TFO and DFO RESPONSES TO AESO INFORMATION REQUESTS

EDI-AESO-2019OCT03-001

Request:

Does EDTI DFO have a comprehensive standalone distribution system planning document (forecast methodology etc.)? If so, it would be helpful to the AESO if EDTI DFO could submit such a document to help the AESO fulsomely understand EDTI's need.

Response:

EDTI does not have a stand-alone distribution planning criteria document that describes EDTI's full distribution planning criteria. See EDI-AESO-2019OCT03-001 Attachment 1, which is a previously provided information request response regarding EDTI DFO's distribution planning criteria.

August 8, 2019

AESO-AUC-2019JUL18-002

Reference: **Exhibit 23943-X0007, Appendix E - DFO Distribution Deficiency Report, PDF page 8**

Issue/sub-issue: **Distribution Planning Criteria**

Quote: "The Firm Capacity of a POD is an important parameter that EDTI DFO considers for distribution planning purposes. EDTI DFO defines a POD's firm capacity as the maximum load that the POD can supply without overloading any transmission equipment under an N-1 contingency. N-1 contingencies include, but are not limited to, the loss of a single transmission line supply to a POD or the loss of a single transformer at a POD. All PODs should operate at or below their firm capacity."

Request:

(a) How, if at all, does EDTI consider, or account for, capacity that could be provided from a nearby POD by implementing distribution system switching in its planning?

(b) Please provide EDTI's full distribution planning criteria.

(c) Please confirm the normal and emergency ratings of EDTI's 14.4-kV distribution feeders.

Response:

(a) EDTI distribution advises that:

As part of EDTI's system planning process, an assessment of its electrical system is completed annually. The system planning assessment:

- Takes into account the most recent (i.e. the previous year's) actual winter and summer peak loads;

- Creates a new summer/winter peak demand forecast, taking into account known new customer load projections and historical load trends;
- Identifies system violations regarding performance specifications (e.g., power quality, voltage levels, equipment ratings, etc.); and
- Evaluates the available firm capacity margin available at each of EDTI's PODs.

In the event that the system planning assessment identifies a deficiency related to POD loading, EDTI will first consider the capacity that can be provided from nearby PODs through distribution system switching to address the deficiency. If spare capacity at nearby PODs is available, EDTI will complete distribution load transfer to address the identified deficiency to the extent possible (see for example response AESO-CCA-2019JUL18-014(d), which includes information regarding distribution load transfers from Garneau to Rossdale in 2011).

(b) EDTI distribution advises that:

EDTI does not have a stand-alone distribution planning criteria document that describes EDTI's full distribution planning criteria. However, EDTI provides the following documents relating to its planning criteria, particularly as they relate to the West Edmonton Transmission Upgrade Project:

- AESO-AUC-2019JUL18-002 Attachment 1: *AESO Distribution Point-of-Delivery Interconnection Process Guideline – Standards of Service, Revision 0.* EDTI's planning practices are consistent with those outlined in this AESO document.
- AESO-AUC-2019JUL18-002 Attachment 2 & 3: These information request responses provide information regarding EDTI's assessment of its ability to address reliability or load growth concerns through purely distribution means (i.e., through distribution circuit switching, system reconfiguration or the addition of new feeders). When EDTI has exhausted the available distribution solutions, the only remaining avenue for resolution is through transmission developments. EDTI will then submit a System Access Service Request and Distribution Deficiency Report to the AESO in order to initiate an AESO Connection Process project.

Additionally, the Distribution Deficiency Report for this Project identifies EDTI's POD loading policy[1]:

> *The Firm Capacity of a POD is an important parameter that EDTI DFO considers for distribution planning purposes. EDTI DFO defines a POD's firm capacity as the maximum load that the POD can supply without overloading any transmission equipment under an N-1 contingency. N-1 contingencies include, but are not limited to, the loss of a single transmission line supply to a POD or the loss of a single transformer at a POD. All PODs should operate at or below their firm capacity.*

(c) EDTI distribution advises that:

The normal and emergency ratings of EDTI's 14.4 kV distribution feeders within the Garneau, Meadowlark, and Rossdale service areas are shown in Table AESO-AUC-2019JUL18-002-1 below. These ratings are typical for EDTI 14.4 kV feeders of similar construction, and actual cable ratings may vary slightly to account for cable construction, site specific construction details or feeder operating characteristics.

Table AESO-AUC-2019JUL18-002-1
EDTI Standard 14.4-kV Distribution Feeders Normal and Emergency Ratings

		A	B	C	D
		Summer Rating[1] [MVA]		**Winter Rating [MVA]**	
	Cable Sizes	**Normal**	**Emergency**	**Normal**	**Emergency**
1	250 MCM	5	6	6	7
2	500 MCM	7	10	9	11
3	750 MCM	9	12	10	13
4	2 x 500 MCM	15	19	17	22
5	2 x 750 MCM	18	25	21	25

[1] All values are rounded to the nearest integer.

[1] Exhibit 23943-X0007, PDF 8.

Table AESO-AUC-2019JUL18-002-2 indicates the number of each size of feeder at Garneau, Meadowlark and Rossdale substations.

Table AESO-AUC-2019JUL18-002-2
Number of Existing Feeders at Garneau, Meadowlark, and Rossdale

		A	B	C	D	E
		Cable Sizes				
	Substation	**250 MCM**	**500 MCM**	**750 MCM**	**2 x 500 MCM**	**2 x 750 MCM**
1	Garneau	0	1	4	5	1
2	Meadowlark	0	16	2	0	0
3	Rossdale	3	20	13	0	0
4	**Total**	**3**	**37**	**19**	**5**	**1**

aeso ALBERTA ELECTRIC SYSTEM OPERATOR

Distribution Point-of-Delivery Interconnection Process Guideline

Standards of Service

	Name	Signature	Date
AESO Approved	Fred Ritter, P.Eng.	F. Ritter	2005-03-22
AESO Approved	Neil Brausen, P.Eng	Neil Brausen	2005-03-23
AESO Management	Neil Millar, P.Eng.	Neil Millar	2005-03-30

Revision 0: Tuesday, March 22, 2005

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1.0 Introduction

1.1 Purpose

This guideline defines the principles and standards that Distribution Facility Owners ("DFO") and/or Transmission Facility Owner ("TFO") shall use to identify interconnection requirements on the Alberta Transmission System ("ATS").

This guideline is intended solely for the purpose of supporting the AESO's customer interconnection process to arrive at proposed interconnection concepts that are optimized on a technical and economic basis. It will not in any way address or determine the AESO's facility cost allocation between system and customer, nor will it be used in any way as a guideline in applying the AESO approved tariffs and investment policy.

This guideline is intended to facilitate documentation of the project need and the evaluation done to support the need, in alignment with the interconnection process. The interconnection process has a requirement for AESO endorsement and AEUB approval of the project need.

1.2 Application of Guideline

This guideline is a reference for other Interconnection Process Guidelines. Because this guideline is used by various TFO's and DFO's with different planning and operating environments, it is recognized that differences may occur. To this end, these planning and operating environments are documented throughout this guideline.

The AESO expects that any deviations from this guideline will be documented, explained and supported by the TFO's and/or DFO's as part of the proposal(s) submitted to the AESO.

1.3 Modifications

In respect to this guideline the AESO will:

a) seek the input and feedback of affected parties prior to making changes or additions to the guideline;
b) make and manage all changes to this guideline;
c) make this guideline publicly available via the AESO website;
d) periodically and within five (5) years of the effective date shown on the cover page review this guideline.

2.0 Capacity Standards of Service

The expectation of electricity customers is that the transmission and distribution systems have the capacity to meet their power requirements when needed.

The two key components used in making a capacity assessment of the transmission and/or distribution system are:

1. Load Forecast - the AESO and Distribution Facility Owner ("DFO") must forecast load in order to plan for the efficient and economical expansion of the transmission and/or distribution system in advance of the need materializing.

2. Capacity of Facilities – the TFO's and DFO's are responsible for identifying the voltage and thermal capacity of their facilities. The AESO, TFO's and DFO's will collaborate and coordinate in determining when the capacity of facilities is going to be exceeded during normal ("steady state") and contingency conditions.

2.1 Load Forecasting Approach

The purpose of forecasting is to anticipate what the power system must be able to deliver in the future and how that differs from today's requirements. This forecast is typically a geographical forecast that identifies how much, where and when capacity is required.

Transmission and distribution facilities are planned and designed to meet the expected peak demand on each distribution feeder and distribution delivery point (i.e. substation). The current approach used by TFO's and DFO's is:

- Feeder-by-Feeder: The peak demand for each feeder is examined separately to ensure the capacity rating of the facilities is adequate for future loading requirements.

- Substations: The peak demand supplied by the transformer(s) in the substation is reviewed to ensure there is sufficient capacity for future forecasted loading. The peak demand on the transformer reflects the coincident peak of all the distribution feeders supplied by the transformer. For substations with multiple transformers, the demand for the same date and time must be summed to obtain coincident peak of the substation.

The approach for forecasting load growth is typically one or both of the following:

- Load growth is determined by extrapolating the historical load into the future and by adding any specifically identified new and/or major loads.

- For proposed development in areas where no electrical facilities exist, the load forecast is developed using typical load density expectations as shown in Table 2.1-1.

Table 2.1-1 Ultimate Load Density

Classification of Load	Load Density (MVA/square mile)
Rural	Site specific (1)
Residential (Urban)	6 to 7
Light Commercial / Industrial	12 to 18
Heavy Commercial / Industrial	27 to 40

Notes:
(1) This is handled on a case-by-case basis, since there are many factors that affect rural load densities, such as terrain, access, agricultural, oilfield services, other land uses, and environmental requirements.

2.1.1 *Geographical Load Forecasting Methodology*

This section provides the methodology for creating a geographical load forecast that will ensure facilities of sufficient capacity are appropriately located and available when needed. The AESO requires clear and consistent load forecasts from all DFO's to evaluate TFO/DFO interconnection proposals. The size of the area covered by the "geographic load forecast" will vary depending on the type of facility being proposed.

Further, load forecasts are a prediction of a future possibility, given historical information and incorporating possible future development in the geographical area. All load forecasts are based on judgments of the future and are subject to variability, sensitivity and uncertainty. Therefore, the AESO will integrate the geographical forecast with its long-term forecasts to ensure that the geographical load forecast will support long term solutions. The long term (20 year) forecast is primarily used for bulk system planning and regional planning.

As a minimum, the geographical load forecast shall:

1. Include five (5) years of historical data and ten (10) years of forecasted load in MVA.

2. Provide load density maps that provide sufficient resolution (i.e. today, 5 year and 10 year) to make decisions and permit realistic siting of

facilities (e.g. substations). An example of a load density map is provided in Appendix 1 – Load Density Map Example.

3. Adjust recorded loads to account for load anomalies (i.e. load transfers between feeders) that could skew the projected load on feeder(s) and/or point of delivery substation(s).

4. Incorporate local information that is available, that could include plans of the Province, County, Municipality, Towns, Cities and/or local industrial or commercial developers that would give an indication of potential future development in the area.

5. Identify whether the geographical forecast is for winter or summer peak, which is typically the time period that the deficiency occurs.

6. Include the following:

   - Load MVA values provided to one decimal place.
   - Individual feeder peaks.
   - Transformer peaks that are the coincident peaks of all the feeders served by that transformer.
   - Station peaks are coincident peaks of all transformer peaks, summing each transformer peak with the same date and time stamp.
   - The area total load in both “Existing” and “Proposed” tables must be identical.

7. Provide two forecasts, one for the existing system and one that incorporates the proposed development clearly illustrating how load shifts between feeders and/or distribution delivery points (i.e. substations)

8. Include all stations that are relevant to the supply and/or backup of the load in the area under consideration. This is typically the point of delivery substations that are immediately adjacent to the location being studied.

9. Include specific notes to the tables that the TFO and/or DFO want to explain or identify. This could include:

   - Assumed power factor
   - Provide an explanation of significant (increases or decreases) in the load.

- Lack of information (i.e. metering) that resulted in applying judgment to prepare the forecast.

2.1.2 *Load Forecast Format & Content Required*

Table Title [describe the area] – Existing System

	Recorded Loading [Summer or Winter peak] (MVA) (1)					Projected Loading [Summer or Winter peak] (MVA) (1)									
	Years					Years									
Description	1	2	3	4	5	1	2	3	4	5	6	7	8	9	10
Feeder 1															
Feeder N															
Transformer 1 Total (2)															
Feeder 1															
Feeder N															
Transformer N Total (2)															
Station [name & number] Total (3)															
Repeat the above for all stations under consideration in the area															
Area Total Load															

Notes:

1. Load MVA values provided to one decimal place.
2. Transformer peaks are the coincident peaks of all the feeders served by that transformer.
3. Station peaks are coincident peaks of all transformer peaks, summing each transformer peak with the same date and time stamp.

Table Title [describe the area] – Proposed Development

	Recorded Loading [Summer or Winter peak] (MVA) (2)					Projected Loading [Summer or Winter peak] (MVA) (2)									
	Years					Years									
Description	1	2	3	4	5	1	2	3	4	5	6	7	8	9	10
Feeder 1															
Feeder n															
New Feeder 1															
Transformer 1 Total (3)															
Feeder 1															
Feeder n															
Transformer N Total (3)															
Station [name & number] Total (4)															
Repeat the above for all stations under consideration in the area including any new station proposed															
Area Total Load (1)															

Notes:

1. Area Total load in both “Existing” and “Proposed” tables must be identical.
2. Load MVA values provided to one decimal place.
3. Transformer peaks are the coincident peak of all the loads served by that transformer.
4. Station peaks are coincident peaks of all transformer peaks, summing each transformer peak with the same date and time stamp.

2.2 Capacity Assessment Criteria

The facilities installed by either the TFO or DFO are designed to operate within certain voltage and thermal ratings during a normal and contingency conditions. Operating facilities beyond their ratings can have:

1. Economic implications such as higher maintenance costs, loss of life, and/or early replacement of equipment that has failed catastrophically.
2. Safety implications to TFO and DFO personnel and the public at large.

The intent of this section is to outline acceptable operating ranges on TFO and DFO facilities during normal and contingency conditions.

2.2.1 *Voltage Assessment Criteria*

Voltages shall be maintained within applicable limits during normal and contingency conditions, such that equipment and facility limits are not exceeded.

2.2.1.1 Voltage Fluctuation Guidelines

This section is for DFO's only and is applicable to the distribution power delivery system.

The voltage at an electricity customer's utilization point must be within the ranges specified by CSA Standard CAN3-C235-83, "Preferred Voltage Levels for AC Systems, 1 to 50,000 volts".

Generally, the DFO's plan their distribution power delivery system to meet the voltage requirements during normal forecast peak load conditions to levels above the minimum voltage levels. Planning in this manner provides operational flexibility and reduces risk of exceeding equipment or facility limits due to unexpected occurrences (e.g. faster load growth, forecast uncertainties).

Table 2.2-1 identifies specific planning methodologies for voltage limits by each DFO.

Table 2.2-1: Specific DFO Planning Methodology for Voltage

DFO	Methodology
ATCO Electric Distribution	• Urban o Voltage on 25 kV overhead feeder ▪ System Normal - 116.4V (0.97 p.u) ▪ Contingency (25 kV alternate feed or T-POD) - 113V (0.94 p.u.) o Feeders with both overhead and underground ▪ System Normal & Contingency (supply from alternate 25 kV feed or POD) - 116.4V (0.97 p.u.) • Rural o Two feeder voltage regulators on a feeder, and; o Three phase 25 kV voltage of 114V (0.95 p.u.), or; o 25 kV voltage of 120 V (1.0 p.u) where: ▪ On the primary of a distribution step down substation (i.e. towns or REA's) ▪ At the tap point of a long three phase tap or a number of long single phase taps, or; o Minimum primary voltage of 114 V (0.95 p.u.) on single phase systems
EPCOR Distribution Inc	• Voltage levels at the customer service entrance are consistent with CSA CAN3-C235-83 • Typically 118 V to 120 V on the primary
ENMAX Distribution	• Voltage levels at the customer service entrance consistent with CSA CAN3-C235-83 for single phase and three phase. • For Planning purposes, the desired feeder voltage range is 125 V (1) to 118.5 V (1) as modeled at primary of customer transformer to allow for adjacent feeder contingency backup to be within the CSA standard at the customer service entrance under normal and contingency operation. • Typically, due to the relatively short, heavily loaded urban feeders, no supplemental line voltage regulation is applied.
FortisAlberta	• The feeder voltage loading limit is reached when the feeder has the following during normal operations:

DFO	Methodology
	o Two voltage regulators and; o Three phase voltage is at 115 V (1) (minimum) as modeled on the primary of a distribution transformer on the three phase distribution line or; o Single phase voltage is at 113 V (1) (minimum) as modeled on the primary of a distribution transformer on the single phase distribution line. • The voltage levels correspond to the minimum acceptable voltage as per CSA Standard.
Lethbridge Distribution	• Voltage levels at the customer service entrance are consistent with CSA CAN3-C235-83. • Typically 118 V to 123 V on the primary. • Due to the relatively short urban feeders, no supplemental line voltage regulation is applied.
Red Deer Distribution	• Voltage levels at the customer service entrance consistent with CSA CAN3-C235-83 for single phase and three phase. • Planned feeder voltage range at primary of customer transformer will allow for adjacent feeder contingency backup to be within the CSA standard at the customer service entrance under normal and contingency operation. • Maximum voltage level is limited by changes in transmission voltage levels to high levels which can not be quickly enough reduced by transmission transformer OLTC. • Due to the relatively short, heavily loaded urban feeders, no supplemental line voltage regulation is normally applied.

Notes:

1) Voltages are on a 120 V base, which is a standard practice for DFO's in Alberta.

2.2.1.2 Voltage Range at Distribution Delivery Points

This section is for TFO's only and is applicable to the transmission system at the point of delivery substation. The AESO's Reliability Criteria is followed with respect to voltage limits at point of delivery (POD) substations.

The distribution bus is the bus that is regulated by means of an upstream device (e.g. substation regulator or transformer equipped with an on load tap changer) within the point of delivery substation. The distribution bus voltage shall be maintained at 125 volts +/- 1.5 volts on a 120 volt base in order to meet the CSA Standard at the customer utilization point.

Refer to the following sections in the AESO's Reliability Criteria for specifics regarding voltage capacity assessments of the ATS:

- Section 4.5 "Point of Delivery (POD) Criteria" in Part II -Transmission System Planning Criteria
- Section 5.1 "Voltage Standards" in Part II-Transmission System Planning Criteria
    - Table 5.1-1 in the AESO's Reliability Criteria identifies the acceptable voltage ranges for normal and contingency conditions.
    - Table 5.1-2 in the AESO's Reliability Criteria identifies the acceptable voltage changes during and after contingency conditions.
- Section 5.6.2 "Voltage Limits" in Part III-Transmission Operating Criteria
    - Table 1 "Transmission Standards – Normal and Contingency Conditions" in Part III-Transmission Operating Criteria of the AESO's Reliability Criteria identifies the acceptable thermal limits during and after contingency conditions.
- Section 5.6.4 "Point of Delivery Limits" in Part III-Transmission Operating Criteria

2.2.2 *Thermal Assessment Criteria*

Generally, thermal loading on power delivery facilities shall be maintained within applicable limits for both normal and contingency conditions. The normal and contingency conditions are defined as:

- Normal Conditions: For planning purposes, no power delivery facility shall be loaded beyond its continuous rating.

- Contingency Conditions: Power delivery facilities can exceed their rated capability for a brief time period, until the power delivery system is restored back to its normal condition. This may require automatic (i.e. remedial action schemes) and/or manual intervention such as;
  - Switching system devices to alter loading (e.g. line breakers, line and/or substation switches):
  - The following measures may be required during real time operations:
    - Shedding load to ensure that the thermal rating of power delivery elements are not exceeded; and/or
    - Rotating outages to ensure that the thermal ratings of power delivery elements are not exceeded.

2.2.2.1 Distribution Power Delivery Systems

All elements will have normal, contingency and emergency thermal ratings as specified by the DFO's. The normal and contingency thermal ratings for elements may be the same or different. During normal, contingency and emergency conditions, elements shall not exceed their respective thermal ratings.

Table 2.2-2 identifies planning methodologies for thermal limits employed by each DFO. Planning in this manner provides operational flexibility and reduces the risk of exceeding equipment or facility limits due to unexpected occurrences (e.g. faster load growth, forecast uncertainties).

Table 2.2-2: Specific DFO Planning Methodology for Thermal Capability

DFO	Methodology
ATCO Electric Distribution	• Refer to Appendix II for details regarding ATCO's definition for an urban area. • Urban 25 kV Overhead Feeder o Normal Conditions: maximum loading of an urban 25 kV overhead feeder is 10 MVA. o Maximum contingency (25 kV alternate feed or Distribution Point-of-Delivery) loading is: ▪ 266 Conductor: 20 MVA ▪ 477 Conductor: 25 MVA • Urban 25 kV Underground Feeder

DFO	**Methodology**
	o Normal Conditions: maximum loading of an urban 25 kV underground feeder is 10 MVA. o Maximum contingency (25 kV alternate feed or Distribution Point-of-Delivery) loading is: ▪ 500 MCM Cable: 17 MVA • Rural 25 kV Overhead Feeder o The maximum loading is governed by: ▪ minimum line voltages under normal and contingency (25 kV alternate feed or T-POD) ▪ requirement to parallel feeders at the substation for 25 kV breaker maintenance, ▪ rating of line switches ▪ motor starting requirements ▪ occasionally U/G cable at the substation ▪ Typically, the maximum loading is much less than 25 MVA because of the preceding limitations. There may be exceptions on express feeders where loads approach 25 MVA.
EPCOR Distribution Inc.	EPCOR's thermal capabilities are based on the ratings of the substation exit cables (6 feeders in a ductline) with mutual heating. Ratings are derived using IEC 287 methods with temperature limits as recommended in CSA Standard 68.1 and AEIC CS5-87. **Normal (Design Loading):** • Traditionally EPCOR has rated cables based on 2/3 of their emergency ratings assuming outages would be relatively short-term (2 to 3 days max). This assumes the ability to split circuits and transfer ½ of the load to two adjacent circuits i.e. this approach assumes highly reliable transmission supplies that preclude long-term outages. Based on this approach the normal peak feeder design limits for standard 750 MCM Cu cables would be (winter/summer): o 15 kV cables: 370 A/340 A (9.2/8.5 MVA @ 14.4 kV)

DFO	Methodology
	• In situations where: o transmission supplies cannot be counted upon to preclude long-term outages; or o in the case of 25 kV where there are very limited ties and/or too many customers (> 3,500) are at risk, cable loading is limited to ½ normal. On this basis the normal peak feeder design limits for standard 750 MCM Cu cables would be (winter/summer): ▪ 15 kV cables: 222 A/190 A (5.5/4.7 MVA @ 14.4 kV) ▪ 25 kV cables: 232 A/195 A (10.4/8.8 MVA @ 26 kV) **Emergency (Contingency) Loading:** • Short Term (2 to 3 days max. Winter/Summer): o 15 kV cables: 560 A/515 A (13.9/12.8 MVA @ 14.4 kV) o 25 kV cables: 535 A/470 A (24.1/21.1 MVA @ 26 kV) • Long Term (Continuous or >2 to 3 days max. Winter/Summer): o 15 kV cables: 445 A/380 A (11.1/9.5 MVA @ 14.4 kV) o 25 kV cables: 465 A/390 A (20.9/17.5 MVA @ 26 kV) • Note, EPCOR has a variety of older feeder cables, some smaller, that would have ratings determined on this same basis.
ENMAX Distribution	• Maximum feeder loading under normal operation for both 13 kV and 25 kV feeders is limited to 300A using either 477 MCM overhead conductor or 750 MCM underground cable. (7.2 MVA at 13 kV and 13.5 MVA at 25 kV). This achieves a full feeder restoration within a 600 A maximum loading. • Facilities are planned to function within normal operational rating however, on a temporary basis during contingency, may be allowed to operate at a higher level but still within the recommended manufacturers overload specification. In cases where there is a risk of overload during normal operation, corrective action is initiated.
FortisAlberta	• Refer to Appendix II for details regarding FortisAlberta's definition for an urban area. • Urban 25 kV Overhead Feeder o Normal Conditions: maximum loading of an urban 25 kV overhead feeder using 477 MCM ACSR conductor as main-line conductor is 13 MVA. This provides capacity in the event that the entire load needs to be supplied from an adjacent feeder due to the loss of a feeder at the terminal or

DFO	Methodology
	25 kV breaker maintenance. The terminal facilities have a capacity of 26 MVA (600A). The overhead line facilities have a thermal capacity of: ▪ 477 MCM ACSR Conductor: 32 MVA • Urban 25 kV Underground Feeder o Normal Conditions: maximum loading of an urban 25 kV underground feeder is 10 MVA. This provides capacity in the event that the entire load needs to be supplied from an adjacent feeder due to the loss of the adjacent feeder. The terminal facilities have a capacity of 26 MVA .The underground line facilities which are the limiting components have a thermal capacity of: ▪ 500 MCM Cable: 17 MVA, 3 cables in one duct in air ▪ 500 MCM Cable: 21 MVA, 1 cable per duct in air • Rural 25 kV Overhead Feeder o Normal Conditions: maximum loading of a rural 25 kV overhead feeder is 13 MVA. Feeder is at its maximum loading when the measured load at the distribution delivery point (i.e. substation) is 50% of the feeder terminal capacity. This allows for the situation in which the combined load of two inter-connected feeders needs to be carried by one or the other for the loss of the terminal facility. The terminal facilities have a capacity of 26 MVA. The overhead line facilities have a thermal capacity of: ▪ 3/0 ACSR Conductor: 17 MVA o The maximum loading may also be governed by: ▪ minimum line voltages under normal conditions, ▪ rating of line switches
Lethbridge Distribution	• Feeder loading under normal operation for 13.8 kV feeders is limited to 5 MVA using either 336.4 MCM ACSR or 500 MCM CU 15 kV underground cables. Maximum Feeder loading during emergency basis is limited to 10 MVA. This allows for full feeder restoration between substations on a long term basis. It also allows for some unplanned load growth in established areas. • Normally, feeders function within normal operational rating however, on a temporary basis during contingency, may be allowed to operate at a higher level but still within the recommended manufacturers overload specification.

DFO	Methodology
Red Deer Distribution	• Maximum feeder loading under normal operation is limited to 200A (8.7 MVA at 25 kV). Exceptions for single large loads are made. This 50% capacity loading enables the load to be supplied by an adjacent feeder.

2.2.2.2 Transmission Power Delivery Systems

This section is for TFO's only and is applicable to the transmission system. All elements will have normal, contingency and emergency thermal ratings as specified by the TFOs. The normal and contingency thermal ratings for elements may be the same or different. Generally, during normal, contingency and emergency conditions, elements shall not exceed their respective thermal ratings.

The specific requirements regarding the thermal capacity of the transmission power delivery system is provided in the AESO's Reliability Criteria. This Reliability Criteria is followed with respect to thermal capacity at point of delivery substations.

For planning purposes, no transmission facility shall be loaded beyond its continuous rating during normal conditions. Refer to the following sections in the AESO's Reliability Criteria[1] for specifics regarding thermal capacity assessments of the ATS:

- Section 5.6.1 "Thermal Limits" in Part III -Transmission Operating Criteria

[1] AESO Reliability Criteria – available at www.aeso.ca

3.0 Reliability Standards of Service

The expectation among electricity customers is that the power supply system provides reliable service at reasonable rates by making economic and efficient use of the power system infrastructure. Within the context of reasonable rates, electric service means that electrical supply is available when required and that there is minimal impact to the electricity customer's ability to operate (loss of goods, services or benefits). As a result, the power supply components are evaluated on their ability to provide reliable electricity. Reliability is comprised of adequacy and security, and is impacted by the ability of the supply to be restored in a timely manner, after a system contingency.

Even though the intention is to avoid power outages, it is not possible or economical to avoid all component or combination of component failures that result in the interruption of electrical service.

Assessing the reliability of the service to electrical customers requires the following information:

- amount of load supplied;
- number of customers supplied;
- type of customers served;
- reliability data for one or a combination of the relevant feeders; and
- reliability data for the relevant distribution delivery points (i.e. substations) and transmission line(s).

Further, the reliability data of the transmission and distribution power delivery system shall be based upon a five (5) year system average historical performance. It is an accepted utility practice to utilize past performance as an indicator of future performance.

3.1 Backup Requirements Assessment Criteria

In principle, the DFO's plan and design their distribution systems with the capability to backup electricity customers. There are many factors that affect the DFO's and TFO's ability to restore service to electricity customers during a contingency. Some projects may be recommended based upon the assessment of the following factors that affect the TFO's and/or DFO's ability to restore service in a timely manner:

- Number of customers affected;

- Density of load;
- Social/economic/environmental impacts;
- Time to repair; and
- Time to restore service, which can be affected by accessibility

Unsupplied Load (see definition) must be restored in both urban and rural systems. A balance between the time required to restore service and the cost of facilitating the restoration of service must be achieved. Service may not be restored to all customers simultaneously following an outage. The intent is to reduce to an acceptable level the number of customers who remain out of service due to an outage while other restoration measures are deployed or the repair work is undertaken. The term acceptable level is at the discretion of the DFO and/or TFO to determine in any situation, since a number of factors affect this, including but not limited to:

- Number of customers.
- Type of load (hospitals, residential, commercial, industrial).
- Outage duration.
- Repair of damaged facilities in a safe manner.

