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Cathedral Square Substation Contingency Plans Using Probabilistic Risk Assessment

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Summary: This report provides a probabilistic risk assessment for the Metro System that investigates the reliability impact due to utilizing different contingency plans for Cathedral Square substation (CSQ). This study focuses on the reliability analysis of the network in close proximity to the CSQ substation rather than focusing on the CSQ substation alone. The socio-economic factor is taken into account in order to identify the most cost-effective planning option.

1. Introduction

Cathedral Square substation supplies load with two transformers fed by three 230kV underground cables (2L31, 2L32 and 2L33). There is a considerable concern in regard to a reliability of Cathedral Square Substation due to a uniqueness of this underground substation serving 30% of all downtown loads. A loss of any transformer will involve a considerable time (up to 2 years) to replace it. A contingency plan should be considered for an outage event that has a low probability of occurrence but results in a high consequence if it occurs. A contingency plan, therefore, is needed for the CSQ substation. This report investigates the impact of different contingency plans associated with their capital and risk costs.

2. Contingency Plans

Three contingency plans for CSQ substation were proposed. The first two contingency plans can be achieved by either cutting 2L31 or 2L32, and then connecting to the 150 MVA mobile transformer up top of the substation. The third contingency plan can be done by adding the third transformer. All the three contingency plans considered in the report are summarized as follows:

Option 1: Cutting 2L31 and connecting to the 150MVA mobile transformer and routing low voltage cables to feeder sections.
Option 2: Cutting 2L32 and connecting to the 150MVA mobile transformer and routing low voltage cables to feeder sections..
Option 3: Adding the third transformer (no transmission network modification).

3. Reliability Study Results

The Metro System network as shown in Appendix A is modeled and used in this study in order to investigate the reliability impact of the whole Metro System associated with different contingency plans. The study considers years 2008 to 2017 load forecast, which respectively has the peak load at 3700.24 MW to 4691.5 MW. The annual load duration curve (based on 8760 hours; hourly average) for the Metro area is obtained from the PI system, and is incorporated in the study by dividing into 20 load step levels. The composite generation and transmission reliability analysis software designated as MECORE Program [1] is used in the study. The Expected Energy Not Supplied (EENS) from years 2008 – 2017 of the Metro System associated with the three options of a contingency plan are shown in Table 1. The results shown in Table 1 are also graphically presented in Figure 1.

Table 1: Expected Energy Not Supplied (EENS) in MWh/year for the three options of a contingency plan.

Year	Option 1	Option 2	Option 3
2008	7840	4878	4713
2009	8162	5073	4804
2010	8484	5268	4895
2011	8806	5463	4986
2012	9128	5658	5077
2013	9450	5853	5168
2014	9772	6048	5259
2015	10094	6243	5350
2016	10416	6438	5441
2017	10738	6636	5530

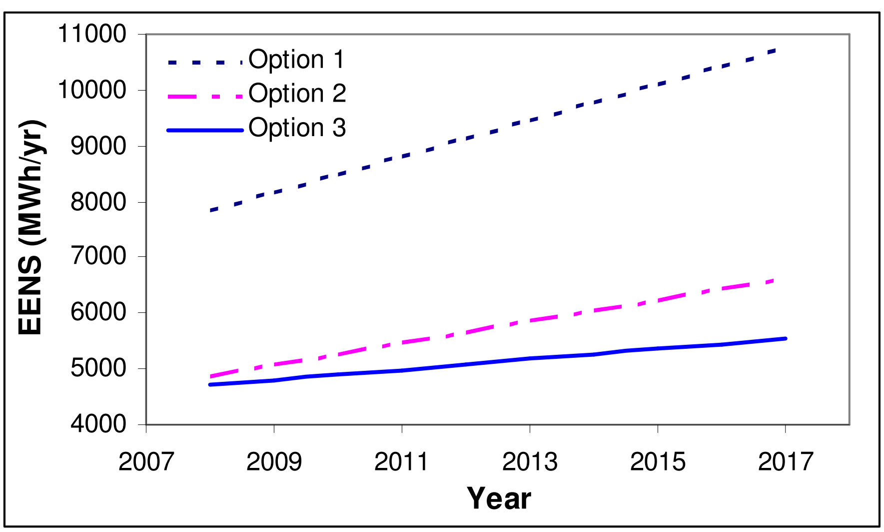


Figure 1: Expected Energy Not Supplied (EENS) for the three options of a contingency plan.

