APPENDIX A CONNECTION ASSESSMENT

Connection Engineering Study Report for AUC Application

ENMAX 162 Substation 138/25 kV 2nd Transformer Addition

Project 1644

Date: April 13, 2016

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Executive Summary

Project Overview

ENMAX Power Corporation (EPC) submitted a System Access Service Request (SASR) to the Alberta Electric System Operator (AESO) to increase the Demand Transmission Service (DTS) contract capacity at the Beddington No. 162 Point of Delivery (POD) substation from the existing 25 MW to 39 MW (Project). EPC has indicated that the Project is required to support area load growth and maintain the restoration capacity to customers in the northeast area of Calgary up to and including the year 2023.

The requested in-service date (ISD) of the Project is December 2017.

Existing System

The Beddington No. 162 substation, located in the AESO Calgary (Area 6) planning area, currently includes two 240/138 kV, 240/320/400 MVA system transformers (162.1TR and 162.2TR) and one 138/25 kV, 30/40/50 MVA POD transformer (162.4TR). This substation is connected to Janet 74S and Benalto 17S through 240 kV lines 932L and 918L, respectively. The Beddington No. 162 substation is also connected to the ENMAX No. 39 substation through the 138 kV line 39.82L; the ENMAX No. 11 substation through the 138 kV line 11.83L; the Balzac 391S substation through the 138 kV line 162.81L; and the ENMAX No. 47 substation through the 138 kV line 771L. The Calgary Energy Center generators (CECGT and CECST) are also connected at the Beddington No. 162 substation.

An existing Remedial Action Scheme (RAS) at the Beddington No. 162 substation is used to mitigate thermal overloads on the 138 kV lines 11.83L (ENMAX No.11 to Beddington No. 162) and 39.82L (ENMAX No. 39 to Beddington No. 162) by splitting the 138 kV bus at Beddington No. 162. Additionally, there is also an existing 752L Overload Mitigation RAS that manages the thermal overloads on 752L (Summit 653S to East Crossfield 64S) by reducing the generation in the area. This RAS is located in the Airdrie (Area 57) Planning area and may be triggered by the 162.81L (Beddington No. 162 to Balzac 391S) contingency.

Study Summary

Study Area for the Project

The Project study area includes the Calgary (Area 6) and Airdrie (Area 57) AESO planning areas, both of which make up the Calgary Region (Study Area). Transmission facilities rated at 138 kV and above within the Study Area and the transmission lines connecting it to the rest of the Alberta Interconnected Electric System (AIES) were studied and monitored for violations of the AESO's Reliability Criteria as described in Section 2.

Studies Performed for the Project

Power flow analysis was performed using the 2017 winter peak (WP) and 2018 summer peak (SP) pre-Project and post-Project scenarios to determine the impact of the Project and the associated transmission development on the AIES.

Voltage stability analysis was performed using only the 2017 WP post-Project scenario to identify violations of the Voltage Stability Criteria.

Results of the pre-Project Studies

The following is a summary of the results of the pre-Project studies.

Category A (N-G-0) conditions

No violation of the Reliability Criteria was observed for Category A conditions in any of the pre-Project scenarios.

Category B (N-G-1) contingencies

In the 2017 WP scenario (Scenario 1), the Category B contingency of the 138 kV line 162.81L (Beddington No. 162 - Balzac 391S) results in a thermal overload on the 138 kV line 752L (Summit tap - East Crossfield 64S) that would trigger the existing 752L Overload Mitigation RAS. After the action of the existing 752L Overload Mitigation RAS was applied, no violation of the Reliability Criteria was observed in this pre-Project scenario.

In the 2018 SP scenario (Scenario 2), a thermal violation of 107% (347 MVA) was observed on the 138 kV line 2.82L (ENMAX No. 2 - ENMAX No. 5) following the Category B contingency of the 138 kV line 2.83L (ENMAX No. 2 - ENMAX No. 13). This thermal violation is below the short-term thermal rating of 2.82L and is currently managed by the AESO and Transmission Facility Owner (TFO) real time operational practices.

Connection alternatives proposed for the Project

EPC examined and ruled out the use of distribution-based solutions to address the Project need. The following transmission alternatives were proposed in the EPC's Statement of Need for the Project[1].

Alternative 1 – Second Transformer Addition at Beddington No. 162 Substation

Alternative 1 involves the addition of a second 138/25 kV 30/40/50 MVA transformer and four 25 kV feeder breakers at the Beddington No. 162 POD substation. The Project would also involve 138 kV bus modifications at the Beddington No. 162 substation and associated 138 kV switchgear to accommodate the second 138/25 kV transformer.

Alternative 2 – Upgrades at the Existing ENMAX No. 39 Substation

In this alternative, the two existing 138/25 kV transformers at ENMAX No. 39 substation would be replaced by two 138/25kV 50/67/83 MVA transformers and two 25kV feeder breakers would be added.

Alternative 3 – New 138/25 KV Distribution Substation to the East of Stoney Trail

In this alternative, a new 138/25 kV POD substation would be constructed to the east of Stoney Trail and would include one 138/25 kV 30/40/50 MVA transformer and two 25 kV feeder breakers. The new POD substation would be radially connected to the AIES using a single 138 kV transmission line. The new POD would either be connected to the existing Beddington No. 162 substation or T-tapped onto the existing 138 kV line 39.82L (Beddington No. 162 - ENMAX No. 39).

Additional connection alternatives for the Project

In addition, the AESO identified the following transmission connection alternatives:

[1] ENMAX Statement Of Need "No.162 Substation 138-25 kV 2nd Transformer Addition" dated October 2014, which is filed under a separate cover.

Alternative 4 – Upgrades at the Existing ENMAX No. 11 Substation

In this alternative, a 138/25 kV 30/40/50 MVA transformer would be added at the ENMAX No. 11 substation with the addition of two 25 kV feeder breakers.

Alternative 5 – Upgrades at the Existing ENMAX No. 47 Substation

In this alternative, a new 138/25 kV 30/40/50 MVA transformer and two 25 kV feeder breakers would be added at the ENMAX No. 47 substation.

<u>Connection alternatives selected for further study</u>

Alternative 2 and Alternative 3 would require more transmission development than Alternative 1 for no incremental benefit and were not selected for further study.

EPC indicated that adding a fifth transformer as proposed in Alternative 4 would pose a reliability risk due to the simple bus configuration at the ENMAX No. 11 substation. This risk could be mitigated by upgrading the configuration at the ENMAX No. 11 substation to a breaker and a third at significantly higher cost than that of Alternative 1.

The ENMAX No. 47 substation is geographically further from the area of the anticipated load growth and would consequently require longer distribution feeders than Alternative 1. EPC rejected Alternative 5 on the basis that the longer distribution feeders in this alternative would present greater operational and reliability challenges. Additionally, as the ENMAX No. 47 substation is connected radially to Beddington No. 162 substation through the 138 kV line 771L (Beddington No. 162 - ENMAX No. 47), this would pose a reliability concern for the transfer of the proposed new load at the ENMAX No. 47 substation after the loss or planned outage of 771L.

Only Alternative 1 was selected for further study based on the above stated rationale.

<u>Results of the post-Project studies</u>

The following is a summary of the results of the post-Project studies using Alternative 1.

<u>Category A (N-G-0) conditions</u>

No violation of the Reliability Criteria was observed for Category A conditions in any of the post-Project scenarios.

<u>Category B (N-G-1) contingencies</u>

Similar to the pre-Project 2017WP scenario, the Category B contingency of the 138 kV line 162.81L (Beddington No. 162 – Balzac 391S) results in a thermal overload on the 138 kV line 752L (Summit tap – East Crossfield 64S) that would trigger the existing 752L Overload Mitigation RAS. After the 752L RAS action was applied, no violation of the Reliability Criteria was observed in this post-Project scenario.

A thermal violation of 109% (352 MVA) was observed on the 138 kV line 2.82L (ENMAX No. 2 - ENMAX No. 5) following the Category B contingency of the 138 kV line 2.83L (ENMAX No. 2 - ENMAX No. 13) in the 2018 SP scenario. This thermal violation is below the short-term thermal rating of 2.82L. Similar to the thermal violation that was observed in the pre-Project 2018 SP scenario, the post-Project 2018 SP thermal violation on the 138 kV line 2.82L will continue to be managed by the real time operational practices.

<u>Voltage Stability</u>

PV analysis was performed using the 2017 WP post-Project scenario (Scenario 3). No violation of the Voltage Stability Criteria was observed subsequent to the connection of the Project using Alternative 1.

Recommendation

The studies demonstrate that the connection of the Project would not adversely impact the performance of the AIES. Consequently, the AESO recommends proceeding with the Project by adding a second transformer at the Beddington No. 162 POD (Alternative 1).

Contents

Attachments

Attachment A	Pre-Project Power Flow Diagrams (Scenarios 1 & 2)
Attachment B	Alternative 1: Power Flow Diagrams (Scenarios 3 & 4)
Attachment C	Alternative 1: Voltage Stability Diagrams (Scenarios 3)

Figures

Tables

1. Introduction

This Customer Connection Engineering Study Report recommends the connection alternative to serve the requested Demand Transmission Service (DTS) capacity increase at the Beddington No. 162 substation from 25 MW to 39 MW and presents the results of the study conducted to analyze the impact of the Project on the performance of the AIES.

1.1. Project

1.1.1. Project Overview

EPC submitted a SASR to the AESO to increase the Demand Transmission Service (DTS) contract capacity at the Beddington No. 162 Point of Delivery (POD), which is located within the Calgary (Area 6) planning area, from the existing 25 MW to 39 MW. EPC has indicated that the Project is required to support load growth in the area and maintain restoration capacity to customers in the northeast area of Calgary up to and including the year 2023.

The requested in-service date (ISD) of the Project is in December 2017.

1.1.2. Load Component

- The requested DTS at the Beddington No. 162 POD is 39 MW by December 2017.
- Load Type: residential, commercial, and industrial services.
- The load addition has been studied assuming a 0.9[2] power factor (pf) lagging.
- EPC has not indicated plans for future load increase at the Project location in the SASR.

1.1.3. Generation Component

- There is no generation component associated with the Project.

1.2. Study Scope

1.2.1. Study Objectives

The objective of the study is as follows:

1. Examine the Project connection alternatives and select an alternative for further assessment.
2. Assess the impact of the recommended Project connection on the AIES and identify mitigation measures to address system performance concerns, if any, to enable the reliable integration of the Project into the AIES.

[2] The minimum lagging power factor requirement for continuous operation per the *AESO Generation and Load Interconnection Standard*, Rev1, September 19, 2006.

1.2.2. Study Area

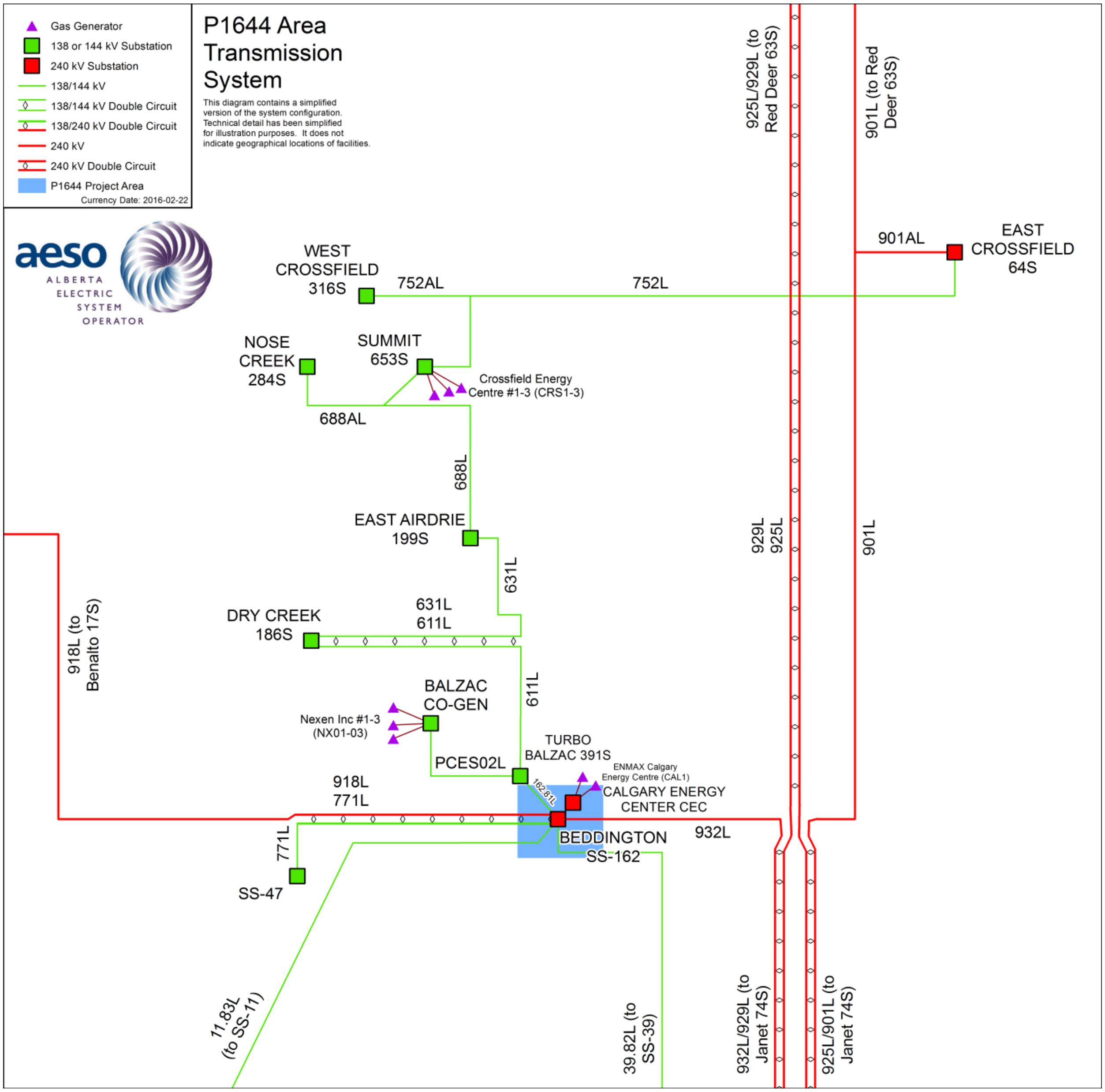
1.2.2.1. Study Area Description

The Project study area includes the Calgary (Area 6) and Airdrie (Area 57) AESO planning areas, both of which make up the Calgary Region (Study Area). The Study Area for the Project includes transmission facilities rated at 138 kV and above and the transmission lines connecting it to the rest of the AIES. All transmission facilities within the Study Area were studied and monitored for violations of the Reliability Criteria (defined in Section 2.1.1). The transmission lines connecting the Study Area to the rest of the AIES are 138 kV lines 150L, 3L, 860L and 765L; and the 240 kV lines 906L, 928L, 918L, 1106L, 1107L, 927L, 924L, 901L, 925L and 929L; and the 500 kV line 1201L.

The Beddington No. 162 substation (the Project location) currently includes two 240/138 kV, 240/320/400 MVA system transformers (162.1TR and 162.2TR) and one 138/25 kV, 30/40/50 MVA POD transformer (162.4TR). This substation is connected to Janet 74S and Benalto 17S through 240 kV lines 932L and 918L, respectively. The Beddington No. 162 substation is also connected to the ENMAX No. 39 substation through the 138 kV line 39.82L; the ENMAX No. 11 substation through the 138 kV line 11.83L; the Balzac 391S substation through the 138 kV line 162.81L; and the ENMAX No. 47 substation through the 138 kV line 771L. The Calgary Energy Center generators (CECGT and CECST) are also connected to the 240 kV bus at the Beddington No. 162 substation via two step-up transformers.

Figure 1-1 shows the existing Study Area transmission system.

Figure 1-1: Existing Study Area Transmission System



1.2.2.2. Existing Constraints

An existing Remedial Action Scheme (RAS) at the Beddington No. 162 substation is used to mitigate thermal overloads on the 138 kV line 11.83L (ENMAX No.11 to Beddington No. 162) and the 138 kV line 39.82L (ENMAX No. 39 to Beddington No. 162). The RAS at Beddington No. 162 splits the 138 kV bus at the Beddington No. 162 substation with no loss of load or generation.

There is also an existing RAS that manages the thermal overloads on 752L (Summit 653S to East Crossfield 64S) in the Airdrie (Area 57) planning area, which may be triggered by the

162.81L (Beddington No. 162 to Balzac 391S) contingency. This RAS trips or curtails generation in the Airdrie planning area to mitigate the overload on 752L.

1.2.2.3. AESO Long-Term Transmission Plans (LTP)

Table 1.2-1 shows the system projects anticipated to be in service in the Calgary area by 2021. As described in the AESO 2015 Long-term Transmission Plan (AESO 2015 LTP)[3], near term system developments in the Calgary and Airdrie planning areas are expected to relieve the existing constraints in the Calgary Region.

The system project stated in Table 1.2-1 is not expected to be in service until 2021 and was not considered in the 2017/2018 impact studies for the Project.

Table 1.2-1: Summary of System Projects in the Calgary Area

Project Number	Project Name	Project Area	In-Service Date
P1456	Calgary Downtown Transmission Reinforcement[4]	Calgary	April 2021

1.2.3. Studies Performed

The following studies were performed in the connection study:

- Power flow analysis (Category A and Category B), pre-Project and post-Project conditions
- Voltage stability analysis (Category A and Category B) post-Project conditions

1.2.4. Studies Excluded

The following study was not performed in the connection study:

- Transient stability analysis

1.3. Report Overview

The Executive Summary provides a high-level summary of the study and its conclusions. Section 1 introduces this engineering study report. Section 2 describes the reliability criteria, system data, and other study assumptions used in this study. Section 3 describes the methodology used for this study. Section 4 discusses the pre-Project assessment of the system. Section 5 presents all the connection alternatives contemplated. Section 6 provides a technical analysis of the connection alternatives considered for further study. Section 7 summarizes the mitigation measures required in the Study Area. Section 8 identifies any interdependencies this project may have. Section 9 presents the summary and conclusions of this study.

3 http://www.aeso.ca/downloads/2015_Long-termTransmissionPlan_WEB.pdf

4 Filed with the AUC on November 18, 2015, Proceeding: 21038 Application: 21038-A001

2. Criteria, System Data, and Study Assumptions

2.1. Criteria, Standards, and Requirements

2.1.1. Transmission Planning Standards and Reliability Criteria

The Transmission Planning (TPL) Standards, which are included in the Alberta Reliability Standards, and the AESO's *Transmission Planning Criteria – Basis and Assumptions* [5] (collectively, the Reliability Criteria) were applied to evaluate system performance under Category A system conditions (i.e., all elements in-service) and following Category B contingencies (i.e., single element outage), prior to and following the studied alternatives. Below is a summary of Category A and Category B system conditions.

Category A, often referred to as the N-0 condition, represents a normal system with no contingencies and all facilities in service. Under this condition, the system must be able to supply all firm load and firm transfers to other areas. All equipment must operate within its applicable rating, voltages must be within their applicable range, and the system must be stable with no cascading outages.

Category B events, often referred to as an N-1 or N-G-1 with the most critical generator out of service, result in the loss of any single specified system element under specified fault conditions with normal clearing. These elements are a generator, a transmission circuit, a transformer, or a single pole of a DC transmission line. The acceptable impact on the system is the same as Category A. Planned or controlled interruptions of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted firm (non-recallable reserved) transmission service electric power transfers.

The Alberta Reliability Standards include the Transmission Planning (TPL) standards that specify the desired system performance under different contingency categories with respect to the Applicable Ratings. The transmission system performance under various system conditions is defined in Appendix 1 of the TPL standards. For the purpose of applying the TPL standards to this study, the Applicable Ratings shall mean:

- Seasonal continuous thermal rating of transmission lines.
- Highest specified loading limit for transformers.
- For Category A conditions: Voltage range under normal operating condition should follow the AESO Information Document ID# 2010-007RS. For the buses not listed in ID#2010-007RS, Table 2-1 in the Reliability Criteria applies.
- For Category B conditions: The extreme voltage range values per Table 2-1 in the Reliability Criteria.
- Desired post-contingency voltage change limits for three defined post event timeframes as provided in Table 2.1-1.

[5] Filed under a separate cover.

Table 2.1-1: Post Contingency Voltage Deviation Guidelines

Parameter and reference point	Time Period		
	Post Transient (up to 30 sec)	Post Auto Control (30 sec to 5 min)	Post Manual Control (Steady State)
Voltage deviation from steady state at POD low voltage bus.	±10%	±7%	±5%

2.1.2. AESO Rules

The AESO Voltage Control Practice ID # 2010-007RS will be applied to establish pre-contingency voltage profiles in the Study Area. The Section 302.1 of the ISO Rules, Real Time Transmission Constraint Management (TCM) will be followed in setting up the study scenarios and assessment of the impact of the Project connection. In addition, due regard will be given to the AESO's Connection Study Requirements and the AESO's Generation and Load Interconnection Standard.

The Reliability Criteria is the basis for planning the AIES. The transmission system will normally be designed to meet or exceed the Reliability Criteria under credible worst-case loading and generation conditions.

2.2. Study Scenarios

Table 2.2-1 provides a list of the study scenarios that were used in the impact assessment for the Project. Scenarios 1 and 2 are the pre-Project scenarios for 2017 WP and 2018 SP, respectively and Scenarios 3 and 4 are the post-Project scenarios for 2017 WP and 2018 SP, respectively. The pre-Project load is the existing DTS of 25 MW and the post-Project load is the requested DTS of 39 MW at the Beddington No. 162 substation. A power factor of 0.9 lagging was used for the new Project load.

