Hourly Electricity Projections from *Canada's Energy Future 2019*

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Abstract

This paper will analyze the electricity results from the Canada Energy Regulator's latest outlook, *Canada's Energy Future 2019* (EF 19) from an hourly perspective. Differences in hourly load, resource availability, and trade highlight substantial variation in electricity trends when temporal granularity is increased. The level of this variation suggests hour-to-hour changes are important to analyze, and should not be taken for granted when developing future projections. The hourly analysis suggests Canada's energy system appears to have enough flexibility to integrate the levels of variable renewable energy projected in the EF 19 Reference Case. However, in scenarios with greater renewable penetration this may not be the case, and the hourly results could highlight important insights. These results can be considered a test case or 'beta' for hourly electricity analysis in the context of the Energy Futures series. Comments to the authors or energyfutures@cer-rec.gc.ca on the results and/or usefulness of the information would be appreciated.

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Views expressed in this paper are of the authors and do not reflect those of the Canada Energy Regulator or the Government of Canada.

1. Introduction

This paper will analyze the electricity results from the Canada Energy Regulator's (CER)[1] latest outlook, *Canada's Energy Future 2019* (EF 19) from an hourly perspective. Historically, the Energy Futures electricity projections were at an annual resolution, with annual projected values modelled for each forecast year for a given region and fuel type. Given the increased penetration of variable renewable electricity generation, models with greater temporal and spatial resolution can improve modeling of the electricity sector. This is in contrast to models with low temporal and spatial resolution, which are not able to fully incorporate the dynamics of electricity systems under high amounts of variable renewable power. This issue has been discussed in detail within the energy economics literature[2], where the tradeoffs between increased spatial/temporal resolution and modelling accuracy are quantified. This literature will be reviewed in detail in later sections of the paper.

EF 19 was the first report in the Energy Futures series to include modelling of Canada's electricity sector at higher spatial and temporal resolutions. Specifically, electricity generation and transmission was modelled at hourly intervals and utilized site specific renewable generation data to compliment the annual projections. The results of this hourly modelling will be the main focus of the paper, highlighting the impact of renewables and the role of electricity trade (both interprovincial and international).The structure of the remainder of the paper is as follows: an overview of key electricity results from EF 19 (Section 2), literature review (Section 3), discussion of EF 19's data and modelling methodology (Section 4), and an in depth review of hourly model results, focusing on 2040 (Section 5).

The Energy Futures series is relied on by Canadian[3] and international[4] researchers as a key benchmark and/or reference point for analysis on the future of the Canadian energy system. The

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[1] Formerly known as the National Energy Board or NEB.
[2] Blandford et al. (2018), Nicolosi (2011), Frew and Jacobson (2016), Pina, Silva and Ferrao (2013).
[3] See for example Institut de l'énergie Trottier (2018) and Environment and Climate Change Canada (2018)
[4] See for example National Renewable Energy Laboratory (2019) and Energy Information Administration (2018)

additional hourly information described in this paper is a first step in making this type of information available. This serves a variety of purposes, including: a) offering additional granularity to improve the transparency of the Energy Futures analysis, b) providing additional results that can be used for insights on the future of Canada's energy system, and c) providing an important benchmark to compare and contrast results. These results can be considered a test case or 'beta' for hourly electricity analysis in the context of the Energy Futures series. Comments to the authors or energyfutures@cer-rec.gc.ca on the results and/or usefulness of the information would be appreciated.

2. EF2019 Electricity Results Overview

This section provides an overview of the annual results for electricity in Canada. These results are consistent with the annual data published in EF 19, including the various datasets that are available[5]. EF 19 provides an update to the baseline projection in the Energy Futures series, the Reference Case. The Reference Case is based on a current economic outlook, a moderate view of energy prices and technological improvements, and climate and energy policies announced and sufficiently detailed for modeling at the time of analysis. In the short term, infrastructure assumptions are based on existing pipeline projects and announced completion dates[6]. After 2025, infrastructure is assumed to be in place to move energy production and markets are found.

2.1 Electricity Demand

In EF 19, total Canadian electricity demand increases nearly 1% per year over the projection period. Electricity demand growth is significantly faster than total energy use. Total secondary or end-use demand grows approximately 0.2% over the projection period. Although electricity grows faster than total energy use, this rate of growth may seem relatively low given the increasing interest in

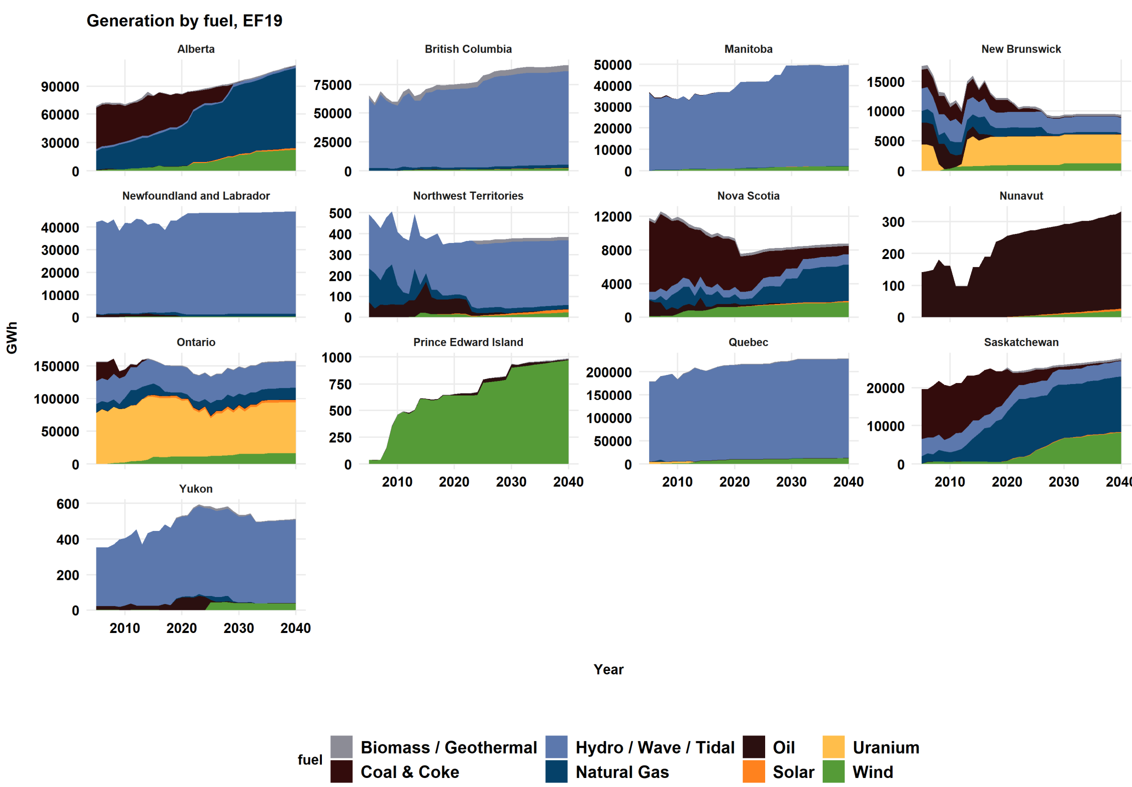
[5] EF 19 data is available at https://apps.cer-rec.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA
[6] These assumptions should not be taken as an endorsement of, or prediction about, any particular project. Rather, they are simple assumptions necessary for the analysis.

electrification in transitioning towards a low carbon economy. From that perspective, it is important to recognize that the EF 19 projections are for a Reference Case, which only includes policies and programs that are in place currently, and a moderate view of technological advancement. Future growth in electricity demand driven by the electrification of services traditionally provides by fossil fuels (driven by future policy and/or technological progress) is a key uncertainty for this Reference Case projection[7].

