Q. Please provide a copy of the East Coast Voltage Study filed at the 1997 Capital Budget Hearing.

A. See attached.

EAST COAST VOLTAGE STUDY

VOLUME 1: FINAL REPORT

Prepared by:

System Planning Department
Newfoundland and Labrador Hydro

November 1995

SUMMARY

The scope of the East Coast Voltage Study is to carry out a thorough review of the east coast transmission network to identify potential areas of concern and analyze solutions from a technical and economic perspective. In order to do this it was first necessary to do a thorough analysis of the existing system to determine it capabilities and limitations. Once the system limitations had been defined, it was possible to identify problem areas and investigate possible solutions.

The technical (load flow) analysis has identified voltage problems particularly during periods when the system is operated without any generation at Holyrood. In addition, thermal overloading has been identified on transmission lines TL202, TL206, TL203, TL207 and TL237 for certain contingency operations. Several alternatives have been proposed to alleviate the voltage problems and other alternatives to eliminate thermal overloading. Load flow analysis indicate that the voltage compensation options are adequate to support voltages on the East Coast for many contingency situations. Cost estimates were requested and obtained from Engineering for these alternatives for subsequent economic analysis.

Based on the load flow analysis and the cost estimates obtained, it is recommended that Unit No. 3 at Holyrood be utilized as a synchronous condenser for voltage support during periods of light and medium loads; that is, periods when generation is normally off at Holyrood. It is also recommended that additional voltage compensation in the form of capacitors (65.6 MVARs) be installed at Hardwoods and Oxen Pond. This static compensation, in addition to existing capacitors at these locations, will complement voltage support supplied by the Hardwoods Gas Turbine during periods when Unit No. 3 at Holyrood is not available.

It is further recommended that transmission lines TL203, TL207 and TL237 be reconductored with Drake conductor and thermally uprated to operate at a 75°C conductor temperature. This will eliminate thermal overloading during certain line out contingencies and allow for the transfer of 365 MW of load from the west as desired for no generation at Holyrood. The thermal uprating of TL202 and TL206 is not recommended since it does not aid in the transfer of 365 MW load.

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1.0 INTRODUCTION

During October 1994 System Planning was requested by the Director of System Operations and Telecontrol to review voltage support requirements for the eastern portion of the Island grid. It was believed that there may be merit in having additional voltage support for the relatively heavy load centres of the Avalon Peninsula. Indeed, it was felt that a voltage support study for the East Coast was manifested by low voltages experienced during certain operating conditions and contingency situations as well as by a perceived lack of reliability in existing voltage support equipment.

The East Coast Voltage Study encompassed equipment and load east of the Bay D'Espoir Generating Plant (refer to Figure 1.0(a) and the single line diagram of Figure 1.0(b)). The equipment includes all bulk (230 kV) transmission lines east of Bay D'Espoir as well as Newfoundland and Labrador Hydro's generating plants located at Holyrood and the Hardwoods Terminal Station. The system load considered comprised that flowing over all 230 kV lines east of Bay D'Espoir. For the most part, this load included the industrial load at Come-By-Chance and Newfoundland Power's load on the Avalon Peninsula.

In February 1995, Operations and Planning personnel met to discuss and agree upon the Terms of Reference for this study. The Terms of Reference, which is included in Appendix A, outlines the objectives of the East Coast Voltage Study and specifies the methodology by which the study will be conducted. In addition, an interim report was prepared and distributed during June 1995 to inform interested parties of the study progress. This report gave the evaluation of the study from the onset, defined the study constraints, assumptions and contingencies, and specified the criteria utilized for the study as well as the alternatives considered. Since the issuance of the interim report, the East

Coast Voltage Study has been completed. The purpose of this final report is to reiterate the study methodology including a review of the study constraints, assumptions, contingencies and criteria. In addition, the findings of the study are presented and recommendations for action are forwarded.

The findings of the study have been documented in two volumes. Volume 1 contains the main report with appendices containing data considered most pertinent to understanding and interpreting the study. Volume 2 contains the remaining supporting documentation of the detailed results related to the load flow analysis conducted. A copy of Volume 2 is kept within System Planning for reference purposes.

