Appendix E: Hybrid solution using microwaves

Echo River

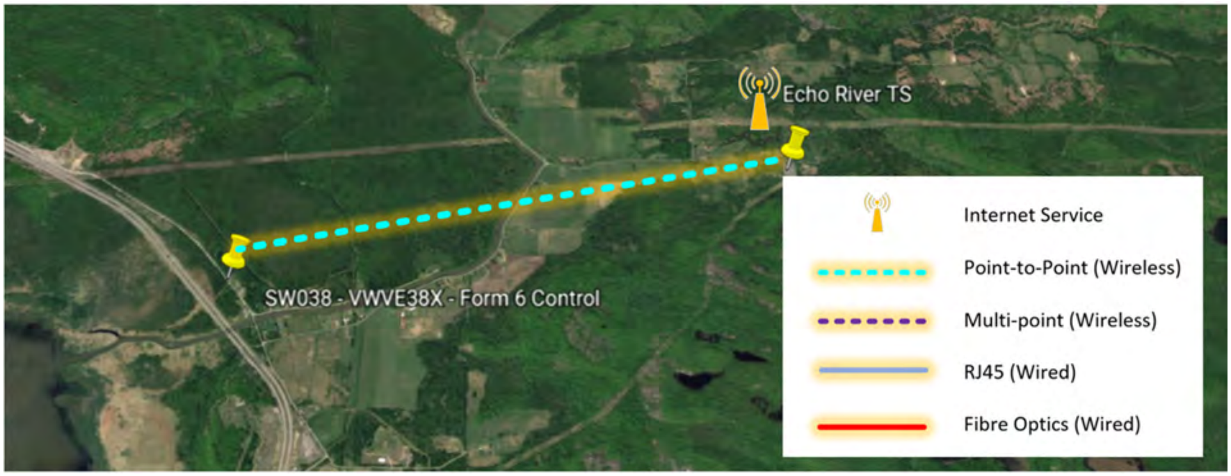


Figure 1: Echo River Hybrid Connection Solution

There is (1) IED asset (SW038) around the Echo River TS area. A point-to-point microwave wireless solution can be deployed to connect Echo River TS with SW038. Echo River TS will have an internet service and a WAN type connection solution to central control.

Bar River

Figure 2: Bar River Hybrid Connection Solution

There are (2) IED assets (CAP3210-118, and SW2020) that are around the Bar River DS area. A point-to-point microwave wireless solution can be deployed to interconnect these assets with Bar River DS. SW2020 will connect to CAP3210-118, then CAP3210-118 will connect to Bar River DS. Bar River DS will have an internet service and a WAN type connection solution to central control.

Desbarats

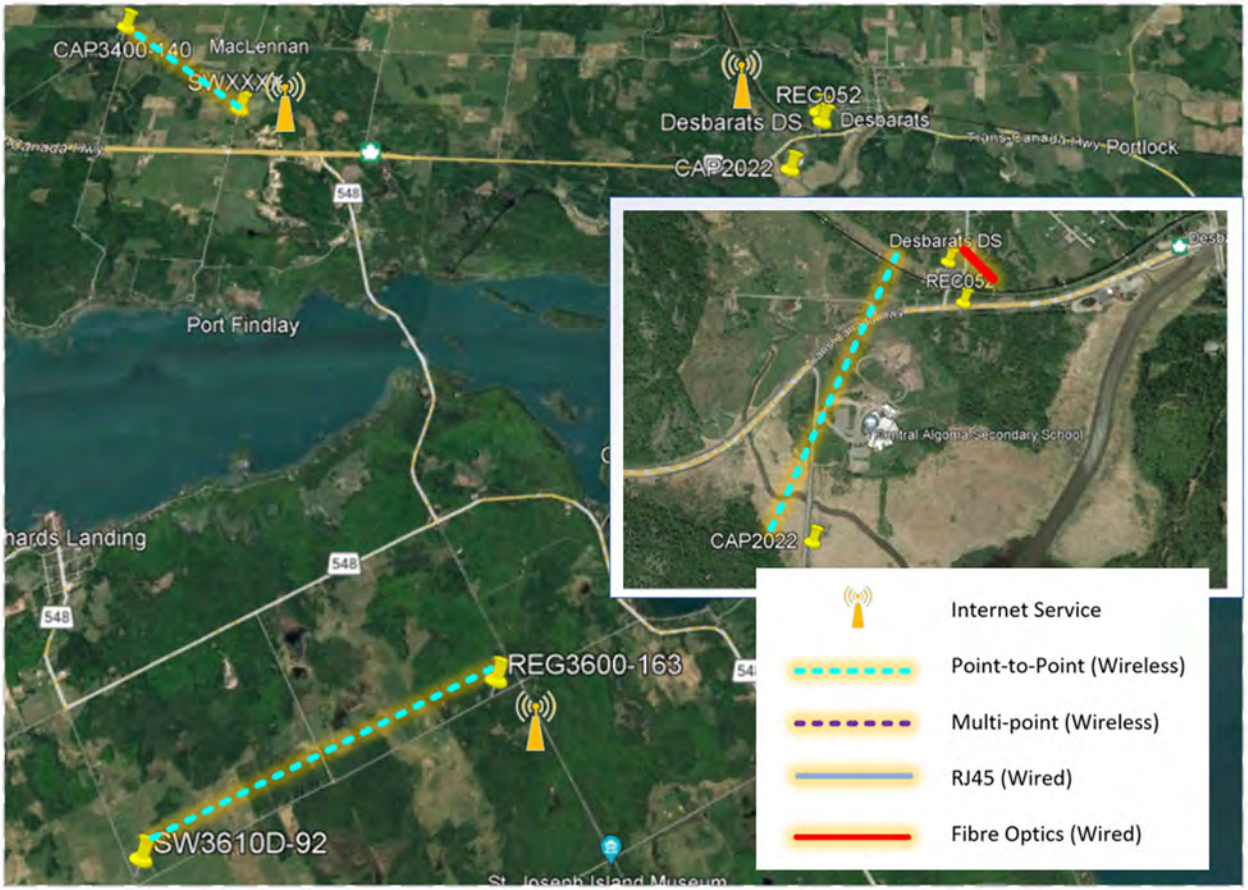


Figure 3: Desbarats Hybrid Connection Solution

There are (6) IED assets (REC052, CAP2022, REG3600-163, SW3610D-92, SWXXXX - future recloser and CAP3400-140) that are around the Desbarats DS area. A point-to-point microwave wireless solution and wired fibre optics can be deployed to interconnect some of the assets together. A cellular internet connection can then be utilized to help establish WAN connectivity.

1. The following will utilize point-to-point microwave wireless:
   - CAP3400-140 will connect to SWXXXX (future recloser)
   - SW3610D-92 will connect to REG3600-163
   - CAP2022 will connect to Desbarats DS

2. The following will utilize cellular internet to establish WAN connection back to central control
   - SWXXXX (future recloser)
   - REG3600-163
   - Desbarats DS

3. REC052 will connect to Desbarats DS using wired fibre optic connection

Bruce Mines

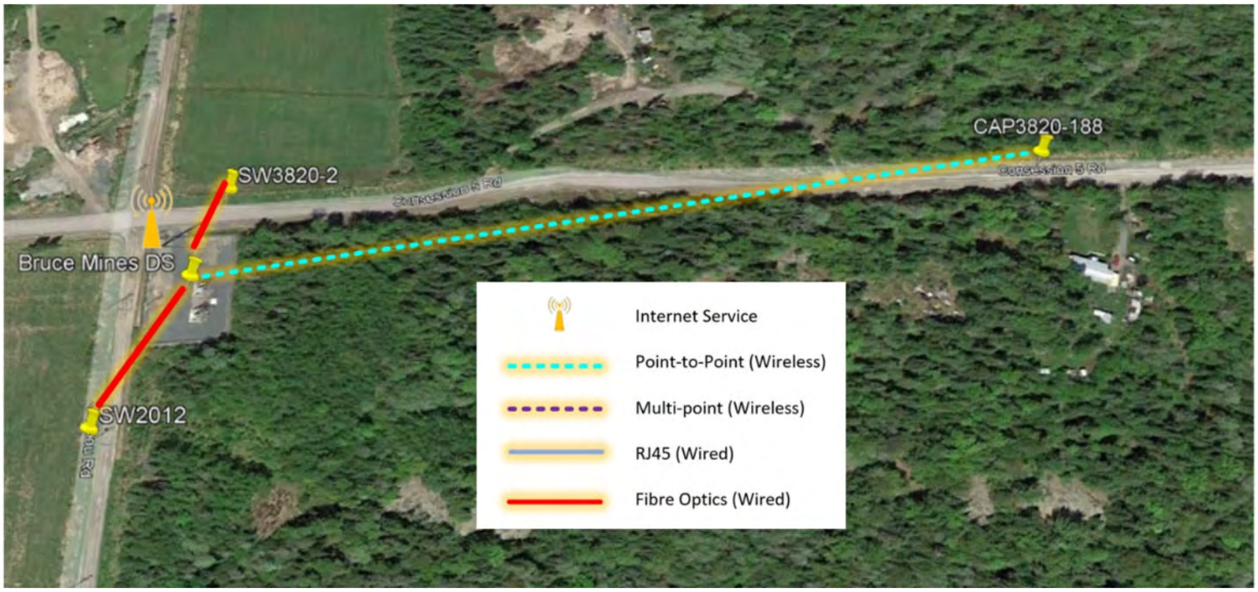


Figure 4: Bruce Mines Hybrid Connection Solution

There are (3) IED assets (SW3820-2, SW2012, and CAP3820-188) that are around the Bruce Mines DS area. A point-to-point microwave wireless solution can be deployed to interconnect CAP3820-188 and Bruce Mines DS together. SW3820-2 and SW2012A will each have a wired fibre optics connection to Bruce Mines DS. Bruce Mines DS will have an internet service and utilize a WAN type connection solution to central control.

Batchewana

Figure 5: Batchewana Hybrid Connection Solution

There are (4) IED assets (SW5220-62, SW5210-72, SW5221-63 and SW5221-64) that are around the Batchewana TS area. A point-to-point microwave wireless solution can be deployed to interconnect some of the assets together. A cellular internet connection can then be utilized to help establish WAN connectivity.

1. The following IED assets will utilize point-to-point microwave wireless:
   - SW5221-63 will connect to SW5210-72
   - SW5210-72 will connect to Batchewana TS
   - SW5220-62 will connect to Batchewana TS

2. The following will utilize cellular internet to establish WAN connection back to central control
   - Batchewana TS
   - SW5221-64

Goulais

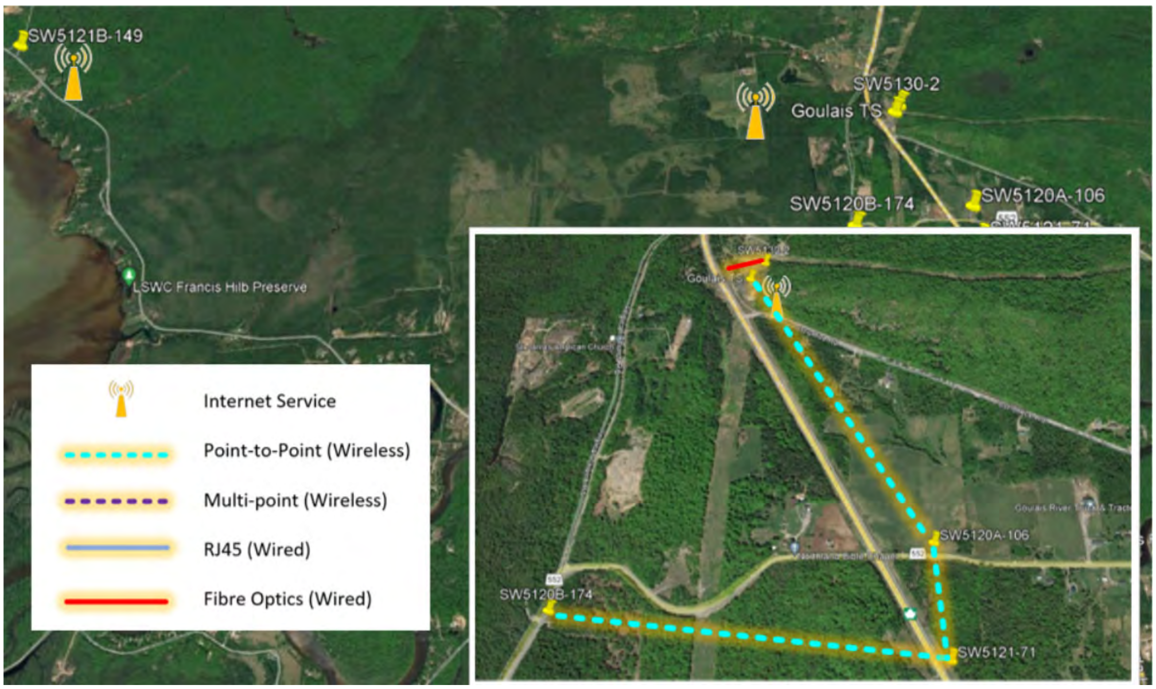


Figure 6: Goulais Hybrid Connection Solution

There are (5) IED assets (SW5130-2, SW5120A-106, SW5121-71, SW5120B-174, SW5121B-149) that are around the Goulais TS area. A point-to-point microwave wireless solution and wired fibre optics can be deployed to interconnect some of the assets together. A cellular internet connection can then be utilized to help establish WAN connectivity.

1. The following IED assets will utilize point-to-point microwave wireless:
   - SW5120B-174 will connect to SW5121-71
   - SW5121-71 will connect to SW5120A-106
   - SW5120A-106 will connect to Goulais TS

2. The following will utilize cellular internet to establish WAN connection back to central control
   - Goulais TS
   - SW5121B-149

3. SW5130-2 will connect to Desbarats DS using wired fibre optic connection

Wawa No. 1 and Wawa No. 2

Figure 7: Wawa Area Hybrid Connection Solution

There are (2) IED assets (SW9110-24, and SW9110-25) that are near the Wawa No. 1 DS. And, there are (3) IED assets (SW9400-84, SW2036, and SW9410E-31) that are in the Wawa No 2 DS area. A point-to-point microwave wireless solution and wired RJ45 can be deployed to interconnect some of the assets together. A cellular internet connection can then be utilized to help establish WAN connectivity.

1. The following will utilize point-to-point microwave wireless:
   - Wawa No. 1 DS will connect to Wawa No. 2 DS
   - SW9400-84 will connect to Wawa No. 2 DS
   - SW9410E-31will connect to Wawa No. 2 DS

2. Wawa No. 2 DS will utilize cellular internet to establish WAN connection back to central control
   - SW5121B-149

3. The following will utilize wired RJ45 connection:
   - SW9110-24
   - SW9110-25

Appendix F: Site Survey Detailed Results

Appendix F.1 Assets site survey observations

The following notes describe what was observed during the selected assets site surveys:

- 24 assets sites were visited;
- 21 of the asset sites had cellular coverage from both providers;
- At all the asset sites where a video call was made, the quality was good enough to confirm the possibility to transfer data across the wireless connection;
- Dubreuilville only had cellular coverage from Rogers;
- The regulator REG3600-163 had cellular coverage from Bell, and about 300 metres away there was signal from Rogers;
- Hollingsworth cellular coverage was weak; however, a signal trace was found about 500 metres away from the asset site; measures were weak at the measurement point, 200 metres away from the station. It was impossible to get closer;
- Mackay measures were very strong at the measure point, 300 metres away from the station. Impossible to get closer;
- The SW3610D-92 IED had signal problems near the pole bottom but about 10 feet away from the pole the strength of the signal increased. This was the sole asset where an audio data call was made because the quality of the video was not good enough. The audio call was excellent at this point;
- At most asset sites potential for copper phone lines from Bell were visually identified, but service availability was not verified during the site visit.
- At Garden River a Shaw fiber optic cable indication near the asset was identified;
- At Bar River a fiber optic cable indication was seen but the provider could not be identified because the label was washed out by the sun.

Appendix F.2 Assets site cellular coverage results

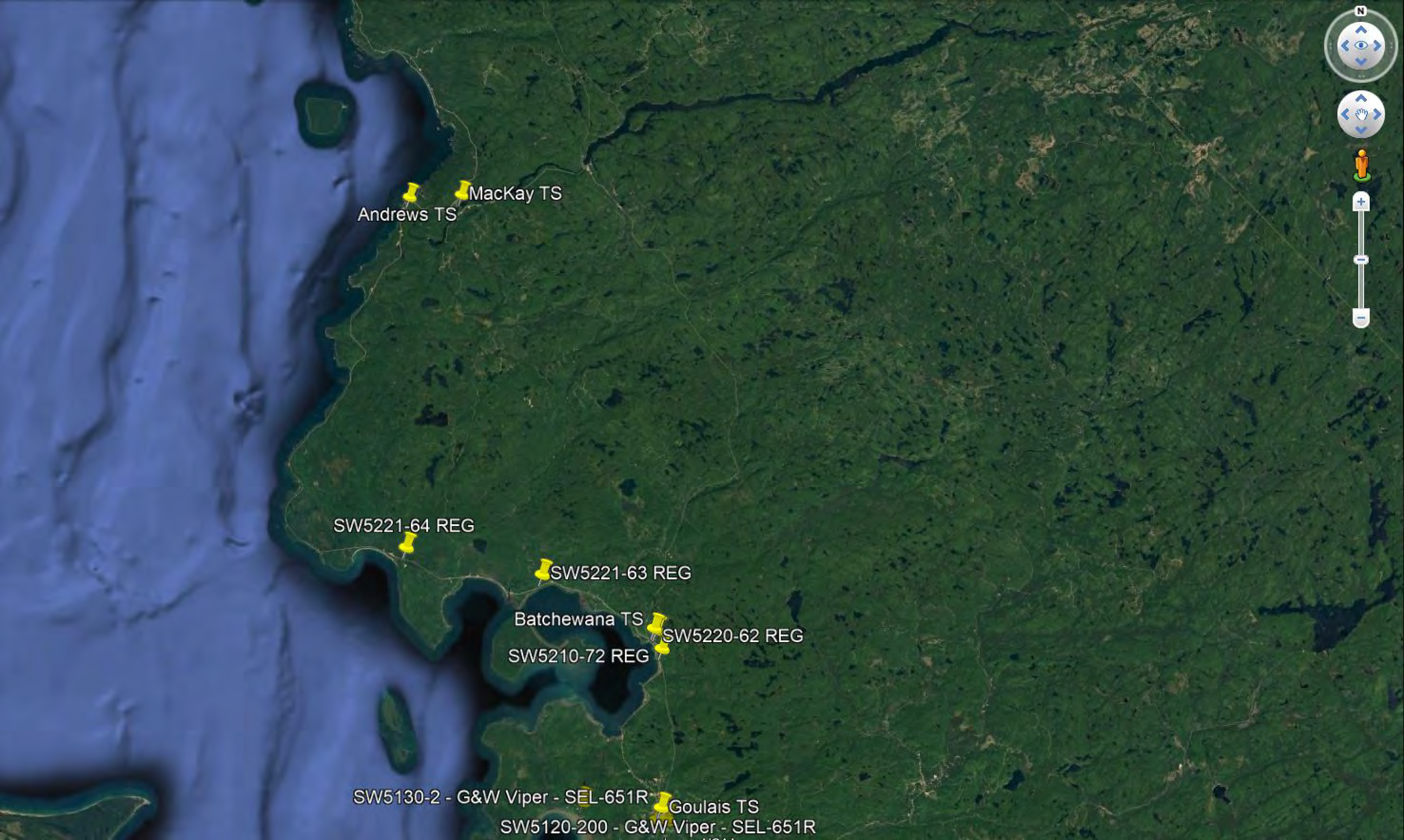
Table 2: Assets sites cellular coverage survey results

Asset No	Asset Name	Signal strength (dBm)	Speed test Rogers Mbps (Up/Down)	Speed test Bell Mbps (Up/Down)	Video Call Quality	Audio Call Quality	Comments
1	Northern Avenue TS	-57	N/A	N/A	Excellent	Not required	No measure was made at this point however, the asset has full coverage from both providers.
2	Garden River TS	-71	17.7 / 0.25	9.13 / 0.15	Excellent	Not required	
3	Echo River TS	-57	110 / 6.92	95.7 / 5.92	Excellent	Not required	
4	Bar River DS	-61	22 / 8.28	40.7 / 6.13	Excellent	Not required	
	Desbarats DS	-65	144 / 46	79.4 / 6.14	Excellent	Not required	
5	FUTURE RECLOSER	-61	50.9 / 8.59	35 / 12.6	Excellent	Not required	
6	SW3610D-92	-77	50.7 / 3.33	45.6 / 2.6	Acceptable	Excellent	10 feet away from the pole the signal was strong
7	REG3600-163	-55	N/A	96.1 / 57.6	Excellent	Not required	100 metres away Rogers signal was available
8	Bruce Mines DS	-56	103 / 11.1	68.5 / 9.78	Excellent	Not required	
Etc.	Batchewana TS	-62	11.4 / 10.1	126 / 13.5	Excellent	Not required	
	SW5221-64	-60	82.6 / 10.1	15 / 3.17	Excellent	Not required	
	SW5221-63	-74	13.8 / 3.38	55.8 / 6.04	Excellent	Not required	

Asset No	Asset Name	Signal strength (dBm)	Speed test Rogers Mbps (Up/Down)	Speed test Bell Mbps (Up/Down)	Video Call Quality	Audio Call Quality	Comments
	SW5210-72	-62	10.5 / 3.08	162 / 8.79	Excellent	Not required	
	Goulais TS	-58	21.6 / 15.3	93.1 / 6.14	Excellent	Not required	
	SW5121B-149	-71	9.08 / --	46.72 / 28.04	N/A	N/A	A difficulty with the phone service at the time of the survey prevented a phone call.
	Andrews TS	-82	8.22 / 0.87	8.05 / 1.41	Excellent	Not required	
	Mackay TS	-74	4.03 / 1.38	7.72 / 1.27	Excellent	Not required	300 metres away from the TS
	Da Watson TS	-90	0.29 / 0.04	2 / 0.07	Good	Not required	Good signal level at west entrance of the substation
	SW9410E-31	-69	53.0 / 0.67	3.97 / 1.46	Excellent	Not required	
	Wawa No 1 DS	-74	1.69 / 0.13	9.51 / 4.24	Excellent	Not required	
	Wawa No 2 DS	-58	107 / 8.31	10.6 / 10.2	Good	Not required	
	Hollingsworth GS	-94	N/A	N/A	N/A	N/A	No call was possible and measures were done 200 meters away from the TS
	Hawk Junction DS	-63	9.74 / 0.4	59.6 / 18.8	Excellent	Not required	
	Dubreuilville DS 86	-60	48.5 / 20.1	N/A	Excellent	Not required	

Appendix G: Algoma Power Assets

Dubreuilville 87 DS
Dubreuilville 86 DS
Hawk Junction
10-24 - Kyle Nova-TS - Form 6-TS Control
SW9120-25 - Kyle Nova-TS - Form 6-TS Control
Wawa No. 1 DS
Hollingsworth TS/GS Demarc.
SW9410E-31 - Kyle Nova-TS - Form 6-TS Control
DA Watson TS


MacKay TS
Andrews TS
SW5221-64 REG
SW5221-63 REG
Batchewana TS
SW5220-62 REG
SW5210-72 REG
SW5130-2 - G&W Viper - SEL-651R
Goulais TS
SW5120-200 - G&W Viper - SEL-651R


SW3120-10 - G&W Viper - SEL-651R
SW3110-7 - G&W Viper - SEL-651R
Goulais River DS
Northern Avenue TS
Echo River TS
SW038 - VWVE38X - Form 6 Control
SW3220-88 - G&W Viper - SEL-651R
SW3210-91 - G&W Viper - SEL-651R
REG-ER1 - Cooper - CL-6B
Bar River DS
SWXXXX - G&W Viper - SEL-651R
CAP3400-140
Desbarats DS
CAP2022
Bruce Mines DS
SW3820-2 - G&W Viper - SEL-651R (NEW)
REG3600-163 - Cooper - CL7 Controller
SW3610D-92 - G&W Viper - SEL-651R

Appendix H: Budgetary Bill of Materials

Kit	Qty/Kit	Qty Tot	OEM	Model #	Description	Unit MSRP (CAD)	Amout MSRP (CAD)	Discount	Discounted Unit Price (CAD)	Discounted Amount (CAD)	Comments
Control Centre											
1	1	1	Sierra Wireless	RV55_1104303	AirLink® RV55: Industrial LTE-A Pro Router Compact, Rugged, Low power, LTE-A Pro or LTE-M/NB-IoT Routers for Industrial IoT, SCADA and Field Service Fleets	$ 1 350.00	$ 1 350.00	**0%**	$ 1 350.00	$ 1 350.00	Seccondary WAN Link to provide backup to existing ISP Internet access.
1	1	1	Sierra Wireless	2000579	AC Adapter, 12VDC	$ 40.00	$ 40.00	**0%**	$ 40.00	$ 40.00	
1	1	1	Sierra Wireless	6000659	DIN Rail Bracket	$ 45.00	$ 45.00	**0%**	$ 45.00	$ 45.00	
1	1	1	Sierra Wireless	6001126	Wall/Mast mount; LTE MIMO; high gain directional antenna for fringe coverage areas	$ 228.00	$ 228.00	**0%**	$ 228.00	$ 228.00	
1	1	1	CITEL	MJ8-POE-C6A	TVSS (Transient Voltage Surge Suppressor) for CAT6	$ 100.00	$ 100.00	**0%**	$ 100.00	$ 100.00	
1	1	1	TBD		Coax Cable Lightning Arrestor	$ 50.00	$ 50.00	**0%**	$ 50.00	$ 50.00	
1	1	1	TBD		Antenna Cable	$ 150.00	$ 150.00	**0%**	$ 150.00	$ 150.00	
1	1	1	TBD		Antenna Mounting Hardware	$ 250.00	$ 250.00	**0%**	$ 250.00	$ 250.00	
1	1	1	TBD		Antenna Installation	$ 600.00	$ 600.00	**0%**	$ 600.00	$ 600.00	
1	2	2	Netgate	7100-1U	NETGATE 7100 1U BASE PFSENSE+ SECURITY GATEWAY (Base w/32 GB RAM, 256 GB Storage)	$ 2 250.00	$ 4 500.00	**0%**	$ 2 250.00	$ 4 500.00	
1	2	2	Netgate	4-port-10-GbE-SFP+	4-port 10 GbE SFP+ Card with PCIe kit (will save on configuration and testing time)	$ 800.00	$ 1 600.00	**0%**	$ 800.00	$ 1 600.00	
1	3	3	Netgate	10G-SFP+_DA	10G SFP+ DIRECT-ATTACHED COPPER TWINAX PASSIVE CABLE (1 METER)	$ 50.00	$ 150.00	**0%**	$ 50.00	$ 150.00	
1	2	2	TBD		UTP Patch Cord 3 FT	$ 10.00	$ 20.00	**0%**	$ 10.00	$ 20.00	
1	2	2	TBD		UTP Patch Cord 6 FT	$ 15.00	$ 30.00	**0%**	$ 15.00	$ 30.00	
1	2	2	APC	SRT1000RMXLA-NC	APC Smart-UPS SRT 1000VA, 120V, LCD, rackmount, 2U, 6x NEMA 5-15R outlets, w/network card	$ 2 000.00	$ 4 000.00	**0%**	$ 2 000.00	$ 4 000.00	
1	2	2	Cisco	IE-4010-4S24P	Cisco Industrial Ethernet 4010 Series - switch - 28 ports - managed	$ 7 500.00	$ 15 000.00	**0%**	$ 7 500.00	$ 15 000.00	
1	1	1	APC	AR3150	APC Netshelter SX, Server Rack Enclosure, 42U, Black, 1991.4H x 750W x 1070D mm	$ 2 500.00	$ 2 500.00	**0%**	$ 2 500.00	$ 2 500.00	
1	2	2	APC	AP7968B	Rack PDU,Switched,ZeroU,12.5kW,208V,(21)C13&(3)C19;3' Cord	$ 2 000.00	$ 4 000.00	**0%**	$ 2 000.00	$ 4 000.00	
1	2	2	APC	AR8442	Vertical Cable Organizer, 8 Cable Rings, Zero U	$ 200.00	$ 400.00	**0%**	$ 200.00	$ 400.00	
1	4	4	APC	AR8426A	Horizontal Cable Organizer 2U	$ 60.00	$ 240.00	**0%**	$ 60.00	$ 240.00	
1	1	1	APC	AR8132A	Combination Lock Handles (Qty 2) for NetShelter SX / SV / VX Enclosures	$ 200.00	$ 200.00	**0%**	$ 200.00	$ 200.00	
1	1	1	APC	AR8122BLK	Fixed Shelf 250lbs/114kg Black	$ 130.00	$ 130.00	**0%**	$ 130.00	$ 130.00	
1	20	20	Belkin	F3A102-06	Power extender - IEC 320 EN 60320 C13 (F) - IEC 320 EN 60320 C14 (M) - 6 ft	$ 25.00	$ 500.00	**0%**	$ 25.00	$ 500.00	
1	1	1	Panduit	DP24688TGY	Cat 6 Punchdown Patch Panel, 24 Ports, 1 RU, Black	$ 450.00	$ 450.00	**0%**	$ 450.00	$ 450.00	
1	1	1	Various		Servers and data protection (backup) hardware and software to support Survalent SCADA HMI and Historian	$ 200 000.00	$ 200 000.00	**0%**	$ 200 000.00	$ 200 000.00	Servers and backup harware and software were not part of the scope, so it is not detailed here, but that budgetary provision is sufficient for BBA to put together the server infrastructure BOM required to support Survalent SCADA software with the feature requirements listed in the FS Report (section 5.4).
							$ 236 533.00			**$ 236 533.00**	

Kit	Qty/Kit	Qty Tot	OEM	Model #	Description	Unit MSRP (CAD)	Amout MSRP (CAD)	Discount	Discounted Unit Price (CAD)	Discounted Amount (CAD)	Comments
IED WAN Networking (ALL WAN LTE NODE)											
1	1	1	Sierra Wireless	RV55_1104303	AirLink® RV55: Industrial LTE-A Pro Router Compact, Rugged, Low power, LTE-A Pro or LTE-M/NB-IoT Routers for Industrial IoT, SCADA and Field Service Fleets	$ 1 350.00	$ 1 350.00	**0%**	$ 1 350.00	$ 1 350.00	
1	1	1	TBD		Power Supply 120AC/24DC	$ 400.00	$ 400.00	**0%**	$ 400.00	$ 400.00	
1	1	1	Sierra Wireless	6000659	DIN Rail Bracket	$ 45.00	$ 45.00	**0%**	$ 45.00	$ 45.00	
1	1	1	Sierra Wireless	6001126	Wall/Mast mount; LTE MIMO; high gain directional antenna for fringe coverage areas	$ 230.00	$ 230.00	**0%**	$ 230.00	$ 230.00	
1	1	1	CITEL	MJ8-POE-C6A	TVSS (Transient Voltage Surge Suppressor) for CAT6	$ 75.00	$ 75.00	**0%**	$ 75.00	$ 75.00	
1	1	1	TBD		Coax Cable Lightning Arrestor	$ 50.00	$ 50.00	**0%**	$ 50.00	$ 50.00	
1	1	1	TBD		Antenna Cable	$ 50.00	$ 50.00	**0%**	$ 50.00	$ 50.00	
1	1	1	TBD		Antenna Mounting Hardware	$ 50.00	$ 50.00	**0%**	$ 50.00	$ 50.00	
1	1	1	TBD		Cabinet Installation	$ 500.00	$ 500.00	**0%**	$ 500.00	$ 500.00	
1	2	2	TBD		UTP Patch Cord 3 FT	$ 10.00	$ 20.00	**0%**	$ 10.00	$ 20.00	
1	1	1	TBD		UTP Patch Cord 6 FT	$ 15.00	$ 15.00	**0%**	$ 15.00	$ 15.00	
1	1	1	Phoenix Contact	2320225	QUINT-UPS/ 24DC/ 24DC/10	$ 600.00	$ 600.00	**0%**	$ 600.00	$ 600.00	
1	1	1	Phoenix Contact	2320322	UPS-BAT/VRLA/24DC/12AH (AGM)	$ 600.00	$ 600.00	**0%**	$ 600.00	$ 600.00	At least 8h of autonomy for RV55
1	1	1	TBD		Cabinet including fabrication (assumin a 10+ quantity)	$ 1 000.00	$ 1 000.00	**0%**	$ 1 000.00	$ 1 000.00	
1	1	1	TBD		Cabinet installation	$ 500.00	$ 500.00	**0%**	$ 500.00	$ 500.00	
							$ 5 485.00			**$ 5 485.00**	
IED WAN Networking (Hybrid LAN/WAN Aggregation Node)											
1	1	1	Sierra Wireless	RV55_1104303	AirLink® RV55: Industrial LTE-A Pro Router Compact, Rugged, Low power, LTE-A Pro or LTE-M/NB-IoT Routers for Industrial IoT, SCADA and Field Service Fleets	$ 1 350.00	$ 1 350.00	**0%**	$ 1 350.00	$ 1 350.00	
1	1	1	TBD		Power Supply 120AC/24DC	$ 400.00	$ 400.00	**0%**	$ 400.00	$ 400.00	
1	1	1	Sierra Wireless	6000659	DIN Rail Bracket	$ 45.00	$ 45.00	**0%**	$ 45.00	$ 45.00	
1	1	1	Sierra Wireless	6001126	Wall/Mast mount; LTE MIMO; high gain directional antenna for fringe coverage areas	$ 230.00	$ 230.00	**0%**	$ 230.00	$ 230.00	
1	1	1	TBD		Coax Cable Lightning Arrestor	$ 50.00	$ 50.00	**0%**	$ 50.00	$ 50.00	
1	1	1	TBD		Antenna Cable	$ 50.00	$ 50.00	**0%**	$ 50.00	$ 50.00	
1	1	1	TBD		Antenna Mounting Hardware	$ 50.00	$ 50.00	**0%**	$ 50.00	$ 50.00	
1	2	2	Netgate	7100-1U	NETGATE 7100 1U BASE PFSENSE+ SECURITY GATEWAY (Base w/32 GB RAM, 256 GB Storage)	$ 2 250.00	$ 4 500.00	**0%**	$ 2 250.00	$ 4 500.00	
1	2	2	Netgate	4-port-10-GbE-SFP+	4-port 10 GbE SFP+ Card with PCIe kit (will save on configuration and testing time)	$ 800.00	$ 1 600.00	**0%**	$ 800.00	$ 1 600.00	
1	3	3	Netgate	10G-SFP+_DA	10G SFP+ DIRECT-ATTACHED COPPER TWINAX PASSIVE CABLE (1 METER)	$ 50.00	$ 150.00	**0%**	$ 50.00	$ 150.00	
1	2	2	Perle	IDS-509-XT	Industrial Managed Ethernet Switch - 9 ports: 9 x 10/100/1000Base-T RJ-45 ports. -40 to 75C Industrial extended operating temperature. PRO software feature set	$ 2 200.00	$ 4 400.00	**0%**	$ 2 200.00	$ 4 400.00	
1	1	1	SEL	RTAC SEL-3530	Real-Time Automation Controller	$ 3 800.00	$ 3 800.00	**0%**	$ 3 800.00	$ 3 800.00	
1	10	10	TBD		UTP Patch Cord 3 FT	$ 10.00	$ 100.00	**0%**	$ 10.00	$ 100.00	
1	10	10	TBD		UTP Patch Cord 6 FT	$ 15.00	$ 150.00	**0%**	$ 15.00	$ 150.00	
1	1	1	CITEL	MJ8-POE-C6A	TVSS (Transient Voltage Surge Suppressor) for CAT6	$ 75.00	$ 75.00	**0%**	$ 75.00	$ 75.00	
1	2	2	APC	SRT1000RMXLA-NC	APC Smart-UPS SRT 1000VA, 120V, LCD, rackmount, 2U, 6x NEMA 5-15R outlets, w/network card	$ 2 000.00	$ 4 000.00	**0%**	$ 2 000.00	$ 4 000.00	
1	1	1	Panduit	DP24688TGY	Cat 6 Punchdown Patch Panel, 24 Ports, 1 RU, Black	$ 450.00	$ 450.00	**0%**	$ 450.00	$ 450.00	
1	1	1	Panduit				$ -		$ -	$ -	
1	1	1	Panduit				$ -		$ -	$ -	
1	1	1	TBD		Cabinet including fabrication (assumin a 10+ quantity)	$ 1 500.00	$ 1 500.00	**0%**	$ 1 500.00	$ 1 500.00	
1	1	1	TBD		Cabinet Installation	$ 500.00	$ 500.00	**0%**	$ 500.00	$ 500.00	
							$ 23 400.00			**$ 23 400.00**	

Algoma Power Inc.

Distribution System Plan

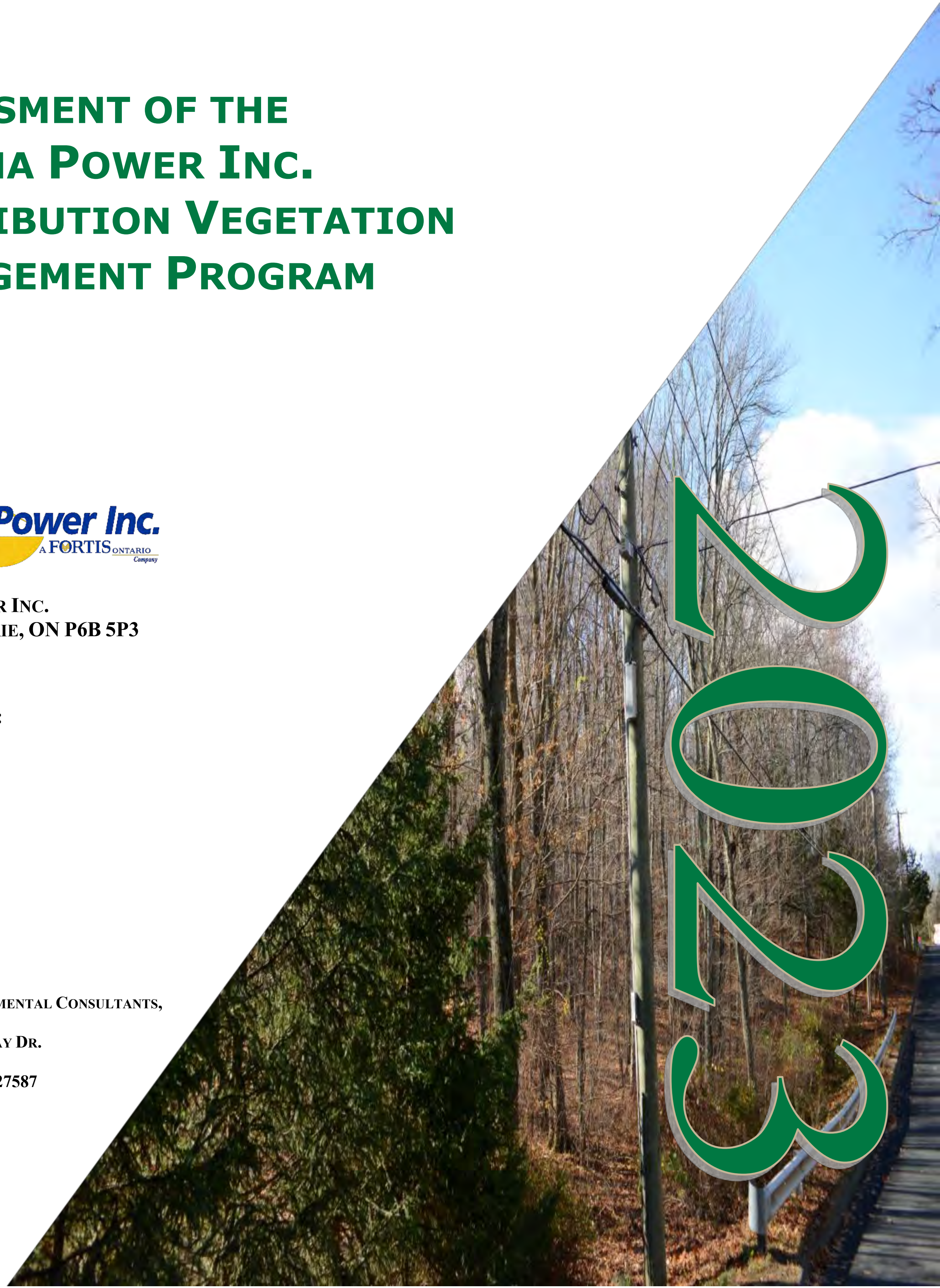
Appendix H

Assessment of the Algoma Power Inc. Distribution Vegetation Management Program

Prepared for:

Algoma Power Inc.
Sault Ste Marie, ON P6B 5P3

Revision Date:
May 28, 2024



Prepared by:

Lakeside Environmental Consultants, LLC
12324 Hampton Way Dr.
Suite 101
Wake Forest, NC 27587

Table of Contents

Executive Summary

Algoma Power Inc. (API) has engaged Lakeside Environmental Consultants, LLC (doing business as, ECI) to conduct a review of its distribution system vegetation management program. The goals were to assess program performance. Of particular importance to API:

- Review of outage data and vegetation related outages.
- Assess API's current standard for ROW clearances.
- Estimate the annual volume increment ("AVI") of work over the next 5 years.
- An analysis of the cost, operational, and environmental benefits of different vegetation maintenance work methods for both line clearing (tree trimming and removals) and brush control.
- A cost and operational assessment of the current cycle frequency and perform a comparison to industry recommended cycle frequency based on work activity.
- Review of related environmental factors and considerations unique to API's service territory and impacts to API's VMP.
- A determination of the annual VM funding requirement over the next 5 years.

ECI's assessment consisted of an analysis of available program documentation and interviews with the Vegetation Management Advisor, along with ECI's extensive experience with reviewing successful utility programs and processes. The review was a cooperative effort between API and ECI.

Summary of Key Recommendations

ECI has formulated the following top key recommendations to address the concerns identified in this study. **In order of importance**:

1. Work collaboratively with vendors to better understand and remove risk barriers that are driving up costs.
2. Consider working several high price bid circuits (pilot) under T&M to measure and quantify the potential savings over firm-price.
3. Pending a successful outcome of the pilot, consider converting the current firm price contract strategy to T&M, eventually building in incentives to encourage the contractor to take responsibility for production goals and targets. T&M contracts will allow for an easy transition to longer-term contracts and lead to the development of a local steady workforce.
4. Require the Arborist/Forester to update work specification documents, process documents and internal control reports to bring API up to best-in-class and meet current industry best management practices.
5. Continue to require the contractor to demonstrate that he/she is setting daily and weekly targets for work completion for his/her crews to control costs.
6. Expand the use of herbicides where allowed to treat stumps on removed deciduous trees (trees removed by contract tree crews) to prevent re-sprouting which leads to increased biomass when one stem becomes many stems.

7. Expand the current herbicide program on distribution line segments, particularly in rural areas. Consider a more robust Integrated Vegetation Management (IVM) program by continuing to implement foliar herbicide applications to control brush on the ROW floors. Refer to the provided IVM Management Plan for additional program enhancements. While initial costs may be significant, the potential for future cost savings is high.
8. Consider a work acceptance (QC) process for planned maintenance work utilizing the ANSI/ASQ Z1.4 audit process to reduce the amount of time required to perform completed work audits (see Appendix B). Incorporate the audit process into existing contracts and specifications.
9. Continue to maintain a maximum six-year maintenance cycle for pruning work. However, consider increasing brush cycle on manual cut rights-of-way (ROW) to recommended nine-year cycle if conditions allow, in order to save O&M planned maintenance expenditures.
10. Begin post-outage investigations on all multi-phase and outages affecting 89 customers or more or where the outage duration is in excess of 221 minutes. This will be beneficial to help identify problem areas requiring maintenance, aid in the development of reliability-based annual and long-range maintenance plans, ensure program dollars are being effectively utilized to reduce outage events, and verify that the correct outage cause-code was used. Refer to Appendix A for an example outage investigation form.
11. Adopt the principles of RCM (reliability centered maintenance) to ensure crews are cutting only the trees that should be maintained (See Appendix E).

Introduction

Algoma Power Inc. (API) is a wholly owned subsidiary of FortisOntario Inc. API, headquartered in Sault Ste Marie, Ontario provides electric service to over 12,000 electric customers in Northern Ontario's Algoma District from Wawa to Thessalon (Figure 1). The API distribution system is comprised of approximately 2,100 total distribution kilometers across a service territory of approximately 14,000 square kilometers.

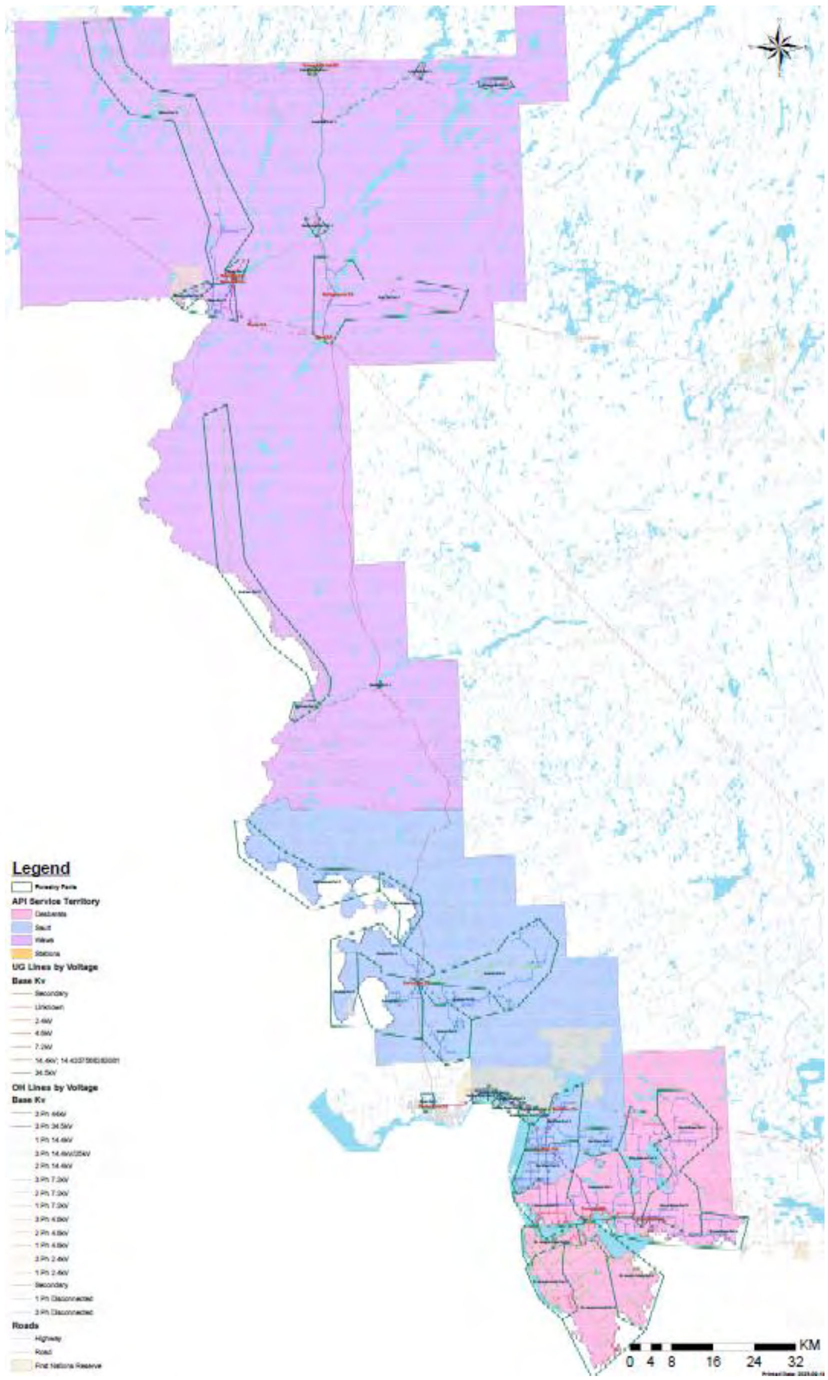


Figure 1. Algoma Power Inc. Service Territory.

API's Vegetation Management (VM) program is a key strategic initiative aimed at ensuring safe and reliable electric service for its customers. API engaged Lakeside Environmental Consultants, LLC (d.b.a., ECI) in September of 2023 to analyze its current vegetation management program with seven main goals in mind:

- Review of outage data and vegetation related outages.
- Assess API's current standard for ROW clearances.
- Estimate the annual volume increment ("AVI") of work over the next 5 years.
- An analysis of the cost, operational, and environmental benefits of different vegetation maintenance work methods for both line clearing (tree trimming and removals) and brush control.
- A cost and operational assessment of the current cycle frequency and perform a comparison to industry recommended cycle frequency based on work activity.
- Review of related environmental factors and considerations unique to API's service territory and impacts to API's VMP.
- A determination of the annual VM funding requirement over the next 5 years.

The focus of this assessment was to analyze the current vegetation management program and to provide recommendations for program improvements to assist API to take the VM program to the next level. The program review consisted of the following:

1. Evaluation of data and record keeping programs.
2. Evaluation of current contract strategies.
3. Evaluation of historical reliability performance.
4. Identification of basic areas where efficiency improvements would be beneficial in reducing costs.
5. Evaluation of clearance specifications, maintenance cycle and brush maintenance.
6. Evaluation of historical expenditures and future funding requirements.

ECI's assessment included an analysis of records and various documents provided by API. Key API management personnel familiar with the VM program provided additional important information during interview sessions with ECI. Information and documentation collected about general conditions, work practices and operating procedures were evaluated based on ECI's extensive experience with effective and efficient best practice right-of-way (ROW) management processes.

Report Structure

This report presents the results of ECI's assessment of the API distribution vegetation management program. The General Assessment and Recommendations section includes an analysis of the current program effectiveness by key program groupings and follows each assessment with specific program recommendations. Appendices contain supplemental, clarifying information relative to the evaluation.

General Assessment and Recommendations

This section presents general findings of ECI's assessment of the effectiveness of the current API VM program. Program effectiveness was evaluated through a review of service reliability, program management, safety, and cost. Recommendations are based on current program effectiveness, future goals and targets, and includes ECI's knowledge obtained from over 200 similar program assessments, and industry best management practices.

Vegetation Outage Analysis

Service reliability is a primary benefit of a well-structured VM program and is a typical measurement of program effectiveness. API provided ECI with all distribution outage data between January 1, 2018, and August 31, 2023. The number of non-storm (i.e., excluding MED and Supply) customers interrupted (CI) attributed to trees for all device types accounted for approximately 30 percent of the total non-storm outages for all cause codes on the distribution system for that same timeframe. Tree-caused outages below 20 percent of the total system outages are normally considered exceptional and a reasonable goal.

API's historical OMS data categorizes all tree-caused outages into nine primary cause codes:

Algoma OMS Tree Cause Codes

Pre-June 2023:

- 301 Falling Trees
- 302 Broken Branch
- 303 Tree Growth/Untrimmed Tree
- 304 Off-ROW Tree
- 305 Other Vegetation

Post-June 2023:

- 311 Falling Tree – On ROW
- 322 Broken Branch
- 323 Tree Growth/Untrimmed Tree
- 334 Falling Tree – Off ROW

In 2023, API was required to re-categorize the outage cause codes based on direction from the Regulator, which was implemented in June 2023. Prior to June 2023, API used cause codes 301, 302, 303, 304, and 305. From June 2023 onwards, API used 311, 322, 323, and 343.

Figure 2 presents the historical tree-caused outage trend for all non-storm distribution primary, secondary and service outages between 2018 and August 2023. Per Figure 2, tree-caused outages and customers interrupted (CI) have increased by 61 percent and 93 percent, respectively between 2018 and 2022. Not surprisingly, the lower CI years of 2018 and 2021 were earmarked by high CI exclusions for MED days which indicates these years may have been experiencing higher storm frequency (both excluded and non-excluded storms). It should be noted therefore, ECI does not feel the increases seen between 2018 and 2022 are systemic of program issues but rather directly related to storm frequency. The year 2023 appears to be on track to be a low CI event year despite having no recorded MED days as of August.

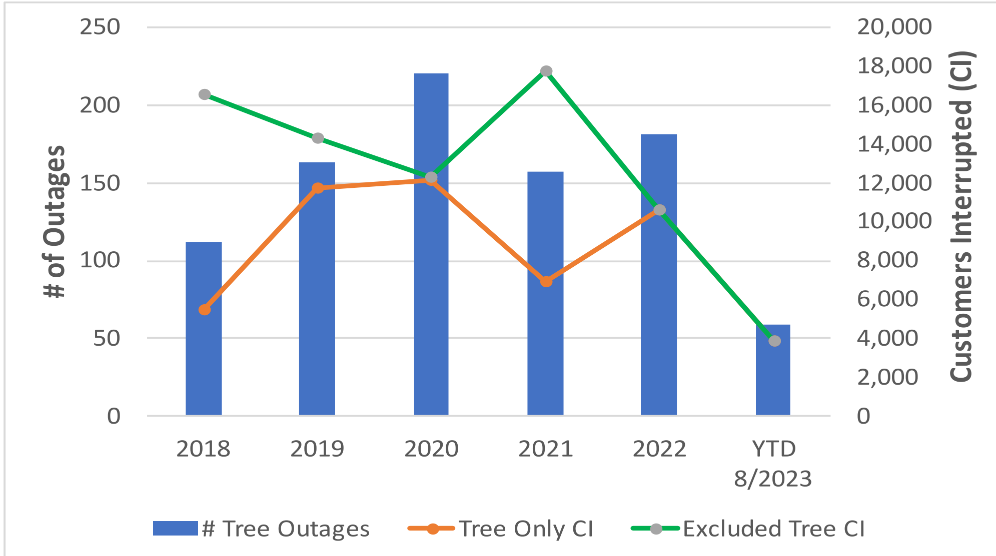


Figure 2. API Tree-Caused Outage Trends Between 2018 and August 2023.

A comparison of outages by single-phase versus multi-phase line sections was possible with the existing OMS data. It is considered important to know the relationship between outages occurring on single-phase versus multi-phase line segments. Namely to understand that outages on multi-phase line sections may, and often do, impact significantly more customers than single-phase outages. It is not uncommon for utilities to focus only on the outage reduction metric as a primary measure of effectiveness. However, it should be considered that customers interrupted (CI) is a much better metric for the measurement of program effectiveness since the reliability goal for a utility should be overall customer impact. The prevention of one transformer interruption affects far fewer customers than the prevention of one three-phase feeder outage.

Based on ECI's analysis, API experienced an annual average of approximately 6.6 multi-phase and 160 single-phase outages per year between 2018 and 2022. The number of customers interrupted (CI) by multi-phase outages approximately 37 percent of the total customers impacted. This slightly higher than the 30 percent we see normally across the industry, indicating there may be some opportunity in CI reductions.

From a customer interrupted (CI) per kilometer perspective, this equates to an annual CI/Km of 1.67 for single-phase (3,477.6 CI per year/2,089 kilometers) and 2.83 for multi-phase lines (5,913 CI per year/2,089 kilometers). Therefore, it should be understood that a dollar spent on multi-phase maintenance of vegetation, contributes more significantly to total customer satisfaction by reducing the number of interruptions a single individual may experience in a given year and will have a much lower cost per CI saved from an overall program effectiveness standpoint.

Benchmark Comparisons

One metric used to compare the effectiveness of vegetation management programs between utilities is non-storm tree-caused outages per 100 overhead line kilometers. ECI used the average between 2020 and 2022 for benchmarking API non-storm tree-caused outages against 11 similar sized Midwest and Northeast utilities (2-

Cooperatives, 1-Municipal, and 8-IOU with three utilities specific to Michigan). Figure 3 compares API tree-caused outage (N) frequency to the defined set of benchmarked electric utilities. API ranked in the third quartile. While this data is not adjusted for exposure (e.g., tree density), it is useful in calibrating outages based on relative distribution size. API reported 5.3 tree-caused outages per 100 kilometers of overhead distribution line in 2018 and an average of 8.9 tree-caused outages per 100 kilometers between 2020 and 2022. In comparison, the average tree-caused outage per 100 kilometers identified in the benchmark group was 10.9.

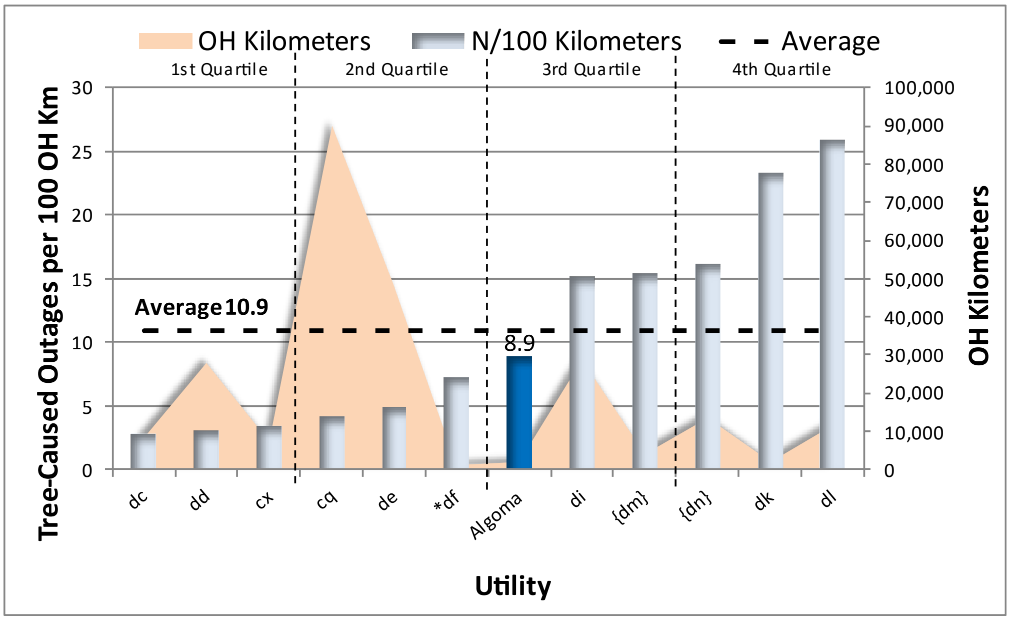


Figure 3. Benchmark of API Non-Storm Tree-Caused Outages per 100 Kilometers of Overhead Distribution Line as Compared to 11 Other Utilities.

Figure 4 and Figure 5 present additional reliability comparisons to the same benchmark group. The reliability provided by API indicates a second quartile performance for customers interrupted (CI) and a first quartile ranking for customer minutes interrupted (CMI) per 100 kilometers from tree-caused outages as compared to this benchmark group. This indicates that API has been relatively effective in preventing tree-caused outages.

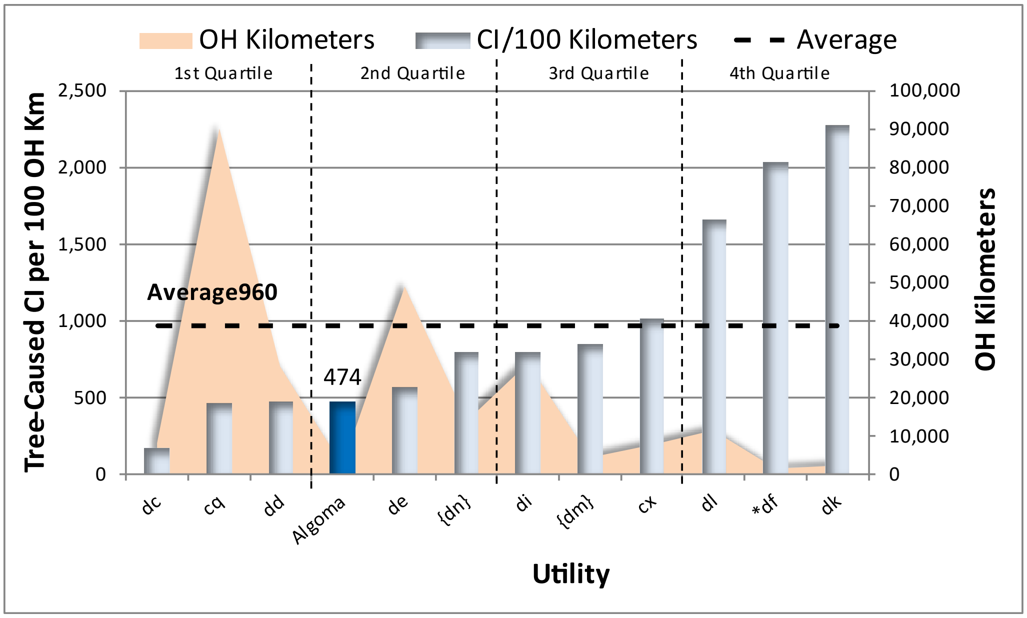


Figure 4. Benchmark of API Non-Storm Tree-Caused Customers Interrupted per 100 Kilometers of Overhead Distribution Line as Compared to 11 Other Utilities.

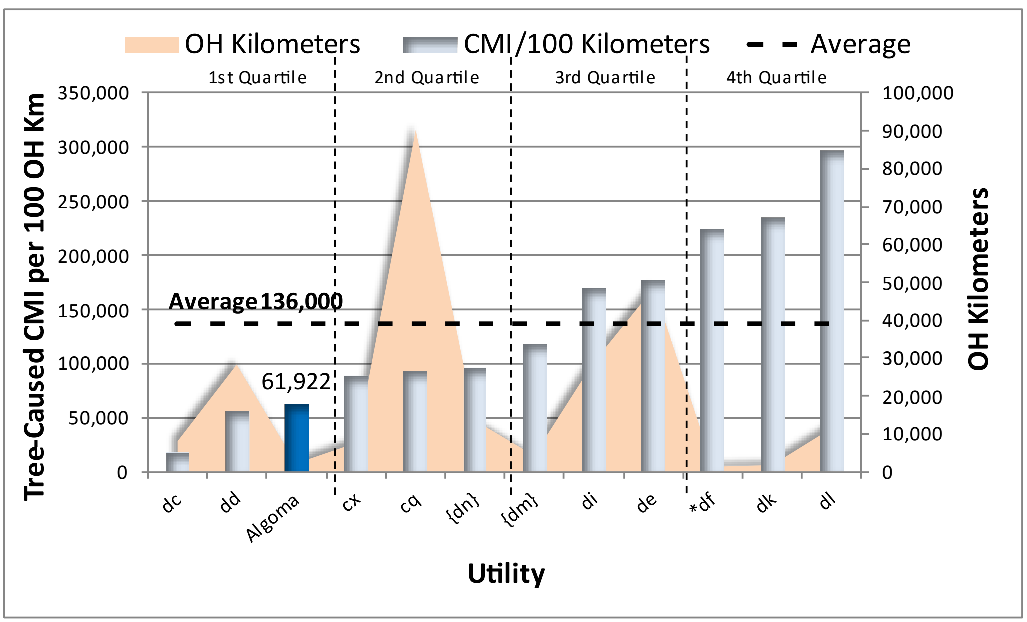


Figure 5. Benchmark of API Non-Storm Tree-Caused Customer Minutes Interrupted per 100 Kilometers of Overhead Distribution Line as Compared to 11 Other Utilities.

System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Customer Average Interruption Duration Index (CAIDI) can be effective tools in measuring the effectiveness of a vegetation management program when isolated to non-storm tree-caused outages. However, it should be noted that utilities with lower customer density (i.e., Algoma) tend to perform worse in these three metrics since the number of customers is the denominator in their calculations. Figure 6 through Figure 8 present the tree only SAIFI, SAIDI, and CAIDI for the API system benchmarked against 11 selected utilities.

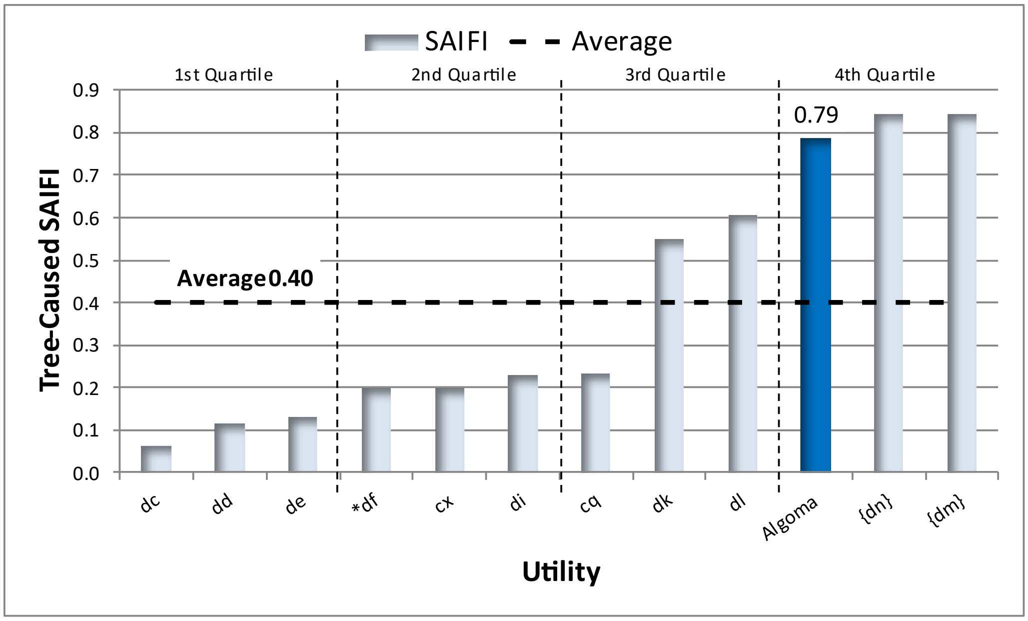


Figure 6. Benchmark of API Non-Storm Tree-Caused System Average Interruption Frequency Index as Compared to 11 Other Utilities.

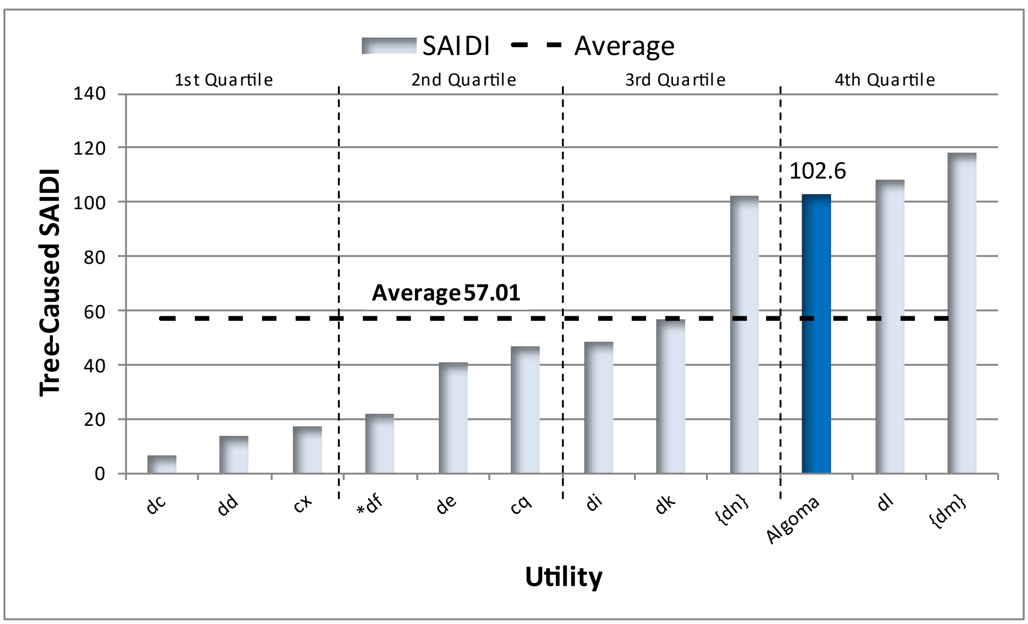


Figure 7. Benchmark of API Non-Storm Tree-Caused System Average Interruption Duration Index as Compared to 11 Other Utilities.

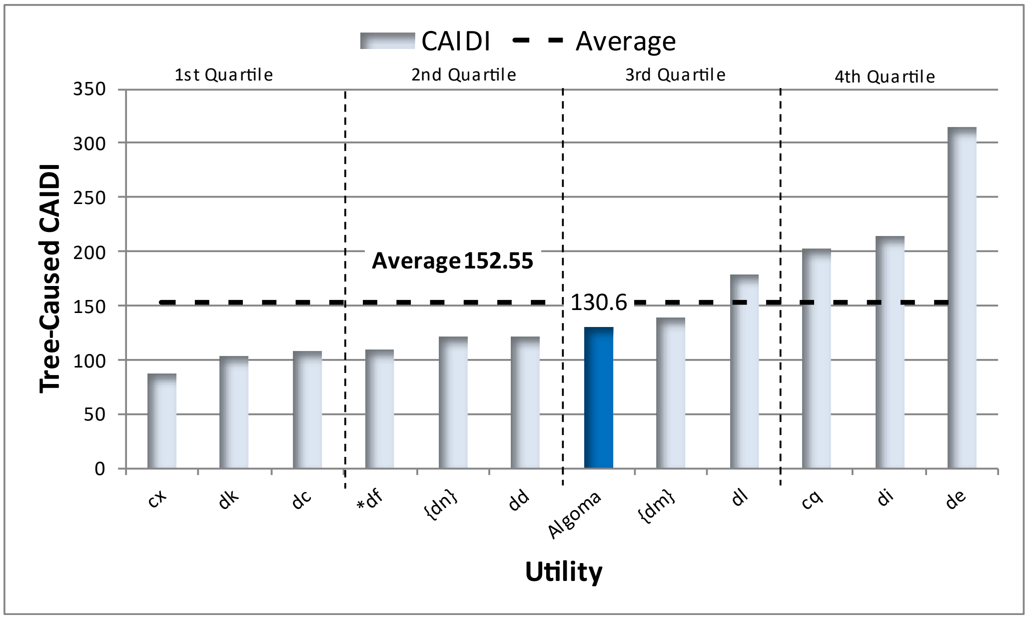


Figure 8. Benchmark of API Non-Storm Tree-Caused Customer Average Interruption Duration Index as Compared to 11 Other Utilities.

API's higher SAIFI, SAIDI, and CAIDI indices are unfortunately a result of API's low customer count per kilometer and not a direct reflection of system performance. While it is a fair representation of the average customer experience, it should be noted that risk exposure to tree and other outages is not customer dependent and there will always be a baseline of outages per kilometer that are fundamental to all overhead line construction (the risk). API's number of customers per kilometer is approximately five times lower than that of the benchmark group. However, that does not implicitly imply that there is no opportunity for system improvement through CI reduction. This may be achieved through a focus on multi-phase line sections. API should begin to conduct post-outage investigations to gather more detailed information on outages that meet specific criteria. The post-outage investigation criterion should include: 1) device type affected; 2) number of phases affected; and 3) construction type (see example data collection form in Appendix A). This may allow for analysis that may indicate certain problematic construction types that are more susceptible to tree outages. Tree-outage cause codes in combination with post-outage investigations can be used to identify the root cause of tree issues. It may also point to causes that occur off-ROW that may warrant a stand-alone hazard tree patrol and removal program or further support the need for a mid-cycle program. It will assist API in determining if program dollars are being targeted to control the cause of tree outages.

Customers Interrupted (CI) and System Average Interruption Frequency Index (SAIFI) are two of the most important indicators of the total customer experience which can be directly impacted by vegetation maintenance. By normalizing CI using circuit kilometers, the worst performing circuits can be identified. This methodology helped to identify one worst performing circuit (Figure 9) that exceeded two standard deviations and accounts for approximately 18 percent of the total CI from 2018 to August 2023 while representing only 0.4 percent of the total system kilometers. This type of data may be used to help re-prioritize annual circuit maintenance plans or adjust inspection plans to get the highest return on investment in terms of improved CI per dollar expended.

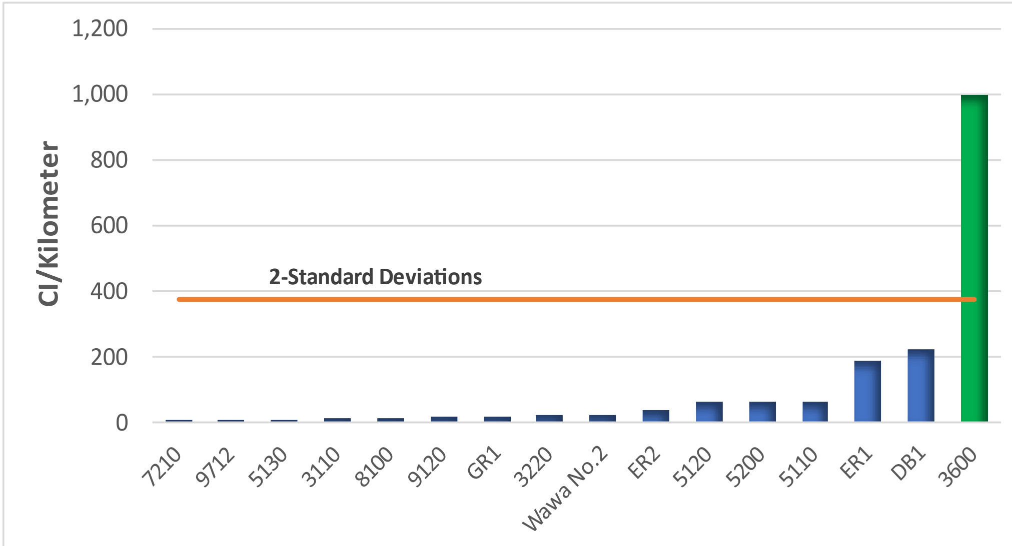


Figure 9. API 2018 to August 2023 Total Customers Interrupted (CI) Per Circuit Kilometer Showing Outlier Circuits Greater Than Two Standard Deviations (STD).

From Figure 9, it can be surmised that the one identified worst performing feeder may have off right-of-way or other issues that are driving the high CI per kilometer. There are often other practices that may be considered to further reduce tree-caused interruptions. Opportunities include an enhanced post-outage investigation program, mid-cycle program, and a hazard (risk) tree identification and mitigation program.

Feeder breaker, substation, and three-phase recloser outages generally generate higher CI. Utilities with high CI can generally benefit from split cycle multi-phase and single-phase maintenance programs. The number of outages per kilometer on the API system along with average CI per kilometer, does indicate a need for a split program at this time. Thorough tree-outage field investigations should be performed to help identify the issues with the circuit outlier identified.

Recommendations

Vegetation Outage Analysis

The recommendations offered below are directed at improving outage data reporting which can be used to help target vegetation program dollars to maximize reliability improvements and drive customer satisfaction improvements:

1. Use device type interrupted (e.g., substation, breaker, recloser, lateral fuse, transformer, service, etc.) and phase interrupted (e.g., A, B, C, AB, AC, etc.) to assist in determining multi-phase versus single-phase outages. This may lead to shortened cycles on multi-phase lines or the need to implement or enhance a mid-cycle (cycle buster) program.
2. Continue to ensure accurate detailed outage data is available in the current OMS to allow for outage analysis to determine high risk circuits and to develop outage mitigation plans.

3. Begin post-outage investigations on all multi-phase tree outages and selected single-phase tree outages affecting 89 customers or more or where the outage duration is in excess of 221 minutes (average CI and duration per outage between 2018 and YTD 9/2023 for all cause codes). This will be beneficial to help identify problem areas requiring maintenance, aid in the development of reliability-based annual and long-range maintenance plans, ensure program dollars are being effectively utilized to reduce outage events, and verify that the correct outage cause-code was used. Refer to Appendix A for an example outage investigation form.
4. Develop and begin to use customized tree outage reports for the day-to-day operations to monitor circuit performance. Currently, outage reports cannot be easily tied to last trim dates due to disassociation of tree maintenance circuit areas (forestry areas) to GIS circuit information. This should be corrected as soon as possible.

Specifications

ECI has reviewed API's specifications and guidelines document titled, ***Schedule B Owners Deliverables*** (see Appendix G). The contract specifications document serves as both a standalone enterprise document and contract document that contains sufficient information for the contractor to meet all the work requirements. A careful review of this document did not yield any major areas of concern and was found to be in line with industry standards. However, a couple of references were noted as needing to be updated. Those are:

- Section OD-8.3.1.2 – Update to newest ANSI A300 reference which is "ANSI A300 2023 Tree Care Standards".
- Section OD-8.3.1.3 (d) – Update same as above.

API utilizes primarily Firm Price or Lump Sum contract service agreements for routine vegetation maintenance performed by the tree contractors. A common industry practice is to retain some level of T&M contracts to perform miscellaneous ticket type work (e.g., customer requests, capital/new construction jobs, operations hot-spot requests) even when firm price is the primary contract type. While it is feasible to bid firm price, lump sum, or unit price contracts for larger operations requests or large capital jobs, smaller jobs (e.g., customer trim requests) typically require too much administrative time to effectively bid as this contract type. Further, by doing so, it can be expected to pay a premium on smaller jobs, driven primarily by contractor mobilization and de-mobilization costs and other start-up costs. Even utilizing unit price contracts for ticket work (e.g., annualized average cost per ticket basis) will have a similar premium rate attached due to the contingencies built into the bids because of fluctuating work scope. Contractors who are guaranteed a presence throughout the budget cycle and over multiple years will typically provide better rates. Fragmenting work into smaller short-term duration work and using multiple contractors will normally equate to higher bid prices.

The main advantage of unit price and firm price contracts for planned maintenance work is that they are inherently performance-based. They generally offer the lowest production risk for the utility by placing the burden to monitor crew productivity on the tree contractor and "incentivize" the contractor to control costs (see Appendix D for additional information). This minimizes the need for the utility to control cost through constant field management. It is possible to have a T&M contract with many of the benefits of lump sum contracts. Performance-based T&M contracts are a contract strategy that works well at accomplishing this goal. Performance-based T&M contracts generally use incentives to share saving and even cost overruns with the contractor (see Incentive Based Contracts in Appendix D). As an example, the utility sets the total circuit cost based on historical data for a given work unit and the tree contractor is "incentivized" to outperform the target by maximizing production in order to reap a bonus check as part of the shared savings.

Recommendations

Specifications

API should:

1. Update specification document Schedule B Owners Deliverables to reflect new ANSI standards updates.

Contract Strategy

In today's labor market, where contractors find the procurement of resources a challenge, T&M may be considered a preferrable contracting strategy as compared to firm price, even though in T&M the burden of ensuring production falls upon the utility. Many utilities have been struggling with completing their annual work plans utilizing firm price contracts. Contractors have been operating with understaffed crews and simply cannot meet the annual kilometer goals requested of them by the utility. What is worse is that tree contractors bid on work knowing that they may struggle with procuring these resources and completing the targets.

ECI suggests that, even though historically ECI or the industry did not commonly recommend T&M as a primary contract strategy for planned maintenance work, there is a case for its use during this time of labor shortages. This strategy may not totally fix the issue of completing the annual targets; however, it does allow for the prevention of overpayment and contract defaults. Even with an hourly contract, a T&M contract with incentives can be established to control costs. See Appendix D under Turnkey and Incentive Based Contracts. Due to the current labor shortage, ECI suggests that API consider hourly contracts to supplement the firm price strategy but consider adding incentives to put some of the burden for production back onto the tree contractor.

Change: Is Firm Price Still the Correct Contract Strategy?

The firm price contract strategy at API has presented increased challenges to the completion of the targeted maintenance kilometers within budget. Average bid cost per kilometer for brush plus line clearing in 2024 to 2027 ($16,264) RFP's have increased as compared to the average cost per kilometer paid between 2018 and 2023 ($12,868). The increases may be attributed to four main cost drivers:

1. Deferral of work (i.e., over six-year cycle).
2. Normal market adjustments.
3. Supply and demand drivers.
4. Covid-19.

Deferring work even one-year past the optimum cycle, can increase future maintenance cost for that circuit by as much as a factor of 1.6[1]. Trees in contact with the wire require additional effort and expense to maintain.

API experienced just slightly higher than average (as compared to industry averages) contracted maintenance cost per kilometer. However, the slightly higher than average cost per kilometer may be attributable to higher tree densities as compared to the benchmarked group. Even with the higher tree densities per kilometer, API was successful in controlling cost attributable to past maintenance practices which kept tree and brush conditions at optimal levels. However, even with these optimal conditions, the contractor rates would not be anticipated to remain static. Increases to employee wages have risen substantially as well as insurance and overheads. ECI feels that a marginal portion of the increases to cost per kilometer in the 2024-2027 bids are due to *normal market adjustments* and bring API closer to industry averages.

Supply and demand drivers on the other hand, are believed to be the main driver in 2024 through 2027's substantial increases. At API as well as practically every utility throughout the country, procuring qualified tree contractors is a challenge. In a good economy, tree contractors find it difficult to hire and retain employees due to competing industries where pay is the same or better. As such, tree contractors increase wages in order to compete. In firm price bid scenarios, tree contractors often bid on work for which they have not yet acquired the resources for which to assign the work. In anticipation of the tight resource market, tree contractors will tend to over-bid work in anticipation of having to attract employees with higher wages. And when faced with smaller contracts that will require the addition of crews, tree contractors may "mark-up" work simply because they anticipate hiring difficulties, or they actually just do not want the work. However, they often over-commit when utilities accept their significant over-bid, and the end result will be that they are either successful and make a huge profit, or they default. Tree contractors know that resources are scarce for all contractors, and that market pressures justify significantly higher bid prices such as experienced by API as well as other utilities throughout the country. It is currently a "buyers" market, and the vendors are taking advantage. In a conversation with a tree contractor manager on another utility, it was boasted that he recently submitted a bid to that utility (work he really did not want or need) that was so outrageous that he was sure they would not accept. The utility needed to get the work completed and therefore accepted his competitive offer, which surprisingly was the lowest. In essence, the utility agreed to pay over $60,000 dollars to prune just over a mile of line. Of course, Covid-19 has further exacerbated the resource shortage and added to additional cost increases such as this.

<u>Solution:</u>

Firm/lump price contracts are considered an industry best practice because they put the burden of monitoring production on the contractor. However, it is becoming apparent in today's economy, that utilities are beginning to pay the price for this convenience. The solution to this situation is not a simple one. The lack of qualified tree trimmers and the inability of the tree industry to attract new people places a dark cloud over the future of firm price contracting, at least for the near future.

[1] Browning, D. M., & Wiant, H. V. (n.d.). The economic impacts of deferring electric ... Environmental Consultants, LLC. https://www.eci-consulting.com/wp-content/uploads/2017/10/Deferring-Electric-Utility-Tree-Maintenance_JOA.pdf

To combat the resource shortage issue, utilities must begin to invest in developing local resources. Local employees that are ingrained in their community can offer workforce stability. This can be accomplished in two ways. Bringing crews in-house (which has its own cost issues and challenges) or by providing long-term contracts to tree contractors. The benefit of long-term contracts (i.e., three to five years) is that longer term employment attracts more candidates. Many people are not willing to leave their existing steady job for short-term employment where work is not guaranteed beyond a year.

The next step is to consider T&M as the primary contract strategy. The fear that many utilities have is that T&M contracts require additional oversight, which may be true, and that budgets become less certain or harder to control. However, the upside is that the potential for significant savings is undeniable, particularly based on the escalating cost per kilometer at API. A T&M contract at API will also allow an easy transition to longer term contracts. T&M contracts with incentives (see Appendix D) can offer much of the same production protections as firm price contracts.

To measure the potential savings that may be gained through a T&M contract, ECI recommends that API consider working several high price bid circuits as T&M. This will allow API management to ascertain enough data to develop a business case for a T&M transition going forward if appropriate.

Recommendations

Contract Strategy

API should:

1. Consider working several high price bid circuits (pilot) under T&M to measure and quantify the potential savings over firm-price.
2. Pending a successful outcome of the pilot, consider converting the current firm price contract strategy to T&M, eventually building in incentives to encourage the contractor to take responsibility for production goals and targets. T&M contracts will allow for an easy transition to longer-term contracts and lead to the development of a local steady workforce.

Clearance and Accessibility

API currently possesses a documented clearance specifications and guidelines document ***Schedule B Owners Deliverables*** (see Appendix G). Clearance specification and guideline documents are considered a best management practice and are considered of utmost importance, particularly the inclusion of specification documents within contract bid documents. A lack of defined processes and procedures can lead to misunderstandings, potential contract disputes, as well as inconsistent or poor work quality. A review of the current API specifications and guidelines document is within industry best management practices.

Utilizing the vegetation workload and growth rate study confirmed in March 2014 by Ecological Solutions Inc., API developed tree clearance charts specific to the regrowth rates documented in that study. Therefore, API uses species specific clearances as recommended by industry best-management practices. The clearance recommendations are based on average regrowth rates for the predominant species on the API system based on a six-year cycle length.

When examining the regrowth rate information collected in the 2014 study (example: Figure 10), API clearance specifications appear adequate and based on utility specific regrowth rates. It should be noted that there is no industry standard for clearance at the time of pruning. Each utility is different based on their cycle goals and species regrowth rates within their service territory. However, ECI can confirm that current API clearances as specified in their clearance standards appears to be reasonable and support a six-year cycle strategy.

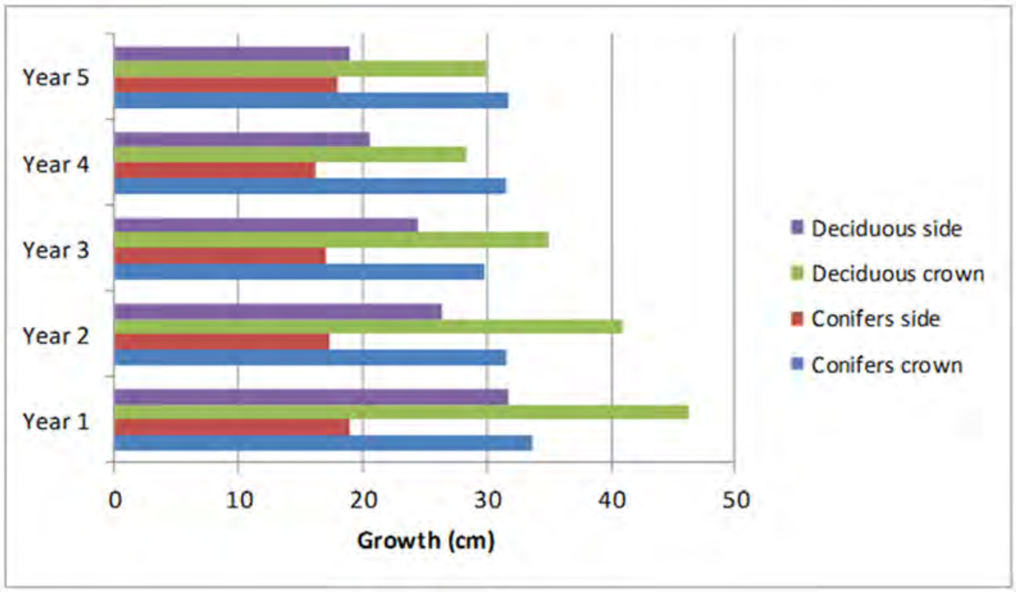


Figure 10. Average Pruning Regrowth Rates by Year Per 2014 Study.

Many utilities that have worked with ECI consider a ten percent tree-to-conductor contact rate over the entire distribution system as an acceptable guideline. Optimally, to maximize ROI, it is considered prudent to schedule a line for maintenance just as trees are approaching the conductors. API appears to currently be at this threshold (Figure 11). However, since trees of the same species can grow at different rates, API should continue to monitor older circuits to determine if the six-year pruning cycle is appropriate. Appendix F contains a summary article from a study conducted by ECI called *"How Trees Cause Outages"*. This study explores the relationship between outage potential from trees, construction, and voltage gradient. This may be helpful to understand the consequences of altering circuit cycles.

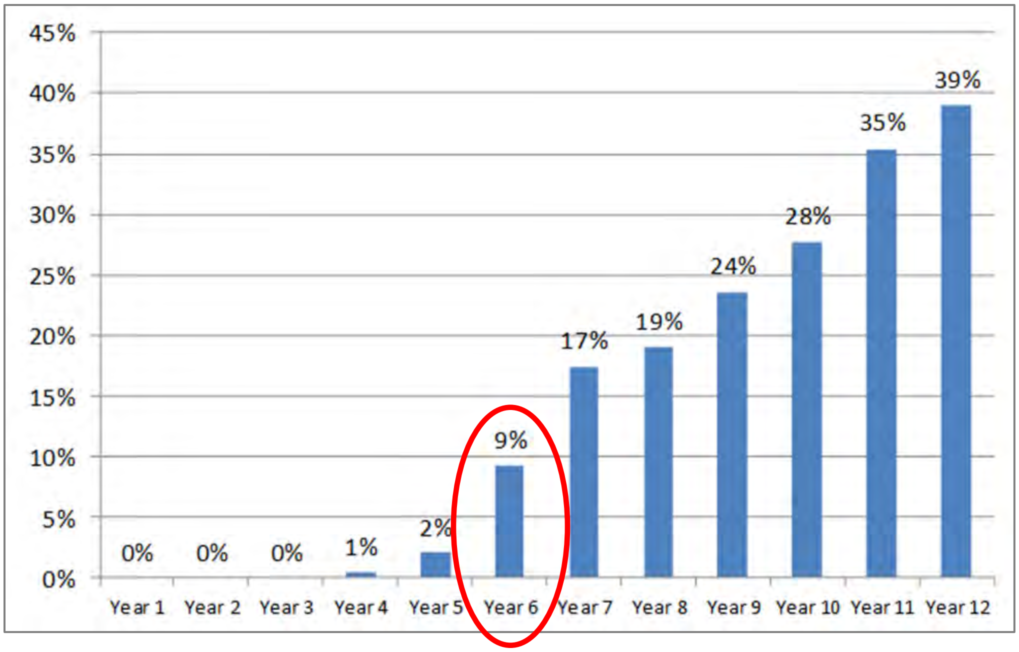


Figure 11. Pruning Breaching Limit of Approach by Year as Calculated in the 2014 Study. Showing Six-Year Cycle at 10 Percent Contact.

Circuit Trimming

It is well understood that in order to have an effective reliability program, a device should be maintained in its entirety. Most utilities recognize this to be the entire feeder and/or lateral segments. A device can be more accurately defined therefore, as the substation switch or lateral fuse. It is possible to isolate pruning to lateral fuses and feeder fuses.

An alternative to circuit trimming is a split cycle between feeder backbone and the rest of the circuit. This normally entails shorter cycle lengths on the feeder backbone (substation to first protective device) to assist with substantially reducing customers interrupted (CI). Since multi-phase line sections are more susceptible to tree-caused outages due to voltage gradient (see Appendix F).

A substation as a maintenance unit (i.e., all circuits issued out of one substation), may be considered too large to effectively target reliability improvement to the worst performing circuits or feeders. If there are for example, four circuits coming out of the substation that total 25 kilometers each, and only one of them is considered to have reliability issues, then 75 percent of the line kilometers trimmed will have little impact on reliability improvement. That is not to say that the rest of the circuits do not need to be trimmed, it just suggests that these circuits should be scheduled after the completion of those circuits with proven reliability issues (i.e., high CI over the past three years).

Fuse Coordination and Smart Metering

Fuse coordination, or properly fusing lateral line sections, is one of the best investments in lowering CI and SAIFI. Improperly fused laterals may inadvertently cause the substation breaker to operate when a tree-caused fault occurs. Many utilities deploy either a fuse save or fuse blow strategy. Those utilities choosing to implement a fuse save strategy, often over-fuse the lateral line sections with the hopes that a lateral fault will be cleared (e.g., in the case of a tree that falls and eventually clears the line) before the substation locks out. Unfortunately, in many cases, the tree fault does not clear, and a subsequent feeder outage occurs. It is a risk that some utilities take in order to reduce customer minutes.

Substation GI/GX setting are another strategy that some utilities take to prevent or reduce outages. By adjusting these settings, which controls the sensitivity at the substation breaker, many lower fault outages are ignored. However, the inherent risk is that in a best-case scenario, a higher GI/GX setting may produce sympathetic outages or momentaries on other feeders within the same substation. At worst case, substation equipment damage may occur.

Smart metering is a great alternative; however, it does not reduce or change the need for adequate tree maintenance, nor does it change the overall maintenance strategy. It may produce short-term results to focus on pruning devices between smart meters, however, ignoring other sections on the feeder backbone will have negative long-term consequences in terms of over-growth conditions that will need to be dealt with. Due to the deferment of these over-growth conditions, costs to maintain these line sections will be much higher. The deferment of maintenance for even one year past the optimal pruning cycle can increase maintenance costs by as much as 60 percent.

Recommendations

Clearance and Accessibility

API should:

1. Keep current pruning maintenance cycle at a maximum of six years. However, continue to monitor older circuits for line contact and adjust the cycle as needed to avoid excessive tree-wire contact.

Program Management and Effectiveness

Sound program management forms the basis for an effective vegetation management program. The most effective and efficient vegetation management programs typically have a centralized management structure and sufficient technical expertise. A knowledgeable individual with the responsibility to enforce established standards is necessary to provide the leadership required to ensure a successful vegetation management program.

There a several work functions common to managing vegetation management programs. Those functions include:

1. Contract administration
2. Budgeting
3. Annual and long-term scheduling
4. Work planning
5. Auditing
6. Planned maintenance work execution
7. Reactive maintenance work execution
8. Customer communications and education

It is important to have adequate resources to manage these functions. Each function carries specific responsibilities that contribute to the success of the Vegetation

Management Program. Generally, the first three functions can be combined under Project Management. The duties for each function typically include:

1. **Project Management**
   - Developing and maintaining standardized clearance specifications and guidelines.
   - Setting system and regional performance goals and objectives for the vegetation management program.
   - Developing and monitoring program metrics to measure compliance with program goals and objectives.
   - Defining and standardizing system processes and procedures.
   - Managing vendor contracts, including contract specs, bid documents, and contract incentive programs.
   - Developing short and long-term budget requirements.
   - Monitoring and tracking of vegetation management expenditures and ensuring expenditures are within approved budgets.
   - Developing short and long-term annual plans and overall schedule based on system performance goals.
   - Drive new technologies to better enhance performance tracking.
   - Internal and external stakeholder communications/reports regarding budget and target compliance.
   - Regulatory compliance support.
2. **Work Planning**
   - Ensuring that tree crews are adequately supplied with scheduled work to maintain high levels of production.
   - Identifying and recording individual work units to be maintained that meet the goals and objectives of the vegetation management program.
   - Removing customer barriers or other obstacles to allow tree crews to focus on production.
   - Obtaining owner permissions for removal and/or obtaining permits.
   - Ensuring customer satisfaction by clearly defining the scope of work.
   - Preparing work packets for tree crews.
   - Act as a liaison between API and its customers.
   - Address and escalate customer issues to API management.

3. **Auditing**

- Random inspection of in-progress tree work to identify defects prior to work completion. This allows the tree contractor to remedy the defects before crews leave the site.
- Inspection of all completed tree work for contractual compliance.
- Issuing defects back to the tree contractor for remedy and tracking remedies for timely completion.
- Tracking defect metrics that can be utilized in performance measures and incentives.

4. **Planned Maintenance Work Execution**

- Direct customer communication regarding planned maintenance work activities.
- Monitoring customer notification process and procedures for planned maintenance work.
- Customer complaint resolution and ensuring complaints are resolved in a timely manner.
- Managing customer expectations through face-to-face meetings and customer education.
- Determining and managing resource requirements.
- Work scheduling and assignment of work packets to contract tree crews and tracking progress.
- Monitoring in-progress and completed work regarding contract compliance.
- Ensuring planned maintenance work activities are completed within budget parameters.
- Monitoring contractor performance to maximize productivity.
- Ensuring program maintenance targets (i.e., kilometers complete) are met.
- Managing internal and external obstacles that may hinder work unit completion.
- Ensuring that crews stay focused on planned maintenance work and prevent the unnecessary pulling of crews that may impact target completion.

5. **Reactive Maintenance Work Execution**

- Managing customer and other reactive requests and accurately track work progress and completion.
- Inspecting reactive requests prior to issuing to tree crews to manage workload and prevent the unnecessary waste of program dollars.

- Managing internal reactive maintenance requests by proactively working with operations groups to maximize impact of limited funding.
- Managing customer expectations through personal contact and education.
- Ensuring valid reactive requests are completed per accepted service level agreements.
- Managing resource requirements and ensuring adequate resource coverage is maintained to support restoration needs.
- Monitoring contractor performance to maximize productivity.
- Monitoring in-progress and completed work regarding contract compliance.
- Performing tree-outage autopsies for root cause analysis.

6. **Customer Communications and Education**

- Integration and alignment of corporate messages throughout various communication tools.
- Assisting in the creation and dissemination of messages related to corporate direction, policy matters, and other relevant topics.
- Translate services and product strategy into effective marketing plans and communications materials.
- Developing technical articles, brochures, and advertisements and the development of on-line content for website.
- Directly interface with customer services to ensure consistent messages through the development of standardized call scripts for vegetation management services.
- Interfacing with corporate communications as needed to develop communications and educational strategies.
- Interfacing with regulatory group as needed.

Adequate supervision of day-to-day operations is essential to the implementation of long-term cost-effective work practices and operating procedures. Most utilities have found that one person can effectively supervise about 8 to 10 small groups (i.e., line clearance crews) consisting of a maximum of about 25 to 30 people. ECI's experience in the utility line clearance industry and several studies support this level of supervision that will include most, if not all the identified job functions listed above.

Figure 12 shows data from two benchmarking studies that evaluated the average number of line clearance crews supervised by utility arborists (excludes supervision/management). In the Pennsylvania Electric Association (PEA) and Edison Electric Institute (EEI) studies, the average ratio of line clearance crews to each utility arborist was respectively 8 and 11 (Figure 12). However, in both studies 75 percent of the reporting utilities average 10 crews or less per supervising arborist. Figure 12 also shows that in a benchmarking study of over 20 utilities, the two-overall best-in-class utilities have a ratio of approximately one utility arborist (including the system arborist) for every six-line clearance crews.

API should review the list of management functions listed above and determine if the current or future vegetation management staff can perform those activities along with the field responsibilities.

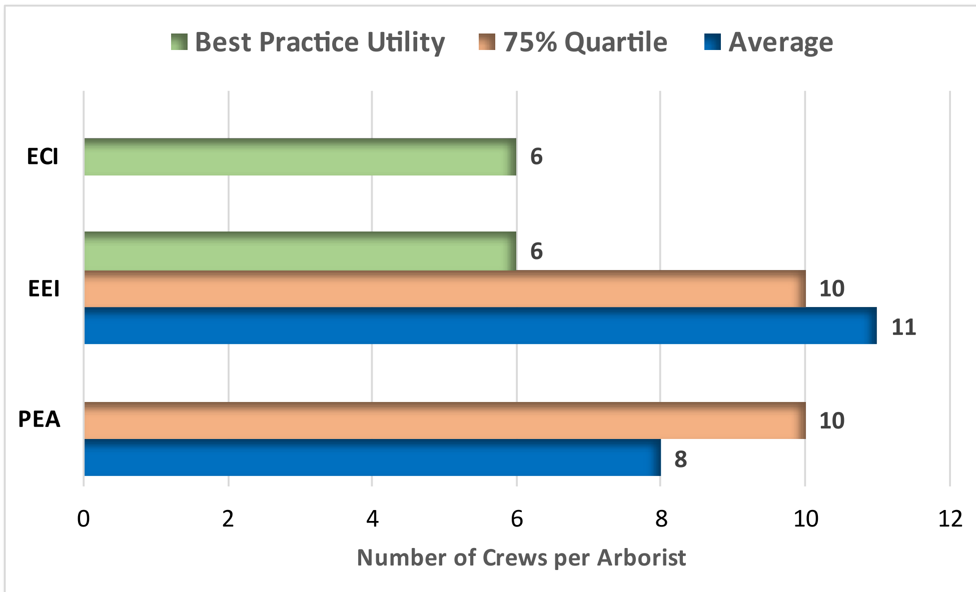


Figure 12. Comparative Data on the Average Number of Line Clearance Crews Overseen by Utility Foresters.

Recommendations

Program Management

API should:

1. Review the various functions outlined for a successful Vegetation Management Program and determine if the current staffing level can effectively manage/support any additional responsibilities not currently performed and consider the addition of foresters/arborist to supervise and support the program.
2. Update process documents which are currently missing to address the work functions and responsible resources.
3. Involve to every extent possible, the vegetation management personnel in International Society of Arboriculture (ISA) meetings and other industry meetings to widen the knowledge database. Work toward arborist certifications where necessary.

Customer/ Property Owner Notification/ Communication

API does currently possess a robust owner notification procedure for scheduled work. Efforts should be made to update the current process and work flow diagram. A clear and concise customer communication process is essential, helping to ensure customer satisfaction.

API currently includes a Vegetation Management webpage (webpage link) on the Company's website which does address some frequently asked questions and serves as a source to provide a call in number for customer tree concerns. It falls short in describing the vegetation management program. A website describing the vegetation management program is a useful tool for communicating to customers. Information regarding the vegetation management program should be included and contain a description of why trees are trimmed, general tree trimming guidelines, species selection for planting near power lines (a.k.a., "Right Tree"), information on API's "Tree Replacement" program, and proper pruning techniques (per ANSI A300). A vegetation management specific website is in-line with industry best practices and offers a level of professionalism that customers can readily access. Caution should, however, be used in posting any clearance specifications and is not recommended since clearances can be easily misinterpreted and are considered dynamic, often allowing exceptions to suite individual site requirements. Information regarding the purpose of vegetation maintenance and benefits are included and considered acceptable.

Overcoming negative publicity that results from enforcing the pruning standards detailed in ANSI A300 (Part 1) can be a challenge at API as with other utilities. When ANSI A300 (Part 1) is enforced, additional clearance is often required when pruning old stub cuts back to an appropriate sized lateral limb. It is considered the number one industry best management practice to enforce pruning trees using the principles outlined in ANSI A300 (Part 1). Customer outreach through city and town hall meetings has been a valuable tool in spreading the benefits of proper arboricultural pruning and a means to gain customer acceptance at many utilities. API has adopted ANSI A300 (Part 1), however, enforcement has not been validated as part of this study. API must enforce adherence to ANSI A300 and provide customers with a visual reference for properly pruned trees on the website as well as within any clearance specification documents.

API should continue to support community outreach programs and participate in organizations that recommend tree policies, educating the community about the benefits of trees and proper tree planting and care, and promote tree planting and preservation.

Recommendations

Customer/Property Owner Notification/ Communication

API should:

1. Periodically include in API television ads, newsletters and/or bill stuffers, information about the importance of ROW maintenance and proper pruning techniques as well as some of the work API is doing to help maintain good reliability through ROW maintenance. If clearance policies, practices, cycles, or standards change, these methods of communication can be used to effectively communicate those changes to API customers. Consult with API internal communications group for potential strategies.
2. Enhance the web page for vegetation management to educate and inform customers about tree pruning and other information about the vegetation management program that will demonstrate the professionalism commitment, and dedication of API to provide reliable electric service. Example web page:

   https://www.nespower.com/electrical-safety/tree-trimming/

3. Update the customer notification process for both planned maintenance work and customer complaint resolution.

Safety

Safety is a critical issue for vegetation management and to the utility as a whole. Worker safety is an issue that always warrants attention, even when the safety performance of a contractor is good. API indicated that there has been no recent public contact with the lines from tree work or recreation. API did not provide indicate any violations or infractions per the Occupational Health Safety (OH&S) or per the Canadian Centre of Occupational Health and Safety (CCOHS).

Recommendations

Safety

API should:

1. Continue to require all contractors to provide API with a safety manual and details concerning their safety programs (if not already made available). Details about a contractor's safety program, including the safety manual and historical number of OHSA recordables, should be required information during the bidding process.
2. Continue to require all contractors to demonstrate full compliance with applicable OHSA requirements.

Program Cost and Funding Analysis

The detailed 2018 through 2023 actual program costs for maintaining vegetation on the API system are presented in Table 1.

Table 1. API Vegetation Management O&M Expenditure History for 2018 to 2023.

*planned

	2018	2019	2020	2021	2022	*2023
VM budget (actual)	3,616,124	3,620,096	3,595,162	3,839,055	3,821,811	4,024,179

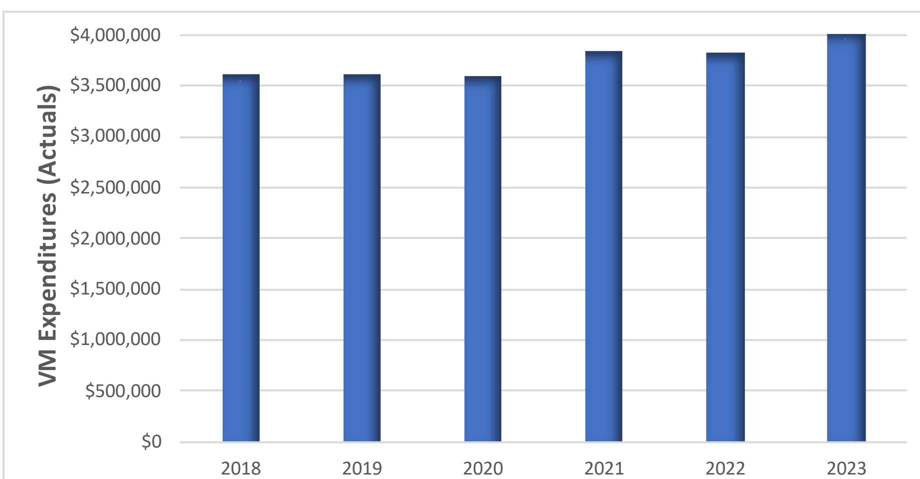


Figure 13. API VM O&M Expenditures 2018 Thru 2023.

Figure 13 above presents a graphical representation of API's annual expenditures to demonstrate the increase in annual spend. Budgets at API are built from a bottom-up approach in which circuit workload drives the budget submitted to management for review. From 2018 to 2023, API has averaged an annual VM spend of approximately $3.73 million. Reactive maintenance (RM) is sometimes called Corrective Maintenance, and Planned Maintenance (PM) is defined in the budget expenditures provided by API. Many utilities find budgeting for reactive and planned maintenance work as separate line items useful in ensuring that reactive work does not erode those dollars required to meet program miles or kilometer targets for planned maintenance. As such, these utilities strive to keep corrective costs to ten percent or below of their total program dollars.

Planned maintenance (PM) expenditures are defined as any costs incurred in the execution of planned routine maintenance and generally will produce a metric in the form of meters cleared, spans cleared, or kilometers maintained. Reactive maintenance (RM) or unplanned maintenance expenditures are those costs associated with specific or isolated pruning locations, such as with customer trim requests or internal operations requests when limited in scope (e.g., hot spot pruning requests). It is referred to as "reactive" maintenance since its origination stems from a specific event, such as a customer trim request or a tree-caused outage. Normally this does not include work orders, storm work, or miscellaneous expenditures. Going forward, API should continue to budget and track RM expenditures separately to monitor potential changes in RM expenditures and act to control costs and to ensure maintenance dollars are kept available to complete annual circuit plans.

Cost per kilometer is a common metric used at many utilities to measure program efficiency. Cost per kilometer is based upon the total number of kilometers completed in each year against the total planned maintenance dollars (excludes RM and admin costs). Based on the data provided by API, the average cost per kilometer was $12,868 between 2018 and 2023.

Going forward, the key to meeting selected budget and cycle goals will be steadfast focus on completing planned maintenance kilometers and to continue to minimize RM expenditures by restricting work scope to imminent threats to the distribution system or customer facilities. Constant crew oversight should be used to drive crew production even on firm price contracts.

Recommendations

Program Cost and Funding Analysis

API should:

1. Continue budgeting and tracking VM expenditures based on detailed work types.
2. Limit RM work to imminent threats to the interruption of electric service. Do not use PM dollars to make up overages on RM spends. Many utilities attempt to minimize RM expenditures to approximately ten percent of the total VM spend.
3. Consider the following to assist with reducing operational cost by:
    a. Provide constant crew oversight and set targets and goals for tree crews to improve production and lower cost per kilometer on future bids.

b. Expand the use of herbicides where possible to maintain right-of-way floors and reduce future workload, primarily stump treatments and foliar herbicides on cross-country routes.

c. Adopt the principles of RCM (reliability centered maintenance) to ensure crews are cutting only the trees that should be maintained (See Appendix E).

AVI Funding Requirements 5-Year Projection

As part of this effort, ECI was tasked with estimating the future budget requirements for the years 2024 through 2028 (five-year outlook). The desired result as expressed by API of this analysis was to help set reasonable funding expectations and explain the significant increase in circuit bid costs as submitted in the 2024-2027 bids. Table 2 presents the Planned Maintenance cost per kilometer comparison between the estimated values calculated from the 2014 study as compared to historical actuals and new bid rates.

Table 2. Calculated Cost Per Kilometer Comparison Between 2014 Estimates and Realized Costs.

	Line Clearing & Brush Clearing
2014 Study Avg $/Km (estimated)	$13,670
2018-2023 Avg $/Km (actual)	$12,868
2024-2027 Avg $/Km (estimated)	$16,264

API's perceived assumption is that the bid cost increases are due to significant increases in vegetation workload when compared to the workload estimate from the 2014 study. While the changes in cost per Km mentioned above, and consequently, total funding requirements may have many cost drivers including labor market pressures, increased labor rates, and fuel rates, API would like to explore the possibility of work volume change (e.g., quantity of work) differences as a potential primary driver. First, we should define "work volume" to ensure consistency. Work volume is defined as:

Work Volume = Number of Vegetation Units to be Maintained

The work volume per 2014 study was presented primarily as m2 values (see Exhibit 1-10 above). It needs to be made clear that "Work Volume" does not include the level of effort required to address those units (i.e., man-hours or cost). Work effort is generally (as in the case of the 2014 study) reflected in the cost per unit. Work Effort then, is defined as:

Work Effort = Cost of Performing a Unit of Work Varying by Degree of Difficulty

For instance, while a hectare of brush will always be a hectare of brush (volume) whether measured now or in 2014, the cost to control that hectare of brush can vary significantly due to the number of stems per hectare and brush height present between those two time periods. The denser the brush stems and taller the brush, the higher the cost to control. Consequently, when attempting to assess the cost or level of effort, we are limited from a comparison value to the categories collected in the workload assessments. Due to the limited categorization of data in the 2014 study, attempting to compare work effort between 2014 and now is not possible. However, changes in volume or number of units can be measured. Increases in brush hectares or increases in pruning trees m2 can be effectively measured and compared. Therefore, the hypothesis can be defined as:

Hypothesis (H0) = Brush (m2)+Herbicide (m2)+Pruning Top (m2)+Pruning Side (m2) in 2014 are less than Brush (m2)+Herbicide (m2)+Pruning Top (m2)+Pruning Side (m2) in 2023

A workload study was out of the scope of this assessment and therefore, proving this hypothesis is not possible at this time. In addition, it should be noted that brush and tree volume rarely change unless there has been a major drive to reduce tree density through removals and conversion of brush hectares that no longer require maintenance. In all, ECI would suggest that the 2014 workload estimates have most likely not changed.

To address another complicating factor, even if the work volumes could be accurately captured and compared, they have little impact upon bid prices from a comparison standpoint. Since utilities forfeited their right to monitor unit production information by changing contract strategies to firm price, there is no way to measure what part of the existing bids are related to anticipated increases in volume (if any). If the vendors did anticipate an increase in work volume as a major driver of their bid increases, then what was it based upon?

The limitation, therefore, is that even if we could compare the 2014 workload to an updated workload estimate today, any increase in volume (or decrease) would be subjective as to its impact on cost. To put it simplistically, the increased bid costs are what they are. Therefore, the only resolution to adjust pricing would be to ask the vendors to have candid conversations about their pricing structure and collaboratively identify risk reduction strategies that will lower pricing. This may include converting the firm price contract strategy to mor T&M or unit price type work going forward.

Calculating Annual Volume Increment Funding Requirements

Considering the information above, and the inability to tie work volume / work effort increases to any cost increases, the calculation to determine the funding requirement becomes quite simple. Determining the number of kilometers to be maintained by work type each year and multiplying those kilometers by the price per km estimates for 2024 to 2027. Work has been selected and awarded for 2024 and 2025 based on current RFP bids. The years 2026 and 2027 reflect the current RFP vendor bids, however, they have not yet been awarded.

Table 3 presents the estimated cost for circuits planned in 2024 through 2027. The cost per kilometer presented in that table serves as the basis for future cost estimation.

Table 3. API Estimated Cost Per Kilometer 2024 Through 2027.

Year	Cost Per Kilometer Brush Clearing	Cost Per Kilometer Line Clearing
2024	$5,107	$10,750
2025	$7,020	$12,225
2026	$4,803	$11,706
2027	$6,134	$7,310
Average	$5,766	$10,498

Therefore, with a desired six-year cycle for brush control and a six-year cycle for line clearance pruning, the annual funding and five-year forecasted funding requirements are presented in Table 4. IMPORTANT: these costs reflect only circuit planned maintenance costs and do not reflect internal staffing costs, hot-spot or CM costs, restoration, or capital funding requirements.

Table 4. API Annual and 5-Year Funding Requirements 2024-2028.

System Km = 2,089.20

	Brush Clearing	Line Clearing	Total
Cycle (in years)	6	6	
Annual Km Target	348.20	348.20	
Cost per Km	$5,766	$10,498	
Estimated O&M Annual Cost for Planned Maintenance Only	$2,007,721	$3,655,404	$5,663,125
5-Year Funding Requirement (Planned Mait. Only):	**$10,038,605**	**$18,277,020**	**$28,315,625**

Recommendations

AVI Funding Requirements 5-Year Projection

API should:

1. Work collaboratively with vendors to better understand and remove risk barriers that are driving up costs.
2. Ensure proper funding to prevent deferral of work that may result in increased future costs.

Cycle Length Analysis

ECI uses a quantitative approach to determine optimal cycle lengths. This approach is dependent on species distribution, growth/regrowth data and current vegetation proximity data gathered through a workload study. Understanding appropriate cycle lengths based on growth and proximity data can be beneficial in formulating a sound strategy. This data can be useful in determining areas of weakness in the cycle plan as well as helping to establish appropriate funding levels. The determination of optimal cycles was performed using this same methodology in the 2014 study. ECI's independent analysis of those cycle recommendations confirm them as accurate. The 2014 study indicated that a six-year line clearing/ pruning cycle was optimal to limit tree-wire contacts to below 10 percent (see Figure 11). It also recommended a nine-year cycle on brush cutting ROW floors if herbicide can be used to extend the cycle. API has elected to reduce the maintenance cycle for brush control to six years in the absence of maximizing herbicide usage. It is estimated that the decreased brush cycle alone accounts for an additional $670 K per year of the total estimated $5.7 M annual funding requirement.

A six-year cycle appears to be appropriate for the API system based upon species regrowth rates and reliability data analysis. Cycles, however, should not be thought about in a single dimension. An effective vegetation management program may be comprised of many sub-programs within its main core. Basic tree pruning, and tree removal programs may be split between single versus multi-phase or supplemented with brush maintenance programs to manage brush within the ROW, mid-cycle programs to reduce "cycle-busters" or reduced clearance situations (e.g., yard trees), risk tree programs to reduce tree-failure outages, and vine removal programs, just to name a few. Cycles for each program may and should vary by what is appropriate for each maintenance activity.

Recommendations

Cycle Lengths

API should:

1. Continue to maintain a maximum six-year maintenance cycle for pruning work. However, consider increasing brush work (hand cutting and mowing) cycle back to the recommended nine-years as per 2014 study.

Scheduling

The basic planned maintenance work unit at API is performed at the circuit and forestry area level. ECI supports scheduling at the circuit level regardless of geographic location to target those feeders with the worst reliability first. Many utilities also find it beneficial to develop a circuit prioritization model that includes customer load, customer type, tree workload, line kilometer, outage history/reliability, and/or other criteria in their circuit prioritization process. These include:

a. Total Kilometers
b. Customers/ Kilometer
c. Last Maintenance Date (Year)
d. Years Since Trim
e. Target Cycle Length
f. Last Maintenance Cost
g. Fast Growing Tree Density
h. Outages (N) All Cause Codes (3Yr Total)
i. Outages (N) Tree Only (3Yr Total)
j. Customers Interrupted (CI) Tree Only (3Yr Total)
k. Customers Minutes (CMI) Tree Only (3Yr Total)
l. On Worst Performing Feeder List (Y or N)
m. Major Capital/ISO Planned (Y or N)
n. Operations Request (Y or N)
o. All Outages (N)/Kilometer
p. Tree Only Outages (N)/Kilometer
q. Tree Only Customers Interrupted (CI)/Kilometer
r. Tree Only Customer Minute (CMI)/Kilometer

s. Percent Three-Phase

The proper scheduling and forecasting of maintenance work is crucial to meeting cycle targets and to maximizing reliability benefits. The maximization of reliability benefits is dependent largely upon the ability of the utility to tie outage data to the work units (i.e., circuits, phase construction, etc.) to be issued. Annual work unit selection should strive to address those work units with the worst reliability issues. Effective scheduling offers the ability to measure the effectiveness of the vegetation maintenance work performed on that individual circuit. Scheduling at the circuit level offers:

- Ease of scheduling.
- Circuit integrity. This allows for the measurement of the effectiveness of the vegetation maintenance work performed on that individual circuit.
- The ability to track the cost of completing a circuit, which can easily be converted to cost per kilometer for benchmarking.
- The ability for the crews to work more linearly. Following a line from the beginning to the end and working within a compact geographic area makes it easier for tree crews to schedule and track completion progress.

Unfortunately, API retains a legacy system that divides some circuits into segments called forestry areas. The need for this segmentation may have been warranted in the past, but it should be terminated going forward in favor of working whole circuits. This will allow for better tracking of circuit performance as a result of line clearing. This will also allow for better tracking of costs per kilometer.

Recommendations

Scheduling

API should:

1. Implement a robust circuit selection and prioritization process. Circuit selection should not be based solely on one criterion (e.g., last maintenance date). The model could include metrics deemed important by API. Consider last maintenance date, voltage, phasing, reliability (e.g., interruptions per kilometer, CI per kilometer, etc.), number of customers per kilometer, critical customers served, and worst performing feeder rankings. Provide a weighting for each criterion to calculate a ranking score.
2. Discontinue the forestry areas and begin issuing and tracking only by circuit.

Work Planning

Work Planning is the process by which the utility or utility designee pre-inspects vegetation maintenance work in advance of a circuit or work unit being issued to the tree contractor. A work plan normally includes the attributes and scope of work for specific trees or other vegetation that require maintenance to meet utility specifications. Work planning improves tree crew production by clearly defining the work scope that meets the utility maintenance specification and avoiding unnecessary work, improving tree removal percentages, reducing tree crew/homeowner interactions for permissioning or notification, and identifying obstacles that can be addressed prior to the tree crew being on site. Work planning is considered an industry best management practice and when performed correctly, is one of the most cost-effective functions a utility can employ to reduce overall program costs.

The use of third-party planners or the use of internal utility staff to perform work planning is considered a best management practice because it eliminates any bias that may be introduced when using the tree contractor to perform the planning and work identification function on the work it will also be performing. Work planning is essential if API wishes to significantly impact cost per kilometer.

Recommendations

Work Planning

API should:

1. Consider work planning to assist in better defining work scope for the tree contractor and drive efficiencies in production.

QA/QC Process

Completed tree contractor work is inspected by the API Contract Monitor Utility Arborist, and formally documented. QA/QC is the single most important process to ensure that services purchased meet the contractual obligations of the contractors and the expectations of the utility.

Quality assurance (QA) and quality control (QC) are activities used to identify and prevent work defects to ensure the delivery of high-quality work planning and line clearance services. A utility vegetation management quality assurance program would entail performing crew evaluations to measure crew safety, productivity, efficient use of equipment, adherence to work specifications, etc. (see Appendix B form example). Statistical process control (SPC) is a category for analytical tools used to measure the stability and capability of processes being performed. An advantage of SPC over other methods of quality control, such as "inspection", is that it emphasizes early detection and prevention of problems, rather than the correction of problems after they have occurred. Stability analytics are used to measure consistency in the process (i.e., proper equipment setup to avoid wasted time between trimming trees) and over time can be used to detect deviations in the process. Capability analytics are used to determine if a specific process can meet the target values required by a customer(s) and if the process results in a product that falls within lower and upper spec limits. The Taguchi Loss Function, developed by the Japanese business statistician Genichi Taguchi, is another tool used for QA analytics to determine the value of products produced by a company. If the process performed by a company begins to shift from spec, the Taguchi Loss Function graphically depicts the incurred cost to the customer.

QC is a set of activities used to identify (and correct) defects in the finished product. Quality control, therefore, is a reactive process. Auditing work completed by tree contractors is an example of a quality control program (see Appendix B form example). Statistical quality control (SQC) is the term used to describe the statistical methods used for measuring product quality or the quality of work performed. SQC encompasses three categories of statistics: SPC, descriptive statistics and acceptance sampling. SPC is generally used for the QA process. Acceptance sampling is the process of randomly selecting the number of items to inspect to determine whether to accept or reject the entire batch (i.e., distribution circuit or line segment). Acceptance sampling is different from SPC because sampling is done after the process has been completed instead of sampling during the process. The keys to acceptance sampling is determining the size of the lot, size of the sample, number of defects that will result in rejecting the batch and the level of confidence in the sample results.

After the tree contractors have completed vegetation line clearance work, utilities may audit 100 percent of the work or only audit a random sample. Both methods have their strengths and weakness even when used correctly. A 100 percent audit allows a utility to report all discrepancies back to the tree contractor to remedy in a timely manner. After the discrepancies have been remedied, an additional audit should be performed to confirm that the identified discrepancies have been rectified before paying the tree contractor. This type of audit requires additional time in the field and if performed as a driving audit, may result in a significant number of missed discrepancies. When auditing a random sample of the work completed, the time required is less, but the audit is performed by walking with more attention to detail, decreasing the chance that a discrepancy could be missed. The starting point is randomly chosen for the sample and the length of the random sample is based upon the line segment or circuit length. An audit of a random sample is not designed to identify all discrepancies to be remedied but is used to determine if work performed by tree contractors meets a determined acceptance level. The acceptance level is a threshold written into the contract language defined by a set number of discrepancies per 100 trees. The threshold can be set differently for discrepancies that are critical (i.e., inadequate side clearance) versus those that are non-critical (i.e., improper cuts). If the work performed by the tree contractor is below the threshold, then the utility accepts the work as complete and pays for the work. However, if the number of discrepancies is above the threshold, then the tree contractor is required to re-patrol the entire work unit and remedy any discrepancies. Then a second random sample is chosen and audited. This process continues until the number of discrepancies identified is less than the threshold. The tree contractor agrees to reimburse the utility for the cost required to perform any additional audits if work fails after the second audit.

The report titled "Utility Line Inspections and Audits" (EPRI, 1012443) states that an audit of only five to ten percent of the work completed by tree contractors will provide an accurate representation of overall quality and compliance. While the EPRI report provides support for only auditing a portion of the work completed, the report does not go into the details needed for such a program and that is why ECI recommends a Six-Sigma approach as a guide for developing a random sampling audit program. Six-Sigma procedures use ANSI/ASQ Z1.4 – Sampling for Attributes, for determining sample size and accept/reject rates on work output. While this normally applies to a product being produced from an assembly line in a factory, it can also be applied to the number of trees being pruned to a specific standard. Acceptance sampling is used by industries worldwide for assuring the quality of incoming and outgoing goods. Acceptance sampling plans determine the sample size and criteria for accepting or rejecting a batch (i.e., line segment or entire circuit) based on the quality of a sample, using statistical principles.

Using a random sample methodology enables the utility to decrease sample size and increase the intensity of the audit. Theoretically, the length of time to perform a random sample audit would be shortened because of the large reduction the in the number of kilometers audited for each circuit.

When performing random sample audits, ECI suggests that discrepancies be split into critical and non-critical discrepancies. The threshold for accepting or rejecting completed work (a.k.a. Acceptable Quality Limits or AQL) should be set differently for deficiencies that are critical or likely to result in tree outages (i.e., inadequate clearance) versus non-critical deficiencies (i.e., improper cuts). ECI further recommends that the acceptance or rejection of work be based on the number of trees that do not meet specification. Discrepancies per 100 trees are a good measure of contractor performance and focuses on critical discrepancies for risk reduction. This unit of measure allows for a more normalized comparison between contractors by eliminating circuit density variations. Refer to Appendix B for more detailed information regarding the proposed ANSI/ASQ Z1.4 audit process.

Recommendations

QA/QC Process

API should:

1. Consider implementing the ANSI/ASQ Z1.4 audit process to reduce the amount of time required to perform post completion work audits.

Environmental Factors Unique to API

All utilities are unique in certain ways. However, these differences are often outweighed by their similarities. The old adage which states that "there are only so many ways to skin a cat" applies to utility vegetation management. While indeed, certain environmental or biological factors can present challenges, there are really only four main factors outside of the utilities control that can significantly impact program costs. Species growth rates (growing season), adverse weather events, wildfire risk, and biological threats requiring mass removal of additional vegetation not normally part of the VM cycle funding.

The API service territory lies within the Great Lakes/St. Lawrence Forest region. The forest is dominated by hardwood forests, featuring species such as maple, oak, yellow birch, white and red pine. Coniferous trees such as white pine, red pine, hemlock and white cedar, commonly mix with deciduous broad-leaved species, such as yellow birch, sugar and red maples, basswood and red oak. Exposure to biological threats such as emerald ash borer, oak wilt, gypsy moth and other flavors of the day, while important, do not represent a heightened risk above what other utilities have and are experiencing throughout North America.

With the northern climate, species regrowth rates are tolerable when compared to accelerated growth rates documented in the southern part of the United States. ECI's environmental review found no unique areas of concern that should be addressed.

Wildfire Mitigation and Risk

Wildfire risk is increasing with global climate change but that risk is generally higher in the western united states. Adverse weather events come in the form of sporadic strong winds or snow loading events, however, with an average of two to three MED days per year from 2018 to 2021 and no MED days in 2022 or 2023, weather does not appear to be a major reliability issue for API.

Current Wildfire Mitigation efforts at API include a Industrial Operations Fire Prevention and Preparedness Plan (see Appendix I). In addition, API tree contractors are required to adhere to basic chainsaw/brush saw and mechanical equipment fire prevention requirements as follows:

- Utilize the Field guide to industrial operations through the Distribution Specialist.
- Distribution Specialist checks the fire map info website to determine the Fire intensity code and the crew checks API operational Risk Classification (Low, Medium, High).

- Backpack pump and fire extinguisher when in use all times of fire season (1 set per truck).
- Ensure spark arresters are present on all chainsaws and brush saws.
- Encourage contractors to use composite tracks to reduce contact of metal to stone to minimize sparks.
- Consider bringing in a larger supply of water with a pump for fire extinguishing and wet areas where machinery will be parked after use if required (very high Fire rating).
- Review work area 1 hour after last cut on ROW.
- Consider working SS (Short Shift) - no operation between 12:00 and 19:00 in extreme fire hazard situation (for machinery with cutter heads) most likely suspend work until condition improve.
- Wet areas where mechanical equipment will be parked and clean off vegetation that could ignite and fall to ground.

The growing threats resulting from an increased frequency of apex fire weather conditions, declining forest health, aging infrastructure, and increased human populations in wildland areas have made preventing wildfires and protecting electrical facilities a significant priority for many utilities in North America. While California continues to gain most of the media coverage due to utility-caused catastrophic wildfires, conditions exist in many other parts of the country where utilities face similar risks and liabilities from their systems. These issues have created another major challenge for utilities and utility contractors to acquire sufficient liability and fire suppression insurances.

To address these challenges, API should assemble a multi-disciplinary team of wildfire subject matter experts (SMEs) experienced in utility wildfire program management, utility vegetation and asset management, wildfire behavior modeling, asset hardening, geospatial analysis, linear optimization, situational awareness, software, and remote sensing to support the development of strategic, tactical and operational programs aimed at mitigating wildfire threats. ECI along with its strategic partner EDM are uniquely qualified to coordinate and assist API with the development of a cross-functional, programmatic approach to wildfire prevention and protection.

One of the most prevalent wildfire mitigation strategies utilities employ, is to develop and implement an enterprise-wide Wildfire Mitigation Plan (WMP). A WMP should consider the current geographic, structural, and procedural risks as they relate to wildfire prevention in API's operating territory. Engagement and collaboration between the strategic partners, and the various API functional areas and utility departments is critical to the success of a successful WMP (e.g., engineering, construction, operations and maintenance, asset management, vegetation management, reliability and system protection, emergency response, meteorology, environmental, including wildlife interactions with energized equipment, legal and risk management, siting and land services, community affairs and corporate communications, GIS, and more). The WMP should include:

- Wildfire risks and drivers
- Situational awareness for fire weather
- Guidance on improving existing wildfire hazard maps

- Emergency preparedness and response
- Strategic wildfire prevention initiatives and programs
- Common industry practices for design and construction that increase fire safety and resilience
- Recommended practices for field work and operating restrictions commensurate with fire weather conditions
- Monitoring, auditing, and continuous improvement
- Collecting and analyzing outages, ignitions, and near-miss ignitions
- Public awareness and communications

While the third-party partner can utilize prevalent industry practices to write and contribute to significant portions of the WMP, it will also be necessary for API to contribute as well. All parties will need to collaborate and work together to develop the WMP, but ultimately the final document should be completed by API. With its local knowledge, more comprehensive understanding of internal programs and organizational culture, the API team can most effectively enhance content and more importantly, add to the spirit of the WMP in order to make the WMP its own.

As the WMP is developed, API representatives may elect to change the scope of work to meet their needs. API could benefit from the consideration of other aspects of wildfire prevention and protection, including:

- Development of a geospatial hazardous fire area (HFA) rating schema specific to the landscape and human population in API's service territory with optional wildfire risk model upgrades that leverage API-specific asset risk data for prioritization and implementation of various wildfire prevention and protection initiatives.
- A comprehensive assessment of enterprise-wide wildfire risks and mitigation opportunities that encompasses:
  - API Leadership (Executives, VPs, Directors, etc.)
  - Asset Programs
  - Vegetation Management
  - Engineering
  - Construction, Operations & Maintenance
  - Standards
  - System Protection and Reliability
  - Substation Construction & Operations
  - System Operators
  - GIS
  - IT
  - Siting & Land Rights
  - Legal
  - Risk Management
  - Emergency Response
  - Community Affairs / Corporate Communications
  - Weather / Meteorology
- Enhanced situational awareness and develop an Electric Standard Practice company procedure for escalating fire weather

- Evaluate and determine levels for additional GIS analysis to guide site-specific structure, equipment, and fuels management-related wildfire risk mitigation priorities and prescriptions
- Development and implementation of an Ignition Management Program (IMP)
- Assessment of facility hardening and protection opportunities to protect API assets
- Prioritization and optimization of risk mitigation initiatives
- Strategic and tactical planning for wildfire programs and initiatives
- Full tactical plan implementation
- Auditing and continuous improvement
- Change management and instilling a fire-safe culture at API

Recommendations

Environmental Factors Unique to API

API should:

1. Consider the development of a Wildfire Mitigation Plan (WMP) to include vegetation management as well as operational initiatives.

Risk Tree Assessment

It should be noted that the terms "danger tree" and "hazard tree" assessments are discussed here as "risk tree" assessment as referenced in ANSI A300 (Part 9). The term "risk" includes the combination of the *Probability* of an event occurring and its potential *Consequences*. Risk tree assessment programs are becoming a more common component of utility line clearance programs. API and tree contractors do identify hazard trees within the fall zone during normal routine maintenance. Any specifications and guidelines documents should sufficiently address risk tree removal requirements in the tree removal guidelines.

Recommendations

Risk Trees

API should:

1. Train API staff and contractors in tree risk assessment principles and practices and risk tree identification. Review ANSI A300 (Part 9) Tree Risk Assessment Standard for applicable assessment procedures.
2. Use post-outage investigation to help define risk levels as appropriate going forward.

Brush Control

API manages brush[2] and vines by mowing, and hand cutting only. Foliar herbicides are used in controlling unwanted vegetation within the ROW on express feeders and stump treatment on removed trees is limited but practiced where possible. Cut-stump treatment is considered an industry best practice to reduce future workload and cost. A peer-reviewed article by Ballard and Nowak (2006) discusses both the timing and effectives of different herbicide mixtures for cut-stump application[3]. The results

[2] Brush is defined by API as small forest type trees growing under the conductors that can be cut without contacting the conductors. Considered to be less than 4" DBH.

[3] Ballard, Benjamin D., and Christopher A. Nowak. 2006. "Timing of Cut-Stump Herbicide Applications for Killing Hardwood Trees on Power Line Rights-of-Way." *Arboriculture and Urban Forestry* 32 (3): 118.

published in the article help to support why cut-stump application of herbicide is considered an industry best practice. The tree crews should be required to carry herbicides so that stumps can be treated immediately after deciduous trees have been removed in order to benefit from active transpiration. The vessels in the phloem, cambium, and xylem begin to close shortly after the tree has been removed. Thus, as the time between the tree being removed and herbicide application increases the effectiveness of the application decreases.

Figure 14 data is based on a regional simulation model from a long term ECI study of brush management on utility ROW in the Northeast United States. It shows the brush density of hand cutting alone vs. cut stump treatment at the end of four years and eight years. At four years, cutting alone resulted in 2,950 stems/ac. vs. 1,450 stem/ac. resulted from cut stump herbicide treatment. With time, the stem density decreased which would result in increased savings. At the end of eight years, density from cutting increased to 4,250 stems/ac. vs. 700 stems/ac. The decrease in workload will result in reduced cost (fewer stems per acre to treat).

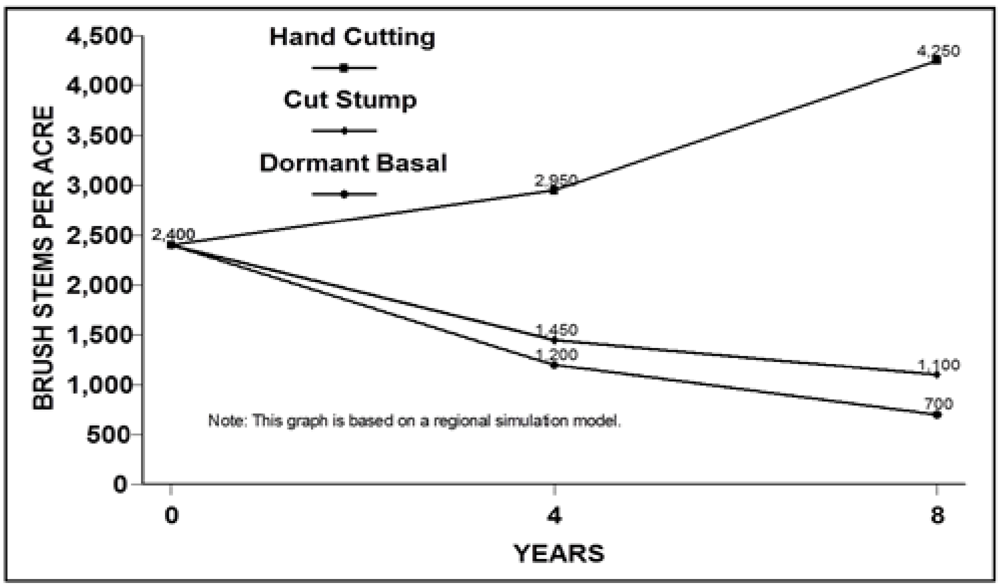


Figure 14. Effectiveness of herbicides for control of brush over time.

Foliar herbicide treatment should generally occur approximately one to two years after a site has been mowed and will occur again in four years or a year after it has been maintained again. There should be at least one full growing season after mowing to allow sufficient brush height for effective herbicide treatments. A standalone program requires a clear schedule based upon brush characteristics (i.e., density, growth rate, and species) and a separate budget that supports the schedule. Well-timed herbicide applications should eliminate much of the need for mowing or hand cutting as brush stem densities continue to decline and brush is treated before it becomes too tall, usually above six to eight feet. The brush control program should be reset to reduce the need of a mower except to chip debris left behind from the mechanical (i.e., Jarraff) crew. Declining stem densities should also result in a reduction in the amount of herbicide applied per acre in future cycles. After the next time an area has been mowed and then treated with herbicide one growing season later, API should revisit the site in two years to inspect brush conditions and schedule the next herbicide treatment. A two to three-year herbicide spraying cycle would be appropriate based upon ECI's field review.

All tree contractors and/or seasonal herbicide applicators should be licensed and be required to purchase the appropriate herbicides. The responsibility falls upon the tree contractors and/or seasonal herbicide applicators for the storage and proper disposal of the herbicide instead of the utility with this agreement. In addition, this type of agreement places the burden of risk on the tree contractor or seasonal herbicide applicator for the efficacy of the product, which is considered an industry best practice. Most utilities allow the licensed herbicide applicator (assuming the risk of the herbicide application) to suggest the appropriate tank mix and herbicide based on the vegetation conditions and species with final approval by the utility. Requirements for certification and registration of applicators is appropriate and in accordance with federal, state, and local laws. Landowner permissioning for herbicide application is not considered a best management practice, but API should consider notifying property owners of the impending herbicide application to prevent public/customer dissatisfaction. In addition, API may need to provide mail stuffer or other means that can explain the environmental and ecological benefits of using herbicides to control brush. A detailed IVM Management Plan for API is included in Appendix H.

API should consider incorporating the aspects of Integrated Vegetation Management (IVM) in respect to the management of brush on the distribution system. IVM is the process of using biological, chemical, manual or mechanical maintenance techniques to control undesirable vegetation. The selection of control options is based on effectiveness, site characteristics, environmental impacts, safety and economics. In relation to herbicide applications, the key components of IVM include the proper prescription, herbicide selection, and timing of herbicide applications in the appropriate areas based on individual site conditions. Therefore, API should consider sites (circuits and areas within circuits) individually prior to issuance of circuits to herbicide applicators rather than going with a one size fits all approach in spraying every circuit one year after it has been mowed. API must be flexible in deferring herbicide work if not needed or in situations where recent pruning/mowing maintenance may render herbicide application ineffective. Ideally, all areas to be sprayed should be identified using software or other means which will allow the calculation of total footage/kilometers to be maintained. Providing exact locations to herbicide applicators will allow for better tracking of actual herbicide application locations and costs and may yield significant cost savings, particularly on future cycles.

Field observations of brush characteristic (i.e., density and height) at API noted a few areas with brush height exceeding six feet or where brush density was higher than 40 percent ground cover. API should begin to inspect circuits two-year following the pruning cycle to prevent brush from getting too tall and requiring it to be brush hogged before herbicide application. In addition, a frequent inspection would also determine if herbicide application can be pushed out another year or two. If possible, the amount of brush to be treated should be recorded as acres so that API can easy monitor changes in workload. ECI noted several opportunities for implementing a herbicide brush program on the API distribution system. Particularly on rural line sections.

Some utilities have been successful with implementing herbicide applications using trained and certified utility crews. While this is doable, it is necessary to consider the cost of training, continual education, and most important, liability in determining the appropriateness of using internal crews.

Recommendations

Brush Control

API should:

1. Consider expanding the herbicide program on distribution line segments, particularly in rural areas.
2. Use herbicides to treat stumps on removed deciduous trees (trees removed by contract tree crews) where allowed to prevent re-sprouting which leads to increased biomass when one stem becomes many stems.
3. Wait at least one growing season after an area has been mowed before completing herbicide applications to ensure sufficient brush height for herbicides to be effective. Brush may be too tall after three growing seasons to efficiently and effectively apply herbicides.
4. Implement a brush control program that utilizes herbicide application on a two- to three-year cycle length and begin to audit areas treated with herbicides to evaluate the efficacy of the treatment. The efficacy rate should be based upon the manufactures' label.
5. Implement an integrated vegetation management program (IVM) philosophy, which integrates all the various management tools including hand cutting, mowing, low-volume foliar and basal herbicide applications together with the benefits of biological control of underbrush. Specifically, API should use herbicides as the primary method to cost-effectively control brush/vines and prevent future expansion of the vegetation workload. A proposed detailed IVM Management Plan for API is included in Appendix H.
6. Consider contracting with commercial herbicide applicators to perform seasonal work on the API distribution and transmission ROW's. An example list of commercial herbicide applicators for API is:
   a. Edko LLC.
      i. http://edkollc.com/services/brush-and-vine-control/
      ii. Contact phone number: (800) 256-8671
   b. Progressive Solutions
      i. http://www.progressivesolutions.net/
      ii. Contact phone number: (706) 741-4073
   c. Sage
      i. Contact phone number: (803) 665-6043
   d. Southeast Woodland Services
      i. http://southeastwoodland.com/right-of-way/
      ii. Contact phone number: (828) 766-0951
   e. Townsend Tree Service
      i. http://www.townsendcorporation.com/services/chemical-herbicidal-spraying/
      ii. Contact phone number: (615) 804-9929

Record Keeping

Record keeping and reporting deficiencies are often areas of great concern. The lack of available data precludes its use in making sound financial decisions, justifying budgets, and effectively utilizing resources to minimize tree-related outages. API should invest a great deal of time and effort into documenting processes and procedures as well as documenting and collecting program metric data. The limited currently available data is maintained across several systems including Excel spreadsheets and multiple API systems. While the data may seem disjointed, it is ECI's experience that this is commonplace since there are no available software systems on the market that can house, manipulate, and analyze the vast array of data required. The concern is the absence of much needed data. This data can be classified into five main categories:

1. Budgets and Expenditures
2. Production
3. Outages and Reliability
4. Scheduling
5. Auditing

The reporting categories and report requirements are detailed in the recommendations section.

Recommendations

Record Keeping

1. **Budgets and Expenditures**:

   Budget

   Distribution reporting requirements for preventative (planned) and reactive (unplanned) maintenance are not clearly delineated in the current API budget. It is important to separate these functions in order to monitor fluctuations in both workload and costs between maintenance types to ensure program goals in respect to program maintenance kilometers are achieved. Budgets should be constructed to include breakouts for each program objective and include budget line items for:

   a. Planned maintenance (PM) for circuit routine maintenance:
      i. Cycle Removal
      ii. Cycle Trimming
      iii. Cycle Brush & Vine Removal
      iv. Stump Removal
      v. Transmission Trimming & Removal
      vi. Mechanical Brush Removal
      vii. Herbicidal Applications
      viii. Tree Planting Program

   b. Unplanned maintenance (RM):
      i. Customer & Stakeholder Initiated Requests
      ii. Reactive Work (Failure, Hot spot, Cycle Buster)
      iii. Weather or Emergency Restoration
      iv. Engineering & Construction Jobs
      v. Wood Residue Disposal

   c. Substation Maintenance
      i. Chemical Control, Bare Ground

   d. ROW & Equipment
      i. Ground Maintenance Mechanical & Manual

    ii. Switch or other Equipment, i.e. Pad-mounted

e. Other VM Costs
    i. Permits
    ii. Traffic Control

f. Outside Services
    i. VM Administrative Services
    ii. VM Personal Services
    iii. VM Communications

Separating budgets and reporting expenses against these classifications help to ensure that expenditures are kept in check and that specific programs (e.g., kilometers maintained, herbicide) retain the proper funding to meet annual kilometer goal objectives. Meeting annual kilometer goals are crucial to developing and maintaining a maintenance cycle. Tracking of these expenditures can be accomplished through the use of unique work order numbers by job classification generated from the job accounting system or utilizing varying FERC accounting codes.

Invoice and Payment

Many utilities require payment approval and authorization procedures to validate invoices and payments. There is no industry best management practice in regard to invoicing and payment because of the wide variability in contractor payment systems and those of the individual utilities. However, in the case where work planning systems can generate invoices for completed work, those utilities have gained benefits from reverse invoicing.

For unplanned maintenance work (RM), each request has a unique job ID or Service Order Number (work request or a work order number) for tracking: initiator (CSR), crew/department assignment, milestone dates, resource requirements, and work performed. For each:

- The VM representative performs a field inspection to determine if there is need.
- If work is in scope, the VM representative assigns the job to the tree crew or API crew.
- Completed jobs and actual job duration are communicated back to the VM representative.
- The VM representative audits the job for completion and QC (rarely done).

Completed Circuit Info Database

API possesses a completed circuit history and tracking report but lacks a tie to capture the cost to complete the circuit. Circuit cost data can be useful in producing future budget projections (i.e., bottom-up approach) and work schedules. ECI noted that this is one area of opportunity to further refine and consolidate this historical information into one system. It appears that trim data and circuit cost data are housed in separate systems. This data should be consolidated as soon as possible. Software platforms are unimportant, and often Excel and Access are viable solutions. In order to capture the cost at a circuit level, it may be necessary to assign individual work orders to each circuit maintained. The consolidated system should include at minimum, the following data for each circuit completed:

a. Substation
b. Feeder/Circuit
c. Voltage
d. Total Circuit Kilometers
e. Number of Customers Served
f. Issue Date (by cycle)
g. Completed Kilometers for Tree Maintenance (by cycle)
h. Complete Date for Tree Maintenance (by cycle)
i. Complete Maintained Cost (by cycle)
j. Spray Acres Maintained (by cycle)
k. Sprayed/Herbicide Date (by cycle)
l. Total Cost to Spray/Herbicide (by cycle)
m. Totals Circuit Spend
n. Schedule Next Prune Date
o. Projected Next Cycle Cost
p. Cycle Length

2. **Production**

<u>*Crew Production*</u>

Managing crew production is the only way to ensure a cost-effective VM program and demonstrate fiscal responsibility. Poor crew performance will result in higher maintenance costs, whether on a time and material contract or firm price. There are two primary methods for measuring crew performance that can be useful to API:

1. Measurement of kilometers complete against a kilometer target.
    a. API should set monthly and annual kilometer targets and hold the tree contractor accountable for obtaining those goals.
2. Measurement of individual tree unit performance.
    a. Develop production monitoring at the crew level to measure and compare individual crew performance. This allows for the identification of inefficient crews that may need supervision assistance or additional training. This production monitoring method requires utilizing crew timesheets to compare hours against the number of units trimmed or removed. The result is a man hours per tree metric that can be directly compared between crews. Through ECI's experience, the average man hours per tree is approximately 1.0 for a bucket crew and 1.5 for an easement or manual crew.

3. **Outages and Reliability**:

Outage Management System Revisions

API should ensure the outage management system include the following information for each tree-related outage:

a. Circuit or feeder number
b. Number of phases affected at outage location
c. Device type (e.g. feeder, primary lateral, secondary, transformer, etc.)
d. Outage time
e. Restore time
f. Customers interrupted
g. Primary and secondary cause codes
h. Comments (used to provide any additional information)

The number of phases and device types will help to stratify outages for use in determining problem line sections. Each is useful in developing the annual and long-range maintenance plans.

Tree Cause Code Changes

- Proper OMS tree-caused outage codes are essential to the development of outage reports that can be used to prioritize maintenance work, identify modes of failure, and develop mitigation strategies to reduce tree outages. API should consider adding additional tree-outage codes in their current OMS system. An example of commonly used outage codes includes:
    - In-ROW
        - Dead Tree Failure
        - Live Tree Failure
        - Limb Failure
        - Overhang
        - Grow-In
    - Outside ROW
        - Dead Tree Failure
        - Live Tree Failure
        - Limb Failure
        - Overhang
        - Grow-In

Performance Tracking

- API should develop daily reporting to inform the VM department of tree-caused outages on a daily basis. This data should be tracked by circuit to accomplish three primary goals:
    1. Monitor circuit performance of circuits recently maintained to identify specific issues from potential skips or other issues.
    2. Monitor performance of circuits on the schedule to determine if those circuits should be reprioritized.

3. Use the data to perform post-outage investigations to determine if there are any trends that may lead to additional mitigation efforts.

4. **Scheduling**:

   Prioritization Model

   A prioritization model helps drive annual and long-range budget requirements, ensure resources are applied to the appropriate circuits to minimize tree-caused outages, and sets the order of circuits to be worked within the budget year. A list of circuits along with reliability metrics, last maintenance date, and other utility defined criteria can be used to rank sections by order of priority. Each circuit can be assigned a calculated priority ranking based on the defined weighted criteria. An Excel spreadsheet can be developed utilizing the following fields as examples:

   a. Circuit Number
   b. Single-Phase Kilometers
   c. Multi-Phase Kilometers
   d. Total Kilometers
   e. Customers Served
   f. Last Maintenance Date (Year)
   g. Target Cycle Length
   h. Last Maintenance Cost
   i. Last Herbicide Date (Year, for non-stump treatment)
   j. Last Herbicide Cost
   k. Outages (N) All Cause Codes (3Yr Total)
   l. Outages (N) Tree Only (3Yr Total)
   m. Customers Interrupted (CI) Tree Only (3Yr Total)
   n. Customers Minutes (CMI) Tree Only (3Yr Total)
   o. On Worst Performing Feeder List (Y or N)
   p. Major Capital/ISO Planned (Y or N)
   q. Operations Request (Y or N)
   r. All Outages (N)/Kilometer
   s. Tree Only Outages (N)/Kilometer
   t. Tree Only Customers Interrupted (CI)/Kilometer
   u. Tree Only Customer Minute (CMI)/Kilometer
   v. Customers/Kilometer Served
   w. Percent Three-Phase
   x. Calculated Circuit Priority Ranking
   y. Estimated Circuit Cost

5. **Auditing**:

   Work Completion

   All completed circuit work should be inspected and approved prior to any contractor payments for firm price work. In the case of work performed under Time and Material (T&M), auditing should be completed as circuit are completed to determine if the utility contractual specifications. Incomplete or unacceptable work should be referred back to the vendor for follow-up work in both firm price and T&M unit work. API should develop and implement a formal auditing process. It will serve as notification to API's accounting department that the invoiced work is acceptable for payment. Refer to Appendix B for a recommended example audit process.

