

Pappas INTERROGATORY #1 List 1

Interrogatory

Issues:

- 1.1. Has the need for the proposed project been established?
- 2.1 Have all reasonable alternatives to the project been identified and considered?
- 2.2 Has an appropriate evaluation methodology been applied to all the alternatives considered?
- 2.4a Have appropriate evaluation criteria and criteria weightings been utilized in the evaluation process for the alternatives and the proposed project and what additional criteria/weightings could be considered?
- 3.1 Are the proposed near term and interim measures as outlined in the application appropriate?

Ref

1. APPENDIX A to Procedural Order No. 5. In The Matter of Leave to Construct Application by Hydro One Networks. EB-2007-0050. Dated February 25, 2008
2. Direction of Board from Issues Day and Schedule Hearing, February. 21, 2008.

Preamble:

The following documents are, in my estimation, entirely relevant and necessary for the understanding of the Board, and the Interveners, of the Application, the Applicant's preferred option and how that option was deemed to be superior to the alternatives. As was determined at the Issues Day and Schedule Revision hearing [Feb. 21, 2008], it is in the best interests of all parties, and the Application process, that these be made immediately available to the Interveners and the Board for review and consideration. Also, at this time it was, apparently, determined that two of these documents were definitely produced with public availability understood, and that there was no matter of confidentiality for any of the first three documents requested. The Applicant voiced no objection to any of this at the hearing [Feb. 21, 2008]. I must state, here, that I will view non-compliance regarding these initial five interrogatories as a matter of Motion, and will request a Motions day on this basis. As I understand, the following requests were, however, to be framed as Interrogatory. So that there will be no chance of refusal based on my earlier written request not being precisely framed in Interrogatory format I have revised them, as follows.

Request:

Will, the Applicant and its Proponents [OPA, IESO] provide the Interveners, and the Board, with the relevant documents, studies, consultations or reports, listed below?

1. IESO_REP_0245v2.0
10-YEAR OUTLOOK:
An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015
[release date: August 15, 2005]
2. IESO_REP_0299
CONNECTION ASSESSMENT & APPROVAL PROCESS SYSTEM IMPACT
ASSESSMENT REPORT
For the Proposed Installation of Series Capacitors in the 500kV Circuits between the Bruce Complex & Nanticoke GS
Applicant: Hydro One Networks Inc.
CAA ID No. 2005 200
Transmission Assessments & Performance Department
FINAL Version
Date: 11th April 2006
3. From: Pg. 38 of the SIA REPORT: INSTALLATION OF 500kV SERIES
COMPENSATION.[#2, above]
The study, cited under: 16.2 Recommendations.
•The ABB Study that was commissioned by Hydro One.

[Response](#)

The requested studies are included as Attachments 1, 2 and 3-1 to 3-3 on the CD being provided. Hard copies of the Attachments 1 and 2 are also included.

Attachment 3 (the ABB study and companion pieces) contains the following reports:

- 3-1 – Main Report (labelled “Draft Report”)
- 3-2 – Appendices
- 3-3 – SSR Mitigation Final Report



10-YEAR OUTLOOK:

An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario

From January 2006 to December 2015

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Executive Summary

The provincial government's plan to phase out coal-fired generation in favour of cleaner forms of generation represents one of the most significant undertakings in the 100-year history of Ontario's electricity sector.

Aging generation facilities and the continued increase in demand for electricity add to the urgency of proceeding with new generating and transmission facilities over the next 10 years.

Over the last 12 months 650 MW of new gas-fired generation has been put in place and 515 MW of nuclear generation and 370 MW of renewable generation is expected to be in service within the next 18 months. There are also a number of projects totalling more than 9,000 MW of additional capacity that are in various stages of discussion, development or negotiation. Timely progress to achieve this additional capacity must continue if Ontario is to ensure a reliable supply of electricity over the next decade and beyond.

This 10-year Outlook from the Independent Electricity System Operator (IESO) provides an assessment of the demand-supply picture for the province over the next decade and provides a plan identifying the timing and requirements of system changes needed to meet the government's coal shutdown timeframe. Under the provisions of Bill 100, the Ontario Power Authority (OPA) is responsible for long term forecasting. However, the IESO has agreed to produce the 10-year Outlook in 2005 while the OPA determines how best to address its forecasting responsibilities.

Electricity Supply Outlook

There have been a number of positive developments in Ontario's electricity sector since the IESO published the previous 10-year Outlook on April 29, 2004.

These new developments include the introduction of 650 MW of gas-fired generation into the Ontario market, the decision to proceed with restarting Pickering Unit 1 (bringing an additional 515 MW on line in September 2005), and the announcement of 2,200 MW of new supply initiatives and 395 MW in renewable energy projects under the provincial government's recent Request for Proposals process. All of the new supply resources announced under the RFP process are expected to be in service within the next four years.

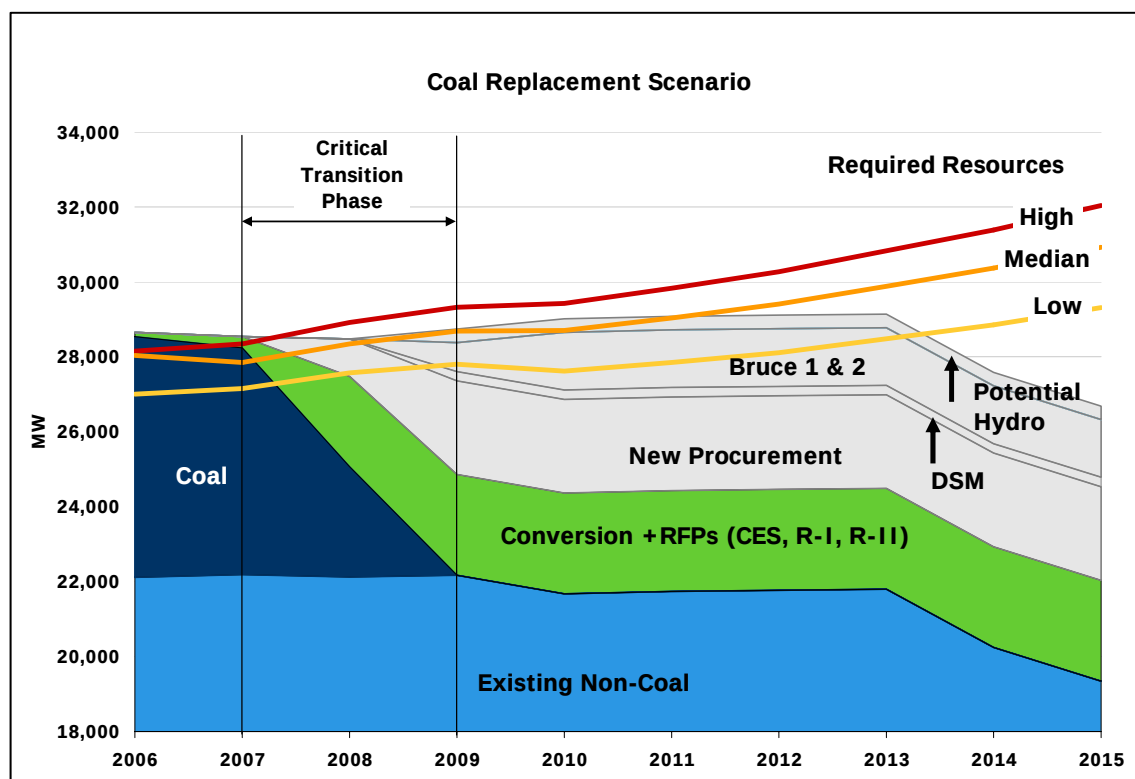
The government has also clarified the timing associated with the commitment to phase out coal-fired generation, which has extended the phase out period for the units at the Nanticoke Generating Station until 2009.

In addition to the committed projects discussed above, there are a number of other projects which are in various stages of discussion, development, or negotiation. These projects represent more than 9,000 MW of additional generation and include:

- the return to service of Bruce GS Units 1 and 2;
- increasing the energy capability of Beck 2 GS by construction of a third tunnel;
- the development of additional hydro-electric generation capacity in Northern Ontario;
- recently announced plans for additional generation in downtown Toronto and the western Greater Toronto Area (GTA), co-generation across the province and demand-side measures;
- the return to service of Pickering GS Units 2 and 3;

- the development of conservation programs under the Ontario Power Authority;
- the development of additional renewable generation to meet the Renewable Portfolio Standard of 2,700 MW by 2010; and
- Long-term power purchases from Manitoba and Newfoundland and Labrador.

Timely decisions on these projects will be key to addressing the projected shortfall which would occur if coal were shut down and not replaced. Continuing progress toward establishing and meeting in-service dates is critical. The supply picture with the first four items included, these being considered to be the more advanced projects, is provided in the diagram below.



Ontario Demand Forecast

The government has set aggressive targets for energy conservation to reduce peak electricity consumption by 5% by 2007. However, because the impact of new conservation initiatives is as yet difficult to forecast, the effects of conservation efforts are not reflected in the Ontario demand forecast used in this Outlook. These conservation efforts can make a significant difference. Without them energy consumption is forecast to grow from about 157 terawatt-hours (TWh) in 2006 to about 170 TWh in 2015, an average annual growth rate of energy of 0.9%.

Normal weather peak demands are expected to increase from about 24,200 MW in 2006 to 26,900 MW in the summer of 2015, an increase of 2,700 MW. Under extreme weather conditions, the summer peak is projected to approach the 30,000 MW level by the end of the forecast period.

Update

This Outlook provides an update on three key issues identified in last year's assessment:

- the Ontario Government's off-coal program (the subject of recent policy pronouncements, the implications of which are reflected in this assessment);
- the supply to downtown Toronto, and;
- the need for additional supply in the western GTA.

Coal Replacement

The Ontario government is committed to phasing out the remaining 6,500 MW of coal-fired generation in the province beginning in 2007 and ending in 2009 as replacement resources become available.

This transition represents the largest and most significant electricity system change ever undertaken in Ontario and involves major technical considerations. It also involves significant risks and challenges that need to be addressed.

The IESO will monitor and assess the coal shutdown and replacement resource plans and will provide advice to all parties regarding the actions or adjustments required to ensure reliability is maintained.

New generation units typically encounter more operating issues affecting their reliability for a period of time after they come in service. These can be significant. Accordingly, a critical requirement of the coal replacement plan is that while coal plants can be scheduled to stop running, those units will be held available for a period of time to operate if necessary to maintain reliability.

Coal supply makes up a large part of Ontario's flexible generation, and it has traditionally been required to meet changing demand, to supply demand when other supply sources are unreliable, and to balance load and generation at all times. The specific operating characteristics of new generation will require changes to current practices in order to provide operating flexibility and sustained energy production capability as and when it is needed.

The impact of new generation on the transmission system will also be assessed, and necessary transmission upgrades must be completed to ensure reliable system operation.

A plan is provided illustrating timing and requirements of system changes needed to meet the government's coal replacement objective.

Supply to Downtown Toronto

New generation and transmission facilities supplying the downtown Toronto area are urgently needed over the next five years to meet this area's growing need for electricity.

The government has requested that the OPA procure 500 MW of new supply to address the concerns raised in the last 10-Year Outlook about supply to downtown Toronto.

There is an increasingly high risk of transmission facilities supplying downtown Toronto becoming overloaded during heavy demand periods and a combination of new generation

capacity, demand-side initiatives and transmission are needed to alleviate this concern. The present transmission facilities are already operated at or near their capacity during hot summer days when electricity demand is high due to the heavy use of air conditioning. As electricity demands continue to grow faster than new transmission can be built, it is vitally important for generation to be located in the downtown area within the next two to three years in order to reduce power flows through heavily loaded transmission facilities to acceptable levels.

In the absence of additional generation as well as demand-side initiatives, it is expected that, emergency load shedding would be required in order to prevent the overloading of transmission facilities.

The immediate risk that load shedding will be necessary in Toronto will be addressed for a number of years by locating additional generation in the area. However, over time, this risk will again grow to unacceptable levels as electricity demand in downtown Toronto continues to grow, and new transmission, or even more generation, must be built to provide more supply capability to downtown Toronto. Hydro One has proposed two alternative transmission projects to address this need – a Direct Current (DC) Option and an Alternating Current (AC) Option. Both options meet IESO criteria and improve the reliability of supply to downtown Toronto. However the DC option is preferred as it requires fewer other transmission system upgrades and provides desirable geographic diversity.

Supply to Western Greater Toronto Area (GTA)

The previous 10-Year Outlook indicated that additional generation capacity or demand-side initiatives were required in the western GTA to replace generation previously supplied by the Lakeview coal-fired station, and to thereby alleviate the risk of auto-transformer overloading.

The recently completed first phase of the Parkway Transformer Station in Markham, the extension of an existing 230 kV double circuit line between Richmond Hill and Markham, and the installation of new transmission equipment in a number of stations within the GTA have provided necessary short term relief.

Several successful RFP projects are located within the western GTA, to be brought into service between fall 2005 and summer 2009. However, these projects are not sufficient to address the growing problem. The need for additional supply in this area is still urgently required. The government's plan includes procurement of an additional 1,000 MW to meet this need.

This Outlook also updates other reliability concerns identified in previous Outlooks and their potential solutions, and identifies emerging reliability concerns.

- End of Section -

Caution and Disclaimer

The contents of these materials are for discussion and information purposes and are provided “as is” without representation or warranty of any kind, including without limitation, accuracy, completeness or fitness for any particular purpose. The Independent Electricity Market Operator (IESO) assumes no responsibility to you or any third party for the consequences of any errors or omissions. The IESO may revise these materials at any time at its sole discretion without notice to you. Although every effort will be made by the IESO to update these materials to incorporate any such revisions it is up to you to ensure you are using the most recent version.

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Table of Contents

Executive Summary	iii
Table of Contents	ix
1.0 Introduction	1
1.1 Changes from the Previous 10-Year Outlook	2
2.0 Resources	5
2.1 Existing Generation Resources Included in this Assessment.....	5
2.2 Committed and Contracted New Generation Resources and Demand-Side Projects.....	5
2.3 Summary of Generation Resource Scenarios	6
3.0 Resource Adequacy Assessment	9
3.1 Supply/Demand Modeling Approach	9
3.2 Load and Capacity Results.....	9
3.3 Other Considerations and Influencing Factors	11
4.0 Transmission Adequacy Assessment.....	17
4.1 Greater Toronto Area.....	17
4.2 Downtown Toronto.....	21
4.3 Supply Issues in the Newmarket - Aurora Area	25
4.4 Kitchener, Waterloo, Cambridge, Guelph and Orangeville Area	25
4.5 Burlington TS.....	26
4.6 Bruce Complex.....	27
4.7 Northeastern Ontario.....	28
4.8 Sarnia-Windsor Area.....	30
4.9 Supply to the Loads in the Oshawa and Belleville Areas	32
4.10 Northwest.....	33
4.11 Ottawa Area	34
4.12 Niagara Area.....	34
4.13 Summary of Transmission Enhancements Identified in the 10-Year Outlook	34
5.0 Coal Replacement Plan	39
5.1 System Aspects of the Coal Replacement Plan	40
5.2 System Transition Risk Mitigation.....	48
6.0 Overall Observations, Findings and Conclusions	53
Appendix A – Resource Adequacy Assessment Details	63
Appendix B Transmission Diagrams	67

List of Tables

Table 2.1 Existing Installed Generation Resources.....	5
Table 2.2 Committed and Contracted Generation Resource Additions and Demand-Side Projects	6
Table 2.3 Installed Generation Resources at Summer Peak	8
Table 4.1 Summary of Transmission Enhancements Identified in the IESO 10-Year Outlook.....	34
Table 5.1 Factors which Reduce Ability to Accommodate Increased Bruce Generation	45
Table 5.2 Coal Replacement Plan Milestones.....	51

List of Figures

Figure 3.1 Resource Adequacy Outlook – Summer Peak	10
Figure 3.2 Resource Adequacy Outlook – Coal Replacement Scenario	11
Figure 5.1 Critical Transition Period	40
Figure 5.2 Power Flow – Southwestern Ontario and the GTA.....	44
Figure 5.3 Impact on Transition Period of Replacement Generation Delays.....	50

1.0 Introduction

This report presents a 10-year forecast and assessment of the adequacy of generation and transmission facilities in Ontario. Its primary purpose is to provide information to the industry for long-term planning and investment decisions.

In addition, this report provides a plan identifying the timing and requirements for system changes needed to meet the government's coal shutdown timeframe.

This report incorporates information received from market participants and others between December 2004 and June 2005. It supersedes the previous 10-Year Outlook published by the Independent Electricity Market Operator (IESO) on April 29, 2004.

The objective of this Outlook is to report the required infrastructure development, including the need for new or modified IESO-controlled grid facilities to maintain the reliability of the system and to assist the IESO-administered markets to operate efficiently. A reporting period of ten years spans the lead-time to install most new generation and transmission facilities. The assessment of generation adequacy is based upon ensuring that sufficient resources are available to meet the forecast demand plus required reserves. Ontario generation that is available to operate is assumed to supply Ontario demand. The assessment of transmission adequacy is based upon ensuring that sufficient transmission capability is available to transmit power to forecast loads in a secure manner.

This Outlook focuses on the assessment of resource and transmission adequacy to reliably supply load. Other supporting information, forecasts and assessments are contained in separate documents. These documents will be updated as required.

The document titled "Ontario Demand Forecast from January 2006 to December 2015" (IESO_REP_0246) (found on the IESO Web site at http://www.ieso.ca/imoweb/pubs/marketReports/10Year_ODF_2005jul.pdf) describes in detail the forecast of electricity demand for Ontario used in this Outlook. The document provides the details regarding peak and energy demand forecasts for Ontario and parts thereof. It also contains information regarding variations in demand due to weather, economic growth and calendar day types.

The document titled "Methodology to Perform Long Term Assessments" (IESO_REP_0266) (found on the IESO Web site at http://www.ieso.ca/imoweb/pubs/marketReports/Methodology_RTAA_2005jun.pdf) contains information regarding the methodology used to perform the demand forecasts, and resource and transmission adequacy assessments in this Outlook.

The document titled "Ontario Transmission System" (IESO_REP_0265) (found on the IESO web site at http://www.ieso.ca/imoweb/pubs/marketReports/OntTxSystem_2005jun.pdf) provides specific details on the transmission system, including the major internal transmission interfaces and interconnections with neighbouring jurisdictions.

Readers are invited to provide comments on this report or to give suggestions as to the content of future reports. To do so, please call the IESO Customer Relations at 905-403-6900 or 1-888-448-7777 or send an email to forecasts.assessments@ieso.ca.

1.1 Changes from the Previous 10-Year Outlook

Changes to Forecast Demands

The most significant impacts on the current electricity demand forecast have been the actual events of 2004 and the updated economic outlook for Ontario. In 2004, the system exceeded historical maximums and set ever higher all-time winter peak demand – twice. The first record winter peak occurred on January 15th, 2004 when the peak demand was 24,937 MW. This record level was exceeded again later in the year on December 20th, 2004 as demand surpassed the January peak by 42 MW to reach 24,979 MW. Overall, the winters of 2003-04 and 2004-05 were milder than normal. As well, the summer of 2004 was also milder than normal. Despite the moderate weather, actual electricity demand grew by 1.1% over 2004 or 1.0% on a weather-corrected basis.

Much of the strength in the growth in 2004 can be attributable to the resource sectors of the economy. Demand for commodities pushed prices up and helped push up electricity demand from the spring through to the end of the year. Low interest rates continued to facilitate domestic demand, construction and business investment leading to economic growth for Ontario in 2004. However, the economy shed manufacturing jobs in 2004 and purchases were funded through higher debt. Growth was not broad-based in 2004.

The economic outlook for the near term (2005-2006) is more moderate than the previous forecast. This is due to the higher dollar, higher oil prices, manufacturing job losses and mixed economic signals. Whereas, the resource sectors drove growth in 2004, these same sectors have started 2005 on a much weaker note. The U.S. has displayed much stronger growth than Canada despite higher interest rates and large budget and trade deficits. Over the near term, high oil prices are expected to slow the economy but at the same time put upward pressure on the Canadian dollar. Lower interest rates compared to the U.S. put downward pressure on the dollar and help facilitate domestic investment and spending. Ultimately, Ontario's economy will benefit from lower oil prices, a lower dollar and continued growth in the U.S.A.

Over the long-term, economic growth is expected to be slightly higher than the last 10 year forecast. This is due to strong economic fundamentals: low interest rates, low inflation and budget surpluses.

After taking into account the actual experiences of 2004 – both economic and electricity demand – in conjunction with the updated economic forecast, the energy and peak demand forecast is lower than the previous 10-Year Outlook. Given that energy and peak demand for 2004 were lower than expected, this forecast begins at a lower starting point. The weaker economic growth in the near term is somewhat offset by the stronger economic growth over the long term. Therefore, although the levels are lower, the growth rates are very similar. Energy demand (under Normal weather) is expected to exhibit average growth of 0.9% per annum over the forecast horizon. This compares to 0.9% for the previous 10-Year Outlook. The low growth scenario predicts energy demand to have average growth of 0.4%, while the high growth scenario has average growth of 1.3% per year. The summer peak is expected to grow at 1.3% (versus 1.1% previously) and the winter peak is expected to grow at an annual average rate of 0.7% (versus 0.7% previously). The Normal weather peaks are predicted to be 25,500 MW for the winter of 2014 (versus 25,600 MW previously) and the forecast summer 2014 peak is 26,500 MW (versus 26,600 MW).

Changes to Resources

The amount of existing installed generation resources has been updated from the previous 10-Year Outlook to include all generators that are registered to participate in the IESO-administered markets. The latest generation resource additions and upgrades, and the latest capacity ratings are also included. The list does not include generators that are not registered to participate in the IESO-administered markets.

The June 15, 2005 announcement by the Ontario Government of their coal shutdown plan has prompted the IESO to define two resource scenarios rather than just a base reference scenario as was the case in 2004. These scenarios are fully described in Section 2. The Reference Resource Scenario is based on existing generation plus the capacity contributions expected from the three RFP's issued to date. The second scenario, which builds on the reference case, includes the capacity contributions expected from the Ministry of Energy's announced plan plus several initiatives previously announced.

Changes to Transmission Outlook

This 10-Year Outlook focuses on transmission constraints critical to the province. Previous deliverability and contingency studies have not been repeated this year since little has changed over the intervening months from the 2004 Outlook. Historical patterns of congestion are expected to change significantly as new supply and infrastructure is implemented associated with the coal replacement plan.

Readers interested in this information may obtain a copy of the 2004 10-Year Outlook from the IESO web site.

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2.0 Resources

This section describes the generation resources that are forecast to be in service throughout the ten-year assessment period, taking into account existing generation, generation resource additions and unit retirements, based on information available to the IESO.

2.1 Existing Generation Resources Included in this Assessment

The existing installed generation capacity included in this assessment is summarized in Table 2.1. It includes nuclear, coal, oil, gas, hydroelectric, wood and waste-fuelled generation, which results in a total installed capacity of 30,114 MW.

The capacity of installed generation resources in Table 2.1 includes Bruce A Units 3 and 4.

With the uncertainty around the reactivation of the remaining Pickering A nuclear units, the IESO has decided to only include the one operable unit, Unit 4, in the list of existing installed generation resources.

Table 2.1 Existing Installed Generation Resources

Resource Type	Total, MW	Percentage of Total, %	# of Stations
Nuclear	10,882	36.1	5
Coal	6,434	21.4	4
Oil / Gas	4,976	16.5	20
Hydroelectric	7,756	25.8	67
Miscellaneous	66	0.2	2
Total	30,114	100.0	98

2.2 Committed and Contracted New Generation Resources and Demand-Side Projects

Table 2.2 summarizes the new generation projects which are under construction or have signed contracts with the provincial government as a result of the first 300 MW Renewables Request for Proposal and the 2,500 MW Clean Generation and Demand-Side Projects RFP. The in-service dates in Table 2.2 have been provided either by generator owners directly or by the Ontario Government, based on the contract date.

This Outlook does not provide a summary of all generation projects in the IESO queue. Details regarding the IESO's Connection Assessment and Approval (CAA) process and the status of all projects in the queue, including copies of available Preliminary Assessment and System Impact Assessment Reports, can be found on the IESO's web site www.ieso.ca under the "Services - Connection Assessments" link.

Table 2.2 Committed and Contracted Generation Resource Additions and Demand-Side Projects

Project	Zone	Fuel Type	Installed Capacity MW	Connection Applicant's Estimated I/S Date
Pickering Unit 1	Toronto	Uranium	515	2005-Q3
Greater Toronto Airports Authority	Toronto	Gas	117	2005-Q4
Kingsbridge Wind Power Project	Southwest	Wind	40	2005-Q4
Melancthon Grey Wind Project	Southwest	Wind	68	2005-Q4
Prince Wind Farm	Northeast	Wind	99	2006-Q1
Erie Shores Wind Farm	Southwest	Wind	99	2006-Q2
Loblaws Properties	distributed	Demand	10	2006-Q2
Blue Highlands Wind Farm	Southwest	Wind	50	2006-Q3
Umbata Falls Hydroelectric	Northwest	Water	23	2007-Q1
Greenfield South Power Project	Toronto	Gas	284	2007-Q4
Greenfield Energy Centre	West	Gas	1,015	2007-Q4
St. Clair Power	West	Gas	688	2008-Q1
Greenfield North Power Project	Toronto	Gas	330	2009-Q2
Total			3,338	

2.3 Summary of Generation Resource Scenarios

Two resource scenarios have been developed for this Outlook, in view of the Ontario Government's recently announced plan to phase out coal-fired generation in the province. These scenarios are described below.

2.3.1 Reference Resource Scenario

The Reference Resource Scenario incorporates existing and committed resources as follows:

- existing Ontario resources, summarized in Table 2.1, will be in-service for the duration of the study period, with the following exceptions:
 - o Lambton units will be removed from service by December 31, 2007 following the reliable incorporation of replacement generation;
 - o Coal-fired generation at Atikokan will be retired and Thunder Bay will be replaced with cleaner generation by December 31, 2007;
 - o Bruce A Unit 3 will be removed from service beginning November 1, 2009. This is a conservative assumption that will be reviewed as part of the market participant's normal business planning process. Further operation beyond this date will depend on the material condition of the unit and market conditions;
 - o Pickering B Units 5, 6 and 7 pressure tubes reach the end of their life by 2013. For analysis purposes, the three units were assumed to be out of service starting January 1, 2014, pending development of refurbishment plans by Ontario Power Generation, (OPG).
 - o Bruce Unit 6 reaches the end of life for its pressure tubes and is assumed to come out of service in 2015.

- the additional committed resources listed in Table 2.2 were assumed to be in service on the dates indicated;
- of the remaining three Pickering A units, Unit 1 was assumed to return to service prior to the 2006 system peak. The return to service date is planned for Q4 2005 based on information provided by OPG;
- no price-responsive demand beyond that shown in Table 2.2 was assumed to provide the equivalent of dependable capacity to the power system. This approach has been adopted because of the ease with which dispatchable and other price-responsive demands can change their operation within the market, easily shifting from being price responsive to being a price taker. Although price-responsive demands will continue to be recognized for operational decision making in the 18-Month Outlooks, the IESO has adopted the approach that these demands will need to be supplied in the longer-term;
- Nanticoke units were considered to be in-service for the entire 10-Year period. Based on the assumptions of the Reference Resource Scenario, all Nanticoke units were required to be in-service for the entire 10-Year period, since the generation and demand side additions in Table 2.2 are insufficient to allow for the removal from service of any of the Nanticoke units;
- Wind generation is assumed to provide a capacity contribution of 10% of the installed capacity of the project at the time of the annual peak; and
- the second renewables RFP was assumed to attract 1,000 MW by 2009. For purposes of analysis, the IESO assumed all of the successful projects for this RFP would be wind generation with a capacity contribution of 10% of the maximum rating of each project at the time of the annual peak.

2.3.2 Coal Replacement Scenario

The Coal Replacement Scenario incorporates existing, committed and additional announced initiatives in various stages of discussion, development or negotiation. This scenario assumes the Reference Resource Scenario with the following modifications:

- Bruce GS Units 1 and 2, amounting to 1540 MW, return to service in 2009;
- Additional power is procured for downtown Toronto (500 MW) and for western GTA (1,000 MW) before the end of 2008 at the latest;
- Cogeneration amounting to 1,000 MW is assumed to come in service in 2008.
- Demand side measures are expected to provide the equivalent of 250 MW of supply starting in 2009
- Potential hydroelectric development of up to 380 MW in the Northeast is assumed to come in service in 2009
- Nanticoke GS generating units (4,000 MW) are assumed to be shutdown over the period 2008 to 2009, as replacement generation and required system infrastructure are brought into service.

The purpose of the coal replacement scenario is to provide a plan identifying timing and requirements of system changes needed to meet the government's coal shutdown timeframe. More details of the plan can be found in Section 5.0.

2.3.3 Installed Resources at the Summer Peak

Table 2.3 shows the installed generation resources, at the time of the summer peak demand, under the Reference Resource Scenario and the Coal Phase out Scenario. The values in the table do not include the 10 MW of demand response contracted under the 2,500 MW RFP.

For the assessment of the entire ten year period, the resource analysis in this Outlook focuses on the summer peak period since this is usually the most challenging seasonal peak to meet. Our examination of the transition period later in the Outlook considers both summer and winter peak periods to provide greater detail.

Table 2.3 Installed Generation Resources at Summer Peak

Year	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Reference Resource Scenario	31,052	30,992	32,024	32,423	31,911	31,984	32,018	32,054	30,502	29,595
Coal Replacement Scenario	31,052	30,992	32,042	32,128	32,386	32,459	32,493	32,529	30,977	30,070

- End of Section -

3.0 Resource Adequacy Assessment

This section provides an assessment of the adequacy of the two resource scenarios described in Section 2 to meet the forecast demand. Capacity analyses were performed using the IESO's Load and Capacity program (L&C). The general methodology and tools used to carry out these analyses are described in detail in the document titled "Methodology to Perform Long Term Assessments" (IESO_REP_0266v2.0). Variations from the standard methodology are described in Section 3.1.

3.1 Supply/Demand Modeling Approach

The two resource availability scenarios described were created based on the assumptions provided in Section 2.3. Generator deratings, planned and long-term generator outages, generation constrained-off due to transmission interface limitations and allowances for non-utility and hydroelectric generation production below rated capacity were also included in the resource assumptions.

For the first year of the study period, specific generator outage plans were used. For the ten year study period a hypothetical outage plan was used which reflects known cyclic outages (such as nuclear station containment outages) and planned outage factors supplied by generator participants. This is referred to as a "generic" outage plan to reflect the fact the majority of assumptions were modeled repetitively for the ten years studied.

The forecast demand scenarios used to perform the adequacy assessment correspond to low, median and high demand growth. Comprehensive analyses were carried out for all combinations of demand growth scenarios and the Reference Resource Scenario. Results for the Coal Replacement Scenario were derived by arithmetic extrapolation from the Reference Resource Scenario.

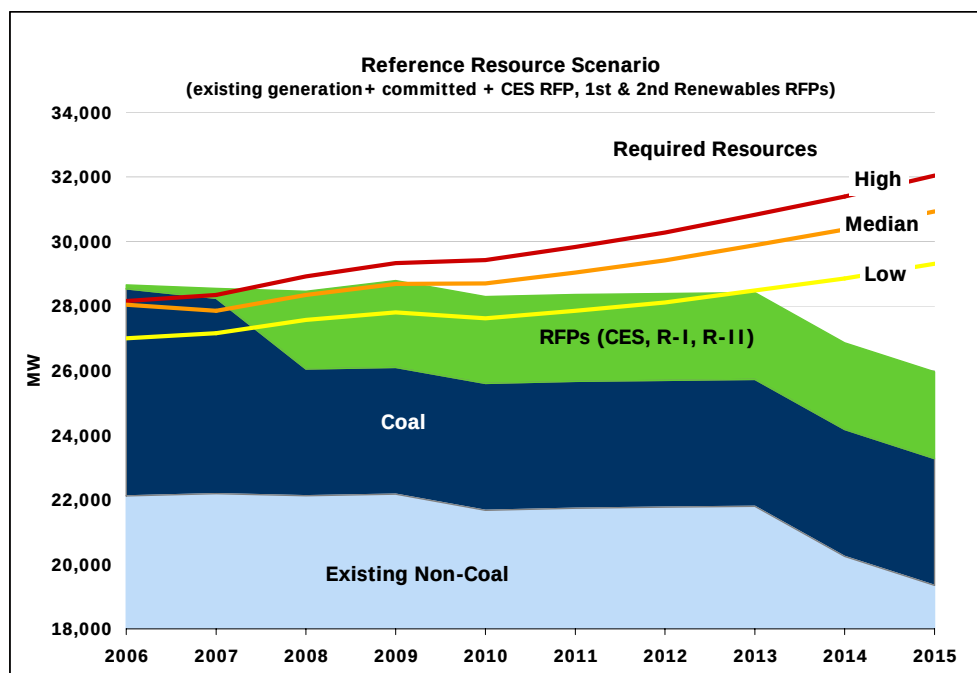
3.2 Load and Capacity Results

Reference Resource Scenario

Load and Capacity (L&C) model calculations were performed for the Reference Resource Scenario described in Section 2.3, with reserves calculated for the weekly peaks of each year in the study period, for each demand scenario. Graphical results of the L&C program calculations, for the summer peaks, are shown in Figure 3.1. Tables A1 to A3 in Appendix A provide more numerical details.

L&C results indicate that Ontario could be facing substantial delays to the coal phase-out and a growing supply shortfall beyond the first few years of the 10 year period, if committed projects are delayed. Reserve requirements will be met in the first five years under the median demand growth scenario if no in-service delays are encountered for the RFP projects. For the low demand scenario, reserve requirements are met until 2013. However, if high demand growth occurs, additional supply will be required by 2008 and possibly earlier.

Figure 3.1 Resource Adequacy Outlook – Summer Peak



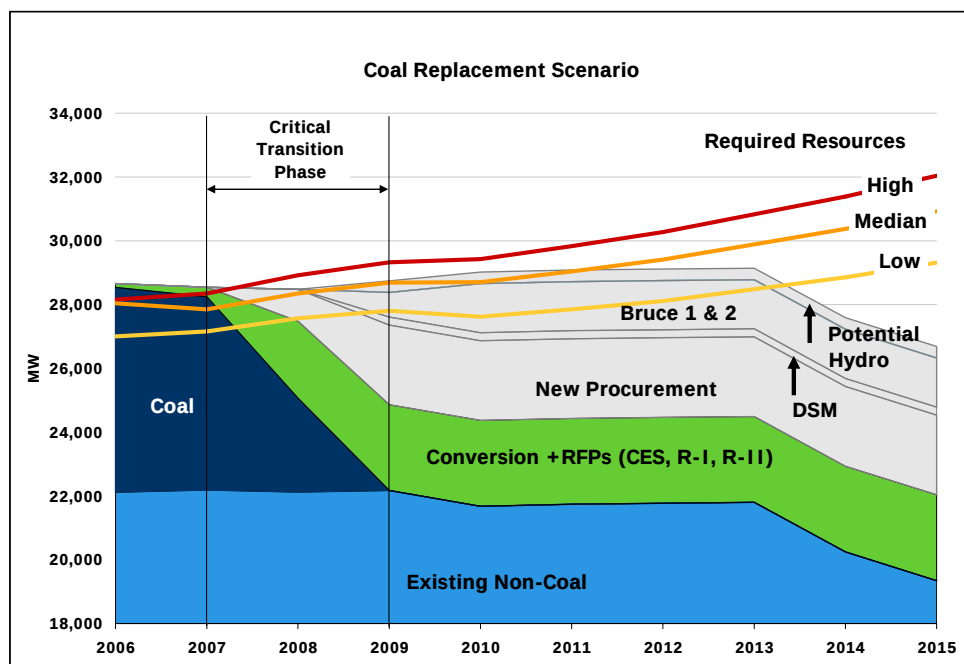
In order to avoid extensive reliance on external supply, any supply shortfall would have to be made up from generation additions and demand-side initiatives within Ontario. Events that would decrease supply availability or increase demand, such as extreme weather, higher than expected generator forced outages, and lower than forecast hydroelectric resources, would result in increased need for additional supply and dependence on external supply through interconnections.

Coal Replacement Scenario

Supply adequacy calculations were also performed for the Coal Replacement Scenario described in Section 2.3, with reserves calculated for the summer peaks of each year in the study period, for each demand scenario. Graphical results of the calculations are shown in Figure 3.2. Tables A4 to A6 in Appendix A provide more numerical details.

The supply adequacy calculations shown in Figure 3.2 illustrate the dependence on achieving all elements of the replacement supply associated with the coal replacement plan. This is a very challenging plan, requiring most actions to be committed before the end of 2005. Any delays in regulatory approvals or construction would result in delays to the coal shutdown for most demand growth assumptions. Once a target shutdown has been established for each plant, the risk that it will be inoperable or less reliable increases as the shutdown date approaches. Because of the high level of uncertainty and the severity of the consequences of supply shortages, it is critically important that replacement supply be fully proven before permanently removing each coal-fired station from service. A period of at least nine months overlap of replacement generation operation with coal-fired generation kept in reserve is required. Retaining coal units in an operable state should not impact on expected emission reductions since unit operation could be limited to periods when operation is essential.

Figure 3.2 Resource Adequacy Outlook – Coal Replacement Scenario



3.3 Other Considerations and Influencing Factors

There are many factors that are important considerations in the redevelopment of Ontario's electricity infrastructure, some of which could cause the long-term supply-demand balance to change. On the supply side, failure to meet the requirements discussed in this section would tend to reduce the operable generation from that assumed in the adequacy analysis.

3.3.1 Demand Growth

Higher demand growth than that assumed under the high demand growth scenario, would create an earlier and larger need for additional resources or demand response. Lower demand growth than assumed under the low demand growth scenario above, would delay and lower the need for additional resources. Lower energy and peak demand growth can be achieved through implementation of conservation programs oriented to demand-side management, energy efficiency and peak demand shifting.

3.3.2 Capacity Sustainability

Experience over the summer has also shown that, even when sufficient capacity is available, its use can be limited because of a lack of energy. An example of this occurs when peaking hydroelectric generation is operated extensively early during summer peak demand periods, in response to market demands and, as a result, the resources have insufficient water available in storage reservoirs to support required levels of operation later in the peak summer demand period. An exceptionally dry season can have the same effect. About 24 percent of the capacity within Ontario is hydroelectric with much of it subject to this risk.

Similarly, wind capacity is only available when the wind blows. During winter periods, a relatively strong coincidence of wind output and peak demand is expected, especially since wind

chill drives heating demand higher. However during summer periods, peak demands typically occur during hot periods with little wind, the type of weather which pushes air conditioning loads to their maximum. The reduced contribution from wind during these periods increases the power system's reliance on alternative supplies of capacity.

3.3.3 Hydroelectric Generation Flexibility

The IESO is concerned with the future management of the Province's water resources as they relate to electricity production. The flexibility in the operation of hydroelectric facilities is of value to the Ontario power system. The importance of this needs to continue to be reflected and balanced with other options which may influence provincial requirements with respect to water management.

Ontario's electricity consumption pattern has changed over the last decade. Consumers have historically used a lot more electricity in the winter than they did in the summer. This has reversed. Peak electricity demands now occur during the summer, the season in which water management is typically most restricted.

Within a typical day, the total hydroelectric energy production pattern follows the shape of the total Ontario electricity demand. This flexibility of hydroelectric generation is significant; these plants can store potential energy when it is needed least (e.g., overnight) and can deliver their energy very quickly when it is needed (e.g., during morning load pickup when Ontario consumers increase their electricity use, at times greater than 3,000 MW per hour). Similar benefit exists from managing the water for electricity production on a weekly and seasonal basis.

The flexibility of hydroelectric generation has always been of value but its importance will increase even more in the future. Coal-fired generation, while not as flexible, currently provides an important capability to meet load pick up and drop out requirements. That capability may be reduced when the coal plants shutdown. Conservation, while reducing overall requirements, will not likely change the load pick-up requirement. Much of the renewable generation is expected to be wind power which has many positive features but cannot effectively be ramped up or down to meet changes in demand. Demand management is likely to help reduce peak demands but is not likely to affect ramping requirements. Gas-fired generation will have the required flexibility but even it can be limited if the plant is an efficient cogeneration facility. Given the expected future mix of resources in Ontario, the value of hydroelectric flexibility will increase.

In addition to providing energy and ramping capability, the flexibility of waterpower makes it extremely valuable for two other essential reliability products; operating reserve and automatic generation control.

- Hydroelectric generation is ideally suited for operating reserve; there is often not enough water to allow full hydro production all of the time, but frequently there is enough to run to full output quickly and maintain it until slower acting generators can increase production.
- The provincial demand for electricity varies second to second, sometimes by surprisingly large amounts. Hydroelectric generation is used very effectively to continuously keep this varying demand and supply in balance, and to keep Ontario's trade with other states and provinces on schedule. Historically in Ontario, very short-time balancing "automatic generation control" has been provided by a small number of hydroelectric plants. Restrictions on the allowable limits within which hydroelectric facilities operate would

require extending the use of automatic generation control to more market participant generators.

Ontario's future generation supply mix will place an increasing reliability value on the flexibility of generating assets to provide load following capability, operating reserve and automatic generation control. Preserving operating flexibility of hydroelectric generating facilities (whether old or new) should be a critical consideration in the development of water management plans.

3.3.4 Integration of Wind Supply

Even prior to the Renewable RFP's, several thousand MW of wind generation had made application to the IESO for connection approval. With the awarding of contracts to several wind proponents, exceeding 350 MW in total with more expected from the second Renewable RFP, it will not be long before significant amounts of wind generation are contributing to the energy needs of the province.

Like the integration of gas-fired generation, connecting large amounts of wind to the grid will not be without challenges. Early studies indicate wind should make significant contributions to energy but there is less certainty with respect to the peak-meeting capacity contribution that wind will make. The geographic diversity of projects around the province should provide some stability to wind output and reduce the impact of local wind fluctuations. Improving the understanding of daily patterns and fluctuations of wind generation will be necessary to determine if changes are needed in IESO operating practices and perhaps the Market Rules. Even the act of assessing the connection of wind generation has needed careful examination with respect to aspects such as a facility's ability to stay connected during low voltage excursions, its ability to supply reactive power, data monitoring requirements and others. Notwithstanding these considerations, the presence of wind on the Ontario grid will be a positive contribution to Ontario's future supply mix. For the purposes of this study, it is assumed 10% of the installed capacity of wind powered generation can be relied on at the time of the annual peak.

3.3.5 New Generation Mix

A diverse generation mix is critical for resource adequacy and market efficiency, through the provision of dispatch flexibility, reduced vulnerability to fuel supply contingencies and fuel price fluctuations. In developing a balanced generation portfolio to minimize fuel supply vulnerability, consideration should be given to providing dual fuel capability at plants which are unable to maintain fuel inventories onsite. In particular, this aspect may be necessary for some new gas-fired generation to ensure operational capability during winter peak periods when gas demand and electricity demand peak simultaneously.

Baseload Generation

Baseload generation largely consists of nuclear and run-of-the-river hydroelectric resources which cannot routinely be cycled on and off in response to demand fluctuations. In future, significant additions of gas-fired cogeneration is expected to also contribute to baseload generation. These types of generators have limited dispatch flexibility, and must be operated at a fixed output, at or near their full capability. If too much baseload generation is present in the supply mix, the amount of generation can have the potential to exceed the market demand, thereby creating a situation known as unutilized baseload generation (UBG). An analysis of the minimum peak demands in the latter years of the study period suggests that up to approximately

4,000 MW of nuclear and run-of-the-river generation resources could be added to the existing in-service baseload facilities towards the end of the ten-year period without causing undue risk of UBG. This amount will be affected by load growth and any load shifting patterns between on-peak periods and off-peak periods.

Intermediate and Peaking Generation

Existing intermediate and peaking generation in Ontario consists mainly of generation fuelled by coal, some gas, oil, and those hydroelectric generators with storage capability. New intermediate and peaking generation must be added to the Ontario resource mix in order to implement the coal replacement plan.

Renewable Generation Resources

Renewable resources consist primarily of hydroelectric, wind, biomass, solar, and geothermal energy sources. These are considered the cleanest and least environmentally impactful of all generation resources. Only wind and a small amount of hydroelectric generation have been contracted under the RFPs for connection to the IESO-controlled grid (ICG). Wind generation, by its nature has very little dispatch flexibility; only when the wind blows, can energy be produced. The diversity among wind projects selected under the RFPs will tend to moderate local fluctuations. Further utilization of wind energy can be achieved through partnering with suitable hydroelectric facilities to co-optimize both types of resources.

3.3.6 Conservation and Demand-Side Measures

The IESO has been identifying the suitability of conservation and demand-side (CDM) measures as part of the supply picture for several years and believes demand reductions and demand shifting should be vigorously pursued in Ontario, as clean and potentially less expensive ways to reduce future supply requirements. The application of such demand initiatives is virtually unrestricted in location.

CDM programs would improve the supply-demand balance in three main ways:

- Price-responsive demand which reacts to market price signals;
- Demand reduction through technological or process efficiency improvements ; and
- Shifting the time of use from peak to off-peak periods through demand-response programs would achieve peak demand reductions.

The Conservation Bureau of the Ontario Power Authority (OPA) has been charged with leading development of conservation and demand-side measures. The provincial government has targeted a 5% demand reduction by 2007 through CDM developments, or approximately 1,350 MW.

The system requires more reactive resources during the summer than the winter for the same level of primary demand. Air-conditioning load is the most significant component of the higher reactive power demand in the summer than in the winter. IESO recommends that Ontario work with other jurisdictions to raise the power factor requirements of new air-conditioning equipment. This would in the long term reduce the need for generation and transmission enhancements to meet the reactive power demand in Ontario. A move to energy efficient appliances has already been encouraged by government programs within Ontario and in other jurisdictions; however, most of these programs have focused on reductions to active (real) power consumption.

3.3.7 Interconnections

In real-time system operation, reliance on external supply through interconnections is mutually beneficial to all interconnected systems, for both reliability and market efficiency reasons. During off-peak periods, attractively priced external supply can provide cost savings to the electricity market. Similarly the interconnections provide access to broader markets for inexpensive Ontario generators. During peak hours, due mainly to the non-coincidence of the peak demands with one or more neighbouring systems, external supply can contribute to meeting peak demand.

Two main aspects are relevant to utilization of interconnection benefits: transmission interconnection capability and external supply availability.

Interconnection Capability

Ontario has a coincident import capability of approximately 4,000 MW through its existing interconnections. Transmission projects have been identified to the IESO through the CAA process to enhance the interconnection capability. An HVDC interconnection with Hydro Quebec of 1,250 MW transfer capability would improve interchanges between Ontario and Quebec. At this time, this project has high project uncertainty.

Although not yet formally submitted for Connection Assessment, an upgrade to the Ontario - Manitoba interconnection would give access to hydroelectric capacity from Manitoba. A joint proposal to receive power from the Lower Churchill Falls area could provide incentive for completion of the development of the proposed HVDC tie with Hydro Quebec.

External Supply Availability

The Northeast Power Coordinating Council (NPCC) CP-5 study entitled "Review of Interconnection Assistance Reliability Benefits" published in May 1999, provided an assessment that over 2,500 MW of interconnection assistance is reasonably available to the Ontario system when needed. More recent studies, conducted in 2004, suggest that a range of 3,150 to 4,050 MW is a reasonable assumption of tie benefit for Ontario from its neighbours, based on interconnection transmission capability and forecast spare supply external to the province.

Future levels of imports into Ontario will vary depending on several factors, including the availability and economic benefits associated with resources in external jurisdictions capable of supplying the Ontario market, and the availability of required transmission capacity. For interconnected supply to contribute to the capacity needs of Ontario, the dependability of supply contracts will need to have an equivalent level of certainty to that of Ontario-based generation.

- End of Section -

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4.0 Transmission Adequacy Assessment

The transmission adequacy assessment provides information to market participants, connection applicants and other stakeholders to assist in planning a reliable transmission system. Where applicable, the assessment also identifies the potential need for IESO-controlled grid (ICG) investments or other actions by market participants to maintain reliability of the IESO-controlled grid and to permit the IESO-administered markets to function efficiently.

The assessments presented in this Outlook, represent the areas of the ICG for which the IESO has concerns or for which transmission enhancement requirements have been identified. Many of the proposed solutions have already been considered by Hydro One in their *“Transmission Solutions, A 10 Year Transmission Plan for the Province of Ontario 2005 – 2014”*.

The general methodology used to assess the transmission adequacy is described in the IESO document titled *“Methodology to Perform Long Term Assessments”* (see Section 1 for a link to that report). Previous deliverability and contingency studies have not been repeated this year since little has changed over the intervening months from the 2004 Outlook. Readers interested in this information may obtain a copy of the 2004 10-Year Outlook from the IESO web site.

Section 4.0 does not exhaustively assess all areas of the IESO-controlled grid. It is possible that other deficiencies in the IESO-controlled grid may exist or emerge. The IESO continuously monitors, assesses and reports the adequacy of the IESO-controlled grid. If additional concerns are identified they will be managed through existing IESO processes.

4.1 Greater Toronto Area

GTA Issues

4.1.1 Lakeview Retirement and the Loading on Claireville and Trafalgar Auto-transformers

The importance of completing the first stage of the development of Parkway TS, together with the installation of the shunt capacitor banks at Richview TS, Burlington TS, Trafalgar TS and John TS was demonstrated during the June 2005 hot spell when a new system peak of 26,157 MW was recorded. The peak transfer through the new 750 MVA auto-transformer at Parkway TS exceeded 600 MVA while the corresponding transfers through each of the four auto-transformers located at Claireville TS and Cherrywood TS were approximately 780 MVA. In addition, the two auto-transformers at Trafalgar TS were operating at close to their nameplate rating of 750 MVA.

Without the new facilities at Parkway TS, it is expected that the 10-day limited-time-ratings of the auto-transformers at Claireville TS, and possibly those at Trafalgar TS, would have been exceeded, necessitating supply interruptions.

4.1.2 New GTA Generation Capacity

Under the Government of Ontario's RFP for 2,500 MW of New Clean Generation Projects, contracts have been awarded to the following three generation projects in the Greater Toronto Area:

Project	Contract Capacity	Connection
Greenfield-South Project	280 MW	230 kV Circuit R24C
Greenfield-North Project	280 MW	230 kV circuits R19T & R21T
GTAA Project	90 MW	44 kV systems of Bramalea TS & Woodbridge TS

The RFP contract capacity indicated in the table above may be less than the expected installed capacity of the generation facilities.

Diagram 1 shows the locations of the new generating facilities.

Analysis has shown that these new generating facilities are expected to result in the following reductions in the transfers through the critical auto-transformers at Claireville TS and Trafalgar TS:

Project		Expected Flow Reductions			
		Claireville TS		Trafalgar TS	
Greenfield-North	280 MW	74 MW	26% of output	44 MW	16% of output
Greenfield-South	280 MW	94 MW	34% of output	23 MW	8% of output
GTAA	90 MW	36 MW	48% of Bramalea Gen.	0 MW	0% of output
		7 MW	48% of Woodbridge Gen.		
Totals	650 MW	211 MW	31% of combined output	67 MW	10% of output

Assuming that the loading on the Claireville and Trafalgar auto-transformers would increase in direct proportion with any increase in the system peak load, then for a peak load of about 27,500 MW, (forecast extreme weather peak for the summer of 2008) these new generating facilities would be expected to be adequate to maintain the transfers through the auto-transformers at Trafalgar TS within their continuous rating.

The new generating facilities would also provide additional margin on the auto-transformers at Claireville TS to accommodate load transfers from the Leaside to the Manby Sector during peak load periods via the new John-to-Esplanade Link without exceeding their continuous rating. However, the new generating facilities would not be able to provide any additional margin on the auto-transformers at either Claireville TS or Trafalgar TS to accommodate future load growth. In addition, the loss of any one of the six auto-transformers at these two transformer stations could cause the 10-day limited-time-ratings of the remaining units to be exceeded, requiring load to be interrupted. Therefore more generation, in addition to the projects listed above, is required beyond summer 2008 to reduce the loading on the Claireville and Trafalgar auto-transformers.

4.1.3 Additional Generation Capacity in the Western GTA

The Government of Ontario has recently announced that the OPA is to procure additional generating capacity totalling approximately 1,500 MW beyond that for which contracts have already been awarded. Of this, approximately 1000 MW is to be incorporated into the western GTA. This is expected to provide further relief for the auto-transformers at Claireville TS, thereby reducing the risk of overloading of the remaining units in the event of a protracted outage involving one of the four Claireville auto-transformers during peak load periods. Depending on the exact location of this new generating capacity, the relief could amount to 480 MW (48%) if the new generation is connected to one of the radial 230 kV circuits from Claireville TS. This would provide an additional deferral of approximately 6 years (until 2014) before the loading on the Claireville auto-transformers would be expected to become an issue once again.

If the new generation is connected to one of the existing 230 kV circuits that are to be reterminated on the new busbar at Cooksville TS, then the relief could amount to 340 MW (34%). The deferral that this would provide before further measures would be required to reduce the loading on the Claireville auto-transformers is expected to be an additional 4 years (until 2012).

Should a portion of the new generation capacity planned for the western GTA be located so that it provides the maximum relief for the loading on the auto-transformers at Trafalgar TS, then this could defer the need for other measures to reduce the transfers through this TS. Incorporating 500 MW of new generation capacity into the 230 kV system between Burlington TS and Richview TS would be expected to defer the need date for further measures until approximately 2013.

Need Date for Additional Generating Capacity in the Western GTA

The completion of the John-to-Esplanade Link at the end-2007 will allow approximately half the load at Terauley TS in the Leaside Sector to be transferred to the Manby Sector during critical supply periods. However, in order to accommodate the transferred load and avoid overloading the auto-transformers at Claireville TS, additional generating capacity will be required in the western GTA, incorporated into the transmission system directly associated with the corridor between Claireville TS, Richview TS and Cooksville TS.

The three Projects that have already been selected for the western GTA (Eastern Power's Greenfield-North, Eastern Power's Greenfield-South and the GTAA Project) will collectively result in a reduction of approximately 210 MW in the transfers through Claireville TS. However, since the Greenfield-North Project is not scheduled to be in-service until the spring-2009, the expected reduction in the transfers through the Claireville auto-transformers during the summer-2008 due to the presence of the other two Projects will only total approximately 130 MW. During peak load periods, this would not be sufficient to accommodate the transferred load as well as the expected load growth in the area that is supplied from Claireville TS.

Consequently, additional generating capacity will be required in the western GTA prior to the summer-2008, so that, in the event of a contingency involving critical facilities in the Leaside Sector during peak load periods, transfers can be made to the Manby Sector via the John-to-Esplanade Link without overloading the auto-transformers at Claireville TS.

4.1.4 500/230 kV Auto-transformers at Trafalgar

The auto-transformers at Trafalgar TS are heavily loaded during summer demands. Actual June 2005 loading was such that an extended outage to one of these auto-transformers would have

resulted in overloading of the remaining transformer such that load interruptions would have been required.

If the new 1,000 MW of generation capacity that is proposed to be installed in the western GTA is located so that it provides the maximum relief for the Claireville auto-transformers, then it is expected that it will provide little relief for the loading on the auto-transformers at Trafalgar TS.

Installing additional auto-transformer capacity at Trafalgar TS would also require the installation of an additional 500 kV line between Milton SS and Trafalgar TS so as to avoid the simultaneous loss of more than two auto-transformers in response to a double-circuit line contingency.

4.1.5 New 230 kV Facilities at Milton SS

One option to unload the Trafalgar and Claireville auto-transformers would involve the installation of two 500/230 kV auto-transformers at Milton SS and the re-termination of the existing connections to Halton TS and Meadowvale TS on to the new 230 kV busbar at Milton SS. This would also reduce the potential for significant load interruption following the loss of any of the existing or proposed radial 230 kV double-circuit lines associated with the Milton - Claireville corridor or the Burlington - Richview corridor. This solution has been proposed by the IESO in earlier versions of the 10-Year Outlook. These new auto-transformers could be connected directly to two of the existing 500 kV circuits in a similar manner to the auto-transformers at Parkway TS so as to minimise the disruption to the existing 500 kV gas-insulated-switchgear at that location.

These new auto-transformers would allow the peak load of approximately 300 MW at Halton TS and Meadowvale TS to be transferred from circuits T38B and T39B, which are supplied predominately from Trafalgar TS, onto the two new auto-transformers. In addition, by extending the connections from Meadowvale TS eastwards to Cardiff TS and Bramalea TS, there would be an opportunity to transfer additional load from the following transformer stations. This would also provide an alternative source of supply to these loads thereby enhancing their supply security:

Station	Peak Load	Existing Supply
Jim Yarrow TS	~ 100 MW	230 kV Circuits R19T & R21T from Richview TS & Trafalgar TS
Pleasant TS	~ 260 MW	
Cardiff TS	~ 40 MW	230 kV circuits V72R & V73R from Claireville TS
Bramalea TS	~ 320 MW	

Diagram 2 shows the proposed arrangement which includes an additional 230 kV switching station at the intersection of the right-of-way of the new 230 kV line between Meadowvale TS and Cardiff TS and that of the existing line to Pleasant TS. This proposal, or an equivalent is needed urgently as actual loading in June 2005 combined with an extended forced outage to one transformer would have exceeded the 10-day limited time rating of the remaining transformers, and necessitated load interruptions.

4.1.6 Reactive Compensation at Halton TS, Meadowvale TS and Palermo TS

None of these transformer stations has any low voltage capacitor banks installed and while their power factors of 0.9 comply with the Market Rules, it means that during peak load periods, over half the output of the new 300 MVar shunt capacitor bank that was recently installed at Trafalgar TS is effectively being used to supply the reactive power demand of these particular loads together with the associated transmission lines losses.

Since it should be possible to install low voltage shunt capacitor banks at these three transformer stations relatively quickly, the additional reactive compensation would then allow the maximum benefit to be derived from the new 300 MVar capacitor bank at Trafalgar TS during the period until the new generating facilities can be incorporated into the system. This upgrade is needed as soon as possible.

4.2 Downtown Toronto

4.2.1 Supply to Downtown Toronto

The downtown area of Toronto is supplied from two sources; Manby TS in the west and Leaside TS in the east, as shown in Diagram 3.

As load grows, the supply to downtown Toronto will be exposed to the potential overload of:

- The 230 kV circuits from Cherrywood to Leaside,
- the 115 kV circuits from Leaside to Hearn,
- the auto-transformers at Manby East and Manby West, and
- the 230 kV circuits from Richview to Manby.

4.2.2 Manby Zone

Manby TS consists of two separate switchyards; Manby East TS and Manby West TS - each of which is equipped with three 230/115 kV auto-transformers. These auto-transformers are all rated at 250 MVA except for unit T8 at Manby East TS which is rated at 225 MVA. The two 230 kV switchyards at Manby TS are each supplied radially from Richview TS via two 230 kV circuits (the R x K circuits).

Although the two switchyards cannot be directly interconnected at Manby TS due to fault level constraints imposed by the existing switchgear, an indirect connection exists between the two 230 kV switchyards via Cooksville TS (via circuits K23C and K21C). This connection is also interconnected with Richview TS via the 230 kV circuit R24C. Apart from providing the supply to southern Mississauga and Oakville, this arrangement is also vital to the supply to Manby TS under contingency conditions involving any of the Richview TS to Manby TS circuits.

To enhance the effectiveness of this indirect connection, which is over twice the length of each of the direct connections, it was Hydro One's original intention to install series capacitors in the 230 kV circuit R24C at its Cooksville terminal. However, with the approval of the Eastern Power Greenfield - South Project, which is to be incorporated into the system via circuit R24C and will have the effect of increasing the flows over this indirect connection, the installation of the series capacitors has been deferred.

4.2.3 Leaside Zone

Leaside TS is supplied radially from Cherrywood TS via six 230 kV circuits that are individually terminated on to the 115 kV busbar via a dedicated 250 MVA 230/115 kV auto-transformer. These six auto-transformers are connected together in pairs, via 230 kV bus-section breakers. Due to fault level constraints, the 115 kV busbar at Leaside TS is normally operated split.

While a limited number of the 115 kV transformer stations in the Leaside sector (Dufferin TS, Bridgman TS, Glengrove TS and Duplex TS) are supplied from both the eastern and western halves of the Leaside 115 kV busbar, all of the remaining transformer stations are supplied exclusively from only one half of the busbar. The 115 kV busbar at Hearn SS, which is normally operated closed, provides the only connection between the two halves of the 115 kV system in the Leaside sector.

4.2.4 Load Transfers between the Manby and Leaside Sectors

Due to fault level constraints, the Manby and Leaside sectors cannot be operated permanently interconnected. However, facilities exist to transfer either the load at Dufferin TS, or the combined load at Dufferin TS and Bridgman TS, from the Leaside Sector to Manby East TS. Since these loads are supplied from both halves of the Leaside 115 kV busbar, their transfer results in an evenly distributed reduction in the loading on each of the six auto-transformers at Leaside TS.

Facilities also presently exist to transfer that portion of the load at Esplanade TS, which is supplied exclusively from 115 kV circuit H2JK, to Manby West TS. This represents approximately one third of the total load at Esplanade TS, and since circuit H2JK is supplied directly from Hearn SS, this transfer also results in an evenly distributed reduction in the loading on each of the six Leaside auto-transformers.

Hydro One has now received all of the approvals required for the construction of the John-to-Esplanade Link, which is scheduled to be completed by the spring-2007. This Link, which is shown in Diagram 4, will allow approximately half the load at Terauley TS to be transferred to Manby West TS. Since only that portion of the load at Terauley TS that was being supplied exclusively from Hearn SS can be transferred, the transfer will result in an approximately even reduction in the loading on each of the six Leaside auto-transformers.

4.2.5 Need Dates

The following need dates are based on the weather-corrected load forecast provided by Toronto Hydro. To ensure continuity of supply under extreme weather conditions, it would be necessary to advance the need dates by at least one to two years.

4.2.6 Leaside Sector

Based on the ability of the remaining facilities to continue to supply the load following a single-element contingency, the IESO has determined that the load meeting capability of the 115 kV transmission facilities in the Leaside Sector will need to be enhanced prior to the summer-2008. This need date can be deferred by transferring load to Manby West TS, but forecast load growth in the Leaside sector will offset this deferral beyond summer 2009. Therefore the need date for enhancing the Leaside sector is summer 2010. These dates are highly dependent on the load forecast, on taking full advantage of the facilities to transfer load out of the Leaside sector, on the

capability of the Manby West facilities to accommodate additional load transfers, and on the availability of resources in the western GTA part of the grid to control voltages and supply Manby West TS.

The existing transmission facilities that comprise the 230 kV corridor between Cherrywood TS and Leaside TS are not expected to be adequate to accommodate the forecast peak loads beyond the summer-2008. Consequently the load meeting capability of these facilities will need to be enhanced prior to the summer-2009. While the transfer of the load at Dufferin TS to Manby East TS would benefit the auto-transformers at Leaside TS as well as the 230 kV circuits on the Cherrywood to Leaside corridor by reducing the respective flows, it would have no impact on the 115 kV transmission facilities between Leaside TS and Hearn SS. Consequently it would not influence the need date for those 115 kV facilities. Furthermore, the transfer of the Dufferin TS load is not expected to be possible during peak load periods beyond the summer-2008 due to limitations imposed by the thermal ratings of the existing 115 kV transmission facilities associated with Manby East TS..

However, with the scheduled completion of the John-to-Esplanade Link in the spring-2007, it would then be possible to reliably transfer approximately half the load at Terauley TS across to Manby West TS. The 115 kV transmission facilities as well as the 230/115 kV auto-transformers associated with Manby TS are expected to be adequate to accommodate the transfer of approximately half the load at Terauley TS through the summer-2009. This capability could be extended through to the summer-2011 by installing an additional 115 kV shunt capacitor bank at either Manby West TS (rated at 125MVAR) or at John TS (rated at 100MVAR). However, following the summer-2009 the benefits derived from transferring half the Terauley load would be offset by the expected load growth within the Leaside sector. Consequently, the need date for enhancing the load-meeting-capability of the Leaside Sector is expected to be the summer of 2010.

4.2.7 Manby Sector

i. Manby East TS

Manby East TS is expected to be able to accommodate future load growth at the three transformer stations that are normally supplied from this station (Fairbank TS, Runnymede TS and Wiltshire TS) to well beyond 2020. However, should this station be required to accommodate the transfer of the load at Dufferin TS during peak load periods beyond the summer-2008, then additional 230/115 kV auto-transformer capacity would need to be installed and the 115 kV transmission lines would also have to be uprated and/or augmented with additional circuits.

Routine maintenance at this station during off-peak periods is not expected to be an issue, since the load at Wiltshire can be readily transferred to the Leaside sector. Consequently, should either of the remaining auto-transformers fail while one unit is out-of-service for maintenance, the off-peak loads could be maintained within the limited-time-rating of the last remaining auto-transformer.

ii. Manby West TS

There is no existing capability for transferring only a portion of the load at John TS to the Leaside sector while maintenance is being performed on those facilities associated with Manby West TS.

Consequently, it is becoming increasingly difficult to schedule maintenance outages. Even with new generation capacity incorporated into the Leaside Sector, it would not be possible to transfer the entire off-peak load at John TS (estimated at 190 MVA) to the Leaside Sector via the new John-to-Esplanade Link while maintaining acceptable voltages and avoiding overloading of the existing facilities supplying Esplanade and Terauley from Hearn SS. Installing additional switching facilities at John TS to permit only a portion of the load to be transferred has already been rejected due to space constraints.

Additional auto-transformer capacity will therefore need to be installed at Manby West TS as soon as possible to allow the existing equipment to be maintained.

4.2.8 Installing New Generation Capacity at Hearn SS

Incorporating additional generation capacity via the 115 kV busbar at Hearn SS would increase the load-meeting-capability of the Leaside Sector by reducing the loading on the following: the 230 kV corridor from Cherrywood TS; the 230/115 kV auto-transformers at Leaside TS; and the 115 kV transmission facilities between Leaside TS and Hearn SS. However, the IESO's analysis has shown that to incorporate additional generation capacity into the Leaside Sector certain specific requirements would need to be satisfied.

To ensure that the fault levels with new generation capacity incorporated do not exceed the interrupting capability of the existing switchgear, the Leaside Sector would need to be operated split into two discrete halves from Cherrywood TS. This would require the 230 kV and 115 kV busbars at Leaside TS as well as the 115 kV busbar at Hearn SS to be operated open at their mid-points. This would introduce an imbalance of approximately 200 MW between the loads supplied from the western half of the Leaside busbar and those supplied from the eastern half. Consequently, the rating of any new generation capacity that it is proposed to incorporate into the western half of the Leaside Sector would need to be at least 200 MW just to restore the transfers through the associated Leaside auto-transformers to their present levels. In addition, the maximum rating of the new generation facility would need to be limited to approximately 600 MW (720 MVA) to respect the fault interrupting capability of the existing equipment. Of this, a maximum of approximately 400 MW (470 MVA) could be connected to the western half of the Hearn 115 kV busbar.

Should the 500 MW of new generating capacity that the Government of Ontario has recently announced for the downtown Toronto core be installed within the Leaside sector, then depending on its exact location and configuration, it could provide a deferral in the need date for further enhancements to the load-meeting-capability of the Leaside Sector to beyond 2012, based on the present, weather-corrected load forecast.

Furthermore, if generation capacity were to be installed in the Leaside Sector prior to the summer-2008, then load transfers to the Manby Sector in response to equipment outages are not expected to be necessary.

It is also worth noting that a 500 MW generation project, incorporated directly into the 115 kV portion of the Leaside Sector, would provide similar benefits in terms of its actual power output, reactive support for voltages in the area and the effect on the transfers through the auto-transformers at Cherrywood TS, as a single generating unit at Pickering GS.

4.2.9 Third Supply for Downtown Toronto

Even with additional generating capacity installed in the downtown Toronto core, it is expected that a third transmission supply (3rd Supply) will need to be installed prior to the summer-2013 to ensure a secure supply for downtown Toronto. However, should additional load growth occur, beyond that which is currently being forecast, it would be necessary to advance this need date.

The IESO has proposed that the John-to-Esplanade Link should be extended through to Hearn SS to allow any new generating capacity that is to be installed in the downtown Toronto core to benefit the Manby Sector as well as the Leaside Sector. This would also allow the requirement for additional auto-transformer capacity to be installed at Manby West TS to be deferred by allowing a portion of the load to be supplied from the Leaside Sector during those periods when maintenance is being performed.

Furthermore, should the dc Option be selected for the 3rd Supply, then installing the back-to-back facilities at Hearn SS in advance of the main phase of the development would provide both the IESO and Hydro One with invaluable operational experience.

4.3 Supply Issues in the Newmarket - Aurora Area

The rapid increases in the load within the Newmarket - Aurora area that have been experienced are taxing the capability of the existing double-circuit line between Claireville TS and Armitage TS. While the initial proposal for enhancing the supply to this area involved the extension of the existing 230 kV double-circuit line from Buttonville TS through to Armitage TS, other options are being examined by the Ontario Power Authority. A recommendation is expected during the fall.

4.4 Kitchener, Waterloo, Cambridge, Guelph and Orangeville Area

This area, which is supplied primarily via the 230 kV system emanating from Detweiler TS continues to be a problem with lower than ideal pre-contingency voltages and with severely depressed post-contingency voltages following the critical 500 kV double-circuit contingency involving the Bruce to Milton/Claireville circuits.

In addition, the 115 kV system between Detweiler TS and Guelph-Cedar TS that is supplied by circuits D7G and D9G is also subject to very low post-contingency voltages following the loss of either 115 kV circuit.

Since these areas are experiencing very high load growth, the situation continues to deteriorate and remedial measures are required urgently.

As the initial stage of their proposed plan for enhancing the load-meeting capability of the area, Hydro One is planning to install a single 230/115 kV auto-transformer at Cambridge-Preston TS, connected to the 230 kV circuits M20D and M21D between Middleport TS and Detweiler TS. The 115 kV terminals of the new auto-transformer are to be connected to circuits D7G and D9G, as shown in Diagram 5. While this arrangement will provide critically-needed support to the 115 kV system following the loss of either of the 115 kV circuits D7G or D9G, the additional load that will be transferred to the 230 kV system will only aggravate the problems with low voltage at the 230 kV transformer stations supplied from circuits M20D and M21D following a contingency involving either of these circuits.

Since this contingency condition is already an operational issue during high load periods, the second stage of the proposed plan will involve the installation of two new 230/115 kV auto-transformers on the right-of-way of the 500 kV circuits M585M and V586M between Middleport TS and the Milton/Claireville transformer stations, together with the construction of a new 230 kV double-circuit line into Cambridge-Preston TS. This stage of the proposed development is also shown in Diagram 5. A second 500/230 kV auto-transformer would then be installed at Cambridge-Preston TS to further enhance the supply reliability of the 115 kV system.

Preliminary studies by the IESO have shown that this proposal would have substantial merit since it would improve the voltage profile of those 230 kV-connected transformer stations in the Cambridge area while also transferring a portion of the load at the Guelph-Cedar TS that is presently supplied from Burlington TS via the 115 kV circuits B5G and B6G, on to the new supply. However, the voltages at the 230 kV transformer stations supplied from circuits D6V and D7V between Detweiler TS and Orangeville TS were shown to remain below 238 kV, which would present problems under contingency conditions.

The IESO has therefore examined the effect of including a further 500/230 kV interconnection in the vicinity of Bellwood Junction where the existing 500 kV right-of-way of circuits B560V and B561M and the 230 kV right-of-way of circuits D6V and D7V intersect. This proposed connection, which is shown in Diagram 5, together with the connection from the 500 kV system into Cambridge-Preston TS, resulted in a significant improvement in the system voltages for the condition with a peak system load of 26,800 MW. In particular, the voltage at Detweiler TS increased from 234 kV, with the existing facilities, to 241 kV, while that at Orangeville TS increased from 234 kV to 246 kV.

This plan, or an alternative that provides equivalent voltage performance, must be included as part of the transmission enhancements used to facilitate the shutdown of Nanticoke TGS in the off-coal strategy. This area is also a good candidate for conservation, demand management and additional generation supply.

It should also be noted that whatever plans are eventually implemented for this area, it will be essential that they be completed prior to the summer-2008 to correspond with the present schedule for the retirement of the generating units at Nanticoke GS.

4.5 Burlington TS

While the recent installation of the additional 230 kV and 115 kV capacitor banks, rated at 300 MVAR and 125 MVAR respectively, has helped to improve the voltage profile in the Burlington area, the loading on the 230/115 kV auto-transformers at Burlington TS remains near their maximum ratings. A decision to proceed with the new 500/230 kV connection into Cambridge-Preston TS and the installation of 230/115 kV auto-transformers to connect to the existing 115 kV system in the area, as discussed above, would then allow some of the load at Burlington TS to be transferred to the new connection. This would improve the situation, although the extent of any benefit would depend on how much load can be transferred.

However, until the two lower-rated 215 MVA auto-transformers are replaced with 250 MVA units, the operational capacity of Burlington TS will continue to be restricted putting equipment at an increased risk of overload and failure, and requiring load transfers and possibly load interruptions at high demands.

4.6 Bruce Complex

Installation of Series Capacitors in the 500 kV Circuits Associated with the Bruce Complex

Hydro One has submitted an application to the IESO for a connection assessment of their proposal to install series capacitors at the approximate mid-points of the following 500 kV circuits, as shown in Diagram 6:

Circuits	Location	Provides Approximate Compensation
B562L and B563L	Bruce GS to Longwood TS	70%
B560V and B561M	Bruce GS to Claireville TS / Milton TS	10%
N582L	Longwood TS to Nanticoke GS	70%

Preliminary analysis shows that this plan has the potential to accommodate the proposed return-to-service of Bruce A Units 1 and 2, and also intended to reduce the reactive power losses of the existing system, particularly under contingency conditions, and thereby decreasing the dependence on Nanticoke GS for voltage support, so that this generation facility can be removed from service.

In order to comply with the Government of Ontario's recently announced schedule for the retirement of the units at Nanticoke GS, the new facilities will need to be in service no later than the spring-2008.

The IESO has yet to perform its full assessment of the impact of the proposed 500 kV series capacitors, coincident with Nanticoke GS no longer operating and with the additional 1,500 MW of generating capacity that is planned to be procured for the western GTA and downtown Toronto in service. However, a limited number of load flow studies with the additional generating capacity included at arbitrary locations have been completed. These have shown that the series capacitors, together with new shunt capacitor banks at Middleport TS and with some of the units at Nanticoke GS converted to synchronous condenser operation, should be sufficient to enhance the transfer capability of the existing transmission facilities to allow Units 1 and 2 at Bruce A GS to be incorporated without the need for any new transmission lines.

To achieve these results, the local-area supply requirements for the Kitchener, Waterloo, Cambridge, Guelph and Orangeville areas must also be addressed. IESO analysis assumed the proposed plans for the Detweiler area as well as the proposed 500/230 kV auto-transformers at Milton SS were in service.

It is intended that the IESO's connection assessment studies will help quantify the following within the next few months:

- the extent of any generation rejection that might be required with the additional generating capacity at the Bruce complex in-service to ensure that post-contingency stability can be maintained for all of the various contingency conditions.
- the requirements for retaining some of the units at Nanticoke in operation as synchronous condensers in order to maintain acceptable post-contingency voltages within the western GTA under all operating conditions.

- the effect that retaining units as synchronous condensers might have on any requirements for initiating generation rejection in response to system contingencies.
- if synchronous condenser capacity is required at Nanticoke GS, then the effect that the installation of new shunt capacitor banks at Middleport TS, and possibly Detweiler and Orangeville would have on this requirement.
- the effect of the series capacitors on the present operating limits for eastward flows across the Buchanan-Longwood Input (Negative BLIP) Interface.

4.7 Northeastern Ontario

4.7.1 System north of Sudbury (Hanmer TS)

The north-eastern part of the Ontario power grid is made up of multiple generating units, a few very large and many small loads, and a relatively sparse transmission system. The grid north of Sudbury is connected to the rest of Ontario via one 500 kV circuit (P502X, Porcupine TS near Timmins, to Hamner TS), and one 115kV circuit (Kirkland Lake TS to Dymond TS). See Diagram 7. The IESO has employed a variety of specific operating procedures and special protection systems to ensure that all of the generation in north-eastern Ontario could be reliably transmitted to the rest of the grid. In doing so, especially when the generation is near maximum, there is some risk of abnormal operation if the 500 kV circuit were to trip (operating statistics show a trip could happen about once a year).

Over the years generation has been added and a reduction in local load has taken place in north-eastern Ontario. Analysis by the IESO has shown that the previous operating measures were insufficient to ensure acceptable operation following the trip of P502X. The studies showed that when southward flows are above about 650 MW, a trip of P502X could result in voltages exceeding equipment limits of 575 kV and 260 kV, a loss of synchronism and transmission separation between north-eastern and southern Ontario, and abnormal voltages and frequencies for facilities that are islanded and remain operational north of Timmins.

To address this and improve reliability for the area, the IESO has recently adopted operation measures during high southward transfers (about 650 MW) to automatically cross trip 500 kV circuit D501P and shutdown the 230 kV system connected to Pinard TS. Normally this will only be initiated following the trip of the 500 kV circuit, will avoid the risk of abnormal voltages and frequencies, and will also allow a quick and orderly re-start of the system. Enhancements to existing transmission facilities and the existing generation rejection scheme are required to allow all of the 115 kV system to remain in service while increasing the threshold above 650 MW.

For contingencies involving 500 kV circuit D501P, the only connection remaining between north and south would be via 115 kV circuit H9K between Kapuskasing TS and Huntla SS. Similar operating measure will be required to respond to any trip of circuit D501P.

Without these measures the existing generation could be significantly restricted with a resulting cost to the market. It is anticipated that these new operating measures would pose little additional risk, would allow all of the generation to be utilized, and would also be of benefit if future generation development were to take place.

4.7.2 System south of Sudbury

Diagram 7 shows the North-South Transmission Interface, which consists of the two 500 kV circuits X503E and X504E between Hanmer TS and Essa TS (in Barrie) and the 230 kV circuit D5H between Otto Holden GS and Des Joachims GS. The existing Flow-South limit for transfers across this interface is 1,400 MW when accompanied with 100 MW of generation rejection. With flows restricted to this maximum transfer, post-contingency stability can be maintained in response to contingencies involving either of the 500 kV circuits X503E or X504E.

Earlier studies have shown that due to the inherent time delay before generation rejection can occur, this limit cannot be increased through an increase in the amount of generation rejection that is initiated.

During recent years there has been an increase in the amount of generation capacity that has been incorporated into the system, together with an increase in the output of many of the existing generating plants. This has been accompanied by a reduction in the local area load, particularly with the closure of some of the mines. The net result has been an increase in the transfers south which occasionally requires generation output to be constrained so that the existing limit is respected.

Hydro One has therefore submitted a proposal to the IESO for a connection assessment that involves installing series capacitors at Nobel SS, the approximate mid-point of circuits X503E and X504E between Hanmer TS and Essa TS. These capacitors are to provide 60% compensation for the line reactance, and preliminary studies by the IESO have shown that they should allow the Flow-South limit to be increased by at least 600 MW depending on how additional resources and associated transmission facilities are developed.

4.7.3 Mattagami Expansion

The existing generating facilities on the lower Mattagami River consist of the following stations:

Generation Station	Connection Voltage	Generating Units
Little Long GS	230 kV	Two 61 MW units
Smoky Falls GS	110 kV	Four 13.5 MW units
Harmon GS	230 kV	Two 68 MW units
Kipling GS	230 kV	Two 68 MW units

Harmon, Kipling and Little Long GS were designed and constructed for their eventual expansion to four-unit generating stations. However, operation of these three plants is presently restricted by the presence of Smoky Falls GS, which is located down-stream of Little Long GS and has only a limited forebay. Smoky Falls GS presently operates as a base-load station providing a back-up supply to the Spruce Falls mill in Kapuskasing in the event that the existing 230 kV supply is interrupted.

Redeveloping Smoky Falls as a peaking facility would therefore allow additional generating capacity to be installed at the other three 230 kV-connected stations.

In the early 1990s, EA Approval was granted for the installation of an additional generating unit at the Harmon, Kipling and Little Long plants and the construction of a new three-unit generating station at Smoky Falls GS. On the assumption that the existing Smoky Falls facility

would be retired, this would have increased the capacity of the generating facilities on the lower Mattagami River by approximately 380 MW.

With the adoption of the new policy for the area north of Hanmer TS, requiring the intentional shutdown of a portion of the north-east system for transfers above a pre-determined threshold in response to 500 kV contingencies, the additional generating capacity could be accommodated within the existing north-east system with only new shunt capacitors installed at Little Long GS, Porcupine TS and Hanmer TS. However, since the existing transfers already exceed the 1,400 MW Flow-South Limit, additional facilities would be required to raise the transfer limit to allow the full increase from the Mattagami Expansion to be accommodated.

Analysis has shown that installing series capacitors in the 500kV circuits P502X, D501P and in X503E & X504E, together with shunt capacitors at Little Long GS and Hanmer TS, would provide the necessary increase in the Flow-South limit to accommodate all of the increased capacity which may be possible from the Mattagami Expansion as well as those existing transfers that exceed the present limit of 1,400 MW.

The facilities that have been proposed to achieve the required increase in the Flow-South Limit to accommodate the Mattagami Expansion, should it be decided to proceed with this development, are also shown in Diagram 7.

4.7.4 Abitibi Canyon GS/Pinard TS

The existing 115 kV switchgear at Abitibi Canyon GS has been deemed to be at end-of-life and Hydro One has proposed that, instead of perpetuating the existing arrangement which suffers from very constricted access, the new switchgear should be consolidated at a new 115 kV busbar at Pinard TS.

This arrangement would have the added benefit of providing a suitable location for a future 230/115 kV auto-transformer to reinforce the existing connection via circuit H9K between the local 230 kV and 115 kV systems in the area.

4.8 Sarnia-Windsor Area

4.8.1 Incorporation of New Generation Capacity

Under the Government of Ontario's RFP for 2,500 MW of New Clean Generation Projects, contracts have been awarded to the following two Projects in the Sarnia area:

Generating Project	Contract Capacity	Connection Point
Greenfield Energy Centre	1,005 MW	230 kV busbar at Lambton SS
St. Clair Power Project	570 MW	Into two of the Lambton to Sarnia-Scott 230 kV circuits

The recent development of new generating facilities within the Michigan system, in close proximity to the Ontario-Michigan Interconnections, has gradually increased the fault levels at Lambton SS, although these presently remain within the rating of the existing switchgear.

However, it is expected that the fault levels will exceed the interrupting capability of the existing 230 kV switchgear at Lambton SS if the existing generation at Lambton GS is operated

coincidentally with the new generation facilities, as is proposed in the off-coal plan. To avoid restrictions on the amount of generating capacity that could be connected to the system simultaneously within the Sarnia area, and to ensure that fault levels remain within the rating of the existing equipment, the Lambton 230 kV busbar must be operated split. To accommodate split operation it will be necessary to reconfigure the terminations at Lambton SS.

Since this work is expected to take approximately two years to complete, then a decision will need to be made as soon as possible to meet the proposed start of commissioning in late-2007 for an expected in-service date of early-2008 for the new generating facilities.

4.8.2 Windsor Area

Operation of the 115 kV system in the Windsor area continues to be a challenge during high load conditions due to the restrictive thermal ratings of the 115 kV circuits and the two 230/115 kV auto-transformers at Keith TS. It is also becoming increasingly difficult to schedule outages, while ensuring continuity of supply in the event of a contingency.

Depending on the generation dispatch in the Windsor area, either a contingency involving one of the 115 kV circuits J3E and J4E between Keith TS and Essex TS or the loss of either of the 230/115 kV auto-transformers at Keith TS can be most severe.

The normal response for a J3E or a J4E circuit contingency, with both the Brighton Beach and West Windsor Power Projects in-service, involves opening the 115 kV breakers of each auto-transformer at Keith TS to limit the flow on the companion circuit. Should either of these generation projects be out-of-service, then the situation would be even more critical.

Upgrading of the 115 kV circuits J3E and J4E, together with the replacement of the auto-transformers at Keith TS with higher-rated units, is therefore required urgently. However, before the outages required to complete this work can be scheduled it will be necessary to complete the re-termination of some of the existing 115 kV circuits at Essex TS together with the expansion of the existing Special Protection System so that additional post-contingency responses can be initiated.

In addition, the installation of the proposed 230/115 kV auto-transformer at Kent TS, to allow the Tilbury-area loads to be transferred from the 115 kV busbar at Lauzon TS, would provide some critical relief for the 115 kV system between Lauzon TS and Kingsville TS, and should therefore be undertaken as soon as possible.

During peak load periods, with the Brighton Beach Project out-of-service, a contingency involving either of the 230 kV circuits C23Z or C24Z between Chatham TS and Lauzon TS is expected to result in overloading of either the companion 230 kV circuit and/or the companion auto-transformer at Lauzon TS. To avoid the load interruption required to correct this overload situation, the IESO recommends that Hydro One assess the feasibility of establishing a new 230 kV connection between Keith TS and Lauzon TS, together with a third 230/115 kV auto-transformer at Lauzon TS.

This new connection would also reduce the area's potential vulnerability to the consequences of double-circuit contingencies involving either the Chatham to Keith 230 kV circuits, C21J and C22J, or the Chatham to Lauzon 230 kV circuits C23Z and C24Z.

The proposed system enhancements for the Windsor area are shown in Diagram 8.

The Windsor area is a good candidate for conservation, demand management and additional generation supply.

4.8.3 J5D Interconnection with Michigan

Since the gas-turbine units of the Brighton Beach Project are not equipped with by-pass facilities, any contingency that involves the loss of the steam-turbine unit will result in the automatic tripping of either of the gas-turbine units should they remain connected. To compensate for the sudden loss of the entire Brighton Beach Project, increased transfers, representing approximately half of the pre-contingency output from the Project, will appear on the J5D Interconnection with Michigan.

The limiting element of the Interconnection is a section of the 230 kV line between the two terminal points, the maximum pre-contingency flows that can occur on this Interconnection must be limited to allow for the increased transfers that would occur following the loss of the entire Brighton Beach Project. However, since the limited-time-rating of the phase-shifter in the Interconnection is higher than that of the limiting line section, higher pre-contingency transfers could be accommodated if the limiting line section were to be upgraded.

The IESO therefore recommends that Hydro One assess the feasibility of upgrading the 230 kV line so that its continuous and limited-time-rating better matches that of the phase-shifter, thereby allowing the transfers from Michigan to Ontario over the J5D Interconnection to be increased by at least 200 MW. It is also important to note that should a decision be made to proceed with this work that it only be scheduled after the upgrading of the 115 kV Keith-to-Essex circuits and the replacement of the Keith auto-transformers have been completed.

4.9 Supply to the Loads in the Oshawa and Belleville Areas

4.9.1 Oshawa Area Supply

The Oshawa area is supplied via two pairs of 230 kV circuits:

- Circuits B23C and M29C, which supply Whitby TS and Wilson TS with a combined peak load of ~ 430 MW
- Circuits H24C and H26C, which supply LASCO, Atlantic Packaging, Thornton TS and Oshawa-GM TS. with a combined peak load of ~ 425 MW

In addition, circuits H24C and H26C provide the exclusive supply to Otonabee TS, which has a peak load of approximately 120 MW.

Circuit B23C, together with circuit H23B from Hinchinbrooke TS, also supplies the substantial load at Belleville TS.

The IESO, in their assessment of the replacement Oshawa GM TS, determined that circuits H24C and H26C would not be capable of accommodating any additional load growth beyond that expected at the Oshawa GM Complex without additional shunt compensation being installed. Furthermore, the peak load supplied exclusively from these two circuits has now exceeded the IESO's threshold of 500 MW for the maximum amount of load that should be exposed to a supply interruption for any recognised system contingency.

Hydro One is proposing to develop Whitby No. 2 TS to accommodate the significant load growth within the Whitby area. However, because of the limited capability of circuits B23C and M29C to accommodate any additional load without adversely affecting their post-contingency performance, it has been proposed to connect the new TS to circuits H24C and H26C.

The Oshawa area is a good candidate for conservation, demand management and additional generation supply.

4.9.2 Belleville Area Supply

Belleville TS is supplied via two 230 kV connections: from Cherrywood TS in the west, via circuit B23C whose length is approximately 164 km; and from Hinchinbrooke TS in the east, via circuit H23B, whose length is approximately 85 km.

The peak load supplied from Belleville TS is approximately 140 MW and this is expected to exceed 150 MW within the next three years. Contingencies involving the companion circuit M29C between Cherrywood TS and Merivale TS, or either of the 230 kV circuits supplying Belleville TS (B23C and H23B) will result in very high post-contingency flows and severely depressed voltages during peak-load periods.

4.9.3 Proposed System Enhancements

To address the loading on circuits H24C and H26C it is proposed that either of the following should be considered for implementation:

- Establish a new 500/230 kV connection in the Bowmanville area in the vicinity where the existing 500 kV and 230 kV rights-of-way cross, by installing one or more 500/230 kV auto-transformers. or
- Reinforce the existing 230 kV connection from Cherrywood TS into the Oshawa area with a new 230 kV double-circuit line approximately 27km long, to allow some of the existing load to be transferred to it.

To address the loading on circuits M29C and B23C it is proposed that the following should be considered for implementation:

- Establish a direct connection between the 230 kV and 500 kV systems in the vicinity where the existing 500 kV and 230 kV rights-of-way cross, by installing one or more 500/230 kV auto-transformers.

The proposed system enhancements are shown in Diagram 9.

4.10 Northwest

Approximately 25% of the load in Northwest Ontario is concentrated near Thunder Bay.

The installation of a shunt capacitor at Birch TS and the subsequent remove from service of the synchronous condenser at Thunder Bay may make it practicable to parallel circuit Q4B, Q5B, and Q8B. This would enhance supply reliability to several very large loads near Thunder Bay. This change should be considered when the Thunder Bay GS units are converted from coal to gas.

Atikokan can cease burning coal and be put on reserve once shunt capacitors are placed in service at Fort Frances and/or Mackenzie TS.

4.11 Ottawa Area

IESO's forecast is showing load growth near Ottawa will exceed the capability of the present transmission system to securely supply this demand. Although not a pressing problem at the moment, the security of supply to Ottawa should be closely monitored. There have been few generation proposals near Ottawa submitted into IESO's Connection and Assessments process. If no generation is situated in the vicinity then additional transmission will be required. The proposed 1,250 MW Ontario-Quebec high voltage direct current (HVdc) connection would provide another significant supply to Ottawa. The status of this HVdc connection is very uncertain and no other major transmissions proposals have been submitted to the IESO. Ottawa also would be a good location for some of the 1,000 MW of cogeneration that is part of the coal replacement plan. The Ottawa area is also a good candidate for conservation, demand management and additional generation supply.

4.12 Niagara Area

The Queenston Flow West (QFW) circuits, between Niagara Falls and Hamilton, have been limiting under hot windless conditions. They currently limit import capability from New York. Without expanding the thermal capability of QFW, adding generation in the Niagara area also does not increase generation availability as the import capability from New York is correspondingly reduced.

Hydro One is proposing to install new transmission facilities to augment the five existing 230 kV circuits that, together, form the QFW Interface.

The facilities that are planned to be installed consist of two new 230 kV circuits between Allanburg TS and Middleport TS. In addition the three existing 230 kV transformer feeders Q26A, Q28A and Q32A between Beck 2 GS and Allanburg TS are to be reconfigured. This will then create two new 230 kV connections between Beck 2 GS and Middleport TS.

The Hydro One proposal is currently in the regulatory approval process. These new facilities are expected to increase the transfer capability of the QFW circuits by approximately 800 MW. This plan is seen as an important risk mitigation measure for the coal replacement plan.

In the past, under peak summer conditions, and recently during hot weather in June 2005, the 230 kV transmission facilities into Burlington TS have also congested Ontario generation and constrained power flows on the QFW circuits. Without reinforcing these 230 kV transmission facilities into Burlington, the full benefit in upgrading the QFW interface may not be realized.

4.13 Summary of Transmission Enhancements Identified in the 10-Year Outlook

The following table summarizes all the key transmission enhancements the IESO recommends for installation across the province to provide necessary IESO-controlled grid reliability. The diagrams are contained in Appendix B.

Table 4.1 Summary of Transmission Enhancements Identified in the IESO 10-Year Outlook

Summary of Transmission Enhancements Identified in the IESO 2005 10-Year Outlook		Need date	Comments	Diagram No.
Facilities required to accommodate the planned shutdown of Nanticoke GS and the return to service of Bruce A units 1 and 2				
1	Series Capacitors in the following 500kV circuits associated with the Bruce Complex: Circuits B562L & B563L between Bruce GS & Longwood TS Circuits B560V & B561M between Bruce GS & Claireville TS/Milton TS Circuit N582L between Longwood TS & Nanticoke GS	Spring-2008	Scheduled for the spring-2009 & the fall-2009, respectively	6
2	Shunt Capacitors at Middleport TS (nominally rated at between 400MVar & 500MVar)	Spring-2008		
3	Conversion of two (or more) generating units at Nanticoke GS to synchronous condenser operation.	Spring-2009		
4	Installation of a 230 kV connection into Cambridge-Preston TS from a new 500/230 kV TS established on the right-of-way of the existing 500kV double-circuit line, M585M & V586M, between Nanticoke GS & Claireville TS/Milton TS. This work would also include the installation of two 230/115kV auto-transformers at Cambridge-Preston TS to provide a connection to the local 115kV system between Detweiler TS and Guelph-Cedar TS.	Spring-2008	To improve voltages and increase the supply capability in the Kitchener, Waterloo, Cambridge, Guelph & Orangeville area. This work is also required to ensure that adequate post-contingency voltages can be maintained following the loss of the Bruce-to-Milton 500kV line.	5
5	Installation of a new 500/230 kV TS at Bellwood Junction, where the existing 500kV (circuits B560V & B561M) & 230 kV (circuits D6V & D7V) rights-of-way intersect.	Spring-2008		
6	Although not a transmission enhancement, the installation of the planned 1,500 MW of additional generating capacity in downtown Toronto & the western GTA is also crucial to the plan to shutdown Nanticoke GS.	Fall-2008	These facilities are required to ensure that adequate post-contingency voltages can be maintained in the GTA following the loss of the Bruce-to-Milton 500kV line.	
Facilities required to accommodate the planned shutdown of Lambton GS				
7	Reconfigure the termination of the existing 230 kV circuits at Lambton TS to allow the busbar to be operated split and respect the fault interrupting capacity of the existing breakers	Fall-2007	To accommodate the commissioning of the new generating facilities in the Sarnia area while the existing units at Lambton GS are still operational.	
Facilities required to address the issues related to the supply to downtown Toronto				
8	Completion of the John-to-Esplanade Link	Fall-2007	This will defer the need date for supply in the Leaside Sector by two-years: to 2010 with weather-corrected loads & 2008 with extreme-weather loads	4

Summary of Transmission Enhancements Identified in the IESO 2005 10-Year Outlook		Need date	Comments	Diagram No.
9	Incorporation of 500 MW of generation capacity into the Hearn 115kV busbar	Spring-2008	The need date for this facility is governed by the planned shutdown of Nanticoke GS. This facility will defer the need date for the 3rd Supply to 2012 (with weather-corrected loads) & 2010 (with extreme-weather loads).	
10	Incorporation of 1000 MW of generation capacity within the western GTA	Fall-2008	The need date for this facility is governed by both the planned shutdown of Nanticoke GS and the requirement to support transfers from the Leaside Sector to the Manby Sector, via the John-to-Esplanade Link.	
11	Extension of the John-to-Esplanade Link to Hearn	Spring-2008	This will address the requirements to perform maintenance on the existing facilities in the Manby West TS.	
12	3rd Supply to Downtown Toronto	Spring-2010	To secure the supply for extreme-weather loads.	
		Spring-2012	To secure the supply for weather-corrected loads.	
Facilities required to accommodate the planned shutdown of Atikokan GS				
13	Install shunt capacitors at Fort Frances or Mackenzie TS.	Before 2007	To offset the reactive capability removed from the system with Atikokan retirement.	
Facilities required to address existing or emerging system issues				
14	Series Capacitors at Nobel SS in the 500kV circuits X503E & X504E, between Hanmer TS & Essa TS.	Existing	To address the worsening congestion situation on the north-south corridor.	7
15	Installation of two 500/230 kV auto-transformers at Milton TS and the extension of the existing double-circuit line from Meadowvale TS through to Cardiff TS via a new 230 kV switching station on the right-of-way of the existing double-circuit line (R19T & R21T) supplying Pleasant TS.	Spring-2008	To relieve the 500/230 kV auto-transformers at Trafalgar TS and also improve supply reliability to Georgetown, north Oakville, north Mississauga & Brampton.	2
16	Installation of a 230/115kV auto-transformer at Kent TS.	Immediate	To improve supply reliability to the Windsor area & avoid supply	8

Summary of Transmission Enhancements Identified in the IESO 2005 10-Year Outlook			Need date	Comments	Diagram No.
17	Uprating of the 115kV circuits J3E & J4E between Keith TS and Essex TS and the replacement of the existing auto-transformers at Keith TS with higher-rated units.			interruptions in the event of equipment failures.	
18	Construction of a new 230 kV connection between Keith TS and Lauzon TS.		Immediate		
19	Increase the transfer capability of J5D conductor to better match the phase-shifter regulating transformer rating.		Not determined	To increase import capability by at least 200 MW.	
20	Installation of a new 500/230 kV TS in the vicinity of the intersection of the Bowmanville TS to Lennox GS 500kV corridor and the 230 kV right-of-way of the circuits supplying Belleville TS		Not determined	To enhance the load meeting capability of the existing facilities to accommodate the growth demand in the Oshawa and Belleville areas.	9
21	Construction of a new double-circuit 230 kV line from Cherrywood TS into the Oshawa area OR The installation of a new 500/230 kV TS at a suitable location east of Wilson Junction along the 500/230 kV corridor between Cherrywood TS and Bowmanville TS.		Not determined		
22	Replacement of the two 215MVA 230/115kV auto-transformers at Burlington TS with higher-rated units		Immediate	To avoid supply interruptions	
23	Reinforcement of the Queenston Flow West (QFW) Interface	230 kV reinforcement between Allanburg TS & Middleport TS	Fall-2007	Identified in IESO's 2004 10-year Outlook	
		Uprating of the existing 230 kV circuits into Burlington TS	Immediate		
24	Implementation of measures within the Ottawa area to address voltage decline issues		Not determined		
25	Enhance reactor switching and P502X special protection system in north-east.		Immediate	To increase the generation and load rejection arming threshold and improve the reliability to northeast 115 kV system.	
Facilities required to accommodate the expansion of the Mattagami River Plants					
26	Installation of series capacitors in the 500kV circuits north of Hanmer TS, together with the installation of shunt capacitor banks at Little Long GS & Hanmer TS, should a decision be made to proceed with the expansion of the Mattagami River Plants.		To suit schedule		7

Notes:

The exact requirements for Items 2 and 3 are to be determined as part of the IESO's assessment of the proposal to install series capacitors in the 500kV circuits associated with the Bruce Complex.
All the items in the table above have been identified in Hydro One's 10 Year Plan or are included in a Connection Assessment and Approval application with the exception if items 2,3,13,15,18, and 26.

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5.0 Coal Replacement Plan

The Ontario government is committed to phasing out the remaining 6,500 MW of coal-fired generation in the province beginning in 2007 as replacement resources become available.

This transition represents the largest and most significant electricity system change ever undertaken in Ontario and involves major technical considerations, significant risks and challenges that need to be addressed.

The coal replacement plan incorporates existing, committed and announced initiatives with respect to additional supply and demand response in various stages of discussion, development, or negotiation. In addition, transmission infrastructure enhancements required to integrate these initiatives have been identified. It must be recognized that significant changes to either the resource or infrastructure plans or timing of the plans will likely jeopardize the ability to retire coal on the timeline proposed.

The IESO will monitor and assess the coal shutdown and replacement resource plans and will provide advice to all parties regarding the actions or adjustments required to ensure reliability is maintained.

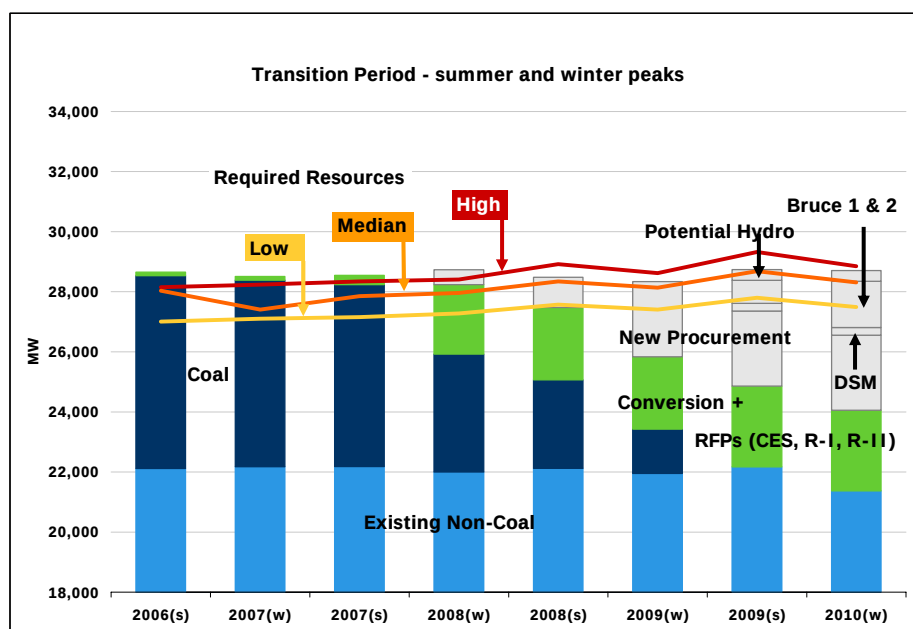
New generation units typically encounter more operating issues affecting their reliability for a period of time after they come in service. These can be significant. Accordingly, a critical requirement of the coal replacement plan is that while coal plants can be scheduled to stop running, those units will be held available for a period of time to operate if necessary to maintain reliability.

Coal supply makes up a large part of Ontario's flexible generation, and it has traditionally been required to meet changing demand, to supply demand when other supply sources are unreliable, and to balance load and generation at all times. Replacement supply must have similar characteristics to provide operating flexibility and sustained energy production as and when it is needed.

The impact of new generation on the transmission system will also be assessed, and necessary transmission upgrades must be completed to ensure reliable system operation.

A plan is provided, illustrating timing and requirements of system changes needed to meet the government's coal shutdown objective. Figure 5.1 provides a graphical comparison of required resources and planned available resources for the critical transition period and includes assessments for both the summer and winter peaks.

Figure 5.1 Critical Transition Period



5.1 System Aspects of the Coal Replacement Plan

In order to preserve grid reliability while implementing the coal replacement program, it is important that replacement generation have suitable operating characteristics, be sited in appropriate locations and that necessary enhancement to transmission infrastructure be undertaken. These requirements are discussed in more detail below.

5.1.1 Location

The location of replacement generation is important to maintaining the capability of the Ontario power system. Reactive power support in critical locations is needed in order to maintain adequate voltages throughout the system, particularly in the Greater Toronto, Golden Horseshoe and the Kitchener-Waterloo-Guelph areas where a significant portion of the load is concentrated. Without voltage support, the ability of the system to transfer energy would be reduced and the ability to supply energy to loads would be lessened. Nanticoke Generating Station is particularly important in this regard.

Under peak load conditions, a minimum of six Nanticoke units are currently required to be in service to ensure reliable system operation. Without these units in service, reductions in the output of the Bruce nuclear generating station would be necessary. In the event that all units at Nanticoke are shut down, and equivalent replacement voltage support is not available, the allowable output from the Bruce generating station would be significantly restricted and the feasibility of returning Units 1 and 2 to service would be jeopardized. This is described in more detail in Section 5.1.6.

The flow eastward on transmission lines into Toronto could also be restricted by substantial amounts, depending on the availability of Nanticoke generation or equivalent replacement generation sources. This could require the operation of other more expensive generation east of

this interface and, under peak load conditions, could result in load interruptions in the Toronto area.

The permissible flow eastward on the transmission lines from southwestern Ontario can be reduced in the order of about 1,000 MW (25 %) in the absence of any Nanticoke units. This could significantly restrict imports from Michigan, thus increasing electricity prices and degrading the adequacy of supply.

Ontario's ability to import and export energy is an essential element of secure and reliable interconnected system operation, and provides large financial benefits to Ontario market participants and rate payers. The ability to import and export energy is dependent on where replacement supply is located.

Replacement generation ideally should be located so that the existing import and export capability is not reduced. If replacement resources are located such that they utilize transmission capability that is normally required to deliver imported power, there could be a decrease in the supply available for Ontario consumers, and degradation in overall system reliability. Some offset of import capability with new resources internal to Ontario may be acceptable. Where practical this should be avoided by locating the replacement supply near the load, near existing generation sites or on transmission paths that do not connect the major tie lines to the load centre in the Greater Toronto Area.

The capability of the Ontario power system can only be maintained with the addition of replacement capacity in the right amounts in the most effective locations. Generation investment in the right locations will take advantage of existing transmission lines and facilitate the continued operation of the remaining non-coal generation.

The generation and demand response which has been selected under the Clean Energy Supply RFP, and the additional generation procurement identified for downtown Toronto and western GTA meet these requirements. This replacement generation has been identified to resolve developing reliability risks and to maximize the benefits of existing transmission. Locating generation in undesirable locations could require substantial (and difficult) transmission investments, strand existing transmission assets and generation investments, and increase risks to the adequacy and reliability of electricity supply to the province.

5.1.2 Energy Capability

In 2004, 7,500 MW of coal-fired generation supplied 26.8 TWh of energy, or about 17% of the total Ontario energy demand, at an average capacity factor of about 40%. Although the energy characteristics of individual replacement generating facilities may differ from existing coal-fired generating stations, the aggregate of the new replacement resources must closely resemble the overall energy capability of existing coal-fired generating stations to ensure that energy is available to serve load with the same level of reliability.

5.1.3 Capability of Replacement Resources to Provide Operating Reserve

The ability to maintain sufficient operating reserve is critical to system reliability, and the IESO is required by NPCC to maintain Operating Reserve in accordance with established criteria. Operating Reserve is required for unexpected system events such as random forced outages of generation or transmission equipment, unexpected increases in load, and uncertainty associated with the performance of generation facilities or dispatchable loads in responding to IESO

dispatch instructions. The IESO operates markets to procure both 10 minute and 30 minute reserves.

Generation and demand response resources providing Operating Reserve must be capable of responding to the IESO's request to increase generation or decrease consumption within 10 or 30 minutes. Coal-fired generation has typically been an important source of operating reserve, and replacement generation will need to have similar capability. Experience in New England has shown that the provision of Operating Reserve from gas-fired generating units may require some changes in unit commitment practice due to their reduced range of flexibility, but gas-fired generating units should otherwise be capable of replacing Operating Reserve currently carried on coal-fired generating units.

However, not all replacement supply is capable of providing Operating Reserve. Nuclear supply, while capable of efficiently providing energy, is typically operated at its' maximum capability and hence cannot contribute to meeting system requirements for Operating Reserve. Similarly, wind facilities typically operate to take full advantage of existing wind conditions, a mode of operation characterized as 'intermittent'. This replacement supply normally cannot contribute to meeting system requirements for Operating Reserve.

The mix of resources brought in service must be capable of continuing to meet system needs for operating reserve.

5.1.4 Flexibility for Load Following

Coal-fired generators currently play an important role in responding to load changes that occur during five-minute intervals throughout the day. The largest load change typically occurs during the morning pick-up period, and is about 60 to 70 MW per minute, with periods of sustained increase or decrease lasting for up to four hours or more. Experience to date indicates that existing Ontario gas-fired generators typically offer load following capability over the upper 25% of their capacity range, whereas coal-fired units can typically achieve load following from minimum load up to maximum output, which represents the upper 80% of each unit's capacity range. Although nuclear units can ramp down and off the system rapidly, existing units are restricted from varying their output up and down for the purposes of load following. Having sufficient load-following capability is essential to reliability, and the mix of replacement generators will need to have sufficient load following capability to meet system needs.

5.1.5 Frequency Stabilization

System frequency of 60 Hz is maintained only when load and generation are in perfect balance. More generation than load will cause the frequency to rise; less generation than load will cause the frequency to fall. If frequency excursions exceed certain small thresholds, load or generation will be automatically removed from service to protect the equipment. Generating units with appropriate governor settings can automatically adjust unit power output in response to frequency deviations to restore the load/supply balance and stabilize frequency at 60Hz. Replacement generators will need to meet IESO Market Rules requirements for speed governor response characteristics.¹

¹ Market Rules, Appendix 4.2

5.1.6 System Requirements Associated with the Shutdown of Nanticoke

Located in Haldimand County, the Nanticoke coal-fired generating station can supply almost 4,000 MW of capacity – enough to meet approximately 20 per cent of Ontario’s peak demand on a spring or fall day. The shutdown of the station is particularly complex due to a number of factors, including the growing demand for power in the Greater Toronto Area (GTA) and the need to supply that demand from power sources outside the area. Nanticoke also provides reactive power to support the heavy power flows from those areas to the GTA as shown in Figure 5.2.

Supply to the GTA remains a critical concern. Current GTA demand is about 10,000 MW or 40% of Ontario’s total demand and is expected to increase by approximately 1,500 MW in the next decade. This is compounded by a lack of generation within the area to supply the forecasted increase in demand. As a result, and until additional sources of supply or demand-side initiatives become available within the GTA, the load must be supplied by generation outside the area. The Nanticoke station provides both energy and capacity to help supply the GTA in addition to providing reactive power to support the transfer of power from southern Ontario supply located some distance from the GTA.

Reactive power, a pre-requisite to the reliable operation of a power system, has been cited as a root cause of the August 14, 2003 blackout. After careful study, experts determined that a severe shortage of reactive power in northern Ohio, caused by power plant and transmission line failures, lead to the blackout.

Produced by generators and consumed by most loads, reactive power is an inherent part of transmitting power over long distances. The longer the distance and the greater the amount of power traveling over that distance, the more reactive power which must be produced by generators to support those power flows.

Currently Nanticoke supplies the greater part of the reactive power needed to transport power to consumers in south-central Ontario and the western GTA, including Brantford, greater Hamilton, Burlington, Guelph, Cambridge, Kitchener-Waterloo, Milton, and parts of Oakville, Mississauga and Brampton. This includes the reactive power needed to support transmission of the Nanticoke station’s own energy production to the GTA as well as increasing amounts of power produced at the Bruce GS and in southwest Ontario. As power flows from these areas increase, the importance of Nanticoke to reliable operation increases.

In addition, Nanticoke units contribute to the voltage control requirements of the grid, especially immediately following disturbances or system events that redirect power along the transmission circuits that connect to the Nanticoke plant. Following a disturbance or system event, the Nanticoke generators automatically provide additional reactive power to the system to support the increased power flows resulting from the event, thus preventing a system collapse.

Reactive power and voltage control capability cannot be supplied over long distances. These capabilities will continue to be required locally from Nanticoke until it can be replaced, either at Nanticoke, from generation located within the major load centres such as the GTA, or by other system developments that reduce the need for reactive power and voltage control at Nanticoke.

It must be recognized that the system requirements associated with the shutdown of Nanticoke are significantly affected by the need to incorporate additional Bruce units.

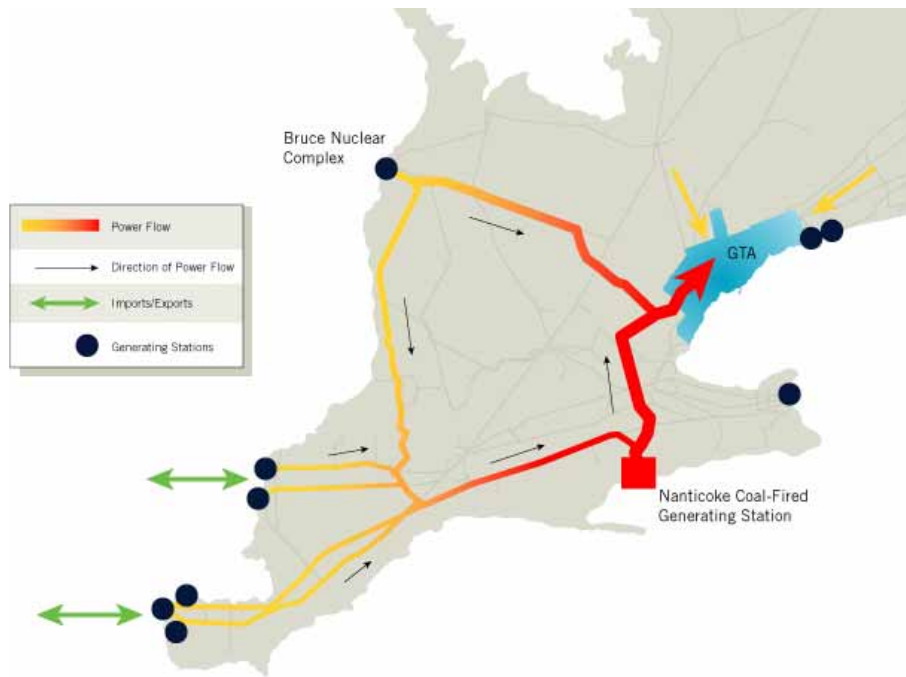
These system requirements address the need for reactive power from Nanticoke and include the following;

- Installation of generation in proximity to the large GTA demand. Location of generation close to the load reduces the need for Nanticoke in two ways; first, less energy needs to be transported long distances to the GTA, and second, reactive power needs of the system are met by the local generation.
- Installation of series compensation in the 500 kV lines serving Bruce and Nanticoke. This form of compensation reduces the need for reactive power to support the large power flows to support the GTA, and reduces the need for post-contingency voltage support
- Installation of shunt capacitors in southwestern Ontario. This form of compensation can provide blocks of reactive power to support voltage and to free reactive capability of generating units. The continuously variable reactive power of generating units is necessary to fine tune voltage in steady state and to regulate voltage following contingencies. The inherent voltage regulation of shunt capacitors is very poor.

It is unlikely that these measures will eliminate the need for dynamic voltage support from the Nanticoke site. The most effective means to provide this capability while meeting the government's policy to cease burning coal at Nanticoke is to convert several units to synchronous condenser operation. In this mode of operation the generator remains connected to the system with full capability to provide reactive power to the system. The steam side of the generating unit may be decommissioned as it is not required in this mode. A minimum of two units are anticipated to be required. The precise requirements will be defined in the near future as the requirements of the coal replacement plan are refined.

A combination of these alternatives has been incorporated into the coal replacement plan.

Figure 5.2 Power Flow – Southwestern Ontario and the GTA



5.1.7 System Requirements Associated with the Incorporation of Bruce Units

The Bruce system consists of eight nuclear units, totaling approximately 6,500 MW of capacity, connected to the power system through four 500 kV lines (two circuits from Bruce to Milton TS, one of which continues on to Claireville and two circuits from Bruce to Longwood TS), and six 230 kV circuits (two circuits from Bruce to Orangeville, two circuits from Bruce to Detweiler and two circuits to Owen Sound, one of which connects to the 115 kV network through to Essa). The Bruce complex is the largest concentration of generating units in North America.

The generation was installed over the mid 70's to mid 80's. Four units were removed from service in 1998, at the same time as four Pickering units. Of these four Bruce units, two units have since been returned to service in 2003. Two units (1 and 2) remain out of service.

The transmission additions constructed to incorporate the station into the Ontario network were not as desired by Ontario Hydro. The preferred implementation included a double circuit 500 kV line from Bruce to Essa in the Barrie area. Public opposition to these circuits ultimately prevented this construction. The Bruce to Longwood 500kV circuits were installed as a somewhat less capable alternative. As a result of this change, the full output of the Bruce complex could not be accommodated by the transmission system. In order to increase the capability of the transmission system to the level required, an automated "Special Protection Scheme" (SPS) was installed. In taking this step, the reliability of both the Bruce generation and many customers in Ontario was reduced to achieve increased economic benefits of the Bruce complex. In essence, the SPS allows for detection of certain power system events and immediately disconnects generators at Bruce and a large amount of customer load throughout southern Ontario to prevent a system disturbance such as that experienced in August 2003.

Without the SPS, Bruce output is limited to approximately 5,000 MW (capacity equivalent to approximately six Bruce units). With the SPS, Bruce output with eight units in operation (6,500 MW) could be accommodated provided up to four units (3,200 MW) were 'rejected' or disconnected instantaneously together with 1,500 MW of customer load (approximately half the load in downtown Toronto). These extensive and complex automatic actions, representing by far the largest use of an SPS by an interconnected system operator, were considered a temporary measure until additional transmission could be constructed. Ontario's neighbouring system operators insisted on stringent conditions with respect to the design and use of the SPS in order to protect their own systems from a cascading disturbance. The majority of the SPS has not been used in over a decade following the shutdown of four Bruce units in 1998.

In the consideration of additional Bruce generation, it is important to understand the relationships of the various factors which impact on the ability of the system to accommodate increased Bruce generation, as well as how the evolution of the electricity system has affected this capability. This information is summarized in the following table.

Table 5.1 Factors which Reduce Ability to Accommodate Increased Bruce Generation

Factors	System in 1980's	Current System
1. Southern Ontario Power Flows are from West to East; - Power flows from	- Ontario is an exporter of	- Ontario is an importer of

Factors	System in 1980's	Current System
Michigan to Ontario - The amount of generation in south western Ontario increases	power to Michigan - Lambton is the only generation in the area (2000 MW)	power from Michigan - Lambton (2000 MW) - TA Sarnia & Dow (635 MW) - Brighton Beach (580 MW) - Imperial Oil (100 MW) - TA Windsor (80 MW) - West Windsor (130 MW)
2. The number of Nanticoke units in Operation is reduced	- Eight units available	- Eight units available - Unit reliability declining
3. Increased need for power flows into the GTA from the west - Increased load in the GTA - The power factor of load decreases - The generation in the GTA decreases	Peak system load (1984) Winter 18,800 MW Summer 15,800 MW Reasonable power factor Lakeview 1,200 MW Hearn 400 MW Pickering 4,120 MW	Peak system Load Winter 25,000 MW Summer 25,500 MW The large majority of this increased load is in the GTA and vicinity Power factor has declined markedly as a result of air-conditioner load, reflecting summer peaking trend in Ontario Lakeview 0 MW Hearn 0 MW Pickering 2,575 MW (unit reliability degraded) Darlington 3,600 MW

In each case, the evolution of the system has been to reduce the capability of the system to accommodate additional Bruce generation. Of course this is not exclusively true; for example, Darlington was constructed to help meet GTA load, expansion of the 500 kV network in south western Ontario has been undertaken and a large number of shunt capacitors have been added in the GTA. However, in general, the net effect has been negative from the perspective of accommodating additional Bruce generation.

In addition, the past reliance on the large 'Special Protection Scheme' to accommodate Bruce output is no longer a desirable practice. The three and four unit rejection associated with this

scheme as well as associated customer load rejection have not been required to be used in a decade. The experience of the August 2003 blackout has altered industry and system operators view of the risks associated with use of these schemes. The side-effects of their operation may no longer be acceptable. The IESO does not recommend reliance on an SPS of this magnitude that involves the rejection of more than 2 generating units combined with extensive load rejection. There is a high degree of uncertainty with respect to our neighbours' agreement with such a scheme's future use. The IESO believes it is prudent to enhance the transmission system so that generation rejection is limited to 2 Bruce units, and the load rejection portion of the special protection scheme is not required to be used in conjunction with generation rejection to maintain Bruce stability. The load rejection portion of the scheme should be maintained only to overcome difficulties in the operating time frame that would otherwise require pre-contingency load shedding. From the late 1990's this was not a major concern as there were no firm plans to rehabilitate units at Bruce. When this became desirable, the studies performed by the IESO, Hydro One and Bruce Power have identified the need for transmission expansion to accommodate additional generation at Bruce. This may take the form of series compensation of existing transmission lines or the additional of new transmission lines.

In summary, the existing system is much less capable of accommodating additional supply at Bruce than it was in the past. A number of factors associated with the dynamic and changing nature of the system have contributed to this including:

- High load growth in the GTA, particularly in summer as air conditioner use has surged;
- Changing nature of the load in the GTA;
- The shutdown of Pickering A;
- The shutdown of Lakeview;
- The growth of imports from Michigan on-peak;
- The addition of generation in southwest Ontario;
- The overall reduction in dependability of some OPG facilities; and
- Changing industry expectations with respect to use of large 'Special Protection Schemes'.

Even with transmission enhancements, it is recognized that the incorporation of additional Bruce units together with the need to cease burning coal at Nanticoke will require significant changes in the supply and delivery infrastructure.

Fortunately, the same types of system developments required to eliminate the need for Nanticoke generation described earlier this section are the same enhancements needed to accommodate additional generation at the Bruce site. These developments include the following:

- Installation of generation in proximity to the large GTA demand. Location of generation close to the load facilitates the installation of additional generation at Bruce in two ways; first, less energy needs to be transported long distances to the GTA reducing competition for transmission capability between Nanticoke and Bruce, and second, reactive power needs of the system are met by the local generation in the GTA;
- Installation of series compensation in the 500 kV lines serving Bruce and Nanticoke. This form of compensation reduces the need for reactive power to support the large power flows to support the GTA, and reduces the need for post-contingency voltage support; and
- Installation of shunt capacitors in southwestern Ontario. This form of compensation provides voltage support to the steady state power system, freeing up dynamic voltage control capability of generating units.

- As was the case for the shutdown of Nanticoke, it is unlikely that these measures will eliminate the need for dynamic voltage support from the Nanticoke site. The most effective means to provide this capability while meeting the government's policy to cease burning coal at Nanticoke is to convert several units to synchronous condenser operation.

5.1.8 Retirement of Atikokan Facilities

A reliability assessment of the Northwest Zone of Ontario has demonstrated that the Atikokan station may be shut down without replacement. These studies demonstrate that the Northwest Zone of Ontario will continue to be compliant with the NPCC A-2 reliability criterion requiring a Loss of Load Expectation (LOLE) of not more than 0.1 days per year, under conservative input assumptions. Under normal operation the area far exceeds the specified reliability criterion. Due to the nature of the northwest system, the study considered probabilistic reductions to transmission interface capabilities between the Northwest and Northeast Zones, and assumed significantly lower than median resource availability from hydroelectric resources in the Northwest zone.

While operation without Atikokan capacity is acceptable from an adequacy perspective, transmission infrastructure changes are required to ensure system security needs are met. Retirement of Atikokan removes an important source of voltage support necessary to support energy flows throughout the long distances inherent to the Northwest system. The additional of shunt capacitors at Fort Frances and or Mackenzie TS will compensate for the retirement of Atikokan.

5.1.9 Treatment of Interconnections in the Coal Replacement Plan

Interconnection capability provides a number of benefits to the Ontario system and market participants. One very important aspect of the availability of energy from interconnections is in response to unforeseen near-term capacity and demand variations. The large centralized nuclear generation facilities in Ontario can expose the system to large capacity availability variations. Similarly, extreme weather in Ontario can result in extremely high temporary requirements for generation. For these reasons it was decided not to rely on interconnections for capacity requirements during the coal replacement transition, but rather to consider generation in Ontario for this purpose. Long term use of interconnections for capacity purposes should be based on the construction of additional interconnection capability, ensuring sufficient capability remains for current purposes.

5.2 System Transition Risk Mitigation

The transition from coal to replacement clean supply is an extremely challenging objective. In terms of the amount of coal generation to be replaced, an amount of clean supply larger than all of the hydroelectric capacity in Ontario must be arranged for, constructed, commissioned and reach a reliable state of operation.

This transition must take place:

- Without jeopardizing electricity reliability;
- Within the capabilities of the industry to deliver; and
- Within the tolerance for change of electricity consumers.

Managing a challenging objective such as this requires planning, monitoring and adjustment of schedules and plans to ensure that reliability is maintained and the transition proceeds efficiently. The IESO will monitor and assess the coal shutdown and replacement resource plans and will provide advice to all parties regarding the actions or adjustments required to ensure reliability is maintained.

The coal replacement plan is made up of a series of broad activities to achieve the desired transition.

1. Identify needs of replacement capacity – the first step is to establish the required characteristics, amounts, and general location of replacement capacity to meet the objectives of transition.
2. Procure the capacity – maximize use of existing processes such as RFP's to procure efficient and economic replacement supply to meet needs.
3. Identify infrastructure enhancements required to support the transition. This can include many diverse areas; however, it is certain to include transmission enhancements to integrate the replacement capacity and gas supply infrastructure to support new gas-fired capacity.
4. Build the new capacity and supporting infrastructure.
5. Integrate the new capacity and infrastructure into a reliably functioning system. This involves well-established commissioning activities and market entry processes.
6. Once replacement capacity has demonstrated reliable operation, only then will coal capacity be retired.

There are many risks associated with these plan activities.

1. Bringing new supply and delivery capacity in service on schedule
2. Maintaining existing coal plants operable and reliable until the new capacity and delivery infrastructure is available. This becomes more challenging as soon as a retirement date is announced for coal facilities.

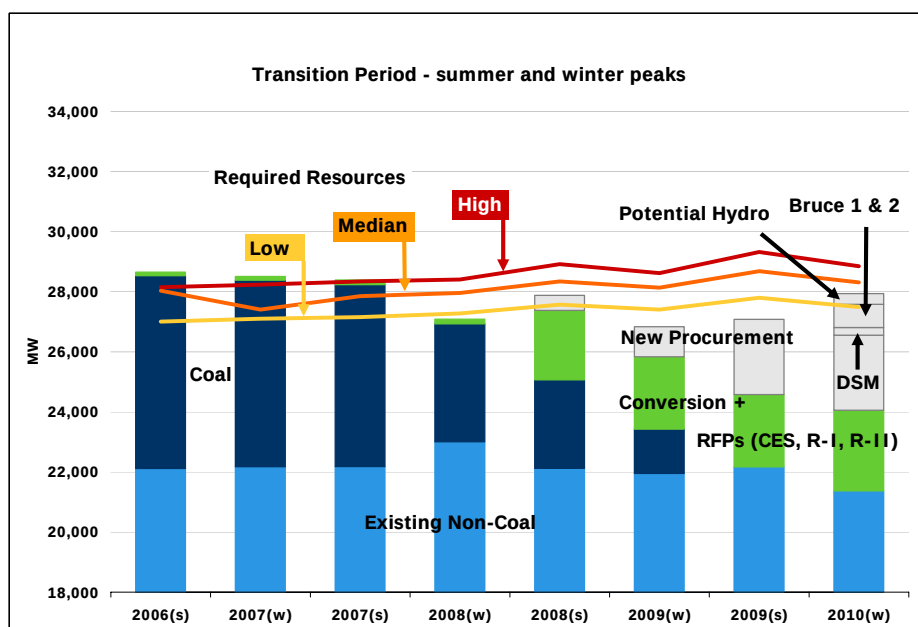
The transition plan incorporates risk mitigation strategies to address known risks. These include:

- Accelerated approvals processes for supply and deliver infrastructure;
- Maximizing use of existing delivery infrastructure to the extent possible;
- Early identification and procurement of necessary infrastructure;
- Establishing coal plants in a reserve state following the in-service of new capacity. This would involve minimizing the need for operation of these coal plants after replacement capacity is available, but retaining the capability for a period of time to guarantee a reliable transition, recognizing inherent risks with respect to early operation of replacement capacity. The importance of this requirement must not be understated; and
- Continuous planning and monitoring of the elements of transition and adjustment of schedules in response to reliability requirements.

It is through these strategies that the IESO proposes to facilitate a reliable transition.

Figure 5.3 illustrates the impact a six month delay in each of the replacement supply elements would have on reserve margins without the availability of coal plants on reserve to address this situation, large supply shortfalls would occur immediately.

Figure 5.3 Impact on Transition Period of Replacement Generation Delays



5.3 Coal Replacement Plan

The coal replacement plan has been developed based on the identified system requirements and incorporates elements of the risk mitigation strategies identified in earlier sections. Where firm plans for new capacity do not exist, the identified in-service dates for new supply should be considered as need dates for purposes of meeting the transition timeline identified by the Ontario Government.

Assumptions inherent in the plan are as follows:

- Best available information is used for in-service dates;
- Coal plants are assumed to remain operable and on reserve for a period of nine months after replacement capacity is declared in service; and
- The dates for coal plants to cease burning coal are based on forecast system conditions. For purposes of the plan, the dates are chosen such that system reserve above requirement is never less than zero for the median demand growth scenario, exclusive of coal capacity operable but on reserve.

The milestone dates identified in the plan represent the required in-service dates to achieve the coal replacement objectives. Achievement of these milestones is expected to be extremely challenging in some cases. Where milestones are not achieved, the retirement of existing capacity must be delayed.

A summary of the milestone dates for the coal replacement plan are contained in the following table.

Table 5.2 Coal Replacement Plan Milestones

Time Period	Summary of the Plan
2007	- Atikokan can cease burning coal and be put on reserve once Northwest transmission enhancements are complete. These enhancements are for shunt capacitors to be placed in service at Fort Frances and/or Mackenzie TS. - Atikokan must remain available for operation, on reserve, until transition of Thunder Bay to gas or equivalent replacement capacity is in service in the same location. - Thunder Bay conversion or replacement must be complete before end of 2007. If the conversion option is chosen, outages to two Thunder Bay units must be scheduled in spring and fall respectively to meet capacity needs over peak periods. - A natural gas pipeline to the Thunder Bay site must be available to meet either Thunder Bay option. - Lambton units can cease burning coal and be put on reserve once replacement capacity is in service. This includes: 1,005 MW Calpine project, 570 MW Invenergy project, and 280 MW Eastern Power GTA project plus completion of 500 MW of centrally located generation assumed to be met by the cogeneration commitment. - It will be necessary to reconfigure the Lambton switchyard to permit commissioning operation of the new supply in the area at the same time as the existing Lambton units.
2008	- Shunt capacitors in southwestern Ontario are required to be in service prior to the shutdown of Nanticoke units - Series compensation of the Bruce and Nanticoke transmission corridors and shunt capacitors in southwestern Ontario are required to be in service prior to the shutdown of Nanticoke units - Nanticoke Units 1 and 2 can cease burning coal and be put on reserve following the January – March winter peak period in 2008. - 500 MW of new capacity is required to be in service by June 2008. This is assumed to be met by the cogeneration commitment. - 1,000 MW of new capacity assumed to be in service in western GTA by fall 2008. - 500 MW of new capacity assumed to be in service in downtown Toronto by the fall of 2008. - Nanticoke units 3 and 4 can cease burning coal and be placed on reserve prior to the winter peak period 2008/9. - Nanticoke Unit 5 ceases burning coal and is placed on reserve by the end of 2008.

Time Period	Summary of the Plan
2009	- Nanticoke Units 1 and 2 are required to be converted to synchronous condenser operation. These outages are assumed to take place in early spring 2009 with actual unit outages limited to a maximum three month period. These facilities must be completed prior to Bruce Units 1 and 2 being placed in service. - 770 MW Bruce A unit returned to service by spring 2009. - Nanticoke Unit 6 ceases burning coal and is placed on reserve by spring of 2009. - Nanticoke Units 7 and 8 cease burning coal and are placed on reserve before summer peak 2009. - 280 MW Eastern Power GTA project placed in service prior to summer 2009. - Up to 380 MW of Mattagami expansion placed in service and series compensation of northeast transmission completed by summer 2009. - Demand side measures equivalent to 250 MW of supply in place by summer 2009 - Second 770 MW Bruce A unit returned to service by fall 2009. - Bruce A Unit 3 is removed from service by late fall 2009.

- End of Section -

6.0 Overall Observations, Findings and Conclusions

Resources

Demand/Supply Balance

- ❑ The phase out of coal-fired generation, aging generation facilities and the continued increase in demand for electricity all contribute to the need for new generating and transmission facilities over the next 10 years. Additional Ontario electricity supply and demand-side measures are required to maintain supply adequacy into the future and to reduce Ontario's dependency on supply from other jurisdictions
- ❑ Under the Reference Resource Scenario, Ontario could be facing a growing supply shortfall beyond the first few years of the 10 year period. Reserve requirements will be met in the first five years under the median demand growth scenario if no in-service delays are encountered for the RFP projects, or alternatively, if there are delays, coal replacement must be deferred. For the low demand scenario, reserve requirements are met until 2013. However, if high demand growth occurs, additional supply will be required by 2010 and possibly earlier.
- ❑ Under the Coal Replacement Scenario, reserve requirements will be met until 2011 under median demand growth assumptions if a number of challenging conditions are met -- no in-service delays are encountered for the successful RFP projects, the procurement of additional generation by the OPA is successful in the right amounts and locations, Bruce Units 1 and 2 are returned to service on-schedule, the development of additional Mattagami generation or similar capacity is completed on-schedule and demand side management projects are implemented. Additional supply is required after 2011.
- ❑ A diverse generation mix of operating types (baseload, intermediate, peaking) as well as diversity among the fuel used by the various supply (hydroelectric, wind, gas, nuclear) is critical for resource adequacy and market efficiency, through the provision of dispatch flexibility, reduced vulnerability to fuel supply contingencies and fuel price fluctuations.
- ❑ Continued flexibility with respect to water use is important to system operation. The IESO is concerned with the future management of the Province's water resources as they relate to electricity production. The flexibility in the operation of hydroelectric facilities is of great benefit to the Ontario power system. The importance of this flexibility needs to continue to be reflected and balanced with other options which may influence provincial requirements with respect to water management. Hydroelectric resources provide energy, ramping capability, operating reserve and automatic generation control. Preserving operating flexibility of hydroelectric generating facilities (whether old or new) should be a critical consideration in the development of water management plans.
- ❑ Connecting large amounts of wind powered generation to the grid will involve challenges, including improving the understanding of daily patterns and fluctuations of wind generation to determine if changes are needed in IESO operating practices and Market Rules. The connection assessment of wind generation needs careful examination with respect to a facility's ability to stay connected during low voltage excursions, its ability to supply reactive power, data monitoring requirements and others. Notwithstanding these considerations, the presence of wind on the Ontario grid will be a positive contribution to Ontario's future

supply mix. For the purposes of this study, it is assumed 10% of the installed capacity of wind powered generation can be relied on at the time of the annual peak.

- ❑ The IESO has been identifying the suitability of conservation and demand-side (CDM) measures as part of the supply picture for several years and believes demand reductions and demand shifting should be vigorously pursued in Ontario, as clean and potentially less expensive ways to reduce future supply requirements. The application of such demand initiatives is virtually unrestricted in location.
- ❑ IESO recommends that Ontario work with other jurisdictions to raise the power factor requirements of new air-conditioning equipment. This would in the long term reduce the need for generation and transmission enhancements to meet the active power demand in Ontario.
- ❑ Interconnections are an important source of energy for Ontario. In real-time system operation, reliance on external supply through interconnections is mutually beneficial to all interconnected systems, for both reliability and market efficiency reasons. During off-peak periods, attractively priced external supply can provide cost savings to the electricity market and access to broader market for inexpensive Ontario generators. During peak hours, due mainly to the non-coincidence of the peak demands with one or more neighbouring systems, external supply can contribute to meeting peak demand.
- ❑ Additional interconnections between Ontario and its neighbours have been proposed. An HVDC interconnection with Hydro Quebec of 1,250 MW transfer capability would improve interchanges between Ontario and Quebec and would be required for future power procured from Lower Churchill Falls. Although not yet formally submitted for Connection Assessment, an upgrade to the Ontario - Manitoba interconnection would give access to hydroelectric capacity from Manitoba
- ❑ Interconnection capability provides a number of benefits to the Ontario system and market participants. One very important aspect of the availability of energy from interconnections is in response to unforeseen near-term capacity and demand variations. The large centralized nuclear generation facilities in Ontario can expose the system to large capacity availability variations. Similarly, extreme weather in Ontario can result in extremely high temporary requirements for generation. Long term use of interconnections for capacity purposes should be based on the construction of additional interconnection capability, ensuring sufficient capability remains for current purposes.

Transmission

Downtown Toronto

- ❑ For expected summer peak load conditions, the power flow on the transmission equipment supplying this zone is expected to be at or near its maximum capability. As load grows annually, the flows through these circuits and transformers will continue to increase, to the point that the downtown Toronto load would have to be interrupted in the event of a failure of a single circuit or transformer. The system is normally designed and operated with some redundancy – i.e., the ability to withstand such an outage without interrupting load. This redundancy is forecast to be lost by summer 2008, but a higher rate of load growth or extreme weather could make it as early as summer 2006.

The transmission system within downtown Toronto is also very heavily loaded and could reach its maximum capacity as early as the summer of 2006, depending on the rate of load growth in the downtown core. Since much of the downtown system consists of underground cables, equipment failure could take a substantial time to repair, exposing the loads to extended supply interruptions. The addition of generation and demand response in downtown Toronto would reduce the power transfers through the heavily loaded transmission facilities between Cherrywood and Leaside, and through the transformers at Leaside TS, and would reduce the loading on the transmission system in downtown Toronto. Hydro One has a transmission reinforcement plan for downtown Toronto (the proposed third supply), and advises that the first stage could be completed no earlier than 2010. An initial phase of this first stage could be in service as early as 2007 (the John-to-Esplanade link), but the capability of this link to provide relief during peak load periods is dependant on transmission or generation reinforcement in the western GTA (Manby sector). Hence additional generation or demand response in the area is crucial to maintaining reliability of supply until 2010. System studies indicate that the maximum amount of generation that can be connected directly to the transmission system in downtown Toronto is limited by transmission equipment short circuit considerations to about 550 MW.

- ❑ New generation capacity is required within the Toronto area and must be sited so that it can be connected directly to the 115kV busbar at Hearn SS. The new capacity must be limited to approximately 720 MVA so that the ratings of the existing switchgear at Leaside TS are not exceeded. This will also require that the generator step-up transformers be suitable for being equipped with neutral reactors.

With all of the new generation capacity incorporated, the existing transmission system in the Toronto area must be operated split into two discrete halves from Cherrywood TS through to Hearn TS. The new capacity is therefore required to comprise individual generating units that will allow between 300 MW and 400 MW to be connected to the western half of the split system and with any remaining capacity connected to the eastern half. In addition, under equipment outage conditions, at least 50% of the generation capacity connected to the western half of the Hearn busbar is required to be available for service.

- ❑ In the absence of additional generation as well as demand-side initiatives, a single transmission facility failure may make it necessary at times to interrupt load in the area in order to prevent the overloading of transmission facilities supplying downtown Toronto, particularly during hot weather conditions. The risk that load shedding will be necessary increases as electricity demand in downtown Toronto continues to grow.
- ❑ With the scheduled completion of the John-to-Esplanade link in the fall of 2007, the need date for additional supply to downtown Toronto may be deferred until the summer of 2008, under extreme weather conditions.
- ❑ Depending on its exact location and configuration, the 500 MW of new generating capacity to be procured by the OPA for the downtown Toronto core could provide a deferral in the need date for further supply to beyond 2010, under extreme weather conditions.
- ❑ Even with additional generating capacity installed in the downtown Toronto core, it is expected that a third supply will need to be installed prior to the summer of 2010 to ensure a secure supply for downtown Toronto. However, should additional load growth occur, beyond that which is currently being forecast, it would be necessary to advance the installation of a third supply.

- ❑ Additional auto-transformer capacity is required at Manby West TS as soon as possible to allow existing equipment to be taken out of service for maintenance without requiring load interruptions.

Greater Toronto Area

- ❑ The electrical loads in the western GTA are supplied by transmission lines and auto-transformers that connect the local transmission and distribution systems to the rest of the high voltage grid. These auto-transformers are key sources of supply to the area. The immediate transmission system impacts arising from the shutdown of the Lakeview coal fired Generating Station in Mississauga on April 30, 2005 have been addressed. Hydro One completed the first phase of the Parkway Transformer Station which alleviates transformer overload concerns. Voltage support requirements have been dealt with by the installation of additional shunt capacitors and related transformer controls by Hydro One. These temporary measures were required to avoid overloading of auto-transformers at the Claireville Transformer Station and Milton Switching Station and lower than acceptable voltages in the western portion of the GTA during heavy load conditions. However additional steps are required to address this growing problem.
- ❑ Once all of the planned facilities are in-service, and depending on the number of remaining generating units that are operational in south central Ontario during peak load periods, the IESO has concluded that the system would only exhibit acceptable voltage performance, without interrupting load, through the summer of 2007.
- ❑ The capability of the existing 230 kV transmission corridor between Richview TS and Manby TS to accommodate further increases in load is already severely limited. To support additional load transfers using the John-to-Esplanade Link would require reinforcement before summer 2007. Consequently, generation capacity located to the south of Manby TS that would reduce the required flows from Richview TS would defer the need to reinforce the Richview-Manby corridor, and will also reduce the transfers through the Claireville auto-transformers.
- ❑ In order to limit the peak flows through the Claireville auto-transformers to a level at or near their continuous ratings during the period 2006 to 2010, it will be necessary to install at least 1000 MW of additional generation and demand response on the 230 kV system in the Claireville area. Load growth and extreme weather could require this as early as summer 2007. Generation capacity connected to the 230 kV circuits that terminate on to the 230 kV busbar at Claireville TS would not only reduce the transfers through the auto-transformers but would also provide direct voltage support for the Claireville busbar following contingencies.
- ❑ Three new generating facilities selected under the 2,500 MW RFP - Greenfield South, Greenfield North and GTAA - are expected to be adequate to maintain the transfers through the auto-transformers at Trafalgar TS within their continuous rating for peak demands up to 27,500 MW. The new generating facilities would also provide additional margin on the auto-transformers at Claireville TS to accommodate possible transfers from the Leaside to the Manby Sector during peak load periods via the new John-to-Esplanade Link without exceeding their continuous rating. However, the new generating facilities are not expected to be sufficient to provide any additional margin on the auto-transformers at either Claireville TS or Trafalgar TS to accommodate future load growth.

- ❑ The approximately 1,000 MW of additional generating capacity to be procured by the OPA for the western GTA, beyond the three Projects that were previously announced for this area, is expected to provide further relief for the auto-transformers at Claireville TS. However, depending on its location, this generation may do little to relieve the loading on the Trafalgar auto-transformers.
- ❑ One option to relieve the loading on the Trafalgar auto-transformers would be the installation of two 500/230 kV auto-transformers at Milton TS and the re-termination of the existing connections to Halton TS and Meadowvale TS.
- ❑ Due to the high load growth in the Newmarket - Aurora area, additional supply capability is required. Options to provide this capability are being examined by the OPA.

Kitchener, Waterloo, Cambridge, Guelph and Orangeville Areas

- ❑ Remedial measures are required urgently to improve voltages and increase supply in the Kitchener, Waterloo, Cambridge, Guelph and Orangeville areas which are primarily supplied from Detweiler TS.
- ❑ Hydro One has proposed a plan for enhancing the load-meeting capability of this area involving the installation of 230/115 kV auto-transformers at Cambridge-Preston TS, the installation of two 500/230 kV auto-transformers on the right-of-way of the 500 kV circuits between Middleport TS and Milton TS/Claireville TS, and the construction of a new 230 kV double-circuit line into Cambridge-Preston TS. IESO studies indicate that this plan has substantial merit, but poor voltages can still result under contingency conditions.
- ❑ The IESO has examined the effect of including a further 500/230 kV interconnection in the vicinity of Bellwood Junction where the existing 500 kV right-of-way of circuits B560V and B561M and the 230 kV right-of-way of circuits D6V and D7V intersect. Preliminary Assessment of this proposed connection, together with the connection from the 500 kV system into Cambridge-Preston TS, resulted in a significant improvement in the system voltages under peak load conditions.
- ❑ Local generation should be considered as an alternative or complementary solution to the transmission proposals indicated.

Bruce Area

- ❑ One of the potential sources of replacement supply for coal fired generation is the return to service of Bruce units 1 and 2. Preliminary IESO studies indicate that the proposed 500 kV series capacitors on the lines emanating from the Bruce Complex should sufficiently enhance the transfer capability of the existing transmission facilities to allow the additional capacity at Bruce GS to be incorporated without the need for any new transmission lines. IESO studies assumed that:
 - o Nanticoke GS was no longer operating as a generating station, but at least two units were operating as synchronous condensers;
 - o additional generating capacity that is expected in the western GTA and in downtown Toronto was in-service; and,
 - o New capacitor banks at Middleport TS were in-service.

Northeastern Ontario

- ❑ The north-eastern part of the Ontario power grid is made up of multiple generating units, a few very large and many small loads, and a relatively sparse transmission system. The grid north of Sudbury is connected to the rest of Ontario via one 500 kV circuit, and one 115kV circuit.

Currently the IESO employs a variety of specific operating procedures and special protection systems to ensure that all of the generation in north-eastern Ontario can be reliably transmitted to the loads in Southern Ontario. In doing so, especially when the generation is operating near maximum output, there is some risk of abnormal operation if the 500 kV circuit were to trip (operating statistics show a trip could happen about once a year).

Over the years generation has been added and a reduction in local load has taken place in north-eastern Ontario. Recent analysis by the IESO indicates that the existing operating measures are no longer sufficient to ensure acceptable operation following the loss of the 500 kV circuit connecting the North-east to the south. To address this, the IESO is adopting operational measures that rely on an automatically cross tripping 500 kV circuit D501P and shutdown the 230 kV system connected to Pinard TS. of the system during high southward transfers. This would only be initiated following the trip of the 500 kV circuit, would avoid the risk of abnormal voltages and frequencies, and would also allow a quick and orderly restart of the system.

Without these new measures the existing generation could be significantly restricted with a resulting cost to the market. It is anticipated that these new operating measures would pose little additional risk, would allow all of the generation to be utilized, and would also be of benefit if the Mattagami development were to take place.

- ❑ Enhancements to the existing transmission facilities and the existing generation rejection scheme are required in order to maintain all of the existing 115 kV system in-service following a 500 kV contingency, while also increasing the transfers between Hanmer TS (Sudbury) and Porcupine TS (Timmins) above 650 MW. This will minimise the impact of the new policy on consumers within the area, and help in the supply restoration process.
- ❑ The existing limit for transfers south from Hanmer TS (Sudbury) to Essa TS (Barrie) over 500 kV circuits X503E and X504E is 1,400 MW when accompanied with 100 MW of generation rejection. During recent years there has been an increase in the transfers south which occasionally requires generation output to be constrained so that the present limit is respected.
- ❑ Hydro One has proposed installing series capacitors at Nobel SS, the approximate mid-point of circuits X503E and X504E. These capacitors would provide 60% compensation for the line reactance, and preliminary studies by the IESO have shown that they should allow the Flow South limit to be increased by at least 600 MW.
- ❑ Additional analysis has shown that installing series capacitors in circuits P502X and D501P, together with shunt capacitors at Little Long GS and Hanmer TS, would provide the necessary increase in the Flow-South limit to accommodate all of the increased capacity from the proposed Mattagami Expansion as well as the existing generating capacity that currently exceeds the present limit of 1,400 MW.

Sarnia-Windsor Area

- ☐ It is necessary to reconfigure the terminations at Lambton SS so that the 230 kV busbar can be operated split in order to ensure that fault levels remain within equipment ratings. Since this work is expected to take approximately two years to complete, it will need to commence as soon as possible to meet the proposed start of commissioning in 2007 for an expected in-service date of early-2008 for the new RFP generating facilities in the Sarnia area.
- ☐ Upgrading of the 115 kV circuits J3E and J4E, together with the replacement of the auto-transformers at Keith TS with higher-rated units, is urgently required. Before this work can be undertaken, it will be necessary to complete the re-termination of some of the existing 115 kV circuits at Essex TS together with the expansion of the existing Special Protection System.
- ☐ Installation of a proposed 230/115 kV auto-transformer at Kent TS should be undertaken as soon as possible. This would allow the Tilbury-area loads to be transferred from the 115 kV busbar at Lauzon TS, and would provide critical relief for the 115 kV system between Lauzon TS and Kingsville TS.
- ☐ During peak load periods, with the Brighton Beach Project out-of-service, a contingency involving either of the 230 kV circuits C23Z or C24Z between Chatham TS and Lauzon TS is expected to result in overloading of either the companion 230 kV circuit and/or the companion auto-transformer at Lauzon TS. To avoid the load interruption required to correct this overload situation, the IESO recommends that assess the feasibility of establishing a new 230 kV connection between Keith TS and Lauzon TS, together with a third 230/115 kV auto-transformer at Lauzon TS.
- ☐ The IESO recommends that Hydro One assess the feasibility of upgrading the 230 kV line so that its continuous and limited-time-rating better matches that of the phase-shifter, thereby allowing the transfers from Michigan to Ontario over the J5D Interconnection to be increased by at least 200 MW. It is also important to note that should a decision be made to proceed with this work that it only be scheduled after the upgrading of the 115 kV Keith-to-Essex circuits and the replacement of the Keith auto transformers have been completed

Oshawa and Belleville Areas

- ☐ To address the loading on circuits H24C and H26C, either of the following alternatives should be considered for implementation:
 - Establish a new 500/230 kV connection in the Bowmanville area in the vicinity where the existing 500 kV and 230 kV rights-of-way cross, by installing one or more 500/230 kV auto-transformers. or
 - Reinforce the existing 230 kV connection from Cherrywood TS into the Oshawa area with a new 230 kV double-circuit line approximately 27km long, to allow some of the existing load to be transferred to it.

To address the loading on circuits M29C and B23C, consideration should be given to establishing a direct connection between the 230 kV and 500 kV systems in the vicinity where the existing 500 kV and 230 kV rights-of-way cross, by installing one or more 500/230 kV auto-transformers.

Niagara Area

- ☐ Thermal loading on circuits between Niagara Falls and Hamilton (QFW) and into Burlington continue to cause congestion and limit import capability from New York. Hydro One's plan

to expand the transfer capability on the QFW circuits is in the regulatory approval process. The upgrade, if approved, is expected to provide an increase in transfer capability of about 800 MW on QFW. This plan is seen as an important risk mitigation measure for the coal replacement plan.

- ❑ In the past, under peak summer conditions, and recently during hot weather in June 2005, the 230 kV transmission facilities into Burlington TS have also congested Ontario generation and constrained power flows on the QFW circuits. Without reinforcing these 230 kV transmission facilities into Burlington, the full benefit in upgrading the QFW interface may not be realized.

Coal Replacement Plan

- ❑ The coal replacement plan incorporates existing, committed and announced initiatives with respect to additional supply and demand response in various stages of discussion, development, or negotiation. In addition, transmission infrastructure enhancements required to integrate these initiatives have been identified. It must be recognized that significant changes to either the resource or infrastructure plans or timing of the plans will likely jeopardize the ability to retire coal on the timeline proposed.
- ❑ The IESO will monitor and assess the coal shutdown and replacement resource plans and will provide advice to all parties regarding the actions or adjustments required to ensure reliability is maintained.
- ❑ As new generation is brought into service, there will be an initial period of “running in” before it becomes fully reliable. Accordingly, one critical aspect of the coal replacement plan is the essential requirement to maintain existing coal-fired plants available for service for a period of time after the actual in-service date of replacement supply. This risk mitigation requirement will help to ensure the continued reliability of the system during this period of substantial system change.
- ❑ Because of the high level of uncertainty and the severity of the consequences of supply shortages, it is critically important that the coal replacement plan incorporate rigorous risk mitigation measures and controls
- ❑ Coal supply makes up a large part of Ontario’s flexible generation, and it has traditionally been required to meet changing demand, to supply demand when other supply sources are unreliable, and to balance load and generation at all times. Replacement supply must have similar characteristics to provide operating flexibility and sustained energy production as and when it is needed.
- ❑ The impact of new generation on the transmission system will also be assessed, and necessary transmission upgrades must be completed to ensure reliable system operation.

Replacement of Nanticoke GS and the Addition of Generation at Bruce

- ❑ Achieving the replacement of Nanticoke generation in appropriate locations is critical to supporting power transfers toward Toronto and to avoiding restrictions on the output from Bruce. The shutdown of the station is particularly complex due to a number of factors, including the desire to refurbish Bruce units 1 and 2, the growing demand for power in the Greater Toronto Area (GTA) and the need to supply that demand from power sources outside the area. Nanticoke also provides reactive power to support the heavy power flows from those areas to the GTA.

- ❑ Developments which are required to support the shutdown of Nanticoke include the following:
 - Installation of generation in proximity to the large GTA demand;
 - Installation of series compensation in the 500 kV lines serving Bruce and Nanticoke; and
 - Installation of shunt capacitors at Middleport TS, in southwestern Ontario.

It is unlikely that these measures will eliminate the need for dynamic voltage support from the Nanticoke site. The most cost-effective means to provide this capability while meeting the government's policy to cease burning coal at Nanticoke is to convert several units to synchronous condenser operation.

- ❑ The coal replacement plan requires that at least two of the Nanticoke units be converted to synchronous condenser operation.
- ❑ Nanticoke units are planned to cease burning coal and be placed on reserve for a period of time beginning in 2008 with the last units placed on reserve in 2009.

Replacement of Lambton GS

- ❑ Lambton can cease burning coal and be put on reserve once replacement capacity is in service. This includes the 1,005 MW Calpine project, the 570 MW Invenergy project, and the 280 MW Eastern Power GTA project all expected in service near the end of 2007 and early 2008.

Replacement of Thunder Bay GS and Atikokan GS

- ❑ Atikokan can cease burning coal and be put on reserve once Northwest Transmission enhancements are complete. These enhancements are for shunt capacitors in service at Fort Frances and/or Mackenzie TS. Atikokan must remain available for operation, on reserve, until transition of Thunder Bay to gas or equivalent replacement capacity is in service in the same location.

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Appendix A – Resource Adequacy Assessment Details

List of Tables

Table A1	Reserve Above Requirement Values Under Low Demand Growth, Summer Peak, Reference Resource Scenario.....	64
Table A2	Reserve Above Requirement Values Under Median Demand Growth, Summer Peak, Reference Resource Scenario.....	64
Table A3	Reserve Above Requirement Values Under High Demand Growth, Summer Peak, Reference Resource Scenario.....	65
Table A4	Reserve Above Requirement Values Under Low Demand Growth, Summer Peak, Coal Replacement Scenario	65
Table A5	Reserve Above Requirement Values Under Median Demand Growth, Summer Peak, Coal Replacement Scenario	65
Table A6	Reserve Above Requirement Values Under High Demand Growth, Summer Peak, Coal Replacement Scenario	66

Resource Adequacy Assessment Tables

The following tables provide numeric results of the resource adequacy assessment. Red with white text cell shading in the 'Reserve Above Requirement' column means the forecast supply deficiency exceeds the current Ontario coincident import capability of ~4,000 MW.

