APPENDIX A CONNECTION ASSESSMENT

aeso ALBERTA ELECTRIC SYSTEM OPERATOR

AESO Engineering Connection Assessment

EPCOR
Strathcona Substation Connection Enhancement

AESO Project Number: 1659

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1. Introduction

This engineering study report (ESR) presents the results of the studies conducted to assess the impact of the Project (as defined below) on the performance of the Alberta interconnected electric system (AIES).

1.1. Project

1.1.1. Project Overview

EPCOR Distribution & Transmission Inc. (EDTI), in its capacity as the legal owner of an electric distribution system (DFO), has submitted a request for system access service to the Alberta Electric System Operator (AESO) to improve the reliability of electricity services in the south Edmonton area.

The DFO's request for system access service includes a request for a Rate DTS, *Demand Transmission Service*, contract capacity increase of 13.9 MW, from 50.3 MW to 64.2 MW, for the system access service provided at the existing Strathcona substation, and a request for transmission development (collectively, the Project).

The scheduled in-service date (ISD) for the Project is October 1, 2019.

1.1.2. Load Component

- The existing Rate DTS contract capacity at Strathcona substation is 50.3MW
- The DFO has requested a Rate DTS contract capacity of 64.2 MW at Strathcona substation
- The project load was studied assuming a 0.9 power factor (pf) lagging.
- Load type: Industrial

1.1.1. Generation Component

There is no generation component associated with the Project.

1.2. Study Scope

1.2.1. Study Objectives

The objectives of the study are the following:

- Assess the impact of the Project on the performance of the AIES.

- Identify any violations of the relevant criteria, standards or requirements of the AESO, both pre-Project and post-Project.
- Evaluate Project connection alternatives and identify the AESO's preferred alternative
- Recommend mitigation measures, if required, to reliably connect the Project to the AIES.

1.2.2. Study Area

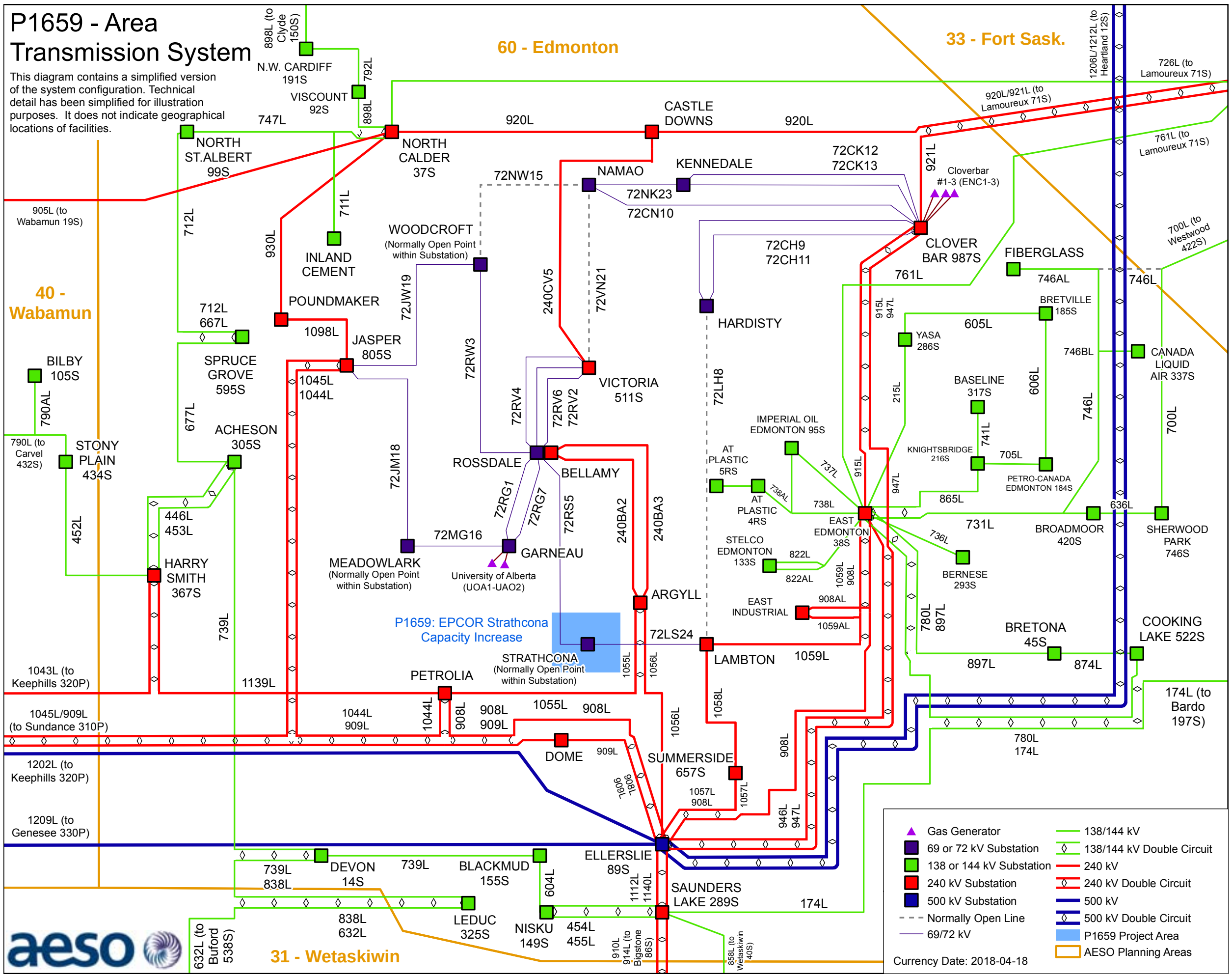
1.2.2.1. Study Area Description

Geographically, the Project is located in the AESO planning area of Edmonton (Area 60), which is part of the AESO Edmonton Planning Region. Edmonton (Area 60) is surrounded by the AESO planning areas of Fort Saskatchewan (Area 33), Athabasca/Lac La Biche (Area 27), Wabamun (Area 40), and Wetaskiwin (Area 31).

From a transmission perspective, Edmonton (Area 60) consists of 500 kV, 240 kV, 138 kV, and 72 kV transmission systems. The Strathcona substation is connected to Rossdale substation through the underground 72 kV transmission line 72RS5. 72RS5 supplies one of the 72/15 kV transformers at Strathcona substation, and the 72 kV bus tie breaker at the Strathcona substation is normally open to isolate this one transformer. Strathcona substation is also connected to Lambton substation via the overhead 72 kV transmission line 72LS24 with a summer rating of 90 MVA and winter rating of 124 MVA. 72LS24 supplies the remaining two 72/15 kV transformers at Strathcona substation.

The Study Area for the Project consists of Edmonton (Area 60) and the tie lines connecting Edmonton (Area 60) to neighbouring AESO planning areas. All 72kV and above transmission facilities within the Study Area were studied and monitored to assess the impact of the Project on the AIES, including any violations of the Reliability Criteria (as defined in Section 2.1.1).

Figure 1-1: Existing Transmission System in the Edmonton Area



1.2.2.2. Existing Constraints

Existing constraints in the Study Area are managed in accordance with the procedures set out in Section 302.1 of the ISO rules, *Real Time Constraint Management* (TCM Rule).

1.2.2.3. AESO Long-Term Transmission Plans

The *AESO 2017 Long-term Transmission Plan* (2017 LTP)[1] includes the following system developments that are in the Edmonton Planning Region in the near term (by 2020):

Development	Description
Yasa-to-East Edmonton – 138kV circuit	• Build a 138 kV circuit between the Yasa 286S and E Edmonton 38S substations
East Edmonton – transformer capacity increase	• Replace or add new transformers at the E Edmonton 38S substation
Acheson to North St. Albert – 138 kV circuit	• Build a new 138 kV circuit from the Acheson 305S substation to North St. Albert 99S substation
City of Edmonton 72 kV upgrades	• Build a new 240/72 kV transformer at Castle Downs substation and a new 240/72 kV Blatchford substation near Namao
	• Build a new 72 kV circuit from Castle Downs substation to Kennedale substation, a new 72 kV circuit from Namao substation to Kennedale substation and a new 72 kV circuit from the new Blatchford substation to Namao substation
	• Discontinue use of 72CK12 and 72CK13 from Clover Bar substation to Kennedale substation
	• Upgrade 72 kV circuit between Clover Bar–Hardisty substations and Garneau–Rossdale substations
North Calder– to– Viscount−rebuild of 138 kV line	• Rebuild 898L from North Calder substation to Viscount substation

None of the system developments described in this section are included in the studies.

1.2.3. Studies Performed

The following studies were performed for the pre-Project analysis:

- Power flow analysis

The following studies were performed for the post-Project analysis:

- Power flow analysis
- Voltage stability analysis

[1] The 2017 LTP document is available on the AESO website.

2. Criteria, System Data, and Study Assumptions

2.1. Criteria, Standards, and Requirements

2.1.1. AESO 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* [2] (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 include 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 TPL standards, TPL-001-AB-0 and TPL-002-AB-0, have referenced Applicable Ratings when specifying the required system performance under Category A and Category B events. For the purpose of applying the TPL standards to the studies documented in this report, Applicable Ratings are defined as follows:

- Seasonal continuous thermal rating of the line's loading limits.
- Highest specified loading limits for transformers.
- For Category A conditions: Voltage range under normal operating condition per AESO Information Document ID# 2010-007RS, *General Operating Practices - Voltage Control*, which relates to Section 304.4 of the ISO rules, *Maintaining Network Voltage*. For the busses not listed in ID#2010-007RS, Table 2-1 in the *Transmission Planning Criteria – Basis and Assumptions* applies.
- For Category B conditions: The extreme voltage range values per Table 2-1 in the *Transmission Planning Criteria – Basis and Assumptions*.

[2] Filed under a separate cover

- Desired post-contingency voltage change limits for three defined post event timeframes as provided in Table 2-1, below

Table 2-1: Post-Contingency Voltage Deviations 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. ISO Rules and Information Documents

AESO ID# 2010-007RS was applied to establish pre-contingency voltage profiles in the Study Area.

The TCM Rule was followed in setting up the study scenarios and in assessing the impact of the Project. The Reliability Criteria is the basis for planning the AIES. In addition, due regard was given to the AESO's *Connection Study Requirements* Document and the AESO's *Generation and Load Interconnection Standard*

2.2. Study Scenarios

The scheduled ISD for the Project is October 1, 2019. Therefore, the studies were performed using the 2020 summer peak (SP) and 2020 winter peak (WP) scenarios.

Table 2-2 provides a list of the study scenarios. The post-Project scenarios include the DFO-requested Rate DTS contract capacity of 64.2 MW. This connection assessment assumed a 0.9 lagging power factor for the Project load.

Table 2-2: List of the Connection Study Scenarios

Scenario	Year/Season Load	Condition	Project Load (MW)	Project Generation (MW)	System Generation Dispatch Conditions
1	2020SP	Pre-Project	50.3	0	Economic Dispatch
2	2020WP	Pre-Project	50.3	0	Economic Dispatch
3	2020SP	Post-Project	64.2	0	Economic Dispatch
4	2020WP	Post-Project	64.2	0	Economic Dispatch

2.3. Load and Generation Assumptions

2.3.1. Load Assumptions

The Study Area and AESO Planning Region load forecast used for this connection study are reflected in Table 2-3 and are based on the *AESO 2017 Long-term Outlook* (2017 LTO) at Edmonton Region Peak. For the studies, when POD loads for the Alberta internal load (AIL) were modified to align with the load forecast from the 2017 LTO, the active power to reactive power ratio in the base case scenarios was maintained.

Table 2-3: Forecast Area Load *(2017 LTO at Edmonton Region Peak)*

AESO Planning Area or Region Name	Season	Forecast Peak Load (MW)
Edmonton	2020 SP	2350
	2020 WP	2343

2.3.2. Generation Assumptions

The generation assumptions for the studies are based on the 2017 LTO. The dispatch assumptions used for the existing generating units in the vicinity of the Study Area are shown in Table 2–4.

The University of Alberta Cogen generators are considered to be the critical generating units for the purpose of the studies, and are assumed to be offline for the power flow and voltage stability analyses.

Table 2-4: Existing Local Generation (MW) in the Study Area

Unit Name	Bus Number	Area	Pmax (MW)	2020 SP Unit Net Generation[a] (MW)	2020 WP Unit Net Generation[a] (MW)
Sundance #1	129	40	280	Retired	Retired
Sundance #2	130	40	280	Retired	Retired
Sundance #3	338	40	368	322	286
Sundance #4	342	40	406	Mothballed	Mothballed
Sundance #5	345	40	406	348	340
Sundance #6	350	40	401	297	311
Keephills #1	422	40	395	341	348
Keephills #2	424	40	395	353	345
Keephills #3	403	40	463	411	393
Genesee #1	491	40	400	393	375
Genesee #2	492	40	400	389	378
Genesee #3	490	40	466	451	442
Cloverbar #1	25516	60	48	0	0
Cloverbar #2	26516	60	101	0	0

Unit Name	Bus Number	Area	Pmax (MW)	2020 SP Unit Net Generation[a] (MW)	2020 WP Unit Net Generation[a] (MW)
Cloverbar #3	27516	60	101	0	0
University of Alberta	25352	60	39	N-G[b]	N-G[b]

[a] "Unit Net Generation" refers to gross generating unit output (MW) less unit service load.

[b] "N-G" indicates the critical generating unit that is assumed by the AESO to be offline to test the N-G contingency condition

All the generation dispatch shown as "0" means the generating unit is not in-merit based on forecasted economic merit order. For the sake of the studies, these units are assumed off-line.

2.3.3. Intertie Flow Assumptions and HVDC Assumptions

The Alberta-BC, Alberta-Montana, and Alberta-Saskatchewan intertie points are deemed to be too far away to have any material impact on the connection assessment for the Project. Therefore, the intertie flows were dispatched the same as in the AESO's base cases.

The Western Alberta Transmission HVDC Line (WATL) and the Eastern Alberta Transmission HVDC Line (EATL) assumptions were expected to have minimal impact for the connection studies. Therefore, HVDC assumptions are kept consistent with that in the AESO planning base cases and not adjusted for this study.

2.4. System Projects

No system projects in the Edmonton planning area as part of the *AESO 2017 Long-Term Transmission Plan* were included in the study scenarios.

2.5. Connection Projects

No connection projects were included in the study scenarios.

