Forecast Renewable Generation Electric Vehicle Load Requirements, a System Analysis of Alberta Canada

1st Mathew McLeod
dept. Electrical and Software Engineering
University of Calgary
Calgary, Canada
mathew.mcleod@ucalgary.ca

2nd William D. Rosehart
dept. Electrical and Software Engineering
University of Calgary
Calgary, Canada
rosehart@ucalgary.ca

***Abstract*—This paper presents a system level analysis of the Alberta Electric System Operator's 2021 Long Term Outlook data, comparing forecast electric vehicle load data against renewable electricity generation.**

***Index Terms*—Electric vehicles, internal combustion engine, combined cycle, compressed air energy storage, Alberta Electric System Operator, Alberta Interconnected Electric System.**

I. Introduction

A. Motivation

Global warming is arguably the greatest modern threat for humanity. Over the past decade anthropogenic contributions to GHG emissions have continued to rise, putting into jeopardy humanity's ability to limit global warming to the accepted 1.5 degrees required to mitigate the climate crisis [1]. The 26th Conference of the Parties (COP26) maintained that the 1.5 degree goal requires quickly moving away from coal power while aggressively increasing the speed at which our global society switches to electric vehicles (EVs) [2]. However, switching from internal combustion engines (ICEs) to EVs still results in significant GHG emissions when fossil fuel sourced electricity continues to be used [3].

The influx of EVs required to replace fossil fuel transportation is expected to increase electricity grid demand profiles, presenting many challenges for transmission and distribution planners [4]. Peak EV charging has been shown to naturally coincide with existing peak load demand, with potential to reduce lifespan of existing distribution transformers and a higher number of customer outages due to blown fuses [5], [6]. EV charge controlling strategies that seek to minimize peak load have been shown to reduce system upgrade requirements when compared with strategies that minimize charging cost or uncontrolled charging strategies [7]. Exploring the limits EVs will place on grid systems at the distribution level will be outside the scope of this paper, instead focus will be on analyzing these profiles at a system level.

With the significant unit costs of wind and solar generation decreasing [1] it seems natural to compliment increasing EV load requirements with renewable power generation while reducing fossil fuel power reliance. Market penetration potential of renewable generation is expected to be jurisdiction specific and dependent on environmental, policy, and techno-economic factors; including carbon pricing [8]. In the Alberta energy jurisdiction, the nature of its real time energy market, where generated electricity is sold through a competitive power pool system [9], make the province an attractive option for renewable generation development. This province's deregulated market puts the risk of investing in renewable energy on the developer in return for the opportunity to sell through the power pool [10].

Due to the intermittency of renewables, installation of enough wind and solar in Alberta to meet the province's base load requirements would require far too costly battery storage installations [11]. The current Alberta strategy for meeting base load demand is to replace or convert coal fired generation with natural gas combined cycle (CC) capacity [11]. Although several energy storage options have been considered for Alberta, including compressed air energy storage (CAES) and pumped hydro storage (PHS) [12], the only current utility scale energy storage in the province is the WindCharger 10 MW battery facility, which required heavy subsidies to bring online [13]. Clearly the province lacks storage capacity to support the intermittency of wind and solar.

The Alberta Electric System Operator (AESO) ensures the Alberta Interconnected Electric System (AIES) – commonly known as the grid – has reliable, safe, and economic operation [9]. The AESO publicly publishes long-term outlook (LTO) electricity plans bi-yearly for stakeholder review and this paper will utilize the AESO's 2021 LTO data for its EV and renewable generation analysis [14]. Although Alberta's electricity generation has potential for a variety of renewable energy sources, such as hydro electric and proposed geothermal [15], this paper will discuss renewables in terms of wind and solar generation where:

$$renewable = wind + solar \tag{1}$$

B. Problem

This paper will seek to understand the following:

- From a system perspective, will renewable power generation hold the potential to meet projected EV loading demand under the AESO's 2021 LTO?
- Where projected EV loading requirement and renewable energy generation deficiencies exist, what type of solutions may be considered to manage these deficiencies?
  - How could adding additional nameplate capacity affect projected demand issues?
  - Would load shifting of EVs help reduce peak demands?
  - Is renewable energy expected to produce a daily energy surplus that could be combined with energy storage technology to meet EV load requirements?

II. Methods

A. Data used

Two AESO data sets were used for this paper's analysis. One data set with actual historical generation data and the second data set containing forecasted generation and EV information.

The historical generation data was obtained at https://public.tableau.com/app/profile/market.analytics/viz/AnnualStatistics_16161854228350/Introduction, where hourly granularity was used under the tab labeled "Generation", allowing a csv download for further analysis [16]. This data set provided actual hourly generation data between midnight January 1, 2015 to midnight March 1, 2022, which included nameplate capacity and actual capacity factors for each hour.

The AESO's 2021 LTO forecast data was obtained from the Excel file https://www.aeso.ca/assets/2021-Long-term-Outlook-data-file-updated-Aug-11.xlsx [14]. Three sheets within the excel LTO data were utilized:

- Electric Vehicle Forecast (EVF)
- Generation data by fuel type (GFT)
- Reference Case Hourly AIL (RCH)

B. Tools

Excel was used to open the original historical generation data for the purpose of combining and eliminating excess title heading rows before exporting the modified file as a csv.

All further data analysis was done within Jupyter Notebook using Python code. The code and modified historical generation data file is available on the author's public GitHub at https://github.com/mcl13/AESO_research_2022.

C. AESO Scenario Choice

The AESO's 2021 LTO includes four scenarios to describe Alberta's future energy market: Reference Case, Clean-Tech, Robust Global Oil and Gas Demand, and Stagnant Global Oil and Gas Demand [17]. The Robust and Stagnant scenarios are largely dependent on market conditions for fossil fuel products [17], and will be ignored in the analysis here. The Refrence Case makes assumption of a \$50-per-tonne carbon price for 2022 followed by a yearly percentage increase, whereas the Clean-Tech scenario follows the ongoing federal carbon pricing plan with a yearly percentage increase after reaching \$170-per-tonne in 2030 [17], [18]. The Clean-Tech scenario assumes faster EV adoption than for the Reference Case [17], which agrees with COP26 EV goals [2] and is further supported through the Canadian Federal Government's Zero Emissions Vehicle (ZEV) program [19]. Although the Reference Case is typically what industry and planners will follow, the Clean-Tech scenario presents the case most closely aligned with current Alberta energy market conditions and will be the focus of analysis here.

D. Data Analysis

All generation and load requirements presented here are assumed to be constant across the given hour, in accordance with given data sets.

1) Renewable Capacity Factor Creation: The AESO's generation history (GH) data was used to create hourly renewable capacity factors (CFs) that would then be used, alongside LTO renewable nameplate capacity, to project hourly renewable generation 20 years forward.

GH data was cleaned in several Python steps before the data was ready for renewable CF extrapolation.

Four differently defined CFs were extrapolated from the GH data to give 8784 different CFs in each category; 8784 to represent each hour of a year including leap year hours: an average CF (CF_{avg}), a minimum CF (CF_{min}), a maximum CF (CF_{max}), and the CFs from the year 2020 (CF_{2020}). CF_{avg} was calculated using the basic average formula:

$$CF_{avg} = \frac{1}{n}\sum_{i=1}^{n} a_i \tag{2}$$

with n as the number of years starting in year 2015, and a_i as the data set value for the particular hour of each year. CF_{min} and CF_{max} are the respective minimum and maximum CFs for each hour of a year from the GH data. CF_{2020} is simply the CFs for each hour of the year 2020, and was chosen to define a typical year's hourly renewable CFs. Year 2020 was also chosen for describing a typical year since it was the most recent year of GH data being a leap year, containing all 8784 required hours.

