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Reference

Exhibit 4, Tab 1, Schedule 1 (DSP), Appendix 16 – Distributed Energy Resources Integration

Preamble: The DER Integration investments consist of (i) the DER Control Platform and (ii) the Smart DER Platform (collectively, the DER Integration Investments) (p. 1).

a) Does Alectra consider "energy storage" to include EV batteries? Please explain your response.

b) Please provide any and all working papers, reports, and analysis conducted to support Alectra's planned investments in the:

(i) DER Control Platform; and

(ii) Smart DER Platform.

c) Alectra notes that the DER Integration Investments are driven by expected increasing adoption of DER in Alectra's service territory and the significant challenges and opportunities that such a trend presents for the utility's distribution system and for its customers (p. 5). Please provide any and all analysis, working papers, and reports related to:

(i) Alectra's expectations and/or forecasts of increased DER adoption in Alectra's service territory, including any and all EV adoption; and

(ii) the challenges and opportunities associated with the trend of increasing DER adoption.

d) Please explain (with examples and with reference to the key areas of focus listed on pp. 8-10) how the DER Integration Investments will support Alectra's capacity to respond to, manage, and benefit from the anticipated "exponential growth in [EV] adoption" and electrification of transportation generally.

e) Please place the following documents referenced in footnotes 149, 150, 152, 153, 154, and 155 of Appendix A16 on the record in this proceeding:

(i) Seba, T. (2017) Clean Disruption of Energy and Transportation, Clean Energy Action Conference, June 8 2017;

(ii) Bloomberg New Energy Finance. (2018). Electric Vehicle Outlook 2018; and

(iii) EY Alectra September 2018. Presentation.

Response:

a) Alectra Utilities considers the batteries inside EVs to be controllable loads only if paired with smart Electric Vehicle Supply Equipment ("EVSE"). As such, EV batteries could be considered as DERs, for the purpose of developing DER Control and Smart DER Platforms.

b) (i) The electricity sector is undergoing transformational changes driven by technology, government policy, the economy, climate change, customer expectations and demographic trends. These factors have driven a proliferation of DERs. Alectra Utilities has performed a feasibility study to investigate the benefits and challenges associated with widespread adoption of residential DERs. The report is attached as DRC-8_Attachment_1 POWER HOUSE Feasibility Study. This study was designed to evaluate the economic and grid benefits that residential DERs can contribute to electricity customers and the electricity system in Ontario, when these DERs are monitored, controlled, and coordinated by a DER control platform. The conducted analyses were aimed to understand:

- the potential adoption of the specific DER technology and the DER control platform and its potential value streams;
- the scalability and costs associated with increased adoption;
- the technical capabilities of the technology;
- the feasibility to defer or eliminate the need for transmission or distribution infrastructure upgrades to meet future demand growth;
- the monetary value associated with the services the technology can provide; and
- the barriers and catalysts to widespread adoption.

Alectra Utilities is the LDC partner for a comprehensive study performed by York University to analyze the impact of electrifying transit network in Alectra's York Region service territory on the distribution grid. More information could be found in the DRC-8_Attachment_2 York University Study_Electrifying Transit Network. A similar study on the operational feasibility and grid impact related to electric buses is also attached as DRC-8_Attachment_3 Operational Feasibility and Grid Impact Analysis. This study is intended to: (1) quantify the energy demands for opportunity versus overnight charging of the electric buses; (2) help understand the required infrastructure of the charging station; (3) test the transit operation feasibility; and (4) generate the charging load profile.

The generated charging load is used to study its impact on: the utilization and lifetime of the transformers; the operation of the local distribution grid; substation transformer and distribution feeders overloading, voltage regulation and quality aspects, and operation of voltage control devices. The findings of this study reveal the need to develop the DER Control Platform and integrate it to traditional distribution operation systems.

(ii) As utilities consider the many opportunities and risks DERs pose to the distribution system, there has been a growing attention towards the need to address not only the control system implications of DERs, but also the economic systems, such as markets, associated with managing DERs in order to fully unlock the value DERs bring to the distribution system, customers and the environment. The reason why economic systems are now playing a role in effectively integrating DERs into the distribution system is because the future decentralized and distributed grid will have many parties at the grid-edge, such as customers with DERs, now involved in providing grid services. Such grid services will have various prices and costs, and utilities will need to use economic tools, such as markets and incentives, to align and manage the different interests of all these parties participating in new energy services, while at the same time ensuring grid safety and reliability isn't compromised.

As a result, this has led to a focus on the use of a combination of economic and control techniques to manage DER participation in grid services - this is exactly what Alectra's Smart DER Platform will provide. The Smart DER platform involves developing a platform that will enable real-time processes for procurement, smart contracting, automated verification, and settlement of energy transactions with customers participating in grid services with their DERs. Please refer to the following link for a report from Gridwise that describes the above benefits of using transactive energy platforms to successfully and effectively integrate DERs into electricity systems. http://www.gridwiseac.org/pdfs/te_framework_report_pnnl-22946.pdf

c) (i) Alectra Utilities has provided its forecast on renewable energy generation ("REG") connections on Page 312 in Exhibit 04, Tab 01, Schedule 01. For Alectra Utilities' forecast on EV, please refer to response to DRC -2 b).

(ii) For more details on the challenges and opportunities associated with the trend of increasing DER adoption, please refer to Page 8-10 in Exhibit 04, Tab 01, Schedule 01, Appendix A16 DER Integration. Please also refer to the response to DRC-08 b).

The challenges and opportunities associated with the trend of increasing DER adoption is also addressed in the feasibility study performed by Alectra Utilities to investigate the benefits and challenges associated with widespread adoption of residential DERs. The report is attached as DRC-8_Attachment_1 POWER HOUSE Feasibility Study.

d) The DER integration investments consist of two projects - DER Control Platform and Smart DER Platform integration. The DER Control Platform project utilizes Distributed Energy Resource Management System ("DERMS") platform to integrate DERs with Alectra Utilities' traditional distribution operation technology systems.

Alectra Utilities' DER Control Platform aggregates, integrates, controls and optimizes the operation of DERs. This will enable Alectra Utilities to utilize DERs as feasible non-wires solutions to: build capabilities that could predict the grid operational impacts of DERs; help mitigate power quality issues associated with DERs; reduce peak demand; enhance system planning; defer distribution and transmission infrastructure expansion; establish safety practices and cyber-security standards to facilitate safe and reliable connection of DERs into the distribution system. In addition, through Alectra Utilities' DER Control Platform, the utility aims to provide a flexible and scalable solution to effectively engage with its customers with DERs, support optimization of their DER utilization and provide automated business processes around DER management. Complementary to this, Alectra Utilities Smart DER Platform will enable customers and the utility to transparently record the flow of electricity to and from DERs, enabling the efficient procurement of energy services, such as demand response, solar generation and frequency regulation.

The Smart DER Platform will provide a robust settlement mechanism backed by timely and efficient financial transactions to enable overall trust and customer value delivery, leading to increased customer satisfaction. These two projects together will provide an end-to-end solution enabling customers owning various types of DERs (e.g., solar generation, battery storage, smart thermostats, electric vehicles ("EVs")) to participate in energy services that provide value to the entire customer base.

e) (i) Please refer to the link below for Tony Seba's presentation on Clean Disruption of Energy and Transportation on June 8, 2017: https://www.youtube.com/watch?v=2b3ttqYDwF0. The extract of the presentation can be found in the attached DRC-8_Attachment_4 Presentation Extract_Clean Disruption of Energy and Transportation.

(ii) Please refer to DRC-8_Attachment_5 Bloomberg New Energy Finance Electric Vehicle Outlook 2018 as attached to the response to this IR.

(iii) Please refer to DRC-8_Attachment_6 EY Report.

DRC-8

ATTACHMENT 1- POWER HOUSE Feasibility Study

POWER.HOUSE
Feasibility Study

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LIST OF FIGURES AND TABLES

1. INTRODUCTION

In 2015, Alectra Utilities launched a residential solar storage pilot program, POWER.HOUSE[1], funded by the Independent Electricity System Operator (IESO) Conservation Fund[2]. The POWER.HOUSE pilot was designed to evaluate the economic and grid benefits that residential solar storage can contribute to electricity customers and the electricity system in Ontario.

Figure 1. POWER.HOUSE System Highlights

The pilot program enabled the deployment of 20 residential solar storage systems in homes within Alectra Utilities' service territory. The pilot enables participating customers to displace a significant portion of the electricity they source from the grid and better manage the electricity that they do use, resulting in reduced energy costs, lowered carbon footprint and improved efficiency. The system is also used by the utility to contribute to grid reliability and resiliency.

Figure 2. Customer Benefits of POWER.HOUSE System

[1] POWER.HOUSE program website: https://www.powerstream.ca/innovation/power-house.html

[2] The IESO Conservation Fund supports new and innovative electricity conservation initiatives, to help Ontario's residents, businesses and institutions cost-effectively reduce their demand for electricity.

Alectra Utilities embarked on a feasibility study in partnership with the IESO in 2016 to investigate the benefits and challenges associated with widespread adoption of the POWER.HOUSE program in Ontario with a specific focus on York Region. The feasibility study was intended to primarily answer two questions:

1. Is it feasible to expand the program to a larger number of residential homes?
2. What are the costs and benefits of, and barriers to an expanded program?

The feasibility study conducted analyses to understand:

- the potential adoption of the POWER.HOUSE technology within York Region from 2016 to 2031;
- the potential value streams that could be realized through increased adoption of POWER.HOUSE;
- the scalability and costs associated with increased adoption;
- the technical capabilities of the technology;
- the feasibility to defer or eliminate the need for transmission or distribution infrastructure upgrades to meet future demand growth;
- the monetary value associated with the services the technology can provide; and
- barriers and catalysts to widespread adoption.

The feasibility study did not examine adoption beyond York Region or specific funding requirements to accelerate technology adoption. In order to determine market potential and adoption rates, a baseline assumption of customer cost sharing and associated benefit was made (i.e. the proportion of total POWER.HOUSE system cost the participating customer would bear and the amount of value they would receive). Total costs were used in the overall cost/benefit analysis outlined in the report. The study identified and quantified these costs and benefits, but made no assumption on how they would be shared and distributed. More details can be found in section 6 of this report.

The results outlined below make a strong case for further study of the technical and commercial potential that residential solar storage can achieve when managed through a software control platform with advanced aggregation capabilities. Further study will also generate additional data for analysis and more opportunity to test against the assumptions contained in the report and to assess other Distributed Energy Resources (DER). The positive direction of these initial results will help inform future efforts that may see these technologies emerge as a sustainable option for thoughtful grid deployment over the course of time.

Virtual Power Plant

A Virtual Power Plant refers to a collection of Distributed Energy Resources controlled through an intelligent software platform to create the functional equivalent of a single, larger generation resource.

For simplicity, the study only examined the technical capabilities of both single POWER.HOUSE units and samples within the existing fleet of 20 units. A further examination of larger numbers of aggregated units within a Virtual Power Plant would be useful in identifying how the system operates under a variety of environmental and system conditions.

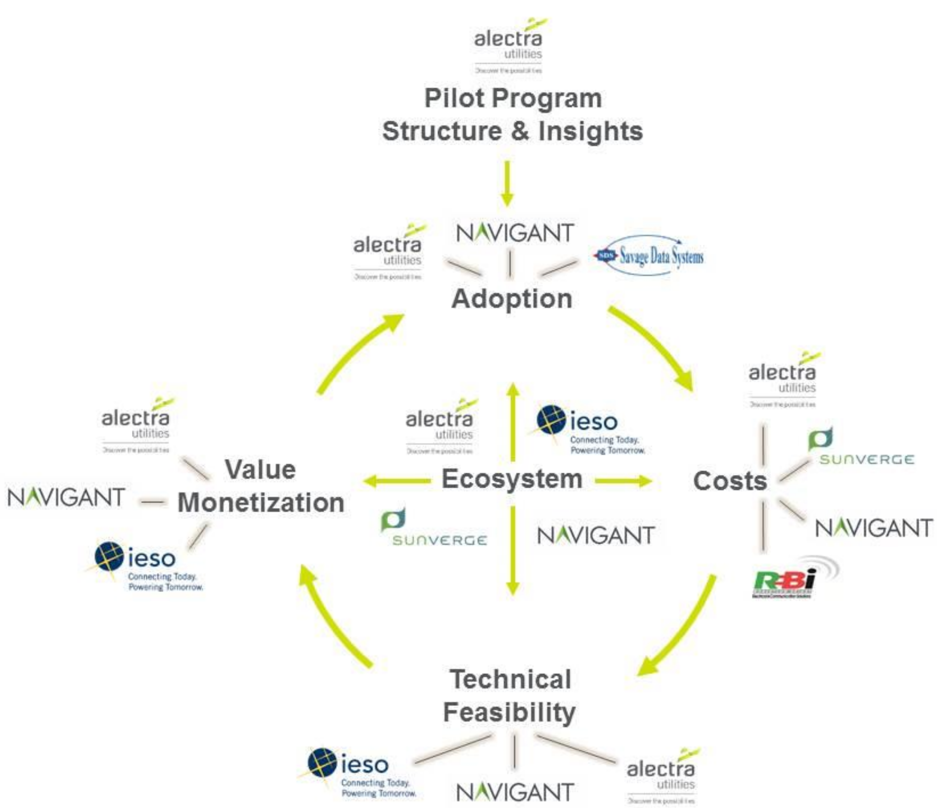
When examining the value streams, costs, and benefits, the study assessed the value of a large-scale POWER.HOUSE deployment on Ontario customers as a whole, independent of who pays or who benefits from the deployment. Two outlooks were established to represent a range of possible outcomes. The first, a base case, reflected existing trends in the electricity market and the cost of various system configurations were explicitly modeled. The second, a deep de-carbonization case, represented higher levels of electricity demand sparked by aggressive policy and market driven electrification. The second outlook contemplates several transformational market changes for both customers and the electricity system, and as such represents a more uncertain outlook compared to the baseline scenario. Actual outcomes will reflect the existence of different barriers and catalysts for adoption.

Under the assumptions used in the study there may be an opportunity to defer the longer-term infrastructure needs in Vaughan for at least 2 years. The value of deferral depends on several uncertainties including the cost decline of technologies, provincial electricity supply outlook and rate of growth in York Region.

2. COLLABORATION

The feasibility study clearly demonstrated the collective benefit that can be achieved when LDCs, the system operator and private sector work in concert towards a common goal. The partners and supporting entities that took part in the study work streams are described in Figure 3, below. The outcomes and insights derived from the study were particularly relevant because they were based on assumptions that were vetted by industry experts. For example, in order to ensure that the technical tests performed as part of the feasibility study reflected realistic reliability services needed for system operations, IESO operations staff were involved in defining the test scenarios and their associated success criteria. IESO planning staff were also involved to help frame the mechanisms for assessing the value of the program to the electricity grid, as well as to validate assumptions, approaches, and results. IESO and Alectra Utilities planning staff also worked together to estimate the value of deferring transmission and distribution investments, as well as the technical requirements and operability the program would need in order to successfully defer upgrading the infrastructure. The feasibility study team's collaboration, organization and engagement enabled the study to be successfully completed by leveraging the expertise of all entities involved.

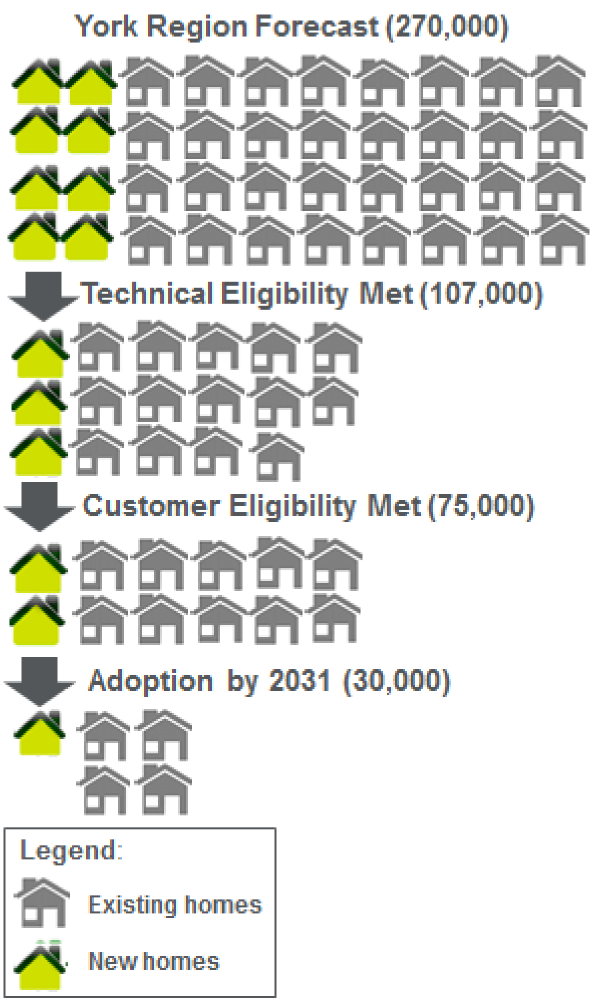
Figure 3. Feasibility Study Structure and Entities



3. POTENTIAL ADOPTION

An assessment was undertaken to understand the realistic adoption of POWER.HOUSE units within York Region, a geographic area in Southern Ontario representing more than one million customers and nine distinct municipalities. For simplicity, two representative configurations of POWER.HOUSE systems were developed: a system catered to larger homes with 5 kilowatt (kW) of solar and 11.6 kilowatt hours (kWh) of integrated storage (single family, detached home) and a smaller home configuration (semi-detached or row home with 3 kW of solar with 7.7 kWh of integrated storage). In order to assess the market adoption, a two stage analysis was performed to determine both the magnitude and pace of market adoption. The methodology is illustrated in Figure 4.

Figure 4. Adoption Methodology and Illustrative Results by 2031



Stage 1: Long Run Market Potential

The analysis began with York Region growth projections[3] expressed in terms of the number of existing and new homes within the 2016 to 2031 study period. To determine the number of homes that would ultimately adopt POWER.HOUSE by 2031, an analysis was conducted that factored both technical and customer eligibility, and was calibrated using a combination of public sources and Alectra Utilities' pilot experience.

Technical eligibility factors included, for example, roof orientation, shading, electrical load of the home, and physical space available for the system. This analysis leveraged both pilot program experience and a National Renewable Energy Laboratory (NREL) study[4].

Customer eligibility factors included, for example, whether a home is rented or owned, annual electricity consumption, and internet connectivity. This analysis leveraged Statistics Canada data and analysis of aggregate Alectra Utilities customer load data from Savage Data Systems.

[3] York Region 2041 Preferred Growth Scenario (https://www.york.ca/wps/wcm/connect/yorkpublic/77c5e970-8020-4b89-a3d0-ff62c60403f1/nov+5+preferred+att+2.pdf?MOD=AJPERES)

[4] Rooftop Photovoltaic Market Penetration Scenarios (http://www.nrel.gov/docs/fy08osti/42306.pdf)

Stage 2: Market Adoption

The pace and shape of adoption was driven primarily by program-specific variables. The adoption assessment considered the program structure; up-front and monthly costs incurred by the customer, anticipated bill savings, and assumed reliability benefits. The adoption presented in this section reflects the base case scenario. Higher anticipated bill savings and a more favourable payback arise when assessing the deep de-carbonization case resulting in higher participation. The pilot study provided market insight into customer payback tied to a specific program offering and provided the baseline economic analysis. The program offer was further refined to arrive at an archetype program offering to carry through the feasibility study. Payback analysis and pilot experience found this archetype offer to reflect a suitable example of a market offering that could support wide-spread deployment. The program offer is outlined in Table 1, below.

Local Dependable Capacity

The local dependable capacity value is a metric that was derived in order to represent the total effective capacity of the Virtual Power Plant while considering the intermittency of solar generation and capacity limitations of storage assets.

The maximum duration of the peak was determined to be three hours when deferring infrastructure capacity upgrades by up to two years, and is based on historical consumption patterns. The ability to meet this peak is based on performance of solar assets within the region and the energy capacity of the storage technology assumed for the feasibility study.

A 33% capacity factor was assumed for the solar assets, based on historical solar performance data in Ontario from the IESO[1]. Effective storage capacity took into account round trip efficiency losses, inverter limitations, and the 3 hour required duration in order to reliably reduce system peak.

Table 1. Feasibility Study Archetype Program Offer

Single family home:

- $4,500 per unit up-front
- $80/month for 10 years
- Payback between 4 and 5 years

Semi-detached/row home:

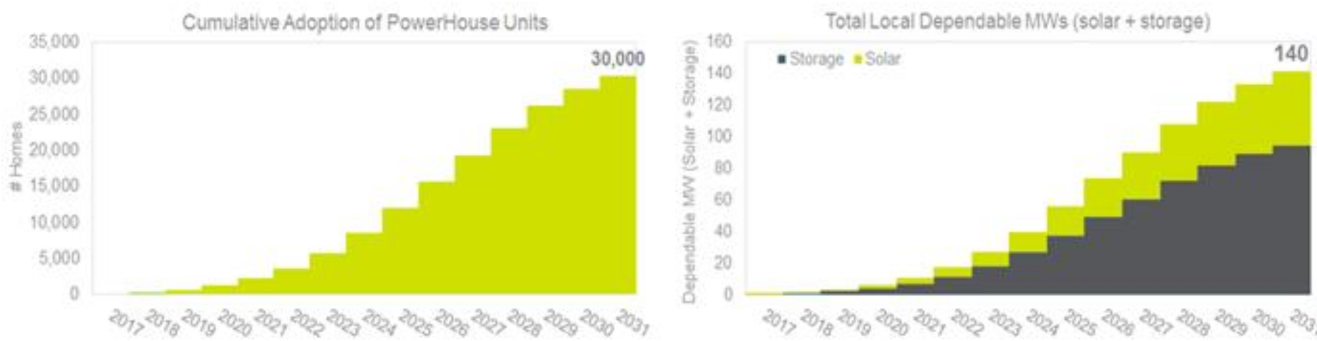
- $3,400 per unit up-front
- $55/month for 10 years
- Payback between 5 and 6 years

To ensure that the capacity identified could be safely and reliably integrated into the Alectra Utilities distribution system, Alectra' system planning staff completed a high-level assessment of the amount of distributed generation that could be connected to the distribution system. This assessment included CYME[5] simulations to ensure that thermal, short circuit, reverse power flow and voltage constraints were not violated on the feeders servicing the region under the proposed DER penetration levels. The assessment was completed for generic DER penetration levels rather than a specific assessment of solar-storage. The assessment found that the anticipated adoption would not result in any issues with the following caveats: the units must be reasonably distributed throughout the network and not all concentrated within a particular area and other DERs must not be growing by a significant amount. The final outcome of the market penetration analysis for the base case found that the adoption of the POWER.HOUSE program could feasibly reach approximately 30,000 residential homes

[5] CYME is a power engineering software package that primarily simulates load flows and distribution system dynamics to assist engineering analysis.

by 2031, which would represent 140 MW of local dependable capacity. The results over the life of the program are summarized in .