Table A1 Reserve Above Requirement Values Under Low Demand Growth, Summer Peak, Reference Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Above Requirement MW
2006	23,292	16-Jul-06	28,671	27,003	5,379	3,711	23.1	15.9	1,668
2007	23,607	15-Jul-07	28,541	27,155	4,934	3,548	20.9	15.0	1,386
2008	23,883	13-Jul-08	28,457	27,570	4,574	3,687	19.2	15.4	887
2009	24,213	12-Jul-09	28,787	27,800	4,574	3,587	18.9	14.8	987
2010	24,300	18-Jul-10	28,292	27,617	3,992	3,317	16.4	13.7	675
2011	24,516	17-Jul-11	28,356	27,848	3,840	3,332	15.7	13.6	508
2012	24,733	15-Jul-12	28,388	28,110	3,655	3,377	14.8	13.7	278
2013	24,954	14-Jul-13	28,416	28,482	3,462	3,528	13.9	14.1	-66
2014	25,159	13-Jul-14	26,860	28,852	1,701	3,693	6.8	14.7	-1,992
2015	25,475	12-Jul-15	25,962	29,311	487	3,836	1.9	15.1	-3,349

Table A2 Reserve Above Requirement Values Under Median Demand Growth, Summer Peak, Reference Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Above Requirement MW
2006	24,089	9-Jul-06	28,655	28,037	4,566	3,948	19.0	16.4	618
2007	24,301	15-Jul-07	28,541	27,848	4,240	3,547	17.5	14.6	693
2008	24,627	13-Jul-08	28,457	28,344	3,830	3,717	15.6	15.1	113
2009	25,045	12-Jul-09	28,787	28,685	3,742	3,640	14.9	14.5	102
2010	25,228	18-Jul-10	28,292	28,701	3,064	3,473	12.2	13.8	-409
2011	25,534	17-Jul-11	28,356	29,037	2,822	3,503	11.1	13.7	-681
2012	25,840	15-Jul-12	28,388	29,411	2,548	3,571	9.9	13.8	-1,023
2013	26,158	14-Jul-13	28,416	29,883	2,258	3,725	8.6	14.2	-1,467
2014	26,461	13-Jul-14	26,860	30,371	399	3,910	1.5	14.8	-3,511
2015	26,874	12-Jul-15	25,962	30,925	-912	4,051	-3.4	15.1	-4,963

Table A3 Reserve Above Requirement Values Under High Demand Growth, Summer Peak, Reference Resource Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Above Requirement MW
2006	24,442	16-Jul-06	28,652	28,151	4,210	3,709	17.2	15.2	501
2007	24,756	15-Jul-07	28,541	28,344	3,785	3,588	15.3	14.5	197
2008	25,116	13-Jul-08	28,457	28,917	3,341	3,801	13.3	15.1	-460
2009	25,594	12-Jul-09	28,787	29,325	3,193	3,731	12.5	14.6	-538
2010	25,844	18-Jul-10	28,292	29,423	2,448	3,579	9.5	13.9	-1,131
2011	26,213	17-Jul-11	28,356	29,830	2,143	3,617	8.2	13.8	-1,474
2012	26,583	15-Jul-12	28,388	30,272	1,805	3,689	6.8	13.9	-1,884
2013	26,968	14-Jul-13	28,416	30,827	1,448	3,859	5.4	14.3	-2,411
2014	27,342	13-Jul-14	26,860	31,385	-482	4,043	-1.8	14.8	-4,525
2015	27,829	12-Jul-15	25,962	32,036	-1,867	4,207	-6.7	15.1	-6,074

Table A4 Reserve Above Requirement Values Under Low Demand Growth, Summer Peak, Coal Replacement Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Above Requirement MW
2006	23,292	16-Jul-06	28,655	27,003	5,363	3,711	23.0%	15.9%	1,652
2007	23,607	15-Jul-07	28,541	27,155	4,934	3,548	20.9%	15.0%	1,386
2008	23,883	13-Jul-08	28,477	27,570	4,594	3,687	19.2%	15.4%	907
2009	24,213	12-Jul-09	28,741	27,800	4,528	3,587	18.7%	14.8%	941
2010	24,300	18-Jul-10	29,016	27,617	4,716	3,317	19.4%	13.7%	1,399
2011	24,516	17-Jul-11	29,080	27,848	4,564	3,332	18.6%	13.6%	1,232
2012	24,733	15-Jul-12	29,112	28,110	4,379	3,377	17.7%	13.7%	1,002
2013	24,954	14-Jul-13	29,140	28,482	4,186	3,528	16.8%	14.1%	658
2014	25,159	13-Jul-14	27,584	28,852	2,425	3,693	9.6%	14.7%	-1,268
2015	25,475	12-Jul-15	26,686	29,311	1,211	3,836	4.8%	15.1%	-2,625

Table A5 Reserve Above Requirement Values Under Median Demand Growth, Summer Peak, Coal Replacement Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Above Requirement MW
2006	24,089	9-Jul-06	28,655	28,037	4,566	3,948	19.0%	16.4%	618
2007	24,301	15-Jul-07	28,541	27,848	4,240	3,547	17.4%	14.6%	693
2008	24,627	13-Jul-08	28,477	28,344	3,850	3,717	15.6%	15.1%	133
2009	25,045	12-Jul-09	28,741	28,685	3,696	3,640	14.8%	14.5%	56
2010	25,228	18-Jul-10	29,016	28,701	3,788	3,473	15.0%	13.8%	315
2011	25,534	17-Jul-11	29,080	29,037	3,546	3,503	13.9%	13.7%	43
2012	25,840	15-Jul-12	29,112	29,411	3,272	3,571	12.7%	13.8%	-299
2013	26,158	14-Jul-13	29,140	29,883	2,982	3,725	11.4%	14.2%	-743
2014	26,461	13-Jul-14	27,584	30,371	1,123	3,910	4.2%	14.8%	-2,787
2015	26,874	12-Jul-15	26,686	30,925	-188	4,051	-0.7%	15.1%	-4,239

Table A6 Reserve Above Requirement Values Under High Demand Growth, Summer Peak, Coal Replacement Scenario

Year	Summer Peak Demand MW	Week Ending	Available Resources MW	Required Resources MW	Available Reserve MW	Required Reserve MW	Available Reserve %	Required Reserve %	Reserve Above Requirement MW
2006	24,442	16-Jul-06	28,655	28,151	4,213	3,709	17.2%	15.2%	504
2007	24,756	15-Jul-07	28,541	28,344	3,785	3,588	15.3%	14.5%	197
2008	25,116	13-Jul-08	28,477	28,917	3,361	3,801	13.4%	15.1%	-440
2009	25,594	12-Jul-09	28,741	29,325	3,147	3,731	12.3%	14.6%	-584
2010	25,844	18-Jul-10	29,016	29,423	3,172	3,579	12.3%	13.8%	-407
2011	26,213	17-Jul-11	29,080	29,830	2,867	3,617	10.9%	13.8%	-750
2012	26,583	15-Jul-12	29,112	30,272	2,529	3,689	9.5%	13.9%	-1,160
2013	26,968	14-Jul-13	29,140	30,827	2,172	3,859	8.1%	14.3%	-1,687
2014	27,342	13-Jul-14	27,584	31,385	242	4,043	0.9%	14.8%	-3,801
2015	27,829	12-Jul-15	26,686	32,036	-1,143	4,207	-4.1%	15.1%	-5,350

Appendix B..... Transmission Diagrams

List of Diagrams

Diagram 1	Location of New, Contracted Generation Projects in the GTA	68
Diagram 2	System Enhancements for the Milton Area – Brampton Area	69
Diagram 3	Distribution of Loads within the Leaside & Manby Sectors	70
Diagram 4	Initial Phase of the 3 rd Supply for Downtown Toronto: the John TS to Esplanade TS Link.....	71
Diagram 5	System Enhancements for the Kitchener, Waterloo, Cambridge, Guelph & Orangeville Area.....	72
Diagram 6	Location of Proposed Series Capacitors in the 500kV Circuits Associated with the Bruce Complex	73
Diagram 7	Proposed System Enhancements in Northeastern Ontario.....	74
Diagram 8	System Enhancements for the Windsor - Chatham Area.....	75
Diagram 9	System Enhancements for the Oshawa – Belleville Area.....	76

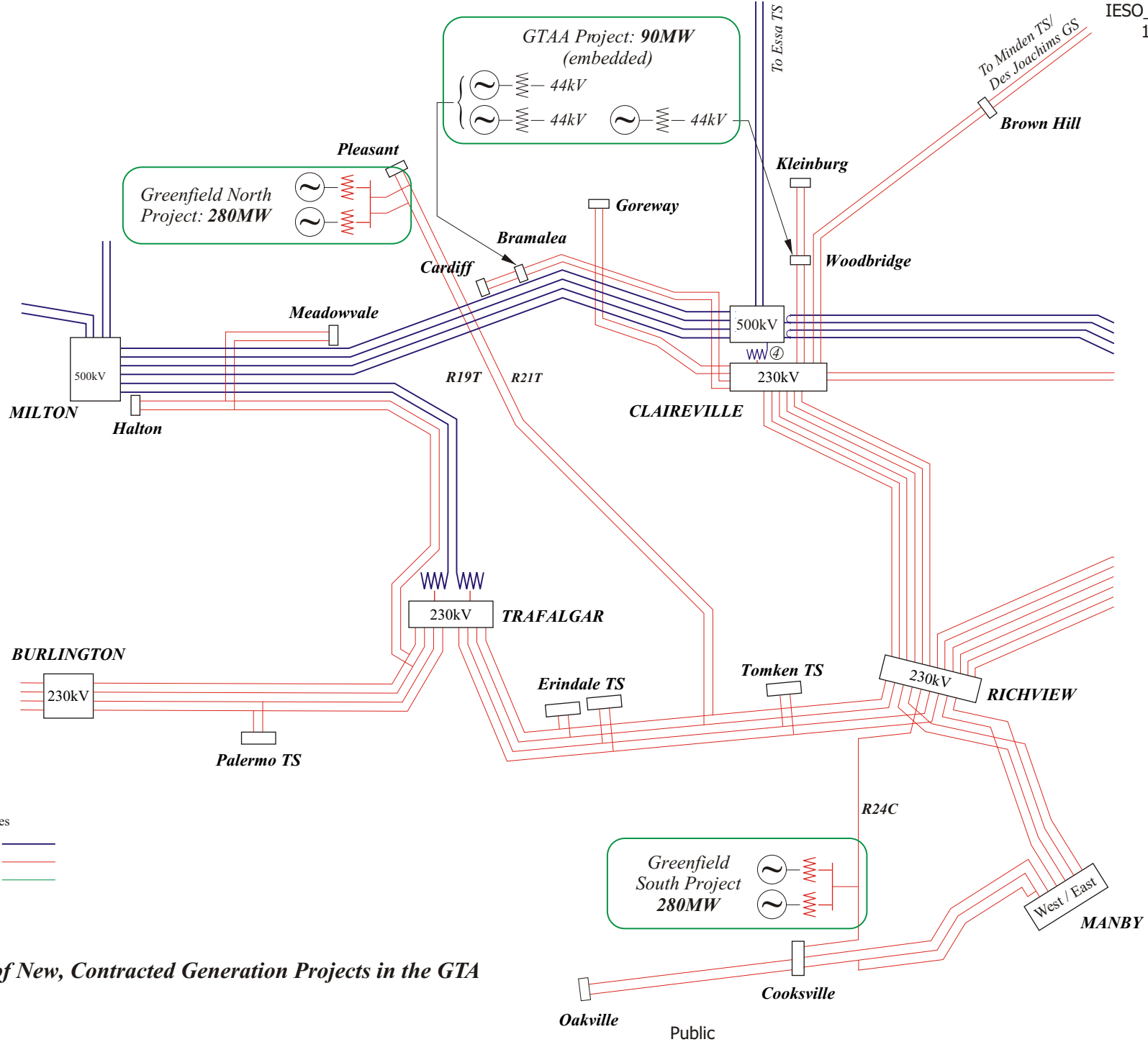
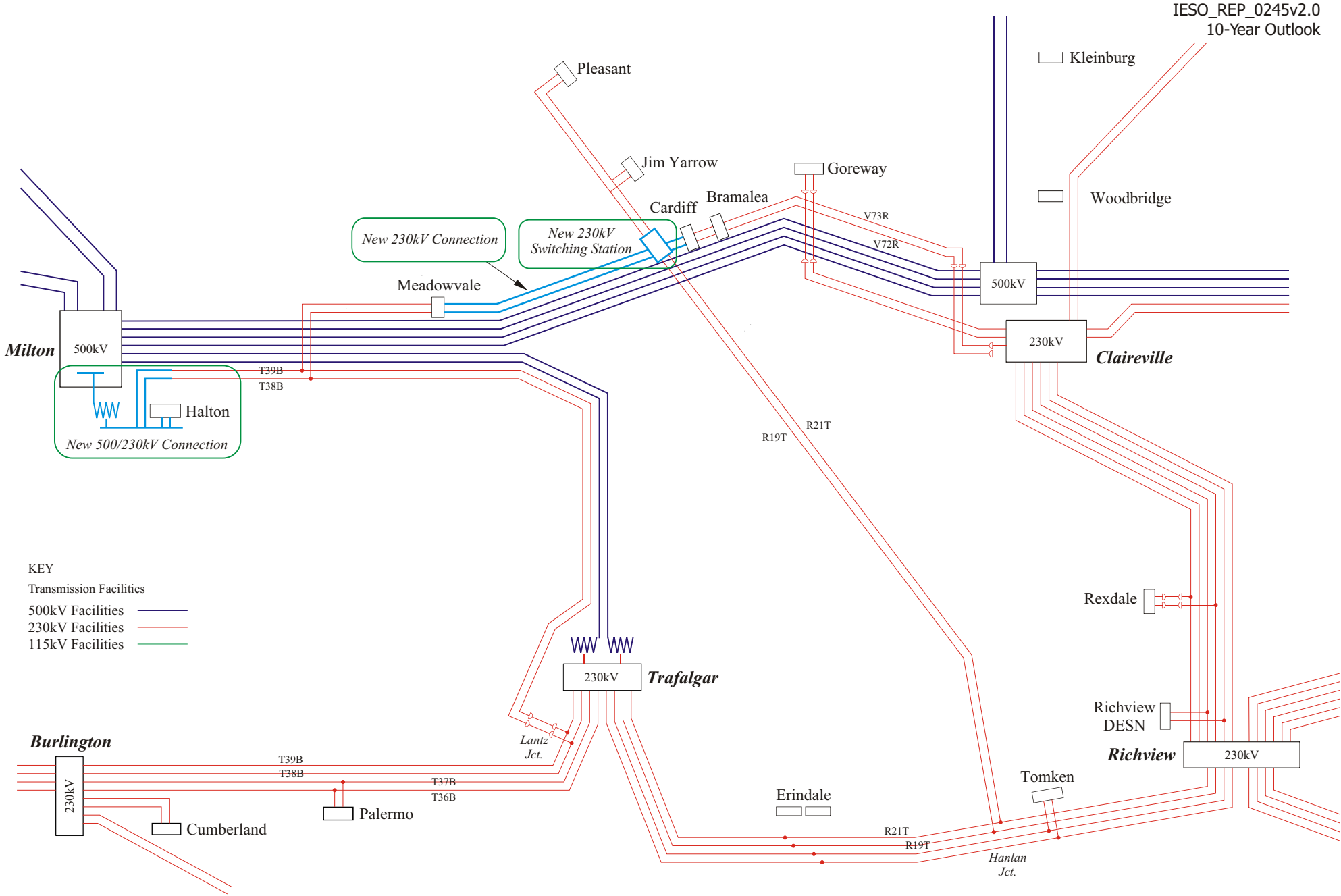


DIAGRAM 1



System Enhancements for the Milton Area - Brampton Area

DIAGRAM 2

— 230kV Facilities
— 115kV Facilities

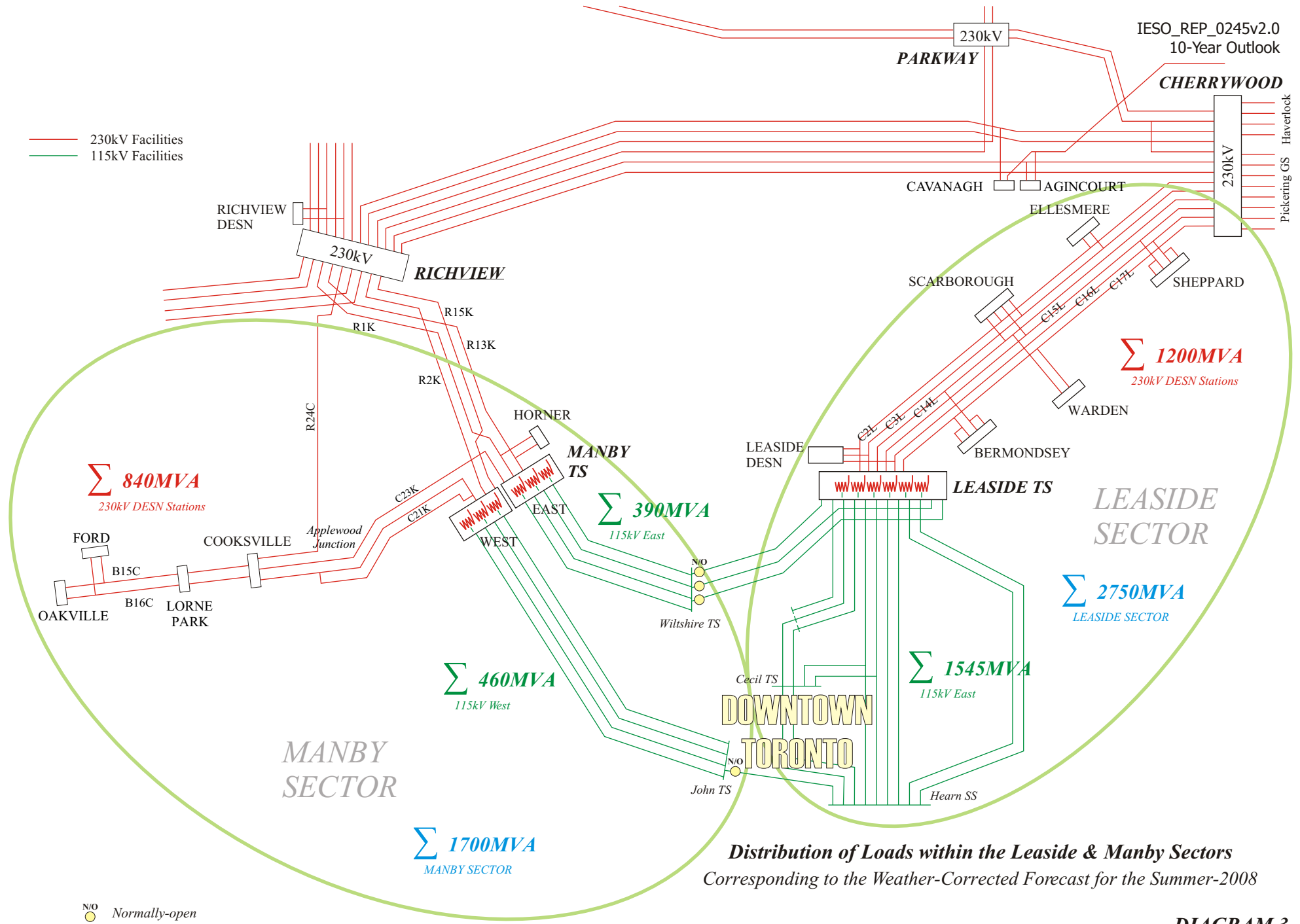
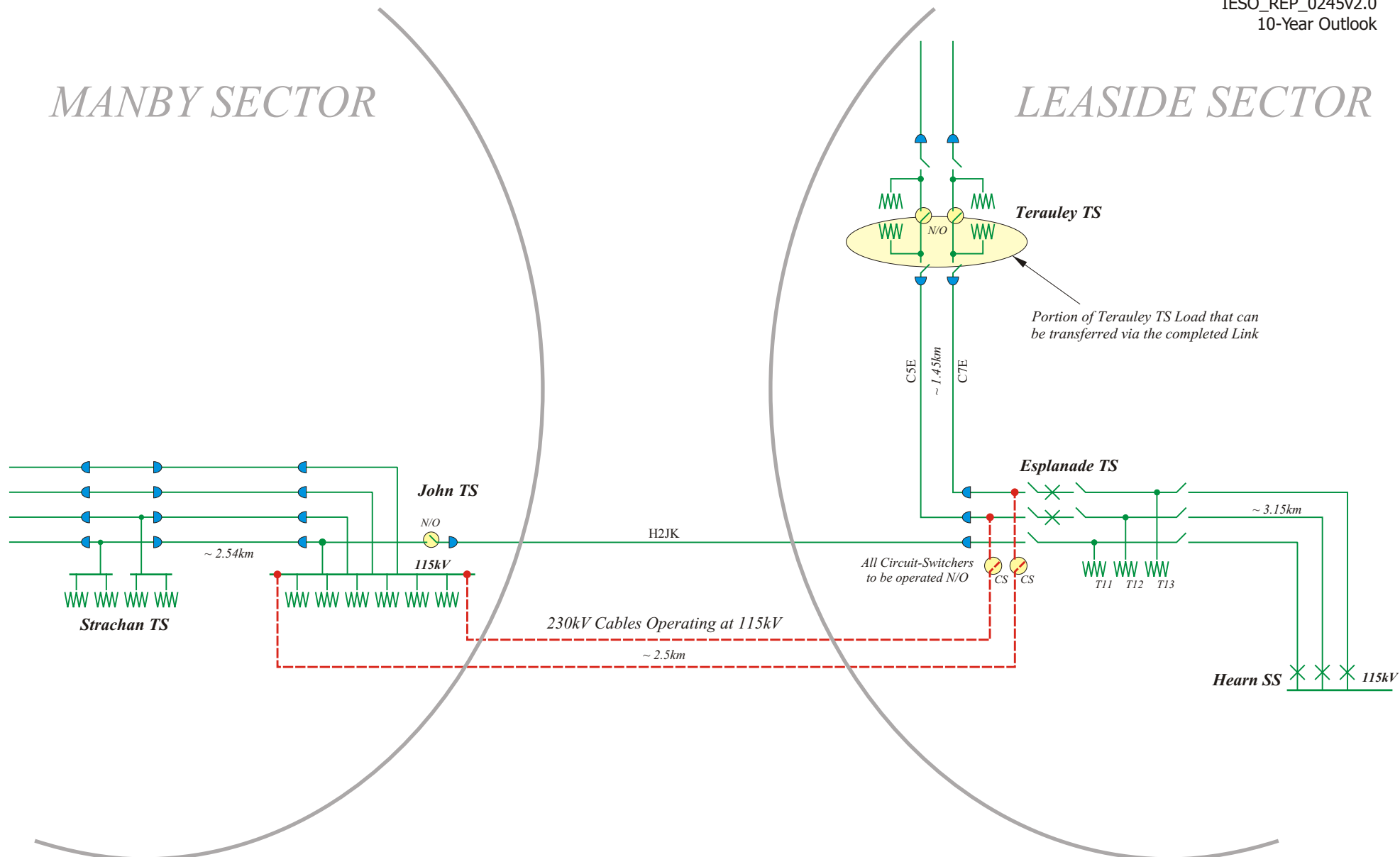


DIAGRAM 3

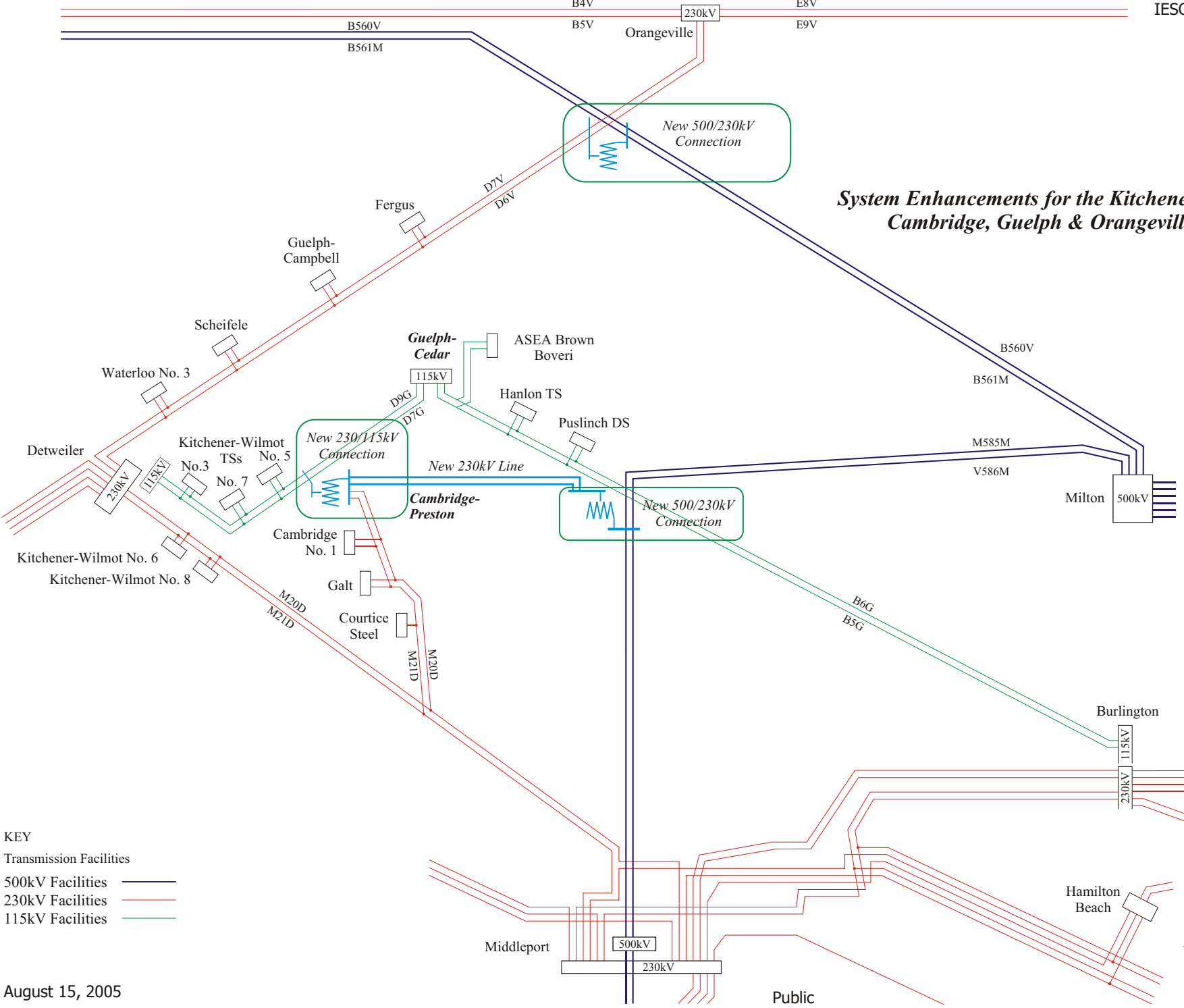
MANBY SECTOR

LEASIDE SECTOR



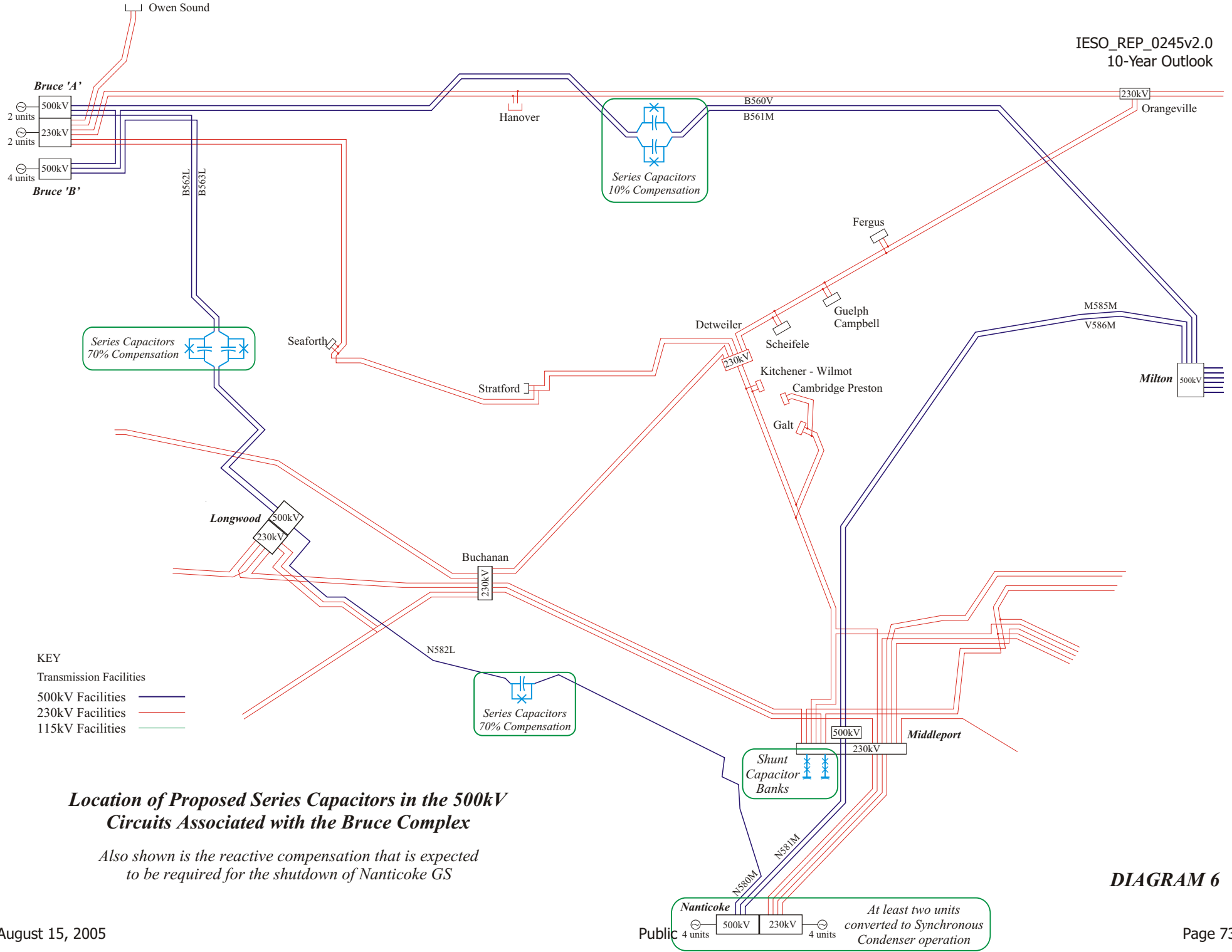
**Initial Phase of the 3rd Supply for Downtown Toronto:
The John TS-to-Esplanade TS Link**

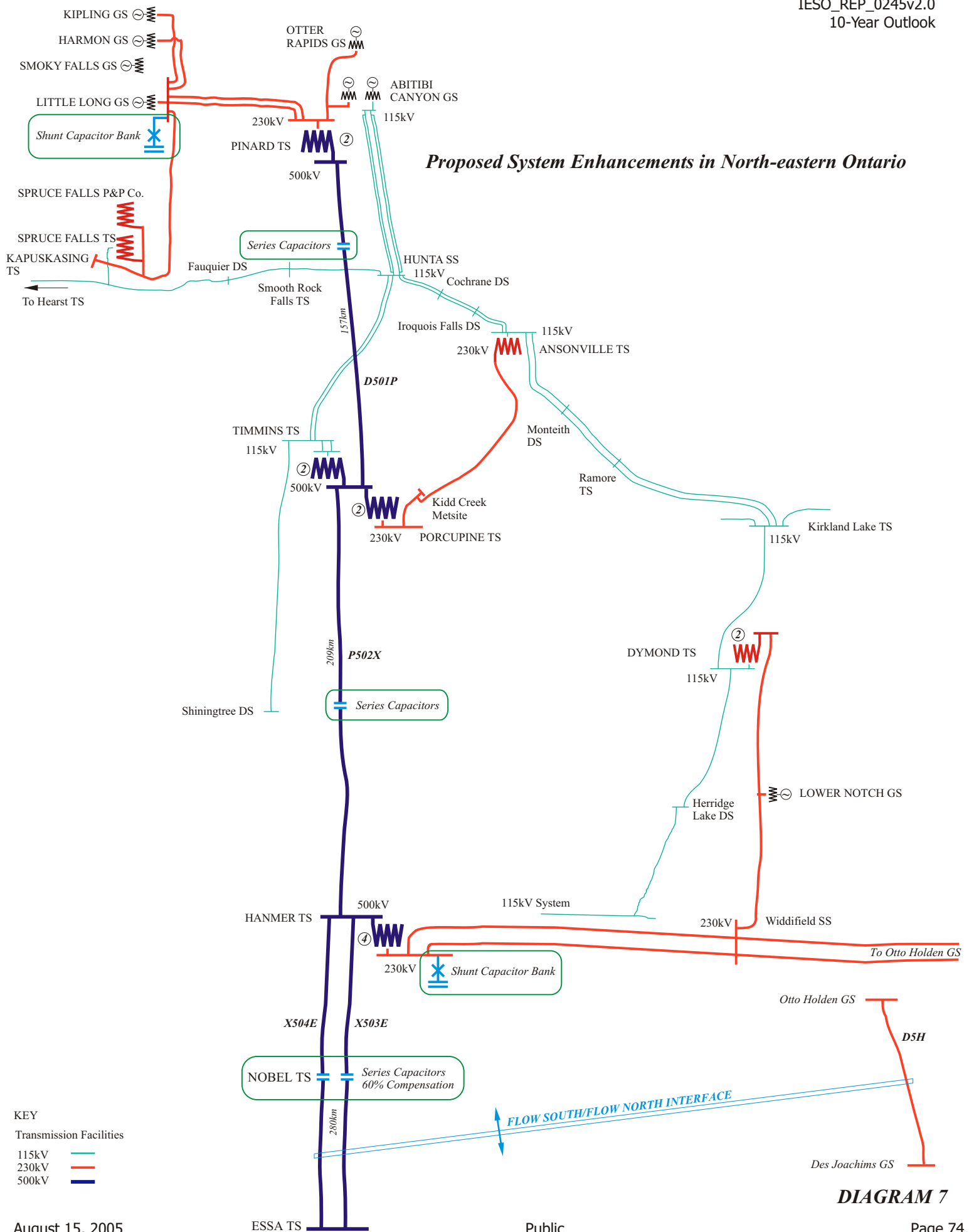
DIAGRAM 4



**System Enhancements for the Kitchener, Waterloo,
Cambridge, Guelph & Orangeville Area**

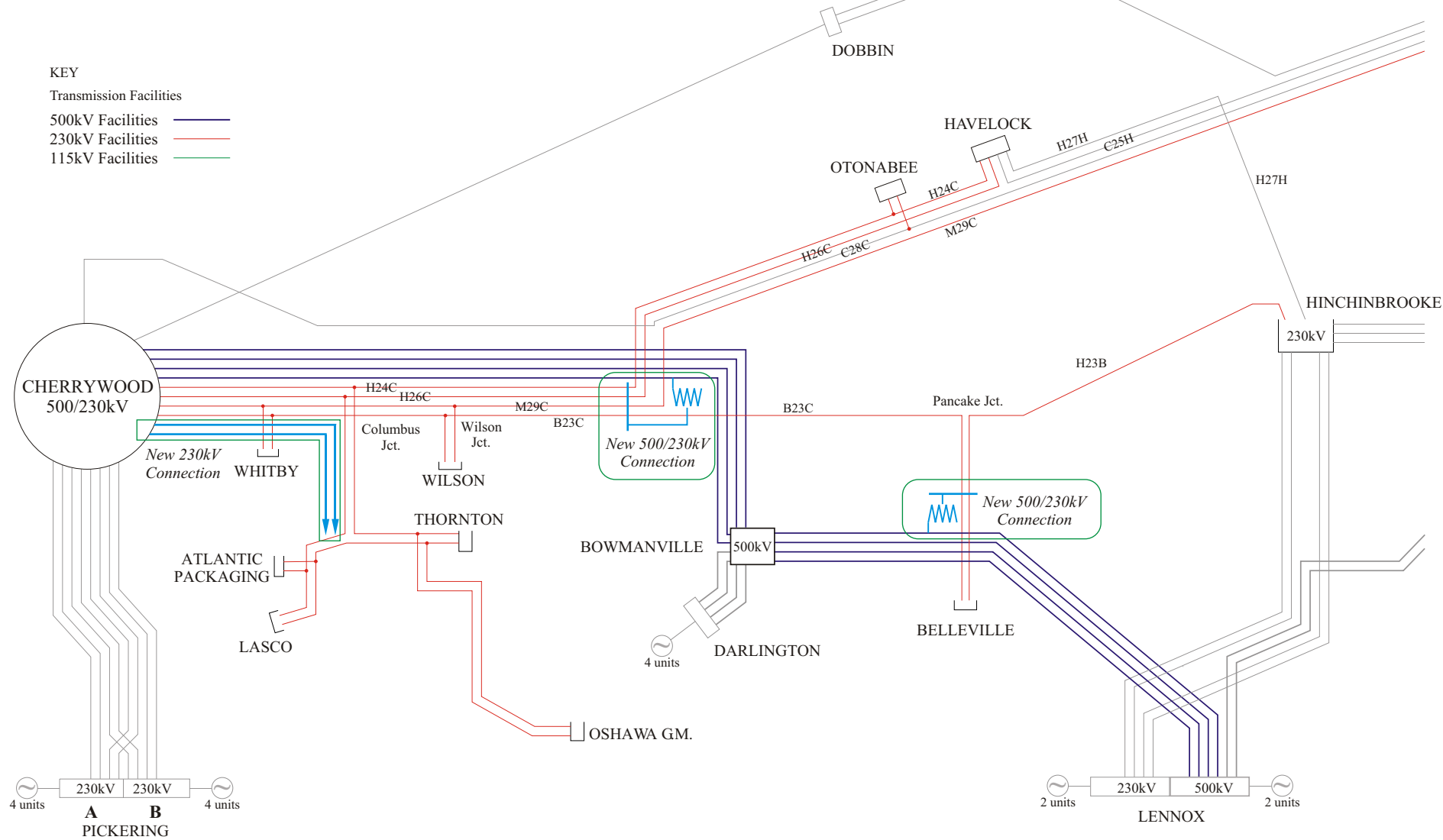
- KEY**
- Transmission Facilities
- 500kV Facilities ———
 - 230kV Facilities ———
 - 115kV Facilities ———





System Enhancements for the Windsor - Chatham Area

System Enhancements for the Oshawa - Belleville Area



- End of Document -

DIAGRAM 9



IESO_REP_0299

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CONNECTION ASSESSMENT & APPROVAL PROCESS

SYSTEM IMPACT ASSESSMENT REPORT

*For the Proposed Installation of Series Capacitors in the 500kV Circuits
between the Bruce Complex & Nanticoke GS*

Applicant: Hydro One Networks Inc.

CAA ID No. 2005-200

Transmission Assessments & Performance Department

FINAL Version

Date: 11th April 2006

System Impact Assessment Report

For the Installation of Series Capacitors in the 500kV Circuits between the Bruce Complex & Nanticoke SS

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Approval of the proposed connection is based on information provided to the IESO by the Hydro One Networks Inc. at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by the transmitter at the request of the IESO.

Furthermore, the connection approval is subject to further consideration due to changes to this information, or to additional information that may become available after the approval has been granted. Approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed facility to the IESO-controlled grid. However, connection approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, you must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to you. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used.

Hydro One

Special Notes and Limitations of Study Results

The results reported in this system impact assessment are based on the information available to Hydro One, at the time of the study, suitable for a system impact assessment of a new transmission facility.

HYDRO ONE NETWORKS Inc.

SYSTEM IMPACT ASSESSMENT REPORT

For the Installation of Series Compensation in the 500kV Circuits Associated with the Bruce Complex

EXECUTIVE SUMMARY

1. General

Agreement has been reached between the Government of Ontario and Bruce Power Inc. for the return to service in 2009 of Units 1 & 2 at the Bruce A nuclear generating facility. In addition, contracts have been awarded under the Government of Ontario's Renewables I & II RFPs for the incorporation of wind-turbine generation capacity totalling 1370MW. Of this, approximately 725MW is to be incorporated into the system directly associated with the Bruce Complex, with a further 200MW to be incorporated into that part of the system that will have a direct effect on the transfers across the Negative-BLIP (Buchanan-Longwood Input) Interface.

To accommodate the additional output from Bruce Units 1 & 2 and from the wind-turbine generation facilities, Hydro One submitted a proposal for the installation of series capacitors in the 500kV transmission facilities associated with the Bruce Complex.

The primary objectives that the installation of the series capacitors were intended to meet were:

- To increase the post-contingency transient stability limit of the existing transmission facilities so as to avoid the need for rejecting any generating capacity in response to a first contingency.
- To encourage a higher proportion of the output from the Bruce Complex to flow through the remaining 500kV transmission facilities between the Bruce Complex and Nanticoke SS following the coincident loss of the 500kV circuits from the Bruce Complex to Milton TS and to Claireville TS.

This was also intended to reduce the post-contingency transfers on the 230kV circuits between the Bruce Complex and Orangeville TS.

- To reduce the reactive power losses and to improve the pre- and post-contingency voltage profiles.

2. Generation Scenarios

Although Bruce Units 1 & 2 are scheduled to be returned to service during 2009, other units at the Bruce Complex are scheduled to be removed from service for maintenance. Consequently during the period between April-2009 and the end-2011, a maximum of only seven Bruce units are expected to be operational.

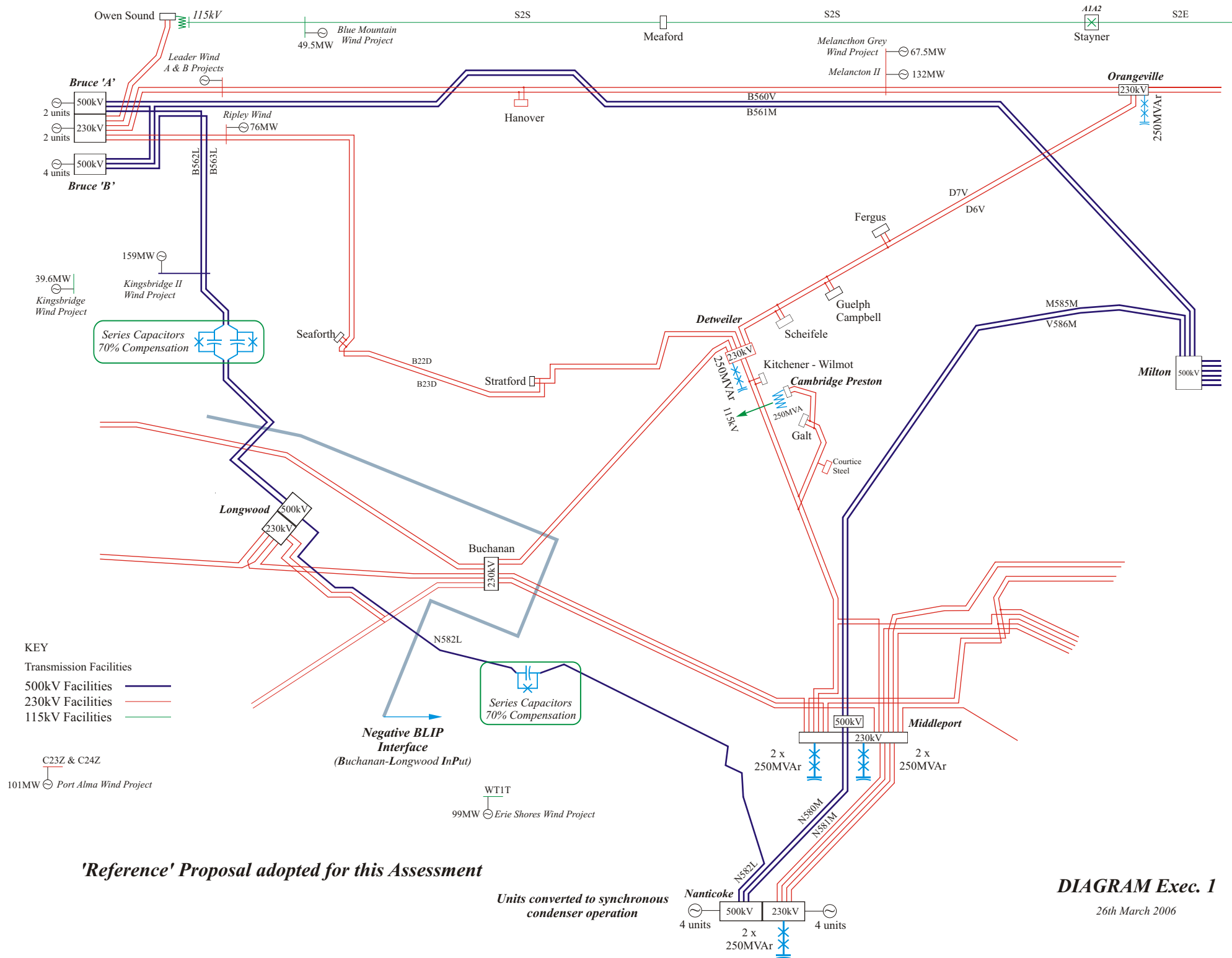
Beyond December-2011, there are expected to be extended periods when all eight Bruce units will be in-service.

The assessment therefore considered these two scenarios.

In addition it was assumed that all of the units at Nanticoke GS would have ceased operation as generating units prior to the first Bruce unit being returned to service in April-2009.

3. Preliminary Review of the Proposal

The IESO identified the following additional facilities that would need to be installed to ensure acceptable post-contingency voltages. These have been shown on Diagram Exec. 1 and the arrangement shown was adopted as the reference proposal for this assessment:



- A 250MVA 230kV shunt capacitor bank at both Detweiler TS and Orangeville TS.
- Two 250MVA 230kV shunt capacitor banks on each half of the 230kV busbar at Middleport TS.
- Two 250MVA 230kV shunt capacitor banks on the 230kV busbar at Nanticoke SS.
- Up to four of the existing generating units at Nanticoke GS converted to synchronous condenser operation.
- A 250MVA 230/115kV auto-transformer at Cambridge-Preston TS to interconnect the 230kV circuits M20D/M21D to the 115kV circuits D7G/D9G.

4. Transient Stability Analysis

The studies that were performed for a line-line-ground fault involving the 500kV circuits B560V & B561M showed that transient stability, with a 10% margin, could be maintained for the following conditions:

Generation Scenario	Transmission Scenario	Series Compensation Required	
		500kV Bruce x Longwood	500kV Longwood x Nanticoke
Seven Bruce Units & 925MW of Wind-turbine Generation	Existing Transmission Facilities	20%	20%
Eight Bruce Units & 925MW of Wind-turbine Generation	With a New 500kV Single-circuit Line: Longwood x Middleport	20%	10% & 10% on the new line
	With a new 500kV Double-Circuit Line: Bruce x Essa	No Compensation Required	
	With a new 500kV Double-Circuit Line: Bruce x Milton		

5. Load Flow Analysis with Seven Bruce Units

Load Flow studies were performed for the condition with maximum transfers into Ontario across the Ontario-Michigan and Ontario-New York Interfaces of 1500MW and 1400MW, respectively.

In addition, with the four units at Lambton GS retired and with the new Calpine - Greenfield Energy Centre and the Invenergy - St Clair Projects assumed to be in-service in the Sarnia area, a system primary demand of 25000MW was found to result in transfers across the Negative-BLIP Interface that were close to the operating limit of 1500MW.

The Load Flow studies showed that with Negative-BLIP transfers of approximately 1500MW and with the 500kV Bruce-to-Longwood and the Longwood-to-Nanticoke circuits compensated to levels **above 50%**, the post-contingency flows on the 500kV Longwood-to-Nanticoke circuit were well in excess of its long-term emergency rating of 3660A at an operating temperature of 127°C.

In addition, regardless of the level of compensation employed, the post-contingency flow on the 115kV circuit S2S between Owen Sound TS and Stayner TS was found to exceed its rating. While the situation was aggravated by the presence of the 50MW Blue Mountain Wind Project, post-contingency rejection of this project was not sufficient to maintain the flows within the circuit's rating. However, cross-tripping of the A1A2 in-line breaker at Stayner TS was found to be effective.

Hydro One subsequently indicated that the 500kV circuit between Longwood TS and Nanticoke SS could be uprated for operation at a temperature of 150°C to provide an enhanced rating of 4110A. However, flows would only be permitted at this level for a maximum of three hours per year.

With the Bruce-to-Longwood and the Longwood-to-Nanticoke circuits compensated **to 50%**, the post-contingency flow of 4043A on the latter circuit would be within its enhanced rating of 4110A. However, the post-contingency flows of 1460A on the section of circuits B4V & B5V between the Melancthon Wind Projects and Orangeville TS would exceed the 4km/hr wind-speed rating of 1180A but would be within the 15km/hr wind-speed rating of 1590A. Since the wind projects require wind-speeds in excess of 8m/sec (~ 30km/hr) to produce approximately half their peak output, using a wind-speed of 15km/hr for calculating ratings for transmission facilities within 50km of a wind-turbine project has been adopted by the IESO for its assessments.

Reducing the level of compensation on the 500kV circuits **to 40%** would reduce the post-contingency flow on circuit N582L between Longwood TS and Nanticoke TS (to 3849A) , but would increase the post-contingency flow on circuits B4V & B5V between the Melancthon Wind Projects and Orangeville TS to 1557A. Although the flow on circuits B4V & B5V would remain within their 15km/hr wind-speed rating, the flow on circuit N582L would still exceed its long-term emergency rating and it would therefore still be necessary to increase its maximum operating temperature above its present value of 127°C.

A further reduction in the level of compensation on the 500kV circuits **to 30%** would achieve a post-contingency flow of 3669A on circuit N582L which would be sufficiently close to the present long-term emergency rating for this circuit of 3660A that uprating could be avoided. However, the post-contingency flows on circuits B4V & B5V would increase to 1649A which would exceed the 15km/hr long-term emergency rating of 1590A for these circuits.

Increasing the sag temperature of this line from its present value of 104°C to 127°C would increase its 4km/hr wind-speed rating to 1400A and its 15km/hr wind-speed rating to 1830A.

Since the level of compensation would still exceed the minimum required to maintain post-contingency transient stability without having to employ generation rejection, the IESO has therefore concluded that either of the following options would be acceptable:

<i>Options for Installing Series Compensation on the 500kV Circuits between the Bruce Complex & Nanticoke SS</i>		
<i>Level of Series Compensation to be installed on the following 500kV Circuits:</i>	<i>Associated Remedial Requirements</i>	
	<i>500kV Circuit N582L: Longwood TS x Nanticoke SS</i>	<i>230kV Circuits B4V & B5V: Section from Hanover TS to Orangeville TS</i>
- B562L & B563L Bruce x Longwood TS - N582L Longwood TS x Nanticoke SS		
1. 50% or 40%	<i>Increase the sag temperature of the line to 150°C</i>	<i>No Action Required</i>
2. 30%	<i>No Action Required</i>	<i>Increase the sag temperature of the line to 127°C</i>

6. Re-Preparation of the System with Seven Bruce Units

In the event of a sustained outage involving the two 500kV circuits B560V & B561M, a subsequent contingency involving the 500kV circuit N582L would be the most onerous for the system. The assessment has shown that for the condition with the 500kV circuits compensated to 50%, the following actions would need to be taken to prepare the system for a subsequent contingency involving circuit N582L during the 30-minute Re-preparation Period:

- Reduce the transfers across the Ontario-New York Interface to their Pre-contingency levels - this would represent a net reduction in imports of approximately 190MW
- Remove the wind-turbine projects that are connected to circuits B4V & B5V from service - this would result in a resource deficiency of approximately 400MW

- Reduce the transfers across the Ontario-Michigan Interface from 1310MW to 775MW - this would represent a net reduction in imports of approximately 535MW

Following these actions the system transmission losses would be approximately 1020MW, representing an increase of approximately 220MW over the pre-contingency losses.

The combined effect of these actions would therefore be a resource deficiency of approximately 1345MW.

Since the IESO is required to maintain a minimum 30-minute operating reserve of 1350MW to compensate for the lost output from one Darlington generating unit and 50% of a second Darlington unit, the resources should be adequate to compensate for the re-preparation actions identified above.

To prepare the system for the critical contingency, the Bruce Special Protection System would need to be armed to initiate the rejection of two Bruce B units together with all the remaining wind-turbine projects. In addition measures would need to be implemented to automatically reduce the transfers across the Negative BLIP Interface to approximately zero to ensure that the post-contingency flows on the 230kV circuits between Longwood TS and Buchanan TS would remain within their long-term emergency ratings. This reduction could be achieved through a reduction of the transfers across the Ontario-Michigan Interface and/or the rejection of generation capacity in the Sarnia-Windsor area.

These actions would result in a resource deficiency of approximately 2300MW, derived as follows:

• Removal from service of all the wind-turbine projects	925MW
• Rejection of two Bruce B generating units	1640MW
• Reduction of the transfers across the Negative BLIP Interface to zero	~ 1150MW
• Change in the transmission system losses	- 50MW
<i>Sub-total</i>	<i>3665MW</i>
Less the normal 30-minute Operating Reserve	1350MW
<i>Resulting Deficiency</i>	<i>~ 2300MW</i>

To address this resource deficiency a combination of increased output from the Ontario generating resources that remain available together with load rejection would therefore be required.

Although the re-preparation of the system was only examined for the condition with 50% compensation of the 500kV circuits, the requirements are expected to be similar for lower levels of series compensation.

7. Bruce Special Protection System

With seven Bruce units in-service together with the new wind-turbine projects, the Bruce Special Protection System will need to be enhanced so that it can react to the following contingency conditions and provide the additional responses identified below:

Contingency conditions that need to be added to the Bruce SPS:

- 500kV circuit N582L
- 230kV circuits B4V & B5V: both single- and double-circuit contingencies
- 230kV circuits B22D & B23D: both single- and double-circuit contingencies

Responses that need to be added to the Bruce SPS:

- Cross-tripping of the 115kV breaker A1A2 at Stayner TS
- Generation Rejection for individual wind-turbine projects (or selected groups)
- Switching of the new shunt capacitor banks
- Additional load rejection selections (if the amount provided by the present selections is insufficient)

8. Load Flow Analysis with Eight Bruce Units

Analysis has shown that regardless of the level of series compensation installed, it would not be possible to accommodate all eight Bruce units and all of the committed wind-turbine projects without having to employ generation rejection in response to a double-circuit contingency involving the 500kV circuits B560V & B561M.

Furthermore, having to reject the equivalent of at least one Bruce unit in response to a first contingency would compound the problems associated with re-preparing the system for a subsequent contingency, and is expected to require substantially more load to be armed for rejection.

In order to comply with the ‘no generation rejection for a first contingency’ criterion, it was therefore concluded that new 500kV transmission facilities would be required to accommodate all eight Bruce units.

The Assessment examined two alternatives:

<i>Alternative 1.</i>	A new 500kV single-circuit line between Longwood TS and Middleport TS Estimated length ~ 150km
<i>Alternative 2.</i>	
<i>Option i.</i>	A new 500kV double-circuit line between the Bruce Complex and Milton TS Estimated length ~ 176km
<i>Option ii.</i>	A new double-circuit 500kV line between the Bruce Complex and Essa TS Estimated length ~ 182km

Alternative 1.

To accommodate the new 500kV line on the existing right-of-way it was assumed that the existing 230kV single-circuit line M31W would have to be removed.

To maintain post-contingency transient stability, the 500kV circuits between the Bruce Complex and Longwood TS would need to be compensated to at least **20%** while those between Longwood TS and Nanticoke SS and between Longwood TS and Middleport TS would need to be compensated to at least **10%**.

To limit the post-contingency flows through the 230kV circuits B4V & B5V, the level of compensation on the 500kV circuits would need to be increased to 40%. With this level of compensation installed, the post-contingency flows on the section of the 230kV circuits B4V & B5V between the Melancthon Projects and Orangeville TS would be within their 15km/hr wind-speed rating of 1590A.

Alternative 2.

Option i.	For this Option there would be no requirement to install series capacitors on any of the 500kV circuits either to maintain post-contingency transient stability or to avoid post-contingency overloading.
Option ii.	Similarly for this Option, there would be no requirement to install series capacitors on any of the 500kV circuits.

Remedial measures would, however, be required to raise the operating temperatures of the two existing Essa-to-Claireville 500kV lines. Since each of these lines is presently rated at only 1900MVA, they would be inadequate for the projected post-contingency flows of approximately 2600MVA per circuit.

Comparison of the Alternatives

Alternative 1 would be substantially inferior to Alternative 2 for the following reasons:

- It would require the 500kV circuits to be series compensated to a level of 40%.
For Alternative 2, none of the 500kV circuits would require series compensation.

- It would require higher levels of post-contingency reactive support to be provided from the synchronous condensers at Nanticoke GS.

Approximately 950MVar of support would need to be available, whereas Alternative 2 would require a maximum of approximately 275MVar.

- It would result in additional post-contingency losses of approximately 400MW, while for Alternative 2 the increased losses would be approximately 160MW.
- It would continue to present challenges for the re-preparation of the system to position it for any subsequent contingency.

Since Alternative 2 involves the installation of an additional, independent path from the Bruce Complex, a sustained outage involving circuits B560V & B561M would essentially return the system to the status quo. For this, the consequences of a single element contingency would be much less severe.

Of the two options for terminating the new 500kV double-circuit line from the Bruce Complex, the one with the line terminated at Milton TS instead of at Essa TS would have the advantage of avoiding the need to uprate the two 500kV lines between Essa TS and Claireville TS.

However, in all other respects, the performance of the two options considered for Alternative 2 would be similar.

9. Synchronous Condensers

For the initial period with seven Bruce units together with 925MW of wind-turbine generation capacity in-service, the post-contingency reactive support requirements could be provided by converting a minimum of three units at Nanticoke GS to synchronous condenser operation. However, to cater for maintenance and forced outages of these units, it would be prudent to convert four of them to synchronous condenser operation.

Once the new 500kV double-circuit line is placed in-service to coincide with all eight Bruce units being in operation, the reactive support that would be required could be provided from a single synchronous condenser. However, as before, it would be prudent to convert an additional unit to provide redundancy.

Since the new 500kV line is required to be in-service no later than the end-2011, the period over which four synchronous condensers would need to be available would be a maximum of three years.

The IESO has therefore recommended that consideration be given to providing a portion of the reactive power requirements from Static VAr Compensators (SVCs). This would limit the number of units at Nanticoke GS that would have to be converted to synchronous condenser operation. In addition, once the new 500kV line is placed in-service and the reactive support requirements are reduced, any surplus SVC capacity could be relocated to other areas of the system that require dynamic voltage support.

10. Recommendations

- The ABB Study that was commissioned by Hydro One has determined that sub-synchronous resonance (SSR) issues associated with the installation of series capacitors in the 500kV circuits connected to either the Bruce Complex or Nanticoke GS could be avoided if the level of compensation were to be maintained below 40%. This would avoid the need to employ mitigating measures such as using thyristor controlled series capacitors (TCSCs) for a portion of the series capacitor installation.

The IESO has determined that installing 30% series compensation would avoid the need to uprate the 500kV circuit N582L although it would result in post-contingency flows on the section of circuits B4V & B5V between Hanover TS and Orangeville TS that would exceed the 15km/hr wind-speed rating of these circuits.

The IESO is therefore recommending that the condition of this section of circuits B4V & B5V be examined to determine whether the line could be uprated for operation at a conductor temperature of 127°C.

If circuits B4V & B5V can be uprated, then the IESO's preference would be to adopt a level of 30% compensation for the series capacitors that it is proposed to install on the 500kV circuits between the Bruce Complex and Longwood TS and between Longwood TS and Nanticoke SS.

- Since extensive modifications to the Bruce SPS are expected to be necessary to provide the additional flexibility that will be required, and in recognition of the complexity of the existing scheme and the associated difficulty of implementing changes, the IESO would support a change to a matrix-based design, similar to that which has been used for other SPSs.
- In the accompanying analysis, extensive use has been made of the 15km/hr wind-speed ratings for the 230kV circuits B4V & B5V in assessing whether post-contingency overloading is expected to occur.

Since the prevailing ambient conditions are expected to have a major influence on these ratings and therefore on the operation of the system with particular emphasis on the post-contingency responses that are adopted, the IESO has recommended that these circuits be equipped with real-time monitoring.

- Review the capability of the Independent Phase Controlled Compensators at Norfolk TS and Tillsonburg TS to determine whether their capacity will be adequate to address the voltage imbalances arising from the increased flows that are expected on circuit N582L once the series capacitors have been installed.

11. Notification of Approval of the Connection Proposal

Subject to the completion of the Customer Impact Assessment and the satisfactory resolution of any issues that it may raise, the IESO has concluded that the following work will have no materially adverse effect on the IESO-controlled grid:

- the installation of series capacitors in the Bruce-to-Longwood and the Longwood-to-Nanticoke 500kV circuits, whether at the 50% or 30% compensation level, and subject to appropriate action to uprate either the 500kV circuit N582L (for 50%) or the 230kV circuits B4V & B5V (for 30%).
- the installation of 230kV shunt capacitor banks at Middleport TS, Nanticoke TS, Detweiler TS & Orangeville TS
- the conversion of up to four units at Nanticoke GS to synchronous condenser operation, and/or the installation of SVCs to provide a portion of the reactive power support that will be required.
- enhancement of the Bruce SPS to expand the number of contingencies to which it can respond as well as the range of actions that can be automatically initiated in response to these contingencies.

It is therefore recommended that a Notification of Conditional Approval to Connect be issued for this Project.

HYDRO ONE NETWORKS Inc.

Installation of Series Compensation in the 500kV Circuits Associated with the Bruce Complex

1. Background Information

The need to increase the capability of the existing transmission system to accommodate additional generating capacity has arisen as a result of a number of recent decisions. Since these decisions have formed the basis for this assessment they have been summarised below.

Renewables I RFP

On 24th November 2004, the Government of Ontario announced the list of projects that had been selected for development in response to the Renewables I RFP. Of the 395MW of new generating capacity that was selected, approximately 255MW is to be incorporated into the system directly associated with the Bruce Complex.

Bruce Units 1 & 2

On 21st March 2005, the Government of Ontario announced that tentative agreement had been reached for the restart of the remaining two generating units at the Bruce Complex.

2500MW New Clean Energy RFP

On 13th April 2005, the Government of Ontario announced that the following projects had been selected for development under the 2500MW RFP for New Clean Generation & Demand-side Projects:

• Greenfield Energy Centre	Capacity: 1005MW	Location: Sarnia-Lambton
• St Clair Power	Capacity: 570MW	Location: Sarnia-Lambton
• GTAA Project	Capacity: 90MW	Location: Mississauga

Hydro One Proposal

In response to the preceding announcements, Hydro One Networks submitted an application to the IESO in April 2005 for a Connection Assessment of their proposal to install series capacitors in the 500kV circuits associated with the Bruce Complex. The intent is to increase the capability of the system to accommodate the additional generating capacity that is to be developed in response to the Government of Ontario's 'off-coal' Policy.

2500MW New Clean Energy RFP (Continued)

On 30th May 2005, the Government of Ontario announced that the Greenfield North & the Greenfield South Projects, each with a capacity of 280MW, had also been selected for development under the 2500MW New Clean Generation RFP.

On 12th August 2005, the Ontario Power Authority announced that mutual agreement had been reached with the Greenfield North Power Corporation not to proceed with a Clean Energy Supply contract for the Greenfield North Project.

Lambton GS & Nanticoke GS

On 15th June 2005, the Government of Ontario announced that Lambton GS, with a capacity of 1975MW would close at the end-2007 and that the generating units at Nanticoke GS, with a combined capacity of 3938MW would be successively retired during 2008 and up to early-2009.

Bruce Units 1 & 2

On 17th October 2005, the Government of Ontario announced that formal agreement had been reached with Bruce Power Inc. for the refurbishment of Units 1 & 2 at the Bruce A nuclear generating facility, near Kincardine. Once these two units are operational in 2009 they are expected to increase the flow away from the Bruce Complex by approximately 1500MW.

West GTA

On 28th October 2005, the Ontario Power Authority issued a news release stating:

- i. that a Request for Qualification had been issued for 1000MW of new electricity supply in the west GTA to address overloading of the auto-transformers at Trafalgar TS, and
- ii that a directive had been issued by the Ministry of Energy to secure up to 900MW of new generating capacity at the Sithe-Goreway facility to address overloading of the auto-transformers at Claireville TS.

Renewables II RFP

On 21st November 2005, the successful projects under the Government of Ontario's Renewables II RFP were announced. The total capacity of the new projects is 975MW, of which approximately 566MW is to be incorporated into the system directly associated with the Bruce Complex. In addition, a further 101MW is to be developed at Port Alma in south-western Ontario which will have a direct effect on the transfers across the Negative-BLIP (Buchanan-Longwood Input) Interface.

2. Hydro One Proposal for Series Capacitors

Hydro One's proposal, as submitted for assessment, included the installation of series capacitors at the approximate mid-point of the following circuits, to provide the level of compensation as indicated for the circuit reactance:

<i>500kV Circuit</i>	<i>Route</i>	<i>Level of Compensation</i>
B560V	Bruce A to Claireville TS	10%
B561M	Bruce B to Milton TS	10%
B562L	Bruce A to Longwood TS	70%
B563L	Bruce B to Longwood TS	70%
N582L	Longwood TS to Nanticoke GS	70%

The proposed locations for the series capacitors are shown in Diagram 1.

3. IESO's Preliminary Review of the Proposal

In the analysis in support of the 10-Year Outlook that was issued on 8th July 2005, the IESO determined that additional reactive power support would be required within the Detweiler area to ensure that an acceptable voltage profile could be maintained following the simultaneous loss of the Bruce to Claireville and Bruce to Milton 500kV circuits.

The new facilities that the IESO proposed should be included with the series capacitors were as follows:

- A 250MVAr 230kV shunt capacitor bank at Detweiler TS
- A 250MVAr 230kV shunt capacitor bank at Orangeville TS

- A 230/115kV auto-transformer at Cambridge-Preston TS to interconnect the 230kV & 115kV systems in the immediate area
- A 500/230kV TS on the right-of-way of the 500kV circuits between Middleport TS and Milton TS/ Claireville TS, together with a new 230kV connection between the TS and Cambridge-Preston TS.
- A 500/230kV TS at Bellwood Junction, on the right-of-way of the 500kV circuits between Bruce GS and Claireville TS/Milton TS to interconnect the 500kV & 230kV systems in the immediate area.

Diagram 2 shows the facilities for enhancing the system in the Detweiler area that had been proposed in the 10-Year Outlook.

In addition, the IESO recommended that shunt capacitor banks (with a nominal rating of between 400MVar & 500MVar) be installed at Middleport TS and that two (or more) of the existing generating units at Nanticoke GS be converted to synchronous condenser operation to provide post-contingency voltage support in the Nanticoke/ Middleport area.

4. Revised Requirements

Subsequent analysis has shown the following:

- That the series capacitors proposed in circuits B560V & B561M in the vicinity of Bellwood Junction would only be required to support transfers to Michigan following the loss of the Bruce to Longwood 500kV circuits, B562L & B563L. Since Ontario is not expected to be in a position to provide substantial power exports to Michigan in the foreseeable future, it has been agreed with Hydro One that these series capacitors should not form part of the current proposal.
- That the proposed 500/230kV interconnection at Bellwood Junction would have only limited benefit particularly since it would be removed from service for the critical contingency involving the loss of both 500kV circuits to which it is connected. It has therefore been removed from the 'reference' proposal.
- That while the 500/230kV TS on the right-of-way of the 500kV circuits between Middleport TS and Milton TS/Claireville TS is expected to be required to address local area supply deficiencies, it is not essential for maintaining an acceptable voltage profile following 500kV contingencies. It has therefore been removed from the 'reference' proposal.

However, it has been confirmed that the 230/115kV auto-transformer at Cambridge-Preston TS is necessary to support the 115kV system supplied from Detweiler TS under contingency conditions involving the 500kV system. It has therefore been retained in the 'reference' proposal.

- That rather than concentrating all of the shunt capacitors at Middleport TS, it would be beneficial to install additional shunt capacitors at Nanticoke GS so as to limit the post-contingency synchronous condenser requirements at that GS.

[OPG has notified the IESO that the maximum reactive power output that can be provided from each unit, measured at the transformer HV terminals, is 375MVar. This would correspond to an output of approximately 400MVar at the generator terminals.]

In the load flow diagrams attached to this report, the MVar values shown are those at the generator terminals]

Diagram 3 shows the 'reference' proposal that was subsequently adopted for this assessment.

This Diagram also shows the Negative-BLIP Interface which is used to monitor the combined transfers eastwards on the 230kV circuits originating from Buchanan TS together with the net transfers eastwards on the 500kV circuits at Longwood TS. The present operational limit for this Interface is 1500MW.

5. Study Constraints

This assessment was subject to the following constraints:

- No generation rejection was to be employed for a first contingency.
- During the period between April-2009 and the end-2011, a maximum of seven units were to be assumed to be in operation at the Bruce Complex.

Although Units G1 & G2 are both scheduled to return to service during 2009, other units at the Bruce Complex are scheduled to be removed from service for maintenance. Consequently, the earliest that all eight units are expected to be operational is December-2011.

- From December-2011 onwards, eight Bruce units were to be assumed to be in-service.
- There should be no adverse impact on Ontario's import capability via its Interconnections.

6. Study Assumptions

The following assumptions were adopted for this assessment:

- The Load Flow Analysis would concentrate on the post-contingency *steady-state* condition

Since no generation rejection was to be initiated in response to first contingencies, the critical post-contingency condition for the system would therefore correspond to the situation with loads restored to their pre-contingency values.

Loads were therefore modelled as *Constant MVA*.

All of the transformer tap-changers that are under automatic control were allowed to move and post-contingency switching of shunt capacitors and reactors were allowed to occur.

- The transfers on the Interconnections would be restored to their pre-contingency levels.

[For this assessment, the transfers into Ontario via the Interconnections were set at the following levels:

Michigan to Ontario	1500MW, and	
New York to Ontario	1400MW	(1200MW at Niagara and 200MW at St Lawrence)]

- The increased losses on the transmission system would be supplied from the 30-minute operating reserve.

Following the loss of the 500kV circuits, B560V & B561M, and with no generating units rejected, there would be a significant increase in the transmission losses. It was assumed that these losses would be supplied internally from those generating units providing operational reserve, thereby allowing the transfers on the Interconnections to be returned to their pre-contingency levels.

- The 'emergency' ratings would be used for the transmission lines.

These ratings correspond to the continuous [*long-term emergency*] rating at a conductor operating temperature of 127°C, or at the sag temperature, if this is lower.

- The following generating facilities would be assumed to be out-of-service:
 - i. Lambton GS
 - ii. Nanticoke GS (except as synchronous condensers)

- The following generation facilities would be assumed to be in-service:

i.	Greenfield Energy Centre	1005MW	
ii.	St Clair Power	570MW	
iii.	GTAA Project	90MW	
iv.	Greenfield South Project	280MW	
v.	Sithe-Goreway Project	1000MW	
vi.	Downtown (Leaside Sector)	500MW	
vii.	‘Trafalgar’ Project	1000MW	(when all other resources are insufficient to meet the system demand.)
- A total of 925MW of wind-turbine generation capacity would be included in the system model, consisting of the following projects:

Renewables I RFP

i.	Erie Shores Wind Farm	99.0MW
ii.	Kingsbridge Wind Power Project	39.6MW
iii.	Melanthon Grey Wind Project	67.5MW
iv.	Blue Highlands Wind Farm	49.5MW
	<i>Sub-total</i>	<i>255.6MW</i>

Renewables II RFP

i.	Kingsbridge II Wind Power Project	158.7MW
ii.	Kruger Energy Port Alma	101.2MW
iii.	Leader Wind Power Project A	100.7MW
iv.	Leader Wind Power Project B	99.0MW
v.	Melanthon II Wind Project	132.0MW
vi.	Ripley Wind Power Project	76.0MW
	<i>Sub-total</i>	<i>667.6MW</i>
	<i>TOTAL</i>	<i>923.2MW</i>

7. Thermal Ratings

Diagram 4 provides details of the transmission facilities in the Bruce-to-Toronto area, as well as the thermal ratings that were used in this assessment.

The ratings for those transmission facilities that were of particular concern as to their ability to support the post-contingency transfers have been summarised in Table 1:

In this Table, all ratings have been determined for an ambient temperature of 35°C, with a wind speed of **0 to 4km/hr**.

TABLE 1	Long-Term Emergency Ratings for the ‘Critical’ Circuits		
Circuits	Sag Temp	Long-Term ‘Emergency’ Rating at 127°C or Sag Temperature, if lower	MVA Rating
<i>500kV circuit N582L</i>			
Longwood TS to Nanticoke GS	127°C	3660A	3423MVA at 540kV
<i>500kV circuits E510V & E511V</i>			
Essa TS to Claireville TS	78°C	2030A	1898MVA at 540kV
<i>230kV circuits B4V & B5V</i>			
Bruce to Hanover TS	127°C	1430A**	594MVA at 240kV
Hanover TS to Orangeville TS	104°C	1180A	491MVA at 240kV
<i>115kV circuit S2S</i>			
Owen Sound to Meaford	150°C	770A	161MVA at 121kV
Meaford to Stayner	128°C	770A	161MVA at 121kV
<i>115kV circuit S2E</i>			
Stayner to Essa	150°C	770A	161MVA at 121kV

Note ** Operation at this current is limited to 50 hours per year because the conductors are classified as of ‘high-aluminum content’

Hydro One has indicated that it should be possible to increase the ground clearances on circuit N582L to allow the conductors to be operated to a maximum (sag) temperature of 150°C.

*However, although this would provide an enhanced rating of **4110A** (3844MVA at 540kV), operation at this temperature is restricted to a maximum of **3 hours per year** since it would result in accelerated annealing of the conductors, thereby reducing the overall life expectancy of the line.*

230kV Circuits B4V & B5V

The two Leader Wind Projects totalling 200MW and the two Melancthon Wind Projects, also totalling 200MW are to be incorporated on to the 230kV circuits B4V & B5V.

The two Leader Wind Projects are to be incorporated on to the section of these circuits between the Bruce Complex and Hanover TS. The two Melancthon Wind Projects are to be incorporated on to the lower-rated section of these circuits between Hanover TS and Orangeville TS.

In recognition that the wind-turbine projects require winds in excess of 8m/sec (~ 30km/hr) to produce approximately half their peak output, the IESO’s Transmission Assessment Criteria state that:

For connection assessments, transmission line ratings will be calculated using a wind-speed of 15km/hr instead of the usual 4km/hr value for transmission facilities within a 50km radius of the proposed wind generator.

The following Table provides the ratings that would be applicable for the condition studied with the Leader & Melancthon Wind Projects operating at their maximum output.

It should also be noted that the 77km section of B4V & B5V between Hanover TS and Orangeville TS is limited to operation at a maximum conductor temperature of only 104°C.

Ratings have also been provided for operation of this section at a maximum conductor temperature of 127°C, although no investigation has been conducted by Hydro One to determine whether this would be feasible.

TABLE 2	Effect of Wind-Speed on Line Ratings on the 230kV Circuits B4V & B5V				
Conductor		Sag Temp	Wind Speed	Long-term ‘Emergency’ Rating at 127 ^o C or the Sag Temperature, if lower	MVA Rating at 240kV
Bruce Complex to Hanover TS48.2km					
1277.5kcmil42/7	93 ^o C / 127 ^o C**	4km/hr	1080A / 1430A**	449 / 594MVA	
		15km/hr	1490A / 1870A**	619 / 777MVA	
Hanover TS to Orangeville TS77.2km					
1192.5kcmil54/19	104 ^o C	4km/hr	1180A	490MVA	
		15km/hr	1590A	661MVA	
	127 ^o C	4km/hr	1400A	582MVA	
		15km/hr	1830A	760MVA	

Note ** Operation at this current is limited to 50 hours per year because these conductors are classified as of ‘high-aluminum content’

8. Area Loads

During the summer-2005, for which an ‘extreme-weather’ peak demand of 26931MW had been forecast, the primary demand on the Ontario system peaked at 26160MW.

Furthermore, the maximum transfers into the Detweiler area via the 230kV transmission system to supply the loads in Kitchener, Waterloo, Cambridge, Guelph & Orangeville peaked at 1405MW during the summer-2005.

For this assessment, the flow into the Detweiler area was therefore adjusted to produce a net infeed of 1400MW for the reference load flow study case with a primary demand of 26000MW.

Subsequent studies were then performed with the system loads scaled so as to produce primary demands of 25000MW, 27000MW, 28000MW and 29000MW.

The 29000MW case was intended to correspond to the summer-2013, for which an ‘extreme-weather’ peak demand of 29029MW has been forecast. [from the IESO 10-Year Demand Forecast, issued on 8th July 2005]

9. Transient Stability Analysis

To establish what minimum levels of series compensation would be acceptable, transient stability studies were performed for normally-cleared line-to-line-ground (LLG) faults on the 500kV circuits B560V & B561M at Willowcreek Junction (approximately 18.3km from the Bruce Complex). For these studies, different levels of series compensation were assumed to be installed on the Bruce-to-Longwood and Longwood-to-Nanticoke 500kV circuits.

With the series compensation maintained at the levels indicated in Table 3 for each of the different generation scenarios that were examined, stable responses, with acceptable machine damping, were obtained. The minimum post-contingency voltages also met the IESO's criteria of:

- i. Remaining above 70% of the nominal voltage, and
- ii. Not falling below 80% of the nominal voltage for more than 250 milliseconds within the 10 second period following the fault.

The level of compensation required to maintain transient stability following a 500kV double-circuit contingency for the condition with either seven or eight Bruce units in operation, together with wind-turbine generation facilities totalling 925MW, can therefore be summarised as follows:

With Seven Bruce units in operation + 925MW of wind-turbine generation

- the minimum amount of series compensation that would be acceptable on the existing transmission facilities would be **20%** on the Bruce-to-Longwood circuits and **20%** on the Longwood-to-Nanticoke circuit.

With Eight Bruce units in operation + 925MW of wind-turbine generation

- with no new transmission facilities, the minimum amount of series compensation would need to be increased to **40%** on the Bruce-to-Longwood circuits and **30%** on the Longwood-to-Nanticoke circuit.
- with a new 500kV single-circuit transmission line between Longwood TS and Middleport TS, the minimum amount of series compensation that would be acceptable would be **20%** on the Bruce-to-Longwood circuits and **10%** on both the existing Longwood-to-Nanticoke circuit and the new Longwood-to-Middleport circuit.

*Transient stability studies were also performed with a new 500kV double-circuit line between the Bruce Complex and either Essa TS or Milton TS. These confirmed that transient stability could be maintained following the loss of either the existing Bruce-to Milton 500kV double-circuit line or the new 500kV double-circuit line with **no series compensation installed**.*

Series Compensation Requirements with no new wind-turbine generation

With no new wind-turbine generating facilities in-service, the level of series compensation that would be required to maintain transient stability without having to employ post-contingency generation rejection in response to the simultaneous loss of the Bruce-to-Claireville & Bruce-to-Milton circuits would be as follows:

With Eight Bruce units in operation & no wind-turbine generation

- the minimum amount of series compensation that would be acceptable on the existing transmission facilities would be **20%** on the Bruce-to-Longwood circuits and **10%** on the Longwood-to-Nanticoke circuit.

TABLE 3 Summary of Transient Stability Analysis: With no new transmission lines

Levels of Compensation Required on the Bruce-to-Longwood (BxL) and Longwood-to-Nanticoke (NxL) Circuits to Maintain Transient Stability

	<i>Generation Scenario</i>	<i>Generation Output Less Station Service Load</i>		<i>FABC Transfer Including 10% Margin</i>	<i>Compensation Required</i>
1.	Six Bruce Units & No Wind-turbine Generation	$2 \times 805 + 4 \times 940$ - $(2 \times 55 + 4 \times 50 + 25)$	5035MW	5540MW	None
2.	Six Bruce Units & 925MW of Wind-turbine Generation	$2 \times 805 + 4 \times 940 + 925$ - $(2 \times 55 + 4 \times 50 + 25)$	5960MW	6560MW	None
3.	Seven Bruce Units & No Wind-turbine Generation	$3 \times 805 + 4 \times 940$ - $(3 \times 55 + 4 \times 50 + 25)$	5785MW	6370MW	None
4.	Seven Bruce Units & 925MW of Wind-turbine Generation	$3 \times 805 + 4 \times 940 + 925$ - $(3 \times 55 + 4 \times 50 + 25)$	6710MW	7380MW	BxL: 20% + NxL: 20%
5.	Eight Bruce Units & No Wind-turbine Generation	$4 \times 805 + 4 \times 940$ - $(4 \times 55 + 4 \times 50 + 25)$	6535MW	7190MW	BxL: 20% + NxL: 10%
6.	Eight Bruce Units & 925MW of Wind-turbine Generation	$4 \times 805 + 4 \times 940 + 925$ - $(4 \times 55 + 4 \times 50 + 25)$	7460MW	8210MW	BxL: 40% + NxL: 30%

Summary of Transient Stability Analysis: With a new 500kV transmission line between Longwood TS and Middleport TS (LxM)

7.	Eight Bruce Units & 925MW of Wind-turbine Generation	$4 \times 805 + 4 \times 940 + 925$ - $(4 \times 55 + 4 \times 50 + 25)$	7460MW	8210MW	BxL: 20% + NxL: 10% + LxM: 10%

10. Load Flow Analysis: With Seven Bruce units & 925MW of wind-turbine generation

Negative-BLIP Transfers

Following the planned shut-down of Lambton GS in 2007 and the development of the two new 'Clean Energy Supply' generating projects in the Sarnia – Lambton area, the residual power available to the remainder of the system will depend on the load within south-western Ontario as well as the level of transfers into Ontario across the Ontario-Michigan Interface.

Consequently, with the Michigan-Ontario transfers maintained at their maximum of 1500MW, the net transfers across the Negative-BLIP Interface will decline as the primary demand, and by extension, the load in south-western Ontario is increased.

Preliminary studies were therefore performed using the 25000MW primary demand case since it was found to result in transfers across the Negative-BLIP Interface that were close to the 1500MW limit.

10.1 With 70% / 70% Compensation

Diagrams 5 & 6 show the pre- and post-contingency results following the loss of circuits B560V & B561M due to a 500kV double-circuit contingency.

For this study, the level of series compensation was set at **70%** in the Bruce-to-Longwood and the Longwood-to-Nanticoke circuits as proposed in the Hydro One application.

The critical flows for this condition are shown in the Table below:

Primary Demand: 25000MW No. of Bruce Units: 7 Negative BLIP Flow: 1478MW Compensation: 70% & 70%									
Condition	Losses	Synchronous Condenser Output	500kV Circuit N582L		Flows on B4V/B5V			Flows on S2S	
			Rating	4110A	Rating	A	1430A	Rating: 770A	
			MW/MVAr	Amps	MW/MVAr	B	1180A		
Pre-cont.	820.6MW	54.0MVAr	2397/ -500	2582A	A	323/ 9	751A	C	430A
					B	360/ -65	853A	D	658A
Post-cont.	1223.5MW	970.0MVAr	4223/ -592	4555A	A	463/ 76	1089A	C	673A
	Δ 402.9MW	Δ 916.0MVAr			B	491/ -96	1217A	D	893A

Note: A refers to the section between Bruce and Hanover TS, and
 B refers to the section between Hanover TS and Orangeville TS.
 C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
 D refers to the section between the Blue Mountain Wind Project and Meaford TS

The results in the Table show that even with the sag temperature of the 500kV circuit N582L increased to its maximum value of 150°C, the post-contingency flow would be expected to exceed its enhanced rating by 445A.

Similarly, the post-contingency flows on the sections of the 230kV circuits B4V & B5V between the Melancthon Wind Projects and Orangeville TS are shown to exceed their '4km/hr' ratings. However, since the high flows on these circuits are due, in part, to the output from the Leader and Melancthon Wind Projects, then the appropriate rating would be 1590A for a 15km/hr wind-speed (from Table 2).

The projected post-contingency flow of 1217A would therefore be well within this rating.

The post-contingency flow on the section of circuit S2S between the Blue Mountain Wind Project and Meaford TS is also shown to exceed its emergency rating at 127°C. This would require either the automatic post-contingency rejection of the Blue Mountain Wind Project and/or the automatic cross-tripping of the A1A2 in-line breaker at Stayner TS to open the connection between circuits S2S & S2E.

It is also worth noting the voltages that were recorded at the terminals of the series capacitor installations, both pre- and post-contingency, for this level of compensation.

Voltages Recorded at the Series Capacitor Installations: <i>with 70% / 70% compensation</i>		
<i>500kV Circuit</i>	<i>Pre-contingency</i>	<i>Post-contingency</i>
B562L	558.1kV	568.1kV
B563L	558.2kV	569.1kV
N582L	566.7kV	577.4kV

10.2 With 60% / 60% Series Compensation

In order to reduce the post-contingency flow on the 500kV circuit N582L, the level of series compensation on both the Bruce-to-Longwood and the Longwood-to-Nanticoke 500kV circuits was reduced to **60%**.

The results from these studies for the pre- and post-contingency conditions following the loss of circuits B560V & B561M due to a 500kV double-circuit contingency are shown in Diagrams 7 & 8, respectively.

The critical flows with the reduced level of series compensation are shown in the Table below:

Primary Demand: 25000MW			No. of Bruce Units: 7		Negative BLIP Flow: 1479MW					
Compensation: 60% & 60%										
Condition	Losses	Synchronous Condenser Output	500kV Circuit N582L		Flows on B4V/B5V			Flows on S2S		
			Rating	4110A	Rating	A	1430A	Rating: 770A		
						B	1180A			
			MW/MVAr	Amps	MW/MVAr		Amps		Amps	
Pre-cont.	807.8MW	-2.0MVAr	2158/ -376	2315A	A	334/ 13	775A		C	446A
					B	370/ -67	879A		D	674A
Post-cont.	1211.4MW	968.0MVAr	3982/ -348	4299A	A	499/ 98	1181A		C	754A
	Δ 403.2MW	Δ 970.0MVAr			B	525/ -109	1318A		D	997A

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.
C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

These results show that while a change in the level of compensation on the 500kV circuits to **60%** would achieve a reduction of 255MW in the post-contingency flow on circuit N582L, its enhanced thermal rating would still be exceeded. In addition, the post-contingency flows appearing on the 230kV circuits B4V & B5V would increase as a result of the lower level of compensation on the 500kV circuits.

The lower level of compensation would also result in the post-contingency flow on the section of circuit S2S between the Blue Mountain Wind Project and Meaford TS exceeding its emergency rating of 770A by approximately 230A. Since rejection of just the 49.5MW Blue Mountain Project would not be sufficient to address this degree of overloading, cross-tripping of the A1A2 in-line breaker at Stayner TS would therefore be unavoidable. However, opening this connection between circuits S2S & S2E would result in higher transfers on the remaining circuits which would therefore aggravate the overloading of circuit N582L.

The lower level of compensation would, however, result in reduced voltages at each series capacitor installation as shown by the values summarised in the following Table. As expected, the more noticeable declines in the voltages are shown to occur post-contingency.

Voltages Recorded at the Series Capacitor Installations: <i>with 60% / 60% compensation</i>				
<i>500kV Circuit</i>	<i>Pre-contingency</i>		<i>Post-contingency</i>	
		<i>Reduction relative to 70% / 70% case</i>		<i>Reduction relative to 70% / 70% case</i>
B562L	553.3kV	0.86%	555.3kV	2.25%
B563L	553.4kV	0.86%	555.7kV	2.35%
N582L	559.4kV	1.29%	561.7kV	2.72%

10.3 With 50% / 50% Compensation

Diagram 9 shows the pre-contingency results for the condition with a system primary demand of 25000MW. Diagram 10 shows the corresponding post-contingency results following the simultaneous loss of the 500kV circuits B560V & B561M.

The critical flows from these two studies are shown in the Table below:

Primary Demand: 25000MW		No. of Bruce Units: 7		Negative BLIP Flow: 1476MW				
Compensation: 50% & 50%								
Losses	Synchronous Condenser Output	500kV Circuit N582L		Flows on B4V/B5V			Flows on S2S	
		Rating	4110A	Rating	A	1430A	Rating: 770A	
					B	1180A		
		MW/MVAr	Amps	MW/MVAr	Amps		Amps	
Pre-contingency. Diagram 9								
800.0MW	-36.8MVAr	1959/-295	2098A	A	342/ 16	795A	C	459A
				B	378/ -69	900A	D	687A
Post-contingency Diagram 10								
1208.4MW	987.2MVAr	3757/ -180	4072A	A	534/ 117	1269A	C	818A
Δ 408.4MW	Δ 1024.0MVAr			B	556/ -126	1414A	D	1062A

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.
C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

These results show that with the level of compensation on the 500kV circuits reduced to 50%, the post-contingency flow on the 500kV circuit N582L could be maintained within its enhanced rating of 4110A for the condition with the Negative BLIP Flow close to its limit of 1500MW.

For the section of circuits B4V & B5V between the Melancthon Wind Projects and Essa TS, the projected flows would remain within the 15km/hr wind-speed rating of 1590A.

To address the excessive overloading of circuit S2S, particularly on the section between the Blue Mountain Wind Project and Meaford TS, it would be necessary to open the in-line breaker A1A2 at Stayner TS. However, since there is no provision within the existing Bruce SPS to automatically initiate the opening of the A1A2 breaker at Stayner TS in response to 500kV contingencies, the scheme would therefore need to be modified to provide this capability.

Diagram 11 shows the effect on the post-contingency results of opening this breaker.

The critical flows from this study are shown in the bottom portion of the Table below:

Primary Demand: 25000MW		No. of Bruce Units: 7		Negative BLIP Flow: 1476MW				
Compensation: 50% & 50%								
Losses	Synchronous Condenser Output	500kV Circuit N582L		Flows on B4V/B5V			Flows on S2S	
		Rating	4110A	Rating	A	1430A	Rating: 770A	
					B	1180A		
		MW/MVAr	Amps	MW/MVAr	Amps		Amps	
Pre-contingency Diagram 9								
800.0MW	-36.8MVAr	1959/-295	2098A	A	342/ 16	795A	C	459A
				B	378/ -69	900A	D	687A
Post-contingency: 115kV Circuit S2S Operated CLOSED Diagram 10								
1208.4MW	987.2MVAr	3757/ -180	4072A	A	534/ 117	1269A	C	818A
Δ 408.4MW	Δ 1024.0MVAr			B	556/ -126	1414A	D	1062A
Post-contingency: 115kV Circuit S2S Operated OPEN at Stayner TS Diagram 11								
1215.4MW	1060.0MVAr	3824/ -178	4155A	A	534/ 125	1274A	C	81A
Δ 415.4MW	Δ 1096.8MVAr			B	577/ -136	1476A	D	318A

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.
C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

The results summarised in Diagram 11 show that opening the in-line breaker at Stayner TS would achieve the required reduction in the flows on circuits S2S but it would increase the post-contingency flows on circuits N582L, B4V and B5V. Since the post-contingency flow on the 500kV circuit N582L is shown to exceed the enhanced rating for this circuit, it would therefore be necessary to adopt either of the following responses:

- Initiate rejection of sufficient generating capacity to ensure that the new rating is respected, or
- Delay the restoration to their pre-contingency levels of the transfers across the Ontario-Michigan & Ontario-New York Interconnections.

Analysis has shown that apart from a significant increase in the transmission losses, the simultaneous loss of the 500kV circuits B560V & B561M would result in a reduction of approximately 12.8% in the transfers from Michigan, with a corresponding increase in the transfers from New York. This reduction occurs as a direct consequence of the resulting increase in the impedance of the transmission path between Michigan and the major load centres in Ontario.

For the condition with a pre-contingency transfer of 1500MW from Michigan, the 500kV double-circuit contingency would therefore result in this transfer being reduced to approximately 1310MW, assuming that all of the increased system losses are supplied from the 30-minute operating reserve. There would also be an equivalent *increase* in the transfers from New York of approximately 190MW.

Effect of Delaying the Restoration of the Post-Contingency Transfers Across the Interconnections

Diagram 12 shows the effect of maintaining the reduction of approximately 190MW in the post-contingency transfers across the Ontario-Michigan Interconnections, together with a corresponding increase in the Ontario-New York transfers, following a 500kV double-circuit contingency and the associated cross-tripping of the Stayner A1A2 breaker in the 115kV circuit S2S.

As before, the increased transmission system losses were assumed to be supplied internally from the 30-minute operating reserve.

The critical flows from this study are shown in the bottom portion of the Table below:

Primary Demand: 25000MW		No. of Bruce Units: 7		Negative BLIP Flow: 1476MW				
Compensation: 50% & 50%								
Losses	Synchronous Condenser Output	500kV Circuit N582L		Flows on B4V/B5V			Flows on S2S	
		Rating	4110A	Rating	A	1430A	Rating: 770A	
					B	1180A		
		MW/MVAr	Amps	MW/MVAr	Amps		Amps	
Pre-contingency								Diagram 9
800.0MW	-36.8MVAr	1959/-295	2098A	A	342/ 16	795A	C	459A
				B	378/ -69	900A	D	687A
Post-contingency: 115kV Circuit S2S OPEN at Stayner TS PLUS No Restoration of the O-M & O-NY Transfers								Diagram 12
1188.4MW	983.2MVAr	3730/ -186	4043	A	530/ 119	1262A	C	81A
Δ 388.4MW	Δ 1020.0MVAr			B	573/ -136	1460A	D	317A

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.
C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

These results show that, as long as the transfers across the Ontario-Michigan and Ontario-New York Interconnections are allowed to remain at their post-contingency levels, the post-contingency flow on circuit N582L could be maintained within its 'enhanced' rating of 4110A following the cross-tripping of circuit S2S.

The post-contingency flows on the section of circuits B4V & B5V between the Melancthon Wind Projects and Orangeville TS are also shown to remain within their **15km/hr** wind-speed rating of 1590A.

10.4 With 40% / 40% Compensation

The pre-contingency results for a system primary demand of 25000MW and with the 500kV circuits compensated to 40% are shown in Diagram 13. The corresponding post-contingency results following the simultaneous loss of the 500kV circuits B560V & B561M are shown in Diagram 14.

In this study the A1A2 breaker at Stayner TS has been assumed to be cross-tripped immediately post-contingency to open the connection between the 115kV circuits S2S & S2E. In addition, the transfers across the Ontario-Michigan and Ontario-New York Interconnections were kept at their post-contingency levels and not returned to their pre-contingency values.

The critical flows from these two studies are shown in the Table below:

Primary Demand: 25000MW		No. of Bruce Units: 7		Negative BLIP Flow: 1476MW				
Compensation: 40% & 40%								
Losses	Synchronous Condenser Output	500kV Circuit N582L		Flows on B4V/B5V			Flows on S2S	
		Rating	4110A	Rating	A	1430A	Rating: 770A	
					B	1180A		
		MW/MVAr	Amps	MW/MVAr	Amps		Amps	
Pre-contingency. Diagram 13								
796.1MW	-56.4MVAr	1794/-240	1919A	A	349/ 20	812A	C	460A
				B	385/ -70	919A	D	700A
Post-contingency: 115kV Circuit S2S OPEN at Stayner TS Diagram 14 PLUS No Restoration of the O-M & O-NY Transfers								
1192.2MW	1044.4MVAr	3511/ -95	3849A	A	562/ 140	1345A	C	81A
Δ 396.1MW	Δ 1100.8MVAr			B	603/ -154	1557A	D	317A

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.
C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

While the lower level of series compensation is shown to result in a lower post-contingency flow on circuit N582L, it would still exceed its present long-term emergency rating of 3660A (corresponding to its sag temperature of 127°C). Consequently, measures would still be required to increase the ground clearances for this line to provide a higher ‘enhanced’ rating of up to 4110A.

The lower level of compensation would also result in higher post-contingency flows on circuits B4V & B5V, although they are shown to remain just marginally within the **15km/hr** wind-speed rating of 1590A. Consequently, any further reduction in the level of compensation would be expected to require additional measures to increase the ratings of circuits B4V & B5V.

10.5 With 30% / 30% Compensation

With the level of series compensation on the 500kV circuits reduced to 30%, the results for the pre-contingency and the post-contingency conditions following a double-circuit contingency involving the 500kV circuits B560V & B561M are shown in Diagrams 15 and 16, respectively.

The post-contingency condition reflects the cross-tripping of the A1A2 breaker at Stayner TS to open the connection between the 115kV circuits S2S & S2E and the retention of the transfers across the Ontario-Michigan and Ontario-New York Interconnections at their post-contingency levels.

The critical flows from these two studies are shown in the Table below:

Primary Demand: 25000MW		No. of Bruce Units: 7		Negative BLIP Flow: 1476MW				
Compensation: 30% & 30%								
Losses	Synchronous Condenser Output	500kV Circuit N582L		Flows on B4V/B5V			Flows on S2S	
		Rating	4110A	Rating	A	1430A	Rating: 770A	
					B	1180A		
		MW/MVAr	Amps	MW/MVAr	Amps		Amps	
Pre-contingency. Diagram 15								
794.6MW	-68.8MVAr	1654/ -201	1770A	A	355/ 23	826A	C	469A
				B	390/ -71	934A	D	710A
Post-contingency: 115kV Circuit S2S OPEN at Stayner TS PLUS No Restoration of the O-M & O-NY Transfers Diagram 16								
1199.0MW	1054.8MVAr	3314/ -21	3669A	A	592/ 161	1424A	C	81A
Δ 404.4MW	Δ 1123.6MVAr			B	630/ -172	1649A	D	317A

Note: A refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.
C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

At this level of series compensation, the post-contingency flow on circuit N582L is shown to be only marginally above (by 9A) the long-term emergency rating for this circuit. Since this is considered to be within acceptable tolerances, no measures would therefore be required to enhance the rating of this circuit if this level of series compensation were to be adopted.

However, since the post-contingency flows on circuits B4V & B5V are shown to be approximately 60A above their **15km/hr** wind-speed rating, these circuits would need to be uprated to increase their present sag temperature of only 104°C.

As shown in Table 2, raising the sag-temperature for this line to 127°C would provide long-term emergency ratings of 1400A and 1830A for wind-speeds of **4km/hr** and **15km/hr**, respectively.

10.6 Summary of Results for Different Levels of Series Compensation

The preceding studies show that employing levels of series compensation on the 500kV circuits between the Bruce Complex and Nanticoke SS that **exceed 50%** would result in excessive post-contingency flows on the 500kV circuit N582L. Even with the operational temperature of this circuit increased to 150°C to provide an ‘enhanced’ rating of 4110A, these flows would still result in overloading.

For all of the studies, post-contingency overloading of the 115kV circuit S2S between Owen Sound TS and Orangeville TS was shown to be an issue. To address this, cross-tripping the A1A2 breaker at Stayner TS to break the connection between the 115kV circuits S2S & S2E was shown to be effective. However, with the interruption of this direct connection between Owen Sound TS and Essa TS, the flows on the 500kV circuit N582L and on the 230kV circuits B4V & B5V were shown to increase.

As discussed in Section 11 of this report, should the fault involving the 500kV circuits B560V & B561M be sustained, then action to restore the transfers across the Interconnections to their pre-contingency levels would be counter-productive. This response would result in a higher flow on circuit N582L while there would be an opposing requirement to reduce this flow to within the circuit’s long-term emergency rating of 3660A (corresponding to a temperature of 127°C) within a maximum of three hours. Furthermore, in order to re-prepare the system for a possible contingency involving the 500kV circuit N582L, the Negative BLIP flow would need to be reduced to avoid the subsequent overloading of the four 230kV circuits between Longwood TS and Buchanan TS.

The post-contingency transfers across the Interconnections were therefore assumed to remain at their post-contingency levels, with no action taken to restore them to the levels that existed pre-contingency.

With the A1A2 breaker at Stayner TS open and with the transfers across the Interconnections maintained at their post-contingency levels, the studies resulted in the following post-contingency flows with series compensation levels on the 500kV circuits of 50%, 40% & 30%.

Line Upgrade Requirements for Different levels of Series Compensation					
Level of Series Compensation on 500kV Circuits	500kV Circuit N582L		230kV Circuits B4V & B5V		
	Post-Contingency Flow	Requirements	Post-Contingency Flows		Requirements
50%	4043A	Sag Temperature of the 500kV circuit to be increased to 150°C	A	1262A	None: Within the 4km/hr emergency rating
			B	1460A	None: Within the 15km/hr emergency rating
40%	3849A		A	1345A	None: Within the 4km/hr emergency rating
			B	1557A	None: Within the 15km/hr emergency rating
30%	3669A	No change required to the Sag Temperature of the 500kV circuit	A	1424A	None: Within the 4km/hr emergency rating
			B	1649A	Sag Temperature to be increased to at least 127°C. Flow would then be within the 15km/hr long-term emergency rating

Note:

A refers to the section between Bruce & Hanover TS

[For the existing sag temp of 127°C: 4km/hr long-term emergency rating 1430A}

B refers to the section between Hanover TS & Orangeville TS

[For the existing sag temp of 104°C: 15km/hr long-term emergency rating 1590A]

[For an increased sag temp of 127°C: 15km/hr long-term emergency rating 1830A]

10.7 Effect of Removing All the Local Wind-turbine Generating Facilities from Service

Since a permanent fault involving the 500kV circuits B560V & B561M would require action to reduce the post-contingency flow on the 500kV circuit N582L to within its long-term emergency rating of 3660A, a study was performed to determine the effect that removing all 925MW of wind-turbine generation capacity from service would have on this flow.

For this study, with 50% series compensation, no adjustment was made to the post-contingency transfers across the Interconnections.

The results from the study have been presented in Diagram 17, while those for the pre-contingency condition have already been shown in Diagram 9.

The following Table summarises the pertinent details from the study.

With Seven Bruce Units & 925MW of Wind-turbine Projects								
Compensation: 50% & 50%								
Primary Demand: 25000MW			Negative BLIP Flow: 1464MW					
Losses	Synchronous Condenser Output	Flows						
		500kV Circuit N582L		230kV Circuits B4V/B5V			115kV Circuit S2S	
		Rating	4110A	Rating	A	1430A	Rating: 770A	
					B	1180A		
		MW/MVAr	Amps	MW/MVAr	Amps		Amps	
Pre-Contingency								Diagram 9
800.0MW	-36.8MVAr	1959/ -295	2098A	A	342/ 16	795A	C	459A
				B	378/ -69	900A	D	687A
Post-Contingency		With 925MW of Generation Rejected						Diagram 17
Circuit S2S Open at Stayner TS								
Transfers Across the Interconnections maintained at their Post-contingency Values								
1057.5MW	628.0MVAr	3313/ -231	3563A	A	511/ 97	1209A	C	319A
Δ 257.5MW	Δ 664.8MVAr			B	452/ -122	1146A	D	319A

Note: A refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.
C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

This Table shows that by rejecting all 925MW of wind-turbine generation in the area, in addition to opening breaker A1A2 at Stayner TS, the post-contingency flow on circuit N582L would be reduced to below its long-term emergency rating of 3660A (for a maximum conductor operating temperature of 127°C).

The results also show that the increase in the post-contingency system losses following the rejection of the wind-turbine projects would be approximately 258MW. Consequently, the post-contingency resource deficiency would total approximately 1183MW (925MW + 258MW).

Since this would be within the 30-minute operating reserve of 1350MW, rejecting all of the wind-turbine projects post-contingency would therefore impose no additional operational burden.

10.8 Studies for Different Primary Demands on the System

With the 500kV circuits between the Bruce Complex and Nanticoke GS compensated to 50%, a series of load flow studies were performed for primary system demands in the range of 25000MW to 29000MW.

In these studies, the post-contingency opening of the A1A2 breaker at Stayner TS was **not** represented in order to allow direct comparisons to be made between the results for the respective primary demands. In addition, the post-contingency transfers across the Interconnections were restored to their pre-contingency levels.

The results from these studies have been presented on the following Diagrams, with the more pertinent details summarised in Table 4.

<i>Load Flow Plots with Seven Bruce units & 925MW of wind-turbine generation in-service With 50% / 50% Series Compensation on the existing transmission facilities</i>				
<i>Diagram No.</i>	<i>Fault Condition</i>	<i>Primary Demand</i>	<i>Negative-BLIP Flow</i>	<i>Detweiler Area Load</i>
9	Pre-contingency	25000MW	1475MW	1344MW
10	Post-contingency			
18	Pre-contingency	26000MW	1354MW	1406MW
19	Post-contingency			
20	Pre-contingency	27000MW	1233MW	1478MW
21	Post-contingency			
22	Pre-contingency	28000MW	1112MW	1551MW
23	Post-contingency			
24	Pre-contingency	29000MW	992MW	1634MW
25	Post-contingency			

As shown in Table 4, increases in the system primary demand would result in decreases in the Negative BLIP flow and these lower Negative BLIP transfers would also result in reduced post-contingency flows on circuit N582L.

Although the lower post-contingency transfers are shown to result in smaller incremental changes between the pre- and post-contingency system losses and reactive power support requirements, these are more than off-set by the increases in the losses and the reactive support due to the higher loads on the system.

This is particularly noticeable for the reactive power support requirement from the Nanticoke synchronous condensers. For a primary demand of 25000MW, the incremental post-contingency requirement is shown as 1020MVar, while for a primary demand of 29000MW this falls to 860MVar. However, the reactive support required pre-contingency for the two primary demands changes from - 40MVar to + 350MVar. This means that in order to ensure that the reactive capability of the synchronous condensers remains available for post-contingency support, additional shunt capacitors would need to be installed at Nanticoke GS as the primary demand increases.

TABLE 4		With Seven Bruce Units + 50% / 50% Series Compensation								
Diagram No.	Condition	Primary Demand Negative-BLIP Transfer	Series Capacitor Voltages	Losses	Synchronous Condenser Output	Flow on 500kV Circuit N582L		Flows on 230kV Circuits B4V/B5V		
						Rating	4110A	Rating	A	1430A
									B	1180A
						MW/MVAr	Amps	MW/MVAr	Amps	
9.	Pre-cont.	25000MW	BxL: 550.5kV NxL: 554.3kV	800.0MW	-36.8MVAr	1959/ -295	2098A	A	342/ 16	795A
			B					378/ -69	900A	
10.	Post-cont.	1475MW	BxL: 546.0kV NxL: 549.1kV	1208.4MW Δ 408.4MW	987.2MVAr Δ 1024.0MVAr	3757/ -180	4072A	A	534/ 117	1269A
			B	556/ -126	1414A					
18.	Pre-cont.	26000MW	BxL: 550.5kV NxL: 545.5kV	806.6MW	27.6MVAr	1920/ -299	2058A	A	345/ 26	804A
			B					379/ -63	907A	
19.	Post-cont.	1354MW	BxL: 546.7kV NxL: 549.8kV	1199.3MW Δ 392.7MW	1004.8MVAr Δ 977.2MVAr	3677/ -197	3982A	A	532/ 122	1267A
			B	552/ -120	1408A					
20.	Pre-cont.	27000MW	BxL: 550.6kV NxL: 554.6kV	815.1MW	98.0MVAr	1880/ -303	2016A	A	349/ 36	815A
			B					380/ -57	915A	
21.	Post-cont.	1233MW	BxL: 547.2kV NxL: 550.2kV	1195.8MW Δ 380.7MW	1074.8MVAr Δ 976.8MVAr	3597/ -211	3891A	A	530/ 129	1266A
			B	548/ 114	1403A					
22.	Pre-cont.	28000MW	BxL: 550.5kV NxL: 554.5kV	831.7MW	215.6MVAr	1842/ -304	1977A	A	353/ 46	827A
			B					381/ 51	924A	
23.	Post-cont.	1112MW	BxL: 547.5kV NxL: 550.5kV	1203.9MW Δ 372.2MW	1160.0MVAr Δ 944.4MVAr	3516/ -224	3802A	A	529/ 134	1267A
			B	545/ -111	1399A					
24.	Pre-cont.	29000MW	BxL: 547.5kV NxL: 554.0kV	851.6MW	347.6MVAr	1785/ -363	1940A	A	359/ 55	844A
			B					385/ -47	938A	
25.	Post-cont.	992MW	BxL: 544.8kV NxL: 550.0kV	1214.3MW Δ 362.7MW	1211.6MVAr Δ 864.0MVAr	3428/ -287	3732A	A	533/ 141	1279A
			B	545/ -109	1407A					

Note: A refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

The table above shows that for a primary demand of 25000MW, with all of the existing and the planned generating facilities except Lambton GS in-service in south-western Ontario, together with seven Bruce units and all of the new wind-turbine generating facilities operating at their peak output, the transfer across the Negative-BLIP Interface would be close to its operating limit of 1500MW.

As the primary demand increases, the transfers across the Negative-BLIP Interface will therefore decline. At a primary demand of 29000MW, the Negative-BLIP transfer is shown to have declined to just under 1000MW.

Voltages at the Series Capacitor Installations

While the voltages recorded at the series capacitor installations with the transmission facilities compensated to 50% will be lower than those with 60% compensation installed, the reductions as shown in the following Table, will be less pronounced than those recorded for a change from 70% to 60% in the level of compensation.

Voltages Recorded at the Series Capacitor Installations: with 50% / 50% compensation (25000MW Case)				
<i>500kV Circuit</i>	<i>Pre-contingency</i>		<i>Post-contingency</i>	
		<i>Reduction relative to 60% / 60% case</i>		<i>Reduction relative to 60% / 60% case</i>
B562L	550.4kV	0.52%	555.8kV	1.71%
B563L	550.5kV	0.52%	546.0kV	1.75%
N582L	554.3kV	0.91%	549.1kV	2.24%

Voltages within the London, Kitchener, Waterloo, Cambridge, Guelph & Orangeville Areas

The following Tables shows the pre- and the post-contingency voltages following a 500kV double-circuit contingency involving circuits B560V & B561M for primary demands of 25000MW and 29000MW, respectively.

Although there is a noticeable reduction (of up to 13kV or 5.5%) in the pre-contingency voltage profiles for the two primary demand levels, this could be addressed through the installation of additional shunt capacitor banks as the area loads increase. The results in the Table also show that the post-contingency voltage declines (with the loads modelled as constant MVA) would not be excessive, with a maximum decline of only 5.5% being recorded. This would be well within the IESO's voltage-decline criterion of 10%.

Voltages in the London, Kitchener, Waterloo, Cambridge, Guelph & Orangeville Area									
	Buchanan TS	Detweiler TS		Orangeville TS	Seaforth TS	Guelph-Campbell TS	Cambridge-Preston TS	Milton TS	Cambridge-Preston Auto-transformer Transfers
		230kV	115kV						
Primary Demand: 25000MW <i>Diagrams 9 & 10</i> Net Inflow via the 230kV System into: i. London area 1033MW ii. Kitchener, Waterloo, Cambridge, Guelph & Orangeville area 1344MW									
<i>Pre-cont.</i>	241.4kV	244.9kV	125.2kV	246.3kV	241.0kV	240.0kV	240.4kV	526.7kV	49.6MVAr
<i>Post-cont.</i>	233.9kV	232.9kV	120.0kV	232.8kV	227.7kV	227.0kV	229.1kV	520.7kV	134.4MVAr
<i>Change</i>	-3.1%	-4.9%	-4.2%	-5.5%	-5.5%	-5.4%	-4.7%	-1.1%	

<i>Primary Demand: 29000MW</i>									<i>Diagrams 24 & 25</i>
<i>Net Inflow via the 230kV System into:</i>									
<i>i. London area</i>									<i>1215MW</i>
<i>ii. Kitchener, Waterloo, Cambridge, Guelph & Orangeville area</i>									<i>1634MW</i>
<i>Pre-cont.</i>	236.3kV	235.8kV	121.4kV	238.6kV	232.5kV	229.5kV	227.3kV	524.7kV	195.5MVAr
<i>Post-cont.</i>	230.2kV	225.4kV	116.4kV	228.2kV	219.9kV	218.7kV	218.1kV	518.6kV	244.7MVAr
<i>Change</i>	-2.6%	-4.4%	-4.1%	-4.4%	-5.4%	-4.7%	-4.0%	-1.2%	

10.10 Other Contingencies

Studies were also performed for the other principal 500kV contingencies that could affect the ability to accommodate the output from the seven Bruce units together with the 925MW of ‘committed’ wind project in the west and south-west of the Province.

For these studies the 25000MW primary demand case was used, for which the results corresponding to the pre-contingency condition are shown in Diagram 9.

500kV Double-Circuit Contingency involving the Bruce-to-Longwood Line: circuits B562L & B563L

The post-contingency results are shown in Diagram 26.

These show that the losses would increase by only 15MW, primarily as a result of the reduced post-contingency flow on circuit N582L. The reduction in the losses on this circuit therefore off-sets the higher losses on the Bruce-to-Claireville / Milton circuits arising from the increased post-contingency flows into Claireville TS / Milton TS.

Furthermore, except for the post-contingency flows (1111A) on the section of circuits B4V & B5V between the Melancthon projects and Orangeville TS (for which the emergency rating is 1180A), all of the flows remain well within their circuit ratings.

The results also show that because of the reduced transfers through Nanticoke GS the synchronous condensers are collectively absorbing approximately 250MVAr. This amount could be reduced either by cross-tripping one of the shunt capacitors at Nanticoke GS or by retaining all five reactors at Longwood TS in-service post-contingency. (It had been assumed that one of the reactors at Longwood TS would need to be tripped post-contingency to compensate for the loss of the Bruce-to-Longwood circuits)

500kV Single-circuit Contingency involving the Longwood-to-Nanticoke Line: circuit N582L

The post-contingency results are shown in Diagram 27.

While these show that the losses for this contingency would be slightly higher at 61MW, the post-contingency flows on each of the circuits between the Melancthon projects and Orangeville TS would be approximately 25MVA lower; providing further margin between the actual flows and the circuit ratings.

All of the remaining flows are shown to be well within their circuit ratings.

500kV Double-Circuit Contingency involving the line section between Bruce Junction & Willowcreek Junction

While this section is only 15.5km in length, it represents a recognised contingency and therefore the consequences of simultaneously losing one of the Bruce-to-Claireville/Milton circuits with one of the Bruce-to-Longwood circuits has been examined.

The post-contingency results are shown in Diagram 28.

For this contingency condition, the losses increase by a modest 122MW (compared to 408MW for the loss of the Bruce-to-Claireville/Milton circuits).

With all of the reactors at the Bruce Complex and at Longwood TS tripped post-contingency, there is very little decline in the voltage profile from the pre-contingency values. The highest declines occur at Milton TS (~ 4kV) and on the 230kV system originating from the Bruce Complex (~ 4kV). Furthermore, only 110MVAR of reactive support is shown to be required from the synchronous condensers at Nanticoke GS.

All of the post-contingency flows except for those on the section of circuits B4V & B5V between the Melancthon projects and Orangeville TS (1129A) remain well within their circuit ratings.

11. Re-Preparation of the System with 7 Bruce Units & 925MW of Wind-Turbine Generation In-Service

For the condition with the 500kV circuits compensated to 50%, the analysis has shown that following the loss of the Bruce-to-Claireville/Milton circuits with seven Bruce units in-service together with the wind-turbine generation, the flows on the 500kV Longwood-to-Nanticoke and the 230kV Bruce-to-Orangeville circuits are expected to be close to their thermal limits.

In response to a subsequent contingency involving the 500kV circuit N582L, all of the wind projects together with two Bruce units would need to be rejected to ensure that transient stability (with margin) can be maintained.

Since there is also a requirement to reduce the transfers on the 500kV circuit to below its long-term emergency rating of 3660A within a maximum period of three hours, then during the 30-minute re-preparation period following a sustained outage of the Bruce-to-Claireville/Milton circuits, either of the following actions (or a combination of them) would need to be taken:

- Remove all of the wind-turbine generating facilities from service
- Reduce the transfers across the Ontario-Michigan Interface

Diagram 17 from Section 10.7 of this Report showed the situation that would exist at the end of the re-preparation period with all 925MW of the wind-turbine projects out-of-service.

Diagram 29 shows the corresponding situation with an equivalent reduction of 925MW in the transfers across the Ontario-Michigan Interface.

The resulting flows on the critical transmission facilities of these two responses are summarised in the following Table:

Comparison of the Re-Preparation Responses								
Primary Demand: 25000MW No. of Bruce Units: 7 Negative BLIP Flow: 1476MW								
Compensation: 50% & 50%								
Losses	Synchronous Condenser Output	500kV Circuit N582L		Flows on B4V/B5V			Flows on S2S	
		Rating	4110A	Rating	A	1430A	Rating: 770A	
					B	1180A		
		MW/MVAr	Amps	MW/MVAr	Amps		Amps	
Immediately Post-contingency Following the Loss of the 500kV Circuits B560V & B561M Diagram 12								
115kV Circuit S2S opened at Stayner TS								
No adjustment of the post-contingency transfers across the Interconnections.								
1188.4MW	983.2MVAr	3730/ -186	4043A	A	530/ 119	1262A	C	81A
				B	573/ -136	1460A	D	317A
Response 1: All 925MW of Wind-turbine Projects Removed from Service Diagram 17								
1057.5MW	628.0MVAr	3313/231	3563A	A	512/ 97	1209A	C	319A
				B	452/ -122	1146A	D	319A
Response 2: Transfers Across the Ontario-Michigan Interface Reduced by 925MW Diagram 29								
1021.4MW	513.2MVAr	3256/ 223	3482A	A	506/ 89	1193A	C	79A
				B	550/ 136	1375	D	316A

Note: A refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.
C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

These results show that reducing the transfers across the Ontario-Michigan Interface would have the greater impact on the flow on circuit N582L, while removing the wind-turbine generators from service would result in a more pronounced reduction in the flows on circuits B4V & B5V.

Consequently, a combination of measures to reduce not only the transfers across the Ontario-Michigan Interface but also to remove from service those wind-turbine projects that are directly connected to circuits B4V & B5V, would appear to offer the greatest benefit. However, these measures, together with accounting for the increased system losses, would need to represent a reduction in resources that would not exceed the 30-minute operating reserve of 1350MW.

Diagram 30 shows the results for the condition with the two Leader Wind and the two Melancthon Wind Projects removed from service and with the transfers from the Ontario-New York Interface reduced to their pre-contingency level of 1400MW. In addition the transfers across the Ontario-Michigan Interface have been reduced by a further 535MW, from 1310MW to 773MW.

For this condition the system losses are shown to total 1020MW, representing a net increase of 220MW over the pre-contingency losses.

Implementing these changes would result in a net reduction in available resources totalling approximately 1345MW, as detailed below:

Reduction in the transfers across the Ontario-New York Interface	190MW
Reduction in the transfers across the Ontario-Michigan Interface	535MW
Removal from service of the wind-turbine projects connected to circuits B4V & B5V	400MW
Increase in transmission losses	220MW
<i>Total</i>	<i>1345MW</i>

The resulting flows on the critical transmission facilities are summarised in the following Table:

Primary Demand: 25000MW		No. of Bruce Units: 7		Negative BLIP Flow: 1476MW				
Compensation: 50% & 50%								
Losses	Synchronous Condenser Output	500kV Circuit N582L		Flows on B4V/B5V			Flows on S2S	
		Rating	4110A	Rating	A	1430A	Rating: 770A	
					B	1180A		
		MW/MVAr	Amps	MW/MVAr	Amps		Amps	
Response 1:		All 925MW of Wind-turbine Projects Removed from Service					Diagram 30	
1019.8MW	516.4MVAr	3303/ -207	3537A	A	513/ 91	1210A	C	79A
				B	461/ -134	1164A	D	316A

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.
C refers to the section between Owen Sound TS and the Blue Mountain Wind Project
D refers to the section between the Blue Mountain Wind Project and Meaford TS

These results show that the proposed combination involving the removal from service of selected wind-turbine projects together with the reduction of transfers across the Ontario-Michigan and Ontario-New York Interfaces would meet the requirement of respecting the long-term emergency ratings of circuits N582L and B4V & B5V.

500kV Single-Circuit Contingency on N582L

Analysis has indicated that the loss of the 500kV circuit N582L when circuits B560V & B561M are already out-of-service would result in a reduction of approximately 45% in the transfers across the Ontario-Michigan Interface. A corresponding increase would occur in the transfers across the Ontario-New York Interface.

For the Re-preparation Condition shown in Diagram 30 which has transfers of 773MW across the Ontario-Michigan Interface, a contingency involving circuit N582L would be expected to reduce them by approximately 350MW to 425MW.

Diagram 31 shows the post-contingency results following a single-circuit contingency involving circuit N582L. In response to this contingency two Bruce B units were also rejected, together with all the wind-turbine projects.

For this study, it was assumed that the resulting resource deficiency would be supplied from existing Ontario generating capacity, although in practice it would be expected to be addressed through a combination of increased output from internal generating facilities as well as load rejection.

The corresponding flows on the critical 230kV circuits are shown in the following Table:

With Seven Bruce Units & 925MW of Wind-turbine Projects						Compensation: 50% & 50%		
Primary Demand: 25000MW								
Losses	Flows							
	230kV Circuits B4V/B5V		230kV Circuits B22D/B23D		230kV Circuits W42L/W43L		230kV Circuits W44LC/W45LC	
	Rating	1430A	Rating	1400A	Rating	1400A	Rating	1460A
	MW/MVAr	Amps	MW/MVAr	Amps	MW/MVAr	Amps	MW/MVAr	Amps
Post-Contingency - Following the loss of circuit N582L & the rejection of Two Bruce Units & the remaining Wind-turbine Projects Ontario-Michigan Transfers reduced to ~ 425MW						Diagram 31 Negative BLIP Flow: 207MW		
816.4MW	563MW 122MVAr	1337A	420MW 91MVAr	1000A	544MW 132MVAr	1305A	645MW 114MVAr	1563A

These results show that even with two Bruce units and the remaining wind-turbine projects rejected, overloading of the 230kV circuits W44LC & W45LC, between Longwood TS and Buchanan TS, would occur following the loss of the 500kV circuit N582L.

Reducing the transfers over the Negative BLIP Interface either through reduced transfers across the Ontario-Michigan Interface or through the rejection of generating capacity in the Sarnia-Windsor area would limit the flows on the 230kV circuits between Longwood TS and Buchanan TS.

The results of a study with the Ontario-Michigan transfers reduced to approximately zero are summarised in Diagram 32 and the corresponding flows on the critical 230kV circuits are shown in the following Table:

With Seven Bruce Units & 925MW of Wind-turbine Projects						Compensation: 50% & 50%		
Primary Demand: 25000MW								
Losses	Flows							
	230kV Circuits B4V/B5V		230kV Circuits B22D/B23D		230kV Circuits W42L/W43L		230kV Circuits W44LC/W45LC	
	Rating	1430A	Rating	1400A	Rating	1400A	Rating	1460A
	MW/MVAr	Amps	MW/MVAr	Amps	MW/MVAr	Amps	MW/MVAr	Amps
Post-Contingency - Following the loss of circuit N582L & the rejection of Two Bruce Units & the remaining Wind-turbine Projects Ontario-Michigan Transfers reduced to ~ 0MW						Diagram 32 Positive BLIP Flow: 192MW		
757.6MW	531MW 94MVAr	1252A	403MW 73MVAr	952A	509MW 88MVAr	1207A	589MW 75MVAr	1411A

The results in the Table above show that rejecting two Bruce B units together with all the remaining wind-turbine projects, as well as reducing the transfers across the Ontario-Michigan Interface to approximately zero, would allow the post-contingency flows on all the 230kV circuits to be maintained within their long-term emergency ratings following a contingency involving the 500kV circuit N582L.

Resulting Resource Deficiency

The resulting resource deficiency from both the re-preparation activities and the subsequent immediate response to a contingency involving the 500kV circuit N582L following a sustained outage of circuits B560V & B561M, would therefore be as follows:

• Rejection of all of the wind-turbine projects in the area	925MW
• Rejection of two of the Bruce B generating units	1640MW
• Reduction of the transfers on the Ontario-Michigan Interface to zero [1500MW less the automatic 350MW reduction following the N582L contingency]	1150MW
• Change in transmission system losses	-50MW
<i>Accumulated Deficiency</i>	<i>3665MW</i>
• Normal 30-minute Operating Reserve	1350MW
<i>Difference</i>	<i>2315MW</i>

To address the resulting 2300MW resource deficiency, a combination of increased output from the Ontario generating resources that remain available and load rejection would therefore be required.

Carrying a higher operating reserve than the minimum required by NPCC would reduce the amount of load that would need to be rejected, however it would impose a significant financial burden for what is considered to be a higher unlikely event.

In addition, although the existing Bruce Special Protection System has the capability to reject load in response to certain contingencies, circuit N582L is presently not one of them. Modification of the SPS would therefore be required so that load and generation rejection could be initiated for the loss of this circuit.

12. Load Flow Analysis: With Eight Bruce Units In-service

12.1 With the Existing Transmission Facilities & No Wind-Turbine Generation

Studies were performed for the condition with all eight Bruce units in-service and with no new wind-turbine generating facilities in-service (essentially corresponding to the situation prior to the shut-down of the Bruce A station in 1998).

The intent was to determine whether the existing transmission facilities with series capacitors installed, would be adequate to allow all eight Bruce units to remain in-service post-contingency, with no overloading of the transmission system.

Diagrams 33 & 34 show the pre- and post-contingency results following the loss of circuits B560V & B561M due to a 500kV double-circuit contingency.

In these studies, although lower levels of compensation would have satisfied the requirements for transient stability, it was found to be necessary to compensate the Bruce-to-Longwood circuits and the Longwood-to-Nanticoke circuit to **50%** to minimise the post-contingency overloading of the 230kV circuits between the Bruce Complex and Orangeville TS.

The resulting flows on the critical transmission circuits are summarised in the following Table:

With Eight Bruce Units & No Wind-turbine Projects							Compensation: 50% & 50%	
Primary Demand:		25000MW		Negative BLIP Flow: 1277MW				
Losses	Synchronous Condenser Output	500kV Circuit N582L		Flows on B4V/B5V			Flows on S2S	
		Rating	4110A	Rating	A	1430A	Rating: 770A	
					B	1180A		
		MW/MVAr	Amps	MW/MVAr	Amps		Amps	
Pre-contingency							Diagram 33	
812.7MW	-29.6MVAr	1936/ -297	2074A	A	364/ 24	848A	608A	
				B	299/ -69	722A		
Post-contingency: Following the loss of the 500kV circuits B560V & B561M 115kV Circuit S2S Open at Stayner TS No Restoration of the O-M & O-NY Transfers to their Pre-contingency Levels								Diagram 34
1215.6MW	994MVAr	3728/ -214	4057A	A	557/ 128	1327A	595A	
Δ 402.9MW	Δ 1023.6MVAr			B	495/ -143	1280A		

Note: A refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

Since the condition examined assumed that there were no wind-turbine projects in-service, it would therefore be inappropriate to use the higher rating corresponding to a wind-speed of 15km/hr for determining the ratings of the circuits.

The results therefore show that following a contingency involving the 500kV circuits B560V & B561M the section of circuits B4V & B5V between Hanover TS and Orangeville TS would be overloaded. Reducing the level of series compensation on the 500kV circuits would increase the post-contingency flows on circuits B4V & B5V, thereby aggravating the extent of the overloading. To address this situation, either the maximum conductor operating temperature of the critical section of circuits B4V & B5V would need to be increased beyond its present value of 104°C or the level of series compensation would need to be increased above the 50% level considered in these studies. However any increase in the level of compensation would need to be limited to ensure that the post-contingency flow on circuit N582L does not exceed its enhanced rating of 4110A.

It would therefore appear that, in the absence of any wind-turbine projects and with series compensation at a level of approximately 50% installed on the 500kV circuits, the existing transmission facilities would be marginally adequate to accommodate all eight Bruce units without having to employ post-contingency generation rejection.

Furthermore to accommodate all eight Bruce units in addition to all of the wind-turbine projects that have been awarded contracts under the Renewables I & II RFPs, it has been concluded that additional transmission facilities will be necessary if generation rejection in response to a first contingency is to be avoided.

12.2 Load Flow Analysis: With Eight Bruce Units In-service & 925MW of Wind-Turbine Generation together with additional Transmission Facilities

For the purpose of this assessment, two distinct alternatives for new 500kV transmission reinforcement have been assumed:

- *Alternative 1: A new 500kV single-circuit line between Longwood TS and Middleport TS.*

Notionally, the route for the new line has been assumed to follow the existing right-of-way between Longwood TS and Buchanan TS and then to replace the 230kV circuit M31W between Buchanan TS and Middleport TS. Based on this route, the length of the new line has been estimated at approximately 150km.

Since the transient stability studies have indicated that series capacitors would be required in this new single-circuit line it was also assumed that they would be installed where the new line by-passes Buchanan TS, approximately 52km from Longwood TS.

- *Alternative 2: A new 500kV double-circuit line between the Bruce Complex and either Milton TS or Essa TS.*

If the new line were to terminate at Milton TS, then it was assumed that it would follow the right-of-way of the existing 500kV double-circuit line and would have a similar length of approximately 176km.

If the new line were to terminate at Essa TS then it was assumed that it would follow the same right-of-way as the existing 500kV double-circuit line but continue along the right-of-way of the existing 230kV line B4V & B5V into Orangeville TS. It was then assumed to follow the right-of-way of the existing 230kV line E8V & E9V into Essa TS. If it were to follow this route, then the length of the new line would be approximately 182km.

Regardless of where the new double-circuit line would be terminated, it was assumed that one of the circuits would originate from the Bruce A 500kV switchyard while the other would originate from the Bruce B switchyard.

With a new 500kV double-circuit line between the Bruce Complex and either Milton TS or Essa TS there would be no requirement for series compensation to be installed on any of the 500kV transmission facilities to maintain post-contingency transient stability.

Load Flow studies were performed for both reinforcement alternatives, using the 25000MW primary demand case so as to obtain the highest Negative-BLIP transfers.

12.2.1 Alternative 1: With a new 500kV single-circuit line between Longwood TS and Middleport TS *(Approximate length of the new line: 150km)*

Although the following minimum levels of series compensation would be required to ensure post-contingency transient stability, they were found to result in overloading of the 230kV circuits B4V & B5V, between the Bruce Complex and Orangeville TS, following a 500kV double-circuit contingency involving circuits B560V & B561M:

- Bruce-to-Longwood 500kV circuits B562L & B563L 20%
- Longwood-to-Nanticoke 500kV circuit N582L 10%
- Longwood-to-Middleport new 500kV circuit 10%

Studies were therefore performed with all of the 500kV circuits listed above compensated to 40% to increase the post-contingency transfers through those circuits.

The results have been presented in Diagrams 35 & 36 for the pre- and post-contingency conditions, respectively.

The critical flows have been summarised in the Table below:

With Eight Bruce Units + 925MW of wind-turbine generation							
With a new 500kV Single-Circuit Line: Longwood TS-to-Middleport TS							
With 40% / 40% Series Compensation, including 40% compensation of the new 500kV circuit							
Negative-BLIP Flow: 1485MW							
Losses	Synchronous Condenser Output	Flows					
		500kV Circuits			230kV Circuits B4V/B5V		
		Rating	3660A 4110A (N582L)		Rating	A	1430A
						B	1180A
		MW/MVAr	Amps	MW/MVAr	Amps		
Pre-Contingency Diagram 35							
825.7MW	-101.6MVAr	B562L	1030/ -133	1100A	A	354/ 21	824A
		B563L	1054/ -125	1122A			
		N582L	1308/ -245	1410A	B	390/ -72	932A
		New	1373/ -177	1468A			
Post-Contingency: Following the loss of the 500kV circuits B560V & B561M 115kV Circuit S2S Open at Stayner TS Transfers Across the O-M & O-NY Interfaces Restored to their Pre-Contingency Levels Diagram 36							
1217.7MW	842.0MVAr	B562L	2356/ -313	2535A	A	539/ 124	1284A
		B563L	2383/ -313	2558A			
		N582L	2362/ -315	2609A	B	581/ -141	1487A
Δ 392.0MW	Δ 943.6MVAr	New	2554/ -119	2798A			

Note: *A* refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

These results show that while the parallelling of the existing 500kV circuit N582L with a new 500kV circuit to Middleport TS would avoid the post-contingency overloading of circuit N582L, the minimum level of compensation that would need to be installed on the 500kV circuits would be 40% so as to limit the post-contingency flows through the 230kV circuits B4V & B5V.

With this level of compensation installed, the post-contingency flows on the section of the 230kV circuits B4V & B5V between the Melancthon Projects and Orangeville TS would be within their long-term emergency rating of 1590A based on a wind speed of **15km/hr**.

The results also show that even with the new line installed and with the 500kV facilities compensated to 40%, approximately 940MVAr of reactive support would still be required from the synchronous condensers at Nanticoke GS to maintain an acceptable post-contingency voltage profile.

It should also be noted that the post-contingency system losses would also increase of approximately 390MW.

12.2.2 Alternative 2.1: With a new 500kV double-circuit line between the Bruce Complex and Milton TS
(Approximately length of the new line: 176km)

The results have been presented in Diagrams 37 & 38 for the pre- and post-contingency conditions, respectively.

The critical flows have been summarised in the Table below:

With Eight Bruce Units + 925MW of wind-turbine generation With a new 500kV Double-Circuit Line: Bruce-to-Milton TS With No Series Compensation Negative BLIP Flow: 1481MW							
Losses	Synchronous Condenser Output	Flows					
		500kV Circuits			230kV Circuits B4V/B5V		
		Rating	3660A 4110A (N582L)		Rating	A	1430A
						B	1180A
		MW/MVAr	Amps	MW/MVAr	Amps		
Pre-Contingency Diagram 37							
741.2MW	-63.2MVAr	BxL:	310/ -25	330A	A	315/ 1	730A
		NxL:	1046/ -136	1115A			
		BxM (Existing):	1274/ 42	1349A	B	352/ -70	831A
		BxM (new):	1231/ 35	1304A			
Post-Contingency: Following the loss of the 500kV circuits B560V & B561M 115kV Circuit S2S OPEN at Stayner TS Transfers Across the O-M & O-NY Interfaces Restored to their Pre-Contingency Levels Diagram 38							
861.1MW	159.6MVAr	BxL:	655/ -227	743A	A	400/ 39	933A
		NxL:	1511/ 34	1564A			
		BxM (Existing):	-	-	B	446/ -92	1081A
Δ 119.9MW	Δ 222.8MVAr	BxM (new):	2019/ 240	2180A			

Note: A refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

For this contingency condition, post-contingency tripping of the A1A2 breaker at Stayner TS was still found to be necessary to avoid overloading the 115kV circuit S2S.

With circuit S2S open and the transfers on the Interconnections restored to their pre-contingency levels, all of the monitored post-contingency flows are shown to remain within the 4km/hr wind-speed ratings for the circuits.

In addition, the presence of the new 500kV double-circuit line is shown to limit the increase in the post-contingency system losses to 120MW while the reactive power requirements from the synchronous condensers at Nanticoke GS is limited to approximately 220MVAr. This would be within the capability of one of the existing generating units at Nanticoke GS, converted to synchronous condenser operation.

12.2.3 Alternative 2.2: With a new 500kV double-circuit line between the Bruce Complex and Essa TS
(Approximate length of the new line: 182km)

The results have been presented in Diagrams 39 & 40 for the pre- and post-contingency conditions, respectively.

The critical flows have been summarised in the Table below:

With Eight Bruce Units + 925MW of wind-turbine generation							
With a new 500kV Double-Circuit Line: Bruce-to-Essa TS							
With No Series Compensation							
Negative BLIP Flow: 1481MW							
Losses	Synchronous Condenser Output	Flows					
		500kV Circuits			230kV Circuits B4V/B5V		
		Rating	3660A 4110A (N582L)		Rating	A	1430A
						B	1180A
		MW/MVAr	Amps	MW/MVAr	Amps		
Pre-Contingency Diagram 39							
747.8MW	-14.8MVAr	BxL:	345/ -21	366A	A	293/ 1	681A
		NxL:	1114/ -131	1186A			
		BxM:	1480/ 99	1569A			
		BxE (new):	1101/ 45	1168A	B	332/ -60	782A
		ExV:	934/ 94	1009A			
Post-Contingency: Following the loss of the 500kV circuits B560V & B561M 115kV Circuit S2S CLOSED at Stayner TS Transfers Across the O-M & O-NY Interfaces Restored to their Pre-Contingency Levels Diagram 40							
906.9MW	256.8MVAr	BxL:	799/ -188	879A	A	388/ 44	906A
		NxL:	1724/ 37	1799A			
		BxM:	-	-			
		BxE (new):	1839/ 189	1981A	B	423/ -72	1026A
Δ 159.1MW	Δ 271.6MVAr	ExV	1675/ -94	1849A			

Note: A refers to the section between Bruce and Hanover TS, and
B refers to the section between Hanover TS and Orangeville TS.

For this contingency condition, since the post-contingency flow on the section of circuit S2S between the Blue Mountain Wind Project and Meaford TS was 733A and therefore within its long-term emergency rating of 770A, post-contingency tripping of the A1A2 breaker at Stayner TS was therefore unnecessary.

While the performance of this arrangement with the proposed 500kV double-circuit line terminated at Essa TS is shown to be similar to that with the new line terminated at Milton TS, it would result in increased transfers over the two 500kV circuits between Essa TS and Claireville TS.

For the case that was studied with a primary demand of 25000MW and without a new 500kV double-circuit line, the combined flow on circuits E510V & E511V between Essa TS and Claireville TS was approximately 40MW.

However, as shown in Figure 1, the transfers over the 500kV circuits E510V & E511V during July & August of last year (which was a very dry year and therefore had an adverse effect on the output from the hydroelectric plants) frequently exceeded 1000MW.

With the new line terminated at Essa TS, the combined flows on these circuits are shown to increase to approximately 1860MW pre-contingency and 3340MW post-contingency. Consequently, superimposing an additional flow of 1000MW on the combined 3340MW post-contingency flow on these circuits would therefore result in their combined rating of approximately 3800MVA (1898MVA per circuit from Table 1) being exceeded.

If the new 500kV double-circuit line were to terminate at Essa TS then remedial measures would need to be taken to raise the operating temperatures of the two existing Essa-to-Claireville 500kV lines. Since Figure 1 shows flows of up to 1400MW, the ratings of each of these circuits would need to be increased to at least 2400MW (2600MVA at 0.9 power factor).

[Although not examined as part of this assessment, the contingency condition involving either circuit E510V or E511V may be more limiting and would need to be considered.]

Comparison of the two Alternatives for new transmission reinforcement

Alternative 1, with a new 500kV single-circuit line installed between Longwood TS and Middleport TS would be substantially inferior to Alternative 2 involving a new 500kV double-circuit line between the Bruce Complex and either Milton TS or Essa TS, for the following reasons:

- It would require the 500kV circuits between the Bruce Complex and Longwood TS, and between Longwood and Nanticoke SS/Middleport TS, to be series compensated to 40%.
For Alternative 2, none of the 500kV circuits would need to have series compensation.
- It would require higher levels of post-contingency reactive support to be provided from the synchronous condensers at Nanticoke GS.
Approximately 950MVAR of support would need to be available, whereas Alternative 2 would require a maximum of approximately 275MVAR.
- It would result in additional post-contingency losses of approximately 400MW, while for Alternative 2 the increased losses would be approximately 160MW.
- It would also present similar challenges with respect to re-preparing the system for a subsequent contingency to those discussed previously in Section 11 for the existing system arrangement.
Since Alternative 2 would provide an additional, independent path from the Bruce Complex, a sustained outage involving circuits B560V & B561M would result in the system appearing similar to today's arrangement. For this, the consequences of a single element contingency would be much less severe.
- It would also present significantly less scope for the incorporation for future generation projects.

The performance of the two options for terminating the new 500kV double-circuit line proposed under Alternative 2 have been shown to be similar, except that if the line were to terminate at Essa TS it would require remedial work on the two existing 500kV single-circuit lines between Essa TS and Claireville TS. This work would involve raising their operating temperature from the present 78°C so as to increase their long-term emergency ratings to at least 2600MVA.

Furthermore, should the new line terminate at Essa TS rather than at Milton TS it would result in an additional 40MW of post-contingency losses and a requirement for an additional 50MVAR of post-contingency reactive support from the Nanticoke synchronous condensers. However, since these increases are not especially large and since they would only occur following a double-circuit contingency, they would not be sufficient to influence any decision on the termination point for the new line.

13. Synchronous Condensers

The results presented in Sections 10.3 to 10.5 for the condition with seven Bruce units and 925MW of wind-turbine generation capacity in-service, and with series capacitors installed on the existing 500kV transmission facilities, that the post-contingency reactive support required from the synchronous condensers at Nanticoke GS totals:

- approximately 1020MVAR with 50% series compensation installed, and
- approximately 1125MVAR with 30% series compensation installed

The 1125MVAR of reactive support could be provided through the conversion of at least three of the existing generating units at Nanticoke GS to synchronous condenser operation.

However, to ensure that adequate capacity remains available while units are being maintained or are forced out of service due to faults, the IESO is recommending that four units be converted.

If a new 500kV line were to be constructed to Milton TS or Essa TS, then the reactive support requirement from Nanticoke GS would fall to approximately 275MVAR. This would be within the capability of a single synchronous condenser, or a maximum of two units if redundancy is to be provided.

The IESO is therefore recommending that the feasibility of installing Static VAR Compensators (SVCs) to provide a portion of the reactive power requirements, be examined. This could allow only one, or possibly two, of the Nanticoke units to be converted to synchronous condenser operation. Furthermore, if the SVCs were to be of a relocatable design this would be an additional benefit, allowing them to be installed at other locations on the system once the new line is placed in-service.

14. Bruce Special Protection System (SPS)

With seven Bruce units in-service together with all of the committed wind-turbine projects, the Bruce Special Protection System will need to be enhanced so that it can react to the following contingency conditions and provide the appropriate responses:

Additional contingency conditions that need to be addressed by the Bruce SPS

- 500kV circuit N582L
- 230kV circuits B4V & B5V: both single- and double-circuit contingencies
- 230kV circuits B22D & B23D: both single- and double-circuit contingencies

Additional responses that need to be included in the Bruce SPS

- Cross-tripping of the 115kV breaker A1A2 at Stayner TS
- Generation rejection for the individual wind-turbine projects (or selected groups of projects)
- Switching of the new shunt capacitor banks
- Additional load rejection selections (if the amount provided through the present selections is insufficient)

The intent of providing post-contingency switching of the shunt capacitor banks is to address those situations, particularly under light load conditions, where switching of the capacitor banks into service pre-contingency would result in excessively high voltages.

15. Independent Phase Controlled Compensators at Tillsonburg TS & Norfolk TS

When the 500kV circuit N582L was constructed between Longwood TS and Nanticoke SS, sections of the 115kV circuits that supply Norfolk TS and Tillsonburg TS were installed on the same structures. It was expected that this could result in excessive voltage imbalances on these 115kV circuits whenever the 500kV circuit N582L was subjected to high power flows, particularly under fault conditions.

Separate schemes, called Independent Phase Controlled Compensators, were therefore installed at both Norfolk TS and Tillsonburg TS to automatically switch capacitor banks into and out-of-service across the appropriate phases of the respective 27.6kV busbars whenever excessive voltage imbalances were detected.

With the introduction of series capacitors into the 500kV path between the Bruce Complex and Nanticoke SS, via Longwood TS, the pre- and post-contingency flows are expected to increase beyond those that were assumed in the original design of the two schemes.

It is therefore recommended that the capability of the existing Independent Phase Controlled Compensators be reviewed to determine whether they will have adequate capacity for the projected duties once the series capacitors have been installed.

16. Conclusions & Recommendations

16.1 Conclusions

The principal conclusions from this assessment are as follows:

- To ensure adequate post-contingency voltages in the Kitchener, Waterloo, Cambridge, Guelph and Orangeville areas following the loss of the 500kV Bruce to Claireville TS / Milton TS circuits, the following facilities will need to be installed:
 - A 250MVar 230kV shunt capacitor bank at both Detweiler TS and at Orangeville TS
 - A 230/115kV auto-transformer at Cambridge-Preston TS to interconnect the 230kV and 115kV systems in the immediate vicinity.

1. With no new transmission facilities and seven Bruce units plus 925MW of wind-turbine generation.

The following conclusions assume that in the event of a sustained outage involving the 500kV circuits B560V & B561M, the post-contingency transfers across the Ontario-Michigan Interface would not be returned to their pre-contingency levels since this would be counter-productive to re-preparing the system for a subsequent contingency. However, it has been assumed that the transfers across the Ontario-New York Interface would be reduced to return them to their pre-contingency levels.

- To maintain post-contingency transient stability, the 500kV circuits between the Bruce Complex and Longwood TS and between Longwood TS and Nanticoke SS would need to be compensated to at least **20%**.
- To avoid post-contingency overloading of the 115kV circuit S2S between Owen Sound TS and Orangeville TS, cross-tripping of the A1A2 breaker at Stayner TS would need to be initiated following a double-circuit contingency involving the 500kV circuits B560V & B561M.
- With the 500kV circuits between the Bruce Complex and Longwood TS and between Longwood TS and Nanticoke SS compensated to either **40% or 50%**, the post-contingency flows on the 230kV circuits B4V & B5V between the Bruce Complex and Orangeville TS would be within their *15km/hr* wind-speed ratings.

However, for these levels of series compensation, the existing 500kV circuit N582L between Longwood TS and Nanticoke GS would need to be uprated so that ground clearances would be adequate to allow the conductors to be operated at temperatures up to the maximum of 150°C. This would provide an enhanced rating of 4110A.

- With the 500kV circuits between the Bruce Complex and Longwood TS and between Longwood TS and Nanticoke SS compensated to **30%**, the post-contingency flow on circuit N582L would be just marginally over its long-term rating of 3660A and would therefore not require this circuit to be uprated.

However, the lower level of compensation on the 500kV circuits would result in higher post-contingency flows on the 230kV circuits B4V & B5V that would exceed their 15km/hr wind-speed rating of 1590A.

To accommodate these higher flows, the maximum conductor operating temperature for the section of circuits B4V & B5V between Hanover TS and Orangeville TS would need to be increased above its present value of 104°C. Raising the operating temperature to 127°C would result in a 15km/hr wind-speed rating of 1830A which would be more than adequate for the projected post-contingency flow of 1650A.

- In the event of a sustained outage involving the 500kV circuits B560V & B561M, the preferred course of action for re-preparing the system for a subsequent contingency would involve the removal from service of the wind-turbine projects connected to the 230kV circuits B4V & B5V, together with reducing the transfers across the Ontario-Michigan Interface. This would be additional to the return of the transfers across the Ontario-New York Interface to their pre-contingency levels.

The cumulative net effect of these actions on the available system resources would need to be limited to approximately 1350MW, to remain within the 30-minute operating reserve for the system.

In addition to these changes, the Bruce SPS would need to be armed so that it can respond to whatever contingency may subsequently occur. For the most-onerous contingency, which would involve the loss of the 500kV circuit N582L, two Bruce B units together with all the remaining wind-turbine projects in the area would need to be armed for automatic rejection. In addition, arming would be required to initiate the rejection of sufficient load to reduce the post-contingency transfers across the Ontario-Michigan Interface to zero.

Although these responses were determined for the condition with the 500kV circuits compensated to a level of 50%, the requirements for lower levels of compensation are expected to be similar.

- With the 500kV circuits between the Bruce Complex and Longwood TS and between Longwood TS and Nanticoke SS compensated to **50%**, all eight Bruce units could be incorporated without any of the wind-turbine projects. However, the 500kV circuit N582L would need uprating to provide an enhanced rating of 4110A so that the post-contingency flow would remain within its rating. In addition, since this condition assumed that there were no wind-turbine projects incorporated it would therefore be inappropriate to use a wind-speed rating of 15km/hr. Consequently, to respect the 4km/hr wind-speed rating of the 230kV circuits B4V & B5V they would also need to be uprated.
- To incorporate all eight Bruce units as well as the 925MW of wind-turbine generation capacity for which contracts have been awarded without having to employ post-contingency generation rejection in response to a first contingency, additional transmission facilities will need to be constructed.

2. With new 500kV Transmission Facilities

The Assessment examined two Alternatives for reinforcing the transmission system to allow all eight Bruce units together with the committed wind-turbine projects to be incorporated without the need to employ post-contingency generation rejection.

Alternative 1: With a new 500kV single-circuit line between Longwood TS and Middleport TS
Approximate length of the new line: 150km.

- To maintain post-contingency transient stability, the 500kV circuits between the Bruce Complex and Longwood TS would need to be compensated to at least **20%** while those between Longwood TS and Nanticoke SS and between Longwood TS and Middleport TS would need to be compensated to at least **10%**.
- To limit the post-contingency flows through the 230kV circuits B4V & B5V, the level of compensation on the 500kV circuits would need to be increased to 40%. With this level of compensation installed, the post-contingency flows on the section of the 230kV circuits B4V & B5V between the Melancthon Projects and Orangeville TS would be within their 15km/hr wind-speed rating of 1590A.

Alternative 2.1 With a new 500kV double-circuit line between the Bruce Complex and Milton TS
Approximate length of the new line: 176km.

- For this Alternative there would be no requirement to install series capacitors on any of the 500kV circuits either to maintain post-contingency transient stability or to avoid post-contingency overloading.

Alternative 2.2 With a new 500kV double-circuit line between the Bruce Complex and Essa TS
Approximate length of the new line: 1826km.

- Similarly for this Alternative, there would be no requirement to install series capacitors on any of the 500kV circuits either to maintain post-contingency transient stability or to avoid post-contingency overloading.
- Remedial measures would, however, be required to raise the operating temperatures of the two existing Essa-to-Claireville 500kV lines. Since each of these lines is presently rated at only 1900MVA, they would be inadequate for the projected post-contingency flows of approximately 2600MVA.

Comparison of the Alternatives

Alternative 1, with a new 500kV single-circuit line installed between Longwood TS and Middleport TS would be substantially inferior to Alternative 2 involving a new 500kV double-circuit line between the Bruce Complex and either Milton TS or Essa TS, for the following reasons:

- It would require the 500kV circuits to be series compensated to a level of 40%.
For Alternative 2, none of the 500kV circuits would require series compensation.
- It would require higher levels of post-contingency reactive support to be provided from the synchronous condensers at Nanticoke GS.
Approximately 950MVAR of support would need to be available, whereas Alternative 2 would require a maximum of approximately 275MVAR.
- It would result in additional post-contingency losses of approximately 400MW, while for Alternative 2 the increased losses would be approximately 160MW.

- It would continue to present challenges for the re-preparation of the system to position it for any subsequent contingency.

Since Alternative 2 involves the installation an additional, independent path from the Bruce Complex, a sustained outage involving circuits B560V & B561M would essentially return the system to the status quo. For this, the consequences of a single element contingency would be much less severe.

Of the two options for terminating the new 500kV double-circuit line from the Bruce Complex, the one with the line terminated at Milton TS instead of at Essa TS would have the advantage of avoiding the need to uprate the two 500kV lines between Essa TS and Claireville TS.

However, in all other respects, the performance of the two options would be similar.

3. Synchronous Condensers

With seven Bruce units together with 925MW of wind-turbine generation capacity incorporated and with the 500kV circuits equipped with series capacitors providing 50% compensation, approximately 1120MVar of post-contingency reactive support is expected to be required from the synchronous condensers at Nanticoke GS.

This could be provided through the conversion of a minimum of three of the existing generating units at Nanticoke GS to synchronous condenser operation, although it would be prudent to convert an additional unit to maintain a degree of redundancy.

Once the new 500kV double-circuit line is placed in-service to coincide with all eight Bruce units being in operation, the reactive support requirement from Nanticoke GS would fall to approximately 275MVar. This would be within the capability of a single synchronous condenser, or a maximum of two units if redundancy is to be provided.

Since the new 500kV line is required to be in-service no later than the end-2011, the period over which four synchronous condensers would need to be available would be a maximum of three years.

The IESO has therefore recommended that consideration be given to providing a portion of the reactive power requirements from Static VAr Compensators (SVCs). This would limit the number of units at Nanticoke GS that would have to be converted to synchronous condenser operation. In addition, once the new 500kV line is placed in-service and the reactive support requirements are reduced, any surplus SVC capacity could be relocated to other areas of the system that require dynamic voltage support.

4. Bruce Special Protection System

Enhancements to the Bruce SPS will be required to expand the number of contingencies to which it can respond as well as the range of actions that can be automatically initiated in response to these contingencies.

16.2 Recommendations

- The ABB Study that was commissioned by Hydro One has determined that sub-synchronous resonance (SSR) issues associated with the installation of series capacitors in the 500kV circuits connected to either the Bruce Complex or Nanticoke GS could be avoided if the level of compensation were to be maintained below 40%. This would avoid the need to employ mitigating measures such as using thyristor controlled series capacitors (TCSCs) for a portion of the series capacitor installation.

The IESO has determined that installing 30% series compensation would not only avoid the need to uprate the 500kV circuit N582L but it would satisfy the requirement for a minimum level of 20% compensation to maintain post-contingency transient stability. However, the post-contingency flows on the section of circuits B4V & B5V between Hanover TS and Orangeville TS would exceed the 15km/hr wind-speed rating of these circuits.

The IESO is therefore recommending that the condition of this section of circuits B4V & B5V be examined to determine whether the line could be uprated for operation at a conductor temperature of 127°C.

If circuits B4V & B5V can be uprated, then the IESO's preference would be to adopt a level of 30% compensation for the series capacitors that it is proposed to install on the 500kV circuits between the Bruce Complex and Longwood TS and between Longwood TS and Nanticoke SS.

- Since extensive modifications to the Bruce SPS are expected to be necessary to provide the additional flexibility that will be required, and in recognition of the complexity of the existing scheme and the associated difficulty of implementing changes, the IESO would support a change to a matrix-based design, similar to that which has been used for other SPSs.
- In the accompanying analysis, extensive use has been made of the 15km/hr wind-speed ratings for the 230kV circuits B4V & B5V in assessing whether post-contingency overloading is expected to occur.

Since the prevailing ambient conditions are expected to have a major influence on these ratings and therefore on the operation of the system with particular emphasis on the post-contingency responses that are adopted, the IESO is therefore recommending that these circuits be equipped with real-time monitoring.

- Since the installation of series capacitors in the 500kV circuits between the Bruce Complex and Nanticoke SS will result in increased pre- and post-contingency flows on the 500kV circuit N582L, this could result in more pronounced voltage imbalances on the 115kV circuits that supply Norfolk TS and Tillsonburg TS.

The IESO is therefore recommending that the design of the existing Independent Phase Controlled Compensators at Norfolk TS and Tillsonburg TS be reviewed to determine whether they have adequate capability to address the expected voltage imbalances that could arise once the series capacitors have been installed.

17. Customer Impact Assessment

Once a decision is made whether or not to proceed with the installation of series capacitors and the level of compensation that is to be employed, Hydro One Networks Inc. is proposing to conduct a Customer Impact Assessment for this Project to determine whether the proposed facilities could have any materially adverse effects on their customers.

Should any issues be identified in the CIA then they will be addressed through an Addendum to this Report.

18. Notification of Approval of the Connection Proposal

Subject to the completion of the Customer Impact Assessment and the satisfactory resolution of any issues that it may raise, the IESO has concluded that the following work will have no materially adverse effect on the IESO-controlled grid:

- the installation of series capacitors in the Bruce-to-Longwood and the Longwood-to-Nanticoke 500kV circuits, whether at the 50% or 30% compensation level, and subject to appropriate action to uprate either the 500kV circuit N582L (for 50%) or the 230kV circuits B4V & B5V (for 30%).
- the installation of 230kV shunt capacitor banks at Middleport TS, Nanticoke TS, Detweiler TS & Orangeville TS
- the conversion of up to four units at Nanticoke GS to synchronous condenser operation, and/or the installation of SVCs to provide a portion of the reactive power support that will be required.

It is therefore recommended that a Notification of Conditional Approval to Connect be issued for this Project

Hydro One Networks Inc.

Southwestern Ontario Transmission 500kV Series Compensation Technical Studies Power Flow and Dynamics Report

DRAFT REPORT

November 30, 2005

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TABLE OF CONTENTS

SUMMARY	S-1
1.0 INTRODUCTION	1
2.0 BASE CASE	3
2.1 DEVELOPMENT OF NETWORK MODEL – EQUIVALENTS FOR THE US AND CANADA.....	3
2.2 BASE CASE POWER FLOW	3
3.0 CONTINGENCY ANALYSES	6
3.1 SINGLE CONTINGENCY ANALYSES:.....	6
TABLE 3.1 STEADY STATE (POST-CONTINGENCY) VOLTAGE LIMITS	7
3.2 SELECTED DOUBLE CONTINGENCY ANALYSES:	9
3.2.1 Willow Creek Junction to Milton Double Circuit Tower Outage	9
3.2.2 Willow Creek Junction to Milton Single Circuit and Longwood-Nanticoke (n-2) Outage:.....	10
4.0 Q-V CURVES:	14
4.1 SINGLE CONTINGENCY:.....	14
4.2 SELECTED DOUBLE CONTINGENCY	19
5.0 SENSITIVITY POWER FLOW CASES:	23
5.1 BRUCE-MILTON D/C OUTAGE:.....	23
5.1.1 Synchronous Condensers at Nanticoke:	23
5.1.2 Reduced Series Compensation with increased Shunt Compensation	23
5.2 HIGHER VOLTAGE AT SERIES CAPACITOR BUSES:.....	31
5.3 FULL EXTERNAL SYSTEM REPRESENTATION:.....	33
5.3.1 Willow Creek Junction to Milton Double Circuit Tower Outage	33
5.3.2 Willow Creek Junction to Milton Single Circuit and Longwood-Nanticoke (n-2) Outage:.....	36
5.3.3 HIGHER IMPORT FROM ITC	38
5.4 GENERATION TRIPPING FOR DOUBLE CONTINGENCY.....	39
6.0 DYNAMICS.....	41
6.1 NORMALLY-CLEARED 3-PHASE FAULTS:	41
6.1.1 Simulations for No-bypass of Series Capacitors:	42
6.1.2 Simulations for with bypass of all Series Capacitors:	44
6.2 SIMULTANEOUS L-G FAULTS:.....	45
6.2.1 No By-pass of Series Capacitors:	45
6.2.2 By-pass of All Series Capacitors:	47
6.3 DELAYED CLEARING WITH L-G FAULTS:.....	47
6.3.1 No By-pass of Series Capacitors:	48
6.3.2 By-pass of All Series Capacitors:	48
6.4 SENSITIVITY CASES:	48
6.4.1 Normally Cleared 3-phase Fault:.....	48
6.4.2 Simultaneous L-G Fault:	49
6.4.3 Normally Cleared Highest 3-phase Fault Level Location:.....	49
6.4.4 Damping Need:.....	51
7.0 CONCLUSIONS.....	52

7.1	STEADY-STATE/POWER-FLOW:	52
7.2	DYNAMICS/STABILITY:	54

Southwestern Ontario Transmission 500kV Series Compensation Technical Studies Power Flow and Dynamics Report

SUMMARY

Since January 2005, Hydro One Networks Inc. (Hydro One) has been working with stakeholders to explore options to increase the transmission capability of the network throughout Southwestern Ontario with the goal of enabling the shutdown of the OPG coal-fired generating stations at Nanticoke GS and Lambton GS. With the possible return of all the nuclear units and the potential for significant new generation in the Bruce area, there is an immediate need to increase the transmission capability of the 500kV system out of the Bruce area. Because of the 6 to 10 years of time requirement to obtain necessary permits and construction of a new 500kV transmission line, Hydro-One investigated different upgrade solutions with new and innovative ideas for possible means to increase transfer capability of the existing transmission facilities. As a result of these investigations installation of new series capacitors on the following 500kV transmission paths was determined to be an effective means of increasing the transfer capability:

1. 70% series compensation on the Bruce GS to Longwood TS 500kV circuits (B562L & B563L)
2. 70% series compensation on the Longwood TS to Nanticoke GS 500kV circuit (N582L)
3. 10% series compensation on the Bruce GS to Claireville TS and Milton TS 500kV circuits (B560V & B561M)

Because, application of series capacitors would be new (to Hydro-One - in fact for the Eastern Interconnection of the North American Transmission system), Hydro-One commissioned ABB to conduct the necessary power system studies to assess and provide recommendations on the series compensation proposal with respect to sizing, location, and design parameters, including the review of studies performed by Hydro One and the IESO.

In this report, results from the steady state and dynamics simulations are presented. These studies are based on the forecasted load and generation for the year 2010, with power transfer of 6,902MW for the FABC (Flow Away from Bruce Complex) interface. Correspondingly the flows in the base case are, almost zero for the BLIP (Buchanan Longwood Input) and 2,157MW for the FETT (Flows East Towards Toronto). The IMO's transmission planning Criteria¹ was used in evaluating the study results. PSS/E² (Version 29.5.0) Power Flow,

¹ IMO Transmission Assessment Criteria, IMO_REQ_0041, Issue 2.0, September 10,2003.

² PTI's Commercial Software Package

Dynamics and Optimal Power Flow programs were used for these simulations. The focus, in these simulations, was mainly 500kV and 230kV transmission levels. Any overload and voltage violations in the 115kV and lower voltage part of the system was considered to be local problems and expected to be resolved in due time by Hydro-one.

Steady State Analyses: The base case (normal system conditions) power flow with the above mentioned percentage series capacitor compensation meets the normal (continuous) transmission planning criteria requirements.

Then, a single contingency (n-1) analyses by taking outage of the 500kV transmission circuits, one at a time, was performed. Two contingencies involving Hanmer-Porcupine-Pinard 500kV single circuit lines indicated Non-converged (NC) condition. This 500kV path being radial, this is expected and again considered to be a local issue. The overload limit for the post-contingency system is tested on the basis of 100% Rate-B. The single contingencies of the 500kV transmission lines did not cause any overloads. For outage of any one of the 500kV circuits from Bruce to Longwood resulted in voltage exceeding 1.1pu at the series capacitor bus on the remaining circuit. The high voltage at the series capacitor buses can be addressed by several different options as noted in this report without great difficulty.

For the main 500kV transmission loop (Bruce to Claireville), eight (8) double contingencies were identified. Out of these 8 double contingencies, the following two double contingencies resulted in NC condition:

- 1) Outage of double circuit tower from Willow Creek Junction to Milton (this is actually a (n-1) level contingency for this system).
- 2) Outage of one circuit from Willow Creek Junction to Milton in combination with Outage of the single circuit from Longwood to Nanticoke

For the remaining 6 double contingencies, there were no overloads or voltage violations.

Resolution of the above #1 contingency requires a total of almost 2,000MVAR reactive support - with nearly one-third (1/3) in the form of new shunt requirement (most at Buchanan 230kV bus) and the other two-thirds (2/3) obtained by switching-off the shunt reactors in Bruce and Longwood substations.

The above double contingency#2 requires nearly 2,500MVAR of reactive support (a high estimate) at Milton 500kV bus to maintain the indicated voltages and resolve the non-convergence of the power flow (or avoid voltage collapse). The reactive power requirements were determined from OPF simulations and independently verified by Q-V curves (including the 10% margin from the voltage collapse point or knee of the P-V curve). Several sensitivity power flow simulations (higher % series compensation, switching-off shunt reactors,

generator tripping, rearranging 500kV circuit connections at Milton 500kV bus etc.) for reducing the amount of reactive support are included in the report. The minimum range is anywhere from 500 – 1,500 MVAR requirement. The final selection of amount of reactive support would probably a combination different possibilities depending upon economic and risk analyses.

In addition, power flow change cases involving many variations of major parameters were simulated. These are reported in Section 5.0 as sensitivity analyses. These evaluations included effect of synchronous condensers at Nanticoke, reduced series compensation with increased shunt compensation, allowing higher voltage at series capacitor buses, full external system representation, higher import from ITC, generator tripping, etc.

Dynamics: The full system with all the interconnections to the Western Province and USA was used for this stability testing. The system stability (both angular and voltage stability) was tested for the following three types of disturbances:

- a) A normally cleared three-phase fault
- b) A normally cleared phase-to-phase-to-ground fault on different phases of a double circuit line
- c) A delayed fault clearance for phase-to-ground fault on one 500kV circuit

Further, the transient voltage sag criteria requirement was also checked.

