Q. (Reference Application, 3.1 Gander-Twillingate Transmission System Planning Study, page 1) Reference is made to Newfoundland Power's 2019 Capital Budget Application, Central Newfoundland System Planning Study.

a) Did this study consider the Gander-Twillingate transmission system?

b) Please file a copy of this study for the record.

A. a) The *Central Newfoundland System Planning Study* filed as part of Newfoundland Power's *2019 Capital Budget Application* assessed alternatives for replacing 66 kV transmission lines 101L and 102L. These transmission lines were built in the 1950s and ran between Grand Falls and Gander substations, providing connections for Rattling Brook, Notre Dame Junction, and Roycefield substations. The scope of the *Central Newfoundland System Planning Study* was limited to addressing the 66 kV transmission network between Grand Falls-Windsor and Gander that had reached end of life. It therefore did not include any assessment pertaining to the downstream 66 kV network supplying the Gander - Twillingate area.

b) See Attachment A.

ATTACHMENT A:

Central Newfoundland System Planning Study
July 2018

Central Newfoundland System Planning Study

July 2018

Prepared by:

Jonathan O'Reilly
Robert Cahill, Eng. L.

Table of Contents

1.0 Introduction

This study was initiated as a result of transmission lines 101L and 102L requiring replacement. These two transmission lines form a 66 kV system supplying customers from Norris Arm South to Birchy Bay in Central Newfoundland, including the town of Lewisporte. Both lines combined are over 90 km in length and are in excess of 60 years old. Inspections have identified that both lines are in deteriorated condition and have reached end of life.[1]

Due to the high capital costs required to rebuild both existing 66 kV transmission lines other alternatives were examined to determine the least cost alternative to address their replacement. This study identifies the capital projects required to provide safe, reliable, least cost electrical service to this Central Newfoundland area.

2.0 Background

The electrical transmission system in Central Newfoundland consists of both 66 kV and 138 kV transmission lines.

The 66 kV transmission lines run between Grand Falls ("GFS') Substation and Gander ("GAN") Substation. This 66 kV system includes 2 transmission lines, 101L and 102L, that interconnect Rattling Brook ("RBK"), Notre Dame Junction ("NDJ") and Roycefield ("RFD") substations. These lines were constructed in the late 1950's to create an integrated electrical system in Central Newfoundland by interconnecting the Rattling Brook hydro development to the isolated electrical distribution systems in Grand Falls, Lewisporte and Gander. Today, the 66 kV system supplies electrical service to approximately 5,000 customers in the communities of Norris Arm South, Lewisporte and surrounding areas.

After the construction of the Bay d'Espoir hydroelectric development in 1967, additional transmission infrastructure was required to accommodate the growing demand for electricity in Central Newfoundland. This led to the establishment of a 138 kV transmission system in Central Newfoundland originating from Stoney Brook ("STY") Terminal Station that included TL210, a 138 kV transmission line constructed by Newfoundland and Labrador Hydro to connect Glenwood ("GLN") and Cobb's Pond ("COB") substations. The expansion of the 138 kV transmission system continued throughout the 1970's and early 1980's as demand for electricity increased. In 1981 a 138 kV transmission line, 136L, was constructed between Bishop Falls ("BFS") and COB substations.[2]

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[1] A condition assessment of 101L and 102L is included as Appendix C of the *2019 Transmission Line Rebuild* report.

[2] BFS Substation is connected to STY Terminal Station by 138 kV transmission line 133L.

Figure 1 illustrates the current configuration and routing of both the 66 kV and 138 kV Central Newfoundland transmission systems.