2.2 Electricity Capacity and Generation

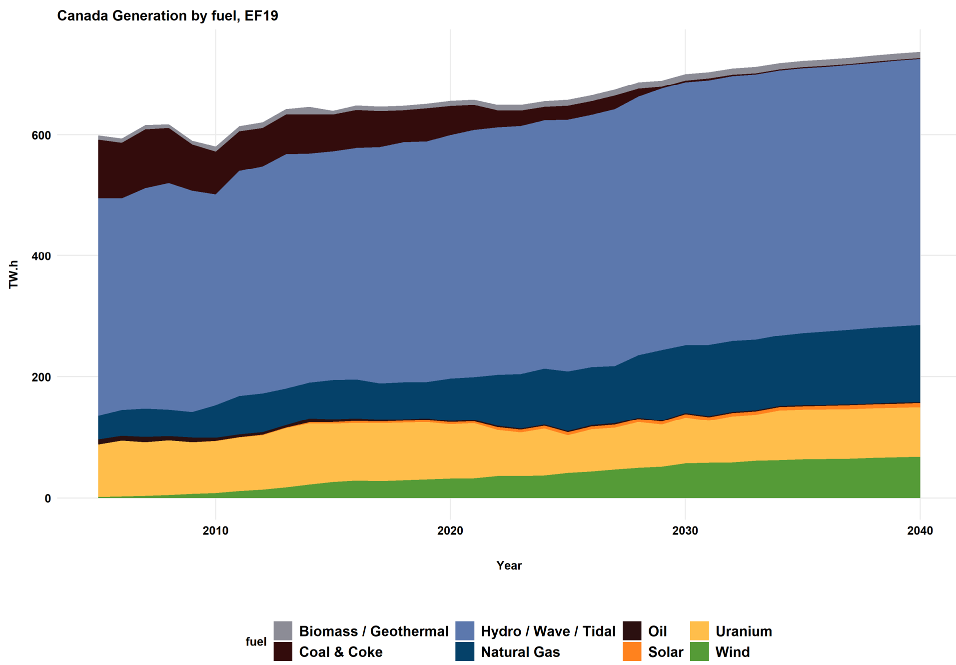
Electricity supply in Canada varies greatly by province, which is mainly due to differences in the availability of natural resources across Canada. Figure 1 and 2 below show the current generation mix by fuel for each province and the whole country, respectively.

Figure 1: Electricity Generation by Fuel and Province, Annual



[7] Previous Energy Futures reports have included additional scenarios. These are available at http://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/index-eng.html.

Figure 2: Electricity Generation by Fuel, Canada



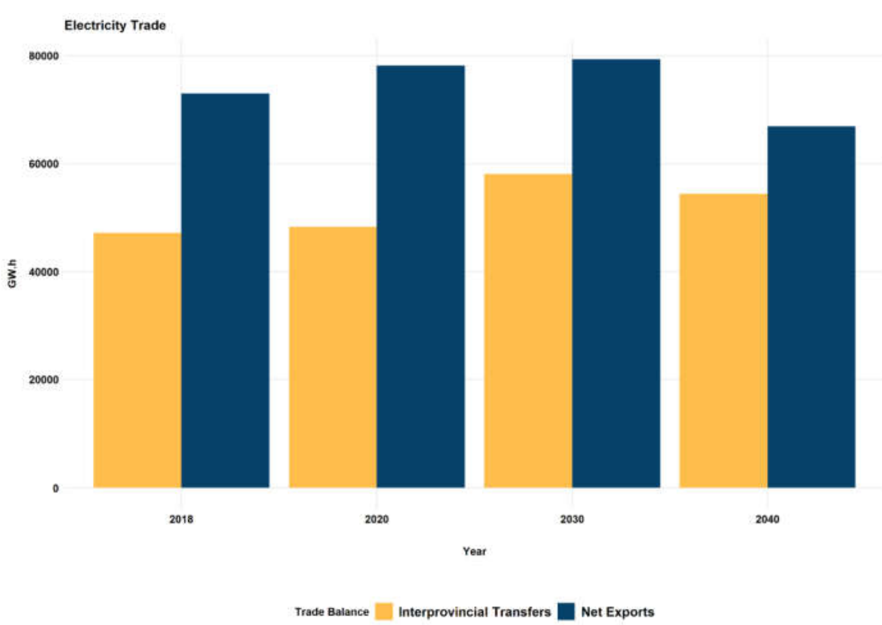
Going forward EF 19 projects a continued greening of Canada's electricity grid, the non-emitting share of Canada's electricity generation is projected to increase from 81% in 2018 to 83% by 2040. The projected increase in renewables will come largely from wind power additions in Alberta and Saskatchewan. The high quality of wind resources in the prairies, coupled with falling costs of wind turbine technology, are key drivers behind the continued adoption of wind power. While EF 19 also projects additions of solar in Alberta and Saskatchewan, the additions are small relative to the total generation mix. Atlantic Canada also makes gains in renewables, with Nova Scotia and New Brunswick phasing out coal generation and adding more natural gas and renewables.

The primary uncertainties in regards to these projections are the cost of competing technologies and uncertainty in demand growth. EF 19 makes assumptions regarding the costs associated with different power generating technologies, which then directly impact the supply mix. For example, if costs of renewables fall at a rate faster than assumed in EF 19 it could result in greater renewable additions than projected. Even more important to the projections of generating capacity is the projected demand for electricity. Electricity demand in EF 19 is a function of numerous macroeconomic variables such as gross domestic product (GDP) growth, population growth, household formation etc. Any deviations in the forecasts of these macro variables will affect demand projections, which in turn will affect capacity projections. As mentioned earlier, emerging policies that will drive electrification across the country, as well as technology advances in areas such as electric vehicles could lead to faster electricity demand growth than shown in EF 19.

2.3 Electricity trade

Electricity trade, both interprovincial and international (between Canada and the U.S.), plays an important role in Canada's electricity sector. The majority of electricity trade occurs between Canada and the U.S., Figure 3 shows the historical and projected breakdown of interprovincial and international electricity flows.

Figure 3: Interprovincial Transfers and Net Exports of Electricity



A key reason for most of the electricity flow going south rather than east or west is due to the superior economics of selling electricity to the U.S., which arise from higher electricity prices and currency differentials. EF 19 projects that this trend will continue going into the future.

Interprovincial trade is concentrated between certain provinces and occurs mostly in Eastern Canada. The large flows from Newfoundland to Quebec are contracted sales to Hydro Quebec from the Churchill Falls generating station in Newfoundland. Electricity trade in Atlantic Canada is more important in regards to ensuring the reliability of supply, relative to the rest of the country. For example, Prince Edward Island imports the entirety of its firm electricity supply, given that's own generating capacity is comprised entirely wind power, with some oil capacity as a back-up. Interprovincial trade between provinces is expected increase going into the future, this can be seen in Figure 3. Trade between Atlantic Provinces increases due to the Muskrat Falls project coming online in Newfoundland. This increases the electricity flow from Newfoundland going to both New Brunswick and Nova Scotia. Additionally, increased trade is projected between Manitoba and Saskatchewan, due to recent long term power purchase contracts signed between Manitoba Hydro and SaskPower[8]. The contracts allow long term purchases of electricity by SaskPower, increasing electricity flow from Manitoba to Saskatchewan.

