AUC
Alberta Utilities Commission

January 24, 2024

AUC comment on Guidehouse's Net-Zero Analysis of Alberta's Electricity Distribution System

The attached Guidehouse report was commissioned by the AUC to study the incremental distribution costs for Alberta's path to net-zero. The analysis resulted in an estimate of approximately $3 billion in incremental distribution costs in Alberta by 2050.

The AUC acknowledges the underlying limitations identified in the report related to the level of data and forecasts available from the distribution companies, as well as the numerous assumptions required in performing the study for the entire provincial distribution system. Given the time and cost limitations of the study and the inherent inaccuracies of a 25-year forecast horizon, a key decision was made to model and analyze a small, statistically selected number of representative feeders to depict the provincial distribution system. A long-term study to predict the future of normal course load growth is inherently uncertain. The decision was made to model baseline load growth on the existing system using the existing customer count and a one per cent net load growth, as historically experienced by Alberta's distribution utilities.

The report's results are related only to distribution infrastructure upgrades at the feeder and transformer levels required to address violations introduced from additional integrating of electric vehicle, solar, and storage deployments on the path to net-zero.

The AUC emphasizes that the report focuses only on the incremental costs due to the net-zero transition, which will be additive to all normal-course distribution costs. These normal-course distribution costs include distribution growth costs associated with supplying new subdivisions, neighbourhoods, towns or cities, and routine capital costs such as replacing aging infrastructure, or costs for grid modification such as smart metering and operational flexibility. Further, the report does not include any transmission costs associated with new substations or transmission lines required to supply the distribution system in the transition to net-zero. These transmission costs are expected to be included in the Alberta Electric System Operator's long-term transmission planning.

In short, the study's results provide directionally reasonable, incremental distribution costs associated with the net-zero transformation at the system level, and provides a framework for future work and refinement as the renewable pathway matures. There will be many opportunities for further refinement in both the technical and economic assessments in future studies.

Alberta Utilities Commission

Guidehouse
Outwit Complexity

Net-Zero Analysis of Alberta's Electricity Distribution System

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Alberta Utilities Commission

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Disclaimers

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List of Acronyms

ACEEE – American Council for an Energy-Efficient Economy

AESO – Alberta Electric System Operator

AUC – Alberta Utilities Commission

BTM – Behind-the-Meter

CYME – Power Engineering Software

DER – Distributed Energy Resources

DFO – Distribution Facility Owner

DR – Demand Response

EE – Energy Efficiency

ES – Energy Storage

EV – Electric Vehicle

EVDC – Electric Vehicle Direct Current chargers

EVSE – Electric Vehicle Supply Equipment

FSA – Forward Sortation Area

NZA – Net-Zero Analysis

PV – Photovoltaic

ROR – Rate of Return

SCC – Social Cost of Carbon

T&D – Transmission and Distribution

TOU – Time-of-Use (Rates)

VAST – Vehicle Analytics & Simulation Tool

Executive Summary

The Alberta Utilities Commission (AUC) engaged Guidehouse to develop an understanding of how the increasing levels of Distributed Energy Resource (DER) penetration related to the transition towards net-zero by 2050 will affect Alberta's distribution power system. Electric vehicles (EV), solar photovoltaics (PV) and energy storage (ES) were the DERs considered. Heating electrification was not considered in the analysis.

Guidehouse worked closely on this project with the AUC, the Alberta Electricity System Operator (AESO), and the seven distribution asset owners in Alberta. Alberta specific distribution system and premise-level historical and forecast data were key in developing reasonable scenarios, mitigation options, and associated integration costs. To avoid duplication of the AESO net-zero transmission cost impacts from the Net-Zero Emissions Pathways Report[1], no transmission system enhancements are included in this study.

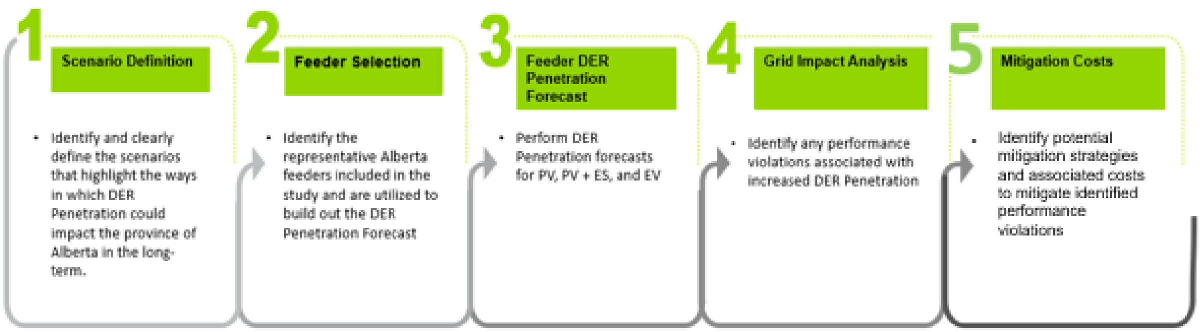
Guidehouse, specifically:

- Created three scenarios (a baseline, net-zero, and net-zero optimized scenario), including DER penetration forecasts, in order to assess the **incremental** cost on the distribution system due to the transition towards net-zero by 2050,
- Analyzed, at the distribution feeder level, the timing of future capacity or voltage constraints requiring mitigation on the distribution system for each of the three scenarios, and
- Forecasted the Alberta integration costs to 2050 associated with implementing the necessary mitigations on the distribution system for each of the three scenarios.

Guidehouse used a phased study approach, which is summarized in Figure 1.

[1] AESO, Net-Zero Emissions Pathways. Available: **https://www.aeso.ca/assets/AESO-Net-Zero-Emissions-Pathways-Report-July7.pdf**

Figure 1. Study Approach



The three scenarios, Baseline, Net-Zero, and Net-Zero Optimized, are described in Table 1.

Table 1. Scenarios Overview

Baseline	Net-Zero	Net-Zero Optimized
• Based on historical growth rates, no material net-zero impact • Load Growth and DER adoption based upon **a net** 1% year-over-year historical load growth • Grid mitigations use existing technologies to address capacity, energy, and voltage/thermal violations	• Based on the AESO's Net-Zero "Renewables and Storage Rush" scenario • High renewable & DER penetrations • Grid mitigations use existing technologies to address capacity, energy, and voltage/thermal violations	• Based on Guidehouse Net-Zero scenario • Applied existing technology grid mitigations plus Guidehouse recommended optimized mitigation strategies

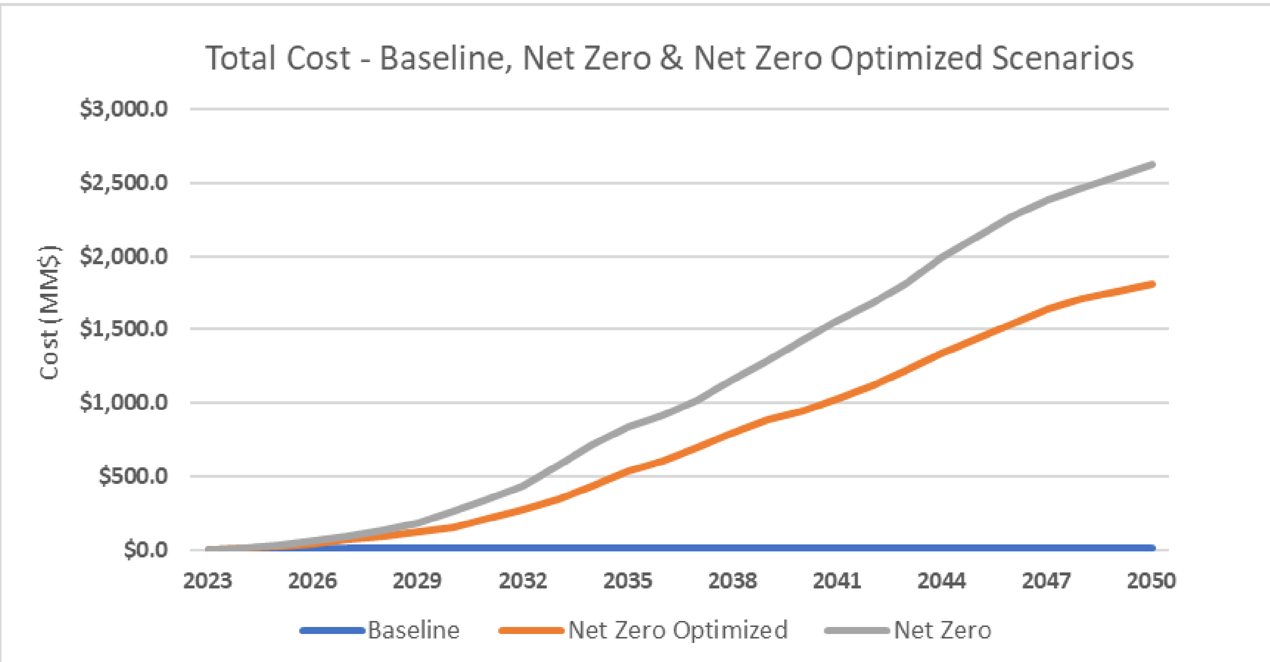
The annual integration costs for the three scenarios (including secondary transformer replacements) are summarized in Figure 2:

- The Baseline scenario is forecast to require $12M to 2035 and $17M to 2050,
- The Net-Zero scenario is forecasted to require an incremental $840M to 2035 and $2,600M to 2050, as compared to the Baseline,
- The Net-Zero Optimized scenario is forecasted to require an incremental $520M to 2035 and $1,800M to 2050, as compared to the Baseline. The approximate $800M reduction compared to the Net-Zero scenario is enabled by a forecasted 35% EV charging profile reduction using a revenue neutral Time-of-Use rate program,
- EV integration drives over 90% of the incremental integration costs. As such, coincident EV charging is a key factor that can accelerate and increase integration costs,
- 266 (2150km) new distribution feeders are forecast to be required by 2050,
- An additional $310M of secondary transformer integration costs by 2050 is forecast associated with the required replacement of over 50,000 transformers across Alberta

- Integration costs will tend to be higher for urban and suburban areas due to the higher density of EVs, and
- Integration costs will tend to be lower in rural areas due to lower EV densities and higher voltage feeders which will be able to accommodate EV driven load growth more easily.

The integration cost forecasts are sensitive to numerous assumptions incorporated into the study analysis, including the rate of adoption of DER's (specifically EV's), estimated mitigation costs, and higher cost escalation compared to the 2% escalation used in the study. All solutions employed to address performance violations are based on currently available technologies. Future advanced technologies may potentially reduce integration costs.

Figure 2. Total Annual Integration Costs



Analysis Improvement Opportunities

While conducting this study, Guidehouse concluded an overall increase in data for the project could have led to a more robust analysis. Improvement opportunities are divided into three categories: DER forecasting, grid impact assessment, and secondary transformer analysis.

- **DER Forecasting**
  - Overall, DFO's were limited in their ability to provide EV historical or adoption forecasts. In the absence of EV forecast data, Alberta-level vehicle registration data would improve the Guidehouse-generated EV adoption forecast,

- A single year of representative weather was used throughout the analysis. Insights on the impacts of climate change on weather patterns could improve the results of the study,
- Limited installed PV data was available. This resulted in no baseline historical PV capacity data for 4 DFOs. PV interconnection data could have led to more accurate baseline and Net-Zero PV adoption forecasts (including counts and segmentation),
- For the PV forecast, the adoption rates at the DFO per circuit did not account for differences in local socioeconomic, urban, suburban, and rural customer profile differences. An increase in customer economics data such as installation costs, retail rates, and socioeconomic data at the census level could have led to a more accurate PV forecast,
- Limited data on customer counts was provided, resulting in a simplified study assumption that resulted in overall customer counts would remain constant over time. A more accurate sense of population growth patterns would improve the maturity of the study, and;
- No energy storage installed data was available resulting in no information on growth and attachment rates for storage in the province of Alberta. Accurate historic and/or detailed forecast data from DFO's on storage attachment rates per customer class would strengthen the overall DER adoption forecast.

Overall, generating more refined and specific forecasts for each DFO would improve the maturity of the forecast and provide the ability to drill deeper into results and understand their drivers in finer detail.

- **Grid Impact Analysis**
  - Increased rigor in the distribution feeder analysis beyond steady state would improve the accuracy of predicting the impact of intermittent output of PV. Further, refinement of large PVs directly connected to primary voltage distribution feeders would improve the accuracy of the modeling and integration cost forecast,
  - Increasing the number of representative feeders and creating feeder clusters for each DFO would improve the accuracy of the integration cost forecasts, and
  - An assessment of Time-of-Use and Managed Use pricing and incentives for EVs is needed to determine incentive costs associated with the Optimized Scenario.
- **Secondary Transformer Analysis**
  - Consistent collection and linkage of customer usage data to individual secondary transformers by all DFOs is needed to improve the accuracy of transformer overloads and replacements caused by the incremental loading of EVs.

1 Introduction

1.1 Context and Objectives

The Federal Government has established a target of net-zero emissions by 2050 in Canada[2]. The decarbonization of the electricity sector has been identified as a critical milestone for this goal to be accomplished.

To achieve the Federal target, the province of Alberta determined that significant changes to the electricity grid will be required. Distribution networks will need to undergo fundamental changes to enable electrification and to accommodate the deployment of Distributed Energy Resources (DERs).

The AUC was seeking to understand the nature, types, and magnitude of investment necessary on the distribution system to meet the Canadian government's Net-Zero goals. More specifically, the AUC wanted to determine the potential investment necessary to maintain system reliability and adequacy on the distribution network to accommodate Net-Zero by 2050, informed by the Alberta Electricity System Operator (AESO's) Renewables and Storage Rush scenario in their Net-Zero Emissions Pathways Report[3].

The AUC engaged Guidehouse to develop a fundamental understanding of the different ways in which DER penetration can impact the Alberta distribution grid. Integration costs associated with the mitigations required to maintain reliability on the distribution system due to increased DER penetrations were estimated between now and 2050. This analysis did not consider the costs of the DERs themselves (PV systems, storage, electric vehicle supply equipment (EVSE)), load impacts due to heating electrification, nor the impacts (and associated costs) of DER adoption on the transmission system.

1.2 Study Approach

Guidehouse was engaged to develop a "reasonable" integration cost forecast at the provincial level, for the enhancements necessary on the distribution system to achieve the Net-Zero goals. Guidehouse functioned as a consulting partner with the AUC during this project. Collaboration between Guidehouse, the AUC, the DFOs, and the AESO were key in exploring the implications of future net-zero pathways for the electricity distribution system in Alberta.

A 5-step phased study approach was followed, as summarized in Figure 3.

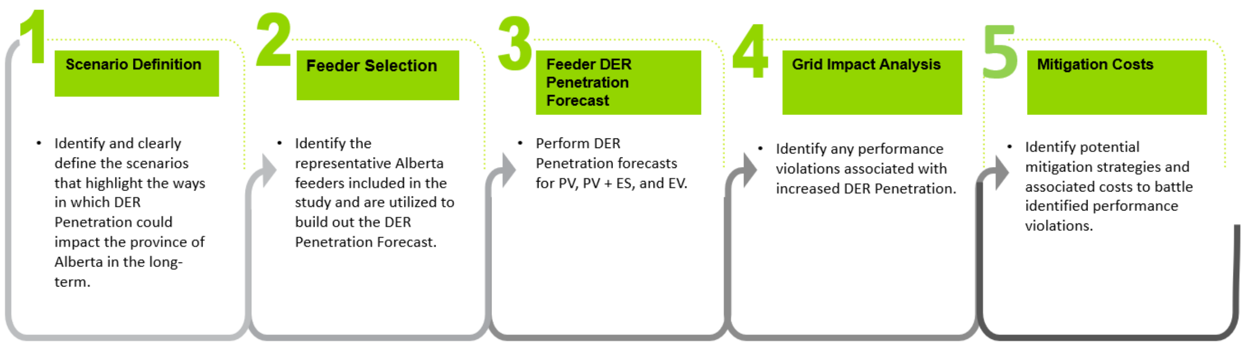
Three scenarios were developed, representative distribution feeders were selected, DER penetration forecasts were created, grid impact power flow analysis was performed on the representative distribution feeders to identify thermal overload and voltage violations caused by

[2] Government of Canada, Net-Zero Emissions by 2050. Available: **https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/net-zero-emissions-2050.html**

[3] AESO, Net-Zero Emissions Pathways. Available: **https://www.aeso.ca/assets/AESO-Net-Zero-Emissions-Pathways-Report-July7.pdf**

increasing PV and EV forecasts, for which mitigations and associated integration costs were subsequently determined.

Figure 3 . Study Approach



Scenarios Developed

Three scenarios were created for the study, as represented in Table 1. The Net-Zero and Net-Zero Optimized scenarios were informed by the "Renewables and Storage Rush" scenario from the AESO's Net-Zero Emissions Pathways report, and the Baseline scenario was informed by historical DFO growth rates.

1.3 Representative Feeders Selected

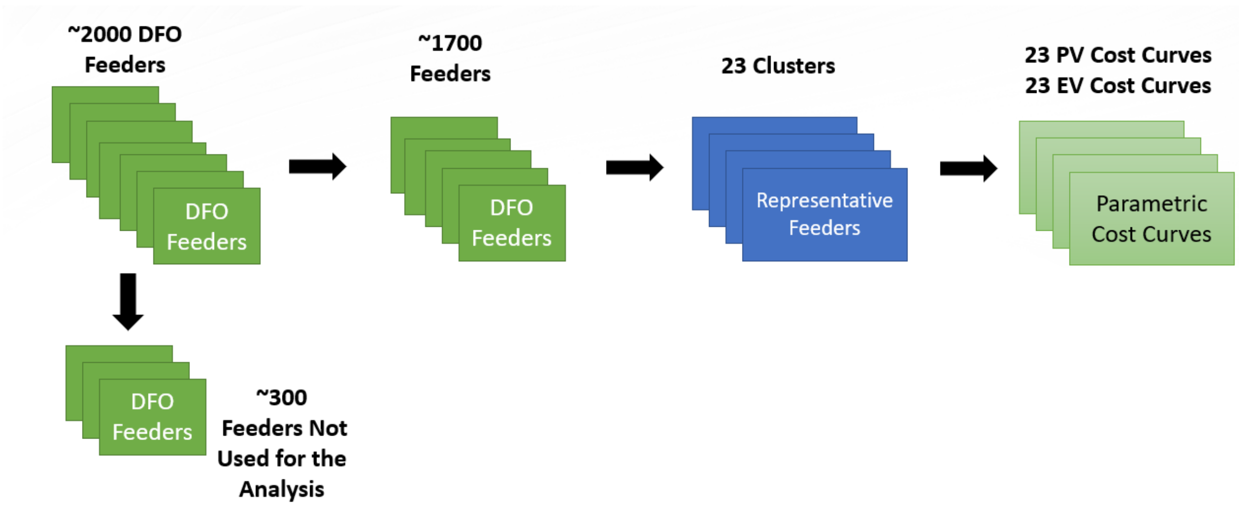
Alberta has seven DFOs with approximately 1900 different distribution feeders, summarized per Table 2.

Table 2. Distribution Feeder Statistics (2022)

DFO	Total Number of Feeders	Total Number of Customers	2022 Peak Load (MW)	Total Feeder Length (km)	Average No. of Customers per km
ATCO	363	252,111	2,175	56,744	4
ENMAX	450	521,828	1,928	9,027	58
EPCOR	305	434,096	1,662	19,642	22
FORTIS	668	605,943	4,167	88,073	7
LETHBRIDGE	51	42,907	243	987	43
MEDICINE HAT	35	32,559	220	758	43
RED DEER	51	-	-	-	-
Total	**1933**	**1,889,444**	**10,395**	**175,537**	**11**

Guidehouse, as per Figure 4, utilized a statistical feeder clustering process to represent these distribution feeders in the study. Approximately 1700 distribution feeders were statistically grouped into 23 representative clusters possessing similar feeder characteristics. The remaining 300 feeders were excluded from the analysis due to being part of a networked urban core distribution system or having zero load or length, typically indicating backup feeders. The derivation of integration cost relied on the use of detailed distribution simulation models to accurately measure the impact of DER at various locations on each DFO feeder.[4] Because of the large number of feeders, a set of feeders that statistically represents the entire population of feeders in Alberta was selected for simulation modeling. A single feeder was selected from each of the 23 representative clusters to best represent all the feeders in that specific cluster. A grid impact analysis was then performed on each of these 23 representative feeders, in order to create 23 distinct PV and EV mitigation cost curves.

Figure 4. Feeder Clustering Process



Sampling Analysis & Feeder Selection

An industry-accepted sampling analysis was applied to statistically group the DFO feeders into the twenty-three (23) clusters[5]. The statistical analysis, commonly referred to as K-Means testing, was used to create feeder clusters with similar properties such as voltage, length, number of customers and average number of customers per kilometer. The feeder with properties closest to the average of the cluster was chosen to represent all other feeders within each of the 23 clusters.

The result of the sampling analysis is presented in Table 3, which summarizes the number of representative feeders selected via the sampling analysis for each DFO.[6] The relatively small number of clusters for ENMAX (2) reflects the lower variability in feeder properties, which for ENMAX tend to be shorter, high load density, and all operating at the same voltage (13.8kV). In contrast, FORTIS has the highest number of representative feeders (8). FORTIS' distribution

[4] The CYME™ Distribution Simulation model is used by each DFO to analyze distribution system impacts and to predict DER impacts for each of the 23 representative feeders.

[5] A cluster is defined as a set of distribution feeders with similar properties as determined by statistical methods.

[6] Each DFO confirmed or recommended a different representative feeder for each cluster to ensure the proposed selection was representative and for which an up-to-date CYME model was available.

system has both the highest number of feeders and greater variability in feeder properties, ranging from short feeders with high load density to very long, low load density feeders with higher distribution feeder operating voltages (i.e., 25 kV).[7]

Table 3. Number of Representative Feeders by DFO

DFO	Total Number of Representative Feeders
ATCO	6
ENMAX	2
EPCOR	5
FORTIS	8
LETHBRIDGE	1
MEDICINE HAT	1
RED DEER	0
Total	**23**

The number of feeders within each of the 23 clusters varies significantly, from a low of 11 (comprised of long feeders serving mostly residential customers) to a high of 202 (very long feeders serving a mix of residential and commercial customers).