EAST COAST VOLTAGE STUDY

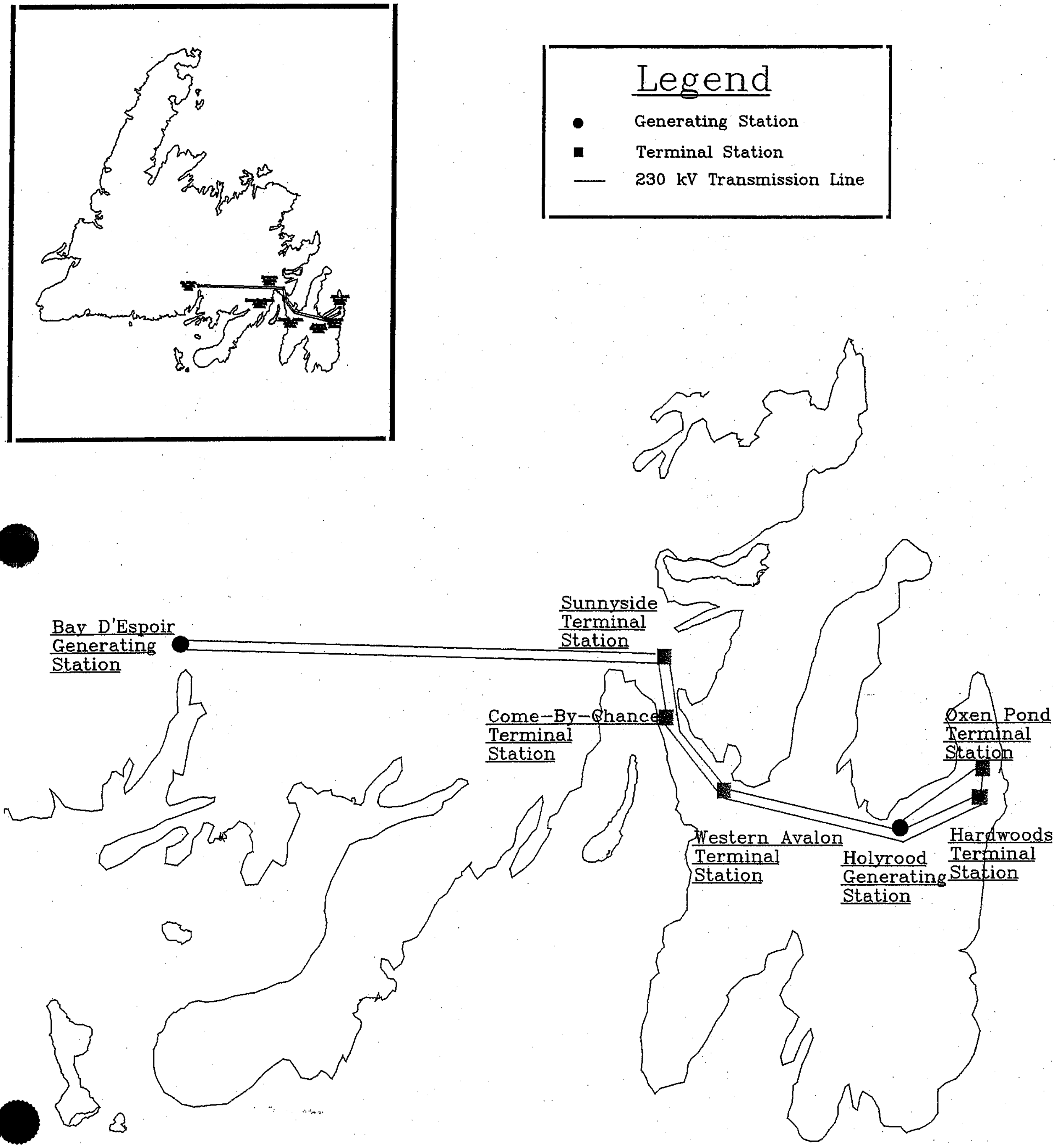

Figure 1.0(a): The East Coast Voltage Study involves all equipment and load East of the Bay D'Espoir Generating Plant.

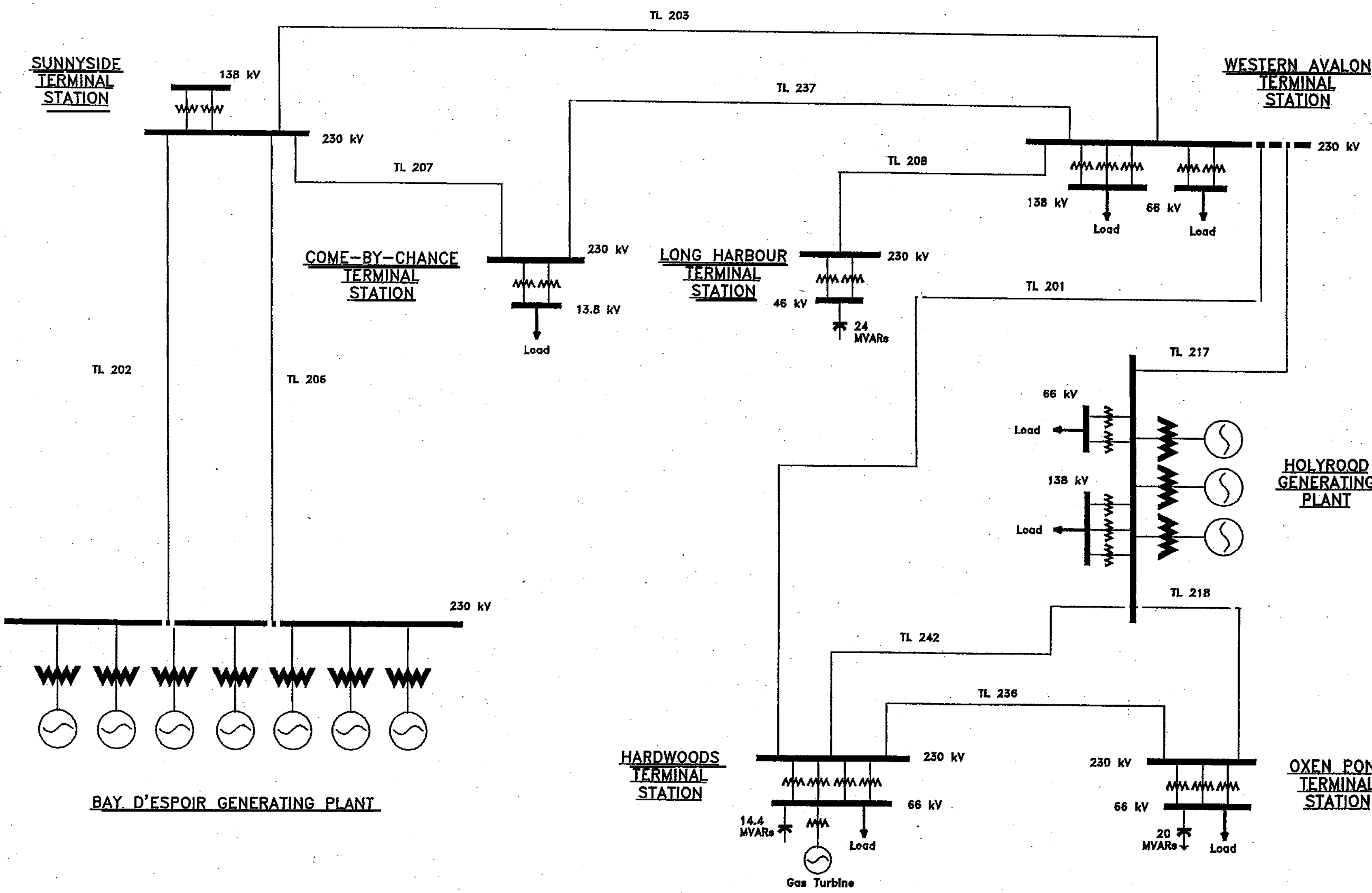

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Figure 1.0(b): Single line diagram which illustrates the load centers and equipment involved with the East Coast Voltage Study.

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DATE:	November, 1995

2.0 SYSTEM PARAMETERS, LIMITATIONS, DEFINITIONS & CRITERIA

As outlined in the Terms of Reference of Appendix A, the initial objectives of this study were to establish load related parameters for and to determine limitations of the existing system. In addition, it was necessary to define particulars related to load magnitudes as well as to identify normal and contingent operating conditions.

2.1 Power Factor

In order to carry out a voltage study, it was first necessary to determine load power factors experienced for daily and seasonal loads. Power factors for all loads across the Island grid were determined using telemetry data obtained from the Energy Management System (EMS) for three load levels as indicated in Appendix B. The power factors utilized for those load centres relevant to the East Coast Voltage Study are tabulated in Table 2.1.

TABLE 2.1
Power Factors Utilized for the East Coast Voltage Study

Load Centre	Power Factor		
	Light	Medium	Heavy
St. John's	0.80	0.93	0.95
Avalon Peninsula	0.80	0.93	0.95
Newfoundland Processing	0.85	0.85	0.85

2.2 Transmission Line Thermal Limits

All 230 kV transmission lines on the Island grid are designed to operate at a 50°C conductor temperature. Depending on the ambient temperature and conductor size, each line has an ampacity corresponding to its 50°C conductor temperature. The maximum capacity in MVA of all 230 kV transmission lines on the East Coast have been calculated and are tabulated in Appendix C.

