Energy Probe Compendium

Panel 2 Intervenor - Energy Transition IGUA M8

and

Panel 3 Intervenor - Energy Transition GEC/ED

EB-2022-0200 Phase 1 Oral Hearing

Table of Contents

Tab 1

EPCOR Presentation – Alberta Experience
Stakeholder Meeting: Sector Evolution – Utility Remuneration and Responding to Distributed Energy Resources (EB-2018-0287/0288)
September 18, 2019

DER INTEGRATION – EPCOR’S EXPERIENCE IN EDMONTON

Darren McCrank, P.Eng.
Director, Ontario Operations
Ontario Region

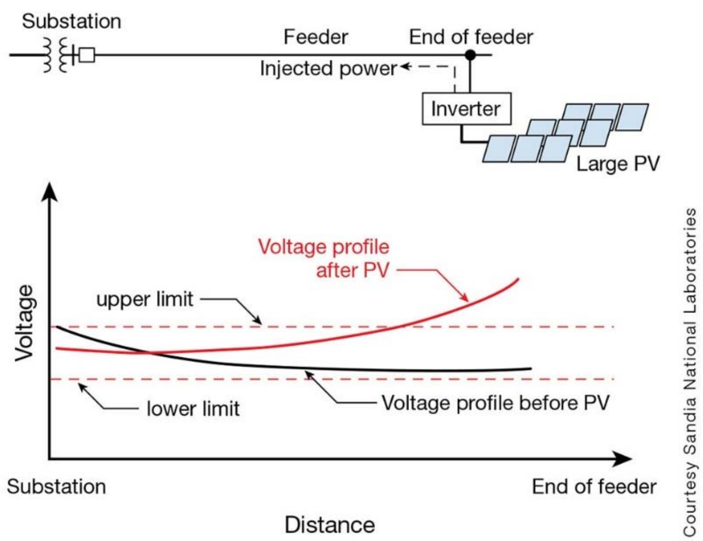
EPCOR

DANGER
HIGH VOLTAGE

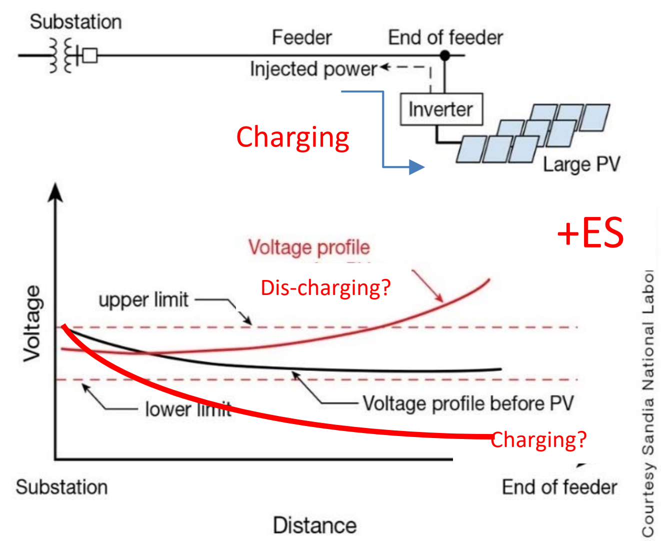
British Columbia
Alberta
Saskatchewan
Ontario
Fort McMurray
Edmonton
Calgary
Vancouver
Britannia Mine
French Creek
Red Deer County
Canmore
Kananaskis
Okotoks
Strathmore
Chestermere
Regina
Toronto
Collingwood
Arizona
New Mexico
Texas
Phoenix
Albuquerque
Clovis
Austin
San Antonio
Houston
EPCOR OPERATIONS
Electricity
Water
Natural Gas
Drainage
Wastewater
Locations at a glance

The Theoretical Impacts of DG and ES

Classic DG Example:

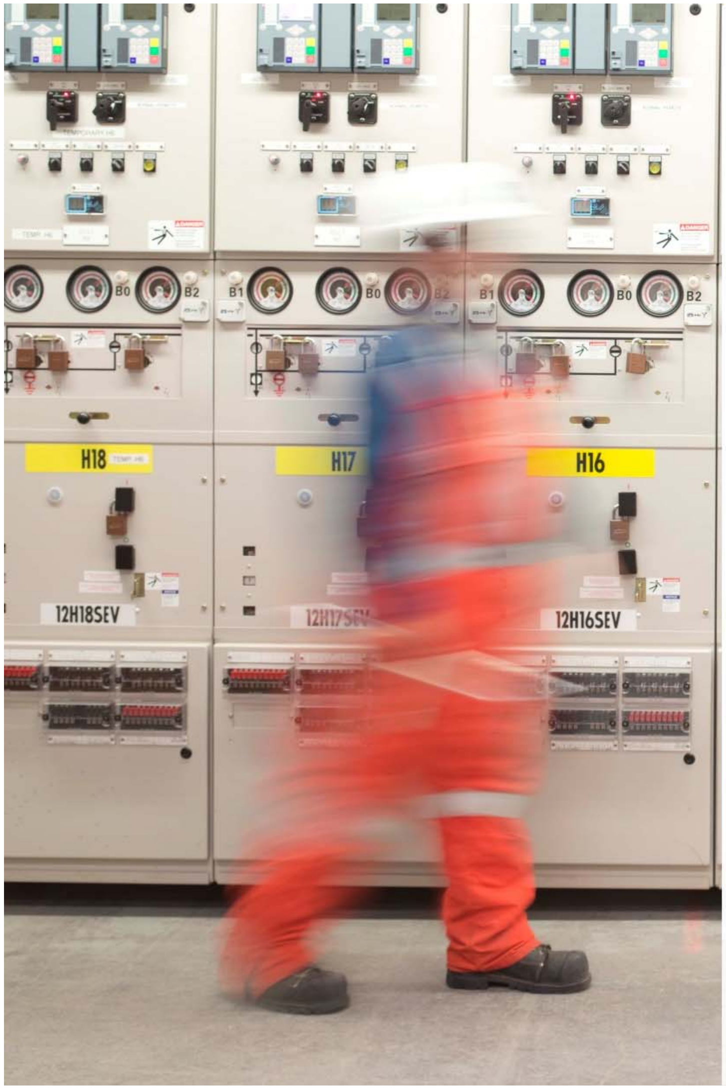


With Battery ES



EDTI's Study with the University of Alberta

- Simulation-based technical study - 2014-2018
- Three-way funding EDTI – U of A - NSERC
- 'Realistic-as-possible' approach:
  - City of Edmonton conditions
  - 39/289 EDTI power system distribution circuit models
  - Capabilities of market-available equipment
  - *Stochastic* approach (Monte Carlo)
- Broadly examine impacts of three classes of *customer-owned* DER:
  - DG: Distributed Generation (e.g. Solar PV)
  - ES: Energy Storage (e.g. Batteries)
  - EV: Electric Vehicle (e.g. Charging)
- Examine effects to the distribution system



Key Findings Distributed Generation

- IF customer PV systems are in-line with Alberta microgen regulation, ~80% of EDTI circuits should only experience outlier problems
- Circuits with voltage outliers still have decent capacity to integrate PV

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Energy Storage

- All ES modelled with co-located PV
- Two behaviours modelled
  - Self-consumption
  - On peak discharge, off peak charge
- Min load when generating, peak load when charging – worst case