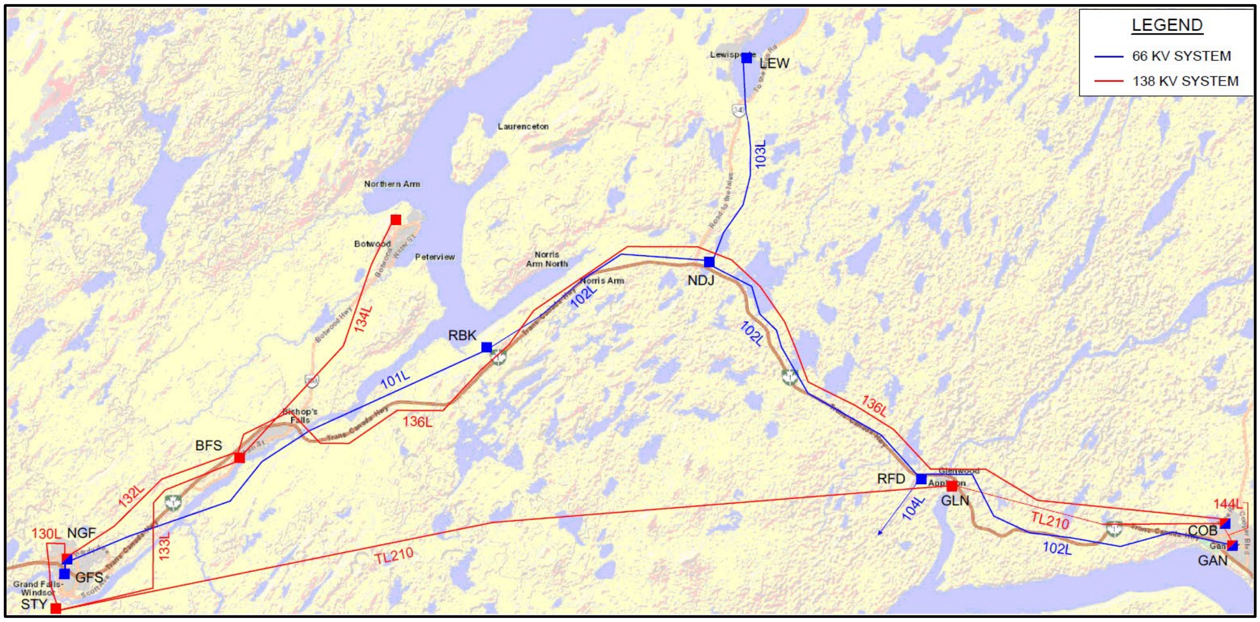

Figure 1: Central Newfoundland Existing System

2.1 Central Newfoundland 66 kV Transmission System

Transmission line 101L was originally constructed in 1957 and is approximately 32.5 km in length. 101L provides a 66 kV link between GFS and RBK substations. 101L leaves GFS Substation and runs east through the Town of Grand Falls-Windsor, along the Trans-Canada Highway to Route 351 and onto RBK Substation.

Transmission line 102L was originally constructed in 1958, is approximately 61 km in length and is divided into three sections. The first section is approximately 17 km and runs from RBK Substation to NDJ Substation. The second section of 102L is approximately 20 km and runs from NDJ Substation to RFD Substation.[3] The third section of 102L is approximately 24 km and runs from RFD Substation to GAN Substation.

Transmission line 103L was originally constructed in 1973, is approximately 14 km in length and provides a 66 kV radial transmission feed from NDJ Substation to Lewisporte ("LEW") Substation.[4]

[3] RFD Substation and the associated 104L radial transmission line were constructed in 1997 to provide electrical service to Beaver Brook Antimony Mine.

[4] Prior to 1973 the Town of Lewisporte was supplied by a distribution feeder from RBK Substation.

2.2 Transmission Line 136L

Transmission line 136L was originally constructed in 1981, is approximately 81.0 km in length and provides a 138 kV link between BFS and COB substations. 136L leaves BFS Substation and generally follows the Trans-Canada Highway to approximately 6.0 km west of the Town of Gander. It then continues cross country for approximately 7.5 km until it enters COB Substation. Most of the structures on 136L are of H-Frame construction.

2.3 System Reliability

Newfoundland Power calculates its reliability performance according to the Canadian Electricity Association ("CEA") guidelines.[5] The existing electrical system reliability for the customers served by the 66kV Central Newfoundland transmission system are at a satisfactory level as indicated by historical reliability statistics. The overall 5-year average SAIDI for the customers supplied from LEW and RBK substations is 4.93 which is comparable with the Company 5-year average of 5.03 for similar rural substations.[6] However, both 66 kV transmission lines supplying these substations have been in service for approximately 60 years and have reached the point where continued maintenance cannot guarantee the provision of safe reliable service into the future.

3.0 Technical Evaluation

The focus of Newfoundland Power's system planning function is to avoid or minimize equipment overloading and provide adequate system voltages to ensure a reliable electricity supply to customers. This process typically involves engineering studies to identify and evaluate cost effective, technically viable upgrade alternatives where necessary. The technical evaluation criteria used to evaluate the alternatives include the minimum and maximum allowable substation voltage levels for both normal and contingency system conditions.[7] The criteria also includes normal and contingency loading limits for substation transformers and transmission lines during summer and winter conditions.[8]

Each potential alternative is examined under normal and contingency system conditions. The examination was completed using zero projected load growth.[9] However, a sensitivity analysis

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5 The CEA's recommended reporting standard is IEEE Std 1366 – 2012, contained within the *IEEE Guide for Electric Power Distribution Reliability Indices*. All reliability data calculated by the Company follows this reporting standard.

6 "SAIDI" denotes System Average Interruption Duration Index. It is a standard metric used to measure the duration of outages experienced by customers. SAIDI is calculated by dividing the total number of customer outage hours by the total number of customers served. Newfoundland Power calculates SAIDI in accordance with CEA guidelines.

7 Contingency is defined as the loss of any single system component, possible multiple component failure or cold load pickup.

8 See Appendix A for Technical Evaluation Criteria.

9 The current 5 year forecast for the study area shows declining customer usage with uncertainty surrounding long term growth.

was completed to evaluate the impact of potential load growth on each of the selected alternatives.[10]

4.0 Development of Alternatives

Three alternatives have been developed and evaluated to meet the long term electrical transmission system requirements for the customers served from RBK and LEW substations.[11]

The section of 102L that connects GAN Substation to RFD Substation was not addressed in alternatives 2 and 3 which involve transferring LEW and RBK substations to the 138 kV transmission system.[12] Beaver Brook Antimony Mine is the only customer supplied from RFD Substation and has been idled since 2013 with minimal electrical load requirements.[13] If the mine was to re-establish operations Newfoundland Power would assess alternatives to provide reliable service to this customer.

The description of each alternative below includes estimates for all of the capital costs involved including substation and transmission line upgrades. See Appendix B for an illustration of each alternative.

4.1 Alternative 1

- In 2019, rebuild the 32.5 km section of 101L transmission line between RBK Substation and GFS Substation.
- In 2020, rebuild the 17.0 km section of 102L transmission line between RBK Substation and NDJ Substation.
- In 2021 rebuild the 20.5 km section of 102L transmission line between NDJ Substation and RFD Substation.
- In 2021 rebuild the 23.5 km section of 102L transmission line between RFD Substation and GAN Substation.