Figure 5. Feasibility Study Results: Adoption and Local Dependable MWs



4. SOLAR STORAGE AS A POTENTIAL NON-WIRES ALTERNATIVE

Even with the near-term actions and on-going conservation efforts identified in the 2015 York Region Integrated Regional Resources Plan, electricity demand growth is expected to exceed the system capability in York Region over the next 10 years. Infrastructure investments could be required in Markham-Richmond Hill in the early 2020s and in Vaughan-Northern York Region in the mid-2020s.

IESO and Alectra Utilities planning staff collaborated to determine whether the anticipated POWER.HOUSE adoption could defer the need for local transmission and/or distribution system investments within the 2016 to 2031 study period. The local dependable MW capacity results by year from 2016 to 2031 were assessed against the local needs for (1) Markham/Richmond Hill and (2) Vaughan based on electricity consumption growth projections for each area. The conclusions of the analysis are described below.

Markham-Richmond Hill Area: Given the timing and magnitude of electricity demand growth in Markham-Richmond Hill area, the study confirmed that it is not feasible to rely on residential solar-storage technology to defer the need in the Markham-Richmond Hill area. The amount of time it would take to procure and physically install the necessary assets, along with time needed for system integration into utility operations would exceed the deadline required to meet the area's capacity needs.

Vaughan: Based on the anticipated POWER.HOUSE adoption level, there may be an opportunity to defer the longer-term infrastructure needs in Vaughan for at least two years.

Using a base case scenario, in Vaughan the value of deferring upgrades for two years was estimated to be $12 million ($2016). There are several factors that influence the ability and value of deferring transmission and distribution investments. Some pertinent factors include whether lines are overhead or underground, growth scenarios (higher growth rates will lower the feasibility and value of deferral and lower growth rates will increase the feasibility and value of deferral), and evolution of climate policy in the province (intense electrification would increase electricity consumption and lower the feasibility and value of deferral). For clarity, it should be noted that the business case for deploying a Virtual Power Plant of distributed assets for the express purpose of infrastructure deferral was not considered in this study. Rather, the deferral benefit was seen as one of several benefit streams that contributed to the overall value proposition the technology may deliver under very specific future market conditions. Sensitivity modelling identified slower growth areas as the ideal candidates to deploy DERs if the system priority is to maximize deferral value. In high growth areas, such as York Region, the overall viability of the system is more closely tied to the evolution of market services, which rely on a variety of external conditions to materialize see section 7.

5. TECHNICAL FEASIBILITY

To determine the capabilities of the POWER.HOUSE technology in terms of providing reliability services to the electricity system, the feasibility study team worked with the IESO operations staff to test several scenarios. During this exercise, the team reviewed two key documents outlining use cases for storage assets: an EPRI abstract[6] and a Lawrence Berkeley National Lab report.[7] The team distilled potential functionality and reliability services/market products to four capabilities or use cases for testing. The team agreed that these four core capabilities were representative of the required functionality DERs would be required to demonstrate in order to participate in most grid support services. These capabilities are described in Table 2. To demonstrate a variety of operating scenarios, tests were conducted at the unit level across multiple units both as isolated, stand-alone capabilities, as well as interdependent or "stacked" capabilities.

Table 2. Technical Capabilities Tested

Capabilities	Potential Service/Market Product
Automatically follow a signal	• Regulation service or frequency regulation requires a unit to respond to a signal within seconds.
Respond to a trigger	• Operating reserve requires a unit to commit in advance to respond to an event when triggered within 10 minutes or 30 minutes.
Scheduled response	• Demand response requires a unit to commit in advance and respond to an event for a four-hour duration. • Potential future Flexibility Products such as responding to solar ramp out to offset the loss of solar generation output as the sun sets at the end of the day.
Sense and predict a home's load + solar production and respond accordingly	• The control software leverages real-time analytics to optimize battery dispatch by considering customer load, time-of-use rates, solar insolation, and the battery's state of charge. This intelligent control ensures that the battery charges when rates are lower and discharges to its maximum allowed capacity during higher priced hours.

[6] Common Functions for Smart Inverters, Version 3 (http://www.epri.com/abstracts/Pages/ProductAbstract. aspx?ProductId =000000003002002233).

[7] Distribution System Pricing with Distributed Energy Resources (https://emp.lbl.gov/publications/distribution-system-pricing).

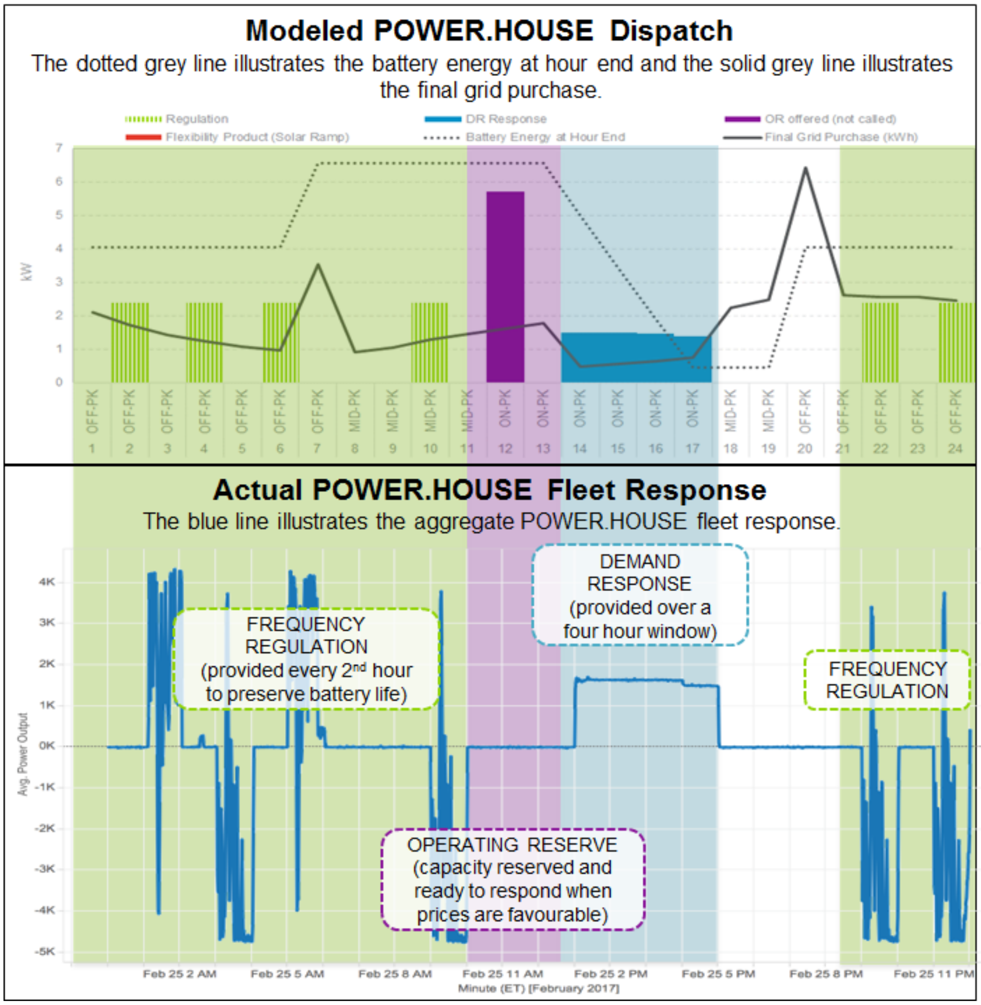
As the timeframe available for testing for this study was limited, the study team had to apply a number of constraints to ensure that the investigation would be completed within the desired timeframe. Table 3 describes the constraints of the testing phase.

Table 3. Testing Constraints

Constraint	Description
Test Sample Size	Tests were conducted on the fleet of existing POWER.HOUSE systems currently installed in Alectra Utilities' territory. To minimize the impact on customers while still providing consistency for analysis, a subset of POWER.HOUSE systems were used for the majority of tests.
Test Capacity Limitations	To maintain existing contractual customer commitments, only a portion of the battery was available for testing. POWER.HOUSE customers are currently entitled to retain 50 per cent of the battery's rated capacity at all times to protect against unplanned outages.
Quantity of Tests	The scope was constrained to demonstrating functionality and technical capability. However, testing to verify repeatability or consistent performance in a variety of changing conditions was not conducted, such conditions include time of day, time of year, weather, communications type, customer type, and location.
Fleet diversity	One of the major advantages of having a large diverse fleet of distributed assets is the flexibility that it provides. Testing was performed on a subset of the fleet, imposing individual constraints on each unit. In practice, the entire aggregate fleet would be seen as a uniform resource and a variety of dynamic dispatch strategies could be used to overcome the limitations of any one (or set of) units. The fleet could, for example, be segmented, and dispatch could be staggered to increase the capacity that could bid into various ancillary services markets. Testing to capture and value such diversity was not within scope of the functional testing.

In order to determine how to stack the proposed value streams, a baseline dispatch model was constructed. The team used a combination of historical and simulated market data to develop an optimized hourly system dispatch profile for a given reference year. This dispatch profile was seen as the reference profile to maximize the value generated by the system both from a customer and market revenue perspective (please refer to the figure in the following section for more detail on system modeling). Figure 5, illustrates both a modeled operating profile extracted directly from the dispatch model and the real time implementation of this operating profile on the fleet of POWER.HOUSE pilot units during the technical testing phase of the study. The figure illustrates a day in which the units provide regulation service every second hour of the day for the full hour, operating reserve during one hour of the day, and demand response over a four hour window in the afternoon. Flexibility product is not provided on this day. Solar generation was minimal and thus provided little opportunity to charge the battery during on-peak hours. The modeled dispatch is presented alongside tests conducted on the fleet of POWER.HOUSE pilot units to implement the optimized profile under actual field conditions.

Figure 5. Modeled and Actual Hourly Dispatch Profile



Additional technical tests were conducted on an opportunistic basis, for example, response of the POWER.HOUSE units during a power outage.

These promising results, although only demonstrated over a short period of time, would suggest that, when aggregated, these systems have the potential to provide these types of reliability services. The technical testing provided the basis for the modeling and analysis described in the following section.

6. VALUE STREAMS AND COST-BENEFIT

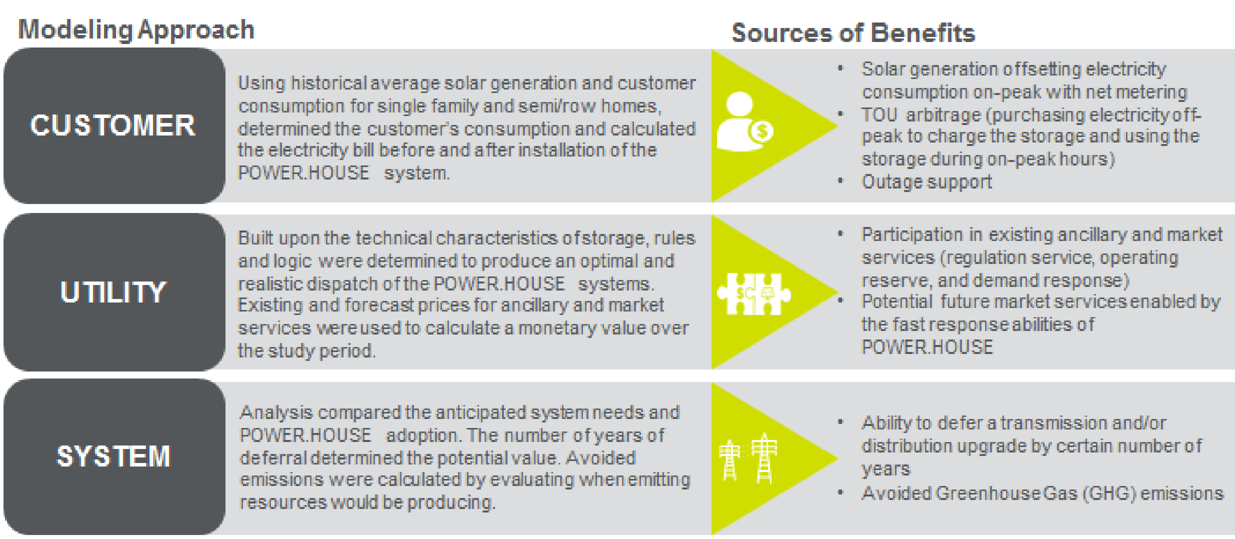
The feasibility study team worked with IESO planning staff to assess the various value streams and the cost-benefits of a large scale POWER.HOUSE deployment in York Region. The focus of the analysis was to assess the economic impact of a large-scale POWER.HOUSE deployment on Ontario electricity customers as a whole, independent of who pays or who benefits from the deployment. This approach is consistent with the perspective used in supporting Long-Term Energy Plan (LTEP) analyses and is expressed in terms of cumulative net benefit reflecting both the total costs and total benefits. Although assumptions about customer's cost contribution to the program were made to estimate the adoption rate and market potential of the POWER.HOUSE technology, the allocation of costs and benefits (e.g., who pays or who benefits) or cost-benefit analysis for each of stakeholder (e.g., the participating customer, other customers, the utility etc.) were beyond the scope of this study.

Cumulative Net Benefit

The economic impact and resulting value to Ontario electricity customers as a whole reflecting both total costs and benefits, independent of who pays or who benefits from the deployment. This approach is consistent with the perspective used in supporting Long-Term Energy Plan (LTEP) analyses.

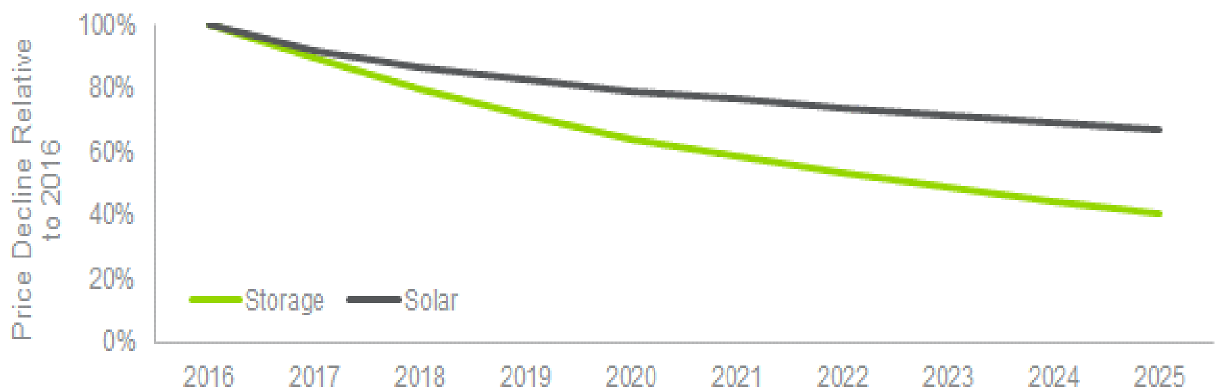
To determine the extent to which large scale POWER.HOUSE deployment would provide a net benefit to all Ontario electricity customers, the study team compared the total cost of deployment, including equipment, installation, and enabling software over the life of the program against the total monetary benefits to all Ontario electricity customers. To assess the total monetary benefits, the study team quantified and summed the various values streams, including the value of deferring transmission and distribution infrastructure in York Region, providing additional energy, capacity, and ancillary services to the electricity system. Increased customer reliability/outage protection and avoided GHG emission were identified as potential value streams, but were considered in a qualitative manner. The modeling approach used to quantify the specific benefits is outlined in Figure 7.

Figure 6. Modeling Approach



The costs associated with POWER.HOUSE technology includes solar PV panels, lithium-ion battery storage, a hybrid inverter, an Energy Management System (EMS), and installation. Costs for storage technologies, solar panels and “balance of system” equipment have declined in the recent past and are anticipated to continue to decline as adoption increases across North America, as illustrated in Figure 7.

Figure 7. Estimated Price Decline of Distributed Solar and Storage Relative to 2016[8][9]



The analysis underpinning this report leverages information from both the 2013 Long Term Energy Plan[10] and Ontario Planning Outlook (OPO)[11] to project prices into the future. Within the Ontario Planning Outlook (OPO), the IESO stated the following.

> *“The demand for electricity is the starting point used in assessing the outlook for the electricity system. There is uncertainty in any demand outlook, as future demand will depend on the economy, demographic, policy, and other considerations. Electricity planning explicitly recognizes the uncertainties in any of these drivers by addressing a range of potential futures.”*

As such, the uncertainty highlighted in the statement above should be considered when reviewing this assessment. The monetary value of the benefits and costs assessed for the POWER.HOUSE feasibility study depend on projections of electricity prices, forecast consumption patterns and the supply mix in Ontario over the next 15 years.

The feasibility study leveraged historical data available from the IESO website for operating reserve prices, demand response auction clearing prices, and leveraged Alectra Utilities’ website to obtain time-of-use rates and distribution charges. Estimates were developed for regulation service payments using historical IESO data for regulation services in aggregate and information from other jurisdictions. The relative proportion of each value stream to the entire stack varied over the years to reflect the fact that certain market products are not currently available and therefore could only be captured in later years.

[8] Residential Energy Storage Systems. Utility Technology Disruption Report. Navigant Research. 3Q 2016.

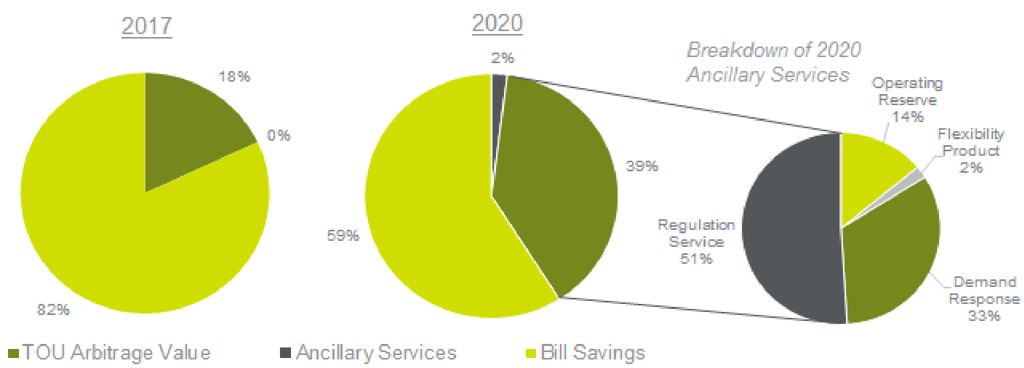
[9] Distributed Solar PV. Navigant Research. Q3 2015.

[10] Long Term Energy Plan (http://www.ieso.ca/Pages/Ontario%27s-Power-System/LTEP/Actual-vs-Forecast-Data.aspx)

[11] Ontario Planning Outlook (http://www.ieso.ca/Pages/Ontario's-Power-System/Ontario-Planning-Outlook/default.aspx)

Figure 9 outlines the proportionate value of each stream in two years of the feasibility study under the base case outlook.

Figure 8. Proportionate Value



As stated earlier, there is considerable uncertainty surrounding these projections. To understand the range and sensitivity of the cumulative net benefit, the feasibility study assessed POWER.HOUSE using two outlooks:

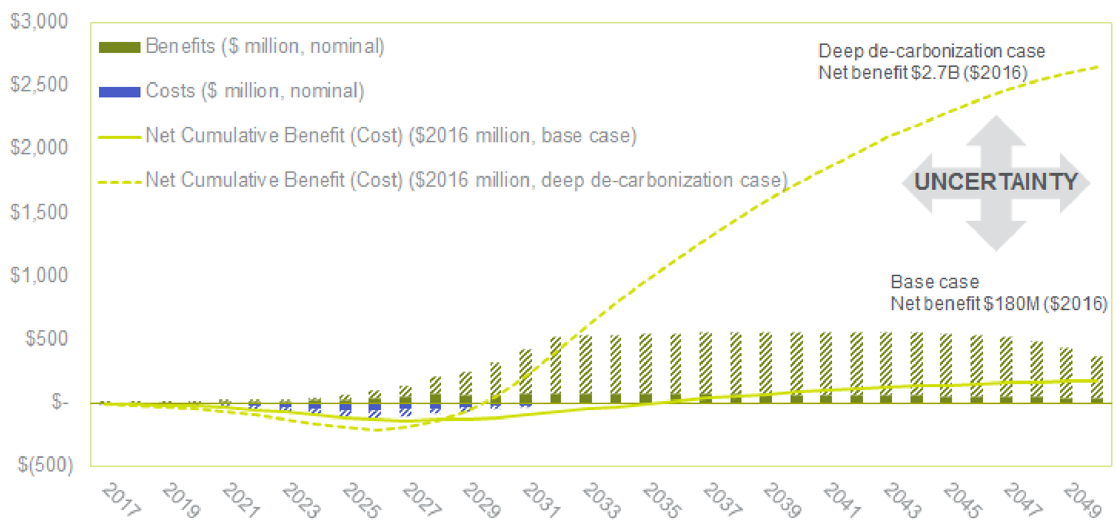
1. **Base case:** derived using publicly available market data, where available, estimates from Navigant, and projections from the 2013 Long Term Energy Plan (e.g., total cost for electricity service, wholesale market services costs, residential bill forecast).
2. **Deep de-carbonization case:** derived using publicly available market data, where available, estimates from Navigant, and electricity system cost outlook projections adapted from the OPO outlook D released in September 2016[12]. OPO outlook D reflects higher levels of demand driven by a high level of electrification associated with potential policy decisions on climate change. This outlook contemplates a transformational change to both customers and the electricity system by considering more aggressive growth in areas such as EV adoption and customer conversions to electric heating. The outcomes associated to this case carry more uncertainty than those outlined in the base case.