Exclusions and Secondary Network Considerations

As indicated, approximately 300 feeders were excluded from the sampling analysis, either due to the absence of data or because of their secondary network configuration.[8] For example, several feeders had zero load or line length – these may serve as back-up feeders that normally do not carry load, and therefore are not candidates for DER. Other feeders had missing data that precluded their inclusion in the sampling analysis. About 175 of the 300 feeders had some missing data so they were excluded from the sampling analysis but were still considered eligible for DER and were therefore included in the cluster groups and assumed to have similar properties and integration cost curves based on the combined average of all other DFO feeders in the cluster. As such, integration costs associated with these 175 feeders were included in the integration cost estimates.

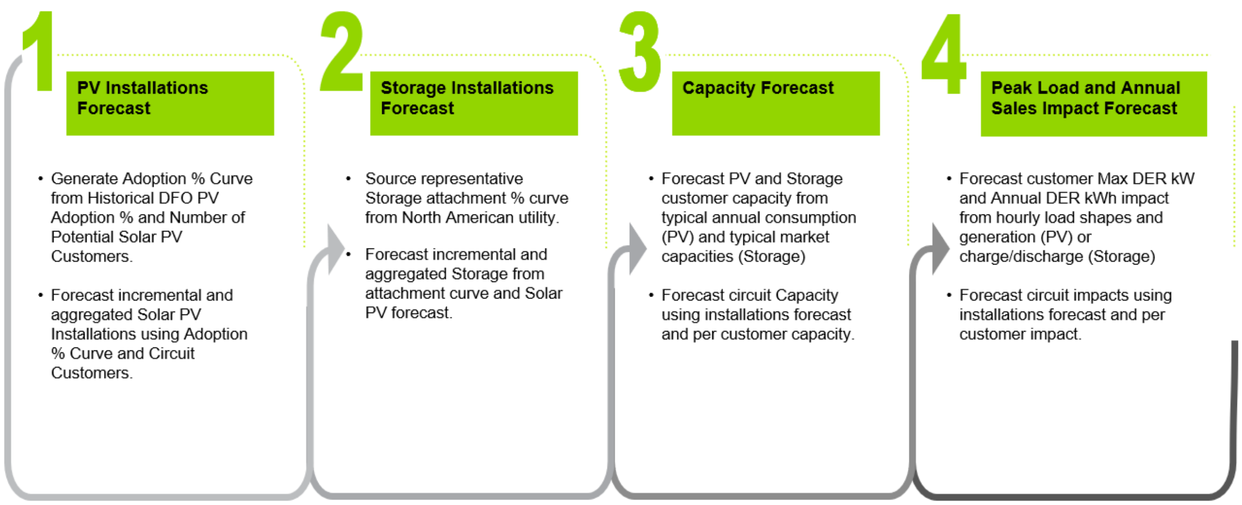
Of the 300 excluded feeders, about 125 feeders serving secondary networks were excluded from the analysis entirely. The network configuration of these feeders and absence of distribution simulation model data resulted in a decision to evaluate DER impacts on these feeders, if needed, in a future report.

[7] Red Deer feeders were excluded from the sampling analysis due to insufficient data. DER integration costs for Red Deer are based on the average of the other six DFOs.
[8] Several of the feeders with missing data needed for the sampling analysis nonetheless were included in the DER forecast. Grid impacts and integration costs for these feeders is derived using the average integration costs of all other DFO feeders included in the sampling analysis.

1.4 DER Penetration Forecast Methodology

Guidehouse utilized a 4-step process, as summarized in Figure 5, to develop the PV and ES penetration forecasts. A more detailed explanation of the forecast methodology can be found in Sections 1.4.2 to 1.4.5. In sequence, the four steps include i) generating PV installation forecasts based on historical data and potential PV customers, ii) obtaining ES customer counts based on PV customer counts and pre-defined storage attachment rates, iii) developing a total PV and ES capacity forecast based on typical system sizes, and iv) forecasting peak demand and consumption associated with these PV and ES counts in order to determine system-level impacts.

Figure 5. Methodology summary for PV Installations Forecast, Storage Installations Forecast, Capacity Forecast, and Peak Load and Annual Sales Impact



1.4.1.1 Customer Segmentation

Table 4 contains 2022 customer counts by segment (commercial, industrial, residential) for each DFO, as provided by the DFOs.

As each customer segment are expected to have different adoption profiles (rates, system size) for the PV, ES, and EV DER technologies, these three different customer segments were forecasted separately utilizing the customer segmentation information in Table 9 as a basis.

Table 4. Customer Counts per DFO for Commercial, Industrial, and Residential Segments

DFO	Commercial	Industrial	Residential
ATCO	63,636	11,992	204,850
ENMAX	35,851	1,722	472,484
EPCOR	34,384	1,706	398,007
FORTIS	73,207	9,598	444,824
LETHBRIDGE	10,139	1,030	31,738
MEDICINE HAT	3,456	7	28,938
RED DEER	3,807	18	33,905

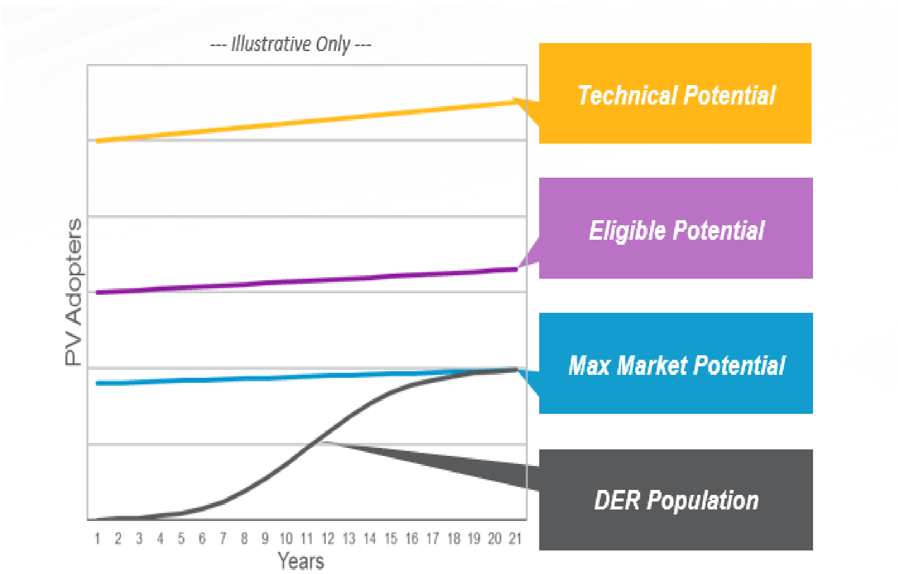
1.4.2 Net-Zero Forecast Methodology for PV Installations

A forecast of solar penetration, guided by a Bass diffusion model, was generated for each DFO and customer sector (Residential, Commercial, and Industrial) during the forecast period from 2023 to 2050.

Guidehouse did not separate between Rural vs. Urban adopters as this information was not available from the DFOs. If available, historical data may show a difference in the solar PV adoption % trends between Rural vs Urban adopters and could have been incorporated into the forecast.

The number of solar PV adopters depends on different technical, financial eligibility and market limitations, as illustrated in Figure 6. These limitations acting sequentially on the full number of utility customers results in a Long Run Market Potential ceiling that serves as the ceiling that bounds the growth of solar PV adoption.

Figure 6. Technical, Eligible and Market Potential



The forecast of solar PV installations is then calculated from the solar PV penetration percentage forecast and feeder circuit customer counts provided by the DFO. This solar PV installation forecast assumes that adoption on each of the DFO's feeder circuits follows a similar trend. The incremental addition of new solar PV installations per feeder circuit is derived from the total number of installations forecast (solar PV population).

The solar historical and adoption limits are represented in Table 5.

Table 5. Solar 2022 Historical Adoption and 2050 Limit in Adoption

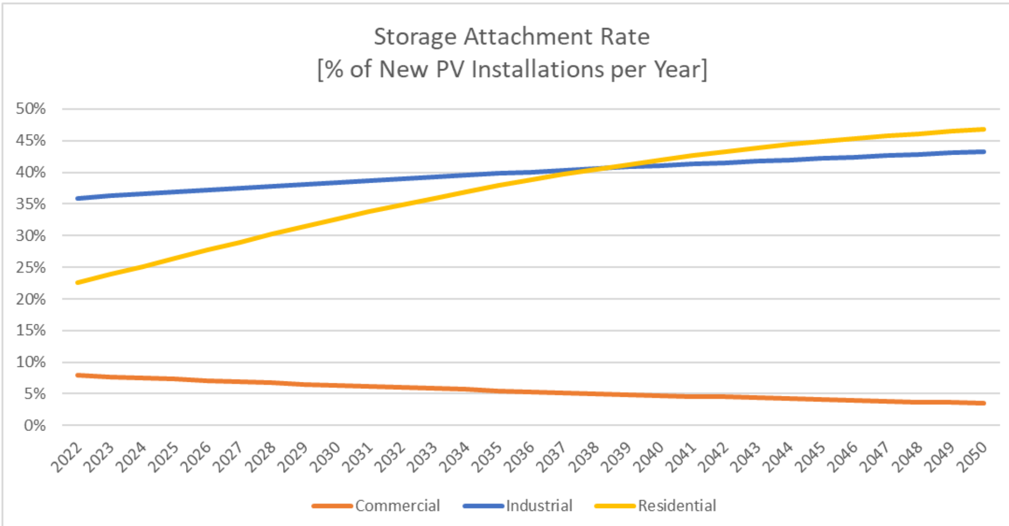
DFO	2022 Historical Adoption (% premises with Solar PV installations) Residential, Commercial, Industrial			2050 Potential Adopters (% premises with Solar PV installations) Residential, Commercial, Industrial		
ATCO	0%	0%	0%	8.3%	8.7%	8.7%
ENMAX	0.7%	0.3%	2.4%	8.3%	8.7%	8.7%
EPCOR	2.3%	1.2%	11.2%	8.3%	8.7%	30%
FORTIS	0.8%	1.2%	15%	8.3%	8.7%	30%
LETHBRIDGE	0.6%	0.5%	0.3%	8.3%	8.7%	8.7%
MEDICINE HAT	1.0%	0.9%	0%	8.3%	8.7%	8.7%
RED DEER	0.2%	0.4%	4.6%	8.3%	8.7%	8.7%

1.4.3 Net-Zero Forecast Methodology for Storage Installations

Instead of forecasting storage adoption independently, ES was forecasted as attached to new solar PV installations. Past Guidehouse engagements with utility companies in the United States have shown storage adoption occurs primarily with a new solar PV installation.

The storage attachment forecast, represented in Figure 7, was sourced from a large midwestern utility company based in the United States and shows the difference in storage attachment rates between the residential, commercial, and industrial sectors.

Figure 7. Storage Attachment Rate Analysis conducted for Midwestern Utility



Guidehouse generated a feeder-level storage forecast using the storage attachment forecast in Figure 7 and the solar PV installations forecast at the feeder level as described in Section 1.4.1.

1.4.4 Net-Zero Forecast Methodology for PV and Storage Capacity

The aggregated/incremental solar PV capacity at the DFO and feeder circuit levels is the aggregated/incremental solar PV population multiplied by the per-system solar PV capacity installed. Table 6 below represents the annual energy consumption per customer type (inferred from the data shared by the DFOs) used for the analysis. For the DFOs for which energy consumption was not provided, an Alberta-wide average based on the consumptions provided by other DFOs, was used.

Table 6. Representative Annual Energy Consumption in kWh (Alberta Average underlined) per Customer Type

DFO	Commercial	Industrial	Residential
ATCO	128,326	21,297,485	6,774
ENMAX	112,549	5,711,344	6,461
EPCOR	193,183	112,652,243	6,142
FORTIS	128,326	21,297,485	6,774
LETHBRIDGE	128,326	21,297,485	6,774
MEDICINE HAT	207,546	30,707,624	7,723
RED DEER	128,326	21,297,485	6,774

Table 7 below indicates the solar and storage system sizes for all DFOs across customer types.

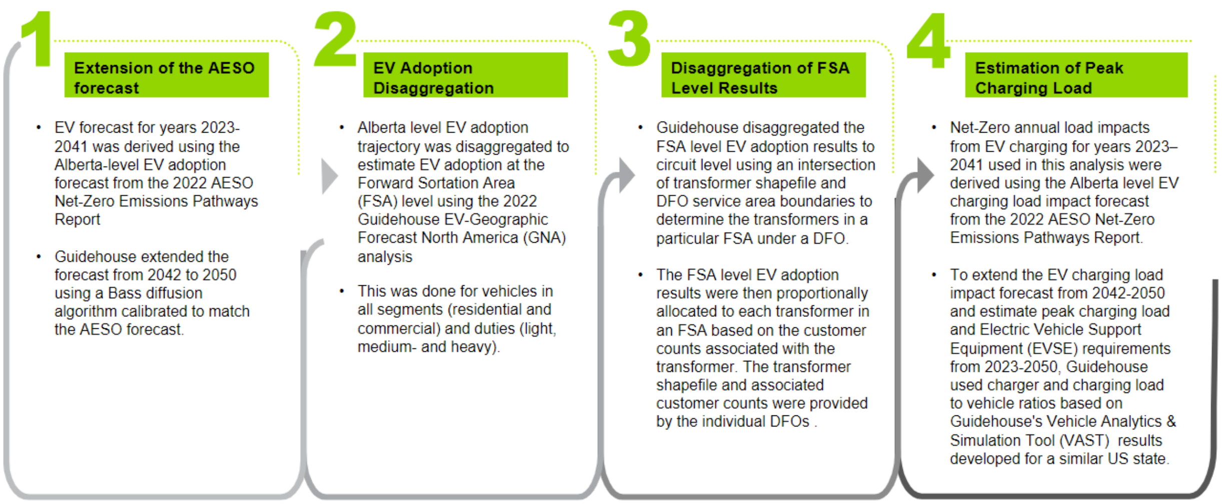
Table 7. Solar PV and Storage System Sizes per Installation

	Solar PV (kW DC)			Storage (kWh)		
DFO	**Commercial**	**Industrial**	**Residential**	**Commercial**	**Industrial**	**Residential**
ATCO	78.0	13,300	4.1	100	100	13.5
ENMAX	64.0	3,300	3.7	100	100	13.5
EPCOR	118.0	70,300	3.7	100	100	13.5
FORTIS	77.0	13,100	4.1	100	100	13.5
LETHBRIDGE	71.0	12,000	3.7	100	100	13.5
MEDICINE HAT	117.2	17,700	4.4	100	100	13.5
RED DEER	77.0	13,100	4.1	100	100	13.5

1.4.5 Net-Zero EV Forecast

Guidehouse utilized a 4-step process, as summarized in Figure 8 , to develop the EV penetration forecasts. A more detailed explanation of the forecast methodology can be found in Appendix B.2.3 EV Forecast Data Application.

Figure 8. Net-Zero EV Forecast Steps



1.5 Grid Impact Analysis and Mitigations

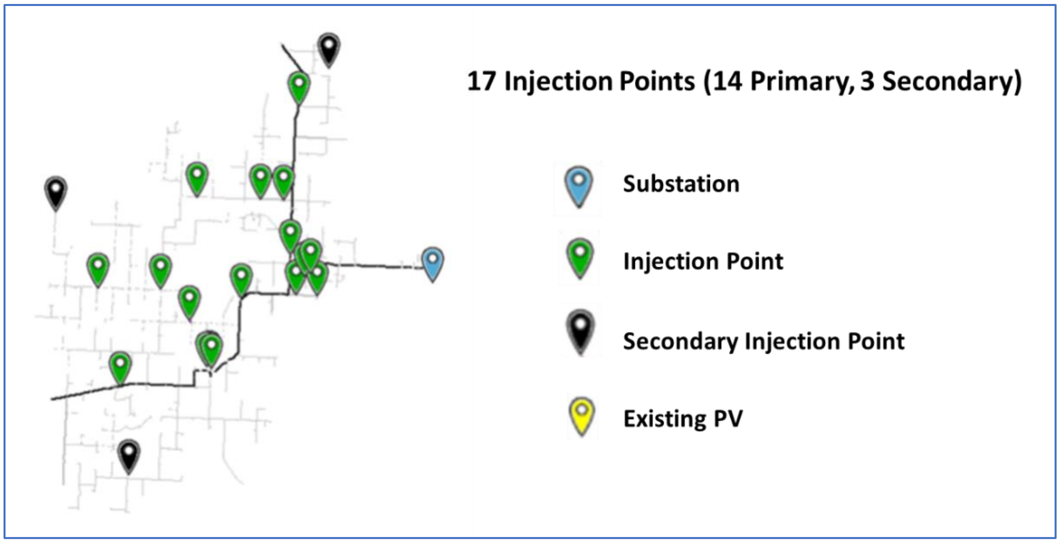
1.5.1 Grid Impact Analysis

Distribution feeder violations resulting from DER penetration growth were identified via power system simulation modeling of the 23 representative feeders using CYME. The DFOs provided their most current CYME model database for each of the 23 feeders for the analysis.

The CYME models were updated to include PV and EV additions up to the full rating of the distribution feeder. Because of the large number of PVs and EVs projected to be installed over the study horizon, it was necessary to allocate DER capacity at pre-determined injection points on both the main and lateral feeder sections. A spreadsheet model designed to identify the minimum number of DER injection points was used to identify the number, location, and size of DER injection points in the CYME simulation model for each representative feeder. The location and number of injection points remains the same for the increasing amounts of PV capacity and EV charging demand forecasted.

Figure 9 illustrates the number and location of DER injection points for a typical feeder, assuming a minimum DER integration of 350 kW per location. For CYME modeling, the location of PV and EV injection points are assumed to be located on the same node even though the amount of PV and EV in kW is increased based on the separate EV and PV forecasted adoption rates for each year in the study horizon.

Figure 9. Representative Feeder DER Injection Locations (ATCO 5L165)



CYME Simulation Modeling Approach

To forecast DER impacts on the 23 representative feeders, increasing amounts of PV and EV capacity are modeled in CYME. Up to six capacity levels are modeled, from 0% up to 100% of the feeder rating.[9] For each capacity level, distribution performance criteria violations are identified and upgrades are modeled in CYME in amounts sufficient to mitigate the violation.

Distribution performance criteria includes steady state voltage violations (over and under voltages) and feeder overloads, with limits consistent with the planning criteria and standards applied by each DFO. In general, most PV violations are over-voltages located on nodes at the end of the longest feeder laterals at the time of maximum PV output during light load conditions. Conversely, most EV violations are feeder or lateral section thermal overloads caused by incremental EV charging during peak or near-peak conditions.

The following set of assumptions were applied when modeling the representative feeders in CYME, consistent with current DFO planning criteria:

1. All CYME models for representative feeders include separate forecasts for PV and EV.

2. A "worst case" screening analysis is performed on the representative feeders to identify those that do not require mitigation of DER impacts during the study horizon.

[9] The maximum allowable DER capacity is limited by DFO capacity planning criteria, which may be below feeder ratings, as substation and feeder ties are used to meet n-1 contingency criteria for some DFOs (e.g., ENAMX and EPCOR.

3. CYME simulations and parametric cost curves for PV and EV are developed separately. Solar peak output is assumed to occur with zero EV charging and vice-versa.

4. A minimum of six PV and EV adoption levels are simulated in the CYME model to create parametric cost curves (excluding those that screened out as described in 2. above).

5. Steady state violations occur when thermal or voltage limits are exceeded per CYME model inputs.

6. Reverse power is allowed on distribution feeders and substation transformers; reverse power is not constrained by transmission protection requirements.

7. Minimum mid-day load is assumed to be 50 percent of the feeder peak for all feeders, unless otherwise specified by the DFO[10].

8. Secondary voltage drop analysis included for selected locations (e.g., end of feeder). Up to 8 locations per feeder, with 50-to-60-meter service drops, 25kVA to 37.5 kVA XFMR and 10kW Solar PV[11] were studied.

9. DER interconnection costs are excluded from the analysis as they are borne by the proponent and not by the DFO.

1.5.1 Conventional Mitigation Solutions

When performance violations resulting from the integration of DER are encountered in the CYME distribution simulation modeling process, the least cost conventional mitigation solution using currently available technologies was selected. Table 8 presents the list of conventional options available to mitigate distribution feeder performance violations.

[10] EPCOR confirmed a minimum mid-day load of 30% applies to each feeder on their distribution system; all other DFOs are assumed to have a minimum mid-day load equal to 50% of the feeder peak.

[11] Modeling of secondary services in CYME is essential to ensure potential voltage violations are identified due to voltage rise on BTM PV installations.

Table 8. Conventional Mitigation Solutions

Grid Mitigation Strategy	Mitigation Description	Mitigation Cost (Rural)	Mitigation Cost (Urban)	Unit
Reconductor Overhead - 1 Phase	Rating based on DFO standard	$12,000 - $100,000	$200,000 - $305,000	Per km
Reconductor Overhead - 3 Phase	Rating based on DFO standard	$40,000 - $155,000	$305,000- $450,000	Per km
Feeder Reconfiguration	Transfer 3-line segments	$10,000	$10,000	Each
New Dist. Feeder - Spare Bay	New substation bay & feeder	$1,000,000	$1,000,000	Feeder
New Dist. Feeder – Up to 50km	New line	$6,500,000	$6,500,000	Each
New Dist. Feeder – Up to 25 km	New line	$3,500,000	$3,500,000	Each
New Dist . Feeder – Up to 10 km	New line	$1,500,000	$1,500,000	Each
New Recloser	3 phase programmable	$75,000	$100,000	Each
Replace 1 Phase Underground Cable	500 mcm copper	$275,000	$275,000 - $600,000	Per km
Replace 3 Phase Underground Cable	750 mcm copper	$435,000 - $475,000	$475,000 - $1,000,000	Per km
New 1 Phase Underground Cable	500 mcm copper	$800,000	$800,000	Per km
New 3 Phase Underground Cable	750 mcm copper	$1,800,000	$1,800,000	Per km
New Regulator (3 Phase)	3 phase bank	$150,000 - $280,000	$235,000 - $460,000	Each
New Regulator (1 Phase)	Single phase bank	$75,000	N/A	Each
New Exit Feeder (Underground)	3 Phase 750 MCM copper	$100,000	$100,000	Each

Table 8 includes urban (e.g., ENMAX, EPCOR) and rural (e.g., ATCO and Fortis) costs to reflect differences in planning and design standards, equipment selection and locational differences, labor/construction costs, and other DFO-specific cost factors. All costs are adjusted annually by 2% to reflect cost escalation.

