Distribution Deficiency Report

No. 54 Substation
138/25 kV Transformer Addition

	Name	Signature	Date
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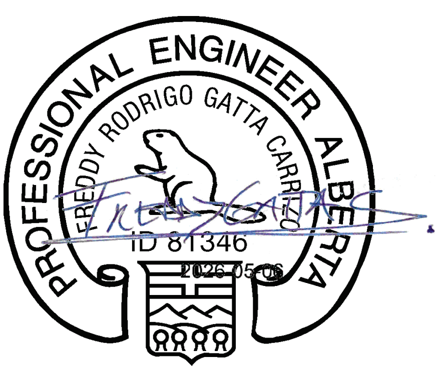

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RM SIGNATURE:

RM APEGA ID #: 97688

DATE: 2026-05-06

PERMIT NUMBER: P006756
The Association of Professional Engineers and Geoscientists of Alberta (APEGA)

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1.0 Executive Summary

ENMAX Power Corporation (EPC) is submitting a System Access Service Request (SASR) to the Alberta Electric System Operator (AESO). The SASR includes a request for a Demand Transmission Service (DTS) contract capacity increase at Substation No. 54, and transmission development.

The study area for this Distribution Deficiency Report (DDR) spans four [4] substations within the 25kV supply area, i.e., ENMAX No. 54 (54 Sub), No. 26 (26 Sub), No. 24 (24 Sub), and No. 37 (37 Sub) Substations. 54 Sub is a 138/25kV transformation source with a single 30/40/50MVA 138/25kV transformer. 26 Sub and 24 Sub both have two [2] 30/40/50MVA 138/25kV transformers. 37 Sub is equipped with two [2] 50 MVA 138/13kV transformers and one [1] 30/40/50MVA 138/25kV transformer to service 25kV load. The 25kV transformer was installed in December 2025 (Refer to approved Statement of Need ("SoN") document - No. 37 Substation 138-25kV Transformer Addition dated August 2018 ("original")).

The focus of this DDR is the need for a 138/25kV 50MVA transformer capacity addition within the 25kV supply area of the Southeast quadrant of the City of Calgary. This capacity addition is required to meet the load growth demands due to forecasted residential, commercial, and industrial developments within the study area while maintaining EPC's Distribution N-1 criteria.

Through system analysis the following deficiencies have been determined:

- The areas supplied by 24 Sub, 26 Sub and 54 Sub have Load at Risk[i] (LAR) in the event of transformer contingencies starting in summer 2023.
- 37 Sub is expected to have LAR in the event of transformer contingency starting in summer 2026.
- Four [4] distribution feeders supplied by 24 Sub and 26 Sub will have LAR in the event of feeder contingencies starting in summer 2027.
- Two [2] feeders supplied by 37 Sub will have LAR starting in summer 2030.
- 24 Sub, 26 Sub and 54 Sub are already in violation of EPC's Distribution System Performance Standard (see Sections 2.2 and 2.3), and 37 Sub will be in violation by 2025.

Multiple distribution and transmission alternatives were considered to address the identified deficiencies. EPC's preferred alternative is to install one [1] 30/40/50MVA 138/25kV transformer at 54 Sub along with associated 25kV infrastructure to accommodate four [4] new distribution feeders. The Distribution scope of work will include constructing three [3] new feeders (approximately 11.5km in total) to offload 26 Sub and support the growth centers within proximity to 54 Sub. Furthermore, approximately 10.9km of existing feeder extensions will be constructed to create new ties between 24 Sub and 37 Sub for reliability support. The estimated Transmission capital cost for the transformer addition is $26,000,000 (+20%/-10%),

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[i] Load at Risk is defined as customer load that cannot be returned to service within a timeframe of one manual switching operation during an N-1 contingency.

while the Distribution capital cost is estimated to be $30,800,000 (+20%/-10%). The expected total project cost is approximately $56,800,000 (+20%/-10%). Please note that the estimates presented include Administrative Overhead (AOH) and Interest During Construction (IDC).

This version of the Distribution Deficiency Report incorporates 2024 and 2025 actual system loads as well as revised development load forecasts across all tables. The transformation capacity addition is necessary to sustain normal operation and restoration capability for the 25kV load supplied from 54 Sub, 26 Sub, 24 Sub and 37 Sub. The capacity addition is also vital in supporting approximately 74MVA of forecasted load growth expected over the next 10 years within the study area. This load growth will drive a DTS contract capacity increase at 54 Sub from 20MW to 80MW. All cost estimates provided in this document account for inflation and include Administrative Overhead (AOH) and Interest During Construction (IDC).

The subsequent sections of this DDR highlight the capacity constraints within the study area and elaborate on the need for the additional 30/40/50 MVA 138/25kV transformer and 25kV distribution feeders at 54 Sub. Taking into consideration the timelines for the required approvals and construction, the required in-service date for this scope is August 1st 2028.

2.0 Distribution System Performance Standard

The EPC Distribution System Performance Standard (refer to Appendix E) outlines the reliability requirements for the EPC Distribution System. The applicable sections are as follows:

2.1 EPC 25 kV Service Area

All new distribution facilities within the ENMAX 25kV Boundary, as defined in the DSP - M.001[ii] map, will be planned and designed to 25kV standards.

2.2 Distribution Point of Delivery (POD) Substations

Distribution POD substations shall be planned, designed, and operated to ensure no loss of load due to substation capacity limitations during a substation transformer N-1 contingency for a period longer than the switching time required to restore service.

2.3 Three Phase Main Distribution System Feeders

Three phase main distribution system feeders[iii] shall be planned, designed, and operated to enable full mutual backup during a feeder N-1 contingency over peak loading conditions.

[ii] Refer to Appendix A for the 25kV Service Boundary map.
[iii] Feeder capacity is based upon equipment ratings. EPC's maximum feeder capacity at 25kV is 25.9MVA.

3.0 Description of the Study Area

3.1 Geographic Study Area

The geographic study area is shown in Figure 1. This area is located within the 25kV service boundary as specified in the EPC Distribution System Performance Standard (refer to Appendix A for the 25kV service boundary map). This Distribution Deficiency Report covers the service area supplied by 24 Sub, 26 Sub, 54 Sub & 37 Sub. The following industrial, commercial, and residential communities are located within this study area:

- Hotchkiss (Industrial)
- EMCOR (Industrial)
- Starfield (Industrial)
- East Hills (Commercial/Residential)
- Point Trotter (Commercial/Industrial)
- Maverick & Violin (Commercial)
- Barlow & Deerfoot Solar Parks (Commercial)
- Shepard (Industrial)
- Canfer Park (Commercial)
- Mahogany (Residential)
- Wolf Willow (Residential)
- Walden (Residential)
- Rangeview (Residential)
- Heather Glen (Industrial)
- McKenzie Towne (Residential)
- New Brighton (Residential
- Seton (Residential/Commercial)
- Belmont (Residential)
- Pine Creek (Residential)
- Pine View (Residential)
- Yorkville (Residential)
- Legacy (Residential)
- South Macleod (Residential)
- Thiessen (Residential)
- Auburn Bay (Residential)
- Copperfield (Residential)
- Chaparral (Residential)
- Logan Landing (Residential)

3.2 Current System Configuration

The 25kV distribution infrastructure (Figure 1) servicing the industrial, commercial, and residential loads within the study area is currently supplied by the following EPC substations:

No. 24 Substation (Figure 2) consisting of the following 25kV infrastructure:

- Two [2] 138/25kV 30/40/50MVA transformers (24.1TR and 24.2TR)
- Four [4] 25 kV distribution feeders connected to 24.1TR, supplying the following areas:
  - **25-24.111** – North McKenzie (Residential) and Barlow Solar Park (Industrial)
  - **25-24.112** – South Foothills (Industrial) and Barlow Solar Park (Commercial)

- 25-24.121 – Deerfoot Solar Park (Commercial), Shepard (Industrial), and New Brighton (Residential), Hotchkiss (Industrial)
- **25-24.122** – Maverick and Violin Amazon warehouses (Commercial)

- Four [4] 25kV distribution feeders connected to 24.2TR, supplying the following areas:
  - **25-24.113** – South Shepard (Industrial). Please note that this feeder will be fully offloaded in 2025 to serve as a backup for 25-24.122 and 25-37.111A
  - **25-24.114** – East Shepard Development (Industrial), Point Trotter (Commercial)
  - **25-24.123** – Deerfoot Solar Park (Commercial) and New Brighton (Residential)
  - **25-24.124** – Dedicated feeder for an existing Equinix data center (Commercial)

No. 26 Substation (Figure 3) consisting of the following 25kV infrastructure:

- Two [2] 138/25 kV 30/40/50MVA transformers (26.1TR and 26.2TR)
- Four [4] 25kV distribution feeders connected to 26.1TR, supplying the following areas:
  - **25-26.111** – McKenzie Towne and Inverness (Both Residential)
  - **25-26.112** – Seton (Commercial/Residential) and Rangeview (Residential)
  - **25-26.121** – Cranston, Chaparral, Wolf Willow and Walden (All Residential)
  - **25-26.122** – Dedicated feeder for the South Health Campus (Commercial)
- Four [4] 25kV distribution feeders connected to 26.2TR, supplying the following areas:
  - **25-26.113** – Copperfield and New Brighton (Both Residential)
  - **25-26.114** – Mahogany (Residential)
  - **25-26.123** – Auburn Bay (Residential)
  - **25-26.124** – Alternate feeder for the South Health Campus (Commercial)

No. 54 Substation (Figure 4) consisting of the following 25kV infrastructure:

- One [1] 138/25kV 30/40/50MVA transformer (54.1TR)

- Four [4] 25kV distribution feeders connected to 54.1TR, supplying the following areas:
    - **25-54.111** – Legacy, Pine Creek, Pine View, Yorkville Belmont, and Thiessen (All Residential). South Macleod (Commercial)
    - **25-54.112** – Spare feeder planned to service Seton Ridge (Residential) and Logan Landing (Residential)
    - **25-54.121** – Cranston (Residential)
    - **25-54.122** – Dedicated feeder for the South Health Campus (Commercial)

No. 37 Substation consisting of the following 25kV infrastructure:

- **Old configuration** (Figure 5): One [1] 13/25kV 10/13.3MVA autotransformer (37.4TR), decommissioned in December 2025.
    - One [1] 25kV distribution feeder (25-37.111) which supplied the industrial/commercial developments of EMCOR, Frontier, Canfer Park, East Hills, and the residential community of Belvedere.
- **New configuration** (Figure 6): One [1] 138/25kV 30/40/50MVA transformer (37.3TR), commissioned in December 2025 to replace 37.4TR autotransformer.
- Two [2] 25kV distribution feeders connected to 37.3TR, supplying the following areas:
    - **25-37.111A**– Starfield (Industrial), East Hills Village (Commercial/ Residential) and Belvedere (Residential)
    - **25-37.112** – Starfield, Heather Glen, EMCOR and Canfer Park (Industrial/Commercial)

Current System Configuration

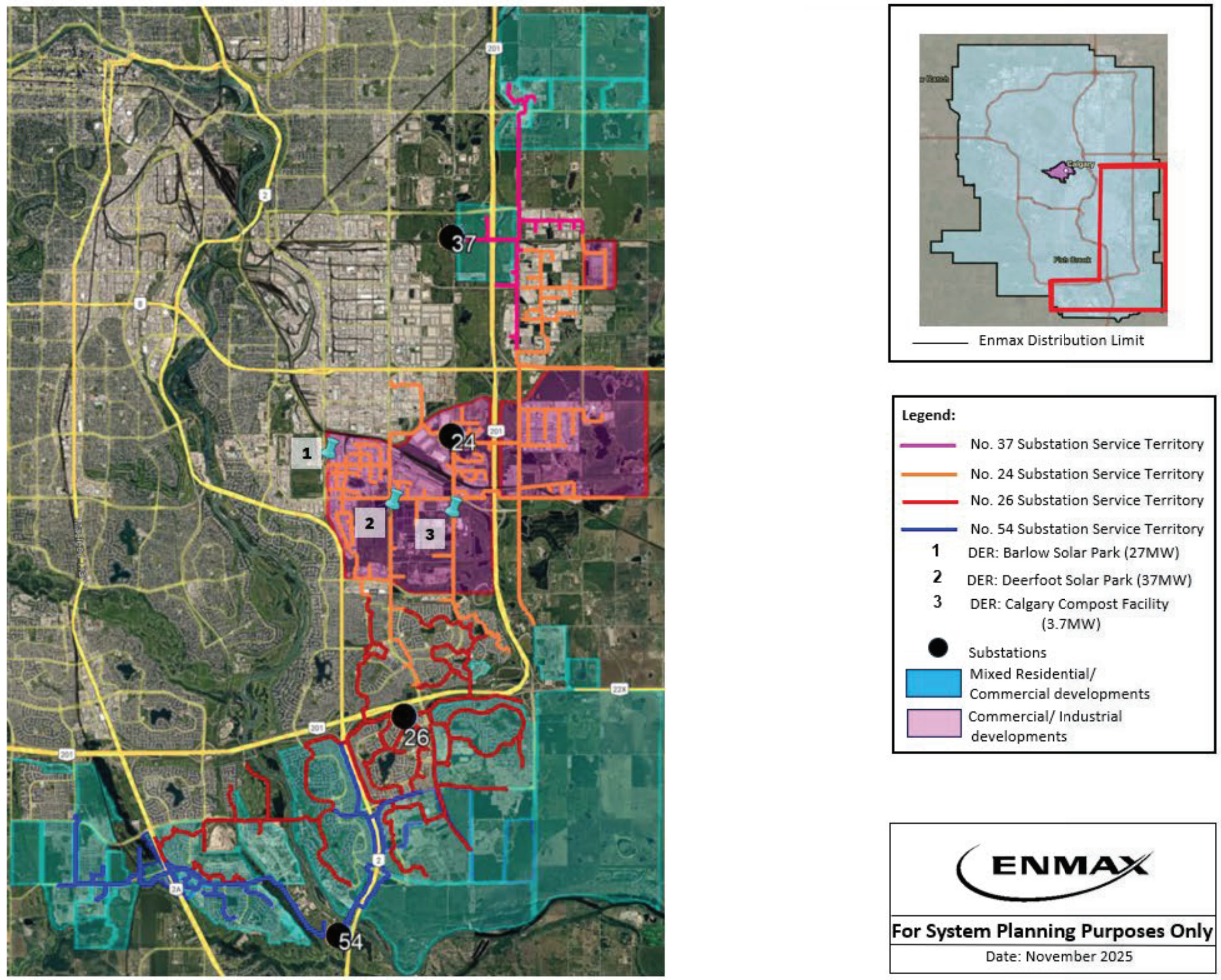

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Figure 1 Current System Configuration