2.6. Facility Ratings and Shunt Elements

The legal owners of transmission facilities (TFOs) provided the thermal ratings assumptions for the existing transmission facilities in the Study Area.The ratings of key transmission lines and key transformers are shown in Table 2-5 and Table 2-6.

Table 2-5: Thermal Rating Assumptions for Key Transmission Lines in the Study Area

Line ID	Line Description	Voltage Class (kV)*	Normal Rating (MVA)		Emergency Rating (MVA)	
			Summer	Winter	Summer	Winter
72RS5	Rossdale-Strathcona	72	25	25	70	73
72RG1	Rossdale-Garneau	72	60	60	65	65

Line ID	Line Description	Voltage Class (kV)*	Normal Rating (MVA)		Emergency Rating (MVA)	
			Summer	Winter	Summer	Winter
72RG7	Rossdale-Garneau	72	80	80	90	90
72LH8	Lambton-Hardisty	72	90	124	105	135
72LS24	Lambton-Strathcona	72	90	124	105	135
72CH11	Hardisty-Cloverbar	72	40	40	80	80
72CK12	Cloverbar-Kennedale	72	48	56	64	68
72CK13	Cloverbar-Kennedale	72	48	56	64	68
1055L	Petrolia-Argyll	240	419	517	419**	517**
1056L	Ellerslie-Argyll	240	419	517	419**	517**
1058L	Summerside-Lambton	240	499	499	499	499
1059L	Lambton-East Edmonton	240	499	499	499	499
240BA2**	Argyll-Bellamy	240	400	479	473**	540**
240BA3**	Argyll-Bellamy	240	400	479	473**	540**

* Ratings for 72kV facilities in the study cases have been converted to MVA ratings based on 69 kV.

** If one of 240BA2 or 240BA3 is out of service, the continuous rating of the remaining cable increases to 453 MVA in summer and 534 MVA in winter.

Table 2-6: Summary of key transformers in the Study Area

Substation Name and Number	Transformer ID	Transformer Voltages (kV)	Rating (MVA)
Heartland 12S	T1	500/240	1200
Ellerslie 89S	T1	500/240	1200
Ellerslie 89S	T2	500/240	1200
Lambton	T3	240/72	80

The TFOs provided the details of the shunt elements in the Study Area, as shown in Table 2-7.

Table 2-7: 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)
East Edmonton 38S	138	2 x 48.91 MVAr	97.82
Leduc 325S	138	1 x 30 MVAr	30.0
Nisku 149S	138	1 x 30 MVAr	30.0

Substation Name and Number	Voltage Class (kV)	Capacitors	
		Number of Switched Shunt Blocks	Total at Nominal Voltage (MVAr)
Acheson 305S	138	1 x 24.46 MVAr	24.46
Jasper	240	1 x 105.31 MVAr	105.31
Rossdale	69	2 x 47.76	95.51
Cloverbar	69	1 x 31.57	31.57
Stelco Edmonton 133S	34.5	1 x 16.8 + 1 x 30 MVAr	46.8

2.7. Voltage Profile Assumptions

ID #2010-007RS is used to establish normal system (i.e. pre-contingency) voltage profiles for key area busses prior to commencing any studies. Table 2-1 of the Transmission Planning Criteria – Basis and Assumptions applies for all the busses not included in ID #2010-007RS. These voltages were used to set the voltage profile for the study base cases prior to power flow studies.The key bus voltages for the Study Area for the project are shown inTable 2-8.

Table 2-8: Summary of the Voltage Operating Ranges at Key Nodes in the Study Area

Substation	Nominal Voltage (kV)	Minimum Operating Limit (kV)	Desired Range (kV)	Maximum Operating Limit (kV)
Genesee 330P	500	518	525 – 540	550
	138	124	124 – 152	152
Lambton 803S	240	240	245 – 254	255
East Edmonton 38S	240	240	240 – 253	255
	138	139	139 – 144	145
Jasper Terminal 805S	240	240	245 – 254	255
Petrolia 816S	240	240	245 – 254	255
Clover Bar 987S	240	240	245 – 254	255

3. Study Methodology

The analyses performed in this connection assessment were completed using PTI PSS/E version 33.

3.1. Connection Studies Carried Out

The studies to be carried out for this connection study are identified in Table 3-1.

Table 3-1: Summary of Studies Performed

Scenario and Condition		System Conditions	Power Flow	Voltage Stability
1	2020 SP Pre-Project	Category A and Category B	X	-
2	2020 WP Pre-Project	Category A and Category B	X	-
3	2020 SP Post-Project	Category A and Category B	X	-
4	2020 WP Post-Project	Category A and Category B	X	X

3.2. Power Flow Studies

Pre-Project and post-Project power flow studies were performed to identify thermal and voltage criteria violations as per the Reliability Criteria, and any deviations from the limits listed in Table 2-1. The purpose of the power flow analysis is to quantify any incremental violations in the Study Area after the Project is connected. For the Category B power flow studies, the transformer taps and switched shunt reactive compensating devices such as shunt capacitors and reactors were locked and continuous shunt devices were enabled.

Point-of-delivery (POD) low voltage bus deviations were assessed for both the pre-Project and post-Project networks by first locking all tap changers and area shunt reactive compensating devices to identify any post transient voltage deviations above 10%. Second, tap changers were allowed to move while shunt reactive compensating devices remained locked to determine if any voltage deviations above 7% would occur in the area. Third, all the taps and shunt reactive compensating devices were allowed to adjust, and voltage deviations above 5%, if any, were reported.

3.2.1. Contingencies Studied

The power flow studies were performed for all Category B contingencies (72 kV facilities and above) within the Study Area. All transmission facilities in the Study Area were monitored for Reliability Criteria violations.

3.3. Voltage Stability (PV) Analysis

The objective of the voltage stability studies is to determine the ability of the network to maintain voltage stability at all the busses in the system under normal and abnormal system conditions. The power-voltage (PV) curve represents voltage change as a result of increased power transfer between two systems. The incremental transfers are reported at the collapse point.

Voltage stability studies were performed for post-Project scenarios. For load connection projects, the load level modelled in post-Project scenarios is the same or higher than in pre-Project scenarios. Therefore, voltage stability studies for pre-Project scenarios would only be performed if the 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 established planned load.

Typically, voltage stability analysis is carried out assuming the worst case scenarios in terms of loading. The voltage stability analysis was performed by increasing load in Edmonton area (Area 60) and by increasing the corresponding generation in Fort McMurray (Area 25).

3.3.1. Contingencies Studied

Voltage stability analysis was performed for the Category A condition and all Category B contingencies (240kV facilities only) in the Study Area for the 2020 WP post-Project scenario.

4. Pre-Project System Assessment

4.1. Power Flow

This section describes the results of the pre-Project power flow studies. The pre-Project power flow diagrams are provided in Attachment A.

4.1.1. Scenario 1 - Pre-Project 2020 SP

Category A condition

No Reliability Criteria violations were observed under the Category A condition.

Category B conditions

No voltage criteria violations or voltage deviations beyond the limits listed in Table 2-1 (hereafter referred to as, point of delivery (POD) bus voltage deviations) were observed under Category B conditions.

Thermal criteria violations were observed under Catgeory B conditions as shown in Table 4-1.

Table 4-1: Thermal Criteria Violations under Category B Conditions for the 2020 SP Pre-Project Scenario

Contingency (System Element Lost)	Details of Violation (Violation Observed On)	Normal Thermal Rating (MVA)	Emergency Thermal Rating (MVA)	Pre-Project Results	
				Observed Power Flow (MVA)	% Loading
72CH9 (Hardisty - Cloverbar)	72CH11 (Hardisty - Cloverbar)	38.3	76.7	66.37	169.37
72CH11 (Hardisty - Cloverbar)	72CH9 (Hardisty - Cloverbar)	38.3	76.7	66.38	169.37
72CK13 (Cloverbar - Kennedale)	72CK12 (Cloverbar - Kennedale)	46	65.2	63.47	133.32
72CK12 (Cloverbar - Kennedale)	72CK13 (Cloverbar - Kennedale)	46	65.2	63.47	133.32
72RG7 (Rossdale - Garneau)	72RG1 (Rossdale - Garneau)	57.5	62.3	96.13	161.67
72RG1 (Rossdale - Garneau)	72RG7 (Rossdale - Garneau)	76.7	86.3	96.18	121.02
72LS24 (Strathcona - Lambton)	72RS5 (Rossdale - Strathcona)	24	70	56.5	229.4*
Lambton Transformer T3	72RS5 (Rossdale - Strathcona)	24	70	55.9	226.91*

*These overloads are only observed when breaker S722 at Strathcona is closed to restore load through 72RS5

4.1.2. Scenario 2 – Pre-Project 2020 WP

Category A condition

No Reliability Criteria violations were observed under the Category A condition.

Category B conditions

No voltage criteria violations or POD bus voltage deviations were observed under Category B conditions.

Thermal criteria violations were observed under Catgeory B conditions as shown in Table 4-2.

Table 4-2: Thermal Criteria Violations under Category B Conditions for the 2020 WP Pre-Project Scenario

Contingency (System Element Lost)	Details of Violation (Violation Observed On)	Normal Thermal Rating (MVA)	Emergency Thermal Rating (MVA)	Pre-Project Results	
				Observed Power Flow (MVA)	% Loading
72CH9 (Hardisty to Cloverbar)	72CH11 (Hardisty to Cloverbar)	38.3	76.7	65.8	166.92
72CH11 (Hardisty to Cloverbar)	72CH9 (Hardisty to Cloverbar)	38.3	76.7	65.82	166.92
72CK13 (Cloverbar to Kennedale)	72CK12 (Cloverbar to Kennedale)	53.7	65.2	62.46	111.76
72CK12 (Cloverbar to Kennedale)	72CK13 (Cloverbar to Kennedale)	53.7	65.2	62.45	111.76
72RG7 (Rossdale to Garneau)	72RG1 (Rossdale to Garneau)	62.3	62.3	79.3	122.79
72LS24 (Strathcona to Lambton)	72RS5 (Rossdale to Strathcona)	24	70	55.12	223.16*
LambtonT3 (Lambton)	72RS5 (Rossdale to Strathcona)	24	70	54.72	221.49*

*These overloads are only observed when breaker S722 at Strathcona is closed to restore load through 72RS5

5. Connection Alternatives

5.1. Overview

The AESO, in consultation with the legal owner of transmission facilities (TFO) in the Study Area, and the DFO, examined five transmission alternatives to meet the DFO's request for system access service.

5.2. Connection Alternatives Identified

Alternative 1: Replace the existing 72 kV circuit 72RS5 between the existing Rossdale and Strathcona substations

Alternative 1 involves replacing the existing underground 72 kV circuit that connects the existing Rossdale and Strathcona substations (72RS5) with new 72kV circuit of higher capacity. The TFO has advised that the new circuit would also be routed underground. The existing 72 kV circuit 72RS5 (Rossdale-Strathcona) would be discontinued from use. The TFO has advised that the new 72 kV underground circuit would be approximately 5.5 km in length.

Alternative 2: Add a 72 kV circuit between the existing Lambton and Strathcona substations and upgrade the Lambton substation

Alternative 2 involves adding one 72 kV circuit between the existing Lambton and Strathcona substations. The TFO has advised that the new 72 kV circuit would be an overhead circuit. Alternative 2 also involes upgrading the existing Lambton substation, including adding one 240/72 kV transformer, one 240 kV circuit breaker, four 72 kV circuit breaker and associated equipment. The existing 72 kV circuit 72RS5 would be discontinued from use. The TFO has advised that the new 72 kV circuit would be approximately 6.5 km in length.

Note also in this alternative, Strathcona 72 kV breaker S722 would be closed to reduce the frequency of forced interruptions at Strathcona substation.

Alternative 3: Upgrading the existing Argyll substation

Alternative 3 involves upgrading the existing Argyll 240 kV substation, including adding three 240/14.4 kV transformers, eleven 240 kV circuit breakers, eighteen 15 kV circuit breakers and associated equipment. The existing Strathcona substation, existing 72 kV circuit 72RS5, and the existing 72 kV circuit 72LS24 that connects Strathcona substation to Lambton substation would be discontinued from use.

The DFO has advised that all distribution feeders supplied by the existing Strathcona substation would be re-routed to connect to the upgraded Argyll substation.

Alternative 4: Add one 72kV circuit between Dome and Strathcona substations

Alternative 4 involves adding one 72 kV circuit between Dome and Strathcona substations. The TFO has advised that the new 72 kV circuit would be an overhead circuit. Alternative 4 also involves upgrading the existing Dome substation, incuding adding one 240/72 kV transformer, one 240 kV circuit breaker, one 72 kV circuit breaker and associated equipment. The existing 72 kV circuit 72RS5 would be discontinued from use. The TFO has advised that the new 72 kV circuit would be approximately 4.5 km in length.

Note also in this alternative, Strathcona 72 kV breaker S722 would be closed to reduce the frequency of forced interruptions at Strathcona substation.

5.2.1. Connection Alternatives Selected for Further Study

Alternative 4 was selected for further study.

5.2.2. Connection Alternatives Not Selected for Further Study

Alternatives 1, 2, and 3 would all involve more overall development, and hence overall increased cost, compared to Alternative 4. Therefore, Alternatives 1, 2 and 3 were not selected for further study.

6. Technical Analysis of the Connection Alternative

This section describes the results of the post-Project power flow studies and voltage stability studies.

6.1. Power Flow Study Results

The post-Project power flow diagrams are provided in Attachment C.

6.1.1. Scenario 3- Post-Project 2020 SP

Category A condition

No Reliability Criteria violations were observed under the Category A condition.

Category B conditions

No voltage criteria violations or POD bus voltage deviations were observed under Category B conditions.

The same thermal criteria violations that were observed under Category B contingency conditions in the pre-Project study scenarios were also observed in the post-Project scenarios, as shown in Table 6-1.

