DFO STATEMENT OF NEED

STATEMENT OF NEED

No. 37 Substation
138/25 kV Transformer Addition

	Name	Signature	Date
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Distribution System Development

August 2018

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1.0 Executive Summary

ENMAX Power Corporation (EPC) is submitting a request for system access service to the Alberta Electric System Operator (AESO). The request for system access service includes a request for a Demand Transmission Service (DTS) contract capacity increase at the No. 37 substation and a request for transmission development.

No. 37 Substation is a 138/13 kV transformation source with a 10/13.3 MVA 13/25 kV autotransformer supplying 25 kV load. The focus of this document is the anticipated developments in the 25 kV area surrounding the substation and the need for a 138/25 kV source to meet the expected industrial, commercial, and residential load growth in 25 kV, as required by the Distribution System Performance Standard (see Section 4.1).

Through system analysis it has been determined that No. 37 Substation area will have unsupplied area load (Load at Risk[1]) during transformer and feeder contingencies beginning in the summer of 2021, and is therefore in violation of EPC's Distribution System Performance Standard (see Sections 4.2 and 4.3).

Multiple distribution and transmission alternatives were considered to address the identified deficiencies. EPC's preferred alternative is the installation of a 30/40/50 MVA 138/25 kV transformer at No. 37 Substation along with 25 kV distribution feeder infrastructure. This has been determined to be the most cost effective engineering solution to address the identified deficiencies.

The requested 138/25kV transformation capacity addition at No. 37 Substation[2] entails installing one [1] 138/25 kV 30/40/50 MVA transformer with associated 25 kV distribution breaker lineup and removing the existing 13/25 kV 10/13.3 MVA autotransformer. The distribution scope of work associated with the capacity addition includes the addition of a 0.2 km 25 kV distribution feeder from No. 37 Substation and a 3 km extension of an existing 25 kV distribution feeder from No. 24 Substation to provide reliability support to the new feeder. The transformation capacity addition is necessary to maintain normal operation and restoration capability for the 25 kV load supplied from No. 37 Substation and to support 21 MVA of new load growth expected over the next 10 years. This load growth is also driving a requested DTS contract capacity increase at No. 37 Substation from 40 MW to 66 MW.

The estimated Transmission capital cost for the transformer addition is approximately $8,567,000[3] (+/-30%). The estimated Distribution capital cost for the new 25 kV distribution feeder is approximately $1,162,000 (+/-30%), for an expected total project cost of $9,729,000 (+/-30%).

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[1] 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

[2] Transmission scope of work and the associated capital cost were provided by EPC TFO and included for the purpose of alternative comparison only

[3] All cost estimates provided in this document are inflated spend, excluding Administrative Overhead (AOH) and Interest During Construction (IDC)

The requested in-service date for the new 30/40/50 MVA 138/25 kV transformer and new 25 kV distribution feeder at No. 37 Substation is July of 2021, which takes into account timelines for the required approvals and construction.

2.0 Description of the Area

2.1 Geographic Study Area

The geographic study area is shown in Figure 1. This area is located within the 25 kV service boundary as specified in the EPC Distribution System Performance Standard. Refer to Appendix A for the 25 kV service boundary map. This Statement of Need covers only the 25 kV facilities supplying load in the following industrial, commercial and residential communities:

- Frontier Industrial (Industrial)
- Emcor (Industrial)
- Janet (Industrial)
- East Hills (Commercial)
- Belvedere (Residential)
- Point Trotter (Industrial)
- East Shepard Business Park (Industrial)
- FortisAlberta Chestermere Area

2.2 Current System Configuration

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

No. 37 Substation (Figure 2) consisting of the following 25 kV infrastructure:

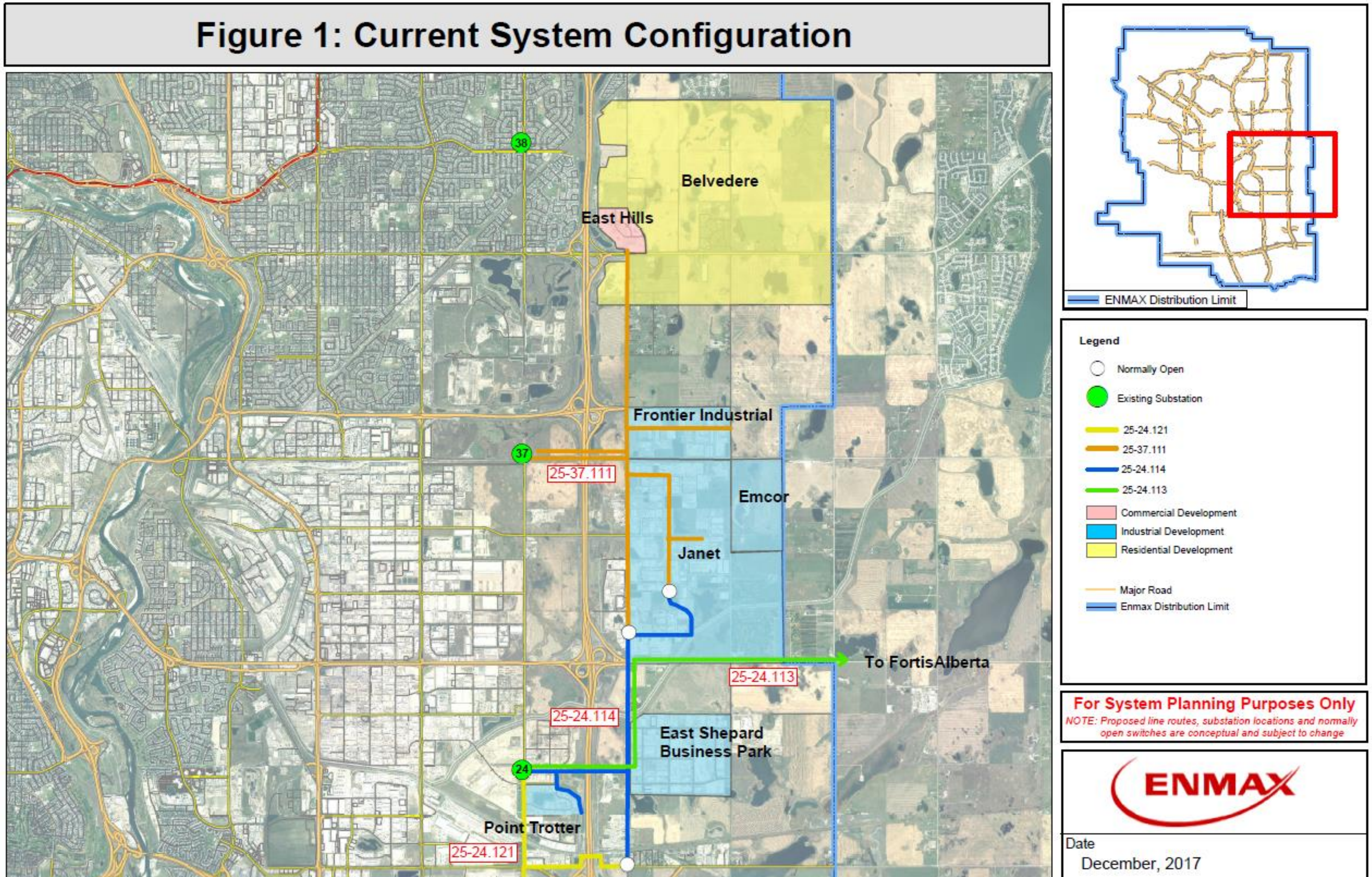
- One [1] 13/25 kV 10/13.3 MVA autotransformer supplying feeder 25-37.111
- One [1] 25 kV distribution feeder servicing the following areas:
    - 25-37.111 – Industrial developments of Frontier Industrial, Janet, and Emcor; the commercial development of East Hills; the residential community of Belvedere.

No. 24 Substation (Figure 3) consisting of the following 25 kV infrastructure within the study area:

- Two [2] 138/25 kV 30/40/50 MVA transformers (24.1TR and 24.2TR)
- One [1] of the Four [4] 25 kV distribution feeders connected to 24.1TR, supplying the following areas:
  - 25-24.121 – Industrial development of Point Trotter
- Two [2] of the Four [4] 25 kV distribution feeders connected to 24.2TR, supplying the following areas:
  - 25-24.114 – Industrial development of East Shepard Business Park
  - 25-24.113 – FortisAlberta Chestermere Area

No. 38 Substation is also located within the study area. It is a 138/13 kV POD substation with only 13 kV infrastructure, which cannot be used to supply the 25 kV load within the study area as per the EPC Distribution System Performance Standard (refer to Section 4.1).

Figure 1: Current System Configuration



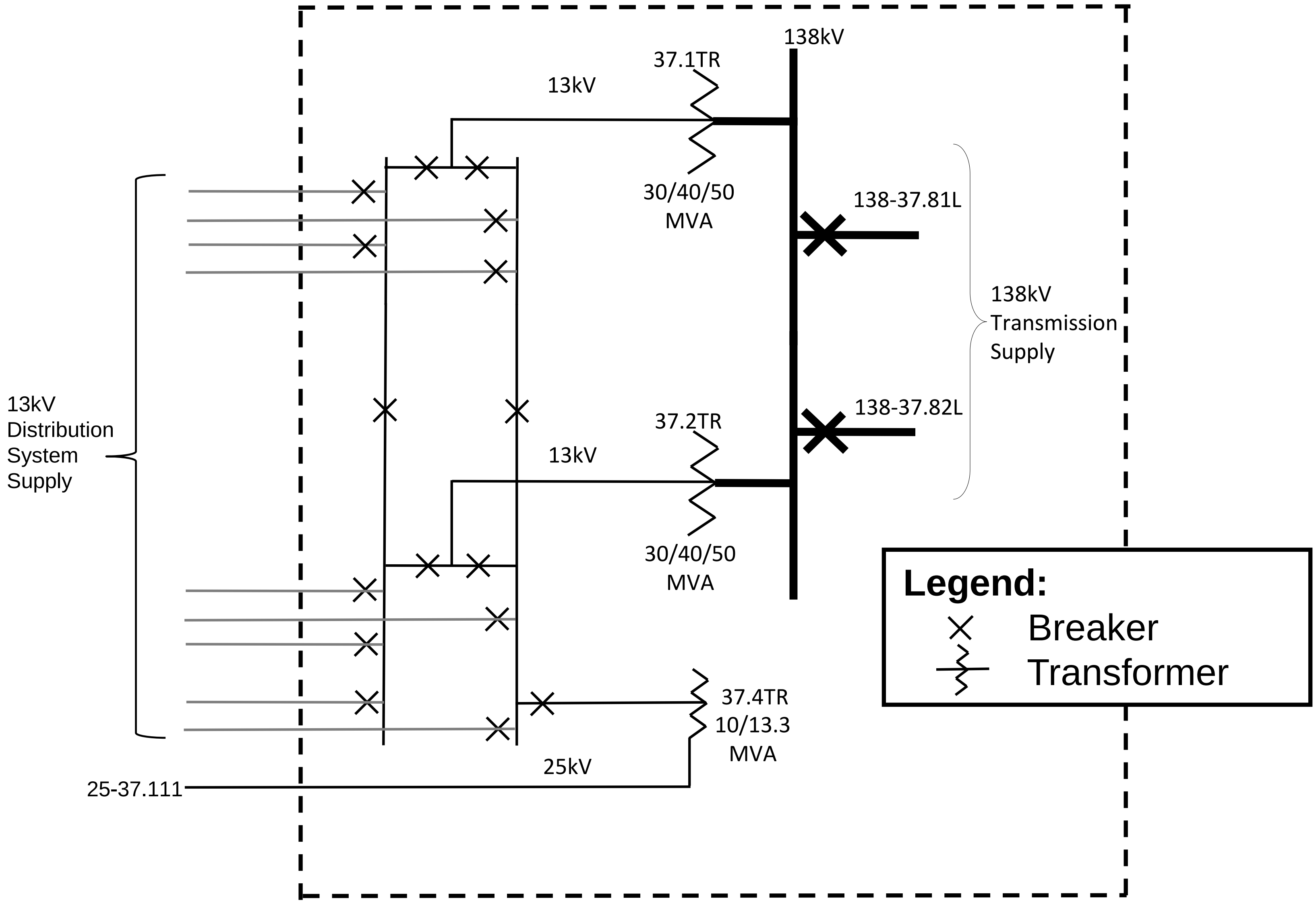
For System Planning Purposes Only

NOTE: Proposed line routes, substation locations and normally open switches are conceptual and subject to change