IT Solutions

The few available customizable off-the-shelf products out there today integrate work planning, execution, and invoicing into one convenient solution. They will not however, eliminate the need to track other metrics manually (i.e., by spreadsheets, etc.) for there is unfortunately, no application that provides one-stop shopping for all vegetation management program requirements.

ECI has a dedicated IT Consulting group for exploring and fitting IT solution software for the specific needs of our clients. Our professional IT Consulting team works directly with utilities to build a business case and scope out future business processes. Our team examines individual utility requirements and matches them to the appropriate IT solution. From the initial scope, future state process development, business case development, and product evaluation, to change management and implementation. The ECI IT Consulting team will work with the utility from start to finish. ECI will be happy to provide a proposal for this service at the request of API.

Over the past few years, a number of utilities have implemented various software applications to assist with their vegetation management planning, execution and reporting. Due to the value that these software applications can bring, many other utilities are currently considering similar projects.

Experience has shown that often the key to successful software implementation projects include engagement from all stakeholders within the utility to ensure that critical business, IT, and security requirements are thoroughly documented. Without the necessary forethought and analysis, utilities may select a vendor that is unable to meet their needs.

Once a project is started, vegetation departments frequently find that they lack the appropriate level of support from internal technology departments, don't possess experience implementing computer technologies or simply don't have the time to dedicate to these efforts. Also, quite often, software vendors do not have the depth of vegetation domain experience or expertise to deal with significant internal business process change that inevitability occurs. As those who have been involved in software implementations will attest, in order to successfully navigate the inherent complexities these projects bring, having proper internal and vendor support is critically important.

Finally, incorporating the new software application into the existing culture can present specific challenges. To address these challenges, a comprehensive change management process is often implemented. Doing so will ensure the anticipated value resulting from the implementation of a software solution is achieved.

ECI has assembled a team of experts with unique domain knowledge to better ensure our clients choose the right software, and then experience a successful implementation satisfying all stakeholders, transforming your vegetation management program.

With that said, Clearion has been a solution recommended by ECI for several of our utility clients, including Detroit Edison (DTE) and We Energies. These projects were completed within the last 12 months and are in the final implementation phase.

Professional Affiliations

The utility vegetation management industry has gained great strides in the last couple of decades in promoting professional utility arboriculture. The International Society of Arboriculture (ISA) and the Utility Arborist Association (UAA) have been the driving force. Arboricultural certification of utility arborists through the ISA can add significant credibility to a utility's vegetation management program. It is recommended that API vegetation management staff become certified through this program and become active customers in these two organizations.

Customer Collateral

Best-in-class utilities have at their disposal, dedicated VM collateral to share with its customers to utilize for many purposes. This collateral can serve as customer notification for tree pruning, removal requests, mail-stuffers, or other educational material that demonstrate the professionalism of the utility and its programs. API has limited customer collateral and should therefore begin to develop custom collateral documents. ECI has provided collateral examples in Appendix I from nearby utilities that demonstrate good customer/customer collateral.

Process Documentation

Best-in-class utilities have documented processes that serve as both a general guideline as well as provide information for new personnel or transitional management. Normally this can be either a process document outlining the steps, a flow chart, or both. The example in the Customer/ Property Owner Notification /Communication section on Page 22 is a process flow example. ECI will provide upon request, additional examples in Excel format for other processes that API can easily modify in order to document other VM processes. API should dedicate a resource to updating these processes due to their importance.

Appendix A Outage Investigation Form

Example Outage Investigation Form

Tree-Caused Outage Investigation

Circuit: _______________
Voltage: ________________

Backbone / Lateral / Secondary / Service
(circle One)

Date of Outage: ____/____/_____
Time of Interruption: _________ AM/PM
# of Customers Affected: ____________
Duration: (hours/minutes)____________

Investigator: ________________
Date of Investigation: ____/____/_____
Circuit Last Trim Date: ____/____/____
Preventable? YES ____ NO ____

Location:
Street Address: ____
or
Street Name ______________________________________ and
Pole number where outage occurred: _____________________________
or
Street Name ______________________________________ and
Nearest intersection ____

Type of Outage:
___ Electrical Fault
Limb with carbon path found (yes or no)

___ Mechanical Failure - tree or part of a tree fell on the system causing outage.

Species: ________________________

Cause of Outage:
Limb fell
___ Small limb (< 4 inches)
___ Large limb (> 4 inches)

Tree fell
___ Major leader broke and fell
___ Trunk broke and fell
___ Tree uprooted and fell

___ Tree growth condition

Other
___ Not tree caused
___ Customer caused
___ Contractor activity
___ Beaver or animal activity
___ Undeterminable

Defect that Caused Failure
___ Codominant stem
___ Codominant stem with included bark
___ Cracks
___ Conks/fruiting bodies
___ Canker

___ Overhang
Decay
___ moderate
___ extensive
___ Dead

___ No causal defect observed
___ Other - describe below

Tree Location (point of tree failure)
___ Within the R/W limits
___ Beyond R/W limits
___ Top growth over line
___ Side growth at or above primary level
___ Side growth at or below primary level
___ Feet - distance from nearest primary

If tree uprooted - soil conditions
___ wet/saturated
___ shallow
___ sandy
___ other - describe

Protective device that operated
___ Substation breaker
___ 3-phase reclosure
___ 3-phase sectionalizer
___ 1-phase reclosure
___ 1-phase sectionalizer
___ 1-phase line fuse

Additional Comments: ____

____

Appendix B QA/QC Process

Example In-Progress Field Crew Audit (QA)

Contractor:	CREW FOREMAN									
Reviewer:										
Week ending:										
GF:										
Mark 1 if the crew complied										
Mark 0 if the crew did not comply										
Leave blank if no observation can be made										
Date▶										
Work Type										
SAFETY										
Cones										
Signs										
Flagger										
PPE (hardhat; chaps; eye & ear protection)										
General Safe Working Practices										
Safety Comments										
QUALITY										
Clearance										
Vines										
Clean Up										
Dead/hazardous Wood Removed										
Stump Treatment Applied										
Proper Cuts										
Timesheet accuracy										
Quality Comments										
PRODUCTIVITY										
Crew at reported location										
Crew Productively Working										
Equipment in Good Repair										
Appropriate Start and Stop Times										
Productivity Comments										
PERMISSION										
Permission Understandable										
Permission Complete										
Permission Comments										
SCORING										
Safety score[1]										
Quality score[1]										
Productivity score[1]										
Permission score[1]										
Total score[2]										

[1] category score = #1's / (#1's + # 0's)

[2] Total Score = categories totaled by 25% weighting each

Example Work Completed QC Form:

District: ____________________ Work Type: __________ Circuit: __________ Miles: __________

Assessor: ____________________ Date: ______________ Time:____________ Town: __________

Span #	Pole#	TotalTree Count in Span	NUMBER OF DISCREPANCIES													# Critical	# Non-Critical	Photo #	Remarks
			Critical									Non-Critical							
			Inadequate Clearance Under	Inadequate Clearance side	Inadequate Clearance Over	Main Stem Clearance	Needs Removal	Dead wood	Brush Topped / Not Removed	Herbicide Application	Danger Tree(s)	Improper Cut	Improper Crown Ratio	One-Third Rule	Clean-Up / Hnagers				
Subtotals:																			

ANSI/ASQ Z1.4 2008 – Sampling for Attributes

Six-Sigma suggests the use of ANSI/ASQ Z1.4 for determining sample size and accept/reject rates on work output. While this normally applies to a product being produced (i.e. the number of widgets coming off the assembly line in a factory), it can also be applied to the number of trees being pruned to a specific standard. Acceptance sampling is used by industries worldwide for assuring the quality of incoming and outgoing goods. Acceptance sampling plans determine the sample size and criteria for accepting or rejecting a batch based on the quality of a sample, using statistical principles. Many organizations require the use of ISO standards (or their ISO/ANSI/ASQC/BS/Military Standards or other counterparts) for purposes of certification.

Table I—Sample size code letters

(See 9.2 and 9.3)

Lot or batch size	Special inspection levels				General inspection levels		
	S-1	S-2	S-3	S-4	I	II	III
2 to 8	A	A	A	A	A	A	B
9 to 15	A	A	A	A	A	B	C
16 to 25	A	A	B	B	B	C	D
26 to 50	A	B	B	C	C	D	E
51 to 90	B	B	C	C	C	E	F
91 to 150	B	B	C	D	D	F	G
151 to 280	B	C	D	E	E	G	H
281 to 500	B	C	D	E	F	H	J
501 to 1200	C	C	E	F	G	J	K
1201 to 3200	C	D	E	G	H	K	L
3201 to 10000	C	D	F	G	J	L	M
10001 to 35000	C	D	F	H	K	M	N
35001 to 150000	D	E	G	J	L	N	P
150001 to 500000	D	E	G	J	M	P	Q
500001 and over	D	E	H	K	N	Q	R

Table II-A—Single sampling plans for normal inspection (Master table)

(See 9.4 and 9.5)

Sample size code letter	Sample size	Acceptance Quality Limits, *AQLs*, in Percent Nonconforming Items and Nonconformities per 100 Items (Normal Inspection)																									
		0.010	0.015	0.025	0.040	0.065	0.10	0.15	0.25	0.40	0.65	1.0	1.5	2.5	4.0	6.5	10	15	25	40	65	100	150	250	400	650	1000
		Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re	Ac Re
A	2	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	0 1	↓	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	30 31
B	3	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	30 31	44 45
C	5	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	30 31	44 45	↑
D	8	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	30 31	44 45	↑	↑
E	13	↓	↓	↓	↓	↓	↓	↓	↓	↓	↓	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	30 31	44 45	↑	↑	↑
F	20	↓	↓	↓	↓	↓	↓	↓	↓	↓	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	↑	↑	↑	↑	↑	↑
G	32	↓	↓	↓	↓	↓	↓	↓	↓	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	↑	↑	↑	↑	↑	↑	↑
H	50	↓	↓	↓	↓	↓	↓	↓	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	↑	↑	↑	↑	↑	↑	↑	↑
J	80	↓	↓	↓	↓	↓	↓	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	↑	↑	↑	↑	↑	↑	↑	↑	↑
K	125	↓	↓	↓	↓	↓	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑
L	200	↓	↓	↓	↓	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑
M	315	↓	↓	↓	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑
N	500	↓	↓	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑
P	800	↓	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑
Q	1250	0 1	↑	↓	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑
R	2000	↑	↑	1 2	2 3	3 4	5 6	7 8	10 11	14 15	21 22	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑	↑

↓ = Use the first sampling plan below the arrow. If sample size equals, or exceeds, lot size, carry out 100 percent inspection.
↑ = Use the first sampling plan above the arrow.
Ac = Acceptance number.
Re = Rejection number.

If the Switching Rules are not specified, then this QA policy criterion will be used:

Normal (II)→ Tightened (III) – When 2 Lots are found nonconforming out of the past 5 or fewer lots, switch from normal to tightened inspection.

Tightened (III) → Normal (II) – When 5 consecutive conforming lots are found, switch from tightened to normal inspection.

Normal (II) → Reduced (I) – When 10 consecutive conforming lots are found, switch from normal to reduced inspection.

Reduced (I) → Normal (II) – When 1 lot is found nonconforming during reduced inspection, switch from reduced to normal inspection.

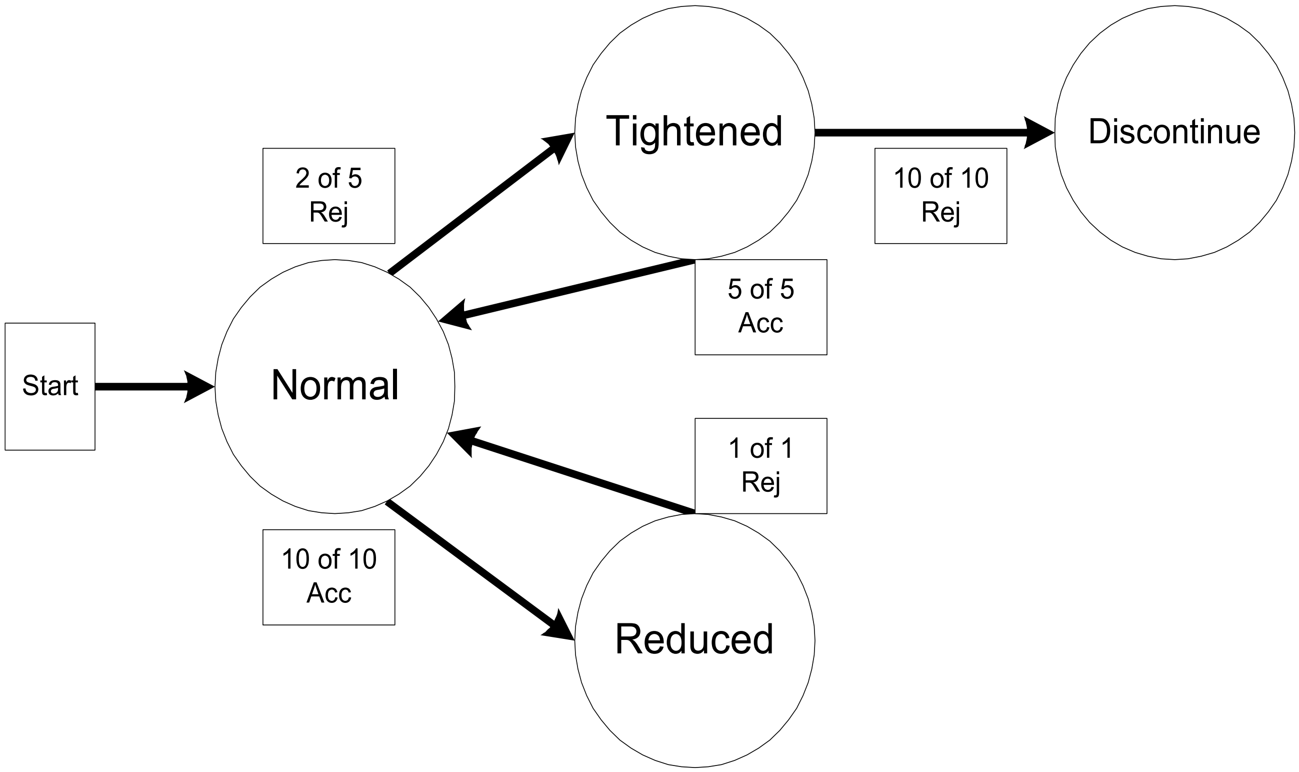


Figure 1. ANSI/ASQ Z1.4 Switching Rules. To Be Used to Determine Audit Intensity.

Goals:

1. To decrease sample size and increase inspection intensity within limits of a statistically valid random sample.
2. To distinguish between critical and non-critical discrepancies.
3. To hold the tree contractor accountable for developing and administering a comprehensive quality assurance (QA) program.
4. Base the accept/reject of entire circuit or segment on the number of discrepancies per 100 trees (not number of deficient spans per kilometer). This is a better measure of overall contractor performance and focuses on critical discrepancies for risk reduction.
5. Set threshold for circuit or line segment acceptance. On reject, require contractor to re-inspect line and correct all discrepancies. Repeat audit after reworks complete.

Determining Acceptable Quality Limits:

Determine the AQL (Acceptable Quality Limits) per 100 trees for the critical and non-critical discrepancies. This is the number of discrepancies the utility is willing to accept and still pay the contractor for the work unit completed. It is suggested that different AQL's be used for critical versus non-critical discrepancies. This will prevent the rejection of a work unit for minor infractions that have little or no bearing on reliability. This is a one-time process and will apply to all circuits or work units being inspected.

Normally, the AQL for critical discrepancies is set to zero. However, critical discrepancies are generally considered defects that may lead to severe injury or death, such as with a defective part in an automobile braking system. Manufacturers cannot tolerate any defects in brake components and would therefore, set their critical discrepancy tolerance to zero percent. Tolerance allowances on the maintenance of vegetation while still important, is less critical than automobile braking systems. So the term "critical" as used here for vegetation maintenance discrepancies is much looser than the traditional definition.

Critical discrepancies in vegetation maintenance work should be defined as insufficient clearance issues or issues involving the failure to remove defective live or dead wood that pose a direct risk to service reliability. Some critical discrepancies may be tolerated in the interest of efficiencies and cost effectiveness. A zero tolerance while ideal in a perfect world, may come at an additional cost that is not easily justifiable. Therefore, the utility should consider an AQL of between 2.5 and 4.0 percent as a good starting point for critical discrepancies. These values can be adjusted at any time by the utility to meet the risk tolerance as conditions change.

Non-critical discrepancies (e.g., improper cuts, poor cleanup, etc.) which reflect poor quality of work more than a specific safety or reliability risk, allow for greater tolerances. These discrepancies are still important because they reflect directly upon the tree vendor's attitudes and abilities. Further, poor quality work can lead to higher future maintenance costs. However, here again, setting the bar too high can result in excessive costs. A starting AQL of ten percent or higher should be considered as a starting point for non-critical discrepancies.

Steps:

1. Note the critical and non-critical AQL's that will be used to determine pass/fail.
2. Determine the number of kilometers completed in the circuit or line segment to be audited.
3. Convert kilometers to number of spans. This is your batch/lot size.
4. Use Table I to determine letter code. Always start with level II (Normal) unless switching rules indicate another level of inspection is required.
5. Use letter code to determine number of spans to sample using Table II. This is your sample size.
6. Select a random starting point on the circuit or line segment using a circuit map (i.e. close your eyes and pick a point or use a random number generator to select specific pole numbers).
7. Field QC:
    a. Start audit at random start location as selected on map or random pole selection.
    b. Begin span to span audit looking at all trees/brush that was and/or should have been maintained.
    c. Use QC form that splits critical vs. non-critical discrepancies (see example below):

Division: _____________ Work Type: __________ Circuit: __________ Miles: __________________

Assessor: ____________ Date: ______________ Time:____________ Town: __________________

			NUMBER OF DISCREPANCIES																
			Critical						Non-Critical										
Span #	Pole#	TotalTree Count in Span	Inadequate Clearance Under	Inadequate Clearance side	Inadequate Clearance Over	Main Stem Clearance	Dead wood	Danger Tree(s)	Should be Removed	Brush Topped / Not Removed	Herbicide Application	Improper Cut	Improper Crown Ratio	One-Third Rule	Clean-Up / Hnagers	# Critical	# Non-Critical	Photo #	Remarks
Subtotals:																			

d. Record total number of trees that were or should have been maintained within each span in the column "Total Tree Count in Span". Brush within a span is counted as a total of one tree regardless of the amount of brush.
e. Record the number of discrepancies in the appropriate column. Continue through all spans.
f. Sum the total discrepancies by critical vs. non-critical.
g. Once all the spans within the sample have been completed total up the total tree count and the critical vs. non-critical discrepancies.
h. Divide the total critical discrepancies by the total tree count and multiply by 100. This is your total critical discrepancies per 100 trees. Repeat the process for the non-critical discrepancies.
i. If the ratio of critical and the ratio of non-critical discrepancies is less than or equal to their respective AQL's, the circuit or line segment is accepted and payable. If either the ratio of critical or the ratio of non-critical discrepancies is higher than their respective AQL's, the circuit or line segment is rejected and that circuit or line segment must be re-patrolled by the tree contractor and all discrepancies remedied.
j. On rejected circuits or line segments that have been remedied, the tree contractor re-submits the circuit to the utility for re-inspection.
k. The utility repeats step (a) through (j) to determine if the remedied circuit or line section can be accepted. Follow the switching rules to determine the new inspection level.

l. If a circuit or line section fails a second time, the work unit is returned to the tree contractor for further remedies AND the tree contractor agrees to reimburse the utility the full cost of the third and subsequent QC audits.

8. With any random sampling process and specifically the ANSI/ASQ 1.4 Acceptance Sample process, there will be a perceived level of discrepancies that will be accepted due to the selected AQL or due to deficient areas that were not selected in the random sample (i.e. skipped line sections not selected in the random sample). It is important therefore, for the VM Arborists to frequently visit work in progress and track work completion over the entirety of the circuit.

9. The contractor scorecard should be amended to use the critical and non-critical scores for measuring tree contractor performance.

<u>Example:</u>

Completed Circuit: AA1234

Circuit Kilometers Completed: 8.45 OH kilometers

Critical AQL: 4.0% (as set by utility)

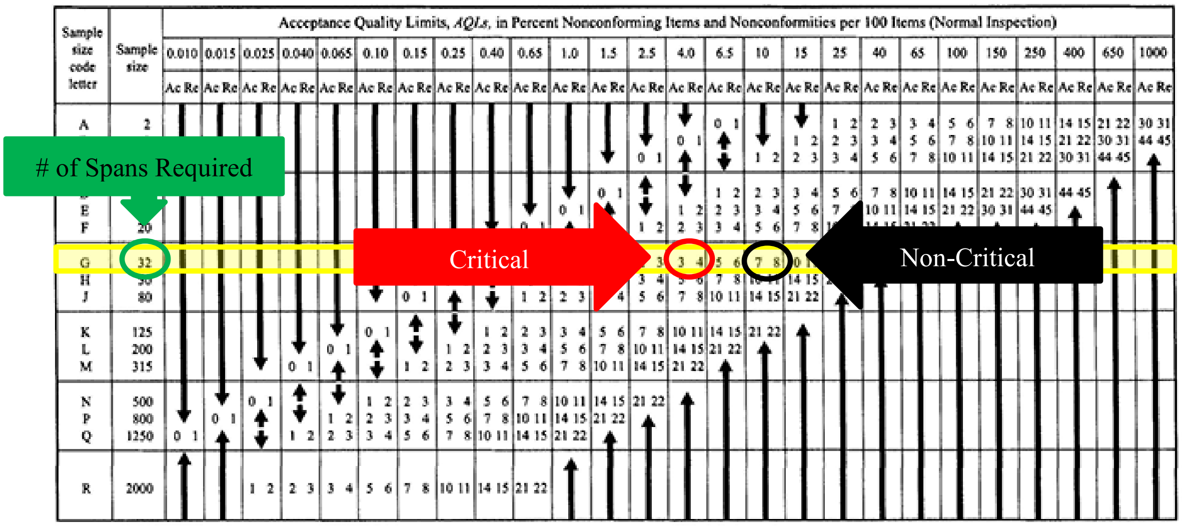
Non-Critical AQL: 10% (as set by utility)

1. **Determining Number of Samples Needed**
    a) Convert the completed circuit kilometers (8.45 kilometers) to a number of spans. If the number of spans is known, use that number, if not, calculate the number of spans based on average span distance or number of spans per kilometer. In this case, the average number of spans per kilometer used is 26. Therefore, the total number of spans completed is 26 x 8.45 kilometers or 220 spans.
    b) Using Table I above, locate the lot or batch size range in the left column which corresponds to 220 spans. Per Table I, the number 220 falls in the range of 151 and 280 (seven rows down).
    c) Assuming a Normal Inspection (II), read across that seventh row to the General Inspection Levels column under II. Note that the sample size code letter is "G".
    d) Using Table II, note the number just to the right of the Sample Size Code Letter column for "G". The number "32" is the number of samples that should be taken. Therefore, the table suggests that 32 spans of the total 220 spans be inspected for discrepancies. See Table II example below.

2. **Determining Accept/Reject Thresholds**
    Use Table II again, to determine the number of allowable discrepancies for both critical and non-critical discrepancies. Reading across row "G", find the numbers under the column for 4.0% AQL. This will be the threshold for critical discrepancies for this circuit. The numbers are "3" (AC-accept) and "4" (RE-reject). Therefore, if the number of discrepancies per 100 trees is three or less, then the work unit is approved. If the number of discrepancies is four or more, then the work unit fails. Find the thresholds for the non-critical discrepancies using the same manner. In this case, those numbers for a 10% AQL are "7" (AC) and "8" (RE). Record these thresholds for later use.

Table II-A—Single sampling plans for normal inspection (Master table)

(See 9.4 and 9.5)



⬇ = Use the first sampling plan below the arrow. If sample size equals, or exceeds, lot size, carry out 100 percent inspection.

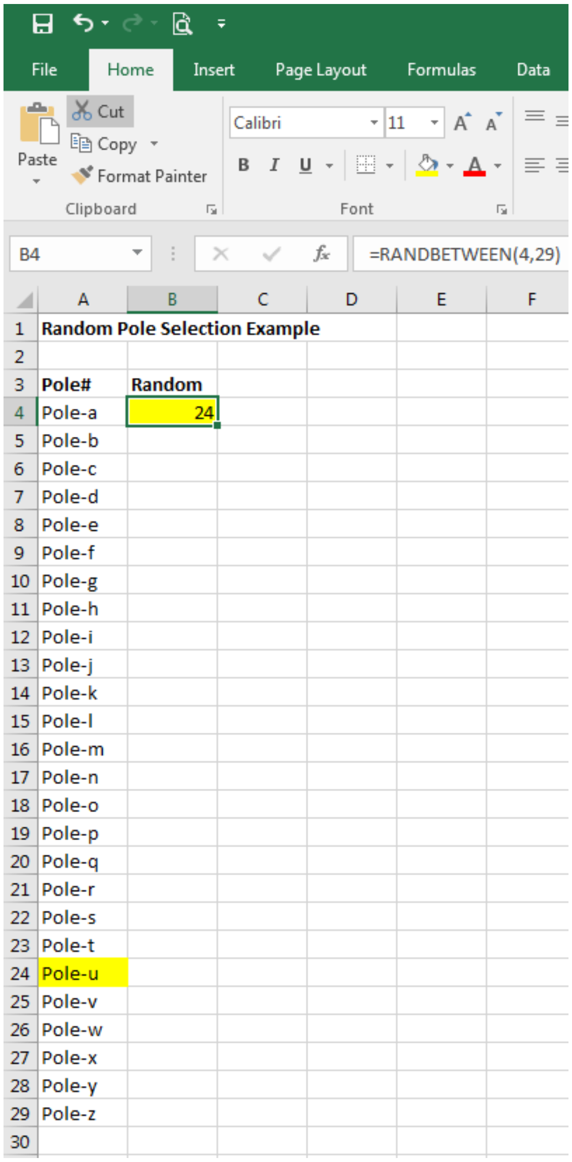
⬆ = Use the first sampling plan above the arrow.

Ac = Acceptance number.

Re = Rejection number.

3. Performing Field Audit

a) Select a random starting point to begin the audit of the 32 required spans as determined above. This can be done by closing your eyes and randomly picking a place on the map, or better yet, using a list of pole numbers or pole locations. We will assume that we have an Excel list of every pole (with pole number and/or GPS location) on circuit AA1234. Since we are looking for only one location, determine the Excel row number for the first pole on the list and also for the last pole on the list. Using Excel formula in any cell, type in "=RandBetween(top row, bottom row)" where "top row" is the cell row of the first pole occurrence and "bottom row" is the last row. See the simplified example below. In this example, "Pole-u' was selected by the random formula inserted in cell b4. "Pole-u" on row 24 therefore, would be our random starting location.



	A	B
1	**Random Pole Selection Example**	
2		
3	**Pole#**	**Random**
4	Pole-a	24
5	Pole-b	
6	Pole-c	
7	Pole-d	
8	Pole-e	
9	Pole-f	
10	Pole-g	
11	Pole-h	
12	Pole-i	
13	Pole-j	
14	Pole-k	
15	Pole-l	
16	Pole-m	
17	Pole-n	
18	Pole-o	
19	Pole-p	
20	Pole-q	
21	Pole-r	
22	Pole-s	
23	Pole-t	
24	Pole-u	
25	Pole-v	
26	Pole-w	
27	Pole-x	
28	Pole-y	
29	Pole-z	
30		

b) After locating "Pole-u" in the field, a contiguous audit of 32 spans is conducted to record discrepancies per the audit form as shown in the **Steps** section above. Each span should be recorded on a separate line on the inspection form. This means that once the form for this audit is completed, it will show 32 lines of data.

c) Contiguous is a relative term. More often than not, you will be required to break-up the inspection line due to hitting a terminal point. When this happens, return to the beginning of that line section that terminated and proceed from that point.

d) Randomness is important, therefore, when beginning the audit, use a coin to determine which direction you will proceed (e.g., left or right).

e) While auditing spans, should you encounter an any line intersection (e.g., where a feeder "T's" off, lateral pulls-off the feeder, a secondary lateral pulls-off the main lateral, etc.) use a coin to determine which direction you should proceed. Do not let ease of access or other factors influence your decision.

f) Record the number of critical and non-critical discrepancies on the audit form. Don't forget to count the total number of trees maintained (or that should have been maintained per the plan) for each span. Note that an individual tree can have multiple discrepancies.

4. Determining Pass/Fail

a) After completing the 32 spans as required in this example, tally up the total discrepancies for critical versus non-critical discrepancies and divide by the total number of trees counted in the 32 spans (note that some spans may have no trees). Let's assume for this example that the auditor found 2 critical discrepancies and 8 non-critical discrepancies in the 32 spans audited. The total number of trees maintained or to be maintained within the 32 spans was determined to be 97 trees. Therefore, the critical discrepancies per 100 trees is calculated to be 2/97=0.021 or 2.1. Likewise, the non-critical discrepancies can be calculated as 8/97=0.082 or 8.2.

b) The critical discrepancies calculated of 2.1 is less than the 4 (RE) critical discrepancy threshold however, the non-critical discrepancies calculated as 8.2 is higher than the reject value of 8 (RE) as determined in Table II (and as originally noted in item 2 above). Therefore, in terms of non-critical discrepancies, the work unit fails. Since the work unit passed in terms of critical discrepancies but failed in non-critical discrepancies, the work unit would fail and be sent back to the vendor to remedy. The vendor should be provided the list of the discrepancies encountered but would be made clear that the "entire" circuit should be rechecked to ensure the types of discrepancies identified are rectified.

Once the tree vendor has notified the utility that the circuit has been remedied (not just the specific spans audited), the utility will begin the audit process all over again by selecting a new random auditing start point and repeating steps 3 and 4 above. The process will continue until the circuit receives a pass on both critical and non-critical discrepancies.

Appendix C Comparison of Relative Pruning and Removal Costs

Comparison of Relative Pruning and Removal Costs

Many utilities have found that it often costs no more to remove trees than to prune them. In fact, tree removal can actually reduce short-term expenditures, since many small trees can be removed for less than it would cost to prune them. Figure 1 shows long-term productivity data confirming that it costs no more to remove small trees than to prune them.

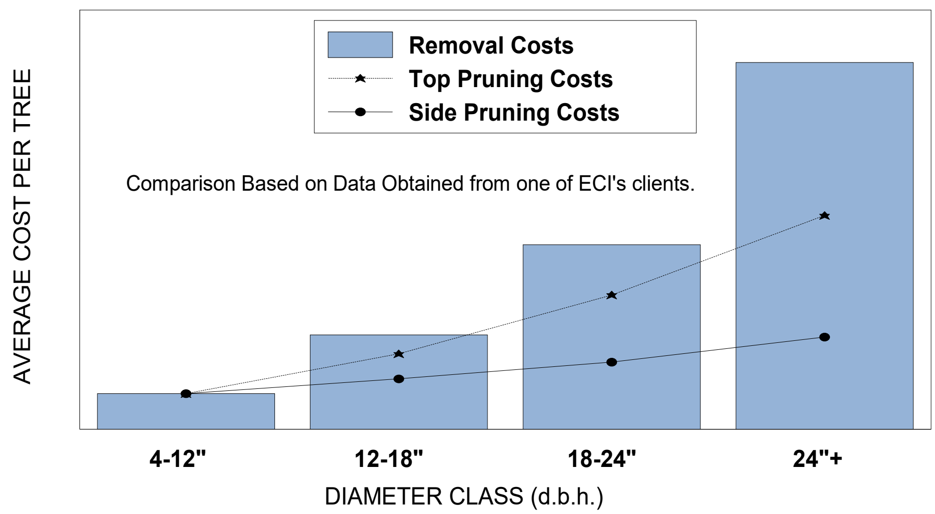


Figure 1. Comparison of Relative Pruning and Removal Costs at Various D.B.H. Size Classes.

Appendix D Contracting Strategies

Introduction to Contracting Strategies

Three different approaches are commonly used by electric utilities to contract line clearance work. These include "time and material/equipment" (T&M), "unit price" and "firm price" or "lump sum" pricing strategies. Each has advantages and disadvantages that are important to understand, and there are multiple variations possible within each pricing family. Each carries a different risk profile for the contractor and the utility. Unit price and firm price contracts are inherently performance-based contracts. However, T&M with incentive pricing can also be a performance-based contracting strategy.

Performance-based contract strategies generally offer the lowest production risk for the utility by placing the burden to monitor crew productivity on the tree contractor and "incentivizing" the contractor to control costs. This applies to firm price, lump sum, unit price, and T&M with incentive type contracts. However, it should be understood that in order for these contract strategies to be effective, the utility and contractor should have a thorough understanding of the work scope, historical man-hours and costs for the work units to be maintained within the contract period. While it is possible to utilize these specific contract types for all work (i.e. ticket type work as well as preventative maintenance work), they are the most effective in situations where the scope of work is better defined such as on preventative maintenance. Ticket work such as Customer Trim Requests and Restoration are often too variable and can lead to higher "unit" prices due to the "contingency" contractors may build into their bid to account for this uncertainty.

Where historical data is not available, some utilities are successful in developing performance-based contracts by clearly defining the project scope prior to bidding through the development of detailed work plans. Pre-planning to define clearances, clearance exceptions, and removals has proven to be a very effective strategy in receiving least cost competitive bids. Contractors provide pricing on the defined work scope that the utility has pre-designated, thus eliminating guess work on the part of the contractor and eliminating the "contingency" cost that contractors build into bids. However, this does require additional effort on the part of the utility to employ knowledgeable personnel to perform the pre-work planning as well as post work acceptance. This strategy generally works well when the utility is developing firm price contracts in the form of a guaranteed cost per kilometer or a guaranteed cost per circuit.

Utilizing a T&M with incentives type contract is a viable alternative for preventative maintenance work but does require an extensive knowledge of historical man-hours in order to develop "should take times" in order to set contractor valid targets or thresholds for each work unit. In this contract type, the utility agrees to pay the contractor for their total actual man-hours incurred to complete the work unit. The contractor in turn, agrees to meet the established target and "share" with the utility any cost savings achieved by completing the work unit with less man-hours than allotted. Some contracts also include a shared "penalty" where the contractor agrees to also share the cost of any work units exceeding the threshold man-hours thus, this provides the contractor with an incentive to find cost savings while minimizing their perceived risk in relation to their skepticism to utility provided targets.

Another variation to this contract type includes a T&M not to exceed. In this contract type, the contractor and utility agree that any cost savings will be shared; however, the contractor bears the entire burden for any cost over-runs above the man-hour threshold set by the utility. The advantage to this contract strategy is that the utility can have 100 percent confidence in their maximum expenditure which they can then use to better plan and budget. The disadvantage is that the contractor may include higher pricing due to the "contingency" variable and therefore, it may not offer the same cost savings as could be expected through the shared incentive/penalty contract.

Utilizing multiple contract strategies for vegetation management is generally the most cost effective. Performance based contracts are preferred for preventative maintenance type work but should be utilized in combination with other contract strategies to ensure overall program cost effectiveness. Firm price or unit price contracts are most effective for brush maintenance or herbicide treatment programs where the contractor can easily inspect and quantify the work volume. Competitive bidding of these work types ensures the contractor will provide the lowest unit price based on their estimated cost to complete the defined work scope and their known material costs (i.e., herbicide costs). T&M contracts (without incentives) offer the greatest level of flexibility to the utility in terms of being able to easily add or remove work scope and therefore are recommended for ticket type work. For the contractor, T&M minimizes their risk where work scope is variable or undefined as in Customer Trim Requests and Restoration type work. This allows the contractor to provide better pricing but shifts the burden to the utility to ensure that crews remain productive. Even so, T&M is generally considered the preferred method for these work types. A combination of all the contract strategies tailored toward specific work types, will offer the greatest potential for cost savings to the utility while minimizing the resources required to monitor contractor performance.

Well-documented inspection of completed work and establishment of clear standards are critical to achieving value from firm price or unit price contracts. Where clearance requirements may be variable due to customer concerns or in situations where work scope is not clearly defined (as with ticket work), T&M normally can provide a better value.

In recent years, the impacts of fuel price fluctuations have become a major concern for contractors as well for the utilities they work for. Concerns arise when contract rates are set at a time when fuel prices are at the extremes and then change dramatically over the life of the contract. This either leaves the contractor with a windfall profit if fuel prices decrease (and the utility with higher costs) or can result in significant loss of profits for the contractor if fuel prices increase. Shorter contract periods (i.e. one-year) can minimize potential risk, but can be costly in terms of the cost to develop new contracts every year, and in terms of higher rates from contractors due to increased risk from shorter contract periods. Many utilities have elected to incorporate fuel escalators into their contracts to offset this concern.

The following are brief descriptions of the common contracting strategies:

Time and Materials (T&M)

T&M is normally the least risky for the contractor since most of the production-related risk is born by the utility. T&M contracts with performance measures and incentives tend to move some of the production risk back to the contractor. T&M often results in the highest work quality. Poor performance may subject a contractor to contract termination or result in assignment of "penalty points" as part of future bid evaluations. For work that is highly variable in nature, difficult to quantify in advance and where quality and customer relations are significant concerns, T&M may be the most desirable method.

Unit Price

Unit price work shifts production risk to the contractor but requires preplanning by the utility to designate which units the contractor should complete. Units are normally a tree trimmed, a square area of brush removed, footage cleared, or a tree removed by diameter classes. There is a natural incentive for the contractor to provide only the level of quality enforced by the utility. Consequently, quality control inspection by the utility is an important administrative requirement for this pricing strategy as well as work completion inspection. Administration of unit price contracts can become burdensome for utilities with high tree densities.

Firm Price

Firm price work also shifts production to the contractor but also shifts work unit selection to the contractor. The natural incentive in this pricing strategy is for the contractor to select the minimum acceptable units and provide the minimum acceptable quality. Post-work inspection by the utility is critical to assuring that all work was completed in compliance with the established specification. Tree removal is often an issue in a firm price contract since costs for tree removal can be highly variable. Consequently, trees to be removed are sometimes identified in advance as part of the bid package preparation. Alternatively, unit prices by size class for tree removal can be established or tree removal can be completed on a T&M basis for trees specifically authorized by the utility. Firm price is best suited to situations where the work can be clearly defined and understood by the bidders. It should also be limited to locations where there will be good competition by a number of bidders. Awarding of concurrent firm price contracts to multiple contractors is desirable. Small firm price contracts bid to companies that do not have a local presence frequently results in higher pricing to cover the cost of per diems or personnel relocations necessary to establish a labor force.

Turnkey and Incentive Based Contracts

Turnkey pricing shifts the maximum risk from the utility to the turnkey service provider. This pricing strategy normally is accomplished by establishing incentives tied to accomplishment of specific objectives such as cost control, tree-related reliability targets, and customer relations. Because most of the program management responsibility is that of the contractor, it is critical that the utility closely monitor the performance objects through periodic review of key performance indicators. A variation of turnkey pricing is a management services contract with a third-party management firm that administers contracts on behalf of the utility. The contracts for craft labor and equipment may continue to be with the utility or through the management company. The management services company may utilize any or all of the other pricing methods. This pricing strategy should be utilized if the utility has limited management resources or desires to totally overhaul existing systems, methods and practices.

Appendix E Prescriptive Reliability

Traditional Vegetation Management Programs

It has long been recognized that trees pose a significant threat to the reliable operation of overhead electric distribution lines. It is estimated that the industry spends in excess of 2 billion dollars annually maintaining vegetation growing in close association with conductors. Contemporary vegetation management programs emphasize the completion of preventive maintenance on a scheduled cycle in an effort to mitigate this threat. The focus of preventive maintenance work is to create and maintain clearance between conductors and trees. This is accomplished by establishing and applying uniform clearance specifications. Vegetation maintenance is typically conducted as a discrete program, with an emphasis on achieving efficiency in completing line clearance work.

Application of RCM to Distribution System Maintenance and Vegetation Management

Recent work in applying Reliability Centered Maintenance (RCM) to a traditional distribution vegetation management program has led ECI to the belief that there is a significant opportunity for improvement in reliability and cost efficiency. Development of a RCM-based approach to overhead distribution maintenance has led to the realization that while it has been useful to manage traditional preventive maintenance efforts as discrete programs for the efficiency's sake, they need to be coordinated so that their composite effect is to optimize the performance of the system.

RCM focuses the allocation of available maintenance resources on the preservation of system function. The analysis process starts by identifying the important systems and the function to be preserved, which is reliable electric service. The process then moves to the identification of the important modes and causes of failure. With a clear understanding of the way interruptions occur, RCM uses a logical decision hierarchy to select preventive maintenance tasks that will be most effective in mitigating the identified risks to system function.

Understanding the Mode & Cause of Tree-Related System Failures

There are two basic ways trees cause distribution system interruptions. Trees fail structurally and mechanically damage the overhead utility infrastructure (mechanical mode), or trees provide a fault current pathway between conductors and /or ground, resulting in a short circuit fault (electrical mode).

The mechanical mode of failure is intuitively obvious and is a major cause of interruptions. Recent research in the area of electrical mode of failure has led to new insight as to what kinds of tree contact pose the greatest threat to reliability. Most tree contact with conductors begins as a high-impedance, low-current fault. Only under certain conditions will this fault evolve from high to low impedance and result in high levels of fault current, operation of overcurrent equipment and, subsequently, an interruption.

Some important points emerge from an understanding of the mode and cause of tree-initiated interruptions. First, the majority of incidental tree contact with energized conductors is of relatively low risk to reliability. Secondly, the structural failure of trees and branches is typically a major cause of both mechanical and electrical failures on a distribution system. Finally, that the overcurrent protection system plays a major role in determining if and how a tree-initiated fault is manifested as an interruption.

It should also be understood that more work needs to be done regarding incidental tree contact with conductors in order to fully understand issues such as the risk to safety by touch potential, risk of initiating wildfires, the economic significance of line loss, and the potential for conductor damage.

The New Maintenance Paradigm - Prescriptive Reliability

Applying an RCM focus of preserving system function to distribution vegetation management leads to a new way of thinking about preventive maintenance. Specifically, the new approach places greater emphasis on assessing field conditions and determining the need for maintenance. Once the need is established, a specific reliability prescription is developed to effectively mitigate risk. The maintenance prescription is an integrated solution including both traditional elements and potentially non-traditional tasks as alternatives to tree pruning and removal.

This maintenance philosophy is consistent with an emerging industry business model that separates asset management and services responsibilities. By practicing prescriptive reliability, the asset represented as overhead distribution infrastructure is actively managed with a focus on preserving system function. This is achieved through an interactive process of resource allocation based on the effectiveness of results, which in this case is reliability. Individual maintenance services, such as the work done by tree crews, are managed for efficiency. This is typically accomplished through existing maintenance contractors. Rather than managing for efficient vegetation work (the service provider's focus) through a prescriptive reliability approach, the maintenance program is managed for optimal reliability by those assigned the responsibility for management of the asset. This avoids the potential for the maintenance program to become focused on the work of maintenance rather than the reason for maintenance.

Changes in the traditional approach to vegetation management. It's not about trimming more trees!

As has been discussed, the traditional cyclical approach to consistent scheduling and completion of preventive maintenance work is a management convenience. However, this philosophy often leads to less than optimal results. The reality is that various elements of the distribution system are not alike in terms of infrastructure, site, and the risk to reliability and consequence of failure. An emphasis on the performance of specific preventative maintenance based on condition assessment is a more intensive form of program management. However, this approach is justifiable given the opportunity for improvements in the effectiveness of resource allocation and reliability.

The second major change to the traditional vegetation management approach is driven by the knowledge that the greatest risk to reliability is caused by the structural failure of trees. This risk can be due to whole tree failure, branch failure within the tree's crown, and the deflection of branches. Loss of tree-conductor clearance is of lesser risk. The concept of clearance remains important, but it should not be as important as it has become. In fact, for much of a distribution system, clearance per se is one step removed from the true risk.

There are three areas where refinement needs to be made to the traditional program, which are as follows:

- Clearance specification,
- Hazard trees maintenance
- Corrective maintenance.

Preventive maintenance clearance specifications should place much greater emphasis on the elimination of potential causes of tree and branch failure. This also includes an important emphasis on proper arboricultural practices. This emphasis is driven by the goal to reduce the risk of structural failure. Trees respond favorably to proper pruning. Improper trimming causes stress, decay, and mortality, which effectively increases the risk of structural failure.

Secondly, because the risk of tree failure is predictable, regular hazard tree inspection and mitigation needs to be included as an important element of the vegetation management program.

Finally, armed with a new understanding of the mode and cause of tree-related interruptions, refinements can be made in the way corrective maintenance tree work (a.k.a. hot spotting) is managed.

Out-Of- The- Box Preventive Maintenance Alternatives

RCM begins with an initial assumption that reliability is an inherent design characteristic of the system. Within this frame of reference, structured decision logic is used to select optimal preventive maintenance tasks. This decision hierarchy define the preferred approach to preventative maintenance as follows:

- Performing maintenance based on-condition
- Performing maintenance based on a fixed time interval
- Not performing preventive maintenance but repairing after failure
- Redesigning the system.

Redesign is recognized as the least preferred preventive maintenance alternative because it is often expensive. Nevertheless, it has a place in the maintenance program. The reality is that traditional vegetation maintenance tasks will not provide adequate risk mitigation for all sites and for all elements of the distribution system. In some small percentage of sites, adequate risk mitigation by traditional tree work is neither practical nor possible. In these cases, redesign alternatives deserve consideration.

Because RCM focuses attention on preserving system function, a number of strategies not traditionally considered to be maintenance items could be included in the maintenance prescription. Examples would include changes to the overcurrent protection system, corrective repair to existing infrastructure, and changes in the infrastructure. While the majority of resources will be allocated to preventive maintenance, (e.g. tree pruning and removal work), these other options will be considered and prescribed based on information acquired during field condition assessment.

Changes in Overcurrent Protection

Tree contact with overhead conductors initiates a fault. Under certain circumstances, the fault evolves from high to low impedance, with a corresponding increase in fault current levels. It is through the operation of the overcurrent protection system that the fault results in an interruption of some duration and size. There are a number of things that should be considered as means of mitigating the risk posed by trees.

Distribution systems are dynamic, and overcurrent protection coordination must keep pace. This is not always the case. A strong argument can be made to include a high level review of overcurrent protection coordination as part of the scheduled preventive vegetation maintenance of a circuit. The combined effect of tree maintenance together with overcurrent protection coordination would yield a return greater than either one done independently.

In addition to finding problems with overcurrent coordination, one will likely find missing, bypassed and/or disabled protection equipment. An example would be the occurrence of un-fused single-phase lateral taps. In this case, the argument can be made that a more effective means of mitigating risk than through tree pruning alone would be shifting part of the tree maintenance expenditures toward fuse installation. This is not to suggest that tree maintenance along single-phase lines isn't important. But with proper overcurrent protection, the intensity of that effort could be reduced, as compared to that required for multi-phase lines.

Finally, there is the issue of overcurrent protection philosophy. An understanding of tree-related fault mode and cause suggests that a review of some basic system protection practices may be in order. The practice of feeder selective relaying, (preserving fuses by recloser operation), is commonly practiced in the industry. One reason for this approach is the belief that most faults on the overhead system are transient in nature. As pointed out, if a tree-initiated short circuit is the cause of the recloser operation, it is because it has provided a low impedance fault pathway. If the tree/branch with fully developed fault pathway remains in contact with the conductor(s), the reclosing operation will close back into a low impedance fault pathway. Based on an understanding of mode and cause, there is reason to question an assumption that the majority of tree-initiated faults would in fact be transient.

ECI acknowledges that the overcurrent protection system must be effective in addressing faults of all causes. However, for circuits where trees pose the dominant threat to reliability, a fuse-sacrifice protection scheme should be considered.

Assessing Opportunities for Changes to Infrastructure

The most intuitively logical element of infrastructure to include in the overhead preventative maintenance program is inspection and correction of obvious defects. As has been discussed, an argument can be made for condition assessment and the development of a specific maintenance prescription. Assessment of the elements of the overhead infrastructure can be easily included in the inspection and maintenance prescription writing process.

On the basis of a generic economic assessment, it would be unlikely that the investment necessary to alter existing infrastructure is justifiable. However, conventional preventive maintenance tree work will not provide cost-effective risk mitigation on all sites and circuits. This is the same basic argument for redesign that supports consideration of change to overcurrent protection.

Here too, a RCM philosophy is useful in assessing where changes in infrastructure may be the preferred alternative. A system-based rather than site-based assessment of preventive maintenance costs is warranted. With an on-condition approach, the cost savings related to future maintenance may come from both a reduction in maintenance intensity and frequency.

The assessment involves comparing the present value of future maintenance costs on the old system to the cost of conversion plus the present value cost of maintaining a new system. Benefits such as potential improvements in reliability between systems should also be considered. The specific approach to economic analysis is beyond the scope of this paper. Conceptually speaking, however, when the cost to change a small portion of infrastructure provides a greater return in terms of cost savings and reliability than repetitive pruning and removal work, it should be included as part of the maintenance prescription. Finally, it is important not to imply high precision in the analysis if it cannot be supported by available data and assessment tools.

Changes to Conductor Orientation and Alignment.

Research into the electrical mode of failure points to the importance of considering the voltage gradient in assessing the risk presented by tree-conductor contact. A second factor is conductor orientation as it relates to branch capture, which is the likelihood of a branch intercepting and remaining in contact with two conductors and or a conductor and the neutral wire. Compact phase configurations create higher voltage gradients and increased potential for faults developing due to branch capture. Horizontal phase orientation can present a high risk of branch capture that could result in phase-to-phase faults. Opening up phase spacing and vertical construction presents lower risk. Both need to be considered when designing new lines, as well as a means to harden the existing system to tree-caused faults.

The other alternative strategy involving conductor position is their physical location. This alternative is intuitive. Realignment or rerouting of conductors to separate them from trees can reduce tree-related risk on some sites. Options include the use of offset arms (a.k.a. wing arm or alley arm), increasing pole height, and the physical relocation (and possible elimination) of the line. The important point is that while some of these options are quite expensive, they deserve consideration on a relatively small percentage of the system.

Changes to Overhead Conductors

The voltage stress gradient impressed upon a branch that falls between two or more conductors may also be reduced by the use of various coated conductor systems, which are collectively known as "tree wire". The options include the use of coated overhead primary, where the coating provides some insulating characteristics, while not being technically rated as insulation. Spacer cable and true aerial cable systems provide increased resistance to tree-initiated faults since the coating serves increasingly as insulation. Getting creative, it is conceivable that adequate reduction in voltage gradient may be achieved with only one phase being replaced with a coated conductor. Finally, it is possible that a field-applied coating system can be developed, reducing the cost of this maintenance alternative by eliminating the need to re-conductor a section of infrastructure.

Tree wire can be applied with excellent results for those portions of circuits where the risk due to trees cannot be effectively mitigated by pruning and tree removal. The point once again is that by including these methods as options, the benefit of an integrated approach to prescriptive reliability can be achieved.

Conversion from Overhead to Underground

The final alternative to traditional tree pruning and removal is converting overhead infrastructure to underground. This is the most effective alternative in reducing the risk of tree-related service interruption. In fact, the risk due to trees is effectively eliminated. Undergrounding overhead lines can be prohibitively expensive. That said, it is important to state again the underlying philosophy; traditional vegetation maintenance will not provide adequate risk mitigation on all sites and for all elements of the distribution system. In some small percentage of sites, where tree pruning and removal is neither practical nor possible, undergrounding deserves consideration.

The cost of underground conversion is highly variable. Factors such as the complexity and function of the overhead infrastructure affect cost of conversion. The construction methods required also influence cost as does the site location and the need for restoration following construction. Likewise, there are locations where cost can be relatively low and where the risk faced by overhead lines is very high. The point once again is that by assessing risk these sites will be identified. Underground conversion applied on a generic basis makes little sense. However, including undergrounding as a specific treatment for a specific high-risk situation can be very effective in improving the reliability of a distribution system.

A final note on underground conversion

Underground construction has greater potential to adversely affect the health of trees than do most overhead maintenance practices, because underground construction has the potential to destroy a tree's root system. Conversion work should include work practices intended to reduce the potential for adversely affecting trees. Useful information in this area can be found in the National Arbor Day Foundation's booklet: "*Trenching & Tunneling Near Trees*".

Summary:

There is room for improvement with respect to traditional vegetation management programs. Too often, traditional vegetation maintenance focuses on just achieving clearance, and not on the ultimate goal, which should be reliability. Prescriptive reliability represents an opportunity to refocus maintenance resources on what counts; improved reliability. This philosophy relies on condition assessment and the development of a specific maintenance prescription. A much wider range of maintenance alternatives are available than are typically found in the traditional program. The resulting integrated maintenance solution provides for a more effective allocation of resources and improvement in reliability.

Reference: Utility Vegetation Management: Use of Reliability Centered Maintenance Concepts to Improve Performance. EPRI. Palo Alto, CA. 2009. 1019417.

Appendix F How Trees Cause Outages

How Trees Cause Outages

by John Goodfellow and Paul Appelt

Abstract. Ten tree species of operational significance to electric utilities were subjected to high voltage gradients in a controlled laboratory environment. Data from this project were combined with those from earlier work, resulting in a database covering 21 species. Differences in electrical conductivity were observed among species. This work confirms that the electrical impedance of live branches is variable and supports the hypothesis that the risk that trees pose to reliability of electric service varies by species. The species of individual trees in close proximity to an overhead distribution line should be an important consideration in assessing risk to reliability. This work also suggests that the majority of tree-conductor contacts result in high impedance faults of low current and is of relatively low risk to reliability. Only under some conditions do tree-initiated faults evolve to become low impedance/high current fault events, and cause interruptions. These findings can be applied in the development risk assessment criteria, and reliability driven preventive maintenance of trees posing a threat to overhead distribution lines. The work identified several important characteristics of the determinant variables of species, voltage gradient and branch diameter that are promising risk assessment criteria.

Key Words. High Impedance Faults, Interruption, Low Impedance Faults, Outage, Voltage Stress Gradient

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Trees continue to be a leading cause of service interruptions on electric distribution systems throughout North America. This in spite of the fact that electric utilities spend more than $2 billion annually on preventive maintenance of vegetation interacting with overhead distribution lines. While numerous refinements have been made in vegetation management practices over past decades, much of the change has been driven by financial and productivity considerations. Very little research has been completed on the fundamental question of how trees cause service interruptions.

The traditional approach to mitigating this risk involves uniform application of a fixed standard for clearance between trees and overhead conductors. Earlier work on a limited number of species led to development of a conceptual model of understanding tree-caused interruptions that provided a new understanding of the risk trees pose to reliability. This project further quantified the relative risk of operationally important tree species impacting overhead distribution electric lines in North America.

Project findings provide a means of assessing the relative risk of different tree species to electrical service reliability. Findings from the investigation also support modification to the tree-to-conductor clearance specifications, and the scheduling of preventive maintenance of trees in close association with overhead distribution lines. An improved understanding of the risk associated with individual tree species will support optimization of reliability-focused maintenance by allowing utility arborists to target more intensive levels of maintenance on those trees that pose the greatest risk of causing an interruption to electrical service.

METHODS

Experience suggests that the list of operationally significant "problem" species faced by utilities in each region tends to be relatively short. Further, the list for any physiographic region will have frequent overlap. A list of the most frequently occurring and operationally significant species in nine regions was developed. Table 1 identifies the important species posing a threat to overhead distribution system reliability in each region. The species that were the focus of this investigation are highlighted in the table and were selected for testing based on the interests of utility cooperators that provided support to the project.

Sample branches were collected from the residues generated by utility line clearance tree crews performing routine preventive maintenance pruning. Seventy-two (72) specimens in four diameter classes were collected. The diameter classes of interest were: 1.27, <2.54, <5.08, and <7.62 centimeters (<½”, <1”, <2”, and <3”). All specimens tested were collected during the dormant season. This was a deliberate choice in the experimental design, as it allowed for ease of collecting, shipping, and preserving the fresh branch specimens from the time of collection in the field, to the time of testing in the laboratory. The samples were shipped to the high voltage testing laboratory in Redmond, Washington. Upon receipt, they were stored in a cool, moist environment until use. No sample was more than one week old when tested.

Table 1. Frequently Occurring Tree Species by Region

NE	Midwest	Temp SE	Gulf Coast	Inter Mt.	Southwest	PNW	Pacific So	Sub Tropical
Northern red oak *(Quercus rubra)*	green ash *(Fraxinus pennsylvanica)*	green ash *(Fraxinus pennsylvanica)*	black gum *(Nyssa sylvatica)*	Siberian elm *(Ulmus pumila)*	Siberian elm *(Ulmus pumila)*	black cottonwood *(Populus trichocarpa)*	sycamore *(Platanus occidentalis)*	live oak *(Quercus virginiana)*
red maple *(Acer rubrum)*	Siberian elm (Ulmus pumila)	sycamore *(Platanus occidentalis)*	live oak *(Quercus virginiana)*	Ponderosa pine *(Pinus ponderosa)*	Ponderosa pine *(Pinus ponderosa)*	red alder (Alnus rubra)	Douglas fir *(Pseudotsuga menziesii)*	queen palm *(Syagrus romanzoffiana)*
black cherry *(Prunus serotina)*	silver maple *(Acer saccharinum)*	black locust *(Robinia pseudoacacia)*	sweetgum *(Liquidambar styraciflua)*	quaking aspen *(Populus tremuloides)*	black cottonwood *(Populus trichocarpa)*	Douglas fir *(Pseudotsuga menziesii)*	bigleaf maple *(Acer macrophyllum)*	royal palm *(Roystonea spp.)*
paper birch *(Betula papyrifera)*	red maple *(Acer rubrum)*	weeping willow *(Salix babylonica)*	boxelder *(Acer negundo)*	red alder (Alnus rubra)	pinyon pine *(Pinus edulis)*	bigleaf maple *(Acer macrophyllum)*	Ponderosa pine *(Pinus ponderosa)*	coconut palm *(Cocus nucifera)*
silver maple *(Acer saccharinum)*	weeping willow *(Salix babylonica)*	honeylocust *(Gleditsia triacanthos)*	slash pine *(Pinus elliottii)*	bigleaf maple *(Acer macrophyllum)*	mulberry *(Morus spp.)*	quaking aspen *(Populus tremuloides)*	eucalyptus *(Eucalyptus spp.)*	ficus *(Ficus spp.)*
sugar maple *(Acer saccharum)*	black locust *(Robinia pseudoacacia)*	slash pine *(Pinus elliottii)*	loblolly pine *(Pinus taeda)*	Douglas fir (Pseudotsuga menziesii)	Freemont cottonwood *(Populus fremontii)*	black locust *(Robinia pseudoacacia)*	blue oak *(Quercus douglasii)*	black olive *(Bucida buceras)*
quaking aspen *(Populus tremuloides)*	sweetgum *(Liquidambar styraciflua)*	loblolly pine *(Pinus taeda)*	hackberry *(Celtis occidentalis)*	paper birch *(Betula papyrifera)*	live oak *(Quercus virginiana)*	lodgepole pine *(Pinus contorta)*	English walnut *(Juglans regia)*	Norfolk Island pine *(Araucaria heterophylla)*
Eastern white pine *(Pinus strobus)*	boxelder *(Acer negundo)*	pecan *(Carya illinoensis)*	water oak *(Quercus nigra)*	black cottonwood *(Populus trichocarpa)*	Lombardy poplar *(Populus nigra 'Italica')*	Lombardy poplar *(Populus nigra 'Italica')*	redwood *(Sequoia sempervirens)*	melaleuca *(Melaleuca quinquenervia)*
weeping willow *(Salix babylonica)*	black walnut *(Juglans nigra)*	water oak *(Quercus nigra)*	palm *(Sabal spp.)*	Western red cedar *(Thuja plicata)*	post oak *(Quercus stellata)*	Pacific willow *(Salix lasiandra)*	palm *(Sabal spp.)*	mahogany *(Swietinia mahagoni)*
boxelder *(Acer negundo)*	hackberry *(Celtis occidentalis)*	sweetgum *(Liquidambar styraciflua)*	bald cypress *(Taxodium distichum)*	boxelder *(Acer negundo)*	Southern red oak *(Quercus falcata)*	Western red cedar *(Thuja plicata)*	live oak *(Quercus virginiana)*	Australian pine *(Casuarina equisetifolia)*

The diameter of each specimen was recorded. A small portion of each specimen was cut off and weighed. This small sample was then dried in a lab kiln at between 101 and 105 degrees Celsius (214- and 221-degrees Fahrenheit) until a constant weight was reached. Each dried portion was then re-weighed to determine the internal moisture content of each specimen being tested.

The project involved two related but different experimental efforts. Both protocols involved subjecting branch specimens to pre-established fixed high voltage stress gradients, typical of those found on energized overhead distribution circuits in the field.

Voltage gradients found on the overhead distribution systems of the utilities participating in this project were determined by reviewing overhead line construction standards. This review provided phase-phase and phase-neutral spacing (***d***), and nominal operating voltage (**v**) information for each line type. Because conductor tension and sag can vary, the distance measurement was taken at the structure between insulators. The voltage gradient for each line type was determined by the following calculation:

Voltage Gradient = v/d

Two factors create higher gradients on multi-phase lines than on single-phase lines. First, the voltage differential between two energized phases is higher than the corresponding phase to neutral voltage. Second, phase-to-phase spacing is usually less than the distance between phase and neutral. The result is that much higher voltage gradients are found on multi-phase (phase-to-phase) lines than those typically seen on single-phase (phase-to-neutral) lines. Voltage gradients present on the cooperating utility's distribution systems were found to vary by an order of magnitude, ranging from <1kV/ft to >10kV/ft.

Both experimental procedures were conducted in a controlled high voltage laboratory setting. Individual test specimens were placed between two conductor segments positioned a fixed distance apart. This configuration permitted the branch specimens to be consistently positioned for each testing sequence. This design allowed a predetermined test voltage level to be impressed uniformly across a fixed distance, achieving the desired voltage stress gradient.

Figure 1. Specimen under high voltage testing.

The voltage gradient impressed on each specimen was controlled and varied for different sample lots by varying the voltage input. A variable output AC high potential test transformer provided a means of voltage control. A 60:1 power transformer with a maximum rated output of 15 kilovolts was used as a high voltage source. An instantaneous current-sensing trip coil of a protective relay protected the test circuit. The relay was set to interrupt at fault current level of 275 mA. Test set instrumentation provided for a continuous record of time and current, as well as real-time observations of current, time and voltage. When the voltage stress gradient was applied to each test specimen, a timer was automatically actuated. Each test was concluded when the current level flowing through the test specimen exceeded the test set output, tripping the protective circuit breaker. In each case, the time to fault (defined as current flow sufficient to cause the instantaneous current sensing trip coil of a protective relay to operate) was recorded. Tests were also declared complete for those specimens that failed to flash over when the fault current levels being measured dropped to a steady level well below that observed on initial energization. A third variant occurred when the specimen failed by either burning through or falling clear.

FINDINGS

- Electrical conductivity Varies by Species. Figure 2 summarizes the variability in measured conductivity observed in 18 of the species tested. Rho is a standard measure of the resistivity of a material.

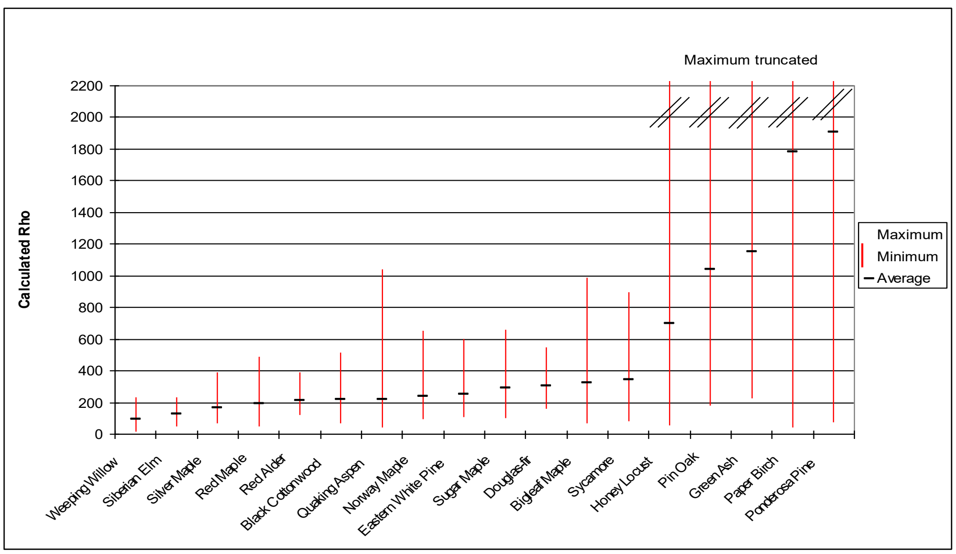

Figure 2. Chart of calculated Rho by species tested.

- Electrical Conductivity Varies by Branch Diameter. Time-to-fault decreases as diameter increases at a given voltage stress gradient as illustrated in Figure 3.

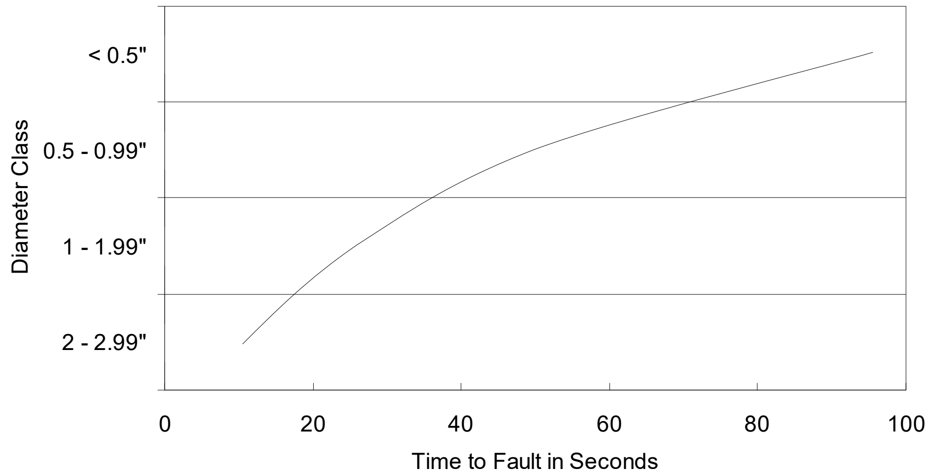

Figure 3. An example of mean variability in measured conductivity observed over the range of diameter classes for a single species (red alder) at 3kV per foot voltage stress gradient.

- Voltage gradient is the most important factor in determining the risk of tree initiated low impedance high current faults. Figure 4 clearly demonstrates the importance of voltage gradient as a factor in determining the risk of a tree contact providing a low impedance pathway and resultant high current fault.

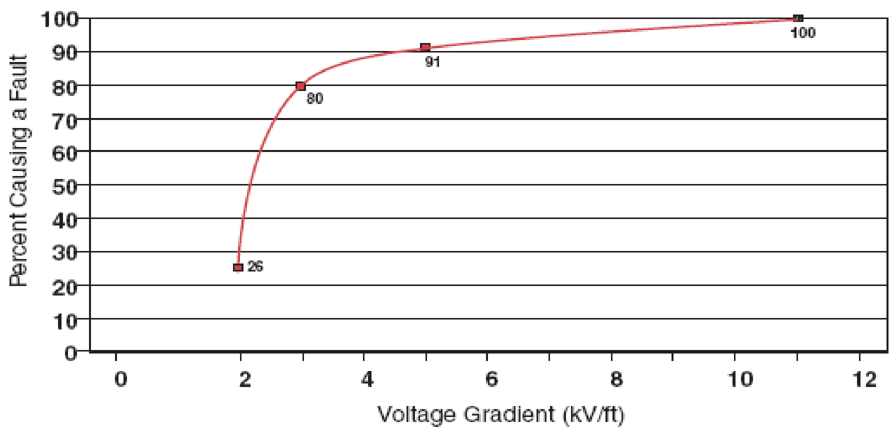

Figure 4. The percent of samples that resulted in a fault increased with voltage gradient

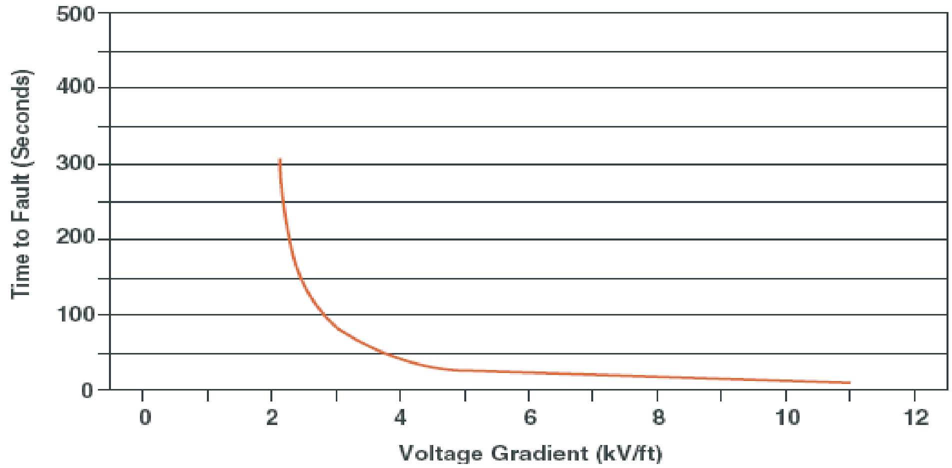

Figure 5. Time-to-fault decreases as voltage stress gradient increases.

- There appears to be a voltage gradient threshold below which a tree branch will not provide a low impedance fault pathway. Figure 5 suggests that tree-initiated fault pathways subject to voltage gradients less than 2kV/ft are much less likely to result in high current faults.

CONCLUSIONS AND RECOMMENDATIONS

Species Considerations

This project clearly establishes that electrical impedance varies by species. The variability between species appears great enough to warrant consideration in evaluating risk to reliability posed by trees on overhead electric distribution circuits.

Overhead Circuit Considerations

This study emphasizes the point that multi-phase lines, which typically have substantially higher voltage gradients than do single phase lines, have greater risk exposure to tree-related interruptions than do single phase lateral taps. This increased risk is due to the higher voltage gradients created by the close proximity of areas of unequal electrical potential. These elevated voltage stress gradients are impressed across a branch when it provides a phase-to-phase fault pathway. Voltage gradients may vary by nearly an order of magnitude on an overhead distribution circuit and should be considered in developing vegetation maintenance prescriptions.

Construction Framing Considerations

The findings of this study demonstrate that the relative risk of tree-related interruptions varies by construction framing standards. Changes may be possible in standard structure design which could reduce the voltage gradient or change the orientation of energized equipment to reduce or eliminate the likelihood that a broken or deflected branch would make contact with two or more areas of unequal electrical potential.

Diameter Considerations

Branch diameter was shown to play a major role in conductivity, with the largest branches being much more conductive than small shoots. This factor should be considered in developing risk assessment criteria. In terms of tree morphology, larger branch diameters occur closer to the main stem. By definition then, conductor contact with larger diameter branches will more often occur with trees in very close proximity to overhead lines. These high-risk contacts will also develop over a long period of time. Branches of only a few growing seasons in age represent relatively lower risk. The implication is that periodic assessment should allow identification of higher risk tree-conductor contacts before they are manifest as an interruption.

Growth Considerations

This project adds to an understanding of the high impedance pathway provided by small diameter new growth and provides an important piece of information useful in scheduling periodic preventive maintenance. Basically, the incidental branch-conductor contacts that develop as a circuit "ages" and trees grow back into the cleared area is of low risk to reliability. Simply stated, it is unlikely that trees cause interruptions on 15kV class distribution lines merely by growing into contact with a conductor. The brown foliage that has traditionally been described as "burning" is more probably leaf wilt. This is due to the effect of resistance heating, desiccation and subsequent death of the living tissues of new shoots and leaves. Wilted foliage is a poor indicator of a tree's threat to reliability. Since these new contacts do not appreciable affect the risk of an interruption, some level of contact can be tolerated. The preventive maintenance cycle period can be based on an economically optimal period, rather than strictly on the basis of maintaining line clearance.

Overcurrent Protection Considerations

The project also confirmed that once formed, the low impedance/high-current fault pathway provided by a tree branch is persistent. This confirmation presents a potential opportunity in re-thinking tree caused faults in the context of system overcurrent protection. If the fault pathway provided by a branch remains, subsequent faults will occur when the circuit is reenergized. The decision to make application of "fuse sacrifice" or "feeder selective relaying" overcurrent protection coordination philosophies on distribution circuits with elevated risk exposure to tree-caused interruptions needs to be made with this in mind. Furthermore, the overcurrent protection scheme in place at many utilities today is designed to protect against faults that occur within a cycle or cycles (60 Hz). This study suggests that tree-related faults often develop over extended periods. This reality may require changes in the design of system protection schemes.

APPLYING THE RESULTS

Based on the enhanced understandings of how trees cause interruptions and documented differences in impedance between tree species, there are considerable situational differences in risk of interruption due to tree contact with energized conductors. Factors such as species, diameter, and voltage gradient discussed in this paper are readily observable in the field. Consequently, this information can be incorporated into risk assessment criteria, maintenance specifications, maintenance planning and scheduling strategies, and site-specific vegetation maintenance prescriptions.

Acknowledgments.

The authors would like to acknowledge the TREE Fund for supporting this project through a Johns Grant. We would also like to acknowledge the support of the following utilities in providing funding and in-kind contributions for specimen collection: Allegheny Power System, Niagara Mohawk Power Corporation (National Grid), Portland General Electric, Illinois Power (Ameren), Central Vermont Public Service, and Black Hills Power.

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Appendix G API Specifications and Guidelines Document

Contents

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OD-1.0 OBJECTIVE

The objective of the Company's Vegetation Management Program is to create and maintain ideal conditions where the vegetation control program is characterized by less effort over subsequent cycles as compatible vegetation becomes more prevalent.

OD-2.0 SCOPE OF WORK

OD-2.1 The Service Provider shall, in accordance with the provisions of the Agreement and following safe work methods, perform the work of managing vegetation whose natural characteristics and/or location have the potential of creating unacceptable risk to the safe, reliable, ongoing operation of the Company's system.

OD-2.2 The Services shall include the supply of all labour, material, equipment and supervision necessary to carry out and complete vegetation management activities on the Company's facilities and joint use communication and service electrical lines, as follows:

(a) Underbrushing – Manual
(b) Underbrushing - Mechanical
(c) Tree Pruning
(d) Tree Removal – Manual
(e) Tree Removal – Mechanical
(f) Disposal of Cut Material, Stump Removal & Grinding and Site Clean-Up
(g) Seeding & Planting
(h) Herbicide Work; and
(i) Other vegetation management services as required by the Company from time to time.

OD-3.0 SAFETY

OD-3.1 General

OD-3.1.1 All work shall be carried out in accordance with all relevant federal and provincial safety legislation and by-laws of municipalities having jurisdiction including without limitation, the Ontario Occupational Health and Safety Act and all relevant regulations made under such legislation, the IHSA Rules, the IHSA Safe Practice Guide "Line Clearing Operations", the Transportation of Dangerous Goods Act, industry best practices, and Company policies, procedures, guidelines and other requirements specified in the Agreement. If there is a conflict in any of the applicable provisions from the aforementioned items, the more stringent or higher guideline, rule, procedure, standard or requirement shall govern.

OD-3.1.2 The Service Provider shall comply in every respect with the requirements of the Workplace Hazardous Materials Information System (WHMIS), including the retention of applicable Material Safety Data Sheets (MSDS) at the Site(s) and provision of copies of same to the Company.

OD-3.1.3 The Service Provider shall ensure that its supervisors are familiar with the appropriate sections of the Utility Work Protection Code (UWPC).

OD-3.1.4 All workers working in the vicinity of electric utility lines and equipment shall have successfully completed the Electrical Safety and Awareness Training or a more advanced line clearing program provided by IHSA or another organization considered by the Company to be an equivalent authority that meets or exceeds MTCU Utility Arborist Program Trade Code 444B, and shall be fully briefed and instructed in the safe working procedures appropriate to the work and to the voltage and condition of the electric apparatus on or near the Site.

OD-3.1.5 The Service Provider shall utilize a daily written job planning technique that includes a documented tailboard checklist that is prepared at the commencement of each work day and whenever the work, workers, Sites, conditions, equipment, work procedures or hazards change. In addition, the Service Provider shall, prior to introducing any new machinery, tools, equipment or processes into the work, prepare and submit to the Company's designated representative, a written change analysis, for the review and approval of the Company.

OD-3.1.6 The Service Provider's supervisor(s) shall, throughout the term of the Agreement, adhere to and maintain the safety and environmental monitoring schedule submitted to the Company by the Service Provider.

OD-3.1.7 Prior to beginning the work, the designated representatives of the parties shall review each Site to ensure it is safe and that all brush and trees to be removed do not encroach within the safe limits of approach observed by the Company. The Service Provider and the Company shall both acknowledge the acceptable condition for the work to begin by signing and dating a Work Approval. The acceptable condition for the work shall be valid until the expiry date. The Service Provider shall continue to assess this condition on a daily basis during execution of the work.

OD-3.1.8 No work shall take place in an area where the Work Approval has expired. The Parties' designated representatives shall conduct another Site visit and a new Work Approval shall be prepared and signed by the Parties, before the work can commence.

OD-3.1.9 There shall be at least two (2) competent and qualified workers on Site at all times when working in the vicinity of lines over 750 volts. Such workers shall be certified by IHSA, and shall understand the hazards and safety standards critical to work in the vicinity of electrical conductors.

OD-3.1.10 Where trainees are involved, they shall be instructed in the safety standards and practices specified in the Agreement, the IHSA Rules and the IHSA Safe Practice Guide "Line Clearing Operations", and industry best practices applicable to the work. Trainees shall work directly with one qualified worker, and there shall be no more than one trainee supervised by each qualified worker at any time.

OD-3.1.11 The Service Provider shall employ a fall protection system when a worker is exposed to any of the hazards specified in Section 26 of the Regulations for Construction Projects (O.Reg.213/91) under the Occupational Health and Safety Act and subsequent revisions.

OD-3.1.12 No worker or object, i.e. safety ropes, tools, cut brush and equipment, shall encroach on the safe limits of approach to utility lines as specified in Section 188 of Ontario Regulation 213/91 of the Occupational Health & Safety Act, Regulations for Construction Projects, unless the worker is approved by the Company to perform such work.

OD-3.1.13 Workers shall not transfer from the bucket of an aerial device to a tree when the bucket and/or boom are positioned over a live conductor.

OD-3.1.14 In the case of a limb or any piece of equipment becoming lodged on one or more conductors, workers shall be warned to keep clear in case a conductor should burn and fall. If a contact should occur or if any part of a tree is found to be contacting a conductor, all workers shall stay clear of the area and the Service Provider will immediately notify the Company.

OD-3.1.15 Hold off protection shall be obtained if deemed necessary in accordance with Supplemental Rule 200 of the IHSA Electrical Utility Safety Rules.

OD-3.1.16 Under no circumstances shall a worker place or wrap a rope around any part of his body.

OD-3.2 Tools and Equipment

OD-3.2.1 All tools, equipment, machinery and protective devices shall be inspected on a regular basis to ensure they are maintained in good and safe working condition. At a minimum, such inspections shall be conducted before the start of each work day, and any defect(s) shall be rectified immediately.

OD-3.2.2 The Service Provider shall maintain at each Site, for review by the Company's designated representative and any authority having jurisdiction over the work, current inventory and inspection records relating to all tools, equipment, machinery, protective devices and personal protective equipment utilized in the performance of the Services.

OD-3.2.3 Approved personal protective equipment including head, eye, ear, leg, foot and hand protection shall be worn by every worker using chain saws, brush saws, or motorized off-road vehicles. Chain saws shall be equipped with safety chains, chain breaks and spark arresters.

OD-3.2.4 CSA approved "Green Patch" and "dielectric" boots shall be worn at all times while performing the work.

OD-3.2.5 Category B leg protection meeting the CAN/BNQ 1923-450/M91 standard "Leg Protective Device for Chain Saw Users" or an equivalent standard, shall be worn by workers using saws.

OD-3.2.6 High visibility clothing, approved by the Company and maintained in good and safe condition, shall be worn at all times by persons performing the Services.

OD-3.2.7 Underbrushing and tree trimming shall be undertaken using chain saws and brush saws or other mechanized equipment that results in the remaining stumps being cut horizontally.

OD-3.2.8 Aerial Lifts shall be kept clean of all grease, dirt, or other objects that could reduce their specific dielectric capacity.

OD-3.2.9 Only non-conductive (fiberglass) ladders shall be employed in the work.

OD-3.2.10 All pruning equipment shall comply with the IHSA Rules and shall be designed specifically for tree work and shall be clean, sharp and in safe working order. Pruning equipment shall be capable of producing clean, proper cuts without tearing or unduly fraying the bark.

OD-3.2.11 Tree climbers or spurs shall only be used only on trees that are being felled; on trees where the bark is thick enough to prevent damage to the tree; and where there is no other practical means of climbing the tree as authorized by Owner.

OD-3.2.12 Each climber shall employ an approved fall arrest system or safety belt and saddle in the tree at all times. When working in an aerial lift, the worker shall remain inside the bucket with an approved harness securely and properly fastened at all times.

OD-3.2.13 Any climbing ropes used on the Site shall be inspected from end to end before the start of each day's work to ensure that there is no weakening, fraying, stressing or other damage that constitutes a danger to climber or co-workers.

OD-3.2.14 All aerial lifts shall be insulated, maintained and tested every twelve (12) months in accordance with the IHSA Rules so as to ensure the safety of any worker in the bucket or at any controls should the lift come into contact with any energized utility line on the Site.

OD-3.3 Communications

OD-3.3.1 Communications shall always be maintained between the power supply authority and the Service Provider when working in the vicinity of energized conductors above 750 volts.

OD-3.3.2 The Service Provider's supervisor(s) shall relay to the Company's designated representative daily, the exact location of the start of work for each crew performing the Services, and the direction of forward progress on the Company's facilities. In addition, the Service Provider shall relay the extent of the forward progress and the finishing point, including where equipment is remaining if different from the Site of forward progress at the end of each working day, for each crew performing the Services.

OD-3.4 Signs

OD-3.4.1 The Service Provider shall, at its own expense, supply and maintain all requisite barriers, fences and warning signs or other precautions to protect workers and the general public against accident or injury.

OD-3.4.2 The Service Provider shall provide and erect signs for herbicide operations as stipulated by legislation, maintaining them in good order at all locations where public access to the area may occur (e.g. access trails) or as instructed by the Company. The signs shall be of sufficient size, colour and lettering, and positioned to inform the public of the pending operations. The Service Provider shall remove all signs in accordance with legislative requirements.

OD-3.4.3 All safety signage and traffic control shall be carried out in accordance with applicable provincial statutes and municipal by-laws.

OD-3.5 Traffic Control

OD-3.5.1 The Service Provider shall take all necessary precautions to ensure the safety of pedestrian and vehicular traffic. All roadway work operations shall be protected using traffic control methods and devices required by the Ontario Traffic Manual, Book 7, Temporary Conditions, Office and Field Editions, March 2001 and subsequent revisions.

OD-3.5.2 Where barricaded or coned off work areas unduly restrict vehicular traffic, or cause unreasonable inconvenience to pedestrians on heavily traveled public or private walkways, warning signs shall be posted and a flag person on continuous duty shall conduct traffic past any point of potential danger while work is in progress. The flag person shall be trained in Work Area Protection.

OD-3.5.3 When working over sidewalks or areas frequented by the public, the area under the tree canopy, plus a safety strip area of at least 3 m (10 feet) shall be coned or barricaded.

OD-3.5.4 Where major limbs are being removed, or where a tree is to be felled, a distance of at least one and one-half (1 ½) times the fall area of the limb or tree (the Danger Zone) shall be coned or barricaded off. Appropriate warning signs of suitable reflective material shall be posted outside of the work area. Ground personnel shall be responsible for ensuring that passers-by remain outside the delineated area.

OD-3.5.5 When working over public sidewalks, walkways, streets or roads, no safety rope shall fall to within 5 m (16 feet) of surfaces traveled by vehicles and within 3 m (10 feet) of pedestrian walkways.

OD-3.5.6 Regardless of the foregoing, the Service Provider shall be responsible for the safety of passers-by and workers on public and private property, and shall take whatever reasonable steps are deemed necessary to ensure safety.

OD-3.6 Preparedness and Response

OD-3.6.1 In the event of an emergency or spill, the Service Provider shall immediately assess and respond to the situation, notify the Company in accordance with instructions received from the Company, secure the Site, and report the incident to the appropriate authorities in accordance with the applicable legislation.

OD-4.0 COMPETENCY LEVELS

OD-4.1 The ability of workers to perform specific work activities (Competencies) from Level D (lowest risk) to Level B (highest risk), recognizing worker qualifications and the attainment of the necessary skills, training and experience to become authorized to work in proximity to energized electrical equipment, while observing the safe limits of approach.

Competency B work

i. Topping of brush from the ground with hand tools;
ii. Tree Pruning and Tree Removal Manual in an energized environment with personnel and equipment following EUSR Rule 129 Safe Limits of Approach; and
iii. Tree Pruning and Tree Removal Manual in a de-energized environment with personnel and equipment following EUSR Rule 129 Safe Limits of Approach

Competency C work

i. Herbicide Application.

Competency D work

i. Underbrushing Manual and Mechanical, Disposal of Cut Material and Site Clean-Up.

OD-5.0 LOCATION

OD-5.1 The Services shall be performed at various locations throughout the Company's network of transmission and distribution power line facilities, as specified in the Work Releases.

OD-6.0 CONDITIONS OF WORK

OD-6.1 The Work shall be carried out in established residential areas, road allowances, farmland, and forested lands; and in such a manner so as to cause the least amount of inconvenience to property owners, residents and the general public.

OD-6.2 The Service Provider shall limit its days of operations to Monday through Saturday, excluding statutory holidays, and its hours of operation to 7:00 a.m. through 6:00 p.m. No work shall be executed outside of these times without specific permission of the Company's designated representative.

OD-6.3 The Service Provider shall use safe work practices to ensure the protection of workers, the public and the environment. The practices shall include, but not necessarily be limited to, job planning (pre-job meetings and tailboard conferences), proper crew supervision, clear understanding and marking of herbicide exclusion zones in accordance with Property Owner Notification and Information documentation compiled by the Company, method adjustments to suit existing and expected weather conditions, traffic warnings, control and safety, and accurate and thorough record keeping. All job planning shall be documented.

OD-6.4 The Service Provider shall conduct a Site visit accompanied by the Company's designated representative prior to commencing work at any Site.

OD-6.5 Bi-weekly progress meetings will be held to discuss (but not limited to); the progress of the Work, HS&E, incident reports and other project related concerns.

OD-7.0 GENERAL REQUIREMENTS

OD-7.1 Examination

OD-7.1.1 In advance of the work, the Service Provider shall be responsible for identifying the limits of the work area.

OD-7.1.2 The Service Provider shall notify the Company of any discrepancy in the measurements of work areas prior to commencing the Services.

OD-7.1.3 The Service Provider shall report to the Company in writing, any conditions encountered before commencing or during the work that could adversely affect the performance of the Services.

OD-7.1.4 Where applicable to the work, existing active services such as sewers, water, gas, communication lines, etc. shall be protected, braced, and supported as required for the proper execution of the work without disturbing the operation of such services.

OD-7.2 Property Owner Notification and Information

OD-7.2.1 The Company has initiated notification to property owners that the Services will be performed, and has recorded details of this contact in Property Owner Notification and Information documentation that shall be provided to the Service Provider with each Work Release.

OD-7.2.2 The Service Provider shall review the Property Owner Notification and Information documentation and if required, shall notify all property owners of pending Work within a reasonable time period prior to the commencement of the Services.

OD-7.2.3 The Service Provider, when entering private property to do work, shall notify the resident that it will be performing vegetation management services on the Company's facilities to reduce the interruptions to the electric service. If the resident requests specific details of the work to be done, the Service Provider shall provide this information.

OD-7.2.4 The Service Provider's supervisors shall review with each crew, on a daily basis, the Property Owner Notification and Information documentation that relates to the applicable work area.

OD-7.2.5 The Service Provider shall not work on properties where the Property Owner Notification and Information documentation identifies that the property owner has not been contacted or has not been agreeable to the work to be conducted, and the Service Provider shall seek further direction and instructions from the Company before proceeding to do work on such properties.

OD-7.2.6 Any dealings with property owners, residents and the Company's customers shall be carried out in a professional and courteous manner. Should differences arise, the Service Provider shall immediately involve the Company, and shall comply with any agreement reached between the Company and the property owner, resident, or customer as the case may be.

OD-7.3 Power Outages

OD-7.3.1 The Company shall coordinate and approve power outages as required to facilitate the work, the details of which shall be planned and arranged by the Service Provider.

OD-8.0 WORK ACTIVITIES

OD-8.1 Underbrushing - Manual

OD-8.1.1 All work shall be carried out in accordance with all relevant federal and provincial safety legislation and by-laws of municipalities having jurisdiction including, without limitation, the *Ontario Occupational Health and Safety Act* and all relevant Regulations made under such legislation, the IHSA Rules, the IHSA Safe Practice Guide “Line Clearing Operations”, industry best practices and Company policies, procedures, guidelines and other requirements specified in the Agreement. If there is a conflict in any of the applicable provisions from the aforementioned items, the more stringent or higher guideline, rule, procedure or standard shall govern.

OD-8.1.2 No vegetation shall be contacted, disturbed or cut where the vegetation encroaches or may encroach within the safe limits of approach to energized electrical conductors for unauthorized workers.

OD-8.1.3 Prior to starting work the designated representatives of the Parties shall sign the Work Approval form and initial and date the other documentation required and maintained by the Company in this regard. The signed Work Approval shall be appended to each Work Release.

OD-8.1.4 Brush is considered to be less than 4” DBH. Trees are considered to be 4” DBH and greater.

OD-8.1.5 All, brush, trees and regenerated growth shall be cut as close to ground level as practicable with no stumps left higher than 7.5 cm (3 inches).

OD-8.1.6 Remove brush either side of power line including brush past tree line to achieve standard clearance.

OD-8.1.7 Tap poles that cross the road from the mainline will be cleared to the appropriate radius to achieve API standard clearance.

OD-8.1.8 Vegetation considered to be brush and beyond the standard ROW clearance width will be cleared out to the road side where previously cut to avoid creation of double-sided ROW. Brush that has not been previously cleared will be assessed by the Company’s designated representative and managed through a work approval process.

OD-8.1.9 Where specified by the Company’s designated representative, compatible vegetation shall be retained.

OD-8.1.10 Stumps shall be cut horizontally to reduce the risk of injury to persons and to maximize the efficacy of the herbicide application.

OD-8.2 Underbrushing - Mechanical

OD-8.2.1 All work shall be carried out in accordance with all relevant federal and provincial safety legislation and by-laws of municipalities having jurisdiction including, without limitation, the Ontario Occupational Health and Safety Act and all relevant Regulations made under such legislation, the IHSA Rules, the IHSA Safe Practice Guide “Line Clearing Operations”, industry best practices and Company policies, procedures, guidelines and other requirements specified in the Agreement. If there is a conflict in any of the applicable provisions from the aforementioned items, the more stringent or higher guideline, rule, procedure or standard shall govern.

Prior to starting work the designated representatives of the Parties shall sign the Work Approval form and initial and date the other documentation required and maintained by the Company in this regard. The signed Work Approval shall be appended to each Work Release.

OD-8.2.2 All persons working within proximity to energized electrical equipment shall have received IHSA Safety in Line Clearing training.

OD-8.2.3 Prior to mechanical Underbrushing, the Service Provider and the Company shall review each site to determine hazardous conditions and the nature, location, size, and extent of vegetative material, debris, and obstructions to be removed or navigated around.

OD-8.2.4 All poorly visible objects such as down guys, anchors, pole line hardware, culverts, standard iron bars (property markers), Geodetic Survey Markers, communication pedestals, septic beds, etc. shall be marked by the Service Provider using highly visible tape or paint to alert the operator of their location. The reparation of any damage to these items shall be the responsibility of the Service Provider. The Company, prior to mechanical Underbrushing, will contact property owners to determine if there are any hidden hazards that require protection and shall communicate this information to the Service Provider through the Property Owner Notification and Information documentation. The approval to remove fences that are in a dilapidated state will also be established and communicated to the Service Provider in this manner.

OD-8.2.5 Prior to any mechanical Underbrushing, the location and marking of underground hazards such as communication wires, electrical wires, gas lines, water lines, etc. must be completed by the Service Provider and updated every two (2) weeks until the work has been completed.

OD-8.2.6 Danger trees and chicos shall be removed prior to mechanical Underbrushing. The removal of trees shall be carried out in accordance with OD-8.4 “Tree Removal – Manual” or OD-8.5 “Tree Removal – Mechanical”, as applicable to the work.

OD-8.2.7 The release of sediment or other debris shall be controlled to prevent entry into any water body. Control may include, without limitation, the use of silt curtains or geo-textile fabrics as approved by the Company’s designated representative.

OD-8.2.8 No grubbing shall be performed within the following distances of a watercourse:

Distance	**Area near Watercourse**
10 meters (33 feet)	0-5% slope
30 meters (98 feet)	6-15% slope
50 meters (164 feet)	16-30% slope
70 meters (230 feet)	31-45% slope
90 meters (295 feet)	46-60% slope

OD-8.2.9 No grubbing shall be performed within 100 meters (329 feet) of a well.

OD-8.2.10 In the event of extreme storm activity, the Service Provider shall provide protective measures to prevent damage to the grubbed area by run-on and shall maintain control of any run-off.

OD-8.2.11 The Service Provider shall, immediately following an extreme storm event, inspect and clean out all temporary control structures from debris and sediment build-up, and repair or replace any damaged areas.

OD-8.2.12 In the event of extreme dry conditions, the Service Provider shall employ means such as water spray and visual observation to control and minimize the emission of dust.

OD-8.2.13 The Service Provider shall avoid entering watercourses with machinery. If such action is necessary, in the sole opinion of the Company's designated representative, existing water-crossing locations shall be used and such crossings shall be planned so as to minimize the frequency of use.

OD-8.2.14 Prior to the start of the work, the Service Provider shall conduct a visual inspection of lines for nicks or weak spots to determine locations where additional hazard awareness needs to be communicated to all workers and the Company's designated representative. Such communication shall be conducted through completion and distribution by the Service Provider of a Hazardous Condition Report in the format provided by the Company.

OD-8.2.15 A Competent Person as defined by IHSA shall accompany the mechanical brush cutter to aid in the observation of brush and machine movement.

OD-8.2.16 The Service Provider shall conduct mechanical Underbrushing so as to have minimal impact on roads, ditches, trails, walks or adjacent facilities and shall not close or obstruct them. Traffic control and public protection shall be the responsibility of the Service Provider, and shall include the use of barricades, signs, signals, etc., as required, for the protection of the public and all workers.

OD-8.2.17 The Service Provider shall ensure that all workers are familiar with and adhere to limits of approach to operating machinery, in accordance with the Manufacturer's Specifications which shall be documented and communicated to all on Site workers through the daily job safety plans.

OD-8.2.18 The Service Provider shall maintain existing grades and levels. Obstacles such as large boulders, stockpiles of fill, or brush/trees shall not be pushed off the right-of-way onto the owners' property without the property owner's consent and the Company's approval. If directed by the Company, fill material may be imported from areas adjacent to the right-of-way, in order to bury brush.

OD-8.2.19 The removal of any hazardous or non-hazardous waste must be made in accordance with provincial and/or municipal laws and regulations and shall be the responsibility of the Service Provider.

OD-8.2.20 Where directed by the Company's designated representative, the mechanical device may grind brush above ground, without the need to follow with seed preparation and application.

OD-8.2.21 All, brush, trees and regenerated growth shall be cut as close to ground level as practicable with no stumps left higher than 7.5 cm (3 inches).

OD-8.2.22 Where specified by the Company's designated representative, compatible vegetation shall be retained.

OD-8.2.23 Stumps shall be cut horizontally to reduce the risk of injury to persons and to maximize the efficacy of the herbicide application.

OD-8.3 Tree Pruning

OD-8.3.1 General

OD-8.3.1.1 All work shall be carried out in accordance with all relevant federal and provincial safety legislation and by-laws of municipalities having jurisdiction including, without limitation, the Ontario Occupational Health and Safety Act and all relevant Regulations made under such legislation, the IHSA Rules, the IHSA Safe Practice Guide "Line Clearing Operations", industry best practices and Company policies, procedures, guidelines and other requirements specified in the Agreement. If there is a conflict in any of the applicable provisions from the aforementioned items, the more stringent or higher guideline, rule, procedure or standard shall govern.

OD-8.3.1.2 All workers involved in tree pruning shall be experienced and knowledgeable in standard pruning practices, and familiar with ANSI A300 1995 and Arborist Safe Work Practices for Fall Protection.

OD-8.3.1.3 In the event of a conflict between any of the pruning specifications, guidelines and standards referred to in this document, the priority of ranking, from highest to lowest, shall be:
(a) Company pruning specifications and guidelines;
(b) IHSA Rules and guidelines;
(c) Arborist Safe Work Practices for Fall Protection;
(d) ANSI A300 Standards for Tree Care Operations - 2001.

OD-8.3.1.4 All persons working in proximity to energized electrical equipment shall have received IHSA Safety in Line Clearing training or an advanced line clearing training program provided by another organization considered by the Company to be an equivalent authority that meets or exceeds MTCU Utility Arborist Program Trade Code 444B, and ongoing training in Tree Rescue and Fall Arrest for Climbers and Aerial Bucket Rescue for Aerial Device Operators.

OD-8.3.1.5 Prior to tree pruning, the Service Provider and the Company shall review each Site. When required, the Company shall provide Work Protection and isolate/de-energize line sections to allow the Service Provider to complete tree pruning of all vegetation that encroaches or will encroach within 3 m (10 feet) of any energized electrical equipment. In energized line sections, the Service Provider and the Company shall both acknowledge the acceptable condition for tree pruning by signing and dating a Work Approval form. The Service Provider shall continue to assess this condition on a daily basis during execution of the work.

OD-8.3.1.6 While performing the pruning work, the Service Provider shall notify the Company of any tree that, because of defects or other conditions present, has the potential to cause an outage. The Service Provider shall notify the Company's designated representative of such potential Danger Trees on an ongoing basis. The Company's designated representative shall then conduct a timely evaluation to designate those Danger Trees considered to be of the highest risk and priority for removal.

OD-8.3.1.7 The Service Provider acknowledges that some Danger Trees may be made safe by pruning. These include specimen trees and those trees where there is an economic advantage to the Company not to incur the expense of removal. In these situations, natural or target pruning shall be utilized, where the tree growth is directed away from the electrical conductors. All dead wood that could potentially contact wire shall be removed from any Danger Trees pruned.

OD-8.3.1.8 The Service Provider shall remove all deadwood that could potentially strike or fall onto energized electrical equipment and cause damage and/or interruption.

OD-8.3.1.9 If a cavity, weakening or decay constitutes an immediate hazard to workers, utility lines, vehicles or structures within the fall area, the tree shall be removed.

OD-8.3.1.10 No limbs that overhang the wires and could potentially contact the wires when loaded with snow or ice, shall be left even if they are outside the zone to be cleared.

OD-8.3.1.11 All seriously abraded and weakened branches and twigs shall be removed where they could constitute a hazard, could fall in high winds or heavy precipitation, or could abrade against other major branches causing further mechanical damage.

OD-8.3.1.12 Any limbs over utility lines, structures, fences, flowerbeds, etc. that cannot be handled or lowered safely by hand shall be carefully roped and lowered.

OD-8.3.1.13 The Service Provider shall remove or stiffen all limbs or main stems of trees that could sag or fall into the conductors when weighted with snow or ice. Branch leader growth shall be directed away from the conductors by pruning to lateral limbs.

OD-8.3.1.14 Good tree maintenance shall be practiced by corrective pruning, the removal of stubs and the correction of faulty cuts.

OD-8.3.1.15 Natural or target pruning shall be utilized where the tree growth is directed away from the electrical conductors.

OD-8.3.1.16 The stubbing of major branches or the trunk shall not be permitted, and all cuts shall be made at the nodes or crotches.

OD-8.3.1.17 Where trees are being topped or pruned, the remaining lateral branches should be at least one-third (1/3) the diameter of the parent limb.

OD-8.3.1.18 All broken branches or limbs shall be pruned back to the nearest suitable trunk, crotch or lateral. To facilitate optimum healing, all branch and twig cuts shall be made just outside the branch collar.

OD-8.3.1.19 Where ropes are to be snubbed around healthy trunks or limbs in lowering and felling operations, care shall be taken to ensure that no peeling, lifting, fraying or other bark damage occurs.

OD-8.3.1.20 When lowering the height of deciduous trees, drop crotch pruning shall be utilized where possible to minimize the likelihood of suckering.

OD-8.3.1.21 No more than one-third (1/3) of the total crown area shall be removed in order to maintain the health of the tree.

OD-8.3.1.22 When cutting larger limbs, precautions shall be taken to prevent stripping or tearing down of the bark. The limb shall be either undercut or stubbed off some distance from the main stem or trunk, then the final cut shall be made.

OD-8.3.1.23 No hangers (cut stems and branches) shall be left in any pruned tree at the close of the day's work, when leaving the Site, or at the end of any shift.

OD-8.3.1.24 All pruning and saw cuts shall be made in a manner approved by the Company.

OD-8.3.1.25 Any changes in pruning methods or techniques, from those specified herein, shall be approved by the Company's designated representative.

OD-8.3.2 Insulated Aerial Devices

OD-8.3.2.1 Aerial devices used by the Service Provider shall be operated in accordance with Rule 123 "Aerial Devices/Boom Trucks" of the IHSA Electrical Utility Safety Rules (revised August 2004) and CSA C225-00. Aerial devices must be dielectrically tested at least every twelve (12) months.

OD-8.3.2.2 All persons working in proximity to energized electrical equipment shall have received IHSA Safety in Line Clearing training or an advanced line clearing training program provided by another organization considered by the Company to be an equivalent authority that meets or exceeds MTCU Utility Arborist Program Trade Code 444B, and ongoing training in Tree Rescue and Fall Arrest for Climbers and Aerial Bucket Rescue for Aerial Device Operators.

OD-8.3.2.3 Each independent aerial device crew shall be comprised of one Approved and Competent worker and, as a minimum, one Approved and Competent apprentice.

OD-8.3.2.4 For every three climbers on a job site, two (2) shall be Approved and Competent worker(s), and the other worker shall be at least an Approved and Competent apprentice.

OD-8.3.2.5 Aerial lifts shall be kept clean of all grease, dirt, or other objects that could reduce their specific dielectric capacity.

OD-8.4 Tree Removal - Manual

OD-8.4.1 General

OD-8.4.1.1 All work shall be carried out in accordance with all relevant federal and provincial safety legislation and by-laws of municipalities having jurisdiction including without limitation, the Ontario Occupational Health and Safety Act and all relevant Regulations made under such legislation, the IHSA Rules, the IHSA Safe Practice Guide "Line Clearing Operations", industry best practices and Company policies, procedures, guidelines and other requirements specified in the Agreement. If there is a conflict in any of the applicable provisions from the aforementioned items, the more stringent or higher guideline, rule, procedure or standard shall govern.

OD-8.4.1.2 All persons working in proximity to energized electrical equipment shall have received IHSA Safety in Line Clearing training or an advanced line clearing training program provided by another organization considered by the Company to be an equivalent authority that meets or exceeds MTCU Utility Arborist Program Trade Code 444B, and ongoing training in Tree Rescue and Fall Arrest for Climbers and Aerial Bucket Rescue for Aerial Device Operators.

OD-8.4.1.3 Prior to tree removal, the Service Provider and the Company shall review each Site. When required, the Company shall provide Work Protection and isolate/de-energize line sections to allow the Service Provider to complete tree removal. In energized line sections, the Service Provider and the Company shall both acknowledge an acceptable condition allowing the removal of trees manually by signing and dating a Work Approval form. The Service Provider shall continue to assess this condition on a daily basis during execution of the work.

OD-8.4.1.4 Prior to the start of the work, the Service Provider shall conduct a visual inspection of lines for nicks or weak spots to determine locations where additional hazard awareness needs to be communicated to all workers and the Company's designated representative. Such communication shall be conducted through completion and distribution by the Service Provider of a Hazardous Condition Report in the format provided by the Company.

OD-8.4.1.5 Trees shall be felled away from power or communication lines, structures, vehicular or pedestrian rights-of-way and horticultural plantings after all limbs have been removed that might contact utility lines or cause damage to other trees or property. If the tree must be felled towards a power or communications line, it shall be topped low enough to clear all conductors, poles, guys and like installations.

OD-8.4.1.6 All trees sufficient in length to reach overhead structures and wires shall be controlled during felling operations, in accordance with IHSA Rules and IHSA Safe Practice Guide "Line Clearing Operations", eliminating the possibility of inadvertent tree contact with energized components of the circuits. Blades attached to mechanical equipment shall not be used to direct trees in the felling process.

OD-8.4.1.7 Guide ropes shall be used on all trees that are large enough to cause damage should they fall in any direction other than that intended. The guide ropes shall be installed before commencing any cutting at the base of the tree.

OD-8.4.1.8 Before any tree is felled, workers other than those operating the saw or giving direction to workers involved, shall remain clear of the Danger Zone. The worker in charge shall have the discretion to vary the size of the Danger Zone after considering all the pertinent factors relative to the tree removal operation.

OD-8.4.1.9 Ample warning shall always be given before a tree is expected to fall and the workers must stand clear in case the tree springs from the stump while falling. No workers shall remain in the Danger Zone except those workers directly involved in cutting the tree or a portion thereof.

OD-8.4.1.10 All brush and other debris or equipment, that would hamper free movement when using sharp tools or when getting clear in case of emergency, shall be cleared away.

OD-8.4.1.11 Trees shall be notched in the direction towards which they are to fall and sufficient holding wood shall be left to provide control.

OD-8.4.1.12 All trees sufficient in length to reach overhead structures and wires shall be properly controlled during felling operations, either by rope guying or the use of mechanical equipment capable of providing controlled felling, to eliminate the possibility of inadvertent tree contact with energized components of the circuits. The use of mechanical equipment shall not include the use of blades attached to skidding equipment, bulldozers or similar equipment.

OD-8.4.1.13 In locations where ordinary felling operations might cause damage to property, trees shall be suitably sectioned and felled using recognized forestry rigging practices, ensuring that any severed portion of the tree is under control at all times.

OD-8.4.1.14 Under no circumstances shall pike poles be used for the purpose of holding or pushing trees during felling operations.

OD-8.4.1.15 Anchors for guide ropes shall be installed in such a position that workers handling the guide ropes are able to stand well outside the striking distance of the tree.

OD-8.4.1.16 Under no circumstances shall a partially cut tree be left standing during rest breaks, lunchtime or overnight.

OD-8.4.1.17 When removing a tree that is split or a tree with twin trunks that is likely to split, chains or cable with adequate strength shall be placed tightly around the tree before commencing the notch cut. At least one chain or cable shall be placed above and as close as practical to the back cut to prevent separation of the trunk.

OD-8.4.1.18 If the trunk of the tree is to be left standing the top must be cut at an angle of at least 45° to prevent people standing on the top and possibly contacting the conductors.

OD-8.4.1.19 Vegetation considered to be trees (4" DBH and greater) and beyond the standard ROW clearance width will be cleared out the road side where previously cleared to avoid creation of double side ROW. Trees that have not been previously cleared will be assessed by the Company's designated representative and managed through a work approval process.

OD-8.4.1.20 Trees shall be cut as flush to the ground as possible, with no stumps left higher than 7.5 cm (3 inches), unless otherwise directed by the property owner or the Company's designated representative.

OD-8.4.2 Insulated Aerial Devices

OD-8.4.2.1 Aerial devices used by the Service Provider shall be operated in accordance with Rule 123 "Aerial Devices/Boom Trucks" of the IHSA Electrical Utility Safety Rules (revised August 2004) and CSA C225-00. Aerial devices must be dielectrically tested at least every twelve (12) months.

OD-8.4.2.2 All persons working in proximity to energized electrical equipment shall have received IHSA Safety in Line Clearing training or an advanced line clearing training program provided by another organization considered by the Company to be an equivalent authority that meets or exceeds MTCU Utility Arborist Program Trade Code 444B, and ongoing training in Tree Rescue and Fall Arrest for Climbers and Aerial Bucket Rescue for Aerial Device Operators.

OD-8.4.2.3 Each independent aerial device crew shall be comprised of one Approved and Competent worker and, as a minimum, one Approved and Competent apprentice.

OD-8.4.2.4 For every three climbers on a job site, two (2) shall be Approved and Competent worker(s), and the other worker shall be at least an Approved and Competent apprentice.

OD-8.4.2.5 Aerial lifts shall be kept clean of all grease, dirt, or other objects that could reduce their specific dielectric capacity.

OD-8.4.3 Danger Trees

OD-8.4.3.1 Danger Trees shall be identified for removal by the Service Provider and/or the Company prior to the start of the work or during the pruning process as identified in OD-8.3.1.6"Tree Pruning". The Company and the Service Provider shall agree, in advance, as to the specific Danger Trees to be removed.

OD-8.4.3.2 Danger Trees shall be properly controlled while being felled to remove the potential of them falling on overhead wires or structures.

OD-8.4.3.3 Danger Trees shall be cut following the completion of pruning work unless the Company has agreed otherwise.

OD-8.4.3.4 The Service Provider shall prepare a report indicating the number of Danger Trees removed, referenced by road, span and species. This report shall be submitted to the Company's designated representative on a weekly basis.

OD-8.5 Tree Removal - Mechanical

OD-8.5.1 General

OD-8.5.1.1 All work shall be carried out in accordance with all relevant federal and provincial safety legislation and by-laws of municipalities having jurisdiction including, without limitation, the *Ontario Occupational Health and Safety Act* and all relevant Regulations made under such legislation, the IHSA Rules, the IHSA Safe

Practice Guide "Line Clearing Operations", industry best practices and Company policies, procedures, guidelines and other requirements specified in the Agreement. If there is a conflict in any of the applicable provisions from the aforementioned items, the more stringent or higher guideline, rule, procedure or standard shall govern.

OD-8.5.1.2 All persons working in proximity to energized electrical equipment shall have received IHSA Safety in Line Clearing training or such other training as is deemed relevant by the Company to the work activity undertaken.

OD-8.5.1.3 Prior to tree removal, the Service Provider and the Company shall review each Site. When required, the Company shall provide Work Protection and isolate/de-energize line sections to allow the Service Provider to complete tree removal. In energized line sections, the Service Provider and the Company shall both acknowledge an acceptable condition allowing the removal of trees mechanically by signing and dating a Work Approval Form. The acceptable condition for tree removal near energized lines shall be valid for two (2) weeks from the date of signing. The Service Provider shall continue to assess this condition on a daily basis during execution of the work.

OD-8.5.1.4 Feller bunchers being used near any power or communications lines shall be equipped with a "cold saw" type of cutting head so as to enable the machine to have full control of the tree prior to saw engagement.

OD-8.5.1.5 The On-Site Supervisor shall be responsible for preplanning any mechanical felling work, including, but not limited to marking anchors, down guys, communication pedestals, survey bars, fences, unsafe trees and buffers around water crossings and environmentally sensitive areas.

OD-8.5.1.6 Prior to the start of the work, the Service Provider shall conduct a visual inspection of lines for nicks or weak spots to determine locations where additional hazard awareness needs to be communicated to all workers and the Company's designated representative. Such communication shall be conducted through completion and distribution by the Service Provider of a Hazardous Condition Report in the format provided by the Company.

OD-8.5.1.7 Unsafe trees are defined as those trees that cannot be handled safely by the mechanical felling equipment due to decay, size or location. In locations where, mechanical felling operations might cause damage to property, trees are inaccessible by machinery, or the condition of the tree is unsuitable for mechanical removal, trees shall be suitably sectioned and felled using recognized forestry rigging practices, ensuring that any severed portion of the tree is under control at all times.

OD-8.5.1.8 Trees shall be felled away from power or communication lines, structures, vehicular or pedestrian rights-of-way, and horticultural plantings. Care shall be taken to move trees so that there is no damage caused to other trees or property. If the tree must be felled towards a power or communication line, it shall be topped low enough to clear all power or communication line, poles, guys and like installations.

OD-8.5.1.9 All trees sufficient in length to reach overhead structures and wires shall be properly controlled during felling operations, either by rope guying or the use of mechanical equipment capable of providing controlled felling, to eliminate the possibility of inadvertent tree contact with energized components of the circuits. The use of mechanical equipment shall not include the use of blades attached to skidding equipment, bulldozers or similar equipment to direct trees in felling process.

OD-8.5.1.10 A Dedicated Observer shall accompany the mechanical equipment to aid in the observation of tree and machine movement.

OD-8.5.1.11 Before any tree is felled, all workers other than the mechanical equipment operator, shall remain clear of the Danger Zone. The operator shall have the discretion to vary the size of the Danger Zone after considering all the pertinent factors relative to the tree removal operation.

OD-8.5.1.12 Under no circumstances shall a partially cut tree be left standing during rest breaks, lunchtime or overnight.

OD-8.5.1.13 When removing a tree that is split or a tree with twin trunks that is likely to split, the feller buncher operator may, at his discretion, remove separate sections of the tree to maintain maximum control of the tree. If this is not feasible, the tree will be left for manual removal.

OD-8.5.1.14 If the trunk of the tree is to be left standing, the top must be cut at an angle of at least forty-five degrees (45°) to prevent people standing on the top and possibly contacting the conductors.

OD-8.5.1.15 Trees shall be cut as flush to the ground as possible, with no stumps left higher than 7.5 cm (3 inches), unless otherwise directed by the property owner or the Company's designated representative.

OD-8.5.2 Danger Trees

OD-8.5.2.1 Danger Trees shall be identified for removal by the Service Provider and/or the Company prior to the start of the work or during the pruning process as identified in OD-8.3.1.6 "Tree Pruning". The Company and the Service Provider shall agree, in advance, as to the specific Danger Trees to be removed.

OD-8.5.2.2 Danger Trees shall be properly controlled while being felled to remove the potential of them falling on overhead wires or structures.

OD-8.5.2.3 The approximate number of Danger Trees shall be indicated on Work Releases prior to the start of the work.

OD-8.5.2.4 Danger Trees shall be cut following the completion of pruning work unless the Company has agreed otherwise.

OD-8.5.2.5 The Service Provider shall prepare a report indicating the number of Danger Trees removed, referenced by road, span and species. This report shall be submitted to the Company's designated representative on a weekly basis.

OD-8.6 Disposal of Cut Material, Stump Removal & Grinding and Site Clean-Up OD-8.6.1

OD-8.6.1 Disposal of Cut Material

OD-8.6.1.1 All work shall be carried out in accordance with all relevant federal and provincial safety legislation and by-laws of municipalities having jurisdiction including, without limitation, the *Ontario Occupational Health and Safety Act* and all relevant Regulations made under such legislation, the IHSA Rules, the IHSA Safe Practice Guide "Line Clearing Operations", the Environmental Protection Act and Waste Management Regulation 347, industry best practices and Company policies, procedures, guidelines, and other requirements specified in the Agreement. If there is a conflict in any of the applicable provisions from the aforementioned items, the more stringent or higher rule, guideline or procedure shall govern.

OD-8.6.1.2 All cut material resulting from the work, including previously cut material that is piled on the right-of-way, deadfall and blow downs that are on the right-of-way, shall be disposed of by utilizing a hydraulic chipper or in a manner otherwise approved by the Company and/or as directed on Site by the Company's designated representative. Disposal of all materials resulting from the cutting operations shall be in compliance with applicable provincial and municipal statutes and regulations.

OD-8.6.1.3 No brush or trees shall be felled or piled off the right-of-way unless directed by the Company's designated representative.

OD-8.6.1.4 When the Company's designated representative directs that a tree be felled off the right-of-way, the tree shall be limbed, cut into sections and left so that the entire length of the tree is in close contact with the ground, and the brush and limbs shall be pulled out and chipped.

OD-8.6.1.5 When approved by the Company, brush can be windrowed and piled along the edge of the right-of-way to provide wildlife habitat. Each brush pile shall be no higher than 0.6 m (2 feet) and no larger on its greatest horizontal dimension than 61 m (200 feet) with a 15-m (50-foot) firebreak between piles. Individual trees being selectively cut shall be limbed and scattered along the right-of-way.

OD-8.6.1.6 No burning of wood or brush shall be permitted unless specifically authorized by the Company.

OD-8.6.1.7 Unless otherwise directed by the Company, all material 10 cm (4 inches) and greater in diameter shall be cut in lengths not exceeding 1.2 m (4 feet) and piled along, and parallel to, the outer limits of the right-of- way.

OD-8.6.1.8 Cut materials and wood chips shall not be placed or left in environmentally sensitive areas such as streams, ponds, lakes and ditches or on footpaths, access trails or roads. In addition, cut materials and wood chips shall not be left or placed in a manner that will interfere with natural drainage courses or drainage patterns.

OD-8.6.1.9 Wood chips shall be spread to less than 15 cm (6 inches) in height within the right-of-way unless otherwise specified by the Company.

OD-8.6.1.10 Trees cut on private lands are owned by the respective property owner. However, all wood chips, brush and limbs shall be disposed of in a manner consistent with applicable provincial statutes and municipal by- laws.

OD-8.6.1.11 Toxic vegetation such as cherry that presents a hazard to livestock, shall be disposed of outside of active pasture areas.

OD-8.6.1.12 Disposal of cleared vegetation and all other work performed by the Service Provider shall be closely coordinated on a daily basis so that the duration of the work at any given location is kept to a minimum.

OD-8.6.2 Stump Removal & Grinding

OD-8.6.2.1 Loose material (i.e. rocks, snow, ice, etc.) shall be removed from around the area of the stump prior to operation.

OD-8.6.2.2 Stumps shall be ground to 10 cm (4 inches) below ground level.

OD-8.6.2.3 All debris shall be moved and disposed of at a regulated waste disposal site.

OD-8.6.2.4 All holes and depressions shall be backfilled with an appropriate soil type and covered with sod or grass seed mix unless otherwise directed by the Company.

OD-8.6.2.5 If the operator leaves the machine for any reason, the work shall cease, the machine shall be stopped and the key shall be removed.

OD-8.6.3 Site Clean-up

OD-8.6.3.1 In all industrial, residential, commercial, park and similarly maintained areas, all gravel, grass and garden areas shall be left fan rake clean. All driveways, walkways, roads, curbs, patios and other asphalt, concrete, stone and similar surfaces shall be broom clean when the Site is vacated at the end of each shift and at the end of each day.

OD-8.6.3.2 All damage caused by workers engaged in the Services shall be repaired at the sole expense of the Service Provider. Damaged turf areas shall be leveled and seeded or replaced with sod; all horticultural planting damaged beyond repair shall be replaced, and any damaged structures, utilities, signs, light fixtures, landscape furniture, etc. shall be repaired or replaced. The Company's designated representative shall approve all repairs and replacements prior to final payment.

OD-8.6.3.3 Before any work is finally accepted by the Company, the Service Provider shall make such corrections of faulty workmanship as have been directed by the Company and shall dispose of rubbish and surplus materials so as to leave all Sites neat and presentable. The Service Provider and the Company shall both acknowledge the acceptable condition of the work by signing and dating a R.O.W. Commissioning Report.

OD-8.7 Seeding and Planting

OD-8.7.1 Unless otherwise directed by the Company's designated representative, the grubbed right-of-way shall be prepared by grinding and/or burying vegetation, scarifying and levelling so as to allow the application of seed.

OD-8.7.2 The Company's designated representative must approve the seed mixture used. Seed shall be applied using a broadcast or hydro seeding method and shall be applied in accordance with the vendors' specifications for coverage. The right-of-way shall be harrowed after seeding to maximize germination and minimize seed loss due to wind, rain or removal by animals.

OD-8.7.3 The Service Provider shall be responsible, at no additional cost to the Company, to reseed areas that did not germinate and shall, if necessary due to the time of year of the original seeding, reseed such areas prior to the end of the subsequent year's growing season.

OD-8.8 Herbicide Work

OD-8.8.1 General

OD-8.8.1.1 OD-8.8.1.1 All work shall be carried out in accordance with all relevant federal and provincial safety legislation and by-laws of municipalities having jurisdiction including, without limitation, the *Ontario Occupational Health and Safety Act* and all relevant Regulations made under such legislation, the Environmental Protection Act and the Waste Management Regulation, the Pest Control Products Act, The Pesticide Act and Regulation 63/09, the Transportation of Dangerous Goods Act, the IHSA Rules, the IHSA Safe Practice Guide "Line Clearing Operations", industry best practices and Company policies, procedures, guidelines and other requirements specified in the Agreement. If there is a conflict in any of the applicable provisions from the aforementioned items, the more stringent or higher guideline, rule, procedure or standard shall govern.

OD-8.8.1.2 All handling, storage, transportation and supervision of application of herbicides shall strictly adhere to all applicable environmental legislation.

OD-8.8.1.3 The Company, at its discretion, shall have on Site a representative to monitor all herbicide handling, mixing, application procedures; application rates; and treatment and disposal of containers.

OD-8.8.1.4 The Company shall approve the Service Provider written instructions provided, in advance of work commencement, from the IPM certified licensed exterminator.

OD-8.8.1.5 The Service Provider shall:

(a) ensure that all herbicide applications are conducted in a manner that prevents damage to trees and property outside the right-of-way;
(b) ensure spraying is discontinued when windy conditions could result in off-target spray drift;
(c) provide full-time, on-site supervision by a licensed pesticide exterminator where the work is being performed;
(d) ensure there is a licensed pesticide exterminator for each crew applying herbicides at separate locations;
(e) ensure a copy of the certificate issued to the Integrated Pest Management (IPM) certified licensed exterminator is on site;
(f) ensure a copy of the written instructions of the IPM certified licensed exterminator is on site;
(g) ensure all mixing and application of herbicides are performed according to the registration of the product label and applicable governmental regulations;
(h) ensure that foliar spray units are refilled with water from a supply vehicle, and that water is not pumped directly from a water source into the spray tank;
(i) ensure that herbicide concentrate is not transported on a vehicle used for supplying water to foliar spray equipment;
(j) ensure that appropriate secondary containment as approved by the Company, is used when transporting herbicides;
(k) ensure that each vehicle used for herbicide application or for transportation of herbicide concentrate on the right-of-way is equipped with a shovel and absorptive material for containing and controlling spills;
(l) immediately report all herbicide spills to the Company's designated representative and to the appropriate authorities;
(m) periodically review the results of the work to ensure adequate coverage of target vegetation.

OD-8.8.1.6 Where specified by the Company's designated representative, compatible vegetation shall be retained.

OD-8.8.1.7 The Company reserves the right to accept or reject the proposed herbicide(s), equipment and methods to be used.

OD-8.8.2 Herbicide Selection

OD-8.8.2.1 The Service Provider shall research and submit to the Company for approval, the herbicide formulation (including dyes that allow for visual inspection of treated stumps) to be used for the work. The selection shall consider all possible herbicides and herbicide formulations (including dyes) and factors such as, but not limited to, safety of workers and the general public, type of vegetation to be controlled, terrain and proximity to open water, wildlife, environmental impacts, land uses adjacent to the application areas, effectiveness, application techniques, timing and manufacturer's transportation, storage and application requirements, but need not be the same formulation for all areas of the work.

OD-8.8.2.2 If herbicide adjuvants (including drift reducing agents and surfactant products) are to be used in combination with the herbicide, they shall be approved under the Pest Control Products Act for this use, or by the herbicide manufacturer in writing to the Company.

OD-8.8.2.3 The Service Provider shall comply with the requirements of WHMIS, and shall submit the manufacturer's information regarding the suitability of the proposed herbicide(s) as well as the MSDSs, relevant manufacturer's labels for the proposed herbicide(s) and information regarding mixing ratios to be used for the review of the Company. Review by the Company shall not relieve the Service Provider of any responsibility or consequence of employing the proposed herbicide.

OD-8.8.3 Herbicide Handling

OD-8.8.3.1 Workers shall handle, transport, store and use the herbicide products in a manner that maximizes safety to the worker, the general public and the environment and in a manner consistent with the manufacturer's requirements.

OD-8.8.3.2 Only equipment in sound condition and proper working order shall be employed in the transportation, storage and application of herbicide(s). All spraying equipment shall have a positive shut off system.

OD-8.8.3.3 The Service Provider shall take the following precautions to protect its equipment and materials from vandalism and unauthorized use when left unattended on the rights-of-way or on Company property not within a secured area.

(a) power-pack or back-pack sprayers shall be emptied or stored in locked compartments;
(b) ignition keys shall be removed from all vehicles used for spraying and vehicles containing herbicide concentrate and spray solution;
(c) ignition keys shall be removed from engines that provide power to pumps on power-driven spray equipment;
(d) engines without lockable ignition systems shall have the sparkplug wire disconnected or otherwise be made inoperable;
(e) the opening to the spray tank on power spray units shall be locked;
(f) drains on spray tanks shall be fitted with lockable valves or threaded caps;
(g) containers carrying herbicide concentrate shall be securely locked or bolted to spray units or other vehicles used to transport herbicide concentrate;
(h) valves or barrel pumps on containers carrying herbicide concentrate shall be locked or removed and replaced with threaded plugs;
(i) threaded plugs shall be mechanically tightened to prevent removal by hand;
(j) pressure control valve(s) shall be closed;
(k) any equipment used for operations involving herbicide applications shall not be left unattended within 30 m (100 feet) of any stream, water body or wetland.

OD-8.8.4 Application Methods

OD-8.8.4.1 The Service Provider shall follow the written instructions of the IPM certified licensed exterminator as approved by the Company.

OD-8.8.4.2 The Service Provider shall follow the manufacturer's label recommendations, and adhere to all label restrictions for mixing herbicide formulations. The Service Provider may increase the quantity of active ingredients provided label recommendations are not exceeded. The Service Provider shall seek the prior approval of the Company concerning any deviation from the formulation. Each formulation shall be agitated sufficiently to ensure proper mixing.

OD-8.8.4.3 The Service Provider shall notify the Company's designated representative as to the source of water to be used for mixing, prior to withdrawing water from any source.

OD-8.8.4.4 Application methods shall conform to the directions supplied by the manufacturer of the selected herbicide(s) in addition to all legislated controls.

OD-8.8.4.5 Cut stumps, if deciduous, shall be treated within twenty-four (24) hours with the appropriate herbicide formulation approved by the Company.

OD-8.8.4.6 The Service Provider shall complete a daily spray diary which shall be signed by the Service Provider's Supervisor in charge of the application, that includes the following technical conditions: date of application; report number; system name; starting and finishing structure/pole on a daily basis; approximate hectares covered daily; applicators' names; herbicide used; mix rate of herbicide and carrier; type and volume of surfactant if added; and location of signs installed. Additional information to be recorded includes weather conditions, average temperature, wind directions and velocity, in the morning and afternoon. Daily spray diaries shall be handed in weekly or as otherwise requested by the Company.

OD-8.8.5 Required Control

OD-8.8.5.1 The Service Provider guarantees that the efficacy rate shall be at least ninety-five percent (95%) without damaging desirable vegetation, as determined during the next growing season in the year following the treatment.

OD-8.8.5.2 The full extent of effective coverage and control shall be determined by field inspection ten (10) to twelve (12) months after the application. Effective performance of the herbicide product and application technique shall be guaranteed by the Service Provider for a period of one (1) year from the date of completion of the Services.

OD-8.8.5.3 The Company may perform random inspections during the one (1) year guarantee period stated in OD-8.8.5.2 above to assess the state of vegetation at that time, and to determine preparatory re-treatment requirements as a result of such inspections.

OD-8.8.6 Approved Disposal

OD-8.8.6.1 All emptied herbicide containers, application materials etc. of the Service Provider shall be disposed of by the Service Provider according to the requirements set out in the Pesticides Act and as required under Part V of the Environmental Protection Act and Regulation 347. Disposal procedures, including rinsing for recycling or return to the vendor, must be in a manner acceptable to the Ministry of the Environment and, where applicable, the Ministry of Natural Resources.

OD-8.8.6.2 Waste pesticide rinsate from triple-rinsing or jet-rinsing an empty container shall be placed back in the spray tank and used in the application or disposed of according to Part V of the Environmental Protection Act and Regulation 347.

OD-8.8.7 Unsatisfactory Results

OD-8.8.7.1 The Service Provider shall be prepared to re-treat with herbicide, at no additional cost to the Company, any portion of the Sites if the original herbicide treatment results are not to the satisfaction of the Company.

OD-9.0 BUFFER AREAS

OD-9.1 General

OD-9.1.1 The Service Provider acknowledges that Buffer Areas are areas where the work activities are either restricted or not permitted due to environmental legislation, for aesthetical reasons or in accordance with Property Owner Notification documentation or Company requirements, and that the Company defines Buffer Areas as No Work Zones, Herbicide Exclusion Zones and Restricted Zones.

OD-9.1.2 The Service Provider shall observe and respect the special considerations and requirements relative to Buffer Areas, and shall identify and clearly mark Buffer Areas relative to all bodies of water, environmentally and aesthetically sensitive areas and private property in accordance with applicable environmental legislation, Property Owner Notification documentation or Company requirements.

OD-9.2 No Work Zones

OD-9.2.1 The Service Provider acknowledges that No Work Zones are areas where work activities are not allowed, and that No Work Zones may be of a permanent or temporary nature.

OD-9.2.2 No Work Zones shall be identified by the Company and/or the Service Provider prior to or during the progress of the work.

OD-9.2.3 The Service Provider shall adhere to and comply with the time restrictions imposed on temporary No Work Zones.

OD-9.3 Herbicide Exclusion Zones

OD-9.3.1 The Service Provider acknowledges that Herbicide Exclusion Zones are those areas where no herbicide application is allowed.

OD-9.3.2 The Service Provider shall identify and retain compatible vegetation in Herbicide Exclusion Zones.

OD-9.4 Restricted Zones

OD-9.4.1 The Service Provider shall cut vegetation in Restricted Zones and the stumps shall be sprayed or, at the discretion of the Company's designated representative, a low volume basal treatment may be used.

OD-9.4.2 No selective ground spray single stem foliar herbicide shall be applied closer than 15 m (49 feet) to a well or other source of drinking water or reservoir, or closer than 10 m (33 feet) to any surface water (Restricted Zone).

OD-9.4.3 No stump or basal herbicide shall be applied to vegetation up to 3 m (10 feet) from any source of water.

OD-9.4.4 Stump and/or basal herbicide treatment shall be used in Restricted Zones for Transmission vegetation management.

OD-9.4.5 Where Site conditions create greater potential for entry of herbicide into water (i.e. steep slopes, rocky terrain, etc.) all minimum distances using any herbicide treatment method shall be increased as required or as specified by the Company or the manufacturer, whichever is the greater distance.

OD-10.0 GLOSSARY

<table>
<tr><td>Approved and Competent</td><td colspan="2">Approved and Competent shall have the meaning specified by the IHSA.</td></tr>
<tr><td>Brush</td><td colspan="2">Small forest type trees growing under the conductors that can be cut without contacting the conductors. Considered to be less than 4” DBH.</td></tr>
<tr><td>Buffer Area</td><td colspan="2">An area where work activities are either limited or prevented for some reason. A buffer area includes No Work Zones, Herbicide Exclusion Zones and Restricted Zones, as defined herein.</td></tr>
<tr><td>Collar Cut</td><td colspan="2">Pruning close to but beyond the branch bark ridge and the collar at the base of the branch.</td></tr>
<tr><td>Compatible Vegetation</td><td colspan="2">Low growing grasses, shrubs and trees that do not grow high enough to contact the electrical conductors. (Refer to OD-12.5.)</td></tr>
<tr><td>Cut Stump</td><td colspan="2">The portion of the tree or brush left after removal, not exceeding 7 cm (2.75 inches) in height (brush), cut horizontal.</td></tr>
<tr><td>Cycle Buster</td><td colspan="2">A specimen tree that cannot be given cycle clearance.</td></tr>
<tr><td>Danger Tree</td><td colspan="2">A dead, leaning, sick or shallow rooted tree either on or outside the ROW that could, when falling, contact the electrical conductors.</td></tr>
<tr><td>Danger Zone</td><td colspan="2">An area 1.5 times the height of the tree or branch to be removed.</td></tr>
<tr><td>Dedicated Observer</td><td colspan="2">A qualified person trained in a specific work activity, who is designated to observe the safe performance of that work as his/her sole function.</td></tr>
<tr><td rowspan="5">Desirable ROW Widths for Existing Lines</td><td>Line Voltage</td><td>Desirable ROW Width (meters/feet))</td></tr>
<tr><td>Under 34.5 kV</td><td>10 meters/33 feet</td></tr>
<tr><td>34.5 & 44 kV</td><td>20 meters/66 feet</td></tr>
<tr><td>115 kV</td><td>30 meters/98 feet</td></tr>
<tr><td>230 kV</td><td>50 meters/164 feet</td></tr>
<tr><td>Herbicide Exclusion Zone</td><td colspan="2">Those areas within the rights-of-way where herbicides are not to be used for vegetation control. These areas may be close to private property, gardens, wells or other sources of drinking water, wetlands, surface water or open bodies of water etc. All vegetation in these areas is to be cut to within 7.5 cm (3 inches) of the ground line.</td></tr>
<tr><td>Effective ROW Width</td><td colspan="2">The right of way width established by the Company’s designated representative, for a particular job.</td></tr>
<tr><td>Joint Use Partners</td><td colspan="2">Other utilities (phone, cable TV, etc) that occupy the Company’s poles.</td></tr>
<tr><td>No Work Zone</td><td colspan="2">An area where vegetation management work activities are not allowed. These areas could include private property, or environmentally or aesthetically sensitive areas. No Work Zones can apply on a permanent or temporary basis.</td></tr>
<tr><td>Overhang</td><td colspan="2">That portion of the tree that is over the electrical conductors.</td></tr>
<tr><td>Restricted Zone</td><td colspan="2">An area where the work is restricted in some manner. This could be for environmental reasons, as a result of Site conditions, property owner preferences, etc.</td></tr>
<tr><td>ROW</td><td colspan="2">Right-of-Way</td></tr>
<tr><td>Specimen Tree – on the ROW</td><td colspan="2">A tree with personal landscape value (example: on a customer’s front lawn).</td></tr>
<tr><td>Target or Natural Pruning</td><td colspan="2">The removal of tree branches using the collar cut and directing the residual portions of the tree away from the lines.</td></tr>
<tr><td>Trees</td><td colspan="2">Considered to be 4”DBH and greater.</td></tr>
</table>

OD-11.0 GUIDELINES

OD-11.1 Guidelines for Tree Work in the Vicinity of Power Lines

OD-11.1.1 Although the retention of healthy trees in their natural form is an objective, safety shall take precedence.

OD-11.1.2 All utility line clearance shall ensure adherence to the Electrical Safety Authority (ESA) minimum line clearance standards to ensure that six (6) full years will have elapsed prior to the need for re-pruning, unless otherwise specified by the Company.

OD-11.1.3 When carrying out line clearance, allowance shall be made for the lateral sway of branches in windy weather, and cold weather pruning shall allow for hot weather utility line sag of 0.6 m (2 feet) equidistant from adjacent utility poles.

OD-11.1.4 When working in the vicinity of communication lines, care shall be taken to avoid hitting or damaging foreign plant.

OD-11.1.5 The notching of tree crowns and other distortions of natural form shall be kept to a minimum.

OD-11.1.6 All branches, limbs or twigs to be removed above utility lines, shall be cut in such a way so as to fall safely away from conductors. If this is not possible, limbs shall be roped for lowering around utility lines.

OD-11.1.7 Shallow rooted trees leaning towards utility lines shall be inspected closely. If there is a potential of the tree falling into the utility lines, it shall be removed.

OD-11.1.8 Priority shall be given to the removal of fast-growing trees (refer to OD-12.1 "Tree Species and Rate of Growth Chart") directly below utility lines.

OD-11.1.9 The Service Provider shall remove overhang and maintain clearances as set out in OD-12.2,OD-12.3 and OD-12.4.

OD-11.2 Guidelines for Tree Pruning

OD-11.2.1 **The Objective** of utility tree pruning is to remove branches in order to prevent the loss of service, prevent damage to equipment, avoid impairment and uphold the intended usage of the facility/utility space.

OD-11.2.2 **Top Pruning** is utilized when the tree is located under the conductors and the top branches must be trimmed back to lower the crown of the tree. The drop crotch or natural pruning technique, as indicated in Figure 1, shall be employed by pruning to a lateral at least 1/3 the diameter of the cut.

OD-11.2.3 **Side Pruning** is utilized when the tree grows beside a conductor and the side branches extend into the zone around the conductors where it is desirous to be kept free of branches. The Company's designated representative shall specify whether trees shall be side pruned to the cutting line or back to the trunk. Limbs shall be felled inside the ROW to avoid damage to trees and property outside the ROW. Caution shall be taken to see that the falling limbs do not come in contact with conductors, guys, poles, or other facilities. Cut material shall be disposed of by the method specified by the Company's designated representative.

OD-11.2.4 **Overhang Pruning** is utilized when the tree grows beside a conductor and the limbs are located above the conductor so as to hang over the line.

OD-11.2.5 **Through Pruning** is utilized when the conductors are located inside the crown of the tree and pruning for the required clearance results in a hole being cut through the crown of the tree.

Emergency Service Restoration

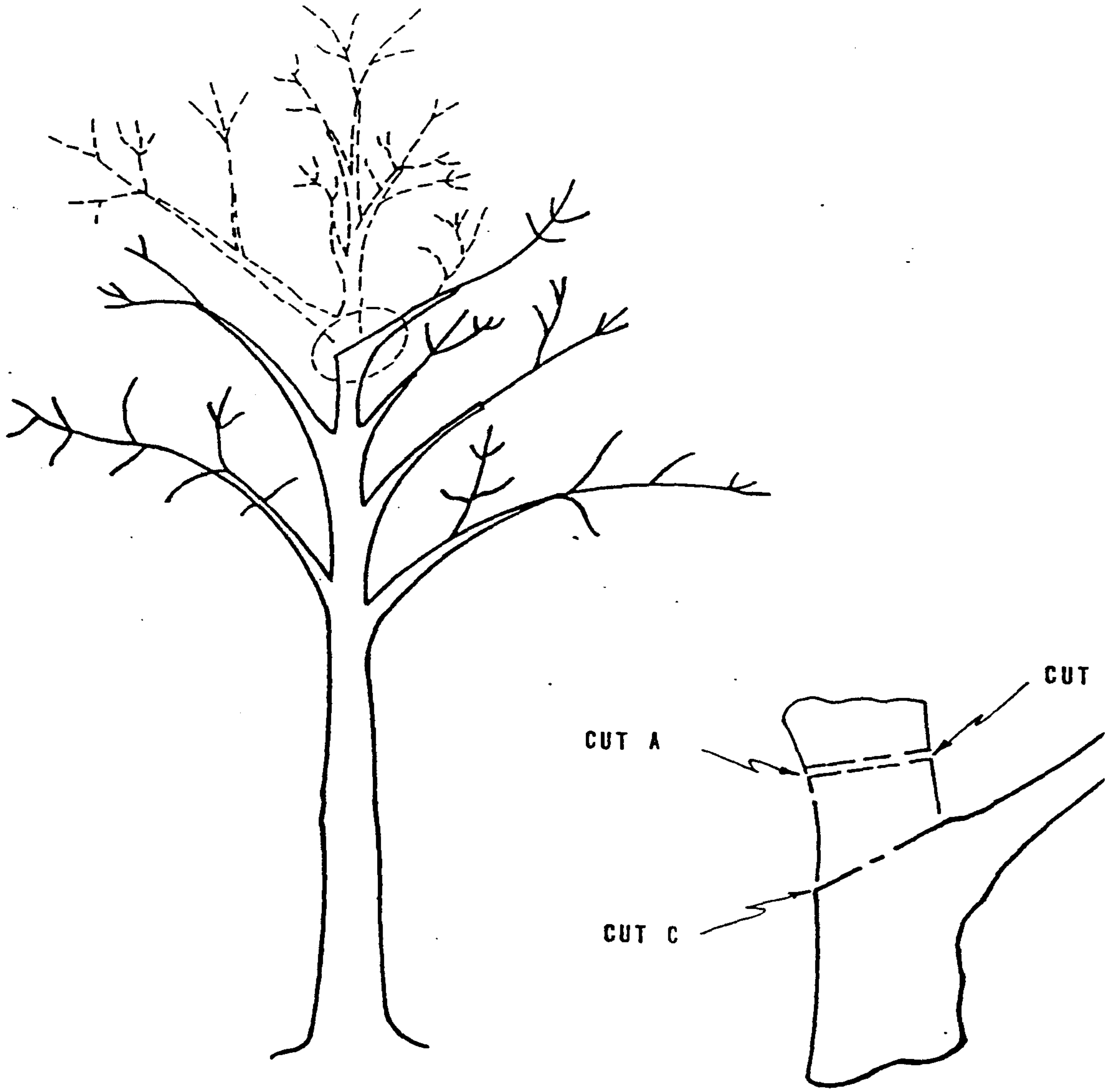

Figure 1. Tree Topping -Drop Crotch or Natural Pruning Technique

During a utility declared emergency, utilities must restore service as quickly as possible. At such times it may be necessary, because of safety and the urgency of service restoration, to deviate from the use of proper pruning techniques as defined in this Guideline and the standards referred to herein.

OD-11.3 Guidelines for Herbicide Application

OD-11.3.1 Selective Cutting and Stump Treatment

OD-11.3.1.1 **Application**

The formulation shall be applied in accordance with methods described below:

(a) Low Volume – The formulation shall be applied to wet the cut surface, bark, root crown and exposed roots. Particular attention shall be given to a complete encircling and wetting of the root collar at the ground line.

(b) Cut Surface Concentrate – The concentrate shall be applied only to the cut surface of the stump. Particular attention shall be given to wetting the entire cambium area next to the bark.

OD-11.3.1.2 **Equipment**

The application equipment to be used is dependent on the formulation type and shall be as follows:

(a) Low Volume – Application to be made with a hand operated backpack sprayer or equivalent gun and nozzle.

(b) Cut Surface Concentrate – application to be made with a hand-operated sprayer or trigger operated squirt bottle.

OD-11.3.1.3 **Weather Conditions**

No application shall be made while rain is falling. Low volume formulations shall not be applied when snow or ice is two (2) or more inches in depth around the stumps to be treated. Cut surface concentrates may be applied when snow or ice is present as long as the cut surface to be treated is free of ice and snow. Stumps treated one (1) hour or less prior to rain shall be sprayed again but not until one (1) hour after runoff has stopped.

OD-11.3.1.4 **Timing**

The predictable stump area shall be treated before cutting (pre-spray) or the stump shall be treated immediately after cutting. Where pre-spray is specified, a waiting period between spraying and cutting, established by the Company, shall be observed. Where a pre-spray is utilized, only formulations containing an oil type carrier shall be used.

OD-11.3.1.5 **Herbicide Formulations**

(a) Low Volume – the herbicide concentrate is mixed with a mineral oil type carrier specifically designed and labeled for this purpose. The herbicide concentrate comprises 20% to 30% of the total mix.

(b) Cut Surface Concentrate – the herbicide is applied as a ready-to-use concentrate or it is diluted with water.

OD-11.3.2 Selective Basal Treatment

OD-11.3.2.1 **Application**

The solution shall be applied to each stem from a point .45 m (18 inches) high on the stem to ground line, completely encircling the stem and any exposed roots. The solution shall be applied only to wet the stem and all exposed roots. Where sprout growth originates from a stump, the treatment shall also be applied to completely encircle the stump and any exposed roots.

OD-11.3.2.2 **Equipment**

Application shall be made with a hand operated backpack sprayer or equivalent gun and nozzle.

OD-11.3.2.3 **Weather Conditions**

No application shall be made while rain is falling or when snow or ice is 5 cm (2 inches) or more in depth around the stems to be treated. Stems treated one hour or less prior to rain shall be sprayed again but not until one hour after runoff has stopped.

OD-11.3.2.4 **Timing**

Basal spray may be applied at any time of the year unless the Company specifies dormant or growing season basal. Dormant selective basal spray shall be done between the time of fall foliage coloration and bud break in the spring. All species of ash, oak and hickory shall be cut and stump treated when treatment occurs between September 15 and March 1.

OD-11.3.3 Selective Stem Foliar Treatment

OD-11.3.3.1 **Application**

The solution shall be applied so as to thoroughly wet the entire stem and foliage to achieve runoff. The applicator shall stand within 3 m to 4.5 m (10 feet to 15 feet) of the target vegetation.

OD-11.3.3.2 **Equipment**

The spray solution shall be applied with power-drive equipment. Spray nozzles shall be adjusted to produce a coarse spray of large droplets at a maximum of 50 pounds pressure at the nozzle. Spray nozzles shall be equipped with a No. 8 or larger orifice disc.

OD-11.3.3.3 **Weather Conditions**

Spraying shall not be done during rain or while rain is dripping from the foliage. Foliage sprayed one hour or less prior to rain shall be sprayed again after run-off has stopped.

OD-11.3.3.4 **Timing**

Spraying shall be done during the growing season while the foliage is fully developed and still has its normal green color and vigor, approximately from mid-June to the end of August.

OD-11.3.4 Selective Low Volume Foliar Treatment

OD-11.3.4.1 **Application**

The solution shall be applied so as to partially wet all foliage. Emphasis shall be given to wetting all vegetation. The applicator shall stand within 1.5 m (5 feet) of the target vegetation.

OD-11.3.4.2 **Equipment**

OD-11.3.4.2.1 The spray solution shall be applied with either a motorized or hand operated backpack sprayer.

OD-11.3.4.2.2 Motorized vehicles with boom or radiarc attachments shall be used for large areas.

OD-11.3.4.2.3 Hand help spray brooms or backpacks shall be used for more smaller locations and spot treatments.

OD-11.3.4.3 **Weather Conditions**

Spraying shall not be done during rain or while rain is dripping from the foliage. Foliage sprayed one hour or less prior to rain shall be sprayed again after run-off has stopped.

OD-11.3.4.4 **Timing**

Spraying shall be done during the growing season while the foliage is fully developed and still has its normal green color and vigor, approximately from mid-June to the end of August.

OD-12.0 REFERENCE MATERIALS

OD-12.1 API ROW Clearance Standards

	*distance from outside powerline	
Line Type	Width (m)*	Width (ft)*
Express Feeder (44kv)	16.5	54
Express Feeder (12.5-34.5kv)	10.5	34
New Primary (2.4-25kv)	6	20
Existing Primary (2.4-25kv)	4.5	15
Secondary (<750V) – System	1.5	5
Secondary (<750V) – Taps	1	3
Underground – Various Voltage Classes	3	10

OD-12.2 Tree Species and Rate of Growth Chart

Growth Type/Species	*Rate of Growth/Year
Fast Growing Trees – Poplars, Willows, Balsam Fir, Silver and Manitoba Maples, Siberian and Chinese Elms, Locust, etc.	1.5 meters (5 feet)
Medium Growing Trees – Ashes, Birches, American Elms, Basswood, Norway & Sugar Maples, Walnut, Butternut, etc.	1 meter (3 feet)
Slow Growing Trees – Oaks, Hickories, All Conifers (Pines, Cedars, Firs, Larches, and Hemlock), etc.	0.6 meters (2 feet)
* ***Based on general guidelines, and dependent upon site conditions, rainfall, etc. Annual sucker growth may exceed the rates shown.***	

OD-12.3 Tree Clearance Chart – Distribution
(6 Year Cycle)

Distribution – Existing Lines 2 kV – 30 kV			
Tree Growth	**Standing Clearance**	**Side Clearance**	**Overhang**
Fast	9 meters (29.5 feet)	2 meters (6.5 feet)	4 meters (13 feet)
Medium	6 meters (20 feet)	1.6 meters (5 feet)	2 meters (6.5 feet)
Slow	4 meters (13 feet)	1.2 meters (4 feet)	1.5 meters (5 feet)
The above values reference distances to conductor based on maximum sag position.			

OD-12.4 Tree Clearance Chart – Sub-Transmission & Transmission - Existing Lines
(6 Year Cycle)

Sub-Transmission & Transmission – Existing Lines 30 kV – 230 kV			
Nominal Line Voltage	**Standing Clearances**	**Falling Clearances**	
		Sound Trees	**Danger Trees**
30 – 50 kV	9 meters (30 ft)	Not Required	9 meters (30 ft)
115 kV	9 meters (30 ft)	Not Required	9 meters (30 ft)
230 kV	10.6 meters (35 ft)	Not Required	12 meters (40 ft)
The above values reference distances to conductor based on maximum sag position.			