Table 6-1: Thermal Criteria Violations under Category B Conditions for the 2020 SP Post-Project Scenario

Contingency (System Element Lost)	Details of Violation (Violation Observed On)	Normal Thermal Rating (MVA)	Emergency Thermal Rating (MVA)	Pre-Project Results		Post-Project Results		% Loading Difference (Post-Pre)
				Power Flow (MVA)	% Loading	Power Flow (MVA)	% Loading	
72CH9 (Hardisty to Cloverbar)	72CH11 (Hardisty to Cloverbar)	38.3	76.7	66.37	169.37	66.38	169.56	0.19
72CH11 (Hardisty to Cloverbar)	72CH9 (Hardisty to Cloverbar)	38.3	76.7	66.38	169.37	66.39	169.56	0.19
72CK13 (Cloverbar to Kennedale)	72CK12 (Cloverbar to Kennedale)	46	65.2	63.47	133.32	63.48	133.47	0.15
72CK12 (Cloverbar to Kennedale)	72CK13 (Cloverbar to Kennedale)	46	65.2	63.47	133.32	63.47	133.47	0.15
72RG7 (Rossdale to Garneau)	72RG1 (Rossdale to Garneau)	57.5	62.3	96.13	161.67	96.1	161.4	-0.27
72RG1 (Rossdale to Garneau)	72RG7 (Rossdale to Garneau)	76.7	86.3	96.18	121.02	96.15	120.81	-0.21

6.1.2. Scenario 4- Post-Project 2020 WP

Category A condition

No Reliability Criteria violations were observed under the Category A condition.

Category B conditions

No voltage criteria violations or POD bus voltage deviations were observed under Category B conditions.

The same thermal criteria violations that were observed under Category B contingency conditions in the pre-Project study scenarios were also observed in the post-Project scenarios, as shown in Table 6-2.

Table 6-2: Thermal Criteria Violations under Category B Conditions for the 2020 WP Post-Project Scenario

Contingency (System Element Lost)	Details of Violation (Violation Observed On)	Normal Thermal Rating (MVA)	Emergency Thermal Rating (MVA)	Pre-Project Results		Post-Project Results		% Loading Difference (Post-Pre)
				Load Flow (MVA)	% Loading	Load Flow (MVA)	% Loading	
72CH9 (Hardisty to Cloverbar)	72CH11 (Hardisty to Cloverbar)	38.2	76.5	65.8	166.92	65.81	167.49	0.57
72CH11 (Hardisty to Cloverbar)	72CH9 (Hardisty to Cloverbar)	38.2	76.5	65.82	166.92	65.82	167.49	0.57
72CK13 (Cloverbar to Kennedale)	72CK12 (Cloverbar to Kennedale)	53.7	65.2	62.46	111.76	62.46	111.85	0.09
72CK12 (Cloverbar to Kennedale)	72CK13 (Cloverbar to Kennedale)	53.7	65.2	62.45	111.76	62.46	111.85	0.09
72RG7 (Rossdale to Garneau)	72RG1 (Rossdale to Garneau)	62.3	62.3	79.3	122.79	79.29	122.65	-0.14

6.2. Voltage Stability Study Results

Voltage stability analysis was performed for the post-Project 2020 WP scenerio. The reference load level for the Study Area is 2343 MW. To meet the voltage stability criteria, the minimum incremental load transfer for the Category B contingencies is 5.0% of the reference load or 101 MW.

Table 6-3 below summarizes the voltage stability results for Category A and the five worst contingencies (major 240 kV transmission lines) for voltage stability transfer margins. Voltage stability diagrams are provided in Attachment 4.

The voltage stability margin was met for all studied conditions.

Table 6-3: Voltage Stability Results for the 2020 WP Post-Project Scenario

Contingency	From	To	Maximum incremental transfer (MW)	Meets 105% transfer criteria?
N-G-0	System Normal		1256.25	Yes
1045L	Jasper	Sundance 310P	1175.00	Yes
1043L	Keephills	Harry Smith 367S	1181.25	Yes
1056L	Ellerslie 89S	Argyll/Bellamy*	1228.13	Yes
1139L	Petrolia	Harry Smith 367S	1235.16	Yes
909L	Sundance 310P	Dome	1249.22	Yes

* Argyll is a transfer station without any circuit breaker.

7. Results Analysis and Mitigation Measures

The Reliability Criteria violations observed during the connection assessment studies and the associated mitigation measures are summarized in Table 7-1. Under certain Category B conditions, thermal criteria violations were observed in the pre-Project and post-Project scenarios.

Table 7-1: Mitigation Measures for Thermal Criteria Violations under Category B Conditions for 2020 SP and 2020 WP Pre Project and Post-Project Scenarios

<table>
<tr><th colspan="4">Identified Reliability Criteria Violations</th><th rowspan="2">Project Impact</th><th rowspan="2">Year/ Season Load</th><th rowspan="2">Mitigation Measures (Pre-Project and Post-Project)</th></tr>
<tr><th>Type</th><th>Violation</th><th>Contingency</th><th>Occurrence (Pre-Project and/or Post-Project Scenarios)</th></tr>
<tr><td rowspan="8">Thermal</td><td>72RG1 (Rossdale to Garneau)</td><td>72RG7 (Rossdale to Garneau)</td><td rowspan="6">Pre-Project and Post-Project</td><td>Marginally reduced*</td><td>2020SP</td><td rowspan="6">Real-time operational practices</td></tr>
<tr><td>72RG7 (Rossdale to Garneau)</td><td>72RG1 (Rossdale to Garneau)</td><td>Marginally reduced*</td><td rowspan="7">2020 SP
2020 WP</td></tr>
<tr><td>72CH11 (Clover Bar to Hardisty)</td><td>72CH9 (Clover Bar to Hardisty)</td><td>Marginally increased**</td></tr>
<tr><td>72CH9 (Clover Bar to Hardisty)</td><td>72CH11 (Clover Bar to Hardisty)</td><td>Marginally increased**</td></tr>
<tr><td>72CK12 (Clover Bar to Kennedale)</td><td>72CK13 (Clover Bar to Kennedale)</td><td>Marginally increased**</td></tr>
<tr><td>72CK13 (Clover Bar to Kennedale)</td><td>72CK12 (Clover Bar to Kennedale)</td><td>Marginally increased**</td></tr>
<tr><td rowspan="2">72RS5 (Rossdale to Strathcona*</td><td>72LS24 (Strathcona to Lambton)</td><td rowspan="2">Pre-Project</td><td rowspan="2">N/A</td><td rowspan="2">Real-time operational practices (Pre-Project only)</td></tr>
<tr><td>LambtonT3</td></tr>
</table>

*Marginally reduced indicates post-Project loading is less than pre-Project loading by less than 3%

**Marginally increased indicates post-Project loading is more than pre-Project loading by less than 3%

Thermal loading above the normal rating 72 kV transmission lines is currently being managed using real-time operational practices. Real-time operational practices can continue to be used to effectively manage these thermal overloads.

8. Project Dependencies

The Project does not require the completion of any AESO plans to expand or enhance the transmission system prior to connection.

9. Conclusion and Recommendations

Based on the study results, Alternative 4 is technically viable. The connection assessment identified pre-Project and post-Project system performance issues. These system performance issues can be managed using real-time operational practices. With the implementation of this mitigation measure, the connection of the project with the proposed alternative will not adversely affect the performance of the AIES.

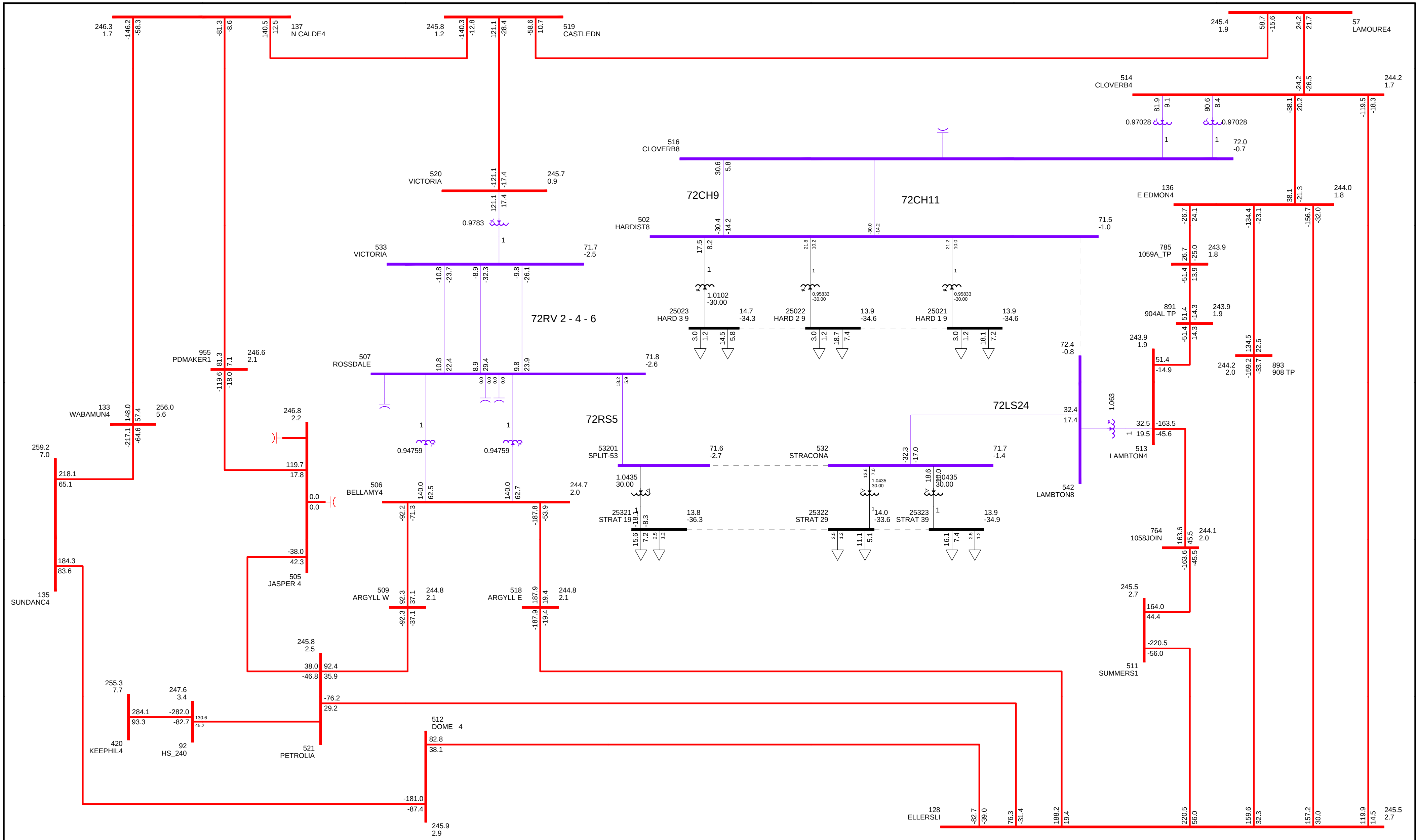
It is recommended to proceed with the Project using Alternative 4 as the preferred option to respond to the DFO's request for system access service. Alternative 4 involves adding one 72 kV circuit between Dome and Strathcona substations. Alternative 4 also involves upgrading the existing Dome substation, incuding adding one 240/72 kV transformer, one 240 kV circuit breaker, one 72 kV circuit breaker and associated equipment. The existing 72 kV circuit 72RS5 would be discontinued from use. It is also recommended to continue to use real-time operational practices to manage the identified system performance issues.

Based on the engineering connection assessment with the requested Rate DTS and proposed transmission development, a minimum transmission line rating of 82 MVA is recommended for the 72 kV circuit between Dome and Strathcona substations and a minimum transformer rating of 82 MVA is recommended for the 240/72 kV transformer at the Dome substation.

Attachment A

Power Flow Diagrams

2020SP/2020WP Pre-Project

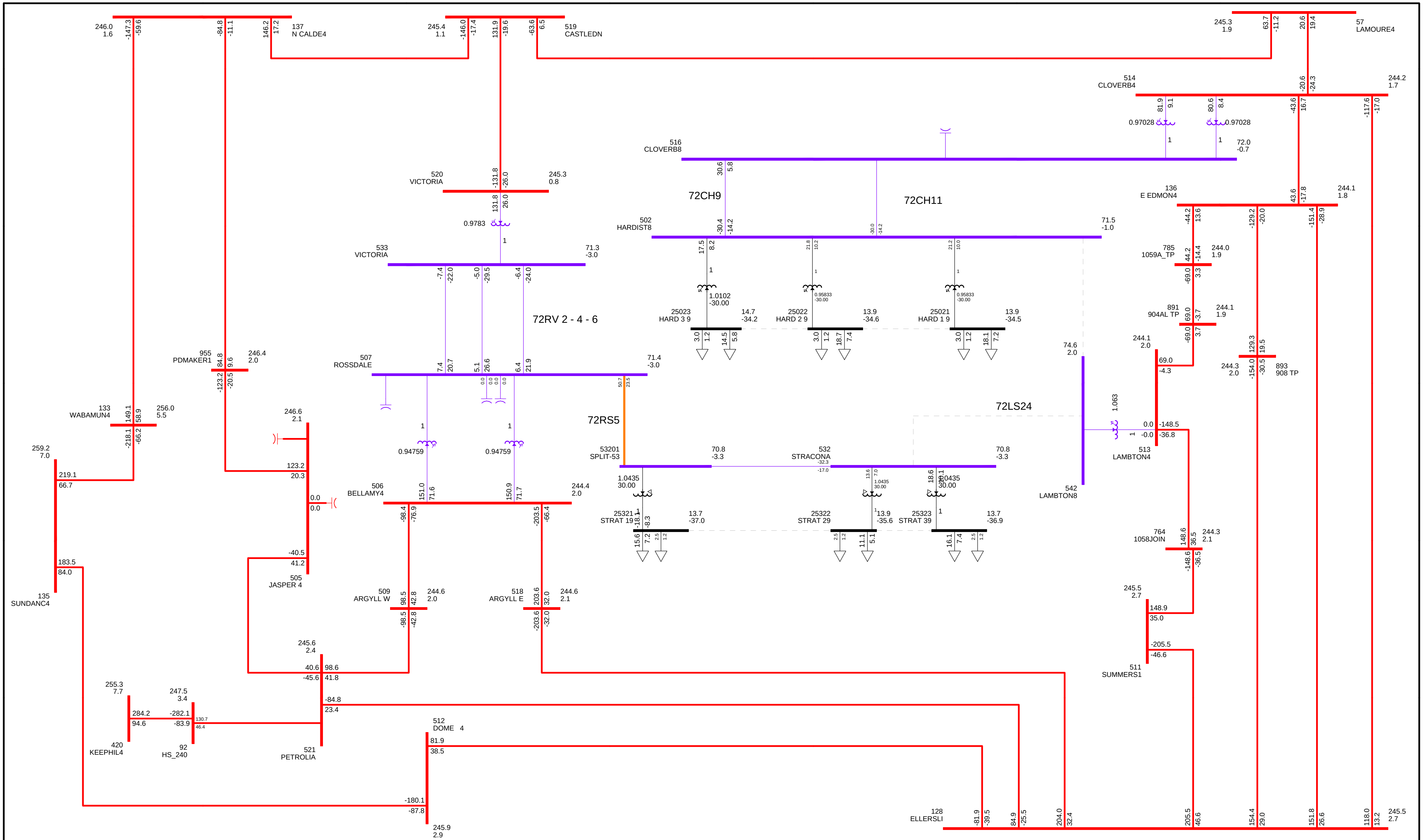


2019SP PRE-PROJECT
BASE CASE (N-0)
FIG A-1
FRI, JUN 01 2018 17:13

Load at Strathcona: 50.3 MW 23.2 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