Additional considerations were given when calculating solar CFs that were not necessary with wind. Solar generation capacity in the province did not come online until late 2017, resulting in a data column containing zero values with the potential to negatively affect the data integrity of solar's CF_{min}, CF_{max}, and CF_{avg}. To mitigate this concern all zero values regarding solar CFs were removed before calculating the applicable solar CF_{min}, CF_{max}, and CF_{avg}. This was done under the assumptions that zero values in the data column either represented times where there was no nameplate solar capacity or nighttime hours where the solar CF will always be zero regardless of nameplate capacity. The additional assumption that year-over-year nighttime hours did not change was also made.

2) Clean-Tech Electric Vehicle Load Data Creation: The AESO provided hourly EV load requirements for their Reference Case ($\text{EVload}_{\text{RC}}$) within the RCH data, which was used with EVF data to create hourly EV load requirements for the AESO's Clean-Tech scenario ($\text{EVload}_{\text{CT}}$). EV numbers for Clean-Tech (EVnum_{CT}) and EV numbers for the Reference Case (EVnum_{RC}) were given for each forecast year in the EVF data and were assumed constant through the respective year. EV load requirements were assumed directly proportional to the number of EVs in the market at the time, therefore:

$$EVload_{\text{CT}} = b_i \cdot EVload_{\text{RC}} \tag{3}$$

where,

$$b = \frac{EVnum_{\text{CT}}}{EVnum_{\text{RC}}} \tag{4}$$

for each *i* year. Here it has been assumed that the daily loading pattern does not change under this overall EV increase, where $\text{EVload}_{\text{CT}}$ follows the identical hourly loading pattern of the Reference Case multiplied by the proportional increase of EVs, b_i.

Once *b* values (4) were determined from EVF data they were then multiplied against respective $\text{EVload}_{\text{RC}}$ (3) from the RCH data to obtain hourly $\text{EVload}_{\text{CT}}$ data.

3) Forecast Renewable Generation and Hourly Generation Output: The author used the *Capacity Begin Year (MW)* column from the GFT data, for each year, as the renewable nameplate capacity and assumed this capacity as constant throughout the entire year in question. New generation capacity was assumed to come online Jan 1 of each year, inline with the *Capacity Begin Year (MW)* column. Although this does not account for generation capacity that comes online throughout the year, the assumption was considered a good approximation for this analysis.

Wind and solar nameplate capacity was given for both the Reference Case and Clean-Tech scenario in the GFT data, with applicable data extracted from the GFT data set before being combined in appropriate columns to the EVH data set.

Next wind and solar CFs were joined into EVH by matching months, days, and hours between data sets. Combining CFs into EVH allowed calculation of actual expected renewable output based on the following:

$$RenewableOuput = RenewableCapacity \cdot CF_{\text{x}} \tag{5}$$

where *x* represents one of the CFs described above (*avg, min, max, 2020*) and Renewable being either wind or solar. However, before calculating (4) within EVH a daylight savings issues within the data had to be managed.

Note each November there is one morning that contains two 2am times due to daylight savings, and one spring morning that skips an early morning hour (i.e. time goes from 1am to 3am). To address the issue of a fall double hour count under EVH data column *Hour Ending*, due to the fall back hour of daylights savings time in Alberta, the double counted hours in *Hour Ending* were first identified as having the label *02X*, before modifying the cell entries. These double hour entries also resulted in null CF column entries when the CFs were previously joined into EVH. The double hour was given the label of 2.5 and an assumed hourly capacity factor identical to the previous hour (i.e. 2am) using a forward fill method. Giving the double hour a label of 2.5, rather than eliminating it from our data set, allows the yearly overall hour total to remain as expected (8760 hours in a normal year, and 8784 hours for a leap year) while also preventing a double hour count during November. Since daylight savings only affected two hours in the year – one missing in spring and a double hour in the fall – making the above modifications to the data to mitigate the issue was not considered to have a significant impact on data integrity.

Renewable output was then calculated for wind and solar using (5) and the various CF conditions.

The final step in preparing the EVH data for analysis was to create a datetime index for the dataframe. To do this the *Hour Ending* column, which was a float, needed to be converted to a string for an effective time conversion in Python. Additionally, an *hour* column had to be created out of the *Hour Ending* column to avoid having a 24$^{\text{th}}$ hour which would be problematic for a time conversion. The hour column was created as a float for string conversion using:

$$hour = HourEnding \cdot 100 - 100 \tag{6}$$

When this string conversion was complete all daylight savings hours labeled *2.5* would require the string of *01:30:00*, however actual entries were *01:05:00*. A direct entry replacement was performed to convert all *01:05:00* entries to *01:30:00* to correct the issue. The *hour* and *date* column were then combined to form a datetime index in EVH.

4) Annual Data: Yearly EV numbers and renewable capacity were combined into a single data frame (EVRC) with applicable data for Reference Case and Clean-Tech scenarios. This data set will be used to compare the number of EVs against the renewable nameplate capacity annually across the twenty-year forecast. From here data sets were ready for analysis.

5) Transmission Losses: During analysis all renewable output was assumed to incurred a 2.8% transmission loss, t_{loss}, inline with the AESO transmission assumption [17]. Distributed renewable was then calculated using:

$$\textit{Distributed} = (1 - t_{\text{loss}}) \cdot \textit{Renewable Output} \tag{7}$$

where t_{loss} is given in fraction form.

E. Load Modifications and Considerations

The analysis presented here first reviews the data under the assumptions that all renewable generation would be theoretically available to charge EVs, nameplate generation follows the AESO's 2021 LTO projections, and EV loading profile does not change with an increase of EVs within the Alberta market; this was treated as a base scenario for analysis. Clearly, some renewable generation will have other end uses within the AIES, however this assumption allows a starting point for analysis. Modifications were applied to data during analysis to consider renewable generation used elsewhere in the AIES, increasing installed nameplate renewable capacity on a compounded annual percentage basis, and a shift of EV load requirements off of peak demand hours to other hours within the same day.

1) Renewable Available: Available distributed renewable was adjusted by removing a percentage from availability using,

$$Available = c \cdot Distributed \tag{8}$$

where c is the fraction of renewable to be used elsewhere in the grid. The analysis here considers the modified case where 50% of generated renewable power is assumed to be used elsewhere within the grid.

2) Additional Nameplate Capacity: Renewable generation capacity was adjusted through a compounded percentage of additional capacity added starting in year 2021 using the following:

$$C_{\mathrm{i}} = \begin{cases} Generation\ Capacity \cdot d & i = 0 \\ (Generation\ Capacity + C_{i\ \text{-}\ 1}) \cdot d & i > 0 \end{cases} \tag{9}$$

where i gives the respective year, starting in 2021 with i = 0. In (9), C is the additional capacity for the respective year, with d the fractional percentage of capacity to be added. The analysis here considers the modified case with 10% additional annual renewable nameplate capacity.

3) Electric Vehicle Load Shifting: The main EV load peaking occurs in evening hours alongside typical residential peak loads [17]. Here the assumption is made that peak EV loading is the result of vehicle owners returning home where they plug in their EV to receive a full charge prior to the next morning. No alternate fleet charging profiles are considered here.