Date

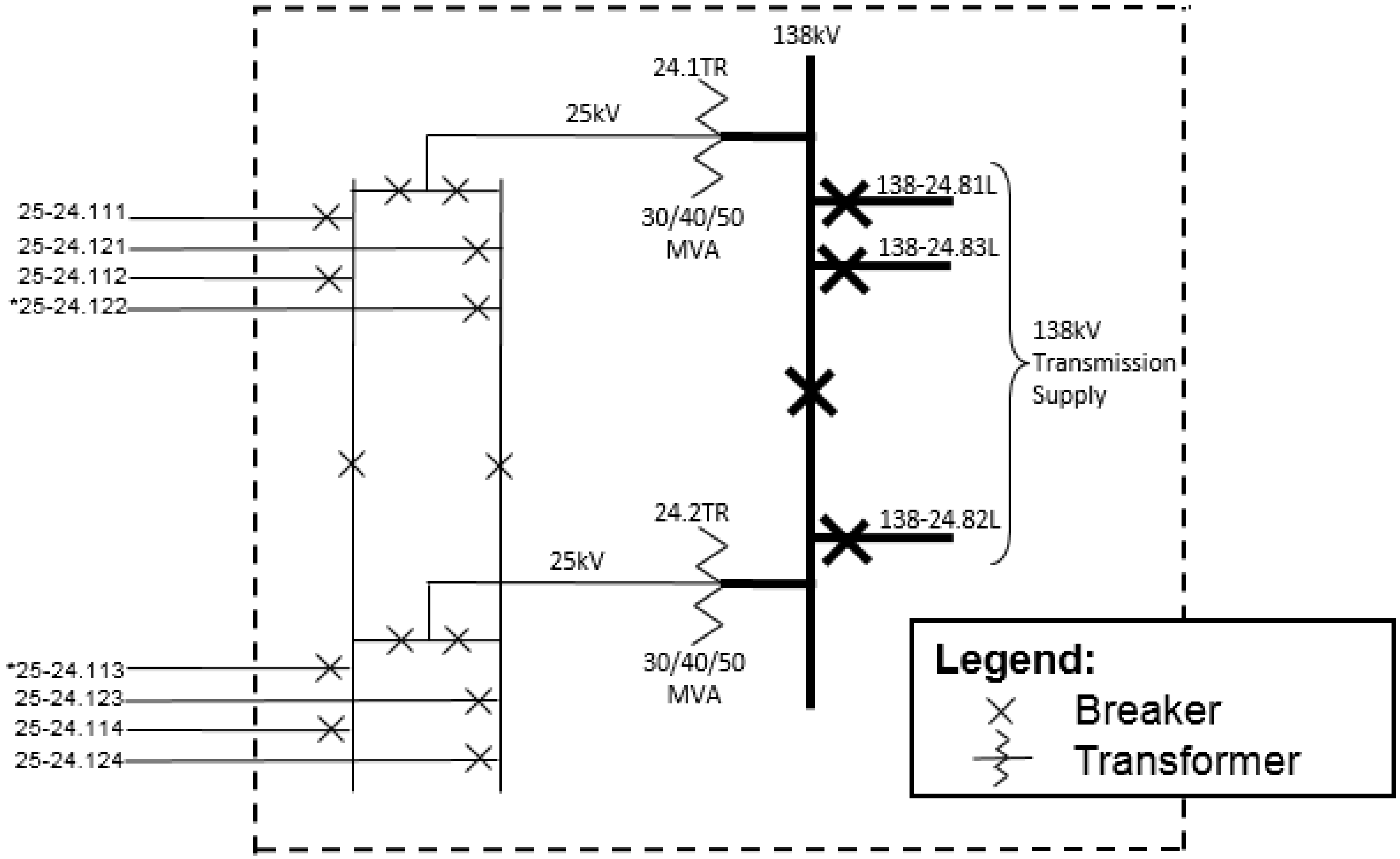
December, 2017

Figure 2: Existing No. 37 Substation Configuration



SIMPLIFIED PLANNING DOCUMENT ONLY. Not to be used for final design or switching purposes.

Figure 3: Existing No. 24 Substation Configuration



* Feeder supplying Chestermere in FortisAlberta service territory

SIMPLIFIED PLANNING DOCUMENT ONLY. Not to be used for final design or switching purposes.

3.0 Area Loading

3.1 Load Growth Development

The major subdivision developments and the associated load growth for the next ten years are listed in Table 1 (below) and shown in Figure 4.

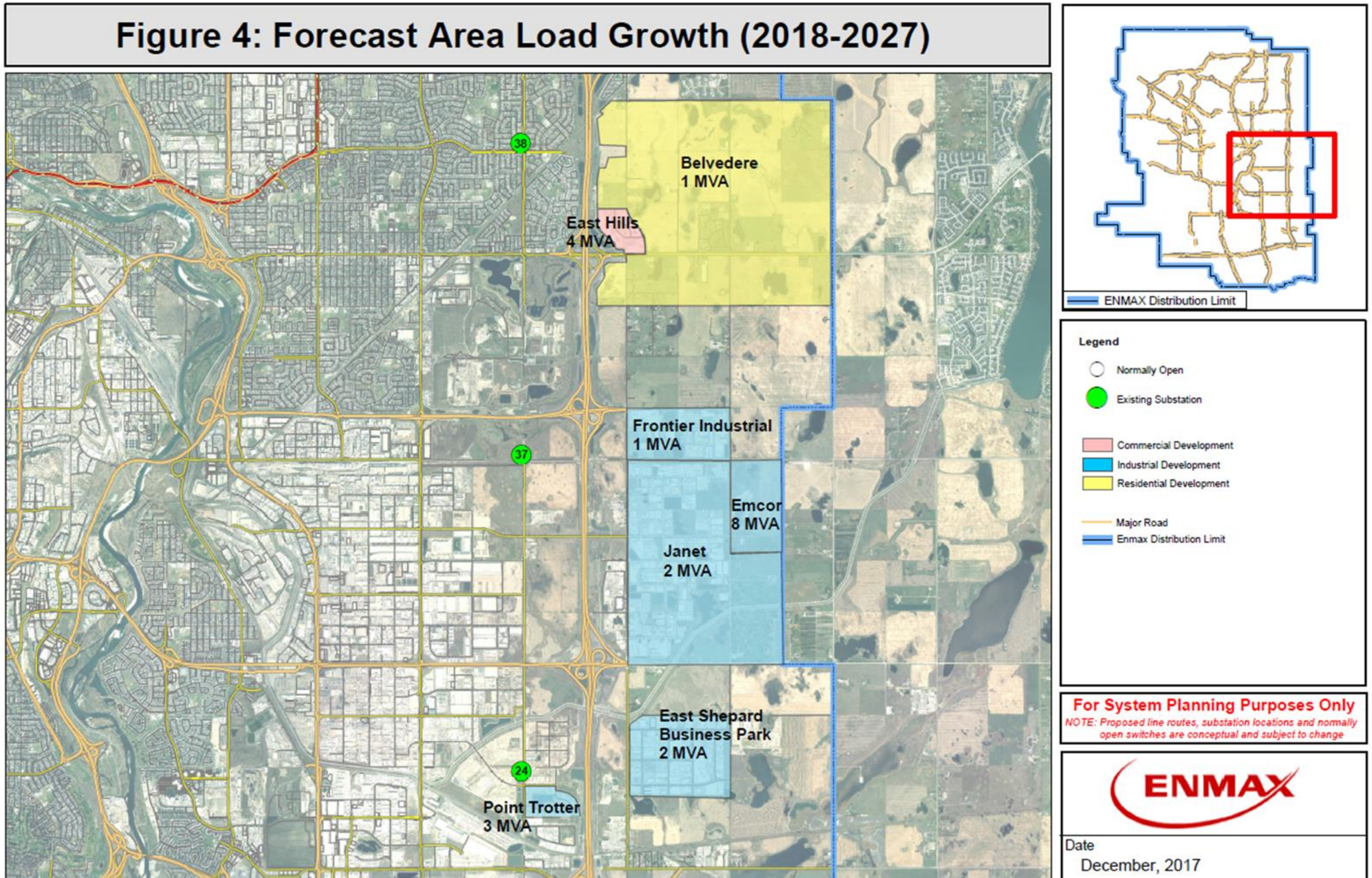
The load growth listed in Table 1 has been integrated into the overall area load forecast, indicated in *Section 3.2 – Load Forecast*.

Table 1 - Major Area Load Additions (2018-2027)

Description of New Load Addition	Forecasted Load [MVA]
Belvedere Residential	1
East Hills Commercial	4
Frontier Industrial	1
Emcor Industrial	8
Janet Industrial	2
East Shepard Business Park	2
Point Trotter Industrial	3
Total Area Load Growth (Non-Diversified[1])	**21**

[1] Non-Diversified load represents the totalized independent peak loads.

Figure 4: Forecast Area Load Growth (2018-2027)



Legend
- Normally Open
- Existing Substation
- Commercial Development
- Industrial Development
- Residential Development
- Major Road
- Enmax Distribution Limit

For System Planning Purposes Only

NOTE: Proposed line routes, substation locations and normally open switches are conceptual and subject to change

ENMAX

Date
December, 2017

3.2 Load Forecast – Current Configuration

Table 2 outlines the load forecast for Point of Delivery (POD) substations No. 37, No. 24 and No. 38. No. 38 Substation is a 138/13 kV POD substation supplying only 13 kV load, which has no impact on the need for this project. The load forecast for this substation is provided only for the completeness of documentation.

No. 37 Substation supplies customer load at both 13 kV and 25 kV, while No. 24 Substation supplies customer load only at 25 kV. The No. 37 Substation POD Load Forecast in Table 2 includes both supply voltages. The 25 kV loading of the study area, which is the focus of this statement of need, is reflected in tables 3 and 4. Table 3 provides forecast load on the autotransformer 37.4TR, transformers 24.1TR and 24.2TR. Table 4 provides forecast load on feeders 25-37.111 and 25.24.114.

To manage load growth prior to substation capacity additions, planned distribution load transfers will be implemented as identified in tables 3 and 4 below.

All forecasted loads are during summer peak periods (summer season is defined as May 1 – September 30).

Table 2 – POD Substation Coincident Load[1] Forecast - Existing System

POD[1]	Peak	PF[2]	Units	Actual Load					Forecasted Load									
				2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
37 S	S	0.95	MVA	49	48	50	54	56	56	50[3]	52	54	56	58	60	62	63	64
			MW	46	45	47	51	53	53	47	50	51	53	55	57	58	60	61
24 S	S	0.96	MVA	48	52	54	53	55	57	55[4]	58	71[5]	74	71	74	78	81	84
			MW	46	50	52	51	53	54	53	56	68	71	68	71	74	78	81
38 S[6]	S	0.96	MVA	35	33	33	31	32	32	32	32	32	32	32	32	32	32	32
			MW	34	32	31	30	31	30	30	30	31	31	31	31	31	31	31

Notes:

1. No. 37 Substation POD supplies distribution both at 13 kV and 25 kV, while No. 24 Substation POD supplies distribution only at 25 kV
2. The POD power factor is calculated using the POD MW and MVA values over the POD peak period
3. No. 37 Substation loading incorporates a planned load transfer from 25-37.111 to 25-24.114 to manage forecasted overloads on 37.4TR in 2019
4. No. 24 Substation loading incorporates multiple load transfers, including removal of FortisAlberta load and temporary load transfer away from the substation in order to support No. 37 Substation load

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

5. No. 24 Substation loading incorporates a planned load transfer to return the load being temporarily transferred away in 2019
6. No. 38 Substation is a 13 kV POD substation. The loading on this substation does not have any impact on the need for 25 kV capacity in the study area. It is provided for the completeness of documentation only.

Table 3 –Transformer Load Forecast - Existing System (MVA)

Transformer	Capacity (MVA)	Peak	Actual Load					Forecasted Load									
			2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
37.4TR	13.3[1]	S	7	7	10	9	9	13	5[2]	6	6	7	8	9	9	10	11
24.1TR	50	S	39	27	27	28	30	32	22[3]	23	35[4]	37	38	39	41	42	44
24.2TR	50	S	14	26	27	26	27	26	35[3]	37	37	38	34	36	39	40	42

Notes:

1. Autotransformer 37.4TR supplies feeder 25-37.111 with a capacity rating less than the thermal limit of the feeder cable (25.9 MVA)
2. 37.4TR transformer loading incorporates a planned load transfer from 25-37.111 to 25-24.114 to manage forecasted overloads on in 2019
3. Transformer loading incorporates multiple load transfers, including removal of FortisAlberta load and temporary load transfer away from the substation in order to support No. 37 Substation load
4. Transformer loading incorporates a planned load transfer to return the load being temporarily transferred away in 2019

Table 4 – 25kV Feeder Load Forecast - Existing System (MVA)

Feeder[1]	Peak	Actual Load [MVA]					Forecasted Load [MVA]									
		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
25-37.111[2]	S	7	7	10	9	9	13	5[4]	6	6	7	8	9	9	10	11
25-24.114	S	6	6	6	5	6	2[3]	12[4]	14	16	17	19	20	22	23	24

Notes:

1. Maximum thermal capacity of 25 kV feeder is 25.9 MVA
2. Autotransformer 37.4TR supplies feeder 25-37.111 with a capacity rating of 13.3 MVA, which is less than the thermal limit of the feeder cable (25.9 MVA)
3. 25-24.114 feeder loading incorporates a planned load transfer to manage customer load development
4. Feeder loading incorporates a planned load transfer from 25-37.111 to 25-24.114 to manage forecasted overloads on 37.4TR in 2019

3.3 Distributed Generation Forecast

No distributed generation within the study area has been identified at the time of this forecast.

4.0 Distribution System Performance Standard

The EPC Distribution System Performance Standard outlines the reliability requirements for the EPC Distribution System. The applicable sections are as follows:

4.1 EPC 25 kV Service Area

All new distribution facilities within the ENMAX 25 kV Boundary, as defined in map DSP - M.001[1], will be planned and designed to 25 kV standards.

4.2 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.

4.3 Three Phase Main Distribution System Feeders

Three phase main distribution system feeders[2] shall be planned, designed and operated to enable full mutual backup within a timeframe of one manual switching operation during a feeder N-1 contingency over peak loading conditions.

5.0 Risk Assessment

5.1 Load at Risk Magnitude

Load at Risk is defined as customer load that cannot be returned to service within a time frame of one manual switching operation during an N-1 contingency. The feeder Load at Risk is outlined in Table 5 and the transformer Load at Risk for the area is outlined in Table 6. The Load at Risk highlighted in Tables 5 and 6 represents the maximum unsupplied customer load under peak loading conditions in the event of the loss of a feeder or a substation transformer respectively.

[1] Refer to Appendix A for the 25 kV Service Boundary map.

[2] Feeder capacity is based upon equipment ratings. The maximum feeder capacity is 25.9 MVA at 25 kV and 13.7 MVA at 13 kV.