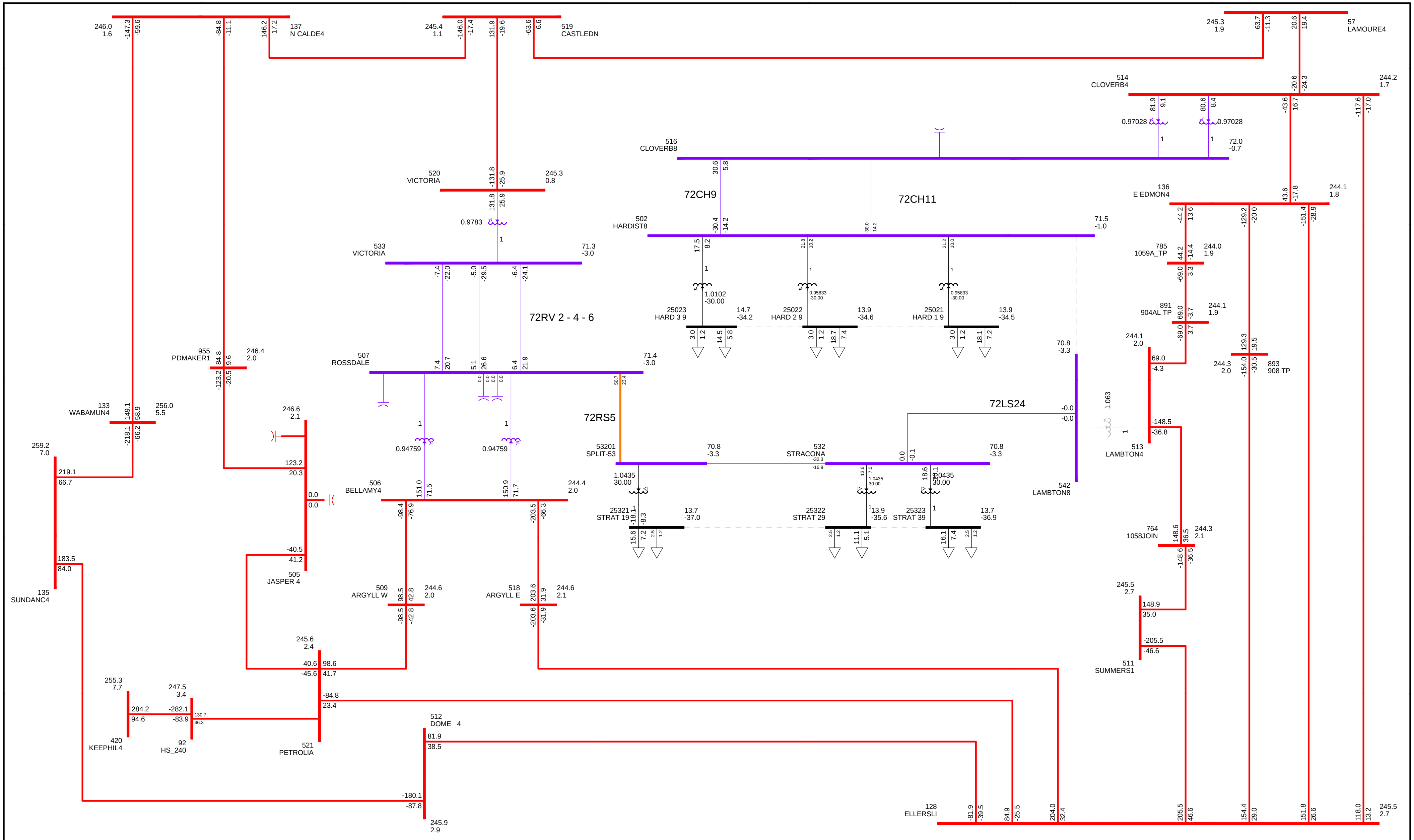


2019SP PRE-PROJECT
72LS24 (N-1)
FIG A-2
FRI, JUN 01 2018 17:13

Load at Strathcona: 50.3 MW 23.2 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

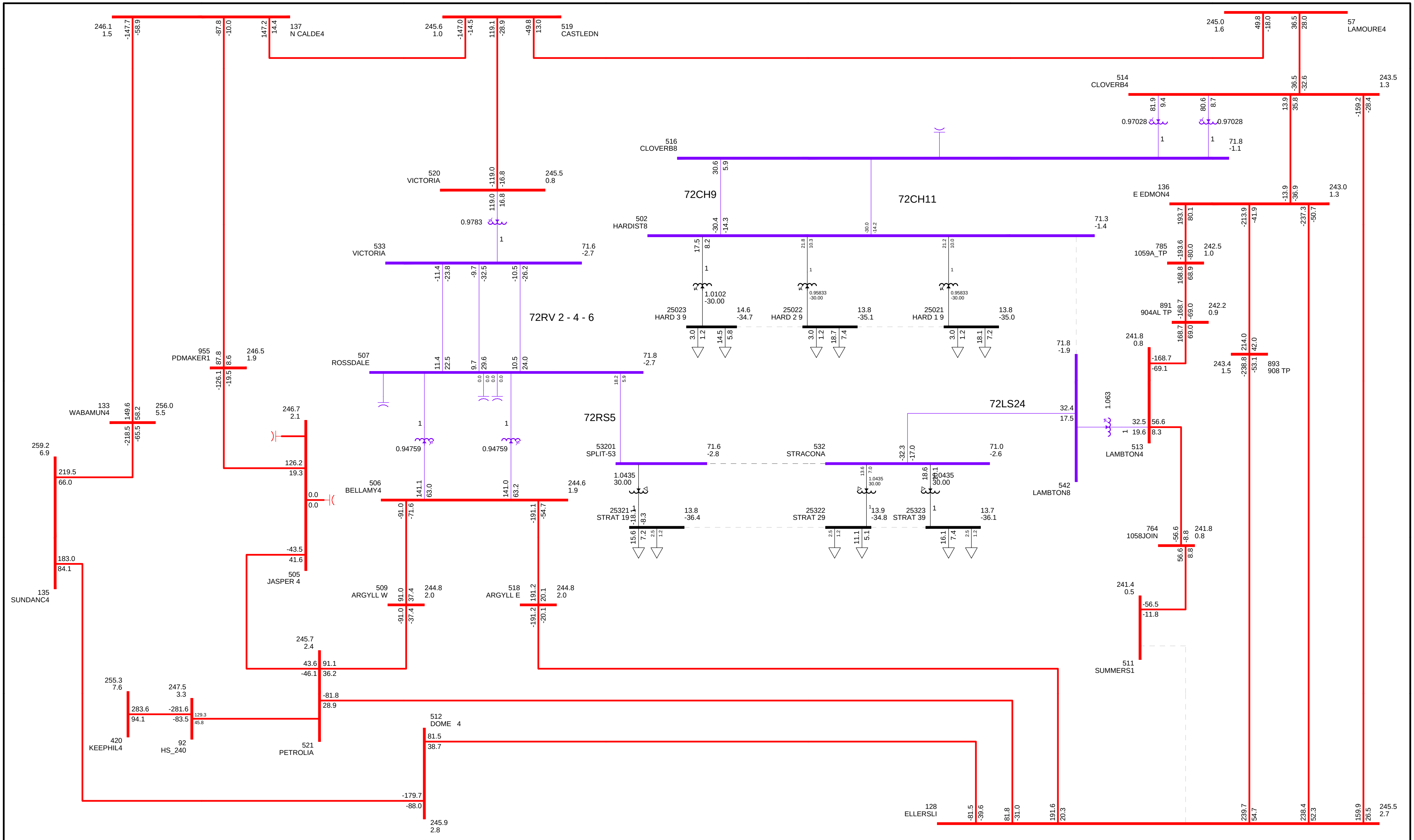


2019SP PRE-PROJECT
LAMBTONT3 (N-1)
FIG A-3
FRI, JUN 01 2018 17:13

Load at Strathcona: 50.3 MW 23.2 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

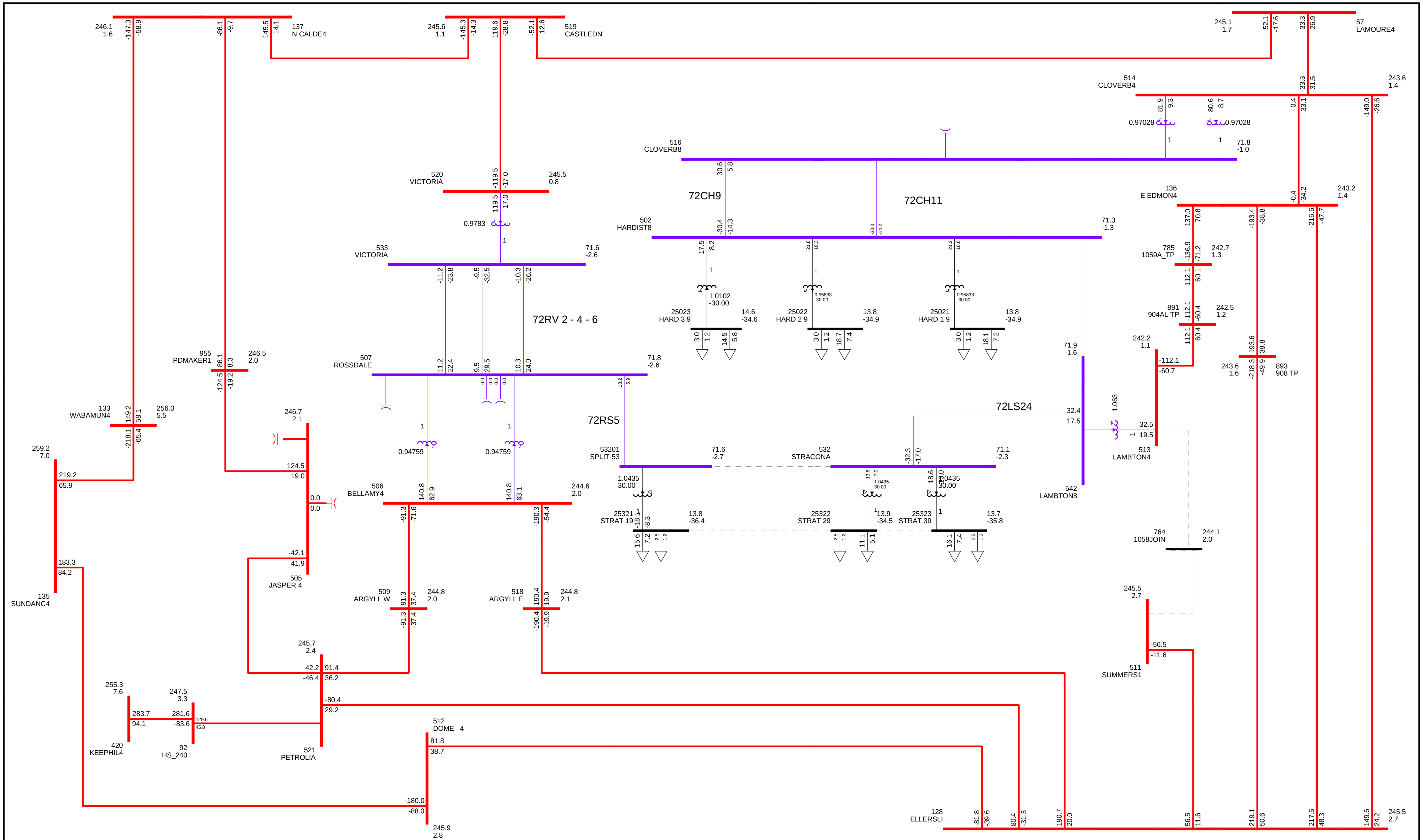


2019SP PRE-PROJECT
1057L (N-1)
FIG A-4
FRI, JUN 01 2018 17:13

Load at Strathcona: 50.3 MW 23.2 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