EV load shifting was considered with the assumption a percentage of vehicle owners would take advantage of charging infrastructure that could be installed at their place of employment. This assumption is quantified by taking a percent of EV load between the hours of 3pm and midnight of each day and shifting that load to be added onto existing EV load 9 hours earlier. The 9 hour load shift was selected on the basis of the typical Alberta work days being 8 hours with a 30 minute assumed commute. To maintain program simplicity the same EV load shifting assumptions were made for weekends and holidays. EV load shifting was done, on the applicable hours, using the following:

$$D_i = EVload_{\mathrm{CT}.i} \cdot g \tag{10}$$

where D is the respective load to be shifted on the i^{th} hour, with g the fractional percent of load to be shifted. D_{i} is then subtracted from the applicable evening hour, to be added to the corresponding hour 9 hours earlier. The analysis here considers the modified case where 20% of the forecast EV load was shifted off peak hours to the applicable times earlier in the same day.

III. Results and Discussion

A. Annual Electric Vehicles with Renewable Generation Forecast

Annual EV units and renewable generation for each forecast year are summarized in *Table 1*, providing summary for Reference Case and Clean-Tech scenarios with expected EV unit numbers given and nameplate generation provided. Starting in 2034 through to end of forecast, EV numbers for Clean-Tech are a magnitude higher than Reference Case EVs. Renewable generation in 2034 was 17.2% higher in Clean-Tech compared to the Reference Case; for 2041 the same comparison showed Clean-Tech at 36.0% higher than the Reference Case.

TABLE I: Annual Electric Vehicle and Renewable Generation, Reference Case (RC) and Clean-Tech scenarios (CT) given.

	Electric Vehicles		**Capacity (MW)**			
Year	EV RC	EV CT	Solar RC	Wind RC	Solar CT	Wind CT
2021	15131	15131	236	1781	236	1781
2022	16256	24385	796	2450	820	2450
2023	17466	34931	954	3327	954	3407
2024	18765	75060	954	3327	1104	3507
2025	20161	100806	1004	3327	1104	3707
2026	21661	129966	1004	3327	1104	3907
2027	23272	139635	1004	4007	1204	4167
2028	25004	175027	1004	4457	1354	4207
2029	26864	188048	1004	4607	1524	4467
2030	31699	253596	1004	4607	1704	4497
2031	37405	299243	1004	4607	1784	4497
2032	44138	397245	1054	4617	1964	4497
2033	52083	468749	1054	4667	1964	4647
2034	61458	614582	1104	4667	2114	4647
2035	72521	725206	1104	4717	2114	4797
2036	85574	855744	1154	4747	2344	4997
2037	100978	1009777	1154	4807	2424	5147
2038	119154	1191537	1204	4726	2654	5066
2039	140601	1406014	1204	4857	2704	5297
2040	165910	1659097	1254	4857	2934	5297
2041	195773	1957734	1254	4907	2934	5447

Table 1 data is displayed in *Fig. 1* and *Fig. 2* presenting annual comparison of EV numbers against renewable capacity.

Fig. 1 gives the Reference Case, while *Fig. 2* displays the Clean-Tech scenario. Renewable energy has been stacked in annual bars, showing wind and solar capacity differences while providing the renewable sum. EV unit numbers are shown along the right vertical scale with generation capacity along the left of the respective figures. An exponential increase in EVs can be observed for both scenarios starting in year 2030. *Fig. 1* shows renewable generation fairly stagnant from 2023 to 2026 with only modest renewable growth forward to 2041; solar generation growth remains relatively flat from 2023 to the end of the forecast period. *Fig. 2* shows the Clean-Tech scenario having relatively strong linear growth in renewable generation from 2024 to the end of forecast, with more modest linear solar growth from 2027 to the end of forecast relative to the Reference Case.

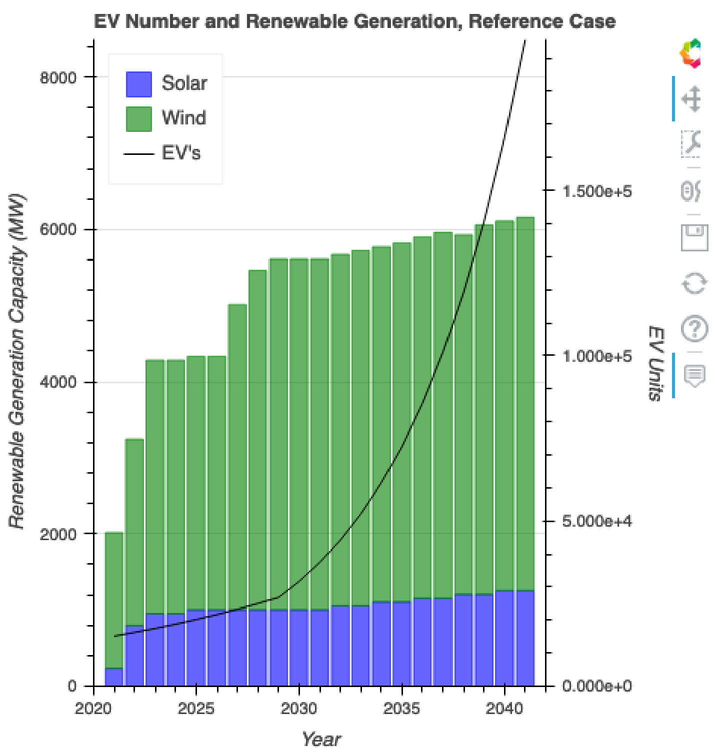


Fig. 1: Yearly EV numbers and renewable generation for the Reference Case. Renewable generation units are left axis, EV numbers are right axis.

Although results presented here are not a direct power comparison, the results clearly indicate that EV growth is forecast to outpace renewable generation capacity. Both the Reference Case and Clean-Tech scenarios see exponential increase in EV units coming into the Alberta market with only modest linear renewable growth across the same time period, with the situation in the Clean-Tech scenario exaggerated when compared against the Reference Case. The next section will analyse how these increasing EV numbers affect the expected EV load requirements against renewable generation.

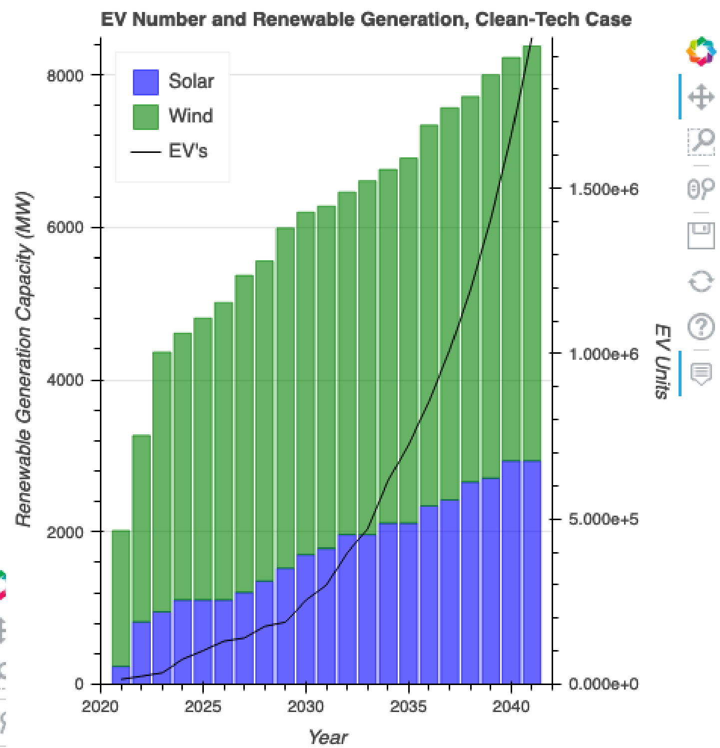


Fig. 2: Yearly EV numbers and renewable generation for the Clean-Tech scenario. Renewable generation units are left axis, EV numbers are right axis.