2.4 Cost Projections[9]

As discussed earlier, assumptions about costs are an important input affecting the projections of the electricity supply mix and will directly impact which generating options are projected to be built. The key metric which captures the relative cost differences between different technology types is the levelized cost of electricity (LCOE). The LCOE of a particular power project is measured in dollars per unit of electricity produced ($/MWh) and can be interpreted as the price required for the project to exactly breakeven. That is, if each unit of electricity produced were to receive the LCOE, then the net present

[8] https://www.hydro.mb.ca/corporate/electricity_exports/power_sale_arrangements/
[9] For a more detailed study into LCOEs across different technologies in Canada, see CERI (2018).

value (NPV) of the project's cash flows would exactly equal 0. In EF 19, the LCOE is calculated by taking the NPV of the project's levered free cash flow by discounting at the cost of equity. Therefore, a project would only be built if the expected electricity price over a given time horizon is greater than a project's LCOE, as this implies a positive NPV. Relevant variables which go into calculating the LCOE are listed in Table 1 below.

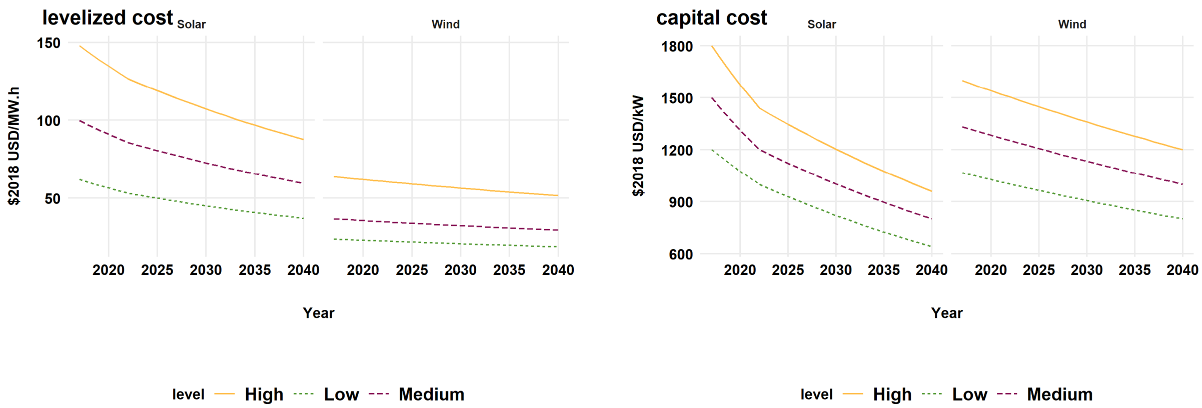
Table 1: Electricity cost assumptions for natural gas, wind and solar to 2040

Real, US$	Capital Cost (2018US$/kilowatt(kW))	Fixed Operating and Maintenance Costs (2018US$/kW)	Variable Operating and Maintenance Costs (2018US$/megawatt hour(MW.h))	Capacity Factor (%)[10]
Gas (Combined Cycle)	1 100-1 450	16	4	70
Gas Peaking	800-1 100	14	4	20
Wind (2020)	1 284	20-45	0	35-50
Wind (2030)	1 133	20-45	0	35-50
Wind (2040)	1 000	20-45	0	35-50
Solar (2020)	1 312	16-20	0	10-20
Solar (2030)	1 000	16-20	0	10-20
Solar (2040)	800	16-20	0	10-20

Using assumptions of future project and financing costs, EF 19 created a projection of LCOE going into the future. Shown below (figure 4) is the projected LCOE for solar and wind, the bands around the lines show the possible ranges the LCOE could take. The ranges are included to highlight the fact that LCOE calculations require a large number of input assumptions, and deviations in any of these assumptions can change the LCOE, sometimes substantially.

[10] Capacity factors are the actual energy produced by a generator divided by the maximum possible generation over a given period.

Figure 4: Levelized Cost and Capital Cost Assumptions, Wind and Solar



Two of the key inputs used to calculate LCOE are the capital cost of a project and the capacity factor. The High/Low bands in Figure 4 show the effect of 20 per cent changes in these variables. The assumed capital cost decline schedule for renewables is also shown in Figure 6. For renewables in particular, capacity factors and capital costs can change from site to site. This happens because wind and solar potential and distance to transmission lines[11] varies from location to location, which impacts capacity factors and capital costs, respectively. As a result, potential renewable projects are evaluated site by site, rather than as one homogeneous technology group. In contrast, siting issues don't effect fossil fuel generators to the same degree, which are treated as one homogeneous group.

3. Background on granular modeling of the electricity sector

A new area of analysis included for the first time in EF 19 is the granular modelling of the Canadian electricity sector at a higher temporal and spatial resolution[12], using hourly and site level data. Recent work in the energy economics literature has found that modelling electricity grids at a low annual resolution to be insufficient, particularly when it comes to accurately modelling scenarios with

[11] It assumed that the firm building the project will incur the cost of building a spur line connecting the project to the bulk transmission system. A longer spur line will increase the capital cost of the project.
[12] For similar work on high resolution modelling of the Canadian electricity sector see Dolter and Rivers (2018).

high penetrations of renewable generation. The specific issues associated with low resolution modelling are discussed in Blandford et al. (2018) and Nicolosi (2011).

Blandford et al. (2018) looks specifically at capacity expansion models and measures the responsiveness of capacity buildouts to increases in carbon price. The main finding of the paper is that models using low resolutions tend to overbuild renewables relative to higher resolution models and that the differences in renewable buildout increases with the carbon price. Models which use representative hours when doing capacity expansion, build greater amounts of renewables in response to carbon prices, relative to models using a larger number of representative hours. The paper's authors use a novel method to select representative hours which incorporated a full year of hourly electricity demand data along with hourly solar and wind generation data. The paper uses a clustering approach to select hours which would be representative of the fluctuations in demand and renewable generation over the course of an entire year. This is in contrast to traditional models which use time slices representative of minimum, maximum and intermediate demand[13]. The EPRI (2019) method is better able to model the intermittency of renewables and in turn gives more accurate estimates of renewable capacity. The paper compares the results from a low resolution model using 9 time slices and the author's own model which uses 103 time slices selected via clustering 8670 hourly observations. Under a no carbon price scenario, cumulative investments in solar and wind are 113 and 35 GW larger under the low resolution model relative to the higher resolution model. These differences are larger when a carbon price is introduced in the models. Under a $50/tonne carbon price, the investments in solar and wind are 217 and 156 GW larger under the low resolution model. Similar results were found in Nicolosi (2011), where the author applies different models to optimize investment decisions in the ERCOT market up to 2030. Three models are compared, under two different scenarios, using 16, 288 and 8760 time slices. The

[13] For example NEMS uses 8 time slices and E2020 uses 6.

results show that optimal investment in different technologies vary significantly for the three models. The key finding was that under high renewable scenarios, models with low resolutions tend to overbuild base load technology and under build peaking capacity, relative to high resolution models.

From the above examples it is clear that modelling resolution warrants more attention and that results from both high and low resolution models should be compared. These reasons were the primary motivation for the inclusion of hourly modelling in EF 19.