The cost of the feeder mitigations required at each of the six capacity levels are tracked to create parametric cost curves, which are further described in the following section. Because PV output reduces feeder demand, PV capacity up to 100% of the feeder rating is modelled in CYME, whereas EV charging is added up until the maximum feeder loading is reached. A new feeder is assumed to be added when EV capacity, plus load, exceeds the feeder capacity planning limit.[12]

Distribution system upgrades and associated costs are derived annually based on the year-by-year DER adoption levels described in sections 1.4.2 - 1.4.5. Appendix B provides a detailed description of the methods and assumptions used to conduct the grid impact analysis.

[12] The cost of a new feeder includes the cost of the substation bay, the exit feeder and between 5 and 25 km of main line feeder, depending on the length of the main line feeders.

1.5.2 Optimized Mitigation Solutions

As an alternative to conventional mitigation solutions, "non-build" solutions such as behind-the-meter (BTM) solutions and incentive rates were evaluated to determine the extent to which optimized solutions can reduce DER integration costs. Five optimized mitigation solutions were evaluated as described below.

1. **Paired Energy Storage** – This option applies primarily to PV, under the assumption that energy storage is installed at the same location as the customer's PV.[13] The energy storage device would be programmed to absorb PV output during maximum output or light load periods and discharge during periods of high distribution feeder demand. Incentives rates or credits may be applied to increase participation.

2. **Time-of-Use (TOU) Rates** – The TOU option applies primarily to EV, under the assumption that EV owners will be incentivized to charge vehicles during periods of low rates, which would align with periods of low distribution feeder demand. The TOU program could apply to both on-premise and distributed charging stations. This program could also be combined with the Paired Energy Storage program.

3. **Managed Charging (MC)** – The MC option enables the utility to directly control EV charge and discharge timing in order to minimize impacts on feeder loading during periods of higher demand. The charge and discharge profiles are expected to be comparable to those under the TOU program.

4. **Demand Response (DR)** – The DR option applies primarily to EV, under the assumption that distribution feeder overloads only occur during a relatively small number of hours. Hence, DR programs could be structured to incentivize customers to participate, as the number of DR events could be capped with modest incentive payments to participants. The DR program could also be combined with the Paired Energy Storage program.

5. **Energy Efficiency (EE)** – The EE option applies primarily to EV, under the assumption that EE programs could be designed to reduce demand at the time of the feeder peak, including peak times that have shifted due to high EV charging demand during shoulder hours. The EE options is considered less cost effective than TOU or DR due to the level of EE participation (and program incentives) that is needed to materially reduce feeder peak demand and eliminated from further consideration as a solution.

Table 9 presents the assumptions and methodology used to derive PV and EV integration costs for the optimized scenario.

Three mitigation options were evaluated to mitigate EV charging impacts. The first, Time-of-Use rates (TOU), assumes that EV owners will adjust charging patterns based on higher on-peak and lower off-peak electricity rates. A recent ENMAX study informed the assumptions applied. The second, Managed Charging, is comparable to TOU, both in terms of the on and off-peak pricing

[13] For example, energy storage could be installed concurrent with PV to reduce the cost of the inverter.

differential, and percent reduction in EV charging during the feeder peak, and therefore was not evaluated separately from TOU. The third, Demand Response (DR), applies to all DFO customers, and is premised on the assumption that a DR program would be established with a goal of feeder peak demand reduction when EVs are in charge mode. The results of a recent ACEEE study informed assumptions applied.

For PV, one mitigation option was applied - the pairing of energy storage in an amount equal to the rated PV capacity. Energy storage is assumed to be fully discharged at the time of the maximum PV output, thus reducing net output to zero with no impact on feeder performance or violations.

Table 9. Optimized Mitigation Solutions

Systemic Mitigation Strategies	Mitigation Description	Additional Considerations	Cost Considerations
Implement TOU Rate Structure	• Increasing off peak charging by 1.5x from a reward of 3.2 cents per kWh. Assume no incentive is provided to customer, as all customers with EVs are charged under the TOU rate. Only program management expenses are included in integration cost totals. • Assumes 35% reduction in on-peak charging • Applies to EV only	• Structured so the non-participants are not negatively impacted, and TOU billings are revenue neutral. Assumes TOU rates are the same as Managed Charging. • Informed by ENMAX EV Pilot + **McKinsey Study**	• TOU tariff applies to all customers with EVs. Tariff could apply to all residential and commercial customers in later years when high adoption rates occur. • Assumed to be revenue neutral with no incentives paid to EV owners. • Program costs include program administration by DFO (ramping up to $10 million annually by 2050 from less than $1 million in 2022)
Managed Charging	• Similar peak reduction is expected from the TOU rate structure • Utility-driven as opposed to consumer-driven. Only program management expenses are included in integration cost totals • Applies to EV only	• Utility is responsible for managing EV charge and discharge intervals. • Similar results achieved from TOU informed by **IEEE Study**	• Similar to the TOU program. Managed Charging assumed to be required absent direct incentives. • Incorporated into TOU analysis with 35% maximum reduction in coincident EV output at the hour of the feeder peak.
Load flexibility/Demand Response	• Assumes 8% feeder peak load reduction as a target. • Applies to EV only	• Applicable to EV, as the highest peak occurs less than 0.4% of the time. • Informed by **ACEEE Study**	• Assumes a nominal payment (cost) included in TOU program administrative cost described above.

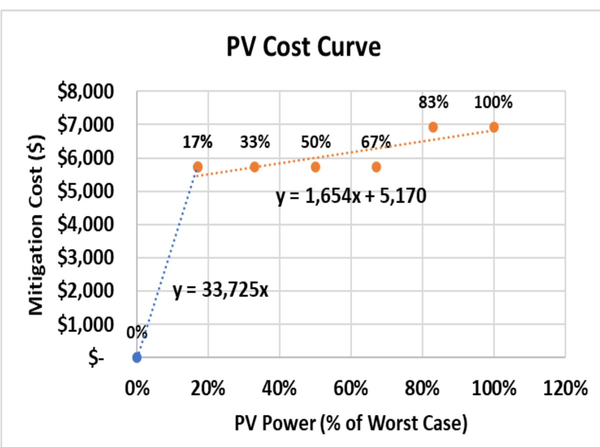
BTM Storage-paired PV	• Current assumption for Net-Zero is 50% storage attachment for PV systems by 2050. • Storage attachment increased to 75% by 2050 under Net-Zero optimized. • No additions are included in integration cost totals, as paired solar and storage are assumed to be driven by market economics. • Applies to PV only	• Guidehouse assumption for-proposed scenario. No sources provided to support long-term solar, and storage forecast for Optimized scenario.	• Paired PV and storage assumed to be market driven, with no additional costs or incentive from DFOs. • Incentives, if any, are provided by federal or provincial entities.

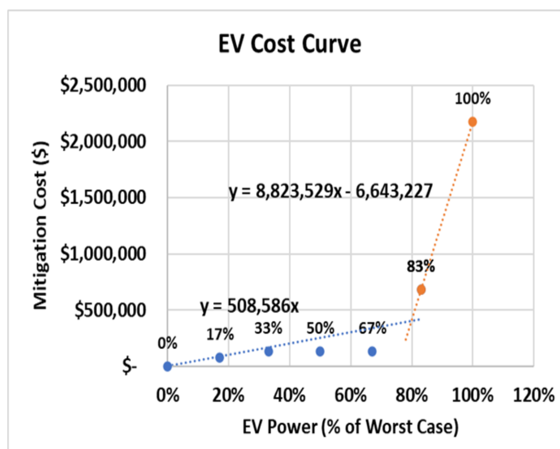
Note. Guidehouse has considered technology-centered mitigation strategies (e.g., implementation of centralized smart-invertor control), but they are immature in the industry and the operational and capital costs associated with communication and centralized control systems are substantial. As a result, these will likely not have a significant benefit in reducing the estimated grid impacts at this point in time, but Guidehouse suggests re-evaluating these strategies in a few years.

Parametric PV and EV Cost Curves

The modeling of representative feeders using CYME for increasing amounts of DER, when combined with the cost of distribution feeder upgrades to mitigate performance violations, provides information that can be used to forecast PV and EV integration costs. For each representative feeder, parametric cost curves are created for PV and EV for capacity levels up to 100% of the feeder ratings. Using a 2-part linear curve fit, equations that calculate the cost of feeder upgrades as a function of PV and EV capacity additions are developed. Figure 10 presents PV and EV cost curves and associated equations for a representative distribution feeder.

Figure 10. PV and EV Cost Curves (Fortis 325S – 193LN)





The equations associated with the parametric cost curves for each representative feeder are then used to determine PV and EV integration costs for each feeder within each cluster – i.e., the same costs curves are applied to every distribution feeder in the cluster. A separate cost model calculates annual integration costs for PV and EV to year 2050. The equations are valid up to the maximum normal feeder rating. If EV charging capacity plus load (escalated annually based on percent load growth) exceeds the feeder planning capacity limit, a new feeder is added to mitigate the violation. Additional detail on the costing analysis approach and assumptions is provided in Appendix B.7 Feeder Cost Model and DER Integration Costs.

Solar PV & EV integration costs are derived for the Net-Zero and Net-Zero Optimized PV and EV adoption forecasts presented in Section 2. Results of the analysis are presented in Section 3. The results of the distribution feeder cost analysis are combined with the cost of secondary transformer replacements described below to derive total PV and EV integration costs.

1.5.3 Secondary Transformer Analysis

Secondary transformers are the last transformers on the distribution feeders that supply the customer premises. A high-level approach was applied to estimate the quantity and cost of secondary transformers requiring replacement as a result of overloading due to EV charging. Unlike the EV distribution feeder analysis (where transformers are subject to numerous EV charging profiles, and therefore low coincidence factors), secondary transformer loadings were derived based on the higher nameplate ratings for EV (high coincidence factor for EVs) - as shown in Appendix D.2 Detailed Study Assumptions (Internal). Further, because charging diversity results in incremental loading well below the total installed EV charge rating, the impact of EV chargers on individual transformers can be significant, particularly on small transformers that serve one or a small number of customers. Each of these transformers will experience incremental loading at or near the rated capacity of the EV charger(s).

An overview of the process followed to conduct the secondary transformer analysis can be found in Figure 11.

Figure 11. Overview of Secondary Transformer Analysis (Example)

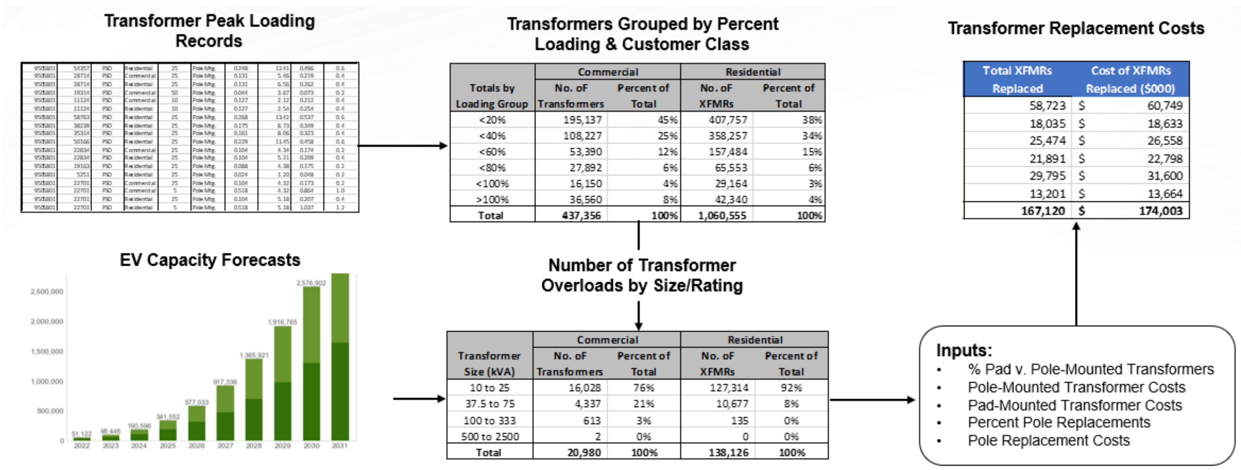


Table 10 lists the number of transformers, aggregate MVA and average transformer rating for secondary transformers serving residential and commercial load.[14] The table excludes transformers serving industrial load or other customer classes as they are assumed to have zero PV and EV additions, in this analysis. The average transformer rating serving residential and commercial load for each DFO varies based on their respective equipment and design practices and standards.

Table 10. Distribution Transformers by DFO

DFO	Number	Transformer Rating (MVA)	Average Rating (kVA)
ATCO	79,383	1,652	21
Residential	61,695	457	7
Commercial	17,688	1,194	68
ENMAX	43,454	2,501	58
Residential	12,740	1,970	155
*Commercial**	30,714	531	17
EPCOR	30,270	2,494	82
Residential	23,852	1,157	48
Commercial	6,418	1,337	208
FORTIS	169,528	7,135	42
Residential	134,346	3,867	29
Commercial	35,182	3,268	93
LETHBRIDGE	0	-	-
Residential	0	No Data	No Data

[14] The number of transformers listed in Table 10 are lower than actual quantities due to the exclusion of network transformers (EPCOR and ENMAX) and transformers rated below 10 kVA, the latter of which is assumed to be unlikely candidates for EVs.

Commercial	0	No Data	No Data
MEDICINE HAT	3,637	265	73
Residential	2,749	109	40
Commercial	888	156	176
RED DEER	0	-	-
Residential	0	No Data	No Data
Commercial	0	No Data	No Data
TOTAL	**326,272**	**14,048**	**43**
Residential	**235,382**	**7,560**	**32**
Commercial	**90,890**	**6,488**	**71**

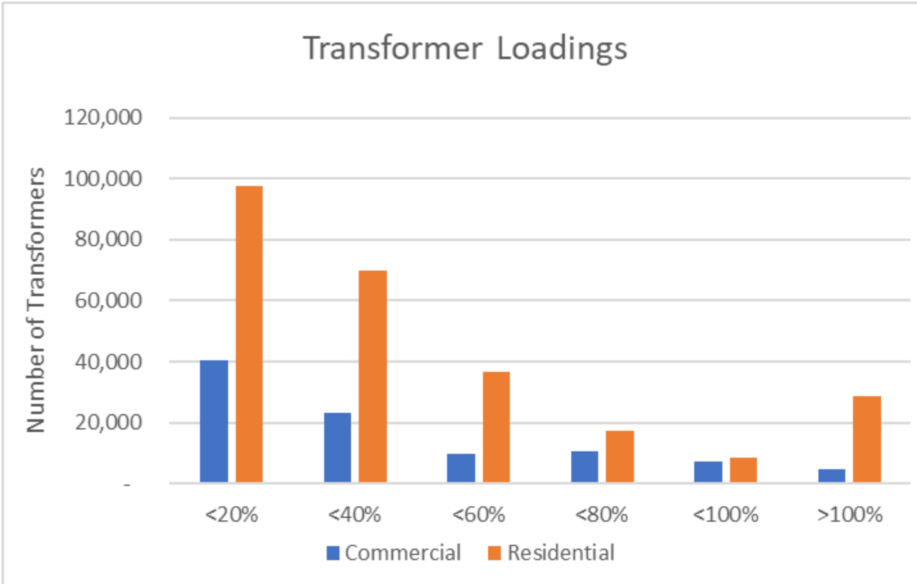
** ENMAX's 37.5KVA transformers were treated as commercial sector transformers.*

Because EV forecasts are at the feeder level, it was not possible to predict EV loadings on individual transformers. However, both the quantity and rating of EV chargers (EVDC, Level 1 and Level 2) are forecasted annually for each DFO. These EV charger adoption forecasts, when combined with the number of transformers by rating and by customer, yields sufficient information needed to predict incremental EV loadings and resulting overloads on secondary transformers within each transformer rating class. The analysis accounts for EV loading diversity on transformers serving multiple customers, such as those connected to several residential customers. The cost of transformer replacements is based on the product of the number and cost of pole-mounted and pad-mounted transformers within each transformer rating class that are overloaded due to EV charging for each year to 2050.

Figure 12 provides the number of transformers by DFO based on six categories of transformer loading. The six loading categories are structured such that all transformers with loadings below the loading threshold are assumed to have a peak demand equal to the threshold. For example, approximately 60,000 transformers serving residential customers with a peak load between 21% and 40% are assumed to have a peak load equal to 40% of the transformer rating.[15] The creation of loading profiles using a range of 20% was applied to capture likely variability in transformer loadings over time and to simplify the logic for determining the number of transformer overloads caused by incremental EV load. The number of transformer overloads (e.g., replacement with higher rated devices) is derived by adding the incremental EV loading, both at the time of the transformer peak as well as off-peak, using the EV adoption forecast described in Section 1.4.5.

[15] Transformers loaded above 100% of rated capacity are assumed to have higher loading limits – for example, devices with very short peaks – or already are overloaded.

Figure 12. Transformer Loading Profile



2 Forecast Results

2.1 PV Penetration

PV penetration is defined as the number of solar PV installations as a percentage of customer count. For DFO's with historical data, historical solar penetration was used to model a forecasted adoption curve for solar PV. Table 11 provides the solar penetration values by DFO and customer segment used for 2022 and 2050.

Table 11. Solar penetration by DFO and customer segment in 2022 and 2050

DFO	2022 Historical Adoption			2050 Adoption Limit		
	Residential	Commercial	Industrial	Residential	Commercial	Industrial
ATCO	0%	0%	0%	8.3%	8.7%	8.7%
ENMAX	0.7%	0.3%	2.4%	8.3%	8.7%	8.7%
EPCOR	2.3%	1.2%	11.2%	8.3%	8.7%	30%
FORTIS	0.8%	1.2%	15%	8.3%	8.7%	30%
LETHBRIDGE	0.7%	0.3%	2.4%	8.3%	8.7%	8.7%
MEDICINE HAT	0.8%	1.2%	15%	8.3%	8.7%	8.7%
RED DEER	0.2%	0.4%	4.6%	8.3%	8.7%	8.7%

Figure 13 provides the resulting net annual GWh impact for PV from 2023 to 2050, based on the forecasted PV growth during this time period.

Figure 13. Net Annual Impact – PV

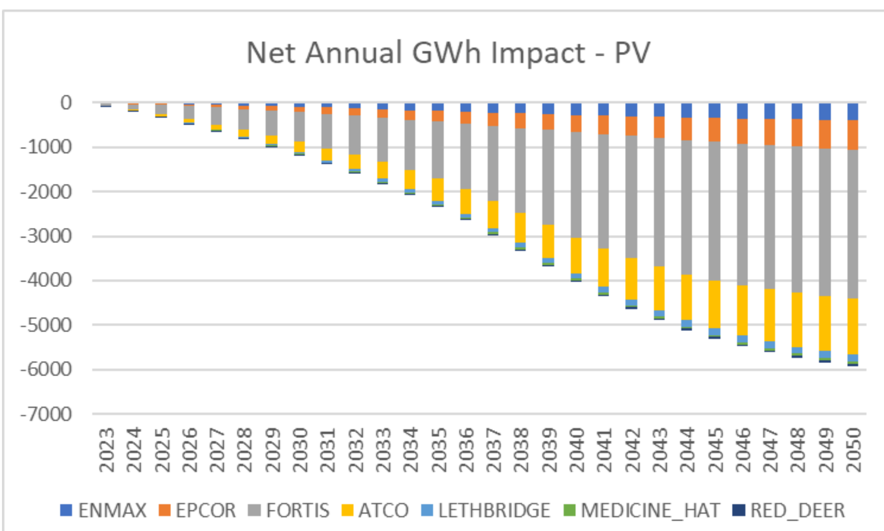
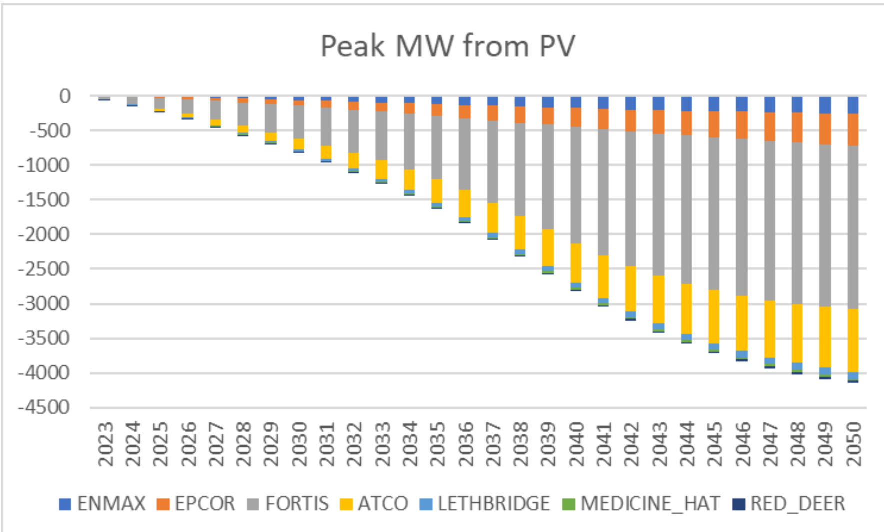


Figure 14 provides the resulting peak MW impact for PV from 2023 to 2050, based on the forecasted PV growth during this time period.

Figure 14. Peak MW from PV



2.2 EVSE Penetration

The annual load impacts from EV charging are calculated using the number of electric vehicles forecasted, annual vehicle miles traveled, weather-varying fuel efficiency for each vehicle, and the load shape associated with each charger by technology and use case. These values along with baseline normalized charging load shapes pertaining to specific charging use cases like residential, workplace, market, and fleet-depot are also used to develop monthly synthetic 24-hour weekday/weekend load shapes and calculate the annual peak EV charging load. Guidehouse used per vehicle annual energy consumption and peak load impact values derived from a previously conducted analysis for a similar US region.

Figure 15 and Figure 16 outline the adoption of EV chargers and EVs in Alberta between 2023 and 2050 for the residential sector (counts per customer and total counts, respectively).