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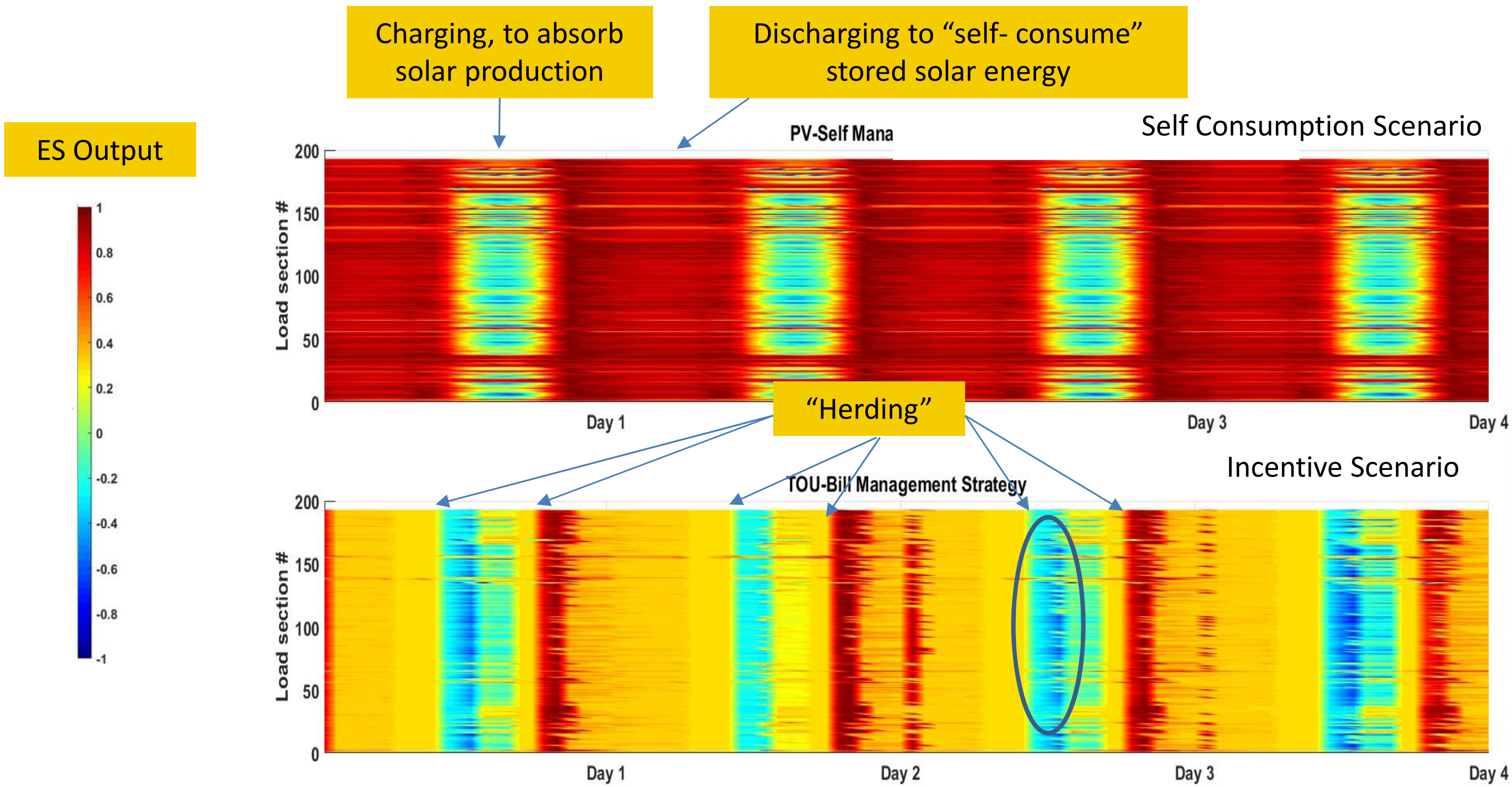
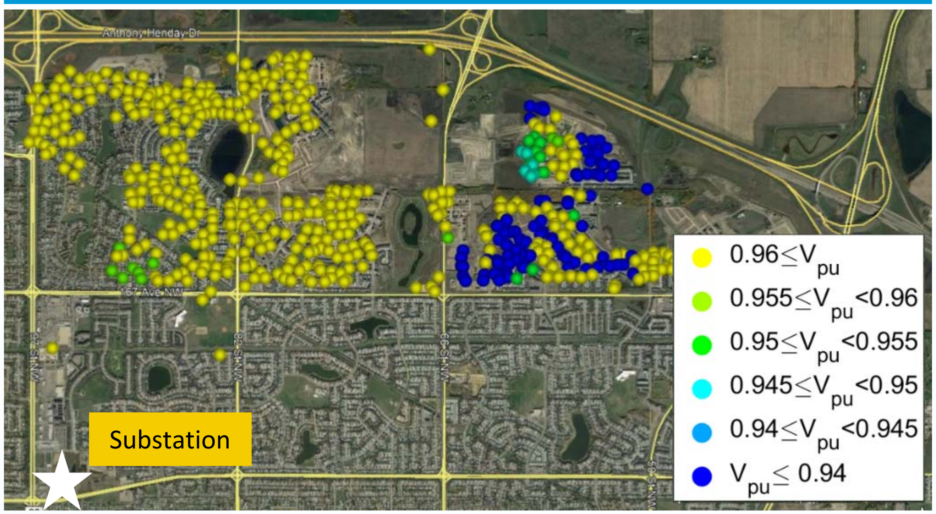
Energy Storage (from the perspective of the ES)