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10 Results of the analysis can be found in Section 5.3 of this study.

11 The 3 alternatives evaluated are the only reasonable alternatives. Other alternatives, including upgrading NDJ Substation, were preliminarily evaluated and ruled out based on the significantly higher capital costs that would be associated with the alternative.

12 For Alternative 1, 102L will be rebuilt in 2021 and will continue to supply RFD substation at 66 kV.

13 The existing 66 kV structures from GAN Substation to RFD Substation will remain in place to serve the minimal electrical load requirements of the Beaver Brook Antimony Mine for Alternatives 2 and 3.

Table 1 shows the capital costs estimated for Alternative 1.[14]

Table 1
Alternative 1 Capital Costs
($000)

Year	Item	Cost
2019	Rebuild 32.5 km of 101L transmission line.	$5,582
2020	Rebuild 17.0 km of 102L transmission line between RBK Substation and NDJ Substation.	$2,998
2021	Rebuild 20.5 km of 102L transmission line between NDJ Substation and RFD Substation.	$3,713
2021	Rebuild 23.5 km of 102L transmission line between RFD Substation and GAN Substation.	$4,256
	Total	**$16,549**

4.2 Alternative 2

- In 2019, build a new 14.0 km, 138 kV transmission line extension from 136L to LEW Substation.
- In 2019, convert LEW Substation from 66 kV to 138 kV which would include the following; replace the existing 25 MVA, 66/25 kV LEW-T1 transformer with a new 25 MVA, 138/25 kV transformer, install a new 138 kV steel bus structure and two new 138 kV breakers, install a new 25kV steel bus structure and relocate existing feeder terminations.[15]
- In 2020, rebuild 14.0 km of 103L as a 138 kV transmission line extension from 136L to LEW Substation. This will involve splitting the existing 136L into two transmission lines, one from GAN Substation to LEW Substation and one from BFS Substation to LEW Substation.[16]
- In 2021, rebuild the 32.5 km of transmission line 101L from GFS Substation to RBK Substation.

[14] This alternative only involves the cost to rebuild 101L and 102L. The future capital costs associated with the rebuild of 103L and refurbishment of LEW Substation, which are both approaching 45 years in service, are not included in Alternative 1. In Alternatives 2 and 3 LEW Substation is being refurbished in 2019 and 103L will be rebuilt in 2020. Addressing the age and deterioration of LEW Substation and 103L at a future date will have the effect of increasing the overall capital costs associated with Alternative 1.

[15] See Appendix C for LEW Substation Single Line - Conversion to 138 kV.

[16] Splitting the existing 136L into two transmission lines, one from GAN Substation to LEW Substation and one from BFS Substation to LEW Substation, and terminating these lines with breakers at LEW Substation, will provide the option of energizing LEW Substation from either the Gander or Bishop Falls ends. This additional flexibility will provide reliability benefits for both planned and unplanned outages.

Table 2 shows the capital costs estimated for Alternative 2.[17]

Table 2
Alternative 2 Capital Costs
($000)

Year	Item	Cost
2019	Build a new 14.0 km, 138 kV transmission line extension from 136L to LEW Substation.	$2,322
2019	Convert LEW Substation from 66 kV to 138 kV.	$4,164
2020	Rebuild 14.0 km of 103L transmission line to 138 kV standards. Split 136L into two 138 kV transmission lines.	$2,383
2021	Rebuild 32.5 km section of 101L from GFS Substation to RBK Substation.	$5,886
	Total	**$14,755**

4.3 Alternative 3

- In 2019, build a new 14.0 km, 138 kV transmission line extension from 136L to LEW Substation.
- In 2019, convert LEW substation from 66 kV to 138 kV which would include the following; replace the existing 25 MVA, 66/25 kV LEW-T1 transformer with a new 25 MVA, 138/25 kV transformer, install a new 138 kV steel bus structure and two new 138 kV breakers, install a new 25kV steel bus structure and relocate existing feeder terminations.[18]
- In 2020, rebuild 14.0 km of 103L as a 138 kV transmission line extension from 136L to LEW Substation. This will involve splitting the existing 136L into two transmission lines, one from GAN Substation to LEW Substation and one from BFS Substation to LEW Substation.[19]
- In 2021, construct two new 1.4 km 138 kV transmission lines from 136L to RBK Substation.

[17] Alternative 2 involves the decommissioning of 102L from RBK Substation to RFD Substation, NDJ Substation, 103L and the 66 kV portions of LEW Substation.
[18] See Appendix C for LEW Substation Single Line - Conversion to 138 kV.
[19] Similar to Alternative 2, splitting the existing 136L into two transmission lines provides additional flexibility and reliability benefits for both planned and unplanned outages.

- In 2021, install a new 25 MVA 138 kV/66 kV system transformer at RBK Substation and install a 138 kV bus structure with two new 138 kV breakers.[20]

Table 3 shows the capital costs estimated for Alternative 3.[21]

Table 3
Alternative 3 Capital Costs
($000)

Year	Item	Cost
2019	Build a new 14.0 km, 138 kV transmission line extension from 136L to LEW Substation.	$2,322
2019	Convert LEW Substation from 66 kV to 138 kV.	$4,164
2020	Rebuild 14.0 km of 103L transmission line to 138 kV standards. Split 136L into two 138 kV transmission lines.	$2,383
2021	Build two new 138 kV transmission lines to RBK from 136L. Split 136L into two 138 kV transmission lines.	$507
2021	Install 138 kV system transformer, structure and 2 new 138 kV breakers at RBK Substation.	$4,265
	Total	**$13,641**

5.0 Evaluation of Alternatives

Each of the 3 alternatives have been evaluated to determine the alternative that best meets the long term electrical transmission system requirements of Central Newfoundland area. These alternatives were evaluated using economic and sensitivity analysis as well as technical evaluation to determine the lowest possible cost solution consistent with safe and reliable service. The economic analysis evaluated the value of each alternative in net present dollars. The technical evaluation used power system analysis software to evaluate each alternative to determine possible operational constraints and/or reliability impacts to customers. The sensitivity analysis included an evaluation of changes to the cost of system losses and effect of future system load growth for each alternative.