Plans are developed that include one or a combination of the following that may be used to restore service to electricity customers during planned or unplanned outages on the transmission and/or distribution power delivery system. In implementing these plans, the TFO and DFO are responsible to decide what measures are appropriate and what order these measures should be applied in any situation.

- Automatic transfer of load to an alternate transmission or distribution supply.
- Manually or remotely switching the distribution supply system to provide an alternate supply route. It is recognized that switching time maybe longer in a rural area compared to an urban area.
- Manually or remotely switching to provide electrical supply from adjacent POD stations.
- Manually or remotely switching within the POD station to transfer the electricity customer to an alternate transformer.
- Other non-switching activities as described below may be used to restore load. An economic evaluation should identify the most cost effective solution.

  - Use of a mobile substation.
  - Use of standby generation supplied by the DFO.
  - Use of standby generation or UPS supplied by the customer.

- Repair the damaged facilities.

- In real time operations, the following provide additional ways to address conditions where the thermal capacity of facilities are exceeded:
  - Partial restoration or rotating outages.
  - Public announcements for curtailment of load

Table 3.1-1 outlines the backup criteria for planning and designing the distribution supply system for rural and/or urban areas. The target restoration times in the table applies to DFOs and/or TFOs.

Table 3.1-1: TFO/DFO Back up and Restoration

Type of load	**Possible means for backup (more than one may be used in any situation)**	**Target Restoration Time Standard (100% of load restored for recognized contingencies)**					
		ATCO Electric Distribution	**EPCOR Distribution Inc.**	**ENMAX Distribution**	**Fortis Alberta**	**Lethbridge Distribution**	**Red Deer Distribution**
Urban Critical - Critical commercial or industrial operation, large downtown core, or public safety related load (hospitals)	▪ Onsite customer provided UPS with auto transfer from DFO ▪ DFO auto transfer ▪ TFO auto transfer ▪ Customer emergency generation	Automatic Transfer	Automatic Transfer	Automatic Transfer	Automatic Transfer	< 2 hrs (6)	Customer emergency generation. Less than or equal to 1 hr
Urban commercial load	▪ Auto transfer ▪ Remote switching ▪ Manual switching	less than or equal to 4 hours Note (1)	less than or equal to 1 hour	Immediate (with Distribution Automation) to <1 hour (if remote or manual switching)	less than or equal to 1 hour	<2 hrs (6)	Less than or equal to 2 hr
Urban residential load	▪ Auto transfer ▪ Remote switching ▪ Manual switching	less than or equal to 4 hours	less than or equal to 1 hour	Immediate (with Distribution Automation) to <1 hour (if remote or	less than or equal to 1 hours	< 2 hrs (6)	Less than or equal to 3 hr

Distribution Point-of-Delivery Interconnection Process Guideline - Standards of Service

Type of load	Possible means for backup (more than one may be used in any situation)	Target Restoration Time Standard (100% of load restored for recognized contingencies)					
		ATCO Electric Distribution	EPCOR Distribution Inc.	ENMAX Distribution	Fortis Alberta	Lethbridge Distribution	Red Deer Distribution
				manual switching)			
Rural Critical commercial, industrial or agricultural load	▪ Onsite customer provided UPS with auto transfer from DFO ▪ DFO supplied auto transfer ▪ Manual switching ▪ Customer or DFO standby generation	Automatic Transfer ≤ 4 hours (if manually switching)	Note 4	Note 4	Automatic Transfer ≤ 4 hours (if manually switching)	Note 4	Note 4
Rural Load (Residential, Farm and Commercial)	▪ Remote switching ▪ Manual switching	less than or equal to 4 hours	Note 4	Note 4	less than or equal to 4 hours	Note 4	Note 4
Oilfield and Industrial	▪ Remote Switching ▪ Manual Switching ▪ Mobile Substation ▪ Customer Emergency Generators	Summer = less than or equal to 24 hours Winter = less than or equal to 4 hours for lights, heat trace and glycol pumps All Load = less than or equal to 24 hours	Note 4	Note 4	Summer = less than or equal to 24 hours Winter = less than or equal to 4 hours for lights, heat trace and glycol pumps	N/A	N/A for oilfield Industrial customer emergency generators Industrial less than or equal to 1 hr

Distribution Point-of-Delivery Interconnection Process Guideline - Standards of Service

Type of load	Possible means for backup (more than one may be used in any situation)	Target Restoration Time Standard (100% of load restored for recognized contingencies)					
		ATCO Electric Distribution	EPCOR Distribution Inc.	ENMAX Distribution	Fortis Alberta	Lethbridge Distribution	Red Deer Distribution
		Note 5					
Remote rural load	▪ Remote switching ▪ Manual switching ▪ Customer Standby generation ▪ Mobile substation (Note 3) ▪ Partial restoration or rotating outages	less than or equal to 4 hours Note (2)	Note 4	Note 4	Note (2)	Note 4	Note 4

Notes:

1) Priority is given to restoring feeders that supply hospitals, institutions and commercial loads.

2) Outages beyond 4 hours are a concern due to freezing up the premise for residential, farm, commercial loads and oilfield and industrial. Restoration time of radial, across country transmission lines and single transformer PODs can be well beyond 4 hours due to the nature of the failure, time of day, accessibility and weather conditions. After 24 hours there is to be no unsupplied load.

3) The mobile substation can be considered as an acceptable method of restoring load in remote rural areas. In assessing if the mobile is an acceptable solution, recognition should be given to the probability of the event, the duration of the event, the consequences, size of load impacted by the event, number of customers, type of load, environmental consequences, location and economic evaluation of the cost of possible solutions to search for the most cost effective solution.

4) Is considered an urban utility and as such does not normally serve rural type load.

5) It may be impractical to manually switch off oilfield only on a feeder that supplies both residential, commercial, and farm as well as oilfield and achieve a restoration time of 4 hours, so in those instances oilfield also may be restored in 4 hours.

6) Time may vary during non-working hours (Lethbridge Distribution)

3.2 Distribution Feeder Reliability Indices

When recommending a system reinforcement project for reliability reasons, the AESO expects the DFOs to provide the following. In Alberta, two of the key feeder reliability indices commonly used by DFO's are SAIDI and SAIFI. SAIDI and SAIFI indices are defined in the definition section.

- A classification of interruptions as either momentary or sustained. Momentary and sustained are defined in the definitions section of this guideline.
- Provide a comparison of the feeder SAIDI and SAIFI (i.e. SAIFI-SI and SAIFI-MI) against the average SAIDI and SAIFI for momentary and sustained interruptions for that DFO's distribution system. The SAIDI and SAIFI indices for momentary and sustained are to be calculated using the standards established by Canadian Electric Association ("CEA").
- A description of the methodology used for tracking and calculating performance of the distribution power delivery system, where the DFO does not use the CEA method for reliability tracking and evaluation (i.e.. SAIDI, SAIFI).
- Additional information that supports the recommendation, that could include:
  - How often the feeder is out.
  - Substantiated customer complaints
- A description of improvements that were implemented to address the feeder performance through maintenance, modifications and/or other means. This should include the timing of such improvements, since sufficient time may or may not have elapsed to determine the impact on reliability of the improvements.

Table 3.2-1 summarizes specific methodologies used by DFO's to identify and recommend system reinforcement projects to address reliability concerns.

Table 3.2-1: DFO Methodologies for Feeder Reliability Concerns

DFO	Methodology
ATCO Electric Distribution	• Does not collect momentary outages for feeders at 25 kV and below. • Tabulates SAIFI, CAIDI and SAIDI for each 25 kV feeder, for each of our service areas and for the total 25 kV system for each year. SAIFI and CAIDI are compared to CEA average indices. • Does not differentiate urban and rural feeders and tabulate an annual number for each category. • Differentiates Planned and Unplanned outages. • Selects the 5% worst performing feeders and does a review to determine the cause of the sustained outages and restoration time.
EPCOR Distribution Inc	• Tracks the performance of all circuits on an on-going basis. Circuits that register 3 outage events in 30 consecutive days trigger an alert. • On a monthly basis the performance of all circuits and YTD system performance are reviewed, tabulated and compared to historical trends. This review includes customer complaints, system and equipment performance trends and maintenance practices. • Although EPCOR does not necessarily rank the circuit based on reliability indices (SAIDI/SAIFI etc.); these are considered in reviewing the numbers of outages (sustained & momentary) and the numbers of customer hours. Not all poorly performing circuits need long-range actions; some causes may be beyond EPCOR's control • All System or Circuit Problems considered "actionable" are assigned for a more thorough investigation; problem solving and ultimately correction actions are taken. If actions were not effective it is expected that the same circuits will again trigger alerts & further investigation/actions will result.
ENMAX Distribution	• Recommends system reinforcement projects based on analyses of worst performing feeders, which are identified through comparison of their relative SAIDI & SAIFI indices and number of operations on a 5 year rolling average. • This is consistent with the AEUB wire owner Service Quality and Reliability Performance Plan (SQRP). • Considers poor feeder performance as only one of the components which may drive the need for a specific system upgrade or addition.

DFO	**Methodology**
FortisAlberta	• Does collect momentary outages for feeders at 25 kV and below. • Presently tabulates SAIFI, CAIDI and SAIDI for each 25 kV feeder and for the total 25 kV system for each year. SAIFI and CAIDI are plotted by year against the CEA annual numbers for the period 2000 to present to see how FortisAlberta numbers are trending as well as checking to see how FortisAlberta numbers are trending relative to CEA averages. • Does differentiate urban and rural feeders and tabulates an annual number for each category. • Does differentiate Planned and Unplanned outages. • Selects the 5% worst performing feeders and does a review to determine the cause of the momentary and sustained outages and restoration time. FortisAlberta then develops work orders to spend capital to reduce the cause of the momentary and sustained outages, to reduce the number of customers impacted, and to reduce the length of time to find the fault.
Lethbridge Distribution	• Tracks all unplanned outages on an ongoing basis. • Does not rank circuits based on reliability indices (SAIDI/SAIFI) but considers these in system reporting. • Circuit outages with an undetermined cause are patrolled for an obvious visible cause and for public safety. 2 outages within 6 months per circuit are inspected in more detail. • Currently evaluating Distribution Automation. Circuits will be evaluated to set criteria.
Red Deer Distribution	• Does not collect momentary outages for feeders. • Tabulates SAIFI, CAIDI and SAIDI for the total service area but not for individual feeders. SAIFI and CAIDI are compared to CEA average indices. • Conducts a review to determine the cause of sustained outages and restoration time. • Poor feeder performance is only one of the components considered when evaluating the need for a specific system upgrade or addition.

3.3 Distribution Delivery Point Substation Reliability

The delivery point substation is the interconnection point between the transmission and distribution power delivery systems. The reliability of the delivery point substation will impact the reliability of all distribution feeders emanating from the substation.

In Alberta, three of the key reliability indices commonly used for point of delivery substations are SAIDI, SAIFI-MI (momentary) and SAIFI-SI (sustained). Each one is broken down by voltage class and computed separately for both single-circuit and multi-circuit supplied point of delivery substations. When recommending a system reinforcement project for reliability reasons, the AESO expects the TFO's and/or DFO's to provide the following for point of delivery substations.

- A classification of interruptions as either momentary or sustained. Momentary and sustained are defined in the definitions section of this guideline.
- TFO's to provide to the AESO, the SAIDI, SAIFI-MI and SAIFI-SI numbers based on the most recent five years of data for the point of delivery substations. The SAIDI, SAIFI-MI and SAIFI-SI shall be calculated using the standards established by the CEA. These reliability indices will include both transmission and point of delivery substations interruptions.
- A description of the methodology used for tracking and calculating performance of the point of delivery substations, where the TFO does not use the CEA method for reliability tracking and evaluation (i.e. SAIDI, SAIFI).
- Provide a comparison of the point of delivery substation SAIDI and SAIFI against the average SAIDI and SAIFI for that TFO and the overall Alberta system average for point of delivery substations. The overall Alberta system average for delivery point substations will be calculated by the AESO based upon the annual information provided by each TFO. The SAIDI and SAIFI indices are to be calculated using the standards established by CEA.
- Additional information that supports the recommendation, that could include:
  - How often the point of delivery substation is out of service.
  - Substantiated customer complaints

- A description of improvements that were done to address the point of delivery substation performance through maintenance, modifications and/or other means. This should include the timing of such improvements, since sufficient time may or may not have elapsed to determine the impact on reliability of the improvements.

Table 3.3-1 summarizes specific methodologies used by TFO's to identify and recommend system reinforcement projects to address reliability concerns at point of delivery substations.

Table 3.3-1 TFO Methodologies for POD Substation Reliability

TFO	**Methodology**
AltaLink	• AltaLink compiles sustained and momentary outage data for delivery points SAIFI, SAIDI, SARI(Restoration), and POD SAIF and SAIDI are also calculated per year and trended over the past five years. Information is available for the Maintenance Planning group to use to develop maintenance programs and capital programs. • When a POD suffers from a sustained or momentary fault a root cause failure analysis is performed to identify concerns with equipment/environment. When a particular a class of equipment is identified as susceptible to a particular failure mode, then an evaluation of possible solutions is undertaken and a business case is prepared. Corrective action can range for equipment modification to requests for a station redesign.
ATCO Electric Transmission	• Compiles sustained and momentary outage data for delivery points. Points of delivery with >2 sustained faults per year and >4 sustained faults over the past five years are selected and put in the under performing table in the annual ATCO Electric Delivery Point Reliability Report. SAIFI, SAIDI, SARI(Restoration), SALI(Load), SAUEI(Unsupplied Energy Index), DPUI(Delivery Point Unreliability), and customer SAIF and SAIDI are also calculated per year and trended over the past five years. Information is available for the Maintenance Group and Planning to use to develop maintenance programs and capital programs. • Loss of a POD is a significant outage and unacceptable outage due to the magnitude and the impact of the outage. AE analyzes all sustained substation outages via an internal review committee that meets monthly to check that all systems performed as expected and whether corrective

TFO	Methodology
	action needs to be taken. Corrective action may be immediate or via a planned program to correct similar deficiencies at other PODs. The corrective action may lead to a request for a POD configuration change or transmission breaker addition. • ATCO Electric is measuring sag and swells for each POD 25 kV bus. Non zero voltage sag and swell deviations is a measure of the quality of the voltage supplied over a period of time. It is usually associated with power quality analysis however it is included here. Zero voltage sags which are a POD outage are also included with the records. Sag and swell Information has been collected over the past three years. The data collection is triggered by a 10% threshold for over or under voltage. The information collects sustained outages to the POD 25 kV bus as the voltage drops to zero volts as well as collecting sags during transmission and distribution faults on area lines. The frequency and depth of the sags is indicative of the area transmission system and distribution system, and available short circuit level.
EPCOR Transmission Inc	• Review the historical performance of the POD and comparison with similar PODs within EPCOR system. Considerations will include number of customer complaints, magnitude of customer load supplied and the sensitivity of load in addition to SAIDI and SAIFI statistics. • As a component of reliability analysis, EPCOR investigates the cause of failure of individual equipment and identifies “type faults”. Corrective measures including repair or replacement decisions are undertaken based on the severity of situations. • EPCOR Distribution PODs are designed to ensure no loss of customer load for periods greater than the normal restoration times
ENMAX Transmission	• The process ENMAX follows is: o Failures of equipment in service are investigated to determine the cause of failure. o Where a class of equipment is identified as susceptible to a particular failure mode, then an evaluation of possible solutions is undertaken. o This may result in a business case being advanced for

TFO	Methodology
	the replacement of the equipment after other factors such as age, environmental factors, and serviceability are taken into account. An example is the replacement of hook stick operated switches in our substation where the analysis showed that replacement was cheaper than continuing a shortened maintenance cycle. • All ENMAX Distribution Point of Delivery substations shall be planned and designed to ensure no loss of load due to transmission capacity limitations under normal operating conditions for a period greater than the switching transfer time required to restore service. • Restoration capability is assessed based on a combination of firm POD capacity remaining, adjacent POD capacity import through distribution feeder interconnections, and the prevailing SAIDI reliability target. The nature and timing of system expansion required to maintain the desired level of service restoration is determined on a site specific basis.
Lethbridge Transmission	• Information to Follow
Red Deer Transmission	• Failures of equipment are investigated to determine cause. • Identify if a particular class of equipment is susceptible. • Evaluate possible solutions to determine if replacement, design change or maintenance is best solution. • POD substations are designed to minimize the potential loss of entire load due to capacity limitations for a time greater than the required switching transfer time to restore service. • Restoration capability considers the POD capacity remaining and the capacity available from other PODs through distribution feeder interconnection.

3.4 Transmission Line and Cable Reliability

Transmission lines transport electricity from generators to and between the point of delivery substations. The reliability of the transmission lines and cables can impact the reliability of the point of delivery substations and distribution feeders emanating from the substation.

In Alberta, transmission line and cable reliability is calculated based upon CEA standards. When recommending a system reinforcement project for reliability reasons, the AESO expects the TFO's to provide the following for transmission lines and cables; in regards to this section, cable refers to a conductor that is buried and operating at a transmission voltage (i.e. 69 kV or above).

- A classification of outages as either momentary or sustained. Momentary and sustained are defined in the definitions section of this guideline.
- TFO's to provide to the AESO, the transmission line and cable indices based on the last five years of data for transmission lines.
- A description of the methodology for tracking and calculating performance of the transmission lines and cables, where the TFO doesn't use the CEA method for reliability tracking and evaluation of transmission lines.
- Provide a comparison of the transmission line and cable indices against the average indices for that TFO and the overall Alberta system average for transmission lines. The overall Alberta system average for transmission lines will be calculated by the AESO based upon the annual information provided by each TFO.
- A description of improvements that were done to address the transmission line or cable performance through maintenance, modifications and/or other means. This should include the timing of such improvements, since sufficient time may or may not have elapsed to determine the impact on reliability of the improvements.

Table 3.4-1 summarizes specific methodologies used by TFO's to identify and recommend system reinforcement projects to address reliability concerns for transmission lines and cables.

Table 3.4-1 TFO Methodologies for Transmission Lines and Cables

TFO	**Methodology**
AltaLink	• The performance of each transmission line is tracked for sustained and momentary outages, and duration on an annual basis as well as a five year rolling average. Indices for annual and a five year rolling average are also tabulated by voltage class. The performance of all transmission lines is

TFO	Methodology
	compared to AltaLink's average for the particular voltage class (69kV, 138 kV, 240 kV). Information is available for the Maintenance Planning group to use to develop maintenance programs and capital programs • When a line suffers from a sustained or momentary fault a root cause failure analysis is completed to identify concerns with equipment/lines. When a particular a class of equipment/line is identified as susceptible to a particular failure mode, then an evaluation of possible solutions is undertaken and a business case is prepared. Corrective action can range for equipment modification to requests for a line rebuild.
ATCO Electric Transmission	• The performance of each transmission line is tracked for sustained and momentary outages, and duration on an annual basis as well as a five year rolling average. Indices for annual and a five year rolling average are also tabulated by voltage class. The performance of deficient transmission lines is compared to ATCO Electric average for the particular voltage class as well as to the 144 kV class which is the most common regional and POD supply voltage. • ATCO Electric has been collecting data for sags and swells for each POD for three years. For a POD supplied by more than one transmission supply and with the assumption that N-1 transmission voltages are acceptable, the impact of a poor performing transmission line is the voltage sag during a line fault. Sags and swell is often incorporated as power quality. • ATCO Electric will include the cost of the option of bringing poor performing lines up to an acceptable level of performance.

TFO	Methodology
EPCOR Transmission Inc	• EPCOR Transmission Inc. utilizes CEA Methodologies to record transmission reliability statistics. Transmission element outage data and POD outage data is compiled and summarized on a yearly basis. Multiple year data summaries are used to calculate historical performance indices. The analysis does not include distribution related outages. • EPCOR performs root cause analysis for failures and identifies solutions • Results of system inspection and testing are used to evaluate the risk and consequences of failure and corrective actions are recommended.
ENMAX Transmission	• The process ENMAX follows is: o Failures of equipment in service are investigated to determine the cause of failure. o Where a class of equipment is identified as susceptible to a particular failure mode, then an evaluation of possible solutions is undertaken. This may result in a business case being advanced for the replacement of the equipment after other factors such as age, service environment, and serviceability are taken into account. One example is the replacement of fiberglass arms on our transmission structures which degrade due to the ultraviolet radiation. The arms lose their insulating capability and fail in service. This failure process is accelerated by the high contamination levels produced by the mixture of sand and salt used on urban streets, especially when coupled with weather conditions. • All ENMAX Distribution Point of Delivery substations shall be planned and designed to ensure no loss of load due to transmission capacity limitations under normal operating conditions for a period greater than the switching transfer time required to restore service • Restoration capability is assessed based on a combination of firm POD capacity remaining, adjacent POD capacity import through distribution feeder interconnections, and the prevailing SAIDI

TFO	Methodology
	reliability target. The nature and timing of system expansion required to maintain the desired level of service restoration is determined on a site specific basis.
Lethbridge Transmission	• Information to Follow

4.0 Power Quality

Power quality is simply defined as the severity of voltage and frequency deviations supplied to the electric customer. If there are sufficient deviations in voltage and frequency of the power supplied to electricity customers, it can affect the safe and reliable operation of the electricity customer's facility.

There are many factors such as the following that can affect the power quality to the electricity customer:

- Sensitivity of the electricity customers' equipment that varies from one manufacturer to another.
- How the electricity power customers' facility was designed and constructed.
- The type of distribution feeder the electricity customer is connected to.

The following categories relate to specific power quality areas that each DFO must manage in supplying its customers. The following is only a brief summary and specific questions should be directed to the DFO. Further, if these standards aren't met, investigation would be initiated by DFO which may ultimately lead to a transmission solution.

4.1 Voltage

Voltage is a relatively broad term area of concern with respect to the area of power quality and may include the following considerations:

- Transients: voltage spikes can be caused by lightning strikes, capacitor switching and switching on the transmission or distribution power delivery system.
- Swells: voltage swells can be caused by switching or circuit to circuit faults on the transmission or distribution systems.
- Sags: voltage sags can be caused by power system faults, customer motor starting, or switching on the transmission or distribution system.
- Flicker
- Voltage Variation
- Interruptions

- Voltage Imbalance
- Waveform Distortion
- Frequency

Table 4.1-1 is summary of the standards that each DFO applies to their distribution system with respect to the quality of voltage provided to electric power consumers.

Table 4.1-1: DFO Standards for Voltage Quality

DFO	Standards
ATCO Electric Distribution	Voltage Flicker: CAN/CSA –C61000-3-7:04 Electromagnetic Compatibility(EMC) – Part 3: Limits-Section 7: Assessment of emission limits for fluctuating loads in MV and HV power systems – Basic EMC publication ATCO Electric Distribution System Standard for the Installation of New Load Voltage sag(dip) threshold: <90% nominal at Point of Common Coupling Voltage swell threshold: >110% nominal at Point of Common Coupling Voltage Unbalance limit: 2% (95% CPF) at Point of Common Coupling
EPCOR Distribution Inc	• As per CSA CAN3-C235-83 • Voltage imbalance limited to 3 %
ENMAX Distribution	• As per CSA voltage standard CAN3-C235-83 • Voltage imbalance limited to 4%
FortisAlberta	• As per CSA CAN3-C235-83 • Voltage imbalance limited to 3 %
Lethbridge Distribution	• As per CSA CAN3-C235-83 • Voltage imbalance limited to 3 %

DFO	Standards
Red Deer Distribution	• As per CSA voltage standard CAN3-C235-83 • Voltage imbalance limited to 4%

4.2 Harmonics

Harmonics is defined as the steady state distortion of the fundamental frequency (60 Hz). Current distortion occurs when sinusoidal voltage is applied to a non-linear load (i.e. electronic light ballast, PLC, adjustable-speed drive, arc furnace, any ac/dc converter). On the other hand, voltage distortion is indirectly the result of harmonic currents flowing through a distribution system.

Table 4.2-1 is summary of the standards that each DFO applies to their distribution system with respect to the harmonics on the distribution power delivery system.

Table 4.2-1: DFO Standards for Harmonics

DFO	Standards
ATCO Electric Distribution	CAN/CSA – C61000-3-6:04 Electromagnetic compatibility (EMC)- Part 3: Limits –Section 6:Assessment of emission limits for distorting loads in MV and HV power systems – Basic EMC publication CAN/CSA – CEI/IEC 61000-2-4:04 Electromagnetic Compatibility (EMC) – Part 2-4: Environment – Compatibility levels in industrial plants for low frequency conducted disturbances ATCO Electric – Distribution System Standard for the Installation of New Loads IEEE Std. 519-1992 – IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems CAN/CSA – C61000-3-6:04 Electromagnetic compatibility (EMC)- Part 3: Limits –Section 6:Assessment of emission limits for distorting loads in MV and HV power systems – Basic EMC publication
EPCOR Distribution Inc	• IEEE Standard 519 and Guide 519A
ENMAX Distribution	• IEEE Standard 519

DFO	Standards
FortisAlberta	• IEEE Standard 519
Lethbridge Distribution	• IEEE 519 Standard
Red Deer Distribution	• IEEE Standard 519-1992

4.3 Fluctuations/Flicker

Typically within Alberta voltage flicker is related to the voltage fluctuations/flicker as a result of starting motors connected to the distribution power delivery system. The fluctuations/flicker depends upon:

- The type of motor starting used by the electric power customer
- Size of motor
- Type of feeder that the electric power customer is interconnected to.
- Available short circuit current

Table 4.3-1 is summary of the standards that each DFO applies to their distribution system with respect to the allowable voltage fluctuations/flicker.

Table 4.3-1: DFO Standards for Fluctuations/Flicker

DFO	Standards
ATCO Electric Distribution	• During the planning phase of a new motor addition, AE applies a table with the most common application being starts ≤ two times per week. • Max Flicker for ≤ two times per week -25 KV regulated bus = 5% -Urban = 5% -Rural = 8 - 10% -Oilfield = 10 – 12 % -Industrial = 10 -12 % • ATCO Electric will allow the upper limit for flicker during motor starts to approach 10 and 12 % for rural, and oilfield and industrial customers, respectively where there are few customers and long

DFO	Standards
	25 kV lines. • AE has a further table with more stringent flicker requirements for more frequent starts. • When an area concern is raised, AE will install recording instruments and apply the following: o Cannot lead to voltage sags or swells outside Swell and Sag thresholds (see Table 4.1-1 above) o Cannot violate normal voltage limits: -8.3/+4.2% of nominal per CSA CAN3 C235-83 at the PCC (Point of Common Coupling) as extended per the CEA Power Quality Protocol 220 D 711 o Cannot lead to Voltage flicker (luminance changes in lighting systems) at the PCC exceeding Pst = 0.9 o Cannot lead to a voltage sag at the transmission substation exceeding 5%
EPCOR Distribution Inc	• IEEE Standard 519 Flicker Curve • Maximum 5% allowable. Measurable on primary of single customer transformer and on secondary of multiple customer transformer
ENMAX Distribution	ENMAX's "Power Quality Specifications and Guidelines for Customers" includes: o In house flicker curve with values dependent on frequency of occurrence. o Maximum 4% allowable. Measurable on primary of single customer transformer and on secondary of multiple customer transformer.
FortisAlberta	• In house flicker curve with values dependent on frequency of occurrence. The same curve as the AESO uses. • Maximum 5% allowable. Measurable on primary of customer transformer.

DFO	Standards
Lethbridge Distribution	• In house flicker curve with values dependent on frequency of occurrence. • Maximum 4% allowable. Measurable on primary of a dedicated customer transformer and on secondary of shared customer transformer.
Red Deer Distribution	• IEEE Standard 519 Flicker Curve • IEEE Standard 1159-1995 • Maximum 4% allowable. Measurable on primary of customer transformer.

4.4 Other Power Quality Standards

The standards for point of delivery substations are currently in development as part of the Interconnection Standards Upgrade.

5.0 Definitions

The following definitions are the basis for the terms used in this document unless otherwise defined herein. The application of these definitions is intended solely for the purpose of this guideline and is not necessarily intended to represent the definitions used by the AESO in other documents.

"Momentary Outage" means interruptions less than one minute in duration

"Sustained Outage" means interruptions one minute or more in duration

"System Average Interruption Duration Index (SAIDI)" is defined as the system average interruption duration for customers served per year.

- The formula to calculate SAIDI for distribution systems is:

$$\text{SAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

- The formula to calculate SAIDI for point of delivery substations is:

$$\text{SAIDI} = \frac{\text{Total Duration of all Delivery Point Interruptions in Minutes}}{\text{Total no. of Delivery Points monitored}}$$

"System Average Interruption Frequency Index (SAIFI)" is defined as the system average number of interruptions per customer served per year.

- The formula to calculate SAIFI for distribution systems is:

$$\text{SAIFI} = \frac{\text{Total Customer-Interruptions}}{\text{Total Customers Served}}$$

- The formula to calculate SAIFI for point of delivery substations is:

$$\text{SAIFI} = \frac{\text{Total no. of Delivery Point Interruptions}}{\text{Total no. of Delivery Points monitored}}$$

"Unsupplied Load" means the load not served after any automatic or manual switching operations have been carried out after the occurrence of a first contingency.