Figure 10, illustrates the results for both scenarios. The costs associated with the base case are shown with solid blue bars and the deep de-carbonization case is shown with diagonal blue bars. The benefits associated with the base case are shown with solid green bars and the deep de-carbonization case is shown with diagonal green bars. The cumulative net benefit for the base case is represented by a solid yellow line and the deep de-carbonization case is represented by a dotted yellow line. As illustrated in the figure below, the base case and the deep de-carbonization scenario represent a wide band of uncertainty.

[12] Ontario Planning Outlook (OPO) projections were not available at the same level of detail as LTEP 2013. As such, Navigant developed an escalator which was applied to projections used in the base case. The escalator was calculated by comparing the Total Cost of Electricity Service in OPO, Outlook D and LTEP 2013.

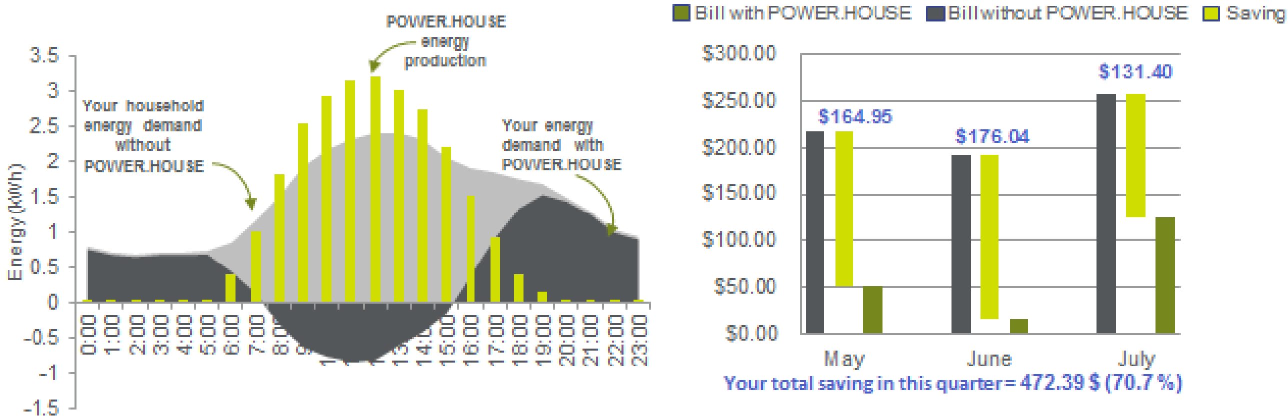
However, positive cumulative net benefit is expected over the longer-term, with the deep carbonization scenario achieving positive values by late 2020's and the base case by the mid 2030's. As with most large infrastructure development, initial investments need to be made several years prior to when their maximum benefit will be realized. In the case of the POWER.HOUSE program, the timing at which benefits can be realized will be greatly impacted by the availability and timing of certain market mechanisms, policy decisions, and other factors. Some key factors affecting the ability of POWER.HOUSE to realize the benefits contemplated in the analysis are described in section 7. These systems however are very flexible and have the ability to adapt to changing market conditions that will help mitigate some of these risks. Avoided GHG emissions provide additional benefits estimated at over $16 million ($2016).

Figure 9. Cumulative Net Benefit of POWER.HOUSE



As part of the analysis, an effort was undertaken to quantify the actual customer benefits that the existing fleet of POWER.HOUSE units has delivered since pilot launch. While the initial data is preliminary and represents a small data set, the early indications are strong that the pilot units are demonstrating significant savings to customers through the solar production and a reduction in electricity consumption from the grid during on-peak time-of-use periods. From May to July 2016, average customer savings were $142/month, for an approximately 77 per cent reduction in total energy costs. Results from a typical customer are illustrated in Figure 11. This data was adjusted for seasonality and used to validate the assumptions made in the report regarding customer benefits and long term savings.

Figure 10. Customer Value



7. KEY ENABLERS

Throughout the feasibility study, a number of key enablers were identified. Capturing these helps build an understanding of the factors that would be required to support or alternately, if not in place, impair the widespread adoption of the POWER.HOUSE system. There are many details that still need to be determined through further study in order to support wide-spread adoption, including building understanding and the infrastructure required to support Virtual Power Plants in Ontario. Though a number of key enablers have been identified throughout the report, four were identified as critical to support the adoption rates identified within the study.

1. **Ancillary Services Market**
   - Utility value is highly dependent on access to demand response and ancillary service markets over the life of the program, beginning in year two.
   - Products, procurement mechanisms and participation requirements would have to be defined while considering cost impacts.
2. **Regulatory**
   - Key regulation changes, including permissions for third party ownership of DERs and recognition of storage as a renewable asset would have to be incorporated into the net metering regulation.
   - Establishment of regulatory structures surrounding DER's in Ontario – particularly if net metering growth becomes extensive.
   - Changes to Ontario's smart metering data management systems would be required to accommodate time-of-use pricing for net metered customers.
3. **Interconnection**
   - Locational incentives for DERs are still lacking.
   - LDCs will have to develop rules on how they manage the allocation of feeder capacity between their own programs such as POWER.HOUSE, other forms of DERs, and electric vehicles that may begin to grow over the next decade

4. Utility and Regional Planning

- Need to formalize processes to incorporate DER integration into traditional utility and regional planning to mitigate local capacity issues.
- No clear regulations on cost responsibility for DER options to meet regional needs (i.e., who pays for DER solutions to address local needs).

8. CONCLUSION

This feasibility study is an important starting point to better understand the capabilities, value streams, costs, and benefits of POWER.HOUSE and the potential for significant large scale adoption of the technology. The study also demonstrates the collective benefit that can be achieved when LDCs, the system operator, and the private sector work in concert towards a common goal. Through collaboration, the team was able to quantify the value of an innovative program that can provide benefits to customers, the electricity system, and the utility. The key achievements of the study are summarized in Figure 12.

Figure 11. Study Highlights

STUDY HIGHLIGHTS

COLLABORATION	High degree of involvement and collaboration between Alectra Utilities, IESO and the private sector.
POTENTIAL ADOPTION	POWER.HOUSE can feasibly reach meaningful uptake in York Region within the study period (2016-2031) - 30,000 units and 140 megawatts (MW) of capacity.
POTENTIAL NON-WIRES ALTERNATIVE	POWER.HOUSE could defer at least 2 years of local transmission/distribution investment in late 2020 timeframe.
TECHNICAL FEASIBILITY	The team worked to understand potential market and reliability services and customer value that the technology could provide.
VALUE STREAMS AND COST-BENEFIT	The team quantified the costs and benefits across two outlooks which saw a positive net benefit by the mid-2030's under the base case scenario or by the late 2020's under a deep de-carbonisation scenario.
KEY ENABLERS	The team identified the factors that would support or alternatively impair the widespread adoption of the POWER.HOUSE system.

DRC-8

ATTACHMENT 2
York University Study – Electrifying Transit Network

York professor powers up the transit network

June 25, 2018

Hany Farag, an associate professor in the Lassonde School of Engineering, is powering up and it has nothing to do with video games. While Farag, who teaches in the Department of Electrical Engineering and Computer Science may like video games, it’s the questions associated with sustainability of electrifying the transit network that feed his passion.

Hany Farag

A researcher at York University, Farag is exploring what the implications are of a fully electrified (that means no gasoline or diesel) bus transit system would mean for municipalities. How would power utilities support the demand for electricity that is required to power battery-based buses? What are the reliability factors for keeping buses going during peak demand times? Would an on-demand “instant” charge system be better over an overnight trickle charge system, or is there an optimal combination of both that could be built?

To answer these questions Farag applied for and received $200,000 (research funds and in-kind) for a two-year study into what the impacts of a full-battery powered electric bus transit network on Ontario’s electricity grid. The grant, awarded under the Independent Electricity System Operator (IESO) Conservation Fund, will support his research as principal investigator into the demand response and load restrictions associated with a fully electrified bus transit system and offer a strategic, research-based roadmap for municipalities seeking to ditch traditional fuel powered buses for the more environmentally friendly, clean technology of electric buses. This is the first study of its kind to document, model and assess the myriad of variables associated with changing over the transit network.

“The key challenge for municipalities is how to support the infrastructure needed for electric buses and what the impact will be on the power grid,” says Farag. “The idea that all buses in the future could be fully electrified is wonderful, but how much energy will be needed over the next 15 years? This research project will help the IESO and stakeholders to strategically plan the conversion to electrified buses, the best combination of battery-powered vehicles and the infrastructure to support electrifying transit systems.”

Farag’s research could result in a paradigm shift for municipalities interested in moving away from gasoline- and diesel-powered vehicles and to the more cost-efficient battery-powered versions. As well, there are huge benefits associated with improving air quality by electrifying the transit network.

This graphic illustrates the difference between an instant on route style of charging batteries (right) versus and overnight system of charging batteries (left). Image courtesy of H. Farag

The research will explore the two types of battery-based buses currently in use, says Farag. The first features a slow, overnight charging system, where the battery-powered buses return to a central hub and connect to the grid. This system offers many advantages, says Farag, in that most of the buses could be charged during off-peak times. The disadvantages are that the batteries are larger and heavier, which means a greater load on the bus. This system is the preferred option for most municipalities in that the demand on the grid is more economical.

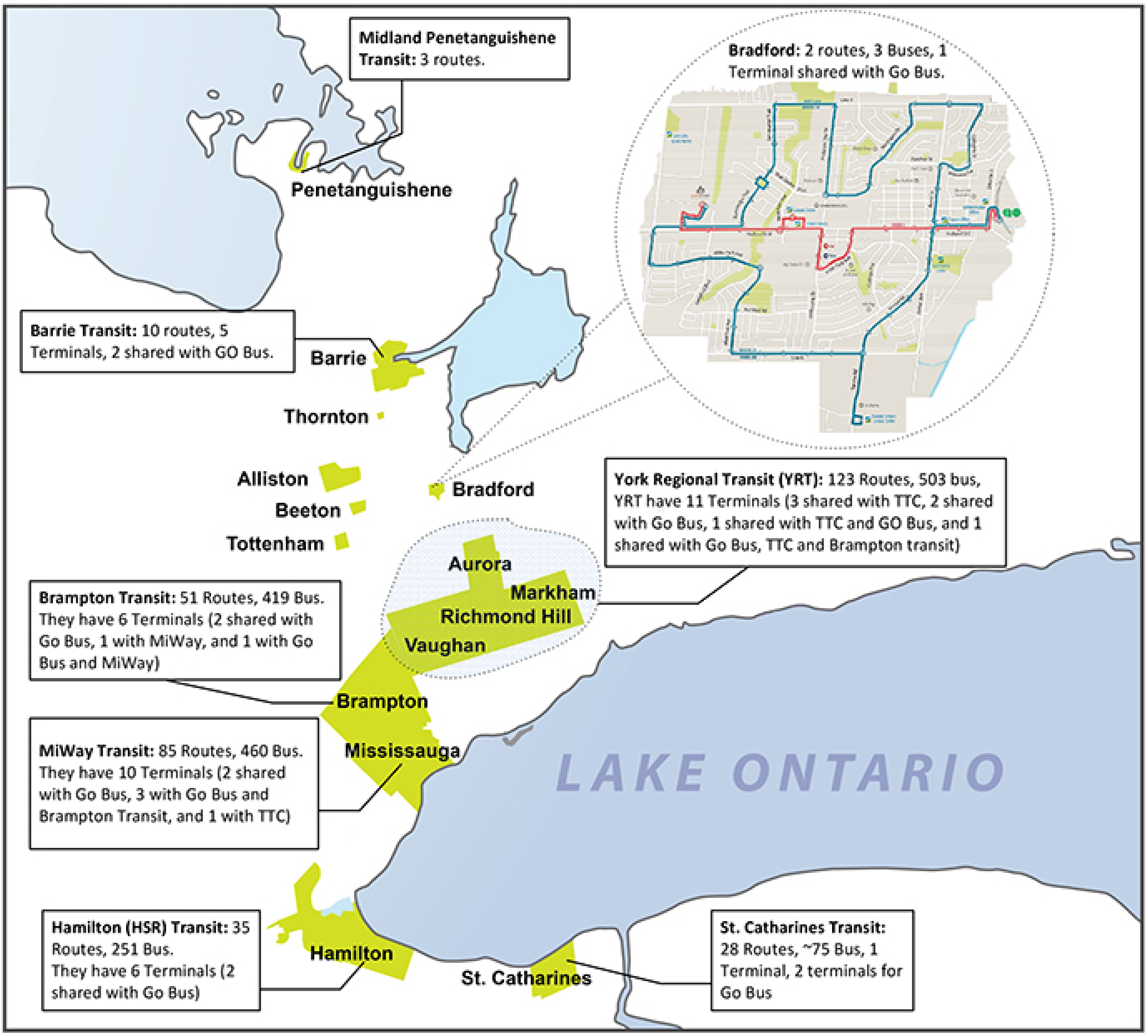
The second type of vehicle uses a system of instant charging, meaning vehicles use an overhead hook up to quickly charge batteries at "stations" located at strategic points along their routes, says Farag. The batteries are smaller and lighter, which reduces the load on the bus, but an infrastructure investment is needed to build charging stations at select points on the route. The overall demand on the grid is less in that the batteries charge in a fraction of the time, but there's also a question about how long a quick-charge bus can travel before needing a recharge and what happens during peak demand times, periods of harsh weather, passenger loads and more.

There are also many questions associated with the lifespan of instant charge batteries versus the longer, slower overnight charge batteries, and the costs associated with maintaining a network of instant charge stations, notes Farag.

"The emerging technologies of electric buses and their associated charging systems have created a new transportation-energy matrix, which is incomprehensible to transit and power stakeholders," says Farag. "Neither the transit operators nor the power suppliers have any idea of what the best way or what the optimal blend would be for powering electric buses."

In the project, Farag and a team of researchers will work in collaboration with industry and municipal partners to model, simulate, analyze and optimize the performance of electrical bus systems and the associated charging stations. The team will work with Alectra Inc., an energy solution provider for the Greater Golden Horseshoe Area of Ontario. (The communities in the Alectra grid are Hamilton-Wentworth, Peel Region, Simcoe County and York Region and municipalities in the study area are Aurora, Richmond Hill, Vaughan, Brampton, Hamilton and St. Catharines.) Using transit networks and charging systems data, the team will develop a simulation-design model (some computer gaming may be at play here for the team) to investigate the technical opportunities and economic viability for different configurations of electrical bus systems, including both the quick-charge and overnight options. From this comprehensive analysis and modelling, they will develop a plan to replace existing diesel buses in each of the identified transit systems in the area.

As part of the investigation, Farag and the academic team will study the costs and implications at a local, regional and provincial level. To do the research, the team will make use of the latest engineering tools to investigate the conservation options and barriers for the adoption of electrical bus systems in different transit fleet sizes in Ontario.



This map shows the impacts of transit bus electrification on the Alectra distribution network. Image supplied by Alectra Inc.

“This is really the first study to integrate both electrified bus operational feasibility and its integration with utility grids in a unified research project,” says Farag, noting that the multidimensional approach will assist municipalities to power up their transit systems in a strategic, informed manner. The results will have major impacts not only for transit providers, but for mitigating climate change at a local, regional, provincial and national level.

In addition to working with the municipalities in the study area and Alectra Inc. Farag is also drawing on the homegrown expertise in Campus Services & Business Operations (CSBO), which is partnering in the study. CSBO will be contributing expertise provided by Brad Cochrane, CSBO’s director of energy management, and Helen Psathas, CSBO’s director of campus planning and development.

The knowledge gained from the study “Impacts of Full Battery-Based Electric Transit Bus Systems on Ontario Electrical Grid” will be shared through two public webinars, two conference presentations, three peer-reviewed journal articles and one stakeholder workshop at York University’s Keele Campus, along with regular project updates in YFile. For more information, visit Farag’s Smart Grid Research lab at http://smartgrid.eecs.yorku.ca/.

DRC-8

ATTACHMENT 3
Operational Feasibility and Grid Impact Analysis

Simulation of Electric Buses on a Full Transit Network: Operational Feasibility and Grid Impact Analysis

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Simulation of Electric Buses on a Full Transit Network: Operational Feasibility and Grid Impact Analysis

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Abstract

This paper presents a twofold modelling exercise to investigate the implementation of battery electric buses (BEBs) in a full transit network. First, using three BEB concepts: flash, opportunity, and overnight, a real-time simulation model is developed for a full transit BEBs operation in order to (1) quantify the energy demands, (2) design the required infrastructure of the charging station, (3) test the transit operation feasibility, and (4) generate the charging load profile. Simulation results show that flash and opportunity BEBs are more feasible for full transit BEBs operation, however they suffer from high and intermittent power demands. Second, the generated charging load profile for each BEB operation is utilized to study its impact on the utilization and lifetime of the transformers, and the operation of the local distribution grid. Results indicate that the operation of overnight electric buses is more feasible as it relates to their impacts on the substation transformer and distribution feeders overloading, voltage regulation and quality aspects, and operation of voltage control devices. Collectively, findings from this study highlight that the selection of BEBs in a full network transit operation hinges on achieving feasible operation while reducing impacts on utility grid. Insights derived from this work can help optimize the implementation of BEBs in transit context.

Keywords

Battery electric bus, full transit network simulation, grid impact analysis, operational feasibility, energy demands

1. Introduction

Electric powertrain technologies are considered promising solution to mitigate increasing transport related greenhouse gas (GHG) emissions [1, 2]. With 24% contribution to the global GHG emissions, transportation sector is often considered the first target for emission reduction [3]. Hence, electric powertrains have been considered of suitable replacement to the traditional oil-dependent Internal Combustion Engine (ICE) [4, 5], and several governments are adopting electric mobility policies as the way forward. In particular, the urban bus transit market is often seen as a suitable context for significant electric mobility penetration [3]. It offers fixed routes, timely operation, and shared infrastructure among several other parameters that could aid the implementation of electric mobility technology [4-7]. However, the utilization of electric powertrain technology in bus transit hinges on several factors that are currently well addressed by ICE technology. These include, but are not limited to: energy logistics, operational demands, infrastructure, cost, and human resources [8]. It is frequently argued that a Battery Electric Bus (BEB) should be able to accommodate the current operational demands, as well as achieving substantial environmental benefits in an economically feasible way if adopted across the sector [4, 6].

Three dominant themes of research have been developed to investigate the implementation of BEBs in transit that span over technological, economic, and environmental aspects. Life cycle cost (LCC) models are frequently utilized to estimate the Total Cost of Ownership (TCO) for adopting BEBs. These models are often associated with environmental analyses that quantify the Well-to-Wheel (WTW) GHG emissions of BEBs [9-11]. In addition, battery technology and energy consumption are studied to optimize BEB technology [3, 12, 13]. Overall, evidence from previous research suggests that BEB is a feasible alternative and could be implemented in the transit context.

However, outside the techno-economic-environmental focus of BEB research, performance-based measures are regarded as the keystone for implementing BEB in the transit sector [4, 6, 9, 14, 15]. It has been argued that the current slow market penetration of BEBs is attributed to the fact that performance-based measures of BEBs are yet to be established [9, 14]. Attempts have been made to study BEB operational barriers and focused on two fundamental aspects; operational feasibility of BEBs and their impacts on utility grid.

As it relates to operational feasibility, De Filippo, et al. [5] simulated BEB operation over six transit corridors serving Ohio State University main campus. They highlighted that the frequency of service might decrease if the current fleet is electrified, yet they pointed out that additional infrastructure (chargers and/or buses) could be utilized to overcome this issue and maintain current frequency, which might add significant financial burden on the implementation of BEB. Li [14] conducted a review of BEB operation globally and concluded that BEB suffers from significant disadvantages. The most notable is operational availability (range/charging time). He has also argued that range remedy methods such as battery swapping, and opportunity charging are not sufficient to overcome range limitation.

Perrotta, et al. [16] investigated the correlations between route characteristics and energy consumption using a case study of three routes. They have argued that routes with sinuous segments and short distance between stops are the most energy demanding, and highlighted that topology variation, in general, has a profound impact on energy consumption of electric buses. In addition, Kontou and Miles [15] have analysed operational measures of a BEB demonstration project at Milton Keynes, and pointed out that route elevation and driving style contribute to significant variation in energy consumption. They have however, argued that BEB is operationally feasible. Rogge, et al. [17] studied the electrification of a full bus transit network using fast charging, and concluded that bus transit could be fully electrified with current battery technology. Yet the configurations of the capacity of battery and chargers have significant impacts on the feasibility of battery electric buses. Recently, Ke, et al. [18] developed a simulation model for bus transit electrification that is aimed at reducing the service construction cost. Although they concluded that day-time charging is more cost effective, several operational constraints were not considered in the model such as increased fleet size for a full electrification.

From a utility perspective, recent studies showed that the rapid growth of electric vehicles (EVs) and its associated energy demands are likely to cause severe consequences for the existing grids [19-21]. Ahmadian, et al. [22] studied the impact of the EVs charging upon the conventional system that leads to the violation of the voltage profile. They have considered the load variability of the EVs and the distributed generations (DGs) upon the system voltage profile, where the authors optimally allocate and size the SCs and the wind based DGs across the system. Moreover, they utilized a short schedule decision for the LTC tap setting. While, Azzouz, et al. [23] considered the high penetration of EVs and DGs that aims to minimize the voltage deviation and LTC tap operation, maximize the EVs delivered power and maximize the power captured by the DGs. Nonetheless, to the best of the author’s knowledge, the literature falls shortly to investigate the BEBs penetration impact upon the distribution network. Surprisingly, previous attempts in the literature have mainly focused on studying the impacts of personal EVs, while fewer attempts have emphasized studying the impacts of fully electrified bus transit service. Personal EVs are intrinsically distributed and thus its impact on the power grid is highly dependent on its penetration level [24, 25]; while an electrified bus transit network could be seen as a concentrated power load. Further, transit terminals are usually located at the city center, which might in turn increase the power demand significantly at the load center of the power grid. Moreover, the flexibility of controlling energy demands from power grids might not be a viable solution in case of transit networks due to operation and reliability constraints [26]. For these reasons, careful study is required to explore the impacts of powering fully electrified transit networks on power distribution grids. Accordingly, this work presents the investigation of the LTC operation in the presence of the intermittent BEBs.