20 See Appendix C for RBK Substation Single Line - 138 kV Substation Expansion.
21 Alternative 3 involves the decommissioning of 101L, 102L from RBK Substation to RFD Substation, NDJ Substation, 103L and the 66 kV portions of LEW Substation.

5.1 Economic Analysis

In order to compare the economic impact of the alternatives, a Net Present Value ("NPV") calculation of customer revenue requirement was completed for each alternative. Capital costs from 2019 to 2021 were converted to the customer revenue requirement and the resulting customer revenue requirement was reduced to a NPV using the Company's weighted average incremental cost of capital.[22] The NPV analysis also accounts for the salvage value of the existing LEW-T1 removed from service when applicable.

The cost of annual system losses for each alternative, calculated at a marginal rate of \$0.050/kWh, is also included in the NPV calculation.[23] Sensitivity analysis of the impact of the cost of system losses at other marginal rates were also completed for each alternative and are included in Section 5.3.

Table 5 shows the NPV of customer revenue requirement for each alternative under the base case load forecast.

Table 5
Net Present Value Analysis
(\$000)

Alternative	NPV
1	29,908
2	25,617
3	24,229

Alternative 3 has the lowest NPV of customer revenue requirement. As a result, Alternative 3 is recommended as the most appropriate alternative from an economic perspective.

5.2 Technical Evaluation

In order to complete the technical evaluation of each alternative, load flows were completed under normal and contingency system conditions using power system analysis software. Each alternative was also evaluated to determine possible operational constraints and/or reliability impacts to customers.

The evaluation concluded that all 3 alternatives will have improved system operation capabilities to provide greater overall reliability to customers. Alternatives 2 and 3 have the greatest

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22 Annual operating maintenance cost differences for each alternative are negligible and do not impact the NPV analysis. As a result, the NPV analysis does include future operating maintenance costs.

23 An estimate of the marginal cost of production during the transition period prior to the Muskrat Falls project completion is 5.0 ¢/kWh for energy in 2019 and 5.3 ¢/kWh for energy in 2020 as per Hydro's 2017 General Rate Application responses to Request for Information CA-NLH-081 and CA-NLH-258 respectively.

potential positive impact on customer reliability due to the addition of a second transmission supply to the approximate 4,400 customers supplied from LEW Substation. Alternative 3 provides additional positive reliability impacts to the 750 customers served from RBK Substation compared to Alternative 2 due to the looped 138 kV transmission supply to RBK Substation included in Alternative 3.

Alternative 3 will provide enhanced electrical service reliability to customers. This supports the conclusion of the economic analysis.

5.3 Sensitivity Analysis

A sensitivity analysis was completed to evaluate (i) changes in the cost of system losses and (ii) the impact of potential load growth on the Central Newfoundland system.

5.3.1 System Losses

In order to compare the impact of changes in system losses for each alternative, a system loss cost calculation was completed for each alternative at marginal rates of \$0.05/kWh ± \$0.02/kWh. To further test the impact of the cost of losses for each alternative, each alternative was evaluated with the cost of losses excluded (i.e. a marginal rate of \$0/kWh).

Table 6 shows the NPV of customer revenue requirement for each alternative including the cost of system losses at \$0.070/kWh, \$0.030/kWh and \$0/kWh marginal cost scenarios.

Table 6
Sensitivity Analysis – System Losses
(\$000)

Alternatives	\$0.070/kWh NPV	\$0.030/kWh NPV	\$0/kWh NPV
1	34,430	25,385	18,601
2	29,209	22,027	16,639
3	27,774	20,684	15,366

Alternative 3 has the lowest NPV of customer revenue requirement including the cost of system losses at \$0.070/kWh, \$0.030/kWh and \$0/kWh marginal cost scenarios and supports the conclusion of the economic analysis.

5.3.2 Load Growth

In order to compare the impact of load growth, each alternative was analyzed to determine how much extra load growth could be supplied without violating any of the technical criteria. The analysis showed that all 3 alternatives could accommodate over 40% additional load growth under normal conditions while maintaining reliable service to customers. Under contingency conditions Alternatives 1 and 3 could both accommodate approximately 10% additional load growth. Alternative 2 could accommodate approximately 7% additional load growth under contingency conditions.

Alternative 3 provides available system capacity for future load growth and supports the conclusion of the economic analysis.

6.0 Recommendation

The economic analysis performed in Section 5.1 of this study indicates Alternative 3 is the least cost alternative that meets all of the required technical criteria. The sensitivity analysis performed in Section 5.3 for both system losses and potential future load growth supports the conclusion of the economic analysis. The technical evaluation of each alternative indicates that Alternative 3 will provide long term reliable electrical service to customers currently supplied by the existing 66 kV transmission system.

Based on this evaluation, Alternative 3 is recommended as the best alternative to meet the long term electrical transmission system requirements of the Central Newfoundland area at the lowest possible cost consistent with safe and reliable service.