4 Methodology

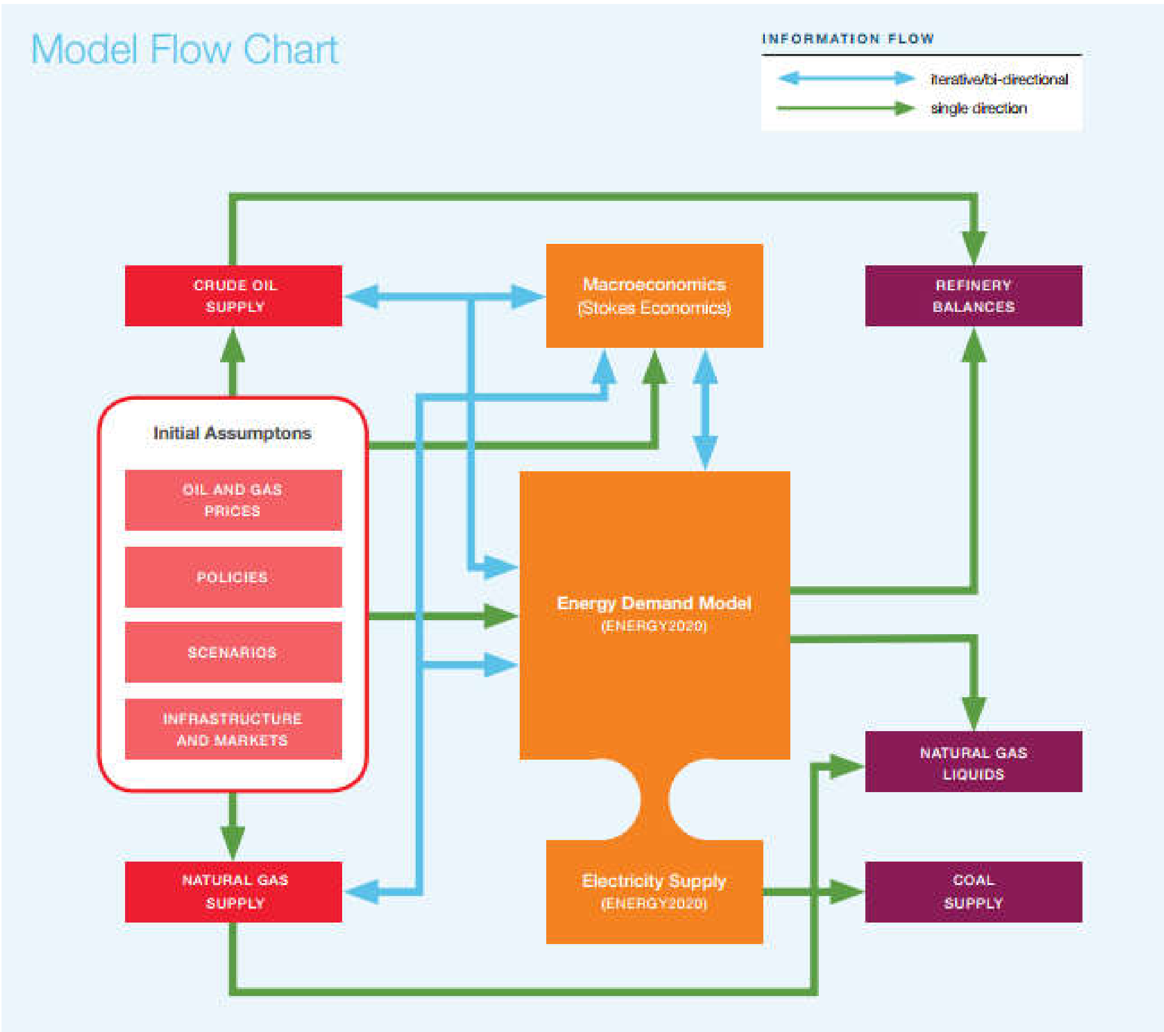
The following section will review the models and methodology used to create the projections seen in EF19. The review will begin with E2020 model, which has been the core model behind the electricity projections in the Energy Futures series, and cover its energy demand and electricity supply modules. Next, a brief overview of Python for Power Systems Analysis (PyPSA) model will be given. PyPSA is an open source power flow optimization model and was used to generate the hourly electricity profiles for EF19.

4.1 ENERGY2020

The CER's *Energy Futures Modeling System* (EFMS) is a multi-model framework used to develop the energy supply and demand projections seen in the Energy Futures series. Figure 5 illustrates the EFMS process. The modelling process incorporates many assumptions of key factors, such as benchmark prices, policies and infrastructure. At the core of the modelling system is the ENERGY2020 model, the flow of the ENERGY2020 model is shown in the diagram below. ENERGY2020 is composed of various modules which cover the supply and demand of different commodities. In general, the model first computes the demands for all given commodities and sectors, these demands are then fed into the different supply modules. The supply modules then compute the production of each given commodity.

Across the various modules there are a number of assumptions about price, policy and infrastructure, each of the assumptions used will be discussed in turn.

Figure 5: Overview of Energy Futures Modeling System



Global and North American benchmark oil and gas prices are set as exogenous assumptions. Canadian benchmark prices are set based on these benchmarks, based on an assessment of future market trends. On the gas side, LNG export facilities are key for production trends, and are exogenously assumed. These assumptions are used as inputs in the oil and gas supply modules. On the demand side, assumptions about policies such as carbon pricing, efficiency regulations, subsidies and consumer incentives are all fed into the model.

The electricity module in ENERGY2020 computes electricity capacity additions, generation and transmission both with the U.S. and between provinces. The electricity module's key inputs are the electricity demand values calculated by the demand module. The demand inputs are combined with assumptions of operating, capital and fuels costs of different generating technologies (natural gas, coal, wind, solar etc.) to create the capacity and generation forecast. Capacity additions are added on least cost basis while satisfying the following constraints for each province and each year: 1. meeting peak demand and 2. maintaining the required operating reserve requirement. Once the capacity additions have been computed, the model then creates the optimal generation profile for each province and forecast year. The optimal generation profile is created using a linear programming model, in which the objective function being minimized is the total cost of operating the grid, while meeting the constraint of fulfilling demand at all time periods. ENERGY2020 uses 6 time slices for the purposes of modelling of capacity and generation. Total demand is divided up into 6 time periods and generation is computed for each period, constraints on renewable generation are added for each time slice, in an attempt to represent the variability of renewable generation.

4.2 PyPSA and Hourly Modelling Methodology Overview

In order to model the electricity sector in greater detail at an hourly resolution, EF 19 complimented the EFMS with PyPSA, an open source power flow optimization model. PyPSA was used to create all of the hourly generation and transmission numbers that are discussed later in the paper. Since extensive documentation outlining the methodology behind the PyPSA model is available from its website[14], the discussion here will be brief. The objective function for the optimization is comprised of

[14] https://pypsa.org/

total capital and generating costs for each network component and generator[15]. Several constraints are added to generators. Minimum and maximum generation constraints for each hour along with hour-to-hour ramping constraints are added for certain technology groups. For example, the maximum hourly generation for wind and solar is determined by site level historical wind speed and solar irradiance data[16]. Similarly, minimum and maximum generating constraints on hydroelectricity are incorporated, based on seasonal availability. Ramping constraints are also imposed based on technology operating characteristics. For example, coal plants and nuclear reactors cannot rapidly ramp their generation up or down, while technologies like simple cycle gas turbines can quickly change generation. These differences are reflected in the ramping constraints. On the demand side, future hourly demand is simulated using a combination of historical hourly load factors and ENERGY2020's forecasted peak demand. The historical load factors are scaled up using the projected peak loads, which gives an hourly demand profile for the given year. All of the above discussed constraints and data are then fed into PyPSA to create the optimal generation and transmission profile for each province and forecast year (this paper focuses on 2040).

5 Detailed Results

This section will look at some of the hourly results from EF19 and discuss both their implications and limitations. These hourly results are developed by taking the projected capacity mix from ENERGY2020 (consistent with published capacity values in EF 19) as given, and using PyPSA to determine the resulting generation and trade patterns for 2040.

[15] For EF 19 PyPSA was used model generation but not capacity or transmission additions. Therefore, the objective function only comprised of generating and shut/down startup costs for generators.

[16] Potential sites for future wind and solar development were selected from sites identified in GE Energy Consulting (2018).