An early attempt by Rogge, et al. [17] generated the load profile of fast opportunity-based charging for a full transit network and briefly discussed the impacts on the power grid. However, they have assumed that the charging stations are distributed across the entire transit network. Further, the study falls short in incorporating the generated load profile in distribution power grid studies or in presenting a detailed analysis for the impact of such load on the operation of local distribution grids. In addition, they gave full attention to opportunity-based charging and did not take into account other viable operation concepts. BEBs could be classified according to their operation concepts into three main types: flash, overnight and opportunity. Each type represents a distinct profile as it relates to operational feasibility and grid impact. We argue that the operation of different BEBs will vary significantly, as will the associated impacts on the distribution power grid.

This paper stands to complement previous efforts and aims at investigating the operational feasibility of different configurations for BEBs in a full transit network context and studying their impacts on the distribution power grid. To the best of the authors' knowledge, this is the first attempt to integrate BEBs operational feasibility and grid impact analysis at the full transit network level. This comprehensive approach will provide a multidimensional evaluation of BEBs implementation in transit context, as well as sound contributions to the decision making process.

To that end, this study is developed based on two integral components. First, a comprehensive logic-based simulation model is developed for the operation of three types of BEBs: flash, opportunity, and overnight. This model is developed to optimize the required infrastructure (chargers) and to assess BEBs operational feasibility. Second, the developed simulation model is utilized to generate the load profile of a fully electrified transit network, which in turn is used, for each BEB configuration, to evaluate its impacts on the operation of local distribution grids.

The rest of the paper is structured as follows: Section two details the proposed methodology as it relates to BEBs configurations, simulation model, and grid impact model. Section three presents the simulation results and discusses the operational feasibility of different BEBs configurations. Section four illustrates the impacts of bus transit electrification on local distribution grids. Section five concludes the paper and summarizes its main contributions.

2. Methodology

In this section, the proposed simulation model for BEBs operation on a full transit network is presented. The output of the proposed simulation model is utilized to generate the load profile of each operation scenario. The load profiles are then incorporated in local distribution grid simulation models to study their impacts.

As it mentioned earlier in the introduction, BEBs operate in three distinct concepts: flash, opportunity, and overnight. The differences between these concepts are mainly attributed to range, battery size, and charging profile. Overnight BEB has relatively longer range and bigger battery capacity, yet it requires long overnight charging. While, both opportunity and flash BEBs benefit from on-route charging capability, yet they have relatively smaller battery capacity and shorter range, specially flash BEB concept.

Five main BEB configurations, illustrated in Table 1, are currently operational in the North-American Bus market. These are offered by three bus manufactures: Proterra (Catalyst 40ft – 80 KWh) that represents flash electric, New Flyer (XE40 – 200 KWh) that represents opportunity electric, and BYD (40E – 324 KWh) that represents overnight electric.

All models are of transit-standard size (40-ft), with varying seating capacity. Four different charging rates are used interchangeably ranging from 80 KW to 500 KW, which offer various BEB configurations. The energy consumption data and charging rates, for each bus model, are derived from the Altoona Bus Research and Testing Centre reports using an average of the three test cycles; Central Business District (CBD=1.910 Miles), Arterial (ART=1.910 Miles), and Commuter (COM= 3.819 Miles) [27-29]. This is to overcome the variation in the characteristics of operation contexts.

Table 1 Electric buses configurations

Variables / Concept	Flash Electric Bus		Opportunity Electric Bus	Overnight Electric Bus	
Configuration ID	1-A	1-B	2-A	3-A	3-B
Manufacture	Proterra	Proterra	New Flyer	BYD	BYD
Model	Catalyst	Catalyst	XE40	40-Electric	40-Electric
Length (ft.)	40	40	40	40	40
Seating (#)	41	41	39	36	36
Battery Capacity (KWh)	80	80	200	324	324
Charging Power (KW)	500	250	250	80	200
Range (Km)	70	70	128	257.5	257.5
Energy Consumption (KWh/Km)	1.05	1.05	1.34	1.33	1.33
Charging Rate (KW/min)	8.33	4.17	4.17	1.33	3.33
Time for a full charge (min)	9.60	19.20	48.00	243.00	97.20

2.1. BEB Simulation model

A logic-based generic simulation model, Figure 1, is developed to simulate the performance of BEBs. The simulation model consists of two modules. The first module calculates the energy consumption for each bus/route and assigns a charging priority to each bus. Concurrently, the second module simulates the charging station, and optimizes the minimum required number of chargers for each operation scenario. Once the minimum number of chargers is identified, a real time simulation of BEBs operation is carried out. The logic-based model has three constraints: operation schedule must be attained, fleet size must be maintained, and full network electrification must be achieved. These constraints are enforced to reflect real-world operational conditions. Failure to meet any of these constraints terminates the simulation model.

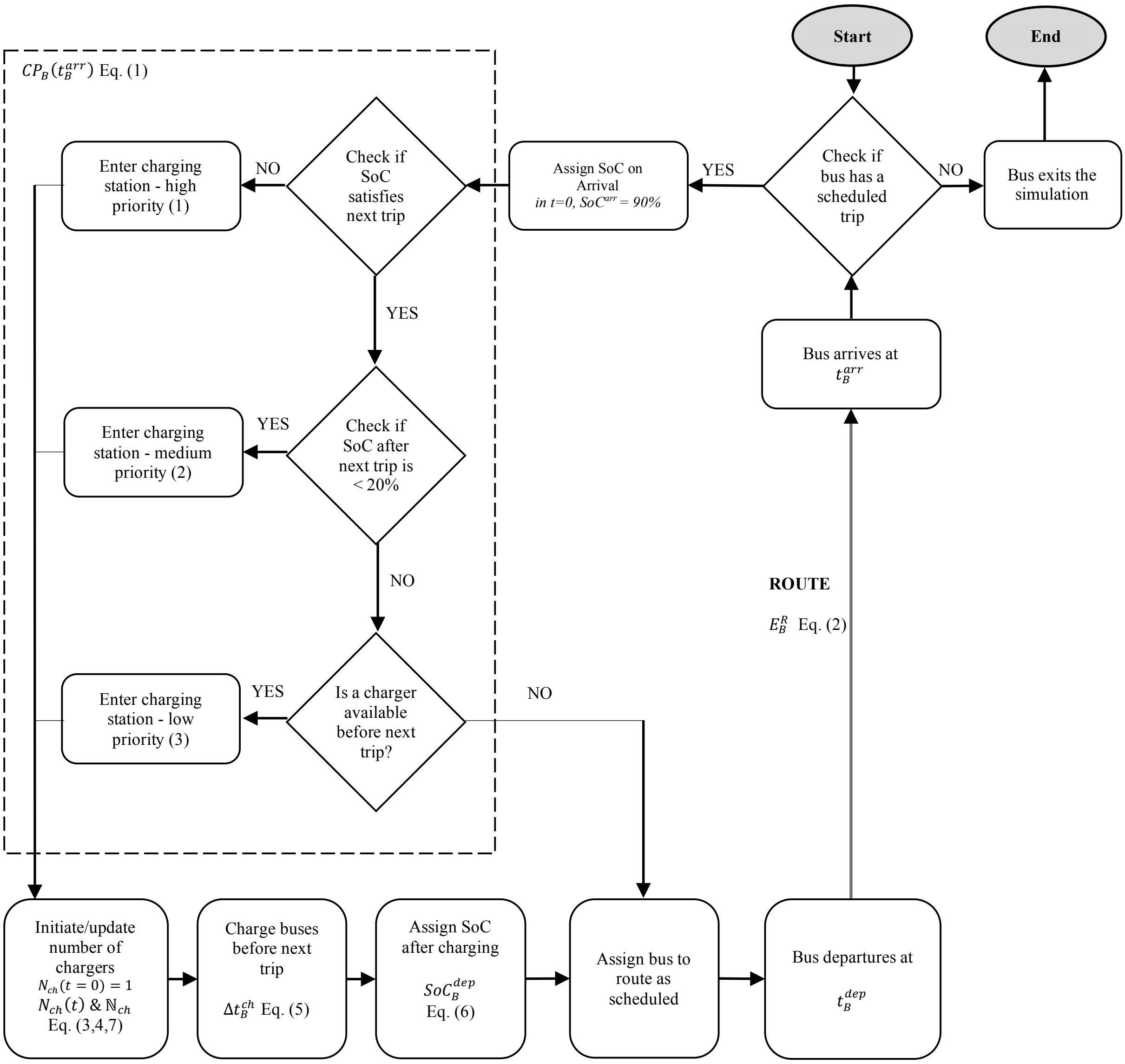


Figure 1 A flowchart of the proposed simulation model

As depicted in Figure 1, the simulation model starts by detecting the Status of Charge (SoC) for the battery of each bus B upon its arrival, SoC_B^{arr}, to the terminal station at each scheduled arrival time t_B^{arr}. Then, three queries are carried out sequentially to decide: 1) if SoC satisfies next trip, 2) if SoC after the completion of next trip is less than the minimum allowed SoC, i.e. SoC_B^{Min} and 3) if SoC_B^{arr} is less than the maximum allowed SoC, i.e. SoC_B^{Max}, and there is an available charger at least 5 minutes before the next scheduled trip. These queries assign a priority of charge for each bus B upon its arrival to the terminal. Accordingly, once bus B arrives to the charging station at time t_B^{arr}, a charging priority CP_B is assigned for it as follows:

$$CP_B(t_B^{arr}) = \begin{cases} 1 & if\ SoC_B^{arr} \leq \frac{E_B^{R,next}}{E_B^{Bat}} \times 100 \\ 2 & if\ SoC_B^{arr} - \frac{E_B^{R,next}}{E_B^{Bat}} \times 100 < SoC_B^{Min} \\ 3 & if \quad SoC_B^{arr} < SoC_B^{Max} \end{cases} \tag{1}$$

where, $E_B^{R,next}$ and E_B^{Bat} are the required energy for the next scheduled trip and the rated capacity of the battery of bus B in KWh, respectively. Also, the integer numbers 1,2 and 3 correspond to high, medium, and low charging priority, respectively. In this work, it is assumed that the minimum and maximum allowed limits for the SoC of each bus are 20% and 90%, respectively. The choice of these values aims to maintain battery long-life and avoid limp issues [15, 17].

The required energy for the next trip $E_B^{R,next}$ of each bus B can be approximately given as:

$$E_B^{R,next} = K_{route} \times E_B^{cons/km} \times l_B^{next} \tag{2}$$

where, $E_B^{cons/km}$ is the rate of energy consumption of each bus B in KWh/Km and l_B^{next} is the distance of the next trip of bus B in Km; K_{route} is a factor that represent the impacts of route-specific energy data such as topography, number of stops, driving style, velocity profile and elevation. However, due to the sensitivity of this factor to operation context, the impacts of this factor on the required energy are neglected in this work, and thus K_{route} is assumed to be unity. In other words, the energy consumption resulting from route topography (e.g. route elevation), and the additional energy generated on route (e.g. regenerative braking system) are not considered in the model. To overcome this limitation, actual energy consumption data that accommodates route characteristics are utilized in this study. Accordingly, and as shown in (2), when $E_B^{cons/km}$ is fixed, the required energy becomes directly dependent on the distance of the trip.

Similar to (1), a queuing logic is developed for the charging station that is mainly constrained to bus schedule. However, Lowest Attribute Value (LAV) queuing policy is adopted at the charging station, meaning that queuing priority is given to the bus with the lowest SoC value in the case of buses with equal charging priorities [5]. The number of required chargers is initialized at the beginning of the simulation as $N_{ch}(t=0)=1$. Throughout the simulation, the number of required chargers is updated based on the minimum requirements to satisfy the operation constraints. Using the assigned priorities of the arriving buses, the number of required chargers N_{ch} at each instant time t of the simulation is calculated as:

$$N_{ch}(t) = n_{bus}^{CP_B=1}(t) + n_{bus}^{CP_B=2}(t) \tag{3}$$

where, $n_{bus}^{CP_B=1}$ and $n_{bus}^{CP_B=2}$ are the number of buses with high and medium charging priorities, respectively. It should be noted, however, that (3) is only applied if bus(s) with medium charging priority is/are unable to join the charging queue due to operation schedule constraints. If queuing is permitted by operation schedule, then the number of required chargers N_{ch} at each instant time t of the simulation is calculated as:

$$N_{ch}(t) = n_{bus}^{CP_B=1} \tag{4}$$

When a charger is allocated for a bus, the effective period of a charging event can be expressed as follows:

$$\Delta t_B^{ch} = t_B^{dep} - t_B^{arr} - \Delta t_c \quad \forall \Delta t_B^{ch} > 0 \tag{5}$$

where, t_B^{dep} is the scheduled departure time of bus B; and $\Delta \mathrm{t_c}$ is the required time to connect on/off the charger for each charging event. In this work, $\Delta \mathrm{t_c}$ is assumed to be 2 minutes following the approach adopted by De Filippo, et al. [5]. Hence, the SoC of each bus B at the departure time t_B^{dep} after a charging event can be calculated as follows:

$$SoC_B^{dep} = SoC_B^{arr} + \left(\frac{\eta_{ch} \times P_{Max}^{Ch} \times \left({\Delta t_B^{ch}}/{60} \right)}{E_B^{Bat}} \times 100 \right) \tag{6}$$

where, P_{Max}^{Ch} is the maximum allowable rate of charge in KW and η_{ch} is the efficiency of the charger, which is assumed to be 90% [15]. Note that Δt_B^{ch} is divided over 60 in (6) to represent the charging time in hours, where E_B^{Bat} is given in KWh.

The total number of required chargers $\mathbb{N}_{ch}$ is determined by the end of the simulation time, which covers the timetable of the full transit network for an entire weekday of operation, as follows:

$$\mathbb{N}_{ch} = Max.\{N_{ch}(t)\} \, \forall 0 \leq t \leq T_{sim} \tag{7}$$

where, T_{sim} is the total simulation time in minutes.

Once the simulation model identifies the total required number of chargers $\mathbb{N}_{\mathrm{ch}}$ that satisfy full network electrification under the imposed constraints, a real-time operational-based simulation is carried out with the new calculated parameters. The real-time simulation model determines the charging decision of each bus B upon its arrival at time instant t taking into consideration its charging priority and the available number of chargers.

2.2. Grid impact model

The simulation model described in the previous section is utilized to generate the load profile of each operation scenario for the full transit network. Using the real-time simulation, the total required power demand of the charging station at each time instant t for each operation scenario could be given as follows:

$$P_{ch}(t) = \sum P_{Max}^{ch}(B,t) \qquad \forall B \in \{B^{ch}(t)\} \tag{8}$$

where, $\left\{\mathrm{B^{ch}(t)}\right\}$ is the set of BEBs that is charging at time instant t.

Using the generated load profile, several studies can be conducted to investigate the impacts of BEBs charging on the local distribution grid. In this paper, particular attention is given to analyze: 1) the load characteristics of the electrified transit (BEBs charging behavior) and the required size of the service transformer for the charging station; 2) the impacts of the charging load profile on the life loss of the substation transformer; 3) the effect of the charging load profile upon the operation of voltage control devices. It is noteworthy that power quality issues related to power electronics of the charger technologies are out of the scope of this work [30, 31]. Usually, the power quality requirements of the charging stations such as the power factor is maintained using power factor correction circuits (i.e. Bridgeless boost PFC), while the harmonics distortion standard is met by utilizing a front-end converter technique [30, 32]. Also, active front-end converters are capable of providing a mean of reactive power support to the grid [30]. Furthermore, interleaving converter topology has been widely used for output ripples cancellation [30, 31]. However, technical aspects related to the required charging devices are not addressed in this work.

Using the generated load profile, rolling-block demand metering is utilized to calculate the 15-minutes billing demand of the charging station D_{15-min}; where the 15-minutes demand interval is broken down into three 5-minutes subintervals. The power meter calculates the average load in each 5-minute subinterval as well as the average of the three 5-minutes subintervals. The load factor F_{LD} of the charging station facility can be calculated as follows [33]:

$$F_{LD} = \frac{D_{av}}{D_{max}} \tag{9}$$

where, D_{avg} is the average demand of the charging station, expressed as follows:

$$D_{avg} = \frac{\sum D_{15-min} \times 1/4}{h_T} \tag{10}$$

where, h_T is the demand period of 24 hours and D_{max} is the maximum coincident power demand of the charging station for the operation period given as:

$$D_{max} = Max\left(P_{ch}(t)\right) \quad \forall t \tag{11}$$

The load factor gives a metric for the utilization of the charging facility transformer for each operation scenario.

The charging station service transformer is a key component that interconnects the charging station to the power distribution grid. In this work, the BEBs charging facility is treated as an individual customer. Hence, the rated power capacity of the service transformer is designed based on the maximum coincident power demand for each operation scenario.

$$S_{ST} = K_{rating} \times D_{max} \tag{12}$$

where K_{rating} is a contingency factor for reasonable unplanned load growth and planned addition load.

2.2.1. Impacts on substation transformers life time

The aging of the transformer is determined by the state of the insulation, which is affected by the temperature [34]. Thus, determination of the hottest-spot temperature is required to evaluate the life loss of a transformer. According to the IEEE C57.91-1995, the hottest-spot temperature should not exceed 110^o C at an average ambient temperature of 30^{o}C [35-37]. In consequence, the rate of aging of the power transformer is accelerated when the hottest-spot temperature exceeds 110^o C, and is reduced when the hottest-spot temperature is below the hottest-spot temperature limit [38]. If the transformer is continuously operated at this temperature, the normal life expectancy of the transformer is approximately 180,000 hours [37-39]. The hottest-spot temperature depends on the ambient temperature (θ_a), top-oil rise over the ambient temperature ($\Delta\theta_o$) and the hottest spot winding rise over top-oil temperature ($\Delta\theta_h$) [40]. The hottest-spot winding temperature (θ_h) is given as follows [39, 40]:

$$\theta_h = \theta_a + \Delta\theta_o + \Delta\theta_h \tag{13}$$

where, $\Delta\theta_o$ is proportional to the transformer losses and can be expressed as follows:

$$\Delta\theta_o = \Delta\theta_{o,r} \times \left(\frac{P_t}{P_r}\right)^x = \Delta\theta_{o,r} \times \left[\frac{1+RL^2}{1+R}\right]^x \tag{14}$$

and, $\Delta\theta_{o,r}$ is the standard top-oil temperature rise above ambient temperature at rated power, P_t is the total transformer losses, P_r is the total transformer losses at rated full load, R is the ratio between transformer load loss and standard load loss at no-load, L is the transformer loading in per unit, and x is the oil exponent.

The hottest spot winding rise over top-oil temperature is directly related to the loading condition, which is dependent on $\Delta\theta_{h,r}$ the standard hot-spot rise over top-oil temperature at rated power, and the winding exponent y. Therefore $\Delta\theta_h$ can be given as follows:

$$\Delta\theta_h = \Delta\theta_{h,r} L^y \tag{15}$$

Given that the ageing of the transformer depends on the hottest-spot temperature, the aging acceleration factor F_{AA} is given as follows:

$$F_{AA} = e^{\left[\frac{1500}{110+273} - \frac{1500}{\theta_h+273}\right]} \tag{16}$$

Therefore, the previous equation can be used to determine the equivalent aging of the transformer for a certain time period as follows:

$$F_{eqA} = \frac{\sum_{n=1}^{N} F_{AA,n} \Delta t_n}{\sum_{n=1}^{N} \Delta t_n} \tag{17}$$

where, $F_{AA,n}$ is the aging acceleration factor for certain temperature that exist for time interval Δt_n, N is the total number of time intervals, and n is an index for time intervals.

To that end, the loss of life of a transformer can be calculated in hours or years by determining its normal expectancy life. The loss of life is given as follows:

$$\%Loss\ of\ life\ = \frac{F_{eqA} \times t \times 100}{normal\ transformer\ life} \tag{18}$$

2.2.2. *Impacts on the voltage regulation and voltage control devices*

The power flow in conventional distribution systems is unidirectional from distribution substations to downstream loads through distribution feeders. This will in turn causes voltage drops, which reduce voltage magnitude at the loads. Voltage magnitudes at service locations must be maintained within specified ranges. Hence, one of the core responsibilities of utility distributors is to deliver voltage to customers within that specified ranges (e.g. most regulatory bodies and utilities in North America follow the ANSI C84.1 voltage standards) [41]. ANSI defines two ranges of voltage; 1) Range A (normal operating conditions): most service voltages are within these limits, and utilities should design electric systems to provide service voltages within these limits, 2) Range B (up-normal operating conditions): these requirements are more relaxed than Range A limits. Although Range B conditions are part of practical operations, they shall be limited in extent, frequency, and duration. Sustained voltage levels falling outside range B will result in unsatisfactory operation of utilization equipment and over-voltages/under-voltages protective devices shall operate to protect such equipment.

Recently, the BEBs has been integrated into the power distribution network due to its environmentally benefits [42]. Nonetheless, connection of the BEBs load into existing distributions systems is expected to create severe impacts on the system voltage profile and losses, especially when BEBs charging demand profile is intermittent [43, 44]. Moreover, such intermittency in the power demand will significantly confuse the operation of voltage control devices such as the load tap changers (LTCs) and the shunt capacitors (SCs) [23, 45]. The interference between the BEBs intermittent charging power demand and the operation of conventional voltage controllers may lead to undervoltage, overvoltage, increasing in the system losses and excessive switching operation of the devices [43, 45]. Where the excessive tap operation due to the fluctuation of the power causes the wear and tear of the voltage control devices and shortens its life expectancy [45].