Table 7 shows the 3-year project description and estimated costs for the recommended alternative.

Table 7
Recommended Capital Project Costs
($000)

Year	Item	Cost
2019	Build a new 14.0 km, 138 kV transmission line extension from 136L to LEW Substation.	$2,322
2019	Convert LEW Substation from 66 kV to 138 kV.	$4,164
2020	Rebuild 14.0 km of 103L transmission line to 138 kV standards. Split 136L into two 138 kV transmission lines.	$2,383
2021	Build two new 138 kV transmission line extensions to RBK from 136L.	$507
2021	Install 138 kV transformer, structure and 2 new 138 kV breakers at RBK Substation.	$4,265
	Total	**$13,641**

Appendix A
Technical Evaluation Criteria

Technical Evaluation Criteria

Voltage Criteria

Minimum allowable voltage levels for all substation transmission buses during normal system conditions is 0.95 p.u. (114 V at 120 V base) and during contingency conditions is 0.90 p.u. (108 V on 120 V base).

The minimum allowable distribution system bus voltage is 0.967 p.u. (116 V on 120 V base).

Maximum allowable voltage level on all buses for normal and contingency system conditions is 1.054 p.u. (126.5 V on 120 V base).

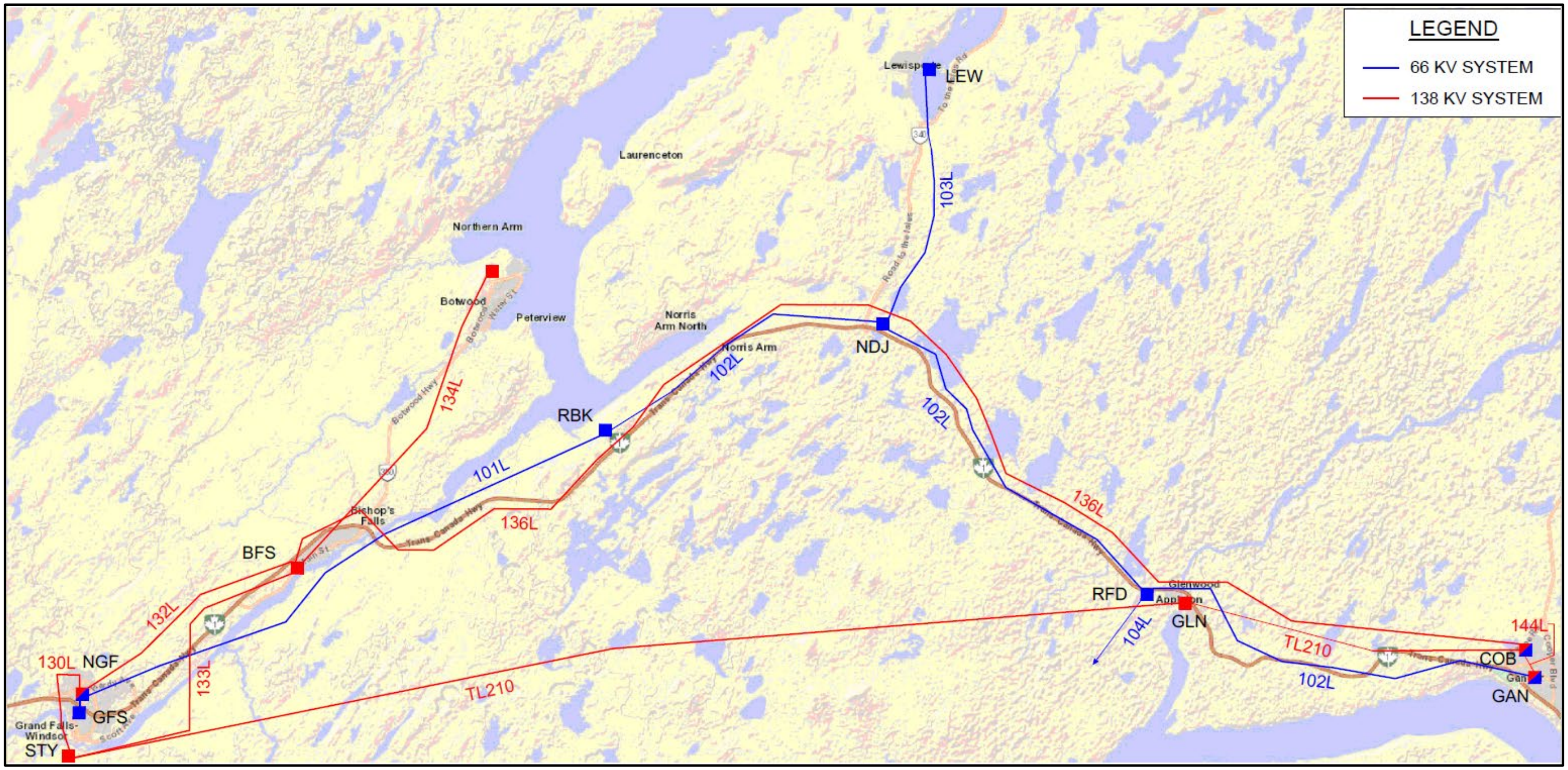
Transformer Loading Criteria

Transformer loading limits are 100% of rated nameplate capacity for normal system conditions. Under contingency conditions the system transformers are permitted to be loaded up to 130% of the nameplate rating during winter conditions.