5.1 Provincial Generation Results

As a compliment to Figure 1, Figure 6 below shows generation by fuel type for various regions for each hour of the year in 2040. These figures highlight the large variability in generation when the temporal resolution is enhanced to the hourly level. Total generation varies significantly at the hourly, daily, and seasonal level. Wind generation varies significantly at the hourly resolution as well, and is particularly important for Alberta, Saskatchewan, and Atlantic Canada. Figure 7 looks specifically at Ontario, which has a diverse mix.

Figure 6: Hourly Generation for 2040 by Fuel and Region

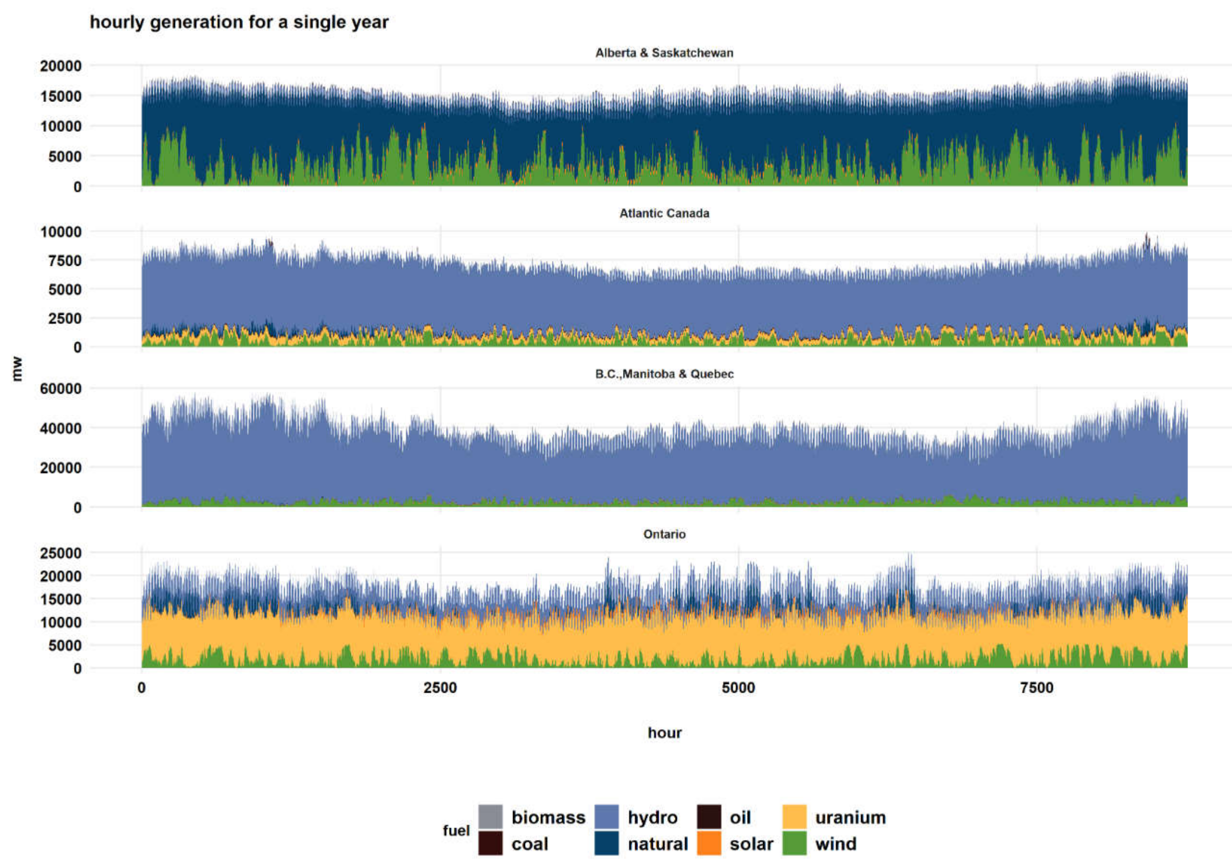


Figure 7: Hourly Generation for 2040 by Fuel, Ontario

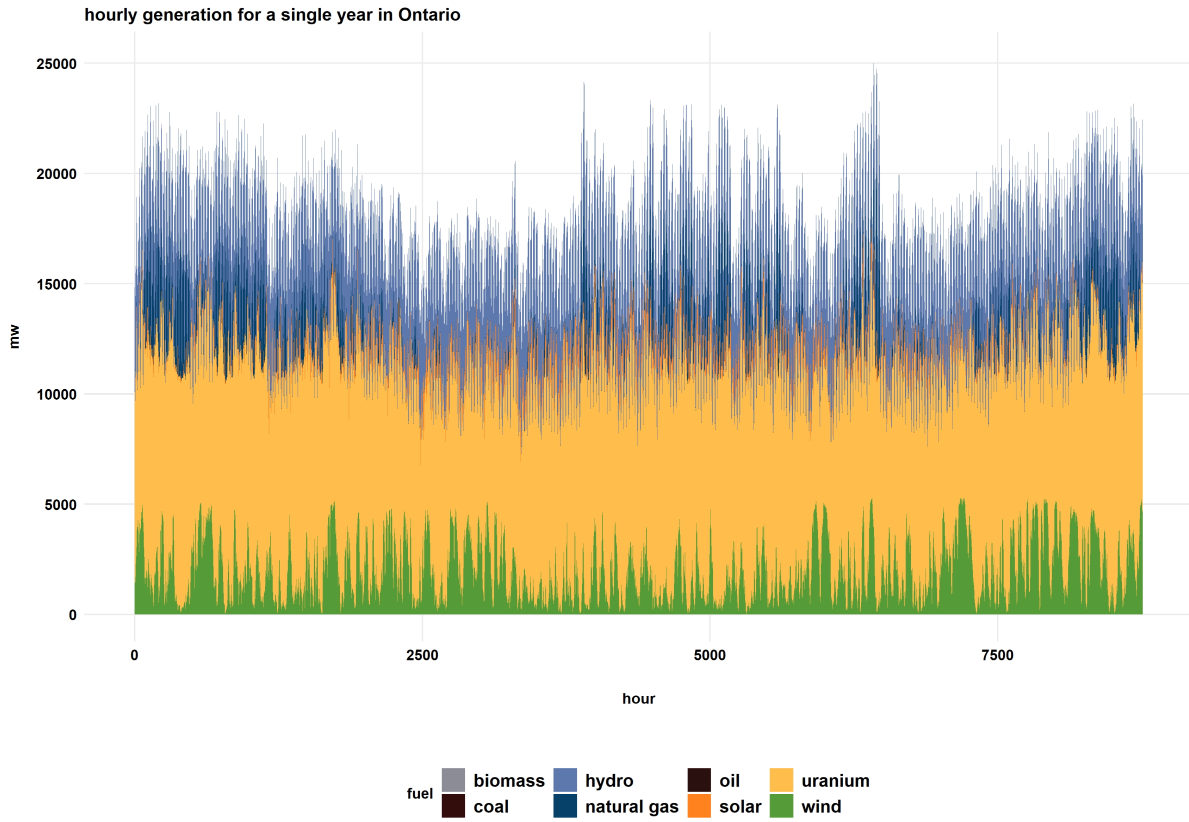


Figure 8 shows the generation on a randomly chosen day for each month, by region, and figure 9 shows generation by season. The results help to highlight the regional diversity of electricity generation in Canada. Both Alberta and Saskatchewan are projected to have diverse fuel mixes which include large amounts of wind generation. Similarly Ontario is projected to have a more diverse mix which includes large amounts of nuclear and hydro, accompanied by small amounts of natural gas and renewables.