OD-12.5 Tree Clearance Chart – New Lines (as per IESO Interim Standards) (6 Year Cycle)

New Lines	
Nominal Line Voltage	**Minimum Standing & Falling Clearances**
115 kV	0.8 meters (2.6 ft) plus trimming cycle growth
230 kV	1.6 meters (5.3 feet) plus trimming cycle growth
The above values reference distances to conductor based on maximum sag position.	

OD-12.6 Compatible Vegetation

Not all of the species listed below are presently found in the Algoma District, but there may be the potential for this vegetation to exist over time.	
Alder Family (Black, Green, Speckled)	Laurel (Bog/Sheep/Labrador Tea)
Arrowwood - Viburnum	Leather Wood
Beaked Hazelnut	Lilac
Bilberry	Maple leaf Viburnum
Blackberries	Mountain Ash

Blueberry	Mountain Laurel
Bracken fern	Nannyberry
Bunchberry	Raspberries
Bush Honeysuckle	Rhododendron
Cranberry	Rose
Dogwood (Alternate Leaf, Red osier)	Serviceberry
Dwarf Fruit Trees (Choke cherry, Pin cherry, Canada Plum)	Shrub Willow
Elderberry	Snowberry
Gooseberries & Currants	Spierea
Ground Hemlock, Canada Yew	Sweet fern/Sweet gale
Hawthorn	Sumac
Hobblebush	Viburnum
Honeysuckle	Winterberry/Wintergreen
Huckleberry	Witherod (Wild Raisin)
Junipers (Common/Ground/Creeping)	
The removal of compatible vegetation may be requested by the Company's designated representative.	

Appendix H API IVM Plan Example

INTEGRATED VEGETATION MANAGEMENT PLAN

For Control of Vegetation within Distribution Rights-of-way

DOCUMENT #: XXXX-XXXX

ISSUED: NOVEMBER 2023

Algoma Power Inc., a Fortis Ontario Company
Vegetation Management Department
251 Industrial Park Crescent
Sault Ste. Marie
Ontario, P6B 5P3

Acknowledgements / Signing Authority:

This document was produced and review by the
API Vegetation Management Department:

(Name – Title) ____
Signature

(Name – Title) ____
Signature

(Name – Title) ____
Signature

(Name – Title) ____
Signature

(Name – Title) ____
Signature

(Name – Title) ____
Signature

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1.0 EXECUTIVE SUMMARY

Integrated Vegetation Management (IVM) is a data-driven, progressive system of information gathering utilized to best plan and complete work, including follow-up auditing, to better ensure the desired results are achieved. It involves the use of various types of vegetation management treatment including the removing, pruning and mowing of vegetation and the treatment of vegetation with herbicides. The overall goal of a utility IVM Plan is to develop compliant, site-specific, environmentally sensitive, cost-effective and socially responsible sustainable solutions to vegetation control near electric facilities.

The IVM process creates a continuous feedback loop that is adjusted over time due to monitoring and adjusting the program to meet changing ecosystem conditions and internal/external factors including reliability, regulatory compliance, site sensitivity, location, stakeholder considerations, and maintenance budgets.

Properly implemented, IVM is recognized as a methodology that encompasses a range of industry-established best practices and is an integral component of an effective vegetation management program.

The successful implementation of an IVM Plan depends on the upfront preparation of internal and external stake holders. This is an on-going process and begins prior to implementation all the way through to completion of an IVM cycle. As additional support, a team of Subject Matter Experts (SME's) should be identified to educate stakeholders and provide quick response to questions or complaints.

A long-term study of successful IVM programs have shown decreased stem counts per acre and long-term cost savings when compared to mechanical control methods.

2.0 INTRODUCTION

2.1 ABOUT API

This document is an Integrated Vegetation Management (IVM) Plan for the management of vegetation on distribution line rights-of-way (ROW) operated by Algoma Power Inc. (API). It has been prepared to be used as a turn-key document for the implementation of an IVM Plan on the API distribution system.

API headquartered in Sault Ste Marie, Ontario provides electric service to over 12,000 electric customers in Northern Ontario's Algoma District from Wawa to Thessalon. The API distribution system is comprised of approximately 1,800 kilometers across a service territory of approximately 14,000 square kilometers.

2.2 INTEGRATED VEGETATION MANAGEMENT (IVM)

IVM is a data-driven, progressive system of information gathering utilized to best plan and complete work, including follow-up auditing, to better ensure the desired results are achieved. It involves the use of various types of vegetation management treatment including the removing, pruning and mowing of vegetation and the treatment of vegetation with herbicides. The overall goal of a utility IVM Plan is to develop compliant, site-specific, environmentally sensitive, cost-effective and socially responsible sustainable solutions to vegetation control near electric facilities.

IVM is a pest control concept borrowed from Integrated Pest Management (IPM) that considers biological, chemical, cultural, and physical (e.g., mechanical and manual techniques) methods to control undesirable vegetation. The method that is implemented to control undesirable vegetation at any given location is selected on the basis of treatment effectiveness, site characteristics, environmental impacts (including impacts to desirable, non-target vegetation species), safety, and economics. Flexibility is a key aspect of IVM to achieve site specific and program objectives.

IVM provides a structure with flexibility that supports the development of a comprehensive approach to preserving and maintaining the purpose and function of electric ROWs. It provides the utility the guidelines to select and schedule appropriate treatment methods and to selectively treat specific sites. IVM is an adaptive system that follows an interdisciplinary approach that crosses utility departments. IVM is based on a deliberate strategy to encourage the development of sustainable compatible vegetative cover types, which suppresses the establishment and growth of incompatible vegetation. Compatible vegetation is consistent with primary operational objectives of reliability, access, safety and regulatory compliance.

IVM is a structured decision-making process. The process is a continuous loop that is adjusted over time because of monitoring and adjusting the program to meet changing ecosystem conditions and current utility needs.

Management objectives are established around specific tolerance levels using IVM principles. These objectives are based on internal and external factors including reliability, regulatory compliance, site sensitivity, location, stakeholder considerations, and maintenance budgets.

Properly implemented, IVM is recognized as a methodology that encompasses a range of industry-established best practices. It is therefore an integral component of an effective vegetation management program.

In general, physical or chemical control methods are the most appropriate incompatible target brush control options for a given electric system. Biological controls (e.g., grazing by animals) and cultural controls (e.g., using fire to eliminate undesirable vegetation) have extremely limited application and are seldom used as a utility vegetation maintenance technique. However, the retention of low-growing, compatible vegetation on the ROW will inhibit the future growth of incompatible species and is therefore considered a form of biological control.

2.2.1 Goals of IVM

API controls tall-growing vegetation to reduce outages caused by trees growing into lines, and to provide safe access to their Rights-of-Way (ROWs). API's policy is to effectively and safely manage the risk of such outages.

The specific goals of the API IVM Plan are to:

- minimize public and worker safety hazards.
- reduce the number of outages due to vegetation.
- reduce the risk of fires caused by trees contacting the lines.
- allow access and lines of sight for maintenance.

The program also strives to:

- encourage a stable, low-growing plant community.
- use leading edge techniques and practices.
- respect agreements with the public, landowners, and other stakeholders.
- comply with all government regulations and corporate policies.
- selectively control only undesirable (target) species.

2.2.2 Site Objectives

The overall objective of managing vegetation is to replace a tall-growing plant community with a low-growing one that will not contact the powerlines. There are three main ways of managing the ROW to achieve this goal:

- **Low-Growing Stable Plant Community** – Control methods will target undesirable (i.e., tall-growing) vegetation and encourage desirable species, such as low-growing shrubs and native non-invasive plants present on site.
- **Compatible Use** – Activities within the ROW that do not conflict with overhead distribution lines and can lead to control or prevention of undesirable vegetation, such as recreational or agricultural uses.
- **Altering Existing Vegetation** – When it is impractical to remove undesirable species within the ROW, existing vegetation may be managed by pruning or trimming to achieve sufficient clearance from conductor, thus protecting overhead distribution lines.

2.3 IDENTIFYING INFORMATION

This IVM Plan applies to all API managed distribution lines. A distribution line carries high-voltage electricity (69 kV or less) from substations and delivers it transformer, where the voltage is reduced for use by customers.

2.3.1 Person Responsible

The person responsible for administering the IVM Plan is Andrea Mattioli, Vegetation Management Advisor, Phone: (705) 941-5607, who is the principal contact for information relating to the plan.

2.3.2 Geographic Boundaries

API manages approximately 1,800 kilometers of overhead distribution lines. The average ROW clearance width from edge-to-edge is 30 feet depending upon line construction and voltage.

Areas Covered by The IVM Plan

This IVM Plan covers vegetation management, including the use of herbicides, within the boundaries of legal ROW.

It also covers facilities associated with the ROW, such as:

- Base of distribution poles and other electrical structures.
- Access roads leading to the ROW or other facilities that API manages.

It also covers areas outside ROW where distribution structures and equipment are located.

3.0 ELEMENTS OF IVM PLAN

Budgets generally do not support 100% of the desired maintenance work; therefore, circuits and potential IVM must be prioritized. As the goal of tree trimming / vegetation maintenance programs is the reduction of tree caused outages, planning should be based on the premise that putting maintenance dollars on those portions of the distribution system where the highest benefits can be realized (maximizing the reduction in tree caused interruptions to the largest group of customers.

It has proven most effective to schedule based on the following criteria to maximize the return on investment for the IVM work within allowable budgets:

1. Highest distribution voltage circuits first, concentrating on; mainline un-fused three-phase back bone out of the substation.
2. Highest distribution voltage circuits concentration on three-phase and three phase fused taps.
3. Other three-phase portions of circuits working from the highest to the lowest voltages; remaining primary distribution system.

Planning the Work

i. First Maintenance Cycle – YEAR ONE:

Using the current work planning program, look at all locations that have been mowed in the past one to two years. Consider these as potential treatment locations. Using these locations return to review for suitability for inclusion in the YEAR ONE herbicide program. Things to check as a part of the field review:

a) was the area / location mowed?

b) If so, is it a suitable location for an herbicide application?

If these locations meet all criteria for herbicide application, secure permission from the property owner. Plan enough work to meet and exceed budget allocations for herbicide treatment. As the final cost based on competitive bid is not known, you want to have enough work identified for the YEAR ONE program. Using the information from the work plan *and* the follow-up field survey for site suitability and permission from property owners secured, put these locations out for competitive bid. Award contract to the extent the budget will allow to save time while securing permission from property owners; put work out to competitive bid based on cost per treated acre. The actual acres for the YEAR ONE program will be known based on the permissions secured and can be awarded within budget based on circuit priority as previously mentioned.

ii. Second and Subsequent Maintenance Cycles

Use the current year's distribution circuit maintenance work to identify the potential mowing locations. While securing permission form ROW mowing, also secure permission for follow-up herbicide application. By using the current work plan where mowing *and* herbicide permission has been secured, the next year's herbicide plan can be developed. By incorporating herbicide permissioning into the current work planning time can be saved later on thus reducing program overhead cost.

Using circuit prioritization by voltage and customers served, identify potential acres for herbicide treatment and put out to competitive bid. Bid more acres / circuits than budget provides for as the final bid cost is unknown at this time.

3.1 INCOMPATIBLE TARGET BRUSH SPECIES

The electric utility vegetation management industry typically defines trees as species with woody stems greater than 4 inches' diameter at breast height (4.5 feet above ground) that mature at heights greater than 20 feet. Immature tree stems (woody species less than 4 inches' diameter at breast height and with the capability to exceed 20 feet in height) are defined as incompatible target brush for the purposes of this manual.

Table 5. Common Incompatible Tree Species.

Common Name	Scientific Name
- - - - - - - - Coniferous Species - - - - - - - -	
Pine, loblolly	*Pinus taeda*
Pine, Virginia	*Pinus Virginia*
Pine, eastern white	*Pinus strobus*
Spruce, blue	*Picea abies*
Spruce, Norway	*Picea pungens*
- - - - - - - - Deciduous Species - - - - - - - -	
Box-elder	*Acer negundo*
Cottonwood, eastern	*Populus deltoids*
Elm	*Ulmus spp.*
Honeylocust	*Gleditsia triacanthos*
Maple, Norway	*Acer platanoides*
Maple, red	*Acer rubrum*
Maple, silver	*Acer saccharinum*
Maple, sugar	*Acer saccharum*
Mulberry	*Morus spp.*
Oak, black	*Quercus, velutina*
Oak, northern red	*Quercus, rubra*
Oak, pin	*Quercus, palustris*
Oak, white	*Quercus, alba*
Pear, Bradford	*Pyrus calleryana*
Tree-of-heaven	*Ailanthus altissima*
Walnut, black	*Juglans nigra*

It should be clearly understood that not all low-height vegetation on a ROW will eventually mature and pose a threat to overhead electric facilities. Small trees with low mature heights, shrubs, grasses, etc., are considered to be compatible with overhead electric facilities. It is neither cost effective nor beneficial to the environment to control this vegetation. Compatible, low-growing vegetation can also help to reduce the occurrence of tall-growing species, which helps to reduce vegetation management costs. Compatible vegetation should therefore be retained and encouraged as much as possible.

Immature trees (target brush) are a component of the vegetation workload that is sometimes overlooked because they typically do not pose an immediate threat to system reliability or safety. However, ignoring incompatible target brush and allowing it to mature can increase maintenance costs, impede or prevent accessibility to facilities, and can result in a significant increase to the tree workload as it matures. Incompatible target brush species can also threaten system reliability and safety as they mature and reach conductor heights.

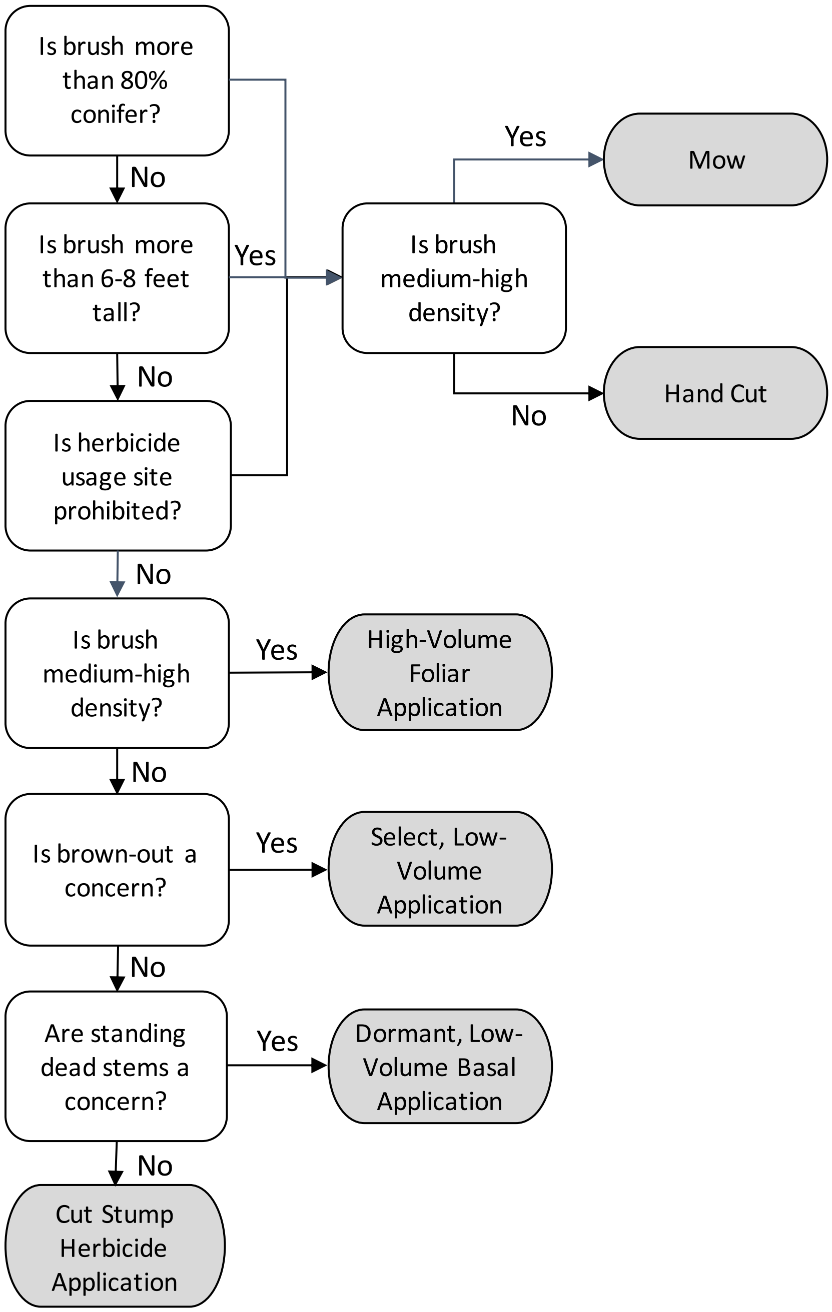
Aggressive incompatible target brush species control is crucial in preventing future expansion of a utility's vegetation workload and future cost increases. The methods used to control incompatible target brush also have an impact on cost effectiveness. Since target brush conditions, geography, terrain, and demographics all vary within a given utility's service area, there are a variety of methods that should be implemented to control incompatible target brush species.

At any given site, the method selected to control incompatible target brush species has a direct impact on the vegetation communities that result following maintenance. In general, non-herbicide physical maintenance techniques (e.g., hand cutting and mowing) will encourage the proliferation of incompatible broadleaf brush species through stump sprouting, and in some species root suckering, thus creating a worse incompatible target brush problem than previously existed prior to the treatment. The use of herbicides will reduce stem densities of incompatible target species and provide long-term control of vegetation, thus reducing long-term maintenance expenditures.

The selection of an incompatible target brush species maintenance technique for a given area will be dictated by a number of factors. Target brush height and density will be the most important criteria in determining the appropriate control technique to employ. Additional factors that help determine an appropriate control method are terrain conditions, density of low-growing compatible vegetation, restrictions to maintenance practices (e.g., land use or public sensitivity), and the availability of expertise to successfully implement and monitor certain control methods such as specialized herbicide applications.

Figure 1 includes a matrix that will assist in developing initial incompatible target brush management prescriptions on the basis of general site conditions. The flowchart provides an indication of the complexities that are involved in selecting appropriate target species control methods. This flowchart is a general guideline for prescribing an appropriate brush control treatment for a specific right-of-way site, but adequate training and experience are essential for successful implementation.

Figure 1. IVM Decision Flowchart.



The chart is not intended to replace the expertise and experience that should be provided by vegetation management professionals. API should retain in-house staff with vegetation management expertise and/or consult with vegetation management contractors, consultants, and chemical company representatives before proceeding with implementing sophisticated IVM strategies to control vegetation.

A professional approach and sufficient technical expertise is particularly critical when implementing a program that includes herbicide applications. A successful IVM Plan and general public acceptance of herbicide use will depend upon an electric utility's commitment to a coordinated and professional effort to ensure the protection of both human health and the environment.

3.2 BRUSH CONTROL METHODS

3.2.1 Hand Cutting

Hand cutting uses a chain saw or brush saw to remove undesirable target vegetation. Hand cutting is the preferred maintenance technique for sites where obstacles (e.g., rocks, poles, or tower bases) exist or terrain conditions prevent access by mowing equipment and where herbicides cannot be used.

Hand cutting results in the immediate elimination of the above ground portion of undesirable target species. Compatible low-growing species are typically retained with this method, and a high level of selectivity can be achieved.

Unfortunately, hand cutting only effects the aboveground portion of the vegetation that is being maintained. The root collar area of the cut vegetation remains intact and viable, and hand cutting typically results in vigorous stump sprouting and, in some species, root suckering as well.

The rapid growth and multiple stems that typically follow hand cutting can increase incompatible target species stem densities significantly, resulting in a worse target species problem than previously existed. The control provided by hand cutting is short term, and the use of this technique alone should be limited. Long-term control of target species that have the capability of re-sprouting can only be achieved by applying an herbicide to the surface of the cut stump immediately following cutting (see Cut Stump Section).

When hand-cutting target vegetation, stems should be cut as close to the ground as possible and stump heights should typically not exceed 3 inches. Cuts should not be made on an angle, which results in pointed stumps that can be hazardous to humans, animals, and equipment.

Hand cutting can be performed at any site that is accessible to workers. This technique can be employed at any time of the year except when deep snow prevents cutting close to ground level.

Hand cutting should generally be limited to sites where target species stem densities are light to moderate and mowing is not economically feasible, and in areas where it is preferable to control incompatible target stems by cutting them at ground level.

It is recommended that tree/ brush removal within the API easement at rural sites and where brush density is low, be conducted without prior landowner approval. There should not be a need for permission if the ROW is adjacent to or on a public road ROW. Prior agreement with the road ROW authority can be secured in these locations to eliminate the need to secure individual permission for this type of tree / brush removal. The same process should be utilized for herbicide applications as well.

<u>Benefits of Hand Cutting</u>

- Hand Cutting allows the immediate removal of target vegetation, with complete retention of low-growing compatible species.
- Conifer trees cut below the lowest branch are permanently controlled.
- Hand Cutting allows spot treatment with herbicides to prevent stumps from Re-sprouting.
- Hand Cutting protects areas close to environmentally sensitive areas.
- Hand Cutting is beneficial in areas where target vegetation is widely scattered (low stem density per acre).

Limitations of Hand Cutting

- Hand Cutting is very labor intensive and can be dangerous to workers in steep terrain.
- Hand Cutting is more difficult in dense vegetation (high stem counts per acre).
- It can increase the fire risk if there is a buildup of debris.
- In the absence of follow-up herbicide treatment, stumps can re-sprout repeatedly (into coppices) each time they are cut, resulting in drastically increased stem densities, growth rates, clearing costs, and shortened treatment cycles in subsequent years.
- Aesthetics of Hand Cutting may be a public concern due to the buildup of debris.

3.2.2 Mowing

Mowing consists of mechanically cutting incompatible target species with a large cutting machine attached to a tracked or rubber-tired vehicle. Although there are numerous sizes and configurations of mowing equipment available, cutting heads for utility vegetation maintenance generally fall into two categories: rotary cutting heads and flail-type.

Rotary cutting heads consist of one or more blades that rotate horizontally, cutting and shredding vegetation. Flail-type mowers consist of metal teeth or chains attached to a rotating drum, which knocks down and shreds vegetation. Rotary style mowers are typically referred to as "brush hogs" and flail-type mowers are generally classified as "hydro-axes".

Depending upon the size of the mowing equipment being used and the target species being managed, vegetation up to about 8 inches in diameter can reasonably be cut. Some specialty vegetation management equipment can even handle larger diameter vegetation.

As with hand cutting, mowing results in the immediate elimination of all undesirable target stems. However, since this technique is not selective, all desirable low-growing vegetation within the mower's path is eliminated as well. Thus, the site is left in a disturbed and more open state, which allows tree seeds to germinate in addition to encouraging stump sprouting.

Mowing will not provide long-term control of communities of target species unless followed up with an herbicide application to control re-sprouting. (See the Herbicide Treatments section for a discussion on mowing with a follow-up herbicide application).

Mowing is the recommended maintenance technique for relatively flat areas with few obstacles (e.g., rock outcroppings, boulders, and stone walls) areas that support moderate to heavy densities of incompatible target species and in locations where herbicides cannot be used. As long as the site is accessible to mowing equipment, mowing will typically be more cost-effective and practical than hand cutting. This is particularly so when areas have been repeatedly mowed over several maintenance cycles and incompatible species densities have increased significantly.

Mowing can be done at any time of the year if sites are accessible. The only difficulties that may prevent mowing are steep slopes, debris on the easement or ROW, and rocky terrain. Mowing is also typically unacceptable on wet sites since heavy equipment can result in significant soil disruption and soft, wet soil conditions can impede or even prohibit the progress of machinery along the ROW.

Selection Criteria for Mowing

Mowing is the preferred method where the terrain allows, and in areas:

- With a density over 8,000 deciduous stems per acre
- With a density over 4,000 coniferous stems per acre

- With target trees between 13-15 feet in height (to reduce slashing debris)

In general, mowing should ***not*** be used:

- On target trees with a DBH over 6-7 inches (mowing larger stems is impractical)
- Where low-growing compatible species are well-established and there are low stem densities of target vegetation
- In areas with a dense understory of low-growing compatible species and high stem densities of target vegetation (an excavator machine should be used)
- In areas with rocks that can cause excessive damage to cutting heads (unless an excavator with an articulating mower is used)
- In areas that are developed or have high public use because of the risk of flying debris
- On properties that face manicured lawns
- In areas with stumps that create accessibility problems
- In boggy areas where the machine will not operate properly
- On slopes that create a worker hazard
- In riparian areas

Benefits of Mowing

- Mowing mulches the vegetation into smaller pieces that readily biodegrade, which reduces fuel loading fire hazards.
- Mowing is seasonally effective, inhibiting growth from spring through late summer. This is important in areas where herbicide follow-up treatment is not possible.
- In areas where fast-regenerating ground covers are plentiful, re-sprouting of unwanted vegetation is suppressed.
- In non-selective mowing (Hydro-axe or Kershaw), all vegetation is cut to ground, leaving a level ROW and facilitating future herbicide applications that use mechanical delivery systems.
- In mowing directed only towards target vegetation (hydraulic excavator, rotary disc, or flail), the ROW retains biodiversity and existing low ground cover.
- Target vegetation can be removed faster and more economically than other methods, especially where the stem count per acre is high and where tall brush exists.
- Work progress and workmanship are clearly visible.
- Using heavy equipment is generally less hazardous to the operator than using hand-held equipment.

Limitations of Mowing

- Mowing is not generally suitable in certain riparian areas and should not be used there unless a site-specific riparian prescription has been produced and approved.
- Mowing alone without follow-up herbicide treatment can promote heavier regrowth of deciduous vegetation resulting in higher stem counts per acre in the future.
- Mowing is often limited by terrain, such as steep slopes, large rocks, stumps, and bodies of water.
- In wet terrain, machines cannot operate effectively.

- Mowing chops / shreds the brush using a high-speed, mowing/flailing action, which can leave ROWs unsightly, hazardous, and subject to public complaints.
- Mowing may result in rutting, track marks, or degradation of the ROW surface.
- Mowing should not be used on slopes greater than 30% because most machines are unsafe to operate.
- Depending on the type of mower being used, black-top roads may be damaged in the summer.

3.3 HERBICIDE TREATMENTS

The routine selective use of herbicides to control undesirable vegetation on electric utility systems is essential to reducing long-term costs and to maximizing the benefits of both tree and incompatible target brush species removal programs. Judicious herbicide use is an important component of an IVM strategy, and it is critical to the establishment of a low-growing plant community on the ROW that results in a cost-effective vegetation management program. Herbicides are often the only effective means of control within ROWs, for safety reasons and to prevent power outages.

An integrated vegetation management program that combines physical techniques with site-specific follow-up use of herbicides is often the most effective way to establish a stable, low-growing plant community. Herbicides are used primarily on deciduous trees, because they are fast-growing and quick to re-sprout, compared to conifers. When conifers are cut below the lowest branch, they will die.

The effectiveness of selective herbicide applications has been well documented by the electric utility vegetation management industry. Selective herbicide applications control unwanted, tall growing target vegetation and encourages retention and expansion of desirable plant communities. Once these low-growing, desirable plant communities become well established, the occurrence of non-compatible tree stems decreases and future maintenance costs are reduced.

The establishment of communities of low-growing, compatible vegetation should be a primary goal of a utility target brush species control program. As progress is made towards achieving this goal, the inputs required to control undesirable vegetation can be reduced over time. The inputs required to manage vegetation can be described as herbicides (including adjuvants and carriers), labor, and equipment. Incentives to reduce the inputs are found in:

- Reducing environmental load.
- Reducing costs.

There are two concepts to consider when practicing vegetation management through the selective use of herbicides on an electric utility system:

1. Selectivity for desirable vegetation based on <u>herbicide selection</u> - Herbicides are selected that predominantly control the undesirable target vegetation while leaving some compatible low-growing desirable vegetation (e.g., grasses) unaffected.
2. Selectivity for desirable vegetation based on <u>application technique</u> - Herbicides are directed vs. broadcast through specific application to the undesirable tall-growing target vegetation. Desirable low-growing vegetation does not receive treatment and is retained on the ROW.

In order to gain control of a ROW filled with undesirable vegetation, an initial clearing or “reclamation” treatment phase is typically required. Vegetation conditions are assessed, and the appropriate herbicide and application technique is chosen. Generally, initial clearing is performed through the broadcast application of an herbicide on all heavy density, incompatible target brush species that typically exhibit various stages of height growth, depending on the time elapsed since the last mowing or hand cutting treatments were performed. In this phase, the vegetation in the target area is predominately undesirable, and an herbicide is applied to achieve coverage of all target stems within the entire ROW area to be managed.

Removal of incompatible target species through herbicide applications will promote a low growing plant cover of shrubs and herbs (grasses and forbs) that helps to resist the establishment of tall growing, undesirable tree species. The conversion of a ROW to this state depends on the amount of desirable vegetation present at the time of the initial reclamation phase. Achievement of the minimum maintenance phase should require no more than two additional applications (4 to 7 years apart) and in some cases only one more treatment will be required. Each subsequent application in the ensuing and minimum maintenance phases uses less herbicide, labor, and fuel since less undesirable target vegetation is present. The reductions in the amount of chemicals used, in the labor required, and in the type and amount of equipment needed to maintain desirable vegetation on the ROW and control target species can translate into significant cost savings for a vegetation management program.

Herbicide applications in later phases are specifically targeted at the undesirable tree species by directed applications. Tremendous selectivity (both with herbicides used and application techniques employed) can be achieved once this phase is reached. Efforts in these later treatment cycles emphasize minimum disturbance to the desirable, low-growing vegetation so as to promote and sustain its continued presence on the ROW.

Herbicide applications should be an integral part of an IVM strategy. An important consideration is that herbicide use must be environmentally compatible and professionally supervised in order to achieve and maintain public acceptance. Crews that have received training in species identification, the handling of herbicides, and application methods should complete all herbicide applications. All applicable pesticide laws and permits regulating herbicide use must be followed. Contractors must hold the required licenses and obtain the necessary permit coverage.

Crew personnel completing herbicide applications have significant responsibility to ensure that herbicides are handled and applied correctly. However, utility management personnel should have the ultimate responsibility for making sure that the overall vegetation management program, including the use of herbicides, is safe, professional, and effective.

The techniques used for herbicide application can be divided into two broad categories: directed (or selective) and broadcast. Directed, as implied, describes an application that is applied only to target stems. The amount of herbicide mix that is applied varies and is dependent on the density and height of target stems that are to be controlled. Broadcast applications are set at a fixed rate per area and once fixed, are independent of the density of the target stems that are to be controlled. Within these two application categories, specific application techniques can be defined as follows:

Recommend API Application Techniques

- Foliar: High Volume and Low Volume Backpack Treatments.
- Basal Bark Low Volume Treatment.
- Cut Surface (Stump Treatment): performed by trees crews when removing trees or brush.
- Directed (selective): to be used on a limited basis mainly on an hourly basis.

Not Recommend Application Techniques

- Cut Stubble: not recommended for API distribution at this time.
- Broadcast: not recommended for API distribution at this time.

3.3.1 Foliar Applications

High Volume Foliar Application

High volume foliar is an application technique that typically utilizes a maneuverable vehicle (such as a truck or tractor) equipped with a large spray tank. Herbicide applications are applied to the foliage of target tree species using a hand-held, high volume spray gun. Maximum effectiveness is generally achieved when target tree heights are between 8 and 15 feet.

The concentration of herbicide used for this technique is low and typically ranges from ½ to 1-1/2 percent of the spray solution. Volumes of spray mixture used will vary depending upon vegetation conditions but will typically range from 100 to 400 gallons of spray solution per acre.

High volume foliar applications apply herbicide to target species 8 to 15 feet tall and of medium to high density by thoroughly wetting all of the leaves and the stem. Operator skill is essential to achieving some selectivity with this technique. Spray pressure at the tip should be the minimum required to obtain plant coverage. The spray should be directed no higher than the target tree being treated. The use of a thickening agent or drift control additive is advisable to avoid the production of fine particles that may drift onto sensitive non-target plants. Nozzle tips that produce coarse droplets of solution should be used to help reduce drift.

High volume foliar applications should be performed during the period of active growth and when leaves are fully formed (generally from late spring to early fall). This technique can be performed on any site as long as terrain conditions permit access by spray vehicles.

When treating a ROW that has a high density of target species, the difference in results between selective high-volume foliar and uniform broadcast applications will oftentimes be minimal. The vast majority of plant materials on the ROW should be target species if either of these application techniques is utilized, which will result in a ROW with a browned-out appearance.

Selection Criteria for Mechanized Foliar Treatment

- This method is optimally used on areas that have been previously mowed or hand-cut to reduce re-sprouts.
- It is often used to treat re-sprouts one to two years after the area has been mowed or hand cut.
- It is recommended for use when there is a high density of target cover at a uniform height. This will reduce the potential for spray runoff to the ground.
- It is an excellent treatment for noxious and invasive weed control.

Benefits of Mechanized Foliar

- Mechanized foliar is an efficient method for managing the re-sprouts of high-density target vegetation.
- It targets specific vegetation, with adjustable application rates and dosages.
- This method often uses a Radiarc nozzle. • The Radiarc nozzle reduces the amount of herbicide used because well- defined droplets are produced, producing good coverage of the foliage with limited runoff.

Limitations of Mechanized Foliar

- It is not as selective as backpack foliar application.

- There is more potential for drift than a backpack foliar application.
- Buffer zones may be required to protect pesticide-free zones, depending on wind direction and topography.
- Caution must be exercised to avoid spraying areas where desirable species may be affected.
- Mechanized foliar is often limited by terrain, such as steep slopes, large rocks, stumps, and bodies of water.
- In wet terrain, machines cannot operate effectively.
- Mechanized foliar may result in rutting, track marks, or degradation of the ROW surface.
- It should not be used on slopes greater than 30% because most machines are unsafe to operate.

Low Volume Foliar Application – Back-Packs

Low volume applications are generally targeted at incompatible stems that are less than 6 to 8 feet in height and of low to moderate density. A conventional diaphragm or piston pump backpack is the most commonly used piece of equipment for low volume applications, but small volume battery operated tanks on ATVs have also been used effectively.

A spray wand can be used to deliver the herbicide solution. However, many applicators have found that equipment similar to the Dual Spray Gunjet® (DSG) offers more versatility. The DSG can be used with a conventional backpack or with the ATV. The DSG allows the applicator to switch between nozzles for the selection of a wide pattern for short spray distances or a narrow pattern for longer distances. Interchangeable nozzles increase the flexibility of this application technique.

Low volume foliar applications are directed at the top of the crown of target stems, and the upper 60 to 75% of the crown typically receives treatment. Application is made to wet the leaves, but not to the point of runoff. As with other foliar application techniques, low volume applications should be done during the period of active growth, when leaves are fully developed.

<u>Benefits of Backpack Foliar</u>

- Backpack foliar is the most efficient method for managing the re-sprouts of high-density target vegetation.
- It targets specific vegetation, with adjustable application rates and dosages.

<u>Limitations of Backpack Foliar</u>

- Buffer zones may be required to protect pesticide-free zones, depending on wind direction and topography.
- The recommended spray height is 1.5m.
- Caution must be exercised to avoid spraying areas where desirable species may be affected.
- There may be a short-term decrease in vegetation forage species.

3.3.2 Basal Bark Low Volume Application

Basal bark treatment involves applying herbicide onto the bark of the target tree. The herbicide penetrates the bark into the cambium layer and diffuses throughout the tree and the roots, to prevent re-sprouting. It is applied with a low-volume backpack or hand-held sprayers with a positive shut-off system.

Low volume basal herbicide applications offer increased flexibility over foliar applications. Basal applications can be performed during the dormant season, as well as during the period of active growth. Dormant season applications allow crews to be productive during the off-season and can be advantageous in some locations where the brownout associated with foliar applications may be objectionable. This is a very selective application technique.

Basal applications control undesirable vegetation through the application of an herbicide and penetrating oil mixture to the lower 12 to 15 inches of target stems. The mixture typically contains a relatively high proportion of herbicide-to-oil (20% to 30% by volume) that effectively controls trees up to 6 inches in diameter at a low spray volume. The basal oil carrier can be kerosene, diesel oil, or a more refined substance such as mineral oil and other naturally derived oils. Many applicators tend to prefer a refined, low-odor oil carrier, which also has fewer environmental impacts than diesel oil or kerosene. The use of any oils in or near waterways (or waters of the state) must be carefully considered before applying herbicides. Even mineral oil or naturally derived oils can cause an environmental noncompliance (e.g., oil sheen). There are ready-to-use formulations and blending services available that can eliminate the need for choosing oil carriers and mixing solutions prior to application.

Basal herbicides are typically applied with a backpack application unit equipped with oil tolerant seals. The backpack unit utilizes a low volume wand that can deliver a small amount of herbicide mixture to the lower stem of target species. Fixed pattern or adjustable nozzle tips are available to increase unit flexibility. The wand should have tip shut-off capabilities to avoid having the spray solution run out of the wand after spraying the stem. The entire circumference of the lower stem of target species is sprayed to wet, but not to the point of runoff. Basal applications can be made at any time of the year except when snow or water prevents spraying stems to the ground line, although they are most effective when applied in the late dormant season (from late winter to early spring) rather than in the late fall or early winter periods.

<u>Basal Bark</u>

- It is a very labor-intensive method and is not cost-effective for dense stands.
- Cut surface treatment is highly effective on most species that do not sucker from their roots.

<u>Selection Criteria for Basal Bark Treatment</u>

- The method is best used on deciduous trees between 2 feet and 12 feet in height, and less than 6 inches DBH.
- Basal treatment is best used on tree densities of 2,400 to 4,000 stems per acre, where most stems are at least 6 inches DBH.

<u>Benefits of Basal Bark</u>

- It is less labor intensive than manual cutting and girdling.
- It is suitable for remote or difficult-to-access areas.
- It treats only targeted individual stems and so is appropriate for areas with low densities of target trees.
- It removes the canopy over a three-year period, allowing a low-growing plant community to establish.

- It is species-specific so the potential for spray drift is reduced.
- There is minimal risk of herbicide exposure to workers or the public due to the targeted nature of the treatment.

Limitations of Basal Bark

- Dead foliage may be objectionable.
- In areas of low clearance, surviving treated stems may continue to grow.
- Backpack foliar treatment sprays herbicides onto the foliage of individual trees or small clusters of trees, using a manually operated, low-volume, pressurized backpack with a positive shut-off system.

3.3.3 Cut Surface Application

Cut surface or cut stump applications involve hand cutting incompatible target vegetation followed immediately (at least within ½ hour) by a waterborne herbicide application to the exposed cambium layer along the perimeter of the stump surface. The treatment window can be extended by up to 6 months if the herbicide solution includes a penetrating oil. If the latter method is employed, any exposed bark and root flares should be treated to the point of runoff to the root collar zone, in addition to treating the cambium layer. Indicator dyes can be included in the solution to help identify stumps that have already been treated.

Immediate cut surface applications are typically applied with a handheld trigger spray bottle. Due to the small amount of herbicide solution that is applied in very close proximity to the cambium area along the edge of the stump surface, there is minimal opportunity for non-target or off-site contamination. Delayed applications may require a backpack applicator due to the greater volumes of herbicide solution that must be applied to each stump.

This is the preferred application technique in areas containing low to moderate densities of incompatible target stems where hand cutting is the preferred maintenance technique and herbicides can be used. Cut surface applications can be made year-round as long as snow does not prevent the cutting of stems at ground level. However, tardiness in the application or outright misses can drastically influence the effectiveness of the treatment. Treatments done in the early spring when tree sap flow is high can also have reduced effectiveness.

This should be completed by the tree contract crew performing the tree/brush removal, at the time of the removal.

Benefits of Cut Surface

- Cut surface treatment can be used in any terrain.
- No standing dead foliage remains, making this technique desirable in highly visible areas.
- It is highly targeted to allow desirable plant species to inhibit the recurrence of target vegetation by competing for water, light, and nutrients.
- There is minimal risk of herbicide exposure to workers or the public due to the directed nature of the treatment.
- Herbicide is limited to the stump surface, resulting in minimal impact on fish, wildlife, or the environment.
- It removes the canopy but increases low-growing forage for wildlife.

Limitations of Cut Surface

- Improper application can result in unsuccessful treatment and may require re-application of the herbicide.

3.3.4 Cut Stubble Application

When a reclamation phase is necessary and the moderate to high density vegetation is too tall to initially implement a broadcast herbicide application, the site should first be mowed before herbicides are applied. A herbicide can be applied via a broadcast foliar application one or two growing seasons following mowing to vegetation that has re-sprouted. An alternative is to immediately follow mowing with a broadcast application of a soil-active herbicide, which prevents re-sprouting altogether. This technique, known as a cut stubble application, can be employed in more visually sensitive areas since treated vegetation has minimal leaf-out and brownout is substantially reduced. This maintenance technique is subject to the same limitations described for mowing and broadcast foliar herbicide applications. The cut stubble technique is not selective, meaning that many desirable species are usually eliminated with this treatment method. Depending upon the herbicide formulation used, some selectivity for grasses can be achieved.

3.4 CRITERIA FOR APPLICATION

3.4.1 Appropriateness

Refer to Figure 1 when determining the appropriateness and application method for brush maintenance.

3.4.2 Restrictions

Certain precautions must be adhered to for a successful herbicide application, regardless of the type of application or the type of herbicide used.

- Caution must be used around wetlands, streams and water courses to avoid application or overspray into these areas. A buffer must be left, suggested minimum of 50 feet, around these areas.
- Proper precautions must be taken to avoid application in or near organic farms, sensitive areas, apiaries and sensitive field crops.
- Check the Ontario Ministry of the Environment, Conservation and Parks (MECP) site for potential locations where landowners do not want pesticides applied.
- In urban and suburban areas, public parks, state parks, conservation areas, school grounds, athletic fields, day care centers: prior permission and notification in writing required prior to application of pesticides. This is a precaution to be taken by API to prevent unauthorized/ unwanted pesticide application and to avoid potential negative publicity.

The following are to be considered herbicide free zones at all times (herbicide treatments not permitted):

- Where permission has not been secured AND pre-notification not provided to the affected landowner.
- Adjacent to organic farms, apiaries, etc. Certified Organic farmers / beekeepers register their farm-sites in Drift Watch at www.driftwatch.org. Refer to the registration list when planning the spray operation and prior to beginning work on a given circuit. This site is a voluntary communication

tool that enables crop producers, beekeepers, and pesticide applicators to work together to protect specialty crops and apiaries through use of mapping programs. It is not a substitute for any state regulatory requirements.

- Wetlands, streams and water courses, avoid application or overspray into these areas. A buffer must be left, suggested minimum of 50 feet, around these areas.

3.5 SECURING PERMISSION

Rather than developing a separate program to secure permission and provide notification to landowners, API can integrate this process into their existing Work Planning process. Part of the existing work planning process at those locations where trees/brush is to be removed by hand cutting or mowing includes providing property owner notification and securing permission. This process can be expanded to include notification/ permission for the follow-up application of herbicides. This will eliminate a separate step or process. The sequence for the completed work plans is:

1. Pass on to the tree contractor performing the tree/brush removal.
2. Completed work passed back to API for QA / verification that work has successfully been completed.
3. Work areas where tree/brush has been successfully removed and verified via API QA are then consolidated by line by location (via google map or other electronic record keeping system) for positive identification of location for herbicide application.

This information is used for a firm price bid one year following the tree/brush removal. By providing accurate treatment locations with associated square feet (acres) to be treated, the herbicide treatment contractors bidding on the work will be able to provide a more concise price reflecting only the work to be completed with minimal guesswork as to location and volume of work they are bidding on. This has resulted in lower bid pricing as contractors are bidding on a known quantity of work at a specific location (by circuit).

3.6 TIMING OF APPLICATION

Several factors will influence the timing of the treatment for optimal control including:

- Stem height
- Stem diameter at breast height (DBH)
- Density of stems
- Growth rate
- Cost of treatment
- Weather
- Application method -
  - Cut stump – to be completed at the time trees/brush is removed or within one hour of removal.
  - Dormant basal – can be conducted any time of the year, a useful tool to be used when brush is in the dormant state.
  - Foliar – successful application depends on fully develop leaves in the spring and before the leaves begin to go dormant in the fall. Suggested times will vary within the service area (north to south). In general, foliar applications should begin about June 1-15th and be completed by September 15th – 30th.

3.7 RECOMMENDED HERBCIDES BY CONTROL METHOD

3.7.1 Low Volume Foliar

Recommended mixtures for low-volume foliar application are (suggestion examples only):

Option 1 – Fairly selective and broad-spectrum control (including conifer)

- 7% Krenite®
- 4 oz./100 Escort XP®
- 0.5% Polaris®
- 92.5% Thinvert RTU®

Option 2 - If you have a lot of boxelder, locust, poplar

- 6% Krenite S®
- 32 oz./100 Veiwpoint®
- 94% Thinvert RTU®

Option 3 (least selective, but very little if any residual, not good on conifers)

- 7% Rodeo®
- 4 oz./100 Escort XP®

Benefits of the THINVERT Ultra-Low Volume**.**

- Drift Control (Thinvert nozzles provide uniform droplets, reduced fines)
- Rain fastness (less likely to wash off)
- Visibility (applicator can see coverage needed on plant and reduces misses)
- Deposition (more products stays on target plant reducing off target damage)
- Environmental Stewardship (Ultra Low Volume makes application more 'selective' because very little material reaches ground)
- Safety (comes as a ready to use mix so applicator does not handle concentrates)
- Improved Brush Control (oils and emulsifiers in Thinvert help herbicide penetrate leaf getting more active ingredient into plant)
- Increased Productivity (using less material per acre means less fill time for crews means more acres treated)
- Quality Assurance (each mix is custom blended in facility for accuracy of herbicide rates & consistency end use mix)

3.7.2 BASAL BARK DORMANT TREATMENT PRODUCT EXAMPLES

Table 6. Basal bark herbicides.

Active Ingredient	Herbicide Trade Name(s)	Application Equipment	Application Method	Mixture (Rate)[1]	Time of Year
2,4-D	DMA 4 IVM®	Backpack sprayer	Wet base and root collar until spray begins to accumulate at ground line	2.6 oz./gal of water	Year-round, except when snow or water prevent spraying to ground line
Imazapyr	Chopper®, Polaris SP®, Stalker®	Backpack sprayer (low volume)	Spray to wet lower 12–18 inches of stem, including root collar	8–12 oz. in 1 gal diesel oil or penetrating oil	Year-round, except when snow or water prevent spraying to ground line
Triclopyr	Element 4®, Garlon 4 Ultra®, Tahoe 4E®	Backpack sprayer, solid cone or flat fan nozzle	Spray to wet lower 12–15 inches of stem, including root collar area, using low volume and low pressure	20–30% in diesel fuel or ker	Year-round, except when snow or water prevent spraying to ground line
Triclopyr	Forestry Garlon XRT®	Backpack sprayer, solid cone or flat fan nozzle	Thoroughly wet basal parts of brush and trees, including root collar, using low volume and low pressure	13–19% in basal oil, diesel fuel, fuel oil, or kerosene	Year-round, except when snow or water prevent spraying to ground line
Triclopyr	Pathfinder II®, Relegate RTU®	Backpack sprayer, solid cone or flat fan nozzle	Spray to wet lower 12–15 inches of stem, including root collar, using low volume and low pressure	Ready-to-use (petroleum distillate in the product)	Year-round, except when snow or water prevent spraying to ground line

Note [1]: Mixtures based on oils, diesel fuel, fuel oil or kerosene should be made off site to prevent spills.

The Garlon 4 Ultra® (triclopyr 60.45 percent) label indicates two types of basal bark treatments:

1. Basal bark treatment: Mix 1–5 gallons of Garlon 4 Ultra® in enough oil to make 100 gallons of mixture (1–5 percent). Apply with a backpack sprayer using low pressure (20–40 psi). Thoroughly wet the basal parts of brush and tree trunks to a height of 12–15 inches from the ground. Spray until runoff at the ground line is noticeable.
2. Low-volume basal bark treatment: Mix 20–30 gallons of Garlon 4 Ultra® in enough oil to make 100 gallons of mixture (20–30 percent). Apply with a backpack sprayer using low pressure and a solid cone or flat fan nozzle. Thoroughly wet the lower stems, including the root collar area of brush and tree trunks. Do not spray to the point of runoff

3.7.3 CUT SURFACE TREATMENT PRODUCT EXAMPLES

- Tordon® RTU (5.4% Picloram and 20.9% 2,4-d) is the *go-to* cut stump herbicide. It comes in a convenient ready to use (RTU) formulation in a handy one-quart bottle with an applicator tip.

- Pathfinder II® is the same chemical combination as Tordon® RTU, but comes in a 2.5-gallon container. If you don't mind refilling applicators, you can save a few dollars by buying Pathway®. Tordon® RTU and Pathway® should be applied to the outer cambium layer of the freshly cut stump to prevent re-sprouting.

  Tordon® RTU/Pathway® are labeled to control the 21-species listed by the manufacturer. Two problem trees, Osage orange and honey locust, are not listed.

- Remedy® Ultra herbicide (60.45% Triclopyr). Per the label, Remedy®Ultra controls Osage orange and locust.

- 5% Transline with water – mid-summer to late fall.

- 10% Milestone VM with water – mid-summer to late fall

- 20% Garlon 4 Ultra + oil – year-round

- 20% Glyphosate – year-round

3.8 API STAFF AND CONTRACTOR RESPONSIBILITIES

API staff should pre-qualify all potential herbicide applicators for inclusion on final bid list. This will be based on previous jobs and reference check, insurance, size of company, etc. API staff and contract work planners are responsible for properly identifying areas to receive herbicide application following tree/brush removal to provide notification to property owner, and to secure permission for the follow-up herbicide application (normally the following year).

Execution:

- Send a follow-up reminder letter to property owners who gave permission for herbicide work.
- Send a follow-up letter to key external stake holders prior to beginning of spray program (state, province county, municipal, etc.)

The Work:

- Use only pre-approved herbicide applicators as determined by internal sake holder group.
- Utilize comprehensive IVM plan, detailed specifications/ scope of work and herbicide application procedures to manage the IVM Plan.

The herbicide application contractor should have sole responsibility for the application process; reviewing restricted spray / no spray areas; complying with all Ontario's rules/ regulations associated with herbicide application; hiring and training of crew customers and ensuring proper licenses/ credentials of crew customers; having a valid pesticide business license in Ontario and possess a valid pest control charter; strict adherence to the work plan as provided by API; adherence to the API herbicide contract and specifications. The application contractor should be held responsible for quality of work for two growing seasons (customer complaints, claims, go backs, etc.).

3.9 EVALUATION OF HERBICIDE APPLICATION QUALITY ASSURANCE (QA)

Tree and brush removal QA should ensure that all trees/ brush designated for removal have in fact be removed. This work now becomes the scheduled work locations for the herbicide follow up applications. This detailed information, by line circuit, is passed on to be made part of the bid package for the herbicide treatment.

Herbicide QA should be conducted by the utility to ensure that herbicide applicator has achieved the desired results. Establish a corporate goal for a successful treatment (e.g., 95% control of target species on a span-by-span basis). It is suggested the QA of herbicide work be a two-part process: Step 1- conduct a 10% audit of completed work on a circuit basis. If the 10% QA meets the 95% goal, no further QA on that circuit. If the QA goal of 95% control is not met, conduct a 100% QA on that circuit.

After vegetation management work has been completed at a site, information is collected to evaluate the effectiveness of the vegetation management program and measure the results against the site objectives.

The purpose of evaluating vegetation management work is to:

- achieve site objectives.
- evaluate and adjust work plans accordingly.
- determine the success of treatment techniques.
- ensure no negative environmental impacts occurred.
- take corrective action where necessary.

Visual evaluations are conducted on the ground. The exact timing and procedure will depend on the treatment methods used, the geographic area, the type and condition of the site, the vegetation being controlled, and the season. All areas treated with herbicide will be evaluated, but not 100% of each treatment area.

Generally, within two to five days of the application, the site should be inspected for accuracy of application, as follows:

- Cut surface – Look for marker dye on stumps.
- Basal – Look at the stem to ensure a proper wrap was made.
- Foliar – Check for coverage by looking for marker dye on foliage.

About 14 days after foliar applications, the site will be inspected by the utility to ensure that:

- Target vegetation was effectively controlled.
- Non-target vegetation was not affected.
- Herbicide treatment did not take place within pesticide-free zones.

Within a year after application, the site will be evaluated by the utility for target mortality to ensure that program objectives were met. Data collected during evaluations consists of qualitative and quantitative observations of mortality of targeted vegetation. These observations will be documented by photographs, field notes, and representative sample plot measurements.

3.10 ESTABLISHMENT OF WILDLIFE HABITAT PRINCIPLES & SUSTAINABILITY

Control methods to encourage desirable species, such as low-growing shrubs and native, non-invasive plants, provide the opportunity to enhance ROWs to create natural, diverse, and sustaining ecosystems.

ROWs managed with IVM create habitat "corridors" or connections between urban and rural areas to provide a valuable benefit to local pollinator species, including butterflies, bees, and other insects; develop general habitat space for wildlife, such as small, migratory birds; and increase plant diversity.

IVM projects that transect land or are adjacent to other ongoing conservation efforts, such as parks or state land, present excellent opportunities for positive conservation impacts and partnerships with community organizations or other company's initiatives. Areas that are good candidates for conservation efforts can be determined by EM&R and/or through external environmental partners.

4.0 APPLICABLE REGULATIONS

4.1 HERBICIDE APPLICATION

Commercial Pesticide Application Business License

In becoming certified/registered you are eligible to apply pesticides as part of your employment. However, your certification/registration does not allow you to legally operate a business where you apply pesticides for hire.

ROW Herbicide Application Notification:

Notification of broadcast or foliar ROW applications and commercial application is required prior to treatment. Residents of property within target areas can be notified through personal contact, local-regular circulation newspaper, or prior written notification.

4.2 DRIFTWATCH ORGANIC FARM REGISTRY

Certified Organic farmers will need to register their farm-sites in Drift watch at www.driftwatch.org. The Driftwatch system is a tool to help protect pesticide-sensitive crops and habitats. These sites may include tomato and grape fields, certified organic farms, and apiaries.

Questions on how to register an Organic Farm-site in the Drift watch system or for trouble following the instructions on the Driftwatch website, please contact:

FieldWatch, Inc.
Purdue Research Park
1281 Win Hentschel Blvd.
West Lafayette, IN 47906
www.fieldwatch.com
Email: support@fieldwatch.com

4.3 ONTARIO'S COMMERICAL APPLICATOR RECORD KEEPING REQUIREMENTS

Ontario Ministry of the Environment, Conservation and Parks (MECP) states that per *Pesticides Act* and the *Ontario Regulation 63/09* *(O. Reg. 63/09)*, Commercial Applicators as defined by Ontario Regulation 63/09 must record the following:

(1) All commercial applicators and pest control operators shall keep true and accurate records of both restricted and non-restricted pesticide use, retain such record for three (3) years, and make the original records and copies thereof available to NCDA&CS upon request.

(2) The records must show:
   a. Name of licensed pesticide applicator or licensed public operator.
   b. Name and address of the person for whom the pesticide was applied.
   c. Identification of farm or site(s) treated with pesticide(s).
   d. Name of crop, commodity, or object(s) which was treated with pesticide(s).
   e. Approximate number of acres or size or number of other object(s) treated.
   f. The year, month, date and the specific time of day when each pesticide application was completed, and each day of application shall be recorded as a separate record.
   g. The brand name of the pesticide(s) and EPA registration number(s).
   h. Amount (volume or weight) of pesticide formulation(s) or active ingredient(s) applied per unit of measure.
   i. Name(s) of person(s) applying pesticide(s).

4.4 ONTARIO MINISTRY OF THE ENVIRONMENT, CONSERVATION AND PARKS (MECP) LICENSING REQUIREMENTS

Commercial and non-commercial pesticide applicators must be both certified and licensed. Refer to the *Ontario Regulation 63/09* for licensing detail.

5.0 COMMUNICATING THE IVM PLAN TO KEY EXTERNAL STAKEHOLDERS

The successful implementation of an IVM Plan depends on the upfront preparation to external stake holders. This is an on-going process and begins prior to implementation all the way through to completion of an IVM cycle. The three critical times for external communication and the steps to take are:

5.1 PRIOR TO IMPLEMENTATION OF IVM PLAN

The development of a public education program is a critical first step. The concepts and benefits of IVM and protecting natural resources must be communicated to all potential external stake holders (state and local government, civic groups, general public, environmental groups).

API staff should participate in community programs where these concepts are presented. API participation in civic activities related to IVM and natural resource issues (Earth Day, Arbor Day, right-tree-right place plantings and demonstrations, pollinator week programs, etc.) provide an avenue for education.

Development of partnership with various groups and organizations such as Boy/Girl Scouts Canada, youth groups, community groups, garden clubs, government agencies. It is important to raise awareness of what IVM is and the benefits to the natural environment that can be achieved through an IVM Plan.

Develop and distribute proactive public educations material (fact sheets, door hangers, brochures, video, newspaper ads) related to IVM practices available to the general public, natural resource agencies, schools, community colleges and other providers of training and education.

Make comprehensive IVM information available to the public on API web site.

- Develop informational program / policy statement for external stake holders.
- API to hold initial meetings with key stakeholders at state, county, municipal level.
- The secondary rollout would be to various interested groups.
- Third – general program announcement to general public explaining IVM and herbicide program; press releases, news article, adds, etc.

Execution

- Send a follow-up reminder letter to property owners who gave permission for herbicide work.
- Send a follow-up letter to key external stake holders prior to beginning of spray program (state, province, county, municipal, etc.)

5.2 AT TIME OF IMPLEMENTATION

The successful implementation of the IVM Plan depends on the following key elements:

- Campaign of education and dissemination of information on IVM has taken place and made available to a wide audience.

- Through API Work Planning, areas for IVM implementation have been properly identified, property owners notified, and permission secured.

- API vegetation management contractors, staff, management, and those that initially respond to customer calls are trained and knowledgeable on IVM principles and goals.

- Contractors are educated on what IVM is and what the goals of the IVM Plan are and what the desired end results will be. Contractors are trained in herbicide application, tree identification, and have the proper certification / licenses credentials for the work they are performing.

- A process is developed prior to starting IVM as to who on the API vegetation management staff will address inquiries / complaints / claims. A rapid response team should be developed and trained in IVM principals to promptly responded (same day or within 24 hours) to these issues. ***Must deal with these ASAP***, within 1-2 business days. Immediate follow-up is critical for the success of the program and to contain any potential negative PR or moving from a complaint to a claim stage.

- API should develop an internal "Speakers Bureau" of subject matter experts to use to spread the word and small gatherings.

5.3 AFTER IMPLEMENTATION

Review the work from the previous IVM maintenance cycle, record success and failures, begin planning for the next IVM cycle and modify the long-term plan as needed and continue the public outreach on IVM. A formal review should include the following:

- It is critical to deal with complaints and inquiries as soon as practical (the same day or within 24 hours) if possible. A quick response helps prevent an issue from being escalated to a higher level, the media, regulators, etc.

- All complaints / inquiries are to be taken seriously and responded to by knowledgeable API vegetation management staff.

- Conduct a post work QA to determine if all goals have been met.

6.0 COMMUNICATING IVM PLAN WITH KEY INTERNAL STAKEHOLDERS

Success of the IVM Plan is based in part on interdisciplinary collaboration with other departments within API. It requires interaction with groups such as Environmental, Corporate Safety, Customer Service / External Affairs, Call Center, Vegetation Management, Contracts/Purchasing, Engineering, Construction and Maintenance groups and others. To best achieve this, it is valuable to develop an interdisciplinary resource directory as well as a flow chart for interface with other key departments within API.

The first step in initiating an IVM Plan is to develop clear goals for a long-range plan and clearly and simply communicate this plan to internal stake holders. This can be accomplished via a series of "town hall" meetings along with the creation and dissemination of brochures and other literature related to IVM.

API must develop a clear plan to provide intra-organization training / awareness and educational sessions to achieve success. This initial process could take several months. Once the initial roll-out is completed, follow-up communication, possibly on a quarterly basis, should be planned to keep API employees up to date on the status of the IVM Plan.

Keys to internal communication success include:

- API to conduct informational meetings with key internal stake holders as part of initial roll out (Operations, Environmental Group, Legal, Call Center, etc.)
- Distribute a program description/ program benefits information to entire company / all employees.
- API develop internal "Speakers Bureau" of subject matter experts to use to spread the word at small gatherings.

It is very important to have internal buy-in for the IVM Plan.

7.0 LIST OF OTHER UTILITIES WITH CONTRACTS THAT UTILIZE IVM PLANS

Partial List of other utilities that utilize IVM Plans:

- American Electric Power (AEP Nation wide)
- Arizona Public Service (AZ)
- Blue Grass Energy (KY)
- Bonneville Power Authority (Pacific NW)
- Central Illinois Public Service (IL)
- Duke Energy (IN, OH, KY, NC, SC, FL)
- Dominion Power (VA)
- Exelon (IL, PA, MD)
- Farmers RECC (KY)
- First Energy (OH, PA, NJ)
- FLORIDA POWER AND LIGHT (FPL FL and Nation wide)
- Gulf Power (MS)
- Louisville Gas and Electric (KY)
- New York State Electric and Gas (NY)
- New Your Power Authority (NY)
- Northeast Utilities (CN, MA)
- Public Service Electric and Gas (PSE&G-NJ, Long Island NY)
- Pacific Gas and Electric (CA)
- South Carolina Electric and Gas (SC)
- Union Electric Coop (NC)
- Xcel Energy (CO, MN)

8.0 FUTURE RELIABIITY AND COST BENEFIT

There may not be an immediate improvement in system reliability with the implementation of an IVM Plan. However, Vegetation Management (VM) /tree pruning program cost will be reduced and these saving can be applied to other critical areas that are often underfunded. These areas include things such as risk tree mitigation, storm hardening, EAB tree removal, spot maintenance on areas of poor system reliability due to trees, fusing single phase taps, planting the right-tree-in the right place and other areas of Utility Vegetation Management (UVM) that are often neglected but can provide a significant contribution to system reliability over time.

Figure 2, Figure 3, and Figure 4 provide real world examples of the ROW maintenance cost saving that can be expected in the conversion from ROW mowing to an IVM Plan fully utilizing herbicides as a maintenance tool.

Figure 2 data is based on a regional simulation model based upon a long term ECI study of brush management on utility ROW in the Northeast United States. It shows the cost of hand cutting alone vs. cut stump treatment at the end of four years and eight years. At four years, cutting alone resulted in 2,950 stems/ac. vs. 1,200 stem/ac. resulted from cut stump herbicide treatment. With time, the stem density decreased which would result in increased savings. At the end of eight years, density from cutting increased to 4,250 stems/ac. vs. 700 stems/ac. The decrease in workload will result in reduced cost (fewer stems per acre to treat).

Figure 2. Effectiveness of herbicides for control of brush over time.

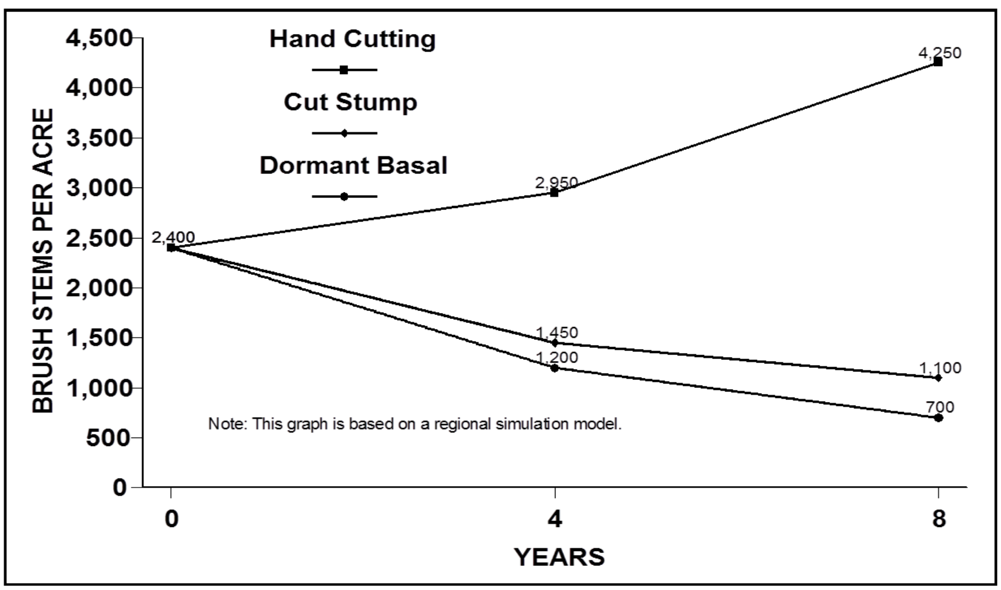


Figure 3 is a Net Present Value Comparison of Mow/ Spray every 10 years vs. Spray every 4 years. Through the 16-year Net Present Value analysis, spraying every four years provides a net savings of $201 per mile of ROW treated.

Figure 3. A rural electric cooperative in the Upper Midwest: Net Present Value Analysis. Current program of Mow/ Spray every 10 years vs. New Program of Spray every 4 years (cost per mile treated).

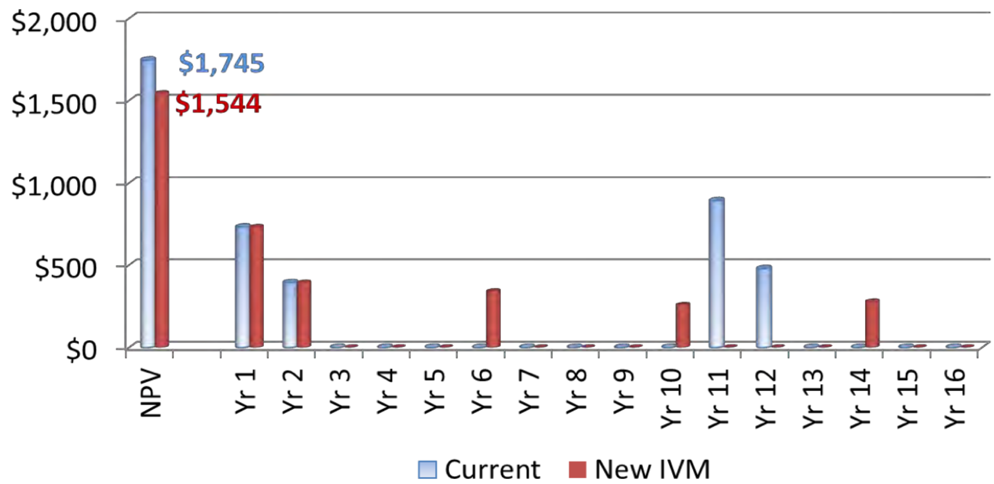


Figure 4 provides a high and low estimate using Net Present Value analysis of mowing alone vs. herbicide treatments at 10 and 20 years in the future. The savings on herbicide treatment vs. mowing at 10 years is 3%, the saving on herbicide treatment vs. mowing at 20 years is 29%. In the long run, herbicide treatment provides significant savings over ROW mowing alone without the use of herbicides to reduce the stems per acre on a ROW.

Figure 4. Present value of mowing vs. IVM for both high and low estimates for herbicide costs.

	PV (10yr) - High	PV (20yr) - High	PV (10yr) - Low	PV (20yr) - Low
Mowing	$6,558	$8,570	$6,558	$8,570
IVM	$6,357	$7,021	$5,645	$6,088

Mowing IVM

- 5.42% Interest: *Utility cost of debt from 2011 business plan.
- 2.13% CPI Source: CBO 10-year inflation forecast.
- data represents utility in Pacific NW of Canada.

8.1 WHAT CAN API EXPECT

Using recent contract cost analysis, low-volume spray contracts can cost from a low of $125 per ROW kilometer treated (a ROW herbicide program that has been in place for several cycles-thus lower stem density) to a high of $350 per ROW kilometer treated (an initial ROW treatment with high brush density and brush that on average exceeds six feet in height). These costs are from an actual contract in a rural area in Kentucky for a 2016 firm price contract.

9.0 METRICS TO MEASURE EFFECTIVNESS OF PROGRAM

IVM is a metrics driven system that is dependent on various VM records to achieve maximum efficiency and savings. The following are the various metrics that need to be captured to best manage an IVM Plan:

- Work Planning: work type, work location (circuit, address, GPS location, quantity of work)
- Assigning work to tree contractor and contractor crews
- Securing permission/notification for tree and brush removal AND secure permission/ provide notification for herbicide application in desired locations at the same time. For the herbicide application, this should include GPS location, name and address of landowner and specific work to be performed.
- VM work assigned to tree crews: need to capture man – hours and equipment hours as well as units of production, trees trimmed / removed.
- Work completed and QA- need to have accurate records of all completed work that has had a QA performed. All exceptions need to be noted and plotted for re-work by vendor. Using "Mowing Work Completed" information (location, GPS coordinates, circuit number) forms the basis for the herbicide treatment program the next growing season. The permission / notifications acquired at the time of original work planning will serve as the permission/ notification to property owners for the subsequent herbicide application. A "Public Notice" still needs to be published in the year treatment will occur, at least 30 days prior to treatments. Follow-up re-notification to property owners affected is strongly suggested as well.
- Herbicide work plan – this is derived from the previous year's mow work plan and would include circuit number, work location, GPS location, name of property owner, date of notification. All herbicide work needs to capture associated acres worked by specific location, herbicides applied and quantities, date the application occurred by specific location.
- QA of completed herbicide work - Using data from herbicide applicator, perform a QA on completed work for compliance with contract. All go-backs need to be recorded by specific location, using GPS location provides the highest level of accuracy to identify these go-back locations.
- Next Maintenance cycle - use data to reevaluate the need / timing for the next herbicide treatment.
- Production and Cost – regardless of contract type, production units and associated cost need to be captured and recorded. It is most valuable to capture this information on a circuit-by-circuit basis to better predict future cycle timing and cost estimates.

A "Must Haves" of an exceptional program oversight - A formal year end program review / Evaluation:

- Did the program meet the corporate goals?
- What were the minor / major problems encountered?
- Were they successfully resolved?
- What was done correctly to resolve these issues?
- If not resolved, what could have been done differently?

Use the results of this comprehensive program review to adjust next year's herbicide program accordingly.

10.0 ROLLOUT PLAN

The following are the sequential steps for implementation of a fully integrated system wide IVM Plan at API:

1. Develop detailed workload analysis.
2. Based on workload analysis, set budget requirements
3. Set IVM Plan goals based on budget and reliability goals.
4. Develop a comprehensive IVM plan around these goals and budget.
5. External stake holder engagement (at least several months before fully implementing IVM)
6. Internal stake holder engagement
7. Develop herbicide contract and specification.
8. Begin developing API data management / mapping system to capture VM requirements by work type, exact work location, volume of work, work requiring QA, results of QA, work requiring herbicide treatment by treatment type, exact location of treatment, QA of completed herbicide work. Use the data management/ mapping system to identify sensitive areas, no spray areas, location of refusals. This data management system will also be used to manage annual and long term IVM plan and capture data related to all phases of the VM program (cost, reliability, work type by location, areas of customer concerns, storage of permission for removal and herbicide treatment, storing herbicide treatment data. An IVM Plan is a very data intensive and requires a rigorous system to collect, store and analyze data associated with the VM process. There are several commercial applications on the market that can accomplish these tasks, such as Clearion.
9. Using workload data from mowing / brush clearing to establish herbicide work scope. Using the herbicide work scope, broken down by work required by circuit and exact location, prepare bid package for foliar herbicide application.
10. Put the work out to bid as a firm price contract based on cost per acre.
11. Contractor performs the herbicide foliar application during the appropriate time window.
12. Perform post-work QA audits.
13. Year-end conduct a review of accomplishments, cost vs. budget and adjust future IVM plan to meet program UVM goals.

10.1 SUGGESTED TIMING AND SCHEDULE

There are numerous critical steps involved in the roll-out of a new program, especially one that could have negative public relations consequences. The timeline that follows provides a very basic timeline. It is suggested that a detailed Gantt chart be developed for all activities associated with the implementation of an IVM plan and the use of herbicides.

Month 1	Formulate detailed IVM plan.
Month 2	Implement internal communication / training.

Month 2-4	Develop all communication materials for internal and external use in communication IVM Plan.
Month 4-6	Put out bid package for annual herbicide work.
Month 6	Award the herbicide contract.
Month 6-9	Plan and budget for the next spray season.
Month 6-12	Conduct herbicide program for the year. Foliar must be done between mid-June and the end of September (Foliar applications).
Month 13-14	Evaluate the work completed the previous year, make any necessary adjustments to the contract, begin Contracting process for current calendar year.

11.0 RISK AND MITIGATION

11.1 KEY RISKS

1. Inadequate internal and external communication roll-out results in push back on the IVM concept, especially the use of herbicides.
2. Extreme push back for external stakeholders, especially regarding herbicide use.
3. Resistance from property owners to the use of herbicides.
4. Regulators / government entities not sold on herbicide portion of IVM.
5. Work planning does not provide adequate property owner notification / permission for herbicide use. The work planning information does not include enough specific, accurate information for herbicide program.
6. Contract price extremely high.
7. Government / landowner complaints on herbicide application.
8. Current programs / software and associated hardware not adequate to manage the data for IVM Plan.

11.2 RISK MITIGATION

1. Take the time to thoroughly develop an in-depth informational program along with necessary handout materials. Consider utilizing a third party to prepare the training and implementation.
2. Have a special team of Subject Matter Experts (SME's) that are experts in IVM and environmental issues to address the sources of pushback or individual property owner concerns. The SME's should be specially educated and well-trained individuals who are available on short notice to quickly respond to question and complaints. It is most desirable for the SME's to address issues the same day as received or within 24 hours of receiving complaints or question.
3. Work with internal team to develop a systematic approach to reach out to regulators prior to program beginning and stay in touch with these agencies, groups to continue to nature their understanding and acceptance of IVM (especially use of herbicides).
4. Revise existing procedures to capture data needed to provide accurate herbicide work locations, including all property owner contact information.
5. Provide accurate information up front on the bid as to exact location and scope of work. Conduct detailed pre-bid meeting to explain API expectations, work locations and scope. The reduction of "unknowns" will provide for tighter bids from contractors.
6. Continue to work with existing programs, hardware and software until exact needs can be determined, THEN move forward with new technology that will fill any gaps in data for the IVM Plan.

Appendix I Algoma Fire Prevention and Preparedness Plan

INDUSTRIAL OPERATIONS FIRE PREVENTION AND PREPAREDNESS PLAN

January 1, 2024 – December 31, 2024

<u>Algoma Power Inc.</u>

This plan has been prepared for submission to the Ministry of Natural Resources and Forestry, Aviation, Forest Fire and Emergency Services in accordance with the requirement under section 21 of the Outdoor Fires Regulation.

Company Representative: Steve Headrick Date: January 1, 2024

Table of Contents

1.0 General

Company: Algoma Power Inc.

Main focus of operations: Power distribution

General location of operations: North of the city limits of Sault Ste Marie to Wawa and Dubreuilville. East of the city limits of Sault Ste Marie to the town of Thessalon.

Operations by risk category:

Risk category	Operations
Very high	Heavy Machines with steel tracks, Mulcher
High	Rock boring during pole line construction
Moderate	>3 Brush Saws, Heavy machines with Rubber Tires
Low	Forestry associated with power line clearing

2.0 Fire Prevention Planning

The following measures will be undertaken to ensure compliance with the *Forest Fires Prevention Act*:

- all camps, mines, mills and dumps will have the area surrounding the camp, mine, mill and dump cleared of flammable debris for a distance of at least 30 metres
- all brush, debris, non-merchantable timber and other flammable material resulting from land clearing will be safely disposed of through piling and burning, chipping or other fire safe methods
- any fires started by the operation will be reported to the MNRF without undue delay
- staff will be instructed on rules around smoking during the fire season and the proper disposal of smoking materials
- all burners, chimneys, engines, incinerators and other spark-emitting outlet will be equipped with an adequate device for arresting sparks

The following measures will be undertaken to ensure compliance with the Outdoor Fires Regulation:

- no fire will be started outdoors unless conditions will allow the fire to burn safely from start to extinguishment
- fires started outdoors will be monitored until extinguished
- brush and debris will be burned in accordance with section 2 of Ontario Regulation 207/96 or any issued fire permit
- fires burned in an incinerator will comply with section 3 of Ontario Regulation 207/96
- grass or leaf litter will be burned in accordance with section 4 of the Ontario Regulation 207/96 or any issued fire permit
- burning will cease when fire permits are suspended or during restricted fire zone periods

- equipment or machinery being operated for industrial purposes within forest areas will be equipped with a serviceable fire extinguisher rated at least 6A80BC
- staff operating chainsaws or brush saws will do so in accordance with section 10 of Ontario Regulation 207/96
- staff operating equipment or machinery in a forest area during the fire season will do so in accordance with section 11 of Ontario Regulation 207/96
- filled back pack pumps will be carried on or be located within 30 metres of every piece of heavy equipment, hot work operation and wherever else required by Table 1 of the IOP
- our operations do not require additional fire suppression equipment

The following are additional measures that will be undertaken to prevent wildland fires:

Daily patrol of the work area prior to leaving the area

3.0 Fire Preparedness

Our operations are to be considered trained and capable.

A minimum of 25% of our field staff are trained and proficient to the pertinent fire suppression level.

Training is delivered by contractors.

Refresher training is done biennially.

In addition to the backpack pumps and equipment caches identified in section 22, we have the following equipment available for fire suppression:

Type of Fire Suppression Equipment
Fire Extinguishers
Water Backpack Extinguishers
Shovels
Rakes
Axes

Wildland fire hazard will be monitored on a daily basis by accessing forecasted weather conditions, fire weather indices and fire intensity codes. Intensity codes representing the operational areas will be determined and modifications/mitigation will be made as required by the Outdoor Fires Regulation.

4.0 Communications

The process for field operations to communicate with MNRF staff will be dependant on location and may include satellite phone, cell phone or via radio through the company office. The process for MNRF to contact field operations will be by whatever means necessary including satellite phone, cell phone, calling the company office and having them relay the message by radio.

The company will ensure that all employees working in field operations will be aware of the standard fire prevention measures as well as the fire hazard and specific fire prevention processes that may entail. The company will do this by providing training and review of specific circumstances on our daily job plans.

5.0 Annual Fire Prevention and Preparedness Plan Update

5.1 Annual Operations

This update applies to the 2024 fire season for Algoma Power Inc. in our service territory north and east of the city of Sault Ste Marie as described in section 1.0.

The following shows the operations being undertaken by area this season:

Operation	Location	Timeframe	Weather Station Code
Pole Line Construction	HWY 101, Anjigami to Jackpine Tower	January - December	DAL
Pole Line Construction	Town of Wawa	January – December	DUB
Pole Line Construction	Jocelyn Dr SJI	January – December	SDL
Pole Line Construction	Lane 8 Off of AHO Rd	January – December	SDL
Pole Line Construction	HWY 17 East of SJI Turnoff	January – December	SDL
Pole Line Construction	A Line South of D Line	January – December	DUB
Pole Line Construction	Old Goulais Bay Rd	January – December	DUB
Pole Line Construction	HWY 17 Batchawana TS to Haviland shores	January – December	DUB
Pole Line Construction	Robertson Lake Rd	January - December	DAL
Pole Line Construction	Echo Lake Rd	January - December	SDL
Pole Line Construction	Deplonty Rd from Bear Rd turn off to Deplonty/Boundary Rd	January - December	SDL
Pole Line Construction	HWY 563, Batchawana	January - December	RAN
Pole Line Construction	HWY 17 at Batchawana TS (4-pole upgrade + UG run for new Egress connection	January - December	RAN
Pole Line Construction	2022 Pole Testing Replacement - 34.5kV - Garden River	January - December	SDL
Pole Line Construction	121.5kV City SSM	January - December	SDL
Vegetation Management	Batchewana – Mamainse Harbour to Haviland Shores Drive	March - December	RAN
Vegetation Management	Goulais Area – East of Hwy 17 North From Pine Shores to Anglican Church Road	April - December	RAN
Vegetation Management	Garden River First Nations	April - December	SDL
Vegetation Management	North of Desbarats, On	March - December	SDL

Vegetation Management	Dubreuilville, ON	March- December	DUB
Vegetation Management	Goudreau, ON	March- November	DUB
Vegetation Management	Hawk Junction, ON	March - December	DUB
Vegetation Management	Lochalsh, ON	March - December	DAL
Vegetation Management	Missanabie, ON	March - December	DAL
Vegetation Management	North of Bruce Mines, ON	March - December	SDL

5.2 Wildland Fire Reporting

Algoma Power Inc. is responsible for the suppression of wildland fires originating from company operations if it is safe for them to do so. All fires will be reported immediately to the local fire service using the appropriate MNRF Wildland Fire Reporting number.

Northwest Region – 310-FIRE (3473) or (807) 937-5261 (Fire Reporting only)

Northeast Region – 310-FIRE (3473) or (705) 564-0289 (Fire Reporting only)

Southern Region – local municipal fire department (911) or MNR at (705) 564-0289

5.3 Company and MNRF Contacts

The following lists the local MNRF/AFFES contacts:

Name	Location	Emergency Number	Phone number
Sault Ste. Marie Fire Dept.	Sault Ste. Marie	911	705-946-1227
Batchawana Bay – Montreal River	Batchawana	911	705-946-1227
Rankin Reserve	Sault Ste. Marie	911	705-946-1227
Bruce Mines	Bruce Mines	911	705-946-1227
Desbarats – Through Johnson Township		911	705-946-1227
Dubreuilville	Dubreuilville	911	705-946-1227
Goulais	Goulais	911	705-946-1227
Heyden (Aweres)	Heyden (Aweres)	911	705-946-1227
Searchmont Fire & Rescue	Searchmont	911	705-946-1227
Wawa	Wawa	911	705-946-1227

MNR Forest Fire Emergency		911 OR 705-310-3473	
OPP Fire		*677 (from Cell Phone)	

* designates the main emergency contact in the AFFES program for this company.

The following lists the company contacts:

Position	Location	Phone number
Distribution Specialist	2 Sackville Rd, Suite A Sault Ste Marie	705-256-3850 x5644 705-542-6875 cell
Supervisor, Line Services	2 Sackville Rd, Suite A Sault Ste Marie	705-941-7185 office 705-852-0005 cell
Forestry Supervisor	2 Sackville Rd, Suite A Sault Ste Marie	705-941-7193 office 705-943-2715 cell

* designates the main emergency contact in the company for AFFES.

The following changes should be considered as amendments to the Fire Prevention and Preparedness Plan:

Insert any pertinent changes to the information contained in the main fire plan.

*

Appendix J Customer Collateral Examples

Example Door Hangers from Nearby Utilities:

1. Door Hanger – Tree Pruning Notification (Distribution Lines)

Tree Trimming Is Needed...

Your Trees Could Cause a Power Outage!

Dear Horry Electric Customer:

Because trees growing into power lines is one of the leading causes of power outages, tree care professionals working for Horry Electric, will be in your neighborhood pruning any trees which may possibly interfere with our distribution lines over the next five years.

Horry Electric provides this regular maintenance service as part of our commitment to supply you and your neighbors with safe and reliable electric service. This service is provided at no extra cost to you.

All trees are pruned according to Horry Electric guidelines, which are based on recommendations by the U.S. Forestry Service and will not harm your trees in any way. The International Society of Arboriculture and the Association of State Foresters endorse this pruning method.

HORRY ELECTRIC COOPERATIVE

A Touchstone Energy® Cooperative
The power of human connections

Possible Pruning Results

We have inspected trees on your property and would like to inform you of our findings. Please contact us within the next five business days. **If we do not hear from you within the next five business days, we will proceed with pruning as scheduled.**

____

____

____

____

____

____

Representative: ________________________

Telephone Number: ______________________

Today's Date: ________________________

The goal of Horry Electric Cooperative's vegetation management program is to ensure that you have safe, reliable electric service. For more information about your co-op's right-of-way clearing policies, please call Buddy Parker, Right-of-Way Supervisor, at 369-6302.

HORRY ELECTRIC COOPERATIVE

A Touchstone Energy® Cooperative
The power of human connections

www.horryelectric.com

KUB

TREE PRUNING NOTICE

As part of our effort to provide customers with safe, reliable electric service, KUB contract crews will be in your area within the next one to two weeks to prune trees and perform other vegetation management work. On the back of this card, you will find examples of work that may be required in the utility maintenance zone on your property to maintain safe and proper clearance around electric lines and poles.

Tree removal may be an alternative to tree pruning in some cases. If you would like to have a KUB forester visit your property to discuss tree removal or pruning plans, please call (865) 558-6658 as soon as possible to schedule an appointment.

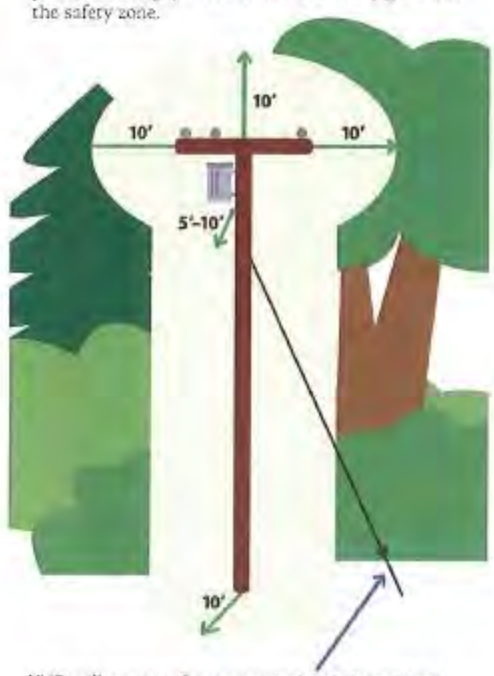
Reliable Power. Healthy Trees.

For your complete customer guide to KUB tree pruning, call (865) 558-6658 or visit www.kub.org.

OVER

Vegetation Management work needs to be done in the utility maintenance zone on your property to maintain safe and reliable electric service. This work may include:

- Pruning tree(s) to maintain a minimum 10-foot safety clearance zone around electric distribution lines in the utility maintenance zone on your property.
- Removing dead, diseased, or weak limbs above the 10-foot safety clearance zone. Small limbs growing in this zone may also be removed as preventive maintenance.
- Removing trees, brush, and vines within the 20-foot utility maintenance zone along electric distribution lines.
- Removal of brush, vines, and small trees less than six inches in diameter which are threatening utility poles, lines or guy wires or will eventually grow into the safety zone.



KUB will prune where vegetation is in contact with or threatening to damage down guy wires.

Distribution Line Clearance Zone

DistributionPruneNotice-Y11M5-Orange

2. Door Hanger – Cleanup Return

KUB DD

WE WILL RETURN

A KUB contract crew was unable to complete cleanup of wood chips, limbs, and other debris resulting from recent tree pruning work in the utility maintenance zone on your property today.

Our goal is to leave a property as clean as we found it, and we always try to complete this work in a timely manner. We apologize for any inconvenience this temporary delay may cause and appreciate your patience.

Weather permitting, we will return to complete this task by ______________________.

KUB
Reliable Power. Healthy Trees.

For your complete customer guide to KUB tree pruning, call (865) 558-6658 or visit www.kub.org.

OVER

WE WILL RETURN

Comments: ______________________

KUB has been recognized by the Arbor Day Foundation for our national leadership in properly caring for trees while meeting customers' needs for reliable utility service.

KUB contract crews are specially qualified to work around power lines and trained to use the lateral pruning method recommended by the Arbor Day Foundation to help protect the trees' health to the extent possible. We regularly evaluate our crews to assess their performance and conduct inspections to identify areas for improvement. Our goal is to ensure that KUB's Vegetation Management program is doing a great job for you.

While crews are working on your property, please feel free to speak with crew members identified by a special "Customer Contact" vest. The customer contact will be happy to answer your questions.

If you wish to discuss any tree-related concerns, please call our Vegetation Management Hotline at (865) 558-6658 Monday through Friday 7 a.m.-9 p.m. or e-mail us at trees@KUB.org. After hours, call (865) 524-2911.

OVER

VMWeWillReturn-YTINS-Blue

3. Door Hanger – Tree Pruning Notice for Work Planners

KUB

TREE PRUNING PLANNING

As part of our effort to provide customers with safe, reliable electric service, KUB contract crews will be in your area soon to prune trees and perform other vegetation management work. In preparation, a KUB representative visited the utility maintenance zone on your property today.

On the back of this card, we have indicated work that needs to be completed to maintain safe and proper clearance around electric lines and poles.

If you have questions, please contact KUB immediately so we can schedule a forester to visit your property and discuss plans with you.

KUB Reliable Power, Healthy Trees.

For your complete customer guide to KUB tree pruning, call (865) 558-6658 or visit www.kub.org.

See back for comments.

KUB contract crews need to complete the following work in the utility maintenance zone on your property to maintain safe and reliable electric service.

- ❑ Prune tree(s) to maintain a minimum safety clearance zone around electric lines.
- ❑ Remove trees, brush, and vines within the 50-foot utility right-of-way along high voltage transmission lines.
- ❑ Remove trees, brush, and vines under distribution lines or around utility poles and guy wires.
- ❑ Remove small tree(s) (less than six inches in diameter) which will eventually grow into the safety zone.
- ❑ Tree(s) may have over 25 percent of the canopy removed to achieve the necessary clearance. KUB would like to discuss options with you.
- ❑ Other (see comments below).
- ❑ KUB would like to discuss removing a tree(s) on your property. Please contact KUB as soon as possible.

Our contract crews use the lateral pruning method recommended by the Arbor Day Foundation to help protect the health of your trees. These crews are specially qualified to work around power lines and trained to prune to industry specifications.

If you wish to have a private service prune your trees, please contact Vegetation Management.

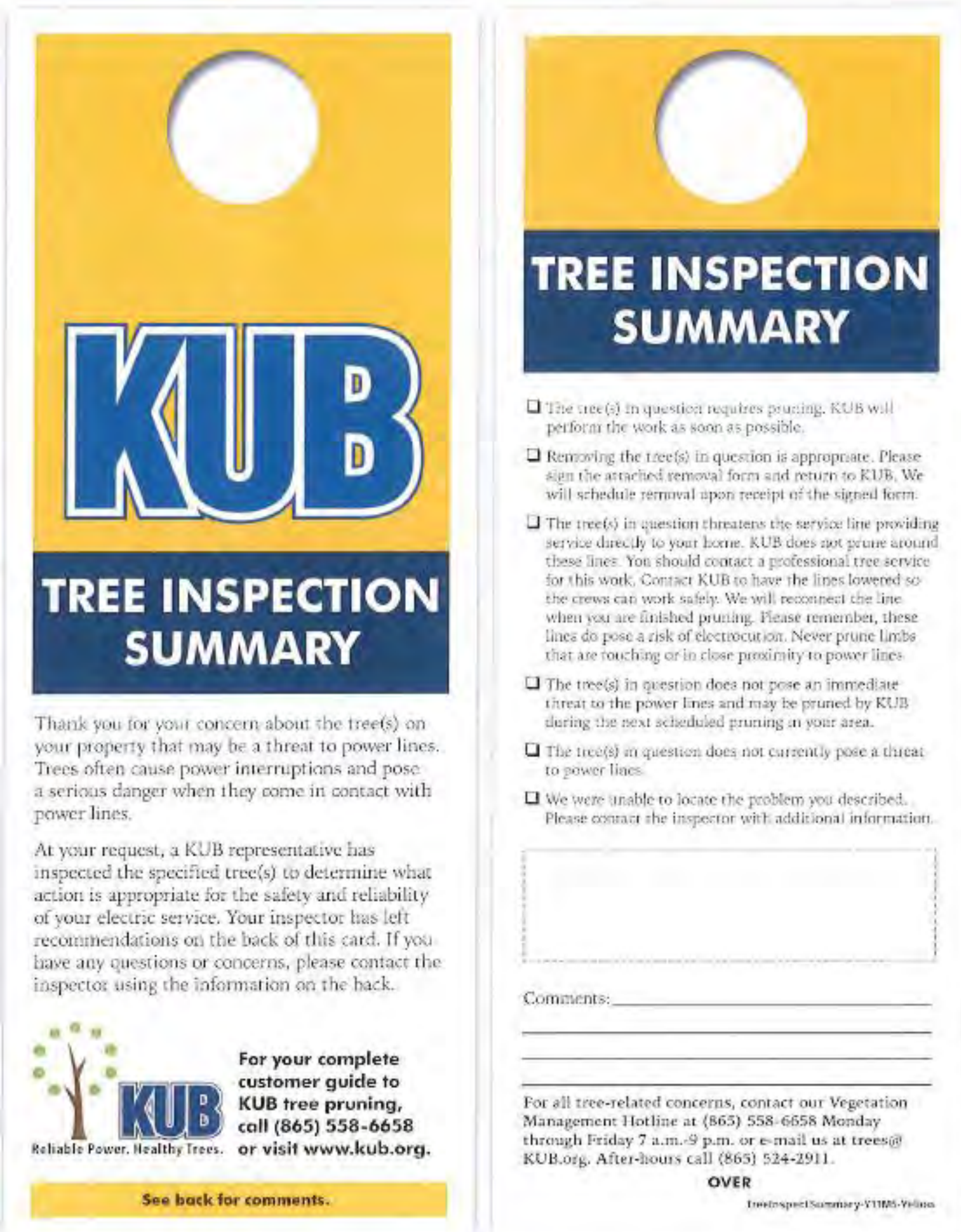
If you have any questions or concerns, please contact the KUB representative listed below as soon as possible. We are available by appointment to discuss any work planned for your property.

Comments: ______________________________

Contact KUB Vegetation Management at (865) 558-6658 Monday through Friday 7 a.m.-9 p.m. or e-mail us at trees@KUB.org. After hours call (865) 524-2911.

OVER VMPre-Plan-Y11M5-Red

4. Door Hanger – Tree Inspection Follow-up for Customer Trimming Requests



KUB

TREE INSPECTION SUMMARY

Thank you for your concern about the tree(s) on your property that may be a threat to power lines. Trees often cause power interruptions and pose a serious danger when they come in contact with power lines.

At your request, a KUB representative has inspected the specified tree(s) to determine what action is appropriate for the safety and reliability of your electric service. Your inspector has left recommendations on the back of this card. If you have any questions or concerns, please contact the inspector using the information on the back.

KUB Reliable Power. Healthy Trees.

For your complete customer guide to KUB tree pruning, call (865) 558-6658 or visit www.kub.org.

See back for comments.

TREE INSPECTION SUMMARY

- ☐ The tree(s) in question requires pruning. KUB will perform the work as soon as possible.
- ☐ Removing the tree(s) in question is appropriate. Please sign the attached removal form and return to KUB. We will schedule removal upon receipt of the signed form.
- ☐ The tree(s) in question threatens the service line providing service directly to your home. KUB does not prune around these lines. You should contact a professional tree service for this work. Contact KUB to have the lines lowered so the crews can work safely. We will reconnect the line when you are finished pruning. Please remember, these lines do pose a risk of electrocution. Never prune limbs that are touching or in close proximity to power lines.
- ☐ The tree(s) in question does not pose an immediate threat to the power lines and may be pruned by KUB during the next scheduled pruning in your area.
- ☐ The tree(s) in question does not currently pose a threat to power lines.
- ☐ We were unable to locate the problem you described. Please contact the inspector with additional information.

Comments: ______________________

For all tree-related concerns, contact our Vegetation Management Hotline at (865) 558-6658 Monday through Friday 7 a.m.-9 p.m. or e-mail us at trees@KUB.org. After-hours call (865) 524-2911.

OVER

5. Door Hanger – Tree Pruning Rework Notice

KUB

TREE PRUNING REWORK NOTICE

Inspection of recent tree pruning and vegetation clearance work in your area has been performed to ensure quality.

Although tree work was recently performed on your property, our inspector has found it will be necessary for our contractor to come back and make corrections. This will include:

- ☐ ...clean up
- ☐ ...pruning for minimum clearance
- ☐ ...removing dead/weak limbs
- ☐ ...correcting pruning cuts
- ☐ ...tree removal
- ☐ ...brush and/or vine cutting
- ☐ ...applying herbicide to stumps to prevent regrowth

There will be a quick turnaround time for this work, so please contact KUB immediately if you have any questions.

Reliable Power. Healthy Trees.

For your complete customer guide to KUB tree pruning, call (865) 558-6658 or visit www.kub.org.

OVER

TREE PRUNING REWORK NOTICE

Comments: ______________________________

KUB has been recognized by the Arbor Day Foundation for our national leadership in properly caring for trees while meeting customers' needs for reliable utility service.

KUB contract crews are specially qualified to work around power lines and trained to use the lateral pruning method recommended by the Arbor Day Foundation to help protect the trees' health to the extent possible. We regularly evaluate our crews to assess their performance and conduct inspections to identify areas for improvement. Our goal is to ensure that KUB's Vegetation Management program is doing a great job for you.

While crews are working on your property, please feel free to speak with crew members identified by a special "Customer Contact" vest. The customer contact will be happy to answer your questions.

If you wish to discuss any tree-related concerns, please call our Vegetation Management Hotline at (865) 558-6658 Monday through Friday 7 a.m.-9 p.m. or e-mail us at trees@KUB.org. After hours, call (865) 524-2911.

OVER

VMRework-Y11M10-Gray

6. Door Hanger – Herbicide Application Notice

KUB

HERBICIDE APPLICATION NOTICE

Dear Customer:

The electric utility maintenance zone adjacent to your property is scheduled for selective treatment with herbicides in the next one to two weeks.

The herbicides used by KUB are approved by the Environmental Protection Agency to control tall-growing species and encourage the growth of low-growing plants.

This work is recommended as a best management practice because it supports the delivery of safe and reliable utility service and has several environmental benefits. The benefits include reducing non-native and invasive plants and improving wildlife habitat.

KUB Reliable Power. Healthy Trees.

For your complete customer guide to KUB tree pruning, call (865) 558-6658 or visit www.kub.org.

OVER

HERBICIDE APPLICATION NOTICE

The work will be performed by a professional licensed by the State of Tennessee and directly supervised by a KUB arborist trained on use of herbicides.

The licensed professional will use hand-pump, backpack sprayers to selectively target tall-growing species, vines, and briers. Yard plants and maintained areas will not be included in the work area.

We appreciate your patience and understanding as crews perform this work. If you have questions about our utility maintenance zone activities, please call KUB Vegetation Management at (865) 558-6658 Monday through Friday, 7 a.m.—9 p.m., or e-mail us at trees@kub.org. Customers with utility emergencies or other needs after hours should call (865) 524-2911.

Comments: ______________________________

OVER

ELECHERBICIDEAPP-Y12M8-Lt.Brown

7. Door Hanger – Brush Control Notification

KUB

BRUSH AND VINE CONTROL NOTICE

Dear Customer:

To provide safe and reliable utility service, KUB must control the growth of brush and vines around poles and overhead electric lines with selective herbicide treatments. This work will be performed by a professional licensed by the State of Tennessee.

The herbicides used by KUB are approved by the Environmental Protection Agency and do not pose a health risk to humans, pets, wildlife, or the environment when applied in accordance with manufacturer's directions as required by KUB.

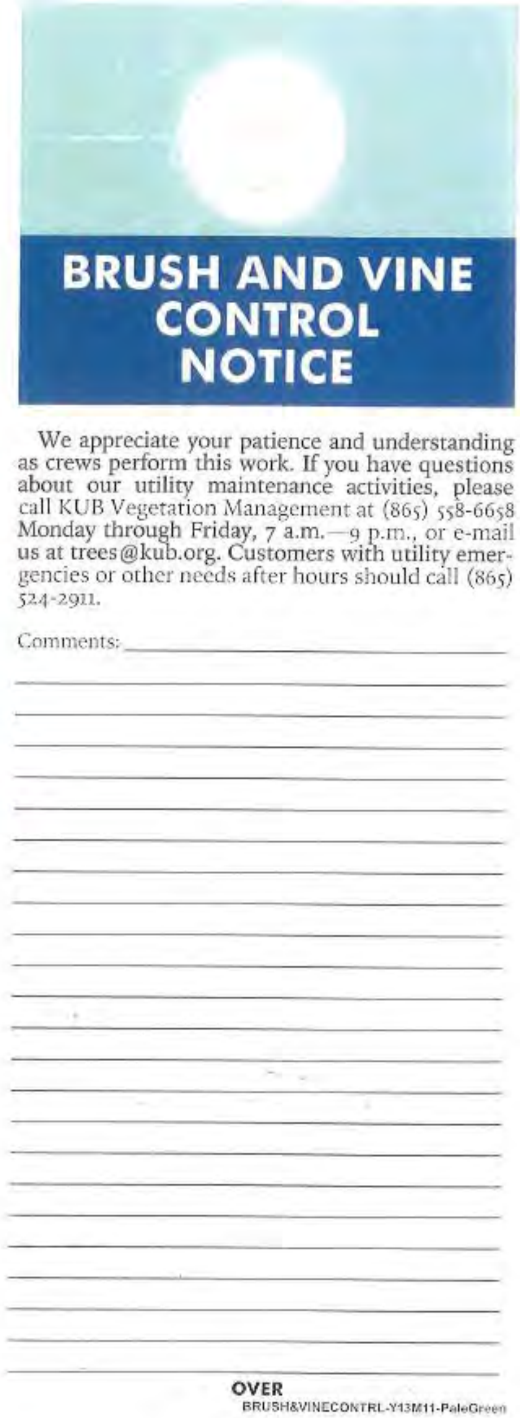
KUB recently identified a pole or equipment on your property that will require routine work to control brush and/or vines.

This work is performed seasonally, between May and October.

KUB Reliable Power. Healthy Trees.

For your complete customer guide to KUB tree pruning, call (865) 558-6658 or visit www.kub.org.

OVER



BRUSH AND VINE CONTROL NOTICE

We appreciate your patience and understanding as crews perform this work. If you have questions about our utility maintenance activities, please call KUB Vegetation Management at (865) 558-6658 Monday through Friday, 7 a.m.—9 p.m., or e-mail us at trees@kub.org. Customers with utility emergencies or other needs after hours should call (865) 524-2911.

Comments: ______________________

OVER

BRUSH&VINECONTRL-Y13M11-PaleGreen

8. Door Hanger – Another example of Scheduled Work Notification

Important Tree Work Scheduled

Our tree program is key to preventing power outages and providing you with the most reliable service possible. NES crews are working in your neighborhood to clear trees, limbs or other plant growth near electric lines and equipment.

- ☐ Trees marked with a spot of yellow / green / orange at the base are to be trimmed.
- ☐ Trees marked with a red "X" will be removed and treated to prevent sprouting. A temporary blue dye is used to show where the treatment is applied.
- ☐ For trees marked with a yellow ribbon, please call NES at 615-695-7400.
- ☐ Vegetation marked with red paint will be removed and treated to prevent regrowth. A temporary blue dye is used to show where the treatment is applied.
- ☐ Other ____

____

NES Contact: ____

____

NES

For more information about the tree work that is scheduled, call our dedicated phone number at 615-695-7400 or visit nespower.com and click on "Tree Trimming."

tree/planning/1-17

Importante Trabajo Programado sobre los Árboles

Nuestro programa de árboles es clave en prevenir apagones y proveer el servicio eléctrico mas confiable posible. Representantes de NES están trabajando en su vecindario para recortar árboles, ramas o plantas que hayan crecido cerca de cables y equipos eléctricos.

- ☐ Los árboles marcados con un punto amarillo / verde / naranja en la base serán podados.
- ☐ Los árboles marcados con una "X" roja serán eliminados y tratados para prevenir el rebrote. Un tinte azul temporal se utilizará para mostrar dónde se aplicó el tratamiento.
- ☐ En el caso de árboles marcados con una cinta amarilla, llame a NES al 615-695-7400.
- ☐ Vegetación marcada con pintura roja se eliminará y se tratará para prevenir al rebrote. Un tinte azul temporal se utilizará para mostrar dónde se aplicó el tratamiento.
- ☐ Otros ____

____

Contacto de NES: ____

____

Para obtener más información acerca de los trabajos programados sobre los árboles, llame a nuestra línea telefónica específica 615-695-7400 o visite nespower.com y haz clic en "Poda de Árboles."

9. Door Hanger – Tree Removal Permissioning

NES

Tree Removal Acknowledgement

Please sign this card and leave it on your door so that we know you received this information.

Print Name ______________________________

Owner's Signature ______________________________

Date: ________ /________ /________

Official Use:

NES Representative ______________________________

Company/Crew Number ______________________________

Removal Address ______________________________

Primary Phone ______________________________

Secondary Phone ______________________________

Number of trees to be removed ______________________________

Substation/Circuit ______________________________

Description/Location ______________________________

____

Date Removed : ________ /________ /________

If you have questions or concerns, call our dedicated phone number at 615-695-7400 or visit **nespower.com/treetrimming.html**.

NES

Confirmación de Remoción de Árboles

Por favor, firme esta tarjeta y déjela colgada en su puerta para que sepamos que usted recibió esta información.

Imprimir Nombre: ______________________________

Firma del propietario: ______________________________

Fecha: ________ /________ /________

Uso oficial

Representante de NES: ______________________________

Empresa/ Número tripulación: ______________________________

Dirección de la eliminación: ______________________________

Teléfono principal: ______________________________

Teléfono secundario: ______________________________

Cantidad de árboles a ser removidos: ______________________________

Subestación/Circuito: ______________________________

Descripción/ Ubicación: ______________________________

____

Fecha Retira: ________ /________ /________

Si tiene alguna pregunta o inquietud, llame a nuestra línea telefónica específica, 615-695-7400, o visite **nespower.com/treetrimming.html**.

10. Letter – Final Notice of Tree Work

<DATE>

FINAL NOTICE ABOUT TREE TRIMMING WORK

Dear Property Owner:

NES' tree trimming program is an integral part of providing reliable power to all of our customers. Crews work to control tree growth in order to prevent outages and to ensure the safety of our customers and employees working in the field. Since our accelerated program began in 2002, the number of tree-related outages has dropped by 20 percent.

Vegetation that has grown around and/or into power lines is one of the most common causes of power outages in our area. It is NES' responsibility to manage all vegetation that could interfere with our electrical equipment or distribution lines.

NES contractors are working in your area and need to complete necessary work on your property.

NES contract crews will return to perform the necessary work on <DATE>,

If you need additional assistance, please call our Vegetation Management Hotline number, 615-695-7400, or contact the NES representative listed below.

______________________	______________________	______________________
NES Representative	Phone Number	Email

☐ **Tree Trimming** ☐ **Tree Removal** ☐ **Brush Removal**

11. Right-Tree, Right-Place Educational Flyer

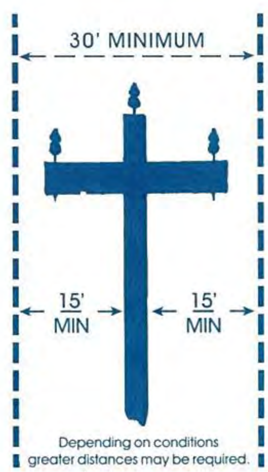
Right-of-Way...

...done the right way.

Ensuring that our member-owners have reliable and efficient electric service is our driving force at Horry Electric Cooperative. One way we do this is by maintaining a clear path, or right-of-way easement, around power lines.

By strategically removing only the branches and undergrowth that directly impact the lines, we strive to have as little effect on our landscape as possible. Once trimmed, we spray trees or undergrowth with an enviromentally conscious herbicide that is not harmful to humans or animals.

On the environmental front, Horry Electric is active in maintaining power line right-of-ways which still provide a natural habitat for wildlife.



So when you plant a tree, think about its future growth and whether it will impact power lines. **Trees with mature heights over 25 feet should be planted at least 30 feet from overhead lines.**

And, when you see maintenance crews trimming or removing trees and shrubs near right-of-ways, remember that they are doing their part to keep your electric service reliable and cost-effective.

Let's work together to prevent costly service interruptions caused by trees damaging power lines!

HORRY ELECTRIC COOPERATIVE

A Touchstone Energy® Cooperative
The power of human connections

PO Box 119 • Conway, SC 29528-0119
(843) 369-2211 • Power out (843) 369-2212
www.horryelectric.com

The Touchstone Energy symbol is your assurance that we're a community-minded electric cooperativce providing high standards of service for customers large and small.

Be Careful Where You Plant

Planting new trees and shrubs? Be knowledgeable of their growth patterns, so that you don't plant them where they will dangerously close to power lines when they mature.

Transplant Trees That Are Underneath Power Lines

If you have young trees that are planted beneath power lines, consider transplanting them rather than leaving them to be cut down or trimmed when they mature and become too close to power lines. For safety, contact Horry Electric Cooperative before moving trees that are more than 6 feet high and under our power lines.

Guide To Planting & Pruning

Don't Plant Near Transformer Pad Mounts

For members in subdivisions with underground power lines, some lots have a transformer pad mount, switch cabinet, pedestals or other devices that cannot operate or be maintained properly if they are obstructed by shrubs and other landscaping. Keep plantings 10 feet away from all above-ground equipment.

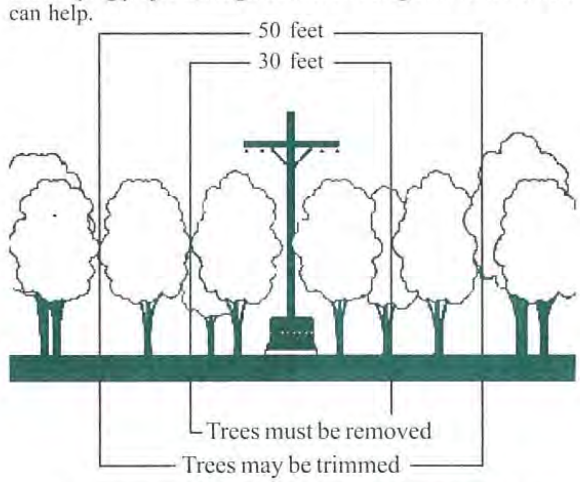
Don't Plant Directly Over Underground Lines

Planting directly over underground utility lines of any kind can disrupt services as the vegetation's root system develops. Also, the lines may need service one day, which will require digging that could damage root systems.

Horry Electric Cooperative, Inc.
2774 Cultra Road - Conway, SC
369-2211
A Touchstone Energy® Cooperative

Plan Before You Plant...

We all enjoy the beauty and environmental benefits of trees and shrubs. Help us protect them and you by being mindful of where you plant. As you begin your winter and spring landscaping projects, the guidelines and diagrams featured here can help.



Horry Electric Maintains 5,000 Miles of Line

Horry Electric Cooperative maintains your co-op's power line rights-of-way across more than 5,000 miles. We work on a five-year cycle, which means crews cover the entire system in a five-year period, then start again. It keeps you safe and helps keep the power on.

Remove Dead Pine Trees

Pine beetles kill many pine trees. To protect our utility line righs-of-way, Horry Electric removes dead pines that are in danger of falling on our lines. You can report any dead pines you see by calling Buddy Parker, Right-of-Way Supervisor, at 369-6302.

Horry Electric Trims/Removes Trees Within Right of Way

Protect your investment. Horry Electric Cooperative maintains a 30-foot right of way along power lines to prevent vegetation from either growing into or falling on lines and causing outages or electric shock to humans or animals. This is why you see existing vegetation trimmed by our contract crews, which can be easily recognized by the HEC Contractor magnetic sign on the side of their vehicles. We trim trees in accordance with U.S. Forestry Service guidelines. Our pruning methods are endorsed by the International Society of Arboriculture and the Association of State Foresters.


Plant the RIGHT TREE in the RIGHT PLACE.
Use this guide to help you select the right tree for the right place on your property. By planning for the tree's growth, you're helping to prevent outages caused by limbs growing into power lines, and you're reducing the need for tree trimming in the future.
LARGE TREES 45 feet
MEDIUM TREES 35 feet
SMALL TREES 15 feet
SHRUBS 10 feet
DISTANCE FROM POWER LINES
LARGE TREES
Mature Height over 50'
Bald Cypress & Dawn Redwood
Green Giant Arborvitae
Red Oaks (Shumard, Southern)
Southern Magnolia
Sugar Maple
White Oaks (Bur, Chinkapin)
MEDIUM TREES
Mature Height up to 50'
American Yellowwood
Black Gum (Black Tupelo)
Elm (Lacebark, Princeton)
Hollies (American, Foster #2)
Magnolias (Saucer, Star, Sweetbay)
October Glory Maple
SMALL TREES
Mature Height up to 30'
Crepe Myrtle
Flowering Cherries
Flowering Dogwoods
Nellie R. Stevens Holly
Redbuds
Trident Maple, Paperbark Maple
SHRUBS
Mature Height up to 20'
American Beautyberry
Emerald Green Arborvitae
Flowering Forsythia
Glossy Abelia
Schip Laurels
Viburnums (Doublefile, Leatherleaf)
remember: Call 811 before planting to learn where underground lines, pipes and cables are buried in your yard.
For more information, visit nespower.com or call our tree hotline at (615) 695-7400.
NES

END

Algoma Power Inc.

Distribution System Plan

Appendix I

East Lake Superior

REGIONAL INFRASTRUCTURE PLAN

October 1st, 2021

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Prepared and supported by:

Company
Hydro One Sault Ste. Marie LP. (Lead Transmitter)
Hydro One Networks Inc. (Transmission)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Distribution)
Algoma Power Inc.
Chapleau Public Utilities Corporation
PUC Distribution Inc.

DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Study Team.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Study Team.

Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE SAULT STE. MARIE LP WITH SUPPORT FROM THE RIP STUDY TEAM IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE EAST LAKE SUPERIOR REGION.

The participants of the Regional Infrastructure Plan ("RIP") Study Team included members from the following organizations:

- Algoma Power Inc. ("API")
- Chapleau Public Utilities Corporation ("Chapleau PUC")
- Hydro One Networks Inc. (Transmission)
- Hydro One Sault Ste. Marie LP. ("HOSSM")
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- PUC Distribution Inc. ("PUC")

This RIP is the final phase of the second cycle of East Lake Superior (ELS) regional planning process, which follows the completion of the East Lake Superior Integrated Regional Resource Plan ("IRRP") in April 2021 and the East Lake Superior Region Needs Assessment ("NA") in June 2019. This RIP provides a consolidated summary of the needs and recommended plans for East Lake Superior Region over the planning horizon (1 – 20 years) based on available information.

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment and IRRP reports for this cycle, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, the following projects are underway or completed

- **End of life Wood Pole Replacements**: Multiple wood pole replacement projects were completed on a number of 115kV and 230kV circuits. These circuits consisted of wood pole structures that were assessed at being at their end of life and in need of replacements. The following circuits have their end of life wood pole structures replacement completed between 2014 to 2019:
    - No.2 and No.3 Algoma (completed in 2014)
    - Northern Ave 115kV circuit (completed in 2014)
    - No.1 Garshore (completed in 2015)
    - Hogg (completed in 2015)
    - P21G (completed in 2019)

- **Hwy 101 TS**: Installed a new control building completed with new protection relays, batteries, chargers, automatic transfer schemes and RTU to replace end of life components such as electro-mechanical relays and batteries. This project was completed and in-serviced in 2015.

- **Anjigami TS**: Performed electrical and civil upgrade, including the installation of a new 44kV breaker, redundant battery and chargers, and replacement of protection equipment and other end of life AC/DC system. It also includes ground grid improvements. This project was completed in 2017.

- **Echo River TS**: Improve transmission reliability with the installation of an additional 230/34.5kV 25MVA Transformer (T2) as an on-site spare. This project is underway with a targeted in-service date of 2023 Q2.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in the Table 1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 1. Recommended Plans in East Lake Superior Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate(1)
1	Eliminate/Minimize manual communication between IESO and OGCC when arming Third Line Instantaneous Load Rejection Scheme	Enable remote arming of Third Line Instantaneous Load Rejection Scheme via ICCP line between IESO's EMS and HONI's NMS	2021	$10K
2	Third line TS: End of life protection	Replace end of life protection per current standard	2022	$0.8M
3	Echo River TS : Transmission Supply Reliability and end of life breaker	Install 'hot' spare transformer and replace end of life breaker	2023/2024	$11.5M
4	115kV Sault No.3: end of life structures and conductor	Replace end of life structure and conductor per current standard[1]	2024	$54.4M
5	Batchawana TS: End of life components	Refurbish Batchawana TS with MUS provision	2024	$6.2M
6	Goulais TS: End of life components	Refurbish Goulais TS with MUS provision	2024	$13.4M
7	Patrick St. TS, Algoma No.1 overload	Implement Automatic Load Rejection Scheme at Patrick St. TS	2023	$1.2M

[1] To coordinated with IESO's 2021 Bulk Planning Study regarding Sault No.3 Circuit Overloading

8	Patrick St. TS: End of life 115kV breaker	Replace end of life 115kV breakers 'like for like' per current standard	2024	$3.3M
9	Third Line TS : T2 end of life	Replace end of life T2 'like for like' per current standard	2025	$16.4M
10	Northern Ave TS: end of life component replacement	Replace end of life T1 with smaller MVA unit and protection relays per current standard	2025	$2.5M
11	Anjigami/Hollingsworth TS : Transformer overload	Build new 115/44kV Station - HOSSM to work with API to continue to develop solutions	2024/2025	$30M
12	Clergue TS: End of life metal clad switch gear	Replace end of life switch gear 'like for like' per current standard	2026	$5.2M
13	Hollingsworth TS: End of life Protection relay	Replace end of life protection per current standard	2025	$1.1M
14	D.A. Watson TS: End of life metal clad switch gear	Replace end of life switch gear 'like for like' per current standard	2026	$9.2M

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 1 while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

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1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE EAST LAKE SUPERIOR REGION BETWEEN 2019 AND 2039.

The report was prepared by Hydro One Sault Ste. Marie LP (HOSSM) on behalf of the Study Team that consists of Hydro One Networks Inc. (Transmission), Hydro One (Distribution), Algoma Power Inc. (API), PUC Distribution Inc., Chapleau Public Utilities Corporation and the Independent Electricity System Operator (“IESO”), in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The East Lake Superior Region is the region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary’s River and St. Joseph Channel to the south as shown in Figure 1.1 below. The region is supplied from a combination of local generation and connection to the Ontario electricity grid via 230 kV transmission lines to Mississagi Transformer Station in the East, 230kV and 115 kV transmission lines to Wawa Transformer Station in the North.

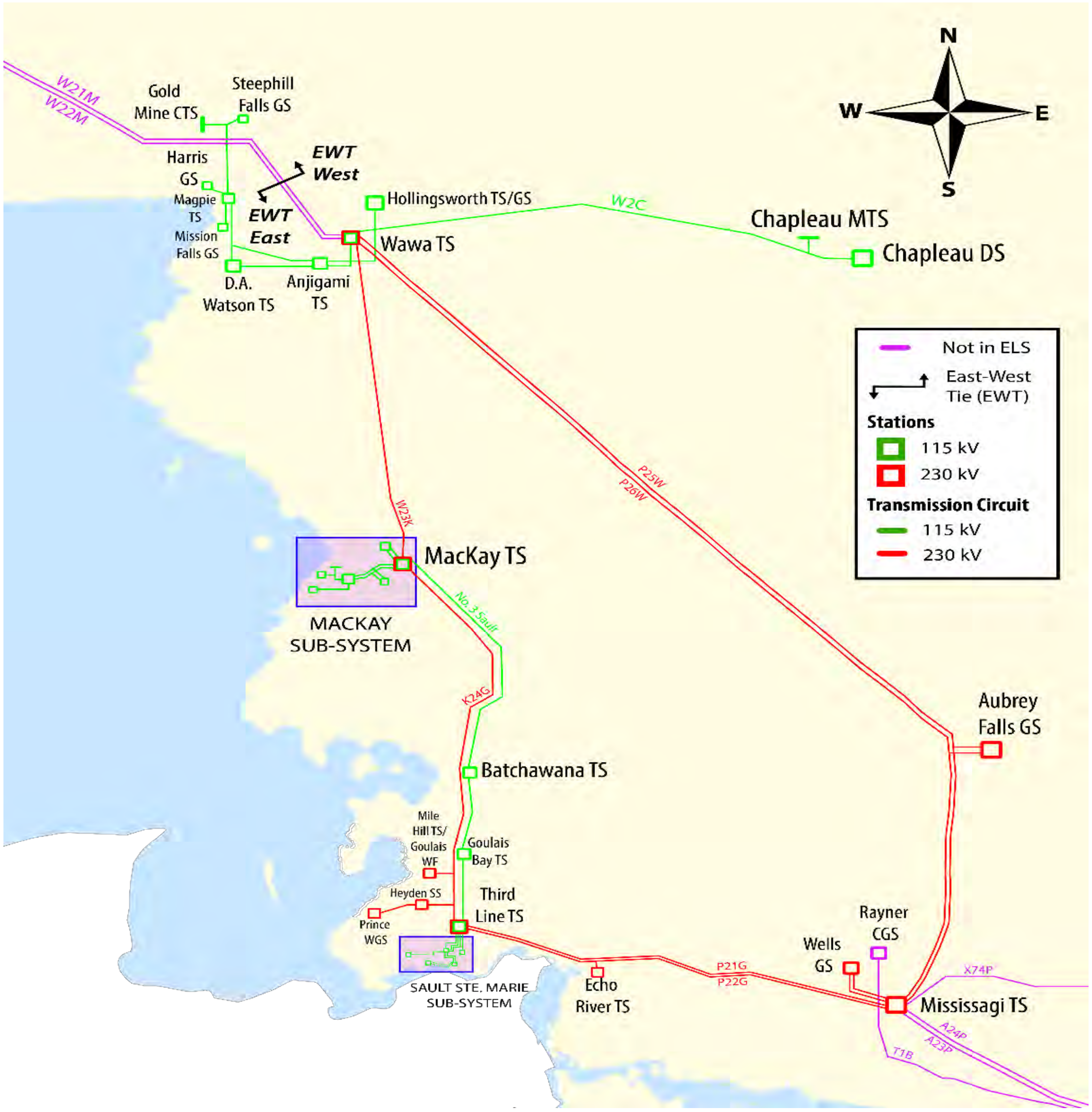

Figure 1-1: East Lake Superior Region Map

1.1 Objectives and Scope

The RIP report examines the needs in the East Lake Superior Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), and/or Integrated Regional Resource Plan ("IRRP");
- Assess and develop a wires plan to address these needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the near, mid- and long-term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the relevant wires plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, and/or Integrated Regional Resource Plan);
- Discussion of any other major transmission infrastructure investment plans over the planning horizon;
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Study Team.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the adequacy of the transmission facilities in the region over the study period.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2 REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[2] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company(s) ("LDC") or customer(s) and develops a Local Plan ("LP") to address them.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation and energy efficiency) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

[2] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region;
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

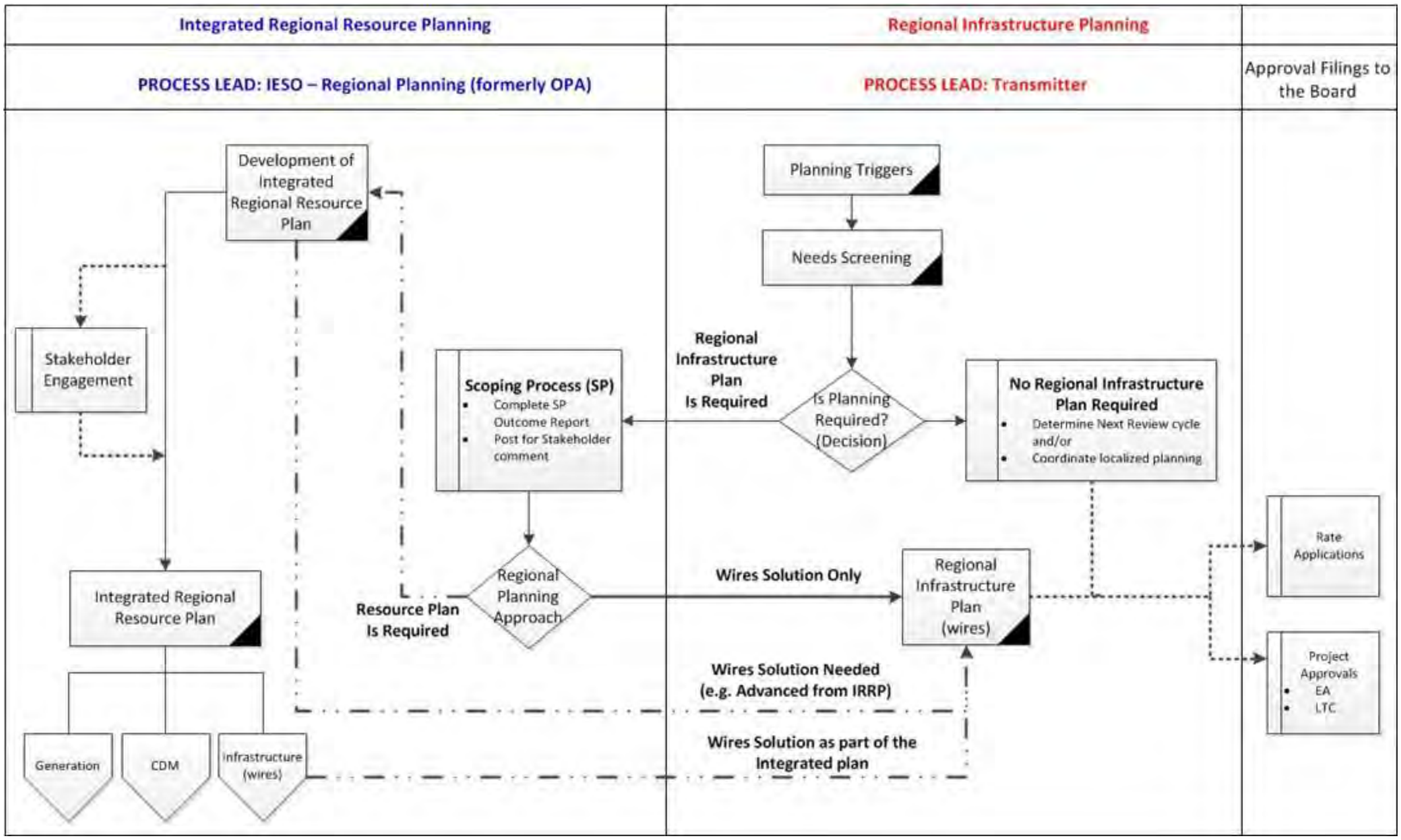

Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required

or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.

3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

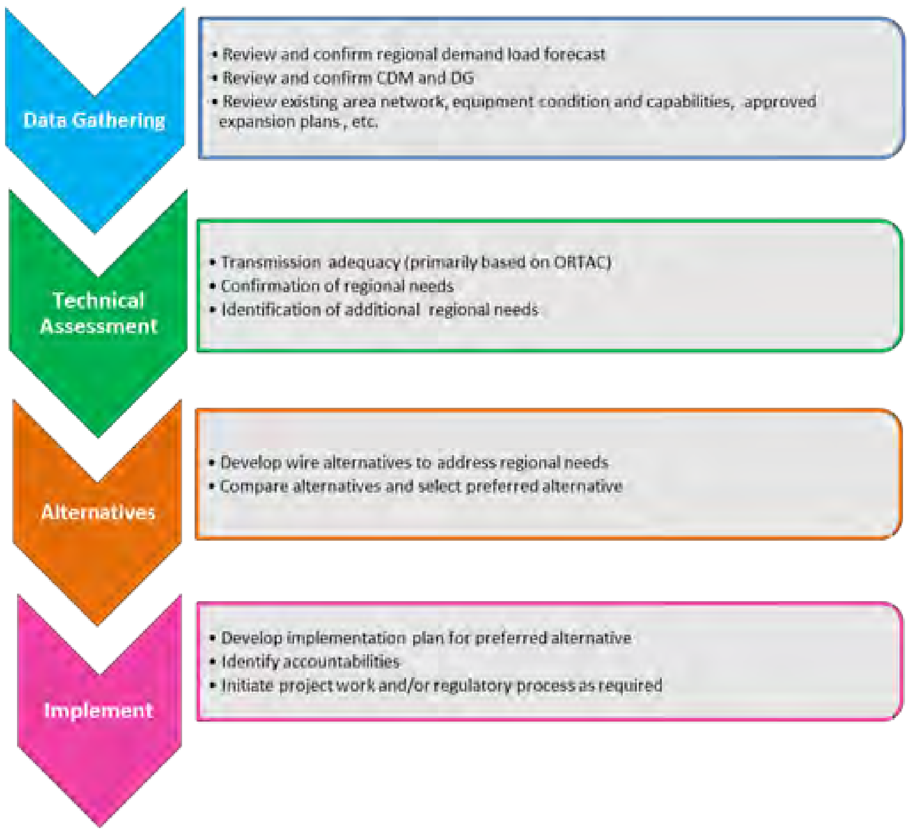

Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE EAST LAKE SUPERIOR REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY TOWN OF DUBERUILVILLE AND HIGHWAY 101 TO THE NORTH AND THE TOWNSHIP OF CHAPLEAU, BRUCE MINES TO THE SOUTH AND INCLUDES THE CITY OF SAULT STE. MARIE, HIGHWAY 129 TO THE EAST, AND LAKE SUPERIOR TO THE WEST. IT CONSISTS OF THE CITY OF SAULT STE. MARIE.

The region is supplied from a combination of local generation and connections to the Ontario electricity grid via 230 kV transmission lines to Mississagi Transformer Station in the East, 230kV and 115 kV transmission lines to Wawa Transformer Station in the North. Majority of the region's electrical need is supplied through a 230/115 kV transformer station at Third Line TS. Local generation in the area consists of mainly hydroelectric and wind generation with a total installed capacity of 1039 MW in the 115 kV and 230kV networks. The East Lake Superior Region is a winter peaking region, with 2020 winter peak demand at 361MW.

PUC Distribution Inc. ("PUC") is the Local Distribution Company ("LDC") which serves the electricity demand in the City of Sault Ste. Marie. The LDC that supplies primarily rural customers – industrial, commercial, and residential customers in the aregion are API, Chapleau PUC and Hydro One Networks Inc. Distribution

Below is a description of major Transmission asset in the region:

- Third line TS is the major transmission station that connects the 115kV system within the City of Sault Ste. Marie via two 230/115kV autotransformer to the 230kV bulk electricity network.
- Mackay TS is a 230/115kV station with one 230/115kV autotransformer that connects the local 115kV network in the vicinity of Montreal River to the 230kV bulk electricity network.
- Wawa TS is a 230/115kV station with two 230/115kV autotransformer that connects the local 115kV network in the vicinity of Michipicoten River.
- 12 other Transmission stations supply the area, with 10 of them operating at 115kV, 1 operating at 230kV , 1 operating at 44kV [3]
- A total of 319 km of 230kV circuits, 232 km of 115kV circuits and 10 km of 44kV circuits interconnect transmission stations, generation customer(s), distribution customer(s) and Transmission connected load customer(s) within the region.

Table in Appendix A and B summarize Transmission station and circuits at different operating voltages and in the area. A geographical map showing the electrical facilities of the East Lake Superior Region is provided in Figure 3-1. A single line diagram showing the electrical facilities of the East Lake Superior Region is provided in Figure 3-2.

[3] The 44kV station and line is included in HOSSM's transmitter license and are deemed transmission asset by the OEB.

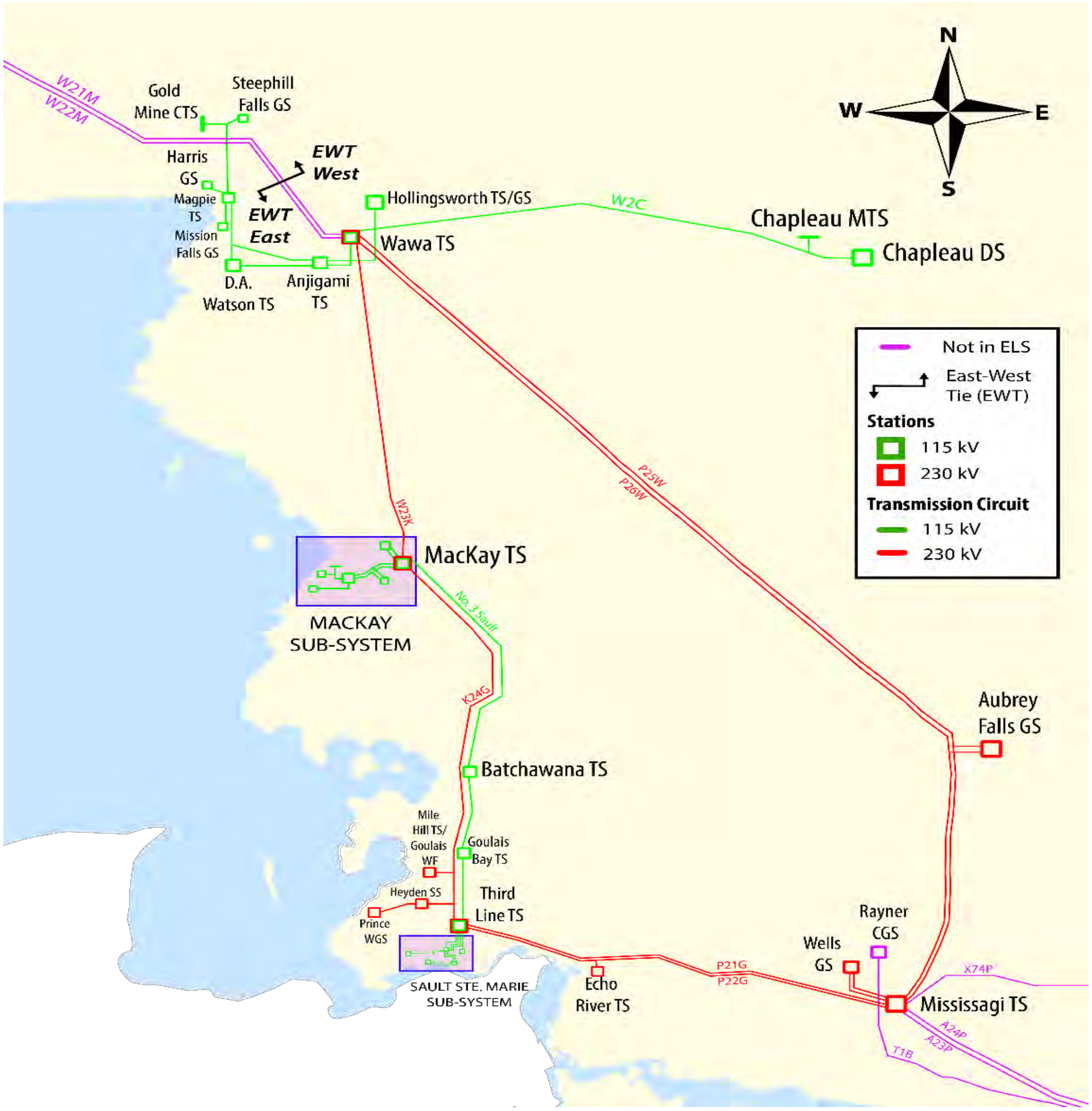

Figure 3-1: East Lake Superior Region's Transmission Network

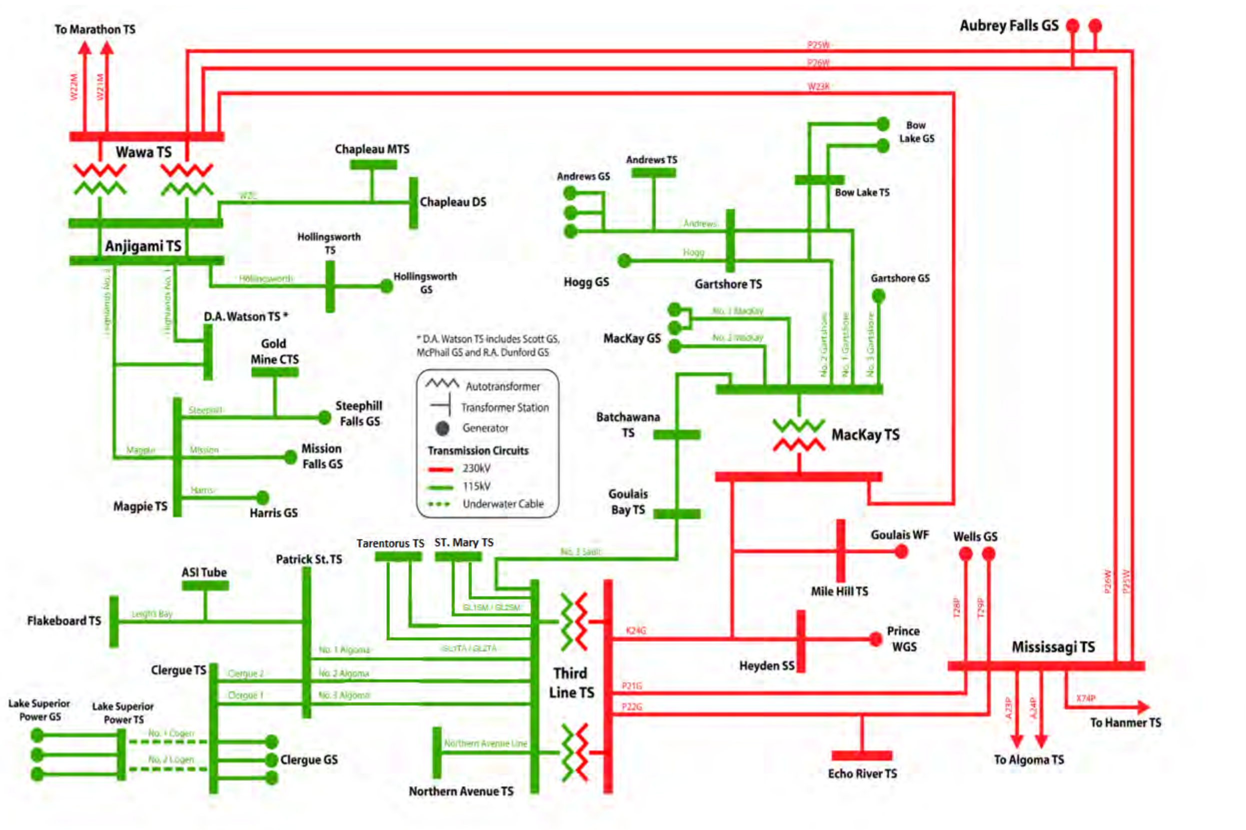

Figure 3-2: Single Line Diagram of East Lake Superior Region's Transmission Network

4 TRANSMISSION FACILITIES/PROJECTS COMPLETED AND/OR UNDERWAY SINCE LAST REGIONAL PLANNING

THE ESL REGIONS COMPLETED IT 1ST CYCLE REGIONAL PLANNING IN 2014. SINCE THAT TIME, SEVERAL \TRANSMISSION PROJECTS HAVE BEEN PLANNED AND/OR UNDERTAKEN BY HYDRO ONE SAULT STE. MARIE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY TO THE EAST LAKE SUPERIOR REGION.

A summary and description of the major projects completed and/or currently underway since the completion of last cycle regional planning is provided below.

- **End of life Wood Pole Replacements**: Multiple wood pole replacement projects were completed on a number of 115kV and 230kV circuits. These circuits consisted of wood pole structures that were assessed at being at their end of life and in need of replacements. The following circuits have their end of life wood pole structures replacement completed between 2013 to 2019:
    - No.2 and No.3 Algoma (completed in 2014)
    - Northern Ave (completed in 2014)
    - No.1 Garshore (completed in 2015)
    - Hogg (completed in 2015)
    - P21G (completed in 2019)

- **Hwy 101 TS**: Installed a new control building completed with new protection relays, batteries, chargers, automatic transfer schemes and RTU to replace end of life components such as electro-mechanical relays and batteries. This project was completed and in-serviced in 2015.

- **Anjigami TS**: Performed electrical and civil upgrade, including the installation of a new 44kV breaker, redundant battery and chargers, and replacement of protection equipment and other end of life AC/DC system. It also includes ground grid improvements. This is completed in 2017.

- **Echo River TS**: Improve transmission reliability with the installation of an additional 230/34.5kV 25MVA Transformer (T2) as an on-site spare. This project is underway and have a targeted in-service date of 2023 Q2.

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The LDCs provided load forecasts for all the stations supplying their loads in the East Lake Superior region for the 20-year study period during the IESO led IRRP phase of regional planning. The net extreme weather corrected winter load forecast was produced by modifying the LDC forecast provided for each station to reflect extreme weather conditions and subtracted the estimated peak demand impacts of provincial conservation policy and committed Distributed Energy Resource (DER) that may have been contracted through previous provincial programs such as the Feed-in Tariff (FIT) and micro FIT program.

The electricity demand in the East Lake Superior Region is anticipated to stay flat over the next 20 years, with a peak of 348W in 2031. Figure 5-1 shows the East Lake Superior Region's Winter peak net load forecast developed during the East Lake Superior IRRP process. This IRRP forecast was used to determine the loading that would be seen by transmission lines and autotransformer stations and to identify the need for additional line and auto-transformation capacity. The IRRP non-coincident load forecasts for the individual stations in the East Lake Superior Region is given in Appendix D, Table D-1 and Table D-2. This forecast does not included a high industrial growth or expansion scenario, which will be studied as part of the IESO's bulk planning study in 2021 given the impact to the bulk transmission network in the broader region

Figure 5-1: East Lake Superior Region Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2038.
- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period are assumed to be in-service.

- Winter is the critical period with respect to line and transformer loadings. The assessment is therefore based on winter peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks. Normal planning supply capacity for transformer stations is determined by the winter 10-day Limited Time Rating (LTR).
- Autotransformers and line capacity adequacy is assessed by using coincident peak loads in the area or supplied station(s). Where a circuit is feeding radial load, the capacity adequacy is assessed by using the connected station's non-coincident peak.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- The East-West Tie Transmission Reinforcement is included in the assessment.
- Hydro-electric generation assumption is taken as the output that is coincident with the region's overall 98% dependable output. Wind generation assumption were modelled by IESO based on their summer and winter capacity contribution factors per IESO Reliability Outlook, multiplied by their peak capacity.
- Sault No.3 circuit will be refurbished and return to network configuration at 115kV.

6 ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION LINE AND TRANSFORMER STATION FACILITIES SUPPLYING THE EAST LAKE SUPERIOR REGION OVER THE PLANNING PERIOD (2019-2038). ALL PROJECTS CURRENTLY UNDERWAY ARE ASSUMED IN-SERVICE.

Within the current regional planning cycle two regional assessments have been conducted for the East Lake Superior Region. The findings of these studies are input to this Regional Infrastructure Plan. The studies are:

- 2019 East Lake Superior Region Needs Assessment ("NA") Report
- 2019 East Lake Superior Region Scoping Assessment ("SA") Report
- 2021 East Lake Superior Integrated Regional Resource Plan ("IRRP") and Appendices

This section provides a review of the adequacy of the transmission lines and stations in the East Lake Superior Region. The adequacy is assessed from a loading perspective using the latest regional load forecast provided in Appendix D. Sustainment aspects were identified in the NA report and are addressed in Section 7 of this report. The review assumes that the following projects shown in Table 6-1 will be in-service. Sections 6.1 to 6.4 present the results of this review.

Table 6-1: New Facilities Assumed In-Service

Facility	In-Service Date
'hot' spare transformer at Echo River TS	2023
115kV Sault No.3 circuit re-conductoring	2024

6.1 230 kV Transmission Facilities

The East Lake Superior 230 kV transmission facilities consist of the following 230 kV transmission circuits (please refer to Figure 3-1 and 3-2):

a) Mississagi TS to Third Line TS 230 kV circuits: P21G and P22G
b) Mississagi TS to Wawa TS 230 kV circuit: P25W and P26W
c) Wawa TS to Mackay TS 230 kV circuits: W23K
d) Mackay TS to Third Line 230 kV circuits: K24G

230kV circuits supplying the region are within their thermal limits as per ORTAC over the study period for the loss of a single 230kV circuit in the region. Voltage concerns is observed when applying multiple contingencies on Bulk Electric System (BES) elements as per performance requirements set out in NERC TLP-001-4.

6.1.1 Voltage Concerns on following the loss of P21G and P22G

P21G and P22G are critical 230kV supply circuits that connects Third Line TS with Mississagi TS. A double circuit loss of P21G and P22G due to them being adjacent circuits on common towers, or the loss of either one circuit, followed by a contingency on the companion circuit would cause voltage decline in violation with ORTAC voltage change limits (i.e., in excess of 10%) at Third Line TS and other 115kV facilities supplied from Third Line TS throughout the planning horizon. Loss of both P21G and P22G will also result in the loss of Third Line autotransformer T1 by configuration. IESO's IRRP has determined that the voltage instability threshold for the region is reached when the GLP inflow interface exceed 230MW and both P21G and P22G are out of service.

Third line TS is equipped with Instantaneous Load Rejection Scheme with six load blocks to be armed for the loss of P21G and P22G, or the loss of T1 and T2. Currently, the IESO will direct HOSSM to arm this scheme via Hydro One's Ontario Grid Control Centre (OGCC) using manual phone call, where IESO will request arming of certain amount of load for rejection depending on prevailing system conditions. HOSSM will prioritize selection of available load blocks. IESO has expressed the need to enable remote arming of this scheme directly from IESO control room to make the arming procedure more efficient. Section 7 will discuss in more detail.

6.2 230/115 kV Autotransformers Facilities

The 230/115 kV autotransformers facilities in the region consist of the following elements:

a. Third Line TS 230/115 kV, 150/200/250MVA autotransformers: T1, T2
b. Mackay TS 230/115 kV, 150/200/250MVA autotransformers: T2

Loading of Third Line TS autotransformers has been identified to approach their 10-day LTR when the companion autotransformer is lost. Loading on companion autotransformer during single event contingency (N-1) would be reduced modestly beyond 2024 when the Sault No.3 circuit returns to a network at 115kV (non-radial configuration).

This is not a firm need as there is no existing violations but this is flagged because loading on Third Line autotransformers is approaching its LTR limit and should continue to be monitored. Despite the fact that one of the autotransformer (T2) has been identified for end-of-life replacement by 2025, such replacement would only marginally improve supply capacity by 10MVA for Third Line's autotransformers due to LTR rating of the existing autotransformer (T1), which was put into service since 2007 and is not near End-of-Life.

6.3 115 kV Transmission Facilities

115kV circuits supplying the region are within their thermal limits as per ORTAC over the study period for the loss of a single transmission element in the region. A list of circuits can be found in Appendix B. Capacity overload is observed on 115kV circuit Algoma No.1 and Sault No.3 following multiple contingencies as per performance requirements set out in NERC TLP-001-4.

6.3.1 Capacity overload on 115kV circuit Algoma No.1

A failure of breaker 214 to operate at Patrick St TS will remove Algoma No.2 and Algoma No. 3 circuits from Third Line TS to Patrick St TS by configuration. This results in thermal overload of the remaining Algoma No. 1 circuit beyond its short-term emergency (STE) rating during peak loads at Patrick St TS, of which Algoma No. 1 is the lowest rated circuit out of the three. This thermal overload on Algoma No. 1 can also occur with one of the Algoma circuits initially out of service, followed by the loss of another Algoma circuit.

This is an existing issue which was also identified in the NA and SA report. This is currently mitigated by the Patrick St TS manual load shedding scheme under which load is curtailed manually at Patrick St TS following the loss of one of the Algoma line circuits. This is done to prevent overloading of the Algoma No. 1 circuit in case the second circuit is also lost. Since this scheme is manual, load has to be shed before the actual contingency of the second circuit has taken place. This scheme was designed as an interim solution until a more permanent solution was implemented. The IRRP has recommended a need for a more permanent solution.

6.3.2 Capacity overload of 115kV circuit Sault No.3

During an outage to either P25W or P26W circuit between Wawa TS to Mississagi TS, a contingency on the K24G circuit between Third Line TS and Mackay TS results in the thermal overload of the Sault No.3 circuit beyond its STE ratings starting in 2023 when No.3 Sault circuit is connected in a network configuration[4]. This phenomenon is a result of high East West Transfer (EWT) flows and losing two circuits that carry that flow.[5]

In addition, when one of the Third Line TS autotransformers is out of service, a Sault No.3 circuit operated as network configuration (after its proposed upgrades) helps to alleviate overloading of the companion Third Line TS autotransformer. However, if the second autotransformer is also lost, Sault No.3 circuit will be overloaded beyond its STE rating and causes a significant voltage decline in the 115kV area served by Third Line TS. The risk of capacity overload on Sault No.3 circuit and area voltage decline as a result of losing both autotransformer is presently mitigated by Third line's Instantaneous Load Rejection scheme. Subjected to the outcome of IESO's 2021 Bulk Planning Study with regards to Sault No.3 overloading, the overloading may continue to be a need.

6.4 Step-Down Transformer Station Facilities

There are a total of 11 step-down transformers stations in the East Lake Superior Region, connected to the 230 kV and 115 kV transmission network as listed below. The stations winter peak load forecast is given in Appendix D.

Table 6-2: East Lake Superior Step-Down Transformer Stations

230 kV Connected	115 kV Connected	
Echo River TS	Andrew TS	Chapleau MTS

[4] Sault No.3 circuit is currently operated radial to Mackay GS (G3) and is being refurbished as part of a sustainment project

[5] EWT is defined as the MW flow at Wawa TS on circuits W21M and W22M. By 2023, EWT tie flow will also include the flow of the new NextBridge circuits.