2.3 Machine Limits

For the purpose of this study, the maximum generation assumed for the Bay d'Espoir Generating Plant, the Holyrood Generating Plant, and the Hardwoods Gas Turbine are as indicated in Table 2.2. The values specified in Table 2.2 are those available to the system after station service.

With the exception of Bay d'Espoir units, the terminal voltage was assumed to be a maximum of 1.05. The maximum terminal voltage used for Bay d'Espoir units was 14.4 kV (or 1.0435 pu).

TABLE 2.2
Machine Active and Reactive Power Limits

Generating Unit	Maximum Limit	
	P_G (MW)	Q_G (MVAR)
Bay D'Espoir Units No. 1-6	71 (each)	35 (each)
Bay D'Espoir Unit No. 7	154	70
Holyrood Units No. 1 & 2	166 (each)	80.4 (each)
Holyrood Unit No. 3	142.5	88.3
Holyrood Unit No. 3 (as S.C.)	0	148
Hardwoods Gas Turbine	40	30.5
Hardwoods Gas Turbine (as S.C.)	0	40

2.4 Definition of Load Magnitudes

The 1995 forecasted peak load for the interconnected Island system is 1310 MW. For study purposes, system loads have been categorized as either Light, Medium or Heavy with the ultimate magnitude being a percentage of the 1995 total system peak load. These magnitudes are specified in Table 2.3 along with the corresponding power factors.

TABLE 2.3
Definition of Load Magnitude and Corresponding Power Factors

Load Magnitude	Percentage of Peak	Actual Load (MW)	Power Factor		
			St. John's	Avalon	Industrial
Light	≤ 45%	≤ 590	0.80	0.80	0.85
Medium	< 80%	< 1048	0.93	0.93	0.85
Heavy	≥ 80%	≥ 1048	0.95	0.95	0.85

2.5 Contingency Analysis and Criteria

Transmission Planning's criteria for contingency studies is normally to maintain load for the loss of any single component (transmission line or transformer) on the system. However, Operations has indicated that the Hardwoods Gas Turbine has not been dependable when called upon during system disturbances. In addition, it was noted that it takes approximately two weeks to convert Unit No. 3 at Holyrood to operate as synchronous condenser making it impractical for responding to emergency situations. Consequently, it was decided that the East Coast Voltage Study would be expanded to investigate multiple contingencies as follows:

(i) the unavailability of Unit No. 3 at Holyrood as a synchronous condenser for voltage support;

(ii) the unavailability of the Hardwoods Gas Turbine; and

(iii) the loss of a single 230 kV transmission line.

As for the normal contingency analysis, the emergency 230 kV system operating voltage will be maintained between 0.90 and 1.10 pu.

3.0 STUDY PROGRESSION

Having established the capabilities of the various generation and transmission elements, the load characteristics and the system contingencies to be evaluated, the next step was to determine how generation dispatch would affect the voltage compensation requirements for the east coast system. In particular, the operating status of the Holyrood Generating Plant has a significant impact on the east coast system.

3.1 Holyrood Generation Dispatch

Discussions with Operations revealed that all three units at Holyrood are normally required for operation from mid to late November until April. Usually starting in April, depending on system load and reservoir levels, one unit at Holyrood can be shut down and as load decreases further during the summer, the second and ideally the third units are also shut down. It is normally during the summer and early fall period that maintenance overhauls are performed on the thermal units.

Further discussions with Operations revealed that the decision to shut down all units at Holyrood is usually not a result of economic generation dispatch but rather system voltage and security concerns. During these light load periods there is more than sufficient hydro capability to supply all loads; however, due to a lack of voltage support on the east coast, it is often necessary to operate a unit at Holyrood to support system voltages.

Based on these discussions, it would appear that there is a period each year when the system is operating at a less than optimum generation dispatch because of inadequate voltage support on the east coast.

3.2 Maximum Power Transfer Requirements

In order to determine the optimum generation dispatch and the resultant voltage compensation requirements, Operations was approached to determine a maximum value of power which would be required to be transmitted from the western portion of the Island grid for various generation dispatch at Holyrood. In response, Operations highlighted various values of generation for which Holyrood units will be required for MWs (refer to Appendix D). Using these limiting values, corresponding Avalon loads were determined which represent the maximum power which would be required to be delivered from the western network. These values are summarized in Table 3.1 and are based on Avalon load of 43% of system load (less losses).

TABLE 3.1
Maximum Power Transfer Requirements
Under Maximum Hydraulic Conditions for
Various Generation Dispatch at Holyrood

Generation Dispatch at Holyrood	System Generation (MW)	Avalon Load (MW)	Losses (MW)	Net Avalon Load (MW)
All Units OFF	869	385	20	365
Unit No. 1 ON (165 MW)	1022	440	20	420
Unit No. 2 ON (165 MW)	1187	510	20	490
Unit No. 3 ON (150 MW)	1337	575	20	555

3.3 Initial Evaluation

Prior to proposing alternatives to mitigate or eliminate voltage problems, it was necessary to identify loads and generation dispatch that would result in voltage problems. In order to accomplish this, a reference load was required for comparison purposes in addition to some preliminary load flow analysis.

3.3.1 Typical Load Shape

A load corresponding to the 1995 load for the Avalon Peninsula was determined as illustrated in Figure 3.1. This load was obtained by utilizing the 1994 actual daily peak loads for the Avalon (obtained from the EMS Archives Data) and scaling it to 1995 using the forecasted load growth from 1994 to 1995. In addition, 27 MW was added to represent the industrial load (North Atlantic Refining Ltd.) at Come-By-Chance.

As can be seen from Figure 3.1, there is a significant window between March 31st and November 30th when total Avalon loads are projected to be below 365 MW. This is the period during which the system should be able to operate without any generation at Holyrood (provided hydraulic conditions are sufficient to allow this operation).