B. Renewable Generation and Electric Vehicle Load Difference and Deficiencies, Snapshot

The notebook program used can output hourly plots displaying renewable generation and EV load difference for anytime within the 20 year forecast period using Clean-Tech data. A 48 hour sample period starting September 1, 2030, is shown in *Fig. 3* with *Fig. 3(a-d)* using the assumed scenarios described in the *Load Modifications and Considerations* section. *Fig. 3* displays the difference of renewable generation with required EV load subtracted while independently displaying only EV load. CF_{avg}, CF_{min}, CF_{max}, and CF_{2020} were all used with (5) in obtaining the various data points displayed in *Fig. 3*. CF_{min} and CF_{max} give the respective whisker extremas, while CF_{avg} and CF_{2020} results are displayed in green and brown line plots respectively. From *Fig. 3* it can be seen that a more typical year, represented by CF_{2020} and (5), gives data both above and below average projections while also intermittently hitting extrema. Several deficient hours, defined as:

$$\textit{Power Difference} < 0, \tag{11}$$

where,

$$\textit{Power Difference} = \textit{Renewable Generation} - \textit{EV load}, \tag{12}$$

are seen in the sample period along the whisker's lower extrema.

From base conditions modified where 50% of renewable generation is assumed utilized elsewhere within the AIES there is a decrease in the overall power surplus alongside an increased number lower extrema deficient hours.

With a 20% EV load shift assumption a distinct difference to the base scenario is a flattening of the red EV load curve's peak during the sample period. The two late evening hours of September 1, 2030, with deficient lower extrema in the base scenario, are positive under load shift assumptions.

For the compounded 10% additional annual renewable nameplate added modification, in relation to the base scenario, fewer deficient negative extrema are seen with greater power surplus across the sample period.

Results here demonstrate that power difference surplus decreases and deficiency increases, as expected, when renewable generation is considered elsewhere within the grid. The EV load shifting assumption used here shows potential to reduce peak demands onto hours where there is greater renewable generation expected, whereas additional nameplate raises the overall power difference profile with potential to mitigate power difference deficiency.

The profiles created in this section should be limited to a "big picture" discussion, and merely reflect a snapshot in time from the forecast period. The extrema bars in *Fig. 3* show that actual renewable has a high potential to deviate from the average created here, with any given year – here CF_{2020} was used – likely to fluctuate well to either side of projected averages. The next section will review power differences across the entire forecast period.

C. Daily Power Surplus/Deficiency Analysis

Results presented in this section are limited to the CleanTech scenario where renewable generation is obtained from (5) using CF_{avg}. Data using CF_{min}, CF_{max}, and CF_{2020} were not applied for results in this section. *Fig. 4-6* each consist of four sub-figures – *(a-d)* – representative of the four scenarios described in the *Load Modifications and Considerations* section: *base scenario*, *renewable used elsewhere*, *EV load shifting*, and annual *additional renewable nameplate*.

1) Hourly Scatter Analysis of Deficiencies: *Fig. 4* provides a scatter plot indicating forecast hours where the particular hour of day experienced deficiency in accordance with (11) and (12). Daily patterns of *Fig. 4* remain consistent across all load modification scenarios, however deficiency magnitude are affected in each scenario. The *renewable used elsewhere* modification is seen increasing the magnitude and frequency of power deficiencies, with significant increase in deficient morning and early afternoon hours in the -1000 to 0 MW range. *EV load shifting* shows a reduction in peak evening deficient hours alongside an slight increase of morning and early afternoon deficient hours in the -1500 to -500 MW range.

2) Hour of Day Deficiency Frequency Histogram: The histogram of *Fig. 5* displays how frequently each hour of the day incurred a power deficiency. Against the base scenario, *EV load shifting* and *additional nameplate* modifications resulted in a decrease of peak hours having power deficiency, whereas *renewable used elsewhere* increased power deficiency frequency across all hours.

3) Power Deficiency Magnitude Histogram: Power deficiency magnitude frequency is shown in the histograms of *Fig. 6*, grouping magnitudes into 125 MW ranges. Against the base scenario, *EV load shifting* and *additional renewable nameplate* modifications can be seen reducing the number of hours where each range of power deficiency occurred, whereas *renewable used elsewhere* significantly increased power deficiency occurrence across power ranges.

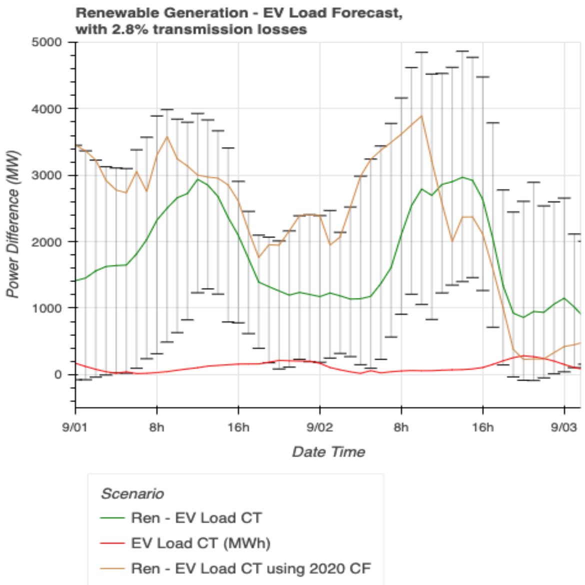
4) Power Deficiency Summary: *Table. 2* provides deficiency analysis summary data for the four load modification scenarios. Of note is the most common hour of the day for deficient hours to exist being 8pm, consistent across all four load modification scenarios. The *Hours* column of *Table. 2* provides the total number of deficient hours across the forecast period in accordance with (11) and (12), with the *First Occurrence* column providing dates where the first deficient hour occurs. The *Average* and *Most Negative* columns of *Table. 2* provide the applicable power deficiency summaries across the forecast period for each scenario.

TABLE II: Renewable Generation Difference with Electric Vehicle Load, Deficiency Summary.

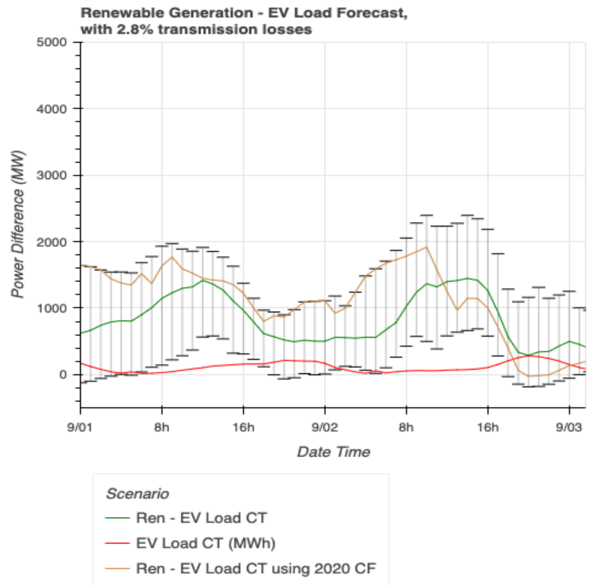
	Renewable – Electric Vehicle Load Deficiency			
Scenario	Hours	First Occurrence	Average (MW)	Most Negative (MW)
Base	7509	2030-12-25	-775	-3991
Renewable Elsewhere	21163	2025-12-25	-824	-4310
EV Load Shift	4758	2031-12-25	-562	-3065
Nameplate Added	5987	2031-12-25	-755	-3920

A summary of daily deficient power differences in accordance with (11) and (12) is presented in *Table 3* providing forecast deficient days, initial deficiency dates, average energy deficiency, greatest deficiency dates, and greatest energy deficiency under the four assumed *Load Modifications and Considerations* scenarios when all CFs are considered (*average, minimum, maximum, 2020*). Initial deficiency dates and greatest deficiency dates, for data obtained from (5) using CF_{avg}, in *Table 3*, are observed to coincide with December 25^{th} of the respective year.