	Anjigami TS	Goulais TS
	Batchawana TS	Hollingsworth TS
	Clergue TS	Northern Ave TS
	Chapleau DS	St Mary CTS
	Tarentorus CTS	

Capacity of Anjigami T1 / Hollingsworth T1 & T2 are exceeded by end of 2024 based on the load forecast provided by LDC, where Hollingsworth T1 & T2 will be overload when Anjigami T1 is out of service, and vice versa. The overload is caused by loading increases on the 44kV circuit that Anjigami TS and Hollingsworth TS supply in parallel. HOSSM is working with the impacted LDC and have proposed to build a new 115/44kV station, with a proposed name Limer TS (subject to change) that will tap off Hollingsworth 115kV circuit to handle the load increase.

6.5 Bulk Areas Need

There is a potential for significant growth in industrial load in the ELS region over the planning period which would have a material impact on the bulk transmission system outside the region. Hence, the IESO has initiated a bulk planning study for this scenario outside of the regional planning process.

Based on the reference load forecast included in the IRRP, the following bulk system need was identified and will be further coordinated with the bulk planning study described above:

- Following the loss of one of the 230 KV circuits, P25W or P26W circuits from Mississagi TS to Wawa TS, the companion circuit becomes loaded beyond its LTR rating under high westward power flow on the EWT.

Results and recommendations from the bulk planning study would be published separately. HOSSM and HONI will work with IESO to address recommendations as appropriate.

7 REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE EAST LAKE SUPERIOR REGION AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses electrical infrastructure needs in the East Lake Superior Region and plans to address these needs. The electrical infrastructure needs encompass both end of life replacement needs identified in the Need Assessment phase, and needs identified in section 6. A list of needs are summarized below in Table 7.1.

Table 7-1: Identified Near and Mid-Term Needs in East Lake Superior Region

Section	Facilities/Circuit	Need	Timing
7.1	Third Line TS/OGCC	Enable remote arming of Third Line TS Instantaneous Load Rejection Scheme	Immediate
7.2	Third Line TS	End of life Protection replacement	2022
7.3	Patrick St TS, Algoma No.1 overload	Automate existing manual load curtailment scheme to meet NERC standards	Immediate
7.4	Echo River TS	Transmission Supply Reliability / End of Life 230kV Breaker replacement	2023/2024
7.5	115kV Sault No.3	Sault No.3 Structure and End of Life Conductor Replacement[6]	2024
7.6	Batchawana TS and Goulais TS	End of Life component replacement	2024
7.7	Patrick St TS	End of Life 115kV breaker replacement	2024
7.8	Third Line TS	T2 End of Life Replacement	2025
7.9	Northern Ave TS	T1 End of Life replacement	2025

[6] To coordinated with IESO's 2021 Bulk Planning Study Regarding Sault No.3 Circuit Overloading

7.10	Anjigami/Hollingsworth TS	Anjigami/Hollingsworth Transformers Overload	2024
7.11	Clergue TS	End of life metal clad switch gear replacement	2026
7.12	Hollingsworth TS	End of life Protection replacement	2026
7.13	Watson TS	End of life metal clad switch gear replacement	2026

7.1 Third Line TS – Enable remote arming of Third Line TS Instantaneous Load Rejection Scheme.

7.1.1 Description

Instantaneous Load Rejection Scheme at Third line TS are designed to respond to the loss of both P21G and P22G, or the loss of both T1 and T2. This scheme is currently armed under the direction of IESO. Upon IESO request, OGCC will manually arm the scheme and prioritized available load blocks for rejection. OGCC has established communication channels to perform arming function via Hydro One Network Management System (NMS).

7.1.2 Alternatives and Recommendation

The following alternatives were considered to address Main TS end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it will not address the manual process involved in arming of the load rejection scheme, as well as the selection of load blocks to be armed. The risk of communication delays between IESO and OGCC is not mitigated.

2. **Alternative 2 – Enable remote arming of Third Line TS Instantaneous Load rejection scheme:** Under this alternative, Hydro One will work with IESO to make necessary control points available on IESO's Energy Management System (EMS) interface such that IESO's control command can be relayed to OGCC's NMS via existing Inter-Control Centre Communication Protocol (ICCP) link, which will subsequently be relayed to Third Line's Instantaneous Load Rejection Scheme.

The Study Team recommends Alternative 2 as the technically preferred and most cost-effective alternative because this will facilitate the automation of dispatch arming from IESO in a real-time setting, and eliminate manual communications delays between IESO and Hydro One. Further, given the ICCP infrastructure already exists, the cost to perform alternative 2 is expect to be limited to control points and status points set up in NMS and EMS respectively, as well as testing activities that can be done in both ends to ensure functionality. The estimated cost for this upgrade is about $10,000 and is expected to in-service by end of 2021.

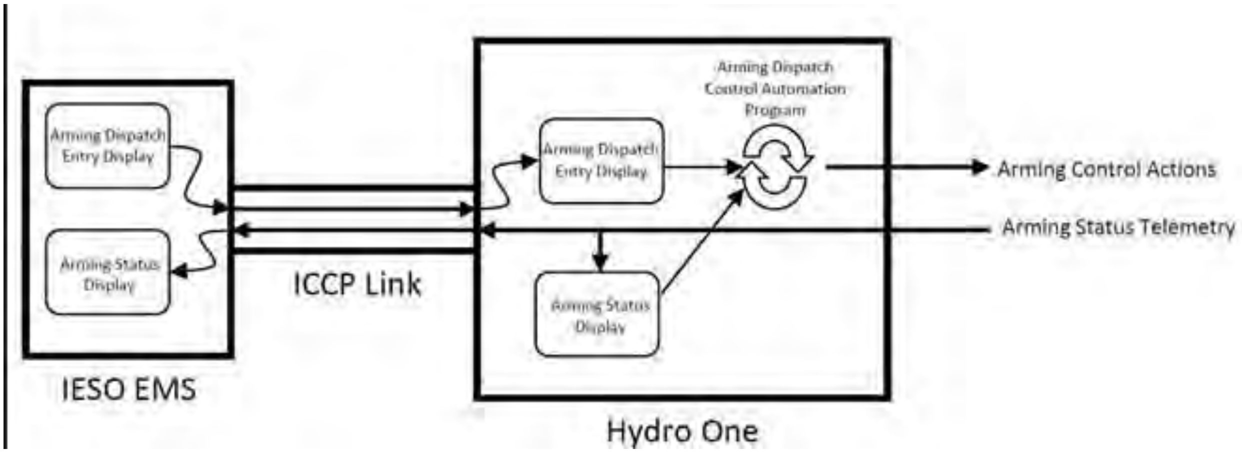

Figure 7-1: ICCP link between IESO and Hydro One.

7.2 Third Line TS – End of life Protection Replacement

7.2.1 Description

Third Line TS is a major transformer station in the region and it consists of two (2) 230/115kV, 150/200/250MVA autotransformers supplied by 230kV circuits K24G, P21G and P22G. Third line TS 115kV station yard supplies multiple load stations via Algoma No. 1, No. 2, No. 3 circuits, No.3 Sault circuit and Northern Ave circuit. It also supplies two (2) LDC HV load supply stations via 115kV circuits GL1SM GL2SM, GL1TA, and GL2TA. Based on an asset condition assessment, P21G's and P22G's line protections are approaching end of life. Further, due to legacy reasons, P21G's and P22G's line protection do not meet standard physical separation requirement .

7.2.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to end-of-life asset condition and would result in increased maintenance expenses and reduce supply reliability to the ELS region.

2. **Alternative 2 – Replace end-of-life protection as per current standard:** Under this alternative the existing end-of-life protection will be replaced with new protection relay consistent with Hydro One standard. This alternative will also implement 'A' and 'B' protection separation, which will

bring these protection be in compliance with reliability standards, addresses the end-of-life assets need, minimizes losses and maintains reliable supply to the customers in the area.

The Study Team recommends Alternative 2 – replace end-of-life protection relay. The protection replacement work is expected to be complete by 2022.

7.3 Patrick St TS – Automatic Load Rejection Scheme

7.3.1 Description

Patrick St TS is an 115kV switching station that consists of thirteen (13) 115kV breakers. It connects to Third Line TS – 115kV station yard via 115kV Algoma No. 1, No. 2 and No. 3 circuits. It also connects to Clergue TS via 115kV Clergue No .1 and No. 2 circuits. The station supplies major industrial customers in the Sault Ste. Marie area. Based on IESO IRRP findings, upon a breaker failure of breaker 214, or a contingency on either Algoma No.2 or Algoma No.3 circuit, followed by another contingency on the remaining circuit, Algoma No.1 will be overloaded beyond its STE rating during peak load. At present, a manual load shedding scheme is implemented as an interim solution until a more permanent solution is available.

7.3.2 Alternatives and Recommendation

The following alternatives were considered to address the interim manual load shedding scheme need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of circuit overload during contingency and could result in equipment (overhead conductor) damage, increase public safety risk and reduce supply reliability to connected customers.

2. **Alternative 2 – Implement Automatic Load Rejection Scheme at Patrick St TS:** This alternative would implement an automatic load rejection upon the loss of Algoma No.2 and Algoma No.3 to reject load blocks and respect the existing LTE rating of Algoma No.1 circuit.

Considering above options, the Study Team recommends that Hydro One proceed with Alternative 2, consistent with recommendation from the ELS's IRRP.

7.4 Echo River TS – Install Spare 230kV Transformer (2023) and end of life 230kV breaker replacement (2024)

7.4.1 Description

Echo River TS is a 230kV load supply station. The station consists of a single 230/115/34.5kV autotransformer and a single 230kV circuit breaker (556) to supply two (2) 34.5 kV customer feeders. Historically, load at Echo River TS can be transferred to Northern Ave TS 34.5 kV feeders via the API's distribution system in case of outages at Echo River TS, such as transformer maintenance or failure.

As per the 2nd cycle of Need Assessment completed in Q2 2019 for the ELS region, it has been identified that the existing back up from Northern Ave TS can no longer provide adequate voltage support at peak load during a transformer outage at Echo River TS.

Echo River 230kV breaker 556 is a live tank minimum oil breaker, which has also been identified to be end of life and obsoleted based on asset condition assessment.

7.4.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address system reliability needs and HOSSM asset needs due to asset condition. This alternative would result in increased maintenance expenses and reduce supply reliability to the customers.

2. **Alternative 2 – "Cold" spare 230kV Transformer and replace end of life 230kV breaker :** install a "cold" spare in Echo River TS that is completed with new spill containment only, without 230kV and 34.5kV connection facilities and dedicated protection equipment. The spare will not normally put on potential. This alternative is not recommended as the load restoration time associated with connecting the unit and making it ready to serve load would exceed ORTAC load restoration requirement.

3. **Alternative 3 – "Hot" spare 230kV Transformer and replace end of life 230kV breaker:** install a "hot" spare in Echo River TS that is completed with new 230kV and 34.5kV connection facilities, dedicated protection equipment and new spill containment systems. The spare transformer is usually on potential and ready to serve load upon switching. This alternative can significantly shorten load restoration time to respect ORTAC load restoration timeline in the event of a transformer outage due to maintenance or failure, which improves local transmission supply reliability.

The Study Team recommends Alternative 3 – "Hot" spare 230kV Transformer and replace end of life 230kV breaker. The spare transformer is planned to be completed by 2023, while the breaker replacement work is planned to be completed in 2024. In lieu of replacing the breaker HOSSM will install a 230 kV circuit switcher and enable transfer trip functionality between Echo River TS and it's terminal stations.

7.5 115kV Sault No.3 Structure and Conductor Replacement

7.5.1 Description

Built in 1929, Sault No.3 is a 90 km long 115kV transmission circuit that runs from MacKay TS 115kV station yard to Third Line TS 115kV station yard. This circuit provides an alternative path for local generation to reach load centres close to the Sault Ste. Marie area. Based on asset condition assessment, approximately 70km of the circuit's conductor from Goulais TS (str # 129) to MacKay TS is the original conductor, and has been rated between "Poor" and "Very Poor" as it has multiple component (sleeves) failures. This circuit also accounts for 39% of all line equipment related outages experienced over the 2013 – 2017 period within HOSSM's sytem. The circuit is currently de-rated as a pre-cautionary action to minimize further stress. Due to the de-rating, Sault No.3 circuit is also forced to operate in a radial configuration to Mackay G3 to limit loading on the line. The end of life replacement work would include 'like for standard' conductor replacement and replacement of selected wood poles along the corridor as condition warrants.

HOSSM has completed the detail project defitnition work for this project. It is noted that the on-going IESO bulk system studies have considered upgrading Sault 3 to 230kV[7] as a potential solution. IESO bulk system studies is expected to be available Q4 2021. Provided that IESO's recommendation is to refurbish the line as per current plan, the project is expected to be completed by 2024.

7.5.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition. Failure of this circuit can impact the power supply to load centres close to the city of Sault Ste. Marie.

2. **Alternative 2 - Replace conductor, structures and associated End-of-Life components with Hydr One standard 115kV equipment:** Under this alternative, the existing conductor and wood pole that are assessed to be end of life will be replaced with new 115 kV rated line and structures. This alternative will also allow Sault No.3 to return to its network configuration.

The Study Team recommends Alternative 2 – the replacement of the end-of-life conductor and wood pole structures between Mackay TS and Goulais TS (str # 129) as it addresses the end-of-life assets need and maintains reliable supply to the customers in the area.

7.6 Batchawana TS and Goulais – End of life Component Replacement

7.6.1 Description

Batchawana TS and Goulais Bay TS are load supply stations with single transformer to supply to the Batchawana Bay and Goulais Bay areas. Goulais Bay TS is about 30 km North of Sault Ste. Marie, while Batchawana TS is about 47 km North of Sault Ste. Marie along Hwy 17. Both are connected to 115kV No.3 Sault circuit. Figure 7-2 below shows geographical location of both station. Based on asset condition assessment, both stations are at End-of-life stage with obsoleted equipment including power transformers, protections (fuse), batteries, chargers, steel structure foundations and remote terminal units. Both stations are also built with legacy design standards and do not provide adequate clearance to today's standard. Their single transformer configuration has also made it difficult to schedule and perform maintenance.

[7] Possibly upgrading to 230kV standard and operate at 115kV until 230kV operation is needed for the bulk system.

Figure 7-2: Batchawana TS and Goulais Bay TS on 115kV circuit

7.6.2 Alternatives and Recommendation

A detailed assessment that analyzed supply options for Batchawana TS and Goulais Bay TS was carried out between HOSSM and API from 2019 -2020 to compare and evaluate supply options based on Transmission and Distribution supply reliability and performances. The assessment compared three (3) different options, they are:

- Option 1: Refurbish both Goulais Bay TS and Batchawana TS using a new 115kV, 3 –phase power transformer, with provision for a 115kV Mobile Unit substation (MUS) connection facility in each station. Transformer capacity to be sized to handle the long term peak forecast of the individual stations.

- Option 2: Consolidate Goulais Bay TS and Batchawana TS into a 'New' TS that is equipped with two 20MVA, 3-phase transformer to supply both distribution sub-system at either 12.5kV or 25kV. The location of this 'New' TS would be in the vicinity of Goulais bay.

- Option 3: Consolidate Goulais Bay TS and Batchawana TS into a 'New' TS with dedicated 25kV "express feeder" between Goulais and Batchawana. This 'New' TS would be located in the vicinity of Goulais bay, and be equipped with two 20MVA, 3-phase transformer to supply both distribution sub-system at either 12.5kV or 25kV. An additional 25/12.5kV unit is required on the distribution system in the vicinity of Batchawana bay to convert voltage from the incoming 25kV dedicated "express feeder" to 12.5kV in order to supply distribution sub-system in the vicinity of Batchawana bay.

Depending on the choice of distribution voltage, there are two (2) different scenarios (12.5kV vs 25kV) for each option above. Evaluation of alternatives was completed by HOSSM and API as documented in the 2021 East Lake Superior Regional Local Planning Report. As per the report's recommendation, HOSSM is proceeding with option 1 - Refurbish both Goulais Bay TS and Batchawana TS. More details related to the supply option analysis can be found in the Local Planning Report – Supply Option Analysis for Goulais and Batchawana (2020), available on Hydro One public website. Refurbishment for both stations are expected to be completed in 2024.

7.7 Patrick St TS – End of life 115kV breaker replacement

7.7.1 Description

Patrick St TS is an 115kV switching station that consists of thirteen (13) 115kV breakers. It connects to Third Line TS – 115kV station yard via 115kV Algoma No. 1, No. 2 and No. 3 circuits. It also connects to Clergue TS via 115kV Clergue No .1 and No. 2 circuits. The station supplies major industrial customers in the Sault Ste. Marie area. Based on asset condition assessment, breaker 208, 211, 214 and 217 are minimum oil live tank breakers that are considered End of Life and obsolete.

7.7.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability for customers.

2. **Alternative 2 - Replace the end-of-life breakers with new standard breakers:** This alternative involves the replacement of breaker 208, 211, 214 and 217 with new SF6 breakers in similar ratings.. This alternative is recommended as it addresses the end-of-life asset needs and maintains reliable supply to customers connected at Patrick St TS by reducing the risk of breaker failure; and reducing on-going maintenance cost associated with obsolete breaker technology.

Alternative 2 is recommended. The project is expected to be completed by 2024.

7.8 Third Line TS – T2 End of Life Replacement

7.8.1 Description

Third Line TS is a major transformer station in the region and it consists of two (2) 230/115kV, 150/200/250MVA autotransformers supplied by 230kV circuits K24G, P21G and P22G. Third line TS 115kV station yard supplies multiple load stations via Algoma No. 1, No. 2, No. 3 circuits, No.3 Sault circuit and Northern Ave circuit. It also supplies two (2) PUC HV load supply stations via 115kV circuits GL1SM GL2SM, GL1TA, and GL2TA. Among the 2 autotransformers, T2 is at end of life based on asset condition assessment. Based on long term load forecast, units with similar ratings are required for the end of life autotransformer T2 replacement.

7.8.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the region.

2. **Alternative 2 – Replace T2 with equivalent size unit as per current standard:** This alternative would replace old T2 with a unit that has equivalent rating. This is recommended alternative as it will mitigate risk of autotransformer failure due to its deteriorating conditions and maintain supply reliability of the region.

3. **Alternative 3 – Replace T2 with larger size unit:** This alternative would replace old T2 with a unit that has higher rating. This alternative is rejected as a 230/115kV autotransformer at 150/200/250MVA is currently the highest rating available based on HOSSM and Hydro One standards.

Alternative 2 is recommended. The project is expected to be completed by 2025.

7.9 Northern Ave TS – T1 End of Life Replacement

Northern Ave TS is a 115kV load supply station that is connected to Third Line TS via 115kV Northern Ave circuit. Northern Ave Transformer T1 is a 115/34.5kV, 20/26.7MVA step down transformer that supplies Algoma Power Inc. via one (1) 34.5kV feeder. Transformer T1 is at end of life. Historically, Northern Ave TS has been used as a backup supply to Echo River TS to facilitate outages. Reliance on Northern Ave TS is expected to reduce starting 2023 as the spare unit at Echo River TS comes into service in 2023. The longer term forecast for Northern Ave TS peaks at 2.7MW.

7.9.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to connected customers.

2. **Alternative 2 – Replace T1 with a smaller MVA size unit as per current standard:** This alternative would replace T1 with a 'like for similar' unit that has a smaller MVA rating compared to existing T1, and would be adequate for Northern Ave's long term load forecast. This is recommended alternative as it will mitigate risk of transformer failure due to its deteriorating conditions and maintain supply reliability of the station.

Alternative 2 is recommended. The project is expected to be completed by 2025.

7.10 Anjigami/Hollingsworth TS – Transformer overload.

Anjigami TS is a 115kV/44kV load supply station with a single transformer. Hollingsworth TS is a 115kV/12.5kV/44kV station that supplies load on 44kV, and connected to Hollingsworth CGS on the 12.5kV. Anjigami's and Hollingsworth's 44kV feeders are connected to each other with a 10km long 44kV line to supply LDC load on No.4 circuit. Base on LDC load forecast, load increase on 44kV system by end of 2024 would exceed transformer capacity in both Anjigami TS and Hollingsworth TS when the companion station is out of service. HOSSM is working with API and have proposed to build a new 115/44kV station, with a proposed name Limer TS (subject to change) that will tap off Hollingsworth 115kV circuit to handle the load increase.

7.10.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the transformer capacity needs based on load forecast.

2. **Alternative 2 – Replace Anjigami T1, Hollingsworth T1 and T2 with a larger MVA size units as per current standard to handle load increases:** This alternative is considered but not recommended as both Anjigami TS and Hollingsworth TS have a limited footprint, and site expansion would be required for both sites for such upgrade. Further, due to Hollingsworth TS existing configuration, upgrades are also required on all existing 12.5kV facilities, including disconnect switches, breakers, and overhead bus work to accommodate the load increase.

3. **Alternative 3 – Build new 115/44kV 'Limer TS' that will be supplied from Hollingsworth 115kV circuit, transfer existing LDC load from existing 44kV system to 'Limer TS' :** This alternative would build a new 115/44kV station in the vicinity of Hollingsworth TS and tap off from 115kV Hollingsworth circuit to supply new loads as well as existing load that are presently supplied by Anjigami/Hollingsworth 44kV system. The new station would be similar to a DESN station with two (2) 115/44kV, 50/67/83MVA transformers as per current HONI standard, HV

and LV connection facilities such as circuit switchers and feeder breakers, modern protections and telecommunication systems to service the new load. API will re-route their 44kV feeder(s) and connect to 'Limer TS'.

Given the alternatives above, Alternative 3 is recommended because it is expected to be the most cost efficient alternatives. Compared to Alternative 2, where it will require the coordination of 2 environmental approvals at different sites for site expansion, replacement of three (3) transformer (Anjigami T1, Hollingsworth T1 and T2), and upgrade on existing 12.5kV equipment at Hollingsworth TS, Alternative 3 has a more concise scope. Building new station will also have less outage constraints when compared to upgrading existing facilities. HOSSM will continue to work with API to develop a local solution. The project is expected to be completed by end of 2024/early 2025.

7.11 Clergue TS - End of life metal clad switch gear replacement

Clergue TS is a 115kV station that connects Clergue Generating Station and LSP co-generation station to the HOSSM system via two (2) 115kV circuits emanating from Patrick St TS. Based on an asset condition assessment, the existing 12 kV minimum-oil metal-clad switchgear is at End-of-Life and obsoleted

Based on the load forecast and expected system conditions, similar equipment ratings are required for end of life replacement.

7.11.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to connected customers.

2. **Alternative 2 – Replace existing metal clad switch gear with SF6 metal clad switch gear as per current standard:** This alternative would replace existing minimal oil metal clad switch gear with SF6 metal clad switch gear. This is recommended alternative as it will mitigate risk of switch gear failure due to its deteriorating conditions and maintain supply reliability of the station.

Alternative 2 is recommended. The project is expected to be completed by 2026.

7.12 Hollingsworth TS – End of life Protection Replacement

Hollingsworth TS is a 115kV station that connects Hollingsworth Generating Station and is supplied by Hollingsworth 115kV circuit. Majority of protection relay equipment in Hollingsworth TS were in-serviced 2005. Based on asset condition assessment, the existing protection relay would approach end of life by 2025.

7.12.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to connected customers.

2. **Alternative 2 – Replace end of life protection with "like for like" protection relay as per current standard:** This alternative would replace identified end of life protection relays with as per current standard. This is recommended alternative as it will mitigate risk of protection relay failure due to their deteriorating conditions and maintain supply reliability to connected customers.

Alternative 2 is recommended. The project is expected to be completed by 2025

7.13 Watson TS - End of life Metal Clad switch gear replacement

DA Watson TS is a 115kV load supply station that also has connectivity with three (3) local hydro generating stations. The station has two 45/60/75 MVA transformers and nine 34.5kV feeders using metal clad switch gear. Based on an asset condition assessment, the existing minimal oil metalclad switch gear are at End of life and obsolete

7.13.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to connected customers.

2. **Alternative 2 – Replace existing metal clad switch gear with SF6 metal clad switch gear as per current standard:** This alternative would replace existing minimal oil metal clad switch gear with SF6 metal clad switch gear. This is recommended alternative as it will mitigate risk of equipment failure due to its deteriorating conditions and maintain supply reliability of the station.

Alternative 2 is recommended. The project is expected to be completed by 2026.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE EAST LAKE SUPERIOR REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 8-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1: Recommended Plans in East Lake Superior Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate
1	Eliminate/Minimize manual communication between IESO and OGCC when arming Third Line Instantaneous Load Rejection Scheme	Enable remote arming of Third Line Instantaneous Load Rejection Scheme via ICCP line between IESO's EMS and HONI's NMS	2021	$10K
2	Third line TS: End of life Protection	Replace end of life protection per current standard	2022	$0.8M
3	Echo River TS : Transmission Supply Reliability and end of life breaker	Install 'hot' spare transformer and replace end of life breaker	2023/2024	$11.5M
4	115kV Sault No.3: end of life structures and conductor	Replace end of life structure and conductor per current standard[8]	2024	$54.4M
5	Batchawana TS: End of life components	Refurbish Batchawana TS with MUS provision	2024	$6.2M
6	Goulais TS: End of life components	Refurbish Goulais TS with MUS provision	2024	$13.4M
7	Patrick St. TS, Algoma No.1 overload	Implement Automatic Load Rejection Scheme at Patrick St. TS	2023	$1.2M
8	Patrick St. TS: End of life 115kV breaker	Replace end of life 115kV breakers	2024	$3.3M
9	Third Line TS : T2 end of life	Replace end of life T2	2025	$16.4M
10	Northern Ave TS: end of life component replacement	Replace end of life T1 with smaller MVA unit and protection relays per current standard	2025	$2.5M
11	Anjigami/Hollingsworth TS : Transformer overload	Build new 115/44kV Station - HOSSM to work with API to continue to develop solutions	2024/2025	$30M

[8] To coordinated with IESO's 2021 Bulk Planning Study Regarding Sault No.3 Circuit Overloading

12	Clergue TS: End of life metal clad switch gear	Replace end of life switch	2026	$5.2M
13	Hollingsworth TS: End of life Protection relay	Replace end of life protections	2025	$1.1M
14	D.A. Watson TS: End of life metal clad switch gear	Replace end of life switch gear	2026	$9.2M

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 8-1 while keeping the Study Team apprised of project status;
- Any other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

9 REFERENCES

[1] East Lake Superior Region Needs Assessment (2019)

[2] East Lake Superior Region Scoping Assessment (2019)

[3] Local Planning Report – Supply Option Analysis for Goulais and Batchawana (2020)

[4] East Lake Superior Integrated Regional Resource Plan (2021)

[5] East Lake Superior Integrated Regional Resource Plan - Appendices (2021)

APPENDIX A. STATIONS IN THE EAST LAKE SUPERIOR REGION

Station	Voltage (kV)	Supply Circuits
Andrews TS	115/25	Andrew 115kV
Anjigami TS	115/44	High falls No.1 /Highfalls No.2
Batchawana TS	115/12.5	Sault No.3
Chapleau DS	115/25	W2C
Chapleau MTS	115kV	W2C
Clergue TS	115/12.5	Clergue No.1 / Clergue No.2
D.A. Watson TS	115/34.5	Magpie 115kV/High falls No.1 /Highfalls No.2
Echo River TS	230/34.5	P22G
Flakeboard CTS	115	Leigh's Bay 115kV
Gartshore SS	115	Gartshore No.1 / Gartshore No.2/ Gartshore No.3 / Hogg 115kV / Andrews 115kV
Gold Mine CTS (Magnacon Mine)	115	Steephill 115kV
Goulais Bay TS	115/12.5	Sault No.3
Heyden CSS	230	K24G
Hollingsworth TS	115/12.5/44	Hollingsworth 115kV
Hwy 101 SS	44	Anjigami 44kV/Limer 44kV
Mackay TS	230	K24G/W23K
Mackay TS	115	Gartshore No.1 / Gartshore No.2/ Mackay No.1/Mackay No.2/Sault No.3
Magpie SS	115	Harris 115kV/Steephill 115kV /Mission Falls 115kV/Magpie 115kV
Mile Hill CTS	230	K24G
Northern Ave. TS	115/34.5/12.5	Northern Ave 115kV
Patrick St. TS	115/34.5	Algoma No.1/No.2/No.3 , Clergue No.1 /No.2
St Mary CTS	115/34.5	GL1SM / GL2SM
Tarentorus CTS	115/34.5	GL1TA / GL2TA
Third Line TS	230	K24G/P21G/P22G
Third Line TS	115	Sault No.3, Algoma No.1/No.2/No.3, Northern Ave 115kV
Wallace Terrace CTS	115/34.5	Leigh's Bay 115kV

Wawa TS	230	P25W/P26W/W21M/W22M/W35M*/W36M*
Wawa TS	115	W2C/ Hollingsworth 115kV

*after the completion of East West Tie

APPENDIX B. TRANSMISSION LINES IN THE EAST LAKE SUPERIOR REGION

Location	Circuit Designations	Voltage (kV)
Mississagi x Third line	P21G , P22G	230
Mississagi x Wawa	P25W, P26W	230
Third line x Mackay	K24G	230
Mackay x Wawa	W23K	230
Third line x Mackay	Sault No.3	115
Third line x Patrick St.	Algoma No.1 / No.2 / No.3	115
Third line x Norther Ave	Northern Ave 115kV	115
Third line x St Mary CTS	GL1SM, GL2SM	115
Third line x Tarentorus CTS	GL1TA , GL1TA	115
Patrick st x Flakeboard CTS	Leigh's Bay 115kV	115
Patrick St. x Clergue TS	Clergue No.1 / No.2	115
Mackay GS x Mackay TS	Mackay No.1 / No.2	115
Gartshore SS x Mackay TS	Gartshore No.1 / No.2	115
Gartshore SS x Hogg CGS	Hogg 115kV	115
Gartshore SS x Andrew CGS	Andrew 115kV	115
Magpie SS x Mission Falls CGS	Mission falls 115kV	115
Magpie SS x Steephill CGS	Steephill 115kV	115
Magpie SS x Harris CGS	Harris 115kV	115
Magpie SS x DA Watson TS	Magpie 115kV	115
DA Watson TS x Wawa TS	High Falls No.1/No.2	115
Hollingsworth TS x Wawa TS	Hollingsworth 115kV	115

Anjigami TS x Hwy 101 SS	Anjigami 44kV	44
Hollingsworth TS x Hwy 101 SS	Limer 44kV	44

APPENDIX C. DISTRIBUTORS IN THE EAST LAKE SUPERIOR REGION

Distributor Name	Station Name	Connection Type
Algoma Power Inc.	Andrew TS	Tx
	Anjigami TS	Tx
	Batchawana TS	Tx
	D.A. Watson TS	Tx
	Echo River TS	Tx
	Goulais TS	Tx
	Mackay TS (115kV)	Tx
	Northern Ave TS	Tx
	Hollingsworth TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Chapleau PUC	Chapleau MTS	Tx
Hydro One Networks Inc. (Dx)	Chapleau DS	Dx
PUC Distribution	St Mary CTS	Tx
	Tarentorus CTS	Tx

APPENDIX D. EAST LAKE SUPERIOR REGION LOAD FORECAST

Table D-1: East Lake Superior Non-coincident peak Load Forecast, with the Impacts of Energy-Efficiency Savings per station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	1.56	1.85	1.86	1.88	1.90	1.91	1.93	1.95	1.97	1.98	2.00	2.02	2.04	2.05	2.06	2.08	2.10	2.12	2.14	2.15
DA Watson TS	8.53	8.57	8.55	8.56	8.57	8.58	8.60	8.63	8.67	8.71	8.75	8.80	8.87	8.93	8.99	9.06	9.13	9.20	9.26	9.32
Echo River TS	14.18	14.23	14.19	14.19	14.17	14.18	14.20	14.23	14.28	14.33	14.38	14.45	14.57	14.67	14.80	14.95	15.06	15.17	15.25	15.33
Goulais Bay TS	8.00	8.00	9.49	9.81	10.40	10.70	10.76	10.83	10.90	10.96	11.01	11.07	11.13	11.18	11.23	11.29	11.36	11.43	11.50	11.57
Limer TS	13.18	13.74	13.81	13.88	13.99	54.00	54.00	28.62	28.65	28.68	28.70	28.76	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00
Andrews TS	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Mackay TS	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Northern Av TS	2.50	2.51	2.50	2.51	2.51	2.51	2.52	2.53	2.54	2.55	2.57	2.58	2.60	2.62	2.63	2.65	2.67	2.70	2.71	2.73
Chapleau DS	6.31	6.47	6.51	9.24	9.32	9.38	9.44	9.51	9.59	9.68	9.76	9.84	9.94	10.03	10.13	10.23	10.33	10.44	10.53	10.63
Chapleau MTS	4.47	4.36	4.44	4.19	4.69	4.58	4.59	4.59	4.21	4.15	4.14	4.27	4.27	4.27	4.27	4.28	4.29	4.29	4.29	4.30
PUC Distribution Inc.	120.7	119.5	117.5	115.9	114.2	112.7	111.4	110.0	108.9	107.9	106.8	109.7	116.5	115.7	114.9	114.2	113.6	112.9	112.3	111.5

Table D-2: East Lake Superior Forecasted Impacts of Energy-Efficiency Savings due to Codes , Standards and Funded CDM Program

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
DA Watson TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Echo River TS	0.11	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.18	0.20	0.24	0.27	0.30	0.32	0.33	0.34	0.34	0.34
Goulais Bay TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Limer TS	0.11	0.19	0.19	0.19	0.15	0.15	0.15	0.15	0.15	0.15	0.17	0.19	0.23	0.25	0.28	0.30	0.32	0.32	0.32	0.32
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.02	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.06	0.06	0.06	0.06
Chapleau DS	0.07	0.12	0.12	0.12	0.10	0.10	0.10	0.10	0.10	0.10	0.12	0.13	0.16	0.18	0.20	0.22	0.23	0.23	0.23	0.23
Chapleau MTS	0.03	0.06	0.06	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.05	0.06	0.07	0.07	0.08	0.09	0.09	0.09	0.09	0.09
St. Mary's TS	0.91	1.58	1.54	1.54	1.16	1.16	1.13	1.12	1.12	1.08	1.17	1.29	1.46	1.60	1.76	1.87	1.93	1.91	1.88	1.86
Tarentorus TS	1.16	2.02	1.97	1.98	1.49	1.48	1.45	1.43	1.43	1.39	1.50	1.66	1.88	2.05	2.25	2.40	2.47	2.44	2.41	2.38
Total	**2.56**	**4.45**	**4.36**	**4.39**	**3.33**	**3.32**	**3.27**	**3.23**	**3.23**	**3.15**	**3.45**	**3.84**	**4.39**	**4.82**	**5.32**	**5.69**	**5.87**	**5.84**	**5.79**	**5.74**

Table D-3: East Lake Superior IRRP Forecasted DER by station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DA Watson TS	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Echo River TS	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.16	0.12	0.08	0.02	0.01	0.00	0.00	0.00
Goulais Bay TS	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Limer TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau DS	2.65	2.65	2.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau MTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
St. Mary's TS	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	0.23	0.18	0.16	0.16	0.16	0.14	0.00	0.00
Tarentorus TS	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	0.14	0.10	0.06	0.03	0.03	0.02	0.00	0.00	0.00

Algoma Power Inc.

Distribution System Plan

Appendix J

ALGOMA POWER

ALTERNATIVES FOR EAST OF THE SAULT RELIABILITY ISSUES

Report No. C16-00105
April 1, 2021

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Algoma Power

Alternatives for East of the Sault Reliability Issues

Reliability Solution Business Case Analysis

Project no C16-00105

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April 1, 2021

Revision History

Version	Date	Prepared by (Deliverable Lead)	QC Reviewer	Project Manager Sign-Off
00	February 3, 2021	Ashley Rist, P.Eng.	Ron LaPier, P.Eng.	Stephen Costello, CET
01	April 1, 2021	Ashley Rist, P.Eng.	Ron LaPier, P.Eng.	Stephen Costello, CET

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1. Executive Summary

Algoma Power services a group of communities designated "East of Sault Ste. Marie" through Hydro One Inc.'s Echo River Transformer Station (ERTS) located in Echo River, Ontario. This transformer station is 230kV/34.5kV, has a single transformer, and two feeders which are very long.

The Independent Electricity System Operator (IESO) conducted a regional planning study in 2019 which determined that if the transformer at ERTS were to fail, power could not be restored to the customers within a reasonable timeframe. Hydro One was engaged to begin planning for upgrades to ERTS which would address the lack of redundancy. The project proposal is to install a second transformer at ERTS and have it as an on-potential spare which could easily begin supplying load if the existing equipment experiences a failure.

The existing alternate 34.5kV feeder is supplied from another Hydro One transformer station, Northern Avenue Transformer Station (NATS) in Sault Ste. Marie, Ontario. This alternate supply is 13km away from the nearest load center, Garden River DS, and 52km from the major load center at Desbarats DS. Long feeders are known for having voltage and reactive power issues, and this alternate feeder is only able to supply the East of Sault customers during summer months when the load is minimal.

CIMA was contracted in 2020 to study the East of Sault system and determine if there is a technically feasible distribution solution to back up ERTS. This study found that any attempt to rectify the voltage issues caused by long feeder lengths is ineffectual if 32km of conductor is not upgraded.

This report compares the upgrading of ERTS versus the reconductoring a significant portion of NATS's feeder. *Table 1* below summarizes the qualities of both projects.

Table 1: Project Comparison

Category	ERTS Upgrade	NATS Feeder Upgrade
Minimum Project Estimate	$6,208,000	$9,470,550
Upper Project Estimate	$10,088,000	$12,461,250
Turn-Key Solution	Yes	No
Construction Risk	Low	Medium
Project Timeline	2 Years	1 Year
Capacity for Future Load Growth	10MW	2.3MW

The budgetary range for these projects does overlap, however, the ERTS Upgrade budget is for a turn-key solution, whereas the NATS Feeder Upgrade budget does not include project management.

The ERTS Upgrade construction risk is low as Hydro One has constructed and maintains hundreds of transformer stations throughout Ontario. In addition to this, the property already has one of their stations constructed on it. The NATS Feeder Upgrade involves kilometers of off-road construction through a complicated right-of-way, which carries more construction risk. The NATS Feeder Upgrade is estimated to take one year, whereas the transformer construction is estimated to take two.

Part of the solution evaluation involves the potential for load growth in the area. Adding a second transformer to ERTS will provide a redundant supply to the East of Sault system for up to an additional 10MW of customer load. Upgrading NATS's feeder conductor will only be able to support 2.3MW of additional load prior to additional voltage regulators being required to boost feeder voltages.

The solutions presented would both solve the reliability issues raised by the IESO. This report will demonstrate that constructing a second transformer at ERTS is the better option.

2. Electrical System Components

2.1 Transformer Stations

Transformer stations are a portion of the electrical system which convert energy from one voltage to another. They change high transmission voltage levels to sub-transmission or distribution voltage levels. The generation and transmission systems (see *Figure 1*) are not the subject of this effort and are not evaluated beyond the outage data for ERTS. There are presently over 300 transformer stations owned by both Hydro One and municipal utilities throughout Ontario. In Northern Ontario it is common to have a sub-transmission voltage of 34.5kV or 44kV between the transmission station and the customer. In the case of Algoma Power's "East of Sault" system, the transformer stations supply at 34.5kV on overhead feeders to Algoma Power substations, which transform from 34.5kV to distribution level voltages of 12.47kV and 25kV.

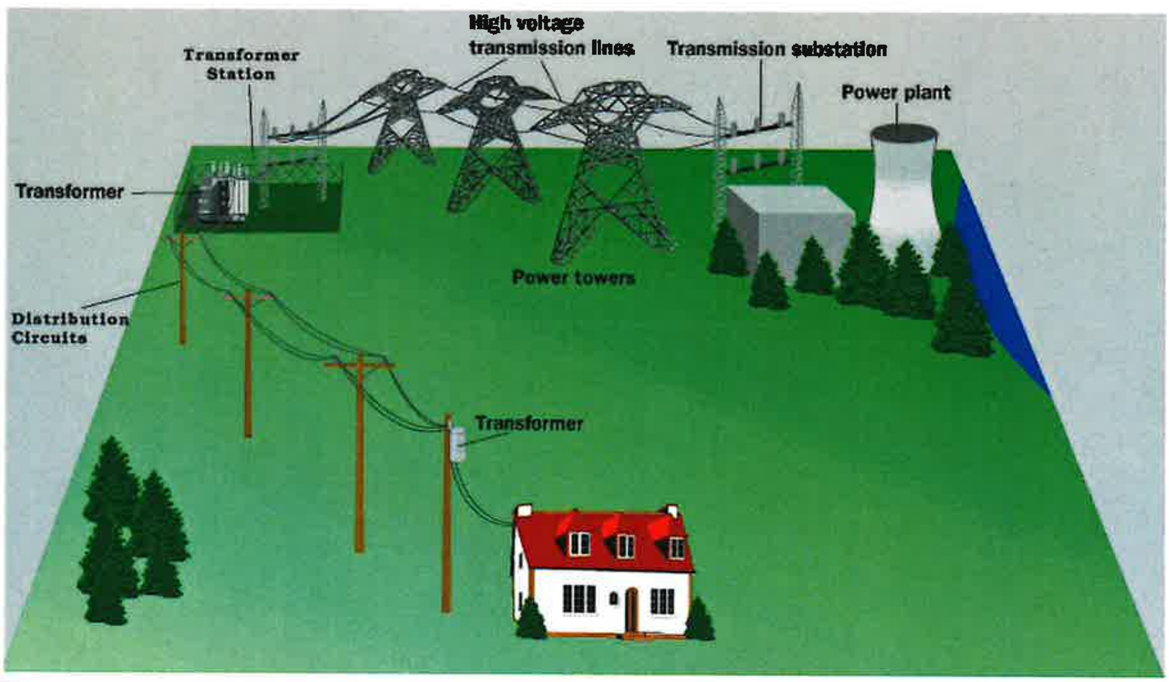

Figure 1: Power Grid Illustration

2.1.1 Transformer Station Redundancy

Transformer stations in Ontario are generally designed to have redundancy in critical components, so that a single component failure will not result in a sustained loss of supply for distribution customers. Transformer stations are usually supplied by two transmission lines to provide a higher level of reliability of the electricity supply during events such as weather-related momentary outages and planned maintenance. In the same manner, Transformer Stations (TS) are typically equipped with two power transformers and all associated components. When a transformer station is fully redundant in this manner, it is referred to as a Dual Element Spot

Network (DESN), which is typically the standard level of redundancy for utility transmission connected assets in Ontario.

As part of the redundancy strategy, power transformers are often designed to be overloaded for a specified duration in the event of the failure of one incoming transmission circuits or the failure of the other transformer in the same station. The magnitude and duration of the permitted overload is based on the original transformer design, which factors in the seasonal ambient temperatures to develop a "Limited Time Rating (LTR)" for the transformer. This LTR rating is the maximum loading permitted on a transformer for a given duration, with expectations of an acceptable loss of life on the unit.

In the event of the loss of one transmission line or power transformer, any station load which exceeds the LTR must be removed from the station. This can be done by transferring load to an adjacent facility, or to enact rotational load shedding (rotating blackouts), if an adequate alternate supply is not available.

As part of normal utility planning processes, the transmission and distribution utilities collectively review the capability of transformer stations to ensure that adequate supply and redundancy exists. Given that new transformer stations require about two to three years to plan, design, and construct, the decision to build new station capacity must be made well before the electrical load approaches the ratings of the transformer station.

2.2 Distribution Circuit Redundancy

2.2.1 Distribution Feeder Planning

In the case of the East of Sault system, Algoma Power receives power at 34.5kV and conveys it to Distribution Substations (DS), which transform down to 12.47kV or 25kV for further distribution to customers throughout their service territory.

Distribution systems in Ontario are typically designed to have backup where reasonably and economically achievable. Distribution feeders will typically have a back up supply from one or more distribution feeders. These back up feeders can be from the same DS or from another DS, depending on factors such as geographical capabilities, total DS load, and switching capabilities. Customers will typically be connected through a single transformer, either pole or pad mounted, to the distribution feeder.

2.2.2 System Power Quality Requirements

Distribution Utilities are required to deliver power within regulated parameters. Power quality encompasses voltage, frequency, harmonics, power factor, and the length of time these parameters can be outside of normal ranges as defined by the Canadian Standards Association CAN-CSA. These standards were adopted to ensure that customer equipment is not damaged by the quality of the power generated and delivered within the electrical grid in Ontario and the wider North American system.

In the case of the East of Sault, the power quality aspects associated with long distribution feeders can be an issue. Voltage performance for physically long feeders with varying load profiles is often a challenge for distribution utilities. A distribution utility may have to implement one or more methods to bring the voltage profile of the feeder into line with the regulated parameters. These options include increasing conductor size to reduce line losses, reactive power compensation by installing capacitors along the line, automatic tap changers on substation transformers, load transfers to other substations, and non-wires solutions to reduce the feeder loads at peak times.

3. Existing Conditions and Challenges

3.1 Existing System Configuration

Algoma Power's (Algoma) 34.5kV East of Sault system is normally supplied by a Hydro One owned transformer station, ERTS, located in Echo River, Ontario. The alternate supply for the East of Sault 34.5kV system is from a single 34.5kV feeder out of the HONI owned NATS located in Sault Ste Marie. The distances between the supply stations are noted in *Figure 2* below.

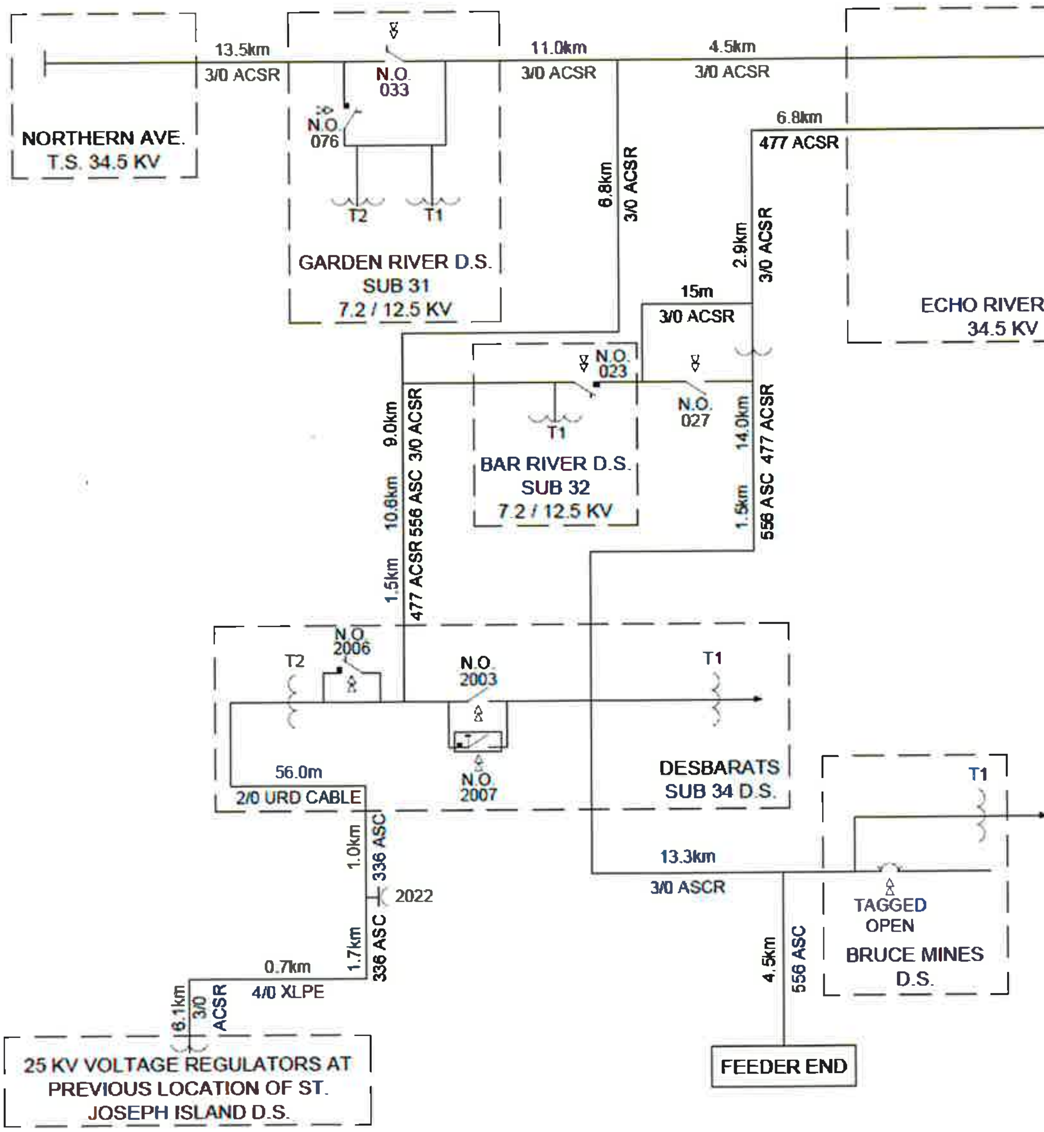

Figure 2: Normal Configuration for Algoma's East of Sault Ste Marie System

3.1.1 Normal Operating Configuration

ERTS is a 230kV/34.5kV station with two incoming 230kV circuits. However, ERTS is not a DESN station as it only has a single transformer and there are no automatic switching capabilities in the station. In addition to the lack of DESN redundancy, the primary switch has reached its end of life and is scheduled for replacement in 2021.

The normal operating configuration for the East of Sault 34.5kV system is fed from two feeders, ER1 and ER2, both of which are over 45km in overall length. Both the ER1 and ER2 feeders are physically situated alongside roadways and through forested off-road areas, with several river crossings. As mentioned earlier, feeders of these lengths can have low voltage issues and energy losses due to the resistive and inductive properties of the conductors. To compensate for the voltage drop, each of the feeders is already equipped with voltage regulators which automatically boost the voltage of the line to adjust for line losses. This is normal practice for local distribution companies with feeders of this length. There are four Algoma distribution stations along the two feeders (Bar River DS, Desbarats DS, Bruce Mines DS, and Garden River DS). Each of these distribution stations is already equipped with capacitors for reactive power support. The capacitors are automatically switched and are able to return the power factor to near unity.

3.1.2 Alternate Configuration

The alternate supply for the East of Sault 34.5kV system is from the Hydro One owned station, NATS, located in Sault Ste Marie, Ontario. NATS is a DESN station but only has one transmission circuit supplying the station.

This alternate, or backup, configuration provides a single 34.5kV feeder from NATS that connects to an open point at Garden River DS. The distance between the alternate supply (NATS) and the point of connection to the ER1/ER2 feeders is 13.5km, much of which is through off-road areas, river crossings, with some sections running adjacent to HWY17.

3.1.3 IESO Outage Requirements

ERTS is connected to the Ontario Transmission System (230kV) and is therefore subject to IESO transmission system requirements. The IESO has divided the province into several regions to address, coordinate, and plan for geographically specific issues. Algoma's East of Sault territory is in the East Lake Superior Region. A joint regional planning study[1] authored by the IESO has determined that a major transformer failure at ERTS would result in an unacceptable duration of outage. The IESO's *Ontario Resource and Transmission Assessment*

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[1] Hydro One, Algoma Power, PUC Services, Chapleau Hydro, IESO. (June 14, 2019). *Needs Assessment Report East Lake Superior Region.*

Criteria, Section 7.2 states that, “All loads must be restored within approximately 8 hours.”[2] With no readily available spare on site, it would take more than 8 hours to procure, install, commission, and energize another transformer.

3.2 Algoma’s Supply Considerations

The East of Sault 34.5kV system has a winter peak load of 15.6MVA and a summer minimum load of 4.5MVA. As a result of the loading profile of the area, the system is more vulnerable to supply constraints during the fall-winter-spring seasons when heating is the predominate load.

Under the normal operating configuration from ERTS, the Algoma East of Sault 34.5kV system performance is well supported by the existing voltage regulation and supplemental reactive power devices.

When forced to change to the alternate supply from NATS, the extremely long feeder lengths and conductor sizing can cause some voltage performance issues. The 2020 study performed by CIMA found that the existing voltage regulators and capacitor banks fail to keep the voltage profile of the 34.5kV system above the minimum levels if the loading on the system is more than 75% of the peak, which is 9 months of the year.

[2] IESO. (August 22, 2007). *Ontario Resource and Transmission Assessment Criteria* (Document ID IMO_REQ_0041). Section 7.2, Page 30.

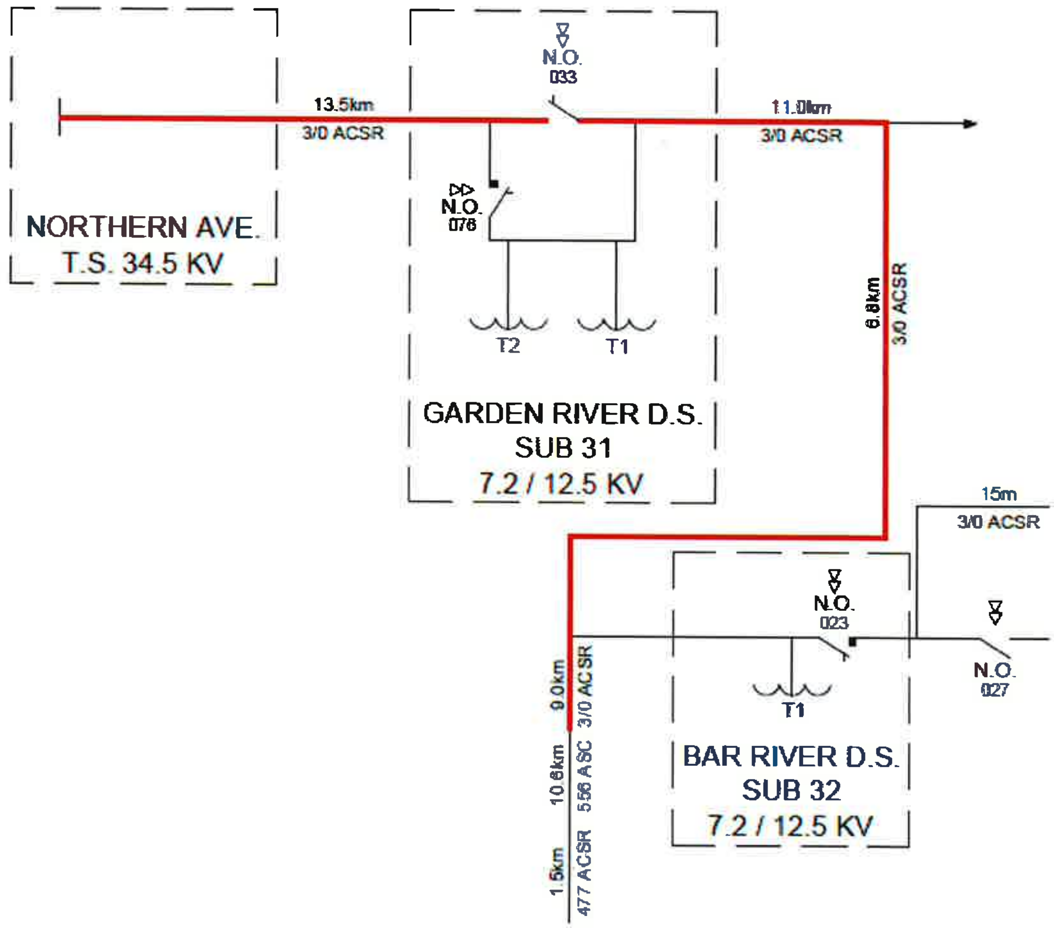

Figure 3: 3/0 Conductor Between NATS and Bar River DS

The main reason for this performance limitation when supplied from NATS is a 31km stretch of 3/0 conductor between NATS and the Bar River DS (refer to *Figure 3* above). The losses and associated voltage drop created by this stretch of conductor exceed the bandwidth limit of existing voltage regulators which results in poor voltage performance to the customer. Therefore, under existing conditions, the NATS supply is only a viable alternative during the summer months.

3.3 Algoma Power Investigations to Date

Algoma has been working to determine what solutions could be implemented to the East of Sault 34.5kV system in order to meet the IESO requirement as well as evaluating the possible solutions on a technical and financial basis. With assistance from Hydro One (HONI), Algoma Power has been reviewing plans and construction cost estimates to install a spare transformer at ERTS, attached in *Appendix A*. The plan developed out of that effort would provide an "On-Potential" spare transformer that could be switched in to replace the failed unit within the mandated 8-hour time frame. The switches would be manual, but this work could be completed and power restored within the IESO outage requirements.

To determine if there was a distribution alternative to the reliability issue, Algoma Power commissioned CIMA+ to study the alternative feed from NATS. CIMA+ conducted the study during 2020, attached in *Appendix B*. The study found that distribution alternatives were ineffective if the 31km of 3/0 conductor between NATS and Bar River DS was not upgraded to a larger size. CIMA+ then prepared construction cost estimates for the conductor upgrade.

The options' evaluations and the economic considerations follow.

4. Alternatives to Meet IESO Reliability Requirements

4.1 Historical Practice (Current Response Plan)

When an outage occurs on the 230kV circuits supplying ERTS, Algoma Power communicates with HONI for a restoration timeline. The restoration timelines usually do not warrant Algoma Power to begin switching activities to restore service to customers, and Algoma Power will wait for HONI to restore a 230kV circuit. There are two 230kV circuits supplying ERTS, so the frequency and duration of 230kV outages to the station are not high. *Table 2* below shows the number of interruptions and the total duration in minutes for 2015-2019.

Table 2: ERTS High Voltage Outage Data

Year	Number of Interruptions	Interruption Duration (Min)
2019	0	0
2018	1	133
2017	2	84
2016	1	7
2015	0	0

The time of year greatly affects Algoma's decision on how to respond to an outage at ERTS. Planned outages are scheduled during the summer so that the load can be transferred to the back-up supply from NATS without creating low voltage issues on the East of Sault system. If an unplanned outage at ERTS were to occur during the summer, Algoma communicates with Hydro One to determine the estimated restoration times. If the restoration time is significant, Algoma initiates plans to transfer loads to the NATS back-up supply.

If a major outage to ERTS occurs when loading is greater than 75% of peak, Algoma maintains communications with Hydro One to determine restoration timelines. If the outage is expected to take more than 8 hours, load may be transferred to NATS and rotating blackouts would be implemented to limit feeder loading and reduce continuous outage times to the customers. Although a workable solution, rotating outages in Northern Ontario during winter months is not popular, certainly an inconvenience, and possibly a safety hazard for any customers without an alternative heating source. Prolonged power outages would also have a significant impact on customers with water wells and sewage pumps.

The conclusion was that leaving the system in its current state has a reliability shortfall. An alternate approach, that will provide a higher level of redundancy for the normal supply out of ERTS, is needed to improve the system reliability and to meet the IESO outage requirements.

4.2 Option 1: Upgrading HONI's ERTS

This option involves installing a new primary switch, spare transformer, and secondary switches at ERTS. The transformer would be left energized but unloaded. Either T1 or T2 would be capable of supplying the full system load out of ERTS, but the secondary switches would need to be manually operated to transfer load to the new transformer in the event of a failure of the normal unit.

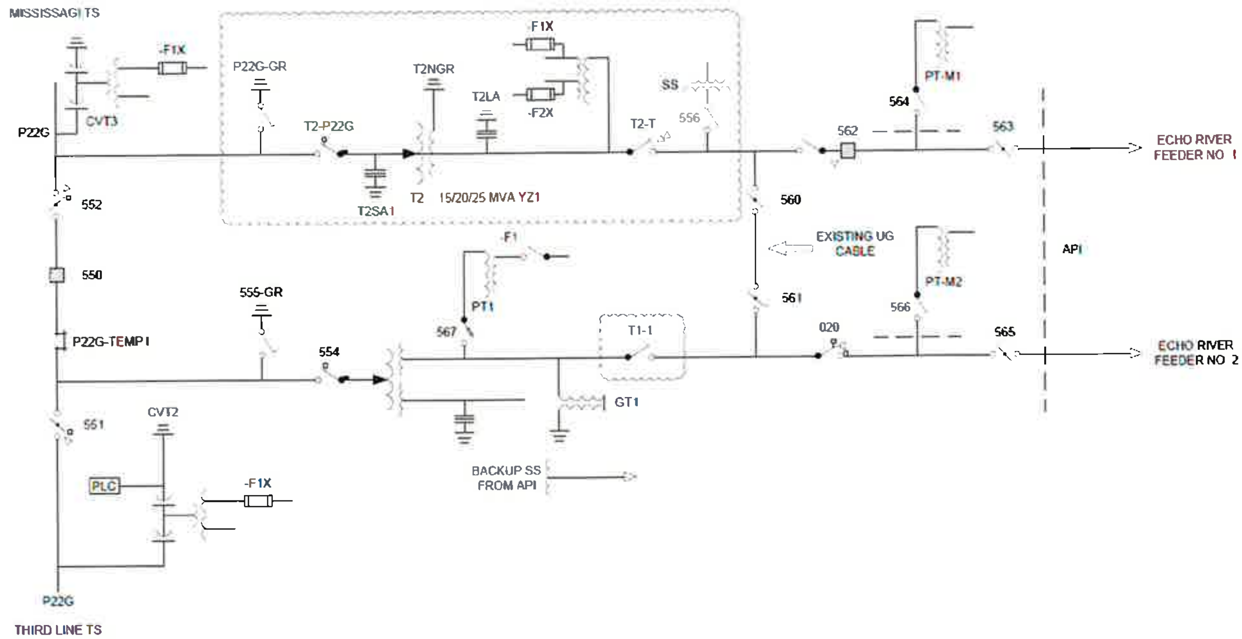

Figure 4: Proposed ERTS Single Line Diagram

This configuration would improve the reliability of ERTS and would address the main concern of a major transformer failure causing an outage duration longer than 8 hours.

4.3 Option 2: Upgrading NATS Alternate Feeder

As explained in *Section 3.2* above, the biggest impediment to using the back-up supply from NATS is the restrictions imposed due to the 31km section of 3/0 conductor between NATS and Bar River DS. The 2020 study done by CIMA+ (*Appendix B*) determined that upgrading this section of conductor was fundamental to any distribution level solutions to deal with voltage constraints when using the back-up supply from NATS.

The CIMA+ study determined that simply adding in more voltage regulators and capacitor banks alone without reconductoring was not a viable solution. Increasing the conductor size of this section would allow existing voltage regulators and reactive power compensation to perform within their rated capabilities and adjust the voltages for the East of Sault system to acceptable values.

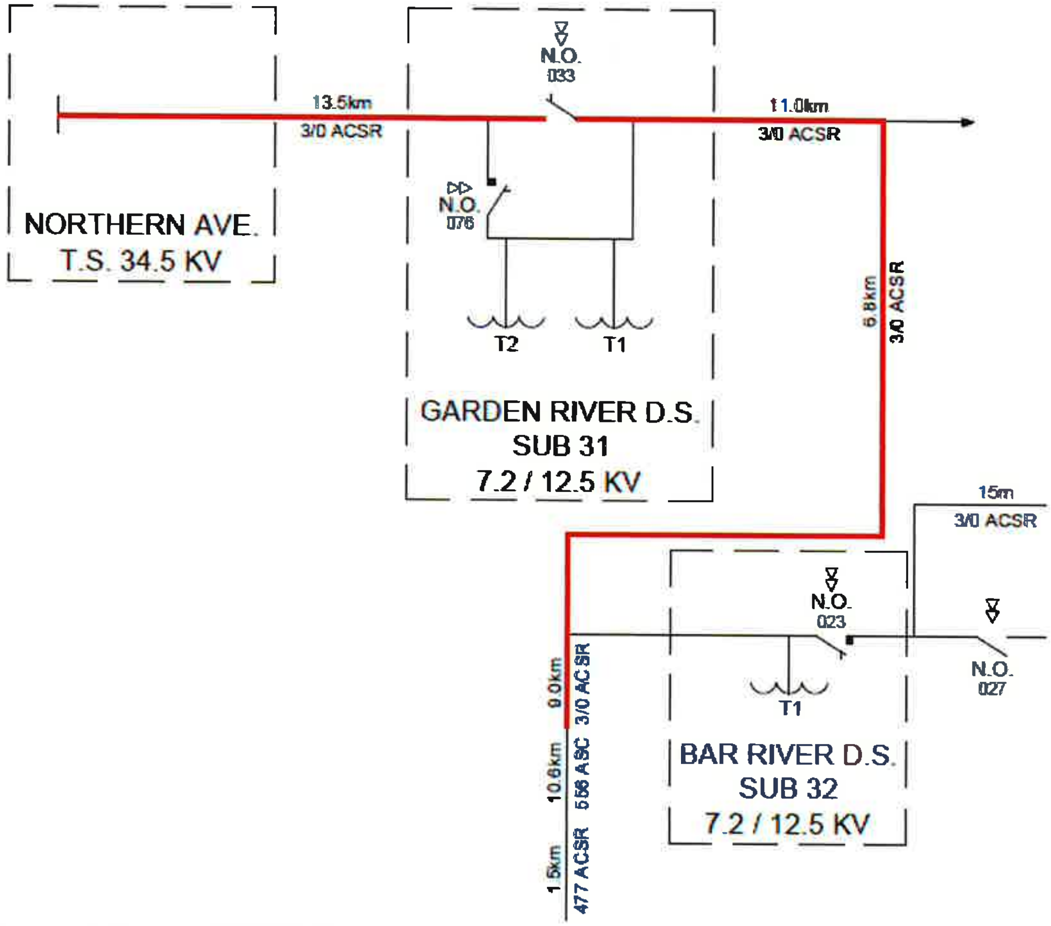

Figure 5: Proposed NATS Feeder Upgrades

Upgrading the size of the 3/0 conductor resolves the issue of a long outage duration by offering a viable alternative year-round source. If any equipment failure or other issue arises with ERTS, the distribution system could be supplied from NATS within acceptable power quality parameters. The necessary switching activities would need to be performed manually, but power could be restored to the East of Sault system within the 8-hour requirement.

5. Economic Evaluation of Alternatives

This section will outline and compare the estimated construction cost budgets for the proposed ERTS and NATS feeder upgrade options identified earlier in the report. Efforts have been made to have the cost estimates match in overall accuracy, but differences in budget accuracy are identified where applicable.

5.1 Upgrading HONI's ERTS

The budget outlined in *Table 3* was supplied by HONI on January 8th, 2021.

Table 3: HONI Supplied Budget

Category	Total Estimated Cost
Preliminary Engineering & Estimating	$393,000
Project Management	$689,000
Engineering	$799,000
Procurement	$2,060,000
Construction	$2,320,000
Commissioning	$622,000
Direct Cost (Subtotal)	**$6,883,000**
Contingency	$883,000
Removal	-$6,000
Total	**$7,760,000**

The ERTS upgrade budget has an accuracy of -20% to +30%. This translates to a range of between $6,208,000 to $10,088,000. This is for a turn-key solution, with minimal extra costs from Algoma to review project progress. The removal credit is for the scrap value of equipment being removed during the project.

5.2 Upgrading NATS Alternate Feeder

The budget outlined in *Table 4* was supplied by PowerTel and CIMA+ on August 6th, 2020. The permitting costs were supplied by Algoma.

Table 4: PowerTel and CIMA+ Supplied Budget

Category	Total Estimated Cost
Preliminary Engineering & Estimating	$393,000
Engineering	$701,000
Local and Construction Permitting	$925,000
Construction/Materials	$7,950,000
Total	**$9,969,000**

The reconductoring budget has an accuracy of -5% to +25% for the engineering, construction and materials. This translates to a range of between $9,470,550 to $12,461,250. This budget does not include project management and administration. It is possible that the all-inclusive cost of construction could exceed the upper estimation.

5.3 Comparison of Budget Costs

The range of the alternatives' estimates does cause some overlap in the possible project costs. The upper range of the HONI ERTS upgrades and lower range of the NATS Feeder upgrades overlap by about $500k. There is a possibility that the NATS Feeder upgrades may cost less than the ERTS upgrades, however, as the project management, and administration has not been included it is unlikely that it will be the less expensive option.

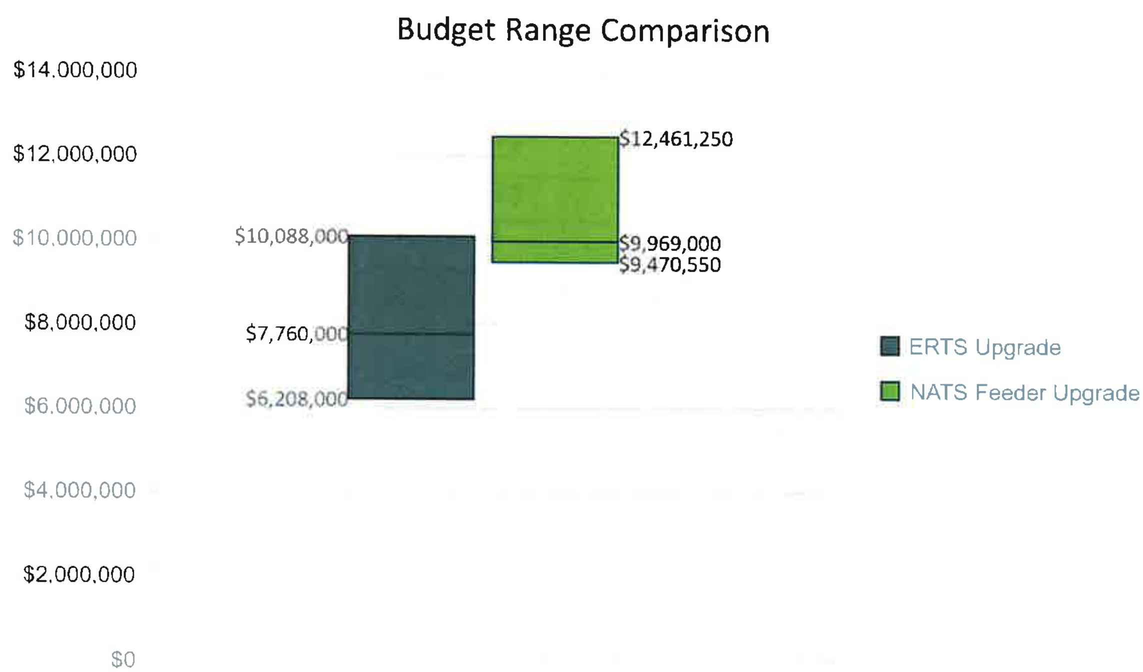

Figure 6: Budget Range Comparison

6. Project Schedules

HONI provided a proposed project schedule on December 15th, 2020. The assumed project start was Q1 of 2021, T2 energization in Q4 2022, and total project completion in Q2 2023 (this would include the T1 primary switch replacement, which is not part of this evaluation). The completion dates would be subject to weather, COVID-19 restrictions, and TS outage times to be coordinated with Algoma. After T2 is completed and in service, T1 will be removed from service to replace the primary switch as identified in the Needs Assessment Report.

As part of the CIMA+ 2020 study, PowerTel was contracted to create an estimate and project timeline for reconductoring the NATS Alternate Feeder. PowerTel determined that a 20-25 person crew could complete construction in 7-8 non-winter months. If construction were to begin in Q1 2021, the in-service date could be Q4 2021. This timeline would be subject to weather, COVID-19 restrictions, and outage availability subject to recall times.

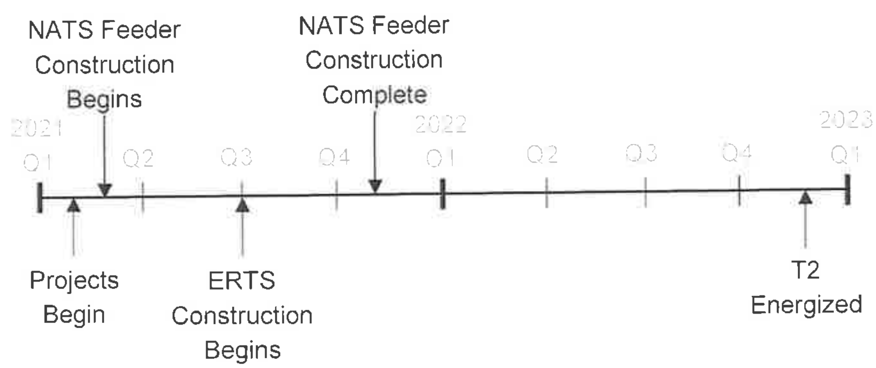

Figure 7: Project Timeline Comparison

The NATS Feeder Upgrades could be completed a year prior to the ERTS upgrades if both projects were started at the same time.

7. Benefits and Challenges

7.1 Upgrading HONI's ERTS

Adding a spare transformer to an existing station yard can have many advantages and challenges. The specifics of adding an on-potential spare transformer and the associated equipment to ERTS will be explored in this section.

7.1.1 Benefits

The primary benefit of adding an on-potential spare transformer to ERTS is the redundancy of equipment. The project scope would duplicate the station equipment and provide additional open tie points. This would address the main concern of being able to restore power within an 8-hour timeframe after a major equipment failure. The redundant equipment adds the ability to more easily isolate equipment within the station for maintenance. A failure of one piece of equipment would still leave two contingency situations with the other half of ERTS as well as the NATS backup during some points of the year.

This option supports long term load growth in the area. The new transformer would be able to supply the existing peak load, plus an additional 10MW (64% of existing peak load). The station currently has two feeders, one 3/0 and one 477, which can carry the full individual transformer capacity of 25MW. The caveat to adding additional load is whether additional voltage support would be required, but that would need to be studied when load is proposed. The additional redundant capacity would better position Algoma to connect future customers, energy storage, and electric vehicles.

The upgrade project can be performed on the existing ERTS site. Land does not need to be purchased, and the station owner, HONI, would be performing the work. The station is located alongside the end of the paved portion of road and can be easily accessed. Equipment could be stationed on the property, and minimal traffic interruption would be required. There would also be no off-road construction, and the site has been constructed on before, minimizing the risk of unknown ground conditions.

One of the benefits to Algoma Power would be that the procurement, construction, and majority of the project management will be performed by Hydro One. The burden on Algoma's staff would be minimal as HONI included project management in the price of the project.

7.1.2 Challenges

This station would still be susceptible to a total 230kV outage, as detailed in *Table 1*. The historical data shows a long duration outage does not have a high probability and would not be expected to impact Algoma's ability to restore power within 8 hours if this solution is implemented.

A catastrophic event could theoretically damage equipment at ERTS and cause a long duration outage. The design of the station will take into account the proximity of the two transformers to each other and have fire detection and suppression methods to prevent a fire from damaging both units. There will be some distance between the two transformers to mitigate the likelihood of both being damaged in one event. There is little traffic on the road, and the pavement ends one property after the station, so the risk of a large vehicular accident is minimal.

One challenge when constructing any electrical infrastructure project is the vulnerability created by removing one of the redundancy options from service. ERTS would require outages to perform work that cannot safely be done when the station is live. Having ERTS deenergized for construction (subject to recall times) would mean that NATS would be the only source for the area. If NATS is the only source for the area any incident along the over 50km of single circuit, the area would be without power until a recall could be performed or the circuit repaired. The obvious loading constraints, which this solution is being proposed to address, would also limit the times when ERTS could be deenergized.

The construction time for this project is two years, which is longer than the other option. A longer construction time means that the reliability issue persists through another winter.

7.2 Upgrading NATS Alternate Feeder

Rebuilding a line comes with its own set of challenges and benefits. In this section the pros and cons of reconductoring the NATS Feeder will be explored.

7.2.1 Benefits

The primary benefit of this solution is diversifying the supply of power. NATS is in a different region from ERTS and any accident, weather, or geological event which compromises ERTS is unlikely to also affect NATS. This option would address the restoration time issue by having a ready alternate which can supply the entire load at any time simply by switching in the system.

As the load in the East of Sault system increases, this solution has the ability to support an additional 2.3MW of load (15% of peak) before delivered voltages dip below acceptable values and more voltage support would be required. If additional supports were put in place, such as on-load tap changers at the DS transformers and additional voltage regulators, then this solution could support an additional 5.8MW of load (37% of peak) before other limitations are reached. (See CIMA's 2020 report in *Appendix A*, Section 6.)

Some of the existing poles are very old and in need of replacement. This project would include the replacement of these poles and decrease the overall likelihood of equipment failure on the feeder.

7.2.2 Challenges

The route from NATS is 13km to Garden River DS, then an additional 18km to Bar River DS, a large portion of which is off-road. This exposes the feeder to several kilometers of possible tree contacts and other forms of physical damage such as accidents. Repairs of off-road lines take significantly longer than lines on roadway allowances due to access issues. Assuming that the load is being supplied from NATS due to an outage at ERTS, the 5000 customer load would be under a single contingency situation. The heavily loaded, single feeder outage would require sectionalized restoration which would increase outage times for customers furthest from the source.

75% of the customers are located 50-70km from NATS. Even after the conductor has been replaced, the long feeder length will still have a significant amount of losses.

This solution faces similar outage challenges during construction as upgrading ERTS. During NATS construction, the area would have a single, non-redundant source from ERTS. If anything were to happen at ERTS then the area would be without power until the NATS route could be recalled or ERTS could be repaired and brought back online.

The NATS Feeder upgrade is unlikely to be the less expensive option based upon the budgetary numbers and the upper and lower budget range. The existing project costs also do not include project management costs, which would need to either be outsourced or internalized by Algoma. The project manager would need to dedicate several hours a week to this project, which could be a burden on an employee's time.

8. Conclusions and Recommendations

Algoma Power's East of Sault distribution system has a reliability vulnerability at ERTS. If there was a major equipment failure, the load would not be consistently restored within an 8-hour timeframe. For this reason, Algoma has been investigating solutions to increase the system redundancy.

Upgrading ERTS to have an on-potential spare transformer is the solution which will likely cost the least, while providing the most long-term benefits. All the costs to upgrade ERTS are known, and as a turn-key project it will place less burden on Algoma's employees. This project will likely be able to handle five times more load growth than upgrading NATS's feeder. The construction risk is lower because the construction will take place on a property owned by HONI and alongside a road, rather than on a complicated right-of-way through various off-road terrains.

The ERTS upgrade project appears to have more and better overall benefits than upgrading the NATS feeder. For these reasons, it is our recommendation to proceed with Hydro One's proposal to install an on-potential spare transformer at ERTS.

A

Appendix A

CIMA+ Report – C16-0056 East Sault Ste Marie Distribution System

CIMA+

ALGOMA POWER

EAST SAULT STE MARIE 34.5KV SUB-TRANSMISSION SYSTEM ANALYSIS

6 August, 2020

C16-0056

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Algoma Power

Type of report

Distribution System Analysis

Low Voltage Analysis and Solution Discussion

Project no. C16-0056

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0	26 June, 2020	Ashley Rist, P.Eng.		Stephen Costello, CET
1	6 August, 2020	Ashley Rist, P.Eng.		Stephen Costello, CET

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1. Executive Summary

The 34.5kV distribution system east of Sault Ste Marie is mostly supplied by Hydro One's Echo River Transformer Station (ERTS). A joint regional planning study (June 2019) authored by the IESO has determined that a major failure at ERTS would result in an unacceptable duration outage (greater than eight hours). CIMA has been commissioned to look at distribution alternatives to Hydro One adding additional capacity at ERTS. Hydro One is currently reviewing the scope, schedule, and costs of upgrading ERTS such that an outage could be managed with a duration shorter than eight hours.

This study is looking at the possibility of supplying the same load area from the Sault Ste Marie Northern Avenue Transformer Station (NATS) over the existing 34.5kV distribution system. CIMA has been engaged to perform a study to asses the existing distribution system's ability to supply all of the load from NATS. The distance of the circuit from NATS is substantially longer than if the load were to be fed from ERTS. In addition, there is relatively small conductor size for approximately 31km from NATS and Bar River Distribution Station.

This study found that it is technically feasible to supply all of the load from NATS, if the 31km stretch of 3/0 ACSR conductor between NATS and Bar River Distribution Station is reconductored. When the system is being supplied from NATS, this section is heavily loaded which contributes to significant voltage drop. If this section of conductor is replaced with 556 ASC, the lowest calculated delivery voltage is within the acceptable range. The cost for rebuilding was estimated by PowerTel and the engineering costs estimated by CIMA+, totalling $8.7M Class 3 (+25%, -5%). This cost does not include other typical project costs, such as Algoma's project management costs or other typical construction project costs for the area.

Other options explored involved voltage support devices, such as voltage regulators, capacitors, and on-load tap changers. It was determined that installing equipment without reconductoring was not enough to correct the voltage, and in addition the 3/0 ACSR conductor became heavily loaded. In the course of our study, we found there are opportunities to improve voltage regulation and efficiency under normal and contingency conditions with relatively minor modifications or additions in equipment. This is discussed later in the report.

2. Introduction

Algoma Power had a previous study performed in 2018 to analyze a contingency situation where the Echo River TS (ERTS) load is supplied by NA1 feeder from Northern Ave TS (NATS). The study found that if the peak load were to be supplied from NATS that the delivery voltage would be unacceptably low to a significant portion of the system. A prolonged outage would require rolling blackouts to maintain acceptable voltages to supplied customers. The recommendation from this report was to procure a spare power transformer for ERTS to mitigate the need to supply the system from NATS. A spare was quoted by Hydro One and would cost approximately $6-9M. This solution provides either an off-potential or on-potential spare, depending on cost. An off-potential spare would add a significant amount of time to process the oil and make all of the terminations. An on-potential spare would still require an extended outage to bring the spare transformer into service and make secondary connections.

As part of its due diligence, Algoma Power requested the services of CIMA+ to analyze distribution solutions for the extremely low voltage issues when in a contingency situation. System data, including existing equipment and equipment controls, historical loading, conductor types and lengths were collected and used to build the base model. The model was then verified using in-field measurements at reclosers, capacitor banks, and regulators. CIMA+ established benchmarks for both ERTS and NATS supplying the system through load flow modelling. Possible scenarios were modeled and compared against the existing situations as well as against each other for feasibility.

All proposed solutions include reconductoring the 31km section of 3/0 ACSR from NATS to Bar River DS. This section is 85% loaded during peak conditions and contributes significant voltage drop and losses in the system. PowerTel was engaged to construct an estimate for replacing this section, their full estimate can be found in *Appendix B*. CIMA+ estimated the cost of engineering for the rebuild and the detailed estimate can be found in *Appendix D*.

3. Assumptions

The system was modeled using CYME V9.0, using the supplied information from API and the assumptions below.

The normal operating conditions were taken from *Bruce Mines 34.5kV Line System Operating Diagram, DB-32001 Rev 58*. To transfer load to NATS, switches 076 and 023 are closed; switches 020 and 562 are opened.

Acceptable voltage range used was -5% to +5%.

Loads in the system were modeled after peak loading in January 2019. Feeder End was assumed to be an industrial load and was modeled using the highest non-coincident kW and kVAr from 2017-2019. Minimum loads were assumed to be 30% of peak. Load power factors were assumed to be 95% lagging.

The model was validated against metered data using two methods. The data collected and calculations to verify the model are detailed in *Appendix B*.

3.1 API Provided Information

- HONI Data
  - Voltage Regulation Information
    - Set Voltage
    - Load Drop Compensation
    - Bandwidth
    - Normal Operating Voltage
    - Minimum and Maximum Bus Voltage
  - Transformer Tap Changer
    - Voltage Range
    - Number of Steps
  - Source Impedance
  - Protection Settings
- Distribution Circuits
  - Operating Map
  - Switching Sequence
  - Station Transformer Data
    - Voltages
    - Impedance
    - Tap Changers (steps, voltage regulation settings)
  - Distribution Regulators
    - Size
    - Range
    - AVR Relay and Settings
  - No capacitors on the system

- Loading
  - HONI PME (ERTS and NATS) Monthly Maximum kVA and kW for three years
  - API DS Monthly Maximum kWh for two years
  - Monthly Minimum and Maximum for Direct 34.5kV customers

A copy of API's 34.5kV single line diagram is included in *Appendix E.*

3.2 CIMA+ Assumptions

The following table describes the assumed conductor and cable impedances used in the model. These are the default values in the CYME library. The overhead conductor spacing was assumed to be linear, two foot spacing.

Table 1: Conductor Assumptions

Conductor Size	Type	Codename	Ampacity	Positive Sequence Impedance (Ω/m)	Zero Sequence Impedance (Ω/m)
2/0	XLPE - CU		275	0.511+j0.242	0.797+j3.999
4/0	XLPE - CU		375	0.338+j0.214	0.6243+j3.971
3/0	ACSR	Pigeon	315	0.555+0.677	1.285+j2.330
336	ASC	Canna	510	0.237+j0.636	0.967+j2.288
477	ACSR	Hawk	640	0.198+j0.606	0.928+j2.258
556	ASC	Dahlia	645	0.170+j0.615	0.900+j2.267

3.3 CYME Analysis Clarifications

The total loads calculated by CYME are as seen from the source, or TS. The rows labeled "Loads" in the following section account for losses, voltage regulation, and capacitive devices.

CYME adjusts loads used in the model, "Load used (Adjusted)" in the Summary Reports, so that the total load analysed will match what was modeled at the source. In this case, the "Loads" in the following section will be 16.2MVA at peak and 4.9MA at minimum less the losses calculated.

DS and customer loads are modeled at 95%, unless data has been provided showing otherwise, but in conjunction with the capacitor banks the transformer stations typically show close to unity power factor.

4. Operating Scenarios

Three scenarios were modeled to determine the voltages across the system and described in this section. A base case was established using existing conditions when the system is fed from ERTS and NATS. The first distribution solution explored was to reconductor 31km of 3/0 ACSR with 556 ASC between NATS and Bar River DS. The second solution involves reconductoring, but also explores having load tap changers on the distribution station transformers and one three phase voltage regulator upstream of Bruce Mines.

Detailed CYME results can be found in *Appendix C*.

4.1 Base Case

The load is usually fed from ERTS. The tables below demonstrate the base case voltage and loading under normal operating conditions.

Table 2: From ERTS Base Case – Peak Load

Total	kW	kVAr	kVA	PF
Sources	15644	1300	15698	99%
Generators (Solar)	239	0	239	100%
Loads	15404	553	15414	99%
Line/Cable Inductance	0	605	605	100%
Calculated Losses	480	1352	1434	31%

Table 3: From ERTS Base Case – Peak Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 081 to 079	42%
Lowest Voltage	A	Feeder End	97%
	B	Feeder End	98%
	C	Feeder End	99%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	ERTS	104%

Table 4: From ERTS Base Case – Minimum Load

Total	kW	kVAr	kVA	PF
Sources	4568	-40	4568	100%
Generators (Solar)	239	0	239	100%
Loads	4761	440	4782	99%
Line/Cable Inductance	0	615	615	100%
Calculated Losses	45	135	143	32%

Table 5: From ERTS Base Case – Minimum Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 081 to 079	12%
Lowest Voltage	A	Feeder End	101%
	B	Feeder End	101%
	C	Feeder End	101%
Highest Voltage	A	Switch 076	104%
	B	Switch 076	104%
	C	Switch 076	104%

Under normal operating conditions from ERTS, delivery voltage parameters are within acceptable limits. The lowest voltage is at Feeder End at 97%. If more load were to be added to the system, there is a possibility that Feeder End could have an under-voltage condition at peak load.

4.2 Base Case from NATS

If the supply from ERTS is interrupted, the backup supply is currently from NATS. This section evaluates supplying the system from NATS at peak and minimum loading.

Table 6: From NATS – Peak Load

Total	kW	kVAr	kVA	PF
Sources	15264	3422	15643	98%
Generators (Solar)	239	0	239	100%
Loads	13319	696	13337	99%
Line/Cable Inductance	0	496	496	100%
Calculated Losses	2185	3222	3893	56%

Table 7: From NATS – Peak Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from NATS to Bar River DS	84%
Lowest Voltage	A	Supply Side of St Joseph Regulator	85%
	B	Supply Side of St Joseph Regulator	85%
	C	Supply Side of St Joseph Regulator	88%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	ERTS	104%

Table 8: From NATS – Minimum Load

Total	kW	kVAr	kVA	PF
Sources	4581	135	4583	99%
Generators (Solar)	239	0	239	100%
Loads	4628	422	4647	99%
Line/Cable Inductance	0	588	588	100%
Calculated Losses	193	300	357	54%

Table 9: From NATS – Minimum Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from NATS to Bar River DS	25%
Lowest Voltage	A	Supply Side of St Joseph Regulator	100%
	B	Supply Side of St Joseph Regulator	98%
	C	Supply Side of St Joseph Regulator	100%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	ERTS	104%

Algoma's peak load occurs during winter months, and it is a single peak load system. The delivery voltages are below acceptable voltage levels when supplied from NATS. Some sections of conductor are over 80% loaded, which contributes to the low voltage issues. If this situation occurs, rolling blackouts are utilized to reduce loading and increase the voltage to acceptable values. Bar River was found to have the lowest voltage at 87%, as it is does not have an upstream voltage regulator. Rotating blackouts in rural Northern Ontario during the winter can be dangerous for the public, as heating homes is a safety issue.

Without any changes, NATS can supply the system with acceptable delivery voltages during minimum load. Algoma's minimum load occurs during the summer.

4.3 From NATS, with Only Regulators

If voltage support devices are installed, the distribution system can adapt to changes in supply and load more effectively. This section outlines the operating conditions when supplied from NATS, after installing several voltage regulators. The regulators were modeled upstream (when supplied from NATS) of Garden River DS, Switch 077, Bar River DS, and Bruce Mines.

Table 10: From NATS – Peak Load

Total	kW	kVAr	kVA	PF
Sources	16294	5039	17055	95%
Generators (Solar)	239	0	239	100%
Loads	15487	2013	15618	99%
Line/Cable Inductance	0	570	570	100%
Calculated Losses	1046	3596	3745	28%

Table 11: From NATS – Peak Load Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from NATS to Garden River	107%
Lowest Voltage	A	Supply Side of Bruce Mines Regulator	89%
	B	Supply Side of Bruce Mines Regulator	93%
	C	Supply Side of Bruce Mines Regulator	93%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	ERTS	104%

4.4 From NATS, with Reconductoring

Reconductoring the 3/0 ACSR from NATS to Bar River DS can resolve the voltage issues. This section describes the conditions for supplying from NATS with a rebuilt line.

Table 12: From NATS – Peak Load

Total	kW	kVAr	kVA	PF
Sources	15705	4660	16381	96%
Generators (Solar)	239	0	239	100%
Loads	14986	1902	15106	99%
Line/Cable Inductance	0	571	571	100%
Calculated Losses	958	3330	3465	28%

Table 13: From NATS – Peak Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 2025 to tie between 023 and 027	48%
Lowest Voltage	A	Supply Side of St Joseph Regulator	94%
	B	Supply Side of St Joseph Regulator	92%
	C	Supply Side of St Joseph Regulator	95%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	ERTS	104%

Table 14: From NATS – Minimum Load

Total	kW	kVAr	kVA	PF
Sources	4575	118	4577	99%
Generators (Solar)	239	0	239	100%
Loads	4734	459	4756	99%
Line/Cable Inductance	0	623	623	100%
Calculated Losses	80	282	293	28%

Table 15: From NATS – Minimum Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	2/0 AL from 2010 to 2011	15%
Lowest Voltage	A	Feeder End	99%
	B	Feeder End	100%
	C	Feeder End	100%
Highest Voltage	A	Bar River LV	105%
	B	Bar River LV	104%
	C	Bar River LV	106%

During peak load, reconductoring improves the lowest voltage point in the system by 12% to 92%. This is not a concern because it is on the supply side of a regulator and the regulator can boost the voltage by 10%. The delivery voltages improve so that the Feeder End load point is at 96%. This is within acceptable limits, though it is on the lower end of acceptable. At minimum load the minimum voltage is improved so that Feeder End is the lowest voltage point at 99%. This means that reconductoring is a viable distribution solution to the voltage issues.

4.5 From ERTS, Reconductor and Voltage Devices

Solutions with just equipment additions, such as adding multiple voltage regulators and capacitor banks along the line, did not adequately resolve the voltage issues and often caused the 3/0 ACSR conductor to become overloaded. This solution includes reconductoring and voltage devices which would improve both normal and contingency operating conditions. Voltage support devices include capacitors, on-load tap changers and voltage regulators.

Algoma's distribution system has capacitor banks installed, and the power factor is close to unity, and even leading in some instances. Therefore, capacitor banks were not modeled to correct the voltage issues on the system.

For this analysis, all distribution station transformers were modeled with on-load secondary tap changers capable of ±10%, set to 102.5% voltage and a 2.5% bandwidth. The on-load tap changers give distribution companies more control over delivery voltages as they adapt to minor changes in the primary voltage.

A voltage regulator which was functionally equivalent to the Bar River regulator was modeled upstream of the Bruce Mines DS connection. This was found to have the most impact on delivery voltages at Feeder End and Bruce Mines.

Table 16: From ERTS – Peak Load

Total	kW	kVAr	kVA	PF
Sources	16115	2747	16348	98%
Generators (Solar)	239	0	239	100%
Loads	15893	1925	16009	99%
Line/Cable Inductance	0	625	625	100%
Calculated Losses	461	1447	1518	30%

Table 17: From ERTS – Peak Load Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 2025 to tie between 023 and 027	43%
Lowest Voltage	A	Supply Side of St Joseph Regulator	93%
	B	Supply Side of St Joseph Regulator	91%
	C	Supply Side of St Joseph Regulator	95%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	Garden River T2	104%

Table 18: From ERTS – Minimum Load

Total	kW	kVAr	kVA	PF
Sources	4575	118	4577	99%
Generators (Solar)	239	0	239	100%
Loads	4734	459	4756	99%
Line/Cable Inductance	0	623	623	100%
Calculated Losses	80	282	293	27%

Table 19: From ERTS – Minimum Load Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 2025 to tie between 023 and 027	14%
Lowest Voltage	A	Feeder End	99%
	B	Feeder End	99%
	C	Feeder End	100%
Highest Voltage	A	Bar River DS LV	105%
	B	Bar River DS LV	104%
	C	Bar River DS LV	106%

In this scenario the delivery voltages are improved from the base case even under normal operational conditions. Feeder End's voltage peak load was calculated to be 101%. Having on-load tap changers and regulators provides greater control and more options for operations staff. The Bar River DS is bordering on high voltage due to the voltage bandwidth, but this could theoretically be reduced by changing the set point for the tap changer.

4.6 From NATS, Reconductor and Voltage Devices

If voltage support devices are installed, the distribution system can adapt to changes in supply and load more effectively. This section outlines the operating conditions when supplied from NATS, after reconductoring and installing the devices outlined in Section 4.5.

Table 20: From NATS – Peak Load

Total	kW	kVAr	kVA	PF
Sources	16294	5039	17055	95%
Generators (Solar)	239	0	239	100%
Loads	15487	2013	15618	99%
Line/Cable Inductance	0	570	570	100%
Calculated Losses	1046	3596	3745	28%

Table 21: From NATS – Peak Load Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 2025 to tie between 023 and 027	52%
Lowest Voltage	A	Supply Side of St Joseph Regulator	93%
	B	Supply Side of St Joseph Regulator	91%
	C	Supply Side of St Joseph Regulator	95%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	Garden River T2	104%

Table 22: From NATS – Minimum Load

Total	kW	kVAr	kVA	PF
Sources	4575	118	4577	99%
Generators (Solar)	239	0	239	100%
Loads	4734	459	4756	99%
Line/Cable Inductance	0	623	623	100%
Calculated Losses	80	282	293	27%

Table 23: From NATS – Minimum Load Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 2025 to tie between 023 and 027	14%
Lowest Voltage	A	Feeder End	99%
	B	Feeder End	99%
	C	Feeder End	100%
Highest Voltage	A	Bar River DS LV	105%
	B	Bar River DS LV	104%
	C	Bar River DS LV	106%

When the peak system load is supplied from NATS, even with reconductoring, the delivery voltage at Feeder End is calculated at 96%. This is acceptable, but marginally, and without room for load growth. With the addition of a regulator and on-load tap changers, the voltage improves to 102% and the system as a whole becomes more flexible in its capabilities for supplying loads.

4.7 From ERTS, with Reconductoring

The conductor from NATS to Bar River is 3/0 ACSR, which is heavily loaded during peak conditions. The first distribution solution is to reconductor this section with 556 ASC. This section explores the impact of reconductoring under normal operating conditions.

Table 24: From ERTS – Peak Load

Total	kW	kVAr	kVA	PF
Sources	15732	2603	15946	99%
Generators (Solar)	239	0	239	100%
Loads	15542	1854	15652	99%
Line/Cable Inductance	0	624	624	100%
Calculated Losses	429	1372	1438	29%

Table 25: From ERTS – Peak Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 081 to 079	43%
Lowest Voltage	A	Feeder End	97%
	B	Feeder End	98%
	C	Feeder End	99%
Highest Voltage	A	Bar River DS LV	104%
	B	Bar River DS LV	104%
	C	Bar River DS LV	105%

Table 26: From ERTS – Minimum Load

Total	kW	kVAr	kVA	PF
Sources	4593	-49	4593	99%
Generators (Solar)	239	0	239	100%
Loads	4791	450	4812	99%
Line/Cable Inductance	0	634	634	100%
Calculated Losses	41	135	141	29%

Table 27: From ERTS – Minimum Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 081 to 079	12%
Lowest Voltage	A	Feeder End	101%
	B	Feeder End	101%
	C	Feeder End	101%
Highest Voltage	A	Bar River DS LV	104%
	B	Bar River DS LV	104%
	C	Bar River DS LV	105%

The length of circuit being reconductored when fed from ERTS is not significant enough to have a material impact. As can be seen from the above tables, there is little difference in normal operating conditions after reconductoring.

5. Solution Comparison

The previous section provided raw data on three modeled scenarios: a base case, reconductoring, and reconductoring with other voltage support devices. This section will take that data and process it to highlight the benefits to the voltage on the system.

The voltage drop along the 3/0 ACSR between NATS and Bar River is unacceptable. During the course of this study, the distribution solution which was found to have the most effective impact was reconductoring the 3/0 ACSR. Other equipment-based solutions ran into issues with heavily loading this section of lines, requiring the conductor to be upgraded either way. This solution has minimal impact upon normal operating conditions, however, under the contingency situation where NATS feeds all of the Algoma East system, the voltage issues are brought within acceptable limits. The cost to reconductor the 31km of lines was estimated by PowerTel to be $7.95M. There would be additional costs for engineering, project management, as well as other typical construction costs. CIMA+ has created an engineering estimate, found in *Appendix D*, estimating the engineering costs to be about $700k.

Augmenting the above scenario, adding on-load tap changers to the existing distribution station transformers and installing a voltage regulator upstream of Bruce Mines will benefit the voltage regulation both during normal operations and in contingency situations. At the time of this study, the difference in cost between an off-load and on-load tap changer is about $100k when ordered on a new transformer. Additional costs for civil upgrades (transformer pad, oil containment, etc.) may be required. Most rural utilities in Ontario have on-load tap changers to aid in voltage regulation on long lines.

Table 28: From ERTS – Comparison of LV Delivery Conditions at Peak Load

Delivery Point	Base Case	Reconductored	Voltage Devices
Bar River	102%	103%	103%
Bruce Mines	101%	101%	104%
Desbarats DS T1	101%	101%	101%
Desbarats DS T2	101%	102%	102%
Garden River DS T1	102%	102%	104%
Garden River DS T2	102%	103%	104%
St Joseph Island	101%	101%	101%
Feeder End	98%	98%	101%

Table 29: From NATS – Comparison of LV Delivery Conditions at Peak Load

Delivery Point	Base Case	Reconductored	Voltage Devices
Bar River	87%	101%	105%
Bruce Mines	95%	99%	102%
Desbarats DS T1	96%	100%	101%
Desbarats DS T2	86%	95%	102%
Garden River DS T1	96%	100%	103%
Garden River DS T2	96%	100%	103%
St Joseph Island	94%	101%	101%
Feeder End	93%	96%	102%

As can be seen from the above tables, reconductoring between NATS and Bar River DS is required to ensure acceptable voltage levels during contingency operation and under peak loading.

Having a two supply points able to supply the system load would be beneficial in several ways. A redundant source increases the resiliency of the whole system. If ERTS had to be removed from service, due to failure or maintenance, a switching operation could be performed to move the load to NATS. This would mean an outage of an two to three hours for switching operations, protection setting changes and drive time during failure scenarios. The system load could be fed from both stations for line maintenance, upgrades, or in emergency situations. If the load in the system were to grow significantly, there would be several options to supply within regulated voltage parameters and without heavily loading conductors. See the next section for the load growth sensitivity analysis.

Adding voltage support devices benefits both normal and contingency operations. Without reconductoring, new equipment alone is not enough to remedy the contingency voltage issues. Adding a voltage regulator upstream of Bruce Mines was beneficial in all studied scenarios and could improve the Feeder End voltage from marginal to nominal or higher. The existing distribution station transformers are between 7 and 33 years old, and it is not practical to replace the transformers for the sole purpose of adding an on-load tap changer. When the transformers are being replaced, an on-load tap changer should be seriously considered. The additional load which can be added if on-load tap changers and a single voltage regulator are considered is more than double reconductoring alone.

If ERTS were to fail and the load switched to NATS, the total load would be dependant on a single 31km stretch through Northern Ontario. If anything were to fail or be damaged from NATS to Bar River DS, the load would not be able to be fed until repairs have been performed. ERTS is fed from a looped feed from HONI's Missisagi TS and Third Line TS, and 115kV outages have relatively quick restoration times. NATS, on the other hand, is a radial feed from Third Line TS and does not have an alternate.

During the seven to eight months of construction the line would be recalled and completely de-energized leaving the load without a backup supply. If ERTS were to have a second transformer put in the station would be de-energized for construction, which would take less time, but would also leave the load without a backup supply. This scenario would have an added challenge because loads would need to be monitored for voltage issues.

6. Solution Sensitivity Analysis

A sensitivity analysis was performed to determine the amount of potential future load which could be added onto the system before low voltage conditions occur at delivery points. Desbarats DS T2, which feeds St Joseph Island, was allowed to reach lower than 95% voltage during this sensitivity test as long as the delivery point at St Joseph Island was within acceptable range.

In this sensitivity test load was increased by 5% until delivery voltages lower than 95% occurred. The applied load was then decreased by 1% in each iteration to determine what percentage of peak load could be applied while maintaining 95% delivery voltages.

Table 30: From NATS Sensitivity Test – Comparison of LV Delivery Conditions

Delivery Point	Reconductored 100% Peak Load	Reconductored 115% Peak Load	Reg and LTC 137% Peak Load
Bar River	101%	102%	97%
Bruce Mines	99%	98%	98%
Desbarats DS T1	100%	98%	98%
Desbarats DS T2	99%	93%	92%
Garden River DS T1	100%	99%	101%
Garden River DS T2	100%	99%	100%
St Joseph Island	101%	100%	99%
Feeder End	96%	95%	95%

Without adding in any other voltage support devices, the reconductored line could potentially support an additional 15% of peak load. If a voltage regulator and on-load tap changers are installed, 137% of peak load could be supplied.

A

Appendix A

PowerTel Report

CIMA+

A CORMORANT UTILITY SERVICES COMPANY

May 5, 2020

CIMA+
Energy & Distribution
4096 Meadowbrook Drive - Unit 112
London, Ontario
N6L 1G4

Attention: Mr. Stephen Costello
Partner, Senior Director

Subject: **Algoma Power – Sault Ste. Marie**
34.5kV Line Rebuild Cost Study

Dear Mr. Costello:

Per CIMA+'s request, PowerTel has completed a budget costing for the rebuilding of Algoma Power's 34.5kV overhead powerline circuit between the Northern Avenue TS in Sault Ste. Marie and the Bar River DS in the Echo Bay area.

PowerTel went through the line route in detail utilizing Google Maps as well as Google Earth to detail (as best as possible) the existing line route in terms of pole quantity and framing types. A basic Line Data is attached showing the existing 34.5kV and underbuild circuits currently and is the basis used for completing the Costing Study. PowerTel notes that no in-field investigations or engineering were conducted for the Study.

Assumptions used for the Costing Study are as follows:

- Line route distance is 31.4 km's long between the Northern Ave. T.S. in Sault Ste. Marie and the Bar River D.S. to the East of the city.
- Line has approx. 468 existing poles / structures.
- Approx. 60% of the route is along roads and 40% off-road or no truck access.
- Existing poles with newer 34.5kV armless framing will be reused and reconductored only including approx. 50 Resin poles along Northern Ave. (total 216 poles). This total includes approx. 5 - 2 and 3 pole structures to be reused in the off-road section just before Bar River D.S.
- Poles with older 34.5kV crossarm / pin insulator framing will be replaced with new poles and armless framing to USF standards (total 252 poles). New poles to be based on 45' to 65' pine, class 3 minimum.
- Approx. 45% of the 468 overall poles have underbuild circuits on them which is a mixture of single and 3-phase lines (some double circuit). All under build circuits for new pole installs will be transferred to the new poles as they appear to already be newer armless construction.
- Existing poles to be replaced that have Underbuild equipment such as transformers, switches, secondary, services, etc. will also be transferred to the new poles.

/...2

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ECRA/ESA LICENCE # 7002926

- Existing 34.5kV circuit conductor size is 3/0 ACSR and will be upgraded to 556.5 ASC conductor. Plan is to place the existing conductor in travelers and use it to pull in the new conductor.
- Work is based on the 34.5kV circuit(s) being de-energized and the underbuild circuits remaining energized for all work operations.
- Some costing was allowed for access construction / upgrading as well as environmental considerations in off-road areas which would have to be confirmed with in-field investigations.
- Some costing was allowed for misc. restoration as required throughout the line route.

Work is anticipated to be completed over a 7-8 month period with a crew of approx. 20-25 workers and addition supervision / management personnel.

Items not included in the Cost Study are as follows:
- Engineering, surveying, approvals, permits, etc. as required.
- Work completed in winter conditions, if required.
- Excavation in rock for poles / anchors, if required
- Premium time for work beyond regular 40 hrs per week.
- Costs or services associated with access on or through private property to access line route.
- Tree trimming, if required, along the line route.
- MTO Permit requirements for crossing or working along-side the 4-lane highway.
- Schedule delays, loss of productivity and / or additional economic costs associated with the COVID-19 pandemic, which may impact this project.

PowerTel's budget costing for this project incorporating the above assumed work scope is approx. $7,950,000.00 (plus applicable HST) with a +% of 25% and a -% of 5%. All labour, equipment and materials required to complete the work is included.

Please do not hesitate to contact PowerTel with any questions or concerns regarding the above or if any other information is required. PowerTel thanks CIMA+ for the opportunity to complete this Cost Study.

Yours truly,
POWERTEL UTILITIES CONTRACTORS LIMITED

Chris Krueger

Chris Krueger
Project Development

CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

On-Road	Reconductor Only
Off-Road	New Poles / Cond.

Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
0	Northern Ave. TS DE					
1	90 Deg. Vert DE		3 Ph Tan			
2	Tangent - Davit Arm		3 Ph Tan			
3	Tangent - Davit Arm		3 Ph Tan			
4	90 Deg. Vert DE		3 Ph DDE			Turn East Along Northern Ave.
5	Tangent X-arm	In-Line Openers	3 x 3Ph DDE		Resin Pole	
6	Tangent Armless		2 x 3Ph Tan		Resin Pole	
7	Tangent Armless		2 x 3Ph Tan		Resin Pole	
8	Tangent Armless		2 x 3Ph Tan	3PH U/G Dip	Resin Pole	
9	Tangent Armless		2 x 3Ph Tan		Resin Pole	
10	Tangent Armless		2 x 3Ph Tan	3PH Tap	Resin Pole	
11	Tangent Armless		2 x 3Ph Tan		Resin Pole	Entrance to Metro / Traffic Lights
12	Tangent Armless		2 x 3Ph Tan		Resin Pole	
13	Tangent Armless		3Ph Tan & 3Ph DDE		Resin Pole	
14	Tangent Armless		2 x 3Ph Tan	3PH U/G Dip	Resin Pole	Great Northern Rd X-ing / Traffic Lights
15	Tangent Armless		2 x 3Ph Tan	3PH Tap	Resin Pole	
16	Tangent Armless		2 x 3Ph Tan	3PH U/G Dip	Resin Pole	
17	Tangent Armless		2 x 3Ph Tan		Resin Pole	
18	Tangent Armless		2 x 3Ph Tan		Resin Pole	
19	Tangent Armless		2 x 3Ph Tan	3PH Tap	Resin Pole	Willow Street X-ing / Traffic Lights
20	Tangent Armless		2 x 3Ph Tan		Resin Pole	
21	Tangent Armless		2 x 3Ph Tan		Resin Pole	
22	Tangent Armless		2 x 3Ph Tan	1Ph Tap	Resin Pole	
23	Tangent Armless		2 x 3Ph Tan		Note - Wood Pole	
24	Tangent Armless		2 x 3Ph Tan		Resin Pole	
25	Tangent Armless		2 x 3Ph Tan		Resin Pole	
26	Tangent Armless		2 x 3Ph Tan		Resin Pole	
27	Tangent Armless		2 x 3Ph Tan	3PH Tap	Resin Pole	Tadcaster Road Crossing
28	Tangent Armless		2 x 3Ph Tan		Resin Pole	
29	Tangent Armless		2 x 3Ph Tan	3PH Tap	Resin Pole	
30	Tangent Armless		2 x 3Ph Tan	3PH Tap & 3Ph U/G Dip	Resin Pole	
31	Tangent Armless		3Ph Tan & 3Ph DDE	3Ph U/G Dip	Resin Pole	Pine Street Crossing / Traffic Lights
32	Tangent Armless		2 x 3Ph Tan	3PH U/G Dip	Resin Pole	
33	Tangent Armless		2 x 3Ph Tan	3PH U/G Dip	Resin Pole	
34	Tangent Armless		2 x 3Ph Tan		Resin Pole	
35	Tangent Armless		2 x 3Ph Tan		Resin Pole	
36	Tangent Armless		2 x 3Ph Tan		Resin Pole	
37	Tangent Armless		2 x 3Ph Tan	3PH U/G Dip	Resin Pole	End Northern Ave. X-ing / Start Bush Path
38	Tangent Armless		2 x 3Ph Tan		Resin Pole	
39	Tangent Armless		2 x 3Ph Tan		Resin Pole	
40	Tangent Armless		2 x 3Ph Tan		Resin Pole	
41	Tangent Armless		2 x 3Ph Tan		Resin Pole	
42	Tangent Armless		2 x 3Ph Tan		Resin Pole	
43	Tangent Armless		2 x 3Ph Tan		Resin Pole	
44	Tangent Armless		2 x 3Ph Tan		Resin Pole	
45	Tangent Armless		2 x 3Ph Tan		Resin Pole	
46	Tangent Armless		2 x 3Ph Tan		Resin Pole	
47	Tangent Armless		2 x 3Ph Tan		Resin Pole	
48	Tangent Armless		2 x 3Ph Tan		Resin Pole	
49	Tangent Armless		2 x 3Ph Tan		Resin Pole	
50	Tangent Armless		2 x 3Ph Tan		Resin Pole	
51	Tangent Armless		2 x 3Ph Tan		Resin Pole	
52	Tangent Armless		2 x 3Ph Tan		Resin Pole	
53	Tangent Armless		2 x 3Ph Tan		Resin Pole	
54	Tangent Armless		3 x 3Ph Tan		Resin Pole	Black Road Crossing
55	Tangent Armless		2 x 3Ph Tan		Resin Pole	
56	Tangent Armless		2 x 3Ph Tan		Resin Pole	
57	Tangent Armless		2 x 3Ph Tan		Resin Pole	
58	Tangent Armless		2 x 3Ph Tan		Resin Pole	
59	Tangent Armless		2 x 3PH DDE		Resin Pole	U/B Turn South
60	Tangent Armless					
61	Tangent Armless					
62	Tangent Armless					
63	Tangent Armless					Cross Under Steel Tower Line
64	Tangent Armless					
65	Tangent Armless					
66	Tangent Armless					
67	Tangent Armless					
68	Tangent Armless					
69	Tangent Armless					
70	Tangent Armless					
71	Tangent Armless					

CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

On-Road	Reconductor Only
Off-Road	New Poles / Cond.

Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
72	Tangent Armless					
73	Tangent Armless					
74	Tangent Armless					
75	Tangent Armless					
76	Tangent Armless					
						Gravel Road Crossing
77	Tangent Armless					
78	Tangent Armless					
79	Tangent Armless					
80	Tangent Armless					
81	Tangent Armless					
82	Tangent Armless					
83	Tangent Armless					
84	Tangent Armless					
85	Tangent Armless					
						Gravel Road Crossing
86	Tangent Armless					
87	Tangent Armless					
88	Tangent Armless					
89	Tangent Armless					
						Bittern Street Crossing In Solar Farm
90	Tangent Armless					
91	Tangent Armless					
92	2 Arm Tangent	Skywire Start?				
93	2 Arm Tangent	Skywire	3 Ph Tan			
						Metig Street Crossing
94	2 Arm Tangent	Skywire				
						Gran Street Crossing
95	2 Arm Tangent	Skywire				
96	2 Arm Tangent	Skywire				
97	Med. Angle	Skywire End?				
98	2 Arm Tangent					
99	2 Arm Tangent					
100	2 Arm Tangent		1Ph Tan	Secondary & Streetlight		
						Tecumseh Street Crossing
101	Tangent - Top Pin & Arm					
102	Tangent - Top Pin & Arm					
103	Tangent - Top Pin & Arm		1Ph Tan	Secondary & Streetlight Over House Trailer		
						Tecumseh Street Crossing Gravel Road Crossing
104	Tangent - Top Pin & Arm		1Ph Tan			
105	Tangent - Top Pin & Arm					
106	Tangent - Top Pin & Arm					
						Gravel Road Crossing
107	Tangent - Top Pin & Arm					
108	Tangent - Top Pin & Arm					
109	Tangent - Top Pin & Arm					
110	Tangent - Top Pin & Arm					
111	Tangent - Top Pin & Arm					
112	Tangent - Top Pin & Arm					
						Gravel Road / Parking Lot
113	Tangent - Top Pin & Arm					
114	Tangent - Top Pin & Arm					
						Gravel Driveway Crossing
115	Tangent - Top Pin & Arm		1Ph DE	Transformer		
116	Tangent - Top Pin & Arm					
117	Tangent - Top Pin & Arm					
						Paved Parking Area
118	Tangent - Top Pin & Arm					
						Gravel Road Crossing
119	Tangent Armless					
120	Tangent Armless					
						4-Lane Crossing
121	Tangent Armless					
122	Tangent Armless					
123	Tangent - Top Pin & Arm					
124	Tangent - Top Pin & Arm					
125	Tangent - Top Pin & Arm					Start Adjacent to Frontenac Road
126	Tangent - Top Pin & Arm					
127	Tangent - Top Pin & Arm					
128	Tangent - Top Pin & Arm					
129	Tangent - Top Pin & Arm					Leave Adjacent to Frontenac Road
130	Tangent - Top Pin & Arm					
131	Tangent - Top Pin & Arm					
132	Tangent - Top Pin & Arm	3Ph Tap to Lumber Yard				
133	DDE					Long Span River Crossing
134	DDE					
135	Tangent - Top Pin & Arm					
136	Tangent - Top Pin & Arm					
137	Tangent - Top Pin & Arm					
138	Tangent - Top Pin & Arm					
139	Tangent - Top Pin & Arm					Gravel Parking Area
140	Tangent - Top Pin & Arm					

CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

On-Road	Reconductor Only
Off-Road	New Poles / Cond.

Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
141	Tangent - Top Pin & Arm					Gravel Road Crossing
142	Tangent - Top Pin & Arm					
143	Tangent - Top Pin & Arm					
144	Tangent - Top Pin & Arm					
145	Tangent - Top Pin & Arm					
146	Tangent - Top Pin & Arm					
147	Tangent - Top Pin & Arm					Gravel Road Crossing
148	Tangent - Top Pin & Arm					Belleau Lake Road Crossing
149	Tangent - Top Pin & Arm					
150	Tangent - Top Pin & Arm					
151	Tangent - Top Pin & Arm					
152	Tangent - Top Pin & Arm					
153	Tangent - Top Pin & Arm					
154	Tangent - Top Pin & Arm					
155	Tangent - Top Pin & Arm					
156	Med. Angle					
157	Tangent - Top Pin & Arm					
158	Tangent - Top Pin & Arm					
159	Tangent - Top Pin & Arm					
160	Tangent - Top Pin & Arm					
161	Tangent - Top Pin & Arm					
162	Tangent - Top Pin & Arm					
163	Tangent - Top Pin & Arm					
164	Tangent - Top Pin & Arm					
165	Tangent - Top Pin & Arm					
166	Tangent - Top Pin & Arm					
167	Tangent - Top Pin & Arm					
168	Tangent - Top Pin & Arm					Gravel Road Crossing
169	Tangent - Top Pin & Arm					
170	Light Angle - Top Pin & Arm					
171	Tangent - Top Pin & Arm					
172	Tangent - Armless		3Ph DE & 3Ph DDE			
173	Tangent - Armless		3Ph Tan			Svrette Lake Road Crossing
174	Tangent - Armless		3Ph Tan	3Ph Tap		
175	Tangent - Armless		3Ph Tan			
176	Tangent - Armless		3Ph Tan			
177	Tangent - Armless		3Ph Tan			
178	Tangent - Armless		3Ph Tan			Muhouak Stereet Crossing
179	Tangent - Armless		3Ph Tan	1Ph Tan & Transformer		
180	Tangent - Armless		3Ph Tan			
181	Tangent - Armless		3Ph Tan			
182	Tangent - Armless		3Ph Tan			
183	Tangent - Armless		3Ph Tan	1Ph Tan		Hawatha Drive Crossing
184	Tangent - Armless		3Ph Tan			
185	Tangent - Armless		3Ph Tan			
186	Tangent - Armless		3Ph Tan			
187	Tangent - Armless		3Ph Tan			
188	Tangent - Armless		3Ph Tan			
189	Light Angle - Armless		3Ph Light Angle	1Ph Transformer		Moccasin Street Crossing
190	Tangent - Armless		3Ph Tan			
191	Tangent - Armless		3Ph Tan			
192	Tangent - Armless		3Ph Tan			
193	Tangent - Armless		3Ph Tan			
194	Tangent - Armless		3Ph Tan	1Ph DE		Wabosssa Street Crossing
195	Tangent - Armless		3Ph Tan			
196	Tangent - Armless		3Ph Tan			
197	Tangent - Armless		3Ph Tan			
198	Tangent - Armless		3Ph Tan	1Ph Transformer		
199	Tangent - Armless		3Ph Tan			
200	Light Angle - Armless		3Ph Angle DDE			
201	Tangent - Top Pin & Arm		3Ph Tan			
202	Tangent - Top Pin & Arm		3Ph Tan	1Ph Transformer		
203	Tangent - Top Pin & Arm		Tangent DDE	3Ph Regulators?		
204	Tangent DDE		Angle DDE	3Ph U/G Service		
205	**Garden River DS DE**					
206	Tangent DDE		Angle DDE	3Ph U/G Service		
207	Tangent - Top Pin & Arm		Tangent DDE	3Ph Regulators?		
208	Tangent - Top Pin & Arm		3Ph Tan			
209	Tangent - Top Pin & Arm		3Ph Tan			
210	Tangent - Top Pin & Arm		3Ph Tan	1Ph Transformer		
211	Tangent - Top Pin & Arm		3Ph Tan			
212	Tangent - Top Pin & Arm		3Ph Tan	1Ph Transformer		

CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

On-Road	Reconductor Only
Off-Road	New Poles / Cond.

Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
213	Tangent - Top Pin & Arm		3Ph Buckarm DDE			
						Jarden Mine Road Crossing
214	Light Angle - Top Pin & Arm					
215	Tangent - Top Pin & Arm					
216	Tangent - Top Pin & Arm					
217	Tangent - Top Pin & Arm					
218	Tangent - Top Pin & Arm					
219	Tangent - Top Pin & Arm					
220	Tangent - Top Pin & Arm					
221	Tangent - Top Pin & Arm					
222	Tangent - Top Pin & Arm					
223	Tangent - Top Pin & Arm					
						River Crossing
224	Angle DDE					
225	Tangent - Top Pin & Arm					
226	Tangent - Top Pin & Arm					
227	Tangent - Top Pin & Arm					
228	MA					
229	Medium Angle					
230	Tangent - Top Pin & Arm					
231	Tangent - Top Pin & Arm					
232	Angle DDE					
233	Tangent - Top Pin & Arm					
234	Tangent - Top Pin & Arm					
235	Tangent - Top Pin & Arm					
236	Angle DDE		1Ph DE	1Ph Transformer		Turn Along Mizigan Street
237	Tangent - Armless		1Ph Tan			
238	Tangent - Armless		1PH Tan			
239	Tangent - Armless		3Ph Light Angle	1Ph DDE		
						Ballpark Road Crossing
240	Tangent - Armless		1Ph DE	Cutout Switch		
241	Tangent - Top Pin & Arm		1PH Tan			
242	Tangent - Top Pin & Arm		1PH Tan			
243	Tangent - Top Pin & Arm		1PH Tan	1Ph Transformer & U/G Service		
244	Tangent - Top Pin & Arm		1PH Tan	Streetlight		
245	Tangent - Top Pin & Arm		1PH Tan	1Ph Transformer		
246	Tangent - Top Pin & Arm		1PH Tan			
247	Tangent - Top Pin & Arm		1PH Tan	1Ph Transformer & U/G Service		
248	Tangent - Top Pin & Arm		1Ph Angle DE	U/G Sec. Service		
						Dreamcatcher Street Crossing
249	Tangent - Top Pin & Arm					
250	Tangent - Top Pin & Arm					
251	Tangent - Top Pin & Arm					
252	Tangent - Top Pin & Arm					
253	Tangent - Top Pin & Arm					
254	Tangent - Top Pin & Arm					
255	Tangent - Top Pin & Arm					
256	Tangent - Top Pin & Arm					
						Sweetgrass Road Crossing
257	Tangent - Top Pin & Arm					
258	Tangent - Top Pin & Arm					
259	Tangent - Top Pin & Arm					
260	Tangent - Top Pin & Arm					
261	Tangent - Top Pin & Arm					
262	Tangent - Top Pin & Arm					
263	Tangent - Top Pin & Arm					
264	Tangent - Top Pin & Arm					
265	Tangent - Top Pin & Arm					
266	Tangent - Top Pin & Arm					
267	Tangent - Top Pin & Arm					
268	Tangent - Top Pin & Arm					
269	Tangent - Top Pin & Arm					
270	Tangent - Top Pin & Arm					
271	Tangent - Top Pin & Arm					
272	Tangent - Top Pin & Arm					
273	Tangent - Top Pin & Arm					
274	Tangent - Top Pin & Arm					
275	Tangent - Top Pin & Arm					
276	Tangent - Top Pin & Arm					
277	Tangent - Top Pin & Arm					
278	Tangent - Top Pin & Arm					
279	Angle DDE					
280	Tangent - Top Pin & Arm					
281	Tangent - Top Pin & Arm					
282	Tangent - Top Pin & Arm					
283	Tangent - Top Pin & Arm					
284	Tangent - Top Pin & Arm					
285	Tangent - Top Pin & Arm					
286	Tangent - Top Pin & Arm					

CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

On-Road	Reconductor Only
Off-Road	New Poles / Cond.

Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
						Under 230kV Lines Star Along 4-Lane / 230kV Lines
287	Vert. Angle DDE					
288	Tangent - Top Pin & Arm					
289	Tangent - Top Pin & Arm					
290	Tangent - Top Pin & Arm					
291	Tangent - Top Pin & Arm					
292	Tangent - Top Pin & Arm					
293	Tangent - Top Pin & Arm					
294	Tangent - Top Pin & Arm					
295	Tangent - Top Pin & Arm					
296	Tangent - Top Pin & Arm					
297	Tangent - Top Pin & Arm					
298	Tangent - Top Pin & Arm					
299	Tangent - Top Pin & Arm					
						Access Gravel Road Crossing
300	Tangent - Top Pin & Arm					
301	Tangent - Top Pin & Arm					
302	Tangent - Top Pin & Arm					
303	Tangent - Top Pin & Arm					
304	Tangent - Top Pin & Arm					
305	Tangent - Top Pin & Arm					
306	Tangent - Top Pin & Arm					
307	Tangent - Top Pin & Arm					
308	Vert. Angle DDE					
309	Vert. Angle DDE					
						4-Lane Hwy. Crossing
310	Vert. Med. Angle					
						Gravel Access Road Crossing
311	Vert. Angle DDE					
						4-Lane Hwy. Crossing
312	Vert. Med. Angle					
313	Vert. Angle DDE					
314	Tangent - Top Pin & Arm					
315	Tangent - Top Pin & Arm					
316	Tangent - Top Pin & Arm					
317	Tangent - Top Pin & Arm					
318	Tangent - Top Pin & Arm					
319	Tangent - Top Pin & Arm					
320	Tangent - Top Pin & Arm					
321	Tangent - Top Pin & Arm					
322	Tangent - Top Pin & Arm					
323	Tangent - Top Pin & Arm					
324	Tangent - Top Pin & Arm					
325	Tangent - Top Pin & Arm					
326	Tangent - Top Pin & Arm					
327	Tangent - Top Pin & Arm					
328	Tangent - Top Pin & Arm					
329	Tangent - Top Pin & Arm					
330	Tangent - Top Pin & Arm					
331	Tangent - Top Pin & Arm					
332	Tangent - Top Pin & Arm					
333	Tangent - Top Pin & Arm					
334	Light Angle - Top Pin & Arm					
335	Tangent - Top Pin & Arm					
336	2P H-frame DDE					
						4-Lane Hwy. Crossing
337	2P H-frame DDE					
						Access Gravel Road Crossing
338	Tangent - Top Pin & Arm					
339	Vert. Med. Angle					
						Under & Between 230kV Lines
340	Tangent - Top Pin & Arm					
341	Tangent - Top Pin & Arm					
342	Tangent - Top Pin & Arm					
343	Tangent - Top Pin & Arm					
						Creek Crossing
344	Tangent - Top Pin & Arm					
345	Tangent - Top Pin & Arm					
346	Tangent - Top Pin & Arm					
						Creek Crossing
347	Tangent - Top Pin & Arm					
348	Tangent - Top Pin & Arm					
349	Tangent - Top Pin & Arm					
350	Tangent - Top Pin & Arm					
351	Tangent - Top Pin & Arm					
352	Tangent - Top Pin & Arm					
353	Tangent - Top Pin & Arm					
354	Tangent Angle DDE					
355	Tangent - Top Pin & Arm					
356	Tangent - Top Pin & Arm					
357	Tangent - Top Pin & Arm					
358	Tangent - Top Pin & Arm					

CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

On-Road	Reconductor Only
Off-Road	New Poles / Cond.

Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
359	Tangent - Top Pin & Arm					
360	Tangent - Armless		1Ph DE	Transformer		
361	Tangent - Armless		1Ph Tan	Transformer		
362	Tangent - Armless		1Ph Tan			
363	Light Angle - Armless		1Ph LA			
						Gravel Road Crossing
364	Tangent - Armless		1Ph Tan	Transformer / Streetlight		
365	Tangent - Armless	Centre Phase Extender	1Ph Tan	1Ph Tap		
						River Crossing
366	Tangent - Armless	Centre Phase Extender	1Ph DDE	Cutout Switch		
367	Tangent - Top Pin & Arm	Set LA's	1Ph Tan	Transformer		
368	Tangent - Top Pin & Arm	Mid-Span Openers	1Ph Tan			
369	Tangent DDE	**3Ph Tap to Echo Bay**	2Ph DDE	2Ph DE Tap		Echo Lake Road Crossing
370	Vertical DDE	Vert. Load Break Switch	2Ph Tan			
371	LA Armless		2Ph LA Armless			
						Echo Lake Road Crossing
372	Tangent - Armless		2Ph Tan Armless			
373	Tangent - Armless		2Ph Tan Armless			
374	LA Armless		2Ph LA Armless			
375	LA Armless		2Ph LA Armless			
376	LA Armless		2Ph LA Armless			
						Echo Lake Road Crossing
377	Med. Angle Armless		2Ph MA Armless	Transformer		
378	Tangent - Armless		2Ph Tan Armless			
379	Buckarm DDE		2Ph Buckarm DDE			
						Echo Lake Road Crossing
380	Buckarm DDE		2Ph Buckarm DDE			
381	Tangent - Armless		2Ph Tan Armless			
382	Tangent - Armless		2Ph Tan Armless			
383	Tangent - Armless		2Ph Tan Armless			
384	Buckarm DDE		2Ph Buckarm DDE	1Ph Tap		
						Echo Lake Road Crossing
385	Tangent - Armless		2Ph Tan Armless			
386	Tangent - Armless		2Ph Tan Armless			
387	Tangent - Armless		2Ph Tan Armless			
388	Tangent - Armless		2Ph Tan Armless	Transformer		
389	LA - Armless		2Ph LA Armless	2Ph Tap		
390	Med. Angle Armless		2Ph MA Armless			
391	Tangent - Armless		2Ph Tan Armless	Transformer		
392	Tangent - Top Pin & Arm		2Ph Tan Armless	Transformer		
393	Tangent - Top Pin & Arm		2Ph Tan Armless			
394	Tangent - Armless		2Ph Tan Armless			
395	Tangent - Armless		2Ph Tan Armless			
396	Double Arm LA	Stub Pole / Span Guy	2Ph LA Armless	Stub Pole / Span Guy		
397	Double Arm Tan		2Ph Tan Armless			
398	Double Arm Tan		2Ph Tan Armless			
399	Double Arm Tan		2Ph Tan Armless	2 x Switch Cutouts		
400	Double Arm Tan		2Ph Tan Armless			
401	Double Arm Tan		2Ph Tan Armless			
402	LA - Armless		2Ph DDE	1Ph Tap		Old Sylain Valley Hill Road Crossing Echo Lake Road Crossing
403	Tangent - Armless		2Ph Tan Armless			
404	Med. Angle Armless		2Ph MA Armless			
405	Double Arm Tan		2Ph Tan X-Arm	Transformer / Streetlight		
						Hwy 638 Crossing
406	Double Arm LA		2Ph LA X-Arm			
407	Double Arm Tan		2Ph Tan X-Arm			
408	Double Arm Tan		2Ph Tan X-Arm			
409	Double Arm Tan		2Ph Tan X-Arm	Transformer		
410	Double Arm LA		2Ph LA X-Arm			
411	Double Arm Tan		2Ph Tan X-Arm	Transformer		
412	Double Arm LA		2Ph LA X-Arm			
						Pioneed Road Crossing
413	Double Arm Tan		2Ph Tan X-Arm			
414	Double Arm Tan		2Ph Tan X-Arm	Transformer		
415	Tangent - Armless		2Ph Tan Armless			
						Joe Findlay Road Crossing
416	Tangent - Armless		2Ph DE	3Ph Tap / Transformer		
417	LA - Armless		1Ph DDE	Cutout Switch		
418	Med. Angle Armless		1P MA Armless			
419	Tangent - Armless		1P Tan Armless			
						Findley Hill Road Crossing
420	Tangent - Armless		1P Tan Armless	Transformer		
421	LA - Armless		1P LA Armless			
422	LA - Armless	Span Guy / Stub Pole	1P LA Armless			
423	Tangent - Armless		1P Tan Armless	Transformer		
424	Tangent - Armless		1P Tan Armless			
425	LA - Armless	Span Guy / Stub Pole	1Ph DDE	Cutout Switch		
426	Tangent - Armless					
427	Tangent - Armless					
428	Tangent - Armless					

CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

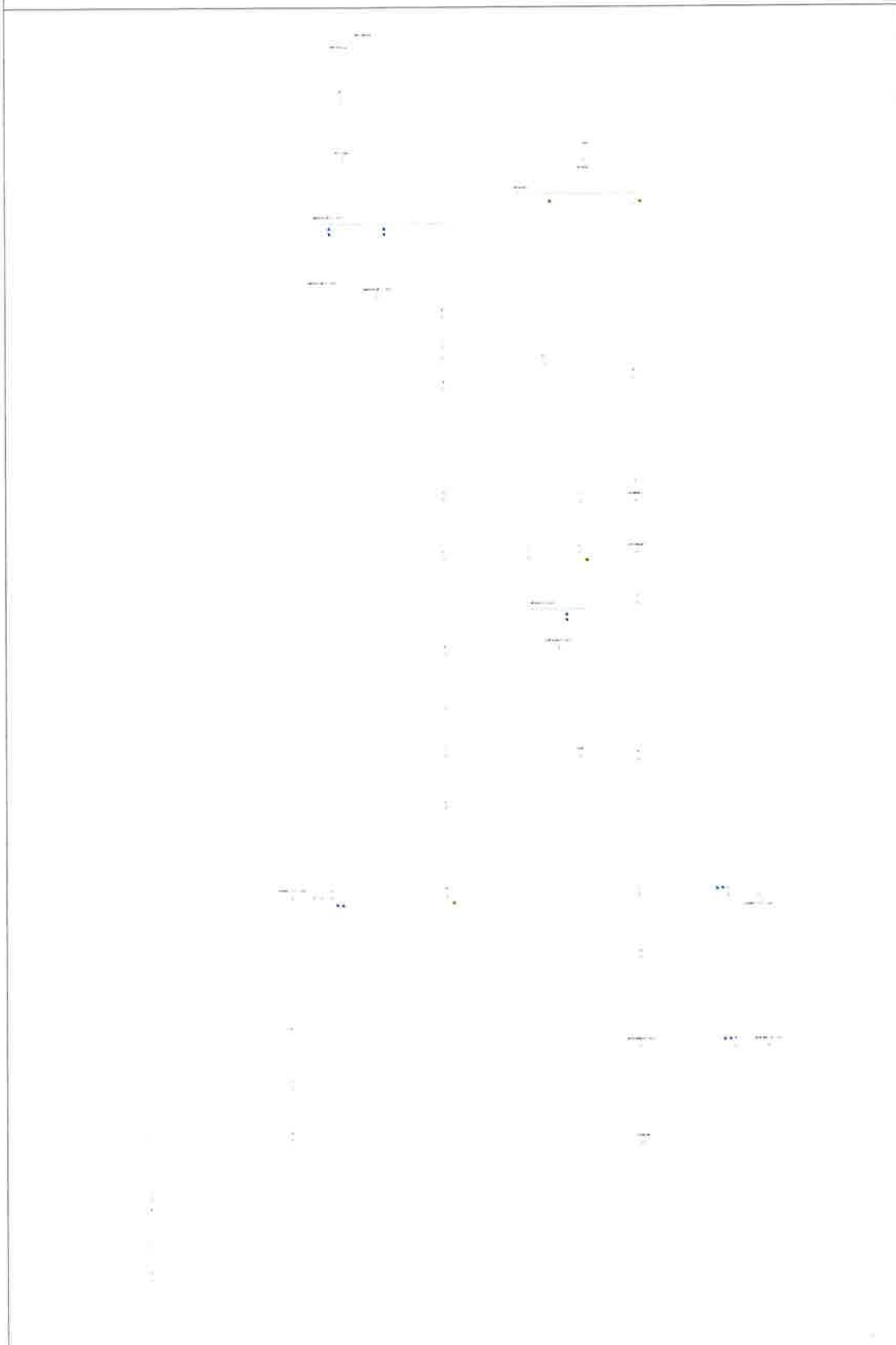
On-Road	Reconductor Only
Off-Road	New Poles / Cond.

Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
429	Tangent - Top Pin & Arm					
430	Tangent - Top Pin & Arm					
431	Tangent - Armless					
432	Vertical DDE	Transposition	1Ph DDE			
433	Vertical DDE	Start Skywire	34.5kV Vert DDE			
434	Vertical Delta	Skywire	34.5kV Vert. Tan			
435	Vertical Delta	Skywire	34.5kV Vert. Tan			
436	Vertical Delta	Skywire	34.5kV Vert. Tan			
437	Vertical Delta	Skywire	34.5kV Vert. Tan			
438	Vertical Delta	Skywire	34.5kV Vert. Tan			
439	Vertical Delta	Skywire	34.5kV Vert. Tan			
440	Vertical Delta	Skywire	34.5kV Vert. Tan			
441	Vertical Delta	Skywire	34.5kV Vert. Tan			
442	Vertical Delta	Skywire	34.5kV Vert. Tan			
						Watson Road East Crossing
443	Vertical Delta	Skywire	34.5kV Vert. Tan	1Ph DDE on Arm		
444	Vertical DDE	Skywire	34.5kV Vert. MA			
445	2P Vert. Angle DDE	Skywire	On Separate Poles Now			
446	Vertical Delta					
447	Vertical Delta					
448	Vertical Delta					
449	Vertical Delta					
450	2P or 3p DDE					
451	3p DDE					
452	3p DDE					
453	Vertical Delta					
454	Vertical Delta					
455	Vertical Delta					
456	Vertical Delta					
457	Vertical Delta					
458	Vertical Delta					
459	Vertical Delta					
460	Vertical Delta					
461	Vertical Delta					
462	Vertical Delta					
						34.5 Circuit Crosses Under
463	Vertical Delta					
						34.5 Circuit Crosses Under
464	Vertical Delta					
465	Vertical Delta					
466	3p DDE					
						Rail Crossing
467	3p DDE		3Ph Buckarm DDE			
468	Tangent - Top Pin & Arm	In-Line Switches	3Ph DDE	Regulators?		
469	Tangent - Top Pin & Arm	**Tap into Bar DS**	3Ph Tan on Arm	Tap into Bar DS		
470	**BAR RIVER DS STR. DE**					

B

Appendix B

CYME Model Validation



Legend

Layer :
Voltage Dip color(%)

Colors :
- 0.000000 1.000000
- 1.000000 2.000000
- 2.000000 3.000000
- 3.000000 5.000000
- 5.000000 999999.0000

Line Types :
- Overhead phase A
- Overhead phase B
- Overhead phase C
- Overhead phase AB
- Overhead phase AC
- Overhead phase BC
- Overhead three-phase
- Cable phase A
- Cable phase B
- Cable phase C
- Cable phase AB
- Cable phase AC
- Cable phase BC
- Cable three-phase

Symbols :
- Switch, (C)
- Spot Load
- Two-Winding Tran.
- Switch, (O)
- Regulator
- Shunt Capacitor
- Shunt Capacitor
- Photovoltaic Sys.
- Two-Winding Tran.

Node	Attached Equipment
46	Switch 386
Truss Plant	Truss Plant
Garden River DS HV Bus	Switch 076
Garden River T1 LV Bus	GDS T1 Load, Cap bank
Garden River T2 LV Bus	GDS T2 Load, Cap bank
Garden River DS HV Bus	Switch 075
51	3/0 to Garden DS
52	Switch 077
53	ER2-NTS Tie Point
54	Switch 079
ER2	Switch 081
Echo River TS Bus	Switch 565
Echo River TS Bus	Switch 9
Echo River TS Bus	Switch 563
ER1	22194 feet downstream of ERTS Bus
58	Switch 2024
VR Primary	Bar River Regulator
VR Secondary	Bar River Regulator
61	Switch 2025
62	Switch 027
69	12665 feet downstream of Switch 079
66	E2 to Bar River
65	Switch 021
Bar River DS HV Bus	Switch 022
Bar River DS HV Bus	Switch 023
Bar River DS LV Bus	Bar River Load, Cap bank
75	Switch 075
71	Switch 071
72	Switch 072
73	Switch 2038
Solar	Solar generator
76	51800 feet downstream of Switch 075
78	28445 feet downstream of Solar tap
542	Switch 091 and Switch 080
77	Switch 77, Switch 81, and Switch 82
81	Desbarats DS T1 LV Bus
Desbarats DS T1 LV Bus	Desbarats DS T1 LV load and Cap bank
86	Desbarats DS T2 LV Bus
8, 7, Desbarats DS T2 LV Bu	Cables downstream of T2 to 2/0 CU
11	End of 2/0 CU
13	Cap Bank 13
14	Transition from 336 to Sub cable
15	Sub Cable to 336
16	HV of SJI Reg
17	LV of SJI Reg
18	SJI Load
82	Switch 053
Bruce Mines DS HV Bus	Switch 084/Feeder end tie
84	Bruce Mines DS LV Bus
Bruce Mines DS LV Bus	Bruce Mines DS LV load and cap bank
Feeder End	Feeder End Load

Two methods of validation were used to validate the model and the associated assumptions; both methods found that the model is reasonably accurate.

Historical Loads with Recent Metered Data

The first method of model validation was to model the typical load level for June and match it to measured values from the metering point for ER1 and ER2. Historical data for 2018 and 2019 was used to determine that June is 40% of peak load. A load flow analysis was performed and then the values at the ER1 and ER2 nodes was compared with metered data for June 1, 2020. It was found that the calculated power was similar to the metered values between 2:00 and 4:00PM.

Metered Vs Calculated Power – ER1

Feeder Name	kVA	kW	kVAr
ER1 – Metered	3477.1	3475.5	-106.5
ER1 – Calculated	3282	3280	-108
Difference	195	195	1.5

Metered Vs Calculated Power – ER2

Feeder Name	kVA	kW	kVAr
ER2 – Metered	3314.7	3276.6	501.1
ER2 – Calculated	3386	3250	950
Difference	71	27	449

The capacitor bank 2022 on ER2 was switched off due to bandwidth in the calculated values. This can account for the difference in reactive power in metered and calculated values.

Metered Data

The second method of validation was to insert measured data from the field and compare the calculated feeder total to the metered data from the same time period. As can be seen from the following tables, the calculated values are quite similar which gives confidence in the model's conductor assumptions.