EAST COAST VOLTAGE STUDY
1995 AVALON LOAD

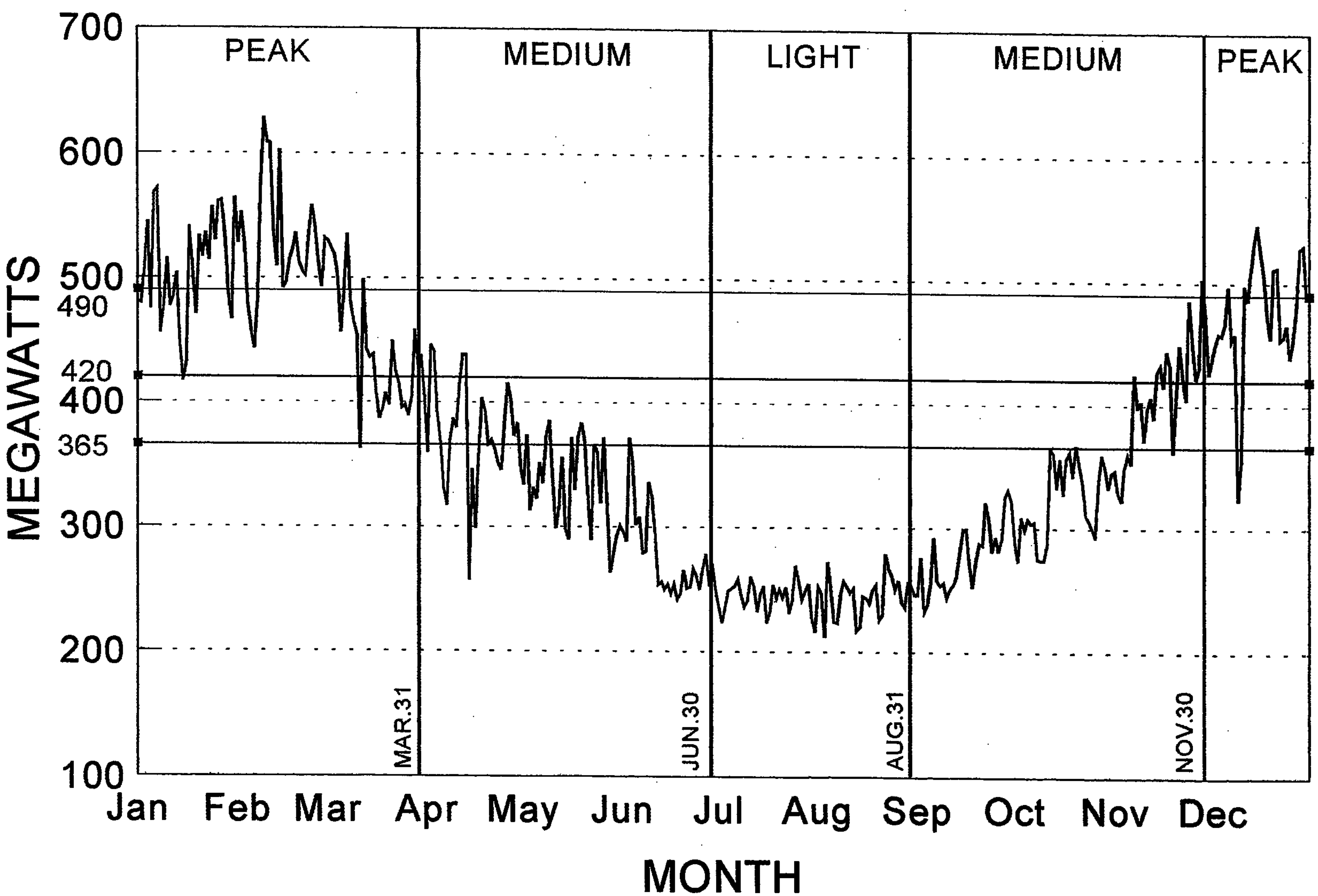

Figure 3.1 Actual 1994 daily peak loads scaled to 1995 using the forecasted growth.

3.3.2 Preliminary Analysis of Existing System

Some initial load flow analysis was conducted to identify exactly what loads and corresponding generation dispatch at Holyrood would result in low voltages. The results of these load flows are summarized in Table 3.2. Please note that these load flows do not consider the loss of a 230 kV transmission line.

TABLE 3.2
Maximum Avalon Load Transfer Capability for Various Generation Dispatch at the Holyrood Generating Plant

Load Scenario	HWD G.T.	HRD Generation	Total Avalon Load (MW)
Medium (1)	OFF SC ON	OFF	282 310 325
Medium (2)	OFF SC ON	OFF (TL208 Out)	265 295 309
Medium (3)	OFF SC ON	1 Unit ON	399 432 445
Medium (4)	OFF SC ON	2 Units ON	508 543 560
Heavy	OFF SC ON	3 Units ON	613 644 653

As indicated in Table 3.2, the most troublesome generation dispatch would be the case of all Holyrood units being shut down. As indicated in Table 3.1, it would be desirable to supply up to 365 MW of load for this operating mode. However, the existing system can only supply 282 MW without the Hardwoods synchronous condenser and 310 MW with the synchronous condenser.

Again, the 365 MW load on the Avalon Peninsula represents the limiting or maximum load which would be available to be transferred from the West Coast without any units on-line at Holyrood. Since this is the most onerous generation dispatch for existing level of compensation, it was evident that the identification of mitigative options to eliminate voltage problems for this generation dispatch would be more than adequate to cover off problems experienced in situations when generation is on at Holyrood.

Further to the results of Table 3.2, additional load flows were carried out to determine the maximum load which may be met on the Avalon Peninsula for a single 230 kV line out contingency. This analysis was conducted assuming no generation at Holyrood and the availability of TL208 and the Long Harbour capacitor bank. The results of this exercise are tabulated in Table 3.3.

TABLE 3.3
Maximum Avalon Load that may be met for Various Line Out Contingencies and Without Generation at Holyrood

TL Out	HWD G.T.	Flow Over TL___ (MVA)	Maximum Avalon Load (MW)
TL202 or TL206	OFF SC ON	TL206 (243) TL206 (274) TL206 (252)	231 260 277
TL203	OFF SC ON	TL207 (270) TL207 (304) TL207 (281)	254 286 304
TL207	OFF SC ON	TL203 (263) TL203 (303) TL203 (278)	248 285 301
TL237	OFF SC ON	TL203 (246) TL203 (279) TL203 (256)	259 291 309
TL201	OFF SC ON	TL217 (160) TL217 (180) TL217 (161)	237 274 287
TL217	OFF SC ON	TL201 (158) TL201 (177) TL201 (160)	238 273 289
TL218	OFF SC ON	TL236 (88) TL236 (102) TL236 (96)	271 307 322
TL236	OFF SC ON	TL218 (78) TL218 (91) TL218 (86)	271 303 317
TL242	OFF SC ON	TL218 (72) TL218 (82) TL218 (71)	270 309 324

3.4 Mitigative Solutions

Subsequent load flow analysis was commenced to evaluate the transfer of a maximum of 365 MW of load to the Avalon for four (4) alternatives as follows:

1) *Alternative No. 1* - This option is an "all capacitor" option which assumes that both the Hardwoods Gas Turbine and Holyrood Unit No. 3 are not available. TL208 and the Long Harbour Terminal Station are assumed to be in service. The distribution of capacitor banks on the Avalon for this alternative is indicated in Table 3.4.

2) *Alternative No. 2* - Same as Alternative No. 1 except TL208 and Long Harbour are assumed to be decommissioned. Again, the distribution of capacitor banks is given in Table 3.4.

