0.00000)		
D × t^3		0.000*** [h]	0.000*** [h]		
		(0.000)	(0.000)		
Constant	-1,747.115***	-418.336***	144.881***	-363.117***	16.073***
	(16.179)	(14.426)	(3.282)	(12.415)	(3.277)

Note: *p<0.1; **p<0.05; ***p<0.01

[f, g] in both static and dynamic models, we use the original series of wind, but in the dynamic model, we include the first lag of wind, while in the static model we do not use any lagged terms. We employ the MA process of load/volatile load in the dynamic model whereas using the original load series in the static model.

[h] estimates for the cubic term are very small. This is because we have over 50,000 observations. time variable (response) is very large, so the coefficients should be close to 0 but not equal to 0.

When we do not account for the dynamic of the electricity system, the offset effect of wind to coal and OCGT tends to be overestimated, and that to CCGT is underestimated. But the aggregate impact of wind electricity on natural gas electricity is underestimated. Each MW of wind electricity helps reduce coal electricity production by 0.977 in the static case and approximately 0.7 in the dynamic case. Each MW of wind electricity reduces gas electricity production by 0.158 in the dynamic case. Although climate policies aim at reducing coal electricity production and increasing wind turbines, after taking into account the policy factor using an interact term of 2018 dummy and linear time trend, we can see that wind still has a larger effect on coal than natural gas. This result differs from Cullen (2013), who found out that wind has larger offset effects on natural gas.

Ramping

Despite estimating the substitution effect, we are also concerned about how the ramping up and down of wind would impact the change in coal and gas generation. While continuing to employ the models for coal, CCGT, and OCGT power from Section 4, we have replaced the original series of the variables with their change from t-1 to t. Details are as follows:

$$\Delta coal_t = \beta + \Delta \boldsymbol{Wind}\ \boldsymbol{\alpha} + \Delta \boldsymbol{importBC}\ \boldsymbol{\gamma} + \Delta \boldsymbol{StableLoad}\ \boldsymbol{\omega} + \epsilon_t$$

$$\Delta CCGT_t = \beta + \Delta \boldsymbol{wind}\ \boldsymbol{\alpha} + \Delta \boldsymbol{load}\ \boldsymbol{\omega} + \epsilon_t$$

$$\Delta OCGT_t = \beta + \Delta \boldsymbol{wind}\ \boldsymbol{\alpha} + \Delta \boldsymbol{X}\ \boldsymbol{\omega} + \epsilon_t$$

The description of the variables in the above regression model is provided in Table 6.

In the coal ramping model, we included the stable load variable approximated by two different approaches: "RevisedLoad" and "StableLoad". We also considered load and volatile load in the OCGT model for comparison, so $\Delta \boldsymbol{X}$ represents either of them.

We do not apply the MA process in this section, because we aim at exploring the contemporaneous and very short-term impact of wind variation. Since coal and CCGT cannot increase output as quickly as OCGT does, we include the first two lags of the independent variables for the coal ramping model and CCGT ramping model, while only allowing for one lag for OCGT ramping model.

Table 6: Estimation Variables for Ramping models

Variable	Description
$\Delta coal_t$	$coal_t - coal_{t-1}$
$\Delta CCGT_t$	$CCGT_t - CCGT_{t-1}$
$\Delta OCGT_t$	$OCGT_t - OCGT_{T-1}$
Δ***Wind***	$\Delta wind_t: wind_t - wind_{t-1}$ $\Delta wind_{t-1}: wind_{t-1} - wind_{t-2}$ $(\Delta wind_{t-2}: wind_{t-2} - wind_{t-3})$
Δ***load***	$\Delta load_t: load_t - load_{t-1}$ $\Delta load_{t-1}: load_{t-1} - load_{t-2}$ $\Delta load_{t-2}: load_{t-2} - load_{t-3}$
Δ***Stable load*** [a]	$\Delta stableload_t: stableload_t - stableload_{t-1}$ [a] $\Delta stableload_{t-1}: stableload_{t-1} - stableload_{t-2}$ [a] $\Delta stableload_{t-2}: stableload_{t-2} - stableload_{t-3}$ [a]
Δ***ImportBC***	$\Delta imprtBC_t: importBC_t - importBC_{t-1}$ $\Delta importBC_{t-1}: importBC_{t-1} - importBC_{t-2}$ $\Delta importBC_{t-2}: importBC_{t-2} - importBC_{t-3}$
Δ***X:*** load or volatile load. Here we only present volatile load	$\Delta voaltile\ load_t: volatile\ load_t - volatile\ load_{t-1}$ $\Delta volatile\ load_{t-1}: volatile\ load_{t-1} - volatile\ load_{t-2}$ $\Delta volatile\ load_{t-2}: volatile\ load_{t-2} - volatile\ load_{t-3}$

[a]: variables Δ**Stable load**, $stableload_t$, $stableload_{t-1}$, …, $stableload_{t-3}$ represents the stable load variables that are generated from two methods: RevisedLoad and StableLoad.