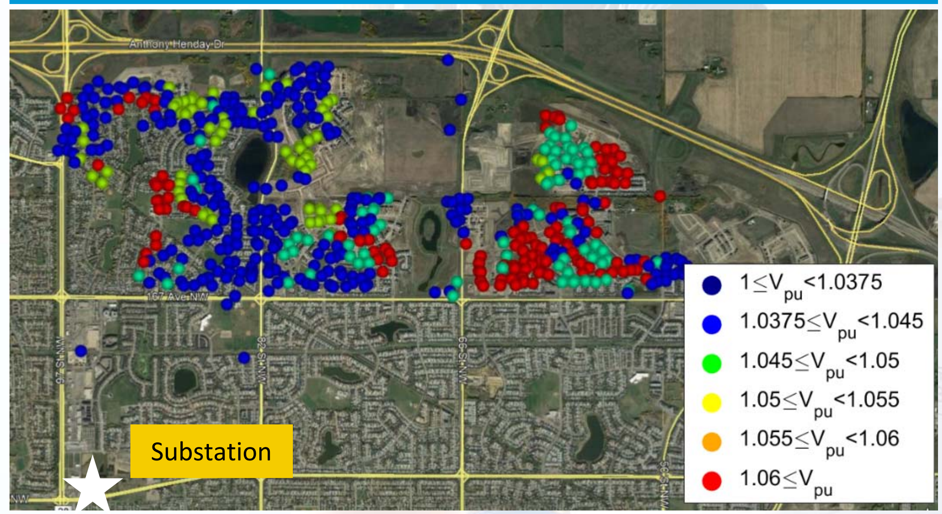


Impacts to a Distribution Circuit – TOU Scenario

Under-voltage, as a result of ES Charging



Over-voltage, as a result of excess PV generation



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Key Findings Energy Storage

- Simulated self-consumption scenario had less impact than incentive scenario
- Mismatch to site demand and co-located generation could lead to over voltage and under voltage impacts – hard to predict
- Potential to exacerbate and or alleviate strain on distribution infrastructure
- More study is needed

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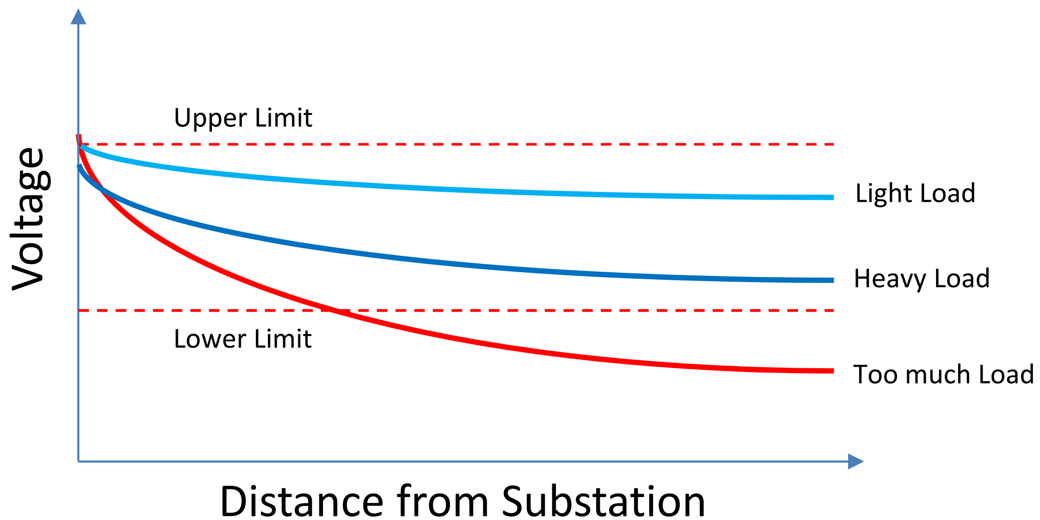
The Impacts of Electric Vehicles

- What makes EV load any different?