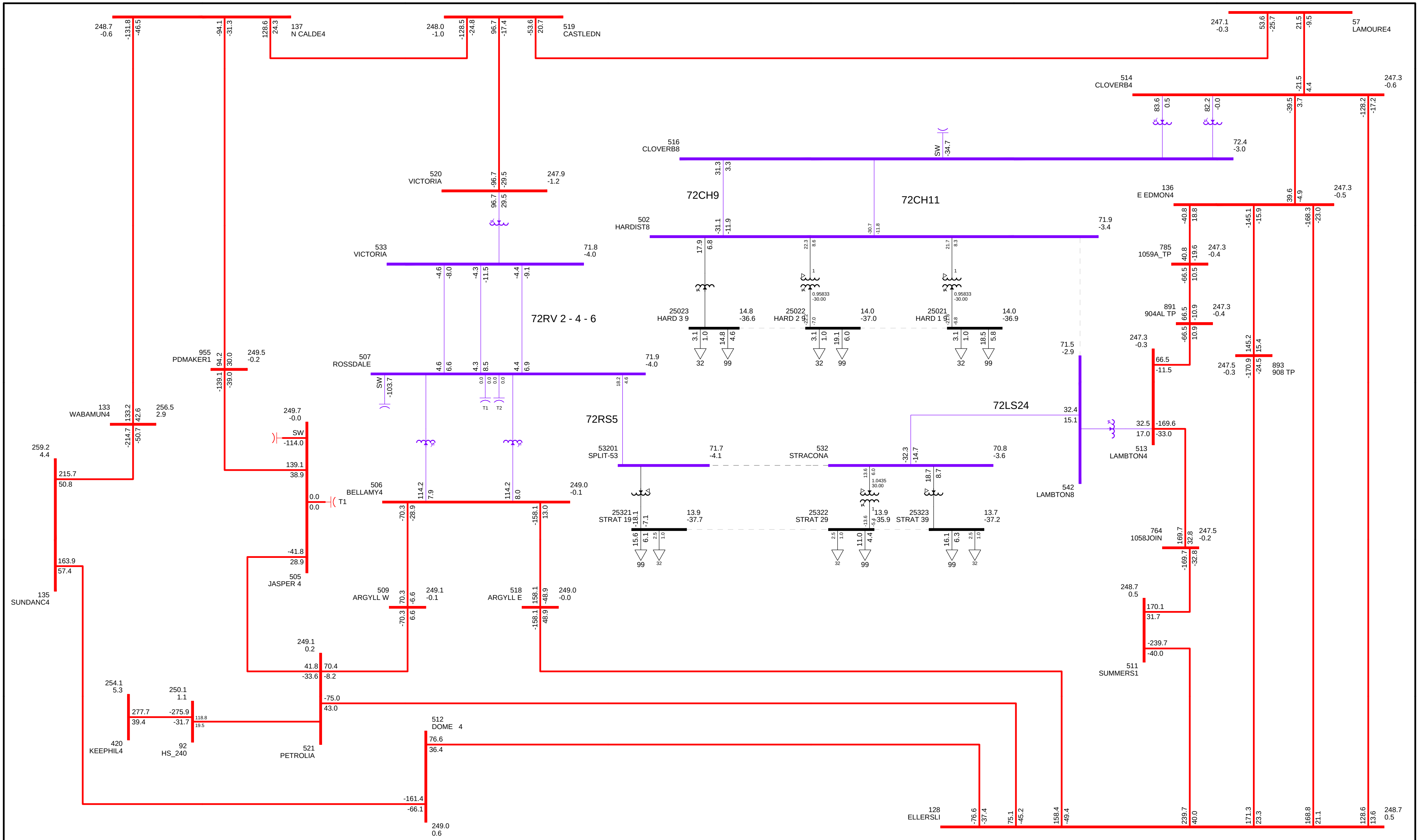


2019SP PRE-PROJECT
1058L (N-1)
FIG A-5
FRI, JUN 01 2018 17:13

Load at Strathcona: 50.3 MW 23.2 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

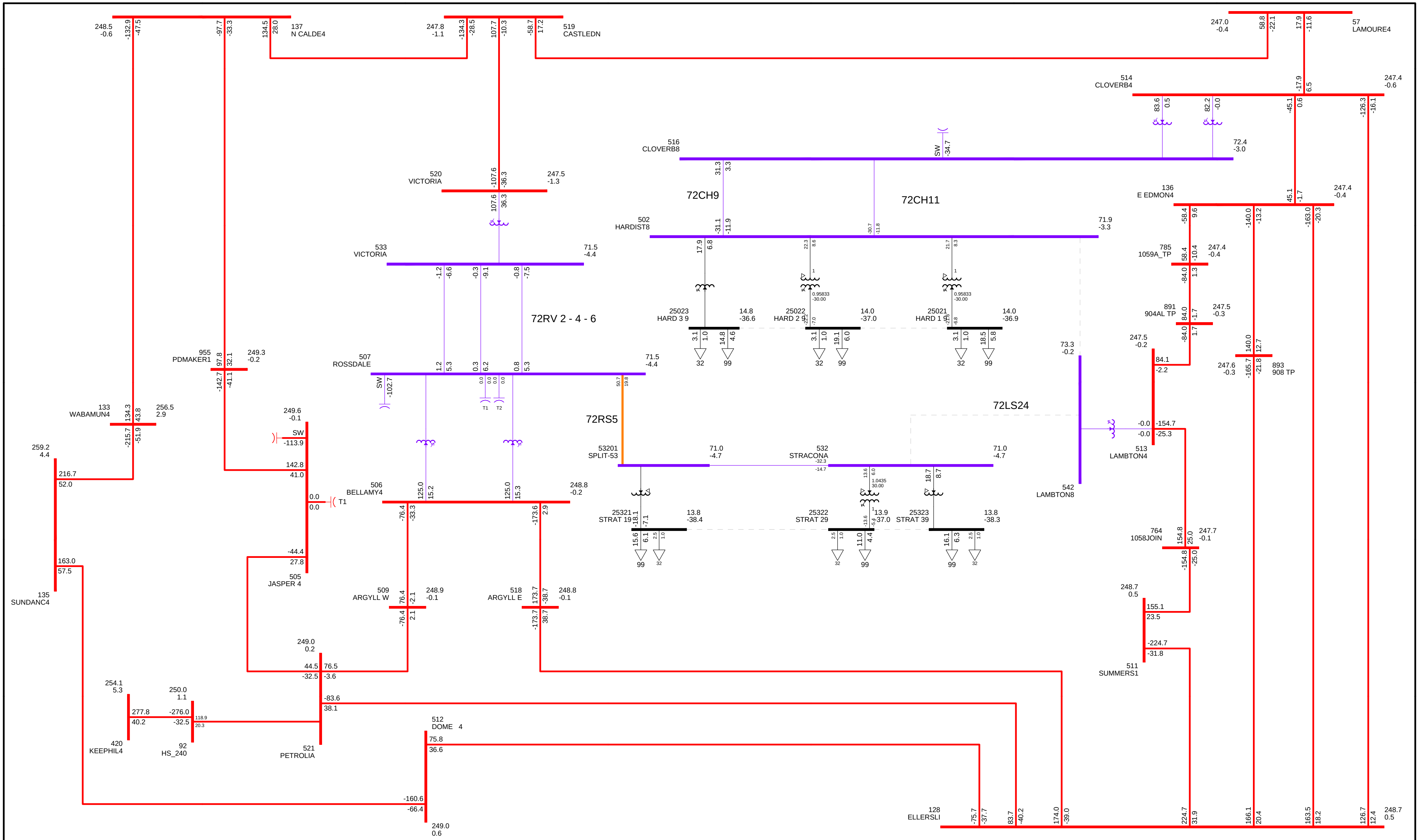


2019WP PRE-PROJECT
BASE CASE (N-0)
FIG A-6
FRI, JUN 01 2018 17:13

Load at Strathcona: 50.3 MW 19.7 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate B

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

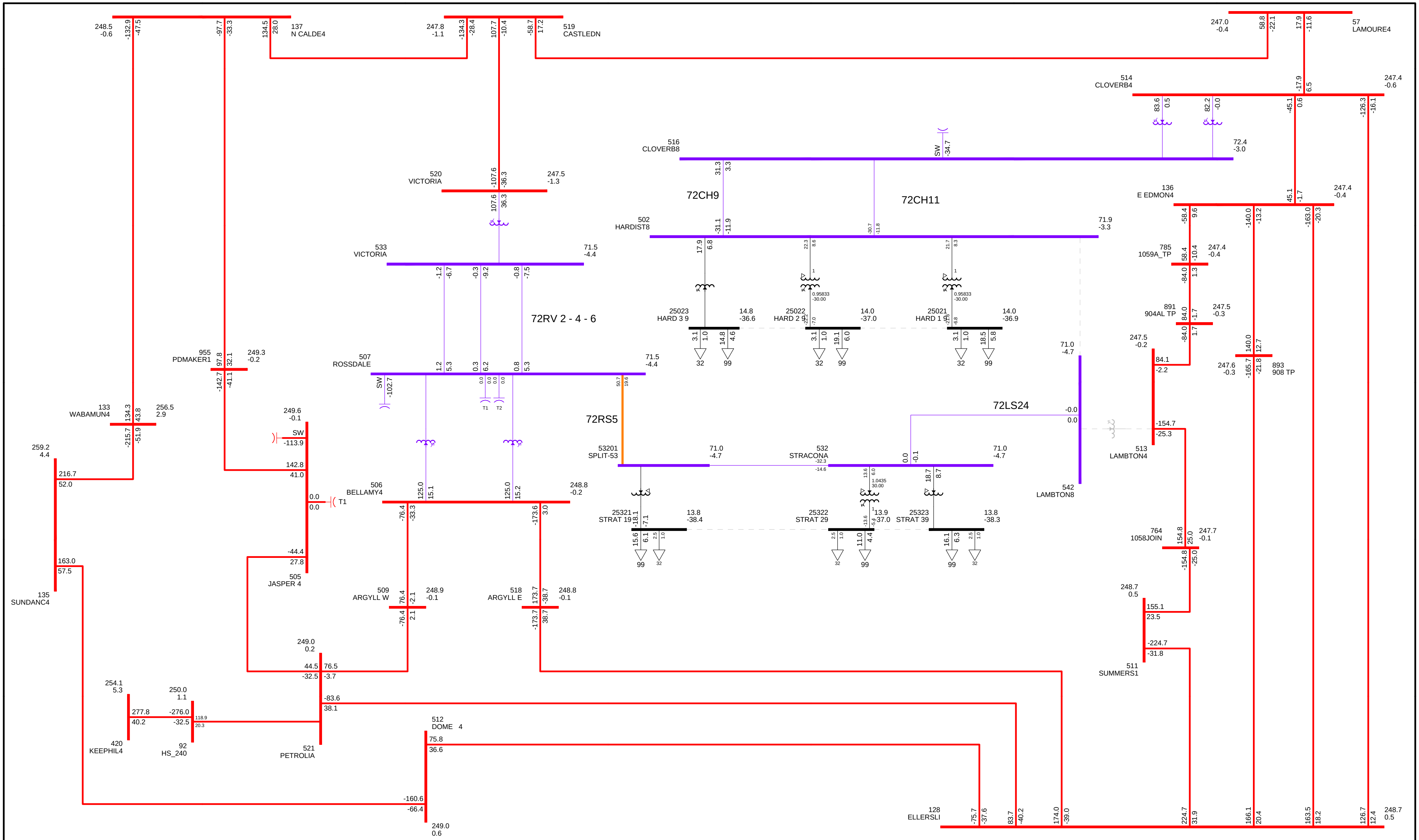


2019WP PRE-PROJECT
72LS24 (N-1)
FIG A-7
FRI, JUN 01 2018 17:13

Load at Strathcona: 50.3 MW 19.7 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate B

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

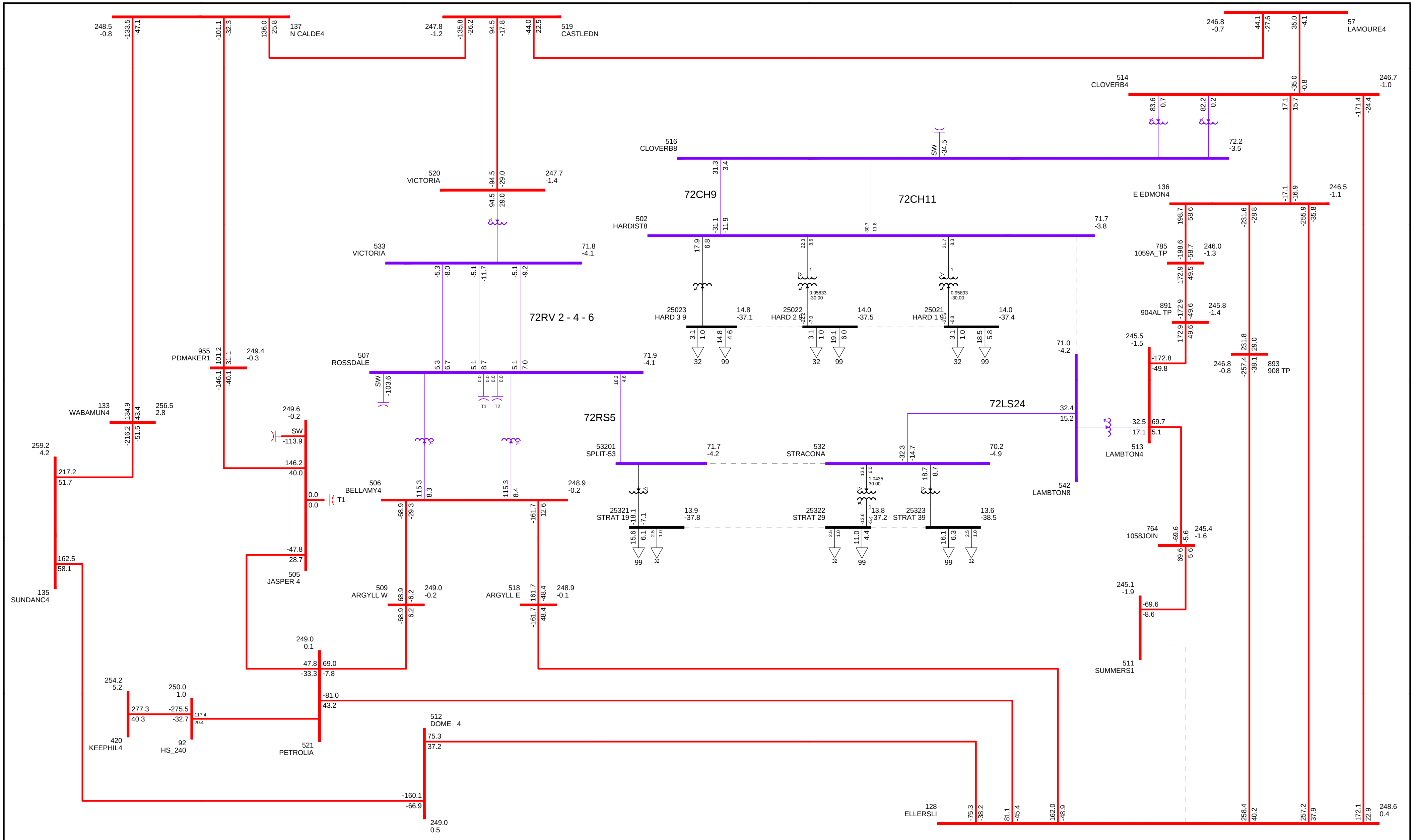


2019WP PRE-PROJECT
LAMBTONT3 (N-1)
FIG A-8
FRI, JUN 01 2018 17:13

Load at Strathcona: 50.3 MW 19.7 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate B