The fault durations assumed for this testing were on the conservative side. Specifically normal clearing time of 6 cycles and delayed clearing of 10 cycles were assumed. The main dynamics simulations consisted of the following cases:

- i. Normally cleared three-phase fault at 4 locations (500kV buses of Bruce, Longwood, Nanticoke and Claireville) with the respective faulted line outaged i.e. no reclosure.
- ii. Normally cleared phase-to-ground fault on different phases of the double circuit Bruce-Milton line – both the faulted circuits outaged i.e. no reclosure.
- iii. Delayed clearance of phase-to-ground fault at 4 locations (500kV buses of Bruce, Longwood, Nanticoke and Claireville) with the respective faulted line outaged i.e. no reclosure.

For each of the above 9 cases, two different types of simulations – bypassing and no-bypassing of series capacitors (during faulted period) were performed. Two extreme cases of bypassing all and none of the series capacitors bracket the expected performance of the system.

The system was found to be stable with acceptable transient voltage recovery characteristic for all the 18 simulation cases. For slower clearing (outside the minimum criteria requirement) of simultaneous L-G fault (≈ 10 cycles) wind farm generator tripping was noted due to the under-voltage protection settings used in these simulations. This indicates that the possibility of changes to such relay settings need to be reviewed.

As a sensitivity case, 110% power transfer from Bruce complex was also tested and found to be stable. This confirms that the additional reactive support from steady state voltage stability testing need not be fast acting (i.e. dynamic).

Another sensitivity testing condition involved fault at two points (about 30% from Longwood and Nanticoke) of zero net series impedance or highest fault level. The system was found to be stable in all the four cases.

A third sensitivity case was run to take a cursory look at damping and this case shows that further examination of damping requirements coupled with the additional reactive support may be necessary.

In conclusion, both the power flow dynamic simulation results confirm that the proposed series compensation of the 500kV lines is feasible and will meet the power transfer requirements. The simulation results show that further optimization (both technical and economic) of both the series and shunt compensation levels is desirable. Such optimized levels compensation should provide a better and more economic solution for the upgrade of the main 500kV transmission loop of Bruce-Longwood-Nanticoke-Claireville-Milton.

Southwestern Ontario Transmission 500kV Series Compensation Technical Studies Power Flow and Dynamics Report

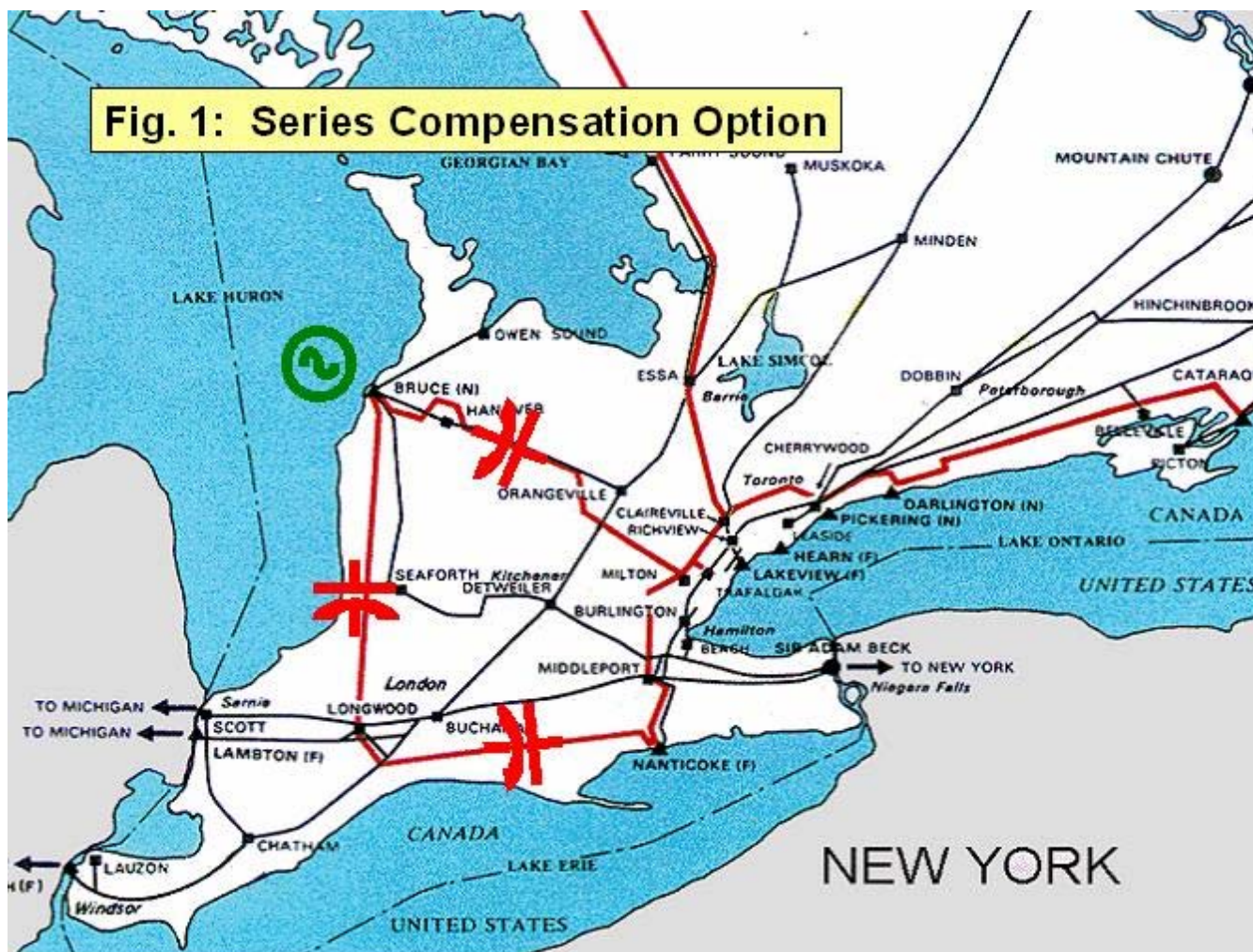
1.0 INTRODUCTION

Since January 2005, Hydro One Networks Inc. (Hydro One) has been working with stakeholders to explore options to increase the transmission capability of the network throughout Southwestern Ontario with the goal of enabling the shutdown of the OPG coal-fired generating stations at Nanticoke GS and Lambton GS. With the possible return of all the nuclear units and the potential for significant new generation in the Bruce area, there is an immediate need to increase the transmission capability of the 500kV system out of the Bruce area (Figure 1.1). To meet these future transmission needs, Hydro-One conducted Transmission Planning Studies. Because of the 6 to 10 years of time requirement to obtain necessary permits and construction of a new 500kV transmission line, such an option was not included in this particular Transmission Planning Study. Instead, Hydro-One investigated different upgrade solutions with new and innovative ideas for possible means to increase transfer capability of the existing transmission facilities. As a result of these investigations installation of new series capacitors on the following 500kV transmission paths was determined to be an effective means of increasing the transfer capability:

1. 70% series compensation on the Bruce GS to Longwood TS 500kV circuits (B562L & B563L)
2. 70% series compensation on the Longwood TS to Nanticoke GS 500kV circuit (N582L)
3. 10% series compensation on the Bruce GS to Claireville TS and Milton TS 500kV circuits (B560V & B561M)

Because, application of series capacitors would be new (to Hydro-One - in fact for the Eastern Interconnection of the North American Transmission system), Hydro-One commissioned ABB to conduct the necessary power system studies to assess and provide recommendations on the series compensation proposal with respect to sizing, location, and design parameters, including the review of studies performed by Hydro One and the IESO.

Figure 1.1 Southwestern Ontario 500-kV Transmission Grid



2.0 BASE CASE

The first task was to develop a base case representing a normal condition with maximum level of power transfer from West (New generation including Bruce Complex plus Wind Resources) to East. Hydro One and IESO provided the power flow model and other supporting data used in Hydro One's preliminary analysis.

2.1 Development of Network Model – Equivalents for the US and Canada

HYDRO-ONE provided a power flow model for the Peak Load Case (Year 2010), a draw file, and stability data in PSS/E format. The full network model included almost all of the Eastern Interconnection Transmission System in the US and Canada. Consequently, the power flow model contained nearly 43,400 buses, almost 58,000 branches, 30 dc ties and about 7,200 generator units. Rather than using such a large model, a reduced network model with a full representation of the HYDRO-ONE and equivalents for external system in the US and Canada is sufficient for the purposes of steady state analyses.

The external part (zone 999 in the power flow model) of the system was represented by equivalents at NYISO, HQTE, MH and MP areas. The procedure used for deriving the equivalents and the resulting equivalents are included in Appendix-A. All the tie lines to the external areas (zone-999) were retained in the equivalenced system. As shown in Appendix-A, the area tie line interchange flows were also maintained at the same level.

2.2 Base Case Power Flow

In the base case, the initial series compensation values, as included in the power flow model by Hydro-One, are assumed. These values are, 70% series compensation on the Bruce GS to Longwood TS 500kV circuits (B562L & B563L) as well as on the Longwood TS to Nanticoke GS 500kV circuit (N582L) and 10% series compensation on the Bruce GS to Claireville TS and Milton TS 500kV circuits (B560V & B561M) are assumed. The assumed generation dispatch is for maximum west to east power transfer condition.

For this initial base case condition, Optimal Power Flow (OPF) was run with an objective function of minimize losses. This objective (without any generation cost data included in the model) has the effect of keeping the voltages as high and as uniformly as possible across the system. The bus voltage limits, shown in Table 2.1, were included as limits or constraints for the OPF run. For the initial OPF run, many local and lower voltage limits were binding. Several adjustments were made to resolve the local problems. Because the focus of this study is the 500kV and 230kV

transmission system, the voltage limits for 120kV and below was relaxed (outside the range shown in Table 2.1) so that successful OPF solution could be obtained.

Table 2.1 Steady State (Pre-Contingency) Voltage Limits

	NOMINAL BUS VOLTAGE (kV)		
	500	230	115
Max. Continuous	550	250	127
Min. Continuous	490	220	113
Max. Continuous (pu)	1.100	1.087	1.104
Min. Continuous (pu)	0.980	0.957	0.983
NOTE: From section 4.2, IMO Transmission planning criteria			

FOR USE WITH PSS/E POWER FLOW VOLTAGE LIMITS				
	NOMINAL BUS VOLTAGE (kV)			
	500	220	118	< 115
Max. Continuous	550	250	127	
Min. Continuous	490	220	113	
Max. Continuous (pu)	1.100	1.136	1.076	1.1
Min. Continuous (pu)	0.980	1.000	0.958	0.95

The power flow in the main 500kV loop for the base case (after the OPF solution) is shown in Figure 2.1. Because of the high amount of series compensation on the Bruce-Longwood-Nanticoke 500kV circuits, there will be a voltage rise across the series capacitor. As shown in Figure 2.1, there is a 4% voltage rise from Bruce to the series capacitor located at nearly the mid point of Bruce-Longwood circuits. In order to ensure that the 500kV bus voltages remain below the 1.1pu maximum for the 500kV buses, the generation scheduled voltages were suitably adjusted by OPF. For example, the adjustment (reduction) to the generator voltages at Bruce Complex (which has the most direct impact) is shown in Table 2.2. Smaller adjustments to various other generator scheduled voltages were also made by OPF.

If it is desirable, essential or advantageous to maintain the scheduled voltage at Bruce Complex close to the maximum (similar to the present practice), then several other options are available to avoid or overcome the high voltage at the series capacitor banks. This includes, splitting the bank size, multiple locations, switching-in part of the series capacitor bank upon contingency, reinsulating part of the 500kV overhead line etc.

In this base case there were no overloaded (on the basis of Rate-A) transmission lines and the major transformers. However, several step down transformers (220kV and 115kV to lower voltages such as 27kV) were flagged as overloaded elements

Figure 2.1 BASE CASE POWER FLOW PLOT WITH OPF SOLUTION

(Please see next page)

Table 2.2 Bruce Complex Generator Dispatch (post OPF run)

BUS	NAME	BSVLT	MW	MVAR	QMAX	QMIN	VSCHED	VACTUAL
6900	BRUCEAG1	18.5	728	324.7	325	-255	0.9819	0.977
6901	BRUCEAG2	18.5	728	324.7	325	-255	0.9819	0.977
6902	BRUCEAG3	18.5	770	30.7	325	-255	1.0208	0.9567
6903	BRUCEAG4	18.5	770	22.6	325	-255	1.0205	0.9556
6904	BRUCEBG5	24	840	60.4	520	-380	0.9995	0.9564
6905	BRUCEBG6	24	866	51.7	520	-380	0.9991	0.9549
6906	BRUCEBG7	24	840	44.6	520	-380	0.9993	0.9543
6907	BRUCEBG8	24	840	57.6	520	-380	0.9992	0.9558
6944	BRUCE 1P	13.8	11.6	7.9	8	-6	1.05	1.0341
6947	BRUCE 2Q	13.8	11.6	7.9	8	-6	1.05	1.0282
6948	BRUCE 3R	13.8	11.6	7.9	8	-6	1.05	1.0326
6951	BRUCE 4S	13.8	11.6	7.9	8	-6	1.05	1.0304
6952	BRUCE 5P	13.8	12.1	8.9	9	-5	1.05	1.0196
6955	BRUCE 6Q	13.8	12.1	8.9	9	-5	1.05	1.0131
6956	BRUCE 7R	13.8	12.1	8.9	9	-5	1.05	1.0196
6959	BRUCE 8S	13.8	12.1	8.9	9	-5	1.05	1.0133

(see Tables in Appendix-B). These are essentially local issues, which have no impact on the compensation of the 500kV transmission lines. Also, these overloads may be mainly due to inconsistent data for the ratings and/or additional transformers may be added in the future.

All the voltages at the 500kV and 220kV buses were within the criteria voltage limits shown in Table 2.1. As mentioned earlier, the voltage constraint for the OPF solution was over a wider range than allowable under the criteria. Consequently, voltages at several of the 115 and lower voltage buses are outside the steady state limits. These are listed in Appendix-B. Again, these voltage limit violations are local in nature.

Thus, this Base Case is considered to meet the normal (continuous) transmission planning criteria requirements.

3.0 CONTINGENCY ANALYSES

3.1 Single contingency Analyses:

As per the transmission planning criteria, the next step is to perform a single contingency (n-1) analyses. All the 500kV transmission circuits were outaged, one at a time (55 contingencies listed in Appendix-C). Activity "ACCC" was used for taking the outage and solving the post contingency power flow conditions. Two contingencies involving Hanmer-Porcupine-Pinard 500kV single circuit lines indicated Non-converged (NC) condition. This 500kV path being radial, this is

expected and again considered to be a local issue. A list of remaining contingencies tested is included in Appendix-C. The overload limit for the post-contingency system

Table 3.1 Steady State (Post-Contingency) Voltage Limits

	NOMINAL BUS VOLTAGE (kV)		
	500	230	115
Max. Continuous	550	250	127
Min. Continuous	470	207	108
Max. Continuous (pu)	1.100	1.087	1.104
Max. Continuous (pu)	0.940	0.900	0.939
From section 4.3, IMO Transmission planning criteria			

	NOMINAL BUS VOLTAGE (kV)			
	500	220	118	< 115
Max. Continuous	550	250	127	
Min. Continuous	470	207	108	
Max. Continuous (pu)	1.100	1.136	1.076	1.1
Max. Continuous (pu)	0.940	0.941	0.915	0.9

FOR USE WITH PSS/E POWER FLOW VOLTAGE LIMITS

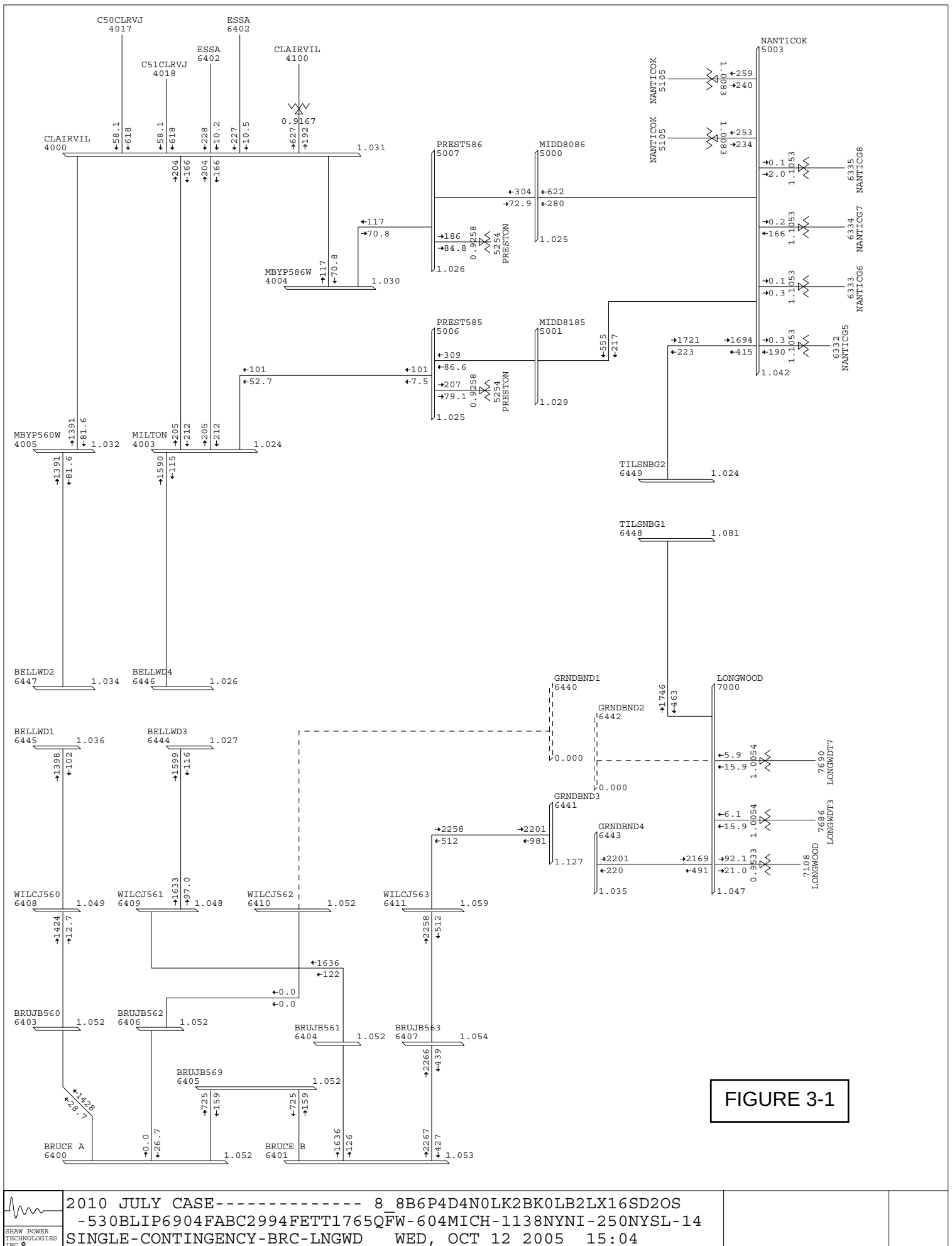
is tested on the basis of 100% Rate-B. The voltage limits used are shown in Table 3.1. A complete output of the contingency analyses report is also included in Appendix-C. The single contingencies of the 500kV transmission lines did not cause any overloads. For outage of any one of the 500kV circuits from Bruce to Longwood resulted in voltage exceeding 1.1pu at the series capacitor bus, as shown in Table 3.2. The first four contingencies, in this table, result in a long and open 500kV transmission line connected to the Longwood bus. Power flow plot for the first contingency (in Table 3.2) is shown in Figure 3.1. Due to higher loading, there is approximately 11% voltage difference across the series capacitor in the remaining line.

Table 3.2 Steady State (Post-Contingency) Over-Voltages

CONTINGENCY	VOLTAGE(PU)	BUS-NAME	BUS-KV
6400 BRUCE A 500 - 6406 BRUJB562 500 ckt 1	1.1484	GRNDBND3	500
6401 BRUCE B 500 - 6407 BRUJB563 500 ckt 1	1.148	GRNDBND1	500
6406 BRUJB562 500 - 6410 WILCJ562 500 ckt 1	1.1466	GRNDBND3	500
6407 BRUJB563 500 - 6411 WILCJ563 500 ckt 1	1.1462	GRNDBND1	500
6410 WILCJ562 500 - 7000 LONGWOOD 500 ckt 1	1.1271	GRNDBND3	500
6411 WILCJ563 500 - 7000 LONGWOOD 500 ckt 1	1.1266	GRNDBND1	500

Figure 3.1 SINGLE CONTINGENCY POWER FLOW PLOT

(Please see next page)



One of the remedies is to set the precontingency voltages 5% lower; meaning that the high limit for normal operation be 1.05pu rather than the presently used 1.1pu. Another option is a type of Special Protection (SPS) for reducing the Bruce generation scheduled voltage by 5%, depending upon the loading on the remaining in-service 500kV line. This may be treated as an exception, rather than being in strict compliance with the criteria requirements.

The last two rows in this table correspond to the outage of one the two parallel series compensated lines. Due to higher power flow on the remaining line, there is overvoltage at the series capacitor bus. If the precontingency voltages were set at 3% lower, then there would not be any over-voltage. The SPS mentioned earlier would be applicable for these contingency conditions as well.

3.2 Selected Double Contingency Analyses:

In general, from a steady state operation point of view, it is necessary to establish that the double contingencies (especially the two circuits on a double circuit tower) would not cause voltage collapse. For the main 500kV transmission loop, 8 double contingencies were identified (listed in Appendix-D). The contingency output (from activity ACCC) is also included in Appendix-D. Out of these 8 double contingencies, the following two double contingencies resulted in NC condition:

- 1) Outage of double circuit tower from Willow Creek Junction to Milton
- 2) Outage of one circuit from Willow Creek Junction to Milton in combination with Outage of the single circuit from Longwood to Nanticoke

For the remaining 6 double contingencies, there were no overloads or voltage violations. The two contingencies causing NC condition will be examined individually.

3.2.1 Willow Creek Junction to Milton Double Circuit Tower Outage

This specific double contingency was solved iteratively by using OPF and regular power flow to determine the additional reactive support (amount and location) required. The number (4) of synchronous condensers is same as in the base case. A total of almost 2,000MVAR reactive support is necessary with nearly one-third (1/3) in the form of new shunt requirement (most at Buchanan 230kV bus) and the other two-thirds (2/3) obtained by switching-off the shunt reactors in Bruce and Longwood substations (Table 3.3). The manner in which this can be achieved is extremely important for avoiding voltage collapse; which in turn will depend upon the precontingency loading levels.

The power-flow plot for this contingency is shown in Figure 3.2. The Longwood-Nanticoke S/C 500kV line is loaded to a bit more than 100% Rate-B (current basis). All bus voltages (500kV and 230kV) are within the criteria limits. The voltages at Nanticoke and Longwood are constrained by the 1.1pu bus voltage limit at the

sending end of the series capacitor bank (see bus#6441 in Figure 3.2) on the Bruce-Longwood line. Due to the lower voltage at Nanticoke 500kV bus, two of the synchronous condensers are not fully loaded.

**Table 3.3 Additional Reactive Support
for the Double Contingency of Willow Creek – Milton**

ADDITIONAL SHUNTS FOR BRUCE-MILTON D/C OUT				
BUS				
#	NAME	KV	MVAR	
7100	BUCHANAN	220	500	
7110	SEAF B22	220	15	
7111	SEAF B23	220	20	
7138	EDGEW 44	220	50	
7139	EDGEW 45	220	50	
7197	TALBTW36	220	30	
		TOTAL	665	
CHANGES IN SWITCHED SHUNTS				
1671	LENX T52	27.6	148.2	REACTOR OFF
6908	BRUCET25	27.6	147.3	REACTOR OFF
6909	BRUCAT27	27.6	147.6	REACTOR OFF
6910	BRUCAT28	27.6	147.6	REACTOR OFF
7686	LONGWDT3	27.6	142.6	REACTOR OFF
7687	LONGWDT4	27.6	142.6	REACTOR OFF
7688	LONGWDT5	27.6	142.6	REACTOR OFF
7689	LONGWDT6	27.6	142.6	REACTOR OFF
7690	LONGWDT7	27.6	141.8	REACTOR OFF
7772	WOODSTOC	27.6	-19.8	CAPACITOR OFF
		TOTAL	1283.1	
	NET MVAR		1948.1	

3.2.2 Willow Creek Junction to Milton Single Circuit and Longwood-Nanticoke (n-2) Outage:

As noted earlier, this double contingency from the base case results in NC power flow solution. The single circuit 500kV line from Longwood to Nanticoke is a very critical element within the main 500kV loop being considered for series compensation. A second outage coupled (simultaneous or subsequent – but nevertheless overlapping) with this critical line outage should not cause voltage collapse. The NC condition for this particular double contingency requires remedy. Several trials of OPF run with ability to add shunt compensation at 500kV and 220kV buses was not successful, indicating that it is difficult (if not impossible) to find

Figure 3.2 WILLOW CREEK JUNCTION– MILTON DOUBLE CONTINGENCY

(Please see next page)



an optimal shunt compensation and satisfy the voltage limits. It should be noted that the starting point is the base case power flow and hence, the changes noted in Table 3.3 are not included for this contingency testing.

The first remedy was to determine the shunt compensation requirements near Milton to make the power flow converge. A synchronous condenser was introduced at Milton (bus#4005) and the power flow was solved. The power flow plot is shown in Figure 3.3. As shown in this figure, nearly 2,500MVAR of reactive support is needed at Milton 500kV bus to maintain the indicated voltages. Approximate requirement for additional reactive requirement (for different amounts of series compensation on the Willowcreek Junction to Milton line) is shown below:

% Series Compensation	Additional MVAR Requirement
10	2,500
20	2260
30	2000
40	1500
50	1400

The above MVAR requirements are not necessarily optimized values.

In the base case, from Milton bus#4005 (MBYP560W) to Claireville (bus#4000) there is only one circuit. Whereas from Milton bus#4003 to Claireville (bus#4000) there are two circuits and in addition, there is a circuit towards Nanticoke whose synchronous condenser capacity is underutilized for this contingency. For the purposes of simulation of a sensitivity case, a bus-tie between bus#4005 and bus#4004(MBYP586W) was introduced and the power flow was resolved (reference case# 1-A). This reduced the reactive requirement to about 1,600MVAR (from nearly 2,500MVAR) at bus#4005. Further reduction in the MVAR (lower scheduled voltage at this bus) caused NC condition. Increasing the series compensation from 10% to 20% further reduces the shunt reactive requirement to 1,100MVAR. Further increase of series compensation to 30% reduces the reactive requirement to 950MVAR (reduction of about 150MVAR). If the 5 shunt reactors are switched-off at Longwood and the 500MVAR capacitor bank at Buchanan (see Table 3.3 for the earlier contingency) is turned on, then the reactive requirement at bus#4005 is only about 400MVAR (reference case# 1-A-1).

Instead of the above-tested bus-tie, another possibility is to of introduce a bus-tie between Milton bus#4005 to bus#4003 (reference #1-B). The reactive requirement is about 1,500MVAR at bus#4005, a reduction of 100MVAR due to flow over 3 circuits from Milton to Claireville instead of 2 circuits in the previous case. Further reduction in the MVAR (lower scheduled voltage at this bus) caused NC condition.

**Figure 3.3 WILLOW CREEK JUNCTION– MILTON and LONGWOOD –
NANTICOKE CIRCUIT OUTAGES**

(Please see next page)

4.0 Q-V CURVES:

The power transfer limits based on steady state limit is addressed in section 4.5.1 of IMO Transmission Assessment Criteria. As per this criterion, the maximum allowable power transfer limit is defined as 10% below (margin) the knee-point of the P-V Curve. Meeting this 10% margin will be demonstrated indirectly through a new power flow case and contingency analyses, rather than drawing a plethora of P-V or Q-V curves.

In the new power flow case the power transfer from Bruce to Claireville from the base case will be increased by 10% on the FABC interface. The flow in the old base case of 6,674MW (4x500kV and 4x230kV circuits from Bruce Complex) is increased to 7,342MW. The zonal native loads for East and Toronto were scaled-up from a total of 12,498+j5,989 to 13,027+j6,243 for this purpose. The additional generation required for this purpose was derived from one fictitious generator at Bruce generating station complex. Figure 4.1 depicts the power flow pattern for this new 110% transfer case. The new and old flows on the FABC interface are shown in Table 4.1. In the new transfer case, the line loadings on the 500kV and 230kV lines and corresponding bus voltages were within the normal limits.

**Table 4.1 FABC INTERFACE FLOW COMPARISON
BETWEEN NEW TRANSFER and BASE CASE**

						NEW TRANSFER CASE		OLD BASE CASE		DELTA	
FROM BUS			TO BUS			CKT ID	MW	MVAR	MW	MVAR	
6400	BRUCE A	500	6403	BRUJB560	500	1	1,430	68	1,277	4	153
6400	BRUCE A	500	6406	BRUJB562	500	1	1,483	(268)	1,321	(337)	162
6401	BRUCE B	500	6404	BRUJB561	500	1	1,639	174	1,483	95	156
6401	BRUCE B	500	6407	BRUJB563	500	1	1,479	(276)	1,338	(354)	141
6500	BRUCE A	220	6537	HANOVVB4	220	1	358	24	341	16	17
6500	BRUCE A	220	6538	HANOVVB5	220	1	360	25	343	18	17
6500	BRUCE A	220	6555	WINGJB22	220	1	296	54	286	48	11
6500	BRUCE A	220	6556	WINGJB23	220	1	296	55	285	49	11
TOTAL							7,342	(144)	6,674	(461)	668
											317

4.1 Single contingency:

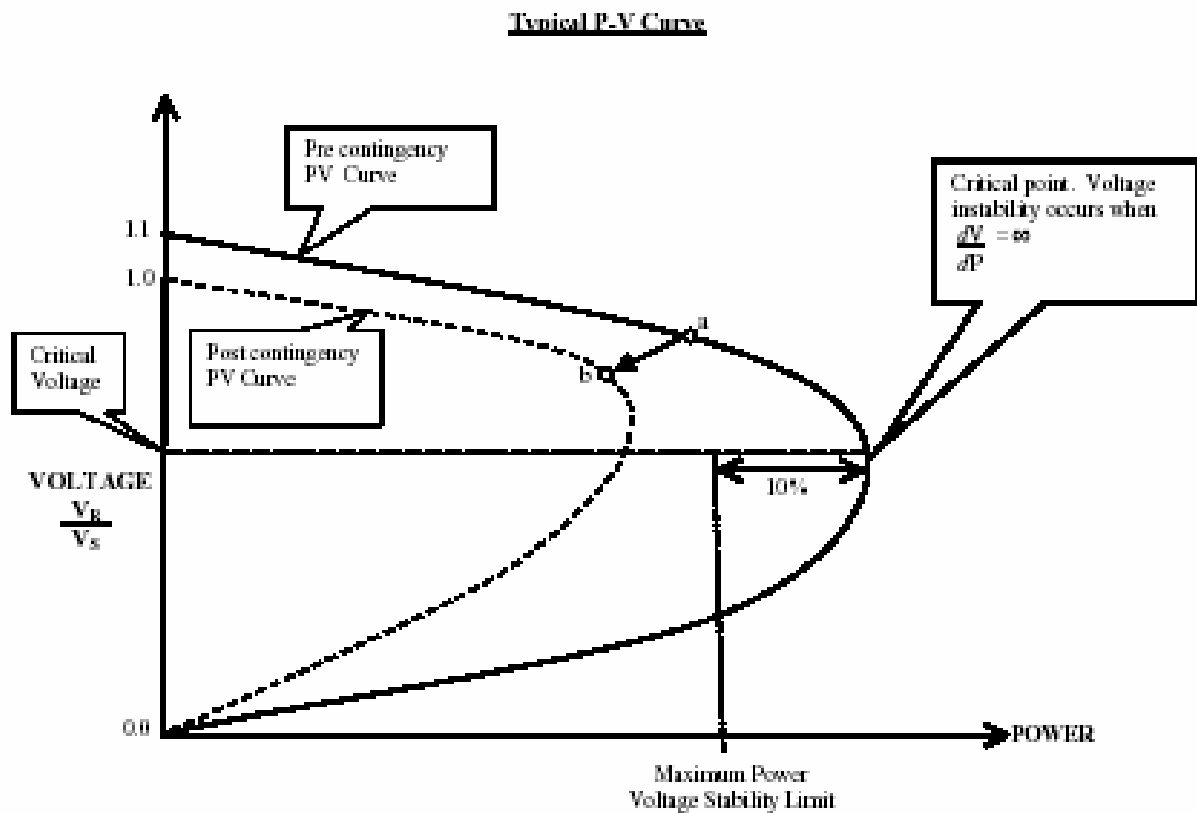
Then, 51 single branch (500 & 230 kV within area-1) contingencies, one at a time, were tested on the new transfer case. There were no non-convergent cases, which establish that the operating points for both the base case and the single post-contingency cases satisfy the requirement of Figure 4.2. Also, the inference is that at least 10% margin between the base case (100% transfer case) and the knee-point on the P-V curve exists. However, the amount of reactive power margin for the contingencies can only be established by Q-V curves.

Figure 4.1 POWER FLOW PLOT for NEW (110%) TRANSFER CASE

(Please see next page)



Figure 4.2 P-V Curves from IMO Transmission Criteria, Section 4.5.1.



For this purpose, Q-V curves for the base case and the three significant single contingencies (within the 500kV Main Loop) are shown in Figure 4.3. As can be seen from this figure, there is sufficient reactive power reserve (margin) for the base case and the Bruce-Milton 500kV S/C outage cases; whereas for the two remaining outages (Bruce – Long wood and Longwood – Nanticoke) the reactive power reserve is zero. As a second confirmation Q-V curves for the original base case with 100% transfer is shown in Figure 4.4. The reactive power margin difference between the 100% and the 110% transfer cases is about 200MVAR at Claireville 500kV bus. In other words, 10% margin on P-V curve is about 200MVAR reactive power margin on the Q-V curve. These two sets of Q-V curves indicate that the initial plan of 70% and 10% series compensation and 4 synchronous condensers is nearly an optimum set-up from steady state voltage collapse (or stability) requirements.

**Figure 4.3 Q-V CURVES for NEW (110%) TRANSFER CASE
BASE CASE & 3 CONTINGENCIES**

(Please see next page)

VOLTAGE COLLAPSE ANALYSIS

CLAIR-Q-FOR-SINGLE-CONTINGENCIES

* DENOTES CASE DID NOT CONVERGE

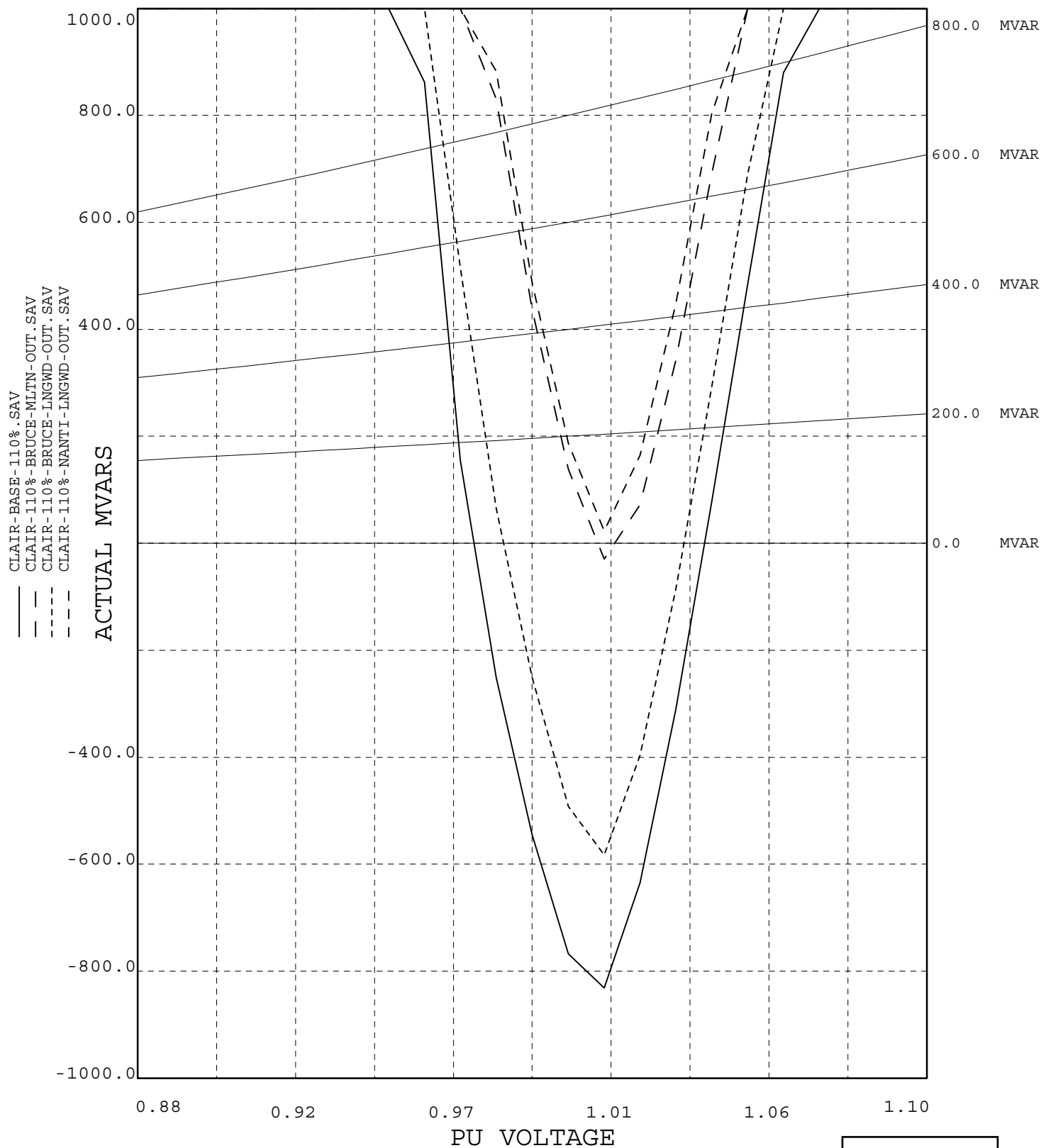


FIGURE 4-3

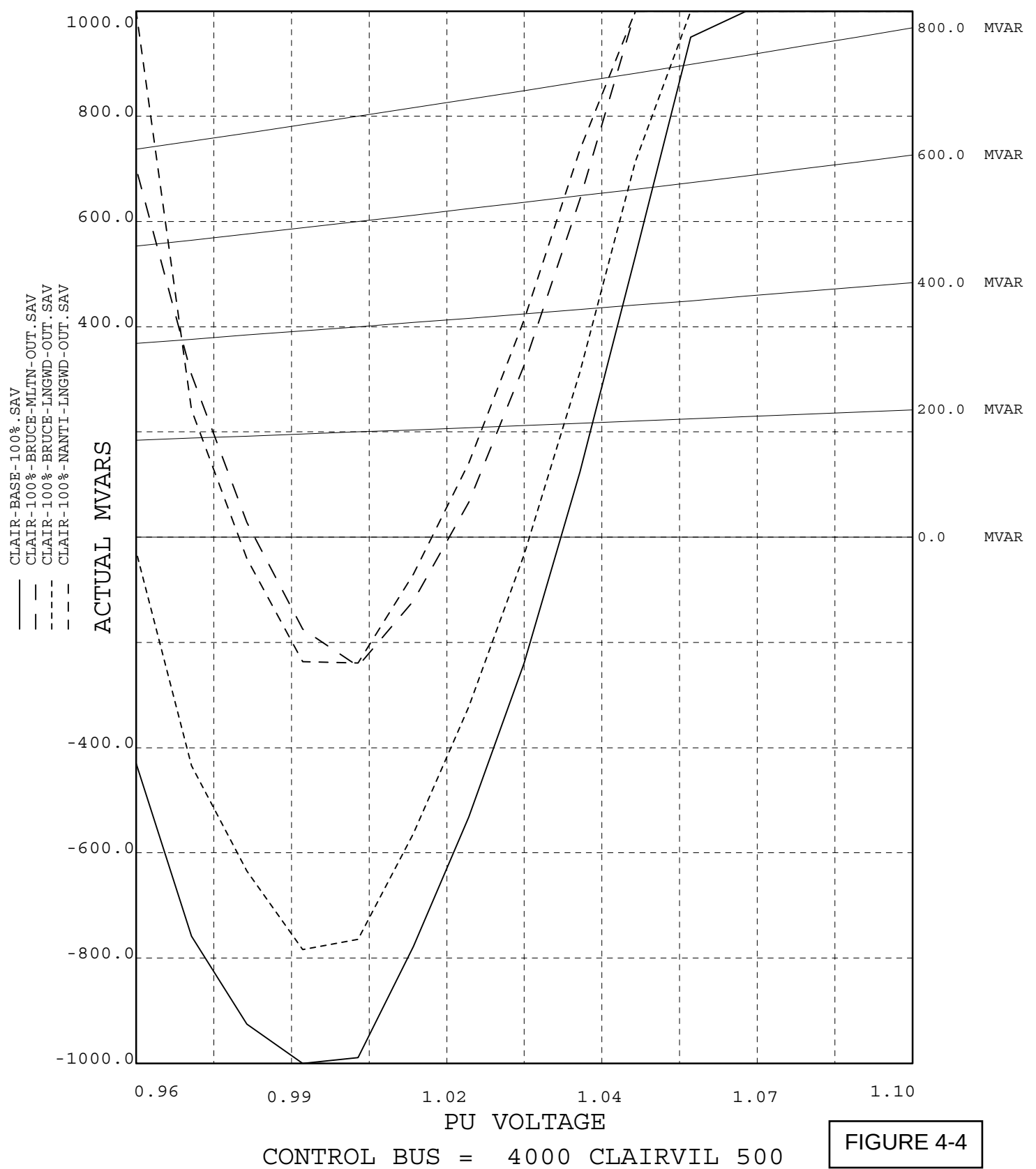
**Figure 4.4 Q-V CURVES for 100% TRANSFER CASE
BASE CASE & 3 CONTINGENCIES**

(Please see next page)

VOLTAGE COLLAPSE ANALYSIS

CLAIR-Q-FOR-SINGLE-CONTINGENCIES-100% TR

* DENOTES CASE DID NOT CONVERGE



4.2 Selected Double Contingency

The next step was to run the set of double contingencies involving the 500kV transmission lines. Out of the 8 double contingencies, the following two double contingencies (same as in the case of 100% transfer) resulted in NC condition:

- i) Outage of one circuit from Willow Creek Junction to Milton in combination with Outage of the single circuit from Willow Creek Junction to Longwood
- ii) Outage of one circuit from Willow Creek Junction to Milton in combination with Outage of the single circuit from Longwood to Nanticoke

Another contingency involving the D/C line from Willowcreek Junction to Milton did not converge.

For the remaining 5 double contingencies, there were no overloads or voltage violations. The Q-V curves for these specific three contingencies causing NC condition are shown in figures 4.5, 4.6 and 4.7 respectively. However, these curves are **based on the 100% transfer case**, because from the earlier section (110% transfer) the reactive margin was almost zero for a couple of single contingencies.

The Q-V curve in Figure 4.5 corresponds to the OPF solution discussed in section 3.2.1. There is about 180MVAR reactive margin at Claireville 500kV bus. However, the OPF run showed that the most desirable location for shunt support is at Buchanan 230kV substation. Hence, Q-V curve for this bus is shown in Figure 4.6. As can be seen in this figure, at zero MVAR line, the voltage is 1.12pu; near the maximum limit (1.136pu) set for OPF. Also, at 1.08pu voltage (200MVAR margin) the power flow did not converge. At this bus, in this solved power flow (by OPF) there is almost 400MVAR from the existing shunt (2x162.69MVAR) and the new shunt of about 500MVAR (Table 3.3) or almost 650MVAR at the maximum voltage limit. These two (existing and new) shunts total to about 1,000MVAR of shunt compensation.

To further establish or confirm that the reactive need is indeed in the 230kV part of the system in this area, Q-V curves for the nearby Detweiler 230kV bus are shown in Figure 4.7. The bottom curve (dashed line) corresponds to the same system condition as in Figure 4.6. With the shunts at Buchanan (and existing shunt at Detweiler), there is reactive margin of about 300MVAR at Detweiler bus. The top curve (solid line) is drawn for a case of no new shunt at Buchanan. In this curve, there is no reactive reserve margin or it is a case of voltage collapse confirming the double contingency result of section 3.2.1. Also, the difference between the two star points (power flow not-converged) is about 550MVAR which corresponds to the new shunt at Buchanan. The new shunt at Buchanan may be divided into two or more locations, with possibly a little bit more of total shunt compensation.

**Figure 4.5 Q-V CURVE at Claireville
for 100% TRANSFER & Bruce-Milton-D/C Outage**

(Please see next page)

VOLTAGE COLLAPSE ANALYSIS

BRUCE-MILTON-D/C-OUTAGE-100%TRANSFER

* DENOTES CASE DID NOT CONVERGE

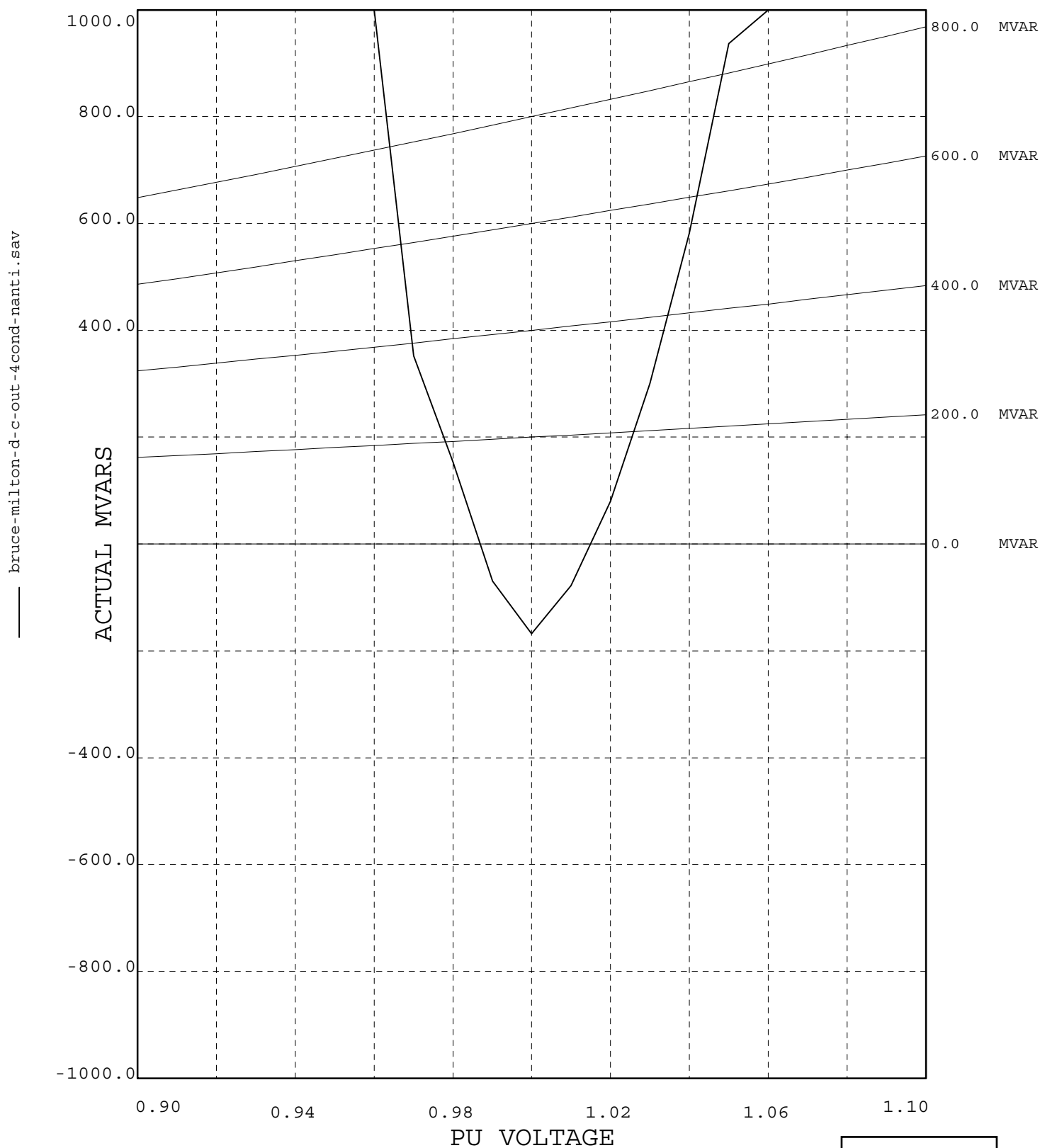


FIGURE 4-5

**Figure 4.6 Q-V CURVE at Buchanan
for 100% TRANSFER & Bruce-Milton-D/C Outage**

(Please see next page)

VOLTAGE COLLAPSE ANALYSIS

BUCHANAN-Q-V-BRUCE-MILTON-D/C-OUT

* DENOTES CASE DID NOT CONVERGE

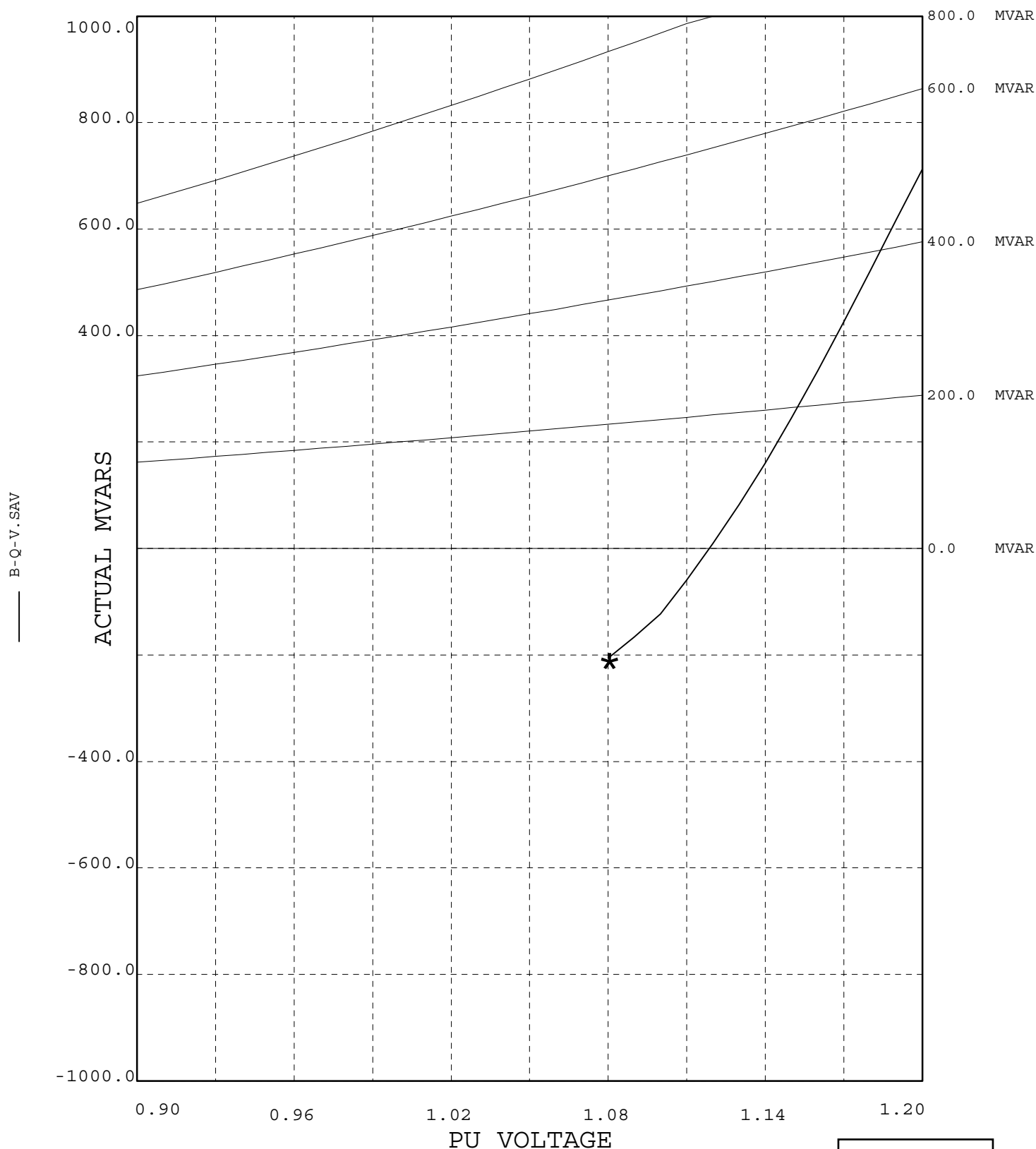


FIGURE 4-6

**Figure 4.7 Q-V CURVE at Detweiler
for 100% TRANSFER & Bruce-Milton-D/C Outage**

(Please see next page)

VOLTAGE COLLAPSE ANALYSIS

DETWEILER-Q-V-BRUCE-MILTOND/C-OUT

* DENOTES CASE DID NOT CONVERGE

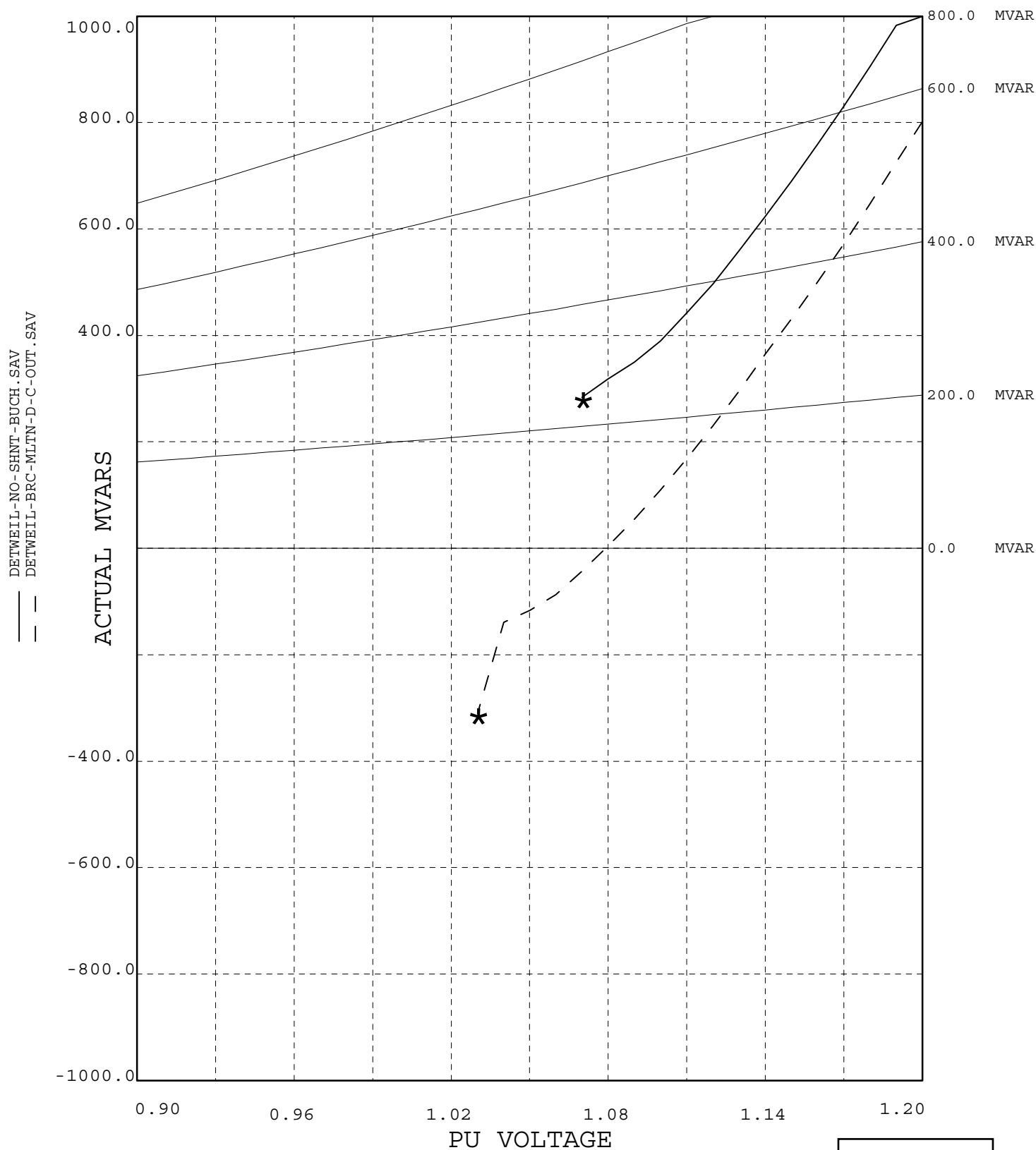


FIGURE 4-7

5.0 Sensitivity Power Flow Cases:

In the previous sections, the focus was on confirming that the proposed series compensation levels (70% and 10%) and 4 synchronous condensers (or equivalent shunt support) at Nanticoke would meet the power transfer needs as given in the base case. Also, any additions (in the form of shunt compensation requirements) or changes were identified. In this section, complimentary question of possibility (or impossibility) of reducing the series compensation levels and the shunt support will be examined.

5.1 Bruce-Milton D/C Outage:

The main reason for the high level of 70% series compensation on the Bruce-Longwood-Nanticoke 500kV lines is for the 500kV D/C tower outage from Willowcreek Junction to Milton. This is coupled with retirement/decommissioning of Nanticoke generation with possibility of converting 4 of the existing generators to synchronous condensers. Hence, the following two sensitivity cases were tested:

- i) Less number of synchronous condensers at Nanticoke
- ii) Reduced Series Compensation with increased Shunt Compensation

5.1.1 Synchronous Condensers at Nanticoke:

As noted in section 3.2.1, for the Bruce-Milton double contingency, two of the four synchronous condensers are very lightly loaded. Hence, these two synchronous condensers were taken out from the power flow and resolved by OPF. The resulting power flow plot is shown in Figure 5.1. All the voltages (500kV and 230kV) are within limits. It should be noted that the shunt adjustments shown in Table 3.3 are included in this case.

5.1.2 Reduced Series Compensation with increased Shunt Compensation

In this case, the series compensation on both the Bruce – Longwood circuits was reduced from 70% (0.0166pu on 100MVA base) to 50% (0.0119pu on 100MVA base). The compensation on the Longwood-Nanticoke remains at 70%. The solved power flow plot (through OPF) is shown in Figure 5.2. There were no overloads or voltage violations for the 500kV and 230kV buses. It should be noted that the shunt adjustments (a total of nearly 2,000MVAR) shown in Table 3.3 are included in this case. If the shunt reactors (about 700MVAR) at Longwood are not (or cannot be) switched-off, then 50% compensation case does not converge

The next step was to try reducing the series compensation on Longwood-Nanticoke single circuit from 70% (0.0146pu on 100MVA base) to 50% (0.010429pu on 100MVA base). The power flow plot for the solved case is shown in Figure 5.3. There were no overloads or voltage violations for the 500kV and 230kV buses. It should be noted that the shunt adjustments (a total of nearly 2,000MVAR) shown in Table 3.3 are included in this case as well.

As noted earlier in the report, the steady state power flow shows that the non-convergence is primarily due to voltage stability issues. Then the obvious question is trade-off between series vs shunt compensation (similar to the discussion in section 3.2.2). The OPF solution indicated that the reactive support is necessary in the Longwood area. Longwood 500kV bus is in the middle of the Bruce-Longwood-Nanticoke 500kV path (only path) upon D/C tower outage of Bruce-Milton 500kV circuits. Hence, the need for reactive support in the Longwood area is not necessarily a revelation to those who are familiar for the Hydro-One transmission system.

In the base case (70% series compensation) and in the sensitivity case (50% series compensation discussed in the above paragraphs) shows that these two series compensation levels, with proper shunt compensation, can be made to be feasible. For the purpose of further sensitivity evaluation, three different cases were tested as shown in the table below:

% Series Compensation	Additional MVAR	Location
0%	2,576	Longwood 500kV Bus
	125	Seaforth 118kV Bus
30%	1,803	Longwood 500kV Bus
40%	1,450	Longwood 500kV Bus

For these cases, a hypothetical synchronous condenser (with open Q-limits) was assumed at Longwood and the %series compensation was varied. In the first case, no series compensation was assumed (actually set to 1/100th of the base case value) on the entire Bruce-Longwood-Nanticoke 500kV path. The power flow did not converge. Through a few trials using OPF, about 125MVAR of reactive support at Seaforth (118kV bus#7306 in SWEST – Zone-8) resolved the problem. All the 500kV and 220kV bus voltages are within the limits for contingency. However, the 220kV lines from Bruce-Hanover-Orangeville are overloaded up to 135% (on current basis) and 115% on MVA basis. This becomes a thermal problem. Even though there is overload and the solved power-flow fails the contingency test, this condition establishes a reference of no-series compensation and maximum shunt compensation. Hence, power flow plot for this condition is shown in Figure 5.4.

In the second case, series compensation was increased (to 30%) until there was no overload on the Bruce-Hanover-Orangeville 220kV lines. The power flow case is shown in Figure 5.5. This case shows about 1,800MVAR reactive power need at Longwood bus. When the five shunt reactors (5x142.5MVAR) at Longwood were switched-off the reactive requirement is correspondingly reduced by about 700MVAR. The shunt reactors at Bruce and Lennox were left in-tact as in base case. The 500MVAR shunt capacitor at Buchanan 220kV bus, shown in Table 3.3, was also not included in this case. There was no need for additional reactive support at Seaforth.

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**Figure 5.1 WILLOW CREEK JUNCTION– MILTON DOUBLE CONTINGENCY
With only 2 Synchronous Condensers at Nanticoke**

(Please see next page)

**Figure 5.2 WILLOW CREEK JUNCTION– MILTON DOUBLE CONTINGENCY
With 50% Compensation on Bruce – Longwood 500kV Lines**

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**Figure 5.3 WILLOW CREEK JUNCTION– MILTON DOUBLE CONTINGENCY
With 50% Compensation on Bruce – Longwood 500kV Lines and
The Longwood-Nanticoke Line**

(Please see next page)

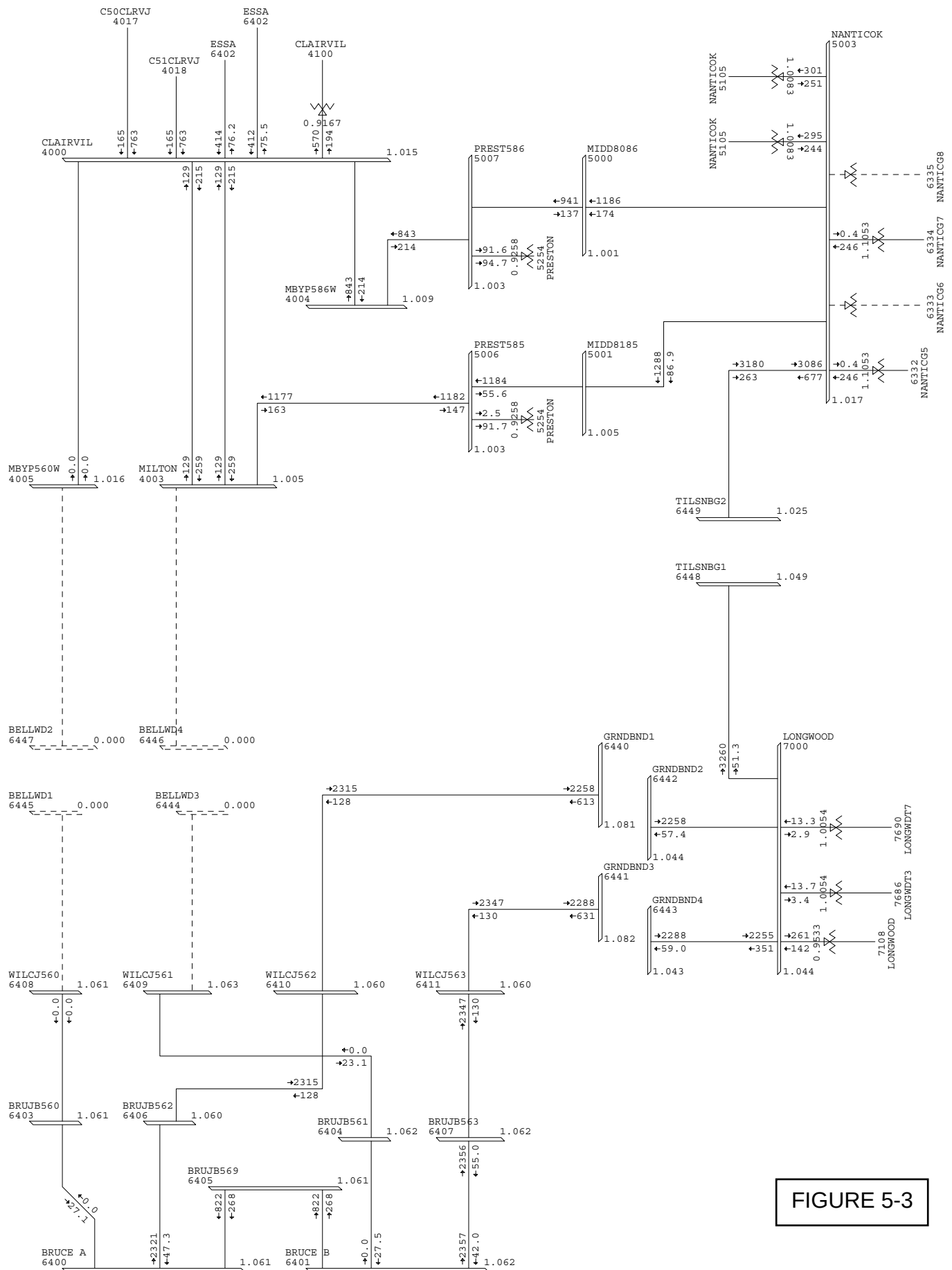


FIGURE 5-3

**Figure 5.4 WILLOW CREEK JUNCTION– MILTON DOUBLE CONTINGENCY
No Series Compensation on Bruce – Longwood 500kV Lines and
Longwood-Nanticoke Line**

(Please see next page)

**Figure 5.5 WILLOW CREEK JUNCTION– MILTON DOUBLE CONTINGENCY
30% Series Compensation on Bruce – Longwood 500kV Lines and
Longwood-Nanticoke Line**

(Please see next page)



This case of 30% series compensation and about 1,100MVAR shunt compensation represents a good trade-off between these two types of compensations for resolving both the thermal overload and voltage collapse conditions. If the series compensation is increased to 40%, the shunt reactive requirement will be further reduced by about 350MVAR.

5.2 Higher Voltage at Series Capacitor Buses:

In the base case (section 2.2) and other contingency cases, the maximum 500kV bus voltage limit was set at 1.1pu (550kV) for the OPF solution. However, if the series capacitors are located in the vicinity of the middle of each circuit, a higher voltage at these locations may be allowed depending upon the line insulation and design of the new series capacitor installation. For this purpose, a sensitivity case was run to determine the benefits from allowing a higher voltage. In this sensitivity run, the maximum limit for the 10 bus voltages for the 5 series capacitor locations (bus# 6440 – 6449) was set at 1.2pu in the OPF solution. Power flow plot for the main 500kV transmission loop is shown in Figure 5.6. As a reminder, 70% and 10% series compensation is assumed – same as in the original base case. There were no over loads on the 500kV and 220kV transmission lines and the 500kV and 220kV bus voltages are within the base case limits.

As compared to power flow plot in Figure 2.1, there is a higher voltage profile across the system in this sensitivity case. Specifically, the 500kV bus voltages at Bruce Complex are about 3% higher (almost 1.1pu) in this sensitivity case. The voltage at series capacitor bus (see bus#6441 – the most limiting bus) is higher by about 2%. The higher voltage profile reduces the losses to 929.4MW & 12,902MVAR as compared to 995.6MW & 13,865MVAR (for Figure 2.1).

In addition to the above base case, three additional contingency power flow cases were solved and significant points are noted below:

- i) Out of the contemplated 5 series capacitor locations, the highest possible voltage is 1.14pu at GRNDBND3 (bus#6441) for the S/C outage of the parallel circuit. A maximum continuous design voltage of 1.2pu (600kV) for the series capacitor installations would provide about 5% margin. Upgrading of line insulation for nearby towers may be necessary.
- ii) Due to higher voltage in the pre-contingency condition, double circuit tower outage of the Willow creek Junction-Milton line did not result in NC and thus did not require any additional shunt compensation of a total of 665MVAR shown in top half of Table 3.3.
- iii) Double contingency involving two different circuit outages (Willow creek Junction – Milton and Longwood – Nanticoke 500kV circuits) required about 1,956MVAR of additional reactive support as compared to 2,479MVAR in the earlier case (Figure 3.3).

Figure 5.6 BASE CASE with Higher Voltage Limit at Series Capacitor Buses

(Please see next page)

Based on the above observations (#ii and iii), it can be concluded that allowing a higher voltage at series capacitor locations (or operating the Bruce Complex at nearly the maximum bus voltage of 1.1 pu for the 500kV) will, at least, result in 500 – 600 MVAR reduction in reactive power requirements during the two most severe multiple contingencies.

5.3 Full External System Representation:

In the earlier sections, the U.S. part of the system (Zone-999) was equivalenced and the swing bus was within Ontario (area-1) at Beck. By locating the swing within area-1, additional power due to losses were made-up by the swing generator. In the actual case of an outage, the AGC within the control area would adjust the generation to maintain nearly the pre-contingency flows on the tie-lines to the external system. Thus the contingency analyses results, in the earlier sections, represent the longer-term post-contingency situation fairly well. However, before the AGC action most of the additional power requirement (immediately after contingency, but in steady state) may come from the external system. If this inter-tie power flow becomes large, it may cause other problems including non-convergence and precipitate voltage collapse. For evaluating any such possibility, in this section, the equivalents are replaced by the full US system. The system swing bus is moved out of Ontario (area-1).

In the base case, the system within Ontario is same as the OPF solved base case of section 2.0. Some minor adjustments were made. The power flow was solved for the full system. All the inter-tie power flows are almost the same as those listed in Appendix-A. The power flow plot for the main 500kV transmission loop is shown in Figure 5.7. Comparison of this plot with Figure 2.1 (Base Case with equivalents), shows that all the flows (within a few MWs) and bus voltages (within 0.1 to 0.2%) are very close. Because the small difference in voltage levels (and profile) across the area-1 system and the system swing being outside the area-1 (i.e. located in US), the losses are a bit higher as shown below:

	P (MW)	Q (MVAR)
BASE CASE- FIGURE 2.2	996	13,865
BASE CASE- FIGURE 5.7	1,004	13,956

5.3.1 Willow Creek Junction to Milton Double Circuit Tower Outage

The next item was to test one of the critical contingencies. As in the earlier case (section 3.2.1), this double contingency (considered n-1 because of tower outage) resulted in non-convergence of the power flow. Then the changes for shunts noted in Table 3.3 were included until the power flow contingency case converged. With switching-off of the shunt reactors alone (bottom half of Table 3.3) or with further addition of shunt capacitor at Buchanan, the power flow did not converge. However when all the shunt changes (as per Table 3.3) were made, the power flow converged. The power flow plot for this condition is shown in Figure 5.8.

Figure 5.7 BASE CASE with Full U.S. System Representation

(Please see next page)

**Figure 5.8 WILLOW CREEK JUNCTION– MILTON DOUBLE CONTINGENCY
with Full U.S. System Representation**

(Please see next page)



The Longwood – Nanticoke 500kV S/C line is loaded to 101% of its Rate-B (current basis); which is same as in section 3.2.1.

The voltage at the series capacitor locations on the Bruce – Longwood circuits is above 1.1. In this case, OPF was not used to constrain the voltages, whereas the plot in Figure 3.2 represents post-OPF results. The difference in voltage levels between these two cases results in different amount of losses as shown below (this is included here just for informational purposes):

	P (MW)	Q (MVAR)
CONTINGENCY CASE - FIGURE 3.2	1,472	16,520
CONTINGENCY CASE - FIGURE 5.8	1,427	16,015

Also for the new condition in Figure 5.8, the system swing being outside area-1, the higher losses (about 423MW) in area-1 in the post-contingency condition (no internal adjustments to output from the area-1 generators) are made-up from US. The intertie power flows are shown in Appendix-E. Comparison of these tie line flows with the base case conditions (Appendix-A) shows that about 65MW (=669 – 604) increase in import from ITC (PAR angles not adjusted from base case), 323MW (=1711 – 1388) from NYISO and the remaining 34MW from western interconnections. Also, from the base case (Figure 5.7) to the contingency case (Figure 5.8) there is about 2,000MVAR increase in reactive losses. As expected almost all (1,850MVAR) of it is made-up from internal resources within area-1.

5.3.2 Willow Creek Junction to Milton Single Circuit and Longwood-Nanticoke (n-2) Outage:

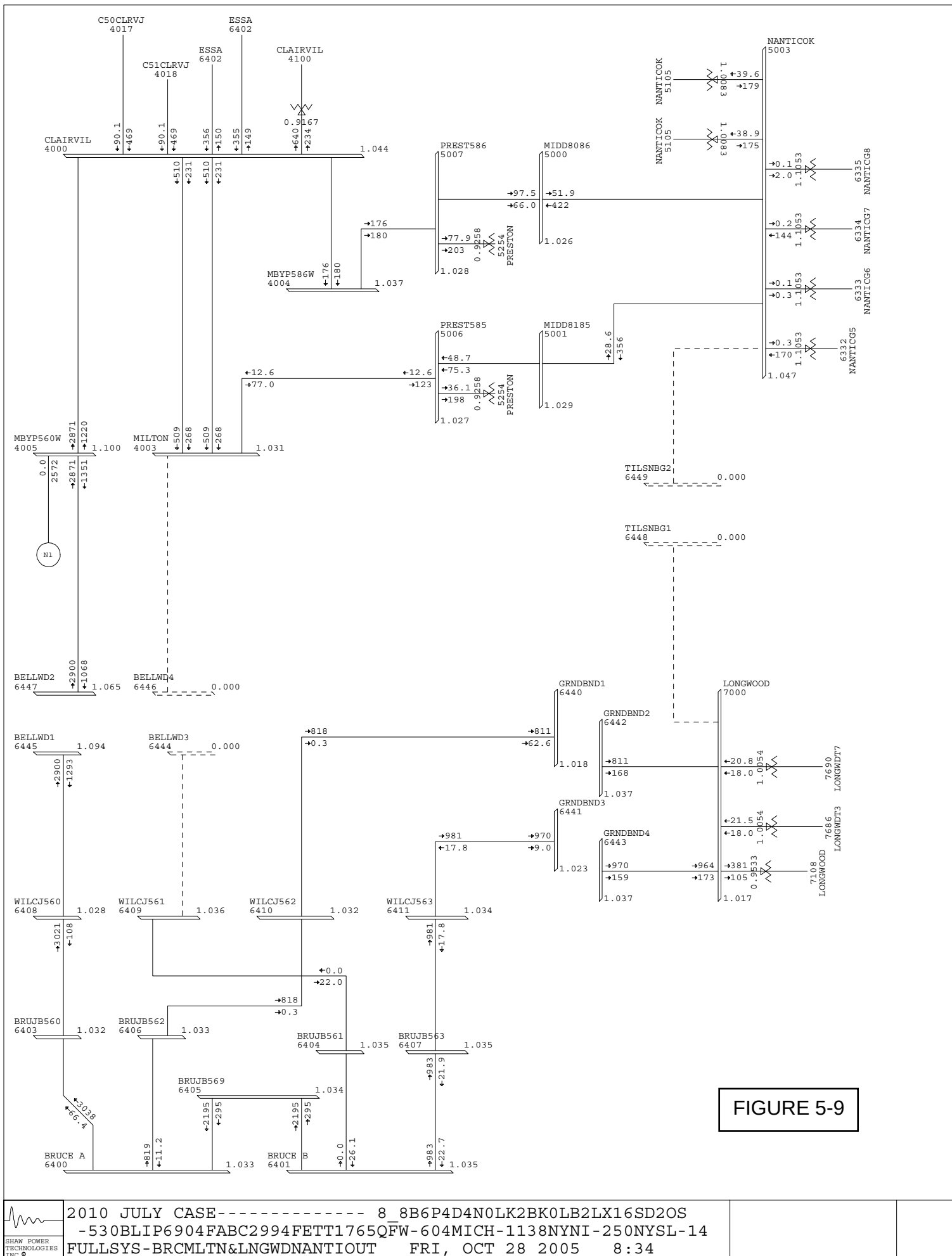
This is a truly double contingency involving two separate 500kV circuits which resulted in non-convergence. Resolution of this NC condition is discussed in the earlier section 3.2.2. In this new section, the equivalent external system was replaced by the full system and the power flow was resolved. The power flow plot for this condition is shown in Figure 5.9. The additional reactive support required at Milton (bus#4005) is about 100MVAR (Figure 5.9) more than what is shown in Figure 3.3 (with equivalent external system)³. The 500kV voltages are a bit lower (less than 1%) in Figure 5.9 when compared to Figure 3.3. OPF was not used here to adjust voltages. The difference in voltage levels between these two cases results in different amount of losses as shown below (this is included here just for informational purposes):

	P (MW)	Q (MVAR)
CONTINGENCY CASE - FIGURE 3.3	1,256	17,080
CONTINGENCY CASE - FIGURE 5.8	1,269	17,217

³ Even with the newly introduced (hypothetical) synchronous condenser at Milton (bus#4005); the dispatch voltage had to be increased to make the power flow converge.

**Figure 5.9 WILLOW CREEK JUNCTION– MILTON and LONGWOOD –
NANTICOKE CIRCUIT OUTAGES
with Full U.S. System Representation**

(Please see next page)



Also, for the new condition in Figure 5.8, the system swing being outside area-1, the higher losses (about 252MW) in area-1 in the post-contingency condition (no internal adjustments to output from the area-1 generators) are made-up from US. The intertie power flows are shown in Appendix-E. Comparison of these tie line flows with the base case conditions (Appendix-A) shows that about 232MW (=604 – 372) decrease in import from ITC (PAR angles not adjusted from base case), 458MW increase (=1711 – 1388) from NYISO and the remaining 36MW from western interconnections. Also, from the base case (Figure 5.7) to the contingency case (Figure 5.9) there is about 3,350MVAR increase in reactive losses. As expected nearly 3,000MVAR of it is made-up from internal resources within area-1.

5.3.3 HIGHER IMPORT FROM ITC

In the base case, the import from ITC was fixed at 604MW. A question was raised regarding the ITC import limit with the proposed compensation levels. Because the most limiting contingency is the D/C tower outage (considered n-1) of Willowcreek – Milton 500kV circuits, the higher import is determined for this specific contingency. There are many different ways of evaluating higher transfer limits. The load in area-1 can be increased, generation decreased or a combination of these two variables. However, these would change many flow patterns, may cause different overloads, under or over-voltages etc. In order to keep the internal (to Hydro-One) system conditions, both the generation and load levels within area-1 were left unchanged from the base case. Then, it just becomes a case of how much of the additional power (423MW increased losses due to the contingency as in section 5.3.1) flowing from NYISO can be shifted to flow from ITC. The phase angles were changed to increase flow from ITC, iteratively. When the angle limits on PARs were reached, the power flow did not converge. The power flow solves (voltage stable or the operating point above the knee of the P-V curve) until the flow from ITC reaches 906MW. When the angles were increased further by one degree the power flow did not converge, but did not diverge (no blown-up message). In fact, addition of about 10MVAR shunt capacitor at one of the problem buses made this particular power flow condition solve, albeit with low voltages (0.84pu at bus#5938). Thus, the limit of import from ITC is less than 922MW from steady state voltage point of view.

The phase angle settings for the final solved power flow (with no other changes) for 906MW (increased from 669MW with original setting) from ITC are,

BUS NAME	FROM	TO	CKT ID	ANGLE (DEGREES)
J5D	7103	7104	PS	31
LAMB T78	7105	7113	51	42.2
LAMB L51	7112	7105	S4	42.5
19B3N PS	28948	29003	PS	47

It should be noted that all angles were increased by the same number of degrees, up to the limit, and there was no optimization of relative settings among these four transformer angles. The flows over the inter-ties are given in Appendix-E. The total

import into the area-1 is 2,470MW, which is about 60MW more than the corresponding original settings for the PAR angles. This may be attributed to higher losses, since the additional flow is shifted to further west. The power flow plot for this higher import from ITC is shown in Figure 5.10. The loading of the Longwood – Nanticoke 500kV S/C line increases to 105% of Rate-B. From the thermal loading point of view, the import limit from ITC (for the base case conditions i.e. for the given Bruce Complex generation dispatch), is about 670MW. For this condition the limiting contingency is Bruce-Milton D/C 500kV tower outage and the limiting element is Longwood – Nanticoke 500kV S/C line.

5.4 GENERATION TRIPPING for DOUBLE CONTINGENCY

Double contingency (n-2) involving Willow Creek Junction to Milton single circuit and Longwood-Nanticoke single circuit was addressed in section 3.2.2. Additional reactive power requirement of about 2,500MVAR was identified for making the power flow to converge for this contingency. For double contingency, generation and/or load tripping is an allowable action. In this section, the impact of generation units tripping for this double contingency is evaluated in terms of reduced reactive power support at Milton. However, it should be added that tripping the base loaded units, particularly nuclear units, is not commonly adopted (or advocated) practice.

In the first test, Bruce unit#6 was tripped and the power flow solved. The power deficit was made up by the assumed swing machine at Beck. To keep the comparisons on the same basis, the voltage at bus#4005 (Milton – hypothetical synchronous condenser) was not changed from the no generation trip case (see Figure 3.3 for reference). The reactive requirement was reduced to 2032MVAR (=2479 – 2032) i.e. reduction of 450MVAR for one unit tripping.

For the next step, two units (Bruce#6 & 5) were tripped. The second unit tripping reduced the reactive support by 280MVAR for the Milton hypothetical synchronous condenser. Generation rejection involving three nuclear base loaded plants may be excessive. But for documentation purposes, three units (Bruce#6,5 & 4) were tripped and the power flow case was solved. The reactive power requirement was reduced by about 175MVAR to 1,577MVAR from the Milton hypothetical synchronous condenser. In order to determine the minimum reactive power support at Milton bus (#4005), an OPF case was run. This showed a need for about 732MVAR from this bus. In this OPF case, the generator voltages were adjusted and also the voltages across the system was maintained as high and uniform level as possible to minimize losses. These are not permissible actions under the contingency testing requirements. Thus, the reactive value obtained from this OPF run basically means that a minimum reactive support of about 700+ MVAR is necessary under the best of the circumstances.

**Figure 5.10 HIGHER IMPORT FROM ITC
WITH WILLOW CREEK JUNCTION– MILTON and LONGWOOD – NANTICOKE
CIRCUIT OUTAGES and with Full U.S. System Representation**

(Please see next page)

6.0 Dynamics

A complete dynamics model was provided by IESO for this study. The pre-contingency condition is represented by the power-flow. The area-1 (Ontario) part of the system was replaced by the base case derived from the OPF solution (Figure 2.1). In the dynamics model, the transient gain for the four Nanticoke synchronous condensers was changed⁴ (see Appendix-F). Then a dynamic simulation without any disturbance was run for 10 secs duration. The system response was flat with no changes in various monitored quantities, indicating a steady state condition for the dynamics model.

Then, as per the requirements in section 2.7.1 of the IMO document⁵, the following types of disturbances were tested:

- d) A normally cleared three-phase fault on one 500kV circuit (main 500kV loop Bruce - Longwood – Nanticoke – Milton) – Faulted line outaged i.e. no reclosure.
- e) A normally cleared phase-to-phase-to-ground fault on different phases of a double circuit line (Bruce-Milton only); – both the faulted circuits outaged i.e. no reclosure.
- f) A delayed fault clearance for phase-to-ground fault on one 500kV circuit (main 500kV loop Bruce - Longwood – Nanticoke – Milton) – Faulted line outaged i.e. no reclosure.

The system should be stable (both angular and voltage stability), for the above three types of disturbances. Further, the voltage recovery should be as shown in Figure 6.1 (transient voltage sag criteria requirement, from the IMO document).

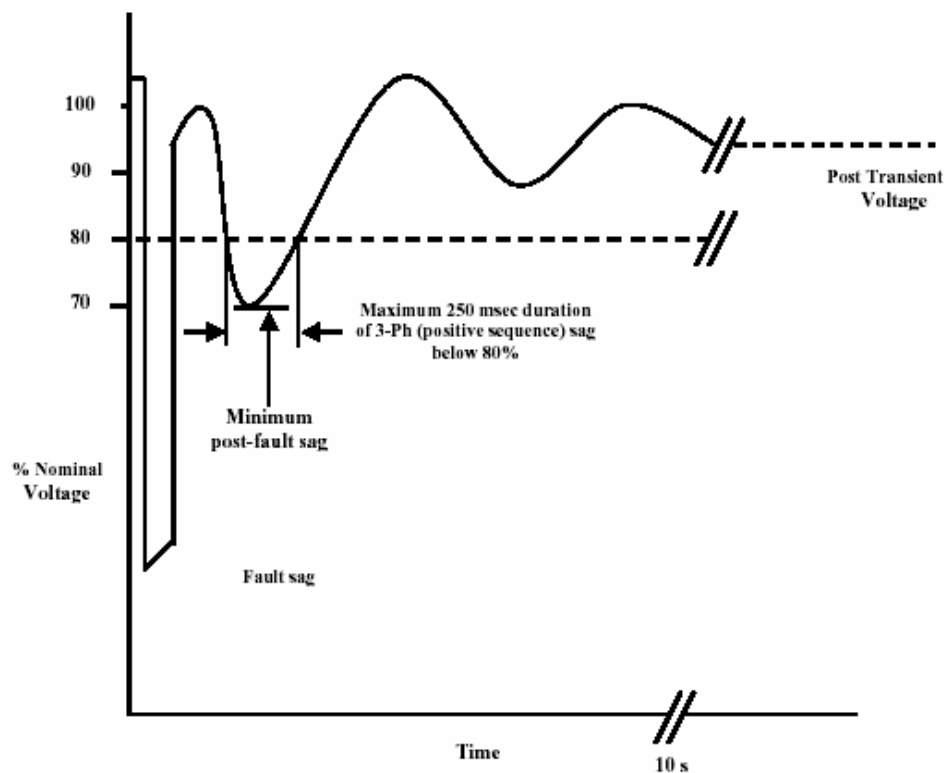
6.1 Normally-Cleared 3-phase faults:

For the purposes of this testing, fault clearing time of 6 cycles (0.1secs) is assumed. The clearing is simultaneous at both ends of the faulted circuit. These two are conservative assumptions as compared to the actual clearing times used for testing by IESO. If the system is stable for this condition, then it would be stable for faster and sequential clearing of the 3-phase faults. Another variable, with series compensated lines is by-passing the series capacitor during faulted period. First a set of dynamic simulations without by-pass will be performed. This will serve as a set of reference cases.

⁴ IESO Comment - The Nanticoke units are synchronous condensers so they have no stabilizer and governor and are round rotor generators with a high gain exciter. Without the stabilizers, the Nanticoke units are more oscillatory than we would like. The settings on the Nanticoke exciters will have to be changed.

⁵ IMO Transmission Assessment Criteria, IMO_REQ_0041, Issue 2.0, September 10,2003.

Figure 6.1 Transient Voltage Recovery from IMO Transmission Criteria, Section 4.4.



6.1.1 Simulations for No-bypass of Series Capacitors:

The following four disturbances were simulated for the normally cleared 3-phase faults (6 cycles – simultaneously at both ends):

- i) Bruce – Milton 500kV Circuit (fault at bus# 6409) – the circuit (B561M) with higher flow in Figure 2.1.
- ii) Bruce – Longwood 500kV Circuit (fault at bus# 6410) – the circuit (B563L) with higher flow in Figure 2.1.
- iii) Longwood – Nanticoke 500kV Circuit (fault at bus# 7000) – circuit B563L
- iv) Bruce – Claireville 500kV Circuit (fault at bus# 4000) – the circuit (B560V) with lower flow in Figure 2.1.

All the four simulations were stable and the monitored 500kV bus voltages were above 0.8pu. Various plots from these dynamics simulations are included in Appendix-G. Out of the above four disturbances, the 4th disturbance results in higher angle deviation and a relatively slower voltage recovery (see Figures 6.2 and 6.3 respectively – only the first 3 seconds of the simulation shown here).

Figure 6.2 BRUCE GENERATOR ANGLES for Normally Cleared 3-Phase Fault at Claireville on the Bruce - Claireville 500kV line (B560V).

(Please see next page)

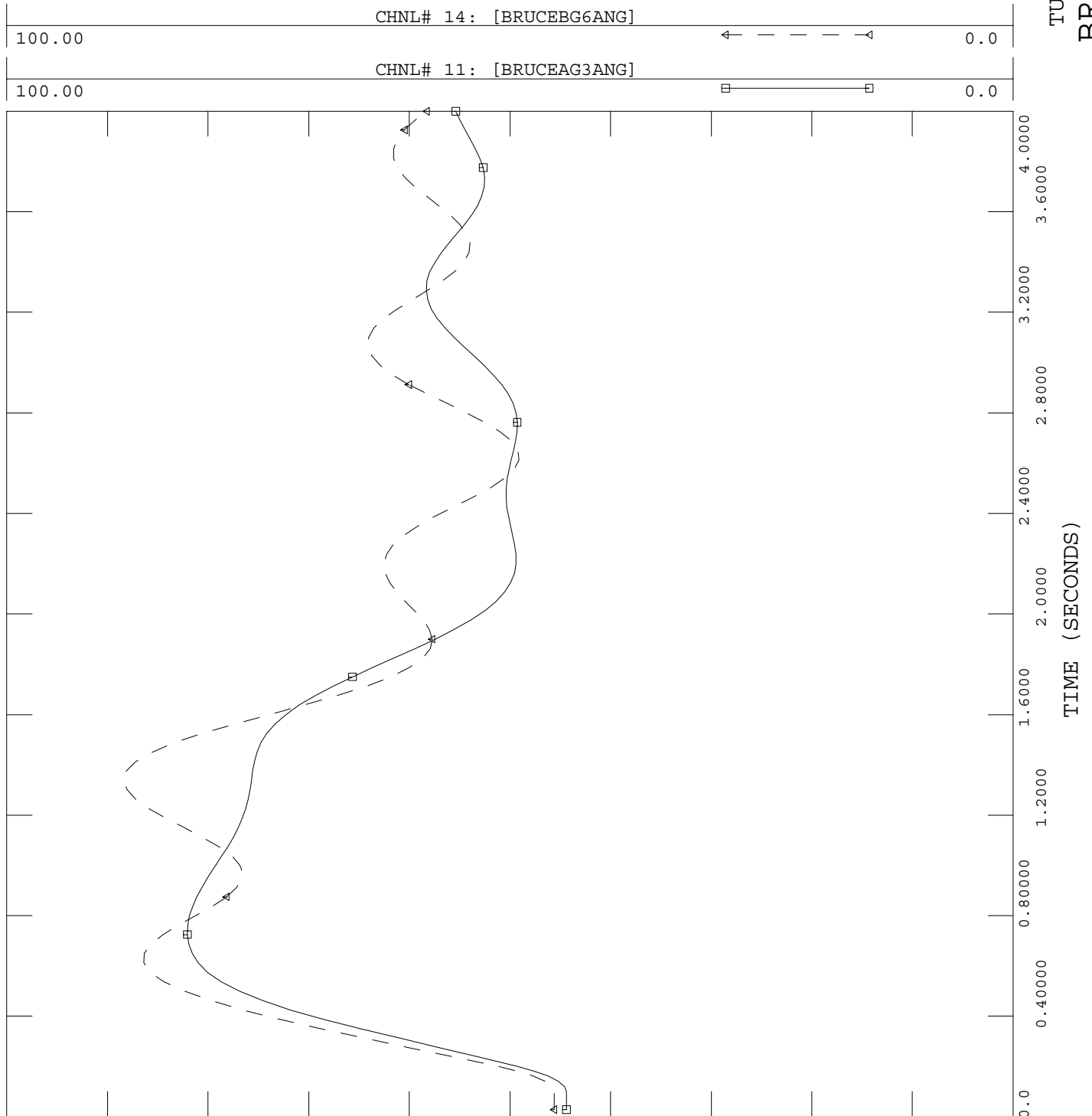
Figure 6.3 BRUCE GENERATOR ANGLES for Normally Cleared 3-Phase Fault at Claireville on the Bruce - Claireville 500kV line (B560V).

(Please see page after next)



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'

FILE: C:\HYDRO-ONE\...\3-PH-NO-BY-PASS\3PH-4000-4005-1.OUT



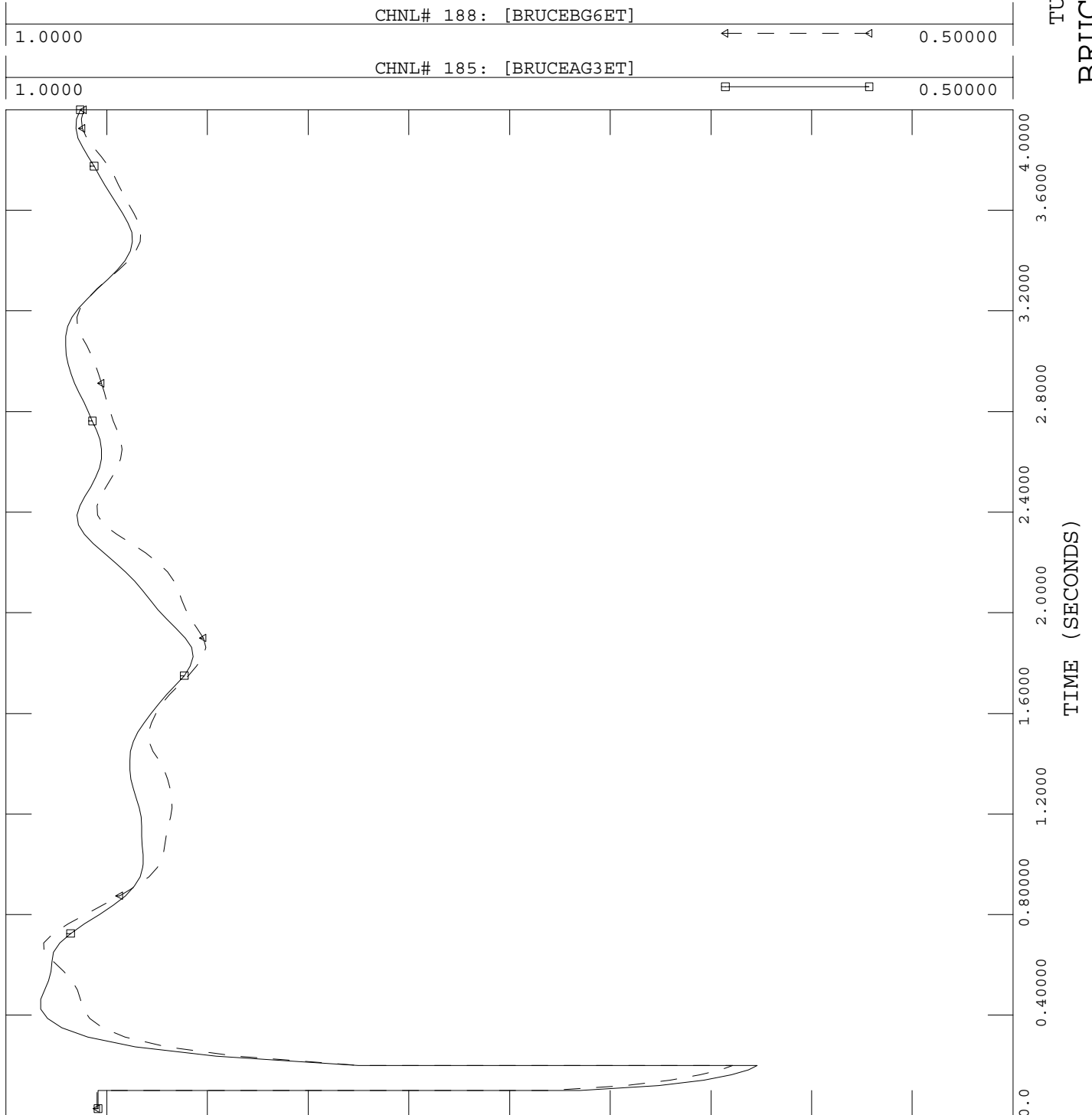
TUE, NOV 08 2005 11:26
BRUCE-GEN-ANGLES

FIGURE 6-2



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'

FILE: C:\HYDRO-ONE\...\3-PH-NO-BY-PASS\3PH-4000-4005-1.OUT



TUE, NOV 08 2005 11:30
BRUCE-TERM-VOLTAGE

FIGURE 6-3

The voltage recovery is also acceptable as shown (in Figure 6.3) by the Bruce generation terminal voltage. In these simulations, there was no switching out of the reactors shown in Table 3.3 (at Bruce, Lenox and Longwood). Also, the additional shunt capacitor for Buchanan was not included. This indicates that the system, with the proposed series capacitors, has sufficient dynamic reactive capability for single contingencies of the main 500kV transmission loop.

6.1.2 Simulations for with bypass of all Series Capacitors:

In general, by-passing the series capacitors should decrease the transfer capability (increase of the impedance) and increase the reactive losses. The increase in impedance may be detrimental to the angular stability and higher reactive losses may cause voltage instability. Hence, dynamic simulations with by-pass of capacitors are included in this section.

By-passing the capacitor for high voltages and currents is an effective method of protecting the series capacitors. Traditionally, a spark gap (gap length adjusted to the desired level of voltage protection) in parallel with the series capacitor has been used to provide protection. The variable nature of spark gap protection is well known. During the last 15 to 20 years, use of metal oxide arresters (MOV) has been applied for better protection. The arrester conducts above a threshold voltage, thereby by-passing the series capacitor⁶. The zinc-oxide varistor in the MOV arrester has a non-linear characteristic. For dynamic simulation, a special model needs to be incorporated into PSS/E dynamics system model. The actual settings for this model would be known only after design of series capacitor bank(s) is completed. However, for the purposes of this study, the impact of by-passing of all the capacitor banks, during the fault period will be determined.

Dynamic simulation for the same four contingencies, as in the previous section, was repeated. These simulations are based on conservative assumptions. Fault duration (6 cycles) is same as before. All the five capacitor banks were by-passed one cycle after the inception of fault and reinserted one cycle after clearing of the fault. In actual conditions, these would occur much faster than the assumed one cycle time. For these simulations, rather than actually by-passing the series capacitors, these were reduced to 1% of the respective values for the by-pass duration and reset to their original values for the remaining simulation period.

The dynamic simulation plots for these four contingencies are included in Appendix-G (Figures G-17 thru' G-32). Comparison of these plots with the corresponding plots of the previous section (Figures G-1 thru' G-16) show no major changes in system performance, except the voltage across the series capacitors being almost zero during the by-pass period. In a few cases, a bit slower damping of the oscillations (for example Nanticoke synchronous condenser for the contingency#1 – see top left plots in Figure G-2 vs Figure G-18) may be seen, but nothing very significant.

⁶ Spark gap may still be used to provide a back-up protection.

6.2 Simultaneous L-G faults:

The second type of disturbance is a normally cleared phase-to-phase-to-ground (LLG) fault, but on different phases of a double circuit line. In the main 500kV loop considered for series compensation, Bruce-Milton line is the only double circuit line. If this type of fault is at or very near a common bus (i.e. both circuits terminating at the same bus), then applying an LLG type of fault at this bus would be proper. However, for the two circuits of the Bruce-Milton line, the fault buses are #6408 (WILCJ560) and #6409 (WILCJ561). Applying L-G faults at these two buses would be two independent faults, but on the same phase. Applying an LLG fault on only one bus, would not represent a fault on the second circuit. The procedure used for applying this fault is discussed in Appendix-G. Because, these two faults are separate L-G faults, delayed fault clearing time of 10 cycles is used; a conservative assumption. For fault clearing, both the circuits are disconnected. Reactor switching-off and generation tripping are not used in this simulation, again a conservative assumption as compared to the present operating practice.

6.2.1 No By-pass of Series Capacitors:

In this first set of simulation for this type of fault, the series capacitors are not by-passed. This may be considered to be an optimistic assumption. Plots for this simulation are included in Appendix G (Figure G-33 thru' G-36). The system is stable (angular stability). The angle excursions are a bit more than the three phase fault case (compare top two curves for LLG in figure 6-4 with bottom two for 3-phase fault), mainly due to longer fault duration as well as fault on two circuits.

The voltage recovery is also a bit slower in this case, but acceptable (lowest 0.84pu after fault clearing), as shown by the generator terminal voltage in Figure 6-5.

In this simulation, the four wind farm generators at BAY_GE (Bus#s 6506 – 6509) tripped on undervoltage after 0.1833 secs from the instant of fault inception (Figure 6-6 for G1). This represents a loss of nearly 1000MW. The total time for undervoltage (0.7 or 0.75pu) tripping is 0.18sec in the model. As can be seen from this figure, the bus voltage does recover, but a bit late for the undervoltage relay setting. Faster clearing of fault, which is probably the case, should mitigate this problem. Another question that would arise is – If the said generator (of nearly 1000MW) did not trip, would the system be stable?

The answer to both questions was obtained by a simulation with normal fault clearing time of 6 cycles instead of the 10 cycles for Figure 6.6. There was no generation tripping and the system was stable. The new plot for the wind farm generator G1 (BAY_GE) is shown in Figure 6-6A, which clearly shows that the generator terminal voltage recovers to 0.75pu by 0.12secs (less than the UVLS setting) from the fault inception.

Figure 6.4 Comparison of BRUCE GENERATOR ANGLES for Normally Cleared 3-Phase Fault and LLG Fault on Bruce - Claireville 500kV line (B560V).

(Please see next page)

Figure 6.5 BRUCE GENERATOR Terminal Voltage for LLG Fault on Bruce - Claireville 500kV line (B560V) – No By-Pass of Series Capacitors.

(Please see page after next)

Figure 6.6 Bay Wind Farm Generator#1 Tripping for 10 Cycles LLG Fault on Bruce - Claireville 500kV line (B560V).

(Please see the 3rd following page)

Figure 6.6A Bay Wind Farm Generator#1 Tripping for 6 Cycles LLG Fault on Bruce - Claireville 500kV line (B560V).

(Please see the 4th following page)

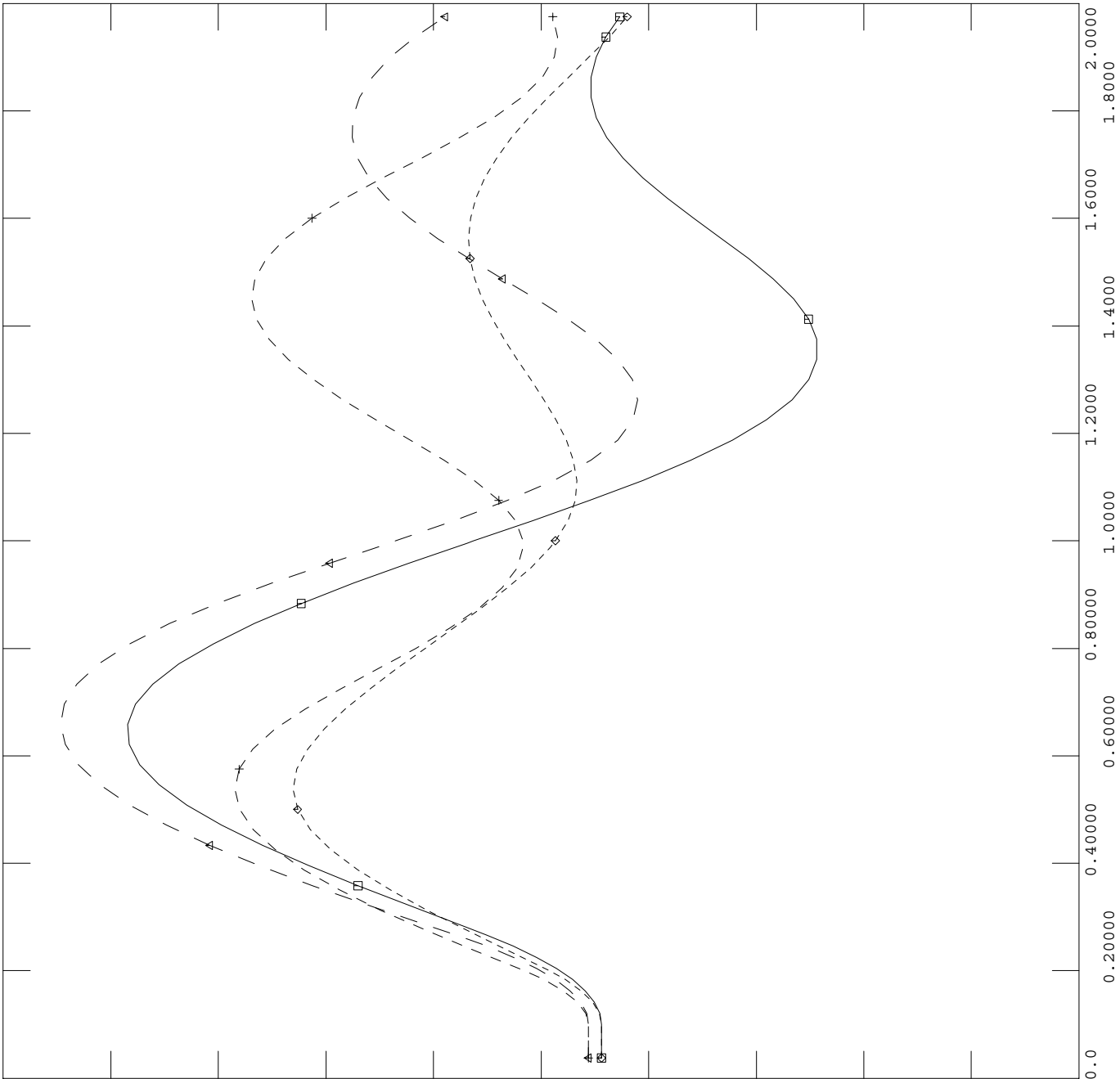
Figure 6.5A BRUCE GENERATOR Terminal Voltage for LLG Fault on Bruce - Claireville 500kV line (B560V) – With By-Pass of Series Capacitors.

(Please see the 5th following page)



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

CHNL# 14: [BRUCEBG6ANG]			
100.00	FILE:...\3-PH-NO-BY-PASS\3PH-6409-4003-1.OUT	+ - - - - +	0.0
CHNL# 11: [BRUCEAG3ANG]			
100.00	FILE:...\3-PH-NO-BY-PASS\3PH-6409-4003-1.OUT	◇ - - - - ◇	0.0
CHNL# 14: [BRUCEBG6ANG]			
100.00	FILE:LLG-6409-4003-1.OUT	← - - - - →	0.0
CHNL# 11: [BRUCEAG3ANG]			
100.00	FILE:LLG-6409-4003-1.OUT	□ - - - - □	0.0



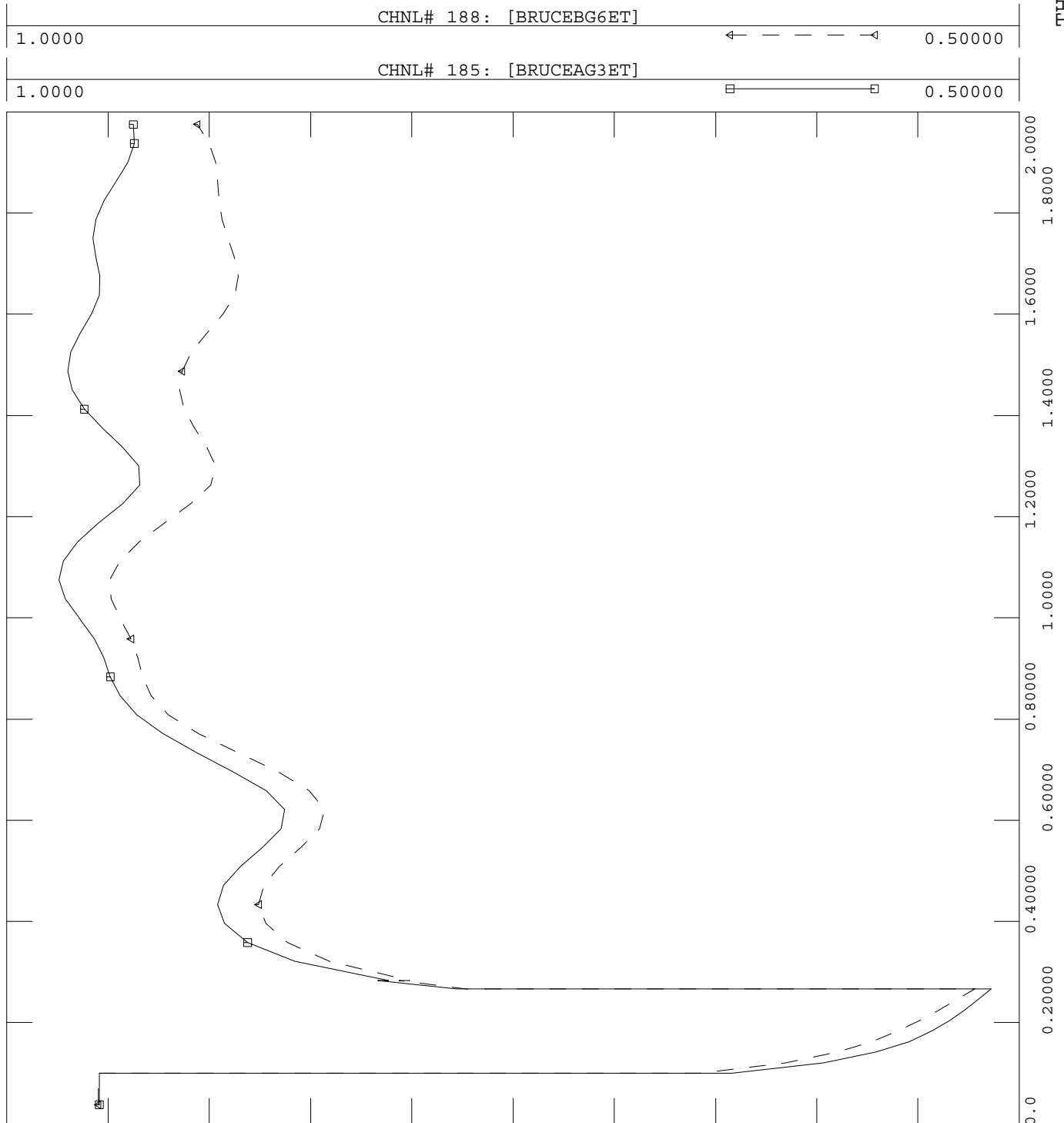
THU, NOV 10 2005 10:43
3-PH. VS LLG FAULT

FIGURE 6-4



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-L-G-FAULT-NO-BY-PASS\LLG-6409-4003-1.OUT



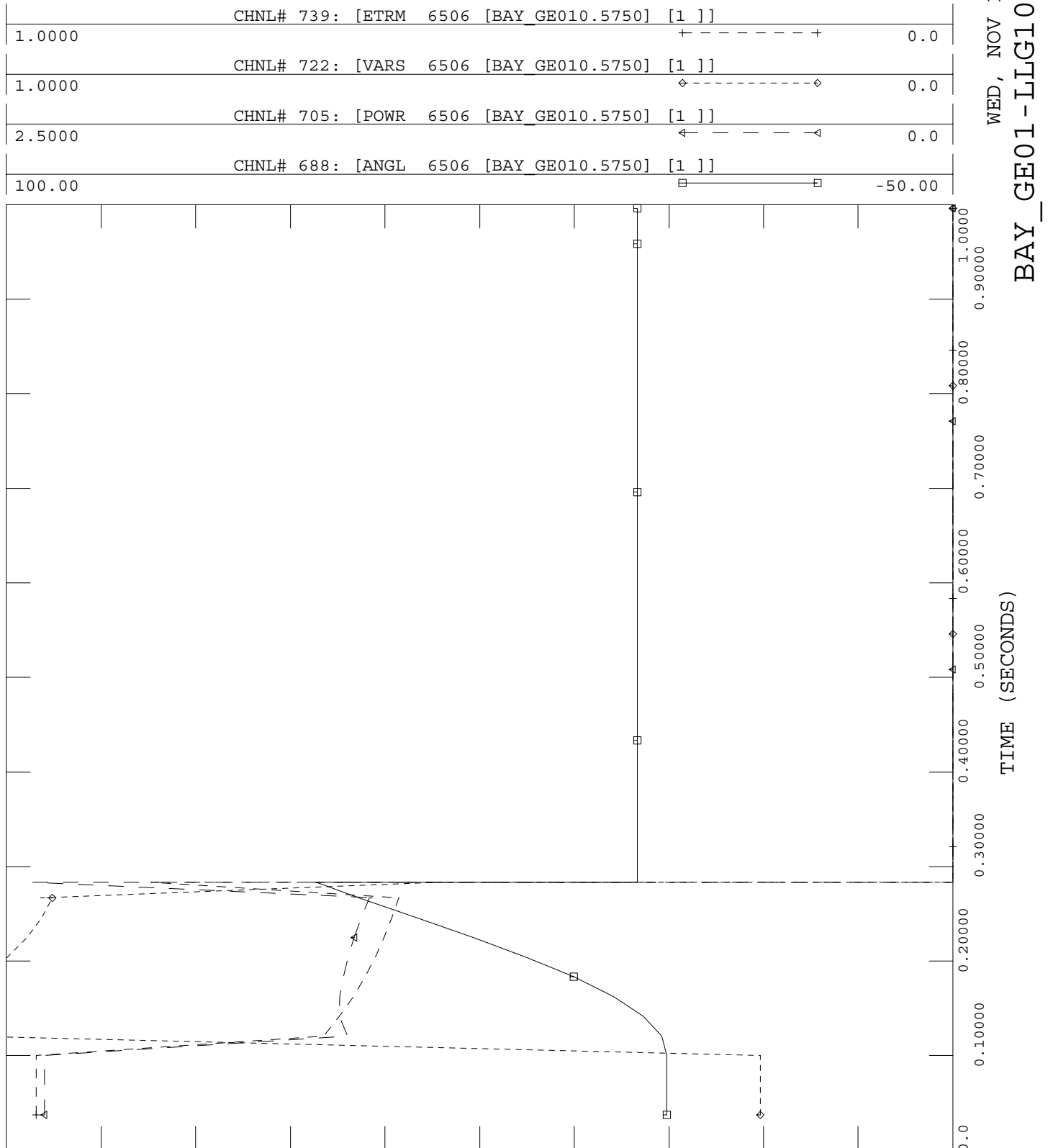
THU, NOV 10 2005 10:23
BRUCE-GEN-TERM-VOLTAGE

FIGURE 6-5



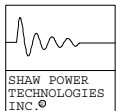
2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-L-G-FAULT-NO-BY-PASS\LLG-6409-4003-1.OUT



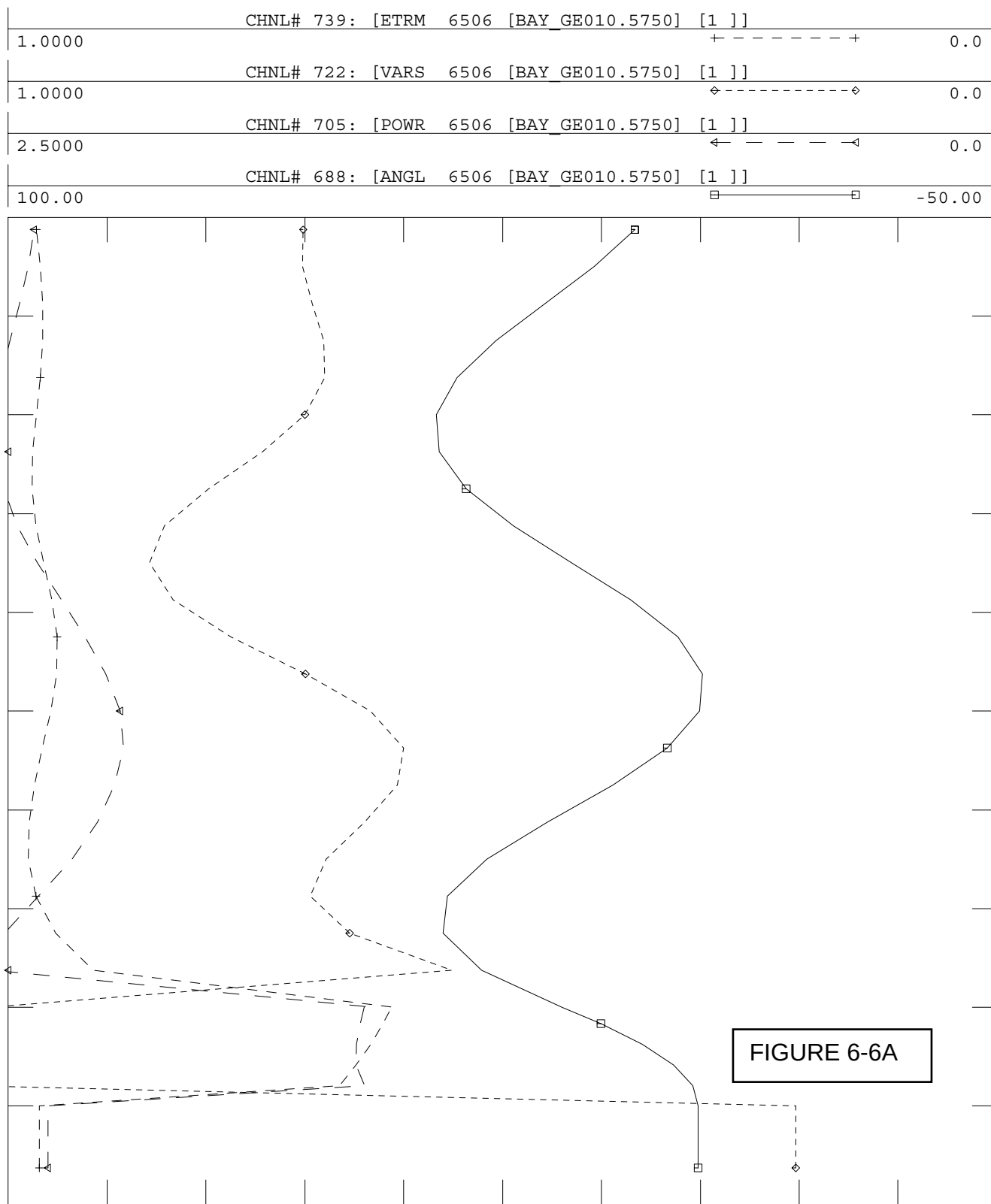
WED, NOV 16 2005 8:22
BAY_GE01-LLG10-GEN-TRIP

FIGURE 6-6

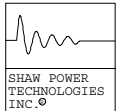


2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: LLG6-6409-4003-1.OUT

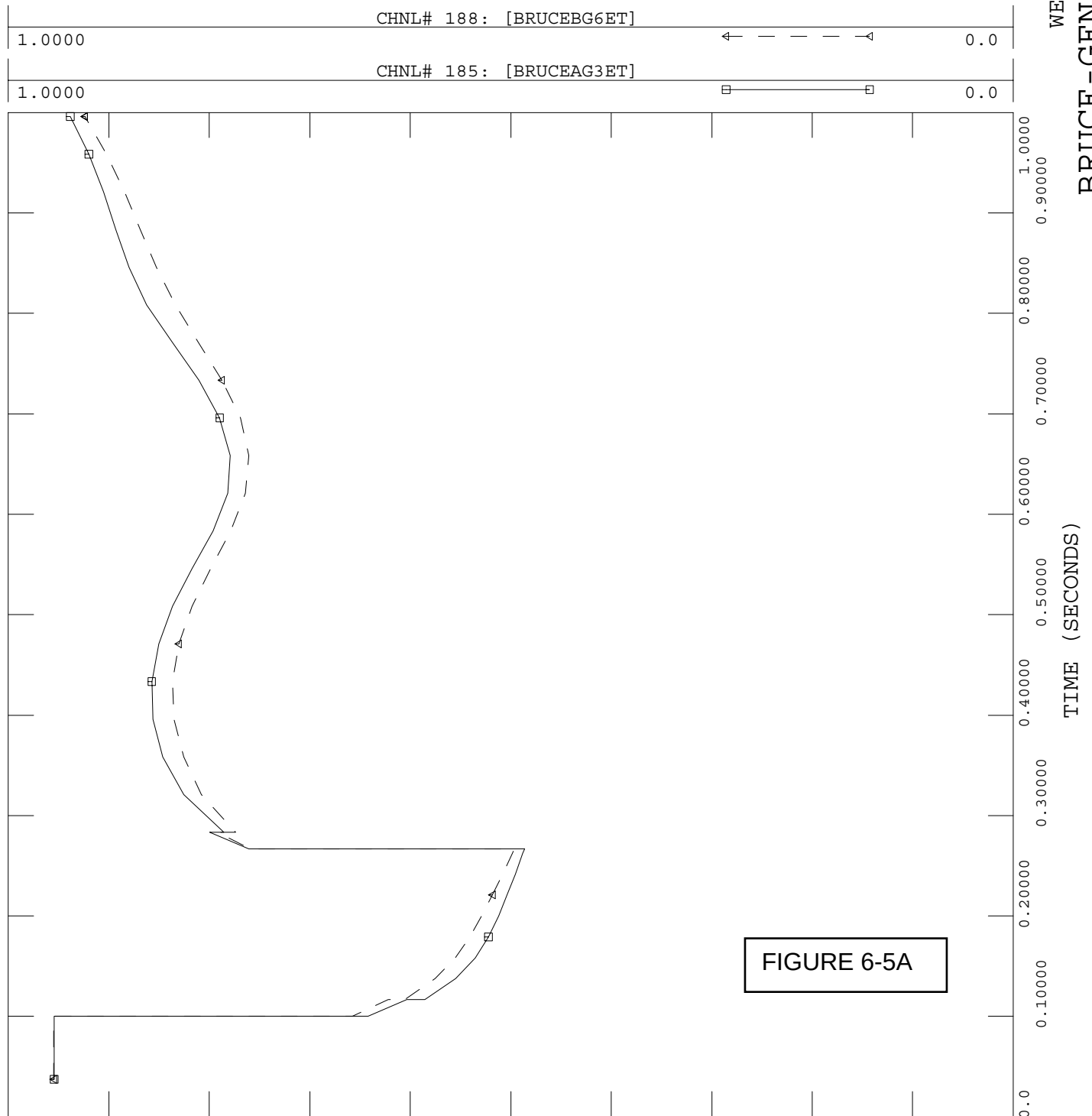


WED, NOV 16 2005 8:09
BAY_GE01, LLG6-NO TRIP



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-L-G-FAULT-BY-PASS\LLG-6409-4003-1a.OUT



WED, NOV 16 2005 10:02
BRUCE-GEN-VT-ALL-BYPASS

6.2.2 By-pass of All Series Capacitors:

During an unbalanced fault, magnitude of fault current in each phase (consequently the voltage drop in the corresponding series capacitor) would be different. Depending upon the voltage drop across the individual phase capacitors by-pass may occur for the fault duration. By-pass of the series capacitors – especially all the phases at all the 5 locations – is less likely as compared to the 3-phase fault case. However, in order to bracket the performance under the two extreme possibilities, by-pass of all series capacitors (same as in the 3-phase case) during this particular unbalanced fault was simulated. This is considered to be a pessimistic assumption.

Plots for this simulation are included in Appendix G (Figure G-53 thru' G-56). The angular swing is about 10 degrees more than the no by-pass case (Figures G-33 thru' G-56). However, the system is stable (angular stability). The voltage recovery is a bit slower in this case, but acceptable (below 0.8pu for about 180msecs – criterion is not to exceed 250msecs duration), as shown by the generator terminal voltage in Figure 6-5A.

As in the no by-pass case, in this simulation, the four wind farm generators at BAY_GE (Bus#s 6506 – 6509) tripped on undervoltage after 0.1833 secs from the instant of fault inception.

6.3 Delayed Clearing with L-G faults:

The third type of disturbance is a single-line to ground fault (L-G) with delayed clearing. The equivalent impedances ($Z_2 + Z_0$), shown below, were used for the simulations. The first two impedances (bus# 6409 & 6411) were provided by Hydro-One and these were calculated without the series capacitors.

BUS #	FAULT ADMITTANCE (MVA)		Fault Clearing Time (cycles)
6409	1,296	-9,533	10
6411	1,073	-10,305	10
7000	2,626	-15,813	10
4000	7,909	-24,632	11

For the last two buses (Longwood and Claireville bus# 7000 and 4000, respectively), the equivalent impedance values were not readily available. Hence, the equivalent impedance was estimated to cause approximately 0.6pu voltage at the faulted bus in the positive sequence network. The assumed fault clearing time for these four disturbances is also shown in the above table. These are about one-half to a cycle later than the data provided by Hydro-One. The fault impedance values, provided later by Hydro-One, were higher or the fault admittance was lower (about 17%) than the values assumed for these simulations (above table), again a conservative assumption.

6.3.1 No By-pass of Series Capacitors:

In this first set of simulation for this type of fault, the series capacitors are not by-passed. This may be considered to be an optimistic assumption. The plots from these four dynamic simulations are included in Appendix-G (Figure G-37 thru'G-52). For all the four L-G faults, the system was stable and voltage recovery satisfactory. There was no generator tripping specifically the one noted for the LLG fault (section 6.2.1). The voltage drop across the series capacitors, shown in this set of figures, for unbalanced faults represents only the positive sequence part. The actual voltage drop (or rise) across each individual phase capacitor is dependent upon the actual line (or phase) current.

6.3.2 By-pass of All Series Capacitors:

By-pass of capacitors in all the unfaulted phases and at all the 5 locations during the L-G fault period is less likely than in the case of more severe faults. However, in order to bracket the performance under the two extreme possibilities, by-pass of all series capacitors (same as in the 3-phase case) during this particular unbalanced fault was simulated. This is considered to be a pessimistic assumption.

The plots from these four dynamic simulations are included in Appendix-G (Figure G-57 thru'G-72). For all the four L-G faults, the system was stable and voltage recovery satisfactory. There was no generator tripping specifically the one noted for the LLG fault (section 6.2.1). As expected, the excursion of various quantities for all the four by-pass cases is more than the corresponding cases of no by-pass. For example, Bruce generator angle excursion is about 10 degrees more.

6.4 Sensitivity Cases:

The IMO criteria require that all stability limits should be shown to be stable if the most critical parameter is increased by 10%. The 10% margin for voltage stability (steady-state) was demonstrated in Section 4 by increasing the power transfer from Bruce Complex to Toronto area by 10%. For testing the transient stability, power flow condition (see Figure 6.8) with 110% power transfer is used for the pre-disturbance condition. Two types of faults showing the most effect on the transient stability of the system are tested for this 110% power transfer case.

6.4.1 Normally Cleared 3-phase Fault:

Three-phase fault at Claireville, normally cleared in 6 cycles by opening the 500kV S/C from Bruce to Claireville, showed the most angle excursion among the four different disturbances tested previously with 100% power transfer. The same disturbance is tested here for 110% power transfer. Because, by-passing all the 5 series capacitors during the fault period is a more conservative assumption; this was included in this sensitivity simulation. The system was found to be stable and voltage recovery acceptable. The plots for this simulation are included in Appendix-G (Figure G-73 thru'G-76).

6.4.2 Simultaneous L-G Fault:

Another significant disturbance is the simultaneous L-G fault on two different phases (LLG) of the Bruce-Milton D/C 500kV line. Normal fault clearing of 6 cycles and by-pass of all the 5 series capacitors was assumed. The system was found to be stable and voltage recovery acceptable. The plots for this simulation are included in Appendix-G (Figure G-77 thru'G-80).

6.4.3 Normally Cleared Highest 3-phase Fault Level Location:

The high level of 70% series compensation, located at or near the midpoint on the Bruce – Longwood and the Longwood – Nanticoke circuits results in two points (about 30% from either end) of zero net series impedance. This (besides being important from the line protection point of view) may make any fault at or near these points to be electrically close to both ends of the circuits. For example, a 3-phase fault at about 30% from Longwood on the Bruce – Longwood circuit will make the fault appear to be at Bruce as well as close to Longwood substation. There would be a complementary point on the other side of the series capacitors on these two circuits. Fault at such locations would cause a larger dip in the voltage (more than for faults at other points) during the fault period at both ends. Lower voltages may affect the stability. This was verified by two simulations:

- i. 3-phase fault on the Bruce – Longwood at 30% from Longwood
- ii. 3-phase fault on the Longwood – Nanticoke circuits at 38.4% from Nanticoke

The voltage at the Bruce and Longwood 500kV buses for a 30% point (from Longwood) fault, on one of the Bruce – Longwood circuits, is shown in Figure 6.9. The voltage at Bruce dips to almost 0.3pu and is lower than the voltage at Longwood. This fault represents a fairly severe disturbance in that the voltages at both Bruce and Longwood are depressed during the fault. In this case, the series capacitors are not by-passed which basically prolongs the voltage depression condition for the whole fault duration.

In actuality, the series capacitors, especially those on the faulted circuits will be by-passed. The by-passing of the series capacitors removes the artificial or electrical nearness of the fault to the actual physical fault location of about 70% of the line away from Bruce. This change can be seen in Figure 6.10, where the Bruce voltage recovers to nearly 0.7pu as soon as the capacitors are by-passed.

Both the cases of no by-pass and all by-pass were simulated for a total of 4 simulations. The system was found to be stable in all the four cases. The plots for these four simulations are included in Appendix G (Figures 81-96).

Figure 6.7 BRUCE GENERATOR Terminal Voltage for the four L-G Faults

(Please see next page)

**Figure 6.8 POWER FLOW PLOT for 110% TRANSFER CASE
used for Transient Stability Testing**

(Please see next page)

**Figure 6.9 Voltage for Normally Cleared 3-Phase Fault
at 30% point on Bruce – Longwood 500kV Circuit**

(Please see the following page)

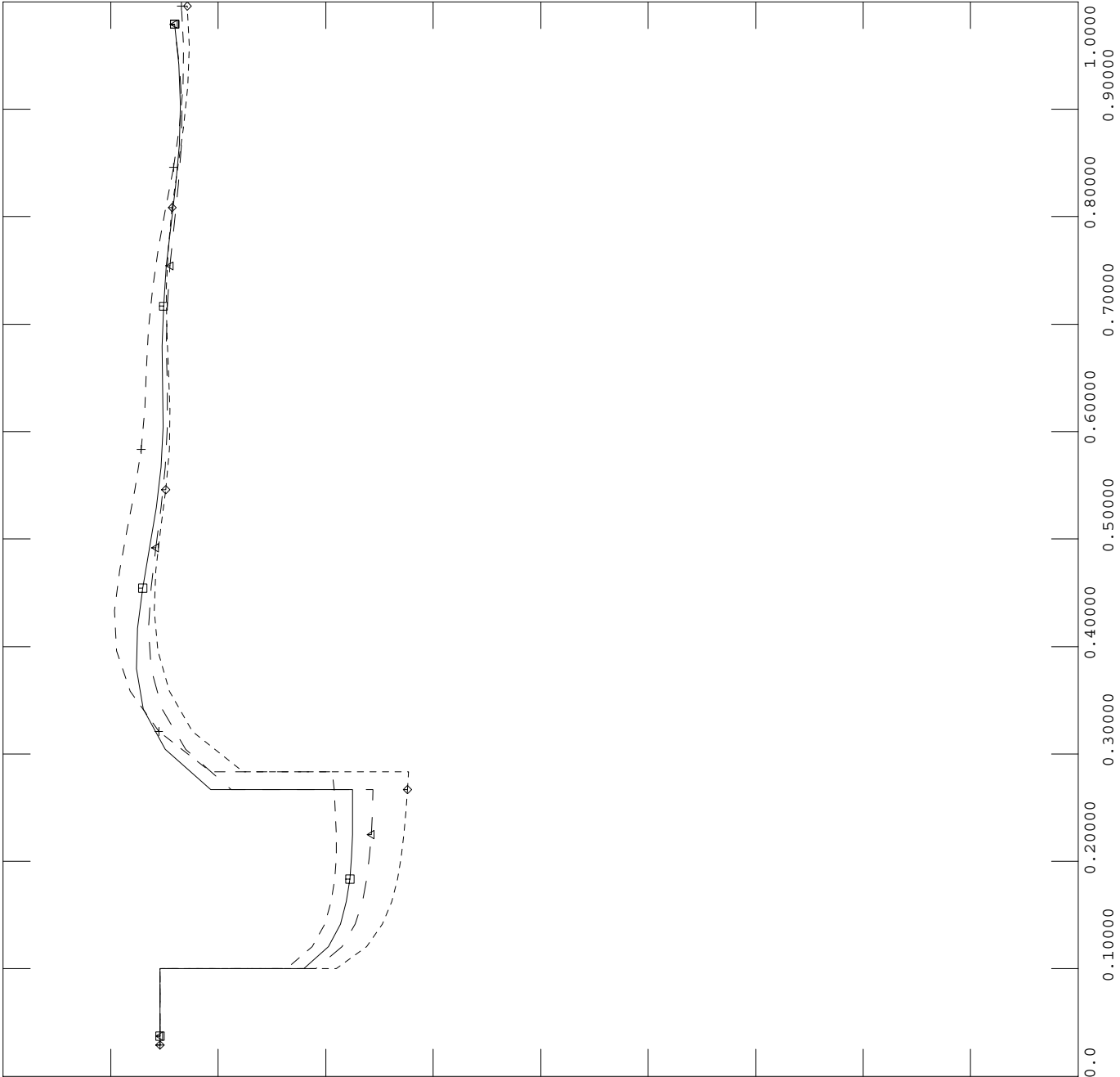
**Figure 6.10 Series Capacitor Voltage for Normally Cleared 3-Phase Fault
at 30% point on Bruce – Longwood 500kV Circuit**

(Please see the following page)

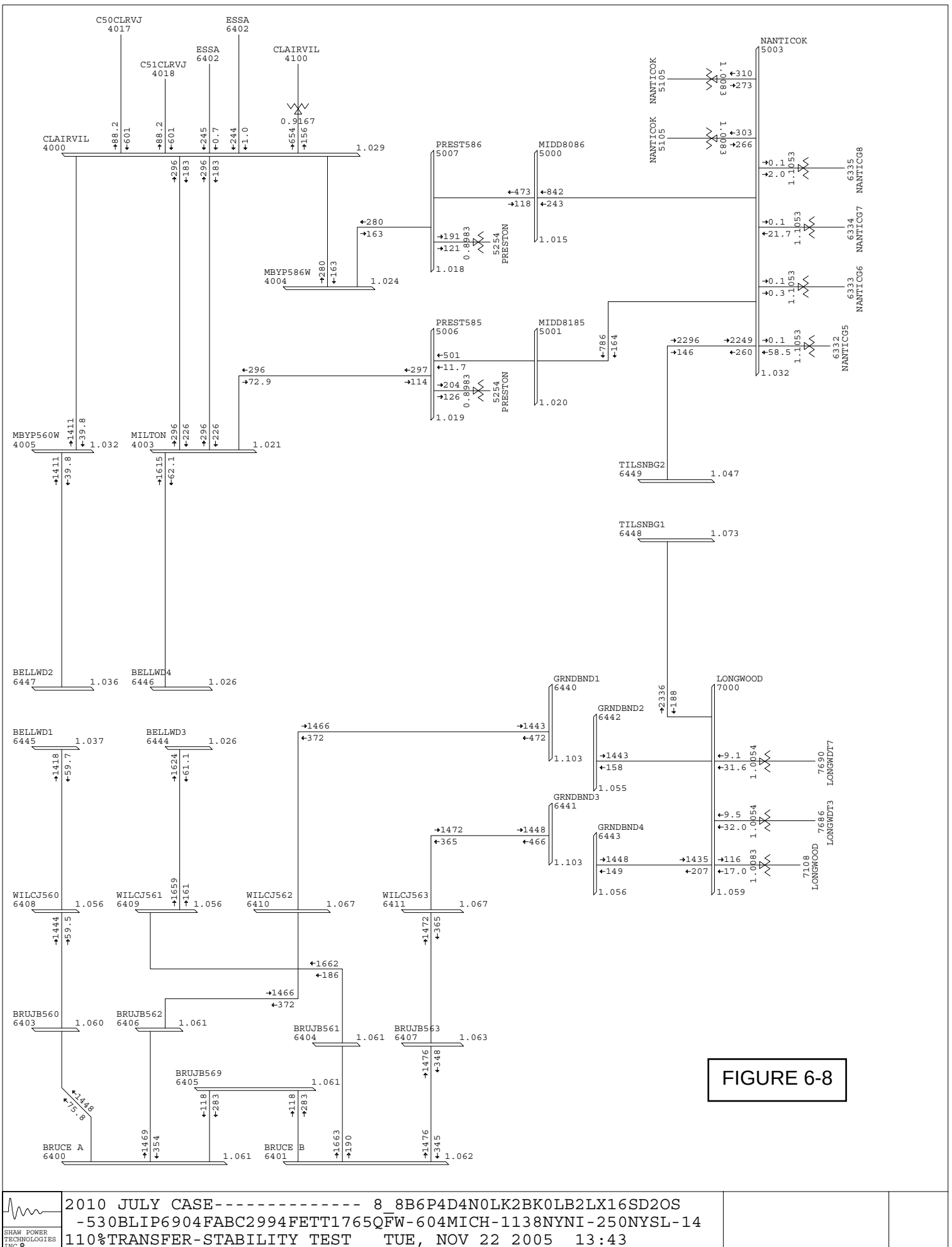


2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

CHNL# 185: [BRUCEAG3ET]			
1.1000	FILE:...\L-G-FAULT-NO-BY-PASS\LG-4000-4005-1.OUT	+ - - - - +	0.10000
CHNL# 185: [BRUCEAG3ET]			
1.1000	FILE:...\L-G-FAULT-NO-BY-PASS\LG-7000-5003-1.OUT	◇ - - - - ◇	0.10000
CHNL# 185: [BRUCEAG3ET]			
1.1000	FILE:...\L-G-FAULT-NO-BY-PASS\LG-6411-7000-1.OUT	← - - - →	0.10000
CHNL# 185: [BRUCEAG3ET]			
1.1000	FILE:...\L-G-FAULT-NO-BY-PASS\LG-6409-4003-1.OUT	▣ - - - ▣	0.10000



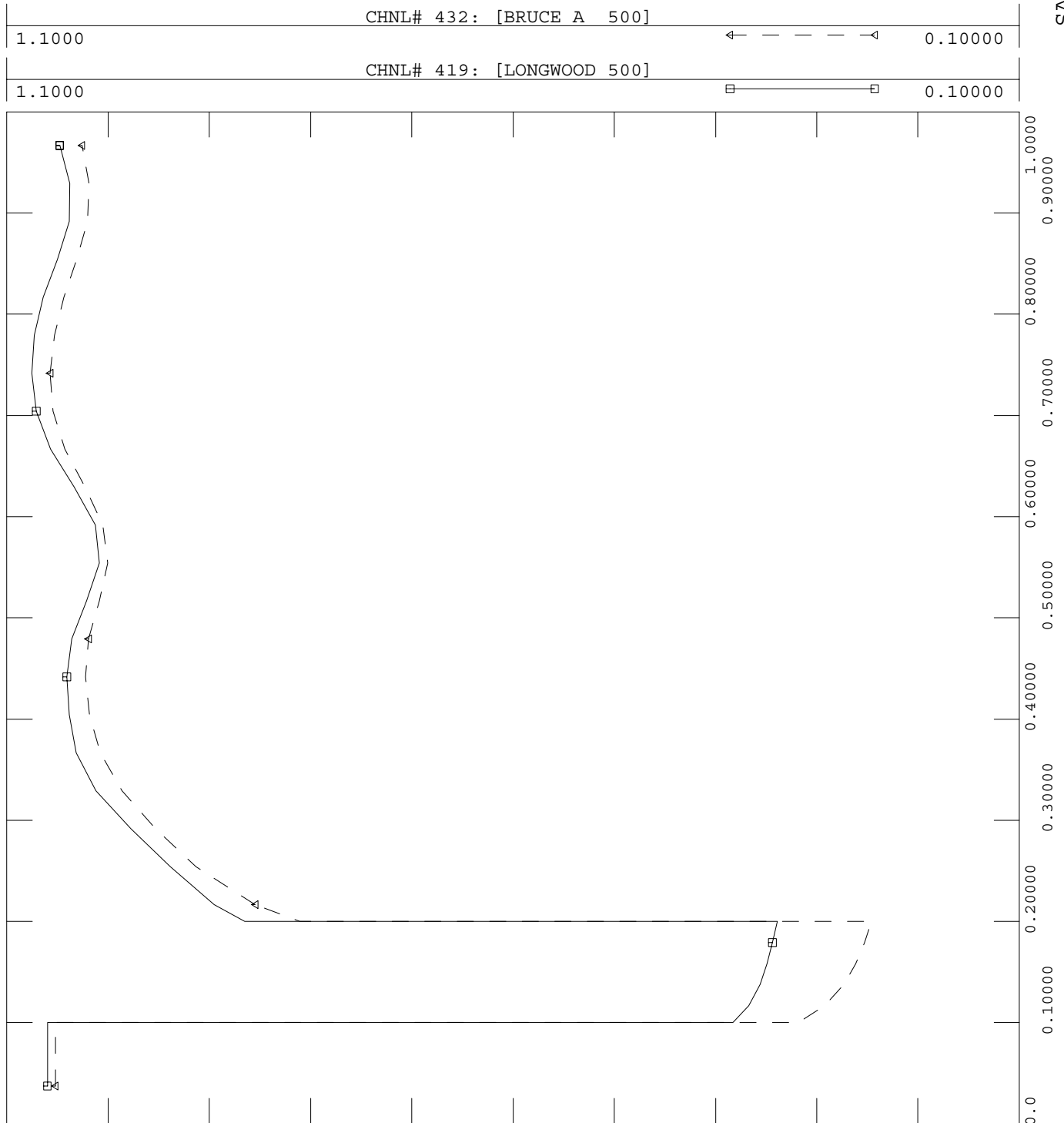
THU, NOV 10 2005 14:12
10-CYCLES, L-G FAULTS
FIGURE 6-7





2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: ... \DYNAMICS-WORST-FAULT-POINT\3PH-46443-7000-1-NO-BY-PASS.OUT



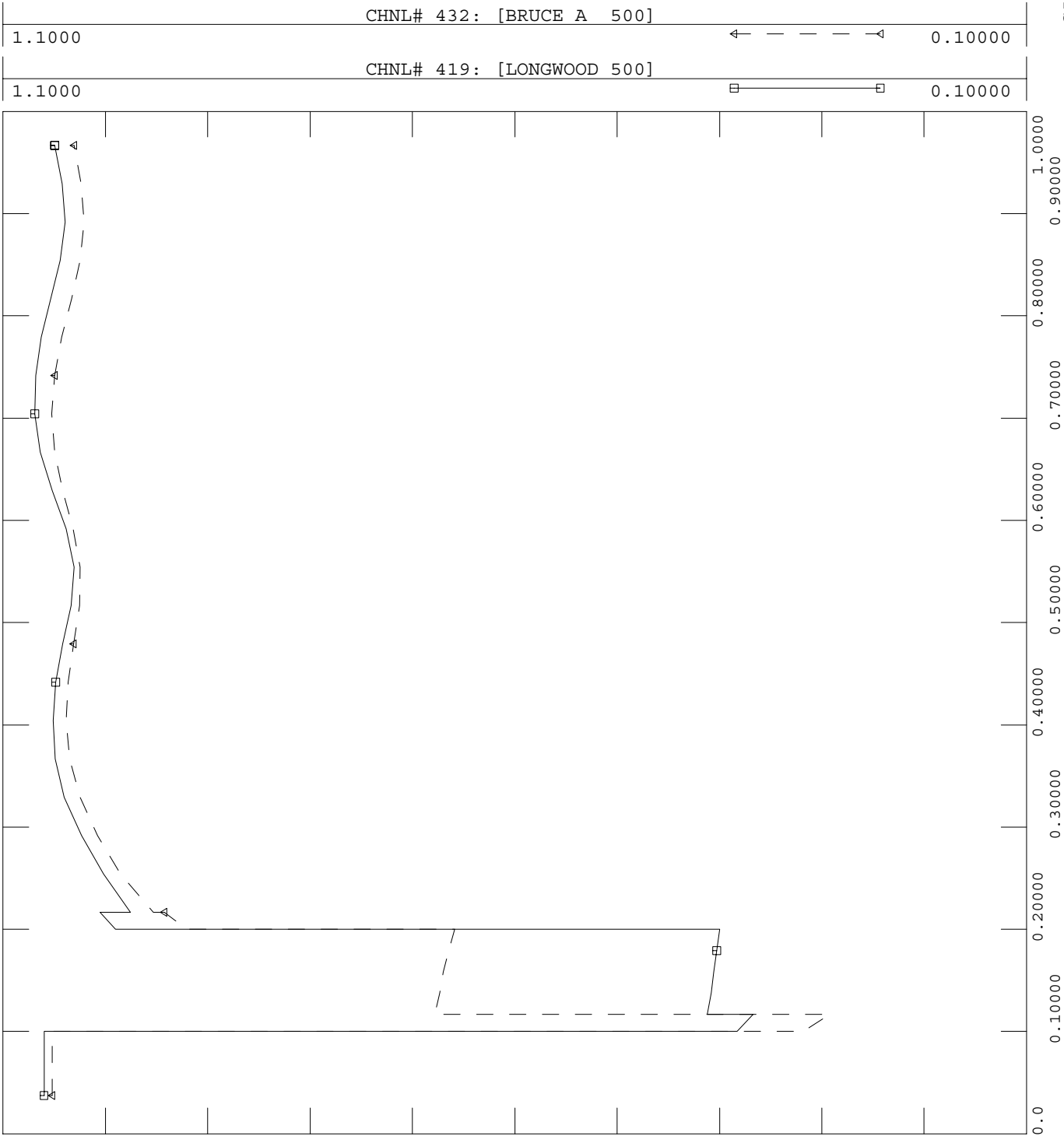
SAT, NOV 19 2005 6:45
BUS-V-NO-BYPASS-WRST-FALT

FIGURE 6-9



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: ...\\DYNAMICS-WORST-FAULT-POINT\\3PH-46443-7000-1-BY-PASS.OUT



SAT, NOV 19 2005 9:25

BUS-V-BY-PASS-WORST-FAULT

FIGURE 6-10

6.4.4 Damping Need:

In Appendix-F, possibility of poor damping or less than desirable is mentioned. With higher power transfer from Bruce Complex and under certain radial conditions, additional damping may become necessary. For a preliminary determination of such damping need, a simple disturbance not involving fault, but line outages was simulated. Starting from the base case, Bruce-B (bus#6401) to Milton was outaged (no fault) and the dynamic simulation was run. As shown in the first part (0.1 – 5 secs) of Figure 6.11, the oscillations decrease in magnitude, albeit slowly. Then the second circuit (Bruce-A to Claireville) was outaged and the dynamic simulation was continued for another 5 secs. The middle part (of the curves) shows some-what better damping. The third disturbance simulated consisted of opening the tie between the two 500kV buses at Bruce Complex. The oscillations of radially connected Bruce-B generators show a need for some more positive damping.

A power flow simulation with these three outages (may be considered n-2) showed that additional reactive support of about 130MVAR at Longwood 500kV bus (not necessarily optimized for amount and location) is necessary for convergence. This was in addition to the changes listed in Table 3.3.

Further investigation is recommended to coordinate and optimize the need for additional damping, additional reactive support at both Longwood and Buchanan. In this investigation, possible benefit from an SVC and/or STATCOM should be included.

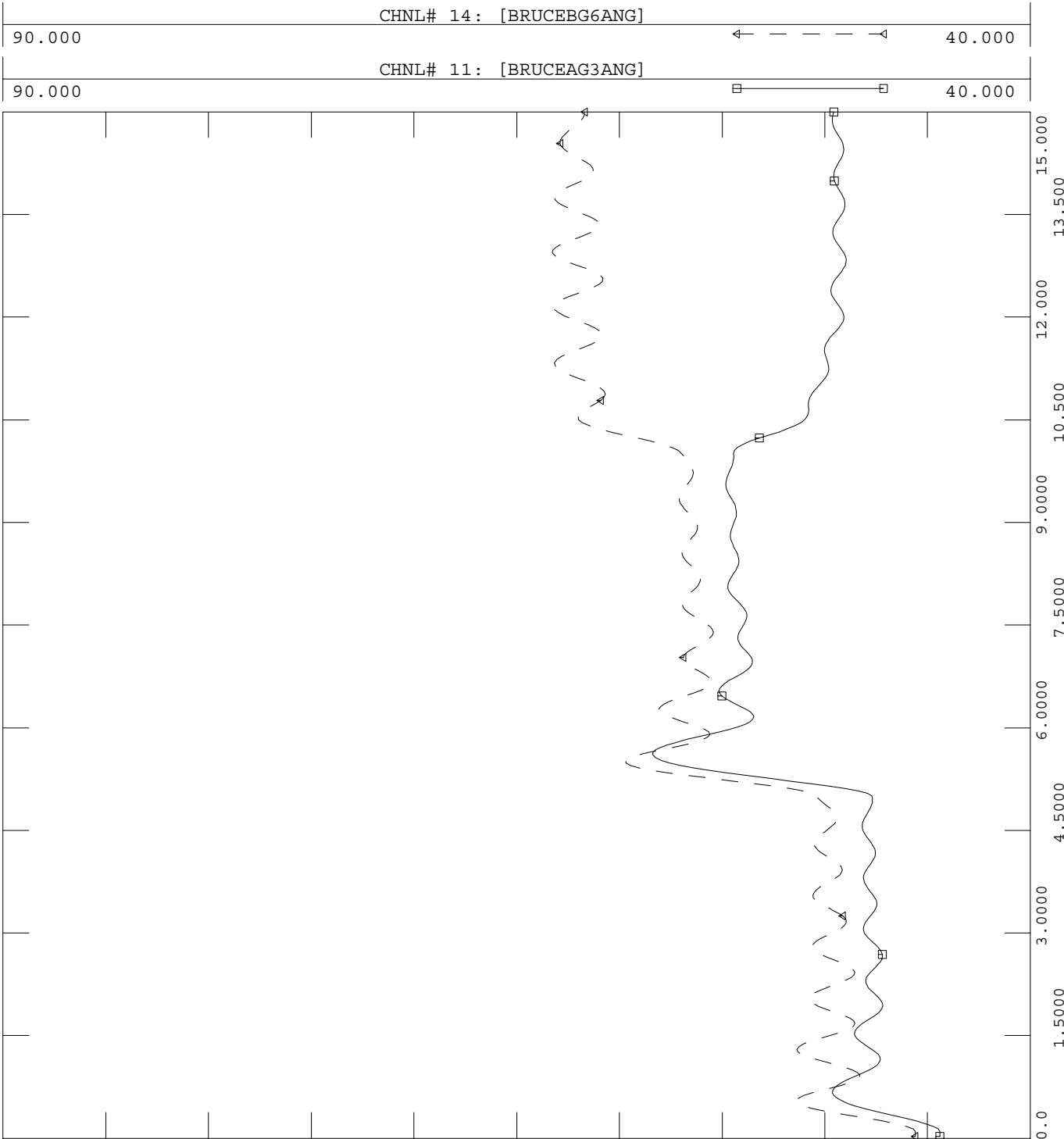
**Figure 6.11 Bruce A & B Generator Angles
for three sequential outages without fault**

(Please see the following page)



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
NO FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: NO-FLT-BXM-D-C.OUT



TUE, NOV 22 2005 9:09
BRUCE-A&B-ANGLES

FIGURE 6.11

7.0 CONCLUSIONS

The forecasted year 2010 system peak conditions are used as basis for the power flow and dynamics simulations. In this base case the power transfers across key interfaces are;

- ◆ 6,902MW for the FABC (Flow Away from Bruce Complex) interface,
- ◆ Almost zero for the BLIP (Buchanan Longwood Input) and
- ◆ 2,157MW for the FETT (Flows East Towards Toronto).

7.1 Steady-State/Power-Flow:

The following conclusions are based on the results from the steady state power flow simulations:

1. In the normal system (base case) condition, there are no overloads (below Rate-A) on the 500kV and 230kV circuits and all the bus voltages are within the Steady State (pre-contingency) Voltage limits as per the criteria.
2. Out of 55 single contingencies (500kV), only two contingencies involving Hanmer-Porcupine-Pinard 500kV single circuit lines indicated Non-converged (NC) condition. This 500kV path being radial, this is considered to be a local issue.
3. For the remaining 53 contingencies, there were no overloads on the 500kV and 230kV transmission lines. Except the series capacitor buses, all the bus voltages (500kV and 230kV) were within the post-contingency limits. The highest voltage for the series capacitor location is 1.15pu (575kV). The OPF solution showed that it is possible to adjust the pre-contingency voltages so that the series capacitor voltages in the post-contingency period are within 1.1pu. Other possible remedies to deal with the higher voltage are included in the report.
4. For the main 500kV transmission loop, 8 double contingencies were identified. Out of these 8 double contingencies, the following two double contingencies resulted in non-converged condition:
 - i) Outage of double circuit tower from Willow Creek Junction to Milton
 - ii) Outage of one circuit from Willow Creek Junction to Milton in combination with Outage of the single circuit from Longwood to Nanticoke

For the remaining 6 double contingencies, there were no overloads or voltage violations.

5. For resolving non-convergence of power flow due to outage of double circuit tower from Willow Creek Junction to Milton [this is actually a (n-1) level contingency for this system], almost 2,000MVAR reactive support is necessary. Nearly one-third (1/3) in the form of new shunt requirement (most at Buchanan 230kV bus) and the other two-thirds (2/3) obtained by switching-off the shunt reactors in Bruce and Longwood substations is required.
6. For resolving non-convergence of power flow due to the outage of one circuit from Willow Creek Junction to Milton in combination with outage of the single circuit from Longwood to Nanticoke, about 2,500MVAR of additional reactive support at Milton 500kV bus is necessary. Depending upon various adjustments that may be possible, the reactive requirement may be reduced to a range of 500 – 1,500MVAR.
7. In order to demonstrate (or ensure) that the base case operating point on the P-V curve has 10% margin from the knee-point, a new power flow with 10% higher power transfer over FABC interface was created. Then a single contingency (51 individual outages) analysis was done. There were no non-convergent cases, thus verifying that 10% margin does exist in the original base case.
8. The availability of reactive margins was further established by Q-V curve analysis for various limiting system conditions. These Q-V curves support the OPF and other power flow case results.
9. Several power flow cases were run as sensitivity cases to illustrate the trade-off between the series and shunt compensation levels. The results clearly show a need for further optimization and overall coordination of the compensation levels.
10. The concept of allowing higher voltage (above 1.1pu) at series capacitor locations results in at least 500 – 600MVAR reduction in reactive power requirements for the two most severe multiple contingencies.
11. All the initial simulations (base case and contingencies) were performed on the basis of an equivalent external system i.e. fixed inter-change over the tie lines, which meant that the swing machine was within Ontario (area-1). The impact of swing machine outside area-1 was evaluated by replacing the equivalent by the full external system. This has an effect on losses, reactive power flow, but no direct effect on the series compensation levels.
12. In the base case, the import from ITC was fixed at 604MW. The maximum import was determined by solving the power flow until non-convergence

(voltage stable or the operating point above the knee of the P-V curve) is reached. This base case or voltage stability (no margin) limit from ITC was 906MW.

13. However, from the thermal loading point of view, the import limit from ITC (for the given Bruce Complex generation dispatch), is about 670MW (604MW in the base case). For this condition the limiting contingency is Bruce-Milton D/C 500kV tower outage and the limiting element is Longwood – Nanticoke 500kV S/C line.
14. The possibility of resolving non-convergence of power flow due to the most restrictive (n-2) contingency [outage of one circuit from Willow Creek Junction to Milton in combination with outage of the single circuit from Longwood to Nanticoke] by generation tripping (G/R) was also tested as a sensitivity case. Tripping of one unit at Bruce complex reduces the reactive requirement by nearly 500MVAR with lesser further reduction for the second (280MVAR) and third (175MVAR) units.

7.2 Dynamics/Stability:

The following conclusions are based on the results from the steady state power flow simulations:

1. The dynamics simulations are based on a complete system model, provided by IESO for this study, with full representation of Ontario and external system in Canada and US.
2. Three different types of faults, as per the IMO criteria, at four different locations (Bruce, Longwood, Nanticoke and Claireville) for a total of 9 specific conditions were tested. In addition, for each of these 9 specific conditions, bypassing and not bypassing of the series capacitors (during faulted period) were performed.
3. The cases for normally cleared (6 cycles) 3-phase fault at the above mentioned four locations were stable. Fault at Claireville with opening of the Bruce-Claireville circuit resulted in the largest angle deviation. There was no transient voltage sag after clearing of the fault and voltage recovered to above 0.8pu level.
4. The corresponding 4 cases with delayed clearing (10 cycles) of L-G faults were also stable and with acceptable transient voltage recovery characteristic.
5. One case of simultaneous L-G fault (6 cycles) on 2 different phases of the two circuits of the Bruce-Milton 50kV double circuit line was also stable and with acceptable transient voltage recovery characteristic.

6. For slower clearing of faults (≈ 10 cycles) wind farm generator tripping was noted due to the undervoltage protection settings used in these simulations.
7. The 9 simulation cases were repeated with the assumption that all the 5 series capacitors would be by-passed during the fault period. In actuality, by-passing of series capacitors would occur on only the circuits with excessive fault current flowing through them. However, the two extreme cases of bypassing all and none of the series capacitors bracket the expected performance of the system. In all these 9 cases, the system was found to be stable with acceptable voltage recovery.
8. The 110% power transfer case used for steady state analyses was also tested for transient stability. Two of the most severe faults (3-phase and L-L-G) on the Bruce-Milton-Claireville 50kV line were used for the two separate simulations. In both cases, the system was stable; thereby satisfying the IMO criteria requirement that the system stability not adversely affected if any of the key parameters are changed by 10%. This also confirms that the additional reactive support from steady state voltage stability testing need not be fast acting (i.e. dynamic).
9. Another sensitivity testing condition involved fault at two points (about 30% from Longwood and Nanticoke) of zero net series impedance or highest fault level. Both the cases of no by-pass and all by-pass of series capacitors were simulated for a total of 4 simulations. The system was found to be stable in all the four cases.
10. A third sensitivity case was run to take a cursory look at damping and this case shows that further examination of damping requirements coupled with the additional reactive support may be necessary.

In summary, both the power flow dynamic simulation results confirm that the proposed series compensation of the 500kV lines is feasible and will meet the power transfer requirements. The simulation results show that further optimization (both technical and economic) of both the series and shunt compensation levels is desirable. Such optimized levels compensation should provide a better and more economic solution for the upgrade of the main 500kV transmission loop of Bruce-Longwood-Nanticoke-Claireville-Milton.