Residential sites in Edmonton:

- 100 or 150A Service
- @ 240V, 20-80A per EV

Variables:

- Base load?
- Where will cars plug in?
- When will they plug in?
- How long will they charge?
- What is the maximum load?

Residential Transformers

DFO's provide **capacity** to non-instantaneous (i.e. system average) **peak load**

Per 37.5kVA Transformer:

- Per house: Average, peak load 2-3kW
- Transformer average peak: 24-36kW
  - >20,000 installed 37.5kVAs in Edmonton

EV Charging Levels:

- Per EV: Charging Demand 3.2-19.2kW
  - Average ~ 7.2kW
- Concurrent charging: two Tesla's at 19.2kW -> 38.4kW

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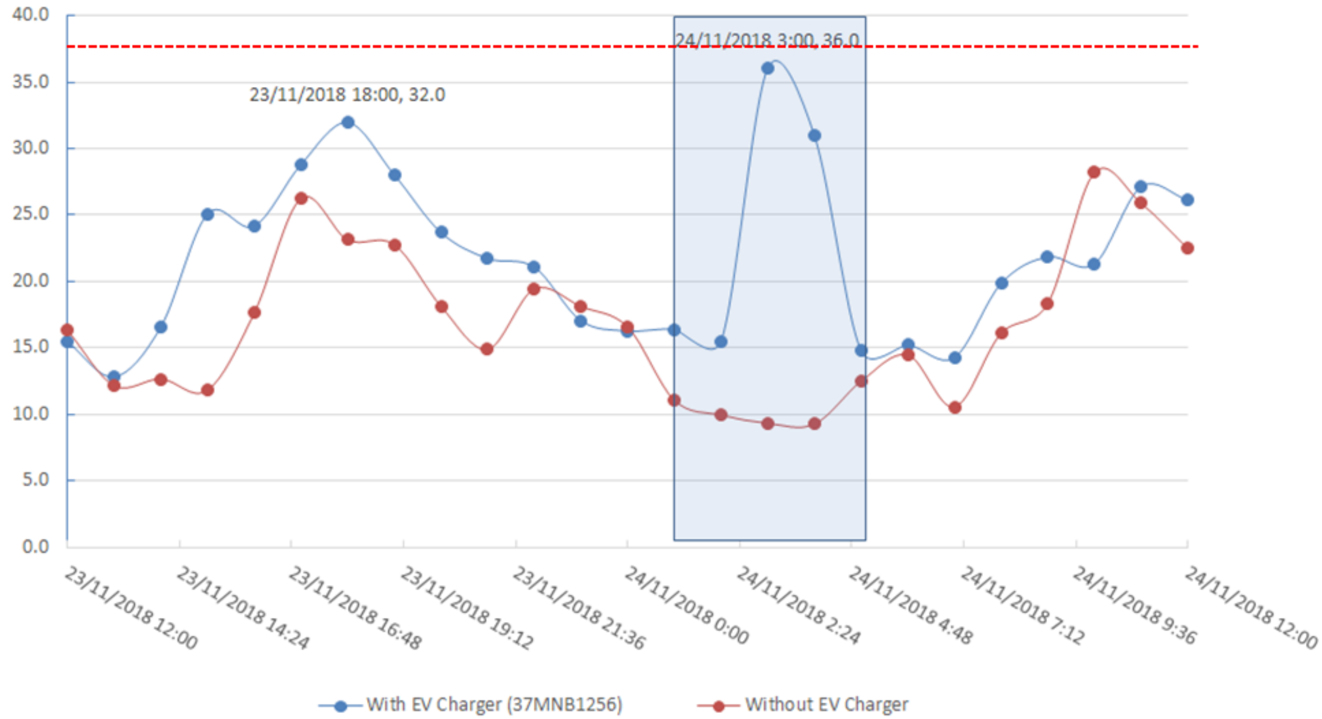
Transformer Load With & Without an EV