EPCOR Distribution & Transmission Inc.

EDTI-AUC-2015JUN26-024

Reference: **Exhibit 20407-X0048, Appendix B-4, page 11, Table 3.2-1; Exhibit 20407-X0112, Appendix A-4, page 17, Table 3.2-1**

Issue/sub-issue: **New 15 kV and 25 kV circuit additions**

Preamble: In 2014 and 2015, EDTI forecast to complete two and three circuit additions, respectively. In 2016 and 2017, EDTI is forecasting to complete four circuit additions each year.

Request:

Outside of the circuit additions required to connect new service sites, how does EDTI forecast circuit additions to complete in a particular year?

Response:

EDTI forecasts the circuit additions to complete in any given year through a review of the peak loads on all circuits on its system for the current year and the forecasted future years' peak loads. The forecasted future years' peak loads are developed using information including circuit historical growth rates, City of Edmonton's growth projections and information respecting new residential and industrial developments, vacant land available for growth and any specific known new customer loads.

Circuit additions are identified by determining which existing circuits are currently overloaded or are forecast to be overloaded (based on the addition of the forecasted future years' peak loads described above). If sufficient load cannot be transferred to adjacent circuits, it is necessary to install a new circuit to transfer the load and alleviate the overload. Additionally, peak loads on adjacent circuits are reviewed to determine if those circuits have sufficient capacity for load to be transferred in the event of an outage of any single circuit. If the adjacent circuits do not have sufficient capacity for load transfer capability, then a new circuit will be installed for contingency purposes.

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A circuit is considered to be overloaded if:

- It is loaded above its normal peak load rating under normal operation. Normal operation means that the circuit is not supplying any additional load from other circuits.
- It is loaded above its emergency peak load rating under emergency conditions. Emergency condition means that the circuit is supplying additional load from other circuits.

EDTI calculates the normal and emergency peak load ratings for each circuit based on the manufacturer's specifications.

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Reference: **Exhibit No. 80, Application, Section 3.1.4, pages 76-79; Exhibit No. 21, Appendix A-4**

Issue/sub-issue: **New 15-kilovolt (kV) and 25-kV circuit additions**

Quote: At paragraph 4 of Appendix A-4 EDTI noted:

"New circuits are only installed when it is no longer possible or practical to transfer load among existing circuits within a local area to maintain circuit loads within their design limits. The need for a new circuit is fairly predictable."

At paragraph 24 of Appendix A-4, EDTI stated:

"EDTI expects that it will be required to load its 11SU, 21SU and 22SU circuits to 19.59 MVA [megavolt-ampere], 12.43 MVA, and 15.68 MVA respectively, by 2014 due to load growth in the southwest 25 kV area, if an additional circuit or circuits are not added to its distribution system. These amounts are above the design load (12 MVA) for all three circuits. The proposed 25 kV circuit will allow EDTI to reduce the load on its 11SU, 21SU and 22SU circuits below their design loads."

At paragraph 25, page 6 of Appendix A-4, EDTI provided the following table:

Table 2.2-1 Historical and Forecast Peak Loads on 11SU and 21SU Circuits (MVA)

		A **2010 A**	B **2011 A**	C **2012 A**	D **2013 F**	E **2014 F**	F **2015 F**	G **2016 F**	H **2017 F**
1	Design load for Summerside Circuits	12	12	12	12	12	12	12	12
2	11SU Circuit Peak Loads	20.41	17.73	18.08	18.84	19.59	20.35	21.10	21.86
3	21SU Circuit Peak Loads	9.08	11.25	11.47	11.95	12.43	12.91	13.39	13.87
4	22SU Circuit Peak Loads	-	-	14.47	15.07	15.68	16.28	16.89	17.49

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At paragraph 77, page 19 of Appendix A-4, EDTI provided the following table:

Table 6.0-1 New 15 kV and 25 kV Circuit Additions 2008–2015 ($ millions)

		A **2008 D**	B **2008 A**	C **2009 D**	D **2009 A**	E **2010 D**	F **2010 A**	G **2011 D**	H **2011 A**	I **2012 D**	J **2012 A**	K **2013 D**	L **2013 PA**	M **2014 F**	N **2015 F**
1	Capital Additions	1.48	4.11	0.00	1.50	3.15	0.30	3.36	4.39	2.45	2.69	4.61	1.52	4.46	8.43
2	Variance		2.63		1.50		(2.85)		1.03		0.25		(3.09)	2.94	3.97

At paragraph 83 of Appendix A-4, EDTI provided following explanation for the $3.09 million decrease from 2013 Decision to 2013 preliminary actual:

"A $3.01 million decrease related to the 13SU circuit addition project reflecting a delay in the commencement of this project. In 2013, EDTI expected to install two new cubicles, replace an existing cubicle and direct bury 6.3 km of 500 MCM aluminum XLPE cable. However, EDTI was only able to install one new cubicle and direct bury approximately 1.0 km of 500 MCM aluminum XLPE cable. As explained above, EDTI intends to complete this project in 2014."

Request:

a) Please elaborate on EDTI's statement that "The need for a new circuit is fairly predictable:"

(i) How can this statement be reconciled with EDTI's history of significant differences between decision and actual amounts as shown on the Table 6.0-1 above?

(ii) How does EDTI predict the number of new circuit additions in a given year?

(iii) Please justify the reasonableness of the 2014 and 2015 circuit additions forecast given the historical differences between the forecast and actual results?

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b) Based on the Table 2.2-1 above, the loads of circuits 11SU and 22SU have been above the design load of 12 MVA since the year they have been installed (11SU in 2010 and 22SU in 2012), please explain for how long and what maximum load a circuit can sustain above the design load, without jeopardising the safety and reliability of the system?

c) Please elaborate on the following: "In 2013, EDTI expected to install two new cubicles, replace an existing cubicle and direct bury 6.3 km of 500 MCM aluminum XLPE cable. However, EDTI was only able to install one new cubicle and direct bury approximately 1.0 km of 500 MCM aluminum XLPE cable." Why was EDTI not able to complete the work?

d) Was there any impact on the company's ability to maintain safe and reliable service resulting from the inability to complete the forecasted work for 2013?

e) Compared with 2013, EDTI is forecasting a similar amount of capital additions for 2014, and almost double the amount of capital additions for 2015. Please explain how EDTI will be able to complete the scheduled amount of work in 2014 and 2015, given that it was unable to complete approximately two-thirds of the work scheduled for 2013 as shown in Table 6.0-1?

f) Please augment Table 3.2-1 provided in paragraph 42 of Appendix A-4 with the number of units to be added for this project in each of 2014 and 2015 and calculate per unit costs. Please explain any significant differences in per-unit costs.

g) Please provide a revised version of Table 2.2-2 of Appendix A-4, showing the actual historical annual peak loads in each of 2010 through 2013 as well as forecast annual peak loads in each of 2014 through 2017, if the proposed 23U circuit is installed.

Response:

a) i) The statement, "The need for a new circuit is fairly predictable" was intended to mean that by monitoring the peak loads of its circuits EDTI can generally

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anticipate when a new circuit will be required due to an increased demand for power.

EDTI has not delayed the installation of a new circuit due to forecast loads not materializing as expected. Therefore, it is not possible to reconcile this statement to historical Decision versus Actual capital additions variances related to this project.

ii) EDTI determines the number of new circuits required each year by primarily using the following two approaches:

1. EDTI reviews the summer and winter peak loads on all circuits to determine which circuits overloaded. If the load cannot be transferred to adjacent circuits then EDTI will install a new circuit and transfer the load to this new circuit to alleviate the overload. Additionally, peak loads on adjacent circuits are reviewed to determine if the circuits have sufficient capacity for load to be transferred in the event of an outage of any single circuit. If the adjacent circuits do not have sufficient capacity for load transfer capability, then a new circuit will be installed for contingency purposes.
2. When one or more new customers with significant load requirements request a service supply in an area where no circuits exist or where existing circuits would become overloaded, a new circuit will be installed to supply the customer.

A circuit is considered to be overloaded if:

- It is loaded above its normal peak load rating under normal operation. Normal operation means that the circuit is not supplying any additional load from other circuits.
- It is loaded above its emergency peak load rating under emergency conditions. Emergency conditions means that the circuit is supplying additional load from other circuits.

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EDTI calculated the normal and emergency peak load ratings for each circuit based on the manufacture's specifications.

iii) As shown in Table 6.0-1 of Appendix A-4 the only years in which the Actual was less than the Forecast capital additions were in 2010 and 2013, and the primary reason for the variance in 2013 was due to uncertainties surrounding the I-X mechanism. EDTI delayed completing the 13SU project due to uncertainties surrounding the I-X mechanism. EDTI notes that its 2014 and 2015 circuit additions are on schedule and still expected to be completed as shown in Table 3.1-1 in Appendix A-4 of the Application.

b) Design load is the maximum load that EDTI plans to operate a circuit under normal operating conditions. This provides the circuit with some reserve capacity to pick up load from other circuits in outage contingency situations without overloading the circuit. EDTI's design load for 25 kV circuits is 12 MVA. Circuits can operate at loads between their design load and their normal peak load rating indefinitely without causing damage to the circuit. However, operating above the design load increases the risk of the circuit being loaded above its emergency peak load rating under emergency conditions.

Normal peak load rating is the maximum continuous load a circuit can be operated at without reducing its service life. The normal peak load ratings for all 25 kV circuits, based upon EDTI's standard 750 MCM Cu cable in substation exit ductlines, are 17.5 MVA in summer and 21 MVA in winter. Circuits can sustain these loads for as much as 8 hours every day assuming the average load throughout the day is approximately 75% of the peak ratings or less and this is called the normal peak load threshold. If the loads of a circuit go above this threshold, the circuit will experience increased thermal degradation which will increase the risk of the circuit failing which jeopardizes the safety and reliability of EDTI's distribution system.

Emergency peak load rating is the maximum load that EDTI plans to operate the circuit under an outage situation when load is transferred from another adjacent circuit that has experienced an outage. The emergency rating is based upon the assumption that the

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maximum number of emergency periods will not exceed 3 periods in any 12 months nor an average of 1 period per year for the life of the cable. The maximum duration of any one period should not exceed 36 hours. EDTI's emergency rating for 25 kV circuits is 21 MVA in summer and 24 MVA in winter. If the loads of a circuit go above the emergency peak load rating, the circuit will experience increased thermal degradation which will increase the risk of the circuit failing, which jeopardizes the safety and reliability of EDTI's distribution system.

In 2013 EDTI was very close to the normal peak load threshold on its 11SU circuit and expects to exceed this threshold in 2014 if 13SU is not installed in 2014 as planned.

Also, if 23SU is not installed in 2015, it is expected that all of the circuits that feed the southwest area of Edmonton will be above their design loads. If this occurs, it is expected that if one of these circuits fails, EDTI will be required to overload the remaining circuits above their emergency peak load ratings.

c) In light of the uncertainty surrounding the Capital Tracker mechanism in 2013, EDTI made the decision to postpone starting this project for a short period of time pending the Commission providing clarification and greater certainty through its Decision in the 2013 Capital Tracker proceeding. Specifically, EDTI determined that this project could be delayed for a short period without significantly increasing the risk of adverse effects on its ability to maintain safe and reliable service in the area.

d) The first stage of the 13SU new circuit project that was planned for 2013 was to provide additional backup support to the 22SU circuit in the case of any outages. The 22SU circuit did not experience any outages in 2013 that could have been alleviated by this first stage of 13SU circuit. Therefore, there was no impact on the company's ability to maintain safe and reliable service.

e) Consistent with its usual practice, EDTI undertook a detailed exercise of budgeting work based on a thorough bottom up review of all work planned for 2014 and 2015 (i.e., all distribution function operating, maintenance, repair and capital planned projects including EDTI's proposed Capital Tracker projects and all the planned work funded

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under the PBR I-X formula). Included as part of EDTI's bottom-up budgeting process is the detailed exercise of budgeting work based on hours of work required for each class of field worker.

As described in paragraph 28 in the Application:

> 28. EDTI's 2014 and 2015 capital forecast went through an extensive internal multi-iteration review process which included in-depth reviews of each functional area. The forecasts were first completed in the spring of 2013, and were subsequently reviewed and updated as necessary, most recently in early 2014 during the preparation of this Application. The latter review included consideration of 2013 Capital Tracker work that was not completed due to the uncertainty surrounding the Capital Tracker mechanism during 2013 (as discussed in more detail in section 2.2 above), and the incorporation of the completion of that work into EDTI's capital additions forecast for this Application.

This rigorous forecast review process ensured that EDTI has forecast sufficient resources (i.e., internal engineering and field labour resources and external contractors and consultants) in 2014 and 2015.

f) Table AUC-EDTI-11-1 shows the number of kilometres of new line, the capital additions and the capital additions per kilometre of line associated with each new circuit.

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Table AUC-EDTI-11-1
Unit Cost of Each New Circuit

	Circuit	A **km of New Circuit**	B **Aerial/Underground Addition**	C **Cost/km ($ millions)**
1	13SU	2.0	Aerial Line	0.19
2	13SU	8.5	Underground Cable	0.45
3	23SU	5.0	Underground Cable	0.10
4	33PM	5.0	Aerial Line	0.25
5	33PM	9.0	Underground Cable	0.51
6	R19	2.5	Underground Cable	0.64
7	V25	0.8	Underground Cable	0.64

EDTI notes that the capital additions per kilometre of line associated with each new circuit will depend of whether the new circuit is underground or overhead, the topography of where the new circuit will be installed, whether it is installed in ducts or direct buried, and whether major road crossings are involved.

g) Table AUC-EDTI-11-2 below provides the requested version of Table 2.2-2.

Table AUC-EDTI-11-2
Historical and Forecast Peak Loads on 11SU, 21SU, 22SU, 13SU and 23SU Circuits (MVA)

		A **2010 A**	B **2011 A**	C **2012 A**	D **2013 A**	E **2014 F**	F **2015 F**	G **2016 F**	H **2017 F**
1	Design load for Summerside Circuits	12	12	12	12	12	12	12	12
2	11SU Circuit Peak Loads	20.41	17.73	18.08	17.8	12	12	12	12
3	21SU Circuit Peak Loads	9.08	11.25	11.47	9.0	12.43	8.0	8.5	9.0
4	22SU Circuit Peak Loads	-	-	14.47	19.2	12	12	12	12
5	13SU Circuit Peak Loads	-	-	-	-	11.27	8.0	8.5	9.0
6	23SU Circuit Peak Loads	-	-	-	-	-	9.54	10.38	11.22

EDI-AESO-2019OCT03-002
Request:

If not addressed in the response to Q1 above, please provide EDTI DFO’s target restoration time(s) for unsupplied loads in the study area. Please specify the restoration times for the feeder contingencies and transmission facility contingencies.

Response:

As shown on PDF page 26 of EDI-AESO-2019OCT03-001 Attachment 1, EDTI DFO targets a restoration time of “automatic transfer” (i.e., switching time only) for “urban critical” loads, and restoration time of less than or equal to 1 hour for other loads.

EDI-AESO-2019OCT03-003
Request:

RE: Technical Supplement dated September 3, 2019,

(a) Please explain the source and type of forecast load growth in the area (2019-2028), as shown in Tables 1 and 2.

Response:

EDTI's load growth forecast at the Summerside 657S and East Industrial substations is the sum of i) the forecasted "natural" load growth in the respective service area and ii) the discrete load additions due to load transfers or as anticipated by EDTI customers. Each component is described below.

<u>Natural load growth</u>: EDTI's load forecasting model is summarized by the following three process steps:

1. Hourly load collection and data cleansing;
2. Weather normalization (an analysis process that removes the effects of weather variations to reveal underlying growth trends); and
3. Regression analysis to produce base load forecast.

Through regression analysis, the base load at the Summerside 657S and East Industrial substations are forecasted to have an annual growth rate of 4.7% and 2.1% for the next 10 years, respectively.

<u>Discrete loads</u>: A small portion of the forecasted load growth in the East Industrial and Summerside service areas is attributed to discrete load additions. A total of 4.0 MVA discrete industrial load was added to the East Industrial service area and a total of 6.0 MVA discrete public transit load was added to the Summerside service area.

EDI-AESO-2019OCT03-004
Request:

There are at least three unused 25 kV breakers at East Edmonton 38S, two unused 25 kV breakers at Riverview and one unused 25 kV breaker at East Industrial. Please provide your assessment for utilizing these breakers and establishing ties between East Edmonton, East Industrial, Summerside 657S and Riverview substations to achieve adequate capacity and back-up capacity.

Response:

Using the three unused 25 kV breakers at East Edmonton 38S was studied in detail and discounted on the grounds of comparatively higher distribution cost ($93.5 million (+/- 50%)), which is primarily due to the longer distribution feeders required (17 km).

Using the two unused 25 kV breakers at Riverview to help resolve the forecasted N-1 firm capacity violations at East Industrial will similarly not be cost effective due to the long distances between the Riverview and East Industrial service areas (as shown in Figure 1 in the DDR Technical Supplement for P2133 submitted on September 3, 2019). Additionally, EDTI has been approached by two large customers regarding planned load additions that will each require the use of a breaker from Riverview.

The one unused 25 kV breaker at East Industrial substation can be used to help address the distribution circuit overloads in the East Industrial service area. However, the use of this breaker is not sufficient to address the N-1 firm capacity overload that exists at the East Industrial and Summerside substations.

EDI-AESO-2019OCT03-005

Request:

Please confirm that Tables 7 to 14 and Tables 16 to 21 of the DDR and Tables 1 to 2 of the DDR Technical Supplement include the backup capacity from the existing ties between Summerside and East Industrial substations. If not, please explain why this was not considered.

Response:

Confirmed.

EDI-AESO-2019OCT03-006
Request:

The following questions are related to Tables 1 to 2 of the DDR Technical Supplement and Tables 7 to 14 of the DDR provided by EDTI DFO:

(a) Please provide the year EDTI became aware of the N-0 feeder loading violations and N-1 POD loading violations respectively.

(b) If the distribution deficiencies existed in the past, please provide the rationale, including any new drivers relative to previous years, for requesting improved transmission reliability service at this time.

(c) Please provide an overview of the procedures followed by EDTI DFO and the estimated time taken by EDTI DFO in mitigating the feeder overloads that occurred at Summerside 657S and East Industrial in the past.

(d) Please provide an overview of the procedures and expected time that EDTI DFO would have taken in order to restore service to customers in the event of an N-1 transformer contingency at Summerside 657S in the years 2018 and 2019.

Response:

(a) EDTI became aware of the N-0 feeder loading violations and N-1 POD loading violations in 2015. It was determined at that time, under consultation with the AESO, that EDTI would address the identified issues in two separate SASRs: one to address the more immediate identified deficiencies (which resulted in Riverview POD, AESO Project #P1695), and afterwards one to address the forecast deficiencies in Southeast Edmonton (which resulted in the current AESO Project #P2133).

(b) The forecasted distribution deficiencies were first identified to the AESO in 2015 and were included as part of the Riverview Substation DDR, which stated. “EDTI intends to request additional transmission capacity in Southeast Edmonton to address capacity and reliability concerns identified in that area starting in 2021. Possible alternatives to resolve this deficiency include an additional supply from the Summerside POD or a new South East POD as described in alternatives 5 and 6, respectively. These alternatives will be discussed in a separate distribution deficiency report, which EDTI plans to submit to the AESO at a future date…". The Southeast Edmonton SASR and DDR was submitted to the AESO on July 31, 2018.

(c) System Operations at EDTI mitigates any feeder overloads to the extent possible by implementing temporary load transfers to adjacent feeders. If the adjacent feeders are operating at or above their design ratings, then such temporary load transfers are only allowed for a maximum duration of 36 hours. After these 36 hours, further adjacent feeders are explored for cascaded temporary load transfers. However, such cascaded load transfers can involve many switching steps and a considerable amount of time and field resources for implementation. Note that cascade switching is often not available during peak load conditions.

A distribution load transfer involving two switching steps and restoration back to normal operating state typically requires 10 man hours (split between the two time frames of 'offload' and 'restoration').

(d) In the event of an N-1 transformer contingency at Summerside 657S during below near-peak loading, EDTI will perform transmission switching and restore all distribution load onto the remaining substation transformer until the failed transformer is restored. No actual N-1 transformer contingency event has occurred at Summerside in the years 2018 and 2019, however if an event were to occur a planned N-1 contingency could last up to two weeks, while an unplanned N-1 contingency could last up to a year depending on the severity of the failure and the ability to have a new transformer purchased, shipped, and installed.

In the event that the failure occurs during peak load conditions, EDTI's Summerside 657S substation presently does not have sufficient N-1 Firm Capacity to maintain service to all substation load. System Operations at EDTI will mitigate any substation transformer overloads under N-1 contingency scenarios by executing temporary load transfers to adjacent substations, if capacity is available or as capacity becomes available. In the scenario that distribution load transfers are not possible, outages to customers served from the Summerside 657S substation will be required.

A distribution load transfer involving two switching steps and restoration back to normal operating state typically requires 10 man hours (split between the two time frames of ‘offload’ and ‘restoration’). However, it should be noted that the existing circuit ties (two between Summerside and East Industrial and one between Summerside and Poundmaker) do not provide enough capacity to address an N-1 transformer contingency at Summerside 657S during peak load conditions.

EDI-AESO-2019OCT03-007
Request:

Please provide a summary of the type of customers (e.g. residential, industrial, commercial, and farming/agriculture) and number of customers within each type served by Summerside 657S and East Industrial. Please describe the potential impacts on the unsupplied loads for each of the N-1 transmission contingency scenarios at Summerside 657S and East Industrial. In the responses, please identify any critical loads with public safety or environmental sensitivities.

Response:

A detailed breakdown of the customers served by the Summerside 657S and East Industrial substations is presented below. EDTI notes that the customer load type tables use the EDTI rate class classifications reflected in EDTI's annual Rule 005 filings to the Alberta Utilities Commission.

Summerside 657S Substation

Customer Load Type	Customer Count
Summerside 657S	**41,194**
Commercial/Industrial < 50kVA	846
Commercial/Industrial 50 – 149 kVA	542
Commercial/Industrial 50 < 4999 kW	49
Primary Commercial/Industrial 150 < 4999 kW	1
Residential	39,593
Security Lighting	21
Unmetered	104
Vacant	38

Specific customers of note served by the Summerside 657S substation include:

- Edmonton Fire Station
- Schools (17)
- EPCOR Water Services (2)
- EPCOR Drainage

- Alberta Health Services
- Edmonton Police Service
- Seniors Home

East Industrial Substation

Customer Load Type	**Customer Count**
East Industrial	**12,738**
Commercial/Industrial < 50kVA	744
Commercial/Industrial 50 – 149 kVA	441
Commercial/Industrial 50 < 4999 kW	96
Primary Commercial/Industrial 150 < 4999 kW	6
Residential	11,381
Security Lighting	21
Unmetered	28
Vacant	20

Specific customers of note served by the East Industrial substation include:

- Schools (5)
- Edmonton Police Service
- Alberta Health Services (3)

In the event of a N-1 transmission contingency at Summerside 657S and/or East Industrial , System Operations at EDTI would attempt to transfer any load in excess of the N-1 firm rating of a substation to adjacent substation(s). These load transfers are implemented using temporary distribution load transfers. Such temporary load transfers, depending on the capacity of the adjacent feeders, are only allowed for a duration of 36 hours. In the event that EDTI does not have the capacity to mitigate N-1 transformer overloads, a rolling load shedding scheme is implemented on the feeder breakers of the overloaded substation. Although EDTI System Operations attempts to ensure that feeders serving customers of note are not de-energized under rolling load shedding, service to these customers is not guaranteed.

EDI-AESO-2019OCT03-008
Request:

Please provide any other information that EDTI DFO thinks would be helpful to the AESO in assessing and supporting the SASR.

Response:

At the time of submitting this response, EDTI DFO does not have any additional information that it considers would be helpful to the AESO in assessing and supporting the SASR.

ETI-AESO-2019OCT03-001
Reference: **Summerside 657S**

Request:

Please provide a history of the forced and planned outages on Summerside 657S transformers T1 and T2 based on the records presently available to EDTI TFO, including the duration of those outages. In the response, please include time, date, duration, and cause for each event.

Response:

The Summerside substation is currently very early into its expected lifespan. The substation was commissioned approximately nine years ago. To date, there have been no forced outages recorded due to major apparatus equipment failure.

Historical transformer outage information for Summerside is provided (from Jan 2015 to Sept 2019) below in Table ETI-AESO-2019OCT01-001-1 including time, date, duration and cause for each event.

EDTI's systems do not track transmission outages automatically; EDTI has therefore assembled the list of historical outages and their causes from its multiple system operation logging sources and manual switching orders.

Table ETI-AESO-2019OCT03-001-1
Forced and Planned Outages on Summerside 657S
Transformer T1 and T2

		A	B	C	D	E	F	G
	Asset	**Start Date**	**Start Time**	**End Date**	**End Time**	**Duration (HR:MIN)**	**Reason**	**Planned**
1	Summerside T1	19/Feb/2019	7:15	23/Feb/2019	15:57	104:42	ISOLATE TX1 - RELAY MTCE	YES
2	Summerside T1	18/Nov/2015	8:56	20/Nov/2015	14:10	53:14	ISOLATE TX1 - INSTALL BUSHING MONITORS	YES
3	Summerside T1	01/Oct/2015	15:29	01/Oct/2015	18:37	03:08	RESTORE TX1 - DOBLE TESTING	YES
4	Summerside T1	28/Sep/2015	10:03	28/Sep/2015	10:12	00:09	ISOLATE TX1 - DOBLE TESTING	YES
5	Summerside T1	30/Mar/2015	9:55	31/Mar/2015	15:35	29:40	ISOLATE TX1 - RELAY MTCE	YES
6	Summerside T2	11/Feb/2019	7:53	16/Feb/2019	19:27	131:34	ISOLATE TX2 - RELAY MTCE	YES
7	Summerside T2	07/Dec/2015	8:39	09/Dec/2015	14:19	53:40	ISOLATE TX2 - INSTALL BUSHING MONITORS	YES
8	Summerside T2	02/Oct/2015	9:43	05/Oct/2015	14:04	76:21	ISOLATE TX2 - DOBLE TESTING	YES
9	Summerside T2	01/Apr/2015	8:12	02/Apr/2015	13:50	29:38	ISOLATE TX2 - RELAY MTCE	YES

ETI-AESO-2019OCT03-002
Reference: Summerside 657S

Request:

Please provide an overview of the procedures EDTI TFO would undertake, and the estimated times EDTI TFO expects it would take, to restore service to the substation in the event of a contingency of Summerside 657S Substation transformers T1 and T2. Please include any details on mobile substations available to restore load, time to deploy to site, and time to install/transfer load to the mobile substation.

Response:

EDTI's response to an outage of any one element will depend on the state of the transmission system at the time of the outage, and will be determined through the application of a general procedure to respond to outage events rather than by the application of pre-established, asset specific procedures. The transmission system is dynamic and pre-established, asset-specific procedures are often not applicable in the specific circumstances of an outage.

The following steps describe how EDTI's system control operators ("SCO") respond to the loss of a system element:

1. Review available alarms in EDTI's Outage Management System ("OMS")
2. Assess new current system state (confirm which elements are in/out of service)
3. Verify loading of elements adjacent to the outage element
4. Review historical loading
5. Complete any initial emergency switching, load transfers and/or load shedding:
   5.1. Create switching orders
      5.1.1. Substation equipment switched through control room
      5.1.2. Manual switching through trouble truck
6. SCO will notify as required:
   6.1. AESO

6.2. ALTALINK
6.3. Foreman
6.4. Mangers
6.5. ATCO
6.6. Power Trouble Dispatch
6.7. Trouble truck crews

7. Field Crews will proceed to damage area and report the following information to SCO:
    7.1. Location of trouble and apparent cause
    7.2. Assessment of damage
    7.3. Action necessary for repair and restoration of service
    7.4. Estimated time until service will be restored
8. SCO will log all applicable information and complete incident in OMS
9. SCO will create plan within 30 minutes to re-prepare system in the event of next contingency.

Restoration times are also dependent on the unique situation of the unplanned outage(s). EDTI has observed the following outage restoration time(s) at other stations in 2019:

- On August 27, 2019, T3 at Woodcroft Substation tripped, creating an outage to 6,840 distribution customers. EDTI system control restored load by restoring bus #3 through bus-tie breakers to T1 @ Woodcroft. This restoration was possible because T1 had enough capacity at the time to take the entire load of bus #3. Total restoration time was 11 minutes.
- On September 4, 2019, T1 at Kennedale Substation tripped, creating an outage to 24,686 customers, as at the time, T2 at Kennedale was out of service for maintenance and all station load was being carried by T1. EDTI executed an emergency return-to-service of T2, and all load at Kennedale was returned to service in 198 minutes.

The above two examples show how the condition of related assets on the transmission system may affect restoration times. It is important to note that in both cases, full load restorations were possible because the available restoration elements (T1 at Woodcroft, and T2 at Kennedale) had sufficient capacity to carry the unsupplied load. If the available transformation capacity in each of the above two situations had not been sufficient for full restoration, then EDTI would have been forced to implement rotating outages in these station service areas until the out of service transformer units could be restored to service. Depending on what is required for restoration this duration could be relatively short (days), or weeks to months.