Table 2.2-1: List of the Connection Study Scenarios

Scenario	Year/Season Load	Condition	Project Load (MW)	System Generation Dispatch Conditions
1	2017 WP	Pre-project	25	Zero intertie and High thermal generation in Calgary and Strathmore (Area 45) areas
2	2018 SP	Pre-Project	25	
3	2017 WP	Post Project	39	
4	2018 SP	Post-Project	39	

2.3. Load and Generation Assumptions

2.3.1. Load Assumptions

The load forecasts used for this connection study are shown in Table 2.3-1 and are based on the *AESO 2014 Long-term Outlook* (2014 LTO). In this study, the active power to reactive power ratio in the study scenarios was maintained when modifying the loads to comply with the forecast shown in Table 2.3-1.

Table 2.3-1: Forecast Area Load *(2014 LTO at AIL Peak)*

Area or Region Name and Season	Forecast Peak Load (MW)	
	2017 WP (MW)	2018 SP (MW)
Calgary Region	1916.9	1861.1
AIL w/o Losses	12796.1	12017.3

2.3.2. Generation Assumptions

The generation conditions for this connection study are described in Table 2.3-2. The study identified the Gas turbine generator (CECGT) at the Calgary Energy Centre plant at Beddington No. 162 substation as the critical generator and it was turned off to represent the N-G study condition for all analyses. As a consequence of the CECGT being turned off in the study, the steam generator (CECST) at the Calgary Energy Centre plant was also turn off in the study, as CECST is dependent on CECGT being online.

Table 2.3-2: Local Generation (MW) in the Study Cases

Existing/Future	Unit Name	Bus Number	Area	Pmax (MW)	2017 WP Unit Net Generation (MW)	2018 SP Unit Net Generation (MW)
Existing	Shepard ST1	773	6	318.0	318.0	219.0
Existing	Shepard GT1	774	6	276.0	242.0	189.0
Existing	Shepard GT2	775	6	276.0	240.0	164.0
Existing	Calgary Energy Centre GT	4187	6	170.2	0.0	0.0
Existing	Calgary Energy Centre ST	3187	6	115.6	0.0	0.0
Existing	Balzac ST1	3290	6	64.1	50.6	46.0
Existing	Balzac GT1	4290	6	64.1	50.6	45.0
Existing	Balzac GT2	4290	6	26.5	22.2	20.0
Existing	Cavalier 1	3247	45	64.1	49.2	31.0
Existing	Cavalier 2	4247	45	64.1	49.2	31.0
Existing	Cavalier 3	4247	45	26.5	21.6	14.0
Existing	Carseland 1	4251	45	64.1	32.0	30.5
Existing	Carseland 2	3251	45	64.1	32.0	30.5
Existing	UofC	2556	6	15.0	10.2	9.0

2.3.3. Intertie Flow Assumptions

The B.C., MATL, and Saskatchewan interties were set to zero in all the studied scenarios.

2.3.4. HVDC Power Order

The HVDC power orders were set based on the minimum loss per the assumptions in pre- and post-Project study scenarios. The power orders used in the study scenarios are shown in Table 2.3-4. The MVAR exchange between the HVDC terminals and the adjacent AC systems for both Western Alberta Transmission Line (WATL) and Eastern Alberta Transmission Line (EATL) were maintained with the limits shown in Table 2.3-5.

Table 2.3-3: HVDC Power Order by Scenario

Case No	Scenario	WATL (MW)	EATL (MW)
1	2017 WP (Pre-Project)	475 N → S[6]	Blocked
2	2018 SP (Pre- Project)	725 N → S	Blocked
3	2017 WP (Post- Project)	475 N → S	Blocked
4	2018 SP (Post- Project)	725 N → S	Blocked

Table 2.3-4: HVDC to Adjacent AC System MVAR exchange Limits

HVDC	North Terminal Limit (MVAR)	South Terminal Limit (MVAR)
EATL	-85 to 75	-35 to 35
WATL	-75 to 75	-35 to 35

2.4. System Projects

Table 2.4-1 lists the system reinforcement subprojects that have been included in this study.

Table 2.4-1: Summary of System Projects Included in the Study Cases

Project	Subproject	Subproject Name	In-Service Date
719	1	East Calgary Transmission Project	In-service
1117	All	Foothills Area Transmission Development – East	In-service
961/737	All	Eastern Alberta Transmission Line (EATL)	In-service
962/737	3	Western Alberta Transmission Line (WATL)	In-service
787	1	911L Replacement	In-service
787	11	Blackie Area Upgrade	April 2016

[6] *N → S: HVDC flow direction is North to South*
S → N: HVDC flow direction is South to North

2.5. Customer Connection Projects

The customer connection projects shown in Table 2.5-1 were included in the study.

Table 2.5-1: Summary of Customer Connection Assumptions

Planning Area	Queue Position*	Planned In-Service Date	Project Name	Project #	Gen (MW)	Load (MW)	Included/Excluded from Studies
6	-	In-service	ENMAX No. 162 138/25kV POD Addition	1314	0.0	25.0	Included
6	41	March 2016	ENMAX No.11 Substation-25KV Breaker Addition	1480	0.0	9.0	Included

* Per the AESO Connection Queue posted in February 2016.

2.6. Facility Ratings and Shunt Elements

Table 2.6-1 summarizes the ratings of some major transmission lines in the Study Area.

Table 2.6-1: Summary of Transmission Line Ratings in the Study Area

Line ID	Line Description	Voltage Class (kV)	Nominal Rating (MVA)	
			Summer	Winter
936L	East Calgary 5S – Langdon 102S	240	481	581
937L	East Calgary 5S – Langdon 102S	240	481	581
1064L	Langdon 102S - Janet 74S	240	974	1208
1065L	Langdon 102S - Janet 74S	240	974	1208
916L	East Calgary 5S - Sarcee 42S	240	408	494
1106L	Foothills 237S - ENMAX No. 65	240	971	1207
1107L	Foothills 237S - ENMAX No. 65	240	971	1207
1080L	ENMAX No.65 - ENMAX No.25	240	441	574
1003L	ENMAX No.25 - Janet 74S	240	973	1039
611L	Balzac 391S - Dry Creek 186S	138	106	117
23.80L	Janet 74S - ENMAX No.23	138	285	287
2.80L	ENMAX No. 23 - ENMAX No. 2	138	285	287
24.83L	Janet 74S - ENMAX No. 24	138	318	392
37.82L	Janet 74S - ENMAX No.37	138	287	287
24.81L	ENMAX No. 24 - ENMAX No. 31	138	287	287
9.80L	ENMAX No. 9 - ENMAX No. 31	138	191	191
26.81L	ENMAX No. 26 - ENMAX No. 54	138	286	286

Line ID	Line Description	Voltage Class (kV)	Nominal Rating (MVA)	
			Summer	Winter
24.82L	ENMAX No. 65 - ENMAX No. 24	138	281	337
26.83L	ENMAX No. 65 - ENMAX No. 26	138	281	337
11.83L	ENMAX No. 11 - Beddington No. 162	138	319	388
162.81L	Beddington No. 162 - Balzac 391S	138	287	287
39.82L	Beddington No. 162 - ENMAX No. 39	138	287	287
2.83L	ENMAX No.5 – Tap 2.83-70	138	287	287
2.83L	ENMAX No.13 – Tap 2.83-70	138	287	287
2.83L	ENMAX No.2 – Tap 2.83-70	138	338	354
2.82L	ENMAX No. 2 - ENMAX No. 5	138	322	349
11.81L	ENMAX No. 11 - ENMAX No. 13	138	287	287
13.82L	ENMAX No. 13 - ENMAX No. 22	138	171	206
22.81L	ENMAX No. 39 - ENMAX No. 22	138	260	287
611L	Balzac 391S – Dry Creek 186S	138	106	117
631L	Dry Creek 186S – East Airdrie 199S	138	106	117
688L	East Airdrie 199S – Summit 653S tap	138	121	142
752L	Summit 653S – 752L tap	138	121	142
752L	East Crossfield 64S – 752L tap	138	119	136

Table 2.6-2 summarizes the ratings of some major transformers in the vicinity of the Study Area.

Table 2.6-2: Summary of Transformer Ratings in the Study Area

Substation Name and Number	Transformer ID	Transformer Voltages (kV)	MVA Rating
Janet 74S	T1	240/138	400
Janet 74S	T2	240/138	400
Sarcee 42S	T1	240/138	400
Sarcee 42S	T2	240/138	400
East Calgary 5S	T1	240/138	400
East Calgary 5S	T2	240/138	400
Beddington No.162	T1	240/138	400
Beddington No.162	T2	240/138	400
East Crossfield 64S	T2	240/138	191

The details of shunt elements in the Study Area are given in Table 2.6-3.

Table 2.6-3: Summary of Shunt Elements in the Study Area

Substation Name and Number	Voltage Class (kV)	Capacitors	
		Number of Switched Shunt Blocks	Total at Nominal Voltage (MVAr)
Janet 74S	240	2	268.8
Janet 74S	138	2	162.0
Sarcee 42S	240	2	201.6
Sarcee 42S	138	1	54.0
ENMAX No.14	138	2	48.91
ENMAX No.21	138	1	48.91
ENMAX No.2	138	2	160.0
ENMAX No.31	138	1	48.11
ENMAX No.38	138	1	48.11
ENMAX No.41	138	1	53.96

2.7. Voltage Profile Assumptions

The AESO Voltage Control Practice ID # 2010-007RS was used to establish normal system (i.e. pre-contingency) voltage profiles for key area buses prior to commencing any studies. Table 2-1 of the Reliability Criteria applies for all the buses not included in the ID 2010-007RS. These voltages were utilized to set the voltage profile for the study base cases prior to power flow analysis.

The Static Var Compensator (SVC) at Langdon 102S was set in the range -80 to +40 MVAr under pre-contingency conditions.

3. Study Methodology

3.1. Connection Studies Carried Out

The studies that were performed for this connection study are shown in Table 3.1-1.

Table 3.1-1: Summary of Studies Performed

Scenario and Condition		Project Load (MW)	System Conditions	Power Flow[7]	Voltage Stability
1	2017 WP Pre-project	25	Category A and Category B	X	NA
2	2018 SP Pre-Project	25	Category A and Category B	X	NA
3	2017 WP Post-Project	39	Category A and Category B	X	X
4	2018 SP Post-Project	39	Category A and Category B	X	NA
5	2025 WP Post-Project	39	NA	NA	NA

3.2. Power Flow Analysis

Power flow analysis was completed for all study scenarios to identify any thermal or voltage violations on any transmission facility in the Study Area as per the Reliability Criteria. Transformer tap and switched shunt reactive compensation devices such as shunt capacitors and reactors were locked and continuous shunt devices were enabled when performing Category B power flow analysis. This assessment was performed for both the pre-Project and post-Project networks.

POD low voltage bus deviations were also assessed by first locking all tap changers and area shunt devices to identify any post-transient voltage deviations above 10%. Tap changers was then allowed to adjust, while reactive power shunt compensating devices remained locked to determine if any voltage deviations above 7% would occur in the Study Area. Adjustment of all transformer taps and reactive power shunt compensating devices were enabled, to determine any voltage deviations above 5%. This assessment was performed for both the pre-Project and post-Project networks.

3.2.1. Contingencies Studied

Power flow analysis was performed for the Category A condition and all Category B contingencies in the Study Area for all pre- and post-Project scenarios.

[7] The critical generator identified for this study was Calgary Energy Center plant at Beddington No. 162.

3.3. Voltage Stability (PV) Analysis

The objective of the voltage stability analysis is to determine the ability of the network to maintain voltage stability at all the buses in the Study Area under normal and abnormal system conditions. The Power-Voltage (PV) curve is a representation of voltage change as a result of increased power transfer between two systems. The reported incremental transfers will be to the collapse point. As per the AESO requirements, no assessment based upon other criteria such as minimum voltage will be made at the PV minimum transfer. Voltage stability analysis for post-Project scenarios will be performed. For load connection projects, the load level modelled in the post-connection scenarios are either the same or higher than in pre-Project scenarios. Therefore, voltage stability analysis for pre-Project scenarios will only be performed if post-Project scenarios show voltage stability criteria violations.

The voltage stability analysis was performed according to the Western Electricity Coordinating Council (WECC) Voltage Stability Assessment Methodology. WECC voltage stability criteria states, for load areas, post-transient voltage stability is required for the area modeled at a minimum of 105% of the reference load level for system normal conditions (Category A) and for single contingencies (Category B). For this standard, the reference load level is the maximum forecasted load for the Study Area.

Typically, voltage stability analysis is carried out assuming the worst case scenarios in terms of loading. Voltage stability analysis was performed by increasing the load in the Study Area and increasing the generation in the Wabamun (Area 40) and the Fort McMurray (Area 25) planning areas.

3.3.1. Contingencies Studied

Voltage stability analysis was performed for the Category A condition and all Category B contingencies in the Study Area using the 2017 WP post-Project scenario only.

3.4. Mitigation Measures

If study results indicate transmission constraints associated with or exacerbated by the Project addition, modification to existing procedures and/or Remedial Action Schemes (RAS) or addition of new procedures and/or RAS may be required.

4. Pre-Project System Assessment

4.1. Pre-Project Power Flow Analysis

4.1.1. 2017 Winter Peak - 2017 WP (Scenario 1)

Category A:

No violation of the Reliability Criteria was found for the Category A condition in this pre-Project scenario.

Category B:

No voltage violations were observed in Scenario 1 for all the studied Category B contingencies.

The Category B contingency of the 138 kV line 162.81L (Beddington No. 162 – Balzac 391S) results in thermal overloads on the 138 kV line 752L (Summit tap – East Crossfield 64S) and 752L (Summit tap – Summit 653S) that would trigger the existing 752L Overload Mitigation RAS. After the 752L RAS action was applied in Scenario 1, no violation of the Reliability Criteria was observed. Table 4.1-1 shows the thermal violations on 752L (Summit tap – East Crossfield 64S) and 752L (Summit tap – Summit 653S) before the actions of the 752L Overload Mitigation RAS are applied following the 162.81L contingency. Table 4.1-2 shows that the thermal violations on 752L (Summit tap – East Crossfield 64S) and 752L (Summit tap – Summit 653S) are mitigated after the actions of the 752L Overload Mitigation RAS are applied following the 162.81L contingency.

Refer to Attachment A for the 2017 WP pre-Project (Scenario 1) power flow diagrams, which illustrates the details for Category A conditions and the Category B contingency of 162.81L with the 752L RAS applied per results shown in Table 4.1-2. The top five Category B contingencies resulting in the highest post-contingency thermal loading on the facilities in the Study Area are included in the Attachment A.

Table 4.1-1: Summary of System Performance for Scenario 1 before RAS action

Contingency	Limiting Branch	Continuous Line Rating (MVA)	Pre-Project	
			Power Flow[8] (MVA)	% Loading[9]
162.81L (Beddington No. 162 - Balzac 391S)	752L (Summit tap – Summit 653S)	142	163	115
	752L (Summit tap – East Crossfield 64S)	136	146	107

Table 4.1-2: Summary of System Performance for Scenario 1 after RAS action

Contingency	Limiting Branch	Continuous Line	Pre-Project

[8] Power flow (MVA) is current expressed as MVA (ie. $S = \sqrt{3} \times V_{base} \times I_{actual}$)

[9] % loading is current expressed as MVA (ie. $S = \sqrt{3} \times V_{base} \times I_{actual}$)

		Rating (MVA)	Power Flow (MVA)	% Loading
162.81L (Beddington No. 162 - Balzac 391S)	752L (Summit tap – Summit 653S)	142	135	95
	752L (Summit tap – East Crossfield 64S)	136	119	87

4.1.2. 2018 Summer Peak - 2018 SP (Scenario 2)

Category A:

No violation of the Reliability Criteria was observed for the Category A condition in this pre-Project scenario.

Category B:

No voltage violations were observed in Scenario 2 for all the studied Category B contingencies

A thermal violation on the 138 kV line 2.82L (ENMAX No. 2 - ENMAX No. 5) was observed following the loss of the 138 kV line 2.83L (ENMAX No. 2 - ENMAX No. 13) in this scenario as shown in Table 4.1-3.

Refer to Attachment A for the 2018 SP pre-Project (Scenario 2) power flow diagrams, which illustrates the details for Category A and the Category B contingency as shown in Table 4.1-3. The top five Category B contingencies resulting in the highest post-contingency thermal loading on the facilities in the Study Area are included in the Attachment A.

Table 4.1-3: Summary of System Performance for Scenario 2

Contingency	Limiting Branch	Continuous Line Rating (MVA)	Pre-Project	
			Power Flow[10] (MVA)	% Loading[11]
2.83L (ENMAX No. 2 – ENMAX No.13)	2.82L (ENMAX No. 2 – ENMAX No. 5)	322	347	107

[10] Power flow (MVA) is current expressed as MVA (ie. $S = \sqrt{3} \times V_{base} \times I_{actual}$)

[11] % loading is current expressed as MVA (ie. $S = \sqrt{3} \times V_{base} \times I_{actual}$)

5. Connection Alternatives

5.1. Overview

EPC examined and ruled out the use of distribution-based solutions to address the need for the Project[12].

The five transmission connection alternatives that were considered for the Project are detailed in Section 5.2.

5.2. Connection Alternatives Identified

A description of the developments associated with each connection alternative is provided below.

Alternative 1 – Second Transformer Addition at Beddington No. 162 Substation

In this alternative a second 138/25 kV 30/40/50 MVA transformer and four 25 kV feeders would be added at the Beddington No. 162 substation. EPC has selected this alternative as their preferred for the following reasons:

- Provides a long term solution that addresses the distribution deficiencies in the area.
- Provides improved reliability and operational flexibility at the Beddington No. 162 substation.
- Makes use of the provision for the expansion at Beddington No. 162 substation.
- Provides sufficient capacity to accommodate forecasted load growth in the area.
- Closer to the geographic area where load growth is anticipated, hence shorter distribution feeders would be required.
- The least cost viable solution.
- Facilitates transformer maintenance at the Beddington No. 162 substation.

Alternative 2 – Upgrades at the Existing ENMAX No. 39 Substation

In this alternative, the two existing 138/25 kV transformers at ENMAX No. 39 substation would be replaced by two 138/25kV 50/67/83 MVA transformers and two 25kV feeder breakers would be added.

Alternative 3 – New 138/25 KV Distribution Substation to the East of Stoney Trail

In this alternative, a new 138/25 kV POD substation would be constructed to the east of Stoney Trail and would include one 138/25 kV 30/40/50 MVA transformer and two 25 kV feeder breakers.

Alternative 4 – Upgrades at the Existing ENMAX No. 11 Substation

In this alternative, a fifth 138/25 kV transformer would be added at the ENMAX No. 11 substation with the addition of two 25 kV feeder breakers.

[12] The report detailing this analysis is included in section 6.0 of the EPC's Statement of *Need Report* titled "No. 162 Substation 138-25 kV Transformer Addition", which is filed under a separate cover.

Alternative 5 – Upgrades at the Existing ENMAX No. 47 Substation

In this alternative, a new 138/25 kV transformer and two 25 kV feeder breakers would be added at the ENMAX No. 47.

5.2.1. Connection Alternatives Selected for Further Studies

Only Alternative 1 was selected for further studies and the results for this alternative are included in this Engineering Study Report.

5.2.2. Connection Alternatives Not Selected for Further Studies

Alternative 2, Alternative 3, Alternative 4 and Alternative 5 would require more development when compared with Alternative 1 and were not selected for further studies. The rationale for rejecting these alternatives is detailed below.

Alternative 2: Even though this alternative could address the Project need, EPC dismissed this alternative due to the long distribution feeders that would be required from ENMAX No. 39 to supply the load in the geographic area where load growth is anticipated.

Alternative 3: Even though this alternative could address the Project need, the construction of a new Point of Delivery (POD) substation and associated transmission facilities would result in an appreciably higher cost when compared with Alternative 1.

Alternative 4: EPC has indicated that due the existing simple bus configuration at the ENMAX No. 11 substation and the use of high-side motorized transformer disconnects, the addition of a fifth 138/25 kV POD transformer in this alternative would pose a reliability risk. EPC indicated that this risk could be mitigated by upgrading the configuration at the ENMAX No. 11 substation to a breaker and a third at significantly higher cost than other than Alternative 1.

Alternative 5: The ENMAX No. 47 substation is geographically further from the area of the anticipated load growth as stated in the EPC's Statement of Need for the Project and would consequently require longer distribution feeders when compared with Alternative 1. EPC has rejected Alternative 5 on the basis that the longer distribution feeders in this alternative would present a greater challenge from a voltage management perspective. Additionally, as the ENMAX No. 47 substation is connected radially to Beddington No. 162 substation through the 138 kV line 771L (Beddington No. 162 - ENMAX No. 47), this would pose a reliability concern for the transfer of the proposed new load at the ENMAX No. 47 substation after the loss or planned outage of 771L. [13]

[13] The AESO identified Alternatives 4 and 5 for consideration; EPC provided rationale for the rejection of these alternatives.

6. Technical Analysis of the Preferred Connection Alternative (Alternative 1)

6.1. Power Flow

The following is a summary of the power flow analysis results for Project using Alternative 1.

6.1.1. 2017 Winter Peak – 2017 WP (Scenario 3)

Category A:

No violation of the Reliability Criteria was observed for the Category A condition in this post-Project scenario.

Category B:

No voltage violations were observed in Scenario 3 for all the studied Category B contingencies.

Similar to the results of the 2017 WP pre-Project scenario (Scenario 1), the Category B contingency of the 138 kV line 162.81L (Beddington No. 162 – Balzac 391S) results in thermal overloads on the 138 kV line 752L (Summit tap – East Crossfield 64S) and 752L (Summit tap – Summit 653S) that would trigger the existing 752L Overload Mitigation RAS. After the 752L RAS action was applied, no violation of the Reliability Criteria was observed in Scenario 3. Table 6.1-1 shows the thermal violation on 752L (Summit tap – East Crossfield 64S) and 752L (Summit tap – Summit 653S) before the actions of the 752L Overload Mitigation RAS are applied following the 162.81L contingency. Table 6.1-2 shows that the thermal violations on 752L (Summit tap – East Crossfield 64S) and 752L (Summit tap – Summit 653S) are mitigated after the actions of the 752L Overload Mitigation RAS are applied following the 162.81L contingency.