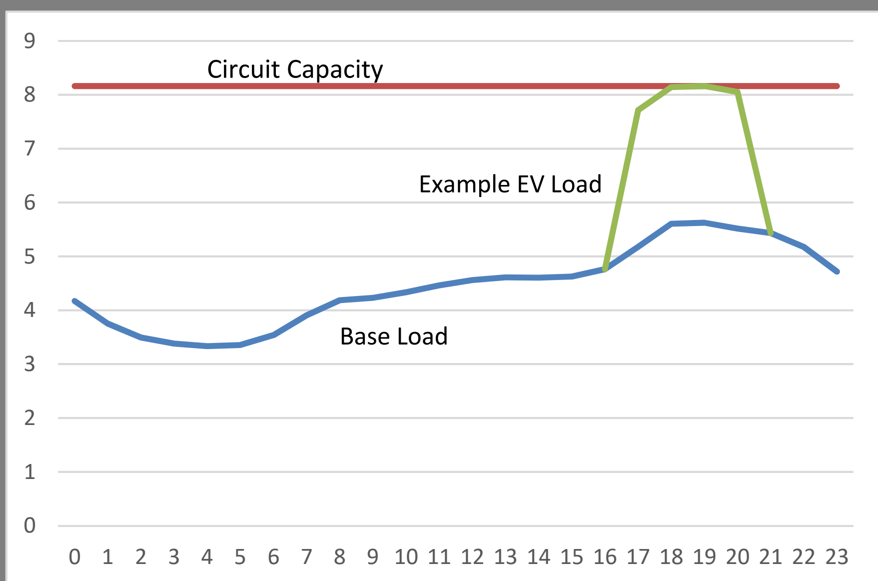
- A real example from EDTI's system:



Impacts to Planning & Forecasting

- DFO's provide **capacity** to non-instantaneous (i.e. system average) **peak load**

Peak demand (MW), 15kV residential circuit



EV Charging Levels:

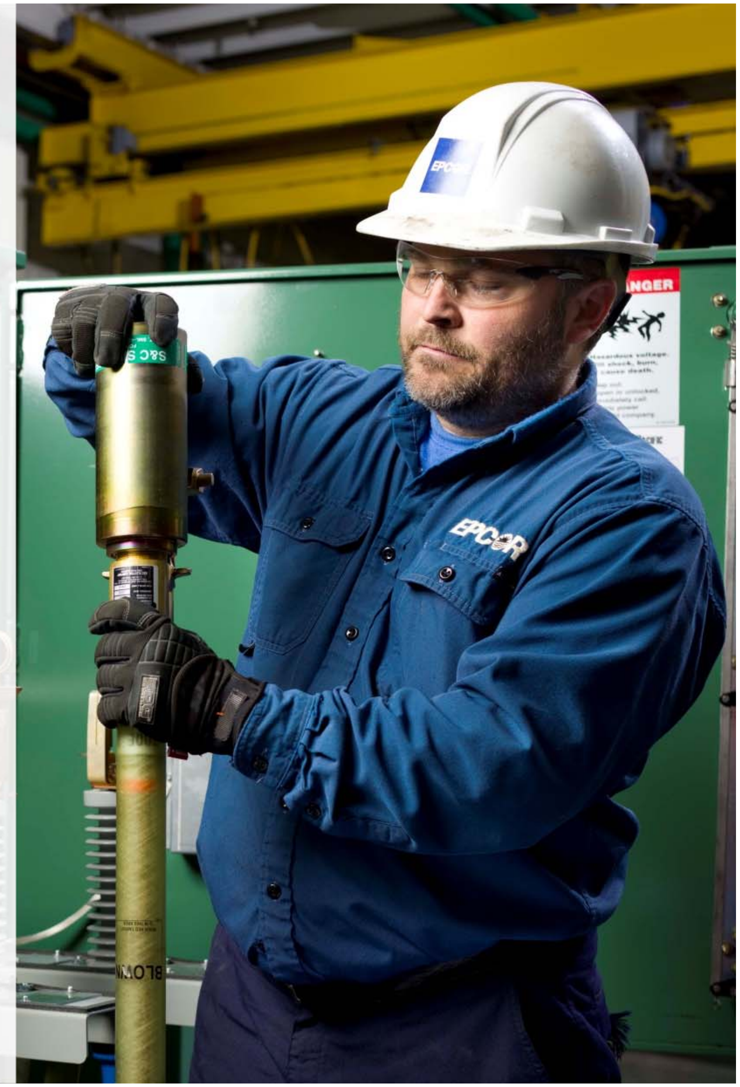
- This circuit peaks at 5.6MW
- 2.5MW of remaining capacity which is the equivalent to:
  - 132 EVs @ 19.2kW or
  - 793 EVs @ 3.2kW
- 5,500+ customers on circuit