EDTI does not have a mobile substation to deploy.

ETI-AESO-2019OCT03-003
Reference: **Summerside 657S**

Request:

Is the historic availability of Summerside 657S Substation transformers T1 and T2 typical for transformers of similar design?

Response:

EDTI is not aware of any facts that would suggest that the historic availability of the Summerside 657S Substation transformers T1and T2 is atypical vis-à-vis transformers of similar design.

EDTI notes that the unavailability of these transformers has historically been related to preventative maintenance and a capital life cycle installation of auxiliary equipment (e.g., bushing monitors).

It would be very difficult to reliably compare the availability of the referenced transformers to industry data/statistics. An individual transformer's availability can vary significantly from year to year based on maintenance requirements alone, making comparisons to "average" availability challenging to say the least. Further, transformer availability over time is a product of factors like historical operation and loading of the equipment, and the specific maintenance practices employed by the operator, which are typically unknown by all but the specific utility operator. Unless these important "drivers" of availability are carefully examined and accounted for in analyzing the data, it is not possible to arrive at "apples-to-apples" comparisons of availability.

Finally, EDTI notes that major equipment failures such as a bushing failure, tapchanger failure, winding fault or a main tank rupture would result in extended unavailability to the equipment. While EDTI stocks spare components such as transformer high and low voltage bushings, an in-service failure of this type of component often results in collateral damage. EDTI does have a spare transformer that can be used at Summerside in the event of total failure, but transportation, retapping and connecting the unit would take between 4 and 6 weeks.

ETI-AESO-2019OCT03-004
Reference: **Summerside 657S**

Request:

Please provide the ages of Summerside 657S Substation transformers T1 and T2. Please describe any planned capital maintenance for these facilities, include durations of planned outages and any measures to be taken during the planned outages to provide service continually.

Response:

Summerside 657S Substation transformers T1 and T2 were manufactured in February 2010, making the assets approximately nine years old. EDTI does not have any planned capital maintenance for these facilities in the 2020-2022 time period.

ETI-AESO-2019OCT03-005
Reference: Summerside 657S

Request:

Please provide a history of the forced and planned outages on other equipment (switches, busses, etc.) at the Summerside 657S substation based on the records presently available to EDTI TFO, including the duration of those outages. In the response, please include time, date, duration, and cause for each event.

Response:

The Summerside substation was commissioned approximately nine years ago and is currently very early into its expected lifespan. To date, there have been no forced outages recorded due to major apparatus equipment failure.

Historical outage information on other equipment (switches, busses, etc.) at Summerside is provided (from Jan 2015 to Sept 2019) below in Table ETI-AESO-2019OCT03-005-1 including time, date, duration and cause for each event.

Table ETI-AESO-2019OCT03-005-1
Forced and Planned Outages on other equipment
Summerside 657S

		A	B	C	D	E	F	G
	Asset	Start Date	Start Time	End Date	End Time	Duration (HR:MIN)	Planned	Reason
1	1057L	17/Sep/2019	8:17	17/Sep/2019	15:20	07:03	YES	ISOLATE 1057L – GOI[1] - ALTALINK
2	1057L	28/Jan/2019	6:27	31/Jan/2019	15:02	80:35	YES	ISOLATE 1057L - RELAY MTCE
3	1057L	11/Dec/2018	7:32	11/Dec/2018	16:19	08:47	YES	ISOLATE 1057L - GOI - ALTALINK
4	1057L	13/Aug/2018	10:40	23/Aug/2018	19:11	248:31	YES	ISOLATE 1057L - GOI - ALTALINK
5	1057L	17/Mar/2017	11:05	17/Mar/2017	14:47	03:42	NO	TRIP 1057L - FAULTY RELAY - ALTALINK
6	1057L	04/Jul/2016	11:38	07/Jul/2016	14:09	74:31	YES	ISOLATE 1057L - GOI - ALTALINK
7	1057L	18/Oct/2015	8:02	18/Oct/2015	17:31	09:29	YES	ISOLATE 1057L - DOBLE TESTING
8	1058L	21/Jan/2019	7:19	25/Jan/2019	14:42	103:23	YES	ISOLATE 1058L - RELAY MTCE
9	1058L	03/Jul/2018	6:56	03/Jul/2018	17:07	10:11	YES	ISOLATE 1058L - DOBLE TESTING
10	1058L	17/Oct/2017	6:47	21/Oct/2017	14:15	103:28	YES	ISOLATE 1058L - DOBLE TESTING
11	1058L	29/Apr/2016	5:43	29/Apr/2016	11:11	05:28	NO	ISOLATE 1058L - RELAY PROT FAIL ALARMS
12	1058L	19/Oct/2015	12:37	23/Oct/2015	14:29	97:52	YES	ISOLATE 1058L - REPLACE CT'S
13	SU2401	06/Oct/2015	9:04	06/Oct/2015	14:32	05:28	YES	ISOLATE SU2401 - DOBLE TESTING
14	SU2402	04/Sep/2018	9:40	04/Sep/2018	13:43	04:03	YES	ADD SF6 TO SU2402
15	SU2402	07/Oct/2015	9:32	07/Oct/2015	15:30	05:58	YES	ISOLATE SU2402 - DOBLE TESTING
16	SU2403	08/Oct/2015	9:39	08/Oct/2015	15:26	05:47	YES	ISOLATE SU2403 - DOBLE TESTING
17	SU2404	15/Oct/2018	11:08	15/Oct/2018	15:17	04:09	YES	ADD SF6 TO SU2404
18	SU2404	09/Oct/2015	9:58	09/Oct/2015	15:06	05:08	YES	ISOLATE - SU2404 - DOBLE TESTING

[1] "GOI" means "guarantee of isolation", which is required in instances where a piece of equipment connects to multiple utilities.

ETI-AESO-2019OCT03-006
Reference: Summerside 657S

Request:

Please provide an overview of procedures that EDTI TFO would take and the estimated times EDTI TFO expects it would take to restore service to the substation in the event of an unplanned outage to other equipment (switches, busses, etc.) at the Summerside 657S substation. Please include any details on mobile substations available to restore load, time to deploy to site, and time to install/transfer load to the mobile substation.

Response:

EDTI's general procedure for responding to transmission contingencies is described in response ETI-AESO-2019OCT03-002. This procedure would be applied in the event of a contingency of other equipment (switches, busses, etc.) at the Summerside substation.

EDTI does not have a mobile substation to deploy.

ETI-AESO-2019OCT03-007
Reference: Summerside 657S

Request:

Is the historic availability of other equipment (switches, busses, etc.) at the Summerside 657S substation typical for similar designs?

Response:

EDTI is not aware of any facts that would suggest that the historic availability of other equipment (switches, busses, etc.) at Summerside 657S substation is atypical vis-à-vis equipment of similar design.

EDTI has not experienced any recent significant failures such equipment at the Summerside substation, and any unavailability of the equipment is historically related to minor repairs and preventative maintenance.

ETI-AESO-2019OCT03-008
Reference: Summerside 657S

Request:

Please provide the age of other equipment (switches, busses, etc.) at the Summerside 657S substation. Please describe any planned capital maintenance for these facilities, include durations of planned outages and any measures to be taken during the planned outages to provide service continuity.

Response:

The Summerside assets were manufactured in 2010, making the assets approximately nine years old. EDTI does not have any planned capital maintenance for these facilities in the 2020-2022 time period.

ETI-AESO-2019OCT03-009
Reference: **Summerside 657S**

Request:

Please provide a summary of any planned TFO Capital Maintenance projects applicable to the project area not described in the responses above. In the response, include durations of planned outages and any measures to be taken during the planned outages to provide service continually.

Response:

EDTI TFO has filed its planned capital maintenance projects within its 2020-2022 General Tariff Application[1]. Forecast projects at Summerside include:

- Remote Terminal Unit ("RTU") Bus Extension
- Substation Building Air Conditioning Install
- Digital Fault Recorder ("DFR") Upgrade

Minor outages may be required to facilitate the RTU bus extension and the DFR upgrade but will be of short duration (multiple 1-2 day outages of various equipment). These equipment outages are not expected to result in any customer outages.

[1] Exhibit 24798-X0003 EDTI 2020-2022 TFO Tariff Application sections 9.2.2.2 and 9.2.2.5.

ETI-AESO-2019OCT03-010
Reference: **Summerside 657S**

Request:

Please provide any other information EDTI TFO thinks would be helpful to the AESO in assessing and supporting the DFO's SASR.

Response:

At this time, EDTI TFO is not aware of any other information that EDTI TFO could provide which would further support the DFO's SASR.

ETI-AESO-2019OCT03-011
Reference: **East Industrial**

Request:

Please provide a history of the forced and planned outages on East Industrial transformers T1 and T2 based on the records presently available to EDTI TFO, including the duration of those outages. In the response, please include time, date, duration, and cause for each event.

Response:

The East Industrial substation was initially commissioned in 1992 with only transformer T1. East Industrial transformer T2 was added in 2006.

Historical transformer outage information for East Industrial is provided (from Jan 2015 to Sept 2019) below in Table ETI-AESO-2019OCT03-11-1 including time, date, duration and cause for each event.

EDTI's systems do not track transmission outages automatically; EDTI has therefore assembled the list of historical outages and their causes from its multiple system operation logging sources and manual switching orders.

Table ETI-AESO-2019OCT03-011-1
Forced and Planned Outages on East Industrial Transformer T1 and T2

		A	B	C	D	E	F	G
	Asset	**Start Date**	**Start Time**	**End Date**	**End Time**	**Duration (HR:MIN)**	**Reason**	**Planned**
1	East Industrial T1	06/Dec/2018	7:32	07/Dec/2018	16:14	32:42	ISOLATE TX1 - CT CUTOVERS	YES
2	East Industrial T2	04/Dec/2018	7:42	05/Dec/2018	17:53	34:11	ISOLATE TX2 - CT CUTOVERS	YES
3	East Industrial T1	27/Nov/2018	7:15	28/Nov/2018	14:00	30:45	ISOLATE TX1 - CT CUTOVERS	YES
4	East Industrial T1	19/Jun/2017	6:57	23/Jun/2017	11:50	100:53	ISOLATE TX1 - DOBLE TESTING	YES
5	East Industrial T2	08/May/2017	7:54	13/May/2017	13:31	125:37	ISOLATE TX2 - DOBLE TESTING	YES
6	East Industrial T2	20/Mar/2017	8:23	23/Mar/2017	11:22	74:59	ISOLATE TX2 - RELAY MTCE	YES
7	East Industrial T1	13/Mar/2017	7:37	16/Mar/2017	11:33	75:56	ISOLATE TX1 - RELAY MTCE	YES
8	East Industrial T1	16/May/2016	8:49	20/May/2016	11:23	98:34	ISOLATE TX1 - DOBLE TESTING	YES
9	East Industrial T2	09/May/2016	9:27	11/May/2016	14:46	53:19	ISOLATE TX2 - DOBLE TESTING	YES
10	East Industrial T1	24/Feb/2016	8:53	24/Feb/2016	17:06	08:13	ISOLATE TX1 - REPAIR OIL LEAK	YES
11	East Industrial T1	26/Aug/2015	3:17	26/Aug/2015	6:25	03:08	ISOLATE TX1 - RELAY ALARMS	NO

ETI-AESO-2019OCT03-012
Reference: **East Industrial**

Request:

Please provide an overview of the procedures that EDTI TFO would undertake, and the estimated times EDTI TFO expects it would take, to restore service to the substation in the event of a contingency of East Industrial Substation transformers T1 and T2. Please include any details on mobile substations available to restore load, time to deploy to site, and time to install/transfer load to the mobile substation.

Response:

EDTI's general procedure for responding to transmission contingencies is described in response ETI-AESO-2019OCT03-002. This procedure would be applied in the event of a contingency of East Industrial substation transformers T1 and/or T2.

EDTI does not have a mobile substation to deploy.

ETI-AESO-2019OCT03-013
Reference: East Industrial

Request:

Is the historic availability of East Industrial Substation transformers T1 and T2 typical for transformers of similar design?

Response:

EDTI is not aware of any facts that would suggest that the historic availability of the East Industrial Substation transformers T1and T2 is atypical vis-à-vis transformers of similar design.

EDTI notes that the unavailability of these transformers has historically been related to preventative maintenance and a capital life cycle installation of auxiliary equipment (e.g., bushing monitors).

It would be very difficult to reliably compare the availability of the referenced transformers to industry data/statistics. An individual transformer's availability can vary significantly from year to year based on maintenance requirements alone, making comparisons to "average" availability challenging to say the least. Further, transformer availability over time is a product of factors like historical operation and loading of the equipment, and the specific maintenance practices employed by the operator, which are typically unknown by all but the specific utility operator. Unless these important "drivers" of availability are carefully examined and accounted for in analyzing the data, it is not possible to arrive at "apples-to-apples" comparisons of availability.

Finally, EDTI notes that major equipment failures such as a bushing failure, tapchanger failure, winding fault or a main tank rupture would result in extended unavailability to the equipment. While EDTI stocks spare components such as transformer high and low voltage bushings, an in-service failure of this type of component often results in collateral damage. EDTI does have a spare transformer that can be used at East Industrial in the event of total failure, but transportation, retapping and connecting the unit would take between 4 and 6 weeks.

ETI-AESO-2019OCT03-014
Reference: **East Industrial**

Request:

Please provide the ages of East Industrial Substation transformers T1 and T2. Please describe any planned capital maintenance for these facilities, include durations of planned outages and any measures to be taken during the planned outages to provide service continually.

Response:

East Industrial Substation transformers T1 and T2 were manufactured in 1991 and 2006, respectively, making the assets approximately 28 and 13 years old, respectively.

EDTI currently plans to replace a dissolved gas analysis monitor on East Industrial T2 in 2021. This work is not anticipated to have any impact on service continuity.

ETI-AESO-2019OCT03-015
Reference: **East Industrial**

Request:

Please provide a history of the forced and planned outages on other equipment (switches, busses, etc.) at the East Industrial substation based on the records presently available to EDTI TFO, including the duration of those outages. In the response, please include time, date, duration, and cause for each event.

Response:

Historical transformer outage information on other equipment (switches, busses, etc.) at East Industrial is provided (from Jan 2015 to Sept 2019) below in Table EDTI-AESO-2019OCT03-015-1 including time, date, duration and cause for each event.

EDTI's systems do not track transmission outages automatically; EDTI has therefore assembled the list of historical outages and their causes from its multiple system operation logging sources and manual switching orders.

Table ETI-AESO-2019OCT03-015-1
Forced and Planned Outages on other equipment
at East Industrial Substation

		A	B	C	D	E	F	G
	Asset	**Start Date**	**Start Time**	**End Date**	**End Time**	**Duration (HR:MIN)**	**Reason**	**Planned**
1	1059L	06/Jul/2018	6:18	07/Jul/2018	16:06	33:48	ISOLATE 1059L - DOBLE TESTING	YES
2	E2402	02/May/2018	9:03	03/May/2018	15:15	15:12	ISOLATE E2402 - BREAKER MTCE	YES
3	908L	12/May/2017	6:47	12/May/2017	12:54	06:07	ISOLATE 908L - DOBLE TESTING	YES
4	1059L	23/Apr/2017	10:57	29/Apr/2017	17:56	150:59	ISOLATE 1059L – GOI[1] - ALTALINK	YES
5	908L	25/Jul/2016	11:28	28/Jul/2016	16:04	76:36	ISOLATE 908L - GOI - ALTALINK	YES
6	1059L	11/Jul/2016	8:38	11/Jul/2016	15:29	06:51	ISOLATE 1059L - DOBLE TESTING	YES

[1] "GOI" means "guarantee of isolation", which is required in instances where a piece of equipment connects to multiple utilities.

ETI-AESO-2019OCT03-016

Reference: **East Industrial**

Request:

Please provide an overview of procedures EDTI TFO would take and the estimated times EDTI TFO expects it would take to restore service to the substation in the event of a N-1 contingency of other equipment (switches, busses, etc.) at the East Industrial substation. Please include any details on mobile substations available to restore load, time to deploy to site, and time to install/transfer load to the mobile substation.

Response:

EDTI's general procedure for responding to transmission contingencies is described in response ETI-AESO-2019OCT03-002. This procedure would be applied in the event of a contingency of other equipment (switches, busses, etc.) at the East Industrial substation.

EDTI does not have a mobile substation to deploy.

ETI-AESO-2019OCT03-017
Reference: **East Industrial**

Request:

Is the historic availability of other equipment (switches, busses, etc.) at the East Industrial substation typical for similar designs?

Response:

EDTI is not aware of any facts that would suggest that the historic availability of other equipment (switches, busses, etc.) at East Industrial substation is atypical vis-à-vis equipment of similar design.

EDTI has not experienced any recent significant failures such equipment at the East Industrial substation, and any unavailability of the equipment is historically related to minor repairs and preventative maintenance.

ETI-AESO-2019OCT03-018
Reference: **East Industrial**

Request:

Please provide the age of other equipment (switches, busses, etc.) at the East Industrial substation. Please describe any planned capital maintenance for these facilities, include durations of planned outages and any measures to be taken during the planned outages to provide service continuity.

Response:

The East Industrial substation was initially commissioned in 1992 with only transformer T1 and a single bus of 25 kV switchgear. East Industrial was expanded with transformer T2 and a second 25 kV bus in 2006. Essentially, the T1 half of the substation is approximately 28 years old, while the T2 half is approximately 13 years old.

EDTI does not have any planned capital maintenance for these facilities (switches, busses, etc.) at East Industrial substation in the 2020-2022 time period.

ETI-AESO-2019OCT03-019
Reference: East Industrial

Request:

Please provide a summary of any other planned TFO Capital Maintenance projects applicable to the project area not described in the responses above. In the response, include durations of planned outages and any measures to be taken during the planned outages to provide service continually.

Response:

EDTI TFO has filed its planned capital maintenance projects within its 2020-2022 General Tariff Application[1]. Forecast projects (not previously mentioned in responses above) at East Industrial include:

- Underfrequency Load Shedder Installation; and
- Substation Automation Upgrade.

Minor outages may be required to facilitate these two protection and communications projects but will be of short duration (multiple 1-2 day outages of various equipment). These equipment outages are not expected to result in any customer outages.

[1] Exhibit 24798-X0003 EDTI 2020-2022 TFO Tariff Application sections 9.2.2.1 and 9.2.2.4.

ETI-AESO-2019OCT03-020
Reference: **East Industrial**

Request:

Please provide any other information EDTI TFO thinks would be helpful to the AESO in assessing and supporting the DFO's SASR).

Response:

At this time, EDTI TFO is not aware of any other information that EDTI TFO could provide which would further support the DFO's SASR.

EDI-AESO-2020FEB12-009
Request:

Clarification to EDTI-AESO-2019OCT03-004 response.
Please provide the below answers either as a formal response or as a technical supplement to the DDR:

(a) Please provide a breakdown of the $93.5 million +/-50% cost estimate for using the 3 East Edmonton feeder breakers for both DFO and TFO including required substation work at East Edmonton to connect to an AltaLink substation.

(b) Please provide a cost estimate and breakdown for use of the 25 kV Riverview breakers to offload the Summerside transformers for both the DFO and TFO. Alternatively please explain why this is not a feasible solution.

Response:

(a) Table EDI-AESO-2020FEB12-009-1 below shows the estimated cost breakdown for using three East Edmonton (38S) feeder breakers.

Table EDI-AESO-2020FEB12-009-1
Cost Breakdown for three (3) East Edmonton (38S) Feeders

	Cost Type	A **Cost** **($ millions)** **+/- 50%**
1	TFO Labor	8.2
2	TFO Material	5.4
3	TFO Contingency	1.3
4	**TFO Total**	**14.9** [1]
5	DFO Labor	44.0
6	DFO Material	29.4
7	DFO Contingency	5.2
8	**DFO Total**	**78.6**
9	**Total**	**93.5**

[1] The estimated TFO costs above include the addition of a power transformer and a 25 kV switchgear lineup at AltaLink's East Edmonton (38S) substation in order to reliably supply EDTI load from East Edmonton (38S) substation. However, EDTI notes that even without these TFO costs the DFO cost of this alternative is significantly higher than the preferred alternative.

Additionally, EDTI notes that using the three East Edmonton (38S) feeder breakers will resolve only a portion of the identified need in southeast Edmonton; an additional two 25 kV distribution feeders would be required from an alternate source to resolve all concerns identified within the DDR. The costs associated with the two additional feeders are not included in the cost estimate above.

(b) EDTI notes that the construction of five 25 kV distribution feeders from the Riverview POD would be required to resolve the N-1 POD deficiencies in the East Industrial and Summerside service areas over the next 10 years. Due to this additional load on the Riverview substation, a third power transformer would be required at the Riverview POD to address an expected N-1 firm capacity violation, and an additional 25 kV switchgear lineup would be required as there are currently only four cells presently available to support this alternative. These costs are included in the estimate provided below in Table EDI-EDTI-AESO-2020FEB12-009-2.

Table EDI-AESO-2020FEB12-009-2
Cost Breakdown for Use of 25 kV Riverview Breakers to Resolve Summerside and East Industrial Deficiencies

	Cost Type	A **Cost** **($ millions)** **+/- 50%**
1	TFO Labor	6.4
2	TFO Material	4.6
3	TFO Contingency	1.4
4	**TFO Total**	**12.4**
5	DFO Labor	27.3
6	DFO Material	18.2
7	DFO Contingency	2.5
8	**DFO Total**	**48.0**
9	**Total**	**60.4**

EDI-AESO-2020FEB12-010
Request:

Additional questions to the DFO related to AUC Proceeding 23943

(a) Are there any load shifting opportunities via new distribution feeders to Cloverbar? (Respond as formal response or in technical DDR supplement)

(b) What is the total existing load shifting capability between Summerside and East Industrial?

(c) What is the historical peak coincident combined POD load at Summerside and East Industrial?

(d) Please provide 2019 summer actual/historical load for Summerside and East Industrial as well as forecast load for Riverview (including planned load transfers).

(e) Has planned maintenance or other work at East Industrial/Summerside been delayed or limited due to the deficiencies listed in the DDR?

Response:

(a) The Cloverbar POD service area is not currently electrically connected to the Summerside or East Industrial service areas due to distance as well as a geographical demarcation between EDTI's and FortisAlberta Inc.'s ("Fortis") respective franchise areas (EDTI's franchise area includes Edmonton, whereas Fortis' includes Sherwood Park). Using Cloverbar POD to supply the identified need would require either very long feeders with multiple river crossings within EDTI's franchise area, or would require new distribution feeders to be installed within Fortis' franchise area (which would be a shorter path without river crossings, and therefore less expensive than the routing that would be possible within EDTI's franchise area).

The Cloverbar POD has only two remaining cells available, 11C and 21C, both of which would require the addition of substation breakers prior to use. Assuming that the installation of feeders within Fortis' franchise area would be allowed, approximately 21.1 km of feeder cable would be required through Fortis' franchise area to reach the area of concern. This longer distance will result in significantly higher distribution costs and also increases the risk of electrical issues (e.g., low voltage) for existing and future customers of southeast Edmonton served by these feeders.

Table EDI-AESO-2020FEB12-010-1 below estimates the cost of using two Cloverbar feeder breakers assuming an alignment is available within Fortis' franchise area.

Table EDI-AESO-2020FEB12-010-1
Cost Breakdown for Cloverbar Alternative

	Cost Type	A **Cost (\$ millions) +/- 50%**
1	TFO Labor	0.14
2	TFO Material	0.12
3	TFO Contingency	0.04
4	**TFO Total**	**0.30**
5	DFO Labor	17.5
6	DFO Material	11.6
7	DFO Contingency	2.0
8	**DFO Total**	**31.1**
9	**Total**	**31.4**

EDTI notes that using feeder breakers 11C and 21C from Cloverbar POD would resolve only a portion of the identified need in southeast Edmonton; an additional three 25 kV distribution feeders from an alternate source would be required to resolve all concerns identified within the DDR. The costs associated with the three additional feeders are not included in the cost estimate above.

(b) The ability to shift load between Summerside and East Industrial is constrained on both the distribution and transmission systems, and there are therefore no viable permanent load shifting opportunities between the Summerside and East Industrial service areas using existing assets.

On the distribution system, two circuit ties between the two POD service areas exist: Summerside feeder 14SU is electrically connected to East Industrial feeder 12E, and Summerside feeder 24SU is electrically connected to East Industrial feeders 12E and 23E.

Table EDI-AESO-2020FEB12-010-2 below (extracted from Table 1 and Table 2 of the DDR Technical Supplement March 2, 2020) shows the historical and forecasted distribution feeder loading for 12E, 23E, 14SU and 24SU.

Table EDI-AESO-2020FEB12-010-2
Historical and Forecast Loading on Feeders 12E, 23E, 14SU and 24SU

Summer	**Historical**						**Forecast**									
	2014	**2015**	**2016**	**2017**	**2018**	**2019A**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
12E [MVA]	10.0	11.5	9.8	11.5	10.4	9.1	11.4	12.0	12.6	13.2	13.8	14.5	15.2	15.9	16.6	17.3
23E [MVA]	6.8	6.7	8.4	5.6	6.7	6.7	6.8	6.9	6.9	7.0	7.1	7.1	7.2	7.3	7.3	7.4
14SU [MVA]	NIS	NIS	6.8	6.5	12.7	11.4	9.5	11.3	12.3	13.2	15.2	15.8	16.3	16.8	17.1	17.4
24SU [MVA]	NIS	NIS	NIS	5.7	6.7	7.0	7.4	8.7	9.8	10.8	11.7	12.4	13.0	13.5	14.0	14.4

Winter	**Historical**					**Forecast**									
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
12E [MVA]	12.3	13.1	11.8	12.9	10.7	10.9	11.4	12.0	12.6	13.3	13.9	14.6	15.3	16.0	16.7
23E [MVA]	6.5	8.4	8.9	5.7	6.3	6.3	6.3	6.4	6.5	6.5	6.6	6.6	6.7	6.8	6.8
14SU [MVA]	NIS	NIS	7.9	7.7	14.0	9.8	11.6	12.7	13.6	15.6	16.2	16.7	17.2	17.6	17.9
24SU [MVA]	NIS	NIS	NIS	6.9	8.3	8.6	9.9	11.0	12.0	12.9	13.6	14.3	14.8	15.2	15.6

As shown in the tables above, Feeder 12E is forecasted to exceed its design rating (N-0) in summer 2021. Also, feeders 14SU and 24SU are forecast to exceed their design ratings (N-0) in summer 2021 and winter 2023, respectively. These overloads prevent any permanent load transfers between the East Industrial and Summerside service areas.

Constraints on the transmission system are shown in Table EDI-AESO-2020FEB12-010-3 below (extracted from Table 1 and Table 2 of the DDR Technical Supplement March 2, 2020), which shows the historical and forecasted POD loading for East Industrial and Summerside PODs.

Table EDI-AESO-2020FEB12-010-3
Historical and Forecast Loading on East Industrial and Summerside PODs

Summer	Historical						Forecast									
	2014	2015	2016	2017	2018	2019A	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
East Industrial POD N-1 Capacity [MVA]	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0
East Industrial POD [MVA]	55.6	58.2	55.5	56.8	56.1	53.8	61.9	63.1	64.2	65.4	66.6	67.9	69.2	70.5	71.9	73.3
Summerside POD N-1 Capacity [MVA]	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0	75.0
Summerside POD [MVA]	55.2	64.6	66.4	72.7	90.0	92.0	91.4	82.3	87.7	92.4	101.5	104.9	107.8	110.3	112.4	114.1

Winter	Historical					Forecast									
	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
East Industrial POD N-1 Capacity [MVA]	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8
East Industrial POD [MVA]	53.4	55.3	54.2	54.6	55.9	60.3	61.4	62.5	63.7	64.9	66.1	67.3	68.6	70.0	71.3
Summerside POD N-1 Capacity [MVA]	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0
Summerside POD [MVA]	67.7	71.1	79.4	88.6	93.9	92.4	83.4	88.9	93.7	102.8	106.3	109.3	111.8	113.9	115.6

As shown in the tables above, the East Industrial POD is forecasted to exceed its N-1 firm capacity beginning in summer 2020 and the Summerside POD has exceeded its N-1 firm capacity since summer 2018. Therefore, in addition to the distribution circuit constraints on load shifting as described above, these transmission asset constraints would also need to be addressed prior to considering distribution circuit load transfers.

(c) The historical peak coincident combined POD load at Summerside and East Industrial is shown in Tables 3 and 4 of the DDR Technical Supplement (March 2, 2020). Tables 3 and 4 also show the respective peak coincident factor of the combined POD load at Summerside and East Industrials PODs.

(d) The 2019 summer actual/historical load for Summerside and East Industrial POD service areas as well as the forecast load for Riverview POD is shown in Tables 1 and 2 of the DDR Technical Supplement (March 2, 2020). Tables 1 and 2 also contain footnotes identifying each of the planned distribution load transfers.

(e) EDTI is unaware of any delays or limitations to planned maintenance or other work in the East Industrial or Summerside service areas due to the deficiencies listed in the DDR.