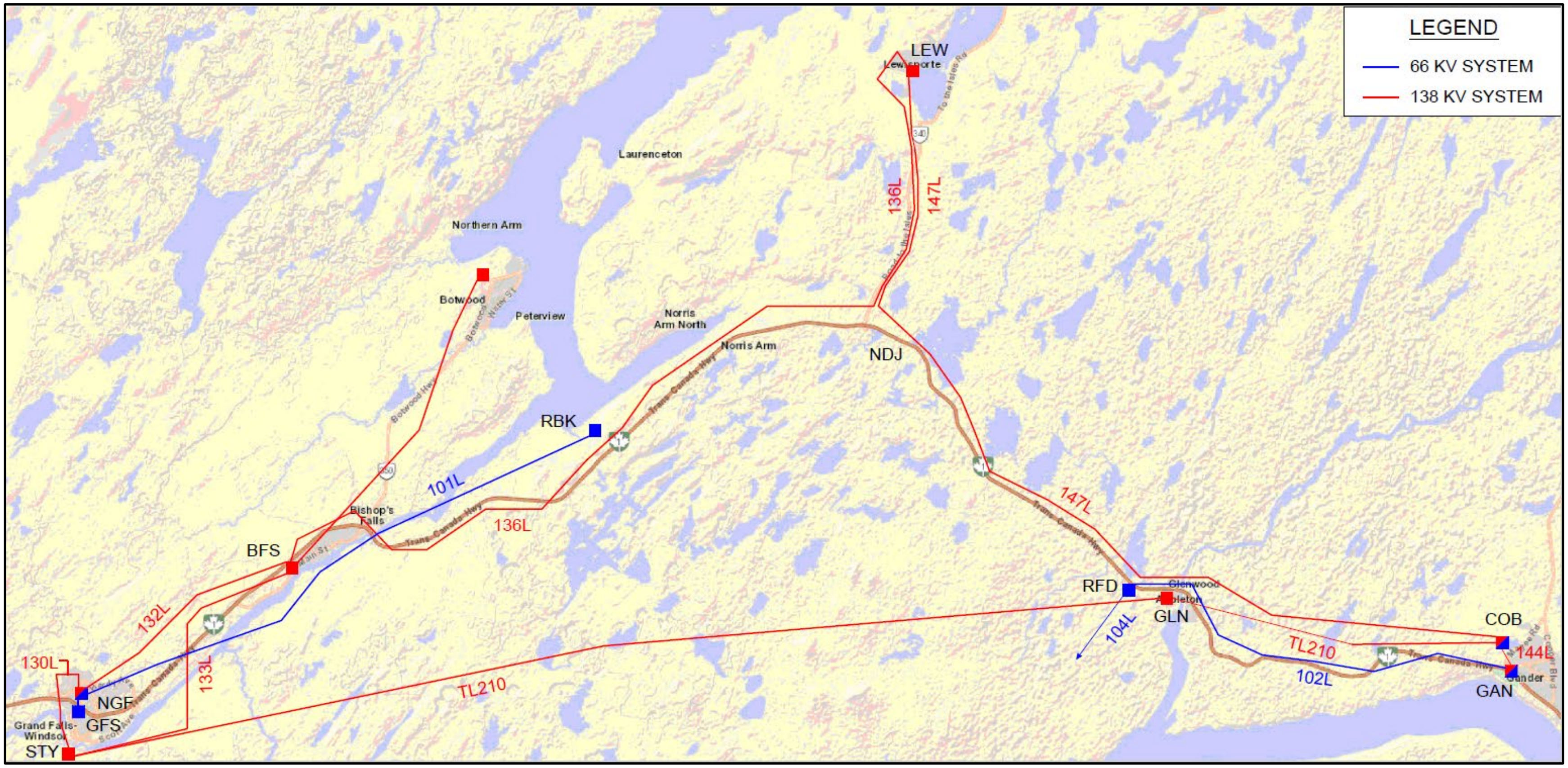
Transmission Line Loading Criteria

Transmission line loading limits are 100% of rated line capacity. Loading limits for transmission lines during the winter are based on a conductor rating at 75°C conductor temperature with 0°C ambient temperature at 2 ft/s (0.61 m/s) wind speed. During the summer the loading limits are based on 75°C conductor temperature with 25°C ambient temperature at 2 ft/s (0.61 m/s) wind speed.