Figure 1 indicates that cutting 2L31 (Option 1) or 2L32 (Option 2) will degrade the system reliability as the network becomes weaker compared to the original network configuration (Option 3). The EENS obtained using Option 3 can be used as the base case due to the fact that there is no network modification. The increment of EENS in Options 1 and 2 compared to the base case (Option 3) indicates the increased risk associated with the contingency plans. Although the EENS in Option 2 may be comparable to that of Option 3 in year 2008, the differences of the EENS between Options 2 and 3 become more significant when considering the load growth, i.e. in year 2017. The EENS can be translated into socio-economic costs by incorporating with the customer interruption cost model to estimate the expected damage cost due to supply failure.

The expected damage cost (EDC) approach can be used as a surrogate of socio-economic costs, which is utilized as a reliability worth indicator. The unit interruption cost (UIC) in $/kWh is used in this case to represent the monetary impact on customers due to unserved energy. Customer damage functions obtained from the customer interruption survey [2] are normally used in this approach. The UIC in $/kWh can be derived from the customer damage function as shown in Appendix B [3]. Customer load compositions in the Metro System are also required in order to calculate composite UIC for the specified area. The customer load compositions and the composite UIC for the selected major substations in the Metro System are shown in Table 2.

Table 2: Customer load composition and composite unit interruption cost (UIC) for selected major substations in Metro System.

Substation	Customer sector load composition			Composite UIC ($/kWh)
	Residential	Commercial	Industrial	
CSQ	2%	96%	2%	35.68
MAN	77%	19%	3%	8.71
SPG	61%	36%	3%	14.52
COK	65%	25%	10%	11.70
LYN	77%	19%	4%	8.73
HPN	56%	38%	5%	15.69
MUR	42%	48%	10%	19.85
BND	63%	29%	8%	12.66
NEL	52%	35%	13%	15.72
CSN	82%	15%	3%	7.21
RIM	57%	39%	4%	15.82
LOH	65%	23%	11%	11.26
DGR	41%	57%	1%	21.86
STV	74%	18%	8%	8.77
CAM	28%	49%	24%	21.97
KI1	44%	28%	28%	15.26
WHY	75%	22%	2%	9.68
SYH	63%	24%	14%	11.65
			Metro System Average UIC =	**15.43**

The expected damage cost (EDC) can be calculated by multiplying the Metro System Average UIC derived in Table 2 with the EENS shown in Table 1. The EDC for three options are shown in Table 3.

Table 3: Expected Damage Cost (EDC) in M$/year for the three options of a contingency Plan together with the increments of EDC compared to Option 3.

Year	EDC (M$/year)			ΔEDC (M$/year) with respect to Option 3	
	Option 1	Option 2	Option 3	Option 1	Option 2
2008	120.971	75.268	72.722	48.250	2.546
2009	125.940	78.276	74.126	51.814	4.151
2010	130.908	81.285	75.530	55.378	5.755
2011	135.877	84.294	76.934	58.943	7.360
2012	140.845	87.303	78.338	62.507	8.965
2013	145.814	90.312	79.742	66.071	10.570
2014	150.782	93.321	81.146	69.636	12.174
2015	155.750	96.329	82.551	73.200	13.779
2016	160.719	99.338	83.955	76.764	15.384
2017	165.687	102.393	85.328	80.359	17.066

Table 3 indicates that adopting Option 2 as a contingency plan for CSQ substation will lead to the increase of expected risk cost about $2.5 million if one of the CSQ transformers fails in year 2008, and $17 million if it fails in year 2017. Option 1 will result in a significant increase in the risk cost, i.e. 48 million in year 2008. In addition, there will be an overload on 2L50 if 2L31 is taken out of service during a system high demand. Although 2L50 can be operated 100 hours at emergency rating, cutting 2L31 and connecting to a mobile transformer as a contingency plan would require one year or longer of 2L31 unavailability until the failed CSQ transformer is repaired or replaced. Consequently, Option 1 (cutting 2L31) should not be considered as a contingency plan for CSQ substation as it will bring the entire Metro System at significantly higher risk. Only Options 2 and 3 will further consider in the study.