Figure 15. EV Penetration Per Customer – Residential Customer Segment

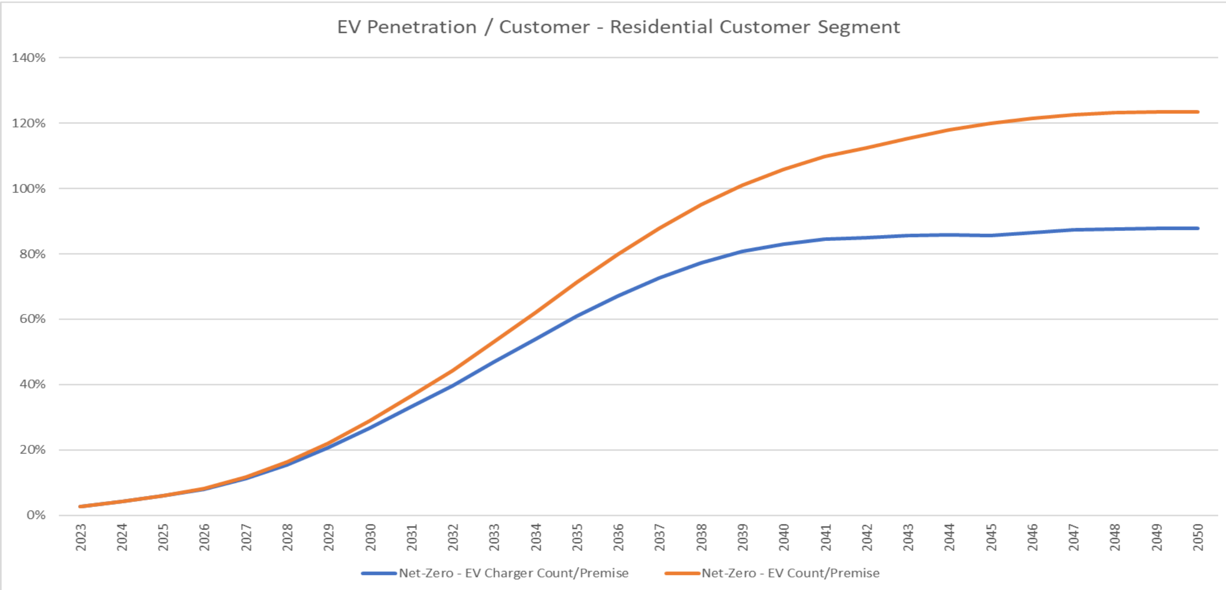


Figure 16. EV Penetration – Total Counts – Residential Customer Segment

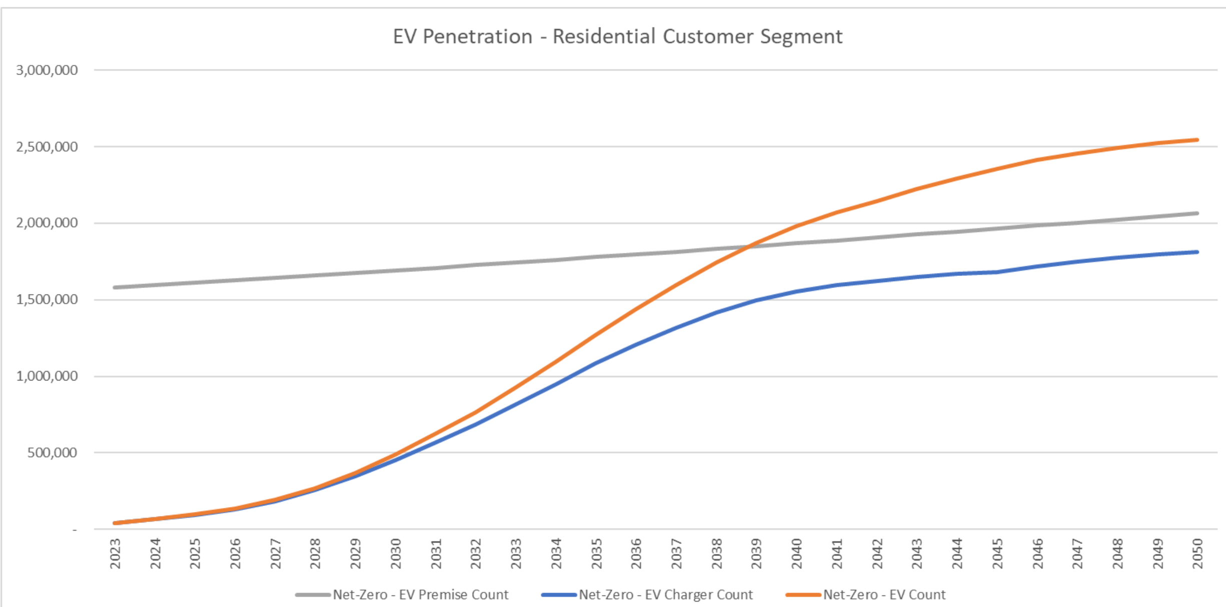


Figure 17 and Figure 18 outline the adoption of EV chargers and EVs in Alberta between 2023 and 2050 for the residential sector (counts per customer, and total counts, respectively).

Figure 17. EV Penetration Per Customer – Commercial Customer Segment

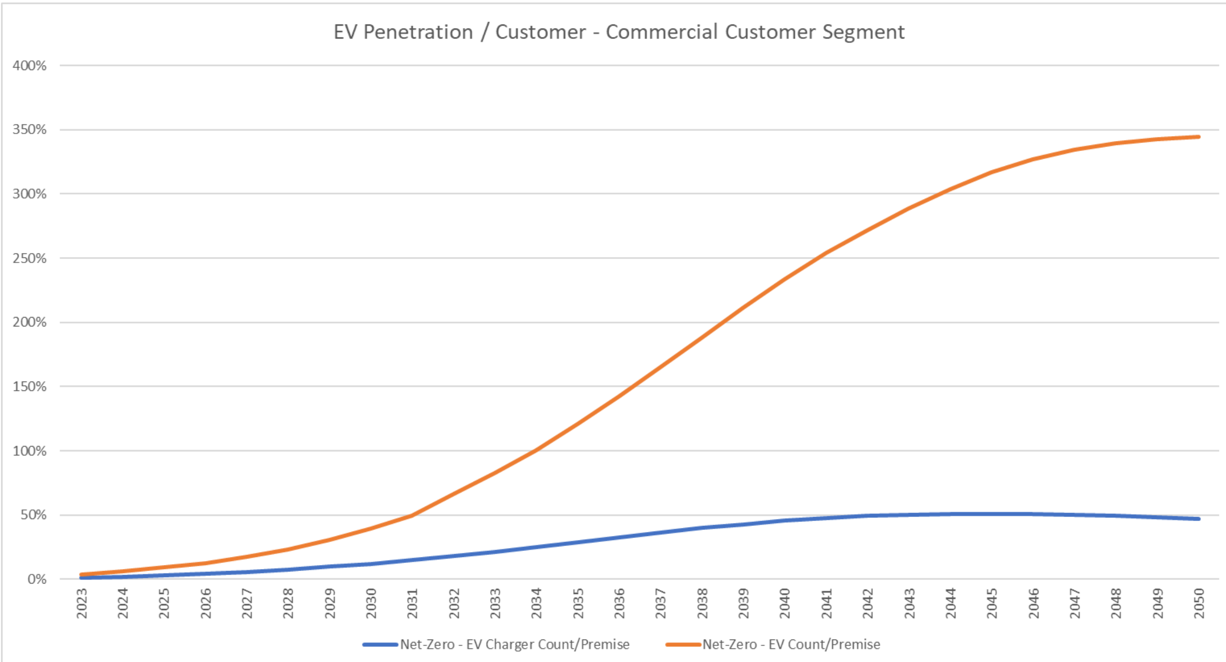


Figure 18. EV Penetration – Total Counts – Commercial Customer Segment

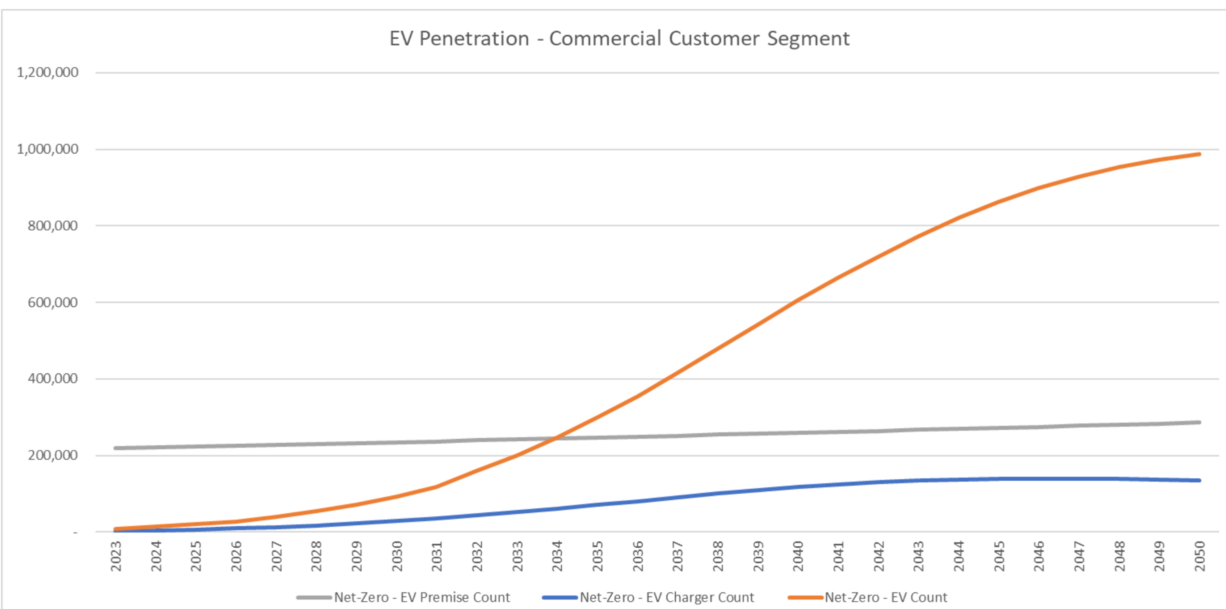


Figure 19 forecasts that EVs will require approximately 18,000 GWh additional charging energy annually in Alberta by 2050.

Figure 19. Net Annual GWh Impact - EV

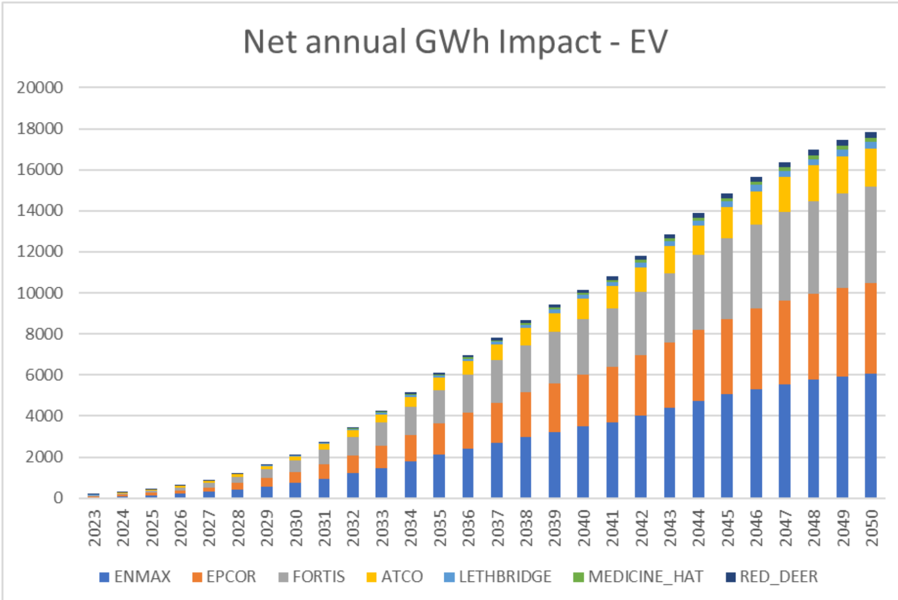
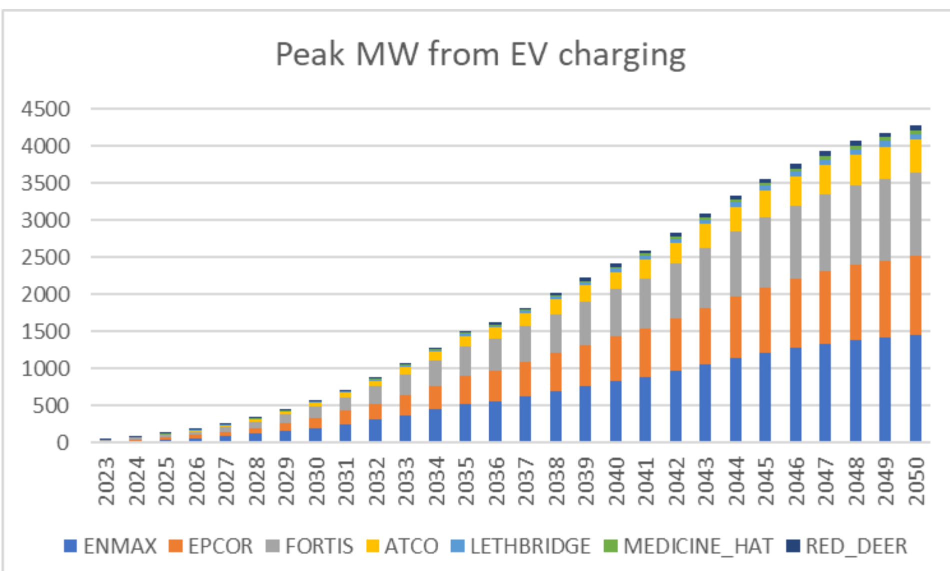


Figure 20 shows that EVs are expected to add approximately 4.2 GW to the peak demand in Alberta by 2050.

Figure 20. Alberta-wide Forecasted Peak Load (MW) from EV Charging

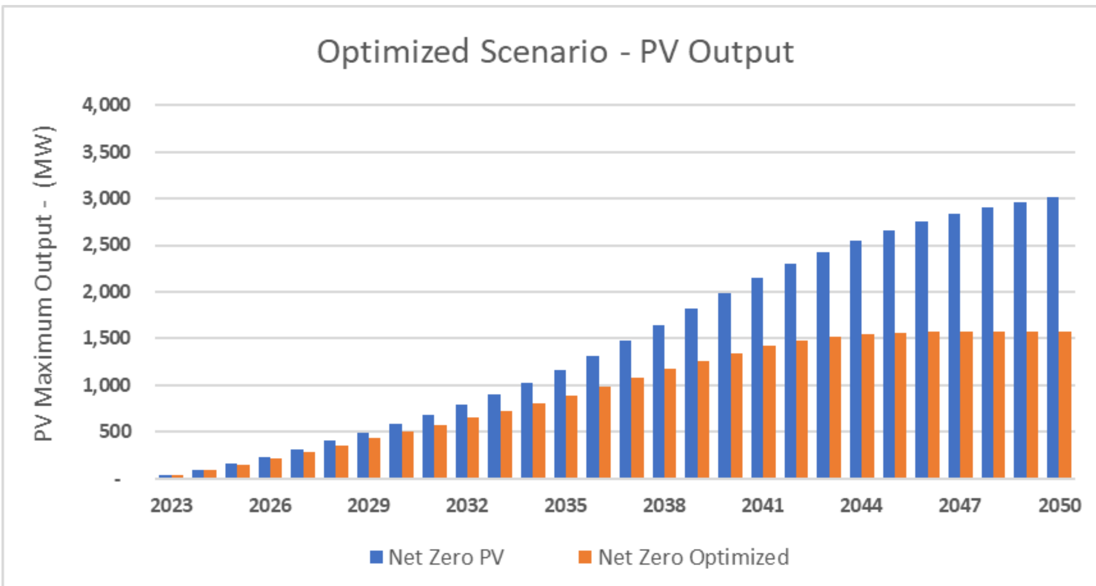


2.3 Net-Zero Optimized – PV Paired with ES

Given the uncertainty[16] associated with the likelihood that customers purchasing PV will elect to simultaneously purchase energy storage (e.g., paired battery storage utilizing a single inverter), the potential associated optimization in PV integration costs is highly variable. The analysis herein assumes that by 2050, sufficient incentives will become available such that virtually all new PV owners will purchase energy storage systems along with PV in 2050.

Figure 21 presents the cumulative PV maximum output for both the Net-Zero and Net-Zero Optimized scenarios.

Figure 21. Cumulative PV Maximum Output for the Optimized and Net-Zero Optimized Scenario



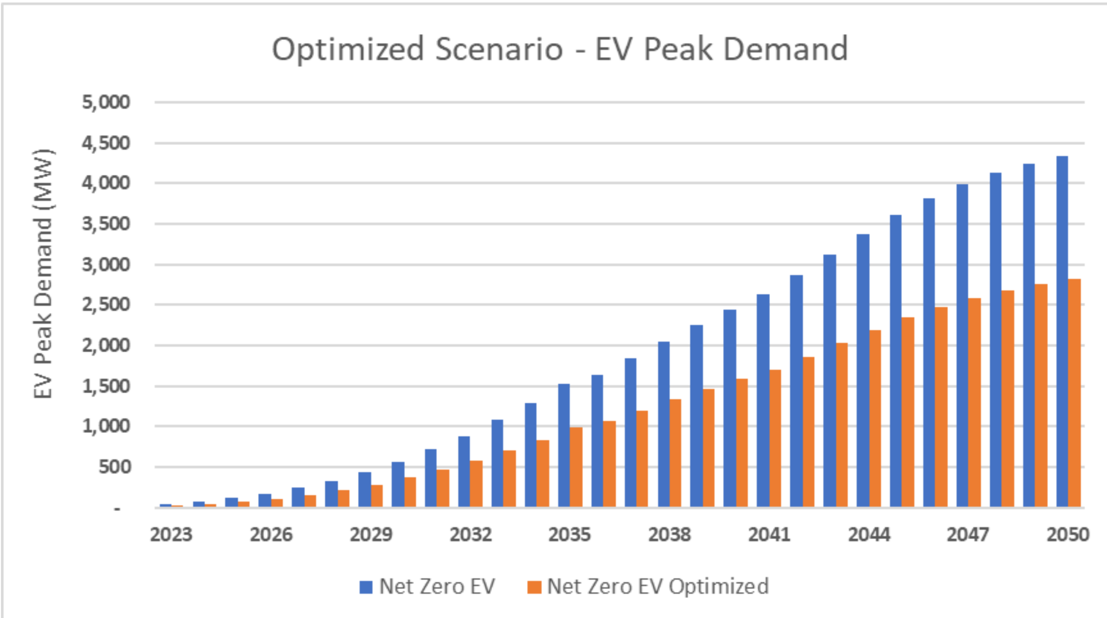
2.4 Net-Zero Optimized – Time-of-Use and Demand Response Programs

Two rate incentive programs were evaluated as non-build alternatives. The first, Time-of-Use (TOU), is designed to encourage EV owners to charge during off-peak hours using price signals within rates. The second, Demand Response (DR), is designed to reduce distribution feeder loading during periods of high demand.

[16] For example, provincial policies, purchase incentives, and ES cost reduction due to economies of scale and worldwide demand, each of the factors has the potential to materially impact customer purchasing decisions.

Figure 22 presents cumulative EV maximum demand at the time of the feeder peak for both the Net Zero and Optimized Net-Zero scenarios.

Figure 22. Feeder Peak Cumulative EV Maximum Demand for the Net-Zero and Net-Zero Optimized Scenario



3 DER Integration Costs

This section presents annual integration costs based on forecasts outlined in Section 2 over the study horizon for the entire population of distribution feeders. Results are presented separately for PV and EV for the Baseline, Net-Zero and Net-Zero Optimized scenarios. Integration costs are presented separately for feeders and distribution transformers, and on a combined basis for the Net-Zero and Net-Zero Optimized scenarios.

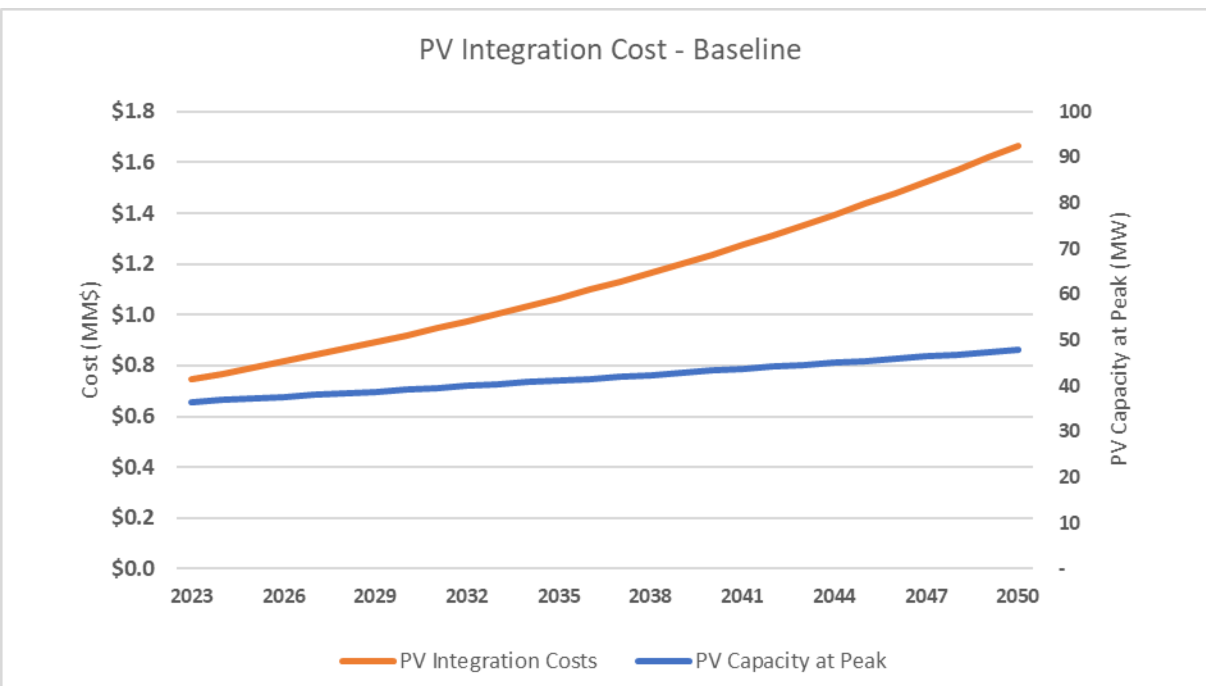
In the charts below, the MW values for EV charging capacity are lower than those presented in Section 2 as they are coincidental values, reflecting the diversity of charging patterns for EV that occur at the time of the feeder peak. The MW values for EV in Section 2 are nameplate values, exclusive of reduced values when charging diversity is considered. Similarly, MW capacity values for PV in the charts below are slightly lower as PV output at the time of the mid-day feeder peak is lower than maximum output values. Tables with numerical values of these results are available in Appendix C.