Refer to Attachment B for the 2017 WP pre-Project (Scenario 3) power flow diagrams, which illustrates the details for Category A conditions and the Category B contingency of 162.81L with the 752L RAS applied per results shown in Table 4.1-2. The top five Category B contingencies resulting in the highest post-contingency thermal loading on the facilities in the Study Area are included in the Attachment B.

Table 6.1-1: Summary of System Performance for Scenario 3 before RAS Action

Contingency	Limiting Branch	Continuous Line Rating (MVA)	Post-Project	
			Power Flow[14] (MVA)	% Loading[15]
162.81L (Beddington No. 162 - Balzac 391S)	752L (Summit tap – Summit 653S)	142	164	116
	752L (Summit tap – East Crossfield 64S)	136	148	109

[14] Power flow (MVA) is current expressed as MVA (ie. $S = \sqrt{3} \times V_{base} \times I_{actual}$)

[15] % loading is current expressed as MVA (ie. $S = \sqrt{3} \times V_{base} \times I_{actual}$)

Table 6.1-2: Summary of System Performance for Scenario 3 after RAS Action

Contingency	Limiting Branch	Continuous Line Rating (MVA)	Post-Project	
			Power Flow[16] (MVA)	% Loading[17]
162.81L (Beddington No. 162 - Balzac 391S)	752L (Summit tap – Summit 653S)	142	134	95
	752L (Summit tap – East Crossfield 64S)	136	119	88

6.1.2. 2018 Summer Peak – 2018 SP (Scenario 4)

<u>Category A:</u>

No violation of the Reliability Criteria was observed for the Category A condition in this post-Project scenario.

<u>Category B:</u>

No voltage violations were observed in Scenario 4 for all the studied Category B contingencies.

Similar to the results of the 2018 SP pre-Project scenario (Scenario 2), a thermal violation on the 138 kV line 2.82L (ENMAX No. 2 - ENMAX No. 5) was observed following the loss of the 138 kV line 2.83L (ENMAX No. 2 - ENMAX No. 13) in Scenario 4 as shown in Table 6.1-1.

Refer to Attachment B for the 2018 SP post-Project power flow diagrams, which illustrates the details for Category A and the Category B contingency shown in Table 6.1-3. Four other Category B contingencies resulting in the highest post-contingency thermal loading (below 100%) on the facilities in the Study Area are also included in the Attachment B.

Table 6.1-3: Summary of System Performance for Scenario 4

Contingency	Limiting Branch	Continuous Line Rating (MVA)	Post-Project	
			Power Flow[18] (MVA)	% Loading[19]
2.83L (ENMAX No. 2 – ENMAX No. 13)	2.82L (ENMAX No. 2 – ENMAX No. 5)	322	352	109

6.2. Voltage Stability

PV analysis was performed using the 2017 WP scenario (Scenario 3). The reference load level for the sink subsystem (the Study Area) is 1916.9 MW. The minimum incremental load transfer

[16] Power flow (MVA) is current expressed as MVA (ie. $S = \sqrt{3} \times V_{base} \times I_{actual}$)

[17] % loading is current expressed as MVA (ie. $S = \sqrt{3} \times V_{base} \times I_{actual}$)

[18] Power flow (MVA) is current expressed as MVA (ie. $S = \sqrt{3} \times V_{base} \times I_{actual}$)

[19] % loading is current expressed as MVA (ie. $S = \sqrt{3} \times V_{base} \times I_{actual}$)

for the Category B contingencies is 5.0% of the reference load or 95.8 MW to meet the voltage stability criteria. Table 6.2-1 summarizes the voltage stability results for Category A and the worst contingencies for voltage stability transfer margins.

The voltage stability diagrams are shown in Attachment C.

Table 6.2-1: Scenario 3: 2017 WP – Voltage stability analysis results

Contingency	From	To	Maximum incremental transfer (MW)	Meets 105% transfer criteria?
N-G-0	System Normal		1000	Yes
1201L	Bennett 520S	Cranbrook BC	875	Yes
906L	Sarcee 42S	Benalto 17S	940	Yes
162.81L	Beddington No. 162	Balzac 391S	945	Yes
688L	East Airdrie 199S	Summit 653S	955	Yes

7. Mitigation Measures

Steady state analysis showed a Category B thermal violation on 2.82L in the 2018 SP pre and post-Project scenarios. The thermal violation on 2.82L is below its short-term thermal rating and will be managed by real-time operational practices.

The Category B contingency of the 138 kV line 162.81L (Beddington No. 162 – Balzac 391S) results in a thermal overloads on the 138 kV line 752L (Summit tap – East Crossfield 64S) and 752L (Summit tap – Summit 653S) in both the 2017 WP pre and post-Project scenarios. The existing 752L Overload RAS would continue to mitigate the thermal overload on 752L in both scenarios.

8. Project Interdependencies

There are no interdependencies between the Project and any other planned connection or transmission system projects.

9. Summary, Conclusion and Recommendation

Project Overview

ENMAX Power Corporation (EPC) submitted a System Access Service Request (SASR) to the Alberta Electric System Operator (AESO) to increase the Demand Transmission Service (DTS) contract capacity at the Beddington No. 162 Point of Delivery (POD) substation from the existing 25 MW to 39 MW (Project). EPC has indicated that the Project is required to support area load growth and maintain the restoration capacity to customers in the northeast area of Calgary up to and including the year 2023.

The requested in-service date (ISD) of the Project is December 2017.

Study Summary

<u>Study Area for the Project</u>

The Project study area includes the Calgary (Area 6) and Airdrie (Area 57) AESO planning areas, both of which make up the Calgary Region (Study Area). Transmission facilities rated at 138 kV and above within the Study Area and the transmission lines connecting it to the rest of the Alberta Interconnected Electric System (AIES) were studied and monitored for violations of the AESO's Reliability Criteria as described in Section 2.

<u>Studies Performed for the Project</u>

Power flow analysis was performed using the 2017 winter peak (WP) and 2018 summer peak (SP) pre-Project and post-Project scenarios to determine the impact of the Project and the associated transmission development on the AIES.

Voltage stability analysis was performed using only the 2017 WP post-Project scenario to identify violations of the Voltage Stability Criteria.

<u>Results of the pre-Project Studies</u>

The following is a summary of the results of the pre-Project studies.

<u>Category A (N-G-0) conditions</u>

No violation of the Reliability Criteria was observed for Category A conditions in any of the pre-Project scenarios.

<u>Category B (N-G-1) contingencies</u>

In the 2017 WP scenario (Scenario 1), the Category B contingency of the 138 kV line 162.81L (Beddington No. 162 - Balzac 391S) results in a thermal overload on the 138 kV line 752L (Summit tap - East Crossfield 64S) that would trigger the existing 752L Overload Mitigation RAS. After the action of the existing 752L Overload Mitigation RAS was applied, no violation of the Reliability Criteria was observed in this pre-Project scenario.

In the 2018 SP scenario (Scenario 2), a thermal violation of 107% (347 MVA) was observed on the 138 kV line 2.82L (ENMAX No. 2 - ENMAX No. 5) following the Category B contingency of the 138 kV line 2.83L (ENMAX No. 2 - ENMAX No. 13). This thermal violation is below the short-term thermal rating of 2.82L and is currently managed by the AESO and Transmission Facility Owner (TFO) real time operational practices.

Connection alternatives proposed for the Project

EPC examined and ruled out the use of distribution-based solutions to address the Project need. The following transmission alternatives were proposed in the EPC's Statement of Need for the Project[20].

Alternative 1 – Second Transformer Addition at Beddington No. 162 Substation

Alternative 1 involves the addition of a second 138/25 kV 30/40/50 MVA transformer and four 25 kV feeder breakers at the Beddington No. 162 POD substation. The Project would also involve 138 kV bus modifications at the Beddington No. 162 substation and associated 138 kV switchgear to accommodate the second 138/25 kV transformer.

Alternative 2 – Upgrades at the Existing ENMAX No. 39 Substation

In this alternative, the two existing 138/25 kV transformers at ENMAX No. 39 substation would be replaced by two 138/25kV 50/67/83 MVA transformers and two 25kV feeder breakers would be added.

Alternative 3 – New 138/25 KV Distribution Substation to the East of Stoney Trail

In this alternative, a new 138/25 kV POD substation would be constructed to the east of Stoney Trail and would include one 138/25 kV 30/40/50 MVA transformer and two 25 kV feeder breakers. The new POD substation would be radially connected to the AIES using a single 138 kV transmission line. The new POD would either be connected to the existing Beddington No. 162 substation or T-tapped onto the existing 138 kV line 39.82L (Beddington No. 162 - ENMAX No. 39).

Additional connection alternatives for the Project

In addition, the AESO identified the following transmission connection alternatives:

Alternative 4 – Upgrades at the Existing ENMAX No. 11 Substation

In this alternative, a 138/25 kV 30/40/50 MVA transformer would be added at the ENMAX No. 11 substation with the addition of two 25 kV feeder breakers.

Alternative 5 – Upgrades at the Existing ENMAX No. 47 Substation

In this alternative, a new 138/25 kV 30/40/50 MVA transformer and two 25 kV feeder breakers would be added at the ENMAX No. 47 substation.

Connection alternatives selected for further study

Alternative 2 and Alternative 3 would require more transmission development than Alternative 1 for no incremental benefit and were not selected for further study.

EPC indicated that adding a fifth transformer as proposed in Alternative 4 would pose a reliability risk due to the simple bus configuration at the ENMAX No. 11 substation. This risk could be mitigated by upgrading the configuration at the ENMAX No. 11 substation to a breaker and a third at significantly higher cost than that of Alternative 1.

The ENMAX No. 47 substation is geographically further from the area of the anticipated load growth and would consequently require longer distribution feeders than Alternative 1. EPC

[20] ENMAX Statement Of Need "No.162 Substation 138-25 kV 2nd Transformer Addition" dated October 2014, which is filed under a separate cover.

rejected Alternative 5 on the basis that the longer distribution feeders in this alternative would present greater operational and reliability challenges. Additionally, as the ENMAX No. 47 substation is connected radially to Beddington No. 162 substation through the 138 kV line 771L (Beddington No. 162 - ENMAX No. 47), this would pose a reliability concern for the transfer of the proposed new load at the ENMAX No. 47 substation after the loss or planned outage of 771L.

Only Alternative 1 was selected for further study based on the above stated rationale.

Results of the post-Project studies

The following is a summary of the results of the post-Project studies using Alternative 1.

Category A (N-G-0) conditions

No violation of the Reliability Criteria was observed for Category A conditions in any of the post-Project scenarios.

Category B (N-G-1) contingencies

Similar to the pre-Project 2017WP scenario, the Category B contingency of the 138 kV line 162.81L (Beddington No. 162 – Balzac 391S) results in a thermal overload on the 138 kV line 752L (Summit tap – East Crossfield 64S) that would trigger the existing 752L Overload Mitigation RAS. After the 752L RAS action was applied, no violation of the Reliability Criteria was observed in this post-Project scenario.

A thermal violation of 109% (352 MVA) was observed on the 138 kV line 2.82L (ENMAX No. 2 - ENMAX No. 5) following the Category B contingency of the 138 kV line 2.83L (ENMAX No. 2 - ENMAX No. 13) in the 2018 SP scenario. This thermal violation is below the short-term thermal rating of 2.82L. Similar to the thermal violation that was observed in the pre-Project 2018 SP scenario, the post-Project 2018 SP thermal violation on the 138 kV line 2.82L will continue to be managed by real time operational practices.

Voltage Stability

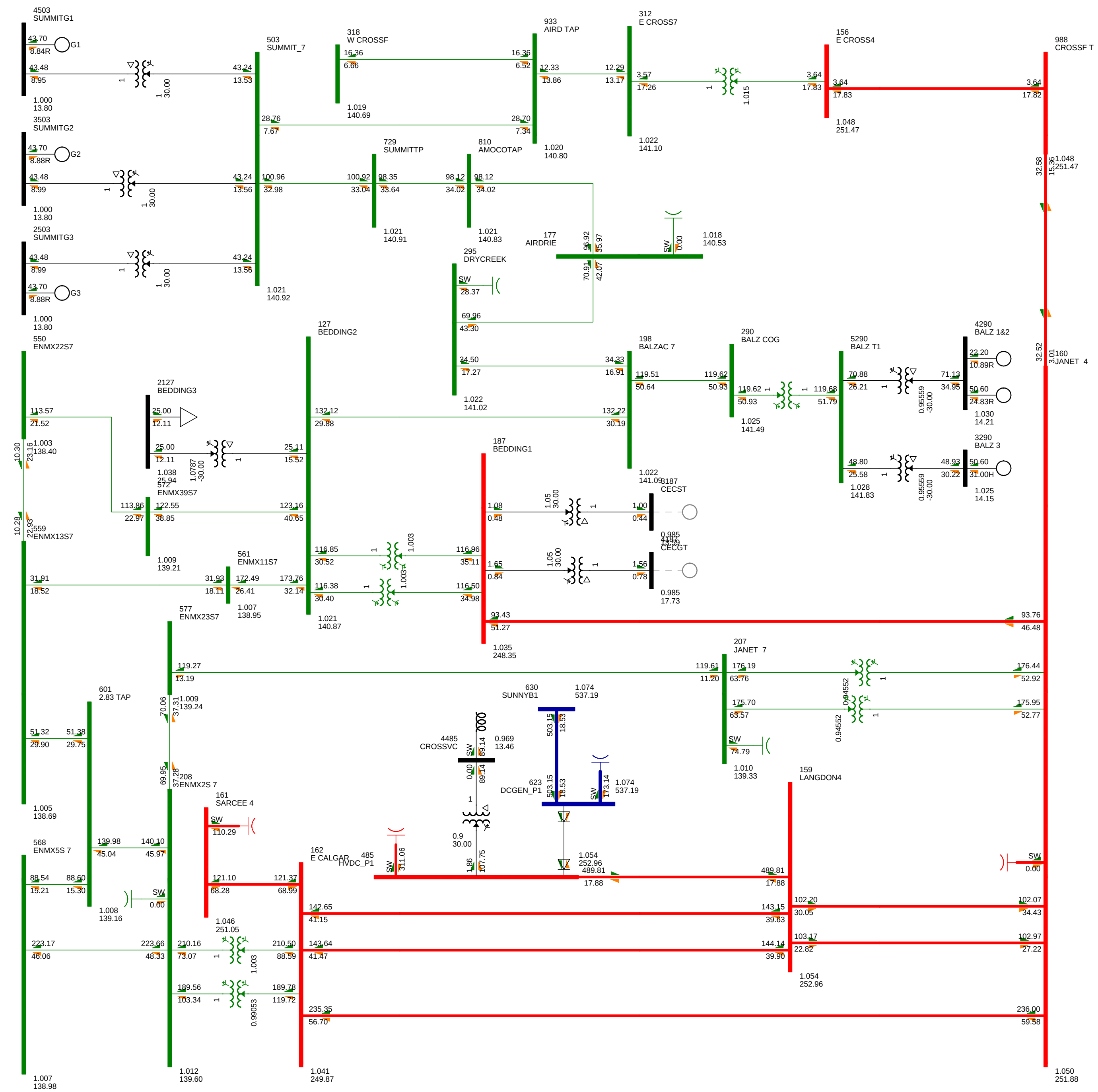
PV analysis was performed using the 2017 WP post-Project scenario (Scenario 3). No violation of the Voltage Stability Criteria was observed subsequent to the connection of the Project using Alternative 1.

Conclusion and Recommendation

The studies demonstrate that the connection of the Project using Alternative 1 would not adversely impact the performance of the AIES. Consequently, the AESO recommends proceeding with the Project by adding a second transformer at the Beddington No. 162 POD (Alternative 1).

Attachment A

Pre-Project Power Flow Diagrams (Scenarios 1 & 2)

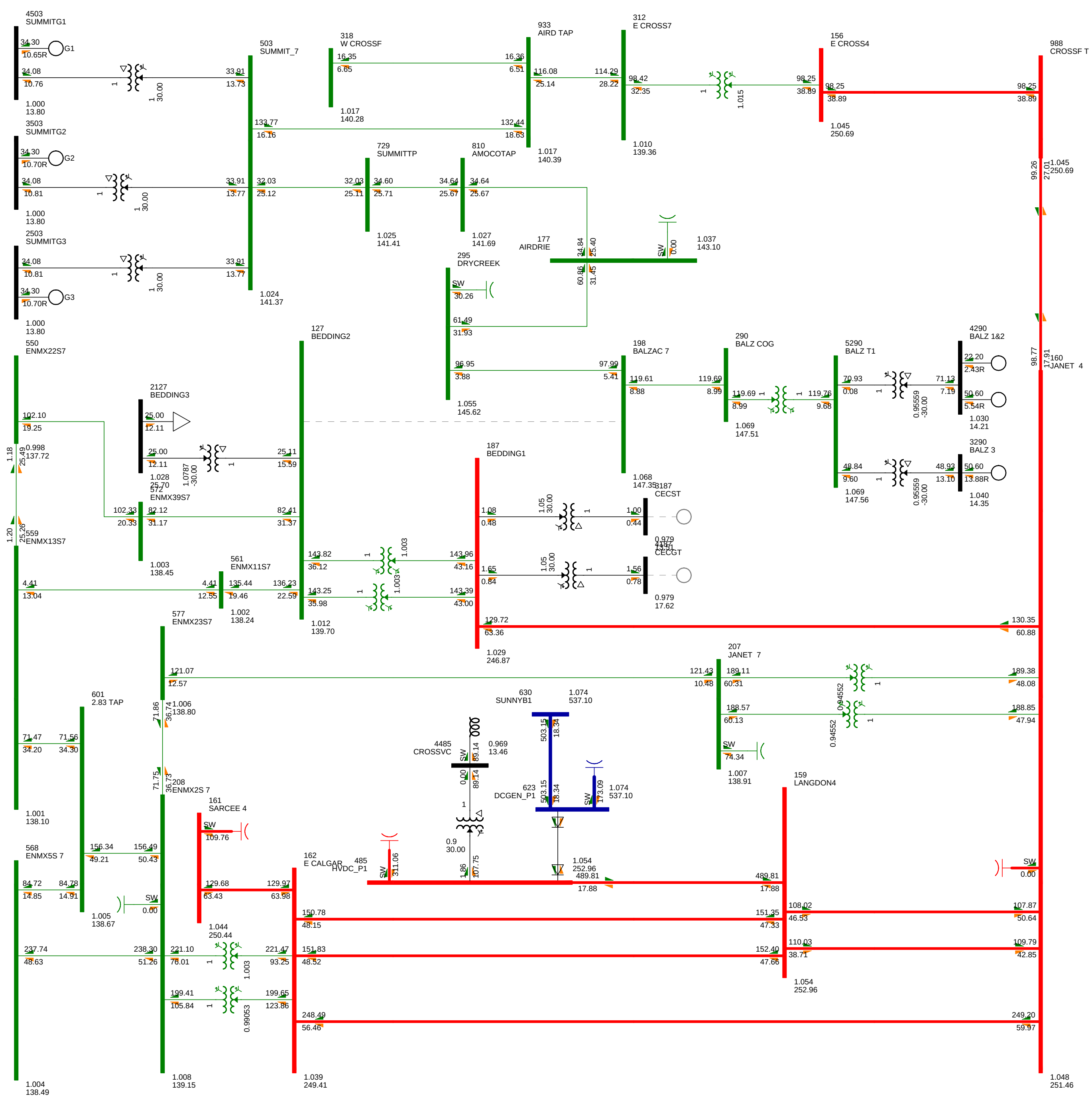


SCENARIO 1 2017 WP (PRE CONNECTION)
BASE CASE
FIG A-1
WED, APR 13 2016 10:55

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

BC-AB: -11.02 MW
MATL import: 0.00 MW
Sask. Import: -0.10 MW

WATL: 489.81 MW
EATL: -0.73 MW



SCENARIO 1 2017 WP (PRE CONNECTION)
162.81L (WITH 752L RAS)
FIG A-2
WED, APR 13 2016 10:56

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

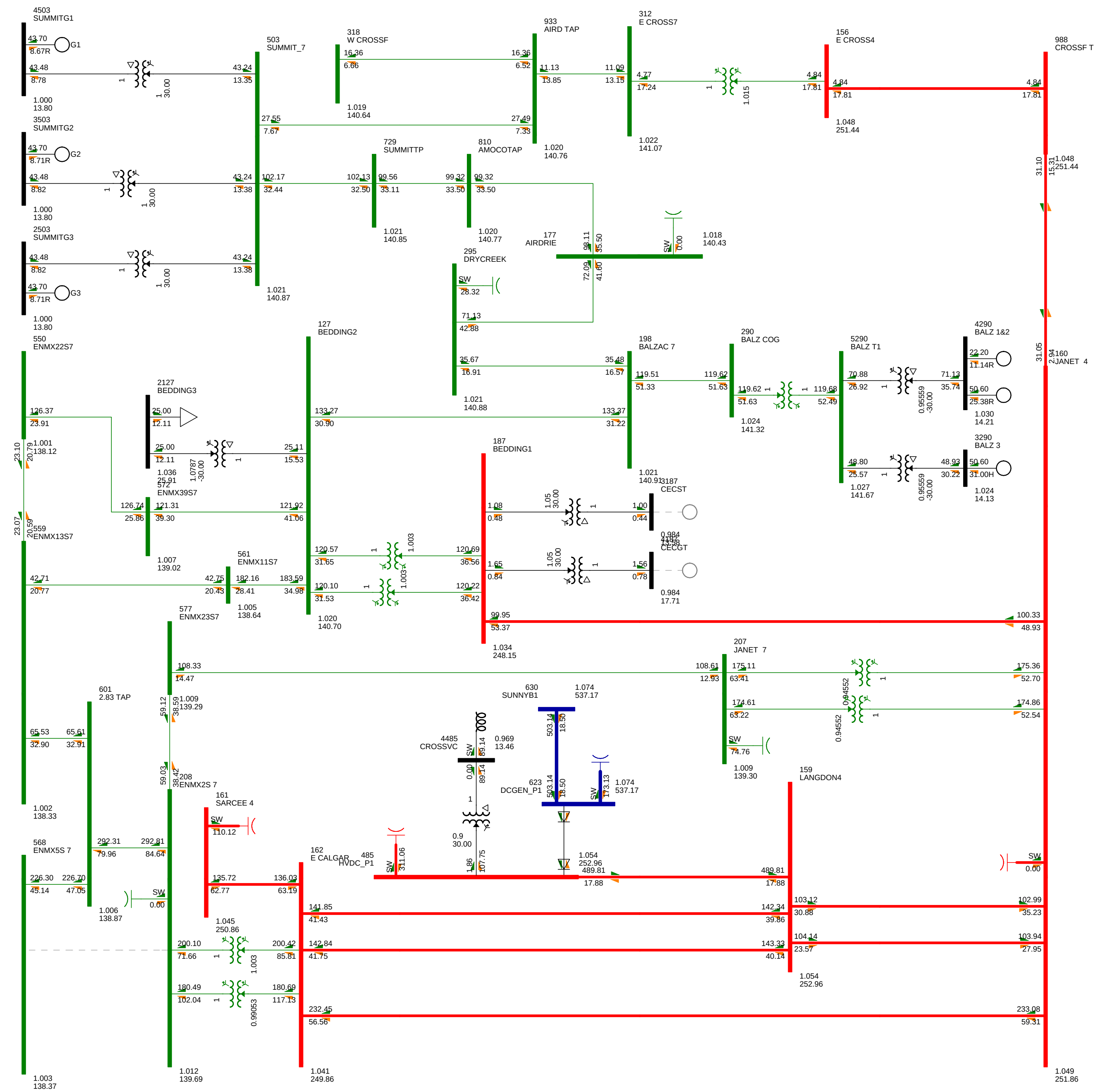
BC-AB: 20.95 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 489.81 MW