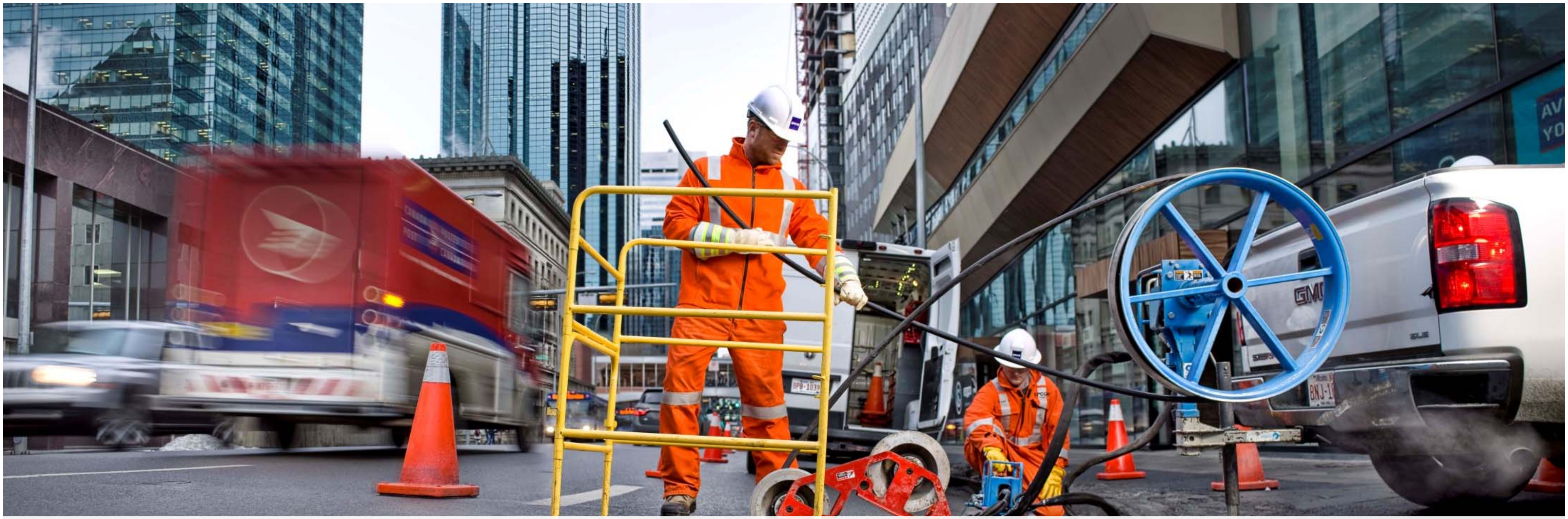
Key Findings

- Unprecedented demand - 2x to 10x addition of load compared to a house
- Granularity is needed – all the way down to the transformer
- Charging demand is what matters
  - Only 1 EV can overload standard service transformer
  - A small number of EVs could lead to circuit overloads

Navigating the EV Challenge

- Fundamental mismatch between existing capacity and future demand
- Will require additional distribution infrastructure
- Potential ways of deferring, delaying, reducing capital investment
  - Smart chargers?
  - Utility visibility / control (DERMS)?
  - Incentives?
  - New rules? New Legislation?
  - Co-located ES, to buffer the power demand?
  - Demand-side technologies?
- For each of these, must consider
  - Impact to customers
  - Complexity of deployment
  - Extent of mitigating effect on utility cost of service





THANK YOU

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Tab 2

IESO Submission on EV Charging
Electric Vehicle Integration (EVI) Initiative File No.: EB-2023-0071
Electric Delivery Rates for Electric Vehicle (EV) Charging Report
June 14, 2023

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Powering Tomorrow.