3.1 Baseline

3.1.1 PV

Figure 23 presents annual PV integration costs for the Baseline scenario. Integration costs are low due to the modest adoption rates over the entire study horizon and low mitigation costs under the 1% growth assumption for PV and EV. Values for the Net-Zero and Net-Zero Optimized scenarios are incremental to values presented for the Baseline scenario.

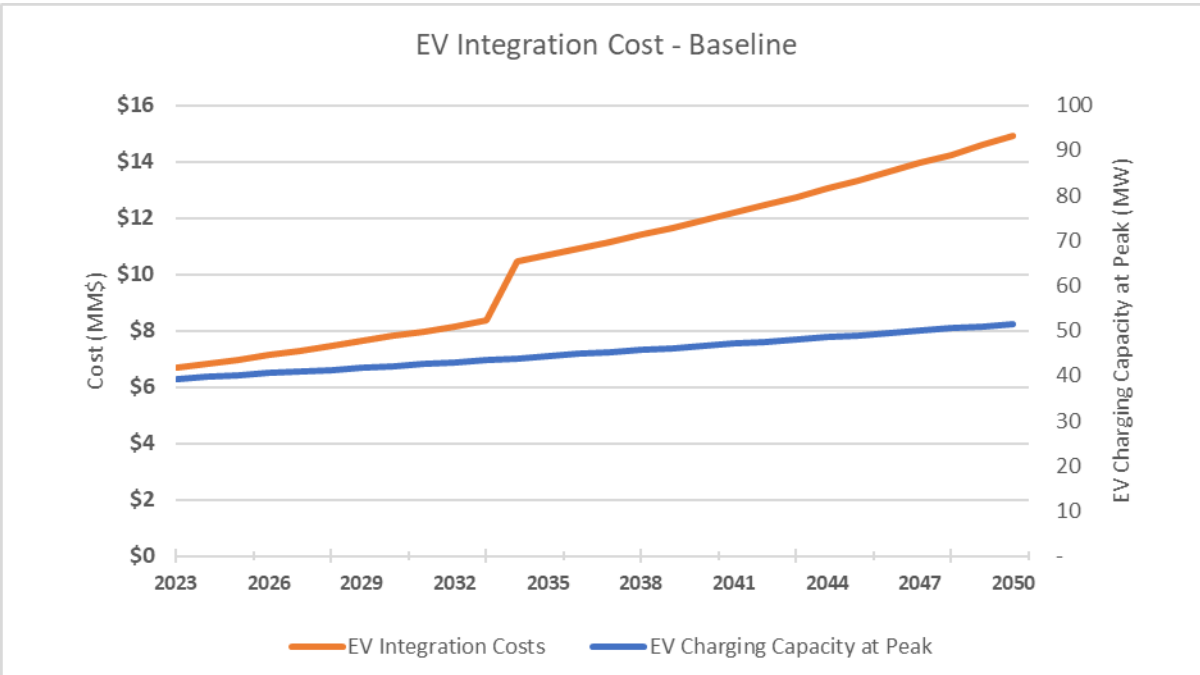
Figure 23. PV Baseline



3.1.2 EVSE

Figure 24 presents annual EV integration costs for the Baseline scenario. Integration costs are low due to the modest adoption rates over the entire study horizon and low mitigation costs under the 1% growth assumption for PV and EV. Values for the Net-Zero and Net-Zero Optimized scenarios are incremental to values presented for the Baseline scenario.

Figure 24. EV Baseline

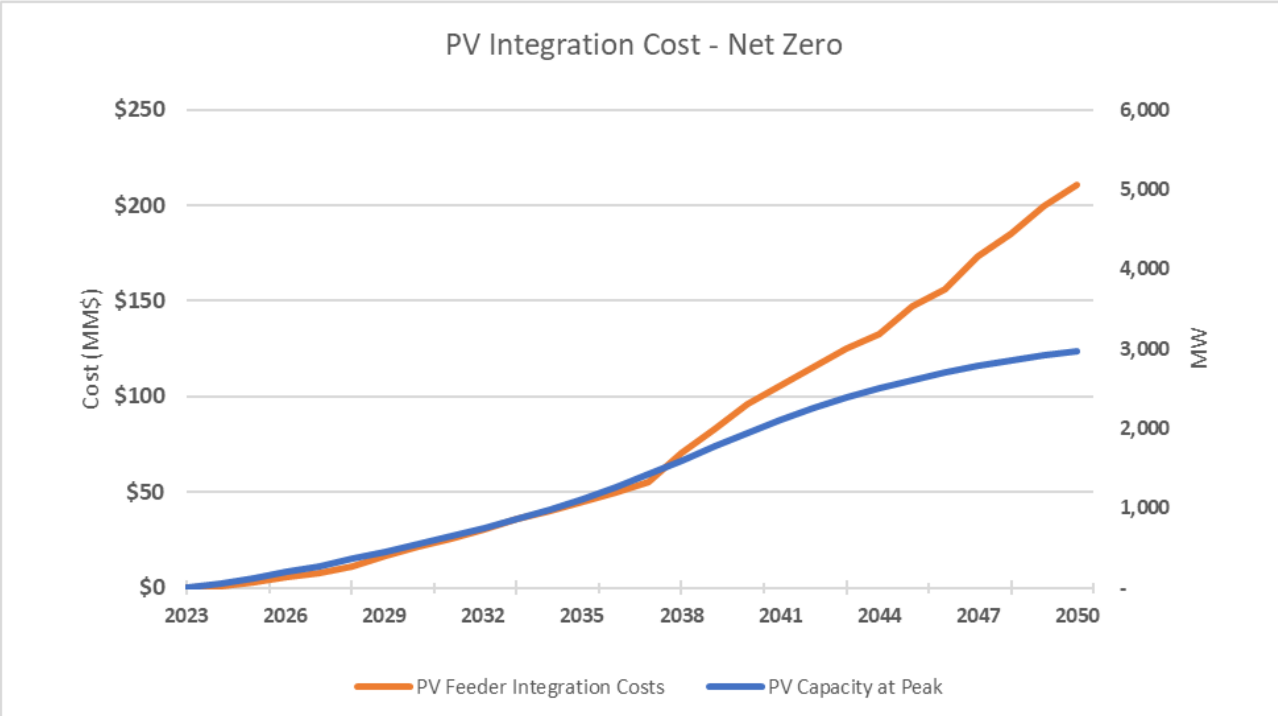


3.2 Net-zero

3.2.1 PV

Figure 25 presents annual PV integration costs for the Net-Zero scenario. Integration costs are modest over the first five to seven years but increase at a higher rate after 2035 due to higher PV adoption and increased mitigation costs. Integration costs based on installed PV capacity is approximately $45 per kW in 2035, increasing to $60 per kW in 2050.

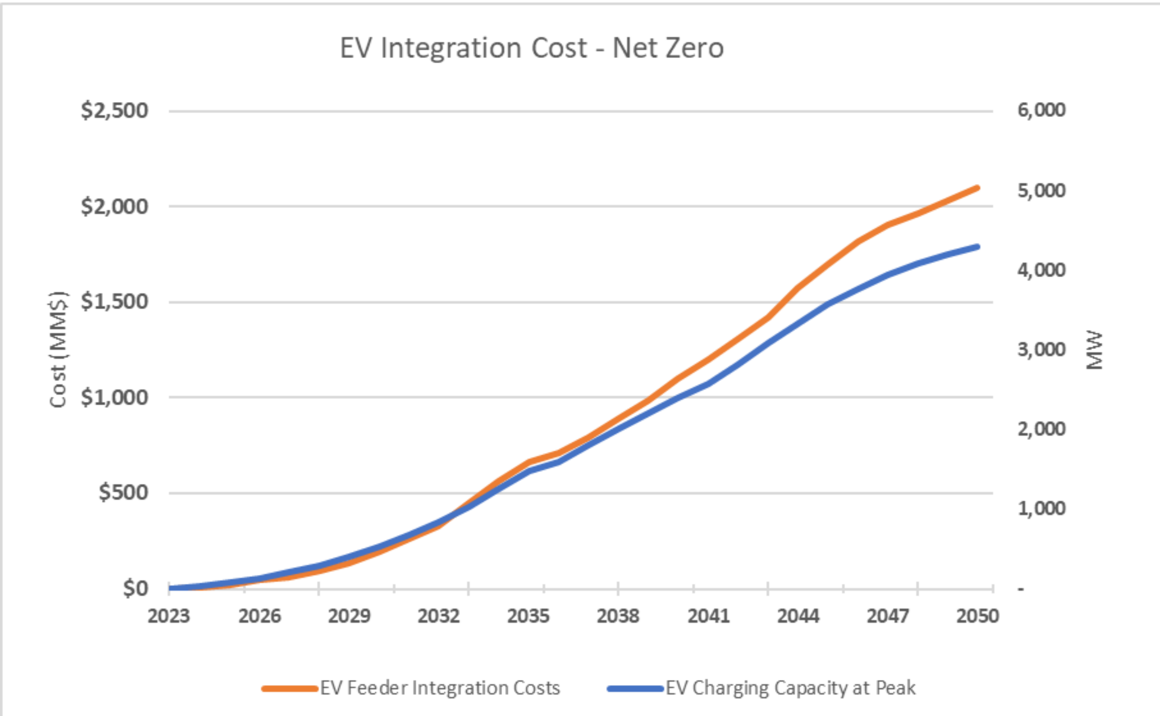
Figure 25. PV Net-Zero



3.2.2 EVSE

Figure 26 presents annual EV integration costs for the Net-Zero scenario. Integration costs are modest over the first five to seven years but increase at a higher rate after 2030 due to higher EV adoption and higher mitigation costs. Integration costs based on total installed EV charge rating is approximately $45 per kW in 2035 and for the remaining years to 2050.

Figure 26. EV Net-Zero



3.2.3 Transformer Replacement Costs

Figure 27 presents annual transformer replacements (counts and costs) caused by incremental charging of EVs at the time of the feeder peak or when off-peak load plus EV charging exceeds the transformer rating. Replacement costs are modest to 2035 due to the lower adoption levels and large percentage of transformers loaded to 20% to 40% of rated capacity. Replacement costs increased markedly after 2035, with over 50,000 distribution transformers replaced at a cost of $311 million by 2050.

Figure 27. Transformer Replacement Costs

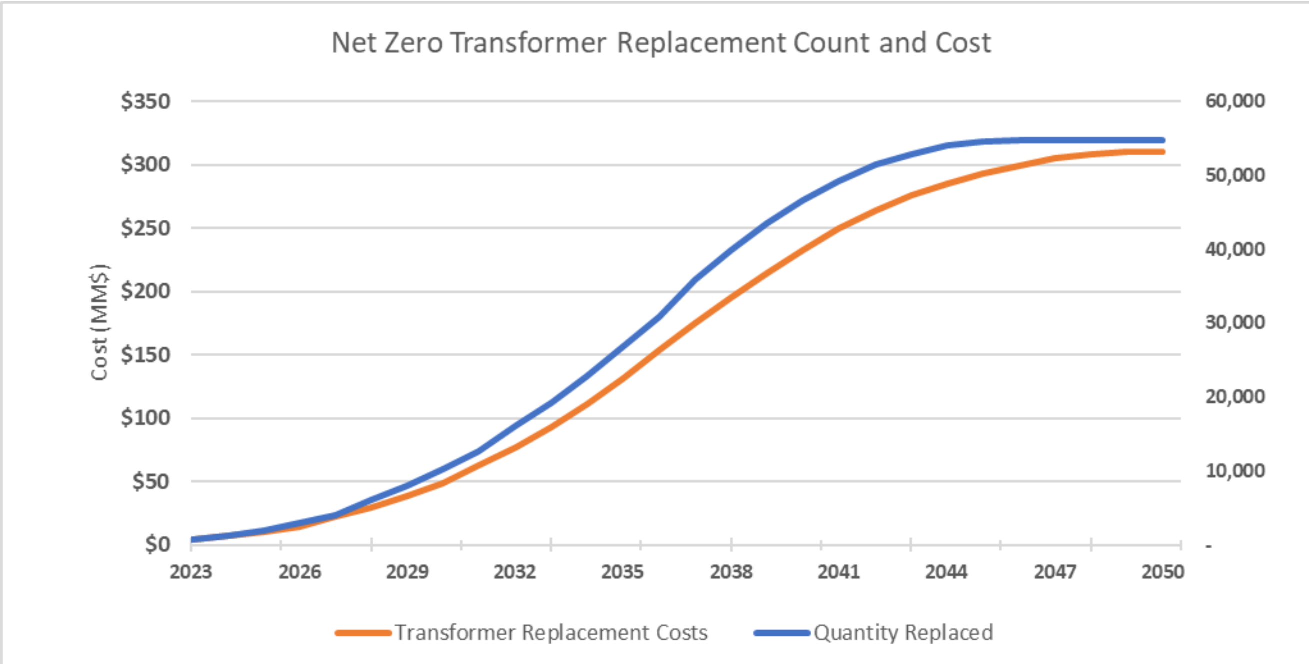
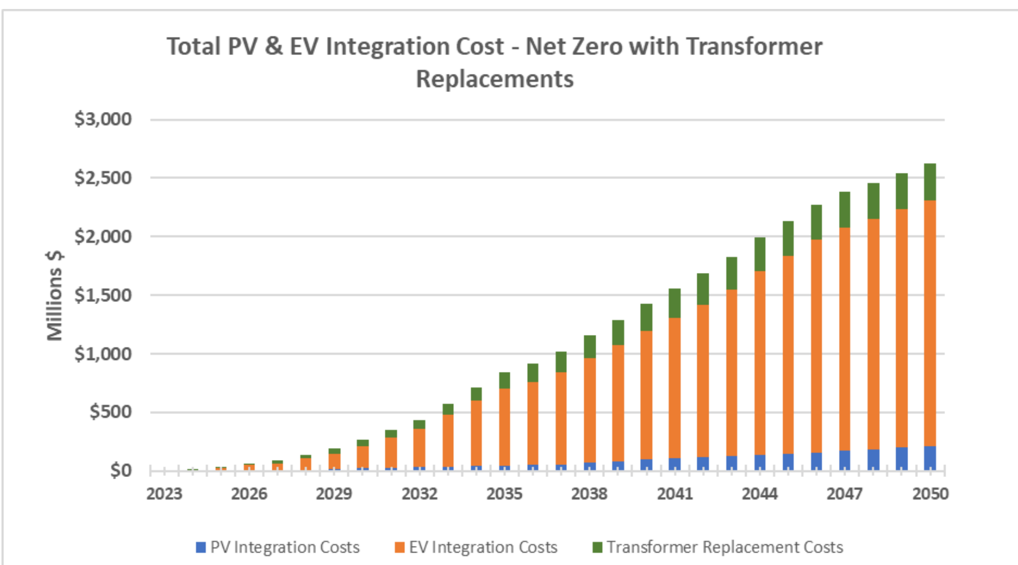


Figure 28 presents total PV and EV integration costs when transformer costs are added to the Net-Zero scenario totals. Total integration cost in 2050 increases from $2,300 million to $2,600 million, of which over $2,400 is due to incremental EV charging.

Figure 28. PV and EV Net-Zero Integration Cost Including Distribution Transformers

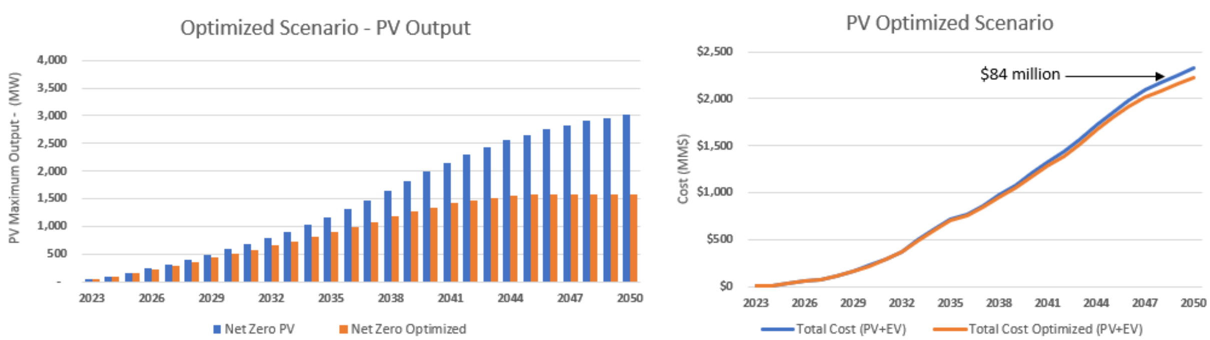


3.3 Net-Zero Optimized

3.3.1 PV

Figure 29 presents annual PV integration costs for the Net-Zero Optimized scenario. Net PV maximum PV output, displayed in the diagram in the left in Figure 29 is reduced by almost 1,500 MW in 2050 when paired with energy storage. Net PV integration cost, displayed in the diagram in the right -- is reduced by about $84 million, or 4% from the Net-Zero scenario. The lower cost of paired energy storage is low relative to total PV and EV integration costs due to the much lower PV integration cost when compared to EV. Similarly, integration costs remain essentially unchanged at approximately $45 per kW in 2035 and $60 per kW in 2050 due to the very low reduction in costs for the Optimized scenario (assumes integration costs are based on the full capacity rating of installed PV).

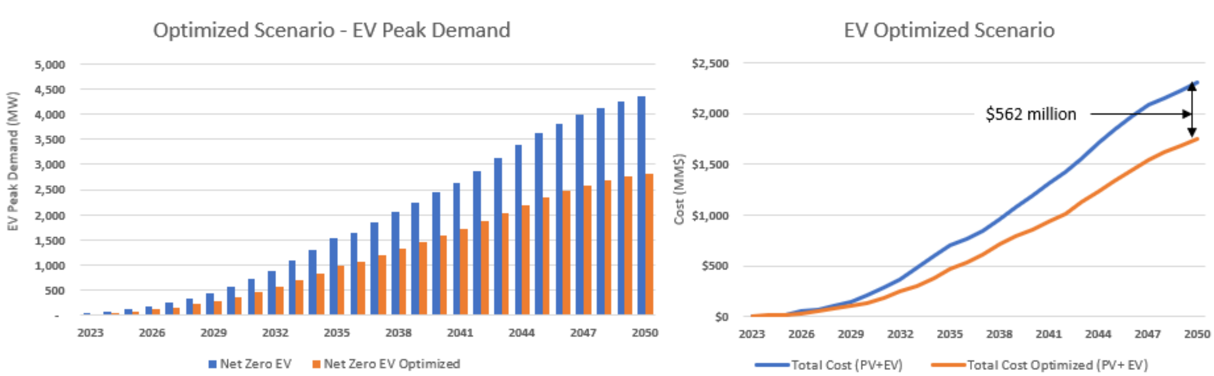
Figure 29. PV Net-Zero Optimized



3.3.2 EVSE

Figure 30 presents annual EV integration costs for the Net-Zero Optimized scenario. Results indicate TOU and DR program may reduce EV integration costs by up to $562 million or about 25% from the Net-Zero scenario.

Figure 30. EV Net-Zero Optimized



3.3.3 Transformer Replacement Costs

Figure 31 presents annual transformer replacements (counts and costs) caused by incremental charging of EVs at the time of the feeder peak or when off-peak load plus EV charging exceeds the transformer rating under the Net-Zero Optimized scenario. Similarly to the Net-Zero scenario, replacement costs increase markedly after 2035, with 40,000 distribution transformers replaced at a cost of $200 million by 2050.