Hydro One Networks Inc.

Southwestern Ontario Transmission 500kV Series Compensation Technical Studies Power Flow and Dynamics Report

APPENDICES

November 22, 2005

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TABLE OF CONTENTS

APPENDIX A EQUIVALENCES.....	3
APPENDIX B BASE CASE DATA, RESULTS AND LIMIT VIOLATIONS.....	12
APPENDIX C SINGLE CONTINGENCY ANALYSES RESULTS	29
APPENDIX D DOUBLE CONTINGENCY ANALYSES RESULTS	41
APPENDIX E BASE CASE RESULTS – WITH FULL SYSTEM.....	46
APPENDIX F DYNAMIC MODEL ADJUSTMENTS	50
APPENDIX G DYNAMICS SIMULATION RESULTS.....	54

APPENDIX A EQUIVALENCES

Transmission system, external to Ontario (area-1), within Zone-999 was equivalenced by using the following steps:

- 1) Purged all the dc ties
- 2) Used activity "BGEN" to replace the converters by appropriate generators and loads
- 3) Used activity "GNET" to net generation and load outside Ontario
- 4) Used activity "EEQV" to obtain equivalents, but retaining all the interties with Area-1 (Ontario).
- 5) At the outside buses, based on the derived equivalents, dummy generators and loads were included.

This type of equivalent is applicable for steady state analyses and the import and export (both real and reactive power) from Ontario (area-1) are fixed. The tie line Interchanges before and after equivalencing the external system are shown in the next two pages. The Interchanges on these two pages are practically same. The area totals are also shown in the following two pages for documentation purposes. The data for IESO (area-1) are identical in both the tables. The Equivalent System for NYISO (as used in the Base Case), including the tie-lines to IESO is shown in Figure A-1. The Equivalent Systems for ITC, MH and MP (as used in the Base Case), including the tie-lines to IESO are shown in Figure A-2. The branch data for the equivalent ties between these external areas are summarized in a table on the following page.

AREA-1 TIE LINE INTERCHANGES BEFORE EQUIVALENCING

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E THU, OCT 06 2005 7:35
 2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS AREA TIE LINE
 -530BLIP6904FABC2994FETT1765QFW-604MICH-1138NYNI-250NYSL-14 INTERCHANGE

FROM AREA 1 IESO

TO AREA 219 ITC

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
7001 LAMB L4D 345	28849* 19STCPP 345	1	-201.3	1.3		
7104* J5D PS 230	28883 19WTRMN 230	1	-103.4	-12.1		
7109* SCOTT 220	29003 19B3N PS 220	1	-98.5	-1.0		
7113* LAMB L51 220	29028 19STCPP 220	1	-200.8	4.1		
TOTAL FROM AREA 1 TO AREA 219					-604.1	-7.6

TO AREA 608 MP

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
9314* ONT-MINN 118	61784 INTPHAS7 118	1	-0.7	7.7		
TOTAL FROM AREA 1 TO AREA 608					-0.7	7.7

TO AREA 667 MH

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
9107* KENORA 220	67556 WHTSL1 4 220	1	-0.5	-12.6		
9107* KENORA 220	67589 WHTSL2 4 220	1	-0.5	-12.6		
TOTAL FROM AREA 1 TO AREA 667					-1.1	-25.2

TO AREA 702 NYISO

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
1110* STLAWL33 230	79589 MOSES E 230	1	-122.8	-12.1		
1111* STLAWL34 230	79589 MOSES E 230	1	-127.4	-3.1		
5004* BECK A 345	79584 NIAG 345 345	1	-322.9	-4.4		
5005* BECK B 345	79584 NIAG 345 345	1	-323.1	-4.3		
5138 BP76 REG 230	76665* PACKARD2 230	1	-198.5	-17.8		
5244 PA27 REG 230	79592* NIAGAR2W 230	1	-293.9	-3.7		
TOTAL FROM AREA 1 TO AREA 702					-1388.7	-45.4

TO AREA 704 HQTE

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
100 CHAT FLS 220	84003* PAUGAN 220	1	0.0	0.0		
345* CHENAU J 118	84011 BRYSON 118	1	0.0	-0.5		
380* IPB H9A 118	84012 MASSON 118	1	0.0	-0.1		
1150 IPB B31L 220	84002* BEAUHB31 220	1	0.0	0.0		
8296* IPB LACA 118	84015 KIPAWA 118	1	0.0	-2.1		
8297* KIPWIESO 118	85716 KIP120 120	T1	-3.8	42.4		
8346* NMILEJD4 118	84016 RAP DES 118	1	0.0	-1.8		
TOTAL FROM AREA 1 TO AREA 704					-3.8	38.0

TOTAL FROM AREA 1			-1998.4	-32.6

AREA-1 TIE LINE INTERCHANGES AFTER EQUIVALENCING

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E THU, OCT 06 2005 7:54
 2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD2OS AREA TIE LINE
 -530BLIP6904FABC2994FETT1765QFW-604MICH-1138NYNI-250NYSL-14 INTERCHANGE

FROM AREA 1 IESO

TO AREA 219 ITC

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
7001 LAMB L4D 345	28849* 19STCPP 345	1	-201.6	1.6
7104* J5D PS 230	28883 19WTRMN 230	1	-103.2	-12.0
7109* SCOTT 220	29003 19B3N PS 220	1	-98.4	-1.0
7113* LAMB L51 220	29028 19STCPP 220	1	-201.1	4.4
TOTAL FROM AREA 1 TO AREA 219			-604.2	-7.1

TO AREA 608 MP

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
9314* ONT-MINN 118	61784 INTPHAS7 118	1	-0.7	7.5
TOTAL FROM AREA 1 TO AREA 608			-0.7	7.5

TO AREA 667 MH

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
9107* KENORA 220	67556 WHTSL1 4 220	1	-0.4	-12.6
9107* KENORA 220	67589 WHTSL2 4 220	1	-0.4	-12.6
TOTAL FROM AREA 1 TO AREA 667			-0.8	-25.2

TO AREA 702 NYISO

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
1110* STLAWL33 230	79589 MOSES E 230	1	-122.3	-12.0
1111* STLAWL34 230	79589 MOSES E 230	1	-126.6	-3.0
5004* BECK A 345	79584 NIAG 345 345	1	-323.1	8.2
5005* BECK B 345	79584 NIAG 345 345	1	-323.3	8.4
5138 BP76 REG 230	76665* PACKARD2 230	1	-198.5	-10.6
5244 PA27 REG 230	79592* NIAGAR2W 230	1	-293.9	5.3
TOTAL FROM AREA 1 TO AREA 702			-1387.6	-3.8

TO AREA 704 HQTE

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
100 CHAT FLS 220	84003* PAUGAN 220	1	0.0	0.0
345* CHENAU J 118	84011 BRYSON 118	1	0.0	-0.5
380* IPB H9A 118	84012 MASSON 118	1	0.0	-0.1
1150 IPB B31L 220	84002* BEAUHB31 220	1	0.0	0.0
8296* IPB LACA 118	84015 KIPAWA 118	1	0.0	-2.1
8297* KIPWIESO 118	85716 KIP120 120	T1	-3.8	42.4
8346* NMILEJD4 118	84016 RAP DES 118	1	0.0	-1.8
TOTAL FROM AREA 1 TO AREA 704			-3.8	38.0
TOTAL FROM AREA 1			-1997.1	9.5

AREA TOTALS BEFORE EQUIVALENCING

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E THU, OCT 06 2005 7:40								
2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS AREA TOTALS								
-530BLIP6904FABC2994FETT1765QFW-604MICH-1138NYNI-250NYSL-14 IN MW/MVAR								
	FROM	TO	TO BUS	TO LINE	FROM	TO		DESIRED
AREA	GENERATION	LOAD	SHUNT	SHUNT	CHARGING	NET INT	LOSSES	NET INT
1	28263.7	29174.6	0.1	114.4	0	-1998.4	973	-2000
IESO	7427.7	14105.7	-11223.8	931.2	9951.6	-32.6	13599	
219	13147.9	12365	83	0	0	457.1	242.8	457
ITC	3702.4	4803.1	-2996.8	0	1612	70.9	3436.9	
608	1680.7	1631.7	0	0	0	-33	82	-33
MP	319.7	572.5	-834	0	342.9	-179.8	1103.9	
667	4341.7	2709.8	0	0	0	1380	252	1380
MH	2198.8	676.3	-2225.4	323.3	1238.8	-74	4737.4	
702	32006.1	30711.2	25.3	9.5	0	418.2	841.9	416
NYISO	9862	13189.1	-6548.3	-406.5	11466.2	-377.5	15471.3	
704	24933.9	21440.6	1.7	0	0	2619.1	872.6	2615
HQTE	3389.6	5769	18082	0	36460.8	-1051.8	17051.2	
TOTALS	104374.1	98032.9	110	123.9	0	2843	3264.3	2835
	26900.2	39115.7	-5746.4	848	61072.2	-1644.7	55399.6	

AREA TOTALS AFTER EQUIVALENCING

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E THU, OCT 06 2005 7:40								
2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD2OS AREA TOTALS								
-530BLIP6904FABC2994FETT1765QFW-604MICH-1138NYNI-250NYSL-14 IN MW/MVAR								
	FROM	TO	TO BUS	TO LINE	FROM	TO		DESIRED
AREA	GENERATION	LOAD	SHUNT	SHUNT	CHARGING	NET INT	LOSSES	NET INT
1	28263.8	29174.6	0.1	114.6	0	-1997.1	971.6	-2000
IESO	7425.9	14105.7	-11242.7	932.2	9961	9.5	13582.2	
219	1645.9	0	1539.4	0	0	171.8	-65.3	457
ITC	586.7	-56.1	-14.5	0	3.4	339.5	321.3	
608	0	-134.9	0	0	0	173.6	-38.7	-33
MP	0	-290	160.5	0	0.1	-110.3	239.9	
667	478.3	0	211.3	0	0	160.7	106.3	1380
MH	120	0	0	0	53.8	-206.7	380.6	
702	2331.1	0	838.4	0	0	1487.2	5.5	416
NYISO	468.3	0	432	0	82.5	6.1	112.8	
704	0	-3.8	0	0	0	3.8	0	2615
HQTE	0	74.9	-32.5	0	4.4	-38	0	
TOTALS	32719.1	29036	2589.2	114.6	0	0	979.4	2835
	26900.2	13834.4	-10697.2	932.2	10105.4	0	14636.8	

**Figure A-1: Equivalent System for NYISO (as used in the Base Case)
including the tie-lines to IESO**

(Please see Next Page)

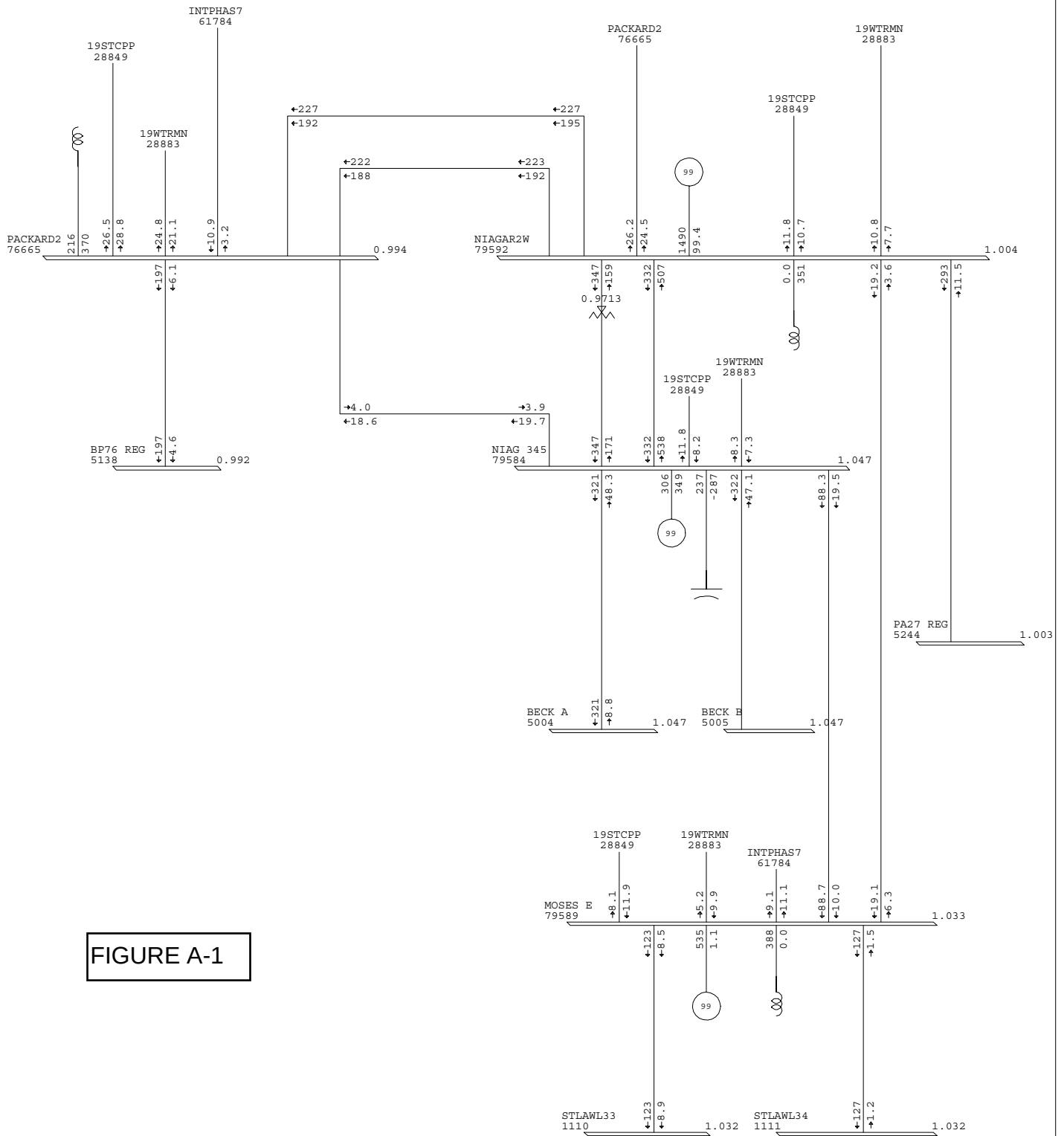


FIGURE A-1

**Figure A-2: Equivalent System for ITC-MH-MP
(as used in the Base Case)
including the tie-lines to IESO**

(Please see Next Page)

FIGURE A-2



MP

ZONE-999 EQUIVALENTS INCLUDING TIES TO ONTARIO														
BUS#	NAME	BSKV	BUS#	NAME	BSKV	CKT	LINE R	LINE X	CHRGING	STATUS	RATEA	RATEB	RATEC	LENGTH
100	CHAT FLS	220	84003	PAUGAN	220	1	0.00883	0.05286	0.07954	1	362.9	403.6	521.9	50.2
345	CHENAU J	118	84011	BRYSON	118	1	0.01494	0.03279	0.00451	1	0	0	0	9.2
379	IPB IDL	118	84012	MASSON	118	1	0.00155	0.00958	0.00125	0	124.7	140	183.8	2.7
380	IPB H9A	118	84012	MASSON	118	1	0.00156	0.00983	0.00122	1	269.1	297.5	385.1	2.7
1110	STLAWL33	230	79589	MOSES E	230	1	0.00091	0.00638	0.0124	1	438.2	482	0	0
1111	STLAWL34	230	79589	MOSES E	230	1	0.00091	0.00638	0.0124	1	438.2	482	0	0
1150	IPB B31L	220	84002	BEAUHB31	220	1	0.00703	0.04173	0.06248	1	0	0	0	39.6
5004	BECK A	345	79584	NIAG 345	345	1	0.00004	0.00034	0.36404	1	1529.8	1732.9	0	0
5005	BECK B	345	79584	NIAG 345	345	1	0.00004	0.00033	0.35084	1	1529.8	1732.9	0	0
5138	BP76 REG	230	76665	PACKARD2	230	1	0.00076	0.00723	0.01463	1	645.4	748.9	0	0
5244	PA27 REG	230	79592	NIAGAR2W	230	1	0.0007	0.00662	0.0134	1	645.4	748.9	0	0
7001	LAMB L4D	345	28849	19STCPP	345	1	0.00012	0.00193	0.01889	1	1003.9	1762.8	0	4.7
7104	J5D PS	230	28883	19WTRMN	230	1	0.00045	0.00257	0.00442	1	438.2	482	0	2.7
7109	SCOTT	220	29003	19B3N PS	220	1	0.0012	0.00375	0.01146	1	480.1	533.5	0	7
7113	LAMB L51	220	29028	19STCPP	220	1	0.00023	0.00458	0.01324	1	1455.6	1749	0	6.2
8296	IPB LACA	118	84015	KIPAWA	118	1	0.04357	0.1871	0.01987	1	0	0	0	47.1
8346	NMILEJD4	118	84016	RAP DES	118	1	0.06883	0.11403	0.01556	1	72.2	72.2	83.1	31.8
9107	KENORA	220	67556	WHTSL1 4	220	1	0.0176	0.129	0.21985	1	335.3	373.4	0	128.7
9107	KENORA	220	67589	WHTSL2 4	220	1	0.01758	0.12901	0.21933	1	335.3	373.4	0	128.7
9314	ONT-MINN	118	61784	INTPHAS7	118	1	0.00165	0.00758	0.00112	1	151.3	163.6	0	2.3
76665	PACKARD2	230	79592	NIAGAR2W	230	1	0.0004	0.005	0.0102	1	717	717	942	0
76665	PACKARD2	230	79592	NIAGAR2W	230	2	0.0004	0.0049	0.01	1	717	717	942	0
28849	19STCPP	345	28883	19WTRMN	230	99	-0.00048	0.02243	0	1	0	0	0	0
28849	19STCPP	345	29003	19B3N PS	220	99	-0.01649	0.08422	0	1	0	0	0	0
28849	19STCPP	345	61784	INTPHAS7	118	99	-0.1782	1.26922	0	1	0	0	0	0
28849	19STCPP	345	67556	WHTSL1 4	220	99	0.48961	1.63269	0	1	0	0	0	0
28849	19STCPP	345	67589	WHTSL2 4	220	99	0.48962	1.63269	0	1	0	0	0	0
28849	19STCPP	345	76665	PACKARD2	230	99	-0.62724	0.61591	0	1	0	0	0	0
28849	19STCPP	345	79584	NIAG 345	345	99	1.71716	1.72847	0	1	0	0	0	0
28849	19STCPP	345	79589	MOSES E	230	99	1.38685	0.81221	0	1	0	0	0	0
28849	19STCPP	345	79592	NIAGAR2W	230	99	-1.39307	1.77653	0	1	0	0	0	0
28883	19WTRMN	230	29003	19B3N PS	220	99	-0.09928	0.37092	0	1	0	0	0	0
28883	19WTRMN	230	61784	INTPHAS7	118	99	-0.36942	1.90648	0	1	0	0	0	0
28883	19WTRMN	230	67556	WHTSL1 4	220	99	0.62985	2.52002	0	1	0	0	0	0
28883	19WTRMN	230	67589	WHTSL2 4	220	99	0.62986	2.52002	0	1	0	0	0	0
28883	19WTRMN	230	76665	PACKARD2	230	99	-0.62742	0.8495	0	1	0	0	0	0
28883	19WTRMN	230	79584	NIAG 345	345	99	2.56068	1.88139	0	1	0	0	0	0
28883	19WTRMN	230	79589	MOSES E	230	99	1.9612	0.73019	0	1	0	0	0	0
28883	19WTRMN	230	79592	NIAGAR2W	230	99	-1.33655	2.36061	0	1	0	0	0	0
61784	INTPHAS7	118	67556	WHTSL1 4	220	99	-4.00541	1.83205	0	1	0	0	0	0
61784	INTPHAS7	118	67589	WHTSL2 4	220	99	-4.0054	1.83206	0	1	0	0	0	0
61784	INTPHAS7	118	76665	PACKARD2	230	99	-2.05926	8.98711	0	1	0	0	0	0
61784	INTPHAS7	118	79589	MOSES E	230	99	8.47232	-0.67001	0	1	0	0	0	0
67556	WHTSL1 4	220	67589	WHTSL2 4	220	99	0.17525	0.4553	0	1	0	0	0	0
76665	PACKARD2	230	79584	NIAG 345	345	99	0.03557	0.29018	0	1	0	0	0	0
76665	PACKARD2	230	79589	MOSES E	230	99	0.05884	0.68867	0	1	0	0	0	0
76665	PACKARD2	230	79592	NIAGAR2W	230	99	0.00166	0.04108	0	1	0	0	0	0
79584	NIAG 345	345	79589	MOSES E	230	99	-0.00538	0.12679	0	1	0	0	0	0
79584	NIAG 345	345	79592	NIAGAR2W	230	99	0.0002	0.00851	0	1	0	0	0	0
79589	MOSES E	230	79592	NIAGAR2W	230	99	0.02615	0.70832	0	1	0	0	0	0

APPENDIX B

BASE CASE DATA, RESULTS AND LIMIT VIOLATIONS

In this Appendix-B, the following items for the Base Case Power Flow model are listed for informational purposes;

On-line Generation Dispatch (4 pages)
Generation in the model, but not used (1 page)
Switched Shunt Data (5pages)
Inter-Face Flows

GENERATOR SUMMARY:												
BUS	NAME	BSVLT	# MACH		TYP	MW	MVAR	QMAX	QMIN	VSCHED	VACTUAL	REM
			ON	OFF								
900	ARNPR G1	13.8	1	0	2	37.1	3.5	20.6	-20.6	1.0005	1.0005	
901	ARNPR G2	13.8	1	0	2	37.1	3.5	20.6	-20.6	1.0005	1.0005	
902	BAR CHG1	13.2	1	0	2	18.4	2.7	14.6	-7.3	1.0005	1.0005	
903	BAR CHG2	13.2	1	0	2	18.4	2.6	14.6	-7.3	1.0004	1.0004	
904	BAR CHG3	13.8	1	0	2	35.5	23.3	46.8	-23.4	1.0007	1.0007	
905	BAR CHG4	13.8	1	0	2	52.1	24	49.1	-24.5	1.0007	1.0007	
906	CHATFG23	13.8	2	0	2	42.9	-11	27	-27	1.0021	1.0021	
907	CHATFG45	13.8	2	0	2	42.9	0.3	27	-27	0.9757	0.9757	
910	CHENAU12	13.8	2	0	2	26.1	1.6	24.8	-12.4	1.0009	1.0009	
911	CHENAU34	13.8	2	0	2	26.1	1.6	24.8	-12.4	1.0009	1.0009	
912	CHENAU56	13.8	2	0	2	26.1	1.6	24.8	-12.4	1.0009	1.0009	
913	CHENAU78	13.8	2	0	2	26	1.6	29.2	-14.6	1.0009	1.0009	
914	D JOACG1	13.8	1	0	2	43.3	3.3	30.7	-15.4	1.0033	1.0033	
915	D JOACG2	13.8	1	0	2	43.3	3.1	30.7	-15.4	1.0034	1.0034	
916	D JOACG3	13.8	1	0	2	43.3	3.1	30.7	-15.4	1.0035	1.0035	
917	D JOACG4	13.8	1	0	2	43.3	2.9	30.7	-15.4	1.0036	1.0036	
918	D JOACG5	13.8	1	0	2	43.3	3.2	30.7	-15.4	1.0035	1.0035	
919	D JOACG6	13.8	1	0	2	43.3	3	30.7	-15.4	1.0036	1.0036	
920	D JOACG7	13.8	1	0	2	43.3	3.3	30.7	-15.4	1.0033	1.0033	
921	D JOACG8	13.8	1	0	2	43.3	3.2	37.7	-18.8	1.0034	1.0034	
922	MT CHUG1	13.8	1	0	2	66.6	20.5	31.6	-31.6	1.001	1.001	
923	MTCHUTG2	13.8	1	0	2	66.6	20.5	31.6	-31.6	1.001	1.001	
925	OHC G1-2	13.8	2	0	2	63.5	-29	40.4	-40.4	1.0017	1.0017	
926	STEWVLG1	13.2	1	2	2	17.8	6.2	17	-17	1.0004	1.0004	
927	STEWVLG2	13.2	1	0	2	17.8	12.4	17	-17	1.023	1.023	
928	STEWVLG3	13.2	1	0	2	17.8	7.8	17	-17	1.0005	1.0005	
929	STEWVLG4	13.8	1	0	2	46.3	-0.8	26	-26	1.0018	1.0018	
930	STEWVLG5	13.8	1	0	2	46.3	-1	26	-26	1.0019	1.0019	
1613	BROCKVIL	44	1	0	2	27.7	14	16	-16	1.0146	1.0146	
1901	LENNOXG1	20	1	0	2	550	176.9	200	-100	0.9994	0.9994	
1902	LENNOXG2	20	1	0	2	550	180.3	200	-100	0.9992	0.9992	
1930	SAUND 12	13.8	2	0	2	97.6	23.3	66	-66	1.0009	1.0009	
1931	SAUND 34	13.8	2	0	2	97.6	20.3	78	-78	1.0009	1.0009	
1932	SAUND 56	13.8	2	0	2	97.6	20.7	58	-58	1.0009	1.0009	
1933	SAUND 78	13.8	2	0	2	97.6	20.6	71	-72	1.0009	1.0009	
1934	SAUND910	13.8	2	0	2	97.6	20.6	66	-66	1.0009	1.0009	
1935	SAUN1112	13.8	2	0	2	97.6	20.7	78	-78	1.0009	1.0009	
1936	SAUN1314	13.8	2	0	2	97.6	21	66	-66	1.0009	1.0009	
1937	SAUN1516	13.8	2	0	2	97.6	20.8	71	-71	1.0009	1.0009	
1950	CARDPWG2	13.8	1	0	2	29.5	-0.2	30.9	-30.9	1.0007	1.0007	
1951	CARDPWG1	13.8	1	0	2	82.8	1.8	66.2	-66.2	1.0015	1.0015	
1953	AES G2	13.8	1	0	2	50	-0.8	23.2	-23.2	1.0004	1.0004	
1954	AES G1	13.8	1	0	2	90	-0.8	43.2	-43.2	1.0007	1.0007	
2610	ARMIT EY	44	1	0	2	30.1	12.8	15	-7.5	1.0485	1.0485	
2656	CHERY BY	44	1	0	-2	27.7	0	0	0	1.0161	1.0163	
2901	DARL G1	22	1	0	2	900	409.7	578	-130	1.0497	1.0497	
2902	DARL G2	22	1	0	2	900	409.6	578	-130	1.0497	1.0497	
2903	DARL G3	22	1	0	2	900	409.6	578	-130	1.0498	1.0498	
2904	DARL G4	22	1	0	2	900	408.8	578	-130	1.0499	1.0499	
2933	PIC A G1	24	1	0	2	542	102.1	240	-100	1.008	1.008	
2936	PIC A G4	24	1	0	2	542	183.4	240	-100	1.0278	1.0278	
2962	PIC B G5	24	1	0	2	542	236	240	-100	1.0457	1.0457	
2963	PIC B G6	24	1	0	2	542	234.7	240	-100	1.0454	1.0454	
2964	PIC B G7	24	1	0	2	542	235	240	-100	1.0447	1.0447	
2965	PIC B G8	24	1	0	2	542	229.3	240	-100	1.0434	1.0434	
2990	WHITBYGS	13.8	1	0	2	51.9	11.7	28	-14	1.0012	1.0012	
3307	HEARNG01	13.8	1	0	2	190	-27.2	92	-63	1.0026	1.0026	
3308	HEARNG02	13.8	1	0	2	190	-27.2	92	-63	1.0026	1.0026	
3309	HEARNG03	13.8	1	0	2	238.5	-9.6	115.5	-79.5	1.0025	1.0025	
3330	PTLANG12	13.8	2	0	2	20	-8.2	55	-27.6	1.0322	1.0322	
3334	PTLANG34	13.8	2	0	2	20	-8.3	55	-27.6	1.0321	1.0321	
4136	EASTGEN1	18	1	0	2	155	55	106	-62	1.054	1.054	
4137	EASTGEN2	18	1	0	2	155	55	106	-62	1.054	1.054	

GENERATOR SUMMARY (Cont'd)												
BUS	NAME	BSVLT	# MACH		TYP	MW	MVAR	QMAX	QMIN	VSCHED	VACTUAL	REM
			ON	OFF								
4610	BRAMA EZ	44	2	0	2	83.9	18.5	41	-21	1.0126	1.0126	
4611	BRAMA JQ	44	1	0	2	51.7	23.3	25	-8	1.0204	1.0204	
4668	SITHEMG1	18	1	0	2	255	17	150	-75	1.0049	1.0049	
4669	SITHEMG2	18	1	0	2	252	16.7	150	-75	1.0049	1.0049	
4673	SITHEMG3	18	1	0	2	255	17	150	-75	1.0049	1.0049	
4678	GTAA STM	13.8	1	0	2	23	-4.4	13	-9	1.0008	1.0008	
4683	GTAA GT1	13.8	1	0	2	47	-2.5	26	-18	1.0008	1.0008	
4684	GTAA GT2	13.8	1	0	2	47	-2.9	26	-18	1.0007	1.0007	
6300	BECK1 G3	13.8	1	0	2	38.3	31.5	42	-42	1	1	
6301	BECK1 G4	13.8	1	0	2	41.1	18.9	57.7	-57.7	1.0005	1.0005	
6302	BECK1 G5	13.8	1	0	2	40	18.7	57.7	-57.7	1.0005	1.0005	
6303	BECK1 G6	13.8	1	0	2	41.1	18.9	57.7	-57.7	1.0005	1.0005	
6304	BECK1 G8	13.8	1	0	2	32.5	17.4	32.4	-16.2	1.0004	1.0004	
6305	BECK1 G9	13.8	1	0	2	32	13.6	41.8	-41.8	1.0003	1.0003	
6306	BECK1G10	13.8	1	0	2	38.3	13.6	46	-46	1.0003	1.0003	
6307	BECK1T60	13.2	1	0	2	0	0.2	45	-22.5	1.0005	1.0005	
6315	BECK2G25	13.8	2	0	3	1367.3	663.3	734.7	-568	1.053	1.053	
6316	BECK2PG1	14	3	0	2	51.1	-4.4	49.2	-58.8	1.0005	1.0005	
6317	BECK2PG4	14	3	0	2	62.4	-4.4	47.1	-51.9	1.0005	1.0005	
6320	DECEW G1	13.8	1	0	2	65.8	-10.3	12	-12	1.0137	1.0137	
6321	DECEW G2	13.8	1	0	2	60.5	-15.3	17.1	-17.1	1.0084	1.0084	
6322	DECEW4-9	2.4	6	0	2	26.8	13.3	19.2	-9.6	0.9999	0.9999	
6328	NANTICG1	22	1	0	2	0	215.3	309	-165	1.0007	1.0007	
6330	NANTICG3	22	1	0	2	0	219.5	309	-165	1.0003	1.0003	
6332	NANTICG5	22	1	0	2	0	176.1	263	-165	0.9808	0.9808	
6334	NANTICG7	22	1	0	2	0	149.8	263	-165	0.9736	0.9736	
6380	BECK1 G1	12	1	0	2	10	0.3	45	-22.5	1.05	1.05	
6430	GREYG101	0.575	1	0	2	15	4.2	4.9	-7.3	1.0498	1.0498	
6431	GREYG102	0.575	1	0	2	15	4.2	4.9	-7.3	1.0498	1.0498	
6432	GREYG103	0.575	1	0	2	15	4.2	4.9	-7.3	1.0498	1.0498	
6433	GREYG104	0.575	1	0	2	15	4.2	4.9	-7.3	1.0498	1.0498	
6506	BAY GE01	0.575	1	0	2	240	46.9	78.4	-116.8	0.9685	0.9685	
6507	BAY GE02	0.575	1	0	2	240	46.9	78.4	-116.8	0.9685	0.9685	
6508	BAY GE03	0.575	1	0	2	240	46.9	78.4	-116.8	0.9685	0.9685	
6509	BAY GE04	0.575	1	0	2	240	46.9	78.4	-116.8	0.9685	0.9685	
6900	BRUCEAG1	18.5	1	0	2	728	322.3	325	-255	0.9769	0.9769	
6901	BRUCEAG2	18.5	1	0	2	728	322.3	325	-255	0.9769	0.9769	
6902	BRUCEAG3	18.5	1	0	2	770	14.2	325	-255	0.9543	0.9543	
6903	BRUCEAG4	18.5	1	0	2	770	5.9	325	-255	0.9532	0.9532	
6904	BRUCEBG5	24	1	0	2	840	59.1	520	-380	0.9563	0.9563	
6905	BRUCEBG6	24	1	0	2	866	50.4	520	-380	0.9548	0.9548	
6906	BRUCEBG7	24	1	0	2	840	43.3	520	-380	0.9542	0.9542	
6907	BRUCEBG8	24	1	0	2	840	56.3	520	-380	0.9557	0.9557	
6944	BRUCE 1P	13.8	1	0	2	11.6	7	8	-6	1.0332	1.0332	
6947	BRUCE 2Q	13.8	1	0	2	11.6	7	8	-6	1.0273	1.0273	
6948	BRUCE 3R	13.8	1	0	2	11.6	7	8	-6	1.0318	1.0318	
6951	BRUCE 4S	13.8	1	0	2	11.6	7	8	-6	1.0295	1.0295	
6952	BRUCE 5P	13.8	1	0	2	12.1	7.8	9	-5	1.0182	1.0182	
6955	BRUCE 6Q	13.8	1	0	2	12.1	7.9	9	-5	1.0117	1.0117	
6956	BRUCE 7R	13.8	1	0	2	12.1	7.8	9	-5	1.0182	1.0182	
6959	BRUCE 8S	13.8	1	0	2	12.1	7.8	9	-5	1.0119	1.0119	
7083	CALGFEC1	18	1	0	2	210	39.1	115	-70	1.0109	1.0109	
7084	CALGFEC2	18	1	0	2	210	39.1	115	-70	1.0109	1.0109	
7085	CALGFEC3	18	1	0	2	210	39.1	115	-70	1.0109	1.0109	
7086	CALGFEC4	18	1	0	2	517	21.3	250	-180	0.9952	0.9952	
7095	INVSCG1	18	1	0	2	162	42.4	125	-70	1.0279	1.0279	
7096	INVSCG1	13.8	1	0	2	134	40.9	80	-50	1.0371	1.0371	
7097	INVSCG2	18	1	0	2	162	42.4	125	-70	1.0279	1.0279	
7098	INVSCG2	13.8	1	0	2	134	40.9	80	-50	1.0371	1.0371	
7606	AIM_GE01	0.575	1	0	2	24	6.1	7.8	-11.7	1.0149	1.0149	

GENERATOR SUMMARY (Cont'd)												
BUS	NAME	BSVLT	# MACH		TYP	MW	MVAR	QMAX	QMIN	VSCHED	VACTUAL	REM
			ON	OFF								
7607	AIM_GE02	0.575	1	0	2	24	6.1	7.8	-11.7	1.0149	1.0149	
7608	AIM_GE03	0.575	1	0	2	24	6.1	7.8	-11.7	1.0149	1.0149	
7609	AIM_GE04	0.575	1	0	2	24	6.1	7.8	-11.7	1.0149	1.0149	
7633	DOW CHEM	14.4	3	1	2	129.9	67.9	76	-38	1.0086	1.0086	
7951	WEST WG1	13.8	1	0	2	93	39.6	52	-52	1.0508	1.0508	
7952	WEST WG2	13.8	1	0	2	27.4	13.2	15.3	-15.3	1.0493	1.0493	
7953	W TRANSA	13.8	2	0	2	72	21.1	42.5	-42.5	1.0017	1.0017	
7954	TRANS861	13.8	1	0	2	100.2	56.3	61.5	-43.5	1.0387	1.0387	
7955	TRANS871	13.8	1	0	2	90.2	55.6	61.5	-43.5	1.0389	1.0389	
7956	TRANS881	13.8	1	0	2	90.2	55.6	61.5	-43.5	1.0389	1.0389	
7957	TRANS891	13.8	1	0	2	90.2	55.6	61.5	-43.5	1.0389	1.0389	
7960	BRIGHSG1	18	1	0	2	216	46.6	120	-70	1.0492	1.0492	
7961	BRIGH G2	18	1	0	2	155	35.4	106	-62	1.0494	1.0494	
7962	BRIGH G3	18	1	0	2	155	47.1	106	-62	1.0522	1.0522	
7963	IMPER G1	13.8	1	0	2	90	-8.5	48	-34	1	1	
7971	KINGCLR1	0.69	1	0	2	9	-0.8	4.1	-4.1	1.0007	1.0007	
7972	KINGCLR2	0.69	1	0	2	9	-0.8	4.1	-4.1	1.0007	1.0007	
7973	KINGCLR3	0.69	1	0	2	10.8	1.1	5.1	-5.1	1.0004	1.0004	
7974	KINGCLR4	0.69	1	0	2	10.8	1.1	5.1	-5.1	1.0004	1.0004	
7975	DVAR	0.48	1	0	2	0	-1.6	2	-2	1.0103	1.0103	
8738	MARTINDL	13.8	1	0	2	0	-0.1	15	-7.5	1.0125	1.0125	
8739	MARTINJZ	44	1	1	2	0	5.5	6.7	-3.3	0.9994	0.9994	
8877	MART L1	13.8	1	0	2	0	-7.2	15	-7.5	1.0144	1.0144	
8900	AUBRY G1	11	1	0	2	62.2	5	24.7	-24.7	1.004	1.004	
8901	AUBRY G2	11	1	0	2	62.2	5	24.7	-24.7	1.004	1.004	
8902	AUX SABL	4.16	1	0	2	3.7	1	2	-1	1.0781	1.0781	
8903	CANYN G1	13.8	1	0	2	60	-7.1	48.5	-24.3	1.0018	1.0018	
8906	CANYNG45	13.8	2	0	2	120	-14.4	72	-72	1.0037	1.0037	
8907	CARM FL	4.16	1	1	2	8.5	3	4.5	-2.2	1.0003	1.0003	
8909	CRYST GS	2.3	4	0	2	6.8	0.7	4	-2	1.0006	1.0006	
8911	HARM G12	13.8	2	0	2	121.7	-11.3	85.4	-85.4	1.0029	1.0029	
8914	HOLD G12	13.8	2	0	2	47.5	13.1	36.8	-36.8	1.003	1.003	
8915	HOLD G34	13.8	2	0	2	47.5	13.4	36.8	-36.8	1.0031	1.0031	
8916	HOLD G56	13.8	2	0	2	47.6	6	36.8	-36.8	1.1012	1.1012	8108
8917	HOLD G78	13.8	2	0	2	47.6	12.6	19.8	-19.8	1.0029	1.0029	
8918	KIPL G12	13.8	2	0	2	120.1	-11.7	107.6	-53.8	1.0028	1.0028	
8920	LIT LG12	13.8	2	0	2	113.6	15.8	95.4	-95.4	1.0024	1.0024	
8922	LOW NOG1	13.8	1	0	2	101.5	-0.9	44	-44	1.1079	1.1079	8147
8923	LOW NOG2	13.8	1	0	2	101.5	-1.1	44	-44	1.0043	1.0043	
8924	NPWRG6	13.8	1	0	2	10	-0.9	21	-16	1.0016	1.0016	
8925	N PWR C	13.8	1	1	2	22	12.8	13.6	-13.6	0.992	0.992	
8926	NPWRG123	13.8	3	0	2	53.4	-3.5	36.9	-16	1.0019	1.0019	
8927	NPWR G45	13.8	2	0	2	38.7	0.2	25.1	-25.1	1.0017	1.0017	
8928	OTT RPG1	13.8	1	0	2	41	12.4	28	-28	0.9999	0.9999	
8929	OTT RPG2	13.8	1	0	2	41	12.9	28	-28	0.9999	0.9999	
8930	TUNIS GS	13.8	2	0	2	63.1	8.2	35.1	-35.1	1.0012	1.0012	
8931	RAYNER	13.8	2	0	2	35.5	8.6	26.4	-26.4	1.0016	1.0016	
8932	RED RKGS	13.8	2	0	2	34.9	3.6	29	-29	1.0024	1.0024	
8933	SERP RIV	4.16	2	0	2	6.6	-1.1	3.4	-3.4	1.0008	1.0008	
8936	TCPL KAP	13.8	2	0	2	49.8	2.3	27.7	-27.7	1.0013	1.0013	
8937	WELLS G2	13.8	1	0	2	92.8	39.4	60	-60	1.0066	1.0066	
8939	WELLS G1	13.8	1	0	2	92.8	39.3	60	-60	1.0066	1.0066	
8944	NORPG1G3	13.8	2	0	2	72.7	-16.1	40.4	-40.4	1.0032	1.0032	
8945	NORPO G2	13.8	1	0	2	43.4	-15.5	24.1	-24.1	1.0027	1.0027	
8946	NAGAGAMI	4.16	2	0	2	12.2	3.1	9	-9	1.0004	1.0004	
8947	LSR G1	4	1	0	2	3.7	-1.7	9.2	-9.2	1.0004	1.0004	
8948	TCPL NB	13.8	2	0	2	49.8	10.6	27.7	-27.7	1.0974	1.0974	8173
8949	CALSTOCK	13.8	1	0	2	36.9	3.1	20.9	-20.9	1.0012	1.0012	
8973	WAWAITGS	12	4	0	2	4	-2.5	5.8	-5.8	0.9985	0.9985	
8975	OTT RPG3	13.8	1	0	2	41	13.1	28	-28	0.9999	0.9999	
8976	OTT RPG4	13.8	1	0	2	41	13.8	28	-28	0.9998	0.9998	

GENERATOR SUMMARY (Cont'd)												
BUS	NAME	BSVLT	# MACH		TYP	MW	MVAR	QMAX	QMIN	VSCHED	VACTUAL	REM
9670	LAKEHDT8	13.8	1	0	2	0	-16.9	60	-30	1.015	1.015	
9710	MURIL B1	25	4	0	2	23.6	2.3	15.1	-15.1	1.0001	1.0001	
9900	ATIKOKAN	18	1	0	2	200	-53.7	70	-80	0.9522	0.9522	
9907	TBAY G1	13.8	1	0	2	0	48.5	65	-20	1.0002	1.0002	
9908	TBAY G2	18	1	0	2	160	62.9	100	-27	1.0013	1.0013	
9909	TBAY G3	18	1	0	2	150	43.7	100	-27	1.0009	1.0009	
9922	AGUASABO	13.8	2	0	2	32.9	17.3	23.8	-23.8	1.0021	1.0021	
9923	ALEXANDR	12	5	0	2	57.2	-2.2	48.1	-52	1.0013	1.0013	
9924	WAWATAY	4.16	3	0	2	12.3	1	6.6	-6.6	1.0074	1.0074	
9926	CAMER 17	12	2	0	2	24.2	-3.4	17	-17	1.0009	1.0009	
9927	CAMER234	12	3	0	2	20.7	-3.3	16	-16	1.0009	1.0009	
9928	CAMER 56	12	2	0	2	14.6	10.8	12	-8	0.9916	0.9916	
9929	CARIBOU	13.8	3	0	2	76	28.4	60.4	-62.2	1.0002	1.0002	
9930	EAR FLSA	6.6	4	0	2	10.1	-5.5	11.6	-5.9	1.0309	1.0309	
9942	WESTCST1	13.8	1	0	2	50	25.5	30.3	-30.3	0.9902	0.9902	
9943	WESTCST2	13.8	1	0	2	39	19.1	23.9	-23.9	0.979	0.979	
9947	MAN FG12	13.8	2	0	2	22.2	2.7	26	-26	0.9984	0.9984	
9948	MAN FG34	13.8	2	0	2	22.6	2.4	26	-26	0.9984	0.9984	
9949	MAN FG5	13.8	1	0	2	11.5	1.4	13.5	-6.7	0.9991	0.9991	
9952	PINE PG1	13.8	1	0	2	23.4	3	20	-20	1.0004	1.0004	
9953	PINE PG2	13.8	1	0	2	23.4	3.1	20	-20	1.0004	1.0004	
9954	PINE PG3	13.8	1	0	2	26.6	3.3	17	-17	1.0003	1.0003	
9955	PINE PG4	13.8	1	0	2	26.6	3.3	17	-17	1.0003	1.0003	
9958	SILVER F	13.8	1	0	2	36.3	11.1	30.7	-30.7	1.0012	1.0012	
9960	TCPL NIP	13.8	2	0	2	36.2	-4.1	19.4	-19.4	1.0011	1.0011	
9961	WHITEDOG	13.8	3	0	2	60.6	-11.4	65.4	-65.4	0.9013	0.9013	
9962	VAL FLS	4.16	2	0	2	8	-3.9	4	-4	1.045	1.045	
9972	BLUEH_01	0.69	1	0	-2	3.6	-1.6	-1.6	-1.6	1.0789	1.079	
9973	BLUEH_03	0.69	1	0	-2	7.2	-3.3	-3.3	-3.3	1.0779	1.0781	
9974	BLUEH_04	0.69	1	0	-2	7.2	-3.3	-3.3	-3.3	1.0779	1.0781	
9975	BLUEH_05	0.69	1	0	-2	7.2	-3.3	-3.3	-3.3	1.0779	1.0781	
9976	BLUEH_06	0.69	1	0	-2	7.2	-3.3	-3.3	-3.3	1.0779	1.0781	
9977	BLUEH_07	0.69	1	0	-2	7.2	-3.3	-3.3	-3.3	1.0779	1.0781	
9978	BLUEH_08	0.69	1	0	-2	7.2	-3.3	-3.3	-3.3	1.0779	1.0781	
10130	HOLINGG1	12	1	0	2	10	3.1	9.7	-5	1.002	1.002	
10141	SCOTT G1	12	1	0	2	4	3.1	6	-3	1.0003	1.0003	
10143	SCOTT G2	12	1	0	2	8	2.8	6	-3	1.0003	1.0003	
10165	MACKYG12	12	2	0	2	18	-0.1	12.2	-8.3	1.0019	1.0019	
10166	MACKY G3	12	1	0	2	22.5	-1.8	15.3	-10.4	1.0018	1.0018	
10169	GARTSHO	12	1	0	2	20	-1.6	9.7	-5	1.0064	1.0064	
10171	HOGG G1	12	1	0	2	10	-0.4	7.3	-3.6	1.0375	1.0375	
10173	ANDREWG3	12	1	0	2	20.1	-4	14.2	-7.1	1.0236	1.0236	
10174	ANDREWG2	12	1	0	2	7	-1	4.9	-2.5	1.0317	1.0317	
10175	ANDREWG1	12	1	0	2	7	-1	4.9	-2.5	1.0317	1.0317	
10203	CLERG G1	4.2	1	0	2	15.1	5.6	5.9	-3	0.9774	0.9774	
10204	CLERG G2	4.2	1	0	2	15.1	5.6	5.9	-3	0.9779	0.9779	
10205	CLERG G3	4.2	1	0	2	15.1	5.6	5.9	-3	0.9773	0.9773	
10207	LKSUPGT1	13.8	1	0	2	43.4	8.9	23.5	-11.7	1.0038	1.0038	
10208	LKSUPGT2	13.8	1	0	2	20.1	7.1	23.5	-11.7	1.0037	1.0037	
10209	LKSUPSG1	13.8	1	0	2	24	4.5	13	-6.5	1.0021	1.0021	
10217	HIFLSRG1	12	1	0	2	11.8	5.9	11.2	-11.2	1.0007	1.0007	
10218	HIFLSRG2	12	1	0	2	11.8	5.9	11.2	-11.2	1.0007	1.0007	
10257	GLPPR_01	0.575	1	0	2	9	2.7	2.9	-4.4	1.027	1.027	
10258	GLPPR_02	0.575	1	0	2	9	2.7	2.9	-4.4	1.027	1.027	
10259	GLPPR_03	0.575	1	0	2	9	2.7	2.9	-4.4	1.027	1.027	
10260	GLPPR_04	0.575	1	0	2	9	2.7	2.9	-4.4	1.027	1.027	
10261	GLPPR_05	0.575	1	0	2	9	2.7	2.9	-4.4	1.027	1.027	
10262	GLPPR_06	0.575	1	0	2	9	2.7	2.9	-4.4	1.027	1.027	
10263	GLPPR_07	0.575	1	0	2	9	2.7	2.9	-4.4	1.027	1.027	
10264	GLPPR_08	0.575	1	0	2	9	2.7	2.9	-4.4	1.027	1.027	
10265	GLPPR_09	0.575	1	0	2	9	2.7	2.9	-4.4	1.027	1.027	
10266	GLPPR_10	0.575	1	0	2	9	2.7	2.9	-4.4	1.027	1.027	
10267	GLPPR_11	0.575	1	0	2	10.5	3.2	3.4	-5.1	1.0271	1.0271	
28849	19STCPP	345	1	0	2	842.4	342.5	9999	-9999	1.0428	1.0428	
29003	19B3N PS	220	1	0	2	803.5	354.9	9999	-9999	1.0874	1.0874	
67556	WHTSL1 4	220	1	0	2	239.2	61.2	9999	-9999	1.1235	1.1235	
67589	WHTSL2 4	220	1	0	2	239.1	61.3	9999	-9999	1.1235	1.1235	
79584	NIAG 345	345	1	0	2	306.2	73.1	9999	-9999	1.0503	1.0503	
79589	MOSES E	230	1	0	2	535.1	1.3	9999	-9999	1.0344	1.0344	
79592	NIAGAR2W	230	1	0	2	1489.8	600.2	9999	-9999	1.0211	1.0211	

Not in-service GENERATOR SUMMARY												
# MACH												
BUS	NAME	BSVLT	ON	OFF	TYP	MW	MVAR	QMAX	QMIN	VSCHED	VACTUAL	REM
9604	ST FF L2	6.6	0	8	1	0	0	0	0	1	1.092	
8938	SMOKG1-4	6.6	0	4	1	0	0	0	0	1	1.0727	
6392	NIAGAR78	12	0	3	4	0	0	0	0	1	1.1988	
8628	CONISTNP	22	0	3	1	0	0	0	0	1	0.9985	
908	CHATFG67	13.8	0	2	4	0	0	0	0	0.975	0.974	
909	CHATFG89	13.8	0	2	4	0	0	0	0	0.975	0.974	
6083	JARVISBY	27.6	0	2	1	0	0	0	0	1	1.0119	
6390	NIAGARY5	12	0	2	4	0	0	0	0	1	1.1988	
6391	NIAGARY5	12	0	2	4	0	0	0	0	1	1.1988	
6393	NIAGARY1	12	0	2	4	0	0	0	0	1	1.1988	
8940	EDDY F89	13.8	0	2	1	0	0	0	0	1	1.026	
8943	TEMSRG12	2.3	0	2	1	0	0	0	0	1	1.0942	
9770	MUSSELWH	4.16	0	2	1	0	0	0	0	1	0.9532	
9773	MURIL B2	25	0	2	1	0	0	0	0	1.0117	1.0139	
9925	CALM LK	6.6	0	2	1	0	0	0	0	1	1.11	
9959	STURGN F	6.6	0	2	1	0	0	0	0	1	1.1064	
926	STEWVLG1	13.2	1	2	2	17.8	6.2	17	-17	1.0004	1.0004	
1904	LENNOXG4	20	0	1	4	0	0	0	0	1	0.9938	
2934	PIC A G2	24	0	1	1	0	0	0	0	0.9952	0.9939	
2935	PIC A G3	24	0	1	1	0	0	0	0	0.9965	0.9954	
3736	MANBYET8	13.8	0	1	1	0	0	0	0	1	0.9846	
3743	MANBYWT1	13.8	0	1	1	0	0	0	0	1	0.9816	
3744	MANBYWT2	13.8	0	1	1	0	0	0	0	1	0.9814	
4632	SITHEBG1	18	0	1	1	0	0	0	0	1	0.9988	
4633	SITHEBG2	18	0	1	1	0	0	0	0	1	0.9988	
4636	SITHEBG3	18	0	1	1	0	0	0	0	1	0.9988	
4637	SITHEBG4	18	0	1	1	0	0	0	0	1	0.9988	
6271	IMP NANC	28	0	1	1	0	0	0	0	1	1.0031	
6329	NANTICG2	22	0	1	1	0	0	0	0	1.015	0.9496	
6331	NANTICG4	22	0	1	1	0	0	0	0	1.015	0.9497	
6333	NANTICG6	22	0	1	1	0	0	0	0	1.037	0.9469	
6335	NANTICG8	22	0	1	1	0	0	0	0	1.0358	0.9469	
6356	NANTRS1A	4.16	0	1	1	0	0	0	0	1	0.9861	
6381	BECK1 G2	12	0	1	1	0	0	0	0	1	1.0478	
6385	BECK25G7	12	0	1	1	0	0	0	0	1	1.0478	
6387	BECK1T40	13.2	0	1	1	0	0	0	0	1	1.1173	
6394	NIAGARY2	12	0	1	4	0	0	0	0	1	1.1988	
7409	AGRAS-G1	13.8	0	1	1	0	0	0	0	1	0.8786	
7757	WALK EQ	27.6	0	1	1	0	0	0	0	1	0.9963	
8654	EDDY FG5	4.16	0	1	1	0	0	0	0	1	1.0272	
8904	CANYN G2	13.8	0	1	1	0	0	0	0	1	0.922	
8905	CANYN G3	13.8	0	1	1	0	0	0	0	1	0.922	
8941	TEM SRG4	13.8	0	1	1	0	0	0	0	1	1.0506	
8942	TEM SRG3	13.8	0	1	1	0	0	0	0	1	1.0486	
9615	WEYH DRY	13.2	0	1	1	0	0	0	0	1	1.0282	
9616	BOWATRT1	13.8	0	1	1	0	0	0	0	1	1.0077	
9620	BOWAT L5	4.16	0	1	1	0	0	0	0	1	1.0158	
9668	KIMB CLA	13.8	0	1	1	0	0	0	0	1	1.0006	
9669	LAKEHDT7	13.8	0	1	1	0	0	0	0	1	1.0261	
9752	AVTB G4	13.8	0	1	1	0	0	0	0	1	0.9387	
10137	MCPHALG1	12	0	1	1	0	0	0	0	1	0.974	
10138	MCPHALG2	12	0	1	1	0	0	0	0	1	0.974	
10147	MISSIOFL	6.6	0	1	1	0	0	0	0	1	0.9931	
10149	HARRISG1	6.6	0	1	1	0	0	0	0	1	0.9931	
10151	STEEPHL	6.6	0	1	1	0	0	0	0	1	0.9933	
10268	GLPPR_01	0.575	0	1	1	0	0	0	0	0.9917	0.9943	
10269	GLPPR_02	0.575	0	1	1	0	0	0	0	0.9917	0.9943	
10270	GLPPR_03	0.575	0	1	1	0	0	0	0	0.9917	0.9943	
10271	GLPPR_04	0.575	0	1	1	0	0	0	0	0.9917	0.9943	
10272	GLPPR_05	0.575	0	1	1	0	0	0	0	0.9917	0.9943	
10273	GLPPR_06	0.575	0	1	1	0	0	0	0	0.9917	0.9943	
10274	GLPPR_07	0.575	0	1	1	0	0	0	0	0.9917	0.9943	
10275	GLPPR_08	0.575	0	1	1	0	0	0	0	0.9917	0.9943	
10276	GLPPR_09	0.575	0	1	1	0	0	0	0	0.9917	0.9943	
10277	GLPPR_10	0.575	0	1	1	0	0	0	0	0.9917	0.9943	
10278	GLPPR_11	0.575	0	1	1	0	0	0	0	0.9917	0.9943	
8739	MARTINJZ	44	1	1	2	0	5.5	6.7	-3.3	0.9994	0.9994	
8907	CARM FL	4.16	1	1	2	8.5	3	4.5	-2.2	1.0003	1.0003	
8925	N PWR C	13.8	1	1	2	22	12.8	13.6	-13.6	0.992	0.992	
7633	DOW CHEM	14.4	3	1	2	129.9	67.9	76	-38	1.0086	1.0086	

SWITCHED SHUNT DATA										
BUS#	MOD	VHI	VLO	MVAR	SHUNTS (NUMBER OF BLOCKS, MVAR/BLOCK)					REMOTE
307	0	1.05	1	187.36	2	93.68				
309	0	1.05	1	94.1	1	94.1				
600	0	1.07	0.9	17.72	1	17.72				
601	0	1.07	0.9	17.72	1	17.72				
622	0	1.07	0.9	26.45	1	26.45				
623	0	1.07	0.9	17.72	1	17.72				
624	0	1.07	0.9	17.72	1	17.72				
683	0	1.07	0.9	57.1	2	28.55				
685	0	1.095	1.065	0	1	-141.43				1
686	0	1.09	1.07	0	1	-141.33				1
709	0	1.07	0.9	17.72	1	17.72				
710	0	1.07	0.9	17.72	1	17.72				
718	0	1.07	0.9	8.14	1	8.14				
719	0	1.07	0.9	8.14	1	8.14				
724	0	1.07	0.9	17.72	1	17.72				
725	0	1.07	0.9	17.72	1	17.72				
754	0	1.07	0.9	31.2	1	31.2				
755	0	1.07	0.9	31.2	1	31.2				
765	0	1.07	0.9	16.28	1	16.28				
766	0	1.07	0.9	16.28	1	16.28				
771	0	1.07	0.9	28.54	2	14.27				
779	0	1.07	0.9	16.28	1	16.28				
789	0	1.07	0.9	16.28	1	16.28				
790	0	1.07	0.9	16.28	1	16.28				
796	0	1.07	0.9	28.55	1	28.55	1	27.17		
800	0	1.07	0.9	14.77	1	14.77				
801	0	1.07	0.9	14.77	1	14.77				
802	0	1.07	0.9	14.77	1	14.77				
809	0	1.07	0.9	39.52	2	19.76				
834	0	1.07	0.9	16.28	1	16.28				
835	0	1.07	0.9	16.28	1	16.28				
1605	0	1.07	0.9	59.28	2	29.64				
1631	0	1.07	0.9	59.66	2	29.83				
1644	0	1.07	0.9	43.44	1	21.84	1	21.6		
1650	0	1.07	0.9	0	2	19.76				
1670	2	1.0565	1.0065	0	1	-147.63				1001
1671	0	1.1	1.05	-148.2	1	-148.2				1001
1700	0	1.07	0.9	36.24	2	18.12				
1705	0	1.07	0.9	19.76	1	19.76				
1733	0	1.07	0.9	38.7	1	18.94	2	19.76		
1746	0	1.07	0.9	19.76	2	19.76				
2600	0	1.07	0.9	19.84	1	19.84				
2601	0	1.07	0.9	19.84	1	19.84				
2608	0	1.07	0.9	36.24	2	18.12				
2610	0	1.07	0.9	36.24	2	18.12				
2617	0	1.07	0.9	39.52	2	19.76				
2621	0	1.07	0.9	19.84	1	19.84				
2622	0	1.07	0.9	19.84	1	19.84				
2623	0	1.07	0.9	21.49	1	21.49				
2624	0	1.07	0.9	21.49	1	21.49				
2637	0	1.07	0.9	21.49	1	21.49				
2638	0	1.07	0.9	21.49	1	21.49				
2656	0	1.07	0.9	52.7	2	26.35				
2670	0	1.07	0.9	21.49	1	21.49				
2671	0	1.07	0.9	21.49	1	21.49				
2679	0	1.07	0.9	35	1	35				
2684	0	1.07	0.9	39.68	2	19.84				
2685	0	1.07	0.9	21.49	1	21.49				2686
2686	0	1.07	0.9	21.49	1	21.49				
2693	0	1.07	0.9	19.76	1	19.76				

SWITCHED SHUNT DATA (Cont'd)										
BUS#	MOD	VHI	VLO	MVAR	SHUNTS (NUMBER OF BLOCKS, MVAR/BLOCK)					REMOTE
2694	0	1.07	0.9	19.76	1	19.76				
2697	0	1.07	0.9	21.49	1	21.49				
2698	0	1.07	0.9	21.49	1	21.49				
2708	0	1.07	0.9	0	1	3.6	1	2.4		
2709	0	1.07	0.9	0	1	3.6	1	2.4		
2712	0	1.07	0.9	39.52	2	19.76				
2713	0	1.07	0.9	42.82	2	21.41				
2726	0	1.07	0.9	21.49	1	21.49				
2727	0	1.07	0.9	21.49	1	21.49				
2728	0	1.07	0.9	21.49	1	21.49				
2729	0	1.07	0.9	21.49	1	21.49				
2740	0	1.07	0.9	39.68	2	19.84				
2753	0	1.07	0.9	52.7	2	26.35				
2756	0	1.07	0.9	21.49	1	21.49				2757
2757	0	1.07	0.9	21.49	1	21.49				
2766	0	1.07	0.9	52.7	2	26.35				
2767	0	1.07	0.9	51.05	1	26.35	1	24.7		
3107	0	1.1364	1.08	260.62	1	260.62				
3108	0	1.1364	1.08	260.62	1	260.62				
3300	0	1.05	1	201.47	1	95.15	1	106.32		
3301	0	1.05	1	193.51	1	107.48	1	86.03		
3305	0	1.05	1	106.32	1	106.32				
3306	0	1.05	1	86.03	1	86.03				
3377	0	1.05	1	85.97	1	85.97				
3678	0	1.07	0.9	39.68	2	19.84				
3679	0	1.07	0.9	39.68	2	19.84				
3684	0	1.07	0.9	21.49	1	21.49				
3685	0	1.07	0.9	21.49	1	21.49				
3710	0	1.07	0.9	22.04	2	22.04				
3711	0	1.07	0.9	15.43	2	15.43				
3734	0	1.07	0.9	19.84	1	19.84				
3740	0	1.07	0.9	21.49	1	21.49				
3741	0	1.07	0.9	21.49	1	21.49				
3742	0	1.07	0.9	19.84	1	19.84				
3758	0	1.07	0.9	19.84	2	19.84				
3781	0	1.07	0.9	14.88	1	14.88				
3782	0	1.07	0.9	14.88	1	14.88				
3783	0	1.07	0.9	14.88	1	14.88				
4103	0	1.1364	1.08	319.25	1	319.25				
4104	0	1.1364	1.08	232.32	1	232.32				
4105	0	1.1364	1.08	319.05	1	319.05				
4600	0	1.07	0.9	19.84	1	19.84				
4601	0	1.07	0.9	19.84	1	19.84				
4602	0	1.07	0.9	19.84	1	19.84				
4603	0	1.07	0.9	19.84	1	19.84				4602
4608	0	1.07	0.9	23.14	1	23.14				
4609	0	1.07	0.9	23.14	1	23.14				
4610	0	1.07	0.9	52.7	2	26.35				
4611	0	1.07	0.9	52.7	2	26.35				
4640	0	1.07	0.9	23.14	1	23.14				4641
4641	0	1.07	0.9	23.14	1	23.14				
4642	0	1.07	0.9	52.7	2	26.35				
4643	0	1.07	0.9	52.7	2	26.35				
4650	0	1.07	0.9	28.65	1	28.65				
4651	0	1.07	0.9	29.76	1	29.76				
4652	0	1.07	0.9	21.49	1	21.49				
4653	0	1.07	0.9	21.49	1	21.49				
4658	0	1.07	0.9	21.49	1	21.49				
4659	0	1.07	0.9	21.49	1	21.49				
4660	0	1.07	0.9	21.49	1	21.49				4661
4661	0	1.07	0.9	21.49	1	21.49				4660
4666	0	1.07	0.9	19.84	1	19.84				
4667	0	1.07	0.9	19.84	1	19.84				
4690	0	1.07	0.9	21.49	2	21.49				
4691	0	1.07	0.9	52.7	2	26.35				
4697	0	1.07	0.9	19.84	1	19.84				

SWITCHED SHUNT DATA (Cont'd)										
BUS#	MOD	VHI	VLO	MVAR	SHUNTS (NUMBER OF BLOCKS, MVAR/BLOCK)					REMOTE
4698	0	1.07	0.9	19.84	1	19.84				
4710	0	1.07	0.9	21.49	2	21.49				
4711	0	1.07	0.9	21.49	2	21.49				
4712	0	1.07	0.9	52.7	2	26.35				
4723	0	1.07	0.9	42.98	2	21.49				
4724	0	1.07	0.9	21.49	2	21.49				
4727	0	1.07	0.9	26.45	1	26.45				
4728	0	1.07	0.9	21.49	1	21.49				
4729	0	1.07	0.9	21.49	1	21.49				4728
4730	0	1.07	0.9	21.49	1	21.49				
4731	0	1.07	0.9	21.49	1	21.49				
4736	0	1.07	0.9	26.35	2	26.35				
4737	0	1.07	0.9	52.7	2	26.35				
4758	0	1.07	0.9	21.6	1	21.6				
4759	0	1.07	0.9	21.6	1	21.6				
4770	0	1.07	0.9	39.68	2	19.84				
4772	0	1.07	0.9	32.94	2	16.47				
5102	0	1.1364	1.08	465.01	1	232.32	1	232.69		
5103	0	1.12	1.1	364.81	1	175.08	1	189.73		
5104	0	1.1	1.08	319.05	1	319.05				
5106	0	1.1	1.08	319.05	1	319.05				
5400	0	1.07	1	0	2	114.18				
5403	0	1.05	1	107.48	1	107.48				
5404	0	1.05	1	190.47	1	96.79	1	93.68		
5913	0	1.07	0.9	26.45	1	26.45				
5926	0	1.07	0.9	9.58	1	9.58				
5938	0	1.07	0.9	19.84	1	19.84				
5940	0	1.07	0.9	19.84	1	19.84				
5941	0	1.07	0.9	19.84	1	19.84				
5944	0	1.07	0.9	19.84	1	19.84				
5956	0	1.07	0.9	21.6	1	21.6				
5957	0	1.07	0.9	19.84	1	19.84				
5958	0	1.0504	1.0165	0	1	-15.83				5403
5960	0	1.05	1	0	1	-16.79				5403
5969	0	1.07	0.9	10.8	1	10.8				
5970	0	1.07	0.9	10.8	1	10.8				
5979	0	1.07	0.9	19.42	1	19.42				
5987	2	1.0021	0.9521	19.74	2	9.92				
5991	0	1.07	0.9	18.37	1	18.37				
5998	0	1.07	0.9	19.84	1	19.84				
6026	0	1.07	0.9	19.84	1	19.84				
6033	0	1.07	0.9	16.53	1	16.53				
6039	0	1.07	0.9	9.92	1	9.92				
6054	0	1.07	0.9	19.84	1	19.84				
6059	0	1.07	0.9	19.84	1	19.84				
6060	0	1.07	0.9	19.84	1	19.84				
6140	0	1.07	0.9	19.84	1	19.84				
6141	0	1.07	0.9	19.84	1	19.84				
6147	0	1.07	0.9	19.84	1	19.84				
6160	0	1.07	0.9	19.84	1	19.84				
6161	0	1.07	0.9	19.84	1	19.84				
6164	0	1.07	0.9	10.8	1	10.8	2	12.12		
6168	0	1.07	0.9	19.84	1	19.84				
6180	0	1.07	0.9	9.88	2	9.88				
6241	0	1.07	0.9	18.18	1	18.18				
6242	0	1.07	0.9	18.18	1	18.18				
6503	0	1.12	1.1	189.73	1	189.73				
6705	0	1.07	0.9	39.52	2	19.76				
6726	0	1.1182	1.0864	0	1	-143.73				
6727	0	1.1182	1.0864	0	1	-141.59				
6734	0	1.07	0.9	21.6	1	21.6				

SWITCHED SHUNT DATA (Cont'd)											
BUS#	MOD	VHI	VLO	MVAR	SHUNTS (NUMBER OF BLOCKS, MVAR/BLOCK)					REMOTE	
6743	0	1.07	0.9	14.82	1	14.82					
6757	0	1.07	0.9	51.98	1	24.7	1	27.28			
6762	0	1.07	0.9	39.52	2	19.76					
6772	0	1.07	0.9	49.4	2	24.7					
6787	0	1.07	0.9	61.12	2	19.76	1	21.6			
6790	0	1.07	0.9	19.76	1	19.76					
6908	0	1.1	1.01	-147.34	1	-147.34					6400
6909	0	1.1	1.02	-147.63	1	-147.63					6400
6910	0	1.1	1.03	-147.63	1	-147.63					6400
7100	0	1.1364	1.08	325.38	2	162.69					
7101	0	1.1364	1.08	350.16	2	175.08	1	162.69			
7108	0	1.1364	1.08	840.4	4	210.1					
7300	0	1.05	1	107.54	1	107.54					
7301	0	1.07	1	94.1	1	94.1					
7302	0	1.07	1	67.86	1	67.86					
7402	2	0.9181	0.9181	10.63	2	5.4					
7600	0	1.07	0.9	0	1	5.4					
7624	0	1.07	0.9	20.72	1	10.8	1	9.92			
7629	0	1.07	0.9	0	1	19.84					
7632	0	1.07	0.9	23.14	2	23.14					
7645	0	1.07	0.9	21.6	2	21.6					
7652	0	1.07	0.9	13.22	2	6.61					
7656	0	1.07	0.9	0	1	19.84					
7661	0	1.07	0.9	30.48	2	15.24					
7669	0	1.07	0.9	23.14	2	23.14					
7670	0	1.07	0.9	0	1	20.4					
7671	0	1.07	0.9	0	1	19.17					
7674	0	1.07	0.9	61.28	1	21.6	1	19.84	2	9.92	
7676	0	1.07	0.9	42.98	1	23.14	1	19.84			
7677	0	1.07	0.9	46.28	2	23.14					
7683	0	1.07	0.9	24.38	2	12.19					
7686	0	1.09	1.08	-142.65	1	-142.65					7000
7687	0	1.0925	1.0775	-142.65	1	-142.65					7000
7688	0	1.095	1.075	-142.65	1	-142.65					7000
7689	0	1.0975	1.0725	-142.65	1	-142.65					7000
7690	0	1.1	1.07	-141.75	1	-141.75					7000
7697	0	1.07	0.9	21.49	1	21.49					
7698	0	1.07	0.9	21.49	1	21.49					
7709	0	1.07	0.9	19.84	1	19.84					
7710	0	1.07	0.9	19.84	1	19.84					
7722	0	1.07	0.9	10.8	1	10.8					
7729	0	1.07	0.9	19.84	2	19.84					
7733	0	1.07	0.9	0	2	4.8					
7737	0	1.07	0.9	43.2	2	21.6					
7739	0	1.07	0.9	9.92	2	9.92					
7750	2	0.97	0.92	35.72	2	18					
7757	0	1.07	0.9	21.6	1	21.6					
7758	0	1.07	0.9	19.56	1	19.56					
7759	0	1.07	0.9	0	1	10.8					
7760	0	1.07	0.9	9.92	1	9.92					
7767	0	1.07	0.9	19.84	2	19.84					
7772	0	1.07	0.9	19.84	1	19.84					
7964	0	1.12	1.09	4	1	4					
7968	0	1.1	1.02	0	1	4					
7971	0	1.0567	1.0567	0	1	4.1					
7972	0	1.0567	1.0567	0	1	4.1					
7973	0	1.0135	1.0135	0	1	5.04					
7974	0	1.0135	1.0135	0	1	5.04					
8100	0	1.1364	1.08	0	1	74.7					
8104	0	1.1364	1.04	149.4	1	149.4					
8258	0	1.076	0.9	0	2	23.42					

SWITCHED SHUNT DATA (Cont'd)											
BUS#	MOD	VHI	VLO	MVAR	SHUNTS (NUMBER OF BLOCKS, MVAR/BLOCK)					REMOTE	
8321	0	1.05	1	0	1	13.44					
8539	0	1.05	1	-4.37	1	-4.37					
8540	0	1.05	1	-4.88	1	-2.44	1	-2.44			
8542	0	1.05	1	-2.44	1	-2.44					
8645	0	1.05	1	0	1	10.8					
8646	0	1.05	1	0	1	11.68					
8665	0	1.07	0.9	10.8	1	10.8					
8683	0	1.09	1.065	0	1	-139.77					8000
8684	0	1.1	1.05	0	1	-50.91					8000
8685	0	1.095	1.055	0	1	-50.91					8000
8686	0	1.085	1.06	0	1	-147.63					8000
8693	0	1.07	0.9	0	2	5.36					
8712	0	1.07	0.9	11.68	1	6.09	1	5.59			
8718	0	1.07	0.9	9.88	1	9.88					
8758	0	1.07	0.9	0	1	9.6					
8769	0	1.1	1.01	0	1	-50.67					
8771	0	1.08	1.03	0	1	-50.67					
8824	0	1.136	1.08	-40	1	-40	1	32.64			8112
8825	0	1.136	1.08	-40	1	-40	1	32.64			8112
9301	0	1.05	1	0	1	67.22					
9304	0	1.0292	0.9953	40.32	2	20.16					
9305	0	1.076	0.9	96.61	1	96.61					
9608	0	1.0655	1.0549	0	1	17.69	1	15.6			
9648	0	1.1202	1.04	-36.16	1	-36.16					9104
9655	0	1.0655	1.0549	0	1	15.6	1	15.77			
9663	0	1.1364	1.0909	-40.04	1	-40.04					9107
9682	0	1.025	0.9911	0	1	-39.55					9392
9689	0	1.0737	1.0356	0	1	33.06					9306
9690	0	1.0737	1.0356	0	1	33.06					9306
9723	0	1.07	0.9	9.88	1	9.88					
9770	0	1.0654	0.94	0	2	13.5					
9972	0	1.0568	1.0568	1.66	1	1.66					
9973	0	1.0559	1.0559	3.24	1	3.24					
9974	0	1.0559	1.0559	3.24	1	3.24					
9975	0	1.0559	1.0559	3.24	1	3.24					
9976	0	1.0559	1.0559	3.24	1	3.24					
9977	0	1.0559	1.0559	3.24	1	3.24					
9978	0	1.0559	1.0559	3.24	1	3.24					
9994	0	1.07	1.02	30	1	30	1	5	1	5	
10106	0	1.04	0.96	19.8	1	19.8					
10107	0	1.04	0.96	19.8	1	19.8					
10188	0	1.07	0.9	10	1	10					
10189	0	1.07	0.9	20	1	20					
10192	0	1.0633	1.0527	20	1	20					
10193	0	1.0633	1.0527	20	1	20					
85716	0	1.05	0.95	29	2	14.5					

ABID

In this Appendix, overloads and voltage violations are listed. These are local problems (which may be reported by the PSS/E program due to different ratings or voltage limits) and do not pertain to the main transmission grid. However, these are included in this Appendix for the sake of completeness.

BASE LOADING VIOLATIONS
OUTPUT FOR AREA 1 [IESO]
BRANCH LOADINGS ABOVE 100.0 % OF RATING SET A:

X-----FROM BUS-----X				X-----TO BUS-----X				CURRENT(MVA)			
BUS	NAME	BSKV	AREA	BUS	NAME	BSKV	AREA	CKT	LOADING	RATING	PERCENT
159	KANATC3S	220	1	844	KANATA	27.6	1	T1	43.3	41.7	103.9
3108	MANBY W	220	1	3742	MANBYWBY	27.6	1	T3	43.2	41.7	103.6
4153	ERINDR14	220	1	4640	ERIND E	27.6	1	T2	68.1	62.5	108.9
4153	ERINDR14	220	1	4641	ERIND Q	27.6	1	T2	66.3	62.5	106.1
4154	ERINDR17	220	1	4640	ERIND E	27.6	1	T1	68.1	62.5	108.9
4154	ERINDR17	220	1	4641	ERIND Q	27.6	1	T1	66.3	62.5	106.1
5102	BURLINGT	220	1	5403	BURLINGT	118	1	12	260.5	250	104.2
5102	BURLINGT	220	1	5403	BURLINGT	118	1	T4	286.6	215	133.3
5102	BURLINGT	220	1	5403	BURLINGT	118	1	T6	258.4	215	120.2
5102	BURLINGT	220	1	5403	BURLINGT	118	1	T9	278.2	250	111.3
5105	NANTICOK	220	1	6357	NANTRS1B	4.16	1	S3	22.5	21.5	104.8
5293	BURL Q25	220	1	5956	BURL BY	27.6	1	15	49.6	37.5	132.4
5293	BURL Q25	220	1	5957	BURL JQ	27.6	1	15	55.3	37.5	147.4
7081	CALGFECF	220	1	7083	CALGFEC1	18	1	G1	210.6	150	140.4
7081	CALGFECF	220	1	7085	CALGFEC3	18	1	G3	210.6	150	140.4
7082	CALGFECQ	220	1	7084	CALGFEC2	18	1	G2	210.6	150	140.4
7082	CALGFECQ	220	1	7086	CALGFEC4	18	1	G4	519.7	360	144.4
7148	KENT L28	220	1	7625	KENT L1	27.6	1	T4	50.3	41.7	120.7
7198	TALBTW37	220	1	7742	TALBTQ12	27.6	1	T3	126.9	62.5	203
7198	TALBTW37	220	1	7743	TALBTJ12	27.6	1	T3	130.9	62.5	209.4

341	CARLNGM5	118	1	624	CARLNGKY	12.5	1	T1	31.2	30	103.9
365	FALLOWFD	118	1	678	FALLOW B	27.6	1	T1	30.8	28	109.9
375	BRIDLEWD	118	1	704	BRIDLEWD	8.32	1	T2	21.2	8	265.4
1331	CARD PWR	118	1	1776	CASCO L3	4.16	1	T3	20.3	15	135.1
1407	DOBB DS	118	1	1630	DOB DSB1	27.6	1	T1	30.3	29.7	102.1
3341	BRIDJL15	118	1	3609	BRIDR13B	13.8	1	13	34.9	33.3	104.8
3373	GLENGRL2	118	1	3683	GLENGR56	13.8	1	T4	35.1	33.3	105.3
5102	BURLINGT	220	1	5403	BURLINGT	118	1	12	260.5	250	104.2
5102	BURLINGT	220	1	5403	BURLINGT	118	1	T4	286.6	215	133.3
5102	BURLINGT	220	1	5403	BURLINGT	118	1	T6	258.4	215	120.2
5102	BURLINGT	220	1	5403	BURLINGT	118	1	T9	278.2	250	111.3
7301	KEITH KP	118	1	7459	CRAWJ 4E	118	1	1	243.3	232.7	104.6
7352	HIGHB W6	118	1	7656	HIGHB JY	27.6	1	T3	90.8	83.3	109
7370	KINGSVK2	118	1	7674	KINGSVIL	27.6	1	T1	48.4	41.7	116
7370	KINGSVK2	118	1	7674	KINGSVIL	27.6	1	T3	41.9	41.7	100.4
7371	KINGSVK6	118	1	7674	KINGSVIL	27.6	1	T2	52.7	41.7	126.4
7371	KINGSVK6	118	1	7674	KINGSVIL	27.6	1	T4	53.9	41.7	129.3
7402	WALLACBG	118	1	7759	WALLACBG	27.6	1	T1	19.4	15	129
7402	WALLACBG	118	1	7759	WALLACBG	27.6	1	T2	19.8	15	131.8
7402	WALLACBG	118	1	7759	WALLACBG	27.6	1	T3	19.1	15	127.5
7402	WALLACBG	118	1	7759	WALLACBG	27.6	1	T4	19.9	18	110.5
7403	WANSTDS2	118	1	7761	WANSTD Y	27.6	1	T1	20	18.8	106.5
7403	WANSTDS2	118	1	7761	WANSTD Y	27.6	1	T2	20.6	18	114.4
8316	KD CK MI	118	1	8884	KD CK MI	4.2	1	K1	14.8	11.2	132.5
8343	MOOSONEE	118	1	8755	MOOSONEE	25	1	T3	9.7	7.5	129.8
8367	TUNIS A5	118	1	8930	TUNIS GS	13.8	1	T1	63.6	45	141.3
9358	NORMAPAC	118	1	9631	NORMAPAC	2.4	1	TB	23.2	12	193.2
9389	WILLS MJ	118	1	9390	WIL MN	118	1	1	35.7	34.8	102.6
9390	WIL MN	118	1	9678	WIL MN14	13.8	1	T1	19.5	13.3	146.8
9408	ABITFTWM	118	1	9699	ABITFTWM	2.4	1	T3	22.3	14.4	154.7
9465	TBAY D	118	1	9908	TBAY G2	18	1	T2	161.4	160	100.9

115KV BUSES WITH VOLTAGE GREATER THAN 1.0760:											
X----- BUS -----X			AREA	V(PU)	V(KV)	X----- BUS -----X			AREA	V(PU)	V(KV)
5800	ALLANB25	118	1	1.1187	132.01	5804	ATLST A1	118	1	1.1186	131.99
5805	BEACH Q7	118	1	1.1184	131.97	5806	BEACH A8	118	1	1.1183	131.96
5809	BECK1 25	118	1	1.1183	131.96	5818	GAGE	118	1	1.1183	131.96
5825	HOLNDJQ7	118	1	1.1185	131.98	5829	MICH JA1	118	1	1.1186	132
5834	NIAGPARK	118	1	1.1183	131.96	5835	NIAGARA	118	1	1.1185	131.98
5840	RAILWJA8	118	1	1.1184	131.97	5841	ROSEDJA8	118	1	1.1188	132.02
5845	TOR POWE	118	1	1.1185	131.98	5886	CROWJ51A	118	1	1.1186	131.99
8218	ISL FLJ1	118	1	1.0801	127.45	8219	ISL FLJ2	118	1	1.0801	127.45
8233	CANYON	118	1	1.0824	127.73	8319	KD CKMET	118	1	1.1786	139.08
8347	N PWRJA4	118	1	1.0766	127.04	8348	N PWR A4	118	1	1.0791	127.34
8359	OTTER RJ	118	1	1.0857	128.11	8430	NAGAGAMI	118	1	1.0839	127.9
8438	CALSTOCK	118	1	1.0785	127.27	8440	ONAKAWNA	118	1	1.0817	127.64
8443	C2H 51J1	118	1	1.0816	127.63	8444	C3H 51J1	118	1	1.0816	127.63
8448	C2H 52J2	118	1	1.0816	127.63	8449	C3H 52J2	118	1	1.0816	127.63
8450	ISL FLJ3	118	1	1.0801	127.45	8451	ISL FLJ4	118	1	1.0801	127.45
8531	TIMMINS	118	1	1.0862	128.17	8532	WAWAITGS	118	1	1.0831	127.8
8535	WAITIN J	118	1	1.0831	127.8	9306	MARATHON	118	1	1.0826	127.75
9350	CARIBOU	118	1	1.102	130.04	9362	EAR FLS	118	1	1.0797	127.4
9394	MAN FLS	118	1	1.0901	128.63	9399	MARATHDS	118	1	1.0769	127.07
9427	PIC JT1M	118	1	1.0792	127.35	9428	PIC DS	118	1	1.0826	127.74
9450	SELCO J	118	1	1.0815	127.61	9483	WHITEDOG	118	1	1.0781	127.21
9492	SLATEFLJ	118	1	1.0779	127.19	9493	SLATE FL	118	1	1.0779	127.19
9526	MAR DS J	118	1	1.0769	127.08	9527	FT JAMES	118	1	1.0767	127.05

115KV BUSES WITH VOLTAGE LESS THAN 0.9580:											
X----- BUS -----X			AREA	V(PU)	V(KV)	X----- BUS -----X			AREA	V(PU)	V(KV)
5428	ALFRDJ12	118	1	0.9153	108	5429	ALFRDJ13	118	1	0.9157	108.05
5443	BRANT A	118	1	0.9022	106.45	5444	BRANT H	118	1	0.9027	106.52
5448	BRONT B8	118	1	0.9393	110.84	5459	CEDAR B5	118	1	0.9203	108.6
5460	CEDAR B6	118	1	0.9206	108.63	5463	CGE JB5G	118	1	0.9203	108.6
5464	CGE JB6G	118	1	0.9206	108.63	5492	ELGINHL3	118	1	0.9544	112.62
5493	ELGINHL4	118	1	0.9544	112.61	5523	ASEA JB5	118	1	0.9203	108.59
5524	ASEA JB6	118	1	0.9205	108.62	5526	GUE HJB6	118	1	0.9237	108.99
5527	H MT JB3	118	1	0.9562	112.83	5528	H MT JB4	118	1	0.9563	112.84
5529	H MTJB12	118	1	0.9567	112.89	5530	H MTJB13	118	1	0.9567	112.89
5531	HANLONB5	118	1	0.9232	108.94	5532	HANLONB6	118	1	0.9236	108.98
5569	MCMASJB3	118	1	0.9574	112.97	5570	MCMASJB4	118	1	0.9574	112.97
5571	MCMASB3	118	1	0.9568	112.9	5572	MCMASB4	118	1	0.9568	112.9
5576	MOHAWKB3	118	1	0.9422	111.18	5577	MOHAWKB4	118	1	0.9425	111.22
5580	NEWTON	118	1	0.9556	112.76	5586	PALMERST	118	1	0.9534	112.51
5588	PALRMJB8	118	1	0.9496	112.06	5593	PUSLINB5	118	1	0.9301	109.75
5594	PUSLINB6	118	1	0.9305	109.8	5623	ABB B5G	118	1	0.9202	108.59
5624	ABB B6G	118	1	0.9205	108.62	5644	BRANT8SW	118	1	0.9427	111.24
5675	GUE HJB5	118	1	0.9233	108.96	5685	BRANT J	118	1	0.9427	111.24
5891	PUSL JB5	118	1	0.9301	109.76	5892	PUSL JB6	118	1	0.9305	109.8
7320	ADELAIDJ	118	1	0.9409	111.03	7321	AYLMER	118	1	0.9573	112.96
7325	BIDLUL J	118	1	0.9488	111.96	7331	LAFRGEWS	118	1	0.9532	112.48
7332	CENTRL7S	118	1	0.9478	111.84	7335	CRANBRYJ	118	1	0.9453	111.54
7342	ENNISBRJ	118	1	0.9551	112.7	7348	FOR JURA	118	1	0.9447	111.48
7349	G BEND E	118	1	0.9291	109.63	7351	G BEND	118	1	0.9288	109.6
7354	INGERW7W	118	1	0.9541	112.59	7357	EN KEYSR	118	1	0.9391	110.82
7366	KERWOD J	118	1	0.9543	112.6	7371	KINGSVK6	118	1	0.9276	109.46
7375	MCGILLIV	118	1	0.9475	111.81	7379	PORTLNDJ	118	1	0.9459	111.61
7383	BLUE CIR	118	1	0.9439	111.39	7386	STRATHRO	118	1	0.9414	111.09
7387	SUN CAN	118	1	0.9542	112.6	7394	TILSONBG	118	1	0.9422	111.18
7402	WALLACBG	118	1	0.9185	108.39	7403	WANSTDS2	118	1	0.9572	112.95
7405	WDSTOCKA	118	1	0.9417	111.12	7406	WDSTOCKH	118	1	0.9358	110.43
7407	WOODSTKJ	118	1	0.9417	111.12	7465	GRND BEJ	118	1	0.9291	109.63
9498	LAC DESI	118	1	0.9242	109.06	9507	LAC DTFR	118	1	0.9232	108.93

LOWER KV (<115KV) BUSES WITH VOLTAGE GREATER THAN 1.0760:											
X----- BUS -----X			AREA	V(PU)	V(KV)	X----- BUS -----X			AREA	V(PU)	V(KV)
794	RUSSDSR1	8.3	1	1.1217	9.332	1677	IVAC RMY	14	1	1.108	15.29
5911	ATLST L2	28	1	1.1421	31.523	5927	GEORGPAC	4.2	1	1.1038	4.592
5948	BUNTINGJ	14	1	1.1156	15.396	5949	BUNTINGQ	14	1	1.115	15.387
5979	CARLTNBY	14	1	1.1174	15.42	5980	CARLTNHK	14	1	1.1086	15.299
5982	CARLTNEQ	14	1	1.1111	15.333	6065	GLEND BJ	14	1	1.1146	15.381
6066	GLEND DQ	14	1	1.1089	15.303	6067	GLEND EY	14	1	1.1119	15.345
6121	KALAR L2	14	1	1.113	15.359	6144	MURRAY B	14	1	1.1065	15.269
6145	MURRAY Y	14	1	1.114	15.373	6147	MURRAY J	14	1	1.1094	15.309
6148	MURRAY K	14	1	1.1093	15.309	6155	NEBO IDL	14	1	1.1367	15.687
6222	STANLYBY	14	1	1.1081	15.292	6223	STANLYJQ	14	1	1.1104	15.324
6247	THORLDBY	14	1	1.107	15.277	6248	THORLDEQ	14	1	1.1159	15.4
6252	VNSIC BY	14	1	1.1141	15.375	6280	ATLST 25	28	1	1.1181	30.858
6288	NIAGPARK	69	1	1.105	76.243	6387	BECK1T40	13	1	1.1173	14.748
7791	LAMB Y	28	1	1.1369	31.38	8645	DYMONDT3	4.2	1	1.1185	4.653
8646	DYMONDT4	4.2	1	1.1182	4.652	8828	WESTON L	25	1	1.1279	28.198
8981	ONAKAWNA	14	1	1.1056	15.257	9654	FTFRANM1	13	1	1.126	14.075
9754	V BAY X	4.2	1	1.1203	4.66	9765	PTART1R2	25	1	1.1125	27.7
9775	CLEARWAT	25	1	1.1068	27.671	9925	CALM LK	6.6	1	1.111	7.333
9959	STURGN F	6.6	1	1.1074	7.309						

LOWER KV (<115KV) BUSES WITH VOLTAGE LESS THAN 0.9000:											
X----- BUS -----X			AREA	V(PU)	V(KV)	X----- BUS -----X			AREA	V(PU)	V(KV)
7409	AGRAS-G1	14	1	0.8819	12.17	9595	LACDEST1	4.2	1	0.8716	3.626
9698	INMET L1	2.4	1	0.8929	2.143						

APPENDIX C

SINGLE CONTINGENCY ANALYSES RESULTS

500kV TRANSMISSION LINES SINGLE CONTINGENCY LIST

CONTINGENCY 'OVRLOD 3 '	'BRUCE B 500.00' TO 'BRUJB561500.00'
CONTINGENCY 'OVRLOD 4 '	'BRUJB561500.00' TO 'WILCJ561500.00'
CONTINGENCY 'OVRLOD 5 '	'WILCJ561500.00' TO 'BELLWD3 500.00'
	'BELLWD3 500.00' TO 'BELLWD4 500.00'
	'MILTON 500.00' TO 'BELLWD4 500.00'
CONTINGENCY 'OVRLOD 8 '	'BRUCE B 500.00' TO 'BRUJB563500.00'
CONTINGENCY 'OVRLOD 10 '	'BRUJB563500.00' TO 'WILCJ563500.00'
CONTINGENCY 'OVRLOD 11 '	'WILCJ563500.00' TO 'GRNDBND3500.00'
	'GRNDBND3500.00' TO 'GRNDBND4500.00'
	'GRNDBND4500.00' TO 'LONGWOOD500.00'
CONTINGENCY 'OVRLOD 13 '	'MILTON 500.00' TO 'TRAFAL72500.00'
CONTINGENCY 'OVRLOD 14 '	'MILTON 500.00' TO 'TRAFAL73500.00'
CONTINGENCY 'OVRLOD 15 '	'BRUCE A 500.00' TO 'BRUJB562500.00'
CONTINGENCY 'OVRLOD 16 '	'BRUJB562500.00' TO 'WILCJ562500.00'
CONTINGENCY 'OVRLOD 17 '	'WILCJ562500.00' TO 'GRNDBND1500.00'
	'GRNDBND1500.00' TO 'GRNDBND2500.00'
	'GRNDBND2500.00' TO 'LONGWOOD500.00'
CONTINGENCY 'OVRLOD 20 '	'BRUCE B 500.00' TO 'BRUJB569500.00'
CONTINGENCY 'OVRLOD 21 '	'BRUCE A 500.00' TO 'BRUJB569500.00'
CONTINGENCY 'OVRLOD 23 '	'TILSNBG1500.00' TO 'LONGWOOD500.00'
	'TILSNBG1500.00' TO 'TILSNBG2500.00'
	'NANTICOK500.00' TO 'TILSNBG2500.00'
CONTINGENCY 'OVRLOD 25 '	'HANRESA1500.00' TO 'HANMER 500.00'
CONTINGENCY 'OVRLOD 26 '	'BRUCE A 500.00' TO 'BRUJB560500.00'
CONTINGENCY 'OVRLOD 27 '	'BRUJB560500.00' TO 'WILCJ560500.00'
CONTINGENCY 'OVRLOD 28 '	'HANRESA3500.00' TO 'HANMER 500.00'
CONTINGENCY 'OVRLOD 30 '	'WILCJ560500.00' TO 'BELLWD1 500.00'
	'BELLWD1 500.00' TO 'BELLWD2 500.00'
	'MBYP560W500.00' TO 'BELLWD2 500.00'
CONTINGENCY 'OVRLOD 32 '	'CLAIRVIL500.00' TO 'MBYP560W500.00'
CONTINGENCY 'OVRLOD 33 '	'C50CHRYJ500.00' TO 'C550 38J500.00'
CONTINGENCY 'OVRLOD 34 '	'CHERRYWD500.00' TO 'C50CHRYJ500.00'
CONTINGENCY 'OVRLOD 35 '	'CHERRYWD500.00' TO 'C51CHRYJ500.00'

CONTINGENCY 'OVRLOD 36 '	'C51CHRYJ500.00' TO 'C551 38J500.00'
CONTINGENCY 'OVRLOD 37 '	'C550 38J500.00' TO 'C550 77J500.00'
CONTINGENCY 'OVRLOD 38 '	'C551 38J500.00' TO 'C551 77J500.00'
CONTINGENCY 'OVRLOD 39 '	'PARKWY51500.00' TO 'C551 77J500.00'
CONTINGENCY 'OVRLOD 40 '	'PARKWY50500.00' TO 'C550 77J500.00'
CONTINGENCY 'OVRLOD 41 '	'CLAIRVIL500.00' TO 'ESSA 500.00'
CONTINGENCY 'OVRLOD 42 '	'CLAIRVIL500.00' TO 'ESSA 500.00'
CONTINGENCY 'OVRLOD 43 '	'MIDD8086500.00' TO 'NANTICOK500.00'
CONTINGENCY 'OVRLOD 44 '	'LENNOX 500.00' TO 'BOWMANVL500.00'
CONTINGENCY 'OVRLOD 45 '	'LENNOX 500.00' TO 'BOWMANVL500.00'
CONTINGENCY 'OVRLOD 46 '	'LENNOX 500.00' TO 'BOWMANVL500.00'
CONTINGENCY 'OVRLOD 47 '	'LENNOX 500.00' TO 'BOWMANVL500.00'
CONTINGENCY 'OVRLOD 48 '	'CLAIRVIL500.00' TO 'C50CLRVJ500.00'
CONTINGENCY 'OVRLOD 49 '	'CLAIRVIL500.00' TO 'C51CLRVJ500.00'
CONTINGENCY 'OVRLOD 50 '	'C550V93J500.00' TO 'C50CLRVJ500.00'
CONTINGENCY 'OVRLOD 51 '	'C551V93J500.00' TO 'C51CLRVJ500.00'
CONTINGENCY 'OVRLOD 52 '	'C550V93J500.00' TO 'PARKWY50500.00'
CONTINGENCY 'OVRLOD 53 '	'C551V93J500.00' TO 'PARKWY51500.00'
CONTINGENCY 'OVRLOD 54 '	'CLAIRVIL500.00' TO 'MILTON 500.00'
CONTINGENCY 'OVRLOD 55 '	'BOWMANVL500.00' TO 'CHERRYWD500.00'
CONTINGENCY 'OVRLOD 56 '	'BOWMANVL500.00' TO 'CHERRYWD500.00'
CONTINGENCY 'OVRLOD 57 '	'MIDD8185500.00' TO 'NANTICOK500.00'
CONTINGENCY 'OVRLOD 58 '	'MILTON 500.00' TO 'PREST585500.00'
CONTINGENCY 'OVRLOD 59 '	'CLAIRVIL500.00' TO 'MBYP586W500.00'
CONTINGENCY 'OVRLOD 60 '	'MBYP586W500.00' TO 'PREST586500.00'
CONTINGENCY 'OVRLOD 61 '	'HAWTHORN500.00' TO 'LENNOX 500.00'
CONTINGENCY 'OVRLOD 62 '	'MIDD8086500.00' TO 'PREST586500.00'
CONTINGENCY 'OVRLOD 63 '	'MIDD8185500.00' TO 'PREST585500.00'
CONTINGENCY 'VLTAGE 1 '	'HANRESA3500.00' TO 'HANRESA4500.00'
CONTINGENCY 'VLTAGE 2 '	'ESSA 500.00' TO 'HANRESA4500.00'
CONTINGENCY 'VLTAGE 3 '	'ESSA 500.00' TO 'HANRESA2500.00'
CONTINGENCY 'VLTAGE 4 '	'HANRESA1500.00' TO 'HANRESA2500.00'

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI, OCT 07 2005 7:57

PAGE 1.

2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
-530BLIP6904FABC2994FETT1765QFW-604MICH-1138NYNI-250NYSL-14

*** ACCC OVERLOAD REPORT: MONITORED ELEMENTS LOADED ABOVE 100.0 % OF RATING SET B ***
*** ACCC VOLTAGE REPORT ***

DISTRIBUTION FACTOR FILE: C:\HYDRO-ONE\POWERFLOW-WITH-IESO-S-CAPS\500KV-(N-1).dfx
SUBSYSTEM DESCRIPTION FILE: C:\HYDRO-ONE\POWERFLOW-WITH-IESO-S-CAPS\IESO.SUB
MONITORED ELEMENT FILE: C:\HYDRO-ONE\POWERFLOW-WITH-IESO-S-CAPS\IESO.mon
CONTINGENCY DESCRIPTION FILE: C:\HYDRO-ONE\POWERFLOW-WITH-IESO-S-CAPS\IESO-500KV-BRANCH.CON

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
BASE CASE ----- BASE CASE

*** NONE ***

X----- BUS -----X V-CONT V-INIT X----- BUS -----X V-CONT V-INIT
'500KV ' BUSES WITH VOLTAGE GREATER THAN 1.1000: 1001 LENNOX 500 1.1004 1.1004 6441 GRNDBND3 500 1.1000 1.1000

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 6401 [BRUCE B 500.00] TO BUS 6404 [BRUJB561500.00] CKT 1 ----- CONTINGENCY OVRLOD 3

*** NONE ***

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 6404 [BRUJB561500.00] TO BUS 6409 [WILCJ561500.00] CKT 1 ----- CONTINGENCY OVRLOD 4

*** NONE ***

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 6409 [WILCJ561500.00] TO BUS 6444 [BELLWD3 500.00] CKT 1 ----- CONTINGENCY OVRLOD 5
OPEN LINE FROM BUS 6444 [BELLWD3 500.00] TO BUS 6446 [BELLWD4 500.00] CKT 1
OPEN LINE FROM BUS 4003 [MILTON 500.00] TO BUS 6446 [BELLWD4 500.00] CKT 1

*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 6401 [BRUCE B 500.00] TO BUS 6407 [BRUJB563500.00] CKT 1 ----- CONTINGENCY OVRLOD 8

*** NONE ***

X----- BUS ----X V-CONT V-INIT X----- BUS ----X V-CONT V-INIT
 '500KV ' BUSES WITH VOLTAGE GREATER THAN 1.1000: 6440 GRNDBND1 500 1.1480 1.0980

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 6407 [BRUJB563500.00] TO BUS 6411 [WILCJ563500.00] CKT 1 ----- CONTINGENCY OVRLOD 10

*** NONE ***

X----- BUS ----X V-CONT V-INIT X----- BUS ----X V-CONT V-INIT
 '500KV ' BUSES WITH VOLTAGE GREATER THAN 1.1000: 6440 GRNDBND1 500 1.1462 1.0980

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 6411 [WILCJ563500.00] TO BUS 6441 [GRNDBND3500.00] CKT 1 ----- CONTINGENCY OVRLOD 11
 OPEN LINE FROM BUS 6441 [GRNDBND3500.00] TO BUS 6443 [GRNDBND4500.00] CKT 1
 OPEN LINE FROM BUS 6443 [GRNDBND4500.00] TO BUS 7000 [LONGWOOD500.00] CKT 1

*** NONE ***

X----- BUS ----X V-CONT V-INIT X----- BUS ----X V-CONT V-INIT
 '500KV ' BUSES WITH VOLTAGE GREATER THAN 1.1000: 6440 GRNDBND1 500 1.1266 1.0980

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 4003 [MILTON 500.00] TO BUS 4010 [TRAFAL72500.00] CKT 1 ----- CONTINGENCY OVRLOD 13

*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 4003 [MILTON 500.00] TO BUS 4011 [TRAFAL73500.00] CKT 1 ----- CONTINGENCY OVRLOD 14

*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT

OPEN LINE FROM BUS 6400 [BRUCE A 500.00] TO BUS 6406 [BRUJB562500.00] CKT 1 ----- CONTINGENCY OVRLOD 15
 *** NONE ***

X----- BUS -----X V-CONT V-INIT X----- BUS -----X V-CONT V-INIT
 '500KV ' BUSES WITH VOLTAGE GREATER THAN 1.1000: 6441 GRNDBND3 500 1.1484 1.1000

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 6406 [BRUJB562500.00] TO BUS 6410 [WILCJ562500.00] CKT 1 ----- CONTINGENCY OVRLOD 16
 *** NONE ***

X----- BUS -----X V-CONT V-INIT X----- BUS -----X V-CONT V-INIT
 '500KV ' BUSES WITH VOLTAGE GREATER THAN 1.1000: 6441 GRNDBND3 500 1.1466 1.1000

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 6410 [WILCJ562500.00] TO BUS 6440 [GRNDBND1500.00] CKT 1 ----- CONTINGENCY OVRLOD 17
 OPEN LINE FROM BUS 6440 [GRNDBND1500.00] TO BUS 6442 [GRNDBND2500.00] CKT 1
 OPEN LINE FROM BUS 6442 [GRNDBND2500.00] TO BUS 7000 [LONGWOOD500.00] CKT 1
 *** NONE ***

X----- BUS -----X V-CONT V-INIT X----- BUS -----X V-CONT V-INIT
 '500KV ' BUSES WITH VOLTAGE GREATER THAN 1.1000: 6441 GRNDBND3 500 1.1271 1.1000

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 6401 [BRUCE B 500.00] TO BUS 6405 [BRUJB569500.00] CKT 1 ----- CONTINGENCY OVRLOD 20
 *** NONE ***

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 6400 [BRUCE A 500.00] TO BUS 6405 [BRUJB569500.00] CKT 1 ----- CONTINGENCY OVRLOD 21
 *** NONE ***

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 6448 [TILSNBG1500.00] TO BUS 7000 [LONGWOOD500.00] CKT 1 ----- CONTINGENCY OVRLOD 23
 OPEN LINE FROM BUS 6448 [TILSNBG1500.00] TO BUS 6449 [TILSNBG2500.00] CKT 1
 OPEN LINE FROM BUS 5003 [NANTICOK500.00] TO BUS 6449 [TILSNBG2500.00] CKT 1

*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 7996 [HANRESA1500.00] TO BUS 8000 [HANMER 500.00] CKT 1 ----- CONTINGENCY OVRLOD 25
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 6400 [BRUCE A 500.00] TO BUS 6403 [BRUJB560500.00] CKT 1 ----- CONTINGENCY OVRLOD 26
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 6403 [BRUJB560500.00] TO BUS 6408 [WILCJ560500.00] CKT 1 ----- CONTINGENCY OVRLOD 27
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 7997 [HANRESA3500.00] TO BUS 8000 [HANMER 500.00] CKT 2 ----- CONTINGENCY OVRLOD 28
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 6408 [WILCJ560500.00] TO BUS 6445 [BELLWD1 500.00] CKT 1 ----- CONTINGENCY OVRLOD 30
OPEN LINE FROM BUS 6445 [BELLWD1 500.00] TO BUS 6447 [BELLWD2 500.00] CKT 1
OPEN LINE FROM BUS 4005 [MBYP560W500.00] TO BUS 6447 [BELLWD2 500.00] CKT 1
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 4000 [CLAIRVIL500.00] TO BUS 4005 [MBYP560W500.00] CKT 1 ----- CONTINGENCY OVRLOD 32
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 2011 [C50CHRYJ500.00] TO BUS 2017 [C550 38J500.00] CKT 1 ----- CONTINGENCY OVRLOD 33
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 2002 [CHERRYWD500.00] TO BUS 2011 [C50CHRYJ500.00] CKT 1 ----- CONTINGENCY OVRLOD 34
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 2002 [CHERRYWD500.00] TO BUS 2012 [C51CHRYJ500.00] CKT 1 ----- CONTINGENCY OVRLOD 35
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 2012 [C51CHRYJ500.00] TO BUS 2018 [C551 38J500.00] CKT 1 ----- CONTINGENCY OVRLOD 36
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 2017 [C550 38J500.00] TO BUS 2019 [C550 77J500.00] CKT 1 ----- CONTINGENCY OVRLOD 37
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 2018 [C551 38J500.00] TO BUS 2020 [C551 77J500.00] CKT 1 ----- CONTINGENCY OVRLOD 38
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 2015 [PARKWY51500.00] TO BUS 2020 [C551 77J500.00] CKT 1 ----- CONTINGENCY OVRLOD 39
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 2016 [PARKWY50500.00] TO BUS 2019 [C550 77J500.00] CKT 1 ----- CONTINGENCY OVRLOD 40
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 4000 [CLAIRVIL500.00] TO BUS 6402 [ESSA 500.00] CKT 1 ----- CONTINGENCY OVRLOD 41
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 4000 [CLAIRVIL500.00] TO BUS 6402 [ESSA 500.00] CKT 2 ----- CONTINGENCY OVRLOD 42
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 5000 [MIDD8086500.00] TO BUS 5003 [NANTICOK500.00] CKT 1 ----- CONTINGENCY OVRLOD 43
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 1001 [LENNOX 500.00] TO BUS 2000 [BOWMANVL500.00] CKT 4 ----- CONTINGENCY OVRLOD 44
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 1001 [LENNOX 500.00] TO BUS 2000 [BOWMANVL500.00] CKT 3 ----- CONTINGENCY OVRLOD 45
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 1001 [LENNOX 500.00] TO BUS 2000 [BOWMANVL500.00] CKT 2 ----- CONTINGENCY OVRLOD 46
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 1001 [LENNOX 500.00] TO BUS 2000 [BOWMANVL500.00] CKT 1 ----- CONTINGENCY OVRLOD 47
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 4000 [CLAIRVIL500.00] TO BUS 4017 [C50CLRVJ500.00] CKT 1 ----- CONTINGENCY OVRLOD 48
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 4000 [CLAIRVIL500.00] TO BUS 4018 [C51CLRVJ500.00] CKT 1 ----- CONTINGENCY OVRLOD 49

*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 2013 [C550V93J500.00] TO BUS 4017 [C50CLRVJ500.00] CKT 1 ----- CONTINGENCY OVRLOD 50
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 2014 [C551V93J500.00] TO BUS 4018 [C51CLRVJ500.00] CKT 1 ----- CONTINGENCY OVRLOD 51
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 2013 [C550V93J500.00] TO BUS 2016 [PARKWY50500.00] CKT 1 ----- CONTINGENCY OVRLOD 52
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 2014 [C551V93J500.00] TO BUS 2015 [PARKWY51500.00] CKT 1 ----- CONTINGENCY OVRLOD 53
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 4000 [CLAIRVIL500.00] TO BUS 4003 [MILTON 500.00] CKT 1 ----- CONTINGENCY OVRLOD 54
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 2000 [BOWMANVL500.00] TO BUS 2002 [CHERRYWD500.00] CKT 3 ----- CONTINGENCY OVRLOD 55
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 2000 [BOWMANVL500.00] TO BUS 2002 [CHERRYWD500.00] CKT 1 ----- CONTINGENCY
OVRLOD 56
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X-MVA(MW)FLOW--X

X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 5001 [MIDD8185500.00] TO BUS 5003 [NANTICOK500.00] CKT 1 ----- CONTINGENCY OVRLOD 57
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 4003 [MILTON 500.00] TO BUS 5006 [PREST585500.00] CKT 1 ----- CONTINGENCY OVRLOD 58
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 4000 [CLAIRVIL500.00] TO BUS 4004 [MBYP586W500.00] CKT 1 ----- CONTINGENCY OVRLOD 59
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 4004 [MBYP586W500.00] TO BUS 5007 [PREST586500.00] CKT 1 ----- CONTINGENCY OVRLOD 60
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 1 [HAWTHORN500.00] TO BUS 1001 [LENNOX 500.00] CKT 1 ----- CONTINGENCY OVRLOD 61
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 5000 [MIDD8086500.00] TO BUS 5007 [PREST586500.00] CKT 1 ----- CONTINGENCY OVRLOD 62
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 5001 [MIDD8185500.00] TO BUS 5006 [PREST585500.00] CKT 1 ----- CONTINGENCY OVRLOD 63
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 7997 [HANRESA3500.00] TO BUS 7999 [HANRESA4500.00] CKT 1 ----- CONTINGENCY VLTAGE 1
 *** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 6402 [ESSA 500.00] TO BUS 7999 [HANRESA4500.00] CKT 2 ----- CONTINGENCY VLTAGE 2
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 6402 [ESSA 500.00] TO BUS 7998 [HANRESA2500.00] CKT 1 ----- CONTINGENCY VLTAGE 3
*** NONE ***

X----- CONTINGENCY EVENTS -----XX-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 7996 [HANRESA1500.00] TO BUS 7998 [HANRESA2500.00] CKT 1 ----- CONTINGENCY VLTAGE 4
*** NONE ***

APPENDIX D DOUBLE CONTINGENCY ANALYSES RESULTS

SELECTED DOUBLE 500KV TRANSMISSION LINE CONTINGENCIES

CONTINGENCY 'BRUCE-MILTON'	'WILCJ560500.00' TO 'BELLWD1 500.00'
	'BELLWD1 500.00' TO 'BELLWD2 500.00'
	'MBYP560W500.00' TO 'BELLWD2 500.00'
	'WILCJ561500.00' TO 'BELLWD3 500.00'
	'BELLWD3 500.00' TO 'BELLWD4 500.00'
	'MILTON 500.00' TO 'BELLWD4 500.00'
CONTINGENCY 'BRUCE-LNGWOD'	'WILCJ562500.00' TO 'GRNDBND1500.00'
	'GRNDBND1500.00' TO 'GRNDBND2500.00'
	'GRNDBND2500.00' TO 'LONGWOOD500.00'
	'WILCJ563500.00' TO 'GRNDBND3500.00'
	'GRNDBND3500.00' TO 'GRNDBND4500.00'
	'GRNDBND4500.00' TO 'LONGWOOD500.00'
CONTINGENCY 'MLTN-CLR-D/C'	'CLAIRVIL500.00' TO 'MILTON 500.00'
	'CLAIRVIL500.00' TO 'MILTON 500.00'
CONTINGENCY 'MILTON-CLAIR'	'CLAIRVIL500.00' TO 'MILTON 500.00'
	'CLAIRVIL500.00' TO 'MBYP560W500.00'
CONTINGENCY 'NANTI-MIDD'	'MIDD8185500.00' TO 'NANTICOK500.00'
	'MIDD8086500.00' TO 'NANTICOK500.00'
CONTINGENCY 'BRCMLTLNGNAN'	'WILCJ561500.00' TO 'BELLWD3 500.00'
	'BELLWD3 500.00' TO 'BELLWD4 500.00'
	'MILTON 500.00' TO 'BELLWD4 500.00'
	'TILSNBG1500.00' TO 'LONGWOOD500.00'
	'TILSNBG1500.00' TO 'TILSNBG2500.00'
	'NANTICOK500.00' TO 'TILSNBG2500.00'
CONTINGENCY 'BRC-MLT-LNGW'	'WILCJ561500.00' TO 'BELLWD3 500.00'
	'BELLWD3 500.00' TO 'BELLWD4 500.00'
	'MILTON 500.00' TO 'BELLWD4 500.00'
	'WILCJ563500.00' TO 'GRNDBND3500.00'
	'GRNDBND3500.00' TO 'GRNDBND4500.00'
	'GRNDBND4500.00' TO 'LONGWOOD500.00'
CONTINGENCY 'BRC-LNGW-NNT'	'WILCJ563500.00' TO 'GRNDBND3500.00'
	'GRNDBND3500.00' TO 'GRNDBND4500.00'
	'GRNDBND4500.00' TO 'LONGWOOD500.00'
	'TILSNBG1500.00' TO 'LONGWOOD500.00'
	'TILSNBG1500.00' TO 'TILSNBG2500.00'
	'NANTICOK500.00' TO 'TILSNBG2500.00'

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI, OCT 07 2005 10:18

PAGE 1.

2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
-530BLIP6904FABC2994FETT1765QFW-604MICH-1138NYNI-250NYSL-14

*** ACCC OVERLOAD REPORT: MONITORED ELEMENTS LOADED ABOVE 100.0 % OF RATING SET B ***
*** ACCC VOLTAGE REPORT ***

DISTRIBUTION FACTOR FILE: C:\HYDRO-ONE\POWERFLOW-WITH-IESO-S-CAPS\500KV-(N-2).dfx
SUBSYSTEM DESCRIPTION FILE: C:\HYDRO-ONE\POWERFLOW-WITH-IESO-S-CAPS\IESO.SUB
MONITORED ELEMENT FILE: C:\HYDRO-ONE\POWERFLOW-WITH-IESO-S-CAPS\IESO.mon
CONTINGENCY DESCRIPTION FILE: C:\HYDRO-ONE\POWERFLOW-WITH-IESO-S-CAPS\IESO-500KV-(N-2).CON

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
BASE CASE ----- BASE CASE

*** NONE ***

X----- BUS -----X V-CONT V-INIT X----- BUS -----X V-CONT V-INIT
'500KV ' BUSES WITH VOLTAGE GREATER THAN 1.1000: 1001 LENNOX 500 1.1004 1.1004 6441 GRNDBND3 500 1.1000 1.1000

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 6408 [WILCJ560500.00] TO BUS 6445 [BELLWD1 500.00] CKT 1 ----- CONTINGENCY BRUCE-MILTON
OPEN LINE FROM BUS 6445 [BELLWD1 500.00] TO BUS 6447 [BELLWD2 500.00] CKT 1
OPEN LINE FROM BUS 4005 [MBYP560W500.00] TO BUS 6447 [BELLWD2 500.00] CKT 1
OPEN LINE FROM BUS 6409 [WILCJ561500.00] TO BUS 6444 [BELLWD3 500.00] CKT 1
OPEN LINE FROM BUS 6444 [BELLWD3 500.00] TO BUS 6446 [BELLWD4 500.00] CKT 1
OPEN LINE FROM BUS 4003 [MILTON 500.00] TO BUS 6446 [BELLWD4 500.00] CKT 1
*** NOT CONVERGED ***

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X-MVA(MW)FLOW--X
X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
OPEN LINE FROM BUS 6410 [WILCJ562500.00] TO BUS 6440 [GRNDBND1500.00] CKT 1 ----- CONTINGENCY BRUCE-LNGWOD
OPEN LINE FROM BUS 6440 [GRNDBND1500.00] TO BUS 6442 [GRNDBND2500.00] CKT 1
OPEN LINE FROM BUS 6442 [GRNDBND2500.00] TO BUS 7000 [LONGWOOD500.00] CKT 1
OPEN LINE FROM BUS 6411 [WILCJ563500.00] TO BUS 6441 [GRNDBND3500.00] CKT 1

OPEN LINE FROM BUS 6441 [GRNDBND3500.00] TO BUS 6443 [GRNDBND4500.00] CKT 1
 OPEN LINE FROM BUS 6443 [GRNDBND4500.00] TO BUS 7000 [LONGWOOD500.00] CKT 1

*** NONE ***

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 4000 [CLAIRVIL500.00] TO BUS 4003 [MILTON 500.00] CKT 1 ----- CONTINGENCY MLTN-CLR-D/C
 OPEN LINE FROM BUS 4000 [CLAIRVIL500.00] TO BUS 4003 [MILTON 500.00] CKT 2

*** NONE ***

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 4000 [CLAIRVIL500.00] TO BUS 4003 [MILTON 500.00] CKT 1 ----- CONTINGENCY MILTON-CLAIR
 OPEN LINE FROM BUS 4000 [CLAIRVIL500.00] TO BUS 4005 [MBYP560W500.00] CKT 1

*** NONE ***

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 5001 [MIDD8185500.00] TO BUS 5003 [NANTICOK500.00] CKT 1 ----- CONTINGENCY NANTI-MIDD
 OPEN LINE FROM BUS 5000 [MIDD8086500.00] TO BUS 5003 [NANTICOK500.00] CKT 1

*** NONE ***

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 6409 [WILCJ561500.00] TO BUS 6444 [BELLWD3 500.00] CKT 1 ----- CONTINGENCY BRCMLTLNGNAN
 OPEN LINE FROM BUS 6444 [BELLWD3 500.00] TO BUS 6446 [BELLWD4 500.00] CKT 1
 OPEN LINE FROM BUS 4003 [MILTON 500.00] TO BUS 6446 [BELLWD4 500.00] CKT 1
 OPEN LINE FROM BUS 6448 [TILSNBG1500.00] TO BUS 7000 [LONGWOOD500.00] CKT 1
 OPEN LINE FROM BUS 6448 [TILSNBG1500.00] TO BUS 6449 [TILSNBG2500.00] CKT 1
 OPEN LINE FROM BUS 5003 [NANTICOK500.00] TO BUS 6449 [TILSNBG2500.00] CKT 1

*** NOT CONVERGED ***

X----- CONTINGENCY EVENTS -----X X-- OVERLOADED LINES --X X--MVA(MW)FLOW--X
 X---- MULTI-SECTION LINE GROUPINGS ----X FROM NAME TO NAME CKT PRE-CNT POST-CNT RATING PERCENT
 OPEN LINE FROM BUS 6409 [WILCJ561500.00] TO BUS 6444 [BELLWD3 500.00] CKT 1 ----- CONTINGENCY BRC-MLT-LNGW
 OPEN LINE FROM BUS 6444 [BELLWD3 500.00] TO BUS 6446 [BELLWD4 500.00] CKT 1
 OPEN LINE FROM BUS 4003 [MILTON 500.00] TO BUS 6446 [BELLWD4 500.00] CKT 1
 OPEN LINE FROM BUS 6411 [WILCJ563500.00] TO BUS 6441 [GRNDBND3500.00] CKT 1
 OPEN LINE FROM BUS 6441 [GRNDBND3500.00] TO BUS 6443 [GRNDBND4500.00] CKT 1

OPEN LINE FROM BUS 6443 [GRNDBND4500.00] TO BUS 7000 [LONGWOOD500.00] CKT 1
*** NONE ***

X----- C O N T I N G E N C Y E V E N T S -----X X-- O V E R L O A D E D L I N E S --X X--MVA(MW)FLOW--X
X---- M U L T I - S E C T I O N L I N E G R O U P I N G S ----X F R O M N A M E T O N A M E C K T P R E - C N T P O S T - C N T R A T I N G P E R C E N T
OPEN LINE FROM BUS 6411 [WILCJ563500.00] TO BUS 6441 [GRNDBND3500.00] CKT 1 ----- CONTINGENCY BRC-LNGW-NNT
OPEN LINE FROM BUS 6441 [GRNDBND3500.00] TO BUS 6443 [GRNDBND4500.00] CKT 1
OPEN LINE FROM BUS 6443 [GRNDBND4500.00] TO BUS 7000 [LONGWOOD500.00] CKT 1
OPEN LINE FROM BUS 6448 [TILSNBG1500.00] TO BUS 7000 [LONGWOOD500.00] CKT 1
OPEN LINE FROM BUS 6448 [TILSNBG1500.00] TO BUS 6449 [TILSNBG2500.00] CKT 1
OPEN LINE FROM BUS 5003 [NANTICOK500.00] TO BUS 6449 [TILSNBG2500.00] CKT 1
*** NONE ***

APPENDIX E

BASE CASE RESULTS – WITH FULL SYSTEM

AREA-1 TIE LINE INTERCHANGES AFTER BRUCE-MILTON D/C TOWER OUTAGE

FROM AREA 1 IESO

TO AREA 219 ITC

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
7001 LAMB L4D 345	28849* 19STCPP 345	1	-224.1	-3.4		
7104* J5D PS 230	28883 19WTRMN 230	1	-110.7	-11.1		
7109* SCOTT 220	29003 19B3N PS 220	1	-112.1	-0.1		
7113* LAMB L51 220	29028 19STCPP 220	1	-222.1	1.4		
TOTAL FROM AREA 1 TO AREA 219				-669.0	-13.2	

TO AREA 608 MP

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
9314* ONT-MINN 118	61784 INTPHAS7 118	1	-14.0	10.2		
TOTAL FROM AREA 1 TO AREA 608				-14.0	10.2	

TO AREA 667 MH

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
9107* KENORA 220	67556 WHTSL1 4 220	1	-10.4	-12.0		
9107* KENORA 220	67589 WHTSL2 4 220	1	-10.4	-11.9		
TOTAL FROM AREA 1 TO AREA 667				-20.7	-23.9	

TO AREA 702 NYISO

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
1110* STLAWL33 230	79589 MOSES E 230	1	-189.9	-18.6		
1111* STLAWL34 230	79589 MOSES E 230	1	-217.2	-8.8		
5004* BECK A 345	79584 NIAG 345 345	1	-372.9	-45.5		
5005* BECK B 345	79584 NIAG 345 345	1	-373.2	-45.4		
5138 BP76 REG 230	76665* PACKARD2 230	1	-230.3	-41.1		
5244 PA27 REG 230	79592* NIAGAR2W 230	1	-327.7	-30.4		
TOTAL FROM AREA 1 TO AREA 702				-1711.2	-189.7	

TO AREA 704 HQTE

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR		
100 CHAT FLS 220	84003* PAUGAN 220	1	0.0	0.0		
345* CHENAU J 118	84011 BRYSON 118	1	0.0	-0.5		
380* IPB H9A 118	84012 MASSON 118	1	0.0	-0.1		
1150 IPB B31L 220	84002* BEAUHB31 220	1	0.0	0.0		
8296* IPB LACA 118	84015 KIPAWA 118	1	0.0	-2.1		
8297* KIPWIESO 118	85716 KIP120 120	T1	-3.8	42.2		
8346* NMILEJD4 118	84016 RAP DES 118	1	0.0	-1.8		
TOTAL FROM AREA 1 TO AREA 704				-3.8	37.8	

TOTAL FROM AREA 1

-2418.6	-178.8

AREA-1 TIE LINE INTERCHANGES

after ONE BRUCE-MILTON and LONGWOOD-NANTICOKE OUTAGE

2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD20S
 -530BLIP6904FABC2994FETT1765QFW-604MICH-1138NYNI-250NYSL-14

CASE C:\HYDRO-ONE\FULL-SYSTN-IESO-OPF\FULL-SYSTEM-BRUCE-MLTN-&LNGWD-NANTI-OUT.sav
 WAS SAVED ON FRI, OCT 28 2005 8:11

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI, OCT 28 2005 9:08
 2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD20S AREA TIE LINE
 -530BLIP6904FABC2994FETT1765QFW-604MICH-1138NYNI-250NYSL-14 INTERCHANGE

FROM AREA 1 IESO

TO AREA 219 ITC

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
7001 LAMB L4D 345	28849* 19STCPP 345	1	-113.6	-71.6
7104* J5D PS 230	28883 19WTRMN 230	1	-63.8	-54.8
7109* SCOTT 220	29003 19B3N PS 220	1	-71.3	-51.7
7113* LAMB L51 220	29028 19STCPP 220	1	-123.0	-65.6
TOTAL FROM AREA 1 TO AREA 219				-371.7 -243.8

TO AREA 608 MP

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
9314* ONT-MINN 118	61784 INTPHAS7 118	1	-15.2	10.5
TOTAL FROM AREA 1 TO AREA 608				-15.2 10.5

TO AREA 667 MH

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
9107* KENORA 220	67556 WHTSL1 4 220	1	-11.2	-11.9
9107* KENORA 220	67589 WHTSL2 4 220	1	-11.2	-11.9
TOTAL FROM AREA 1 TO AREA 667				-22.5 -23.8

TO AREA 702 NYISO

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
1110* STLAWL33 230	79589 MOSES E 230	1	-179.1	-15.3
1111* STLAWL34 230	79589 MOSES E 230	1	-202.6	-5.0
5004* BECK A 345	79584 NIAG 345 345	1	-424.2	-47.6
5005* BECK B 345	79584 NIAG 345 345	1	-424.5	-47.6
5138 BP76 REG 230	76665* PACKARD2 230	1	-257.9	-42.9
5244 PA27 REG 230	79592* NIAGAR2W 230	1	-358.2	-32.2
TOTAL FROM AREA 1 TO AREA 702				-1846.7 -190.6

TO AREA 704 HQTE

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
100 CHAT FLS 220	84003* PAUGAN 220	1	0.0	0.0
345* CHENAU J 118	84011 BRYSON 118	1	0.0	-0.5
380* IPB H9A 118	84012 MASSON 118	1	0.0	-0.1
1150 IPB B31L 220	84002* BEAUHB31 220	1	0.0	0.0
8296* IPB LACA 118	84015 KIPAWA 118	1	0.0	-2.1
8297* KIPWIESO 118	85716 KIP120 120	T1	-3.8	42.3
8346* NMILEJD4 118	84016 RAP DES 118	1	0.0	-1.8
TOTAL FROM AREA 1 TO AREA 704				-3.8 37.9

TOTAL FROM AREA 1			-2259.9	-409.8

AREA-1 TIE LINE INTERCHANGES with Highest import from ITC For BRUCE-MILTON D/C TOWER OUTAGE

PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E FRI, OCT 28 2005 14:05
 2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD20S AREA TIE LINE
 -530BLIP6904FABC2994FETT1765QFW-604MICH-1138NYNI-250NYSL-14 INTERCHANGE

FROM AREA 1 IESO

TO AREA 219 ITC

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
7001 LAMB L4D 345	28849* 19STCPP 345	1	-313.0	-23.7
7104* J5D PS 230	28883 19WTRMN 230	1	-182.4	-18.3
7109* SCOTT 220	29003 19B3N PS 220	1	-107.6	-10.2
7113* LAMB L51 220	29028 19STCPP 220	1	-303.1	-9.6
TOTAL FROM AREA 1 TO AREA 219			-906.0	-61.7

TO AREA 608 MP

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
9314* ONT-MINN 118	61784 INTPHAS7 118	1	-8.4	9.2
TOTAL FROM AREA 1 TO AREA 608			-8.4	9.2

TO AREA 667 MH

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
9107* KENORA 220	67556 WHTSL1 4 220	1	-6.2	-12.2
9107* KENORA 220	67589 WHTSL2 4 220	1	-6.2	-12.1
TOTAL FROM AREA 1 TO AREA 667			-12.5	-24.3

TO AREA 702 NYISO

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
1110* STLAWL33 230	79589 MOSES E 230	1	-172.9	-18.6
1111* STLAWL34 230	79589 MOSES E 230	1	-194.5	-9.6
5004* BECK A 345	79584 NIAG 345 345	1	-331.7	-68.5
5005* BECK B 345	79584 NIAG 345 345	1	-331.9	-68.4
5138 BP76 REG 230	76665* PACKARD2 230	1	-206.7	-53.2
5244 PA27 REG 230	79592* NIAGAR2W 230	1	-301.9	-44.7
TOTAL FROM AREA 1 TO AREA 702			-1539.5	-263.0

TO AREA 704 HQTE

X-----FROM-----X	X-----TO-----X	CKT	MW	MVAR
100 CHAT FLS 220	84003* PAUGAN 220	1	0.0	0.0
345* CHENAU J 118	84011 BRYSON 118	1	0.0	-0.5
380* IPB H9A 118	84012 MASSON 118	1	0.0	-0.1
1150 IPB B31L 220	84002* BEAUHB31 220	1	0.0	0.0
8296* IPB LACA 118	84015 KIPAWA 118	1	0.0	-2.1
8297* KIPWIESO 118	85716 KIP120 120	T1	-3.7	41.9
8346* NMILEJD4 118	84016 RAP DES 118	1	0.0	-1.8
TOTAL FROM AREA 1 TO AREA 704			-3.7	37.4

TOTAL FROM AREA 1

-2470.1 -302.4

APPENDIX F DYNAMIC MODEL ADJUSTMENTS

NANTICOKE SYNCHRONOUS CONDENSER MODEL CHANGES

As mentioned by IESO,

“The Nanticoke units are synchronous condensers so they have no stabilizer and governor and are round rotor generators with a high gain exciter. Without the stabilizers, the Nanticoke units are more oscillatory than we would like. The settings on the Nanticoke exciters will have to be changed.”

The Nanticoke units have the following model parameters in the case provided by IESO (out of the four synchronous condensers in the dynamics model only one unit is shown here):

```
PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      FRI, NOV 04 2005   8:14
2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD20S
-530BLIP6904FABC2994FETT1765QFW-604MICH-1138NYNI-250NYSL-14
```

PLANT MODELS

REPORT FOR ALL MODELS

BUS 6328 [NANTICG122.000] MODELS

```
** GENROU **  BUS X-- NAME --X BASEKV MC      C O N S      S T A T E S
                6328      NANTICG1 22.000 1      1799-1812      821-826

                MBASE      Z S O R C E      X T R A N      GENTAP
                588.0      0.00250+J 0.21500      0.00000+J 0.00000      1.00000

T'D0 T''D0 T'Q0 T''Q0      H      DAMP      XD      XQ      X'D      X'Q      X''D      XL
10.00 0.030 1.50 0.350      1.13      0.00 2.3900 2.3100 0.2870 0.3400 0.2150 0.1900

                S(1.0) S(1.2)
                0.2100 0.5500
```

```
** ESST1A **  BUS X-- NAME --X BASEKV MC      C O N S      S T A T E S      I C O N S
                6328      NANTICG1 22.000 1      91433-91450      43291-43295      3883-3884

                UEL VOS      TR      VIMAX      VIMIN      TC      TB      TC1      TB1      KA
                1      1      0.015      1.150      0.000      0.000      0.000      0.000      200.0

                TA      VAMAX      VAMIN      VRMAX      VRMIN      KC      KF      TF      KLR      ILR
                0.010 999.000-999.000      9.970      -9.630 0.100      0.000      1.000 16.000      5.190
```

Two parameters in the exciter model, TC and TB were changed from 0.0 & 0.0 in the above model to 1.0 & 4.0 respectively, to reduce the transient gain¹ by a factor of 4. This change was made for all the 4 synchronous condensers in the dynamics model. Comparison of the synchronous condenser performance, with the original (SIM#1.out) and after the change of parameters (SIM#1A.out), is shown in the attached Figure F.1.

¹ Koessler, R.J., “Techniques for Tuning Excitation System Parameters”, IEEE Transactions on Energy Conversion, Vol. EC-3, No. 4, December 1988, pp. 785-791.

**Figure F-1: Comparison of Nanticoke Synchronous Condenser
With and without Changes in the Exciter Parameters**

(Please see Next Page)

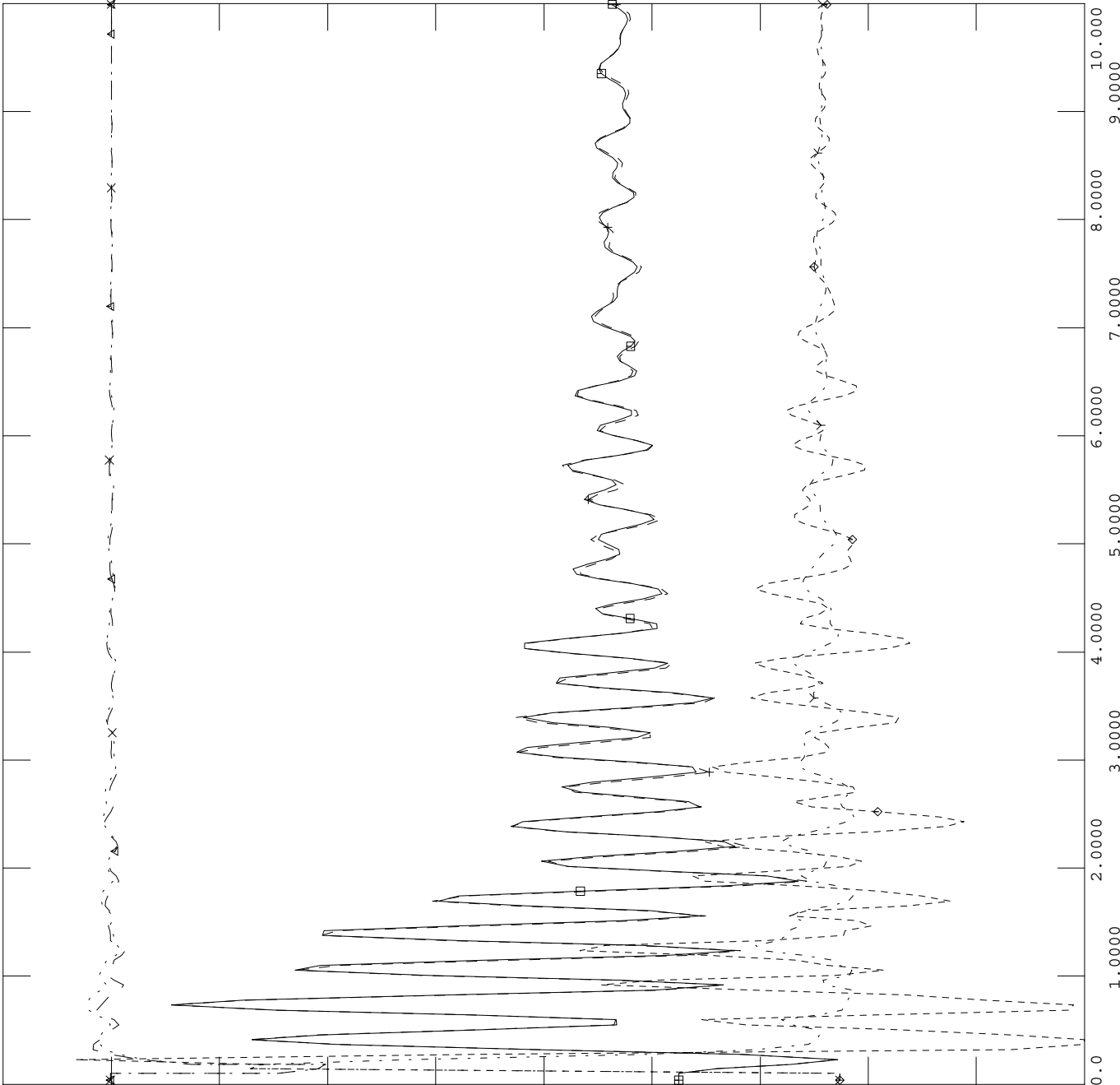
The top 2 curves in the figure correspond to terminal voltage (bus#6328) and there is a small difference up to a few seconds, but almost the same. The two curves in the middle are the angles. These two curves are, practically, on top of each other. The two curves at the bottom correspond to the 'Efd'. Larger swings in the original case (diamonds) as compared to the changed case (Y-symbol) can be seen.

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2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
-530BLIP6904FABC2994FETT1765QFW-604MICH-1138NYNI-250NYSL-14

CHNL# 257: [NANTICG1EFD]			
10.000	FILE:...\DYNAMICS-WITH-ABB-POWER-FLOW\SIM#1A.OUT	➤-----➤	0.0
CHNL# 199: [NANTICG1ET]			
1.1000	FILE:...\DYNAMICS-WITH-ABB-POWER-FLOW\SIM#1A.OUT	✕-----✕	0.10000
CHNL# 25: [NANTICG1ANG]			
0.0	FILE:...\DYNAMICS-WITH-ABB-POWER-FLOW\SIM#1A.OUT	+-----+	-50.00
CHNL# 257: [NANTICG1EFD]			
10.000	FILE:...\DYNAMICS-WITH-ABB-POWER-FLOW\SIM#1.out	◇-----◇	0.0
CHNL# 199: [NANTICG1ET]			
1.1000	FILE:...\DYNAMICS-WITH-ABB-POWER-FLOW\SIM#1.out	◄-----►	0.10000
CHNL# 25: [NANTICG1ANG]			
0.0	FILE:...\DYNAMICS-WITH-ABB-POWER-FLOW\SIM#1.out	▣-----▣	-50.00



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NANTI - OLD - NEW - EXCTRS

FIGURE F-1

APPENDIX G DYNAMICS SIMULATION RESULTS

3-PHASE FAULT, NORMALLY CLEARED, NO-BYPASS of SERIES CAPACITORS

Plots for the following four disturbances are shown in the following order in this Appendix:

i) Bruce – Milton 500kV Circuit (fault at bus# 6409)

Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G1&G2
Voltage Drop² across the 5 series capacitors – Figure G3

Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G4

ii) Bruce – Longwood 500kV Circuit (fault at bus# 6410)

Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G5&G6
Voltage Drop across the 5 series capacitors – Figure G7

Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G8

iii) Longwood – Nanticoke 500kV Circuit (fault at bus# 7000)

Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G9&G10
Voltage Drop across the 5 series capacitors – Figure G11

Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G12

iv) Bruce – Clairville 500kV Circuit (fault at bus# 4000)

Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G13&G14
Voltage Drop across the 5 series capacitors – Figure G15

Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G16

² In Figures G3, G7, G11 and G15, for the 4th graph, the Y-axis title is in error. It should read [V-BLWD1]-[VBLWD2]

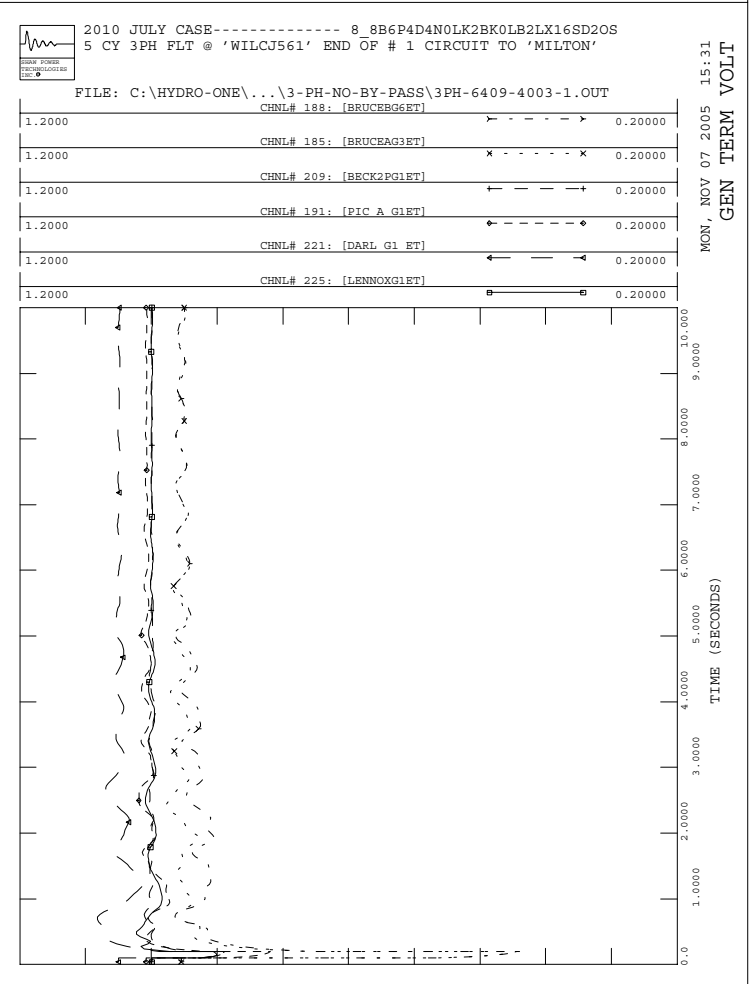
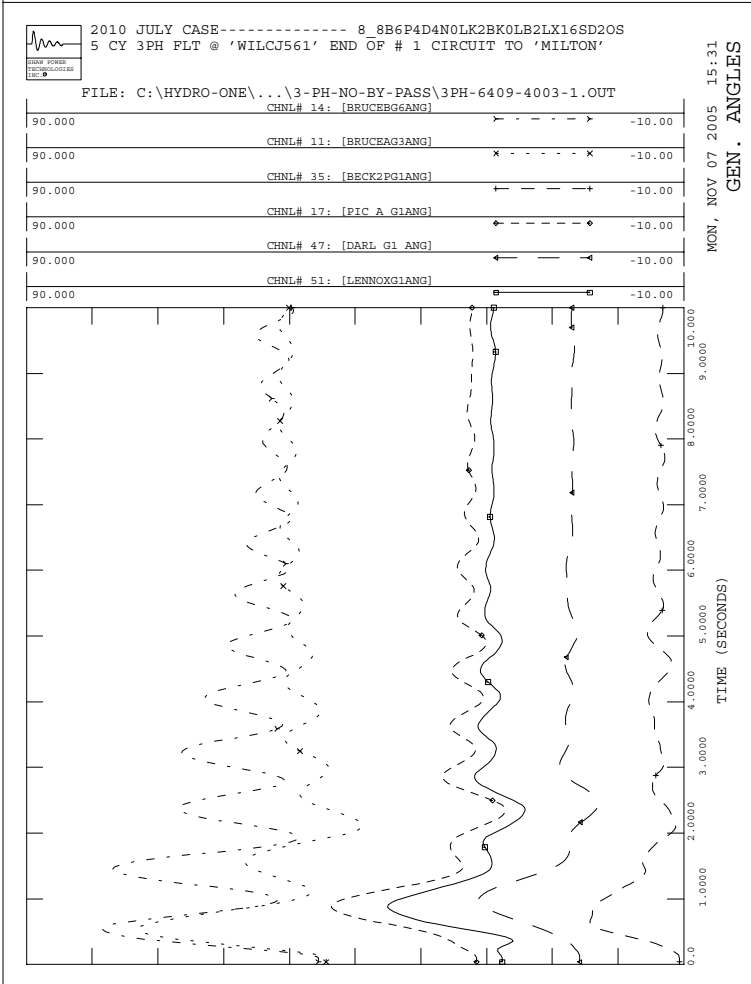
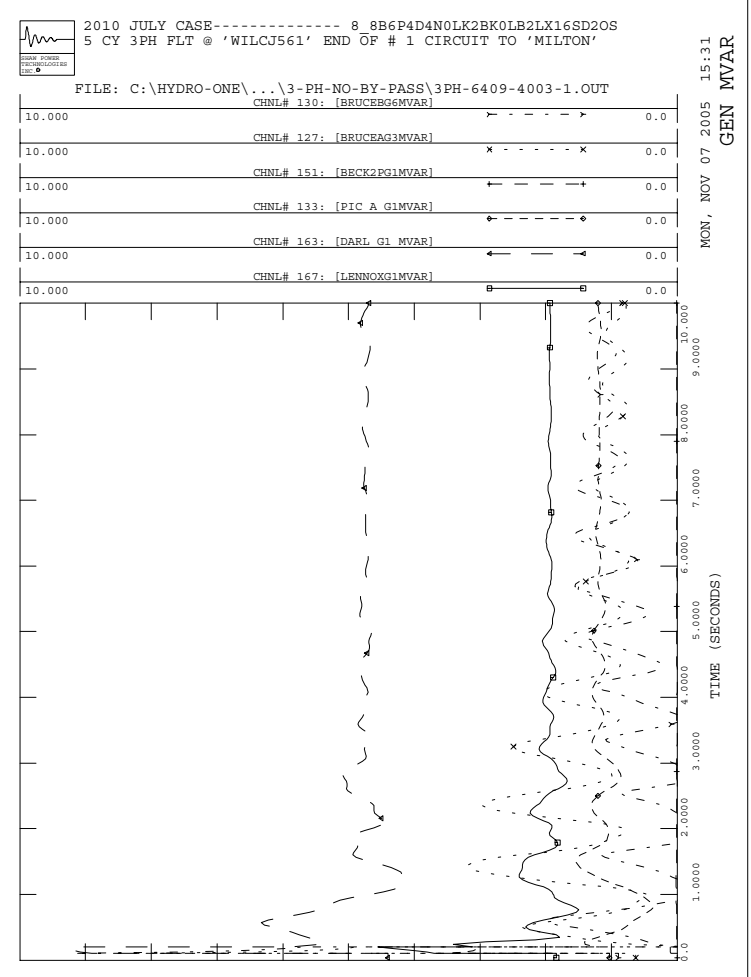
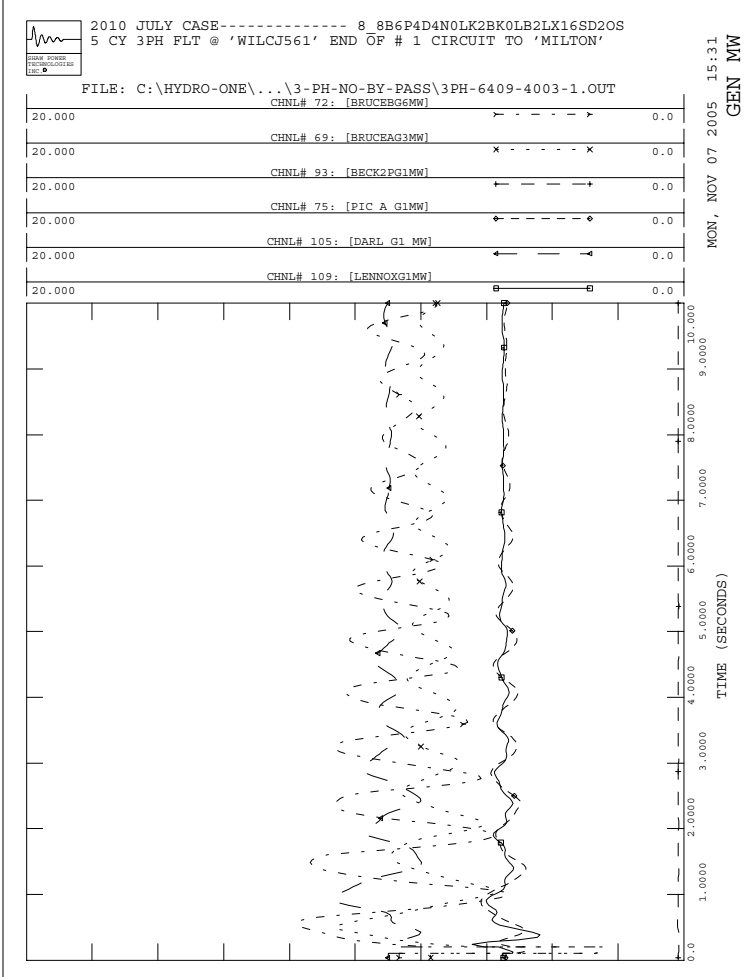


FIGURE G-1

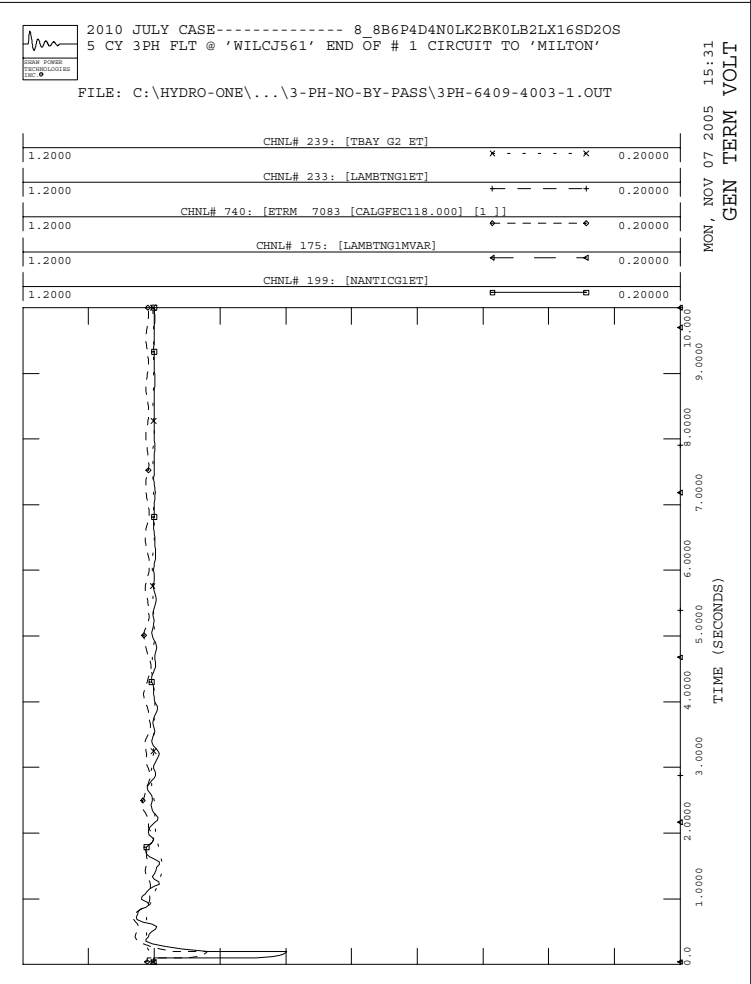
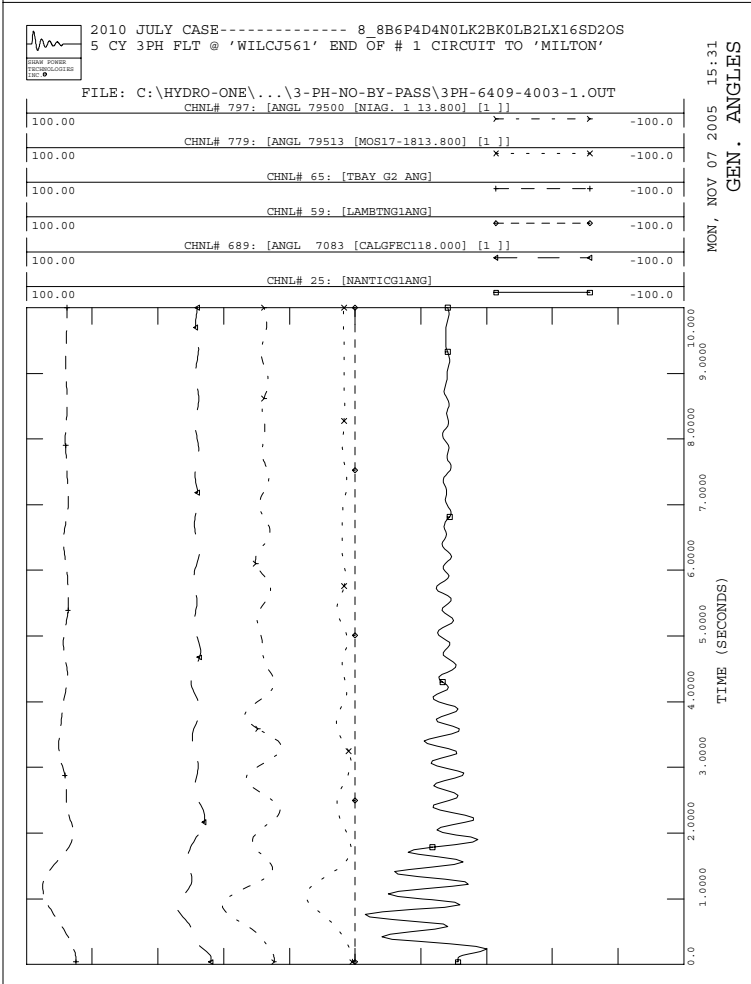
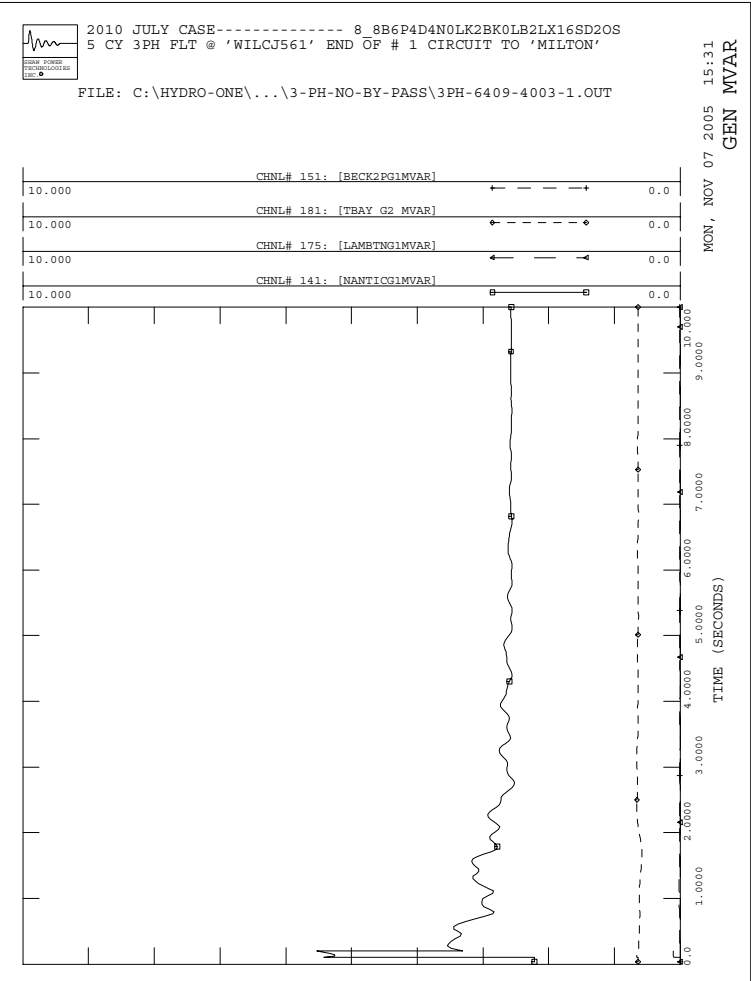
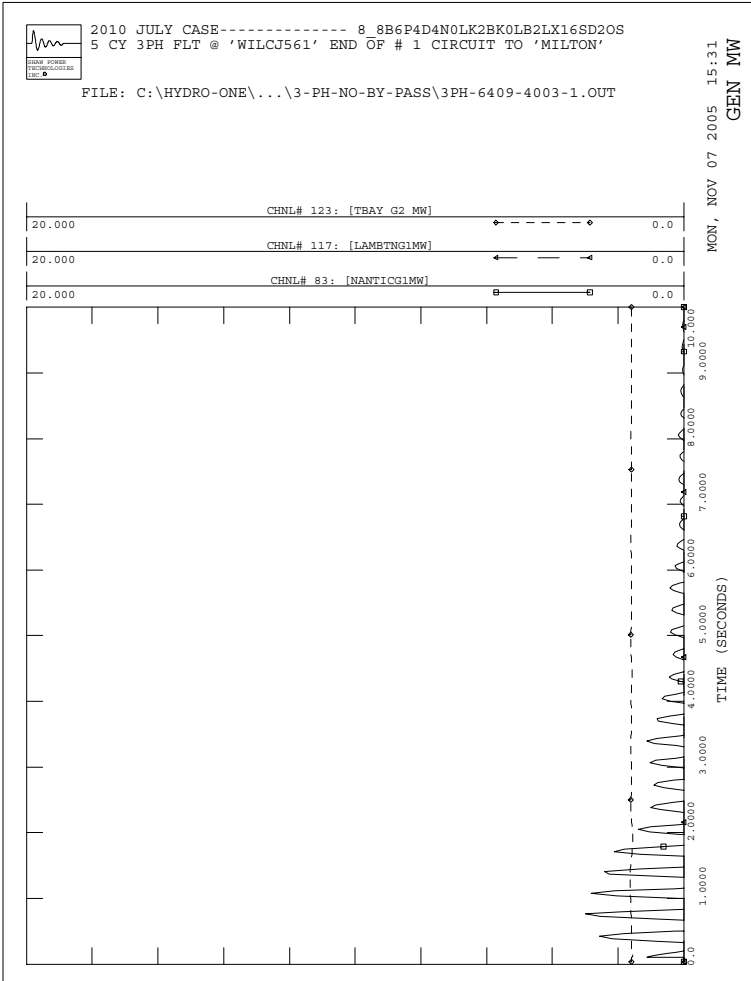
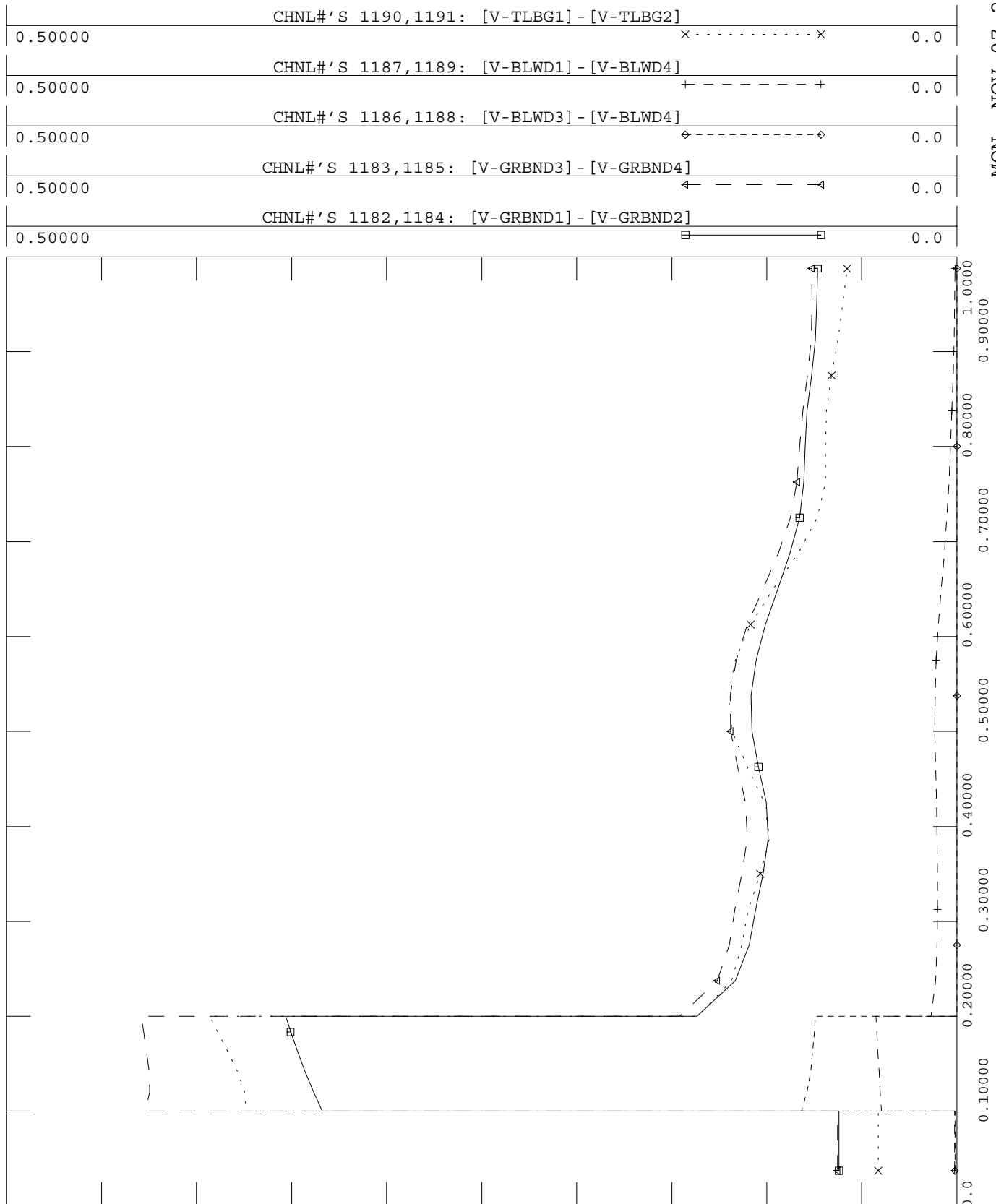