ETI-AESO-2020FEB12-011
Request:

Additional questions to TFO related to AUC Proceeding 23943

(a) Has planned maintenance or other work at East Industrial/Summerside been delayed or limited? If so, please provide a high level description.

(b) EDTI stated they have a spare 240/25 kV transformer in inventory. What would the approximate cost and approximate lead time be on replacing the failed transformer at Summerside or East Industrial with the spare following the loss of any of the existing transformers? Can the spare transformer be stored at the Summerside or East Industrial yard?

Response:

(a) EDTI is unaware of any delays or limitations to planned maintenance or other work at the East Industrial or Summerside substations.

(b) The approximate cost to replace a failed transformer at Summerside or East Industrial substations is $750k with a duration of approximately 6-8 weeks. The spare transformer is currently stored at East Industrial substation, and EDTI considers that it would be possible to store it at the Summerside substation.

2000 – 10423 101 St NW, Edmonton, AB
T5H 0E8 Canada
epcor.com

October 23, 2020

Alberta Electricity Systems Operator
330 5 Avenue S.W.
Calgary, AB T2P 0L4

Dear Sir/Madame:

Re: EPCOR Distribution & Transmission Inc. ("EDTI")
N-1 Contingency, Unsupplied Load, Forecast Load Growth and Special Loads

EDTI received the following questions from the AESO via email on October 16 and October 19, 2020:

Q1. Please complete the provided example N-1 Contingency Table to help the AESO understand the potential peak unsupplied load following a transformer contingency and post-contingency switching of feeder ties to transfer Summerside load to alternate PODs. Please also explain how backup capability is calculated.

A1. The table below follows the format of the example table sent by the AESO, and a description of the analysis completed and the methodology for determining backup capacity is provided beneath Table 1.

Table 1
Summerside TX N-1 Contingency

	Summerside N-1 Contingency Table	A 2020	B 2021	C 2022	D 2023	E 2024	F 2025	G 2026	H 2027	I 2028	J 2029
1	Summerside Load (MVA) (Summer)	83.7	87.1	91.2	90.3	89.5	92.2	102.9	105.6	108.2	110.7
2	N-1 Capacity (MVA) (Summer)	75	75	75	75	75	75	75	75	75	75
3	Backup from 23E (Calculation using design cable limit 12MVA)	4.7	4.6	4.4	4.3	4.1	4.0	3.8	3.7	3.6	3.4
4	Backup from 12E (Calculation using design cable limit 12MVA)	0.7	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	Backup from 11RV (Calculation using design cable limit 12MVA)	2.3	1.9	1.6	1.4	1.1	0.8	0.5	0.3	0.0	0.0
6	Backup from 22RV (Calculation using design cable limit 12MVA)	3.7	2.7	2.5	1.2	0.3	0.0	0.0	0.0	0.0	0.0
7	**Backup from 14E (Calculation using design cable limit 12MVA)										
8	Backup from 14RV (Calculation using design cable limit 12MVA)	0	0	0	6.0	6.0	6.0	6.0	6.0	6.0	6.0
9	Backup from 23RV (Calculation using design cable limit 12MVA)	0	0	0	0	0	0	4.6	4.1	3.5	2.9
10	N-1 Unsupplied load	0.0	2.8	7.7	2.4	2.9	6.4	12.9	16.5	20.1	23.3

Summerside Load: Summerside POD load was extracted directly from EDTI's 2020 Load Forecast, which includes all planned load transfers and forecast special load additions. The loading values shown in Table 1 are the summer non-coincident peaks, as Summerside is a summer peaking POD.

Backup Circuits Used: The existing circuits that can be used as backup in the case of a transformer outage at Summerside (SU) are from East Industrial 23E and 12E, and from Riverview 11RV and 22RV. Additionally, two proposed circuits from Riverview (14RV (planned for install in 2023) and 23RV (planned for install in 2026)) are included as backup circuits starting in the appropriate years.

Circuits 31SU and 32SU are not included in the analysis for backup capacity as both circuits rely on the installation of a third transformer at Summerside substation to provide their intended use. As stated in a previous AESO inquiry response, the main function of circuits 31SU and 32SU with respect to the overall capacity issues in SE Edmonton is to offload East Industrial ("EI") POD to help bring that POD's loading below EI's N-1 Firm Capacity of 63 MVA.

Backup Capacity Calculation:
The calculation of backup capacity for each feeder is completed by subtracting the peak non-coincident forecast circuit load from the total design rating of the circuit. The design rating of EDTI 25kV circuits is 12 MVA, which is two-thirds of the emergency rating of the mainline cable. This planning practice for 25kV areas is driven by some key factors: due to the larger number of customers and larger geographical areas typically served by EDTI's 25 kV circuits, and the relatively small number of circuit ties into these feeders, EDTI has limited the design load rating for 25 kV feeders to 12 MVA to provide an appropriate level of overall system reliability as further described in part b) of information response AUC-EDTI-11 (beginning on PDF 54 of Attachment 2).

Also as described in part b) of information response AUC-EDTI-11, in order to mitigate the impacts of feeder contingencies the emergency rating of distribution circuits can be used; for 25kV circuits, this rating is 18MVA. According to EDTI's Circuit Loading policy for an outage of 36 hours or less the loading of the circuit can be pushed up to the emergency rating of the cable.

However, in the case of a transformer outage at SU, the replacement of the transformer with the spare transformer stored at East Industrial could take up to 8 weeks. For a Transmission outage of this length, EDTI will only load Distribution circuits to their design rating, which is the normal operating condition of the Distribution system. If loaded to a level between the Design Load Rating and the Normal Peak Load Rating, it will not be possible to rely on the planned circuit load transfer capability to support N-1 Distribution contingency conditions. Distribution infrastructure is significantly more exposed to outside factors that could cause outages than the Transmission system. For example, vehicles striking transformers, animal contacts, struck poles, etc. are all relatively common on the Distribution system of an urban utility when compared to the Transmission system.

This methodology is consistent with what EDTI has stated in past regulatory filings as well. In EDTI's 2014-2015 Performance-Based Regulation filing (Application No. 1610362/ID 3100), EDTI states:

> "Circuits can operate at loads between their design load and their normal peak load rating indefinitely without causing damage to the circuit. However, operating above the design load increases the risk of the circuit being loading above its emergency peak load rating under emergency conditions."

Over the course of the 8 week transformer repair or replacement period, these emergency conditions could result from any number of circumstances typically seen by urban utilities. Furthermore, EDTI's circuit loading policy is based around the idea of a reliable Transmission supply, the reliability of which is ensured by EDTI's POD Loading Policy. In the event of a transformer outage at the substation, EDTI considers the Transmission supply to be unreliable, which is consistent with what EDTI has stated in past regulatory filings. The Distribution Point-of-Delivery Interconnection Process Guideline – Standards of Service (PDF 20 of Attachment 2) states:

> "EPCOR has rated cables based on 2/3 of their emergency ratings assuming outages would be short-term (2 to 3 days max)…In situations where:

- Transmission supplies cannot be counted upon to preclude long-term outages;”

For 25kV, this would put the cable ratings for backup circuits at 12MVA. The above quoted information can be found in Attachment 2 - EDI-AESO-2019OCT03-001 on pages 54 and 20 respectively.

It is apparent from Table 1 that there will be 2.8 MVA of unsupplied load starting in 2021 for an N-1 transformer outage, which will grow to 7.7 MVA by 2022. While the addition of 14RV and 23RV will mitigate the unsupplied load growth somewhat, the addition of 23RV backup capacity is largely absorbed by the expected addition of the 10MVA Southwest Hospital load in 2026, for which EDTI has received commitment via email from Alberta Infrastructure.

Q2. Please provide the supporting rationale for the following load forecasts:

(a) 2018 = 56.1MVA; 2019 = 61.9MVA. This is a 5.8MVA increase (approx. 10%)
(b) Feeder 11E 2018 = 6.5 MVA; 2019 = 10.6
(c) Feeder 12E 2018 = 10.4; 2019 = 11.4
(d) Feeder 12E 2020 to 2028 has 5% annual load growth. The historical past 5 yrs. is relatively flat.

A2. Below are the supporting rationale for the load forecast responses:

(a) The 5.8 MVA load increase at East Industrial POD is due to the following:

Table 2
East Industrial POD Load Forecast Explanation

		A **MVA**
1	Special/Discrete Load Addition (General Recycling)	4.0
2	Weather adjustments up to 90th percentile (34 degrees)	0.7
3	Expected natural load growths	1.1
4	**Total**	**5.8**

(b) General Recycling was forecast to be added to 11E in 2019, which is a 4MVA load and accounts for the growth from 6.5MVA to 10.6MVA between 2018 and 2019 in the 2019 forecast.

An update on General Recycling customer in 2020:

As of October 2020, General Recycling is not in service. In 2020, General Recycling and EPCOR have preliminarily agreed on a 5MVA supply from 11E. The customer is allowed to increase the demand from 4MVA to 5MVA due to proposed distribution reconfiguration works that will give more capacity for 11E. It is anticipated that the customer will sign off once the distribution project has been completed.

(c) The 1.0 MVA load increase on 12E is due to the following:

Table 3
12E Load Forecast Explanation (2018 to 2019)

		A **MVA**
1	Weather adjustments up to 90th percentile (34 degrees)	0.3
2	Expected natural load growths	0.7
3	**Total**	**1.0**

(d) As described in EDTI's Load Forecast Methodology (Attachment 1), EDTI's forecast growth for individual circuits is based in part on the amount of undeveloped land served by each circuit. As discussed below, circuit 12E supplies a number of neighbourhoods with significant growth potential.

The following map, Figure 1, illustrates the area that circuit 12E supplies. The neighborhoods with significant potential growth are as follow: Maple, Tamarack, Silver Berry, Laurel, Astor, Decoteau and Rural South East (Mattson).

Figure 1
12E Map

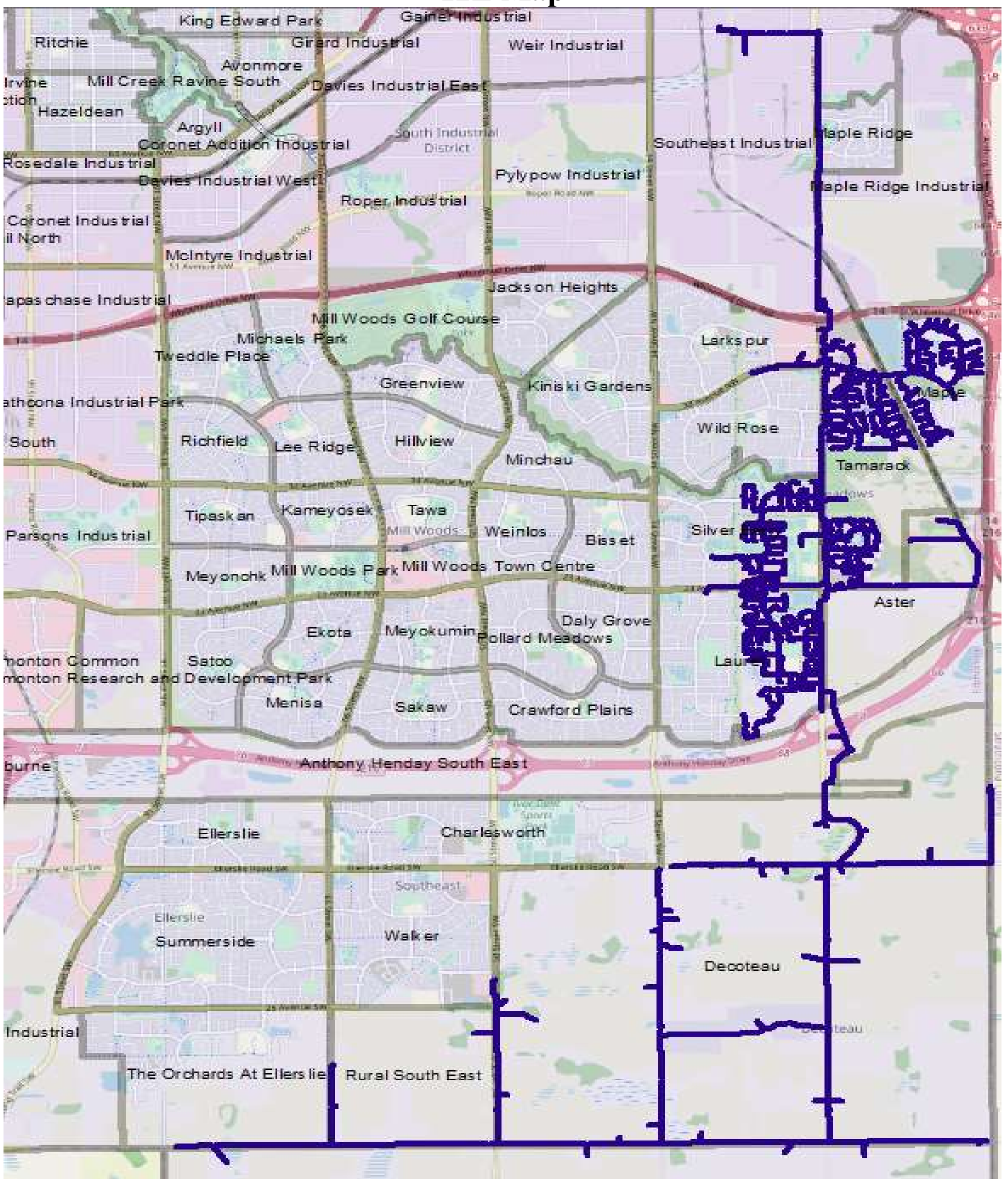


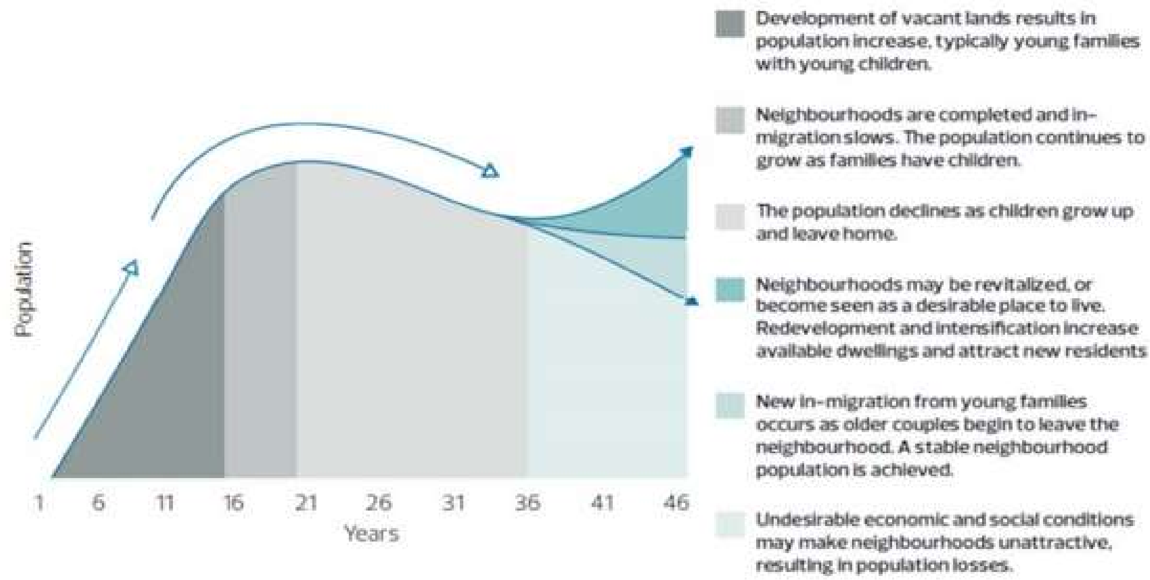
Table 4 below provides an analysis of the neighbourhoods in question, including the anticipated number of residential and commercial units and estimated total load.

Table 4
12E Load Forecast Explanation (Area Growth)

Residential (2KVA per Residential Unit)	Total Residential Units	Estimated Total Load	Existing Load	Potential Growth
Maple	2627	5.3		
Tamarack	3646	7.3		
Silver Berry	1812	3.6		
Laurel	5278	10.6		
Aster	3499	7.0		
Decoteau	29518	59.0		
Rural South East (Mattson)	4364	8.7		
		101.5		
Commercial (15MVA per Square Miles)	**Square Miles**	**Estimated Total Load**	**Existing Load**	**Potential Growth**
Maple	0.00	0.0		
Tamarack	0.00	0.0		
Silver Berry	0.03	0.5		
Laurel	0.00	0.0		
Aster	0.01	0.1		
Decoteau	0.21	3.1		
Rural South East (Mattson)	0.16	2.4		
		6.1		
Neighborhoods Total		**Estimated Total Load**	**Existing Load**	**Potential Growth**
Maple		5.3	0.8	4.5
Tamarack		7.3	2.4	4.9
Silver Berry		4.1	3.0	1.1
Laurel		10.6	4.5	6.1
Aster		7.1	0	7.1
Decoteau		62.1	0	62.1
Rural South East (Mattson)		11.2	0	11.2
Total Potential Load Growth				**96.9**

As demonstrated by Figure 1 and Table 4, this area contains a significant amount of land still available for future development. As illustrated below and described in more detail on PDF 13 of EDTI's Load Forecast Methodology (Attachment 1), the potential for growth is highest in new development areas.

Figure 2
Neighborhood Growth Lifecycle



Circuit 12E, in its current configuration, will supply the majority of the near term potential residential growth. Because of this, when East Industrial's POD forecast is calculated based on regression analysis, the majority of the predicted growth is allocated to 12E resulting in the 5% annual growth rate and the essentially flat (0.5%) growth rate on other East Industrial circuits. It is important to note that the total area growth of 97MVA is long term projections and not all of the load will materialize in the next 10 years.

EDTI considers that this approach to allocating forecast POD load to individual circuits to reflect potential growth is better at identifying and predicting the potential risks in the system.

Q3. POD 2021=87.7; 2023 = 101.5, this is a 16% load growth.

A3. The increase in Summerside load forecast is primarily attributed to discrete load additions from 2022 to 2023 (92.4MVA to 101.5MVA = > 9.1MVA growth). Specifically, they are from new LRT stations. This is illustrated in the table below:

Table 5
Summerside Load Forecast Explanation

		A **MVA**
1	1 Capital Line South LRT Stations (applied to 14SU)	1.25
2	1 Capital Line South LRT Stations (applied to 22SU)	1.25
3	2 Capital Line South LRT Stations (applied to 23SU)	2.5
4	Expected natural load growths	4.1
5	**Total**	**9.1**

EDTI currently expects that the four LRT stations will be completed by 2023 as a part of the Capital Line South LRT Project. On June 1, 2020, the Council has approved the first portion of the project starting in 2021[1].

Sincerely,

Travis Shmyr, R.E.T., P.L. Eng.
Director, Planning & Engineering
EPCOR Distribution & Transmission
Ph. 780-412-4586

Attachments:

Attachment 1 - Load Forecasting Methodology
Attachment 2 - EDI-AESO-2019OCT03-001

[1] https://majorprojects.alberta.ca/details/Capital-Line-LRT-Expansion-South-Ellerslie/3448

DISTRIBUTION SYSTEM PLANNING MANUAL

Load Forecast Methodology

Distribution System Planning
18/09/2020

PROVIDING MORE EPCOR

1.0 APPROVAL

Load Forecast Methodology

	Name and Title	**Date**	**Signature**
Reviewer	Sarah Hanson, P.Eng	2020-09-18	
Approver	Nataliya Kazakova, P.Eng	2020-09-18	

Authentication Stamp	**Verification Stamp**
PROFESSIONAL ENGINEER MICHAEL SMEDING ALBERTA Sept 18 2020	PERMIT TO PRACTICE EPCOR DISTRIBUTION & TRANSMISSION INC RM SIGNATURE: RM APEGA ID #: 80498 DATE: Sept. 18, 2020 PERMIT NUMBER: P007061 The Association of Professional Engineers and Geoscientists of Alberta (APEGA)

Revision History	**Date**	**Author**
First Draft	July 19, 2017	Boyang Xu, EIT
Second Draft	May 1, 2018	Gene Liu, P. Eng
Initial Release	Sept 1, 2020	Michael Smeding, P.Eng

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DISTRIBUTION SYSTEM PLANNING MANUAL

LOAD FORECAST METHODOLOGY

2.0 PURPOSE

The Load Forecast Methodology of the Distribution Planning Manual contains a high level summary of the essential information needed for system planners to forecast annual peak electricity demands for circuits, PODs and for EDTI's entire distribution system.

This document provides an overview of the following key aspects:

- An outline of EDTI's compliance requirements
- An overview of EDTI's forecast process including
    - Data collection requirements
    - Weather normalization
    - Regression analysis
    - Urban growth analysis
    - Necessary refinements
    - Effects of DERs

In addition, this manual provides all other EPCOR personnel with the same overview to help communicate the expectations of planners to support staff.

This load forecast methodology document will continue to be modified or upgraded as required to meet present and future system and **end-use customer** needs as identified by annually performed system assessments.

DISTRIBUTION SYSTEM PLANNING MANUAL

LOAD FORECAST METHODOLOGY

3.0 BACKGROUND

While there is no specific regulation within Alberta which obligates EDTI to produce annual forecasts, it is a common practice for an electric utility to forecast the electricity needs to ensure that sufficient capacity is installed in a timely manner to support the energy use of end-use customers. In so doing, EDTI is able to best fulfil its mandate[1]:

> *"to make decisions about building, upgrading and improving the* ***electric distribution system*** *for the purpose of providing safe, reliable and economic delivery of electric energy having regard to managing losses of electric energy to customers in the* ***service area*** *served by the electric distribution system;"*

Furthermore, the Alberta Electric System Operator (AESO) does have obligations to forecast transmission system need[2]; and consequently provides forecasting specifications[3] in support of the expansion of the distribution and transmission system.

> *"The AESO requires clear and consistent load forecasts from all DFO's to evaluate TFO/DFO interconnection proposals."*

Therefore, EDTI's Load Forecast Methodology has been historically designed to meet the AESO's required specifications while looking to continually improve the quality of forecasting results as new methods and technologies become available. As such, EDTI employs a dynamic methodology whereby the Load Forecast Methodology works alongside the annual released Load Forecast Reports to provide complete overview of the forecasting processes and results. The process is shown in Figure 1.

---

[1] Alberta Electric Utilities Act, Section 105(1)(b)

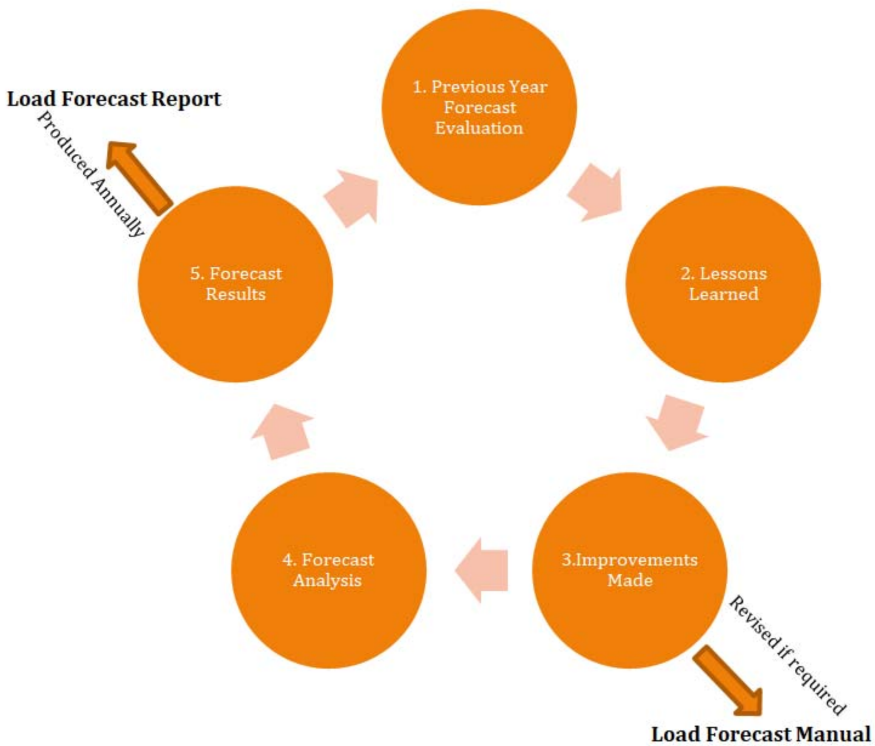
[2] Alberta Electric Utilities Act , Section 33(1)

[3] 2005 Distribution Point-of-Delivery Interconnection Process Guideline Section 2.1, and the 2017 Distribution Deficiency Report Author's Guideline

DISTRIBUTION SYSTEM PLANNING MANUAL

LOAD FORECAST METHODOLOGY

Figure 1: Annual Improvement Model

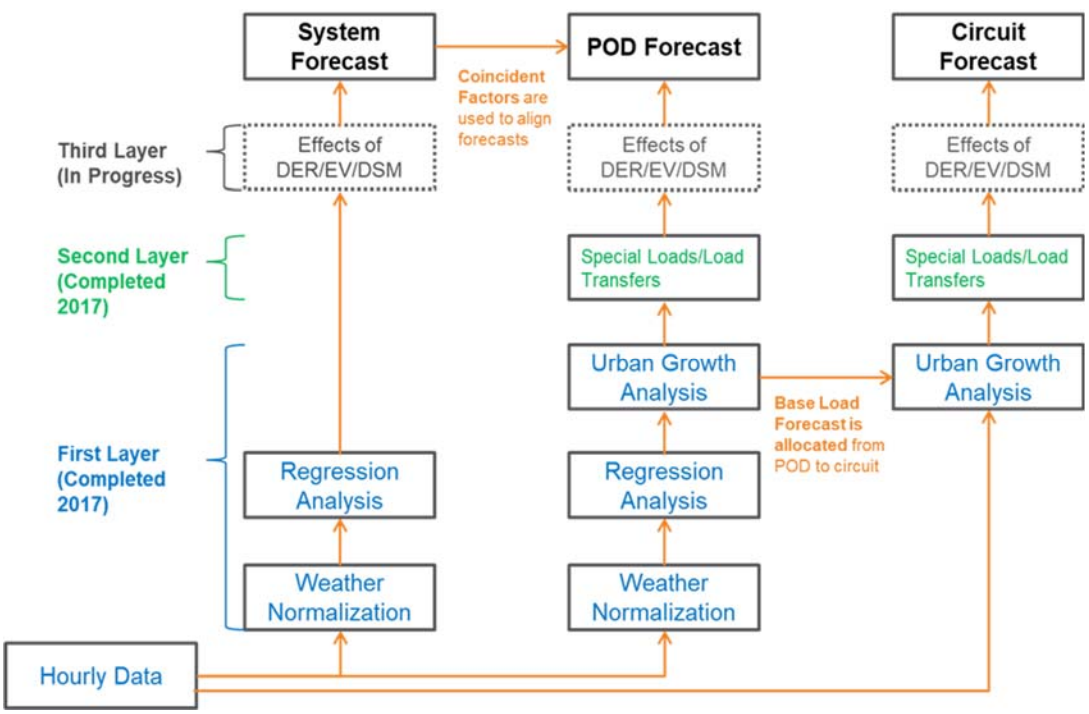


4.0 SYSTEM FORECAST PROCESS

Each year, EDTI prepares a detailed 10-year **peak demand forecast** for each **distribution circuit**, **Point of Delivery (POD)** and the overall system. The forecast is a key indicator used to drive the need for new distribution and transmission facilities or to identify modifications to existing facilities. Specifically, the forecast predicts future electricity demand, identifies upcoming capacity constraints on the distribution feeders, and provides insight into when increased supply is needed from new transmission facility assets. Typically the peak demand forecast is released by the end of April each year, as EDTI is also obligated to submit the POD load demand forecast results to AESO by the end of May.

EDTI's load demand forecast methodology consists of data collection, weather normalization, regression analysis, and urban growth analysis, as well as the addition of special loads and distribution load transfers, as shown in Figure 2. This process is completed for both the peak **summer season** and **winter season**.