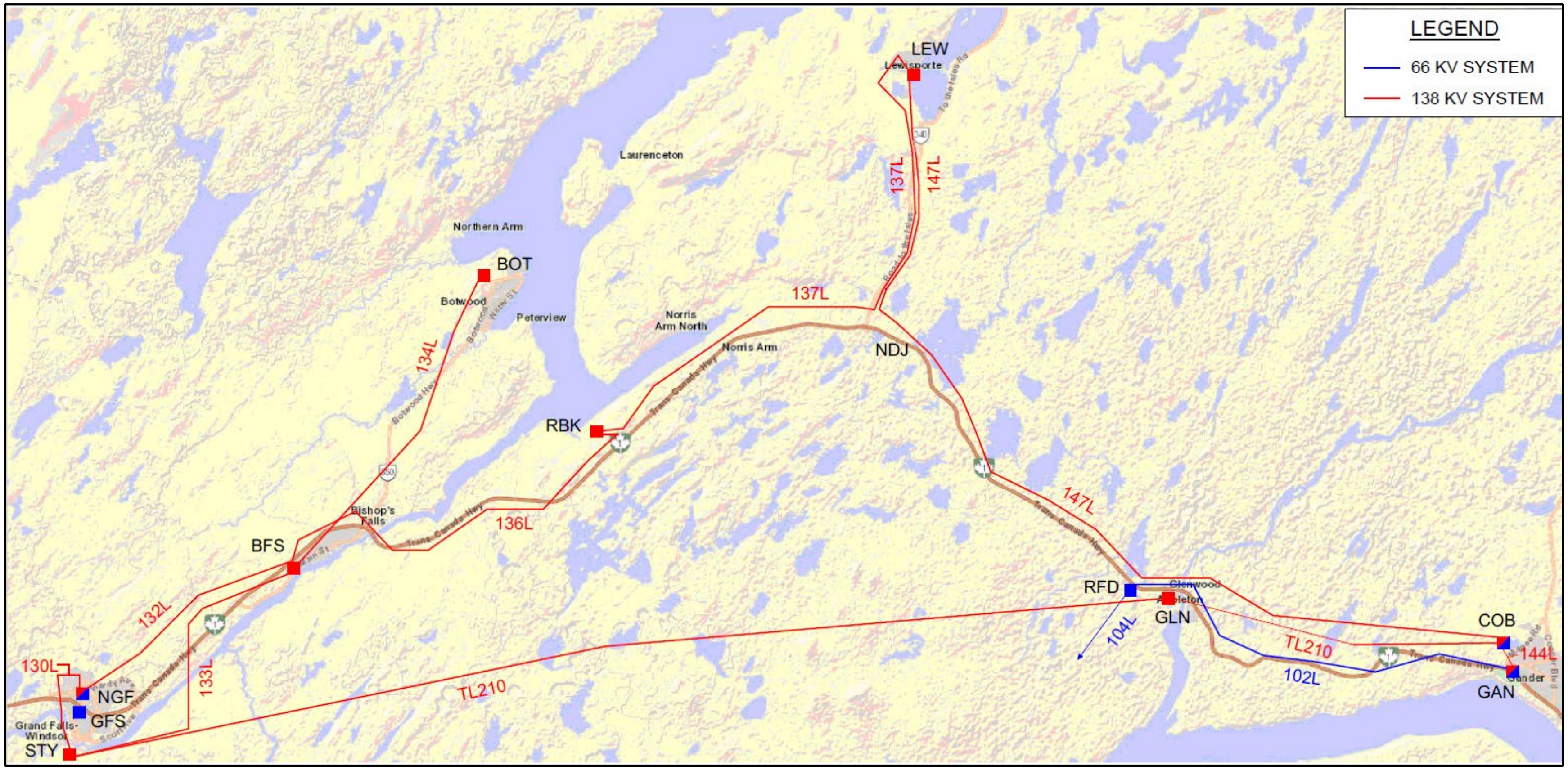
Appendix B
Illustrations of Alternatives