FIGURE G-2



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

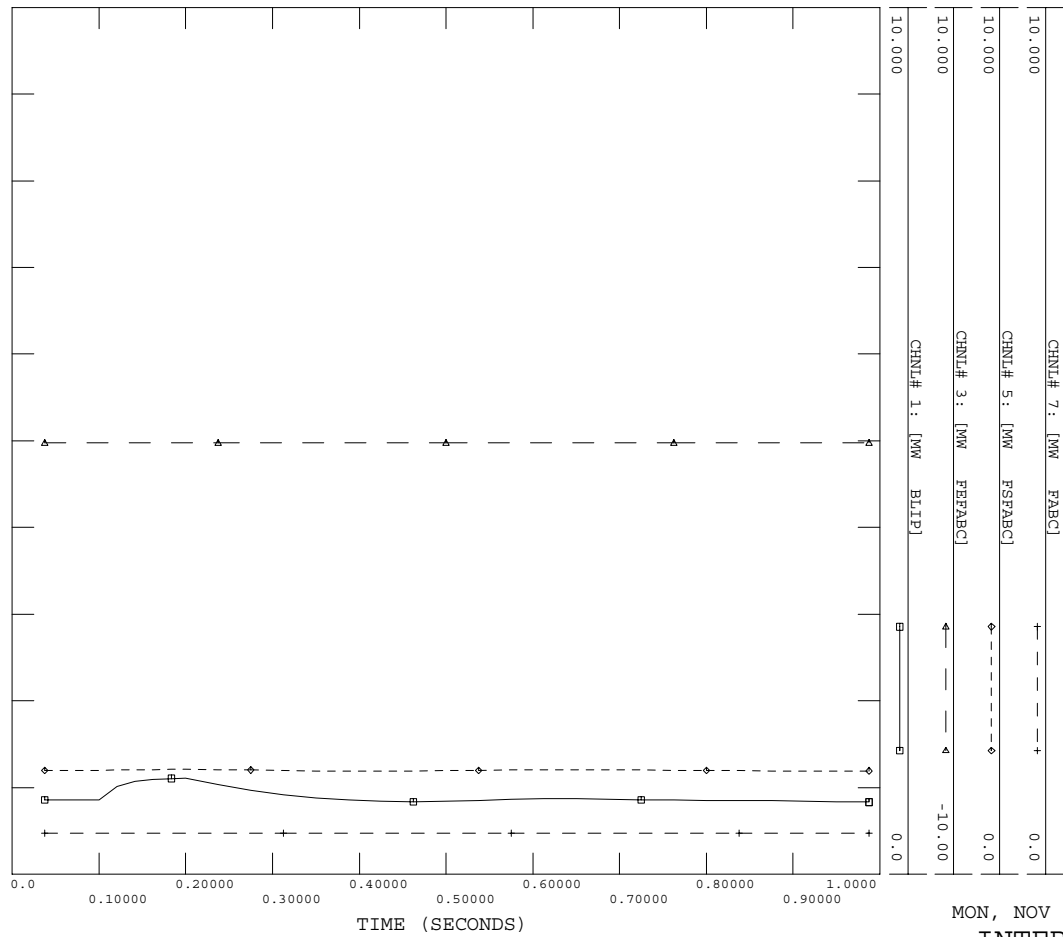
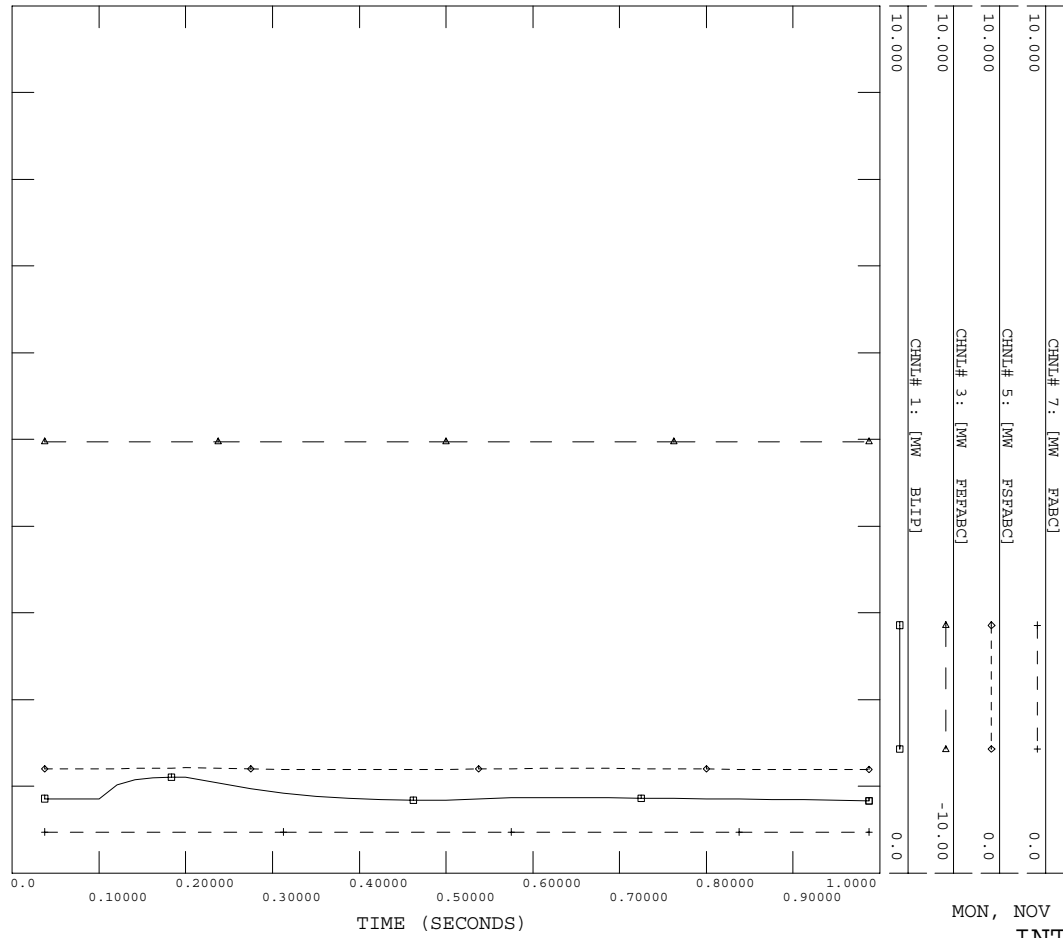
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DV-ACROSS-S-CAPS

FIGURE G-3

FIGURE-4



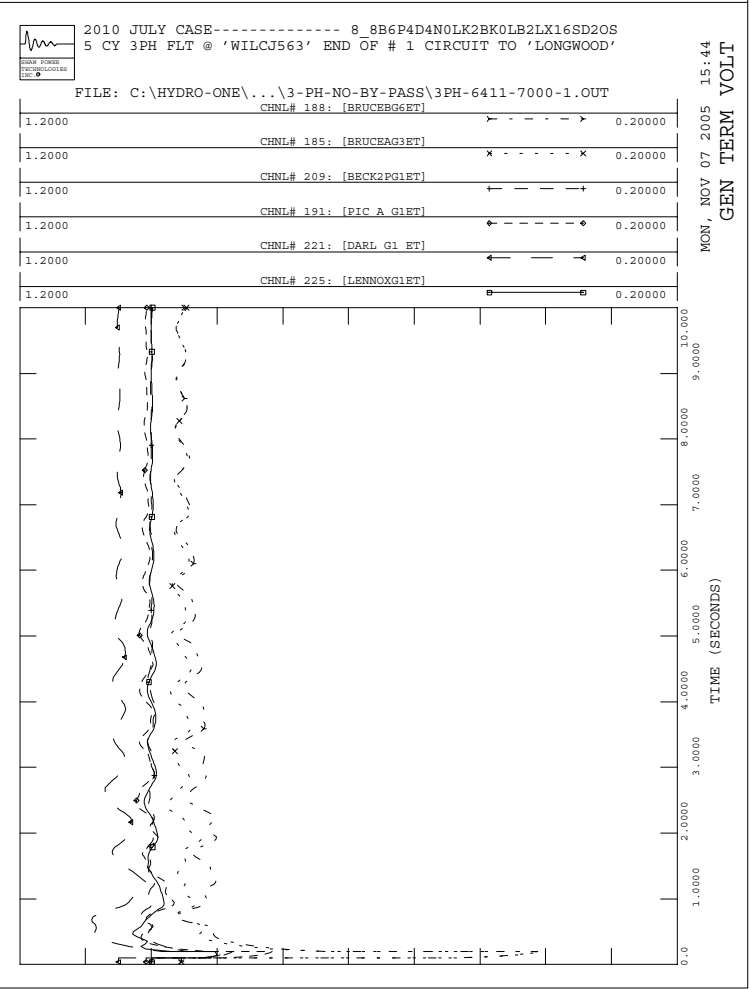
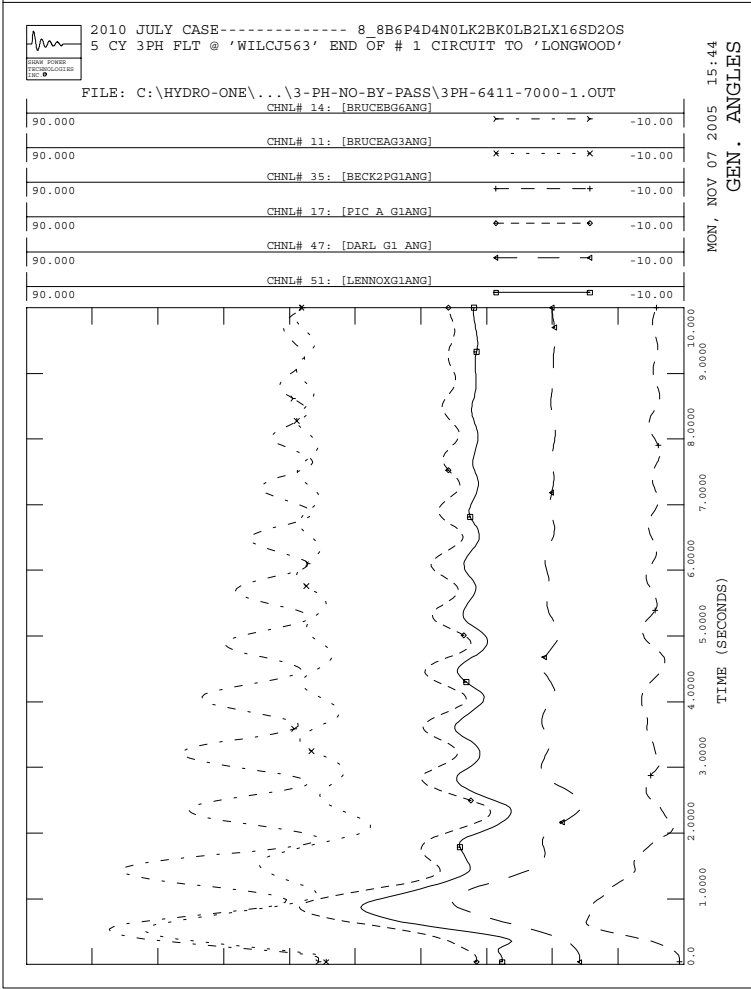
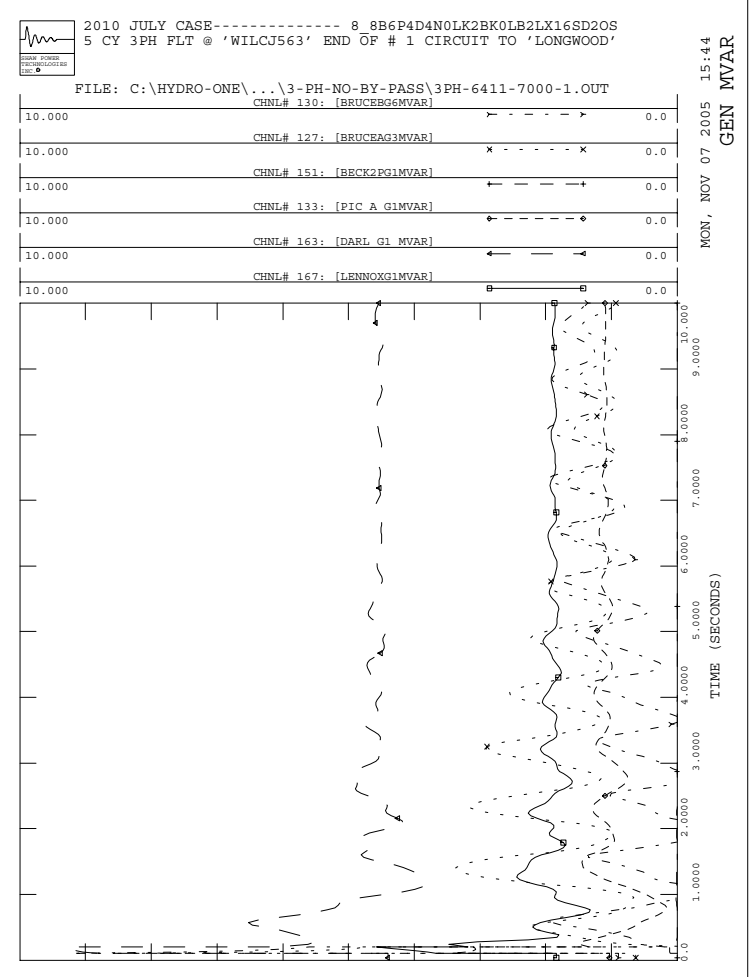
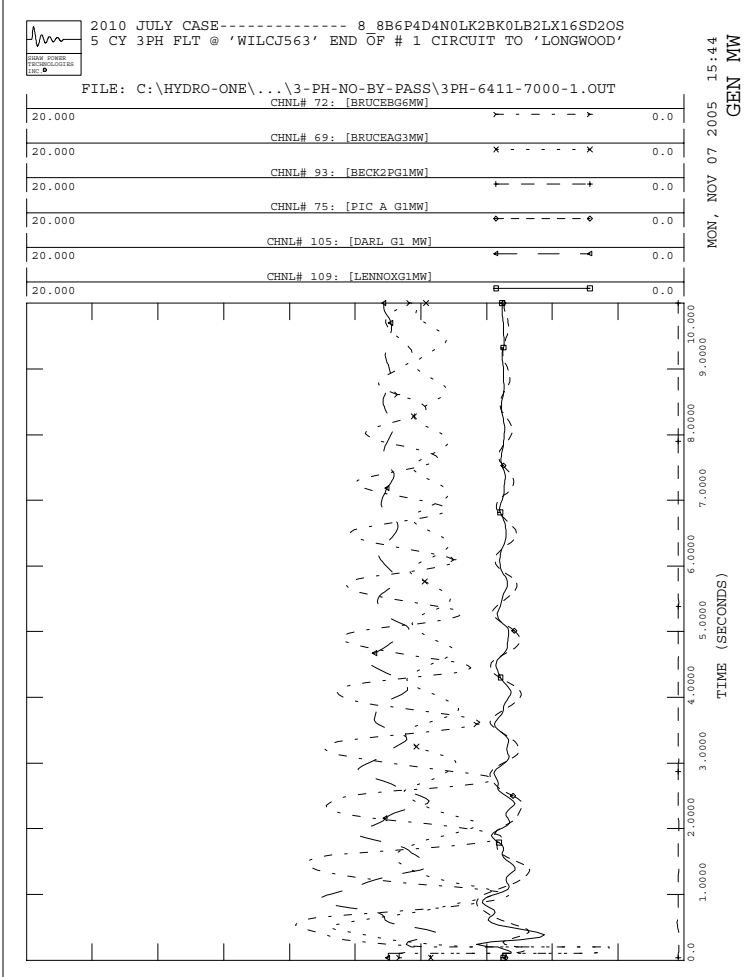


FIGURE G-5

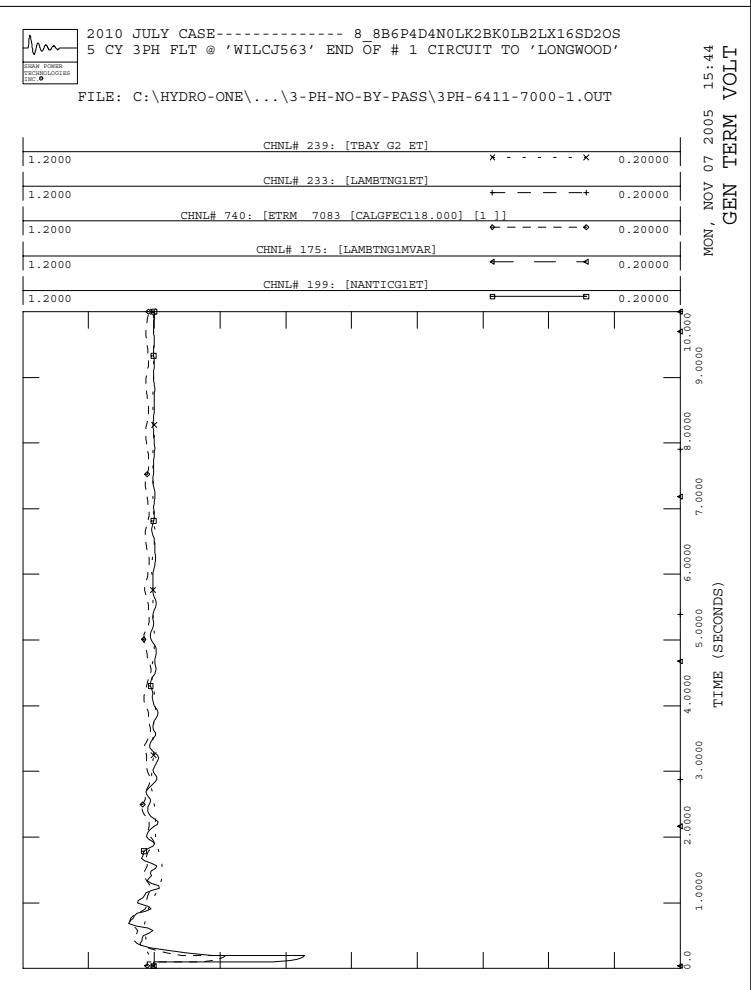
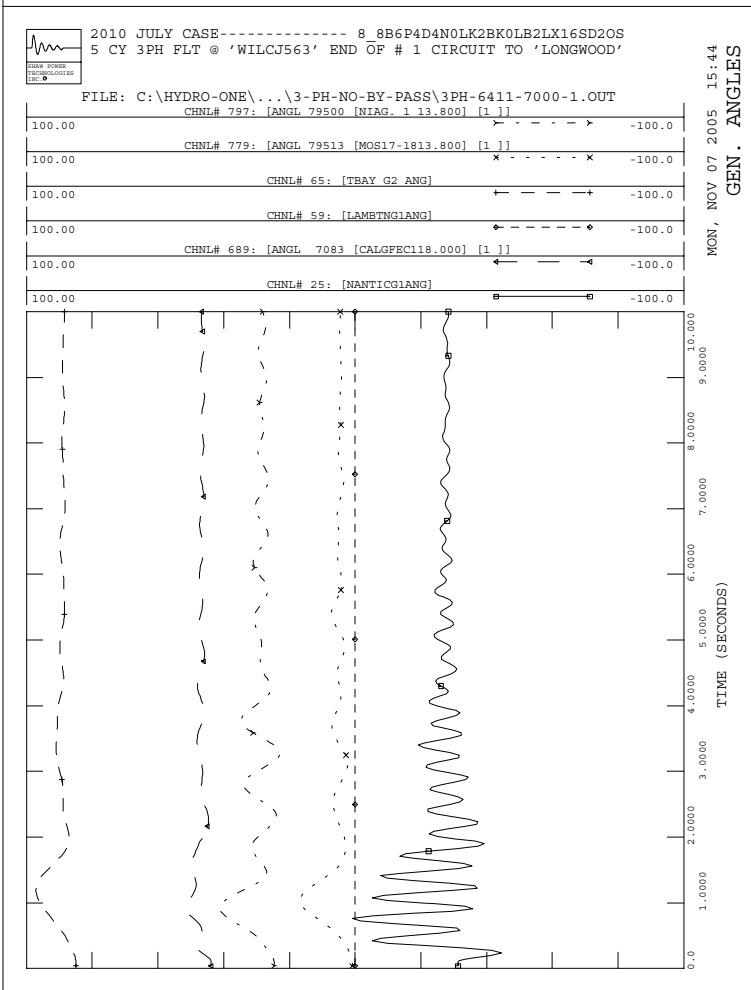
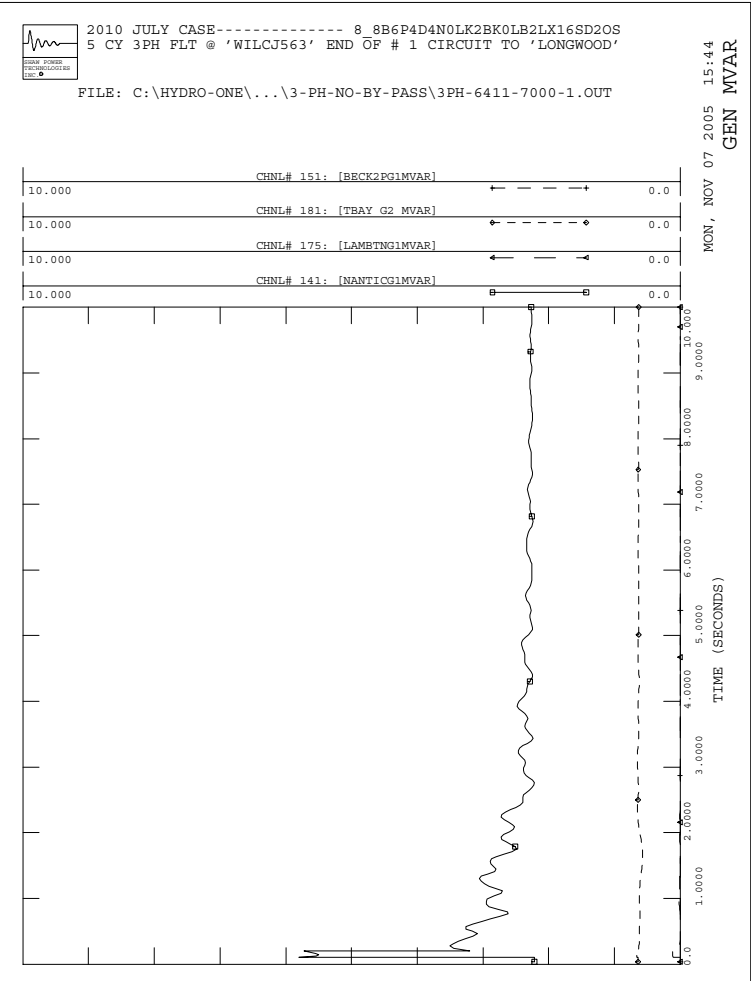
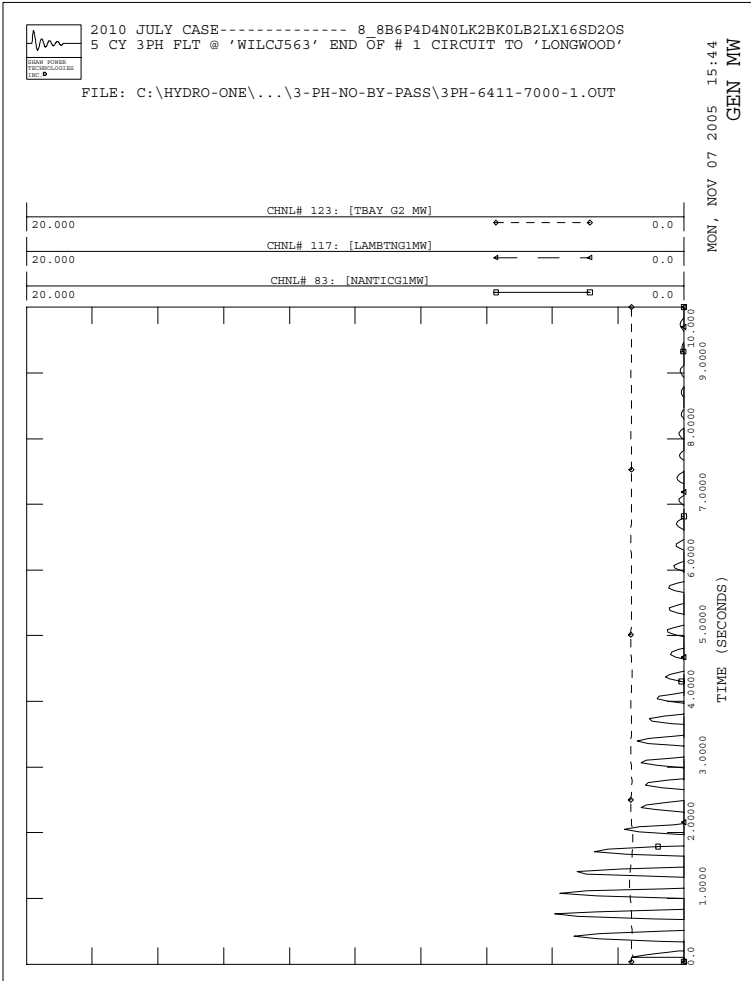


FIGURE G-6



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: C:\HYDRO-ONE\...\3-PH-NO-BY-PASS\3PH-6411-7000-1.OUT

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DV-ACROSS-S-CAPS

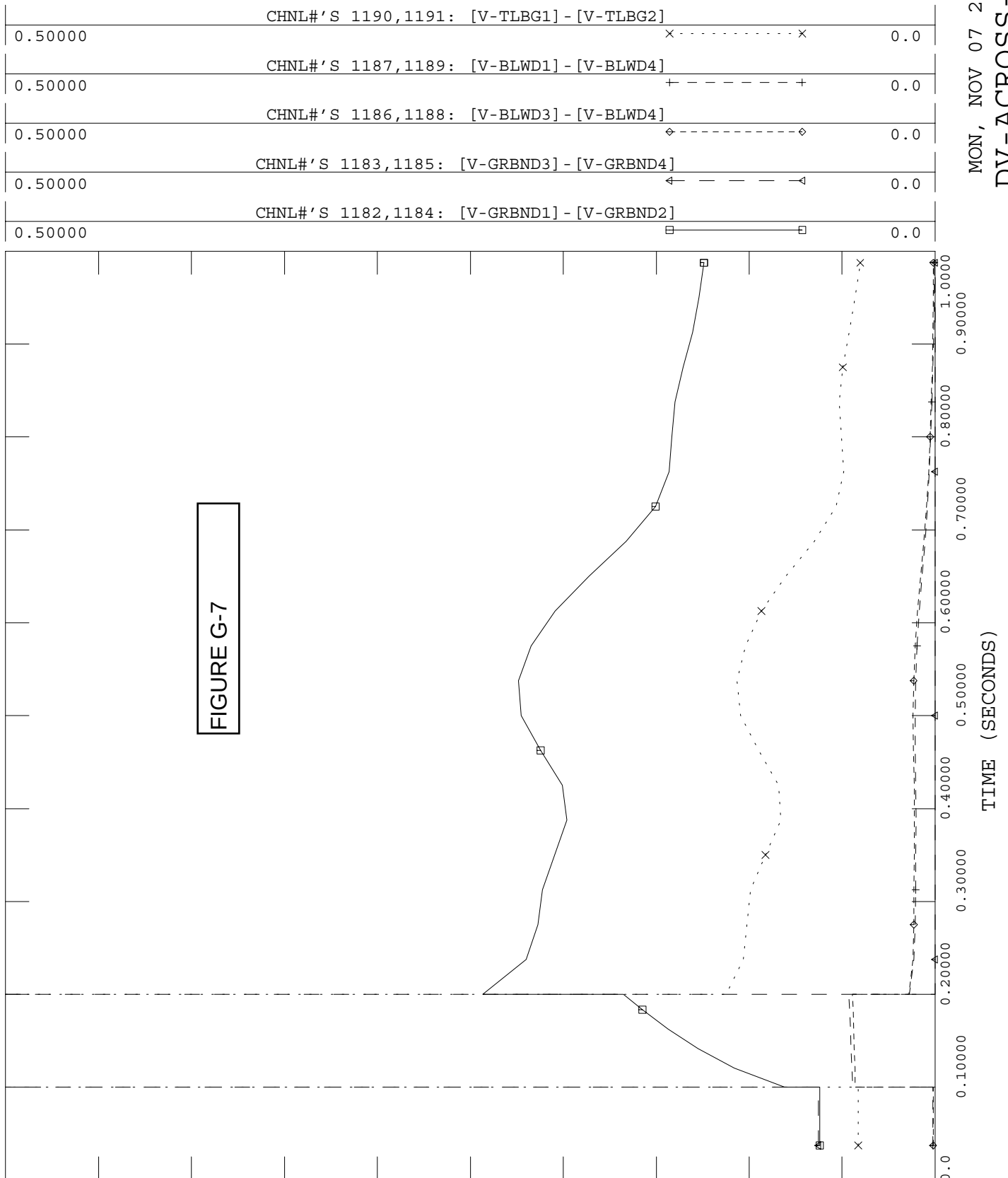
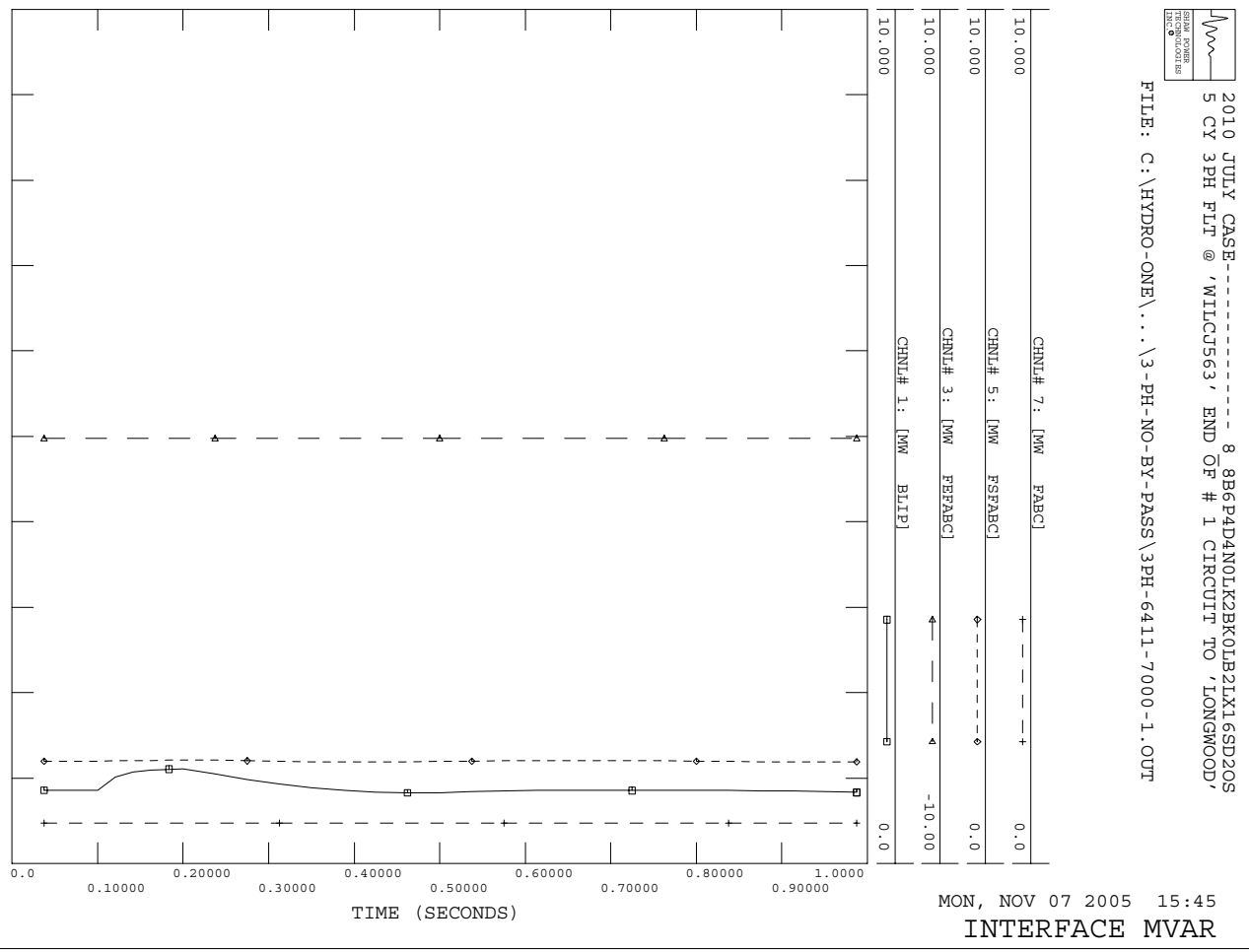
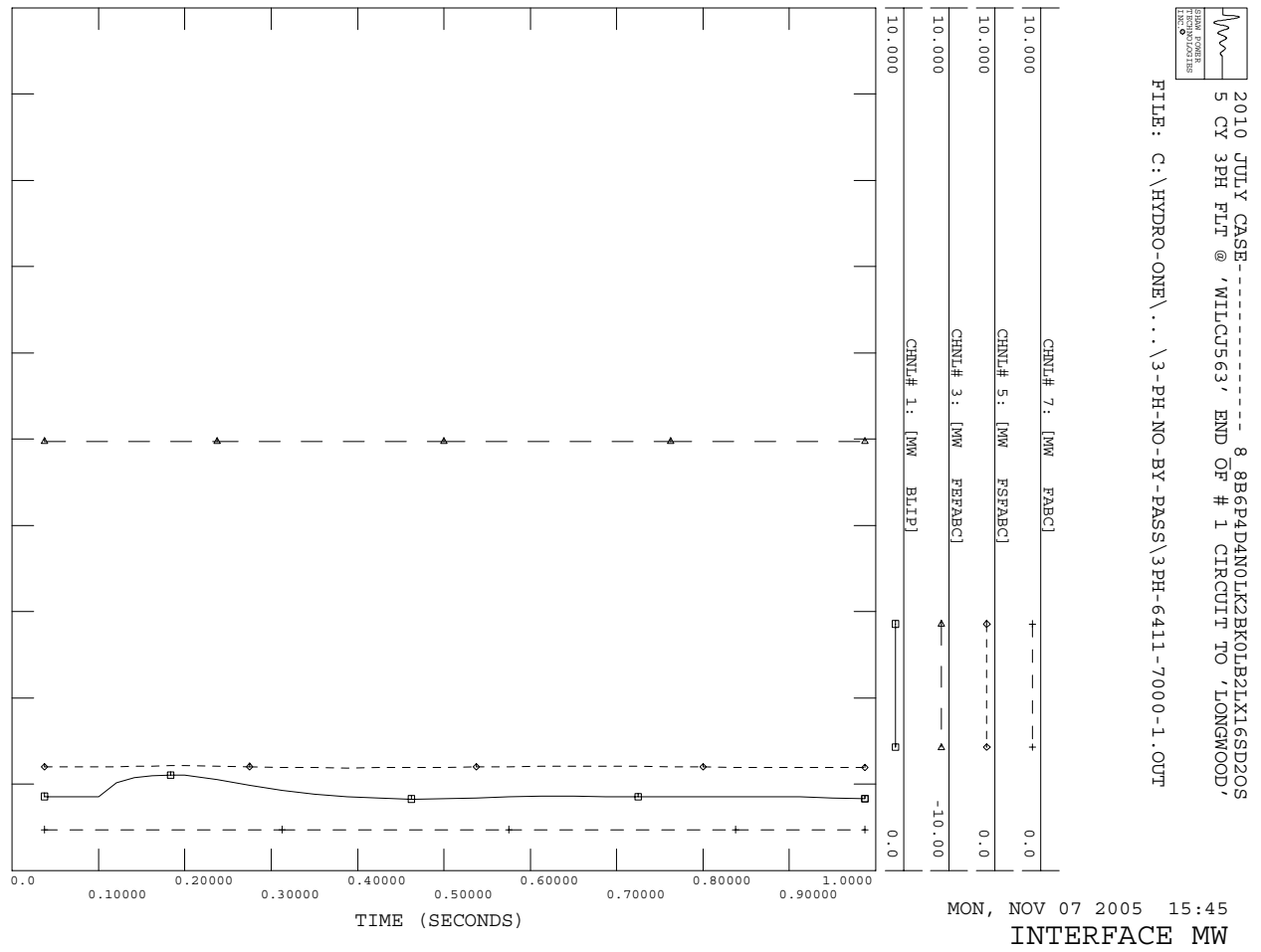


FIGURE G-8



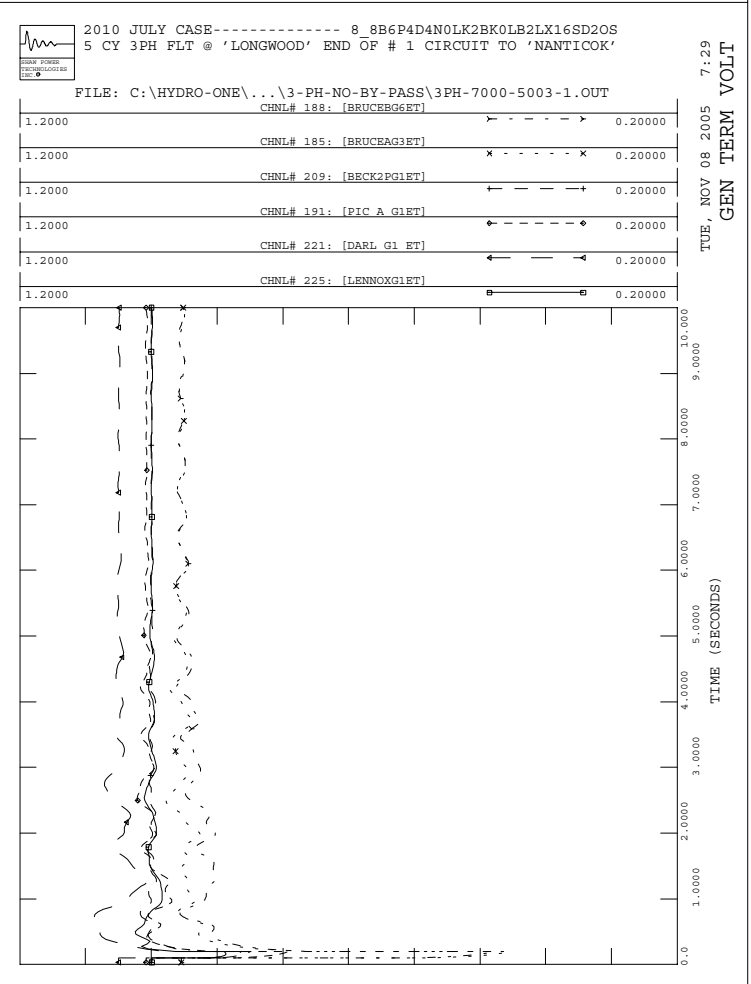
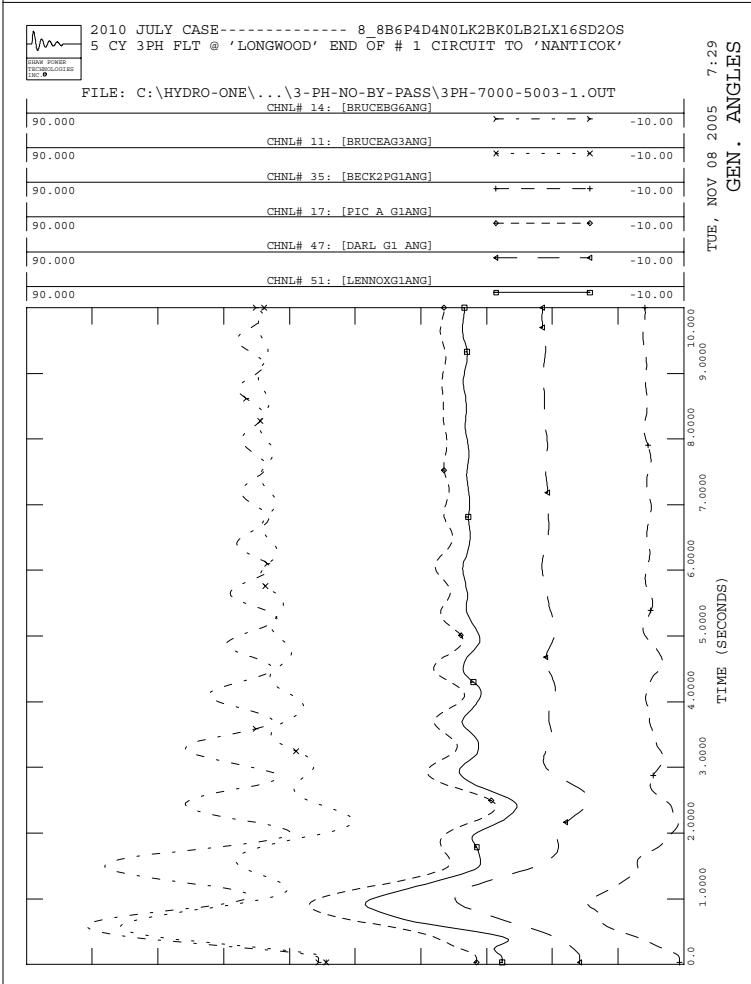
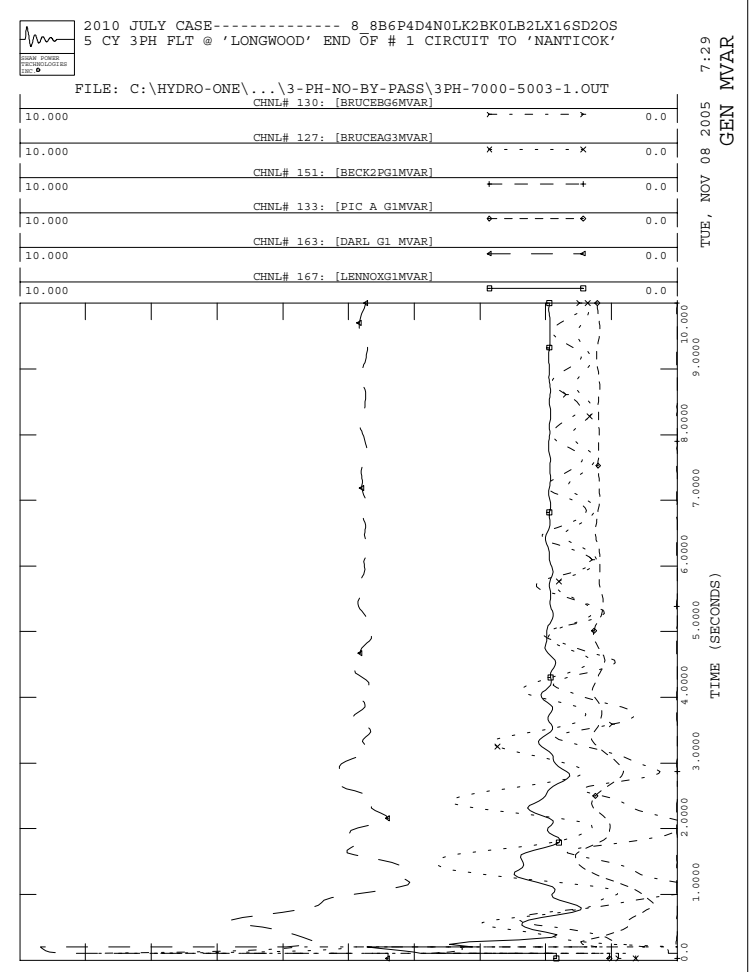
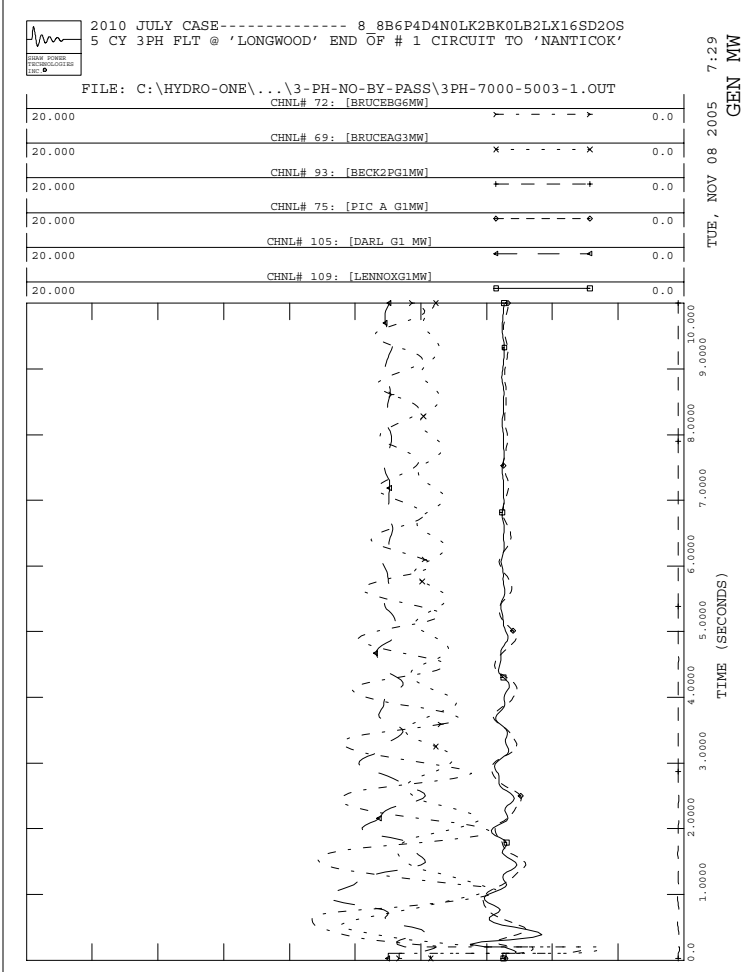
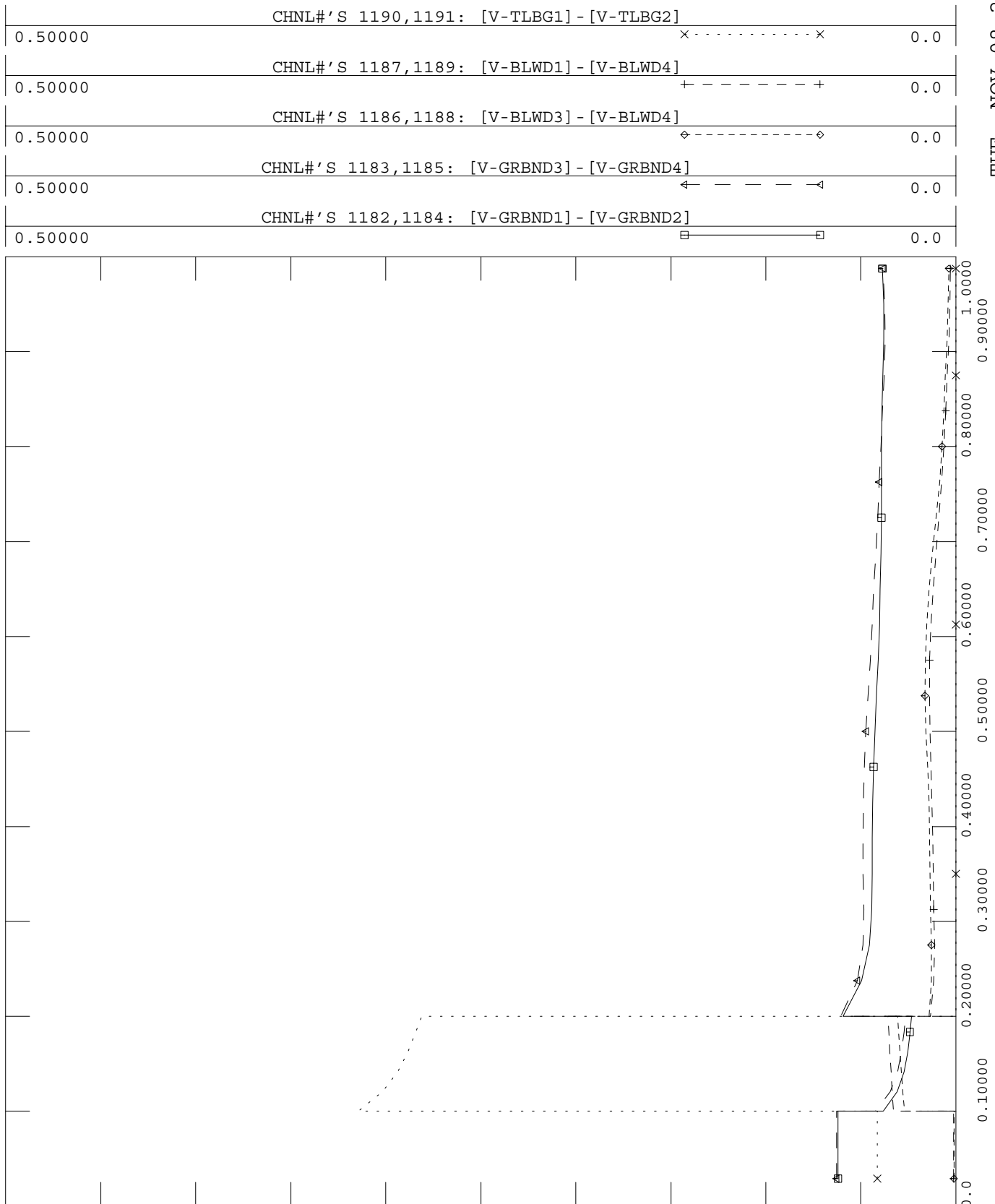


FIGURE G-9



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'LONGWOOD' END OF # 1 CIRCUIT TO 'NANTICOK'

FILE: C:\HYDRO-ONE\...\3-PH-NO-BY-PASS\3PH-7000-5003-1.OUT



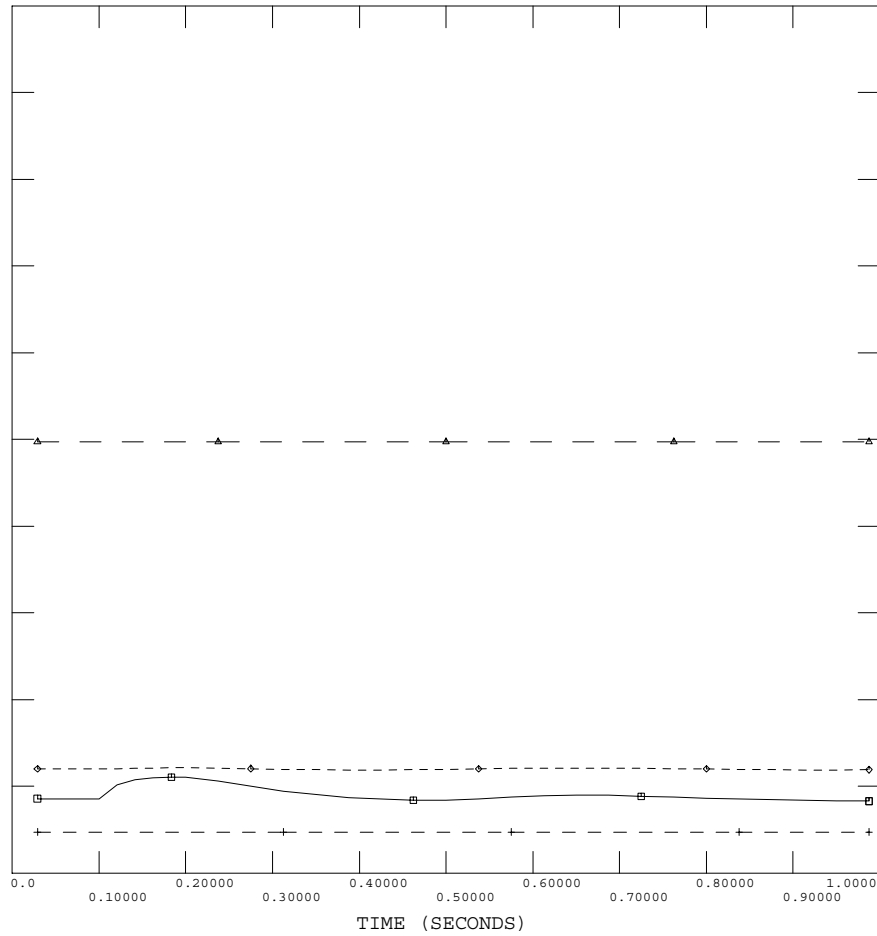
TUE, NOV 08 2005 7:36
DV-ACROSS-S-CAPS

FIGURE G-11



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'LONGWOOD' END OF # 1 CIRCUIT TO 'NANTICOK'
FILE: C:\HYDRO-ONE\...\3-PH-NO-BY-PASS\3PH-7000-5003-1.0UT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	■ - - - ■	0.0

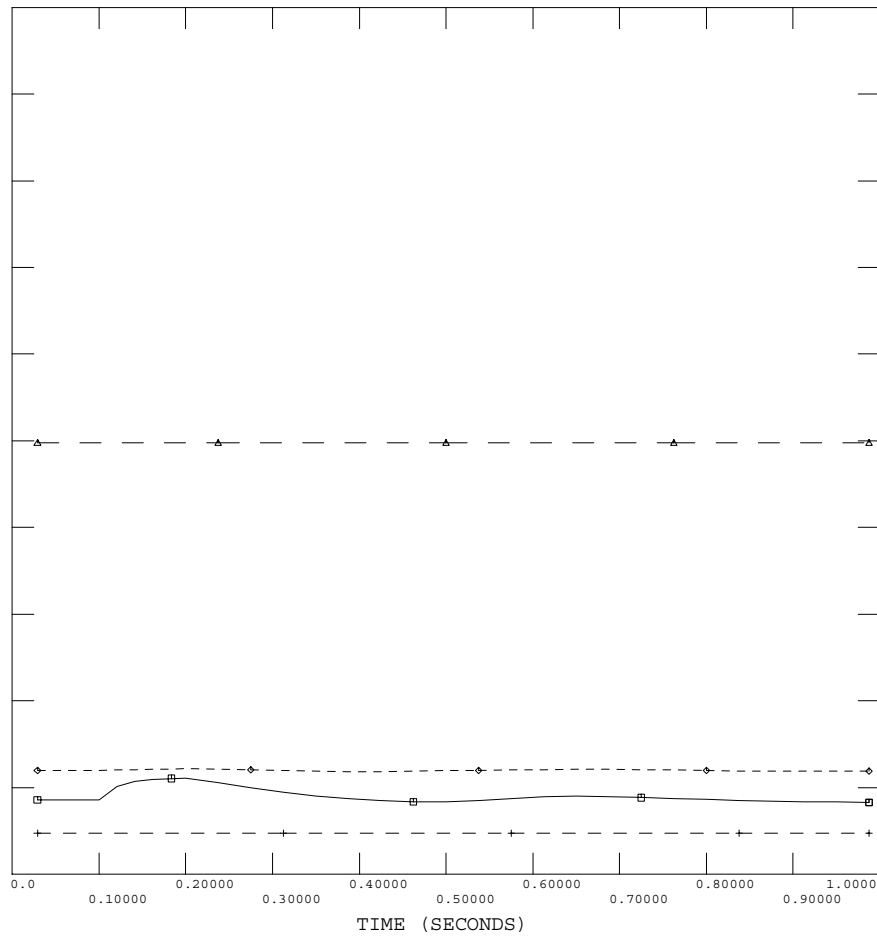


TUE, NOV 08 2005 7:36
INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'LONGWOOD' END OF # 1 CIRCUIT TO 'NANTICOK'
FILE: C:\HYDRO-ONE\...\3-PH-NO-BY-PASS\3PH-7000-5003-1.0UT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	■ - - - ■	0.0



TUE, NOV 08 2005 7:36
INTERFACE MVAR

FIGURE G-12

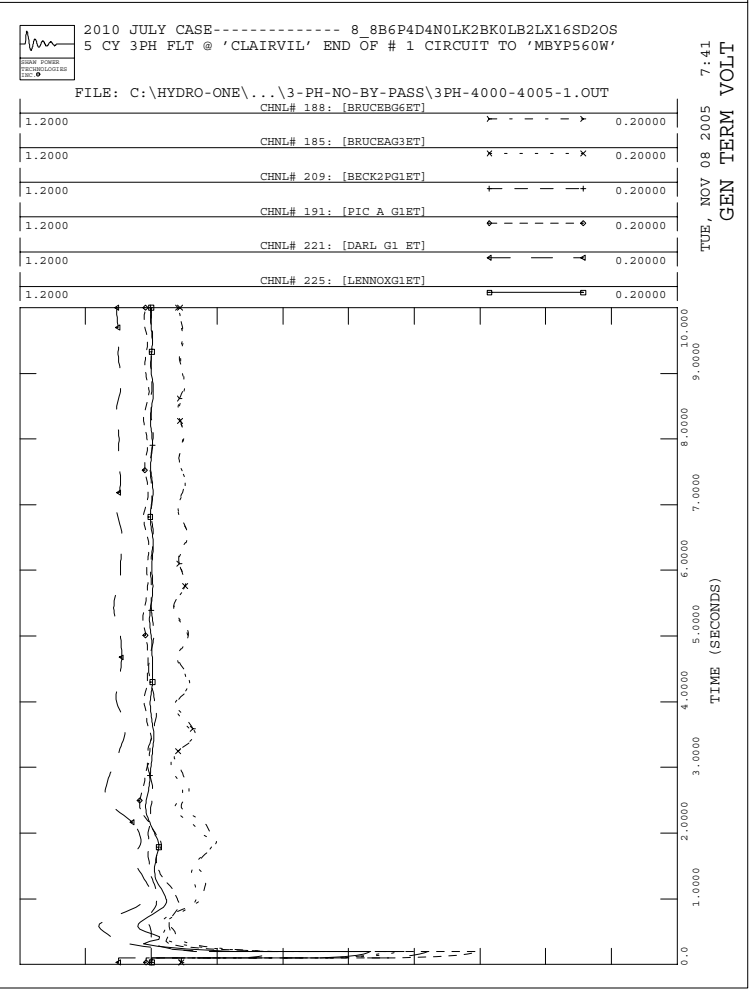
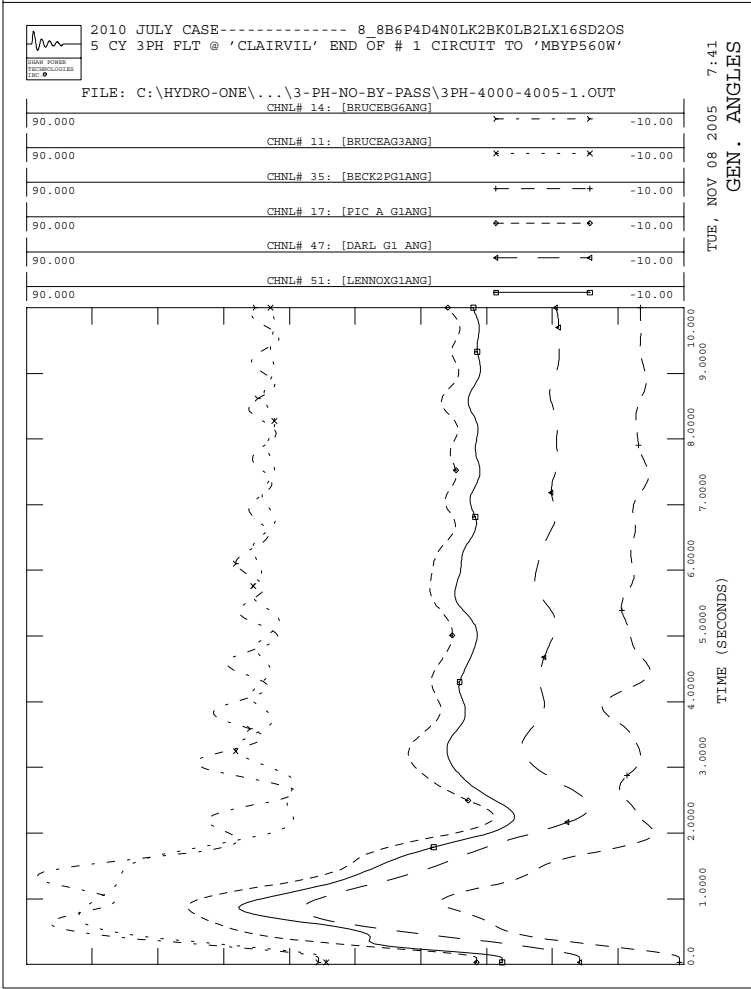
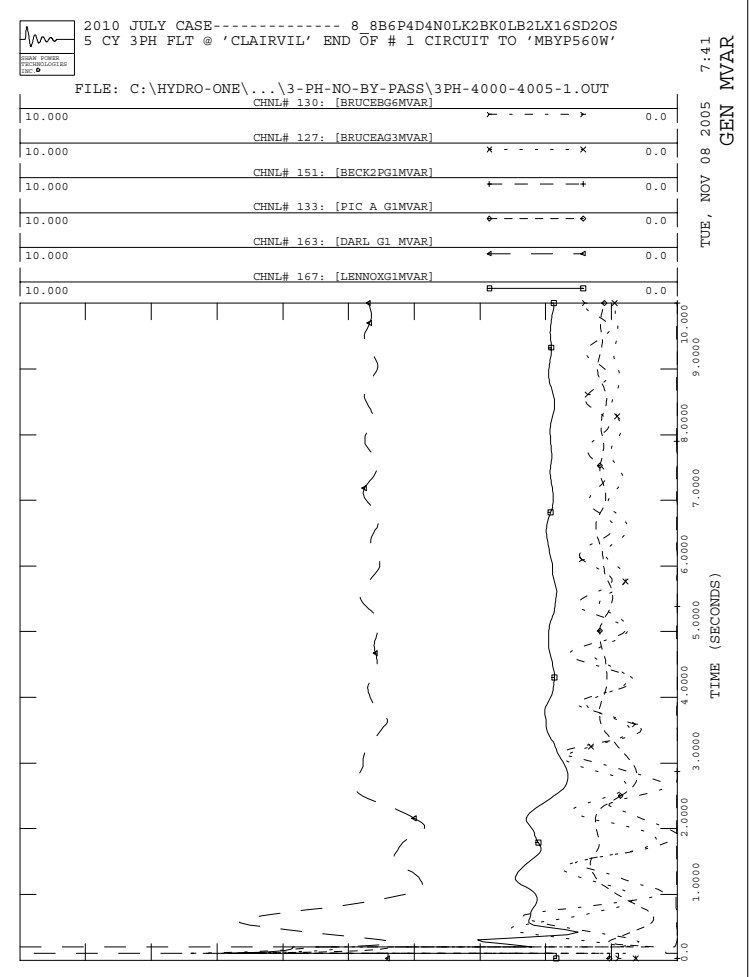
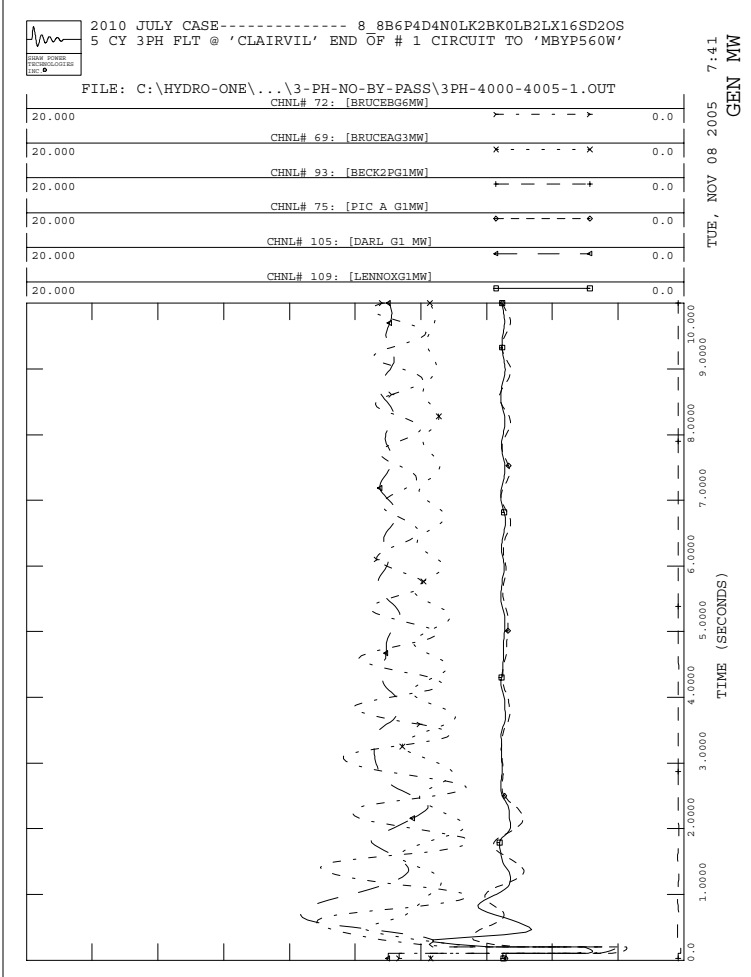


FIGURE G-13

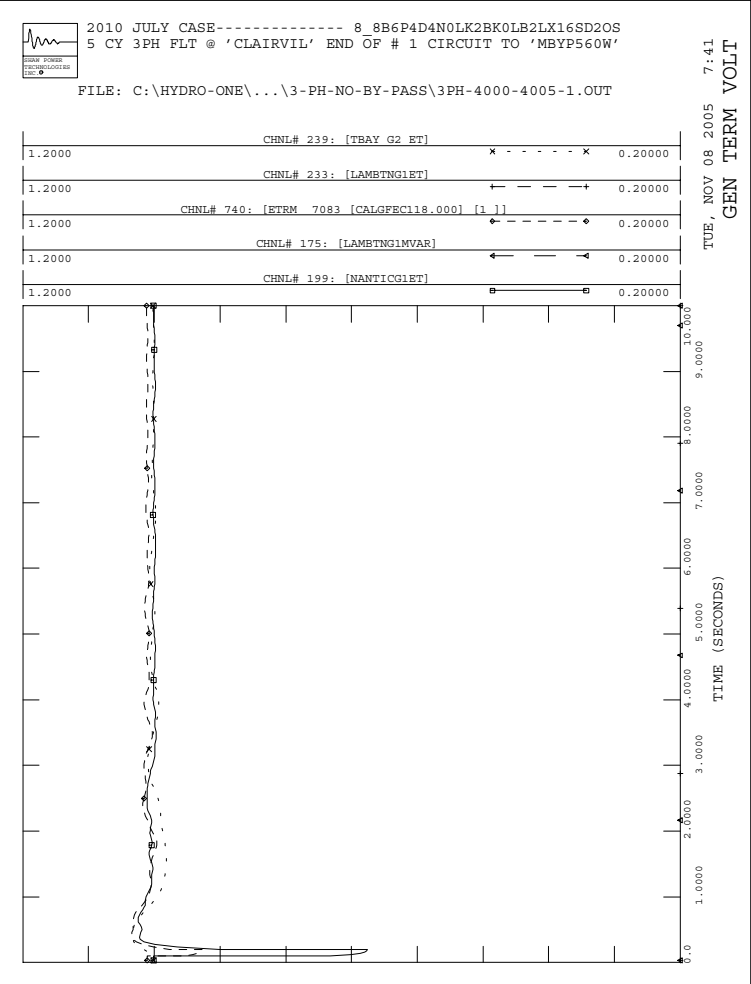
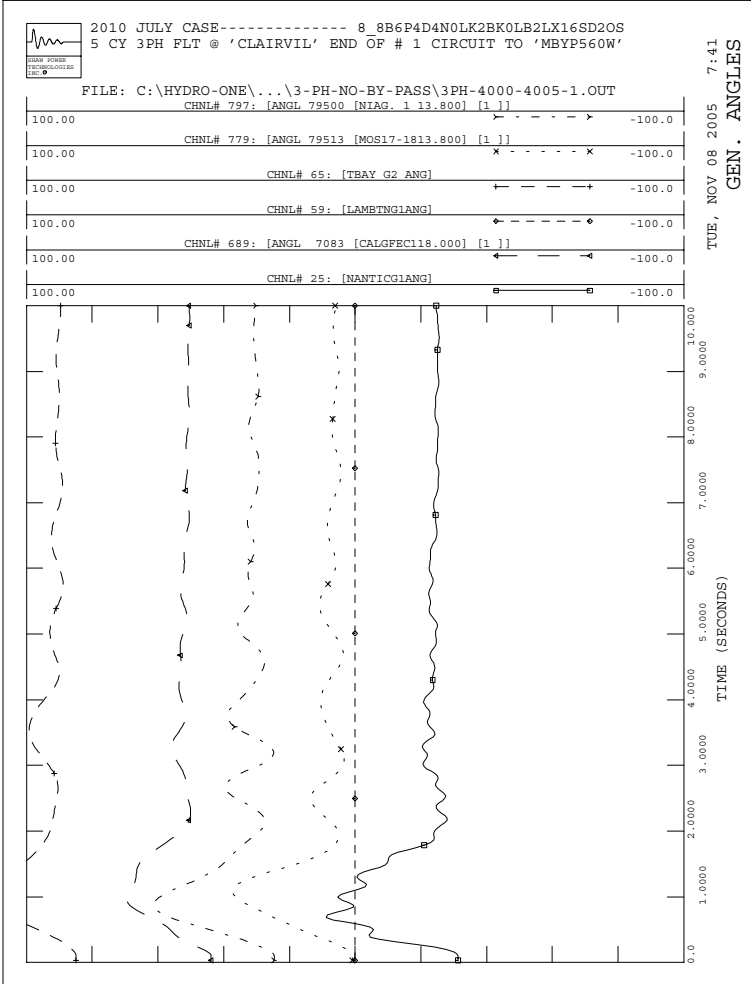
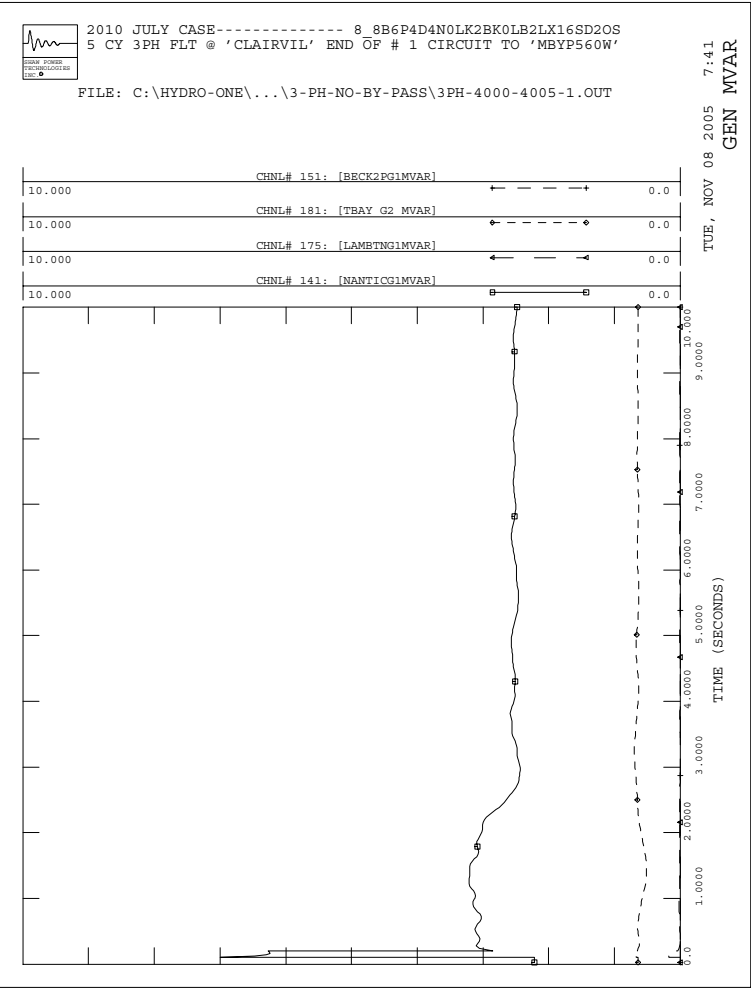
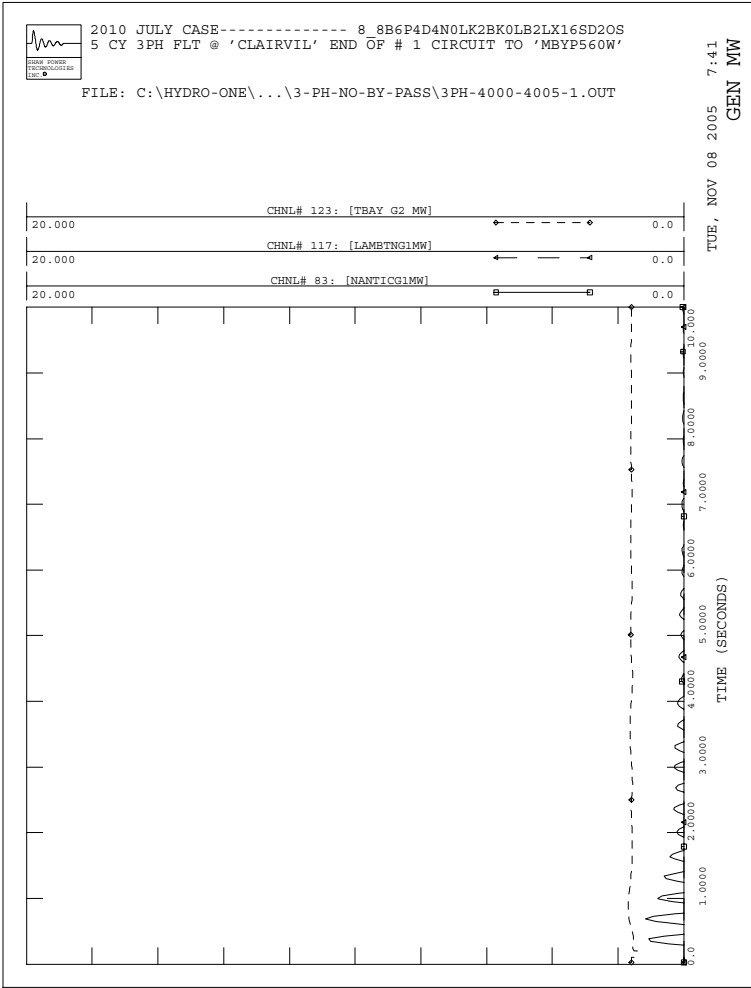
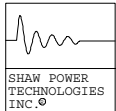


FIGURE G-14



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'

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TUE, NOV 08 2005 8:28
DV-ACROSS-S-CAPS

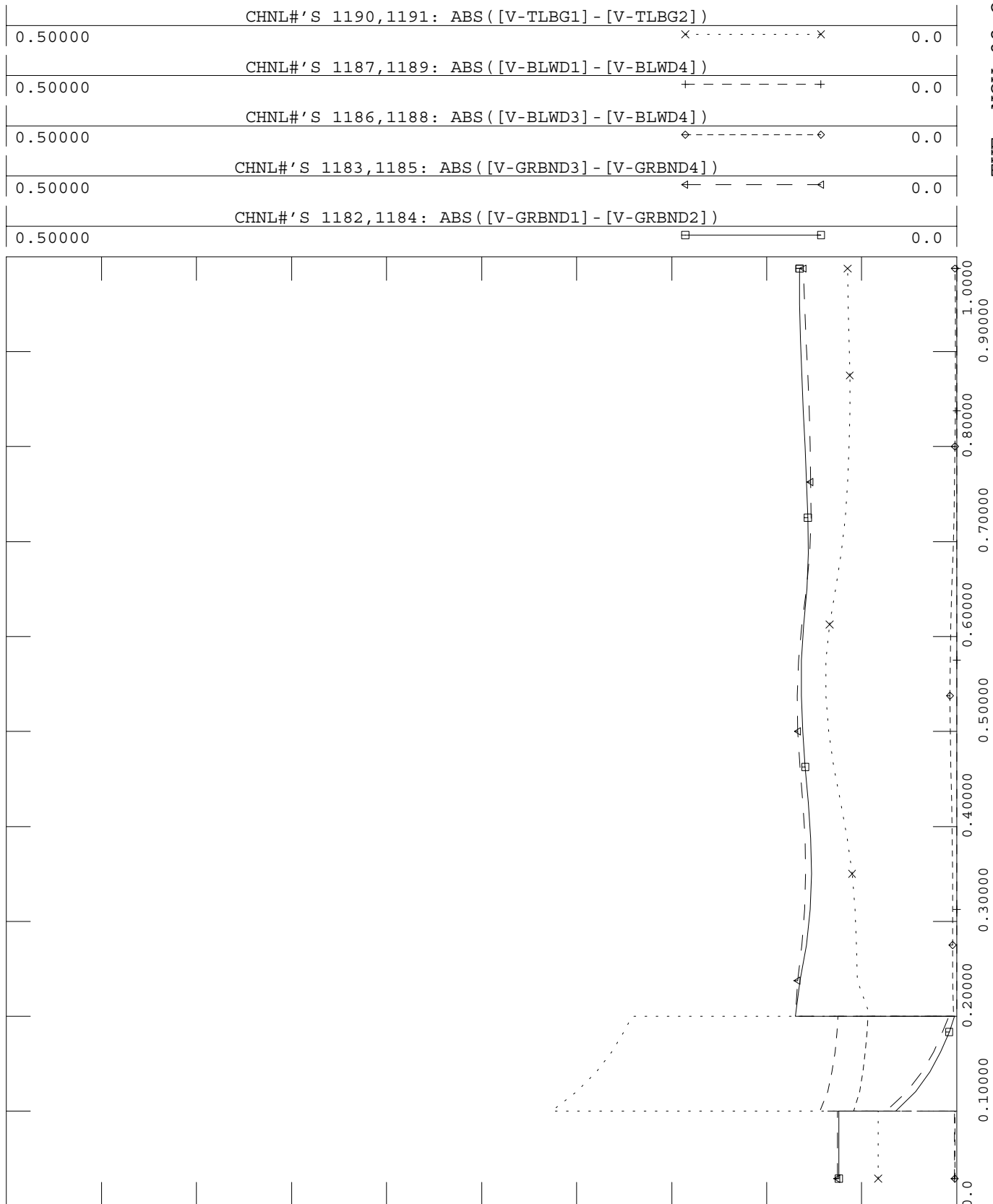
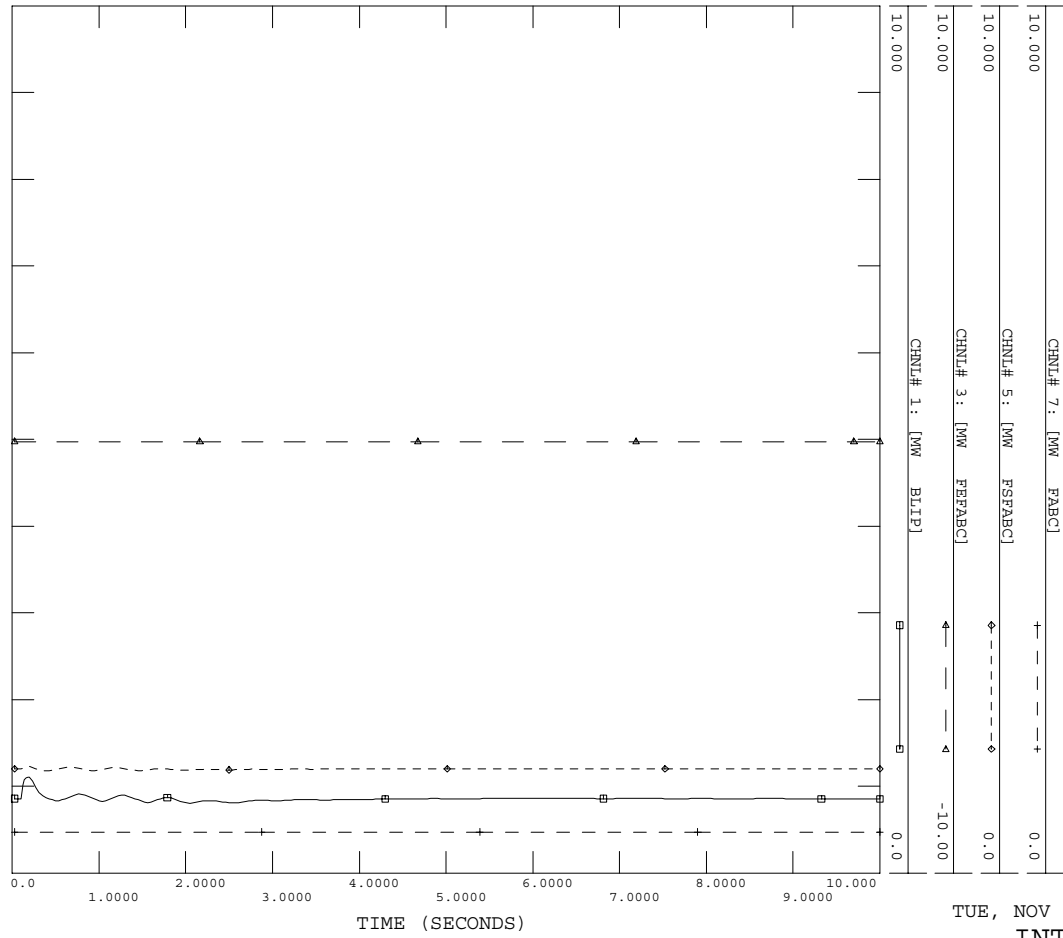


FIGURE G-15



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'
FILE: C:\HYDRO-ONE\...\3-PH-NO-BY-PASS\3PH-4000-4005-1.OUT



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
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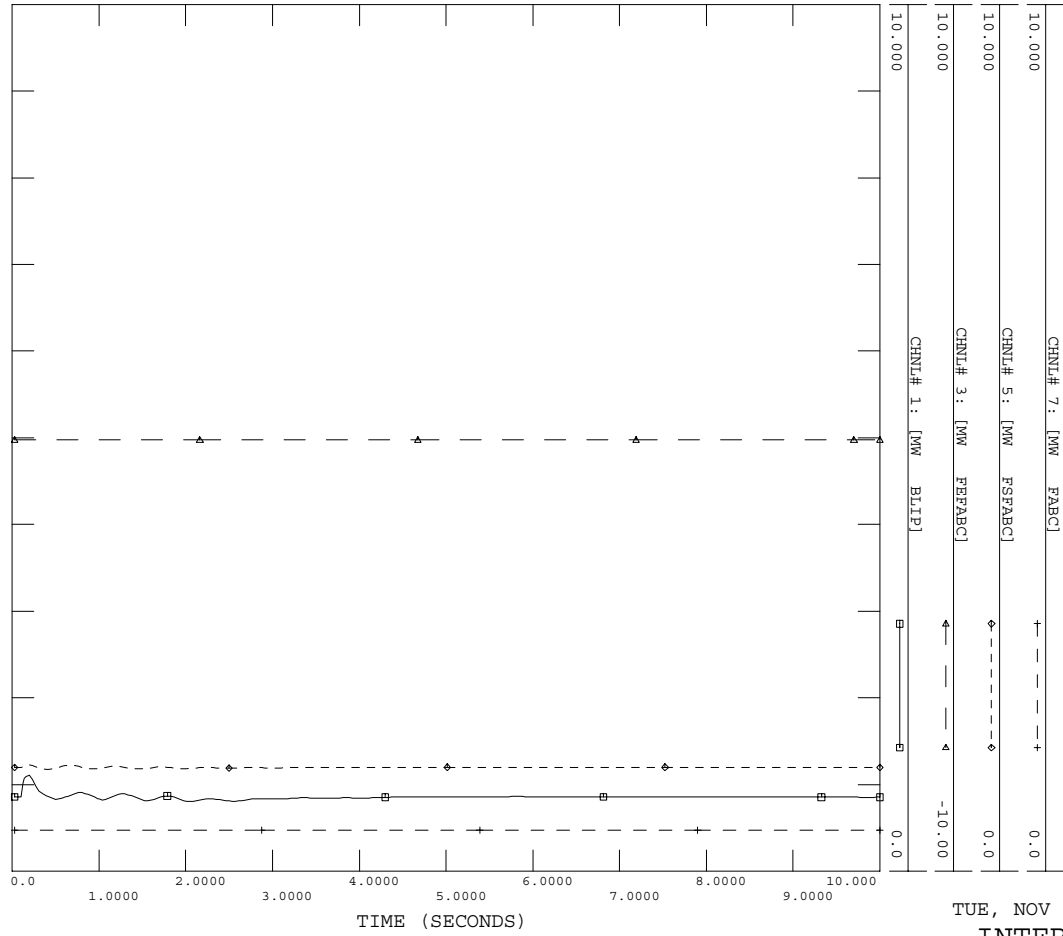


FIGURE G-16

3-PHASE FAULT, NORMALLY CLEARED, BYPASS of ALL SERIES CAPACITOR BANKS

For simulation purposes, Series Capacitor by-pass assumed to occur 1 cycle after the 3-phase fault and reinsertion 1 cycle after clearing of the 3-phase fault.

Plots for the following four disturbances are shown in the following order in this Appendix:

- i) Bruce – Milton 500kV Circuit (fault at bus# 6409)
Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G17&G18
Voltage Drop across the 5 series capacitors – Figure G19
Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G20
- ii) Bruce – Longwood 500kV Circuit (fault at bus# 6410)
Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G21&G22
Voltage Drop across the 5 series capacitors – Figure G23
Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G24
- iii) Longwood – Nanticoke 500kV Circuit (fault at bus# 7000)
Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G25&G26
Voltage Drop across the 5 series capacitors – Figure G27
Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G28
- iv) Bruce – Clairville 500kV Circuit (fault at bus# 4000)
Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G29&G30
Voltage Drop across the 5 series capacitors – Figure G31
Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G32

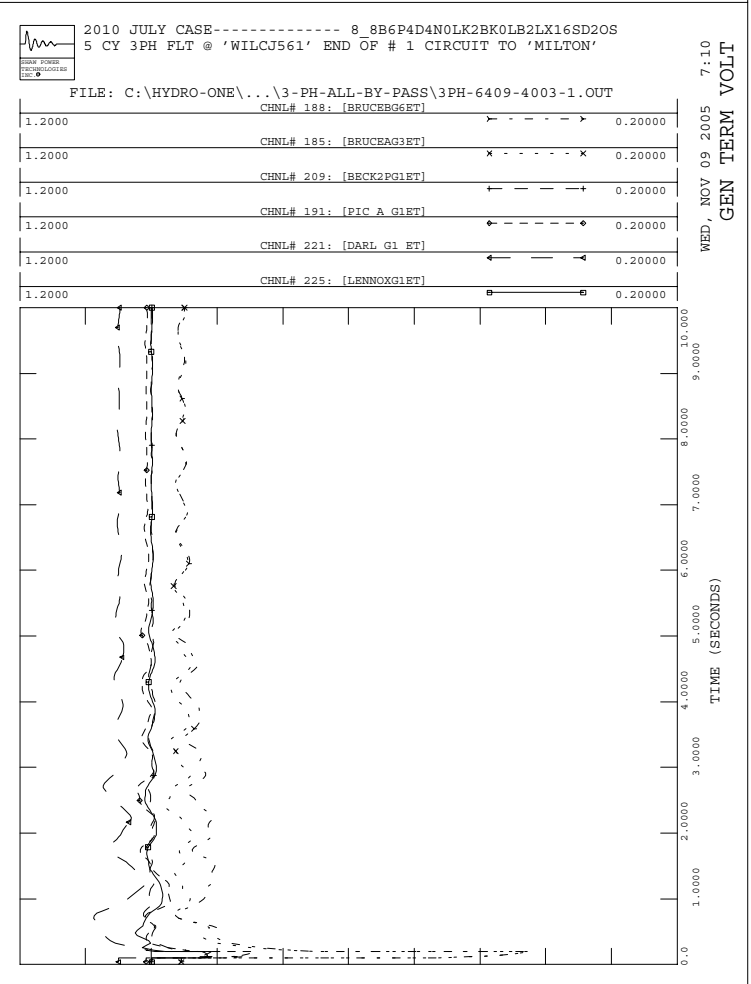
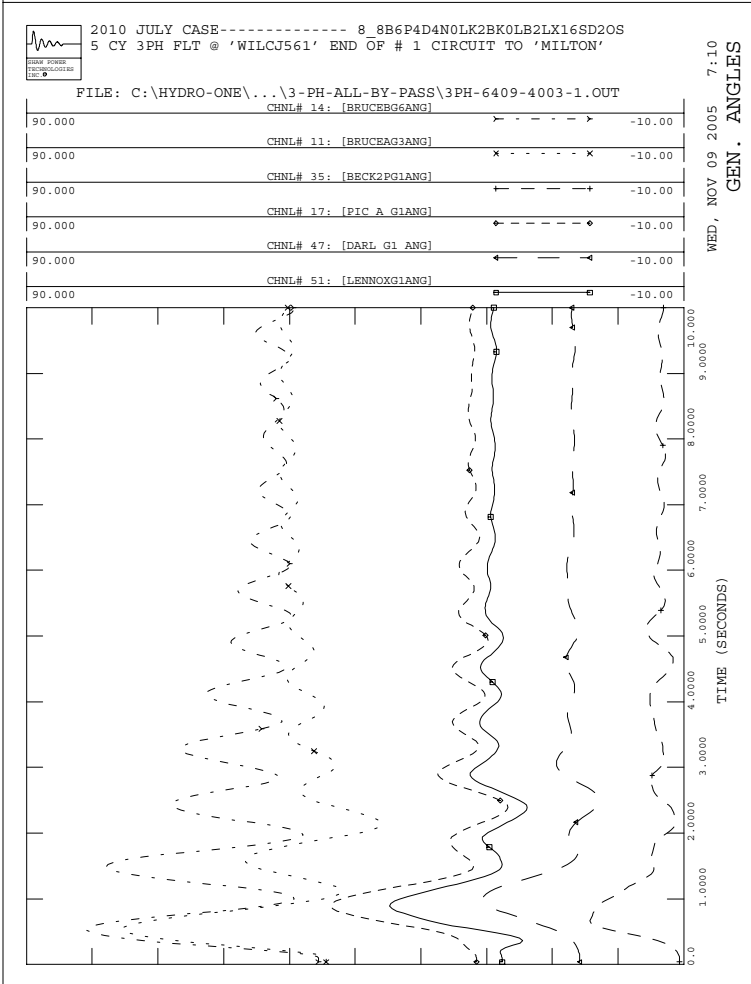
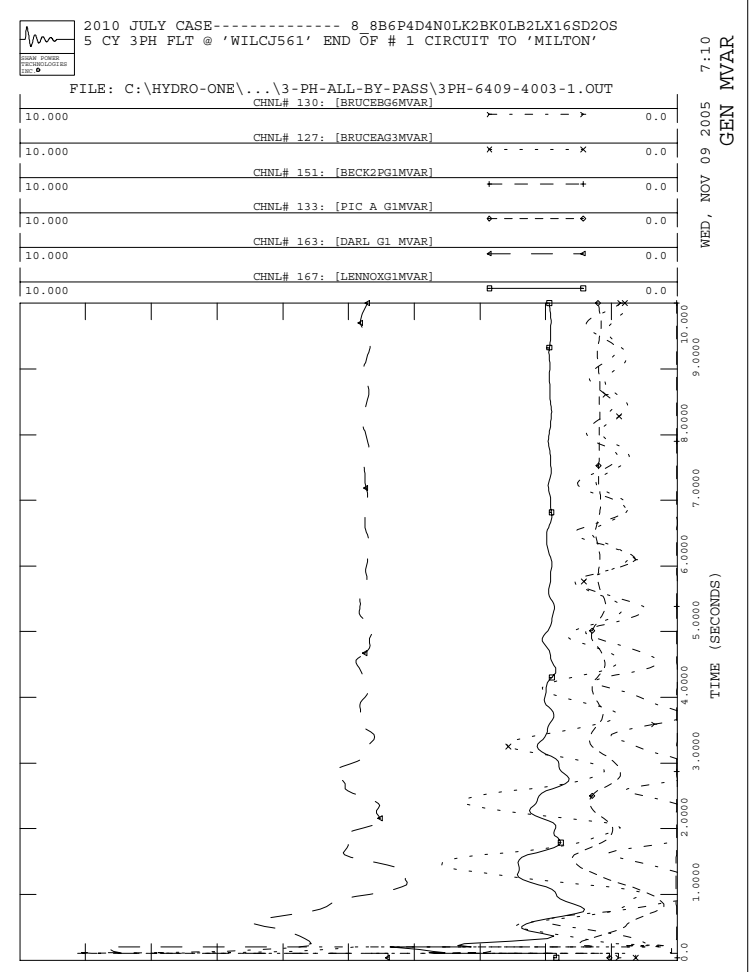
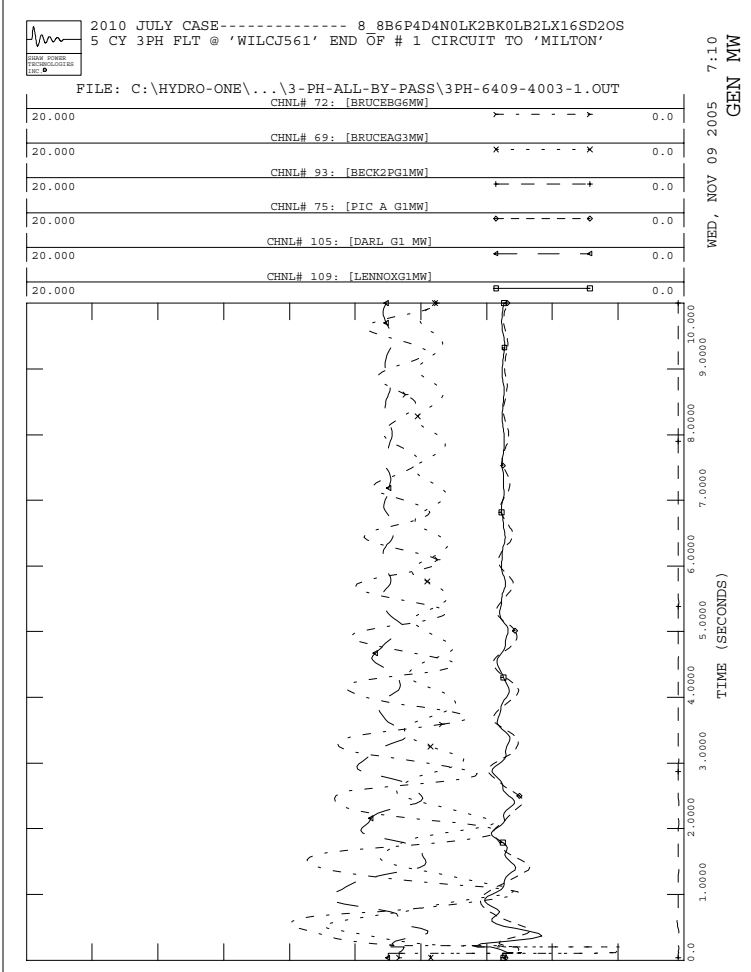


FIGURE G-17

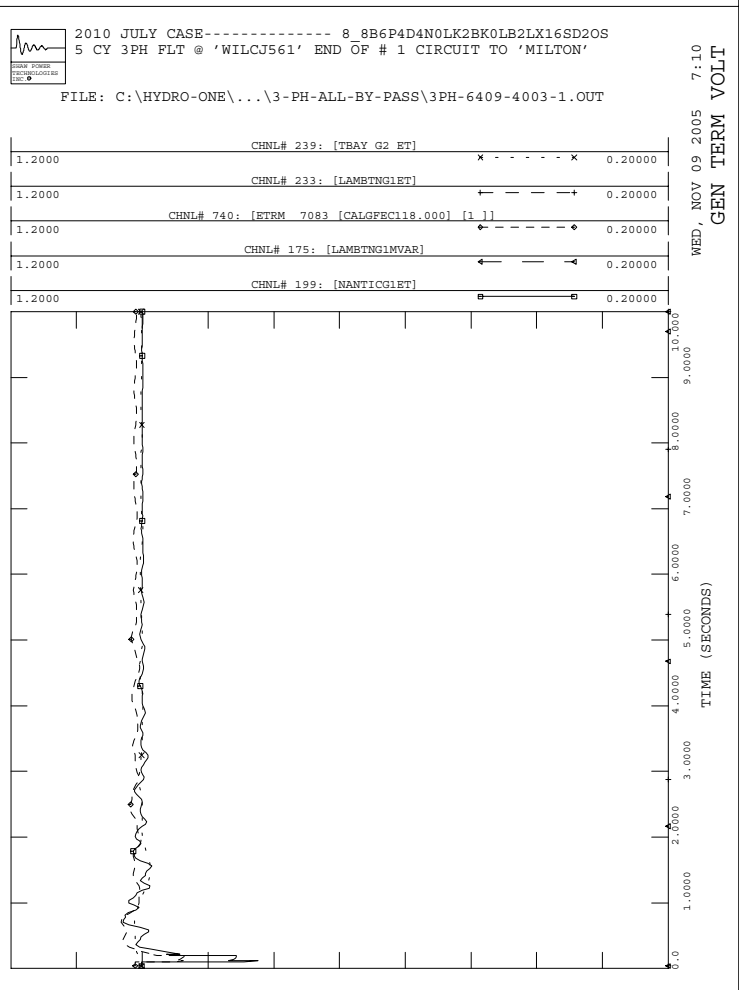
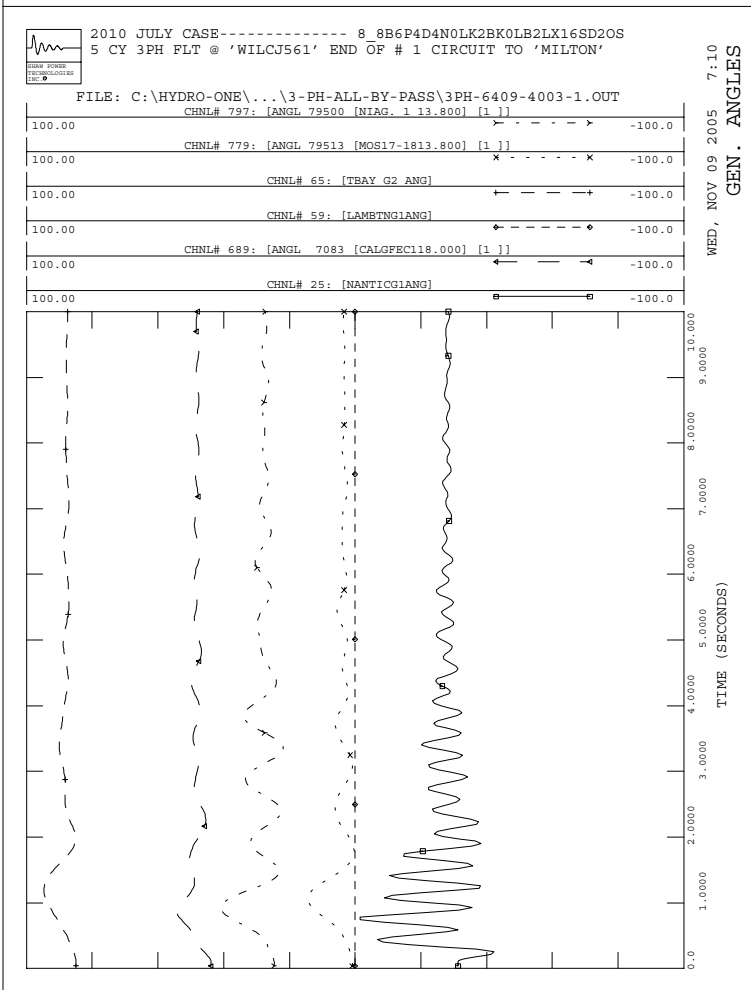
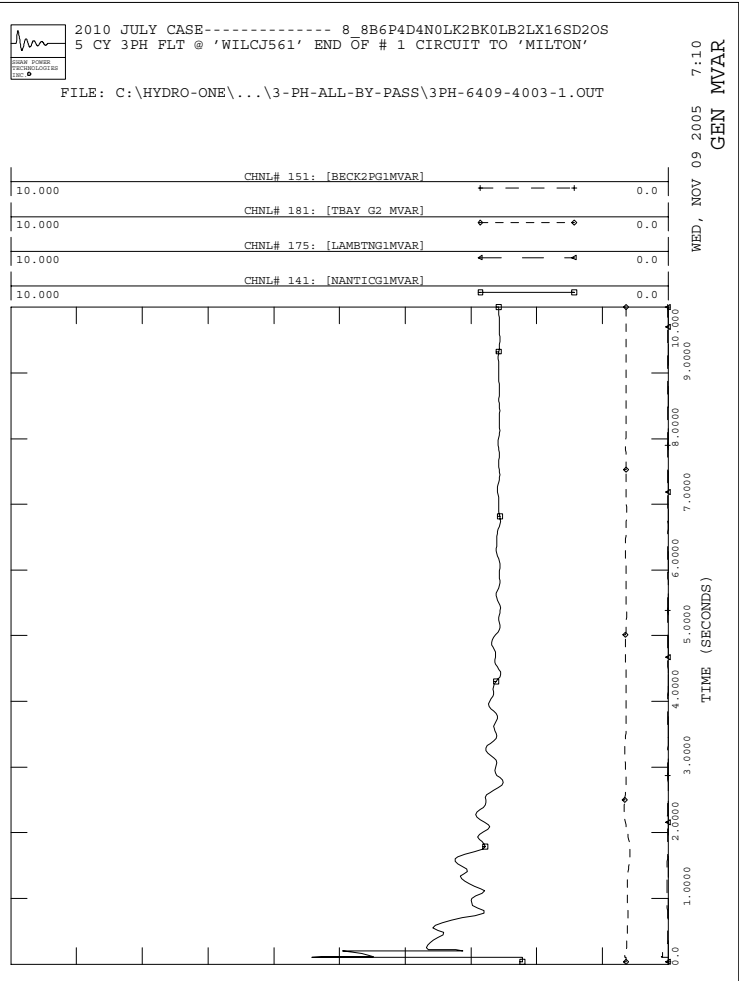
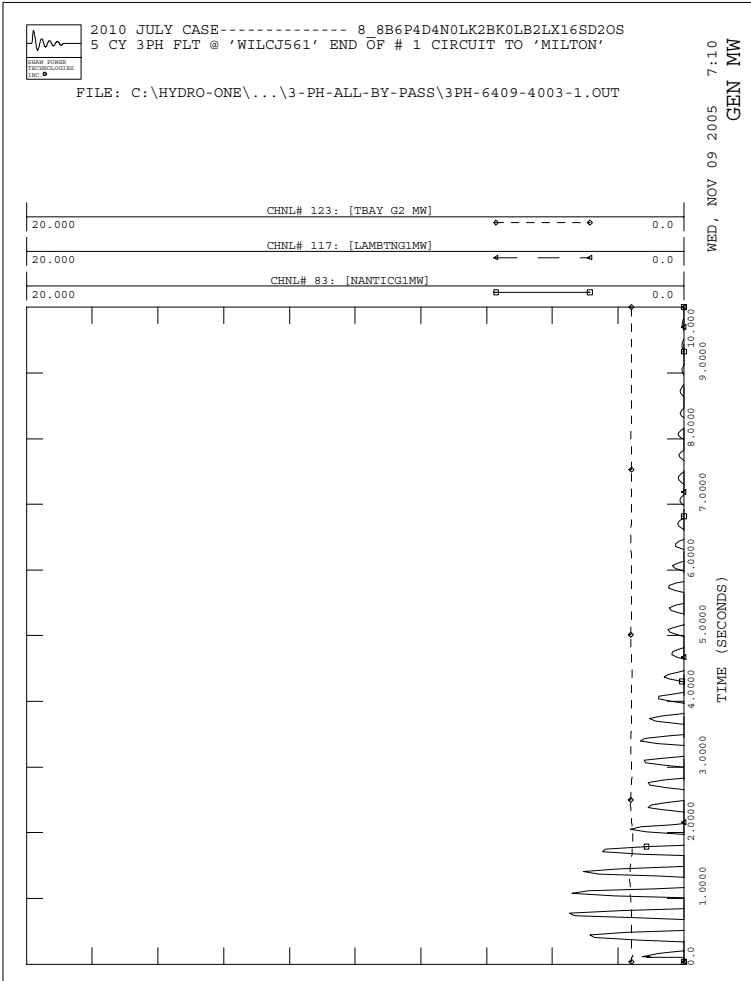


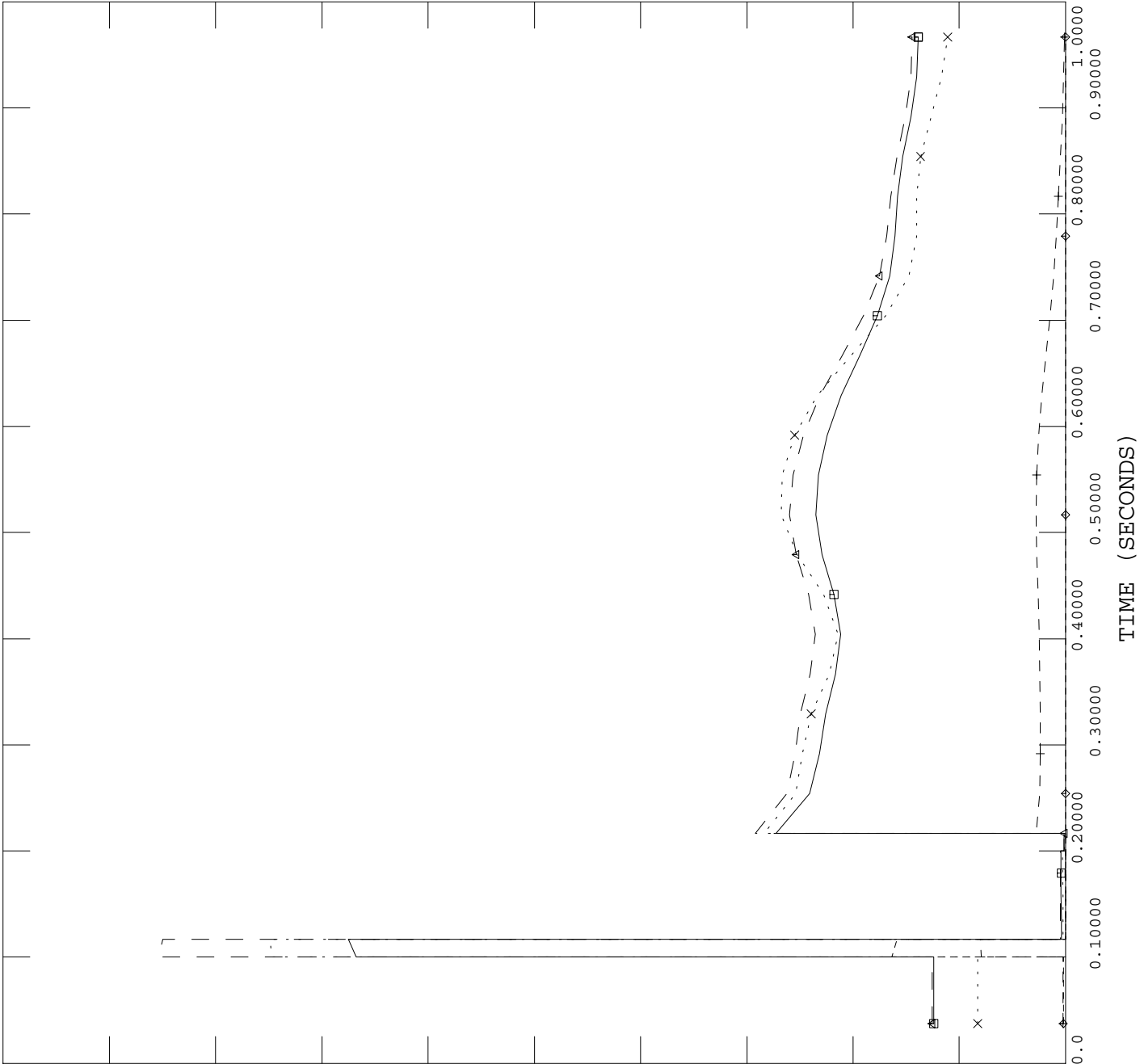
FIGURE G-18



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\3-PH-ALL-BY-PASS\3PH-6409-4003-1.OUT

0.50000	CHNL#'S 1190,1191: ABS ([V-TLBG1] - [V-TLBG2])	X - - - - - X	0.0
0.50000	CHNL#'S 1187,1189: ABS ([V-BLWD1] - [V-BLWD2])	+ - - - - +	0.0
0.50000	CHNL#'S 1186,1188: ABS ([V-BLWD3] - [V-BLWD4])	◇ - - - - ◇	0.0
0.50000	CHNL#'S 1183,1185: ABS ([V-GRBND3] - [V-GRBND4])	← - - - - →	0.0
0.50000	CHNL#'S 1182,1184: ABS ([V-GRBND1] - [V-GRBND2])	□ - - - - □	0.0



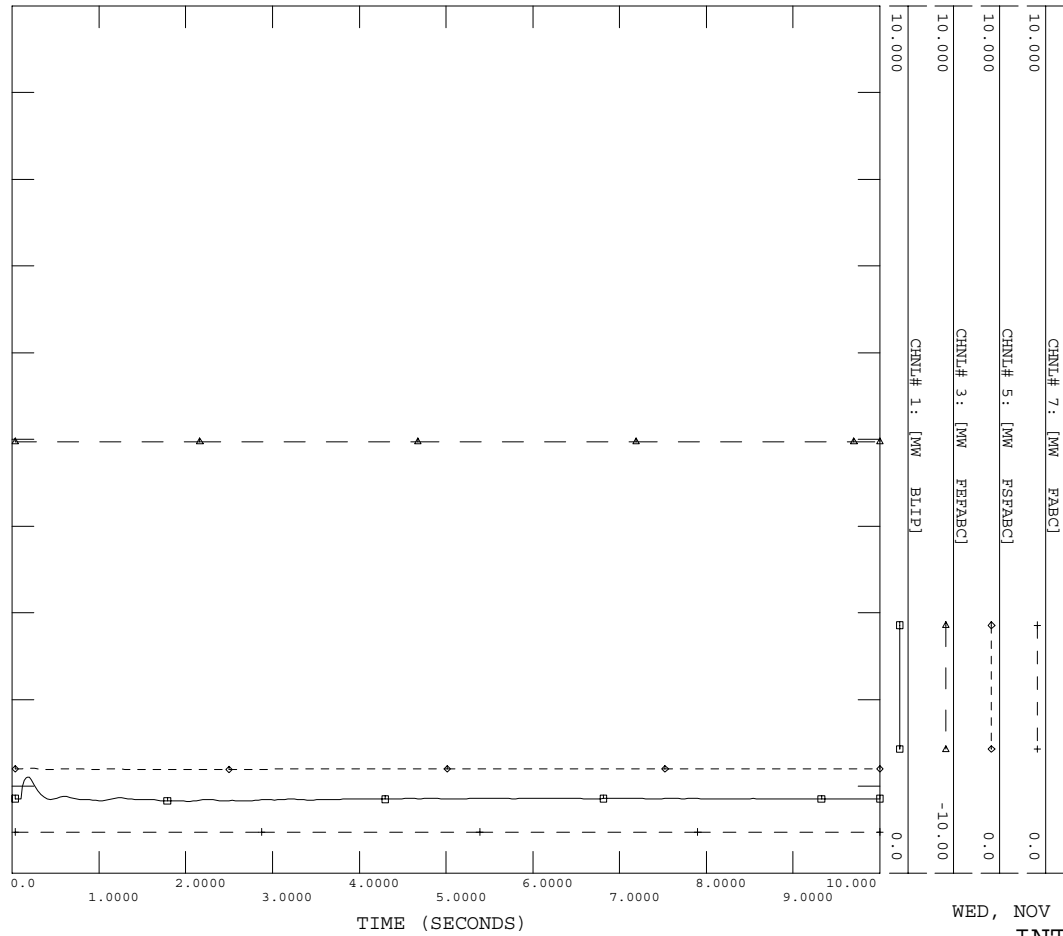
WED, NOV 09 2005 7:27
DV-ACROSS-S-CAPS

FIGURE G-19



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\3-PH-ALL-BY-PASS\3PH-6409-4003-1.OUT

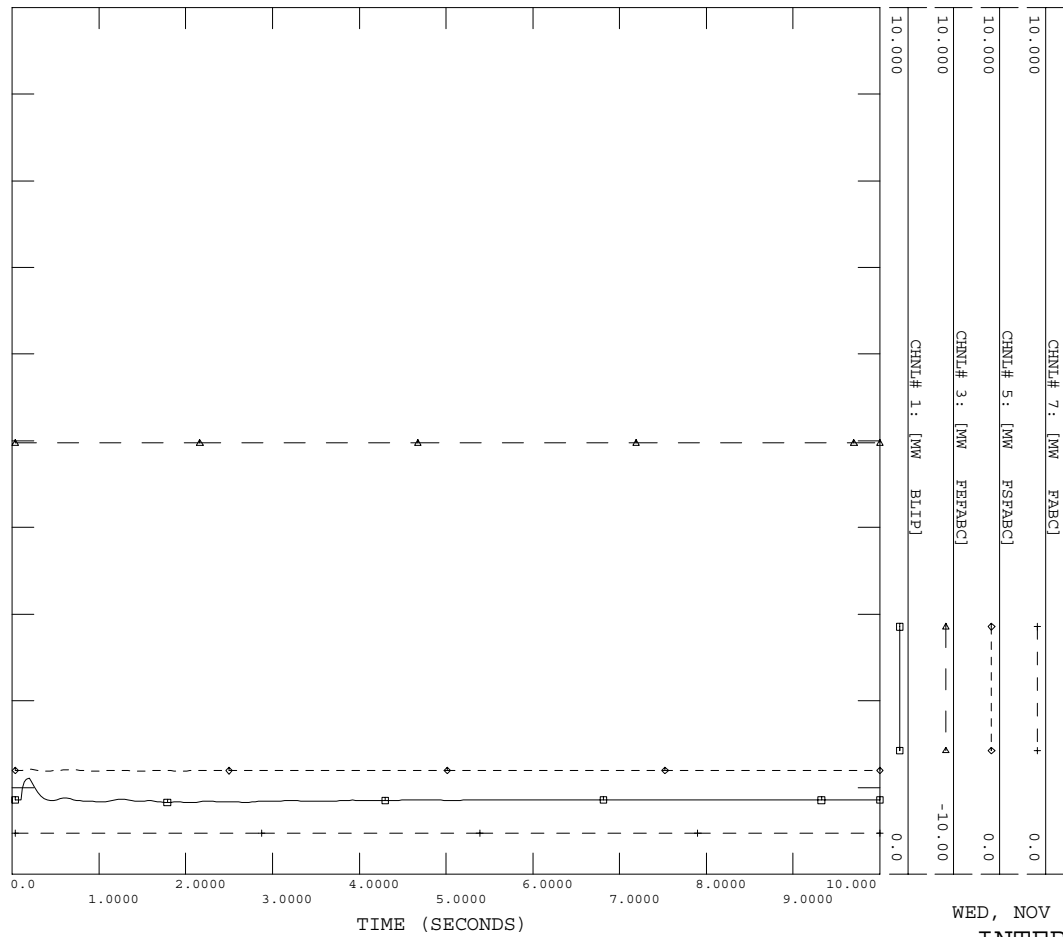


WED, NOV 09 2005 7:34
INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\3-PH-ALL-BY-PASS\3PH-6409-4003-1.OUT



WED, NOV 09 2005 7:34
INTERFACE MVAR

FIGURE G-20

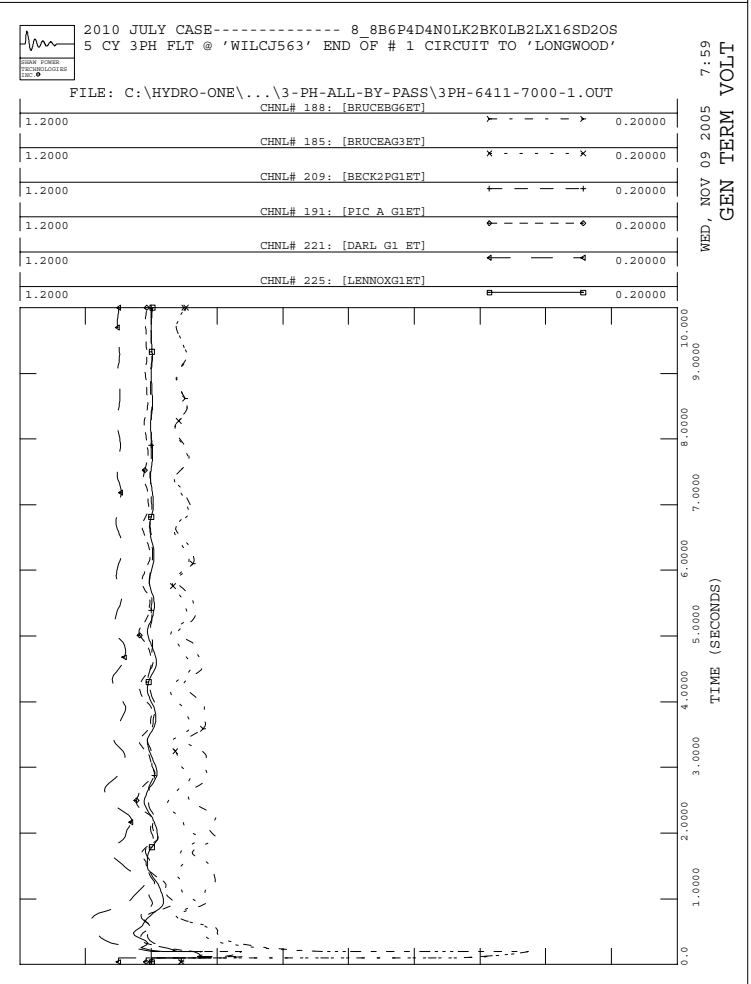
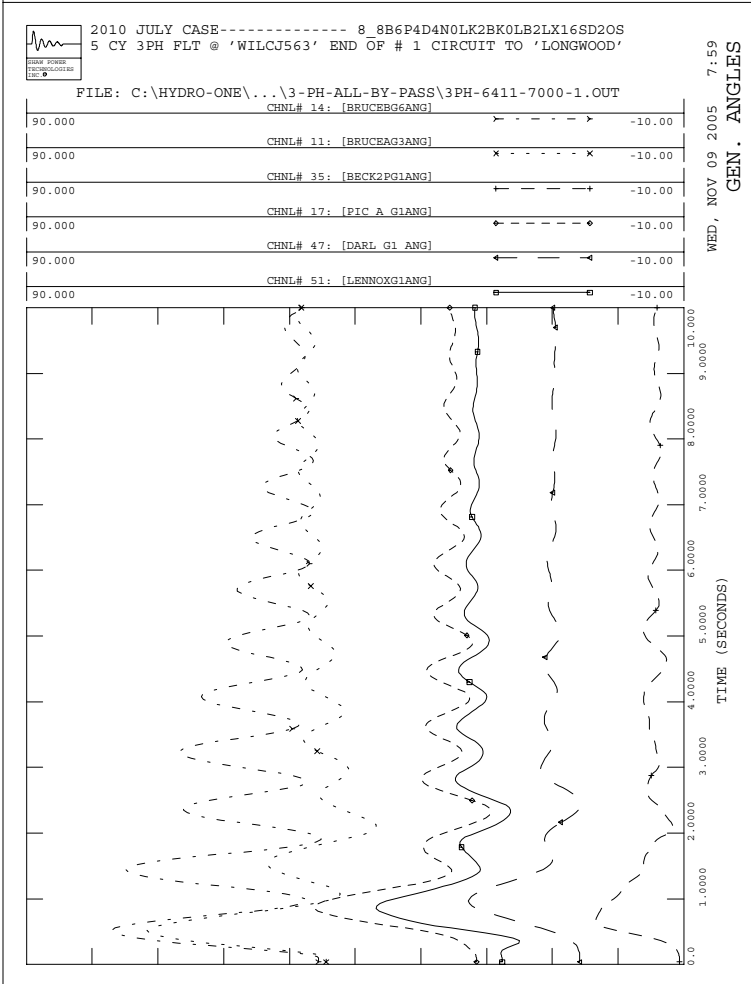
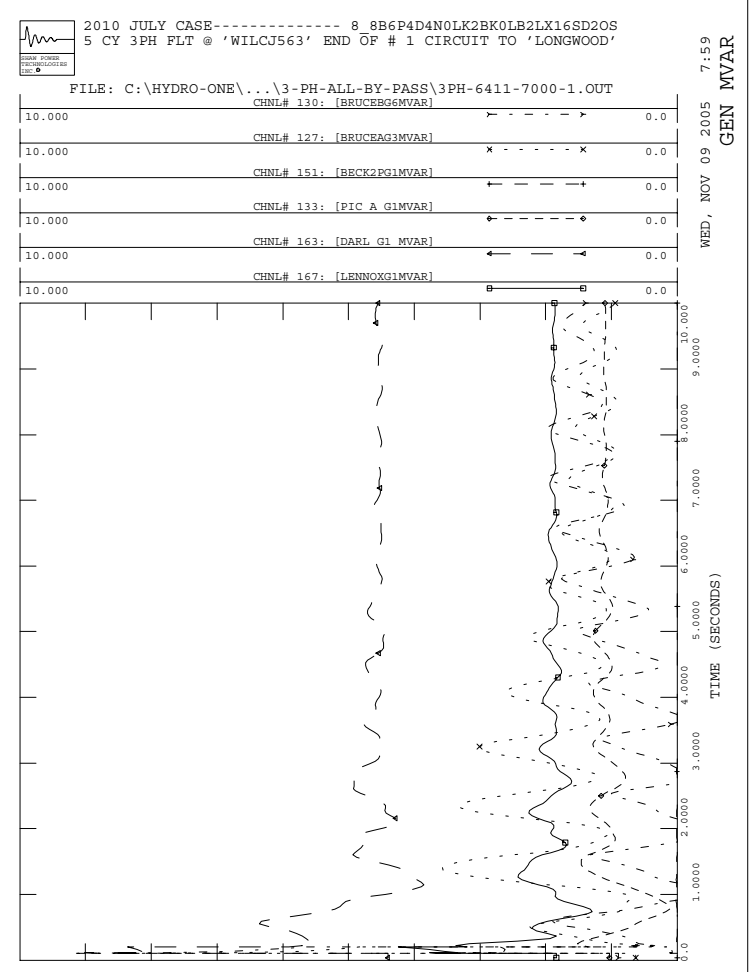
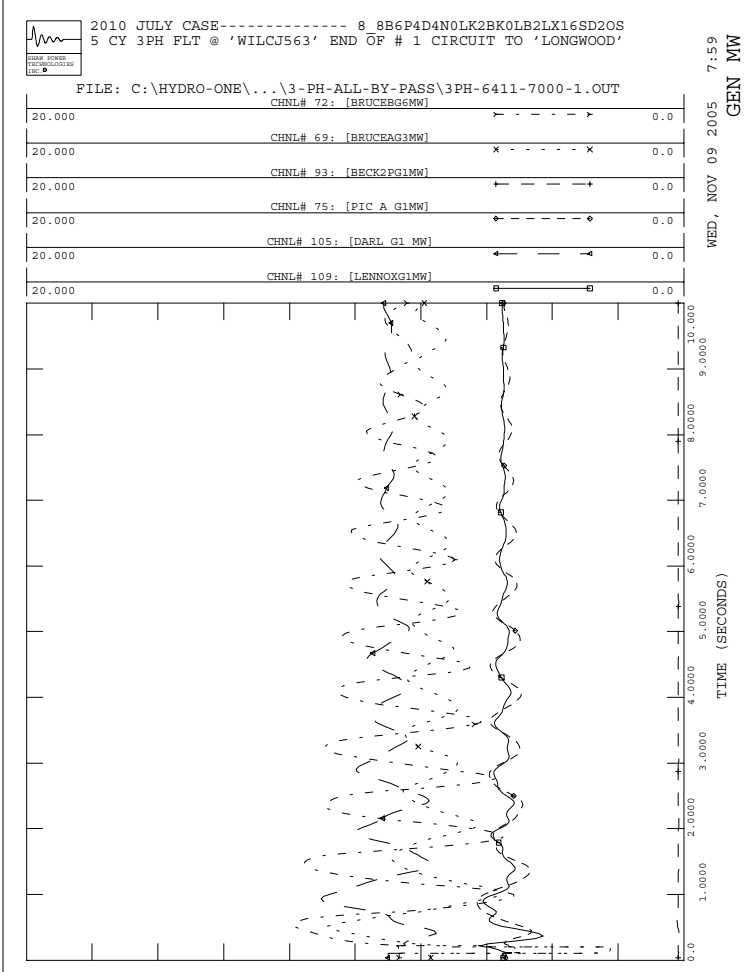


FIGURE G-21

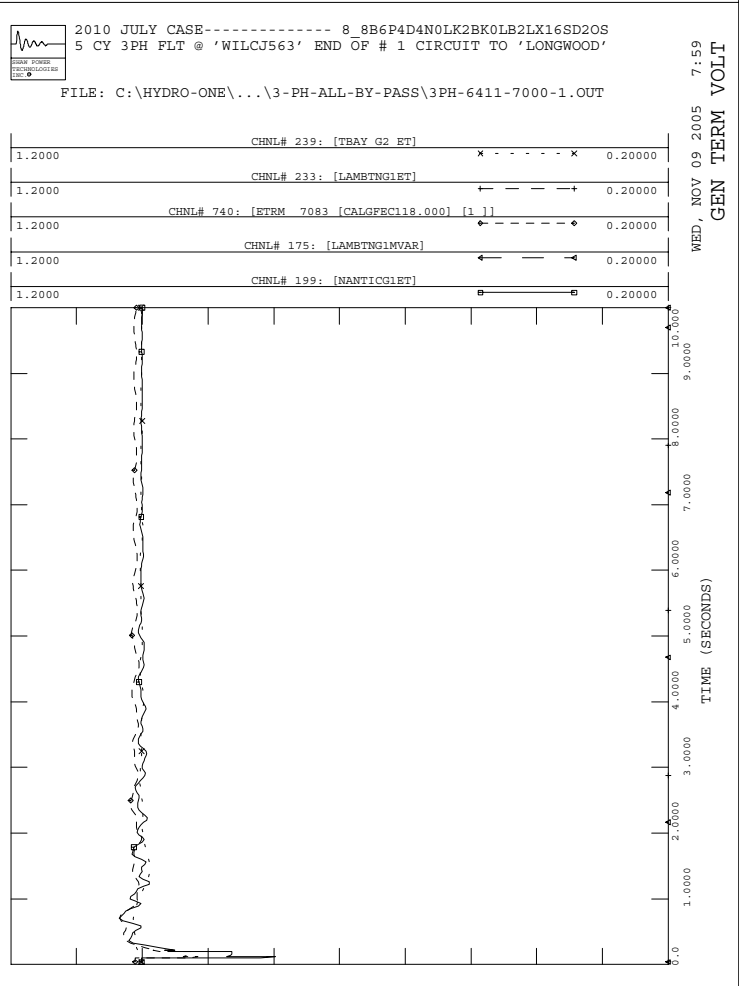
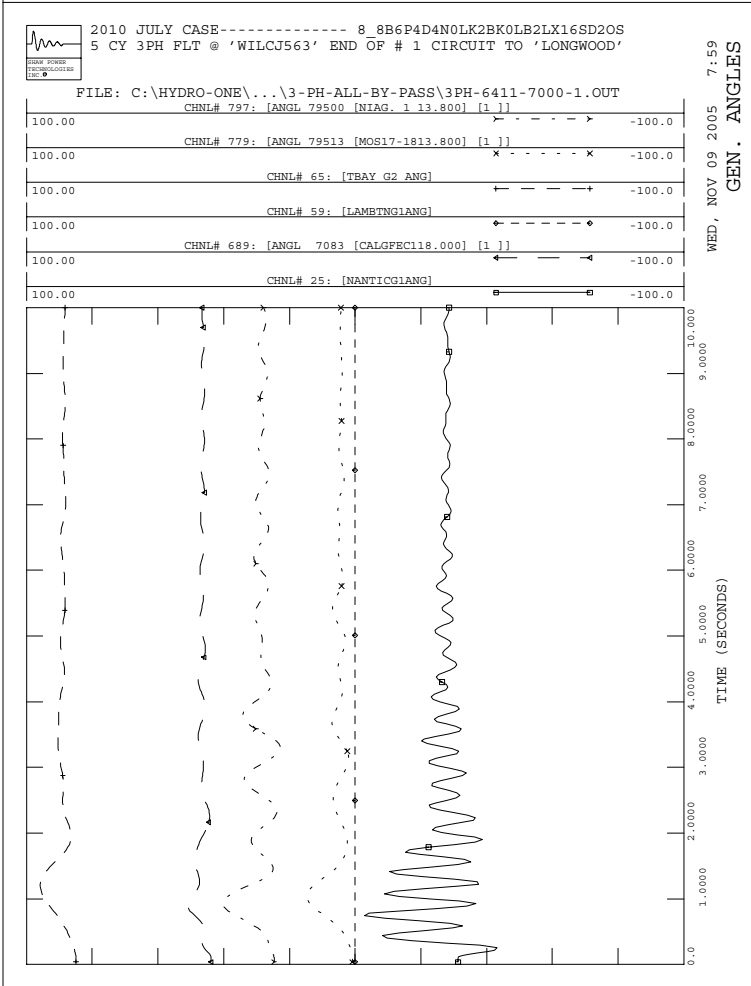
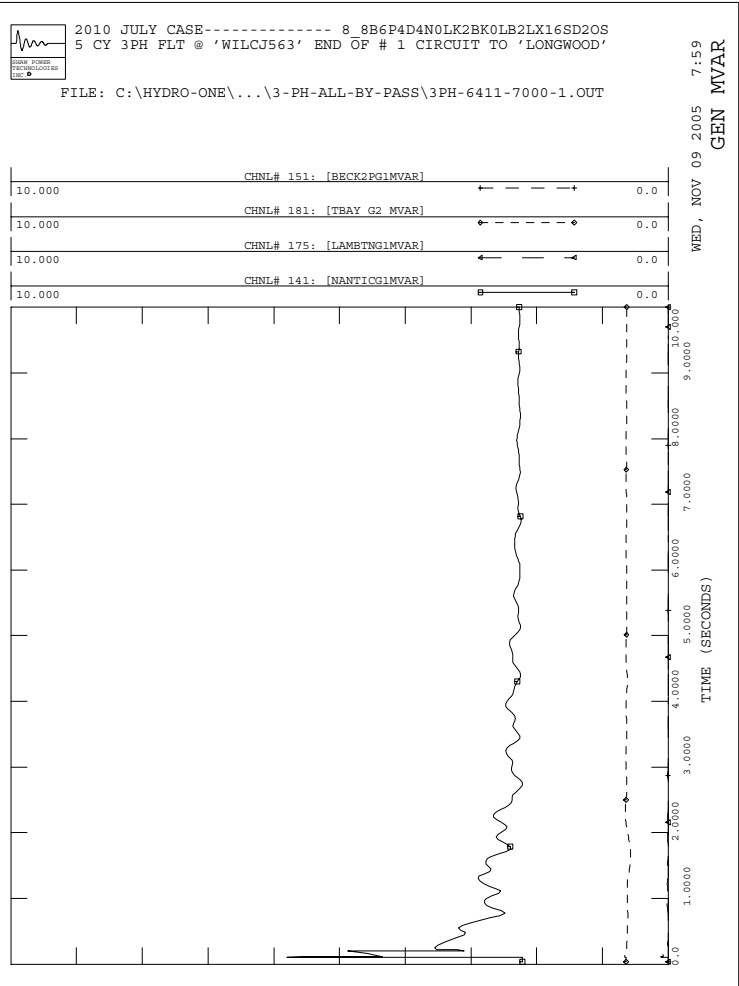
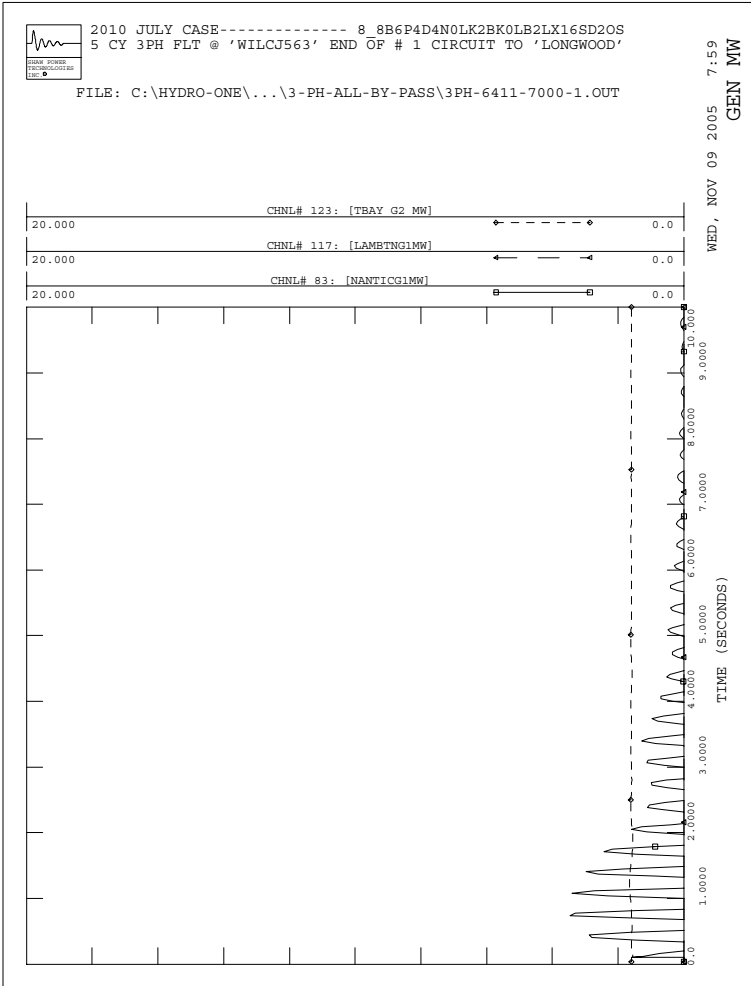


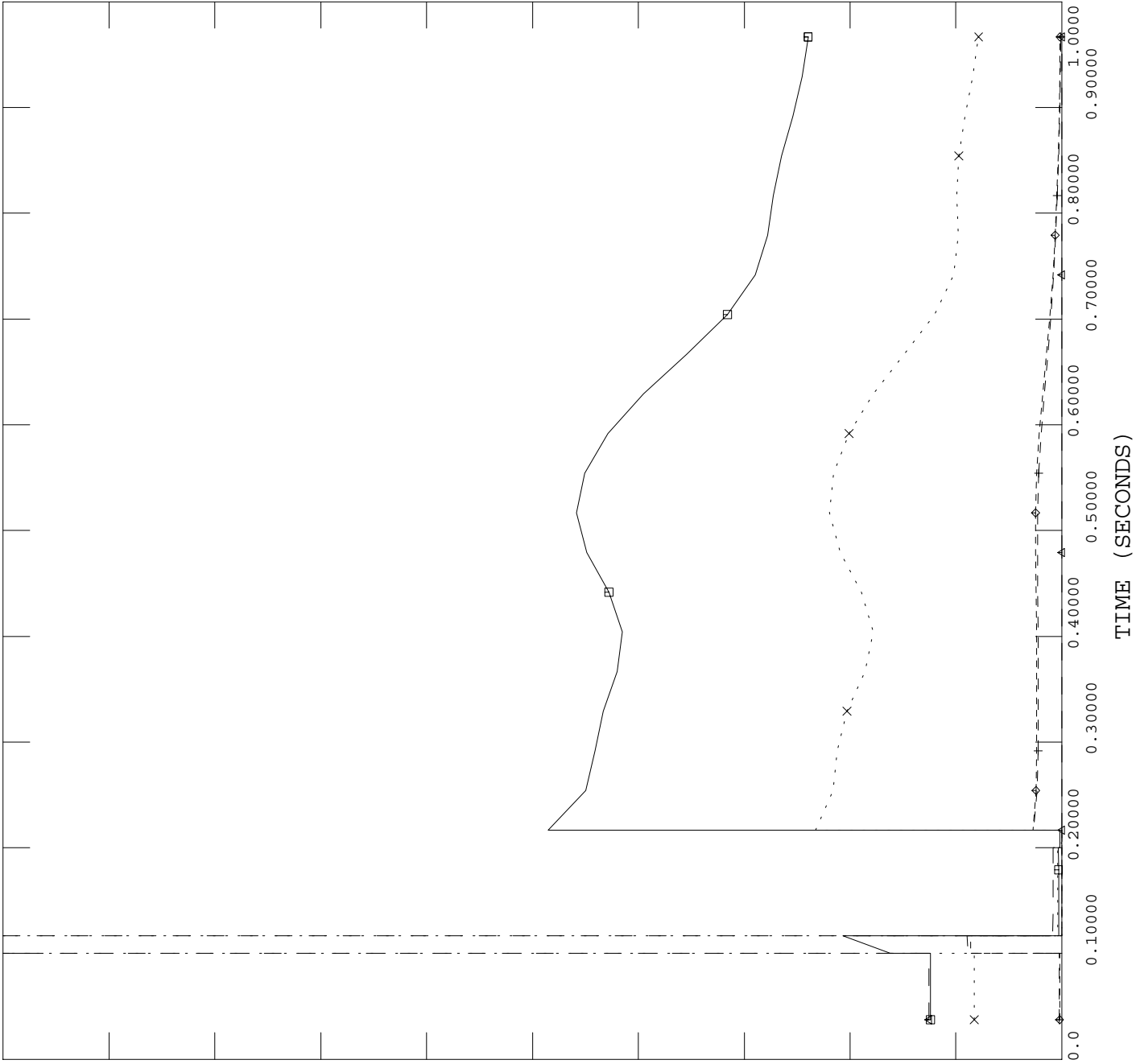
FIGURE G-22



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: C:\HYDRO-ONE\...\3-PH-ALL-BY-PASS\3PH-6411-7000-1.OUT

0.50000	CHNL#'S 1190,1191: ABS ([V-TLBG1] - [V-TLBG2])	X - - - - - X	0.0
0.50000	CHNL#'S 1187,1189: ABS ([V-BLWD1] - [V-BLWD2])	+ - - - - +	0.0
0.50000	CHNL#'S 1186,1188: ABS ([V-BLWD3] - [V-BLWD4])	◇ - - - - ◇	0.0
0.50000	CHNL#'S 1183,1185: ABS ([V-GRBND3] - [V-GRBND4])	← - - - - →	0.0
0.50000	CHNL#'S 1182,1184: ABS ([V-GRBND1] - [V-GRBND2])	□ - - - - □	0.0

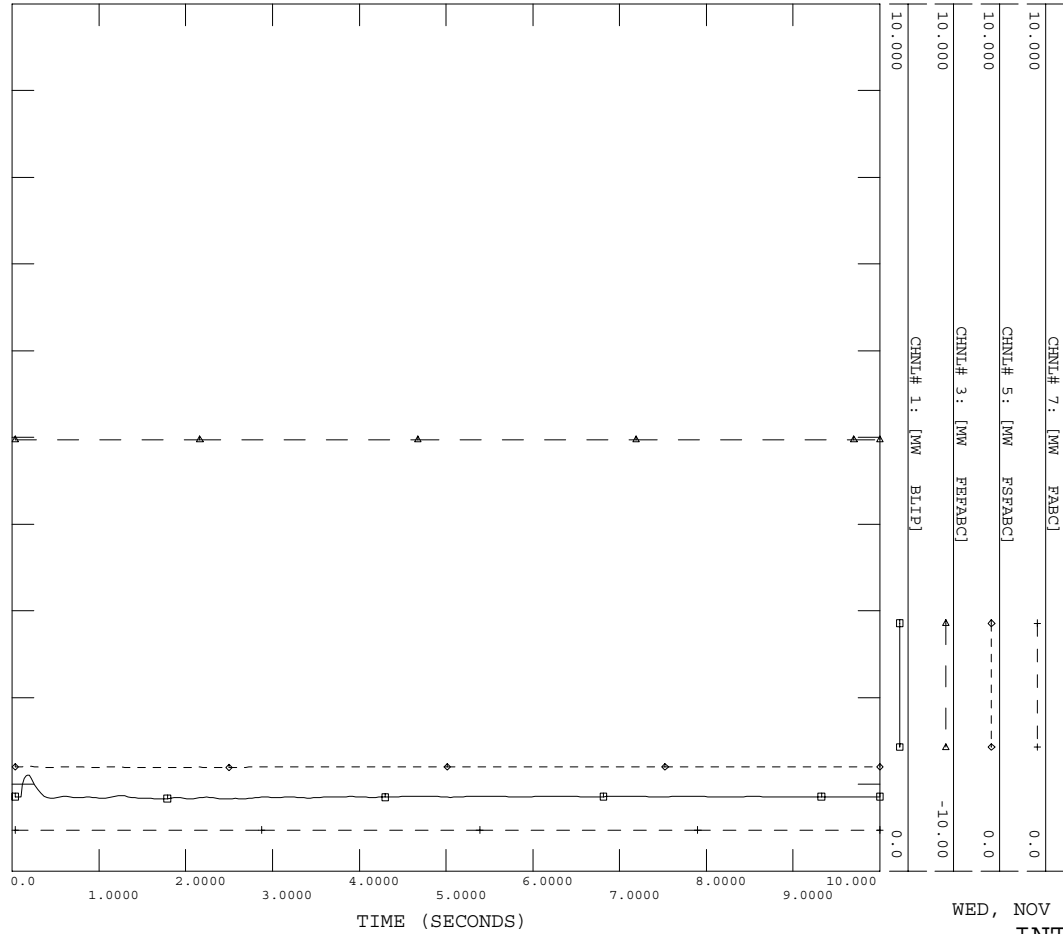


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FIGURE G-23



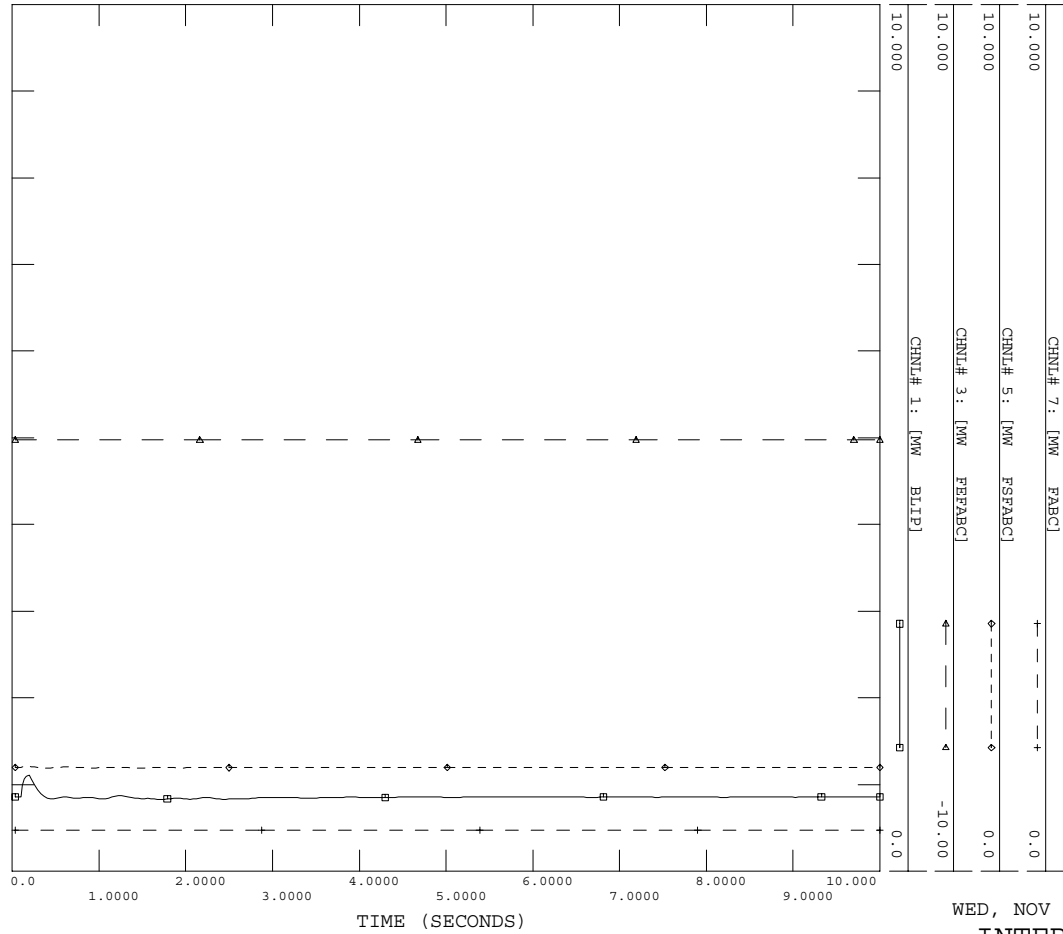
2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'
FILE: C:\HYDRO-ONE\...\3-PH-ALL-BY-PASS\3PH-6411-7000-1.OUT



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INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'
FILE: C:\HYDRO-ONE\...\3-PH-ALL-BY-PASS\3PH-6411-7000-1.OUT



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INTERFACE MVAR

FIGURE G-24

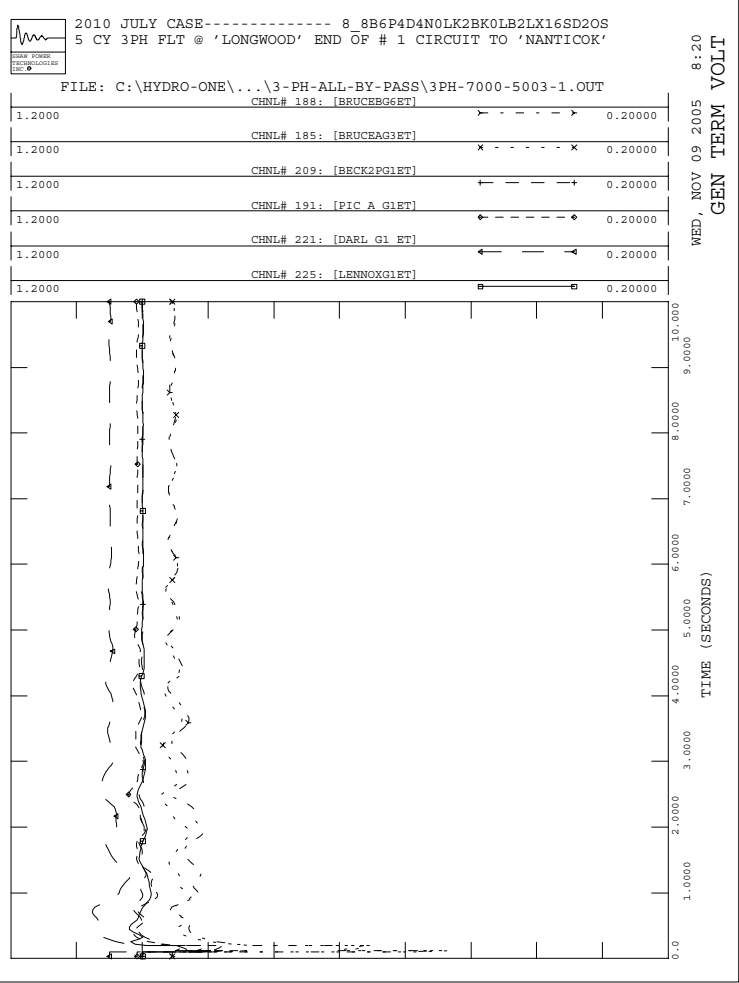
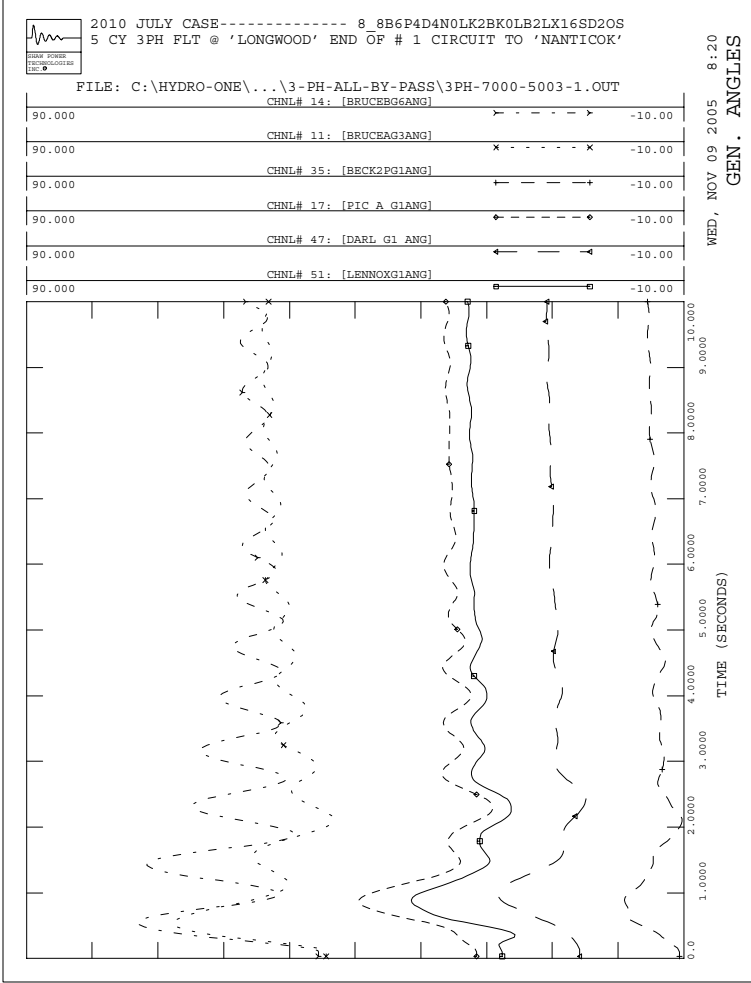
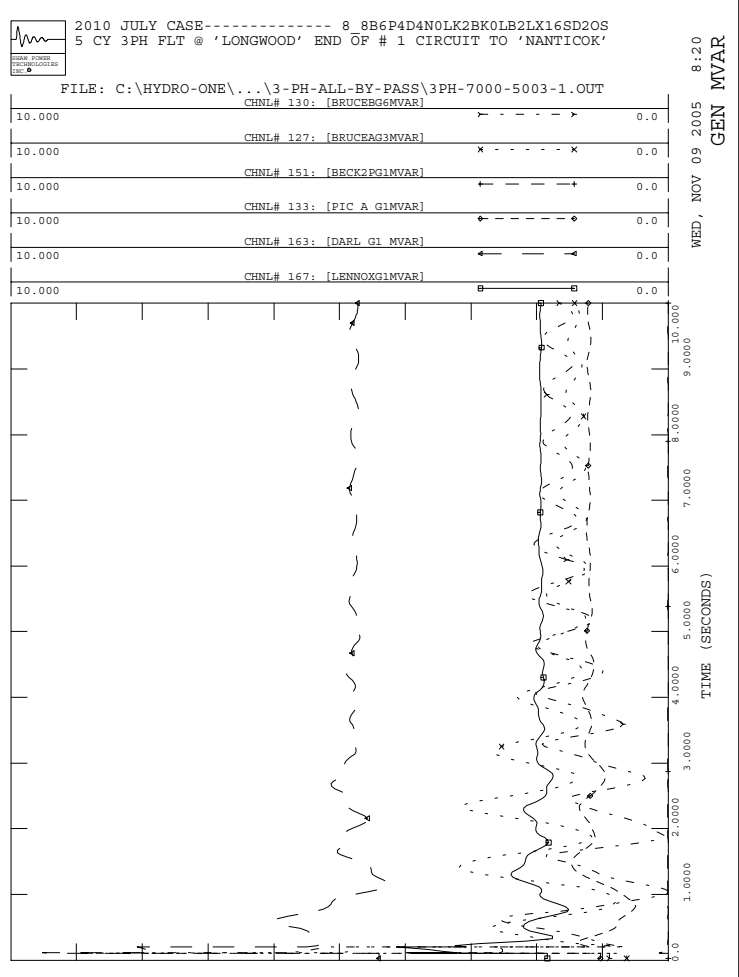
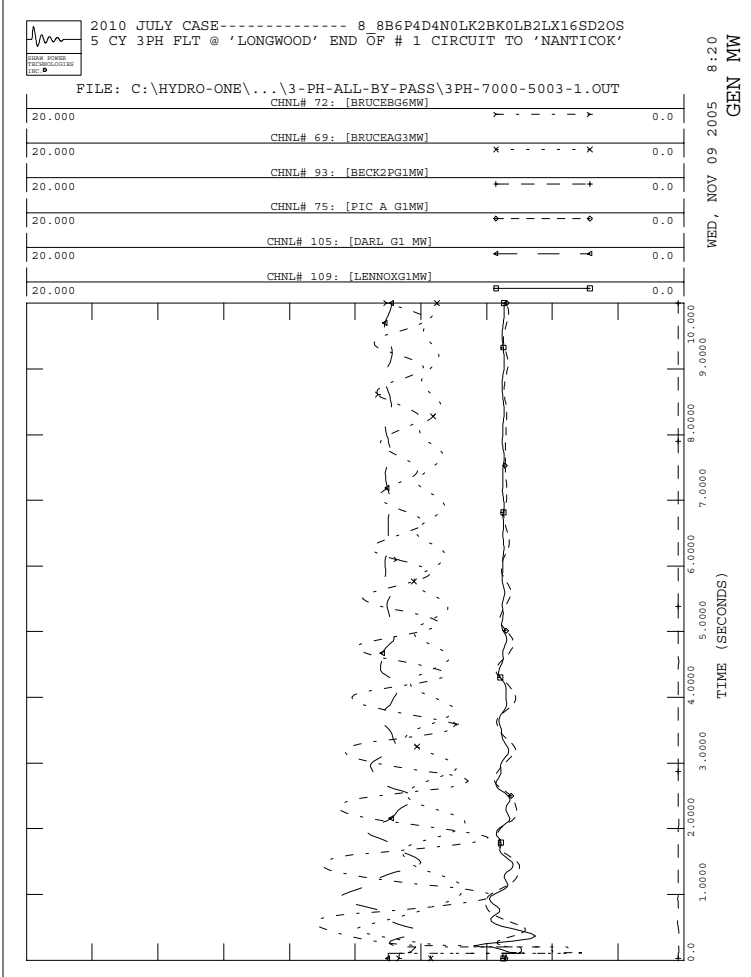