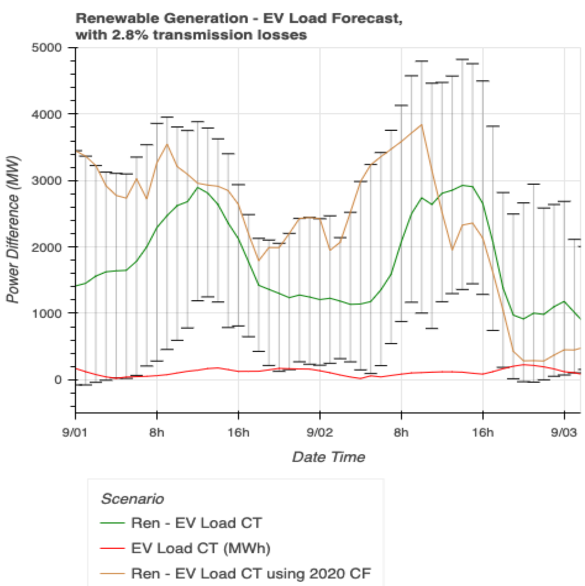
Results presented in this section demonstrate that power deficiencies, in accordance with (11) and (12), are expected within the forecast period base scenario. Load modifications show varying effects on forecast power deficiency. For the *additional renewable nameplate* modification from the base scenario, a reduction in deficient hour frequency is observed in *Fig. 5d*, a decrease in each hour's greatest deficiency magnitude is observed in *Fig. 4d*, with *Fig. 6d* showing a



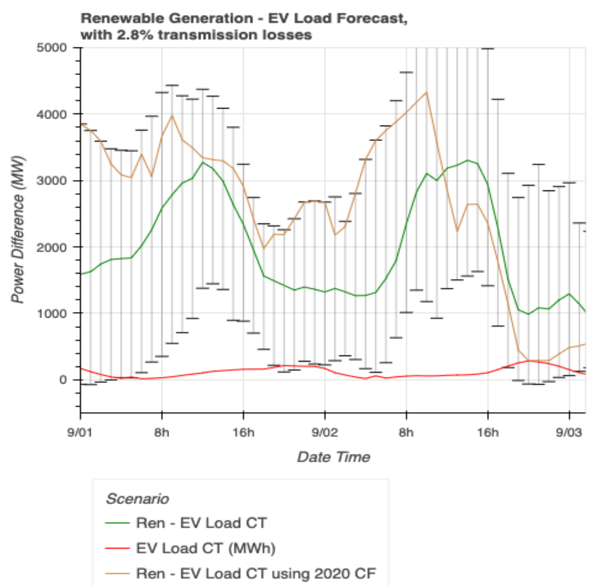
(a) Base Scenario



(b) 50% Renewable used elsewhere



(c) 20% Electric Vehicle Load Shift



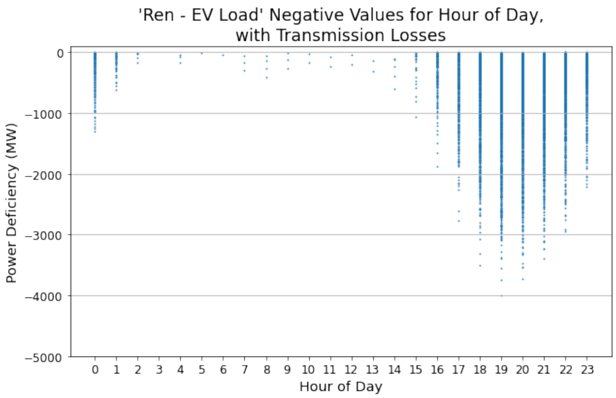
(d) 10% Additional Renewable Nameplate

Fig. 3: Renewable generation with electric vehicle load subtracted for a 48 hour sample period beginning September 1, 2030 for the Clean-Tech scenario with: *(a)* Base Scenario; *(b)* 50% Renewable used elsewhere; *(c)* 20% Electric Vehicle Load Shift; *(d)* 10% Additional Renewable Nameplate. The green line displays data when CF_{avg} was used in (5) with whisker bars resulting from using CF_{min} and CF_{max} with (5). The brown line plots the same difference when CF_{2020} is used in (5). The red line gives the electric vehicle load requirement used to find the respective differences.

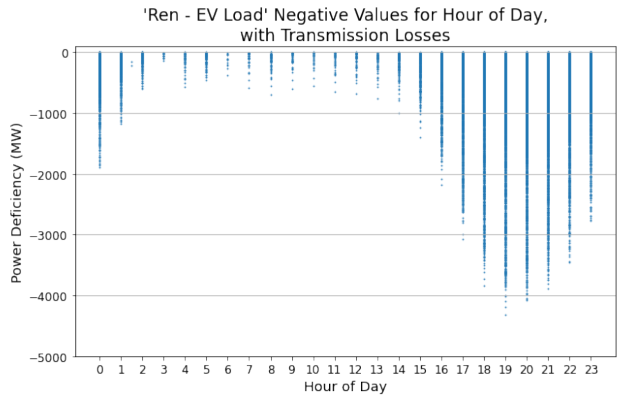
decrease in the frequency of each power deficiency range. *EV load shifting* modifications are shown to increase midday power deficient frequency while decreasing evening hour deficient frequency in *Fig. 4c* and *Fig. 5c*, while also reducing occurrence in each deficiency range as shown in *Fig. 6c*. *Table 3* results further extrapolate that these load modifications have the same system wide effect regardless of the CF considered. Overall, *renewable used elsewhere* has a negative effect on power deficiency, *additional renewable nameplate* results in power deficiency mitigation, where *EV load shifting* mitigates evening peak hour concerns while increasing daytime power deficiency occurrence and magnitudes.

D. Annual Power Surplus/Deficiency Analysis

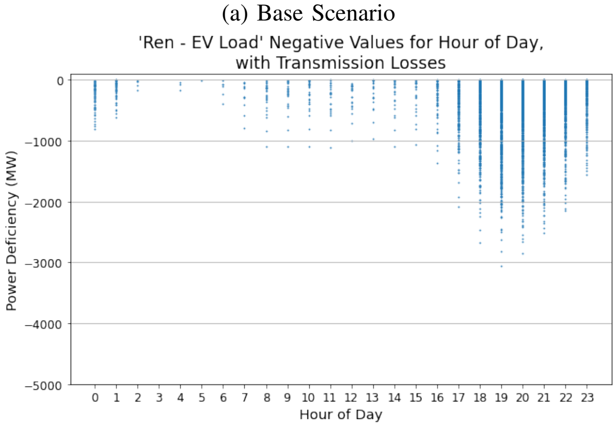
Daily renewable generation and EV load differences are shown in the scatter plot of *Fig. 7*. The distinct curve of