Table 5 – Forecasted Feeder Load at Risk during Summer Peak (MVA)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Loss of Feeder 25-24.114										
25-24.114 Feeder Loading	2	12[3]	14	16	17	19	20	22	23	24
Total Tie-Away[1]	17	20	19	6[4]	6	0	0	0	0	0
Load at Risk[2]	0	0	0	10	11	19	20	22	23	24
Loss of Feeder 25-37.111 (or Autotransformer 37.4TR)										
25-37.111 Feeder Loading	13	5[3]	6	6	7	8	9	9	10	11
Total Tie-Away[1]	24	14	12	10	9	2[5]	2	2	2	2
Load at Risk[2]	0	0	0	0	0	6	7	7	8	9

Notes:

1. Total 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. 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
3. Feeder loading incorporates a planned load transfer from 25-37.111 to 25-24.114 to manage forecasted overloads on 37.4TR
4. Decrease in Tie-Away capacity due to the return of the load temporarily transferred away in 2019 to the tie-away feeder
5. Decrease in Tie-Away capacity due to load growth on both feeders involved in the tie-away

Table 6 – Forecasted Transformer Load at Risk during Summer Peak (MVA)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Loss of Transformer 24.1TR										
24.1TR Loading	32	22[3]	23	35[4]	37	38	39	41	42	44
Total Tie Away[1]	46	35	34	23	24	26	26	24	24	22
Load at Risk[2]	0	0	0	12	13	12	13	17	18	22
Loss of Transformer 24.2TR										
24.2TR Loading	26	35[3]	37	37	38	34	36	39	40	42
Total Tie Away[1]	40	48	48	25	25	22	23	21	22	20
Load at Risk[2]	0	0	0	12	13	12	13	17	18	22

Notes:

1. Total 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.
2. 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
3. Transformer loading incorporates multiple load transfers, including offload of FortisAlberta load and temporary load transfer away from the substation in order to support No. 37 Substation load
4. Transformer loading incorporates a load transfer to return the load being temporarily transferred away in 2019

6.0 Area Supply Deficiencies

The existing 25 kV supply source from No. 37 Substation and the associated distribution infrastructure will not be able to meet the EPC Distribution System Performance Standard as set out in sections 4.2 and 4.3, beginning in the 2021 summer peak season.

The identified system deficiencies include:

6.1 No. 24 Substation feeder 25-24.114 Load at Risk during contingency

By the summer of 2021, a loss of feeder 25-24.114 will result in 10 MVA of load at risk during summer peak conditions. The magnitude increases to 24 MVA by 2027 (Table 5).

6.2 No. 37 Substation feeder 25-37.111 Load at Risk during contingency

By the summer of 2023 a loss of either the autotransformer (37.4TR) or the feeder (25-37.111) results in 6 MVA of load at risk during summer peak conditions. The magnitude increases to 9 MVA by 2027 (Table 5).

6.3 No. 24 Substation transformer 24.1TR Load at Risk during contingency

By the summer of 2021, a loss of transformer 24.1TR will result in 12 MVA of load at risk during summer peak conditions. The magnitude increases to 22 MVA by 2027 (Table 6).

6.4 No. 24 Substation transformer 24.2TR Load at Risk during contingency

By the summer of 2021, a loss of transformer 24.2TR will result in 12 MVA of load at risk during summer peak conditions. The magnitude increases to 22 MVA by 2027 (Table 6).

7.0 Alternatives Considered to Address Deficiency

Distribution Alternatives Considered

7.1 Alternative 1: Do nothing

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

- Existing system infrastructure cannot support the forecasted load under a single transformer contingency by 2021
- Existing system infrastructure cannot support the forecasted load under a single feeder contingency by 2021

7.2 Alternative 2: Load Transfer to Adjacent Substations

As required by the EPC Distribution System Performance Standard (refer to Section 4.1), the load growth within the study area must be supplied at 25 kV. The only 25 kV source substation in the area is No. 24 Substation to the south. Multiple feeder load transfers from No. 37 Substation to No. 24 Substation have been planned in 2018 and 2019 as noted in Table 4. Without these load transfers there is an inability to supply the expected load growth in areas such as Emcor, Frontier industrial, and others outlined in Table 1. The proposed transfers will accommodate load growth until 2021.

Beyond 2021, widespread deficiencies are seen at No. 24 Substation, eliminating its ability to support additional load transfers. Therefore, load transfers to adjacent substations cannot mitigate the identified deficiencies.

Advantages:

- Does not require additional transmission infrastructure

Disadvantages:

- Does not address identified system deficiencies
- As identified in Tables 5 and 6, No. 24 Substation is unable to support the load during contingency in 2021 and beyond

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 4.1 and 4.2).

Transmission Alternatives Considered

The transmission scope of work and the associated cost for each alternative were provided by EPC TFO and presented below for the purpose of alternative comparison only.

7.3 Alternative 3 (Preferred): Addition of 25 kV Capacity at No. 37 Substation

Install one [1] 138/25 kV 30/40/50 MVA transformer with associated distribution breaker lineup and remove the existing 13/25 kV 10/13.3 MVA autotransformer at No. 37 Substation. Connect feeder 25-37.111 to the new transformer. Construct one [1] new feeder to offload southeast section of feeder 25-37.111 supplying the Janet industrial area (approximately 0.2 km). Extend feeder 25-24.113 to provide reliability support to the new feeder from No. 37 Substation (approximately 3 km). See section 8.3 and Figure 6 in section 9 for a detailed scope.

<u>Capital Cost Estimate:</u> $9,729,000 +/- 30%

<u>Advantages:</u>

- Increases capacity to adequately supply the anticipated load growth during normal operation and feeder contingency beyond the 10 year forecast timeframe.
- Meets substation transformer reliability needs for the forecasted load growth until 2025
- Provides the nearest 25 kV source to load center
- Releases 13 kV transformer capacity and breaker (originally used by the autotransformer) for future use
- Most prudent alternative that aligns with EPC's long term distribution strategy to provide efficient 25 kV source to the customer developments located within the ENMAX 25 kV Boundary
- Lowest cost alternative

<u>Disadvantages:</u>

- No material disadvantages

<u>Alternative 3 is considered to be the preferred alternative as it addresses the identified system capacity deficiencies and provides the most cost effective long term solution.</u>

7.4 Alternative 4: Addition of 25 kV Capacity at No. 38 Substation

Install one [1] 138/25 kV 30/40/50 MVA transformer and the associated distribution breaker lineup at No. 38 Substation and remove the existing 13/25 kV 10/13.3 MVA autotransformer at No. 37 Substation. Construct two [2] new 25 kV distribution feeders from No. 38 Substation. One new feeder is to offload Belvedere from 25-37.111 as well as interconnect with a feeder from No. 39 Substation to the north for reliability support (approximately 9.2 km). The other feeder will offload the northeast section of feeder 25-37.111 supplying Frontier (approximately 2.6 km). Extend feeder 25-24.113 to offload the southeast section of feeder 25-37.111 supplying the Janet industrial area (approximately 0.5 km). See section 8.4 and Appendix B Figure B.1 for a detailed scope.

<u>Capital Cost Estimate:</u> $13,478,000 +/- 30%

<u>Advantages:</u>

- Increases capacity to adequately supply the anticipated load growth during normal operation and feeder contingency beyond the 10 year forecast timeframe
- Meets substation transformer reliability needs for the forecasted load growth until 2025
- Releases 13 kV transformer capacity and breaker (originally used by the autotransformer) for future use
- Provides support to 25 kV system north of No. 38 Substation

<u>Disadvantages:</u>

- Requires additional distribution infrastructure to achieve same result as Alternative 3
- Cannot provide the most effective support to the expected load growth under normal operating and contingency conditions as No. 38 Substation is geographically further from the growth center
- Higher cost ($3.75 M more) than the preferred Alternative 3

<u>This alternative was dismissed due to high costs and additional distribution system infrastructure required as compared to the preferred Alternative 3.</u>

7.5 Alternative 5: Addition of 25 kV Capacity at No. 24 Substation

Install one [1] 138/25 kV 30/40/50 MVA transformer and the associated distribution breaker lineup at No. 24 Substation. Construct one [1] new feeder from No. 24 Substation to offload the southeast section of feeder 25-37.111 supplying the Janet industrial area (approximately 3.8 km). Extend feeder 25-24.113 to offload the northeast section of 25-37.111 supplying Frontier (approximately 3 km). See section 8.5 and Appendix B Figure B.2 for a detailed scope.

<u>Capital Cost Estimate:</u> $9,863,000 +/-30%

<u>Advantages:</u>

- Increases capacity to adequately supply the anticipated load growth during normal operation and feeder contingency beyond the 10 year forecast timeframe
- Meets substation transformer reliability needs for the forecasted load growth until 2025

<u>Disadvantages:</u>

- Marginally higher cost ($0.13 M) than the preferred Alternative 3
- Requires additional distribution infrastructure, therefore, impacting more land owners as compared to the preferred Alternative 3
- Does not align with EPC's long term distribution strategy to develop 25 kV source to the north of No. 24 Substation in order to supply the 25 kV customer developments in the study area in an efficient manner. This alternative will provide a 25 kV supply that is centralized at No. 24 Substation, which will create challenges in the long term for supplying load in the Belvedere area and areas further north due to voltage drop on long feeders.

<u>This alternative was dismissed as it does not align with EPC's long term distribution strategy to provide efficient 25 kV source to the customer developments located within the ENMAX 25 kV Boundary as per the EPC Distribution System Performance Standard and higher cost than the preferred Alternative 3.</u>

7.6 Alternative 6: New Distribution Point of Delivery Substation

Install one [1] 138/25 kV 30/40/50 MVA transformer with associated distribution breaker line up at a new Point of Delivery Substation (POD) located within the EPC service territory between Highway 1A (17th Ave SE) and Peigan Trail, east of 100 St. SE. Remove the existing 13/25 kV 10/13.3 MVA autotransformer at No. 37 Substation. Construct two [2] new 25 kV distribution feeders from the new POD. One new feeder is to offload East Hills and Belvedere from 25-37.111 as well as interconnect with a feeder from No. 39 Substation to the north for reliability support (approximately 8.7 km). The other new feeder is to offload the section of feeder 25-37.111 supplying Frontier. Extend feeder 25-24.113 to offload the southeast section of feeder 25-37.111 supplying the Janet industrial area (approximately 2.3 km). See section 8.6 and Appendix B Figure B.3 for a detailed scope.

<u>Capital Cost Estimate:</u> $42,408,000 +/-30%

<u>Advantages:</u>

- Increases capacity to adequately supply the anticipated load growth during normal operation beyond the 10 year forecast timeframe
- Meets substation transformer reliability needs for the forecasted load growth until 2025
- Releases 13 kV transformer capacity and breaker (originally used by the autotransformer) for future use
- Provides support to 25 kV system north of No. 38 substation

<u>Disadvantages:</u>

- Requires additional transmission and distribution infrastructure to achieve same result as the preferred Alternative 3
- Requires more time to construct a new substation, which results in an ISD later than the required 2021, and therefore longer period of load at risk
- Highest cost of all the alternatives

<u>This alternative was dismissed due to increased costs and additional transmission and distribution system infrastructure required as compared to the preferred Alternative 3.</u>

7.7 Alternative 7: Addition of 25 kV Capacity at Chestermere 419S Substation: Dedicated to EPC Load

Install one [1] 138/25 kV 30/40/50 MVA transformer with associated distribution breaker lineup at Chestermere 419S Substation[1]. Remove the existing 13/25 kV 10/13.3 MVA autotransformer at No. 37 Substation. Construct one [1] new feeder from Chestermere 419S Substation to offload the southeast section of feeder 25-37.111 supplying the Janet industrial (approximately 12.2 km). Construct a second new feeder from Chestermere 419S Substation to offload northeast section of feeder 25-37.111 supplying East Hills and Belvedere (approximately 12.2 km). Extend feeder 25-24.113 to provide reliability support to the second new feeder supplying East Hills and Belvedere (approximately 3 km). See section 8.7 and Appendix B Figure B.4 for a detailed scope.

<u>Distribution Only Capital Cost Estimate[2]:</u> $8,752,000 +/- 30%
<u>Transmission Capital Cost Estimate:</u> not available at this time, to be provided by the TFO (AltaLink) if required

<u>Advantages:</u>

- Increases capacity to adequately supply the anticipated load growth during normal operation and feeder contingency beyond the 10 year forecast timeframe
- Meets substation transformer reliability needs for the forecasted load growth until 2025
- Releases 13 kV transformer capacity and breaker (originally used by the autotransformer) for future use

<u>Disadvantages:</u>

- Requires 24 km of additional distribution feeder infrastructure to achieve the same result as the preferred Alternative 3
- FortisAlberta has indicated that constructing two feeders from the Chestermere 419S Substation to EPC service territory will be very challenging due to feeder routing difficulties.
- Inefficient supply configuration under normal and contingency conditions due to the length of the feeders from the Chestermere 419S Substation to the load center as compared to the preferred Alternative 3
- Total capital cost including transmission is expected to be higher than the preferred Alternative 3 due to much higher distribution cost

[1] Chestermere 419S Substation is a new substation proposed by FortisAlberta and approved by AUC (AESO project number 1631).
[2] Cost estimate includes the cost provided by FortisAlberta for building the portion of the feeders located within its service territory.

This alternative was dismissed due to significantly more additional distribution development required and potentially higher total cost compared to the preferred Alternative 3.

8.0 Capital Cost Estimates

Cost estimates were prepared for technically viable alternatives 3, 4, 5, 6, and 7. The transmission scope of work and the associated cost were provided by EPC TFO and presented in this section for the purpose of alternative comparison. Alternatives 1 and 2 were deemed not viable and dismissed.

8.1 Alternative 1: Do nothing

No capital cost associated with Alternative 1 and does not address the identified system deficiencies.

8.2 Alternative 2: Load Transfer to Adjacent Substations

No capital cost estimates were prepared for Alternative 2 as it does not address the identified system deficiencies.