4. Cost-Effective Planning

The total project cost should not only take the investment cost into account, but should also include the associated risk cost such as the expected damage cost. Utility customers receive least cost service when the combined utility and customer outage costs are minimized. Reliability cost/worth analysis therefore establishes a balance between the costs of improving service reliability with the benefits that the improvement brings to the customer. The balance is achieved by minimizing the total cost (TOC) shown as follows:

Total Cost = Utility Investment Cost + Expected Damage Cost

Assumptions:

- CSQ transformer addition project cost = \$8 million
- Reconducting 2L32 and connecting to 150MVA mobile transformer = \$5 million

For Option 2:
Investment cost = \$5 million
Expected damage cost in year 2008 = \$2.5 million
Therefore, total cost for Option 2 = 5 + 2.5 = \$7.5 million

The above result is assumed that the CSQ transformer fails in year 2008 and it takes one year to repair (very optimistic case). If the new transformer is required in order to replace the failed transformer, the lead time for such a unique transformer and substation might take up to 2 years, and the Metro System will be at a high risk (due to cutting 2L32) during these 2 years. The risk cost in this case will be a combination of EDC from years 2008 and 2009, which is \$6.6 million. The total cost will be \$11 .6 million (6.6+5). However, if the CSQ transformer fails in year 2016, Option 2 will result in the total cost of \$20.4 million (15.4+5) based on one year unavailability of 2L32. This indicates that selecting Option 2 as a contingency plan is subject to higher uncertainty of the risk cost (when will it fail, and how long does it take to replace?). It is important to note that the aging failure of the transformer will increase when the transformer become older. This implies that the risk cost is more likely to be at the high degree.

For Option 3:
Investment cost = \$8 million
Expected damage cost in year 2008 = \$0 million (base case)
Therefore, total cost for Option 2 = 8 + 0 = \$8 million

5. Conclusions

Option 2 (cutting 2L32) might result in a lower investment cost for the CSQ substation contingency plan compared to Option 3 (adding the third transformer), but the risk associated with expected damage cost is quite significant as this option degrades the system reliability and the robustness of the Metro System. The total cost (investment cost + expected damage cost) for Option 2 is very similar to that of Option 3 when considering the associated risk cost even under an optimistic situation, i.e. a transformer fails in 2008 and it takes one year to replace. The total cost for Option 2 would be over four times higher than that of Option 3 under a severe case, i.e. transformer fails in 2016 and it takes 2 years to replace. Generally speaking, the expected total cost for Option 2 would be considerably higher than that of Option 3 due to the fact that the aging failure increases with time. Consequently, Option 3 (adding the third transformer) should be the best contingency plan option and at the same time to reduce the supply failure in downtown associated with aging failure concern and to facilitate the firm load associated with the future load growth for the long-term planning consideration.

It is worth noting that the probabilistic risk assessment and the benefit/cost analysis applied to the CSQ substation only (stand alone study) may not be able to prove that adding the third transformer can be justified based on a pure reliability viewpoint as the substation is considerably reliable. However, if a contingency plan has to be considered for the outage event that has a low probability but high consequence, adding the third transformer should be the most cost-effective option among the three alternatives considered in this study. The third transformer addition is therefore an attractive option based on the contingency plan perspective.