The empirical results presented in Table 7 reveal that the change in wind energy has negative effects on the change in fossil fuel electricity, particularly coal-fired power. The negative coefficients imply that when wind ramps down, coal power plants would have to ramp up contemporaneously to compensate for the loss in power supply. They also indicate a negative marginal effect of wind relative to fossil fuel, meaning that wind has a larger marginal effect on coal power plants than on natural gas power plants. The penetration of wind energy replaces the electricity output from fossil fuel generators, therefore helping reduce GHG emissions. At the same time, however, the intermittent nature of wind requires fossil fuel generators to ramp up and down more rapidly, which might induce more GHG emissions.

Table 7: Impact of the Intermittent Nature of Wind

	CoalRamp		CCGTRamp	OCGTRamp	
	StableLoad	RevisedLoad		Load	Volatile Load
windRamp	-0.598^{***}	-0.747^{***}	-0.137^{***}	-0.045^{***}	-0.047^{***}
	(0.007)	(0.005)	(0.003)	(0.002)	(0.003)
Windramp_{t-1}	-0.225^{***}	-0.233^{***}	0.018^{***}	-0.016^{***}	-0.025^{***}
	(0.008)	(0.005)	(0.003)	(0.002)	(0.003)
Windramp_{t-2}	0.050^{***}	0.075^{***}	0.005		
	(0.007)	(0.005)	(0.003)		
Load Change	0.425^{***}	0.719^{***}	0.141^{***}	0.072^{***}	0.037^{***}
	(0.006)	(0.003)	(0.002)	(0.001)	(0.002)
Load Change_{t-1}	0.072^{***}	0.085^{***}	0.021^{***}	0.032^{***}	0.034^{***}
	(0.008)	(0.004)	(0.003)	(0.001)	(0.002)
Load Change_{t-2}	0.022^{***}	-0.025^{***}	-0.0002		
	(0.005)	(0.003)	(0.002)		
Import Change	-0.575^{***}	-0.767^{***}			
	(0.007)	(0.005)			
$\text{Import Change}_{t-1}$	-0.105^{***}	-0.149^{***}			
	(0.007)	(0.005)			
$\text{Import Change}_{t-2}$	-0.030^{***}	-0.020^{***}			
	(0.007)	(0.005)			
Constant	-0.043	-0.033	0.017	0.004	0.005
	(0.460)	(0.314)	(0.204)	(0.169)	(0.184)

Note: $^{*}p<0.1$; $^{**}p<0.05$; $^{***}p<0.01$

6. CONCLUSIONS AND DISCUSSION

Focusing on the Alberta electricity market, this essay investigates the substitution effect of electricity produced by wind on fossil fuel-powered electricity. As Canada proceeds to "Net-zero", coal power plants are being phased out and transited to natural gas power plants, followed by a decreasing trend in coal-powered electricity and an increase in natural-gas-powered electricity. Despite this policy influence, we explored the impact of wind energy and emphasized its dynamic effect.

Our study showed that natural gas is leading the province in electricity generation. Due to the coal plants phasing out plan, most of the coal-fired electricity generation facilities transformed into natural gas power plants. Other than this, the wind has played an important role. When considering the dynamics, the estimated offset effect is not as significant as the static model, wind energy helps crowd out the coal electricity production. In terms of natural gas-powered electricity, the static model tends to underestimate the effect of wind, but wind electricity still offsets part of the natural gas electricity production, though not as significant as coal. In this sense, wind energy contributes to the gradual phasing out of coal-fired electricity and could help Alberta achieve its goal of reducing emissions. However, when we account for the instability of wind, we find that the unpredictable variation of wind imposes significant uncertainty on the power system, causing fossil fuel generators, especially coal plants, to ramp up and down more than their design specification. This raises concerns because, at lower operating efficiencies, fossil-fuel plants have higher CO_2 emissions per MWh, while frequent ramping will increase the wear and tear of machinery.