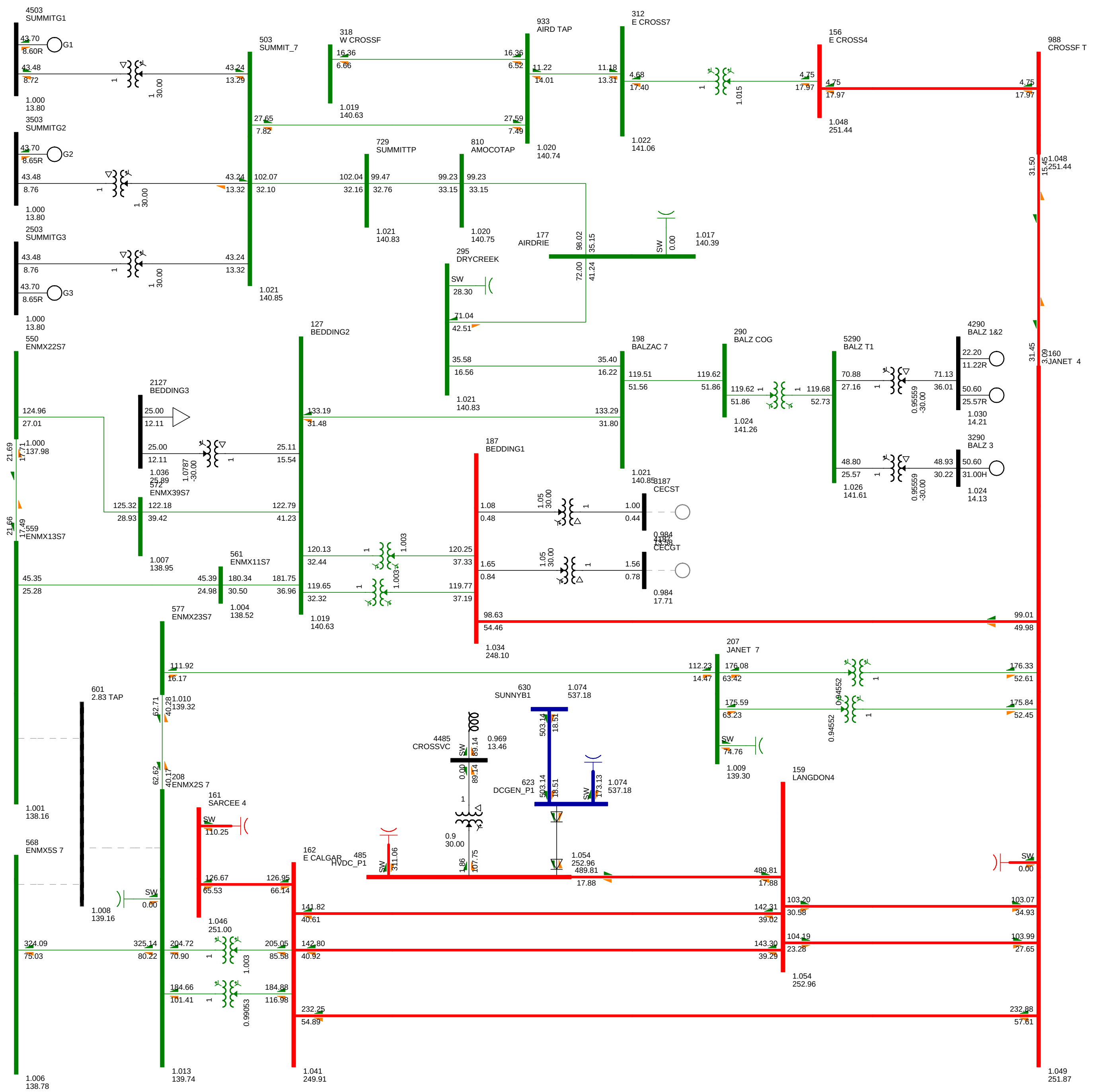
EATL: -0.73 MW



SCENARIO 1 2017 WP (PRE CONNECTION)
2.82L
FIG A-3
WED, APR 13 2016 10:56

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

BC-AB: -9.95 MW
MATL import: 0.00 MW
Sask. Import: -0.10 MW
WATL: 489.81 MW
EATL: -0.73 MW



SCENARIO 1 2017 WP (PRE CONNECTION)
2.83L
FIG A-4
WED, APR 13 2016 10:56

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

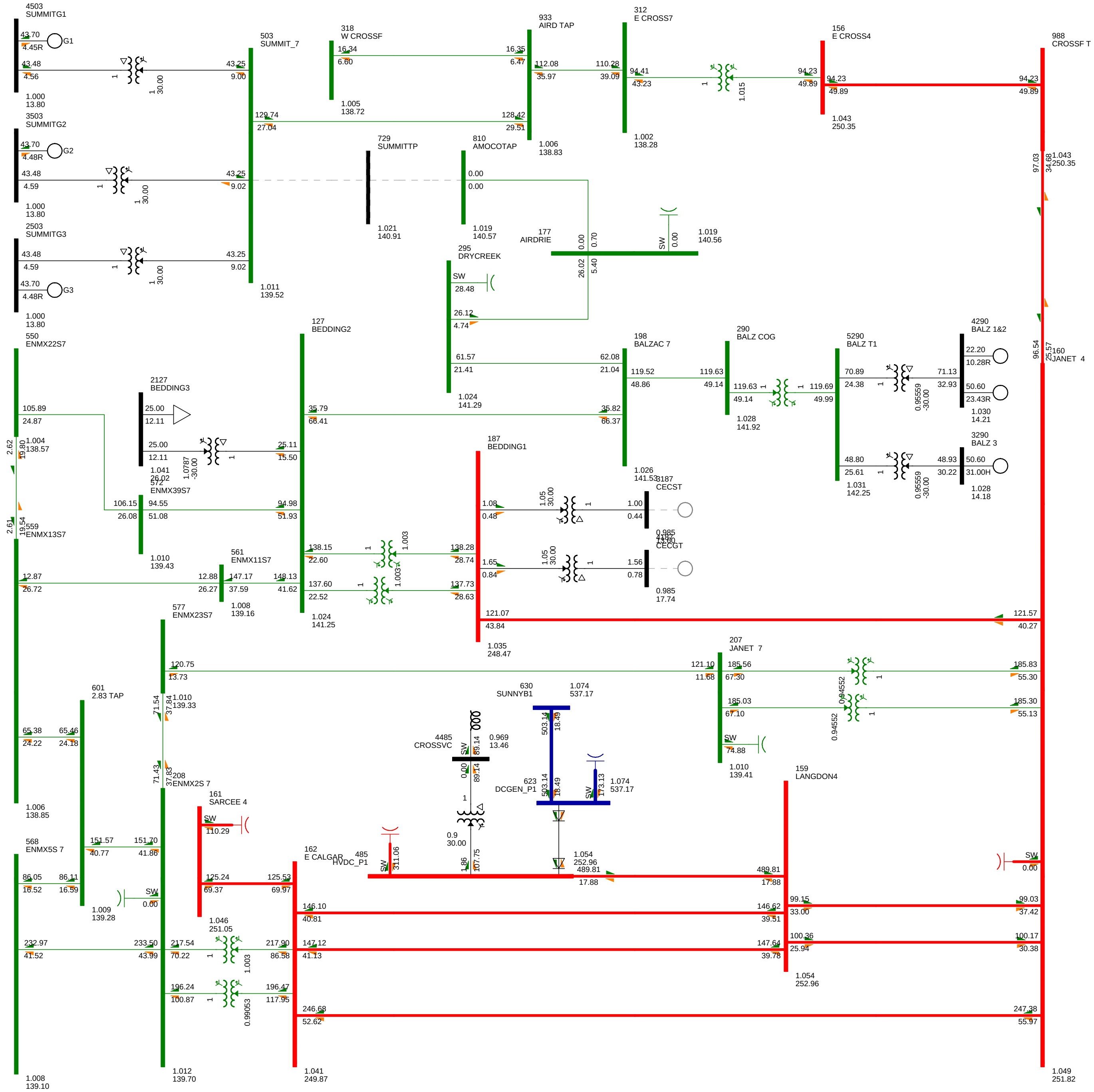
BC-AB: -10.24 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 489.81 MW

EATL: -0.73 MW



SCENARIO 1 2017 WP (PRE CONNECTION)
688L
FIG A-5
WED, APR 13 2016 10:56

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

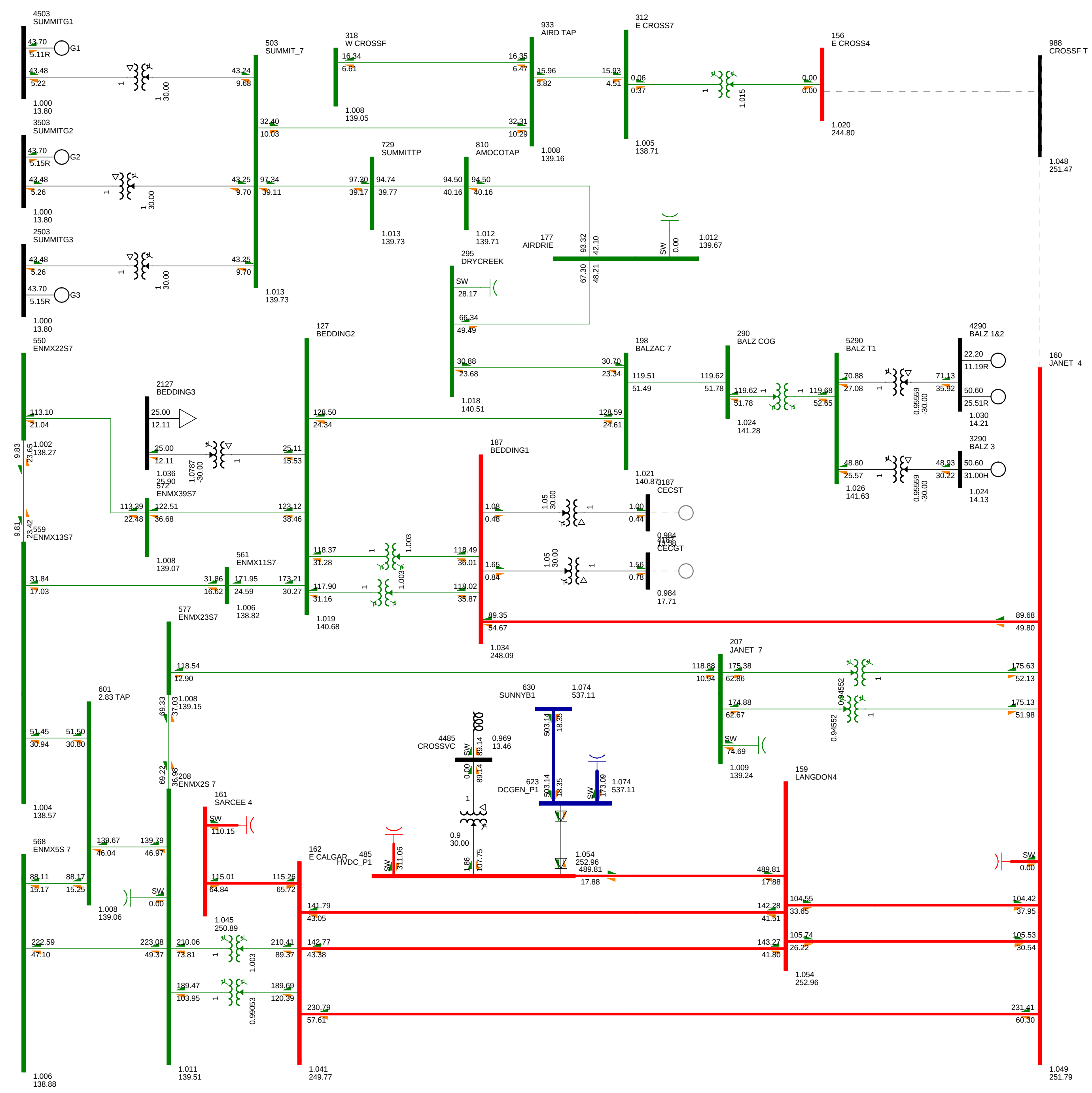
BC-AB: -11.33 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 489.81 MW

EATL: -0.73 MW



SCENARIO 1 2017 WP (PRE CONNECTION)
901L
FIG A-6
WED, APR 13 2016 10:56

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

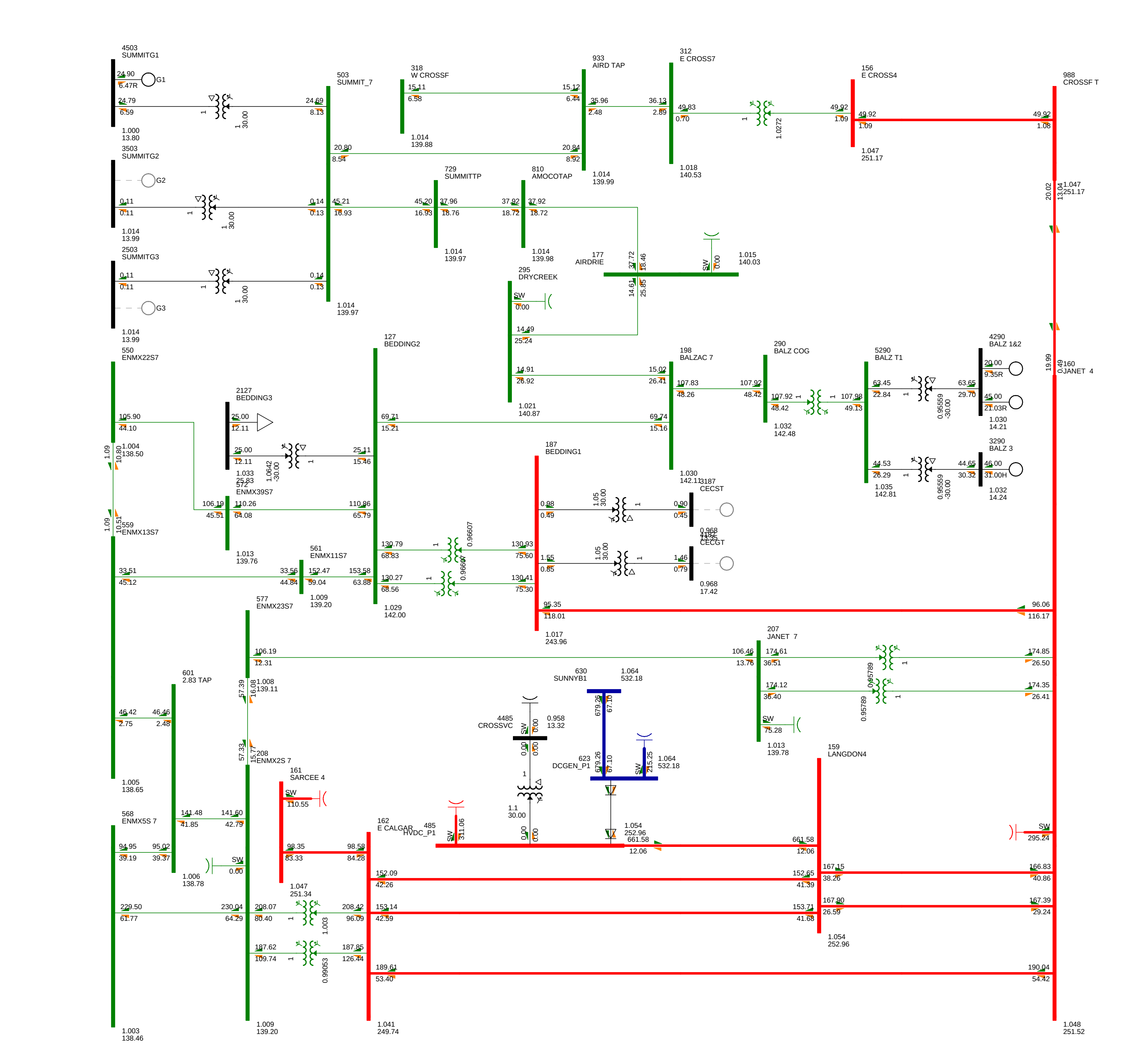
BC-AB: -10.59 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 489.81 MW

EATL: -0.73 MW



SCENARIO 2 2018 SP (PRE CONNECTION)
BASE CASE
FIG A-7
WED, APR 13 2016 10:56

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

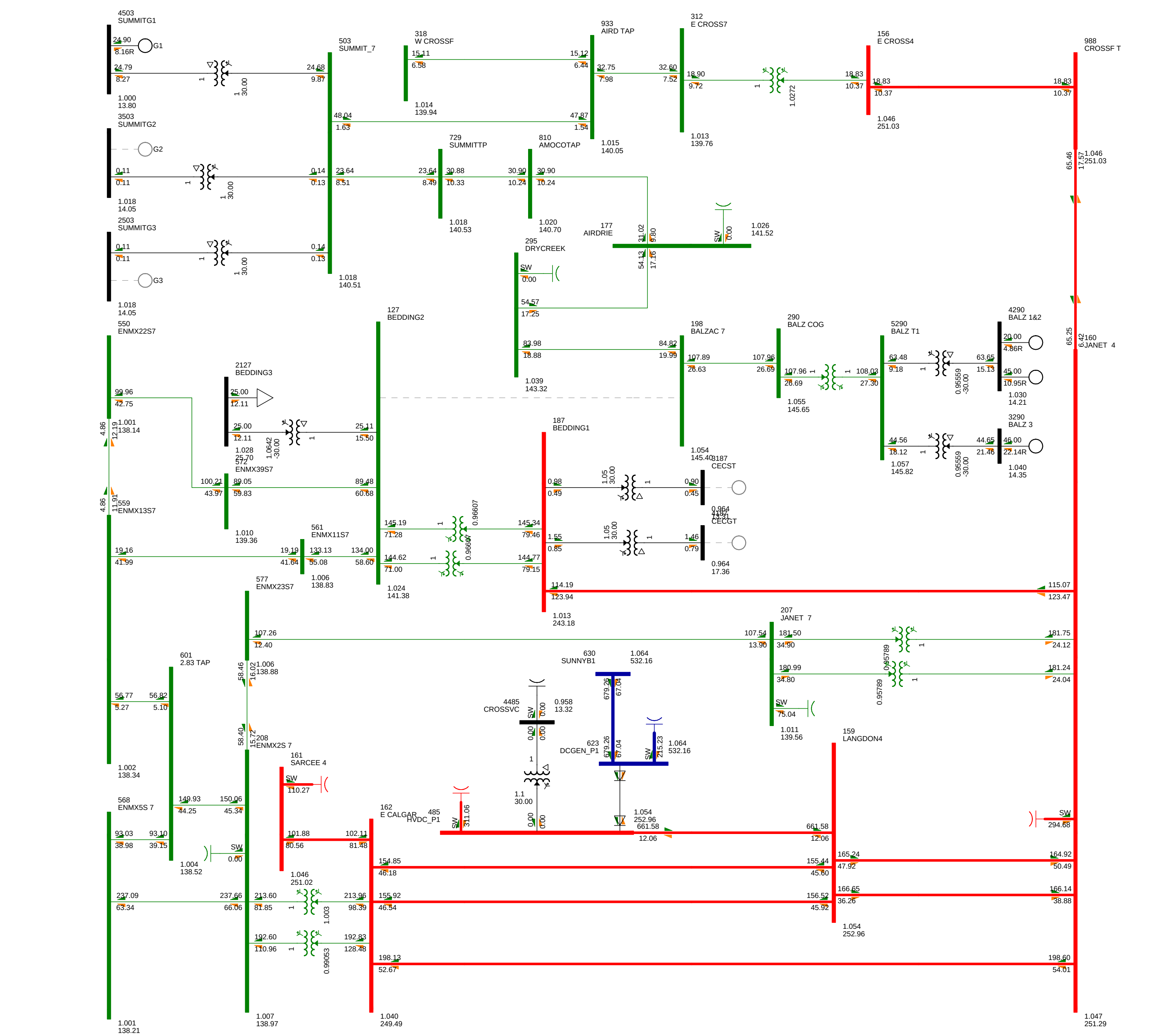
BC-AB: -11.65 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 661.58 MW