Figure 8: Hourly Generation by Fuel for Each Region, Random day for each Month

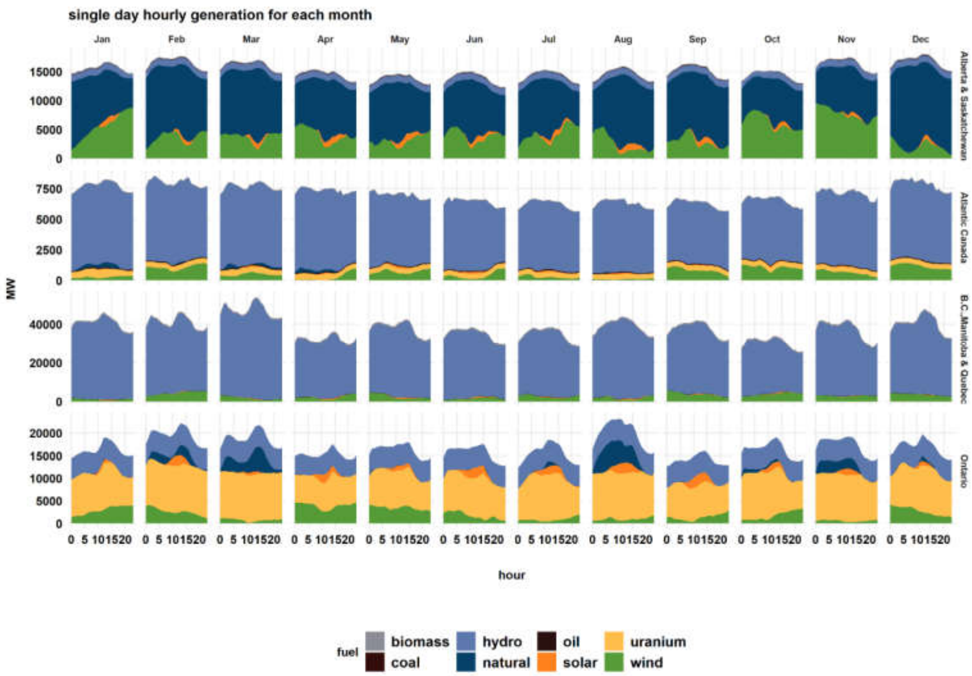
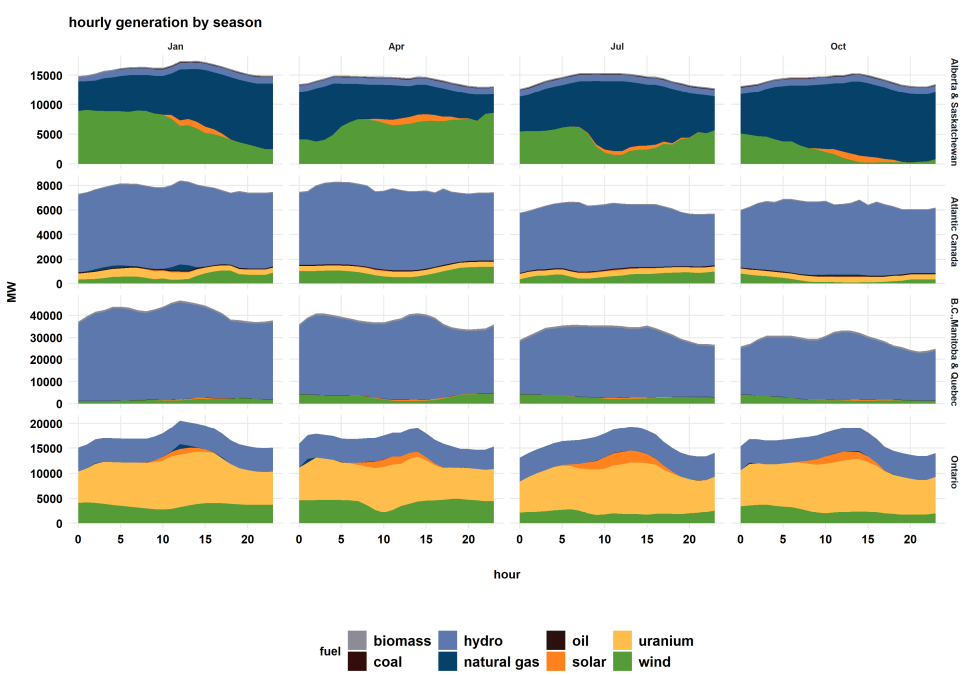
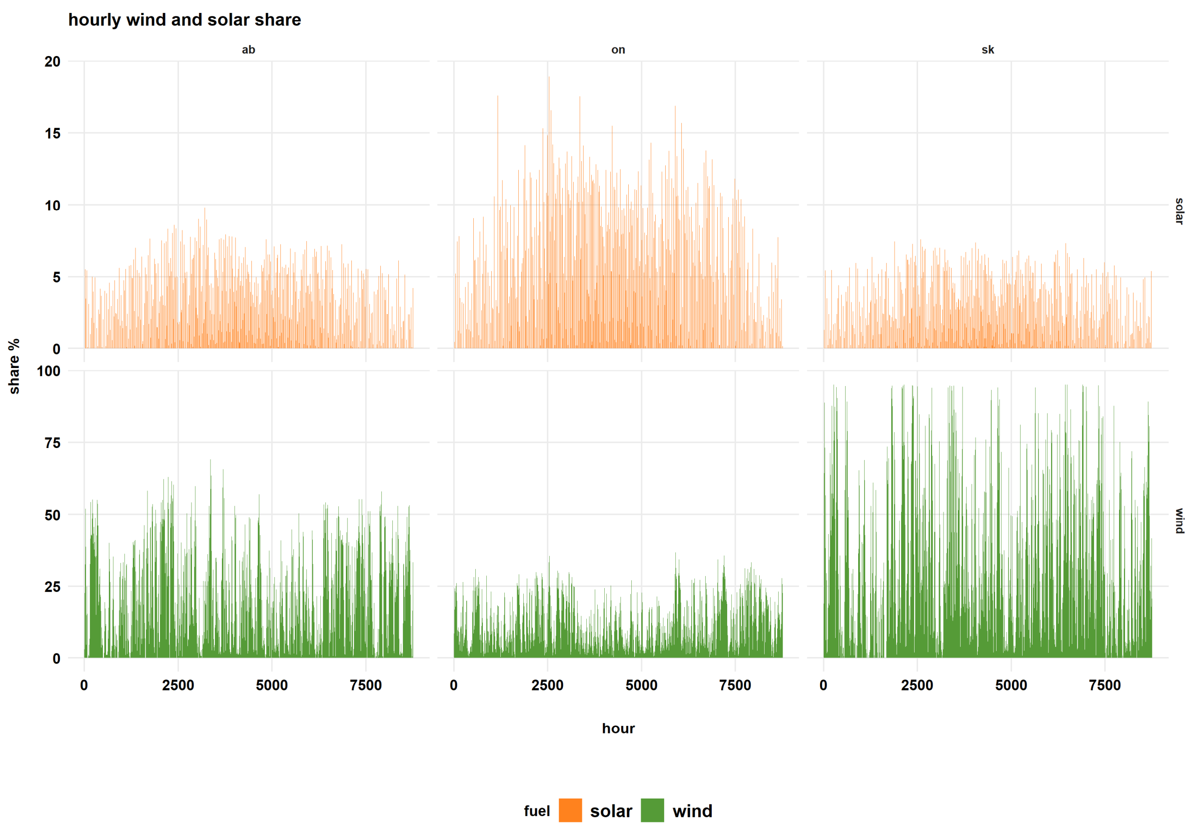