The voltage regulation requirements are accomplished in both fixed designs of the distribution system and by voltage control equipment such as LTC and SC. LTC is a mechanical device that is often installed at the substation transformer. The main functionality of LTCs devices is to hold the voltage magnitude of a certain targeted node close to a specified value under changing load conditions. Hence, the voltage magnitude at the target point V_{TP} can be expressed as:

$$V_{TP}^{LB} \le V_{TP} \le V_{TP}^{UB} \tag{19}$$

where:

$V_{TP}^{LB} = V_{TP}^{*} - 0.5 \times \Delta V_{DB}$ lower boundary voltage;

$V_{TP}^{UB} = V_{TP}^{*} + 0.5 \times \Delta V_{DB}$ upper boundary voltage;

V_{TP}^{*} is the set point voltage and ΔV_{DB} is the dead band at which no actions occur to prevent oscillations and repeated activation-deactivation cycle. The line drop compensation (LDC) circuit shown in Figure 2 is the control circuit of the LTC [33].The LDC circuit consists of a current transformer (CT) and a potential transformer (PT) to step down the measured current and voltage magnitude of the substation transformer, respectively. The LDC control unit continuously monitors voltages and load currents to adjust tap position accordingly.

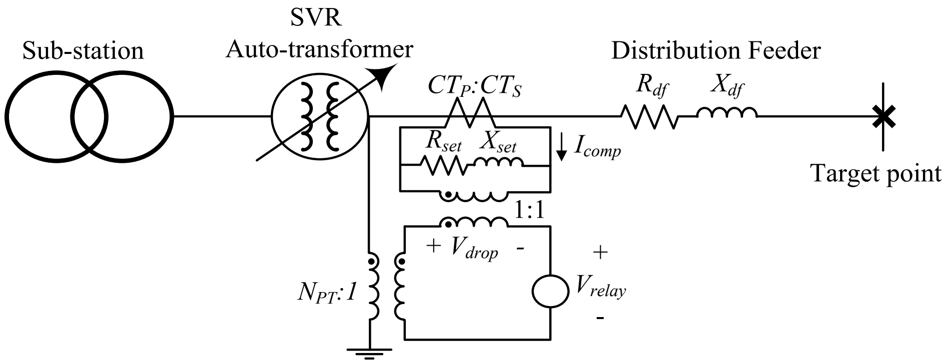


Figure 2 Line drop compensator circuit

As illustrated in the figure, the LDC circuit tends to estimate the voltage magnitude of its target point referred to the LDC side as follows:

$$V_{relay} = V_{reg} - I_{comp}(R_{set} + jX_{set}) \tag{20}$$

where, V_{reg} is the voltage magnitude at the secondary side of the substation transformer referred to the LDC side; I_{comp} is the downstream feeder current refereed to the LDC side; and R_{set} and X_{set} are the LDC circuit parameters that emulate the actual distribution feeder impedance (R_{df} and X_{df}). Using the estimated voltage magnitude of the target point, the number of requited changes in the taps at each time instant t can be calculated as follows:

$$\Delta Tap(t) = \begin{cases} 0 & if\ \frac{V_{TP}^{LB}}{N_{PT}} \le V_{relay} \le \frac{V_{TP}^{UB}}{N_{PT}} \\ round\left(\frac{V_{TP}^{*} - V_{relay}}{0.75}\right) & if\ V_{relay} \le \frac{V_{TP}^{LB}}{N_{PT}} \\ -1 \times round\left(\frac{V_{relay} - V_{TP}^{*}}{0.75}\right) & if \quad if\ V_{relay} \ge \frac{V_{TP}^{UB}}{N_{PT}} \end{cases} \tag{21}$$

Note that each tap setting of the auto-transformer corresponds to a change of $0.75\ volts$ in the LDC control circuit.

In this study, the model of the charging facility (i.e. load profile and distribution transformer) is incorporated in the power flow studies of distribution systems in order to investigate the impacts of the BEBs charging of a full transit network on 1) the voltage profile, 2) the operation of voltage control devices and 3) systems losses of distribution systems.

3. Simulation results

A case study is developed in order to validate the proposed methodology using five different bus configurations highlighted in Table1. The selection process is based on choosing a network representative of Canadian bus transit service. In Canada, bus transit service is classified into 5 groups based on the population served as illustrated in Figure 3 [46]. Almost 42% of bus transit providers operate in small cities of population less than 50,000. In addition, 46% of Canadian bus fleets have less than 50 buses [46]. Therefore, this segment is representative of a considerable proportion of Canadian transit providers. Hence, results generated from this study could be readily adopted by a wide range of bus operators across different Canadian jurisdictions. That is being said, the developed model could be implemented at any case study.

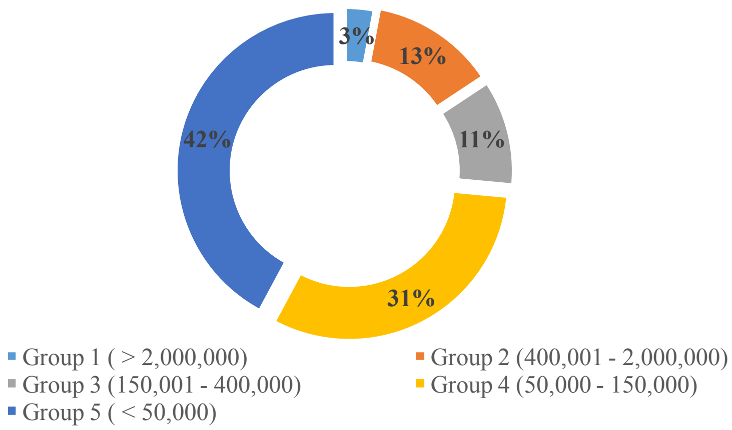


Figure 3 Canadian bus transit operators by population group (2014)

Belleville, Ontario is selected to represent this segment. Belleville Transit, a municipal department, provides bus services to 37,000 people through 15 standard diesel buses. The service covers 247.2 square kilometres with an annual average of 740,426 fleet kilometres. Belleville's transit network features 9 fixed-routes that include both urban and sub-urban sections, with an average route length of 10 kilometers as illustrated in Table 2 and Figure 4. Each bus is dedicated to a single route; hence operation data could be easily extracted from operation schedule (time-tables). The service operates for an average of 17 hours during weekdays, using 11 buses during peak hours, and 9 buses during off peak hours as detailed in [46].

The frequency of service is structured to allow maximum integration and trip interchange between all routes at Belleville's bus terminal (*165 Pinnacle Street*). The average per cycle time is 25 minutes for all routes, while the recovery time varies between 5 to 35 minutes during peak and off peak hours. On a typical weekday, Belleville's fleet travels approximately 2,550 kilometers with an average speed of 18.27 Km/h.

Table 2 Belleville bus transit information

Route ID	Route Name	Length (km)	Hours of service	Number of Trips (Weekdays)	Number of buses/route	Avg. per-cycle time (min)
1	Plaza Dundas	9.564	06:30-18:25	24	1	25
2	Parkwood Heights	9.705	05:00-22:25	31	1	25
3	College East	12.392	05:30-21:25	29	1	25
4	Mall North Front	9.601	06:30-21:55	28	2	25
5	Parkdale Mall	9.448	05:00-21:55	31	2	25
6	Avondale	10.378	06:30-18:25	24	1	25
7	Loyalist	12.157	06:30-22:25	29	1	25
8	North Park	9.998	06:30-21:55	28	1	25
9	Quinte Sport Centre	8.508	08:30-19:55	23	1	25

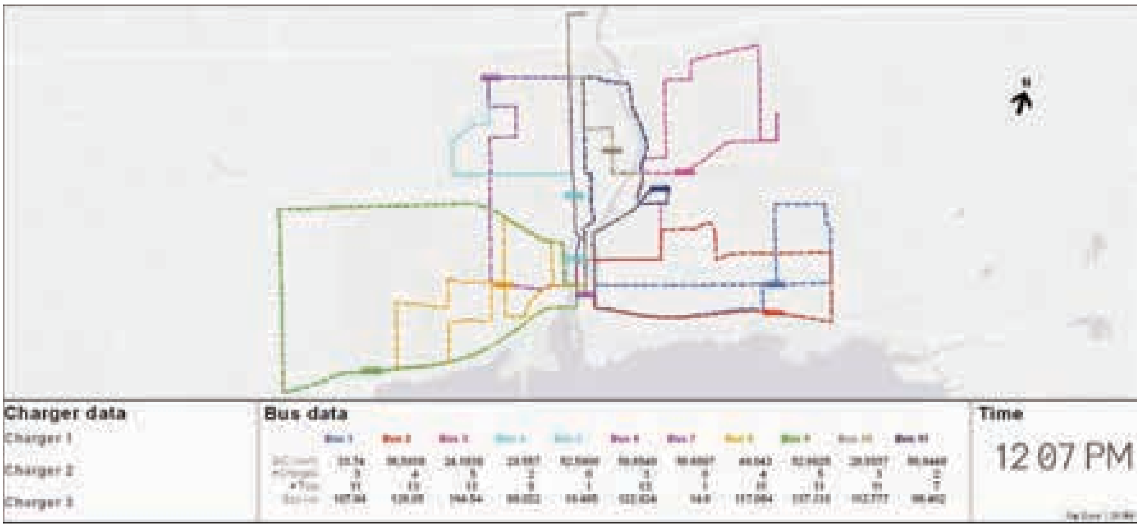


Figure 4 Map of Belleville bus transit routes captured from the simulation model (2-A)

2.3. Operational feasibility of battery electric buses

The simulation results indicate that all five configurations are capable of fulfilling the weekday operational schedule of Belleville transit without increasing fleet size or altering the operation schedule. Each configuration completed 245 cycles, and travelled 2377.45 kilometers. As it relates to utilized buses, the results show that 13 overnight electric buses are required to operate Belleville's transit network, compared to 11 buses in the case of flash and opportunity electric buses as detailed in Table 3. These results provide evidence that BEBs are operationally feasible, and could be readily implemented in small size cities.

Table 3 Electric bus operation simulation results

Attribute \ Configuration	1-A	1-B	2-A	3-A	3-B
Number of trips	245	245	245	245	245
Number of buses	11	11	11	13	13
Total travelled distance (km)	2377.45	2377.45	2377.45	2377.45	2377.45
Total energy consumed (KWh)	2496.32	2496.32	3185.78	3162.01	3162.01
Number of chargers	3	5	5	3	2
Charger Power (KW)	500	250	250	80	200
Number of charging events	87	151	156	13	13
Average charging events per bus (min-max)	7.9 (2-13)	13.7 (2-24)	14.2 (2-27)	1 (13-13)	1 (13-13)
Charging event average duration (min)	6.41	6.28	7.31	198.46	80.77
Chargers' utilization time (h)	8.33	15.92	19.00	43.00	17.50
Average utilization time per charger (h)	2.77	3.18	3.80	14.33	8.75
Peak power demand (KW)	1500	1250	1250	240	400

It is apparent in the simulation results that the required number of chargers varies significantly across the five configurations. The flash electric (1-A and 1-B) requires a minimum of 3*(500 kw) and 5*(250 kw) chargers with an average utilization time of 2.77 and 3.18 hours daily per charger respectively. For the opportunity electric (2-A), a minimum of 5*(250 kw) chargers are required, each is utilized for 3.8 hours daily. The overnight electric (3-A and 3-B) requires relatively few chargers, 3*80 kw and 2*200 kw for scenarios 3-A and 3-B respectively. However, the daily utilization time per charger is relatively high with14.33 and 8.75 hours for each scenario respectively.

Similarly, the results indicate varying frequencies for charging events across BEBs configurations as illustrated in Figure 5 and Figure 6. It is evident that the frequency of charging is highly sensitive to the charger's power, while battery capacity seems to have little influence on the charging profile especially for the on-route electric buses. This finding could be clearly observed from comparing simulation results generated from 1-A and 1-B. The charging profiles for 1-B and 2-A indicate that although they operate with different battery capacity (80 & 200 kwh respectively), both have similar charging routine as it relates to frequency of charging and number of chargers. This is arguably due to the fact that both utilize the same charging power. On the other hand, results for 1-A and 1-B indicate significantly different charging routines, Figure 5, and number of chargers despite the fact that both represent the same bus with different charging power. Therefore, it could be argued that charger's power is the significant contributing factor that governs the electric bus charging routine. That is said, the validity of such an observation is very sensitive to operational conditions and to the features of the transit network.

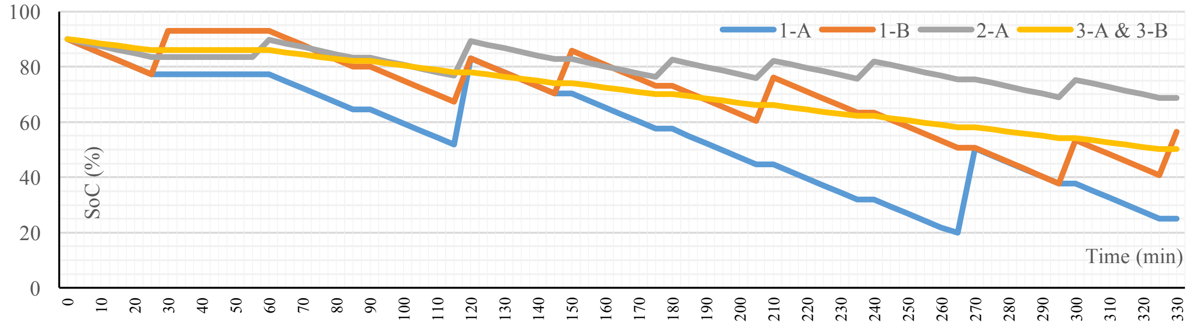


Figure 5 SoC% for bus-2/Route-2 from 05:00-10:30 am

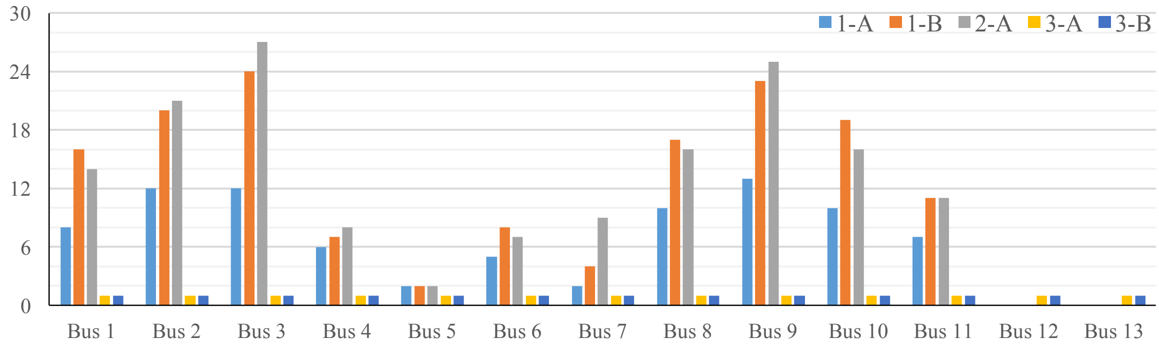
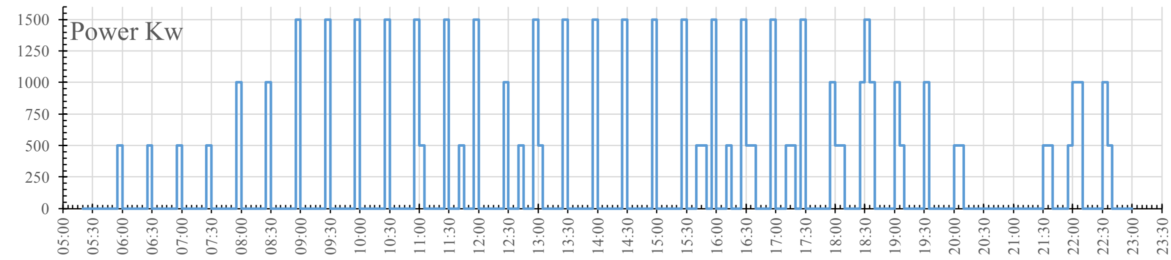
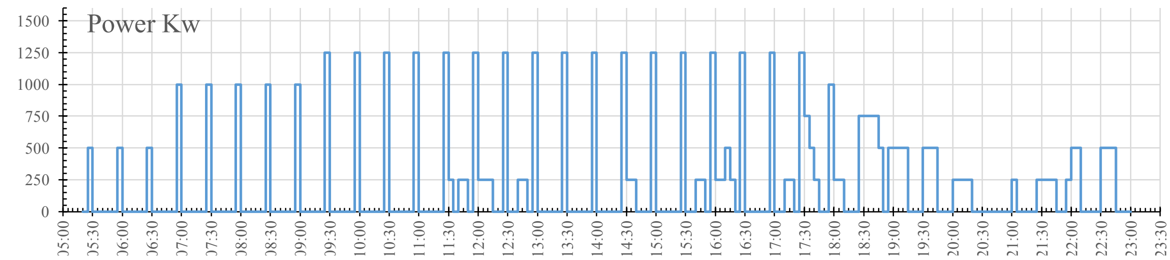


Figure 6 Frequency of charging events for each bus – weekdays schedule

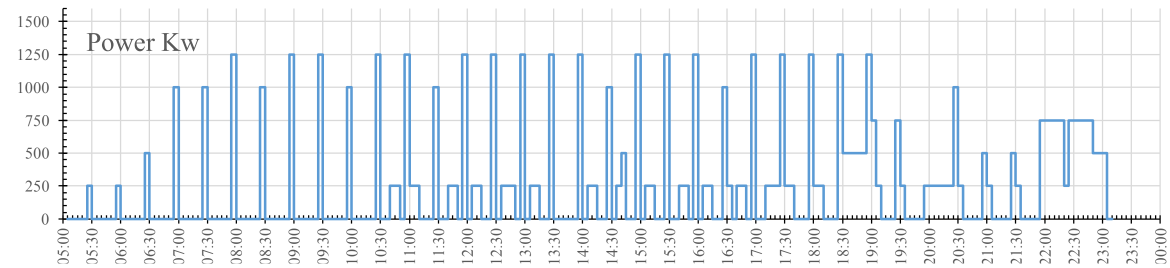
Several insights emerge from the simulation models. It could be argued that current BEB technologies are feasible and could be readily operationalized in small-medium cities. All electric concepts fulfill the operational demands of Belleville's transit network. However, the results show that on-route charging concepts (flash and opportunity) are more suitable for operation as they provide better availability ratio compared to the overnight electric that requires more buses due to the lengthy charging duration. Overall, from an operational perspective, configuration 1-A could be argued more feasible as it provides full operation with relatively fewer number of chargers and less frequent charging events.



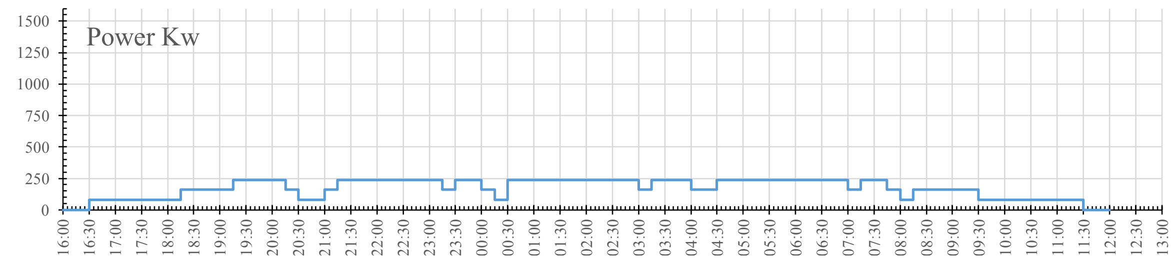
1-A: Flash Electric (3*500kw) chargers



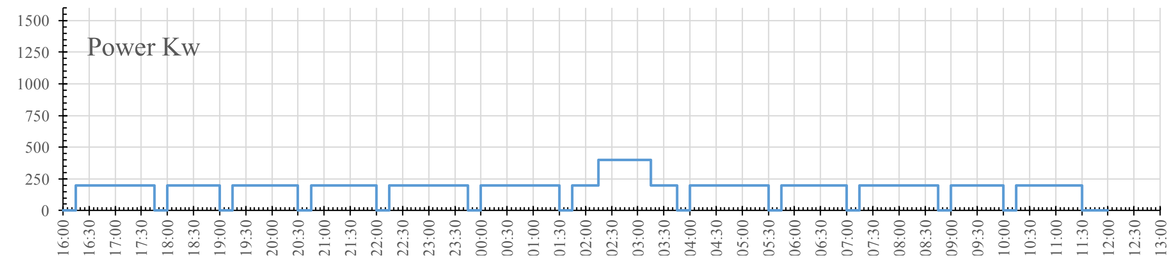
1-B: Flash Electric (5*250kw) chargers



2-A: Opportunity Electric (5*250kw) chargers



3-A: Overnight Electric (3*80kw) chargers



3-B: Overnight Electric (2*200kw) chargers

Figure 7 Power demand over time for electric buses

From an energy perspective however, each configuration provided a different energy profile as illustrated in Figure 7. It is apparent that on-route charging concepts have higher demand for energy during operation compared to the overnight charging. This could represent a major roadblock for the electrification of bus transit service. Hence, the following section provides detailed results on the impact of each BEB configuration on the utility local grid.

4. Impact of battery electric buses on utility grid

Table 4 shows the size of the required service transformer and the load metrics of the charging station for all BEBs configurations. As shown in the table, the required size of the service transformer for flash and opportunity operation (scenarios 1-A, 2-A, and 1-B) is 5-6 times the required size for overnight operation (3-A and 3-B). Also, the average demand and the load factor of flash and opportunity are very low compared to overnight operation. Where from the utility`s prospective, the optimal load factor is one. In such cases of low load factor, the utility may penalize the customers on their electric bills, as the system has been designed to serve the maximum demand.

Table 4 Load metrics and service transformer size

BEBs Configurations	1-A	1-B	2-A	3-A	3-B
Transformer Size (KVA)	1500	1250	1250	250	400
Average Demand (KVA)	173.612	164.93	197.92	144.17	145.84
Load Factor	0.116	0.132	0.1583	0.6	0.364583

The generated load profile and the model of the designed service transformer for each BEB operation are incorporated in the power flow studies of distribution systems. A typical weekday study has been selected in order to investigate the impacts of the BEBs charging on 1) the lifetime of the substation transformer, 2) the voltage profile, 3) the operation of LTC and 4) systems losses of distribution systems. The impact upon the substation transformer has been studied according to seasonal average ambient temperature basis. The ambient temperature for the City of Belleville is found to be 6.6^{o}C, -9.1^{o}C, 13.2^{o}C and 20^{o}C, for fall, winter, spring and summer, respectively [41]. The cooling system for the substation transformer is assumed to be Natural oil-air (OA) cooling. The parameters for calculating the transformer lifetime are found in [39].