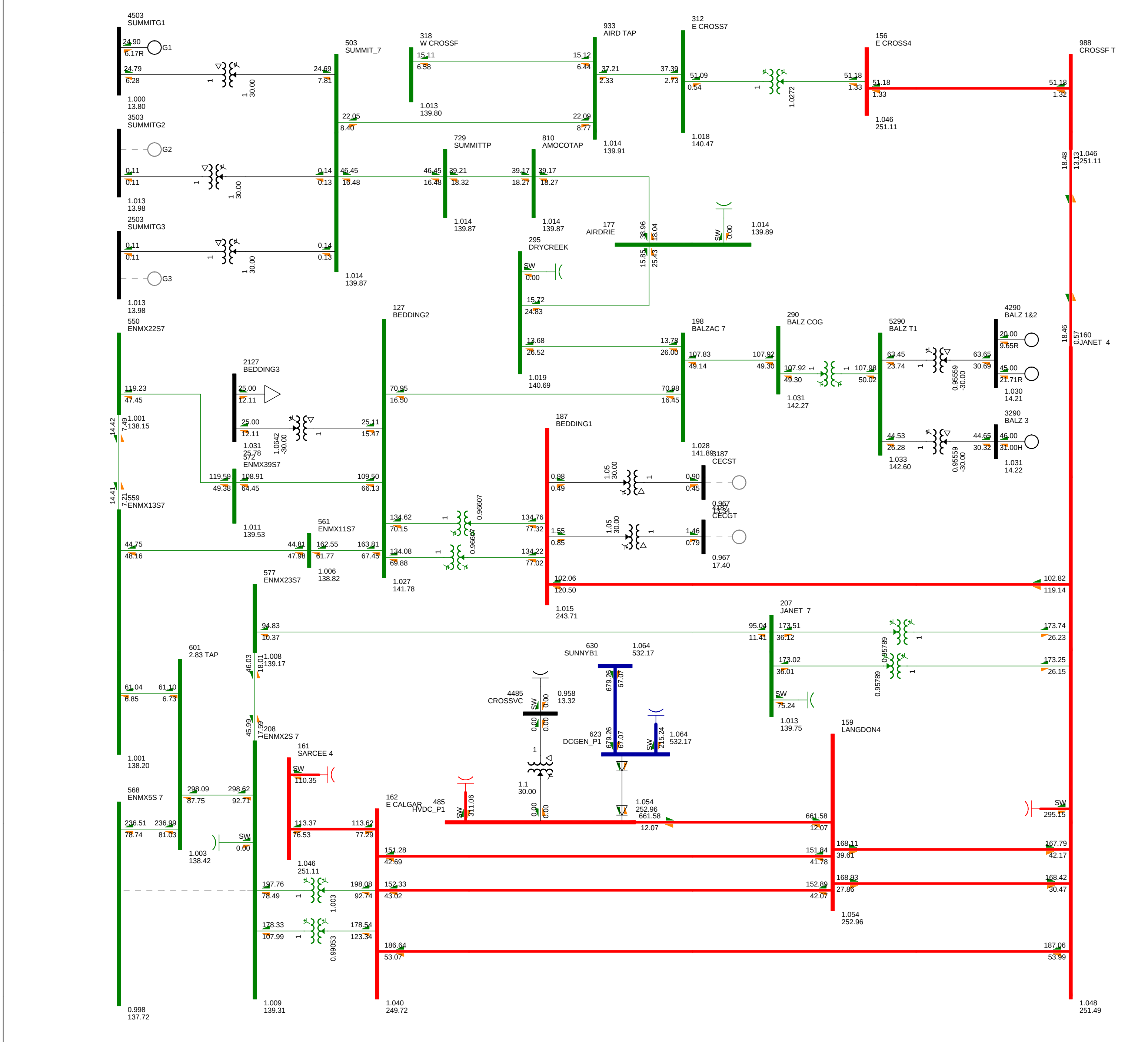
EATL: -0.73 MW



SCENARIO 2 2018 SP (PRE CONNECTION)
162.81L
FIG A-8
WED, APR 13 2016 10:56

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

BC-AB: -9.83 MW
MATL import: 0.00 MW
Sask. Import: -0.10 MW
WATL: 661.58 MW
EATL: -0.73 MW



SCENARIO 2 2018 SP (PRE CONNECTION)
2.82L
FIG A-9
WED, APR 13 2016 10:56

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

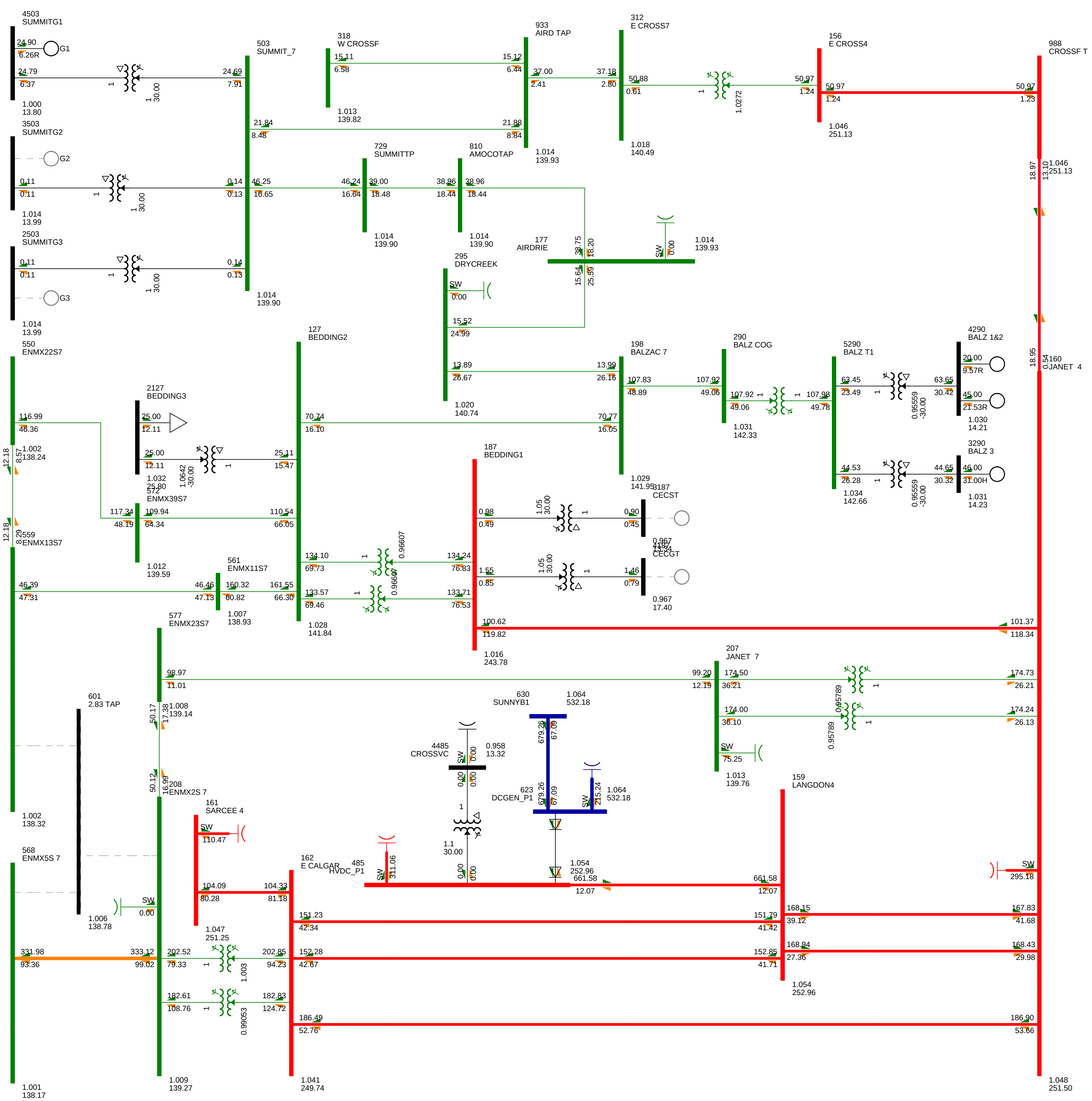
BC-AB: -10.46 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 661.58 MW

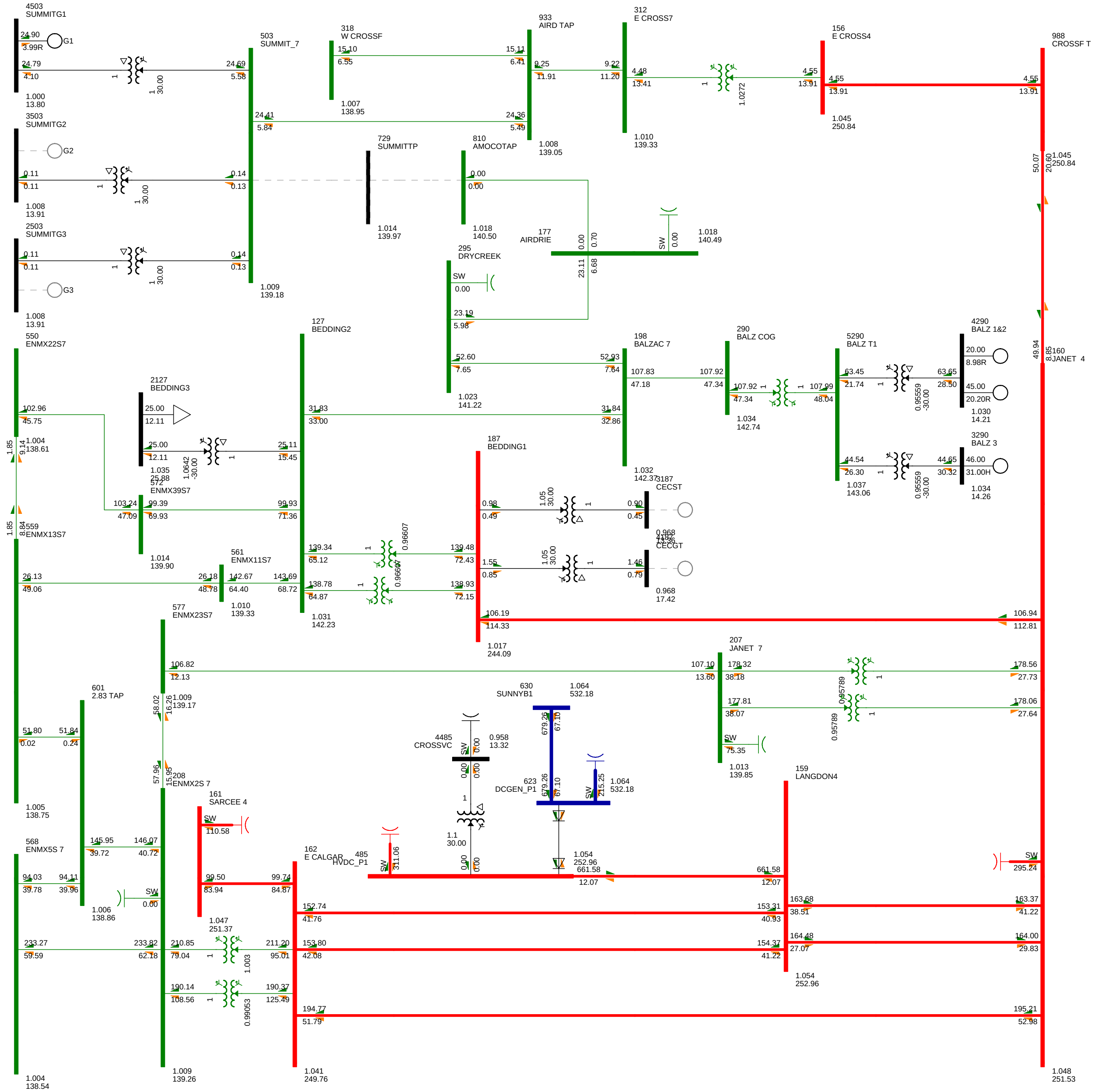
EATL: -0.73 MW



SCENARIO 2 2018 SP (PRE CONNECTION)
2.83L
FIG A-10
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

BC-AB: -10.88 MW
MATL import: 0.00 MW
Sask. Import: -0.10 MW
WATL: 661.58 MW
EATL: -0.73 MW

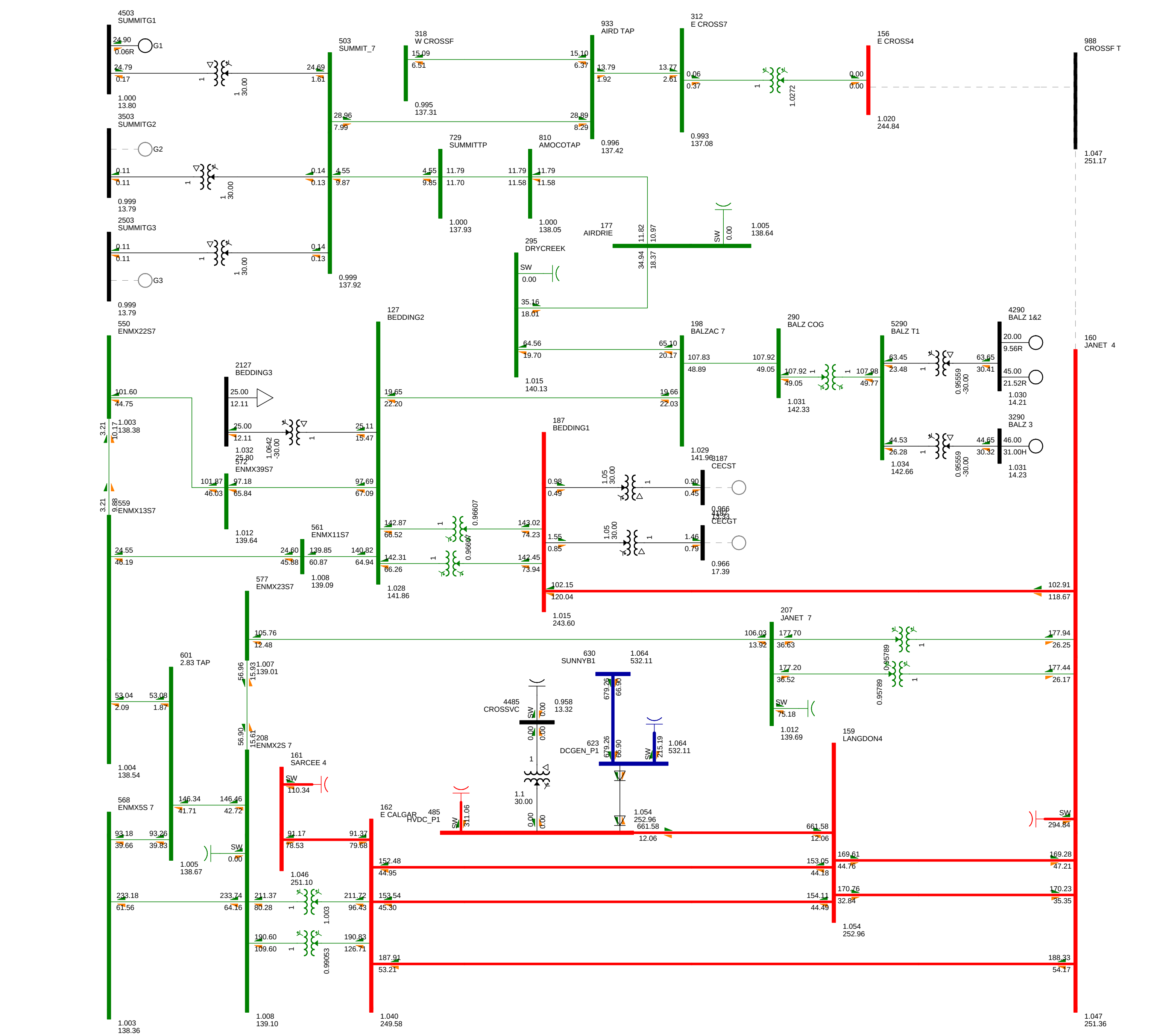


SCENARIO 2 2018 SP (PRE CONNECTION)
688L
FIG A-11
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

BC-AB: -18.76 MW
MATL import: 0.00 MW
Sask. Import: -0.10 MW

WATL: 661.58 MW
EATL: -0.73 MW



SCENARIO 2 2018 SP (PRE CONNECTION)
901L
FIG A-12
WED, APR 13 2016 10:57

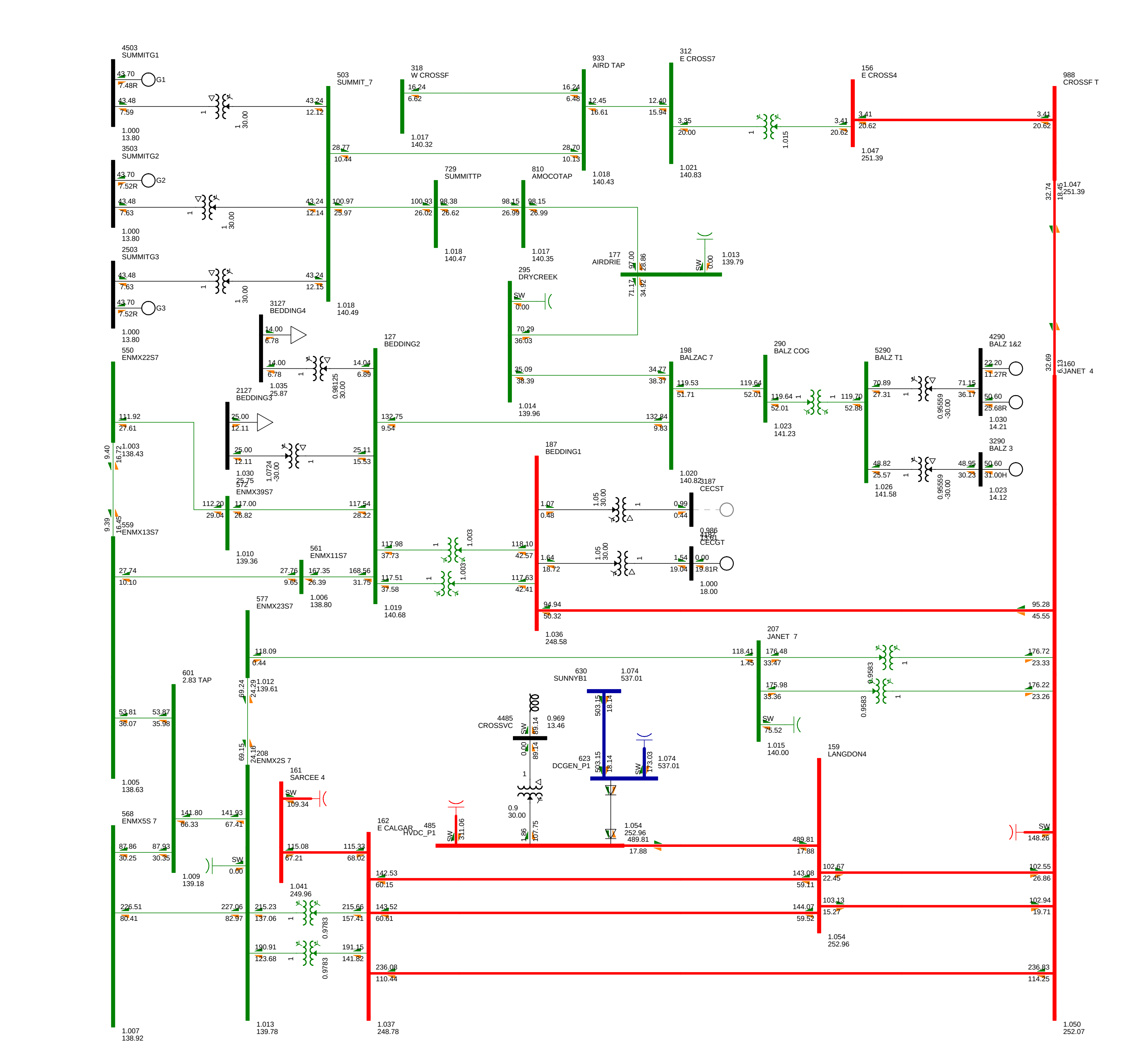
Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.120OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

BC-AB: -10.14 MW
MATL import: 0.00 MW
Sask. Import: -0.10 MW

WATL: 661.58 MW
EATL: -0.73 MW

Attachment B

Alternative 1: Power Flow Diagrams (Scenarios 3 & 4)