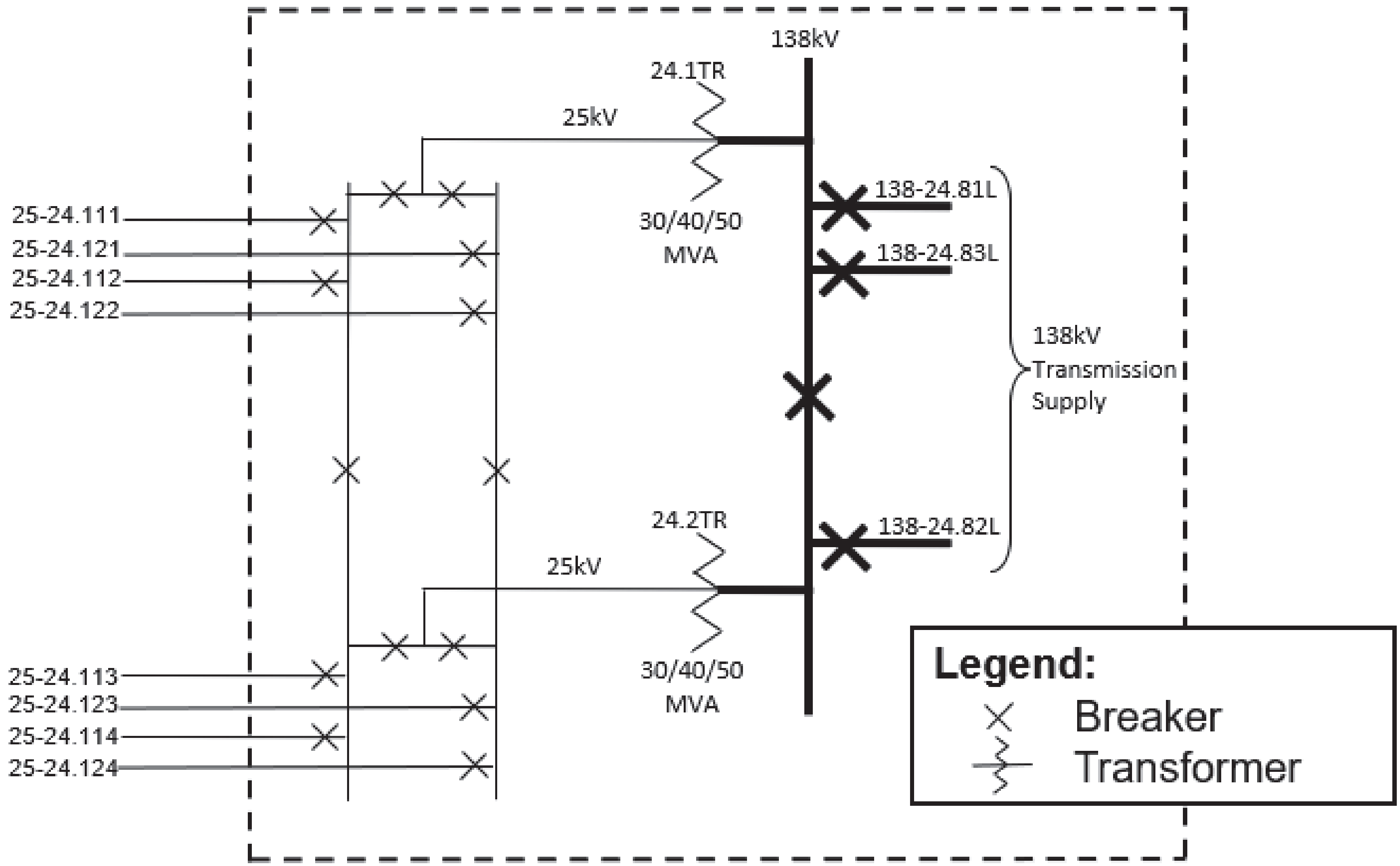


Figure 2: Existing No. 24 Substation Configuration

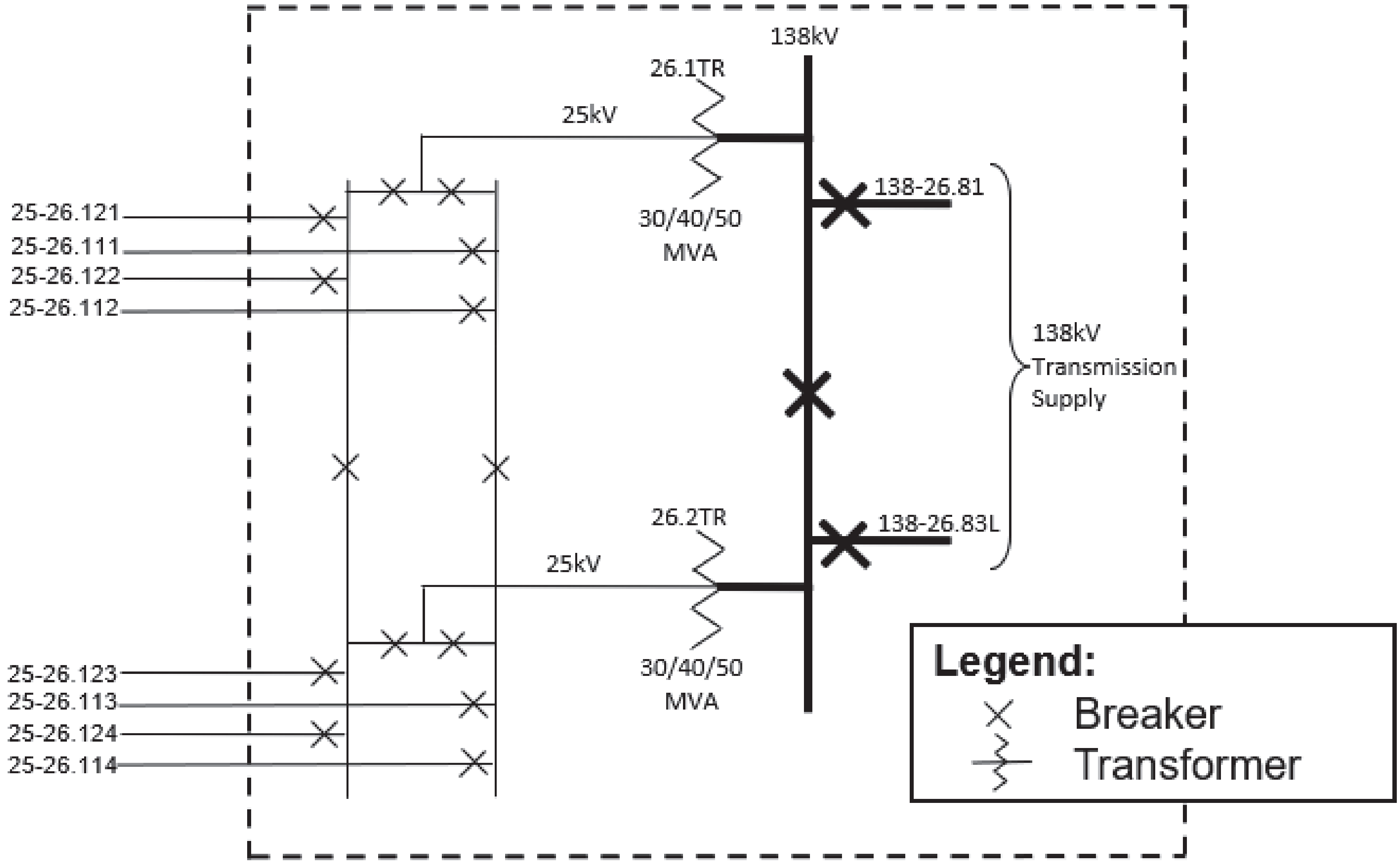


Figure 3: Existing No. 26 Substation Configuration

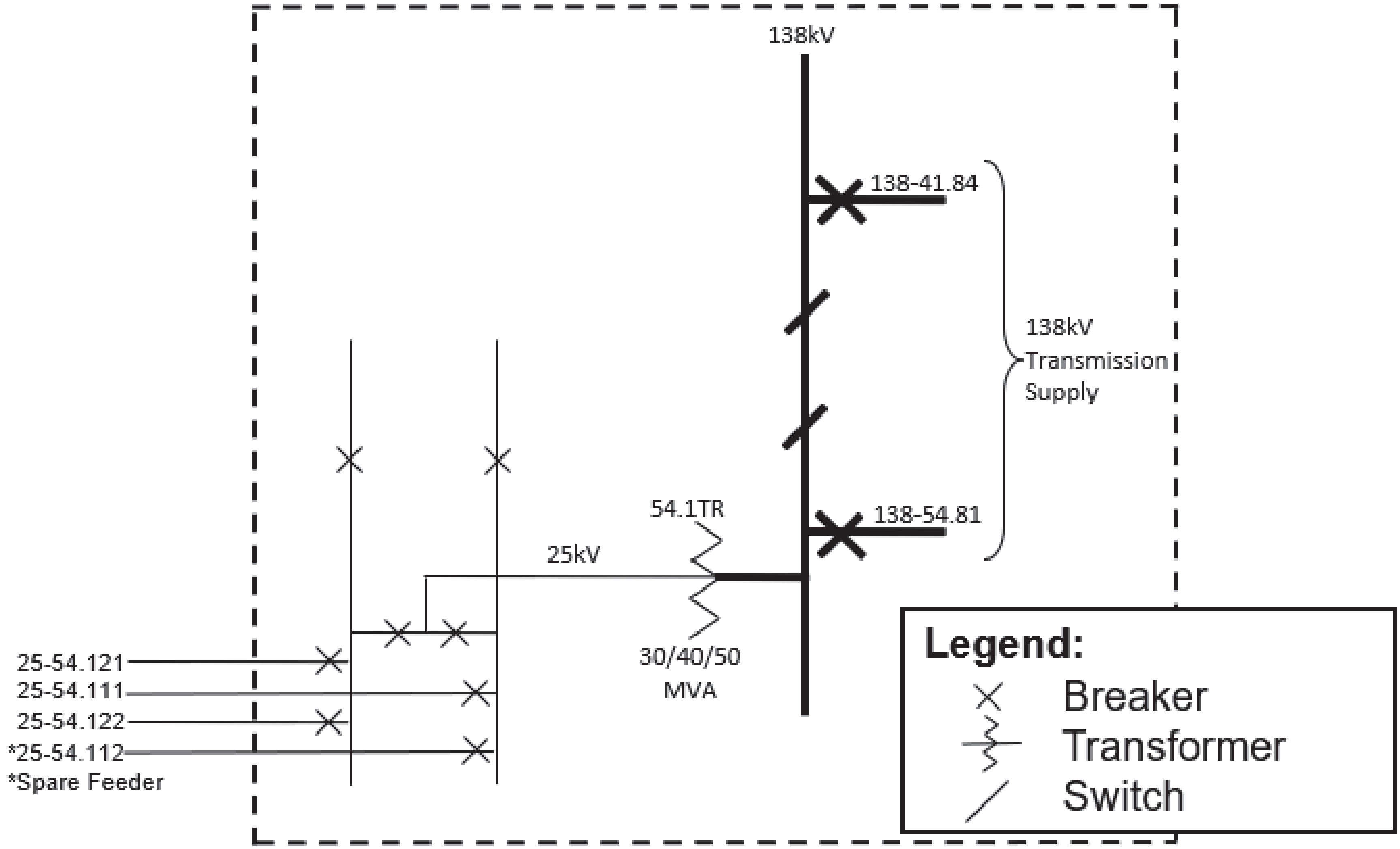


Figure 4: Existing No. 54 Substation Configuration

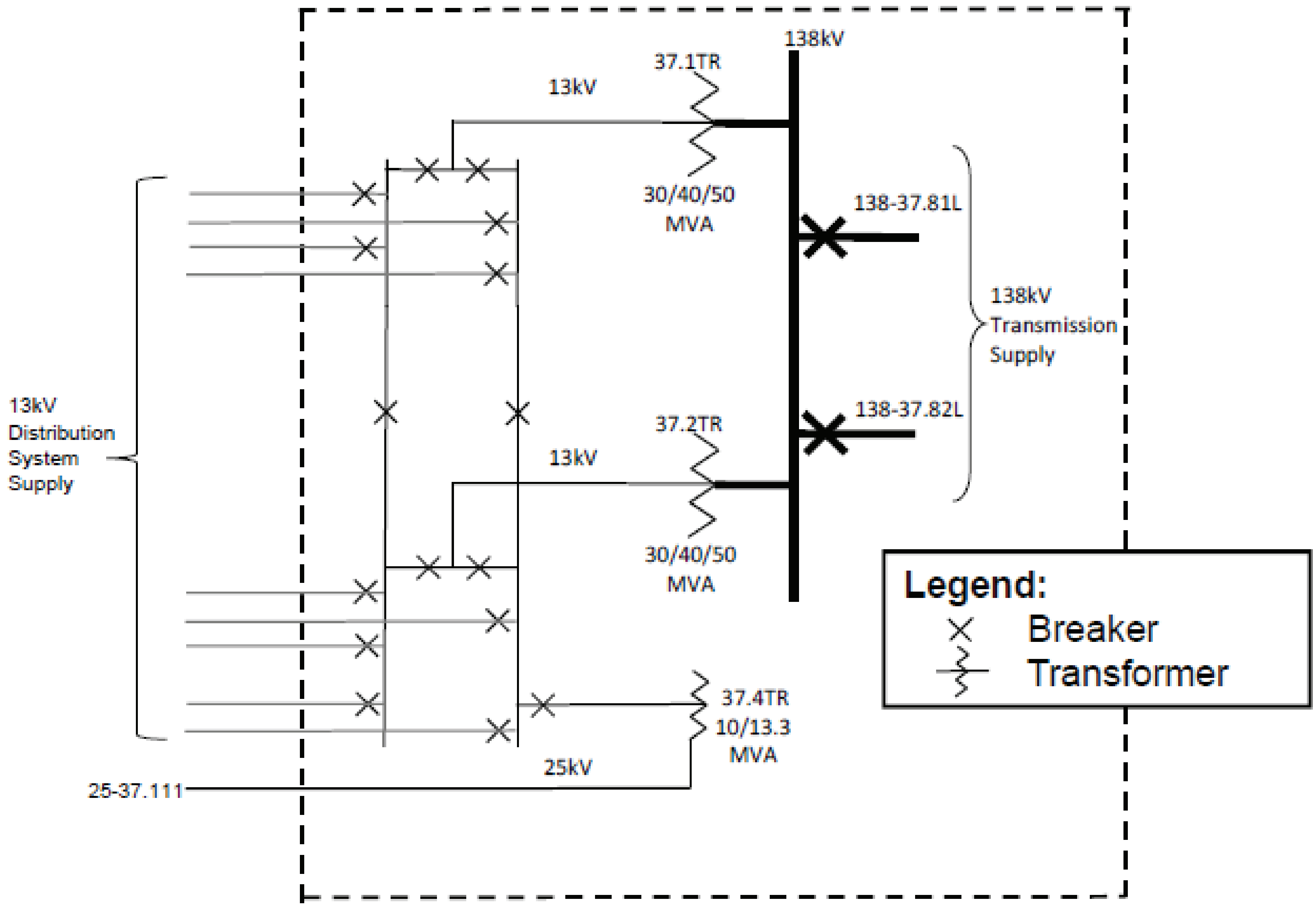


Figure 5: Old No. 37 Substation Configuration (see new configuration on next page)

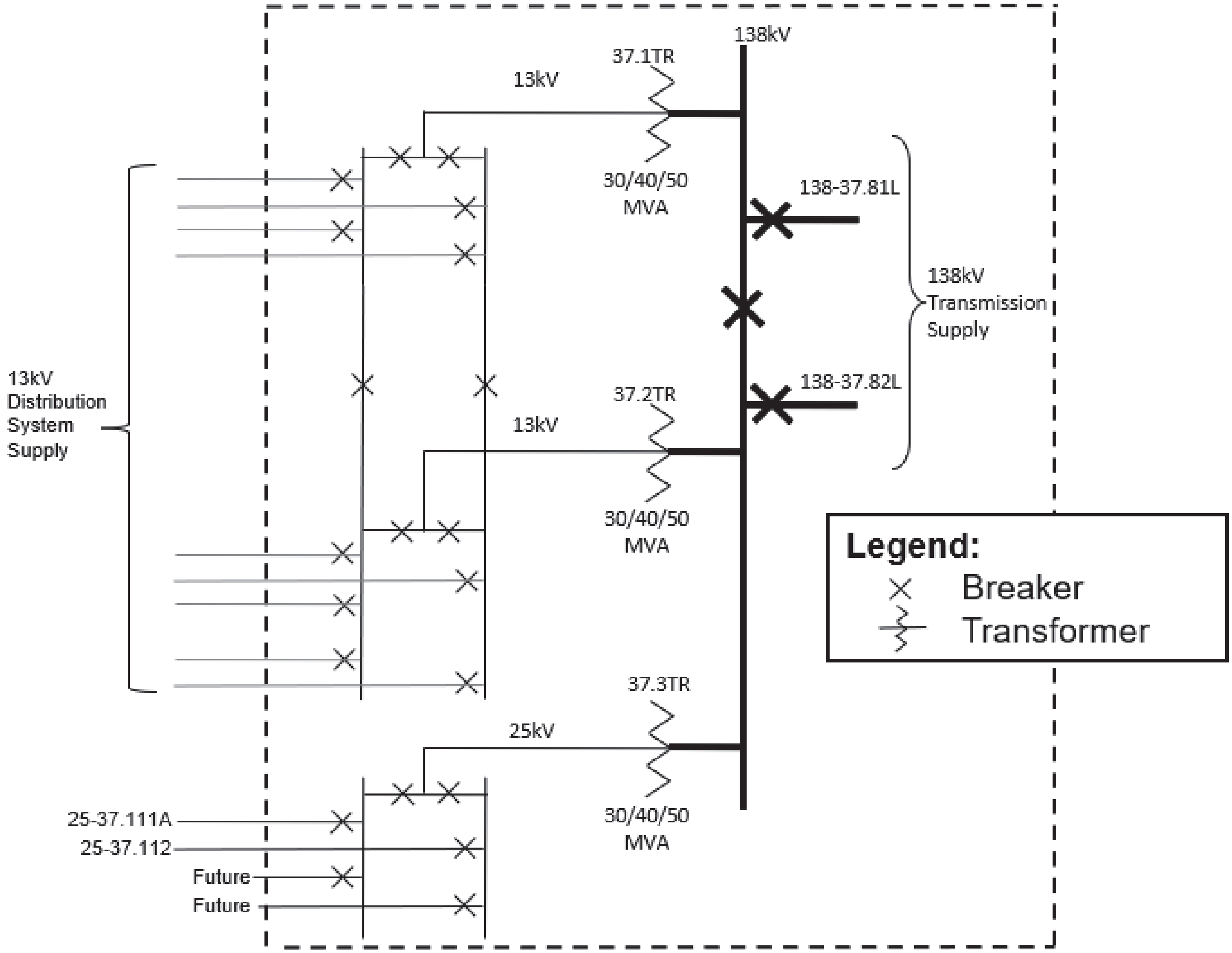


Figure 6: New No. 37 Substation Configuration (ISD Dec 2025)

4.0 Study Area Load and Distributed Generation

Figure 7 showcases EPC's load capacity map for the city of Calgary, published in December 2025. The map highlights the capacity constraints in the Southeast quadrant of the city.

4.1 Load Growth Developments

The major subdivision developments and the associated load growth for the next ten years are listed in Table 1. Note that the load growth listed in Table 1 has been integrated into the overall area load forecast, indicated in *Section 4.2 Load Forecast – Current Configuration*. Figure 8 illustrates the location of major developments as well as distributed generation with an installed capacity greater than 1MVA.

Table 1: Major Load Additions within Study Area (2026-2034)

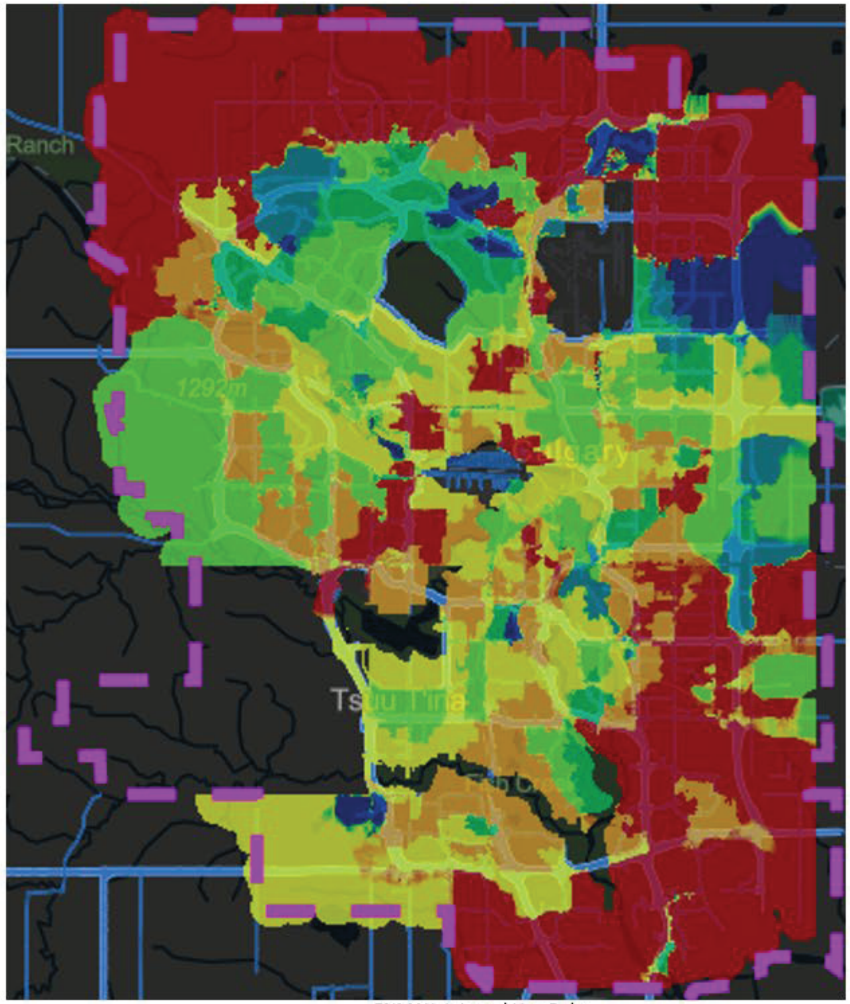
Description of New Load Addition	Forecasted Load 2026-2034 [MVA]	Projected Load 2034+ [MVA][iv]
Belmont (Residential)	1.97	3.88
Yorkville (Residential)	0.75	-
Legacy (Residential)	2.10	2.15
Pine Creek (Residential)	1.70	2.02
South Macleod (Residential)	3.80	2.38
Thiessen (Residential)	1.66	1.27
Rangeview (Residential)	3.89	11.04
Seton (Residential/commercial)	4.94	1.45
Mahogany (Residential)	2.23	1.16
Wolf Creek/Wolf Willow (Residential)	2.35	6.65
Walden (Residential)	0.70	0.70
New Brighton (Residential)	0.65	-
Shepard (Commercial/Industrial)	7.10	-
Greenline LRT Maintenance center & GL Shepard Station	3.00	-
Hotchkiss (Residential/commercial)	1.53	6.47
Point Trotter Industrial (Commercial/Industrial)	5.84	3.73
Starfield (Industrial)	10.00	2.60
Easthills (Residential/Commercial)	2.83	-
Heather Glen (Industrial)	2.65	-
Belvedere (Residential/Commercial)	2.18	1.83
Canfer Park (Industrial)	3.50	1.50
EMCOR (Industrial)	0.70	4.70
Sora[v] (Residential/commercial)	-	3.30
Seton Ridge & Logan Landing (Residential)	8.00	3.8
Total Area Load Growth (non-diversified[vi])	**74.07**	**60.63**

Note:

1. The impact of Distributed Generation facilities with export capability has not been accounted for in the load forecast. Please refer to *Appendix C-Load Forecasting Methodology* for further details.

[iv] Load projections beyond 2034 are not included in the load forecasts and listed here for information only.
[v] City circulations received; project initiation pending.
[vi] Non-Diversified load represents the sum of independent peak loads.

ENMAX Load Capacity Map



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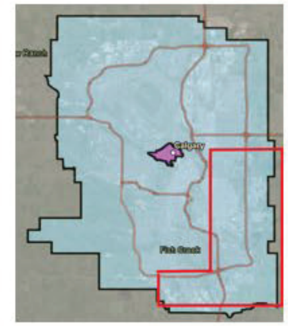

Enmax Distribution Limit

Legend:

Estimated Remaining Load Capacity (December 2025)

Estimated Remaining Load Capacity (December 2025)

- 11,000 - 12,999 KVA (Lowest likelihood for system upgrades)
- 9,000 - 10,999 KVA
- 7,000 - 8,999 KVA
- 5,000 - 6,999 KVA
- 3,000 - 4,999 KVA
- 1,000 - 2,999 KVA
- < 999 KVA (Highest likelihood for system upgrades)

Areas with no data - Please contact ENMAX

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Figure 6: ENMAX Load Capacity Map

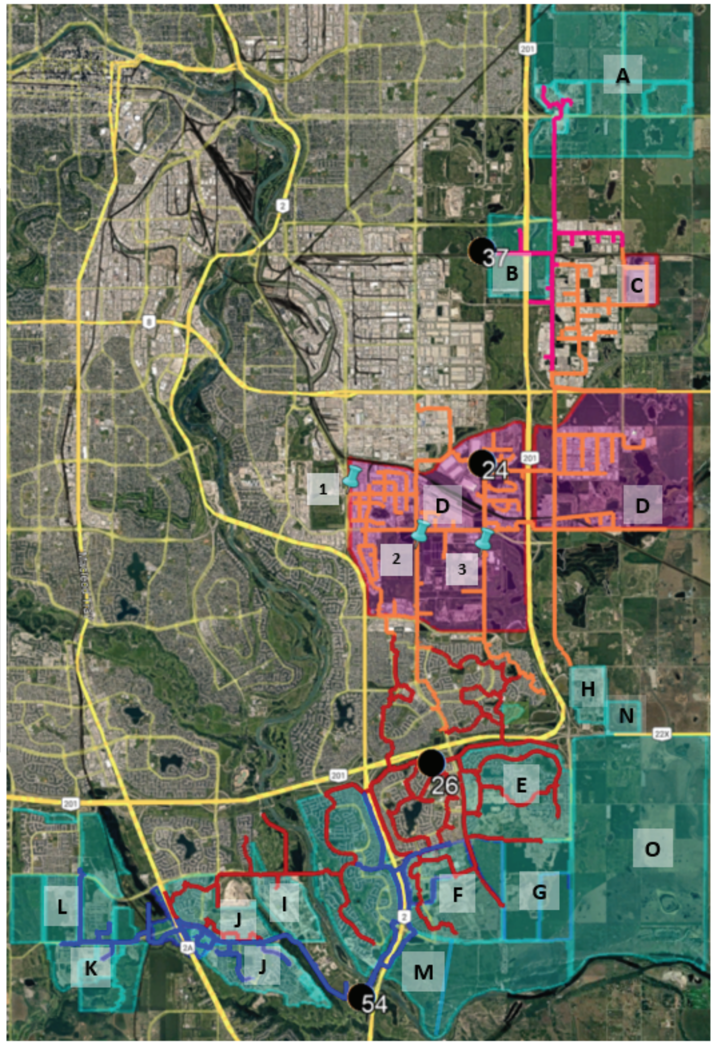
Forecasted Load Growth & Locations of Distributed Generation with Installed Capacity >1MVA

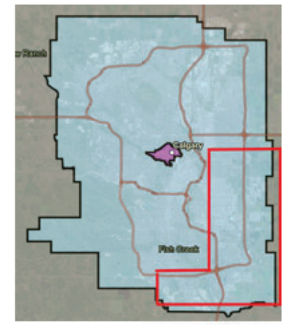
Forecast Area Load Growth (2026-2034)

A: Belvedere, East Hills - 5MVA (Multiphase)
B: Starfield- 10MVA
C: Emcor, Heather Glen- 3.35MVA
D: Shepard, Canfer Park, Point Trotter-19.44MVA
E: Mahogany- 2.23MVA
F: Seton- 4.94MVA
G: Rangeview- 3.89MVA
H: Hotchkiss- 1.53MVA
I: Wolf Willow- 2.35MVA
J: Legacy, Walden, South Macleod- 6.6MVA
K: Pine Creek, Thiessen- 3.36MVA
L: Belmont, Yorkville- 2.72MVA
M: Seton Ridge-8MVA

Future developments (Not Included in 10-year Forecast)

N: Sora-3.3MVA
O:Future loads- TBD





Enmax Distribution Limit

Legend:

- No. 37 Substation Service Territory
- No. 24 Substation Service Territory
- No. 26 Substation Service Territory
- No. 54 Substation Service Territory
- 1 DER: Barlow Solar Park (27MW)
- 2 DER: Deerfoot Solar Park (37MW)
- 3 DER: Calgary Compost Facility (3.7MW)
- Mixed Residential/ Commercial developments
- Commercial/ Industrial developments
- Substations

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Figure 7: Forecasted Load Growth and locations of Distributed Generation with Capacity >1MVA

4.2 Load Forecast – Current Configuration

Annual load forecasts are developed for major elements of the distribution system, including substations (PODS), substation transformers, distribution feeders and network feeders. A summary of EPC's load forecasting methodology is included in Appendix C for reference. Note that the impacts of distributed generation are currently not included in the forecasts.