Figure 9: Hourly Generation by Region and Fuel, Random day for Each Season



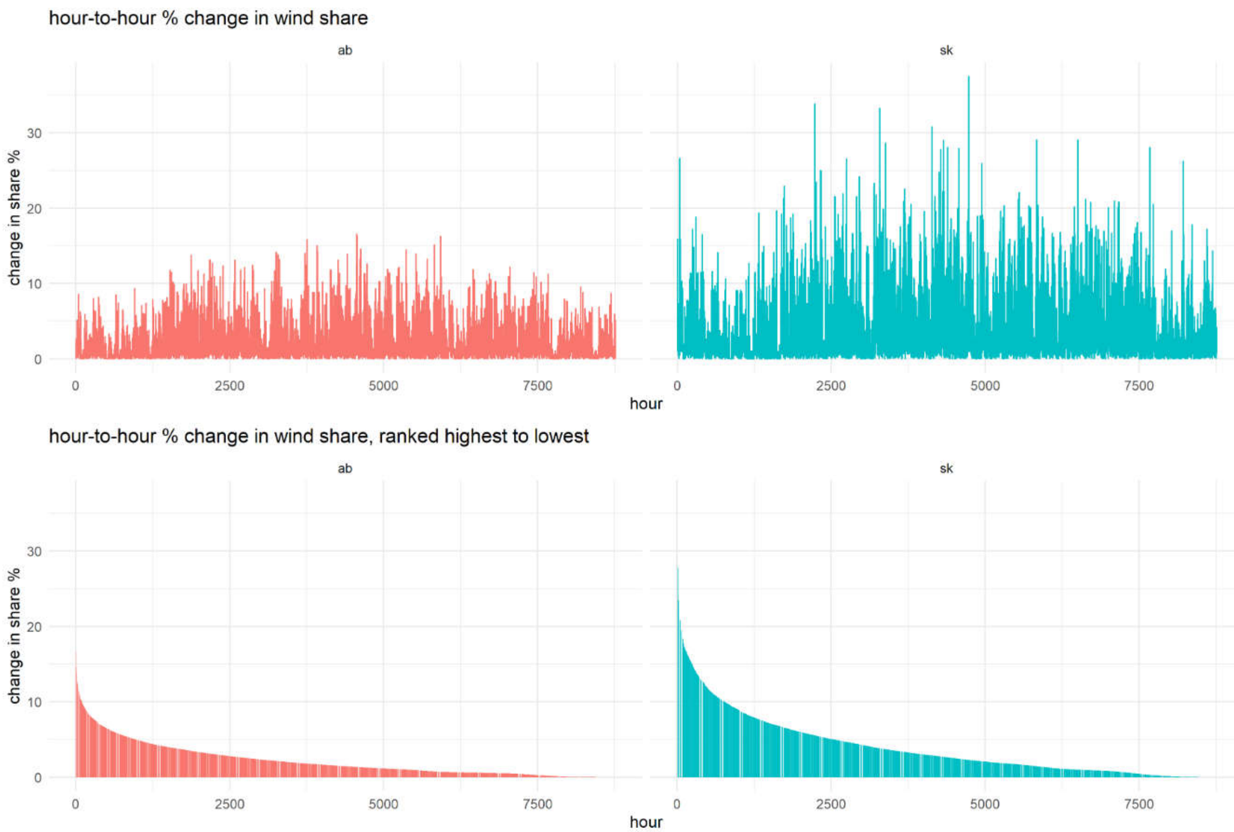
Over the course of a year wind generation shows great variability. While the average generation shown in Figures 1 and 2 may give the illusion of steady generation, in reality generation can fluctuate significantly throughout the year, anywhere between zero to maximum capacity. Figure 10 illustrates this variability by showing the hourly wind and solar share of total generation for Alberta, Ontario, and Saskatchewan.

Figure 10: Share of Wind and Solar in Total Generation, Alberta, Saskatchewan, and Ontario



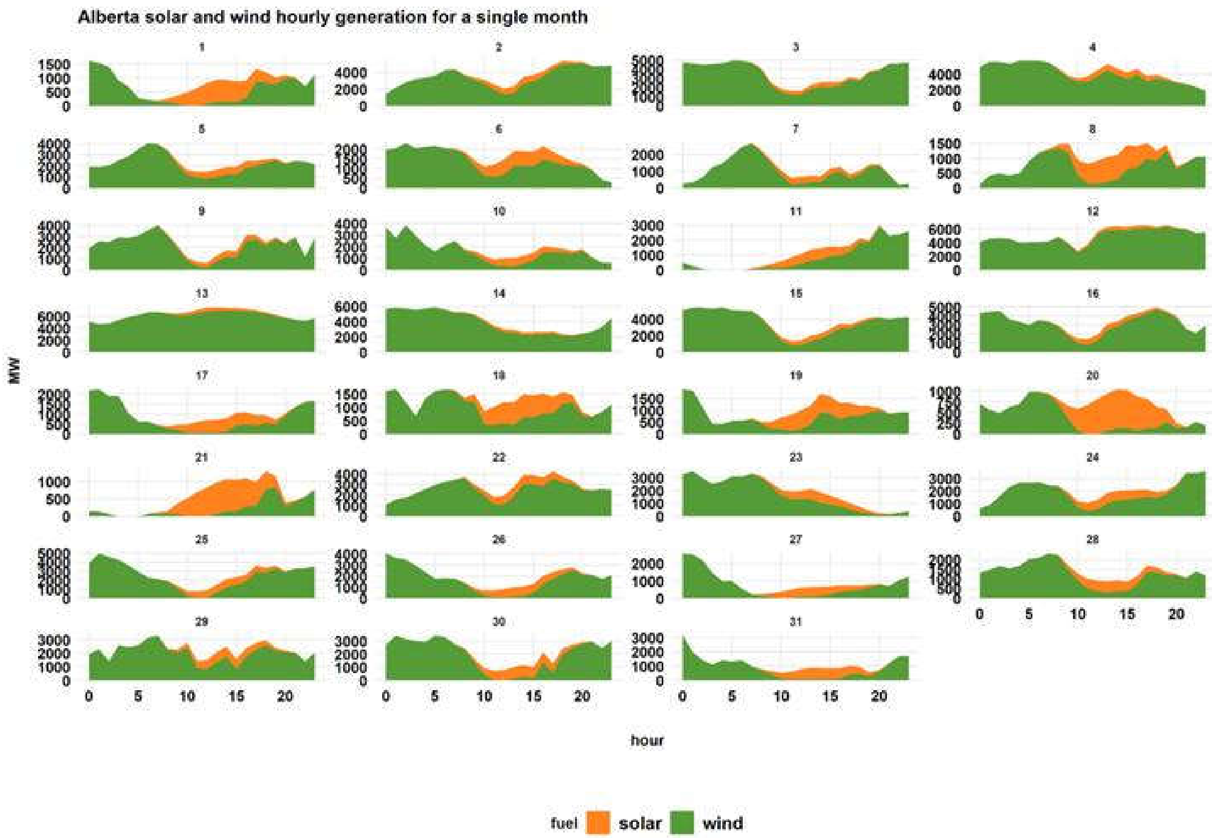
Another way to show the variability is to calculate how the share changes from hour-to-hour. This is demonstrated in Figure 11, which is the absolute value of the first-difference of the wind share for Alberta and Saskatchewan shown in Figure 10. The top row shows the change in share as it is modeled hour-to-hour, while the second row sorts the change from maximum to minimum. It shows that for Alberta, on an hour to hour basis the share of wind in total generation could change by 0 to nearly 17 percentage points, with the median change 1.4% (mean=2.2%). For Saskatchewan, the share can change from 0 to 37.5%, with the median change 2.6 (mean=3.9%).

Figure 11: Hour-to-Hour Change in Wind Share (Absolute Value), Alberta and Saskatchewan



In contrast to wind, solar has a more predictable generation profile, demonstrated in the Alberta example below (Figure 12). Given that projected solar capacity by 2040 is quite small relative to other generating technologies, we do not see the presence of a “duck curve” for any province in Canada.