Measurements Collected June 1, 2020

Asset ID	Time	Current (A)			Voltage (V)			Power (kW)				PF (%)
		R	W	B	R	W	B	R	W	B	3PH	
Garden River DS T1	11:00AM	37	11	21	7200	7100	7200	229	80	118	435	98.8
Garden River DS T2	11:00AM	12	5	12	7200	7100	7200	94	42	81	234	96.6
Bar River T1	12:00PM	38	91	30+ -	7400	7400	7500	281	673	222	1177	95
Desbarats T1	5:00PM	7	22	21	7200	7200	7200				360	96
Bar River Regulator	12:00PM	43	-	40	125 in 121.3 out	125 in 121.6 out	125 in 121.5 out					95-98
St Joseph Regulator	5:00PM	27	42	31	127.4 in 121.6 out	128 in 121.6 out	126.1 in 121.2 out					
Feeder End	6:30PM	31	32	30								
Recloser 038	11:00AM	11	12	7								
Recloser 052	5:00PM	56	58	62								
Recloser 2010	3:00PM	24	38	31	15200	15600	15100	355	599	463	1430	99.8
Recloser 2020	12:00PM	21	20	17	20500	20500	20500					

Calculated Values from Measurements Collected June 1, 2020

Asset ID	Current (A)			Voltage (V)			Power (kW)				PF (%)
	R	W	B	R	W	B	R	W	B	3PH	
Garden River DS T1	33	12	17	7400	7500	7500	244	86	126	456	99
Garden River DS T2	4	3	5	7400	7500	7500	68	69	95	232	96
Bar River T1	33	22	22	7500	7500	7500	559	431	282	1272	83
Desbarats T1	7	23	22	7300	7300	7300	52	164	155	371	96
Bar River Regulator	59	72	69	124.1 in 122.9 out	124.1 in 122.9 out	124.1 in 122.9 out	1205	1462	1409	4076	100
St Joseph Regulator	29	45	33	123 in 123 out	120.6 in 120.6 out	122.2 in 122.2 out	423	636	483	1541	98
Feeder End	29	45	34	14800	14500	14700	423	636	483	1541	98
Recloser 038	12	9	14	20700	20700	20700	226	178	287	691	99
Recloser 052	53	64	64	20200	20200	20300	1080	1291	1303	3674	100
Recloser 2010	29	44	33	14800	14700	14700	425	640	483	1548	99
Recloser 2020	23	23	18	20600	20600	20700	475	472	373	1321	99

C

Appendix C

CYME Results

CIMA+

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-4-2020 existing conductors.sxst
Date	Tue Jun 16 2020
Time	15h01m48s
Project Name	Base Case from ERTS Min Load - by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	**kW**	**kvar**	**kVA**	**PF(%)**
Sources (Swing)	4567.52	-39.82	4567.69	-100.00
Generators	239.00	0.00	239.00	100.00
Total Generation	**4806.51**	**-39.83**	**4806.68**	**-100.00**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4761.34	1703.29	5056.84	94.16
Shunt capacitors (Adjusted)	0.00	-1263.21	1263.21	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4761.34**	**440.08**	**4781.64**	**99.58**
Cable Capacitance	0.00	-70.73	70.73	0.00
Line Capacitance	0.00	-544.57	544.57	0.00
Total Shunt Capacitance	**0.00**	**-615.30**	**615.30**	**0.00**
Line Losses	40.17	87.69	96.45	41.65
Cable Losses	0.25	0.15	0.29	85.29
Transformer Load Losses	4.76	47.55	47.79	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**45.17**	**135.39**	**142.73**	**31.65**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	105.57 %
	B	1	87	104.47 %
	C	1	87	105.76 %
Under-Voltage	A	0	FEEDER END	100.60 %
	B	0	FEEDER END	100.61 %
	C	0	FEEDER END	101.01 %
Over-Voltage	A	0	076	104.01 %
	B	0	076	104.01 %
	C	0	076	104.01 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	40.17	351.87	35.19
Cable Losses	0.25	2.15	0.22
Transformer Load Losses	4.76	41.66	4.17
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	45.17	395.68	39.57

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	8.7	1621.0	100.5	104.00
ECHO RIVER TS 081		DEFAULT	Switch	4.0	703.7	248.3	104.00
ECHO RIVER TS 081		DEFAULT	Switch	4.0	703.1	254.6	103.81
ECHO RIVER TS 077		DEFAULT	Switch	0.5	78.5	33.5	103.81
ECHO RIVER TS 51		DEFAULT	Switch	0.5	78.4	52.0	103.69
ECHO RIVER TS 49		GARDEN T2	Two-Winding Transforme	4.4	44.4	16.5	103.50
ECHO RIVER TS 555		GARDEN T1	Two-Winding Transforme	0.4	34.0	35.5	103.44
ECHO RIVER TS 67		DEFAULT	Switch	3.6	624.6	221.3	103.81
ECHO RIVER TS 66		DEFAULT	Switch	2.3	384.9	186.4	103.29
ECHO RIVER TS 65		DEFAULT	Switch	2.3	384.9	186.5	103.29
ECHO RIVER TS 68		BAR RIVER T1	Two-Winding Transforme	16.6	384.9	186.5	102.83
ECHO RIVER TS 68		1200 KVAR 7 KV	Shunt Capacitor	0.0	488.5	160.6	102.82
ECHO RIVER TS 71		DEFAULT	Switch	1.3	237.3	43.4	103.29
ECHO RIVER TS 72		DEFAULT	Switch	1.3	236.8	57.6	103.07
ECHO RIVER TS 74		DEFAULT	Switch	0.4	-79.6	-0.1	103.05
ECHO RIVER TS 79		DEFAULT	Switch	1.8	316.1	79.1	102.90
ECHO RIVER TS 86		DESBARATS T2	Two-Winding Transforme	19.5	316.1	79.1	102.51
ECHO RIVER TS 13		1200 KVAR 20 KV	Shunt Capacitor	0.0	316.0	76.2	102.47
ECHO RIVER TS 17		25 KV 600A 1PH	Regulator	3.8	315.4	103.7	100.94
ECHO RIVER TS 56		DEFAULT	Switch	5.0	917.3	-147.8	104.00
ECHO RIVER TS 58		DEFAULT	Switch	5.0	914.9	-137.0	103.86
ECHO RIVER TS 5		34.5KV_200A_1PH_COOPER_REGULATOR_6	Regulator	22.4	914.9	-136.8	101.92
ECHO RIVER TS 62		DEFAULT	Switch	0.0	0.0	0.0	103.86
ECHO RIVER TS 64		DEFAULT	Switch	0.0	0.0	0.0	103.29
ECHO RIVER TS 75		DEFAULT	Switch	5.1	914.9	-136.7	101.91
ECHO RIVER TS 77		DEFAULT	Switch	5.0	910.9	-120.4	101.67
ECHO RIVER TS 80		DEFAULT	Switch	0.0	0.0	0.0	102.90
ECHO RIVER TS 81		DEFAULT	Switch	2.6	315.5	-349.7	101.67
ECHO RIVER TS 81		DESBARATS T1	Two-Winding Transforme	23.5	315.5	-349.7	102.75
ECHO RIVER TS 87		1200 KVAR 7 KV	Shunt Capacitor	105.6	244.2	-342.0	102.75
ECHO RIVER TS 82		DEFAULT	Switch	3.5	595.3	229.3	101.67
ECHO RIVER TS 83		DEFAULT	Switch	3.5	595.3	229.4	101.66
ECHO RIVER TS 84		DEFAULT	Switch	1.6	277.4	103.8	100.70
ECHO RIVER TS 84		BRUCE MINES T1	Two-Winding Transforme	16.7	277.4	103.8	103.08
ECHO RIVER TS 88		1200 KVAR 7 KV	Shunt Capacitor	0.0	296.5	97.4	103.08
ECHO RIVER TS 61		DEFAULT	Switch	0.0	0.0	-0.1	103.86

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	0.1	5.4	-20.3	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	0.0	0.0	-8.4	104.01
NORTHERN AVE TS	076	DEFAULT	Switch	0.0	0.0	0.0	103.69

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.8	34.500	14794.7	2093	491	2150	97.03	34.6	-13.20	1.7	6.3	5.8
55	53	ER2	3/0ACSR	Overhead Line	35.8	34.500	144.4	2092	510	2153	96.83	34.7	-13.86	0.1	0.1	11.9
52	52	53	3/0ACSR	Overhead Line	35.8	34.500	213.3	395	77	403	94.70	6.5	-11.19	0.0	0.0	2.7
077	R 038	52	3/0ACSR	Overhead Line	35.8	34.500	1889.0	395	77	403	94.68	6.5	-11.23	0.0	0.0	2.7
51	GARDEN RIVER DS HV BUS	R 038	3/0ACSR	Overhead Line	35.8	34.500	34354.4	395	80	403	94.55	6.5	-11.64	0.5	0.7	2.7
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.9	12.470	100.0	108	35	113	95.01	5.1	-48.52	0.0	0.0	1.0
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.9	12.470	100.0	286	94	301	95.00	13.5	-48.90	0.0	0.0	4.5
54	53	54	3/0ACSR	Overhead Line	35.8	34.500	147.6	1696	433	1751	96.24	28.2	-14.48	0.0	0.0	10.2
67	69	54	3/0ACSR	Overhead Line	35.7	34.500	12664.6	1696	433	1751	96.24	28.2	-14.49	3.3	4.0	10.2
70	69	66	3/0ACSR	Overhead Line	35.7	34.500	9594.3	1693	449	1752	96.01	28.3	-15.10	2.5	3.0	10.2
66	65	66	3/0ACSR	Overhead Line	35.7	34.500	100.0	977	330	1031	92.91	16.7	-19.01	0.0	0.0	6.6
65	BAR RIVER DS HV BUS	65	3/0ACSR	Overhead Line	35.7	34.500	64.0	977	330	1031	92.90	16.7	-19.01	0.0	0.0	6.6
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	12.9	12.470	100.0	976	321	1027	95.00	46.2	-49.02	0.0	0.1	10.8
71	66	R 2020	3/0ACSR	Overhead Line	35.7	34.500	82.0	714	130	726	98.37	11.7	-10.68	0.0	0.0	3.7
72	R 2020	72	3/0ACSR	Overhead Line	35.6	34.500	29000.0	714	131	726	98.37	11.7	-10.69	1.3	1.6	3.7
73	72	73	556ASC	Overhead Line	35.6	34.500	6391.1	713	173	733	97.17	11.9	-14.09	0.1	0.3	1.8
74	73	SOLAR	556ASC	Overhead Line	35.6	34.500	100.0	-239	0	239	100.00	3.9	179.52	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.6	34.500	28445.2	951	184	969	98.18	15.7	-11.39	0.7	2.5	2.4
79	78	542	477ACSR	Overhead Line	35.5	34.500	5072.2	951	230	978	97.20	15.9	-14.16	0.1	0.4	2.5
86	542	86	556ASC	Overhead Line	35.5	34.500	100.0	951	238	980	97.01	15.9	-14.65	0.0	0.0	2.5
8	86	8	556ASC	Overhead Line	25.6	25.000	10.0	949	226	976	97.29	22.0	-44.65	0.0	0.0	3.4
7	8	R 2010	556ASC	Overhead Line	25.6	25.000	10.0	949	226	976	97.29	22.0	-44.66	0.0	0.0	3.4
89	R 2010	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	25.6	25.000	50.0	949	226	976	97.29	22.0	-44.66	0.0	0.0	4.3
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	25.6	25.000	185.0	949	226	976	97.29	22.0	-44.66	0.0	0.0	8.0
13	11	13	336AAC	Overhead Line	25.6	25.000	3500.0	949	229	977	97.21	22.0	-44.85	0.2	0.6	4.3
14	13	14	336AAC	Overhead Line	25.6	25.000	5717.0	949	231	977	97.16	22.0	-45.02	0.4	1.0	4.3
15	14	15	35 KV 4/0 CU 100% CN	Cable	25.6	25.000	2345.0	949	235	977	97.06	22.0	-45.30	0.2	0.1	5.9
16	15	16	336AAC	Overhead Line	25.6	25.000	13595.0	949	302	996	95.28	22.4	-49.06	0.9	2.5	4.4
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	948	311	997	95.00	22.8	-49.69	0.0	0.0	4.5
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.9	34.500	22193.7	2458	-470	2502	-97.87	40.3	10.82	4.1	12.5	7.0
2024	ER1	58	477ACSR	Overhead Line	35.8	34.500	9412.4	2454	-444	2494	-98.04	40.2	9.96	1.7	5.3	7.0
59	58	VR PRIMARY	477ACSR	Overhead Line	35.8	34.500	24.2	2452	-433	2490	-98.12	40.1	9.59	0.0	0.0	7.0
62	VR SECONDARY	62	477ACSR	Overhead Line	35.2	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.6	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	35.2	34.500	100.0	2452	-432	2490	-98.12	40.9	9.57	0.0	0.1	7.1
76	75	76	477ACSR	Overhead Line	35.1	34.500	51800.0	2452	-432	2490	-98.12	40.9	9.57	9.8	30.1	7.1
77	76	77	556ASC	Overhead Line	35.1	34.500	100.0	2442	-377	2471	-98.46	40.6	7.62	0.0	0.1	7.0
80	542	77	556ASC	Overhead Line	35.1	34.500	100.0	0	0	0	0.00	0.0	88.86	0.0	0.0	0.0
81	77	81	556ASC	Overhead Line	35.1	34.500	100.0	724	-1011	1244	-57.77	20.5	53.23	0.0	0.0	3.6
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.8	12.470	100.0	723	-1026	1255	-55.95	56.6	23.23	0.0	0.1	9.9
82	77	R 052	3/0ACSR	Overhead Line	35.1	34.500	100.0	1718	635	1832	93.75	30.1	-21.42	0.0	0.0	10.0
83	R 052	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	34.8	34.500	41600.0	1718	635	1832	93.74	30.1	-21.42	12.1	14.7	10.0
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	34.8	34.500	100.0	763	258	806	94.42	13.4	-20.15	0.0	0.0	4.7
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.8	12.470	39.9	762	251	802	95.00	36.1	-50.16	0.0	0.0	6.5
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	34.8	34.500	15088.3	943	423	1034	91.25	17.2	-25.58	0.4	1.6	2.7
61	VR PRIMARY	61	477ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0
63	61	62	3/0ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0
NA1	NORTHERN AVE TS	46	3/0ACSR	Overhead Line	35.9	34.500	100.0	16	-61	63	-25.69	1.0	75.11	0.0	0.0	0.3
390	46	TRUSS PLANT	3/0ACSR	Overhead Line	35.9	34.500	27986.1	16	-61	63	-25.75	1.0	75.08	0.0	0.0	0.3
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	3/0ACSR	Overhead Line	35.9	34.500	16346.2	0	-25	25	0.01	0.4	90.00	0.0	0.0	0.1

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Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-4-2020 existing conductors.sx
Date	Tue Jun 16 2020
Time	14h59m10s
Project Name	Base Case from ERTS Max Load - by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=100.00%, Q=100.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	15643.82	1300.48	15697.78	99.66
Generators	238.98	-0.02	238.98	100.00
Total Generation	**15882.80**	**1300.46**	**15935.95**	**99.67**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	15404.08	5496.25	16355.26	94.18
Shunt capacitors (Adjusted)	0.00	-4942.72	4942.72	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**15404.08**	**553.53**	**15414.02**	**99.94**
Cable Capacitance	0.00	-68.68	68.68	0.00
Line Capacitance	0.00	-536.09	536.09	0.00
Total Shunt Capacitance	**0.00**	**-604.78**	**604.78**	**0.00**
Line Losses	436.63	948.43	1044.11	41.82
Cable Losses	2.85	1.76	3.35	85.12
Transformer Load Losses	40.15	401.52	403.52	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**479.63**	**1351.71**	**1434.28**	**33.44**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	4	68	103.11 %
	B	3	68	104.57 %
	C	4	68	106.84 %
Under-Voltage	A	0	FEEDER END	97.26 %
	B	0	FEEDER END	97.97 %
	C	0	FEEDER END	98.62 %
Over-Voltage	A	0	ECHO RIVER TS	104.00 %
	B	0	ECHO RIVER TS	104.00 %
	C	0	ECHO RIVER TS	104.00 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	436.63	3824.88	382.49
Cable Losses	2.85	24.96	2.50
Transformer Load Losses	40.15	351.73	35.17
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	479.63	4201.58	420.16

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	29.8	5501.7	791.3	104.00
ECHO RIVER TS 081		DEFAULT	Switch	13.7	2526.8	367.6	104.00
ECHO RIVER TS 081		DEFAULT	Switch	13.7	2519.5	349.9	103.56
ECHO RIVER TS 077		DEFAULT	Switch	1.6	256.8	155.1	103.54
ECHO RIVER TS 51		DEFAULT	Switch	1.7	256.0	172.6	103.12
ECHO RIVER TS 49		GARDEN T2	Two-Winding Transforme	14.6	145.5	55.0	102.48
ECHO RIVER TS 555		GARDEN T1	Two-Winding Transforme	1.2	110.5	117.6	102.31
ECHO RIVER TS 67		DEFAULT	Switch	12.2	2262.3	194.5	103.54
ECHO RIVER TS 66		DEFAULT	Switch	6.9	1247.7	220.5	102.12
ECHO RIVER TS 65		DEFAULT	Switch	6.9	1247.7	220.5	102.11
ECHO RIVER TS 68		BAR RIVER T1	Two-Winding Transforme	52.1	1247.7	220.5	101.55
ECHO RIVER TS 68		1200 KVAR 7 KV	Shunt Capacitor	103.1	1587.3	109.8	101.51
ECHO RIVER TS 71		DEFAULT	Switch	5.4	986.1	-49.4	102.12
ECHO RIVER TS 72		DEFAULT	Switch	5.4	978.9	-43.8	101.42
ECHO RIVER TS 74		DEFAULT	Switch	0.4	-79.3	-0.1	101.38
ECHO RIVER TS 79		DEFAULT	Switch	5.8	1054.7	-34.4	101.12
ECHO RIVER TS 86		DESBARATS T2	Two-Winding Transforme	63.5	1054.7	-34.4	101.10
ECHO RIVER TS 13		1200 KVAR 20 KV	Shunt Capacitor	102.7	1053.5	-78.7	100.98
ECHO RIVER TS 17		25 KV 600A 1PH	Regulator	12.7	1046.8	343.4	100.69
ECHO RIVER TS 56		DEFAULT	Switch	16.1	2975.0	423.7	104.00
ECHO RIVER TS 58		DEFAULT	Switch	16.1	2949.8	365.7	102.79
ECHO RIVER TS 5		34.5KV_200A_1PH_COOPER_REGULATOR_€	Regulator	72.6	2949.8	365.8	102.15
ECHO RIVER TS 62		DEFAULT	Switch	0.0	0.0	0.0	102.79
ECHO RIVER TS 64		DEFAULT	Switch	0.0	0.0	0.0	102.11
ECHO RIVER TS 75		DEFAULT	Switch	16.2	2949.7	365.7	102.14
ECHO RIVER TS 77		DEFAULT	Switch	16.2	2908.3	266.9	100.26
ECHO RIVER TS 80		DEFAULT	Switch	0.0	0.0	0.0	101.12
ECHO RIVER TS 81		DEFAULT	Switch	5.7	1010.7	-169.4	100.26
ECHO RIVER TS 81		DESBARATS T1	Two-Winding Transforme	57.5	1010.7	-169.4	101.20
ECHO RIVER TS 87		1200 KVAR 7 KV	Shunt Capacitor	102.4	789.3	-150.2	101.18
ECHO RIVER TS 82		DEFAULT	Switch	10.8	1897.6	436.3	100.26
ECHO RIVER TS 83		DEFAULT	Switch	10.8	1897.5	436.3	100.25
ECHO RIVER TS 84		DEFAULT	Switch	5.0	878.1	-54.1	97.59
ECHO RIVER TS 84		BRUCE MINES T1	Two-Winding Transforme	50.9	878.1	-54.1	100.91
ECHO RIVER TS 88		1200 KVAR 7 KV	Shunt Capacitor	101.8	946.7	-96.2	100.90
ECHO RIVER TS 61		DEFAULT	Switch	0.0	0.0	-0.1	102.79

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	0.1	18.0	-14.2	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	0.0	0.0	-8.4	103.99
NORTHERN AVE TS	076	DEFAULT	Switch	0.0	0.0	0.0	103.12

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.8	34.500	14794.7	7562	248	7566	99.63	121.8	-1.88	21.5	77.6	20.7
55	53	ER2	3/0ACSR	Overhead Line	35.8	34.500	144.4	7541	195	7543	99.65	121.8	-2.07	0.7	0.8	42.4
52	52	53	3/0ACSR	Overhead Line	35.8	34.500	213.3	1290	405	1352	92.15	21.8	-18.03	0.0	0.0	9.2
077	R 038	52	3/0ACSR	Overhead Line	35.8	34.500	1889.0	1290	405	1352	92.14	21.8	-18.04	0.3	0.4	9.2
51	GARDEN RIVER DS HV BUS	R 038	3/0ACSR	Overhead Line	35.6	34.500	34354.4	1290	408	1353	92.09	21.8	-18.16	6.0	7.3	9.2
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.8	12.470	100.0	354	116	372	95.00	16.8	-49.38	0.0	0.0	3.4
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.8	12.470	100.0	927	305	976	95.00	44.4	-50.60	0.1	0.2	14.7
54	53	54	3/0ACSR	Overhead Line	35.8	34.500	147.6	6250	-210	6254	-99.39	101.0	1.34	0.5	0.6	35.0
67	69	54	3/0ACSR	Overhead Line	35.5	34.500	12664.6	6250	-211	6253	-99.39	101.0	1.33	41.7	50.9	35.0
70	69	66	3/0ACSR	Overhead Line	35.4	34.500	9594.3	6208	-242	6213	-99.37	101.0	1.16	31.6	38.5	35.0
66	65	66	3/0ACSR	Overhead Line	35.4	34.500	100.0	3206	-111	3208	-98.06	52.4	0.51	0.1	0.1	19.8
65	BAR RIVER DS HV BUS	65	3/0ACSR	Overhead Line	35.4	34.500	64.0	3206	-111	3208	-98.06	52.4	0.51	0.1	0.1	19.8
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	12.6	12.470	100.0	3196	-207	3203	-98.31	145.0	-29.49	0.3	1.1	33.7
71	66	R 2020	3/0ACSR	Overhead Line	35.4	34.500	82.0	2970	-155	2974	-99.86	48.5	1.57	0.1	0.1	15.4
72	R 2020	72	3/0ACSR	Overhead Line	35.1	34.500	29000.0	2970	-155	2974	-99.86	48.5	1.57	21.5	26.3	15.4
73	72	73	556ASC	Overhead Line	35.1	34.500	6391.1	2949	-138	2952	-99.89	48.5	0.73	1.5	5.3	7.5
74	73	SOLAR	556ASC	Overhead Line	35.1	34.500	100.0	-239	0	239	100.00	3.9	177.92	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.0	34.500	28445.2	3186	-133	3189	-99.91	52.4	0.33	7.5	27.3	8.1
79	78	542	477ACSR	Overhead Line	35.0	34.500	5072.2	3179	-113	3181	-99.94	52.4	-0.51	1.6	4.8	8.2
86	542	86	556ASC	Overhead Line	35.0	34.500	100.0	3177	-109	3179	-99.94	52.4	-0.66	0.0	0.1	8.1
8	86	8	556ASC	Overhead Line	25.3	25.000	10.0	3164	-244	3173	-99.70	72.3	-30.66	0.0	0.0	11.2
7	8	R 2010	556ASC	Overhead Line	25.3	25.000	10.0	3164	-244	3173	-99.70	72.3	-30.66	0.0	0.0	11.2
89	R 2010	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	25.3	25.000	50.0	3164	-244	3173	-99.70	72.3	-30.66	0.0	0.1	14.2
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	25.3	25.000	185.0	3164	-244	3173	-99.70	72.3	-30.67	0.3	0.1	26.4
13	11	13	336AAC	Overhead Line	25.3	25.000	3500.0	3163	-241	3173	-99.71	72.3	-30.72	2.6	6.9	14.2
14	13	14	336AAC	Overhead Line	25.2	25.000	5717.0	3161	993	3313	95.41	75.6	-52.63	4.4	11.8	14.9
15	14	15	35 KV 4/0 CU 100% CN	Cable	25.2	25.000	2345.0	3157	985	3307	95.46	75.6	-52.70	2.6	1.6	20.2
16	15	16	336AAC	Overhead Line	25.1	25.000	13595.0	3154	1049	3324	94.89	76.1	-53.78	10.6	28.4	15.0
18	17	18	336AAC	Overhead Line	25.2	25.000	25.0	3144	1032	3309	95.01	75.8	-53.96	0.0	0.1	14.9
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.6	34.500	22193.7	8027	1096	8102	98.73	130.4	-7.77	42.9	131.7	22.7
2024	ER1	58	477ACSR	Overhead Line	35.5	34.500	9412.4	7985	1002	8047	98.86	130.4	-8.04	18.2	55.9	22.7
59	58	VR PRIMARY	477ACSR	Overhead Line	35.5	34.500	24.2	7966	962	8024	98.92	130.5	-8.15	0.0	0.1	22.7
62	VR SECONDARY	62	477ACSR	Overhead Line	35.4	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	35.4	34.500	100.0	7966	963	8024	98.92	131.0	-8.15	0.2	0.6	22.8
76	75	76	477ACSR	Overhead Line	34.8	34.500	51800.0	7966	962	8024	98.92	131.0	-8.15	101.3	310.9	22.8
77	76	77	556ASC	Overhead Line	34.8	34.500	100.0	7865	737	7899	99.19	131.2	-8.76	0.2	0.6	22.7
80	542	77	556ASC	Overhead Line	34.8	34.500	100.0	0	0	0	0.01	0.0	86.63	0.0	0.0	0.0
81	77	81	556ASC	Overhead Line	34.8	34.500	100.0	2327	-401	2362	-95.88	39.3	6.30	0.0	0.1	8.0
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.6	12.470	100.0	2321	-460	2367	-95.39	108.6	-23.71	0.2	0.6	24.8
82	77	R 052	3/0ACSR	Overhead Line	34.8	34.500	100.0	5537	1137	5653	97.90	93.8	-15.00	0.3	0.3	31.0
83	R 052	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	33.9	34.500	41600.0	5537	1137	5652	97.90	93.8	-15.00	116.1	141.7	31.0
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	33.9	34.500	100.0	2446	-344	2470	-98.72	42.1	3.38	0.1	0.1	14.4
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.6	12.470	39.9	2438	-422	2474	-98.21	113.4	-26.63	0.1	0.2	20.3
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	33.8	34.500	15088.3	2975	1398	3287	90.51	56.0	-29.73	4.6	16.6	8.7
61	VR PRIMARY	61	477ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0
63	61	62	3/0ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0
NA1	NORTHERN AVE TS	46	3/0ACSR	Overhead Line	35.9	34.500	100.0	54	-43	69	-78.38	1.1	38.39	0.0	0.0	0.4
390	46	TRUSS PLANT	3/0ACSR	Overhead Line	35.9	34.500	27986.1	54	-43	69	-78.49	1.1	38.29	0.0	0.0	0.4
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	3/0ACSR	Overhead Line	35.9	34.500	16346.2	0	-25	25	0.02	0.4	90.00	0.0	0.0	0.1

42.37619931

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-4-2020 existing conductors.sxst
Date	Tue Jun 16 2020
Time	14h55m01s
Project Name	Base Case from NTS Min Load - Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	**kW**	**kvar**	**kVA**	**PF(%)**
Sources (Swing)	4581.45	134.75	4583.44	99.96
Generators	238.98	-0.01	238.98	100.00
Total Generation	**4820.44**	**134.74**	**4822.32**	**99.96**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4627.53	1656.01	4914.92	94.15
Shunt capacitors (Adjusted)	0.00	-1234.07	1234.07	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4627.53**	**421.95**	**4646.73**	**99.59**
Cable Capacitance	0.00	-66.23	66.23	0.00
Line Capacitance	0.00	-521.34	521.34	0.00
Total Shunt Capacitance	**0.00**	**-587.58**	**587.58**	**0.00**
Line Losses	187.96	253.10	315.26	59.62
Cable Losses	0.26	0.16	0.30	85.67
Transformer Load Losses	4.71	47.11	47.35	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**192.93**	**300.37**	**356.99**	**54.04**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	102.74 %
	B	1	87	101.87 %
	C	1	87	103.89 %
Under-Voltage	A	0	16	98.82 %
	B	0	16	98.46 %
	C	0	16	99.60 %
Over-Voltage	A	0	ECHO RIVER TS	104.00 %
	B	0	ECHO RIVER TS	104.00 %
	C	0	ECHO RIVER TS	104.00 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	187.96	1646.50	164.65
Cable Losses	0.26	2.26	0.23
Transformer Load Losses	4.71	41.27	4.13
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	192.93	1690.04	169.00

E

Appendix E

Algoma Power 34.5kV Single Line Diagram

CIMA+

CIMA+ Canada

555 Edgewater Road
Sudbury, Ontario
P3G 1J7
T: (705) 470-3090 x 101

4096 Meadowbrook Dr., Unit 112
London, Ontario
N6L 1G4
T: (519) 203-1222

C16-0056 East SaultDist System
Detailed Engineering Estimate - 35km of Pole Line CLASS 3

Algoma Power

SCOPE: See Below

Rate Sheet (A, B, C)	A
VP/Principal	$206
Senior Eng./ Associate	$184
Eng./ Project Manager	$172
Inter. Eng/ Tech	$159
JR. Eng./ Tech.	$131
Drafting	$131
Mileage rate	$0.77
Small Vehicle	$17/hr
Daily Expense Estimate	$375

Task	VP/ Principal	Senior Eng./ Associate	Eng./ Project Manager	Inter. Eng/ Tech	JR. Eng./ Tech.	Drafting	Cost	Travel	Expenses	Total
Topographical Survey - assumed to be by others, but estimated at $100k							$ -		$ 100,000	$ 100,000
							$ -			$ -
Field data collection for approximately 468 poles							$ -			$ -
4 staff assigned at an average of 50 poles per day x 12hr/day	16			500			$ 82,606			$ 82,606
OT				90			$ 21,414			$ 21,414
ATVs rentals (estimated at $2000 each per week with trailer and truck)							$ -		$ 4,000	$ 4,000
fuel/oil and incidentals							$ -		$ 3,000	$ 3,000
Accommodations for 4 staff x 11 days							$ -		$ 16,500	$ 16,500
Travel to/From SSM for 4 staff (London-SSM-Return)				240			$ 38,069		$ 5,000	$ 43,069
							$ -			$ -
Process and file field data				120			$ 19,034			$ 19,034
							$ -			$ -
Pole modelling and design (average of 2 hr per pole)	40			940			$ 157,343			$ 157,343
Drafting						250	$ 32,703			$ 32,703
							$ -			$ -
Pole staking and layout (in conjuction with orginal surveyor)	12			190			$ 32,610		$ 15,000	$ 47,610
OT				40			$ 9,517			$ 9,517
CIMA staff travel to/from SSM				120			$ 19,034		$ 1,200	$ 20,234
accommodations for two for 8 days							$ -		$ 2,520	$ 2,520
ATVs rentals (estimated at $500 each per week with trailer and truck)							$ -		$ 1,000	$ 1,000
							$ -			$ -
							$ -			$ -
* HST not included in proposal	68	0	0	2240	0	250			Sub-total	$ 560,550
									Contingency (25%)	$ 140,137
	Total Hours	2558								
	Average Hourly Rate	274							**Maximum Upset Price**	**$ 700,687**

Percentage Engineering/estimated Construction of $7.95M 8.81%

D

Appendix D

CIMA+ Engineering Estimate

CIMA+

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	48.5	7838.2	4502.7	103.98
NORTHERN AVE TS	390	DEFAULT	Switch	48.4	7644.0	3885.9	98.84
NORTHERN AVE TS	076	DEFAULT	Switch	48.4	7544.1	3532.9	95.98
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	18.7	185.3	71.0	99.56
NORTHERN AVE TS	51	DEFAULT	Switch	46.1	7215.7	3305.6	95.98
NORTHERN AVE TS	077	DEFAULT	Switch	46.2	7014.3	2594.2	90.37
NORTHERN AVE TS	67	DEFAULT	Switch	46.2	7012.3	2593.5	90.31
NORTHERN AVE TS	66	DEFAULT	Switch	37.4	5528.1	1872.7	87.14
NORTHERN AVE TS	65	DEFAULT	Switch	37.4	5527.9	1871.9	87.13
NORTHERN AVE TS	64	DEFAULT	Switch	27.5	4049.7	1436.4	87.13
NORTHERN AVE TS	61	DEFAULT	Switch	27.5	4048.8	1435.0	87.10
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	123.9	4048.6	1447.1	95.80
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	87.12
NORTHERN AVE TS	75	DEFAULT	Switch	25.0	4048.4	1446.6	95.79
NORTHERN AVE TS	77	DEFAULT	Switch	25.1	3949.7	1167.7	91.61
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	84.75
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	84.6	1408.8	249.1	93.52
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	87.8	1459.2	136.8	93.29
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	19.1	1441.4	474.3	100.97
NORTHERN AVE TS	81	DEFAULT	Switch	8.3	1355.8	-63.4	91.61
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	76.8	1355.7	-63.4	102.36
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	104.8	1106.4	-55.1	102.33
NORTHERN AVE TS	82	DEFAULT	Switch	17.5	2593.9	1231.1	91.61
NORTHERN AVE TS	83	DEFAULT	Switch	17.5	2593.7	1230.9	91.60
NORTHERN AVE TS	83	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	78.9	2485.1	1114.2	95.36
NORTHERN AVE TS	84	DEFAULT	Switch	7.7	1209.4	509.1	95.36
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	72.9	1209.4	509.1	103.43
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	1362.6	448.3	103.42
NORTHERN AVE TS	85	DEFAULT	Switch	0.0	0.0	0.0	94.91
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-12.7	87.09
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	62.0	1478.2	435.5	96.28
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	92.7	1954.3	273.0	96.23
NORTHERN AVE TS	71	DEFAULT	Switch	8.9	1359.9	280.9	87.15
NORTHERN AVE TS	72	DEFAULT	Switch	8.9	1340.4	267.3	85.65
NORTHERN AVE TS	74	DEFAULT	Switch	0.5	-77.8	0.8	85.51
NORTHERN AVE TS	79	DEFAULT	Switch	9.4	1408.9	249.2	84.75
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-6.4	90.33
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	1.6	143.2	156.3	100.48

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS	9	DEFAULT	Switch	0.0	0.0	0.0	104.00

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	22865	11510	25598	89.17	411.9	-26.72	1.7	6.0	67.7
390	46	TRUSS PLANT	556ASC	Overhead Line	34.3	34.500	27986.1	22863	11504	25594	89.18	411.9	-26.72	462.3	1671.8	67.7
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	556ASC	Overhead Line	33.4	34.500	16346.2	22333	9846	24407	91.34	411.0	-26.81	268.7	971.7	67.5
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.5	12.470	100.0	457	150	481	95.00	22.3	-53.75	0.0	0.0	4.6
51	GARDEN RIVER DS HV BUS	51	556ASC	Overhead Line	31.8	34.500	34354.4	20366	8279	21984	92.35	380.0	-27.02	485.0	1753.7	64.4
077	51	52	556ASC	Overhead Line	31.7	34.500	1889.0	19881	6574	20940	94.62	380.3	-27.14	26.7	96.5	64.4
52	52	53	556ASC	Overhead Line	31.7	34.500	213.3	19854	6480	20885	94.74	380.3	-27.15	3.0	10.9	64.4
54	53	54	556ASC	Overhead Line	31.7	34.500	147.6	19851	6490	20885	94.72	380.5	-27.20	2.1	7.5	64.4
67	69	54	556ASC	Overhead Line	31.2	34.500	12664.6	19849	6482	20881	94.73	380.5	-27.20	179.1	647.5	64.4
70	69	66	556ASC	Overhead Line	30.8	34.500	9594.3	19670	5852	20522	95.51	380.6	-27.24	135.7	490.7	64.5
66	65	66	556ASC	Overhead Line	30.8	34.500	100.0	15339	4552	16000	95.34	300.8	-28.45	0.9	3.2	52.1
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	30.8	34.500	64.0	15338	4549	15998	95.35	300.8	-28.45	0.6	2.1	52.1
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	30.8	34.500	100.0	11383	4197	12132	93.53	228.1	-32.09	0.6	1.8	38.7
63	61	62	3/0ACSR	Overhead Line	30.8	34.500	100.0	11382	4196	12131	93.54	228.1	-32.09	1.7	2.0	78.6
61	VR PRIMARY	61	477ACSR	Overhead Line	30.8	34.500	100.0	11381	4194	12129	93.54	228.1	-32.09	0.6	1.8	38.7
62	VR SECONDARY	62	477ACSR	Overhead Line	33.8	34.500	100.0	0	0	0	-0.01	0.0	78.18	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	33.8	34.500	100.0	11380	4232	12142	93.44	207.6	-32.26	0.5	1.5	35.2
76	75	76	477ACSR	Overhead Line	32.5	34.500	51800.0	11380	4231	12141	93.44	207.6	-32.27	252.9	776.2	35.2
77	76	77	556ASC	Overhead Line	32.5	34.500	100.0	11127	3531	11674	94.99	208.0	-32.61	0.4	1.5	35.0
80	542	77	556ASC	Overhead Line	32.5	34.500	100.0	0	0	0	-0.01	0.0	75.06	0.0	0.0	0.0
86	542	86	556ASC	Overhead Line	30.0	34.500	100.0	4348	732	4409	98.60	84.9	-23.37	0.1	0.3	13.4
8	86	8	556ASC	Overhead Line	23.5	25.000	10.0	4312	377	4329	99.62	106.6	-53.37	0.0	0.0	16.8
7	8	7	556ASC	Overhead Line	23.5	25.000	10.0	4312	377	4329	99.62	106.6	-53.37	0.0	0.0	16.8
89	7	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	23.5	25.000	50.0	4312	377	4329	99.62	106.6	-53.37	0.1	0.2	21.3
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	23.4	25.000	185.0	4312	377	4328	99.62	106.6	-53.37	0.6	0.3	39.5
13	11	13	336AAC	Overhead Line	23.4	25.000	3500.0	4311	379	4328	99.61	106.6	-53.41	5.6	15.1	21.3
14	13	14	336AAC	Overhead Line	23.3	25.000	5717.0	4306	1426	4536	94.93	111.9	-66.87	9.6	25.9	22.4
15	14	15	35 KV 4/0 CU 100% CN	Cable	23.3	25.000	2345.0	4296	1404	4520	95.05	111.9	-66.92	5.7	3.6	30.4
16	15	16	336AAC	Overhead Line	23.1	25.000	13595.0	4290	1456	4531	94.69	112.4	-67.59	23.1	62.1	22.4
18	17	18	336AAC	Overhead Line	25.1	25.000	25.0	4267	1404	4492	94.99	103.4	-67.69	0.0	0.1	20.4
81	77	81	556ASC	Overhead Line	32.5	34.500	100.0	3214	-72	3214	-97.15	57.6	-13.92	0.0	0.1	11.5
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.7	12.470	100.0	3201	-200	3207	-98.04	146.6	-43.93	0.4	1.2	33.6
82	77	82	3/0ACSR	Overhead Line	32.5	34.500	100.0	7913	3602	8694	90.96	154.5	-39.47	0.8	0.9	50.1
83	82	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	30.8	34.500	41600.0	7912	3601	8693	90.97	154.5	-39.47	314.5	384.1	50.1
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	33.9	34.500	100.0	3527	1338	3772	93.22	64.3	-37.38	0.1	0.2	21.9
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.9	12.470	39.9	3508	1154	3693	94.99	165.2	-67.38	0.1	0.4	29.9
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	33.8	34.500	15088.3	4071	1929	4505	90.36	76.6	-41.80	8.6	31.1	12.2
59	58	VR PRIMARY	477ACSR	Overhead Line	30.8	34.500	24.2	0	-40	40	-0.01	0.8	78.18	0.0	0.0	0.1
2024	ER1	58	477ACSR	Overhead Line	30.8	34.500	9412.4	0	-40	40	-0.01	0.8	78.18	0.0	0.0	0.1
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	30.8	34.500	22193.7	0	-28	28	-0.01	0.5	78.18	0.0	0.0	0.1
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	12.2	12.470	100.0	3935	155	3938	99.06	187.6	-47.27	0.6	1.9	44.1
71	66	71	3/0ACSR	Overhead Line	30.8	34.500	82.0	4196	821	4275	98.12	80.2	-22.88	0.2	0.2	25.9
72	71	72	3/0ACSR	Overhead Line	30.3	34.500	29000.0	4195	821	4275	98.13	80.2	-22.88	58.9	71.9	25.9
73	72	73	556ASC	Overhead Line	30.2	34.500	6391.1	4137	782	4210	98.25	80.3	-23.31	4.0	14.4	12.7
74	73	SOLAR	556ASC	Overhead Line	30.2	34.500	100.0	-239	0	239	99.98	4.6	167.20	0.0	0.0	0.7
78	73	78	556ASC	Overhead Line	30.0	34.500	28445.2	4372	775	4440	98.45	84.8	-22.85	19.8	71.6	13.4
79	78	542	477ACSR	Overhead Line	30.0	34.500	5072.2	4352	738	4414	98.58	84.9	-23.29	4.1	12.6	13.5
55	53	ER2	3/0ACSR	Overhead Line	31.7	34.500	144.4	0	-20	20	-0.01	0.4	80.98	0.0	0.0	0.1
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	31.7	34.500	14794.7	0	-20	20	-0.01	0.4	80.98	0.0	0.0	0.1
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.5	12.470	100.0	1235	406	1300	94.99	60.0	-55.47	0.1	0.3	19.9

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	2	5	123.92 %
	B	1	5	109.90 %
	C	3	87	111.86 %
Under-Voltage	A	94	86	84.75 %
	B	90	86	87.07 %
	C	61	86	88.75 %
Over-Voltage	A	0	ECHO RIVER TS	104.00 %
	B	0	ECHO RIVER TS	104.00 %
	C	11	84	107.26 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	2273.02	19911.62	1991.16
Cable Losses	6.30	55.17	5.52
Transformer Load Losses	92.52	810.48	81.05
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	2371.84	20777.28	2077.73

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-18-2020 LTC.sxst
Date	Mon Jul 27 2020
Time	09h17m50s
Project Name	Uprated conductor with regulators and LTC, 137% Load by Ash
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=137.00%, Q=137.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	22864.71	11510.12	25598.39	89.32
Generators	239.02	0.03	239.02	100.00
Total Generation	**23103.73**	**11510.14**	**25812.12**	**89.51**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	20731.40	7413.53	22017.07	94.16
Shunt capacitors (Adjusted)	0.00	-3453.58	3453.58	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**20731.40**	**3959.95**	**21106.21**	**98.22**
Cable Capacitance	0.00	-58.56	58.56	0.00
Line Capacitance	0.00	-461.46	461.46	0.00
Total Shunt Capacitance	**0.00**	**-520.02**	**520.02**	**0.00**
Line Losses	2273.02	7141.10	7494.12	30.33
Cable Losses	6.30	3.91	7.41	84.98
Transformer Load Losses	92.52	925.21	929.82	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**2371.84**	**8070.21**	**8411.53**	**28.20**

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	36.5	6379.2	2343.8	103.99
NORTHERN AVE TS	390	DEFAULT	Switch	36.4	6256.4	1994.6	100.73
NORTHERN AVE TS	076	DEFAULT	Switch	36.4	6196.4	1796.7	98.92
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	15.5	154.3	58.4	99.28
NORTHERN AVE TS	51	DEFAULT	Switch	34.6	5924.8	1612.1	98.92
NORTHERN AVE TS	077	DEFAULT	Switch	34.6	5803.7	1214.9	95.46
NORTHERN AVE TS	67	DEFAULT	Switch	34.7	5802.5	1218.2	95.43
NORTHERN AVE TS	66	DEFAULT	Switch	28.0	4609.2	854.7	93.48
NORTHERN AVE TS	65	DEFAULT	Switch	28.0	4609.0	854.3	93.47
NORTHERN AVE TS	64	DEFAULT	Switch	19.5	3220.7	531.6	93.47
NORTHERN AVE TS	61	DEFAULT	Switch	19.5	3220.3	531.0	93.46
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	87.7	3220.2	545.4	100.46
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	93.47
NORTHERN AVE TS	75	DEFAULT	Switch	18.1	3220.1	545.2	100.45
NORTHERN AVE TS	77	DEFAULT	Switch	18.2	3166.8	413.5	98.11
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	91.88
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	70.7	1179.8	114.1	93.28
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	87.4	1225.1	51.2	93.11
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	16.0	1213.4	398.0	101.08
NORTHERN AVE TS	81	DEFAULT	Switch	6.3	1101.5	-131.5	98.11
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	62.0	1101.5	-131.5	99.04
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	98.1	869.5	-106.5	99.02
NORTHERN AVE TS	82	DEFAULT	Switch	12.1	2065.3	545.1	98.11
NORTHERN AVE TS	83	DEFAULT	Switch	12.1	2065.2	545.0	98.10
NORTHERN AVE TS	84	DEFAULT	Switch	5.6	947.3	-2.5	95.01
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	53.8	947.3	-2.5	98.19
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	96.4	1031.0	-46.7	98.18
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-14.7	93.45
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	57.8	1388.3	322.7	101.80
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	103.6	1834.4	189.2	101.76
NORTHERN AVE TS	71	DEFAULT	Switch	6.7	1118.6	117.8	93.48
NORTHERN AVE TS	72	DEFAULT	Switch	6.7	1107.4	116.2	92.44
NORTHERN AVE TS	74	DEFAULT	Switch	0.5	-77.8	1.1	92.36
NORTHERN AVE TS	79	DEFAULT	Switch	7.2	1179.9	114.1	91.88
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-7.2	95.44
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	1.3	117.3	126.2	99.09

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS	9	DEFAULT	Switch	0.0	0.0	0.0	104.00

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	18140	5321	18904	95.74	304.2	-16.35	0.9	3.3	50.9
390	46	TRUSS PLANT	556ASC	Overhead Line	35.0	34.500	27986.1	18139	5318	18902	95.75	304.2	-16.35	252.8	914.2	50.9
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	556ASC	Overhead Line	34.5	34.500	16346.2	17827	4423	18367	96.84	303.3	-16.45	146.8	530.8	50.7
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.4	12.470	100.0	380	125	400	95.00	18.7	-52.75	0.0	0.0	3.8
51	GARDEN RIVER DS HV BUS	51	556ASC	Overhead Line	33.6	34.500	34354.4	16288	3422	16643	97.49	279.0	-15.90	262.6	949.6	48.3
077	51	52	556ASC	Overhead Line	33.5	34.500	1889.0	16025	2525	16223	98.39	279.1	-16.08	14.4	52.2	48.3
52	52	53	556ASC	Overhead Line	33.5	34.500	213.3	16011	2476	16201	98.44	279.1	-16.09	1.6	5.9	48.3
54	53	54	556ASC	Overhead Line	33.5	34.500	147.6	16009	2493	16202	98.42	279.2	-16.17	1.1	4.1	48.4
67	69	54	556ASC	Overhead Line	33.2	34.500	12664.6	16008	2489	16200	98.42	279.2	-16.17	96.9	350.5	48.4
70	69	66	556ASC	Overhead Line	33.0	34.500	9594.3	15911	2157	16057	98.70	279.2	-16.24	73.5	265.6	48.4
66	65	66	556ASC	Overhead Line	33.0	34.500	100.0	12387	1560	12485	98.59	218.7	-16.64	0.5	1.7	39.0
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	33.0	34.500	64.0	12387	1559	12484	98.59	218.7	-16.64	0.3	1.1	39.0
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	33.0	34.500	100.0	8702	1467	8825	98.23	154.6	-18.95	0.3	0.8	27.4
63	61	62	3/0ACSR	Overhead Line	33.0	34.500	100.0	8702	1466	8824	98.23	154.7	-18.95	0.8	0.9	55.7
61	VR PRIMARY	61	477ACSR	Overhead Line	33.0	34.500	100.0	8701	1465	8823	98.23	154.7	-18.96	0.3	0.8	27.4
62	VR SECONDARY	62	477ACSR	Overhead Line	34.7	34.500	100.0	0	0	0	0.00	0.0	80.68	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	34.7	34.500	100.0	8701	1511	8831	98.15	147.0	-19.21	0.2	0.8	25.5
76	75	76	477ACSR	Overhead Line	34.0	34.500	51800.0	8700	1510	8830	98.15	147.0	-19.21	127.3	390.7	25.5
77	76	77	556ASC	Overhead Line	34.0	34.500	100.0	8573	1201	8657	98.64	147.2	-19.74	0.2	0.8	25.3
80	542	77	556ASC	Overhead Line	34.0	34.500	100.0	0	0	0	0.00	0.0	78.30	0.0	0.0	0.0
86	542	86	556ASC	Overhead Line	32.5	34.500	100.0	3640	341	3656	99.56	65.0	-16.17	0.0	0.1	10.2
8	86	8	556ASC	Overhead Line	23.3	25.000	10.0	3619	134	3621	99.93	89.7	-46.17	0.0	0.0	14.1
7	8	7	556ASC	Overhead Line	23.3	25.000	10.0	3619	134	3621	99.93	89.7	-46.17	0.0	0.0	14.1
89	7	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	23.3	25.000	50.0	3619	134	3621	99.93	89.7	-46.17	0.1	0.1	17.9
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	23.3	25.000	185.0	3619	134	3621	99.93	89.7	-46.17	0.4	0.2	33.1
13	11	13	336AAC	Overhead Line	23.3	25.000	3500.0	3618	136	3621	99.93	89.7	-46.22	4.0	10.7	17.9
14	13	14	336AAC	Overhead Line	23.2	25.000	5717.0	3614	1175	3801	95.10	94.3	-62.21	6.8	18.4	18.8
15	14	15	35 KV 4/0 CU 100% CN	Cable	23.2	25.000	2345.0	3608	1161	3790	95.20	94.3	-62.27	4.0	2.5	25.5
16	15	16	336AAC	Overhead Line	23.0	25.000	13595.0	3604	1213	3802	94.77	94.8	-63.06	16.4	44.1	18.9
18	17	18	336AAC	Overhead Line	25.1	25.000	25.0	3587	1178	3776	95.01	86.9	-63.19	0.0	0.1	17.2
81	77	81	556ASC	Overhead Line	34.0	34.500	100.0	2539	-260	2552	-96.63	43.5	-6.05	0.0	0.1	8.8
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.3	12.470	100.0	2531	-334	2553	-96.88	120.3	-36.05	0.2	0.8	27.6
82	77	82	3/0ACSR	Overhead Line	34.0	34.500	100.0	6034	1461	6209	97.13	105.4	-25.35	0.4	0.4	34.7
83	82	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	33.0	34.500	41600.0	6034	1461	6208	97.13	105.4	-25.35	146.5	178.9	34.7
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	33.0	34.500	100.0	2651	-189	2657	-99.44	46.5	-9.05	0.1	0.1	15.9
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.2	12.470	39.9	2641	-285	2656	-99.17	125.4	-39.05	0.1	0.3	22.6
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	32.9	34.500	15088.3	3237	1527	3579	90.45	62.6	-38.26	5.7	20.7	9.8
59	58	VR PRIMARY	477ACSR	Overhead Line	33.0	34.500	24.2	0	-46	46	0.00	0.8	80.68	0.0	0.0	0.1
2024	ER1	58	477ACSR	Overhead Line	33.0	34.500	9412.4	0	-46	46	0.00	0.8	80.68	0.0	0.0	0.1
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	33.0	34.500	22193.7	0	-32	32	0.00	0.6	80.68	0.0	0.0	0.1
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	12.8	12.470	100.0	3670	-54	3670	-98.80	165.9	-41.08	0.4	1.5	39.0
71	66	71	3/0ACSR	Overhead Line	33.0	34.500	82.0	3451	345	3468	99.50	60.6	-15.02	0.1	0.1	19.6
72	71	72	3/0ACSR	Overhead Line	32.7	34.500	29000.0	3451	345	3468	99.50	60.6	-15.03	33.7	41.1	19.6
73	72	73	556ASC	Overhead Line	32.6	34.500	6391.1	3417	342	3434	99.50	60.7	-15.65	2.3	8.2	9.6
74	73	SOLAR	556ASC	Overhead Line	32.6	34.500	100.0	-239	0	239	99.99	4.2	169.92	0.0	0.0	0.7
78	73	78	556ASC	Overhead Line	32.5	34.500	28445.2	3654	343	3670	99.56	64.9	-15.43	11.6	41.9	10.2
79	78	542	477ACSR	Overhead Line	32.5	34.500	5072.2	3642	341	3658	99.56	65.0	-16.06	2.4	7.4	10.3
55	53	ER2	3/0ACSR	Overhead Line	33.5	34.500	144.4	0	-22	22	0.00	0.4	82.78	0.0	0.0	0.1
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	33.5	34.500	14794.7	0	-22	22	0.00	0.4	82.78	0.0	0.0	0.1
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.4	12.470	100.0	1008	331	1061	95.00	49.6	-53.98	0.1	0.2	16.4

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	68	103.63 %
	B	1	68	101.27 %
	C	2	68	110.51 %
Under-Voltage	A	66	86	91.88 %
	B	26	16	90.14 %
	C	9	16	93.82 %
Over-Voltage	A	0	ECHO RIVER TS	104.00 %
	B	0	ECHO RIVER TS	104.00 %
	C	5	68	105.13 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	1211.55	10613.16	1061.32
Cable Losses	4.46	39.03	3.90
Transformer Load Losses	56.33	493.45	49.35
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	1272.33	11145.64	1114.56

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-16-2020 uprated conductors.s
Date	Fri Jul 24 2020
Time	10h02m54s
Project Name	Uprated Conductor Sensitivity Test - 115%, by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=115.00%, Q=115.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	18139.62	5321.34	18904.03	95.96
Generators	238.98	-0.01	238.98	100.00
Total Generation	**18378.60**	**5321.33**	**19133.47**	**96.05**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	17106.52	6096.34	18160.36	94.20
Shunt capacitors (Adjusted)	0.00	-4628.17	4628.17	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**17106.52**	**1468.17**	**17169.41**	**99.63**
Cable Capacitance	0.00	-57.96	57.96	0.00
Line Capacitance	0.00	-504.14	504.14	0.00
Total Shunt Capacitance	**0.00**	**-562.11**	**562.11**	**0.00**
Line Losses	1211.55	3849.22	4035.39	30.02
Cable Losses	4.46	2.75	5.24	85.09
Transformer Load Losses	56.33	563.30	566.11	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**1272.33**	**4415.27**	**4594.94**	**27.69**

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	34.5	5815.9	2763.4	103.99
NORTHERN AVE TS	390	DEFAULT	Switch	34.5	5703.3	2447.8	100.43
NORTHERN AVE TS	076	DEFAULT	Switch	34.5	5647.6	2268.5	98.43
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	14.4	143.3	54.1	102.65
NORTHERN AVE TS	51	DEFAULT	Switch	32.8	5395.2	2097.5	98.43
NORTHERN AVE TS	077	DEFAULT	Switch	32.8	5282.7	1737.6	94.46
NORTHERN AVE TS	67	DEFAULT	Switch	32.9	5281.6	1741.1	94.42
NORTHERN AVE TS	66	DEFAULT	Switch	27.3	4261.2	1480.8	92.12
NORTHERN AVE TS	65	DEFAULT	Switch	27.3	4261.1	1480.3	92.12
NORTHERN AVE TS	64	DEFAULT	Switch	19.5	3100.9	882.3	92.12
NORTHERN AVE TS	61	DEFAULT	Switch	19.5	3100.4	881.6	92.10
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	88.0	3100.3	895.6	100.72
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	92.11
NORTHERN AVE TS	75	DEFAULT	Switch	17.9	3100.2	895.4	100.72
NORTHERN AVE TS	77	DEFAULT	Switch	17.9	3045.9	766.3	97.81
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	90.88
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	61.0	1016.4	41.2	92.85
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	86.6	1058.3	-4.8	92.71
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	13.9	1049.4	345.2	100.84
NORTHERN AVE TS	81	DEFAULT	Switch	5.5	955.0	-167.5	97.81
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	53.6	955.0	-167.5	99.00
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	98.0	755.6	-143.5	98.98
NORTHERN AVE TS	82	DEFAULT	Switch	13.1	2090.8	933.9	97.81
NORTHERN AVE TS	83	DEFAULT	Switch	13.1	2090.7	933.7	97.80
NORTHERN AVE TS	83	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	59.0	2028.0	876.5	102.87
NORTHERN AVE TS	84	DEFAULT	Switch	5.5	942.1	365.7	102.87
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	55.1	942.1	365.7	104.07
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	1007.1	331.4	104.06
NORTHERN AVE TS	85	DEFAULT	Switch	0.0	0.0	0.0	102.50
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-14.3	92.09
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	50.7	1160.2	598.0	99.78
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	0.0	1532.5	504.6	99.74
NORTHERN AVE TS	71	DEFAULT	Switch	5.8	951.0	37.3	92.13
NORTHERN AVE TS	72	DEFAULT	Switch	5.8	942.8	39.0	91.30
NORTHERN AVE TS	74	DEFAULT	Switch	0.5	-77.6	1.2	91.23
NORTHERN AVE TS	79	DEFAULT	Switch	6.2	1016.4	41.2	90.88
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-7.0	94.44
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	1.2	109.1	116.9	102.47

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS	9	DEFAULT	Switch	0.0	0.0	0.0	104.00

79	78	542	477ACSR	Overhead Line	32.2	34.500	5072.2	3151	126	3153	99.92	56.5	-11.73	1.8	5.6	9.0
55	53	ER2	3/0ACSR	Overhead Line	33.2	34.500	144.4	0	-22	22	-0.01	0.4	83.67	0.0	0.0	0.1
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	33.2	34.500	14794.7	0	-22	22	-0.01	0.4	83.67	0.0	0.0	0.1
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.8	12.470	100.0	937	308	986	94.99	44.6	-53.36	0.1	0.2	14.8

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	16361	6676	17671	92.40	284.3	-22.20	0.8	2.9	48.2
390	46	TRUSS PLANT	556ASC	Overhead Line	34.9	34.500	27986.1	16361	6674	17669	92.40	284.3	-22.20	221.1	799.4	48.2
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	556ASC	Overhead Line	34.3	34.500	16346.2	16088	5897	17135	93.70	283.7	-22.32	128.5	464.6	48.1
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.8	12.470	100.0	353	116	372	95.00	16.8	-52.22	0.0	0.0	3.4
51	GARDEN RIVER DS HV BUS	51	556ASC	Overhead Line	33.3	34.500	34354.4	14666	4999	15495	94.32	260.8	-22.35	229.9	831.1	45.8
077	51	52	556ASC	Overhead Line	33.2	34.500	1889.0	14437	4221	15041	95.64	261.1	-22.54	12.7	45.7	45.8
52	52	53	556ASC	Overhead Line	33.2	34.500	213.3	14424	4178	15017	95.71	261.1	-22.55	1.4	5.2	45.8
54	53	54	556ASC	Overhead Line	33.2	34.500	147.6	14422	4195	15020	95.68	261.2	-22.63	1.0	3.6	45.8
67	69	54	556ASC	Overhead Line	32.9	34.500	12664.6	14421	4192	15018	95.68	261.2	-22.63	84.9	307.1	45.8
70	69	66	556ASC	Overhead Line	32.6	34.500	9594.3	14336	3903	14858	96.14	261.3	-22.70	64.4	232.8	45.9
66	65	66	556ASC	Overhead Line	32.6	34.500	100.0	11325	3575	11876	94.84	210.7	-25.82	0.4	1.6	38.1
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	32.6	34.500	64.0	11325	3573	11875	94.84	210.7	-25.82	0.3	1.0	38.1
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	32.6	34.500	100.0	8254	2451	8610	95.54	152.8	-24.79	0.3	0.8	27.5
63	61	62	3/0ACSR	Overhead Line	32.6	34.500	100.0	8254	2450	8610	95.54	152.8	-24.79	0.7	0.9	55.8
61	VR PRIMARY	61	477ACSR	Overhead Line	32.6	34.500	100.0	8253	2449	8609	95.54	152.8	-24.79	0.3	0.8	27.5
62	VR SECONDARY	62	477ACSR	Overhead Line	34.7	34.500	100.0	0	0	0	-0.01	0.0	81.81	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	34.7	34.500	100.0	8253	2494	8622	95.40	143.5	-25.05	0.2	0.7	25.1
76	75	76	477ACSR	Overhead Line	33.8	34.500	51800.0	8253	2493	8621	95.40	143.5	-25.05	121.7	373.5	25.1
77	76	77	556ASC	Overhead Line	33.8	34.500	100.0	8131	2201	8424	96.19	143.9	-25.58	0.2	0.7	25.0
80	542	77	556ASC	Overhead Line	33.8	34.500	100.0	0	0	0	-0.01	0.0	79.64	0.0	0.0	0.0
86	542	86	556ASC	Overhead Line	32.2	34.500	100.0	3149	128	3151	99.92	56.5	-11.85	0.0	0.1	8.9
8	86	8	556ASC	Overhead Line	23.2	25.000	10.0	3133	-29	3133	-99.99	78.0	-41.86	0.0	0.0	12.2
7	8	7	556ASC	Overhead Line	23.2	25.000	10.0	3133	-29	3133	-99.99	78.0	-41.86	0.0	0.0	12.2
89	7	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	23.2	25.000	50.0	3133	-29	3133	-99.99	78.0	-41.86	0.0	0.1	15.5
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	23.2	25.000	185.0	3133	-29	3133	-99.99	78.0	-41.86	0.3	0.2	28.7
13	11	13	336AAC	Overhead Line	23.2	25.000	3500.0	3133	-27	3133	-99.99	78.0	-41.91	3.0	8.1	15.5
14	13	14	336AAC	Overhead Line	23.1	25.000	5717.0	3129	1004	3287	95.22	81.9	-60.31	5.2	13.9	16.3
15	14	15	35 KV 4/0 CU 100% CN	Cable	23.1	25.000	2345.0	3124	994	3279	95.30	82.0	-60.37	3.1	1.9	22.1
16	15	16	336AAC	Overhead Line	22.9	25.000	13595.0	3121	1047	3292	94.81	82.4	-61.28	12.4	33.4	16.4
18	17	18	336AAC	Overhead Line	25.1	25.000	25.0	3109	1022	3273	94.99	75.4	-61.43	0.0	0.1	14.9
81	77	81	556ASC	Overhead Line	33.8	34.500	100.0	2195	-380	2227	-95.80	38.1	-0.75	0.0	0.1	7.7
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.2	12.470	100.0	2189	-437	2232	-95.36	105.4	-30.75	0.2	0.6	24.0
82	77	82	3/0ACSR	Overhead Line	33.8	34.500	100.0	5936	2581	6473	91.65	110.5	-33.90	0.4	0.5	37.3
83	82	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	32.6	34.500	41600.0	5936	2581	6473	91.65	110.5	-33.90	161.4	197.1	37.3
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	35.2	34.500	100.0	2564	930	2728	93.70	44.7	-31.41	0.1	0.1	15.7
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.9	12.470	39.9	2555	841	2690	94.99	120.6	-61.42	0.1	0.2	21.9
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	35.1	34.500	15088.3	3210	1509	3547	90.50	58.1	-36.60	5.0	17.9	9.1
59	58	VR PRIMARY	477ACSR	Overhead Line	32.6	34.500	24.2	0	-45	45	-0.01	0.8	81.82	0.0	0.0	0.1
2024	ER1	58	477ACSR	Overhead Line	32.6	34.500	9412.4	0	-45	45	-0.01	0.8	81.82	0.0	0.0	0.1
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	32.6	34.500	22193.7	0	-32	32	-0.01	0.6	81.82	0.0	0.0	0.1
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	12.5	12.470	100.0	3058	1007	3220	94.99	149.2	-58.54	0.3	1.1	34.8
71	66	71	3/0ACSR	Overhead Line	32.6	34.500	82.0	2947	109	2949	99.93	52.2	-10.29	0.1	0.1	16.9
72	71	72	3/0ACSR	Overhead Line	32.3	34.500	29000.0	2947	109	2949	99.93	52.2	-10.29	24.9	30.4	16.9
73	72	73	556ASC	Overhead Line	32.3	34.500	6391.1	2922	116	2924	99.92	52.2	-11.01	1.7	6.1	8.2
74	73	SOLAR	556ASC	Overhead Line	32.3	34.500	100.0	-239	0	239	99.99	4.3	171.11	0.0	0.0	0.7
78	73	78	556ASC	Overhead Line	32.2	34.500	28445.2	3159	119	3162	99.93	56.5	-11.01	8.8	31.7	8.9

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	0	87	98.00 %
	B	0	87	92.83 %
	C	0	87	98.44 %
Under-Voltage	A	78	86	90.88 %
	B	36	16	89.91 %
	C	19	16	93.29 %
Over-Voltage	A	0	84	104.07 %
	B	0	ECHO RIVER TS	104.00 %
	C	0	ECHO RIVER TS	104.00 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	1094.34	9586.43	958.64
Cable Losses	3.38	29.64	2.96
Transformer Load Losses	45.25	396.35	39.63
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	1142.97	10012.42	1001.24

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-18-2020 LTC.sxst
Date	Thu Jun 18 2020
Time	14h31m52s
Project Name	Uprated from NTS with Reg and LTC by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=100.00%, Q=100.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	16361.37	6676.35	17671.11	92.59
Generators	239.00	0.03	239.00	100.00
Total Generation	**16600.37**	**6676.38**	**17892.63**	**92.78**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	15457.07	5553.16	16424.33	94.11
Shunt capacitors (Adjusted)	0.00	-2193.07	2193.07	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**15457.07**	**3360.10**	**15818.07**	**97.72**
Cable Capacitance	0.00	-57.43	57.43	0.00
Line Capacitance	0.00	-500.47	500.47	0.00
Total Shunt Capacitance	**0.00**	**-557.90**	**557.90**	**0.00**
Line Losses	1094.34	3419.65	3590.48	30.48
Cable Losses	3.38	2.08	3.97	85.19
Transformer Load Losses	45.25	452.45	454.71	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**1142.97**	**3874.18**	**4039.26**	**28.30**

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	4653	154	4656	99.73	74.9	-1.90	0.1	0.2	12.5
390	46	TRUSS PLANT	556ASC	Overhead Line	35.7	34.500	27986.1	4653	154	4656	99.73	74.9	-1.90	15.3	55.4	12.5
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	556ASC	Overhead Line	35.7	34.500	16346.2	4622	139	4624	99.73	74.7	-2.40	8.9	32.2	12.5
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.9	12.470	100.0	107	35	113	95.01	5.1	-49.40	0.0	0.0	1.0
51	GARDEN RIVER DS HV BUS	51	556ASC	Overhead Line	35.5	34.500	34354.4	4220	3	4220	99.57	68.3	-1.11	15.8	57.0	11.9
077	51	52	556ASC	Overhead Line	35.5	34.500	1889.0	4204	4	4204	99.57	68.3	-1.90	0.9	3.1	11.9
52	52	53	556ASC	Overhead Line	35.5	34.500	213.3	4203	4	4203	99.57	68.3	-1.95	0.1	0.4	11.9
54	53	54	556ASC	Overhead Line	35.5	34.500	147.6	4203	29	4203	99.57	68.3	-2.30	0.1	0.2	11.9
67	69	54	556ASC	Overhead Line	35.5	34.500	12664.6	4203	29	4203	99.57	68.3	-2.30	5.8	21.0	11.9
70	69	66	556ASC	Overhead Line	35.4	34.500	9594.3	4197	29	4197	99.57	68.3	-2.59	4.4	15.9	11.9
66	65	66	556ASC	Overhead Line	35.4	34.500	100.0	3480	-103	3481	-99.34	56.7	-0.71	0.0	0.1	10.1
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.4	34.500	64.0	3480	-103	3481	-99.34	56.7	-0.71	0.0	0.1	10.1
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.4	34.500	100.0	2467	-446	2507	-98.04	40.8	7.85	0.0	0.1	7.2
63	61	62	3/0ACSR	Overhead Line	35.4	34.500	100.0	2467	-446	2507	-98.04	40.8	7.84	0.1	0.1	14.6
61	VR PRIMARY	61	477ACSR	Overhead Line	35.4	34.500	100.0	2467	-446	2507	-98.04	40.8	7.84	0.0	0.1	7.2
62	VR SECONDARY	62	477ACSR	Overhead Line	34.8	34.500	100.0	0	0	0	0.01	0.0	87.63	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	34.8	34.500	100.0	2467	-392	2498	-98.39	41.5	6.65	0.0	0.1	7.2
76	75	76	477ACSR	Overhead Line	34.7	34.500	51800.0	2467	-392	2498	-98.39	41.5	6.65	10.1	31.0	7.2
77	76	77	556ASC	Overhead Line	34.7	34.500	100.0	2457	-340	2480	-98.68	41.3	4.74	0.0	0.1	7.2
80	542	77	556ASC	Overhead Line	34.7	34.500	100.0	0	0	0	0.01	0.0	86.90	0.0	0.0	0.0
86	542	86	556ASC	Overhead Line	35.3	34.500	100.0	950	239	979	96.98	16.0	-16.77	0.0	0.0	2.5
8	86	8	556ASC	Overhead Line	25.5	25.000	10.0	949	226	975	97.27	22.1	-46.78	0.0	0.0	3.5
7	8	7	556ASC	Overhead Line	25.5	25.000	10.0	949	226	975	97.27	22.1	-46.78	0.0	0.0	3.5
89	7	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	25.5	25.000	50.0	949	226	975	97.27	22.1	-46.78	0.0	0.0	4.4
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	25.5	25.000	185.0	949	227	975	97.26	22.1	-46.78	0.0	0.0	8.1
13	11	13	336AAC	Overhead Line	25.5	25.000	3500.0	949	230	976	97.19	22.1	-46.98	0.2	0.6	4.4
14	13	14	336AAC	Overhead Line	25.4	25.000	5717.0	948	232	976	97.13	22.1	-47.14	0.4	1.0	4.4
15	14	15	35 KV 4/0 CU 100% CN	Cable	25.4	25.000	2345.0	948	236	977	97.04	22.2	-47.42	0.2	0.1	6.0
16	15	16	336AAC	Overhead Line	25.4	25.000	13595.0	948	302	995	95.27	22.6	-51.13	0.9	2.5	4.5
18	17	18	336AAC	Overhead Line	25.2	25.000	25.0	947	311	997	95.00	22.8	-51.75	0.0	0.0	4.5
81	77	81	556ASC	Overhead Line	34.7	34.500	100.0	707	-988	1215	-57.75	20.2	51.27	0.0	0.0	3.6
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.6	12.470	100.0	706	-1003	1226	-55.92	55.9	21.27	0.0	0.1	9.8
82	77	82	3/0ACSR	Overhead Line	34.7	34.500	100.0	1750	649	1866	93.70	31.0	-23.47	0.0	0.0	10.4
83	82	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	34.4	34.500	41600.0	1749	649	1866	93.69	31.0	-23.48	12.8	15.7	10.4
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	35.1	34.500	100.0	777	263	820	94.40	13.5	-22.13	0.0	0.0	4.7
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	13.0	12.470	39.9	776	255	817	95.00	36.4	-52.14	0.0	0.0	6.6
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	35.1	34.500	15088.3	960	430	1052	91.25	17.3	-27.56	0.4	1.6	2.7
59	58	VR PRIMARY	477ACSR	Overhead Line	35.4	34.500	24.2	0	-53	53	0.00	0.9	87.62	0.0	0.0	0.1
2024	ER1	58	477ACSR	Overhead Line	35.4	34.500	9412.4	0	-53	53	0.00	0.9	87.62	0.0	0.0	0.1
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.4	34.500	22193.7	0	-37	37	0.00	0.6	87.62	0.0	0.0	0.1
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.1	12.470	100.0	1011	332	1065	95.00	47.0	-51.16	0.0	0.1	11.0
71	66	71	3/0ACSR	Overhead Line	35.4	34.500	82.0	713	133	725	98.30	11.8	-12.94	0.0	0.0	3.8
72	71	72	3/0ACSR	Overhead Line	35.4	34.500	29000.0	713	133	725	98.30	11.8	-12.95	1.3	1.6	3.8
73	72	73	556ASC	Overhead Line	35.4	34.500	6391.1	712	175	733	97.09	12.0	-16.31	0.1	0.3	1.9
74	73	SOLAR	556ASC	Overhead Line	35.4	34.500	100.0	-239	0	239	100.00	3.9	177.47	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.3	34.500	28445.2	951	186	969	98.14	15.8	-13.56	0.7	2.5	2.5
79	78	542	477ACSR	Overhead Line	35.3	34.500	5072.2	950	231	978	97.17	16.0	-16.29	0.1	0.4	2.5
55	53	ER2	3/0ACSR	Overhead Line	35.5	34.500	144.4	0	-25	25	0.00	0.4	88.13	0.0	0.0	0.1
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.5	34.500	14794.7	0	-25	25	0.00	0.4	88.13	0.0	0.0	0.1
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.9	12.470	100.0	286	94	301	95.00	13.5	-49.71	0.0	0.0	4.5

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	9.0	1664.1	158.3	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	8.9	1652.6	150.3	103.50
NORTHERN AVE TS	076	DEFAULT	Switch	8.9	1649.1	147.1	103.21
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	4.4	44.0	16.3	103.28
NORTHERN AVE TS	51	DEFAULT	Switch	8.5	1571.4	95.5	103.21
NORTHERN AVE TS	077	DEFAULT	Switch	8.5	1564.3	90.9	102.65
NORTHERN AVE TS	67	DEFAULT	Switch	8.5	1564.2	99.2	102.65
NORTHERN AVE TS	66	DEFAULT	Switch	7.2	1322.0	52.5	102.30
NORTHERN AVE TS	65	DEFAULT	Switch	7.2	1322.0	52.6	102.30
NORTHERN AVE TS	64	DEFAULT	Switch	5.1	925.0	-140.0	102.30
NORTHERN AVE TS	61	DEFAULT	Switch	5.1	925.0	-139.9	102.29
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	22.9	925.0	-122.3	101.02
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	102.30
NORTHERN AVE TS	75	DEFAULT	Switch	5.2	924.9	-122.2	101.01
NORTHERN AVE TS	77	DEFAULT	Switch	5.1	920.7	-107.0	100.73
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	101.90
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	19.6	316.4	78.5	102.00
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	0.0	316.8	76.7	101.96
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	3.8	316.2	103.9	101.06
NORTHERN AVE TS	81	DEFAULT	Switch	2.6	308.1	-343.3	100.73
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	22.9	308.1	-343.2	101.63
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	103.3	238.8	-334.6	101.62
NORTHERN AVE TS	82	DEFAULT	Switch	3.6	612.7	236.3	100.73
NORTHERN AVE TS	83	DEFAULT	Switch	3.6	612.7	236.3	100.72
NORTHERN AVE TS	83	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	16.6	607.9	250.4	102.21
NORTHERN AVE TS	84	DEFAULT	Switch	1.7	284.9	105.7	102.21
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	17.0	284.9	105.7	104.14
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	302.6	99.4	104.14
NORTHERN AVE TS	85	DEFAULT	Switch	0.0	0.0	0.0	102.10
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-17.6	102.29
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	17.1	397.0	192.5	104.86
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	0.0	507.9	167.0	104.85
NORTHERN AVE TS	71	DEFAULT	Switch	1.3	237.9	43.7	102.30
NORTHERN AVE TS	72	DEFAULT	Switch	1.3	237.4	57.7	102.07
NORTHERN AVE TS	74	DEFAULT	Switch	0.4	-79.3	0.3	102.05
NORTHERN AVE TS	79	DEFAULT	Switch	1.8	316.4	78.4	101.90
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-8.3	102.65
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	0.4	33.8	35.3	103.23

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS	9	DEFAULT	Switch	0.0	0.0	0.0	104.00

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	103.26 %
	B	1	87	101.94 %
	C	1	87	103.42 %
Under-Voltage	A	0	83	99.72 %
	B	0	83	99.57 %
	C	0	83	99.67 %
Over-Voltage	A	0	68	104.86 %
	B	0	BAR RIVER DS LV BUS	104.46 %
	C	4	68	105.52 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	78.66	689.06	68.91
Cable Losses	0.25	2.18	0.22
Transformer Load Losses	4.84	42.37	4.24
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	83.74	733.60	73.36

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-18-2020 LTC.sxst
Date	Thu Jun 18 2020
Time	14h32m51s
Project Name	Uprated from NTS with LTC and Reg Min by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	**kW**	**kvar**	**kVA**	**PF(%)**
Sources (Swing)	4653.04	153.97	4655.58	99.95
Generators	239.00	-0.01	239.00	100.00
Total Generation	**4892.03**	**153.96**	**4894.45**	**99.95**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4808.41	1720.76	5107.03	94.15
Shunt capacitors (Adjusted)	0.00	-1234.53	1234.53	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4808.41**	**486.23**	**4832.93**	**99.49**
Cable Capacitance	0.00	-69.79	69.79	0.00
Line Capacitance	0.00	-554.41	554.41	0.00
Total Shunt Capacitance	**0.00**	**-624.21**	**624.21**	**0.00**
Line Losses	78.66	243.42	255.81	30.75
Cable Losses	0.25	0.15	0.29	85.04
Transformer Load Losses	4.84	48.37	48.61	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**83.74**	**291.94**	**303.71**	**27.57**

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	0.1	18.0	-16.8	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	0.1	0.0	-9.4	104.00
NORTHERN AVE TS	076	DEFAULT	Switch	0.0	0.0	0.0	103.10

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	31.3	5695.7	1302.7	104.00
ECHO RIVER TS 081		DEFAULT	Switch	14.5	2569.2	817.1	104.00
ECHO RIVER TS 081		DEFAULT	Switch	14.5	2561.2	796.3	103.36
ECHO RIVER TS 077		DEFAULT	Switch	1.7	262.5	157.5	103.35
ECHO RIVER TS 51		DEFAULT	Switch	1.7	262.2	177.1	103.10
ECHO RIVER TS 49		GARDEN T2	Two-Winding Transforme	15.0	149.1	56.4	103.81
ECHO RIVER TS 555		GARDEN T1	Two-Winding Transforme	1.3	113.1	120.7	103.63
ECHO RIVER TS 67		DEFAULT	Switch	12.9	2298.3	638.5	103.35
ECHO RIVER TS 66		DEFAULT	Switch	7.9	1294.3	665.2	102.54
ECHO RIVER TS 65		DEFAULT	Switch	7.9	1294.3	665.2	102.54
ECHO RIVER TS 68		BAR RIVER T1	Two-Winding Transforme	56.6	1294.3	665.2	103.45
ECHO RIVER TS 68		1200 KVAR 7 KV	Shunt Capacitor	0.0	1646.4	542.9	103.41
ECHO RIVER TS 71		DEFAULT	Switch	5.4	994.4	-49.0	102.55
ECHO RIVER TS 72		DEFAULT	Switch	5.4	987.1	-43.4	101.84
ECHO RIVER TS 74		DEFAULT	Switch	0.4	-79.4	0.0	101.80
ECHO RIVER TS 79		DEFAULT	Switch	5.8	1063.0	-34.0	101.54
ECHO RIVER TS 86		DESBARATS T2	Two-Winding Transforme	63.8	1063.0	-34.0	101.55
ECHO RIVER TS 13		1200 KVAR 20 KV	Shunt Capacitor	103.6	1062.6	-78.6	101.44
ECHO RIVER TS 17		25 KV 600A 1PH	Regulator	12.8	1055.5	347.2	101.14
ECHO RIVER TS 56		DEFAULT	Switch	17.0	3126.5	485.6	104.00
ECHO RIVER TS 58		DEFAULT	Switch	17.0	3097.5	418.7	102.66
ECHO RIVER TS 5		34.5KV_200A_1PH_COOPER_REGULATOR_6	Regulator	76.4	3097.5	418.8	102.01
ECHO RIVER TS 62		DEFAULT	Switch	0.0	0.0	0.0	102.66
ECHO RIVER TS 64		DEFAULT	Switch	0.0	0.0	0.0	102.54
ECHO RIVER TS 75		DEFAULT	Switch	17.1	3097.4	418.7	102.01
ECHO RIVER TS 77		DEFAULT	Switch	17.1	3049.6	304.9	99.92
ECHO RIVER TS 80		DEFAULT	Switch	0.0	0.0	0.0	101.54
ECHO RIVER TS 81		DEFAULT	Switch	5.7	1005.2	-169.2	99.92
ECHO RIVER TS 81		DESBARATS T1	Two-Winding Transforme	57.3	1005.2	-169.2	101.05
ECHO RIVER TS 87		1200 KVAR 7 KV	Shunt Capacitor	102.1	787.1	-149.8	101.03
ECHO RIVER TS 82		DEFAULT	Switch	11.7	2044.4	474.1	99.92
ECHO RIVER TS 83		DEFAULT	Switch	11.7	2044.3	474.0	99.91
ECHO RIVER TS 83		34.5KV_200A_1PH_COOPER_REGULATOR_6	Regulator	52.8	1994.6	433.2	101.22
ECHO RIVER TS 84		DEFAULT	Switch	5.2	942.1	-60.9	101.22
ECHO RIVER TS 84		BRUCE MINES T1	Two-Winding Transforme	54.3	942.1	-60.9	104.05
ECHO RIVER TS 88		1200 KVAR 7 KV	Shunt Capacitor	108.3	1006.7	-102.4	104.04
ECHO RIVER TS 85		DEFAULT	Switch	0.0	0.0	0.0	100.87
ECHO RIVER TS 61		DEFAULT	Switch	0.0	0.0	-0.1	102.66

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.7	34.500	14794.7	7682	1569	7841	97.68	126.2	-11.54	23.1	83.4	21.2
55	53	ER2	3/0ACSR	Overhead Line	35.7	34.500	144.4	7659	1511	7807	97.81	126.2	-11.73	0.7	0.9	43.5
52	52	53	556ASC	Overhead Line	35.7	34.500	213.3	1321	412	1383	92.19	22.4	-17.89	0.0	0.0	4.6
077	51	52	556ASC	Overhead Line	35.7	34.500	1889.0	1321	412	1384	92.19	22.4	-17.91	0.1	0.4	4.6
51	GARDEN RIVER DS HV BUS	51	556ASC	Overhead Line	35.6	34.500	34354.4	1321	415	1384	92.13	22.4	-18.04	1.9	7.0	4.6
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	13.0	12.470	100.0	363	119	382	95.00	17.0	-49.41	0.0	0.0	3.5
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.9	12.470	100.0	952	313	1003	94.99	45.0	-50.66	0.1	0.2	14.9
54	53	54	556ASC	Overhead Line	35.7	34.500	147.6	6337	1099	6432	97.97	104.0	-10.41	0.2	0.6	18.0
67	69	54	556ASC	Overhead Line	35.6	34.500	12664.6	6337	1098	6432	97.97	104.0	-10.41	13.6	49.1	18.0
70	69	66	556ASC	Overhead Line	35.5	34.500	9594.3	6324	1071	6414	98.03	104.1	-10.60	10.3	37.2	18.0
66	65	66	556ASC	Overhead Line	35.5	34.500	100.0	3322	1204	3534	92.25	57.5	-21.24	0.0	0.1	11.0
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.5	34.500	64.0	3322	1204	3534	92.25	57.5	-21.24	0.0	0.1	11.0
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.0	12.470	100.0	3311	1091	3486	94.98	155.3	-51.24	0.4	1.2	36.1
71	66	71	3/0ACSR	Overhead Line	35.5	34.500	82.0	2991	-155	2995	-99.87	48.7	1.68	0.1	0.1	15.5
72	71	72	3/0ACSR	Overhead Line	35.3	34.500	29000.0	2991	-154	2995	-99.87	48.7	1.68	21.7	26.5	15.5
73	72	73	556ASC	Overhead Line	35.2	34.500	6391.1	2969	-137	2972	-99.89	48.7	0.84	1.5	5.3	7.6
74	73	SOLAR	556ASC	Overhead Line	35.2	34.500	100.0	-239	0	239	100.00	3.9	178.05	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.2	34.500	28445.2	3207	-132	3209	-99.92	52.6	0.44	7.6	27.5	8.2
79	78	542	477ACSR	Overhead Line	35.1	34.500	5072.2	3199	-112	3201	-99.94	52.6	-0.40	1.6	4.8	8.2
86	542	86	556ASC	Overhead Line	35.1	34.500	100.0	3198	-109	3199	-99.94	52.6	-0.55	0.0	0.1	8.2
8	86	8	556ASC	Overhead Line	25.4	25.000	10.0	3184	-244	3193	-99.71	72.5	-30.55	0.0	0.0	11.3
7	8	7	556ASC	Overhead Line	25.4	25.000	10.0	3184	-244	3193	-99.71	72.5	-30.55	0.0	0.0	11.3
89	7	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	25.4	25.000	50.0	3184	-244	3193	-99.71	72.5	-30.55	0.0	0.1	14.3
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	25.4	25.000	185.0	3184	-244	3193	-99.71	72.5	-30.55	0.3	0.1	26.4
13	11	13	336AAC	Overhead Line	25.4	25.000	3500.0	3184	-241	3193	-99.71	72.5	-30.61	2.6	7.0	14.3
14	13	14	336AAC	Overhead Line	25.3	25.000	5717.0	3181	1001	3335	95.39	75.8	-52.51	4.4	11.9	14.9
15	14	15	35 KV 4/0 CU 100% CN	Cable	25.3	25.000	2345.0	3176	993	3328	95.44	75.8	-52.59	2.6	1.7	20.3
16	15	16	336AAC	Overhead Line	25.2	25.000	13595.0	3174	1058	3345	94.87	76.3	-53.67	10.7	28.6	15.0
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	3163	1040	3330	95.00	76.1	-53.85	0.0	0.1	14.9
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.6	34.500	22193.7	8379	1228	8469	98.59	136.3	-8.34	46.9	144.1	23.9
2024	ER1	58	477ACSR	Overhead Line	35.5	34.500	9412.4	8332	1122	8407	98.75	136.4	-8.59	19.9	61.2	23.9
59	58	VR PRIMARY	477ACSR	Overhead Line	35.5	34.500	24.2	8312	1077	8382	98.82	136.4	-8.70	0.1	0.2	23.9
62	VR SECONDARY	62	477ACSR	Overhead Line	35.3	34.500	100.0	0	0	0	0.00	0.0	88.70	0.0	0.0	0.0
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.70	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	35.3	34.500	100.0	8312	1077	8382	98.82	137.0	-8.70	0.2	0.7	24.0
76	75	76	477ACSR	Overhead Line	34.7	34.500	51800.0	8312	1077	8381	98.82	137.0	-8.70	110.8	340.1	24.0
77	76	77	556ASC	Overhead Line	34.7	34.500	100.0	8201	822	8242	99.14	137.1	-9.28	0.2	0.7	23.9
80	542	77	556ASC	Overhead Line	34.7	34.500	100.0	0	0	0	0.01	0.0	86.48	0.0	0.0	0.0
81	77	81	556ASC	Overhead Line	34.7	34.500	100.0	2319	-399	2353	-95.90	39.2	6.15	0.0	0.1	7.9
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.6	12.470	100.0	2313	-459	2358	-95.39	108.4	-23.86	0.2	0.6	24.8
82	77	82	3/0ACSR	Overhead Line	34.7	34.500	100.0	5882	1221	6008	97.85	99.9	-15.27	0.3	0.4	33.5
83	82	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	33.8	34.500	41600.0	5882	1221	6007	97.85	99.9	-15.27	131.7	160.8	33.5
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	34.9	34.500	100.0	2596	-363	2621	-98.73	43.3	3.15	0.1	0.1	14.9
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	13.0	12.470	39.9	2587	-447	2626	-98.22	116.9	-26.85	0.1	0.2	20.9
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	34.8	34.500	15088.3	3155	1482	3485	90.51	57.6	-29.96	4.9	17.6	8.9
61	VR PRIMARY	61	477ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.70	0.0	0.0	0.0
63	61	62	3/0ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.70	0.0	0.0	0.0
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	54	-51	74	-73.04	1.2	43.08	0.0	0.0	0.2
390	46	TRUSS PLANT	556ASC	Overhead Line	35.9	34.500	27986.1	54	-50	74	-73.16	1.2	42.98	0.0	0.0	0.2
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	556ASC	Overhead Line	35.9	34.500	16346.2	0	-28	28	0.02	0.5	90.00	0.0	0.0	0.1

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	3	88	108.25 %
	B	2	88	106.94 %
	C	3	88	109.08 %
Under-Voltage	A	0	83	96.98 %
	B	0	83	98.10 %
	C	0	83	98.74 %
Over-Voltage	A	0	84	104.05 %
	B	0	GARDEN RIVER T1 LV BUS	104.61 %
	C	4	68	105.15 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	415.74	3641.86	364.19
Cable Losses	2.90	25.41	2.54
Transformer Load Losses	42.64	373.50	37.35
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	461.28	4040.77	404.08

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-18-2020 LTC.sxst
Date	Thu Jun 18 2020
Time	14h30m18s
Project Name	Uprated with LTC and Reg, Peak by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=100.00%, Q=100.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	**kW**	**kvar**	**kVA**	**PF(%)**
Sources (Swing)	16115.18	2746.79	16347.60	98.58
Generators	239.02	0.03	239.02	100.00
Total Generation	**16354.20**	**2746.82**	**16583.27**	**98.62**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	15893.08	5687.12	16879.97	94.15
Shunt capacitors (Adjusted)	0.00	-3762.20	3762.20	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**15893.08**	**1924.92**	**16009.23**	**99.27**
Cable Capacitance	0.00	-69.14	69.14	0.00
Line Capacitance	0.00	-555.60	555.60	0.00
Total Shunt Capacitance	**0.00**	**-624.74**	**624.74**	**0.00**
Line Losses	415.74	1018.48	1100.07	37.79
Cable Losses	2.90	1.79	3.41	85.14
Transformer Load Losses	42.64	426.36	428.49	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**461.28**	**1446.64**	**1518.40**	**30.38**

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	0.1	5.4	-22.9	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	0.1	0.0	-9.4	104.01
NORTHERN AVE TS	076	DEFAULT	Switch	0.0	0.0	0.0	103.74

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS	9	DEFAULT	Switch	8.8	1639.5	105.8	104.00
ECHO RIVER TS	081	DEFAULT	Switch	4.1	715.2	250.8	104.00
ECHO RIVER TS	081	DEFAULT	Switch	4.1	714.5	257.0	103.81
ECHO RIVER TS	077	DEFAULT	Switch	0.5	78.5	31.4	103.81
ECHO RIVER TS	51	DEFAULT	Switch	0.5	78.5	52.1	103.74
ECHO RIVER TS	49	GARDEN T2	Two-Winding Transformer	4.4	44.4	16.5	103.58
ECHO RIVER TS	555	GARDEN T1	Two-Winding Transformer	0.4	34.1	35.6	103.52
ECHO RIVER TS	67	DEFAULT	Switch	3.6	636.0	225.8	103.81
ECHO RIVER TS	66	DEFAULT	Switch	2.4	396.4	192.1	103.55
ECHO RIVER TS	65	DEFAULT	Switch	2.4	396.4	192.2	103.55
ECHO RIVER TS	68	BAR RIVER T1	Two-Winding Transformer	17.1	396.4	192.2	104.38
ECHO RIVER TS	68	1200 KVAR 7 KV	Shunt Capacitor	0.0	503.2	165.5	104.36
ECHO RIVER TS	71	DEFAULT	Switch	1.3	238.8	43.6	103.55
ECHO RIVER TS	72	DEFAULT	Switch	1.3	238.4	57.9	103.33
ECHO RIVER TS	74	DEFAULT	Switch	0.4	-79.6	0.0	103.30
ECHO RIVER TS	79	DEFAULT	Switch	1.8	317.7	79.4	103.15
ECHO RIVER TS	86	DESBARATS T2	Two-Winding Transformer	19.6	317.7	79.5	102.78
ECHO RIVER TS	13	1200 KVAR 20 KV	Shunt Capacitor	0.0	317.7	76.6	102.74
ECHO RIVER TS	17	25 KV 600A 1PH	Regulator	3.8	317.1	104.2	101.19
ECHO RIVER TS	56	DEFAULT	Switch	5.0	924.4	-145.0	104.00
ECHO RIVER TS	58	DEFAULT	Switch	5.0	921.9	-134.3	103.85
ECHO RIVER TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	22.5	921.9	-134.1	101.91
ECHO RIVER TS	62	DEFAULT	Switch	0.0	0.0	0.0	103.85
ECHO RIVER TS	64	DEFAULT	Switch	0.0	0.0	0.0	103.55
ECHO RIVER TS	75	DEFAULT	Switch	5.1	921.9	-134.0	101.91
ECHO RIVER TS	77	DEFAULT	Switch	5.1	917.8	-117.9	101.64
ECHO RIVER TS	80	DEFAULT	Switch	0.0	0.0	0.0	103.15
ECHO RIVER TS	81	DEFAULT	Switch	2.6	315.5	-349.6	101.64
ECHO RIVER TS	81	DESBARATS T1	Two-Winding Transformer	23.5	315.5	-349.6	102.75
ECHO RIVER TS	87	1200 KVAR 7 KV	Shunt Capacitor	105.6	244.2	-342.0	102.74
ECHO RIVER TS	82	DEFAULT	Switch	3.5	602.3	231.8	101.64
ECHO RIVER TS	83	DEFAULT	Switch	3.5	602.3	231.8	101.64
ECHO RIVER TS	83	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	16.1	597.8	246.6	101.29
ECHO RIVER TS	84	DEFAULT	Switch	1.6	280.6	104.4	101.29
ECHO RIVER TS	84	BRUCE MINES T1	Two-Winding Transformer	16.9	280.6	104.4	103.40
ECHO RIVER TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	298.3	98.0	103.40
ECHO RIVER TS	85	DEFAULT	Switch	0.0	0.0	0.0	101.19
ECHO RIVER TS	61	DEFAULT	Switch	0.0	0.0	-0.1	103.85

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.8	34.500	14794.7	2119	490	2175	97.09	35.0	-13.01	1.8	6.4	5.9
55	53	ER2	3/0ACSR	Overhead Line	35.8	34.500	144.4	2117	509	2178	96.89	35.1	-13.67	0.1	0.1	12.1
52	52	53	556ASC	Overhead Line	35.8	34.500	213.3	395	71	402	94.97	6.5	-10.32	0.0	0.0	1.3
077	51	52	556ASC	Overhead Line	35.8	34.500	1889.0	395	71	402	94.96	6.5	-10.37	0.0	0.0	1.3
51	GARDEN RIVER DS HV BU	51	556ASC	Overhead Line	35.8	34.500	34354.4	395	74	402	94.82	6.5	-10.82	0.2	0.6	1.3
49	GARDEN RIVER DS HV BU	GARDEN RIVER T2 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	108	35	114	95.01	5.1	-48.53	0.0	0.0	1.0
50	GARDEN RIVER DS HV BU	GARDEN RIVER T1 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	287	94	302	95.00	13.5	-48.91	0.0	0.0	4.5
54	53	54	556ASC	Overhead Line	35.8	34.500	147.6	1722	438	1777	96.23	28.6	-14.43	0.0	0.0	5.1
67	69	54	556ASC	Overhead Line	35.8	34.500	12664.6	1722	438	1777	96.23	28.6	-14.44	1.0	3.7	5.1
70	69	66	556ASC	Overhead Line	35.8	34.500	9594.3	1721	456	1780	95.98	28.7	-15.11	0.8	2.9	5.1
66	65	66	556ASC	Overhead Line	35.8	34.500	100.0	1006	340	1062	92.90	17.1	-19.04	0.0	0.0	3.3
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.8	34.500	64.0	1006	340	1062	92.89	17.1	-19.05	0.0	0.0	3.3
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.0	12.470	100.0	1005	330	1058	94.99	46.9	-49.06	0.0	0.1	10.9
71	66	71	3/0ACSR	Overhead Line	35.8	34.500	82.0	714	129	726	98.39	11.7	-10.62	0.0	0.0	3.7
72	71	72	3/0ACSR	Overhead Line	35.7	34.500	29000.0	714	130	726	98.39	11.7	-10.63	1.3	1.6	3.7
73	72	73	556ASC	Overhead Line	35.7	34.500	6391.1	713	173	733	97.19	11.9	-14.05	0.1	0.3	1.8
74	73	SOLAR	556ASC	Overhead Line	35.7	34.500	100.0	-239	0	239	100.00	3.9	179.50	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.6	34.500	28445.2	952	183	969	98.19	15.7	-11.36	0.7	2.5	2.4
79	78	542	477ACSR	Overhead Line	35.6	34.500	5072.2	951	229	978	97.22	15.9	-14.15	0.1	0.4	2.5
86	542	86	556ASC	Overhead Line	35.6	34.500	100.0	951	237	980	97.02	15.9	-14.64	0.0	0.0	2.5
8	86	8	556ASC	Overhead Line	25.7	25.000	10.0	950	225	976	97.30	21.9	-44.64	0.0	0.0	3.4
7	8	7	556ASC	Overhead Line	25.7	25.000	10.0	950	225	976	97.30	21.9	-44.65	0.0	0.0	3.4
89	7	DESBARATS DS T2 LV BU	336AAC	Overhead Line	25.7	25.000	50.0	950	225	976	97.30	21.9	-44.65	0.0	0.0	4.3
11	DESBARATS DS T2 LV BU	11	28 KV 2/0 CU 100% C	Cable	25.7	25.000	185.0	950	225	976	97.30	21.9	-44.65	0.0	0.0	8.0
13	11	13	336AAC	Overhead Line	25.7	25.000	3500.0	950	229	977	97.22	21.9	-44.84	0.2	0.6	4.3
14	13	14	336AAC	Overhead Line	25.7	25.000	5717.0	949	231	977	97.17	22.0	-45.01	0.4	1.0	4.3
15	14	15	35 KV 4/0 CU 100% C	Cable	25.7	25.000	2345.0	949	235	978	97.07	22.0	-45.29	0.2	0.1	5.9
16	15	16	336AAC	Overhead Line	25.6	25.000	13595.0	949	302	996	95.28	22.4	-49.07	0.9	2.5	4.4
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	948	311	998	95.00	22.8	-49.70	0.0	0.0	4.5
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.9	34.500	22193.7	2472	-463	2515	-97.92	40.5	10.61	4.1	12.7	7.1
2024	ER1	58	477ACSR	Overhead Line	35.8	34.500	9412.4	2468	-438	2506	-98.09	40.4	9.76	1.7	5.4	7.0
59	58	VR PRIMARY	477ACSR	Overhead Line	35.8	34.500	24.2	2466	-427	2503	-98.16	40.3	9.39	0.0	0.0	7.0
62	VR SECONDARY	62	477ACSR	Overhead Line	35.2	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	35.2	34.500	100.0	2466	-426	2503	-98.16	41.1	9.38	0.0	0.1	7.2
76	75	76	477ACSR	Overhead Line	35.1	34.500	51800.0	2466	-426	2503	-98.16	41.1	9.37	9.9	30.4	7.2
77	76	77	556ASC	Overhead Line	35.1	34.500	100.0	2456	-371	2484	-98.50	40.9	7.43	0.0	0.1	7.1
80	542	77	556ASC	Overhead Line	35.1	34.500	100.0	0	0	0	0.00	0.0	88.86	0.0	0.0	0.0
81	77	81	556ASC	Overhead Line	35.1	34.500	100.0	724	-1011	1244	-57.77	20.4	53.23	0.0	0.0	3.6
87	81	DESBARATS DS T1 LV BU	556ASC	Overhead Line	12.8	12.470	100.0	723	-1025	1254	-55.95	56.6	23.22	0.0	0.1	9.9
82	77	82	3/0ACSR	Overhead Line	35.1	34.500	100.0	1732	641	1847	93.74	30.4	-21.44	0.0	0.0	10.1
83	82	BRUCE MINES DS HV BU	3/0ACSR	Overhead Line	34.8	34.500	41600.0	1732	641	1847	93.73	30.4	-21.45	12.3	15.0	10.1
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	34.9	34.500	100.0	769	260	812	94.42	13.4	-20.15	0.0	0.0	4.7
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.9	12.470	39.9	768	253	809	95.00	36.2	-50.16	0.0	0.0	6.5
85	BRUCE MINES DS HV BU	FEEDER END	556ASC	Overhead Line	34.9	34.500	15088.3	951	426	1042	91.25	17.2	-25.59	0.4	1.6	2.7
61	VR PRIMARY	61	477ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0
63	61	62	3/0ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	16	-69	71	-22.97	1.1	76.72	0.0	0.0	0.2
390	46	TRUSS PLANT	556ASC	Overhead Line	35.9	34.500	27986.1	16	-69	70	-23.03	1.1	76.69	0.0	0.0	0.2
076	TRUSS PLANT	GARDEN RIVER DS HV BU	556ASC	Overhead Line	35.9	34.500	16346.2	0	-28	28	0.01	0.5	90.00	0.0	0.0	0.1

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	105.57 %
	B	1	87	104.45 %
	C	1	87	105.74 %
Under-Voltage	A	0	83	100.66 %
	B	0	83	100.69 %
	C	0	18	100.70 %
Over-Voltage	A	0	68	104.38 %
	B	0	BAR RIVER DS LV BUS	104.53 %
	C	0	68	104.86 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	36.19	317.06	31.71
Cable Losses	0.24	2.14	0.21
Transformer Load Losses	4.81	42.14	4.21
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	41.25	361.34	36.13

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-18-2020 LTC.sxst
Date	Thu Jun 18 2020
Time	14h29m12s
Project Name	New
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	4607.22	-42.24	4607.42	-100.00
Generators	239.00	0.00	239.00	100.00
Total Generation	**4846.22**	**-42.24**	**4846.41**	**-100.00**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4804.97	1718.88	5103.17	94.16
Shunt capacitors (Adjusted)	0.00	-1263.00	1263.00	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4804.97**	**455.87**	**4826.55**	**99.55**
Cable Capacitance	0.00	-71.06	71.06	0.00
Line Capacitance	0.00	-563.38	563.38	0.00
Total Shunt Capacitance	**0.00**	**-634.44**	**634.44**	**0.00**
Line Losses	36.19	88.07	95.22	38.01
Cable Losses	0.24	0.15	0.29	85.23
Transformer Load Losses	4.81	48.10	48.34	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**41.25**	**136.32**	**142.43**	**28.96**

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	8.8	1627.0	143.2	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	8.7	1615.9	136.3	103.53
NORTHERN AVE TS	076	DEFAULT	Switch	8.7	1612.6	133.8	103.25
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	4.4	44.0	16.3	103.30
NORTHERN AVE TS	51	DEFAULT	Switch	8.3	1534.8	82.1	103.25
NORTHERN AVE TS	077	DEFAULT	Switch	8.3	1528.2	78.9	102.73
NORTHERN AVE TS	67	DEFAULT	Switch	8.3	1528.1	87.3	102.72
NORTHERN AVE TS	66	DEFAULT	Switch	7.0	1285.7	41.3	102.39
NORTHERN AVE TS	65	DEFAULT	Switch	7.0	1285.7	41.3	102.39
NORTHERN AVE TS	64	DEFAULT	Switch	4.9	888.2	-151.7	102.39
NORTHERN AVE TS	61	DEFAULT	Switch	4.9	888.2	-151.7	102.39
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	22.0	888.2	-134.0	100.47
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	102.39
NORTHERN AVE TS	75	DEFAULT	Switch	5.0	888.2	-133.9	100.47
NORTHERN AVE TS	77	DEFAULT	Switch	5.0	884.3	-118.1	100.22
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	101.99
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	19.6	316.9	78.7	102.04
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	0.0	317.1	76.8	102.00
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	3.8	316.5	104.0	101.10
NORTHERN AVE TS	81	DEFAULT	Switch	2.5	305.8	-340.4	100.22
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	22.8	305.8	-340.3	101.37
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	102.7	237.7	-332.9	101.36
NORTHERN AVE TS	82	DEFAULT	Switch	3.4	578.5	222.3	100.22
NORTHERN AVE TS	83	DEFAULT	Switch	3.4	578.5	222.3	100.22
NORTHERN AVE TS	83	1800 KVAR 20 KV	Shunt Capacitor	0.0	578.5	222.3	99.27
NORTHERN AVE TS	84	DEFAULT	Switch	1.6	269.6	100.3	99.27
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	16.2	269.6	100.3	101.70
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	288.5	94.8	101.69
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-17.6	102.39
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	17.1	397.5	193.0	104.91
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	0.0	508.4	167.1	104.89
NORTHERN AVE TS	71	DEFAULT	Switch	1.3	238.3	43.9	102.39
NORTHERN AVE TS	72	DEFAULT	Switch	1.3	237.9	57.9	102.17
NORTHERN AVE TS	74	DEFAULT	Switch	0.4	-79.3	0.2	102.14
NORTHERN AVE TS	79	DEFAULT	Switch	1.8	316.9	78.6	101.99
NORTHERN AVE TS	79	1800 KVAR 20 KV	Shunt Capacitor	0.0	317.0	76.0	101.99
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-8.3	102.72
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	0.4	33.8	35.3	103.25

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	0.0	0.0	0.0	104.00

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	4575	118	4577	99.75	73.6	-1.48	0.1	0.2	12.2
390	46	TRUSS PLANT	556ASC	Overhead Line	35.8	34.500	27986.1	4575	118	4577	99.75	73.6	-1.48	14.8	53.5	12.2
076	TRUSS PLANT	GARDEN RIVER DS HV B	556ASC	Overhead Line	35.7	34.500	16346.2	4544	105	4546	99.76	73.4	-1.99	8.6	31.1	12.2
49	GARDEN RIVER DS HV B	GARDEN RIVER T2 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	107	35	113	95.01	5.1	-49.38	0.0	0.0	1.0
51	GARDEN RIVER DS HV B	51	556ASC	Overhead Line	35.6	34.500	34354.4	4143	-30	4143	-99.57	67.0	-0.64	15.2	54.9	11.6
077	51	52	556ASC	Overhead Line	35.5	34.500	1889.0	4127	-27	4127	-99.57	67.0	-1.45	0.8	3.0	11.6
52	52	53	556ASC	Overhead Line	35.5	34.500	213.3	4127	-27	4127	-99.57	67.0	-1.49	0.1	0.3	11.6
54	53	54	556ASC	Overhead Line	35.5	34.500	147.6	4126	-1	4126	-99.57	67.0	-1.85	0.1	0.2	11.6
67	69	54	556ASC	Overhead Line	35.5	34.500	12664.6	4126	-1	4126	-99.57	67.0	-1.85	5.6	20.2	11.6
70	69	66	556ASC	Overhead Line	35.5	34.500	9594.3	4121	0	4121	-99.57	67.0	-2.15	4.2	15.3	11.6
66	65	66	556ASC	Overhead Line	35.5	34.500	100.0	3402	-133	3405	-99.31	55.4	-0.14	0.0	0.1	9.8
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.5	34.500	64.0	3402	-133	3405	-99.31	55.4	-0.14	0.0	0.1	9.8
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.5	34.500	100.0	2389	-476	2436	-97.72	39.7	8.90	0.0	0.1	6.9
63	61	62	3/0ACSR	Overhead Line	35.5	34.500	100.0	2389	-476	2436	-97.72	39.7	8.90	0.1	0.1	14.0
61	VR PRIMARY	61	477ACSR	Overhead Line	35.5	34.500	100.0	2389	-476	2436	-97.72	39.7	8.89	0.0	0.1	6.9
62	VR SECONDARY	62	477ACSR	Overhead Line	34.7	34.500	100.0	0	0	0	0.00	0.0	87.66	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	34.7	34.500	100.0	2389	-422	2426	-98.11	40.3	7.67	0.0	0.1	7.0
76	75	76	477ACSR	Overhead Line	34.7	34.500	51800.0	2389	-422	2426	-98.11	40.3	7.66	9.5	29.3	7.0
77	76	77	556ASC	Overhead Line	34.7	34.500	100.0	2379	-368	2408	-98.46	40.1	5.71	0.0	0.1	6.9
80	542	77	556ASC	Overhead Line	34.7	34.500	100.0	0	0	0	0.00	0.0	86.95	0.0	0.0	0.0
86	542	86	556ASC	Overhead Line	35.3	34.500	100.0	951	239	980	96.98	16.0	-16.73	0.0	0.0	2.5
8	86	8	556ASC	Overhead Line	25.5	25.000	10.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	3.5
7	8	7	556ASC	Overhead Line	25.5	25.000	10.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	3.5
89	7	DESBARATS DS T2 LV BU	336AAC	Overhead Line	25.5	25.000	50.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	4.4
11	DESBARATS DS T2 LV BU	11	28 KV 2/0 CU 100% C	Cable	25.5	25.000	185.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	8.1
13	11	13	336AAC	Overhead Line	25.5	25.000	3500.0	950	230	977	97.19	22.1	-46.93	0.2	0.6	4.4
14	13	14	336AAC	Overhead Line	25.5	25.000	5717.0	949	232	977	97.13	22.1	-47.10	0.4	1.0	4.4
15	14	15	35 KV 4/0 CU 100% C	Cable	25.5	25.000	2345.0	949	236	978	97.04	22.2	-47.37	0.2	0.1	6.0
16	15	16	336AAC	Overhead Line	25.4	25.000	13595.0	949	303	996	95.27	22.6	-51.09	0.9	2.5	4.5
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	948	311	998	95.00	22.8	-51.71	0.0	0.0	4.5
81	77	81	556ASC	Overhead Line	34.7	34.500	100.0	705	-986	1212	-57.71	20.2	51.34	0.0	0.0	3.6
87	81	DESBARATS DS T1 LV BU	556ASC	Overhead Line	12.6	12.470	100.0	703	-1000	1223	-55.88	55.9	21.34	0.0	0.1	9.7
82	77	82	3/0ACSR	Overhead Line	34.7	34.500	100.0	1674	619	1785	93.75	29.7	-23.34	0.0	0.0	9.9
83	82	BRUCE MINES DS HV BU	3/0ACSR	Overhead Line	34.3	34.500	41600.0	1674	619	1785	93.75	29.7	-23.34	11.8	14.4	9.9
84	BRUCE MINES DS HV BU	84	3/0ACSR	Overhead Line	34.3	34.500	100.0	743	252	785	94.42	13.2	-22.08	0.0	0.0	4.6
88	84	BRUCE MINES DS LV BU	556ASC	Overhead Line	12.7	12.470	39.9	743	244	782	95.00	35.6	-52.09	0.0	0.0	6.4
85	BRUCE MINES DS HV BU	FEEDER END	556ASC	Overhead Line	34.3	34.500	15088.3	919	412	1007	91.25	16.9	-27.50	0.4	1.5	2.6
59	58	VR PRIMARY	477ACSR	Overhead Line	35.5	34.500	24.2	0	-53	53	0.00	0.9	87.66	0.0	0.0	0.1
2024	ER1	58	477ACSR	Overhead Line	35.5	34.500	9412.4	0	-53	53	0.00	0.9	87.66	0.0	0.0	0.1
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.5	34.500	22193.7	0	-37	37	0.00	0.6	87.66	0.0	0.0	0.1
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.1	12.470	100.0	1012	333	1066	95.00	47.0	-51.12	0.0	0.1	11.0
71	66	71	3/0ACSR	Overhead Line	35.5	34.500	82.0	714	133	726	98.30	11.8	-12.90	0.0	0.0	3.8
72	71	72	3/0ACSR	Overhead Line	35.4	34.500	29000.0	714	133	726	98.30	11.8	-12.91	1.3	1.6	3.8
73	72	73	556ASC	Overhead Line	35.4	34.500	6391.1	713	175	734	97.10	12.0	-16.26	0.1	0.3	1.9
74	73	SOLAR	556ASC	Overhead Line	35.4	34.500	100.0	-239	0	239	100.00	3.9	177.51	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.3	34.500	28445.2	952	186	970	98.14	15.8	-13.52	0.7	2.5	2.5
79	78	542	477ACSR	Overhead Line	35.3	34.500	5072.2	951	231	979	97.17	16.0	-16.25	0.1	0.4	2.5
55	53	ER2	3/0ACSR	Overhead Line	35.5	34.500	144.4	0	-25	25	0.00	0.4	88.16	0.0	0.0	0.1
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.5	34.500	14794.7	0	-25	25	0.00	0.4	88.16	0.0	0.0	0.1
50	GARDEN RIVER DS HV B	GARDEN RIVER T1 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	286	94	301	95.00	13.5	-49.70	0.0	0.0	4.5

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	102.75 %
	B	1	87	101.51 %
	C	1	87	103.55 %
Under-Voltage	A	0	FEEDER END	99.17 %
	B	0	FEEDER END	99.52 %
	C	0	FEEDER END	99.68 %
Over-Voltage	A	0	68	104.91 %
	B	0	BAR RIVER DS LV BUS	104.53 %
	C	4	68	105.56 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	75.19	658.69	65.87
Cable Losses	0.24	2.15	0.21
Transformer Load Losses	4.80	42.05	4.20
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	80.24	702.88	70.29

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-16-2020 uprated conductors.sxst
Date	Tue Jun 16 2020
Time	14h45m38s
Project Name	Uprated from NTS Min Load - by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	4575.32	118.12	4576.84	99.97
Generators	238.99	-0.01	238.99	100.00
Total Generation	**4814.31**	**118.11**	**4815.76**	**99.97**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4734.10	1690.70	5026.95	94.17
Shunt capacitors (Adjusted)	0.00	-1231.27	1231.27	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4734.10**	**459.43**	**4756.35**	**99.53**
Cable Capacitance	0.00	-69.87	69.87	0.00
Line Capacitance	0.00	-553.28	553.28	0.00
Total Shunt Capacitance	**0.00**	**-623.14**	**623.14**	**0.00**
Line Losses	75.19	233.68	245.48	30.63
Cable Losses	0.24	0.15	0.29	85.37
Transformer Load Losses	4.80	48.00	48.24	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**80.24**	**281.82**	**293.02**	**27.38**

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	8.8	1627.0	143.2	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	8.7	1615.9	136.3	103.53
NORTHERN AVE TS	076	DEFAULT	Switch	8.7	1612.6	133.8	103.25
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	4.4	44.0	16.3	103.30
NORTHERN AVE TS	51	DEFAULT	Switch	8.3	1534.8	82.1	103.25
NORTHERN AVE TS	077	DEFAULT	Switch	8.3	1528.2	78.9	102.73
NORTHERN AVE TS	67	DEFAULT	Switch	8.3	1528.1	87.3	102.72
NORTHERN AVE TS	66	DEFAULT	Switch	7.0	1285.7	41.3	102.39
NORTHERN AVE TS	65	DEFAULT	Switch	7.0	1285.7	41.3	102.39
NORTHERN AVE TS	64	DEFAULT	Switch	4.9	888.2	-151.7	102.39
NORTHERN AVE TS	61	DEFAULT	Switch	4.9	888.2	-151.7	102.39
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	22.0	888.2	-134.0	100.47
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	102.39
NORTHERN AVE TS	75	DEFAULT	Switch	5.0	888.2	-133.9	100.47
NORTHERN AVE TS	77	DEFAULT	Switch	5.0	884.3	-118.1	100.22
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	101.99
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	19.6	316.9	78.7	102.04
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	0.0	317.1	76.8	102.00
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	3.8	316.5	104.0	101.10
NORTHERN AVE TS	81	DEFAULT	Switch	2.5	305.8	-340.4	100.22
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	22.8	305.8	-340.3	101.37
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	102.7	237.7	-332.9	101.36
NORTHERN AVE TS	82	DEFAULT	Switch	3.4	578.5	222.3	100.22
NORTHERN AVE TS	83	DEFAULT	Switch	3.4	578.5	222.3	100.22
NORTHERN AVE TS	83	1800 KVAR 20 KV	Shunt Capacitor	0.0	578.5	222.3	99.27
NORTHERN AVE TS	84	DEFAULT	Switch	1.6	269.6	100.3	99.27
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	16.2	269.6	100.3	101.70
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	288.5	94.8	101.69
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-17.6	102.39
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	17.1	397.5	193.0	104.91
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	0.0	508.4	167.1	104.89
NORTHERN AVE TS	71	DEFAULT	Switch	1.3	238.3	43.9	102.39
NORTHERN AVE TS	72	DEFAULT	Switch	1.3	237.9	57.9	102.17
NORTHERN AVE TS	74	DEFAULT	Switch	0.4	-79.3	0.2	102.14
NORTHERN AVE TS	79	DEFAULT	Switch	1.8	316.9	78.6	101.99
NORTHERN AVE TS	79	1800 KVAR 20 KV	Shunt Capacitor	0.0	317.0	76.0	101.99
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-8.3	102.72
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	0.4	33.8	35.3	103.25

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	0.0	0.0	0.0	104.00

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	4575	118	4577	99.75	73.6	-1.48	0.1	0.2	12.2
390	46	TRUSS PLANT	556ASC	Overhead Line	35.8	34.500	27986.1	4575	118	4577	99.75	73.6	-1.48	14.8	53.5	12.2
076	TRUSS PLANT	GARDEN RIVER DS HV B	556ASC	Overhead Line	35.7	34.500	16346.2	4544	105	4546	99.76	73.4	-1.99	8.6	31.1	12.2
49	GARDEN RIVER DS HV B	GARDEN RIVER T2 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	107	35	113	95.01	5.1	-49.38	0.0	0.0	1.0
51	GARDEN RIVER DS HV B	51	556ASC	Overhead Line	35.6	34.500	34354.4	4143	-30	4143	-99.57	67.0	-0.64	15.2	54.9	11.6
077	51	52	556ASC	Overhead Line	35.5	34.500	1889.0	4127	-27	4127	-99.57	67.0	-1.45	0.8	3.0	11.6
52	52	53	556ASC	Overhead Line	35.5	34.500	213.3	4127	-27	4127	-99.57	67.0	-1.49	0.1	0.3	11.6
54	53	54	556ASC	Overhead Line	35.5	34.500	147.6	4126	-1	4126	-99.57	67.0	-1.85	0.1	0.2	11.6
67	69	54	556ASC	Overhead Line	35.5	34.500	12664.6	4126	-1	4126	-99.57	67.0	-1.85	5.6	20.2	11.6
70	69	66	556ASC	Overhead Line	35.5	34.500	9594.3	4121	0	4121	-99.57	67.0	-2.15	4.2	15.3	11.6
66	65	66	556ASC	Overhead Line	35.5	34.500	100.0	3402	-133	3405	-99.31	55.4	-0.14	0.0	0.1	9.8
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.5	34.500	64.0	3402	-133	3405	-99.31	55.4	-0.14	0.0	0.1	9.8
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.5	34.500	100.0	2389	-476	2436	-97.72	39.7	8.90	0.0	0.1	6.9
63	61	62	3/0ACSR	Overhead Line	35.5	34.500	100.0	2389	-476	2436	-97.72	39.7	8.90	0.1	0.1	14.0
61	VR PRIMARY	61	477ACSR	Overhead Line	35.5	34.500	100.0	2389	-476	2436	-97.72	39.7	8.89	0.0	0.1	6.9
62	VR SECONDARY	62	477ACSR	Overhead Line	34.7	34.500	100.0	0	0	0	0.00	0.0	87.66	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	34.7	34.500	100.0	2389	-422	2426	-98.11	40.3	7.67	0.0	0.1	7.0
76	75	76	477ACSR	Overhead Line	34.7	34.500	51800.0	2389	-422	2426	-98.11	40.3	7.66	9.5	29.3	7.0
77	76	77	556ASC	Overhead Line	34.7	34.500	100.0	2379	-368	2408	-98.46	40.1	5.71	0.0	0.1	6.9
80	542	77	556ASC	Overhead Line	34.7	34.500	100.0	0	0	0	0.00	0.0	86.95	0.0	0.0	0.0
86	542	86	556ASC	Overhead Line	35.3	34.500	100.0	951	239	980	96.98	16.0	-16.73	0.0	0.0	2.5
8	86	8	556ASC	Overhead Line	25.5	25.000	10.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	3.5
7	8	7	556ASC	Overhead Line	25.5	25.000	10.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	3.5
89	7	DESBARATS DS T2 LV BU	336AAC	Overhead Line	25.5	25.000	50.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	4.4
11	DESBARATS DS T2 LV BU	11	28 KV 2/0 CU 100% C	Cable	25.5	25.000	185.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	8.1
13	11	13	336AAC	Overhead Line	25.5	25.000	3500.0	950	230	977	97.19	22.1	-46.93	0.2	0.6	4.4
14	13	14	336AAC	Overhead Line	25.5	25.000	5717.0	949	232	977	97.13	22.1	-47.10	0.4	1.0	4.4
15	14	15	35 KV 4/0 CU 100% C	Cable	25.5	25.000	2345.0	949	236	978	97.04	22.2	-47.37	0.2	0.1	6.0
16	15	16	336AAC	Overhead Line	25.4	25.000	13595.0	949	303	996	95.27	22.6	-51.09	0.9	2.5	4.5
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	948	311	998	95.00	22.8	-51.71	0.0	0.0	4.5
81	77	81	556ASC	Overhead Line	34.7	34.500	100.0	705	-986	1212	-57.71	20.2	51.34	0.0	0.0	3.6
87	81	DESBARATS DS T1 LV BU	556ASC	Overhead Line	12.6	12.470	100.0	703	-1000	1223	-55.88	55.9	21.34	0.0	0.1	9.7
82	77	82	3/0ACSR	Overhead Line	34.7	34.500	100.0	1674	619	1785	93.75	29.7	-23.34	0.0	0.0	9.9
83	82	BRUCE MINES DS HV BU	3/0ACSR	Overhead Line	34.3	34.500	41600.0	1674	619	1785	93.75	29.7	-23.34	11.8	14.4	9.9
84	BRUCE MINES DS HV BU	84	3/0ACSR	Overhead Line	34.3	34.500	100.0	743	252	785	94.42	13.2	-22.08	0.0	0.0	4.6
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.7	12.470	39.9	743	244	782	95.00	35.6	-52.09	0.0	0.0	6.4
85	BRUCE MINES DS HV BU	FEEDER END	556ASC	Overhead Line	34.3	34.500	15088.3	919	412	1007	91.25	16.9	-27.50	0.4	1.5	2.6
59	58	VR PRIMARY	477ACSR	Overhead Line	35.5	34.500	24.2	0	-53	53	0.00	0.9	87.66	0.0	0.0	0.1
2024	ER1	58	477ACSR	Overhead Line	35.5	34.500	9412.4	0	-53	53	0.00	0.9	87.66	0.0	0.0	0.1
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.5	34.500	22193.7	0	-37	37	0.00	0.6	87.66	0.0	0.0	0.1
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.1	12.470	100.0	1012	333	1066	95.00	47.0	-51.12	0.0	0.1	11.0
71	66	71	3/0ACSR	Overhead Line	35.5	34.500	82.0	714	133	726	98.30	11.8	-12.90	0.0	0.0	3.8
72	71	72	3/0ACSR	Overhead Line	35.4	34.500	29000.0	714	133	726	98.30	11.8	-12.91	1.3	1.6	3.8
73	72	73	556ASC	Overhead Line	35.4	34.500	6391.1	713	175	734	97.10	12.0	-16.26	0.1	0.3	1.9
74	73	SOLAR	556ASC	Overhead Line	35.4	34.500	100.0	-239	0	239	100.00	3.9	177.51	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.3	34.500	28445.2	952	186	970	98.14	15.8	-13.52	0.7	2.5	2.5
79	78	542	477ACSR	Overhead Line	35.3	34.500	5072.2	951	231	979	97.17	16.0	-16.25	0.1	0.4	2.5
55	53	ER2	3/0ACSR	Overhead Line	35.5	34.500	144.4	0	-25	25	0.00	0.4	88.16	0.0	0.0	0.1
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.5	34.500	14794.7	0	-25	25	0.00	0.4	88.16	0.0	0.0	0.1
50	GARDEN RIVER DS HV B	GARDEN RIVER T1 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	286	94	301	95.00	13.5	-49.70	0.0	0.0	4.5

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	102.75 %
	B	1	87	101.51 %
	C	1	87	103.55 %
Under-Voltage	A	0	FEEDER END	99.17 %
	B	0	FEEDER END	99.52 %
	C	0	FEEDER END	99.68 %
Over-Voltage	A	0	68	104.91 %
	B	0	BAR RIVER DS LV BUS	104.53 %
	C	4	68	105.56 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	75.19	658.69	65.87
Cable Losses	0.24	2.15	0.21
Transformer Load Losses	4.80	42.05	4.20
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	**80.24**	**702.88**	**70.29**

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-16-2020 uprated conductors.sxst
Date	Tue Jun 16 2020
Time	14h45m38s
Project Name	Uprated from NTS Min Load - by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	**kW**	**kvar**	**kVA**	**PF(%)**
Sources (Swing)	4575.32	118.12	4576.84	99.97
Generators	238.99	-0.01	238.99	100.00
Total Generation	**4814.31**	**118.11**	**4815.76**	**99.97**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4734.10	1690.70	5026.95	94.17
Shunt capacitors (Adjusted)	0.00	-1231.27	1231.27	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4734.10**	**459.43**	**4756.35**	**99.53**
Cable Capacitance	0.00	-69.87	69.87	0.00
Line Capacitance	0.00	-553.28	553.28	0.00
Total Shunt Capacitance	**0.00**	**-623.14**	**623.14**	**0.00**
Line Losses	75.19	233.68	245.48	30.63
Cable Losses	0.24	0.15	0.29	85.37
Transformer Load Losses	4.80	48.00	48.24	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**80.24**	**281.82**	**293.02**	**27.38**

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.7	34.500	14794.7	7651	1556	7807	97.69	125.6	-11.50	22.9	82.7	21.1
55	53	ER2	3/0ACSR	Overhead Line	35.7	34.500	144.4	7628	1499	7774	97.82	125.7	-11.68	0.7	0.9	43.3
52	52	53	556ASC	Overhead Line	35.7	34.500	213.3	1289	399	1350	92.24	21.8	-17.79	0.0	0.0	4.5
077	51	52	556ASC	Overhead Line	35.7	34.500	1889.0	1289	400	1350	92.23	21.8	-17.81	0.1	0.4	4.5
51	GARDEN RIVER DS HV BI	51	556ASC	Overhead Line	35.6	34.500	34354.4	1289	403	1351	92.17	21.8	-17.94	1.8	6.7	4.5
49	GARDEN RIVER DS HV BI	GARDEN RIVER T2 LV BU	556ASC	Overhead Line	12.8	12.470	100.0	354	116	373	95.00	16.8	-49.40	0.0	0.0	3.4
50	GARDEN RIVER DS HV BI	GARDEN RIVER T1 LV BU	556ASC	Overhead Line	12.8	12.470	100.0	930	306	979	94.99	44.5	-50.61	0.1	0.2	14.7
54	53	54	556ASC	Overhead Line	35.7	34.500	147.6	6338	1099	6432	97.97	104.0	-10.40	0.2	0.6	18.0
67	69	54	556ASC	Overhead Line	35.6	34.500	12664.6	6338	1098	6432	97.97	104.0	-10.41	13.6	49.1	18.0
70	69	66	556ASC	Overhead Line	35.5	34.500	9594.3	6324	1071	6414	98.03	104.1	-10.59	10.3	37.2	18.0
66	65	66	556ASC	Overhead Line	35.5	34.500	100.0	3323	1204	3534	92.25	57.5	-21.23	0.0	0.1	11.0
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.5	34.500	64.0	3323	1204	3534	92.25	57.5	-21.24	0.0	0.1	11.0
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.0	12.470	100.0	3311	1091	3486	94.98	155.3	-51.24	0.4	1.2	36.1
71	66	71	3/0ACSR	Overhead Line	35.5	34.500	82.0	2991	-155	2995	-99.87	48.7	1.68	0.1	0.1	15.5
72	71	72	3/0ACSR	Overhead Line	35.3	34.500	29000.0	2991	-154	2995	-99.87	48.7	1.68	21.7	26.5	15.5
73	72	73	556ASC	Overhead Line	35.2	34.500	6391.1	2969	-137	2973	-99.89	48.7	0.84	1.5	5.3	7.6
74	73	SOLAR	556ASC	Overhead Line	35.2	34.500	100.0	-239	0	239	100.00	3.9	178.05	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.2	34.500	28445.2	3207	-132	3210	-99.92	52.6	0.45	7.6	27.5	8.2
79	78	542	477ACSR	Overhead Line	35.1	34.500	5072.2	3199	-112	3201	-99.94	52.6	-0.40	1.6	4.8	8.2
86	542	86	556ASC	Overhead Line	35.1	34.500	100.0	3198	-109	3200	-99.94	52.6	-0.55	0.0	0.1	8.2
8	86	8	556ASC	Overhead Line	25.4	25.000	10.0	3184	-244	3193	-99.71	72.5	-30.55	0.0	0.0	11.3
7	8	7	556ASC	Overhead Line	25.4	25.000	10.0	3184	-244	3193	-99.71	72.5	-30.55	0.0	0.0	11.3
89	7	DESBARATS DS T2 LV BU	336AAC	Overhead Line	25.4	25.000	50.0	3184	-244	3193	-99.71	72.5	-30.55	0.0	0.1	14.3
11	DESBARATS DS T2 LV BU	11	28 KV 2/0 CU 100% C	Cable	25.4	25.000	185.0	3184	-244	3193	-99.71	72.5	-30.55	0.3	0.1	26.4
13	11	13	336AAC	Overhead Line	25.4	25.000	3500.0	3184	-241	3193	-99.71	72.5	-30.61	2.6	7.0	14.3
14	13	14	336AAC	Overhead Line	25.3	25.000	5717.0	3181	1001	3335	95.39	75.8	-52.51	4.4	11.9	14.9
15	14	15	35 KV 4/0 CU 100% C	Cable	25.3	25.000	2345.0	3177	993	3328	95.44	75.9	-52.59	2.6	1.7	20.3
16	15	16	336AAC	Overhead Line	25.2	25.000	13595.0	3174	1058	3346	94.87	76.3	-53.67	10.7	28.6	15.0
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	3163	1040	3330	95.00	76.1	-53.85	0.0	0.1	14.9
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.6	34.500	22193.7	8027	1097	8102	98.73	130.4	-7.78	42.9	131.7	22.7
2024	ER1	58	477ACSR	Overhead Line	35.5	34.500	9412.4	7984	1003	8047	98.86	130.4	-8.05	18.2	55.9	22.7
59	58	VR PRIMARY	477ACSR	Overhead Line	35.5	34.500	24.2	7966	963	8024	98.92	130.5	-8.16	0.0	0.1	22.7
62	VR SECONDARY	62	477ACSR	Overhead Line	35.4	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	35.4	34.500	100.0	7966	964	8024	98.92	131.0	-8.16	0.2	0.6	22.8
76	75	76	477ACSR	Overhead Line	34.8	34.500	51800.0	7966	963	8024	98.92	131.0	-8.16	101.3	310.9	22.8
77	76	77	556ASC	Overhead Line	34.8	34.500	100.0	7865	738	7899	99.19	131.2	-8.77	0.2	0.6	22.7
80	542	77	556ASC	Overhead Line	34.8	34.500	100.0	0	0	0	0.00	0.0	86.62	0.0	0.0	0.0
81	77	81	556ASC	Overhead Line	34.8	34.500	100.0	2327	-400	2362	-95.88	39.3	6.29	0.0	0.1	8.0
87	81	DESBARATS DS T1 LV BU	556ASC	Overhead Line	12.6	12.470	100.0	2321	-460	2366	-95.39	108.6	-23.72	0.2	0.6	24.8
82	77	82	3/0ACSR	Overhead Line	34.8	34.500	100.0	5537	1138	5653	97.89	93.8	-15.01	0.3	0.3	31.0
83	82	BRUCE MINES DS HV BU	3/0ACSR	Overhead Line	33.9	34.500	41600.0	5537	1138	5652	97.89	93.8	-15.01	116.1	141.7	31.0
84	BRUCE MINES DS HV BU	84	3/0ACSR	Overhead Line	33.9	34.500	100.0	2446	-343	2470	-98.73	42.1	3.36	0.1	0.1	14.4
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.6	12.470	39.9	2438	-422	2474	-98.22	113.4	-26.64	0.1	0.2	20.3
85	BRUCE MINES DS HV BU	FEEDER END	556ASC	Overhead Line	33.8	34.500	15088.3	2975	1398	3287	90.50	56.0	-29.74	4.6	16.6	8.7
61	VR PRIMARY	61	477ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0
63	61	62	3/0ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	54	-51	74	-73.04	1.2	43.08	0.0	0.0	0.2
390	46	TRUSS PLANT	556ASC	Overhead Line	35.9	34.500	27986.1	54	-50	74	-73.16	1.2	42.98	0.0	0.0	0.2
076	TRUSS PLANT	GARDEN RIVER DS HV BI	556ASC	Overhead Line	35.9	34.500	16346.2	0	-28	28	0.02	0.5	90.00	0.0	0.0	0.1

43.2539411

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	0.1	18.0	-16.8	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	0.1	0.0	-9.4	104.00
NORTHERN AVE TS	076	DEFAULT	Switch	0.0	0.0	0.0	103.11

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS	9	DEFAULT	Switch	30.4	5537.9	1237.0	104.00
ECHO RIVER TS	081	DEFAULT	Switch	14.4	2563.0	812.6	104.00
ECHO RIVER TS	081	DEFAULT	Switch	14.4	2555.0	792.0	103.37
ECHO RIVER TS	077	DEFAULT	Switch	1.6	256.2	153.1	103.35
ECHO RIVER TS	51	DEFAULT	Switch	1.7	255.9	172.7	103.11
ECHO RIVER TS	49	GARDEN T2	Two-Winding Transforme	14.6	145.5	55.0	102.56
ECHO RIVER TS	555	GARDEN T1	Two-Winding Transforme	1.2	110.4	117.7	102.38
ECHO RIVER TS	67	DEFAULT	Switch	12.9	2298.5	638.6	103.35
ECHO RIVER TS	66	DEFAULT	Switch	7.9	1294.4	665.2	102.55
ECHO RIVER TS	65	DEFAULT	Switch	7.9	1294.4	665.2	102.54
ECHO RIVER TS	68	BAR RIVER T1	Two-Winding Transforme	56.6	1294.4	665.2	103.46
ECHO RIVER TS	68	1200 KVAR 7 KV	Shunt Capacitor	0.0	1646.5	543.0	103.42
ECHO RIVER TS	71	DEFAULT	Switch	5.4	994.4	-49.0	102.55
ECHO RIVER TS	72	DEFAULT	Switch	5.4	987.2	-43.4	101.84
ECHO RIVER TS	74	DEFAULT	Switch	0.4	-79.4	0.0	101.80
ECHO RIVER TS	79	DEFAULT	Switch	5.8	1063.0	-34.0	101.55
ECHO RIVER TS	79	1800 KVAR 20 KV	Shunt Capacitor	0.0	1063.6	-35.2	101.55
ECHO RIVER TS	86	DESBARATS T2	Two-Winding Transforme	63.8	1063.0	-34.0	101.56
ECHO RIVER TS	13	1200 KVAR 20 KV	Shunt Capacitor	103.6	1062.7	-78.6	101.44
ECHO RIVER TS	17	25 KV 600A 1PH	Regulator	12.8	1055.6	347.2	101.15
ECHO RIVER TS	56	DEFAULT	Switch	16.1	2974.9	424.5	104.00
ECHO RIVER TS	58	DEFAULT	Switch	16.1	2949.8	366.5	102.79
ECHO RIVER TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_6	Regulator	72.6	2949.7	366.6	102.15
ECHO RIVER TS	62	DEFAULT	Switch	0.0	0.0	0.0	102.79
ECHO RIVER TS	64	DEFAULT	Switch	0.0	0.0	0.0	102.54
ECHO RIVER TS	75	DEFAULT	Switch	16.2	2949.7	366.5	102.14
ECHO RIVER TS	77	DEFAULT	Switch	16.2	2908.2	267.6	100.26
ECHO RIVER TS	80	DEFAULT	Switch	0.0	0.0	0.0	101.55
ECHO RIVER TS	81	DEFAULT	Switch	5.7	1010.7	-169.2	100.26
ECHO RIVER TS	81	DESBARATS T1	Two-Winding Transforme	57.5	1010.7	-169.2	101.20
ECHO RIVER TS	87	1200 KVAR 7 KV	Shunt Capacitor	102.4	789.4	-150.1	101.17
ECHO RIVER TS	82	DEFAULT	Switch	10.8	1897.5	436.9	100.26
ECHO RIVER TS	83	DEFAULT	Switch	10.8	1897.4	436.8	100.25
ECHO RIVER TS	83	1800 KVAR 20 KV	Shunt Capacitor	0.0	1897.4	436.8	97.59
ECHO RIVER TS	84	DEFAULT	Switch	5.0	878.1	-53.8	97.59
ECHO RIVER TS	84	BRUCE MINES T1	Two-Winding Transforme	50.9	878.1	-53.8	100.90
ECHO RIVER TS	88	1200 KVAR 7 KV	Shunt Capacitor	101.8	946.8	-95.9	100.90
ECHO RIVER TS	61	DEFAULT	Switch	0.0	0.0	-0.1	102.79

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	3	13	103.61 %
	B	2	13	103.42 %
	C	3	13	104.60 %
Under-Voltage	A	0	FEEDER END	97.25 %
	B	0	FEEDER END	97.97 %
	C	0	FEEDER END	98.62 %
Over-Voltage	A	0	076	104.01 %
	B	0	BAR RIVER DS LV BUS	104.05 %
	C	4	68	105.15 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	384.28	3366.31	336.63
Cable Losses	2.90	25.42	2.54
Transformer Load Losses	42.01	368.01	36.80
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	429.19	3759.74	375.97

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-16-2020 uprated conductors.s
Date	Tue Jun 16 2020
Time	14h41m16s
Project Name	Uprated ERTS Peak Load - By Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=100.00%, Q=100.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	**kW**	**kvar**	**kVA**	**PF(%)**
Sources (Swing)	15731.96	2602.76	15945.82	98.66
Generators	239.02	0.03	239.02	100.00
Total Generation	**15970.99**	**2602.79**	**16181.68**	**98.70**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	15541.64	5546.95	16501.85	94.18
Shunt capacitors (Adjusted)	0.00	-3692.65	3692.65	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**15541.64**	**1854.31**	**15651.87**	**99.30**
Cable Capacitance	0.00	-69.15	69.15	0.00
Line Capacitance	0.00	-554.76	554.76	0.00
Total Shunt Capacitance	**0.00**	**-623.91**	**623.91**	**0.00**
Line Losses	384.28	950.50	1025.24	37.48
Cable Losses	2.90	1.79	3.41	85.14
Transformer Load Losses	42.01	420.10	422.20	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**429.19**	**1372.39**	**1437.94**	**29.85**

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)	
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.8	34.500	14794.7	2119	490	2175	97.09	35.0	-13.01	1.8	6.4	5.9	12.0607414
55	53	ER2	3/0ACSR	Overhead Line	35.8	34.500	144.4	2117	509	2178	96.89	35.1	-13.67	0.1	0.1	12.1	
52	52	53	556ASC	Overhead Line	35.8	34.500	213.3	395	71	402	94.97	6.5	-10.32	0.0	0.0	1.3	
077	51	52	556ASC	Overhead Line	35.8	34.500	1889.0	395	71	402	94.96	6.5	-10.37	0.0	0.0	1.3	
51	GARDEN RIVER DS HV B	51	556ASC	Overhead Line	35.8	34.500	34354.4	395	74	402	94.82	6.5	-10.82	0.2	0.6	1.3	
49	GARDEN RIVER DS HV B	GARDEN RIVER T2 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	108	35	114	95.01	5.1	-48.53	0.0	0.0	1.0	
50	GARDEN RIVER DS HV B	GARDEN RIVER T1 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	287	94	302	95.00	13.5	-48.91	0.0	0.0	4.5	
54	53	54	556ASC	Overhead Line	35.8	34.500	147.6	1722	438	1777	96.23	28.6	-14.43	0.0	0.0	5.1	
67	69	54	556ASC	Overhead Line	35.8	34.500	12664.6	1722	438	1777	96.23	28.6	-14.44	1.0	3.7	5.1	
70	69	66	556ASC	Overhead Line	35.8	34.500	9594.3	1721	456	1780	95.98	28.7	-15.11	0.8	2.9	5.1	
66	65	66	556ASC	Overhead Line	35.8	34.500	100.0	1006	340	1062	92.90	17.1	-19.04	0.0	0.0	3.3	
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.8	34.500	64.0	1006	340	1062	92.89	17.1	-19.05	0.0	0.0	3.3	
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.0	12.470	100.0	1005	330	1058	94.99	46.9	-49.06	0.0	0.1	10.9	
71	66	71	3/0ACSR	Overhead Line	35.8	34.500	82.0	714	129	726	98.39	11.7	-10.62	0.0	0.0	3.7	
72	71	72	3/0ACSR	Overhead Line	35.7	34.500	29000.0	714	130	726	98.39	11.7	-10.63	1.3	1.6	3.7	
73	72	73	556ASC	Overhead Line	35.7	34.500	6391.1	713	173	733	97.19	11.9	-14.05	0.1	0.3	1.8	
74	73	SOLAR	556ASC	Overhead Line	35.7	34.500	100.0	-239	0	239	100.00	3.9	179.50	0.0	0.0	0.6	
78	73	78	556ASC	Overhead Line	35.6	34.500	28445.2	952	183	969	98.19	15.7	-11.36	0.7	2.5	2.4	
79	78	542	477ACSR	Overhead Line	35.6	34.500	5072.2	951	229	978	97.22	15.9	-14.15	0.1	0.4	2.5	
86	542	86	556ASC	Overhead Line	35.6	34.500	100.0	951	237	980	97.02	15.9	-14.64	0.0	0.0	2.5	
8	86	8	556ASC	Overhead Line	25.7	25.000	10.0	950	225	976	97.30	21.9	-44.64	0.0	0.0	3.4	
7	8	7	556ASC	Overhead Line	25.7	25.000	10.0	950	225	976	97.30	21.9	-44.65	0.0	0.0	3.4	
89	7	DESBARATS DS T2 LV BU	336AAC	Overhead Line	25.7	25.000	50.0	950	225	976	97.30	21.9	-44.65	0.0	0.0	4.3	
11	DESBARATS DS T2 LV BU	11	28 KV 2/0 CU 100% C	Cable	25.7	25.000	185.0	950	225	976	97.30	21.9	-44.65	0.0	0.0	8.0	
13	11	13	336AAC	Overhead Line	25.7	25.000	3500.0	950	229	977	97.22	21.9	-44.84	0.2	0.6	4.3	
14	13	14	336AAC	Overhead Line	25.7	25.000	5717.0	949	231	977	97.17	22.0	-45.01	0.4	1.0	4.3	
15	14	15	35 KV 4/0 CU 100% C	Cable	25.7	25.000	2345.0	949	235	976	97.07	22.0	-45.29	0.2	0.1	5.9	
16	15	16	336AAC	Overhead Line	25.6	25.000	13595.0	949	302	996	95.28	22.4	-49.07	0.9	2.5	4.4	
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	948	311	998	95.00	22.8	-49.70	0.0	0.0	4.5	
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.9	34.500	22193.7	2458	-470	2502	-97.87	40.3	10.82	4.1	12.5	7.0	
2024	ER1	58	477ACSR	Overhead Line	35.8	34.500	9412.4	2454	-444	2494	-98.04	40.2	9.96	1.7	5.3	7.0	
59	58	VR PRIMARY	477ACSR	Overhead Line	35.8	34.500	24.2	2452	-433	2490	-98.12	40.1	9.59	0.0	0.0	7.0	
62	VR SECONDARY	62	477ACSR	Overhead Line	35.2	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0	
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0	
75	VR SECONDARY	75	477ACSR	Overhead Line	35.2	34.500	100.0	2452	-432	2490	-98.12	40.9	9.57	0.0	0.1	7.1	
76	75	76	477ACSR	Overhead Line	35.1	34.500	51800.0	2452	-432	2490	-98.12	40.9	9.57	9.8	30.1	7.1	
77	76	77	556ASC	Overhead Line	35.1	34.500	100.0	2442	-377	2471	-98.46	40.6	7.62	0.0	0.1	7.0	
80	542	77	556ASC	Overhead Line	35.1	34.500	100.0	0	0	0	0.00	0.0	88.86	0.0	0.0	0.0	
81	77	81	556ASC	Overhead Line	35.1	34.500	100.0	724	-1011	1244	-57.77	20.5	53.23	0.0	0.0	3.6	
87	81	DESBARATS DS T1 LV BU	556ASC	Overhead Line	12.8	12.470	100.0	723	-1026	1255	-55.95	56.6	23.23	0.0	0.1	9.9	
82	77	82	3/0ACSR	Overhead Line	35.1	34.500	100.0	1718	635	1832	93.75	30.1	-21.42	0.0	0.0	10.0	
83	82	BRUCE MINES DS HV BU	3/0ACSR	Overhead Line	34.8	34.500	41600.0	1718	635	1832	93.74	30.1	-21.42	12.1	14.7	10.0	
84	BRUCE MINES DS HV BU	84	3/0ACSR	Overhead Line	34.8	34.500	100.0	763	258	806	94.42	13.4	-20.15	0.0	0.0	4.7	
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.8	12.470	39.9	762	251	802	95.00	36.1	-50.16	0.0	0.0	6.5	
85	BRUCE MINES DS HV BU	FEEDER END	556ASC	Overhead Line	34.8	34.500	15088.3	943	423	1034	91.25	17.2	-25.58	0.4	1.6	2.7	
61	VR PRIMARY	61	477ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0	
63	61	62	3/0ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0	
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	16	-69	71	-22.97	1.1	76.72	0.0	0.0	0.2	
390	46	TRUSS PLANT	556ASC	Overhead Line	35.9	34.500	27986.1	16	-69	70	-23.03	1.1	76.69	0.0	0.0	0.2	
076	TRUSS PLANT	GARDEN RIVER DS HV B	556ASC	Overhead Line	35.9	34.500	16346.2	0	-28	28	0.01	0.5	90.00	0.0	0.0	0.1	

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	0.1	5.4	-22.9	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	0.1	0.0	-9.4	104.01
NORTHERN AVE TS	076	DEFAULT	Switch	0.0	0.0	0.0	103.74

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	8.8	1632.4	103.0	104.00
ECHO RIVER TS 081		DEFAULT	Switch	4.1	715.2	250.8	104.00
ECHO RIVER TS 081		DEFAULT	Switch	4.1	714.5	257.0	103.81
ECHO RIVER TS 077		DEFAULT	Switch	0.5	78.5	31.4	103.81
ECHO RIVER TS 51		DEFAULT	Switch	0.5	78.5	52.1	103.74
ECHO RIVER TS 49		GARDEN T2	Two-Winding Transforme	4.4	44.4	16.5	103.58
ECHO RIVER TS 555		GARDEN T1	Two-Winding Transforme	0.4	34.1	35.6	103.52
ECHO RIVER TS 67		DEFAULT	Switch	3.6	636.0	225.8	103.81
ECHO RIVER TS 66		DEFAULT	Switch	2.4	396.4	192.1	103.55
ECHO RIVER TS 65		DEFAULT	Switch	2.4	396.4	192.2	103.55
ECHO RIVER TS 68		BAR RIVER T1	Two-Winding Transforme	17.1	396.4	192.2	104.38
ECHO RIVER TS 68		1200 KVAR 7 KV	Shunt Capacitor	0.0	503.2	165.5	104.36
ECHO RIVER TS 71		DEFAULT	Switch	1.3	238.8	43.6	103.55
ECHO RIVER TS 72		DEFAULT	Switch	1.3	238.4	57.9	103.33
ECHO RIVER TS 74		DEFAULT	Switch	0.4	-79.6	0.0	103.30
ECHO RIVER TS 79		DEFAULT	Switch	1.8	317.7	79.4	103.15
ECHO RIVER TS 79		1800 KVAR 20 KV	Shunt Capacitor	0.0	317.7	76.7	103.15
ECHO RIVER TS 86		DESBARATS T2	Two-Winding Transforme	19.6	317.7	79.5	102.78
ECHO RIVER TS 13		1200 KVAR 20 KV	Shunt Capacitor	0.0	317.7	76.6	102.74
ECHO RIVER TS 17		25 KV 600A 1PH	Regulator	3.8	317.1	104.2	101.19
ECHO RIVER TS 56		DEFAULT	Switch	5.0	917.3	-147.8	104.00
ECHO RIVER TS 58		DEFAULT	Switch	5.0	914.9	-137.0	103.86
ECHO RIVER TS 5		34.5KV_200A_1PH_COOPER_REGULATOR_6	Regulator	22.4	914.9	-136.8	101.92
ECHO RIVER TS 62		DEFAULT	Switch	0.0	0.0	0.0	103.86
ECHO RIVER TS 64		DEFAULT	Switch	0.0	0.0	0.0	103.55
ECHO RIVER TS 75		DEFAULT	Switch	5.1	914.9	-136.7	101.91
ECHO RIVER TS 77		DEFAULT	Switch	5.0	910.9	-120.4	101.67
ECHO RIVER TS 80		DEFAULT	Switch	0.0	0.0	0.0	103.15
ECHO RIVER TS 81		DEFAULT	Switch	2.6	315.5	-349.7	101.67
ECHO RIVER TS 81		DESBARATS T1	Two-Winding Transforme	23.5	315.5	-349.7	102.75
ECHO RIVER TS 87		1200 KVAR 7 KV	Shunt Capacitor	105.6	244.2	-342.0	102.75
ECHO RIVER TS 82		DEFAULT	Switch	3.5	595.3	229.3	101.67
ECHO RIVER TS 83		DEFAULT	Switch	3.5	595.3	229.4	101.66
ECHO RIVER TS 83		1800 KVAR 20 KV	Shunt Capacitor	0.0	595.3	229.4	100.70
ECHO RIVER TS 84		DEFAULT	Switch	1.6	277.4	103.8	100.70
ECHO RIVER TS 84		BRUCE MINES T1	Two-Winding Transforme	16.7	277.4	103.8	103.08
ECHO RIVER TS 88		1200 KVAR 7 KV	Shunt Capacitor	0.0	296.5	97.4	103.08
ECHO RIVER TS 61		DEFAULT	Switch	0.0	0.0	-0.1	103.86

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	105.57 %
	B	1	87	104.47 %
	C	1	87	105.76 %
Under-Voltage	A	0	FEEDER END	100.60 %
	B	0	FEEDER END	100.61 %
	C	0	18	100.70 %
Over-Voltage	A	0	68	104.38 %
	B	0	BAR RIVER DS LV BUS	104.53 %
	C	0	68	104.86 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	35.82	313.77	31.38
Cable Losses	0.24	2.14	0.21
Transformer Load Losses	4.80	42.08	4.21
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	40.87	357.99	35.80

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-16-2020 uprated conductors.s
Date	Tue Jun 16 2020
Time	14h43m49s
Project Name	Uprated from ERTS Min Load - By Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	**kW**	**kvar**	**kVA**	**PF(%)**
Sources (Swing)	4593.23	-48.70	4593.48	-99.99
Generators	239.00	0.00	239.00	100.00
Total Generation	**4832.23**	**-48.69**	**4832.47**	**-99.99**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4791.36	1713.30	5088.47	94.16
Shunt capacitors (Adjusted)	0.00	-1263.21	1263.21	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4791.36**	**450.09**	**4812.45**	**99.56**
Cable Capacitance	0.00	-71.06	71.06	0.00
Line Capacitance	0.00	-563.21	563.21	0.00
Total Shunt Capacitance	**0.00**	**-634.27**	**634.27**	**0.00**
Line Losses	35.82	87.29	94.36	37.96
Cable Losses	0.24	0.15	0.29	85.23
Transformer Load Losses	4.80	48.04	48.28	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**40.87**	**135.48**	**141.51**	**28.88**

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	29.4	5270.3	1490.7	103.98
NORTHERN AVE TS	390	DEFAULT	Switch	29.3	5048.1	1245.2	98.98
NORTHERN AVE TS	076	DEFAULT	Switch	29.3	4928.5	1106.7	96.13
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	12.8	126.5	47.9	96.00
NORTHERN AVE TS	51	DEFAULT	Switch	27.9	4706.2	955.7	96.13
NORTHERN AVE TS	077	DEFAULT	Switch	27.9	4466.4	677.9	90.38
NORTHERN AVE TS	67	DEFAULT	Switch	27.9	4464.0	681.6	90.32
NORTHERN AVE TS	66	DEFAULT	Switch	22.6	3486.4	473.7	86.91
NORTHERN AVE TS	65	DEFAULT	Switch	22.6	3486.1	473.4	86.90
NORTHERN AVE TS	64	DEFAULT	Switch	16.7	2583.0	309.4	86.90
NORTHERN AVE TS	61	DEFAULT	Switch	16.7	2582.7	308.9	86.88
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	75.2	2582.6	321.4	95.57
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	86.89
NORTHERN AVE TS	75	DEFAULT	Switch	15.2	2582.5	321.2	95.57
NORTHERN AVE TS	77	DEFAULT	Switch	15.2	2546.2	234.4	93.80
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	85.75
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	54.4	897.1	40.5	86.35
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	74.9	916.1	-4.3	86.23
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	13.0	909.1	298.5	93.83
NORTHERN AVE TS	81	DEFAULT	Switch	5.3	885.3	-150.5	93.80
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	51.0	885.3	-150.5	95.68
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	91.5	705.9	-134.4	95.65
NORTHERN AVE TS	82	DEFAULT	Switch	10.1	1660.8	385.0	93.80
NORTHERN AVE TS	83	DEFAULT	Switch	10.1	1660.8	384.9	93.79
NORTHERN AVE TS	84	DEFAULT	Switch	4.7	768.0	-45.1	91.30
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	45.1	768.0	-45.1	95.40
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	91.0	846.8	-86.0	95.40
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-12.7	86.88
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	38.1	903.1	164.0	87.42
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	76.4	1176.7	81.3	87.38
NORTHERN AVE TS	71	DEFAULT	Switch	5.3	829.7	35.7	86.92
NORTHERN AVE TS	72	DEFAULT	Switch	5.3	822.7	37.5	86.14
NORTHERN AVE TS	74	DEFAULT	Switch	0.5	-78.0	0.2	86.08
NORTHERN AVE TS	79	DEFAULT	Switch	5.8	897.1	40.5	85.75
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-6.4	90.35
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	1.1	95.9	103.2	95.84

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS	9	DEFAULT	Switch	0.0	0.0	0.0	104.00