Table 2 outlines the load forecast for the Point of Delivery (POD) substations 24 Sub, 26 Sub, 54 Sub, and 37 Sub. 37 Sub supplies customer load at both 13 kV and 25 kV, while 24 Sub, 26 Sub and 54 Sub only supply customer loads at 25kV. The load forecasts of the substation transformers, and the feeders are outlined in Table 3 and Table 4, respectively.

Note that summer and winter peak periods are recorded between May 1st – October 30th and November 1st – April 30th respectively.

Table 2: POD Substation Coincident Load[vii] Forecast - Existing System

POD	Capacity (MVA)	Peak Season	PF[1]	Actual Load (MVA)					Forecasted Load (MVA)									
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
24 S	100	S	0.90	60	61	64	74	68[2]	74	77	78	83	86	87	89	90	91	91
26 S	100	S	0.97	82	81	85	95	91	89[3]	91	93	94	94	95	95	95	96	96
54 S	50	S	0.99	24	24	26	30	31	37[3]	38	40	41	43	45	45	46	46	46
37 S	150[4]	S	0.90	53	54	53	54	66[2]	74	82	87	91	97	102	104	106	106	106

Notes:

1. The POD power factor is calculated using the POD MW and MVA values over the POD peak period.
2. Planned load transfer of 8.7MVA from 24 Sub to 37 Sub in 2025 to leverage the capacity of the new 25kV transformer at 37 Sub. The transfers at both stations are counteracted by additional load growth at 24S.
3. Planned load transfer of 4.4MVA from 26 Sub to 54 Sub in 2026.
4. 37 Sub forecast includes both 13kV and 25kV load. This study only considers the 25kV load. The station capacity increased from 100MVA to 150MVA with addition of a 50MVA transformer (37.3TR) in December 2025.

Table 3: Transformer Load Forecast - Existing System

Transformer	Capacity (MVA)	Peak Season	PF	Actual Load (MVA)					Forecasted Load (MVA)									
				2021	2022	2023	2024[6]	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
24.1TR	50	S	0.90	29	32	34	45	35[3]	43	44	45	47	48	49	49	50[2]	50[2]	50[2]
24.2TR	50	S	0.91	31	30	31	34	29[1]	32	35	35	37	40	40	41	42	42	42
26.1TR	50	S	0.96	43	43	45	51	47[3]	48	49	50[2]	51[2]	51[2]	52[2]	52[2]	53[2]	53[2]	53[2]
26.2TR	50	S	0.97	40	38	40	44	43	42	42	43	43	43	43	43	43	43	43
54.1TR	50	S	0.99	24	24	26	30	31	37[3]	39	40	42	43	45	46	46	47	47
37.3TR[4]	50	S	-	-	-	-	-	17	20	23	27	30	34	38	40	41	42	42
37.4TR	13.3	S	0.90	6	7	6	7	-	-	-	-	-	-	-	-	-	-	-
6.4TR[5]	50	S	0.99	6	6	7	8	8	9	11	12	12	13	14	14	15	15	15

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vii Substation POD Coincident Load: represents the substation POD peak demand at a specific time during a season (summer or winter) by summing all the individual loads supplied by the substation at the time.

Notes:

1. Planned load transfer of approximately 8.7MVA from 25-24.114 to 25-37.111A & 25-37.112 in 2025 as part of the 37 Sub capacity upgrade project. Additional load growth on other feeders supplied by 24.2TR counteracts the effect of this transfer.
2. Values identified in red indicate that the 50MVA transformer thermal rating is met or exceeded.
3. Lower peaks than expected were observed in the summer of 2025.
4. 37.3TR is a new 50MVA transformer at 37 Sub, installed in December 2025. 37.4TR was decommissioned after commissioning of 37.3TR.
5. Included in this table per DDR guideline to provide peak loading data for relevant back up facilities. 6.4TR supplies feeder 25-6.111 which is a backup feeder for 25-54.111.
6. Per EPC's Distribution System Performance Standard, we plan and operate our substation transformers at levels that maximize available capacity in the pre-contingency scenario, while ensuring that we can restore load under N-1 contingency with one [1] switching operation. This includes tying away load to adjacent substations through distribution feeder ties and/or closing the station bus tie breaker to leverage the alternate transformer at each station during an N-1 contingency scenario. Transformer N-1 deficiencies within the study area begin in 2024 as shown in Table 8.

Table 4: 25kV Feeder Load Forecast - Existing System

Feeder	Capacity (MVA)	Source Transformer	Peak	Actual Load (MVA)					Forecasted Load (MVA)									
				2021	2022	2023	2024	2025	2026	2027[6]	2028	2029	2030	2031	2032	2033	2034	2035
No. 24 Substation																		
25-24.111	25.9	24.1	S	7	9	12	13	11	12	12	12	14	14	14	15	15	15	15
25-24.112	25.9	24.1	S	13	13	13	13	12	14	14	14	15	15	15	16	16	16	16
25-24.121	25.9	24.1	S	9	9	9	14	11	12	13	13	13	13	14	14	14	14	14
25-24.122	25.9	24.1	S	0	1	3	6	5	6	6	6	6	6	6	6	6	6	6
25-24.113	25.9	24.2	S	5	5	5	5[1]	0	0	0	0	0	0	0	0	0	0	0
25-24.114	25.9	24.2	S	8	8	8	10	8[1]	12	14	14	14	14	15	15	15	15	15
25-24.123	25.9	24.2	S	13	12	12	14	11	12	12	12	15	17	18	18	19	19	19
25-24.124	25.9	24.2	S	5	6	6	6	6	9	9	9	9	9	9	9	9	9	9
No. 37 Substation																		
25-37.111	25.9	54.1	S	6	7	6	7	-	-	-	-	-	-	-	-	-	-	-
25-37.111A	25.9	54.1	S	-	-	-	-	9[2]	11	13	14	16	17	19	21	22	22	22
25-37.112	25.9	54.1	S	-	-	-	-	8[2]	9	11	13	14	17	19	19	19	20	20
No. 26 Substation																		
25-26.111	25.9	26.1	S	13	12	12	13	13	13	13	13	13	13	13	13	13	13	13
25-26.112	25.9	26.1	S	8	10	11	14	15	16	17	18	19	19	20	20	20	21	21
25-26.121	25.9	26.1	S	17	17	19	21	20	16[7]	17	17	17	17	17	17	17	17	17
25-26.122[3]	25.9	26.1	S	4	4	4	3	4	3	3	3	3	3	3	3	3	3	3
25-26.113	25.9	26.2	S	25	24[4]	11	12	12	11	11	11	11	11	11	11	11	11	11
25-26.114	25.9	26.2	S	0	0[4]	14	16	16	16	17	17	17	17	17	17	17	17	17
25-26.123	25.9	26.2	S	15	14	15	15	13	15	15	15	15	15	15	15	15	15	15
25-26.124[3]	25.9	26.2	S	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
No. 54 Substation																		
25-54.111	25.9	54.1	S	7	9	11	14	15	18	19	20	22	23	23	24	24	24	24
25-54.112	25.9	54.1	N/A	0	0	0	0	0	5	5	6	6	6	6	7	7	7	7
25-54.121	25.9	54.1	S	13	12	12	12	11	11	11	11	11	11	13	13	13	13	13
25-54.122[3]	25.9	54.1	S	5	5	4	5	4	5	5	5	5	5	5	5	5	5	5
No. 6 Substation				Back up option for Feeder 25-54.111														
25-6.111[5]	25.9	6.4	S	6	6	6	7	7	8	8	8	9	9	9	9	10	10	10

Notes:

1. Approximately 8.7MVA of planned load transfers from 25-24.114 to 25-37.111A & 25-37.112 planned in 2025. In addition, all the load on 25-24.113 (5MVA) will be transferred to 25-24.114. Feeder 25-24.113 will be offloaded to support 25-24.122 & 25-37.111A during N-1 contingency scenarios.
2. New 25kV feeders at 37 Sub energized in December 2025.

3. 25-26.122, 25-26.124 and 25-54.122 are dedicated feeders to the South Health Campus in Seton.
4. Permanent load transfer from 25-26.113 to 25-26.114 to balance feeder loading.
5. Included in this table per DDR guideline to provide peak loading data for relevant back up facilities. Feeder 25-6.111 provides backup capacity for 25-54.111.
6. Per our Distribution System Performance Standard, we plan and operate our distribution feeders at levels that maximize available capacity in the pre-contingency scenario, while still ensuring that we can restore load under N-1 contingency with one [1] switching operation. This entails tying away load to adjacent feeders through distribution feeder ties during N-1 contingency scenarios. Feeder level N-1 deficiencies within the study area begin in 2027 as shown in Table 7.
7. Planned load transfer of 4.4MVA from feeder 25-26.121 to 25-54.112.

4.3 Distributed Generation Summary

Table 5 provides a list of existing distributed generation with an installed capacity greater than 1MVA in the study area. In addition, Table 6 gives a summary of the total aggregated micro generation(<1MVA) within the service area of each POD.

Table 5: Distributed Generation with Installed Capacity greater than 1MVA

POD	DER Name or ID	Type	Installed Capacity (MW)	Comments
24	Calgary Compost Facility	Solar	3.7	Customer consumes most of the generation to offset their own demand. Rarely exports.
24	Barlow Solar Park	Solar	27	Commissioned and began exporting in May 2023.
24	Deerfoot Solar Park	Solar	37	Commissioned and began exporting in Fall 2023.

Table 6: Total Aggregated Microgeneration in Study Area- Installed Capacity <1MVA (2025 data)

POD	Type	Installed Capacity (MW)
24	Solar	2.01
26	Mix (Solar, natural gas, diesel gen)	12.39
54	Solar	3.14

4.4 Contributing Load Growth Factors Within the Study Area

Large load additions from new and existing customers/developments are the main contributing factor for the load growth observed within the study area.

24 Sub and 37 Sub will experience commercial, industrial and some residential load growth, while 26 Sub and 54 Sub will experience residential load growth with some commercial/retail developments.

The organic growth within the study area is negligible.

Refer to *Section 4.1* – Load Growth Developments which summarizes the expected developments.

5.0 Risk Assessment

5.1 Load at Risk Magnitude

The feeder-level Load at Risk in the study area is outlined in Table 7. Note that, only feeders with load at risk within the study area were included in this section. The transformer-level Load at Risk is outlined in Table 8.

The Load at Risk highlighted in Table 7 and Table 8 represents the maximum unsupplied customer load under peak loading conditions in the event of the loss of a feeder or a substation transformer, respectively.

Table 7: Forecasted Feeder Load at Risk during the Summer Peak Season (MVA)[viii]

	Actual		Forecast (MVA)									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Loss of 25-24.123	Summer Peak											
25-24.123 Total Load	14	11	12	12	12	15	17	18	18	19	19	19
Back up from 25-24.111	7	7	7	0[1]	0	0	0	0	0	0	0	0
Back up from 25-26.113	7	7	7	0	0	0	0	0	0	0	0	0
Total Unsupplied Load	0	0	0	12	12	15	17	18	18	19	19	19
Loss of 25-37.111A[3]	Summer Peak											
25-37.111A Total Load	-	9	11	13	14	16	17	19	21	22	22	22
Back up from 25-24.113	-	21	18	15	15	13	0[2]	0	0	0	0	0
Back up from 25-37.112[3]	-	6	6	6	6	6	0	0	0	0	0	0
Total Unsupplied Load	-	0	0	0	0	0	17	19	21	22	22	22
Loss of 25-37.112	Summer Peak											
25-37.112 Total Load	-	8	9	11	13	14	17	19	19	19	20	20
Back up from 25-24.114	-	18	14	12	12	12	0[4]	0	0	0	0	0
Back up from 25-37.111A	-	6	6	6	6	6	0	0	0	0	0	0
Total Unsupplied Load	-	0	0	0	0	0	17	19	19	19	20	20
Loss of 25-26.121	Summer Peak											
25-26.121 Total Load	21	20	16	17	17	17	17	17	17	17	17	17
Back up from 25-26.111	9	9	9	0	0	0	0	0	0	0	0	0
Back up from 25-54.111	12	11	8	0[5]	0	0	0	0	0	0	0	0
Total Unsupplied Load	0	0	0	17	17	17	17	17	17	17	17	17
Loss of 25-26.113	Summer Peak											
25-26.113 Total Load	12	12	11	11	11	11	11	11	11	11	11	11
Back up from 25-24.123	14	14	14	14	14	11	0[6]	0	0	0	0	0
Total Unsupplied Load	0	0	0	0	0	0	11	11	11	11	11	11

*Feeder 25-24.121 was not included in the updated version of Table 7 as a distribution solution was found with the existing ties to alleviate load at risk (relative to the previous version of the report)

Notes:

1. Back up capacity on 25-24.111 is limited by 24.1TR transformer overload during feeder 25-24.123 contingency scenario in 2027, therefore the double tie solution is insufficient.

[viii] Feeder back up or tie-away capacity is the maximum capacity available to effectively transfer load to adjacent feeders by tying away either the entire feeder or sections of the feeder.

2. Decrease in Tie-Away capacity on 25-24.113 beginning in 2030 due to 24.2TR transformer capacity limitation.
3. 25-37.111A & 25-37.112 are new 25kV feeders at 37 Sub energized in December 2025.
4. Decrease in Tie-Away capacity on 25-24.114 due to capacity limitation on 24.2TR during contingency scenario beginning in 2030.
5. 25-54.111 feeder capacity is limited during feeder 25-26.121 contingency scenario in 2027, therefore the double tie solution is insufficient.
6. 25-24.123 feeder capacity exceeded during feeder 25-26.113 contingency scenario in 2030.

Table 8: Forecasted Transformer Load at Risk during Summer Peak (MVA)[ix]

	Actual		Forecast (MVA)									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Loss of 24.1TR or 24.2TR		Summer Peak										
24 S Total Load[1]	79	64[12]	75	79	80	84	88	89	90	92	92	92
Alternate TX Capacity (24.1TR or 24.2TR)	50	50	50	50	50	50	50	50	50	50	50	50
Back up from 26 S	0[2]	0	0	0	0	0	0	0	0	0	0	0
Back up from 37 S	0[3]	8	12	14	14	14	14	5[4]	5	0	0	0
Total Unsupplied Load	29	6[5]	13	15	16	20	24	34	35	42	42	42
Loss of 26.1TR or 26.2TR	Summer Peak											
26 S Total Load[1]	95	90	90	92	93	94	94	95	95	96	96	96
Alternate TX Capacity (26.1TR or 26.2TR)	50	50	50	50	50	50	50	50	50	50	50	50
Back up from 24 S	13	13	13	13	13	0[6]	0	0	0	0	0	0
Back up from 54 S	15	15	0[7]	0	0	0	0	0	0	0	0	0
Total Unsupplied Load	17	12	27	29	30	44	44	45	45	46	46	46
Loss of 54.1TR	Summer Peak											
54 S Total Load[1]	30	31	37	39	40	42	43	45	46	46	47	47
Back up from 26 S	0[8]	8	8	8	0[9]	0	0	0	0	0	0	0
Back up from 6 S	14	15	18	0[10]	0	0	0	0	0	0	0	0
Total Unsupplied Load	16	8	11	31	40	42	43	45	46	46	47	47
Loss of 37.3TR (25kV)[11]	Summer Peak											
37 S Total Load[1]	-	17	20	23	27	30	34	38	40	41	42	42
Back up from 24 S	-	21	18	15	15	13	10	10	9	8	8	8
Total Unsupplied Load	-	0	2	8	12	17	24	28	31	33	34	34

Notes:

1. Utilized the sum of the respective transformer peaks to determine total load, as opposed to the diversified station peaks.
2. Back up capacity from 26 Sub (utilizing tie-away feeder: 25-26.113) is limited by 26.2TR transformer overload between 2024-2034 during N-1 contingency. 24 Sub only has two existing ties to 26 Sub. With both 26.1TR & 26.2TR transformers having capacity constraints, there is limited capacity at 26 Sub to support 24 Sub during N-1 contingency scenarios.
3. Insufficient back up capacity from 37 Sub in 2024, because the pre-existing 37.4TR autotransformer was rated at 13.3MVA. With the 50MVA transformer commissioning in 2025, additional N-1 support becomes available from 2025.

[ix] Transformer back up or tie-away capacity is the maximum capacity available to effectively transfer load away from the out-of-service transformer using existing feeder ties and/or substation secondary bus ties.

4. Decreased back up capacity from 37 Sub, due to 37.3TR limitation.
5. Decreased load at risk due to additional back up capacity availability from new 37.3TR transformer at 37 Sub, and lower summer 2025 peak loading at 24 S.
6. Feeder overload on 25-24.123 during contingency scenario beginning in 2029.
7. Back up capacity from 54 Sub (25-54.121) limited by 54.1TR transformer overload beginning in 2026.
8. Limited back up capacity from 26.2TR due to high summer peak in 2024.
9. Back up capacity from 26 Sub (utilizing tie-away feeder: 25-26.123) is limited by 26.2TR transformer overload during contingency scenario in 2028.
10. Back up capacity from 6 Sub (utilizing tie-away feeder: 25-6.111) is limited by 25-6.111 feeder overload during contingency scenario in 2027.
11. Load at Risk for new 50MVA transformer (37.3TR) at 37 Sub. 37.3TR is the only 25kV transformer at 37 Sub, therefore it will rely solely on 24 Sub for back up supply.
12. Lower peak loading observed at 24 S in Summer 2025.

5.2 Summary of Study Area Supply Deficiencies

The existing 25kV supply sources from 24 Sub, 26 Sub, 37 Sub and 54 Sub, including five [5] distribution feeders, will not be able to meet the EPC Distribution System Performance Standard within the study area as set out in Section 2.2 and Section 2.3. The station level deficiencies began in the 2024 summer peak season for 24 Sub, 26 Sub, and 54 Sub and are forecasted to increase year over year until 2035. In addition, 37 Sub will experience deficiencies beginning in the summer of 2026.

The identified feeder and transformer level deficiencies, as well as substation load trend graphs for the first year of deficiency are outlined in the subsequent sections.

5.2.1 Feeder Level deficiencies during contingency (Refer to Table 7):

5.2.1.1 No. 24 Substation feeder 25-24.123 Load at Risk

By the summer of 2027, loss of feeder 25-24.123 will result in 12MVA of load at risk during summer peak conditions. The LAR magnitude increases to 19MVA by 2035.

5.2.1.2 No. 37 Substation feeder 25-37.111A Load at Risk

By the summer of 2030, loss of feeder 25-37.111A will result in 17MVA of load at risk during summer peak conditions. The LAR magnitude increases to 22MVA by 2035.

5.2.1.3 No. 37 Substation feeder 25-37.112 Load at Risk

By the summer of 2030, loss of feeder 25-37.112 will result in 17MVA of load at risk during summer peak conditions. The LAR magnitude increases to 20MVA by 2035.

5.2.1.4 No. 26 Substation feeder 25-26.121 Load at Risk

By the summer of 2027, loss of feeder 25-26.121 will result in 17MVA of load at risk during summer peak conditions. The LAR magnitude remains the same until 2035.

5.2.1.5 No. 26 Substation feeder 25-26.113 Load at Risk

By the summer of 2030, loss of feeder 25-26.113 will result in 11MVA of load at risk during summer peak conditions. The LAR magnitude remains the same until 2035.

5.2.2 Transformer level deficiencies during contingency (Refer to Table 8):

5.2.2.1 No. 24 Substation transformer 24.1TR & 24.2TR Load at Risk

By the summer of 2024, loss of either transformer 24.1TR or 24.2TR would result in 29MVA of load at risk during summer peak conditions. The LAR magnitude steadily increases to 42MVA by 2035.

5.2.2.2 No. 26 Substation transformer 26.1TR & 26.2TR Load at Risk

By the summer of 2024, loss of either transformer 26.1TR or 26.2TR would result in 17MVA of load at risk during summer peak conditions. The LAR magnitude steadily increases to 46MVA by 2035.

5.2.2.3 No. 54 substation transformer 54.1TR Load at Risk

By the summer of 2024, loss of transformer 54.1TR would result in 16MVA of load at risk during summer peak conditions. The LAR magnitude increases to 47MVA by 2035.

5.2.2.4 No. 37 Substation transformer 37.3TR Load at Risk

By the summer of 2026, loss of transformer 37.3TR would result in 2MVA of load at risk during summer peak conditions. The LAR magnitude increases to 34MVA by 2035.

5.3 Load trend graphs for the first year of deficiency:

Load trend graphs for the first year of deficiency were generated for each transformer and substation POD total load in the following format: MVA on the Y-axis, and hour-day-month-year on the X-axis.