3) *Alternative No. 3* - Holyrood Unit No. 3 is utilized as synchronous condenser (148 MVARs). In addition to the existing capacitors at Hardwoods and Oxen Pond, a further 30 MVARs was assumed for each of these stations (66 kV). The Long Harbour capacitor bank (24 MVARs) and TL208 are assumed to be in service.

4) *Alternative No. 4* - Same as Alternative No. 3 except the Long Harbour Terminal Station and TL208 are assumed to be decommissioned.

TABLE 3.4
Additional Capacitor Banks as Required for Alternatives No. 1 and No. 2

Alternative	Location	Capacitors (MVAR)		
		Existing	Additional	Total
No. 1	HWD 66	14.4	35.6	50
	OPD 66	20	30	50
	LHR 66	24	26	50
	CBC 13.8	-	10	10
	HRD 138	-	50	50
	WAV 138	-	75	75
	Total	58.4	226.6	285
No. 2	HWD 66	14.4	35.6	50
	OPD 66	20	30	50
	CBC 13.8	-	10	10
	HRD 138	-	85	85
	WAV 138	-	90	90
	Total	34.4	250.6	285

3.4.1 Initial Load Flow Results

From a transfer capability perspective, all four alternatives are essentially equal. Analysis to date has been concentrated on the alternatives which utilize the Holyrood Unit No. 3 as a synchronous condenser as it is felt that these alternatives would be more practical and cost effective to implement.

The results for the synchronous condenser case are summarized in Table 3.5. As indicated in this table, an additional 30 MVARs of capacitors at Hardwoods as well as Oxen Pond will cover off all contingencies and allow for the required 365 MW load to be met except in the case of the loss of TL202 or TL206.

In addition, these tables indicate that the thermal limits of TL206, TL207, TL237 and TL203 will be exceeded for a 15°C ambient temperature and for certain line out contingencies.

TABLE 3.5
Maximum Avalon Load Transfer Capability for Alternative No. 3

HRD Generation	HWD G.T.	TL OUT	TL Overload (MVA)	Avalon Load (MW)
OFF	ON as SC (40 MVARs)	None	None	365
No. 3 as SC (78 MVARs)	OFF	None	None	365
No. 3 as SC (147 MVARs)	OFF	TL202	TL206 (375) [300]	346
No. 3 as SC (111 MVARs)	OFF	TL203	TL207 (398) [354] TL237 (371) [260]	365
No. 3 as SC (132 MVARs)	OFF	TL207	TL203 (402) [230]	365
No. 3 as SC (123 MVARs)	OFF	TL237	TL203 (372) [230]	365
No. 3 as SC (135 MVARs)	OFF	TL201	None	365
No. 3 as SC (128 MVARs)	OFF	TL217	None	365
No. 3 as SC (101 MVARs)	OFF	TL236	None	365
No. 3 as SC (103 MVARs)	OFF	TL218	None	365
No. 3 as SC (100 MVARs)	OFF	TL242	None	365

Notes: 1) In addition to the HWD G.T. not being available, this analysis assumes the existing capacitor banks at HWD and OPD are in service. In addition, a further 30 MVARs at each of these stations is assumed (as per previous Capital Budget Proposals).

2) TL208 and the LHR capacitor bank (24 MVARs) are assumed to be in service.

3) The values in square brackets [ ] under the "TL Overload" column refers to the thermal limits of the transmission line as in Appendix C.

It should be noted that while these alternatives do not utilize the Hardwoods Gas Turbine for normal operating conditions, it is assumed to be available to complement the capacitor banks during periods when Holyrood No. 3 may not be available. In addition, its availability will facilitate a smoother and more reliable conversion period when Holyrood Unit No. 3 is converted from generator to synchronous condenser and vice versa.

Cost estimates for the four alternatives have been requested and obtained from Engineering (refer to Appendix E). In addition, Engineering were asked to investigate and cost alternatives which may alleviate the problem with the thermal limits of the transmission circuits between Sunnyside and Western Avalon. The results of this analysis will form an integral part of any recommendations coming from this study.

4.0 RESULTS

Since the preparation of the "Interim Planning Report" for this study in June, it has been decided to utilize 35.6 MVARs of capacitors at Hardwoods for Alternative No. 3 and Alternative No. 4 as opposed to the 30 MVARs originally proposed. This slight increase in voltage compensation in addition to existing capacitors, will provide 50 MVARs at each of the Hardwoods and Oxen Pond Terminal Stations. Subsequent load flow analysis was conducted using the 50 MVAR values. The load flow results are discussed in successive sections.

In addition, Albright and Wilson Americas have been unsuccessful in acquiring an alternate supplier of energy and, therefore, will continue to be a customer of Hydro. Consequently, the future of the Long Harbour Terminal Station and TL208 is no longer an issue. As a result of this, the four alternatives originally forwarded for reactive power (voltage) support have been effectively reduced to two (2) basic alternatives.

4.1 Technical Results

As discussed in Section 3.4.1, all load flow analysis assumes the availability of Unit No. 3 at Holyrood for synchronous condenser operation **or** the Hardwoods Gas Turbine in the absence of the former. Unit No. 3 at Holyrood may not be available due to a forced or scheduled outage or due to conversion from generation to synchronous condenser in the late spring or vice versa in the early fall.

The Hardwoods Gas Turbine has less reactive power capability (40 MVARs) than that of the Unit No. 3 at Holyrood (148 MVARs) and is by no means a substitute for the Holyrood unit. However, in the event of the unavailability of Holyrood, Hardwoods, when utilized as a synchronous condenser in combination with the new capacitors, is capable of providing the desired 365 MW transfer capability. This of course is assuming all 230 kV transmission is available. Table 3.5 has been updated to include this single contingency of the non-availability of Holyrood as a synchronous condenser.

Load flows and corresponding analysis indicate that the desired 365 MW load may be met for all but one contingency which is the loss of TL202 or TL206. The maximum load transferable with one of these lines out of service is 346 MW as indicated in Table 3.4.

Alternative No. 1 and No. 2, in addition to 65.6 MVARs of capacitors at Hardwoods and Oxen Pond, called for the installation of some 161 MVARs of capacitors at various locations on the Avalon Peninsula (see Table 3.3). These two alternatives were originally forwarded assuming that Holyrood Unit No. 3 could not be utilized as a synchronous condenser and relied upon for voltage support. However, during the course of this study these two alternatives have been viewed less favourably than Alternatives No. 3 and No. 4. The reasons for this negative viewpoint are as follows:

(i) utilization of Unit No. 3 as a synchronous condenser was favoured over static capacitors since the voltage support provided by the synchronous condenser is self-regulating whereas capacitors are not;

(ii) Unit No. 3 at Holyrood is a potential source of voltage compensation which already exists and is favoured over the costs associated with the installation of an inferior source of voltage compensation (capacitors); and

(iii) Unit No. 3 at Holyrood was utilized and operated as a synchronous condenser this summer from May 30th to September 20th and it provided extra voltage support as well as savings in not having to turn ON a thermal unit for MWs.