Due to a lack of data about the distribution system in Belleville, the 33-bus radial distribution test system shown in Figure 8 is utilized for this study. The substation transformer is equipped with a LDC-controlled LTC device. The average permissible tap changes for the LTC is 20 taps per day. Details about the system loads and the feeder parameters are detailed in [47]. Figure 9 shows a typical profile of the conventional loads in per unit system for the studied day with 30-minutes time interval. It is assumed that all conventional loads at all load nodes are following the profile shown in Figure 9 based on their ratings. The charging station facility is assumed to be connected at the center load (i.e. bus 10) of the test system. The distribution power flow algorithm was coded in MATLAB and run in steps of 5-minutes for the entire day under study to capture the changes of the voltage profile and the tap settings of the LTC at the different loading conditions of the charging station.

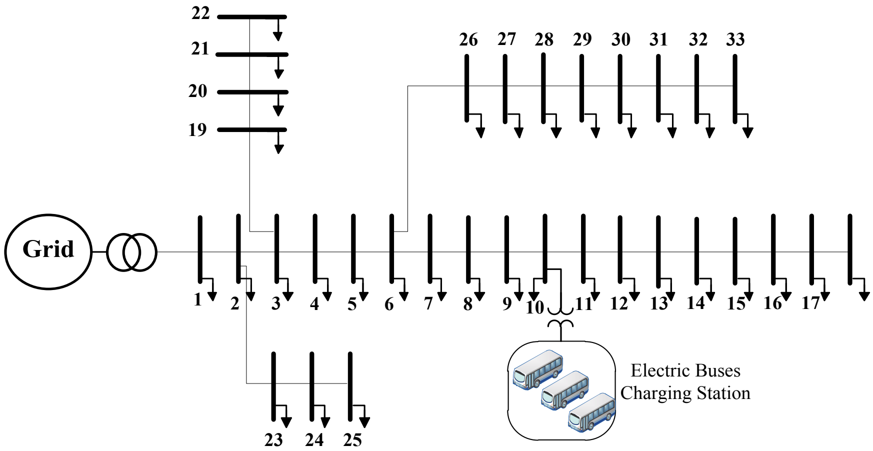


Figure 8 Single line diagram of the 33-bus test system

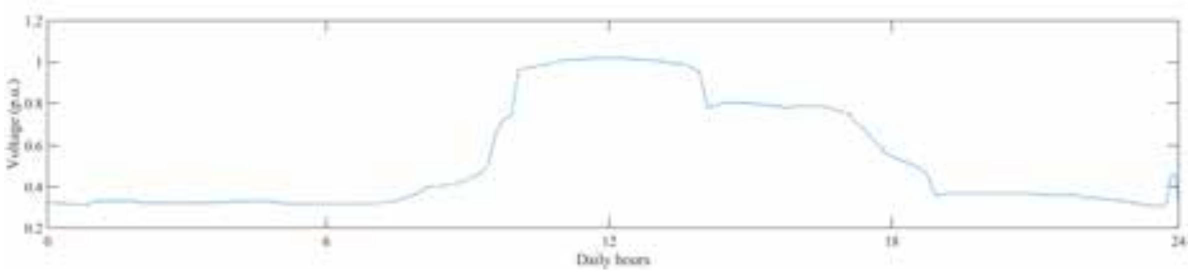


Figure 9 Daily load profile

Six operation cases have been conducted to investigate the impacts of fully electrified bus transit: base case without the charging station and the aforementioned five operation configurations. Table 5 shows the loss of life of the substation transformer, the number of daily tap changing of the LTC, and the overall energy losses for the five operation configurations. As shown in the table, the impact of the charging station on the percent of loss of the transformer lifetime for all charging operation configurations compared with the base case is not significant. The reason is that the overloading of the transformer due to flash and opportunity operation scenarios occurs in a very short period of time due to the intermittent charging profile. Although overnight charging has a flat/continuous loading profile, its impact on the lifetime of the substation transformer is also not significant due to the facts that; 1) the charging occurs during off-peak operation condition, and 2) the maximum coincident demand for the charging is much less than fast charging operation configurations.

Table 5 Impacts of fully electrified transit on the utility

BEB Configuration	BASE CASE	1-A	1-B	2-A	3-A	3-B
Loss of life %	2.46%	2.56%	2.55%	2.563%	2.522%	2.527%
LTC daily switching	7	98	50	55	8	8
Daily losses (MWh)	1.51	1.96	1.8856	1.9353	1.5462	1.67495

As depicted in Table 5, the fast charging operation configurations cause excessive tap switching for the LTC of the substation transformer. The excessive tap operation occurs due to the intermittent charging profile of the transit buses. Such continuous changes in the tap switching will cause wear and tear for the LTC and thus it significantly affects the maintenance cost and lifetime of the LTC. Also, the table shows that the overall daily energy losses in the distribution system due to fast charging operation configurations has increased almost 30% compared with the base case scenario (without BEBs charging). The increase in the daily energy losses due to overnight charging configurations, however, is found to be less than 10% of the base case scenario.

Figure 10 shows the minimum voltage magnitude in the system, the permissible minimum voltage limit, and the change of the tap settings for the day under study for flash, opportunity and overnight charging configurations. As shown in the figure, both flash and opportunity (i.e. fast) charging cause a sudden voltage dip. Further, when several buses are charging simultaneously during the on-peak system loading, undervoltages might occur. Given the short duration and the intermittency of the charging profile, the voltage dip could be also observed as a voltage sag in some circumstances (e.g., weak distribution systems, heavily loaded system, or large transit networks). Such voltage issues (i.e., voltage dip, undervoltages, and voltage sags) will have serious impacts on the operational characteristics of sensitive loads and protective devices. Moreover, and as illustrated in the figure, the intermittent loading of the fast chargers causes excessive wear and tear for the tap switching of LTCs.

In contrast, configurations 3-A & 3-B show that overnight charging does not have significant impacts on the voltage profile and the operation of LTC. Hence, the simulation results in this section show that careful consideration should be given for the voltage regulation issues of distribution systems before the deployment of fast charging fully-electrified transit networks. In particular, the simulation results show that from a utility perspective, the operation of overnight charging is more feasible than flash and opportunity charging in terms of their impacts on the substation transformer and distribution feeders overloading, voltage regulation and quality aspects, and operation of voltage control devices.

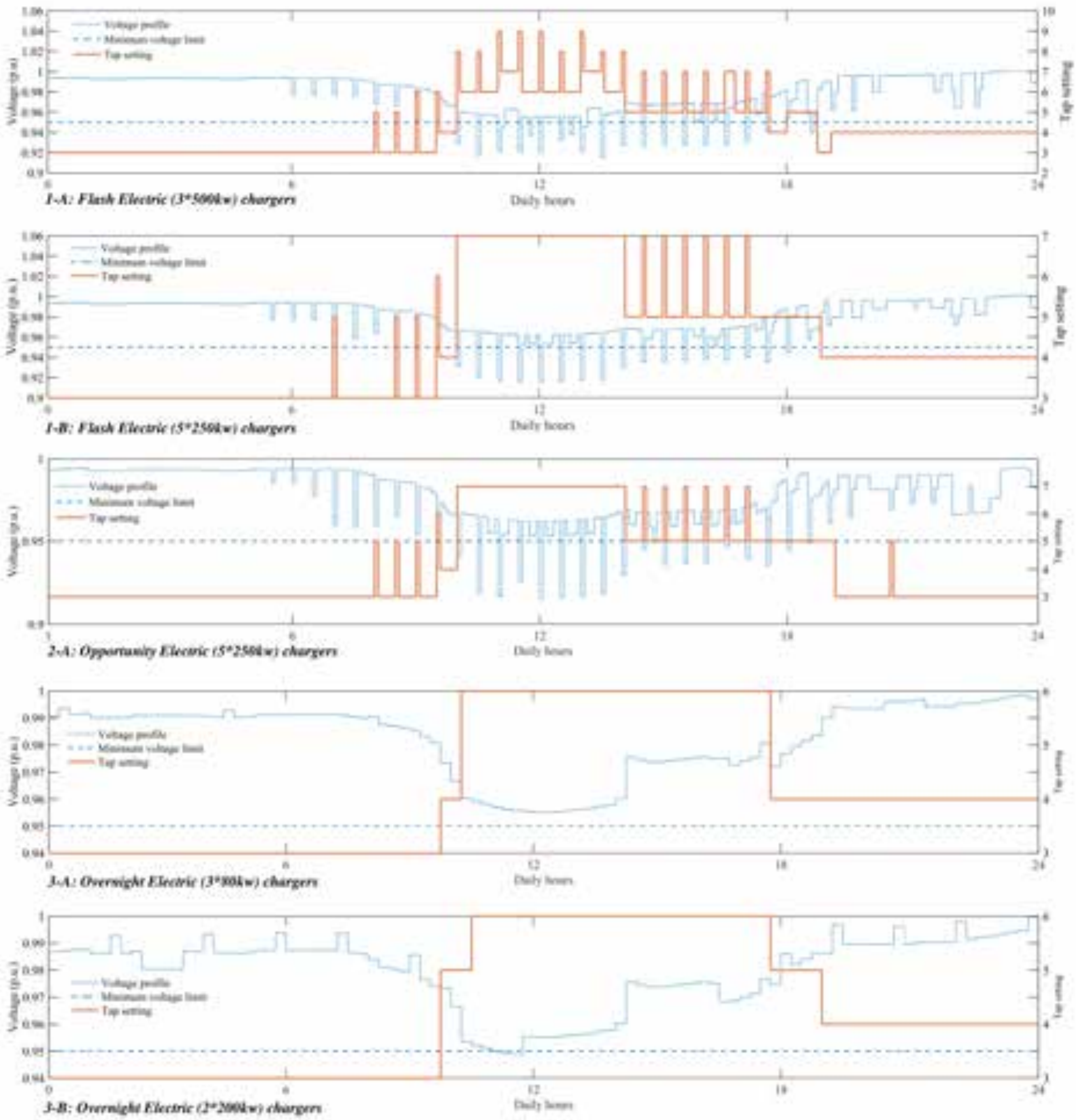


Figure 10 Tap setting and minimum bus voltage

5. Discussion and conclusion

This paper investigates the operational feasibility and utility impact of Battery Electric Buses on a full transit network. The study is developed in two stages. To that end, a real-time simulation model for BEB operation is developed taking into consideration real world transit constraints. In particular, five configurations are investigated that stand to represent three concepts flash, opportunity, and overnight electric buses. Results from the simulation highlighted that all BEBs configurations are capable of fulfilling the operational demands of Belleville Transit, yet significant variation in the operation of different BEBs was clearly depicted. Predominantly, energy demand, infrastructure requirements, and the charging behavior of each BEB configuration were very distinct. Overall, flash electric bus coupled with fast-charging technology is shown to offer superior operation compared to other BEB configurations.

That being said, the second stage of this study investigated the impact of each BEB configuration on the utility distribution grid to further portray the constraints to operationalize BEBs. In particular, the focus of this study was oriented to investigate the utilization and lifetime of the service transformer, and the operation of the local distribution grid. Using load profile data generated from the first stage, models were developed to evaluate the load characteristics and required size of the service transformer for the charging station, as well as to quantify the impacts of the charging load profile on the life loss of the substation transformer, voltage regulation, and operation of voltage control devices.

The findings indicated that operating flash and opportunity electric buses require a service transformer of a size 5-6 times that required from overnight operation. Also, average demand and the load factor are very low compared to overnight operation. Furthermore, the operation of fast-charging flash electric bus has substantial impacts on the substation transformer and distribution feeders overloading, voltage regulation and quality aspects, and operation of voltage control devices. Therefore, from a utility perspective, fast-charging flash electric bus is deemed the least suitable option.

Taken together, operational feasibility simulation and grid impact models generate contradictory recommendations for the selection of a suitable BEB configuration. This outcome in itself is significant, as it highlights the need to consider both operational constraints and grid impacts simultaneously. Therefore, additional research efforts are required to optimize BEBs configuration on a multitude of energy, utility and operational aspects.

6. Acknowledgments

The authors of this article would like to acknowledge support from *Social Sciences and Humanities Research Council of Canada* (SSHRC) Grant No: 886-2013-0001, and *Natural Sciences and Engineering Research Council of Canada* (NSERC) Grant No: 504122.

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ATTACHMENT 4
Presentation Extract - Clean Disruption of Energy and Transportation

DRC-8 Attachment 4 – Presentation Extract, Clean Disruption of Energy and Transportation

Tony Seba is a thought leader in the clean tech industry through his roles as an instructor at Stanford University, an entrepreneur of clean technology companies, and an author of the book 'Clean Disruption of Energy and Transportation'. Tony Seba presented his book at a conference in Boulder, Colorado on June 8, 2017, and below is a summary of his conference presentation:

Tony discussed how exponentially improving technologies such as solar, electric vehicles, and autonomous (self-driving) cars will disrupt and sweep away the current energy and transportation industries. He uses technology cost curves, business model innovation, and technology converge to make various projections on the market penetration, tipping points, and adoption of clean technologies at a global level. His main conclusion is that the era of centralized, command-and-control, extraction-resource-based energy sources (oil, gas, coal and nuclear) will not end because we run out of petroleum, natural gas, coal, or uranium. It will end because these energy sources, the business models they employ, and the products that sustain them will be disrupted by superior clean technologies, product architectures, and business models. This is technology-based disruption reminiscent of how the cell phone, Internet, and personal computer swept away industries such as landline telephony, publishing, and mainframe computers. Just like those technology disruptions flipped the architecture of information and brought abundant, cheap and participatory information, the clean disruption will flip the architecture of energy and bring abundant, cheap and participatory energy. Just like those previous technology disruptions, the clean disruption is inevitable, and it will be swift.

Please see the following YouTube link for a full video of Tony Seba's conference presentation on his book 'Clean Disruption of Energy and Transportation': https://www.youtube.com/watch?v=2b3ttqYDwF0.

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ATTACHMENT 5
Bloomberg New Energy Finance Electric Vehicle Outlook 2018

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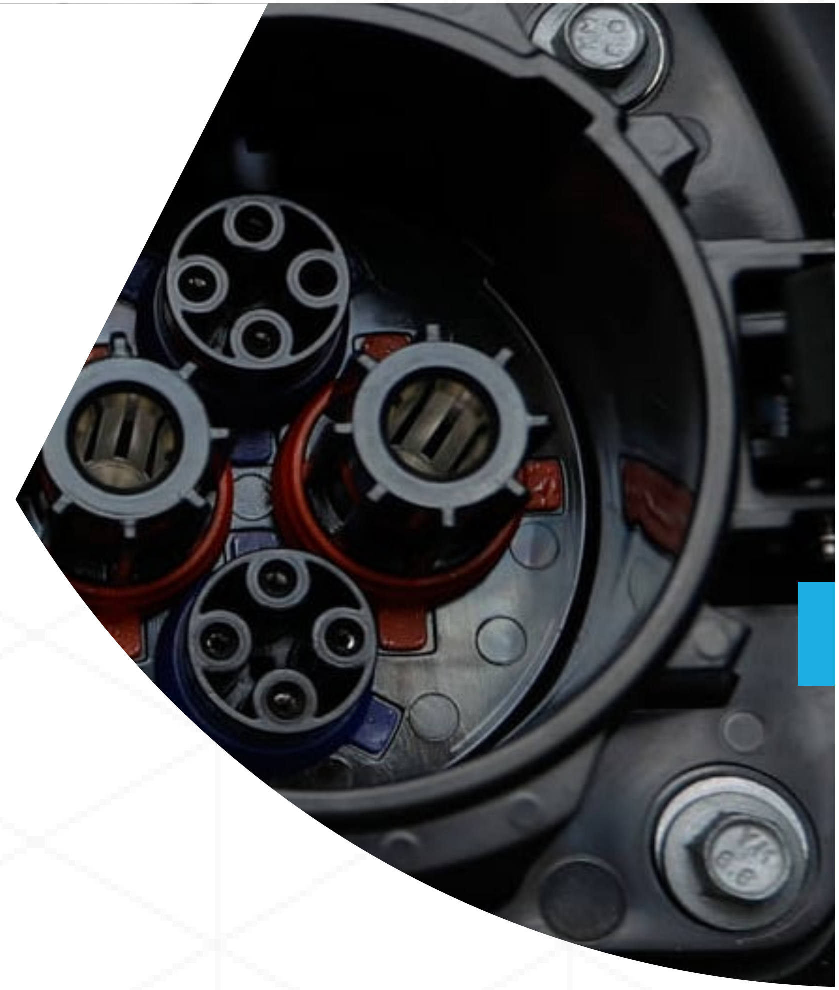

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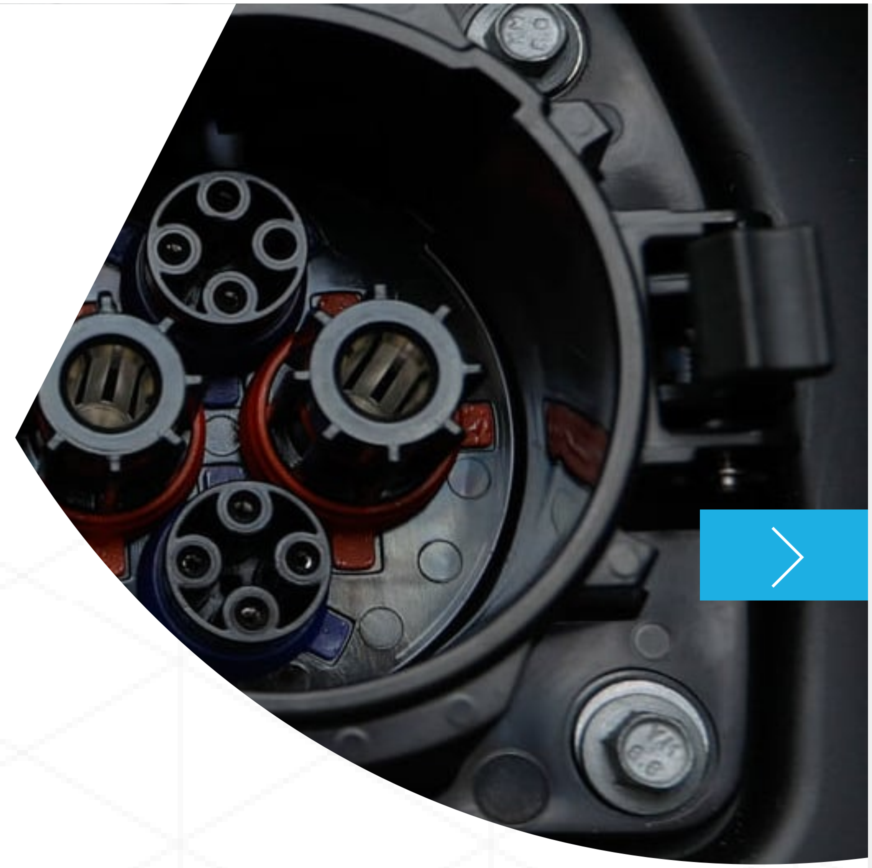

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Electric Vehicle Outlook: 2018

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Setting the scene

By Colin McKerracher, BNEF

The global auto market is changing rapidly. Once derided as toys, electric vehicle sales are on pace to reach over 1.6 million this year, up from just a few hundred thousand in 2014. There are several important factors driving the market forward:

Lithium-ion battery prices have tumbled in recent years. BNEF first started tracking EV battery prices back in 2010, when average battery pack prices were $1,000/kWh.

Fast forward to the end of 2017 and average prices hit a low of $209/kWh, a remarkable 79% drop in seven years. Average energy density of EV batteries is also improving at around 5-7% per year.

Policy support. Governments around the world have offered generous EV purchase incentives to help get the market rolling. At the same time, tightening fuel economy standards will require significant electrification of the vehicle fleet, and China's 'New Energy Vehicle' quota is forcing automakers into EVs faster than most of them would like.

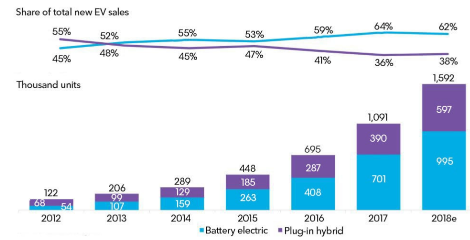
But, this is not only being driven at a national and state level. In 2017, 21% of all global EV sales were in just 6 Chinese cities, all of which have significant restrictions on buying and using new internal combustion engine vehicles.

In Europe, the spectre of potential bans is pushing both buyers and automakers away from diesel. Urban air quality concerns have quickly become central pillars of municipal policy and EVs sales are benefiting.

Rising commitments from automakers. VW, Daimler, Nissan, Volvo and other global automakers have all made aggressive plans to electrify their vehicles over the next 10 years.

The number of EV models available is set to jump from 155 at the end of 2017 to 289 by 2022. Chinese automakers are going further, with

Global passenger EV sales by type



Source: Bloomberg New Energy Finance

companies like Chang'an committing to sell only electric vehicles after 2025.

The share that EVs have of global auto sales is still small – under 2% in most regions – but some countries are jumping ahead, and the next 20 years will bring major changes.

Still, there are challenges. Charging infrastructure remains a barrier in many countries and supply of raw materials like cobalt could create some bumps in the road to cheaper batteries.

BNEF's EV Outlook explores these changes and the impacts they will have across energy, automotive and mining.

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Global sales outlook

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By Salim Morsy, BNEF

Our latest forecast shows sales of electric vehicles (EVs) increasing from a record 1.1 million worldwide in 2017, to 11 million in 2025 and then surging to 30 million in 2030 as they become cheaper to make than internal combustion engine (ICE) cars.

China will lead this transition, with sales there accounting for almost 50% of the global EV market in 2025 and 39% in 2030. China also leads on percentage adoption, with EVs accounting for 19% of all passenger vehicle sales in China in 2025.

Europe is next at 14%, followed by the U.S. at 11%.

"In 2040, some 60 million EVs are projected to be sold, equivalent to 55% of the global light-duty vehicle market."