The first year of deficiency for 24 Sub, 26 Sub and 54 Sub was 2024, therefore actual load profiles from January 1st, 2024 to December 31st, 2024 are illustrated in Figures 9-15. Similarly, the expected load trends for 37 Sub from Jan 1st, 2026 to December 31st, 2026 are illustrated in Figures 16-17.

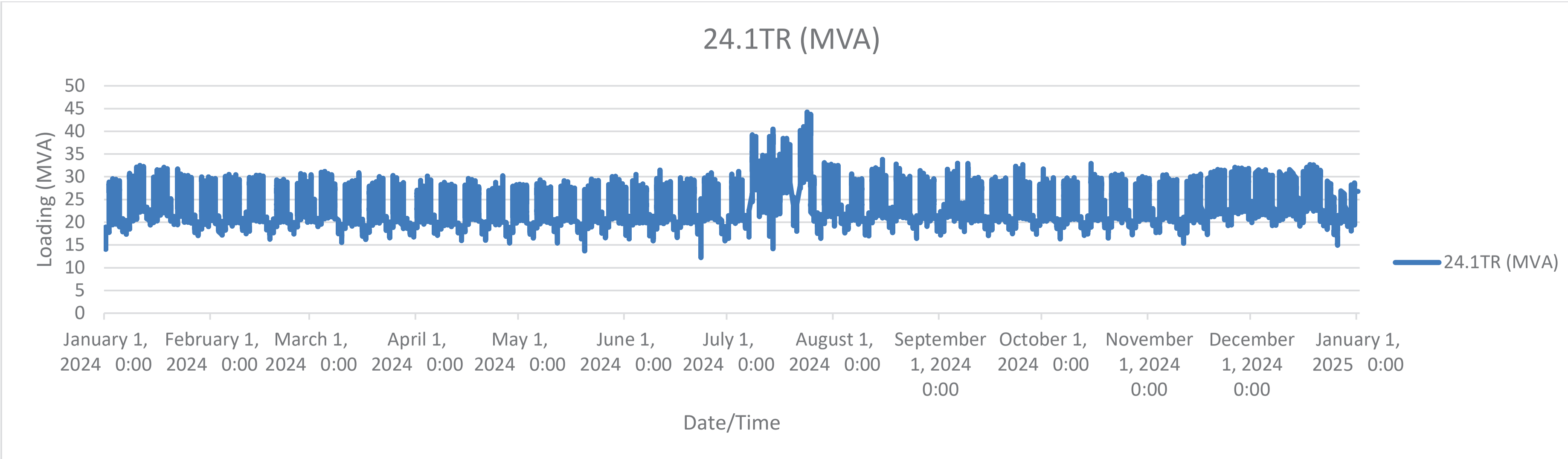


Figure 8: 12-month hourly load trend line for 24.1TR (January 1st 2024 – December 31st 2024)

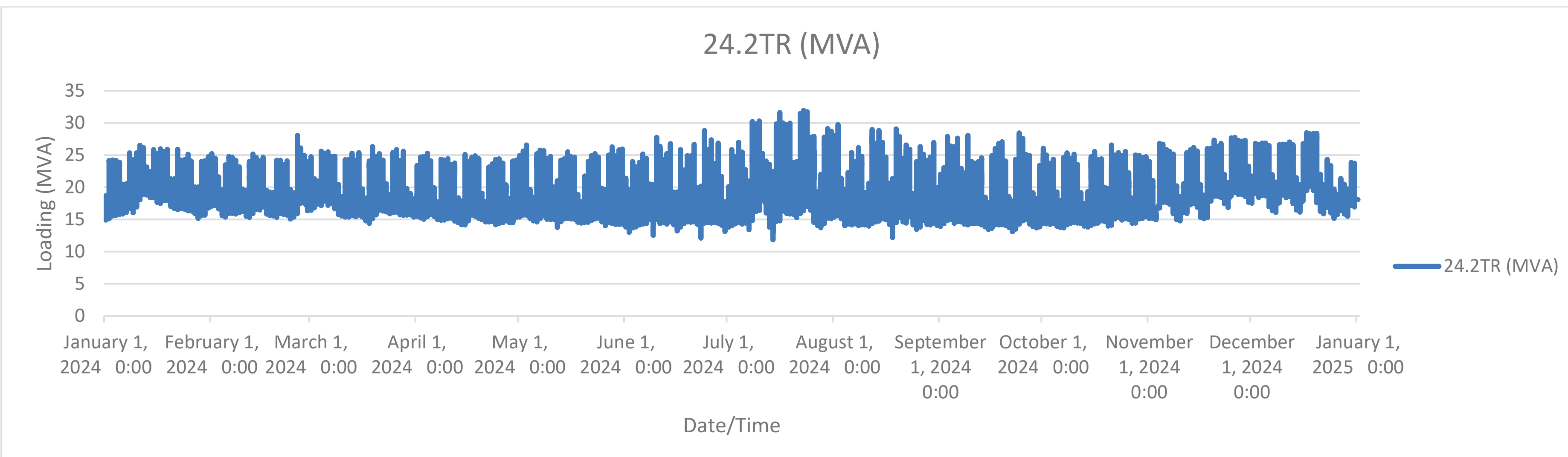


Figure 9: 12-month hourly load trend line for 24.2TR (January 1st 2024 – December 31st 2024)

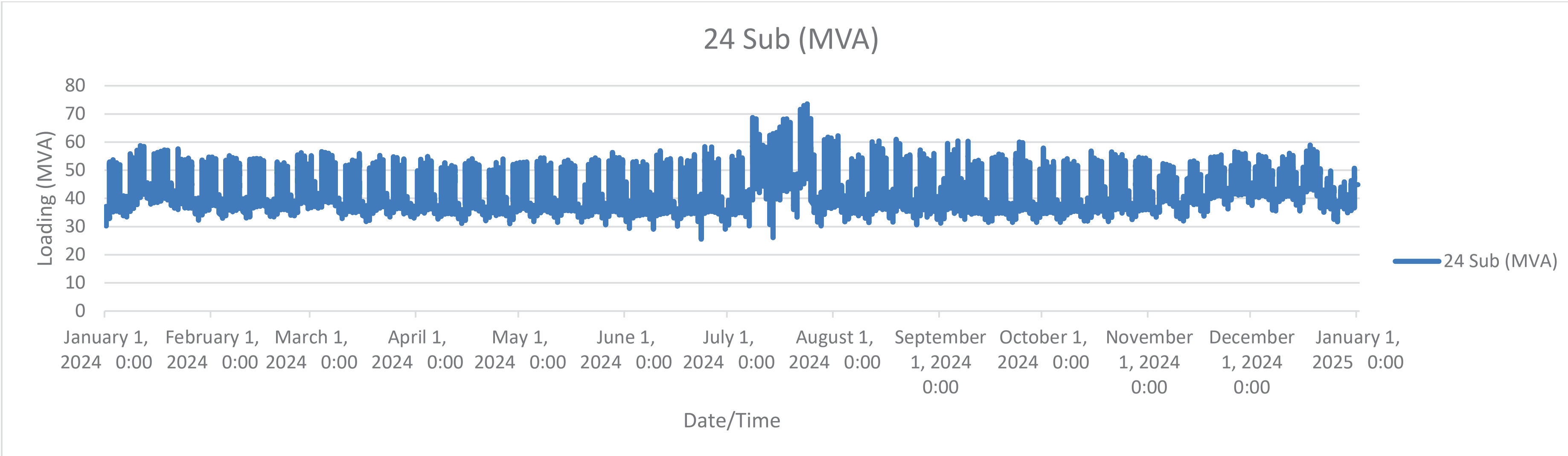


Figure 10: 12-month hourly load trend line for 24 Sub POD (January 1st 2024 – December 31st 2024)

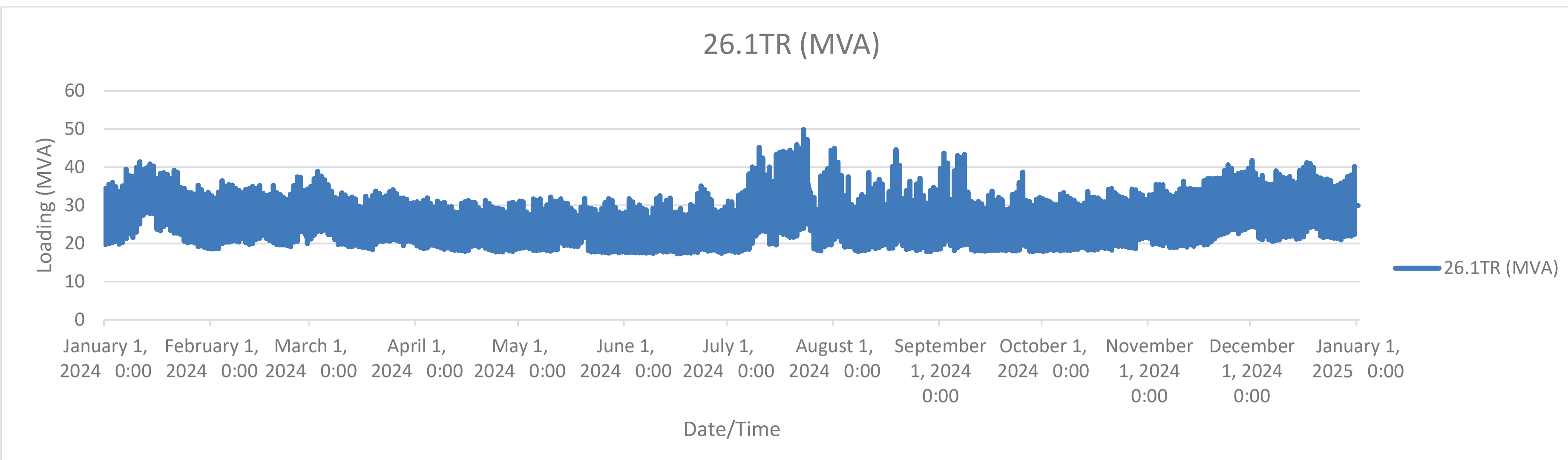


Figure 11: 12-month hourly load trend line for 26.1TR (January 1st 2024 – December 31st 2024)

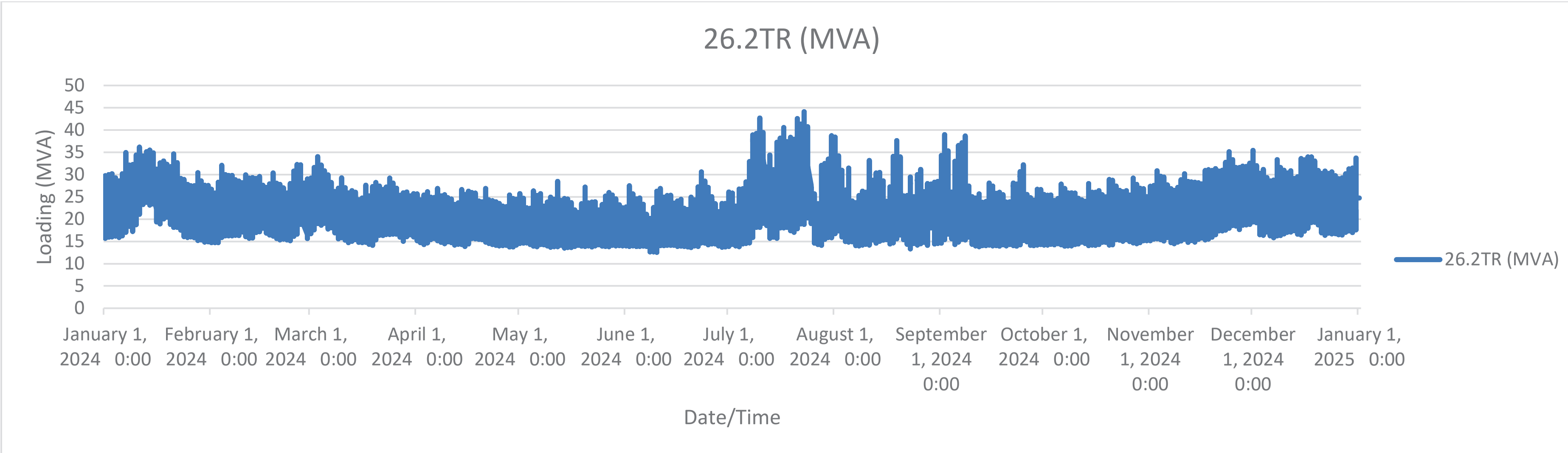


Figure 12: 12-month hourly load trend line for 26.2TR (January 1st 2024 – December 31st 2024)

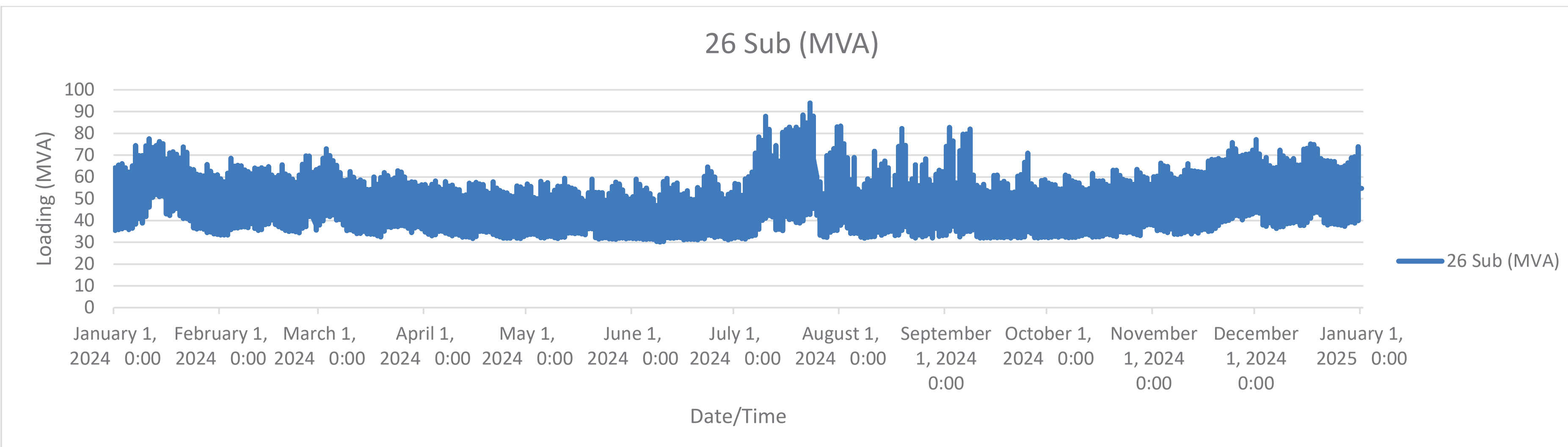


Figure 13: 12-month hourly load trend line for 26 Sub POD (January 1st 2024 – December 31st 2024)

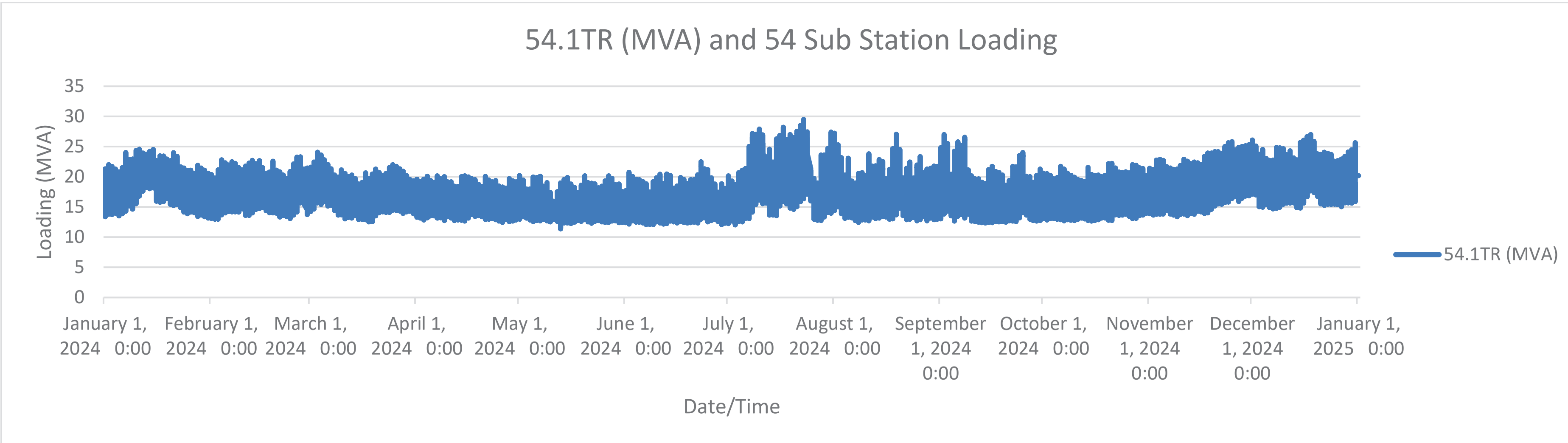


Figure 14[x]: 12-month hourly load trend line for 54.1TR/54 Sub POD (January 1st 2024 – December 31st 2024)

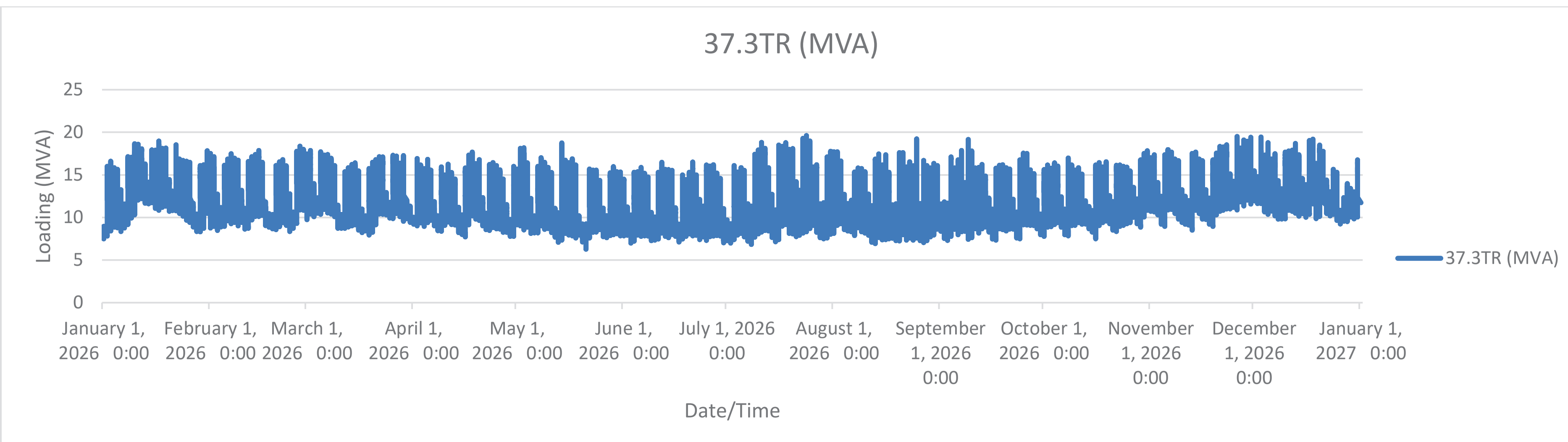


Figure 15: 12-month hourly load trend line for 37.3TR (January 1st 2026 – December 31st 2026)

[x] 54 Sub has a single 25kV transformer, therefore the load profile for 54.1TR is the substation POD profile.

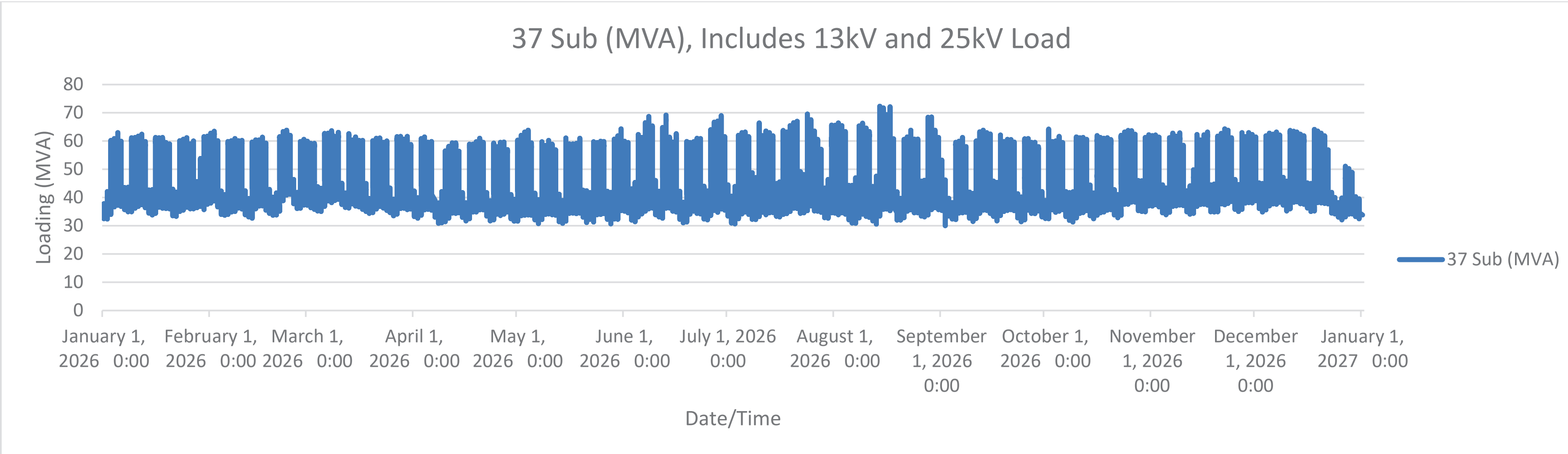


Figure 16: 12-month hourly load trend line for 37 Sub POD (January 1st 2026 – December 31st 2026)

5.4 Study Area Customer Type Breakdown

The substations within the study area each serve a mixture of D100 (Residential), D200 (Small Commercial), D300 (Medium Commercial), D310 (Large Commercial – Secondary Fed), D410 (Large Commercial – Primary Fed) and D600 (Large Distributed Generation) customers, as defined by EPC's Distribution Tariff. Table 9 provides a summary of the customer counts by rate class (as of November 2025).