Though we studied the operation of the electricity system and estimated econometric models for different generating technologies, this research can still be improved in the following ways: first of all, our study uses reduced form models rather than structural form. The operation of the Alberta grid is based on the forecast of market demand, meaning that when generators are making the supply bids, the forecast of market condition is likely an important consideration. Load, pool price, weather conditions and electricity generated from other facilities might also be the factors impacting fossil fuel generation. More specifically, the generation from natural gas might also affect the electricity from coal plants. Taking this into consideration, simultaneous equation model (SEM) can be an alternative to modelling. Second, while we studied the substitution effect of wind using data from 2015 to 2020, there was a significant drop in coal plants in 2021. From

2020 to 2022, a large scale of solar panels has been installed. If more updated data are available, this decrease in coal and increase in solar can also be considered, and the results should be intriguing.

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APPENDIX

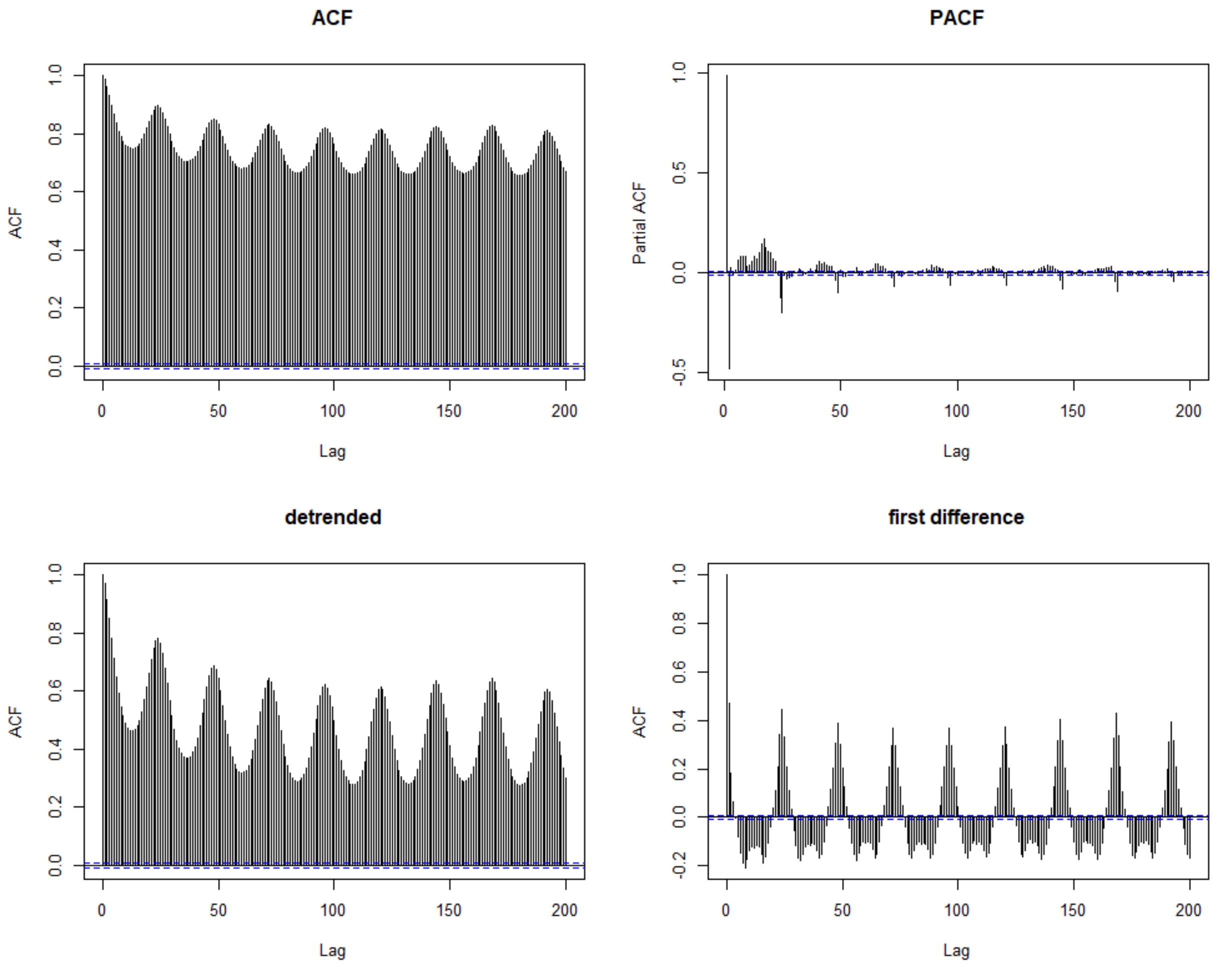

Figure 3: ACF and PACF of Coal, ACF of Detrended Coal and First Differenced Coal

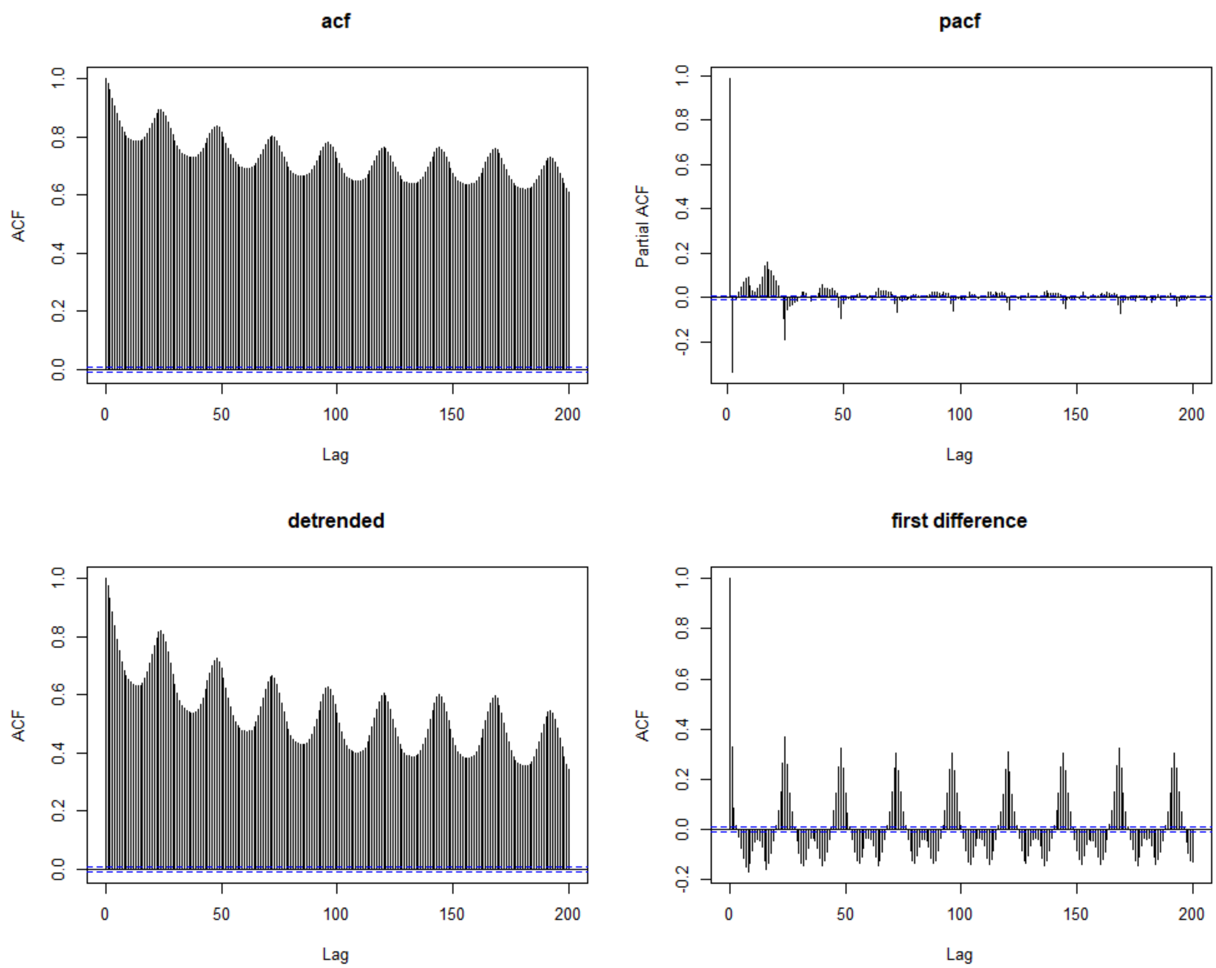

Figure 4: ACF and PACF of CCGT, ACF of Detrended Coal and First Differenced CCGT