Figure 2: EDTI Load Demand Forecasting Process



DISTRIBUTION SYSTEM PLANNING MANUAL

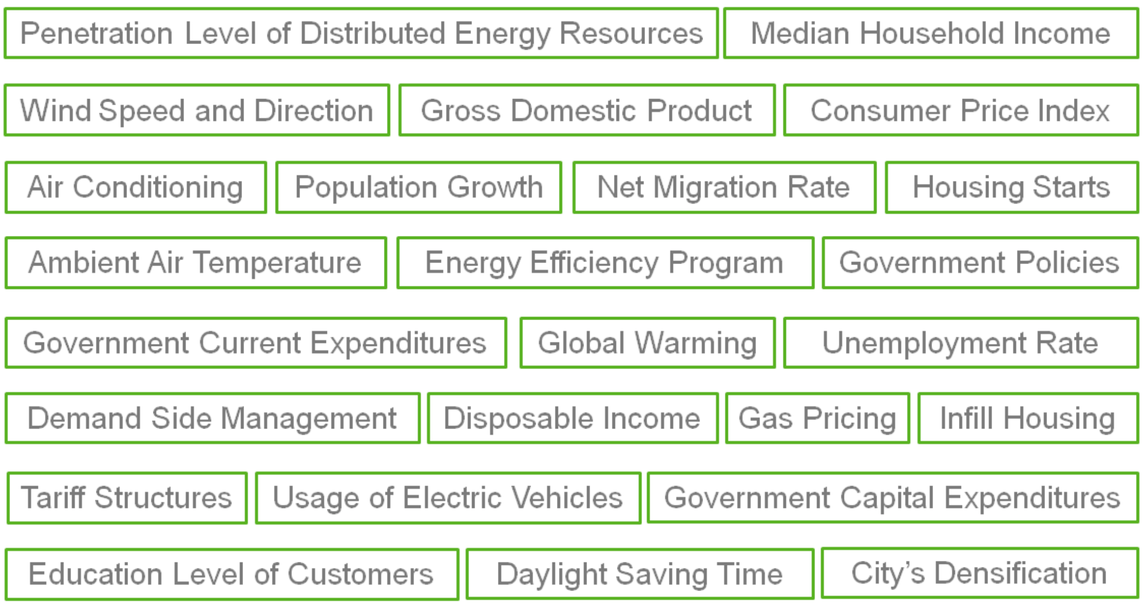
LOAD FORECAST METHODOLOGY

4.1 Data Collection

Prior to determining what data sources were required to produce a dependable and trustworthy forecast, a detailed assessment was conducted to determine what factors influenced the forecast accuracy to the greatest degree.

25 different factors were considered and are listed in Figure 3.

Figure 3: Considered Factors for EDTI Forecast Accuracy



As determined by R-squared correlation methodology, four factors were considered to have the greatest influence: ambient air temperature, gross domestic product, development housing starts, and population growth.

Data collection for the system level forecast requires less data as compared to circuit and POD forecasts. For the system forecast, the following data is required:

- Hourly system loading data from May 1 through October 31 for the summer dataset and from November 1 through April 30 of the following year for the winter dataset,
- Hourly temperature[4] data from May 1 through October 31 for the summer dataset and from November 1 through April 30 of the following year for the winter dataset.

The following 10-year historical data is used for POD load forecasting:

- Hourly POD loading data from May 1 through October 31 for the summer dataset and from November 1 through April 30 of the following year for the winter dataset,
- Annual historical and forecasted economic GDP[5] data,
- Annual historical and forecasted population[6] data, and
- Hourly temperature[4] data from May 1 through October 31 for the summer dataset and from November 1 through April 30 of the following year for the winter dataset.

As the circuit forecast makes use of a “top down” approach, much of the POD data is included within the allocation of load. As such, the following additional data is used for circuit load forecasting:

- Hourly circuit loading data from May 1 through October 31 for the summer dataset and from November 1 through April 30 of the following year for the winter dataset.

---

[4] Temperature data is collected from the Blatchford weather station: http://climate.weather.gc.ca/historical_data/search_historic_data_stations_e.html?searchType=stnName&timeframe=1&txtStationName=Edmonton&searchMethod=contains&optLimit=yearRange&StartYear=2016&EndYear=2017&Year=2017&Month=6&Day=21&selRowPerPage=25.

[5] Collected from the City of Edmonton’s economic forecast; at the system level the CMA forecast is used.

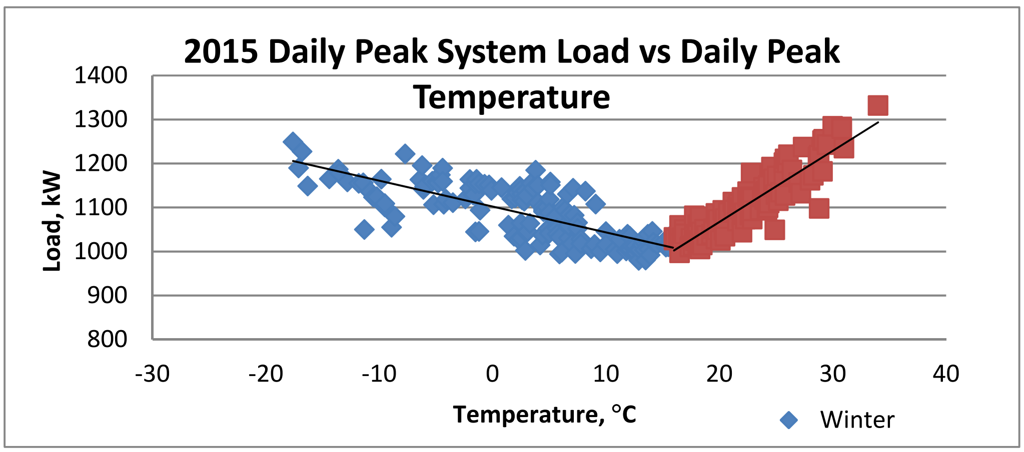
[6] Collected from the City of Edmonton statistician

4.2 Weather Normalization

The idea behind performing weather normalization is to remove the pseudo-random factors that unexpectedly influence electrical energy usage of end-use customers. The goal is to produce a base dataset in which non-weather sensitive load growth occurs from year to year whereby planners more accurately identify load patterns for data regression analysis.

For the majority of EDTI's circuits, the Jack-knife method is used to determine the non-weather sensitive base load. The relationship between weather and load can be modelled and the crossing point between winter and summer slope can be identified as the non-weather sensitive load, as shown in the example in Figure 4.

Figure 4: Jack-knife Method Example



The general formula used for weather normalization is as follows:

$$Y = (W * b) * (T_1 - T_2)$$

Where:

Y is the forecasted load at the defined percentile,

W is the slope of weather against load data,

b is the crossing point between and winter and summer slopes,

T_1 is the temperature at the defined percentile and,

T_2 is the average crossing temperature.

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Once the jack-knife method is performed, the three separate datasets are produced at 10th, 50th and 90th temperature percentiles listed in Table 1.

These are used to produce three separate forecasts for the system and POD level, allowing for planners to have a better understanding of the future load growth within Edmonton, dependant of the expected temperature of a given year. For the circuit forecast only the 90th percentile is used as planners must consider the non-coincident circuit load at the local level.

Table 1: Temperature Percentiles

	Summer	Winter
10th percentile	28.3°C	-16.4°C
50th percentile	30.7°C	-26.3°C
90th percentile	34.0°C	-32.8°C

This can be further illustrated by the example below; Figure 5 shows how removing the weather-sensitive load from the load dataset can produce a stable load growth curve. The weather-sensitive load is then added back in the form of temperature percentiles, as shown in Figure 6.

Figure 5: Removing Weather-Sensitive Load

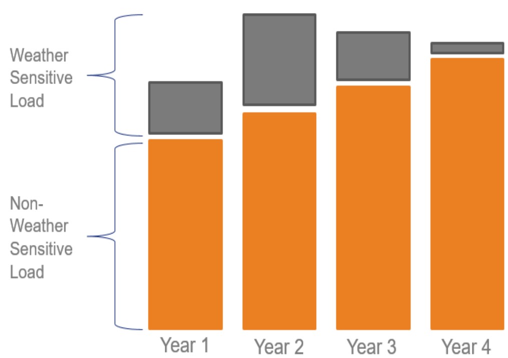
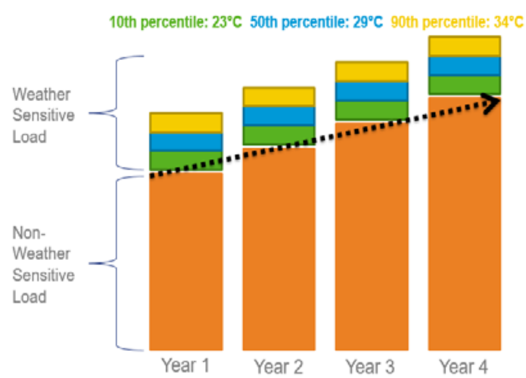


Figure 6: Adding Temperature Percentile Load



Where the jack-knife method does not provide clear results as to what the cross-point value is, tools such as Python's xgboost machine learning algorithm can be used to produce more accurate results. However, due to the added complexity and computation required and compared against the relative accuracy of the Jack-knife method; these alternative methods do not necessarily add sufficient merit to warrant a change to the existing process.

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4.3 Regression Analysis

When it comes to regression analysis of electric energy forecasts, it is commonly understood that different regression requirements exist, depending on the length of time is forecasted. For example, short term forecasting (less than 1 year in duration) requires artificial neural network or advanced mathematical methods in coming up with accurate results. However, for long term forecasting (greater than 5 years in duration) much simpler methods are employed which provide more accurate results that the methods of short term forecasting would provide. This is due to the degree of uncertainty of future load; more advanced techniques generally do not improve the load forecasting results without a greater quantity of known data. Most utilities in North America still use the traditional econometric model due to its reliability and simple explanation of the model.

Within EDTI, the Python's Statsmodel is currently used for performing regression analysis. This open source tool is widely used for regression statistical analysis amongst distribution utilities.

EDTI performs multiple regression analysis with the following general equation:

$$L_{(i)} = C_1 * G_{(i)} + C_2 * H_i + C_3 * P_{(i)} + C_4$$

Where:

L is the peak demand,

i is the year of the forecast,

G is GDP,

H is Housing starts and

P is population.

C_1, C_2, C_3, and C_4 are coefficients to be calculated from the model based on historical data.

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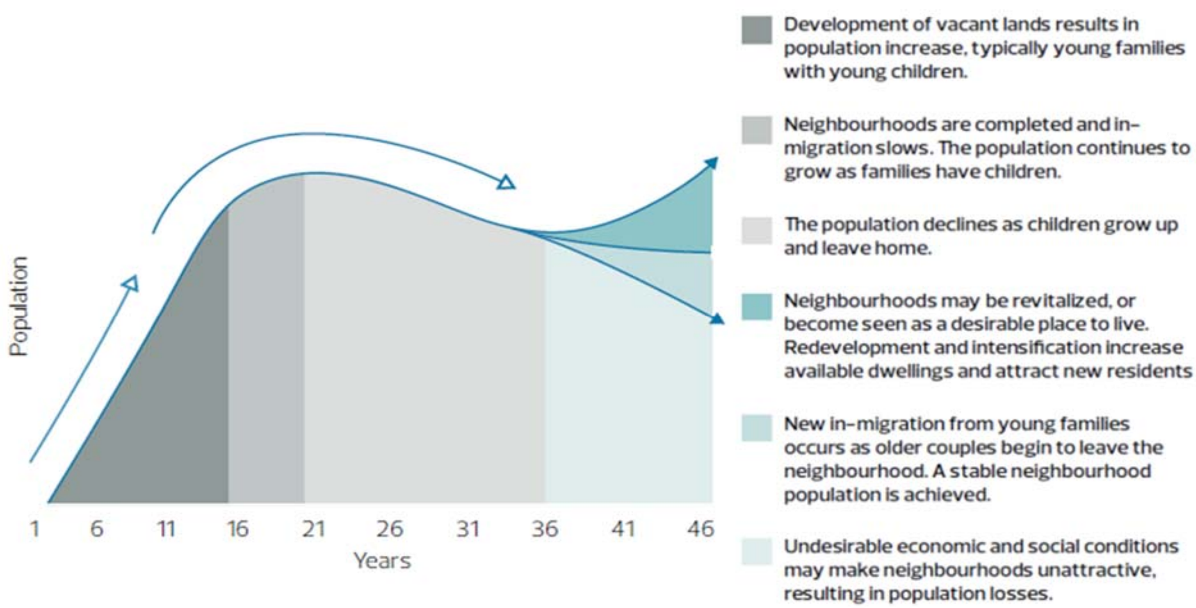
4.4 Urban Growth Analysis

It is also important to consider local factors when developing the forecast. The lifecycle of the local neighborhood is a concept that can be readily seen in every municipal neighborhood and is generalized in Figure 7.

Figure 7: Neighborhood Growth Lifecycle



The general formula used for urban growth analysis is as follows:

$$y(t) = \alpha e^{-e^{c(t-\Delta t)}}$$

Where:

α is the saturated load of the study area,

c is the growth rate of the study area, and

t is the year of the forecast of the study area

The resulting growth curves are then translated into capacity requirements by means of and area density study. Using City of Edmonton area structure plan (ASP), land development applications (LDA), and known zoning for the area, EDTI applies forecasted load, calculated on either square miles or per housing unit.

- For residential: 8 MVA/Square Miles or 2KVA per single family unit.
- For commercial: 10 MVA/Square Miles.
- For Industrial: 12-15 MVA/Square Miles.

The resulting information provides additional insight as to how the growth curve for the neighborhood will conclude, identifying the maximum capacity a given area will require under current end-use customer energy use practices.

4.5 Refinements

Additional local area considerations are given to neighborhoods where atypical growth is expected, but is not forecasted through the regression model. This type of load growth generally consists of large customer demand additions or large load transfers from adjacent areas to which the historical data – and therefore regression model – is unable to take into account. EDTI generally denotes these types of load additions as ‘special load’.

For permanent load additions from special loads the following is considered:

- Any demand requests with signed commitments from the customer or physical evidence (e.g., building in construction) are to be considered as special load if the distribution circuit that services the customer is not forecasted to increase by more than 1% annually.
- In areas where the distribution circuit is forecasted to increase by more than 1% annually, only demand requests of 1 MVA or greater are considered as special loads.

For permanent load transfers form adjacent areas, the following is considered:

- 3-phase average non-coincident peak demand is used to estimate the total peak demand being transferred between circuits (and PODs)

DISTRIBUTION SYSTEM PLANNING MANUAL

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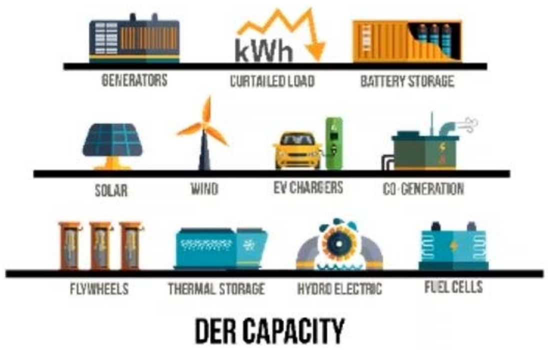
4.6 Effects of DER

Distribution Energy Resources consist of a wide spectrum of technologies and not all technologies consist of solely generating energy at the distribution level. Some technologies, such as battery storage or electric vehicle charging stations can operate as a demand or a generator, depending on circumstances. Figure 8 provides a listing of example DER technologies.

Figure 8: Example DER Technologies



The addition of DER results in multi-direction power flow within a distribution system. As North American distribution systems have historically been uni-direction power flow systems, forecasting methodologies have not yet adapted to the change that DER technologies bring to the grid. As such, DER presently introduces additional uncertainty into the load forecast.

While several approaches could be used to estimate the impacts of DERs on a distribution system, at present no established or recognized method has been adopted as good industry practice.

However, presently EDTI’s exposure to DER within the City of Edmonton is very low and therefore the impacts on the annual load forecast can be considered marginalized. For example, penetration from generation sources within Edmonton is only at 1.4% of the total peak demand. Also, adoption of electric vehicles is presently at approximately 1250 out of 410,000 customers. Both of these indicators presently show that there is no demonstrative impact on the current forecasting methodology.

As DER adoption increases, forecasting methodologies will adjust to properly accommodate.

AESO-AUC-2019JUL18-002

Reference: **Exhibit 23943-X0007, Appendix E - DFO Distribution Deficiency Report, PDF page 8**

Issue/sub-issue: **Distribution Planning Criteria**

Quote: "The Firm Capacity of a POD is an important parameter that EDTI DFO considers for distribution planning purposes. EDTI DFO defines a POD's firm capacity as the maximum load that the POD can supply without overloading any transmission equipment under an N-1 contingency. N-1 contingencies include, but are not limited to, the loss of a single transmission line supply to a POD or the loss of a single transformer at a POD. All PODs should operate at or below their firm capacity."

Request:

(a) How, if at all, does EDTI consider, or account for, capacity that could be provided from a nearby POD by implementing distribution system switching in its planning?

(b) Please provide EDTI's full distribution planning criteria.

(c) Please confirm the normal and emergency ratings of EDTI's 14.4-kV distribution feeders.

Response:

(a) EDTI distribution advises that:

As part of EDTI's system planning process, an assessment of its electrical system is completed annually. The system planning assessment:

- Takes into account the most recent (i.e. the previous year's) actual winter and summer peak loads;

- Creates a new summer/winter peak demand forecast, taking into account known new customer load projections and historical load trends;
- Identifies system violations regarding performance specifications (e.g., power quality, voltage levels, equipment ratings, etc.); and
- Evaluates the available firm capacity margin available at each of EDTI's PODs.

In the event that the system planning assessment identifies a deficiency related to POD loading, EDTI will first consider the capacity that can be provided from nearby PODs through distribution system switching to address the deficiency. If spare capacity at nearby PODs is available, EDTI will complete distribution load transfer to address the identified deficiency to the extent possible (see for example response AESO-CCA-2019JUL18-014(d), which includes information regarding distribution load transfers from Garneau to Rossdale in 2011).

(b) EDTI distribution advises that:

EDTI does not have a stand-alone distribution planning criteria document that describes EDTI's full distribution planning criteria. However, EDTI provides the following documents relating to its planning criteria, particularly as they relate to the West Edmonton Transmission Upgrade Project:

- AESO-AUC-2019JUL18-002 Attachment 1: *AESO Distribution Point-of-Delivery Interconnection Process Guideline – Standards of Service, Revision 0.* EDTI's planning practices are consistent with those outlined in this AESO document.
- AESO-AUC-2019JUL18-002 Attachment 2 & 3: These information request responses provide information regarding EDTI's assessment of its ability to address reliability or load growth concerns through purely distribution means (i.e., through distribution circuit switching, system reconfiguration or the addition of new feeders). When EDTI has exhausted the available distribution solutions, the only remaining avenue for resolution is through transmission developments. EDTI will then submit a System Access Service Request and Distribution Deficiency Report to the AESO in order to initiate an AESO Connection Process project.

Additionally, the Distribution Deficiency Report for this Project identifies EDTI's POD loading policy[1]:

> *The Firm Capacity of a POD is an important parameter that EDTI DFO considers for distribution planning purposes. EDTI DFO defines a POD's firm capacity as the maximum load that the POD can supply without overloading any transmission equipment under an N-1 contingency. N-1 contingencies include, but are not limited to, the loss of a single transmission line supply to a POD or the loss of a single transformer at a POD. All PODs should operate at or below their firm capacity.*

(c) EDTI distribution advises that:

The normal and emergency ratings of EDTI's 14.4 kV distribution feeders within the Garneau, Meadowlark, and Rossdale service areas are shown in Table AESO-AUC-2019JUL18-002-1 below. These ratings are typical for EDTI 14.4 kV feeders of similar construction, and actual cable ratings may vary slightly to account for cable construction, site specific construction details or feeder operating characteristics.

Table AESO-AUC-2019JUL18-002-1
EDTI Standard 14.4-kV Distribution Feeders Normal and Emergency Ratings

		A	B	C	D
		Summer Rating[1] [MVA]		**Winter Rating [MVA]**	
	Cable Sizes	**Normal**	**Emergency**	**Normal**	**Emergency**
1	250 MCM	5	6	6	7
2	500 MCM	7	10	9	11
3	750 MCM	9	12	10	13
4	2 x 500 MCM	15	19	17	22
5	2 x 750 MCM	18	25	21	25

[1] All values are rounded to the nearest integer.

[1] Exhibit 23943-X0007, PDF 8.

Table AESO-AUC-2019JUL18-002-2 indicates the number of each size of feeder at Garneau, Meadowlark and Rossdale substations.

Table AESO-AUC-2019JUL18-002-2
Number of Existing Feeders at Garneau, Meadowlark, and Rossdale

		A	B	C	D	E
		Cable Sizes				
	Substation	**250 MCM**	**500 MCM**	**750 MCM**	**2 x 500 MCM**	**2 x 750 MCM**
1	Garneau	0	1	4	5	1
2	Meadowlark	0	16	2	0	0
3	Rossdale	3	20	13	0	0
4	**Total**	**3**	**37**	**19**	**5**	**1**

aeso
ALBERTA ELECTRIC SYSTEM OPERATOR

Distribution Point-of-Delivery Interconnection Process Guideline

Standards of Service

	Name	Signature	Date
AESO Approved	Fred Ritter, P.Eng.	F. Ritter	2005-03-22
AESO Approved	Neil Brausen, P.Eng	Neil Brausen	2005-03-23
AESO Management	Neil Millar, P.Eng.	Neil Millar	2005-03-30

Revision 0: Tuesday, March 22, 2005

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1.0 Introduction

1.1 Purpose

This guideline defines the principles and standards that Distribution Facility Owners ("DFO") and/or Transmission Facility Owner ("TFO") shall use to identify interconnection requirements on the Alberta Transmission System ("ATS").

This guideline is intended solely for the purpose of supporting the AESO's customer interconnection process to arrive at proposed interconnection concepts that are optimized on a technical and economic basis. It will not in any way address or determine the AESO's facility cost allocation between system and customer, nor will it be used in any way as a guideline in applying the AESO approved tariffs and investment policy.

This guideline is intended to facilitate documentation of the project need and the evaluation done to support the need, in alignment with the interconnection process. The interconnection process has a requirement for AESO endorsement and AEUB approval of the project need.

1.2 Application of Guideline

This guideline is a reference for other Interconnection Process Guidelines. Because this guideline is used by various TFO's and DFO's with different planning and operating environments, it is recognized that differences may occur. To this end, these planning and operating environments are documented throughout this guideline.

The AESO expects that any deviations from this guideline will be documented, explained and supported by the TFO's and/or DFO's as part of the proposal(s) submitted to the AESO.

1.3 Modifications

In respect to this guideline the AESO will:

a) seek the input and feedback of affected parties prior to making changes or additions to the guideline;
b) make and manage all changes to this guideline;
c) make this guideline publicly available via the AESO website;
d) periodically and within five (5) years of the effective date shown on the cover page review this guideline.

2.0 Capacity Standards of Service

The expectation of electricity customers is that the transmission and distribution systems have the capacity to meet their power requirements when needed.

The two key components used in making a capacity assessment of the transmission and/or distribution system are:

1. Load Forecast - the AESO and Distribution Facility Owner ("DFO") must forecast load in order to plan for the efficient and economical expansion of the transmission and/or distribution system in advance of the need materializing.

2. Capacity of Facilities – the TFO's and DFO's are responsible for identifying the voltage and thermal capacity of their facilities. The AESO, TFO's and DFO's will collaborate and coordinate in determining when the capacity of facilities is going to be exceeded during normal ("steady state") and contingency conditions.

2.1 Load Forecasting Approach

The purpose of forecasting is to anticipate what the power system must be able to deliver in the future and how that differs from today's requirements. This forecast is typically a geographical forecast that identifies how much, where and when capacity is required.

Transmission and distribution facilities are planned and designed to meet the expected peak demand on each distribution feeder and distribution delivery point (i.e. substation). The current approach used by TFO's and DFO's is:

- Feeder-by-Feeder: The peak demand for each feeder is examined separately to ensure the capacity rating of the facilities is adequate for future loading requirements.

- Substations: The peak demand supplied by the transformer(s) in the substation is reviewed to ensure there is sufficient capacity for future forecasted loading. The peak demand on the transformer reflects the coincident peak of all the distribution feeders supplied by the transformer. For substations with multiple transformers, the demand for the same date and time must be summed to obtain coincident peak of the substation.

The approach for forecasting load growth is typically one or both of the following:

- Load growth is determined by extrapolating the historical load into the future and by adding any specifically identified new and/or major loads.

- For proposed development in areas where no electrical facilities exist, the load forecast is developed using typical load density expectations as shown in Table 2.1-1.

Table 2.1-1 Ultimate Load Density

Classification of Load	Load Density (MVA/square mile)
Rural	Site specific (1)
Residential (Urban)	6 to 7
Light Commercial / Industrial	12 to 18
Heavy Commercial / Industrial	27 to 40

Notes:
(1) This is handled on a case-by-case basis, since there are many factors that affect rural load densities, such as terrain, access, agricultural, oilfield services, other land uses, and environmental requirements.

2.1.1 *Geographical Load Forecasting Methodology*

This section provides the methodology for creating a geographical load forecast that will ensure facilities of sufficient capacity are appropriately located and available when needed. The AESO requires clear and consistent load forecasts from all DFO's to evaluate TFO/DFO interconnection proposals. The size of the area covered by the "geographic load forecast" will vary depending on the type of facility being proposed.

Further, load forecasts are a prediction of a future possibility, given historical information and incorporating possible future development in the geographical area. All load forecasts are based on judgments of the future and are subject to variability, sensitivity and uncertainty. Therefore, the AESO will integrate the geographical forecast with its long-term forecasts to ensure that the geographical load forecast will support long term solutions. The long term (20 year) forecast is primarily used for bulk system planning and regional planning.

As a minimum, the geographical load forecast shall:

1. Include five (5) years of historical data and ten (10) years of forecasted load in MVA.

2. Provide load density maps that provide sufficient resolution (i.e. today, 5 year and 10 year) to make decisions and permit realistic siting of

facilities (e.g. substations). An example of a load density map is provided in Appendix 1 – Load Density Map Example.

3. Adjust recorded loads to account for load anomalies (i.e. load transfers between feeders) that could skew the projected load on feeder(s) and/or point of delivery substation(s).

4. Incorporate local information that is available, that could include plans of the Province, County, Municipality, Towns, Cities and/or local industrial or commercial developers that would give an indication of potential future development in the area.

5. Identify whether the geographical forecast is for winter or summer peak, which is typically the time period that the deficiency occurs.

6. Include the following:

   - Load MVA values provided to one decimal place.
   - Individual feeder peaks.
   - Transformer peaks that are the coincident peaks of all the feeders served by that transformer.
   - Station peaks are coincident peaks of all transformer peaks, summing each transformer peak with the same date and time stamp.
   - The area total load in both “Existing” and “Proposed” tables must be identical.

7. Provide two forecasts, one for the existing system and one that incorporates the proposed development clearly illustrating how load shifts between feeders and/or distribution delivery points (i.e. substations)

8. Include all stations that are relevant to the supply and/or backup of the load in the area under consideration. This is typically the point of delivery substations that are immediately adjacent to the location being studied.

9. Include specific notes to the tables that the TFO and/or DFO want to explain or identify. This could include:

   - Assumed power factor
   - Provide an explanation of significant (increases or decreases) in the load.

- Lack of information (i.e. metering) that resulted in applying judgment to prepare the forecast.

2.1.2 *Load Forecast Format & Content Required*

Table Title [describe the area] – Existing System

	Recorded Loading [Summer or Winter peak] (MVA) (1)					Projected Loading [Summer or Winter peak] (MVA) (1)									
	Years					Years									
Description	1	2	3	4	5	1	2	3	4	5	6	7	8	9	10
Feeder 1															
Feeder N															
Transformer 1 Total (2)															
Feeder 1															
Feeder N															
Transformer N Total (2)															
Station [name & number] Total (3)															
Repeat the above for all stations under consideration in the area															
Area Total Load															

Notes:

1. Load MVA values provided to one decimal place.
2. Transformer peaks are the coincident peaks of all the feeders served by that transformer.
3. Station peaks are coincident peaks of all transformer peaks, summing each transformer peak with the same date and time stamp.

Table Title [describe the area] – Proposed Development

	Recorded Loading [Summer or Winter peak] (MVA) (2)					Projected Loading [Summer or Winter peak] (MVA) (2)									
	Years					Years									
Description	1	2	3	4	5	1	2	3	4	5	6	7	8	9	10
Feeder 1															
Feeder n															
New Feeder 1															
Transformer 1 Total (3)															
Feeder 1															
Feeder n															
Transformer N Total (3)															
Station [name & number] Total (4)															
Repeat the above for all stations under consideration in the area including any new station proposed															
Area Total Load (1)															

Notes:

1. Area Total load in both “Existing” and “Proposed” tables must be identical.
2. Load MVA values provided to one decimal place.
3. Transformer peaks are the coincident peak of all the loads served by that transformer.
4. Station peaks are coincident peaks of all transformer peaks, summing each transformer peak with the same date and time stamp.

2.2 Capacity Assessment Criteria

The facilities installed by either the TFO or DFO are designed to operate within certain voltage and thermal ratings during a normal and contingency conditions. Operating facilities beyond their ratings can have:

1. Economic implications such as higher maintenance costs, loss of life, and/or early replacement of equipment that has failed catastrophically.
2. Safety implications to TFO and DFO personnel and the public at large.

The intent of this section is to outline acceptable operating ranges on TFO and DFO facilities during normal and contingency conditions.

2.2.1 *Voltage Assessment Criteria*

Voltages shall be maintained within applicable limits during normal and contingency conditions, such that equipment and facility limits are not exceeded.

2.2.1.1 Voltage Fluctuation Guidelines

This section is for DFO's only and is applicable to the distribution power delivery system.

The voltage at an electricity customer's utilization point must be within the ranges specified by CSA Standard CAN3-C235-83, "Preferred Voltage Levels for AC Systems, 1 to 50,000 volts".

Generally, the DFO's plan their distribution power delivery system to meet the voltage requirements during normal forecast peak load conditions to levels above the minimum voltage levels. Planning in this manner provides operational flexibility and reduces risk of exceeding equipment or facility limits due to unexpected occurrences (e.g. faster load growth, forecast uncertainties).