Table 9: Customer Count by Rate Class (2025 data)

POD	Feeder Class	Customer Count by Rate Class					
		D100 *Residential*	D200 *Small Commercial*	D300 *Medium Commercial*	D310 *Large Commercial Secondary*	D410 *Large Commercial primary*	D600 *Large Distributed Generation*
24	25 kV	5,513	1,082	468	103	6	4
26	25 kV	40,058	634	215	22	1	-
54	25 kV	12,351	261	68	5	1	-
37	25 kV	475	214	51	12	-	-

5.5 Critical customers

EPC identifies critical customers as those customers that if a power interruption is experienced could result in putting someone's life or limb at risk. These types of customers are hospitals, 911 services, control centers for utilities, etc.

The main critical customer in the area is the South Health Campus in Seton which is supplied by two [2] primary feeders (25-26.122 & 25-54.122) and one [1] standby/backup feeder (25-26.124). The South Health Campus also has back-up diesel generators with a total installed capacity of 27MW.

6.0 Alternatives Considered to Address the Identified Deficiency

<u>Distribution Alternatives:</u>

6.1 Alternative 1: Do Nothing

<u>The Do-Nothing option is in contravention of the EPC Distribution System Performance Standard and was dismissed for the following reasons:</u>

- Existing system infrastructure at 24 Sub, 26 Sub and 54 Sub cannot support the forecasted load under a single transformer contingency beginning in 2024, and 2026 for 37 Sub.
- Existing system infrastructure for five [5] feeders listed in section 5.2.1 cannot support the forecasted load under a single feeder contingency by 2027.

- Without balancing the load between the station transformers, existing system infrastructure at 26 Sub (26.1TR) cannot support the forecasted load under normal operating conditions beginning in 2028.

6.2 Alternative 2: Load Transfers to Adjacent Substations

As illustrated in Sections 4.2 and Section 5.0 of this report, the substations within the study area are capacity constrained and unable to meet EPC's Distribution System Performance requirements for N-1 contingency operation in their existing configuration.

Notes:

- 24 Sub and 26 Sub are forecasted to be loaded at 91% and 96% of their station capacity by 2034. 54 Sub and 37 Sub (25kV load) have forecasts of 92% and 84% respectively. Considering the growth trends expected beyond 2034, all the substations within the study area will not be able to sustain the load under contingency.
- 54 Sub and 37 Sub each have a single 25kV transformer, adding to the reliability constraints within their service areas.
- 24 Sub and 37 Sub are located adjacent to 13kV service territories, thus limiting the tie-away options available to these stations within the 25kV supply area.

Alternative 2 was dismissed as it does not adequately address the identified system deficiencies and is therefore in violation of the EPC Distribution System Performance Standard (Sections 2.1 and 2.2)

Transmission Alternatives:

The transmission scope of work and the associated cost for each alternative are presented below for the purpose of alternative comparison only.

6.3 Alternative 3 (Preferred): Addition of 25 kV Transformation Capacity at 54 Sub

Scope:

- Install one [1] 138/25kV 30/40/50MVA transformer, 138kV bus tie breaker, and associated 25kV MV switchgear lineup with four [4] new feeder positions at 54 Sub.
- The distribution scope for this alternative includes the following:
  - Construct three [3] new feeders to offload the following load pockets from 26 Sub:
    - Feeder 25-54.113 to offload 25-26.121, transferring 21MVA of load within Cranston, Walden, Wolf Willow, and Chaparral Meadows. (Approximately 2.5km)
    - Feeder 25-54.114 to offload 25-26.112, transferring 14MVA of load from Seton (Approximately 4.5 km)

        - Feeder 25-54.123 to offload 25-26.123, transferring 15MVA of load from Auburn Bay (approximately 4.5km).
    - Extend existing section of offloaded 25-26.121 feeder approximately 4.5km North on Deerfoot Trail SE to create a new tie with feeder 25-24.111 and transfer approximately 5.6MVA of load to 25-26.121.

      In addition, feeder 25-26.121 will be extended approximately 1.9km to the south of the developed Inverness community to create new ties with feeders 25-24.123 and 25-26.113. Approximately 1.9MVA of load will be transferred from feeder 25-24.123 to 25-26.121.
    - Extend 25-37.112 feeder approximately 4.5km south on 68 St SE to create a new tie with 25-24.112 for increased reliability.

See Section 7.1 and Figure 18 & Figure 19 in Section 8.0 for detailed scope.

Technical review

- Alternative 3 resolves all identified transformer and feeder N-1 deficiencies at 24 Sub, 26 Sub, 54 Sub and 37 Sub within the 10-year forecast timeframe, under both normal operating conditions and contingency scenarios.
- 54 Sub currently has only one 25kV transformer. Adding a second transformer eliminates the single point of failure, increases substation reliability, and provides flexibility for maintenance planning and operations.
- The existing station layout at 54 Sub is configured to accommodate an additional transformer without requiring station expansion, making implementation technically straightforward compared to the other alternatives.
- 54 Sub provides the nearest 25kV source to the primary growth centers in the Southeast and Southwest of the city. The three new feeders (approximately 11.5 km in total) are shorter than those required under Alternatives 4 and 5, ensuring voltages remain above the planning criteria minimum threshold of 110/220 V under normal conditions and 106/212 V under contingency conditions throughout the study area.
- Offloading approximately 50MVA from 26 Sub to 54 Sub reduces 26 Sub loading to approximately 58MVA during normal operation, providing sufficient capacity at 26 Sub to support feeder and transformer contingency scenarios at 24 Sub, 37 Sub and 54 Sub.

Cost review

- Capital Cost Estimate: $56,800,000 (+20%/-10%), revised to Class 3 accuracy given this is the preferred alternative, reflecting a 10% net increase over the previous Class 5 estimate. This net increase is driven primarily by a 66% increase in the transmission scope estimate, partially offset by a modest 2% increase in the distribution scope estimate.
- Alternative 3 is the lowest-cost option among the three technically viable transmission alternatives.

- No station expansion is required at 54 Sub as the existing layout already accommodates the additional transformer, avoiding the additional civil and structural costs incurred under Alternatives 4 and 5.

Environment and Land review

- Implementation of Alternative 3 is confined within the existing 54 Sub fence line, as the station layout already has a spare transformer position. No fence extension or additional land acquisition is required.
- The new distribution feeders (approximately 11.5 km of new construction and 10.9 km of feeder extensions) follow existing utility corridors, minimizing disturbance to the surrounding environment.
- The compact feeder lengths result in the smallest overall infrastructure footprint among the technically viable alternatives, limiting environmental impact.

Alternative 3 is the preferred alternative as it fully addresses the identified system capacity deficiencies across all four substations, is the most technically efficient solution given its proximity to the primary growth centers, carries the lowest capital cost, and results in the smallest environmental and land footprint. It is therefore recommended for implementation.

6.4 Alternative 4: Addition of 25 kV Transformation Capacity at 26 Sub

Scope:

- Install one [1] 138/25kV 30/40/50MVA transformer with associated bus work, 138kV tie breaker, and 25kV MV switchgear lineup with four [4] new feeder positions at 26 Sub.
- The distribution scope for this alternative includes the following:
  - Transfer two [2] existing feeders (25-26.121 & 25-26.123) to the new station bus to balance the existing loading on the buses within the station. This can be achieved either by installing DA switches close to the station or transferring the load at the station buses.
  - Construct three [3] new 25kV distribution feeders from 26 Sub.
    - One new feeder (approximately 4.5km North on Deerfoot Trail & 1.9km Northeast of 26 Sub to the Inverness community) to offload approximately 9.4MVA of load from 24 Sub and increase reliability via new ties to feeders 25-24.111 and 25-24.123.
    - A second feeder will extend approximately 6 km south on Deerfoot Trail SE towards the 54 Sub area to pick up growing load pockets in South Seton.
    - The third feeder will extend approximately 6.7km West on Stoney Trail SE and South towards the Wolf Willow and Walden communities to service growing communities in the area.

- Extend feeder 25-37.112 approximately 4.5km south on 68 St SE to create a new tie with 25-24.112 for increased reliability.

See Section 7.2 and Appendix B Figure B.1 for a detailed scope.

Technical review

- While Alternative 4 increases transformation capacity and would supply the anticipated load growth within the 10-year forecast timeframe under normal and contingency conditions, its location at 26 Sub is not well aligned with the primary growth centers in the Southeast and Southwest of the city. With a straight-line distance of approximately 6 km between 26 Sub and 54 Sub — which is centrally located relative to those growth areas — feeders originating from 26 Sub would need to travel significantly greater distances to serve the same load pockets.
- Serving the southern growth areas from 26 Sub requires long feeder extensions, producing undervoltage conditions — specifically, voltages falling 2% to 3% below the planning criteria minimum threshold of 110/220 V under normal operating conditions and 106/212 V under contingency conditions.
- Most communities within close proximity to 26 Sub (i.e., Auburn Bay, McKenzie Towne, Inverness, Copperfield, and New Brighton) are saturated loads with no forecasted growth for the foreseeable future. Mahogany is the only growing community that will remain within the 26 Sub service territory; Seton is located further south, in closer proximity to 54 Sub (Alternative 3).
- It is therefore not technically favorable to increase capacity at 26 Sub when the primary load growth is occurring in areas better served by 54 Sub.

Cost review

- Capital Cost Estimate[xi]: $72,713,543 (Class 5, +50%/-30%), not revised to Class 3 given this is not the preferred alternative. ENMAX expects costs would increase similarly to the increases observed on the preferred 54 Sub alternative (+10%), which would sustain or widen the cost differential.
- Alternative 4 carries a delta of approximately $15,913,543 above the preferred Alternative 3 ($56,800,000), making it the highest-cost option among the three transmission alternatives.
- Additional civil and structural costs are required to expand the existing station layout at 26 Sub to accommodate a third transformer. This expenditure is not required under the preferred Alternative 3.

[xi] The cost estimate does not include voltage regulation devices. Although longer feeders from 26 Sub would produce undervoltage conditions, voltage regulators are not a viable long-term solution as they address the symptom rather than the underlying cause and require ongoing maintenance and additional operations on the system.

Environment and Land review

- Implementing Alternative 4 requires a fence extension at 26 Sub to accommodate a third transformer, increasing the substation footprint beyond its current boundary.
- Serving the southern growth centers from 26 Sub requires longer feeder routes than those needed under the preferred Alternative 3. The combined effect of longer distribution feeders and fence expansion results in an overall infrastructure footprint significantly greater than that of Alternative 3.
- Consequently, the impact on the environment and land is greater under this alternative compared to the preferred Alternative 3.

This alternative was dismissed on technical, economic, and environmental grounds. From a technical perspective, the location of 26 Sub is not well aligned with the primary growth centers, requiring long feeder extensions that produce undervoltage conditions, Alternative 4 is the highest-cost option, representing a delta of approximately $16M above the preferred Alternative 3. From an environmental and land perspective, the longer feeders combined with the fence extension required at 26 Sub result in a significantly greater footprint than Alternative 3.

6.5 Alternative 5: Addition of 25 kV Transformation Capacity at 24 Sub

Scope:

- Install one [1] 138/25 kV 30/40/50MVA transformer with associated bus work, 138kV tie breaker, and 25kV MV switchgear lineup with four [4] feeder positions at 24 Sub.
- The distribution scope for this alternative includes the following:
    - Construct two [2] new 25kV distribution feeders from 24 Sub.
        - One new feeder will extend approximately 4.5km North on 68 St SE to create a new tie with 25-24.112 for increased reliability.
        - The second feeder will extend approximately 7 km along 52 St SE and Deerfoot Trail SE to offload 12MVA from feeder 25-26.111.
    - Two [2] existing feeders (25-24.112 & 25-24.114) will be transferred to the new station bus to balance the existing loading on the buses within the station. This can be achieved either by installing DA switches close to the station or transferring the load at the station buses.

See Section 7.3 and Appendix B Figure B.2 for a detailed scope.

Technical review

- Includes the technical assessment of the transformer addition at 24 Substation and the associated local feeder connections required to serve the immediate 24 Sub and 37 Sub service areas. Longer feeder extensions that would be required to supply load growth areas located farther south, closer to 54 Sub, were not included in the detailed technical evaluation. A high-level screening assessment was performed to confirm that such longer feeders would introduce potential undervoltage limitations due to their extended lengths.

- Alternative 5 increases transformation capacity at 24 Sub and partially addresses load growth within the 24 Sub and 37 Sub service areas under normal and contingency conditions. However, it does not adequately mitigate the identified load at risk at 26 Sub and 54 Sub.
- 24 Sub is located far from the primary load centers in the South of the study area (refer to Figure 7 and Figure 8). With a straight-line distance of approximately 13 km between 24 Sub and the southern growth areas near 54 Sub — which is centrally located relative to those load centers — feeders originating from 24 Sub would need to travel significantly greater distances to serve the same load pockets.
- Serving those growth centers from 24 Sub requires long feeder extensions, producing undervoltage conditions — specifically, voltages falling 3% to 4% below the planning criteria minimum threshold of 110/220 V under normal operating conditions and 106/212 V under contingency conditions.
- Alternative 5 was evaluated as a potential supply option utilizing existing infrastructure at Substation 24, with feeders extended to serve the SE Calgary growth area. Based on ENMAX's distribution planning criteria (minimum service voltage of 110/220V under normal operating conditions and 106/212V under contingency conditions), feeder voltage performance was assessed across an estimated high-level route range of 16–22 km required to reach the load growth center. Analysis confirms that a feeder of this length, under projected load growth conditions, would breach normal voltage thresholds prior to full area buildout. Extending service beyond this limit would necessitate multiple voltage support devices, introducing additional capital cost and operational complexity without resolving the underlying constraint.
- A 50 MVA transformer (37.3TR) was commissioned at 37 Sub in December 2025, located approximately 4.5 km north of 24 Sub. This existing capacity addition is already available to support 24 Sub under contingency conditions, making an additional transformer at 24 Sub redundant for that purpose.
- It is therefore technically preferable to address the demand constraints in the Southeast through 54 Sub (Alternative 3), which is better positioned relative to the growth centers.

<u>Cost review</u>

- Capital Cost Estimate[xii]: $57,429,283 (Class 5, +50%/-30%). ENMAX expects costs of this alternative would increase similarly to the increases observed on the preferred

[xii] The cost estimate does not include voltage regulation devices. Although longer feeders from 24 Sub would produce undervoltage conditions, voltage regulators are not a viable long-term solution as they address the symptom rather than the underlying cause and require ongoing maintenance and additional operations on the system.

54 Sub alternative (+10%) when updated to Class 3, which would sustain or widen the cost differential.

- Alternative 5 includes capital costs for the transformer addition at 24 Sub and associated local feeder infrastructure serving the immediate 24 Sub and 37 Sub service areas. Costs for longer feeder extensions required to supply southern load growth areas closer to 54 Sub were not included due to anticipated undervoltage limitations associated with extended feeder lengths.
- Additional civil and structural costs are required to expand the existing station layout at 24 Sub to accommodate a third transformer, including a fence extension. These expenditures are not required under the preferred Alternative 3.

Environment and Land review

- Implementing Alternative 5 requires a fence extension at 24 Sub to accommodate a third transformer, increasing the substation footprint beyond its current boundary.
- Serving the southern growth centers from 24 Sub requires longer feeder routes than those needed under the preferred Alternative 3. The combined effect of longer distribution feeders and fence expansion results in an overall infrastructure footprint significantly greater than that of Alternative 3.
- Consequently, the impact on the environment and land is greater under this alternative compared to the preferred Alternative 3.

Alternative 5 was dismissed on technical, economic, and environmental grounds. While the estimated capital cost of Alternative 5 is comparable to the preferred Alternative 3, it is limited to serving the immediate 24 Sub and 37 Sub service areas and does not include the longer feeder extensions required to supply the primary southern growth centers closer to 54 Sub. High-level screening indicated that such long feeders would introduce undervoltage limitations and would not adequately mitigate load at risk at 26 Sub and 54 Sub. In addition, the required substation fence expansion at 24 Sub and longer feeder routes would result in a larger overall footprint compared to Alternative 3.

7.0 Capital Cost Estimates

Cost estimates were prepared for technically viable Alternative 3, Alternative 4, and Alternative 5. The transmission scope of work and the associated cost are presented in this section for the purpose of alternative comparison. Alternative 1 and Alternative 2 were deemed not viable and dismissed.

7.1 Alternative 3 (preferred): Addition of 25kV Transformation at 54 Sub

Table 10: Alternative 3 Cost Estimate (Class 3 +20%/-10%)

Project Description	Capital Cost Estimate[xiii]
Transmission (2028): Installation of one [1] 138/25 kV 30/40/50 MVA transformer at existing spare position within 54 Sub, and 138kV bus tie breaker. Installation of new 25kV MV switchgear lineup for four 25 kV feeders.	$26,000,000
Distribution (2028): Construction of one [1] new 25 kV feeder (25-54.113) approximately 2.5 km West of 54 S to offload feeder 25-26.121 supplying Walden, Wolf Willow, and Cranston. Construction of one [1] new 25 kV feeder (25-54.114) approximately 4.5 km north on Deerfoot trail SE to offload feeder 25-26.112 supplying Seton. Construction of one [1] new 25 kV feeder (25-54.123) approximately 4.5 km north on Deerfoot trail SE to offload feeder 25-26.123 supplying Auburn Bay. Extension of future feeder 25-37.112 approximately 4.5 km south on 68 St SE to create a new tie with feeder 25-24.112) Extension of existing feeder 25-26.121 approximately 4.5 km North on Deerfoot Trail SE to create a new tie with feeder 25-24.111, and 1.9 km Northeast of 26 Sub to the Inverness community to tie to feeders 25-24.123 and 25-26.113.	$30,800,000
IDC ($2,600,000); E&S/Overhead ($6,500,000)	Included above
Total Project Cost:	**$56,800,000**

Please note that the cost estimates for Alternative 3 were revised to Class 3; +20%/-10% (relative to the initial DDR submission in 2024) given it is the preferred alternative.

[xiii] Cost estimate includes Interest Under Construction (IDC) costs and Administrative Overhead (AOH).

7.2 Alternative 4: Addition of 25kV Transformation at 26 Sub

Table 11: Alternative 4 Cost Estimate (Class 5 +50%/-30%)

Project Description	Capital Cost Estimate[xiv]
Transmission (2028): Installation of one [1] 138/25 kV 30/40/50 MVA transformer and associated bus work including 138kV bus tie breaker. Installation of new 25kV MV switchgear lineup for four 25 kV feeders.	$29,843,718
Distribution (2028): Transfer two [2] existing feeders (25-26.121 & 25-26.123) to the new station bus to redistribute station load. This can be achieved either by installing DA switches close to the station or transferring the load at the station buses. Construction of one [1] new 25 kV feeder (25-26.XXX, TBD) approximately 4.5 km North on Deerfoot Trail SE to create a new tie with feeder 25-24.111, and 1.9 km Northeast of 26 Sub to the Inverness community to tie to feeders 25-24.123 and 25-26.113 adjacent to switch # 25-26.113-48. Construction of one [1] new 25 kV feeder (25-26.XXX, TBD) approximately 6 km south on Deerfoot Trail SE to pick up growing load pockets in the South of Seton. Construction of one [1] new 25 kV feeder (25-26.XXX, TBD) approximately 6.7 km West on Stoney Trail SE and South towards the Wolf Willow and Walden communities (new open point at switch # 25-26.121-34) to service growing communities in the area. Extension of future feeder 25-37.112 approximately 4.5 km south on 68 St SE to create a new tie with feeder 25-24.112).	$33,893,968
IDC ($2,102,763) E&S/Overhead ($6,284,146)	$8,386,908
Total Project Cost:	**$72,713,543**

Please note that the cost estimates for Alternative 4 were not revised to Class 3 +20%/-10% (relative to the initial DDR submission in 2024) given it is the not preferred alternative.

[xiv] Cost estimate includes Interest Under Construction (IDC) costs and Administrative Overhead (AOH).

7.3 Alternative 5: Addition of 25kV Transformation at 24 Sub

Table 12: Alternative 5 Cost Estimate (Class 5 +50%/-30%)

Project Description	**Capital Cost Estimate**
Transmission (2028): Installation of one [1] 138/25 kV 30/40/50 MVA transformer and associated bus work including 138kV bus tie breaker. Installation of new 25kV MV switchgear lineup for four 25 kV feeders.	$30,371,945
Distribution (2028): Transfer two [2] existing feeders (25-24.112 & 25-24.114) to the new station bus to redistribute station load. This can be achieved either by installing DA switches close to the station or transferring the load at the station buses. Construction of one [1] new 25 kV feeder approximately 4.5 km north on 68 St SE to create a new tie with feeder 25-24.112). Construction of one [1] new 25 kV feeder approximately 7 km along 52 St SE and Deerfoot Trail SE to offload 12MVA from feeder 25-26.111 (create new tie adjacent to switch # 25-24.123-39).	$20,377,532
IDC ($1,342,160) E&S/Overhead ($4,982,329)	$6,324,489
Total Project Cost:	**$57,429,283**

Please note that the cost estimates for Alternative 5 were not revised to Class 3; +20%/-10% (relative to the initial DDR submission in 2024) given it is the not preferred alternative.