8.3 Alternative 3 (preferred): Addition of 138/25 kV Transformation at No. 37 Substation

Table 7 – Cost Estimate (+/- 30%)

Project Description	Capital Cost Estimate
Transmission (2021): - Installation of one [1] 138/25 kV 30/40/50 MVA transformer and removal of existing 13/25 kV 10/13.3 MVA autotransformer - Installation of new 25 kV distribution feeder breakers for two 25 kV feeders	$8,567,000
Distribution (2021): - Connection of feeder 25-37.111 to the new transformer - Construction of one [1] new 25 kV feeder (25-37.XXX) to offload southeast section of feeder 25-37.111 supplying Janet (approximately 0.2 km) - Extension of feeder existing feeder 25-24.113 to provide reliability support to the new feeder (28-37.XXX) (approximately 3 km)	$1,162,000
Total Project Cost:	**$9,729,000**

8.4 Alternative 4: Addition of 25 kV Capacity at No. 38 Substation

Table 8 - Cost Estimate (+/- 30%)

Project Description	**Capital Cost Estimate**
<u>Transmission (2021):</u> - Installation of one [1] 138/25 kV 30/40/50 MVA transformer and associated bus work and removal of existing 13/25 kV 10/13.3 MVA autotransformer - Installation of new 25 kV distribution feeder breakers for two 25 kV feeders	$8,749,000
<u>Distribution (2021):</u> - Construction of one new 25 kV feeder to offload Belvedere from 25-37.111 as well as interconnect with a feeder from No. 39 Substation to the north for reliability support (approximately 9.2 km) - Construction of another new feeder to offload the northeast section of feeder 25-37.111 supplying Frontier (approximately 2.6 km) - Extension of feeder 25-24.113 to offload the southeast section of feeder 25-37.111 supplying Janet (approximately 0.5 km)	$4,729,000
<u>Total Project Cost:</u>	**$13,478,000**

8.5 Alternative 5: Addition of 25 kV Capacity at No. 24 Substation

Table 9 - Cost Estimate (+/- 30%)

Project Description	**Capital Cost Estimate**
<u>Transmission (2021):</u> - Installation of one [1] 138/25 kV 30/40/50 MVA transformer and associated bus work - Installation of new 25 kV distribution feeder breakers for one 25 kV feeder	$7,538,000
<u>Distribution (2021):</u> - Construction of one [1] new 25 kV feeder from No. 24 Substation to offload the southeast section of feeder 25-37.111 supplying Janet (approximately 3.8 km) - Extension of feeder 25-24.113 to offload the northeast section of feeder 25-37.111 supplying Frontier (approximately 3 km)	$2,325,000
<u>Total Project Cost:</u>	**$9,863,000**

8.6 Alternative 6: New Distribution Point of Delivery (POD) Substation

Table 10 - Cost Estimate (+/- 30%)

Project Description	**Capital Cost Estimate**
Transmission (2022): - Construction of new transmission lines to supply new POD (approximately 13.5 km) - Installation of one [1] 138/25 kV 30/40/50 MVA transformer and associated bus work and removal of existing 13/25 kV 10/13.3 MVA autotransformer - Installation of new 25 kV distribution feeder breakers for two 25 kV feeders	$38,477,000
Distribution (2022): - Construction one new 25 kV feeder from the new substation to offload East Hills and Belvedere from feeder 25-37.111 as well as interconnect with a feeder from No. 39 Substation (approximately 8.7 km) - Construction of another new 25 kV feeder from the new substation to offload the rest of feeder 25-37.111 supplying Frontier (approximately 2.3 km)	$3,931,000
Total Project Cost:	**$42,408,000**

8.7 Alternative 7: Addition of 25 kV Capacity at Chestermere 419S Substation

Table 11 - Cost Estimate (+/- 30%)

Project Description	**Capital Cost Estimate**
Transmission (2021): - Installation of one [1] 138/25 kV 30/40/50 MVA transformer and associated bus work and removal of existing 13/25 kV 10/13.3 MVA autotransformer - Installation of new 25 kV distribution feeder breakers for two 25 kV feeders	N/A[1]
Distribution (2021): - Construction of one new 25 kV feeder from Chestermere 419S Substation to offload East Hills and Belvedere from feeder 25-37.111 (approximately 12.2 km) - Construction of another new 25 kV feeder from the Chestermere Substation to offload the rest of feeder 25-37.111 supplying Frontier (approximately 12.2 km) - Extension of feeder 25-24.113 to offload the southeast section of feeder 25-37.111 supplying Frontier (approximately 3 km)	$8,752,000[2]
Total Project Cost:	**N/A**

[1] Transmission cost not available at this time, to be provided by the TFO (AltaLink) if required.
[2] Cost estimate includes the cost provided by FortisAlberta for building the portion of the feeders located within its service territory.

9.0 Proposed System Development - Preferred Alternative 3

9.1 Preferred Alternative Transmission Scope of Work:

- Install one [1] 138/25 kV 30/40/50 MVA transformer and associated switchgear
- Remove existing 13/25 kV 10/13.3 MVA autotransformer
- Install new 25 kV feeder breakers for two 25 kV feeders

The requested in service date for the 138/25 kV transformer addition at No. 37 Substation is July 2021.The estimated capital cost for the required substation work is $8,567,000 (+/- 30%).

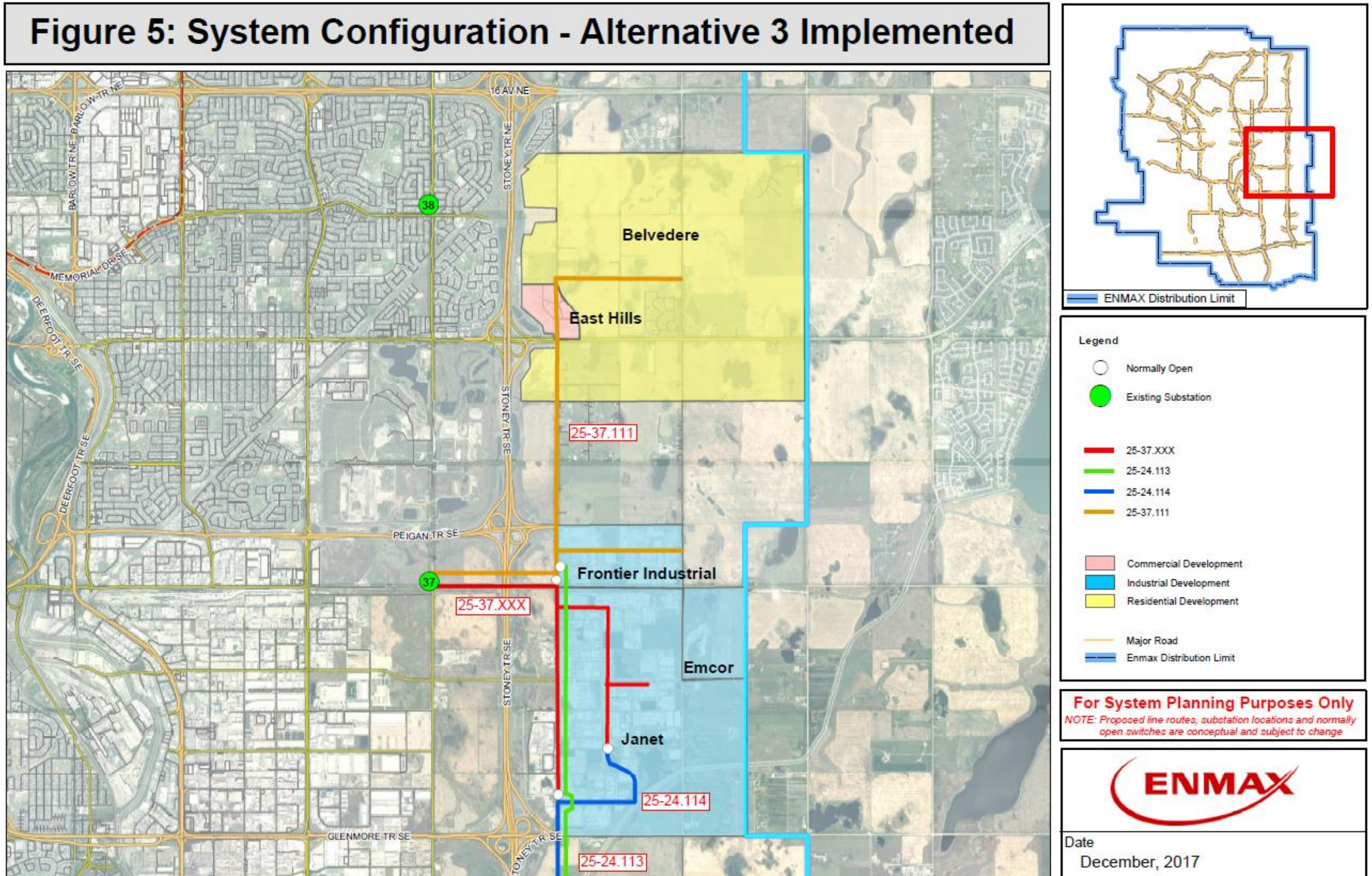
Transmission scope of work and the associated cost were provided by EPC TFO and presented here for information only.

9.2 Preferred Alternative Distribution Scope of Work (Figure 5):

- Connect feeder 25-37.111 to the new transformer
- Construct one [1] new 25 kV feeder (25-37.XXX) to offload southeast section of feeder 25-37.111supplying Janet (approximately 0.2 km)
- Extend existing feeder 25-24.113 to provide reliability support to the new feeder (25-37.XXX) (approximately 3 km)

The requested in service date for the distribution infrastructure associated with No. 37 Substation is July 2021 and the estimated capital cost is $1,162,000 (+/- 30%).

Figure 5: System Configuration - Alternative 3 Implemented



Legend

- Normally Open
- Existing Substation
- 25-37.XXX
- 25-24.113
- 25-24.114
- 25-37.111
- Commercial Development
- Industrial Development
- Residential Development
- Major Road
- Enmax Distribution Limit

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NOTE: Proposed line routes, substation locations and normally open switches are conceptual and subject to change

ENMAX

Date
December, 2017

10.0 Load Forecast – Preferred Alternative 3 Implemented

This section provides the load forecast and Load at Risk with the preferred Alternative 3 implemented.

Table 12 – POD Load Forecast - Preferred Alternative Implemented

POD[1]	Peak	PF[2]	Units	Forecasted Load									
				2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
37 S	S	0.95	MVA	56	50[3]	52	65[5]	67	70	72	74	75	77
			MW	53	47	50	62	63	66	68	70	71	72
24 S	S	0.96	MVA	57	55[4]	58	60[6]	64	60	63	66	69	73
			MW	54	53	56	58	61	58	60	63	67	70

Notes:

1. No. 37 Substation supplies distribution both at 13 kV and 25 kV
2. The POD power factor is calculated using the POD MW and MVA values over the POD peak period
3. Substation No. 37 loading incorporates a planned load transfer from 25-37.111 to 25-24.114 to manage forecasted overloads on 37.4TR in 2019
4. No. 24 Substation loading incorporates multiple load transfers, including removal of FortisAlberta load, temporary load transfer away from the substation in order to support No. 37 Substation load.
5. No. 37 Substation loading incorporates a load transfer from No. 24 Substation to No. 37 Substation after the proposed new 138/25 kV 30/40/50 MVA transformer is in service
6. No. 24 Substation loading incorporates load transfer to No. 37 Substation and returned of the load being temporarily transferred away

Table 13 – Transformer Load Forecast - Preferred Alternative Implemented (MVA)

Transformer	Installed Capacity [MVA]	Peak	Forecasted Load									
			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
37.4TR	13.3	S	13	5[1]	6	-[3]	-	-	-	-	-	-
37.3TR	50	S	-	-	-	17[3]	18	20	20	21	22	23
24.1TR	50	S	32	22[2]	23	35[4]	37	38	39	41	42	44
24.2TR	50	S	26	35[2]	37	26[4]	28	23	25	27	28	30

Notes:

1. Transformer loading incorporates a planned load transfer from 25-37.111 to 25-24.114 to manage forecasted overloads in 2019
2. Transformer loading incorporates multiple load transfers, including removal of FortisAlberta load, temporary load transfer away from the substation in order to support No. 37 Substation load
3. Transformer loading incorporates planned load transfers from the autotransformer 37.4TR and No 24 Substation following the energization of the proposed new 138/25 kV 30/40/50 MVA transformer and decommissioning of 37.4TR
4. Transformer loading incorporates planned load transfer to No. 37 Substation following the energization of the new 138/25 kV transformer and return of the load being temporarily transferred away in 2019

Table 14 – 25 kV Feeder Load Forecast - Preferred Alternative Implemented (MVA)

Feeder	Peak	Forecasted Load [MVA]									
		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
25-37.111	S	13	5[1]	6	8	8	9	9	10	10	11
25-37.XXX	S	-	-	-	11[2]	11	12	13	13	14	14
25-24.114	S	2	12[1]	14	4[2]	5	6	7	8	9	10

Notes:

1. Feeder loading incorporates a planned load transfer from 25-37.111 to 25-24.114 to manage forecasted overloads on 37.4TR in 2019
2. Proposed new feeder to be in service with load transferred from 25.24.114 following the energization of the proposed new 138/25 kV 30/40/50 MVA transformer at No. 37 Substation

Table 15 indicates that the implementation of the preferred alternative mitigates the identified load at risk during a transformer contingency at No. 37 Substation until 2025. Plans to manage the load at risk after 2025 are outlined in Section 12.0.