Even though these two alternatives were exempted from further analysis, they were costed by Engineering. These costs are discussed subsequently.

With respect to technical results and as noted previously in Section 3.4.1 and Table 3.5, the thermal limits of TL202, TL206, TL203, TL207 and TL237 would be exceeded for certain line out contingencies for medium loads at a 15°C ambient temperature. Engineering were also requested to cost various alternatives associated with the elimination of this thermal overloading.

4.2 Cost Estimates and Alternatives

Engineering were requested to provide cost estimates associated with terminal stations and reactive power support as well as transmission lines and their thermal limitations (refer to Appendix E). These cost estimates are discussed individually in the following sections:

4.2.1 Terminal Station Costs

As previously discussed, alternatives for reactive power support have been reduced to two basic options due to the continuation of our industrial customer at Long Harbour. The costs associated with these two scenarios are summarized in Table 4.1 and a brief discussion of each follows.

TABLE 4.1
Terminal Station Costs

Option	Terminal Station Costs			
	Hardwoods	Oxen Pond	Avalon Region	Total
No. 1	35.6 MVARs of Caps $481,000	30 MVARs of Caps $406,000		$887,000
No. 2	35.6 MVARs of Caps $481,000	30 MVARs of Caps $406,000	Additional 161 MVARs of Caps $3,000,000	$3,887,000

Option No. 1 - The main source of voltage support for this option is the utilization of Unit No. 3 at Holyrood as a synchronous condenser. Table 4.1 provides the costs associated with an additional 65.6 MVARs of static var compensation at Hardwoods and Oxen Pond. This compensation would be necessary in conjunction with the voltage support provided by the Hardwoods Gas Turbine during times when Unit No. 3 is not available.

Option No. 2 - The source of voltage support for this option is primarily that of static capacitors. A total of 161 MVARs of capacitors distributed along the Avalon Peninsula will be required in addition to the 65.6 MVARs proposed for Hardwoods and Oxen Pond. Again, this option assumes Holyrood Unit No. 3 cannot and will not be utilized for compensation.

As is evident from Table 4.1, Option No. 1 is by far less capital intensive than the "all capacitor" option.

4.2.2 Transmission Line Costs

As indicated in Appendix E, four options were requested for costing related to the elimination of thermal overloading of TL202, TL206, TL203, TL207 and TL237 during line out contingencies. The costs associated with these options are supplied in Table 4.2. In addition, a brief description of each option follows in which the uprated thermal capability is specified.

TABLE 4.2
Transmission Line Options and Costs

Option	Description	Uprated Thermal Capability (MVA)	Total Cost	Comments
No. 1	Thermal Uprating of TL202 and TL206	TL202: from 293 to 400 TL206: from 293 to 400	$200,000	Even though the thermal capability will be 400 MVA, the desired load of 365 MW cannot be met with the loss of one of these lines due to "bottle necking". The maximum load attainable with one of these lines is 346 MW.
No. 2	Thermal Uprating of TL203, TL207 and TL237	TL203: from 230 to 308 TL207: currently at 354 TL237: from 264 to 354	$900,000	TL207 can presently be operated at 75°C.
No. 3	Thermal Uprating & Reconductoring of TL203, TL207 and TL237	TL203: from 230 to 400 TL207: from 354 to 400 TL237: from 264 to 400	$4,001,000	Thermal uprating and reconductoring will increase the thermal capability of each line to the desired 400 MVA (synonymous with 365 MW).
No. 4	Construction of a new 230 kV line from Sunnyside to Western Avalon	(see comment)	$5,855,000	Adding a new line will eliminate thermal overloading during single line out contingencies.

Option No. 1 - This option includes costs associated with the thermal uprating of TL202 and TL206 to operate at a conductor temperature of 75°C. This will increase the thermal capability of each of these lines from 293 to 400 MVA (which is equivalent to a 365 MW load on the Avalon Peninsula). However, this desired load of 365 MW cannot be met with the loss of one of these lines due to "bottle necking". As noted earlier, the maximum load attainable with one of these lines out of service is 346 MW. In order to increase the thermal capability to 400 MVA, series compensation will be required. Another alternative would be to eliminate thermal overloading by building an additional line from Bay d'Espoir to Sunnyside or Western Avalon. Both of these alternatives are capital intensive and were not entertained.

Option No. 2 - The option includes costs associated with the thermal uprating of TL203, TL207 and TL237 to operate at a conductor temperature of 75°C. As noted in Table 4.2 above, it was determined that TL207 can be operated at 75°C without modifications. The corresponding uprated thermal capability for each of these lines would be as follows:

(i) TL203: from 230 to 308 MVA;
(ii) TL207: currently at 354 MVA; and
(iii) TL237: from 264 to 354 MVA.

Option No. 3 - This option includes all costs associated with the reconductoring of TL203, TL207 and TL237 with Drake conductor including any thermal uprating through the addition of mid-span structures such that it may operate at a maximum conductor temperature of 75°C. This thermal uprating and reconductoring will increase the thermal capability of each line to the desired 400 MVA. (Again, 400 MVA and 365 MW are synonymous.)

Option No. 4 - This option includes all costs associated with the design and construction as well as the purchase and installation of equipment and materials for a new 230 kV transmission line from the Sunnyside Terminal Station to the Western Avalon Terminal Station. Adding a new line will eliminate thermal overloading during single line out contingencies. Therefore, the 365 MW load requirement will be met.

4.2.3 Cost Alternatives

The cost information supplied in Table 4.1 and 4.2 was combined and used to construct various cost alternatives which represent costs to solve both the voltage support problems as well as the thermal overloading problem. In total, six (6) combinations were realized as indicated in Table 4.3 on the next page.

The thermal uprating of TL202 and TL206 was not included in Table 4.3. The reason for its exclusion is due to the fact that it does not aid in increasing the transfer capability of one of the lines when the other is out of service.