8.0 Proposed System Development - Preferred Alternative 3

As summarized in Section 6.0, Alternative 3 - Addition of 25kV Transformation at 54 Sub is the preferred option to mitigate the distribution deficiencies outlined in this DDR. Figure 18 and Figure 19 outline the Transmission and Distribution scope associated with Alternative 3.

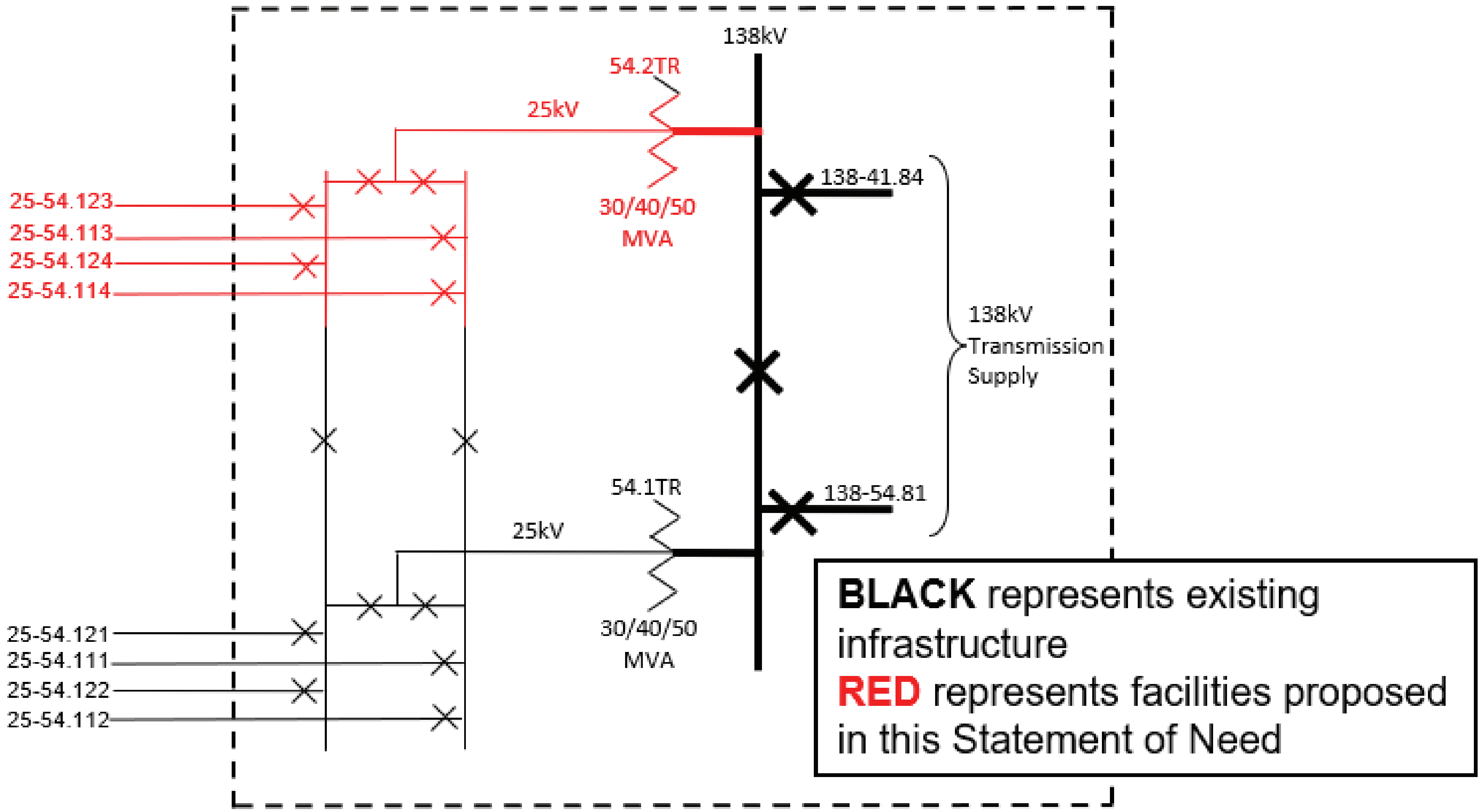


Figure 17: Existing No. 54 Substation Configuration with Alternative 3 Implemented

Preferred Alternative 3 Scope of Work

Alternative 3 Scope (Preferred Alternative)
A: Construct one [1] new 25 kV feeder (25-54.113) approximately 2.5 km Northwest of 54 Sub to offload feeder 25-26.121 supplying Wolf Willow, Walden and Cranston area.
B: Construct two [2] new 25 kV feeders (25-54.114 & 25-54.123) approximately 4.5 km north on Deerfoot trail SE to offload feeders 25-26.112 supplying Seton and 25-26.123 supplying Auburn Bay.
C: Extension of existing feeder 25-26.121 approximately 4.5 km North on Deerfoot Trail SE to create a new tie with feeder 25-24.111 and transfer approximately 5.6MVA of load to feeder 25-26.121.
-Feeder 25-26.121 will also be extended 1.9 km Northeast of 26 Sub to the South of the developed Inverness community, to tie to feeders 25-24.123 and 25-26.113. Approximately 1.9MVA of load will be transferred from feeder 25-24.123 to feeder 25-26.121.
D: Extension of future 25-37.112 feeder approximately 4.5 km south on 68 St SE to create a new tie with feeder 25-24.112)

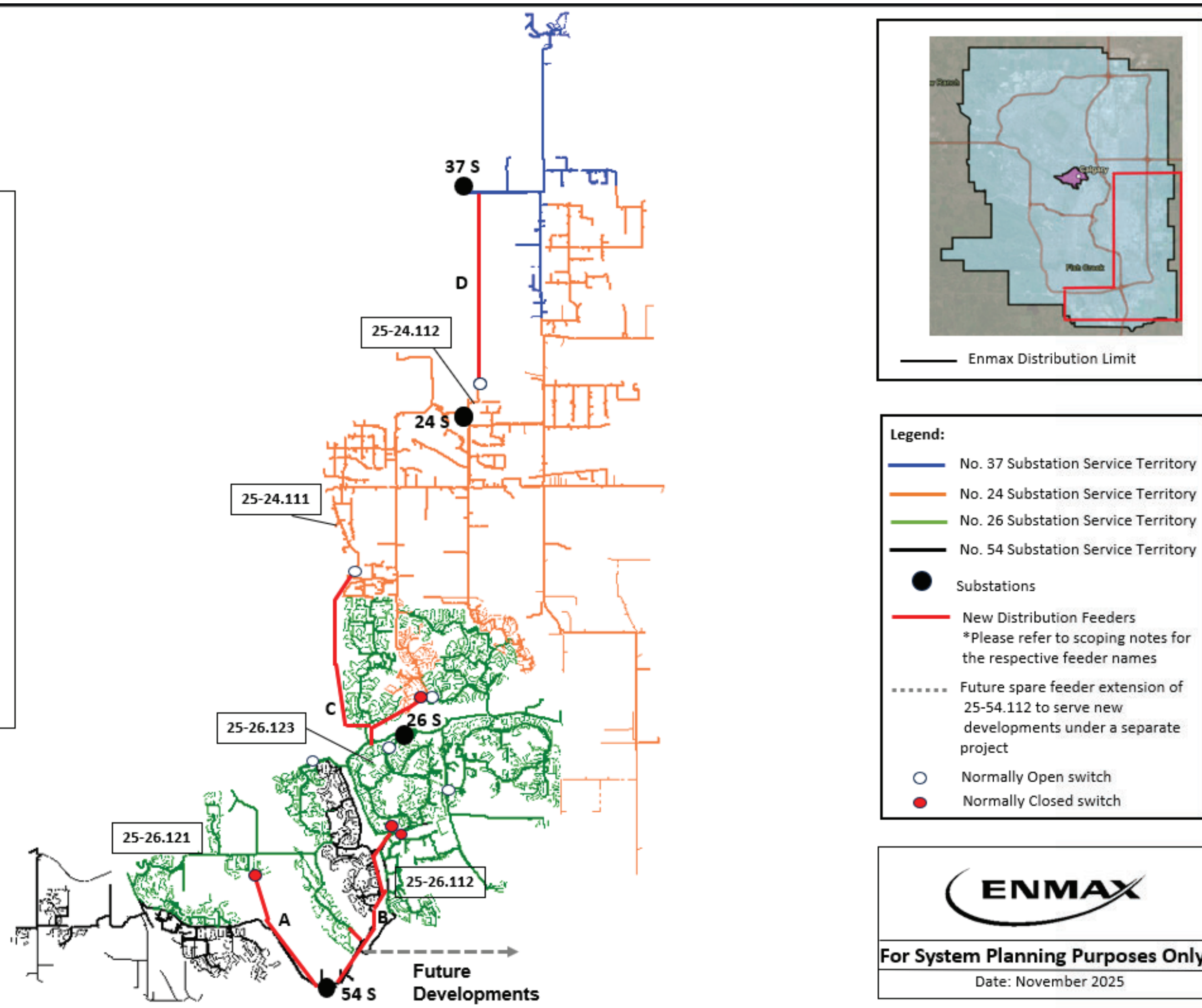


Figure 18: Preferred Alternative 3 Scope of Work

9.0 Load Forecast – Preferred Alternative 3 Implemented

This section provides substation, transformer and feeder load forecasts and Load at Risk with the preferred Alternative 3 implemented. It is assumed that the preferred alternative will be implemented in Summer 2028.

Table 13: POD Load Forecast - Preferred Alternative Implemented (MVA)

POD	Capacity (MVA)	Peak Season	PF[1]	Actual Load (MVA)					Forecasted Load (MVA)									
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
24 S	100	S	0.90	60	61	64	74	68[2]	74	77	68[3]	72	75	76	78	79	80	80
26 S	100	S	0.97	82	81	85	95	91	89[8]	91	58[4]	59	59	59	59	59	59	59
54 S	100[7]	S	0.99	24	24	26	30	31	37	38	85[5]	87	89	91	92	93	94	94
37 S	150[6]	S	0.90	53	54	53	54	66[2]	74	82	87	91	97	102	104	106	106	106

Notes:

1. The POD power factor is calculated using the POD MW and MVA values over the POD summer peak period.
2. Planned load transfer of 8.7MVA from 24 Sub to 37 Sub in 2025 to leverage the capacity of the new 25kV transformer at 37 Sub. The transfers are counteracted by additional load growth at the station.
3. Planned load transfer of 10.4MVA from 24 Sub to 26 Sub in 2028.
4. Planned load transfer of 50.1MVA from 26 Sub to 54 Sub, 10.4MVA from 24 Sub to 26 Sub and 4.5MVA from 54 Sub to 26 Sub in 2028.
5. Planned load transfer of 50.1MVA from 26 Sub to 54 Sub and 4.5MVA from 54 Sub to 26 Sub in 2028.
6. Installed capacity at 37 Sub increased from 100MVA to 150MVA with addition of a 50MVA transformer (37.3TR) in 2025.
7. 54 Sub capacity will be increased from 50MVA to 100MVA after the project ISD in 2028.
8. Planned load transfer of 4.4MVA from 26 Sub to 54 Sub in 2026.

Table 14: Transformer Load Forecast - Preferred Alternative Implemented (MVA)

Transformer	Capacity (MVA)	Peak	PF	Actual Load (MVA)					Forecasted Load (MVA)									
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
24.1TR	50	S	0.90	29	32	34	45	35[4]	43	44	37[2]	38	38	39	40	41	41	41
24.2TR	50	S	0.91	31	30	31	34	29[1]	32	35	33[3]	35	38	38	39	40	40	40
26.1TR	50	S	0.96	43	43	45	51	47[4]	48	49	27[5]	28	28	28	28	28	28	28
26.2TR	50	S	0.97	40	38	40	44	43	42	42	31[6]	31	31	31	31	31	31	31
54.1TR	50	S	0.99	24	24	26	30	31	37[4]	39	40	42	43	45	46	46	47	47
54.2TR[8]	50	S	-	-	-	-	-	-	-	-	46[7]	46	47	47	48	48	49	49
37.3TR[9]	50	S	-	-	-	-	-	17	20	23	27	30	34	38	40	41	42	42
37.4TR	13.3	S	0.90	6	7	6	7	-	-	-	-	-	-	-	-	-	-	-
6.4TR	50	S	0.99	6	6	7	8	8	9	11	12	12	13	14	14	15	15	15

Notes:

1. Planned load transfer of approximately 8.7MVA from feeder 25-24.114 to 25-37.111A & 25-37.112 in 2025 as part of the 37 Sub capacity upgrade project. Additional load growth on other feeders supplied by 24.2TR counteracts the effect of this transfer.

2. Planned transfer of 8.5MVA from 24.1TR to 26 Sub in 2028.
3. Planned transfer of 1.9MVA from 24.2TR to 26 Sub in 2028.
4. Lower peak loading observed in summer 2025.
5. Planned transfer of 35.3MVA from 26.1TR to 54 Sub and 11.9MVA from 24 Sub and 54 Sub to 26.1TR in 2028.
6. Planned transfer of 14.8MVA from 26.2TR to 54 Sub and 2.9MVA from 24 Sub to 26.2TR in 2028.
7. Planned transfer of 45.7MVA from 26 Sub to 54.2TR in 2028.
8. New 50MVA transformer installation at 54 Sub in 2028 as part of the preferred alternative.
9. 37.3TR is the new 50MVA transformer at 37 Sub, energized in 2025. 37.4TR was decommissioned.

Table 15: 25 kV Feeder Load Forecast - Preferred Alternative Implemented (MVA)

Feeder	Capacity (MVA)	Source Transformer	Peak	Actual Load (MVA)					Forecasted Load (MVA)									
				2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
No. 24 Substation																		
25-24.111	25.9	24.1	S	7	9	12	13	11	12	12	7[2]	7	7	8	8	8	8	8
25-24.112	25.9	24.1	S	13	13	13	13	12	14	14	14	15	15	15	16	16	16	16
25-24.121	25.9	24.1	S	9	9	9	14	11	12	13	10[3]	10	11	11	11	11	11	11
25-24.122	25.9	24.1	S	0	1	3	6	5	6	6	6	6	6	6	6	6	6	6
25-24.113	25.9	24.2	S	5	5	5	5[1]	0	0	0	0	0	0	0	0	0	0	0
25-24.114	25.9	24.2	S	8	8	8	10	8[1]	12	14	14	14	14	15	15	15	15	15
25-24.123	25.9	24.2	S	13	12	12	14	11	12	12	10[4]	13	15	16	16	17	17	17
25-24.124	25.9	24.2	S	5	6	6	6	6	9	9	9	9	9	9	9	9	9	9
No. 37 Substation																		
25-37.111	25.9	37.4	S	6	7	6	7	-	-	-	-	-	-	-	-	-	-	-
25-37.111A	25.9	37.3	S	-	-	-	-	9[5]	11	13	14	16	17	19	21	22	22	22
25-37.112	25.9	37.3	S	-	-	-	-	8[5]	9	11	13	14	17	19	19	19	20	20
No. 26 Substation																		
25-26.111	25.9	26.1	S	13	12	12	13	13	13	13	13	13	13	13	13	13	13	13
25-26.112	25.9	26.1	S	8	10	11	14	15	16	17	-[8]	-	-	-	-	-	-	-
25-26.121	25.9	26.1	S	17	17	19	21	20	16[11]	17	12[9]	13	13	13	13	13	13	13
25-26.122[6]	25.9	26.1	S	4	4	4	3	4	3	3	3	3	3	3	3	3	3	3
25-26.113	25.9	26.2	S	25	24[7]	11	12	12	11	11	14[3]	14	14	14	14	14	14	14
25-26.114	25.9	26.2	S	0	0[7]	14	16	16	16	17	17	17	17	17	17	17	17	17
25-26.123	25.9	26.2	S	15	14	15	15	13	15	15	-[10]	-	-	-	-	-	-	-
25-26.124[6]	25.9	26.2	S	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
No. 54 Substation																		
25-54.111	25.9	54.1	S	7	9	11	14	15	18	19	20	22	23	23	24	24	24	24
25-54.112	25.9	54.1	S	0	0	0	0	0	5[11]	5	6	6	6	6	7	7	7	7
25-54.121	25.9	54.1	S	13	12	12	12	11	11	11	11	11	11	13	13	13	13	13
25-54.122[6]	25.9	54.1	S	5	5	4	5	4	5	5	5	5	5	5	5	5	5	5
25-54.113	25.9	54.2	S	-	-	-	-	-	-	-	13[12]	13	13	13	13	13	13	13
25-54.114	25.9	54.2	S	-	-	-	-	-	-	-	18[13]	19	19	20	20	20	21	21
25-54.123	25.9	54.2	S	-	-	-	-	-	-	-	15[14]	15	15	15	15	15	15	15
25-54.124	25.9	54.2	S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
No. 6 Substation				Back up option for Feeder 25-54.111														
25-6.111	25.9	6.4	S	5	6	6	6	7	7	8	8	8	9	9	9	9	10	10

Notes:

1. Approximately 8.7MVA of planned load transfers from 25-24.114 to 25-37.111A & 25-37.112 in 2025 as part of the 37 Sub capacity upgrade project. In addition, all the load on 25-24.113 (5MVA) will be transferred to 25-24.114. Feeder 25-24.113 will be offloaded to provide N-1 capacity to 25-24.122 & 25-37.111A during contingency scenarios.
2. Planned transfer of 5.6MVA from 25-24.111 to 25-26.121 in 2028.
3. Planned transfer of 2.9MVA from 25-24.121 to 25-26.113 in 2028.

4. Planned transfer of 1.9MVA from 25-24.123 to 25-26.121 in 2028.
5. New 25kV feeders at 37 Sub energized in December 2025.
6. 25-26.122, 25-26.124 and 25-54.122 are dedicated feeders to the South Health Campus in Seton.
7. Permanent load transfer from 25-26.113 to 25-26.114 in 2023 to balance feeder loading.
8. Planned transfer of 18.3MVA from 25-26.112 to 25-54.114 in 2028.
9. Planned transfer of 12.5MVA from 25-26.121 to 25-54.113 and addition of 7.5MVA in total from 25-24.111 & 25-24.123 to 25-26.121 in 2028.
10. Planned transfer of 14.8MVA from 25-26.123 to 25-54.123 in 2028.
11. Planned transfer of 4.4MVA from 25-26.121 to 25-54.112 in 2026.
12. Planned transfer of 12.5MVA from 25-26.121 to 25-54.113 in 2028.
13. Planned transfer of 18.3MVA from 25-26.112 to 25-54.114 in 2028. Forecasted load growth from 2028 onwards is reflected in feeder forecast.
14. Planned transfer of 14.8MVA from 25-26.123 to 25-54.123 in 2028.

As illustrated in Table 16, implementing the preferred alternative mitigates the identified load at risk during transformer contingency scenarios in all the stations after 2028.

Table 16: Transformer Load at Risk - Preferred Alternative Implemented (MVA)

	Actual		Forecast (MVA)									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Loss of 24.1TR or 24.2TR		Summer Peak										
24 S Total Load[1]	79	64[20]	75	79	70[6]	73	76	78	79	80	81	81
Alternate TX Capacity (24.1TR or 24.2TR)	50	50	50	50	50	50	50	50	50	50	50	50
Back up from 26 S	0[2]	0	0	0	27[4]	30	31	32	32	32	32	32
Back up from 37 S	0[3]	8	12	14	14	14	14	5[19]	5	0	0	0
Total Unsupplied Load	29	6[5]	13	15	0	0	0	0	0	0	0	0
Loss of 26.1TR or 26.2TR	Summer Peak											
26 S Total Load[1]	95	90	90	92	56[7]	60	60	60	60	60	60	60
Alternate TX Capacity (26.1TR or 26.2TR)	50	50	50	50	50	50	50	50	50	50	50	50
Back up from 24 S	13	13	13	13	10[9]	10	10	10	10	10	10	10
Back up from 54 S	15	15	0[8]	0	-[10]	-	-	-	-	-	-	-
Total Unsupplied Load	17	12	27	29	0	0	0	0	0	0	0	0
Loss of 54.1TR	Summer Peak											
54 S Total Load[1]	30	31	37	39	86[11]	88	90	92	93	94	95	95
Alternate TX Capacity (54.1TR or 54.2TR)	-	-	-	-	50	50	50	50	50	50	50	50
Back up from 26 S	0[12]	8	8	8	33[14]	34	34	34	35	35	36	36
Back up from 6 S	14	15	18	0[13]	0	0	0	0	0	0	0	0
Back up from 24 S	-	-	-	-	10[15]	10	10	10	10	10	10	10
Total Unsupplied Load	16	8	11	31	0	0	0	0	0	0	0	0
Loss of 37.3TR (25kV)[18]	Summer Peak											
37 S Total Load[1]	-	17	20	23	27	30	34	38	40	41	42	42
Temporary Load Transfer to 26 S[16-a]	-	-	-	-	20	23	24	24	24	24	24	24
Back up from 24 S[16a-b]	-	21	18	15	50[17]	48	47	47	45	43	43	43
Total Unsupplied Load	-	0	2	8	0	0	0	0	0	0	0	0

Notes:

1. Utilized the sum of the respective transformer peaks to determine total load, as opposed to the diversified station peaks.