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

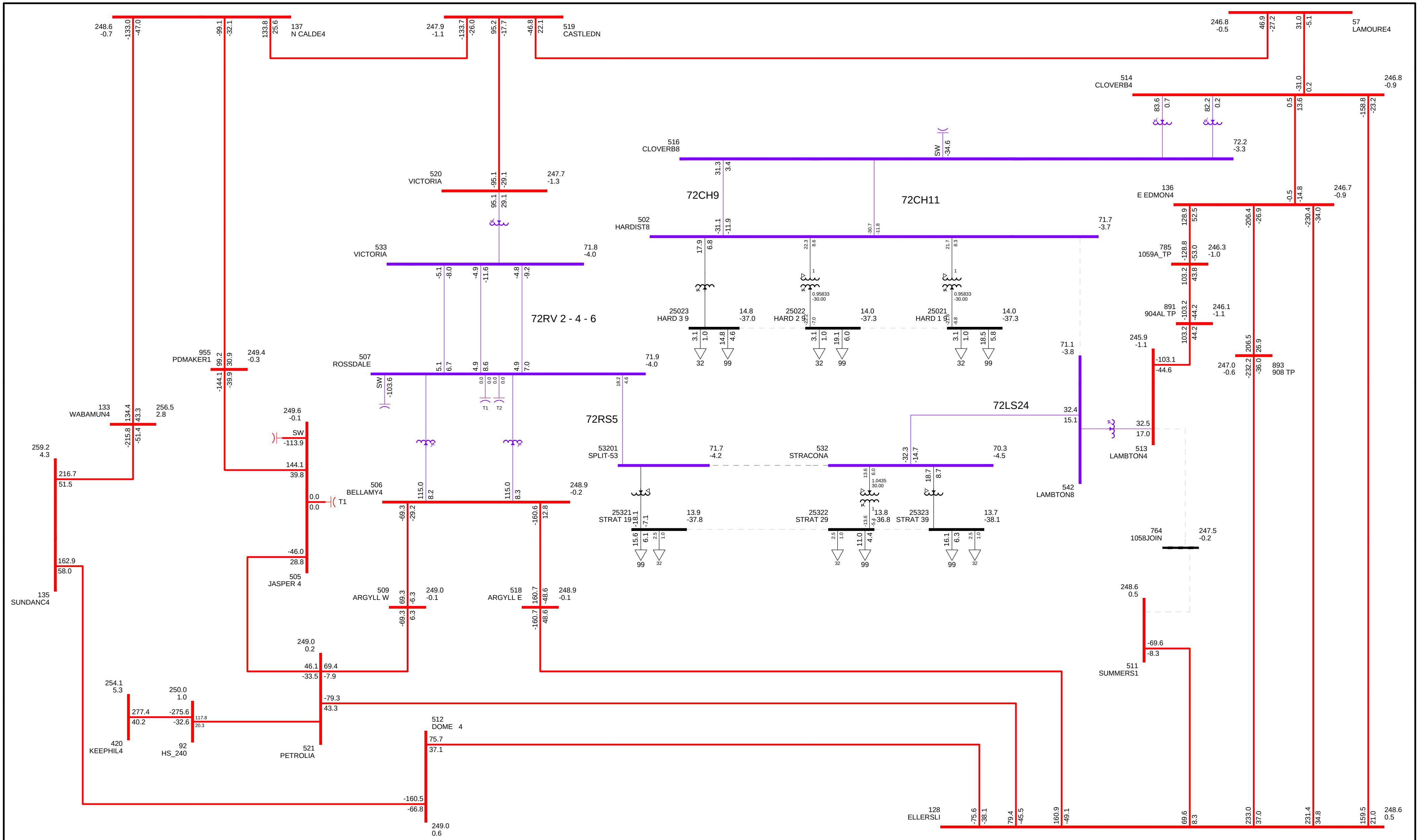


2019WP PRE-PROJECT
1057L (N-1)
FIG A-9
FRI, JUN 01 2018 17:14

Load at Strathcona: 50.3 MW 19.7 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate B

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000



2019WP PRE-PROJECT
1058L (N-1)
FIG A-10
FRI, JUN 01 2018 17:14

Load at Strathcona: 50.3 MW 19.7 Mvar

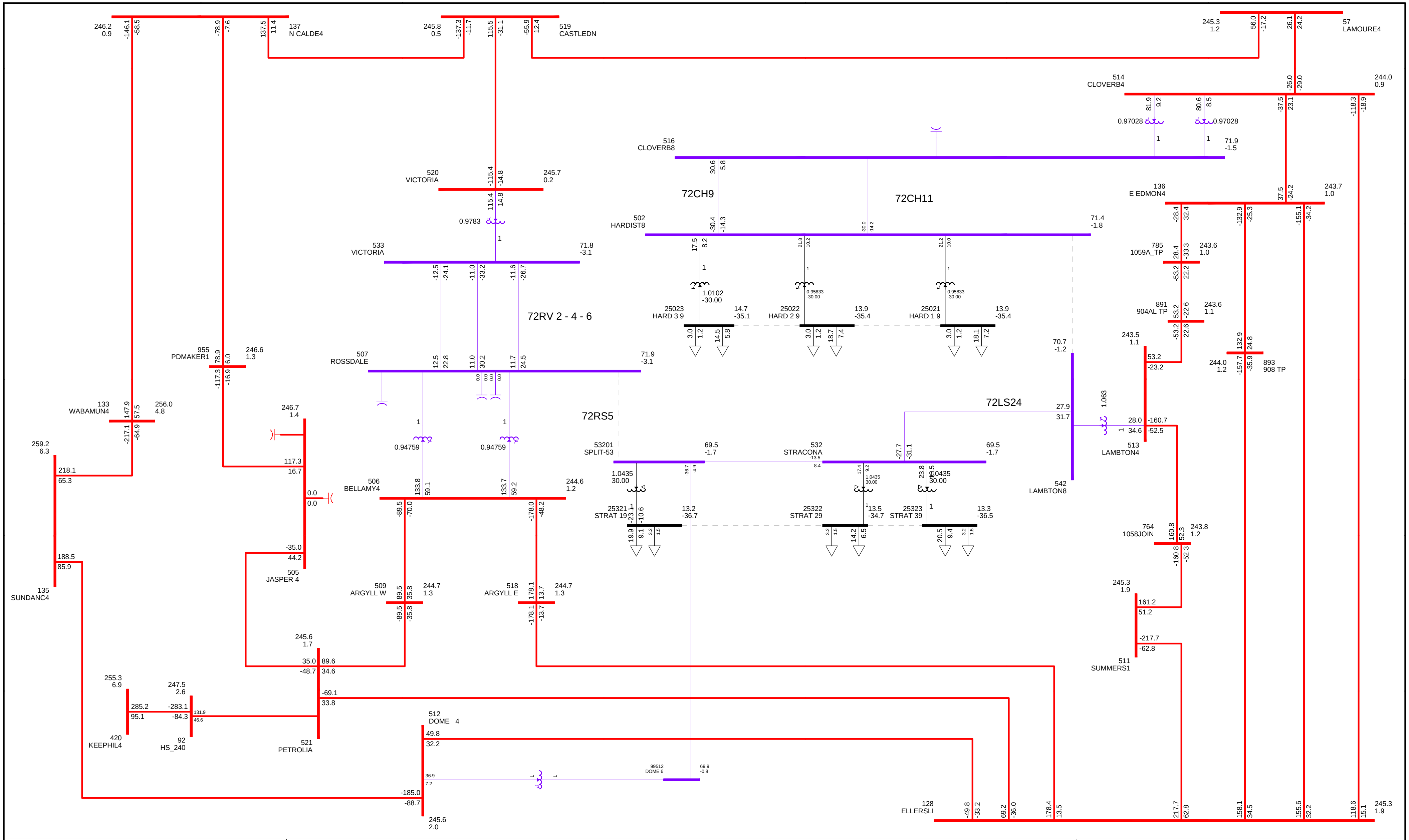
Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate B

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

Attachment B

Power Flow Diagrams

2020SP/2020WP Post-Project

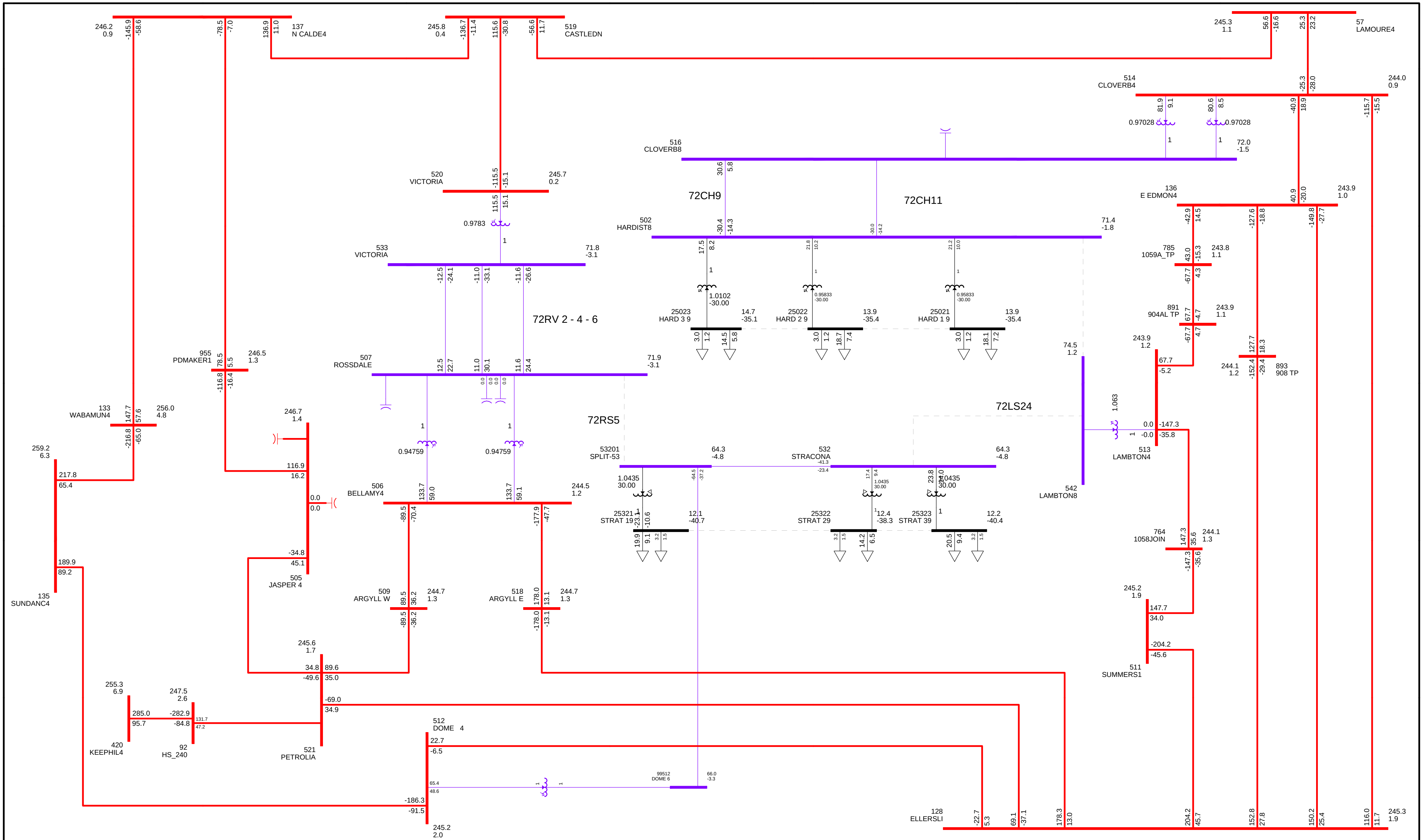


2019SP POST-PROJECT
BASE CASE (N-0)
FIG B-1
FRI, JUN 01 2018 17:14

Load at Strathcona: 64.2 MW 29.6 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

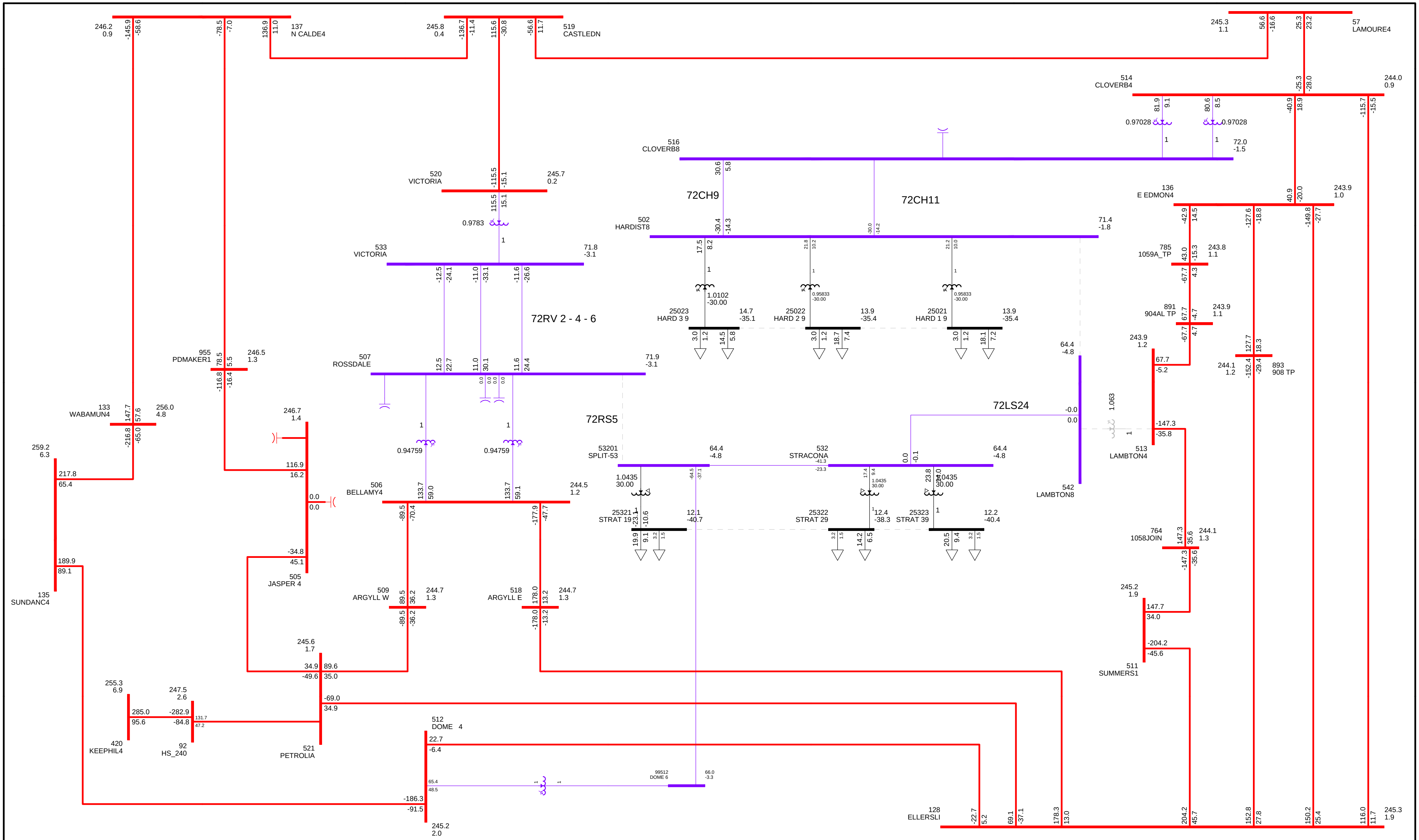


2019SP POST-PROJECT
72LS24 (N-1)
FIG B-2
FRI, JUN 01 2018 17:14

Load at Strathcona: 64.2 MW 29.6 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