Figure 31. Net Zero Optimized Secondary Transformer Replacements

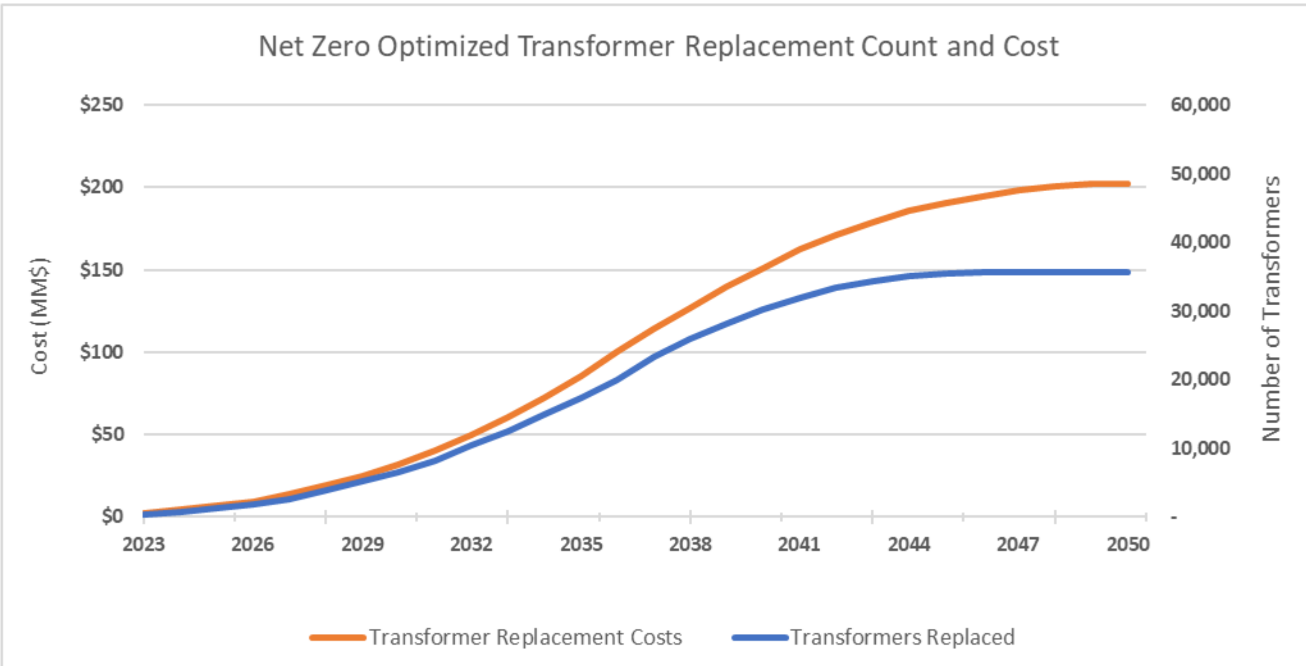
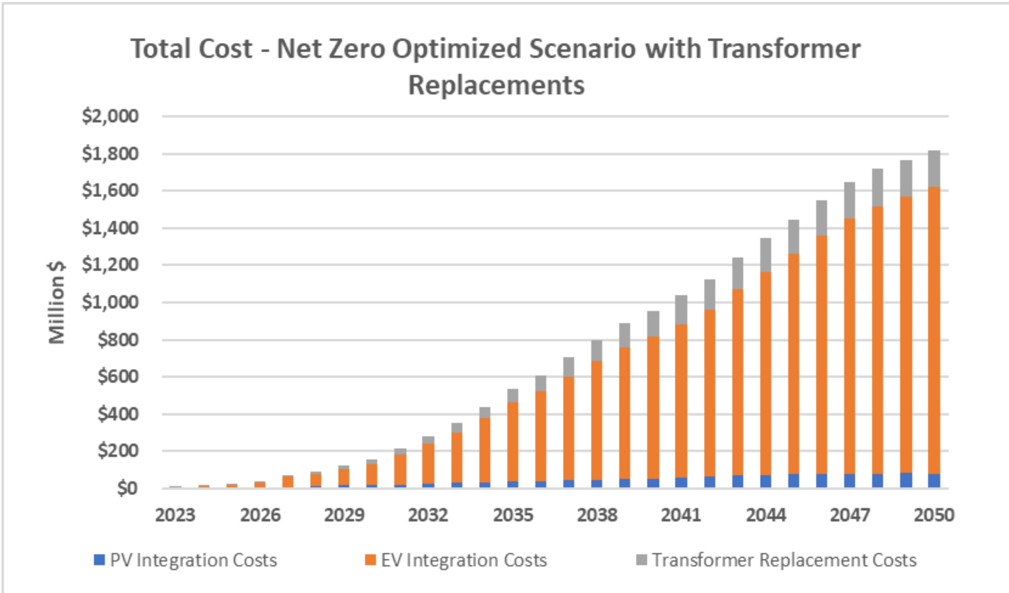


Figure 32 presents total PV and EV integration costs when transformer costs ($202 million in 2050) are added to the Net-Zero Optimized scenario totals. Total integration cost in 2050 increases from $1,600 million to $1,800 million, of which over $1,700 is due to incremental EV charging. The addition of transformer replacements increases total integration cost under the Net-Zero Optimized scenario by approximately 13 percent.

Figure 32. PV and EV Net-Zero Optimized Integration Cost Including Distribution Transformers



Appendix A. Data Inputs

A.1 Data Request

Table 12. Premise Data Request

Premise Template	YEAR
	TERRITORY
	Site ID
	Site Address
	RATE_CODE
	CUSTOMER_SEGMENT
	SUBSTATION_ID
	FEEDER_ID
	Annual kWh
	Peak kW
	Solar PV Installed Yes/No
	PV Size kW DC
	Storage Installed Yes/No
	Storage Size kWh
	EVSE Number of Ports
	EVSE kW per Port

Table 13. Distribution System GIS Data Request

Distribution System GIS	OBJECT_ID
	FEEDER_ID
	SUBSTATION_ID
	TERRITORY
	CAPACITY
	CIRCUIT_STATE
	SHAPE_Length
	Geometry

Table 14. Feeder Data Request

Feeder Template	TERRITORY
	SUBSTATION_ID
	YEAR
	FEEDER_ID
	RATE_CODE
	CUSTOMER_SEGMENT
	SOLAR_PV_INSTALLATIONS
	SOLAR_PV_KW_DC
	STORAGE_INSTALLATIONS
	STORAGE_KWH
	STORAGE_KW
	EVSE_PORTS
	EVSE_KW
	CUSTOMER_COUNT
	Feeder Voltage (kV)
	Overhead line miles – main line (3 phase) (km)
	Overhead line miles – laterals (1/2 phase) (km)
	Underground line miles – main line (3 phase) (km)
	Underground line miles – laterals (1/2 phase) (km)

	Peak load (kW)
	No. of line regulators
	No. of capacitors
	No. of line transformers
	No. of line reclosers
	Net Annual Consumption (MWh)

Table 15. Customer Load Profile Data Request

Customer Load Profile	TERRITORY
	CUSTOMER_SEGMENT
	RATE_CODE
	HOUR_OF_YEAR
	kW

Table 16. Circuit Load Forecast Data Request

Circuit Load Forecast	TERRITORY
	FEEDER_ID
	RATE_CODE
	CUSTOMER_SEGMENT
	YEAR
	PEAK_DEMAND
	ANNUAL_ENERGY

Table 17. DER Adoption Forecast Data Request

DER Adoption Forecast	CUSTOMER_SEGMENT
	TERRITORY
	APPLIED_TECHNOLOGY
	YEAR
	DER_Population

A.2 Quality Assurance

A.2.1 PV Data Quality Assurance

The following PV data underwent a quality assurance process:

- The customer counts were verified by:
    - Comparing the provided premise and feeder level customer counts by customer segment to the counts that are publicly available.
    - Comparing counts among the various customer segments and among the various DFOs for reasonableness.
- The solar PV installations were verified to be installed at the premise level. Any solar installations that were at the utility level were excluded.

- The solar penetration values were compared among DFO's for reasonableness.

A.2.2 EV Data Quality Assurance

The following EV data underwent a quality assurance process:

- The EV adoption and load impact results were checked for completeness to ensure inclusion of all DFOs, Circuits, FSAs, Segments, Years, etc.
- The EV adoption and load impact results were checked for reasonableness to ensure metrics like EVs per account, kWh per EV etc. made sense.
- The EV adoption penetration levels were compared across the various DFOs for reasonableness.
- The EV adoption results were reconciled with the 2022 EV-GNA analysis for reasonableness.

A.2.3 ES Data Quality Assurance

There was no DFO ES data leveraged in this study, as none was available. This includes any data related to historical interconnection for storage.

As a result, Guidehouse sourced attachment rates from a previous engagement with a large USA-based Midwestern utility company. These assumptions and attachment rates were vetted and accepted by key AUC stakeholders as reasonable given the maturity of the forecast.

A.3 Inputs (External)

A.3.1 AESO Inputs

Guidehouse compared the final feeder level Solar PV capacity forecast with two AESO's Alberta wide forecast:

- AESO's Net-Zero Emissions Pathways[17]
- AESO's 2021 Long Term Outlook[18]

From these two reports, Guidehouse extracted Solar PV aggregated capacity forecasts and compared with Guidehouse's own forecast at the feeder level. This comparison assumes that:

[17] https://www.aeso.ca/assets/Datafile_NetZero_Publication_V1.xlsx

[18] https://www.aeso.ca/assets/2021-Long-term-Outlook-data-file-updated-Aug-11.xlsx

- Both AESO's Alberta and Guidehouse's feeder circuit forecasts cover the same area.
- Guidehouse partial picture of historical interconnection data does not affect significantly Solar PV aggregated capacity at the end of the forecast window.

A.3.2 DFO Inputs

For Fortis and Medicine Hat, the Farm Customer Segment was excluded from the feeder level forecast. This was due to limited data available. The historical feeder solar penetration was missing for ATCO, so a historical solar penetration value of 0 was assumed for every feeder. For Red Deer, the premise level customer segmentation averages and average solar penetration by customer segment were applied uniformly across all customer segments since the premise to feeder map was missing. For EPCOR, the sample's customer segmentation was applied uniformly among the remaining feeders that had missing customer segmentation since not all feeders had segmentation provided from the DFO.

Using the assumptions above the provided DFO inputs for customer counts at the feeder and premise level, and interconnection data were used to determine the historical solar penetration values for each feeder, customer segment and DFO combination. These historical values were then used to forecast the adoption of solar penetration for each feeder, customer segment and DFO combination.

Appendix B. Study Methodology

B.1 Feeder Selection

The following sections provide a detailed description of the methods and assumption to select a set of representative feeders and assumptions applied to predict DER integration costs for each scenario.

Sampling Analysis & Feeder Selection

The purpose and desired outcomes of the Sampling analysis is to identify a statistically valid sample of distribution feeders that is representative of the entire feeder population for each DFO's distribution feeder (approximately 23 out of approximately 2,000). The feeder clustering and selection process is summarized in Figure 33.

Figure 33. Feeder Selection Process

Cluster Feeders by physical properties and customer/load mix	Select representative feeders from each cluster to model in CYME
Feeder attributes determine clusters (i.e. voltage, total length, number of regulating devices, feeder peak load, and total customers)	A single feeder from each group is selected for load flow modeling to reduce analysis time while remaining statistically accurate
The circuit which best represents each cluster is chosen as a representative feeder	Representative feeders are selected from each of the clusters; they are the feeders in each cluster whose profile is closest to the average for that group
Approach has been used since the early 1980s to select distribution feeders to represent the entire feeder population*	AUC ensures selections are suitable for CYME load flow simulation

Details on the sampling methodology and formula applied to create feeder clusters is provided below.

- First, the sampling formula in Figure 34 is applied to create feeder clusters. The objective function is one that minimizes the differences between subsequent iterations, at which point all feeders within each cluster are deemed to have comparable properties.

Figure 34. Sampling Formula for Feeder Clusters

$$d(i,j) = \sqrt{w_1 |x_{i1} - x_{j1}|^2 + w_2 |x_{i2} - x_{j2}|^2 + \cdots + w_k |x_{ik} - x_{jk}|^2}$$

Note. where x is a feeder property and i is a single feeder in the cluster from which all other feeders up to k are compared via the sum of squares formula, and where k is the weighting factor applied to each feeder property.

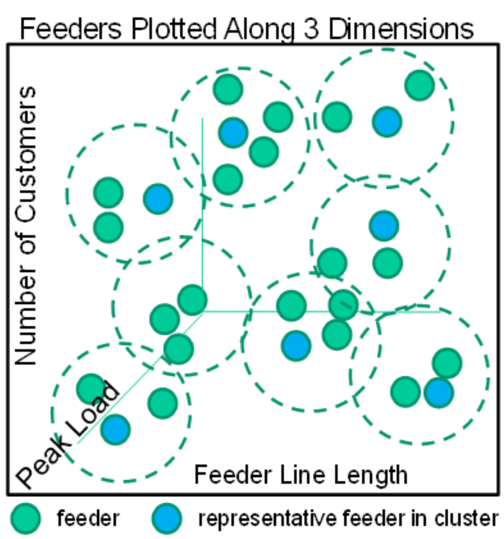
Table 18 lists the weighting factors applied in the feeder sampling process. Key properties such as feeder voltage and line length are given higher weights due to greater extent each has on sampling outcomes and PV and EV simulation modeling results.

Table 18. Feeder Selection Weighting Factors

Category	Weight
Voltage	12
Total Line km	10
Total Customers	6
Peak Load	1
Peak Load per Customer	8
Customers km of Line	6
% 3 Phase km	4
% 1/2 Phase km	4
% OH	2
No. of Line Regulators	1
No. of Capacitors	4
No. of Line Reclosers	1

- Next, a single feeder within each cluster that best represents the average properties in the cluster is selected for CYME modeling, as illustrated in Figure 35. As noted in Table 18, 12 weighting factors were applied in the feeder clustering formula and selection process.

Figure 35. Representative Feeder Selection Illustration (2 Properties)



- Up to five candidate feeders for CYME modeling are selected as the best choice as the representative feeder for the cluster. A recommended feeders among the five was initially chosen and reviewed by the DFOs. For some of the 23 clusters, the DFOs suggested other feeders rather than the recommended selection to be more representative of the cluster – in each of the cases, the DFO suggested alternative was selected.

Primary steps in the sampling process are outlined below:

1. Establish feeder attributes/parameters for the entire population of feeders (voltage, length, OH/UG lines km, number of devices, peak load, # of customers)
2. Conduct statistical sampling analysis and feeder selection
3. Confirm feeder attributes and weighting factors
4. Confirm feeder attributes and weighting factors used in sampling analysis
5. Select representative feeders based on CYME modeling suitability
6. Validate the set of representative feeders for CYME simulation modeling

B.2 Forecast Data Application

B.2.1 PV Forecast Data Application

The following describes the methodology utilized when applying the data inputs to come up with the final forecast:

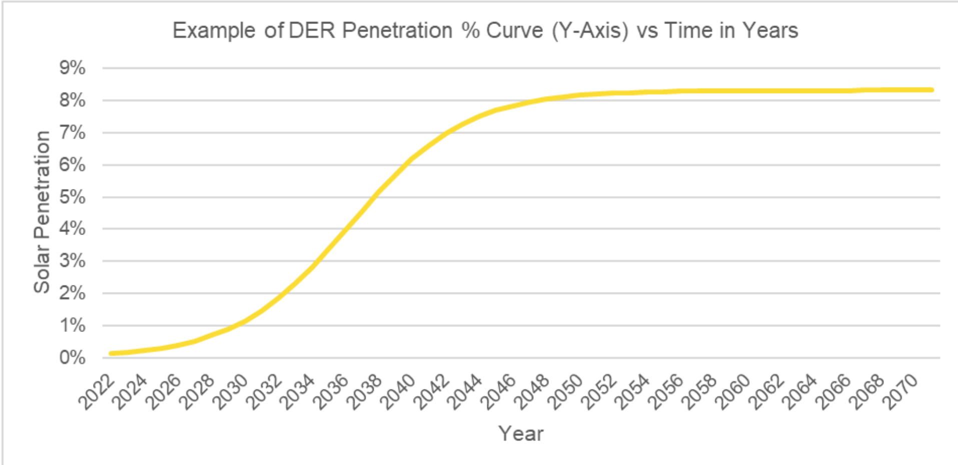
The customer counts and solar installations were both aggregated to include the indexes of DFO, Feeder, Year and Customer Segment. The solar penetration was determined by dividing the solar installations by the customer counts by DFO, Feeder, Year, and Customer Segment.

The Solar penetration forecast curve was determined at the DFO level by aggregating over the feeder. ENMAX, EPCOR and FORTIS have historical data which enabled a forecast curve to be determined for each customer segment. The forecast was then applied to each feeder, by finding on the forecast curve where each feeder was currently, based on solar penetration. The forecast for each feeder was then extended based on the determined forecast solar penetration forecast curve.

Guidehouse's forecast of solar penetration percentage per DFO uses two main parameters as inputs:

1. The calculated historical solar penetration at the DFO level of each customer sector. This ensures that the first forecast year matches local historical trends.
2. The 2050 Long Run Market Potential of potential Solar PV adopters that bounds the upper limit of the forecast.

Figure 36. Example of DER Penetration % Curve (Y-Axis) vs Time in Years



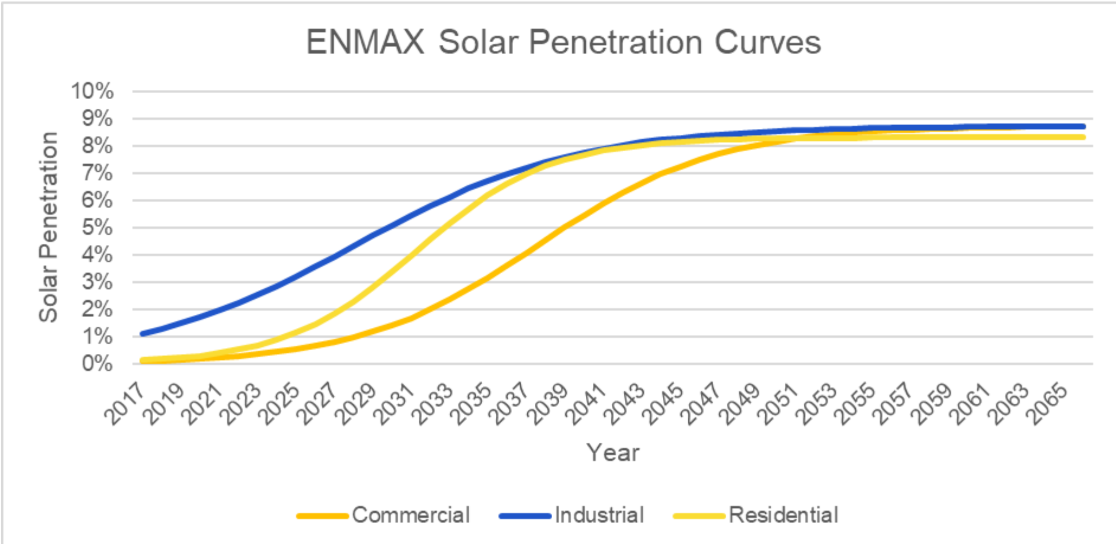
Two inputs (i.e. 2020 actuals and 2050 limit) are used to generate a sigmoid shaped timeseries, as represented on Figure 36 (i.e., from essentially 0% PV penetration in the year 2000 to likely 2050 market ceiling) solar penetration percentage forecast per DFO segment that then is mapped to each circuit in a DFO.

The forecast of solar PV population is then calculated from the solar PV penetration percentage forecast and feeder circuit customer counts provided by the DFO. This solar PV population forecast assumes that adoption on each of the DFO's feeder circuits follows a similar trend. The incremental addition of new solar PV installations per feeder circuit is derived from the total number of installations forecast (solar PV population).

B.2.2 PV Rate of Adoption

The rate of adoption follows the solar penetration curve developed at the DFO-level. Adoption is defined as a percent of the customers that have adopted solar in a particular DFO, Customer Segment, Year and Feeder. Figure 37 is an example of the ENMAX solar penetration curve developed using the historical data, with the assumptions mentioned in the report to fill any data gaps.

Figure 37. ENMAX Solar Penetration Curves



B.2.3 EV Forecast Data Application

The following describes the methodology utilized when applying the data inputs to come up with the final forecast:

GIS data received from each DFO was used in a spatial allocation process to assign EV adoption results from each FSA to each circuit that touched an FSA, based on transformers geolocated within each FSA.

- Customer Counts from each DFO were used to allocate EVs to the residential and commercial segments of each circuit.
- The AESO NZ Forecast was extended to 2050
- VAST results from a similar US State were used to inform load impacts, peak load and EVSE count.
- EV-GNA results were used to inform the spatial distribution of EV adoption across Alberta at the FSA level.

B.2.4 ES Forecast Data Application

Historical interconnection data was not available for storage, so attachment rates were sourced from a previous Guidehouse forecast for a large Midwestern (USA) utility company. An attachment rate is the percent of all new solar PV customers that will also install storage. The attachment rate forecast was extracted from a large US electrical utility company and used as a template applicable to AUC. The attachment rate forecast is mapped to each feeder solar PV forecast of new installations. The output is a forecast of Solar PV + Storage installations. This storage component is used to calculate new storage installations and storage capacity per feeder circuit and customer segment.

B.3 Net-Zero Methodology for Peak Load and Annual Sales Impact Forecast

Figure 38. DER Impact per Customer Equations

$$\boldsymbol{Net\ Load} = \text{Load before Adoption} - \text{Load after Adoption}$$
$$\boldsymbol{Impact} = \text{Load before Adoption} - \text{Net Load}$$
$$\boldsymbol{Peak\ Load}\ [\boldsymbol{kW}] = \max(\text{Impact})$$
$$\boldsymbol{Annual\ Impact}\ [\boldsymbol{kWh}] = \sum \text{Impact}$$

The solar PV and Storage System sizes from Table 7. Solar PV and Storage System Sizes per Installation per customer were derived using the equations described in Figure 38 and through the following inputs:

- Representative hourly customer load shapes, DER installations and capacity forecasts.
- Hourly PV generation and storage charge/discharge profiles using representative PV and storage capacities per installation.

Finally, total feeder impacts were calculated using the impacts per customer multiplied by the number of forecasted DER installations in a given forecast year.

B.4 DFO Allocation Methodology

B.4.1 PV Allocation Methodology

The allocation of PV was based on the feeder level customer count. Once the solar penetration was determined at the feeder level, the PV counts were calculated by multiplying solar penetration by the customer counts. This makes the allocation for PV based on the allocation of the customer counts that is available from the DFO data. DFO's with a higher customer count will also have higher solar PV counts, and higher solar penetrations will result in DFO's having higher allocation.

The following describes how inputs related to PV were applied across the DFO's:

- For EPCOR, Lethbridge, ATCO, Red Deer, and Medicine Hat, the ENMAX rate of adoption curve at the DFO was used at the Feeder level due to lack of historical data for these 5 DFOs.
- Exceptions to the solar penetration asymptote were applied for FORTIS and EPCOR, industrial segment, and a value of 30% was used for these segments. Based on the long run market share calculations, the following asymptotes were used for each DFO by customer segment: Residential 8.3%, Commercial 8.7%, Industrial 8.7%.

B.4.2 EV Allocation Methodology

The Alberta level EV adoption and load impact results derived from the AESO Net-Zero Emissions Pathways study were disaggregated to FSA level using the average FSA level EV penetration ratios calculated using the 2022 EV-GNA study. The FSA level EV results were further disaggregated to the transformer level using proportional allocations based on customer counts associated with each transformer in an FSA under a particular DFO.

The following describes how inputs related to EV were applied across the DFO's:

- Around 5.5% and 9% of the feeders were dropped for FORTIS and ATCO respectively because of missing data (customer counts, customer segment, mapping ids, etc.)
- For EPCOR, the sample's customer segmentation was applied uniformly among the remaining feeders that had missing customer segmentation since not all feeders had segmentation provided from the DFO.
- For FORTIS and Lethbridge, the transformer shapefiles were not provided. Guidehouse assumed a certain number of transformers uniformly placed along the circuits to generate a dummy transformer shapefile to complete the analysis.
- EV forecasts were not generated for circuits with non-zero or missing customer counts.
- DFO shapefiles were generated from the transformer shapefiles obtained from the individual DFOs and were subsequently used for the FSA to circuit level disaggregation.

B.4.3 ES Allocation Methodology

The feeder level Storage allocation was driven by the generated Solar PV forecast of new installations. New Storage installations were calculated using a forecast of Storage attachment % and incremental Solar PV installations. Storage and Solar PV both align in spatial (per feeder) and temporal (year to year) granularity. The growth of Solar PV is reflected in the growth of Storage.