2. Back up capacity from 26 Sub (utilizing tie-away feeder: 25-26.113) is limited by 26.2TR transformer overload between 2024-2027 during N-1 contingency. 24 Sub only has two existing ties to 26 Sub. With both 26.1TR & 26.2TR transformers having capacity constraints, there is limited N-1 support available to 24 Sub from 26 Sub.
3. Insufficient back up capacity from 37 Sub in 2024, because the pre-existing 37.4TR autotransformer was rated at 13.3MVA. With the new 50 MVA transformer addition in 2025, N-1 support becomes available from 2025.
4. Additional back up capacity available on 26.1/26.2TR in 2028, due to station offload aligned with Alternative 3.
5. Decreased load at risk due to available back up capacity from new 37.3TR transformer at 37 Sub.
6. Planned transfer of 10.4MVA from 24 Sub to 26 Sub in 2028 decreases station loading. The transfers are counteracted by additional load growth at the station.
7. Planned net transfer of 35.2MVA from 26 Sub to 54 Sub in 2028 decreases loading (i.e. 50.1MVA transferred from 26 Sub to 54 Sub and 14.9MVA from 24 Sub to 26 Sub).
8. Back up capacity from 54 Sub (25-54.121) limited by 54.1TR transformer overload beginning in 2026.
9. Additional back up capacity available on 24.2TR in 2028, due to station offload aligned with Alternative 3.
10. Decreased back up capacity from 54 Sub (via feeder 25-54.121) in 2028, due to load additions, but the back up from 24 Sub is sufficient during 26 Sub contingency.
11. Planned transfer of 45.7MVA from 26 Sub to 54 Sub in 2028.
12. Limited back up capacity from 26 Sub (utilizing tie-away feeder: 25-26.123) due to high summer peak loading on 26.2TR transformer in 2024.
13. Back up capacity from 6 Sub (utilizing tie-away feeder: 25-6.111) is limited by 6.1TR transformer overload during contingency scenario in 2027.
14. Additional back up available at 26 Sub after station offload in 2028.
15. Additional back up available from 24 Sub in 2028 through cascading load transfers.
16. After the preferred alternative is implemented in 2028, loss of 37.3TR can be supported by 24 Sub through cascading load transfers from 24 Sub to 26 Sub, and then 37 Sub to 24 Sub. Below is a summary of the steps required:
    a. Offload 20-24MVA from 24 Sub to 26 Sub to have available back up capacity at 24 Sub to support 37 Sub. This can be achieved by temporarily transferring all the load from 25-24.121 to 25-26.113, and partial transfer of 25-24.123 to 25-26.111.
        i. In addition, all the load supplied by feeder 25-24.112 would need to be temporarily offloaded to 25-24.111, to provide capacity on 25-24.112 for a total feeder transfer from 25-37.112 utilizing the new tie.
    b. After step 16a, residual load at 24 Sub will range from 50-57MVA between 2028 and 2034. During a transformer contingency scenario at 37 Sub occurring after implementation of the preferred alternative, 24 Sub will have adequate capacity to pick up all the load from 37 Sub via feeders 25-37.111A & 25-37.112.
17. Increased back up capacity at 24 Sub after station offload to 26 Sub during 37.3TR contingency scenario.
18. Load at Risk for new 50MVA transformer (37.3TR) at 37 Sub. 37.3TR is the only 25kV transformer at 37 Sub, therefore it will rely solely on 24 Sub for back up supply.
19. Decreased back up capacity from 37 Sub, due to 37.3TR limitation.
20. Lower summer peak loading observed at 24 S in 2025.

As demonstrated in Table 17, the preferred alternative mitigates the identified load at risk on all feeders except 25-37.111A/25-37.112 during a 25 kV feeder contingency in 2032-2035.

Table 17: 25 kV Feeder Load at Risk - Preferred Alternative Implemented (MVA)

	Actual		Forecast (MVA)									
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Loss of 25-24.123	Summer Peak											
25-24.123 Total Load	14	11	12	12	10[2]	13	15	16	16	17	17	17
Back up from 25-24.111	7	7	7	0[1]	0	0	0	0	0	0	0	0
Back up from 25-26.113	7	7	7	0	10[3]	10	10	10	10	10	10	10
Back up from new tie to 25-26.121	-	-	-	-	7[4]	7	7	7	7	7	7	7
Total Unsupplied Load	0	0	0	12	12	0	0	0	0	0	0	0
Loss of 25-37.111A[7]	Summer Peak											
25-37.111A Total Load	0	9	11	13	14	16	17	19	21	22	22	22
Back up from 25-24.113	-	21	18	15	17[5]	15	12	12	11	10	10	10
Back up from 25-37.112[5]	-	6	6	6	6	6	6	6	6	6	6	6
Total Unsupplied Load	-	0	0	0	0	0	0	0	4[6]	6	6	6
Loss of 25-37.112[7]	Summer Peak											
25-37.112 Total Load	0	8	9	11	13	14	17	19	19	19	20	20
Back up from 25-24.114	-	18	14	12	12	12	12	11	11	10	10	10
Back up from 25-37.111A	-	6	6	6	6	6	6	6	0	0	0	0
Back up from new tie to 25-24.112	-	-	-	-	12[8]	11	11	11	10	9	9	9
Total Unsupplied Load	-	0	0	0	0	0	0	0	0	0	1	1
Loss of 25-26.121	Summer Peak											
25-26.121 Total Load	21	20	16	17	12[9]	13	13	13	13	13	13	13
Back up from 25-26.111	9	9	9	0	13[10]	13	13	13	13	13	13	13
Back up from 25-54.121	12	11	8	0[11]	0	0	0	0	0	0	0	0
Total Unsupplied Load	0	0	0	17	0	0	0	0	0	0	0	0
Loss of 25-26.113	Summer Peak											
25-26.113 Total Load	12	12	11	11	14[12]	14	14	14	14	14	14	14
Back up from 25-24.123	14	14	14	14	0	0	0	0	0	0	0	0
Back up from 25-26.121	-	-	-	-	14[13]	14	14	14	14	14	14	14
Total Unsupplied Load	0	0	0	0	0	0	0	0	0	0	0	0

Notes:

1. Back up capacity on 25-24.111 is limited by 24.1TR transformer overload during feeder 25-24.123 contingency scenario in 2027, therefore the double tie solution is insufficient.
2. Planned transfer of 1.9MVA from 25-24.123 to 25-26.121 in 2028.
3. Increased back up capacity on 25-26.113 due to capacity increase on 26.2TR transformer after 2028 offload.
4. New tie created between 26-26.121 & 25-24.123 in 2028 provides additional back up capacity.

5. Slight increase in back up capacity on 25-24.113 due to 1.9MVA load transfer from 24.2TR to 26 Sub in 2028.
6. There is insufficient capacity to support 1-6 MVA of load serviced by 25-37.111A/25-37.112 in 2032-2034.
7. 25-37.111A & 25-37.112 are new 25kV feeders at 37 Sub, energized in December 2025.
8. New tie between 25-24.112 and 25-37.112 provides additional back up capacity. It is preferred to utilize a double tie between 25-24.112 and 25-24.114 (back up from 25-37.112 not required) during 25-37.112 contingency beyond 2028.
9. Planned transfer of 12.5MVA from 25-26.121 to 25-54.113 and addition of 7.5MVA in total from 25-24.111 & 25-24.123 to 25-26.121 in 2028.
10. Increased back up capacity on 25-26.111 after 26.1TR transformer offload in 2028.
11. 25-54.111 feeder capacity exceeded during feeder 25-26.121 contingency scenario in 2027.
12. Planned transfer of 2.9MVA from 25-24.121 to 25-26.113 in 2028.
13. New feeder tie created between 25-26.121 & 25-26.113 in 2028 provides additional back up capacity in 2028.

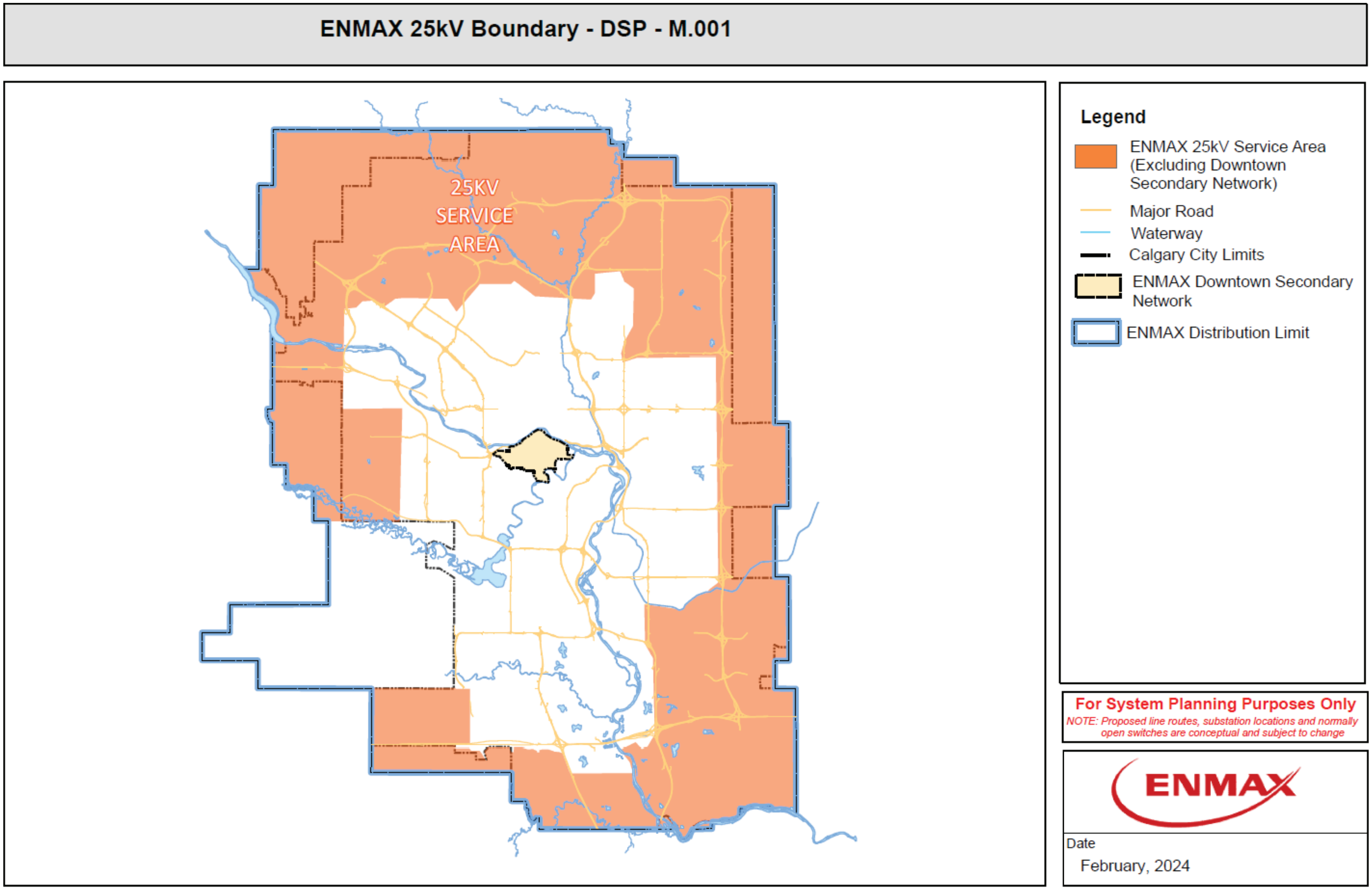
10.0 Proposed In-Service Date for Preferred Alternative

Considering the capacity constraints highlighted in this Distribution Deficiency Report, the 138/25kV 30/40/50MVA transformer at 54 Sub and construction of the new 25kV distribution feeders are critically required. An in-service date of August 1st 2028 is required, assuming the following timelines: Approximately one [1] year for the AESO approval process, and a construction schedule of approximately three [3] years.

11.0 Future System Development

The implementation of the preferred alternative will provide sufficient capacity for the anticipated load growth in the study area under normal operation beyond the 10-year load forecast timeframe. However, as indicated in *Section 4.1 – Load Growth Developments,* additional growth is expected within the study area beyond 2034. This includes pre-project planning inquiries for large commercial customers (e.g., data centers) with distribution demand ranging from 10 – 50 MVA. Additional system capacity and transmission infrastructure will likely be required as the area develops. A separate Statement of Need document and AESO System Access Service Request (SASR) application will be prepared for this new capacity addition when required.

APPENDIX A: ENMAX 25 kV Boundary – DSP – M.001



APPENDIX B: System Configurations for Alternatives 4 and 5

Alternative 4 Scope of Work

Alternative 4 Scope

A: Construct one [1] new 25 kV feeder (25-26.XXX) approximately 4.5 km North on Deerfoot Trail SE to create a new tie with feeder 25-24.111, and 1.9 km Northeast of 26 Sub to the Inverness community to tie to feeders 25-24.123 and 25-26.113.

B: Construct one [1] new 25 kV feeder (25-26.XXX) approximately 6 km south on Deerfoot Trail SE to pick up growing load pockets in the South of Seton.

C: Construct one [1] new 25 kV feeder (25-26.XXX) approximately 6.7 km West on Stoney Trail SE and South towards the Wolf Willow and Walden communities to service growing communities in the area.

D: Extension of future 25-37.112 feeder approximately 4.5 km south on 68 St SE to create a new tie with feeder 25-24.112)

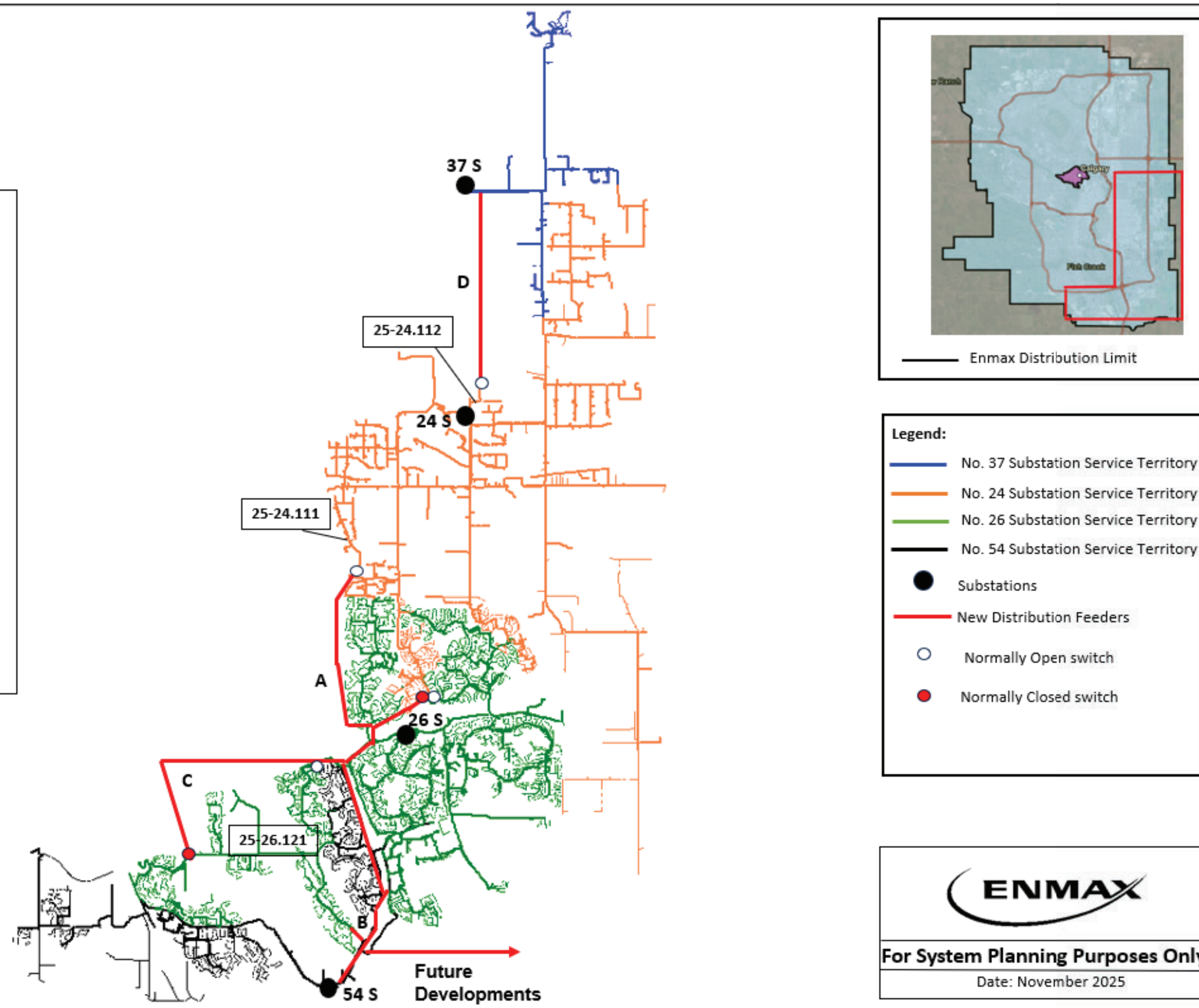


Figure B.1: Alternative 4 Scope of Work

Alternative 5 Scope of Work

Alternative 5 Scope
A: Construction of one [1] new 25 kV feeder approximately 4.5 km north on 68 St SE to create a new tie with feeder 25-24.112).
B: Construct one [1] new 25 kV feeder (25-24.XXX) approximately 7 km along 52 St SE and Deerfoot Trail SE to offload 11MVA from feeder 25-26.111.

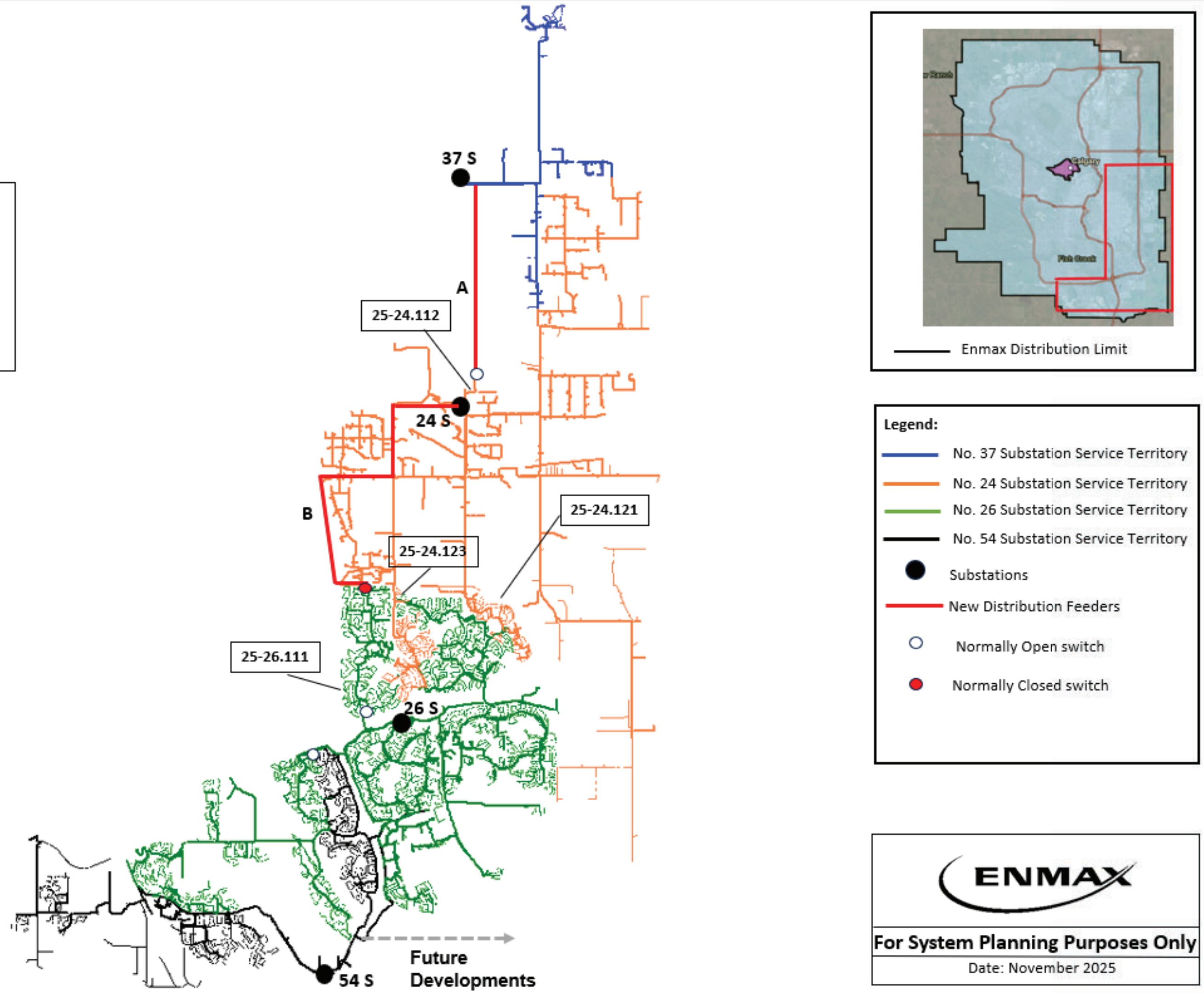


Figure B.2: Alternative 5 Scope of Work

APPENDIX C: Load Forecasting Methodology

Load Forecasting Methodology

Annual load forecasts are developed for major elements of the distribution system, including substations (PODS), substation transformers, distribution feeders and network feeders. The load forecast for each element is developed for the upcoming 10-year period, considering summer and winter peak conditions.

EPC utilizes a Bottom-Up & Top-Down methodology for the annual load forecast. The base forecast is developed using the Bottom-Up method, and the result of the Top-Down method is used as a reference to consolidate the Bottom-Up forecasts. This approach ensures that both micro (e.g., organic growth) and macro (e.g., GDP) influential factors are adequately accounted for.