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June 14, 2023

Via Email and RESS

Ms. Nancy Marconi
Registrar
Ontario Energy Board
27th Floor 2300 Yonge Street
Toronto, ON M4P 1E4

Dear Ms. Marconi:

Re: Electric Vehicle Integration (EVI) Initiative File No.: EB-2023-0071
Electric Delivery Rates for Electric Vehicle (EV) Charging Report

The Independent Electricity System Operator (IESO) appreciates the opportunity to submit comments on the OEB consultant report, *Electric Delivery Rates for Electric Vehicle Charging*. The report discusses the findings of examining the electricity delivery rates for commercial EV charging and exploring alternative rate design options that could support the efficient integration of EVs in Ontario

The IESO is responsible for maintaining the security and reliability of electricity supply in Ontario and for operating and directing the operations of the IESO-controlled grid. Transportation electrification represents a major source of demand growth with significant implications for provincial power system planning. IESO has provided comments below on the findings in the report.

General Comments

The IESO has been following the OEB's Electric Vehicle (EV) Integration initiative with interest as transportation electrification represents a major source of demand growth with significant implications for provincial power system planning. In the latest Annual Planning Outlook (APO), the IESO forecasts EV demand will grow from approximately 1 TWh in 2024 to over

28 TWh in 2043, representing a transition from less than one percent to more than ten percent of the Ontario's annual energy consumption. Additionally, recognizing the increasing importance of EV charging demand, the IESO's recent Mid-Term Review of the 2021-2024 Conservation & Demand Management (CDM) Framework identifies the introduction of program offerings for personal and commercial EVs complimentary to rates as a potential opportunity to evolve provincial CDM programming to respond to evolving system and consumer needs.

As has been discussed in this engagement, provincial system peak demand is a major driver of system capacity needs, and by extension, costs that must be borne by ratepayers to maintain a reliable electricity system. The *Electric Delivery Rates for Electric Vehicles Charging* report prepared for the OEB notes that "on a province-wide basis, peaks are typically in the afternoon hours in the summer months." Based on the 2022 APO, the IESO expects provincial system peak to shift from mid-summer afternoons to mid-winter mid-night periods sometime in the mid-2030s, partially driven by increased overnight demand from EV charging demand. A number of factors will impact the exact timing of this shift. Prior to this seasonal shift, various factors (increased penetration of embedded solar PV, evolving demand patterns with electrification, etc.) are expected to contribute to the summer peak shifting later in the day.

Consequently, if the OEB proceeds with establishing new rate options for non-Regulated Price Plan customers that, among other things, seek to better account for customer contribution to system coincident peak such as a Time-of-Use Demand Charge for Commercial EV Fleets, it would be prudent to design the rate option(s) with sufficient flexibility to reflect the evolving timing of provincial system peak. This would support continued alignment with standard rate making principles regarding cost causation.

<u>Page 14 of the report notes the following:</u>

"Commercial EV fleets with NCP demand that occurs overnight cause little or no incremental transmission or distribution costs for the rest of the system beyond the local connection costs to serve the fleet's NCP demand. This may result in commercial EV fleets unfairly subsidizing other customers through their demand charges. In addition, there may be potential for system-wide cost savings if there is a stronger incentive for commercial EV fleets with flexible schedules to shift their charging to off-peak times."

This is true to some extent, especially in aggregate where EV fleet charging may statistically behave in a certain way where their NCP occurs overnight. However, from a regional transmission and distribution system planning perspective, once connected EV charging customers have the flexibility to consume at any time regardless of what their rates are and thereby make use of the regional transmission and distribution infrastructure. Therefore, these customers still have the ability to charge coincident to system peaks. The IESO suggests that the OEB consider this behaviour in the design of rates.

The IESO appreciates the opportunity to provide comments on the report and welcomes further discussion to assist the OEB, as required. If you have any questions, please contact me at 416-710-0620 or by email at Beverly.Nollert@ieso.ca

Yours truly,

Beverly Nollert
Senior Manager, Regulatory Affairs