FIGURE G-25

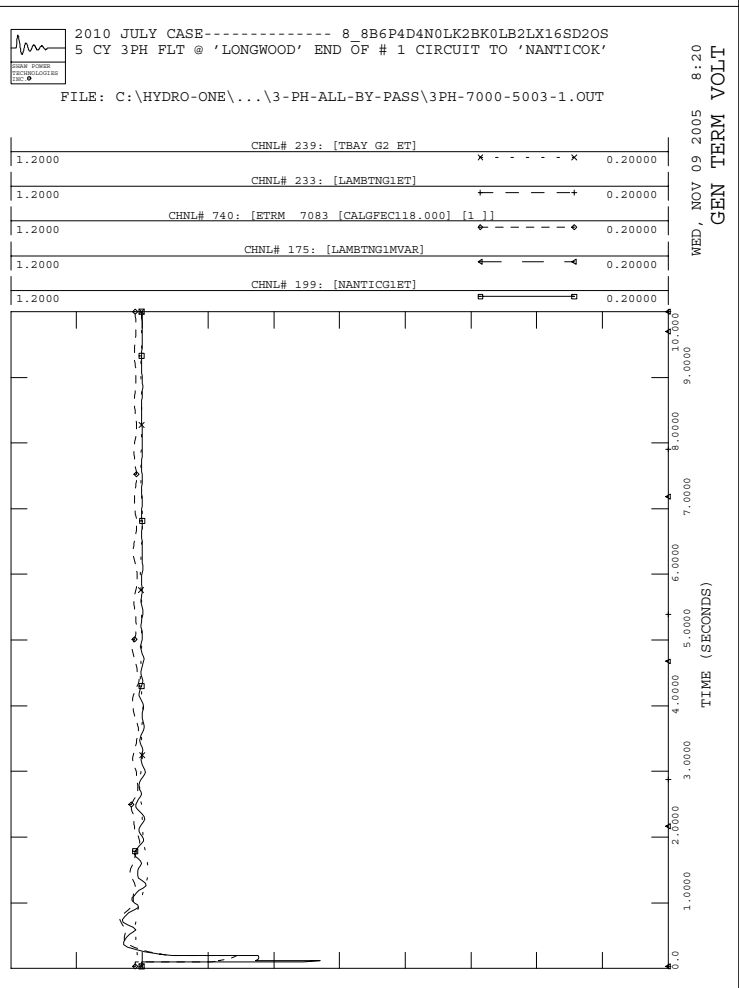
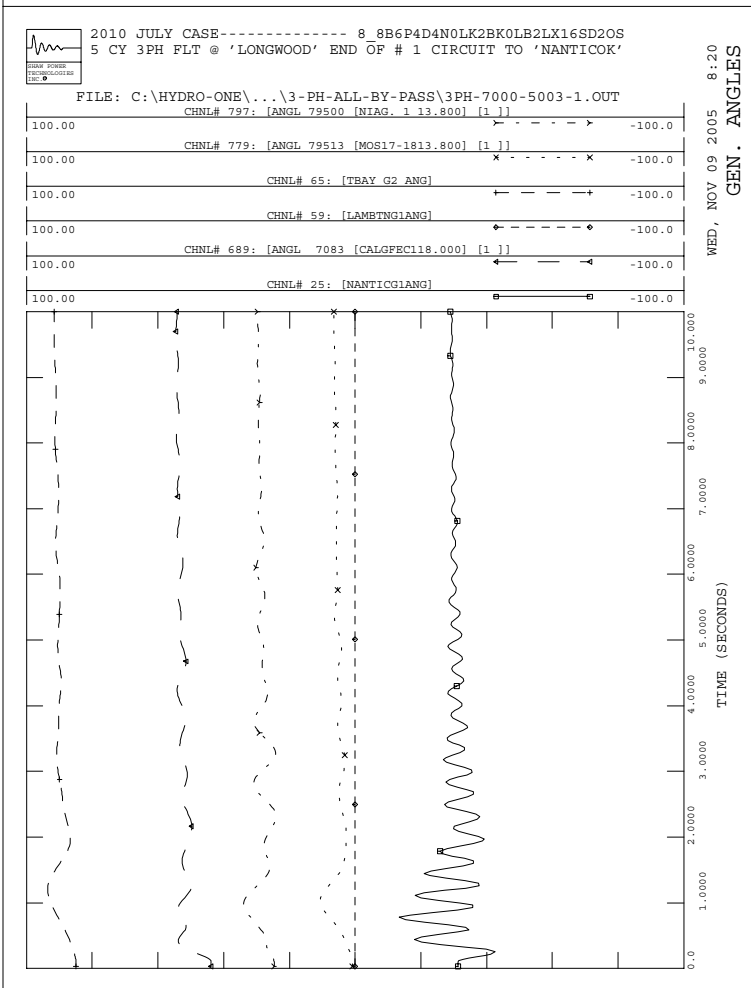
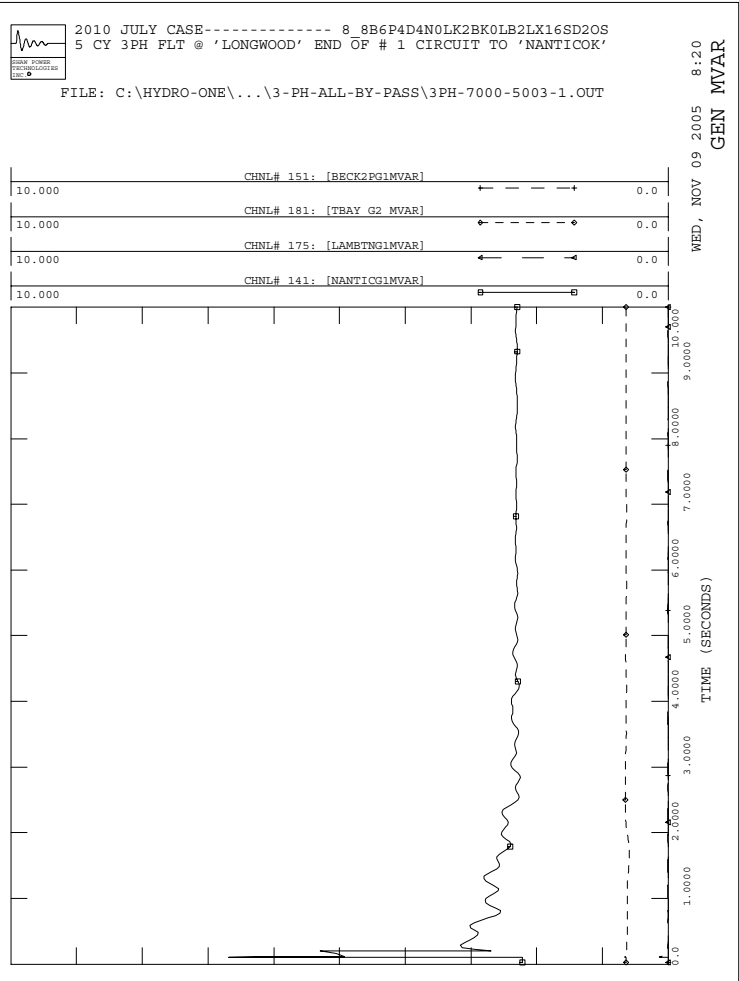
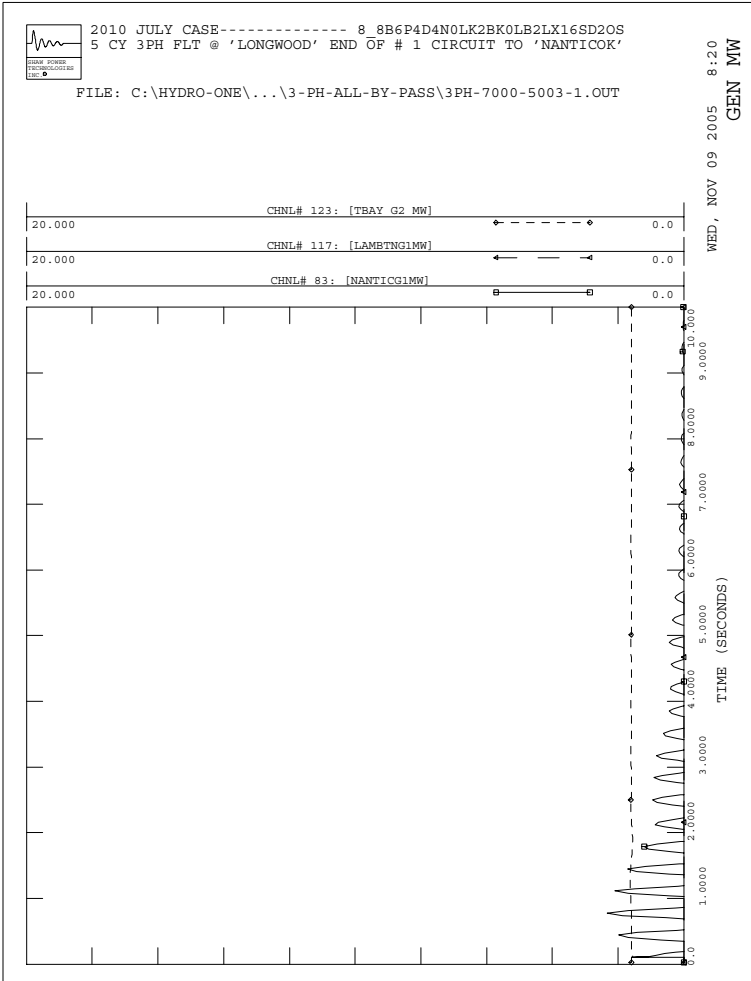
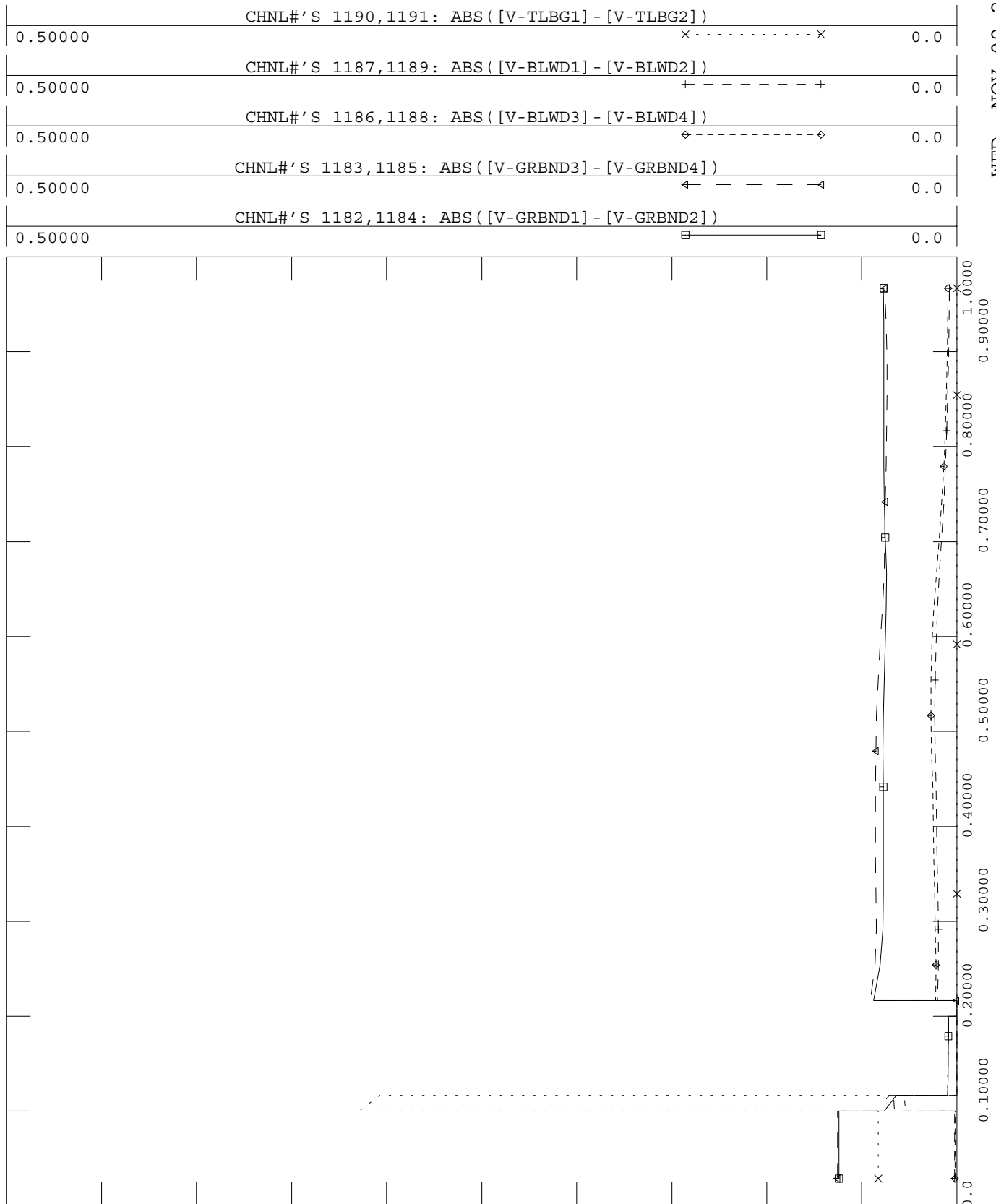


FIGURE G-26



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'LONGWOOD' END OF # 1 CIRCUIT TO 'NANTICOK'

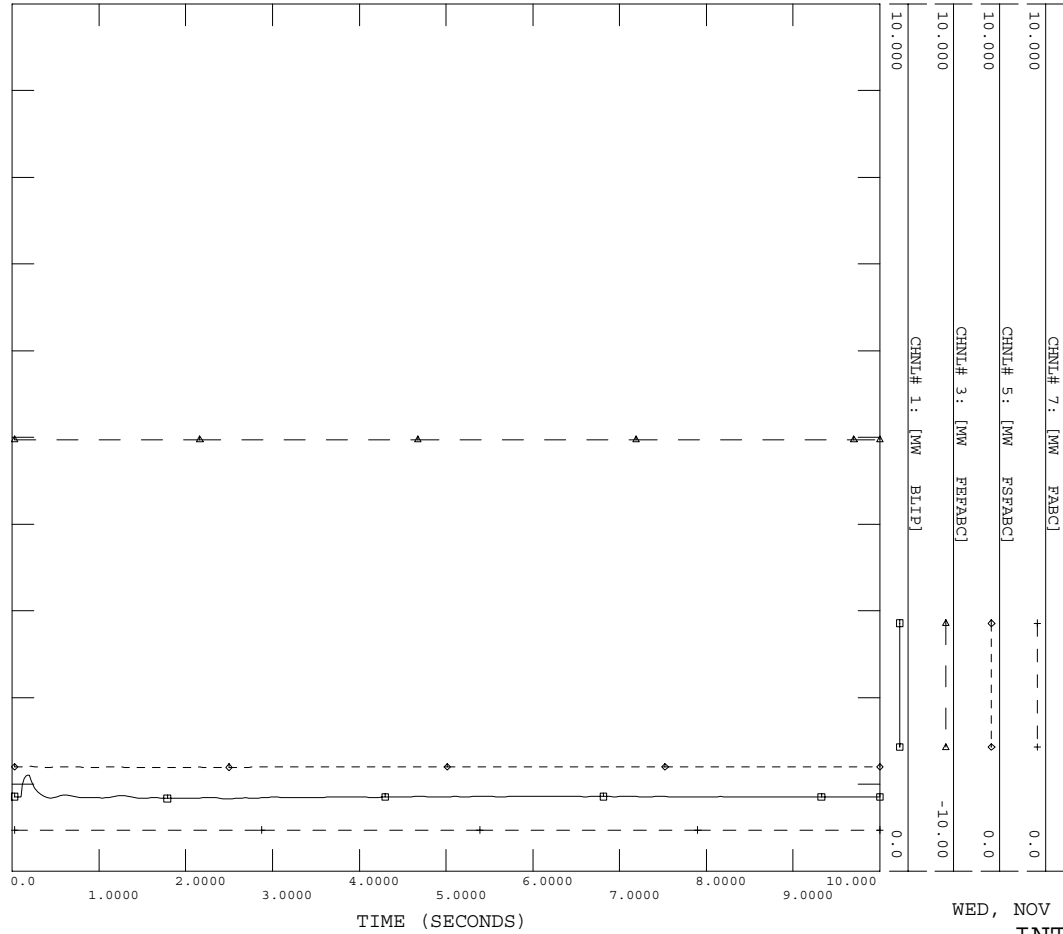
FILE: C:\HYDRO-ONE\...\3-PH-ALL-BY-PASS\3PH-7000-5003-1.OUT



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FIGURE G-27

2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'LONGWOOD' END OF # 1 CIRCUIT TO 'NANTICOK'
FILE: C:\HYDRO-ONE\...\3-PH-ALL-BY-PASS\3PH-7000-5003-1.0UT



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'LONGWOOD' END OF # 1 CIRCUIT TO 'NANTICOK'
FILE: C:\HYDRO-ONE\...\3-PH-ALL-BY-PASS\3PH-7000-5003-1.0UT

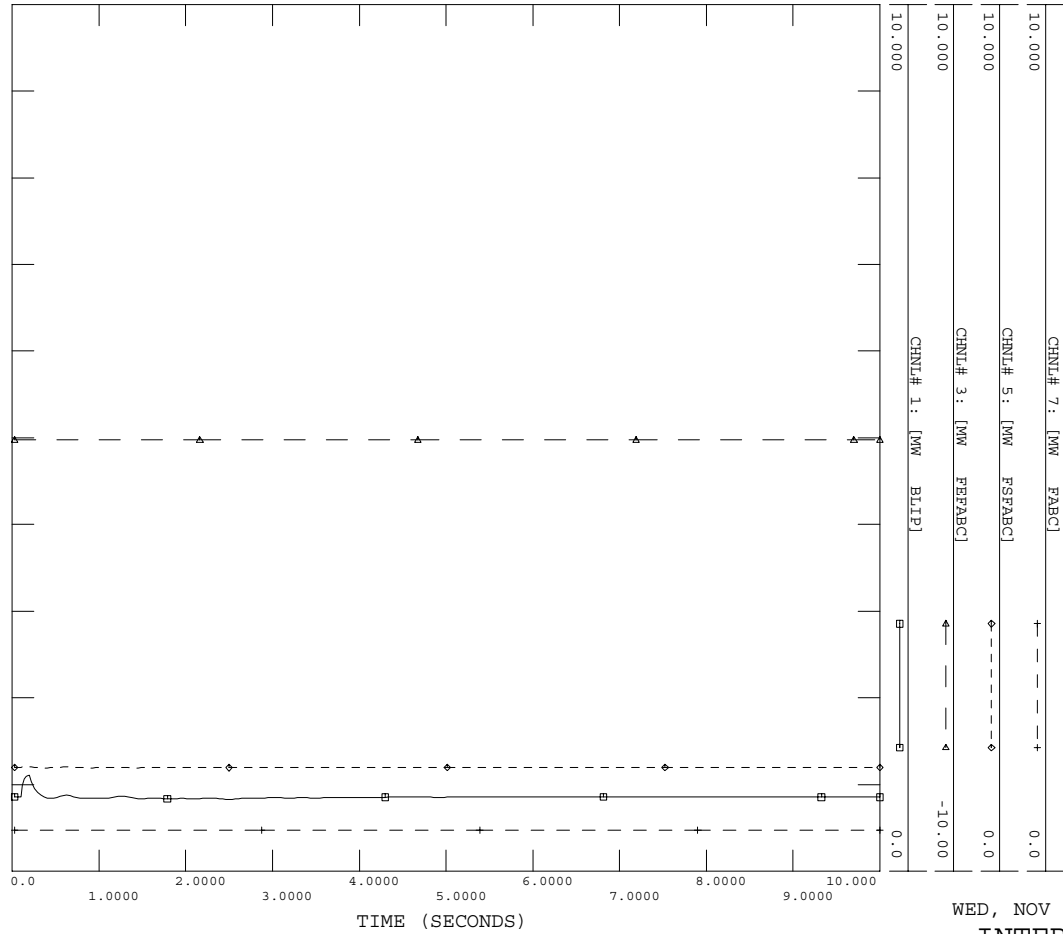


FIGURE G-28

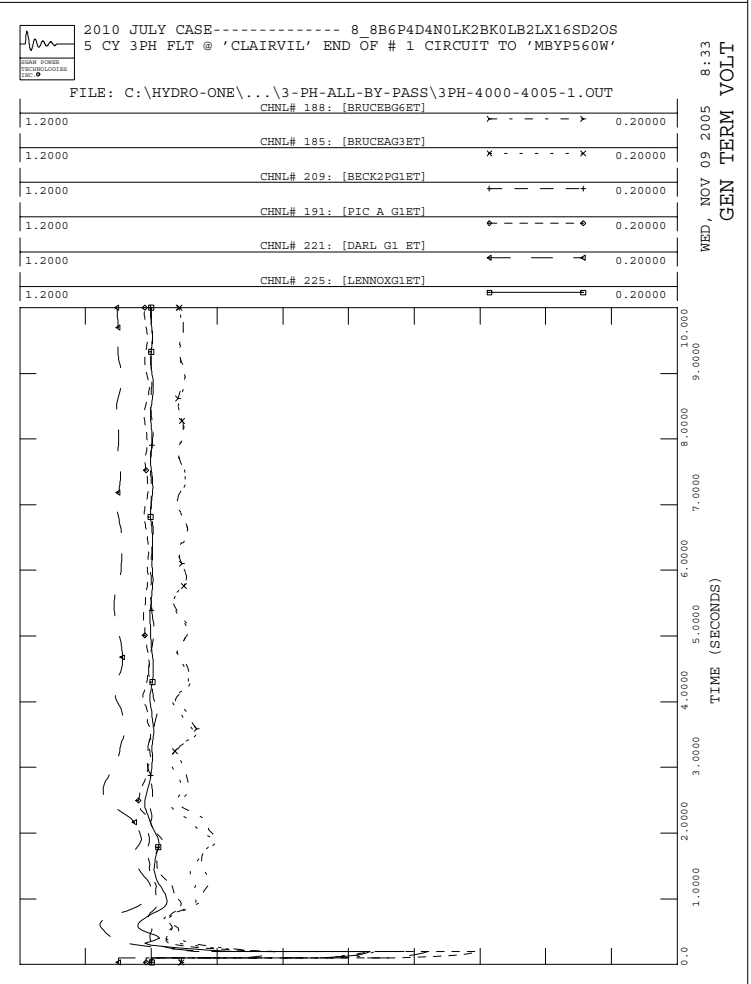
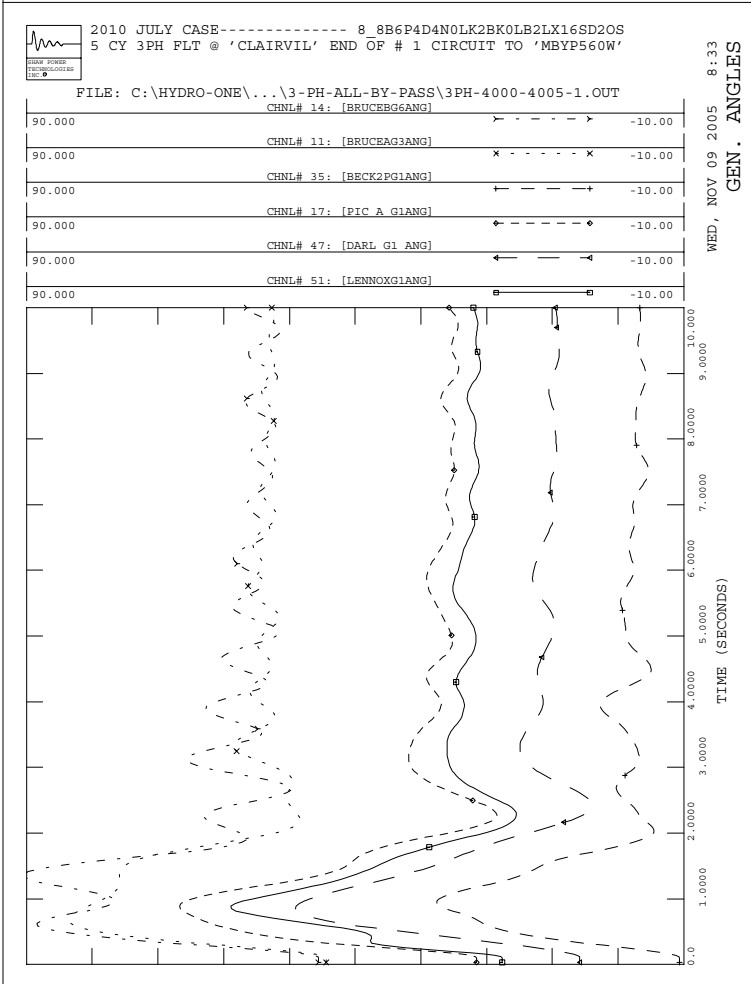
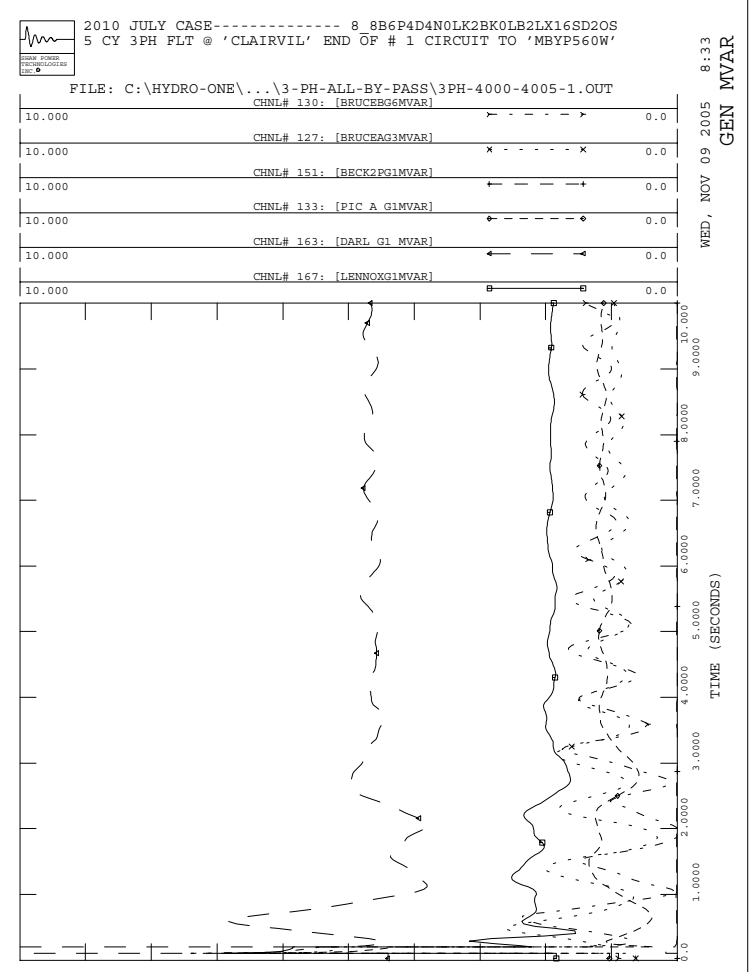
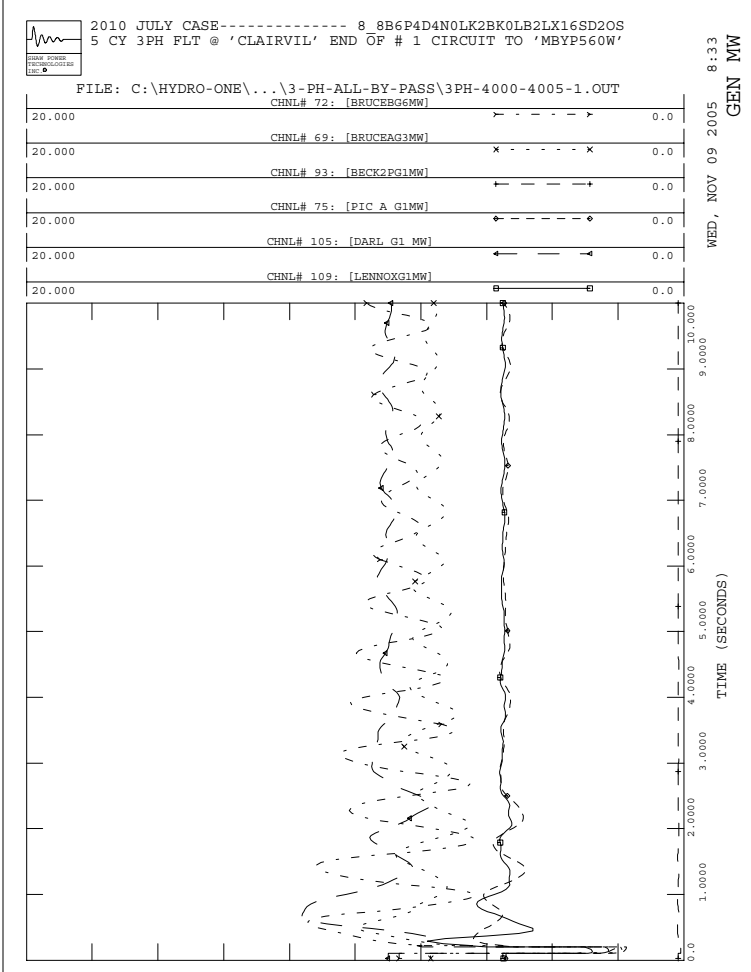


FIGURE-29

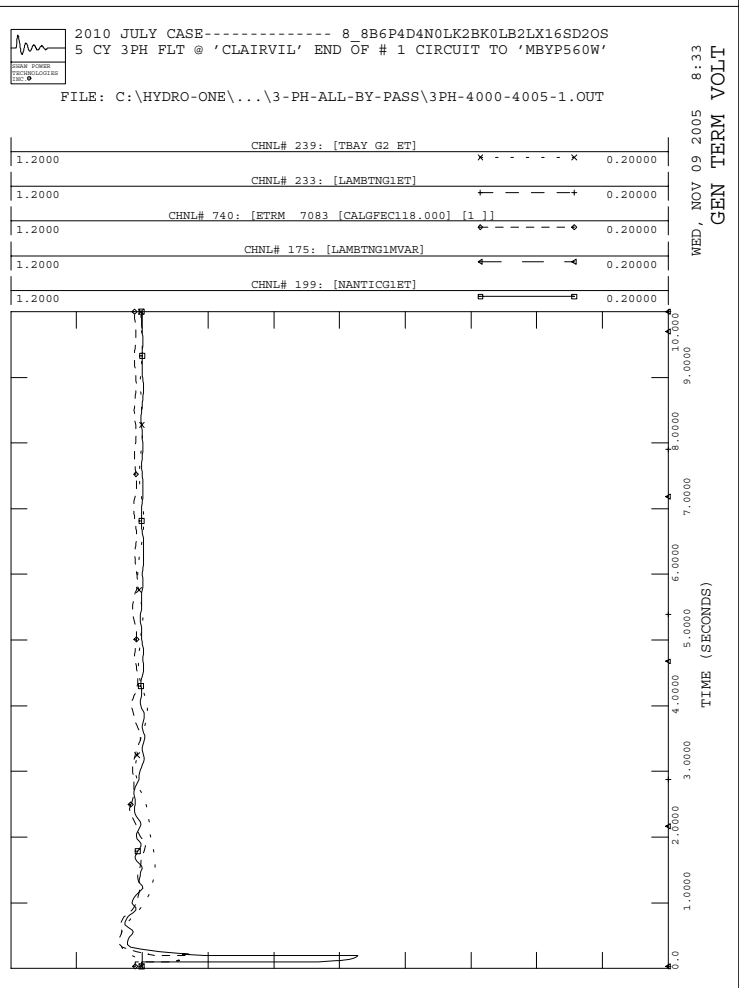
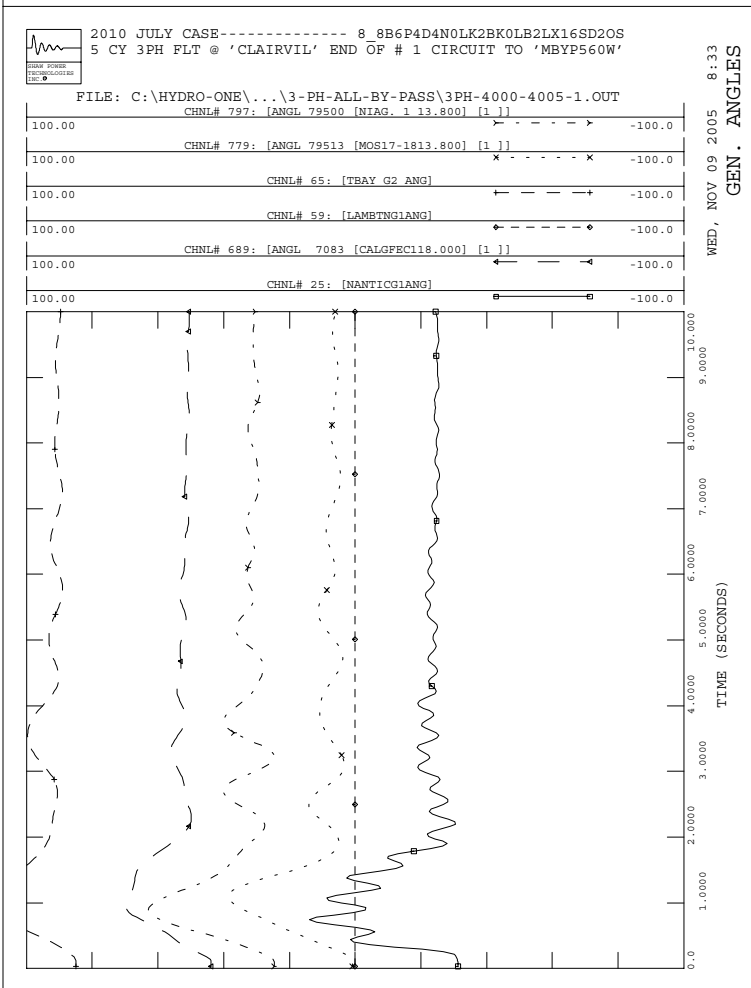
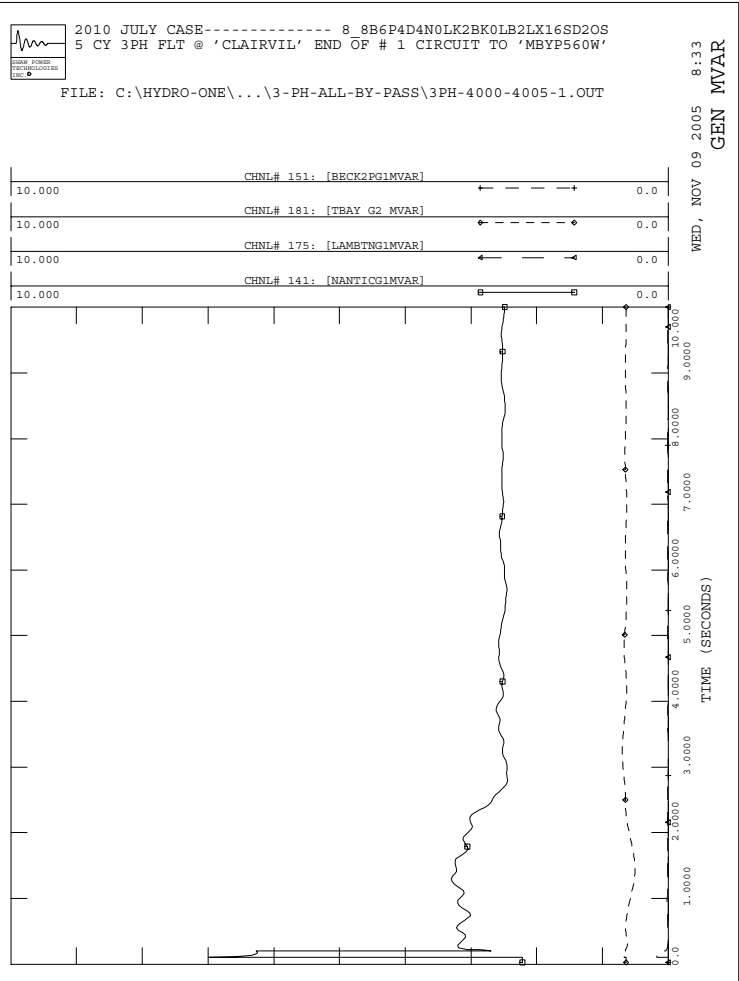
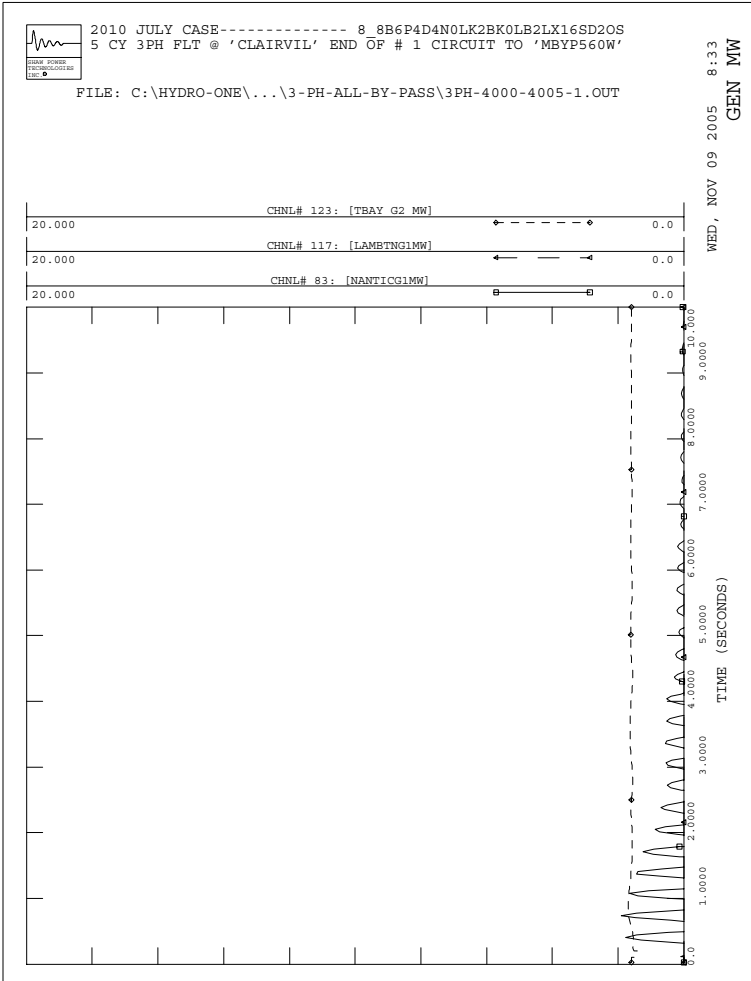


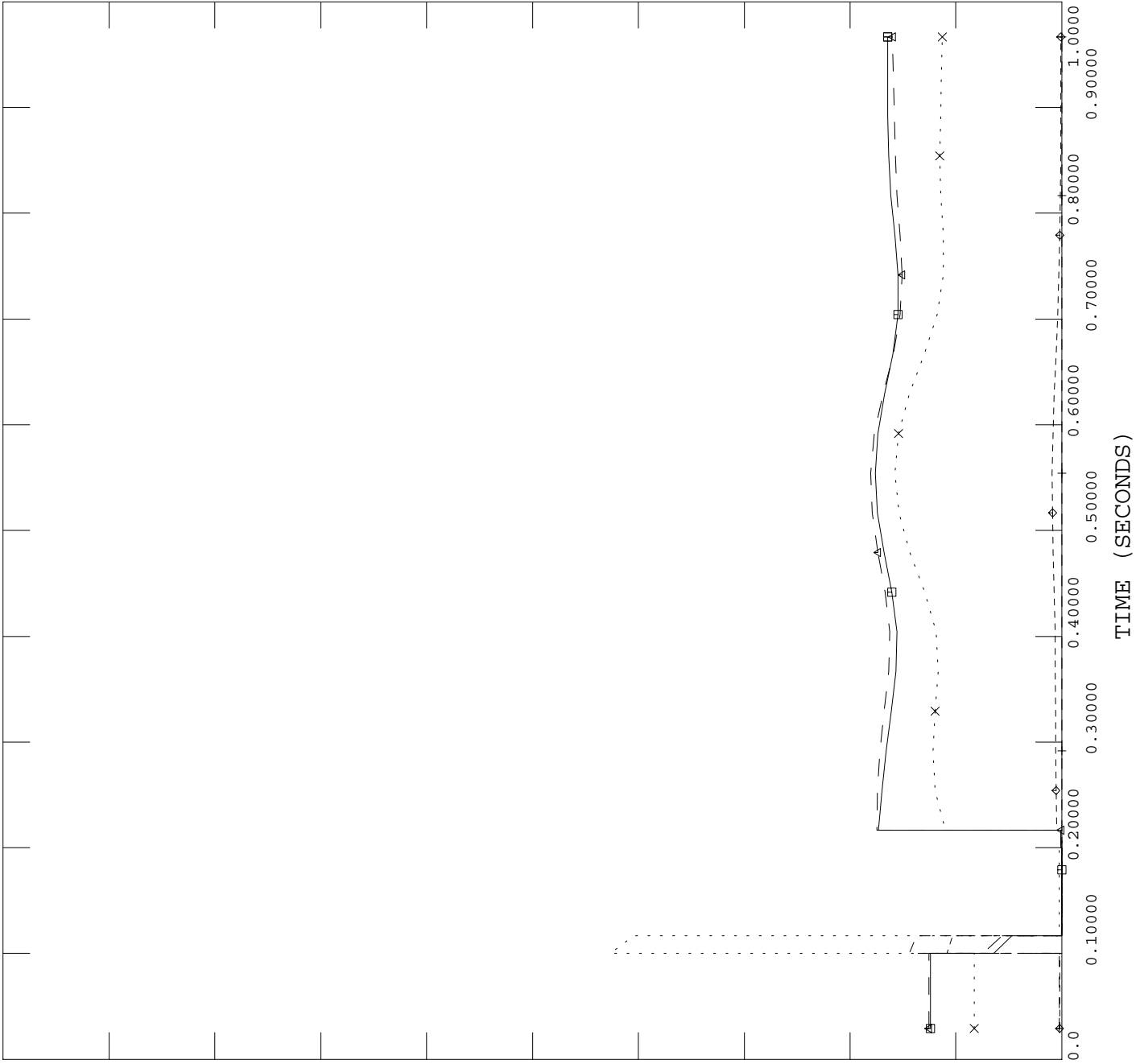
FIGURE-30



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'

FILE: C:\HYDRO-ONE\...\3-PH-ALL-BY-PASS\3PH-4000-4005-1.OUT

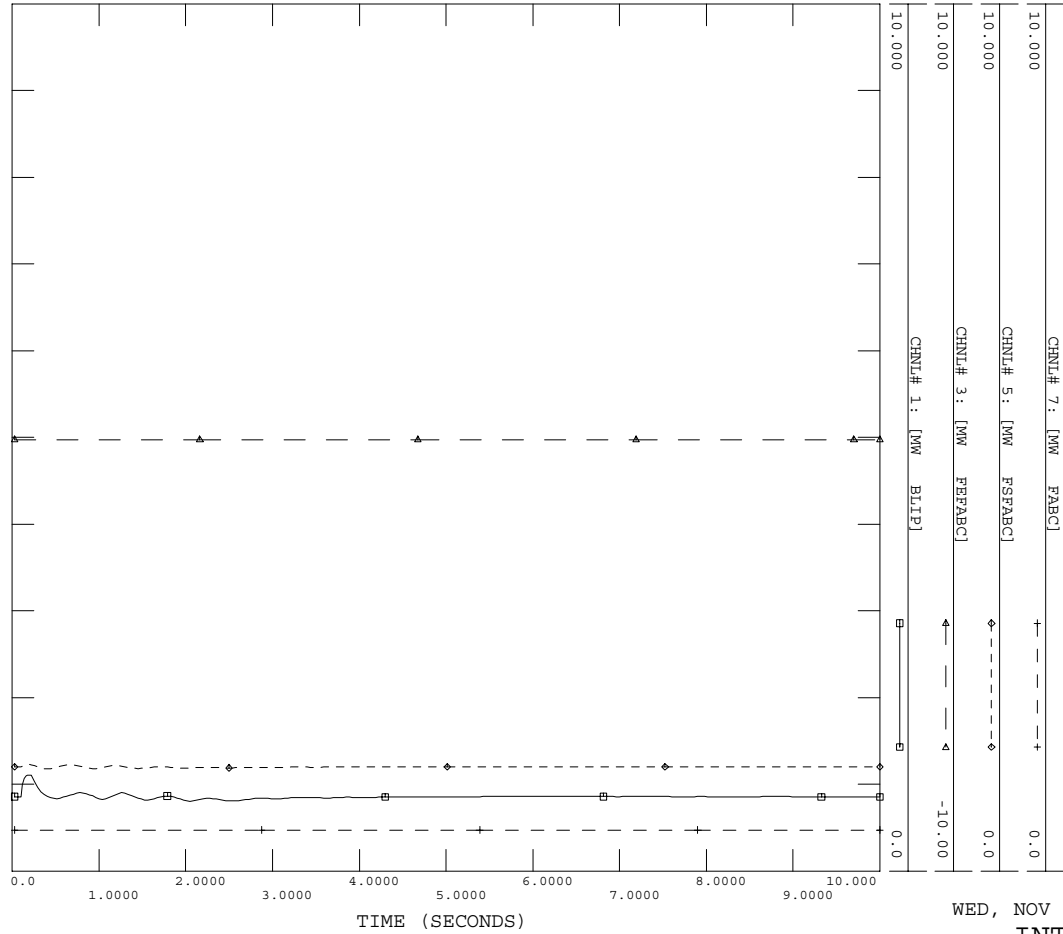
0.50000	CHNL#'S 1190,1191: ABS ([V-TLBG1] - [V-TLBG2])	x-----x	0.0
0.50000	CHNL#'S 1187,1189: ABS ([V-BLWD1] - [V-BLWD2])	+-----+	0.0
0.50000	CHNL#'S 1186,1188: ABS ([V-BLWD3] - [V-BLWD4])	◇-----◇	0.0
0.50000	CHNL#'S 1183,1185: ABS ([V-GRBND3] - [V-GRBND4])	←-----→	0.0
0.50000	CHNL#'S 1182,1184: ABS ([V-GRBND1] - [V-GRBND2])	□-----□	0.0



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FIGURE-31

2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
 5 CY 3PH FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'
 FILE: C:\HYDRO-ONE\...\3-PH-ALL-BY-PASS\3PH-4000-4005-1.OUT



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
 5 CY 3PH FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'
 FILE: C:\HYDRO-ONE\...\3-PH-ALL-BY-PASS\3PH-4000-4005-1.OUT

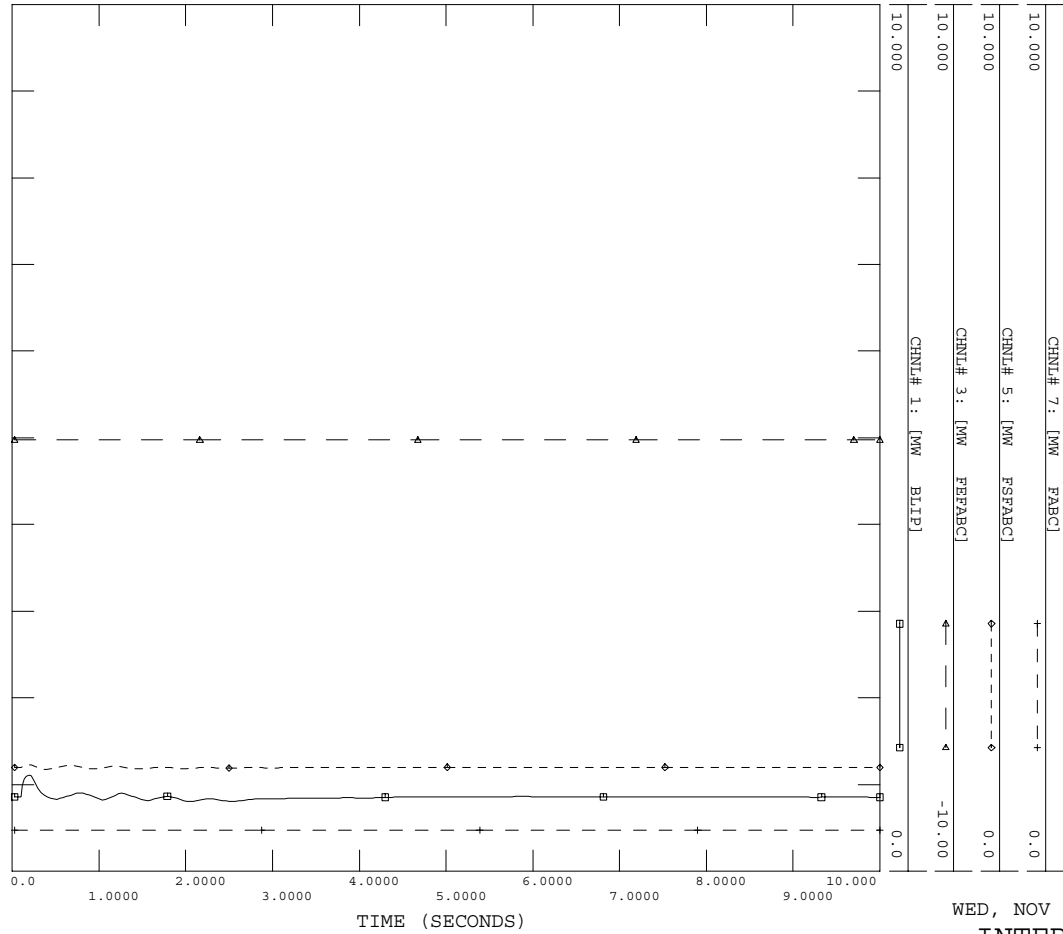


FIGURE G-32

L-G (L-L-G) FAULTS, on Different Phases of the Bruce-Milton D/C tower CLEARED in 10 cycles, NO-BYPASS of SERIES CAPACITORS

For representing an unbalanced fault in the dynamics simulation, an equivalent admittance for the negative and zero sequence networks, as seen from the fault point is necessary. In the table below, the equivalent impedance calculation is shown. In the first part, the positive sequence impedance is obtained from applying 3-phase fault at the two buses for the base case power flow conditions³. In the second part, the sum of negative and zero sequence impedance were provided by Hydro-One. In the third part, the zero sequence impedance is calculated by

$$Z_0 = (Z_2 + Z_0) - Z_1$$

on the basis of assuming that $Z_2 \approx Z_1$. Then the equivalent impedance (or admittance) for representing L-L-G fault is calculated. But the last two rows show the equivalent impedance for two independent L-L-G faults at the two buses. For simulating a common L-L-G fault at these two buses, while applying the fault, a zero impedance line between these two buses was introduced. Then the average admittance shown in the last row was represented as the fault admittance. When the fault is cleared, both the circuits are opened along with the zero-impedance tie.

----- AT BUS -----			MAG	RADS	REAL	IMAG
			Z1 (pu)			
6409	WILCJ561	500	0.004832	1.76645	-0.000939	0.00474
6408	WILCJ560	500	0.00492	1.7558	-0.000905	0.004836
			Z2+Z0 (pu)			
6409	WILCJ561	500	0.009652	1.46705	0.0009996	0.0096
6408	WILCJ560	500	0.010394	1.43568	0.0014002	0.0103
			Z0 (pu)			
6409	WILCJ561	500	0.005233	1.19122	0.0019389	0.00486
6408	WILCJ560	500	0.00593	1.17148	0.0023053	0.005463
			Z2*Z0/(Z2+Z0) pu			
6409	WILCJ561	500	0.00262	1.49063	0.0002098	0.002611
6408	WILCJ560	500	0.002807	1.49161	0.000222	0.002798
			ADMITTANCE (pu)			
6409	WILCJ561	500	381.741	-1.4906	30.571609	-380.5149
6408	WILCJ560	500	356.2617	-1.4916	28.182498	-355.1453
AVERAGE					29.377053	-367.8301
pu on 100MVA Base						

Because, the equivalent fault admittance to represent the fault in the dynamic simulation was not readily available. In order to meet dead line requirements, these runs were made with the values in the above table. However, Hydro-One provided the sequence impedance values later. These are included in this Appendix for reference purposes (see next page).

³ It should be noted that the fault calculations in this section are not maximum fault levels.

Base MVA =100, Base kV = 500						
Existing	Positive Sequence		Zero Sequence		Negative Sequence	
Fault at 500 kV Bus	Z1: Real(pu)	Z1: Imag(pu)	Z0: Real(pu)	Z0: Imag(pu)	Z2: Real(pu)	Z2: Imag(pu)
Bruce A	0.00022	0.00443	0.00015	0.00241	0.00022	0.00443
Bruce B	0.0002	0.00437	0.00014	0.0024	0.0002	0.00437
Willow Creek Junction (562)	0.00033	0.00613	0.00134	0.00719	0.00033	0.00613
Willow Creek Junction (563)	0.00037	0.00614	0.00143	0.0075	0.00037	0.00614
Willow Creek Junction (560)	0.00037	0.00599	0.0014	0.00756	0.00037	0.00599
Willow Creek Junction (561)	0.00031	0.00584	0.00131	0.00704	0.00031	0.00584
Claireville	0.00015	0.00274	0.00051	0.00283	0.00015	0.00274
Milton	0.00022	0.00359	0.00113	0.00507	0.00022	0.00359
Longwood (1)	0.00049	0.00686	0.00062	0.00555	0.00049	0.00686
Longwood (2)	0.00049	0.00686	0.00062	0.00555	0.00049	0.00686

with Series Comp (10% BxM/V, 70% NxL, 70% BxL)	Positive Sequence		Zero Sequence		Negative Sequence	
Fault at 500 kV Bus	Z1: Real(pu)	Z1: Imag(pu)	Z0: Real(pu)	Z0: Imag(pu)	Z2: Real(pu)	Z2: Imag(pu)
Bruce A	0.00025	0.00417	0.00015	0.0024	0.00025	0.00417
Bruce B	0.00024	0.00412	0.00014	0.00239	0.00024	0.00412
Willow Creek Junction (562)	0.00044	0.00531	0.00137	0.00691	0.00044	0.00531
Willow Creek Junction (563)	0.00046	0.00531	0.00146	0.00718	0.00046	0.00531
Willow Creek Junction (560)	0.00037	0.00588	0.0014	0.00752	0.00037	0.00588
Willow Creek Junction (561)	0.00032	0.00572	0.00131	0.00701	0.00032	0.00572
Claireville	0.0015	0.00273	0.00051	0.00283	0.0015	0.00273
Milton	0.00022	0.00357	0.00113	0.00506	0.00022	0.00357
Longwood (1)	0.00059	0.00563	0.00063	0.00551	0.00059	0.00563
Longwood (2)	0.00061	0.00527	0.00067	0.0054	0.00061	0.00527

Based on most recent Hydro-One sequence impedance values (previous page), the fault impedances for representation were calculated and shown in the following Table. Comparison of the equivalent admittance used in the simulations (earlier table) and the values listed in the table below (as provided by Hydro-One), show that the admittance values are higher for the L-L-G faults simulated at Bruce, i.e. the simulations are on the conservative side.

Existing				
----- AT BUS -----			REAL	IMAG
			Z1 (pu)	
6409	WILCJ561	500	0.00031	0.00584
6408	WILCJ560	500	0.00037	0.00599
			Z2+ZO (pu)	
6409	WILCJ561	500	0.00162	0.01288
6408	WILCJ560	500	0.00177	0.01355
			ZO (pu)	
6409	WILCJ561	500	0.00131	0.00704
6408	WILCJ560	500	0.0014	0.00756
			Z2*ZO/(Z2+ZO) pu	
6409	WILCJ561	500	0.0003602	0.003205825
6408	WILCJ560	500	0.00038716	0.003354367
			ADMITTANCE (pu)	
6409	WILCJ561	500	34.6110446	-308.0433955
6408	WILCJ560	500	33.95614	-294.1997055
AVERAGE			34.2835923	-301.1215505
pu on 100MVA Base				
with Series Comp (10% BxM/V, 70% NxL, 70% BxL)				
----- AT BUS -----			REAL	IMAG
			Z1 (pu)	
6409	WILCJ561	500	0.00032	0.00572
6408	WILCJ560	500	0.00037	0.00588
			Z2+ZO (pu)	
6409	WILCJ561	500	0.00163	0.01273
6408	WILCJ560	500	0.00177	0.0134
			ZO (pu)	
6409	WILCJ561	500	0.00131	0.00701
6408	WILCJ560	500	0.0014	0.00752
			Z2*ZO/(Z2+ZO) pu	
6409	WILCJ561	500	0.00035984	0.003162965
6408	WILCJ560	500	0.0003845	0.003311952
			ADMITTANCE (pu)	
6409	WILCJ561	500	35.5088192	-312.1193592
6408	WILCJ560	500	34.5867232	-297.9214454
AVERAGE			35.0477712	-305.0204023
pu on 100MVA Base				
Base MVA =100, Base kV = 500				

Plots for the following disturbance are shown in the following order in this Appendix:

i) Bruce – Milton 500kV D/C (L-L-G fault at bus# 6408 and 6409)

Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G33&G34

Voltage Drop across the 5 series capacitors – Figure G35

Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G36

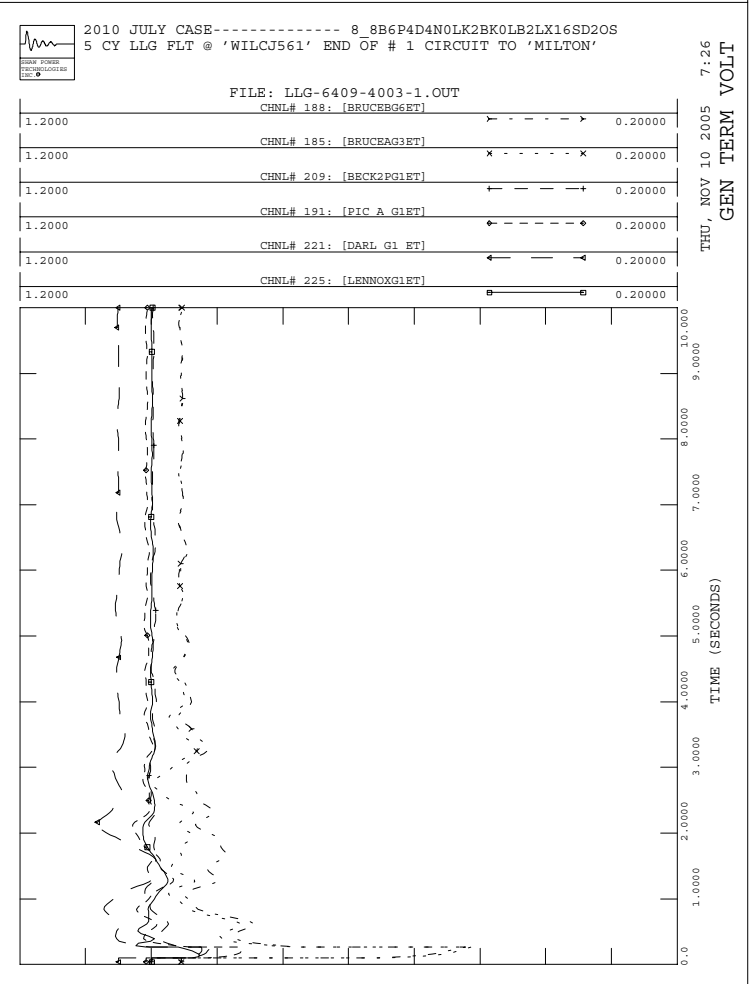
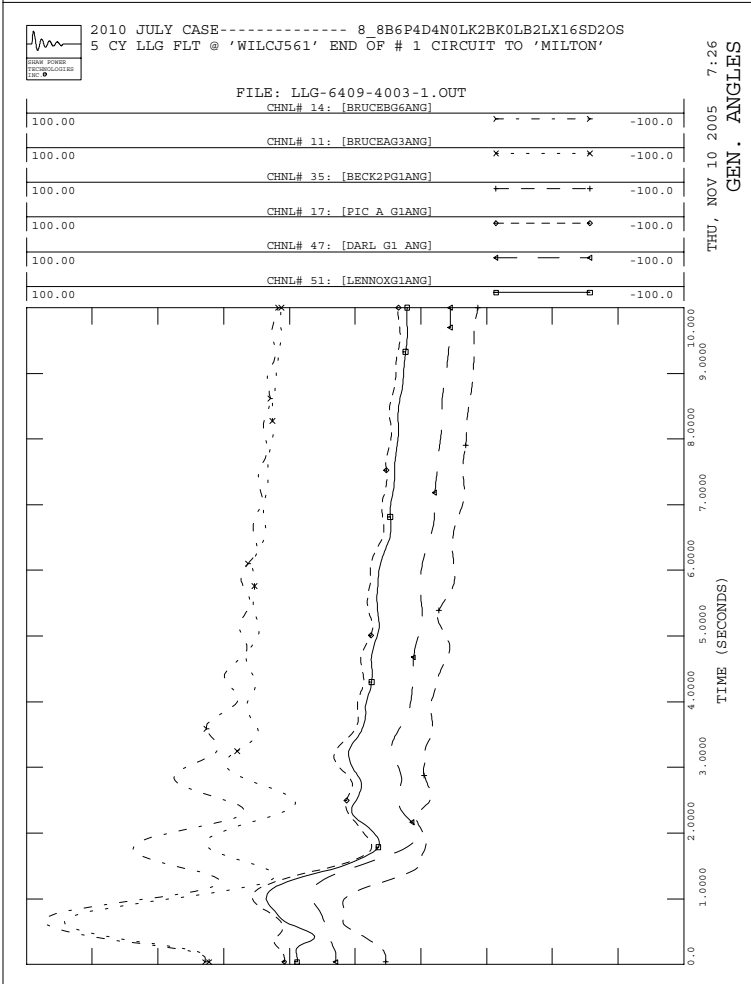
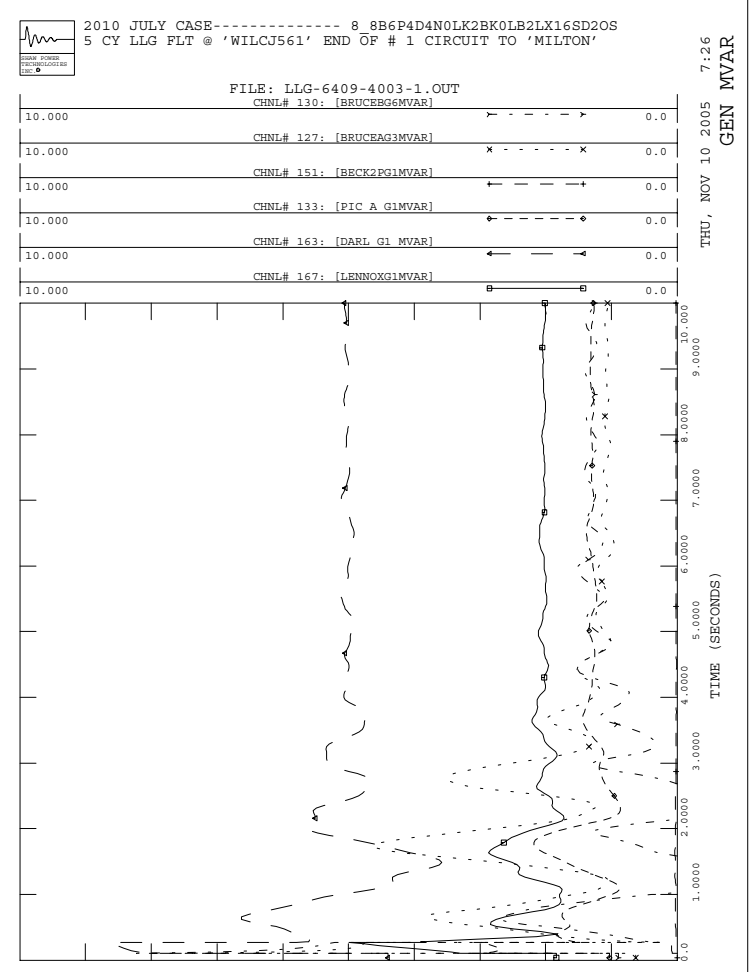
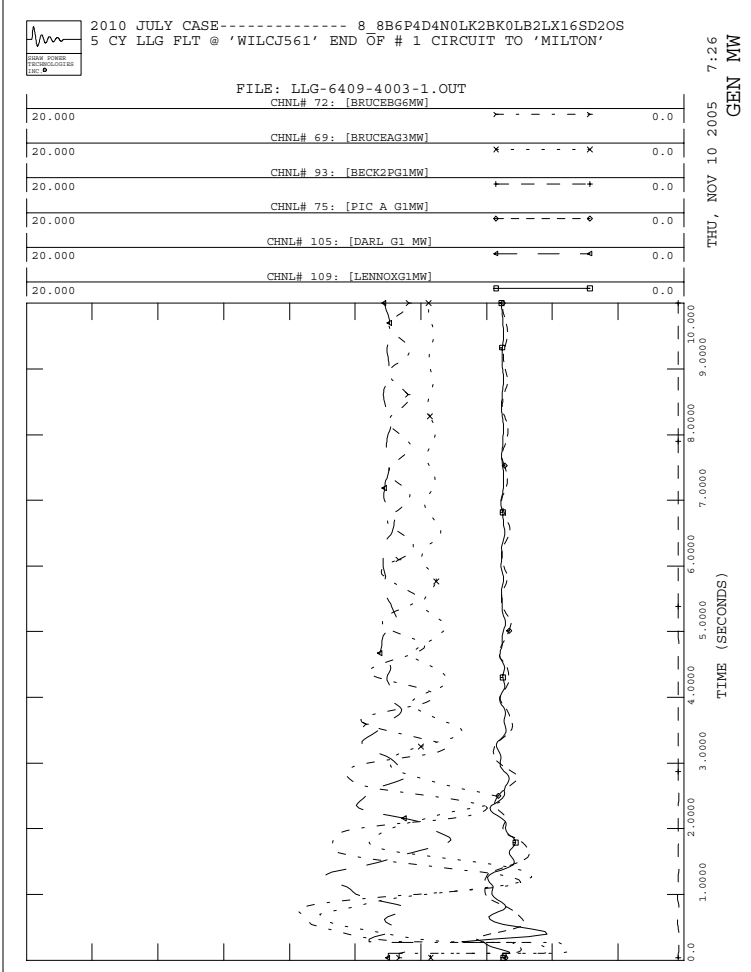


FIGURE G-33

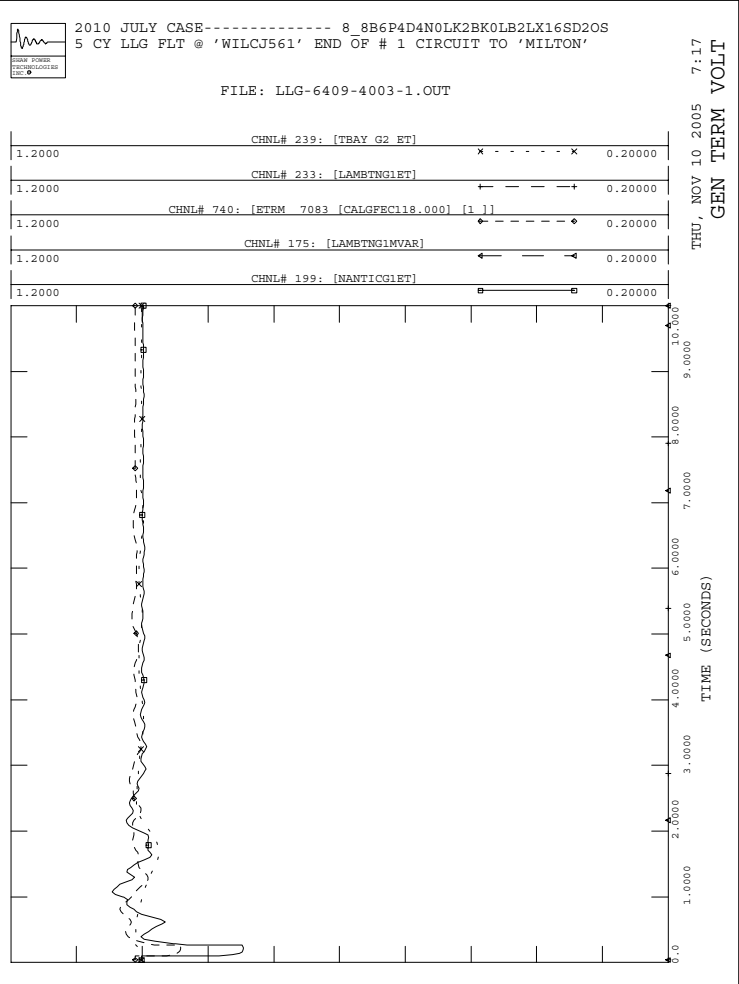
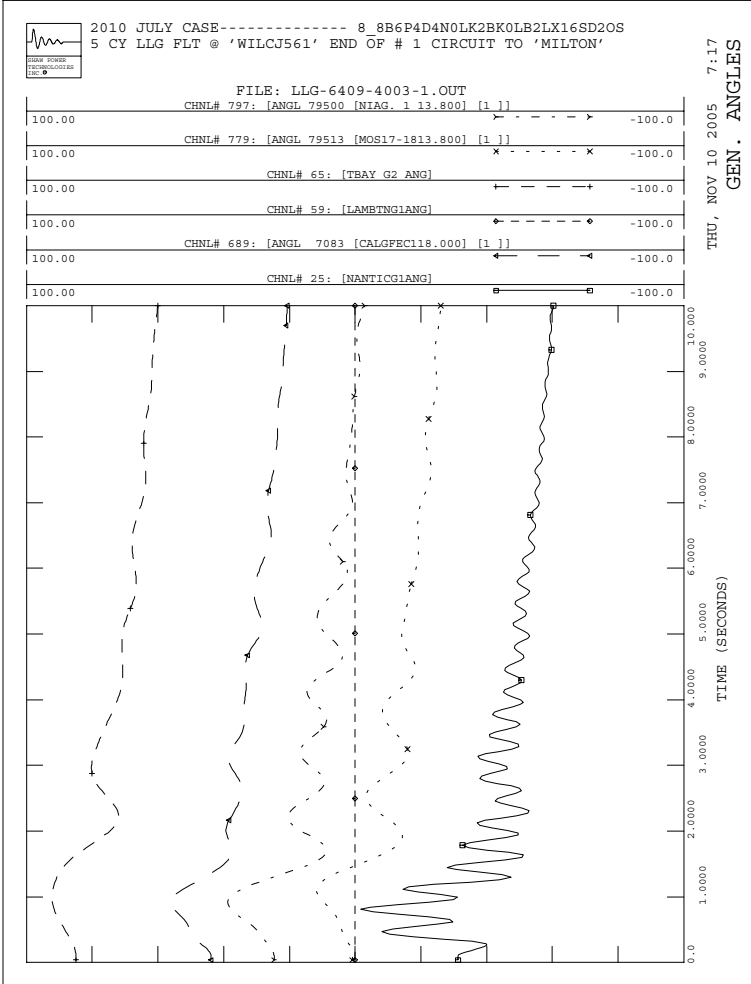
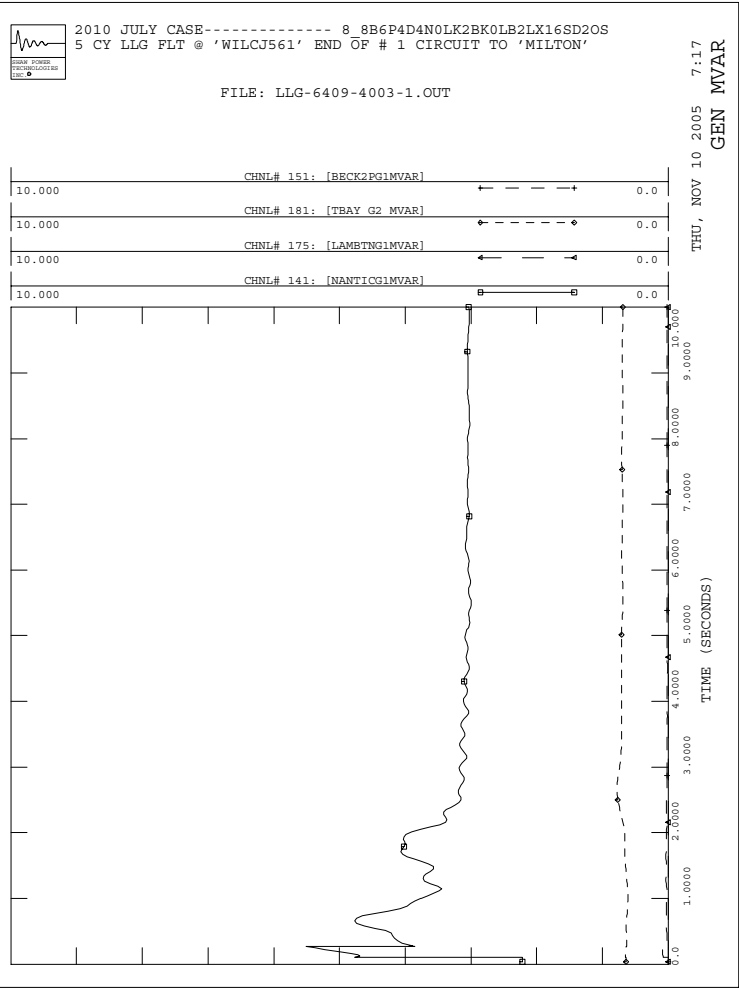
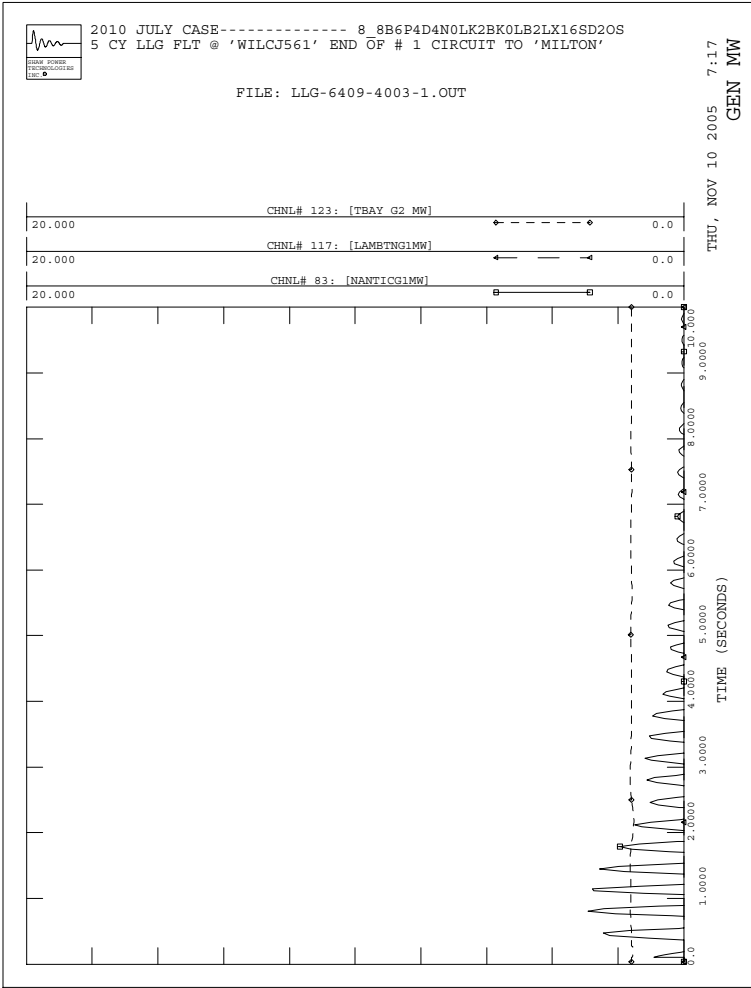


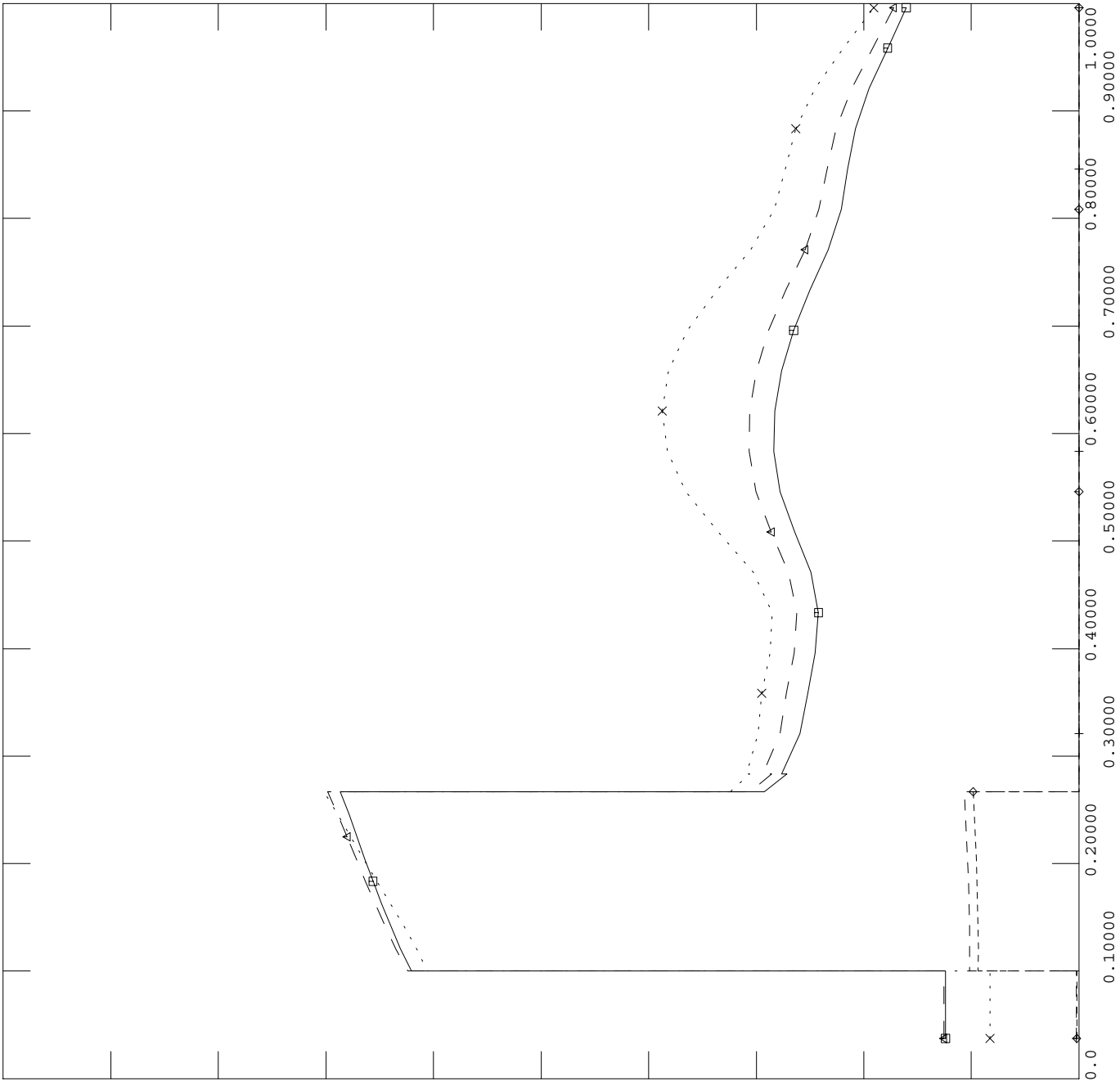
FIGURE G-34



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: LLG-6409-4003-1.OUT

0.50000	CHNL#'S 1190,1191: ABS ([V-TLBG1] - [V-TLBG2])	X-----X	0.0
0.50000	CHNL#'S 1187,1189: ABS ([V-BLWD1] - [V-BLWD2])	+-----+	0.0
0.50000	CHNL#'S 1186,1188: ABS ([V-BLWD3] - [V-BLWD4])	◇-----◇	0.0
0.50000	CHNL#'S 1183,1185: ABS ([V-GRBND3] - [V-GRBND4])	△-----△	0.0
0.50000	CHNL#'S 1182,1184: ABS ([V-GRBND1] - [V-GRBND2])	□-----□	0.0



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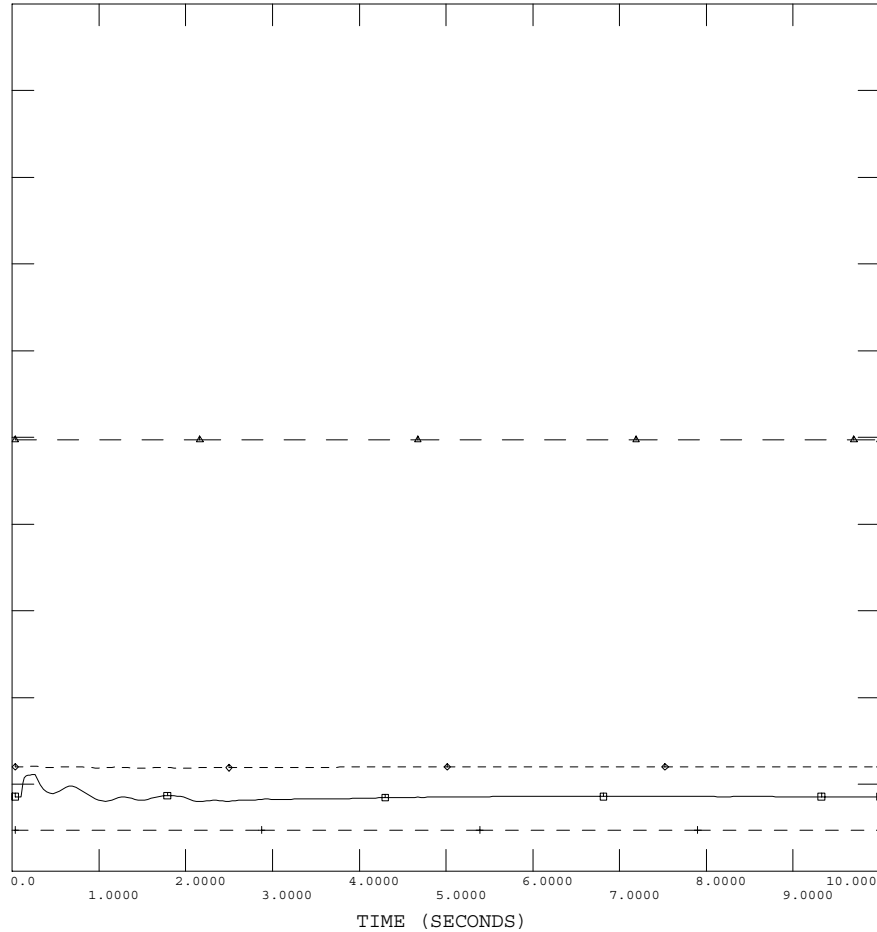
FIGURE G-35



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-L-G-FAULT-NO-BY-PASS\LLG-6409-4003-1.OUT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	□ - - - □	0.0



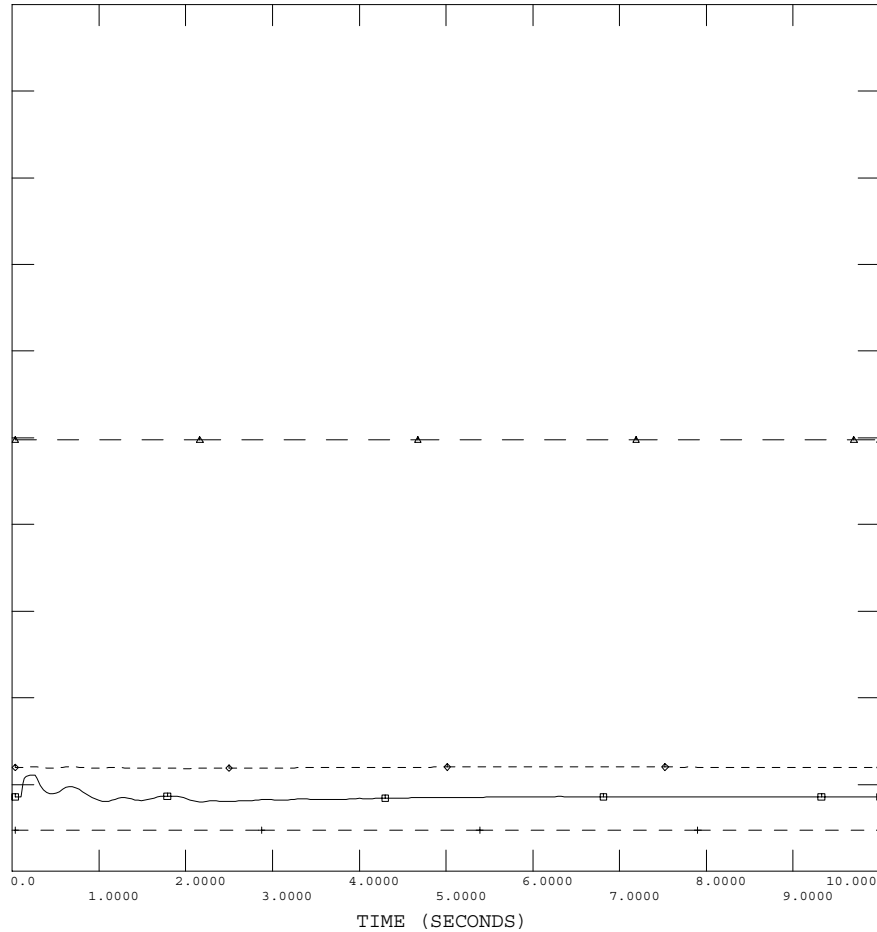
THU, NOV 10 2005 9:49
INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-L-G-FAULT-NO-BY-PASS\LLG-6409-4003-1.OUT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	□ - - - □	0.0



THU, NOV 10 2005 9:49
INTERFACE MVAR

FIGURE G-36

DELAYED CLEARING (10 CYCLES) OF L-G FAULTS, NO-BYPASS OF SERIES CAPACITORS

Plots for the following disturbance are shown in the following order in this Appendix:

i. Bruce – Milton 500kV Circuit (fault at bus# 6409)

Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G37&G38

Voltage Drop across the 5 series capacitors – Figure G39

Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G40

ii. Bruce – Longwood 500kV Circuit (fault at bus# 6410)

Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G41&G42

Voltage Drop across the 5 series capacitors – Figure G43

Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G44

iii. Longwood – Nanticoke 500kV Circuit (fault at bus# 7000)

Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G45&G46

Voltage Drop across the 5 series capacitors – Figure G47

Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G48

iv. Bruce – Clairville 500kV Circuit (fault at bus# 4000)

Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G49&G50

Voltage Drop across the 5 series capacitors – Figure G51

Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G52

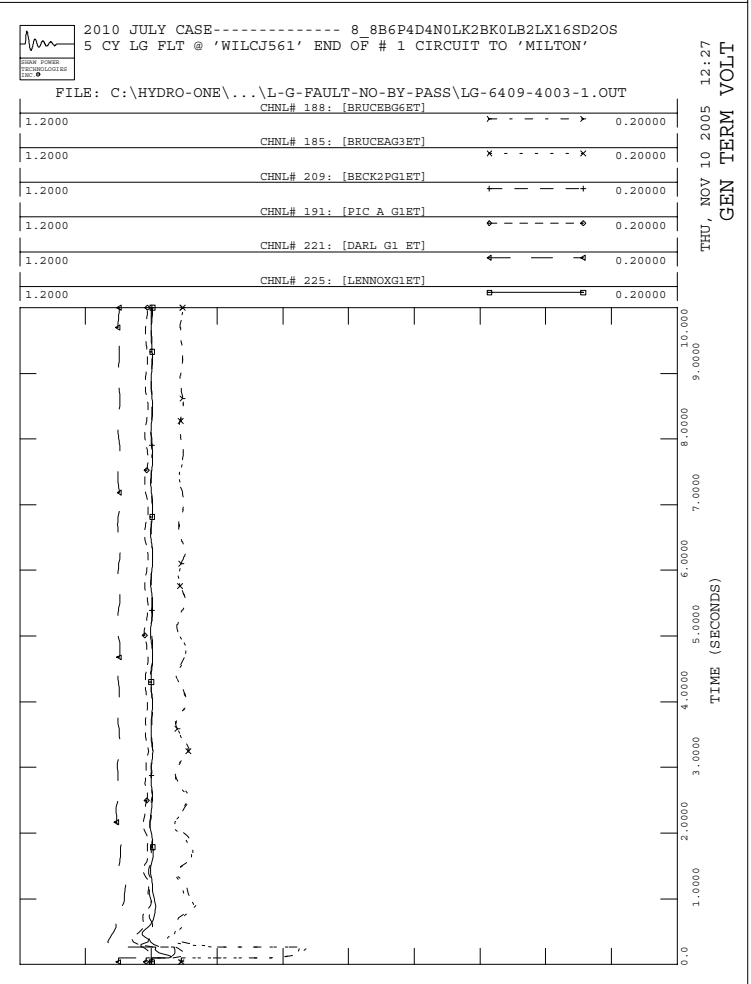
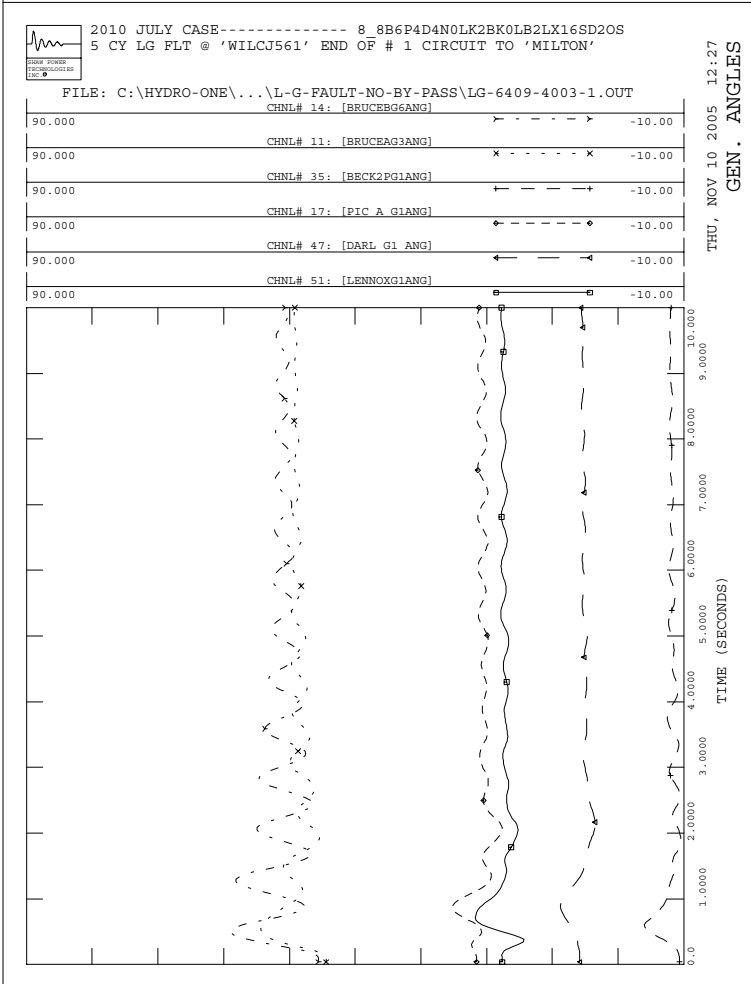
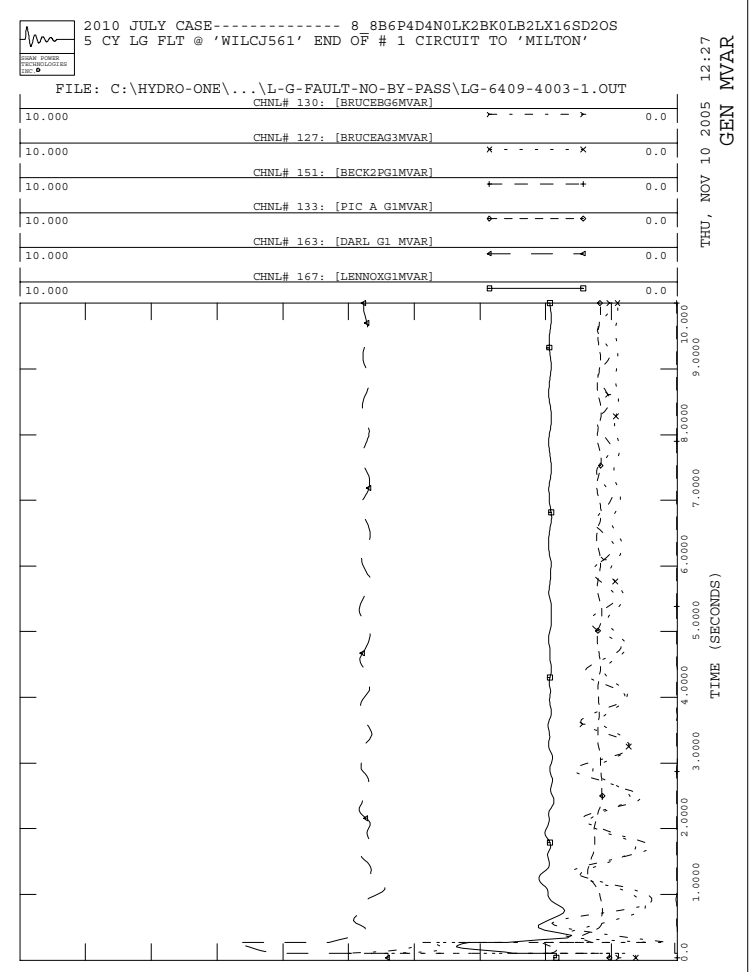
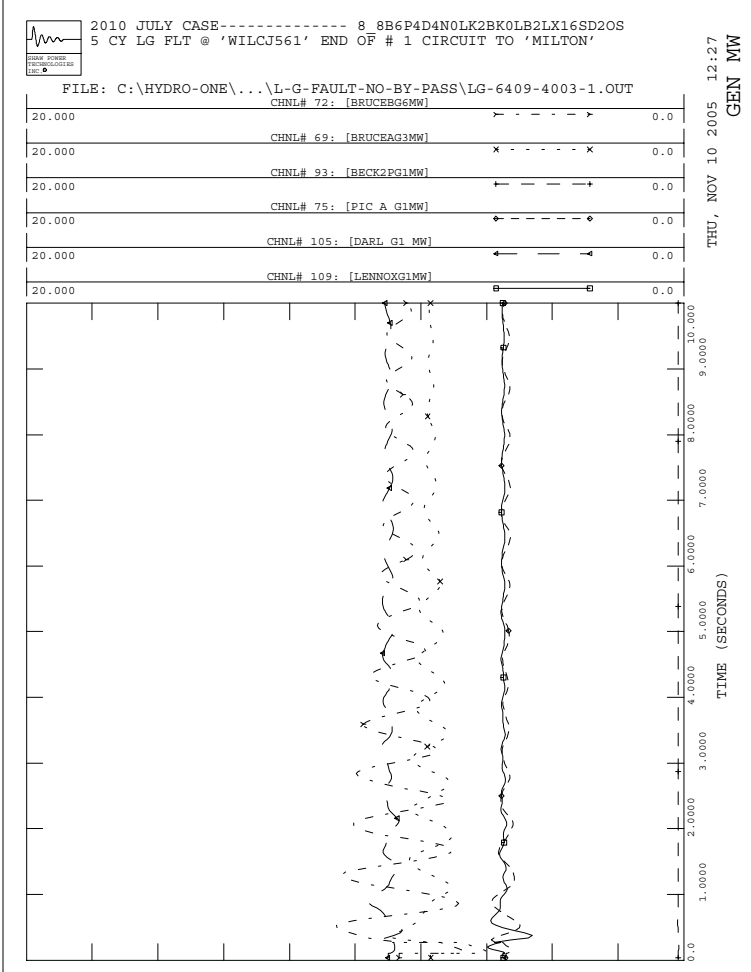


FIGURE G-37

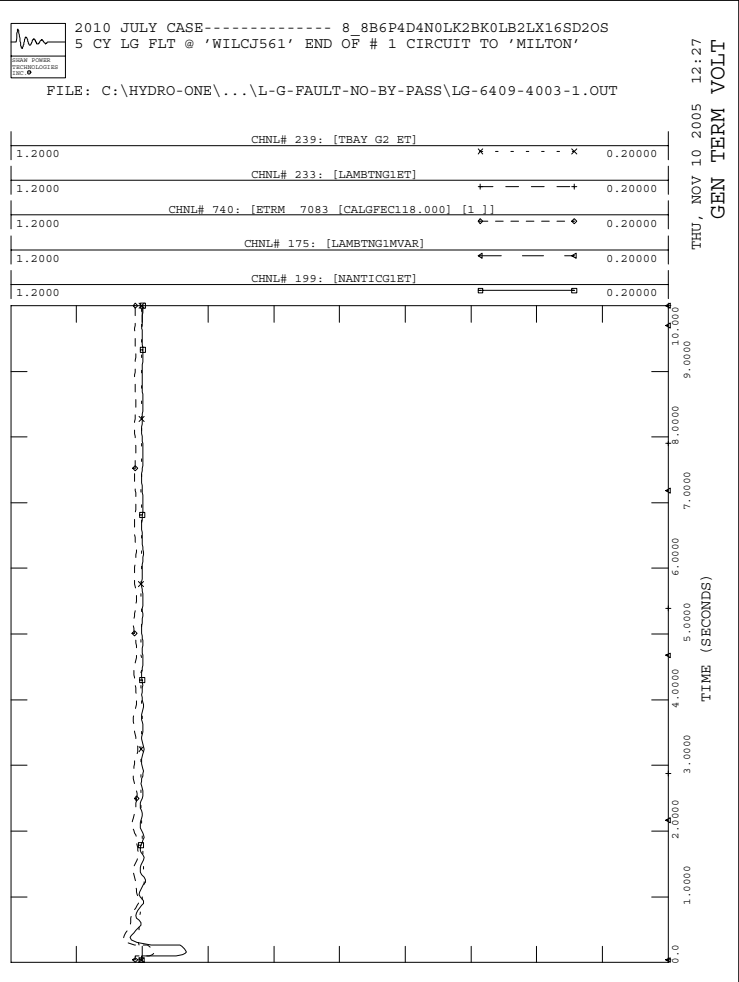
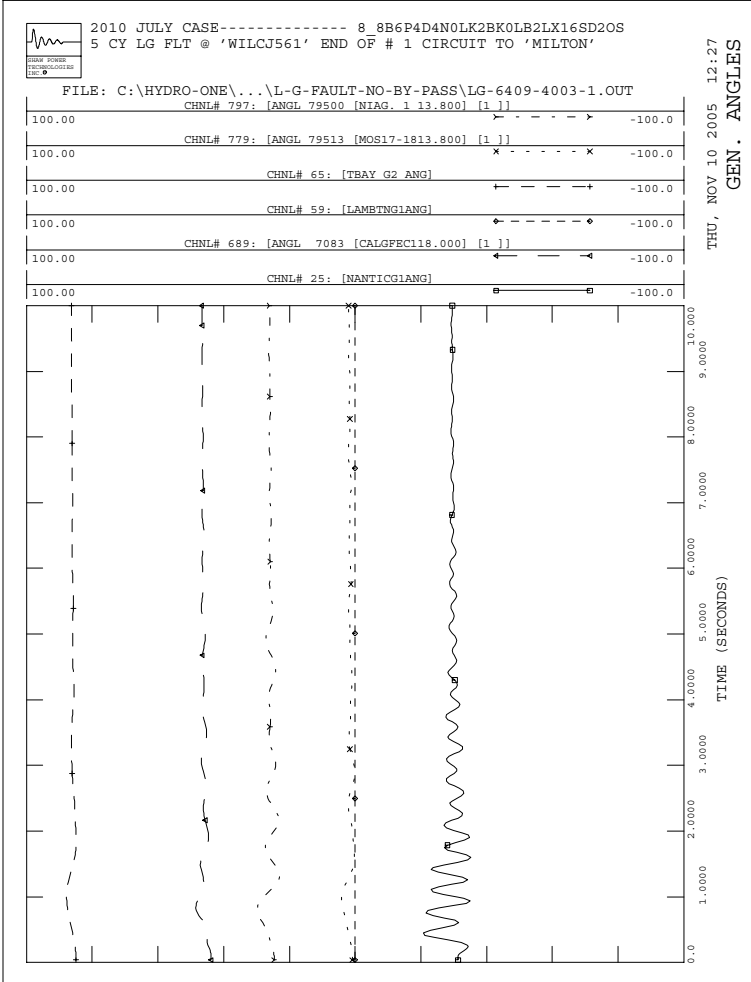
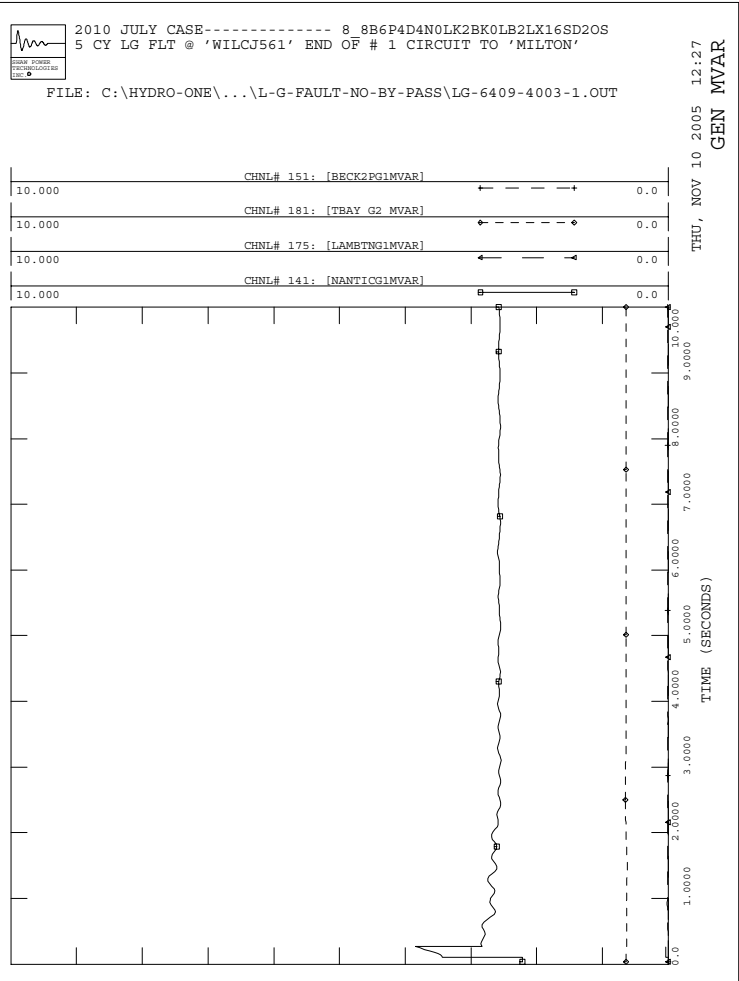
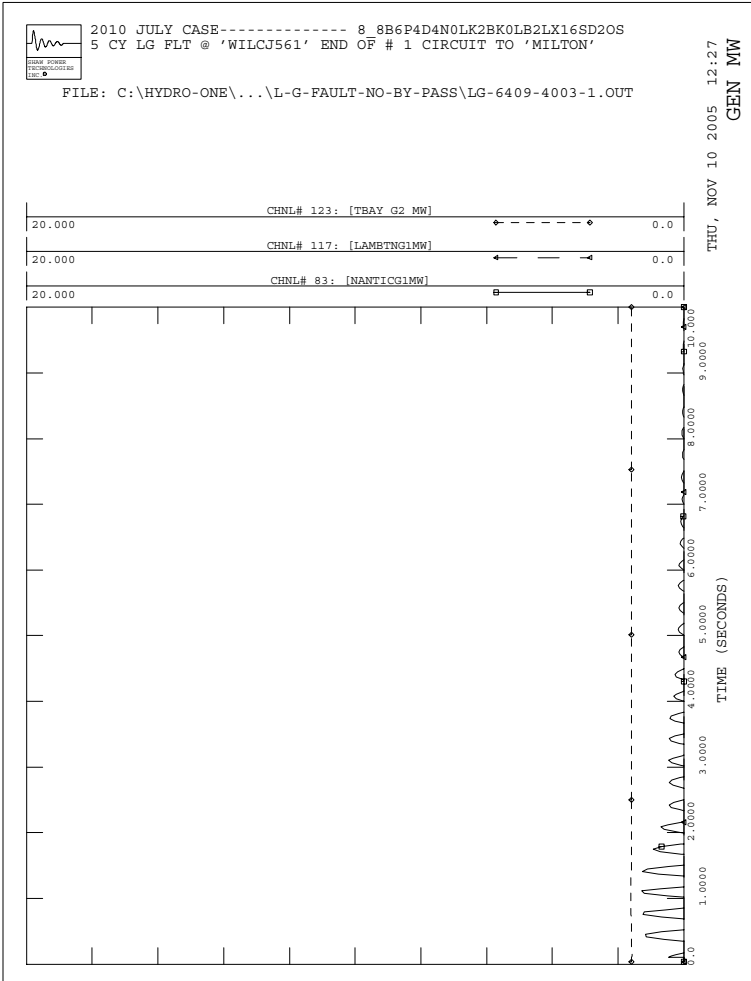
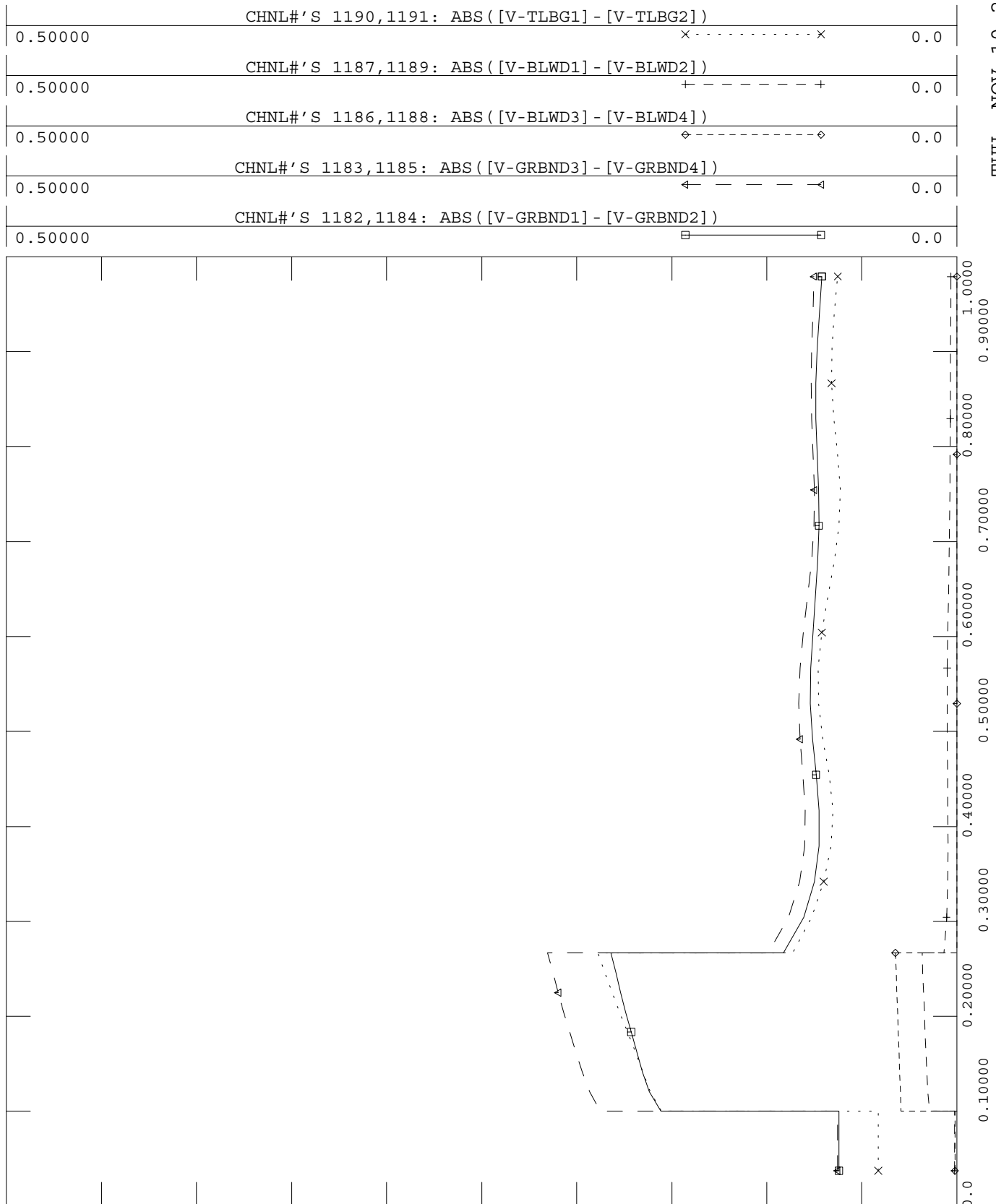


FIGURE G-38



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-NO-BY-PASS\LG-6409-4003-1.OUT



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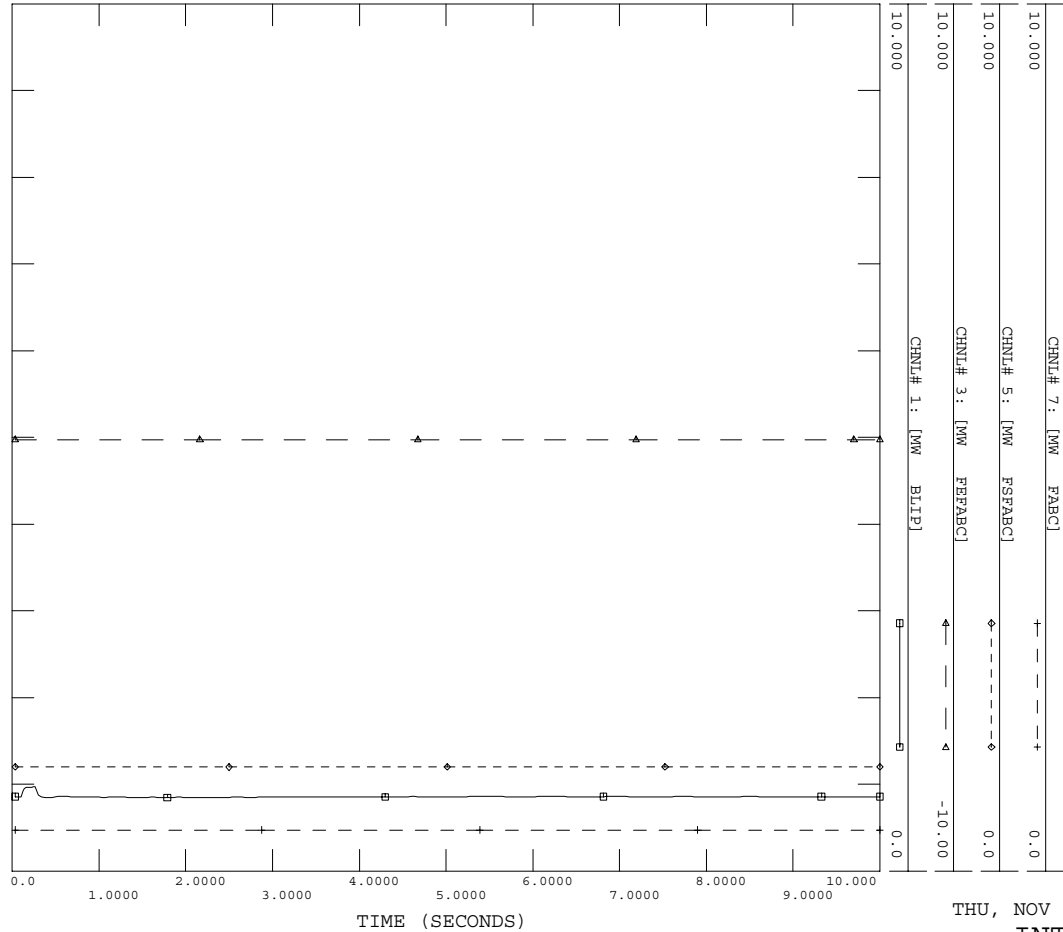
FIGURE G-39



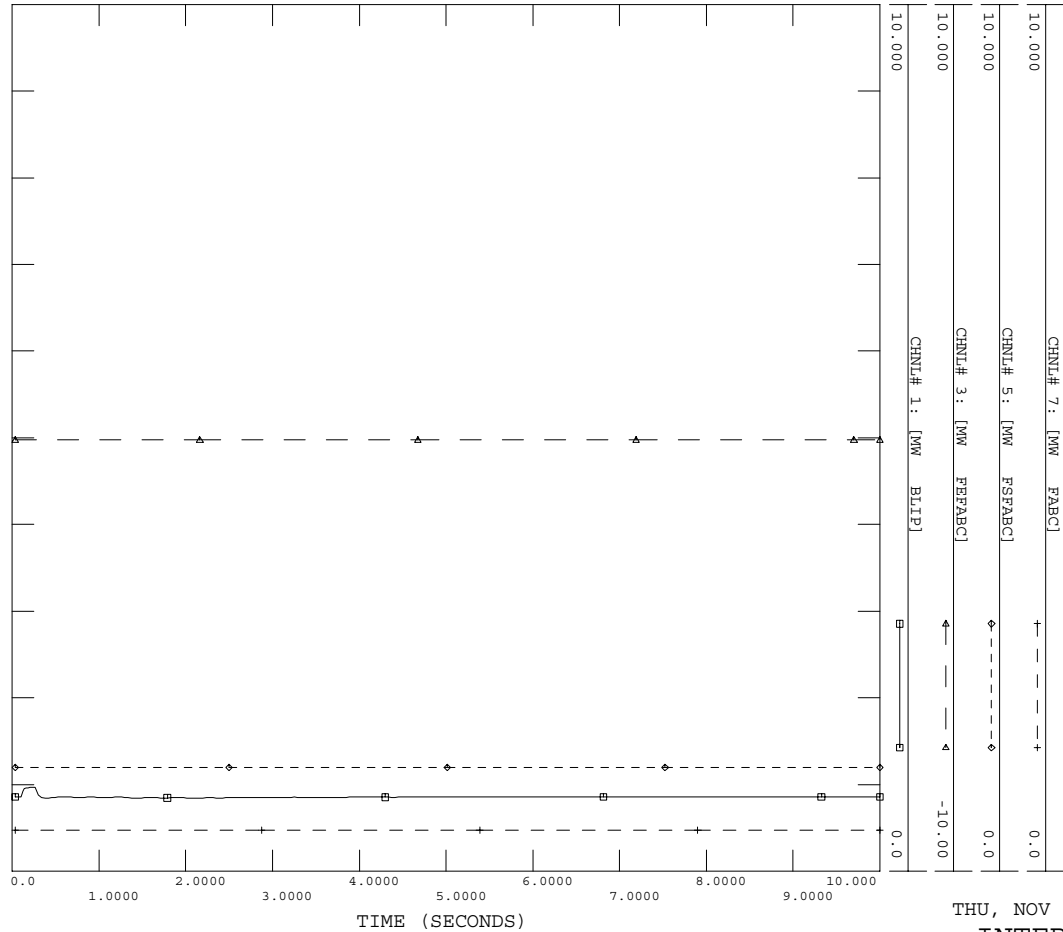
2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'
FILE: C:\HYDRO-ONE\...\L-G-FAULT-NO-BY-PASS\LG-6409-4003-1.OUT



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'
FILE: C:\HYDRO-ONE\...\L-G-FAULT-NO-BY-PASS\LG-6409-4003-1.OUT



THU, NOV 10 2005 12:27
INTERFACE MW



THU, NOV 10 2005 12:27
INTERFACE MVAR

FIGURE G-40

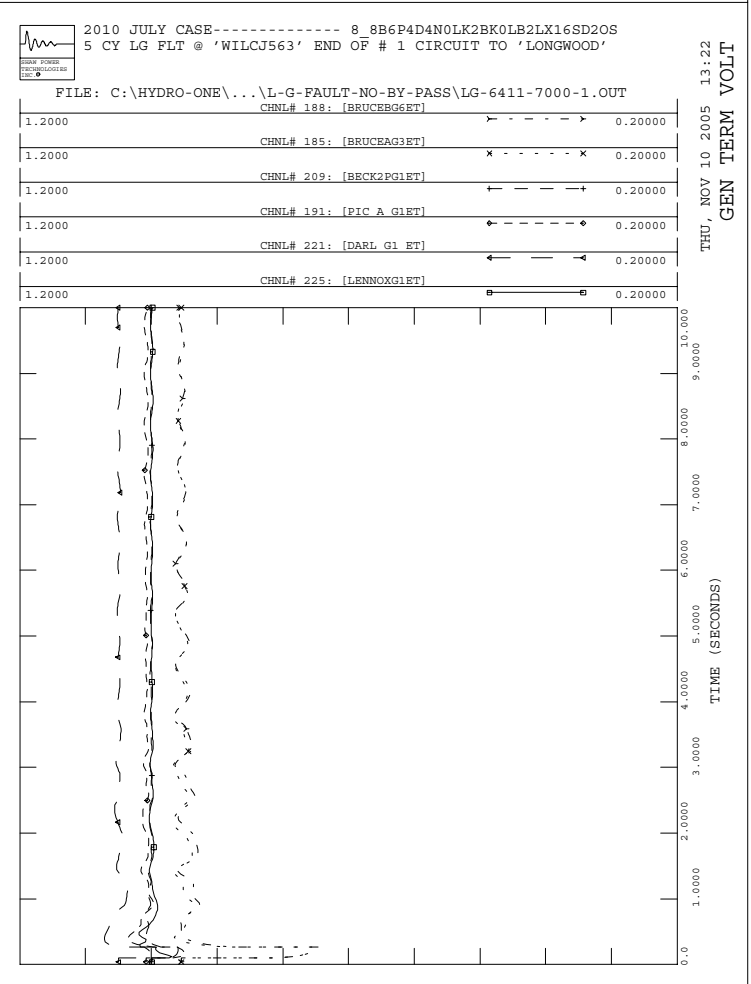
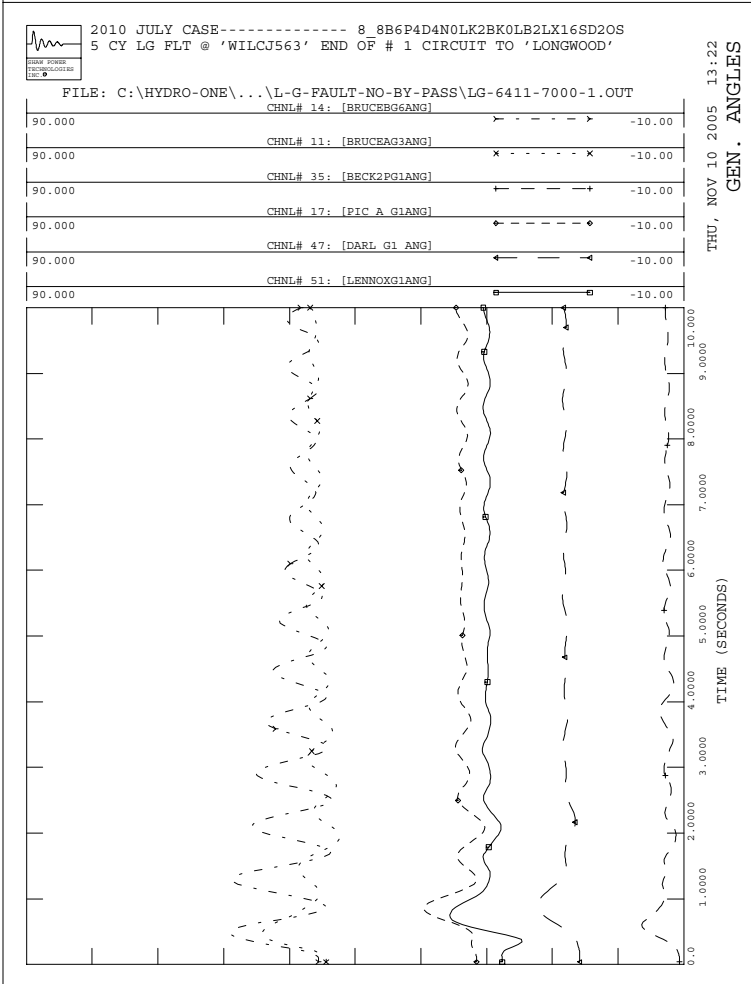
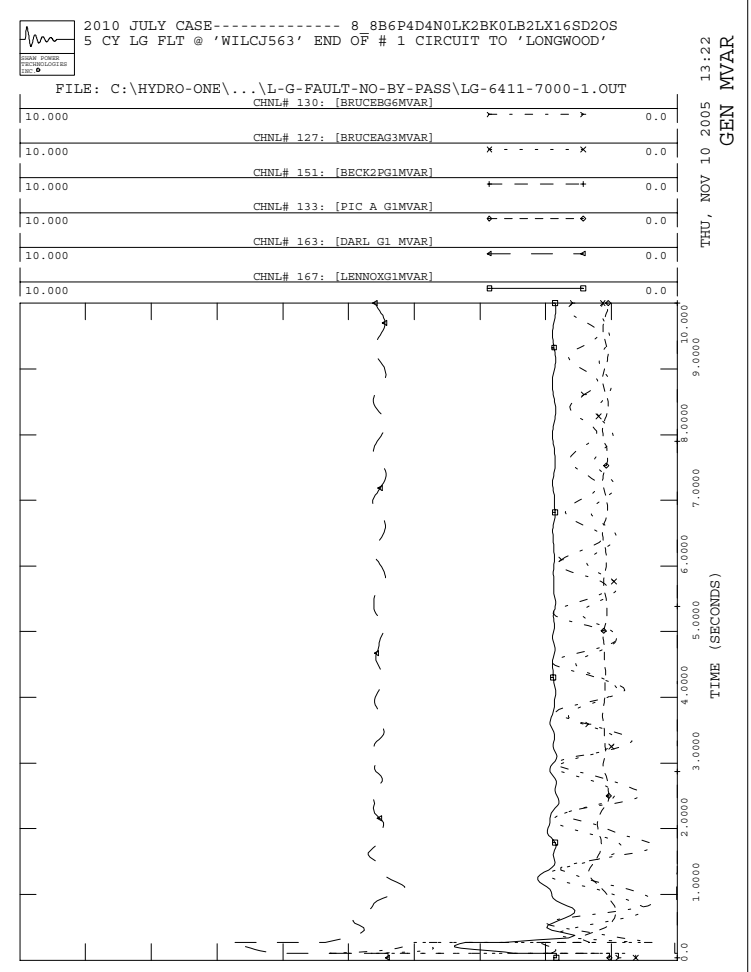
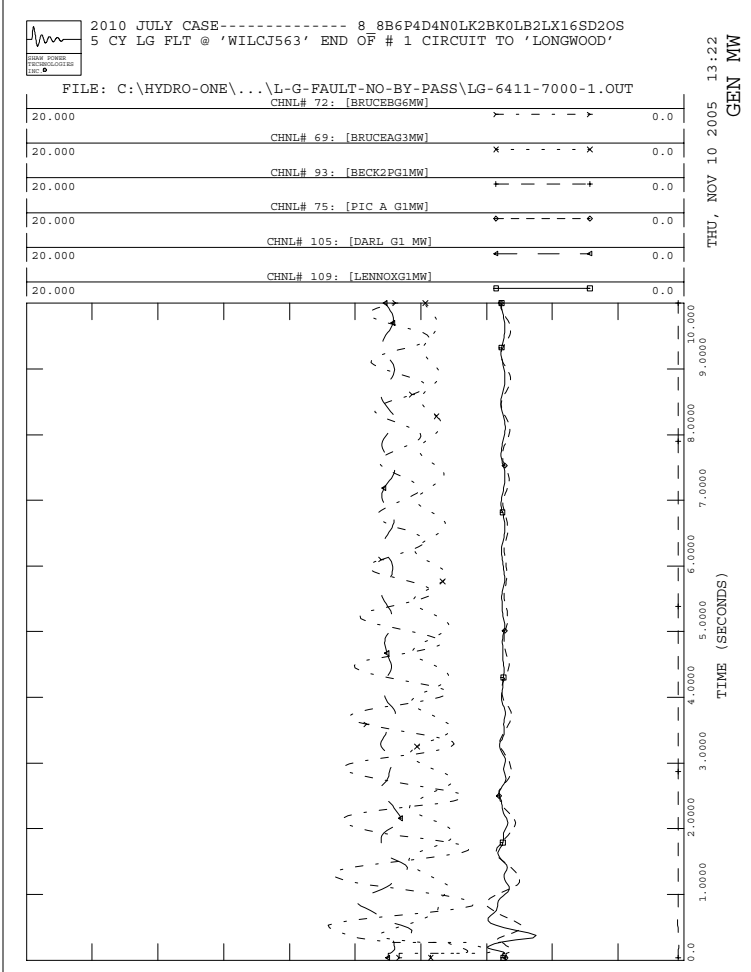


FIGURE G-41

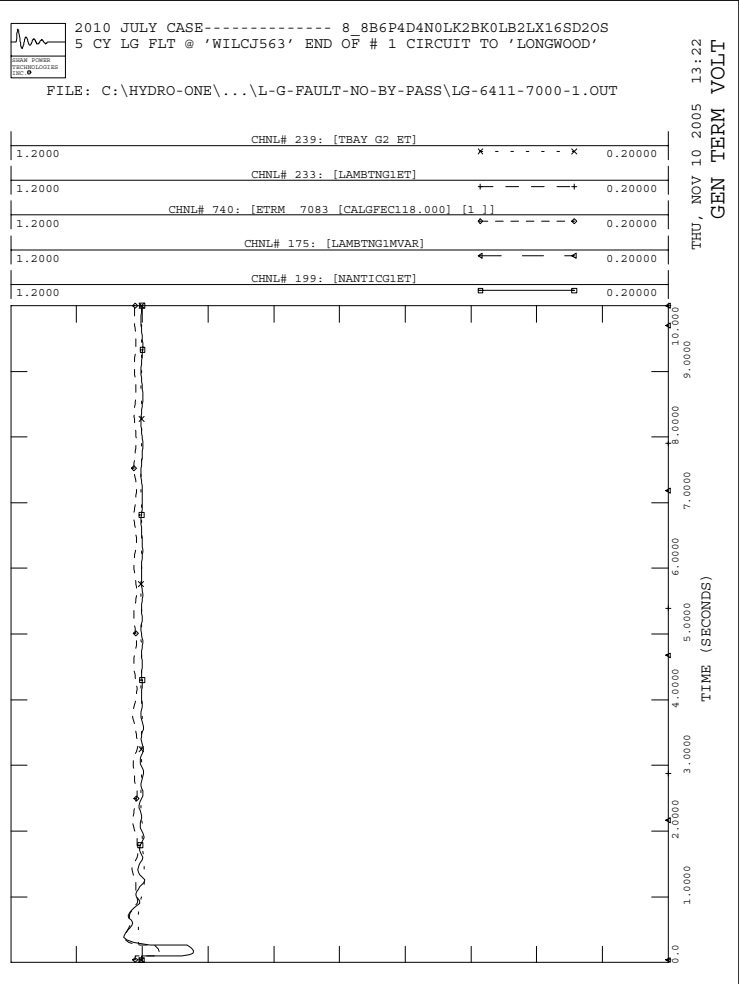
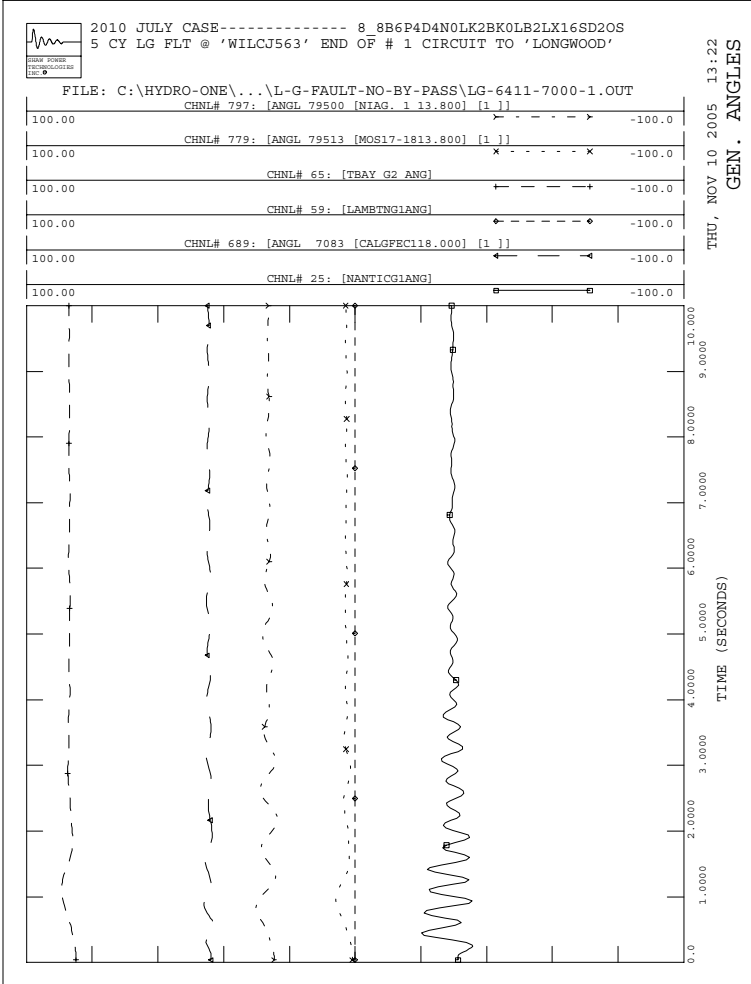
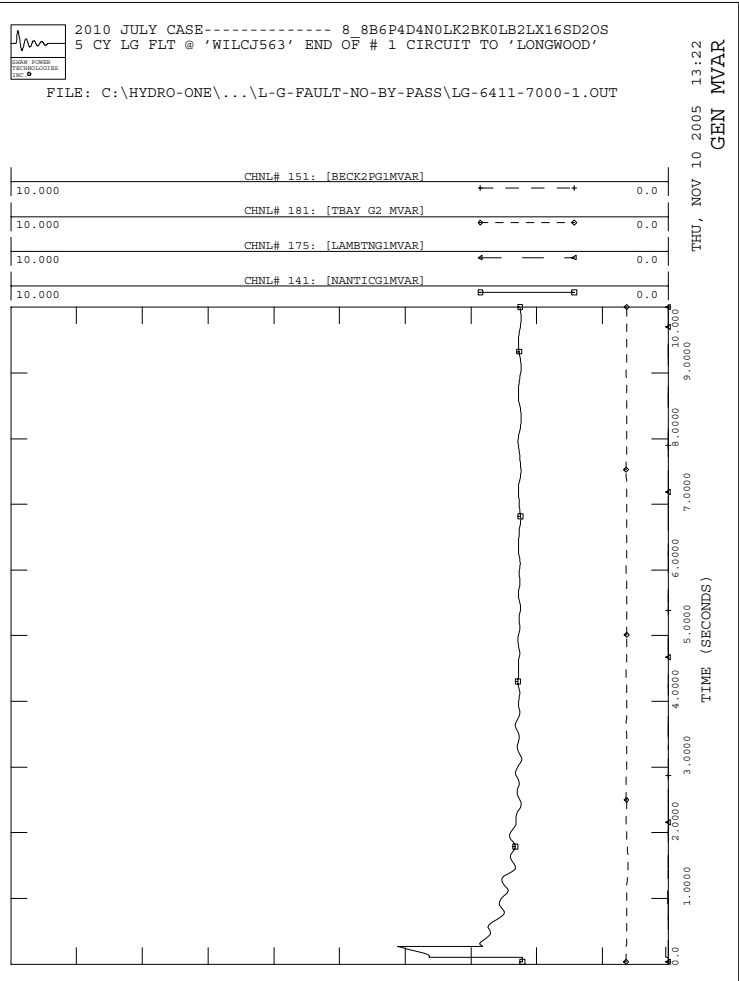
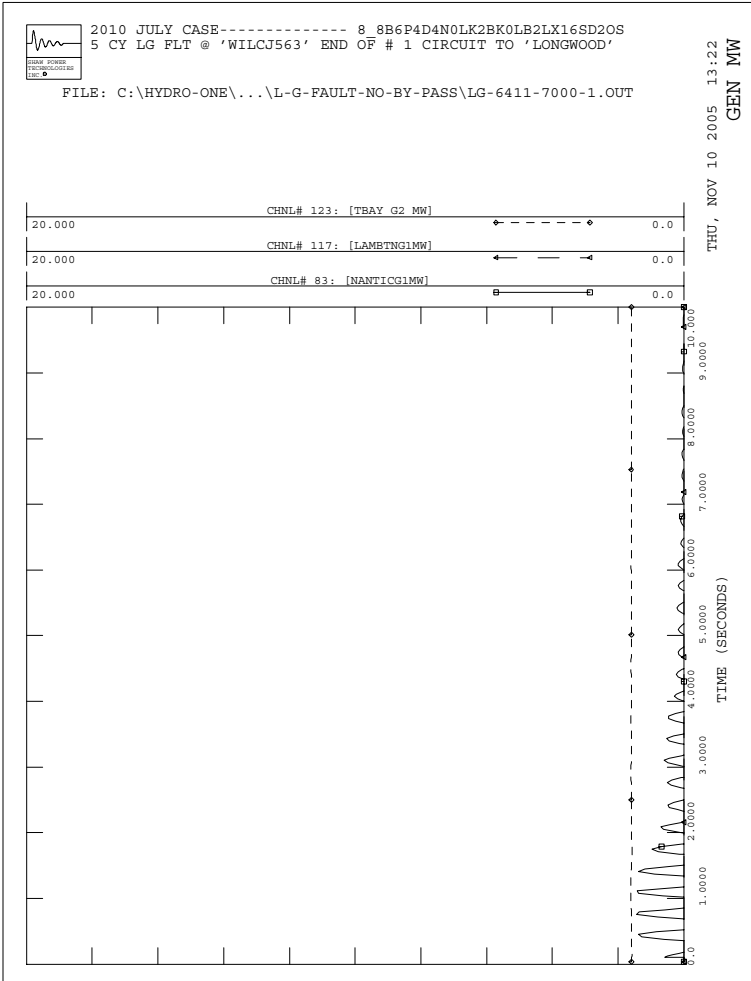
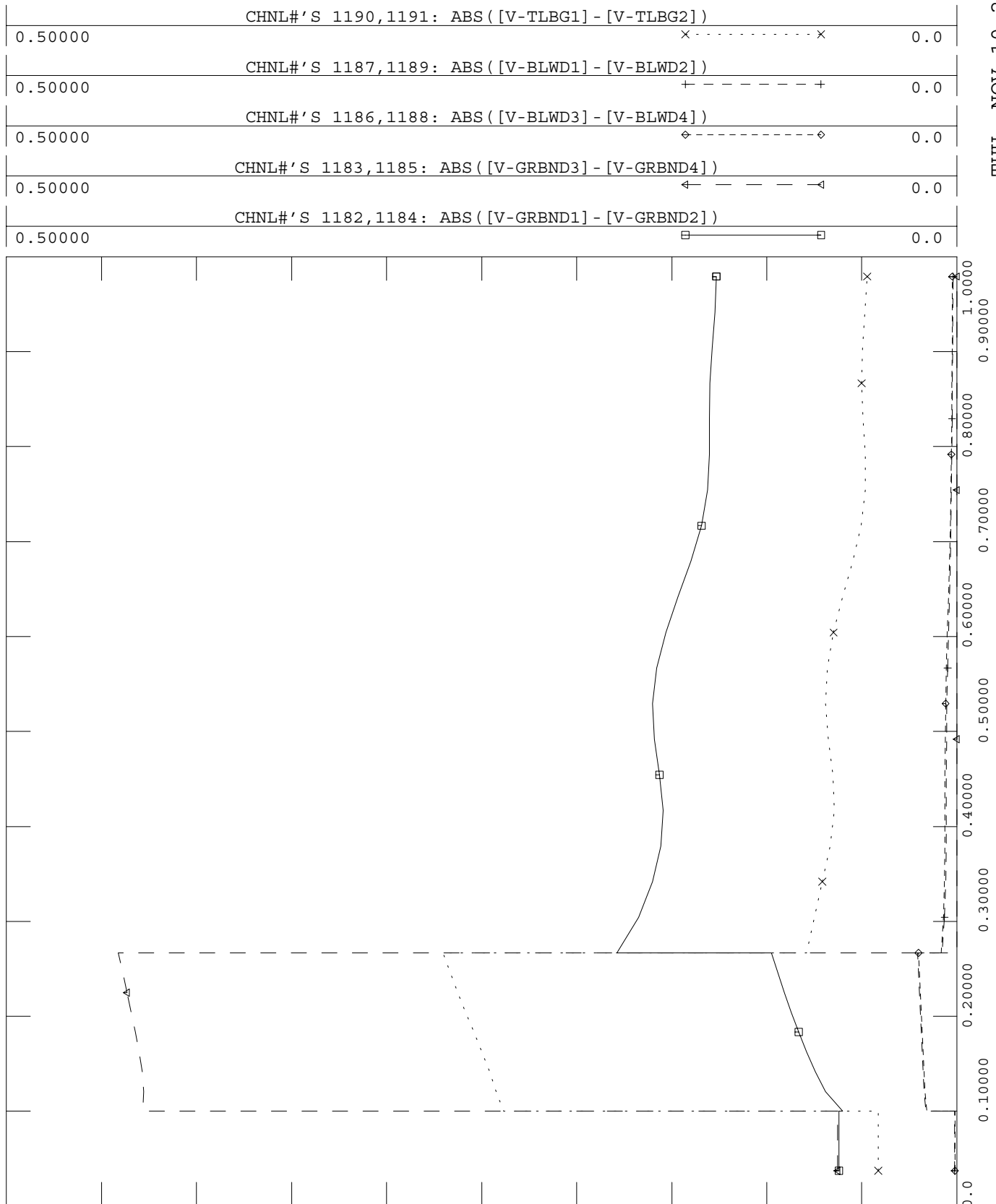


FIGURE G-42



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LG FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-NO-BY-PASS\LG-6411-7000-1.OUT



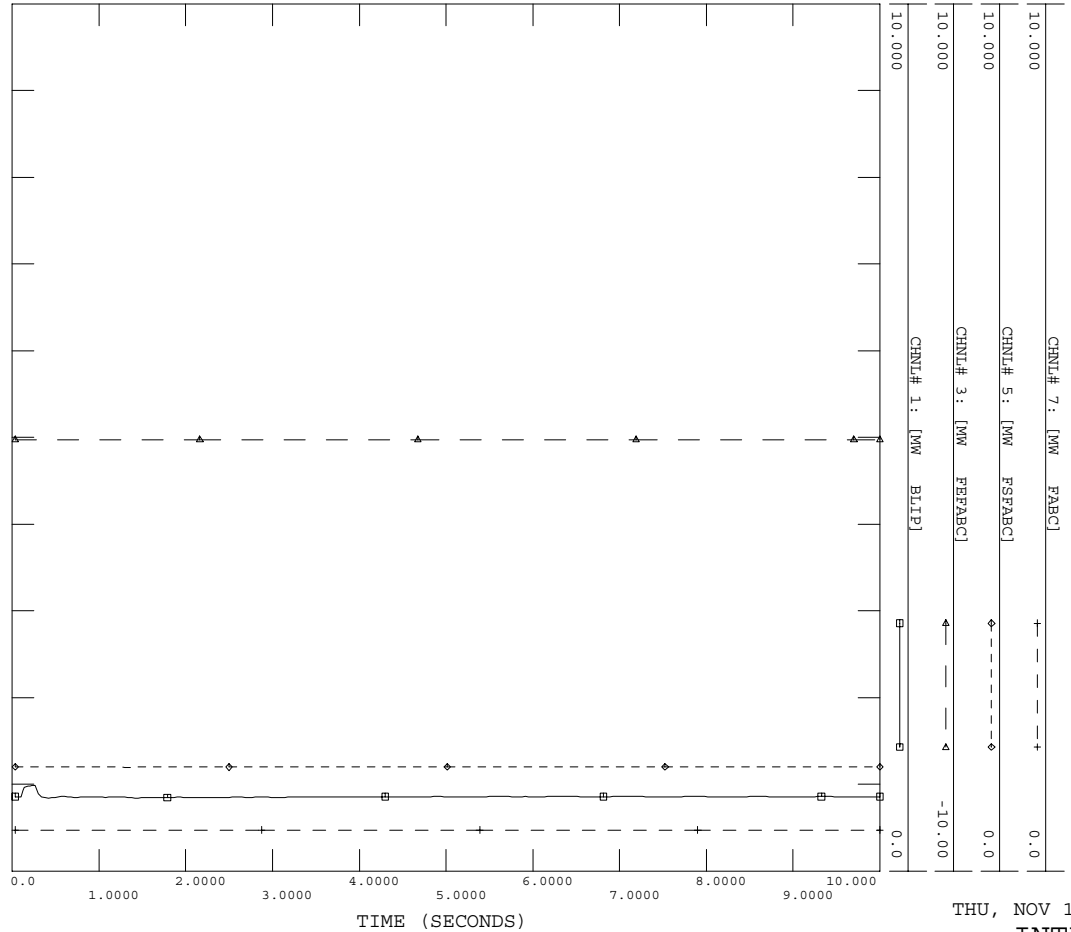
THU, NOV 10 2005 13:22
DV-ACROSS-S-CAPS

FIGURE G-43



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LG FLT @ 'WILCU563' END OF # 1 CIRCUIT TO 'LONGWOOD'
FILE: C:\HYDRO-ONE\...\L-G-FAULT-NO-BY-PASS\LG-6411-7000-1.OUT

THU, NOV 10 2005 13:23
INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LG FLT @ 'WILCU563' END OF # 1 CIRCUIT TO 'LONGWOOD'
FILE: C:\HYDRO-ONE\...\L-G-FAULT-NO-BY-PASS\LG-6411-7000-1.OUT

THU, NOV 10 2005 13:23
INTERFACE MVAR

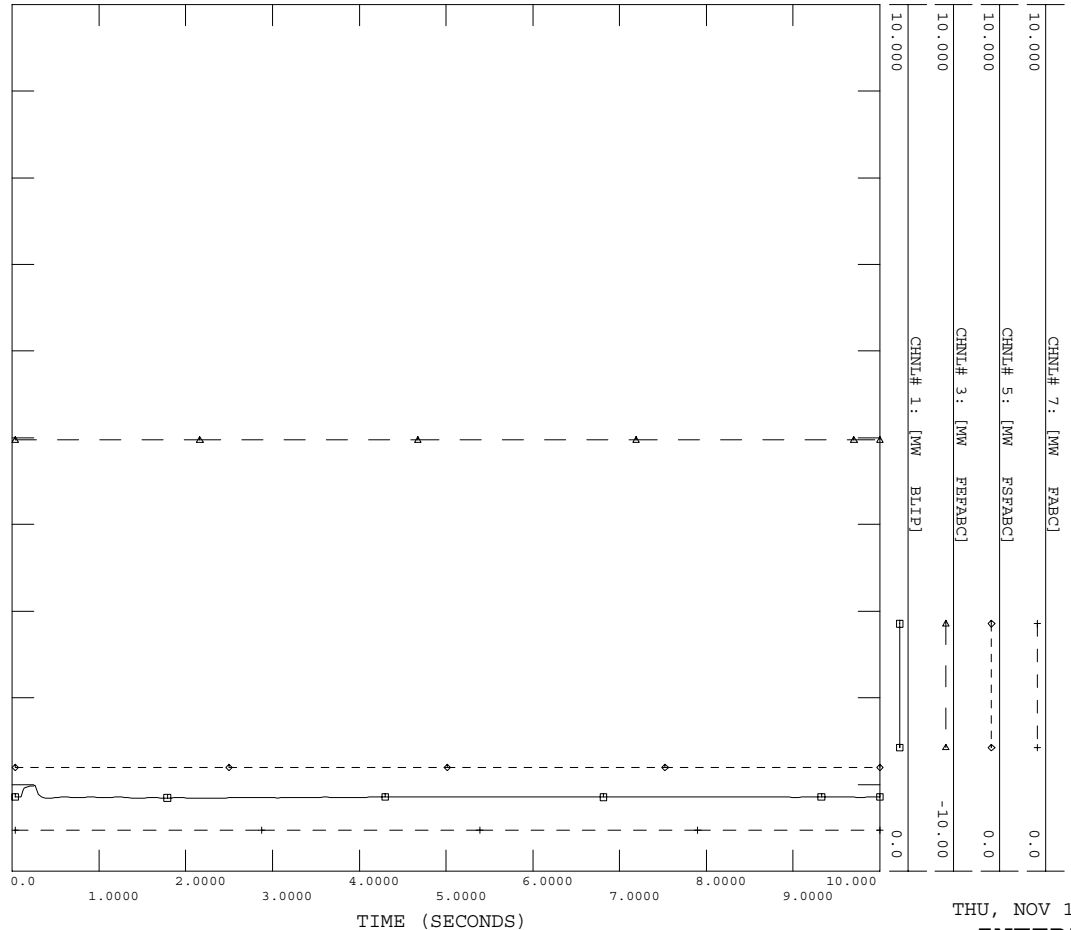


FIGURE G-44

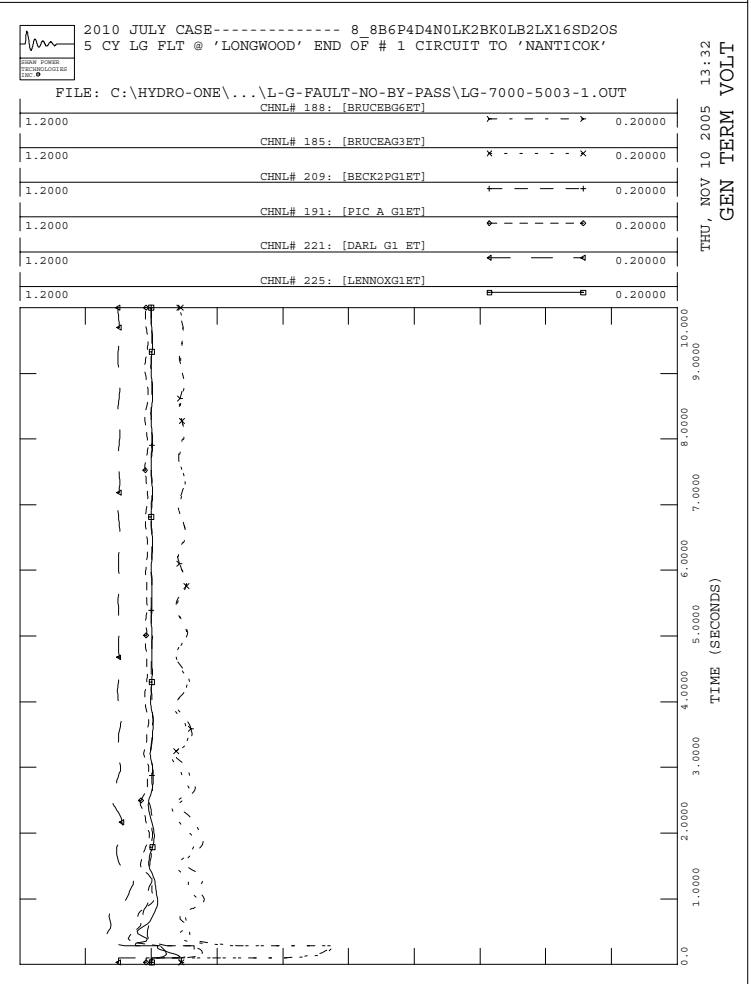
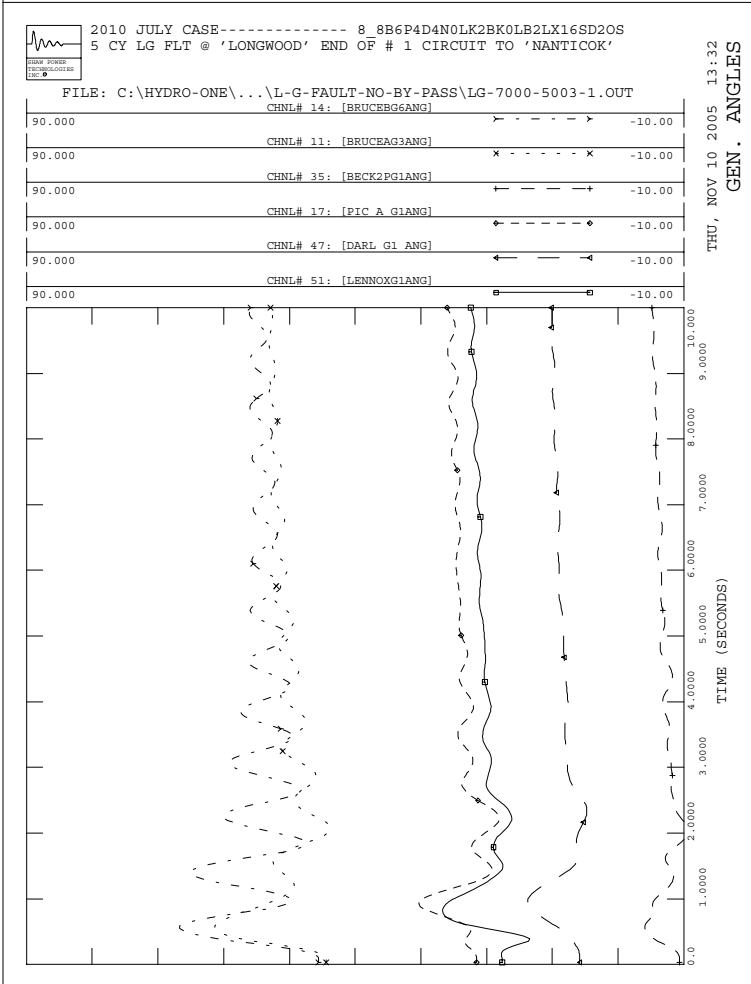
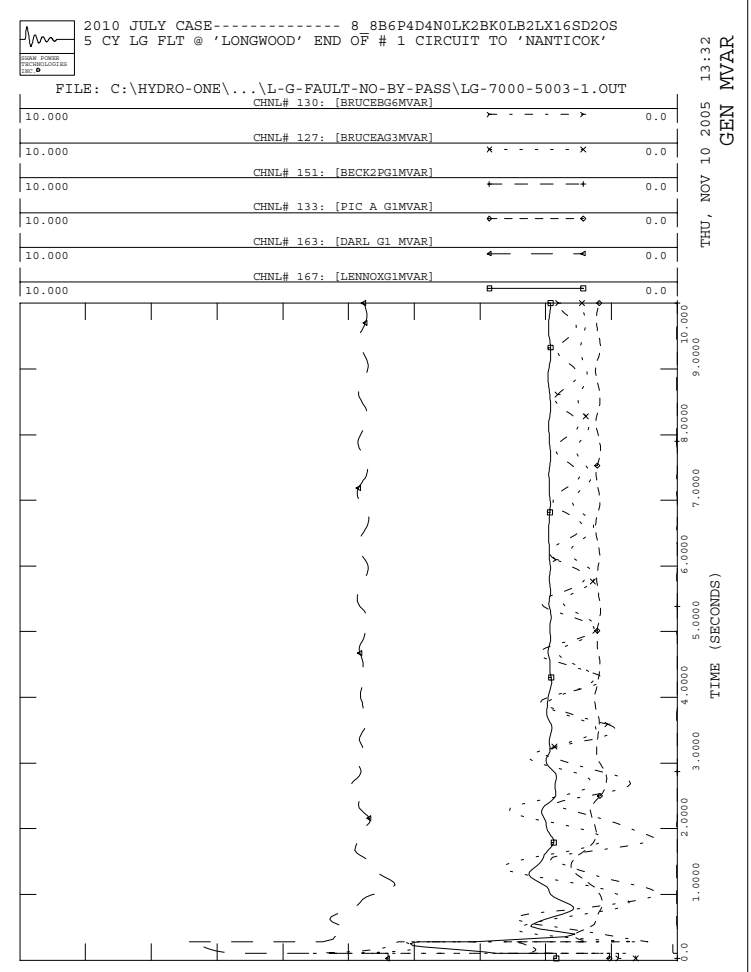
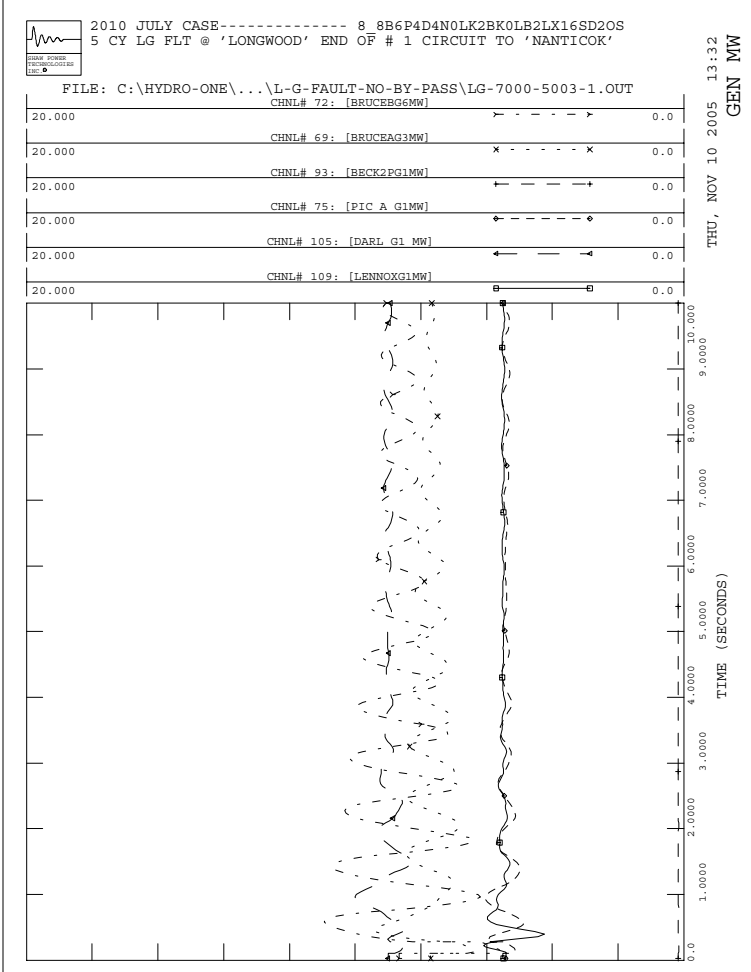


FIGURE G-45

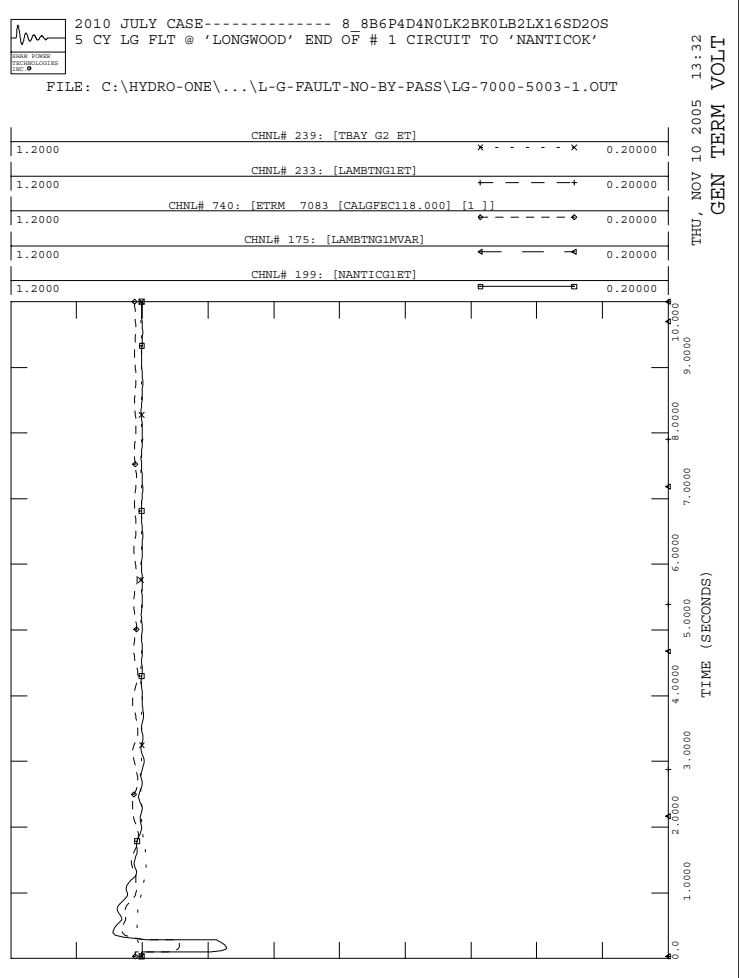
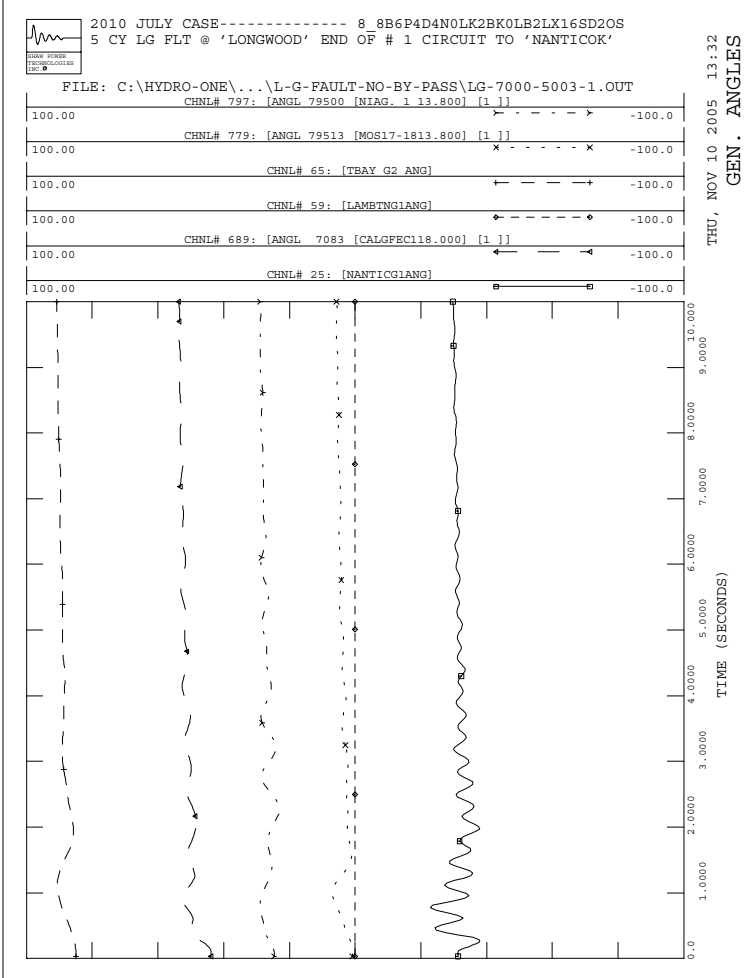
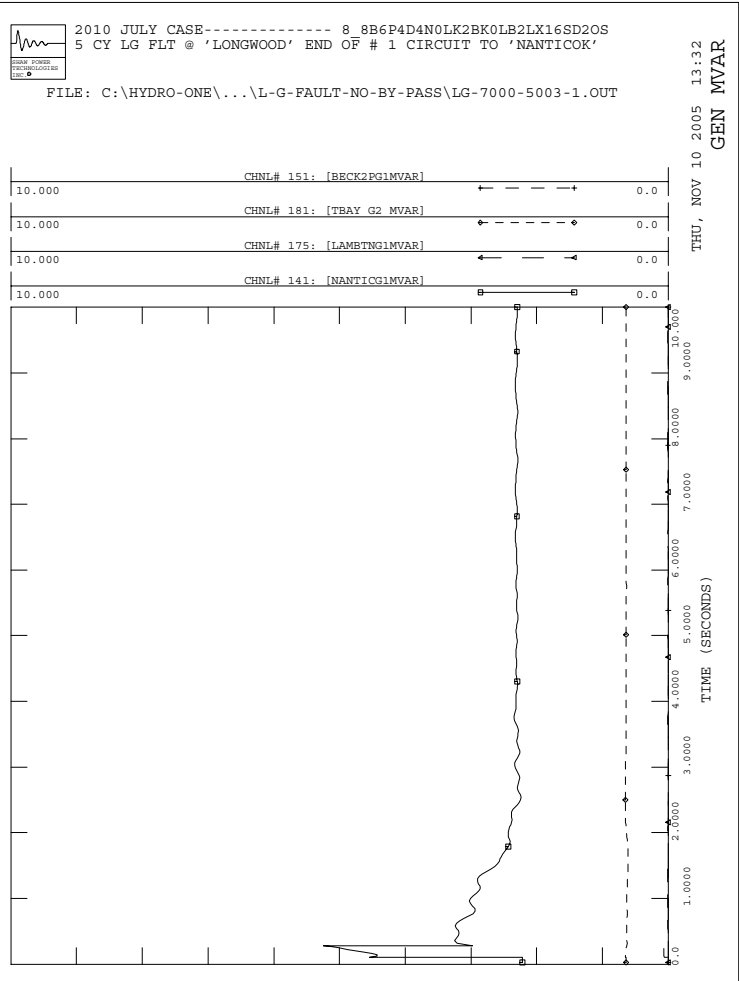
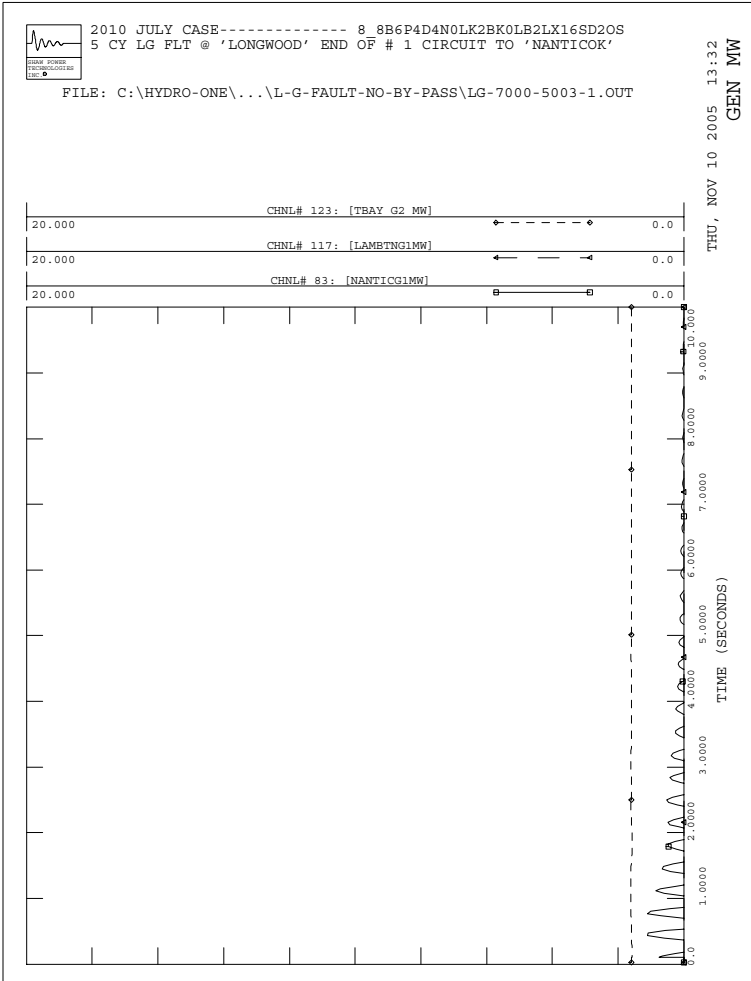
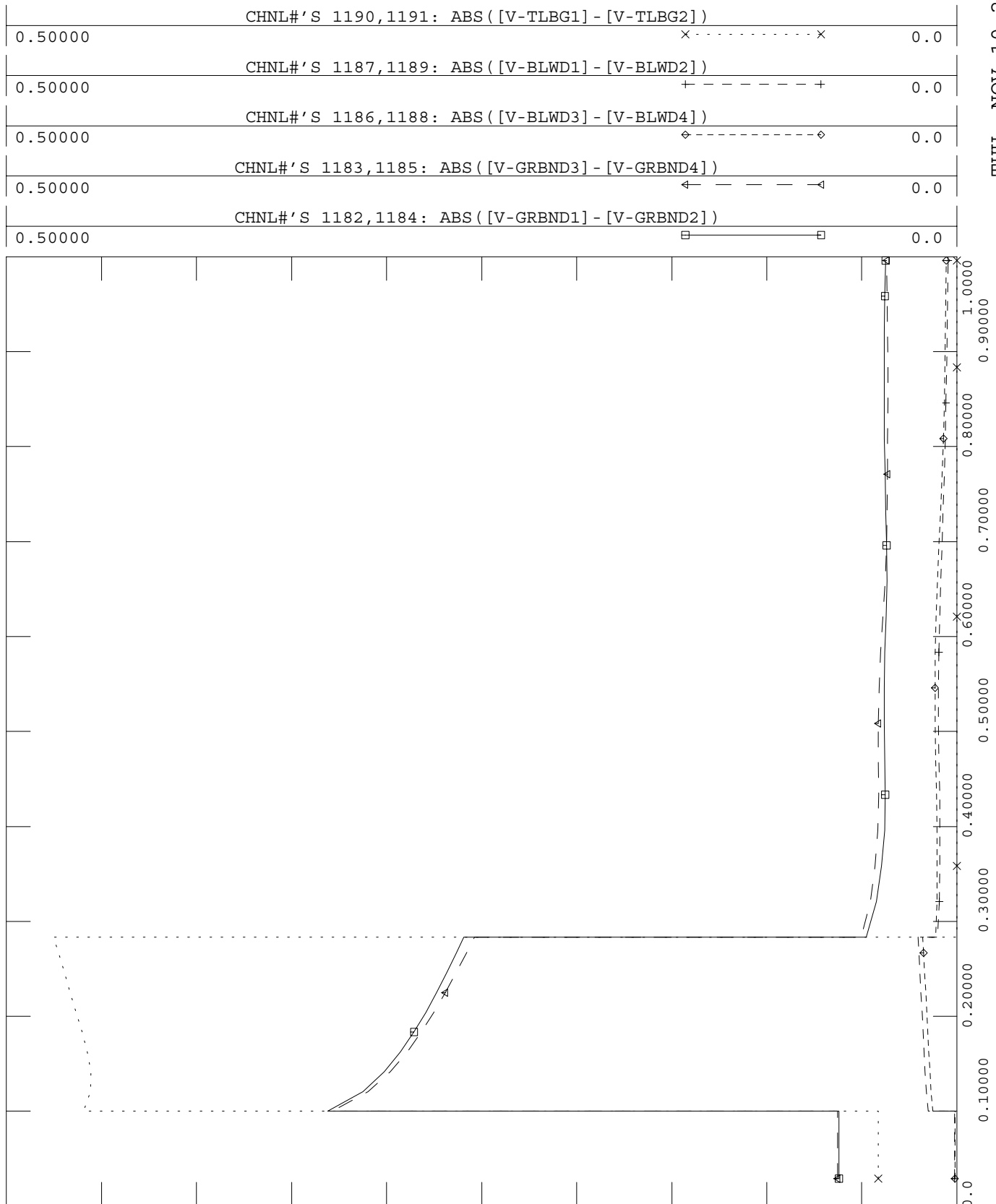