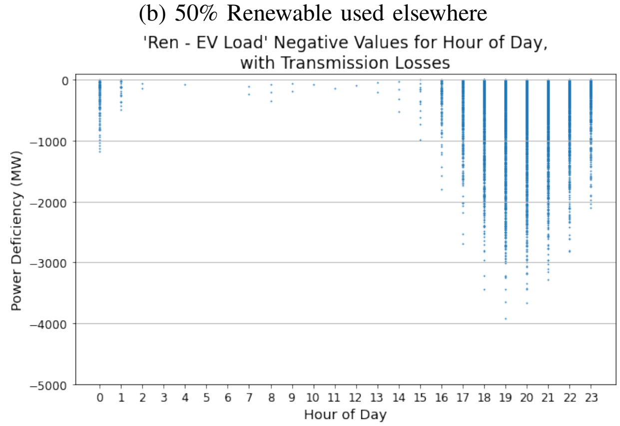
(a) Base Scenario



(b) 50% Renewable used elsewhere



(c) 20% Electric Vehicle Load Shift



(d) 10% Additional Renewable Nameplate

Fig. 4: Scatter points indicate power deficiency and hour of day for any deficient hour in forecast period in accordance with (11): *(a)* Base Scenario; *(b)* 50% Renewable used elsewhere; *(c)* 20% Electric Vehicle Load Shift; *(d)* 10% Additional Renewable Nameplate.

outliers that can be seen near the bottom of the plot occur once each year on December 25$^{\text{th}}$ due to relatively high forecast EV load for that day. This suggests that the *Greatest Deficiency* dates and magnitudes categories in *Table 3* are heavily skewed because of outlier data. A consistent annual scatter pattern is observed across the forecast period with the pattern displaying greater energy variance while approaching the end of forecast.

Annual energy surplus or deficiency are given in *Fig. 8* using:

$$NetAnnualEnergy_f = \sum_{i=1}^{8760 or 8784} PowerDifference_i.f \tag{13}$$

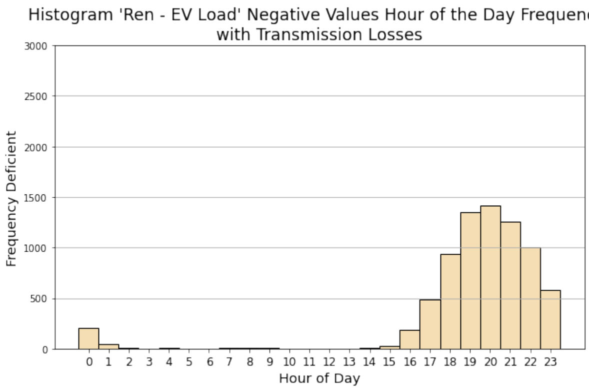
where i is the respective hour of each year, *f*, and *Power Difference* is found using (12).

The four *Load Modifications and Considerations* scenarios are shown in *Fig. 8 (a-d)*, providing annual power difference surplus or deficiency in accordance with (12) and (13), with renewable generation projected using each CF considered in this analysis: CF_{avg}, CF_{min}, CF_{max}, and CF_{2020}. Against the base scenario the load modifications; *renewable used elsewhere* reduced surplus (or increased deficiency), *EV load shift* had no effect on surplus or deficiency, and *additional nameplate* increased surplus (or reduced deficiency).

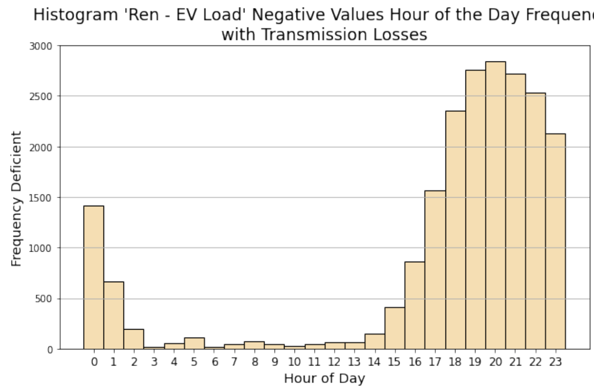
Results in this section indicate annual energy surplus in accordance with (12) for the base scenario using all but the worst case CF, CF_{min}, where annual deficiency begins occurring in year 2035 for this worst case. Only when the *renewable used elsewhere* modification is used are annual deficiencies observed using CF_{avg}, CF_{max}, and CF_{2020} with first occurrence in year 2040. Importantly, a typical year – represented with CF_{2020} data– shows energy surplus across the forecast period with the exception of the *renewable used elsewhere* modification having deficiency starting in year 2040. These results suggest that incorporating energy storage options into the grid could theoretically allow renewable energy to supply all EV load requirements across the forecast period for all but worst case CFs.

IV. Conclusions

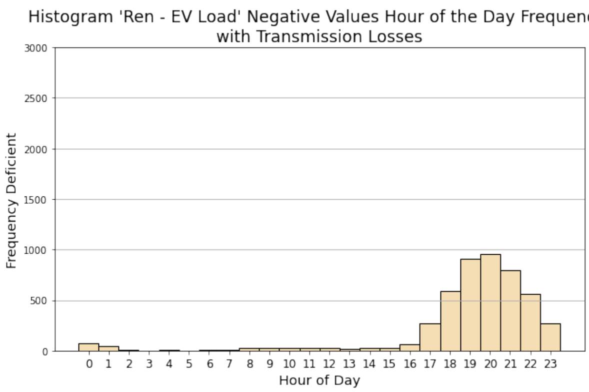
EV units in the Alberta electricity market are set to outpace renewable generation capacity installation. As a result, from a system level over the long term, renewable generation will not be capable of meeting EV load demand under the conditions set out in this paper. Furthermore, for the sake of argument,



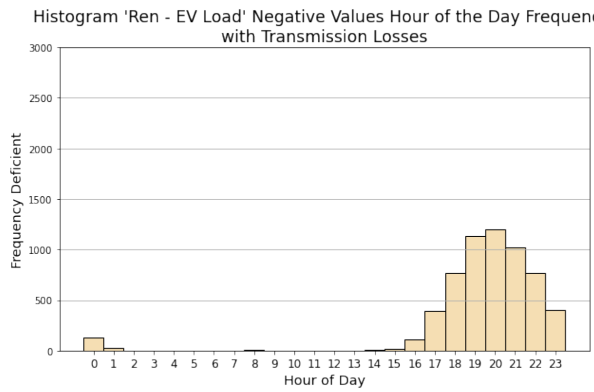
(a) Base Scenario



(b) 50% Renewable used elsewhere



(c) 20% Electric Vehicle Load Shift



(d) 10% Additional Renewable Nameplate

Fig. 5: Frequency of deficient hour, in accordance with (11), for each hour of the day across forecast period: *(a)* Base Scenario; *(b)* 50% Renewable used elsewhere; *(c)* 20% Electric Vehicle Load Shift; *(d)* 10% Additional Renewable Nameplate.

this paper makes the far reaching assumption that all renewable generation would be available for EV charging, an assumption that is clearly impractical from an application standpoint. Shown above are results where power deficiencies, both in frequency and magnitude, increase significantly when 50% of renewable generation is distributed toward non-EV charging end uses; increasing the inability of renewable generation to meet all EV charging requirements. Increasing nameplate renewable installation and promoting consumer behaviour that encourages EV charging to off evening hours are shown here to alleviate some power deficiency concerns. EV load shifting can reduce peak EV daily loading requirements while additional nameplate generation installation can mitigates power deficiency across all hours of a day. Since the Alberta grid meets its internal load demands over and above renewable generation using thermal generation, system planners should should remain aware of these forecast power deficiencies while working towards non-GHG emitting solutions.

Intermittency is a well known concern for renewable power generation. This paper has shown that although periods exist where renewables cannot meet EV loading requirements, there are often periods where renewable generation exceeds required EV load. Implementation of energy storage to harness this power surplus has great potential to meet EV load requirements with renewable generation, from all the considerations described in this paper. Therefore, system planning should incorporate an energy storage strategy and policy makers should be encouraged to create policy in support of such strategy.