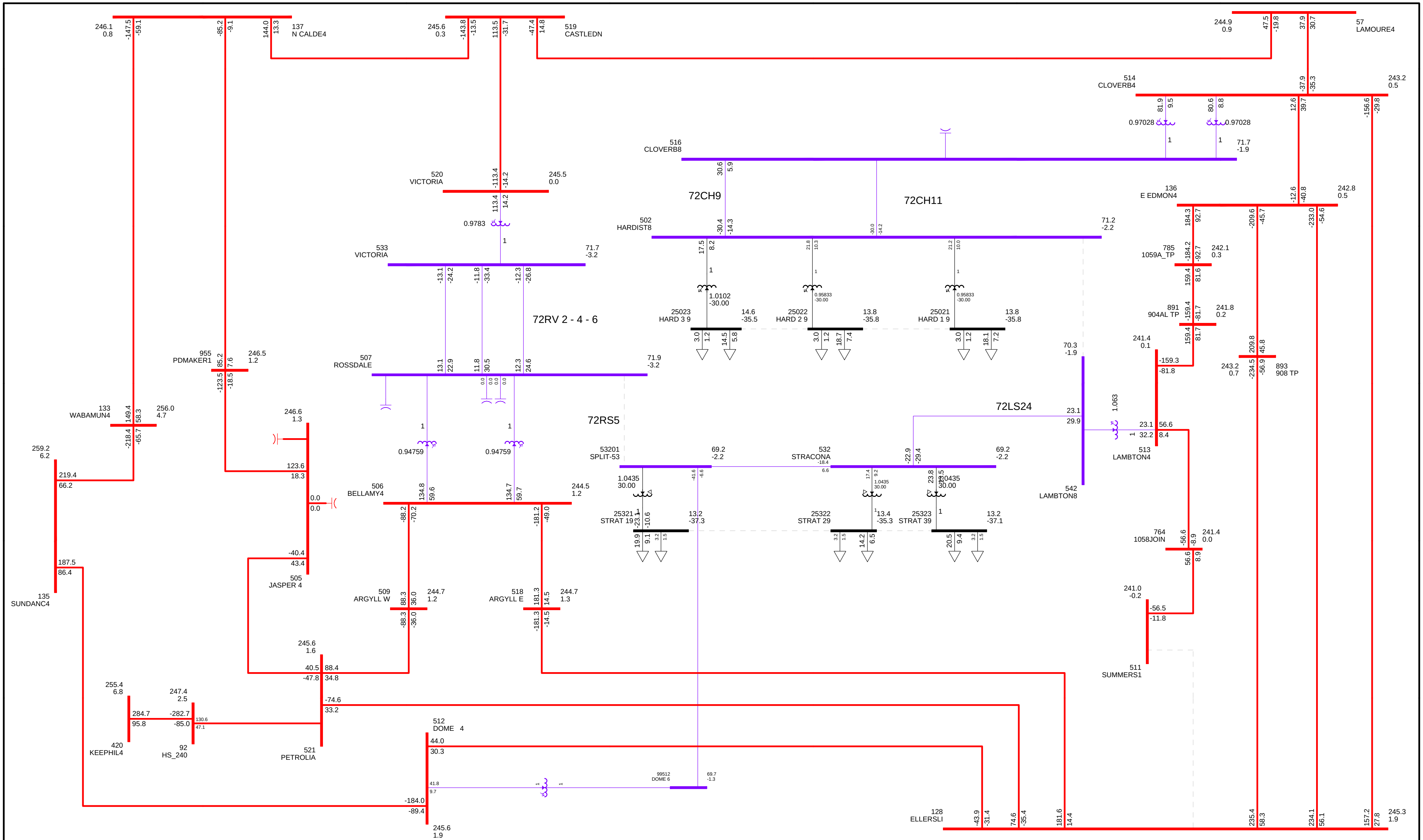


2019SP POST-PROJECT
LAMBTONT3 (N-1)
FIG B-3
FRI, JUN 01 2018 17:14

Load at Strathcona: 64.2 MW 29.6 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

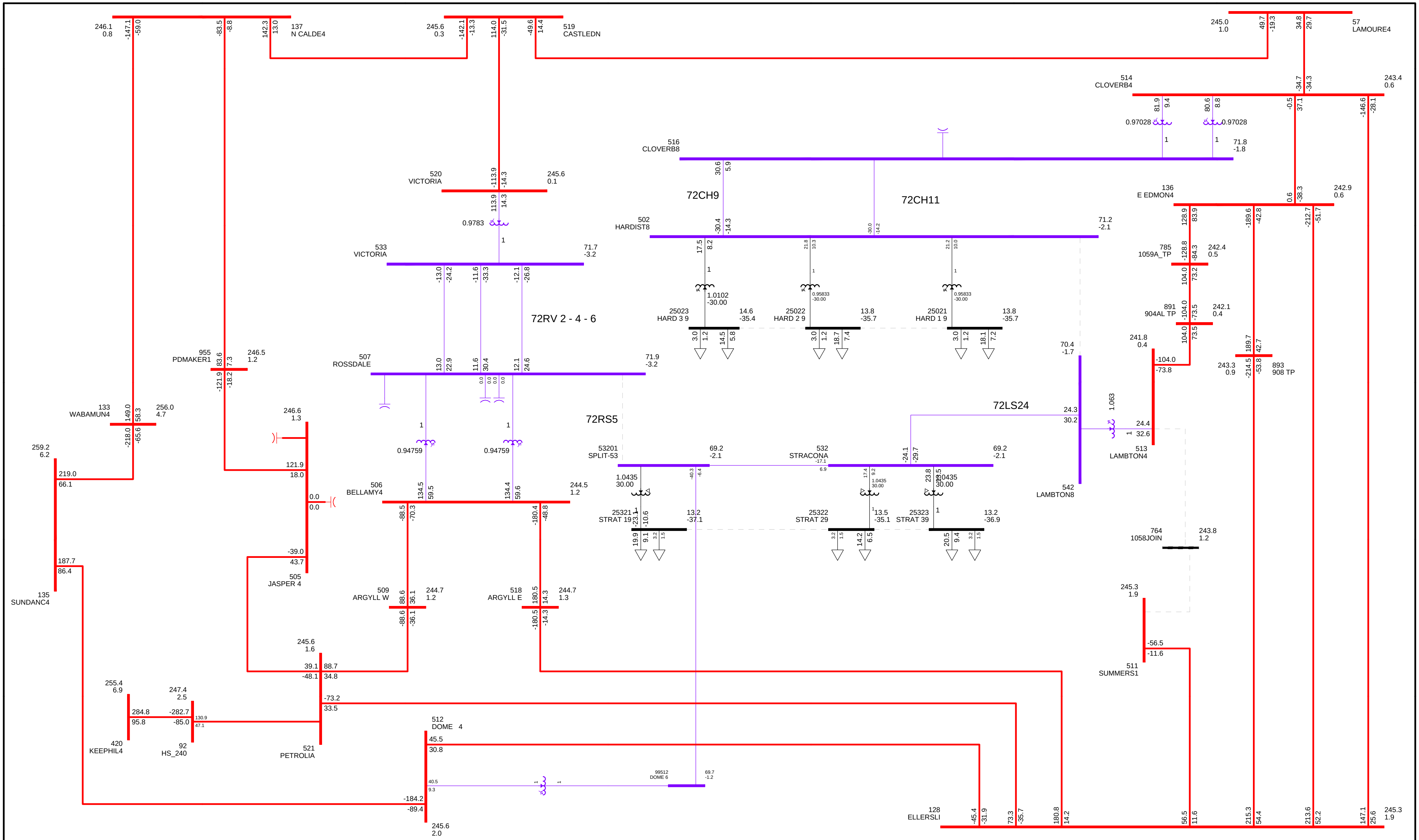


2019SP POST-PROJECT
1057L (N-1)
FIG B-4
FRI, JUN 01 2018 17:14

Load at Strathcona: 64.2 MW 29.6 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

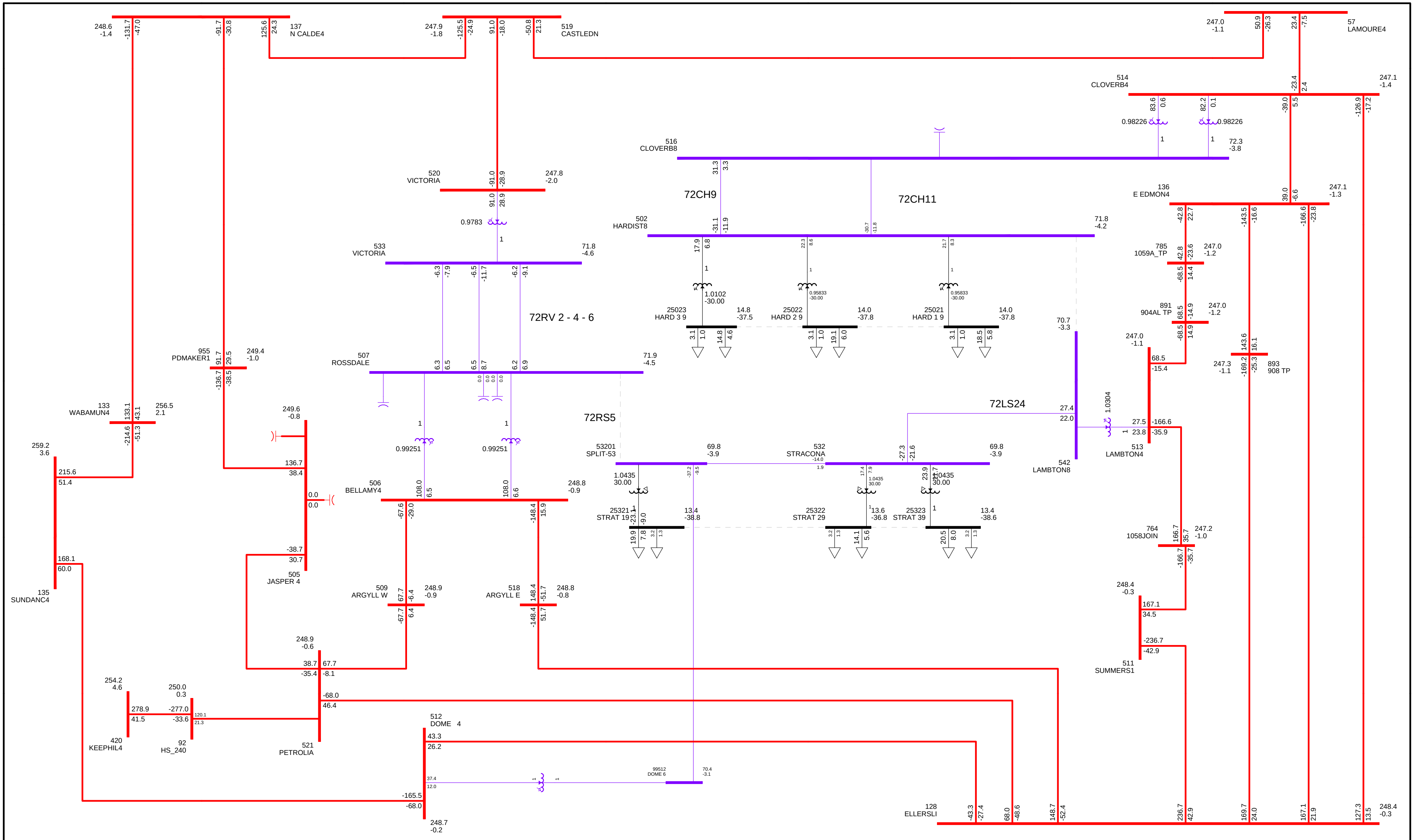


2019SP POST-PROJECT
1058L (N-1)
FIG B-5
FRI, JUN 01 2018 17:14

Load at Strathcona: 64.2 MW 29.6 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate A