Table 15 – Transformer Load at Risk - Preferred Alternative Implemented (MVA)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Loss of Transformer 37.3TR										
37.3 Transformer Loading	-	-	-	17	18	19	20	21	22	23
Total Tie Away[1]	-	-	-	24	22	27	25	23	14[6]	14
Load at Risk[2]	-	-	-	0	0	0	0	0	10	11
Loss of Transformer 24.1TR										
24.1 Transformer Loading	32	22[3]	23	35[5]	37	38	39	41	42	44
Total Tie Away[1]	46	35	34	49	49	48	48	48	48	48
Load at Risk[2]	0	0	0	0	0	0	0	0	0	0
Loss of Transformer 24.2TR										
24.2 Transformer Loading	26	35[3]	37	26[5]	28	23	25	27	28	30
Total Tie Away[1]	40	48	48	40	39	33	33	34	34	34
Load at Risk[2]	0	0	0	0	0	0	0	0	0	0

Notes:

1. Total Tie-Away Capacity is the maximum capacity available to effectively transfer load away from the out-of-service substation transformer using existing feeder ties and/or substation secondary bus ties
2. Load at Risk is defined as the customer load that cannot be returned to service within a timeframe of one manual switching operation
3. Transformer loading incorporates multiple load transfers, including removal of FortisAlberta load, temporary load transfer away from the substation in order to support No. 37 Substation load
4. Transformer loading incorporates planned load transfers from the autotransformer 37.4TR and No. 24 Substation following the energization of the proposed new 138/25 kV 30/40/50 MVA transformer and decommissioning of 37.4TR
5. Transformer loading incorporates planned load transfer to No. 37 Substation following the energization of the new 138/25 kV transformer and return of the load being temporarily transferred away
6. Decrease in total tie away capacity due to load growth on all the transformers and feeders involved in the tie away

Table 16 indicates that the preferred alternative mitigates the identified load at risk during a 25 kV feeder contingency at No. 37 Substation beyond the 10 year forecast.

Table 16 – 25 kV Feeder Load at Risk - Preferred Alternative Implemented (MVA)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Loss of Feeder 25-37.111										
25-37.111 Feeder Loading	13	5[3]	6	8	8	9	9	10	10	11
Total Tie Away[1]	24	14	12	22	21	20	19	18	17	16
Load at Risk[2]	0	0	0	0	0	0	0	0	0	0
Loss of Feeder 25-37.XXX										
25-37.XXX Feeder Loading	-	-	-	11[4]	11	12	13	13	14	14
Total Tie Away[1]	-	-	-	16	16	23	23	23	23	23
Load at Risk[2]	0	0	0	0	0	0	0	0	0	0
Loss of Feeder 25-24.114										
25-24.114 Feeder Loading	2	12[3]	14	4[4]	5	6	7	8	9	10
Total Tie Away[1]	17	20	19	18	18	17	17	16	16	15
Load at Risk[2]	0	0	0	0	0	0	0	0	0	0

Notes:

1. Total 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. Load at Risk is defined as the customer load that cannot be returned to service within a timeframe of one manual switching operation
3. 25-24.114 and 25-37.111 feeder loading incorporates a planned load transfer from 25-37.111 to 25-24.114 to manage forecasted overloads on 37.4TR
4. Proposed new feeder to be in service with load transferred from 25.24.114 following the energization of the proposed new 138/25 kV 30/40/50 MVA transformer at No. 37 Substation

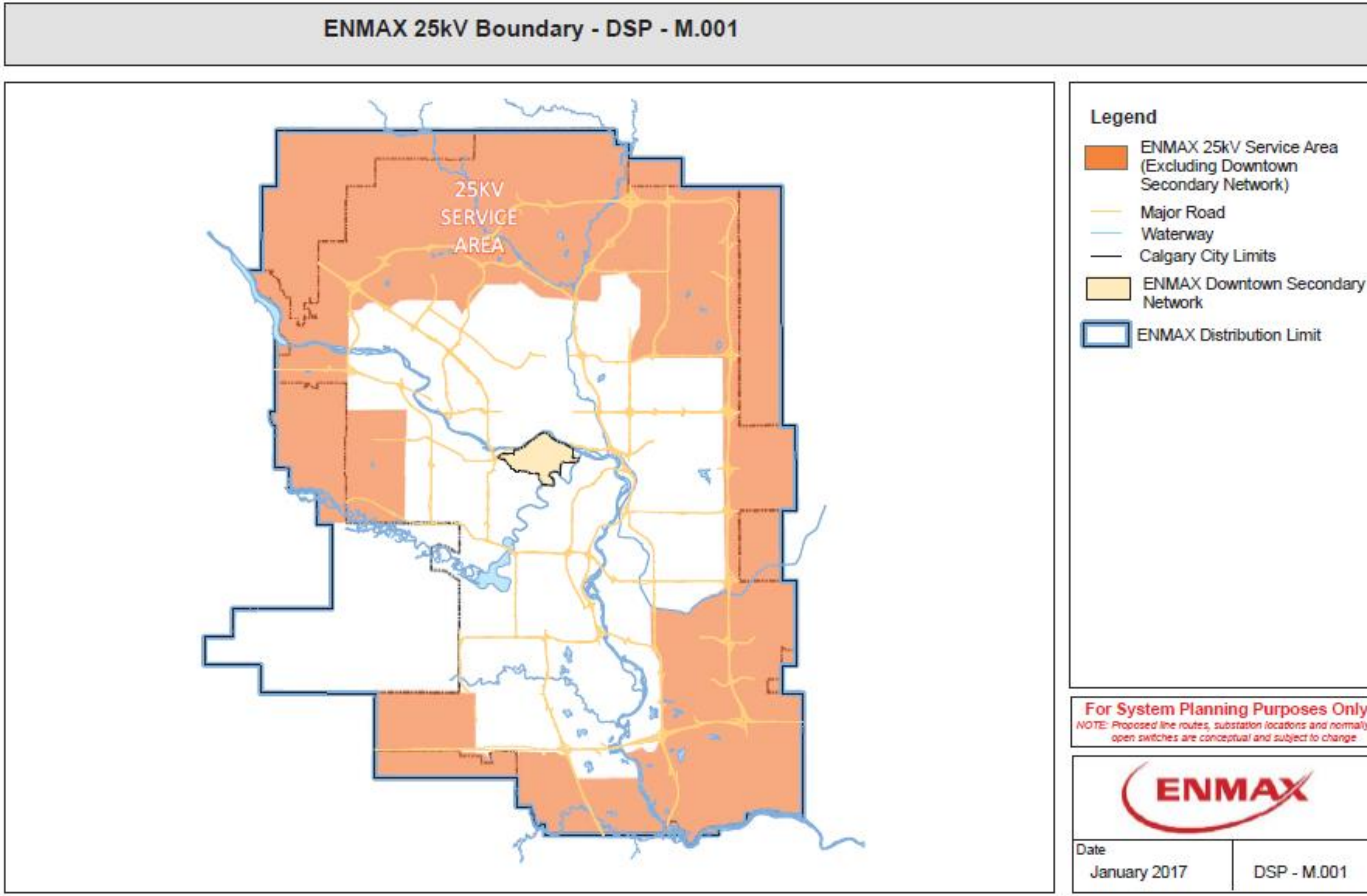
11.0 In-Service Date

Requested in-service date for the 138/25 kV 30/40/50 MVA transformer at No. 37 Substation and the construction of the new 25 kV distribution feeders is July of 2021.

12.0 Future System Development

The implementation of the preferred alternative will provide sufficient capacity for the anticipated load growth in the area under normal operation beyond the 10-year load forecast timeframe. However, as indicated in Table 15, reliability deficiencies start to reoccur by 2026. Additional system capacity and transmission infrastructure will 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, 5, 6 and 7