A. Future Research

This paper has analysed the Alberta electricity market LTO data from a system level on the theoretical ability to meet EV load requirements with renewable energy. Ignored here has been costs associated with any suggested mitigation techniques or policy requirements to support such mitigation. Future research is required that incorporates cost variables for industry stakeholders to understand the viability of addressing forecast power deficiencies before they come to term.

Additionally, author suggested mitigation techniques were independently reviewed on their potential to alleviate forecast power deficiency issues. A combination of techniques is likely more appropriate, and future research could expand on results here to find an optimized approach that combines mitigation strategies while also incorporating costs.

Acknowledgment

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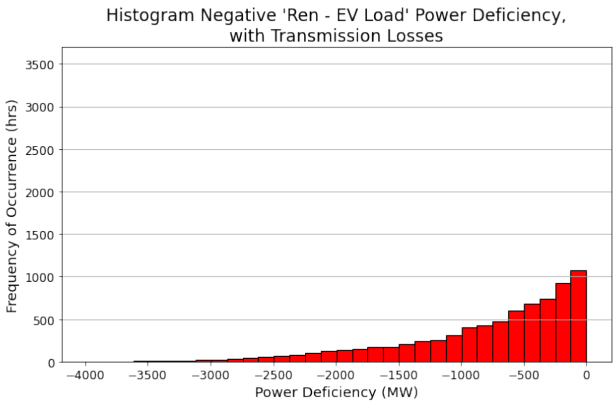
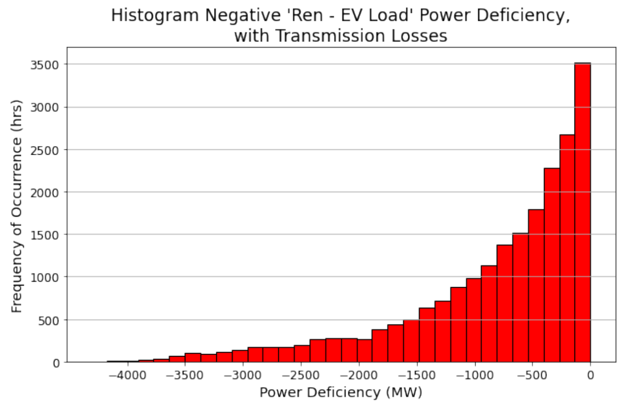
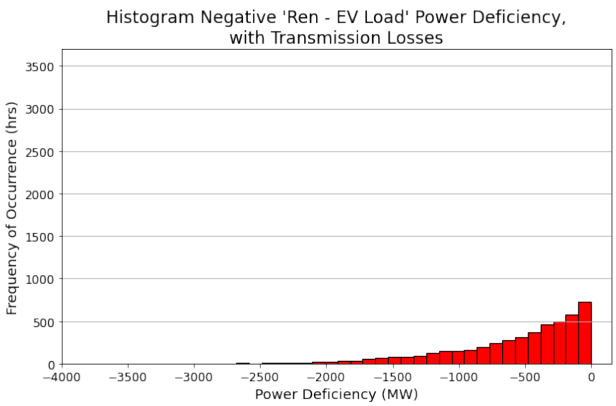


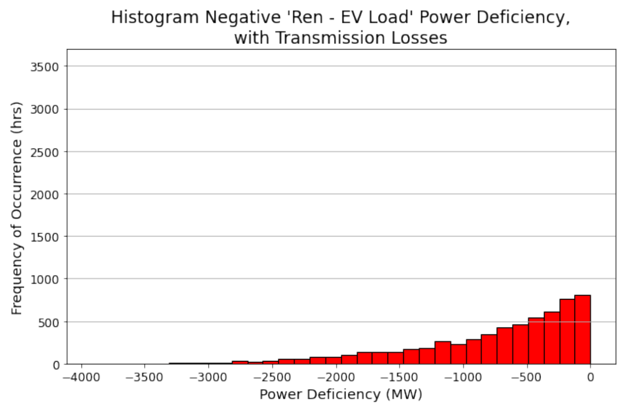
(a) Base Scenario



(b) 50% Renewable used elsewhere



(c) 20% Electric Vehicle Load Shift



(d) 10% Additional Renewable Nameplate

Fig. 6: Frequency across forecast period, in number of hours, of power deficiency broken into ranges: *(a)* Base Scenario; *(b)* 50% Renewable used elsewhere; *(c)* 20% Electric Vehicle Load Shift; *(d)* 10% Additional Renewable Nameplate. Each bar spans a deficiency range of 125 MW.

provided this research opportunity.

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TABLE III: Daily Renewable Generation Difference against Electric Vehicle Load Deficiency Summary.

Deficiency Type	Scenario	Capacity Factor Used			
		Average	Minimum	Maximum	2020
Number of Deficient Days	Base	34	2819	0	322
	Renewable Elsewhere	728	4260	15	947
	EV Load Shift	34	2818	0	322
	Nameplate Added	18	2581	0	279
Initial Deficiency Date	Base	2035-12-25	2021-01-02	n/a	2025-01-15
	Renewable Elsewhere	2041-12-25	2021-01-02	2038-12-25	2024-01-13
	EV Load Shift	2035-12-25	2021-01-02	n/a	2041-12-25
	Nameplate Added	2036-12-25	2021-01-08	n/a	2025-01-15
Average Deficiency (MWh)	Base	-5985	-11221	n/a	-21615
	Renewable Elsewhere	-8743	-10785	-39359	-21201
	EV Load Shift	-5985	-11225	n/a	-21615
	Nameplate Added	-6717	-11415	n/a	-21300
Greatest Deficiency Date	Base	2041-12-25	2041-12-25	0	2041-02-03
	Renewable Elsewhere	2041-12-25	2041-12-25	2038-12-25	2041-12-25
	EV Load Shift	2041-12-25	2021-01-02	n/a	2025-01-15
	Nameplate Added	2041-12-25	2041-12-25	n/a	2041-02-03
Greatest Deficiency (MWh)	Base	-27177	-44710	n/a	-44235
	Renewable Elsewhere	-36139	-44906	-44107	-44906
	EV Load Shift	-27177	-44710	n/a	-44235
	Nameplate Added	-25190	-44666	n/a	-44139

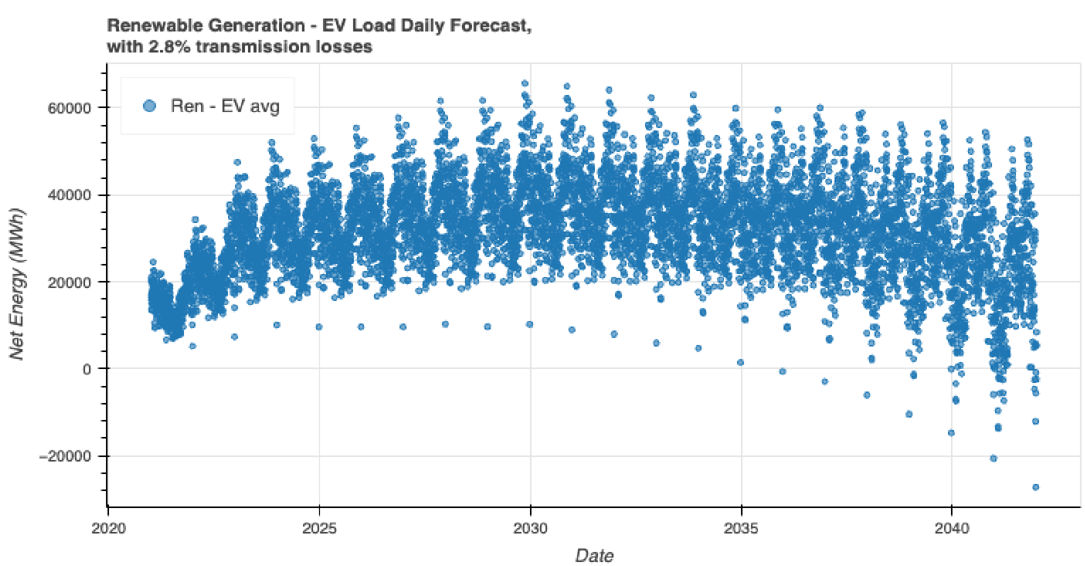

Fig. 7: Daily net energy scatter plot for forecast period's Clean-Tech scenario under base conditions. Renewable generation difference with electric vehicle load requirements are shown.