SCENARIO 3 2017 WP (POST CONNECTION)
BASE CASE
FIG B-1
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

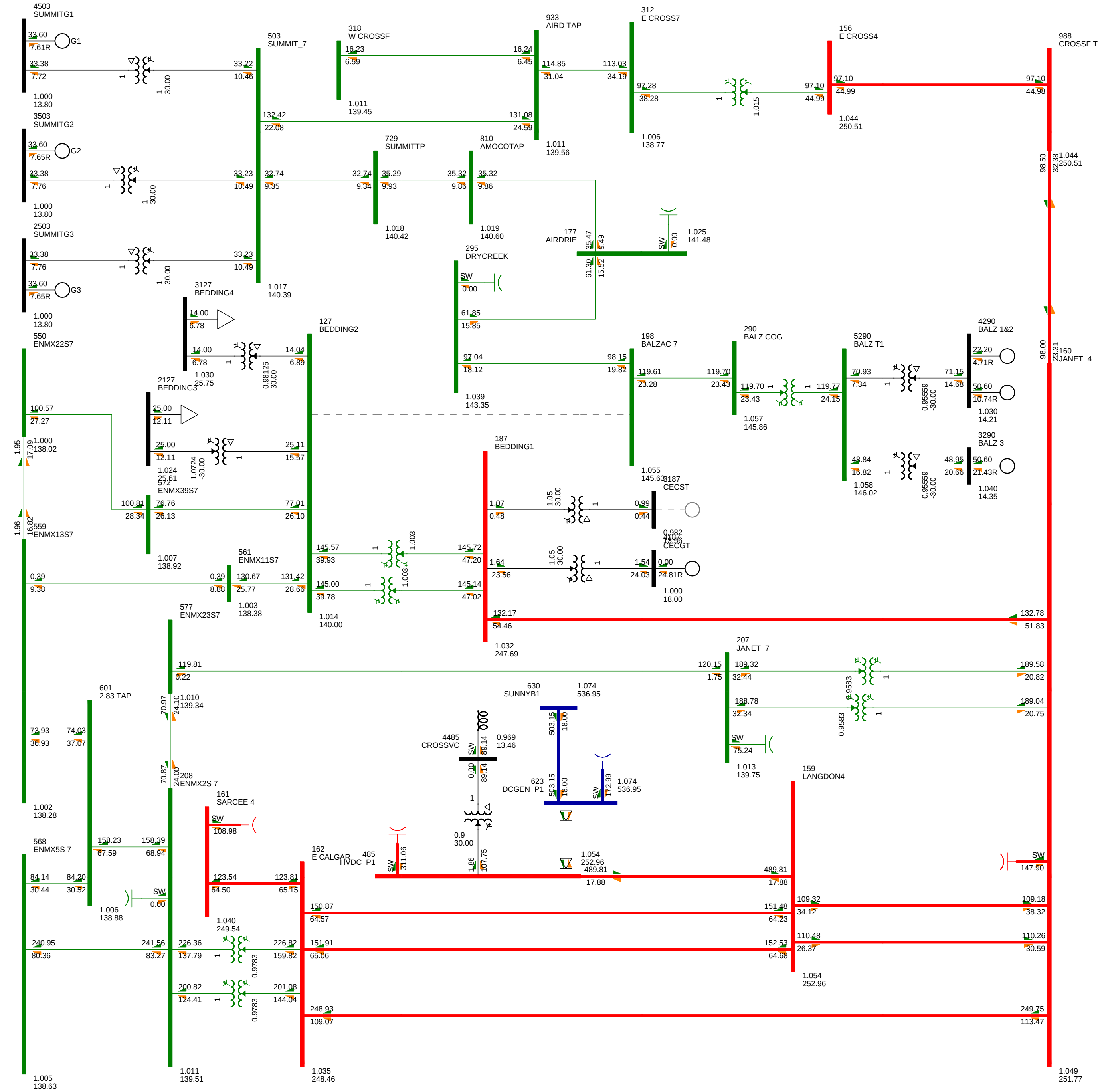
BC-AB: -10.77 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 489.81 MW

EATL: -0.73 MW



SCENARIO 3 2017 WP (POST CONNECTION)
162.81L (WITH 752L RAS)
FIG B-2
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar

100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

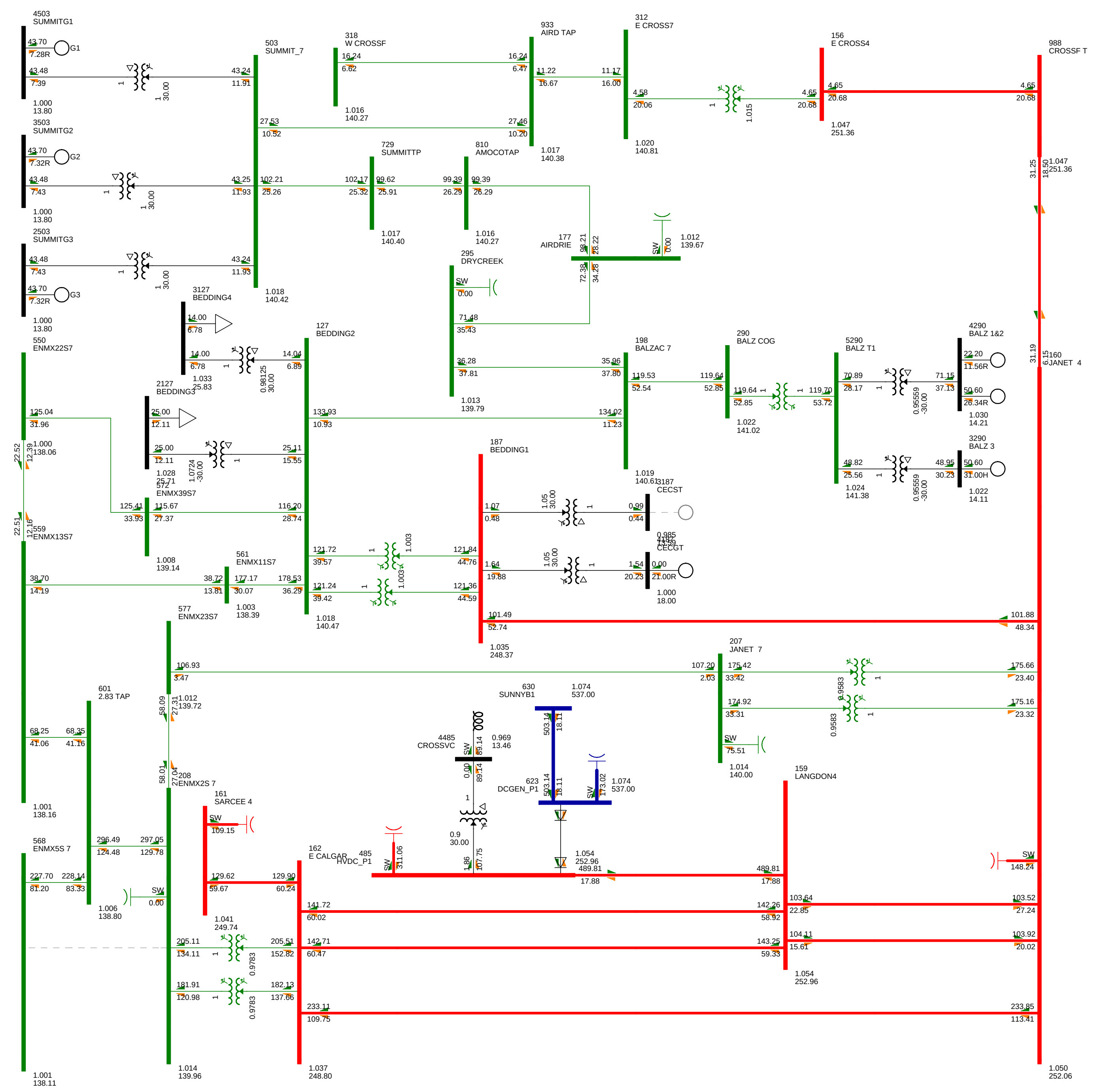
BC-AB: 23.19 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 489.81 MW

EATL: -0.73 MW

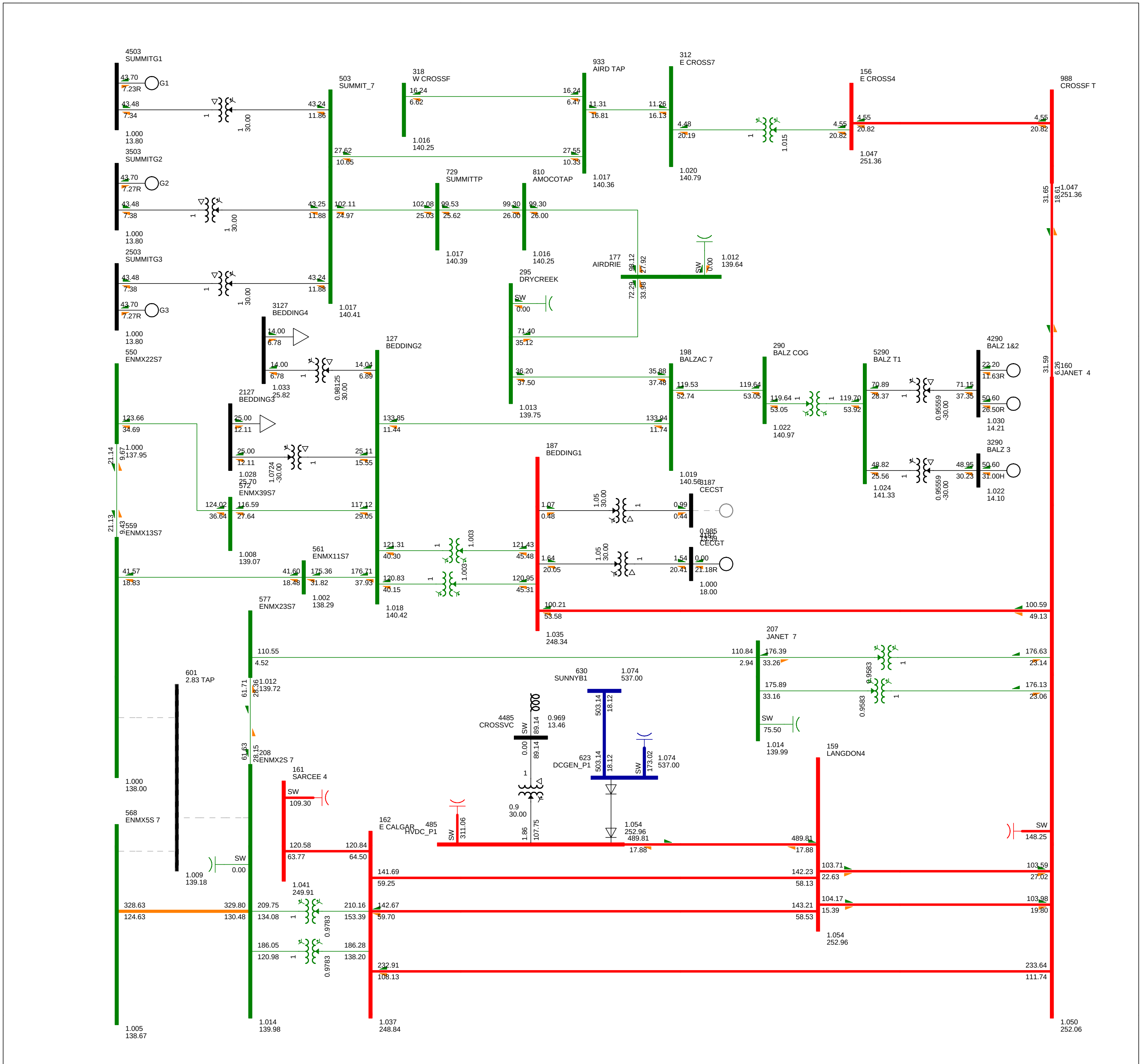


SCENARIO 3 2017 WP (POST CONNECTION)
2.82L
FIG B-3
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.120OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

BC-AB: -9.65 MW
MATL import: 0.00 MW
Sask. Import: -0.10 MW

WATL: 489.81 MW
EATL: -0.73 MW



SCENARIO 3 2017 WP (POST CONNECTION)
2.83L
FIG B-4
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

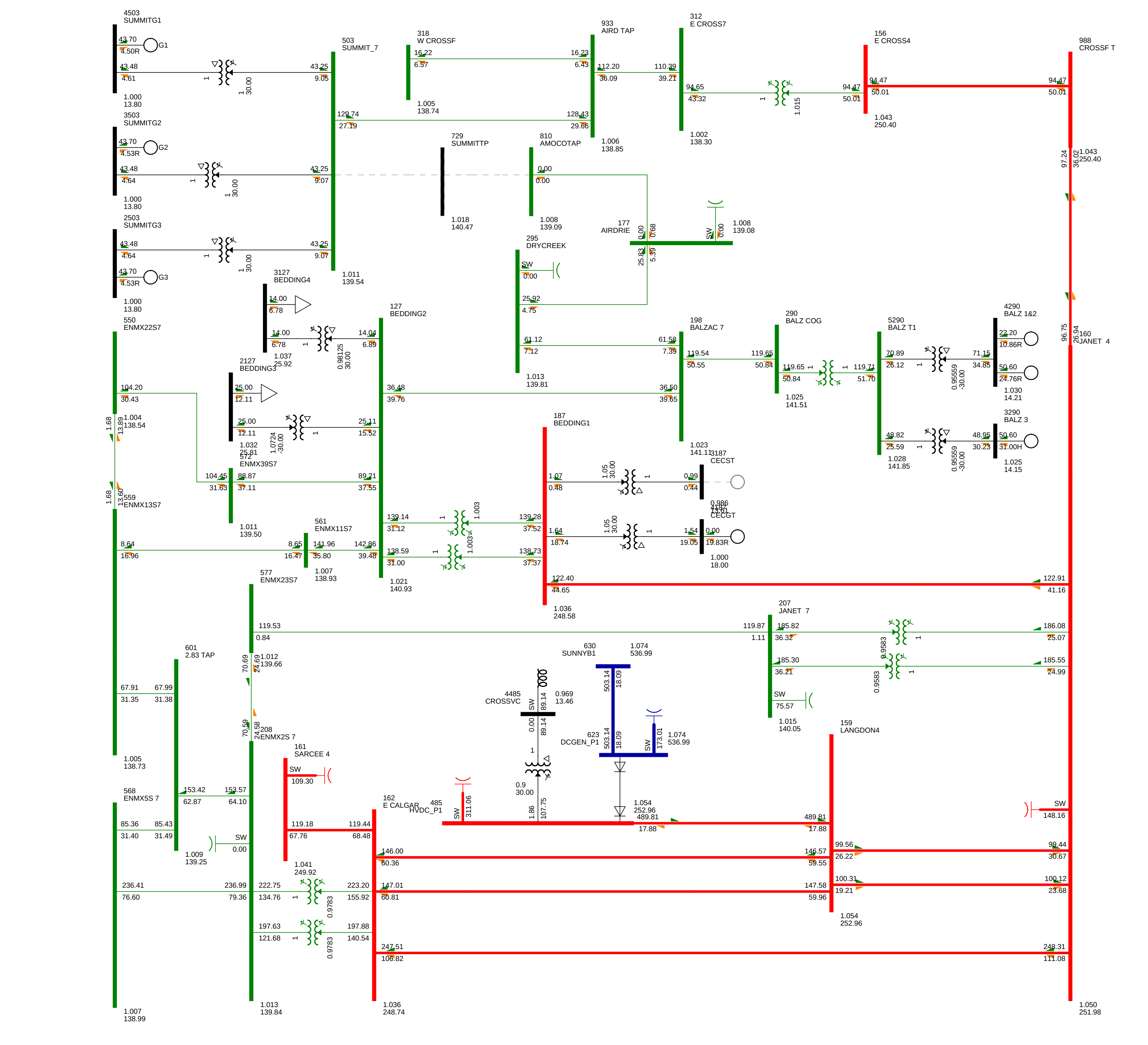
BC-AB: -9.95 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 489.81 MW

EATL: -0.73 MW



SCENARIO 3 2017 WP (POST CONNECTION)
688L
FIG B-5
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

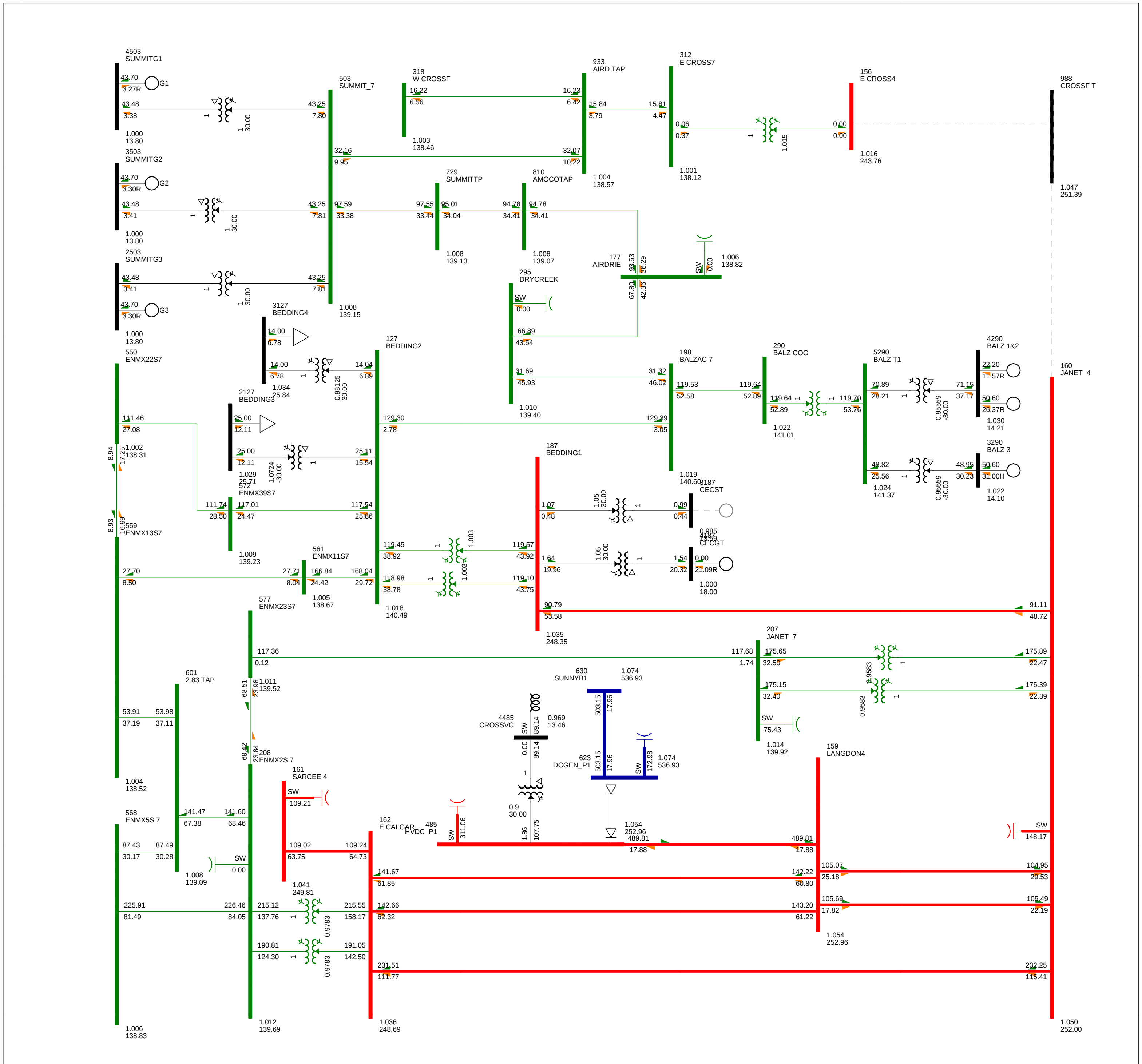
BC-AB: -11.14 MW

WATL: 489.81 MW

MATL import: 0.00 MW

EATL: -0.73 MW

Sask. Import: -0.10 MW



SCENARIO 3 2017 WP (POST CONNECTION)
901L
FIG B-6
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.100OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

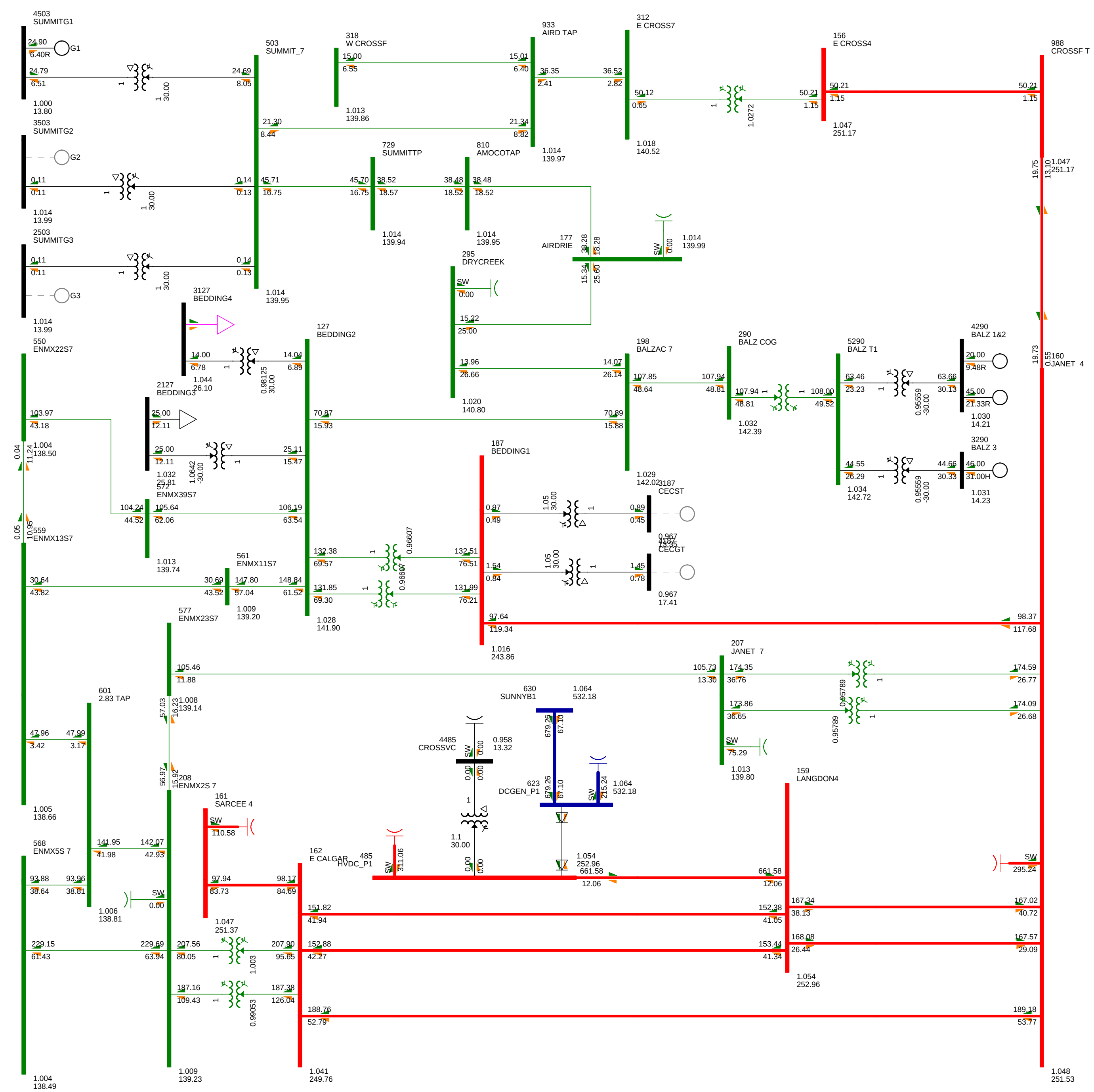
BC-AB: -10.28 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 489.81 MW