559 million EVs on the road by 2040, representing 33% of the global car fleet

55% EV share of new car sales in 2040

$70/kWh Lithium-ion battery pack prices in 2030

The number of ICE vehicles sold per year (gasoline or diesel) is expected to start declining in the mid-2020s, as EVs bite hard into their market.

'Shared mobility' cars will be a small but growing element. The advance of e-buses will be even more rapid than that of electric cars (read further in the report for a deeper view on e-buses).

While BNEF's long-term outlook remains similar to last year's predictions, our forecast sees the short-term growth in EV sales and market share grow rapidly.

The outlook for EV sales in the long term will be influenced by how quickly charging infrastructure spreads across key markets, and also by the growth of 'shared mobility'.

While we're optimistic on EV demand over the coming years, we see two important hurdles emerging: a risk of cobalt shortages in the early 2020s that could slow down the rapid battery cost declines seen recently, and the challenge of charging infrastructure.

Highlights from the forecast

By 2040, 55% of all new car sales and 33% of the global fleet will be electric.

China is and will continue to be the largest EV market in the world through 2040.

EV costs. The upfront cost of EVs will become competitive on an unsubsidized basis starting in 2024. By 2029, most segments reach parity as battery prices continue to fall.

E-buses. Buses go electric faster than light duty vehicles.

Displacement of transport fuel. Electrified buses and cars will displace a combined 7.3 million barrels per day of transportation fuel in 2040.

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BNEF clients have access to the full EV Outlook and the underlying charts and datasets.

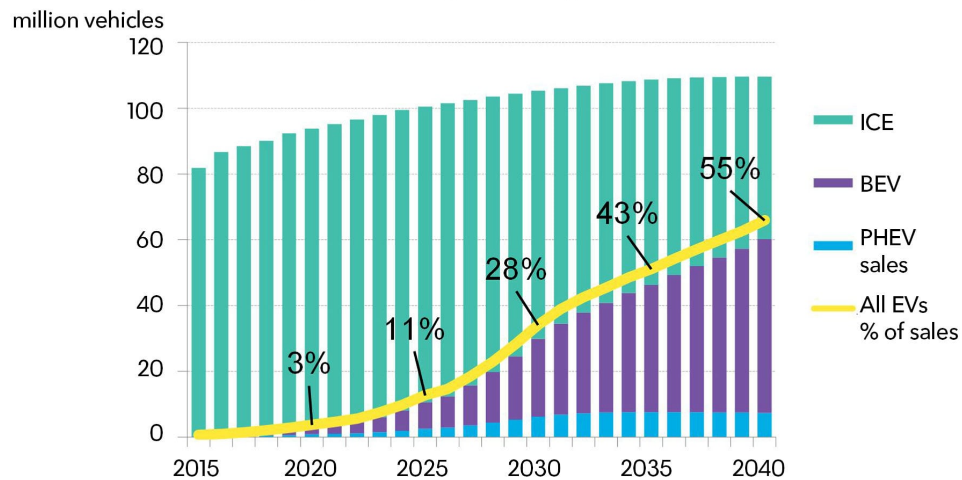
Visit the EVO website to learn more about the Outlook and access related content.

What share do you think EVs will have of global vehicle sales in 2030?

- 5%
- 10%
- 25%
- 50%
- +50%

See results

Annual global light duty vehicle sales



Source: Bloomberg New Energy Finance

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China will lead the transition

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Bloomberg New Energy Finance

By Nannan Kou, BNEF

China will lead the transition from internal combustion engines to electric cars, with EV sales accounting for almost 50% of the global market from now to 2025 and 39% in 2030.

China is also leading the charge on e-buses, with several major Chinese cities on track to fully electrify their e-bus fleets by 2020 and some even sooner. China's push is as much about industrial policy as it is about environmental or energy security concerns. China is building national champions and an e-mobility ecosystem for what it sees as a major strategic industry over the coming decades.

National, regional and municipal policies in China are all pushing the EV market forward. National subsidies are being phased out by 2020, but beginning in 2019 automakers will be forced into EVs through the 'New Energy Vehicle' credit system. Similar to a program in California, the system effectively acts as an EV quota, requiring

Share of global EV market in 2030 by country

Source: Electric Vehicle Outlook 2018, BNEF

automakers to generate credits through the sale of EVs. Automakers who do not sell enough EVs are forced to buy credits from competitors.

This is the single most important piece of EV policy globally and is shaping automakers' electrification plans. We expect China to increase the quota in order to hit its 2025 target of EVs representing 20% of vehicle sales in the country.

City level policies will also play a major role; we expect more cities to add restrictions on buying and using ICE vehicles over the coming years.

EVs reach almost 10% of total Chinese passenger vehicle sales in 2022 in our forecast, 19% in 2025, then 41% by 2030 and 60% by 2040.

We expect the market to slow down in the 2030s due to infrastructure constraints, particularly in high density cities where opportunities to charge at home are limited. By 2040, we expect China to have 200 million EVs on the road.

Which country do you think will have the most EVs on the road in 2040?

- China
- U.S.
- Japan
- Germany

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Batteries and material demand

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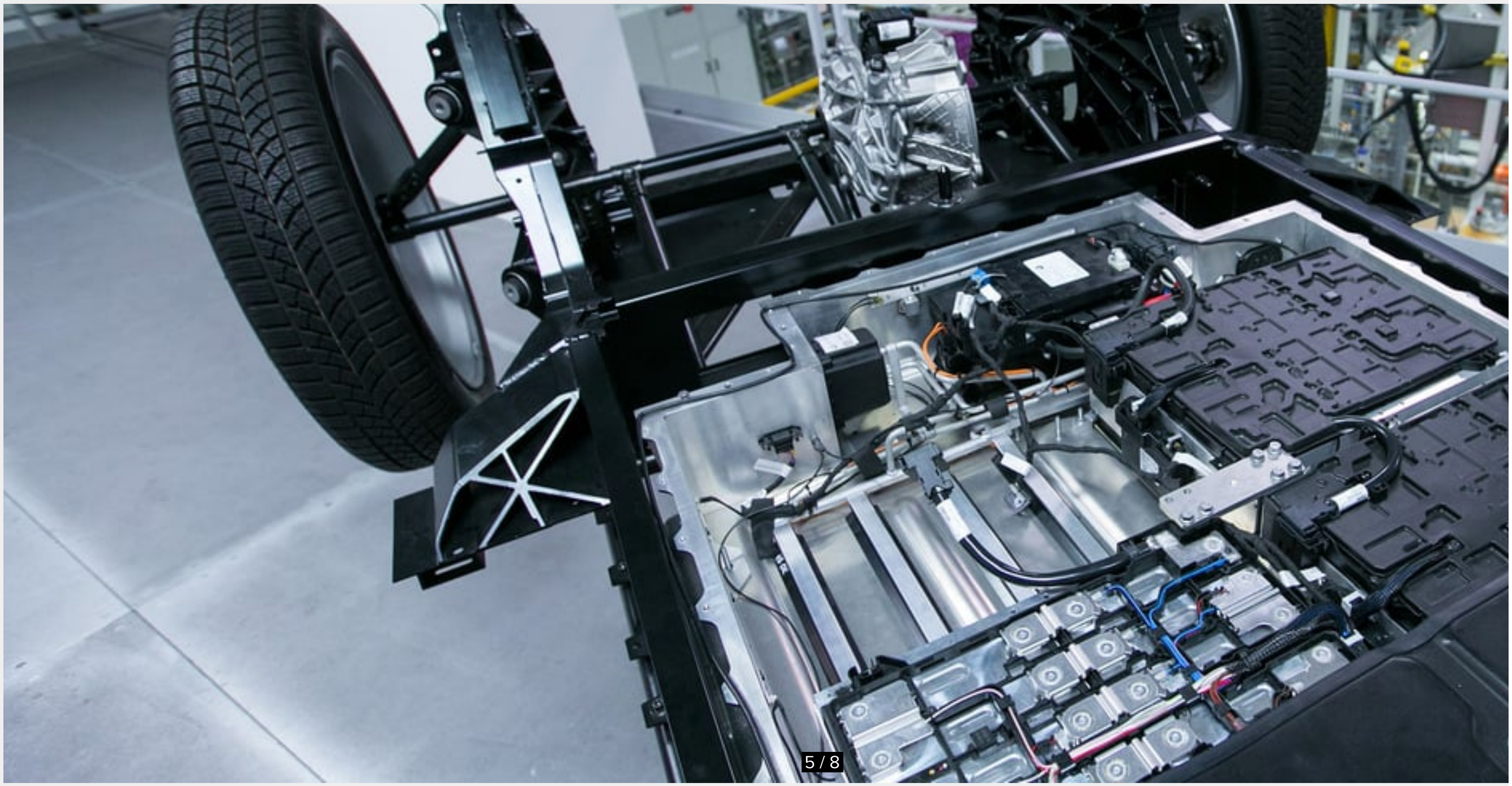

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By Logan Goldie-Scot, BNEF

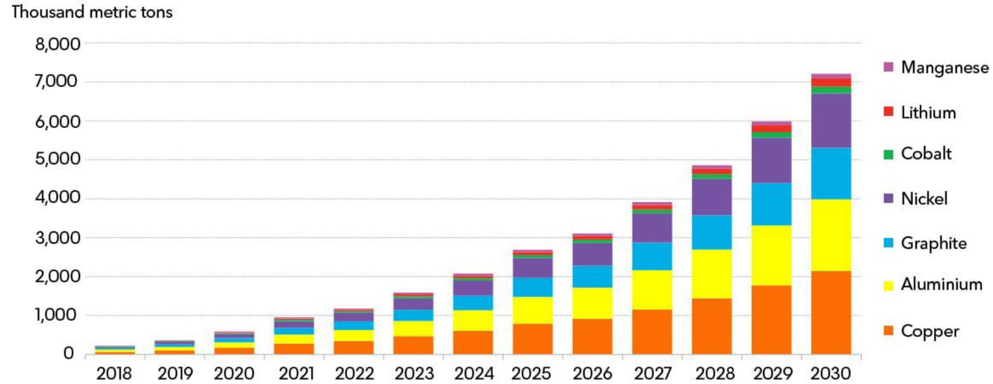
The growth of electric vehicles will require a dramatic scale-up in the lithium-ion battery supply chain.

Lithium-ion battery manufacturing capacity today is around 131 GWh per year. Based on plants announced and under construction, this is set to jump to over 400 GWh by 2021 with 73% of the global capacity concentrated in China.

Further investments will still be needed; by 2030, we expect global EV lithium-ion battery demand to be over 1,500 GWh. All of this is driving up demand – and price – for key battery materials like cobalt, lithium and nickel.

Demand for the components that make up lithium-ion batteries (electrodes, electrolytes) will also increase, from almost 0.7 million metric tons in 2018 to over 10 million metric tons in 2030.

Metals and materials demand from lithium-ion battery packs in passenger EVs



Source: Electric Vehicle Outlook 2018, Bloomberg New Energy Finance. Note: Copper includes copper current collectors and pack wiring. Aluminium includes aluminium current collectors, cell and pack materials and aluminium in cathode active materials.

Manufacturers are pursuing different strategies, with some opting to manufacture everything from the active materials to finished battery packs in-house. Others prefer to buy electrode active materials or electrode rolls from external suppliers and simply manufacture the cells in-house.

Raw material prices are set to rise, speeding up the adoption of low-cobalt battery chemistries.

NMC batteries contain 70% less cobalt than some current batteries and will be adopted quickly as a result of the increase in the prices of cobalt and lithium.

This will help to drive down the cost of battery packs, but for battery pack prices to fall significantly below $100/kWh, a step change in technology will likely be needed.

Cobalt supply still looks challenging. Despite the move to low cobalt chemistries, based on current announcements there will be shortages of cobalt by the early 2020s. Recycling and reductions from other sources of cobalt demand can help alleviate but not fully eliminate some of these constraints.

We view cobalt supply as one of the largest potential risks to EV sales over the next 5-7 years. In the longer term we expect high prices to bring on new supply and accelerate the adoption of new battery chemistries.

Lithium supply will not be a risk to EV adoption in the near-term. High lithium prices over the last few years have led to significant increases in investment in new capacity.

While we do not expect all of this capacity to come online on schedule, we foresee sufficient supply to meet our demand forecast for at least the next 5-7 years. Further investment will be needed in the 2020s.

How much do you expect average lithium-ion battery prices to fall between now and 2025?

- 5-10%
- 30%
- 50%
- 80%

See results

Electric buses in cities

Read more

By Aleksandra O'Donovan, BNEF

Key findings in the report, *Electric Buses in Cities: Driving Towards Cleaner Air and Lower CO2*, authored by BNEF on behalf of the C40 Cities Climate Leadership Group, highlight e-buses' competitiveness with conventional diesel and CNG fueled buses.

Growing pains. Air quality is a growing concern in many urban environments and has direct health implications for residents. Tailpipe emissions from internal combustion engines are one of the major sources of harmful pollutants such as nitrogen oxides and particulates.

Diesel engines in particular have high nitrogen oxide emissions and yet these make up the majority of the global bus fleet.

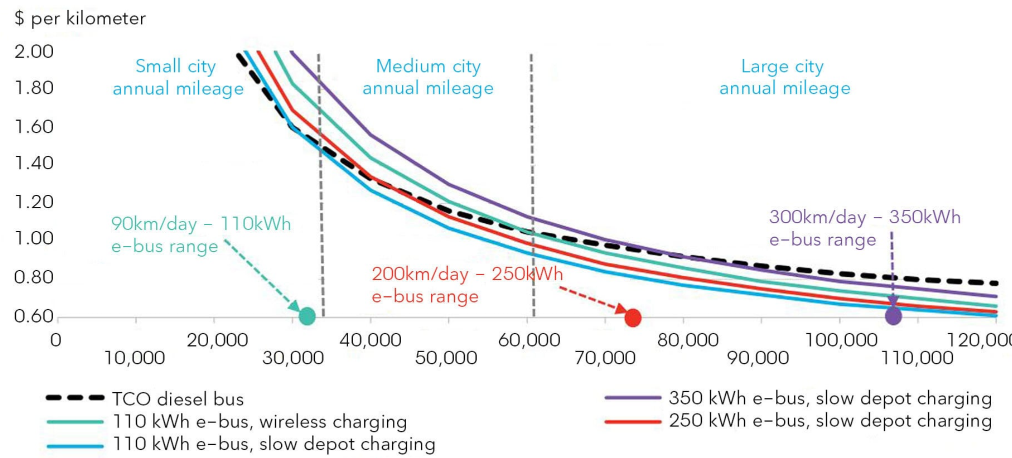
As the world's urban population continues to grow, identifying sustainable, cost effective transport options is becoming more critical.

Electric buses are one of the most promising ways of reducing harmful emissions and improving overall air quality in cities. There are already well over 300,000 e-buses on the road globally, with the vast majority of them in China.

Many Western cities are also making aggressive commitments to electrifying their municipal bus fleets over the next decade.

Total cost of ownership: E-buses vs conventional buses. E-buses have much lower operating costs and can already be cheaper, on the basis of total cost of ownership, than conventional buses today.

TCO comparison for e–buses and diesel buses with different annual distance traveled



Source: Bloomberg New Energy Finance. Note: Diesel price at $0.66/liter ($2.5/gallon), electricity price at $0.10/kWh, annual kilometers traveled – variable. Bus route length will not always correspond with city size.

Bloomberg
New Energy Finance

The TCO of all electric bus configurations that we modelled improves significantly in relation to diesel buses as the number of kilometers traveled annually increases.

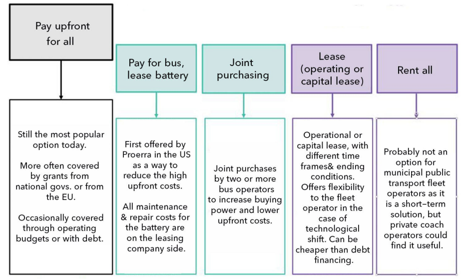
For example, a 110kWh battery e-bus coupled with the most expensive wireless charging reaches TCO parity with diesel bus at around 60,000km traveled per year (37,000 miles).

This means that a bus with the smallest battery, even when coupled with the most expensive charging option, would be cheaper to run in a medium sized city, where buses travel on average 170km/day (106 miles).

Despite the potential operational savings, there are still some challenges for electric buses, with their high upfront cost compared to equivalent diesel buses being one of the biggest obstacles.

To tackle this, new business models are emerging, involving battery leasing, joint procurement and bus sharing.

Different e–bus financing approaches



Source: Bloomberg New Energy Finance.

E-bus forecast

Our EV Outlook this year includes a full e-bus forecast, some highlights include:

1. By 2030, we expect 84% of all municipal bus sales globally to be electric. China has led this market in spectacular style, accounting for 99% of the world total last year.

The rest of the world will follow, and by 2040 we expect 80% of the global municipal bus fleet to be electric.

2. By 2040, we expect around 2.3 million e-buses on the road globally.

3. E-buses add to oil displacement and battery demand impacts over the next five years but are dwarfed by light duty EV sales once that market gets going from the mid-2020s onwards.

Download the [full report here](#).

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EVs impact on oil

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Bloomberg New Energy Finance

By David Doherty, BNEF

The rapid expansion of electric vehicles has a profound effect on global oil consumption. As electric vehicle sales surpass 50% of all new vehicles sold by 2040, we expect 7.3 million barrels per day of transport fuel will be displaced.

7.3 mbpd Fuel displaced by passenger EVs and e-buses by 2040

90% Gasoline proportion of every barrel of fuel displaced by 2040

2024 EVs displace more oil than e-buses

Displaced oil.

As the most prevalent fuel consumed by the global light duty vehicle fleet, gasoline accounts for 94% of transportation fuel displaced by passenger EVs and intelligent mobility.

By 2040, diesel represents around 5% of displaced fuel demand, the majority of which in Europe. Additionally, we expect passenger EVs and intelligent mobility to displace over 60 kbpd of LPG demand by 2040.

Where?

China accounts for almost 2.5 mbpd of this eroded demand, followed by the U.S. and Europe at 2.3 and 1.1 mbpd, respectively.

In the short-term, the majority of curbed demand stems from diesel consumption, with gasoline taking over from 2023.

By 2040, diesel accounts for just under 10% of displaced volume of fuel, while gasoline demand displaced by electric vehicles will be in excess of 6.4 mbpd.

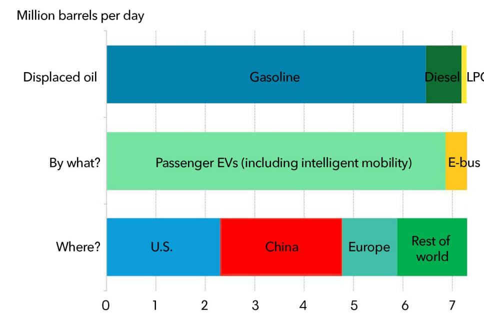
By what?

Over the long-term passenger EVs (including those used in intelligent mobility applications like car sharing and ride hailing), begin to make a material impact on the demand outlook, displacing almost 6.9 mbpd of liquid fuel consumption by 2040.

Although passenger EVs and intelligent mobility have a limited impact in the short to medium-term, e-buses are already starting to make a dent in oil consumption. This is the case particularly in China, where we expect to see close to 240 kbpd of oil demand displaced in 2018.

While gasoline dominates the displacement of fuel in the passenger market, diesel does so in the bus fleet.

Oil displaced due to electrification in 2040



Source: Bloomberg New Energy Finance

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ATTACHMENT 6 – EY Report

EY
Building a better working world

When competitors have a head start, how can US utilities innovate to overtake?

By Dana Hanson

5 minute read 7 Jun 2018

Compared to counterparts in other markets, US utilities have longer to prepare for disruption from lower cost distributed energy resources (DERs). But how they use their time will determine their fate in the new energy world.

Around the world, energy markets are transforming. And most are changing much faster than previously expected. Together with a global analyst house, we've determined three critical tipping points that mark the utility sector's progression on a journey to fundamental change.

The first of these tipping points — when going off-grid becomes as affordable and accessible as staying on it — will hit Oceania in 2021 and Europe in 2022. Two further tipping points will follow shortly afterward. The countdown for utilities in these markets is on.

But our modeling of the US market reveals a very different story. We've determined the tipping points for five US markets and found that they will hit much later than in other parts of the world.

Tipping point methodology

The energy industry is at the start of a period of unprecedented change, one that will fundamentally change the market place (presenting new challenges as well as new opportunities). Three tipping points will mark the emergence of a new energy system.

Tipping point one is when self-generation reaches cost parity with grid-delivered electricity. To determine this date, we calculated the projected demand for electricity, future generation mix and cost of delivering electricity via a central grid between 2015 and 2050, and then compared it to the predicted cost of self-generating electricity using solar PV and battery storage.

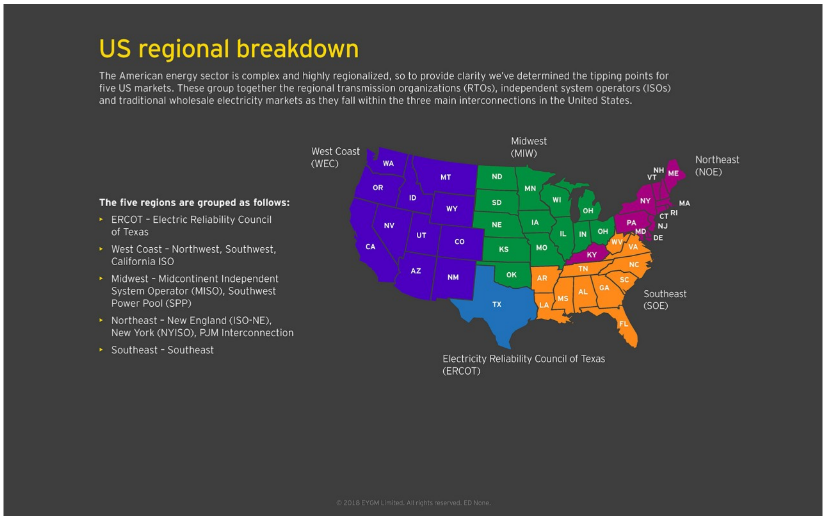
To help determine when these costs would reach parity, we worked with a leading global analyst house to model the expected adoption and interactive impacts on electricity demands and costs of 10 core distributed energy and information technologies: solar PV; battery storage; electric vehicles; microgrids; home and building energy management systems; P2P electricity exchange; smart meters; artificial intelligence; grid-edge technology; and cloud.