Figure 12: Example of Alberta solar and wind hourly generation for July in 2040



One of the findings of the hourly analysis is that with the EF 19 projected wind capacity in Alberta and Saskatchewan, curtailments[17] were very minimal. This implies that a larger buildout of wind and solar could potentially be accommodated. EF 19 currently projects 7000 MW of wind in Alberta and over 3168 MW in Saskatchewan, by 2040. Under these wind capacities curtailment in Alberta is zero and 0.5% in Saskatchewan. To further explore these dynamics, we have conducted some additional sensitivity analysis:

- **Higher wind levels in AB/SK:** When doing the capacity optimization at an hourly level, we find that it is possible to substitute more wind for natural gas without increasing the total grid costs.

[17] Note that when analyzing curtailments intra-provincial transmission constraints were not considered. It is assumed that additional transmission capacity will be built as it is needed.

For example wind capacity in Alberta was raised to 10000 MW before curtailments became over 2%, similarly in Saskatchewan, wind capacity could be increased to around 5000 MW before curtailments increased above 2%.

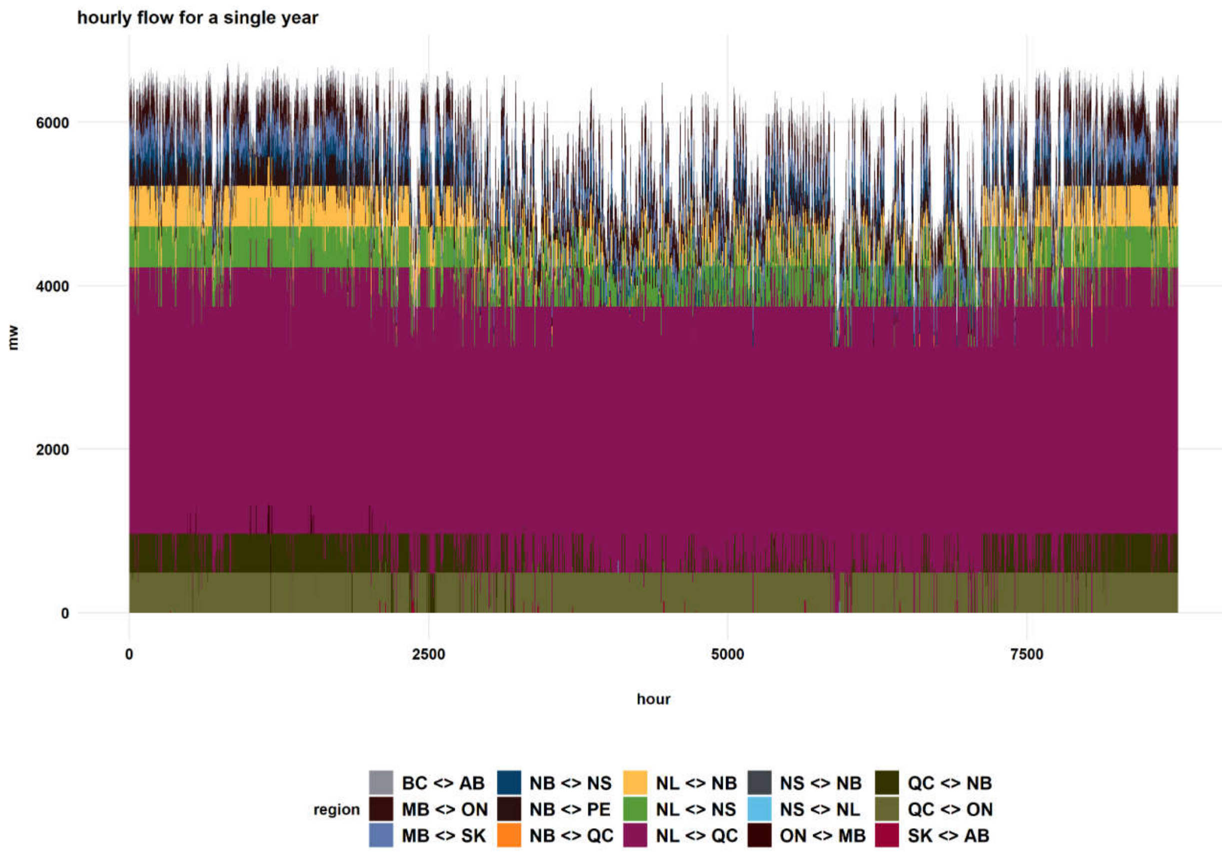
- **PyPSA optimized capacity in 2040:** If we allow PyPSA to optimally determine capacity levels in 2040, it produces an overall capacity mix similar to that found in EF 19. A key difference, as expected from the literature, is that the hourly model opted to substitute a mix of wind and natural gas peaking capacity for natural gas base load, with the net costs to the grid remaining the same. It should be noted that transmission costs for additional wind capacity are assumed to remain constant. In reality this may not hold true, as siting constraints for each incremental wind farm may move them further away from the existing transmission network. This then raises the costs of extending the transmission network to reach these additional wind farms.

5.2 Trade results

Another important aspect to the hourly analysis concerns electricity trade. Figure 13 shows simulated hourly trade patterns between provinces. It shows large amounts of fairly firm trade between certain regions, and a considerable amount of variation among others.

Trade with the U.S. was not explicitly modelled and for the purpose of this analysis is assumed to follow historical patterns. Trade between Newfoundland and its neighboring provinces will increase as the Muskrat Falls project comes online. Similarly, trade between Manitoba and Saskatchewan is expected to increase. A key uncertainty regarding trade is future U.S. demand for Canadian electricity imports. Currently, the majority of electricity trade with the U.S. is comprised of hydro exports from British Columbia, Manitoba and Quebec, with the destination markets for these exports being California, New York/New England and the Midwest, respectively. Any reduction in demand from these destination markets could incent these exporting provinces to engage in more interprovincial trade.

Figure 13: Simulated interprovincial trade for 2040



Conclusion

This paper has explored the 2040 electricity projections from the CER's study *Canada's Energy Future 2019* in the context of hourly analysis. Key conclusions from this review are:

- Differences in hourly load, resource availability, and trade highlight substantial variation in electricity trends when you increase the temporal granularity. The level of this variation suggests hour-to-hour changes are important to analyze, and should not be taken for granted when developing future projections. This is especially true as levels of renewable penetration increase.

- The hourly analysis suggests Canada's energy system appears to have enough flexibility to integrate the levels of variable renewable energy projected in the EF 19 Reference Case. Curtailments in provinces that add a significant share of wind and solar (Alberta and Saskatchewan) are close to zero, despite the share of renewables in the total generation mix changing significantly from hour-to-hour. So, overall this confirms the robustness of the EF 19 Reference Case projection, even though the main modelling structure that created it was annual with limited time-slices.
- Our sensitivity analysis did suggest that at a greater penetration of renewables, there could be integration challenges at an hourly level. This would result in higher levels of curtailment. As such, projections such at the "Technology Case" from *Canada's Energy Future 2018* could benefit from an enhanced temporal granularity. These levels may also necessitate additional measures such as demand-side management or storage, which are not discussed here. Higher levels of renewables also suggest an optimal generation mix involves a greater share of flexible peaking natural gas generation.

Overall, the results highlight that bringing an hourly perspective to the traditionally annual *Energy Futures* projections provides additional value to the projections in terms of transparency and understanding of how the electricity system could operate given the projected resource mix. As noted in the introduction, comments to the authors or energyfutures@cer-rec.gc.ca on the results and/or usefulness of the information would be appreciated.

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