FIGURE G-46



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LG FLT @ 'LONGWOOD' END OF # 1 CIRCUIT TO 'NANTICOK'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-NO-BY-PASS\LG-7000-5003-1.OUT



THU, NOV 10 2005 13:32
DV-ACROSS-S-CAPS

FIGURE G-47



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LG FLT @ 'LONGWOOD' END OF # 1 CIRCUIT TO 'NANTICOK'
FILE: C:\HYDRO-ONE\...\L-G-FAULT-NO-BY-PASS\LG-7000-5003-1.OUT



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LG FLT @ 'LONGWOOD' END OF # 1 CIRCUIT TO 'NANTICOK'
FILE: C:\HYDRO-ONE\...\L-G-FAULT-NO-BY-PASS\LG-7000-5003-1.OUT

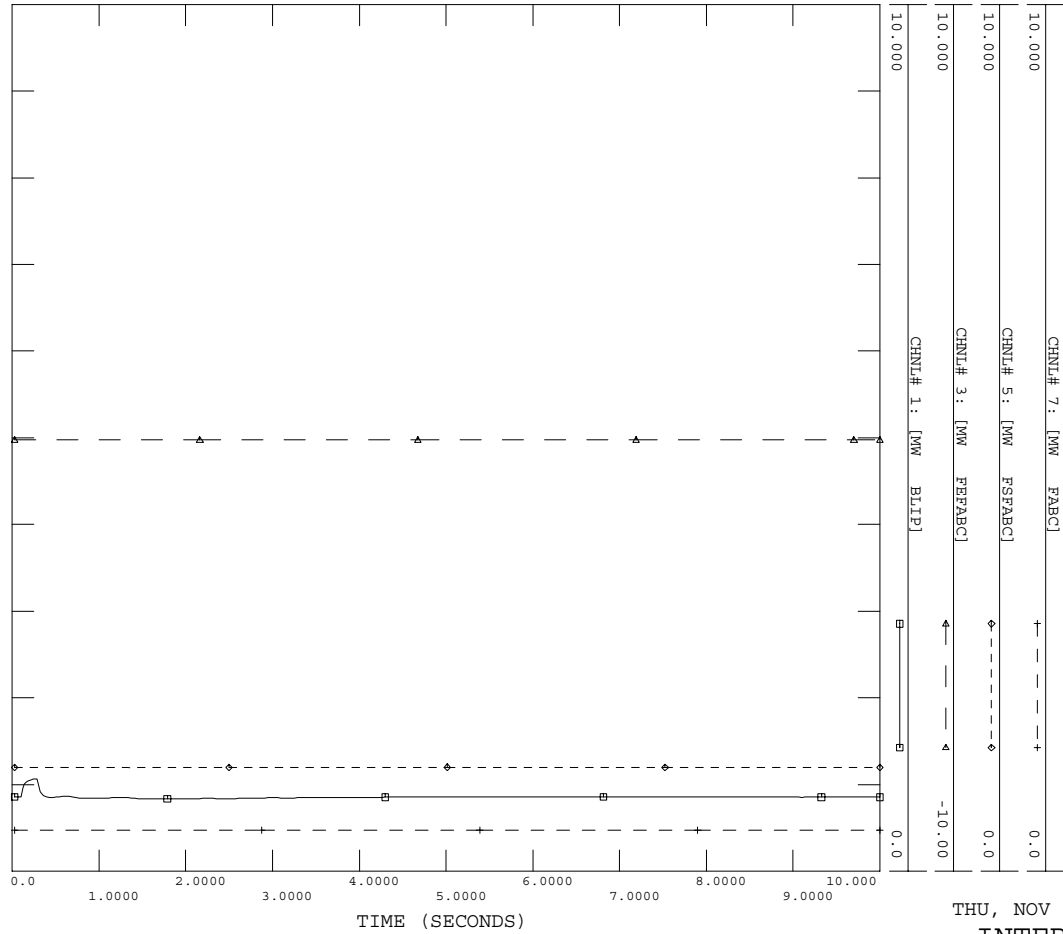
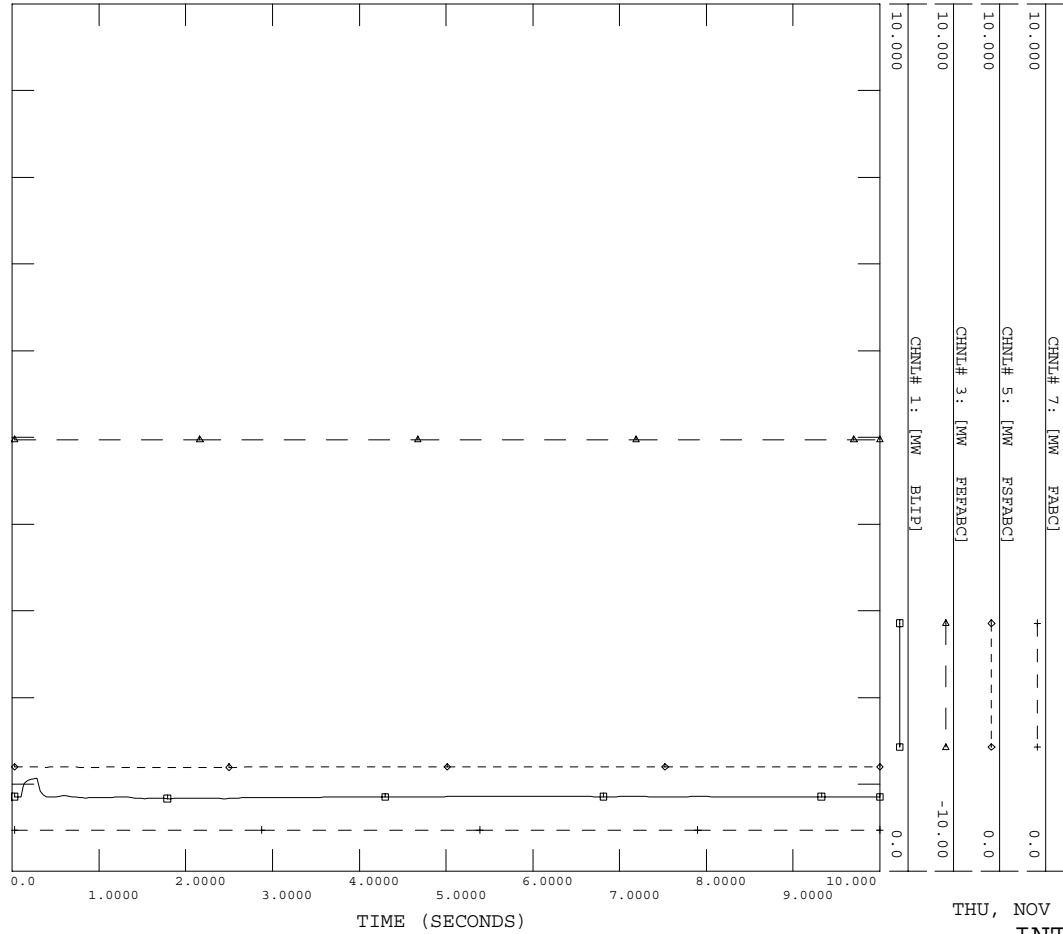


FIGURE G-48

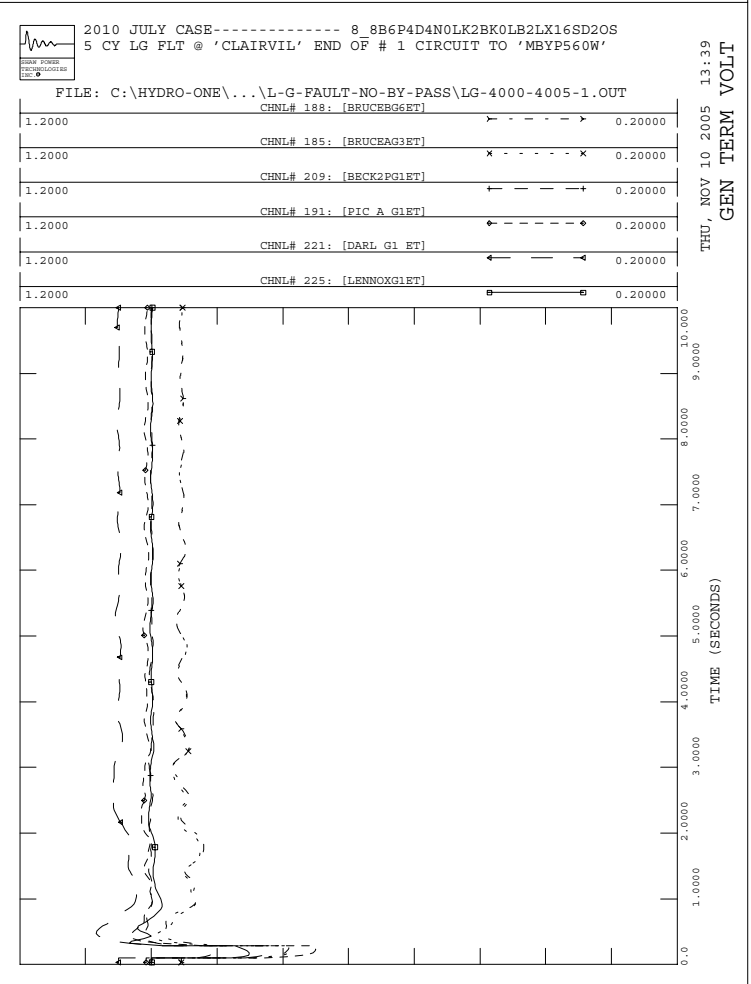
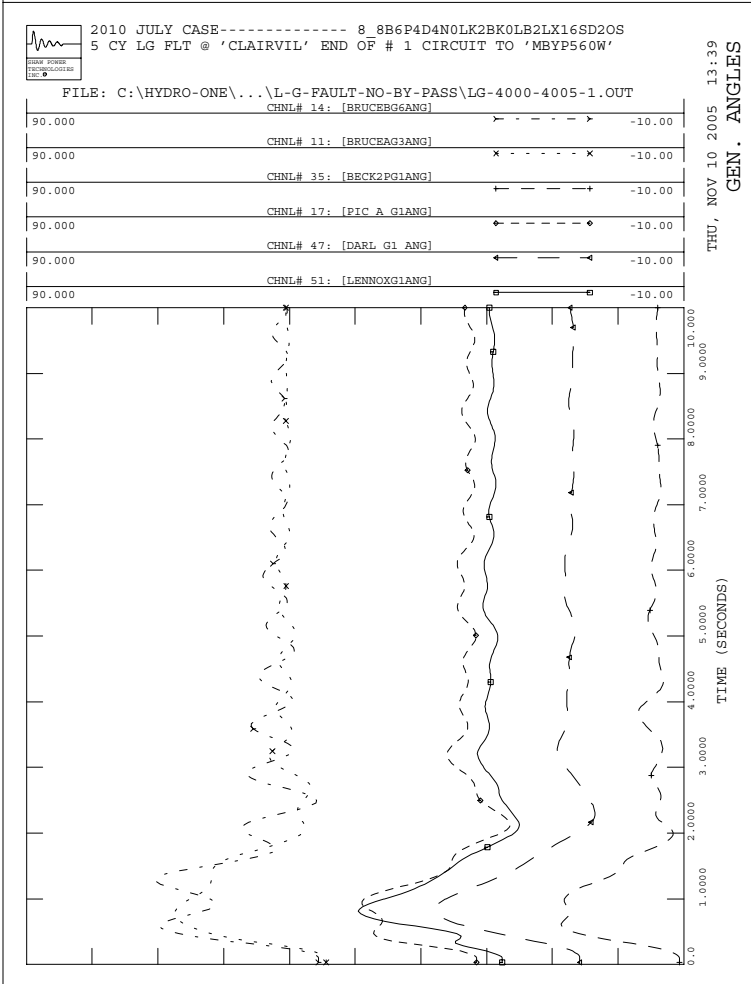
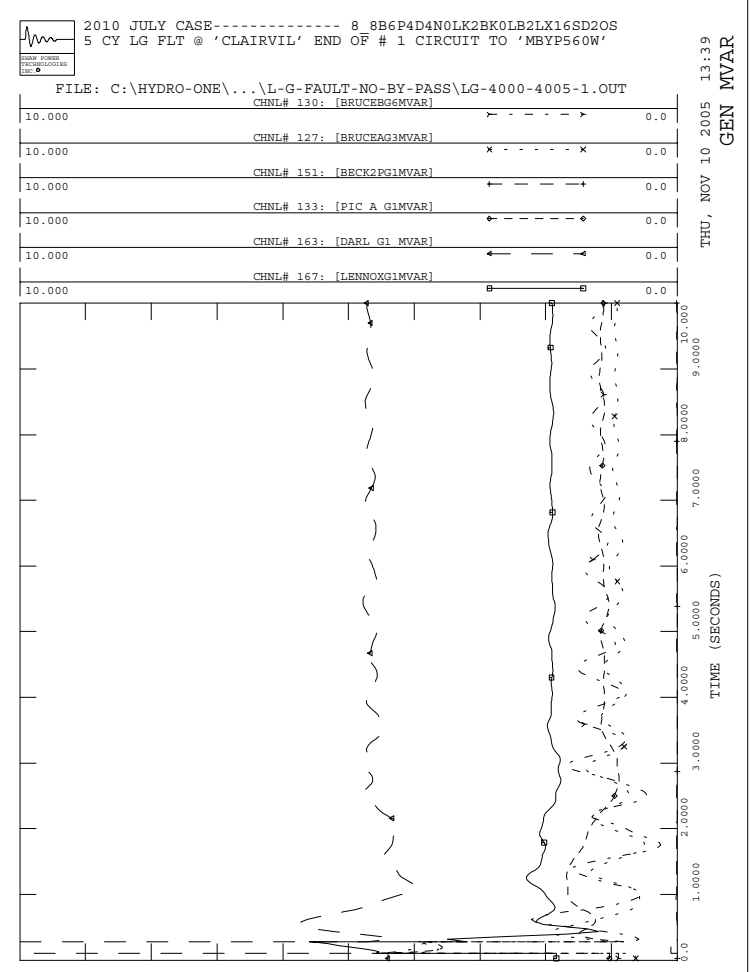
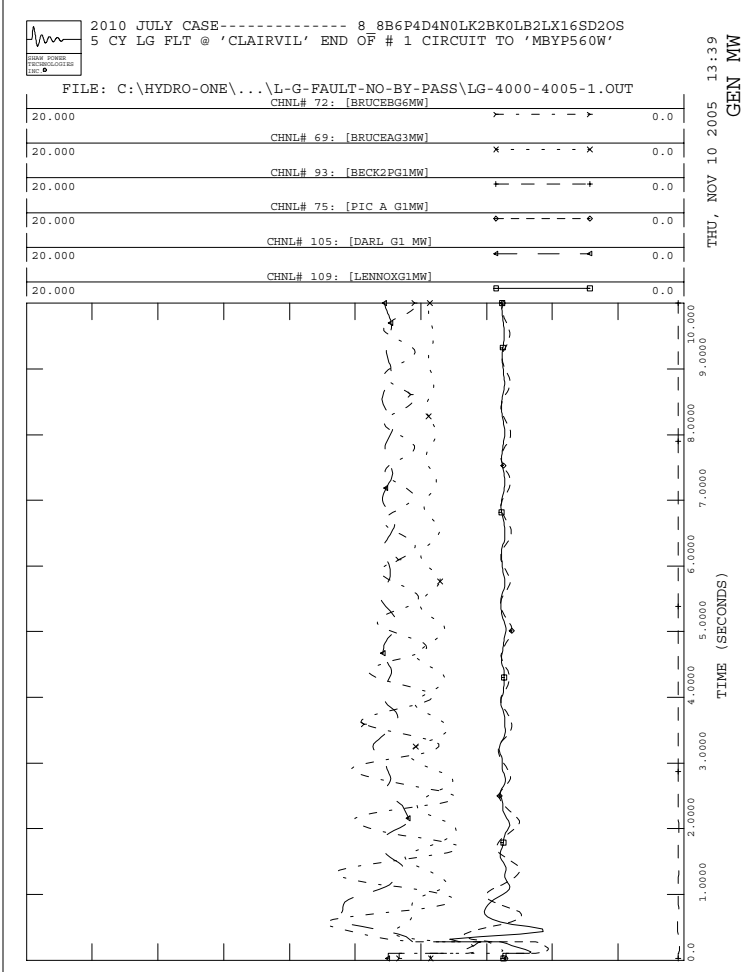


FIGURE G-49

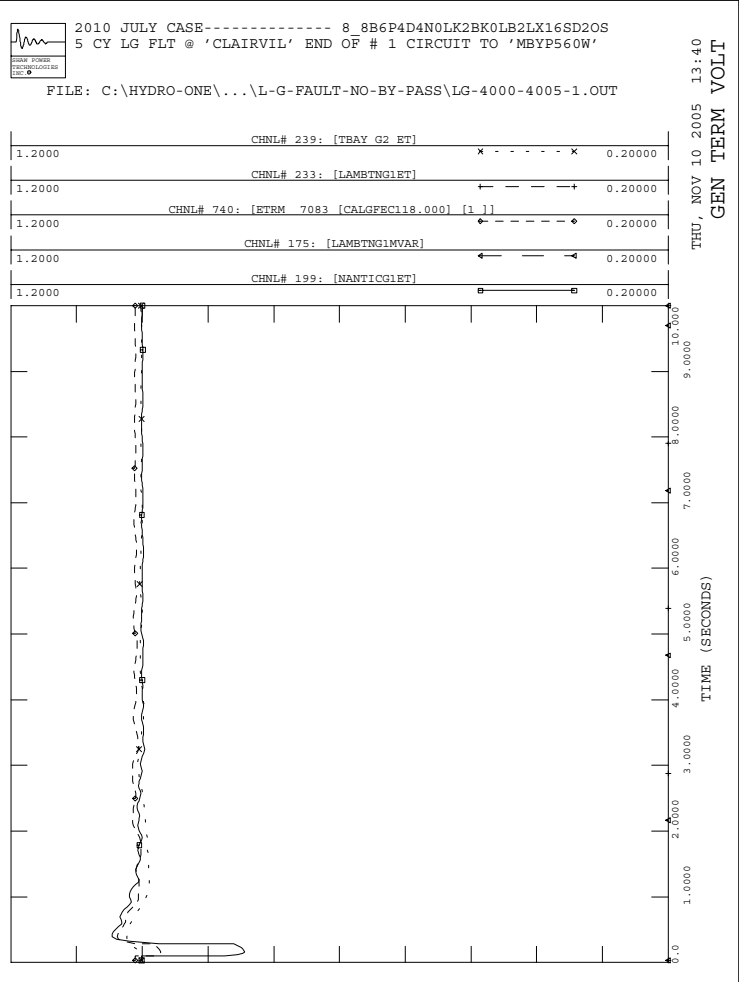
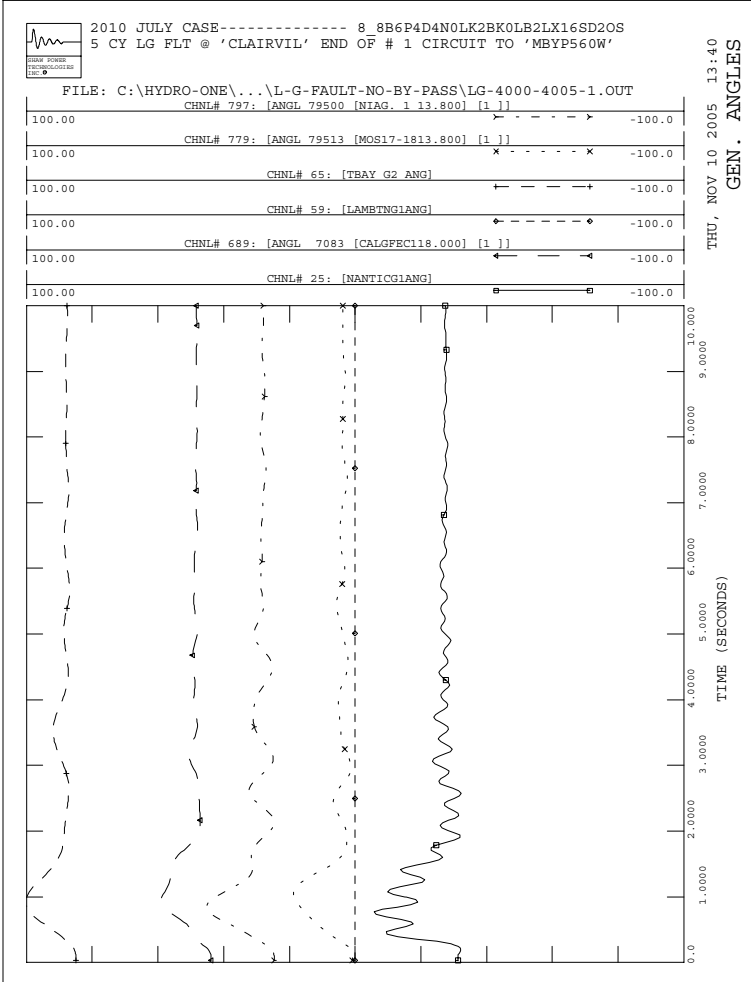
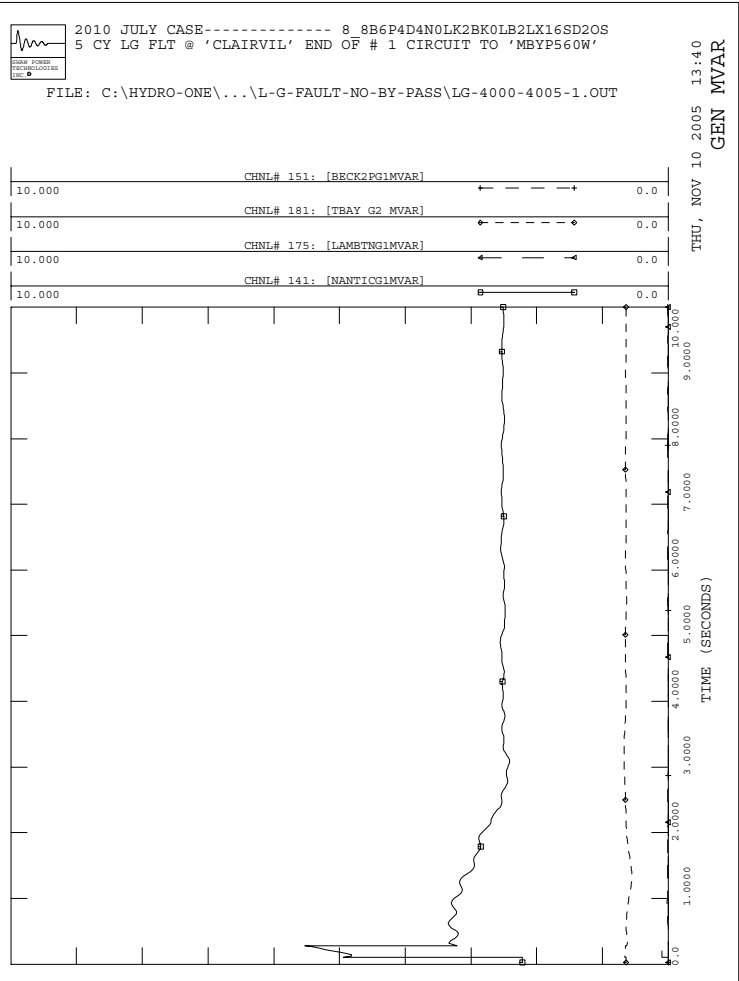
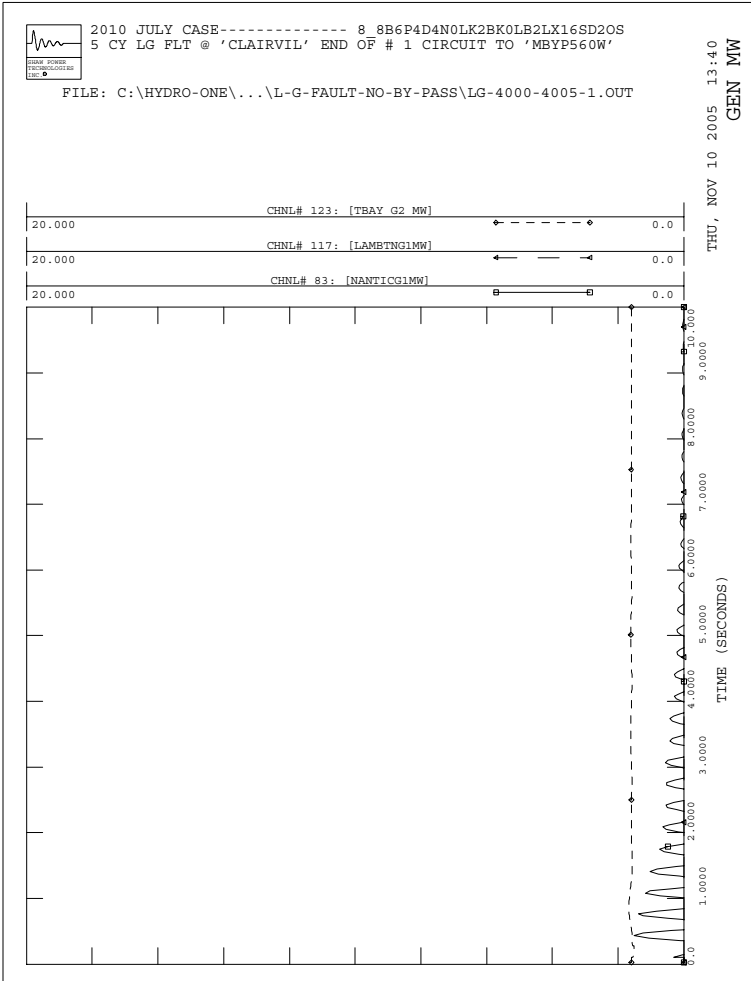
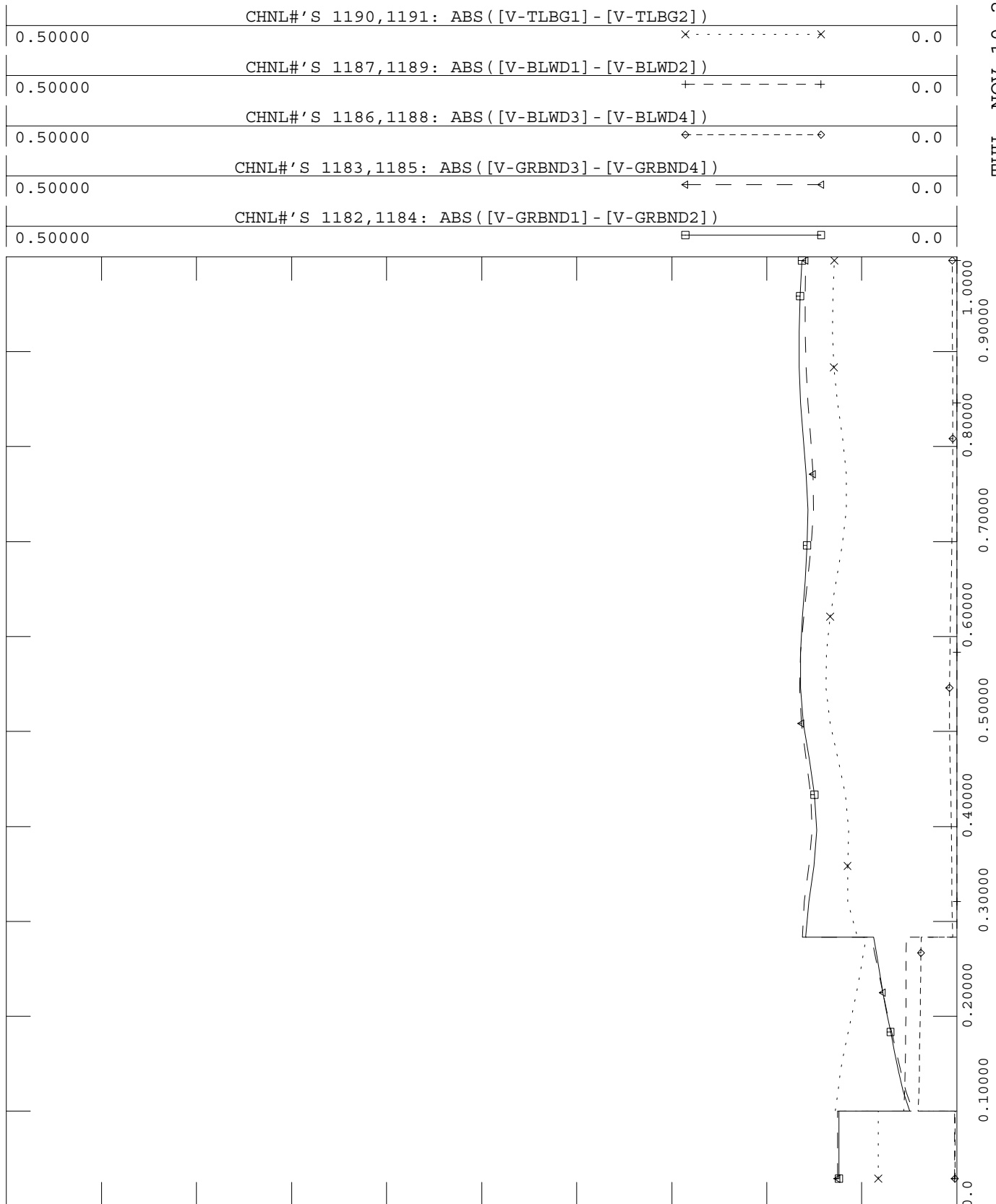


FIGURE G-50



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LG FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-NO-BY-PASS\LG-4000-4005-1.OUT



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DV-ACROSS-S-CAPS

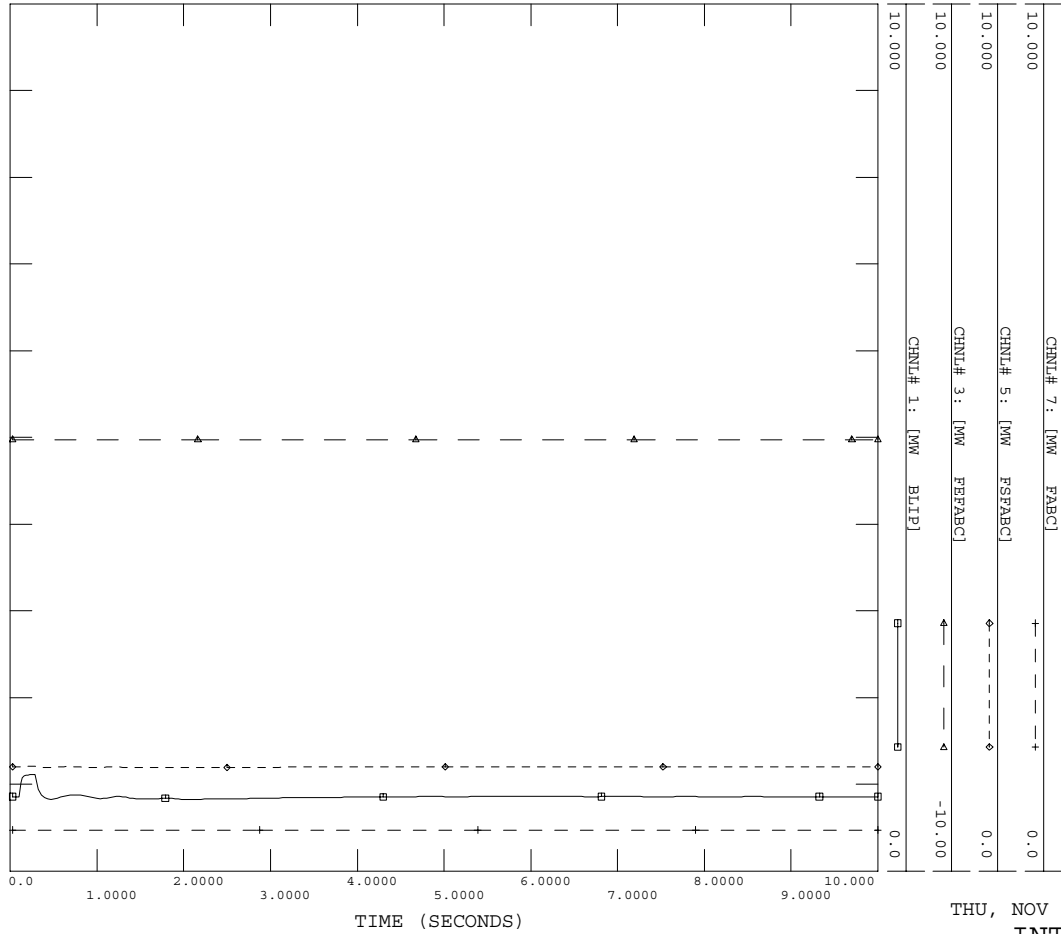
FIGURE G-51



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LG FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'
FILE: C:\HYDRO-ONE\...\L-G-FAULT-NO-BY-PASS\LG-4000-4005-1.OUT

THU, NOV 10 2005 13:40

INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LG FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'
FILE: C:\HYDRO-ONE\...\L-G-FAULT-NO-BY-PASS\LG-4000-4005-1.OUT

THU, NOV 10 2005 13:40

INTERFACE MVAR

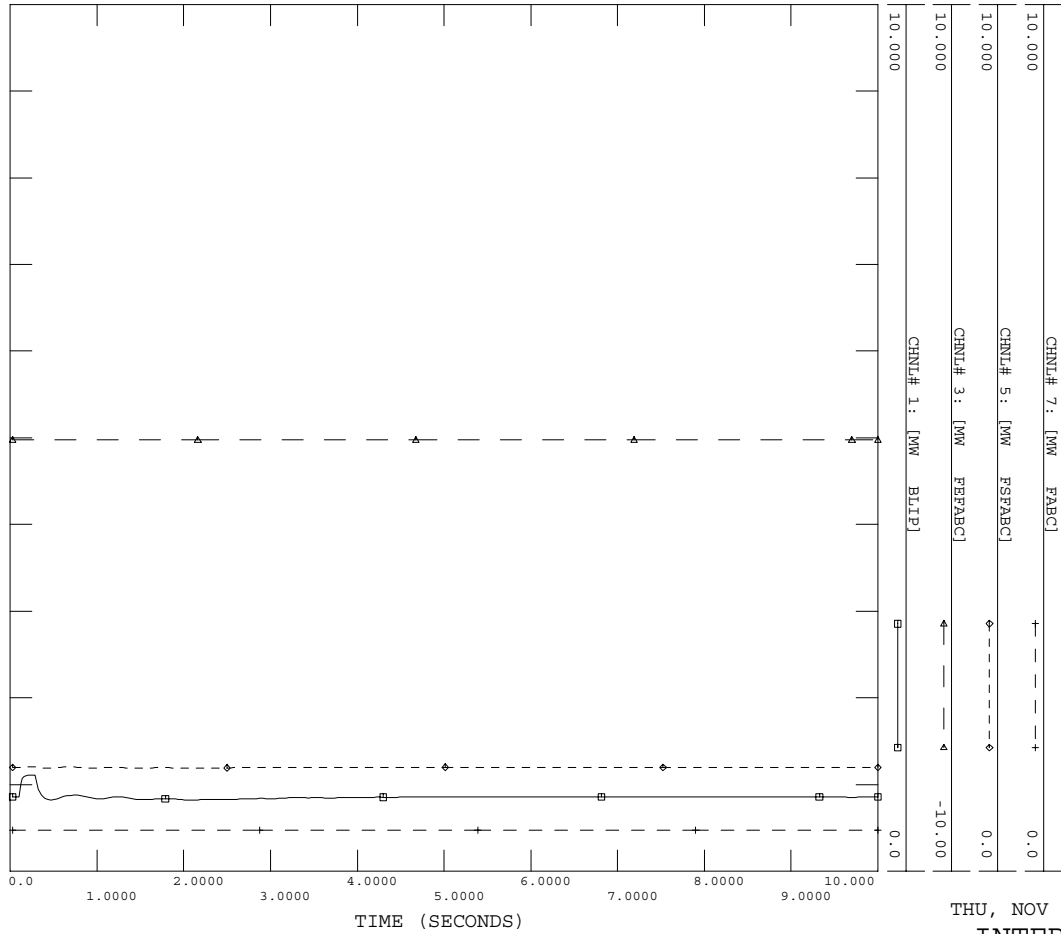


FIGURE G-52

**L-G (L-L-G) FAULTS, on Different Phases of the
Bruce-Milton D/C tower CLEARED in 10 cycles,
BYPASS of SERIES CAPACITORS**

Plots for the following disturbance are shown in the following order in this Appendix:

- i. Bruce – Milton 500kV D/C (L-L-G fault at bus# 6408 and 6409)

Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G53&G54

Voltage Drop across the 5 series capacitors – Figure G55

Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G56

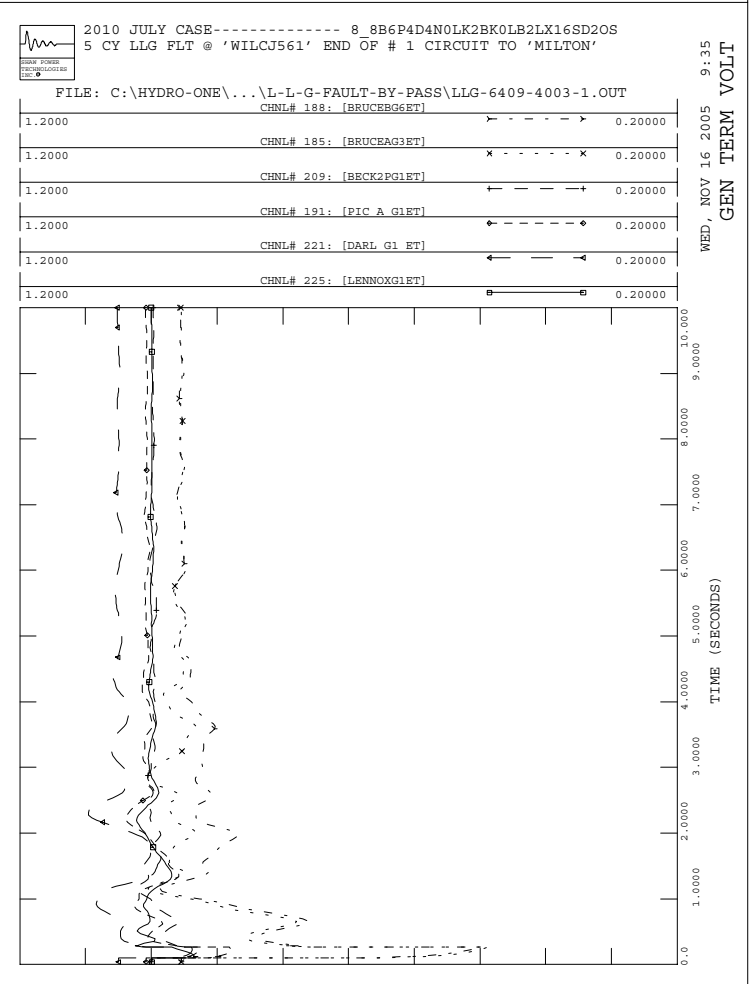
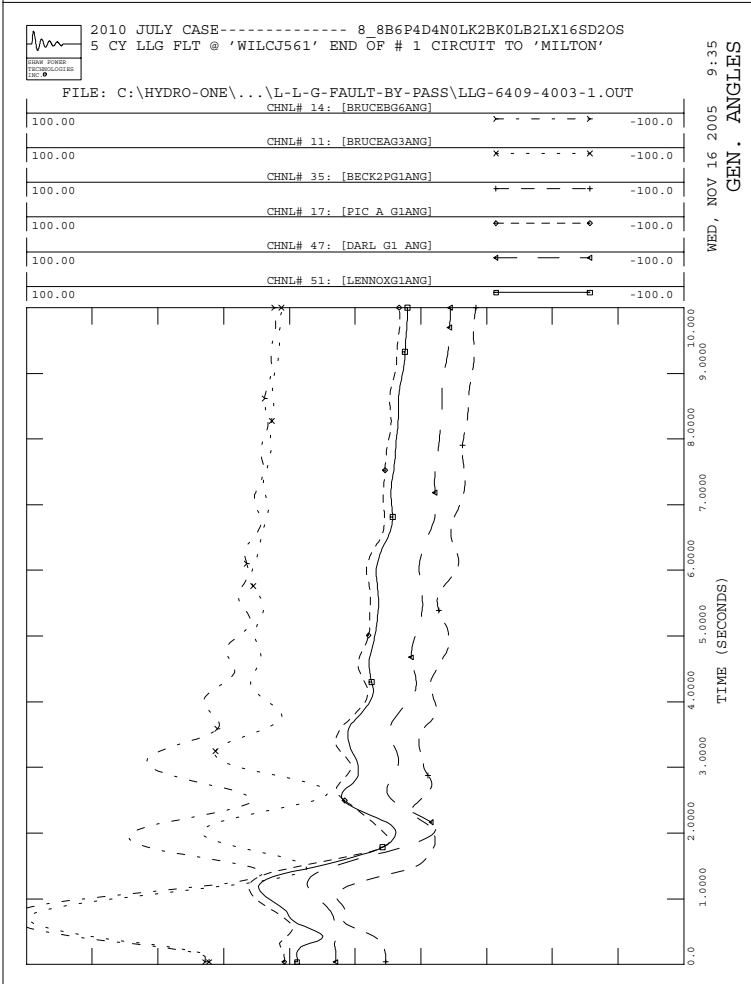
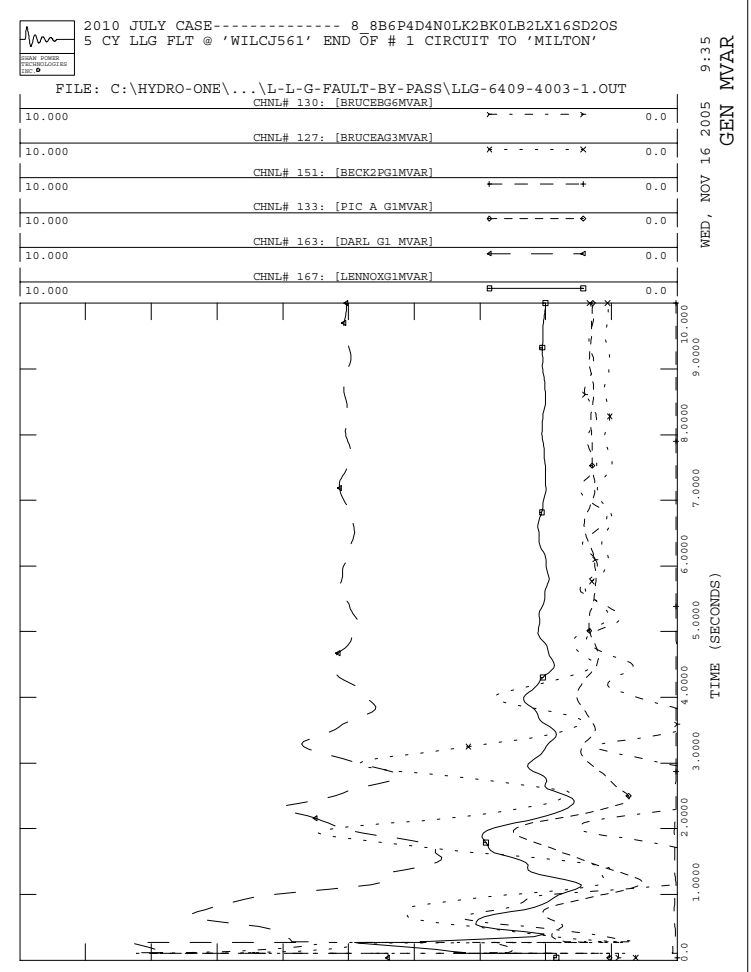
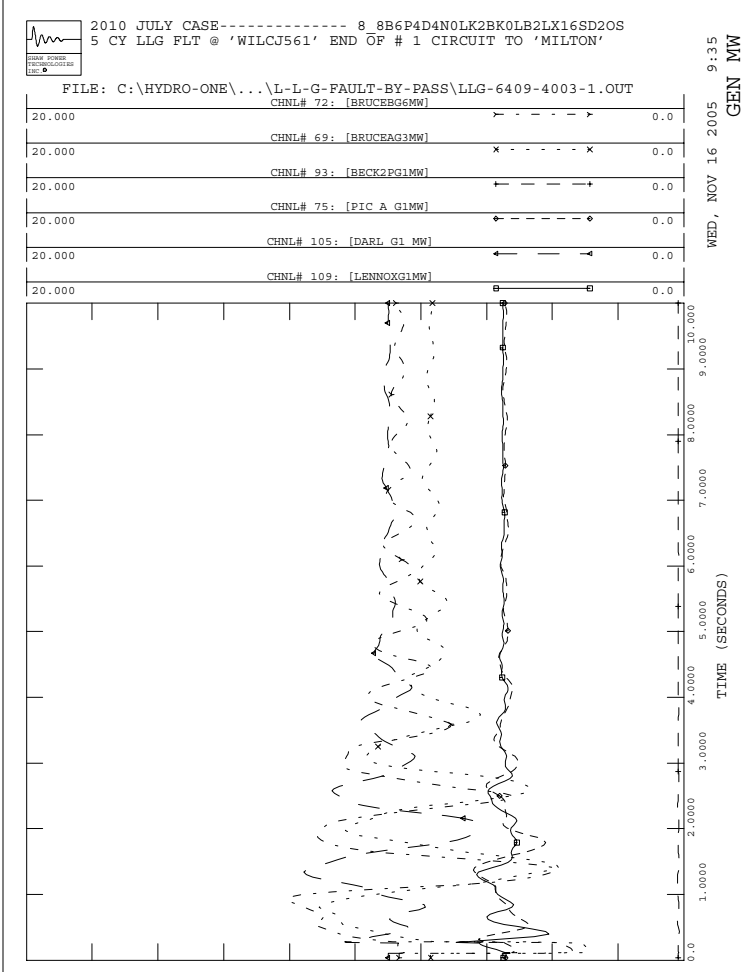


FIGURE G-53

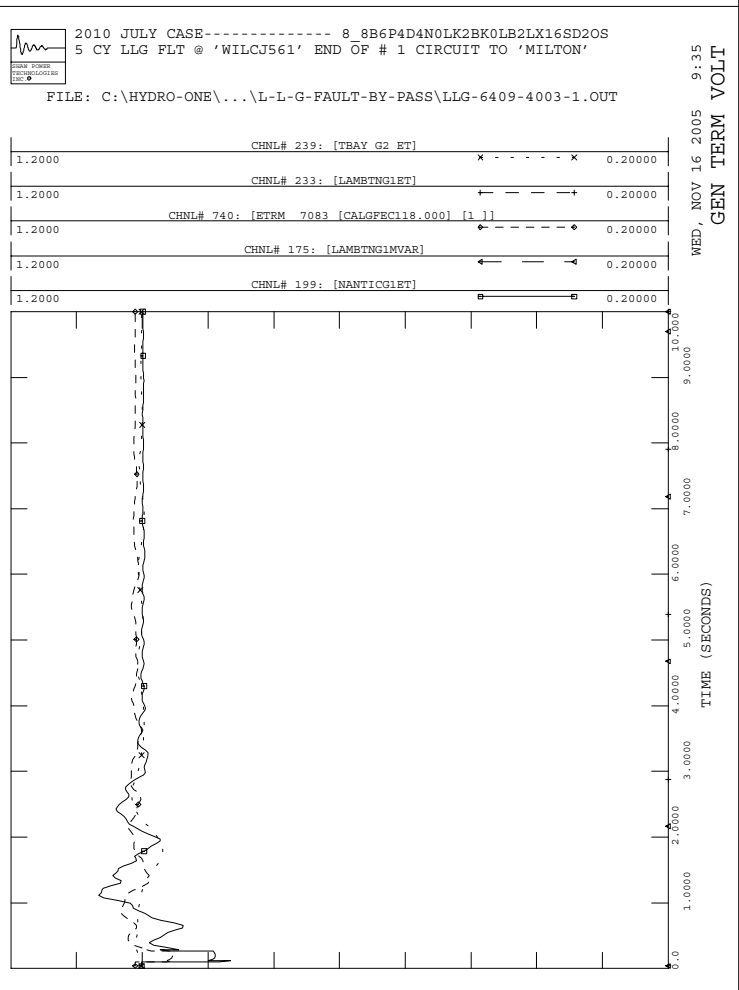
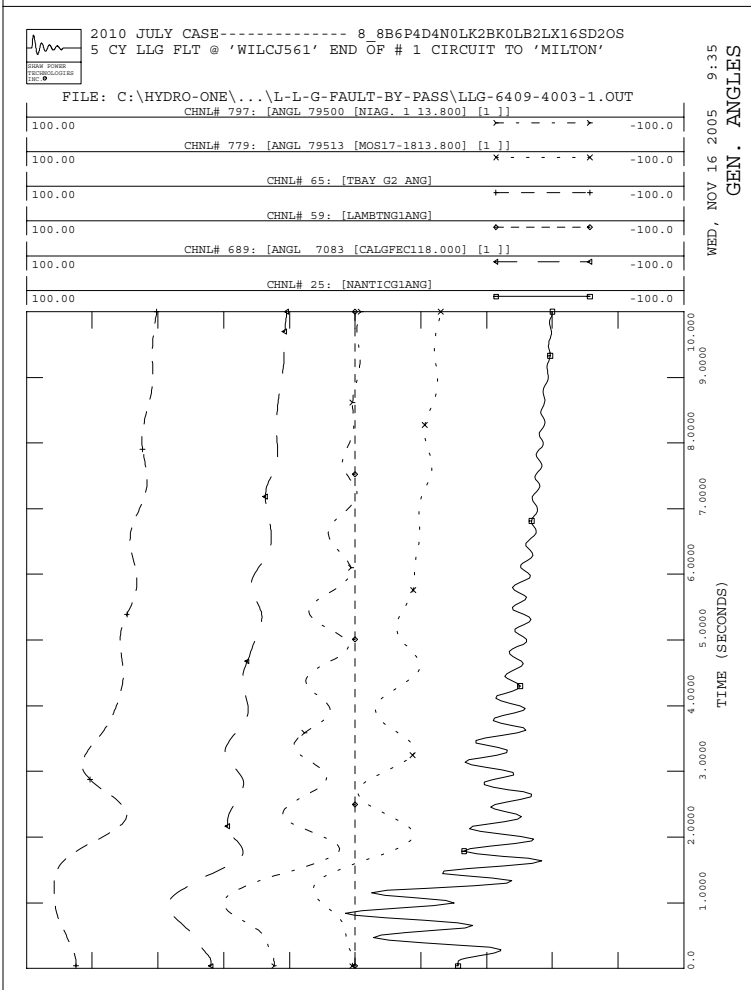
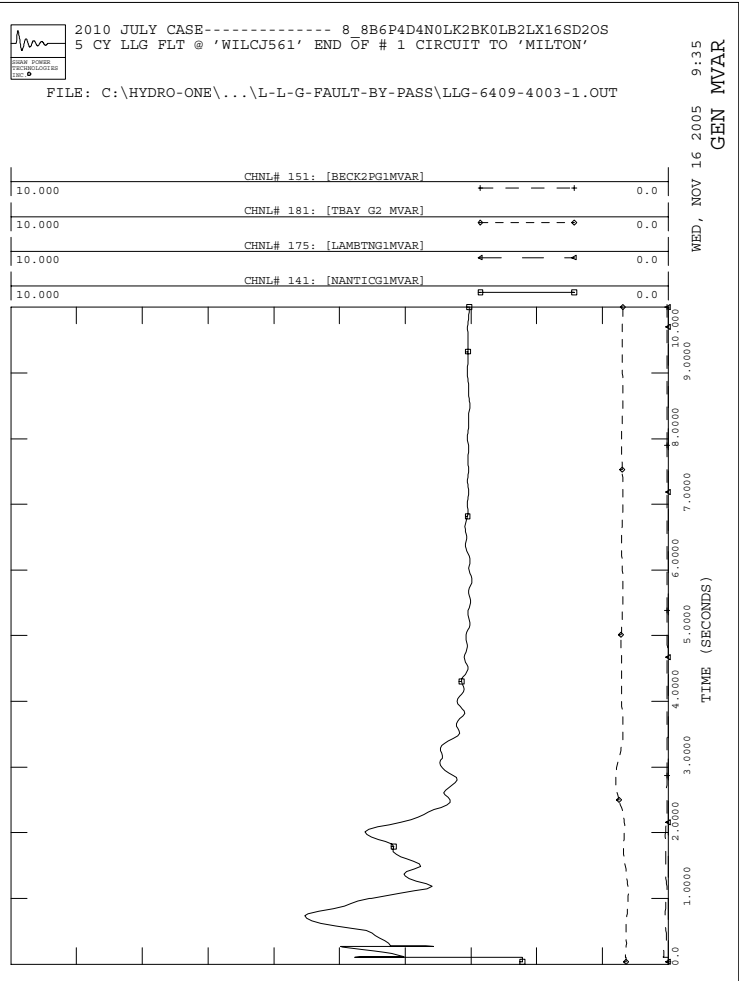
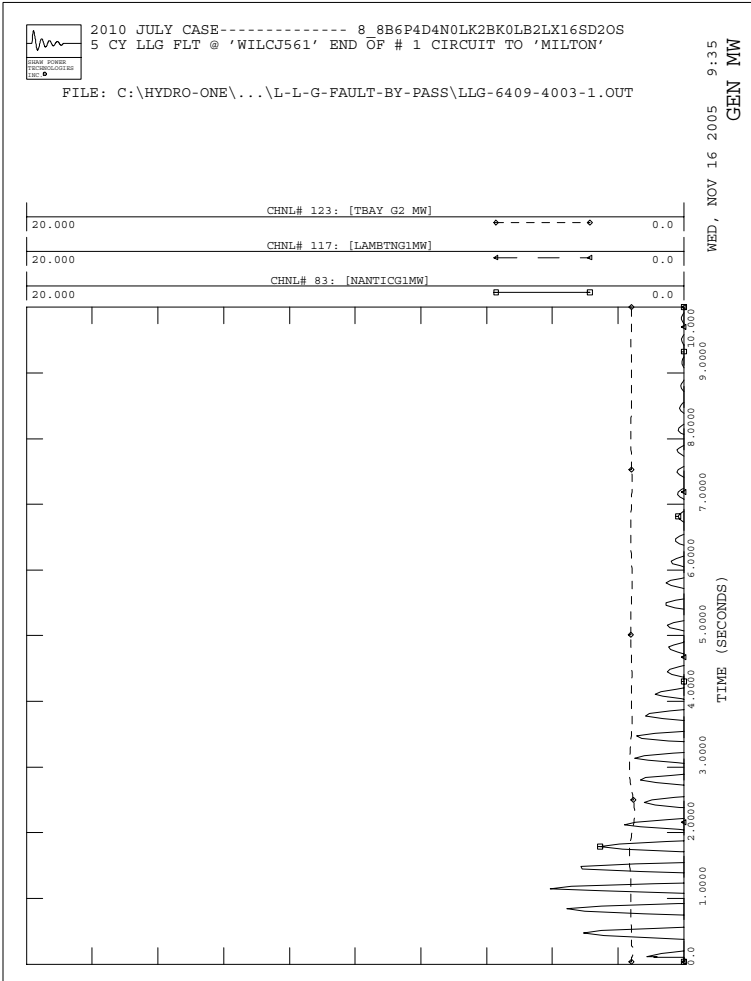
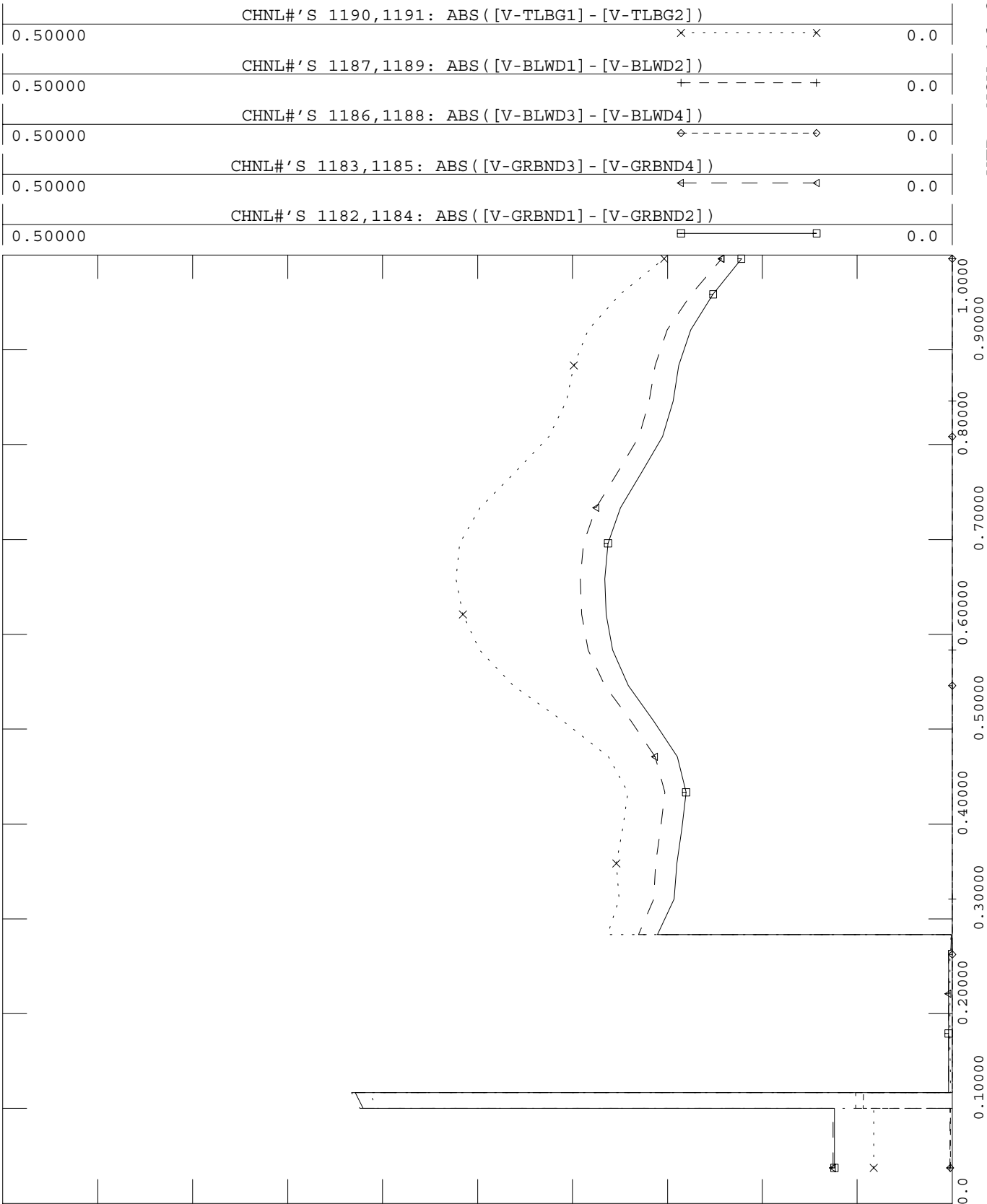


FIGURE G-54



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-L-G-FAULT-BY-PASS\LLG-6409-4003-1.OUT



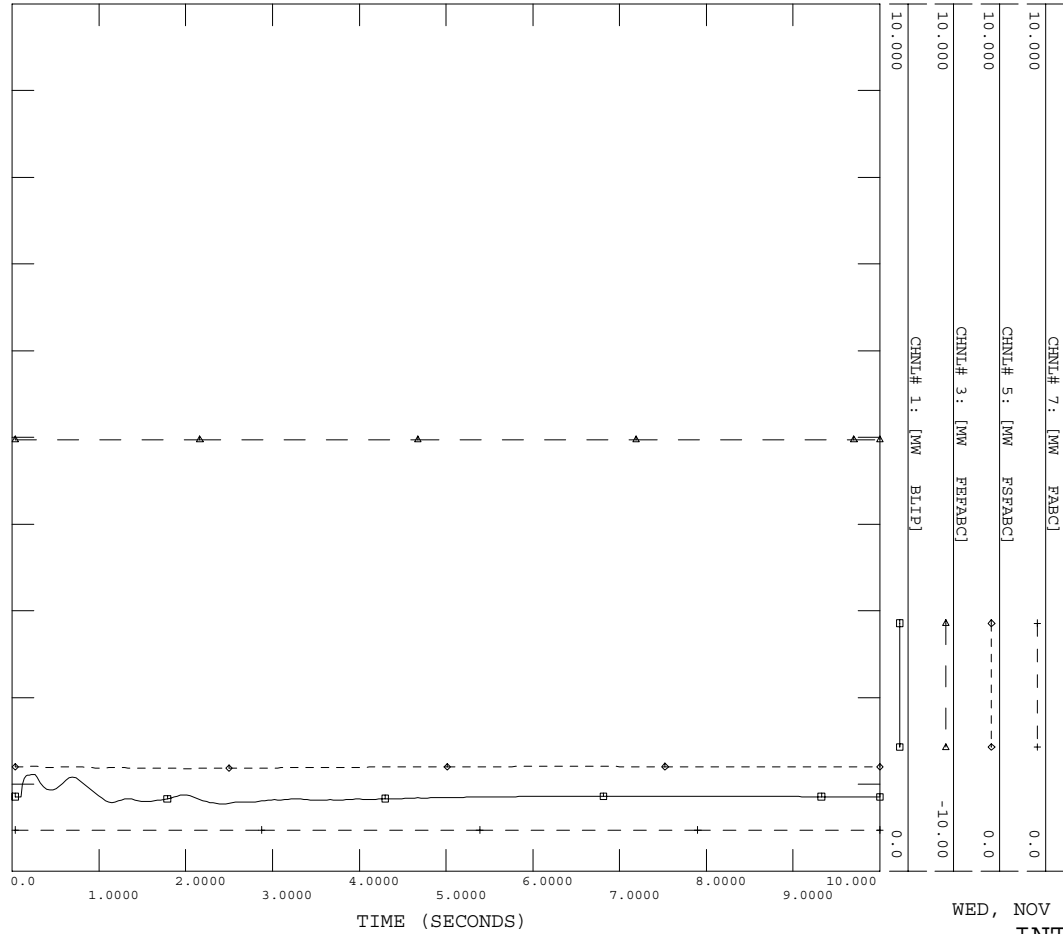
WED, NOV 16 2005 9:36
DV-ACROSS-S-CAPS

FIGURE G-55



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-L-G-FAULT-BY-PASS\LLG-6409-4003-1.OUT



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-L-G-FAULT-BY-PASS\LLG-6409-4003-1.OUT

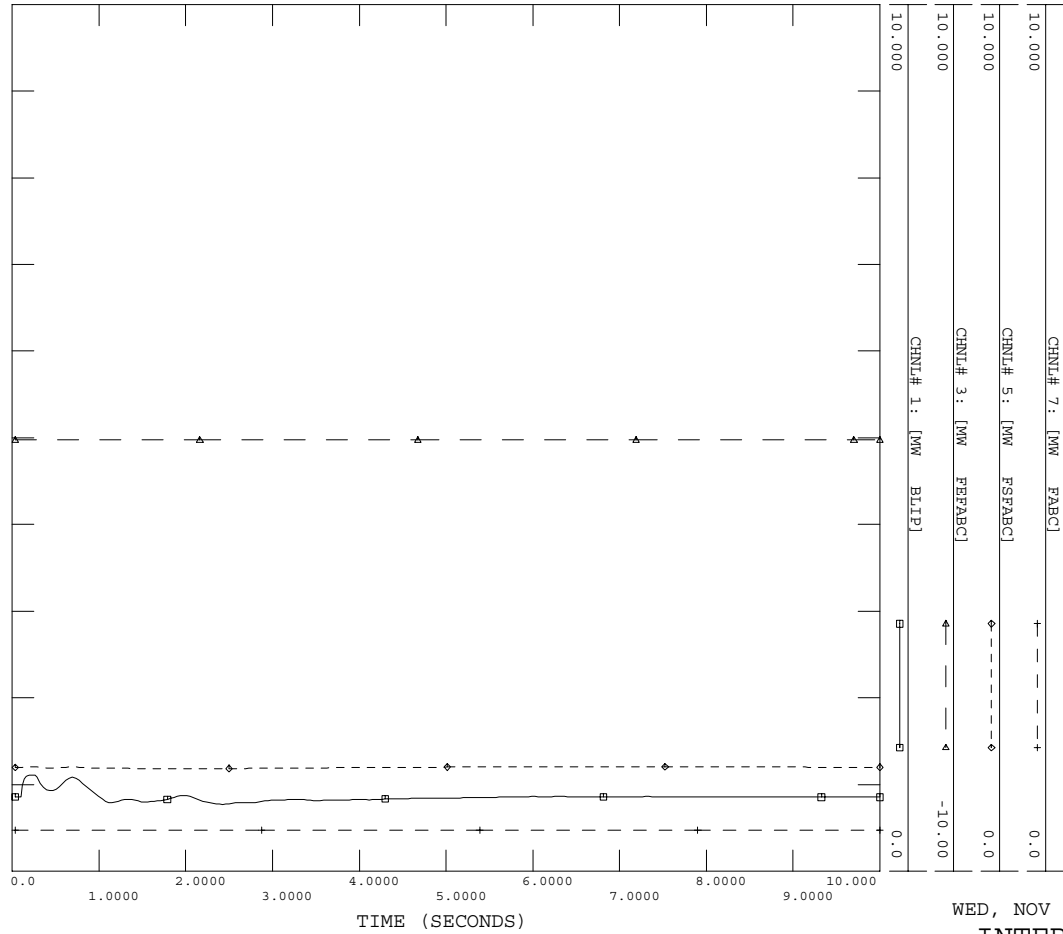


FIGURE G-56

DELAYED CLEARING (10 CYCLES) OF L-G FAULTS, BYPASS OF SERIES CAPACITORS

Plots for the following disturbance are shown in the following order in this Appendix:

- v. Bruce – Milton 500kV Circuit (fault at bus# 6409)
Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G57&G58
Voltage Drop across the 5 series capacitors – Figure G59
Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G60
- vi. Bruce – Longwood 500kV Circuit (fault at bus# 6410)
Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G61&G62
Voltage Drop across the 5 series capacitors – Figure G63
Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G64
- vii. Longwood – Nanticoke 500kV Circuit (fault at bus# 7000)
Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G65&G66
Voltage Drop across the 5 series capacitors – Figure G67
Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G68
- viii. Bruce – Clairville 500kV Circuit (fault at bus# 4000)
Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G69&G70
Voltage Drop across the 5 series capacitors – Figure G71
Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G72

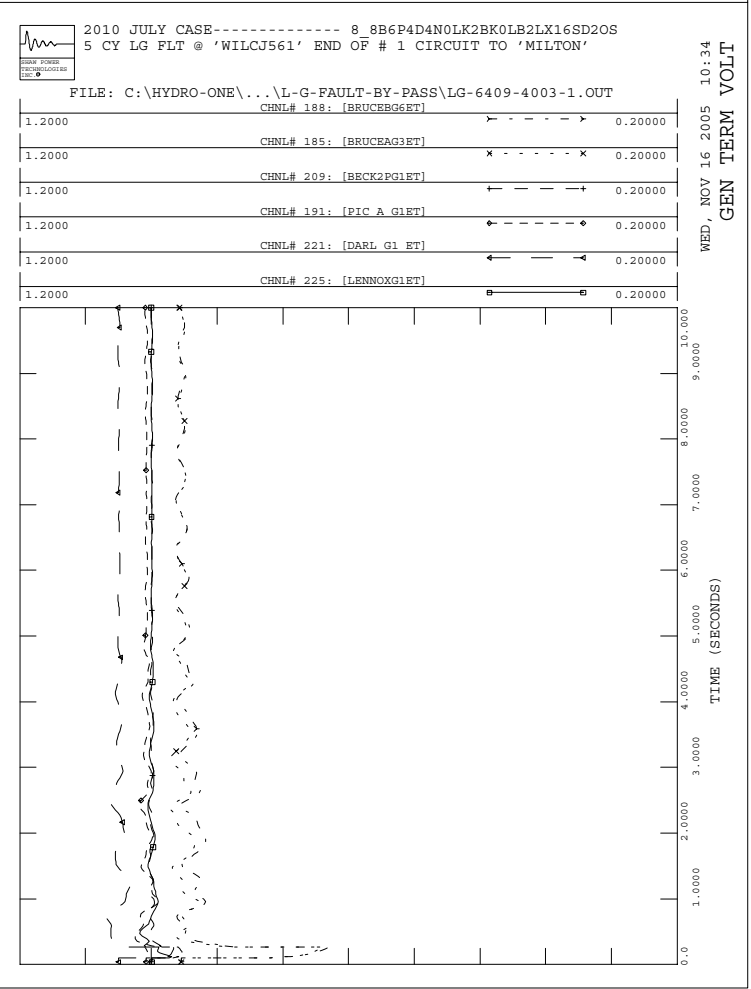
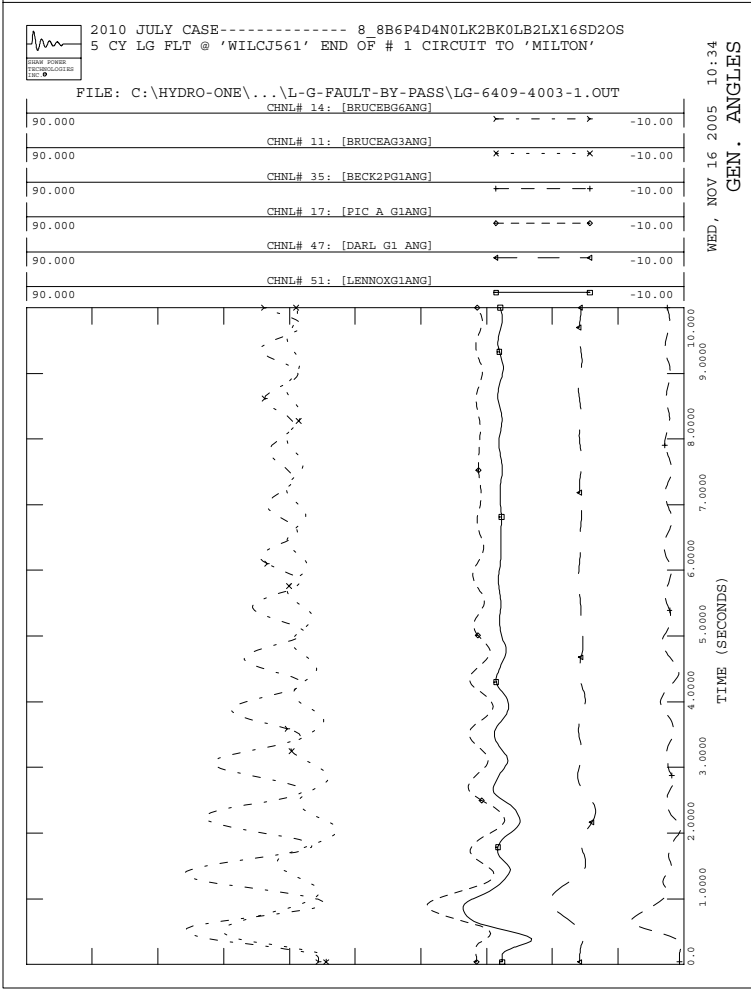
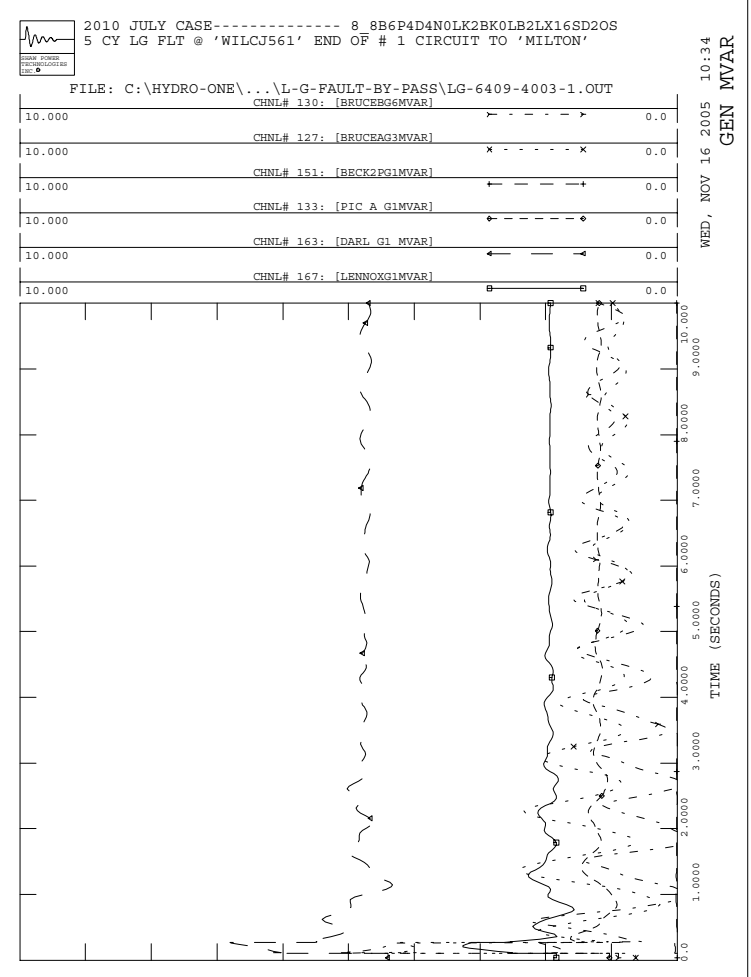
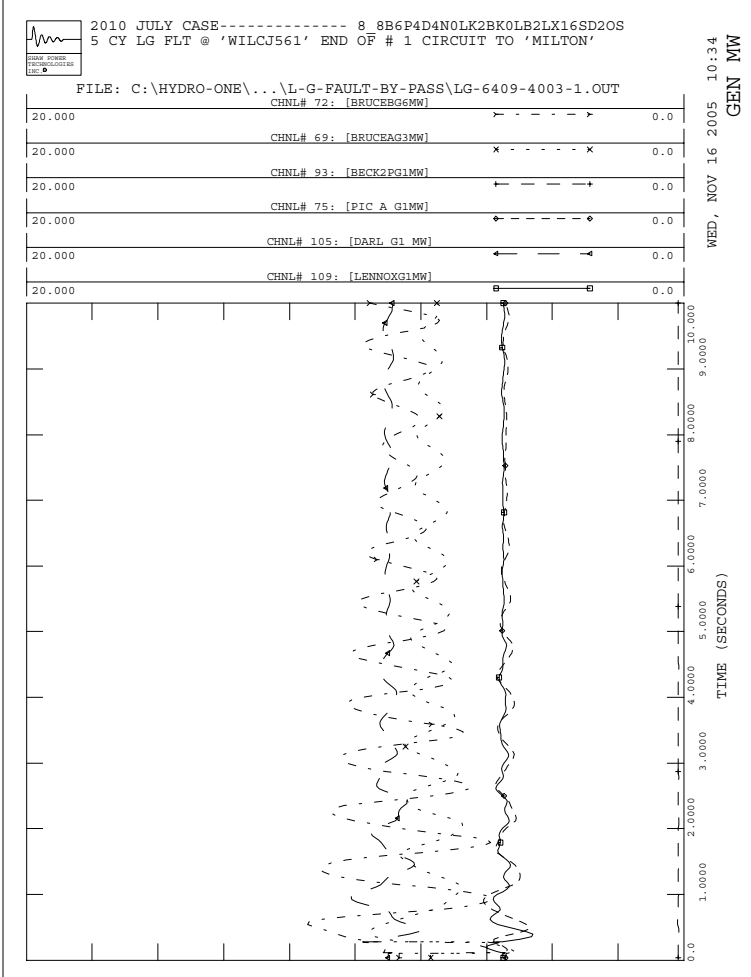


FIGURE G-57

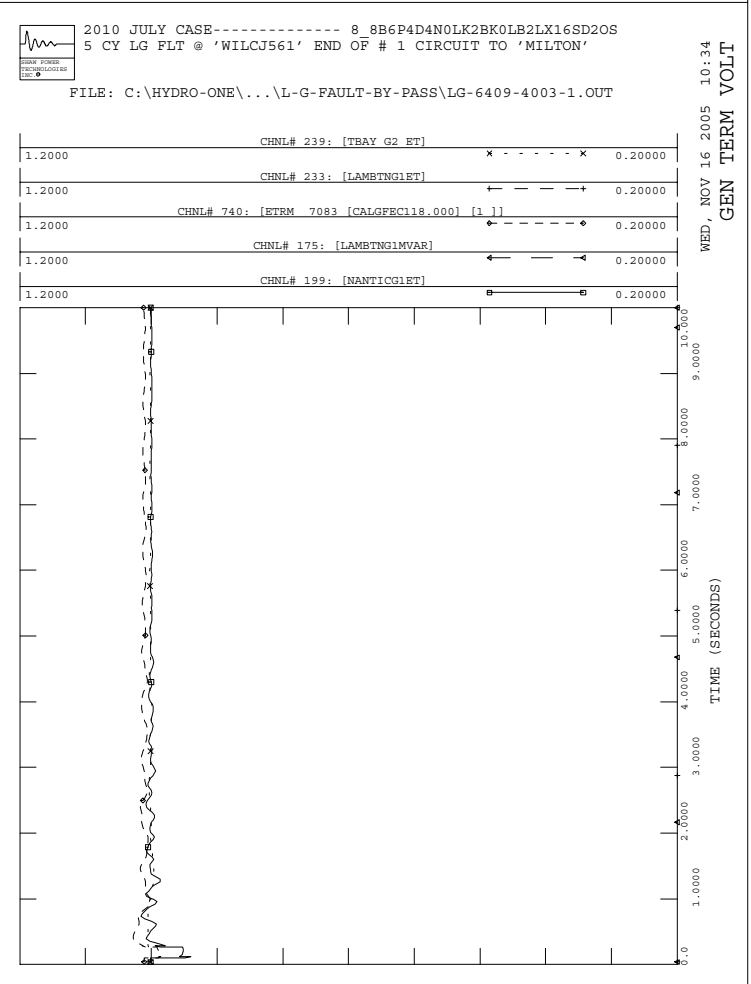
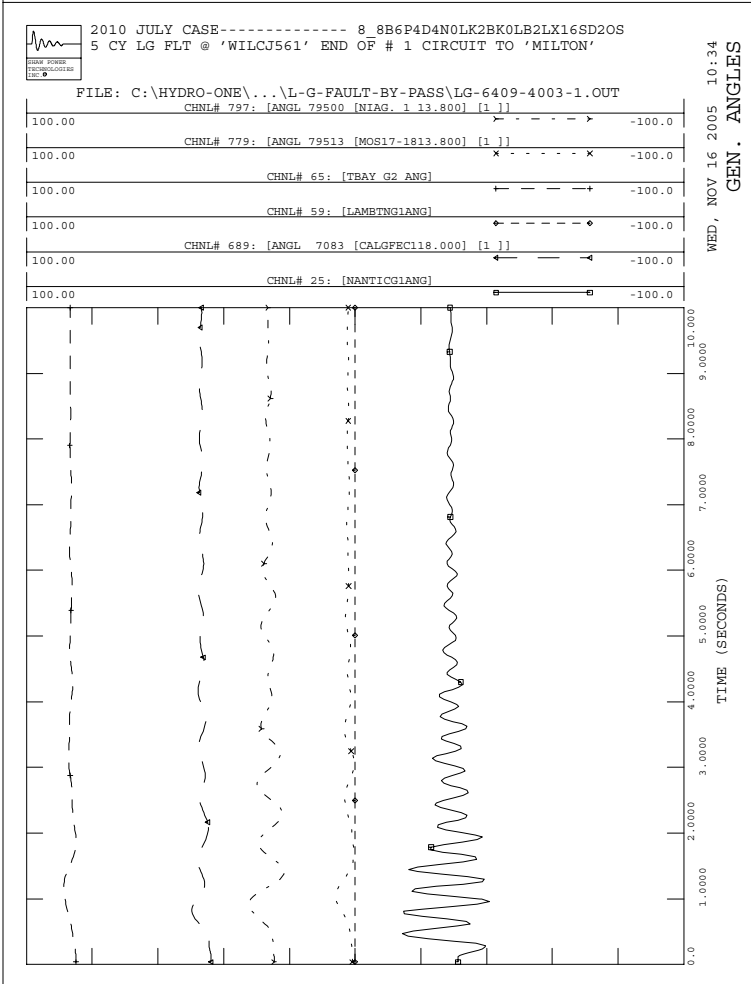
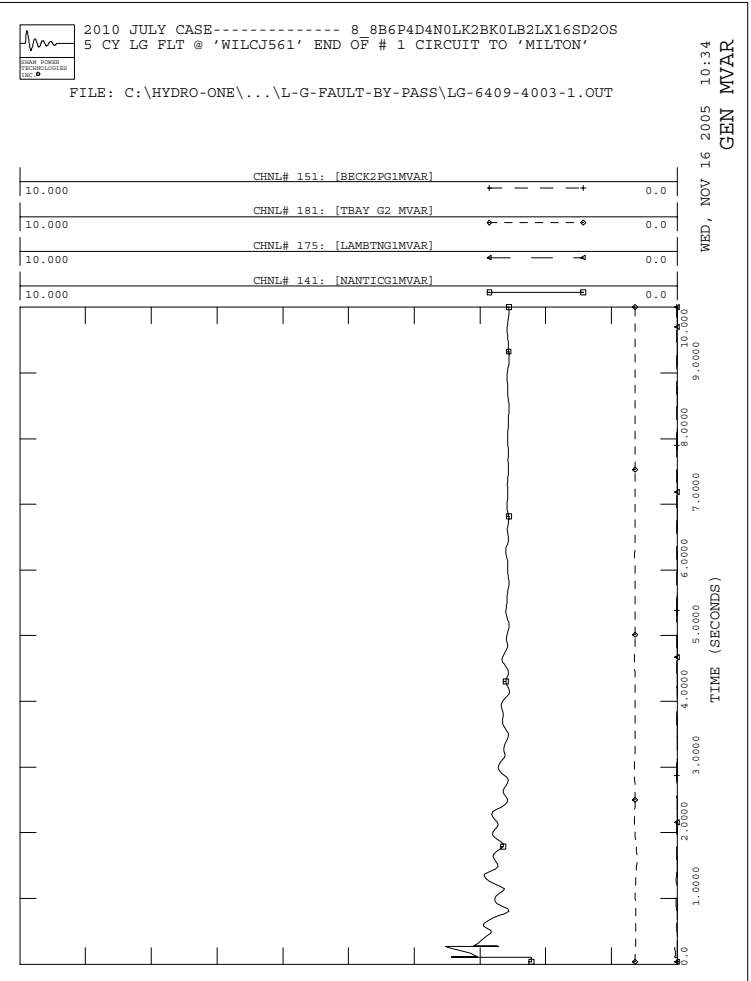
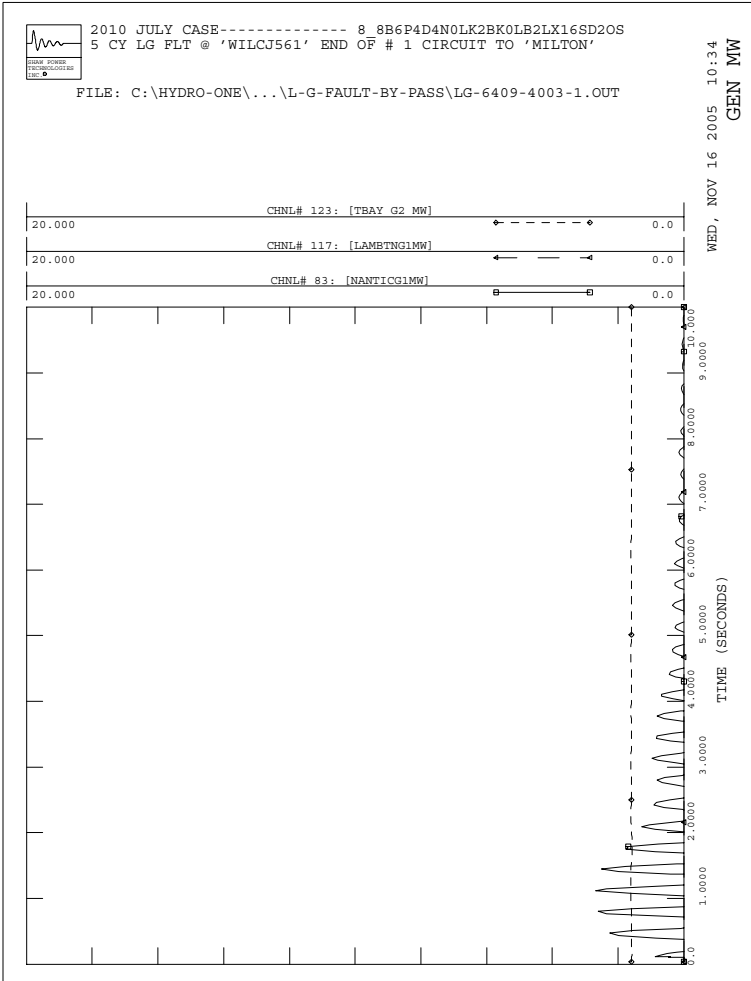
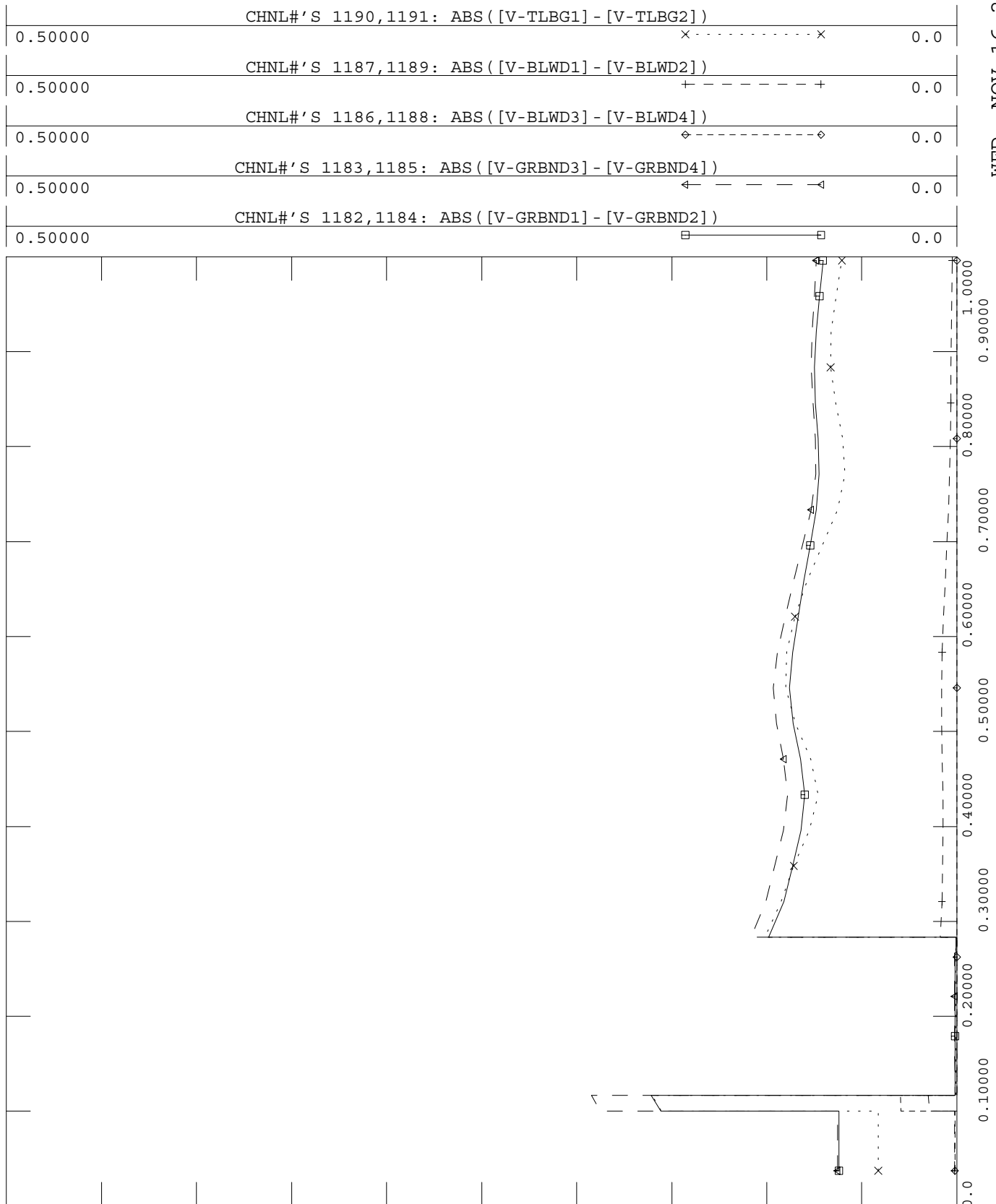


FIGURE G-58



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-BY-PASS\LG-6409-4003-1.OUT



WED, NOV 16 2005 10:34
DV-ACROSS-S-CAPS

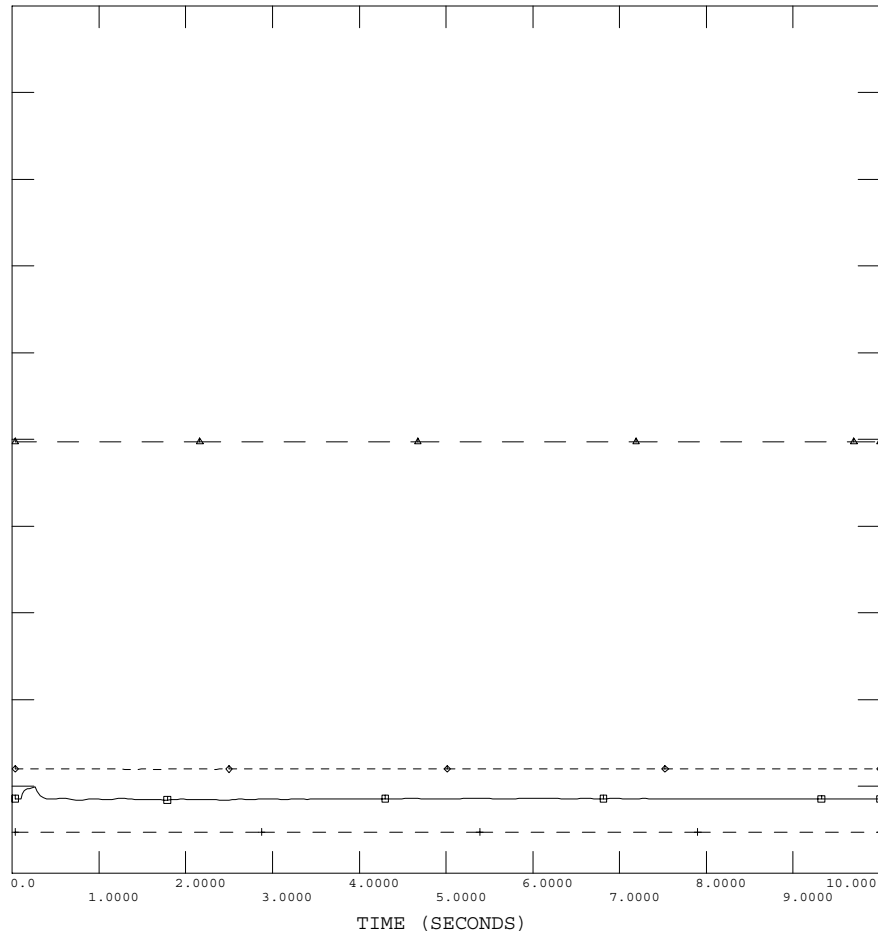
FIGURE G-59



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-BY-PASS\LG-6409-4003-1.OUT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	□ - - - □	0.0



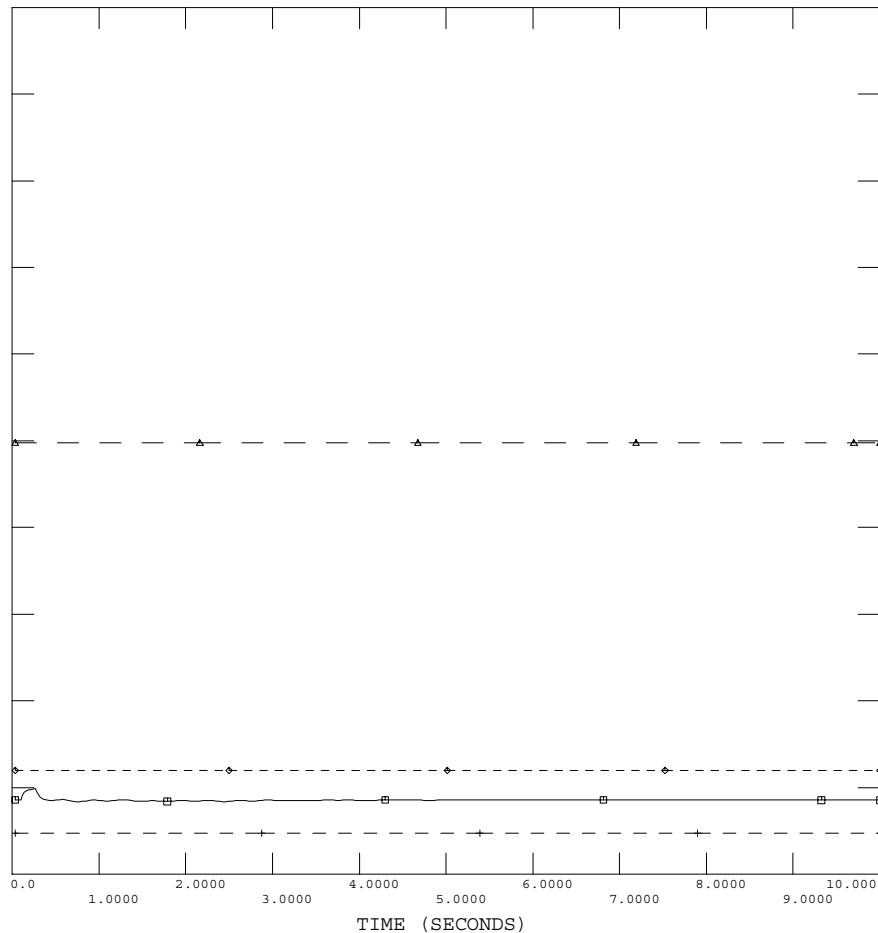
WED, NOV 16 2005 10:34
INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-BY-PASS\LG-6409-4003-1.OUT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	□ - - - □	0.0



WED, NOV 16 2005 10:34
INTERFACE MVAR

FIGURE G-60

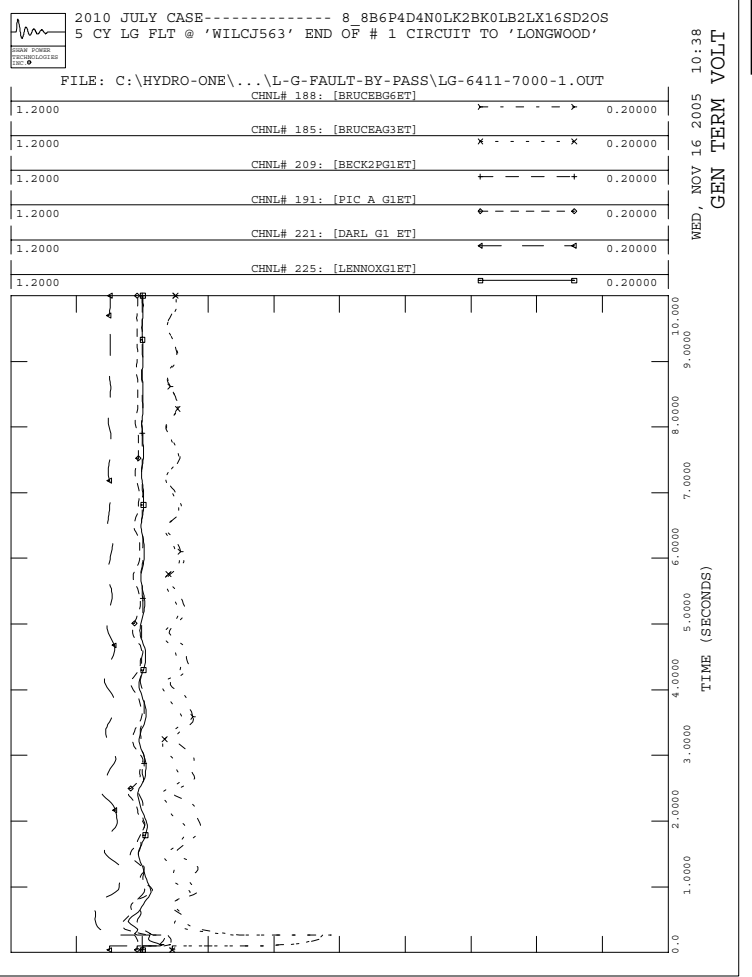
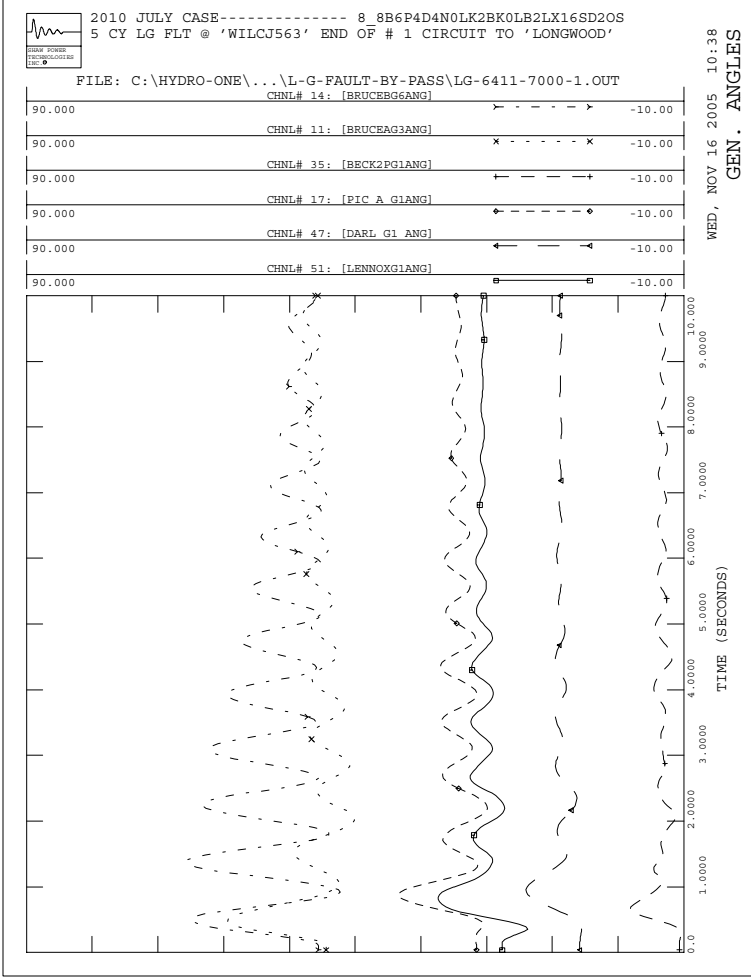
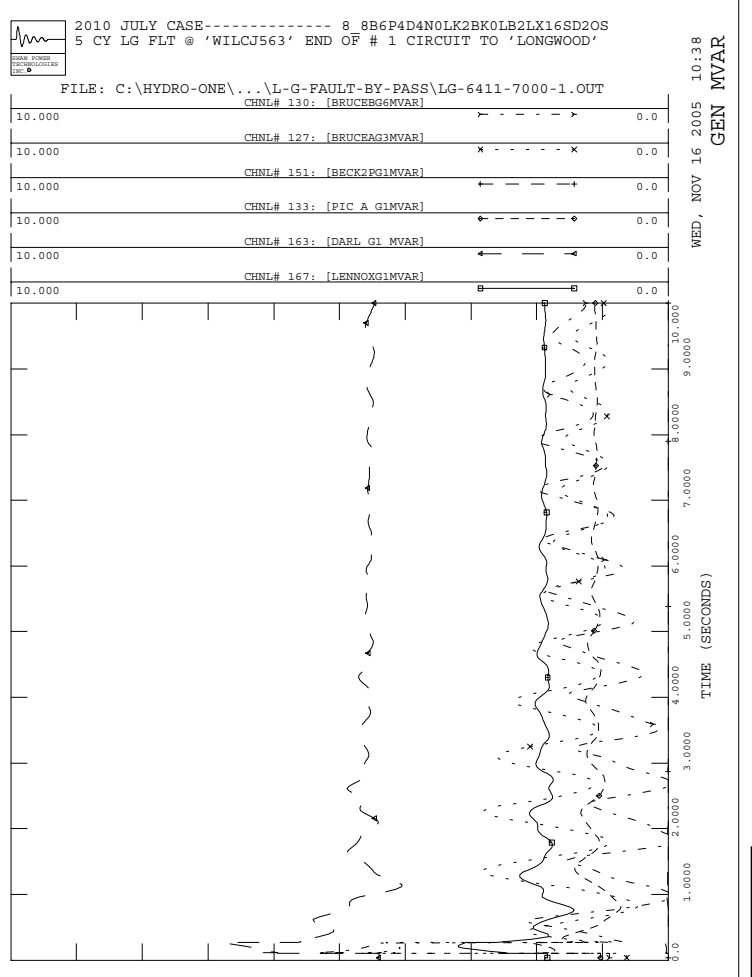
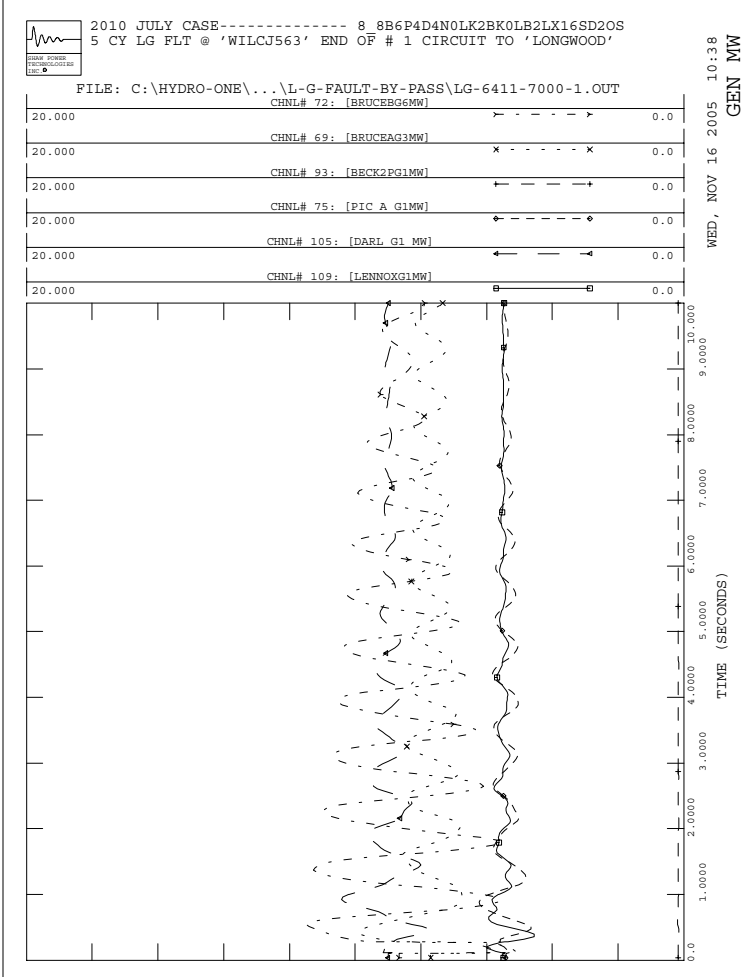


FIGURE G-61

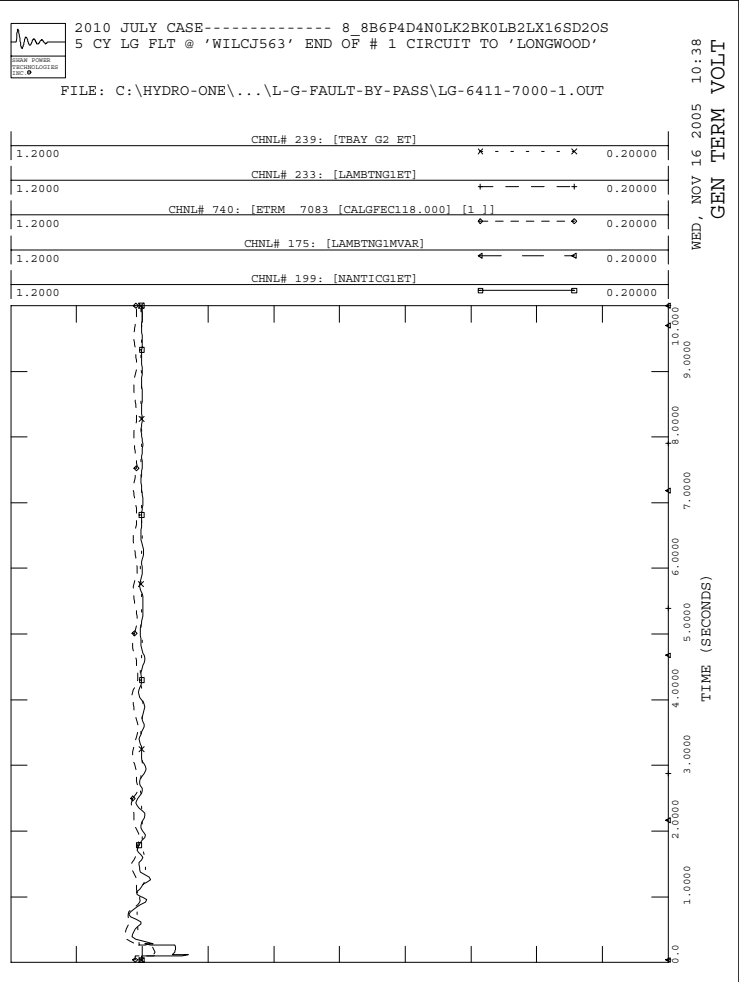
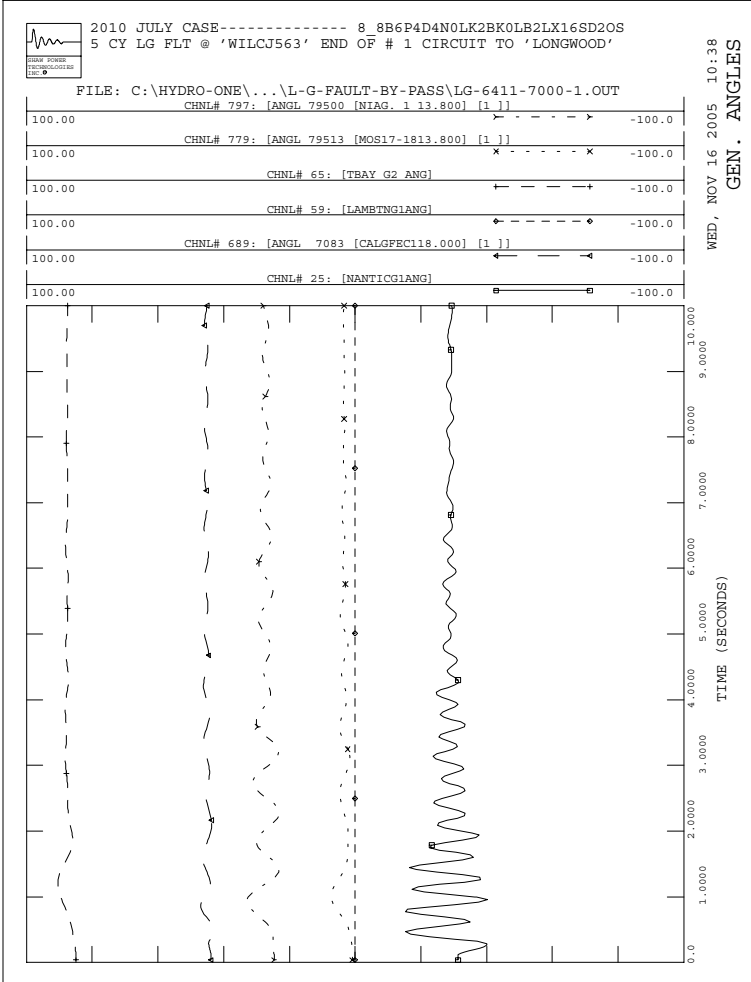
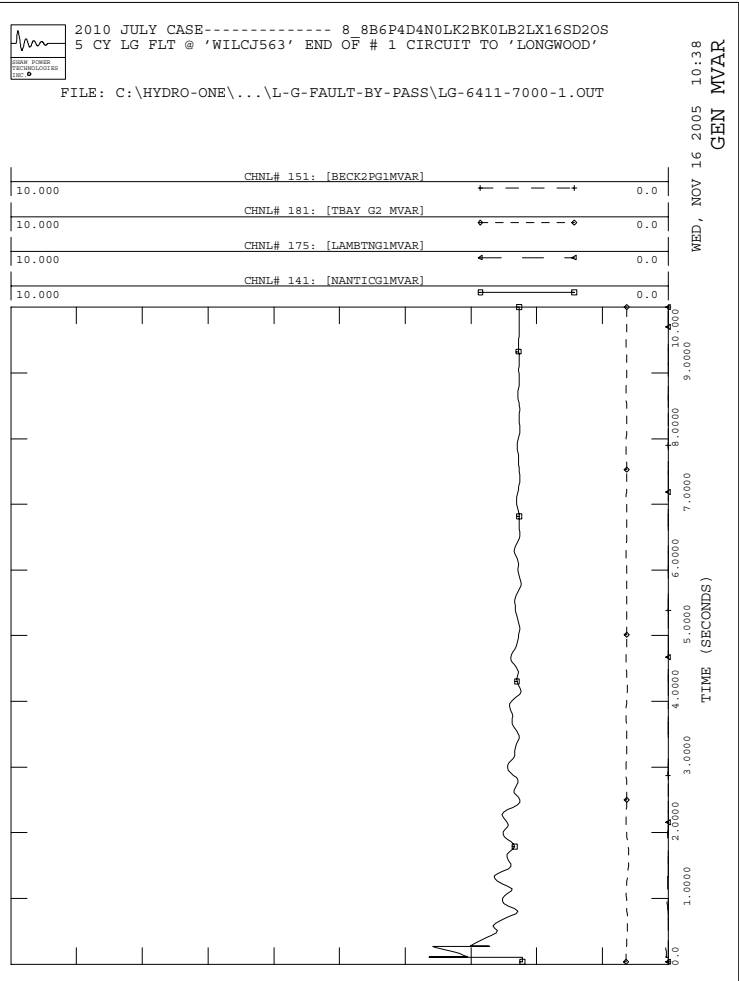
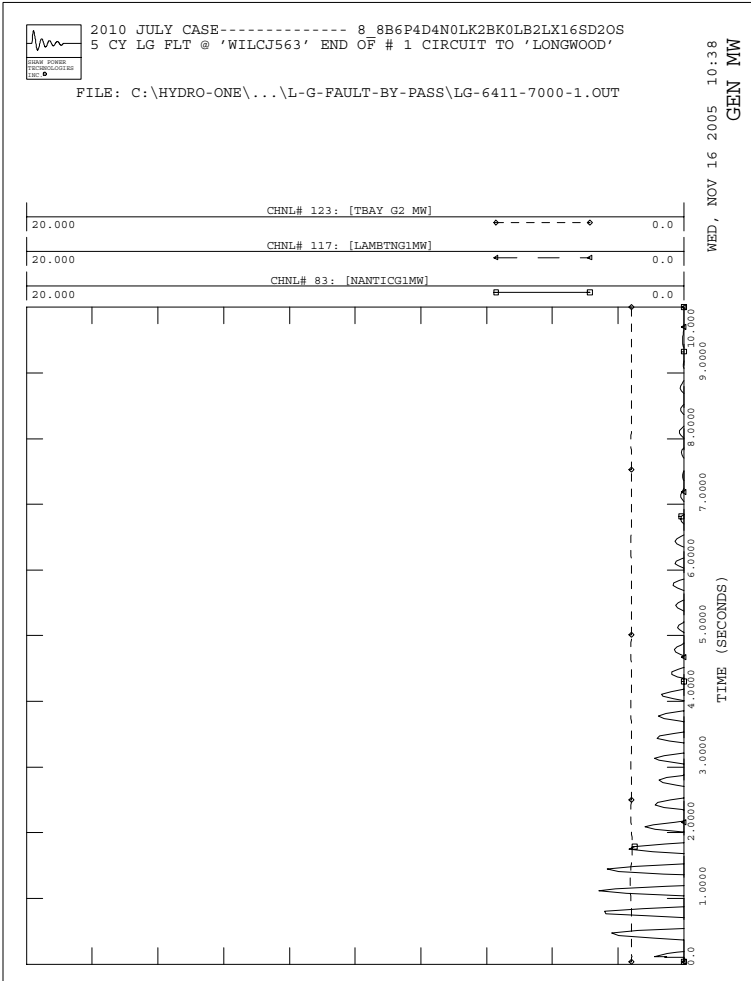
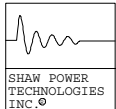
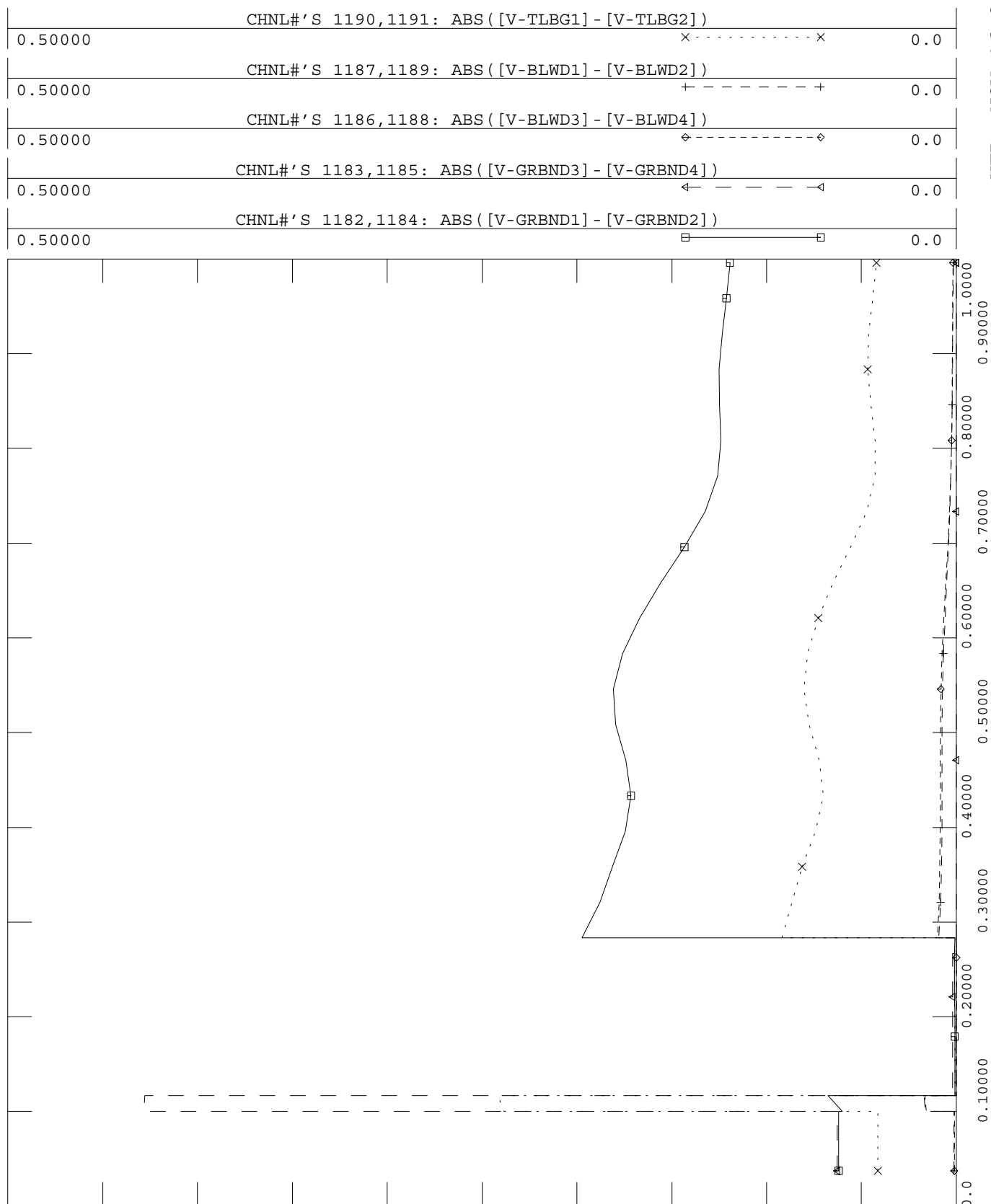


FIGURE G-62



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LG FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-BY-PASS\LG-6411-7000-1.OUT



WED, NOV 16 2005 10:39
DV-ACROSS-S-CAPS

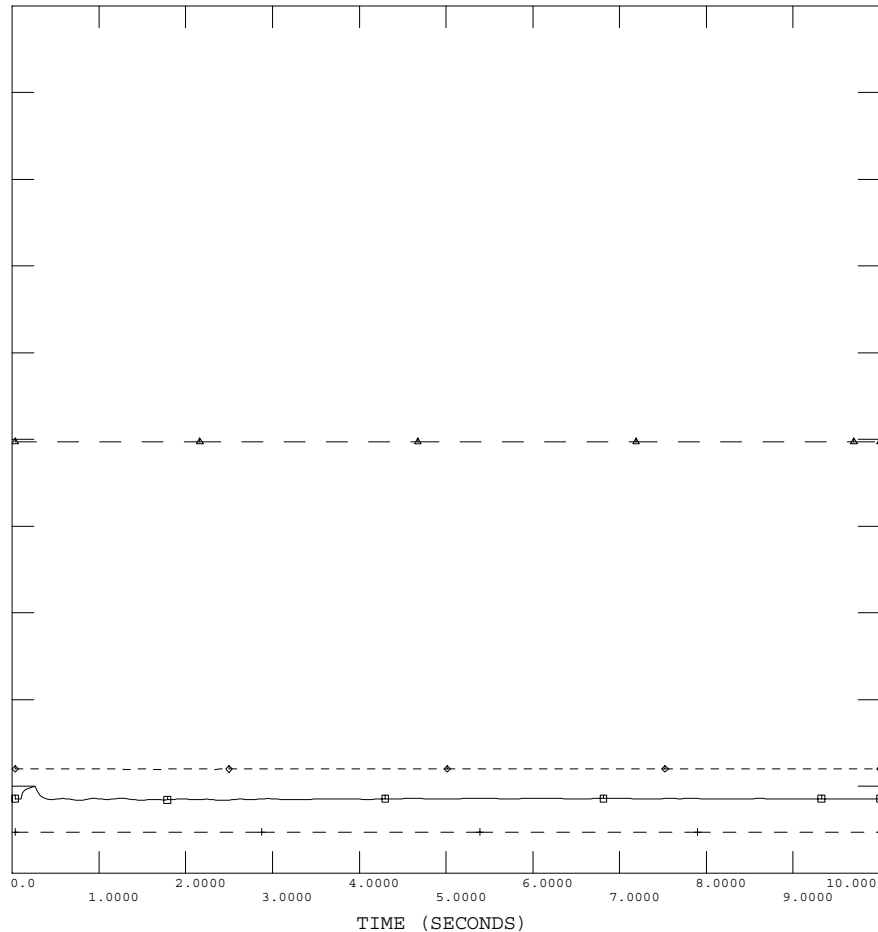
FIGURE G-63



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LG FLT @ 'WILCU563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-BY-PASS\LG-6411-7000-1.OUT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	□ - - - □	0.0



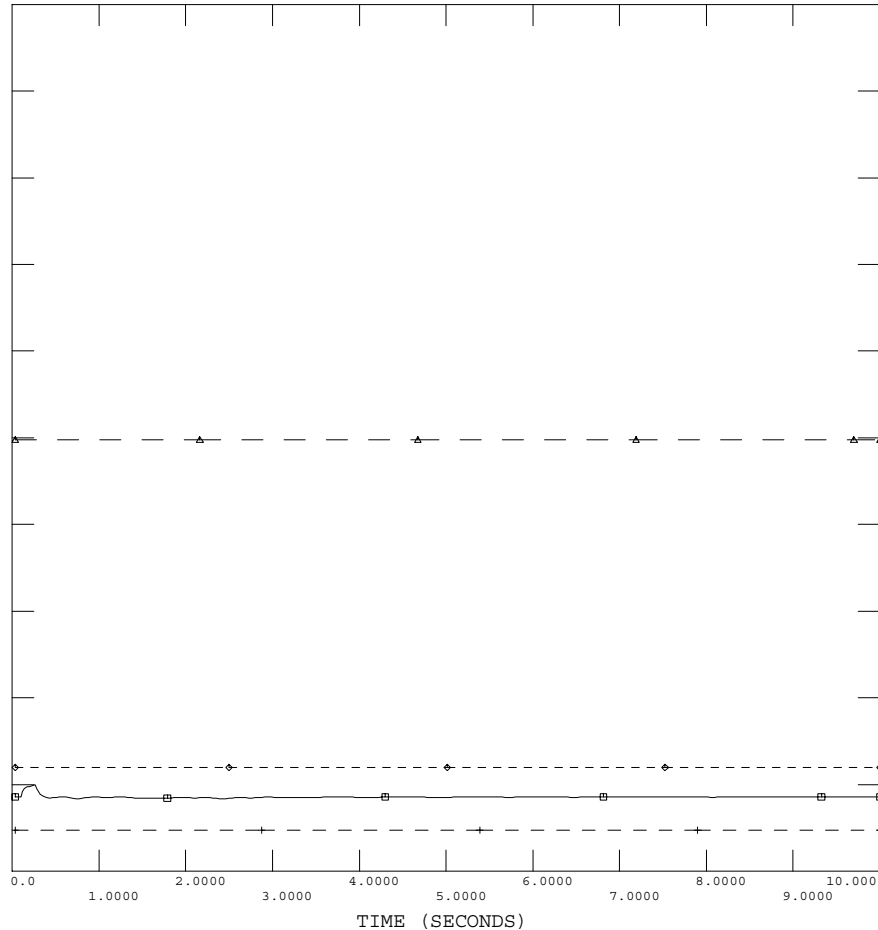
WED, NOV 16 2005 10:39
INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LG FLT @ 'WILCU563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-BY-PASS\LG-6411-7000-1.OUT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	□ - - - □	0.0



WED, NOV 16 2005 10:39
INTERFACE MVAR

FIGURE G-64

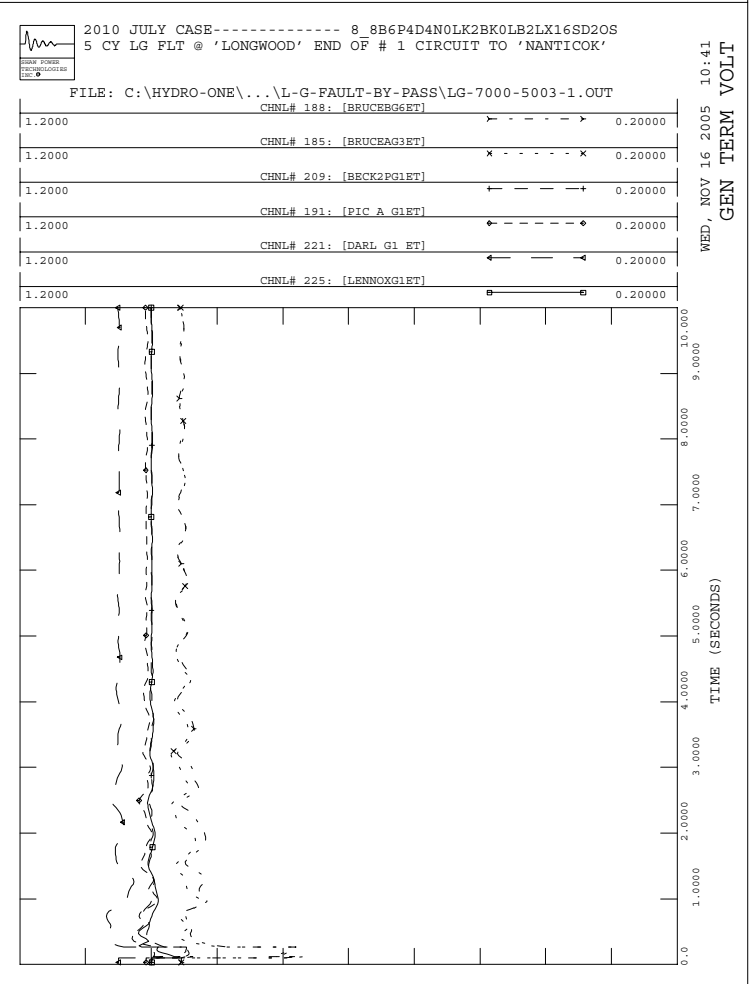
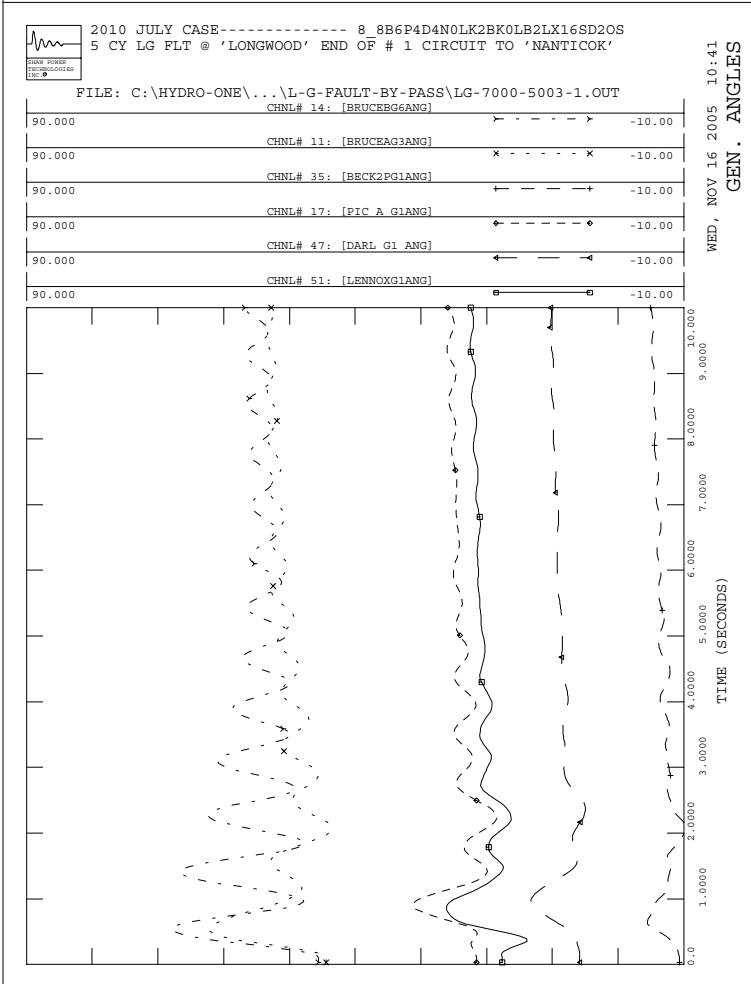
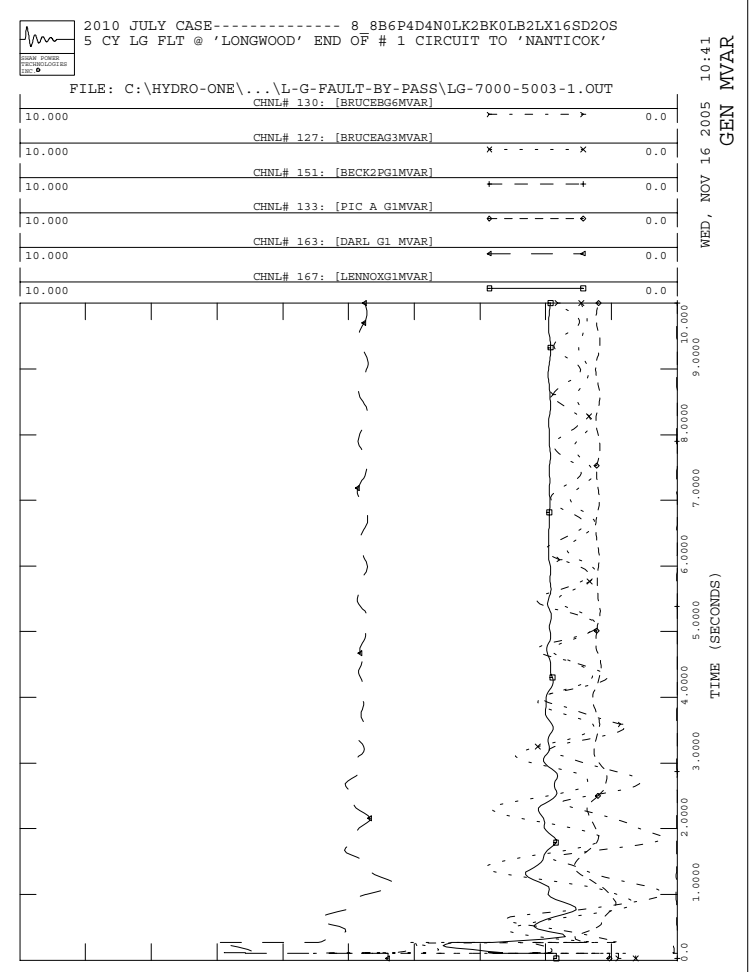
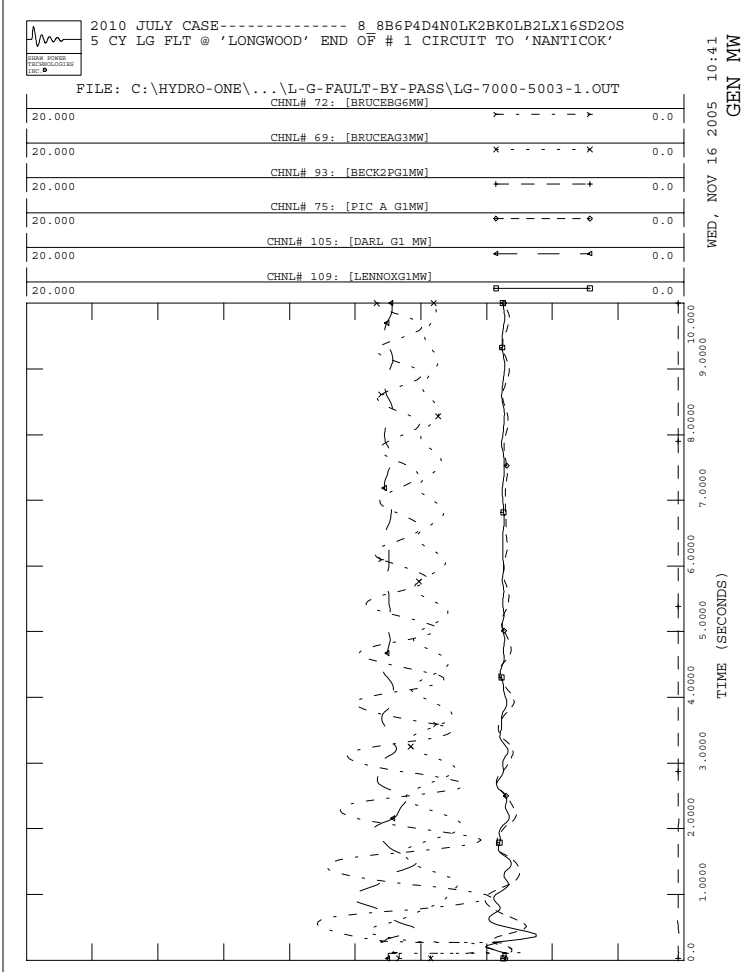


FIGURE G-65

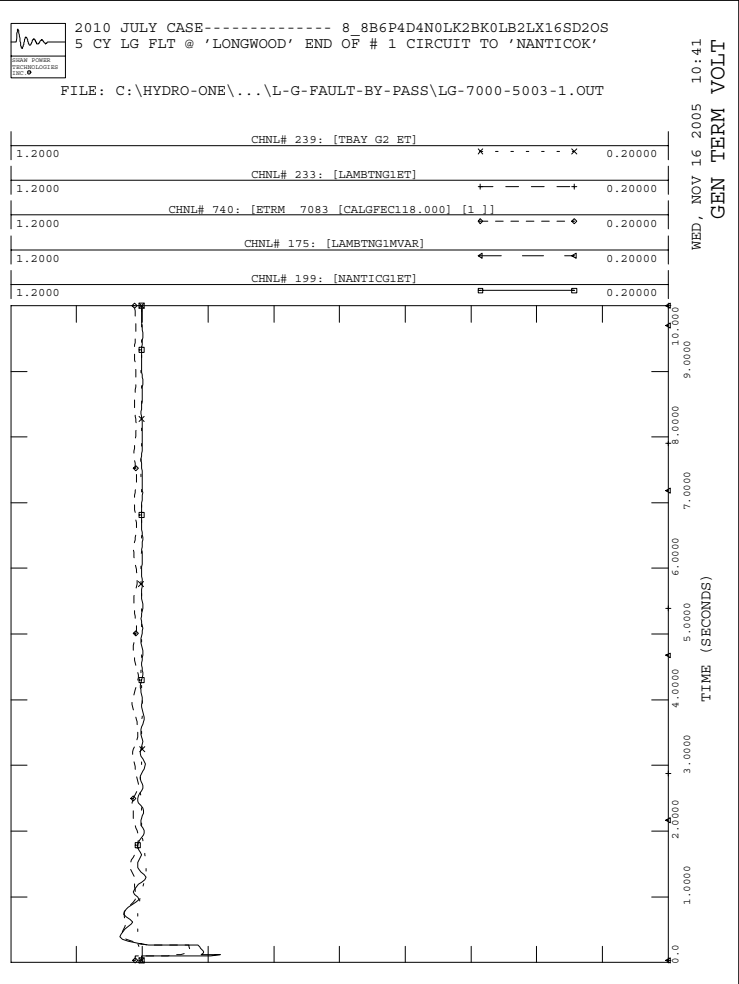
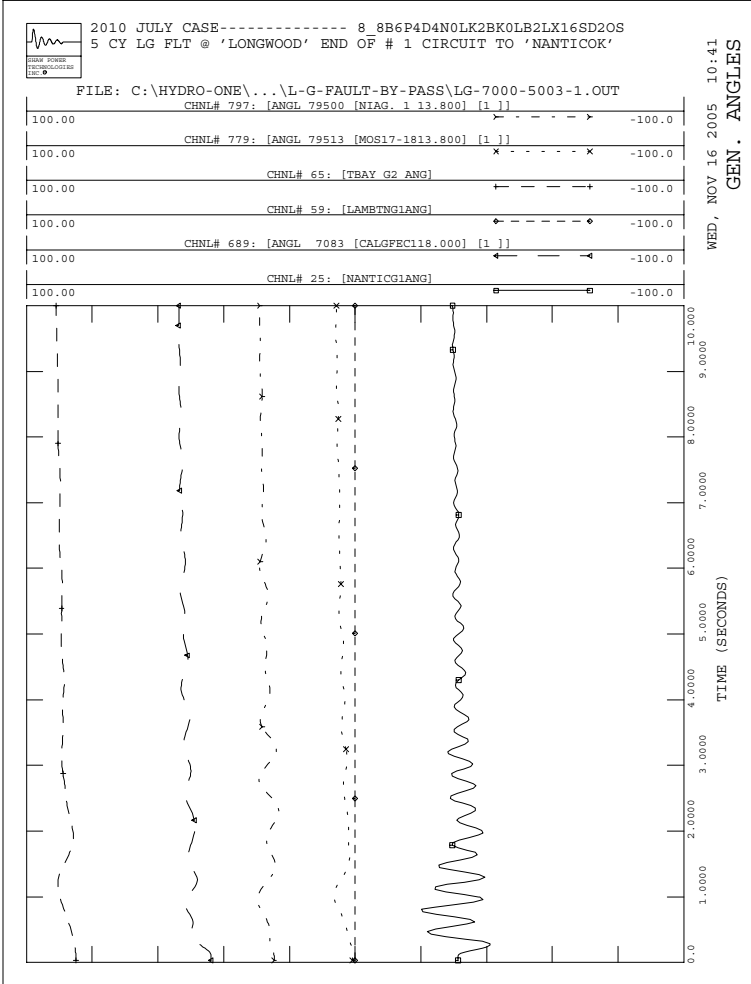
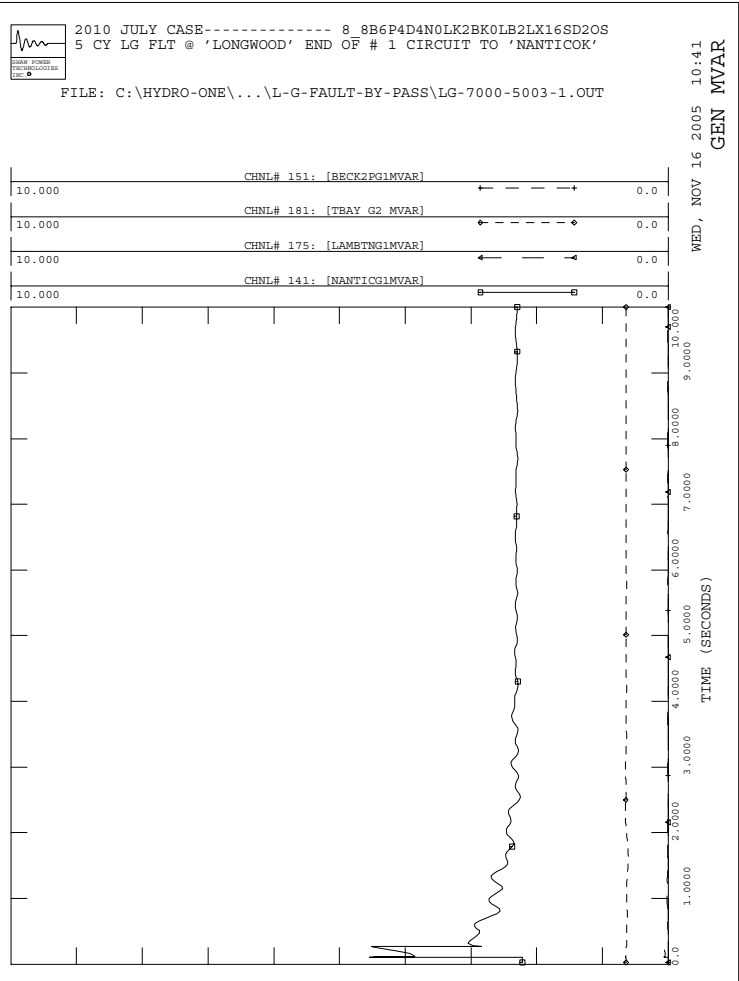
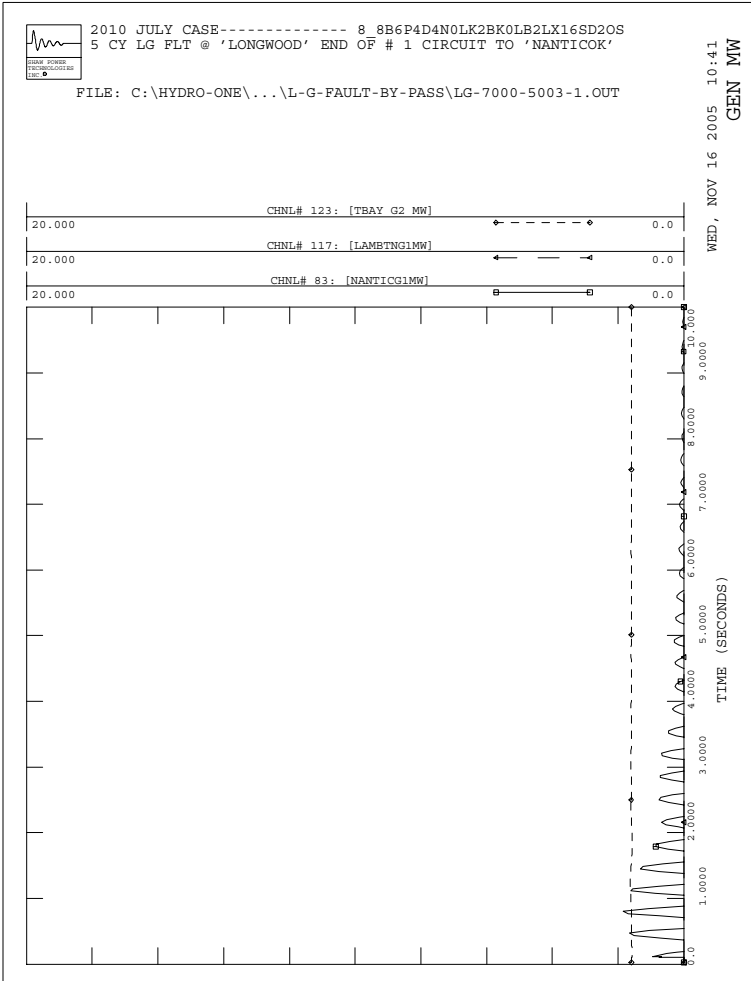
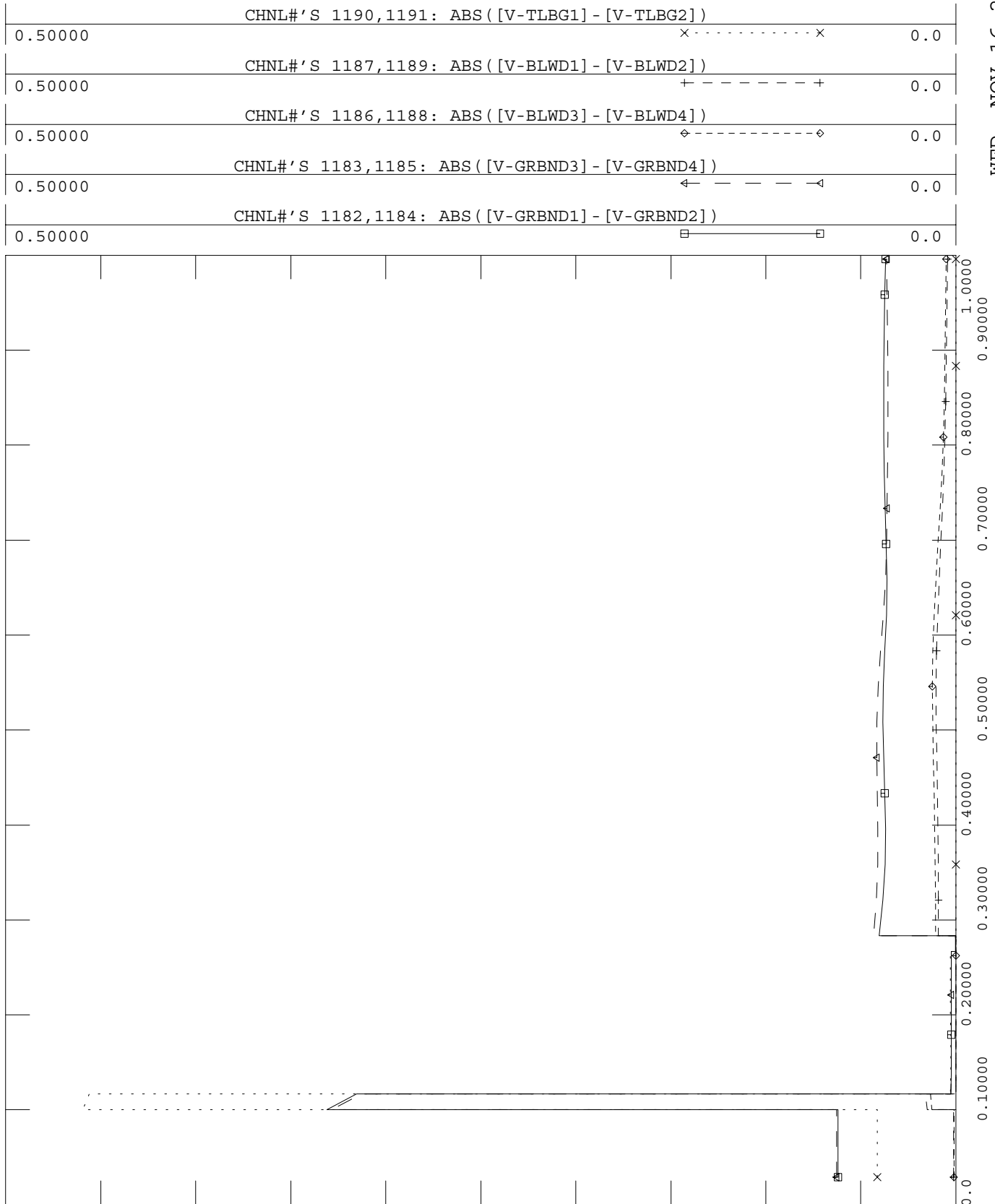


FIGURE G-66



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LG FLT @ 'LONGWOOD' END OF # 1 CIRCUIT TO 'NANTICOK'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-BY-PASS\LG-7000-5003-1.OUT



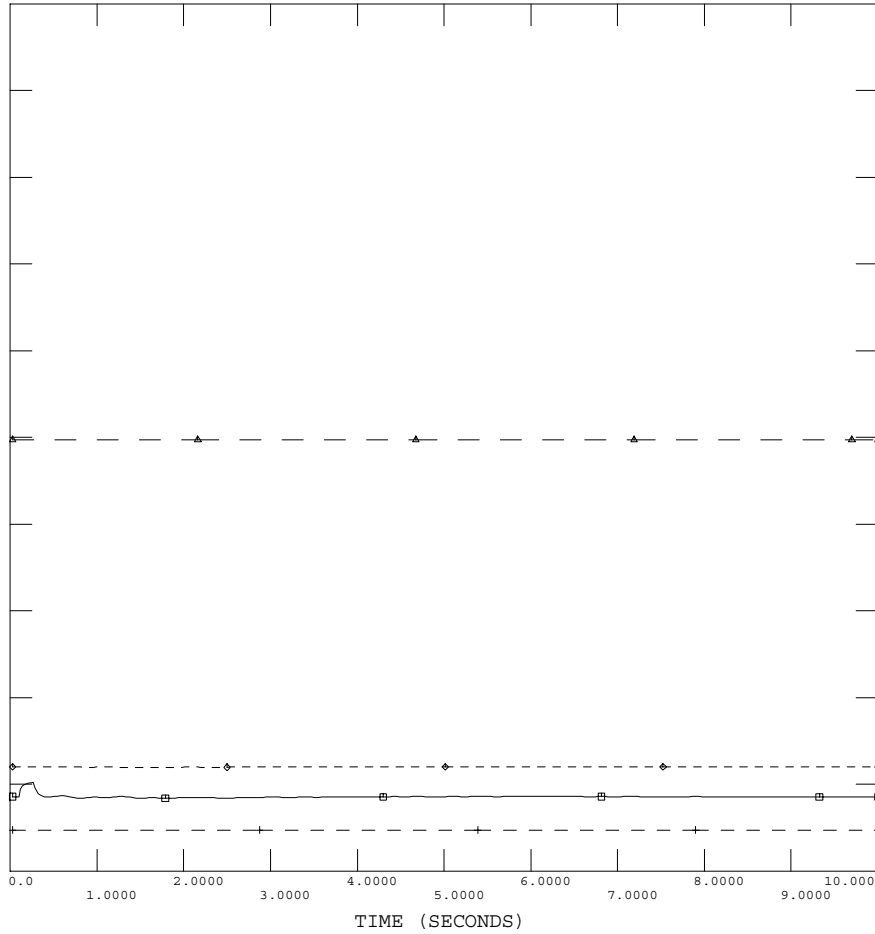
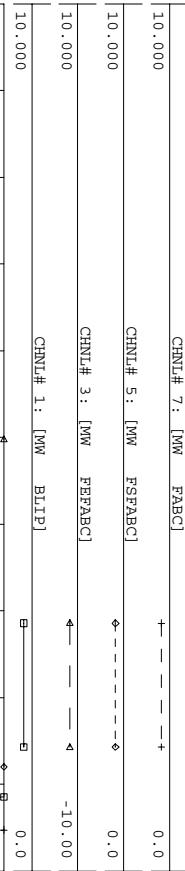
WED, NOV 16 2005 10:41
DV-ACROSS-S-CAPS

FIGURE G-67



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LG FLT @ 'LONGWOOD' END OF # 1 CIRCUIT TO 'NANTICOK'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-BY-PASS\LG-7000-5003-1.OUT

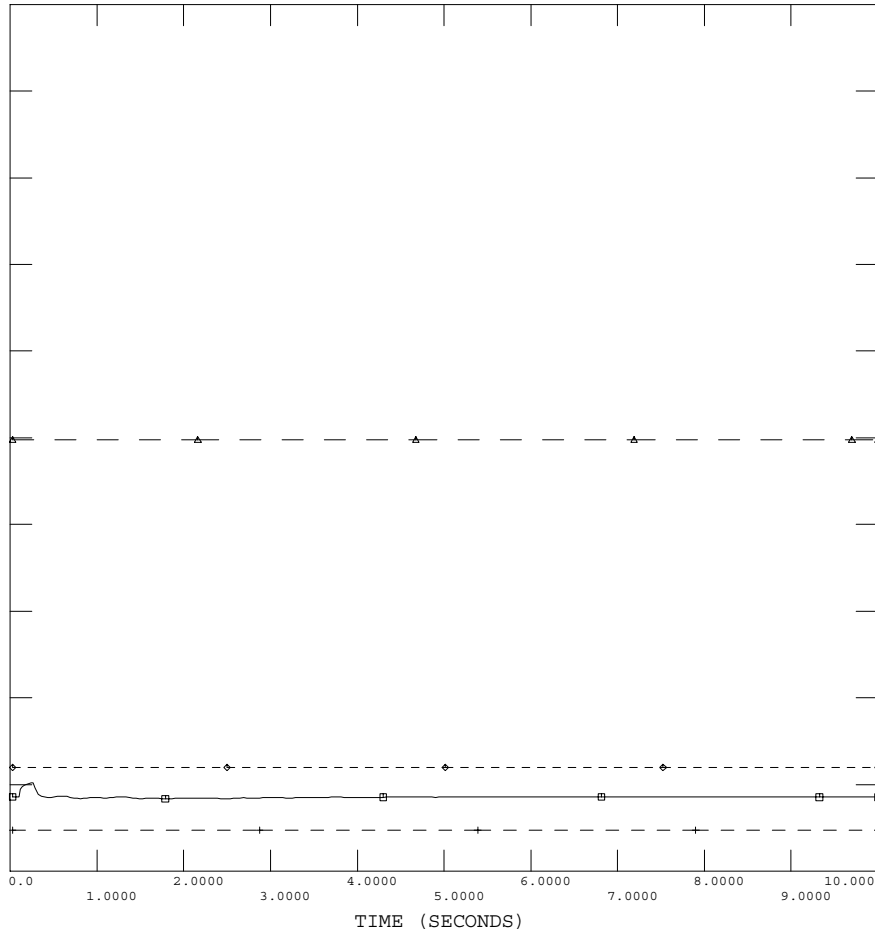
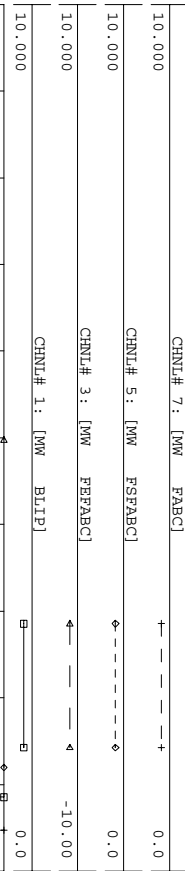


WED, NOV 16 2005 10:41
INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LG FLT @ 'LONGWOOD' END OF # 1 CIRCUIT TO 'NANTICOK'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-BY-PASS\LG-7000-5003-1.OUT