The study also identified two further tipping points for the energy industry:

- *Tipping point 2*: when the price of battery electric vehicles reaches cost and performance parity with traditional cars with internal combustion engines

- *Tipping point 3*: when the mere cost of delivering electricity (i.e., the unit-cost of electricity transmission and distribution) exceeds the cost of self-generated electricity

Because drivers vary across markets, the tipping points will hit different regions at different times. The American energy sector is complex and highly regionalized, making it difficult to get one clear picture of what is driving change. To provide clarity we've determined the tipping points for five US markets – ERCOT, Westcoast, Midwest, Northeast and Southeast, with a focus case study on California.



Why will disruption hit American markets much later?

The American energy sector is complex and highly regionalized, making it difficult to get one clear picture of what is driving change. But several common factors can help explain why the rise of DERs will impact US utilities at a slower pace than elsewhere:

Low coal, gas generation and utility-scale renewable costs

Wholesale power prices have fallen across all of the major US trading hubs, mostly because of sustained low costs of natural gas — the fuel that often determines the marginal generation cost in most power markets. Natural gas costs in the US are almost half that paid in Europe (US$2.5/MMBtu compared to $4.9/MMBtu), while coal in the US is just US$12 a ton compared to US$64 a ton in Europe. Such low fuel costs combined with the low-marginal cost of utility-scale renewables drive electricity prices lower. At these low prices, consumer pressure for change will come more slowly and grid price parity for distributed generation (DG) plus storage will take much longer to achieve.

Low taxes

One of the biggest factors behind lower energy prices in the US is a much lower rate of taxation compared to other regions.

- Taxes contribute only 5% of US retail electricity prices — compared to making up one-third of prices in Europe.
- In the US, generation costs make up 50%-60% of electricity retail prices compared to only 38% in Europe.

Lower transmission and distribution (T&D) costs

Over recent decades, US utilities have generally invested less (as a percentage of total capital spend) in the electricity grid compared to utilities in other developed regions of the world. This, along with a tendency to deploy overground poles and wires rather than the underground infrastructure used in much of Europe, has led to lower costs. But while years of lower T&D investment may have helped keep consumer energy bills lower in the past, this has changed in recent years. Several utilities have announced multibillion-dollar programs to modernize the grid and upgrade aging infrastructure over the next 5–10 years.

Accelerating technology and consumer demands could bring tipping points forward

But while grid parity for PV plus storage is expected to occur more slowly in the US compared to other countries, this first tipping point is only 13 years away for the US Northeast region. For an industry used to investment timelines that span 40 or 50 years, this is a compressed time frame in which to make big changes. And most US regions will experience all three tipping points in quick succession, leaving little room for adaptation once these changes come thick and fast.

Across the country, two factors could also bring tipping points forward:

- Accelerating technology: Advances in digital technology are increasing exponentially, creating new products and services that may transform energy use in a way we cannot even imagine today. At the same time, technology is continually improving the performance and reducing the cost of existing services and products such as solar PV generation and batteries.
- Consumer demand: While residential solar PV currently sits at just 1%, changing consumer attitudes toward renewable energy and the technology that supports it could see this figure rise quickly. Meanwhile, corporate consumers, including some of the world's most influential companies are investing heavily in DG to take charge of energy bills and boost their "clean and green" reputations.

State-based initiatives will make the difference

The highly localized nature of the US energy market means that real change will be driven at a state or regional level. So while the federal government has withdrawn some support for renewables, increased clean energy initiatives at a state level may speed up progress toward tipping points in some areas.

For example, while California sits within the West Coast region — where tipping point 1 is expected in 2034 — we've modeled that the state will reach this milestone in just a decade. If other states are inspired to adopt some of California's world-leading policies and programs around DER and electric vehicles, we may see more US "hotspots" of energy transformation emerge.

Case study: The California Way

Time to prepare for a new energy world

It's clear that DERs will play a critical role in shaping the future US energy market, with generation becoming more diverse, decentralized and enabled by a digital grid powered by automation and data-led intelligence.

To find out about how the generation mix is changing across the US, see the video below:

Those that stand the best chance of success in this new US energy sector are those taking action now to prepare. Now is the time for utilities to:

- Rethink investment priorities as the energy mix shifts. More renewables and natural gas generation will require appropriate grid upgrades and new capabilities, including digital technologies. Several major US utilities have announced investments in solar, smart meters, grid modernization and batteries.
- Leverage the potential of EVs: Modeling predicts that there will be 7m EVs in the US by 2025 — and 88m by 2050. With each EV holding up to 30KWh of battery storage, utilities should consider how this can be used to benefit consumers while strengthening and enhancing the grid.
- Learn lessons from other regions: US utilities could benefit from taking a more outward view to learn from energy companies in other regions that have already had to adapt to much higher market penetration rates of distributed generation, especially rooftop solar.
- Accelerate diversification to mitigate risk: Diversifying into natural gas, renewable generation and advanced energy storage now will position

utilities to take advantage of a changing energy mix.

- Explore connections with corporate consumers with sustainability agendas: Opportunities to help corporate clients build and manage self-generation and storage facilities could be lucrative. Brokering power purchase agreements of off-site, large-scale wind and solar energy is another strong growth area.
- Consider collaborations with innovators in other industries: US utilities are already forming partnerships with companies in adjacent industries, such as battery manufacturers and technology firms, to enhance their capabilities in new energy services and develop innovative products and services.
- Get closer to regulators to shape new regulatory frameworks: Energy regulations lag the transformation of the sector. Different models of rewarding sector investment could help incentivize innovative new business models. In addition to New York's REV, Illinois's recent energy reforms that reward utilities for investing in distributed generation are expected to help shape new solar-based business models.

US utilities should seize opportunities of change

The US is a patchwork of regional differences in market structures, retail prices and resource availability. Each region is on its own path to transformation and now we've modeled the date on which US energy markets will change forever.

Now is the time to rethink investment strategies, innovate new business models, learn lessons from other regions and industries, and take a proactive role in the transformation of the utility sector.

Summary

As the countdown to increasingly feasible grid defection by customers accelerates and a new distributed model emerges, American utilities can seize the opportunities that extra lead time allows them.

About this article

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Helping clients transform their businesses during this time of change and convergence.

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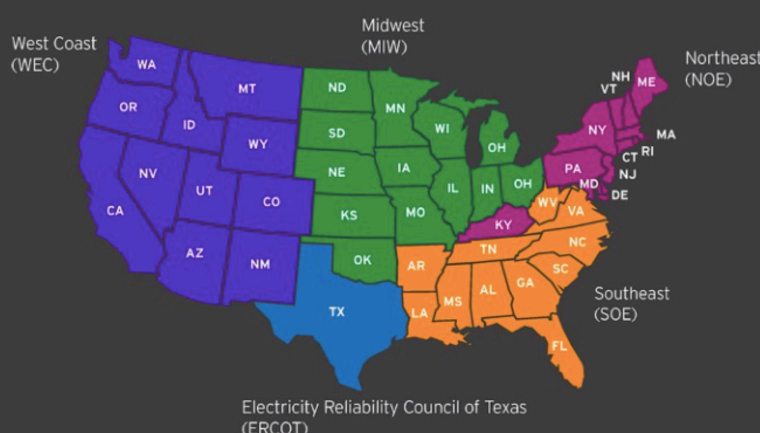
US regional breakdown

The American energy sector is complex and highly regionalized, so to provide clarity we've determined the tipping points for five US markets. These group together the regional transmission organizations (RTOs), independent system operators (ISOs) and traditional wholesale electricity markets as they fall within the three main interconnections in the United States.

The five regions are grouped as follows:

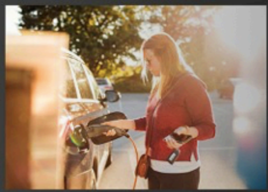
- ERCOT – Electric Reliability Council of Texas
- West Coast – Northwest, Southwest, California ISO
- Midwest – Midcontinent Independent System Operator (MISO), Southwest Power Pool (SPP)
- Northeast – New England (ISO-NE), New York (NYISO), PJM Interconnection
- Southeast – Southeast



US regional breakdown

Conversely, due to the low energy prices across all regions in the US, the first tipping point reached will be tipping point 2 in 2025: When EVs reach price and performance parity with traditional internal combustion engine cars.

- Rapid advancements in technology, low gas prices, and policy choices have already led to significant changes within the US electric power markets.
- Changing consumer preferences towards renewable generation and advances in technology could accelerate how quickly change happens.
- Every part of the continental US has sufficient solar resources for solar to play significant roles in regional electricity mixes.



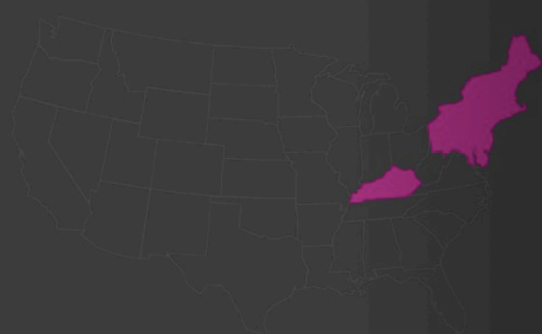
US regional breakdown

Tipping point 1:

The cost of delivering electricity exceeds the cost of self-generated and stored electricity.

Northeast 13 years: 2031

- The Northeast has high electricity rates, influenced by high wholesale winter electricity prices.
- Rapid advances in technology, changes in fuel prices, aging infrastructure in need of replacement, and state and federal policy choices are driving system change.
- Investment in energy storage and smart grid technologies is on the rise.
- Consumers are embracing new innovative technologies, like electric vehicles, changing how consumers interact with the grid.



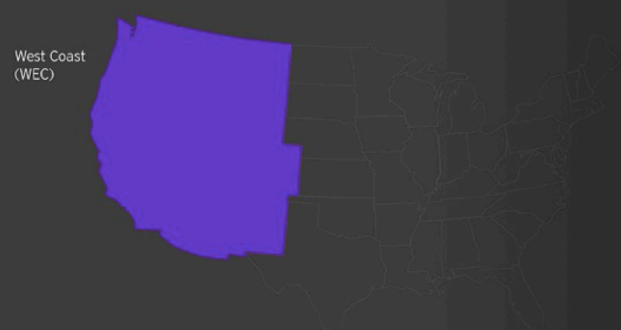
US regional breakdown

Tipping point 1:

The cost of delivering electricity exceeds the cost of self-generated and stored electricity.

West Coast 16 years: 2034

- The rise of renewable energy has transformed power markets in the US West Coast states, particularly California.
- Utility-scale solar power plants remain concentrated primarily in California due to strong government policies and incentives.
- Nearly 70% of the Westcoast's distributed solar and 50% of the region's EVs are in California.



US regional breakdown

Tipping point 1:

The cost of delivering electricity exceeds the cost of self-generated and stored electricity.

Midwest 18 years: 2036

- An increasing number of coal plants cannot compete economically with low cost power and natural gas.
- Majority of states have binding standards for clean energy and are supporting these through wind, bio-fuels and solar.
- 18% contribution of wind to total electricity demand by 2036.

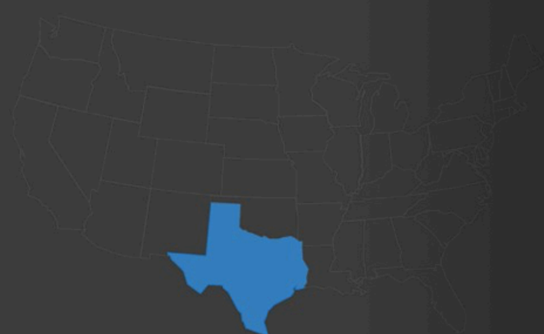
US regional breakdown

Tipping point 1:

The cost of delivering electricity exceeds the cost of self-generated and stored electricity.

ERCOT 20 years: 2038

- Market forces are driving an overhaul of power generation capacity in Texas.
- Oversupply and low power prices have increased competition for the state's power generators, forcing them to shut down old inefficient coal power stations.
- Declining cost combined with excellent solar potential are poised to cause a boom.



Electricity Reliability Council of Texas (ERCOT)

US regional breakdown

Tipping point 1:

The cost of delivering electricity exceeds the cost of self-generated and stored electricity.

Southeast 24 years: 2042

- A high proportion of the US nuclear fleet is in the Southeast.
- While enormous amounts of solar PV is expected to be built in the future, the majority of this will be grid-scale.
- Retail rates are some of the lowest in the US.
- Solar deployment is slow to non-existent, mostly due to lack of state support. Wind capacity is virtually absent from the south.

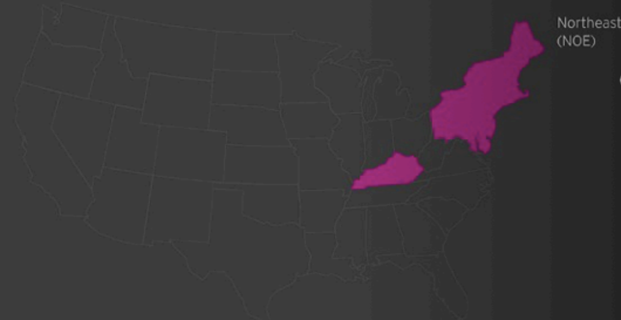
US regional breakdown

Tipping point 3:

The cost of delivering electricity exceeds the cost of self-generated and stored electricity.

Northeast 21 years: 2039

- Many Northeast states have set ambitious greenhouse gas reduction goals of 80% by 2050.
- By 2050 distributed solar generation will make up 10% of total demand, up from 1% today.



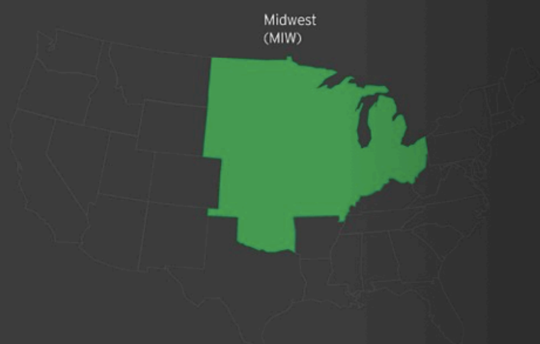
US regional breakdown

Tipping point 3:

The cost of delivering electricity exceeds the cost of self-generated and stored electricity.

Midwest 26 years: 2044

- Balanced portfolio of coal 30%, natural gas 30% and renewables 28%, with wind making up the majority of the energy mix.
- To unlock wind potential, significant transmission expansion to population centers on the East Coast, West Coast, and South is needed.
- Solar will only experience modest growth.



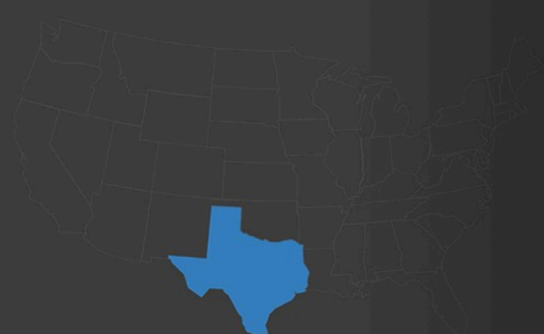
US regional breakdown

Tipping point 3:

The cost of delivering electricity exceeds the cost of self-generated and stored electricity.

ERCOT 27 years: 2046

- The market is continuing to undergo unprecedented transformation with wind generation and transmission upgrades dominating investment supported by market reforms.
- 7% share of distributed solar generation as % of total demand.



Electricity Reliability Council of Texas (ERCOT)

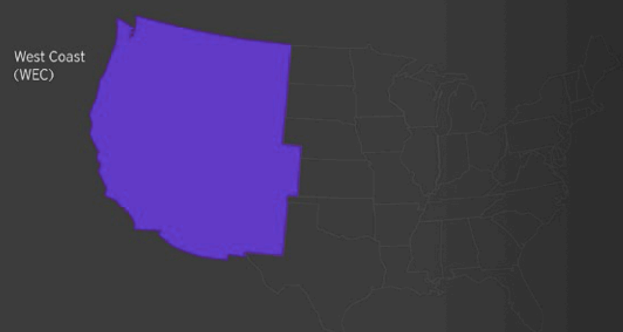
US regional breakdown

Tipping point 3:

The cost of delivering electricity exceeds the cost of self-generated and stored electricity.

Westcoast 27 years: 2045

- The region is expected to see the US's strongest uptake of renewable energy with almost half of demand met by renewables by 2050.
- Distributed renewable generation will contribute 27% of the region's energy mix by 2050.
- Distributed solar alone will help meet 22% of total demand of the Westcoast by 2050.
- 573GWh - net storage capacity from 19 million EVs by 2045.



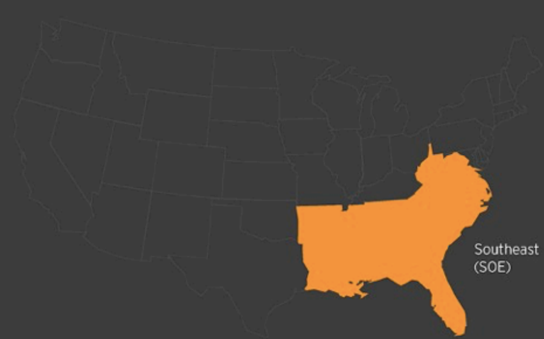
US regional breakdown

Tipping point 3:

The cost of delivering electricity exceeds the cost of self-generated and stored electricity.

Southeast after 2050

- Continued decline in solar PV costs and aging nuclear and coal capacity will accelerate solar PV but gas will remain the dominant energy source.
- Limited wind resources partially explains the notable lack of Renewable Portfolio Standard policies.
- 4% share of distributed solar generation as % of total demand.



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Reference

Exhibit 4, Tab 1, Schedule 1 (DSP), Appendix H (Regional Planning Reports)

Preamble: The York Region Integrated Regional Resource Plan prepared by the IESO on behalf of the York Region Working Group (which included PowerStream Inc.); the Northwest Greater Toronto Area Integrated Regional Resource Plan prepared by the IESO on behalf of the Northwest Greater Toronto Area Working Group (which included Hydro One Brampton); and the Parry Sound / Muskoka Sub-region Integrated Regional Resource Plan prepared by the IESO on behalf of the Parry Sound / Muskoka Sub-region Working Group (which included PowerStream Inc.) (collectively, the IRRPs) identify the following key consideration related to planning for long-term needs:

- **The "community self-sufficiency" approach entails an emphasis on meeting community needs largely with local, distributed resources, which can include: aggressive conservation beyond provincial targets; demand response; distributed generation and storage; smart grid technologies for managing distributed resources; integrated heat/power/process systems; and EVs.**

The York Region IRRP (in Appendix A, p. 2), makes reference to "battery [EV] storage capabilities, especially for load intensification cluster applications".

a) Please explain how Alectra's DSP has been informed by the "community self-sufficiency" approach to regional electricity planning, as discussed in the IRRPs, including the extent to which Alectra has considered the capacity of EVs, "prosumers", and other DERs to meet integrated energy planning needs.

b) Please describe all measures that Alectra is undertaking to facilitate the integration of EVs, "prosumers", and other DERs in its energy planning and business planning processes.

Response:

a) Alectra Utilities believes that utility planning should proactively take into account current DER growth trends and has adopted an integrated planning approach which considers wire and non wire alternatives to address capacity needs in the near and long term.

Alectra Utilities considers the impact of conservation, EV and distribution generation, which is accounted for as part of the non-coincident peak load forecast underpinning the Lines Capacity and Stations Capacity investments.

Alectra Utilities considered non-wires alternatives such as conservation and DERs for the stations and lines projects as well as specific system renewal projects. Currently, the use of non-wires alternatives for stations and lines expansion projects, identified that these alternative options are not yet economically feasible to meet the load growth and contingency requirements over the DSP period. However, Alectra Utilities believes that such non-wire alternatives could contribute to the deferral of wires investment beyond the DSP period as cost of such solutions continue to reduce. On this basis, Alectra Utilities proposes to invest in developing capacity and monitoring DERs, with the objective of being able to deploy such assets at scale to defer investments such as Transformer Station and Municipal Station upgrades, as well as other distribution infrastructure, which would otherwise be planned to take place in the period after 2020-2024.

b) Alectra Utilities provides a summary list of measures that the company is undertaking to facilitate the integration of EV and DERs in its system and business planning processes.

Alectra Utilities' non-coincident peak load forecast process considers the impact of conservation, EV and DER, and has adopted an integrated planning approach which considers wire and non wire alternatives to address capacity needs in the near and long term. Please see Exhibit 4 Tab1 Schedule 1 Ch. 5.3.1 Page 155 to 157

Alectra Utilities continues to track and monitor its stations and feeders to determine that adequate capacity is available within the distribution system to facilitate the connections of DERs. Please see Exhibit 4 Tab1 Schedule 1 Ch. 5.3.4 Page 311-319.

Alectra Utilities plans to evaluate the operational effectiveness of DERs deployed across the service area as non wires solution, in order to defer and/or avoid distribution infrastructure investments. Further information on this investment is provided in Appendix A13 Stations Capacity Page 36.

Alectra Utilities plans to invest in DER platforms, which will provide the organization with the capability to monitor; control; and optimize the integration of DERs (e.g., solar generation, battery storage, smart thermostats, EVs) into the distribution system, and to provide real-time transparent, tracking and management of DER participation in energy services. Please see Appendix A16 DER Integration.

Alectra Utilities continues to support the IESO and other local distributors to investigate the non wires alternatives for all regional planning projects. In 2018, Alectra Utilities and InnPower, with support from the IESO's conservation fund, commenced a Local Achievable Potential ("LAP") study for the Barrie TS service area which was completed in 2019. Another regional planning cycle is underway for York Sub-Region in which Alectra Utilities in conjunction with IESO and other LDC partners will be completing a Local Achievable Potential Study for the York region. Please see Exhibit 4 Tab1 Schedule 1 Ch. 5.2.2 Page 68 and 77

Alectra Utilities continues to work with the municipalities it serves on their energy planning activities. Please see Exhibit 4 Tab1 Schedule 1 Ch. 5.2.2 Page 56