Figure B.1 : System Configuration - Alternative 4

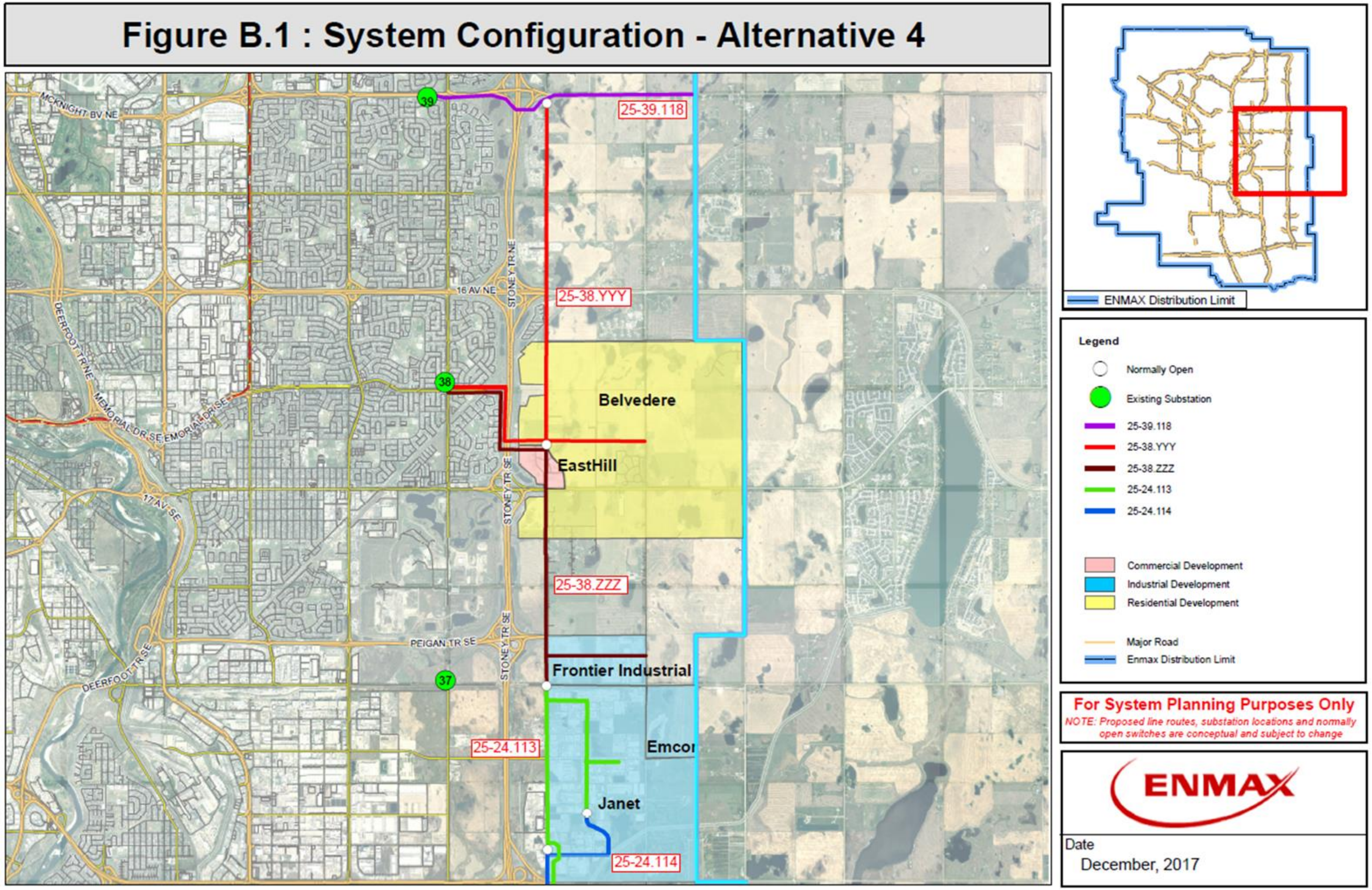


Figure B.2 : System Configuration - Alternative 5

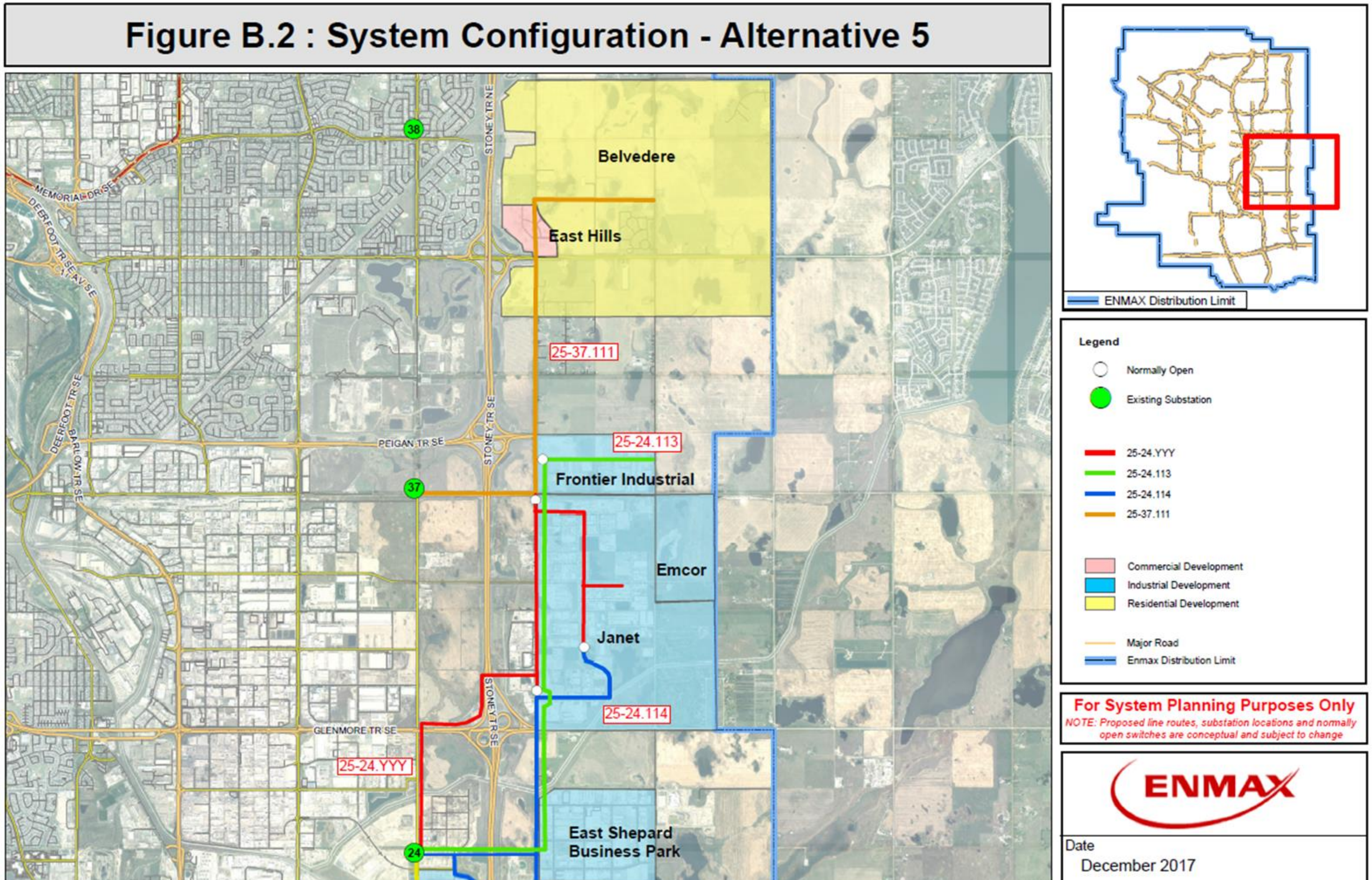
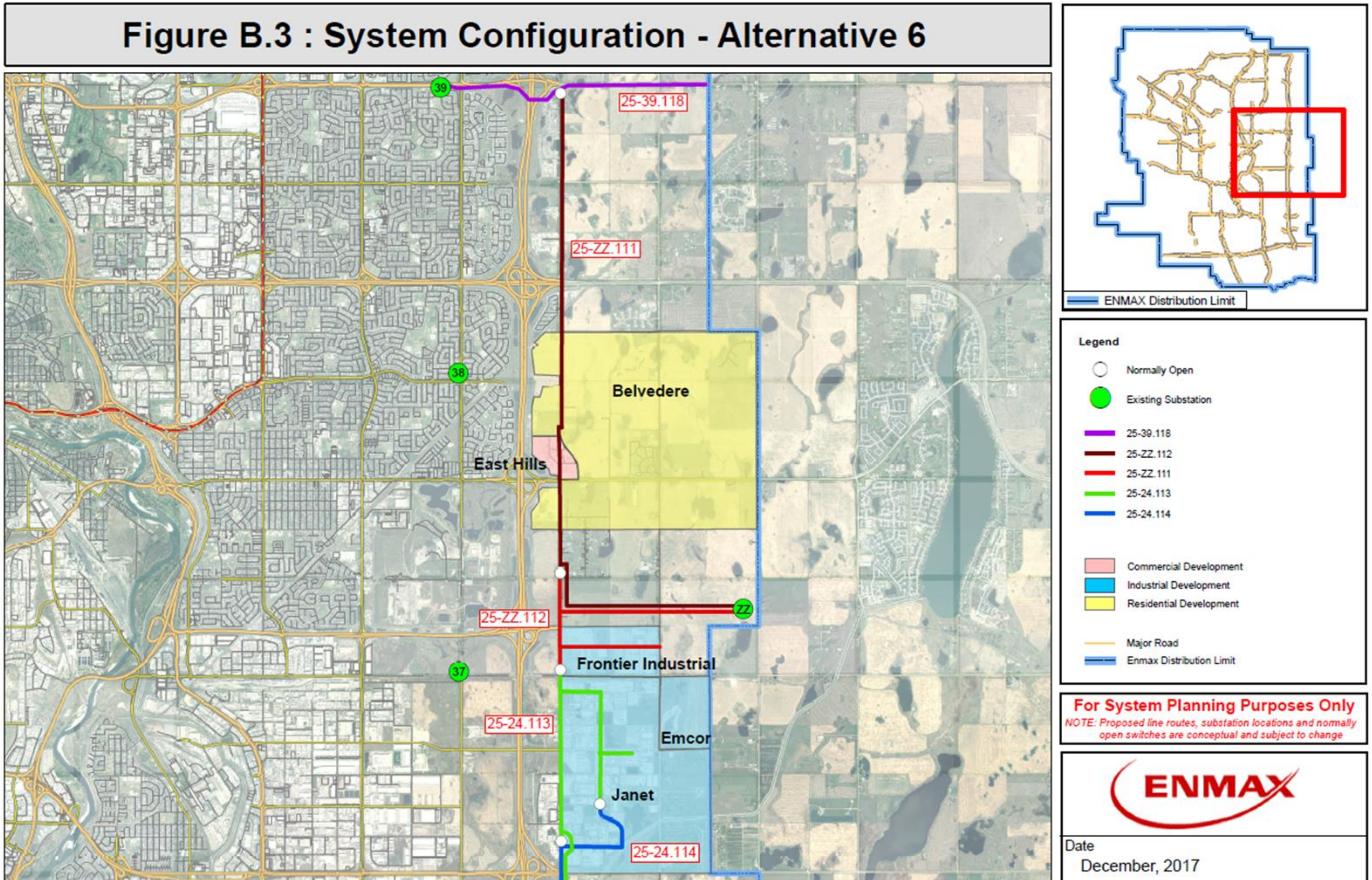


Figure B.3 : System Configuration - Alternative 6



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NOTE: Proposed line routes, substation locations and normally open switches are conceptual and subject to change

Date

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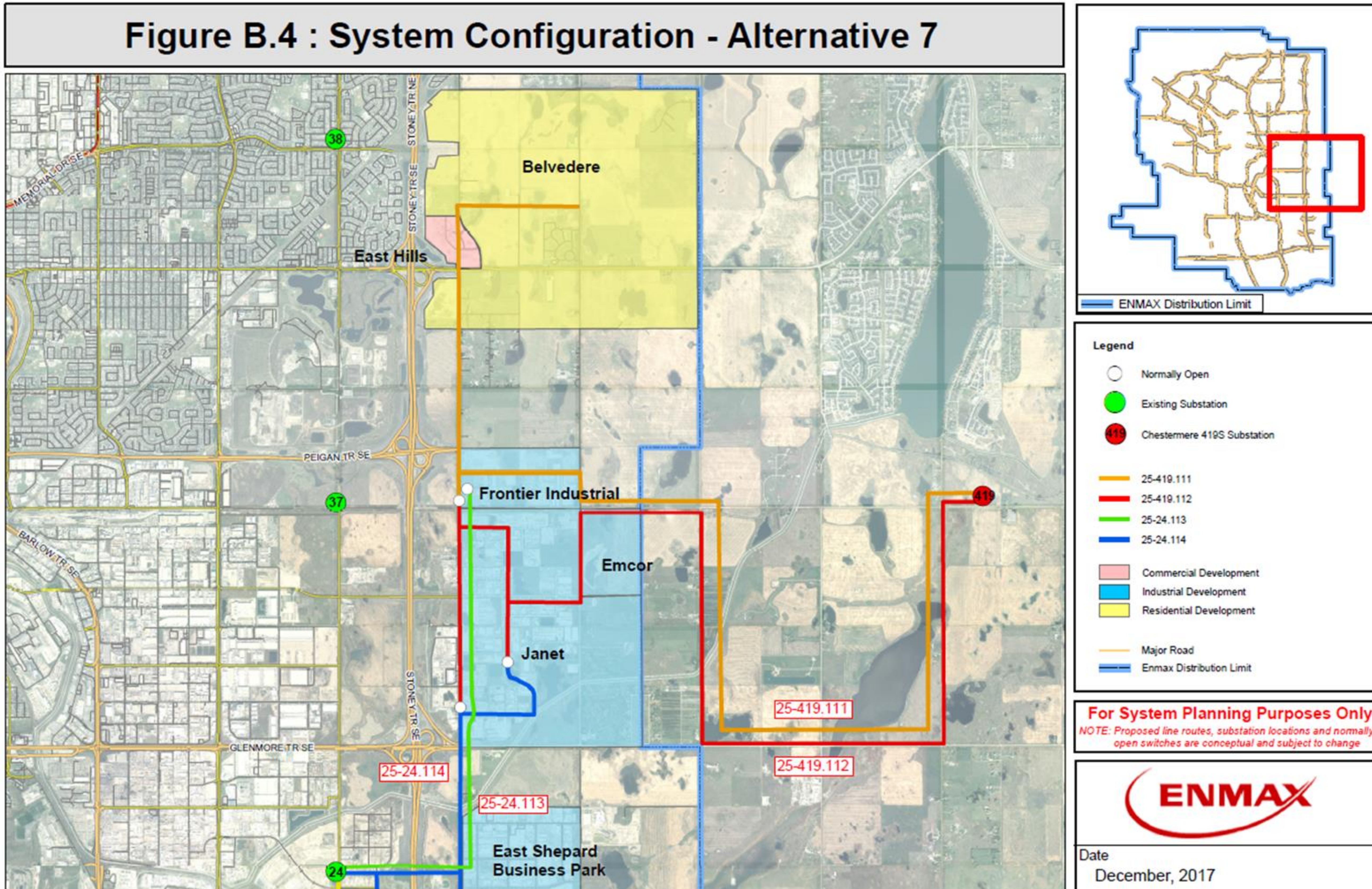
Figure B.4 : System Configuration - Alternative 7



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NOTE: Proposed line routes, substation locations and normally open switches are conceptual and subject to change

ENMAX

Date

December, 2017

ADDENDUM TO STATEMENT OF NEED

No. 37 Substation
138/25 kV Transformer Addition

	Name	Signature	Date
Approved:	Leonard Huynh Manager, System Development and Asset Management		

This addendum supplements the No. 37 Substation 138-25kV Transformer Addition statement of need. The purpose of this document is to provide further clarification on the deficiency calculations and the distribution alternatives considered.

Due to the continuing economic uncertainty caused by both the COVID-19 pandemic as well as the collapse of oil price in the first half of 2020, EPC is unable to provide an updated load forecast for the study area at this time. EPC still supports the 2019 Load Forecast indicating 27MVA of load growth over the 2018 to 2028 period in the study area and the deficiencies identified.

Requirement for Load Transfers from No. 26 Substation to No. 24 Substation

One factor driving the deficiency in 2021 is a load transfer from No. 26 Substation to No. 24 Substation. This load transfer is needed.

Load was temporarily transferred from No. 24 Substation to No. 26 Substation in 2018 to manage a capacity deficiency at 37 No. Substation. This load is currently supplied by feeder 25-26.112. This load will be transferred back to No. 24 Substation in 2020 due to an overload that has been identified on feeder 25-26.112. Although the physical transfer will occur in 2020 it will be reflected in the load forecast starting in 2021. This need for the transfer back is due to feeder 25-26.112 overloading as identified below.

Distribution feeder 25-26.112 has normal open points that allow for connection to both feeders 25-26.113 and 25-26.123 at No. 26 Substation. During a contingency on feeder 25-26.112, feeders 25-26.113 and 25-26.123 are required to supply the combined loads of all three feeders. The maximum capacity available for two feeders is 52MVA or 26MVA per feeder. Table 1 below shows that the total load of the three feeders exceeds the capacity of two feeders in 2021 during an N-1 contingency of 25-26.112. To alleviate the identified overload, EPC must offload 25-26.112 by transferring back the 10 MVA of load from No. 26 Substation to No. 24 Substation. This will lower the loading level on 25-26.112 so that in the event of an N-1 feeder outage, restoration of all customer load can be accomplished.

Table 1: Tie-away Feeder Overload during Feeder 25-26.112 Contingency

Feeder	Season	2018 A[2]	2019 F[3]	2020 F	2021 F	2022 F	2023 F	2024 F	2025 F	2026 F	2027 F	2028 F
25-26.112	Winter	14	16	17	18	19	20	21	21	23	24	24
25-26.113	Winter	17	18	19	20	20	21	21	21	21	21	21
25-26.123	Winter	15	15	16	16	17	17	17	18	18	19	19

Total Load	Winter	45	49	52	54	56	58	59	60	62	64	65
Overload[1]		0	0	0	2	4	6	7	8	10	12	13

1. The combined capacity of feeders 25-26.113 and 25-26.123 is 52MVA. The overload does not account of location of each feeder's inline switches.
2. A: means actual
3. F: means forecast

N-1 Unsupplied Feeder Load Calculation Clarification

Table 2 below is intended to provide more clarity on how the N-1 Unsupplied Feeder Load is calculated. The feeder total capacity of each tie-away feeder has been specified. 'Capacity remaining' is the feeder total capacity minus the pre-contingency loading. The 'Capacity utilized for tie-away' is the amount of load on the feeder under contingency that could be effectively tied away considering the limitations based on the geographic location of the feeder's in-line normally closed switches.

Table 2: Backup Calculations for 25-24.114 Contingency (load in MVA)

25-24.114 Contingency	2018 A2	2019 F	2020 F	2021 F	2022 F	2023 F	2024 F	2025 F	2026 F	2027 F	2028 F
25-24.114 Total Load:	2	12	14	18	20	21	21	22	24	25	27
Capacity remaining:											
25-24.121 (26 MVA Cap.)	18	21	21	8[1]	7	7	7	6	6	6	6
25-37.111 (13.3MVA Cap.)	2	10	9	8	7	6	4	4	3	3	3
Capacity utilized for tie-away:											
25-24.121	2	12	14	-	-	3	3	3	3	3	3
25-37.111	0	-	-	6	6	-	-	-	-	-	-
N-1 Unsupplied load	**0**	**0**	**0**	**12**	**14**	**18**	**18**	**19**	**21**	**22**	**24**

1. Reduction in Capacity remaining due to load increase on the feeder caused by load transfer and new customer load additions

Although feeder 25-24.114 is tied to two feeders, 25-24.121 and 25-37.111, only one can be utilized during a contingency. EPC planning criteria allows for one manual operation for each feeder switching. In the case of a contingency on feeder 25-24.114 in 2021, 25-37.111 does not have sufficient capacity to support the full 18 MVA of load on 25-24.114 and only a portion of 25-24.114 load that can be accommodated by an in-line switch to 25-37.111 can be tied away; the remaining will be unsupplied. While 25-37.111's remaining capacity is 8 MVA, when the limitations from the location of the in-line switches is considered, only 6 MVA can actually be tied away. Therefore, 12 MVA (18 MVA – 6 MVA) of load will remain unsupplied.