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)	
NA1	NORTHERN AVE TS	46	3/0ACSR	Overhead Line	35.9	34.500	100.0	15264	3422	15643	97.44	251.7	-12.63	2.0	2.5	83.9	83.94972295
390	46	TRUSS PLANT	3/0ACSR	Overhead Line	34.3	34.500	27986.1	15262	3419	15641	97.45	251.7	-12.64	562.7	687.2	83.9	
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	3/0ACSR	Overhead Line	33.4	34.500	16346.2	14650	2750	14906	98.13	251.0	-12.73	326.6	398.8	83.7	
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.0	12.470	100.0	311	102	327	95.00	15.7	-52.03	0.0	0.0	3.2	
51	GARDEN RIVER DS HV BUS	R 038	3/0ACSR	Overhead Line	31.6	34.500	34354.4	13185	1972	13332	98.61	230.6	-11.91	582.2	711.0	79.6	
077	R 038	52	3/0ACSR	Overhead Line	31.7	34.500	1889.0	12603	1305	12670	99.14	230.7	-12.10	32.0	39.1	79.7	
52	52	53	3/0ACSR	Overhead Line	31.7	34.500	213.3	12571	1268	12635	99.17	230.7	-12.11	3.6	4.4	79.7	
54	53	54	3/0ACSR	Overhead Line	31.6	34.500	147.6	12567	1284	12633	99.15	230.7	-12.20	2.5	3.1	79.7	
67	69	54	3/0ACSR	Overhead Line	31.1	34.500	12664.6	12565	1281	12630	99.16	230.7	-12.21	214.8	262.3	79.7	
70	69	66	3/0ACSR	Overhead Line	30.6	34.500	9594.3	12350	1034	12393	99.31	230.7	-12.27	162.8	198.7	79.7	
66	65	66	3/0ACSR	Overhead Line	30.6	34.500	100.0	9587	735	9615	99.14	181.7	-12.76	1.1	1.3	64.5	
65	BAR RIVER DS HV BUS	65	3/0ACSR	Overhead Line	30.6	34.500	64.0	9586	734	9614	99.14	181.7	-12.76	0.7	0.8	64.5	
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	30.6	34.500	100.0	7199	822	7246	98.99	136.9	-14.83	0.2	0.7	23.5	
63	61	62	3/0ACSR	Overhead Line	30.6	34.500	100.0	7199	822	7245	98.99	136.9	-14.83	0.6	0.7	47.7	
61	VR PRIMARY	61	477ACSR	Overhead Line	30.6	34.500	100.0	7198	821	7245	99.00	136.9	-14.83	0.2	0.7	23.5	
62	VR SECONDARY	62	477ACSR	Overhead Line	33.7	34.500	100.0	0	0	0	0.00	0.0	81.70	0.0	0.0	0.0	
75	VR SECONDARY	75	477ACSR	Overhead Line	33.7	34.500	100.0	7198	860	7249	98.93	124.6	-15.15	0.2	0.5	21.4	
76	75	76	477ACSR	Overhead Line	33.1	34.500	51800.0	7198	860	7249	98.93	124.6	-15.15	91.2	279.9	21.4	
77	76	77	556ASC	Overhead Line	33.1	34.500	100.0	7106	658	7137	99.20	124.7	-15.76	0.2	0.5	21.2	
80	542	77	556ASC	Overhead Line	33.1	34.500	100.0	0	0	0	0.01	0.0	79.58	0.0	0.0	0.0	
86	542	86	556ASC	Overhead Line	30.2	34.500	100.0	2806	127	2809	99.90	53.7	-12.23	0.0	0.1	8.4	
8	86	8	556ASC	Overhead Line	21.8	25.000	10.0	2792	-15	2792	-100.00	74.1	-42.23	0.0	0.0	11.7	
7	8	R 2010	556ASC	Overhead Line	21.8	25.000	10.0	2792	-15	2792	-100.00	74.1	-42.23	0.0	0.0	11.7	
89	R 2010	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	21.8	25.000	50.0	2792	-15	2792	-100.00	74.1	-42.23	0.0	0.1	14.8	
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	21.8	25.000	185.0	2792	-15	2792	-100.00	74.1	-42.23	0.3	0.1	27.5	
13	11	13	336AAC	Overhead Line	21.7	25.000	3500.0	2792	-13	2792	-100.00	74.1	-42.28	2.7	7.3	14.8	
14	13	14	336AAC	Overhead Line	21.7	25.000	5717.0	2789	895	2929	95.22	77.8	-60.46	4.7	12.5	15.6	
15	14	15	35 KV 4/0 CU 100% CN	Cable	21.6	25.000	2345.0	2784	886	2922	95.30	77.8	-60.53	2.7	1.7	21.2	
16	15	16	336AAC	Overhead Line	21.5	25.000	13595.0	2782	932	2934	94.82	78.2	-61.42	11.2	30.1	15.7	
18	17	18	336AAC	Overhead Line	23.6	25.000	25.0	2771	910	2916	95.00	71.2	-61.58	0.0	0.0	14.2	
81	77	81	556ASC	Overhead Line	33.1	34.500	100.0	2090	-371	2123	-95.79	37.3	-0.50	0.0	0.1	7.5	
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.0	12.470	100.0	2085	-425	2128	-95.21	103.1	-30.50	0.2	0.6	23.4	
82	77	R 052	3/0ACSR	Overhead Line	33.1	34.500	100.0	5016	1028	5120	97.90	89.3	-22.06	0.3	0.3	29.0	
83	R 052	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	32.3	34.500	41600.0	5016	1028	5120	97.90	89.3	-22.07	105.0	128.2	29.0	
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	32.3	34.500	100.0	2211	-315	2234	-98.69	40.0	-3.67	0.1	0.1	13.4	
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.0	12.470	39.9	2204	-386	2238	-98.18	107.8	-33.67	0.1	0.2	19.2	
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	32.2	34.500	15088.3	2699	1268	2983	90.51	53.3	-36.78	4.2	15.0	8.4	
59	58	VR PRIMARY	477ACSR	Overhead Line	30.6	34.500	24.2	0	-40	40	0.00	0.7	81.70	0.0	0.0	0.1	
2024	ER1	58	477ACSR	Overhead Line	30.6	34.500	9412.4	0	-40	40	0.00	0.7	81.70	0.0	0.0	0.1	
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	30.6	34.500	22193.7	0	-28	28	0.00	0.5	81.70	0.0	0.0	0.1	
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	11.1	12.470	100.0	2379	-160	2385	-98.25	124.9	-36.46	0.3	0.8	29.1	
71	66	R 2020	3/0ACSR	Overhead Line	30.6	34.500	82.0	2600	111	2603	99.91	49.1	-10.72	0.1	0.1	15.8	
72	R 2020	72	3/0ACSR	Overhead Line	30.3	34.500	29000.0	2600	111	2603	99.91	49.1	-10.72	22.0	26.9	15.8	
73	72	73	556ASC	Overhead Line	30.3	34.500	6391.1	2578	117	2581	99.90	49.1	-11.44	1.5	5.4	7.7	
74	73	SOLAR	556ASC	Overhead Line	30.3	34.500	100.0	-239	0	239	99.99	4.5	171.00	0.0	0.0	0.7	
78	73	78	556ASC	Overhead Line	30.2	34.500	28445.2	2816	119	2818	99.91	53.6	-11.39	7.9	28.6	8.4	
79	78	542	477ACSR	Overhead Line	30.2	34.500	5072.2	2808	125	2811	99.90	53.7	-12.10	1.6	5.0	8.5	
55	53	ER2	3/0ACSR	Overhead Line	31.7	34.500	144.4	0	-20	20	0.00	0.4	83.68	0.0	0.0	0.1	
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	31.7	34.500	14794.7	0	-20	20	0.00	0.4	83.68	0.0	0.0	0.1	
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.0	12.470	100.0	825	271	868	95.00	41.9	-53.26	0.1	0.2	13.9	

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	0	87	91.53 %
	B	0	88	88.90 %
	C	0	87	97.62 %
Under-Voltage	A	106	16	85.30 %
	B	106	16	84.88 %
	C	82	16	87.73 %
Over-Voltage	A	0	ECHO RIVER TS	104.00 %
	B	0	ECHO RIVER TS	104.00 %
	C	0	ECHO RIVER TS	104.00 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	2145.32	18792.98	1879.30
Cable Losses	3.04	26.59	2.66
Transformer Load Losses	36.60	320.65	32.06
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	2184.96	19140.22	1914.02

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-4-2020 existing conductors.sxst
Date	Tue Jun 16 2020
Time	14h57m29s
Project Name	Base Case from NTS Max Load
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=100.00%, Q=100.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	**kW**	**kvar**	**kVA**	**PF(%)**
Sources (Swing)	15264.44	3421.77	15643.27	97.58
Generators	238.93	-0.01	238.93	100.00
Total Generation	**15503.38**	**3421.76**	**15876.50**	**97.65**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	13318.81	4772.47	14148.04	94.14
Shunt capacitors (Adjusted)	0.00	-4076.18	4076.18	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**13318.81**	**696.29**	**13337.00**	**99.86**
Cable Capacitance	0.00	-50.57	50.57	0.00
Line Capacitance	0.00	-445.58	445.58	0.00
Total Shunt Capacitance	**0.00**	**-496.15**	**496.15**	**0.00**
Line Losses	2145.32	2853.72	3570.17	60.09
Cable Losses	3.04	1.86	3.56	85.30
Transformer Load Losses	36.60	366.04	367.86	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**2184.96**	**3221.62**	**3892.67**	**56.13**

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	8.8	1629.7	141.5	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	8.8	1606.0	130.8	102.70
NORTHERN AVE TS	076	DEFAULT	Switch	8.8	1595.2	125.8	101.96
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	4.3	42.9	15.9	102.00
NORTHERN AVE TS	51	DEFAULT	Switch	8.3	1519.4	75.4	101.96
NORTHERN AVE TS	077	DEFAULT	Switch	8.3	1497.9	66.9	100.43
NORTHERN AVE TS	67	DEFAULT	Switch	8.3	1497.7	74.8	100.42
NORTHERN AVE TS	66	DEFAULT	Switch	7.0	1248.7	22.4	99.48
NORTHERN AVE TS	65	DEFAULT	Switch	7.0	1248.7	22.4	99.47
NORTHERN AVE TS	64	DEFAULT	Switch	5.1	891.5	-151.0	99.47
NORTHERN AVE TS	61	DEFAULT	Switch	5.1	891.4	-151.0	99.47
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	22.7	891.4	-134.3	100.71
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	99.47
NORTHERN AVE TS	75	DEFAULT	Switch	5.0	891.4	-134.2	100.71
NORTHERN AVE TS	77	DEFAULT	Switch	5.0	887.5	-118.3	100.47
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	99.06
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	19.5	314.0	79.6	99.14
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	0.0	314.5	77.6	99.10
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	3.9	313.8	103.1	100.68
NORTHERN AVE TS	81	DEFAULT	Switch	2.5	306.7	-341.5	100.47
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	22.9	306.7	-341.4	101.37
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	102.7	237.7	-332.9	101.36
NORTHERN AVE TS	82	DEFAULT	Switch	3.5	580.8	223.2	100.47
NORTHERN AVE TS	83	DEFAULT	Switch	3.5	580.8	223.2	100.46
NORTHERN AVE TS	84	DEFAULT	Switch	1.6	270.4	100.5	99.51
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	16.3	270.4	100.6	101.70
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	288.5	94.8	101.69
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-16.6	99.47
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	15.5	357.2	173.4	99.51
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	0.0	457.5	150.4	99.50
NORTHERN AVE TS	71	DEFAULT	Switch	1.3	235.7	46.9	99.48
NORTHERN AVE TS	72	DEFAULT	Switch	1.4	235.2	60.0	99.25
NORTHERN AVE TS	74	DEFAULT	Switch	0.4	-79.1	0.1	99.22
NORTHERN AVE TS	79	DEFAULT	Switch	1.8	314.0	79.6	99.06
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-7.9	100.42
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	0.4	32.9	34.5	101.95

Load Flow - Detailed ECHO RIVER

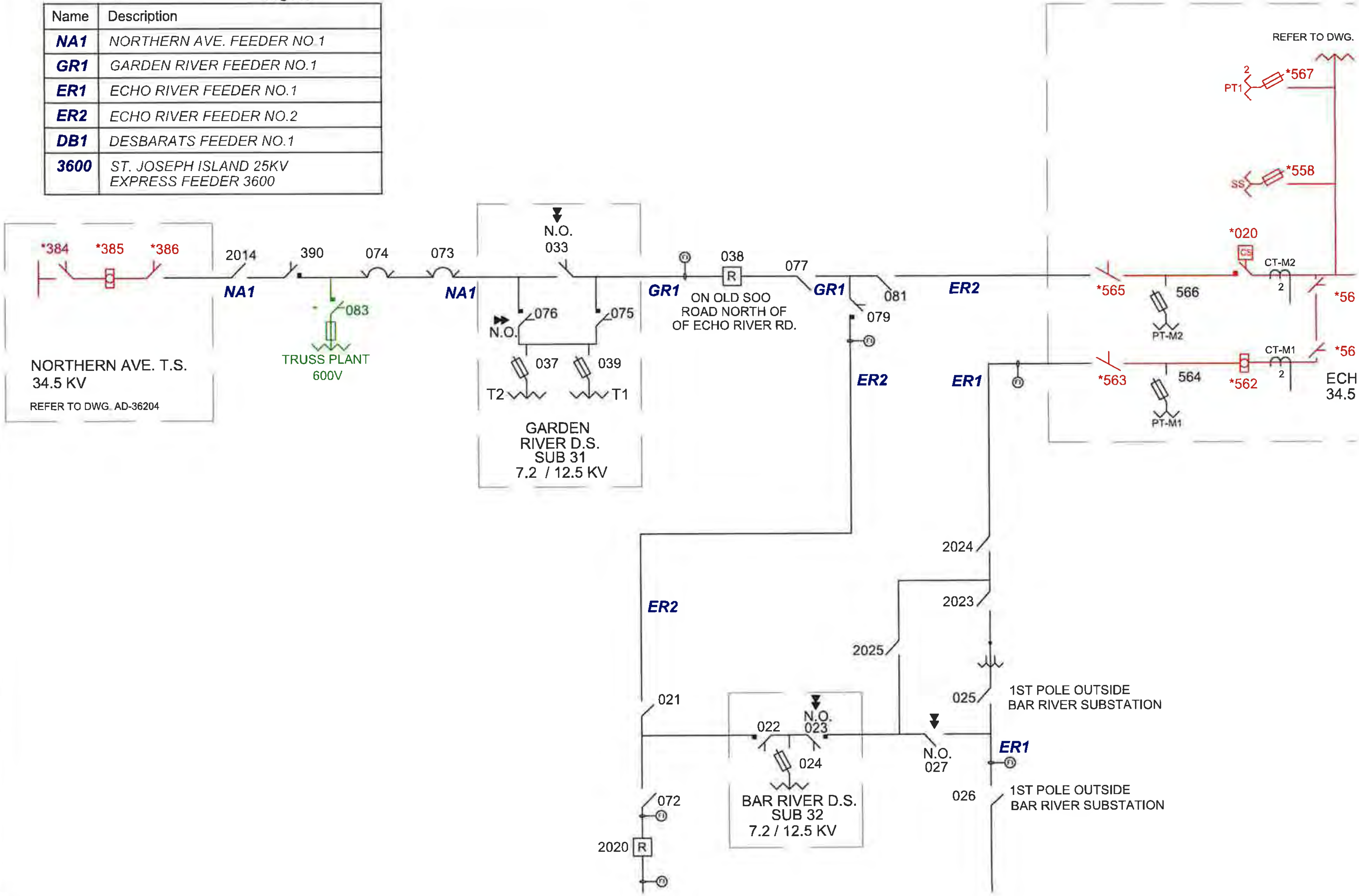
Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS	9	DEFAULT	Switch	0.0	0.0	0.0	104.00

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
NA1	NORTHERN AVE TS	46	3/0ACSR	Overhead Line	35.9	34.500	100.0	4581	135	4583	99.77	73.8	-1.68	0.2	0.2	25.1
390	46	TRUSS PLANT	3/0ACSR	Overhead Line	35.5	34.500	27986.1	4581	135	4583	99.77	73.8	-1.69	48.4	59.1	25.1
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	3/0ACSR	Overhead Line	35.3	34.500	16346.2	4517	111	4518	99.77	73.5	-2.13	28.1	34.3	25.0
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.7	12.470	100.0	105	34	110	95.01	5.0	-49.47	0.0	0.0	1.0
51	GARDEN RIVER DS HV BUS	R 038	3/0ACSR	Overhead Line	34.8	34.500	34354.4	4105	-28	4105	-99.60	67.2	-0.77	49.7	60.7	23.8
077	R 038	52	3/0ACSR	Overhead Line	34.8	34.500	1889.0	4055	-38	4055	-99.59	67.2	-1.48	2.7	3.3	23.8
52	52	53	3/0ACSR	Overhead Line	34.8	34.500	213.3	4052	-38	4052	-99.59	67.2	-1.52	0.3	0.4	23.8
54	53	54	3/0ACSR	Overhead Line	34.8	34.500	147.6	4052	-14	4052	-99.59	67.2	-1.87	0.2	0.3	23.8
67	69	54	3/0ACSR	Overhead Line	34.7	34.500	12664.6	4052	-14	4052	-99.59	67.2	-1.87	18.3	22.4	23.8
70	69	66	3/0ACSR	Overhead Line	34.6	34.500	9594.3	4033	-18	4033	-99.59	67.2	-2.13	13.9	17.0	23.8
66	65	66	3/0ACSR	Overhead Line	34.5	34.500	100.0	3309	-165	3313	-99.28	55.4	0.21	0.1	0.1	20.0
65	BAR RIVER DS HV BUS	65	3/0ACSR	Overhead Line	34.5	34.500	64.0	3309	-165	3313	-99.28	55.4	0.21	0.1	0.1	20.0
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	34.5	34.500	100.0	2394	-474	2441	-97.73	40.8	8.57	0.0	0.1	7.1
63	61	62	3/0ACSR	Overhead Line	34.5	34.500	100.0	2394	-474	2441	-97.73	40.8	8.57	0.1	0.1	14.5
61	VR PRIMARY	61	477ACSR	Overhead Line	34.5	34.500	100.0	2394	-474	2441	-97.73	40.8	8.57	0.0	0.1	7.1
62	VR SECONDARY	62	477ACSR	Overhead Line	34.8	34.500	100.0	0	0	0	0.00	0.0	87.40	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	34.8	34.500	100.0	2394	-423	2431	-98.11	40.4	7.41	0.0	0.1	7.0
76	75	76	477ACSR	Overhead Line	34.7	34.500	51800.0	2394	-423	2431	-98.11	40.4	7.40	9.6	29.3	7.0
77	76	77	556ASC	Overhead Line	34.7	34.500	100.0	2385	-369	2413	-98.45	40.2	5.45	0.0	0.1	6.9
80	542	77	556ASC	Overhead Line	34.7	34.500	100.0	0	0	0	0.00	0.0	86.68	0.0	0.0	0.0
86	542	86	556ASC	Overhead Line	34.4	34.500	100.0	947	243	978	96.85	16.4	-17.30	0.0	0.0	2.5
8	86	8	556ASC	Overhead Line	24.8	25.000	10.0	946	230	974	97.16	22.7	-47.31	0.0	0.0	3.5
7	8	R 2010	556ASC	Overhead Line	24.8	25.000	10.0	946	230	974	97.16	22.7	-47.31	0.0	0.0	3.5
89	R 2010	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	24.8	25.000	50.0	946	230	974	97.16	22.7	-47.31	0.0	0.0	4.5
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	24.8	25.000	185.0	946	230	974	97.16	22.7	-47.31	0.0	0.0	8.3
13	11	13	336AAC	Overhead Line	24.8	25.000	3500.0	946	234	974	97.09	22.7	-47.49	0.2	0.6	4.5
14	13	14	336AAC	Overhead Line	24.8	25.000	5717.0	946	236	975	97.03	22.7	-47.65	0.4	1.1	4.5
15	14	15	35 KV 4/0 CU 100% CN	Cable	24.8	25.000	2345.0	945	239	975	96.95	22.7	-47.91	0.2	0.1	6.1
16	15	16	336AAC	Overhead Line	24.7	25.000	13595.0	945	302	992	95.25	23.1	-51.44	1.0	2.6	4.6
18	17	18	336AAC	Overhead Line	25.2	25.000	25.0	944	310	994	95.00	22.8	-52.04	0.0	0.0	4.5
81	77	81	556ASC	Overhead Line	34.7	34.500	100.0	706	-988	1215	-57.70	20.2	51.08	0.0	0.0	3.6
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.6	12.470	100.0	705	-1002	1225	-55.88	55.9	21.07	0.0	0.1	9.8
82	77	R 052	3/0ACSR	Overhead Line	34.7	34.500	100.0	1678	620	1789	93.75	29.8	-23.60	0.0	0.0	9.9
83	R 052	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	34.4	34.500	41600.0	1678	620	1789	93.74	29.8	-23.61	11.8	14.4	9.9
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	34.4	34.500	100.0	745	252	786	94.41	13.2	-22.34	0.0	0.0	4.6
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.7	12.470	39.9	744	245	783	95.00	35.6	-52.35	0.0	0.0	6.4
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	34.4	34.500	15088.3	921	413	1010	91.25	17.0	-27.77	0.4	1.5	2.6
59	58	VR PRIMARY	477ACSR	Overhead Line	34.5	34.500	24.2	0	-51	51	0.00	0.8	87.39	0.0	0.0	0.1
2024	ER1	58	477ACSR	Overhead Line	34.5	34.500	9412.4	0	-51	51	0.00	0.8	87.39	0.0	0.0	0.1
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	34.6	34.500	22193.7	0	-35	35	0.00	0.6	87.39	0.0	0.0	0.1
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	12.4	12.470	100.0	914	300	962	95.00	44.7	-51.37	0.0	0.1	10.4
71	66	R 2020	3/0ACSR	Overhead Line	34.6	34.500	82.0	711	143	725	98.02	12.1	-14.00	0.0	0.0	3.8
72	R 2020	72	3/0ACSR	Overhead Line	34.5	34.500	29000.0	711	143	725	98.02	12.1	-14.01	1.4	1.7	3.8
73	72	73	556ASC	Overhead Line	34.5	34.500	6391.1	709	183	733	96.82	12.3	-17.19	0.1	0.3	1.9
74	73	SOLAR	556ASC	Overhead Line	34.5	34.500	100.0	-239	0	239	100.00	4.0	177.24	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	34.4	34.500	28445.2	948	193	968	97.98	16.2	-14.25	0.7	2.6	2.5
79	78	542	477ACSR	Overhead Line	34.4	34.500	5072.2	947	236	976	97.04	16.4	-16.84	0.2	0.5	2.6
55	53	ER2	3/0ACSR	Overhead Line	34.8	34.500	144.4	0	-24	24	0.00	0.4	87.96	0.0	0.0	0.1
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	34.8	34.500	14794.7	0	-24	24	0.00	0.4	87.96	0.0	0.0	0.1
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.7	12.470	100.0	279	92	294	95.00	13.3	-49.83	0.0	0.0	4.4

25 07036422

Sub-Transmission Feeder Section Legend

Name	Description
NA1	NORTHERN AVE. FEEDER NO.1
GR1	GARDEN RIVER FEEDER NO.1
ER1	ECHO RIVER FEEDER NO.1
ER2	ECHO RIVER FEEDER NO.2
DB1	DESBARATS FEEDER NO.1
3600	ST. JOSEPH ISLAND 25KV EXPRESS FEEDER 3600



B

Appendix B

HONI Supplied Budget and Scope

CIMA+

Table: HONI Supplied Budget

Category	Total Estimated Cost
Preliminary Engineering & Estimating	$393,000
Project Management	$689,000
Engineering	$799,000
Procurement	$2,060,000
Construction	$2,320,000
Commissioning	$622,000
Direct Cost (Subtotal)	**$6,883,000**
Contingency	$883,000
Removal	-$6,000
Total	**$7,760,000**

The scope of the project includes the following:

1) Addition of a new 230/34.5kV transformer, with adequate foundation, spill containment and its control systems.
2) Remove existing End-of-Life 230kV breaker 556.
3) Addition of two (2) tree-phase 230kV circuit switchers with ground switch.
4) Removal of existing disconnect switch 554.
5) Provide new three-phase wave trap rated at 230kV, between the new transformer and circuit P22G with continuous rating of minimum 1200A.
6) Assess noise levels and provide mitigation measures to meet local by-law requirements and MOE guidelines.
7) Identify equipment and building proximity to the 230/34.5kV transformers and provide fire barriers.
8) Addition of Transformer Surge Protection.
9) Addition of four (4) new 34.5kV disconnect switches.
10) Re-locate existing station service to be electrically between T1-T and switch 561.
11) Provide operational local and remote metering as required in accordance with the SPCN Standards.
12) Perform grounding studies to ensure the station grounding installations are capable of carrying the maximum foreseeable fault current.
13) Obtain necessary Environmental Compliance Approvals.
14) Post In-service checks of all protection, control and telecom equipment are to be performed after commissioning.

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Algoma Power Inc.

Distribution System Plan

Appendix K

API – GREENFIELD TS STUDY REPORT

LICENSED PROFESSIONAL ENGINEER
T. ABDELGALIL
100143354
PROVINCE OF

5	Final Report	08/11/2019	HI	TA	TA
4	Issued for Review	06/11/2019	HI	TA	TA
3	Issued for Review	24/10/2019	HI	TA	TA
2	Issued for Review	23/09/2019	HI	TA	TA
1	Issued for Review	20/08/2019	HI	TA	TA
0	Issued for Review	31/07/2019	HI	TA	TA
REV.	DESCRIPTION	DATE	PRP'D	CHK'D	APPR'D
			SNC-Lavalin		

EXECUTIVE SUMMARY

Algoma Power Inc. (API) has major concerns related to supply contingency for Goulais TS and Batchawana TS systems. API engaged SNC-Lavalin to undertake this study with the objective of performing techno-economic analysis to evaluate possible system configurations to feed both service areas based on the following three options:

Option 1: Establishing a new two-element substation near Goulais TS and identifying the associated distribution system modifications. Two scenarios are evaluated:

Scenario 1-A: Keeping the voltage of the distribution feeders at 12.5kV
Scenario 1-B: Voltage uprating of the distribution feeders to 25kV

Option 2: Refurbishing the existing Goulais TS and Batchawana TS and identifying the associated distribution system modifications in case Batchawana TS operates as a back-up for Goulais TS. Two scenarios are evaluated:

Scenario 2-A: Keeping the voltage of the distribution feeders at 12.5kV
Scenario 2-B: Voltage uprating of the distribution feeders to 25kV

Option 3: Establishing a new two-element substation near Goulais TS with two outgoing feeders and identifying the associated distribution system modifications. One outgoing feeds Goulais TS load at 12.5kV. Batchawana TS load is fed through the other 25kV express feeder.

OPTION 1: Establishing a new two-element substation near Goulais TS

The analysis performed in this option considered a single supply point to feed both service areas of Goulais TS and Batchawana TS. The proposed substation is located south of Goulais TS. The analysis performed considered operating the system at 12.5kV or 25kV.

OPTION 1-A: Operating the system at 12.5kV

In addition to the cost of the new substation, this option also entails additional system reinforcements and the cost associated with converting a portion of the system to three-phase in order to allow power transfer on all three phases.

Table ES-1 Upgrade Cost for Option 1-A

Upgrade	Technical Justification	Cost ($)
Several Shunt capacitors and voltage regulators installation	Voltage profile improvement	932,000
New Substation (3-breaker configuration)*	Replacing the existing substations	10,300,000
Converting a portion of the system to three-phase	Allow transfer of power on three phases	4,000,000
Total Cost		15,232,000

* From Development of Greenfield Transmission Station Feasibility Study

OPTION 1-B: Operating the system at 25kV

In addition to the cost of the new substation, this option also entails replacing transformers with 12.5kV primary with new ones having 25kV primary voltage rating. In addition, the cost associated with converting a portion of the system to three-phase is considered.

Table ES-2 Upgrade Cost for Option 1-B

Upgrade	Technical Justification	Cost ($)
New Substation (3-breaker configuration)*	Replacing the existing substations	10,300,000
Replacement of distribution transformers with 12.5kV primary voltage to 25kV	Transformers primary voltage to match system operating voltage	3,430,000**
Converting a portion of the system to three-phase	Allow transfer of power on all three phases	4,000,000
Total Cost		17,730,000

* From Development of Greenfield Transmission Station Feasibility Study
** In recent years, API has been procuring and installing dual-voltage transformers. Based on an equipment report, 1429 transformers need to be replaced in both areas.

OPTION 2: Refurbishing the Existing Goulais TS and Batchawana TS

In this option, the existing vintage equipment in both substations will be replaced with new equipment. Technical analysis is performed to examine the system in case of operating Batchawana TS as a back-up in case of loss of Goulais TS. The results indicate that this would be a viable option only if the system voltage is converted to 25kV.

OPTION 2-A: Operating the system at 12.5kV

The system is inoperable with Batchawana TS operating as a back-up for Goulais TS at this voltage level. The system would operate with its normal in which each substation feeds its service area. In this option, the cost is that associated with replacing vintage equipment in both substations.

Table ES-3 Upgrade Cost for Option 2-A

Upgrade	Justification	Cost ($)
Refurbishing the existing Goulais TS	Replacing vintage equipment	4,700,000
Refurbishing the existing Batchawana TS	Replacing vintage equipment	2,500,000
Reinforcements with normal configuration*	Voltage profile improvement	550,000
Total Cost		7,750,000

* From Distribution System Planning Study

OPTION 2-B: Operating the system at 25kV

With voltage uprating to 25kV, Batchawana TS can operate as a back-up in case of loss of Goulais TS. However, a large number of elements would experience thermal violation due to overloading and should be considered for replacement with properly-sized replacements. Alternatively, Batchawana TS can feed its load and 50% of Goulais TS load without any thermal violations. The following table lists the costs associated with this option.

Table ES-4 Upgrade Cost for Option 2-B

Upgrade	Justification	Cost ($)
Refurbishing the existing Goulais TS	Replacing vintage equipment	4,700,000
Refurbishing the existing Batchawana TS	Replacing vintage equipment	2,500,000
Reinforcements with normal configuration*	Voltage profile improvement	550,000
Several shunt capacitors/regulars to support voltage under back up operation	Voltage profile improvement	676,000
Replacement of distribution transformers with 12.5kV primary voltage to 25kV	Transformers primary voltage to match system operating voltage	3,430,000**
Converting a portion of the system to three-phase	Allow transfer of power on all three phases	4,000,000
Total Cost		15,856,000

* From Distribution System Planning Study
** In recent years, API has been procuring and installing dual-voltage transformers. Based on an equipment report, 1429 transformers need to be replaced in both areas.

OPTION 3: Establishing a new two-element substation near Goulais TS with 25kV Express Feeder

The analysis performed in this option considered a single supply point to feed both service areas of Goulais TS and Batchawana TS. The proposed substation is located south of Goulais TS (like in Option 1). Greenfield TS would operate at 25kV with two outgoing feeders. On one feeder, the voltage is stepped down to 12.5kV and the feeder is connected to the existing Goulais TS service area, such that its load is fed at 12.5kV. The step-down transformers would be located within Greenfield TS. The other 25kV outgoing would be an express feeder running in parallel with the existing feeders till the location of the tie coupling the two service areas, and would then feed the Batchawana TS service area at 25kV.

In addition to the cost of the new substation, this option also entails additional system reinforcements and the cost associated with the new express feeder and converting a portion of the system to three-phase in order to allow power transfer on all three phases to Batchawana TS service area.

Table ES-1 Upgrade Cost for Option 3

Upgrade	Technical Justification	Cost ($)
Several Shunt capacitors installation	Voltage profile improvement	421,000
New Substation (3-breaker configuration)*	Replacing the existing substations	10,300,000
Two 12MVA, 25/12.5kV transformers and relevant buswork, site, concrete work, .etc	Voltage step down to feed Goulais TS load	1,500,000
Replacement of distribution transformers with 12.5kV primary voltage to 25kV	Transformers primary voltage to match system operating voltage	718,000**
Converting a portion of the system to three-phase and new express feeder	Allow transfer of power on three phases	4,000,000
Total Cost		16,939,000

* From Development of Greenfield Transmission Station Feasibility Study

** In recent years, API has been procuring and installing dual-voltage transformers. Based on an equipment report, 299 transformers need to be replaced in Batchawana area.

In all options, estimation of the cost of converting a portion of the system to three-phase is based on a new line. Old poles cannot be utilized as longer ones would be required because of the existing communication lines. Estimation of the cost in options 1 and 2 is based on a total length of about 20km and a cost of $200/m [4]. For option 3, the estimation is based on 10km of lines to be converted to three-phase, in addition to 10km new express feeder and a cost of $200/m [4].

Table ES-5 Comparison of Options

Option	Option 1-A	Option 1-B	Option 2-A	Option 2-B	Option 3
Total Cost	$15.232M	$17.73M	$7.75M	$15.856M	$16.939M
Technical Analysis/Limitation	No back-up in case of loss of Greenfield TS	No back-up in case of loss of Greenfield TS	- The system operates with the current configuration - Batchawana TS cannot operate as back-up for Goulais TS	- The system operates with the current configuration - Batchawana TS can operate as back-up for Goulais TS	No back-up in case of loss of Greenfield TS

Conclusions and Recommendations

With only the new substation feeding both service areas, the cost would be approximately $15.3M with 12.5kV system voltage (Option 1-A). This will result in lower voltage profile in several areas of the system that would require voltage support via a mix of the voltage regulator and shunt capacitors.

Converting system voltage to 25kV (Option 1-B) will improve the voltage profile and eliminate the need for extra shunt capacitors and voltage regulator and will cost about $17.8M.

On the other hand, in the refurbishment option, the system would operate with its current (normal) configuration. This results in lower costs (expected cost is approximately $8M for Option 2-A).

Moreover, Batchawana TS can operate as a back-up and feed half Goulais TS load without thermal violations and provide supply redundancy. This requires system modifications that would cost almost additional $7.9M, which will bring the total cost for Option 2-B to about $15.9M.

For Option 3, Batchawana TS service area is fed at 25kV with no voltage violations observed. Some system reinforcements are required in Goulais TS area. The cost of this option would be in the order of $17M, which is mainly because of the new Greenfield TS, new express feeder and the portion to be converted to three-phase in Batchawana TS area.

Hence, we recommend refurbishing the existing substations with distribution system upgrades (Option 2) over building a new substation to feed both service areas (Options 1 and 3).

CONTENT

LIST OF FIGURES

LIST OF TABLES

1 Introduction

This is a draft report of the study entitled "**Greenfield TS Study,**" which commenced on July 2019. This study, undertaken at the request of Algoma Power Inc. (API) is conducted by SNC-Lavalin Inc. Toronto, Canada, as the Consultant.

1.1 Background and Drivers

Algoma Power Inc. (API) has had major concerns related to supply contingency for Goulais TS and Batchawana TS systems. The main issues identified are:

1. In the Distribution System Planning Study previously performed by SNC Lavalin, it was recommended to establish a new supply point to feed both service areas because of the findings from the outage information and the fact that both substations have been in service for more than 40 years [1].
2. In addition to the fact that equipment in both substations are approaching their end of life, a previous feasibility study highlighted the growing need for maintenance for reliable operation of both substations. The operational restrictions resulting in extended outages were discussed, and the study concluded that replacement of both substations with a single transmission station improves system availability and provides a greater margin for load growth [2].
3. Batchawana TS transformers are mismatched in terms of rated power and impedance.
4. Single-phase tie between the two service areas greatly affects the transfer capability between the two stations.

API engaged SNC-Lavalin to undertake this study with the objective of performing techno-economic analysis to evaluate possible system configurations to feed both service areas based on the following three options:

> Option 1: Establishing a new two-element substation near Goulais TS and identifying the associated distribution system modifications. Two scenarios to be evaluated:

Scenario 1-A: Keeping the voltage of the distribution feeders at 12.5kV
Scenario 1-B: Voltage uprating of the distribution feeders to 25kV

> Option 2: Refurbishing the existing Goulais TS and Batchawana TS and identifying the associated distribution system modifications in case Batchawana TS operates as a back-up for Goulais TS. Two scenarios to be evaluated:

Scenario 2-A: Keeping the voltage of the distribution feeders at 12.5kV
Scenario 2-B: Voltage uprating of the distribution feeders to 25kV

> Option 3: Establishing a new two-element substation near Goulais TS with 25kV Express Feeder to Batchawana TS service area

1.2 Description of Goulais TS and Batchawana TS Service Territories

Figure 1-1 shows the service areas of Goulais TS and Batchawana TS and the transmission corridor (in red) owned by Hydro One.Two 12.5kV and one 25kV feeders are supplied from Goulais TS (refer to SLD in Appendix-B). Single-phase feeding in Goulais TS service area extends to relatively long distances contributing considerably to voltage deviations. For instance, more than 27.7km, 26km and 24km of Phase-B and 15.7km of Phase-C.

For Batchawana TS, there are two outgoing 7.2kV single-phase feeders (refer to SLD in Appendix-B). Also, Phase-B supply extends to more than 10km, while Phase-C extends to more than 35km. This highly affects the voltage profiles of these single-phase fed areas.

The single-line diagram showing the tie of both substations to the 115kV transmission line is presented in Figure 1-2.

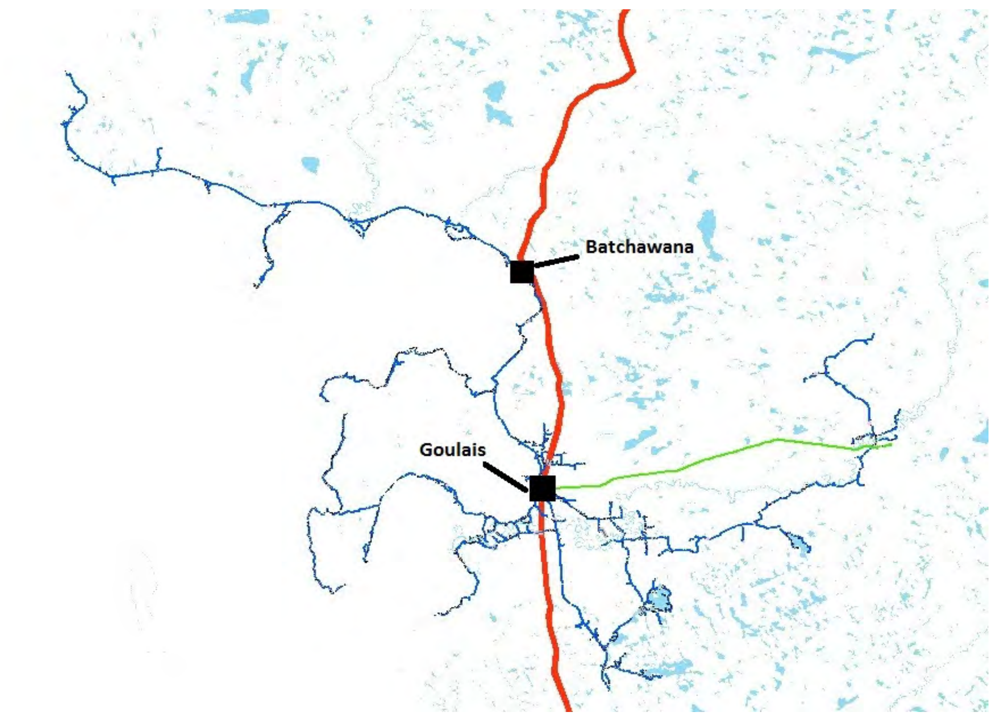


Figure 1-1 Goulais and Batchawana Service Areas

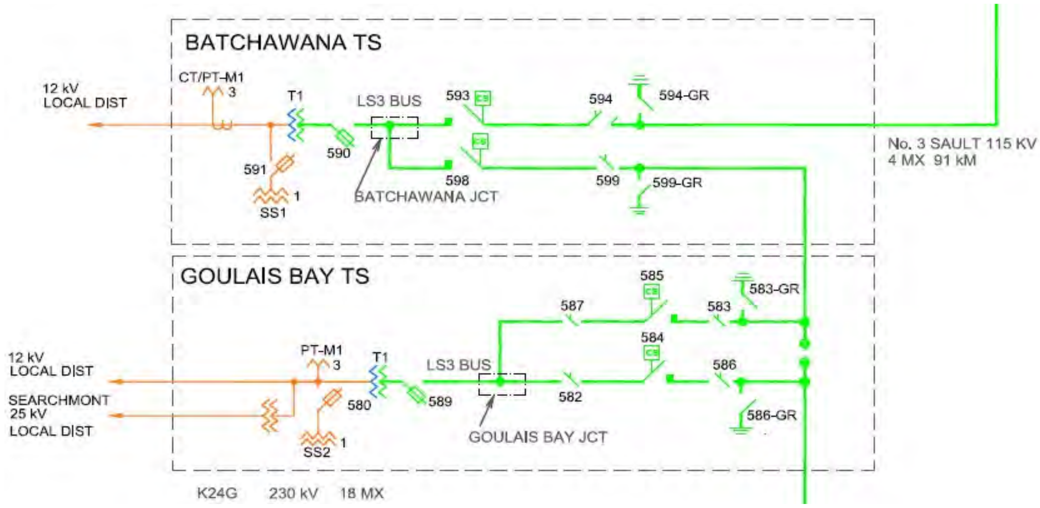


Figure 1-2 Goulais TS and Batchawana Single-line Diagram

1.3 Scope of Work

Option 1: Establishing a new two-element substation near Goulais TS

1. Updating the existing system model to include the new substation and modifying the distribution system.
2. Technical analysis to identify issues (equipment overloading, voltage violations) for the new model with the current and forecasted load.
3. Defining system upgrade alternatives (distribution voltage levels and line configurations). With the current system configuration, major distribution system modifications might be necessary.
4. Costing of different viable alternatives.

Option 2: Refurbishing the existing Goulais TS and Batchawana TS

1. Defining the replacement or upgrade of equipment in Goulais TS and Batchawana TS.
2. Updating existing system models and technical evaluation of the proposed alternatives.
3. Evaluating reinforcement of the 12.5kV system between Goulais and Batchewana such that Batchawana TS can operate as a back-up to Goulais TS and identifying the level and type of distribution system enhancement required to enable such back-up.
4. Costing of different viable alternatives

Option 3: Establishing a new two-element substation near Goulais TS with 25kV Express Feeder to Batchawana TS service area

1. Updating the existing system model to include the new substation, new 25kV express feeder and modifying the distribution system.
2. Technical analysis to identify issues (equipment overloading, voltage violations) for the new model with the current and forecasted load.
3. Defining system upgrades.
4. Costing of different viable alternatives.

Technical and economic analyses of the alternatives to select the most viable option based on these perspectives.

2 Assumptions and Criteria

2.1 Assumptions

System Construction

The following is assumed pertaining to system construction:

1. The system is built with an insulation level of 28kV.
2. Though the SLD of Goulais TS does not show a distribution neutral on the 25kV feeder, it is confirmed that a distribution neutral exists.
3. The Windmil model of the voltage regulators added for voltage improvement follows the definition VR-44. The rating is 150A, percent boost is 10%, the step size is 32, and bandwidth is 24V.
4. The location of the proposed Greenfield TS is expected to be located south of Goulais Bay TS, adjacent to Highway 552, on the right of way (ROW) corridor for the K24G 230KV transmission line and No.3 Sault 115kV transmission line [2]. The exact location used in Windmill model is shown in Figure 2-1.

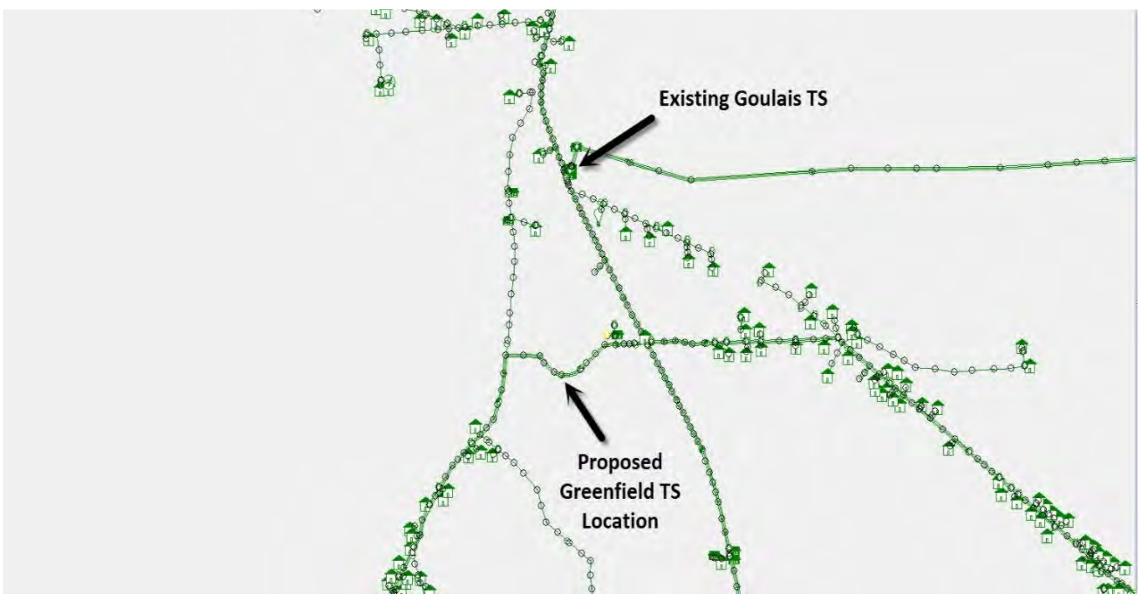


Figure 2-1 Proposed Greenfield TS Location

Because of the selected location, the distribution lines and series switches between Goulais TS and Batchawana TS should entirely be converted to three-phase lines in either of the first two options studied to allow power transfer on all three phases. The same applies for Option 3 to the lines between the tie coupling the two service aeas and Batchawana TS.

5. In Option 2, the system is examined in case Batchawana TS is operated as a back-up in case of loss of Goulais TS to feed both service areas.

Load Allocation Methodology and Data

The billing load data are integrated into the Milsoft Windmil model of the system. Load allocation analysis is performed to export the billing load data to the connected load of each consumer while maintaining the active and reactive powers injected by each control point (previously-mentioned supply points) during peak period to the following values as reported by API:

Table 2-1 Peak Active and Reactive Powers injected by Control Points

Supply Point	Peak (kW)	Peak (kVAr)
Batchewana TS	1,518.04	510.40
Goulais TS	8,916.60	1,932.40

Additional fine-tuning is performed in the Goulais service area. The load allocation downstream of the two feeders, OHG2I5121D-1 and OHH1I5112-1, is adjusted from the anomalies reported on January 6, 2018 which showed coincident peaks of 740kVA and 1020kVA respectively. Eleven peaks were provided by API. The non-coincident second peaks (613kVA and 802kVA respectively) are selected to represent the load downstream these two feeders, as this scenario resulted in the closest voltage profile to meter data. The model is validated by performing load flow analysis and comparing a set of calculated consumer voltages with meter data.

Load Forecast

The forecasted load in each of the substations service areas for the next 15 years is provided and summarized in the following table.

Table 2-2 15-year Forecasted Load in MW

Year	Batchawana	Goulais	Year	Batchawana	Goulais
2018	1.5	8.2	2026	1.6	8.9
2019	1.5	8.3	2027	1.6	9
2020	1.5	8.4	2028	1.7	9.1
2021	1.5	8.4	2029	1.7	9.1
2022	1.6	8.5	2030	1.7	9.2
2023	1.6	8.6	2031	1.7	9.3
2024	1.6	8.7	2032	1.7	9.4
2025	1.6	8.8	2033	1.7	9.5

2.2 Study Criteria

Thermal Criteria

Load flow analysis is performed for all scenarios to identify any thermal violations as per the following criteria:

Thermal Loading Criteria require that the continuous thermal rating of an element is not exceeded under different operating scenarios. Thermal limits are assumed to be 100% of the respective normal ratings. Emergency limits are not considered in the evaluation.

Voltage Criteria

Load flow analysis is performed for all scenarios to identify any voltage violations as per the following criteria:

The voltage criterion follows the CSA Standards[1], which limits the changes in the voltage at ±6% from the primary feeder nominal voltage.

[1] CSA CAN3-C235-83 Preferred Voltage Levels for AC Systems, 0 to 50,000 V

3 Existing System Adequacy

Load flow analysis is performed with the current year load for both substations. The main voltage deviations on the primary side are shown in Figure 3-1 and Figure 3-2. The red areas are experiencing voltages lower than 94%.

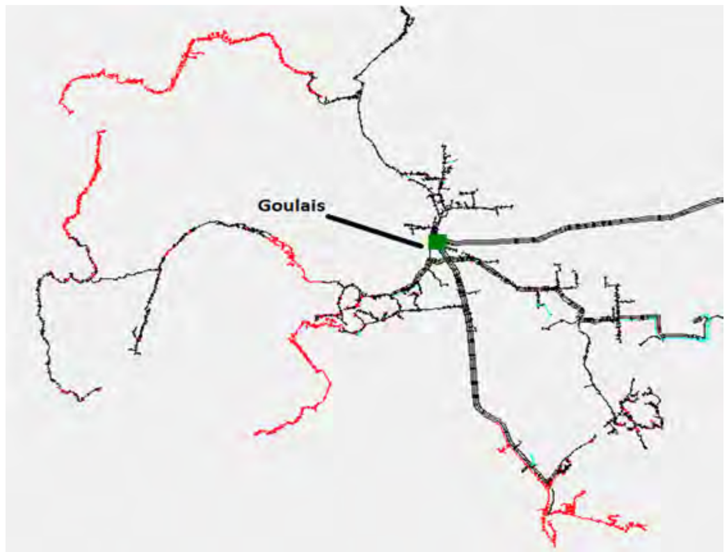


Figure 3-1 Goulais Service Area Voltage Profile – Current Load

Figure 3-2 Batchawana Service Area Voltage Profile – Current Load

The following table summarizes the lowest voltages encountered on the primary side (2.4kV and above) by analyzing the existing system with the current load. The table shows the voltages in % and the relevant phase. No thermal violations are encountered with the existing system current load.

Table 3-1 Summary of Lowest Primary Voltages – Current Load

Substation	Normal Configuration
Goulais	88.8% Phase-B
Batchawana	88.3% Phase-C

4 Analysis Development

The following sections present the analysis findings and the required system reinforcements to meet the voltage drop criteria. Also, thermal violations are presented in Appendix-A.

4.1 Option 1: Establishing a new two-element substation near Goulais TS

Windmill model is updated to include the new substation at the proposed location to feed both service areas with present system load. The system would experience major voltage violations, especially in remote areas within the Batchawana TS service area. To overcome the voltage violations, the following developments are proposed.

Operating the system at 12.5kV (Option 1-A)

Keeping the outgoing feeders operating at a voltage level of 12.5kV would require the following reinforcements to be applied to the system in order to overcome the voltage violations:

Table 4-1 Recommended Reinforcements at 12.5kV with Present Load (Option 1)

#	Item Description	Rating	Phase(s)	Location
1	Shunt Capacitor	400kVAr	C	Pole PJ4H5221-147A
2	Shunt Capacitor	400kVAr	C	Pole PJ4H5221-51
3	Shunt Capacitor	400kVAr	B	Pole PH3H5112H-134A
4	Shunt Capacitor	800kVAr	B	Pole PH3H5112H-43
5	Shunt Capacitor	400kVAr	B	Pole PH1I5112-51
6	Shunt Capacitor	200kVAr	B	Pole PG3H5121B8-14
7	Shunt Capacitor	600kVAr	C	Pole PG3H5120B5-75
8	Shunt Capacitor	800kVAr	BC*	Pole PF3I5121G1-4
9	Series Voltage regulator	3.2MVA**	BC	Between lines OHH1I5112-73 & OHH1I5112-74
10	Series Voltage regulator	1.6MVA**	BC	Between lines OHI2I5210-78 & OHI2I5210-77

*Split equally between phases

**Higher rating is required with the forecasted system load

Furthermore, Table 0-1 in Appendix-A lists all the elements operating beyond their capacities in this scenario. The overall conductor length is about 9.8km.

Similar analysis is performed to the modified Windmil model with the forecasted system load considered. In addition to the reinforcements listed in Table 4-1, the following capacitors are necessary. Also, higher ratings are required for voltage regulators:

Table 4-2 Recommended Reinforcements at 12.5kV with Forecasted Load (Option 1)

#	Item Description	Rating	Phase(s)	Location
1	Shunt Capacitor	200kVAr**	B	Pole PH1I5112-51
2	Shunt Capacitor	400kVAr**	B	Pole PG3H5121B8-14
3	Shunt Capacitor	200kVAr**	C	Pole PG3H5120B5-75
4	Shunt Capacitor	200kVAr**	BC*	Pole PF3I5121G1-4
5	Shunt Capacitor	200kVAr	A	Pole PG2J5123A-149
6	Series Voltage regulator	3.5MVA	BC	Between lines OHH1I5112-73 & OHH1I5112-74
7	Series Voltage regulator	1.75MVA	BC	Between lines OHI2I5210-78 & OHI2I5210-77

*Split equally between phases

**This is in addition to the Capacitors on the same pole recommended with present system load listed in Table 4-1

Furthermore, Table 0-3 in Appendix-A lists all the elements operating beyond their capacities in this scenario. The overall conductor length is about 10km.

Operating the system at 25kV (Option 1-B)

Voltage uprating to 25kV was examined as a possible solution to improve voltage profile. The results show that the system can operate with no voltage violations with voltage conversion to 25kV. This, however, requires the change of distribution transformers to have the proper primary voltage rating. In recent years, API has been procuring and installing dual-voltage transformers. The remaining 1429 transformers in both areas (as per API equipment report) should also be replaced.

Furthermore, Table 0-2 in Appendix-A lists all the elements operating beyond their capacities in this scenario. The overall conductor length is about 0.5km.

Similar analysis is performed to the modified Windmil model with the forecasted system load considered. The results show that the system can operate with no voltage violations with voltage conversion to 25kV.

Furthermore, Table 0-4 in Appendix-A lists all the elements operating beyond their capacities in this scenario. The overall conductor length is about 0.8km.

4.2 Option 2: Refurbishing the existing Goulais TS and Batchawana TS

Windmill model is updated so that Batchawana TS operates as a back-up in case of loss of Goulais TS and feeds both service areas. The results are as follows:

Operating the system at 12.5kV (Option 2-A)

With the outgoing feeders operating at a voltage level of 12.5kV, the system fails to converge to a load flow solution.

Similar analysis is performed to the modified Windmil model with the forecasted system load considered. With a larger load on the system, the system diverges more rapidly, and no-load flow solution is reached. So, Batchawana TS cannot operate as a back-up to Goulais TS by feeding both service areas if the system is operating at 12.5kV.

Operating the system at 25kV (Option 2-B)

Voltage uprating to 25kV was examined as a possible solution to find a load flow solution. The results show that the system needs voltage conversion in addition to some reinforcements as listed in Table 4-3.

Table 4-3 Recommended Reinforcements at 25kV with Present Load (Option 2)

#	Item Description	Rating	Phase(s)	Location
1	Shunt Capacitor	400kVAr	B	Pole PH3H5112H-43
2	Shunt Capacitor	100kVAr	B	Pole 34779
3	Series Voltage regulator	8.4MVA*	AB	Between lines OHH1I5112-73 & OHH1I5112-74
4	Series Voltage regulator	10MVA*	B	Between lines OHI2I5210-78 & OHI2I5210-77

*Higher rating is required with forecasted system load

Furthermore, Table 0-5 in Appendix-A lists all the elements operating beyond their capacities in this scenario. The overall conductor length is about 13km.

Similar analysis is performed to the modified Windmil model with the forecasted system load considered. The results show that the system needs voltage conversion in addition to some reinforcements as listed in Table 4-4.

Table 4-4 Recommended Reinforcements at 25kV with Forecasted Load (Option 2)

#	Item Description	Rating	Phase(s)	Location
1	Shunt Capacitor	400kVAr*	B	Pole PH3H5112H-43
2	Shunt Capacitor	300kVAr*	B	Pole 34779
3	Series Voltage regulator	9.6MVA	AB	Between lines OHH1I5112-73 & OHH1I5112-74
4	Series Voltage regulator	11.4MVA	B	Between lines OHI2I5210-78 & OHI2I5210-77
5	Series Voltage regulator	6.7MVA	B	Between lines OHH1I5120-21 & OHH1I5120-22

*This is in addition to the Capacitors on the same pole recommended with present system load listed in Table 4-3

Furthermore, Table 0-6 in Appendix-A lists all the elements operating beyond their capacities in this scenario. The overall conductor length is about 17.5km.

In recent years, API has been procuring and installing dual-voltage transformers. In addition to the above-mentioned reinforcements in both scenarios, the remaining 1429 transformers in both areas (as per API equipment report) should also be replaced. Moreover, Batchawana TS can feed its load and 50% of Goulais TS load without thermal violations in both scenarios.

4.3 Option 3: Establishing a new two-element substation near Goulais TS with Express Feeder to Batchawana TS Service Area

The analysis is discussed in Appendix-D.

5 Summary

5.1 System Modifications

1. In Option 1, a new supply point (Greenfield TS) is proposed to feed both service areas of Goulais TS and Batchawana TS. With this configuration, the system experiences major voltage violations. The following are the options examined to improve the voltage profile:
   a. Operating the system at 12.5kV (Option 1-A)
      The following reinforcements are required to bring the voltage profile within acceptable limits:

Table 5-1 Recommended Reinforcements at 12.5kV (Option 1-A)

#	Item Description
1	400kVAr, 7.2kV, single-phase capacitor bank at pole PJ4H5221-147A in Batchawana.
2	400kVAr, 7.2kV, single-phase capacitor bank at pole PJ4H5221-51 in Batchawana.
3	400kVAr, 7.2kV, single-phase capacitor bank at pole PH3H5112H-134A in Goulais.
4	800kVAr, 7.2kV, single-phase capacitor bank at pole PH3H5112H-43 in Goulais.
5	400kVAr, 7.2kV, single-phase capacitor bank at pole PH1I5112-51 in Goulais.
6	200kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5121B8-14 in Goulais.
7	600kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5120B5-75 in Goulais.
8	800kVAr, 7.2kV, two-phase capacitor bank at pole PF3I5121G1-4 in Goulais.
9	200kVAr, 7.2kV, single-phase capacitor bank at pole PH1I5112-51 in Goulais.
10	400kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5121B8-14 in Goulais.
11	200kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5120B5-75 in Goulais.
12	200kVAr, 7.2kV, single-phase capacitor bank at pole PF3I5121G1-4 in Goulais.
13	200kVAr, 7.2kV, single-phase capacitor bank at pole PG2J5123A-149 in Goulais.
14	4MVA, 12.5kV, two-phase voltage regulator between lines OHH1I5112-73 & OHH1I5112-74 in Goulais.
15	2MVA, 12.5kV, two-phase voltage regulator between lines OHI2I5210-78 & OHI2I5210-77 in Batchawana.

   b. Operating the system at 25kV (Option 1-B)
      No system reinforcements are required in this scenario. However, the replacement of 1429 distribution transformers with ones with the proper primary voltage rating is necessary to match the system operating voltage.

2. In Option 2, the existing vintage equipment in both substations will be replaced with new equipment. The system will operate with its current configuration; i.e., each substation feeds its own service area. The reinforcements required for the system are as follows [1]:

Table 5-2 Recommended Reinforcements for System Current Configuration

#	Item Description	System Load
1	400kVAr, 7.2kV, single-phase capacitor bank at pole PH3H5112H-43 in Goulais.	Present load
2	600kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5121B8-14 in Goulais.	Present load
3	400kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5120B5-75 in Goulais.	Present load
4	400kVAr, 7.2kV, two-phase capacitor bank at pole PF3I5121G1-4 in Goulais.	Present load
5	600kVAr, 7.2kV, single-phase capacitor bank at pole PJ4H5221-149 in Batchawana.	Present load
6	200kVAr, 7.2kV, single-phase capacitor bank at pole PJ4H5221-51 in Batchawana.	Forecasted load
7	200kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5121B8-14 in Goulais.	Forecasted load
8	200kVAr, 7.2kV, two-phase capacitor bank at pole PF3I5121G1-4 in Goulais.	Forecasted load
9	200kVAr, 7.2kV, single-phase capacitor bank at pole PG3J5123A9-33 in Goulais.	Forecasted load

The system is examined in case of loss of Goulais TS. Batchawana TS operates as back-up to feed both service areas. The results indicate that the system cannot operate at 12.5kV as there is no load flow solution then. Batchawana operating as back-up would be a viable option only if system voltage conversion to 25kV is considered. Also, 1429 distribution transformers should be replaced to match the system operating voltage in addition to the following reinforcements:

Table 5-3 Recommended Reinforcements at 25kV (Option 2-B)

#	Item Description
1	400kVAr, 14.4kV, single-phase capacitor bank at pole PH3H5112H-43 in Goulais.
2	100kVAr, 14.4kV, single-phase capacitor bank at pole 34779 in Goulais.
3	400kVAr, 14.4kV, single-phase capacitor bank at pole PH3H5112H-43 in Goulais.
4	200kVAr, 14.4kV, single-phase capacitor bank at pole 34779 in Goulais.
5	10MVA, 25kV, two-phase voltage regulator between lines OHH1I5112-73 & OHH1I5112-74 in Goulais.
6	12MVA, 25kV, two-phase voltage regulator between lines OHI2I5210-78 & OHI2I5210-77 in Batchawana.
7	7MVA, 25kV, two-phase voltage regulator between lines OHH1I5120-21 & OHH1I5120-22 in Goulais.

3. In Option 3, a new supply point (Greenfield TS) is proposed to feed both service areas of Goulais TS and Batchawana TS. Greenfield TS would operate at 25kV with two outgoing feeders. On one feeder, the voltage is stepped down to 12.5kV and the feeder is connected to the existing Goulais TS service area, such that its load is fed at 12.5kV. The step-down transformers would be located within Greenfield TS. The other 25kV outgoing would be an express feeder running in parallel with the existing feeders till the location of the tie coupling the two service areas, and would then feed the Batchawana TS service area at 25kV. Hence, 299 distribution transformers within Batchawana area should be replaced to match the system operating voltage in addition to the following reinforcements:

Table 5-4 Recommended Reinforcements at 12.5kV (Option 3)

#	Item Description
1	400kVAr, 7.2kV, single-phase capacitor bank at pole PH3H5112H-134A in Goulais.
2	800kVAr, 7.2kV, single-phase capacitor bank at pole PH3H5112H-43 in Goulais.
3	600kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5121B8-14 in Goulais.
4	800kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5120B5-75 in Goulais.
5	800kVAr, 7.2kV, two-phase capacitor bank at pole PF3I5121G1-4 in Goulais.
6	200kVAr, 7.2kV, single-phase capacitor bank at pole PG3J5123A9-33 in Goulais.

4. In Options 1-A, 1-B, and 2-B, the lines and series switches between Goulais TS and Batchawana TS should be converted to three-phase lines to allow power transfer on all three phases. The portion of the system to be converted to three-phase is shown in orange in Figure 5-1 (about 20km).

   In Option 3, the lines and series switches between Batchawana TS and the location of the tie coupling the two service areas should be converted to three-phase to allow power transfer to Batchawana area on all phases. The portion of the system to be converted to three-phase is shown in orange in Figure 5-2 (about 10km).

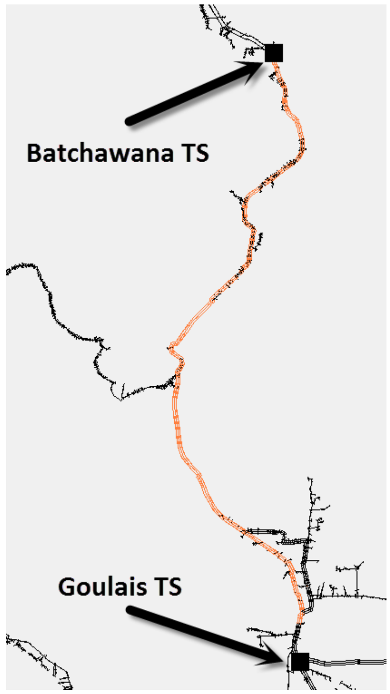


Figure 5-1 Portion of the System to be converted to Three-phase in Options 1-A, 1-B, and 2-B

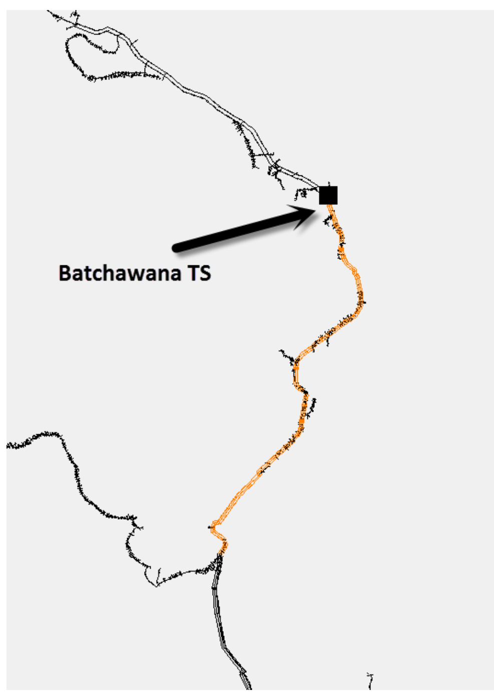


Figure 5-2 Portion of the System to be converted to Three-phase in Option 3

5. It is expected that detailed engineering studies will be carried out before the shunt capacitor deployment to ensure they do not cause any power quality violations for end customers. Further analysis to investigate the impact of shunt capacitors on system power quality (transients, harmonics, and flicker) should be conducted at a later stage to ensure the addition of large capacitors would not negatively impact distribution system reliability and quality of supply.

6. The elements experiencing thermal violations are listed in Appendix-A for each scenario in all options. The root cause of a large number of elements operating beyond their capacities is load unbalance. The loading on each phase per scenario is summed up inTable 5-5. Load unbalance reaches 155% in Option 2-B with forecasted load. Reallocating the loads between phases would enhance the system from the operation perspective in terms of voltage profile and thermal violations. However, this will come at a cost because the system is mostly single-phase in nature. In Goulais, single-phase feed with phase-B extends to more than 154km and with phase-C to more than 47km. In Batchawana, single-phase feed with phase-C extends to more than 92km. So, additional cost associated with conversion to three-phase or two-phase feed will be necessary to achieve load balancing.

Table 5-5 Phase Loading per Scenario

Option	Scenario	TS	System Load	Phase-A Load (MVA)	Phase-B Load (MVA)	Phase-C Load (MVA)
1	1-A	Greenfield	Present	2.2	5.9	3.8
		Greenfield	Forecasted	2.5	6.6	4.4
	1-B	Greenfield	Present	2.3	5.3	3.5
		Greenfield	Forecasted	2.6	5.8	3.9
2	2-B	Batchawana	Present	2.4	5.9	3.4
		Batchawana	Forecasted	2.7	7	3.8
3	-	Greenfield	Present	2.1	5.1	3.3
		Greenfield	Forecasted	2.4	5.9	3.9

7. Options 1-A, 1-B, and 2-B assessed in this study show that major modifications might be necessary if these options are considered. The analysis shows that a large number of system elements (listed in Appendix-A) would be operating beyond their thermal capacity limits, and hence, should be considered for replacement. Alternatively, in Option 2-B, Batchawana TS can feed its load and 50% of Goulais TS load without thermal violations.

5.2 Total System Power Losses

The total active power losses for each scenario are summarized in Table 5-6.

With Greenfield TS feeding both service areas in option 1, operating the system at 25kV (scenario 1-B) results in 71.2% improvement in active power losses as opposed to operating it at 12.5kV (scenario 1-A) with either present or forecasted load. The losses reported for option 2 are the losses in normal system configuration where each of Goulais TS and Batchawana TS feeds its service area at 25kV.

Table 5-6 System Power Losses per Scenario

Option	Scenario	TS	System Load	Losses (kW)	Load (kW)	Active Power Losses (%)
1	1-A	Greenfield	Present	1927	11880.75	16.22
		Greenfield	Forecasted	2363	13343.87	17.71
	1-B	Greenfield	Present	555	11004.67	5.04
		Greenfield	Forecasted	681	12170.6	5.60
2*	2-B	Goulais and Batchawana	Present	488	11135.5	4.4
		Goulais and Batchawana	Forecasted	621	12448.33	5
3	-	Greenfield	Present	1186	10467.05	11.33
		Greenfield	Forecasted	1524	12235.3	12.46

*Losses in normal system configuration where each of Goulais TS and Batchawana TA feeds its service area at 25kV

5.3 Cost Estimate

Assumptions

1. The new substation configuration is a 3-breaker configuration.
2. The portion of the system to be converted to three-phase is considered as a new line. Old poles cannot be utilized as longer ones would be required because of the existing communication lines. Estimation of the cost in options 1 and 2 is based on a total length of about 20km and a cost of $200/m [4]. For option 3, the estimation is based on 10km of lines to be converted to three-phase, in addition to 10km new express feeder and a cost of $200/m [4].
3. For option 2, the estimate includes the cost of replacing only equipment with similar ratings and similar functionality/mounting, which will enable the use of existing structure/foundations with minor repair works.
4. For option 2, it is assumed that there is no control building to be replaced.
5. For option 2, construction, engineering, and project management and project control (PMPC) costs are estimated to be 35%, 15%, and 7.5% of the equipment cost respectively.
6. Equipment cost is estimated/adjusted based on offers for similar projects/applications.
7. The estimated annual O&M costs due to additional equipment (regulators and capacitors) are based on $2,200/device plus 5% contingency.
8. The O&M costs of substation equipment are assumed to be comparable in all options. Hence, they are excluded from the analysis.

Option 1-A

Table 5-7 Cost Estimate of Option 1-A

Upgrade	Cost ($)
400kVAr, 7.2kV, single-phase capacitor bank at pole PJ4H5221-147A in Batchawana	55,000
400kVAr, 7.2kV, single-phase capacitor bank at pole PJ4H5221-51 in Batchawana	55,000
400kVAr, 7.2kV, single-phase capacitor bank at pole PH3H5112H-134A in Goulais	55,000
800kVAr, 7.2kV, single-phase capacitor bank at pole PH3H5112H-43 in Goulais	73,000
400kVAr, 7.2kV, single-phase capacitor bank at pole PH1I5112-51 in Goulais	55,000
200kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5121B8-14 in Goulais	46,000
600kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5120B5-75 in Goulais	64,000
800kVAr, 7.2kV, two-phase capacitor bank at pole PF3I5121G1-4 in Goulais	110,000
200kVAr, 7.2kV, single-phase capacitor bank at pole PH1I5112-51 in Goulais	46,000
400kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5121B8-14 in Goulais	55,000
200kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5120B5-75 in Goulais	46,000
200kVAr, 7.2kV, single-phase capacitor bank at pole PF3I5121G1-4 in Goulais	46,000
200kVAr, 7.2kV, single-phase capacitor bank at pole PG2J5123A-149 in Goulais	46,000
4MVA, 12.5kV, two-phase voltage regulator between lines OHH1I5112-73 & OHH1I5112-74 in Goulais	100,000
2MVA, 12.5kV, two-phase voltage regulator between lines OHI2I5210-78 & OHI2I5210-77 in Batchawana	80,000
New Substation (3-breaker configuration)*	10,300,000
Converting a portion of the system to three-phase	4,000,000
Estimated annual O&M costs due to additional reinforcements as per Table 5-1	37,000

* From Development of Greenfield Transmission Station Feasibility Study

Option 1-B

Table 5-8 Cost Estimate of Option 1-B

Upgrade	Cost ($)
New Substation (3-breaker configuration)*	10,300,000
Replacement of distribution transformers with 12.5kV primary voltage to 25kV	3,430,000**
Converting a portion of the system to three-phase	4,000,000

* From Development of Greenfield Transmission Station Feasibility Study

** In recent years, API has been procuring and installing dual-voltage transformers. Based on an equipment report, 1429 transformers need to be replaced in both areas.

Option 2-A

The system is inoperable with Batchawana TS operating as a back-up for Goulais TS at this voltage level. The system would operate with its normal in which each substation feeds its service area. In this option, the cost is that associated with replacing vintage equipment in both substations.

Table 5-9 Cost Estimate of Option 2-A

Upgrade	Cost ($)
Refurbishing the existing Goulais TS	4,700,000
Refurbishing the existing Batchawana TS	2,500,000
Reinforcements with normal configuration*	550,000
Estimated annual O&M costs due to additional reinforcements as per Table 5-2	25,500

* From Distribution System Planning Study

Option 2-B

With voltage uprating to 25kV, Batchawana TS can operate as a back-up to feed its load in addition to half of Goulais TS load without thermal violations. The cost of this option is noted in Table 5-8

Table 5-10 Cost Estimate of Option 2-B

Upgrade	Cost ($)
Refurbishing the existing Goulais TS	4,700,000
Refurbishing the existing Batchawana TS	2,500,000
Reinforcements with normal configuration*	550,000
400kVAr, 14.4kV, single-phase capacitor bank at pole PH3H5112H-43 in Goulais.	55,000
100kVAr, 14.4kV, single-phase capacitor bank at pole 34779 in Goulais.	40,000
400kVAr, 14.4kV, single-phase capacitor bank at pole PH3H5112H-43 in Goulais.	55,000
200kVAr, 14.4kV, single-phase capacitor bank at pole 34779 in Goulais.	46,000
10MVA, 25kV, two-phase voltage regulator between lines OHH1I5112-73 & OHH1I5112-74 in Goulais.	160,000
12MVA, 25kV, two-phase voltage regulator between lines OHI2I5210-78 & OHI2I5210-77 in Batchawana.	200,000
7MVA, 25kV, two-phase voltage regulator between lines OHH1I5120-21 & OHH1I5120-22 in Goulais.	120,000
Replacement of distribution transformers with 12.5kV primary voltage to 25kV	3,430,000**
Converting a portion of the system to three-phase	4,000,000
Estimated annual O&M costs due to additional reinforcements as per Table 5-2 and Table 5-3	42,000

* From Distribution System Planning Study

** In recent years, API has been procuring and installing dual-voltage transformers. Based on an equipment report, 1429 transformers need to be replaced in both areas.

Option 3

Table 5-11 Cost Estimate of Option 3

Item Description	Cost ($)
400kVAr, 7.2kV, single-phase capacitor bank at pole PH3H5112H-134A in Goulais.	55,000
800kVAr, 7.2kV, single-phase capacitor bank at pole PH3H5112H-43 in Goulais.	73,000
600kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5121B8-14 in Goulais.	64,000
800kVAr, 7.2kV, single-phase capacitor bank at pole PG3H5120B5-75 in Goulais.	73,000
800kVAr, 7.2kV, two-phase capacitor bank at pole PF3I5121G1-4 in Goulais.	110,000
200kVAr, 7.2kV, single-phase capacitor bank at pole PG3J5123A9-33 in Goulais.	46,000
New Substation (3-breaker configuration)*	10,300,000
Two 12MVA, 25/12.5kV transformers and relevant buswork, site, concrete work, …etc	1,500,000
Replacement of distribution transformers with 12.5kV primary voltage to 25kV	718,000**
Converting a portion of the system to three-phase and new express feeder	4,000,000
Estimated annual O&M costs due to additional reinforcements as per Table 5-4	16,500

* From Development of Greenfield Transmission Station Feasibility Study

** In recent years, API has been procuring and installing dual-voltage transformers. Based on an equipment report, 299 transformers need to be replaced in Batchawana area.

5.4 Conclusions and Recommendations

With only the new substation feeding both service areas, the cost would be approximately $15.3M with 12.5kV system voltage (Option 1-A). This will result in lower voltage profile in several areas of the system that would require voltage support via a mix of the voltage regulator and shunt capacitors.

Converting system voltage to 25kV (Option 1-B) will improve the voltage profile and eliminate the need for extra shunt capacitors and voltage regulator and will cost about $17.8M.

On the other hand, in the refurbishment option, the system would operate with its current (normal) configuration. This results in lower costs (expected cost is approximately $8M for Option 2-A).

Moreover, Batchawana TS can operate as a back-up and feed half Goulais TS load without thermal violations and provide supply redundancy. This requires system modifications that would cost almost additional $7.9M, which will bring the total cost for Option 2-B to about $15.9M.

For Option 3, Batchawana TS service area is fed at 25kV with no voltage violations observed. Some system reinforcements are required in Goulais TS area. The cost of this option would be in the order of $17M, which is mainly because of the new Greenfield TS, new express feeder and the portion to be converted to three-phase in Batchawana TS area.

Hence, refurbishing the existing substations with distribution system upgrades (Option 2) seems to be a better solution than building a new substation to feed both service area (Options 1 and 3).

REFERENCES

[1]. API Distribution System Planning Study report no. 657327-18010-40EE-SN-0005-PA.

[2]. Development of Greenfield Transmission Station Feasibility Study, Report no. 15-079-01, rev.C.

[3]. CSA CAN3-C235-83 Preferred Voltage Levels for AC Systems, 0 to 50,000 V.

[4]. Unit Cost Estimates for Transmission Lines and Facilities in Northern Ontario and the Far North Report, presented by SNC-Lavalin to OPA, October 2011.

APPENDIX A: Technical Analysis

The following tables summarize all the elements operating above 100% of their respective capacities in all scenarios.

Table 0-1 Elements operating beyond 100% Capacity (Option 1-A, Present Load)

Element	Operating at (% Capacity)	Element	Operating at (% Capacity)
OHSER1056150	339.167	OHH1I5112-39	105.937
UGG2I5120B-9	242.488	OHH1I5112-38	105.937
OHG2I5120B-8	184.752	OHH1I5112-41	105.936
OHG2I5120B-7	184.752	OHH1I5112-40	105.936
OHG2I5120B-6	184.751	OHH1I5112-42	105.935
OHG2I5120B-5	184.751	OHH1I5112-44	105.878
OHG2I5120B-4	184.751	OHH1I5112-46	105.877
OHG2I5120B-3	184.751	OHH1I5112-45	105.877
OHG2I5120B-2-a	184.751	OHH1I5112-49	105.73
OHG2I5120B-1-a	184.751	OHH1I5112-50	105.645
OHSER1055976	181.448	OHH1I5112-51	105.346
AP002870-T1	178.119	UGSER1062982	104.344
OHSECG4I5120A42-8	174.434	AP003620-T1	103.656
OHH1I5112-17A	166.949	OHH3H5112H-2	103.271
OHH1I5112-43	158.902	OHH3H5112H-3	103.27
AP003813-T1	153.937	OHH3H5112H-4	103.269
AP002908-T1	153.315	OHH3H5112H-6	103.268
OH41077	152.246	OHH3H5112H-5	103.268
OHSER1056017	141.922	OHH3H5112H-7	103.267
OHSER1056149	140.699	OHG2I5121-1A	102.686
OHSECF3I5121J-4S1R	139.482	OHG2I5121-5	102.685
OHH1I5112-2	129.993	OHG2I5121-4A	102.685
OHH1I5112-1	129.993	OHG2I5121-4	102.685
OHH1I5112-4	129.456	OHG2I5121-3A	102.685
OHH1I5112-3	129.456	OHG2I5121-3	102.685
OHH1I5112-5	129.156	OHG2I5121-2A	102.685
OHH1I5112-6	128.728	OHG2I5121-2	102.685
OHH1I5112-7	128.445	OHG2I5121-1B	102.685
OHH1I5112-8	128.165	OHG2I5121-9	102.684
OHH1I5112-9	128.036	OHG2I5121-8A	102.684
OHH1I5112-12	127.903	OHG2I5121-8	102.684
OHH1I5112-11	127.903	OHG2I5121-7	102.684
OHH1I5112-10	127.903	OHG2I5121-6	102.684
OHH1I5112-13	127.902	OHG2I5121-5A	102.684
OHH1I5112-14	127.829	OHG2I5121-9A	102.683
OHH1I5112-16	127.386	OHG2I5121-11A	102.683
OHH1I5112-15	127.386	OHG2I5121-11	102.683
OHH1I5112-16A	127.001	OHG2I5121-10A	102.683
OHH1I5112-17	126.937	OHG2I5121-10	102.683
OHH1I5112-22	123.489	OHG2I5121-15	102.673
OHH1I5112-24A	123.488	OHG2I5121-14	102.673
OHH1I5112-24	123.488	OHG2I5121-13	102.673
OHH1I5112-23	123.488	OHG2I5121-12	102.673

OHH1I5112-25	123.056	OHG2I5121-17	102.672
OHH1I5112-26	122.729	OHG2I5121-16	102.672
OHH1I5112-28	122.728	OHG2I5121-19	102.671
OHH1I5112-27	122.728	OHG2I5121-18A	102.671
OHH1I5112-29	122.237	OHG2I5121-18	102.671
OHH1I5112-31	122.236	OHH3H5112H-9	102.643
OHH1I5112-30	122.236	OHH3H5112H-8	102.643
OHH1I5112-32	122.065	OHH3H5112H-11	102.642
OHH1I5112-34	121.752	OHH3H5112H-10	102.642
OHH1I5112-33	121.752	OHH3H5112H-13	102.641
OHH1I5112-36	121.751	OHH3H5112H-12	102.641
OHH1I5112-35	121.751	OHH3H5112H-14	102.64
OHH1I5112-37	121.75	OHG2I5121-22	102.572
OHH1I5112-47	120.586	OHG2I5121-21	102.572
OHH1I5112-48	120.585	OHG2I5121-20	102.572
OHSECG4I5120A43-7	119.555	OHG2I5121-25	102.571
OHH1I5111-1	115.811	OHG2I5121-24	102.571
OHH1I5111-3	115.581	OHG2I5121-23	102.571
OHH1I5111-2	115.581	OHG2I5121-28	102.57
OHH1I5111-4	115.504	OHG2I5121-27	102.57
OHH1I5111-7A	115.503	OHG2I5121-26	102.57
OHH1I5111-6A	115.503	AP003539-T1	102.187
OHH1I5111-8	115.503	OHH3H5112H-15	101.683
OHH1I5111-7	115.503	OHH3H5112H-17	101.682
OHH1I5111-6	115.503	OHH3H5112H-16	101.682
OHH1I5111-5	115.503	OHH3H5112H-19	101.594
OHH1I5111-9	115.502	OHH3H5112H-18	101.594
OHH1I5111-8A	115.502	OHH3H5112H-21	101.593
OHH1I5111-11	115.502	OHH3H5112H-20	101.593
OHH1I5111-10	115.502	OHH3H5112H-22	100.927
OHH1I5111-12	115.501	OHH3H5112H-24	100.926
OHH1I5111-13	114.314	OHH3H5112H-23	100.926
OHH1I5111-17	114.313	OHH3H5112H-25	100.925
OHH1I5111-16	114.313	OHH3H5112H-26	100.873
OHH1I5111-15	114.313	OHH3H5112H-27	100.872
OHH1I5111-14	114.313	VR-32	100.539
OHH1I5111-18	114.312	AP003393-T1	100.424
OHH1I5111-20	114.248	OHH3H5112H-29	100.3
OHH1I5111-19	114.248	OHH3H5112H-28	100.3
OHH1I5112-21	110.86	OHH3H5112H-30	100.079
OHH1I5112-20	110.86	OHH3H5112H-31	100.078
OHSECH3H5112H-45	110.546	OHH3H5112H-32	100.015
UGSER1055983	109.317		

Table 0-2 Elements operating beyond 100% Capacity (Option 1-B, Present Load)

Element	Operating at (% Capacity)	Element	Operating at (% Capacity)
OHSER1056150	348.219	OHSECG4I5120A42-1C02C2R	104.525
OHSECG4I5120A42-8	186.279	OHSECG4I5120A42-1C02C1R	104.525
OHSER1055976	183.657	AP003396-T1	104.183
AP002870-T1	166.093	AP003539-T1	103.645
AP003813-T1	157.1	AP003385-T1	103.421
OHSECF3I5121J-4S1R	147.563	AP003094-T1	102.853
AP002908-T1	144.062	OHSECF3I5121F-3	102.491
OHSER1056017	143.027	OHSECH3H5112H-45	102.411
OHSER1056149	141.234	AP003713-T1	102.337
OHSECG4I5120A43-7	127.701	UGG2I5120B-9	101.714
UGSER1055983	111.95	OHSECG4I5120A43-10	100.505
AP003620-T1	109.42	OHSER1055947	100.152
AP003393-T1	106.65	OHSECG2I5121-13S3	100.152
UGSER1062982	105.547		

Table 0-3 Elements operating beyond 100% Capacity (Option 1-A, Forecasted Load)

Element	Operating at (% Capacity)	Element	Operating at (% Capacity)
OHSER1056150	379.908	OHG2I5121-9	119.626
UGG2I5120B-9	266.083	OHG2I5121-8A	119.626
OHSER1055976	203.805	OHG2I5121-8	119.626
OHG2I5120B-8	202.729	OHG2I5121-7	119.626
OHG2I5120B-7	202.729	OHG2I5121-11A	119.625
OHG2I5120B-6	202.729	OHG2I5121-11	119.625
OHG2I5120B-5	202.729	OHG2I5121-10A	119.625
OHG2I5120B-4	202.729	OHG2I5121-10	119.625
OHG2I5120B-3	202.728	OHG2I5121-15	119.614
OHG2I5120B-2-a	202.728	OHG2I5121-14	119.614
OHG2I5120B-1-a	202.728	OHG2I5121-13	119.614
AP002870-T1	194.126	OHG2I5121-12	119.614
OHSECG4I5120A42-8	191.912	OHG2I5121-17	119.613
OHH1I5112-17A	181.491	OHG2I5121-16	119.613
OHH1I5112-43	172.678	OHG2I5121-19	119.612
AP003813-T1	169.646	OHG2I5121-18A	119.612
OH41077	168.985	OHG2I5121-18	119.612
AP002908-T1	164.866	OHG2I5121-21	119.506
OHSER1056017	158.862	OHG2I5121-20	119.506
OHSER1056149	157.871	OHG2I5121-24	119.505
OHSECF3I5121J-4S1R	152.734	OHG2I5121-23	119.505
OHH1I5112-2	141.368	OHG2I5121-22	119.505
OHH1I5112-1	141.368	OHG2I5121-27	119.504
OHH1I5112-4	140.775	OHG2I5121-26	119.504
OHH1I5112-3	140.775	OHG2I5121-25	119.504
OHH1I5112-5	140.443	OHG2I5121-28	119.503
OHH1I5112-6	139.97	OHSECH3H5112H-45	118.481
OHH1I5112-7	139.657	UGSER1062982	116.437

OHH1I5112-8	139.348	OHH1I5112-38	115.121
OHH1I5112-9	139.206	OHH1I5112-40	115.12
OHH1I5112-10	139.059	OHH1I5112-39	115.12
OHH1I5112-13	139.058	OHH1I5112-42	115.119
OHH1I5112-12	139.058	OHH1I5112-41	115.119
OHH1I5112-11	139.058	OHH1I5112-46	115.055
OHH1I5112-14	138.977	OHH1I5112-45	115.055
OHH1I5112-16	138.488	OHH1I5112-44	115.055
OHH1I5112-15	138.488	OHH1I5112-49	114.894
OHH1I5112-16A	138.064	OHH1I5112-50	114.801
OHH1I5112-17	137.993	OHH1I5112-51	114.473
OHH1I5112-22	134.201	AP003620-T1	113.912
OHH1I5112-24	134.2	AP003539-T1	112.668
OHH1I5112-23	134.2	VR-32	111.098
OHH1I5112-24A	134.199	AP003393-T1	110.549
OHH1I5112-25	133.726	AP003713-T1	109.677
OHH1I5112-27	133.365	OHSECG4I5120A42-1C02C2R	108.474
OHH1I5112-26	133.365	OHSECG4I5120A42-1C02C1R	108.474
OHH1I5112-28	133.364	AP003385-T1	108.473
OHH1I5112-29	132.825	AP002985-T1	107.892
OHH1I5112-31	132.824	OHSER1055947	107.788
OHH1I5112-30	132.824	OHSECG2I5121-13S3	107.788
OHH1I5112-32	132.635	AP003094-T1	106.738
OHH1I5112-34	132.295	AP003396-T1	106.592
OHH1I5112-33	132.295	OHSECF3I5121F-3	105.982
OHH1I5112-37	132.294	OHSER1062406	105.137
OHH1I5112-36	132.294	OHSECG2I5120A-40S2	105.137
OHH1I5112-35	132.294	OHSECG2I5120A-40S1	105.137
OHSECG4I5120A43-7	132.118	AP004092-T1	104.849
OHH1I5112-47	131.037	OHSECG3J5123A9-37S1	104.492
OHH1I5112-48	131.036	OHSECG4I5120A43-10	104.232
OHH1I5111-1	125.976	OHH3H5112H-3	103.758
OHH1I5111-3	125.722	OHH3H5112H-2	103.758
OHH1I5111-2	125.722	OHH3H5112H-4	103.757
OHH1I5111-7A	125.636	OHH3H5112H-6	103.756
OHH1I5111-6A	125.636	OHH3H5112H-5	103.756
OHH1I5111-7	125.636	OHH3H5112H-7	103.755
OHH1I5111-6	125.636	OHH3H5112H-9	103.014
OHH1I5111-5	125.636	OHH3H5112H-8	103.014
OHH1I5111-4	125.636	OHH3H5112H-11	103.013
OHH1I5111-9	125.635	OHH3H5112H-10	103.013
OHH1I5111-8A	125.635	OHH3H5112H-13	103.012
OHH1I5111-8	125.635	OHH3H5112H-12	103.012
OHH1I5111-10	125.635	OHH3H5112H-14	103.011
OHH1I5111-12	125.634	OHH3H5112H-16	101.87
OHH1I5111-11	125.634	OHH3H5112H-15	101.87
OHH1I5111-14	124.321	OHH3H5112H-17	101.869
OHH1I5111-13	124.321	OHH3H5112H-19	101.764
OHH1I5111-17	124.32	OHH3H5112H-18	101.764
OHH1I5111-16	124.32	OHH3H5112H-21	101.763

OHH1I5111-15	124.32	OHH3H5112H-20	101.763
OHH1I5111-18	124.319	OHSECG2H5121B85-119	101.758
OHH1I5111-20	124.248	AP004101-T1	101.573
OHH1I5111-19	124.248	OHSER1061505	101.481
UGSER1055983	121.717	OHSECG4I5120A411-13S1	101.481
OHH1I5112-20	120.511	OHH3H5112H-23	100.966
OHH1I5112-21	120.51	OHH3H5112H-22	100.966
OHG2I5121-3	119.628	OHH3H5112H-25	100.965
OHG2I5121-2A	119.628	OHH3H5112H-24	100.965
OHG2I5121-2	119.628	OHH3H5112H-27	100.902
OHG2I5121-1B	119.628	OHH3H5112H-26	100.902
OHG2I5121-1A	119.628	OHSECI2I5210-95S1	100.563
OHG2I5121-6	119.627	AP003732-T1	100.359
OHG2I5121-5A	119.627	AP003165-T1	100.294
OHG2I5121-5	119.627	OHH3H5112H-29	100.216
OHG2I5121-4A	119.627	OHH3H5112H-28	100.216
OHG2I5121-4	119.627	OHH1I5112-53	100.112
OHG2I5121-3A	119.627	OHH1I5112-52	100.112
OHG2I5121-9A	119.626		

Table 0-4 Elements operating beyond 100% Capacity (Option 1-B, Forecasted Load)

Element	Operating at (% Capacity)	Element	Operating at (% Capacity)
OHSER1056150	391.354	UGG2I5120B-9	112.244
OHSER1055976	207.058	OHSECH3H5112H-45	110.57
OHSECG4I5120A42-8	203.238	OHSER1055947	110.444
AP002870-T1	182.142	OHSECG2I5121-13S3	110.444
AP003813-T1	173.174	OHSECG4I5120A43-10	110.414
OHSECF3I5121J-4S1R	162.527	OHSECG3J5123A9-37S1	109.111
OHSER1056017	160.258	AP002985-T1	108.851
OHSER1056149	158.547	OHSECG2H5121B85-119	108.581
AP002908-T1	156.806	OHSER1061505	107.269
OHSECG4I5120A43-7	139.949	OHSECG4I5120A411-13S1	107.269
UGSER1055983	125.789	OHSER1062406	107.096
AP003620-T1	120.699	OHSECG2I5120A-40S2	107.096
UGSER1062982	118.197	OHSECG2I5120A-40S1	107.096
AP003393-T1	117.655	AP004092-T1	105.77
OHSECG4I5120A42-1C02C2R	114.744	AP003732-T1	103.736
OHSECG4I5120A42-1C02C1R	114.744	AP004101-T1	103.532
AP003539-T1	114.279	AP003165-T1	103.398
AP003385-T1	114.217	OHSER1066964	102.312
AP003396-T1	113.739	OHSECG4I5120A42-9	102.122
AP003094-T1	112.908	AP003033-T1	100.515
AP003713-T1	112.685	OHSECI2I5210-95S1	100.147
OHSECF3I5121F-3	112.345		

Table 0-5 Elements operating beyond 100% Capacity (Option 2-B, Present Load)

Element	Operating at (% Capacity)	Element	Operating at (% Capacity)
OHSER1056150	348.219	OHI2I5210-104	125.481
OHI2I5210-43A	209.255	OHI2I5210-2	124.468
OHI2I5210-109A	185.731	OHI2I5210-1	124.467
OHSER1055976	183.657	OHI2I5210-3	124.3
OHSECG4I5120A42-8	181.221	OHSECG4I5120A43-7	124.233
AP002870-T1	161.751	OHI2I5210-108	124.18
OHI2I5210-6	161.65	OHI2I5210-107	124.179
OHI2I5210-5	161.65	OHI2I5210-106	124.179
OHI2I5210-4	161.65	OHI2I5210-109	123.82
OHI2I5210-8	161.39	OHI2I5210-115	123.534
OHI2I5210-7	161.39	OHI2I5210-114	123.534
OHI2I5210-6A	161.389	OHI2I5210-113	123.534
OHI2I5210-10	160.685	OHI2I5210-112	123.534
OHI2I5210-9	160.684	OHI2I5210-111	123.533
OHI2I5210-11	160.382	OHI2I5210-110	123.533
OHI2I5210-15	160.328	OHI2I5210-119	123.167
OHI2I5210-14	160.328	OHI2I5210-118	123.167
OHI2I5210-13	160.328	OHI2I5210-117	123.167
OHI2I5210-12	160.327	OHI2I5210-116	123.166
OHI2I5210-16	160.271	OHI2I5210-120	123.107
OHI2I5210-21	159.713	OHI2I5210-123	122.974
OHI2I5210-20	159.713	OHI2I5210-122	122.974
OHI2I5210-19	159.712	OHI2I5210-121	122.973
OHI2I5210-18	159.712	OHI2I5210-126	122.855
OHI2I5210-17	159.712	OHI2I5210-125	122.855
OHI2I5210-24	159.638	OHI2I5210-124A	122.855
OHI2I5210-23	159.638	OHI2I5210-124	122.855
OHI2I5210-22	159.638	OHI2I5210-127	122.802
OHI2I5210-25	159.539	OHI2I5210-131A	122.761
OHI2I5210-26	159.509	OHI2I5210-131	122.761
AP003813-T1	153.64	OHI2I5210-130	122.761
OHSECF3I5121J-4S1R	143.795	OHI2I5210-129	122.761
OHSER1056017	143.027	OHI2I5210-128	122.76
OHSER1056149	141.234	OHI2I5210-133	122.666
AP002908-T1	140.492	OHI2I5210-132	122.665
OHI2I5210-38	139.862	OHI2I5210-135	122.638
OHI2I5210-37	139.862	OHI2I5210-134	122.637
OHI2I5210-36	139.862	OHI2I5210-156	122.445
OHI2I5210-35	139.861	OHI2I5210-155	122.445
OHI2I5210-34	139.861	OHI2I5210-154	122.445
OHI2I5210-33	139.861	OHI2I5210-153	122.445
OHI2I5210-32	139.86	OHI2I5210-152	122.445
OHI2I5210-31A	139.86	OHI2I5210-151	122.444
OHI2I5210-31	139.86	OHI2I5210-150	122.444
OHI2I5210-30	139.86	OHI2I5210-149	122.444
OHI2I5210-29	139.86	OHI2I5210-148A	122.444
OHI2I5210-28	139.86	OHI2I5210-148	122.444
OHI2I5210-27	139.86	OHI2I5210-147	122.443
OHI2I5210-41	139.777	OHI2I5210-146	122.443

OHI2I5210-40	139.776	OHI2I5210-145	122.443
OHI2I5210-39	139.776	OHI2I5210-144	122.443
OHI2I5210-43	139.534	OHI2I5210-143	122.443
OHI2I5210-42	139.534	OHI2I5210-142	122.443
OHI2I5210-45	139.468	OHI2I5210-141	122.442
OHI2I5210-44	139.468	OHI2I5210-140	122.442
OHI2I5210-47	139.187	OHI2I5210-139	122.442
OHI2I5210-46	139.187	OHI2I5210-138	122.442
OHI2I5210-48	139.123	OHI2I5210-137	122.442
OHI2I5210-52	139.054	OHI2I5210-136	122.441
OHI2I5210-51	139.053	OHI2I5210-166	122.418
OHI2I5210-50	139.053	OHI2I5210-165	122.417
OHI2I5210-49	139.053	OHI2I5210-164	122.417
OHI2I5210-54	139.005	OHI2I5210-163	122.417
OHI2I5210-53	139.005	OHI2I5210-162	122.417
OHI2I5210-55	138.897	OHI2I5210-161	122.417
OHI2I5210-56	138.889	OHI2I5210-160	122.417
OHI2I5210-58	138.866	OHI2I5210-159	122.417
OHI2I5210-57	138.865	OHI2I5210-158	122.416
OHI2I5210-61	138.684	OHI2I5210-157	122.416
OHI2I5210-60	138.684	OHI2I5210-170	122.195
OHI2I5210-59	138.684	OHI2I5210-169	122.195
OHI2I5210-63	138.634	OHI2I5210-168	122.195
OHI2I5210-62	138.634	OHI2I5210-167	122.194
OHI2I5210-65	138.583	UGSER1055983	111.95
OHI2I5210-64	138.583	OHI2I5210-0	109.824
OHI2I5210-67	138.564	AP003393-T1	106.297
OHI2I5210-66	138.564	UGSER1062982	105.547
OHI2I5210-68	138.523	OHH1I5112-48	105.382
OHI2I5210-70	138.426	OHH1I5112-47	105.382
OHI2I5210-69	138.425	OHH1I5112-34	104.506
OHI2I5210-72	138.391	OHH1I5112-33	104.506
OHI2I5210-71	138.391	OHH1I5112-37	104.505
OHH1I5112-43	138.385	OHH1I5112-36	104.505
OHI2I5210-77	138.19	OHH1I5112-35	104.505
OHI2I5210-76	138.19	OHH1I5112-32	104.285
OHI2I5210-75	138.187	OHH1I5112-31	104.172
OHI2I5210-74	138.187	OHH1I5112-30	104.172
OHI2I5210-73	138.187	OHH1I5112-29	104.172
OHH1I5112-17A	133.007	OHH1I5112-28	103.844
OHI2I5210-82	128.146	OHH1I5112-27	103.844
OHI2I5210-81	128.145	OHH1I5112-26	103.844
OHI2I5210-80	128.145	AP003396-T1	103.838
OHI2I5210-79	128.145	OHH1I5112-25	103.63
OHI2I5210-78	128.145	OHH1I5112-24	103.343
OHI2I5210-83	127.929	OHH1I5112-23	103.343
OHI2I5210-88	127.21	OHH1I5112-22	103.343
OHI2I5210-87	127.209	OHH1I5112-24A	103.342
OHI2I5210-86	127.209	AP003385-T1	103.079
OHI2I5210-85	127.209	OHH1I5112-76	102.904
OHI2I5210-84	127.209	OHH1I5112-75	102.904
OHI2I5210-89A	126.856	OHH1I5112-74	102.904

OHI2I5210-89	126.856	OHSECG4I5120A42-1C02C2R	101.687
OHI2I5210-91	126.592	OHSECG4I5120A42-1C02C1R	101.687
OHI2I5210-90	126.592	AP003620-T1	101.663
OHI2I5210-94	126.559	OHH1I5112-17	101.129
OHI2I5210-93	126.559	OHH1I5112-16A	101.09
OHI2I5210-92	126.559	OHH1I5112-16	100.849
OHI2I5210-99	126.019	OHH1I5112-15	100.849
OHI2I5210-98	126.019	OHH1I5112-14	100.574
OHI2I5210-97	126.019	OHH1I5112-13	100.531
OHI2I5210-96	126.019	OHH1I5112-12	100.531
OHI2I5210-95	126.019	OHH1I5112-11	100.531
OHI2I5210-100	126.019	OHH1I5112-10	100.531
OHI2I5210-103	125.679	OHH1I5112-9	100.452
OHI2I5210-102	125.679	OHH1I5112-8	100.375
OHI2I5210-101	125.679	OHH1I5112-7	100.205
OHI2I5210-105	125.482	AP003094-T1	100.06

Table 0-6 Elements operating beyond 100% Capacity (Option 2-B, Forecasted Load)

Element	Operating at (% Capacity)	Element	Operating at (% Capacity)
OHSER1056150	391.354	OHI2I5210-150	144.116
OHI2I5210-43A	248.363	OHI2I5210-149	144.116
OHI2I5210-109A	218.478	OHI2I5210-148A	144.116
OHSER1055976	207.058	OHI2I5210-148	144.116
OHSECG4I5120A42-8	196.967	OHI2I5210-147	144.116
OHI2I5210-6	191.704	OHI2I5210-146	144.116
OHI2I5210-5	191.703	OHI2I5210-145	144.116
OHI2I5210-4	191.703	OHI2I5210-144	144.115
OHI2I5210-8	191.41	OHI2I5210-143	144.115
OHI2I5210-7	191.41	OHI2I5210-142	144.115
OHI2I5210-6A	191.41	OHI2I5210-141	144.115
OHI2I5210-10	190.618	OHI2I5210-140	144.115
OHI2I5210-9	190.617	OHI2I5210-139	144.115
OHI2I5210-11	190.275	OHI2I5210-138	144.115
OHI2I5210-15	190.214	OHI2I5210-137	144.115
OHI2I5210-14	190.213	OHI2I5210-136	144.115
OHI2I5210-13	190.213	OHI2I5210-166	144.085
OHI2I5210-12	190.213	OHI2I5210-165	144.085
OHI2I5210-16	190.149	OHI2I5210-164	144.085
OHI2I5210-21	189.523	OHI2I5210-163	144.085
OHI2I5210-20	189.523	OHI2I5210-162	144.084
OHI2I5210-19	189.523	OHI2I5210-161	144.084
OHI2I5210-18	189.523	OHI2I5210-160	144.084
OHI2I5210-17	189.522	OHI2I5210-159	144.084
OHI2I5210-24	189.439	OHI2I5210-158	144.084
OHI2I5210-23	189.439	OHI2I5210-157	144.084
OHI2I5210-22	189.439	OHI2I5210-170	143.838
OHI2I5210-25	189.327	OHI2I5210-169	143.838
OHI2I5210-26	189.293	OHI2I5210-168	143.838

AP002870-T1	177.789	OHI2I5210-167	143.838
AP003813-T1	168.045	OHSECG4I5120A43-7	135.631
OHI2I5210-38	165.977	OHI2I5210-0	130.228
OHI2I5210-37	165.977	UGSER1055983	125.789
OHI2I5210-36	165.976	OHH1I5112-48	125.295
OHI2I5210-35	165.976	OHH1I5112-47	125.295
OHI2I5210-34	165.976	OHH1I5112-34	124.347
OHI2I5210-33	165.976	OHH1I5112-33	124.347
OHI2I5210-32	165.976	OHH1I5112-37	124.346
OHI2I5210-31A	165.975	OHH1I5112-36	124.346
OHI2I5210-31	165.975	OHH1I5112-35	124.346
OHI2I5210-30	165.975	OHH1I5112-32	124.107
OHI2I5210-29	165.975	OHH1I5112-29	123.984
OHI2I5210-28	165.975	OHH1I5112-31	123.983
OHI2I5210-27	165.975	OHH1I5112-30	123.983
OHI2I5210-41	165.881	OHH1I5112-28	123.625
OHI2I5210-40	165.88	OHH1I5112-27	123.625
OHI2I5210-39	165.88	OHH1I5112-26	123.625
OHI2I5210-43	165.61	OHH1I5112-25	123.391
OHI2I5210-42	165.61	OHH1I5112-22	123.078
OHI2I5210-45	165.535	OHH1I5112-24A	123.077
OHI2I5210-44	165.535	OHH1I5112-24	123.077
OHI2I5210-47	165.222	OHH1I5112-23	123.077
OHI2I5210-46	165.222	OHH1I5112-75	122.736
OHI2I5210-48	165.15	OHH1I5112-74	122.736
OHI2I5210-52	165.073	OHH1I5112-76	122.735
OHI2I5210-51	165.072	AP003620-T1	121.021
OHI2I5210-50	165.072	OHH1I5112-17	120.66
OHI2I5210-49	165.072	OHH1I5112-16A	120.616
OHI2I5210-54	165.019	OHH1I5112-15	120.354
OHI2I5210-53	165.018	OHH1I5112-16	120.353
OHI2I5210-55	164.897	OHH1I5112-14	120.053
OHI2I5210-56	164.889	OHH1I5112-13	120.006
OHI2I5210-58	164.862	OHH1I5112-12	120.006
OHI2I5210-57	164.862	OHH1I5112-11	120.006
OHI2I5210-61	164.66	OHH1I5112-10	120.006
OHI2I5210-60	164.66	OHH1I5112-9	119.92
OHI2I5210-59	164.659	OHH1I5112-8	119.835
OHI2I5210-63	164.604	OHH1I5112-7	119.651
OHI2I5210-62	164.604	OHH1I5112-6	119.465
OHH1I5112-43	164.554	OHH1I5112-5	119.189
OHI2I5210-65	164.547	OHH1I5112-3	118.996
OHI2I5210-64	164.547	OHH1I5112-4	118.995
OHI2I5210-67	164.525	OHH1I5112-2	118.651
OHI2I5210-66	164.525	OHH1I5112-1	118.651
OHI2I5210-68	164.476	UGSER1062982	118.197
OHI2I5210-70	164.368	AP003393-T1	117.655
OHI2I5210-69	164.367	AP003385-T1	114.217
OHI2I5210-72	164.329	AP003396-T1	113.739
OHI2I5210-71	164.328	OHSECG4I5120A42-1C02C2R	111.204
OHI2I5210-77	164.104	OHSECG4I5120A42-1C02C1R	111.204

OHI2I5210-76	164.104	OHSER1055947	111.003
OHI2I5210-75	164.102	OHSECG2I5121-13S3	111.003
OHI2I5210-74	164.102	OHH1I5112-64	110.465
OHI2I5210-73	164.102	OHH1I5112-63	110.465
OHSER1056017	160.258	OHH1I5112-62	110.465
OHH1I5112-17A	158.694	OHH1I5112-61	110.465
OHSER1056149	158.547	OHH1I5112-68	110.464
OHSECF3I5121J-4S1R	157.887	OHH1I5112-67	110.464
AP002908-T1	153.484	OHH1I5112-66	110.464
OHI2I5210-82	150.488	OHH1I5112-65	110.464
OHI2I5210-81	150.488	OHH1I5112-73	110.463
OHI2I5210-80	150.488	OHH1I5112-72	110.463
OHI2I5210-79	150.488	OHH1I5112-71	110.463
OHI2I5210-78	150.488	OHH1I5112-70	110.463
OHI2I5210-83	150.246	OHH1I5112-69	110.463
OHI2I5210-88	149.438	OHH1I5112-60	110.345
OHI2I5210-87	149.438	OHH1I5112-59	110.345
OHI2I5210-86	149.437	OHH1I5112-58	110.345
OHI2I5210-85	149.437	OHH1I5112-57	110.309
OHI2I5210-84	149.437	OHH1I5112-56	110.242
OHI2I5210-89A	149.04	OHH1I5112-55	110.242
OHI2I5210-89	149.04	OHH1I5112-54	110.242
OHI2I5210-91	148.744	OHH1I5112-53	110.164
OHI2I5210-90	148.744	OHH1I5112-52	110.164
OHI2I5210-94	148.707	OHH1I5112-51	110.164
OHI2I5210-93	148.707	OHH1I5112-50	109.926
OHI2I5210-92	148.707	AP003539-T1	109.909
OHI2I5210-99	148.108	OHH1I5112-49	109.86
OHI2I5210-98	148.108	OHH1I5112-44	109.747
OHI2I5210-97	148.108	OHH1I5112-46	109.746
OHI2I5210-96	148.108	OHH1I5112-45	109.746
OHI2I5210-100	148.108	OHH1I5112-38	109.704
OHI2I5210-95	148.107	OHH1I5112-42	109.703
OHI2I5210-103	147.727	OHH1I5112-41	109.703
OHI2I5210-102	147.727	OHH1I5112-40	109.703
OHI2I5210-101	147.727	OHH1I5112-39	109.703
OHI2I5210-2	147.592	AP003094-T1	109.425
OHI2I5210-1	147.592	AP003713-T1	109.214
OHI2I5210-105	147.507	OHSECF3I5121F-3	109.114
OHI2I5210-104	147.506	OHSECG2H5121B85-119	108.581
OHI2I5210-3	147.403	OHSECH3H5112H-45	108.228
OHI2I5210-108	146.054	OHSECG4I5120A43-10	107.008
OHI2I5210-107	146.054	OHH1I5112-21	106.1
OHI2I5210-106	146.054	OHH1I5112-20	106.1
OHI2I5210-109	145.652	AP004092-T1	105.77
OHI2I5210-115	145.332	OHSECG3J5123A9-37S1	105.75
OHI2I5210-114	145.332	AP002985-T1	104.691
OHI2I5210-113	145.332	OHSECI2I5210-95S1	104.66
OHI2I5210-112	145.332	OHSER1061505	103.959
OHI2I5210-111	145.331	OHSECG4I5120A411-13S1	103.959

OHI2I5210-110	145.331	OHH1I5111-20	103.888
OHI2I5210-119	144.927	OHH1I5111-19	103.888
OHI2I5210-118	144.927	OHH1I5111-17	103.849
OHI2I5210-117	144.927	OHH1I5111-16	103.849
OHI2I5210-116	144.927	OHH1I5111-15	103.849
OHI2I5210-120	144.86	OHH1I5111-14	103.849
OHI2I5210-123	144.71	OHH1I5111-13	103.849
OHI2I5210-122	144.71	OHH1I5111-18	103.848
OHI2I5210-121	144.71	AP004101-T1	103.532
OHI2I5210-126	144.578	AP003732-T1	103.499
OHI2I5210-125	144.578	OHH1I5111-6A	103.131
OHI2I5210-124A	144.578	OHH1I5111-6	103.131
OHI2I5210-124	144.577	OHH1I5111-5	103.131
OHI2I5210-127	144.518	OHH1I5111-4	103.131
OHI2I5210-131A	144.472	OHH1I5111-7A	103.13
OHI2I5210-131	144.472	OHH1I5111-9	103.13
OHI2I5210-130	144.472	OHH1I5111-8A	103.13
OHI2I5210-129	144.472	OHH1I5111-8	103.13
OHI2I5210-128	144.471	OHH1I5111-7	103.13
OHI2I5210-133	144.365	OHH1I5111-12	103.13
OHI2I5210-132	144.365	OHH1I5111-11	103.13
OHI2I5210-135	144.334	OHH1I5111-10	103.13
OHI2I5210-134	144.333	OHH1I5111-3	103.085
OHI2I5210-156	144.117	OHH1I5111-2	103.085
OHI2I5210-155	144.117	OHSER1062406	102.985
OHI2I5210-154	144.117	OHSECG2I5120A-40S2	102.985
OHI2I5210-153	144.116	OHSECG2I5120A-40S1	102.985
OHI2I5210-152	144.116	OHH1I5111-1	102.948
OHI2I5210-151	144.116		

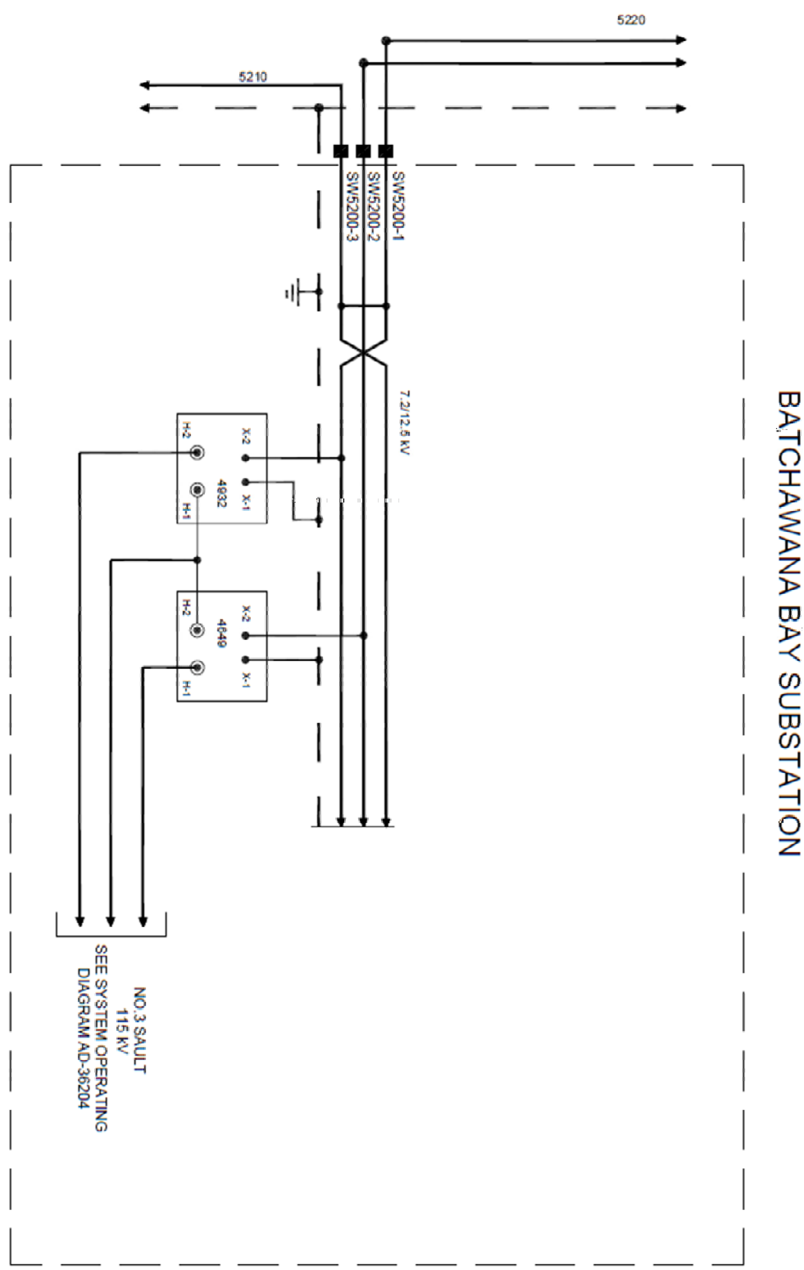
Table 0-7 Elements operating beyond 100% Capacity (Option 3, Present Load)

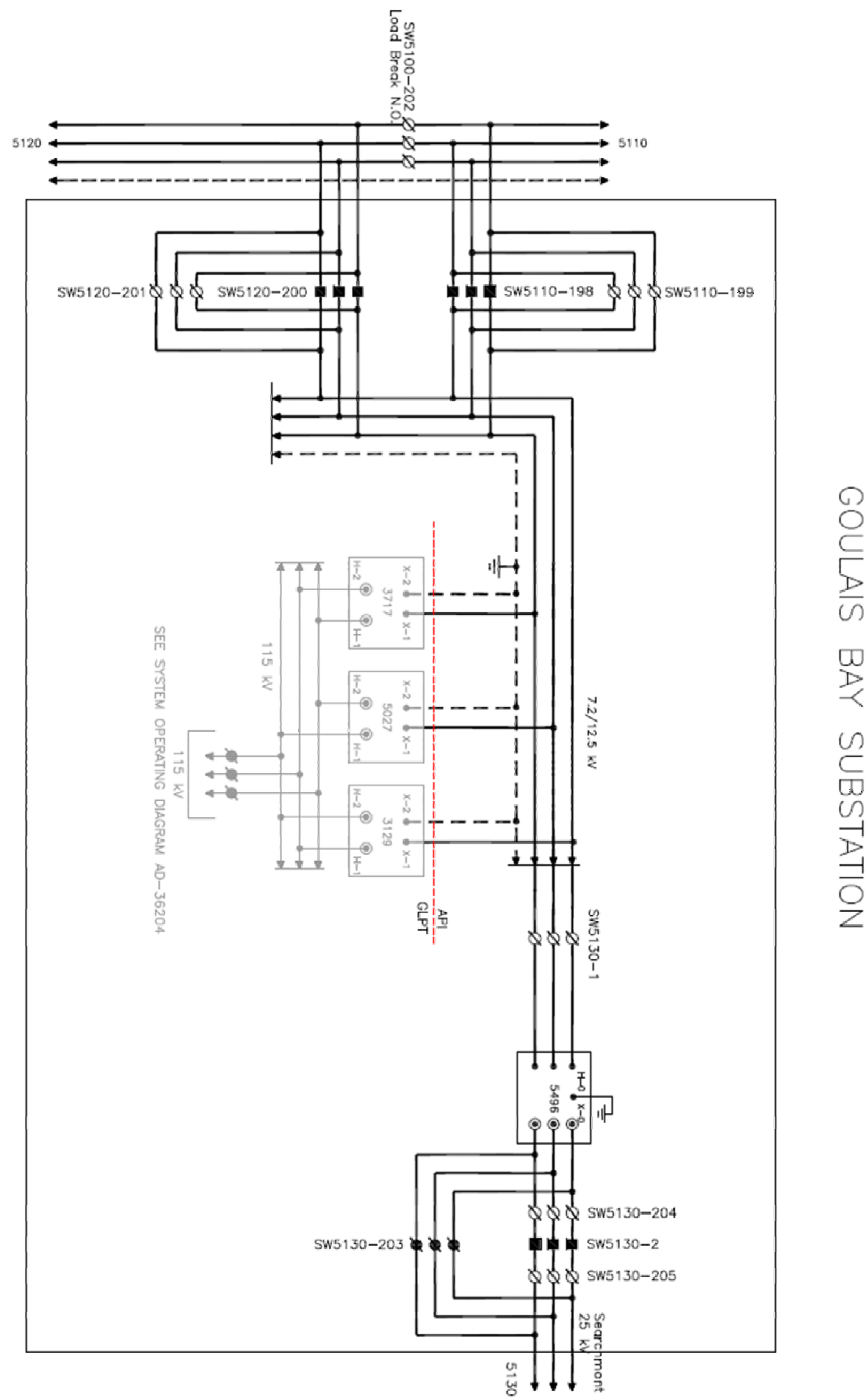
Element	Operating at (% Capacity)	Element	Operating at (% Capacity)
OHSER1056150	342.755	OHG2I5120B-2-a	141.385
UGG2I5120B-9	185.569	OHG2I5120B-1-a	141.385
OHSER1055976	180.724	OHSER1056017	140.79
AP002870-T1	165.75	OHSER1056149	139.029
OHSECG4I5120A42-8	161.879	OHSECF3I5121J-4S1R	129.205
AP002908-T1	142.365	OH41077	121.944
AP003813-T1	142.352	OHSECG4I5120A43-7	110.769
OHG2I5120B-8	141.385	UGSER1055983	110.193
OHG2I5120B-7	141.385	OHH1I5112-17A	109.576
OHG2I5120B-6	141.385	UGSER1062982	103.915
OHG2I5120B-5	141.385	OHH1I5112-43	103.005
OHG2I5120B-4	141.385	OHSECH3H5112H-45	102.926
OHG2I5120B-3	141.385		

Table 0-8 Elements operating beyond 100% Capacity (Option 3, Forecasted Load)

Element	Operating at (% Capacity)	Element	Operating at (% Capacity)
OHSER1056150	396.002	OHG2I5121-10	110.413
OHSER1055976	209.518	OHG2I5121-11A	110.412
UGG2I5120B-9	208.47	OHG2I5121-11	110.412
OHSECG4I5120A42-8	187.034	OHG2I5121-10A	110.412
AP002870-T1	186.529	OHG2I5121-14	110.402
AP003813-T1	165.727	OHG2I5121-13	110.402
OHSER1056017	162.231	OHG2I5121-12	110.402
OHSER1056149	160.416	OHG2I5121-17	110.401
OHG2I5120B-8	158.834	OHG2I5121-16	110.401
OHG2I5120B-7	158.834	OHG2I5121-15	110.401
OHG2I5120B-6	158.833	OHG2I5121-19	110.4
OHG2I5120B-5	158.833	OHG2I5121-18A	110.4
OHG2I5120B-4	158.833	OHG2I5121-18	110.4
OHG2I5120B-3	158.833	OHG2I5121-21	110.296
OHG2I5120B-2-a	158.833	OHG2I5121-20	110.296
OHG2I5120B-1-a	158.833	OHG2I5121-25	110.295
AP002908-T1	157.435	OHG2I5121-24	110.295
OHSECF3I5121J-4S1R	149.989	OHG2I5121-23	110.295
OH41077	140.282	OHG2I5121-22	110.295
OHSECG4I5120A43-7	128.786	OHG2I5121-28	110.294
UGSER1055983	127.314	OHG2I5121-27	110.294
UGSER1062982	119.623	OHG2I5121-26	110.294
OHH1I5112-17A	114.108	AP003393-T1	107.858
OHSECH3H5112H-45	113.276	AP004092-T1	107.073
AP003620-T1	111.421	AP002985-T1	106.155
AP003539-T1	110.515	OHSER1055947	106.006
OHG2I5121-2	110.415	OHSECG2I5121-13S3	106.006
OHG2I5121-1B	110.415	AP003385-T1	105.857
OHG2I5121-1A	110.415	OHH1I5112-43	105.537
OHG2I5121-6	110.414	OHSECG4I5120A42-1C02C2R	105.401
OHG2I5121-5A	110.414	OHSECG4I5120A42-1C02C1R	105.401
OHG2I5121-5	110.414	AP003713-T1	105.384
OHG2I5121-4A	110.414	OHSECI2I5210-95S1	105.198
OHG2I5121-4	110.414	AP004101-T1	104.781
OHG2I5121-3A	110.414	OHSECF3I5121F-3	104.129
OHG2I5121-3	110.414	AP003396-T1	103.852
OHG2I5121-2A	110.414	AP003094-T1	103.715
OHG2I5121-9A	110.413	OHSER1062406	103.438
OHG2I5121-9	110.413	OHSECG2I5120A-40S2	103.438
OHG2I5121-8A	110.413	OHSECG2I5120A-40S1	103.438
OHG2I5121-8	110.413	OHSECG3J5123A9-37S1	102.482
OHG2I5121-7	110.413	OHSECG4I5120A43-10	101.496

APPENDIX B: Single-line Diagrams





SW5100–202
Load Break N.O.
5120
5110
SW5120–201
SW5120–200
SW5110–198
SW5110–199
7.2/12.5 kV
115 kV
SEE SYSTEM OPERATING DIAGRAM AD–36204
3717
5027
3129
API
GLPT
SW5130–1
5496
SW5130–204
SW5130–2
SW5130–205
SW5130–203
Searchmont
25 kV
5130
GOULAIS BAY SUBSTATION

APPENDIX C: Cost Estimate of Option 2

Goulais Bay TS						R03			
SLD Eq. Designation	**Equipment Description**	**Manufacturer/Make**	**Equipment Model /Cat number**	**Qty**	**Unit Price**	**Total price**			
583 & 583-Gr, 586 & 586-GR	**115kV,** Group operated, Manually Operated Disconnect Switch with integral ground switch, **3pole,** 1200A, 50kA momentary current, 650kV BIL, 4-hole NEMA pad connectors, Vertical break, with minimum 6NO+6NC auxiliary contacts and arcing horn.	Southern States	EV-2 138	2	120000	240000			
582, 583, 586, 587	**115kV,** Group operated, Manually Operated Disconnect Switch, **3pole,** 1200A, 50kA momentary current, 650kV BIL, 4-hole NEMA pad connectors, Vertical break, with minimum 6NO+6NC auxiliary contacts and arcing horn.	Southern States	EV-2 138	2	91000	182000			
584, 585	115 KV - 1200 A - 550 KV BIL - 50 KA Short Circuit - Circuit -Switcher Series 2000 Model 2010 with horizontal interrupters and Vertical Break power operatred Disconnect 84 inches spacings, with mounitng pedestals (strturctures)	S & C, SERIES 2000	197738-BE12H1, MODEL - 2010	2	90000	180000			
589	Power Fuse, 115kV, 45 deg Opening, 115kV, 550kv BIL C/W 250E Fuse	S & C	SMD-2B	3	12000	36000			
T1-A,B,C(3717, 5027, 3129)	Two Phase step down transformer, 115/12.5kV, 10**MVA**, 6% Positive Sequence Impedance, 1phase, Directly grounded, outdoor, oil filled step-down Power Transformer with manual off load tap changer on HV winding to allow +5%-7.5% voltage variation to nominal voltage in 2.5% steps. provided with 550kV bushing on HV and 200kV bushing on LV, 95kV bushing on LV neutral, two(02) 600-5A,MR,C200 CT cores on each HV bushing, 2 Surge Arrestors on HV side, 2 Surge Arrestors on LV side to be provided on the transformer.With Qualitrol 509 transformer monitor	ABB/SIEMENS/HUNDAI/PTI		3	410000	1230000			
SW5120-200 SW5110-198	Reclosers, solid dielectric, 27kV, 125kV BIL,16kA interrupting - Centermount or cross-arm frames with factory installed Accusense voltage sensors and lightning arrestors. -Additional site-ready options of potential transformers for control power. -stanard Aluminum frames -with SEL-351R controls in a separate control cabinet	G&W Electric	VIP388ER-16-1-ST	2	110000	220000			
SW5120-201 SW5110-199	25/34.5 KV 600 A, 200 BIL --ALDUTI-RUPTER Switch Outdoor distribution, Three -Pole Vertical Break, Integer style, Steel base, Cypoxy insulators without interupters. - Reciprocating Operating Mechanism ED-151R1, 125VDC control/motor voltage AS-10 Switch Operator, Cat # 38852R4-B-KMVWY	S & C	135714R2-L-E	2	15000	30000			
SW100-202	25/34.5 KV 600 A, 200 BIL --ALDUTI-RUPTER Switch Outdoor distribution, Three -Pole Vertical Break, Integer style, Steel base, Cypoxy insulators with interupters. - Reciprocating Operating Mechanism ED-151R1 AS-10 Switch Operator, Cat # 38852R4-B-KMVWY	S & C	135714R2-L-E	1	20000	20000			
CT/PT-M1	Potential Transformer, 15kV Class, Rating - 7.2kV/115-69/115-69V, PTR : 105-63:1 , 2 secondary windings with accuracy 0.3 WXYZ,3PZ on each winding, 125kV BIL,	ARTECHE		3	2500	7500			
CT/PT-M1	Current Transformer, 2 core, 12.5kV Class, Rating - 600-5A, MR,C200 & 0.3B2.0/C200, 125kV BIL, 17kA momentary current	ARTECHE		3	3000	9000			
SS2	Polemounted Station service transformer, 150kVA, 13.8kV, 13.8kV/120-208V, 1 phase	ABB/SIEMENS		1	14000	14000			
580	13.8kV SINGLE PHASE Fuse Cutoutand Fuse Holder (C/W 2-HOLE NEMA PAD)	S & C		1	3000	3000			
CT/PT-M1	12.5kV Combined Revenue Metering Unit, C/W Current and Voltage Transformer, 125kV BIL, 50/95kV Insulation Level, Current Ratio : 800-5A, 0.15SB0.5/B0.9/B0.9, Voltage Ratio: 7.2kV-69V 0.3WXY 1000VA THERMAL 1.9UN 30 SEC,ITH 20kA, 1sec	SIEMENS		1	12000	12000			
COMMUNICATION DEVICES	RTU, Cabinet, Power supplies, Antenna, communication cables, Batteries, Radio etc, for the data to be communicated to SCADA/upstream control room	SEL		1	9000	9000			
5496	12.5/25kV, **7.5MVA**, **3 phase**, Dyn1 directly grounded, outdoor, oil filled step-up Power Transformer with Off load tap changer on HV winding to allow +5%-7.5% voltage variation to nominal voltage in 2.5% steps. 125kV bushing on LV and 200kV bushing on HV, 95kV bushing on LV neutral, 3 Surge Arrestors on HV side, 3 Surge Arrestors on LV side to be provided on the transformer. with Qualitrol 509 transformer monitor	ABB/SIEMENS/HUNDAI/PTI		1	350000	350000			
SW130-2	Reclosers, solid dielectric, 27kV, 125kV BIL,16kA interrupting - Centermount or cross-arm frames with factory installed Accusense voltage sensors and lightning arrestors. -Additional site-ready options of potential transformers for control power. -stanard Aluminum frames -with SEL-351R controls in a separate control cabinet	G&W Electric	VIP388ER-16-1-ST	1	110000	110000			
SW130-204 sw130-205	25/34.5 KV 600 A, 200 BIL --ALDUTI-RUPTER Switch Outdoor distribution, Three -Pole Vertical Break, Integer style, Steel base, Cypoxy insulators without interupters. - Reciprocating Operating Mechanism ED-151R1 AS-10 Switch Operator, Cat # 38852R4-B-KMVWY	S & C	135714R2-L-E	2	28000	56000			
SW130-203	25/34.5 KV 600 A, 200 BIL --ALDUTI-RUPTER Switch Outdoor distribution, Three -Pole Vertical Break, Integer style, Steel base, Cypoxy insulators with interupters. - Reciprocating Operating Mechanism ED-151R1 AS-10 Switch Operator, Cat # 38852R4-B-KMVWY	S & C	135714R2-L-E	1	3000	3000	% of total project cost	2243250	
Total Equipment cost						2711500	63.49	4270612.5	
Construction cost						949025	22.22	6513862.5	total
Engineering						406725	9.52		
PMPC						203362.5	4.76	new stn option	
Grand Total (total Project cost estimate for Goulais Bay TS)						**4270612.5**	100.00	10328273	
								%	
								63.07	

* Notes:
1. Construction cost is estimated as approx. 23% of project cost (35% of equipment cost).
2. Engineering cost is estimated as approx. 10% of project cost (15% of equipment cost).
3. PMPC cost is estimated as approx. 5% of project cost (7.5% of equipment cost).
4. Equipment cost is estimated/adjusted based on offers for similar projects/applications.
5. Equipment is listed based on SLD and other project related information provided.

Batchawana TS						R03	
SLD Eq. Designation	Equipment Description	Manufacturer/Make	Equipment Model /Cat number	Qty	Unit Price	Total price	
594 & 594-Gr, 599 & 599-GR	**115kV,** Group operated, Manually Operated Disconnect Switch with integral ground switch, **3pole,** 1200A, 50kA momentary current, 650kV BIL, 4-hole NEMA pad connectors, Vertical break, with minimum 6NO+6NC auxiliary contacts and arcing horn	Southern States	EV-2 138	2	120000	240000	
593, 598	115 KV - 1200 A - 550 KV BIL - 50 KA Short Circuit - Circuit -Switcher Series 2000 Model 2010 with horizontal interrupters and Vertical Break power operatred Disconnect 84 inches spacings, with mounitng pedestals (strturctures)	S & C, SERIES 2000	197738-BE12H1, MODEL - 2010	2	90000	180000	
590	Power Fuse, 115kV, 45 deg Opening, 115kV, 550kv BIL C/W 250E Fuse	S & C	SMD-2B	3	12000	36000	
T1-A,B (4932, 4649)	Two Phase step down transformer, 115/12.5kV, 10**MVA**, 6% Positive Sequence Impedance, 1phase, Directly grounded, outdoor, oil filled step-down Power Transformer with manual off load tap changer on HV winding to allow +5%-7.5% voltage variation to nominal voltage in 2.5% steps. provided with 550kV bushing on HV and 200kV bushing on LV, 95kV bushing on LV neutral, two(02) 600-5A,MR,C200 CT cores on each HV bushing, 2 Surge Arrestors on HV side, 2 Surge Arrestors on LV side to be provided on the transformer.With Qualitrol 509 transformer monitor	ABB/SIEMENS/HUNDAI/PTI		2	410000	820000	
SW5200 SW5110-198	Single Phase Reclosers, solid dielectric, 15kV, 110kV BIL,20kA interrupting - Centermount or cross-arm frames with factory installed Accusense voltage sensors and lightning arrestors. -Additional site-ready options of potential transformers for control power. -stanard Aluminum frames -with SEL-351R controls in a separate control cabinet	G&W Electric	VIP178ER-12-SP	3	40000	120000	
SW5120-201 SW5110-199	Single Pole Disconnect Switch, 25/34.5 KV 600 A, 200 BIL --ALDUTI-RUPTER Switch Outdoor distribution, Three -Pole Vertical Break, Integer style, Steel base, Cypoxy insulators without interupters. - Reciprocating Operating Mechanism ED-151R1, 125VDC control/motor voltage AS-10 Switch Operator, Cat # 38852R4-B-KMVWY	S & C	135714R2-L-E	3	15000	45000	
CT/PT-M1	Potential Transformer, 25kV Class, Rating - 7.2kV/115-69/115-69V, PTR : 105-63:1 , 2 secondary windings with accuracy 0.3 WXYZ,3PZ on each winding, 125kV BIL,	ARTECHE		3	2500	7500	
CT/PT-M1	Current Transformer, 2 core, 12.5kV Class, Rating - 600-5A, MR,C200 & 0.3B2.0/C200, 125kV BIL, 17kA momentary current	ARTECHE		3	3000	9000	
SS2	Polemounted Station service transformer, 150kVA, 13.8kV, 13.8kV/120 208V, 1 phase	ABB/SIEMENS		1	14000	14000	
580	13.8kV SINGLE PHASE Fuse Cutoutand Fuse Holder (C/W 2-HOLE NEMA PAD)	S & C		1	3000	3000	
CT/PT-M1	12.5kV Combined Revenue Metering Unit, C/W Current and Voltage Transformer, 125kV BIL, 50/95kV Insulation Level, Current Ratio : 800-5A, 0.15SB0.5/B0.9/B0.9, Voltage Ratio: 7.2kV-69V 0.3WXY 1000VA THERMAL 1.9UN 30 SEC,ITH 20kA, 1sec	SIEMENS		1	12000	12000	
COMMUNICATION DEVICES	RTU, Cabinet, Power supplies, Antenna, communication cables, Batteries, Radio etc, for the data to be communicated to SCADA/upstream control room	SEL		1	9000	9000	% of total project cost
Total Equipment cost						1495500	66.67
Construction cost						523425	23.33
Engineering						224325	10.00
PMPC						112162.5	5.00
Grand Total (total Project cost estimate for Batchawana TS)						**2243250**	100.00

* Notes:
1. Construction cost is estimated as approx. 23% of project cost (35% of equipment cost).
2. Engineeing cost is estimated as approx. 10% of project cost (15% of equipment cost).
3. PMPC cost is estimated as approx. 5% of project cost (7.5% of equipment cost).
4. Equipment cost is estimated/adjusted based on offers for similar projects/applications.
5. Equipment is listed based on SLD and other project related information provided.

APPENDIX D: Analysis of Option 3

1. Description

In this option, the new Greenfield TS would feed both service areas of Goulais TS and Batchawana TS (like Option 1). Greenfield TS would operate at 25kV with two outgoing feeders. On one feeder, the voltage is stepped down to 12.5kV and the feeder is connected to the existing Goulais TS service area, such that its load is fed at 12.5kV. The step-down transformers would be located within Greenfield TS. The other 25kV outgoing would be an express feeder running in parallel with the existing feeders till the location of the tie coupling the two service areas, and would then feed the Batchawana TS service area at 25kV. The route of this proposed express feeder is shown in orange in Figure 0-1. The line between Batchawana TS and the location of the tie would be converted to three-phase to enable feeding the loads within Batchawana TS service area.

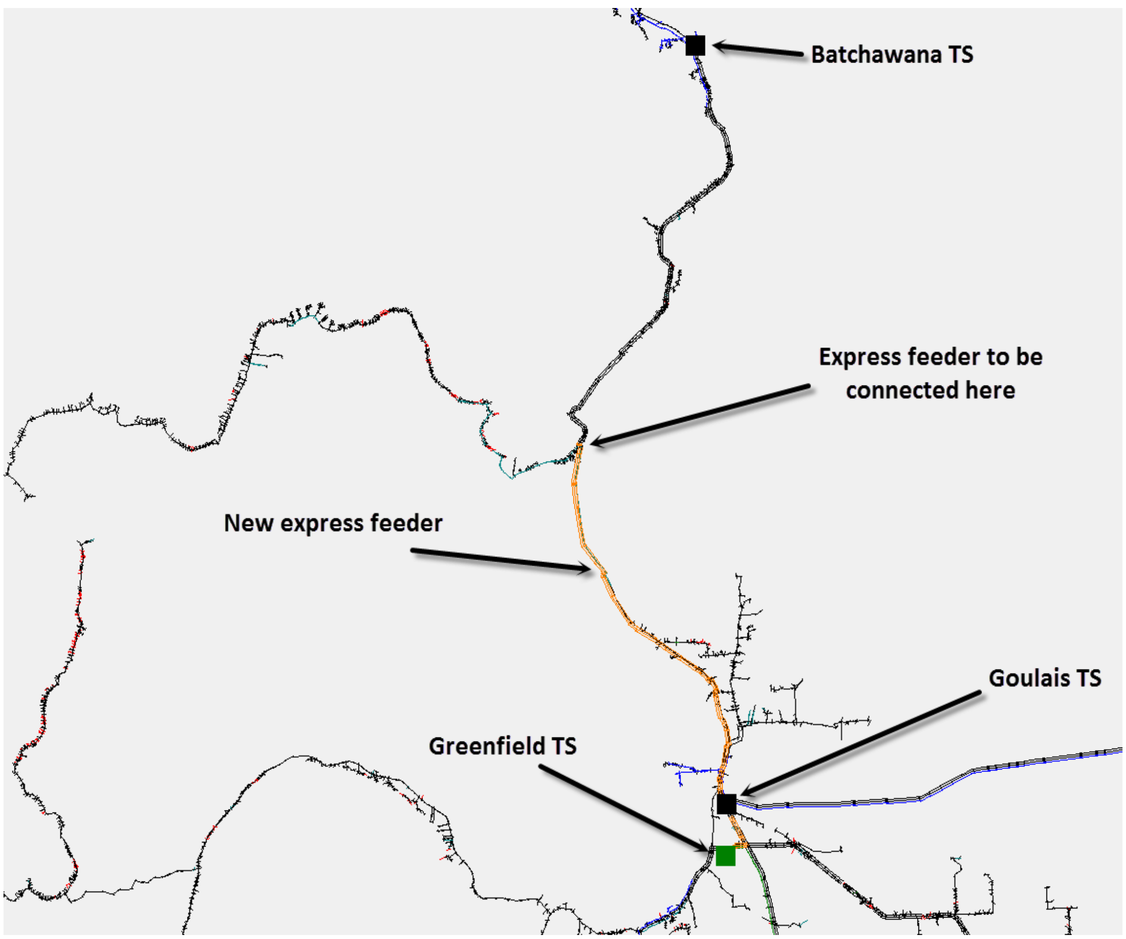


Figure 0-1 Route of the Proposed Express Feeder

2. Analysis Development

Windmill model is updated to include the new substation at the proposed location to feed both service areas with present system load. The express feeder is also modeled to run in parallel with the existing line from Greenfield TS till the tie between the two service areas.

The analysis shows that Batchawana TS service area would not experience voltage violations whether present or forecasted load is considered. This is mainly because of the 25kV voltage feed. However, in Goulais TS service area, some voltage violations are observed and can be resolved using the reinforcements in Table 0-9 for present load.

Table 0-9 Recommended Reinforcements with Present Load (Option 3)

#	Item Description	Rating	Phase(s)	Location
1	Shunt Capacitor	400kVAr	B	Pole PH3H5112H-134A
2	Shunt Capacitor	800kVAr	B	Pole PH3H5112H-43
3	Shunt Capacitor	200kVAr	B	Pole PG3H5121B8-14
4	Shunt Capacitor	600kVAr	C	Pole PG3H5120B5-75
5	Shunt Capacitor	800kVAr*	BC	Pole PF3I5121G1-4

*Split equally between phases

Furthermore, Table 0-7 in Appendix-A lists all the elements operating beyond their capacities in this scenario. The overall conductor length is about 1km.

Similar analysis is performed to the modified Windmil model with the forecasted system load considered. In addition to the reinforcements listed in Table 0-9, the following capacitors are necessary:

Table 0-10 Recommended Reinforcements with Forecasted Load (Option 3)

#	Item Description	Rating	Phase(s)	Location
1	Shunt Capacitor	400kVAr*	B	Pole PG3H5121B8-14
2	Shunt Capacitor	200kVAr*	B	Pole PG3H5120B5-75
3	Shunt Capacitor	200kVAr	A	Pole PG3J5123A9-33

*This is in addition to the Capacitors on the same pole recommended with present system load listed in Table 0-9

Furthermore, Table 0-8 in Appendix-A lists all the elements operating beyond their capacities in this scenario. The overall conductor length is about 3.5km.

Since Batchawana area would be fed at 25kV in this option, the replacement of 299 distribution transformers with ones with the proper primary voltage rating is necessary to match the system operating voltage.

Algoma Power Inc.

Distribution System Plan

Appendix L

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

LOCAL PLANNING REPORT

East Lake Superior Region: Supply Option Analysis for Batchawana and Goulais Bay Area

Revision: FINAL
Date: February 25th, 2021

Prepared by:

Hydro One Sault Ste. Marie LP.

Algoma Power Inc.

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Study Team

Organization
Hydro One Sault Ste. Marie LP. (Lead Transmitter)
Algoma Power Inc. (Distribution)

DISCLAIMER

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the East Lake Superior Region that do not require further coordinated regional planning. The preferred solution(s) that has been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Sault Ste. Marie (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Local Planning Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Local Planning Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Local Planning Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Local Planning Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

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LOCAL PLANNING EXECUTIVE SUMMARY

REGION	East Lake Superior Region (the "Region")		
LEAD	Hydro One Sault Ste. Marie LP. ("HOSSM")		
START DATE	September , 2019	**END DATE**	December, 2020

1. INTRODUCTION

The purpose of this Local Planning (LP) report is to develop wires-only options and recommend a preferred solution that will address the local needs identified in the Needs Assessment (NA) report for the East Lake Superior (ELS) Region dated June 14, 2019. The development of the LP report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

Based on Section 7 of the NA report, the study team recommended that no further coordinated regional planning is required to address the local needs of Batchawana and Goulais Bay area in the ELS region. These needs are local in nature and to be addressed by wires options through local planning led by the transmitter, Hydro One Sault Ste. Marie LP (HOSSM) with participation of the impacted LDC, Algoma Power Inc. (API).

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

End-of-life asset needs as well as load restoration needs at Batchawana TS and Goulais TS is the local need addressed in this report.

3. OPTIONS CONSIDERED AND ANALYSIS METHODOLOGY

Hydro One Sault Ste. Marie LP (Transmitter) and Algoma Power Inc (LDC) have considered addressing the need to refurbish Batchawana TS & Goulais TS with the following options:

Option 1-A – Refurbish both Batchawana TS & Goulais Bay TS.
Option 1-B – Refurbish both Batchawana TS & Goulais Bay TS and convert to 25kV.
Option 2-A – Build one new TS (115/12.5kV) to replace Batchawana TS & Goulais Bay TS.
Option 2-B – Build one new TS (115/25kV) to replace Batchawana TS & Goulais Bay TS.
Option 3-A – Build one new TS (115/12.5kV) with 25kV "express feeder "to feed Batchawana area.
Option 3-B – Build one new TS (115/25kV) with 25kV "express feeder "to feed Batchawana area.

HOSSM (Transmitter) and Algoma Power Inc. (LDC) have evaluated the above options with the following objectives and criteria:

Objective

Overall least total life-cycle cost for Transmission and Distribution system, which included both capital and Operation, Administration and Maintenance (OM&A) cost. Cost incremental that contributed to increased reliability and system performance should be considered and justifiable.

Criteria

1. Meet the long term load forecast provide by API.
2. Address the needs of existing Transmission facilities per section 3, which included:
    - Aging infrastructure and equipment
    - Electrical clearance concerns
    - Ability to conduct regular maintenance with minimal interruption of supply
    - Provide standard transmission protection system that is coordinated with downstream distribution system protection
    - Ability to provide load restoration in acceptable timeframe
    - Minimizes LDC connection work required during planned outages
3. Status quo, or improved overall system reliability (Transmission and Distribution)
4. Status quo, or improved overall system performance (Transmission and Distribution)

Refer to Section 4 for further details.

4. CONCLUSION & PREFERRED SOLUTION

HOSSM (Transmitter) and Algoma Power Inc. (LDC) have agreed that Option 1-A – Refurbish Batchawana TS & Goulais Bay TS is the recommended option to be considered to meet the local need. Refer to Section 5 for details.

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1 Introduction

The 2nd cycle Needs Assessment (NA) for the East Lake Superior Region ("Region") was completed in June 2019 as part of the OEB-mandated regional planning process. The IESO subsequently carried out its Scoping Assessment and concluded that the end-of-life replacement assets needs in Batchawana TS and Goulais TS should be addressed through Local Planning between HOSSM and impacted local distribution customer (LDC). As part of the regional planning process, Hydro One Networks Inc. (HONI), on behalf of HOSSM, has engaged the impacted LDC, Algoma Power Incorporated (API) to explore different options and to arrive at a mutually agreeable solution to address the end-of-life asset needs at Batchawana TS and Goulais TS.

The purpose of this Local Planning report is to review future power supply requirements and facility needs at Batchawana TS and Goulais Bay TS, as well as to provide analysis of various supply options. A recommendation for the preferred supply option for Batchawana Bay and Goulais Bay area has been proposed in this report.

1.1 Background Information

Batchawana Transformer Station and Goulais Transformer Station (TS), built in 1970's and 1960's respectively by Great Lakes Power, are 115kV load facilities with single transformer to supply to the Batchawana Bay and Goulais Bay areas. The areas consists of a mixture of residential, commercial and farming load. Batchawana TS is located 47 km north of the city of Sault Ste. Marie, while Goulais TS is located 30 km north of the City of Sault Ste. Marie.

Due to the station's deteriorating equipment conditions, inadequate clearance and inability to schedule and perform maintenance without a station outage, Great Lake Power Transmission (GLPT) engaged a consultant to explore the feasibility of building a new 115kV facility with 2 transformers to replace Batchawana TS and Goulais TS . A final feasibility report (Feasibility Report) was prepared and submitted to GLPT in July 2016[1]. GLPT did not further materialize the proposal, nor conducted further customer engagement to finalize the transmission solution. In the same year, Hydro One Inc. received regulatory approval from Ontario Energy Board (OEB) to acquire GLPT, and renamed it Hydro One Sault Ste. Marie LP (HOSSM).

In 2018, as part of the filing requirements for HOSSM's 2019-2026 Transmission Rate Application (the Application), HOSSM engaged a separate consultant to conduct an Asset Condition Assessment (ACA). The ACA provided detailed condition assessments of the HOSSM system on an individual equipment basis, which provided the foundation of HOSSM's 2019 – 2026 Transmission System Plan (TSP). In the ACA and the TSP, both Batchawana and Goulais TS had been identified in near end-of-life condition. Together with the feasibility report, a plan of building a new 115kV transmission facility to replace both stations was proposed in the TSP. The rate application was filed with OEB in July 2018 and received OEB's decision on June 20th, 2019. In

OEB's decision, OEB accepted the TSP and ACA as filed, and found that HOSSM's regulatory requirements and commitments have been fulfilled for the proceeding. Note that the purpose of the ACA & TSP were to provide information to the OEB to demonstrate a utility's capital planning and prioritization process in support of its revenue requirement. OEB did not provide distinct approval of these individual documents. [2]

In parallel of the Application, Hydro One Networks Inc. (HONI) undertook an integration initiative to operationally integrate HOSSM into part of HONI. As a result of the integration, HONI started to provide services to HOSSM as of October 1st, 2018, including system planning and operating functions via an established Service Level Agreement. In Quarter 1 of 2019, HONI , on behalf of HOSSM, initiated the *Need Assessment* (*NA*) phase of the second cycle of the *East Lake Superior Regional Planning*.

Led by HONI, the *NA* phase of *East Lake Superior Regional Planning* collected and reviewed future power requirements of the region from all transmission connected customers, assessed regional transmission system capacity and supply reliability , identified system needs, as well as provided plans to meet the region's short to medium term needs. The *NA* concluded that the implementation and execution for replacement of end-of-life transmission assets in Batchawana TS and Goulais TS would be coordinated between HOSSM and impacted local distribution customer (LDC) as required. As part of the regional planning process, HONI (on behalf of HOSSM) has actively engaged the impacted LDC, Algoma Power Incorporated (API) to explore different options and to arrive at a mutually agreeable solution to address the end-of-life asset needs at Batchawana TS and Goulais TS.

1.2 East Lake Superior Region Description and Connection Configuration

The East Lake Superior Region are bounded by the town of Wawa in the North to the town of Bruce Mines in south and includes the city of Sault Ste. Marie and the township of Chapleau. Highway 127 roughly borders the Region geographically to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel to the south. A map of the region is shown below in Figure 1.