Table 2.2-1 identifies specific planning methodologies for voltage limits by each DFO.

Table 2.2-1: Specific DFO Planning Methodology for Voltage

DFO	Methodology
ATCO Electric Distribution	• Urban o Voltage on 25 kV overhead feeder ▪ System Normal - 116.4V (0.97 p.u) ▪ Contingency (25 kV alternate feed or T-POD) - 113V (0.94 p.u.) o Feeders with both overhead and underground ▪ System Normal & Contingency (supply from alternate 25 kV feed or POD) - 116.4V (0.97 p.u.) • Rural o Two feeder voltage regulators on a feeder, and; o Three phase 25 kV voltage of 114V (0.95 p.u.), or; o 25 kV voltage of 120 V (1.0 p.u) where: ▪ On the primary of a distribution step down substation (i.e. towns or REA's) ▪ At the tap point of a long three phase tap or a number of long single phase taps, or; o Minimum primary voltage of 114 V (0.95 p.u.) on single phase systems
EPCOR Distribution Inc	• Voltage levels at the customer service entrance are consistent with CSA CAN3-C235-83 • Typically 118 V to 120 V on the primary
ENMAX Distribution	• Voltage levels at the customer service entrance consistent with CSA CAN3-C235-83 for single phase and three phase. • For Planning purposes, the desired feeder voltage range is 125 V (1) to 118.5 V (1) as modeled at primary of customer transformer to allow for adjacent feeder contingency backup to be within the CSA standard at the customer service entrance under normal and contingency operation. • Typically, due to the relatively short, heavily loaded urban feeders, no supplemental line voltage regulation is applied.
FortisAlberta	• The feeder voltage loading limit is reached when the feeder has the following during normal operations:

DFO	Methodology
	o Two voltage regulators and; o Three phase voltage is at 115 V (1) (minimum) as modeled on the primary of a distribution transformer on the three phase distribution line or; o Single phase voltage is at 113 V (1) (minimum) as modeled on the primary of a distribution transformer on the single phase distribution line. • The voltage levels correspond to the minimum acceptable voltage as per CSA Standard.
Lethbridge Distribution	• Voltage levels at the customer service entrance are consistent with CSA CAN3-C235-83. • Typically 118 V to 123 V on the primary. • Due to the relatively short urban feeders, no supplemental line voltage regulation is applied.
Red Deer Distribution	• Voltage levels at the customer service entrance consistent with CSA CAN3-C235-83 for single phase and three phase. • Planned feeder voltage range at primary of customer transformer will allow for adjacent feeder contingency backup to be within the CSA standard at the customer service entrance under normal and contingency operation. • Maximum voltage level is limited by changes in transmission voltage levels to high levels which can not be quickly enough reduced by transmission transformer OLTC. • Due to the relatively short, heavily loaded urban feeders, no supplemental line voltage regulation is normally applied.

Notes:

1) Voltages are on a 120 V base, which is a standard practice for DFO's in Alberta.

2.2.1.2 Voltage Range at Distribution Delivery Points

This section is for TFO's only and is applicable to the transmission system at the point of delivery substation. The AESO's Reliability Criteria is followed with respect to voltage limits at point of delivery (POD) substations.

The distribution bus is the bus that is regulated by means of an upstream device (e.g. substation regulator or transformer equipped with an on load tap changer) within the point of delivery substation. The distribution bus voltage shall be maintained at 125 volts +/- 1.5 volts on a 120 volt base in order to meet the CSA Standard at the customer utilization point.

Refer to the following sections in the AESO's Reliability Criteria for specifics regarding voltage capacity assessments of the ATS:

- Section 4.5 "Point of Delivery (POD) Criteria" in Part II -Transmission System Planning Criteria
- Section 5.1 "Voltage Standards" in Part II-Transmission System Planning Criteria
    - Table 5.1-1 in the AESO's Reliability Criteria identifies the acceptable voltage ranges for normal and contingency conditions.
    - Table 5.1-2 in the AESO's Reliability Criteria identifies the acceptable voltage changes during and after contingency conditions.
- Section 5.6.2 "Voltage Limits" in Part III-Transmission Operating Criteria
    - Table 1 "Transmission Standards – Normal and Contingency Conditions" in Part III-Transmission Operating Criteria of the AESO's Reliability Criteria identifies the acceptable thermal limits during and after contingency conditions.
- Section 5.6.4 "Point of Delivery Limits" in Part III-Transmission Operating Criteria

2.2.2 *Thermal Assessment Criteria*

Generally, thermal loading on power delivery facilities shall be maintained within applicable limits for both normal and contingency conditions. The normal and contingency conditions are defined as:

- Normal Conditions: For planning purposes, no power delivery facility shall be loaded beyond its continuous rating.

- Contingency Conditions: Power delivery facilities can exceed their rated capability for a brief time period, until the power delivery system is restored back to its normal condition. This may require automatic (i.e. remedial action schemes) and/or manual intervention such as;
    - Switching system devices to alter loading (e.g. line breakers, line and/or substation switches):
    - The following measures may be required during real time operations:
        - Shedding load to ensure that the thermal rating of power delivery elements are not exceeded; and/or
        - Rotating outages to ensure that the thermal ratings of power delivery elements are not exceeded.

2.2.2.1 Distribution Power Delivery Systems

All elements will have normal, contingency and emergency thermal ratings as specified by the DFO's. The normal and contingency thermal ratings for elements may be the same or different. During normal, contingency and emergency conditions, elements shall not exceed their respective thermal ratings.

Table 2.2-2 identifies planning methodologies for thermal limits employed by each DFO. Planning in this manner provides operational flexibility and reduces the risk of exceeding equipment or facility limits due to unexpected occurrences (e.g. faster load growth, forecast uncertainties).

Table 2.2-2: Specific DFO Planning Methodology for Thermal Capability

DFO	Methodology
ATCO Electric Distribution	• Refer to Appendix II for details regarding ATCO's definition for an urban area. • Urban 25 kV Overhead Feeder o Normal Conditions: maximum loading of an urban 25 kV overhead feeder is 10 MVA. o Maximum contingency (25 kV alternate feed or Distribution Point-of-Delivery) loading is: ▪ 266 Conductor: 20 MVA ▪ 477 Conductor: 25 MVA • Urban 25 kV Underground Feeder

Distribution Point-of-Delivery Interconnection Process Guideline - Standards of Service

DFO	Methodology
	o Normal Conditions: maximum loading of an urban 25 kV underground feeder is 10 MVA. o Maximum contingency (25 kV alternate feed or Distribution Point-of-Delivery) loading is: ▪ 500 MCM Cable: 17 MVA • Rural 25 kV Overhead Feeder o The maximum loading is governed by: ▪ minimum line voltages under normal and contingency (25 kV alternate feed or T-POD) ▪ requirement to parallel feeders at the substation for 25 kV breaker maintenance, ▪ rating of line switches ▪ motor starting requirements ▪ occasionally U/G cable at the substation ▪ Typically, the maximum loading is much less than 25 MVA because of the preceding limitations. There may be exceptions on express feeders where loads approach 25 MVA.
EPCOR Distribution Inc.	EPCOR's thermal capabilities are based on the ratings of the substation exit cables (6 feeders in a ductline) with mutual heating. Ratings are derived using IEC 287 methods with temperature limits as recommended in CSA Standard 68.1 and AEIC CS5-87. **Normal (Design Loading):** • Traditionally EPCOR has rated cables based on 2/3 of their emergency ratings assuming outages would be relatively short-term (2 to 3 days max). This assumes the ability to split circuits and transfer ½ of the load to two adjacent circuits i.e. this approach assumes highly reliable transmission supplies that preclude long-term outages. Based on this approach the normal peak feeder design limits for standard 750 MCM Cu cables would be (winter/summer): o 15 kV cables: 370 A/340 A (9.2/8.5 MVA @ 14.4 kV)

<table>
<tr><th><u>DFO</u></th><th><u>Methodology</u></th></tr>
<tr><td></td><td>

In situations where:

transmission supplies cannot be counted upon to preclude long-term outages; or
in the case of 25 kV where there are very limited ties and/or too many customers (> 3,500) are at risk, cable loading is limited to ½ normal. On this basis the normal peak feeder design limits for standard 750 MCM Cu cables would be (winter/summer):

15 kV cables: 222 A/190 A (5.5/4.7 MVA @ 14.4 kV)
25 kV cables: 232 A/195 A (10.4/8.8 MVA @ 26 kV)

<u>Emergency (Contingency) Loading</u>:

Short Term (2 to 3 days max. Winter/Summer):

15 kV cables: 560 A/515 A (13.9/12.8 MVA @ 14.4 kV)
25 kV cables: 535 A/470 A (24.1/21.1 MVA @ 26 kV)

Long Term (Continuous or >2 to 3 days max. Winter/Summer):

15 kV cables: 445 A/380 A (11.1/9.5 MVA @ 14.4 kV)
25 kV cables: 465 A/390 A (20.9/17.5 MVA @ 26 kV)

Note, EPCOR has a variety of older feeder cables, some smaller, that would have ratings determined on this same basis.

</td></tr>
<tr><td>ENMAX Distribution</td><td>

Maximum feeder loading under normal operation for both 13 kV and 25 kV feeders is limited to 300A using either 477 MCM overhead conductor or 750 MCM underground cable. (7.2 MVA at 13 kV and 13.5 MVA at 25 kV). This achieves a full feeder restoration within a 600 A maximum loading.
Facilities are planned to function within normal operational rating however, on a temporary basis during contingency, may be allowed to operate at a higher level but still within the recommended manufacturers overload specification. In cases where there is a risk of overload during normal operation, corrective action is initiated.

</td></tr>
<tr><td>FortisAlberta</td><td>

Refer to Appendix II for details regarding FortisAlberta's definition for an urban area.
<u>Urban 25 kV Overhead Feeder</u>

Normal Conditions: maximum loading of an urban 25 kV overhead feeder using 477 MCM ACSR conductor as main-line conductor is 13 MVA. This provides capacity in the event that the entire load needs to be supplied from an adjacent feeder due to the loss of a feeder at the terminal or

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<table>
<tr><th><u>DFO</u></th><th><u>Methodology</u></th></tr>
<tr><td></td><td>25 kV breaker maintenance. The terminal facilities have a capacity of 26 MVA (600A). The overhead line facilities have a thermal capacity of:
477 MCM ACSR Conductor: 32 MVA
<u>Urban 25 kV Underground Feeder</u>
Normal Conditions: maximum loading of an urban 25 kV underground feeder is 10 MVA. This provides capacity in the event that the entire load needs to be supplied from an adjacent feeder due to the loss of the adjacent feeder. The terminal facilities have a capacity of 26 MVA .The underground line facilities which are the limiting components have a thermal capacity of:
500 MCM Cable: 17 MVA, 3 cables in one duct in air
500 MCM Cable: 21 MVA, 1 cable per duct in air
<u>Rural 25 kV Overhead Feeder</u>
Normal Conditions: maximum loading of a rural 25 kV overhead feeder is 13 MVA. Feeder is at its maximum loading when the measured load at the distribution delivery point (i.e. substation) is 50% of the feeder terminal capacity. This allows for the situation in which the combined load of two inter-connected feeders needs to be carried by one or the other for the loss of the terminal facility. The terminal facilities have a capacity of 26 MVA. The overhead line facilities have a thermal capacity of:
3/0 ACSR Conductor: 17 MVA
The maximum loading may also be governed by:
minimum line voltages under normal conditions,
rating of line switches</td></tr>
<tr><td>Lethbridge Distribution</td><td>Feeder loading under normal operation for 13.8 kV feeders is limited to 5 MVA using either 336.4 MCM ACSR or 500 MCM CU 15 kV underground cables. Maximum Feeder loading during emergency basis is limited to 10 MVA. This allows for full feeder restoration between substations on a long term basis. It also allows for some unplanned load growth in established areas.
Normally, feeders function within normal operational rating however, on a temporary basis during contingency, may be allowed to operate at a higher level but still within the recommended manufacturers overload specification.</td></tr>
</table>

DFO	Methodology
Red Deer Distribution	• Maximum feeder loading under normal operation is limited to 200A (8.7 MVA at 25 kV). Exceptions for single large loads are made. This 50% capacity loading enables the load to be supplied by an adjacent feeder.

2.2.2.2 Transmission Power Delivery Systems

This section is for TFO's only and is applicable to the transmission system. All elements will have normal, contingency and emergency thermal ratings as specified by the TFOs. The normal and contingency thermal ratings for elements may be the same or different. Generally, during normal, contingency and emergency conditions, elements shall not exceed their respective thermal ratings.

The specific requirements regarding the thermal capacity of the transmission power delivery system is provided in the AESO's Reliability Criteria. This Reliability Criteria is followed with respect to thermal capacity at point of delivery substations.

For planning purposes, no transmission facility shall be loaded beyond its continuous rating during normal conditions. Refer to the following sections in the AESO's Reliability Criteria[1] for specifics regarding thermal capacity assessments of the ATS:

- Section 5.6.1 "Thermal Limits" in Part III -Transmission Operating Criteria

[1] AESO Reliability Criteria – available at www.aeso.ca

3.0 Reliability Standards of Service

The expectation among electricity customers is that the power supply system provides reliable service at reasonable rates by making economic and efficient use of the power system infrastructure. Within the context of reasonable rates, electric service means that electrical supply is available when required and that there is minimal impact to the electricity customer's ability to operate (loss of goods, services or benefits). As a result, the power supply components are evaluated on their ability to provide reliable electricity. Reliability is comprised of adequacy and security, and is impacted by the ability of the supply to be restored in a timely manner, after a system contingency.

Even though the intention is to avoid power outages, it is not possible or economical to avoid all component or combination of component failures that result in the interruption of electrical service.

Assessing the reliability of the service to electrical customers requires the following information:

- amount of load supplied;
- number of customers supplied;
- type of customers served;
- reliability data for one or a combination of the relevant feeders; and
- reliability data for the relevant distribution delivery points (i.e. substations) and transmission line(s).

Further, the reliability data of the transmission and distribution power delivery system shall be based upon a five (5) year system average historical performance. It is an accepted utility practice to utilize past performance as an indicator of future performance.

3.1 Backup Requirements Assessment Criteria

In principle, the DFO's plan and design their distribution systems with the capability to backup electricity customers. There are many factors that affect the DFO's and TFO's ability to restore service to electricity customers during a contingency. Some projects may be recommended based upon the assessment of the following factors that affect the TFO's and/or DFO's ability to restore service in a timely manner:

- Number of customers affected;

- Density of load;
- Social/economic/environmental impacts;
- Time to repair; and
- Time to restore service, which can be affected by accessibility

Unsupplied Load (see definition) must be restored in both urban and rural systems. A balance between the time required to restore service and the cost of facilitating the restoration of service must be achieved. Service may not be restored to all customers simultaneously following an outage. The intent is to reduce to an acceptable level the number of customers who remain out of service due to an outage while other restoration measures are deployed or the repair work is undertaken. The term acceptable level is at the discretion of the DFO and/or TFO to determine in any situation, since a number of factors affect this, including but not limited to:

- Number of customers.
- Type of load (hospitals, residential, commercial, industrial).
- Outage duration.
- Repair of damaged facilities in a safe manner.

Plans are developed that include one or a combination of the following that may be used to restore service to electricity customers during planned or unplanned outages on the transmission and/or distribution power delivery system. In implementing these plans, the TFO and DFO are responsible to decide what measures are appropriate and what order these measures should be applied in any situation.

- Automatic transfer of load to an alternate transmission or distribution supply.
- Manually or remotely switching the distribution supply system to provide an alternate supply route. It is recognized that switching time maybe longer in a rural area compared to an urban area.
- Manually or remotely switching to provide electrical supply from adjacent POD stations.
- Manually or remotely switching within the POD station to transfer the electricity customer to an alternate transformer.
- Other non-switching activities as described below may be used to restore load. An economic evaluation should identify the most cost effective solution.

  - Use of a mobile substation.
  - Use of standby generation supplied by the DFO.
  - Use of standby generation or UPS supplied by the customer.

- Repair the damaged facilities.

- In real time operations, the following provide additional ways to address conditions where the thermal capacity of facilities are exceeded:
  - Partial restoration or rotating outages.
  - Public announcements for curtailment of load

Table 3.1-1 outlines the backup criteria for planning and designing the distribution supply system for rural and/or urban areas. The target restoration times in the table applies to DFOs and/or TFOs.

Table 3.1-1: TFO/DFO Back up and Restoration

Type of load	Possible means for backup (more than one may be used in any situation)	Target Restoration Time Standard (100% of load restored for recognized contingencies)					
		ATCO Electric Distribution	**EPCOR Distribution Inc.**	**ENMAX Distribution**	**Fortis Alberta**	**Lethbridge Distribution**	**Red Deer Distribution**
Urban Critical - Critical commercial or industrial operation, large downtown core, or public safety related load (hospitals)	▪ Onsite customer provided UPS with auto transfer from DFO ▪ DFO auto transfer ▪ TFO auto transfer ▪ Customer emergency generation	Automatic Transfer	Automatic Transfer	Automatic Transfer	Automatic Transfer	< 2 hrs (6)	Customer emergency generation. Less than or equal to 1 hr
Urban commercial load	▪ Auto transfer ▪ Remote switching ▪ Manual switching	less than or equal to 4 hours Note (1)	less than or equal to 1 hour	Immediate (with Distribution Automation) to <1 hour (if remote or manual switching)	less than or equal to 1 hour	<2 hrs (6)	Less than or equal to 2 hr
Urban residential load	▪ Auto transfer ▪ Remote switching ▪ Manual switching	less than or equal to 4 hours	less than or equal to 1 hour	Immediate (with Distribution Automation) to <1 hour (if remote or	less than or equal to 1 hours	< 2 hrs (6)	Less than or equal to 3 hr

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Type of load	Possible means for backup (more than one may be used in any situation)	Target Restoration Time Standard (100% of load restored for recognized contingencies)					
		ATCO Electric Distribution	EPCOR Distribution Inc.	ENMAX Distribution	Fortis Alberta	Lethbridge Distribution	Red Deer Distribution
				manual switching)			
Rural Critical commercial, industrial or agricultural load	▪ Onsite customer provided UPS with auto transfer from DFO ▪ DFO supplied auto transfer ▪ Manual switching ▪ Customer or DFO standby generation	Automatic Transfer ≤ 4 hours (if manually switching)	Note 4	Note 4	Automatic Transfer ≤ 4 hours (if manually switching)	Note 4	Note 4
Rural Load (Residential, Farm and Commercial)	▪ Remote switching ▪ Manual switching	less than or equal to 4 hours	Note 4	Note 4	less than or equal to 4 hours	Note 4	Note 4
Oilfield and Industrial	▪ Remote Switching ▪ Manual Switching ▪ Mobile Substation ▪ Customer Emergency Generators	Summer = less than or equal to 24 hours Winter = less than or equal to 4 hours for lights, heat trace and glycol pumps All Load = less than or equal to 24 hours	Note 4	Note 4	Summer = less than or equal to 24 hours Winter = less than or equal to 4 hours for lights, heat trace and glycol pumps	N/A	N/A for oilfield Industrial customer emergency generators Industrial less than or equal to 1 hr

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Type of load	Possible means for backup (more than one may be used in any situation)	Target Restoration Time Standard (100% of load restored for recognized contingencies)					
		ATCO Electric Distribution	EPCOR Distribution Inc.	ENMAX Distribution	Fortis Alberta	Lethbridge Distribution	Red Deer Distribution
		Note 5					
Remote rural load	▪ Remote switching ▪ Manual switching ▪ Customer Standby generation ▪ Mobile substation (Note 3) ▪ Partial restoration or rotating outages	less than or equal to 4 hours Note (2)	Note 4	Note 4	Note (2)	Note 4	Note 4

Notes:

1) Priority is given to restoring feeders that supply hospitals, institutions and commercial loads.

2) Outages beyond 4 hours are a concern due to freezing up the premise for residential, farm, commercial loads and oilfield and industrial. Restoration time of radial, across country transmission lines and single transformer PODs can be well beyond 4 hours due to the nature of the failure, time of day, accessibility and weather conditions. After 24 hours there is to be no unsupplied load.

3) The mobile substation can be considered as an acceptable method of restoring load in remote rural areas. In assessing if the mobile is an acceptable solution, recognition should be given to the probability of the event, the duration of the event, the consequences, size of load impacted by the event, number of customers, type of load, environmental consequences, location and economic evaluation of the cost of possible solutions to search for the most cost effective solution.

4) Is considered an urban utility and as such does not normally serve rural type load.

5) It may be impractical to manually switch off oilfield only on a feeder that supplies both residential, commercial, and farm as well as oilfield and achieve a restoration time of 4 hours, so in those instances oilfield also may be restored in 4 hours.

6) Time may vary during non-working hours (Lethbridge Distribution)

3.2 Distribution Feeder Reliability Indices

When recommending a system reinforcement project for reliability reasons, the AESO expects the DFOs to provide the following. In Alberta, two of the key feeder reliability indices commonly used by DFO's are SAIDI and SAIFI. SAIDI and SAIFI indices are defined in the definition section.

- A classification of interruptions as either momentary or sustained. Momentary and sustained are defined in the definitions section of this guideline.
- Provide a comparison of the feeder SAIDI and SAIFI (i.e. SAIFI-SI and SAIFI-MI) against the average SAIDI and SAIFI for momentary and sustained interruptions for that DFO's distribution system. The SAIDI and SAIFI indices for momentary and sustained are to be calculated using the standards established by Canadian Electric Association ("CEA").
- A description of the methodology used for tracking and calculating performance of the distribution power delivery system, where the DFO does not use the CEA method for reliability tracking and evaluation (i.e.. SAIDI, SAIFI).
- Additional information that supports the recommendation, that could include:
    - How often the feeder is out.
    - Substantiated customer complaints
- A description of improvements that were implemented to address the feeder performance through maintenance, modifications and/or other means. This should include the timing of such improvements, since sufficient time may or may not have elapsed to determine the impact on reliability of the improvements.

Table 3.2-1 summarizes specific methodologies used by DFO's to identify and recommend system reinforcement projects to address reliability concerns.

Table 3.2-1: DFO Methodologies for Feeder Reliability Concerns

DFO	Methodology
ATCO Electric Distribution	• Does not collect momentary outages for feeders at 25 kV and below. • Tabulates SAIFI, CAIDI and SAIDI for each 25 kV feeder, for each of our service areas and for the total 25 kV system for each year. SAIFI and CAIDI are compared to CEA average indices. • Does not differentiate urban and rural feeders and tabulate an annual number for each category. • Differentiates Planned and Unplanned outages. • Selects the 5% worst performing feeders and does a review to determine the cause of the sustained outages and restoration time.
EPCOR Distribution Inc	• Tracks the performance of all circuits on an on-going basis. Circuits that register 3 outage events in 30 consecutive days trigger an alert. • On a monthly basis the performance of all circuits and YTD system performance are reviewed, tabulated and compared to historical trends. This review includes customer complaints, system and equipment performance trends and maintenance practices. • Although EPCOR does not necessarily rank the circuit based on reliability indices (SAIDI/SAIFI etc.); these are considered in reviewing the numbers of outages (sustained & momentary) and the numbers of customer hours. Not all poorly performing circuits need long-range actions; some causes may be beyond EPCOR's control • All System or Circuit Problems considered "actionable" are assigned for a more thorough investigation; problem solving and ultimately correction actions are taken. If actions were not effective it is expected that the same circuits will again trigger alerts & further investigation/actions will result.
ENMAX Distribution	• Recommends system reinforcement projects based on analyses of worst performing feeders, which are identified through comparison of their relative SAIDI & SAIFI indices and number of operations on a 5 year rolling average. • This is consistent with the AEUB wire owner Service Quality and Reliability Performance Plan (SQRP). • Considers poor feeder performance as only one of the components which may drive the need for a specific system upgrade or addition.

DFO	**Methodology**
FortisAlberta	• Does collect momentary outages for feeders at 25 kV and below. • Presently tabulates SAIFI, CAIDI and SAIDI for each 25 kV feeder and for the total 25 kV system for each year. SAIFI and CAIDI are plotted by year against the CEA annual numbers for the period 2000 to present to see how FortisAlberta numbers are trending as well as checking to see how FortisAlberta numbers are trending relative to CEA averages. • Does differentiate urban and rural feeders and tabulates an annual number for each category. • Does differentiate Planned and Unplanned outages. • Selects the 5% worst performing feeders and does a review to determine the cause of the momentary and sustained outages and restoration time. FortisAlberta then develops work orders to spend capital to reduce the cause of the momentary and sustained outages, to reduce the number of customers impacted, and to reduce the length of time to find the fault.
Lethbridge Distribution	• Tracks all unplanned outages on an ongoing basis. • Does not rank circuits based on reliability indices (SAIDI/SAIFI) but considers these in system reporting. • Circuit outages with an undetermined cause are patrolled for an obvious visible cause and for public safety. 2 outages within 6 months per circuit are inspected in more detail. • Currently evaluating Distribution Automation. Circuits will be evaluated to set criteria.
Red Deer Distribution	• Does not collect momentary outages for feeders. • Tabulates SAIFI, CAIDI and SAIDI for the total service area but not for individual feeders. SAIFI and CAIDI are compared to CEA average indices. • Conducts a review to determine the cause of sustained outages and restoration time. • Poor feeder performance is only one of the components considered when evaluating the need for a specific system upgrade or addition.

3.3 Distribution Delivery Point Substation Reliability

The delivery point substation is the interconnection point between the transmission and distribution power delivery systems. The reliability of the delivery point substation will impact the reliability of all distribution feeders emanating from the substation.

In Alberta, three of the key reliability indices commonly used for point of delivery substations are SAIDI, SAIFI-MI (momentary) and SAIFI-SI (sustained). Each one is broken down by voltage class and computed separately for both single-circuit and multi-circuit supplied point of delivery substations. When recommending a system reinforcement project for reliability reasons, the AESO expects the TFO's and/or DFO's to provide the following for point of delivery substations.

- A classification of interruptions as either momentary or sustained. Momentary and sustained are defined in the definitions section of this guideline.
- TFO's to provide to the AESO, the SAIDI, SAIFI-MI and SAIFI-SI numbers based on the most recent five years of data for the point of delivery substations. The SAIDI, SAIFI-MI and SAIFI-SI shall be calculated using the standards established by the CEA. These reliability indices will include both transmission and point of delivery substations interruptions.
- A description of the methodology used for tracking and calculating performance of the point of delivery substations, where the TFO does not use the CEA method for reliability tracking and evaluation (i.e. SAIDI, SAIFI).
- Provide a comparison of the point of delivery substation SAIDI and SAIFI against the average SAIDI and SAIFI for that TFO and the overall Alberta system average for point of delivery substations. The overall Alberta system average for delivery point substations will be calculated by the AESO based upon the annual information provided by each TFO. The SAIDI and SAIFI indices are to be calculated using the standards established by CEA.
- Additional information that supports the recommendation, that could include:
    - How often the point of delivery substation is out of service.
    - Substantiated customer complaints

- A description of improvements that were done to address the point of delivery substation performance through maintenance, modifications and/or other means. This should include the timing of such improvements, since sufficient time may or may not have elapsed to determine the impact on reliability of the improvements.

Table 3.3-1 summarizes specific methodologies used by TFO's to identify and recommend system reinforcement projects to address reliability concerns at point of delivery substations.