Table 3: Backup Calculation for 25-37.111 Contingency (Load in MVA)

25-37.111 Contingency	2018 A[1]	2019 F[2]	2020 F	2021 F	2022 F	2023 F	2024 F	2025 F	2026 F	2027 F	2028 F
25-37.111 Total Load:	12	3	4	5	7	8	9	9	10	10	10
Capacity remaining: 25-24.114 (26MVA Cap.)	24	14	12	8	6	5	5	4	2	1	0
Capacity utilized: 25-24.114	12	3	4	5	6	2	2	2	0	0	0
N-1 Unsupplied load	**0**	**0**	**0**	**0**	**1**	**6**	**7**	**7**	**8**	**9**	**10**

1. A: means actual
2. F: means forecast

Typically, load is not evenly distributed along the feeder and that due to the topology of main feeder trunk and branch circuitry. An in-line switch cannot be located to perfectly spilt the feeder load and optimize the remaining capacity on adjacent feeders.

Alternatives: Distribution Load Transfers to Address Deficiencies

There is limited ability for the surrounding distribution infrastructure to accommodate load transfers to alleviate the identified load at risk due to the limited 25kV capacity at No. 37 Substation and No. 24 Substation. The only other adjacent POD that has 138/25kV transformation capacity is No. 26 Substation to the south of No. 24 Substation.

D1: Transferring load away from No. 24 Substation

The distribution alternative of transferring load away from No. 24 Substation to No. 37 Substation was dismissed due to limited 25kV capacity at No. 37 Substation. As indicated in the DDR (SON), No. 37 Substation has a 13/25kV auto-transformer (13.3MVA), which has a capacity less than that of a typical 25kV feeder (26MVA). In 2019, EPC already transferred load to mitigate the overload of the auto-transformer by moving load from No. 37 Substation's 25-37.111 feeder to No. 24 Substation's 25-24.114. Transferring this 10MVA load back to No. 37 Substation will overload the auto-transformer.

Another distribution alternative that was explored was the transfer of load from No. 24 Substation to No. 26 Substation using existing feeders. This alternative would shift the deficiency from one substation to another. This is demonstrated in the discussion above regarding the overload that occurs at No. 26 Substation from continuing to supply the load transferred from No 24 Substation to No 26 Substation.

D2: Building a new feeder from No. 26 Substation

EPC explored the alternative of building a new feeder from No. 26 Substation to create a new tie to No. 24 Substation. This alternative would utilize a currently unused feeder breaker 25-26.114 to offload 24S feeder 25-24.112, which is the closest feeder to No. 26 Substation. This alternative involves constructing an approximately 7.5km long new feeder through fully developed areas to the tie point. An order of magnitude estimate for 7.5km of feeder cable in duct is $11.2M. A high-level assessment indicate that this solution would only defer the need for a substation upgrade for 2-4 years.

D3: Balancing load within No. 24 Substation Feeders

Transferring load between feeders at No. 24 Substation via construction of feeder extensions may be effective in resolving feeder N-1 deficiencies, however it does not create more tie-away capability during transformer N-1 contingencies, which is a main driver for the need of this project.

There are only three feeders (25-24.121. 25-24.114, 25-24.123) at No. 24 Substation that are tied to adjacent substations. These feeders are currently heavily loaded, which allows significant amounts of load to be tied to the adjacent substations during a No. 24 Substation transformer or feeder contingency.

The lighter loaded feeders at No. 24 Substation tie only to other feeders at No. 24 Substation. Under transformer N-1 contingency at No. 24 Substation, the load on these feeders will have to be supplied by the remaining transformer at No. 24 Substation. Transferring load away from these heavily loaded feeders to the lighter loaded feeders will reduce the tie-away capability under transformer contingency. Therefore, balancing the feeders at No. 24 Substation is ineffective in mitigating the capacity issue as it does not allow more load to be transferred away from the substation during an N-1 substation transformer contingency.

Utilization of Existing Feeder Supplying Fortis

Two of the No. 24 Substation feeders (25-24.113 and 25-24-122) were supplying load in FortisAlberta’s service territory. The FortisAlberta load has been transferred away in 2019 to a new substation built by AltaLink. The capacity that was made available has been incorporated in the load forecast. Feeder 25-24.113 is used to resolve a feeder deficiency in 2019 and is currently supplying load. The other feeder 25-24.122 is planned to supply new customer loads in the near future. Using 25-24.122 to off load the heavily loaded will not more tie way capability to adjacent substations.

ADDENDUM TO STATEMENT OF NEED

No. 37 Substation
138/25 kV Transformer Addition

	Name	Signature	Date
Prepared by:	Kaelen Young, P.L. (Eng) System Development Technologist		Feb 11, 2022
Approved:	Matt Dimoff P. Eng. Manager, Planning & Asset Regulatory Requirements	Matt Dimoff Matt Dimoff (Feb 11, 2022 11:55 MST)	Feb 11, 2022

1.0 Executive Summary

This document is an addendum to the approved Statement of Need ("SoN") – No. 37 Substation 138-25 kV Transformer Addition dated August 2018 ("original"). The No.37 Substation SoN identified the need to install a 138-25 kV transformer with the ability to connect at minimum two new 25kV feeders.

In the original SoN ENMAX requested the DTS contract at No. 37 Substation to be increased from 40 MW to 66 MW. After reviewing the updated load forecast values this request remains unchanged.

ENMAX Power Corporation ("EPC") is requesting an In Service Date (ISD) of Q4 2024 due to overloads beginning in 2023 and increasing in duration and severity over the forecast period. EPC will manage outage risk through operational plans until additional substation capacity is available.

2.0 Updated Forecast – Current Configuration

Table 1 outlines the updated load forecast for Point of Delivery ("POD") substations No. 37, No.24, No. 26, and No.38. No. 38 Substation is a 138/13 kV POD Substation supplying 13 kV Load and has been included for a complete understanding of the substation infrastructure surrounding the study area.

No. 37 Substation supplies customer load at both 13 kV and 25 kV, while No. 24 and No. 26 Substations supplies customer load at 25 kV. The No. 37 Substation POD load forecast in Table 1 includes both supply voltages. The 25 kV loading in the study area, which is the focus of this addendum is reflected in Tables 2 and 3. Table 2 provides an updated load forecast for autotransformer 37.4TR, transformers 24.1TR, 24.2TR, 26.1TR and 26.2TR. Table 3 provides updated forecast load for 25kV feeders 25-37.111 and 25-24.114.

All forecasted loads represent summer peak periods (summer season is defined as May 1 to October 31).

Table 1 – POD Substation Coincident Load Forecast – Existing System [Table 2 in original SoN]

POD	PF	Units	Actual Load					Forecasted Load									
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
37 S	0.89	MVA	55.6	57.4	54.8	51.5	53.0	56.6	63.7	66.2	68.2	68.9	69.3	69.7	70.1	70.4	70.8
		MW	49.2	50.8	48.5	45.6	46.9	50.2	56.4	58.6	60.4	61.1	61.4	61.7	62.1	62.3	62.7
24 S	0.89	MVA	54.7	56.0	41.1	48.5	59.6	68.0	75.2	78.4	81.0	82.1	85.0	87.0	88.0	88.7	89.5
		MW	49.0	50.1	36.8	43.4	53.3	60.9	67.3	70.1	72.5	73.5	76.1	77.8	78.7	79.4	80.1
26 S	0.96	MVA	41.7	53.1	53.7	60.1	82.3	78.9	80.3	82.0	83.6	85.0	85.7	86.5	87.5	88.5	89.5
		MW	39.9	50.9	51.5	57.6	78.8	75.6	76.9	78.5	80.1	81.3	82.0	82.8	83.8	84.7	85.7
38 S	0.94	MVA	32.0	34.0	32.0	32.4	35.9	34.8	34.9	34.9	34.9	34.9	34.8	34.8	34.8	34.8	34.8
		MW	30.2	32.0	30.2	30.5	33.8	32.8	32.9	32.9	32.9	32.8	32.8	32.8	32.8	32.7	32.7

Table 2 – Transformer Updated Load Forecast – Existing System (MVA) [Table 3 in original SoN]

Transformer	Capacity (MVA)	Actual Load					Forecasted Load									
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
37.4TR	13.3	9.4	11.8	11.2	5.6	6.0	6.7	8.5	10.5	11.9	12.7	13.0	13.3	**13.6**[1]	**13.7**[1]	**13.9**[1]
24.1TR	50	29.7	32.7	23.9	19.7	28.8	34.9	39.2	41.5	43.1	43.3	44.5	44.7	44.8	45.0	45.0
24.2TR	50	26.9	26.3	17.6	29.2	30.9	35.0	37.5	38.2	39.1	39.9	41.7	43.4	44.2	44.8	45.4
26.1TR	50	15.9	25.7	28.1	32.2	42.5	40.5	41.5	42.8	44.0	45.1	45.8	46.7	47.7	48.8	49.8
26.2TR	50	26.4	28.2	26.4	28.1	40.1	40.6	41.2	41.8	42.2	42.5	42.5	42.5	42.5	42.5	42.5

1. Values identified in orange exceed the 13.3MVA thermal rating of 37.4TR

Table 3 – 25kV Feeder Loading Forecast - Existing System (MVA) [Table 4 in original SoN]

Feeder	Capacity (MVA)	Actual Load					Forecasted Load									
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
25-37.111	13.3	9.4	11.8	11.2	5.6	6.0	6.7	8.5	10.5	11.9	12.7	13.0	13.3	**13.6**[1]	**13.7**[1]	**13.9**[1]
25-24.114	25.9	5.8	2.0	1.9	7.1	7.8	8.2	8.8	9.3	10.0	10.7	11.4	12.1	12.7	13.2	13.6

1. Values identified in orange exceed the 13.3MVA thermal rating of 37.4TR

Table 4 provides a summary of the Distribution Connection Generation (DCG) within the study area. There is one DCG connected to POD No.24 Substation and is designed to support the customer load at its site under normal operation.

Table 4 – DCG Summary – Existing System

POD	DCG Name or ID	Type	Installed Capacity (kW)	Comment
24 S	0020008003457	Solar	3700	Customer offsets their own demand and then exports to grid. No agreement to dispatch generation.

Table 5 provides information on the major load additions forecast in the study area and compares major load additions identified in the original SoN to the updated major loads reflected within the load forecasts provided in this addendum. Overall, there has been an increase in major load connection requests and resulting forecast load growth.

Table 5 – Major Load Additions Update and Comparison (2018-2027 vs 2022-2031 Forecast)

Description of New Load Addition	Original Expected Load MVA (2018 - 2027)	Updated Expected Load MVA (2022 - 2031)	Difference in Load (MVA)
Belvedere Residential[2]	1	2	1
East Hills Commercial	4	0	-4
Frontier Industrial	1	0	-1
EMCOR Industrial	8	1	-7
Janet Industrial	2	0	-2
East Shepard Business Park[2]	2	2	0
Point Trotter Industrial	3	2	-1
Hotchkiss Residential[2]	n/a[1]	2	2
East Hills Village (Residential)	n/a[1]	1	1
Green Line Related Projects	n/a[1]	3	3
Heather Glen Industrial Business Park	n/a[1]	3	3
Canal Lands Buildings	n/a[1]	1	1
Food Processing Plant	n/a[1]	1	1
Non-Sort Distribution Facility (1 of 2)	n/a[1]	8	8
Non-Sort Distribution Facility (2 of 2)	n/a[1]	5	5
Data Center - Upgrade	n/a[1]	6	6
Film Studio Lot	n/a[1]	5	5
Total Area Load Growth (Non-Diversified)	21	42	21

1. “n/a” identifies Major Load additions that were not initiated at the time of the original SoN.
2. Development areas expected to continue to experience load growth beyond the 10-year forecast timeframe.

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. EPC has no customers which falls under this category within the study area.

3.0 Updated Deficiency Analysis

3.1 Distribution System Performance Standard

The EPC Distribution system Performance standard (published in 2018) outlines the reliability requirements for the EPC Distribution System. The applicable sections are as follows:

A1 - 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.

A2 - Three Phase Main Distribution System Feeders

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

A3 - EPC 25kV Service Area

All new distribution facilities within the EPC 25 kV boundary, as defined in map DSP-M.001 of the original SoN, will be planned and designed to 25 kV standards.

3.2 Study Area Customer Type Breakdown

EPC No. 24 and No. 37 substations each serve a mixture of D100 (Residential), D200 (Small Commercial), D300 (Medium Commercial), D310 (Large Commercial – Secondary Fed), and D410 (Large Commercial – Primary Fed) customer load, as defined by EPC's Distribution Tariff. Detailed customer counts by rate class for ENMAX No. 24 and ENMAX No. 37 substations are provided in Table 6. Customer counts shown are as of the end of 2021.

Table 6 – 2021 Customer Count by Rate Class

Substation	Feeder Class	Customer Count by Rate Class				
		D100 *Residential*	D200 *Small Commercial*	D300 *Medium Commercial*	D310 *Large Commercial Secondary*	D410 *Large Commercial Primary*
No. 24	25kV	5200	1209	422	89	5
No. 37	25kV	53	189	61	13	0
	13kV	4873	565	308	78	5

3.3 Risk Assessment

Load at Risk is defined as customer load that cannot be returned to service within a time frame of one manual switching operation during an N-1 contingency. Table 7 below demonstrates the Load at Risk in the event of feeder 25-37.111 contingency. Table 8 below demonstrates the Load at Risk in the event of either 24.1TR or 24.2TR contingency. The Load at Risk highlighted in Tables 7 and 8 represents the maximum unsupplied customer load under peak loading conditions.

The methodology used to calculate maximum back up capability from adjacent PODs and feeders was completed using 15-minute 2021 load profile data. Using peak values for each forecast year, EPC completed a load flow analysis to determine if the feeder or transformers used in the restoration would experience overload. If an overload was identified, an assessment of switching points was completed to find locations where restoration of customer load could be maximized while avoiding feeder and transformer overload.