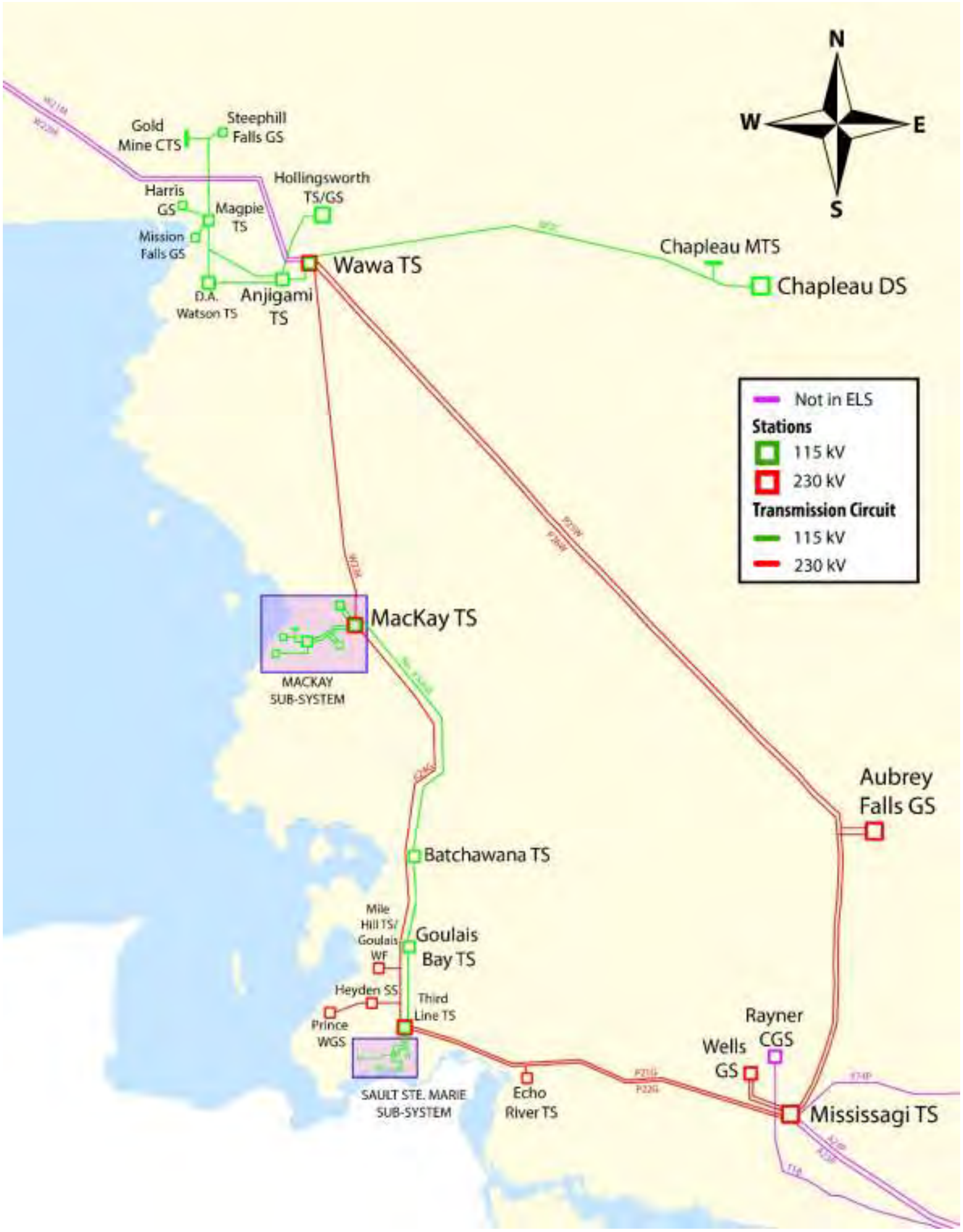

Figure 1: East Lake Superior Region Map

Electrical supply to the Region is provided primarily through 230/115 kV autotransformers at Third Line TS, Wawa TS and MacKay TS as well as the 230 kV and 115 kV transmission lines and step-down transformation facilities. The Region is defined electrically by the 230 kV transmission circuits bounded by Wawa TS to the northwest and Mississagi TS to the southeast.

This region has the following four local distribution companies (LDC):

Hydro One Networks (distribution)
Algoma Power Inc.
Sault Ste. Marie PUC
Chapleau PUC.

1.3 Transmission Study Area and Impacted Local Distribution Company (LDC)

The Transmission study area considered by this local planning report is Batchawana TS and Goulais Bay TS that are connected to No. 3 Sault transmission circuit at 115kV. It excludes the 115kV system at Third Line TS and Mackay TS. The single line diagram of the study area is shown Figure 2 and the geographical transmission map is shown is Figure 3.

The LDC in the area is Algoma Power Inc. (API). It is the sole customer supplied by Batchawana TS and Goulais TS. Batchawana TS supplies its load at 12.5kV, while Goulais TS supplies its load at both 12.5kV and 25kV.

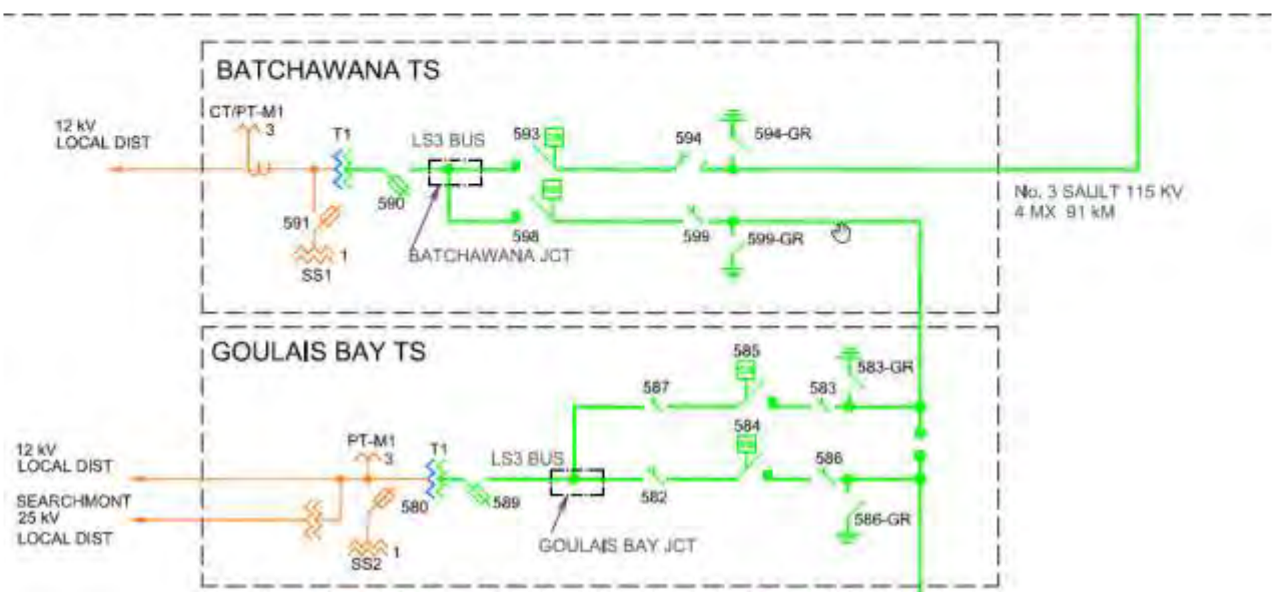

Figure 2: Single Line Diagram of Study Area

Figure 3: Geographical Transmission map of study area.

1.4 Distribution Study Area

The distribution system study area consists of the distribution systems fed directly by Batchawana TS and Goulais TS. While there exists a normally opened tie point with limited transfer capability between the two distribution systems, they operate largely as two separate distribution systems.

Batchawana distribution system: The 7.2 kV distribution system supplied by the Batchawana TS is a single phase radial system that supplies mainly seasonal loads, as well as some commercial and residential loads. The distribution system has approximately 86.2 primary circuit kilometers, covering the area from the south of Havilland area all the way to the north-west of the Ryan area. Figure 4 shows the single line diagram of the Batchawana distribution system sub-system.

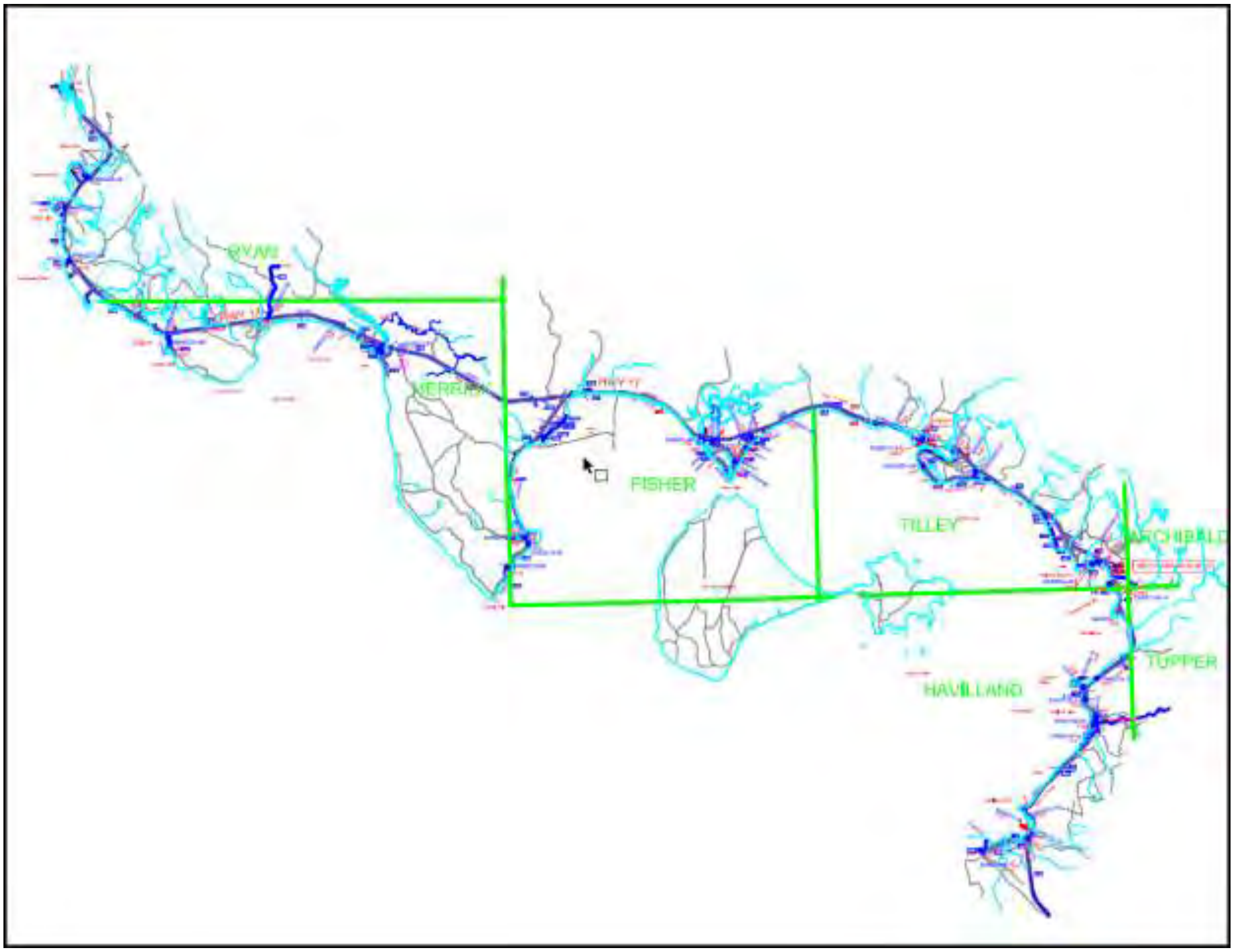

Figure 4: Single Line of Batchawana distribution system

Goulais distribution system: The 12.5kV and 25kV distribution system supplied by the Goulais TS is a hybrid system consisting of both three phase and single phase loads. The distribution system has approximately 285 primary circuit kilometers, covering the area from the south of Aweres to the north of Havilland and Ley. The 25kV distribution serves the area to the east in the Searchmont area and Hodgins township. Figure 5 shows the single line diagram of the Goulais distribution system sub-system.

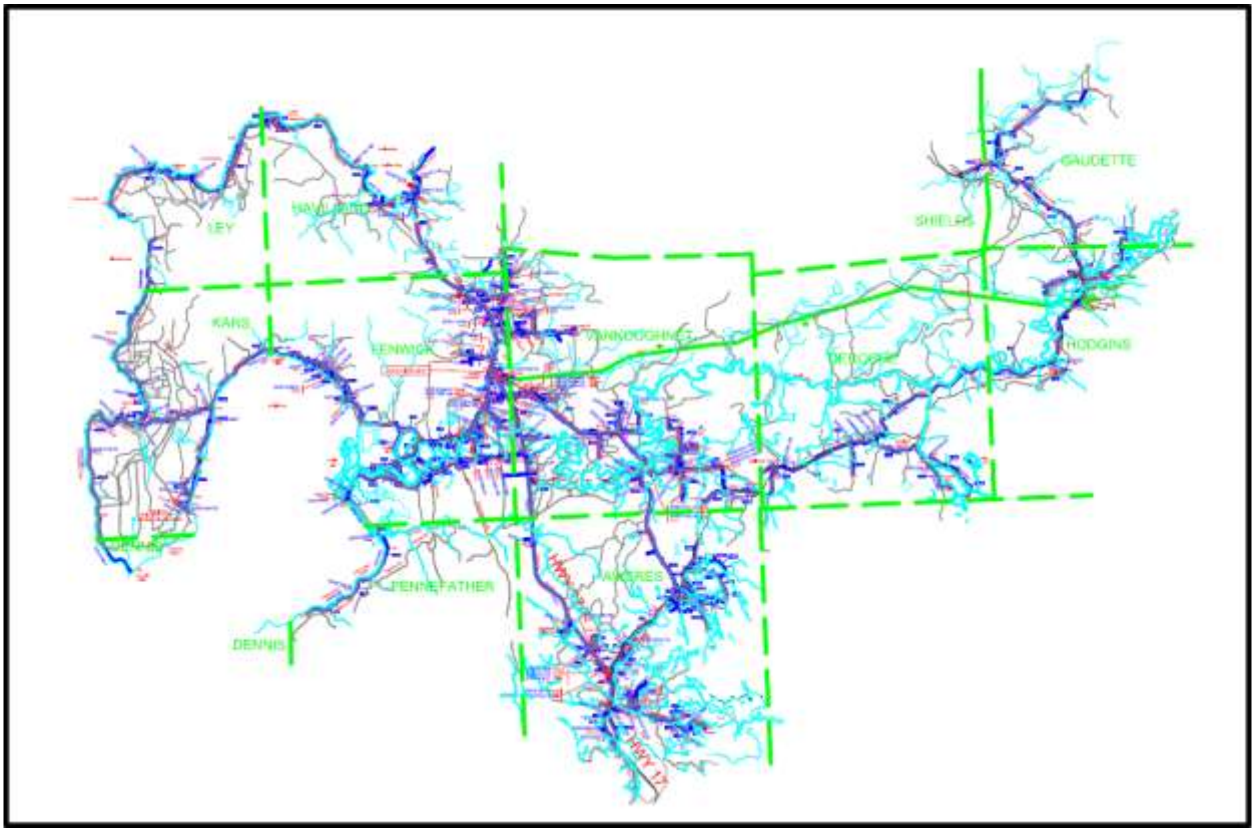

Figure 5: Single Line of Goulais distribution system

2 Load Forecast

API provided three (3) load growth scenarios using peak demand forecast covering the period 2020 – 2050 for Batchawana TS and Goulais TS. They are:

1. Annual trend line growth + Large customer expansion (285 kW for Batchawana TS , 500kW for Goulais TS)
2. Annual trend line growth + residential/seasonal electric vehicle (EV) penetration
3. Annual trend line growth + Large customer expansion + residential/seasonal electric vehicle(EV) penetration

In all scenarios, a fixed annual growth rate of 0.83% was applied to Batchawana TS, and a 0.6% annual growth rate was applied to Goulais TS. Residential EV penetration by 2050 is assumed to be 90%. Seasonal EV penetration by 2050 is assumed to be 70%. A coincident factor of 20% was assumed in the load forecast. Scenario 3 above was selected as it provides the most limiting case.

With the above assumptions and scenarios, load forecast by 2050 for respective stations are:

Batchawana TS : The baseline (2019) winter peak demand was 1.5MW . The station's load is forecasted to grow at 0.83% annually, up to 2.43MW by 2050. API indicated that maximum of 4MW load transfer from Goulais TS to Batchawana TS is possible upon API's completion of the 3 phase tie switch[1], putting maximum demand to 6.43MW with load transfer.

Goulais TS : The baseline (2019) winter peak demand was 8.1MW . The station's load is forecasted to grow at 0.6% annually, up to 10.67MW by 2050. API indicated that maximum of 2.5MW load transfer from Batchawana TS to Goulais TS is possible upon API's completion of the 3 phase tie switch[2], putting the maximum demand of 13.17 MW with load transfer.

Detail load forecast can be found in Appendix A.

3 Area Needs

3.1 Batchawana TS

Batchawana TS is an 115kV facility located approximately 47km north of the city of Sault Ste. Marie along Hwy 17. It consists of 2 single phase units (1 at 1.5MVA, 1 at 2.8MVA). Both units do not have limited time rating (LTR). Existing transformers capacity is expected to be able to handle forecasted load without load transfer capability from the station by 2050. However, it would not be able to handle load transfer requirements as indicated by API. The existing configuration also does not permit API to connect any 3-phase loads.

The ACA conducted in 2018 has concluded that the existing transformers are in Fair condition [3]. However, the Feasibility Report has identified other deteriorating equipment and infrastructures that requires attention. They include:

- Degraded structure foundations
- Rusty structures

Other needs of the station includes:

- Clearance to live components in station is not meeting modern limits of approach standard [1].

[1] The existing tie switch is a single phase, normally open tie switch. API indicated that they are exploring options to upgrade it to a three phase tie switch

[2] The existing tie switch is a single phase, normally open tie switch. API indicated that they are exploring options to upgrade it to a three phase tie switch

- The station does not currently have modern transmission protections, and relies on a transformer high side fuses to provide protection. Fuse replacement takes substantial time which leads to longer restoration time [1].
- The following equipment cannot be maintained without customer outages: Main Power Transformer T1, disconnect switch #590, circuit switchers #593 and #598, LS3 bus [1].
- In the event of transformer failure, the restoration timeline could be extensive as there is no spare or load transfer capability at Batchawana TS.

Pictures in Appendix B illustrates asset degradation at Batchawana TS.

3.2 Goulais TS

Goulais TS is an 115kV facility located approximately 30km north of the city of Sault Ste. Marie along Hwy 17. It consists of a 3 single phase units (5MVA each), for a total of 15MVA. The single phase units do not have limited time rating (LTR). Existing transformers capacity is expected to be able to handle forecasted load with load transfer capability from the station by 2050.

The ACA conducted in 2018 had concluded that the existing transformers are in Poor to Fair condition [3]. The Feasibility Report and ACA have identified other deteriorating equipment and infrastructures that requires replacement. They include:

- Outdoor Batteries requires frequent maintenance.
- Degraded structure foundations
- Rusty structures

Other needs of the station includes:

- Clearance to live components in station is also not meeting modern limits of approach standard [1].
- The station do not currently have any protections installed, and rely on a transformer high side fuse to provide protection. Fuse replacement takes time and lead to longer restoration time [1].
- The following equipment cannot be maintained without customer outages: T1, disconnect switch #589, LS3 bus [1].

- In the event of transformer failure, the restoration timeline could be extensive as the there is no spare or load transfer capability at Goulais TS.

- Currently, any maintenance requirements on T1 require API to physical disconnect leads off of it's 12.5kV bus, which requires significant effort and an outage to the 12.5kV bus and all downstream customers.

Pictures in Appendix C illustrates asset degradation at Goulais TS.

With the rural and radial nature of API's distribution system, API recognized there could be a need to convert the distribution voltage from 12.5kV to 25kV, which is dependent on actual load level increases in future years. As a result, API is working with HOSSM to consider transmission options capable of dual secondary voltage (12.5kV and 25kV), that would permit a voltage conversion in the future if needed.

3.3 Distribution System Needs

The distribution system needs are based on capacity, reliability and supply configuration-based needs.

API's distribution system needs include the following:

- 3-Phase supply from both the Batchawana TS and Goulais TS
- Status quo or better on supply reliability
- No negative impact on the distribution reliability and power quality
- Adequate transformation capacity to meet the distribution system's load term forecasted needs

Currently, API supply both 12.5kV and 25kV load from Goulais Bay TS using its 12.5/25kV transformer. There is a distribution system requirement to keep this dual voltage supply configuration.

4 Supply Alternatives Considered and Analysis Methodology

4.1 Supply Alternatives

Based on asset needs in both Goulais TS and Batchawana TS, the following options were considered and explored in collaboration with API:

- **Option 1** - Refurbish both Goulais TS and Batchawana TS; each station to have a single 3-phase transformer with provision for a Mobile Unit substation (MUS) connection facility in each station. Both distribution sub-systems will be supplied at: a) 12.5 kV or b) 25kV[3]. Transformer capacity of Batchawana TS and Goulais TS would be:
  - Batchawana TS : 7.5/10/12.5 MVA
  - Goulais TS : 10/13/16 MVA

- **Option 2** - Consolidate Goulais TS and Batchawana TS by building a "New" TS[4] . "New" TS will be equipped with two (2) 20MVA 3-phase transformers[1] to supply both distribution sub-systems at either a) 12.5 kV or b) 25kV[5]. The "New" TS is expected to be located closer to existing Goulais TS.

- **Option 3** - Consolidate Goulais TS and Batchawana TS by building a "New" TS with dedicated 25kV "express feeder" between Goulais bay area and Batchawana bay area. The "New" TS is expected to be located closer to existing Goulais TS. "New" TS will be equipped with two (2) 20MVA 3 phase transformer[1] to supply both distribution sub-systems at either a) 12.5 kV or b) 25kV[6] . An additional 25/12.5kV unit is required on the distribution system in the vicinity of Batchawana Bay to convert voltage from the incoming 25kV dedicated "express feeder" to 12.5kV.

Single line diagram for option 2 – 3 are available in Appendix D.

Depending on the chosen distribution voltage, each options would require specific distribution system upgrades. A total 6 different scenarios (2 scenarios for each of the 3 options above) for two (2) voltage permutations (12.5 kV vs 25 kV), are summarized in Table 1 below.

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[3] Depending on the final choice of distribution system supply voltage, the LDC will require a transformer to convert voltage to/from 25kV from/to 12.5kV to supply its 25kV/12.5kV customers on different feeders

[4] The "New" TS was referred to as "Greenfield TS" in [1].

[5] Depending on the final choice of distribution system supply voltage, the LDC will require a transformer to convert voltage to/from 25kV from/to 12.5kV to supply its 25kV/12.5kV customers on different feeders

[6] Depending on the final choice of distribution system supply voltage, the LDC will require a transformer to convert voltage to/from 25kV from/to 12.5kV to supply its 25kV/12.5kV customers on different feeders

Table 1: Summary of Supply Alternatives with details on Distribution system

	Options					
	Option 1-A	**Option 1-B**	**Option 2-A**	**Option 2-B**	**Option 3-A**	**Option 3-B**
Supply Configuration Description	Refurbishment 12.5kV for both Goulais TS Batchewana TS	Refurbishment 25kV for both Goulais TS and Batchewana TS	Build "New" TS at 115/12.5 kV	Build "New" TS at 115/25 kV	Build "New" TS at 115/12.5 kV with 25kV "express feeder" to Batchewana TS	Build "New" TS at 115/25 kV with 25kV "express feeder" to Batchewana TS
Supply Voltage - "NEW" TS			7.2/12.5kV 3PH	14.4/25kV 3PH	7.2/12.5kV 3PH	14.4/25kV 3PH
Distribution Area Voltage-Goulais	7.2/12.5kV 3PH	14.4/25kV 3PH	7.2/12.5kV 3PH	14.4/25kV 3PH	7.2/12.5kV 3PH	7.2/12.5kV 3PH
Distribution Area Voltage-Batchewana	7.2/12.5kV 3PH	14.4/25kV 3PH	7.2/12.5kV 3PH	14.4/25kV 3PH	14.4/25kV 3PH (Express), 7.2/12.5kV 3PH (distribution)	14.4/25kV 3PH (Express), 14.4/25kV 3PH (distribution)
Distribution Configuration -Goulais Load	Status Quo	Convert entire system voltage to 14.4/25kV	Extend 3PH from Greenfield TS and connect to existing 3PH Goulais feeders	Convert entire system voltage to 14.4/25kV; Extend 3PH from Greenfield TS and connect to existing 3PH Goulais feeders	Extend 3-phase from "New" TS	Install 3PH stepdown transformer (12MVA, 25:12.5); Extend 3PH from "New" TS and connect to existing 3PH 12.5kV Goulais feeders
Distribution Configuration -Searchmont area Load	Status Quo	Status Quo	Install 3PH stepup transformer (3-5MVA, 12.5:25) near "New" TS site; Extend 3PH 25kV from stepup transformer to existing Searchmont 25kV (at Goulais TS site)	Extend 3PH 25kV from "New" TS site to existing Searchmont 25kV (at Goulais TS site)	See note for Batchewana Load	Extend 3PH 25kV from "New" TS site to existing Searchmont 25kV (at Goulais TS site)

Distribution Configuration -Batchawana Load	Status Quo	Convert entire system voltage to 14.4/25kV	Extend 3-phase from Greenfield TS site to Batchewana TS site	Extend 3-phase from Greenfield TS site to Batchewana TS site; Convert entire system voltage to 14.4/25kV	Install 3PH stepup transformer (5MVA, 12.5:25); Extend 3PH to existing Searchmont 25kV and to Batchewana TS site. Install 3PH stepdown transformer (3MVA, 25:12.5) near Batchewana	Extend 3-phase from Greenfield TS site to Searchomont 25kV and to Batchewana TS site; Install 3PH stepdown transformer (3MVA, 25:12.5) near Batchewana

4.2 Analysis Methodology

HOSSM and API evaluated each scenario with the following objectives and criteria:

Objective

- Overall least total life-cycle cost for Transmission and Distribution system, which included both capital cost and operation, administration and maintenance (OM&A) cost. Cost incremental that contributed to increased reliability and system performance should be considered and justifiable.

Criteria

1. Meet the long term load forecast provide by API.
2. Address the needs of existing Transmission facilities per section 3 , which included:
   - Aging infrastructure and equipment
   - Electrical clearance concerns
   - Ability to conduct regular maintenance with minimal interruption of supply
   - Provide standard transmission protection system that is coordinated with downstream distribution system protection
   - Ability to provide load restoration in acceptable timeframe
   - Minimize LDC connection work required during planned outages.
3. Status quo , or improved overall system reliability (Transmission and Distribution)

4. Status quo , or improved overall system performance (Transmission and Distribution)

Other Considerations

Other project risks that are not objectives nor criteria, but are taking into consideration includes:

- Potential outage requirements during project execution
- Potential environmental impact
- Potential regulatory implications, such as OEB section 92 application.

4.2.1 Meeting long term load forecast & Address Assets Needs

All 6 scenarios will satisfy criteria 1 and 2 above.

4.2.2 System Reliability Analysis

System reliability is further split into Transmission supply reliability and Distribution system reliability, with each subdivided into interruption duration and frequency.

Transmission Supply Reliability – Interruption Duration

Transmission Supply Reliability for Option 1 is considered to be status quo, with marginal improvement as the MUS connection facility will facilitate a faster restoration upon transformer contingency. The MUS would also allow outages to be scheduled to facilitate planned maintenance activities. However, as MUS would not permanently be located on-site and requires time for transportation and connection, hence the outage duration is expected to be longer compared to option 2 and 3. Option 2 and option 3, from a station asset point of view, will increase Transmission supply reliability in the study area as the “New” TS will be equipped with two transformers to provide redundant transformation, and hence reduce outage duration upon loss of a single transformer.

Transmission Supply Reliability – Interruption Frequency

Under all options the station(s) will remain supplied solely by one (1) 115kV circuit – Sault #3 Circuit. Sault #3 is about 90km long. Due to its higher environmental exposure compared to a station, the frequency of interruption for all options will not materially change.

Distribution Supply Reliability – Interruption Duration

API's distribution system in the Batchawana and Goulais areas are rural and remote and in some part, located off the shores of Lake Superior. As a result, during major events, such as storms (winter or summer), interruption duration could be long if the storm is severe. The majority of API's pole line is also not road accessible, and requires special off road vehicles for accessing and repair any issues. In options 2 and 3, API would see an increase in outage duration for any permanent faults along the new 3-phase line extension between the existing two TS sites.

Option 1 would permit API to transfer load between the two stations, and result in increased distribution reliability during planned and unplanned outages compared to that of Option 2 and 3.

Distribution Supply Reliability – Frequency of Interruption

Option 2 and option 3 will decrease Distribution supply reliability in the study area as the "New" TS consolidates Transmission supply point from existing two (2) stations to only one (1). This eliminates feeder sections that are supplied from either Batchawana or Goulais TS. Longer portions of distribution feeders increases the exposure level and probability of causing customers' interruption increases. API would be exposing approximately 840 customers to a new 10 km radial feeder and approximately 620 customers to an additional 10 km radial feeder.

Option 2 and 3 would not permit API to perform any load transfers that option 1 can afford during any planned maintenance work (e.g. pole change, line clearing) that take place at regular intervals.

Transmission vs Distribution

It is expected that the probability of distribution interruption will be greater than that of transmission, as the distribution system has more circuit kilometers compared to that of transmissions, and cover a larger geographical area compared to the transmission study area.,

Table 2 summarized system reliability assessment for Transmission and Distribution system.

Table 2: System reliability comparison among all alternatives

	System Reliability Comparison					
	Option 1-A	**Option 1-B**	**Option 2-A**	**Option 2-B**	**Option 3-A**	**Option 3-B**
Transmission Reliability - Duration	Status Quo – Marginal Improvement	Status Quo – Marginal Improvement	Increased	Increased	Increased	Increased
Transmission Reliability – Frequency	Status Quo	Status Quo	Status Quo	Status Quo	Status Quo	Status Quo
Distribution Reliability - Duration	Status Quo	Status Quo	Decreased	Decreased	Decreased	Decreased
Distribution Reliability – Frequency	Status Quo	Status Quo	Decreased	Decreased	Decreased	Decreased
Overall	**Marginally Improved**	**Marginally Improved**	**Marginally degraded**	**Marginally degraded**	**Marginally degraded**	**Marginally degraded**

4.2.3. System Performance Analysis

System Performance is evaluated based on voltage performance and system loss.

4.2.3.1 Distribution Voltage Performance Analysis

API evaluated the distribution voltage performance under different scenarios and summarized its respective voltage re-enforcement requirements. In this evaluation, performance of Option 1-A is chosen as the baseline for benchmarking purpose because this represents the existing situation. Table 3 below summarized voltage support requirements in different scenarios

It is observed that except for option 2-B, all options required some voltage support throughout the distribution system to provide adequate voltages for the anticipated load growth within the the period 2020 – 2050, as well as to accommodate different Transmission supply configuration options..

Option 2-A would require the most voltage support among all considered alternatives, followed by 3-A and 3-B.

Table 3: Distribution voltage performance and support requirements comparison

Distribution Voltage Performance and Support Requirement Comparison					
Option 1-A	**Option 1-B**	**Option 2-A**	**Option 2-B**	**Option 3-A**	**Option 3-B**
7.2/12.5kV 3PH	14.4/25kV 3PH	7.2/12.5kV 3PH	14.4/25kV 3PH	7.2/12.5kV 3PH	14.4/25kV 3PH
Voltage support required based on load forecast	Voltage Support only required to maximize load transfer capabilities between Batchewana TS and Goulais TS	Voltage support required based on load forecast. Additional voltage support required to accommodate single supply station in Batchewana. Potential additional voltage support required in Goulais depending on location of Greenfield TS	Not required	Voltage support required based on load forecast. Potential additional voltage support in Goulais depending on location of Greenfield TS	Voltage support required based on load forecast. Potential additional voltage support in Goulais depending on location of Greenfield TS

4.2.3.2 Distribution System Losses Analysis

API evaluated the distribution system losses based on proposed voltage of different options[7]. Option 1-A is chosen as benchmark for comparison purpose.

According to the analysis, it is observed that Option 2-A, 3-A and 3-B – options which consolidates Batchawana and Goulais TS and supply the area at 12.5kV – would result in higher active power losses in the study area compared to the benchmark due to the loss of a second Transmission infeed to the distribution system. This results in using longer distribution feeders to connect load to electrical source. A consolidated supply configuration only reduces system losses if the distribution voltage is also upgrade to 25kV.

The difference in active power losses between a consolidated Transmission infeed ("New" TS) vs two (Batchawana and Goulais) becomes non-material if distribution voltage is upgraded to 25kV. Based on the study, option 2-B (consolidation – 25kV) have 0.6% higher losses compared to option 1-B (keep Batchawana and Goulais – 25kV). In conclusion, system loss performance is more sensitive to the choice of distribution voltage instead of supply configuration.

Table 4: Distribution system losses comparison

	System Loss Comparison					
	Option 1-A	**Option 1-B**	**Option 2-A**	**Option 2-B**	**Option 3-A**	**Option 3-B**
Supply Voltage	7.2/12.5kV 3PH	14.4/25kV 3PH	7.2/12.5kV 3PH	14.4/25kV 3PH	7.2/12.5kV 3PH	14.4/25kV 3PH
Active Power Losses	10.24%	5.00%	17.71%	5.60%	12.46%	12.46%
Distribution System Loss Impact	Status Quo	Overall decrease in Active System Loss by 51%	Increase in Active System Loss by ~73%	Overall decrease in Active System Loss by 45%	Increase in active losses by ~22%	Increase in active losses by ~22%

[7] Evaluation performed by 3rd party

4.2.4 Cost Analysis

Depending on the different distribution voltage, each scenario would require specific distribution system upgrades. HOSSM and API had utilized their respective internal planning allowance to estimate the cost for various scenarios. Cost estimates are intended for the purpose of option comparison, and are not within sufficient accuracy to be relied upon for project financing. Table 5 summarized capital and OM&A costs for each scenarios.

Cost to build the "New" TS is based on recently completed HONI High Voltage Distribution Station (HVDS) projects[8] with real estate allowance, which HOSSM believe would represent a more realistic cost estimations compared to costs provided in [1]. Voltage support requirements in Distribution system, and its associated costs, are based on API's Supply Configuration Alternative analysis.

Based on Table 5, it is observed that all options have comparable capital costs among scenarios supplying the same distribution voltage (12.5 kV, 25kV), regardless of supply configurations (Consolidation vs Individual stations rebuild). There are sizable cost incremental (30-40% more) when options are upgrade to 25kV, compared to remaining at 12.5kV in the distribution system. Option 2 and 3 (Consolidation) show clear OM&A advantage over option 1 (Individual stations rebuild) as maintaining one station would be more economic than maintaining two. The combined suggested that Consolidation resulted in slightly lower total life cycle cost compared to that of Individual comparable distribution voltage. Overall, Individual stations rebuild (Option 1) is about 10% - 12.5% more expensive compared to consolidation options with the same distribution voltage, however it provides improvements to system reliability and performance.

[8]Assumed 2X the cost form a HVDS project completed in 2018 to account for 2 transformers, plus real estate expansion allowance.

Table 5: Total life cycle cost comparison for various options

	Description	Cost Comparison ($M)					
		Option 1-A	**Option 1-B**	**Option 2-A**	**Option 2-B**	**Option 3-A**	**Option 3-B**
Transmission Cost	New Substation to replace exciting stations	-	-	$14.4	$14.4	$14.4	$14.4
	Refurbish the existing Goulais TS	$9.1	$9.1	-	-	-	-
	Refurbish the existing Batchewana TS	$6.2	$6.2	-	-	-	-
Distribution Tie-Line Reinforcement	Install three-phase tie switch to allow load transfer	-	-	$4.0	$4.0	$4.0	$4.0
12.5/25kV Power Transformer	Two 12MVA, 25/12.5kV transformers and relevant buswork, site, concrete work, .etc	-	-	-	-	-	$1.5
	Two 5MVA, 12.5/25kV transformers and relevant buswork, site, concrete work, .etc	-	-	-	-	$0.6	-
	One 2MVA, 25kV/12.5kV Transformer Bank to step the voltage down at Batchewana	-	-		-	$ 0.3	$ 0.3
Voltage Reinforcement	Several Shunt capacitors and voltage regulators installation for voltage profile control	-	-	$ 0.9	-		-

	Reinforcements with normal configuration for voltage profile control	$ 0.6	-	-	-	$ 0.6	$ 0.6
	Several shunt capacitors/regulars to support voltage under back up operation	-	$ 0.7	-	-		-
	Several Shunt capacitors installation for voltage profile control	-	-	-	-	$ 0.1	$ 0.1
Voltage Conversion Requirement	Replace of distribution transformers with 12.5kV primary voltage to 25kV	-	$ 3.4	-	$ 3.4		-
	Insulator Upgrade to 28kV	-	$ 5.0	-	$5.0		-
TOTAL CAPITAL COST (ESTIMATED)		**$15.9**	**$24.4**	**$ 19.3**	**$26.8**	**19.7**	**$ 20.6**
Maintenance Cost (50 year lifecycle)		$7.1	$7.1	$4.7	$ 4.7	$4.7	$4.7
Total Life Cycle Cost (50 year life cycle)		**$ 23.0**	**$ 31.5**	**$ 24.0**	**$ 31.5**	**$ 24.4**	**$ 25.3**

4.2.5 Cost- Benefit Analysis

Previous sections provided analysis on different criteria based on different scenarios. Table 6 below illustrates a summary of cost-benefit analysis, where cells in green indicated an improvement, while cells in red indicated a degradation. It is observed that Options 1-A (Rebuild Batchawana and Goulais- 12.5kV) achieves the best balance between costs and meeting various evaluation criteria. Other options that builds a "New" TS are either more expensive, or unable to provide the same level of system reliability and performance despite being more economical.

Although option 1-B provides the best system reliability and performance among all options, option 1-A is the least cost option that would meet all transmission and distribution needs...

Table 6: Cost benefit summary

Cost Benefit	Option 1-A	Option 1-B	Option 2-A	Option 2-B	Option 3-A	Option 3-B
System Reliability	Marginally improved	Marginally improved	Marginally degraded	Marginally degraded	Marginally degraded	Marginally degraded
Voltage support Requirements	Benchmark	Minor	Major	None	Some	Some
Active Power loss	Benchmark (10.24%)	5.00%	17.71%	5.60%	12.46%	12.46%
Capital Cost	$15.90	$24.40	$19.30	$26.80	$19.7	$20.60
OM&A Cost (50 years)	$7.10	$7.10	$4.70	$4.70	$4.70	$4.70
Total Cost ($M)	**$23.00**	**$31.50**	**$24.00**	**$31.50**	**$24.40**	**$25.30**

4.2.6 Discussion on Common Project Execution Risks

In addition to meeting the objective and criteria, the working group considered other commonly known project risks, as the ultimate recommendation should not introduce major misalignment with these risks. It is not the scope of this planning report to predict future outcome of these project risks, but rather, to provide an overview and discuss its implication.

Compared to station expansion, it is anticipated that building a "New" TS would, in general, trigger larger real estate and easements right requirements and a more complex environmental assessment. These risks introduce cost and schedule uncertainty to the project.

The working group also recognized that the existing station configuration, inadequate electrical clearances, extremely limited load transfer capability between stations, and small station footprints in both Batchawana TS and Goulais TS could constraint outage availability during construction, which would lead to a longer and more complex construction schedule. In contrast, building a new TS on a "greenfield" site would have fewer outage constraints, and would possibly resulted in a more compressed construction schedule.

5 Conclusion and Recommended Solution.

As a recommendation of the 2019 *Need Assessment*, HOSSM and API have conducted a coordinated review and evaluation on the supply options to the Batchawana and Goulais Bay area. The working group reviewed the study area, facilities needs and future load forecast. Six scenarios were developed based upon these foundations and presented in this review. They include 1) Refurbish both Batchawana TS and Goulais TS, 2) Build a "New" TS to replace both Batchawana TS and Goulais TS, and 3) Build a "New" TS with a dedicate 25kV feeder to supply between the Batchawana and Goulais areas to replace both existing stations.

These six scenarios were evaluated based on system reliability, system performance, and total life-cycle cost to determine the optimal solution that balances cost with various system benefits. The agreed upon option is Option 1-A as it will allow HOSSM to address deteriorating asset condition at Batchawana TS and Goulais TS in the short to medium time frame, to meet load forecast, as well as to maintain the long term supply reliability to API customers.

The analysis also concludes that the choice of distribution voltage (12.5kV vs 25kV) has a more dominant impact on both system performance and cost over the choice of supply configuration. A consolidation of Batchawana TS and Goulais TS into a single station would have also resulted in a marginal degradation of overall system reliability and more observable shortfalls in distribution system performance compared to present day's benchmark. A cost-benefit analysis reveals that Option 1-A provides the lowest total life cycle cost and achieve the best balance between cost vs system benefits. Therefore, Option 1-A is recommended.

6 References

[1] *Development of Greenfield Transmission Station Feasibility Study, Report No 15-079-01, Revision C*. OneLine Engineering , Great Lake Power Transmission , (2016), Sault Ste. Marie, Ontario.

[2] *Decision and Order EB-2018-0218, Hydro One Sault Ste. Marie LP, Application for electricity transmission revenue requirement beginning January 1, 2019 and related matters* , Ontario Energy Board (2019), Ontario.

[3] *Asset Condition Assessment for the Hydro One Sault Ste. Marie Transmission System*. Metsco, (2018), Toronto, Ontario.

Appendix A: Load Forecast for Goulais TS & Batchawana TS (2020-2050)

Goulais TS Load Forecast (2020-2050) [MW]:

Scenarios	GROWTH RATE	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Annual Trendline Growth	0.60%	8.10	8.15	8.19	8.24	8.29	8.34	8.39	8.44	8.50	8.55	8.60	8.65	8.70	8.75	8.81	8.86	8.91	8.97
Annual Trendline Growth+Large Customer Expansion(500kW)	0.60%	8.10	8.15	9.52	9.73	10.28	10.55	10.60	10.65	10.71	10.76	10.81	10.86	10.91	10.96	11.02	11.07	11.12	11.18
Annual Trendline Growth+Residential/Seasonal EV Penetration	0.60%	8.10	8.15	8.31	8.37	8.44	8.50	8.57	8.63	8.70	8.76	8.83	8.90	8.96	9.03	9.10	9.16	9.23	9.30
Annual Trendline Growth+Residential/Seasonal EV Penetration+Large Customer Expansion(500kW)	0.60%	8.10	8.15	9.64	9.96	10.52	10.82	10.88	10.95	11.02	11.08	11.15	11.22	11.29	11.35	11.42	11.49	11.56	11.63

Scenarios	GROWTH RATE	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Annual Trendline Growth	0.60%	9.02	9.08	9.13	9.19	9.24	9.30	9.35	9.41	9.46	9.52	9.58	9.64	9.69	9.75
Annual Trendline Growth+Large Customer Expansion(500kW)	0.60%	11.23	11.29	11.34	11.40	11.45	11.51	11.56	11.62	11.67	11.73	11.79	11.85	11.90	11.96
Annual Trendline Growth+Residential/Seasonal EV Penetration	0.60%	9.37	9.44	9.51	9.58	9.65	9.72	9.79	9.86	9.93	10.01	10.08	10.15	10.22	10.29
Annual Trendline Growth+Residential/Seasonal EV Penetration+Large Customer Expansion(500kW)	0.60%	11.70	11.77	11.84	11.91	11.98	12.05	12.12	12.20	12.27	12.34	12.42	12.49	12.56	12.64

Batchawana TS Load Forecast (2020-2050) [MW]

Scenarios	GROWTH RATE	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Annual Trendline Growth	0.83%	1.58	1.59	1.60	1.62	1.63	1.64	1.66	1.67	1.69	1.70	1.71	1.73	1.74	1.76	1.77	1.79	1.80	1.82
Annual Trendline Growth+Large Customer Expansion(285kW)	0.83%	1.58	1.88	1.89	1.90	1.92	1.93	1.94	1.96	1.97	1.99	2.00	2.01	2.03	2.04	2.06	2.07	2.09	2.10
Annual Trendline Growth+Residential/Seasonal EV Penetration	0.83%	1.58	1.59	1.61	1.62	1.64	1.66	1.68	1.69	1.71	1.73	1.75	1.76	1.78	1.80	1.82	1.83	1.85	1.87
Annual Trendline Growth+Residential/Seasonal EV Penetration+Large Customer Expansion(285kW)	0.83%	1.58	1.88	1.89	1.91	1.93	1.94	1.96	1.98	2.00	2.01	2.03	2.05	2.07	2.08	2.10	2.12	2.14	2.16

Scenarios	GROWTH RATE	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Annual Trendline Growth	0.83%	1.83	1.85	1.86	1.88	1.89	1.91	1.93	1.94	1.96	1.97	1.99	2.01	2.02	2.04
Annual Trendline Growth+Large Customer Expansion(285kW)	0.83%	2.12	2.13	2.15	2.16	2.18	2.19	2.21	2.23	2.24	2.26	2.27	2.29	2.31	2.32
Annual Trendline Growth+Residential/Seasonal EV Penetration	0.83%	1.89	1.91	1.93	1.95	1.97	1.99	2.00	2.02	2.04	2.06	2.08	2.10	2.12	2.14
Annual Trendline Growth+Residential/Seasonal EV Penetration+Large Customer Expansion(285kW)	0.83%	2.18	2.19	2.21	2.23	2.25	2.27	2.29	2.31	2.33	2.35	2.37	2.39	2.41	2.43

Appendix B: Asset Pictures at Batchawana TS [1]



Corrosion on Transformer T1 at Batchawana TS

Low clearance fence

Rusty structures

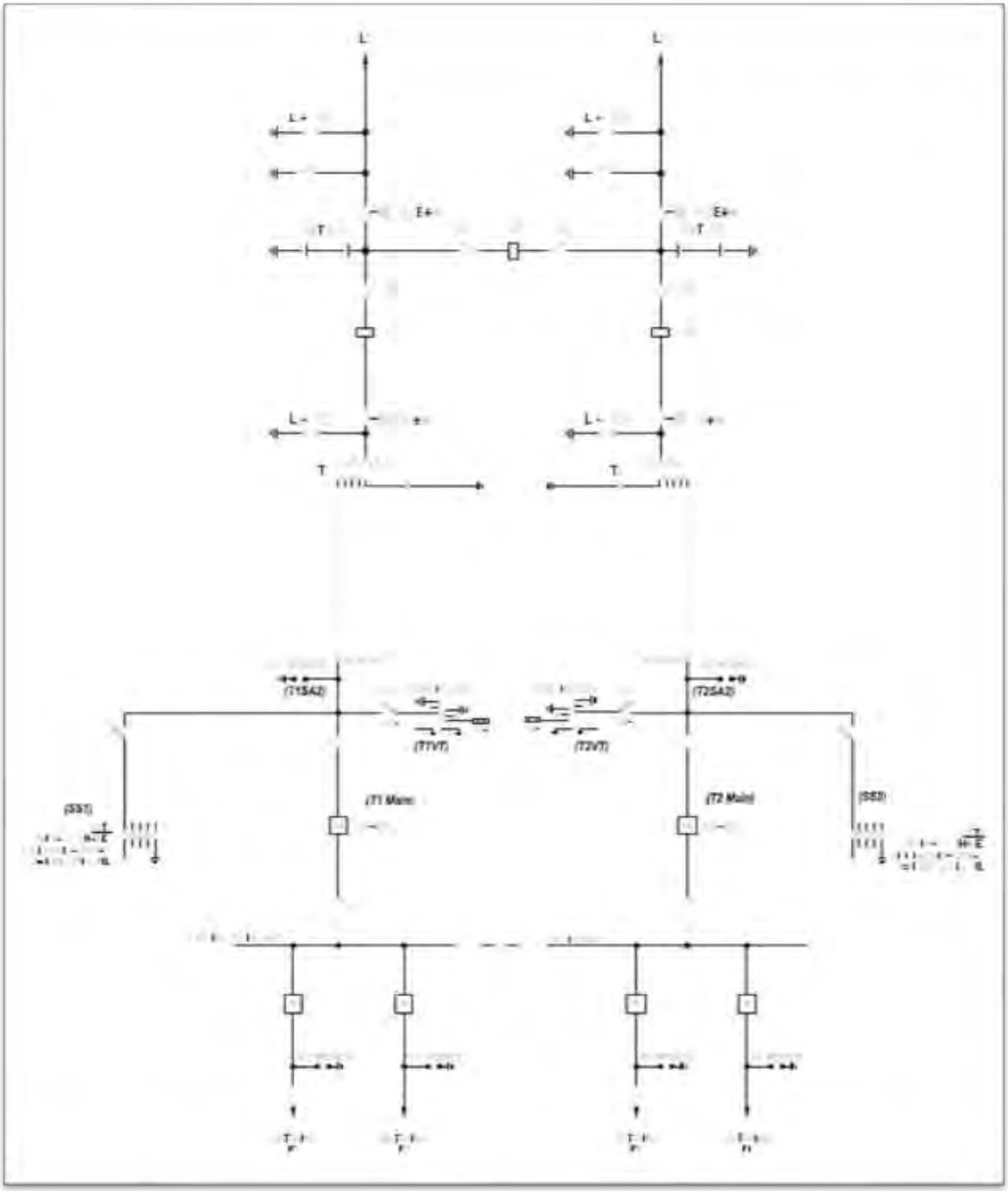
Degraded Foundations

Appendix C: Asset Pictures at Goulais Bay TS [1]

Detached and degraded foundations (left and right picture)

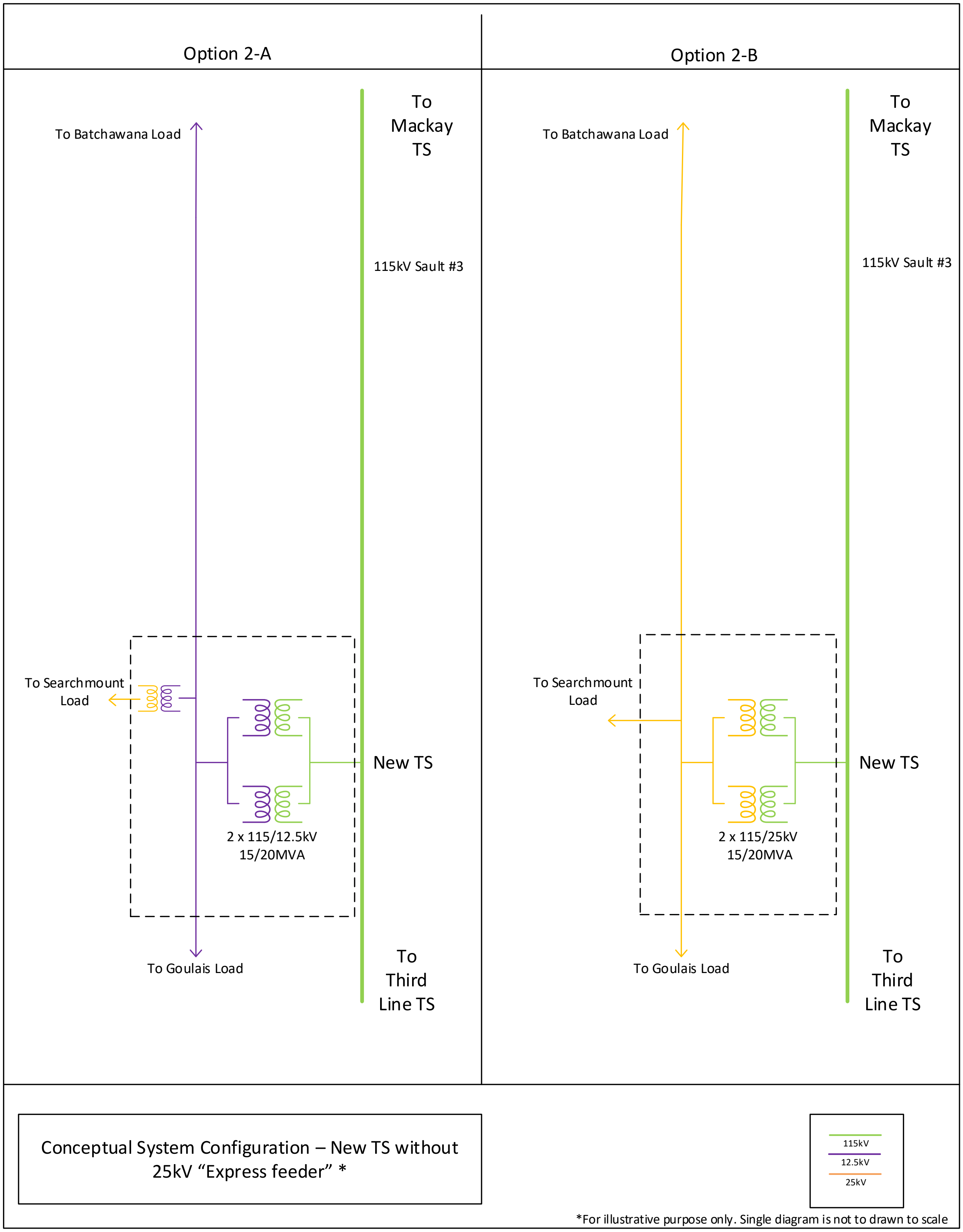
Goulais T1 with signs of oil leak

Appendix D: Single Line Diagram for New TS[1]

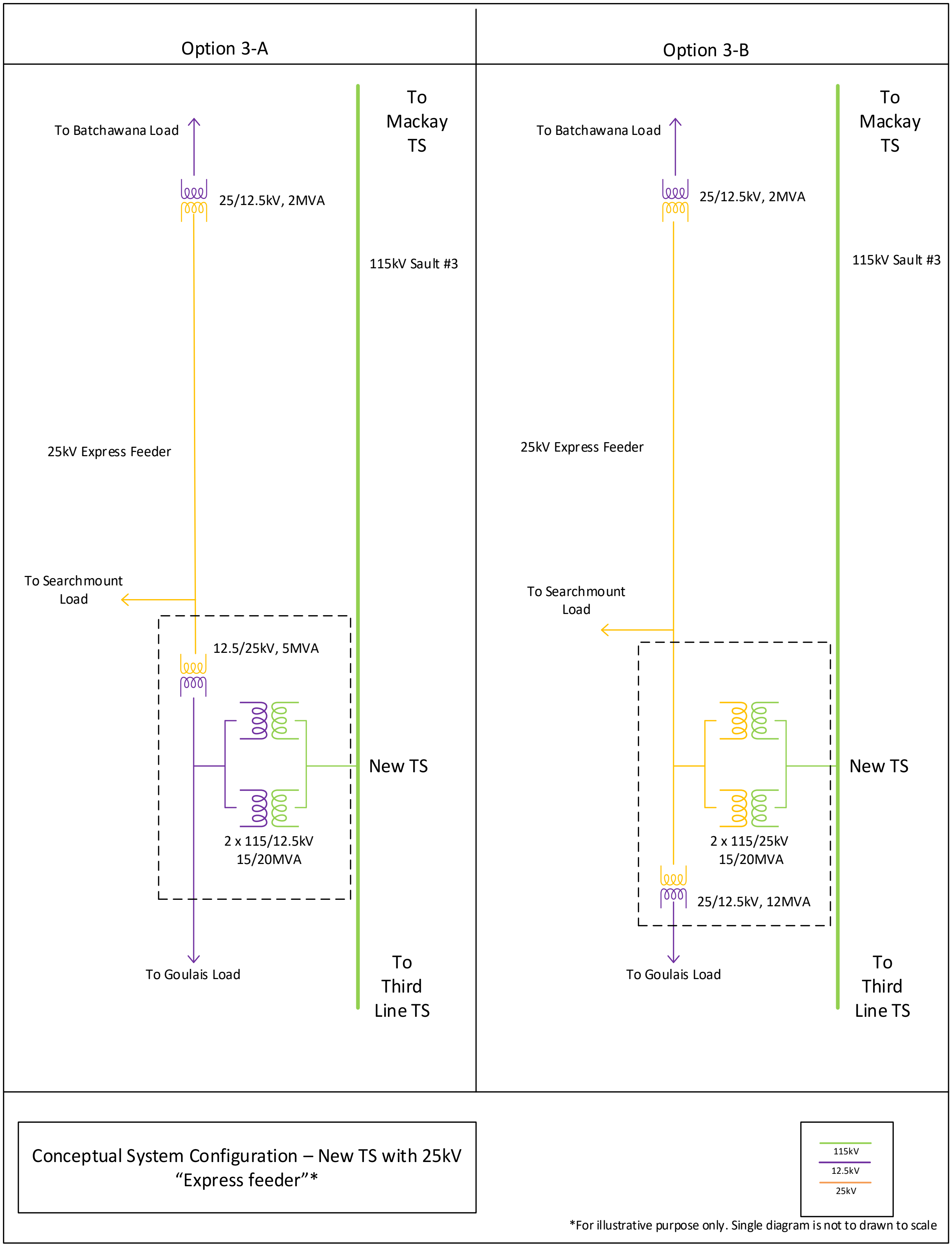


Single line diagram that illustrates the recommended station configuration from Feasibility Report in [1].

Appendix E: Conceptual System Configuration for New TS (Option 2)



Appendix F: Conceptual System Configuration for New TS with 25kV Express Feeder (Option 3)



Algoma Power Inc.

Distribution System Plan

Appendix M

ALGOMA POWER

EAST SAULT STE MARIE 34.5KV SUB-TRANSMISSION SYSTEM ANALYSIS

6 August, 2020

C16-0056

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Type of report

Distribution System Analysis

Low Voltage Analysis and Solution Discussion

Project no. C16-0056

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0	26 June, 2020	Ashley Rist, P.Eng.		Stephen Costello, CET
1	6 August, 2020	Ashley Rist, P.Eng.		Stephen Costello, CET

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1. Executive Summary

The 34.5kV distribution system east of Sault Ste Marie is mostly supplied by Hydro One's Echo River Transformer Station (ERTS). A joint regional planning study (June 2019) authored by the IESO has determined that a major failure at ERTS would result in an unacceptable duration outage (greater than eight hours). CIMA has been commissioned to look at distribution alternatives to Hydro One adding additional capacity at ERTS. Hydro One is currently reviewing the scope, schedule, and costs of upgrading ERTS such that an outage could be managed with a duration shorter than eight hours.

This study is looking at the possibility of supplying the same load area from the Sault Ste Marie Northern Avenue Transformer Station (NATS) over the existing 34.5kV distribution system. CIMA has been engaged to perform a study to asses the existing distribution system's ability to supply all of the load from NATS. The distance of the circuit from NATS is substantially longer than if the load were to be fed from ERTS. In addition, there is relatively small conductor size for approximately 31km from NATS and Bar River Distribution Station.

This study found that it is technically feasible to supply all of the load from NATS, if the 31km stretch of 3/0 ACSR conductor between NATS and Bar River Distribution Station is reconductored. When the system is being supplied from NATS, this section is heavily loaded which contributes to significant voltage drop. If this section of conductor is replaced with 556 ASC, the lowest calculated delivery voltage is within the acceptable range. The cost for rebuilding was estimated by PowerTel and the engineering costs estimated by CIMA+, totalling $8.7M Class 3 (+25%, -5%). This cost does not include other typical project costs, such as Algoma's project management costs or other typical construction project costs for the area.

Other options explored involved voltage support devices, such as voltage regulators, capacitors, and on-load tap changers. It was determined that installing equipment without reconductoring was not enough to correct the voltage, and in addition the 3/0 ACSR conductor became heavily loaded. In the course of our study, we found there are opportunities to improve voltage regulation and efficiency under normal and contingency conditions with relatively minor modifications or additions in equipment. This is discussed later in the report.

2. Introduction

Algoma Power had a previous study performed in 2018 to analyze a contingency situation where the Echo River TS (ERTS) load is supplied by NA1 feeder from Northern Ave TS (NATS). The study found that if the peak load were to be supplied from NATS that the delivery voltage would be unacceptably low to a significant portion of the system. A prolonged outage would require rolling blackouts to maintain acceptable voltages to supplied customers. The recommendation from this report was to procure a spare power transformer for ERTS to mitigate the need to supply the system from NATS. A spare was quoted by Hydro One and would cost approximately $6-9M. This solution provides either an off-potential or on-potential spare, depending on cost. An off-potential spare would add a significant amount of time to process the oil and make all of the terminations. An on-potential spare would still require an extended outage to bring the spare transformer into service and make secondary connections.

As part of its due diligence, Algoma Power requested the services of CIMA+ to analyze distribution solutions for the extremely low voltage issues when in a contingency situation. System data, including existing equipment and equipment controls, historical loading, conductor types and lengths were collected and used to build the base model. The model was then verified using in-field measurements at reclosers, capacitor banks, and regulators. CIMA+ established benchmarks for both ERTS and NATS supplying the system through load flow modelling. Possible scenarios were modeled and compared against the existing situations as well as against each other for feasibility.

All proposed solutions include reconductoring the 31km section of 3/0 ACSR from NATS to Bar River DS. This section is 85% loaded during peak conditions and contributes significant voltage drop and losses in the system. PowerTel was engaged to construct an estimate for replacing this section, their full estimate can be found in *Appendix B*. CIMA+ estimated the cost of engineering for the rebuild and the detailed estimate can be found in *Appendix D*.

3. Assumptions

The system was modeled using CYME V9.0, using the supplied information from API and the assumptions below.

The normal operating conditions were taken from *Bruce Mines 34.5kV Line System Operating Diagram, DB-32001 Rev 58*. To transfer load to NATS, switches 076 and 023 are closed; switches 020 and 562 are opened.

Acceptable voltage range used was -5% to +5%.

Loads in the system were modeled after peak loading in January 2019. Feeder End was assumed to be an industrial load and was modeled using the highest non-coincident kW and kVAr from 2017-2019. Minimum loads were assumed to be 30% of peak. Load power factors were assumed to be 95% lagging.

The model was validated against metered data using two methods. The data collected and calculations to verify the model are detailed in *Appendix B*.

3.1 API Provided Information

- HONI Data
  - Voltage Regulation Information
    - Set Voltage
    - Load Drop Compensation
    - Bandwidth
    - Normal Operating Voltage
    - Minimum and Maximum Bus Voltage
  - Transformer Tap Changer
    - Voltage Range
    - Number of Steps
  - Source Impedance
  - Protection Settings
- Distribution Circuits
  - Operating Map
  - Switching Sequence
  - Station Transformer Data
    - Voltages
    - Impedance
    - Tap Changers (steps, voltage regulation settings)
  - Distribution Regulators
    - Size
    - Range
    - AVR Relay and Settings
  - No capacitors on the system

- Loading
  - HONI PME (ERTS and NATS) Monthly Maximum kVA and kW for three years
  - API DS Monthly Maximum kWh for two years
  - Monthly Minimum and Maximum for Direct 34.5kV customers

A copy of API's 34.5kV single line diagram is included in *Appendix E*.

3.2 CIMA+ Assumptions

The following table describes the assumed conductor and cable impedances used in the model. These are the default values in the CYME library. The overhead conductor spacing was assumed to be linear, two foot spacing.

Table 1: Conductor Assumptions

Conductor Size	Type	Codename	Ampacity	Positive Sequence Impedance (Ω/m)	Zero Sequence Impedance (Ω/m)
2/0	XLPE - CU		275	0.511+j0.242	0.797+j3.999
4/0	XLPE - CU		375	0.338+j0.214	0.6243+j3.971
3/0	ACSR	Pigeon	315	0.555+0.677	1.285+j2.330
336	ASC	Canna	510	0.237+j0.636	0.967+j2.288
477	ACSR	Hawk	640	0.198+j0.606	0.928+j2.258
556	ASC	Dahlia	645	0.170+j0.615	0.900+j2.267

3.3 CYME Analysis Clarifications

The total loads calculated by CYME are as seen from the source, or TS. The rows labeled "Loads" in the following section account for losses, voltage regulation, and capacitive devices.

CYME adjusts loads used in the model, "Load used (Adjusted)" in the Summary Reports, so that the total load analysed will match what was modeled at the source. In this case, the "Loads" in the following section will be 16.2MVA at peak and 4.9MA at minimum less the losses calculated.

DS and customer loads are modeled at 95%, unless data has been provided showing otherwise, but in conjunction with the capacitor banks the transformer stations typically show close to unity power factor.

4. Operating Scenarios

Three scenarios were modeled to determine the voltages across the system and described in this section. A base case was established using existing conditions when the system is fed from ERTS and NATS. The first distribution solution explored was to reconductor 31km of 3/0 ACSR with 556 ASC between NATS and Bar River DS. The second solution involves reconductoring, but also explores having load tap changers on the distribution station transformers and one three phase voltage regulator upstream of Bruce Mines.

Detailed CYME results can be found in *Appendix C*.

4.1 Base Case

The load is usually fed from ERTS. The tables below demonstrate the base case voltage and loading under normal operating conditions.

Table 2: From ERTS Base Case – Peak Load

Total	kW	kVAr	kVA	PF
Sources	15644	1300	15698	99%
Generators (Solar)	239	0	239	100%
Loads	15404	553	15414	99%
Line/Cable Inductance	0	605	605	100%
Calculated Losses	480	1352	1434	31%

Table 3: From ERTS Base Case – Peak Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 081 to 079	42%
Lowest Voltage	A	Feeder End	97%
	B	Feeder End	98%
	C	Feeder End	99%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	ERTS	104%

Table 4: From ERTS Base Case – Minimum Load

Total	kW	kVAr	kVA	PF
Sources	4568	-40	4568	100%
Generators (Solar)	239	0	239	100%
Loads	4761	440	4782	99%
Line/Cable Inductance	0	615	615	100%
Calculated Losses	45	135	143	32%

Table 5: From ERTS Base Case – Minimum Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 081 to 079	12%
Lowest Voltage	A	Feeder End	101%
	B	Feeder End	101%
	C	Feeder End	101%
Highest Voltage	A	Switch 076	104%
	B	Switch 076	104%
	C	Switch 076	104%

Under normal operating conditions from ERTS, delivery voltage parameters are within acceptable limits. The lowest voltage is at Feeder End at 97%. If more load were to be added to the system, there is a possibility that Feeder End could have an under-voltage condition at peak load.

4.2 Base Case from NATS

If the supply from ERTS is interrupted, the backup supply is currently from NATS. This section evaluates supplying the system from NATS at peak and minimum loading.

Table 6: From NATS – Peak Load

Total	kW	kVAr	kVA	PF
Sources	15264	3422	15643	98%
Generators (Solar)	239	0	239	100%
Loads	13319	696	13337	99%
Line/Cable Inductance	0	496	496	100%
Calculated Losses	2185	3222	3893	56%

Table 7: From NATS – Peak Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from NATS to Bar River DS	84%
Lowest Voltage	A	Supply Side of St Joseph Regulator	85%
	B	Supply Side of St Joseph Regulator	85%
	C	Supply Side of St Joseph Regulator	88%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	ERTS	104%

Table 8: From NATS – Minimum Load

Total	kW	kVAr	kVA	PF
Sources	4581	135	4583	99%
Generators (Solar)	239	0	239	100%
Loads	4628	422	4647	99%
Line/Cable Inductance	0	588	588	100%
Calculated Losses	193	300	357	54%

Table 9: From NATS – Minimum Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from NATS to Bar River DS	25%
Lowest Voltage	A	Supply Side of St Joseph Regulator	100%
	B	Supply Side of St Joseph Regulator	98%
	C	Supply Side of St Joseph Regulator	100%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	ERTS	104%

Algoma's peak load occurs during winter months, and it is a single peak load system. The delivery voltages are below acceptable voltage levels when supplied from NATS. Some sections of conductor are over 80% loaded, which contributes to the low voltage issues. If this situation occurs, rolling blackouts are utilized to reduce loading and increase the voltage to acceptable values. Bar River was found to have the lowest voltage at 87%, as it is does not have an upstream voltage regulator. Rotating blackouts in rural Northern Ontario during the winter can be dangerous for the public, as heating homes is a safety issue.

Without any changes, NATS can supply the system with acceptable delivery voltages during minimum load. Algoma's minimum load occurs during the summer.

4.3 From NATS, with Only Regulators

If voltage support devices are installed, the distribution system can adapt to changes in supply and load more effectively. This section outlines the operating conditions when supplied from NATS, after installing several voltage regulators. The regulators were modeled upstream (when supplied from NATS) of Garden River DS, Switch 077, Bar River DS, and Bruce Mines.

Table 10: From NATS – Peak Load

Total	kW	kVAr	kVA	PF
Sources	16294	5039	17055	95%
Generators (Solar)	239	0	239	100%
Loads	15487	2013	15618	99%
Line/Cable Inductance	0	570	570	100%
Calculated Losses	1046	3596	3745	28%

Table 11: From NATS – Peak Load Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from NATS to Garden River	107%
Lowest Voltage	A	Supply Side of Bruce Mines Regulator	89%
	B	Supply Side of Bruce Mines Regulator	93%
	C	Supply Side of Bruce Mines Regulator	93%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	ERTS	104%

4.4 From NATS, with Reconductoring

Reconductoring the 3/0 ACSR from NATS to Bar River DS can resolve the voltage issues. This section describes the conditions for supplying from NATS with a rebuilt line.

Table 12: From NATS – Peak Load

Total	kW	kVAr	kVA	PF
Sources	15705	4660	16381	96%
Generators (Solar)	239	0	239	100%
Loads	14986	1902	15106	99%
Line/Cable Inductance	0	571	571	100%
Calculated Losses	958	3330	3465	28%

Table 13: From NATS – Peak Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 2025 to tie between 023 and 027	48%
Lowest Voltage	A	Supply Side of St Joseph Regulator	94%
	B	Supply Side of St Joseph Regulator	92%
	C	Supply Side of St Joseph Regulator	95%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	ERTS	104%

Table 14: From NATS – Minimum Load

Total	kW	kVAr	kVA	PF
Sources	4575	118	4577	99%
Generators (Solar)	239	0	239	100%
Loads	4734	459	4756	99%
Line/Cable Inductance	0	623	623	100%
Calculated Losses	80	282	293	28%

Table 15: From NATS – Minimum Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	2/0 AL from 2010 to 2011	15%
Lowest Voltage	A	Feeder End	99%
	B	Feeder End	100%
	C	Feeder End	100%
Highest Voltage	A	Bar River LV	105%
	B	Bar River LV	104%
	C	Bar River LV	106%

During peak load, reconductoring improves the lowest voltage point in the system by 12% to 92%. This is not a concern because it is on the supply side of a regulator and the regulator can boost the voltage by 10%. The delivery voltages improve so that the Feeder End load point is at 96%. This is within acceptable limits, though it is on the lower end of acceptable. At minimum load the minimum voltage is improved so that Feeder End is the lowest voltage point at 99%. This means that reconductoring is a viable distribution solution to the voltage issues.

4.5 From ERTS, Reconductor and Voltage Devices

Solutions with just equipment additions, such as adding multiple voltage regulators and capacitor banks along the line, did not adequately resolve the voltage issues and often caused the 3/0 ACSR conductor to become overloaded. This solution includes reconductoring and voltage devices which would improve both normal and contingency operating conditions. Voltage support devices include capacitors, on-load tap changers and voltage regulators.

Algoma's distribution system has capacitor banks installed, and the power factor is close to unity, and even leading in some instances. Therefore, capacitor banks were not modeled to correct the voltage issues on the system.

For this analysis, all distribution station transformers were modeled with on-load secondary tap changers capable of ±10%, set to 102.5% voltage and a 2.5% bandwidth. The on-load tap changers give distribution companies more control over delivery voltages as they adapt to minor changes in the primary voltage.

A voltage regulator which was functionally equivalent to the Bar River regulator was modeled upstream of the Bruce Mines DS connection. This was found to have the most impact on delivery voltages at Feeder End and Bruce Mines.

Table 16: From ERTS – Peak Load

Total	kW	kVAr	kVA	PF
Sources	16115	2747	16348	98%
Generators (Solar)	239	0	239	100%
Loads	15893	1925	16009	99%
Line/Cable Inductance	0	625	625	100%
Calculated Losses	461	1447	1518	30%

Table 17: From ERTS – Peak Load Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 2025 to tie between 023 and 027	43%
Lowest Voltage	A	Supply Side of St Joseph Regulator	93%
	B	Supply Side of St Joseph Regulator	91%
	C	Supply Side of St Joseph Regulator	95%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	Garden River T2	104%

Table 18: From ERTS – Minimum Load

Total	kW	kVAr	kVA	PF
Sources	4575	118	4577	99%
Generators (Solar)	239	0	239	100%
Loads	4734	459	4756	99%
Line/Cable Inductance	0	623	623	100%
Calculated Losses	80	282	293	27%

Table 19: From ERTS – Minimum Load Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 2025 to tie between 023 and 027	14%
Lowest Voltage	A	Feeder End	99%
	B	Feeder End	99%
	C	Feeder End	100%
Highest Voltage	A	Bar River DS LV	105%
	B	Bar River DS LV	104%
	C	Bar River DS LV	106%

In this scenario the delivery voltages are improved from the base case even under normal operational conditions. Feeder End's voltage peak load was calculated to be 101%. Having on-load tap changers and regulators provides greater control and more options for operations staff. The Bar River DS is bordering on high voltage due to the voltage bandwidth, but this could theoretically be reduced by changing the set point for the tap changer.

4.6 From NATS, Reconductor and Voltage Devices

If voltage support devices are installed, the distribution system can adapt to changes in supply and load more effectively. This section outlines the operating conditions when supplied from NATS, after reconductoring and installing the devices outlined in Section 4.5.

Table 20: From NATS – Peak Load

Total	kW	kVAr	kVA	PF
Sources	16294	5039	17055	95%
Generators (Solar)	239	0	239	100%
Loads	15487	2013	15618	99%
Line/Cable Inductance	0	570	570	100%
Calculated Losses	1046	3596	3745	28%

Table 21: From NATS – Peak Load Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 2025 to tie between 023 and 027	52%
Lowest Voltage	A	Supply Side of St Joseph Regulator	93%
	B	Supply Side of St Joseph Regulator	91%
	C	Supply Side of St Joseph Regulator	95%
Highest Voltage	A	ERTS	104%
	B	ERTS	104%
	C	Garden River T2	104%

Table 22: From NATS – Minimum Load

Total	kW	kVAr	kVA	PF
Sources	4575	118	4577	99%
Generators (Solar)	239	0	239	100%
Loads	4734	459	4756	99%
Line/Cable Inductance	0	623	623	100%
Calculated Losses	80	282	293	27%

Table 23: From NATS – Minimum Load Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 2025 to tie between 023 and 027	14%
Lowest Voltage	A	Feeder End	99%
	B	Feeder End	99%
	C	Feeder End	100%
Highest Voltage	A	Bar River DS LV	105%
	B	Bar River DS LV	104%
	C	Bar River DS LV	106%

When the peak system load is supplied from NATS, even with reconductoring, the delivery voltage at Feeder End is calculated at 96%. This is acceptable, but marginally, and without room for load growth. With the addition of a regulator and on-load tap changers, the voltage improves to 102% and the system as a whole becomes more flexible in its capabilities for supplying loads.

4.7 From ERTS, with Reconductoring

The conductor from NATS to Bar River is 3/0 ACSR, which is heavily loaded during peak conditions. The first distribution solution is to reconductor this section with 556 ASC. This section explores the impact of reconductoring under normal operating conditions.

Table 24: From ERTS – Peak Load

Total	kW	kVAr	kVA	PF
Sources	15732	2603	15946	99%
Generators (Solar)	239	0	239	100%
Loads	15542	1854	15652	99%
Line/Cable Inductance	0	624	624	100%
Calculated Losses	429	1372	1438	29%

Table 25: From ERTS – Peak Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 081 to 079	43%
Lowest Voltage	A	Feeder End	97%
	B	Feeder End	98%
	C	Feeder End	99%
Highest Voltage	A	Bar River DS LV	104%
	B	Bar River DS LV	104%
	C	Bar River DS LV	105%

Table 26: From ERTS – Minimum Load

Total	kW	kVAr	kVA	PF
Sources	4593	-49	4593	99%
Generators (Solar)	239	0	239	100%
Loads	4791	450	4812	99%
Line/Cable Inductance	0	634	634	100%
Calculated Losses	41	135	141	29%

Table 27: From ERTS – Minimum Load: Maximum and Minimum Conditions

Condition	Phase	ID	Value
Heaviest Loaded Conductor	3 PH	3/0 ACSR from 081 to 079	12%
Lowest Voltage	A	Feeder End	101%
	B	Feeder End	101%
	C	Feeder End	101%
Highest Voltage	A	Bar River DS LV	104%
	B	Bar River DS LV	104%
	C	Bar River DS LV	105%

The length of circuit being reconductored when fed from ERTS is not significant enough to have a material impact. As can be seen from the above tables, there is little difference in normal operating conditions after reconductoring.

5. Solution Comparison

The previous section provided raw data on three modeled scenarios: a base case, reconductoring, and reconductoring with other voltage support devices. This section will take that data and process it to highlight the benefits to the voltage on the system.

The voltage drop along the 3/0 ACSR between NATS and Bar River is unacceptable. During the course of this study, the distribution solution which was found to have the most effective impact was reconductoring the 3/0 ACSR. Other equipment-based solutions ran into issues with heavily loading this section of lines, requiring the conductor to be upgraded either way. This solution has minimal impact upon normal operating conditions, however, under the contingency situation where NATS feeds all of the Algoma East system, the voltage issues are brought within acceptable limits. The cost to reconductor the 31km of lines was estimated by PowerTel to be $7.95M. There would be additional costs for engineering, project management, as well as other typical construction costs. CIMA+ has created an engineering estimate, found in *Appendix D*, estimating the engineering costs to be about $700k.

Augmenting the above scenario, adding on-load tap changers to the existing distribution station transformers and installing a voltage regulator upstream of Bruce Mines will benefit the voltage regulation both during normal operations and in contingency situations. At the time of this study, the difference in cost between an off-load and on-load tap changer is about $100k when ordered on a new transformer. Additional costs for civil upgrades (transformer pad, oil containment, etc.) may be required. Most rural utilities in Ontario have on-load tap changers to aid in voltage regulation on long lines.

Table 28: From ERTS – Comparison of LV Delivery Conditions at Peak Load

Delivery Point	Base Case	Reconductored	Voltage Devices
Bar River	102%	103%	103%
Bruce Mines	101%	101%	104%
Desbarats DS T1	101%	101%	101%
Desbarats DS T2	101%	102%	102%
Garden River DS T1	102%	102%	104%
Garden River DS T2	102%	103%	104%
St Joseph Island	101%	101%	101%
Feeder End	98%	98%	101%

Table 29: From NATS – Comparison of LV Delivery Conditions at Peak Load

Delivery Point	Base Case	Reconductored	Voltage Devices
Bar River	87%	101%	105%
Bruce Mines	95%	99%	102%
Desbarats DS T1	96%	100%	101%
Desbarats DS T2	86%	95%	102%
Garden River DS T1	96%	100%	103%
Garden River DS T2	96%	100%	103%
St Joseph Island	94%	101%	101%
Feeder End	93%	96%	102%

As can be seen from the above tables, reconductoring between NATS and Bar River DS is required to ensure acceptable voltage levels during contingency operation and under peak loading.

Having a two supply points able to supply the system load would be beneficial in several ways. A redundant source increases the resiliency of the whole system. If ERTS had to be removed from service, due to failure or maintenance, a switching operation could be performed to move the load to NATS. This would mean an outage of an two to three hours for switching operations, protection setting changes and drive time during failure scenarios. The system load could be fed from both stations for line maintenance, upgrades, or in emergency situations. If the load in the system were to grow significantly, there would be several options to supply within regulated voltage parameters and without heavily loading conductors. See the next section for the load growth sensitivity analysis.

Adding voltage support devices benefits both normal and contingency operations. Without reconductoring, new equipment alone is not enough to remedy the contingency voltage issues. Adding a voltage regulator upstream of Bruce Mines was beneficial in all studied scenarios and could improve the Feeder End voltage from marginal to nominal or higher. The existing distribution station transformers are between 7 and 33 years old, and it is not practical to replace the transformers for the sole purpose of adding an on-load tap changer. When the transformers are being replaced, an on-load tap changer should be seriously considered. The additional load which can be added if on-load tap changers and a single voltage regulator are considered is more than double reconductoring alone.

If ERTS were to fail and the load switched to NATS, the total load would be dependant on a single 31km stretch through Northern Ontario. If anything were to fail or be damaged from NATS to Bar River DS, the load would not be able to be fed until repairs have been performed. ERTS is fed from a looped feed from HONI's Missisagi TS and Third Line TS, and 115kV outages have relatively quick restoration times. NATS, on the other hand, is a radial feed from Third Line TS and does not have an alternate.

During the seven to eight months of construction the line would be recalled and completely de-energized leaving the load without a backup supply. If ERTS were to have a second transformer put in the station would be de-energized for construction, which would take less time, but would also leave the load without a backup supply. This scenario would have an added challenge because loads would need to be monitored for voltage issues.

6. Solution Sensitivity Analysis

A sensitivity analysis was performed to determine the amount of potential future load which could be added onto the system before low voltage conditions occur at delivery points. Desbarats DS T2, which feeds St Joseph Island, was allowed to reach lower than 95% voltage during this sensitivity test as long as the delivery point at St Joseph Island was within acceptable range.

In this sensitivity test load was increased by 5% until delivery voltages lower than 95% occurred. The applied load was then decreased by 1% in each iteration to determine what percentage of peak load could be applied while maintaining 95% delivery voltages.

Table 30: From NATS Sensitivity Test – Comparison of LV Delivery Conditions

Delivery Point	Reconductored 100% Peak Load	Reconductored 115% Peak Load	Reg and LTC 137% Peak Load
Bar River	101%	102%	97%
Bruce Mines	99%	98%	98%
Desbarats DS T1	100%	98%	98%
Desbarats DS T2	99%	93%	92%
Garden River DS T1	100%	99%	101%
Garden River DS T2	100%	99%	100%
St Joseph Island	101%	100%	99%
Feeder End	96%	95%	95%

Without adding in any other voltage support devices, the reconductored line could potentially support an additional 15% of peak load. If a voltage regulator and on-load tap changers are installed, 137% of peak load could be supplied.

A

Appendix A

PowerTel Report

CIMA+

A CORMORANT UTILITY SERVICES COMPANY

May 5, 2020

CIMA+
Energy & Distribution
4096 Meadowbrook Drive - Unit 112
London, Ontario
N6L 1G4

Attention: Mr. Stephen Costello
Partner, Senior Director

Subject: **Algoma Power – Sault Ste. Marie**
34.5kV Line Rebuild Cost Study

Dear Mr. Costello:

Per CIMA+'s request, PowerTel has completed a budget costing for the rebuilding of Algoma Power's 34.5kV overhead powerline circuit between the Northern Avenue TS in Sault Ste. Marie and the Bar River DS in the Echo Bay area.

PowerTel went through the line route in detail utilizing Google Maps as well as Google Earth to detail (as best as possible) the existing line route in terms of pole quantity and framing types. A basic Line Data is attached showing the existing 34.5kV and underbuild circuits currently and is the basis used for completing the Costing Study. PowerTel notes that no in-field investigations or engineering were conducted for the Study.

Assumptions used for the Costing Study are as follows:

- Line route distance is 31.4 km's long between the Northern Ave. T.S. in Sault Ste. Marie and the Bar River D.S. to the East of the city.
- Line has approx. 468 existing poles / structures.
- Approx. 60% of the route is along roads and 40% off-road or no truck access.
- Existing poles with newer 34.5kV armless framing will be reused and reconductored only including approx. 50 Resin poles along Northern Ave. (total 216 poles). This total includes approx. 5 - 2 and 3 pole structures to be reused in the off-road section just before Bar River D.S.
- Poles with older 34.5kV crossarm / pin insulator framing will be replaced with new poles and armless framing to USF standards (total 252 poles). New poles to be based on 45' to 65' pine, class 3 minimum.
- Approx. 45% of the 468 overall poles have underbuild circuits on them which is a mixture of single and 3-phase lines (some double circuit). All under build circuits for new pole installs will be transferred to the new poles as they appear to already be newer armless construction.
- Existing poles to be replaced that have Underbuild equipment such as transformers, switches, secondary, services, etc. will also be transferred to the new poles.

/...2

POWERTEL

A CORMORANT UTILITY SERVICES COMPANY

- Existing 34.5kV circuit conductor size is 3/0 ACSR and will be upgraded to 556.5 ASC conductor. Plan is to place the existing conductor in travelers and use it to pull in the new conductor.
- Work is based on the 34.5kV circuit(s) being de-energized and the underbuild circuits remaining energized for all work operations.
- Some costing was allowed for access construction / upgrading as well as environmental considerations in off-road areas which would have to be confirmed with in-field investigations.
- Some costing was allowed for misc. restoration as required throughout the line route.

Work is anticipated to be completed over a 7-8 month period with a crew of approx. 20-25 workers and addition supervision / management personnel.

Items not included in the Cost Study are as follows:

- Engineering, surveying, approvals, permits, etc. as required.
- Work completed in winter conditions, if required.
- Excavation in rock for poles / anchors, if required
- Premium time for work beyond regular 40 hrs per week.
- Costs or services associated with access on or through private property to access line route.
- Tree trimming, if required, along the line route.
- MTO Permit requirements for crossing or working along-side the 4-lane highway.
- Schedule delays, loss of productivity and / or additional economic costs associated with the COVID-19 pandemic, which may impact this project.

PowerTel's budget costing for this project incorporating the above assumed work scope is approx. $7,950,000.00 (plus applicable HST) with a +% of 25% and a -% of 5%. All labour, equipment and materials required to complete the work is included.

Please do not hesitate to contact PowerTel with any questions or concerns regarding the above or if any other information is required. PowerTel thanks CIMA+ for the opportunity to complete this Cost Study.

Yours truly,
POWERTEL UTILITIES CONTRACTORS LIMITED

Chris Krueger

Chris Krueger
Project Development

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CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

On-Road	Reconductor Only
Off-Road	New Poles / Cond.

Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
0	Northern Ave. TS DE					
1	90 Deg. Vert DE		3 Ph Tan			
2	Tangent - Davit Arm		3 Ph Tan			
3	Tangent - Davit Arm		3 Ph Tan			
4	90 Deg. Vert DE		3 Ph DDE			Turn East Along Northern Ave.
5	Tangent X-arm	In-Line Openers	3 x 3Ph DDE		Resin Pole	
6	Tangent Armless		2 x 3Ph Tan		Resin Pole	
7	Tangent Armless		2 x 3Ph Tan		Resin Pole	
8	Tangent Armless		2 x 3Ph Tan	3PH U/G Dip	Resin Pole	
9	Tangent Armless		2 x 3Ph Tan		Resin Pole	
10	Tangent Armless		2 x 3Ph Tan	3PH Tap	Resin Pole	
11	Tangent Armless		2 x 3Ph Tan		Resin Pole	Entrance to Metro / Traffic Lights
12	Tangent Armless		2 x 3Ph Tan		Resin Pole	
13	Tangent Armless		3Ph Tan & 3Ph DDE		Resin Pole	
14	Tangent Armless		2 x 3Ph Tan	3PH U/G Dip	Resin Pole	Great Northern Rd X-ing / Traffic Lights
15	Tangent Armless		2 x 3Ph Tan	3PH Tap	Resin Pole	
16	Tangent Armless		2 x 3Ph Tan	3PH U/G Dip	Resin Pole	
17	Tangent Armless		2 x 3Ph Tan		Resin Pole	
18	Tangent Armless		2 x 3Ph Tan		Resin Pole	
19	Tangent Armless		2 x 3Ph Tan	3PH Tap	Resin Pole	Willow Street X-ing / Traffic Lights
20	Tangent Armless		2 x 3Ph Tan		Resin Pole	
21	Tangent Armless		2 x 3Ph Tan		Resin Pole	
22	Tangent Armless		2 x 3Ph Tan	1Ph Tap	Resin Pole	
23	Tangent Armless		2 x 3Ph Tan		Note - Wood Pole	
24	Tangent Armless		2 x 3Ph Tan		Resin Pole	
25	Tangent Armless		2 x 3Ph Tan		Resin Pole	
26	Tangent Armless		2 x 3Ph Tan		Resin Pole	
27	Tangent Armless		2 x 3Ph Tan	3PH Tap	Resin Pole	Tadcaster Road Crossing
28	Tangent Armless		2 x 3Ph Tan		Resin Pole	
29	Tangent Armless		2 x 3Ph Tan	3PH Tap	Resin Pole	
30	Tangent Armless		2 x 3Ph Tan	3PH Tap & 3Ph U/G Dip	Resin Pole	
31	Tangent Armless		3Ph Tan & 3Ph DDE	3Ph U/G Dip	Resin Pole	Pine Street Crossing / Traffic Lights
32	Tangent Armless		2 x 3Ph Tan	3PH U/G Dip	Resin Pole	
33	Tangent Armless		2 x 3Ph Tan	3PH U/G Dip	Resin Pole	
34	Tangent Armless		2 x 3Ph Tan		Resin Pole	
35	Tangent Armless		2 x 3Ph Tan		Resin Pole	
36	Tangent Armless		2 x 3Ph Tan		Resin Pole	
37	Tangent Armless		2 x 3Ph Tan	3PH U/G Dip	Resin Pole	End Northern Ave. X-ing / Start Bush Path
38	Tangent Armless		2 x 3Ph Tan		Resin Pole	
39	Tangent Armless		2 x 3Ph Tan		Resin Pole	
40	Tangent Armless		2 x 3Ph Tan		Resin Pole	
41	Tangent Armless		2 x 3Ph Tan		Resin Pole	
42	Tangent Armless		2 x 3Ph Tan		Resin Pole	
43	Tangent Armless		2 x 3Ph Tan		Resin Pole	
44	Tangent Armless		2 x 3Ph Tan		Resin Pole	
45	Tangent Armless		2 x 3Ph Tan		Resin Pole	
46	Tangent Armless		2 x 3Ph Tan		Resin Pole	
47	Tangent Armless		2 x 3Ph Tan		Resin Pole	
48	Tangent Armless		2 x 3Ph Tan		Resin Pole	
49	Tangent Armless		2 x 3Ph Tan		Resin Pole	
50	Tangent Armless		2 x 3Ph Tan		Resin Pole	
51	Tangent Armless		2 x 3Ph Tan		Resin Pole	
52	Tangent Armless		2 x 3Ph Tan		Resin Pole	
53	Tangent Armless		2 x 3Ph Tan		Resin Pole	
54	Tangent Armless		3 x 3Ph Tan		Resin Pole	Black Road Crossing
55	Tangent Armless		2 x 3Ph Tan		Resin Pole	
56	Tangent Armless		2 x 3Ph Tan		Resin Pole	
57	Tangent Armless		2 x 3Ph Tan		Resin Pole	
58	Tangent Armless		2 x 3Ph Tan		Resin Pole	
59	Tangent Armless		2 x 3PH DDE		Resin Pole	U/B Turn South
60	Tangent Armless					
61	Tangent Armless					
62	Tangent Armless					
63	Tangent Armless					Cross Under Steel Tower Line
64	Tangent Armless					
65	Tangent Armless					
66	Tangent Armless					
67	Tangent Armless					
68	Tangent Armless					
69	Tangent Armless					
70	Tangent Armless					
71	Tangent Armless					

CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

On-Road	Reconductor Only
Off-Road	New Poles / Cond.

Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
72	Tangent Armless					
73	Tangent Armless					
74	Tangent Armless					
75	Tangent Armless					
76	Tangent Armless					
77	Tangent Armless					Gravel Road Crossing
78	Tangent Armless					
79	Tangent Armless					
80	Tangent Armless					
81	Tangent Armless					
82	Tangent Armless					
83	Tangent Armless					
84	Tangent Armless					
85	Tangent Armless					
86	Tangent Armless					Gravel Road Crossing
87	Tangent Armless					
88	Tangent Armless					
89	Tangent Armless					
90	Tangent Armless					Bittern Street Crossing In Solar Farm
91	Tangent Armless					
92	2 Arm Tangent	Skywire Start?				
93	2 Arm Tangent	Skywire	3 Ph Tan			
94	2 Arm Tangent	Skywire				Metig Street Crossing
95	2 Arm Tangent	Skywire				Gran Street Crossing
96	2 Arm Tangent	Skywire				
97	Med. Angle	Skywire End?				
98	2 Arm Tangent					
99	2 Arm Tangent					
100	2 Arm Tangent		1Ph Tan	Secondary & Streetlight		
101	Tangent - Top Pin & Arm					Tecumseh Street Crossing
102	Tangent - Top Pin & Arm					
103	Tangent - Top Pin & Arm		1Ph Tan	Secondary & Streetlight Over House Trailer		
104	Tangent - Top Pin & Arm		1Ph Tan			Tecumseh Street Crossing Gravel Road Crossing
105	Tangent - Top Pin & Arm					
106	Tangent - Top Pin & Arm					
107	Tangent - Top Pin & Arm					Gravel Road Crossing
108	Tangent - Top Pin & Arm					
109	Tangent - Top Pin & Arm					
110	Tangent - Top Pin & Arm					
111	Tangent - Top Pin & Arm					
112	Tangent - Top Pin & Arm					
113	Tangent - Top Pin & Arm					Gravel Road / Parking Lot
114	Tangent - Top Pin & Arm					
115	Tangent - Top Pin & Arm		1Ph DE	Transformer		Gravel Driveway Crossing
116	Tangent - Top Pin & Arm					
117	Tangent - Top Pin & Arm					
118	Tangent - Top Pin & Arm					Paved Parking Area
119	Tangent Armless					Gravel Road Crossing
120	Tangent Armless					
121	Tangent Armless					4-Lane Crossing
122	Tangent Armless					
123	Tangent - Top Pin & Arm					
124	Tangent - Top Pin & Arm					
125	Tangent - Top Pin & Arm					Start Adjacent to Frontenac Road
126	Tangent - Top Pin & Arm					
127	Tangent - Top Pin & Arm					
128	Tangent - Top Pin & Arm					
129	Tangent - Top Pin & Arm					Leave Adjacent to Frontenac Road
130	Tangent - Top Pin & Arm					
131	Tangent - Top Pin & Arm					
132	Tangent - Top Pin & Arm	**3Ph Tap to Lumber Yard**				
133	DDE					Long Span River Crossing
134	DDE					
135	Tangent - Top Pin & Arm					
136	Tangent - Top Pin & Arm					
137	Tangent - Top Pin & Arm					
138	Tangent - Top Pin & Arm					
139	Tangent - Top Pin & Arm					Gravel Parking Area
140	Tangent - Top Pin & Arm					

CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

On-Road	Reconductor Only
Off-Road	New Poles / Cond.

Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
141	Tangent - Top Pin & Arm					Gravel Road Crossing
142	Tangent - Top Pin & Arm					
143	Tangent - Top Pin & Arm					
144	Tangent - Top Pin & Arm					
145	Tangent - Top Pin & Arm					
146	Tangent - Top Pin & Arm					
147	Tangent - Top Pin & Arm					Gravel Road Crossing
148	Tangent - Top Pin & Arm					Belleau Lake Road Crossing
149	Tangent - Top Pin & Arm					
150	Tangent - Top Pin & Arm					
151	Tangent - Top Pin & Arm					
152	Tangent - Top Pin & Arm					
153	Tangent - Top Pin & Arm					
154	Tangent - Top Pin & Arm					
155	Tangent - Top Pin & Arm					
156	Med. Angle					
157	Tangent - Top Pin & Arm					
158	Tangent - Top Pin & Arm					
159	Tangent - Top Pin & Arm					
160	Tangent - Top Pin & Arm					
161	Tangent - Top Pin & Arm					
162	Tangent - Top Pin & Arm					
163	Tangent - Top Pin & Arm					
164	Tangent - Top Pin & Arm					
165	Tangent - Top Pin & Arm					
166	Tangent - Top Pin & Arm					
167	Tangent - Top Pin & Arm					
168	Tangent - Top Pin & Arm					Gravel Road Crossing
169	Tangent - Top Pin & Arm					
170	Light Angle - Top Pin & Arm					
171	Tangent - Top Pin & Arm					
172	Tangent - Armless		3Ph DE & 3Ph DDE			
173	Tangent - Armless		3Ph Tan			Svrette Lake Road Crossing
174	Tangent - Armless		3Ph Tan	3Ph Tap		
175	Tangent - Armless		3Ph Tan			
176	Tangent - Armless		3Ph Tan			
177	Tangent - Armless		3Ph Tan			
178	Tangent - Armless		3Ph Tan			Muhouak Stereet Crossing
179	Tangent - Armless		3Ph Tan	1Ph Tan & Transformer		
180	Tangent - Armless		3Ph Tan			
181	Tangent - Armless		3Ph Tan			
182	Tangent - Armless		3Ph Tan			
183	Tangent - Armless		3Ph Tan	1Ph Tan		Hawatha Drive Crossing
184	Tangent - Armless		3Ph Tan			
185	Tangent - Armless		3Ph Tan			
186	Tangent - Armless		3Ph Tan			
187	Tangent - Armless		3Ph Tan			
188	Tangent - Armless		3Ph Tan			
189	Light Angle - Armless		3Ph Light Angle	1Ph Transformer		Moccasin Street Crossing
190	Tangent - Armless		3Ph Tan			
191	Tangent - Armless		3Ph Tan			
192	Tangent - Armless		3Ph Tan			
193	Tangent - Armless		3Ph Tan			
194	Tangent - Armless		3Ph Tan	1Ph DE		Wabosssa Street Crossing
195	Tangent - Armless		3Ph Tan			
196	Tangent - Armless		3Ph Tan			
197	Tangent - Armless		3Ph Tan			
198	Tangent - Armless		3Ph Tan	1Ph Transformer		
199	Tangent - Armless		3Ph Tan			
200	Light Angle - Armless		3Ph Angle DDE			
201	Tangent - Top Pin & Arm		3Ph Tan			
202	Tangent - Top Pin & Arm		3Ph Tan	1Ph Transformer		
203	Tangent - Top Pin & Arm		Tangent DDE	3Ph Regulators?		
204	Tangent DDE		Angle DDE	3Ph U/G Service		
205	**Garden River DS DE**					
206	Tangent DDE		Angle DDE	3Ph U/G Service		
207	Tangent - Top Pin & Arm		Tangent DDE	3Ph Regulators?		
208	Tangent - Top Pin & Arm		3Ph Tan			
209	Tangent - Top Pin & Arm		3Ph Tan			
210	Tangent - Top Pin & Arm		3Ph Tan	1Ph Transformer		
211	Tangent - Top Pin & Arm		3Ph Tan			
212	Tangent - Top Pin & Arm		3Ph Tan	1Ph Transformer		

CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

On-Road	Reconductor Only
Off-Road	New Poles / Cond.

Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
213	Tangent - Top Pin & Arm		3Ph Buckarm DDE			
214	Light Angle - Top Pin & Arm					Jarden Mine Road Crossing
215	Tangent - Top Pin & Arm					
216	Tangent - Top Pin & Arm					
217	Tangent - Top Pin & Arm					
218	Tangent - Top Pin & Arm					
219	Tangent - Top Pin & Arm					
220	Tangent - Top Pin & Arm					
221	Tangent - Top Pin & Arm					
222	Tangent - Top Pin & Arm					
223	Tangent - Top Pin & Arm					
224	Angle DDE					River Crossing
225	Tangent - Top Pin & Arm					
226	Tangent - Top Pin & Arm					
227	Tangent - Top Pin & Arm					
228	MA					
229	Medium Angle					
230	Tangent - Top Pin & Arm					
231	Tangent - Top Pin & Arm					
232	Angle DDE					
233	Tangent - Top Pin & Arm					
234	Tangent - Top Pin & Arm					
235	Tangent - Top Pin & Arm					
236	Angle DDE		1Ph DE	1Ph Transformer		Turn Along Mizigan Street
237	Tangent - Armless		1Ph Tan			
238	Tangent - Armless		1PH Tan			
239	Tangent - Armless		3Ph Light Angle	1Ph DDE		
240	Tangent - Armless		1Ph DE	Cutout Switch		Ballpark Road Crossing
241	Tangent - Top Pin & Arm		1PH Tan			
242	Tangent - Top Pin & Arm		1PH Tan			
243	Tangent - Top Pin & Arm		1PH Tan	1Ph Transformer & U/G Service		
244	Tangent - Top Pin & Arm		1PH Tan	Streetlight		
245	Tangent - Top Pin & Arm		1PH Tan	1Ph Transformer		
246	Tangent - Top Pin & Arm		1PH Tan			
247	Tangent - Top Pin & Arm		1PH Tan	1Ph Transformer & U/G Service		
248	Tangent - Top Pin & Arm		1Ph Angle DE	U/G Sec. Service		
249	Tangent - Top Pin & Arm					Dreamcatcher Street Crossing
250	Tangent - Top Pin & Arm					
251	Tangent - Top Pin & Arm					
252	Tangent - Top Pin & Arm					
253	Tangent - Top Pin & Arm					
254	Tangent - Top Pin & Arm					
255	Tangent - Top Pin & Arm					
256	Tangent - Top Pin & Arm					
257	Tangent - Top Pin & Arm					Sweetgrass Road Crossing
258	Tangent - Top Pin & Arm					
259	Tangent - Top Pin & Arm					
260	Tangent - Top Pin & Arm					
261	Tangent - Top Pin & Arm					
262	Tangent - Top Pin & Arm					
263	Tangent - Top Pin & Arm					
264	Tangent - Top Pin & Arm					
265	Tangent - Top Pin & Arm					
266	Tangent - Top Pin & Arm					
267	Tangent - Top Pin & Arm					
268	Tangent - Top Pin & Arm					
269	Tangent - Top Pin & Arm					
270	Tangent - Top Pin & Arm					
271	Tangent - Top Pin & Arm					
272	Tangent - Top Pin & Arm					
273	Tangent - Top Pin & Arm					
274	Tangent - Top Pin & Arm					
275	Tangent - Top Pin & Arm					
276	Tangent - Top Pin & Arm					
277	Tangent - Top Pin & Arm					
278	Tangent - Top Pin & Arm					
279	Angle DDE					
280	Tangent - Top Pin & Arm					
281	Tangent - Top Pin & Arm					
282	Tangent - Top Pin & Arm					
283	Tangent - Top Pin & Arm					
284	Tangent - Top Pin & Arm					
285	Tangent - Top Pin & Arm					
286	Tangent - Top Pin & Arm					

CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

On-Road	Reconductor Only
Off-Road	New Poles / Cond.

Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
287	Vert. Angle DDE					Under 230kV Lines Star Along 4-Lane / 230kV Lines
288	Tangent - Top Pin & Arm					
289	Tangent - Top Pin & Arm					
290	Tangent - Top Pin & Arm					
291	Tangent - Top Pin & Arm					
292	Tangent - Top Pin & Arm					
293	Tangent - Top Pin & Arm					
294	Tangent - Top Pin & Arm					
295	Tangent - Top Pin & Arm					
296	Tangent - Top Pin & Arm					
297	Tangent - Top Pin & Arm					
298	Tangent - Top Pin & Arm					
299	Tangent - Top Pin & Arm					
						Access Gravel Road Crossing
300	Tangent - Top Pin & Arm					
301	Tangent - Top Pin & Arm					
302	Tangent - Top Pin & Arm					
303	Tangent - Top Pin & Arm					
304	Tangent - Top Pin & Arm					
305	Tangent - Top Pin & Arm					
306	Tangent - Top Pin & Arm					
307	Tangent - Top Pin & Arm					
308	Vert. Angle DDE					
309	Vert. Angle DDE					
						4-Lane Hwy. Crossing
310	Vert. Med. Angle					
						Gravel Access Road Crossing
311	Vert. Angle DDE					
						4-Lane Hwy. Crossing
312	Vert. Med. Angle					
313	Vert. Angle DDE					
314	Tangent - Top Pin & Arm					
315	Tangent - Top Pin & Arm					
316	Tangent - Top Pin & Arm					
317	Tangent - Top Pin & Arm					
318	Tangent - Top Pin & Arm					
319	Tangent - Top Pin & Arm					
320	Tangent - Top Pin & Arm					
321	Tangent - Top Pin & Arm					
322	Tangent - Top Pin & Arm					
323	Tangent - Top Pin & Arm					
324	Tangent - Top Pin & Arm					
325	Tangent - Top Pin & Arm					
326	Tangent - Top Pin & Arm					
327	Tangent - Top Pin & Arm					
328	Tangent - Top Pin & Arm					
329	Tangent - Top Pin & Arm					
330	Tangent - Top Pin & Arm					
331	Tangent - Top Pin & Arm					
332	Tangent - Top Pin & Arm					
333	Tangent - Top Pin & Arm					
334	Light Angle - Top Pin & Arm					
335	Tangent - Top Pin & Arm					
336	2P H-frame DDE					
						4-Lane Hwy. Crossing
337	2P H-frame DDE					
						Access Gravel Road Crossing
338	Tangent - Top Pin & Arm					
339	Vert. Med. Angle					
340	Tangent - Top Pin & Arm					Under & Between 230kV Lines
341	Tangent - Top Pin & Arm					
342	Tangent - Top Pin & Arm					
343	Tangent - Top Pin & Arm					
						Creek Crossing
344	Tangent - Top Pin & Arm					
345	Tangent - Top Pin & Arm					
346	Tangent - Top Pin & Arm					
						Creek Crossing
347	Tangent - Top Pin & Arm					
348	Tangent - Top Pin & Arm					
349	Tangent - Top Pin & Arm					
350	Tangent - Top Pin & Arm					
351	Tangent - Top Pin & Arm					
352	Tangent - Top Pin & Arm					
353	Tangent - Top Pin & Arm					
354	Tangent Angle DDE					
355	Tangent - Top Pin & Arm					
356	Tangent - Top Pin & Arm					
357	Tangent - Top Pin & Arm					
358	Tangent - Top Pin & Arm					

CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

On-Road	Reconductor Only
Off-Road	New Poles / Cond.

Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
359	Tangent - Top Pin & Arm					
360	Tangent - Armless		1Ph DE	Transformer		
361	Tangent - Armless		1Ph Tan	Transformer		
362	Tangent - Armless		1Ph Tan			
363	Light Angle - Armless		1Ph LA			
364	Tangent - Armless		1Ph Tan	Transformer / Streetlight		Gravel Road Crossing
365	Tangent - Armless	Centre Phase Extender	1Ph Tan	1Ph Tap		
366	Tangent - Armless	Centre Phase Extender	1Ph DDE	Cutout Switch		River Crossing
367	Tangent - Top Pin & Arm	Set LA's	1Ph Tan	Transformer		
368	Tangent - Top Pin & Arm	Mid-Span Openers	1Ph Tan			
369	Tangent DDE	**3Ph Tap to Echo Bay**	2Ph DDE	2Ph DE Tap		Echo Lake Road Crossing
370	Vertical DDE	Vert. Load Break Switch	2Ph Tan			
371	LA Armless		2Ph LA Armless			
372	Tangent - Armless		2Ph Tan Armless			Echo Lake Road Crossing
373	Tangent - Armless		2Ph Tan Armless			
374	LA Armless		2Ph LA Armless			
375	LA Armless		2Ph LA Armless			
376	LA Armless		2Ph LA Armless			
377	Med. Angle Armless		2Ph MA Armless	Transformer		Echo Lake Road Crossing
378	Tangent - Armless		2Ph Tan Armless			
379	Buckarm DDE		2Ph Buckarm DDE			
380	Buckarm DDE		2Ph Buckarm DDE			Echo Lake Road Crossing
381	Tangent - Armless		2Ph Tan Armless			
382	Tangent - Armless		2Ph Tan Armless			
383	Tangent - Armless		2Ph Tan Armless			
384	Buckarm DDE		2Ph Buckarm DDE	1Ph Tap		
385	Tangent - Armless		2Ph Tan Armless			Echo Lake Road Crossing
386	Tangent - Armless		2Ph Tan Armless			
387	Tangent - Armless		2Ph Tan Armless			
388	Tangent - Armless		2Ph Tan Armless	Transformer		
389	LA - Armless		2Ph LA Armless	2Ph Tap		
390	Med. Angle Armless		2Ph MA Armless			
391	Tangent - Armless		2Ph Tan Armless	Transformer		
392	Tangent - Top Pin & Arm		2Ph Tan Armless	Transformer		
393	Tangent - Top Pin & Arm		2Ph Tan Armless			
394	Tangent - Armless		2Ph Tan Armless			
395	Tangent - Armless		2Ph Tan Armless			
396	Double Arm LA	Stub Pole / Span Guy	2Ph LA Armless	Stub Pole / Span Guy		
397	Double Arm Tan		2Ph Tan Armless			
398	Double Arm Tan		2Ph Tan Armless			
399	Double Arm Tan		2Ph Tan Armless	2 x Switch Cutouts		
400	Double Arm Tan		2Ph Tan Armless			
401	Double Arm Tan		2Ph Tan Armless			
402	LA - Armless		2Ph DDE	1Ph Tap		Old Sylain Valley Hill Road Crossing Echo Lake Road Crossing
403	Tangent - Armless		2Ph Tan Armless			
404	Med. Angle Armless		2Ph MA Armless			
405	Double Arm Tan		2Ph Tan X-Arm	Transformer / Streetlight		
406	Double Arm LA		2Ph LA X-Arm			Hwy 638 Crossing
407	Double Arm Tan		2Ph Tan X-Arm			
408	Double Arm Tan		2Ph Tan X-Arm			
409	Double Arm Tan		2Ph Tan X-Arm	Transformer		
410	Double Arm LA		2Ph LA X-Arm			
411	Double Arm Tan		2Ph Tan X-Arm	Transformer		
412	Double Arm LA		2Ph LA X-Arm			
413	Double Arm Tan		2Ph Tan X-Arm			Pioneed Road Crossing
414	Double Arm Tan		2Ph Tan X-Arm	Transformer		
415	Tangent - Armless		2Ph Tan Armless			
416	Tangent - Armless		2Ph DE	3Ph Tap / Transformer		Joe Findlay Road Crossing
417	LA - Armless		1Ph DDE	Cutout Switch		
418	Med. Angle Armless		1P MA Armless			
419	Tangent - Armless		1P Tan Armless			
420	Tangent - Armless		1P Tan Armless	Transformer		Findley Hill Road Crossing
421	LA - Armless		1P LA Armless			
422	LA - Armless	Span Guy / Stub Pole	1P LA Armless			
423	Tangent - Armless		1P Tan Armless	Transformer		
424	Tangent - Armless		1P Tan Armless			
425	LA - Armless	Span Guy / Stub Pole	1Ph DDE	Cutout Switch		
426	Tangent - Armless					
427	Tangent - Armless					
428	Tangent - Armless					

CIMA - ALGOMA POWER
34.5kV CIRCUIT - NORTHERN AVENUE TO BAR RIVER
RECONDUCTORING / REBUILDING

On-Road	Reconductor Only
Off-Road	New Poles / Cond.

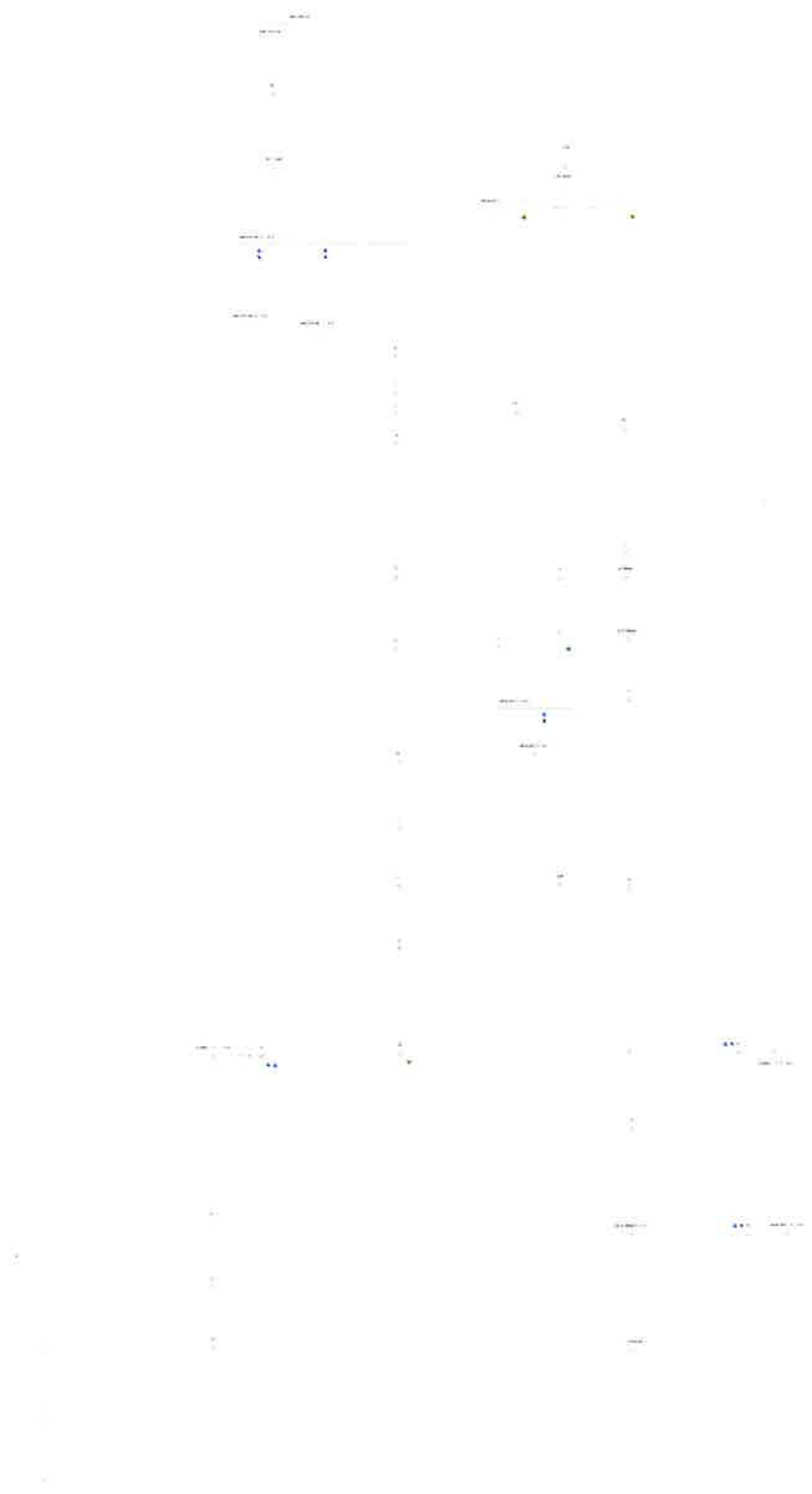
Pole #	34.5 kV Framing	Notes	Underbuild Framing	Notes	Pole Type	Identifiers
429	Tangent - Top Pin & Arm					
430	Tangent - Top Pin & Arm					
431	Tangent - Armless					
432	Vertical DDE	Transposition	1Ph DDE			
433	Vertical DDE	Start Skywire	34.5kV Vert DDE			
434	Vertical Delta	Skywire	34.5kV Vert. Tan			
435	Vertical Delta	Skywire	34.5kV Vert. Tan			
436	Vertical Delta	Skywire	34.5kV Vert. Tan			
437	Vertical Delta	Skywire	34.5kV Vert. Tan			
438	Vertical Delta	Skywire	34.5kV Vert. Tan			
439	Vertical Delta	Skywire	34.5kV Vert. Tan			
440	Vertical Delta	Skywire	34.5kV Vert. Tan			
441	Vertical Delta	Skywire	34.5kV Vert. Tan			
442	Vertical Delta	Skywire	34.5kV Vert. Tan			Watson Road East Crossing
443	Vertical Delta	Skywire	34.5kV Vert. Tan	1Ph DDE on Arm		
444	Vertical DDE	Skywire	34.5kV Vert. MA			
445	2P Vert. Angle DDE	Skywire	On Separate Poles Now			
446	Vertical Delta					
447	Vertical Delta					
448	Vertical Delta					
449	Vertical Delta					
450	2P or 3p DDE					
451	3p DDE					
452	3p DDE					
453	Vertical Delta					
454	Vertical Delta					
455	Vertical Delta					
456	Vertical Delta					
457	Vertical Delta					
458	Vertical Delta					
459	Vertical Delta					
460	Vertical Delta					
461	Vertical Delta					
462	Vertical Delta					34.5 Circuit Crosses Under
463	Vertical Delta					34.5 Circuit Crosses Under
464	Vertical Delta					
465	Vertical Delta					
466	3p DDE					Rail Crossing
467	3p DDE		3Ph Buckarm DDE			
468	Tangent - Top Pin & Arm	In-Line Switches	3Ph DDE	Regulators?		
469	Tangent - Top Pin & Arm	**Tap into Bar DS**	3Ph Tan on Arm	Tap into Bar DS		
470	**BAR RIVER DS STR. DE**					

B

Appendix B

CYME Model Validation

CIMA+



Legend

Layer :
Voltage Dip color(%)

Colors :
- 0.000000 1.000000
- 1.000000 2.000000
- 2.000000 3.000000
- 3.000000 5.000000
- 5.000000 999999.0000

Line Types :
- Overhead phase A
- Overhead phase B
- Overhead phase C
- Overhead phase AB
- Overhead phase AC
- Overhead phase BC
- Overhead three-phase
- Cable phase A
- Cable phase B
- Cable phase C
- Cable phase AB
- Cable phase AC
- Cable phase BC
- Cable three-phase

Symbols :
- Switch, (C)
- Spot Load
- Two-Winding Tran.
- Switch, (O)
- Regulator
- Shunt Capacitor
- Shunt Capacitor
- Photovoltaic Sys.
- Two-Winding Tran.

Node	Attached Equipment
46	Switch 386
Truss Plant	Truss Plant
Garden River DS HV Bus	Switch 076
Garden River T1 LV Bus	GDS T1 Load, Cap bank
Garden River T2 LV Bus	GDS T2 Load, Cap bank
Garden River DS HV Bus	Switch 075
51	3/0 to Garden DS
52	Switch 077
53	ER2-NTS Tie Point
54	Switch 079
ER2	Switch 081
Echo River TS Bus	Switch 565
Echo River TS Bus	Switch 9
Echo River TS Bus	Switch 563
ER1	22194 feet downstream of ERTS Bus
58	Switch 2024
VR Primary	Bar River Regulator
VR Secondary	Bar River Regulator
61	Switch 2025
62	Switch 027
69	12665 feet downstream of Switch 079
66	E2 to Bar River
65	Switch 021
Bar River DS HV Bus	Switch 022
Bar River DS HV Bus	Switch 023
Bar River DS LV Bus	Bar River Load, Cap bank
75	Switch 075
71	Switch 071
72	Switch 072
73	Switch 2038
Solar	Solar generator
76	51800 feet downstream of Switch 075
78	28445 feet downstream of Solar tap
542	Switch 091 and Switch 080
77	Switch 77, Switch 81, and Switch 82
81	Desbarats DS T1 LV Bus
Desbarats DS T1 LV Bus	Desbarats DS T1 LV load and Cap bank
86	Desbarats DS T2 LV Bus
8, 7, Desbarats DS T2 LV Bu	Cables downstream of T2 to 2/0 CU
11	End of 2/0 CU
13	Cap Bank 13
14	Transition from 336 to Sub cable
15	Sub Cable to 336
16	HV of SJI Reg
17	LV of SJI Reg
18	SJI Load
82	Switch 053
Bruce Mines DS HV Bus	Switch 084/Feeder end tie
84	Bruce Mines DS LV Bus
Bruce Mines DS LV Bus	Bruce Mines DS LV load and cap bank
Feeder End	Feeder End Load

Two methods of validation were used to validate the model and the associated assumptions; both methods found that the model is reasonably accurate.

Historical Loads with Recent Metered Data

The first method of model validation was to model the typical load level for June and match it to measured values from the metering point for ER1 and ER2. Historical data for 2018 and 2019 was used to determine that June is 40% of peak load. A load flow analysis was performed and then the values at the ER1 and ER2 nodes was compared with metered data for June 1, 2020. It was found that the calculated power was similar to the metered values between 2:00 and 4:00PM.

Metered Vs Calculated Power – ER1

Feeder Name	kVA	kW	kVAr
ER1 – Metered	3477.1	3475.5	-106.5
ER1 – Calculated	3282	3280	-108
Difference	195	195	1.5

Metered Vs Calculated Power – ER2

Feeder Name	kVA	kW	kVAr
ER2 – Metered	3314.7	3276.6	501.1
ER2 – Calculated	3386	3250	950
Difference	71	27	449

The capacitor bank 2022 on ER2 was switched off due to bandwidth in the calculated values. This can account for the difference in reactive power in metered and calculated values.

Metered Data

The second method of validation was to insert measured data from the field and compare the calculated feeder total to the metered data from the same time period. As can be seen from the following tables, the calculated values are quite similar which gives confidence in the model's conductor assumptions.

Measurements Collected June 1, 2020

Asset ID	Time	Current (A)			Voltage (V)			Power (kW)				PF (%)
		R	W	B	R	W	B	R	W	B	3PH	
Garden River DS T1	11:00AM	37	11	21	7200	7100	7200	229	80	118	435	98.8
Garden River DS T2	11:00AM	12	5	12	7200	7100	7200	94	42	81	234	96.6
Bar River T1	12:00PM	38	91	30+-	7400	7400	7500	281	673	222	1177	95
Desbarats T1	5:00PM	7	22	21	7200	7200	7200				360	96
Bar River Regulator	12:00PM	43	-	40	125 in 121.3 out	125 in 121.6 out	125 in 121.5 out					95-98
St Joseph Regulator	5:00PM	27	42	31	127.4 in 121.6 out	128 in 121.6 out	126.1 in 121.2 out					
Feeder End	6:30PM	31	32	30								
Recloser 038	11:00AM	11	12	7								
Recloser 052	5:00PM	56	58	62								
Recloser 2010	3:00PM	24	38	31	15200	15600	15100	355	599	463	1430	99.8
Recloser 2020	12:00PM	21	20	17	20500	20500	20500					

Calculated Values from Measurements Collected June 1, 2020

Asset ID	Current (A)			Voltage (V)			Power (kW)				PF (%)
	R	W	B	R	W	B	R	W	B	3PH	
Garden River DS T1	33	12	17	7400	7500	7500	244	86	126	456	99
Garden River DS T2	4	3	5	7400	7500	7500	68	69	95	232	96
Bar River T1	33	22	22	7500	7500	7500	559	431	282	1272	83
Desbarats T1	7	23	22	7300	7300	7300	52	164	155	371	96
Bar River Regulator	59	72	69	124.1 in 122.9 out	124.1 in 122.9 out	124.1 in 122.9 out	1205	1462	1409	4076	100
St Joseph Regulator	29	45	33	123 in 123 out	120.6 in 120.6 out	122.2 in 122.2 out	423	636	483	1541	98
Feeder End	29	45	34	14800	14500	14700	423	636	483	1541	98
Recloser 038	12	9	14	20700	20700	20700	226	178	287	691	99
Recloser 052	53	64	64	20200	20200	20300	1080	1291	1303	3674	100
Recloser 2010	29	44	33	14800	14700	14700	425	640	483	1548	99
Recloser 2020	23	23	18	20600	20600	20700	475	472	373	1321	99

C

Appendix C

CYME Results

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-4-2020 existing conductors.sxst
Date	Tue Jun 16 2020
Time	15h01m48s
Project Name	Base Case from ERTS Min Load - by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	4567.52	-39.82	4567.69	-100.00
Generators	239.00	0.00	239.00	100.00
Total Generation	**4806.51**	**-39.83**	**4806.68**	**-100.00**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4761.34	1703.29	5056.84	94.16
Shunt capacitors (Adjusted)	0.00	-1263.21	1263.21	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4761.34**	**440.08**	**4781.64**	**99.58**
Cable Capacitance	0.00	-70.73	70.73	0.00
Line Capacitance	0.00	-544.57	544.57	0.00
Total Shunt Capacitance	**0.00**	**-615.30**	**615.30**	**0.00**
Line Losses	40.17	87.69	96.45	41.65
Cable Losses	0.25	0.15	0.29	85.29
Transformer Load Losses	4.76	47.55	47.79	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**45.17**	**135.39**	**142.73**	**31.65**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	105.57 %
	B	1	87	104.47 %
	C	1	87	105.76 %
Under-Voltage	A	0	FEEDER END	100.60 %
	B	0	FEEDER END	100.61 %
	C	0	FEEDER END	101.01 %
Over-Voltage	A	0	076	104.01 %
	B	0	076	104.01 %
	C	0	076	104.01 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	40.17	351.87	35.19
Cable Losses	0.25	2.15	0.22
Transformer Load Losses	4.76	41.66	4.17
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	45.17	395.68	39.57

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)	
ECHO RIVER TS 9		DEFAULT	Switch	8.7	1621.0	100.5		104.00
ECHO RIVER TS 081		DEFAULT	Switch	4.0	703.7	248.3		104.00
ECHO RIVER TS 081		DEFAULT	Switch	4.0	703.1	254.6		103.81
ECHO RIVER TS 077		DEFAULT	Switch	0.5	78.5	33.5		103.81
ECHO RIVER TS 51		DEFAULT	Switch	0.5	78.4	52.0		103.69
ECHO RIVER TS 49		GARDEN T2	Two-Winding Transforme	4.4	44.4	16.5		103.50
ECHO RIVER TS 555		GARDEN T1	Two-Winding Transforme	0.4	34.0	35.5		103.44
ECHO RIVER TS 67		DEFAULT	Switch	3.6	624.6	221.3		103.81
ECHO RIVER TS 66		DEFAULT	Switch	2.3	384.9	186.4		103.29
ECHO RIVER TS 65		DEFAULT	Switch	2.3	384.9	186.5		103.29
ECHO RIVER TS 68		BAR RIVER T1	Two-Winding Transforme	16.6	384.9	186.5		102.83
ECHO RIVER TS 68		1200 KVAR 7 KV	Shunt Capacitor	0.0	488.5	160.6		102.82
ECHO RIVER TS 71		DEFAULT	Switch	1.3	237.3	43.4		103.29
ECHO RIVER TS 72		DEFAULT	Switch	1.3	236.8	57.6		103.07
ECHO RIVER TS 74		DEFAULT	Switch	0.4	-79.6	-0.1		103.05
ECHO RIVER TS 79		DEFAULT	Switch	1.8	316.1	79.1		102.90
ECHO RIVER TS 86		DESBARATS T2	Two-Winding Transforme	19.5	316.1	79.1		102.51
ECHO RIVER TS 13		1200 KVAR 20 KV	Shunt Capacitor	0.0	316.0	76.2		102.47
ECHO RIVER TS 17		25 KV 600A 1PH	Regulator	3.8	315.4	103.7		100.94
ECHO RIVER TS 56		DEFAULT	Switch	5.0	917.3	-147.8		104.00
ECHO RIVER TS 58		DEFAULT	Switch	5.0	914.9	-137.0		103.86
ECHO RIVER TS 5		34.5KV_200A_1PH_COOPER_REGULATOR_6	Regulator	22.4	914.9	-136.8		101.92
ECHO RIVER TS 62		DEFAULT	Switch	0.0	0.0	0.0		103.86
ECHO RIVER TS 64		DEFAULT	Switch	0.0	0.0	0.0		103.29
ECHO RIVER TS 75		DEFAULT	Switch	5.1	914.9	-136.7		101.91
ECHO RIVER TS 77		DEFAULT	Switch	5.0	910.9	-120.4		101.67
ECHO RIVER TS 80		DEFAULT	Switch	0.0	0.0	0.0		102.90
ECHO RIVER TS 81		DEFAULT	Switch	2.6	315.5	-349.7		101.67
ECHO RIVER TS 81		DESBARATS T1	Two-Winding Transforme	23.5	315.5	-349.7		102.75
ECHO RIVER TS 87		1200 KVAR 7 KV	Shunt Capacitor	105.6	244.2	-342.0		102.75
ECHO RIVER TS 82		DEFAULT	Switch	3.5	595.3	229.3		101.67
ECHO RIVER TS 83		DEFAULT	Switch	3.5	595.3	229.4		101.66
ECHO RIVER TS 84		DEFAULT	Switch	1.6	277.4	103.8		100.70
ECHO RIVER TS 84		BRUCE MINES T1	Two-Winding Transforme	16.7	277.4	103.8		103.08
ECHO RIVER TS 88		1200 KVAR 7 KV	Shunt Capacitor	0.0	296.5	97.4		103.08
ECHO RIVER TS 61		DEFAULT	Switch	0.0	0.0	-0.1		103.86

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	0.1	5.4	-20.3	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	0.0	0.0	-8.4	104.01
NORTHERN AVE TS	076	DEFAULT	Switch	0.0	0.0	0.0	103.69

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)	
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.8	34.500	14794.7	2093	491	2150	97.03	34.6	-13.20	1.7	6.3	5.8	11 92615907
55	53	ER2	3/0ACSR	Overhead Line	35.8	34.500	144.4	2092	510	2153	96.83	34.7	-13.86	0.1	0.1	11.9	
52	52	53	3/0ACSR	Overhead Line	35.8	34.500	213.3	395	77	403	94.70	6.5	-11.19	0.0	0.0	2.7	
077	R 038	52	3/0ACSR	Overhead Line	35.8	34.500	1889.0	395	77	403	94.68	6.5	-11.23	0.0	0.0	2.7	
51	GARDEN RIVER DS HV BUS	R 038	3/0ACSR	Overhead Line	35.8	34.500	34354.4	395	80	403	94.55	6.5	-11.64	0.5	0.7	2.7	
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.9	12.470	100.0	108	35	113	95.01	5.1	-48.52	0.0	0.0	1.0	
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.9	12.470	100.0	286	94	301	95.00	13.5	-48.90	0.0	0.0	4.5	
54	53	54	3/0ACSR	Overhead Line	35.8	34.500	147.6	1696	433	1751	96.24	28.2	-14.48	0.0	0.0	10.2	
67	69	54	3/0ACSR	Overhead Line	35.7	34.500	12664.6	1696	433	1751	96.24	28.2	-14.49	3.3	4.0	10.2	
70	69	66	3/0ACSR	Overhead Line	35.7	34.500	9594.3	1693	449	1752	96.01	28.3	-15.10	2.5	3.0	10.2	
66	65	66	3/0ACSR	Overhead Line	35.7	34.500	100.0	977	330	1031	92.91	16.7	-19.01	0.0	0.0	6.6	
65	BAR RIVER DS HV BUS	65	3/0ACSR	Overhead Line	35.7	34.500	64.0	977	330	1031	92.90	16.7	-19.01	0.0	0.0	6.6	
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	12.9	12.470	100.0	976	321	1027	95.00	46.2	-49.02	0.0	0.1	10.8	
71	66	R 2020	3/0ACSR	Overhead Line	35.7	34.500	82.0	714	130	726	98.37	11.7	-10.68	0.0	0.0	3.7	
72	R 2020	72	3/0ACSR	Overhead Line	35.6	34.500	29000.0	714	131	726	98.37	11.7	-10.69	1.3	1.6	3.7	
73	72	73	556ASC	Overhead Line	35.6	34.500	6391.1	713	173	733	97.17	11.9	-14.09	0.1	0.3	1.8	
74	73	SOLAR	556ASC	Overhead Line	35.6	34.500	100.0	-239	0	239	100.00	3.9	179.52	0.0	0.0	0.6	
78	73	78	556ASC	Overhead Line	35.6	34.500	28445.2	951	184	969	98.18	15.7	-11.39	0.7	2.5	2.4	
79	78	542	477ACSR	Overhead Line	35.5	34.500	5072.2	951	230	978	97.20	15.9	-14.16	0.1	0.4	2.5	
86	542	86	556ASC	Overhead Line	35.5	34.500	100.0	951	238	980	97.01	15.9	-14.65	0.0	0.0	2.5	
8	86	8	556ASC	Overhead Line	25.6	25.000	10.0	949	226	976	97.29	22.0	-44.65	0.0	0.0	3.4	
7	8	R 2010	556ASC	Overhead Line	25.6	25.000	10.0	949	226	976	97.29	22.0	-44.66	0.0	0.0	3.4	
89	R 2010	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	25.6	25.000	50.0	949	226	976	97.29	22.0	-44.66	0.0	0.0	4.3	
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	25.6	25.000	185.0	949	226	976	97.29	22.0	-44.66	0.0	0.0	8.0	
13	11	13	336AAC	Overhead Line	25.6	25.000	3500.0	949	229	977	97.21	22.0	-44.85	0.2	0.6	4.3	
14	13	14	336AAC	Overhead Line	25.6	25.000	5717.0	949	231	977	97.16	22.0	-45.02	0.4	1.0	4.3	
15	14	15	35 KV 4/0 CU 100% CN	Cable	25.6	25.000	2345.0	949	235	977	97.06	22.0	-45.30	0.2	0.1	5.9	
16	15	16	336AAC	Overhead Line	25.6	25.000	13595.0	949	302	996	95.28	22.4	-49.06	0.9	2.5	4.4	
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	948	311	997	95.00	22.8	-49.69	0.0	0.0	4.5	
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.9	34.500	22193.7	2458	-470	2502	-97.87	40.3	10.82	4.1	12.5	7.0	
2024	ER1	58	477ACSR	Overhead Line	35.8	34.500	9412.4	2454	-444	2494	-98.04	40.2	9.96	1.7	5.3	7.0	
59	58	VR PRIMARY	477ACSR	Overhead Line	35.8	34.500	24.2	2452	-433	2490	-98.12	40.1	9.59	0.0	0.0	7.0	
62	VR SECONDARY	62	477ACSR	Overhead Line	35.2	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0	
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0	
75	VR SECONDARY	75	477ACSR	Overhead Line	35.2	34.500	100.0	2452	-432	2490	-98.12	40.9	9.57	0.0	0.1	7.1	
76	75	76	477ACSR	Overhead Line	35.1	34.500	51800.0	2452	-432	2490	-98.12	40.9	9.57	9.8	30.1	7.1	
77	76	77	556ASC	Overhead Line	35.1	34.500	100.0	2442	-377	2471	-98.46	40.6	7.62	0.0	0.1	7.0	
80	542	77	556ASC	Overhead Line	35.1	34.500	100.0	0	0	0	0.00	0.0	88.86	0.0	0.0	0.0	
81	77	81	556ASC	Overhead Line	35.1	34.500	100.0	724	-1011	1244	-57.77	20.5	53.23	0.0	0.0	3.6	
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.8	12.470	100.0	723	-1026	1255	-55.95	56.6	23.23	0.0	0.1	9.9	
82	77	R 052	3/0ACSR	Overhead Line	35.1	34.500	100.0	1718	635	1832	93.75	30.1	-21.42	0.0	0.0	10.0	
83	R 052	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	34.8	34.500	41600.0	1718	635	1832	93.74	30.1	-21.42	12.1	14.7	10.0	
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	34.8	34.500	100.0	763	258	806	94.42	13.4	-20.15	0.0	0.0	4.7	
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.8	12.470	39.9	762	251	802	95.00	36.1	-50.16	0.0	0.0	6.5	
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	34.8	34.500	15088.3	943	423	1034	91.25	17.2	-25.58	0.4	1.6	2.7	
61	VR PRIMARY	61	477ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0	
63	61	62	3/0ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0	
NA1	NORTHERN AVE TS	46	3/0ACSR	Overhead Line	35.9	34.500	100.0	16	-61	63	-25.69	1.0	75.11	0.0	0.0	0.3	
390	46	TRUSS PLANT	3/0ACSR	Overhead Line	35.9	34.500	27986.1	16	-61	63	-25.75	1.0	75.08	0.0	0.0	0.3	
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	3/0ACSR	Overhead Line	35.9	34.500	16346.2	0	-25	25	0.01	0.4	90.00	0.0	0.0	0.1	

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-4-2020 existing conductors.sx
Date	Tue Jun 16 2020
Time	14h59m10s
Project Name	Base Case from ERTS Max Load - by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=100.00%, Q=100.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	15643.82	1300.48	15697.78	99.66
Generators	238.98	-0.02	238.98	100.00
Total Generation	**15882.80**	**1300.46**	**15935.95**	**99.67**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	15404.08	5496.25	16355.26	94.18
Shunt capacitors (Adjusted)	0.00	-4942.72	4942.72	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**15404.08**	**553.53**	**15414.02**	**99.94**
Cable Capacitance	0.00	-68.68	68.68	0.00
Line Capacitance	0.00	-536.09	536.09	0.00
Total Shunt Capacitance	**0.00**	**-604.78**	**604.78**	**0.00**
Line Losses	436.63	948.43	1044.11	41.82
Cable Losses	2.85	1.76	3.35	85.12
Transformer Load Losses	40.15	401.52	403.52	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**479.63**	**1351.71**	**1434.28**	**33.44**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	4	68	103.11 %
	B	3	68	104.57 %
	C	4	68	106.84 %
Under-Voltage	A	0	FEEDER END	97.26 %
	B	0	FEEDER END	97.97 %
	C	0	FEEDER END	98.62 %
Over-Voltage	A	0	ECHO RIVER TS	104.00 %
	B	0	ECHO RIVER TS	104.00 %
	C	0	ECHO RIVER TS	104.00 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	436.63	3824.88	382.49
Cable Losses	2.85	24.96	2.50
Transformer Load Losses	40.15	351.73	35.17
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	**479.63**	**4201.58**	**420.16**

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	29.8	5501.7	791.3	104.00
ECHO RIVER TS 081		DEFAULT	Switch	13.7	2526.8	367.6	104.00
ECHO RIVER TS 081		DEFAULT	Switch	13.7	2519.5	349.9	103.56
ECHO RIVER TS 077		DEFAULT	Switch	1.6	256.8	155.1	103.54
ECHO RIVER TS 51		DEFAULT	Switch	1.7	256.0	172.6	103.12
ECHO RIVER TS 49		GARDEN T2	Two-Winding Transforme	14.6	145.5	55.0	102.48
ECHO RIVER TS 555		GARDEN T1	Two-Winding Transforme	1.2	110.5	117.6	102.31
ECHO RIVER TS 67		DEFAULT	Switch	12.2	2262.3	194.5	103.54
ECHO RIVER TS 66		DEFAULT	Switch	6.9	1247.7	220.5	102.12
ECHO RIVER TS 65		DEFAULT	Switch	6.9	1247.7	220.5	102.11
ECHO RIVER TS 68		BAR RIVER T1	Two-Winding Transforme	52.1	1247.7	220.5	101.55
ECHO RIVER TS 68		1200 KVAR 7 KV	Shunt Capacitor	103.1	1587.3	109.8	101.51
ECHO RIVER TS 71		DEFAULT	Switch	5.4	986.1	-49.4	102.12
ECHO RIVER TS 72		DEFAULT	Switch	5.4	978.9	-43.8	101.42
ECHO RIVER TS 74		DEFAULT	Switch	0.4	-79.3	-0.1	101.38
ECHO RIVER TS 79		DEFAULT	Switch	5.8	1054.7	-34.4	101.12
ECHO RIVER TS 86		DESBARATS T2	Two-Winding Transforme	63.5	1054.7	-34.4	101.10
ECHO RIVER TS 13		1200 KVAR 20 KV	Shunt Capacitor	102.7	1053.5	-78.7	100.98
ECHO RIVER TS 17		25 KV 600A 1PH	Regulator	12.7	1046.8	343.4	100.69
ECHO RIVER TS 56		DEFAULT	Switch	16.1	2975.0	423.7	104.00
ECHO RIVER TS 58		DEFAULT	Switch	16.1	2949.8	365.7	102.79
ECHO RIVER TS 5		34.5KV_200A_1PH_COOPER_REGULATOR_6	Regulator	72.6	2949.8	365.8	102.15
ECHO RIVER TS 62		DEFAULT	Switch	0.0	0.0	0.0	102.79
ECHO RIVER TS 64		DEFAULT	Switch	0.0	0.0	0.0	102.11
ECHO RIVER TS 75		DEFAULT	Switch	16.2	2949.7	365.7	102.14
ECHO RIVER TS 77		DEFAULT	Switch	16.2	2908.3	266.9	100.26
ECHO RIVER TS 80		DEFAULT	Switch	0.0	0.0	0.0	101.12
ECHO RIVER TS 81		DEFAULT	Switch	5.7	1010.7	-169.4	100.26
ECHO RIVER TS 81		DESBARATS T1	Two-Winding Transforme	57.5	1010.7	-169.4	101.20
ECHO RIVER TS 87		1200 KVAR 7 KV	Shunt Capacitor	102.4	789.3	-150.2	101.18
ECHO RIVER TS 82		DEFAULT	Switch	10.8	1897.6	436.3	100.26
ECHO RIVER TS 83		DEFAULT	Switch	10.8	1897.5	436.3	100.25
ECHO RIVER TS 84		DEFAULT	Switch	5.0	878.1	-54.1	97.59
ECHO RIVER TS 84		BRUCE MINES T1	Two-Winding Transforme	50.9	878.1	-54.1	100.91
ECHO RIVER TS 88		1200 KVAR 7 KV	Shunt Capacitor	101.8	946.7	-96.2	100.90
ECHO RIVER TS 61		DEFAULT	Switch	0.0	0.0	-0.1	102.79

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	0.1	18.0	-14.2	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	0.0	0.0	-8.4	103.99
NORTHERN AVE TS	076	DEFAULT	Switch	0.0	0.0	0.0	103.12

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.8	34.500	14794.7	7562	248	7566	99.63	121.8	-1.88	21.5	77.6	20.7
55	53	ER2	3/0ACSR	Overhead Line	35.8	34.500	144.4	7541	195	7543	99.65	121.8	-2.07	0.7	0.8	42.4
52	52	53	3/0ACSR	Overhead Line	35.8	34.500	213.3	1290	405	1352	92.15	21.8	-18.03	0.0	0.0	9.2
077	R 038	52	3/0ACSR	Overhead Line	35.8	34.500	1889.0	1290	405	1352	92.14	21.8	-18.04	0.3	0.4	9.2
51	GARDEN RIVER DS HV BUS	R 038	3/0ACSR	Overhead Line	35.6	34.500	34354.4	1290	408	1353	92.09	21.8	-18.16	6.0	7.3	9.2
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.8	12.470	100.0	354	116	372	95.00	16.8	-49.38	0.0	0.0	3.4
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.8	12.470	100.0	927	305	976	95.00	44.4	-50.60	0.1	0.2	14.7
54	53	54	3/0ACSR	Overhead Line	35.8	34.500	147.6	6250	-210	6254	-99.39	101.0	1.34	0.5	0.6	35.0
67	69	54	3/0ACSR	Overhead Line	35.5	34.500	12664.6	6250	-211	6253	-99.39	101.0	1.33	41.7	50.9	35.0
70	69	66	3/0ACSR	Overhead Line	35.4	34.500	9594.3	6208	-242	6213	-99.37	101.0	1.16	31.6	38.5	35.0
66	65	66	3/0ACSR	Overhead Line	35.4	34.500	100.0	3206	-111	3208	-98.06	52.4	0.51	0.1	0.1	19.8
65	BAR RIVER DS HV BUS	65	3/0ACSR	Overhead Line	35.4	34.500	64.0	3206	-111	3208	-98.06	52.4	0.51	0.1	0.1	19.8
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	12.8	12.470	100.0	3196	-207	3203	-98.31	145.0	-29.49	0.3	1.1	33.7
71	66	R 2020	3/0ACSR	Overhead Line	35.4	34.500	82.0	2970	-155	2974	-99.86	48.5	1.57	0.1	0.1	15.4
72	R 2020	72	3/0ACSR	Overhead Line	35.1	34.500	29000.0	2970	-155	2974	-99.86	48.5	1.57	21.5	26.3	15.4
73	72	73	556ASC	Overhead Line	35.1	34.500	6391.1	2949	-138	2952	-99.89	48.5	0.73	1.5	5.3	7.5
74	73	SOLAR	556ASC	Overhead Line	35.1	34.500	100.0	-239	0	239	100.00	3.9	177.92	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.0	34.500	28445.2	3186	-133	3189	-99.91	52.4	0.33	7.5	27.3	8.1
79	78	542	477ACSR	Overhead Line	35.0	34.500	5072.2	3179	-113	3181	-99.94	52.4	-0.51	1.6	4.8	8.2
86	542	86	556ASC	Overhead Line	35.0	34.500	100.0	3177	-109	3179	-99.94	52.4	-0.66	0.0	0.1	8.1
8	86	8	556ASC	Overhead Line	25.3	25.000	10.0	3164	-244	3173	-99.70	72.3	-30.66	0.0	0.0	11.2
7	8	R 2010	556ASC	Overhead Line	25.3	25.000	10.0	3164	-244	3173	-99.70	72.3	-30.66	0.0	0.0	11.2
89	R 2010	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	25.3	25.000	50.0	3164	-244	3173	-99.70	72.3	-30.66	0.0	0.1	14.2
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	25.3	25.000	185.0	3164	-244	3173	-99.70	72.3	-30.67	0.3	0.1	26.4
13	11	13	336AAC	Overhead Line	25.3	25.000	3500.0	3163	-241	3173	-99.71	72.3	-30.72	2.6	6.9	14.2
14	13	14	336AAC	Overhead Line	25.2	25.000	5717.0	3161	993	3313	95.41	75.6	-52.63	4.4	11.8	14.9
15	14	15	35 KV 4/0 CU 100% CN	Cable	25.2	25.000	2345.0	3157	985	3307	95.46	75.6	-52.70	2.6	1.6	20.2
16	15	16	336AAC	Overhead Line	25.1	25.000	13595.0	3154	1049	3324	94.89	76.1	-53.78	10.6	28.4	15.0
18	17	18	336AAC	Overhead Line	25.2	25.000	25.0	3144	1032	3309	95.01	75.8	-53.96	0.0	0.1	14.9
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.6	34.500	22193.7	8027	1096	8102	98.73	130.4	-7.77	42.9	131.7	22.7
2024	ER1	58	477ACSR	Overhead Line	35.5	34.500	9412.4	7985	1002	8047	98.86	130.4	-8.04	18.2	55.9	22.7
59	58	VR PRIMARY	477ACSR	Overhead Line	35.5	34.500	24.2	7966	962	8024	98.92	130.5	-8.15	0.0	0.1	22.7
62	VR SECONDARY	62	477ACSR	Overhead Line	35.4	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	35.4	34.500	100.0	7966	963	8024	98.92	131.0	-8.15	0.2	0.6	22.8
76	75	76	477ACSR	Overhead Line	34.8	34.500	51600.0	7966	962	8024	98.92	131.0	-8.15	101.3	310.9	22.8
77	76	77	556ASC	Overhead Line	34.8	34.500	100.0	7865	737	7899	99.19	131.2	-8.76	0.2	0.6	22.7
80	542	77	556ASC	Overhead Line	34.8	34.500	100.0	0	0	0	0.01	0.0	86.63	0.0	0.0	0.0
81	77	81	556ASC	Overhead Line	34.8	34.500	100.0	2327	-401	2362	-95.88	39.3	6.30	0.0	0.1	8.0
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.6	12.470	100.0	2321	-460	2367	-95.39	108.6	-23.71	0.2	0.6	24.8
82	77	R 052	3/0ACSR	Overhead Line	34.8	34.500	100.0	5537	1137	5653	97.90	93.8	-15.00	0.3	0.3	31.0
83	R 052	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	33.9	34.500	41600.0	5537	1137	5652	97.90	93.8	-15.00	116.1	141.7	31.0
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	33.9	34.500	100.0	2446	-344	2470	-98.72	42.1	3.38	0.1	0.1	14.4
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.6	12.470	39.9	2438	-422	2474	-98.21	113.4	-26.63	0.1	0.2	20.3
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	33.8	34.500	15088.3	2975	1398	3287	90.51	56.0	-29.73	4.6	16.6	8.7
61	VR PRIMARY	61	477ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0
63	61	62	3/0ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0
NA1	NORTHERN AVE TS	46	3/0ACSR	Overhead Line	35.9	34.500	100.0	54	-43	69	-78.38	1.1	38.39	0.0	0.0	0.4
390	46	TRUSS PLANT	3/0ACSR	Overhead Line	35.9	34.500	27986.1	54	-43	69	-78.49	1.1	38.29	0.0	0.0	0.4
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	3/0ACSR	Overhead Line	35.9	34.500	16346.2	0	-25	25	0.02	0.4	90.00	0.0	0.0	0.1

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Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-4-2020 existing conductors.sxst
Date	Tue Jun 16 2020
Time	14h55m01s
Project Name	Base Case from NTS Min Load - Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	**kW**	**kvar**	**kVA**	**PF(%)**
Sources (Swing)	4581.45	134.75	4583.44	99.96
Generators	238.98	-0.01	238.98	100.00
Total Generation	**4820.44**	**134.74**	**4822.32**	**99.96**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4627.53	1656.01	4914.92	94.15
Shunt capacitors (Adjusted)	0.00	-1234.07	1234.07	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4627.53**	**421.95**	**4646.73**	**99.59**
Cable Capacitance	0.00	-66.23	66.23	0.00
Line Capacitance	0.00	-521.34	521.34	0.00
Total Shunt Capacitance	**0.00**	**-587.58**	**587.58**	**0.00**
Line Losses	187.96	253.10	315.26	59.62
Cable Losses	0.26	0.16	0.30	85.67
Transformer Load Losses	4.71	47.11	47.35	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**192.93**	**300.37**	**356.99**	**54.04**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	102.74 %
	B	1	87	101.87 %
	C	1	87	103.89 %
Under-Voltage	A	0	16	98.82 %
	B	0	16	98.46 %
	C	0	16	99.60 %
Over-Voltage	A	0	ECHO RIVER TS	104.00 %
	B	0	ECHO RIVER TS	104.00 %
	C	0	ECHO RIVER TS	104.00 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	187.96	1646.50	164.65
Cable Losses	0.26	2.26	0.23
Transformer Load Losses	4.71	41.27	4.13
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	192.93	1690.04	169.00

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	105.57 %
	B	1	87	104.47 %
	C	1	87	105.76 %
Under-Voltage	A	0	FEEDER END	100.60 %
	B	0	FEEDER END	100.61 %
	C	0	18	100.70 %
Over-Voltage	A	0	68	104.38 %
	B	0	BAR RIVER DS LV BUS	104.53 %
	C	0	68	104.86 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	35.82	313.77	31.38
Cable Losses	0.24	2.14	0.21
Transformer Load Losses	4.80	42.08	4.21
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	40.87	357.99	35.80

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-16-2020 uprated conductors.s
Date	Tue Jun 16 2020
Time	14h43m49s
Project Name	Uprated from ERTS Min Load - By Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	4593.23	-48.70	4593.48	-99.99
Generators	239.00	0.00	239.00	100.00
Total Generation	**4832.23**	**-48.69**	**4832.47**	**-99.99**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4791.36	1713.30	5088.47	94.16
Shunt capacitors (Adjusted)	0.00	-1263.21	1263.21	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4791.36**	**450.09**	**4812.45**	**99.56**
Cable Capacitance	0.00	-71.06	71.06	0.00
Line Capacitance	0.00	-563.21	563.21	0.00
Total Shunt Capacitance	**0.00**	**-634.27**	**634.27**	**0.00**
Line Losses	35.82	87.29	94.36	37.96
Cable Losses	0.24	0.15	0.29	85.23
Transformer Load Losses	4.80	48.04	48.28	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**40.87**	**135.48**	**141.51**	**28.88**