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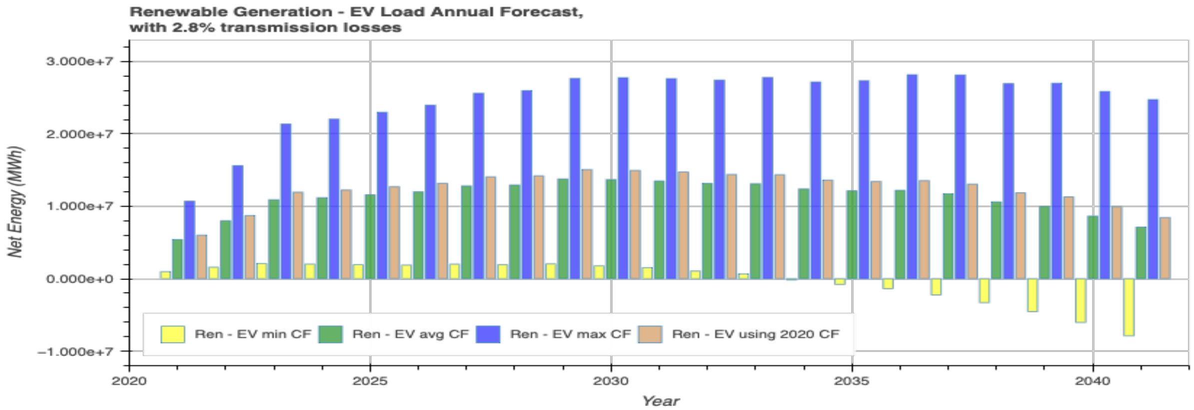
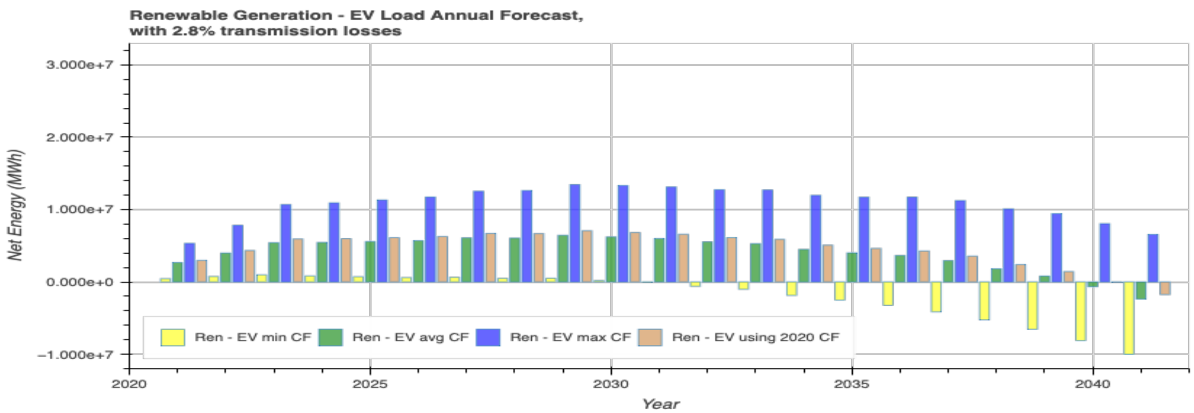
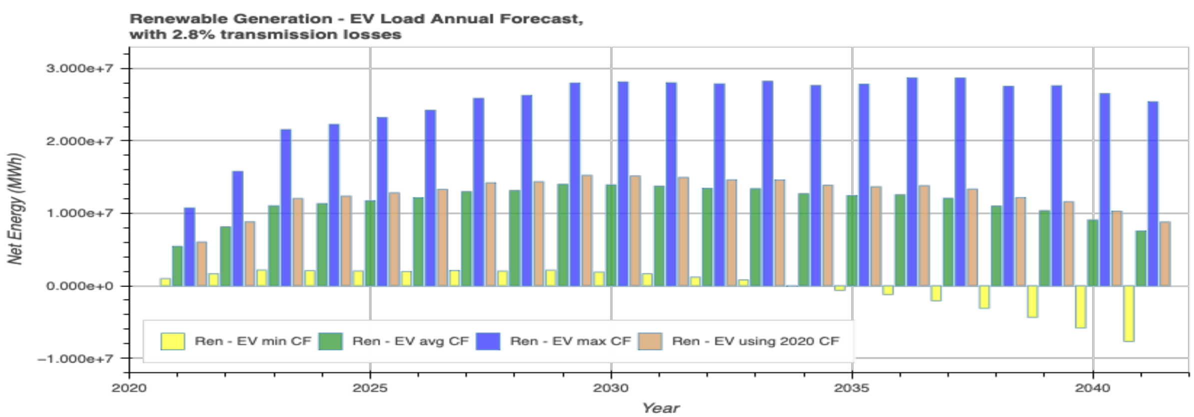


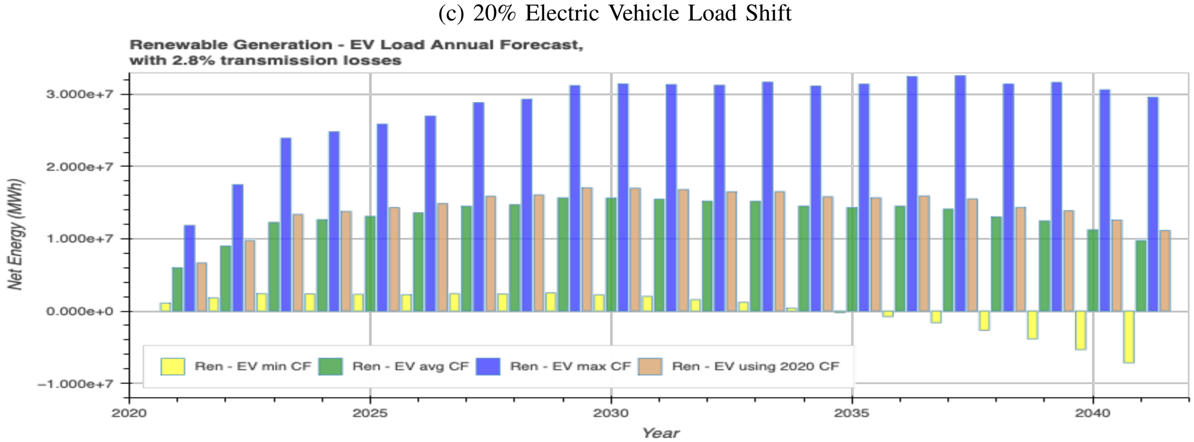
(a) Base Scenario



(b) 50% Renewable used elsewhere



(c) 20% Electric Vehicle Load Shift



(d) 10% Additional Renewable Nameplate

Fig. 8: Annual energy surplus using specified capacity factors to project renewable generation: *(a)* Base Scenario; *(b)* 50% Renewable used elsewhere; *(c)* 20% Electric Vehicle Load Shift; *(d)* 10% Additional Renewable Nameplate.