Table 7 – Forecasted Feeder Load at Risk during Summer Peak (MVA)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Loss of 25-37.111										
25-37.111 Total Load	6.7	8.5	10.5	11.9	12.7	13.0	13.3	**13.6**[3]	**13.7**[3]	**13.9**[3]
Back up from25-24.114	6.7	8.5	10.5	9.8	10.4	13	13	14	14	14
Back up from 24.2TR	6.7	8.5	10.5	9.8	10.4	0	0	0	0	0
Total Unsupplied Load	**0**	**0**	**0**	**2.1**	**2.3**	**13.0**[2]	**13.3**	**13.6**	**13.7**	**13.9**

1. Values in red represent Load at Risk
2. Load at Risk is due to capacity limitations on 24.2TR
3. Values identified in orange exceed the 13.3MVA thermal rating of 37.4TR

Table 8 - Forecasted Transformer Load at Risk during Summer Peak (MVA)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Loss of Transformer 24.1TR or 24.2TR										
24S Total Loading	69.3	76.2	79.3	81.7	82.8	85.7	87.6	88.5	89.2	89.8
Back up from 26 S	12.9	13.4	13.6	13.7	13.8	14.2	14.4	14.6	14.7	14.8
Back up from 37 S	6.5	0	0	0	0	0	0	0	0	0
Remaining Load at 24 S	49.9	49.0	49.1	48.4	48.6	49.1	46.3	47.0	46.9	47.4
Load at Risk	0	**13.8**	**16.6**	**19.7**	**20.4**	**22.5**	**26.9**	**26.9**	**27.6**	**27.6**

1. Values in red represent Load at Risk

The duration of the Load at Risk was determined using 15 minute interval data. An assessment of each 15-minute interval was conducted to identify overload conditions. All 15-minute intervals in which an overload occurred were aggregated to determine the annual duration of Load at Risk. The values shown in Table 9 below represents the annual hours of Load at Risk.

Table 9 – Forecast Duration of Load at Risk full year (Hours)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Loss of Transformer 24.1TR or 24.2TR										
Load at Risk Duration	0	34	241	685	910	1237	1524	1663	1909	1971

4.0 Area Supply Deficiencies

The existing 25 kV supply source from No. 37 Substation and the associated distribution infrastructure will not be able to meet the EPC Distribution Performance Standard as set out in section 3.1, beginning in the 2023 summer peak season.

The identified system deficiencies include:

4.1 No. 24 Substation transformer contingency Load at Risk

By the summer of 2023, a loss of either transformer 24.1TR or 24.2TR will result in 13.8 MVA of load at risk during summer peak conditions. The magnitude increases to 27.6 MVA by 2031 (Table 8).

4.2 No. 37 Substation feeder 25-37.111 contingency Load at Risk

By the summer of 2025 of a loss feeder (25-37.111) results in 2.1 MVA of load at risk during summer peak conditions (Table 7). The magnitude increases to 13.9 MVA in 2031, this trend is expected to continue to worsen.

4.3 No. 37 Substation autotransformer 37.4TR overload under normal operation

By the summer 2029 under normal operation autotransformer 37.4TR will experience overloading during peak period (Table 2).

5.0 Preferred Alternative

EPC has investigated multiple alternatives which can be found in the original SoN. The preferred alternative has not changed since the original submission to the AESO. The preferred solution (Alternative 3 in the original SoN) consists of the addition of 25 kV capacity at No. 37 Substation. This would include the installation of one [1] 138/25 kV 30/40/50 MVA transformer with associated distribution breaker line up. The existing 13/25 kV 10/13.3 MVA autotransformer (37.4TR) at No. 37 Substation would be removed. The following will be a DFO cost to the project, the construction of one [1] new feeder to offload the southeast section of feeder 25-37.111 supplying the Janet / EMCOR industrial area. Extend feeder 25-24.113 to provide reliability support to the new feeder from No. 37 Substation (approximately 3 km).

6.0. Load Forecast - Post Implementation of Preferred Alternative

This section provides the load forecast and Load at Risk with the preferred alternative implemented. The requested ISD for the No. 37 Substation capacity addition is Q4 2024 and the changes take effect in the forecast table below starting in 2025.

Table 10 – POD Substation Coincident Summer Load Forecast – Future System [Table 12 In original SoN]

POD	PF	Units	Actual Load					Forecasted Load										
			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
37 S	0.89	MVA	55.6	57.4	54.8	51.5	53.0	56.6	63.7	66.2	76.0	77.4	78.4	79.5	80.4	81.0	81.7
		MW	49.2	50.8	48.5	45.6	46.9	50.2	56.4	58.6	67.4	68.6	69.5	70.4	71.2	71.8	72.4
24 S	0.89	MVA	54.7	56.0	41.1	48.5	59.6	68.0	75.2	78.4	75.2	75.7	78.2	79.5	80.1	80.6	80.9
		MW	49.0	50.1	36.8	43.4	53.3	60.9	67.3	70.1	67.3	67.8	70.0	71.2	71.7	72.1	72.4

Note:

1.No. 37 Substation supplies distribution both at 13 kV and 25 kV

Table 11 – Transformer Summer Load Forecast – Future System (MVA) [Table 13 in original SoN]

Transformer	Capacity (MVA)	Actual Load					Forecasted Load									
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
37.4TR	13.3	9.4	11.8	11.2	5.6	6.0	6.7	8.5	10.5	-	-	-	-	-	-	-
37.3TR[1]	50	-	-	-	-	-	-	-	-	18.4	19.8	20.7	21.6	22.4	22.9	23.4
24.1TR	50	29.7	32.7	23.9	19.7	28.8	34.9	39.2	41.5	43.1	43.3	44.5	44.7	44.8	45.0	45.0
24.2TR	50	26.9	26.3	17.6	29.2	30.9	35.0	37.5	38.2	32.6	32.9	34.2	35.4	35.8	36.2	36.5

Note:

1. New 138/25 kV 30/40/50 MVA transformer

Table 12 – 25kV Feeder Summer Load Forecast - Future System (MVA) [Table 14 in original SoN]

Feeder	Capacity (MVA)	Actual Load					Forecasted Load									
		2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
25-37.111	25.9	9.4	11.8	11.2	5.6	6.0	6.7	8.5	10.5	7.3	7.6	8.0	8.4	8.8	9.1	9.4
25-37.112[1]	25.9	-	-	-	-	-	-	-	-	11.2	12.2	12.7	13.2	13.6	13.8	14.1
25-24.114	25.9	5.8	2.0	1.9	7.1	7.8	8.2	8.8	9.3	8.5	8.7	8.9	9.1	9.3	9.5	9.7

Note:

1. New 25kV feeder

Table 13 indicates that the preferred alternative mitigates the identified load at risk during a 25 kV feeder contingency at No. 37 Substation to beyond the 2031 forecast.

Table 13 – Forecasted Feeder Load at Risk during Summer Peak (MVA)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Loss of Feeder 25-37.111										
25-37.111 Total Load	6.7	8.5	10.5	7.3	7.6	8.0	8.4	8.8	9.1	9.4
Back up from 25-24.114	6.7	8.5	10.5	17.4	17.2	17.0	16.8	16.6	16.4	16.3
Back up from 24.2TR	6.7	8.5	10.5	17.4	17.1	15.8	14.6	14.2	13.8	13.5
Total Unsupplied Load	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Loss of Feeder 25-37.112										
25-37.112 Total Load	-	-	-	11.2	12.2	12.7	13.2	13.6	13.8	14.1
Back up from 25-37.111	-	-	-	18.6	18.3	17.9	17.5	17.1	16.8	16.5
Total Unsupplied Load	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Table 14 includes a Load at Risk assessment for a 24.1TR or 24.2TR contingency following the implementation of the preferred alternative. Starting in 2027, there is minimal amount of Load at Risk identified. Table 15 provides an assessment of the duration of this Load at Risk which has a total duration of less than one day per year through the remainder of the planning horizon. EPC will continue to assess the system through its annual planning cycle and manage this relatively low amount of Load at Risk through operational measures, non-wire solutions, or system capacity additions as required.

Table 14 - Forecasted Transformer Load at Risk during Summer Peak (MVA)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Loss of Transformer 24.1TR or 24.2TR										
24S Total Loading	69.3	76.2	79.3	75.2	75.7	78.2	79.5	80.1	80.6	80.9
Back up from 26 S	12.9	13.4	13.6	8.7	6.4	6.5	6.6	6.7	6.8	6.8
Back up from 37 S	6.5	0	0	19.1	19.2	19.4	19.6	19.8	20.0	20.2
Load on Remaining Transformer	49.9	49.0	49.1	47.4	50.1	49.6	49.5	49.8	50.0	48.6
Load at Risk	0	**13.8**	**16.6**	0.0	0.0[1]	**2.7**	**3.8**	**3.8**	**3.8**	**5.3**

1. Due to the magnitude of overload the Load at Risk is considered 0
2. Values in red represent Load at Risk

Table 15 – Forecast Duration of Load at Risk full year (Hours)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Loss of Transformer 24.1TR or 24.2TR										
Load at Risk Duration	0	0	0	0	0	13	16	17	18	18

7.0. Historical SAIFI, SAIDI and Outage History

Table 16 below provides 10 years of historical SAIDI and SAIDI performance for the EPC system as submitted to the AUC in EPCs Rule 002 reporting.

Table 16 – SAIFI and SAIDI (Overall System 10 Year Historical)

Year	SAIFI	SAIDI
2010	0.91	0.49
2011	0.66	0.36
2012	0.66	0.39
2013	0.76	0.43
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

In Table 17 and 18, ENMAX has provided historical outages (Sept 2019 to Dec 2021) for feeders 25-37.111 and 25-24.114 respectively. These tables are an update to Table 23 and Table 24 in IR Response titled ENMAX Power Corporation Project P2102 – AESO SON Questions Responses Revision 1.0.

Table 17 – ENMAX Feeder 25-37.111 Historical Outages (Sept 2019 - Dec 2021)

Outage Type	Feeder	Outage Date/Time	Cause	Duration (Min)	Load loss (MW)
Feeder	25-37.111	6/17/2020 4:39	Animal Contact	<1	2.2
Feeder	25-37.111	3/10/2021 2:05	Equipment Failure	66	2.5
Feeder[1]	25-37.111	7/25/2021 9:51	Unknown	443	2.3
Feeder[1]	25-37.111	10/6/2021 8:42	Animal Contact	6	4.5

Note:
1. On 3/10/2021, 37.4TR equipment failure occurred. Feeder 25-37.111 was supplied by feeder 25-24.114 starting on 3/10/2021.

Table 18 – ENMAX Feeder 25-24.114 Historical Outages (Sept 2019 - Dec 2021)

Outage Type	Feeder	Outage Date/Time	Cause	Duration (Min)	Load loss (MW)
Feeder	25-24.114	4/25/2020 11:45	Animal Contact	157	2.1
Feeder	25-24.114	7/20/2020 20:37	Unknown	6	2.6
Feeder	25-24.114	8/9/2020 9:45	Animal Contact	2	1.9
Feeder	25-24.114	9/29/2020 19:37	Unknown	6	3.0
Feeder	25-24.114	11/7/2020 15:56	Wind	<1	3.3
Feeder	25-24.114	11/7/2020 15:58	Wind	5	2.6
Feeder	25-24.114	11/7/2020 16:14	Wind	5	3.3
Feeder	25-24.114	11/7/2020 16:35	Wind	5	3.5

Feeder	25-24.114	11/7/2020 17:03	Snow	<1	3.5
Feeder	25-24.114	11/7/2020 17:05	Snow	5	2.9
Feeder	25-24.114	11/7/2020 17:11	Snow	5	0.5
Feeder	25-24.114	11/7/2020 17:34	Wind	4	0.8
Feeder	25-24.114	11/7/2020 17:39	Wind	5	1.1
Feeder	25-24.114	11/7/2020 17:45	Wind	5	0.5
Feeder	25-24.114	11/7/2020 17:59	Wind	1	1.6
Feeder	25-24.114	11/7/2020 18:41	Wind	65	0.7
Feeder	25-24.114	7/2/2021 18:40	Major Storm	<1	3.1

In Table 19, 20, and 21, ENMAX has provided an update to historical outages for transformer 37.2TR (Supplies 37.4TR), 24.1TR and 24.2TR respectively. These tables are an update to Table 7, 8 and 9 in IR Response titled ENMAX Power Corporation Project P2102 – AESO SON Questions Responses Revision 1.0.

Table 19 – ENMAX: No. 37 Substation – 37.2TR (and 37.4TR) Outage History (Sept 2019 to Dec 2021)

Outage Type	Asset	Outage Start (Date & Time)	Outage End (Date & Time)	Duration (Hours)	Cause of Outage	Caused Sub. Trip
Planned	37.2 TR	9/30/2019 10:00	10/10/2019 14:15	244.3	Transformer differential relay panel replacement	No
Planned	37.2 TR	3/2/2020 8:00	3/2/2020 14:45	6.8	Hotspot 37.2TR H1. Oil sampling MT, TC. Check reversing switch. Gas relay testing.	No
Planned	37.2 TR	6/8/2020 8:30	6/11/2020 14:30	78	Power factor test transformer, Transformer Secondary Cable Tests, Transformer Maintenance. Oil sampling MT.	No
Planned	37.2 TR	8/10/2020 8:30	8/13/2020 8:30	72	Reinhausen Tap changer Maintenance.	No
Planned	37.2 TR	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	37.2 TR	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 20 – ENMAX: No. 24 Substation – 24.1TR Outage History (April 2019 to Dec 2021)

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 - 24.1TR 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 - 24.1TR XO ground cable corrective	No

Table 21 – ENMAX: No. 24 Substation – 24.2TR Outage History (April 2019 to Dec 2021)

Outage Type	Asset	Outage Start (Date & Time)	Outage End (Date & Time)	Duration (Hours)	Cause of Outage	Caused Sub. Trip
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

ADDENDUM TO STATEMENT OF NEED - 37S Transformer Upgrade Feb 2022

Final Audit Report 2022-02-11

Created:	2022-02-11
By:	Jennifer Poty (jpoty@enmax.com)
Status:	Signed
Transaction ID:	CBJCHBCAABAAq9JnzAf0FkglJ_SdG4ibLjHBLm3W7MV3

"ADDENDUM TO STATEMENT OF NEED - 37S Transformer U pgrade Feb 2022" History

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