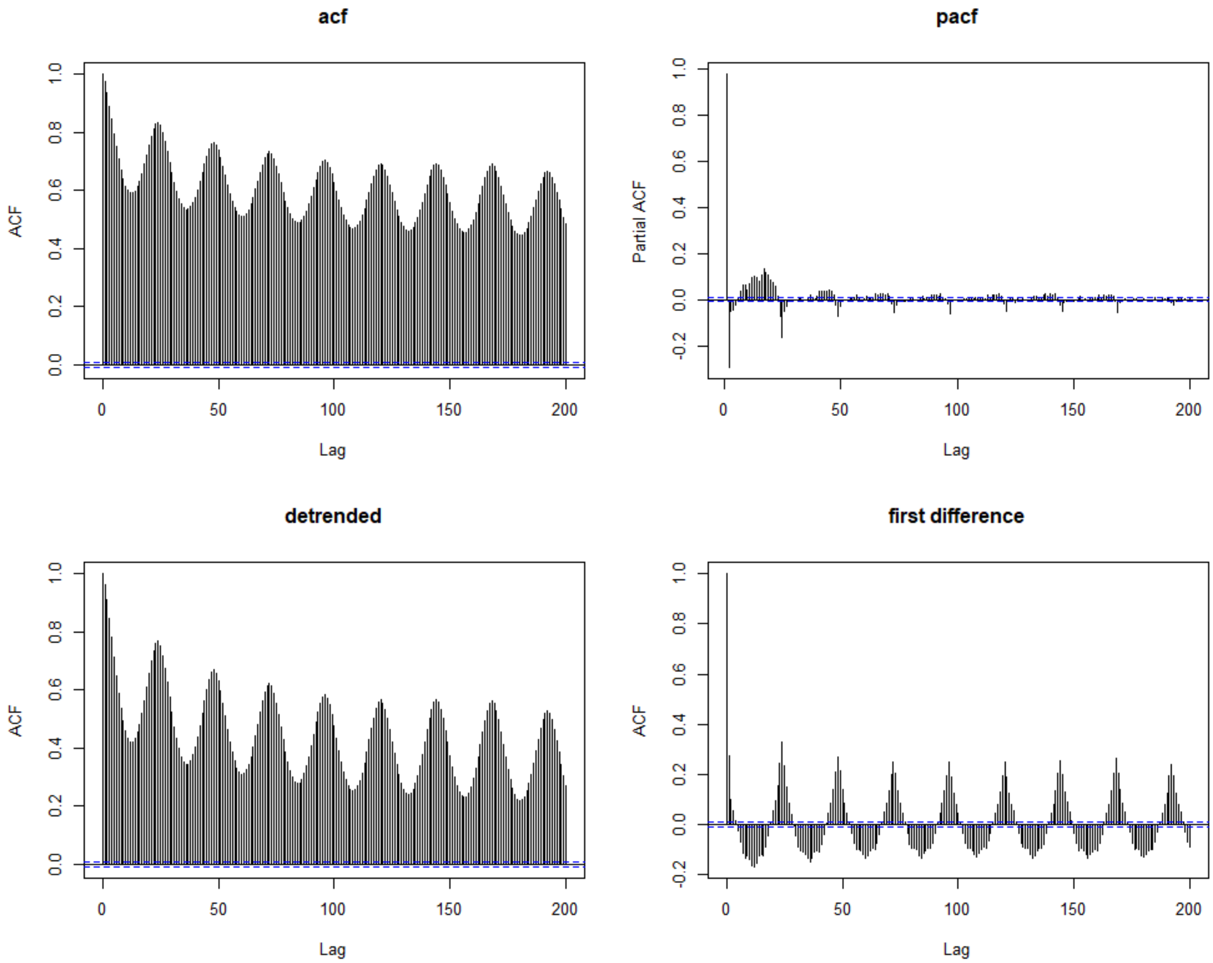

Figure 5: ACF and PACF of OCGT, ACF of Detrended Coal and First Differenced OCGT

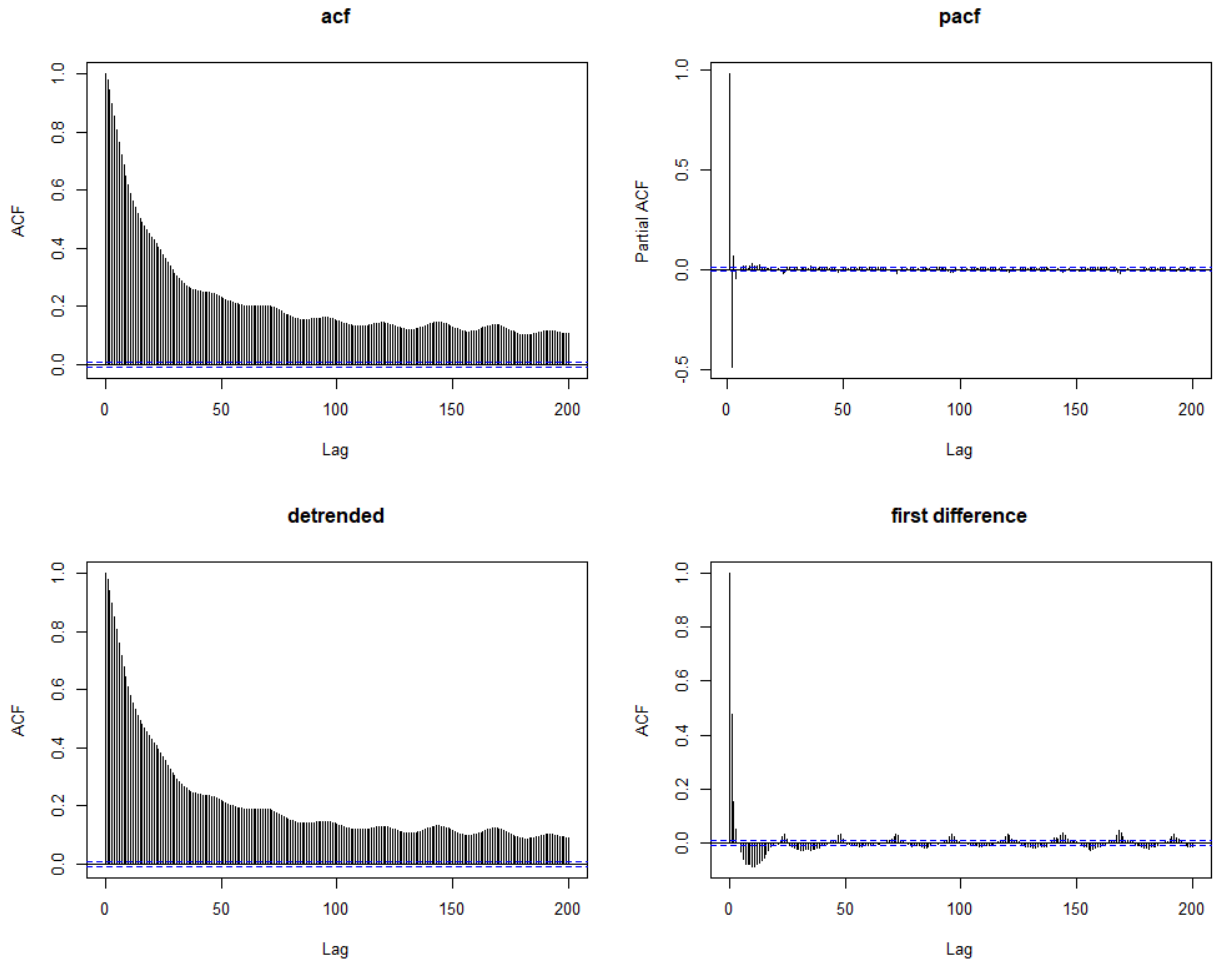

Figure 6: ACF and PACF of Wind, ACF of Detrended Coal and First Differenced Wind

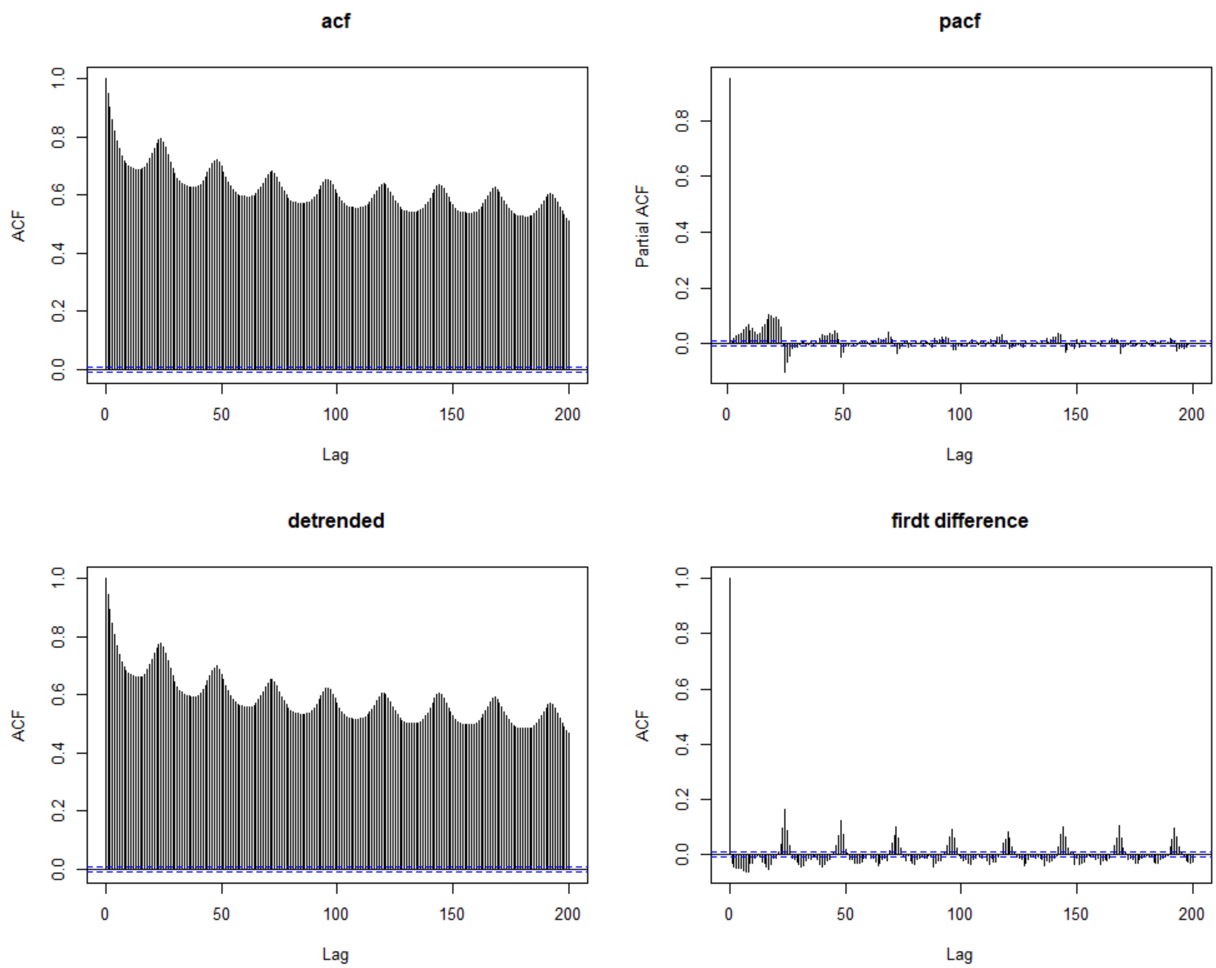

Figure 7: ACF and PACF of ImportBC, ACF of Detrended Coal and First Differenced ImportBC