Alternative 1

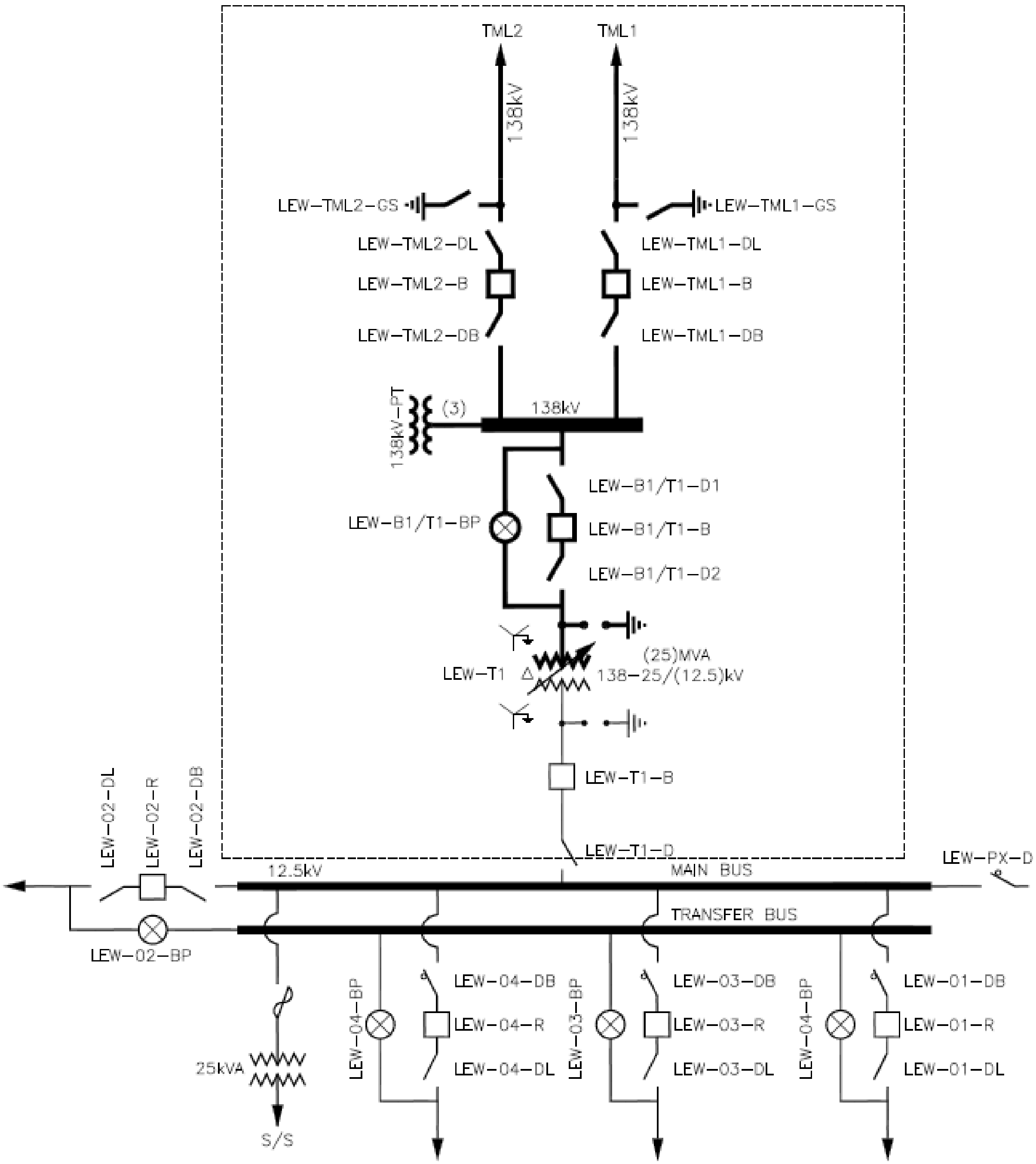


Alternative 2
(New 138 kV Line Designations Included)

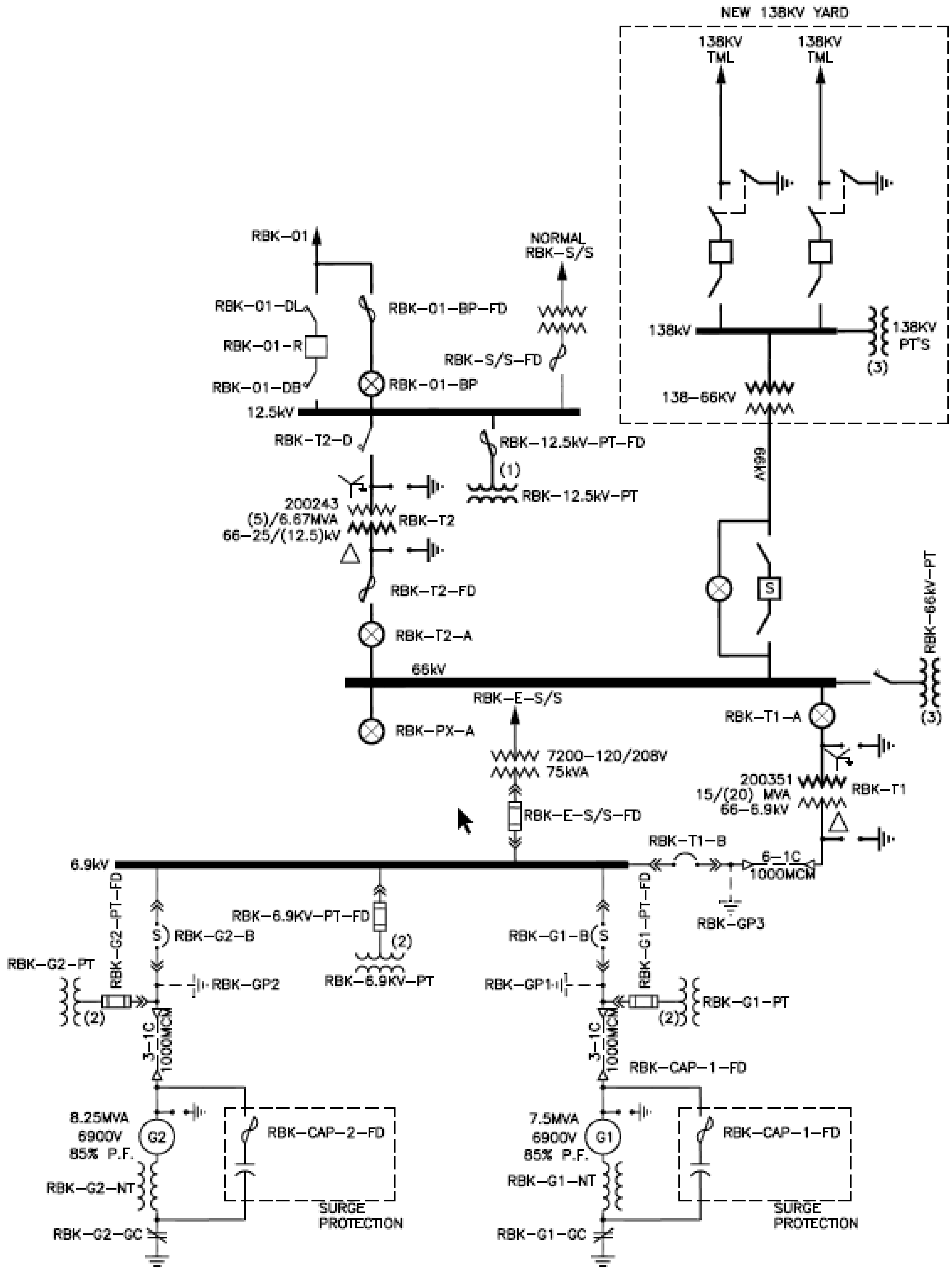


Alternative 3
(New 138 kV Line Designations Included)

Appendix C
Revised Substation Single Line Diagrams



LEW Substation Single Line - Conversion to 138 kV (Alternatives 2 and 3)



RBK Substation Single Line - 138 kV Substation Expansion (Alternative 3)