TABLE 4.3
Cost Alternatives Resulting from the East Coast Voltage Study

Cost Alternative	Terminal Station Costs							Total Cost
	Hardwoods	Oxen Pond	Avalon	TL203	TL207	TL237	Other	
No. 1	35.6 MVARs of Caps $481,000	30 MVARs of Caps $406,000		Thermal Uprating $100,000	Thermal Uprating $0	Thermal Uprating $800,000		$1,787,000
No. 2	35.6 MVARs of Caps $481,000	30 MVARs of Caps $406,000		Uprating & Reconductoring $1,866,000	Reconductoring $345,000	Uprating & Reconductoring $1,790,000		$4,888,000
No. 3	35.6 MVARs of Caps $481,000	30 MVARs of Caps $406,000					New Line $5,855,000	$6,742,000
No. 4	35.6 MVARs of Caps $481,000	30 MVARs of Caps $406,000	Additional 161 MVARs of Caps $3,000,000	Uprating & Reconductoring $100,000	Thermal Uprating $0	Thermal Uprating $800,000		$4,787,000
No. 5	35.6 MVARs of Caps $481,000	30 MVARs of Caps $406,000	Additional 161 MVARs of Caps $3,000,000	Uprating & Reconductoring $1,866,000	Reconductoring $345,000	Uprating & Reconductoring $1,790,000		$7,888,000
No. 6	35.6 MVARs of Caps $481,000	30 MVARs of Caps $406,000	Additional 161 MVARs of Caps $3,000,000				New Line $5,855,000	$9,742,000

5.0 DISCUSSIONS AND RECOMMENDATIONS

Initially, at the onset of this study, the future of the Long Harbour Terminal Station and TL208 was not known. This is due to the fact that the industrial customer at Long Harbour (Albright & Wilson Americas) had indicated that they were seeking an alternate supplier of energy to meet their requirements. However, throughout the course of this study this customer was unsuccessful in obtaining another supplier and has indicated that they will continue to be a customer of Newfoundland and Labrador Hydro. Consequently, the equipment at Long Harbour and TL208 will remain intact and its future is no longer a concern of this study.

The initial phase of this study was concerned with the determination of actual load power factors and the identification of realistic operating conditions and contingencies which would require mitigative measures to be taken. From conversations held with Operations personnel, it was ascertained that a 365 MW load is desired to be supplied to the east coast (Avalon Peninsula) without having any generation ON at Holyrood. Subsequent load flows determined that it was this operating scenario (i.e. no generation at Holyrood) which was the most onerous for the existing system under normal operating conditions. It was evident that even with all transmission lines in service, it is not possible to deliver 365 MW to the Avalon without generation at Holyrood. The load flow analysis also indicated thermal overloading of five transmission lines (TL202, TL206, TL203, TL207 and TL237) for certain line out contingencies.

The remainder of the analysis concentrated on the development of mitigative solutions to permit the transfer of up to 365 MW to the Avalon and to eliminate thermal overloading for normal and single transmission line contingencies in the absence of Holyrood generation. Based on this analysis, the following action items are recommended:

(i) Holyrood Unit No. 3 should be utilized as a synchronous condenser during periods of light and medium loads occurring during late spring and early fall when Holyrood is normally not generating power. With time and assuming that load growth is positive, this window for no generation at Holyrood will become shorter and will eventually disappear. However, and until that time, it is desired to operate without any generation at Holyrood and to reap the savings of not burning Bunker "C".

(ii) It is recommended that additional static VARs (or capacitors) be installed at Hardwoods and Oxen Pond for voltage support. This compensation will be required to complement existing capacitors and the gas turbine for those times when Unit No. 3 is not available. Table 3.5 indicates the load supplied to the Avalon Peninsula when Holyrood Unit No. 3 is operating as a synchronous condenser. Furthermore, this table indicates the same for the case when Unit No. 3 is not available and the Hardwoods Gas Turbine is utilized as a synchronous condenser. Again, the gas turbine will be utilized as a synchronous condenser as back-up for those times when the major source of compensation (Holyrood Unit No. 3) is not available.

(iii) It is recommended that transmission lines TL203, TL207 and TL237 be:

(a) reconductored with Drake conductor and thermally uprated to operate at a conductor temperature of 75°C (Option No. 3); or

(b) thermally uprated to operate at a conductor temperature of 75°C (Option No. 2 in Table 4.2).

Reconductoring and uprating will ensure that the whole 365 MW load (or 400 MVA) can be served without experiencing thermal overload. Uprating alone will not provide the full 365 MW transfer capability but will provide a substantial improvement over the current situation. The uprating of TL202 and TL206 is not recommended since it does not facilitate the transfer of the 365 MW load during a single line out (TL202 or TL206) contingency.

In conclusion, the above recommendations are mitigative measures intended to improve voltages on the east coast during normal and single contingency operation. In addition, the reconductoring and/or thermal uprating will reduce or eliminate thermal overloading during single line out contingencies.

This study was mainly focussed on the improvement of voltages on the Avalon and the elimination of transmission line thermal overloading for **single** contingencies in the absence of Holyrood generation. Benefits of having the additional capacitors are also evident for multiple contingencies. Additional load flow analysis was conducted to obtain flows for a double contingency (the unavailability of Holyrood No. 3 as a synchronous condenser **and** a single line out contingency). The results of this analysis are summarized in Table 5.1 and as can be seen the additional capacitors at Hardwoods and Oxen Pond will provide an extra 40 to 50 MW transfer capability to the Avalon Peninsula.

TABLE 5.1
Maximum Avalon Load that may be met for Various Line Out Contingencies and Without Generation at Holyrood

TL Out	HWD G.T.	Existing System		Proposed Capacitors	
		Flow Over TL__ (MVA)	Max. Avalon Load (MW)	Flow Over TL__ (MVA)	Max. Avalon Load (MW)
TL202 or TL206	OFF SC ON	TL206 (243) TL206 (274) TL206 (252)	231 260 277	TL206 (280) TL206 (300 TL206 (277)	274 294 311
TL203	OFF SC ON	TL207 (270) TL207 (304) TL207 (281)	254 286 304	TL207 (328) TL207 (350) TL207 (320)	309 331 345
TL207	OFF SC ON	TL203 (263) TL203 (303) TL203 (278)	248 285 301	TL203 (320) TL203 (347) TL203 (328)	302 328 350
TL237	OFF SC ON	TL203 (246) TL203 (279) TL203 (256)	259 291 309	TL203 (297) TL203 (328) TL203 (304)	309 337 355
TL201	OFF SC ON	TL217 (160) TL217 (180) TL217 (161)	237 274 287	TL217 (193) TL217 (212) TL217 (193)	271 329 345
TL217	OFF SC ON	TL201 (158) TL201 (177) TL201 (160)	238 273 289	TL201 (191) TL201 (210) TL201 (192)	298 330 347
TL218	OFF SC ON	TL236 (88) TL236 (102) TL236 (96)	271 307 322	TL236 (106) TL236 (115) TL236 (115)	332 360 382
TL236	OFF SC ON	TL218 (78) TL218 (91) TL218 (86)	271 303 317	TL218 (92) TL218 (102) TL218 (97)	332 359 377
TL242	OFF SC ON	TL218 (72) TL218 (82) TL218 (71)	270 309 324	TL218 (89) TL218 (100) TL218 (89)	330 364 382

APPENDIX A

TERMS OF REFERENCE

EAST COAST VOLTAGE STUDY

TERMS OF REFERENCE

OBJECTIVES

1. To establish load related parameters for the Eastern portion of the Island grid such as actual load power factors.

2. To identify those normal and contingent operating conditions which will have a reasonable probability of occurring and will, therefore, require mitigation analysis.