B.5 DER Capacity Allocation

B.5.1 PV Capacity Allocation

Solar PV capacity at the feeder level was allocated using historical installed capacity per feeder (when interconnection data was available from the DFO's), as well as incremental Solar PV installed capacity per year calculated from the typical customer system sizes multiplied by the forecasted count of new installations per year.

Using the historical and forecasted annual added capacity, Guidehouse was able to forecast Incremental and Aggregated Solar PV capacities.

B.5.2 EVSE Capacity and Load Allocation

Guidehouse used results from a previous VAST analysis conducted for a similar US state to calculate EVSE counts, charger rated capacity and peak load impacts per EV. These ratios were then multiplied to the feeder level EV adoption results to get feeder level EVSE counts and load impacts.

B.5.3 ES Capacity Allocation

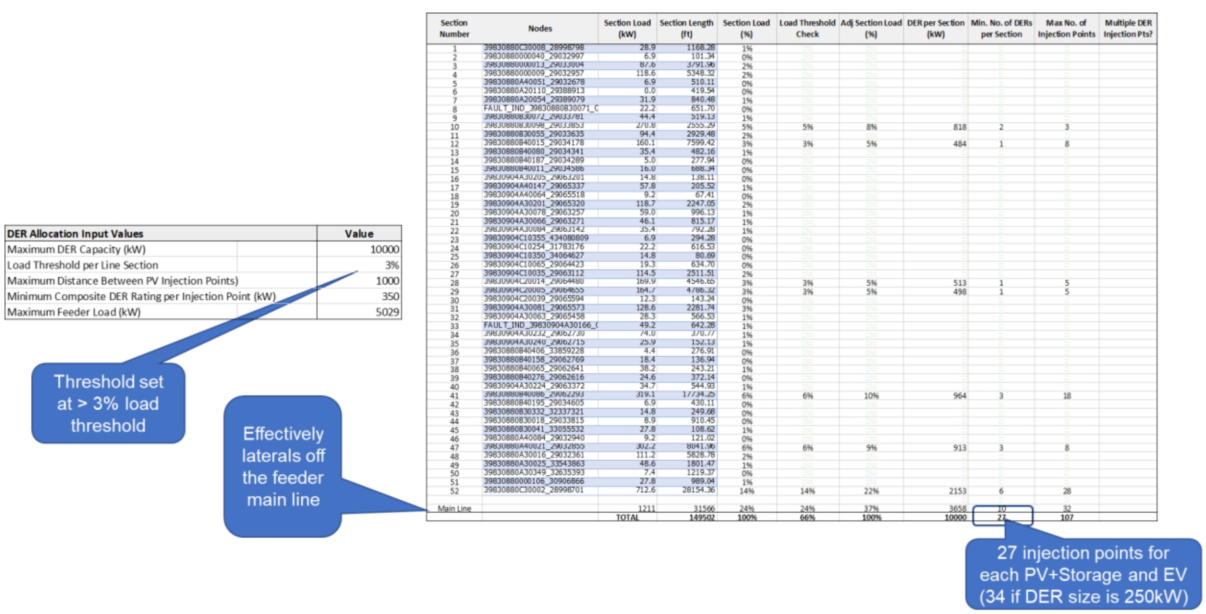
Storage capacity was allocated on a per-circuit basis using incremental Storage installations and the typical storage capacity per customer. Aggregated Storage capacities start on the first forecast year (2023) since there was not historical interconnection data available for Storage.

B.5.4 CYME DER Capacity Allocation & PV and EV Aggregation

As described earlier, DER impacts were analyzed for each representative feeder via CYME simulation modeling.

A separate Excel-based model is used to allocation DER capacity at feeder nodes contained in the CYME model for each of the representative feeders. Each representative feeder is assigned a minimum number of injection points based on factors such as feeder length, load distribution and feeder ratings. In the example presented in Figure 39**,** a minimum of 27 injection points is required to properly model DER impacts in CYME. The minimum number of injection points for each representative feeder can vary, with short feeders needing as few as 10 injections points or less, and up to 40 for longer feeders.

Figure 39. DER Allocation Process



DER Allocation Input Values	Value
Maximum DER Capacity (kW)	10000
Load Threshold per Line Section	3%
Maximum Distance Between PV Injection Points)	1000
Minimum Composite DER Rating per Injection Point (kW)	350
Maximum Feeder Load (kW)	5029

Section Number	Nodes	Section Load (kW)	Section Length (ft)	Section Load (%)	Load Threshold Check	Adj Section Load (%)	DER per Section (kW)	Min. No. of DERs per Section	Max No. of Injection Points	Multiple DER Injection Pts?
1	39830880C30008_28998798	28.9	1168.28	1%						
2	39830880000040_29032997	6.9	101.34	0%						
3	39830880000013_29033004	87.6	3791.96	2%						
4	39830880000009_29032957	118.6	5348.32	2%						
5	39830880A40051_29032678	6.9	510.11	0%						
6	39830880A20110_29388913	0.0	419.54	0%						
7	39830880A20054_29389079	31.9	840.48	1%						
8	FAULT_IND_39830880B30071_C	22.2	651.70	0%						
9	39830880B30072_29033781	44.4	519.13	1%						
10	39830880B30098_29033853	270.8	2555.29	5%	5%	8%	818	2	3	
11	39830880B30055_29033635	94.4	2929.48	2%						
12	39830880B40015_29034178	160.1	7599.42	3%	3%	5%	484	1	8	
13	39830880B40080_29034341	35.4	482.16	1%						
14	39830880B40187_29034289	5.0	277.94	0%						
15	39830880B40011_29034586	16.0	688.34	0%						
16	39830904A30205_29063201	14.8	138.11	0%						
17	39830904A40147_29065337	57.8	205.52	1%						
18	39830904A40064_29065518	9.2	67.41	0%						
19	39830904A30201_29065320	118.7	2247.05	2%						
20	39830904A30078_29063257	59.0	996.13	1%						
21	39830904A30066_29063271	46.1	815.17	1%						
22	39830904A30084_29063142	35.4	792.28	1%						
23	39830904C10355_434080809	6.9	294.28	0%						
24	39830904C10254_31783176	22.2	616.53	0%						
25	39830904C10350_34064627	14.8	80.69	0%						
26	39830904C10065_29064423	19.3	634.70	0%						
27	39830904C10035_29063112	114.5	2511.51	2%						
28	39830904C20014_29064480	169.9	4546.65	3%	3%	5%	513	1	5	
29	39830904C20005_29064655	164.7	4786.32	3%	3%	5%	498	1	5	
30	39830904C20039_29065594	12.3	143.24	0%						
31	39830904A30081_29065573	128.6	2281.74	3%						
32	39830904A30063_29065458	28.3	566.53	1%						
33	FAULT_IND_39830904A30166_(	49.2	642.28	1%						
34	39830904A30232_29062730	74.0	370.77	1%						
35	39830904A30240_29062715	25.9	152.13	1%						
36	39830880B40406_33859228	4.4	276.91	0%						
37	39830880B40158_29062769	18.4	136.94	0%						
38	39830880B40065_29062641	38.2	243.21	1%						
39	39830880B40276_29062616	24.6	372.14	0%						
40	39830904A30224_29063372	34.7	544.93	1%						
41	39830880B40086_29062293	319.1	17734.25	6%	6%	10%	964	3	18	
42	39830880B40195_29034605	6.9	430.11	0%						
43	39830880B30332_32337321	14.8	249.68	0%						
44	39830880B30018_29033815	8.9	910.45	0%						
45	39830880B30041_33055532	27.8	108.62	1%						
46	39830880A40084_29032940	9.2	121.02	0%						
47	39830880A40021_29032855	302.2	8041.96	6%	6%	9%	913	3	8	
48	39830880A30016_29032361	111.2	5828.78	2%						
49	39830880A30025_33543863	48.6	1801.47	1%						
50	39830880A30349_32635393	7.4	1219.37	0%						
51	39830880000106_30906866	27.8	989.04	1%						
52	39830880C30002_28998701	712.6	28154.36	14%	14%	22%	2153	6	28	
Main Line		1211	31566	24%	24%	37%	3658	10	32	
		TOTAL	149502	100%	66%	100%	10000	27	107	

Following the selection of the 23 representative feeders, CYME simulation analyses were conducted for each representative feeder. Figure 40 presents the modeling process applied to each of the 23 representative feeders. The CYME analysis evaluates PV and EV impacts separately, as the timing of the PV peak is independent of the EV peak (i.e., peak occurs mod-day, while EV peaks at night when PV output is zero) If no violations are identified at the maximum PV or EV feeder capacity rating, no additional analysis is required, and the cost curve equations are set to zero.

Figure 40. CYME Modeling Process

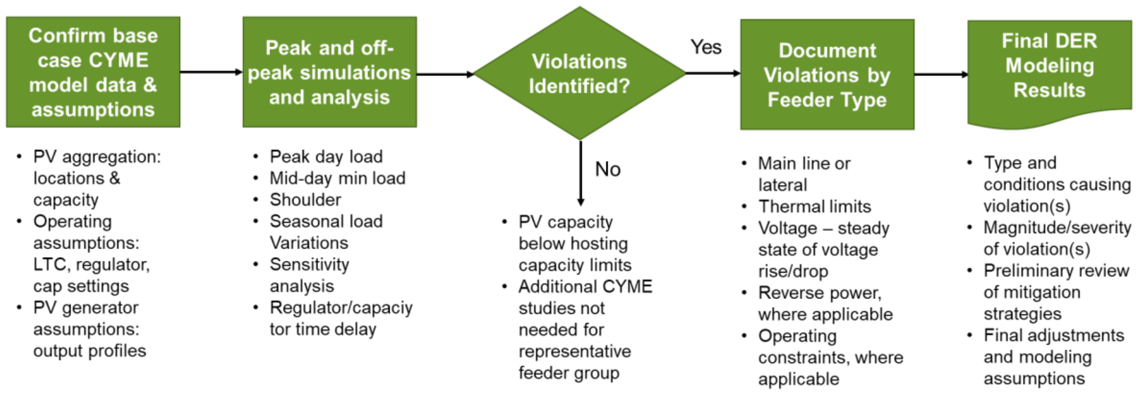
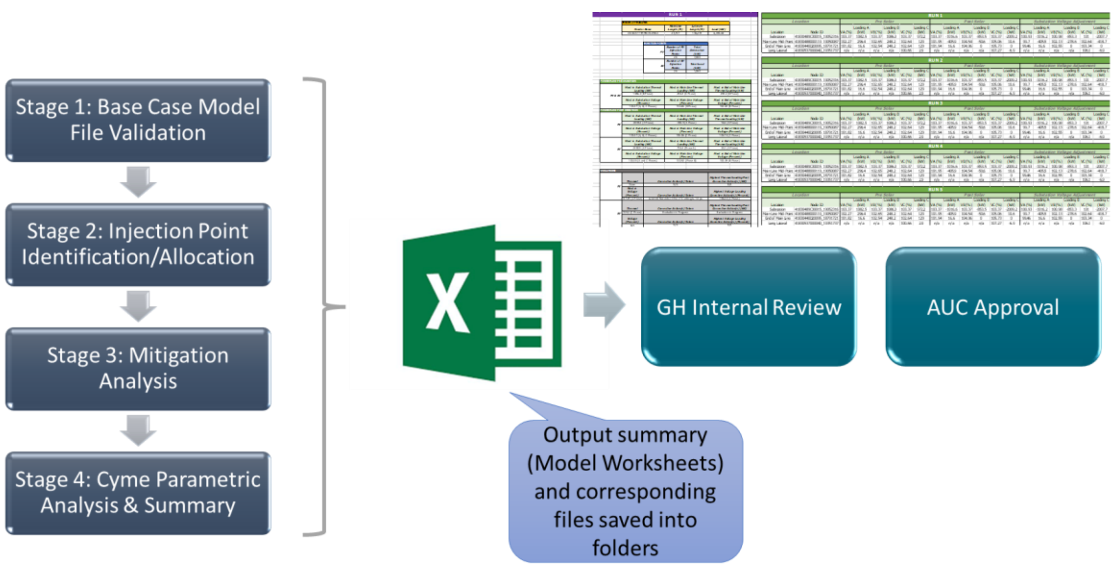


Figure 41 illustrates steps undertaken for feeder modeling review and approval. Each representative feeder is analyzed for increasing amounts of PV and EV capacity, up to the feeder rating, and mitigation is applied sequentially to increasing amounts of DER. The output worksheets and cost equations are then transferred to a separate Excel-based Feeder Cost Model to determine integration costs for each feeder within each cluster.

Figure 41. Feeder Modeling Review and Approval



Distribution Primary and Secondary Models

All primary main line and lateral segments and equipment are modeled in CYME. Most DER injections are assumed to be connected to primary voltage lines. However, between 3 to 6 secondary PV connections are required to capture voltage rise caused by PV injection behind the customer meter. Typically, up to 2% voltage rise can occur on secondary lines, resulting in overvoltage violations.

B.6 Grid Impact Assessment - Baseline

Grid impacts resulting from PV and EV incremental capacity additions as determined via CYME simulation are limited to steady state performance violations. Virtually all performance violations identified via CYME are voltage violations or main line and lateral line section overloads.[19]

PV Performance Violations

CYME modeling indicates that PV violations typically are overvoltages on lateral line sections with small wire or cable size (i.e., high impedance) or on those located furthest from the substation. For very high PV adoption, which infrequently occurs on individual feeders, some line sections, mostly laterals, become overloaded due to reverse power. Overvoltages due to PV capacity injection are mitigated primarily via installation of voltage regulators, with line reconductoring as the next least costly alternative; the latter is required mostly when PV capacity nears feeder ratings. Several of the overvoltage conditions occur at the end of the secondaries (i.e., customer premise or meter).[20]

EV Performance Violations

CYME modeling indicates that EV violations typically main line and lateral overloads, caused by incremental EV charging at the time of the feeder peak. In virtually all cases, line reconductoring was needed to address the overload. When EV charging caused loadings above capacity planning ratings, a new feeder was added. Feeder cost model logic accounts for the potential for the new feeder (and reconfigured existing feeder) could encounter violations following the transfer of load and EV chargers to the new feeder.

Under high load conditions – e.g., high EV capacity combined with high existing loads – the exit feeder became overloaded, with the main line sections within limits. Because of the complexity of replacing exit feeders, particularly for underground cable located in concrete duct banks, the cost of replacement was far high than individual line sections.

[19] Detailed results of the CYME simulation results are summarized in the appendix.

[20] Between 3 and 6 secondary nodes are modeled in CYME to capture the rise in secondary voltages. Proxy distances, conductor size and transformer ratings were applied as the CYME models included primary lines and equipment.

B.7 Feeder Cost Model and DER Integration Costs

B.7.1 Approach

The final step in the grid impact and DER cost analysis is the application of the cost curve equations derived for each of the representative feeders to other feeders assigned with the cluster. A separate Excel-based feeder cost model incorporates the cost equations, separately for PV and EV, and applies them annually to the PV and EV adoption forecasts to derive integration costs on a cumulative basis. Model logic recognizes feeder capacity planning limits and assumes a new feeder is installed when these limits are exceeded. Model output includes annual cost for PV, EV, adjustments for common costs (i.e., mitigation that applies to both PV and EV) to avoid double accounting, and additional integration costs for new feeders that are impacted by DER. Section 3 presents DER integration costs for each scenario based on feeder cost model results.

B.7.2 Convention Mitigation Options

The above process and prior sections describe mitigation options for the conventional "build" options. Because mitigation costs differ among the DFOs, an adjustment factor is applied to each DFO feeder that requires mitigation to capture these differences.

B.7.3 Optimized Solutions

The same feeder cost model described above is also used to derive integration costs for the optimized solutions. Each of the optimized solutions effectively is a peak load reduction measure for EV, as incremental demand for each feeder is reduced by the amounts estimated via TOU programs and DR measures. For PV, PV output is reduced in equal amounts to the PV rating by paired energy storage based on the percentage of PV installations that will be equipped with energy storage over time.

B.7.4 Transformer Replacements

Transformer replacements resulting from incremental EV charging is based on the current population of transformers for each DFO. Each set of DFO transformer are grouped by rating[21] and by percent of transformer loadings within 20% intervals.

The following outlines the steps used to determine the number of transformers with EV's within each rating group.

[21] Transformers are grouped according to the following set of kVA ratings. Transformers with ratings not within these groups are assigned to the group closest to the actual rating. kVA ratings: 10, 15, 25, 37.5, 50, 67.5, 75, 100, 112.5, 150, 167, 225, 300, 333, 750, 1000, 1500, 2000, 2500.

1. The total number of EVs installed each year of the study is obtained from output files derived from the commercial and residential EV adoption forecasts and quantities described in Section B.1 for EVSEs.

2. The quantities from the EVSE output files are subdivided into the number of Level 1 and 2 chargers for residential, and Level 1, Level 2 and EVDC chargers for commercial based on the Midwestern utility study cited in Section B.1.

    a. The split between Level 1 and Level 2 EV residential chargers in 2023 is 75% and 25%, respectively; increasing to 50% each by the mid-2030's and 25% Level 1 and 75% Level 2 by 2050.

    b. The split between EVDC and Level 2 commercial chargers for chargers in 2023 is 30% and 70% (Level 1 chargers are near 0%), respectively; gradually changing to 40% and 60% by 2050.

3. The EV charger quantities and EV loadings (kW) developed in Step 2 are adjusted to align with total EV charging capacity.

4. The number of residential and commercial EVs per transformer are assigned to the 20% to 120% loading bins based on the percentage of transformers in each bin to the total number of residential and commercial transformers, respectively.

5. The number of transformers that need to be replaced annually due to overloads caused by incremental EV loading is determined by multiplying the quantity of transformers by the EVDC, Level 1 and Level 2 charger ratings. These ratings increase over time as outlined in the Assumptions section below.

6. The number of transformers that need to be replaced per Step 5 accounts for loading diversity for transformers serving multiple customers. Diversity factors are outlined in the Assumptions section below. Most transformers serving multiple charges are commercial.

7. The annual cost of replacements is equal to transformer replacement cost for each transformer rating class (e.g., 25 kVA versus 100 kVA), escalated over time

8. The average replacement cost is adjusted based on the average number and cost of pole versus padmounted transformers in each rating class.

Appendix C. Integration Costs

The grid impact assessment identifies the annual cost of integrating PV and EV on DFO distribution feeders for the Baseline, Net-Zero and Net-Zero Optimized scenarios. Feeder integration costs are derived separately for PV and EV using the representative feeder parametric cost curves developed per Section 1.5 above. The feeder integration costs are provided on a combined basis for each DFO and for all of Alberta.

In addition, the cost of replacing transformers due to EV charging is derived and combined with feeder integration costs under the Net-Zero scenario. Results are summarized below and in Section 3.

C.1 Baseline PV & EV Integration Costs

The Baseline scenario integration cost forecast assumes historical PV and EV adoption levels continue resulting in a net 1% year-over-year load growth. Integration costs for the Baseline scenario provide a “floor” for determining incremental costs associated with the Net-Zero scenarios.

Integration costs for each of the 23 clusters were derived for the Baseline scenario out to 2050 based on the application of the parametric cost curves developed via the grid impact analysis. All costs are escalated at a real escalation rate of two percent compounded annually.

C.2 Net-Zero PV & EV Feeder Integration Costs

Integration costs for each of the 23 clusters were derived for the Net-Zero scenario out to 2050 based on the application of the parametric cost curves developed via the grid impact analysis. All feeder integration costs are escalated at a real escalation rate of two percent compounded annually.

C.3 Net-Zero Optimized PV & EV Feeder Integration Costs

C.3.1 Overview

The role of “non-build” options to reduce and optimize integration costs was evaluated for both PV and EV for the Net-Zero forecasts. The non-build options include for EV, a rate incentive to favorably adjust EV charging profiles and for PV, the pairing of customer-owned energy storage with new PV installations. Demand Response was also evaluated as an option to reduce the impact of EV loadings at the time of the distribution feeder peak.

The 3 optimization programs identified in the Net-Zero Optimized scenario are:

1. Time of Use (TOU)/Managed Charging:
    - reduce EV loading by 35%
2. Load Flexibility/ Demand response:
    - reduce extreme load peak (less than 0.4% of the calendar year) events by 8%
3. Paired ES/PV:
    - for the Net-Zero scenario, assume a 50% storage pairing for new PV systems by 2050.

- for the Net-Zero Optimized scenario, assume a 75% storage pairing for new PV systems by 2050.

C.3.2 Net-Zero Optimized PV & EV Feeder Integration Costs

Feeder integration costs for each of the 23 clusters were derived for the Net-Zero Optimized scenario, based on the application of the parametric cost curves which incorporated the use of the optimized mitigations solutions above, developed via the grid impact analysis. All integration costs are net of the Baseline costs and are escalated at a real escalation rate of two percent compounded annually.

Total feeder integration costs for the Optimized Net-Zero scenario are approximately $800 M below the Net-Zero scenario. The Net-Zero scenario drives higher integrations costs due to the higher unoptimized EV and PV demands moving up the higher end of the parametric cost curves resulting in higher integration costs.[22]

C.4 Secondary Transformer Integration Costs

An additional $310M of secondary transformer integration costs by 2050 associated with the required replacement of over 50,000 transformers across Alberta are forecast, based on the transformer loading analysis for the Net-Zero scenario found in Section1.5.3. For DFO's for which no analysis was conducted (Lethbridge, Red Deer), Guidehouse used the average from other DFOs as a proxy to ensure the transformer replacement costs were included.