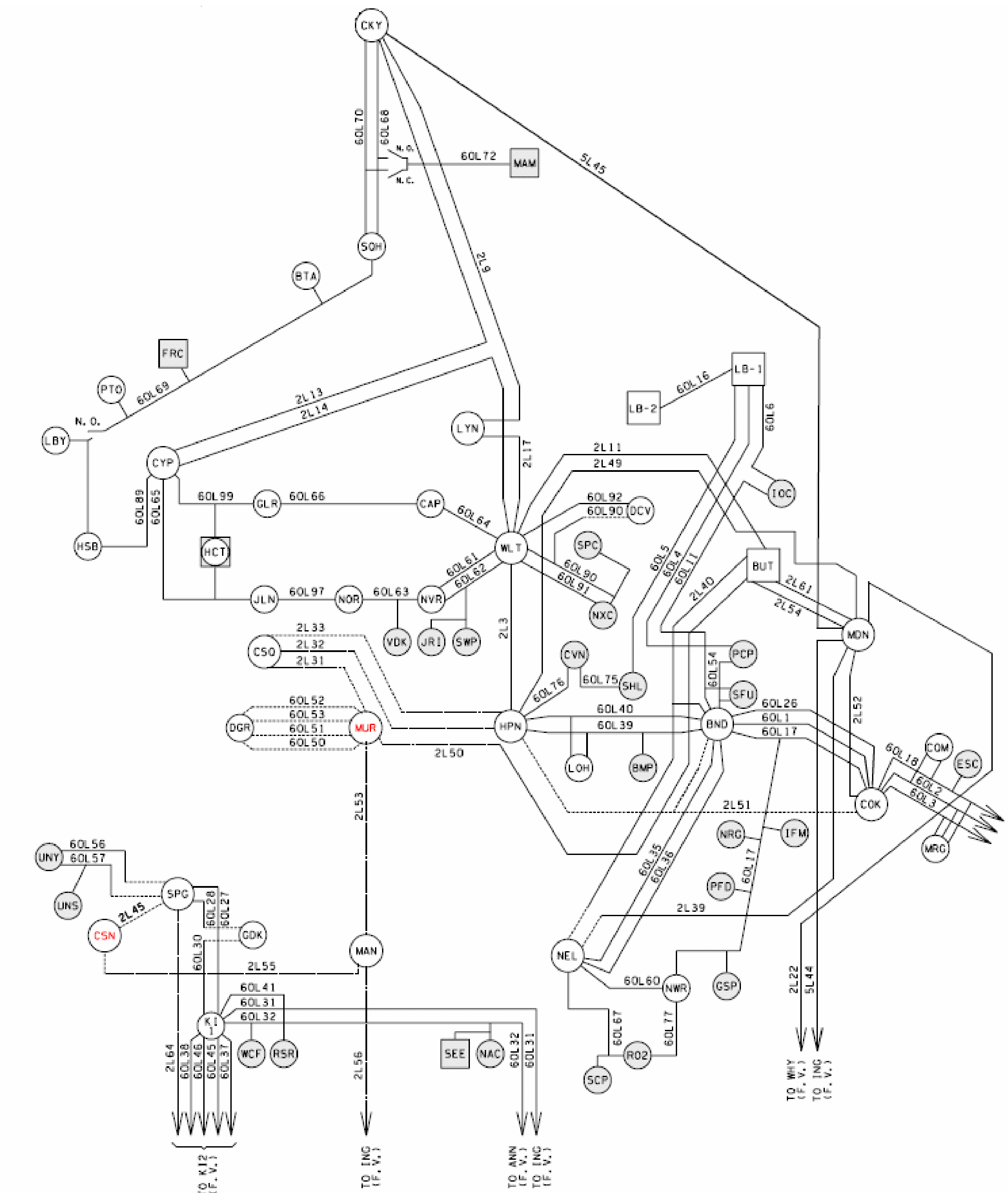
References

[1] Wenyuan Li, "MECORE Program: User's Manual", BC Hydro, Canada, December 2001.