Table 3.3-1 TFO Methodologies for POD Substation Reliability

TFO	Methodology
AltaLink	• AltaLink compiles sustained and momentary outage data for delivery points SAIFI, SAIDI, SARI(Restoration), and POD SAIF and SAIDI are also calculated per year and trended over the past five years. Information is available for the Maintenance Planning group to use to develop maintenance programs and capital programs. • When a POD suffers from a sustained or momentary fault a root cause failure analysis is performed to identify concerns with equipment/environment. When a particular a class of equipment is identified as susceptible to a particular failure mode, then an evaluation of possible solutions is undertaken and a business case is prepared. Corrective action can range for equipment modification to requests for a station redesign.
ATCO Electric Transmission	• Compiles sustained and momentary outage data for delivery points. Points of delivery with >2 sustained faults per year and >4 sustained faults over the past five years are selected and put in the under performing table in the annual ATCO Electric Delivery Point Reliability Report. SAIFI, SAIDI, SARI(Restoration), SALI(Load), SAUEI(Unsupplied Energy Index), DPUI(Delivery Point Unreliability), and customer SAIF and SAIDI are also calculated per year and trended over the past five years. Information is available for the Maintenance Group and Planning to use to develop maintenance programs and capital programs. • Loss of a POD is a significant outage and unacceptable outage due to the magnitude and the impact of the outage. AE analyzes all sustained substation outages via an internal review committee that meets monthly to check that all systems performed as expected and whether corrective

TFO	Methodology
	action needs to be taken. Corrective action may be immediate or via a planned program to correct similar deficiencies at other PODs. The corrective action may lead to a request for a POD configuration change or transmission breaker addition. • ATCO Electric is measuring sag and swells for each POD 25 kV bus. Non zero voltage sag and swell deviations is a measure of the quality of the voltage supplied over a period of time. It is usually associated with power quality analysis however it is included here. Zero voltage sags which are a POD outage are also included with the records. Sag and swell Information has been collected over the past three years. The data collection is triggered by a 10% threshold for over or under voltage. The information collects sustained outages to the POD 25 kV bus as the voltage drops to zero volts as well as collecting sags during transmission and distribution faults on area lines. The frequency and depth of the sags is indicative of the area transmission system and distribution system, and available short circuit level.
EPCOR Transmission Inc	• Review the historical performance of the POD and comparison with similar PODs within EPCOR system. Considerations will include number of customer complaints, magnitude of customer load supplied and the sensitivity of load in addition to SAIDI and SAIFI statistics. • As a component of reliability analysis, EPCOR investigates the cause of failure of individual equipment and identifies “type faults”. Corrective measures including repair or replacement decisions are undertaken based on the severity of situations. • EPCOR Distribution PODs are designed to ensure no loss of customer load for periods greater than the normal restoration times
ENMAX Transmission	• The process ENMAX follows is: o Failures of equipment in service are investigated to determine the cause of failure. o Where a class of equipment is identified as susceptible to a particular failure mode, then an evaluation of possible solutions is undertaken. o This may result in a business case being advanced for

TFO	Methodology
	the replacement of the equipment after other factors such as age, environmental factors, and serviceability are taken into account. An example is the replacement of hook stick operated switches in our substation where the analysis showed that replacement was cheaper than continuing a shortened maintenance cycle. • All ENMAX Distribution Point of Delivery substations shall be planned and designed to ensure no loss of load due to transmission capacity limitations under normal operating conditions for a period greater than the switching transfer time required to restore service. • Restoration capability is assessed based on a combination of firm POD capacity remaining, adjacent POD capacity import through distribution feeder interconnections, and the prevailing SAIDI reliability target. The nature and timing of system expansion required to maintain the desired level of service restoration is determined on a site specific basis.
Lethbridge Transmission	• Information to Follow
Red Deer Transmission	• Failures of equipment are investigated to determine cause. • Identify if a particular class of equipment is susceptible. • Evaluate possible solutions to determine if replacement, design change or maintenance is best solution. • POD substations are designed to minimize the potential loss of entire load due to capacity limitations for a time greater than the required switching transfer time to restore service. • Restoration capability considers the POD capacity remaining and the capacity available from other PODs through distribution feeder interconnection.

3.4 Transmission Line and Cable Reliability

Transmission lines transport electricity from generators to and between the point of delivery substations. The reliability of the transmission lines and cables can impact the reliability of the point of delivery substations and distribution feeders emanating from the substation.

In Alberta, transmission line and cable reliability is calculated based upon CEA standards. When recommending a system reinforcement project for reliability reasons, the AESO expects the TFO's to provide the following for transmission lines and cables; in regards to this section, cable refers to a conductor that is buried and operating at a transmission voltage (i.e. 69 kV or above).

- A classification of outages as either momentary or sustained. Momentary and sustained are defined in the definitions section of this guideline.
- TFO's to provide to the AESO, the transmission line and cable indices based on the last five years of data for transmission lines.
- A description of the methodology for tracking and calculating performance of the transmission lines and cables, where the TFO doesn't use the CEA method for reliability tracking and evaluation of transmission lines.
- Provide a comparison of the transmission line and cable indices against the average indices for that TFO and the overall Alberta system average for transmission lines. The overall Alberta system average for transmission lines will be calculated by the AESO based upon the annual information provided by each TFO.
- A description of improvements that were done to address the transmission line or cable performance through maintenance, modifications and/or other means. This should include the timing of such improvements, since sufficient time may or may not have elapsed to determine the impact on reliability of the improvements.

Table 3.4-1 summarizes specific methodologies used by TFO's to identify and recommend system reinforcement projects to address reliability concerns for transmission lines and cables.

Table 3.4-1 TFO Methodologies for Transmission Lines and Cables

TFO	**Methodology**
AltaLink	• The performance of each transmission line is tracked for sustained and momentary outages, and duration on an annual basis as well as a five year rolling average. Indices for annual and a five year rolling average are also tabulated by voltage class. The performance of all transmission lines is

TFO	**Methodology**
	compared to AltaLink's average for the particular voltage class (69kV, 138 kV, 240 kV). Information is available for the Maintenance Planning group to use to develop maintenance programs and capital programs • When a line suffers from a sustained or momentary fault a root cause failure analysis is completed to identify concerns with equipment/lines. When a particular a class of equipment/line is identified as susceptible to a particular failure mode, then an evaluation of possible solutions is undertaken and a business case is prepared. Corrective action can range for equipment modification to requests for a line rebuild.
ATCO Electric Transmission	• The performance of each transmission line is tracked for sustained and momentary outages, and duration on an annual basis as well as a five year rolling average. Indices for annual and a five year rolling average are also tabulated by voltage class. The performance of deficient transmission lines is compared to ATCO Electric average for the particular voltage class as well as to the 144 kV class which is the most common regional and POD supply voltage. • ATCO Electric has been collecting data for sags and swells for each POD for three years. For a POD supplied by more than one transmission supply and with the assumption that N-1 transmission voltages are acceptable, the impact of a poor performing transmission line is the voltage sag during a line fault. Sags and swell is often incorporated as power quality. • ATCO Electric will include the cost of the option of bringing poor performing lines up to an acceptable level of performance.

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TFO	Methodology
EPCOR Transmission Inc	• EPCOR Transmission Inc. utilizes CEA Methodologies to record transmission reliability statistics. Transmission element outage data and POD outage data is compiled and summarized on a yearly basis. Multiple year data summaries are used to calculate historical performance indices. The analysis does not include distribution related outages. • EPCOR performs root cause analysis for failures and identifies solutions • Results of system inspection and testing are used to evaluate the risk and consequences of failure and corrective actions are recommended.
ENMAX Transmission	• The process ENMAX follows is: o Failures of equipment in service are investigated to determine the cause of failure. o Where a class of equipment is identified as susceptible to a particular failure mode, then an evaluation of possible solutions is undertaken. This may result in a business case being advanced for the replacement of the equipment after other factors such as age, service environment, and serviceability are taken into account. One example is the replacement of fiberglass arms on our transmission structures which degrade due to the ultraviolet radiation. The arms lose their insulating capability and fail in service. This failure process is accelerated by the high contamination levels produced by the mixture of sand and salt used on urban streets, especially when coupled with weather conditions. • All ENMAX Distribution Point of Delivery substations shall be planned and designed to ensure no loss of load due to transmission capacity limitations under normal operating conditions for a period greater than the switching transfer time required to restore service • Restoration capability is assessed based on a combination of firm POD capacity remaining, adjacent POD capacity import through distribution feeder interconnections, and the prevailing SAIDI

TFO	Methodology
	reliability target. The nature and timing of system expansion required to maintain the desired level of service restoration is determined on a site specific basis.
Lethbridge Transmission	• Information to Follow

4.0 Power Quality

Power quality is simply defined as the severity of voltage and frequency deviations supplied to the electric customer. If there are sufficient deviations in voltage and frequency of the power supplied to electricity customers, it can affect the safe and reliable operation of the electricity customer's facility.

There are many factors such as the following that can affect the power quality to the electricity customer:

- Sensitivity of the electricity customers' equipment that varies from one manufacturer to another.
- How the electricity power customers' facility was designed and constructed.
- The type of distribution feeder the electricity customer is connected to.

The following categories relate to specific power quality areas that each DFO must manage in supplying its customers. The following is only a brief summary and specific questions should be directed to the DFO. Further, if these standards aren't met, investigation would be initiated by DFO which may ultimately lead to a transmission solution.

4.1 Voltage

Voltage is a relatively broad term area of concern with respect to the area of power quality and may include the following considerations:

- Transients: voltage spikes can be caused by lightning strikes, capacitor switching and switching on the transmission or distribution power delivery system.
- Swells: voltage swells can be caused by switching or circuit to circuit faults on the transmission or distribution systems.
- Sags: voltage sags can be caused by power system faults, customer motor starting, or switching on the transmission or distribution system.
- Flicker
- Voltage Variation
- Interruptions

- Voltage Imbalance
- Waveform Distortion
- Frequency

Table 4.1-1 is summary of the standards that each DFO applies to their distribution system with respect to the quality of voltage provided to electric power consumers.

Table 4.1-1: DFO Standards for Voltage Quality

DFO	Standards
ATCO Electric Distribution	Voltage Flicker: CAN/CSA –C61000-3-7:04 Electromagnetic Compatibility(EMC) – Part 3: Limits-Section 7: Assessment of emission limits for fluctuating loads in MV and HV power systems – Basic EMC publication ATCO Electric Distribution System Standard for the Installation of New Load Voltage sag(dip) threshold: <90% nominal at Point of Common Coupling Voltage swell threshold: >110% nominal at Point of Common Coupling Voltage Unbalance limit: 2% (95% CPF) at Point of Common Coupling
EPCOR Distribution Inc	• As per CSA CAN3-C235-83 • Voltage imbalance limited to 3 %
ENMAX Distribution	• As per CSA voltage standard CAN3-C235-83 • Voltage imbalance limited to 4%
FortisAlberta	• As per CSA CAN3-C235-83 • Voltage imbalance limited to 3 %
Lethbridge Distribution	• As per CSA CAN3-C235-83 • Voltage imbalance limited to 3 %

DFO	Standards
Red Deer Distribution	• As per CSA voltage standard CAN3-C235-83 • Voltage imbalance limited to 4%

4.2 Harmonics

Harmonics is defined as the steady state distortion of the fundamental frequency (60 Hz). Current distortion occurs when sinusoidal voltage is applied to a non-linear load (i.e. electronic light ballast, PLC, adjustable-speed drive, arc furnace, any ac/dc converter). On the other hand, voltage distortion is indirectly the result of harmonic currents flowing through a distribution system.

Table 4.2-1 is summary of the standards that each DFO applies to their distribution system with respect to the harmonics on the distribution power delivery system.

Table 4.2-1: DFO Standards for Harmonics

DFO	Standards
ATCO Electric Distribution	CAN/CSA – C61000-3-6:04 Electromagnetic compatibility (EMC)- Part 3: Limits –Section 6:Assessment of emission limits for distorting loads in MV and HV power systems – Basic EMC publication CAN/CSA – CEI/IEC 61000-2-4:04 Electromagnetic Compatibility (EMC) – Part 2-4: Environment – Compatibility levels in industrial plants for low frequency conducted disturbances ATCO Electric – Distribution System Standard for the Installation of New Loads IEEE Std. 519-1992 – IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems CAN/CSA – C61000-3-6:04 Electromagnetic compatibility (EMC)- Part 3: Limits –Section 6:Assessment of emission limits for distorting loads in MV and HV power systems – Basic EMC publication
EPCOR Distribution Inc	• IEEE Standard 519 and Guide 519A
ENMAX Distribution	• IEEE Standard 519

DFO	Standards
FortisAlberta	• IEEE Standard 519
Lethbridge Distribution	• IEEE 519 Standard
Red Deer Distribution	• IEEE Standard 519-1992

4.3 Fluctuations/Flicker

Typically within Alberta voltage flicker is related to the voltage fluctuations/flicker as a result of starting motors connected to the distribution power delivery system. The fluctuations/flicker depends upon:

- The type of motor starting used by the electric power customer
- Size of motor
- Type of feeder that the electric power customer is interconnected to.
- Available short circuit current

Table 4.3-1 is summary of the standards that each DFO applies to their distribution system with respect to the allowable voltage fluctuations/flicker.

Table 4.3-1: DFO Standards for Fluctuations/Flicker

DFO	Standards
ATCO Electric Distribution	• During the planning phase of a new motor addition, AE applies a table with the most common application being starts ≤ two times per week. • Max Flicker for ≤ two times per week -25 KV regulated bus = 5% -Urban = 5% -Rural = 8 - 10% -Oilfield = 10 – 12 % -Industrial = 10 -12 % • ATCO Electric will allow the upper limit for flicker during motor starts to approach 10 and 12 % for rural, and oilfield and industrial customers, respectively where there are few customers and long

DFO	**Standards**
	25 kV lines. • AE has a further table with more stringent flicker requirements for more frequent starts. • When an area concern is raised, AE will install recording instruments and apply the following: o Cannot lead to voltage sags or swells outside Swell and Sag thresholds (see Table 4.1-1 above) o Cannot violate normal voltage limits: -8.3/+4.2% of nominal per CSA CAN3 C235-83 at the PCC (Point of Common Coupling) as extended per the CEA Power Quality Protocol 220 D 711 o Cannot lead to Voltage flicker (luminance changes in lighting systems) at the PCC exceeding Pst = 0.9 o Cannot lead to a voltage sag at the transmission substation exceeding 5%
EPCOR Distribution Inc	• IEEE Standard 519 Flicker Curve • Maximum 5% allowable. Measurable on primary of single customer transformer and on secondary of multiple customer transformer
ENMAX Distribution	ENMAX's "Power Quality Specifications and Guidelines for Customers" includes: o In house flicker curve with values dependent on frequency of occurrence. o Maximum 4% allowable. Measurable on primary of single customer transformer and on secondary of multiple customer transformer.
FortisAlberta	• In house flicker curve with values dependent on frequency of occurrence. The same curve as the AESO uses. • Maximum 5% allowable. Measurable on primary of customer transformer.

DFO	Standards
Lethbridge Distribution	• In house flicker curve with values dependent on frequency of occurrence. • Maximum 4% allowable. Measurable on primary of a dedicated customer transformer and on secondary of shared customer transformer.
Red Deer Distribution	• IEEE Standard 519 Flicker Curve • IEEE Standard 1159-1995 • Maximum 4% allowable. Measurable on primary of customer transformer.

4.4 Other Power Quality Standards

The standards for point of delivery substations are currently in development as part of the Interconnection Standards Upgrade.

5.0 Definitions

The following definitions are the basis for the terms used in this document unless otherwise defined herein. The application of these definitions is intended solely for the purpose of this guideline and is not necessarily intended to represent the definitions used by the AESO in other documents.

"Momentary Outage" means interruptions less than one minute in duration

"Sustained Outage" means interruptions one minute or more in duration

"System Average Interruption Duration Index (SAIDI)" is defined as the system average interruption duration for customers served per year.

- The formula to calculate SAIDI for distribution systems is:

$$\text{SAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

- The formula to calculate SAIDI for point of delivery substations is:

$$\text{SAIDI} = \frac{\text{Total Duration of all Delivery Point Interruptions in Minutes}}{\text{Total no. of Delivery Points monitored}}$$

"System Average Interruption Frequency Index (SAIFI)" is defined as the system average number of interruptions per customer served per year.

- The formula to calculate SAIFI for distribution systems is:

$$\text{SAIFI} = \frac{\text{Total Customer-Interruptions}}{\text{Total Customers Served}}$$

- The formula to calculate SAIFI for point of delivery substations is:

$$\text{SAIFI} = \frac{\text{Total no. of Delivery Point Interruptions}}{\text{Total no. of Delivery Points monitored}}$$

"Unsupplied Load" means the load not served after any automatic or manual switching operations have been carried out after the occurrence of a first contingency.

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Reference: **Exhibit 20407-X0048, Appendix B-4, page 11, Table 3.2-1; Exhibit 20407-X0112, Appendix A-4, page 17, Table 3.2-1**

Issue/sub-issue: **New 15 kV and 25 kV circuit additions**

Preamble: In 2014 and 2015, EDTI forecast to complete two and three circuit additions, respectively. In 2016 and 2017, EDTI is forecasting to complete four circuit additions each year.

Request:

Outside of the circuit additions required to connect new service sites, how does EDTI forecast circuit additions to complete in a particular year?

Response:

EDTI forecasts the circuit additions to complete in any given year through a review of the peak loads on all circuits on its system for the current year and the forecasted future years' peak loads. The forecasted future years' peak loads are developed using information including circuit historical growth rates, City of Edmonton's growth projections and information respecting new residential and industrial developments, vacant land available for growth and any specific known new customer loads.

Circuit additions are identified by determining which existing circuits are currently overloaded or are forecast to be overloaded (based on the addition of the forecasted future years' peak loads described above). If sufficient load cannot be transferred to adjacent circuits, it is necessary to install a new circuit to transfer the load and alleviate the overload. Additionally, peak loads on adjacent circuits are reviewed to determine if those circuits have sufficient capacity for load to be transferred in the event of an outage of any single circuit. If the adjacent circuits do not have sufficient capacity for load transfer capability, then a new circuit will be installed for contingency purposes.

A circuit is considered to be overloaded if:

- It is loaded above its normal peak load rating under normal operation. Normal operation means that the circuit is not supplying any additional load from other circuits.
- It is loaded above its emergency peak load rating under emergency conditions. Emergency condition means that the circuit is supplying additional load from other circuits.

EDTI calculates the normal and emergency peak load ratings for each circuit based on the manufacturer's specifications.

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Reference: **Exhibit No. 80, Application, Section 3.1.4, pages 76-79; Exhibit No. 21, Appendix A-4**

Issue/sub-issue: **New 15-kilovolt (kV) and 25-kV circuit additions**

Quote: At paragraph 4 of Appendix A-4 EDTI noted:

"New circuits are only installed when it is no longer possible or practical to transfer load among existing circuits within a local area to maintain circuit loads within their design limits. The need for a new circuit is fairly predictable."

At paragraph 24 of Appendix A-4, EDTI stated:

"EDTI expects that it will be required to load its 11SU, 21SU and 22SU circuits to 19.59 MVA [megavolt-ampere], 12.43 MVA, and 15.68 MVA respectively, by 2014 due to load growth in the southwest 25 kV area, if an additional circuit or circuits are not added to its distribution system. These amounts are above the design load (12 MVA) for all three circuits. The proposed 25 kV circuit will allow EDTI to reduce the load on its 11SU, 21SU and 22SU circuits below their design loads."

At paragraph 25, page 6 of Appendix A-4, EDTI provided the following table:

Table 2.2-1 Historical and Forecast Peak Loads on 11SU and 21SU Circuits (MVA)

		A **2010 A**	B **2011 A**	C **2012 A**	D **2013 F**	E **2014 F**	F **2015 F**	G **2016 F**	H **2017 F**
1	Design load for Summerside Circuits	12	12	12	12	12	12	12	12
2	11SU Circuit Peak Loads	20.41	17.73	18.08	18.84	19.59	20.35	21.10	21.86
3	21SU Circuit Peak Loads	9.08	11.25	11.47	11.95	12.43	12.91	13.39	13.87
4	22SU Circuit Peak Loads	-	-	14.47	15.07	15.68	16.28	16.89	17.49

At paragraph 77, page 19 of Appendix A-4, EDTI provided the following table:

Table 6.0-1 New 15 kV and 25 kV Circuit Additions 2008–2015 ($ millions)

		A 2008 D	B 2008 A	C 2009 D	D 2009 A	E 2010 D	F 2010 A	G 2011 D	H 2011 A	I 2012 D	J 2012 A	K 2013 D	L 2013 PA	M 2014 F	N 2015 F
1	Capital Additions	1.48	4.11	0.00	1.50	3.15	0.30	3.36	4.39	2.45	2.69	4.61	1.52	4.46	8.43
2	Variance		2.63		1.50		(2.85)		1.03		0.25		(3.09)	2.94	3.97

At paragraph 83 of Appendix A-4, EDTI provided following explanation for the $3.09 million decrease from 2013 Decision to 2013 preliminary actual:

“A $3.01 million decrease related to the 13SU circuit addition project reflecting a delay in the commencement of this project. In 2013, EDTI expected to install two new cubicles, replace an existing cubicle and direct bury 6.3 km of 500 MCM aluminum XLPE cable. However, EDTI was only able to install one new cubicle and direct bury approximately 1.0 km of 500 MCM aluminum XLPE cable. As explained above, EDTI intends to complete this project in 2014.”

Request:

a) Please elaborate on EDTI’s statement that “The need for a new circuit is fairly predictable:”

(i) How can this statement be reconciled with EDTI’s history of significant differences between decision and actual amounts as shown on the Table 6.0-1 above?

(ii) How does EDTI predict the number of new circuit additions in a given year?

(iii) Please justify the reasonableness of the 2014 and 2015 circuit additions forecast given the historical differences between the forecast and actual results?

b) Based on the Table 2.2-1 above, the loads of circuits 11SU and 22SU have been above the design load of 12 MVA since the year they have been installed (11SU in 2010 and 22SU in 2012), please explain for how long and what maximum load a circuit can sustain above the design load, without jeopardising the safety and reliability of the system?

c) Please elaborate on the following: "In 2013, EDTI expected to install two new cubicles, replace an existing cubicle and direct bury 6.3 km of 500 MCM aluminum XLPE cable. However, EDTI was only able to install one new cubicle and direct bury approximately 1.0 km of 500 MCM aluminum XLPE cable." Why was EDTI not able to complete the work?

d) Was there any impact on the company's ability to maintain safe and reliable service resulting from the inability to complete the forecasted work for 2013?

e) Compared with 2013, EDTI is forecasting a similar amount of capital additions for 2014, and almost double the amount of capital additions for 2015. Please explain how EDTI will be able to complete the scheduled amount of work in 2014 and 2015, given that it was unable to complete approximately two-thirds of the work scheduled for 2013 as shown in Table 6.0-1?

f) Please augment Table 3.2-1 provided in paragraph 42 of Appendix A-4 with the number of units to be added for this project in each of 2014 and 2015 and calculate per unit costs. Please explain any significant differences in per-unit costs.

g) Please provide a revised version of Table 2.2-2 of Appendix A-4, showing the actual historical annual peak loads in each of 2010 through 2013 as well as forecast annual peak loads in each of 2014 through 2017, if the proposed 23U circuit is installed.

Response:

a) i) The statement, "The need for a new circuit is fairly predictable" was intended to mean that by monitoring the peak loads of its circuits EDTI can generally anticipate when a new circuit will be required due to an increased demand for power.

EDTI has not delayed the installation of a new circuit due to forecast loads not materializing as expected. Therefore, it is not possible to reconcile this statement to historical Decision versus Actual capital additions variances related to this project.

ii) EDTI determines the number of new circuits required each year by primarily using the following two approaches:

1. EDTI reviews the summer and winter peak loads on all circuits to determine which circuits overloaded. If the load cannot be transferred to adjacent circuits then EDTI will install a new circuit and transfer the load to this new circuit to alleviate the overload. Additionally, peak loads on adjacent circuits are reviewed to determine if the circuits have sufficient capacity for load to be transferred in the event of an outage of any single circuit. If the adjacent circuits do not have sufficient capacity for load transfer capability, then a new circuit will be installed for contingency purposes.
2. When one or more new customers with significant load requirements request a service supply in an area where no circuits exist or where existing circuits would become overloaded, a new circuit will be installed to supply the customer.

A circuit is considered to be overloaded if:

- It is loaded above its normal peak load rating under normal operation. Normal operation means that the circuit is not supplying any additional load from other circuits.
- It is loaded above its emergency peak load rating under emergency conditions. Emergency conditions means that the circuit is supplying additional load from other circuits.

EDTI calculated the normal and emergency peak load ratings for each circuit based on the manufacture's specifications.

iii) As shown in Table 6.0-1 of Appendix A-4 the only years in which the Actual was less than the Forecast capital additions were in 2010 and 2013, and the primary reason for the variance in 2013 was due to uncertainties surrounding the I-X mechanism. EDTI delayed completing the 13SU project due to uncertainties surrounding the I-X mechanism. EDTI notes that its 2014 and 2015 circuit additions are on schedule and still expected to be completed as shown in Table 3.1-1 in Appendix A-4 of the Application.

b) Design load is the maximum load that EDTI plans to operate a circuit under normal operating conditions. This provides the circuit with some reserve capacity to pick up load from other circuits in outage contingency situations without overloading the circuit. EDTI's design load for 25 kV circuits is 12 MVA. Circuits can operate at loads between their design load and their normal peak load rating indefinitely without causing damage to the circuit. However, operating above the design load increases the risk of the circuit being loaded above its emergency peak load rating under emergency conditions.

Normal peak load rating is the maximum continuous load a circuit can be operated at without reducing its service life. The normal peak load ratings for all 25 kV circuits, based upon EDTI's standard 750 MCM Cu cable in substation exit ductlines, are 17.5 MVA in summer and 21 MVA in winter. Circuits can sustain these loads for as much as 8 hours every day assuming the average load throughout the day is approximately 75% of the peak ratings or less and this is called the normal peak load threshold. If the loads of a circuit go above this threshold, the circuit will experience increased thermal degradation which will increase the risk of the circuit failing which jeopardizes the safety and reliability of EDTI's distribution system.

Emergency peak load rating is the maximum load that EDTI plans to operate the circuit under an outage situation when load is transferred from another adjacent circuit that has experienced an outage. The emergency rating is based upon the assumption that the maximum number of emergency periods will not exceed 3 periods in any 12 months nor an average of 1 period per year for the life of the cable. The maximum duration of any one period should not exceed 36 hours. EDTI's emergency rating for 25 kV circuits is 21 MVA in summer and 24 MVA in winter. If the loads of a circuit go above the emergency peak load rating, the circuit will experience increased thermal degradation which will increase the risk of the circuit failing, which jeopardizes the safety and reliability of EDTI's distribution system.

In 2013 EDTI was very close to the normal peak load threshold on its 11SU circuit and expects to exceed this threshold in 2014 if 13SU is not installed in 2014 as planned.

Also, if 23SU is not installed in 2015, it is expected that all of the circuits that feed the southwest area of Edmonton will be above their design loads. If this occurs, it is expected that if one of these circuits fails, EDTI will be required to overload the remaining circuits above their emergency peak load ratings.

c) In light of the uncertainty surrounding the Capital Tracker mechanism in 2013, EDTI made the decision to postpone starting this project for a short period of time pending the Commission providing clarification and greater certainty through its Decision in the 2013 Capital Tracker proceeding. Specifically, EDTI determined that this project could be delayed for a short period without significantly increasing the risk of adverse effects on its ability to maintain safe and reliable service in the area.

d) The first stage of the 13SU new circuit project that was planned for 2013 was to provide additional backup support to the 22SU circuit in the case of any outages. The 22SU circuit did not experience any outages in 2013 that could have been alleviated by this first stage of 13SU circuit. Therefore, there was no impact on the company's ability to maintain safe and reliable service.

e) Consistent with its usual practice, EDTI undertook a detailed exercise of budgeting work based on a thorough bottom up review of all work planned for 2014 and 2015 (i.e., all distribution function operating, maintenance, repair and capital planned projects including EDTI's proposed Capital Tracker projects and all the planned work funded under the PBR I-X formula). Included as part of EDTI's bottom-up budgeting process is the detailed exercise of budgeting work based on hours of work required for each class of field worker.

As described in paragraph 28 in the Application:

> 28. EDTI's 2014 and 2015 capital forecast went through an extensive internal multi-iteration review process which included in-depth reviews of each functional area. The forecasts were first completed in the spring of 2013, and were subsequently reviewed and updated as necessary, most recently in early 2014 during the preparation of this Application. The latter review included consideration of 2013 Capital Tracker work that was not completed due to the uncertainty surrounding the Capital Tracker mechanism during 2013 (as discussed in more detail in section 2.2 above), and the incorporation of the completion of that work into EDTI's capital additions forecast for this Application.

This rigorous forecast review process ensured that EDTI has forecast sufficient resources (i.e., internal engineering and field labour resources and external contractors and consultants) in 2014 and 2015.

f) Table AUC-EDTI-11-1 shows the number of kilometres of new line, the capital additions and the capital additions per kilometre of line associated with each new circuit.

Table AUC-EDTI-11-1
Unit Cost of Each New Circuit

	Circuit	A **km of New Circuit**	B **Aerial/Underground Addition**	C **Cost/km ($ millions)**
1	13SU	2.0	Aerial Line	0.19
2	13SU	8.5	Underground Cable	0.45
3	23SU	5.0	Underground Cable	0.10
4	33PM	5.0	Aerial Line	0.25
5	33PM	9.0	Underground Cable	0.51
6	R19	2.5	Underground Cable	0.64
7	V25	0.8	Underground Cable	0.64

EDTI notes that the capital additions per kilometre of line associated with each new circuit will depend of whether the new circuit is underground or overhead, the topography of where the new circuit will be installed, whether it is installed in ducts or direct buried, and whether major road crossings are involved.

g) Table AUC-EDTI-11-2 below provides the requested version of Table 2.2-2.

Table AUC-EDTI-11-2
Historical and Forecast Peak Loads on 11SU, 21SU, 22SU, 13SU and 23SU Circuits (MVA)

		A **2010 A**	B **2011 A**	C **2012 A**	D **2013 A**	E **2014 F**	F **2015 F**	G **2016 F**	H **2017 F**
1	Design load for Summerside Circuits	12	12	12	12	12	12	12	12
2	11SU Circuit Peak Loads	20.41	17.73	18.08	17.8	12	12	12	12
3	21SU Circuit Peak Loads	9.08	11.25	11.47	9.0	12.43	8.0	8.5	9.0
4	22SU Circuit Peak Loads	-	-	14.47	19.2	12	12	12	12
5	13SU Circuit Peak Loads	-	-	-	-	11.27	8.0	8.5	9.0
6	23SU Circuit Peak Loads	-	-	-	-	-	9.54	10.38	11.22