EATL: -0.73 MW



SCENARIO 4 2018 SP (POST CONNECTION)
BASE CASE
FIG B-7
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

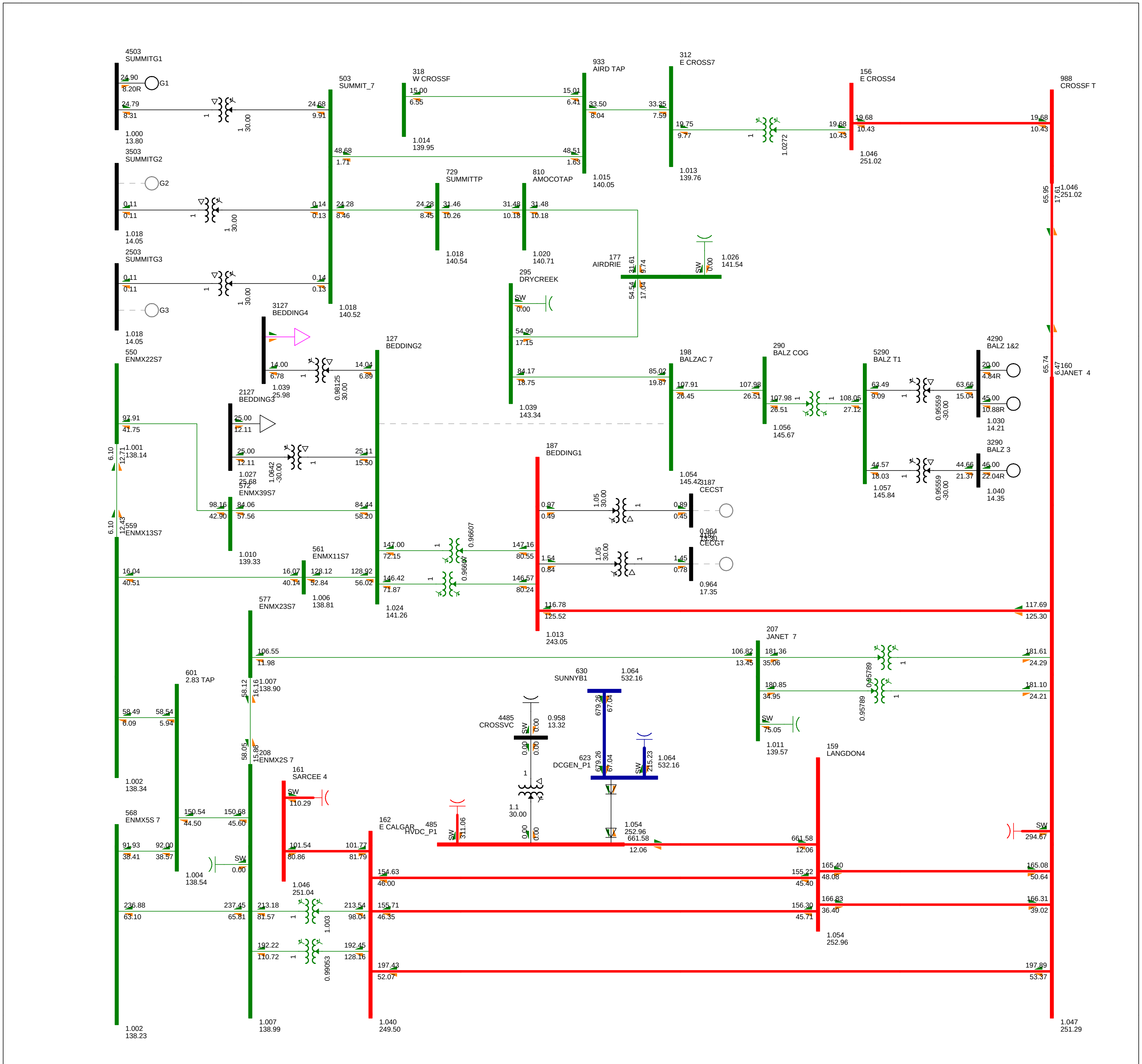
BC-AB: -11.83 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 661.58 MW

EATL: -0.73 MW



SCENARIO 4 2018 SP (POST CONNECTION)
162.81L
FIG B-8
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar

100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

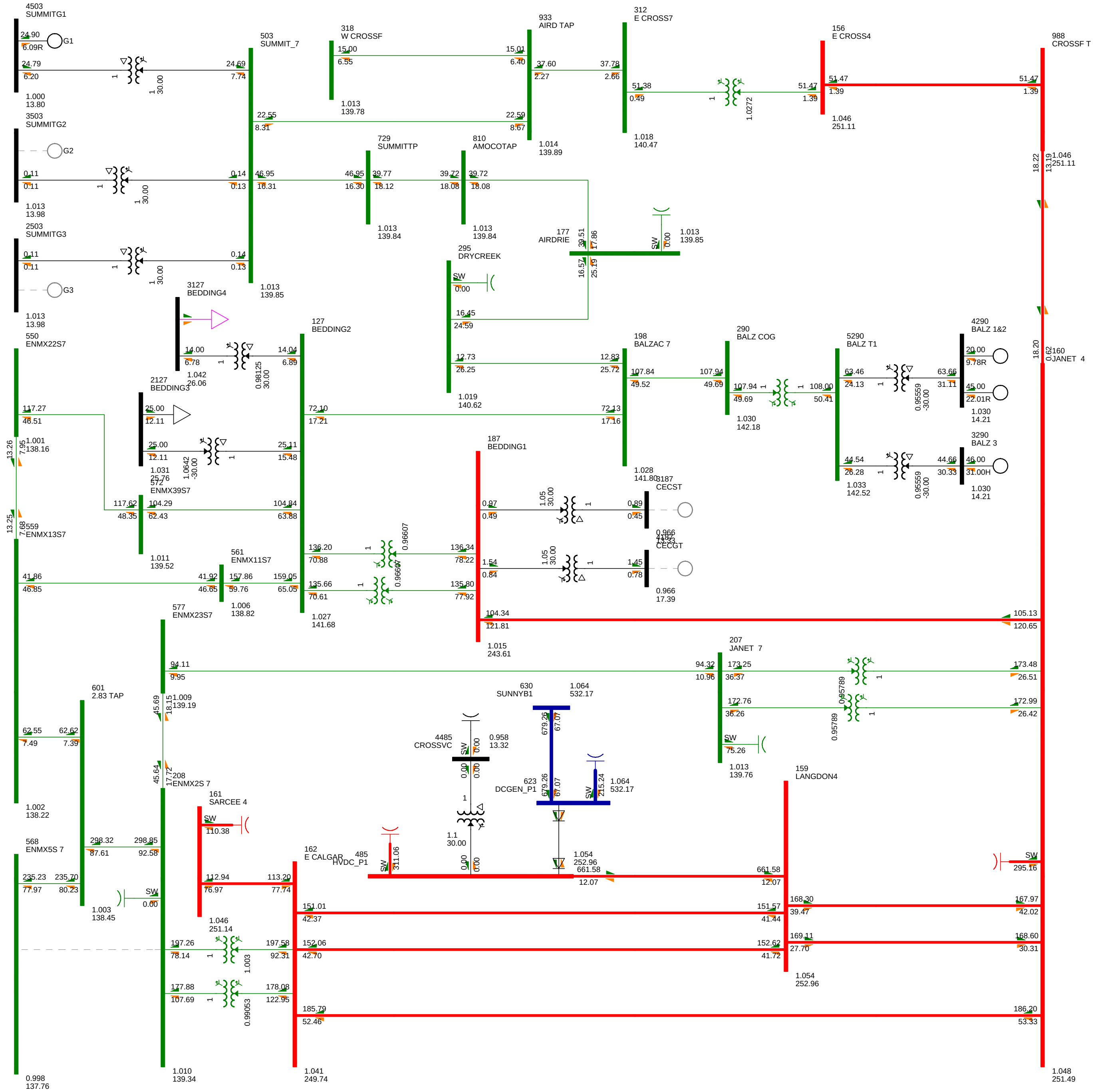
BC-AB: -9.94 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 661.58 MW

EATL: -0.73 MW



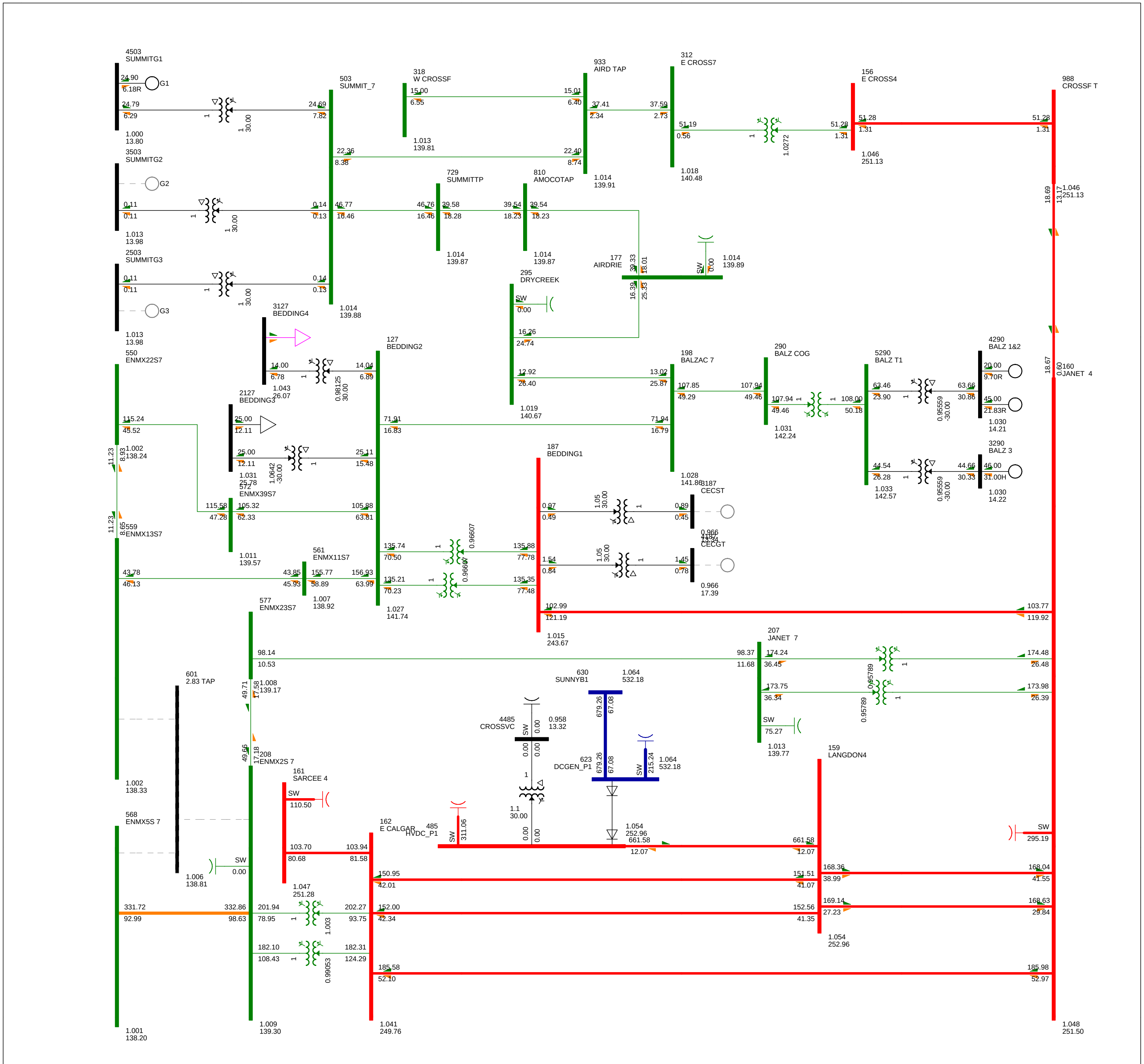
SCENARIO 4 2018 SP (POST CONNECTION)
2.82L
FIG B-9
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar

100.0%Rate A
1.100OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

BC-AB: -10.65 MW
MATL import: 0.00 MW
Sask. Import: -0.10 MW

WATL: 661.58 MW
EATL: -0.73 MW



SCENARIO 4 2018 SP (POST CONNECTION)
2.83L
FIG B-10
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

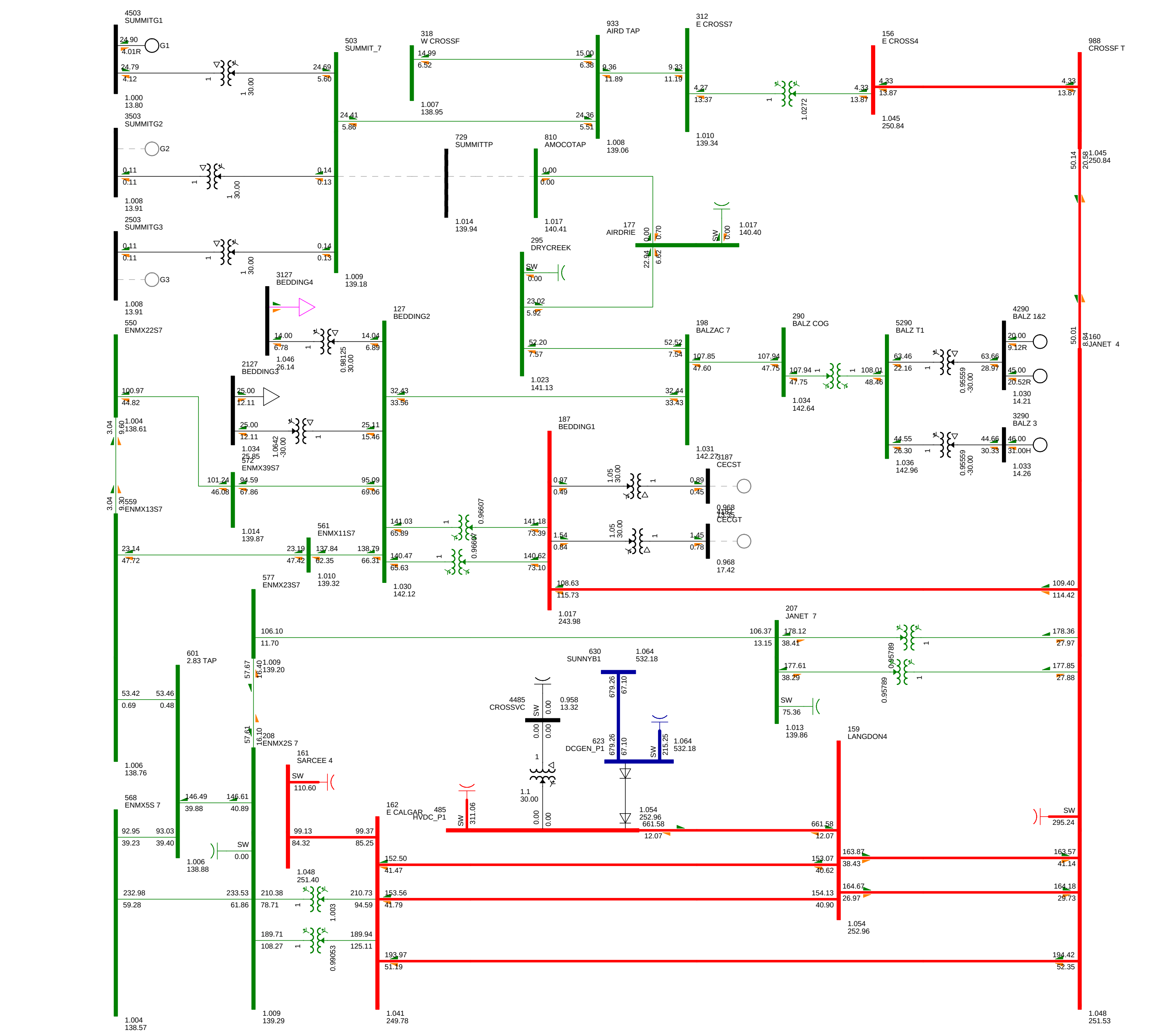
BC-AB: -11.05 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 661.58 MW

EATL: -0.73 MW



SCENARIO 4 2018 SP (POST CONNECTION)
688L
FIG B-11
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

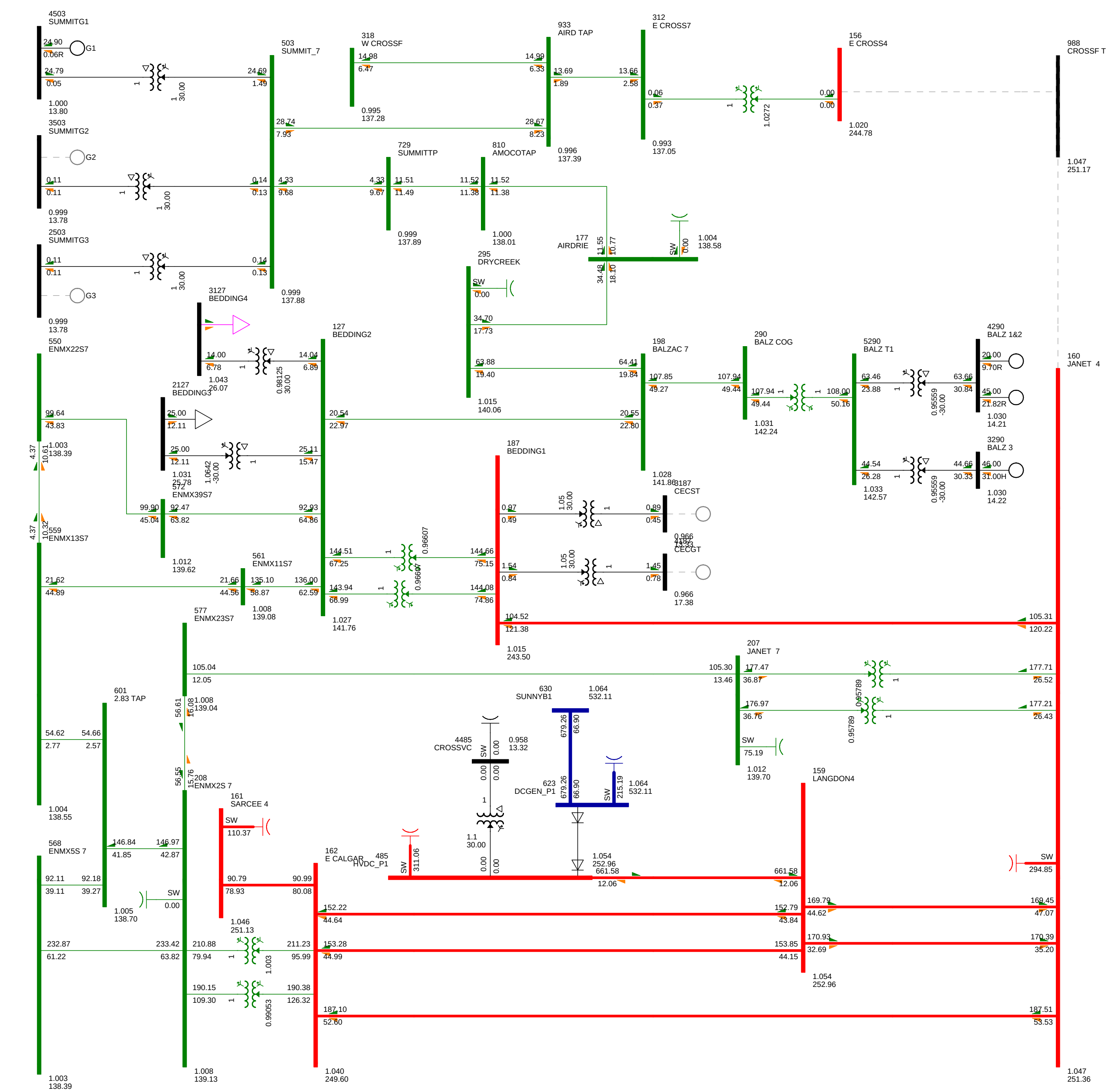
BC-AB: -18.88 MW

MATL import: 0.00 MW

Sask. Import: -0.10 MW

WATL: 661.58 MW

EATL: -0.73 MW



SCENARIO 4 2018 SP (POST CONNECTION)
901L
FIG B-12
WED, APR 13 2016 10:57

Bus - Voltage (kV/pu)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A
1.050OV 0.950UV
kV: <=4.160 <=13.800 <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