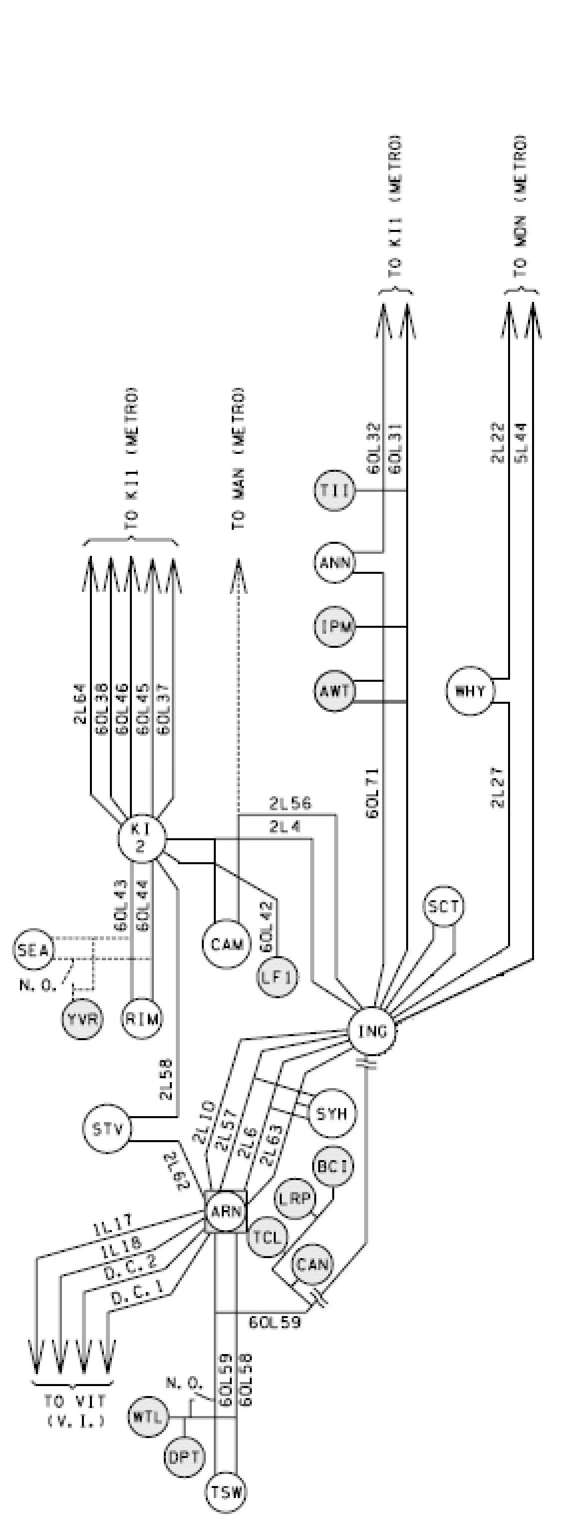
[2] R. Billinton, G. Wacker and G. Tollefson, *Assessment of Reliability Worth in Electric Power Systems in Canada*, NSERC Strategic Grant STR0045005, June 1993.

[3] Wenyuan Li, "*Expected Energy Not Served (EENS) Study for Vancouver Island Transmission Reinforcement Project: Part 4 - Effects of Existing HVDC on VI Power Supply Reliability*", British Columbia Transmission Corporation (BCTC), Vancouver, Canada, January 9, 2006.

Appendix A: Single Line Diagram of the Study System (Metro System)



Appendix A (Continued): Single Line Diagram of the Study System (Metro System)



Appendix B: Customer Interruption Cost

A customer interruption cost survey was conducted by the Power System Research Group at the University of Saskatchewan with participation of all major Canadian utilities. This report was released in 1993 [2]. In this survey, a specific customer damage function for BC Hydro system was created and included in the "Capital Planning Guidelines" document of BC Hydro dated April 1, 1993. This customer damage function is shown in Table B1. The customer damage functions shown in Table B1 are expressed in $/kW with different outage durations. The mid value of each duration range is used to convert the $/kW value into the customer damage functions in $/kWh, which is shown in Table B2 [3].

Table B1: Customer damage function for different customer sectors in $/kW.

Duration	Residential	Commercial	Industrial	Unknown mix
0 to 19 min.	0.2	11.4	5.5	1.9
20 to 59 min.	0.6	26.4	8.6	4.0
60 to 119 min.	2.8	40.1	19.6	8.5
120 to 239 min.	5.0	72.6	33.6	15.1
240 to 480 min.	7.2	147.6	52.1	26.5

Table B2: Customer damage function for different customer sectors in $/kWh.

Duration	Residential	Commercial	Industrial	Unknown mix
10 min.	1.2	68.4	33.0	11.4
40 min.	0.9	39.6	12.9	6.0
90 min.	1.9	26.7	13.1	5.7
180 min.	1.7	24.2	11.2	5.0
360 min.	1.2	24.6	8.6	4.4
Average	**1.38**	**36.70**	**15.76**	**6.5**