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

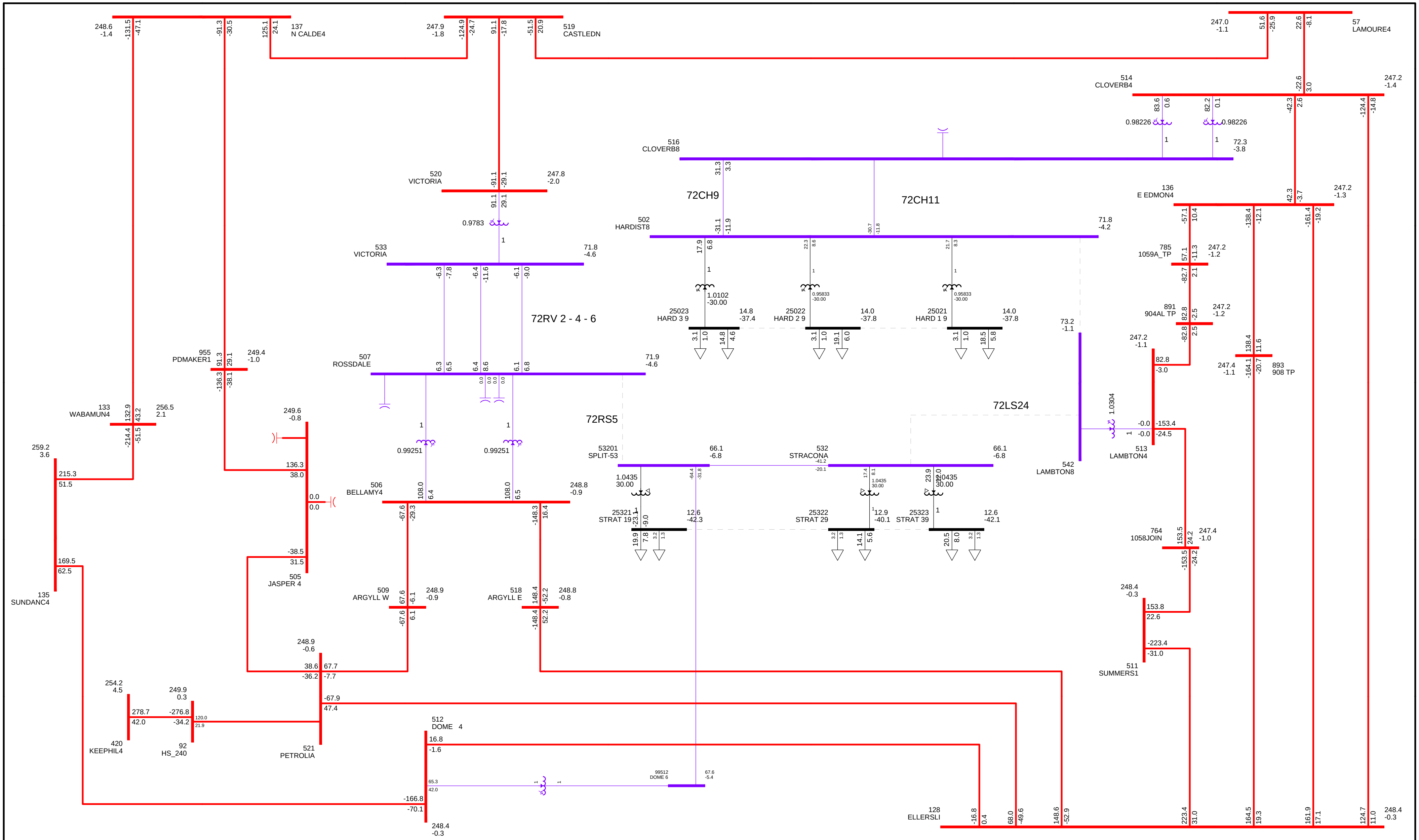


2019WP POST-PROJECT
BASE CASE (N-0)
FIG B-6
FRI, JUN 01 2018 17:14

Load at Strathcona: 64.2 MW 25.2 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate B

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

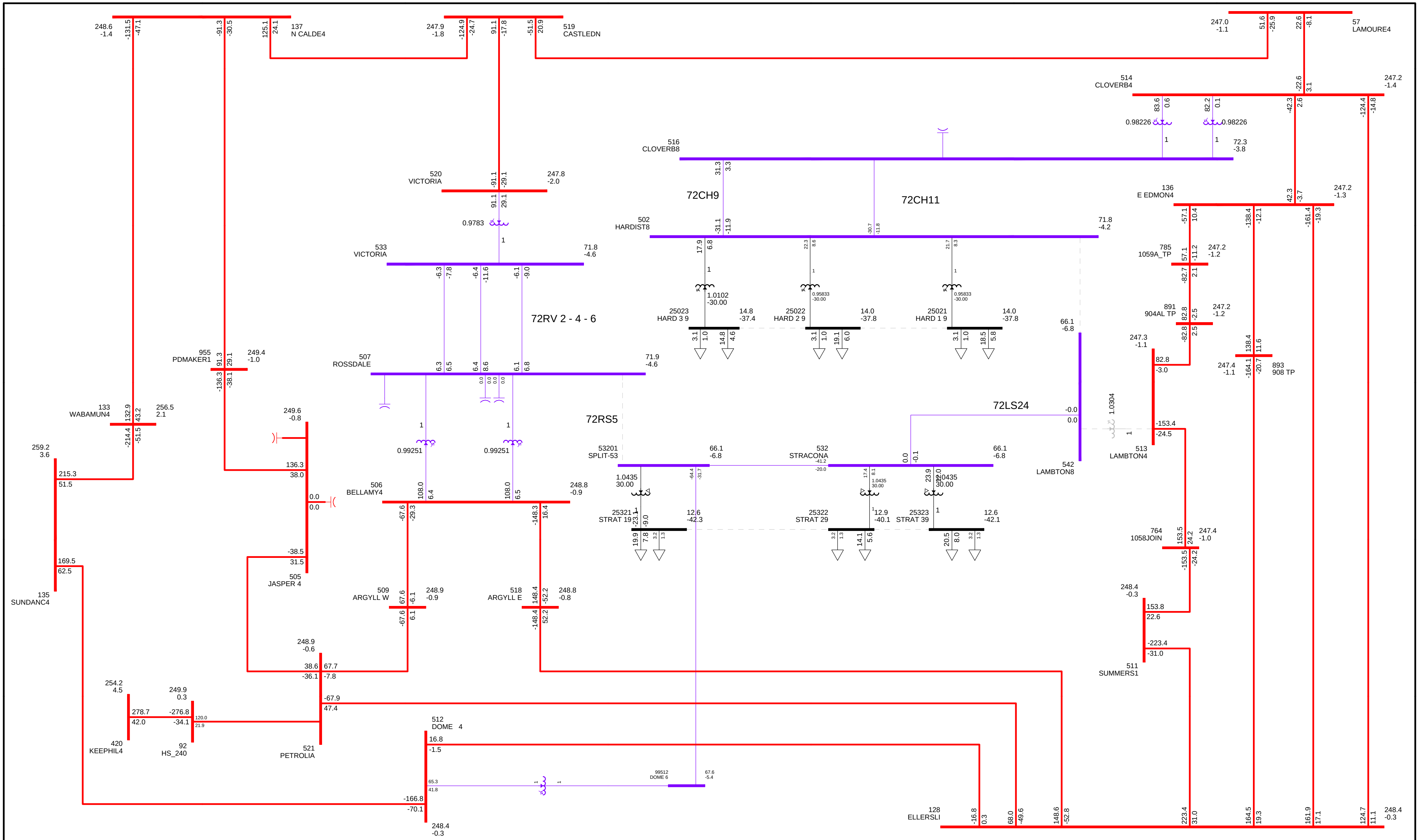


2019WP POST-PROJECT
72LS24 (N-1)
FIG B-7
FRI, JUN 01 2018 17:14

Load at Strathcona: 64.2 MW 25.2 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate B

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

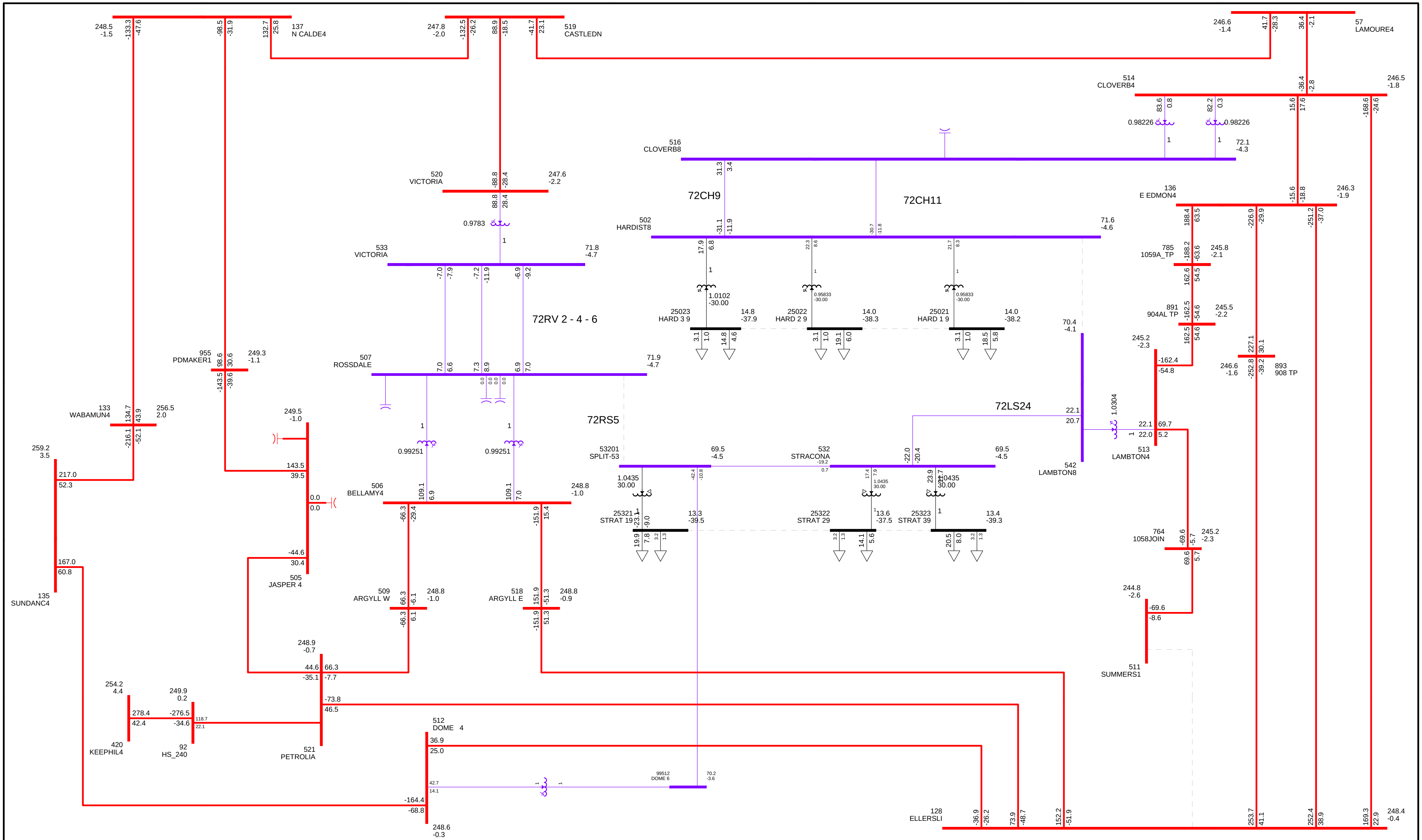


2019WP POST-PROJECT
LAMBTONT3 (N-1)
FIG B-8
FRI, JUN 01 2018 17:14

Load at Strathcona: 64.2 MW 25.2 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate B

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

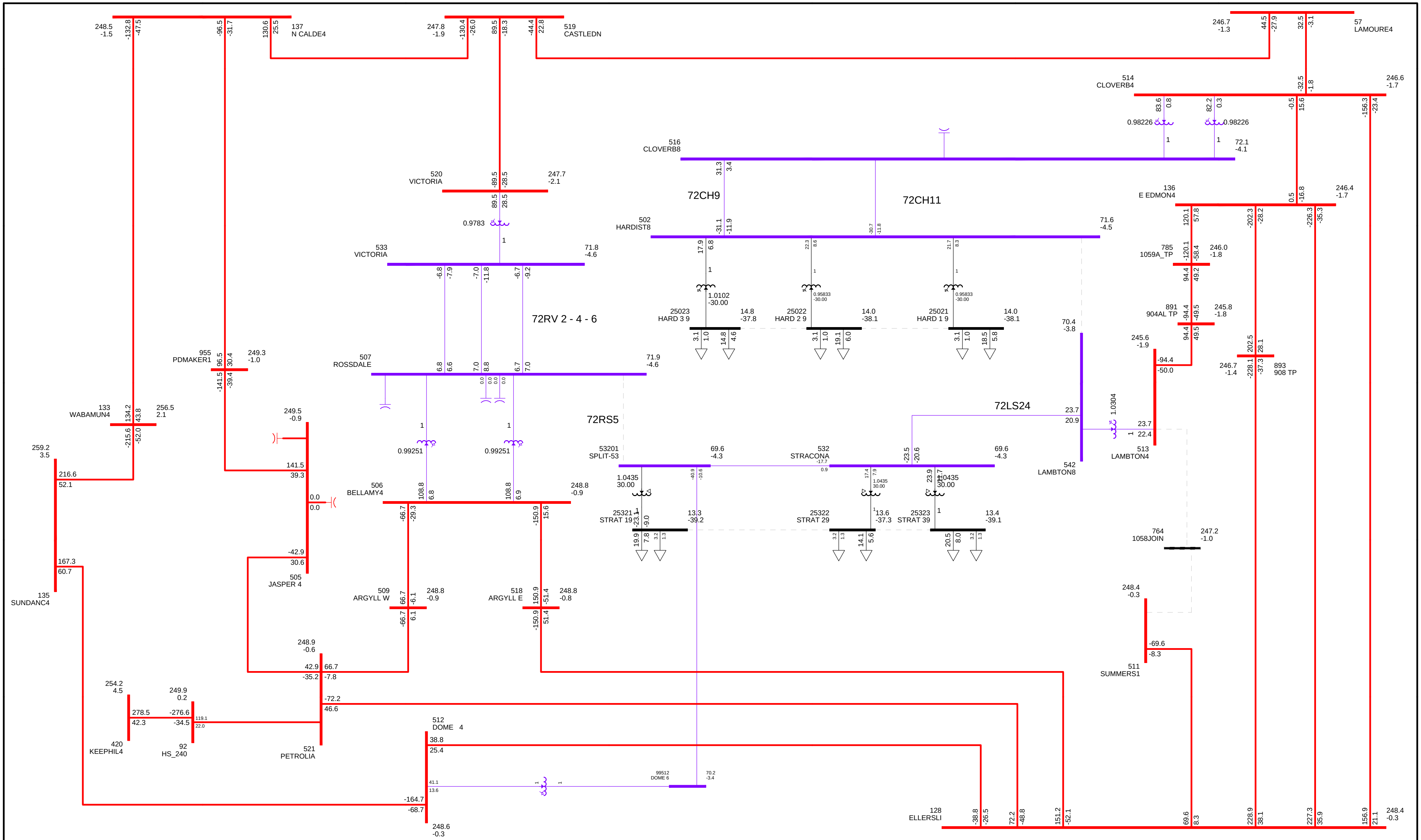


2019WP POST-PROJECT
1057L (N-1)
FIG B-9
FRI, JUN 01 2018 17:14

Load at Strathcona: 64.2 MW 25.2 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate B

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000



2019WP POST-PROJECT
1058L (N-1)
FIG B-10
FRI, JUN 01 2018 17:14

Load at Strathcona: 64.2 MW 25.2 Mvar

Bus - Base voltage (kV)
Branch - MW/Mvar
Equipment - MW/Mvar
100.0%Rate B

kV: <=25.000 <=69.000 <=138.000 <=240.000 <=500.000 >500.000

Attachment C

Voltage Stability Diagrams

2020WP Post-Project

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FRI, JUN 01 2018 17:36