A summary of the two methodologies is provided below.

Bottom-Up methodology – The bottom-up methodology considers the individual elements from the bottom, (i.e., customers) and goes through the system hierarchy up to the overall system level. The process will result in creating one set of forecasts using a predetermined forecast model. Figure C.1 shows the overall bottom-up forecasting framework for distribution and downtown network systems. Major inputs to this method include:

- Actual peaks of all system elements (e.g., feeders, vaults, transformers) in the previous year. The peaks are gathered, evaluated, and normalized (in case an abnormal condition occurred such as temporary load transfers between feeders).
- Planned permanent load transfers (e.g., planned re-allocation of load between feeders, substation transformers, Network buses, etc.)
- Customer load growth (e.g., near and long term, including information from ongoing customer projects, residential subdivision developments, City of Calgary growth plans, developer inputs, etc.)

Top-Down methodology – In this methodology the overall system level forecast is developed to reflect the economic outlook, demographic and weather trends, and its influence on the system's load growth based on regression analyses Major inputs to this methodology include:

- Calgary real GDP growth
- Industrial Product Price Index
- Calgary Inflation Rate
- WTI Oil Price
- Population growth
- Calgary Unemployment rate
- Calgary Total Housing Completions
- Downtown Office Vacancy Rate

- Average Temperature
- Max/Min Temperature

As shown in Figure C.1, diversity factors (DF) are calculated at each level of the bottom-up forecast from feeder level through the system hierarchy up to the overall system level. DFs show how close the summation of the peak values of the components downstream of an element is to the peak of that component. The DFs are used to forecast the next upstream element, i.e., substation transformers, substations, and overall system-level loading. As an example, the diversity factor of a transformer in a distribution substation for summer 2023 is the ratio of the transformer peak during summer 2023 to the total peak values of the feeders fed by that transformer. In summary, a transformer's peak load forecasted is calculated as follows:

$$Transformer\ Peak = Total\ Peak\ Load\ of\ connected\ feeders \times Transformer's\ DF$$

Note that, The DF of a component is forecasted by taking the weighted average of the DFs for the past five years. The weighting is spread out over the 5-year period as follows, with higher weight given to recent years: 70%, 15%, 10%, 3%, 2%.

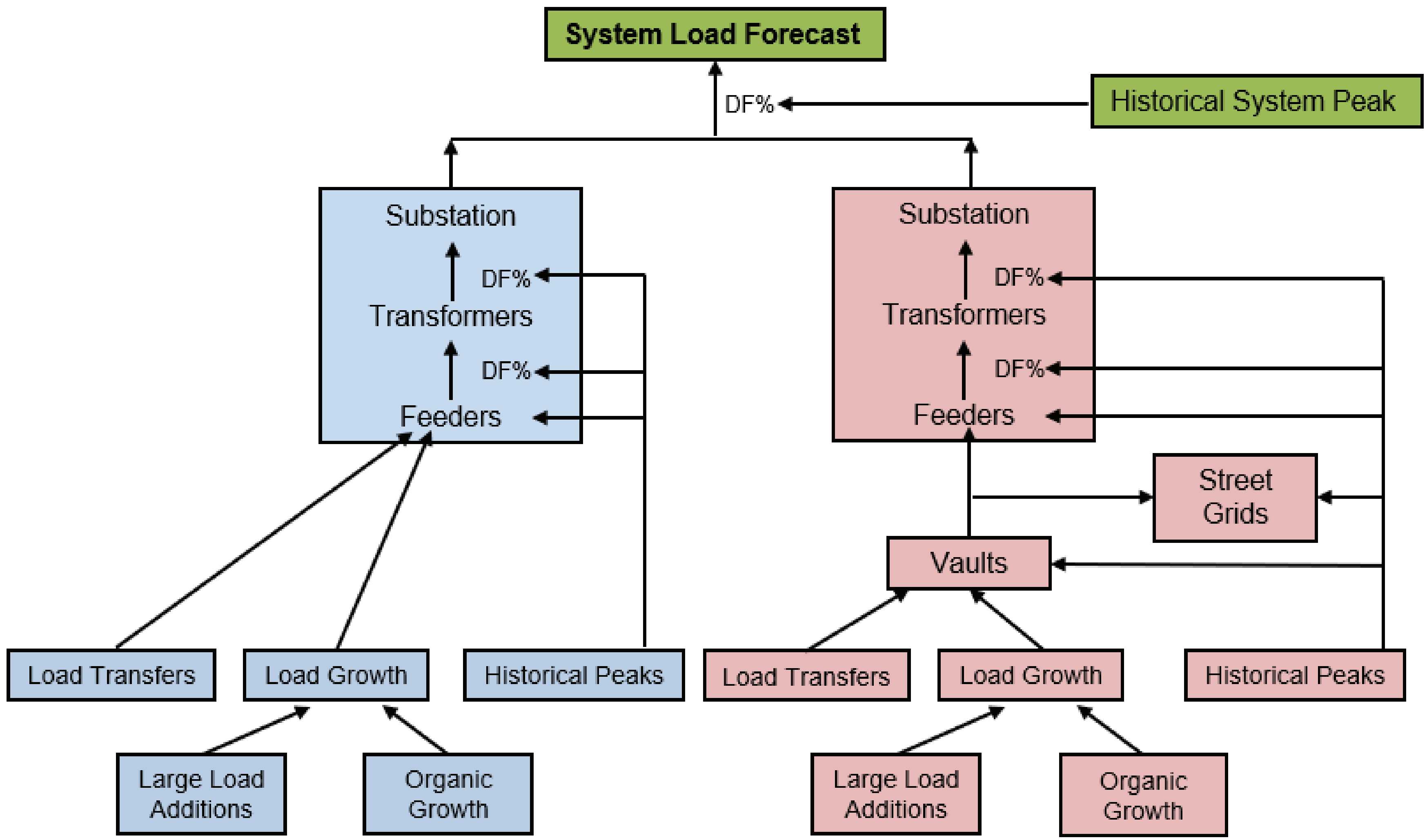


Figure C.1: Bottom-Up Methodology Framework

Large Load Additions

For service requests exceeding 1MVA, customers provide the following technical specifications to EPC:

- Type of load (residential, commercial, retail, warehouses, data centers, industrial, etc.)
- Targeted in service date, including load staging for multi-year developments.
- Anticipated demand load and existing demand if applicable.
- Service size, i.e., voltage and amperage rating of requested service.
- Single Line diagrams
- Applicable layout plans: number of units, building square footage, etc.

EPC communicates with customers to refine, update, and confirm the above information. EPC also references historical trends on typical load density for different customer classes to compare actual load from fully developed areas to the expected demand submitted by customers.

This data forms the basis of the load additions included in the forecasts, and how they are staggered throughout the decade.

Impact of Distributed Generation

DERs with an installed capacity greater than 1MVA are listed in section 4.3, however, the load forecasts presented in this report do not include the impact of Electric Vehicles (EV), residential Photo Voltaic (PV) or other emerging technologies. EPC's System Planning department is working towards integrating these technologies into the load forecasts for future years.

At a high-level, EPC plans to use sample metering data from existing EV/PV connections to create hourly profiles of consumption (for EVs) and generation (for solar PV). This data will be modelled against third-party forecasts of expected EV and solar PV market penetration to push the penetration rates to the neighborhood level. The results will be used to estimate and forecast the impacts of EV charging and PV penetration on ENMAX system peak demand.

APPENDIX D: Historical Performance Information

Table D.1 below provides 10 years of historical SAIDI and SAIFI performance indices for the EPC system. Table D.2 outlines the transformer outages, including 37.2TR which currently supplies the 37.4TR autotransformer, and Table D.3 outlines the feeder outage history.

Table D.1- SAIFI and SAIDI (Overall System 10 Year Historical)

Year	SAIFI	SAIDI
2014	0.99	0.48
2015	0.77	0.54
2016	0.59	0.38
2017	0.64	0.47
2018	0.80	0.54
2019	0.72	0.42
2020	0.54	0.47
2021	0.62	0.53
2022	0.65	0.50
2023	0.52	0.62
2024	0.55	0.64

Table D.2: Historical 10-year outages of EPC Substation transformers within the study area

Outage Type	Asset	Outage Start (Date & Time)	Outage End (Date & Time)	Duration (hours)	Cause of Outage	Caused Sub. Trip
Planned	24.1TR	5/6/2019 9:45	5/10/2019 14:30	100.7	Doble test transformer. Transformer Secondary Cable Tests. Transformer Maintenance. Gas Relay Testing	No
Planned	24.1TR	8/24/2019 7:30	8/24/2019 17:30	10	HV Breaker Maintenance 24B138-24.81. Doble 24PT138-Z31, 24B138-24.83 CT Repair or Replace Center Phase Mech Cover [AVANTIS)	No
Planned	24.1TR	9/3/2019 8:30	9/4/2019 13:45	29.3	Tap changer inspection. Check reversing switch. Oil sampling MT, TC. Outage Required - 24.lTR XO ground cable corrective	No
Planned	24.1TR	11/24/2019 12:00	11/24/2019 14:15	2.3	RTU upgrade. CAC OAC commissioning. Control Center will have no control on equipment	No
Planned	24.1TR	12/5/2019 8:15	12/5/2019 14:30	6.2	Outage Required - 24.lTR XO ground cable corrective	No
Planned	24.2TR	11/17/2019 11:30	11/17/2019 17:30	6	Corrective. SW 81 @ 24 Sub Does not open past 90 degrees and is stiff (east phase). Check reversing switch 24.2TR	No
Planned	24.2TR	11/24/2019 8:00	11/24/2019 12:00	4	RTU upgrade. CAC OAC commissioning. Control Center will have no control on equipment	No
Unplanned	24.2TR	6/20/2022 05:22	6/20/2022 05:39	0.28	Cable Failure	No
Unplanned	26.1TR	15/5/2019 05:36	15/5/2019 05:41	0.08	Relay Failure	Yes
Unplanned	54.1TR	1/6/2020 10:27	1/6/2020 10:29	0.05	Human Elemenent	Yes
Planned	37.2TR	9/30/2019 10:00	10/10/2019 14.15	244.3	Transformer differential relay panel replacement	No
Planned	37.2TR	3/2/2020 8:00	3/2/2020 14:45	6.8	Hotspot 37.2TR Hl. Oil sampling MT, TC. Check reversing switch. Gas relay testing.	No
Planned	37.2TR	6/8/2020 8:30	6/11/2020 14:30	78	Power factor test, transformer secondary cable tests, Transformer Maintenance. Oil Sampling MT	No
Planned	37.2TR	8/10/2020 8:30	8/13/2020 8:30	72	Reinhausen Tap changer Maintenance	No
Planned	37.2TR	2/13/2021 8:30	2/14/2021 14:15	29.8	HV SW maintenance SW84, SW85, SW86, MD-37.2TR. Check reversing switch. 37B138-37.82 CT. Corrective- CT's are not grounded. SF6 Gas Sample	No
Planned	37.2TR	11/2/2021 11:30	11/2/2021 15:00	3.5	Oil Sampling MT, TC. 37.2TR LTC mech heaters R2 and R3- need to be replaced.	No

Table D.3: Historical 10-year outages of EPC feeders within the study area

feeder	cause	customer_count	date_time	Duration HH:MM
25-24.121	Lightning Arrestor	2735	2012-07-05 19:09	0:08
25-24.121	Pole Fire	2756	2013-03-03 19:40	0:00
25-24.121	Pole Fire	2756	2013-03-03 19:40	0:48
25-24.121	Pole Fire	2756	2013-03-03 19:40	7:22
25-24.121	Pole Fire	2756	2013-03-03 19:40	0:00
25-24.121	Wildlife or Birds	2756	2013-03-17 16:18	0:00
25-24.121	Insulator Failure	2747	2012-08-10 14:04	0:00
25-24.121	Wildlife or Birds	3246	2013-10-03 15:50	0:00
25-24.121	Under Investigation	2753	2013-10-03 15:50	0:01
25-24.121	Wildlife or Birds	3550	2014-04-11 15:51	0:00
25-24.121	Wildlife or Birds	3551	2014-07-15 12:10	0:00
25-24.121	Wildlife or Birds	1621	2015-05-05 12:05	0:00
25-24.121	Wildlife or Birds	2739	2016-04-17 15:25	0:00
25-24.121	Conductor Failure - Primary	2690	2017-09-13 15:01	0:00
25-24.121	Conductor Failure - Primary	2690	2017-09-13 15:01	0:51
25-24.121	Conductor Failure - Primary	2690	2017-09-13 15:01	6:04
25-24.122	Customer Equipment	1	2013-06-18 9:32	0:00
25-24.122	Unknown	1	2015-08-26 19:57	0:00
25-24.122	Wildlife or Birds	1	2015-09-20 16:49	0:00
25-24.122	Wildlife or Birds	1	2016-05-18 5:25	0:00
25-24.123	Unknown	3566	2014-07-31 20:37	0:00
25-24.123	Unknown	3566	2014-07-31 20:37	0:02
25-24.123	Unknown	3566	2014-07-31 20:37	0:00
25-24.123	Unknown	3566	2014-07-31 20:37	0:13
25-24.123	Unknown	2663	2015-05-02 6:02	0:00
25-24.123	Snow	2740	2015-11-17 22:08	0:00
25-24.123	Equipment Failure	2879	2016-04-07 13:29	0:04
25-24.123	Wildlife or Birds	2893	2017-03-14 8:52	0:00
25-24.123	Wildlife or Birds	2893	2017-03-14 8:52	0:06
25-24.123	Wildlife or Birds	2893	2017-03-14 8:52	0:07
25-24.123	Wildlife or Birds	2893	2017-04-11 9:01	0:00
25-26.113	Cable Failure	7582	2016-05-12 11:03	0:51
25-26.113	Cable Failure	7582	2016-05-12 11:03	1:11
25-26.113	Cable Failure	7582	2016-05-12 11:03	0:06
25-26.113	Cable Failure	8087	2016-10-11 8:35	0:00
25-26.113	Cable Failure	8087	2016-10-11 8:35	0:00
25-26.113	Cable Failure	8087	2016-10-11 8:35	0:02
25-26.121	Public Interference	2221	2012-06-18 9:37	0:24
25-26.121	Public Interference	4635	2012-06-18 9:04	0:01
25-54.121	EPC Transmission Loss of Supply	1033	2013-10-04 11:54	0:12
25-54.121	Unknown	4004	2016-01-22 20:43	0:00
25-54.121	Unknown	4147	2016-07-26 0:34	0:03
25-54.121	Unknown	4147	2016-07-26 0:34	0:02
25-37.111	Major Storm	151	2012-08-14 15:09	0:04
25-37.111	Pole Fire	160	2013-04-07 3:24	1:15
25-37.111	Pole Fire	160	2013-04-07 3:24	1:44
25-37.111	Pole Fire	160	2013-04-07 3:24	7:14
25-37.111	Snow	218	2015-11-18 0:05	0:15

25-37.111	Public Interference	319	2016-11-02 4:33	1:22
25-37.111	Equipment Failure	327	2018-05-04 15:44	0:01
25-37.111	Wind	1	2019-07-28 15:55	1:11
25-37.111	Cable Dig In	2	2019-09-16 16:45	2:25
25-37.111	H Connector – Primary	4	2020-10-11 7:55	0:42
25-37.111	Public Interference	2	2021-03-02 19:56	1:27
25-37.111	H Connector – Secondary	1	2021-09-21 8:48	5:27
25-37.111	Unknown/Other	1	2022-05-30 9:12	2:21
25-37.111	U/G Dist Xfm	1	2022-07-14 16:35	1:09

Table D.4: Estimated Restoration Times

General Response Process - 24.1TR, 24.2TR, 26.1TR and 26.2TR Transformer Contingency

1. Automated processes:
    - Protection relays trip opening the following breakers: (~5 cycles)
        - 25 kV transformer breakers
        - 138kV bus-tie breaker
        - 138kV line breakers on the same bus section as the faulting transformer

      This results in a partial substation outage. All feeders supplied by the faulted transformer are affected. 138 kV transmission lines terminated on the same 138 kV bus section as the faulted transformer are affected.
    - Distribution Automation (DA) engages: (<1 minute)
        - Feeders with DA installed attempt to automatically tie-away to adjacent feeders if capacity is available
    - Substation auto-switching engages: (1 minute)
        - The motorized disconnect (MD) on the faulting transformer is opened. This removes the transformer from service.
        - 138 kV bus-tie and line breakers re-close restoring the 138 kV bus.
2. Operations reviews alarms within EPC's SCADA and OMS (Outage Management System) to respond accordingly.
3. Operations assess current system state & confirms which element are in/out of service.
4. Operations assess loading of existing equipment and available tie capacity.
5. Operations restores feeders using substation switching and feeder ties:
    - Close in the 25 kV bus-tie breakers restoring feeders that did not automatically tie-away. (5-10 minutes)
    - If additional capacity is required, utilize feeder ties to supply load from an adjacent substation. (5-10 minutes for remote switching; 30-90 Minutes for manual switching)
    - If capacity exists tie-back feeders that were tied-away automatically. (As system conditions permit)
6. Operations dispatch crew to site to assess the faulted transformer and perform manual switching if required. (30-90 minutes)

7. Asset repair or replace the faulted transformer. (12-14 months for like for like replacement)
8. If capacity does not exist to fully support all load, EPC would manually tie-away feeders to adjacent substations if possible.

General Response Process – 37.3TR Transformer Contingency

1. Automated processes:
   - Protection relays trip opening the following breakers: (~5 cycles)
     - 25 kV transformer breaker
     - 138kV bus-tie breaker
     - 138kV line breakers on the same bus section as the faulting transformer

     This results in a partial substation outage. All feeders supplied by the faulted transformer are affected. 138 kV transmission lines terminated on the same 138 kV bus section as the faulted transformer are affected.
   - Distribution Automation (DA) engages: (<1 minute)
     - Feeders with DA installed attempt to automatically tie-away to adjacent feeders if capacity is available
2. Operations reviews alarms within EPC's SCADA and OMS (Outage Management System) to respond accordingly.
3. Operations assess current system state & confirms which element are in/out of service.
4. Operations assess loading of existing equipment and available tie capacity.
5. Operations dispatch crew to site to assess the faulted transformer and perform manual switching if required. (30-60 minutes)
6. Asset repair or replace the faulted transformer. (12-14 months for like for like replacement)

General Response Process – 54.1TR Transformer Contingency

1. Automated processes:
   a. Protection relays trip opening the following breakers: (~5 cycles)
      i. 25 kV transformer breaker
      ii. 138kV line breaker

      This results in a total substation outage because this station only has one transformer. All feeders supplied by the faulted transformer are affected. 138 kV transmission line feeding the faulted transformer is affected.
   - Distribution Automation (DA) engages: (<1 minute)
     - Feeders with DA installed attempt to automatically tie-away to adjacent feeders if capacity is available
2. Operations reviews alarms within EPC's SCADA and OMS (Outage Management System) to respond accordingly.
3. Operations assess current system state & confirms which element are in/out of service.

4. Operations assess loading of existing equipment and available tie capacity.
5. Operations dispatch crew to site to assess the faulted transformer and perform manual switching if required. (30-60 minutes)
6. Asset repair or replace the faulted transformer. (12-14 months for like for like replacement)

APPENDIX E: ENMAX Distribution System Performance Standard

ENMAX	ENMAX Power Corporation			Standard
	Distribution System Performance			
EPC-Distribution	Effective Date: Nov 15, 2024		Rev. 2	Pg. 5 of 9

<u>**APPENDIX 1 - DISTRIBUTION SYSTEM CONDITIONS – NORMAL AND EMERGENCY**</u>

A1 **Distribution Point of Delivery (POD) substations** shall be planned, designed and operated to ensure no loss of load due to substation capacity limitations during a substation transformer **N-1 contingency** for a period longer than the **switching time** required to restore service.

A1.1 Restoration capability will be assessed based on a combination of **firm POD transformer capacity** remaining and load transfer capability from adjacent POD through distribution feeder interconnections.

A2 Three phase main distribution system feeders shall be planned, designed, and operated to enable full mutual backup capability during a feeder **N-1 contingency** over **peak loading conditions.**

A3 All new distribution facilities within the ENMAX 25 kV Boundary, as defined in map DSP - M.001, will be planned and designed to 25 kV standards.

A4 **Distribution Point of Delivery (POD) substations** supplying **secondary network bus** areas within the Downtown Network Boundary, as defined in map DSP-M.002, shall have capacity planned, designed, and operated to ensure that, at a minimum, the independent loss of two substation transformers (substation transformer **N-1-1 contingency**), will not result in the interruption of customer service for a period longer than the time required to restore service through switching of existing infrastructure within the POD substation.

A5 Distribution feeders supplying a downtown **secondary network bus area** shall be planned, designed, and operated for full mutual backup capability that allows for the simultaneous loss of any two feeders (feeder **N-2 contingency**) with no interruption in customer service over **peak loading conditions**.

A6 **Secondary Network Systems**, including **network transformers** and **secondary ties**, within the Downtown Network Boundary shall be planned, designed, and operated to ensure no interruption of service to customers in the event of the simultaneous loss of two feeders or two network service transformers (feeder or network service transformer **N-2 contingency**) over **peak loading conditions**.

A7 **Distribution Point of Delivery (POD) substations** shall be planned, designed and operated to ensure no more than two POD substations are supplied radially as a result of a planned transmission circuit or autotransformer outage. Pre-system reconfigurations that require distribution load transfers to alleviate transmission system overloads are not acceptable due to the increased customer outage risk under the next contingency.

A8 **Distribution Point of Delivery (POD) substations** shall be planned, designed and operated to ensure no customer load interruption during a transmission circuit, autotransformer or common structure **N-1 contingency**.