3. To determine, based on the aforementioned parameters and for the identified operating conditions, limitations of the existing and proposed systems such as the thermal capability limits of 230 kV transmission lines.

4. To propose specific remedial measures or alternatives to mitigate or eliminate any voltage problems as determined from the initial evaluation.

5. To evaluate each of the alternatives from a technical and/or operating point of view and to reject any option which may be inadequate.

6. To cost the remaining alternatives and to evaluate them from an economic point of view.

7. To recommend, based on the outcome from a decision matrix, that alternative which will be the optimum solution to rectify existing and future problems.

PROCEDURAL METHODOLOGY

Existing System

An evaluation of the existing system will involve:

1. The acquisition of information related to past operating conditions and voltage problems as may be obtained through discussions with ECC personnel and analysis of EMS Archives data;

2. The determination of an actual power factor for loads on the Eastern portion of the system through load flow and EMS data analysis;

3. The determination of maximum power transfer capability on the Eastern transmission network from Bay D'Espoir for "expected" and contingent operating conditions through load flow analysis. This analysis will be performed with consideration given to thermal limits of existing lines for the following generation dispatch and operating situations:

   (i) the unavailability of any generation from Holyrood (including Unit No. 3 as synchronous condenser);

   (ii) the unavailability of the Hardwoods gas turbine;

   (iii) limited generation from Holyrood;

   (iv) the loss of TL202 or TL206 between BDE and SSD;

   (v) the loss of TL203 or TL237; and

   (vi) the loss of TL201 or TL217 from WAV;

4. The determination of the future applicability of the Long Harbour Capacitor Bank (24 MVARS) to the East Coast voltage problems;

5. The determination of the impact that any proposed mitigation technique may have on the remainder of the Island grid.

In addition to acquiring information and determining limitations of the existing system, this evaluation will provide the timing for compensation as required for voltage support.

<u>Future System</u>

Load flow analysis will be conducted with consideration given to proposed generation expansion projects to determine the impact that sequential development may have on the East Coast voltages and VAR requirements. The potential projects are as follows:

NUGS (38 MW)
Granite Canal
Island Pond
Round Pond

St. John's - South Side Combined Cycle (71.6 MW)
Gas Turbine
Holyrood IV

Evaluation of Alternatives - Technical

A number of compensation options will be evaluated on a technical basis through normal load flow and stability analysis. These options may include but are not restricted to the following:

1. Capacitor banks;

2. Series compensation;

3. Static Var Compensation (SVC);

4. Additional 230 kV transmission line;

5. Status quo (This will be a "do nothing" option with consideration given to making mitigative changes to the existing system in addition to proposed projects such as gas turbine addition, Holyrood IV, etc); and

6. Others
   - combination of capacitors and proposed generation additions.
   - thermal uprating of existing lines.

During this evaluation process, each alternative will be ranked according to its technical suitability based on certain criteria such as: (i) the impact upon the electrical system; (ii) the time period of adequacy; and (iii) the order of magnitude of cost. Any alternative which falls short of being adequate will not be given further consideration.

Evaluation of Alternatives - Economic

Cost estimates will be requested from Engineering for those alternatives which are considered to be technically feasible. These cost estimates and subsequent cost analysis will determine the optimum solution from an economic point of view.

APPENDIX B

POWER FACTORS

EAST COAST VOLTAGE STUDY

Power Factors for Various Loads

Zone	Power Factor Determined			Power Factor Suggested		
	Light	Medium	Heavy	Light	Medium	Heavy
St. John's	.8029	0.9283	0.9555	0.80	0.930	0.95
Avalon Peninsula	.8062	0.9325	0.9575	0.80	0.930	0.95
Burin Peninsula	.9320	0.9725	0.9840	0.930	0.975	0.975
Central	.9614	0.9874	0.9770	0.96	0.975	0.975
Western	.8818	0.9209	0.9750	0.880	0.920	0.975
GNP	.9618	0.9445	0.9850	0.950	0.950	0.975
Bay D'Espoir	.9238	0.9381	0.9900	0.920	0.930	0.980
NLH Customers	.9686	0.9556	0.9750	0.960	0.960	0.960
Industrial						
Nfld. Processing	0.8800	0.8779	0.8314	0.850	0.850	0.850
ABI-GFC	0.9863	0.9957	1.0000	0.990	0.990	0.990
Kruger	0.9900	0.9809	0.9685	0.975	0.975	0.975
ABI-SVL	0.9980	0.9985	1.0000	0.990	0.990	0.990
Royal Oak	0.9960	0.9940	0.9950	0.990	0.990	0.990

APPENDIX C

THERMAL LIMITS OF 230 KV TRANSMISSION LINES

EAST COAST VOLTAGE STUDY

Thermal Limits of 230 kV Transmission Lines

Transmission Line	Maximum Capacity (MVA)		
	Light Load	Medium Load	Heavy Load
TL201	175	260	325
TL202	200	300	370
TL203	155	230	285
TL206	200	300	370
TL207	175	260	325
TL208	200	300	340
TL217	190	275	340
TL218	200	300	370
TL236	200	300	370
TL237	175	260	325
TL242	275	420	525

Notes:

1. The capacities cited above are based on a 50°C conductor temperature and ambient temperatures of 30°C, 15°C and 0°C corresponding to periods of light, medium, and heavy loads, respectively.

2. In the case of two or more different conductors per line, the maximum transfer capacity of the smallest conductor was evaluated.

APPENDIX D

SYSTEM LOAD LEVELS
VERSUS
HOLYROOD UNIT OPERATION

System Load Levels versus Holyrood Unit Operation

Units on and Capability Assumed			System Load
Operating			
Hinds Lake	75	MW	
Upper Salmon	84		
Cat Arm	130		
Bay D'Espoir	580		
Total	869		
Stand-by			
Stephenville	54		
Hardwoods	54		
Holyrood	10		
Greenhill	25		
Salt Pond	10		
Total	153		
NO UNITS ON AT HOLYROOD (NOT WINTER)			869
ONE UNIT ON AT HOLYROOD (NOT WINTER)			1022
Holyrood Unit 1	165		
TWO UNITS ON AT HOLYRCOD (NOT WINTER)			1187
Holyrood Unit 2	165		
THREE UNITS ON AT HOLYROOD (NOT WINTER)			1337
Holyrood Unit 3	150		
THREE UNITS ON AT HOLYROOD (WINTER)			1383
Interruptible "B"	46		

Assumptions
1) No spinning reserve
2) Can meet load with loss of largest operating unit
3) All units available

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