BC-AB: -10.33 MW
MATL import: 0.00 MW
Sask. Import: -0.10 MW

WATL: 661.58 MW
EATL: -0.73 MW

Attachment C

Alternative 1: Voltage Stability Diagrams (Scenarios 3)

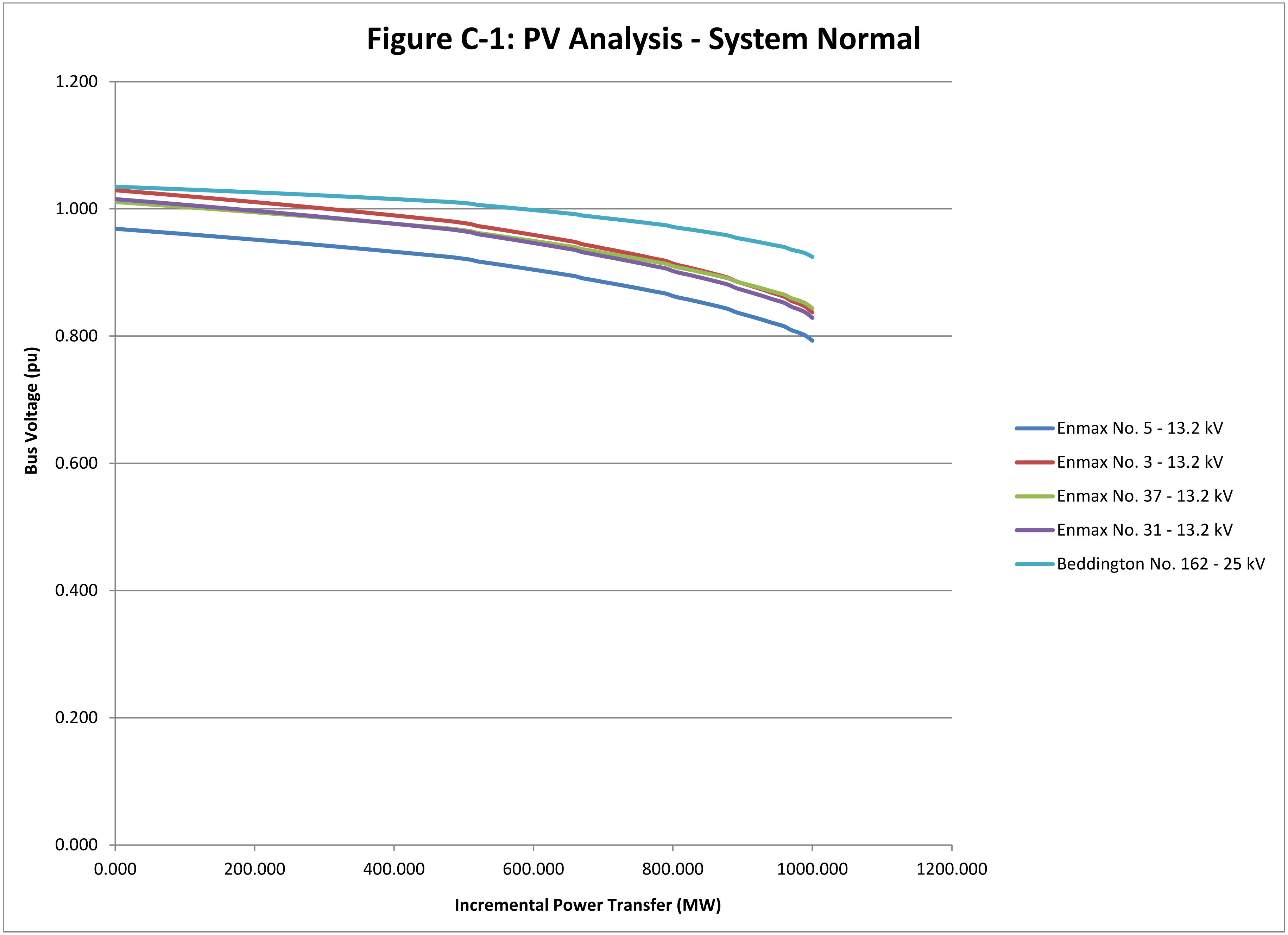


Figure C-1: PV Analysis - System Normal
1.200
1.000
0.800
0.600
0.400
0.200
0.000
Bus Voltage (pu)
0.000
200.000
400.000
600.000
800.000
1000.000
1200.000
Incremental Power Transfer (MW)
Enmax No. 5 - 13.2 kV
Enmax No. 3 - 13.2 kV
Enmax No. 37 - 13.2 kV
Enmax No. 31 - 13.2 kV
Beddington No. 162 - 25 kV

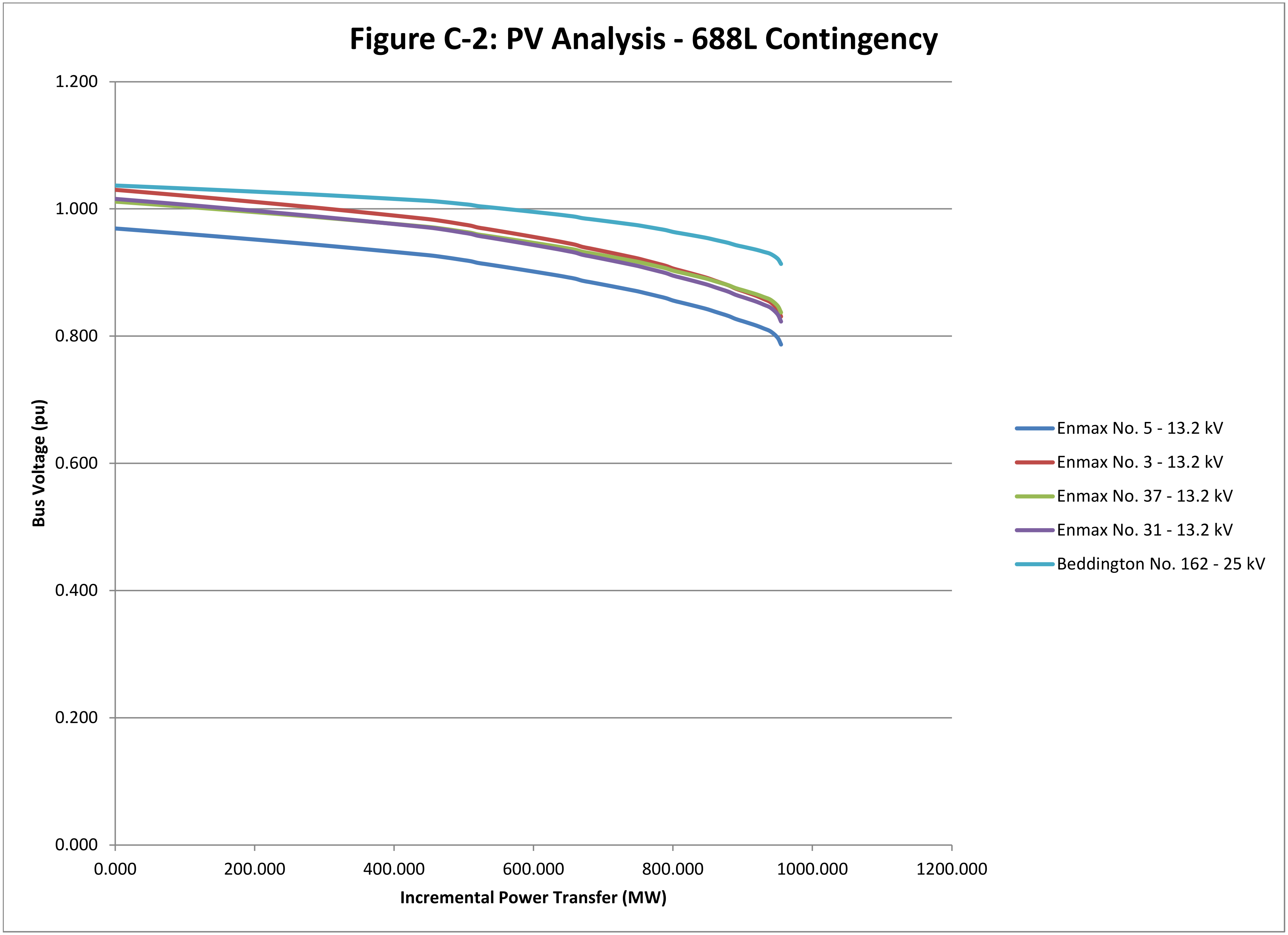


Figure C-2: PV Analysis - 688L Contingency
Bus Voltage (pu)
1.200
1.000
0.800
0.600
0.400
0.200
0.000
0.000
200.000
400.000
600.000
800.000
1000.000
1200.000
Incremental Power Transfer (MW)
Enmax No. 5 - 13.2 kV
Enmax No. 3 - 13.2 kV
Enmax No. 37 - 13.2 kV
Enmax No. 31 - 13.2 kV
Beddington No. 162 - 25 kV

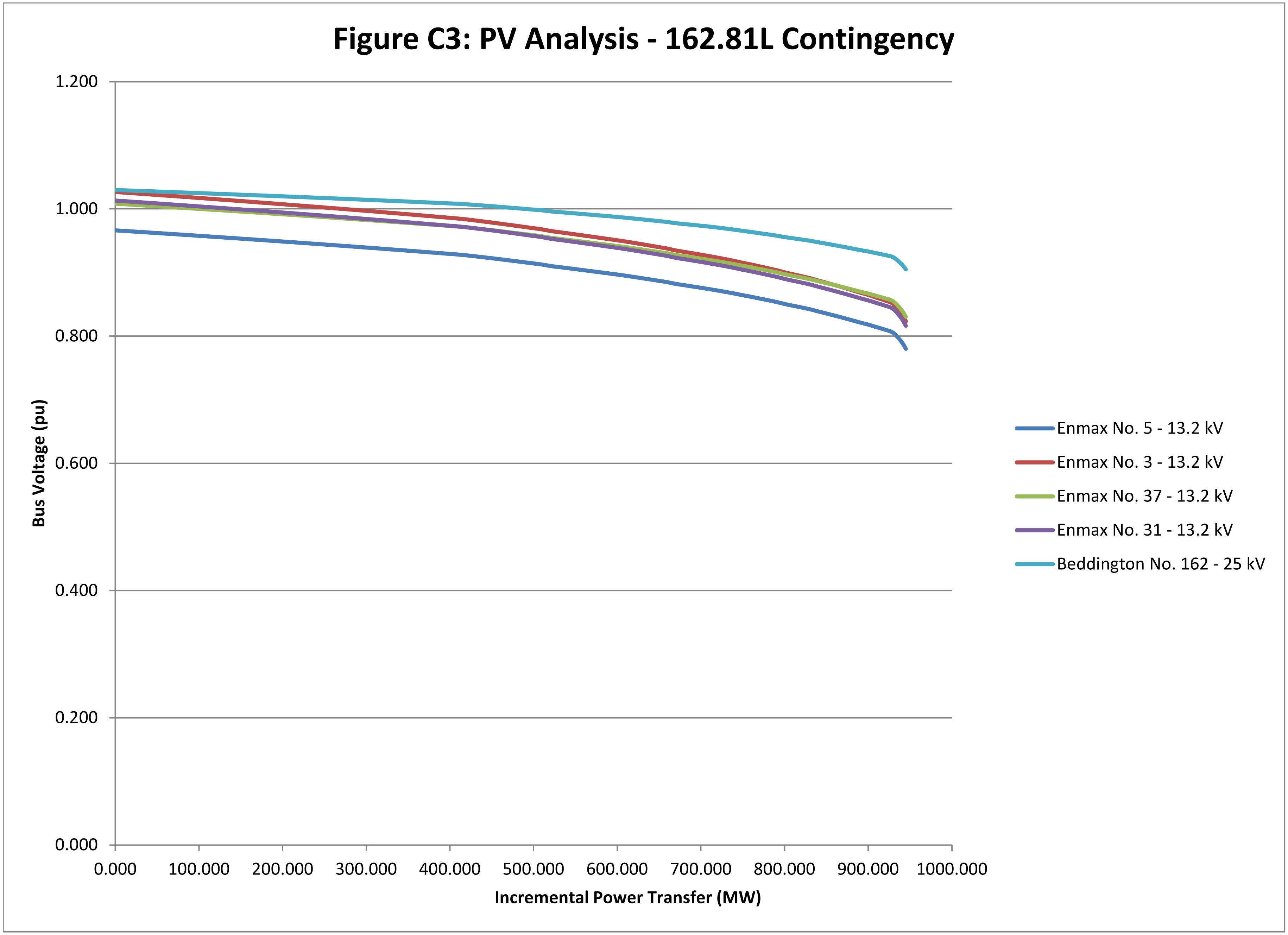
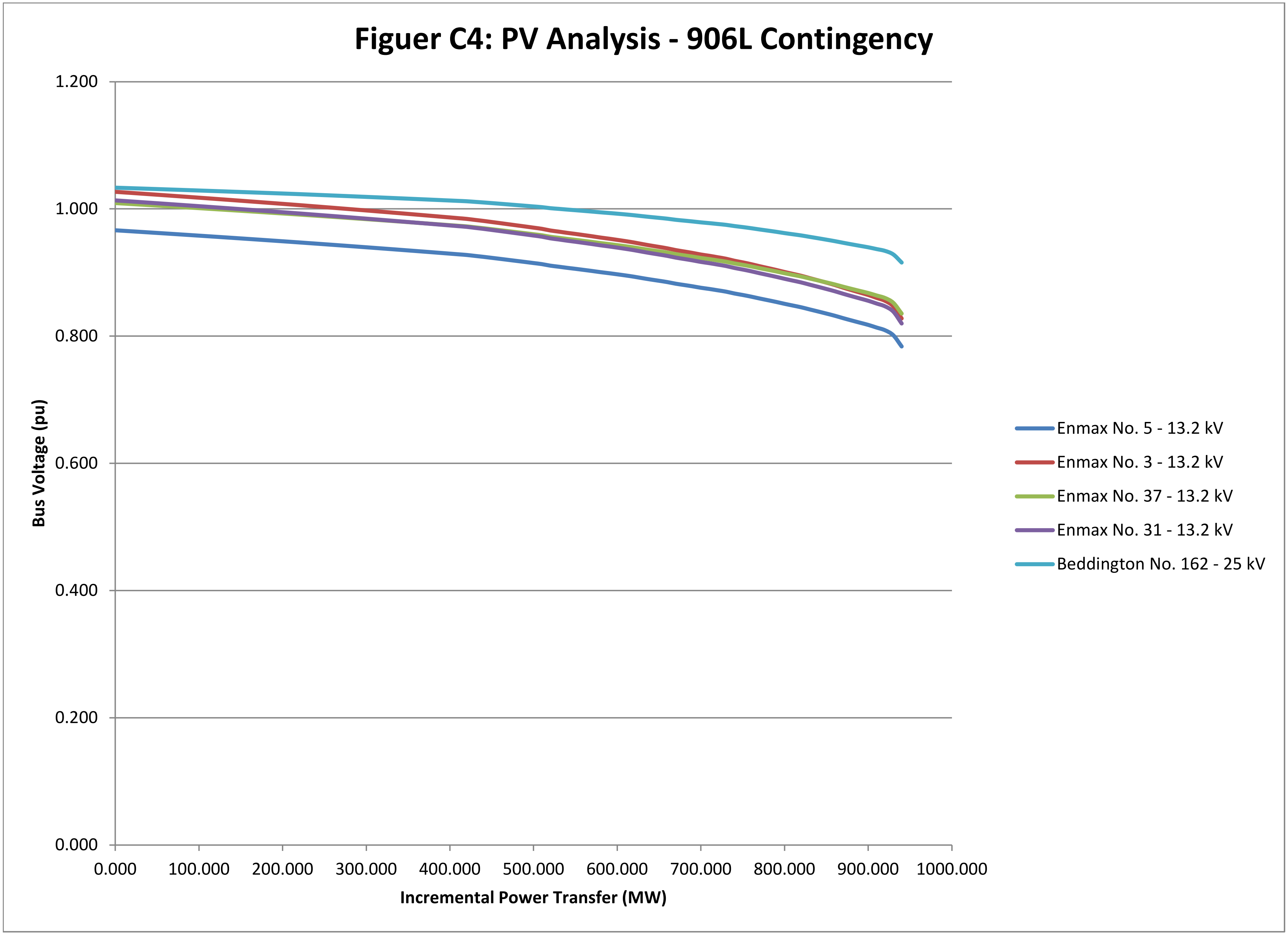


Figure C3: PV Analysis - 162.81L Contingency
1.200
1.000
0.800
0.600
0.400
0.200
0.000
Bus Voltage (pu)
0.000
100.000
200.000
300.000
400.000
500.000
600.000
700.000
800.000
900.000
1000.000
Incremental Power Transfer (MW)
Enmax No. 5 - 13.2 kV
Enmax No. 3 - 13.2 kV
Enmax No. 37 - 13.2 kV
Enmax No. 31 - 13.2 kV
Beddington No. 162 - 25 kV


Figuer C4: PV Analysis - 906L Contingency
1.200
1.000
0.800
0.600
0.400
0.200
0.000
Bus Voltage (pu)
0.000
100.000
200.000
300.000
400.000
500.000
600.000
700.000
800.000
900.000
1000.000
Incremental Power Transfer (MW)
Enmax No. 5 - 13.2 kV
Enmax No. 3 - 13.2 kV
Enmax No. 37 - 13.2 kV
Enmax No. 31 - 13.2 kV
Beddington No. 162 - 25 kV

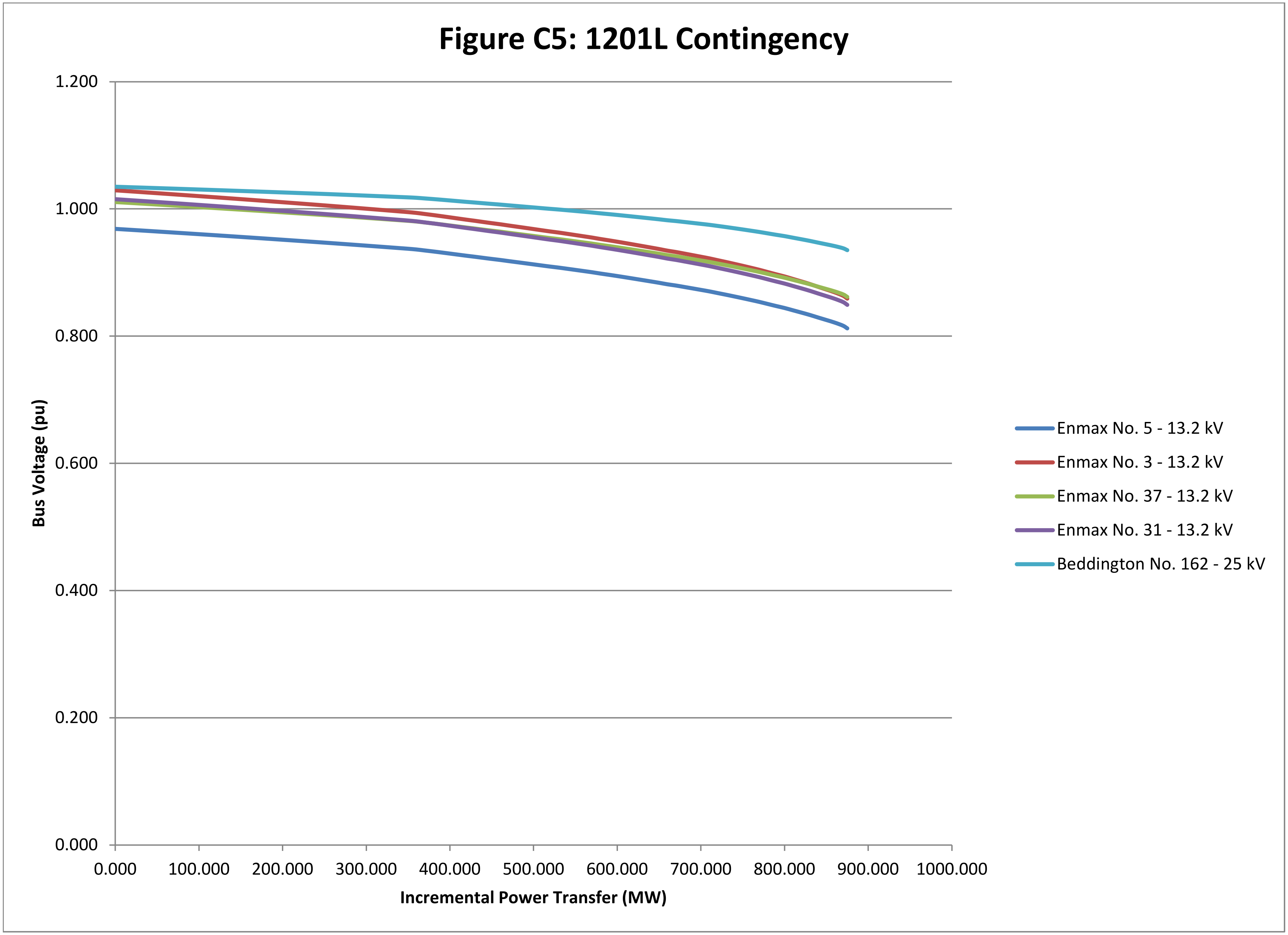


Figure C5: 1201L Contingency
Bus Voltage (pu)
1.200
1.000
0.800
0.600
0.400
0.200
0.000
0.000
100.000
200.000
300.000
400.000
500.000
600.000
700.000
800.000
900.000
1000.000
Incremental Power Transfer (MW)
Enmax No. 5 - 13.2 kV
Enmax No. 3 - 13.2 kV
Enmax No. 37 - 13.2 kV
Enmax No. 31 - 13.2 kV
Beddington No. 162 - 25 kV