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	29.4	5270.3	1490.7	103.98
NORTHERN AVE TS	390	DEFAULT	Switch	29.3	5048.1	1245.2	98.98
NORTHERN AVE TS	076	DEFAULT	Switch	29.3	4928.5	1106.7	96.13
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	12.8	126.5	47.9	96.00
NORTHERN AVE TS	51	DEFAULT	Switch	27.9	4706.2	955.7	96.13
NORTHERN AVE TS	077	DEFAULT	Switch	27.9	4466.4	677.9	90.38
NORTHERN AVE TS	67	DEFAULT	Switch	27.9	4464.0	681.6	90.32
NORTHERN AVE TS	66	DEFAULT	Switch	22.6	3486.4	473.7	86.91
NORTHERN AVE TS	65	DEFAULT	Switch	22.6	3486.1	473.4	86.90
NORTHERN AVE TS	64	DEFAULT	Switch	16.7	2583.0	309.4	86.90
NORTHERN AVE TS	61	DEFAULT	Switch	16.7	2582.7	308.9	86.88
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	75.2	2582.6	321.4	95.57
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	86.89
NORTHERN AVE TS	75	DEFAULT	Switch	15.2	2582.5	321.2	95.57
NORTHERN AVE TS	77	DEFAULT	Switch	15.2	2546.2	234.4	93.80
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	85.75
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	54.4	897.1	40.5	86.35
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	74.9	916.1	-4.3	86.23
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	13.0	909.1	298.5	93.83
NORTHERN AVE TS	81	DEFAULT	Switch	5.3	885.3	-150.5	93.80
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	51.0	885.3	-150.5	95.68
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	91.5	705.9	-134.4	95.65
NORTHERN AVE TS	82	DEFAULT	Switch	10.1	1660.8	385.0	93.80
NORTHERN AVE TS	83	DEFAULT	Switch	10.1	1660.8	384.9	93.79
NORTHERN AVE TS	84	DEFAULT	Switch	4.7	768.0	-45.1	91.30
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	45.1	768.0	-45.1	95.40
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	91.0	846.8	-86.0	95.40
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-12.7	86.88
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	38.1	903.1	164.0	87.42
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	76.4	1176.7	81.3	87.38
NORTHERN AVE TS	71	DEFAULT	Switch	5.3	829.7	35.7	86.92
NORTHERN AVE TS	72	DEFAULT	Switch	5.3	822.7	37.5	86.14
NORTHERN AVE TS	74	DEFAULT	Switch	0.5	-78.0	0.2	86.08
NORTHERN AVE TS	79	DEFAULT	Switch	5.8	897.1	40.5	85.75
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-6.4	90.35
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	1.1	95.9	103.2	95.84

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	0.0	0.0	0.0	104.00

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)	
NA1	NORTHERN AVE TS	46	3/0ACSR	Overhead Line	35.9	34.500	100.0	15264	3422	15643	97.44	251.7	-12.63	2.0	2.5	83.9	83.94972295
390	46	TRUSS PLANT	3/0ACSR	Overhead Line	34.3	34.500	27986.1	15262	3419	15641	97.45	251.7	-12.64	562.7	687.2	83.9	
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	3/0ACSR	Overhead Line	33.4	34.500	16346.2	14650	2750	14906	98.13	251.0	-12.73	326.6	398.8	83.7	
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.0	12.470	100.0	311	102	327	95.00	15.7	-52.03	0.0	0.0	3.2	
51	GARDEN RIVER DS HV BUS	R 038	3/0ACSR	Overhead Line	31.8	34.500	34354.4	13185	1972	13332	98.61	230.6	-11.91	582.2	711.0	79.6	
077	R 038	52	3/0ACSR	Overhead Line	31.7	34.500	1889.0	12603	1305	12670	99.14	230.7	-12.10	32.0	39.1	79.7	
52	52	53	3/0ACSR	Overhead Line	31.7	34.500	213.3	12571	1268	12635	99.17	230.7	-12.11	3.6	4.4	79.7	
54	53	54	3/0ACSR	Overhead Line	31.6	34.500	147.6	12567	1284	12633	99.15	230.7	-12.20	2.5	3.1	79.7	
67	69	54	3/0ACSR	Overhead Line	31.1	34.500	12664.6	12565	1281	12630	99.16	230.7	-12.21	214.8	262.3	79.7	
70	69	66	3/0ACSR	Overhead Line	30.6	34.500	9594.3	12350	1034	12393	99.31	230.7	-12.27	162.8	198.7	79.7	
66	65	66	3/0ACSR	Overhead Line	30.6	34.500	100.0	9587	735	9615	99.14	181.7	-12.76	1.1	1.3	64.5	
65	BAR RIVER DS HV BUS	65	3/0ACSR	Overhead Line	30.6	34.500	64.0	9586	734	9614	99.14	181.7	-12.76	0.7	0.8	64.5	
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	30.6	34.500	100.0	7199	822	7246	98.99	136.9	-14.83	0.2	0.7	23.5	
63	61	62	3/0ACSR	Overhead Line	30.6	34.500	100.0	7199	822	7245	98.99	136.9	-14.83	0.6	0.7	47.7	
61	VR PRIMARY	61	477ACSR	Overhead Line	30.6	34.500	100.0	7198	821	7245	99.00	136.9	-14.83	0.2	0.7	23.5	
62	VR SECONDARY	62	477ACSR	Overhead Line	33.7	34.500	100.0	0	0	0	0.00	0.0	81.70	0.0	0.0	0.0	
75	VR SECONDARY	75	477ACSR	Overhead Line	33.7	34.500	100.0	7198	860	7249	98.93	124.6	-15.15	0.2	0.5	21.4	
76	75	76	477ACSR	Overhead Line	33.1	34.500	51800.0	7198	860	7249	98.93	124.6	-15.15	91.2	279.9	21.4	
77	76	77	556ASC	Overhead Line	33.1	34.500	100.0	7106	658	7137	99.20	124.7	-15.76	0.2	0.5	21.2	
80	542	77	556ASC	Overhead Line	33.1	34.500	100.0	0	0	0	0.01	0.0	79.58	0.0	0.0	0.0	
86	542	86	556ASC	Overhead Line	30.2	34.500	100.0	2806	127	2809	99.90	53.7	-12.23	0.0	0.1	8.4	
8	86	8	556ASC	Overhead Line	21.8	25.000	10.0	2792	-15	2792	-100.00	74.1	-42.23	0.0	0.0	11.7	
7	8	R 2010	556ASC	Overhead Line	21.8	25.000	10.0	2792	-15	2792	-100.00	74.1	-42.23	0.0	0.0	11.7	
89	R 2010	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	21.8	25.000	50.0	2792	-15	2792	-100.00	74.1	-42.23	0.0	0.1	14.8	
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	21.8	25.000	185.0	2792	-15	2792	-100.00	74.1	-42.23	0.3	0.1	27.5	
13	11	13	336AAC	Overhead Line	21.7	25.000	3500.0	2792	-13	2792	-100.00	74.1	-42.28	2.7	7.3	14.8	
14	13	14	336AAC	Overhead Line	21.7	25.000	5717.0	2789	895	2929	95.22	77.8	-60.46	4.7	12.5	15.6	
15	14	15	35 KV 4/0 CU 100% CN	Cable	21.6	25.000	2345.0	2784	886	2922	95.30	77.8	-60.53	2.7	1.7	21.2	
16	15	16	336AAC	Overhead Line	21.5	25.000	13595.0	2782	932	2934	94.82	78.2	-61.42	11.2	30.1	15.7	
18	17	18	336AAC	Overhead Line	23.6	25.000	25.0	2771	910	2916	95.00	71.2	-61.58	0.0	0.0	14.2	
81	77	81	556ASC	Overhead Line	33.1	34.500	100.0	2090	-371	2123	-95.79	37.3	-0.50	0.0	0.1	7.5	
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.0	12.470	100.0	2085	-425	2128	-95.21	103.1	-30.50	0.2	0.6	23.4	
82	77	R 052	3/0ACSR	Overhead Line	33.1	34.500	100.0	5016	1028	5120	97.90	89.3	-22.06	0.3	0.3	29.0	
83	R 052	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	32.3	34.500	41600.0	5016	1028	5120	97.90	89.3	-22.07	105.0	128.2	29.0	
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	32.3	34.500	100.0	2211	-315	2234	-98.69	40.0	-3.67	0.1	0.1	13.4	
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.0	12.470	39.9	2204	-386	2238	-98.18	107.8	-33.67	0.1	0.2	19.2	
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	32.2	34.500	15088.3	2699	1268	2983	90.51	53.3	-36.78	4.2	15.0	8.4	
59	58	VR PRIMARY	477ACSR	Overhead Line	30.6	34.500	24.2	0	-40	40	0.00	0.7	81.70	0.0	0.0	0.1	
2024	ER1	58	477ACSR	Overhead Line	30.6	34.500	9412.4	0	-40	40	0.00	0.7	81.70	0.0	0.0	0.1	
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	30.6	34.500	22193.7	0	-28	28	0.00	0.5	81.70	0.0	0.0	0.1	
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	11.1	12.470	100.0	2379	-160	2385	-98.25	124.9	-36.46	0.3	0.8	29.1	
71	66	R 2020	3/0ACSR	Overhead Line	30.6	34.500	82.0	2600	111	2603	99.91	49.1	-10.72	0.1	0.1	15.8	
72	R 2020	72	3/0ACSR	Overhead Line	30.3	34.500	29000.0	2600	111	2603	99.91	49.1	-10.72	22.0	26.9	15.8	
73	72	73	556ASC	Overhead Line	30.3	34.500	6391.1	2578	117	2581	99.90	49.1	-11.44	1.5	5.4	7.7	
74	73	SOLAR	556ASC	Overhead Line	30.3	34.500	100.0	-239	0	239	99.99	4.5	171.00	0.0	0.0	0.7	
78	73	78	556ASC	Overhead Line	30.2	34.500	28445.2	2816	119	2818	99.91	53.6	-11.39	7.9	28.6	8.4	
79	78	542	477ACSR	Overhead Line	30.2	34.500	5072.2	2808	125	2811	99.90	53.7	-12.10	1.6	5.0	8.5	
55	53	ER2	3/0ACSR	Overhead Line	31.7	34.500	144.4	0	-20	20	0.00	0.4	83.68	0.0	0.0	0.1	
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	31.7	34.500	14794.7	0	-20	20	0.00	0.4	83.68	0.0	0.0	0.1	
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.0	12.470	100.0	825	271	868	95.00	41.9	-53.26	0.1	0.2	13.9	

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	0	87	91.53 %
	B	0	88	88.90 %
	C	0	87	97.62 %
Under-Voltage	A	106	16	85.30 %
	B	106	16	84.88 %
	C	82	16	87.73 %
Over-Voltage	A	0	ECHO RIVER TS	104.00 %
	B	0	ECHO RIVER TS	104.00 %
	C	0	ECHO RIVER TS	104.00 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	2145.32	18792.98	1879.30
Cable Losses	3.04	26.59	2.66
Transformer Load Losses	36.60	320.65	32.06
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	2184.96	19140.22	1914.02

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-4-2020 existing conductors.sxst
Date	Tue Jun 16 2020
Time	14h57m29s
Project Name	Base Case from NTS Max Load
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=100.00%, Q=100.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	15264.44	3421.77	15643.27	97.58
Generators	238.93	-0.01	238.93	100.00
Total Generation	**15503.38**	**3421.76**	**15876.50**	**97.65**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	13318.81	4772.47	14148.04	94.14
Shunt capacitors (Adjusted)	0.00	-4076.18	4076.18	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**13318.81**	**696.29**	**13337.00**	**99.86**
Cable Capacitance	0.00	-50.57	50.57	0.00
Line Capacitance	0.00	-445.58	445.58	0.00
Total Shunt Capacitance	**0.00**	**-496.15**	**496.15**	**0.00**
Line Losses	2145.32	2853.72	3570.17	60.09
Cable Losses	3.04	1.86	3.56	85.30
Transformer Load Losses	36.60	366.04	367.86	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**2184.96**	**3221.62**	**3892.67**	**56.13**

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	8.8	1629.7	141.5	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	8.8	1606.0	130.8	102.70
NORTHERN AVE TS	076	DEFAULT	Switch	8.8	1595.2	125.8	101.96
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	4.3	42.9	15.9	102.00
NORTHERN AVE TS	51	DEFAULT	Switch	8.3	1519.4	75.4	101.96
NORTHERN AVE TS	077	DEFAULT	Switch	8.3	1497.9	66.9	100.43
NORTHERN AVE TS	67	DEFAULT	Switch	8.3	1497.7	74.8	100.42
NORTHERN AVE TS	66	DEFAULT	Switch	7.0	1248.7	22.4	99.48
NORTHERN AVE TS	65	DEFAULT	Switch	7.0	1248.7	22.4	99.47
NORTHERN AVE TS	64	DEFAULT	Switch	5.1	891.5	-151.0	99.47
NORTHERN AVE TS	61	DEFAULT	Switch	5.1	891.4	-151.0	99.47
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	22.7	891.4	-134.3	100.71
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	99.47
NORTHERN AVE TS	75	DEFAULT	Switch	5.0	891.4	-134.2	100.71
NORTHERN AVE TS	77	DEFAULT	Switch	5.0	887.5	-118.3	100.47
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	99.06
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	19.5	314.0	79.6	99.14
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	0.0	314.5	77.6	99.10
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	3.9	313.8	103.1	100.68
NORTHERN AVE TS	81	DEFAULT	Switch	2.5	306.7	-341.5	100.47
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	22.9	306.7	-341.4	101.37
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	102.7	237.7	-332.9	101.36
NORTHERN AVE TS	82	DEFAULT	Switch	3.5	580.8	223.2	100.47
NORTHERN AVE TS	83	DEFAULT	Switch	3.5	580.8	223.2	100.46
NORTHERN AVE TS	84	DEFAULT	Switch	1.6	270.4	100.5	99.51
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	16.3	270.4	100.6	101.70
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	288.5	94.8	101.69
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-16.6	99.47
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	15.5	357.2	173.4	99.51
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	0.0	457.5	150.4	99.50
NORTHERN AVE TS	71	DEFAULT	Switch	1.3	235.7	46.9	99.48
NORTHERN AVE TS	72	DEFAULT	Switch	1.4	235.2	60.0	99.25
NORTHERN AVE TS	74	DEFAULT	Switch	0.4	-79.1	0.1	99.22
NORTHERN AVE TS	79	DEFAULT	Switch	1.8	314.0	79.6	99.06
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-7.9	100.42
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	0.4	32.9	34.5	101.95

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	0.0	0.0	0.0	104.00

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)	
NA1	NORTHERN AVE TS	46	3/0ACSR	Overhead Line	35.9	34.500	100.0	4581	135	4583	99.77	73.8	-1.68	0.2	0.2	25.1	25.07036422
390	46	TRUSS PLANT	3/0ACSR	Overhead Line	35.5	34.500	27986.1	4581	135	4583	99.77	73.8	-1.69	48.4	59.1	25.1	
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	3/0ACSR	Overhead Line	35.3	34.500	16346.2	4517	111	4518	99.77	73.5	-2.13	28.1	34.3	25.0	
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.7	12.470	100.0	105	34	110	95.01	5.0	-49.47	0.0	0.0	1.0	
51	GARDEN RIVER DS HV BUS	R 038	3/0ACSR	Overhead Line	34.8	34.500	34354.4	4105	-28	4105	-99.60	67.2	-0.77	49.7	60.7	23.8	
077	R 038	52	3/0ACSR	Overhead Line	34.8	34.500	1889.0	4055	-38	4055	-99.59	67.2	-1.48	2.7	3.3	23.8	
52	52	53	3/0ACSR	Overhead Line	34.8	34.500	213.3	4052	-38	4052	-99.59	67.2	-1.52	0.3	0.4	23.8	
54	53	54	3/0ACSR	Overhead Line	34.8	34.500	147.6	4052	-14	4052	-99.59	67.2	-1.87	0.2	0.3	23.8	
67	69	54	3/0ACSR	Overhead Line	34.7	34.500	12664.6	4052	-14	4052	-99.59	67.2	-1.87	18.3	22.4	23.8	
70	69	66	3/0ACSR	Overhead Line	34.6	34.500	9594.3	4033	-18	4033	-99.59	67.2	-2.13	13.9	17.0	23.8	
66	65	66	3/0ACSR	Overhead Line	34.5	34.500	100.0	3309	-165	3313	-99.28	55.4	0.21	0.1	0.1	20.0	
65	BAR RIVER DS HV BUS	65	3/0ACSR	Overhead Line	34.5	34.500	64.0	3309	-165	3313	-99.28	55.4	0.21	0.1	0.1	20.0	
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	34.5	34.500	100.0	2394	-474	2441	-97.73	40.8	8.57	0.0	0.1	7.1	
63	61	62	3/0ACSR	Overhead Line	34.5	34.500	100.0	2394	-474	2441	-97.73	40.8	8.57	0.1	0.1	14.5	
61	VR PRIMARY	61	477ACSR	Overhead Line	34.5	34.500	100.0	2394	-474	2441	-97.73	40.8	8.57	0.0	0.1	7.1	
62	VR SECONDARY	62	477ACSR	Overhead Line	34.8	34.500	100.0	0	0	0	0.00	0.0	87.40	0.0	0.0	0.0	
75	VR SECONDARY	75	477ACSR	Overhead Line	34.8	34.500	100.0	2394	-423	2431	-98.11	40.4	7.41	0.0	0.1	7.0	
76	75	76	477ACSR	Overhead Line	34.7	34.500	51800.0	2394	-423	2431	-98.11	40.4	7.40	9.6	29.3	7.0	
77	76	77	556ASC	Overhead Line	34.7	34.500	100.0	2385	-369	2413	-98.45	40.2	5.45	0.0	0.1	6.9	
80	542	77	556ASC	Overhead Line	34.7	34.500	100.0	0	0	0	0.00	0.0	86.68	0.0	0.0	0.0	
86	542	86	556ASC	Overhead Line	34.4	34.500	100.0	947	243	978	96.85	16.4	-17.30	0.0	0.0	2.5	
8	86	8	556ASC	Overhead Line	24.8	25.000	10.0	946	230	974	97.16	22.7	-47.31	0.0	0.0	3.5	
7	8	R 2010	556ASC	Overhead Line	24.8	25.000	10.0	946	230	974	97.16	22.7	-47.31	0.0	0.0	3.5	
89	R 2010	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	24.8	25.000	50.0	946	230	974	97.16	22.7	-47.31	0.0	0.0	4.5	
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	24.8	25.000	185.0	946	230	974	97.16	22.7	-47.31	0.0	0.0	8.3	
13	11	13	336AAC	Overhead Line	24.8	25.000	3500.0	946	234	974	97.09	22.7	-47.49	0.2	0.6	4.5	
14	13	14	336AAC	Overhead Line	24.8	25.000	5717.0	946	236	975	97.03	22.7	-47.65	0.4	1.1	4.5	
15	14	15	35 KV 4/0 CU 100% CN	Cable	24.8	25.000	2345.0	945	239	975	96.95	22.7	-47.91	0.2	0.1	6.1	
16	15	16	336AAC	Overhead Line	24.7	25.000	13595.0	945	302	992	95.25	23.1	-51.44	1.0	2.6	4.6	
18	17	18	336AAC	Overhead Line	25.2	25.000	25.0	944	310	994	95.00	22.8	-52.04	0.0	0.0	4.5	
81	77	81	556ASC	Overhead Line	34.7	34.500	100.0	706	-988	1215	-57.70	20.2	51.08	0.0	0.0	3.6	
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.6	12.470	100.0	705	-1002	1225	-55.88	55.9	21.07	0.0	0.1	9.8	
82	77	R 052	3/0ACSR	Overhead Line	34.7	34.500	100.0	1678	620	1789	93.75	29.8	-23.60	0.0	0.0	9.9	
83	R 052	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	34.4	34.500	41600.0	1678	620	1789	93.74	29.8	-23.61	11.8	14.4	9.9	
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	34.4	34.500	100.0	745	252	786	94.41	13.2	-22.34	0.0	0.0	4.6	
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.7	12.470	39.9	744	245	783	95.00	35.6	-52.35	0.0	0.0	6.4	
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	34.4	34.500	15088.3	921	413	1010	91.25	17.0	-27.77	0.4	1.5	2.6	
59	58	VR PRIMARY	477ACSR	Overhead Line	34.5	34.500	24.2	0	-51	51	0.00	0.8	87.39	0.0	0.0	0.1	
2024	ER1	58	477ACSR	Overhead Line	34.5	34.500	9412.4	0	-51	51	0.00	0.8	87.39	0.0	0.0	0.1	
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	34.6	34.500	22193.7	0	-35	35	0.00	0.6	87.39	0.0	0.0	0.1	
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	12.4	12.470	100.0	914	300	962	95.00	44.7	-51.37	0.0	0.1	10.4	
71	66	R 2020	3/0ACSR	Overhead Line	34.6	34.500	82.0	711	143	725	98.02	12.1	-14.00	0.0	0.0	3.8	
72	R 2020	72	3/0ACSR	Overhead Line	34.5	34.500	29000.0	711	143	725	98.02	12.1	-14.01	1.4	1.7	3.8	
73	72	73	556ASC	Overhead Line	34.5	34.500	6391.1	709	183	733	96.82	12.3	-17.19	0.1	0.3	1.9	
74	73	SOLAR	556ASC	Overhead Line	34.5	34.500	100.0	-239	0	239	100.00	4.0	177.24	0.0	0.0	0.6	
78	73	78	556ASC	Overhead Line	34.4	34.500	28445.2	948	193	968	97.98	16.2	-14.25	0.7	2.6	2.5	
79	78	542	477ACSR	Overhead Line	34.4	34.500	5072.2	947	236	976	97.04	16.4	-16.84	0.2	0.5	2.6	
55	53	ER2	3/0ACSR	Overhead Line	34.8	34.500	144.4	0	-24	24	0.00	0.4	87.96	0.0	0.0	0.1	
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	34.8	34.500	14794.7	0	-24	24	0.00	0.4	87.96	0.0	0.0	0.1	
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.7	12.470	100.0	279	92	294	95.00	13.3	-49.83	0.0	0.0	4.4	

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	8.8	1632.4	103.0	104.00
ECHO RIVER TS 081		DEFAULT	Switch	4.1	715.2	250.8	104.00
ECHO RIVER TS 081		DEFAULT	Switch	4.1	714.5	257.0	103.81
ECHO RIVER TS 077		DEFAULT	Switch	0.5	78.5	31.4	103.81
ECHO RIVER TS 51		DEFAULT	Switch	0.5	78.5	52.1	103.74
ECHO RIVER TS 49		GARDEN T2	Two-Winding Transforme	4.4	44.4	16.5	103.58
ECHO RIVER TS 555		GARDEN T1	Two-Winding Transforme	0.4	34.1	35.6	103.52
ECHO RIVER TS 67		DEFAULT	Switch	3.6	636.0	225.8	103.81
ECHO RIVER TS 66		DEFAULT	Switch	2.4	396.4	192.1	103.55
ECHO RIVER TS 65		DEFAULT	Switch	2.4	396.4	192.2	103.55
ECHO RIVER TS 68		BAR RIVER T1	Two-Winding Transforme	17.1	396.4	192.2	104.38
ECHO RIVER TS 68		1200 KVAR 7 KV	Shunt Capacitor	0.0	503.2	165.5	104.36
ECHO RIVER TS 71		DEFAULT	Switch	1.3	238.8	43.6	103.55
ECHO RIVER TS 72		DEFAULT	Switch	1.3	238.4	57.9	103.33
ECHO RIVER TS 74		DEFAULT	Switch	0.4	-79.6	0.0	103.30
ECHO RIVER TS 79		DEFAULT	Switch	1.8	317.7	79.4	103.15
ECHO RIVER TS 79		1800 KVAR 20 KV	Shunt Capacitor	0.0	317.7	76.7	103.15
ECHO RIVER TS 86		DESBARATS T2	Two-Winding Transforme	19.6	317.7	79.5	102.78
ECHO RIVER TS 13		1200 KVAR 20 KV	Shunt Capacitor	0.0	317.7	76.6	102.74
ECHO RIVER TS 17		25 KV 600A 1PH	Regulator	3.8	317.1	104.2	101.19
ECHO RIVER TS 56		DEFAULT	Switch	5.0	917.3	-147.8	104.00
ECHO RIVER TS 58		DEFAULT	Switch	5.0	914.9	-137.0	103.86
ECHO RIVER TS 5		34.5KV_200A_1PH_COOPER_REGULATOR_6	Regulator	22.4	914.9	-136.8	101.92
ECHO RIVER TS 62		DEFAULT	Switch	0.0	0.0	0.0	103.86
ECHO RIVER TS 64		DEFAULT	Switch	0.0	0.0	0.0	103.55
ECHO RIVER TS 75		DEFAULT	Switch	5.1	914.9	-136.7	101.91
ECHO RIVER TS 77		DEFAULT	Switch	5.0	910.9	-120.4	101.67
ECHO RIVER TS 80		DEFAULT	Switch	0.0	0.0	0.0	103.15
ECHO RIVER TS 81		DEFAULT	Switch	2.6	315.5	-349.7	101.67
ECHO RIVER TS 81		DESBARATS T1	Two-Winding Transforme	23.5	315.5	-349.7	102.75
ECHO RIVER TS 87		1200 KVAR 7 KV	Shunt Capacitor	105.6	244.2	-342.0	102.75
ECHO RIVER TS 82		DEFAULT	Switch	3.5	595.3	229.3	101.67
ECHO RIVER TS 83		DEFAULT	Switch	3.5	595.3	229.4	101.66
ECHO RIVER TS 83		1800 KVAR 20 KV	Shunt Capacitor	0.0	595.3	229.4	100.70
ECHO RIVER TS 84		DEFAULT	Switch	1.6	277.4	103.8	100.70
ECHO RIVER TS 84		BRUCE MINES T1	Two-Winding Transforme	16.7	277.4	103.8	103.08
ECHO RIVER TS 88		1200 KVAR 7 KV	Shunt Capacitor	0.0	296.5	97.4	103.08
ECHO RIVER TS 61		DEFAULT	Switch	0.0	0.0	-0.1	103.86

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	0.1	5.4	-22.9	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	0.1	0.0	-9.4	104.01
NORTHERN AVE TS	076	DEFAULT	Switch	0.0	0.0	0.0	103.74

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)	
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.8	34.500	14794.7	2119	490	2175	97.09	35.0	-13.01	1.8	6.4	5.9	12.0607414
55	53	ER2	3/0ACSR	Overhead Line	35.8	34.500	144.4	2117	509	2178	96.89	35.1	-13.67	0.1	0.1	12.1	
52	52	53	556ASC	Overhead Line	35.8	34.500	213.3	395	71	402	94.97	6.5	-10.32	0.0	0.0	1.3	
077	51	52	556ASC	Overhead Line	35.8	34.500	1889.0	395	71	402	94.96	6.5	-10.37	0.0	0.0	1.3	
51	GARDEN RIVER DS HV B	51	556ASC	Overhead Line	35.8	34.500	34354.4	395	74	402	94.82	6.5	-10.82	0.2	0.6	1.3	
49	GARDEN RIVER DS HV B	GARDEN RIVER T2 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	108	35	114	95.01	5.1	-48.53	0.0	0.0	1.0	
50	GARDEN RIVER DS HV B	GARDEN RIVER T1 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	287	94	302	95.00	13.5	-48.91	0.0	0.0	4.5	
54	53	54	556ASC	Overhead Line	35.8	34.500	147.6	1722	438	1777	96.23	28.6	-14.43	0.0	0.0	5.1	
67	69	54	556ASC	Overhead Line	35.8	34.500	12664.6	1722	438	1777	96.23	28.6	-14.44	1.0	3.7	5.1	
70	69	66	556ASC	Overhead Line	35.8	34.500	9594.3	1721	456	1780	95.98	28.7	-15.11	0.8	2.9	5.1	
66	65	66	556ASC	Overhead Line	35.8	34.500	100.0	1006	340	1062	92.90	17.1	-19.04	0.0	0.0	3.3	
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.8	34.500	64.0	1006	340	1062	92.89	17.1	-19.05	0.0	0.0	3.3	
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.0	12.470	100.0	1005	330	1058	94.99	46.9	-49.06	0.0	0.1	10.9	
71	66	71	3/0ACSR	Overhead Line	35.8	34.500	82.0	714	129	726	98.39	11.7	-10.62	0.0	0.0	3.7	
72	71	72	3/0ACSR	Overhead Line	35.7	34.500	29000.0	714	130	726	98.39	11.7	-10.63	1.3	1.6	3.7	
73	72	73	556ASC	Overhead Line	35.7	34.500	6391.1	713	173	733	97.19	11.9	-14.05	0.1	0.3	1.8	
74	73	SOLAR	556ASC	Overhead Line	35.7	34.500	100.0	-239	0	239	100.00	3.9	179.50	0.0	0.0	0.6	
78	73	78	556ASC	Overhead Line	35.6	34.500	28445.2	952	183	969	98.19	15.7	-11.36	0.7	2.5	2.4	
79	78	542	477ACSR	Overhead Line	35.6	34.500	5072.2	951	229	978	97.22	15.9	-14.15	0.1	0.4	2.5	
86	542	86	556ASC	Overhead Line	35.6	34.500	100.0	951	237	980	97.02	15.9	-14.64	0.0	0.0	2.5	
8	86	8	556ASC	Overhead Line	25.7	25.000	10.0	950	225	976	97.30	21.9	-44.64	0.0	0.0	3.4	
7	8	7	556ASC	Overhead Line	25.7	25.000	10.0	950	225	976	97.30	21.9	-44.65	0.0	0.0	3.4	
89	7	DESBARATS DS T2 LV BU	336AAC	Overhead Line	25.7	25.000	50.0	950	225	976	97.30	21.9	-44.65	0.0	0.0	4.3	
11	DESBARATS DS T2 LV BU	11	28 KV 2/0 CU 100% C	Cable	25.7	25.000	185.0	950	225	976	97.30	21.9	-44.65	0.0	0.0	8.0	
13	11	13	336AAC	Overhead Line	25.7	25.000	3500.0	950	229	977	97.22	21.9	-44.84	0.2	0.6	4.3	
14	13	14	336AAC	Overhead Line	25.7	25.000	5717.0	949	231	977	97.17	22.0	-45.01	0.4	1.0	4.3	
15	14	15	35 KV 4/0 CU 100% C	Cable	25.7	25.000	2345.0	949	235	978	97.07	22.0	-45.29	0.2	0.1	5.9	
16	15	16	336AAC	Overhead Line	25.6	25.000	13595.0	949	302	996	95.28	22.4	-49.07	0.9	2.5	4.4	
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	948	311	998	95.00	22.8	-49.70	0.0	0.0	4.5	
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.9	34.500	22193.7	2458	-470	2502	-97.87	40.3	10.82	4.1	12.5	7.0	
2024	ER1	58	477ACSR	Overhead Line	35.8	34.500	9412.4	2454	-444	2494	-98.04	40.2	9.96	1.7	5.3	7.0	
59	58	VR PRIMARY	477ACSR	Overhead Line	35.8	34.500	24.2	2452	-433	2490	-98.12	40.1	9.59	0.0	0.0	7.0	
62	VR SECONDARY	62	477ACSR	Overhead Line	35.2	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0	
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0	
75	VR SECONDARY	75	477ACSR	Overhead Line	35.2	34.500	100.0	2452	-432	2490	-98.12	40.9	9.57	0.0	0.1	7.1	
76	75	76	477ACSR	Overhead Line	35.1	34.500	51800.0	2452	-432	2490	-98.12	40.9	9.57	9.8	30.1	7.1	
77	76	77	556ASC	Overhead Line	35.1	34.500	100.0	2442	-377	2471	-98.46	40.6	7.62	0.0	0.1	7.0	
80	542	77	556ASC	Overhead Line	35.1	34.500	100.0	0	0	0	0.00	0.0	88.86	0.0	0.0	0.0	
81	77	81	556ASC	Overhead Line	35.1	34.500	100.0	724	-1011	1244	-57.77	20.5	53.23	0.0	0.0	3.6	
87	81	DESBARATS DS T1 LV BU	556ASC	Overhead Line	12.8	12.470	100.0	723	-1026	1255	-55.95	56.6	23.23	0.0	0.1	9.9	
82	77	82	3/0ACSR	Overhead Line	35.1	34.500	100.0	1718	635	1832	93.75	30.1	-21.42	0.0	0.0	10.0	
83	82	BRUCE MINES DS HV BU	3/0ACSR	Overhead Line	34.8	34.500	41600.0	1718	635	1832	93.74	30.1	-21.42	12.1	14.7	10.0	
84	BRUCE MINES DS HV BU	84	3/0ACSR	Overhead Line	34.8	34.500	100.0	763	258	806	94.42	13.4	-20.15	0.0	0.0	4.7	
88	84	BRUCE MINES DS LV BU	556ASC	Overhead Line	12.8	12.470	39.9	762	251	802	95.00	36.1	-50.16	0.0	0.0	6.5	
85	BRUCE MINES DS HV BU	FEEDER END	556ASC	Overhead Line	34.8	34.500	15088.3	943	423	1034	91.25	17.2	-25.58	0.4	1.6	2.7	
61	VR PRIMARY	61	477ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0	
63	61	62	3/0ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0	
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	16	-69	71	-22.97	1.1	76.72	0.0	0.0	0.2	
390	46	TRUSS PLANT	556ASC	Overhead Line	35.9	34.500	27986.1	16	-69	70	-23.03	1.1	76.69	0.0	0.0	0.2	
076	TRUSS PLANT	GARDEN RIVER DS HV B	556ASC	Overhead Line	35.9	34.500	16346.2	0	-28	28	0.01	0.5	90.00	0.0	0.0	0.1	

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-16-2020 uprated conductors.s
Date	Tue Jun 16 2020
Time	14h41m16s
Project Name	Uprated ERTS Peak Load - By Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=100.00%, Q=100.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	**kW**	**kvar**	**kVA**	**PF(%)**
Sources (Swing)	15731.96	2602.76	15945.82	98.66
Generators	239.02	0.03	239.02	100.00
Total Generation	**15970.99**	**2602.79**	**16181.68**	**98.70**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	15541.64	5546.95	16501.85	94.18
Shunt capacitors (Adjusted)	0.00	-3692.65	3692.65	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**15541.64**	**1854.31**	**15651.87**	**99.30**
Cable Capacitance	0.00	-69.15	69.15	0.00
Line Capacitance	0.00	-554.76	554.76	0.00
Total Shunt Capacitance	**0.00**	**-623.91**	**623.91**	**0.00**
Line Losses	384.28	950.50	1025.24	37.48
Cable Losses	2.90	1.79	3.41	85.14
Transformer Load Losses	42.01	420.10	422.20	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**429.19**	**1372.39**	**1437.94**	**29.85**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	3	13	103.61 %
	B	2	13	103.42 %
	C	3	13	104.60 %
Under-Voltage	A	0	FEEDER END	97.25 %
	B	0	FEEDER END	97.97 %
	C	0	FEEDER END	98.62 %
Over-Voltage	A	0	076	104.01 %
	B	0	BAR RIVER DS LV BUS	104.05 %
	C	4	68	105.15 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	384.28	3366.31	336.63
Cable Losses	2.90	25.42	2.54
Transformer Load Losses	42.01	368.01	36.80
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	429.19	3759.74	375.97

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	30.4	5537.9	1237.0	104.00
ECHO RIVER TS 081		DEFAULT	Switch	14.4	2563.0	812.6	104.00
ECHO RIVER TS 081		DEFAULT	Switch	14.4	2555.0	792.0	103.37
ECHO RIVER TS 077		DEFAULT	Switch	1.6	256.2	153.1	103.35
ECHO RIVER TS 51		DEFAULT	Switch	1.7	255.9	172.7	103.11
ECHO RIVER TS 49		GARDEN T2	Two-Winding Transforme	14.6	145.5	55.0	102.56
ECHO RIVER TS 555		GARDEN T1	Two-Winding Transforme	1.2	110.4	117.7	102.38
ECHO RIVER TS 67		DEFAULT	Switch	12.9	2298.5	638.6	103.35
ECHO RIVER TS 66		DEFAULT	Switch	7.9	1294.4	665.2	102.55
ECHO RIVER TS 65		DEFAULT	Switch	7.9	1294.4	665.2	102.54
ECHO RIVER TS 68		BAR RIVER T1	Two-Winding Transforme	56.6	1294.4	665.2	103.46
ECHO RIVER TS 68		1200 KVAR 7 KV	Shunt Capacitor	0.0	1646.5	543.0	103.42
ECHO RIVER TS 71		DEFAULT	Switch	5.4	994.4	-49.0	102.55
ECHO RIVER TS 72		DEFAULT	Switch	5.4	987.2	-43.4	101.84
ECHO RIVER TS 74		DEFAULT	Switch	0.4	-79.4	0.0	101.80
ECHO RIVER TS 79		DEFAULT	Switch	5.8	1063.0	-34.0	101.55
ECHO RIVER TS 79		1800 KVAR 20 KV	Shunt Capacitor	0.0	1063.6	-35.2	101.55
ECHO RIVER TS 86		DESBARATS T2	Two-Winding Transforme	63.8	1063.0	-34.0	101.56
ECHO RIVER TS 13		1200 KVAR 20 KV	Shunt Capacitor	103.6	1062.7	-78.6	101.44
ECHO RIVER TS 17		25 KV 600A 1PH	Regulator	12.8	1055.6	347.2	101.15
ECHO RIVER TS 56		DEFAULT	Switch	16.1	2974.9	424.5	104.00
ECHO RIVER TS 58		DEFAULT	Switch	16.1	2949.8	366.5	102.79
ECHO RIVER TS 5		34.5KV_200A_1PH_COOPER_REGULATOR_6	Regulator	72.6	2949.7	366.6	102.15
ECHO RIVER TS 62		DEFAULT	Switch	0.0	0.0	0.0	102.79
ECHO RIVER TS 64		DEFAULT	Switch	0.0	0.0	0.0	102.54
ECHO RIVER TS 75		DEFAULT	Switch	16.2	2949.7	366.5	102.14
ECHO RIVER TS 77		DEFAULT	Switch	16.2	2908.2	267.6	100.26
ECHO RIVER TS 80		DEFAULT	Switch	0.0	0.0	0.0	101.55
ECHO RIVER TS 81		DEFAULT	Switch	5.7	1010.7	-169.2	100.26
ECHO RIVER TS 81		DESBARATS T1	Two-Winding Transforme	57.5	1010.7	-169.2	101.20
ECHO RIVER TS 87		1200 KVAR 7 KV	Shunt Capacitor	102.4	789.4	-150.1	101.17
ECHO RIVER TS 82		DEFAULT	Switch	10.8	1897.5	436.9	100.26
ECHO RIVER TS 83		DEFAULT	Switch	10.8	1897.4	436.8	100.25
ECHO RIVER TS 83		1800 KVAR 20 KV	Shunt Capacitor	0.0	1897.4	436.8	97.59
ECHO RIVER TS 84		DEFAULT	Switch	5.0	878.1	-53.8	97.59
ECHO RIVER TS 84		BRUCE MINES T1	Two-Winding Transforme	50.9	878.1	-53.8	100.90
ECHO RIVER TS 88		1200 KVAR 7 KV	Shunt Capacitor	101.8	946.8	-95.9	100.90
ECHO RIVER TS 61		DEFAULT	Switch	0.0	0.0	-0.1	102.79

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	0.1	18.0	-16.8	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	0.1	0.0	-9.4	104.00
NORTHERN AVE TS	076	DEFAULT	Switch	0.0	0.0	0.0	103.11

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)	
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.7	34.500	14794.7	7651	1556	7807	97.69	125.6	-11.50	22.9	82.7	21.1	43.2539411
55	53	ER2	3/0ACSR	Overhead Line	35.7	34.500	144.4	7628	1499	7774	97.82	125.7	-11.68	0.7	0.9	43.3	
52	52	53	556ASC	Overhead Line	35.7	34.500	213.3	1289	399	1350	92.24	21.8	-17.79	0.0	0.0	4.5	
077	51	52	556ASC	Overhead Line	35.7	34.500	1889.0	1289	400	1350	92.23	21.8	-17.81	0.1	0.4	4.5	
51	GARDEN RIVER DS HV B	51	556ASC	Overhead Line	35.6	34.500	34354.4	1289	403	1351	92.17	21.8	-17.94	1.8	6.7	4.5	
49	GARDEN RIVER DS HV B	GARDEN RIVER T2 LV BU	556ASC	Overhead Line	12.8	12.470	100.0	354	116	373	95.00	16.8	-49.40	0.0	0.0	3.4	
50	GARDEN RIVER DS HV B	GARDEN RIVER T1 LV BU	556ASC	Overhead Line	12.8	12.470	100.0	930	306	979	94.99	44.5	-50.61	0.1	0.2	14.7	
54	53	54	556ASC	Overhead Line	35.7	34.500	147.6	6338	1099	6432	97.97	104.0	-10.40	0.2	0.6	18.0	
67	69	54	556ASC	Overhead Line	35.6	34.500	12664.6	6338	1098	6432	97.97	104.0	-10.41	13.6	49.1	18.0	
70	69	66	556ASC	Overhead Line	35.5	34.500	9594.3	6324	1071	6414	98.03	104.1	-10.59	10.3	37.2	18.0	
66	65	66	556ASC	Overhead Line	35.5	34.500	100.0	3323	1204	3534	92.25	57.5	-21.23	0.0	0.1	11.0	
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.5	34.500	64.0	3323	1204	3534	92.25	57.5	-21.24	0.0	0.1	11.0	
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.0	12.470	100.0	3311	1091	3486	94.98	155.3	-51.24	0.4	1.2	36.1	
71	66	71	3/0ACSR	Overhead Line	35.5	34.500	82.0	2991	-155	2995	-99.87	48.7	1.68	0.1	0.1	15.5	
72	71	72	3/0ACSR	Overhead Line	35.3	34.500	29000.0	2991	-154	2995	-99.87	48.7	1.68	21.7	26.5	15.5	
73	72	73	556ASC	Overhead Line	35.2	34.500	6391.1	2969	-137	2973	-99.89	48.7	0.84	1.5	5.3	7.6	
74	73	SOLAR	556ASC	Overhead Line	35.2	34.500	100.0	-239	0	239	100.00	3.9	178.05	0.0	0.0	0.6	
78	73	78	556ASC	Overhead Line	35.2	34.500	28445.2	3207	-132	3210	-99.92	52.6	0.45	7.6	27.5	8.2	
79	78	542	477ACSR	Overhead Line	35.1	34.500	5072.2	3199	-112	3201	-99.94	52.6	-0.40	1.6	4.8	8.2	
86	542	86	556ASC	Overhead Line	35.1	34.500	100.0	3198	-109	3200	-99.94	52.6	-0.55	0.0	0.1	8.2	
8	86	8	556ASC	Overhead Line	25.4	25.000	10.0	3184	-244	3193	-99.71	72.5	-30.55	0.0	0.0	11.3	
7	8	7	556ASC	Overhead Line	25.4	25.000	10.0	3184	-244	3193	-99.71	72.5	-30.55	0.0	0.0	11.3	
89	7	DESBARATS DS T2 LV BU	336AAC	Overhead Line	25.4	25.000	50.0	3184	-244	3193	-99.71	72.5	-30.55	0.0	0.1	14.3	
11	DESBARATS DS T2 LV BU	11	28 KV 2/0 CU 100% C	Cable	25.4	25.000	185.0	3184	-244	3193	-99.71	72.5	-30.55	0.3	0.1	26.4	
13	11	13	336AAC	Overhead Line	25.4	25.000	3500.0	3184	-241	3193	-99.71	72.5	-30.61	2.6	7.0	14.3	
14	13	14	336AAC	Overhead Line	25.3	25.000	5717.0	3181	1001	3335	95.39	75.8	-52.51	4.4	11.9	14.9	
15	14	15	35 KV 4/0 CU 100% C	Cable	25.3	25.000	2345.0	3177	993	3328	95.44	75.9	-52.59	2.6	1.7	20.3	
16	15	16	336AAC	Overhead Line	25.2	25.000	13595.0	3174	1058	3346	94.87	76.3	-53.67	10.7	28.6	15.0	
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	3163	1040	3330	95.00	76.1	-53.85	0.0	0.1	14.9	
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.6	34.500	22193.7	8027	1097	8102	98.73	130.4	-7.78	42.9	131.7	22.7	
2024	ER1	58	477ACSR	Overhead Line	35.5	34.500	9412.4	7984	1003	8047	98.86	130.4	-8.05	18.2	55.9	22.7	
59	58	VR PRIMARY	477ACSR	Overhead Line	35.5	34.500	24.2	7966	963	8024	98.92	130.5	-8.16	0.0	0.1	22.7	
62	VR SECONDARY	62	477ACSR	Overhead Line	35.4	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0	
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0	
75	VR SECONDARY	75	477ACSR	Overhead Line	35.4	34.500	100.0	7966	964	8024	98.92	131.0	-8.16	0.2	0.6	22.8	
76	75	76	477ACSR	Overhead Line	34.8	34.500	51800.0	7966	963	8024	98.92	131.0	-8.16	101.3	310.9	22.8	
77	76	77	556ASC	Overhead Line	34.8	34.500	100.0	7865	738	7899	99.19	131.2	-8.77	0.2	0.6	22.7	
80	542	77	556ASC	Overhead Line	34.8	34.500	100.0	0	0	0	0.00	0.0	86.62	0.0	0.0	0.0	
81	77	81	556ASC	Overhead Line	34.8	34.500	100.0	2327	-400	2362	-95.88	39.3	6.29	0.0	0.1	8.0	
87	81	DESBARATS DS T1 LV BU	556ASC	Overhead Line	12.6	12.470	100.0	2321	-460	2366	-95.39	108.6	-23.72	0.2	0.6	24.8	
82	77	82	3/0ACSR	Overhead Line	34.8	34.500	100.0	5537	1138	5653	97.89	93.8	-15.01	0.3	0.3	31.0	
83	82	BRUCE MINES DS HV BU	3/0ACSR	Overhead Line	33.9	34.500	41600.0	5537	1138	5652	97.89	93.8	-15.01	116.1	141.7	31.0	
84	BRUCE MINES DS HV BU	84	3/0ACSR	Overhead Line	33.9	34.500	100.0	2446	-343	2470	-98.73	42.1	3.36	0.1	0.1	14.4	
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.6	12.470	39.9	2438	-422	2474	-98.22	113.4	-26.64	0.1	0.2	20.3	
85	BRUCE MINES DS HV BU	FEEDER END	556ASC	Overhead Line	33.8	34.500	15088.3	2975	1398	3287	90.50	56.0	-29.74	4.6	16.6	8.7	
61	VR PRIMARY	61	477ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0	
63	61	62	3/0ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.75	0.0	0.0	0.0	
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	54	-51	74	-73.04	1.2	43.08	0.0	0.0	0.2	
390	46	TRUSS PLANT	556ASC	Overhead Line	35.9	34.500	27986.1	54	-50	74	-73.16	1.2	42.98	0.0	0.0	0.2	
076	TRUSS PLANT	GARDEN RIVER DS HV B	556ASC	Overhead Line	35.9	34.500	16346.2	0	-28	28	0.02	0.5	90.00	0.0	0.0	0.1	

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-16-2020 uprated conductors.sxst
Date	Tue Jun 16 2020
Time	14h45m38s
Project Name	Uprated from NTS Min Load - by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	**kW**	**kvar**	**kVA**	**PF(%)**
Sources (Swing)	4575.32	118.12	4576.84	99.97
Generators	238.99	-0.01	238.99	100.00
Total Generation	**4814.31**	**118.11**	**4815.76**	**99.97**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4734.10	1690.70	5026.95	94.17
Shunt capacitors (Adjusted)	0.00	-1231.27	1231.27	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4734.10**	**459.43**	**4756.35**	**99.53**
Cable Capacitance	0.00	-69.87	69.87	0.00
Line Capacitance	0.00	-553.28	553.28	0.00
Total Shunt Capacitance	**0.00**	**-623.14**	**623.14**	**0.00**
Line Losses	75.19	233.68	245.48	30.63
Cable Losses	0.24	0.15	0.29	85.37
Transformer Load Losses	4.80	48.00	48.24	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**80.24**	**281.82**	**293.02**	**27.38**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	102.75 %
	B	1	87	101.51 %
	C	1	87	103.55 %
Under-Voltage	A	0	FEEDER END	99.17 %
	B	0	FEEDER END	99.52 %
	C	0	FEEDER END	99.68 %
Over-Voltage	A	0	68	104.91 %
	B	0	BAR RIVER DS LV BUS	104.53 %
	C	4	68	105.56 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	75.19	658.69	65.87
Cable Losses	0.24	2.15	0.21
Transformer Load Losses	4.80	42.05	4.20
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	80.24	702.88	70.29

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	4575	118	4577	99.75	73.6	-1.48	0.1	0.2	12.2
390	46	TRUSS PLANT	556ASC	Overhead Line	35.8	34.500	27986.1	4575	118	4577	99.75	73.6	-1.48	14.8	53.5	12.2
076	TRUSS PLANT	GARDEN RIVER DS HV B	556ASC	Overhead Line	35.7	34.500	16346.2	4544	105	4546	99.76	73.4	-1.99	8.6	31.1	12.2
49	GARDEN RIVER DS HV B	GARDEN RIVER T2 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	107	35	113	95.01	5.1	-49.38	0.0	0.0	1.0
51	GARDEN RIVER DS HV B	51	556ASC	Overhead Line	35.6	34.500	34354.4	4143	-30	4143	-99.57	67.0	-0.64	15.2	54.9	11.6
077	51	52	556ASC	Overhead Line	35.5	34.500	1889.0	4127	-27	4127	-99.57	67.0	-1.45	0.8	3.0	11.6
52	52	53	556ASC	Overhead Line	35.5	34.500	213.3	4127	-27	4127	-99.57	67.0	-1.49	0.1	0.3	11.6
54	53	54	556ASC	Overhead Line	35.5	34.500	147.6	4126	-1	4126	-99.57	67.0	-1.85	0.1	0.2	11.6
67	69	54	556ASC	Overhead Line	35.5	34.500	12664.6	4126	-1	4126	-99.57	67.0	-1.85	5.6	20.2	11.6
70	69	66	556ASC	Overhead Line	35.5	34.500	9594.3	4121	0	4121	-99.57	67.0	-2.15	4.2	15.3	11.6
66	65	66	556ASC	Overhead Line	35.5	34.500	100.0	3402	-133	3405	-99.31	55.4	-0.14	0.0	0.1	9.8
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.5	34.500	64.0	3402	-133	3405	-99.31	55.4	-0.14	0.0	0.1	9.8
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.5	34.500	100.0	2389	-476	2436	-97.72	39.7	8.90	0.0	0.1	6.9
63	61	62	3/0ACSR	Overhead Line	35.5	34.500	100.0	2389	-476	2436	-97.72	39.7	8.90	0.1	0.1	14.0
61	VR PRIMARY	61	477ACSR	Overhead Line	35.5	34.500	100.0	2389	-476	2436	-97.72	39.7	8.89	0.0	0.1	6.9
62	VR SECONDARY	62	477ACSR	Overhead Line	34.7	34.500	100.0	0	0	0	0.00	0.0	87.66	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	34.7	34.500	100.0	2389	-422	2426	-98.11	40.3	7.67	0.0	0.1	7.0
76	75	76	477ACSR	Overhead Line	34.7	34.500	51800.0	2389	-422	2426	-98.11	40.3	7.66	9.5	29.3	7.0
77	76	77	556ASC	Overhead Line	34.7	34.500	100.0	2379	-368	2408	-98.46	40.1	5.71	0.0	0.1	6.9
80	542	77	556ASC	Overhead Line	34.7	34.500	100.0	0	0	0	0.00	0.0	86.95	0.0	0.0	0.0
86	542	86	556ASC	Overhead Line	35.3	34.500	100.0	951	239	980	96.98	16.0	-16.73	0.0	0.0	2.5
8	86	8	556ASC	Overhead Line	25.5	25.000	10.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	3.5
7	8	7	556ASC	Overhead Line	25.5	25.000	10.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	3.5
89	7	DESBARATS DS T2 LV BU	336AAC	Overhead Line	25.5	25.000	50.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	4.4
11	DESBARATS DS T2 LV BU	11	28 KV 2/0 CU 100% C	Cable	25.5	25.000	185.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	8.1
13	11	13	336AAC	Overhead Line	25.5	25.000	3500.0	950	230	977	97.19	22.1	-46.93	0.2	0.6	4.4
14	13	14	336AAC	Overhead Line	25.5	25.000	5717.0	949	232	977	97.13	22.1	-47.10	0.4	1.0	4.4
15	14	15	35 KV 4/0 CU 100% C	Cable	25.5	25.000	2345.0	949	236	978	97.04	22.2	-47.37	0.2	0.1	6.0
16	15	16	336AAC	Overhead Line	25.4	25.000	13595.0	949	303	996	95.27	22.6	-51.09	0.9	2.5	4.5
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	948	311	998	95.00	22.8	-51.71	0.0	0.0	4.5
81	77	81	556ASC	Overhead Line	34.7	34.500	100.0	705	-986	1212	-57.71	20.2	51.34	0.0	0.0	3.6
87	81	DESBARATS DS T1 LV BU	556ASC	Overhead Line	12.6	12.470	100.0	703	-1000	1223	-55.88	55.9	21.34	0.0	0.1	9.7
82	77	82	3/0ACSR	Overhead Line	34.7	34.500	100.0	1674	619	1785	93.75	29.7	-23.34	0.0	0.0	9.9
83	82	BRUCE MINES DS HV BU	3/0ACSR	Overhead Line	34.3	34.500	41600.0	1674	619	1785	93.75	29.7	-23.34	11.8	14.4	9.9
84	BRUCE MINES DS HV BU	84	3/0ACSR	Overhead Line	34.3	34.500	100.0	743	252	785	94.42	13.2	-22.08	0.0	0.0	4.6
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.7	12.470	39.9	743	244	782	95.00	35.6	-52.09	0.0	0.0	6.4
85	BRUCE MINES DS HV BU	FEEDER END	556ASC	Overhead Line	34.3	34.500	15088.3	919	412	1007	91.25	16.9	-27.50	0.4	1.5	2.6
59	58	VR PRIMARY	477ACSR	Overhead Line	35.5	34.500	24.2	0	-53	53	0.00	0.9	87.66	0.0	0.0	0.1
2024	ER1	58	477ACSR	Overhead Line	35.5	34.500	9412.4	0	-53	53	0.00	0.9	87.66	0.0	0.0	0.1
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.5	34.500	22193.7	0	-37	37	0.00	0.6	87.66	0.0	0.0	0.1
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.1	12.470	100.0	1012	333	1066	95.00	47.0	-51.12	0.0	0.1	11.0
71	66	71	3/0ACSR	Overhead Line	35.5	34.500	82.0	714	133	726	98.30	11.8	-12.90	0.0	0.0	3.8
72	71	72	3/0ACSR	Overhead Line	35.4	34.500	29000.0	714	133	726	98.30	11.8	-12.91	1.3	1.6	3.8
73	72	73	556ASC	Overhead Line	35.4	34.500	6391.1	713	175	734	97.10	12.0	-16.26	0.1	0.3	1.9
74	73	SOLAR	556ASC	Overhead Line	35.4	34.500	100.0	-239	0	239	100.00	3.9	177.51	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.3	34.500	28445.2	952	186	970	98.14	15.8	-13.52	0.7	2.5	2.5
79	78	542	477ACSR	Overhead Line	35.3	34.500	5072.2	951	231	979	97.17	16.0	-16.25	0.1	0.4	2.5
55	53	ER2	3/0ACSR	Overhead Line	35.5	34.500	144.4	0	-25	25	0.00	0.4	88.16	0.0	0.0	0.1
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.5	34.500	14794.7	0	-25	25	0.00	0.4	88.16	0.0	0.0	0.1
50	GARDEN RIVER DS HV B	GARDEN RIVER T1 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	286	94	301	95.00	13.5	-49.70	0.0	0.0	4.5

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	0.0	0.0	0.0	104.00

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	8.8	1627.0	143.2	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	8.7	1615.9	136.3	103.53
NORTHERN AVE TS	076	DEFAULT	Switch	8.7	1612.6	133.8	103.25
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	4.4	44.0	16.3	103.30
NORTHERN AVE TS	51	DEFAULT	Switch	8.3	1534.8	82.1	103.25
NORTHERN AVE TS	077	DEFAULT	Switch	8.3	1528.2	78.9	102.73
NORTHERN AVE TS	67	DEFAULT	Switch	8.3	1528.1	87.3	102.72
NORTHERN AVE TS	66	DEFAULT	Switch	7.0	1285.7	41.3	102.39
NORTHERN AVE TS	65	DEFAULT	Switch	7.0	1285.7	41.3	102.39
NORTHERN AVE TS	64	DEFAULT	Switch	4.9	888.2	-151.7	102.39
NORTHERN AVE TS	61	DEFAULT	Switch	4.9	888.2	-151.7	102.39
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	22.0	888.2	-134.0	100.47
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	102.39
NORTHERN AVE TS	75	DEFAULT	Switch	5.0	888.2	-133.9	100.47
NORTHERN AVE TS	77	DEFAULT	Switch	5.0	884.3	-118.1	100.22
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	101.99
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	19.6	316.9	78.7	102.04
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	0.0	317.1	76.8	102.00
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	3.8	316.5	104.0	101.10
NORTHERN AVE TS	81	DEFAULT	Switch	2.5	305.8	-340.4	100.22
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	22.8	305.8	-340.3	101.37
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	102.7	237.7	-332.9	101.36
NORTHERN AVE TS	82	DEFAULT	Switch	3.4	578.5	222.3	100.22
NORTHERN AVE TS	83	DEFAULT	Switch	3.4	578.5	222.3	100.22
NORTHERN AVE TS	83	1800 KVAR 20 KV	Shunt Capacitor	0.0	578.5	222.3	99.27
NORTHERN AVE TS	84	DEFAULT	Switch	1.6	269.6	100.3	99.27
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	16.2	269.6	100.3	101.70
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	288.5	94.8	101.69
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-17.6	102.39
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	17.1	397.5	193.0	104.91
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	0.0	508.4	167.1	104.89
NORTHERN AVE TS	71	DEFAULT	Switch	1.3	238.3	43.9	102.39
NORTHERN AVE TS	72	DEFAULT	Switch	1.3	237.9	57.9	102.17
NORTHERN AVE TS	74	DEFAULT	Switch	0.4	-79.3	0.2	102.14
NORTHERN AVE TS	79	DEFAULT	Switch	1.8	316.9	78.6	101.99
NORTHERN AVE TS	79	1800 KVAR 20 KV	Shunt Capacitor	0.0	317.0	76.0	101.99
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-8.3	102.72
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	0.4	33.8	35.3	103.25

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-16-2020 uprated conductors.sxst
Date	Tue Jun 16 2020
Time	14h45m38s
Project Name	Uprated from NTS Min Load - by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	4575.32	118.12	4576.84	99.97
Generators	238.99	-0.01	238.99	100.00
Total Generation	**4814.31**	**118.11**	**4815.76**	**99.97**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4734.10	1690.70	5026.95	94.17
Shunt capacitors (Adjusted)	0.00	-1231.27	1231.27	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4734.10**	**459.43**	**4756.35**	**99.53**
Cable Capacitance	0.00	-69.87	69.87	0.00
Line Capacitance	0.00	-553.28	553.28	0.00
Total Shunt Capacitance	**0.00**	**-623.14**	**623.14**	**0.00**
Line Losses	75.19	233.68	245.48	30.63
Cable Losses	0.24	0.15	0.29	85.37
Transformer Load Losses	4.80	48.00	48.24	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**80.24**	**281.82**	**293.02**	**27.38**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	102.75 %
	B	1	87	101.51 %
	C	1	87	103.55 %
Under-Voltage	A	0	FEEDER END	99.17 %
	B	0	FEEDER END	99.52 %
	C	0	FEEDER END	99.68 %
Over-Voltage	A	0	68	104.91 %
	B	0	BAR RIVER DS LV BUS	104.53 %
	C	4	68	105.56 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	75.19	658.69	65.87
Cable Losses	0.24	2.15	0.21
Transformer Load Losses	4.80	42.05	4.20
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	80.24	702.88	70.29

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	4575	118	4577	99.75	73.6	-1.48	0.1	0.2	12.2
390	46	TRUSS PLANT	556ASC	Overhead Line	35.8	34.500	27986.1	4575	118	4577	99.75	73.6	-1.48	14.8	53.5	12.2
076	TRUSS PLANT	GARDEN RIVER DS HV B	556ASC	Overhead Line	35.7	34.500	16346.2	4544	105	4546	99.76	73.4	-1.99	8.6	31.1	12.2
49	GARDEN RIVER DS HV B	GARDEN RIVER T2 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	107	35	113	95.01	5.1	-49.38	0.0	0.0	1.0
51	GARDEN RIVER DS HV B	51	556ASC	Overhead Line	35.6	34.500	34354.4	4143	-30	4143	-99.57	67.0	-0.64	15.2	54.9	11.6
077	51	52	556ASC	Overhead Line	35.5	34.500	1889.0	4127	-27	4127	-99.57	67.0	-1.45	0.8	3.0	11.6
52	52	53	556ASC	Overhead Line	35.5	34.500	213.3	4127	-27	4127	-99.57	67.0	-1.49	0.1	0.3	11.6
54	53	54	556ASC	Overhead Line	35.5	34.500	147.6	4126	-1	4126	-99.57	67.0	-1.85	0.1	0.2	11.6
67	69	54	556ASC	Overhead Line	35.5	34.500	12664.6	4126	-1	4126	-99.57	67.0	-1.85	5.6	20.2	11.6
70	69	66	556ASC	Overhead Line	35.5	34.500	9594.3	4121	0	4121	-99.57	67.0	-2.15	4.2	15.3	11.6
66	65	66	556ASC	Overhead Line	35.5	34.500	100.0	3402	-133	3405	-99.31	55.4	-0.14	0.0	0.1	9.8
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.5	34.500	64.0	3402	-133	3405	-99.31	55.4	-0.14	0.0	0.1	9.8
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.5	34.500	100.0	2389	-476	2436	-97.72	39.7	8.90	0.0	0.1	6.9
63	61	62	3/0ACSR	Overhead Line	35.5	34.500	100.0	2389	-476	2436	-97.72	39.7	8.90	0.1	0.1	14.0
61	VR PRIMARY	61	477ACSR	Overhead Line	35.5	34.500	100.0	2389	-476	2436	-97.72	39.7	8.89	0.0	0.1	6.9
62	VR SECONDARY	62	477ACSR	Overhead Line	34.7	34.500	100.0	0	0	0	0.00	0.0	87.66	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	34.7	34.500	100.0	2389	-422	2426	-98.11	40.3	7.67	0.0	0.1	7.0
76	75	76	477ACSR	Overhead Line	34.7	34.500	51800.0	2389	-422	2426	-98.11	40.3	7.66	9.5	29.3	7.0
77	76	77	556ASC	Overhead Line	34.7	34.500	100.0	2379	-368	2408	-98.46	40.1	5.71	0.0	0.1	6.9
80	542	77	556ASC	Overhead Line	34.7	34.500	100.0	0	0	0	0.00	0.0	86.95	0.0	0.0	0.0
86	542	86	556ASC	Overhead Line	35.3	34.500	100.0	951	239	980	96.98	16.0	-16.73	0.0	0.0	2.5
8	86	8	556ASC	Overhead Line	25.5	25.000	10.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	3.5
7	8	7	556ASC	Overhead Line	25.5	25.000	10.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	3.5
89	7	DESBARATS DS T2 LV BL	336AAC	Overhead Line	25.5	25.000	50.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	4.4
11	DESBARATS DS T2 LV BL	11	28 KV 2/0 CU 100% C	Cable	25.5	25.000	185.0	950	227	976	97.27	22.1	-46.74	0.0	0.0	8.1
13	11	13	336AAC	Overhead Line	25.5	25.000	3500.0	950	230	977	97.19	22.1	-46.93	0.2	0.6	4.4
14	13	14	336AAC	Overhead Line	25.5	25.000	5717.0	949	232	977	97.13	22.1	-47.10	0.4	1.0	4.4
15	14	15	35 KV 4/0 CU 100% C	Cable	25.5	25.000	2345.0	949	236	978	97.04	22.2	-47.37	0.2	0.1	6.0
16	15	16	336AAC	Overhead Line	25.4	25.000	13595.0	949	303	996	95.27	22.6	-51.09	0.9	2.5	4.5
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	948	311	998	95.00	22.8	-51.71	0.0	0.0	4.5
81	77	81	556ASC	Overhead Line	34.7	34.500	100.0	705	-986	1212	-57.71	20.2	51.34	0.0	0.0	3.6
87	81	DESBARATS DS T1 LV BL	556ASC	Overhead Line	12.6	12.470	100.0	703	-1000	1223	-55.88	55.9	21.34	0.0	0.1	9.7
82	77	82	3/0ACSR	Overhead Line	34.7	34.500	100.0	1674	619	1785	93.75	29.7	-23.34	0.0	0.0	9.9
83	82	BRUCE MINES DS HV BU	3/0ACSR	Overhead Line	34.3	34.500	41600.0	1674	619	1785	93.75	29.7	-23.34	11.8	14.4	9.9
84	BRUCE MINES DS HV BU	84	3/0ACSR	Overhead Line	34.3	34.500	100.0	743	252	785	94.42	13.2	-22.08	0.0	0.0	4.6
88	84	BRUCE MINES DS LV BU	556ASC	Overhead Line	12.7	12.470	39.9	743	244	782	95.00	35.6	-52.09	0.0	0.0	6.4
85	BRUCE MINES DS HV BU	FEEDER END	556ASC	Overhead Line	34.3	34.500	15088.3	919	412	1007	91.25	16.9	-27.50	0.4	1.5	2.6
59	58	VR PRIMARY	477ACSR	Overhead Line	35.5	34.500	24.2	0	-53	53	0.00	0.9	87.66	0.0	0.0	0.1
2024	ER1	58	477ACSR	Overhead Line	35.5	34.500	9412.4	0	-53	53	0.00	0.9	87.66	0.0	0.0	0.1
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.5	34.500	22193.7	0	-37	37	0.00	0.6	87.66	0.0	0.0	0.1
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.1	12.470	100.0	1012	333	1066	95.00	47.0	-51.12	0.0	0.1	11.0
71	66	71	3/0ACSR	Overhead Line	35.5	34.500	82.0	714	133	726	98.30	11.8	-12.90	0.0	0.0	3.8
72	71	72	3/0ACSR	Overhead Line	35.4	34.500	29000.0	714	133	726	98.30	11.8	-12.91	1.3	1.6	3.8
73	72	73	556ASC	Overhead Line	35.4	34.500	6391.1	713	175	734	97.10	12.0	-16.26	0.1	0.3	1.9
74	73	SOLAR	556ASC	Overhead Line	35.4	34.500	100.0	-239	0	239	100.00	3.9	177.51	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.3	34.500	28445.2	952	186	970	98.14	15.8	-13.52	0.7	2.5	2.5
79	78	542	477ACSR	Overhead Line	35.3	34.500	5072.2	951	231	979	97.17	16.0	-16.25	0.1	0.4	2.5
55	53	ER2	3/0ACSR	Overhead Line	35.5	34.500	144.4	0	-25	25	0.00	0.4	88.16	0.0	0.0	0.1
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.5	34.500	14794.7	0	-25	25	0.00	0.4	88.16	0.0	0.0	0.1
50	GARDEN RIVER DS HV B	GARDEN RIVER T1 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	286	94	301	95.00	13.5	-49.70	0.0	0.0	4.5

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	0.0	0.0	0.0	104.00

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	8.8	1627.0	143.2	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	8.7	1615.9	136.3	103.53
NORTHERN AVE TS	076	DEFAULT	Switch	8.7	1612.6	133.8	103.25
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	4.4	44.0	16.3	103.30
NORTHERN AVE TS	51	DEFAULT	Switch	8.3	1534.8	82.1	103.25
NORTHERN AVE TS	077	DEFAULT	Switch	8.3	1528.2	78.9	102.73
NORTHERN AVE TS	67	DEFAULT	Switch	8.3	1528.1	87.3	102.72
NORTHERN AVE TS	66	DEFAULT	Switch	7.0	1285.7	41.3	102.39
NORTHERN AVE TS	65	DEFAULT	Switch	7.0	1285.7	41.3	102.39
NORTHERN AVE TS	64	DEFAULT	Switch	4.9	888.2	-151.7	102.39
NORTHERN AVE TS	61	DEFAULT	Switch	4.9	888.2	-151.7	102.39
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	22.0	888.2	-134.0	100.47
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	102.39
NORTHERN AVE TS	75	DEFAULT	Switch	5.0	888.2	-133.9	100.47
NORTHERN AVE TS	77	DEFAULT	Switch	5.0	884.3	-118.1	100.22
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	101.99
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	19.6	316.9	78.7	102.04
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	0.0	317.1	76.8	102.00
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	3.8	316.5	104.0	101.10
NORTHERN AVE TS	81	DEFAULT	Switch	2.5	305.8	-340.4	100.22
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	22.8	305.8	-340.3	101.37
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	102.7	237.7	-332.9	101.36
NORTHERN AVE TS	82	DEFAULT	Switch	3.4	578.5	222.3	100.22
NORTHERN AVE TS	83	DEFAULT	Switch	3.4	578.5	222.3	100.22
NORTHERN AVE TS	83	1800 KVAR 20 KV	Shunt Capacitor	0.0	578.5	222.3	99.27
NORTHERN AVE TS	84	DEFAULT	Switch	1.6	269.6	100.3	99.27
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	16.2	269.6	100.3	101.70
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	288.5	94.8	101.69
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-17.6	102.39
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	17.1	397.5	193.0	104.91
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	0.0	508.4	167.1	104.89
NORTHERN AVE TS	71	DEFAULT	Switch	1.3	238.3	43.9	102.39
NORTHERN AVE TS	72	DEFAULT	Switch	1.3	237.9	57.9	102.17
NORTHERN AVE TS	74	DEFAULT	Switch	0.4	-79.3	0.2	102.14
NORTHERN AVE TS	79	DEFAULT	Switch	1.8	316.9	78.6	101.99
NORTHERN AVE TS	79	1800 KVAR 20 KV	Shunt Capacitor	0.0	317.0	76.0	101.99
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-8.3	102.72
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	0.4	33.8	35.3	103.25

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-18-2020 LTC.sxst
Date	Thu Jun 18 2020
Time	14h29m12s
Project Name	New
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	4607.22	-42.24	4607.42	-100.00
Generators	239.00	0.00	239.00	100.00
Total Generation	**4846.22**	**-42.24**	**4846.41**	**-100.00**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4804.97	1718.88	5103.17	94.16
Shunt capacitors (Adjusted)	0.00	-1263.00	1263.00	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4804.97**	**455.87**	**4826.55**	**99.55**
Cable Capacitance	0.00	-71.06	71.06	0.00
Line Capacitance	0.00	-563.38	563.38	0.00
Total Shunt Capacitance	**0.00**	**-634.44**	**634.44**	**0.00**
Line Losses	36.19	88.07	95.22	38.01
Cable Losses	0.24	0.15	0.29	85.23
Transformer Load Losses	4.81	48.10	48.34	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**41.25**	**136.32**	**142.43**	**28.96**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	105.57 %
	B	1	87	104.45 %
	C	1	87	105.74 %
Under-Voltage	A	0	83	100.66 %
	B	0	83	100.69 %
	C	0	18	100.70 %
Over-Voltage	A	0	68	104.38 %
	B	0	BAR RIVER DS LV BUS	104.53 %
	C	0	68	104.86 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	36.19	317.06	31.71
Cable Losses	0.24	2.14	0.21
Transformer Load Losses	4.81	42.14	4.21
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	41.25	361.34	36.13

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.8	34.500	14794.7	2119	490	2175	97.09	35.0	-13.01	1.8	6.4	5.9
55	53	ER2	3/0ACSR	Overhead Line	35.8	34.500	144.4	2117	509	2178	96.89	35.1	-13.67	0.1	0.1	12.1
52	52	53	556ASC	Overhead Line	35.8	34.500	213.3	395	71	402	94.97	6.5	-10.32	0.0	0.0	1.3
077	51	52	556ASC	Overhead Line	35.8	34.500	1889.0	395	71	402	94.96	6.5	-10.37	0.0	0.0	1.3
51	GARDEN RIVER DS HV BU	51	556ASC	Overhead Line	35.8	34.500	34354.4	395	74	402	94.82	6.5	-10.82	0.2	0.6	1.3
49	GARDEN RIVER DS HV BU	GARDEN RIVER T2 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	108	35	114	95.01	5.1	-48.53	0.0	0.0	1.0
50	GARDEN RIVER DS HV BU	GARDEN RIVER T1 LV BU	556ASC	Overhead Line	12.9	12.470	100.0	287	94	302	95.00	13.5	-48.91	0.0	0.0	4.5
54	53	54	556ASC	Overhead Line	35.8	34.500	147.6	1722	438	1777	96.23	28.6	-14.43	0.0	0.0	5.1
67	69	54	556ASC	Overhead Line	35.8	34.500	12664.6	1722	438	1777	96.23	28.6	-14.44	1.0	3.7	5.1
70	69	66	556ASC	Overhead Line	35.8	34.500	9594.3	1721	456	1780	95.98	28.7	-15.11	0.8	2.9	5.1
66	65	66	556ASC	Overhead Line	35.8	34.500	100.0	1006	340	1062	92.90	17.1	-19.04	0.0	0.0	3.3
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.8	34.500	64.0	1006	340	1062	92.89	17.1	-19.05	0.0	0.0	3.3
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.0	12.470	100.0	1005	330	1058	94.99	46.9	-49.06	0.0	0.1	10.9
71	66	71	3/0ACSR	Overhead Line	35.8	34.500	82.0	714	129	726	98.39	11.7	-10.62	0.0	0.0	3.7
72	71	72	3/0ACSR	Overhead Line	35.7	34.500	29000.0	714	130	726	98.39	11.7	-10.63	1.3	1.6	3.7
73	72	73	556ASC	Overhead Line	35.7	34.500	6391.1	713	173	733	97.19	11.9	-14.05	0.1	0.3	1.8
74	73	SOLAR	556ASC	Overhead Line	35.7	34.500	100.0	-239	0	239	100.00	3.9	179.50	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.6	34.500	28445.2	952	183	969	98.19	15.7	-11.36	0.7	2.5	2.4
79	78	542	477ACSR	Overhead Line	35.6	34.500	5072.2	951	229	978	97.22	15.9	-14.15	0.1	0.4	2.5
86	542	86	556ASC	Overhead Line	35.6	34.500	100.0	951	237	980	97.02	15.9	-14.64	0.0	0.0	2.5
8	86	8	556ASC	Overhead Line	25.7	25.000	10.0	950	225	976	97.30	21.9	-44.64	0.0	0.0	3.4
7	8	7	556ASC	Overhead Line	25.7	25.000	10.0	950	225	976	97.30	21.9	-44.65	0.0	0.0	3.4
89	7	DESBARATS DS T2 LV BU	336AAC	Overhead Line	25.7	25.000	50.0	950	225	976	97.30	21.9	-44.65	0.0	0.0	4.3
11	DESBARATS DS T2 LV BU	11	28 KV 2/0 CU 100% C	Cable	25.7	25.000	185.0	950	225	976	97.30	21.9	-44.65	0.0	0.0	8.0
13	11	13	336AAC	Overhead Line	25.7	25.000	3500.0	950	229	977	97.22	21.9	-44.84	0.2	0.6	4.3
14	13	14	336AAC	Overhead Line	25.7	25.000	5717.0	949	231	977	97.17	22.0	-45.01	0.4	1.0	4.3
15	14	15	35 KV 4/0 CU 100% C	Cable	25.7	25.000	2345.0	949	235	978	97.07	22.0	-45.29	0.2	0.1	5.9
16	15	16	336AAC	Overhead Line	25.6	25.000	13595.0	949	302	996	95.28	22.4	-49.07	0.9	2.5	4.4
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	948	311	998	95.00	22.8	-49.70	0.0	0.0	4.5
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.9	34.500	22193.7	2472	-463	2515	-97.92	40.5	10.61	4.1	12.7	7.1
2024	ER1	58	477ACSR	Overhead Line	35.8	34.500	9412.4	2468	-438	2506	-98.09	40.4	9.76	1.7	5.4	7.0
59	58	VR PRIMARY	477ACSR	Overhead Line	35.8	34.500	24.2	2466	-427	2503	-98.16	40.3	9.39	0.0	0.0	7.0
62	VR SECONDARY	62	477ACSR	Overhead Line	35.2	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	35.2	34.500	100.0	2466	-426	2503	-98.16	41.1	9.38	0.0	0.1	7.2
76	75	76	477ACSR	Overhead Line	35.1	34.500	51800.0	2466	-426	2503	-98.16	41.1	9.37	9.9	30.4	7.2
77	76	77	556ASC	Overhead Line	35.1	34.500	100.0	2456	-371	2484	-98.50	40.9	7.43	0.0	0.1	7.1
80	542	77	556ASC	Overhead Line	35.1	34.500	100.0	0	0	0	0.00	0.0	88.86	0.0	0.0	0.0
81	77	81	556ASC	Overhead Line	35.1	34.500	100.0	724	-1011	1244	-57.77	20.4	53.23	0.0	0.0	3.6
87	81	DESBARATS DS T1 LV BU	556ASC	Overhead Line	12.8	12.470	100.0	723	-1025	1254	-55.95	56.6	23.22	0.0	0.1	9.9
82	77	82	3/0ACSR	Overhead Line	35.1	34.500	100.0	1732	641	1847	93.74	30.4	-21.44	0.0	0.0	10.1
83	82	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	34.8	34.500	41600.0	1732	641	1847	93.73	30.4	-21.45	12.3	15.0	10.1
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	34.9	34.500	100.0	769	260	812	94.42	13.4	-20.15	0.0	0.0	4.7
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.9	12.470	39.9	768	253	809	95.00	36.2	-50.16	0.0	0.0	6.5
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	34.9	34.500	15088.3	951	426	1042	91.25	17.2	-25.59	0.4	1.6	2.7
61	VR PRIMARY	61	477ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0
63	61	62	3/0ACSR	Overhead Line	35.8	34.500	100.0	0	0	0	0.00	0.0	89.58	0.0	0.0	0.0
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	16	-69	71	-22.97	1.1	76.72	0.0	0.0	0.2
390	46	TRUSS PLANT	556ASC	Overhead Line	35.9	34.500	27986.1	16	-69	70	-23.03	1.1	76.69	0.0	0.0	0.2
076	TRUSS PLANT	GARDEN RIVER DS HV BU	556ASC	Overhead Line	35.9	34.500	16346.2	0	-28	28	0.01	0.5	90.00	0.0	0.0	0.1

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS	9	DEFAULT	Switch	8.8	1639.5	105.8	104.00
ECHO RIVER TS	081	DEFAULT	Switch	4.1	715.2	250.8	104.00
ECHO RIVER TS	081	DEFAULT	Switch	4.1	714.5	257.0	103.81
ECHO RIVER TS	077	DEFAULT	Switch	0.5	78.5	31.4	103.81
ECHO RIVER TS	51	DEFAULT	Switch	0.5	78.5	52.1	103.74
ECHO RIVER TS	49	GARDEN T2	Two-Winding Transformer	4.4	44.4	16.5	103.58
ECHO RIVER TS	555	GARDEN T1	Two-Winding Transformer	0.4	34.1	35.6	103.52
ECHO RIVER TS	67	DEFAULT	Switch	3.6	636.0	225.8	103.81
ECHO RIVER TS	66	DEFAULT	Switch	2.4	396.4	192.1	103.55
ECHO RIVER TS	65	DEFAULT	Switch	2.4	396.4	192.2	103.55
ECHO RIVER TS	68	BAR RIVER T1	Two-Winding Transformer	17.1	396.4	192.2	104.38
ECHO RIVER TS	68	1200 KVAR 7 KV	Shunt Capacitor	0.0	503.2	165.5	104.36
ECHO RIVER TS	71	DEFAULT	Switch	1.3	238.8	43.6	103.55
ECHO RIVER TS	72	DEFAULT	Switch	1.3	238.4	57.9	103.33
ECHO RIVER TS	74	DEFAULT	Switch	0.4	-79.6	0.0	103.30
ECHO RIVER TS	79	DEFAULT	Switch	1.8	317.7	79.4	103.15
ECHO RIVER TS	86	DESBARATS T2	Two-Winding Transformer	19.6	317.7	79.5	102.78
ECHO RIVER TS	13	1200 KVAR 20 KV	Shunt Capacitor	0.0	317.7	76.6	102.74
ECHO RIVER TS	17	25 KV 600A 1PH	Regulator	3.8	317.1	104.2	101.19
ECHO RIVER TS	56	DEFAULT	Switch	5.0	924.4	-145.0	104.00
ECHO RIVER TS	58	DEFAULT	Switch	5.0	921.9	-134.3	103.85
ECHO RIVER TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	22.5	921.9	-134.1	101.91
ECHO RIVER TS	62	DEFAULT	Switch	0.0	0.0	0.0	103.85
ECHO RIVER TS	64	DEFAULT	Switch	0.0	0.0	0.0	103.55
ECHO RIVER TS	75	DEFAULT	Switch	5.1	921.9	-134.0	101.91
ECHO RIVER TS	77	DEFAULT	Switch	5.1	917.8	-117.9	101.64
ECHO RIVER TS	80	DEFAULT	Switch	0.0	0.0	0.0	103.15
ECHO RIVER TS	81	DEFAULT	Switch	2.6	315.5	-349.6	101.64
ECHO RIVER TS	81	DESBARATS T1	Two-Winding Transformer	23.5	315.5	-349.6	102.75
ECHO RIVER TS	87	1200 KVAR 7 KV	Shunt Capacitor	105.6	244.2	-342.0	102.74
ECHO RIVER TS	82	DEFAULT	Switch	3.5	602.3	231.8	101.64
ECHO RIVER TS	83	DEFAULT	Switch	3.5	602.3	231.8	101.64
ECHO RIVER TS	83	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	16.1	597.8	246.6	101.29
ECHO RIVER TS	84	DEFAULT	Switch	1.6	280.6	104.4	101.29
ECHO RIVER TS	84	BRUCE MINES T1	Two-Winding Transformer	16.9	280.6	104.4	103.40
ECHO RIVER TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	298.3	98.0	103.40
ECHO RIVER TS	85	DEFAULT	Switch	0.0	0.0	0.0	101.19
ECHO RIVER TS	61	DEFAULT	Switch	0.0	0.0	-0.1	103.85

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	0.1	5.4	-22.9	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	0.1	0.0	-9.4	104.01
NORTHERN AVE TS	076	DEFAULT	Switch	0.0	0.0	0.0	103.74

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-18-2020 LTC.sxst
Date	Thu Jun 18 2020
Time	14h30m18s
Project Name	Uprated with LTC and Reg, Peak by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=100.00%, Q=100.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	16115.18	2746.79	16347.60	98.58
Generators	239.02	0.03	239.02	100.00
Total Generation	**16354.20**	**2746.82**	**16583.27**	**98.62**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	15893.08	5687.12	16879.97	94.15
Shunt capacitors (Adjusted)	0.00	-3762.20	3762.20	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**15893.08**	**1924.92**	**16009.23**	**99.27**
Cable Capacitance	0.00	-69.14	69.14	0.00
Line Capacitance	0.00	-555.60	555.60	0.00
Total Shunt Capacitance	**0.00**	**-624.74**	**624.74**	**0.00**
Line Losses	415.74	1018.48	1100.07	37.79
Cable Losses	2.90	1.79	3.41	85.14
Transformer Load Losses	42.64	426.36	428.49	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**461.28**	**1446.64**	**1518.40**	**30.38**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	3	88	108.25 %
	B	2	88	106.94 %
	C	3	88	109.08 %
Under-Voltage	A	0	83	96.98 %
	B	0	83	98.10 %
	C	0	83	98.74 %
Over-Voltage	A	0	84	104.05 %
	B	0	GARDEN RIVER T1 LV BUS	104.61 %
	C	4	68	105.15 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	415.74	3641.86	364.19
Cable Losses	2.90	25.41	2.54
Transformer Load Losses	42.64	373.50	37.35
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	461.28	4040.77	404.08

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.7	34.500	14794.7	7682	1569	7841	97.68	126.2	-11.54	23.1	83.4	21.2
55	53	ER2	3/0ACSR	Overhead Line	35.7	34.500	144.4	7659	1511	7807	97.81	126.2	-11.73	0.7	0.9	43.5
52	52	53	556ASC	Overhead Line	35.7	34.500	213.3	1321	412	1383	92.19	22.4	-17.89	0.0	0.0	4.6
077	51	52	556ASC	Overhead Line	35.7	34.500	1889.0	1321	412	1384	92.19	22.4	-17.91	0.1	0.4	4.6
51	GARDEN RIVER DS HV BUS	51	556ASC	Overhead Line	35.6	34.500	34354.4	1321	415	1384	92.13	22.4	-18.04	1.9	7.0	4.6
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	13.0	12.470	100.0	363	119	382	95.00	17.0	-49.41	0.0	0.0	3.5
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.9	12.470	100.0	952	313	1003	94.99	45.0	-50.66	0.1	0.2	14.9
54	53	54	556ASC	Overhead Line	35.7	34.500	147.6	6337	1099	6432	97.97	104.0	-10.41	0.2	0.6	18.0
67	69	54	556ASC	Overhead Line	35.6	34.500	12664.6	6337	1098	6432	97.97	104.0	-10.41	13.6	49.1	18.0
70	69	66	556ASC	Overhead Line	35.5	34.500	9594.3	6324	1071	6414	98.03	104.1	-10.60	10.3	37.2	18.0
66	65	66	556ASC	Overhead Line	35.5	34.500	100.0	3322	1204	3534	92.25	57.5	-21.24	0.0	0.1	11.0
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.5	34.500	64.0	3322	1204	3534	92.25	57.5	-21.24	0.0	0.1	11.0
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.0	12.470	100.0	3311	1091	3486	94.98	155.3	-51.24	0.4	1.2	36.1
71	66	71	3/0ACSR	Overhead Line	35.5	34.500	82.0	2991	-155	2995	-99.87	48.7	1.68	0.1	0.1	15.5
72	71	72	3/0ACSR	Overhead Line	35.3	34.500	29000.0	2991	-154	2995	-99.87	48.7	1.68	21.7	26.5	15.5
73	72	73	556ASC	Overhead Line	35.2	34.500	6391.1	2969	-137	2972	-99.89	48.7	0.84	1.5	5.3	7.6
74	73	SOLAR	556ASC	Overhead Line	35.2	34.500	100.0	-239	0	239	100.00	3.9	178.05	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.2	34.500	28445.2	3207	-132	3209	-99.92	52.6	0.44	7.6	27.5	8.2
79	78	542	477ACSR	Overhead Line	35.1	34.500	5072.2	3199	-112	3201	-99.94	52.6	-0.40	1.6	4.8	8.2
86	542	86	556ASC	Overhead Line	35.1	34.500	100.0	3198	-109	3199	-99.94	52.6	-0.55	0.0	0.1	8.2
8	86	8	556ASC	Overhead Line	25.4	25.000	10.0	3184	-244	3193	-99.71	72.5	-30.55	0.0	0.0	11.3
7	8	7	556ASC	Overhead Line	25.4	25.000	10.0	3184	-244	3193	-99.71	72.5	-30.55	0.0	0.0	11.3
89	7	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	25.4	25.000	50.0	3184	-244	3193	-99.71	72.5	-30.55	0.0	0.1	14.3
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	25.4	25.000	185.0	3184	-244	3193	-99.71	72.5	-30.55	0.3	0.1	26.4
13	11	13	336AAC	Overhead Line	25.4	25.000	3500.0	3184	-241	3193	-99.71	72.5	-30.61	2.6	7.0	14.3
14	13	14	336AAC	Overhead Line	25.3	25.000	5717.0	3181	1001	3335	95.39	75.8	-52.51	4.4	11.9	14.9
15	14	15	35 KV 4/0 CU 100% CN	Cable	25.3	25.000	2345.0	3176	993	3328	95.44	75.8	-52.59	2.6	1.7	20.3
16	15	16	336AAC	Overhead Line	25.2	25.000	13595.0	3174	1058	3345	94.87	76.3	-53.67	10.7	28.6	15.0
18	17	18	336AAC	Overhead Line	25.3	25.000	25.0	3163	1040	3330	95.00	76.1	-53.85	0.0	0.1	14.9
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.6	34.500	22193.7	8379	1228	8469	98.59	136.3	-8.34	46.9	144.1	23.9
2024	ER1	58	477ACSR	Overhead Line	35.5	34.500	9412.4	8332	1122	8407	98.75	136.4	-8.59	19.9	61.2	23.9
59	58	VR PRIMARY	477ACSR	Overhead Line	35.5	34.500	24.2	8312	1077	8382	98.82	136.4	-8.70	0.1	0.2	23.9
62	VR SECONDARY	62	477ACSR	Overhead Line	35.3	34.500	100.0	0	0	0	0.00	0.0	88.70	0.0	0.0	0.0
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.70	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	35.3	34.500	100.0	8312	1077	8382	98.82	137.0	-8.70	0.2	0.7	24.0
76	75	76	477ACSR	Overhead Line	34.7	34.500	51800.0	8312	1077	8381	98.82	137.0	-8.70	110.8	340.1	24.0
77	76	77	556ASC	Overhead Line	34.7	34.500	100.0	8201	822	8242	99.14	137.1	-9.28	0.2	0.7	23.9
80	542	77	556ASC	Overhead Line	34.7	34.500	100.0	0	0	0	0.01	0.0	86.48	0.0	0.0	0.0
81	77	81	556ASC	Overhead Line	34.7	34.500	100.0	2319	-399	2353	-95.90	39.2	6.15	0.0	0.1	7.9
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.6	12.470	100.0	2313	-459	2358	-95.39	108.4	-23.86	0.2	0.6	24.8
82	77	82	3/0ACSR	Overhead Line	34.7	34.500	100.0	5882	1221	6008	97.85	99.9	-15.27	0.3	0.4	33.5
83	82	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	33.8	34.500	41600.0	5882	1221	6007	97.85	99.9	-15.27	131.7	160.8	33.5
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	34.9	34.500	100.0	2596	-363	2621	-98.73	43.3	3.15	0.1	0.1	14.9
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	13.0	12.470	39.9	2587	-447	2626	-98.22	116.9	-26.85	0.1	0.2	20.9
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	34.8	34.500	15088.3	3155	1482	3485	90.51	57.6	-29.96	4.9	17.6	8.9
61	VR PRIMARY	61	477ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.70	0.0	0.0	0.0
63	61	62	3/0ACSR	Overhead Line	35.5	34.500	100.0	0	0	0	0.00	0.0	88.70	0.0	0.0	0.0
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	54	-51	74	-73.04	1.2	43.08	0.0	0.0	0.2
390	46	TRUSS PLANT	556ASC	Overhead Line	35.9	34.500	27986.1	54	-50	74	-73.16	1.2	42.98	0.0	0.0	0.2
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	556ASC	Overhead Line	35.9	34.500	16346.2	0	-28	28	0.02	0.5	90.00	0.0	0.0	0.1

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS 9		DEFAULT	Switch	31.3	5695.7	1302.7	104.00
ECHO RIVER TS 081		DEFAULT	Switch	14.5	2569.2	817.1	104.00
ECHO RIVER TS 081		DEFAULT	Switch	14.5	2561.2	796.3	103.36
ECHO RIVER TS 077		DEFAULT	Switch	1.7	262.5	157.5	103.35
ECHO RIVER TS 51		DEFAULT	Switch	1.7	262.2	177.1	103.10
ECHO RIVER TS 49		GARDEN T2	Two-Winding Transforme	15.0	149.1	56.4	103.81
ECHO RIVER TS 555		GARDEN T1	Two-Winding Transforme	1.3	113.1	120.7	103.63
ECHO RIVER TS 67		DEFAULT	Switch	12.9	2298.3	638.5	103.35
ECHO RIVER TS 66		DEFAULT	Switch	7.9	1294.3	665.2	102.54
ECHO RIVER TS 65		DEFAULT	Switch	7.9	1294.3	665.2	102.54
ECHO RIVER TS 68		BAR RIVER T1	Two-Winding Transforme	56.6	1294.3	665.2	103.45
ECHO RIVER TS 68		1200 KVAR 7 KV	Shunt Capacitor	0.0	1646.4	542.9	103.41
ECHO RIVER TS 71		DEFAULT	Switch	5.4	994.4	-49.0	102.55
ECHO RIVER TS 72		DEFAULT	Switch	5.4	987.1	-43.4	101.84
ECHO RIVER TS 74		DEFAULT	Switch	0.4	-79.4	0.0	101.80
ECHO RIVER TS 79		DEFAULT	Switch	5.8	1063.0	-34.0	101.54
ECHO RIVER TS 86		DESBARATS T2	Two-Winding Transforme	63.8	1063.0	-34.0	101.55
ECHO RIVER TS 13		1200 KVAR 20 KV	Shunt Capacitor	103.6	1062.6	-78.6	101.44
ECHO RIVER TS 17		25 KV 600A 1PH	Regulator	12.8	1055.5	347.2	101.14
ECHO RIVER TS 56		DEFAULT	Switch	17.0	3126.5	485.6	104.00
ECHO RIVER TS 58		DEFAULT	Switch	17.0	3097.5	418.7	102.66
ECHO RIVER TS 5		34.5KV_200A_1PH_COOPER_REGULATOR_6	Regulator	76.4	3097.5	418.8	102.01
ECHO RIVER TS 62		DEFAULT	Switch	0.0	0.0	0.0	102.66
ECHO RIVER TS 64		DEFAULT	Switch	0.0	0.0	0.0	102.54
ECHO RIVER TS 75		DEFAULT	Switch	17.1	3097.4	418.7	102.01
ECHO RIVER TS 77		DEFAULT	Switch	17.1	3049.6	304.9	99.92
ECHO RIVER TS 80		DEFAULT	Switch	0.0	0.0	0.0	101.54
ECHO RIVER TS 81		DEFAULT	Switch	5.7	1005.2	-169.2	99.92
ECHO RIVER TS 81		DESBARATS T1	Two-Winding Transforme	57.3	1005.2	-169.2	101.05
ECHO RIVER TS 87		1200 KVAR 7 KV	Shunt Capacitor	102.1	787.1	-149.8	101.03
ECHO RIVER TS 82		DEFAULT	Switch	11.7	2044.4	474.1	99.92
ECHO RIVER TS 83		DEFAULT	Switch	11.7	2044.3	474.0	99.91
ECHO RIVER TS 83		34.5KV_200A_1PH_COOPER_REGULATOR_6	Regulator	52.8	1994.6	433.2	101.22
ECHO RIVER TS 84		DEFAULT	Switch	5.2	942.1	-60.9	101.22
ECHO RIVER TS 84		BRUCE MINES T1	Two-Winding Transforme	54.3	942.1	-60.9	104.05
ECHO RIVER TS 88		1200 KVAR 7 KV	Shunt Capacitor	108.3	1006.7	-102.4	104.04
ECHO RIVER TS 85		DEFAULT	Switch	0.0	0.0	0.0	100.87
ECHO RIVER TS 61		DEFAULT	Switch	0.0	0.0	-0.1	102.66

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	0.1	18.0	-16.8	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	0.1	0.0	-9.4	104.00
NORTHERN AVE TS	076	DEFAULT	Switch	0.0	0.0	0.0	103.10

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-18-2020 LTC.sxst
Date	Thu Jun 18 2020
Time	14h32m51s
Project Name	Uprated from NTS with LTC and Reg Min by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=30.00%, Q=30.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	4653.04	153.97	4655.58	99.95
Generators	239.00	-0.01	239.00	100.00
Total Generation	**4892.03**	**153.96**	**4894.45**	**99.95**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	4808.41	1720.76	5107.03	94.15
Shunt capacitors (Adjusted)	0.00	-1234.53	1234.53	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**4808.41**	**486.23**	**4832.93**	**99.49**
Cable Capacitance	0.00	-69.79	69.79	0.00
Line Capacitance	0.00	-554.41	554.41	0.00
Total Shunt Capacitance	**0.00**	**-624.21**	**624.21**	**0.00**
Line Losses	78.66	243.42	255.81	30.75
Cable Losses	0.25	0.15	0.29	85.04
Transformer Load Losses	4.84	48.37	48.61	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**83.74**	**291.94**	**303.71**	**27.57**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	87	103.26 %
	B	1	87	101.94 %
	C	1	87	103.42 %
Under-Voltage	A	0	83	99.72 %
	B	0	83	99.57 %
	C	0	83	99.67 %
Over-Voltage	A	0	68	104.86 %
	B	0	BAR RIVER DS LV BUS	104.46 %
	C	4	68	105.52 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	78.66	689.06	68.91
Cable Losses	0.25	2.18	0.22
Transformer Load Losses	4.84	42.37	4.24
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	83.74	733.60	73.36

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS	9	DEFAULT	Switch	0.0	0.0	0.0	104.00

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	9.0	1664.1	158.3	104.00
NORTHERN AVE TS	390	DEFAULT	Switch	8.9	1652.6	150.3	103.50
NORTHERN AVE TS	076	DEFAULT	Switch	8.9	1649.1	147.1	103.21
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	4.4	44.0	16.3	103.28
NORTHERN AVE TS	51	DEFAULT	Switch	8.5	1571.4	95.5	103.21
NORTHERN AVE TS	077	DEFAULT	Switch	8.5	1564.3	90.9	102.65
NORTHERN AVE TS	67	DEFAULT	Switch	8.5	1564.2	99.2	102.65
NORTHERN AVE TS	66	DEFAULT	Switch	7.2	1322.0	52.5	102.30
NORTHERN AVE TS	65	DEFAULT	Switch	7.2	1322.0	52.6	102.30
NORTHERN AVE TS	64	DEFAULT	Switch	5.1	925.0	-140.0	102.30
NORTHERN AVE TS	61	DEFAULT	Switch	5.1	925.0	-139.9	102.29
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	22.9	925.0	-122.3	101.02
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	102.30
NORTHERN AVE TS	75	DEFAULT	Switch	5.2	924.9	-122.2	101.01
NORTHERN AVE TS	77	DEFAULT	Switch	5.1	920.7	-107.0	100.73
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	101.90
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	19.6	316.4	78.5	102.00
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	0.0	316.8	76.7	101.96
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	3.8	316.2	103.9	101.06
NORTHERN AVE TS	81	DEFAULT	Switch	2.6	308.1	-343.3	100.73
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	22.9	308.1	-343.2	101.63
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	103.3	238.8	-334.6	101.62
NORTHERN AVE TS	82	DEFAULT	Switch	3.6	612.7	236.3	100.73
NORTHERN AVE TS	83	DEFAULT	Switch	3.6	612.7	236.3	100.72
NORTHERN AVE TS	83	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	16.6	607.9	250.4	102.21
NORTHERN AVE TS	84	DEFAULT	Switch	1.7	284.9	105.7	102.21
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	17.0	284.9	105.7	104.14
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	302.6	99.4	104.14
NORTHERN AVE TS	85	DEFAULT	Switch	0.0	0.0	0.0	102.10
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-17.6	102.29
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	17.1	397.0	192.5	104.86
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	0.0	507.9	167.0	104.85
NORTHERN AVE TS	71	DEFAULT	Switch	1.3	237.9	43.7	102.30
NORTHERN AVE TS	72	DEFAULT	Switch	1.3	237.4	57.7	102.07
NORTHERN AVE TS	74	DEFAULT	Switch	0.4	-79.3	0.3	102.05
NORTHERN AVE TS	79	DEFAULT	Switch	1.8	316.4	78.4	101.90
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-8.3	102.65
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	0.4	33.8	35.3	103.23

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	4653	154	4656	99.73	74.9	-1.90	0.1	0.2	12.5
390	46	TRUSS PLANT	556ASC	Overhead Line	35.7	34.500	27986.1	4653	154	4656	99.73	74.9	-1.90	15.3	55.4	12.5
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	556ASC	Overhead Line	35.7	34.500	16346.2	4622	139	4624	99.73	74.7	-2.40	8.9	32.2	12.5
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.9	12.470	100.0	107	35	113	95.01	5.1	-49.40	0.0	0.0	1.0
51	GARDEN RIVER DS HV BUS	51	556ASC	Overhead Line	35.5	34.500	34354.4	4220	3	4220	99.57	68.3	-1.11	15.8	57.0	11.9
077	51	52	556ASC	Overhead Line	35.5	34.500	1889.0	4204	4	4204	99.57	68.3	-1.90	0.9	3.1	11.9
52	52	53	556ASC	Overhead Line	35.5	34.500	213.3	4203	4	4203	99.57	68.3	-1.95	0.1	0.4	11.9
54	53	54	556ASC	Overhead Line	35.5	34.500	147.6	4203	29	4203	99.57	68.3	-2.30	0.1	0.2	11.9
67	69	54	556ASC	Overhead Line	35.5	34.500	12664.6	4203	29	4203	99.57	68.3	-2.30	5.8	21.0	11.9
70	69	66	556ASC	Overhead Line	35.4	34.500	9594.3	4197	29	4197	99.57	68.3	-2.59	4.4	15.9	11.9
66	65	66	556ASC	Overhead Line	35.4	34.500	100.0	3480	-103	3481	-99.34	56.7	-0.71	0.0	0.1	10.1
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	35.4	34.500	64.0	3480	-103	3481	-99.34	56.7	-0.71	0.0	0.1	10.1
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	35.4	34.500	100.0	2467	-446	2507	-98.04	40.8	7.85	0.0	0.1	7.2
63	61	62	3/0ACSR	Overhead Line	35.4	34.500	100.0	2467	-446	2507	-98.04	40.8	7.84	0.1	0.1	14.6
61	VR PRIMARY	61	477ACSR	Overhead Line	35.4	34.500	100.0	2467	-446	2507	-98.04	40.8	7.84	0.0	0.1	7.2
62	VR SECONDARY	62	477ACSR	Overhead Line	34.8	34.500	100.0	0	0	0	0.01	0.0	87.63	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	34.8	34.500	100.0	2467	-392	2498	-98.39	41.5	6.65	0.0	0.1	7.2
76	75	76	477ACSR	Overhead Line	34.7	34.500	51800.0	2467	-392	2498	-98.39	41.5	6.65	10.1	31.0	7.2
77	76	77	556ASC	Overhead Line	34.7	34.500	100.0	2457	-340	2480	-98.68	41.3	4.74	0.0	0.1	7.2
80	542	77	556ASC	Overhead Line	34.7	34.500	100.0	0	0	0	0.01	0.0	86.90	0.0	0.0	0.0
86	542	86	556ASC	Overhead Line	35.3	34.500	100.0	950	239	979	96.98	16.0	-16.77	0.0	0.0	2.5
8	86	8	556ASC	Overhead Line	25.5	25.000	10.0	949	226	975	97.27	22.1	-46.78	0.0	0.0	3.5
7	8	7	556ASC	Overhead Line	25.5	25.000	10.0	949	226	975	97.27	22.1	-46.78	0.0	0.0	3.5
89	7	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	25.5	25.000	50.0	949	226	975	97.27	22.1	-46.78	0.0	0.0	4.4
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	25.5	25.000	185.0	949	227	975	97.26	22.1	-46.78	0.0	0.0	8.1
13	11	13	336AAC	Overhead Line	25.5	25.000	3500.0	949	230	976	97.19	22.1	-46.98	0.2	0.6	4.4
14	13	14	336AAC	Overhead Line	25.4	25.000	5717.0	948	232	976	97.13	22.1	47.14	0.4	1.0	4.4
15	14	15	35 KV 4/0 CU 100% CN	Cable	25.4	25.000	2345.0	948	238	977	97.04	22.2	-47.42	0.2	0.1	6.0
16	15	16	336AAC	Overhead Line	25.4	25.000	13595.0	948	302	995	95.27	22.6	-51.13	0.9	2.5	4.5
18	17	18	336AAC	Overhead Line	25.2	25.000	25.0	947	311	997	95.00	22.8	-51.75	0.0	0.0	4.5
81	77	81	556ASC	Overhead Line	34.7	34.500	100.0	707	-988	1215	-57.75	20.2	51.27	0.0	0.0	3.6
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.6	12.470	100.0	706	-1003	1226	-55.92	55.9	21.27	0.0	0.1	9.8
82	77	82	3/0ACSR	Overhead Line	34.7	34.500	100.0	1750	649	1866	93.70	31.0	-23.47	0.0	0.0	10.4
83	82	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	34.4	34.500	41600.0	1749	649	1866	93.69	31.0	-23.48	12.8	15.7	10.4
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	35.1	34.500	100.0	777	263	820	94.40	13.5	-22.13	0.0	0.0	4.7
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	13.0	12.470	39.9	776	255	817	95.00	36.4	-52.14	0.0	0.0	6.6
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	35.1	34.500	15088.3	960	430	1052	91.25	17.3	-27.56	0.4	1.6	2.7
59	58	VR PRIMARY	477ACSR	Overhead Line	35.4	34.500	24.2	0	-53	53	0.00	0.9	87.62	0.0	0.0	0.1
2024	ER1	58	477ACSR	Overhead Line	35.4	34.500	9412.4	0	-53	53	0.00	0.9	87.62	0.0	0.0	0.1
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	35.4	34.500	22193.7	0	-37	37	0.00	0.6	87.62	0.0	0.0	0.1
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	13.1	12.470	100.0	1011	332	1065	95.00	47.0	-51.16	0.0	0.1	11.0
71	66	71	3/0ACSR	Overhead Line	35.4	34.500	82.0	713	133	725	98.30	11.8	-12.94	0.0	0.0	3.8
72	71	72	3/0ACSR	Overhead Line	35.4	34.500	29000.0	713	133	725	98.30	11.8	-12.95	1.3	1.6	3.8
73	72	73	556ASC	Overhead Line	35.4	34.500	6391.1	712	175	733	97.09	12.0	-16.31	0.1	0.3	1.9
74	73	SOLAR	556ASC	Overhead Line	35.4	34.500	100.0	-239	0	239	100.00	3.9	177.47	0.0	0.0	0.6
78	73	78	556ASC	Overhead Line	35.3	34.500	28445.2	951	186	969	98.14	15.8	-13.56	0.7	2.5	2.5
79	78	542	477ACSR	Overhead Line	35.3	34.500	5072.2	950	231	978	97.17	16.0	-16.29	0.1	0.4	2.5
55	53	ER2	3/0ACSR	Overhead Line	35.5	34.500	144.4	0	-25	25	0.00	0.4	88.13	0.0	0.0	0.1
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	35.5	34.500	14794.7	0	-25	25	0.00	0.4	88.13	0.0	0.0	0.1
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.9	12.470	100.0	286	94	301	95.00	13.5	-49.71	0.0	0.0	4.5

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-18-2020 LTC.sxst
Date	Thu Jun 18 2020
Time	14h31m52s
Project Name	Uprated from NTS with Reg and LTC by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=100.00%, Q=100.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	16361.37	6676.35	17671.11	92.59
Generators	239.00	0.03	239.00	100.00
Total Generation	**16600.37**	**6676.38**	**17892.63**	**92.78**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	15457.07	5553.16	16424.33	94.11
Shunt capacitors (Adjusted)	0.00	-2193.07	2193.07	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**15457.07**	**3360.10**	**15818.07**	**97.72**
Cable Capacitance	0.00	-57.43	57.43	0.00
Line Capacitance	0.00	-500.47	500.47	0.00
Total Shunt Capacitance	**0.00**	**-557.90**	**557.90**	**0.00**
Line Losses	1094.34	3419.65	3590.48	30.48
Cable Losses	3.38	2.08	3.97	85.19
Transformer Load Losses	45.25	452.45	454.71	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**1142.97**	**3874.18**	**4039.26**	**28.30**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	0	87	98.00 %
	B	0	87	92.83 %
	C	0	87	98.44 %
Under-Voltage	A	78	86	90.88 %
	B	36	16	89.91 %
	C	19	16	93.29 %
Over-Voltage	A	0	84	104.07 %
	B	0	ECHO RIVER TS	104.00 %
	C	0	ECHO RIVER TS	104.00 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	1094.34	9586.43	958.64
Cable Losses	3.38	29.64	2.96
Transformer Load Losses	45.25	396.35	39.63
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	1142.97	10012.42	1001.24

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	16361	6676	17671	92.40	284.3	-22.20	0.8	2.9	48.2
390	46	TRUSS PLANT	556ASC	Overhead Line	34.9	34.500	27986.1	16361	6674	17669	92.40	284.3	-22.20	221.1	799.4	48.2
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	556ASC	Overhead Line	34.3	34.500	16346.2	16088	5897	17135	93.70	283.7	-22.32	128.5	464.6	48.1
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.8	12.470	100.0	353	116	372	95.00	16.8	-52.22	0.0	0.0	3.4
51	GARDEN RIVER DS HV BUS	51	556ASC	Overhead Line	33.3	34.500	34354.4	14666	4999	15495	94.32	260.8	-22.35	229.9	831.1	45.8
077	51	52	556ASC	Overhead Line	33.2	34.500	1889.0	14437	4221	15041	95.64	261.1	-22.54	12.7	45.7	45.8
52	52	53	556ASC	Overhead Line	33.2	34.500	213.3	14424	4178	15017	95.71	261.1	-22.55	1.4	5.2	45.8
54	53	54	556ASC	Overhead Line	33.2	34.500	147.6	14422	4195	15020	95.68	261.2	-22.63	1.0	3.6	45.8
67	69	54	556ASC	Overhead Line	32.9	34.500	12664.6	14421	4192	15018	95.68	261.2	-22.63	84.9	307.1	45.8
70	69	66	556ASC	Overhead Line	32.6	34.500	9594.3	14336	3903	14858	96.14	261.3	-22.70	64.4	232.8	45.9
66	65	66	556ASC	Overhead Line	32.6	34.500	100.0	11325	3575	11876	94.84	210.7	-25.82	0.4	1.6	38.1
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	32.6	34.500	64.0	11325	3573	11875	94.84	210.7	-25.82	0.3	1.0	38.1
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	32.6	34.500	100.0	8254	2451	8610	95.54	152.8	-24.79	0.3	0.8	27.5
63	61	62	3/0ACSR	Overhead Line	32.6	34.500	100.0	8254	2450	8610	95.54	152.8	-24.79	0.7	0.9	55.8
61	VR PRIMARY	61	477ACSR	Overhead Line	32.6	34.500	100.0	8253	2449	8609	95.54	152.8	-24.79	0.3	0.8	27.5
62	VR SECONDARY	62	477ACSR	Overhead Line	34.7	34.500	100.0	0	0	0	-0.01	0.0	81.81	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	34.7	34.500	100.0	8253	2494	8622	95.40	143.5	-25.05	0.2	0.7	25.1
76	75	76	477ACSR	Overhead Line	33.8	34.500	51800.0	8253	2493	8621	95.40	143.5	-25.05	121.7	373.5	25.1
77	76	77	556ASC	Overhead Line	33.8	34.500	100.0	8131	2201	8424	96.19	143.9	-25.58	0.2	0.7	25.0
80	542	77	556ASC	Overhead Line	33.8	34.500	100.0	0	0	0	-0.01	0.0	79.64	0.0	0.0	0.0
86	542	86	556ASC	Overhead Line	32.2	34.500	100.0	3149	128	3151	99.92	56.5	-11.85	0.0	0.1	8.9
8	86	8	556ASC	Overhead Line	23.2	25.000	10.0	3133	-29	3133	-99.99	78.0	-41.86	0.0	0.0	12.2
7	8	7	556ASC	Overhead Line	23.2	25.000	10.0	3133	-29	3133	-99.99	78.0	-41.86	0.0	0.0	12.2
89	7	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	23.2	25.000	50.0	3133	-29	3133	-99.99	78.0	-41.86	0.0	0.1	15.5
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	23.2	25.000	185.0	3133	-29	3133	-99.99	78.0	-41.86	0.3	0.2	28.7
13	11	13	336AAC	Overhead Line	23.2	25.000	3500.0	3133	-27	3133	-99.99	78.0	-41.91	3.0	8.1	15.5
14	13	14	336AAC	Overhead Line	23.1	25.000	5717.0	3129	1004	3287	95.22	81.9	-60.31	5.2	13.9	16.3
15	14	15	35 KV 4/0 CU 100% CN	Cable	23.1	25.000	2345.0	3124	994	3279	95.30	82.0	-60.37	3.1	1.9	22.1
16	15	16	336AAC	Overhead Line	22.9	25.000	13595.0	3121	1047	3292	94.81	82.4	-61.28	12.4	33.4	16.4
18	17	18	336AAC	Overhead Line	25.1	25.000	25.0	3109	1022	3273	94.99	75.4	-61.43	0.0	0.1	14.9
81	77	81	556ASC	Overhead Line	33.8	34.500	100.0	2195	-380	2227	-95.80	38.1	-0.75	0.0	0.1	7.7
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.2	12.470	100.0	2189	-437	2232	-95.36	105.4	-30.75	0.2	0.6	24.0
82	77	82	3/0ACSR	Overhead Line	33.8	34.500	100.0	5936	2581	6473	91.65	110.5	-33.90	0.4	0.5	37.3
83	82	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	32.6	34.500	41600.0	5936	2581	6473	91.65	110.5	-33.90	161.4	197.1	37.3
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	35.2	34.500	100.0	2564	930	2728	93.70	44.7	-31.41	0.1	0.1	15.7
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.9	12.470	39.9	2555	841	2690	94.99	120.6	-61.42	0.1	0.2	21.9
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	35.1	34.500	15088.3	3210	1509	3547	90.50	58.1	-36.60	5.0	17.9	9.1
59	58	VR PRIMARY	477ACSR	Overhead Line	32.6	34.500	24.2	0	-45	45	-0.01	0.8	81.82	0.0	0.0	0.1
2024	ER1	58	477ACSR	Overhead Line	32.6	34.500	9412.4	0	-45	45	-0.01	0.8	81.82	0.0	0.0	0.1
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	32.6	34.500	22193.7	0	-32	32	-0.01	0.6	81.82	0.0	0.0	0.1
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	12.5	12.470	100.0	3058	1007	3220	94.99	149.2	-58.54	0.3	1.1	34.8
71	66	71	3/0ACSR	Overhead Line	32.6	34.500	82.0	2947	109	2949	99.93	52.2	-10.29	0.1	0.1	16.9
72	71	72	3/0ACSR	Overhead Line	32.3	34.500	29000.0	2947	109	2949	99.93	52.2	-10.29	24.9	30.4	16.9
73	72	73	556ASC	Overhead Line	32.3	34.500	6391.1	2922	116	2924	99.92	52.2	-11.01	1.7	6.1	8.2
74	73	SOLAR	556ASC	Overhead Line	32.3	34.500	100.0	-239	0	239	99.99	4.3	171.11	0.0	0.0	0.7
78	73	78	556ASC	Overhead Line	32.2	34.500	28445.2	3159	119	3162	99.93	56.5	-11.01	8.8	31.7	8.9

79	78	542	477ACSR	Overhead Line	32.2	34.500	5072.2	3151	126	3153	99.92	56.5	-11.73	1.8	5.6	9.0
55	53	ER2	3/0ACSR	Overhead Line	33.2	34.500	144.4	0	-22	22	-0.01	0.4	83.67	0.0	0.0	0.1
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	33.2	34.500	14794.7	0	-22	22	-0.01	0.4	83.67	0.0	0.0	0.1
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.8	12.470	100.0	937	308	986	94.99	44.6	-53.36	0.1	0.2	14.8

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS	9	DEFAULT	Switch	0.0	0.0	0.0	104.00

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	34.5	5815.9	2763.4	103.99
NORTHERN AVE TS	390	DEFAULT	Switch	34.5	5703.3	2447.8	100.43
NORTHERN AVE TS	076	DEFAULT	Switch	34.5	5647.6	2268.5	98.43
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	14.4	143.3	54.1	102.65
NORTHERN AVE TS	51	DEFAULT	Switch	32.8	5395.2	2097.5	98.43
NORTHERN AVE TS	077	DEFAULT	Switch	32.8	5282.7	1737.6	94.46
NORTHERN AVE TS	67	DEFAULT	Switch	32.9	5281.6	1741.1	94.42
NORTHERN AVE TS	66	DEFAULT	Switch	27.3	4261.2	1480.8	92.12
NORTHERN AVE TS	65	DEFAULT	Switch	27.3	4261.1	1480.3	92.12
NORTHERN AVE TS	64	DEFAULT	Switch	19.5	3100.9	882.3	92.12
NORTHERN AVE TS	61	DEFAULT	Switch	19.5	3100.4	881.6	92.10
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	88.0	3100.3	895.6	100.72
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	92.11
NORTHERN AVE TS	75	DEFAULT	Switch	17.9	3100.2	895.4	100.72
NORTHERN AVE TS	77	DEFAULT	Switch	17.9	3045.9	766.3	97.81
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	90.88
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	61.0	1016.4	41.2	92.85
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	86.6	1058.3	-4.8	92.71
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	13.9	1049.4	345.2	100.84
NORTHERN AVE TS	81	DEFAULT	Switch	5.5	955.0	-167.5	97.81
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	53.6	955.0	-167.5	99.00
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	98.0	755.6	-143.5	98.98
NORTHERN AVE TS	82	DEFAULT	Switch	13.1	2090.8	933.9	97.81
NORTHERN AVE TS	83	DEFAULT	Switch	13.1	2090.7	933.7	97.80
NORTHERN AVE TS	83	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	59.0	2028.0	876.5	102.87
NORTHERN AVE TS	84	DEFAULT	Switch	5.5	942.1	365.7	102.87
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	55.1	942.1	365.7	104.07
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	1007.1	331.4	104.06
NORTHERN AVE TS	85	DEFAULT	Switch	0.0	0.0	0.0	102.50
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-14.3	92.09
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	50.7	1160.2	598.0	99.78
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	0.0	1532.5	504.6	99.74
NORTHERN AVE TS	71	DEFAULT	Switch	5.8	951.0	37.3	92.13
NORTHERN AVE TS	72	DEFAULT	Switch	5.8	942.8	39.0	91.30
NORTHERN AVE TS	74	DEFAULT	Switch	0.5	-77.6	1.2	91.23
NORTHERN AVE TS	79	DEFAULT	Switch	6.2	1016.4	41.2	90.88
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-7.0	94.44
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	1.2	109.1	116.9	102.47

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-16-2020 uprated conductors.s
Date	Fri Jul 24 2020
Time	10h02m54s
Project Name	Uprated Conductor Sensitivity Test - 115%, by Ashley Rist
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=115.00%, Q=115.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	18139.62	5321.34	18904.03	95.96
Generators	238.98	-0.01	238.98	100.00
Total Generation	**18378.60**	**5321.33**	**19133.47**	**96.05**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	17106.52	6096.34	18160.36	94.20
Shunt capacitors (Adjusted)	0.00	-4628.17	4628.17	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**17106.52**	**1468.17**	**17169.41**	**99.63**
Cable Capacitance	0.00	-57.96	57.96	0.00
Line Capacitance	0.00	-504.14	504.14	0.00
Total Shunt Capacitance	**0.00**	**-562.11**	**562.11**	**0.00**
Line Losses	1211.55	3849.22	4035.39	30.02
Cable Losses	4.46	2.75	5.24	85.09
Transformer Load Losses	56.33	563.30	566.11	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**1272.33**	**4415.27**	**4594.94**	**27.69**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	1	68	103.63 %
	B	1	68	101.27 %
	C	2	68	110.51 %
Under-Voltage	A	66	86	91.88 %
	B	26	16	90.14 %
	C	9	16	93.82 %
Over-Voltage	A	0	ECHO RIVER TS	104.00 %
	B	0	ECHO RIVER TS	104.00 %
	C	5	68	105.13 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	1211.55	10613.16	1061.32
Cable Losses	4.46	39.03	3.90
Transformer Load Losses	56.33	493.45	49.35
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	1272.33	11145.64	1114.56

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (°)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	18140	5321	18904	95.74	304.2	-16.35	0.9	3.3	50.9
390	46	TRUSS PLANT	556ASC	Overhead Line	35.0	34.500	27986.1	18139	5318	18902	95.75	304.2	-16.35	252.8	914.2	50.9
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	556ASC	Overhead Line	34.5	34.500	16346.2	17827	4423	18367	96.84	303.3	-16.45	146.8	530.8	50.7
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.4	12.470	100.0	380	125	400	95.00	18.7	-52.75	0.0	0.0	3.8
51	GARDEN RIVER DS HV BUS	51	556ASC	Overhead Line	33.6	34.500	34354.4	16288	3422	16643	97.49	279.0	-15.90	262.6	949.6	48.3
077	51	52	556ASC	Overhead Line	33.5	34.500	1889.0	16025	2525	16223	98.39	279.1	-16.08	14.4	52.2	48.3
52	52	53	556ASC	Overhead Line	33.5	34.500	213.3	16011	2476	16201	98.44	279.1	-16.09	1.6	5.9	48.3
54	53	54	556ASC	Overhead Line	33.5	34.500	147.6	16009	2493	16202	98.42	279.2	-16.17	1.1	4.1	48.4
67	69	54	556ASC	Overhead Line	33.2	34.500	12664.6	16008	2489	16200	98.42	279.2	-16.17	96.9	350.5	48.4
70	69	66	556ASC	Overhead Line	33.0	34.500	9594.3	15911	2157	16057	98.70	279.2	-16.24	73.5	265.6	48.4
66	65	66	556ASC	Overhead Line	33.0	34.500	100.0	12387	1560	12485	98.59	218.7	-16.64	0.5	1.7	39.0
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	33.0	34.500	64.0	12387	1559	12484	98.59	218.7	-16.64	0.3	1.1	39.0
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	33.0	34.500	100.0	8702	1467	8825	98.23	154.6	-18.95	0.3	0.8	27.4
63	61	62	3/0ACSR	Overhead Line	33.0	34.500	100.0	8702	1466	8824	98.23	154.7	-18.95	0.8	0.9	55.7
61	VR PRIMARY	61	477ACSR	Overhead Line	33.0	34.500	100.0	8701	1465	8823	98.23	154.7	-18.96	0.3	0.8	27.4
62	VR SECONDARY	62	477ACSR	Overhead Line	34.7	34.500	100.0	0	0	0	0.00	0.0	80.68	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	34.7	34.500	100.0	8701	1511	8831	98.15	147.0	-19.21	0.2	0.8	25.5
76	75	76	477ACSR	Overhead Line	34.0	34.500	51800.0	8700	1510	8830	98.15	147.0	-19.21	127.3	390.7	25.5
77	76	77	556ASC	Overhead Line	34.0	34.500	100.0	8573	1201	8657	98.64	147.2	-19.74	0.2	0.8	25.3
80	542	77	556ASC	Overhead Line	34.0	34.500	100.0	0	0	0	0.00	0.0	78.30	0.0	0.0	0.0
86	542	86	556ASC	Overhead Line	32.5	34.500	100.0	3640	341	3656	99.56	65.0	-16.17	0.0	0.1	10.2
8	86	8	556ASC	Overhead Line	23.3	25.000	10.0	3619	134	3621	99.93	89.7	-46.17	0.0	0.0	14.1
7	8	7	556ASC	Overhead Line	23.3	25.000	10.0	3619	134	3621	99.93	89.7	-46.17	0.0	0.0	14.1
89	7	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	23.3	25.000	50.0	3619	134	3621	99.93	89.7	-46.17	0.1	0.1	17.9
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	23.3	25.000	185.0	3619	134	3621	99.93	89.7	-46.17	0.4	0.2	33.1
13	11	13	336AAC	Overhead Line	23.3	25.000	3500.0	3618	136	3621	99.93	89.7	-46.22	4.0	10.7	17.9
14	13	14	336AAC	Overhead Line	23.2	25.000	5717.0	3614	1175	3801	95.10	94.3	-62.21	6.8	18.4	18.8
15	14	15	35 KV 4/0 CU 100% CN	Cable	23.2	25.000	2345.0	3608	1161	3790	95.20	94.3	-62.27	4.0	2.5	25.5
16	15	16	336AAC	Overhead Line	23.0	25.000	13595.0	3604	1213	3802	94.77	94.8	-63.06	16.4	44.1	18.9
18	17	18	336AAC	Overhead Line	25.1	25.000	25.0	3587	1178	3776	95.01	86.9	-63.19	0.0	0.1	17.2
81	77	81	556ASC	Overhead Line	34.0	34.500	100.0	2539	-260	2552	-96.63	43.5	-6.05	0.0	0.1	8.8
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.3	12.470	100.0	2531	-334	2553	-96.88	120.3	-36.05	0.2	0.8	27.6
82	77	82	3/0ACSR	Overhead Line	34.0	34.500	100.0	6034	1461	6209	97.13	105.4	-25.35	0.4	0.4	34.7
83	82	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	33.0	34.500	41600.0	6034	1461	6208	97.13	105.4	-25.35	146.5	178.9	34.7
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	33.0	34.500	100.0	2651	-189	2657	-99.44	46.5	-9.05	0.1	0.1	15.9
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.2	12.470	39.9	2641	-285	2656	-99.17	125.4	-39.05	0.1	0.3	22.6
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	32.9	34.500	15088.3	3237	1527	3579	90.45	62.6	-38.26	5.7	20.7	9.8
59	58	VR PRIMARY	477ACSR	Overhead Line	33.0	34.500	24.2	0	-46	46	0.00	0.8	80.68	0.0	0.0	0.1
2024	ER1	58	477ACSR	Overhead Line	33.0	34.500	9412.4	0	-46	46	0.00	0.8	80.68	0.0	0.0	0.1
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	33.0	34.500	22193.7	0	-32	32	0.00	0.6	80.68	0.0	0.0	0.1
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	12.5	12.470	100.0	3670	-54	3670	-98.80	165.9	-41.08	0.4	1.5	39.0
71	66	71	3/0ACSR	Overhead Line	33.0	34.500	82.0	3451	345	3468	99.50	60.6	-15.02	0.1	0.1	19.6
72	71	72	3/0ACSR	Overhead Line	32.7	34.500	29000.0	3451	345	3468	99.50	60.6	-15.03	33.7	41.1	19.6
73	72	73	556ASC	Overhead Line	32.6	34.500	6391.1	3417	342	3434	99.50	60.7	-15.65	2.3	8.2	9.6
74	73	SOLAR	556ASC	Overhead Line	32.6	34.500	100.0	-239	0	239	99.99	4.2	169.92	0.0	0.0	0.7
78	73	78	556ASC	Overhead Line	32.5	34.500	28445.2	3654	343	3670	99.56	64.9	-15.43	11.6	41.9	10.2
79	78	542	477ACSR	Overhead Line	32.5	34.500	5072.2	3642	341	3658	99.56	65.0	-16.06	2.4	7.4	10.3
55	53	ER2	3/0ACSR	Overhead Line	33.5	34.500	144.4	0	-22	22	0.00	0.4	82.78	0.0	0.0	0.1
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	33.5	34.500	14794.7	0	-22	22	0.00	0.4	82.78	0.0	0.0	0.1
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.4	12.470	100.0	1008	331	1061	95.00	49.6	-53.98	0.1	0.2	16.4

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS	9	DEFAULT	Switch	0.0	0.0	0.0	104.00

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	36.5	6379.2	2343.8	103.99
NORTHERN AVE TS	390	DEFAULT	Switch	36.4	6256.4	1994.6	100.73
NORTHERN AVE TS	076	DEFAULT	Switch	36.4	6196.4	1796.7	98.92
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	15.5	154.3	58.4	99.28
NORTHERN AVE TS	51	DEFAULT	Switch	34.6	5924.8	1612.1	98.92
NORTHERN AVE TS	077	DEFAULT	Switch	34.6	5803.7	1214.9	95.46
NORTHERN AVE TS	67	DEFAULT	Switch	34.7	5802.5	1218.2	95.43
NORTHERN AVE TS	66	DEFAULT	Switch	28.0	4609.2	854.7	93.48
NORTHERN AVE TS	65	DEFAULT	Switch	28.0	4609.0	854.3	93.47
NORTHERN AVE TS	64	DEFAULT	Switch	19.5	3220.7	531.6	93.47
NORTHERN AVE TS	61	DEFAULT	Switch	19.5	3220.3	531.0	93.46
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	87.7	3220.2	545.4	100.46
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	93.47
NORTHERN AVE TS	75	DEFAULT	Switch	18.1	3220.1	545.2	100.45
NORTHERN AVE TS	77	DEFAULT	Switch	18.2	3166.8	413.5	98.11
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	91.88
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	70.7	1179.8	114.1	93.28
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	87.4	1225.1	51.2	93.11
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	16.0	1213.4	398.0	101.08
NORTHERN AVE TS	81	DEFAULT	Switch	6.3	1101.5	-131.5	98.11
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	62.0	1101.5	-131.5	99.04
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	98.1	869.5	-106.5	99.02
NORTHERN AVE TS	82	DEFAULT	Switch	12.1	2065.3	545.1	98.11
NORTHERN AVE TS	83	DEFAULT	Switch	12.1	2065.2	545.0	98.10
NORTHERN AVE TS	84	DEFAULT	Switch	5.6	947.3	-2.5	95.01
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	53.8	947.3	-2.5	98.19
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	96.4	1031.0	-46.7	98.18
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-14.7	93.45
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	57.8	1388.3	322.7	101.80
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	103.6	1834.4	189.2	101.76
NORTHERN AVE TS	71	DEFAULT	Switch	6.7	1118.6	117.8	93.48
NORTHERN AVE TS	72	DEFAULT	Switch	6.7	1107.4	116.2	92.44
NORTHERN AVE TS	74	DEFAULT	Switch	0.5	-77.8	1.1	92.36
NORTHERN AVE TS	79	DEFAULT	Switch	7.2	1179.9	114.1	91.88
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-7.2	95.44
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	1.3	117.3	126.2	99.09

Load Flow - Summary Report

Study Parameters	
Study Name	C16-0056 System CYME Model 6-18-2020 LTC.sxst
Date	Mon Jul 27 2020
Time	09h17m50s
Project Name	Uprated conductor with regulators and LTC, 137% Load by Ash
Calculation Method	**Voltage Drop - Unbalanced**
Tolerance	0.1 %
Load Factors	Global (P=137.00%, Q=137.00%)
Motor Factors	As defined
Generator Factors	As defined
Shunt Capacitors	On
Sensitivity Load Model	From Library

Total Summary	kW	kvar	kVA	PF(%)
Sources (Swing)	22864.71	11510.12	25598.39	89.32
Generators	239.02	0.03	239.02	100.00
Total Generation	**23103.73**	**11510.14**	**25812.12**	**89.51**
Load read (Non-adjusted)	15227.00	5458.83	16175.92	94.13
Load used (Adjusted)	20731.40	7413.53	22017.07	94.16
Shunt capacitors (Adjusted)	0.00	-3453.58	3453.58	0.00
Shunt reactors (Adjusted)	0.00	0.00	0.00	0.00
Motors	0.00	0.00	0.00	0.00
Total Loads	**20731.40**	**3959.95**	**21106.21**	**98.22**
Cable Capacitance	0.00	-58.56	58.56	0.00
Line Capacitance	0.00	-461.46	461.46	0.00
Total Shunt Capacitance	**0.00**	**-520.02**	**520.02**	**0.00**
Line Losses	2273.02	7141.10	7494.12	30.33
Cable Losses	6.30	3.91	7.41	84.98
Transformer Load Losses	92.52	925.21	929.82	9.95
Transformer No-Load Losses	0.00	0.00	0.00	0.00
Total Losses	**2371.84**	**8070.21**	**8411.53**	**28.20**

Abnormal Conditions	Phase	Count	Worst Condition	Value
Overload	A	2	5	123.92 %
	B	1	5	109.90 %
	C	3	87	111.86 %
Under-Voltage	A	94	86	84.75 %
	B	90	86	87.07 %
	C	61	86	88.75 %
Over-Voltage	A	0	ECHO RIVER TS	104.00 %
	B	0	ECHO RIVER TS	104.00 %
	C	11	84	107.26 %

Annual Cost of System Losses	kW	MW-h/year	k$/year
Line Losses	2273.02	19911.62	1991.16
Cable Losses	6.30	55.17	5.52
Transformer Load Losses	92.52	810.48	81.05
Transformer No-Load Losses	0.00	0.00	0.00
Total Losses	2371.84	20777.28	2077.73

Load Flow - Lines and Cables

Equipment No	From Node	To Node	Equipment Id	Code	V (kVLL)	Base Voltage (kVLL)	Length (ft)	Total Thru Power (kW)	Total Thru Power (kvar)	Total Thru Power (kVA)	Pf avg (%)	IBal (A)	Angle I (º)	Total Loss (kW)	Total Loss (kvar)	Loading (%)
NA1	NORTHERN AVE TS	46	556ASC	Overhead Line	35.9	34.500	100.0	22865	11510	25598	89.17	411.9	-26.72	1.7	6.0	67.7
390	46	TRUSS PLANT	556ASC	Overhead Line	34.3	34.500	27986.1	22863	11504	25594	89.18	411.9	-26.72	462.3	1671.8	67.7
076	TRUSS PLANT	GARDEN RIVER DS HV BUS	556ASC	Overhead Line	33.4	34.500	16346.2	22333	9846	24407	91.34	411.0	-26.81	268.7	971.7	67.5
49	GARDEN RIVER DS HV BUS	GARDEN RIVER T2 LV BUS	556ASC	Overhead Line	12.5	12.470	100.0	457	150	481	95.00	22.3	-53.75	0.0	0.0	4.6
51	GARDEN RIVER DS HV BUS	51	556ASC	Overhead Line	31.8	34.500	34354.4	20366	8279	21984	92.35	380.0	-27.02	485.0	1753.7	64.4
077	51	52	556ASC	Overhead Line	31.7	34.500	1889.0	19881	6574	20940	94.62	380.3	-27.14	26.7	96.5	64.4
52	52	53	556ASC	Overhead Line	31.7	34.500	213.3	19854	6480	20885	94.74	380.3	-27.15	3.0	10.9	64.4
54	53	54	556ASC	Overhead Line	31.7	34.500	147.6	19851	6490	20885	94.72	380.5	-27.20	2.1	7.5	64.4
67	69	54	556ASC	Overhead Line	31.2	34.500	12664.6	19849	6482	20881	94.73	380.5	-27.20	179.1	647.5	64.4
70	69	66	556ASC	Overhead Line	30.8	34.500	9594.3	19670	5852	20522	95.51	380.6	-27.24	135.7	490.7	64.5
66	65	66	556ASC	Overhead Line	30.8	34.500	100.0	15339	4552	16000	95.34	300.8	-28.45	0.9	3.2	52.1
65	BAR RIVER DS HV BUS	65	556ASC	Overhead Line	30.8	34.500	64.0	15338	4549	15998	95.35	300.8	-28.45	0.6	2.1	52.1
64	62	BAR RIVER DS HV BUS	477ACSR	Overhead Line	30.8	34.500	100.0	11383	4197	12132	93.53	228.1	-32.09	0.6	1.8	38.7
63	61	62	3/0ACSR	Overhead Line	30.8	34.500	100.0	11382	4196	12131	93.54	228.1	-32.09	1.7	2.0	78.6
61	VR PRIMARY	61	477ACSR	Overhead Line	30.8	34.500	100.0	11381	4194	12129	93.54	228.1	-32.09	0.6	1.8	38.7
62	VR SECONDARY	62	477ACSR	Overhead Line	33.8	34.500	100.0	0	0	0	-0.01	0.0	78.18	0.0	0.0	0.0
75	VR SECONDARY	75	477ACSR	Overhead Line	33.8	34.500	100.0	11380	4232	12142	93.44	207.6	-32.26	0.5	1.5	35.2
76	75	76	477ACSR	Overhead Line	32.5	34.500	51800.0	11380	4231	12141	93.44	207.6	-32.27	252.9	776.2	35.2
77	76	77	556ASC	Overhead Line	32.5	34.500	100.0	11127	3531	11674	94.99	208.0	-32.61	0.4	1.5	35.0
80	542	77	556ASC	Overhead Line	32.5	34.500	100.0	0	0	0	-0.01	0.0	75.06	0.0	0.0	0.0
86	542	86	556ASC	Overhead Line	30.0	34.500	100.0	4348	732	4409	98.60	84.9	-23.37	0.1	0.3	13.4
8	86	8	556ASC	Overhead Line	23.5	25.000	10.0	4312	377	4329	99.62	106.6	-53.37	0.0	0.0	16.8
7	8	7	556ASC	Overhead Line	23.5	25.000	10.0	4312	377	4329	99.62	106.6	-53.37	0.0	0.0	16.8
89	7	DESBARATS DS T2 LV BUS	336AAC	Overhead Line	23.5	25.000	50.0	4312	377	4329	99.62	106.6	-53.37	0.1	0.2	21.3
11	DESBARATS DS T2 LV BUS	11	28 KV 2/0 CU 100% CN	Cable	23.4	25.000	185.0	4312	377	4328	99.62	106.6	-53.37	0.6	0.3	39.5
13	11	13	336AAC	Overhead Line	23.4	25.000	3500.0	4311	379	4328	99.61	106.6	-53.41	5.6	15.1	21.3
14	13	14	336AAC	Overhead Line	23.3	25.000	5717.0	4306	1426	4536	94.93	111.9	-66.87	9.6	25.9	22.4
15	14	15	35 KV 4/0 CU 100% CN	Cable	23.3	25.000	2345.0	4296	1404	4520	95.05	111.9	-66.92	5.7	3.6	30.4
16	15	16	336AAC	Overhead Line	23.1	25.000	13595.0	4290	1456	4531	94.69	112.4	-67.59	23.1	62.1	22.4
18	17	18	336AAC	Overhead Line	25.1	25.000	25.0	4267	1404	4492	94.99	103.4	-67.69	0.0	0.1	20.4
81	77	81	556ASC	Overhead Line	32.5	34.500	100.0	3214	-72	3214	-97.15	57.6	-13.92	0.0	0.1	11.5
87	81	DESBARATS DS T1 LV BUS	556ASC	Overhead Line	12.7	12.470	100.0	3201	-200	3207	-98.04	146.6	-43.93	0.4	1.2	33.6
82	77	82	3/0ACSR	Overhead Line	32.5	34.500	100.0	7913	3602	8694	90.96	154.5	-39.47	0.8	0.9	50.1
83	82	BRUCE MINES DS HV BUS	3/0ACSR	Overhead Line	30.8	34.500	41600.0	7912	3601	8693	90.97	154.5	-39.47	314.5	384.1	50.1
84	BRUCE MINES DS HV BUS	84	3/0ACSR	Overhead Line	33.9	34.500	100.0	3527	1338	3772	93.22	64.3	-37.38	0.1	0.2	21.9
88	84	BRUCE MINES DS LV BUS	556ASC	Overhead Line	12.9	12.470	39.9	3508	1154	3693	94.99	165.2	-67.38	0.1	0.4	29.9
85	BRUCE MINES DS HV BUS	FEEDER END	556ASC	Overhead Line	33.8	34.500	15088.3	4071	1929	4505	90.36	76.6	-41.80	8.6	31.1	12.2
59	58	VR PRIMARY	477ACSR	Overhead Line	30.6	34.500	24.2	0	-40	40	-0.01	0.8	78.18	0.0	0.0	0.1
2024	ER1	58	477ACSR	Overhead Line	30.6	34.500	9412.4	0	-40	40	-0.01	0.8	78.18	0.0	0.0	0.1
ER1	ECHO RIVER TS	ER1	477ACSR	Overhead Line	30.8	34.500	22193.7	0	-28	28	-0.01	0.5	78.18	0.0	0.0	0.1
68	BAR RIVER DS HV BUS	BAR RIVER DS LV BUS	556ASC	Overhead Line	12.2	12.470	100.0	3935	155	3938	99.06	187.6	-47.27	0.6	1.9	44.1
71	66	71	3/0ACSR	Overhead Line	30.8	34.500	82.0	4196	821	4275	98.12	80.2	-22.88	0.2	0.2	25.9
72	71	72	3/0ACSR	Overhead Line	30.2	34.500	29000.0	4195	821	4275	98.13	80.2	-22.88	58.9	71.9	25.9
73	72	73	556ASC	Overhead Line	30.2	34.500	6391.1	4137	782	4210	98.25	80.3	-23.31	4.0	14.4	12.7
74	73	SOLAR	556ASC	Overhead Line	30.2	34.500	100.0	-239	0	239	99.98	4.6	167.20	0.0	0.0	0.7
78	73	78	556ASC	Overhead Line	30.0	34.500	28445.2	4372	775	4440	98.45	84.8	-22.85	19.8	71.6	13.4
79	78	542	477ACSR	Overhead Line	30.0	34.500	5072.2	4352	738	4414	98.58	84.9	-23.29	4.1	12.6	13.5
55	53	ER2	3/0ACSR	Overhead Line	31.7	34.500	144.4	0	-20	20	-0.01	0.4	80.98	0.0	0.0	0.1
ER2	ER2	ECHO RIVER TS	556ASC	Overhead Line	31.7	34.500	14794.7	0	-20	20	-0.01	0.4	80.98	0.0	0.0	0.1
50	GARDEN RIVER DS HV BUS	GARDEN RIVER T1 LV BUS	556ASC	Overhead Line	12.5	12.470	100.0	1235	406	1300	94.99	60.0	-55.47	0.1	0.3	19.9

Load Flow - Detailed ECHO RIVER

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
ECHO RIVER TS	9	DEFAULT	Switch	0.0	0.0	0.0	104.00

Load Flow - Detailed NORTHERN A

Feeder Id	Section Id	Equipment Id	Code	Loading A (%)	Thru Power A (kW)	Thru Power A (kvar)	VA (%)
NORTHERN AVE TS	386	DEFAULT	Switch	48.5	7838.2	4502.7	103.98
NORTHERN AVE TS	390	DEFAULT	Switch	48.4	7644.0	3885.9	98.84
NORTHERN AVE TS	076	DEFAULT	Switch	48.4	7544.1	3532.9	95.98
NORTHERN AVE TS	49	GARDEN T2	Two-Winding Transformer	18.7	185.3	71.0	99.56
NORTHERN AVE TS	51	DEFAULT	Switch	46.1	7215.7	3305.6	95.98
NORTHERN AVE TS	077	DEFAULT	Switch	46.2	7014.3	2594.2	90.37
NORTHERN AVE TS	67	DEFAULT	Switch	46.2	7012.3	2593.5	90.31
NORTHERN AVE TS	66	DEFAULT	Switch	37.4	5528.1	1872.7	87.14
NORTHERN AVE TS	65	DEFAULT	Switch	37.4	5527.9	1871.9	87.13
NORTHERN AVE TS	64	DEFAULT	Switch	27.5	4049.7	1436.4	87.13
NORTHERN AVE TS	61	DEFAULT	Switch	27.5	4048.8	1435.0	87.10
NORTHERN AVE TS	5	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	123.9	4048.6	1447.1	95.80
NORTHERN AVE TS	62	DEFAULT	Switch	0.0	0.0	0.0	87.12
NORTHERN AVE TS	75	DEFAULT	Switch	25.0	4048.4	1446.6	95.79
NORTHERN AVE TS	77	DEFAULT	Switch	25.1	3949.7	1167.7	91.61
NORTHERN AVE TS	80	DEFAULT	Switch	0.0	0.0	0.0	84.75
NORTHERN AVE TS	86	DESBARATS T2	Two-Winding Transformer	84.6	1408.8	249.1	93.52
NORTHERN AVE TS	13	1200 KVAR 20 KV	Shunt Capacitor	87.8	1459.2	136.8	93.29
NORTHERN AVE TS	17	25 KV 600A 1PH	Regulator	19.1	1441.4	474.3	100.97
NORTHERN AVE TS	81	DEFAULT	Switch	8.3	1355.8	-63.4	91.61
NORTHERN AVE TS	81	DESBARATS T1	Two-Winding Transformer	76.8	1355.7	-63.4	102.36
NORTHERN AVE TS	87	1200 KVAR 7 KV	Shunt Capacitor	104.8	1106.4	-55.1	102.33
NORTHERN AVE TS	82	DEFAULT	Switch	17.5	2593.9	1231.1	91.61
NORTHERN AVE TS	83	DEFAULT	Switch	17.5	2593.7	1230.9	91.60
NORTHERN AVE TS	83	34.5KV_200A_1PH_COOPER_REGULATOR_60HZ	Regulator	78.9	2485.1	1114.2	95.36
NORTHERN AVE TS	84	DEFAULT	Switch	7.7	1209.4	509.1	95.36
NORTHERN AVE TS	84	BRUCE MINES T1	Two-Winding Transformer	72.9	1209.4	509.1	103.43
NORTHERN AVE TS	88	1200 KVAR 7 KV	Shunt Capacitor	0.0	1362.6	448.3	103.42
NORTHERN AVE TS	85	DEFAULT	Switch	0.0	0.0	0.0	94.91
NORTHERN AVE TS	58	DEFAULT	Switch	0.1	0.0	-12.7	87.09
NORTHERN AVE TS	56	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	68	BAR RIVER T1	Two-Winding Transformer	62.0	1478.2	435.5	96.28
NORTHERN AVE TS	68	1200 KVAR 7 KV	Shunt Capacitor	92.7	1954.3	273.0	96.23
NORTHERN AVE TS	71	DEFAULT	Switch	8.9	1359.9	280.9	87.15
NORTHERN AVE TS	72	DEFAULT	Switch	8.9	1340.4	267.3	85.65
NORTHERN AVE TS	74	DEFAULT	Switch	0.5	-77.8	0.8	85.51
NORTHERN AVE TS	79	DEFAULT	Switch	9.4	1408.9	249.2	84.75
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	-6.4	90.33
NORTHERN AVE TS	081	DEFAULT	Switch	0.0	0.0	0.0	104.00
NORTHERN AVE TS	555	GARDEN T1	Two-Winding Transformer	1.6	143.2	156.3	100.48

D

Appendix D

CIMA+ Engineering Estimate

CIMA+

CIMA+ Canada

555 Edgewater Road
Sudbury, Ontario
P3G 1J7
T: (705) 470-3090 x 101

4096 Meadowbrook Dr., Unit 112
London, Ontario
N6L 1G4
T: (519) 203-1222

C16-0056 East SaultDist System
Detailed Engineering Estimate - 35km of Pole Line CLASS 3

Algoma Power

SCOPE: See Below

Rate Sheet (A, B, C)	A
VP/Principal	$206
Senior Eng./ Associate	$184
Eng./ Project Manager	$172
Inter. Eng/ Tech	$159
JR. Eng./ Tech.	$131
Drafting	$131
Mileage rate	$0.77
Small Vehicle	$17/hr
Daily Expense Estimate	$375

Task	VP/ Principal	Senior Eng./ Associate	Eng./ Project Manager	Inter. Eng/ Tech	JR. Eng./ Tech.	Drafting	Cost	Travel	Expenses	Total
Topographical Survey - assumed to be by others, but estimated at $100k							$ -		$ 100,000	$ 100,000
							$ -			$ -
Field data collection for approximately 468 poles							$ -			$ -
4 staff assigned at an average of 50 poles per day x 12hr/day	16			500			$ 82,606			$ 82,606
OT				90			$ 21,414			$ 21,414
ATVs rentals (estimated at $2000 each per week with trailer and truck)							$ -		$ 4,000	$ 4,000
fuel/oil and incidentals							$ -		$ 3,000	$ 3,000
Accommodations for 4 staff x 11 days							$ -		$ 16,500	$ 16,500
Travel to/From SSM for 4 staff (London-SSM-Return)				240			$ 38,069		$ 5,000	$ 43,069
							$ -			$ -
Process and file field data				120			$ 19,034			$ 19,034
							$ -			$ -
Pole modelling and design (average of 2 hr per pole)	40			940			$ 157,343			$ 157,343
Drafting						250	$ 32,703			$ 32,703
							$ -			$ -
Pole staking and layout (in conjuction with orginal surveyor)	12			190			$ 32,610		$ 15,000	$ 47,610
OT				40			$ 9,517			$ 9,517
CIMA staff travel to/from SSM				120			$ 19,034		$ 1,200	$ 20,234
accommodations for two for 8 days							$ -		$ 2,520	$ 2,520
ATVs rentals (estimated at $500 each per week with trailer and truck)							$ -		$ 1,000	$ 1,000
							$ -			$ -
							$ -			$ -
* HST not included in proposal	68	0	0	2240	0	250			Sub-total	$ 560,550
									Contingency (25%)	$ 140,137
									Maximum Upset Price	**$ 700,687**

Total Hours	2558
Average Hourly Rate	274

Percentage Engineering/estimated Construction of $7.95M 8.81%

E

Appendix E

Algoma Power 34.5kV Single Line Diagram

CIMA+

Sub-Transmission Feeder Section Legend

Name	Description
NA1	*NORTHERN AVE. FEEDER NO.1*
GR1	*GARDEN RIVER FEEDER NO.1*
ER1	*ECHO RIVER FEEDER NO.1*
ER2	*ECHO RIVER FEEDER NO 2*
DB1	*DESBARATS FEEDER NO.1*
3600	*ST. JOSEPH ISLAND 25KV EXPRESS FEEDER 3600*