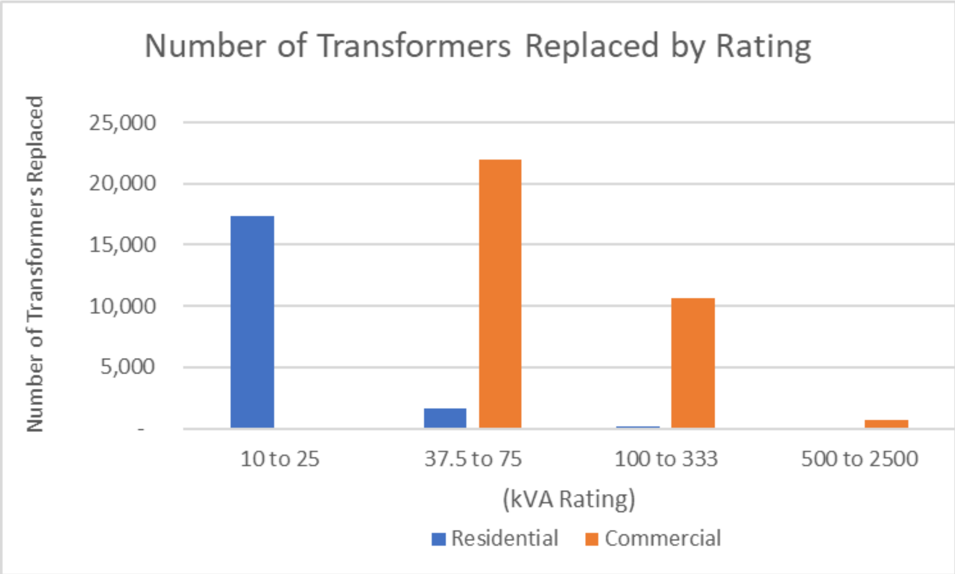
Approximately 85% of the transformer integration costs are a result of the higher cost to replace the overloaded larger commercial transformers caused by the larger EVDC charger ratings. Level 1 and 2 and EVDC loading assumptions and charger ratings are described in greater detail in Appendix B.5.2 EVSE Capacity and Load Allocation. Annual transformer replacements are presented in Section 3.3.3.

Figure 42 presents the total number of transformers replaced by rating class (classes combined for brevity) for residential and commercial EV installations. Results indicate most residential transformers replaced are rated 25 kVA and below while most transformers replaced connected to commercial EVs are rated 75 kVA and below.[23]

[22] Each of the 23 parametric cost curves are comprised of 2 equations used to calculate integration cost. The slope of the second equation often has a higher slope than the first equation, resulting in higher proportional reduction in costs when feeder loading is reduced via demand reduction programs.

[23] As noted in Appendix B, due to limited data, the study methodology assumes all transformers serving commercial load are rated between 37.5 kVA and 500 kVA.

Figure 42. Transformers Replaced by Rating



Appendix D. Assumptions

D.1 Uncertainty / Maturity

Using the full capabilities of DERSim, Guidehouse would have determined Solar PV and Storage adoption using a nuanced study of customer economics using:

- Customer rates unique to each DFO
- Applicable installation incentives for customer
- Cashflow model of cost of DER
- Logit model of market share competition between different DER technologies (i.e., Solar PV, Storage and Solar PV + Storage)

Due to scope of this analysis, the adoption drivers were simplified into a calculated payback time per typical installed system and how likely are customers to prefer DER given a payback time. This customer preference is the percentage of customers likely to adopt DER at a future time. Therefore, there is room to improve the accuracy of the forecast when the full capability of DERSim including customer economics and adoption model is used in the future.

D.1.1 Uncertainty and Maturity - PV

Guidehouse's Solar PV aggregated capacity forecast at the feeder level aligns with AESO's Net-Zero Alberta wide forecast. However, there are some uncertainties in the DFO and below level of granularity:

- Historical interconnection data is missing in 4 out of 7 DFO's. Therefore, the pre-2023 Solar PV capacity is not known at the moment and by what percentage will shift up the Alberta aggregated capacity.
- Customer loads shapes were only available for 3 DFO's. Guidehouse generated a blend for the other 4 DFO's (see Table 7 for available vs blend data) using provided hourly data.
- Likely limits on who could eventually adopt Solar PV was calculated at the DFO level and does not consider the socio-economic differences between different feeder circuits.
- Solar PV and Storage capacities does not consider future changes in installed capacities per adopter. This uncertainty will affect future incremental and aggregated capacities.
- Storage adoption was not modelled independently from Solar PV and assumes that adoption trajectories in North American are similar. The effects of local Time-of-Use (TOU) rates used to incentivize Storage adoption were not considered in this study.

D.1.2 Uncertainty and Maturity - EV

The uncertainties related to the EV Forecast are as follows:

- There are some uncertainties whether vehicle OEMs would be able to respond to the strict zero—emissions transition guidelines laid out by the AESO in time. If vehicle manufacturers are slow to respond to the demand for electric vehicles it might lead to some gaps in the expected and actual EV adoption values, since this forecast is being driven by policy and pursuant demand rather than supply.

- There are some uncertainties surrounding electrification of Medium and Heavy-Duty vehicles. It could be the case that in future hydrogen fuel cell powered vehicles end up dominating the Zero-Emissions vehicle segment in the medium and heavy-duty market rather than electric vehicles.

- The Alberta EV market is quite nascent currently and there are uncertainties surrounding charging preferences for different EV segments like residential, fleet etc. which would subsequently affect the load impact estimates.

D.2 Detailed Study Assumptions (Internal)

D.2.1 Assumptions for Net-Zero PV Forecast

Guidehouse made the following assumptions to generate a Solar PV adoption forecast using feeder level customer and historical adoption information:

- The DFO level customer adoption curve was applied to each feeder. This assumes each circuit will approach the long run market share by the end of the study period. While this is reasonable at an aggregate level, this assumption was made at the feeder level.

- The feeders with higher penetration in the current year were assumed to be further along their adoption curve and thus would experience less adoption in the forecast years.

- The feeders with less adoption were assumed to be earlier in their adoption curve and therefore would have a greater increase in adoption in the forecast years.

- The adoption curve was used to determine the PV counts forecast by multiplying the penetration by the customer count at each feeder and customer segment. The customer counts were assumed to be the same as the current year, so the increases in the PV counts were due to increases in forecasted solar penetration. This approach would result in higher adoption in solar PV from the feeders that have the higher customer counts.

D.2.2 Assumptions for Net-Zero EV Forecast

Guidehouse made the following assumptions to disaggregate Alberta level EV results obtained from the AESO Net-Zero Emissions Pathways report to the FSA and subsequently to the feeder level for the complete forecast period (2023-2050):

- The province-level EV forecast obtained from AESO's Net-Zero Emission Pathways Report was extended from 2042 to 2050 by fitting a sigmoid function to the forecast. This allowed feeder forecasts and associated costs to be projected for the years 2042-2050 that were not covered in the AESO forecast.

- The rate and trajectory of adoption from 2023-2041 was determined by the AESO's Net-Zero Emissions Pathways Report and is uniform across the FSAs, however since FSA populations vary greatly, this heterogeneity was captured in the forecast through a spatial distribution.
- The spatial distribution of adoption is based on demographic indicators including income and education level, consequently each FSA gets a unique penetration of EV adoption according to the distribution of FSA level results in Guidehouse's 2022 EV-GNA report.
- EV adoption results were only prepared for two customer segments – Residential and Commercial. All the vehicle class and duties were mapped to these two segments.
- The relative adoption of EVs by Residential and Commercial customers was assumed to be proportional to the Alberta wide values in the 2022 EV-GNA report.
- The ratio of Medium and Heavy-Duty adoption to Light Duty adoption in Alberta was assumed to be the same as estimated for a similar US region (VAST analysis previously conducted by Guidehouse).
- The charger to vehicle ratios and rated capacity per EVSE were derived from a previously conducted VAST analysis for a similar US region.

D.2.3 Assumptions for Net-Zero ES Forecast

Guidehouse made the following assumptions to generate a unique feeder level storage forecast:

- Storage adoption is driven by new Solar PV installations and therefore it will be modeled using an attachment rate % forecast. Therefore, an increase in the rate of Solar PV installations will also proportionally increase Storage adoption.
- Current storage adoption in North American can be used as a template to map the future storage adoption in Alberta.
- Storage attachment per segment maps to each circuit and DFO. This means that attachment rates are similar in each feeder circuit across Alberta.
- Typical Residential and C&I storage capacities will match common options available in the market.

D.2.4 Assumptions for Grid Impact Assessment

Key assumptions to support the methodology outlined in Appendix A and the main report are summarized below:

- **DER Integration Requirements**

  Application of the CYME and Feeder Cost Models are dependent on the availability of DFO input data and forecast results. Primary data requirements and assumptions are listed below:

- **Feeder Data –** Feeder properties including feeder ID, peak load, number of customers served, feeder length (overhead and underground) number of devices (e.g., reclosers and regulators), line length (1/2 and 3-phase).
- **Load Forecasts** – Annual PV and EV forecasts at the time of the feeder peak (EV) and minimum mid-day load. Maximum PV output typically occurs at 13:00 hours and maximum coincident EV charging at 19:00 hours for most DFOs.
- **CYME Models** – Up-to-date CYME model databases for each of the representative feeders, verified by DFOs.
- **Energy Storage** – Maximum ES output (charging or discharging) at the time of the feeder peak.

- **DFO Planning Criteria**
- **Feeder Loading Limits** – ENMAX and EPCOR capacity planning limits are set at 50% of the feeder emergency rating; 300 amps was applied to each DFO. All other DFO's are assumed to load feeders up to their maximum normal rating.
- **Voltage Regulation** – Practices related to the maximum number of regulators allowed. Practices vary by DFO, from none allowed by EPCOR to up to 4 for DFOs with longer feeders.
- **Reverse Power** – Allowable for all DFOs.
- **Operating Limits –** None observed, except for capacity planning limits.
- **Engineering and Modelling Assumptions**
  - **DER & EV Aggregation** – Number of nodes (injection points in CYME) and locations determined via separate Excel model.
  - **Performance Violations** – Limited to over- and undervoltages and exceedance of feeder planning limits.
  - **Parametric Cost Curves** – Minimum of five capacity levels modeled in CYME for PV and EV, if violations are detected at maximum PV and EV output.
- **Mitigation Options and Unit Costs**
  - **Mitigation Options** – Limited to currently available technologies (e.g., active inverter control precluded as an option).
  - **DFO Unit Costs** – Based on unit costs provided by each DFO; adjustments are made where differences exist among DFOs.

- **Mitigation Selection Criteria** – Least cost mitigation at the time (i.e., year) of the performance violation; mitigation strategies assume future PV and EV adoption is unknown during the year in which mitigation is required.

- **New Feeder Cost** – When a new feeder is required due to loading in violation of the DFOs capacity planning criteria, the cost of a new feeder include a $1,000,000 base cost for the substation bay position and exit feeder, plus a per mile line charge based on main line feeder length:

  (1) For main line feeders less than 10 kilometers, the cost of the new line is the DFO per kilometer cost over 5 kilometers.

  (2) For main line feeders between 10 and 25 kilometers, the cost of the new is DFO per kilometer cost over 12.5 kilometers.

  (3) For main line feeders greater than 50 kilometers, the cost of the new is DFO per kilometer cost over 25 kilometers.

- **Representative Feeder Analysis**

  - Feeder clusters are derived using the sampling analysis described in Section B.3.

  - Following the initial sampling analysis to identify the minimum number of required clusters for representative feeder selection, clusters with common properties are combined (e.g., Clusters 2 and 4).

  - Clusters are then disaggregated based on voltage – accurate modeling of EV impacts require most, if not all, feeders within a single cluster have the same operating voltage (e.g., Subgroups 1 and 2 for Groups 2 %).

  - Table 19 lists the feeder properties for the 23 feeders selected via the sampling analysis

Table 19. Representative Feeder Properties

			Number of Feeders by DFO							Average Feeder Properties									
Group No.	Primary Rate Code	No, of Feeders	ENMAX	EPCOR	FORTIS	APCO	Medicine Hat	Letheridge	Red Deer	Primary Voltage (kV)	Feeder Length (km)	Total Cust. per Feeder	Peak Load (MW)	Ave. Peak Ld per Cust (kW)	Customers per Line km	% 3 Phase	% 1/2 Phase	% OH	%UG
1	Res / Com	46	36	3	0	0	0	7	0	15 / 13.8	8	233	4	20	32	93%	7%	46%	54%
2, 4 - SG 1	Res / Com	89	45	29	0	0	2	13	0	15 / 13.8	14	800	4	10	65	58%	42%	37%	63%
2, 4 - SG 2	Res / Com	49	4	0	34	11	0	0	0	25.0	23	688	5	11	28	72%	28%	56%	44%
3 - SG 1	Res / Com	46	6	36	1	0	0	3	0	15 / 13.8	11	293	5	24	27	56%	44%	40%	60%
3 - SG 2	Res / Com	33	7	0	18	8	0	0	0	25.0	21	94	3	26	5	88%	12%	72%	28%
6 - SG 1	Res / Com	15	0	15	0	0	0	0	0	15.0	26	1,306	7	17	42	35%	65%	22%	78%
6 - SG 2	Res / Com	97	0	7	61	29	0	0	0	25.0	59	694	5	19	11	64%	36%	80%	20%
7 SG 1	Res	38	1	37	0	0	0	0	0	15.0	28	2,693	6	2	117	29%	71%	33%	67%
7 SG 2	Res	82	0	2	60	20	0	0	0	25.0	52	2,805	9	7	54	52%	48%	37%	63%
8	Res	174	127	27	1	7	0	12	0	15 / 13.8	31	2,380	6	3	85	39%	61%	38%	62%
5, 9 - SG 1	Com / Ind	42	17	9	1	0	10	5	0	15 / 13.8	9	107	5	59	15	86%	14%	35%	65%
5, 9 - SG 2	Com / Ind	67	1	5	45	16	0	0	0	25.0	51	95	5	65	3	82%	18%	79%	21%
10 - SG 1	Res	46	9	22	0	0	15	0	0	15 / 13.8	46	3,012	7	3	73	35%	65%	41%	59%
10 - SG 2	Res / Com	41	0	0	28	13	0	0	0	25.0	114	884	5	10	8	57%	43%	90%	10%
10 - SG 3	Res	45	19	16	5	5	0	0	0	25.0	75	4,124	9	3	55	29%	71%	23%	77%
11	Res / Com	202	0	1	149	52	0	0	0	25.0	186	878	6	13	5	52%	48%	93%	7%
12, 14	Res / Com	167	6	2	93	66	0	0	0	25.0	352	1,338	7	10	5	37%	63%	93%	7%
13	Com / Ind	103	10	8	53	30	2	0	0	25.0	34	36	6	225	2	90%	10%	70%	30%
15	Res	11	4	0	0	7	0	0	0	25.0	81	5,166	12	3	224	64%	36%	49%	51%
16, 18	Com / Ind	54	5	3	24	21	0	1	0	25.0	12	8	6	760	1	94%	6%	66%	34%
17	Inst / Ind	41	7	4	13	14	2	1	0	25.0	10	4	8	1,964	2	97%	3%	45%	55%
19-22, 24	Inst / Ind	64	8	4	21	28	2	1	0	25.0	5	2	11	8,149	4	98%	1%	54%	45%
23	Res	37	0	0	14	23	0	0	0	25.0	661	1,609	6	4	6	22%	78%	93%	7%
	Totals	**1589**	**312**	**230**	**621**	**350**	**33**	**43**	**0**										

D.2.5 Assumptions for Grid Impact Assessment – Secondary Transformers

Due to limited availability of transformer data – for example, the absence of data indicating the type of load connected to each transformer – several assumptions were required to determine the number of transformers that are expected to be replaced due to incremental EV loading. The following lists key assumptions applied to the secondary transformer analysis.

1. All transformers connected to EV chargers are rated 10 kVA and above

2. The following convention was applied to assign transformers to rate classes

    a. All transformers rated 25 kVA and below assumed to connect to residential EVs

    b. All transformers connected to more than 5 customers are assumed to serve residential load and EVs

    c. Fifty percent of transformers rated 37.5 kVA are assumed to serve an equal number of residential and commercial customers and EVs

    d. All transformers rated above 37.5 kVA and up to 500 kVA are assumed to serve commercial load and EVs, except for those serving more than 5 customers as noted above

    e. All transformers rated above 500 kVA are assumed to serve industrial load, and are excluded from the analysis as the number of EVs is based solely on residential and commercial forecasts

3. Residential transformers are connected only to Level 1 and 2 EV chargers, with the percentage of those connected Level 2 chargers increasing over time

4. Commercial transformers are connected only to Level 2 and EVDC chargers, with the percentage connected to EVDC charges increasing over time

5. The rating of Level 2 and EVDC chargers increase over time

6. Maximum transformer ratings are set at 100% of normal rating. Transformers are replaced when incremental charger loading that causes transformer loadings to exceed 100%[24]

7. Both on-peak and off-peak EV loading conditions are incorporated into transformer model logic

8. A diversity factor is applied to transformers connected to multiple EVs (see table below)

9. The assumptions on transformer loading and cost profiles for Lethbridge and Red Deer are based on those assigned to Medicine Hat, as data was not available for these DFOs

10. Transformer replacement costs are adjusted based on the percentage of pole and padmounted transformers

Table 20 presents EV charger ratings applied to the three types of chargers applied to residential and commercial EVs described above. Except for Level 1 chargers, the chargers rating are assumed to increase over time. After 2033, charger ratings are assumed to increase 5% annually.

Table 20. EV Charger Ratings

EV Ratings	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
EVDC	100	118	140	165	195	231	273	322	381	400	400
Level 1	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Level 2	12.0	12.6	13.3	14.0	14.8	15.6	16.4	17.3	18.2	19.2	20

Table 21 lists the number of EVs connected to each customer as a function of transformer kVA rating. For example, all transformers rated 100 kVA are assumed to have five EVs connected to each customer assigned with EVs installations.

Table 21. Number of EVs per Transformer kVA Rating

Number of EVs per customer per XFMR kVA	Commercial EVs	Residential EVs
10	1	1.5*
15	1	
25	1	
37.5	2	
50	2	

[24] The maximum loading limit can be adjusted in the transformer model

67.5	3
75	4
100	5
112	5
150	6
167	6
225	8
250	8
300	10
333	12
500	20
1000	40
1500	50
2000	75
2500	100

*All transformers serving residential customers are assumed to have, on average, 1.5 EVs connected per customer

Table 22 lists the diversity factors applied to transformers connected to EV by rating class. The diversity factor is applied to the total number of transformers within each rating group, which reduces the net EV loading.

Table 22. EV Diversity Factors

Transformer Rating (kVA)	Factor
10	0.10
25	0.15
50	0.20
75	0.25
100	0.30
300+	0.50

D.3 Study Improvement Opportunities

Multiple assumptions and simplifications were used to account for gaps in the data provided by the DFO's. This section details what gaps existed in each portion of the analysis, and thereby resulted in some risks. These risks could have been mitigated from the start by receiving better data from the DFO's. A breakdown of risks and the potential mitigations associated to PV and Storage, and EV can be seen in

Table 23 and Table 24 respectively.

D.3.1 PV and Storage

Table 23. PV and Storage Forecast: Risks and Mitigations

Risks	Mitigations
For the technical potential, limited interconnection data was provided for PV which resulted in there being no available baseline historical capacity data for 4 DFOs. No interconnection data was provided for storage resulting in no Alberta information on growth and attachment rates for storage. Only a single year of customer demand data was provided, so an assumption of 0% growth year over year was used in the model. A single year of representative weather data was provided, so the PV impacts were based this single year of data.	These risks could have been mitigated by having more historical data provided earlier on in the study.
For the PV forecast, the full DERSim customer economics and adoption analysis was not included in this study, and a less granular and nuanced DER customer preference approach was used as a proxy. In this study no DFO customer rates were used. The adoption rates at the DFO level mapped to each circuit in a DFO which does not account for differences in local socioeconomic, or urban, suburban, and rural differences.	This risk could have been mitigated with additional data on the customer economics such as installation costs and retail rates. The forecast could have also been more granular with additional data such as socioeconomic data at the census level.
For the Storage forecast, storage was only forecasted as an attachment to new solar PV installations. The full DERSim customer economics and adoption analysis would have modelled storage adoption independently of solar PV. No DFO customer rates were used in this study so benefits on time of use rates were not explored. Due to gaps in Alberta storage interconnection data, storage attachment rates per customer segment were sourced from a previous Guidehouse engagement with a large Midwestern utility. Storage attachment rates per segment were applied equally to every circuit in Alberta.	This risk could have been mitigated by having been provided more data early on with the historical interconnection data.
For the grid impacts, the PV and storage grid impacts per customer are similar year over year as only one year of 8760 customer demand load shape was available and system sizes were assumed to be the same year over year.	This risk could have been mitigated with additional data.

D.3.2 EV

Table 24. EV Forecast: Risks and Mitigations

Risks	Mitigations
Using the AESO forecast provides a consistent forecast across the province, and aligns perfectly with AESO's outlook, however, the forecast presented here lacks the fidelity or specificity that could come from conducting individual forecasts for each DFO or geography (FSA) individually. While the approach taken for this study does disaggregate AESO results geographically according to demographics and in line with the 2022 EV-GNA report, and re-aggregate them according to DFO-specific GIS asset data, there are gaps in some data which were filled with Province-wide assumptions, gaps in circuit-level data which were filled with DFO-wide assumptions, etc.	Generating more granular and specific forecasts for each DFO could have provided a richer result with "bottom-up" insights, and the ability to drill deeper into results and understand the drivers of results in finer detail.
Multiple assumptions were made based on a previously conducted VAST analysis done for a similar US region which may or may not reflect vehicle, fleet, population, and EV load characteristics of Alberta completely, and certainly is not tailored to each DFO.	Using Alberta level vehicle registrations data and a forecasting model calibrated to historical EV adoption in the state could have provided a more accurate forecast.
The analysis didn't involve any granular vehicle class or powertrain distinctions like passenger cars, delivery and semi-trucks, school, and transit buses, fully electric or plug-in hybrid electric vehicles etc. This limited the capability to accurately model charging load impacts of these vehicles as all these classes of vehicles have different driving patterns, duty cycle, and charging requirements.	This risk could have been mitigated using Alberta level vehicle registration data and information specific to Alberta's vehicle use market.
The analysis didn't include distinctions between charging use cases like fleet vs depot charging, market or workplace vs residential charging which affects peak load impacts since each use case has a distinct charging load profile which was averaged out by grouping the use cases in two broad segments for this analysis: residential and commercial. The same holds true for charging technologies like Level 1, Level 2 and DC fast charging, the distinction of which was excluded from the forecast.	Using a bottom-up approach and relying on specific charger to vehicle ratios based on charging use cases in Alberta would provide a more granular EVSE forecast.
High-level assumptions were made regarding the number of customers associated with each transformer that affected the model's capability to accurately forecast load impacts at the transformer level.	Using granular data on different transformers associated with a feeder and customer counts serviced by the transformers for all DFOs could have provided a better and accurate forecast of impacts of EV charging load on all the transformers.