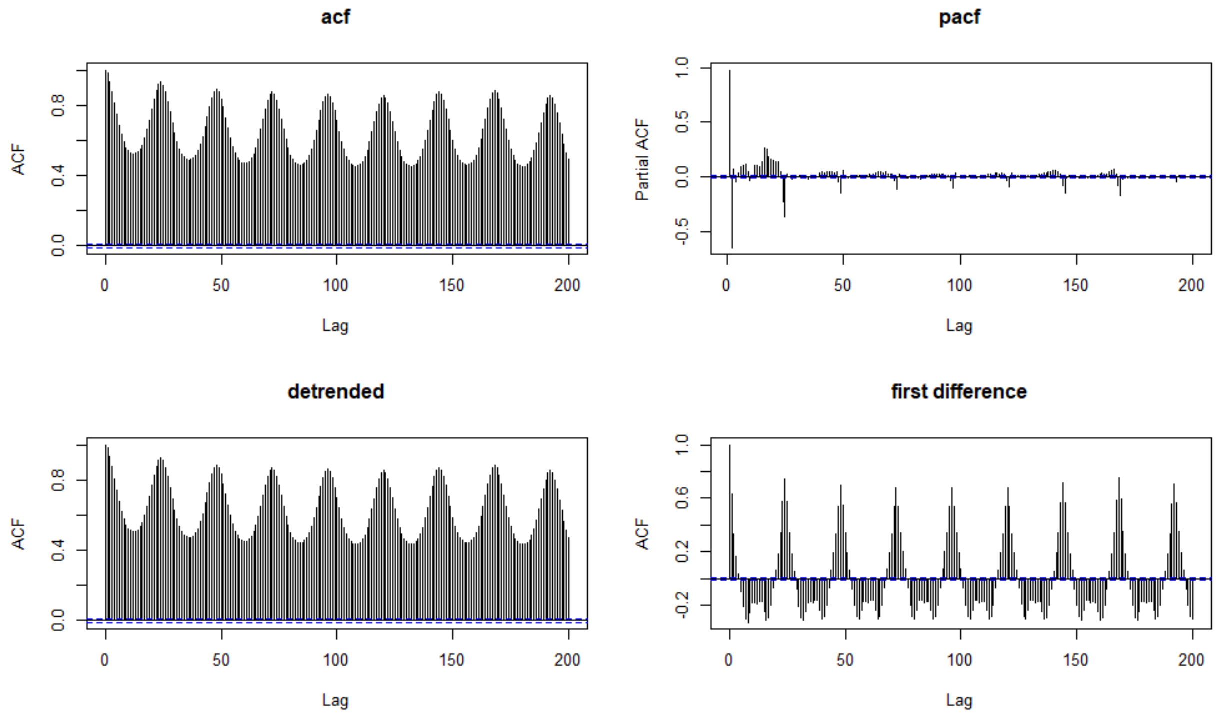

Figure 8: ACF and PACF of RevisedLoad, ACF of Detrended Coal and First Differenced RevisedLoad

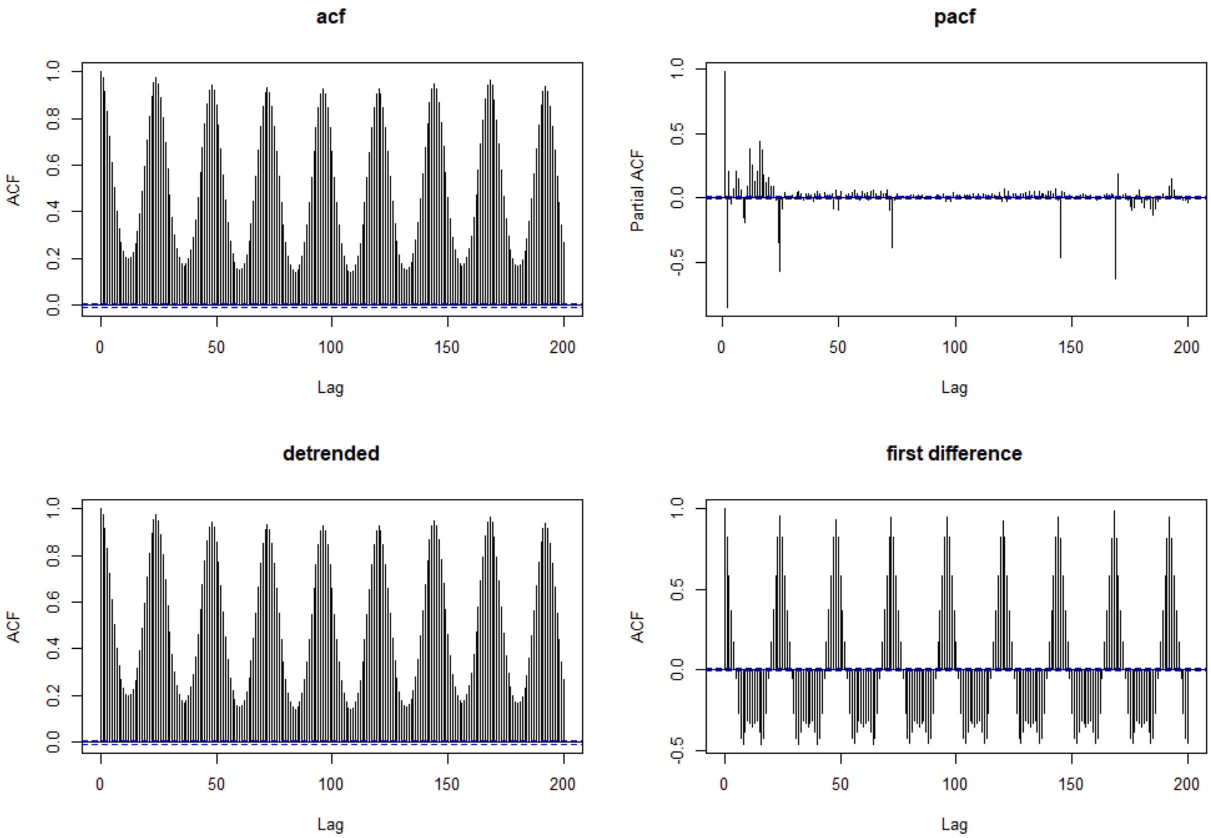

Figure 9: ACF and PACF of StableLoad, ACF of Detrended Coal and First Differenced StableLoad