WED, NOV 16 2005 10:41
INTERFACE MVAR

FIGURE G-68

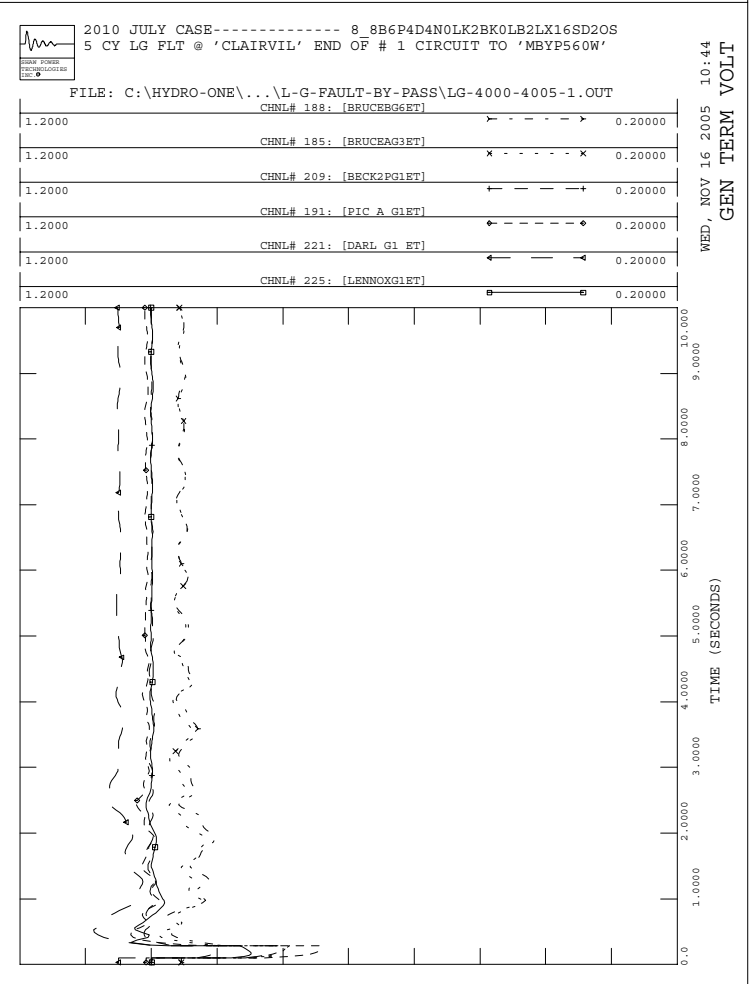
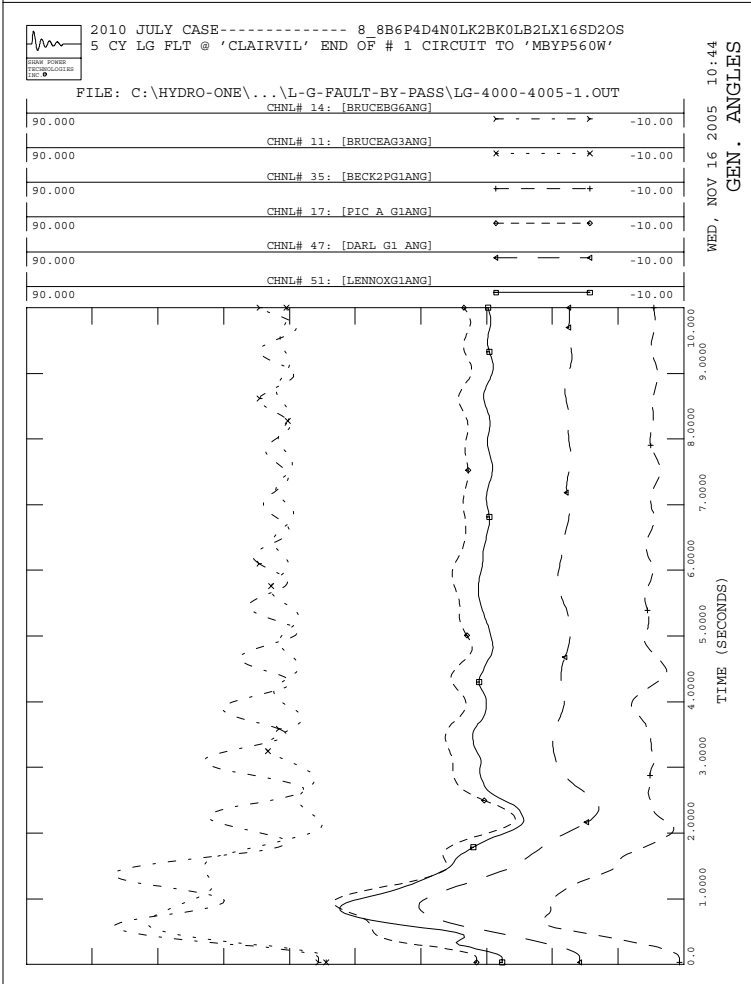
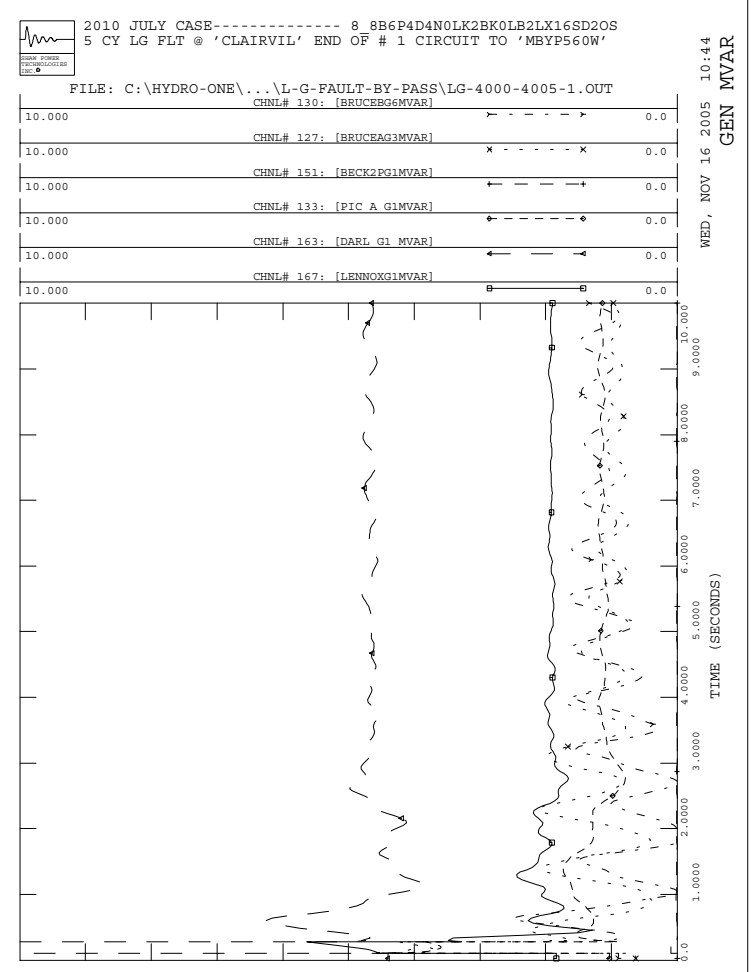
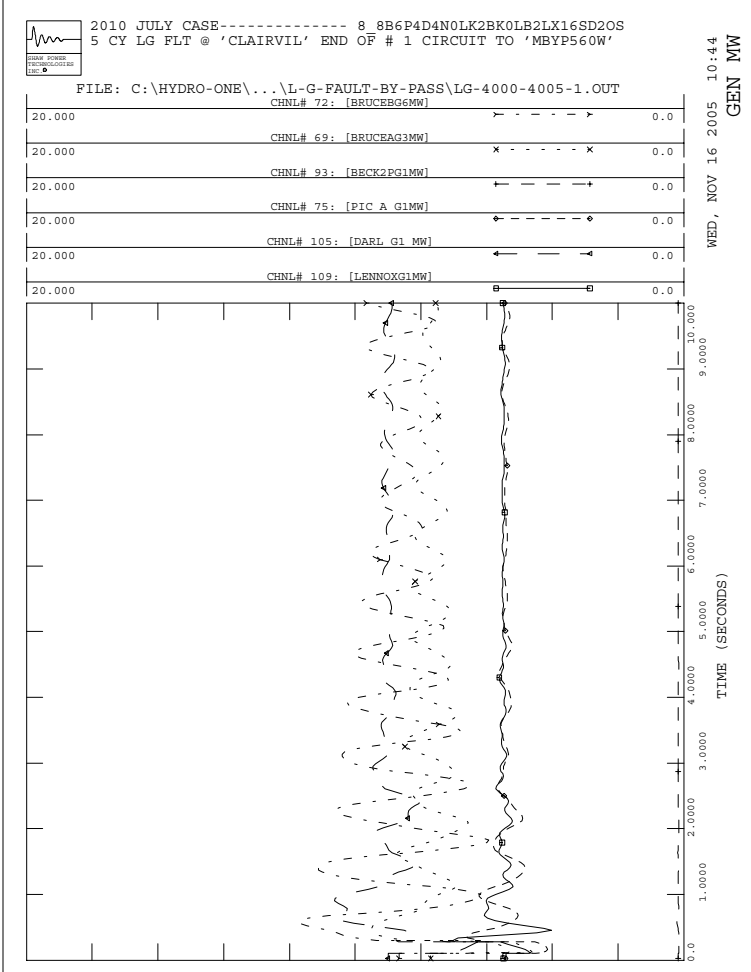


FIGURE G-69

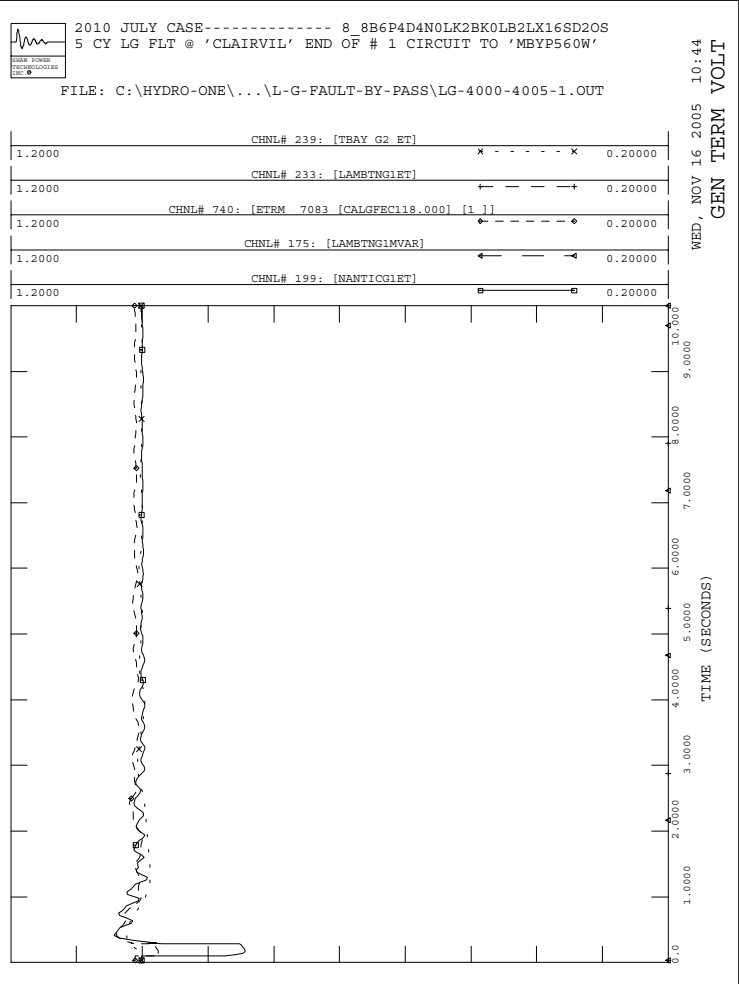
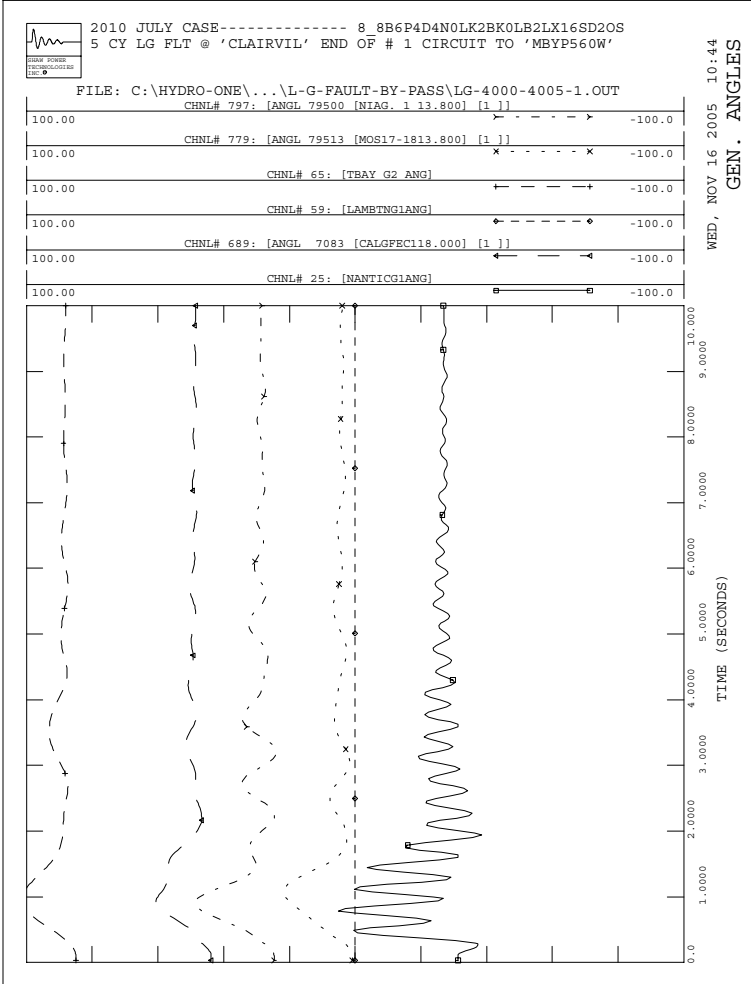
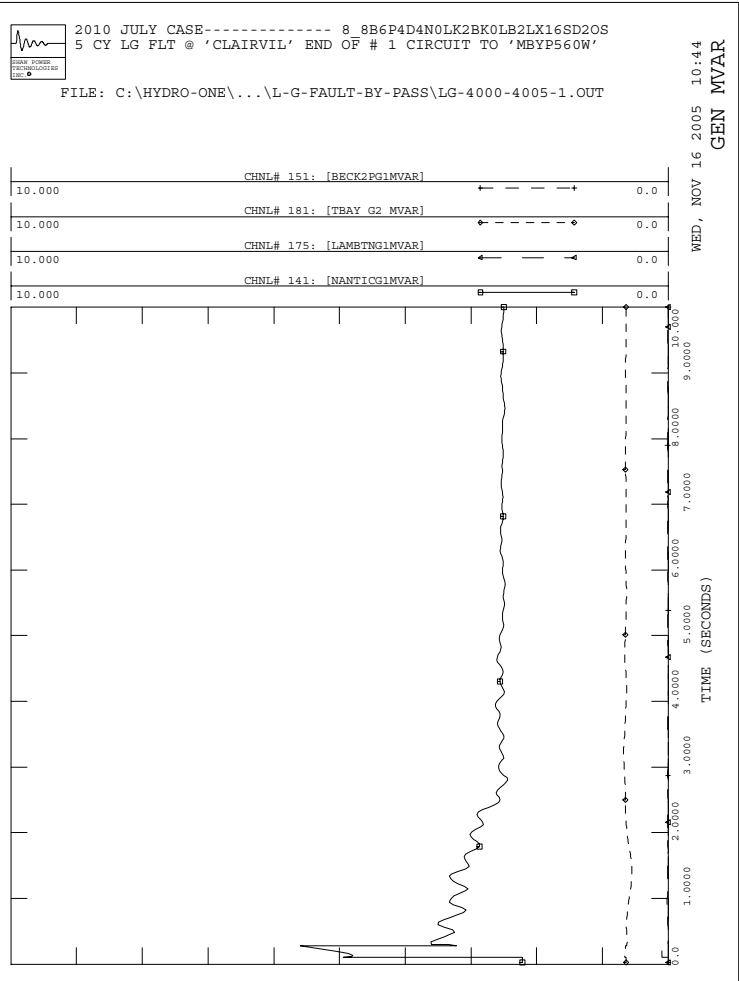
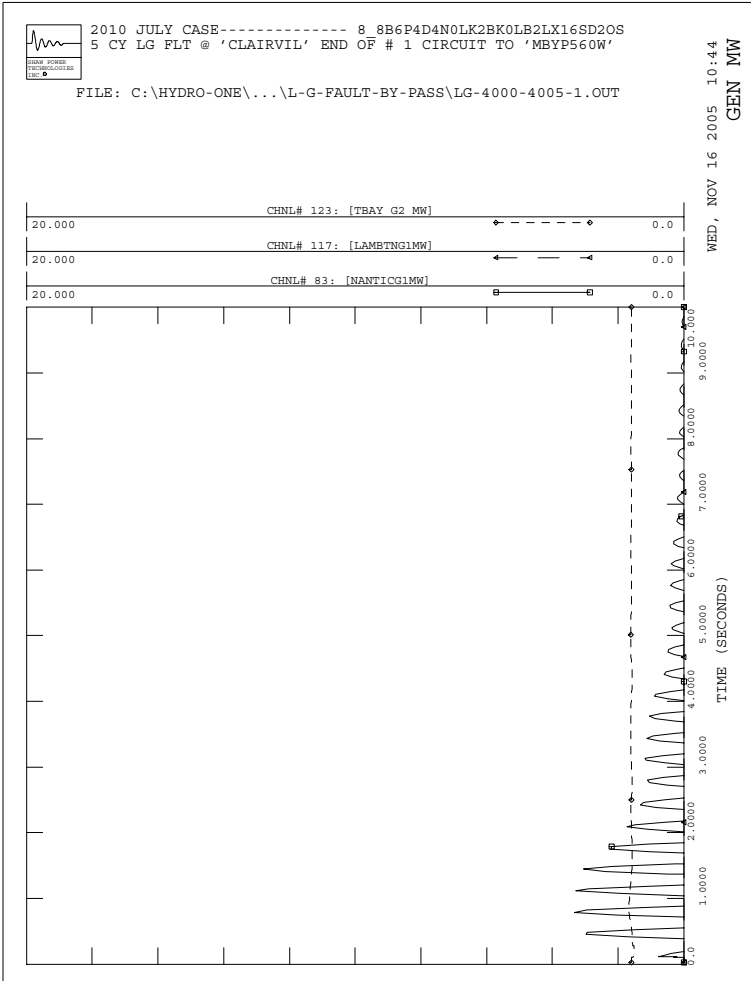


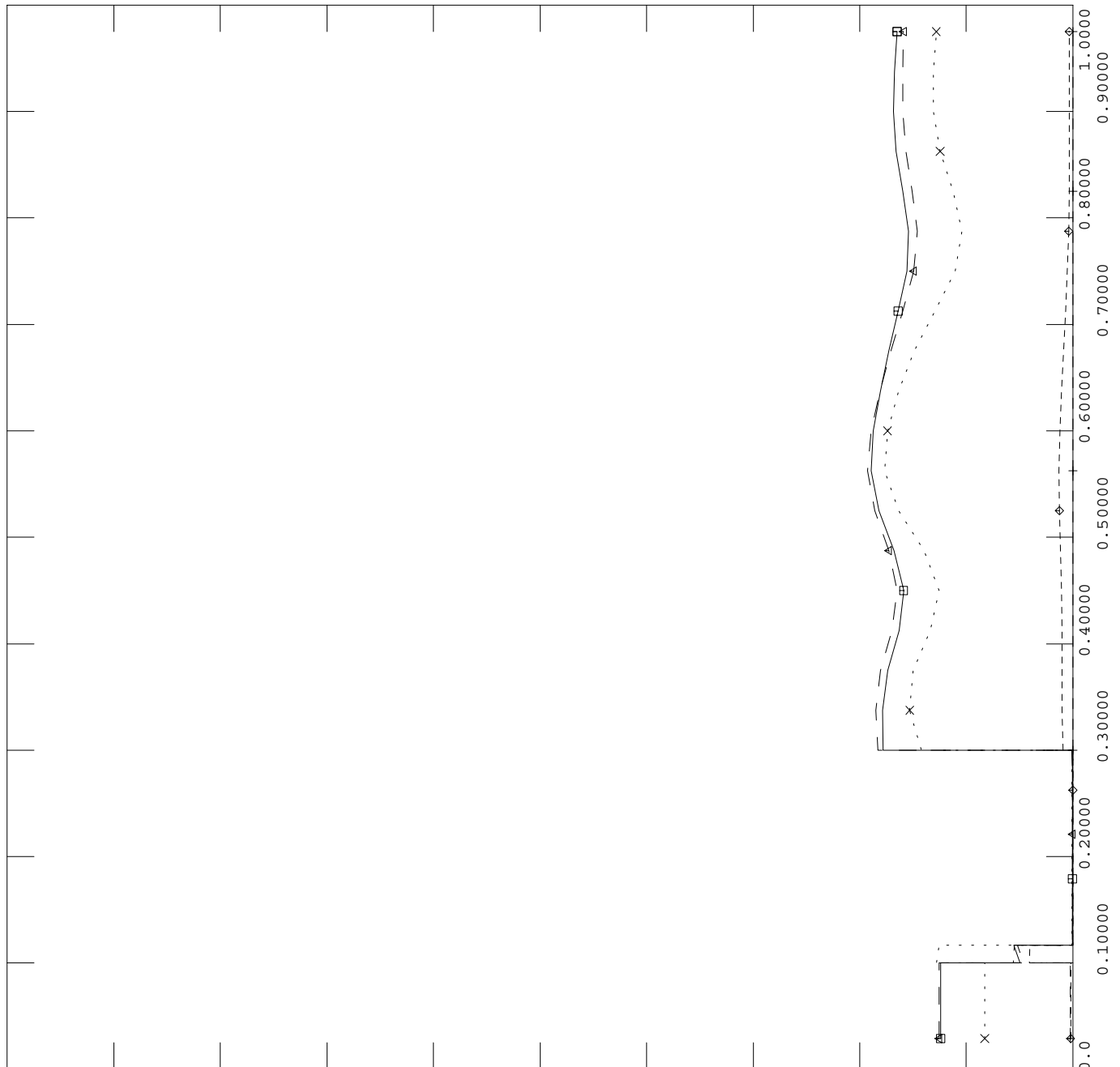
FIGURE G-70



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LG FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-BY-PASS\LG-4000-4005-1.OUT

0.50000	CHNL#'S 1190,1191: ABS ([V-TLBG1] - [V-TLBG2])	X - - - - - X	0.0
0.50000	CHNL#'S 1187,1189: ABS ([V-BLWD1] - [V-BLWD2])	+ - - - - +	0.0
0.50000	CHNL#'S 1186,1188: ABS ([V-BLWD3] - [V-BLWD4])	◇ - - - - ◇	0.0
0.50000	CHNL#'S 1183,1185: ABS ([V-GRBND3] - [V-GRBND4])	← - - - - →	0.0
0.50000	CHNL#'S 1182,1184: ABS ([V-GRBND1] - [V-GRBND2])	□ - - - - □	0.0



WED, NOV 16 2005 10:44
DV-ACROSS-S-CAPS

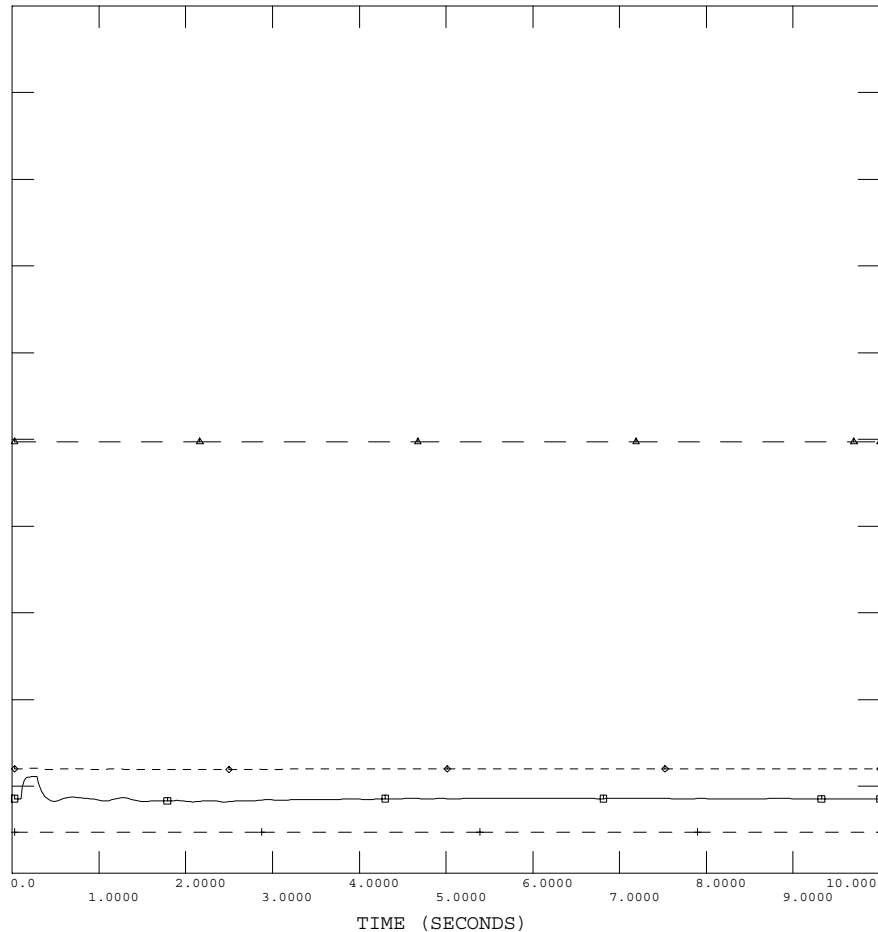
FIGURE G-71



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LG FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-BY-PASS\LG-4000-4005-1.OUT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	□ - - - □	0.0



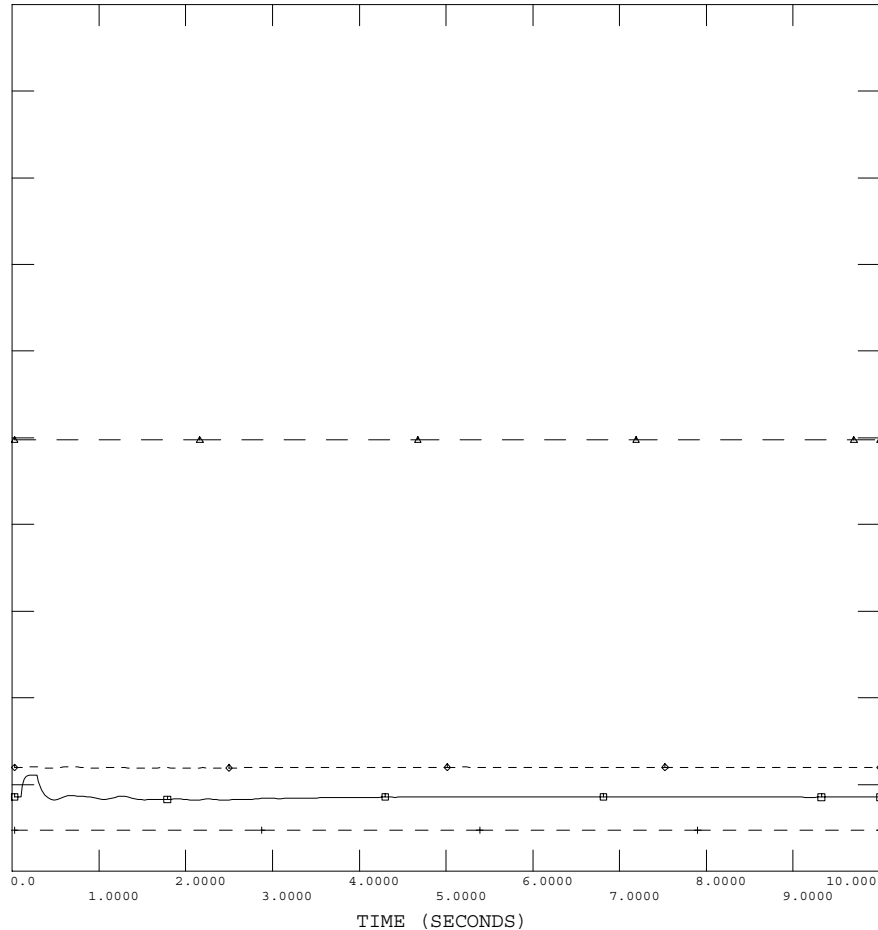
WED, NOV 16 2005 10:44
INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LG FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'

FILE: C:\HYDRO-ONE\...\L-G-FAULT-BY-PASS\LG-4000-4005-1.OUT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	□ - - - □	0.0



WED, NOV 16 2005 10:44
INTERFACE MVAR

FIGURE G-72

**110% POWER TRANSFER
3-PHASE FAULT, NORMALLY CLEARED,
BYPASS of ALL SERIES CAPACITOR BANKS**

Plots for the following disturbance are shown in the following order in this Appendix:

- i) Bruce – Clairville 500kV Circuit (fault at bus# 4000)

Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G73&G74
Voltage Drop across the 5 series capacitors – Figure G75
Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G76

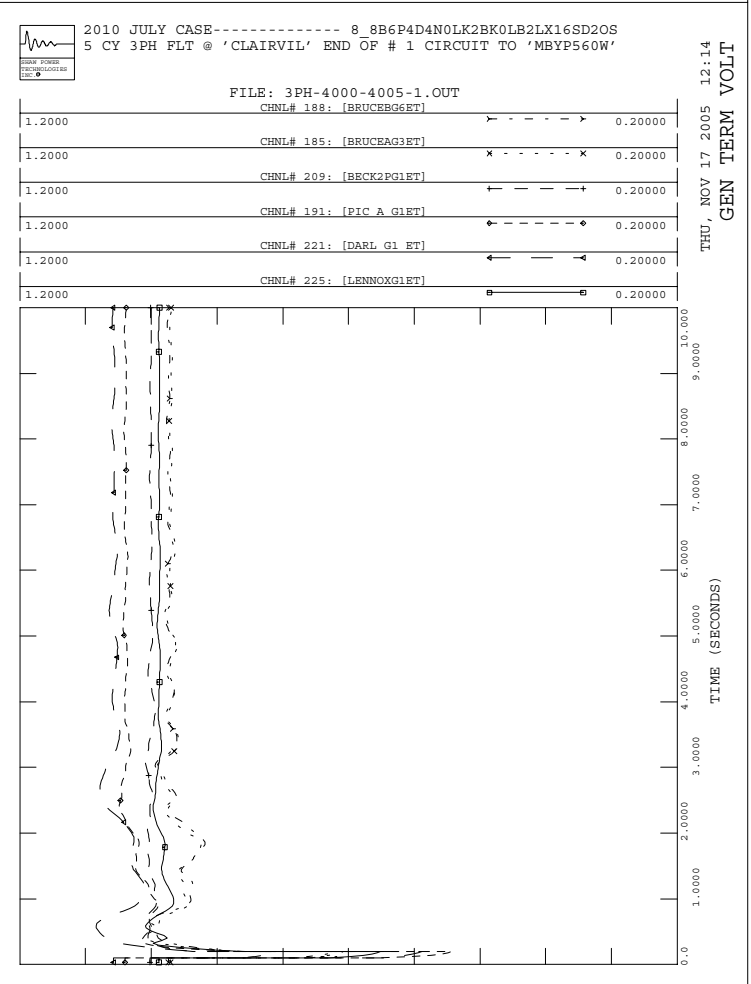
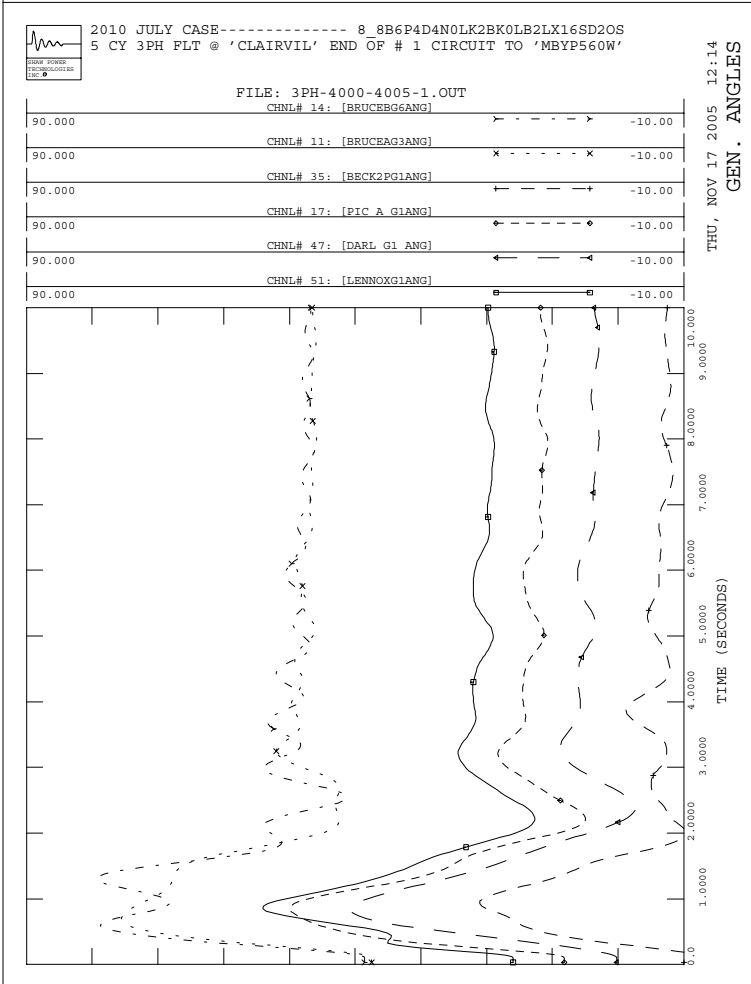
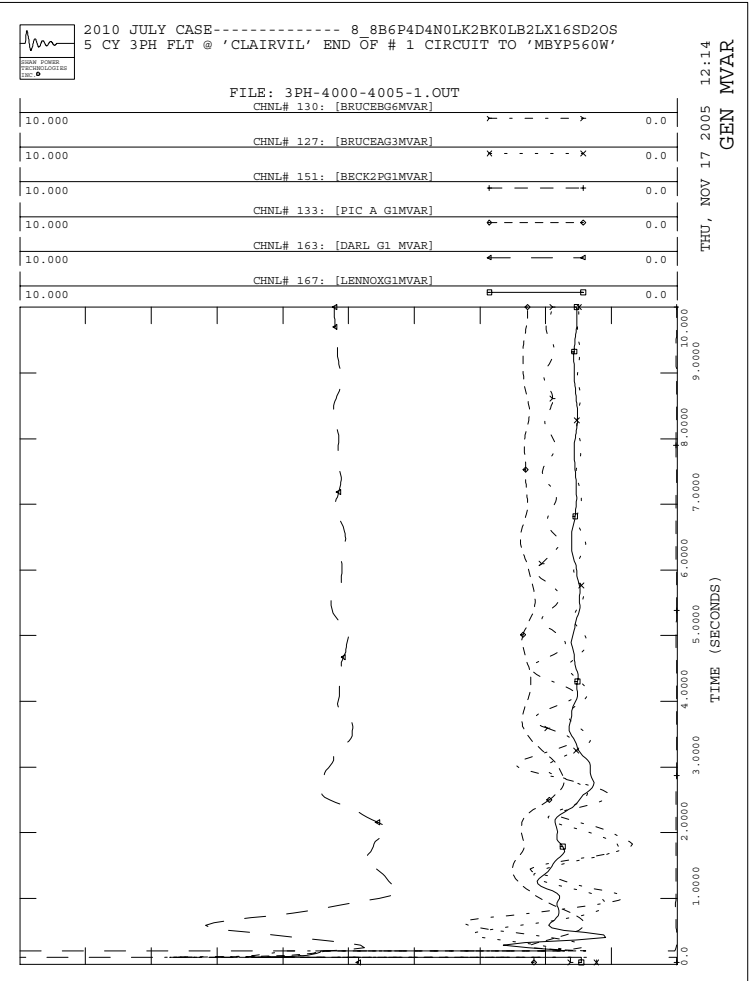
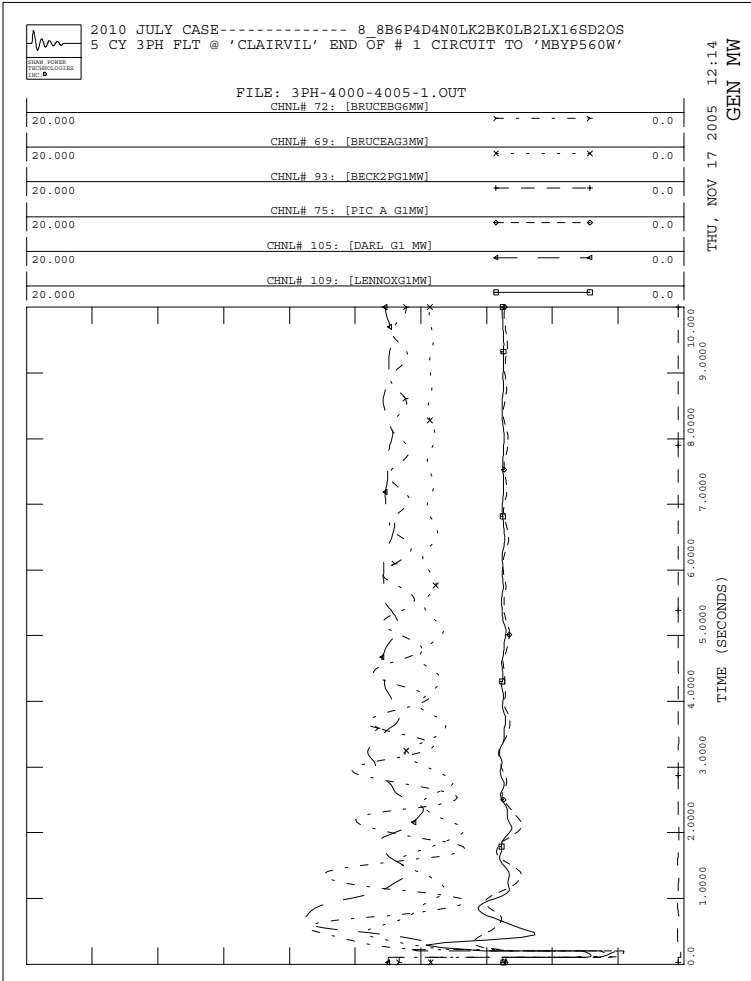


FIGURE G-73

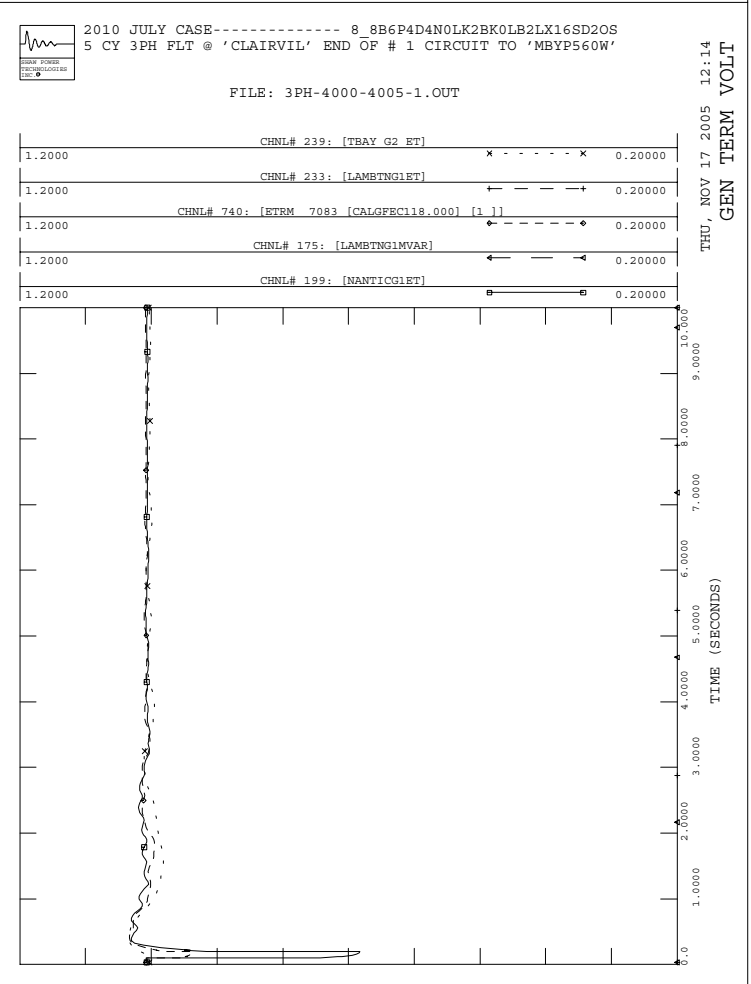
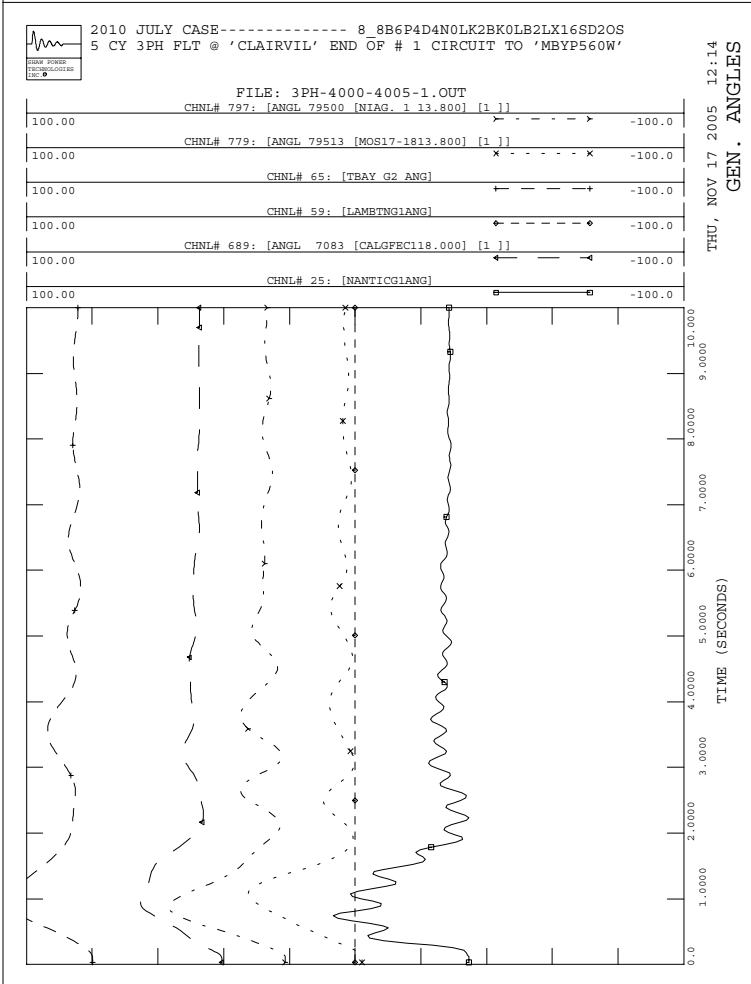
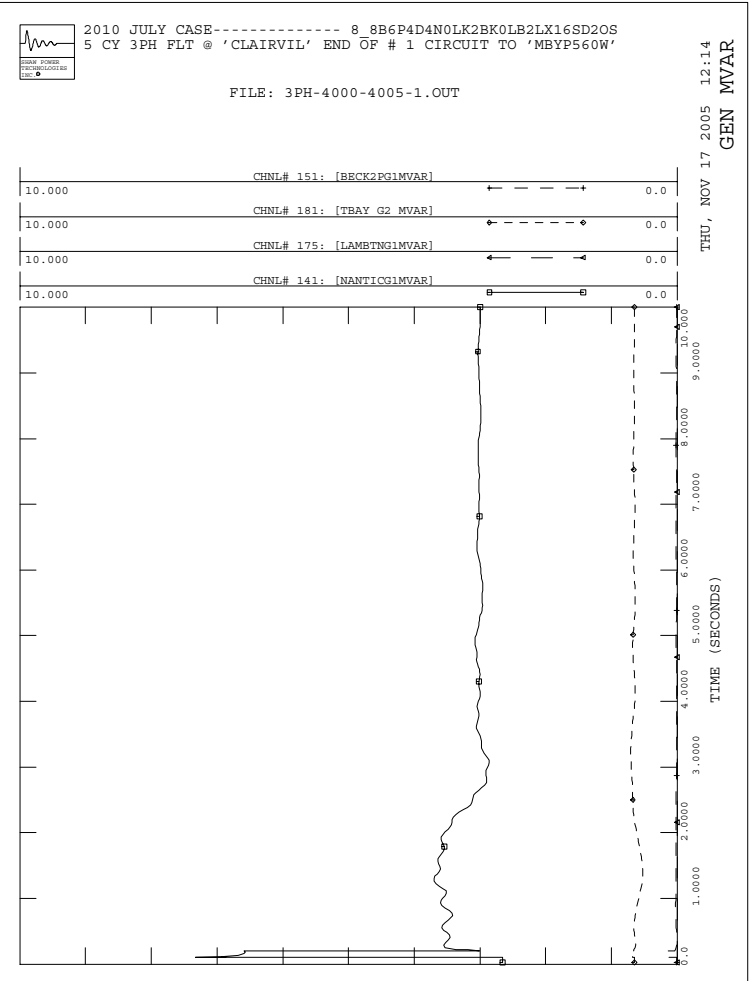
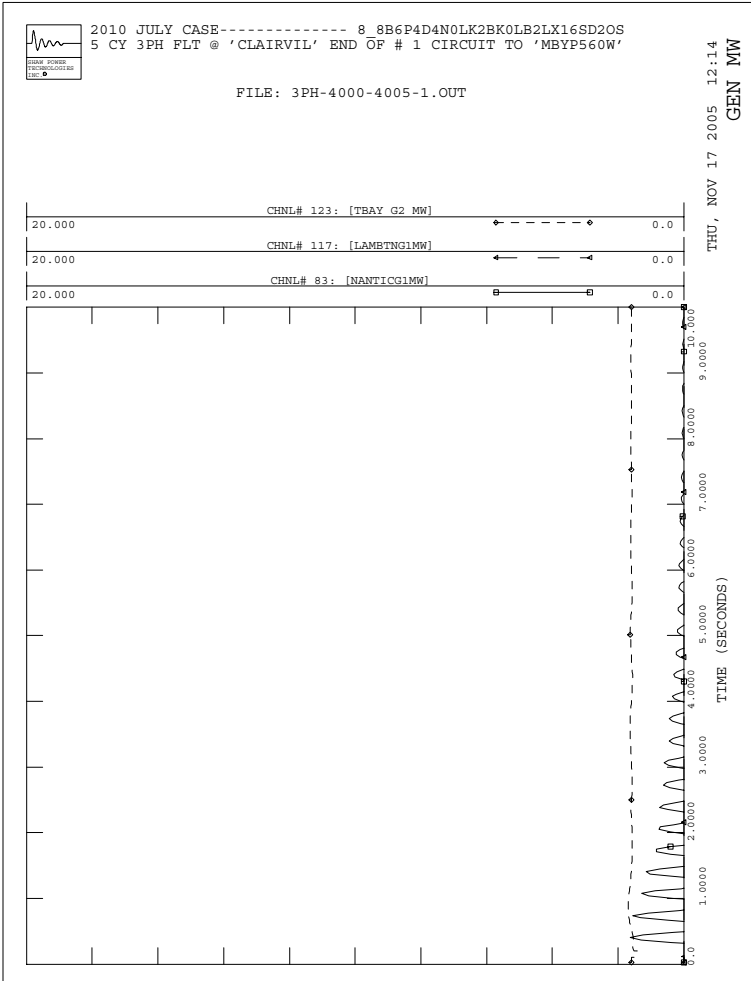


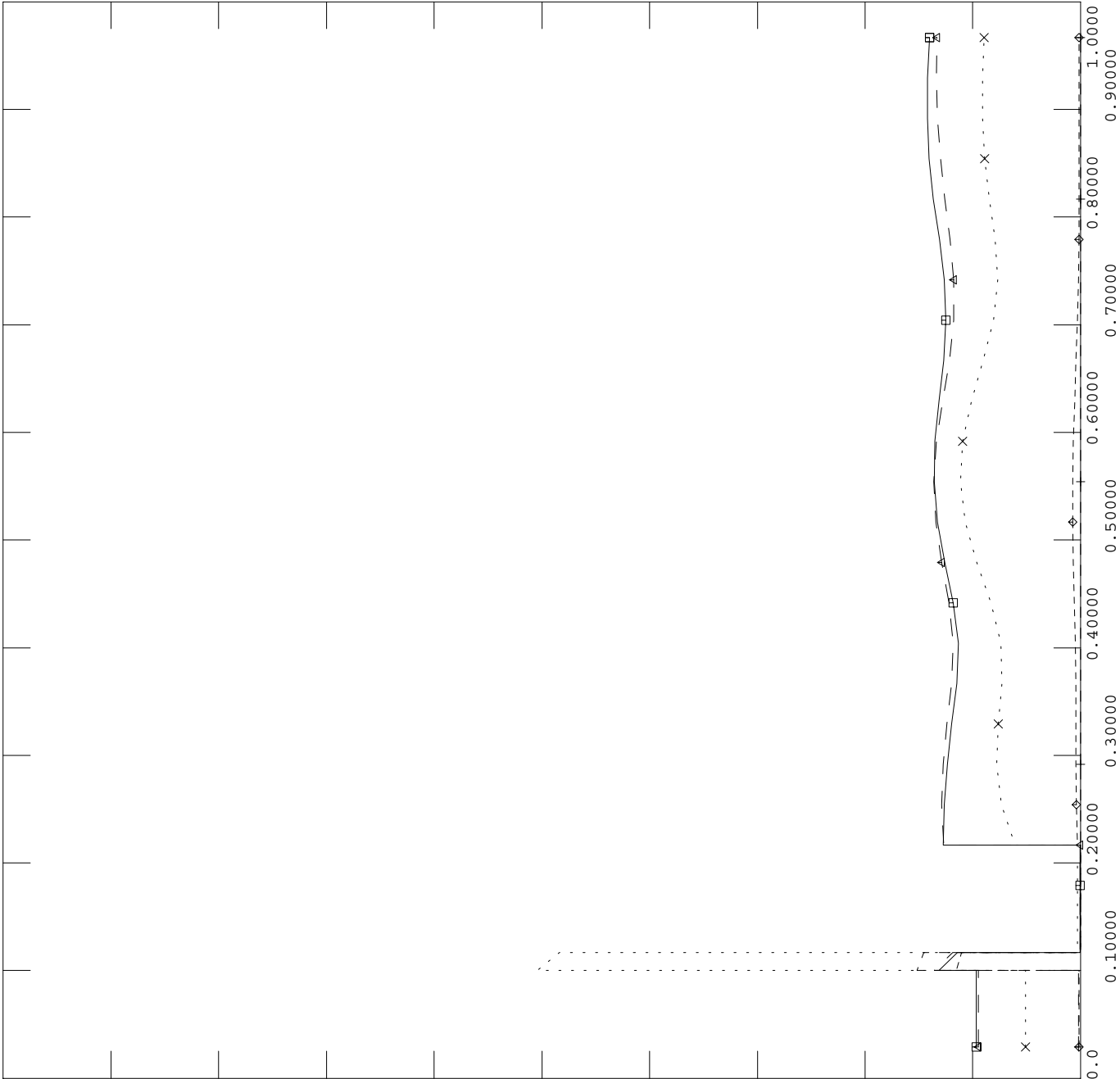
FIGURE G-74



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'

FILE: 3PH-4000-4005-1.OUT

0.50000	CHNL#'S 1190,1191: ABS ([V-TLBG1] - [V-TLBG2])	X - - - - - X	0.0
0.50000	CHNL#'S 1187,1189: ABS ([V-BLWD1] - [V-BLWD2])	+ - - - - +	0.0
0.50000	CHNL#'S 1186,1188: ABS ([V-BLWD3] - [V-BLWD4])	◇ - - - - ◇	0.0
0.50000	CHNL#'S 1183,1185: ABS ([V-GRBND3] - [V-GRBND4])	← - - - - →	0.0
0.50000	CHNL#'S 1182,1184: ABS ([V-GRBND1] - [V-GRBND2])	□ - - - - □	0.0



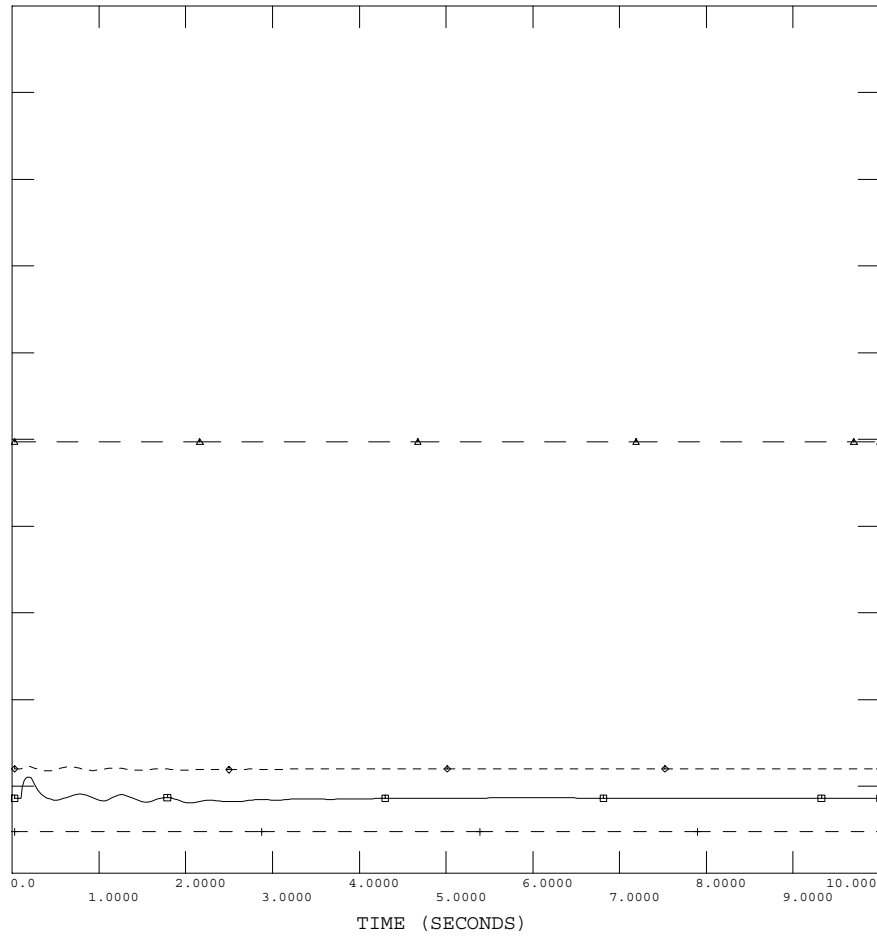
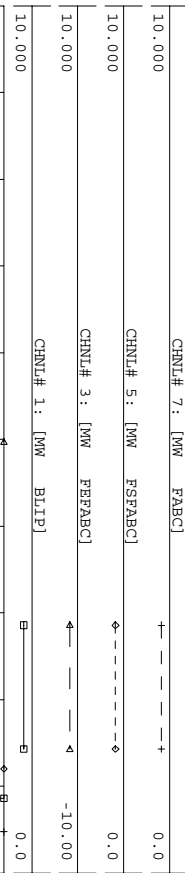
THU, NOV 17 2005 12:14
DV-ACROSS-S-CAPS

FIGURE G-75



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'

FILE: 3PH-4000-4005-1.OUT

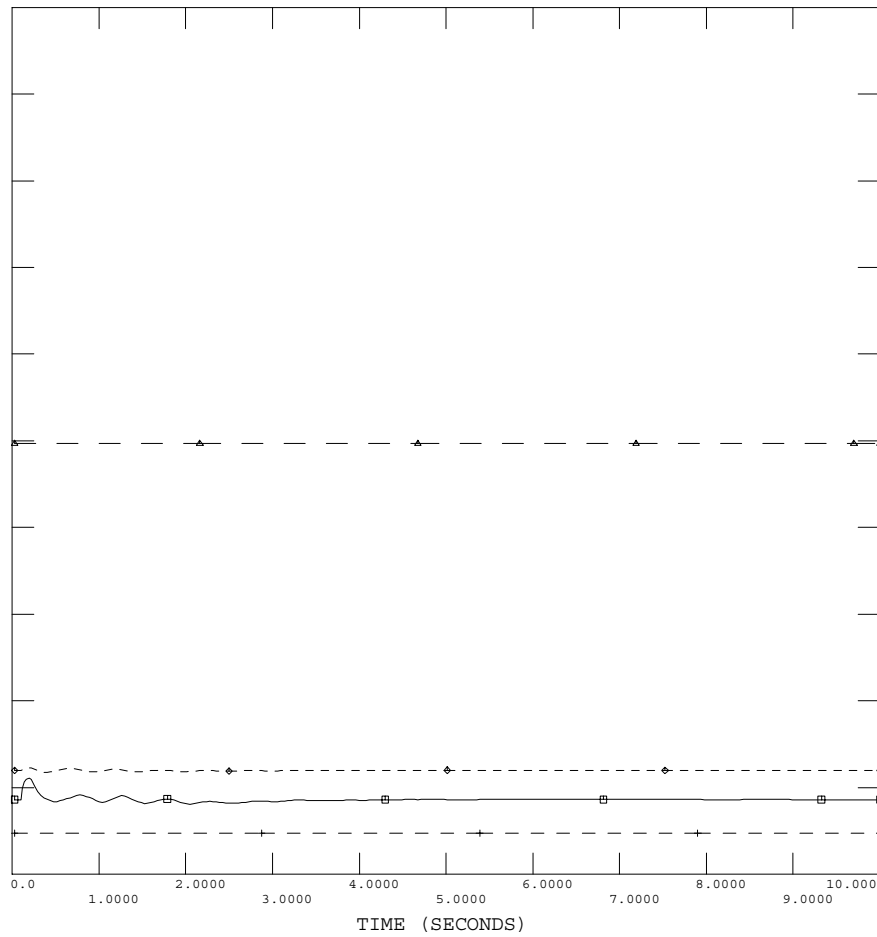
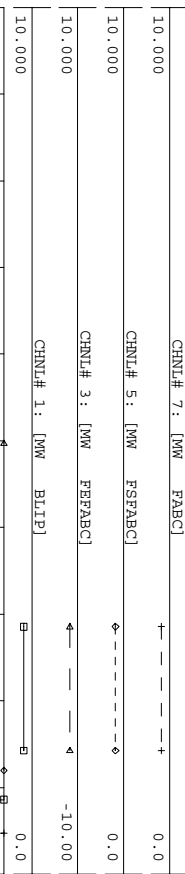


THU, NOV 17 2005 12:15
INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'CLAIRVIL' END OF # 1 CIRCUIT TO 'MBYP560W'

FILE: 3PH-4000-4005-1.OUT



THU, NOV 17 2005 12:15
INTERFACE MVAR

FIGURE G-76

**110% POWER TRANSFER
L-G (L-L-G) FAULTS, on Different Phases of the
Bruce-Milton D/C tower CLEARED in 6 cycles,
BYPASS of SERIES CAPACITORS**

Plots for the following disturbance are shown in the following order in this Appendix:

- ii. Bruce – Milton 500kV D/C (L-L-G fault at bus# 6408 and 6409)

Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G77&G78

Voltage Drop across the 5 series capacitors – Figure G79

Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G80

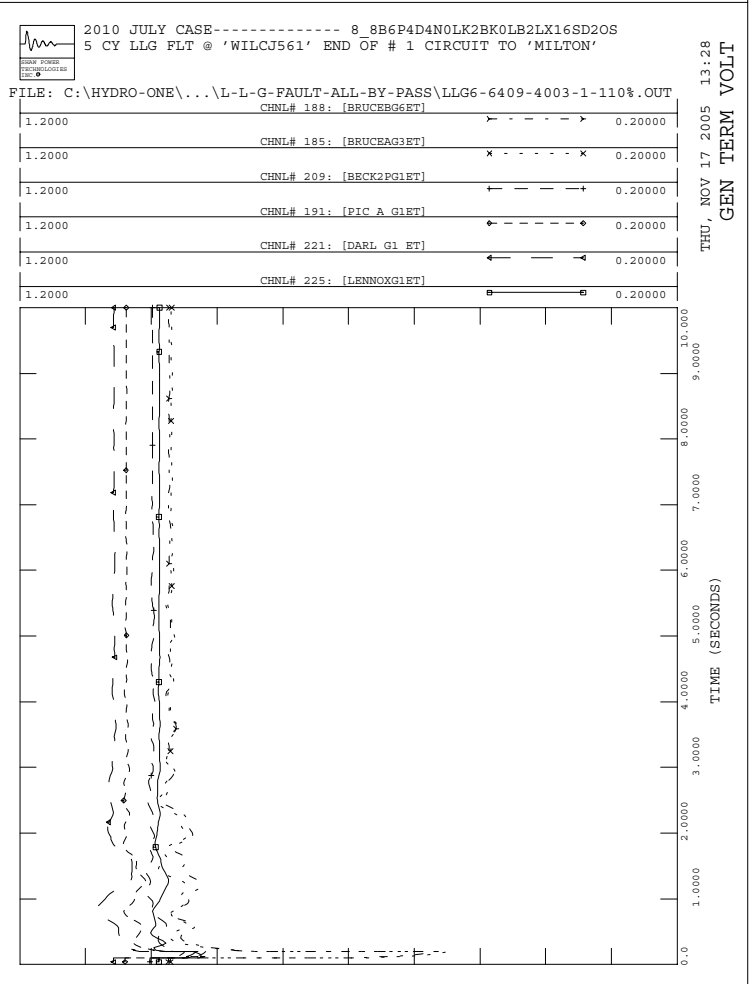
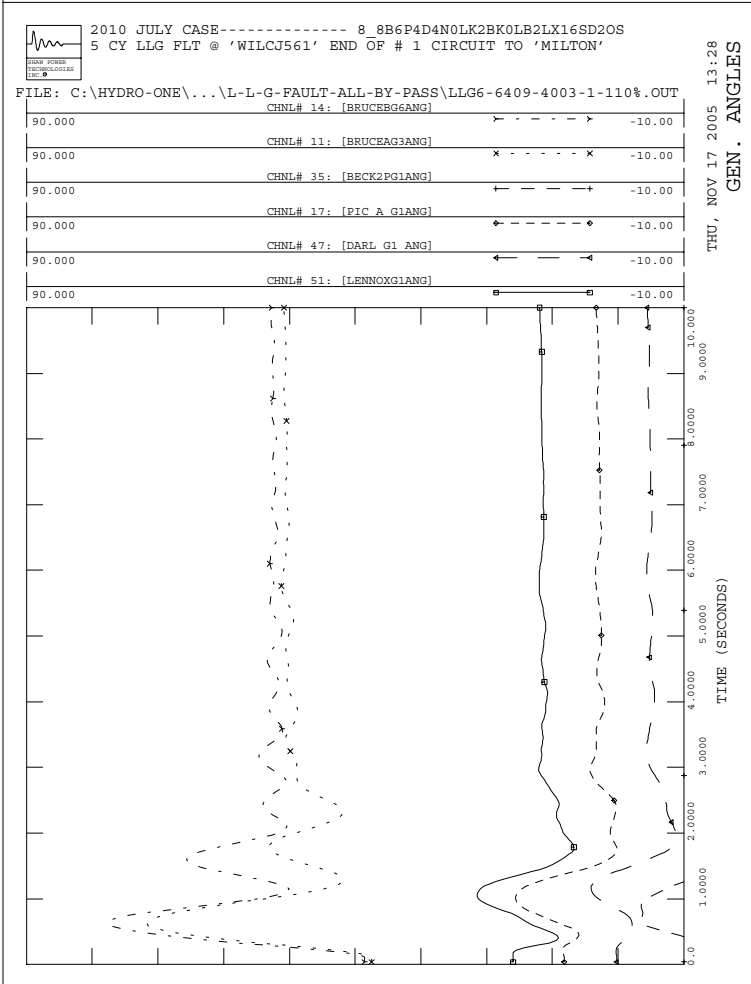
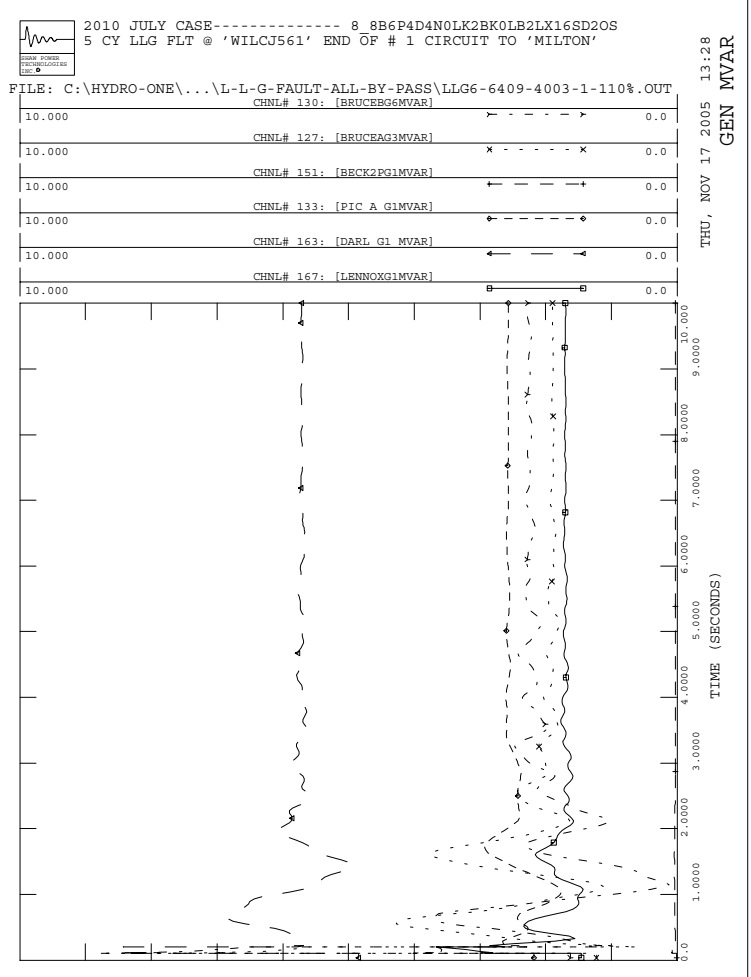
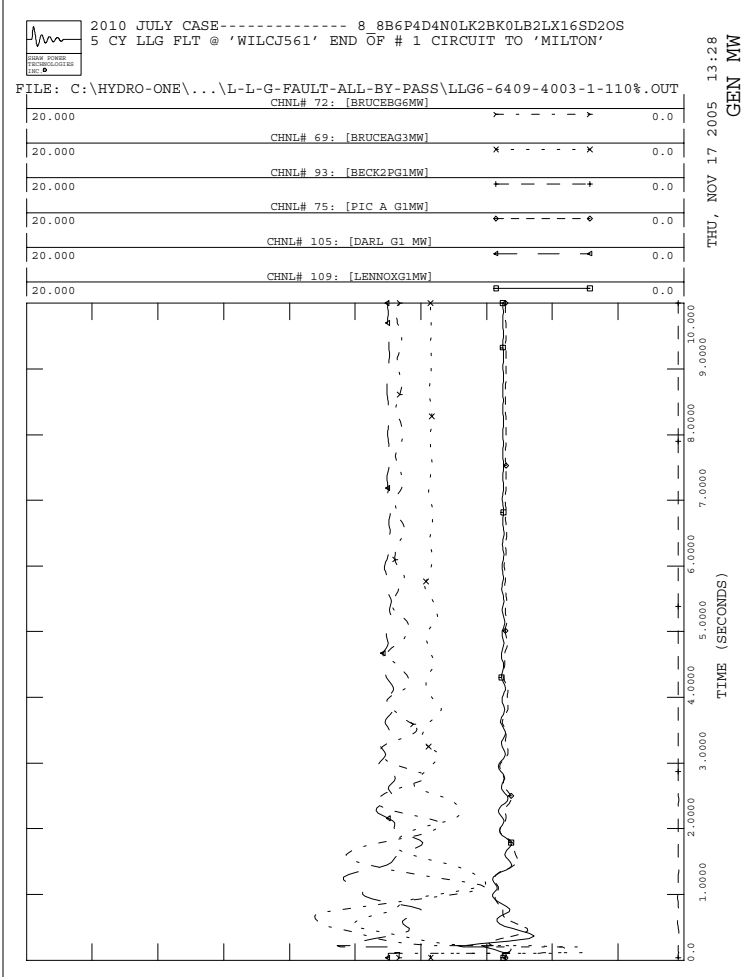


FIGURE G-77

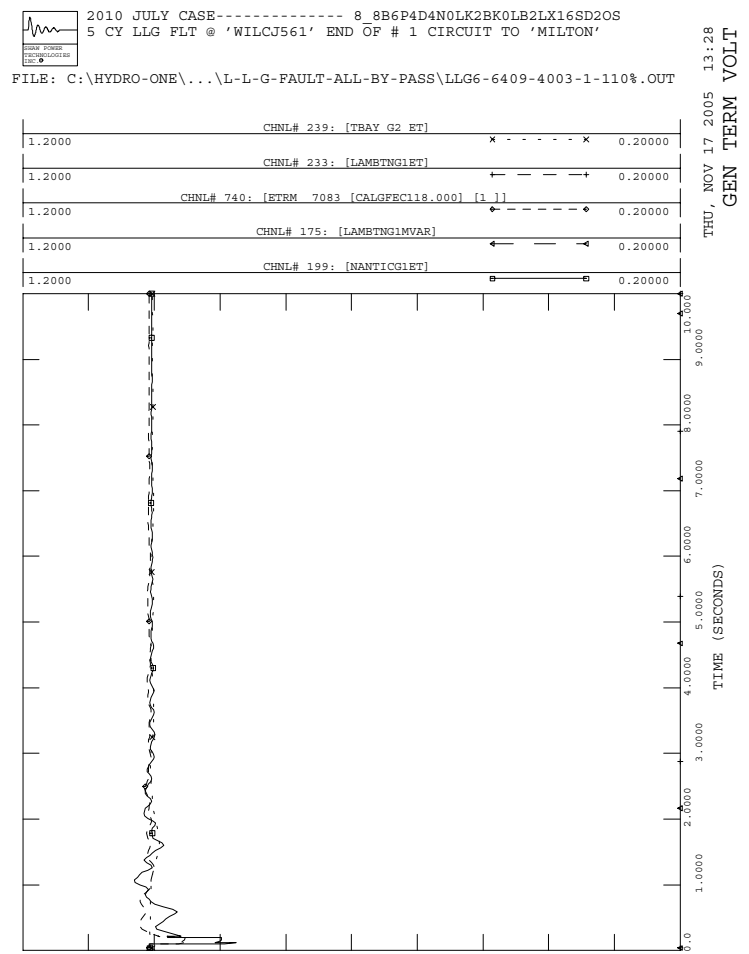
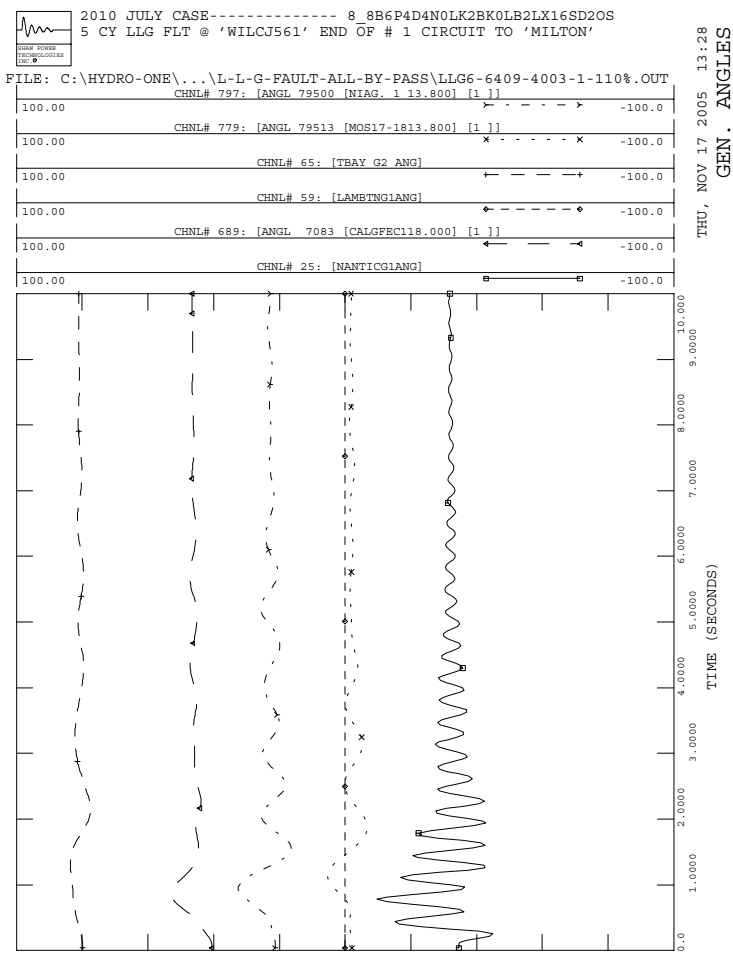
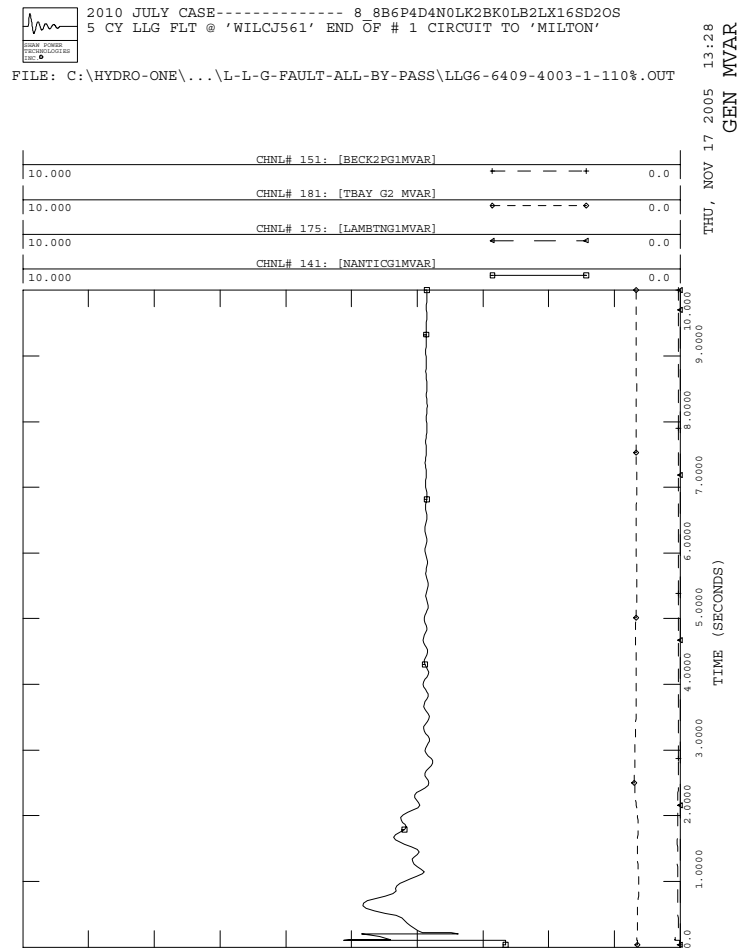
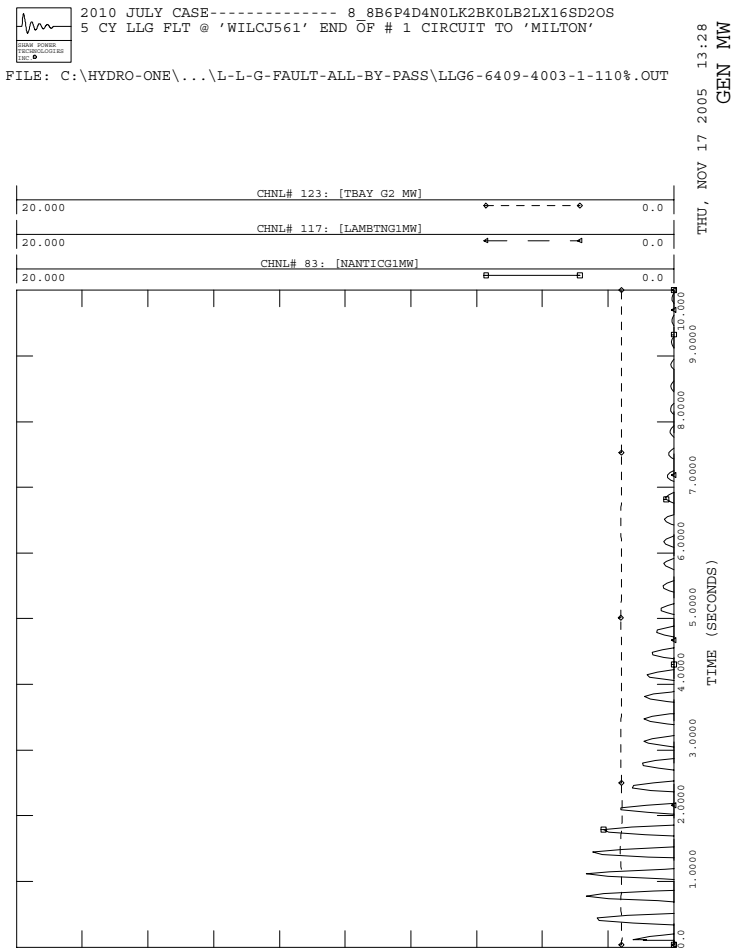
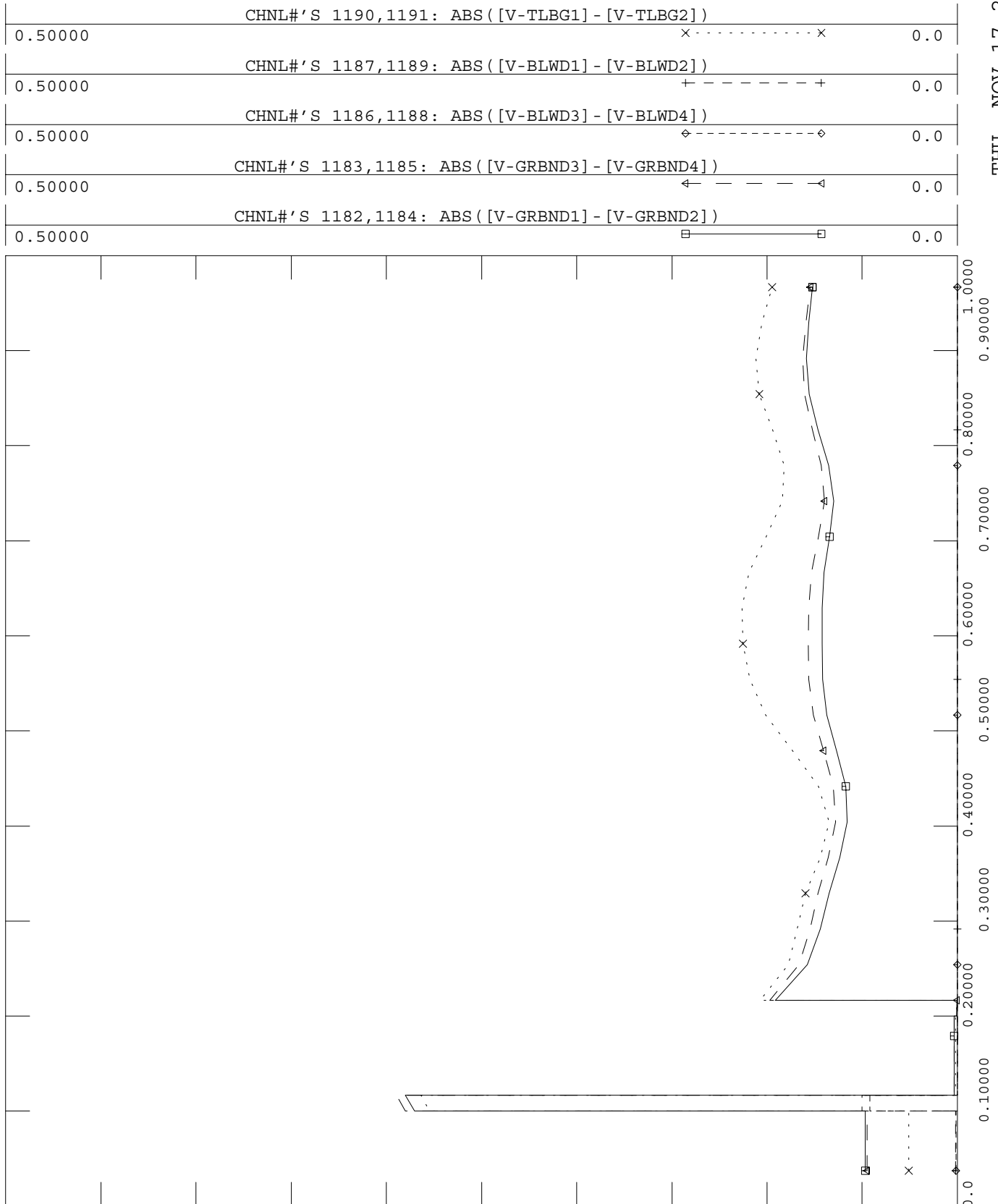


FIGURE G-78



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-L-G-FAULT-ALL-BY-PASS\LLG6-6409-4003-1-110%.OUT



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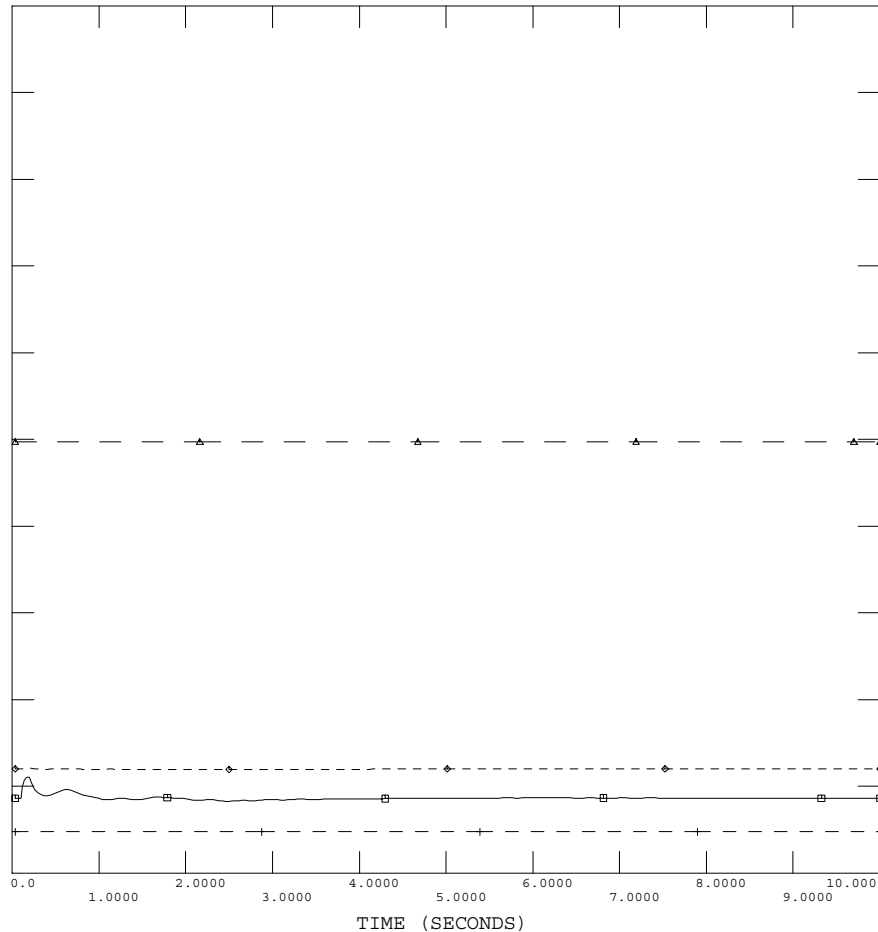
FIGURE G-79



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-L-G-FAULT-ALL-BY-PASS\LLG6-6409-4003-1-110%.OUT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	▢ - - - ▢	0.0



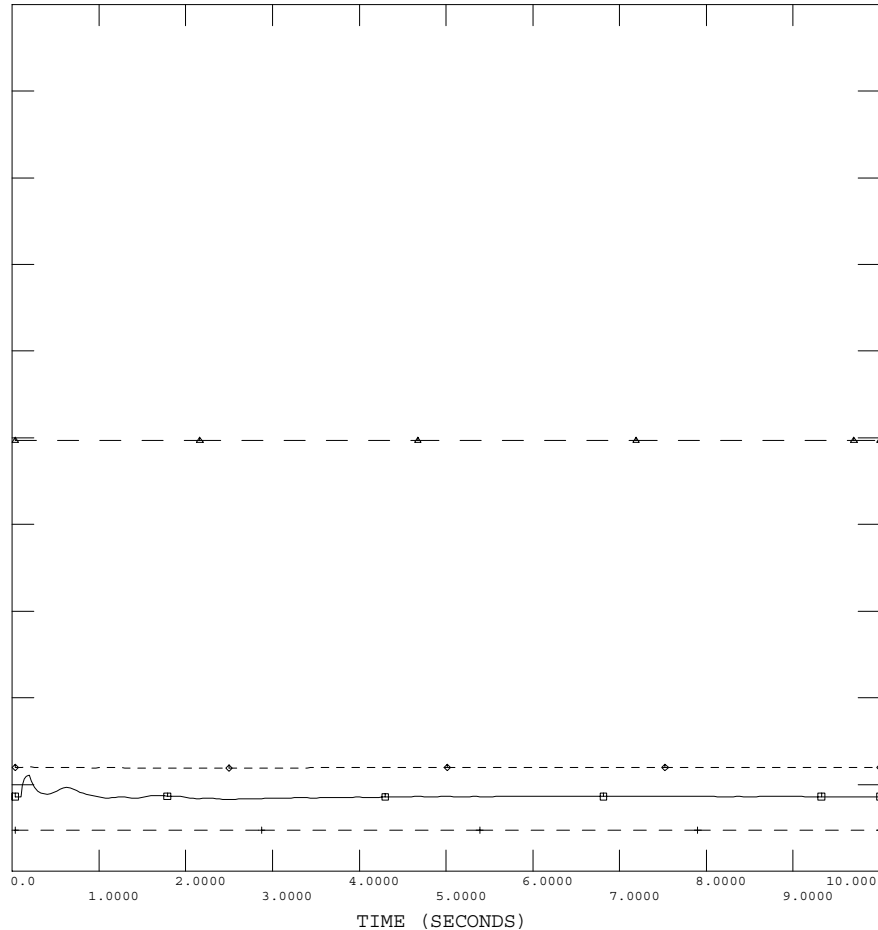
THU, NOV 17 2005 13:29
INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY LLG FLT @ 'WILCJ561' END OF # 1 CIRCUIT TO 'MILTON'

FILE: C:\HYDRO-ONE\...\L-L-G-FAULT-ALL-BY-PASS\LLG6-6409-4003-1-110%.OUT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	▢ - - - ▢	0.0



THU, NOV 17 2005 13:29
INTERFACE MVAR

FIGURE G-80

**HIGH FAULT LEVEL LOCATION
3-PHASE FAULT, NORMALLY CLEARED,
NO-BYPASS of SERIES CAPACITOR BANKS**

Plots for the following disturbance are shown in the following order in this Appendix:

- i. Bruce – Longwood 500kV Circuit (fault at 30% from Longwood)
Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G81&G82
Voltage Drop across the 5 series capacitors – Figure G83
Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G84
- ii. Longwood – Nanticoke 500kV Circuit (fault at bus# 7000)
Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G85&G86
Voltage Drop across the 5 series capacitors – Figure G87
Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G88

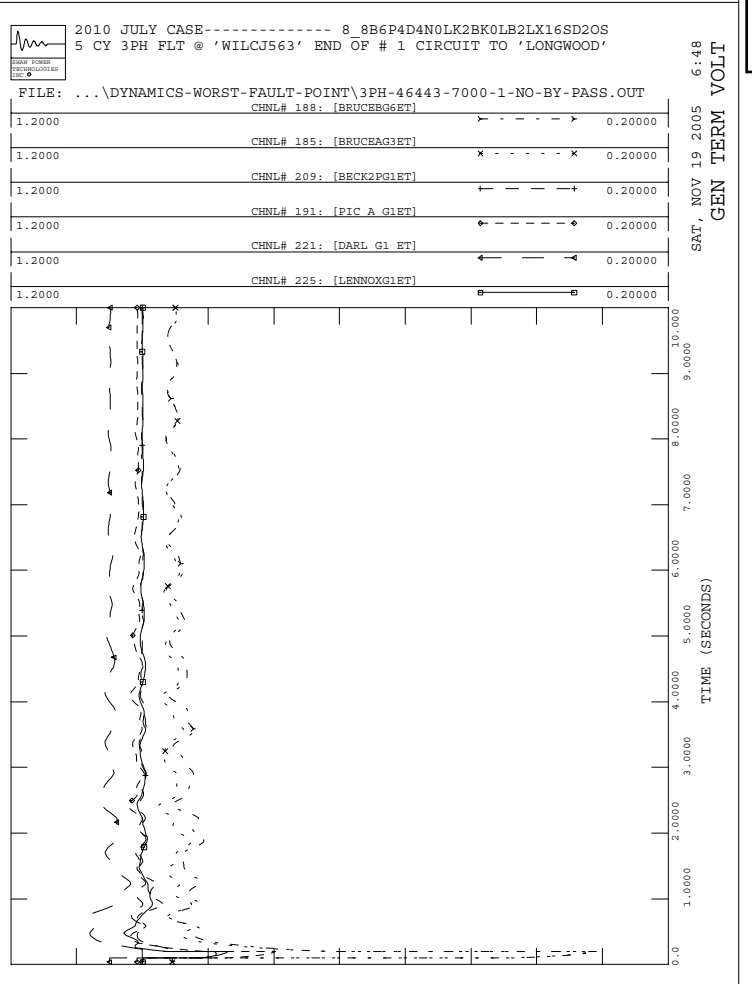
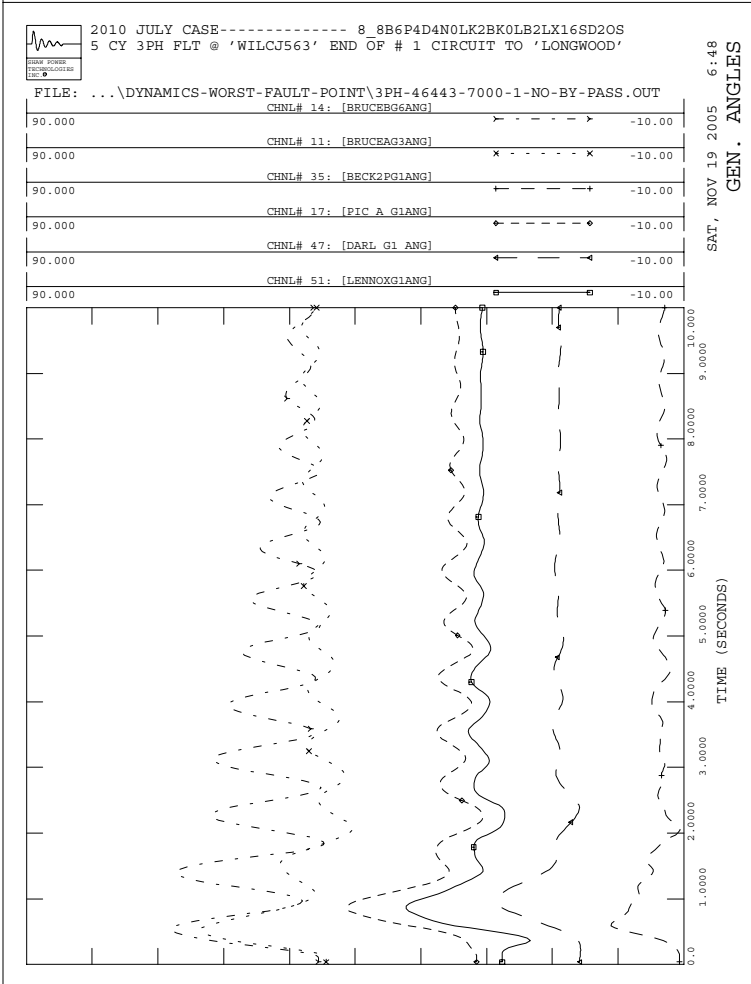
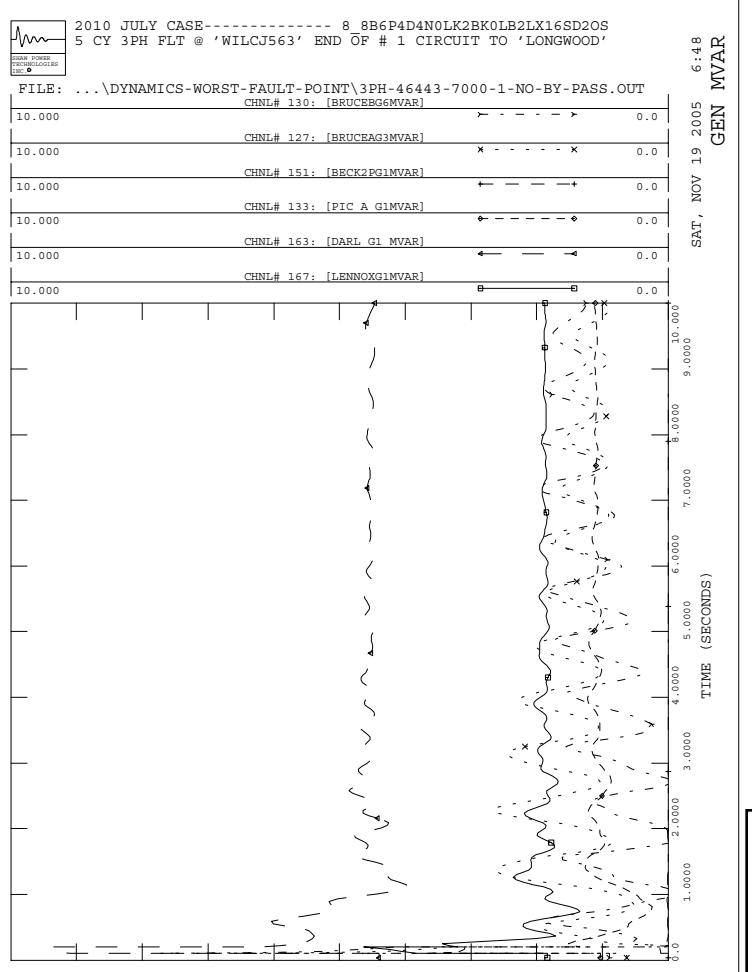
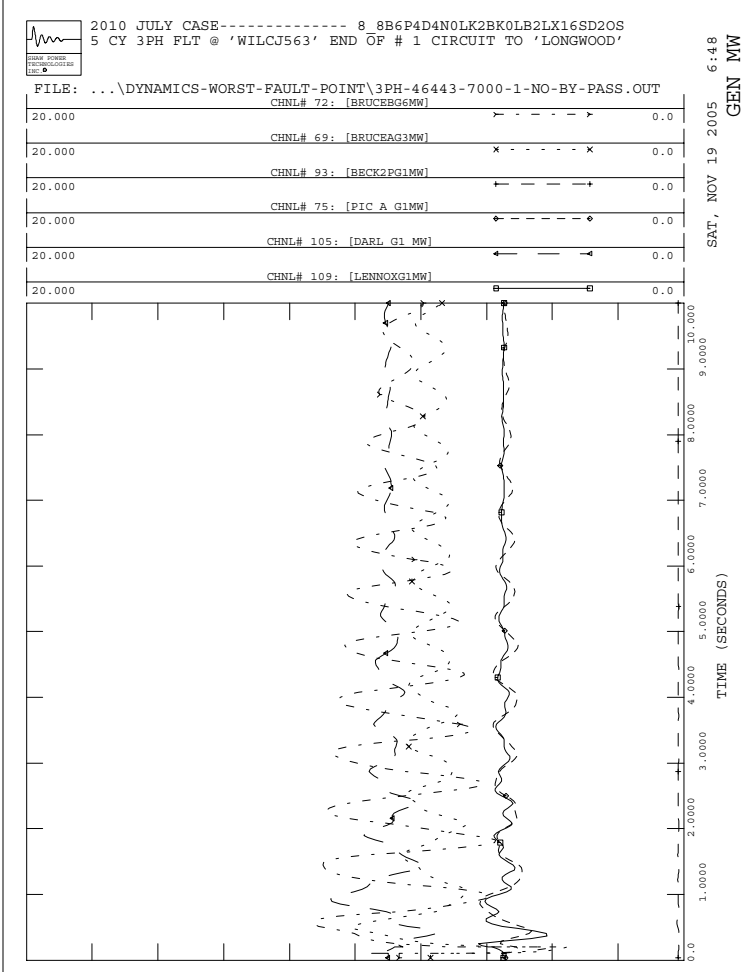


FIGURE G-81

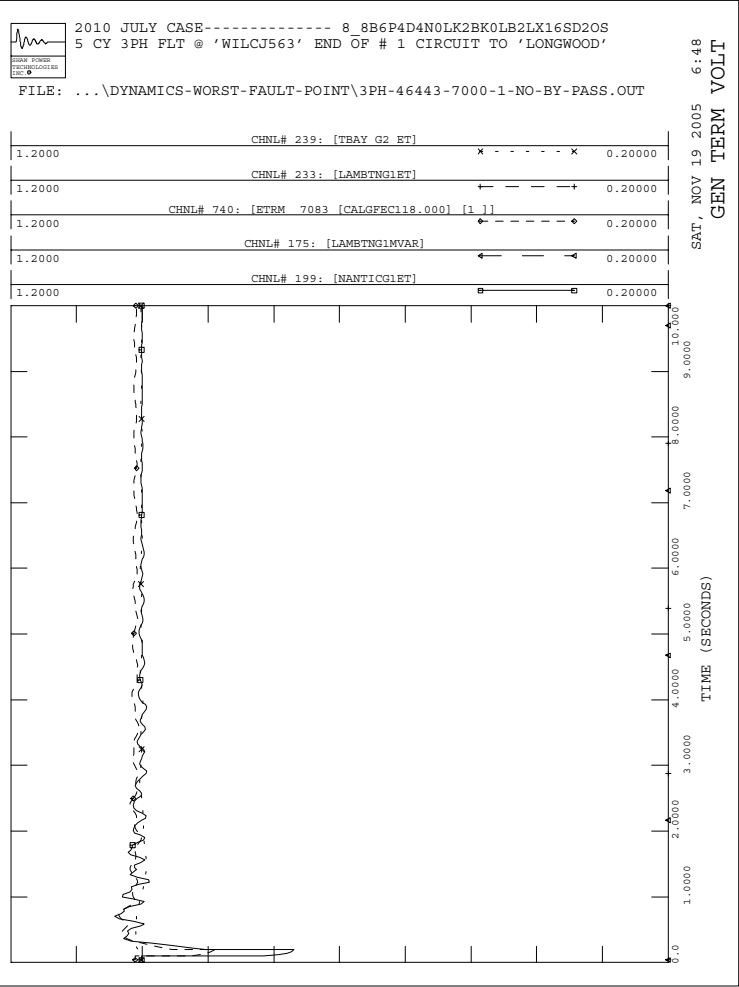
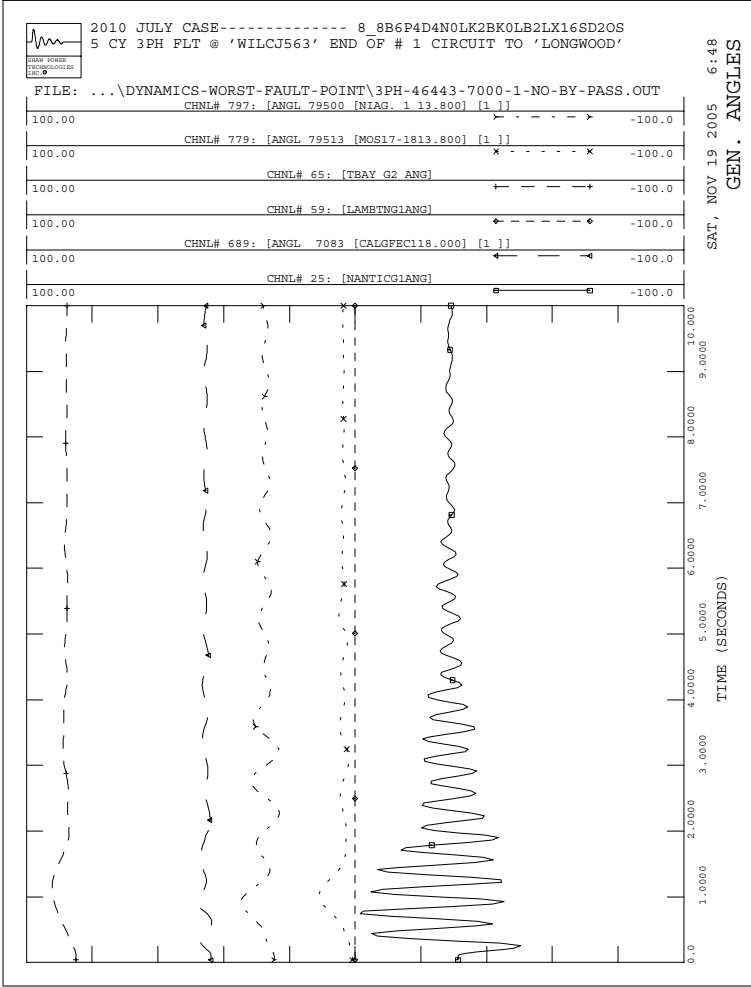
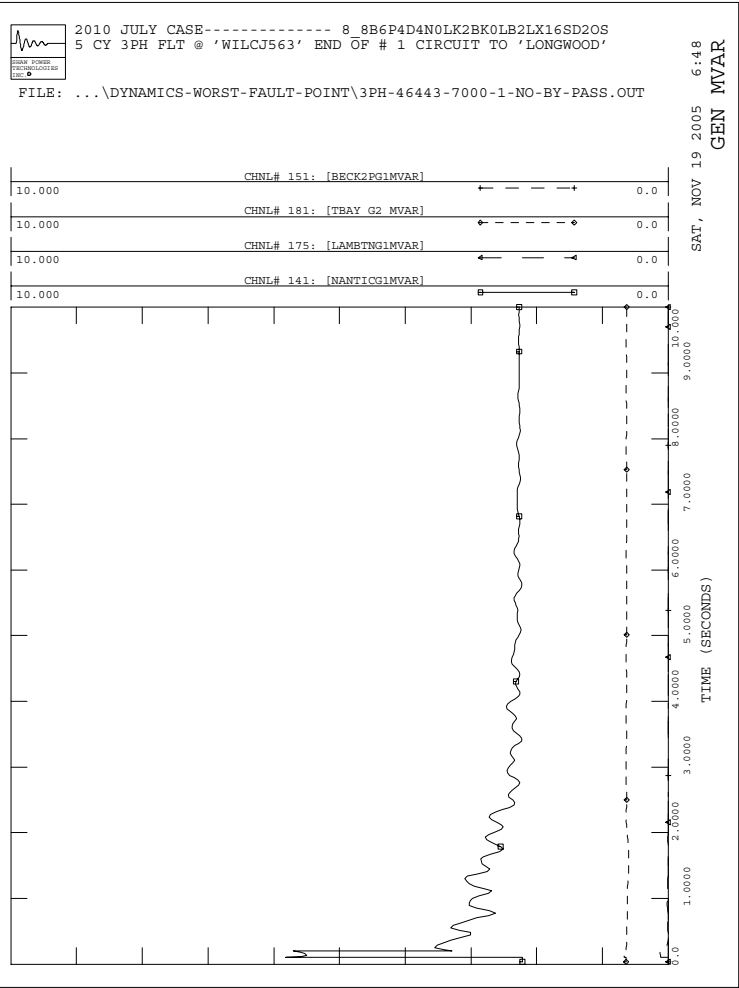
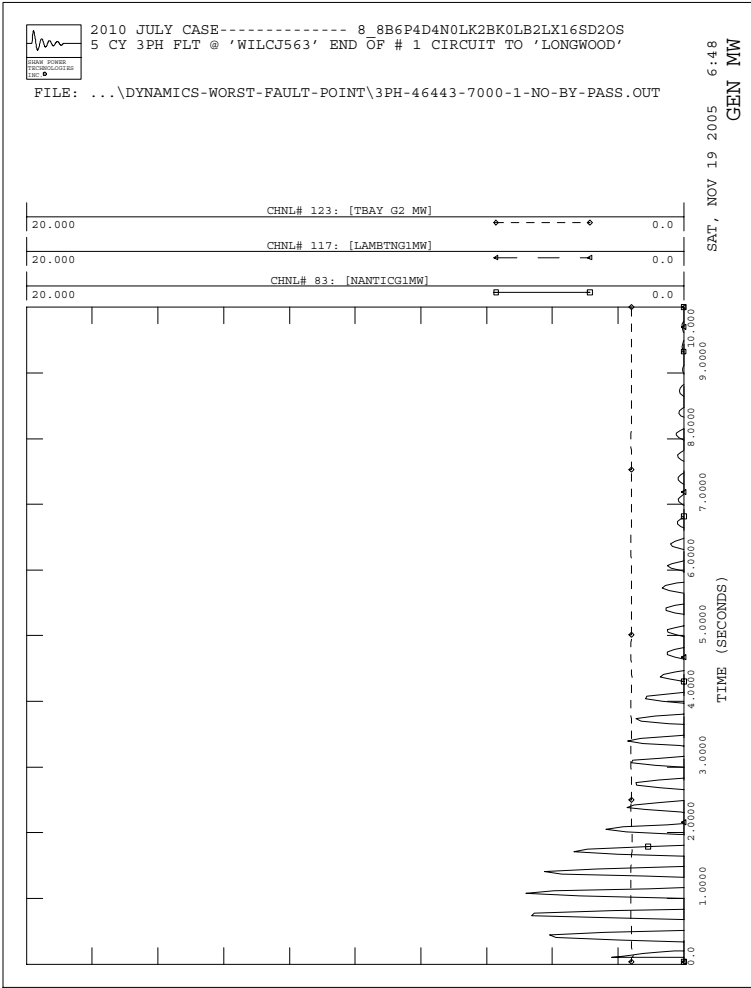


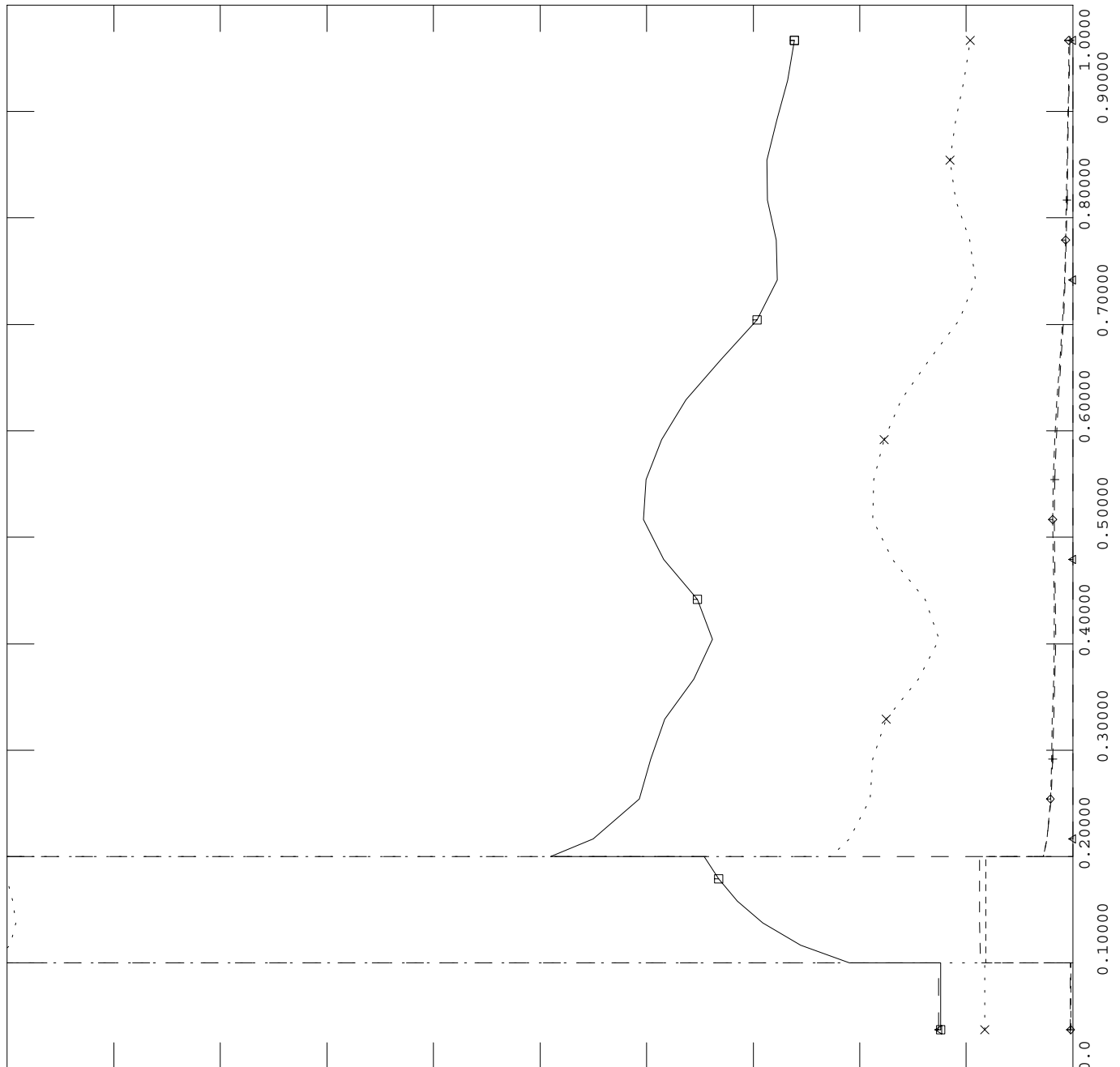
FIGURE G-82



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: ... \DYNAMICS-WORST-FAULT-POINT\3PH-46443-7000-1-NO-BY-PASS.OUT

0.50000	CHNL#'S 1190,1191: ABS ([V-TLBG1] - [V-TLBG2])	X - - - - - X	0.0
0.50000	CHNL#'S 1187,1189: ABS ([V-BLWD1] - [V-BLWD2])	+ - - - - +	0.0
0.50000	CHNL#'S 1186,1188: ABS ([V-BLWD3] - [V-BLWD4])	◇ - - - - ◇	0.0
0.50000	CHNL#'S 1183,1185: ABS ([V-GRBND3] - [V-GRBND4])	← - - - - →	0.0
0.50000	CHNL#'S 1182,1184: ABS ([V-GRBND1] - [V-GRBND2])	□ - - - - □	0.0

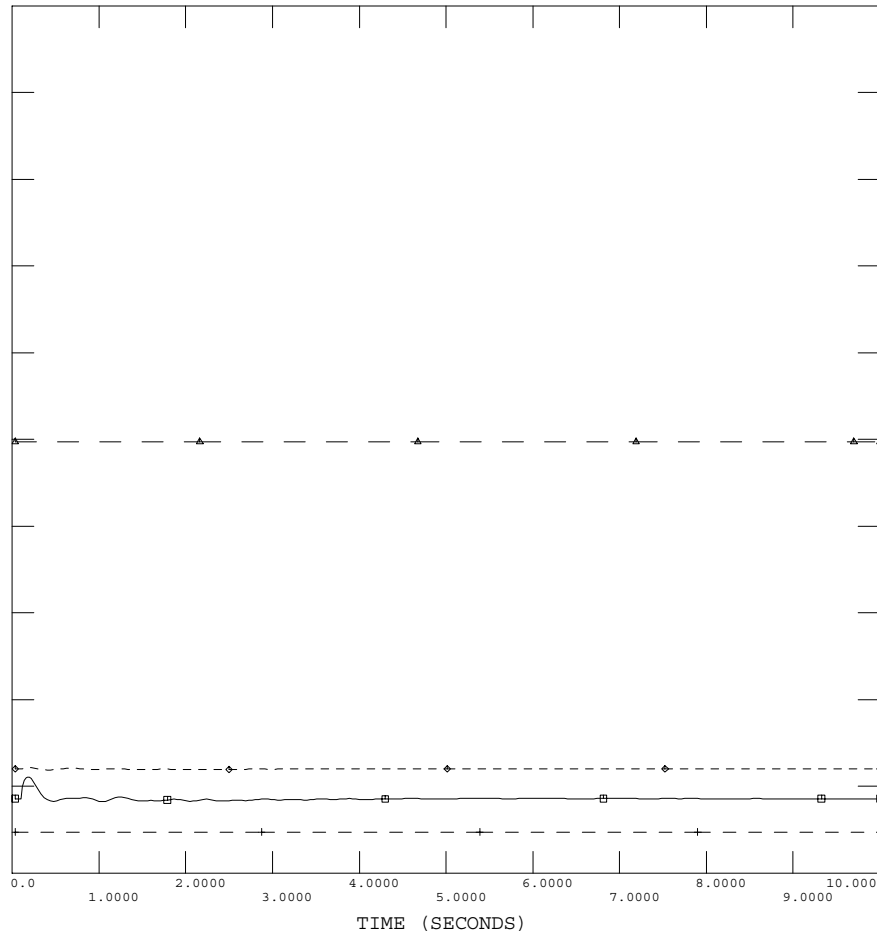


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FIGURE G-83

2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'
FILE: ... \DYNAMICS-WORST-FAULT-POINT\3PH-46443-7000-1-NO-BY-PASS.OUT

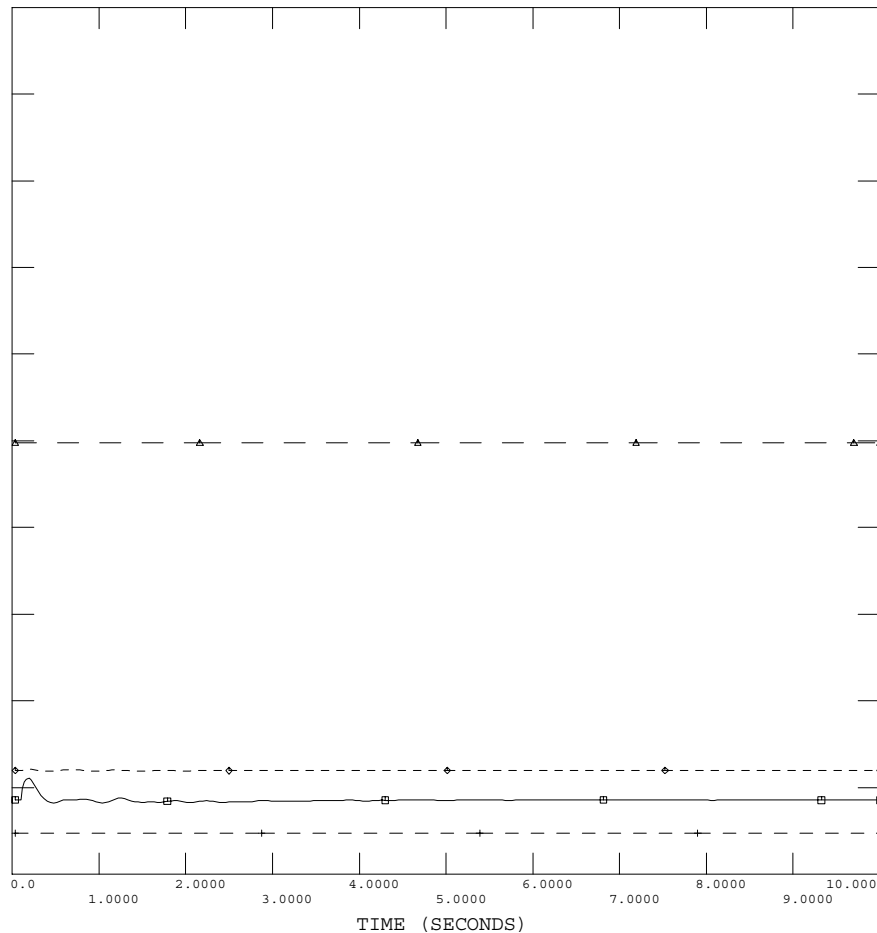
10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	■ - - - ■	0.0



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INTERFACE MW

2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'
FILE: ... \DYNAMICS-WORST-FAULT-POINT\3PH-46443-7000-1-NO-BY-PASS.OUT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	■ - - - ■	0.0



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INTERFACE MVAR

FIGURE G-84

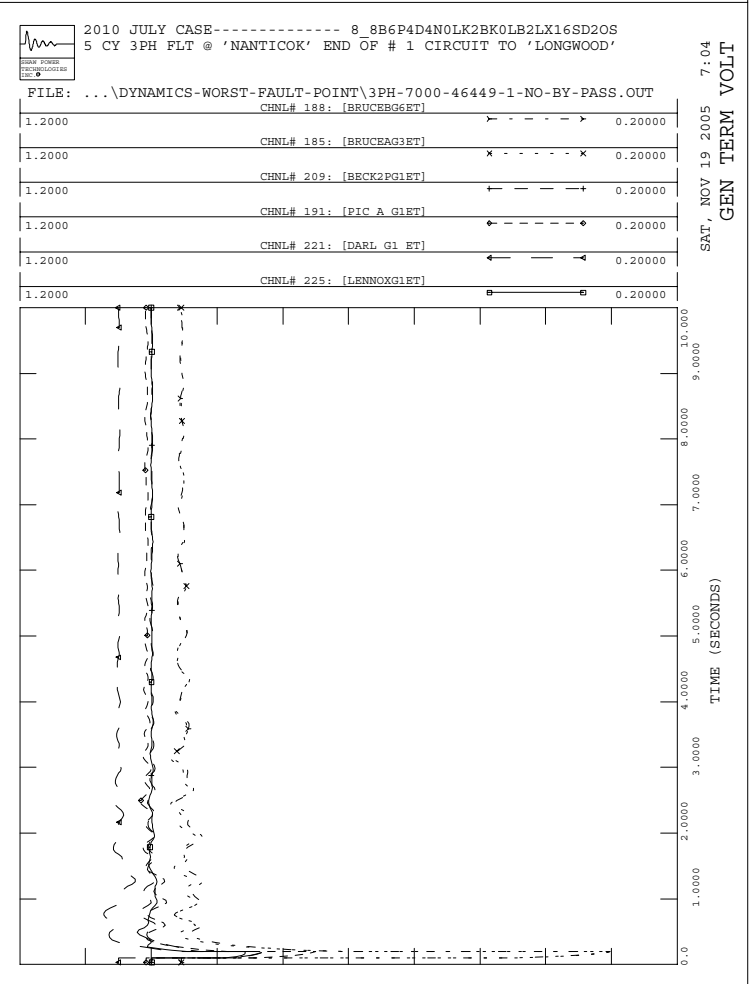
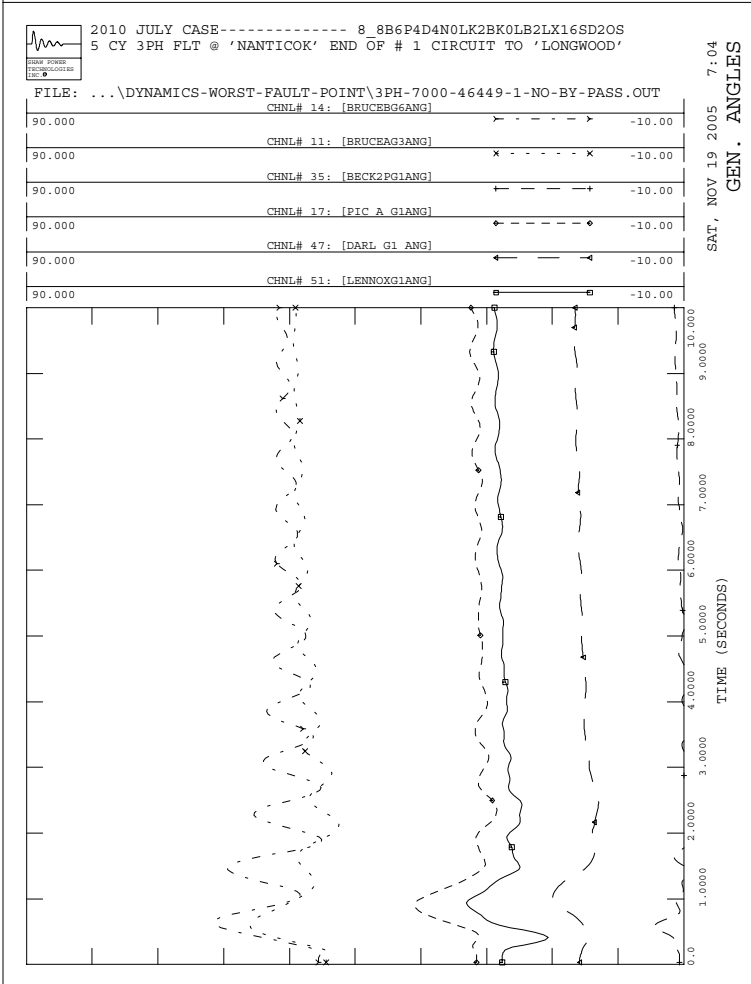
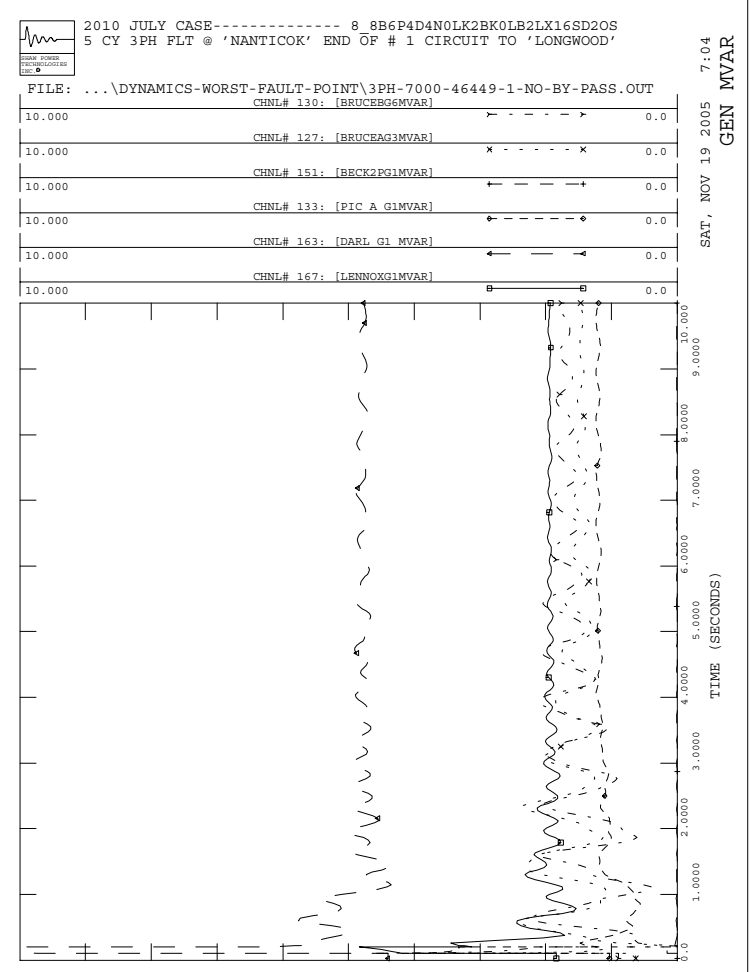
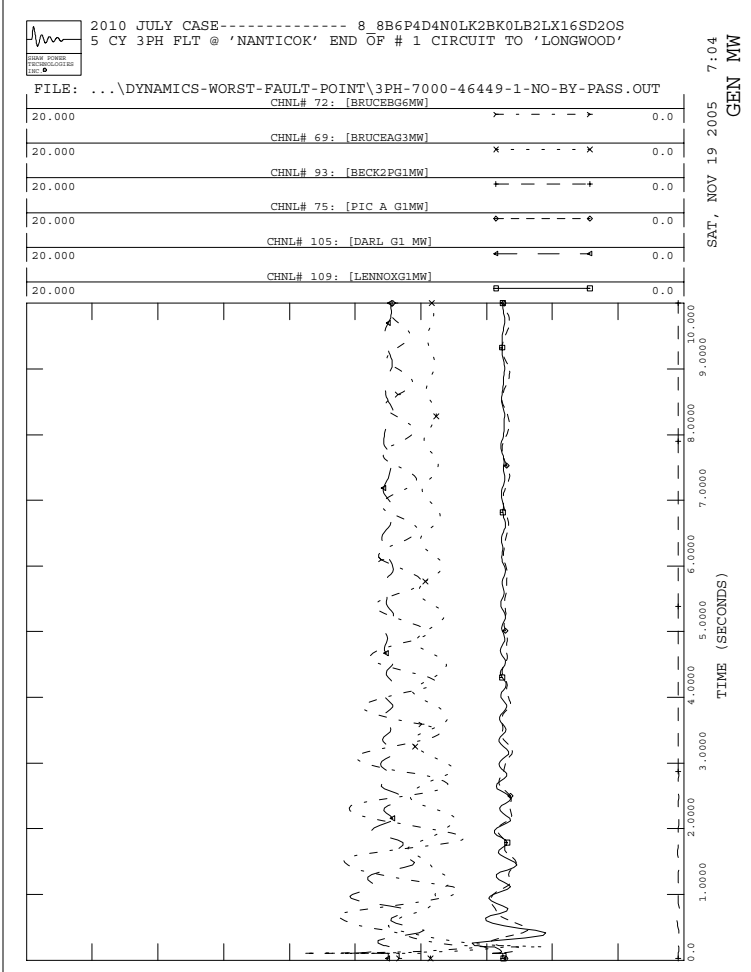


FIGURE G-85

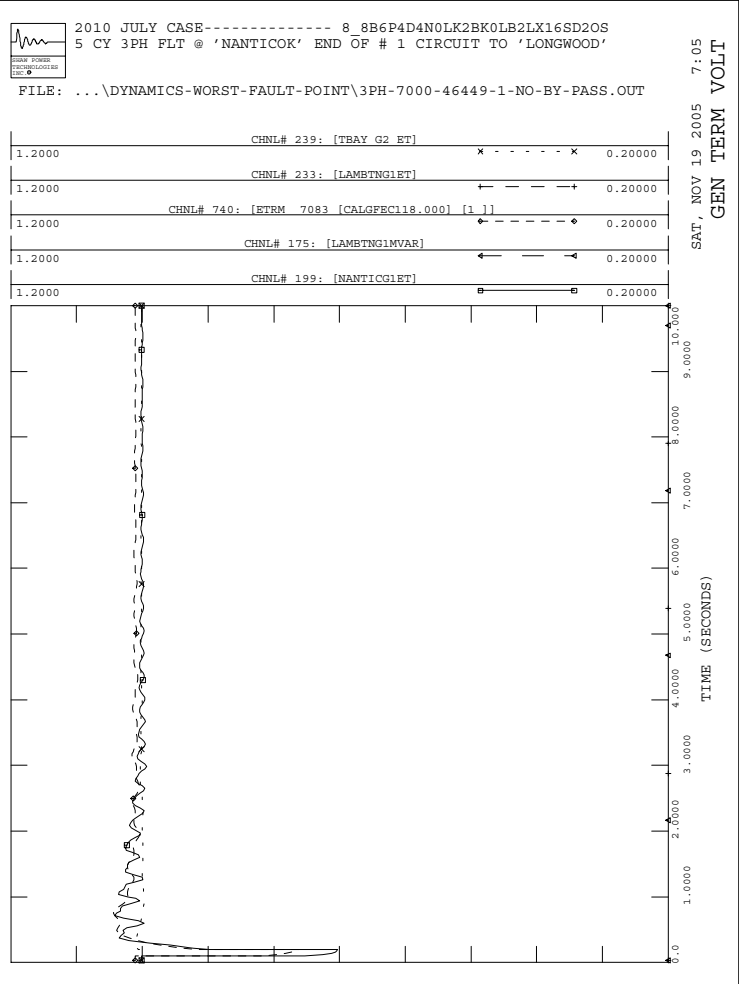
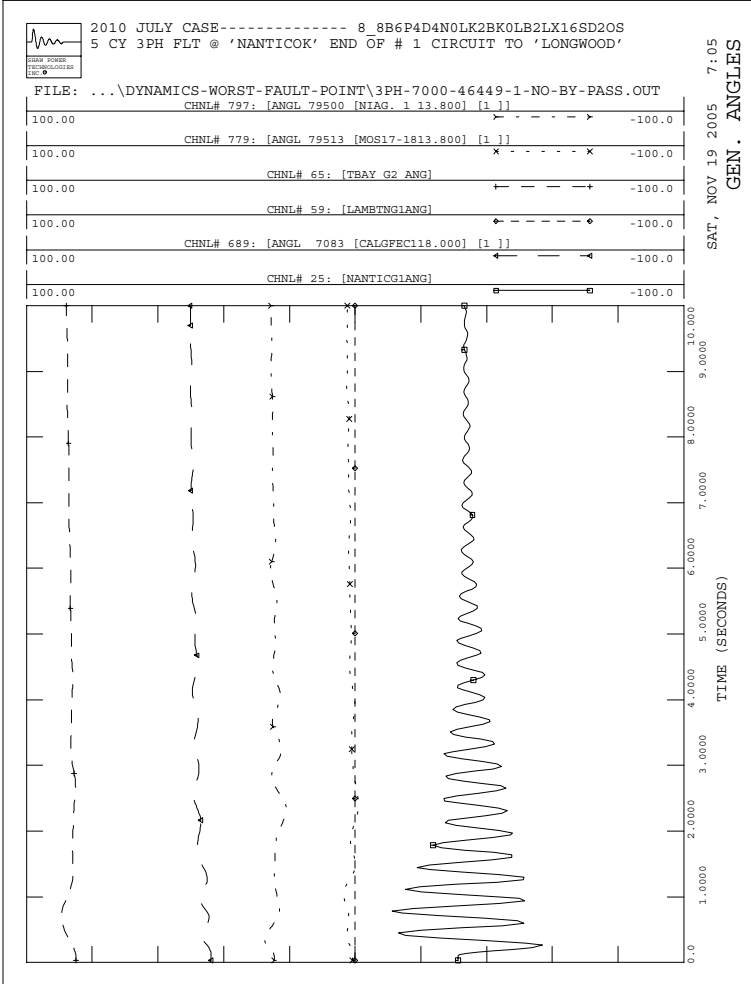
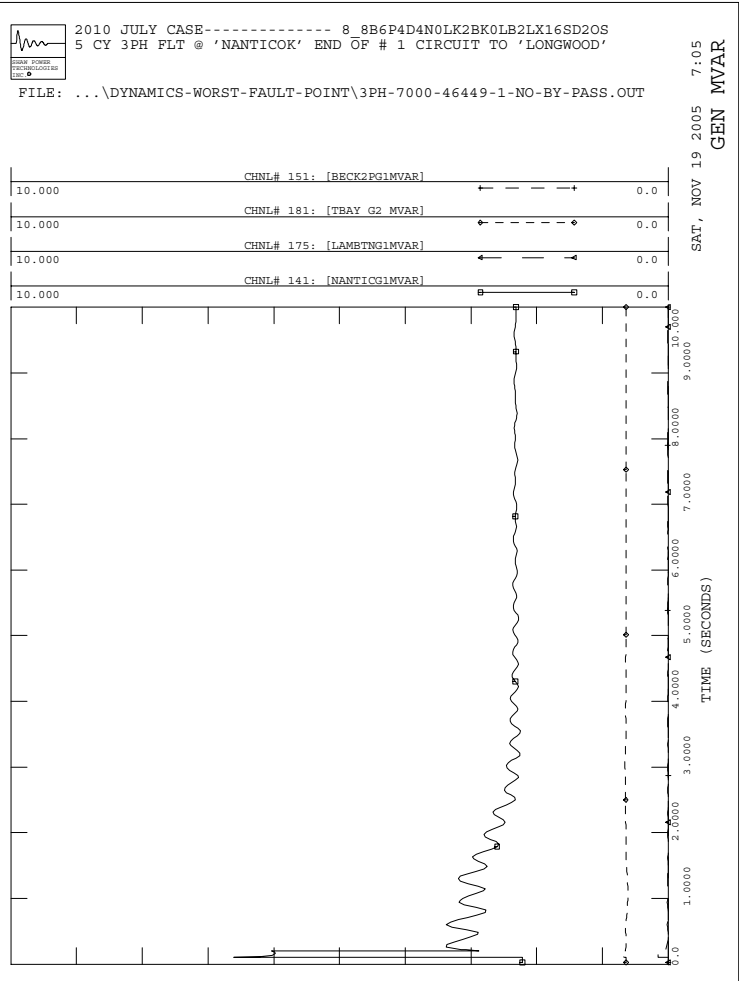
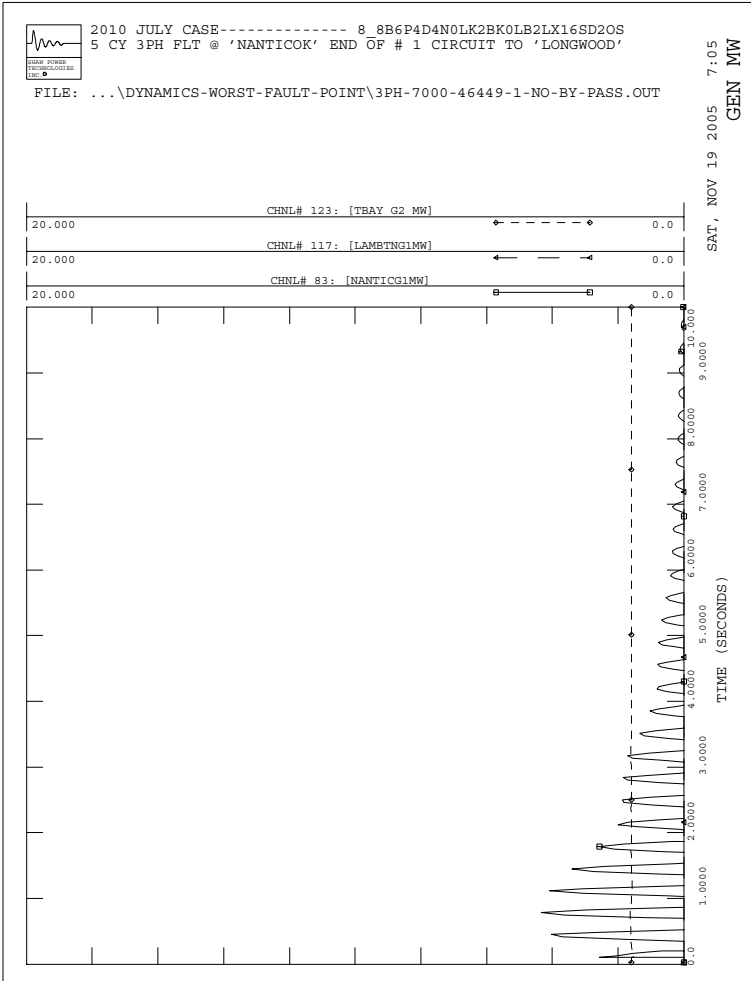
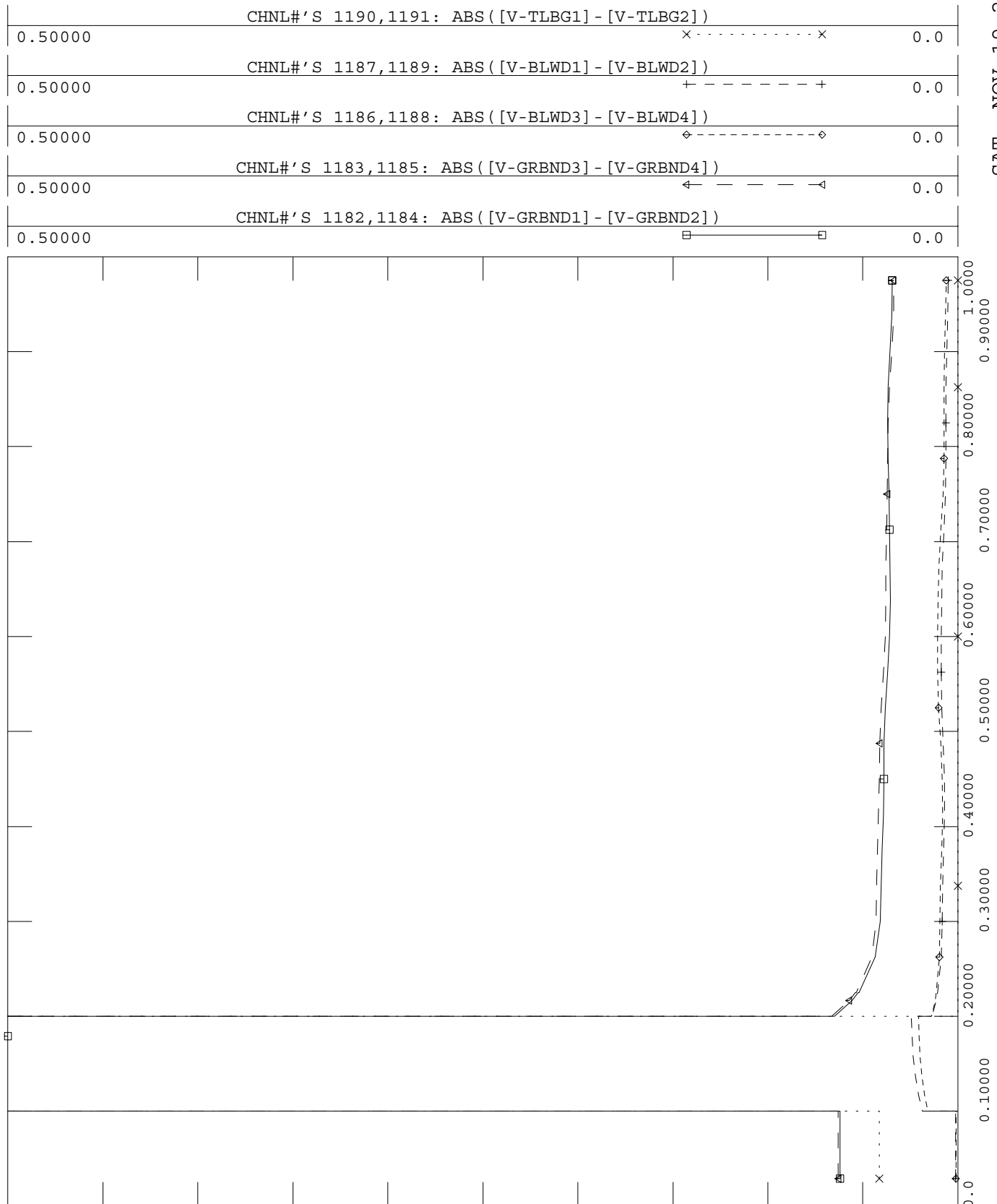


FIGURE G-86



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'NANTICOK' END OF # 1 CIRCUIT TO 'LONGWOOD'

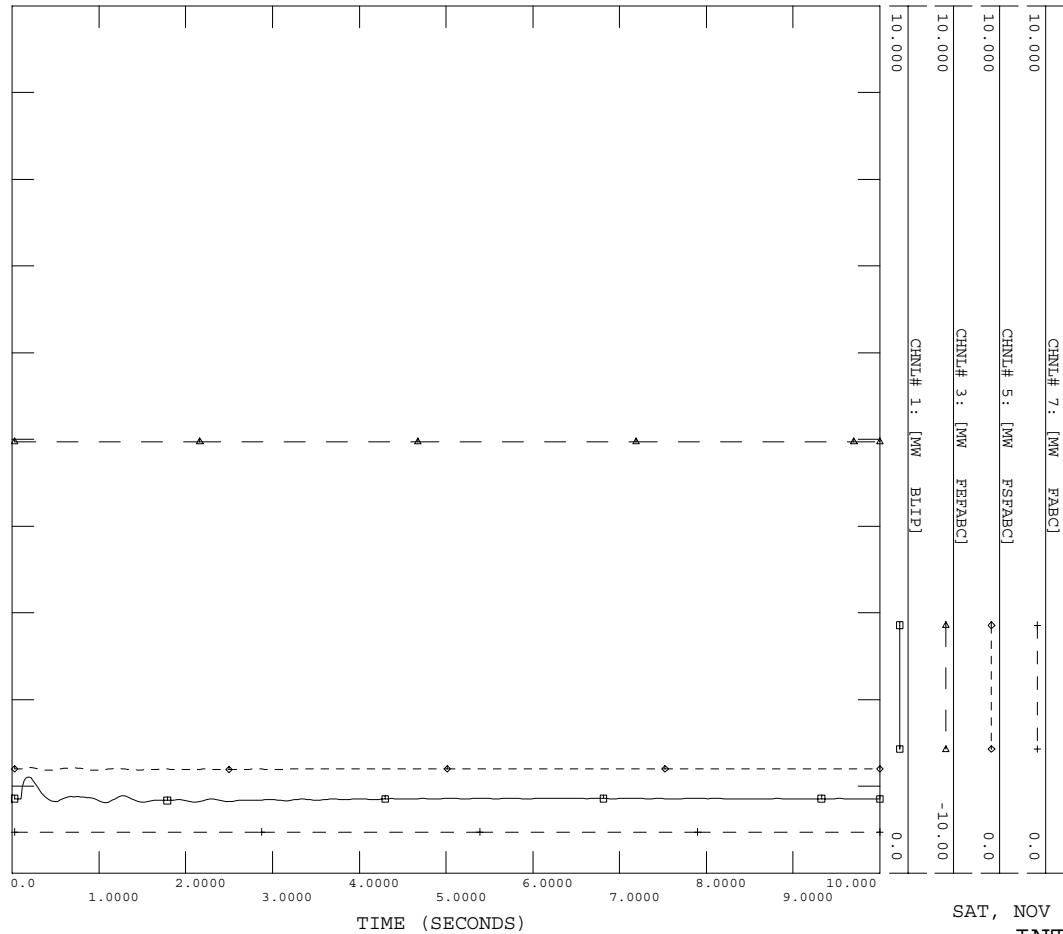
FILE: ... \DYNAMICS-WORST-FAULT-POINT\3PH-7000-46449-1-NO-BY-PASS.OUT



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FIGURE G-87

2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'NANTICOK' END OF # 1 CIRCUIT TO 'LONGWOOD'
FILE: ... \DYNAMICS-WORST-FAULT-POINT\3PH-7000-46449-1-NO-BY-PASS.OUT



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'NANTICOK' END OF # 1 CIRCUIT TO 'LONGWOOD'
FILE: ... \DYNAMICS-WORST-FAULT-POINT\3PH-7000-46449-1-NO-BY-PASS.OUT

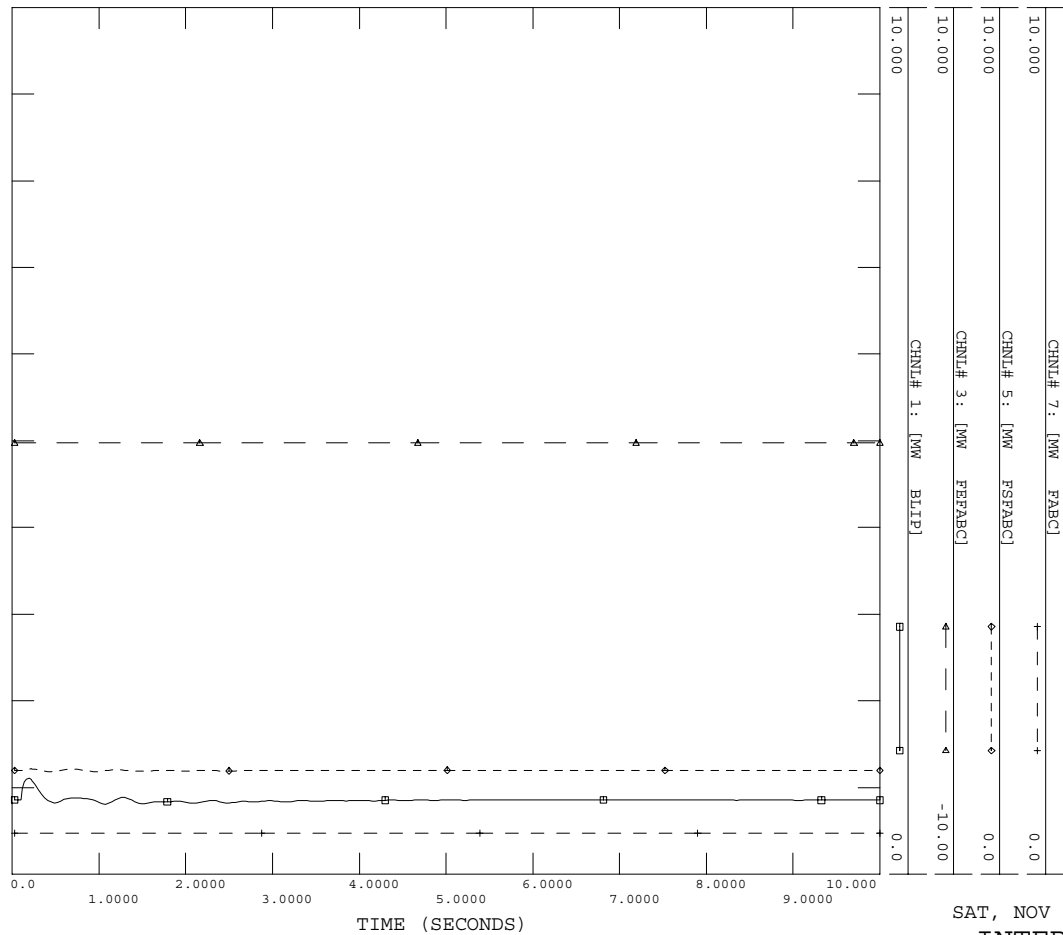


FIGURE G-88

**HIGH FAULT LEVEL LOCATION
3-PHASE FAULT, NORMALLY CLEARED,
BYPASS of ALL SERIES CAPACITOR BANKS**

Plots for the following disturbance are shown in the following order in this Appendix:

- iii. Bruce – Longwood 500kV Circuit (fault at 30% from Longwood)
Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G89&G90
Voltage Drop across the 5 series capacitors – Figure G91
Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G92

- iv. Longwood – Nanticoke 500kV Circuit (fault at bus# 7000)
Key Generators--Angles, MW, Terminal Voltage, MVAR (2pages) Figures G93&G94
Voltage Drop across the 5 series capacitors – Figure G95
Interface (FABC, FSFABC, FEFABC, BLIP) Flows – MW and MVAR – Figure G96

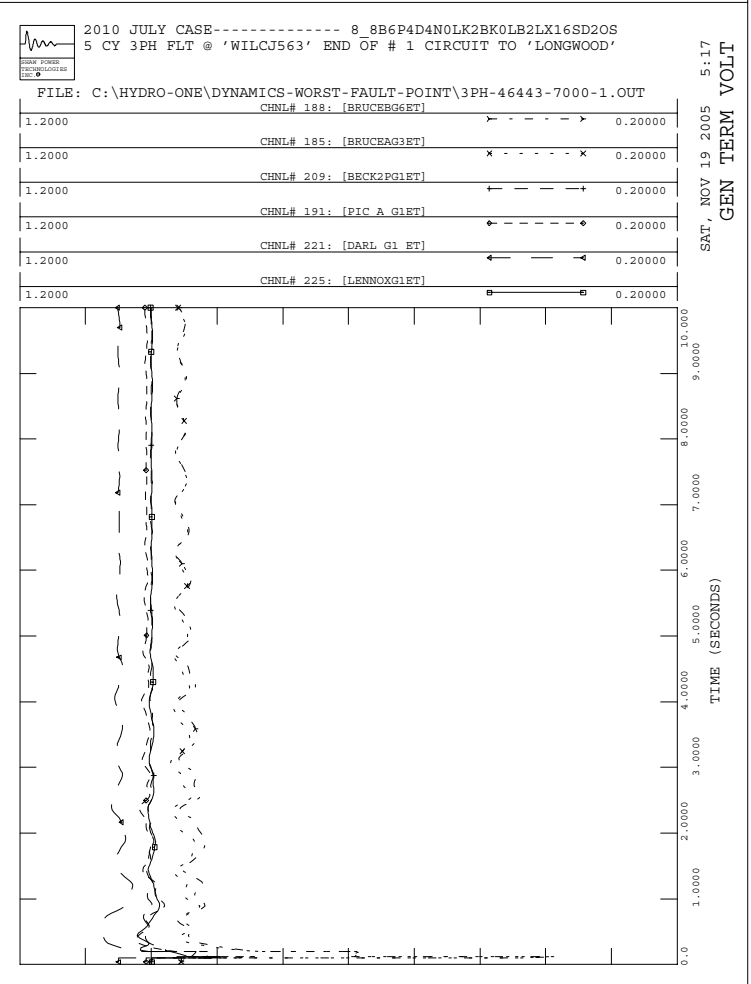
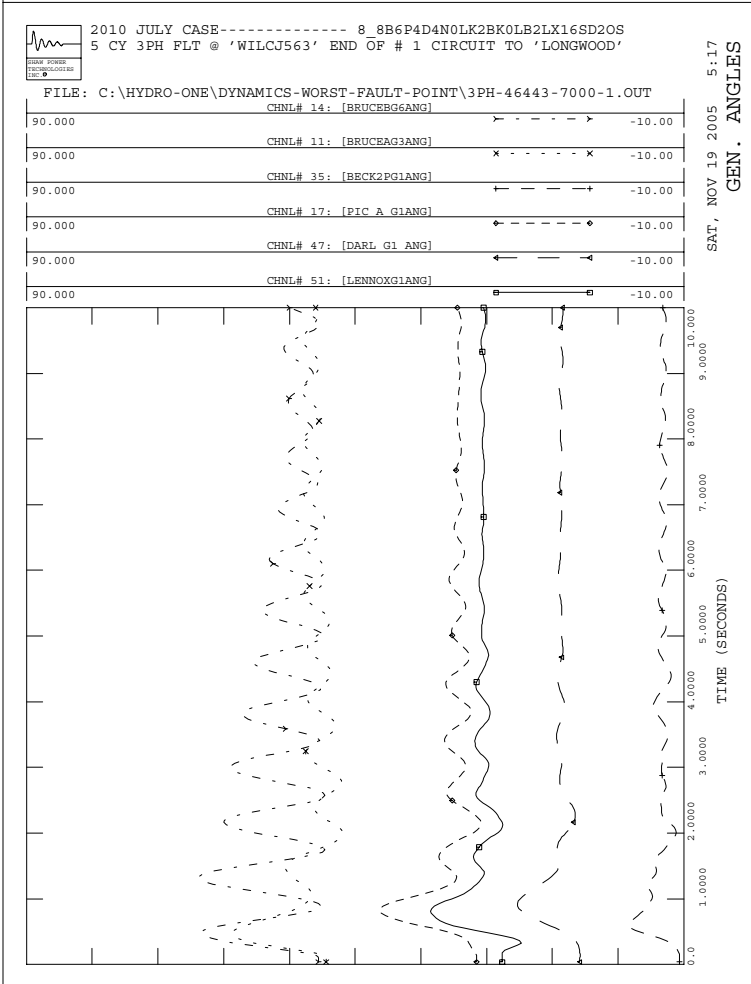
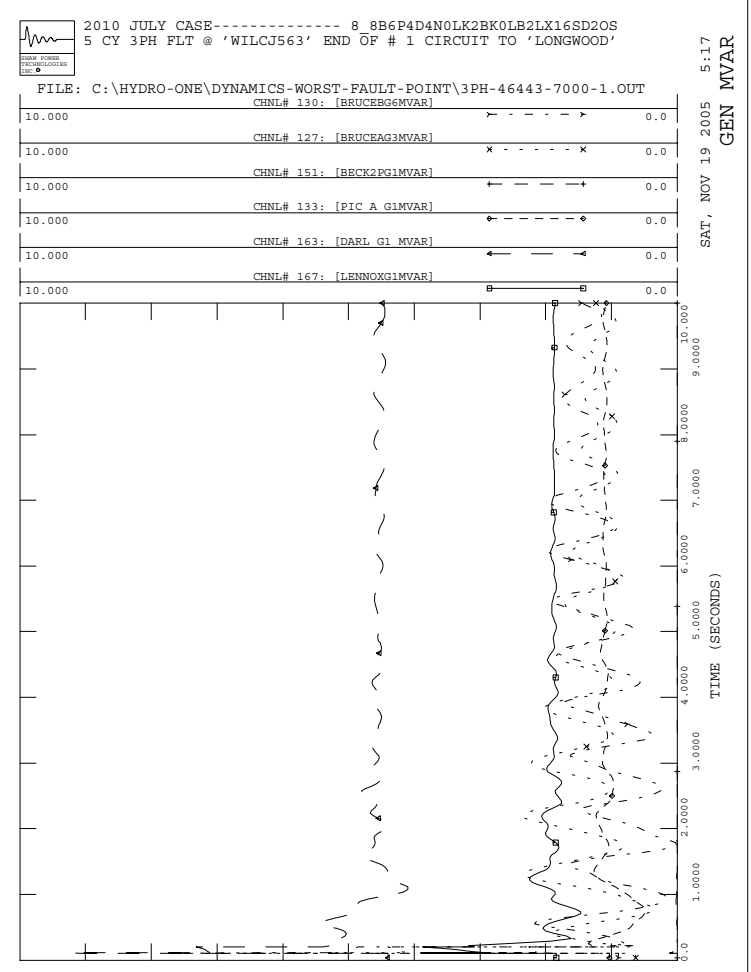
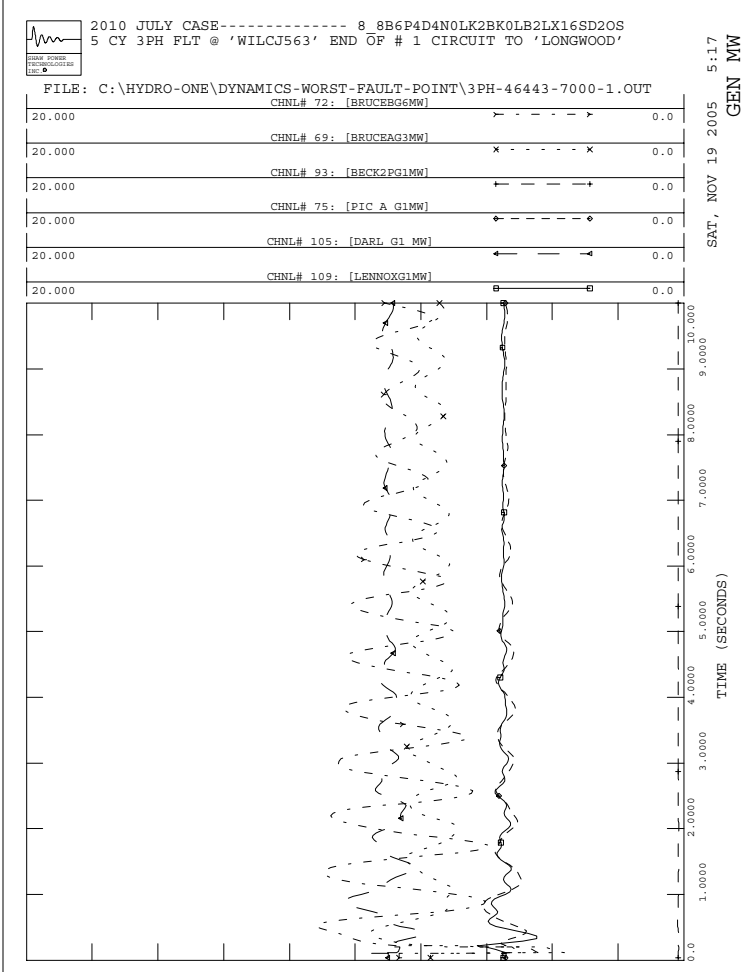
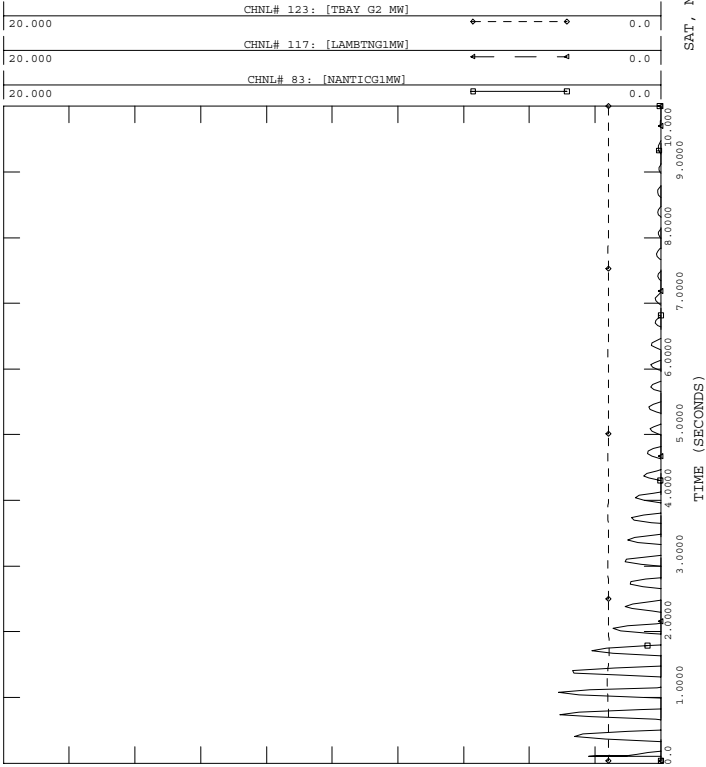


FIGURE G-89



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: C:\HYDRO-ONE\DYNAMICS-WORST-FAULT-POINT\3PH-46443-7000-1.OUT

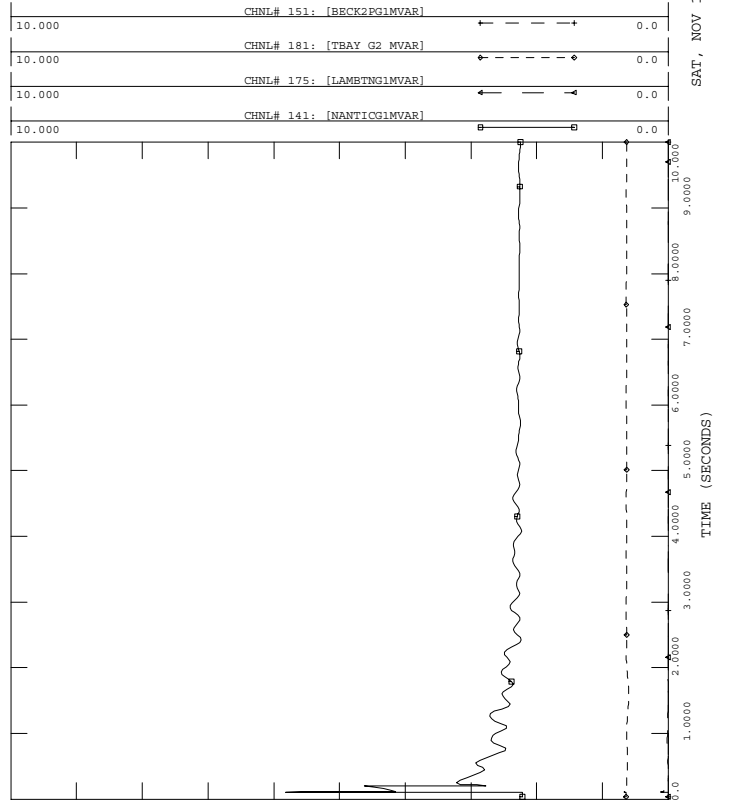


SAT, NOV 19 2005 5:18
GEN MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: C:\HYDRO-ONE\DYNAMICS-WORST-FAULT-POINT\3PH-46443-7000-1.OUT

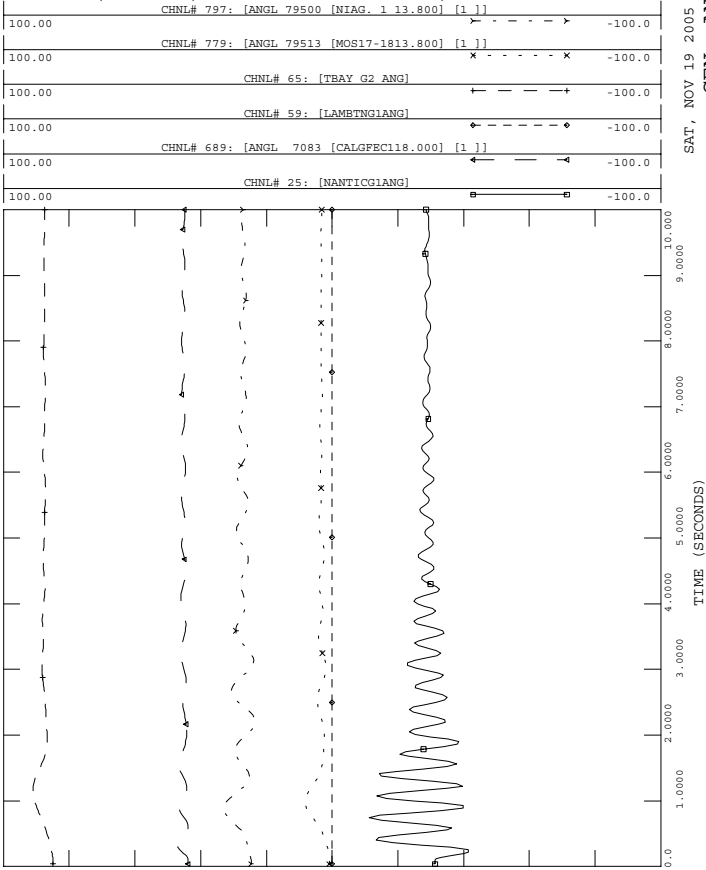


SAT, NOV 19 2005 5:18
GEN MVAR



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: C:\HYDRO-ONE\DYNAMICS-WORST-FAULT-POINT\3PH-46443-7000-1.OUT

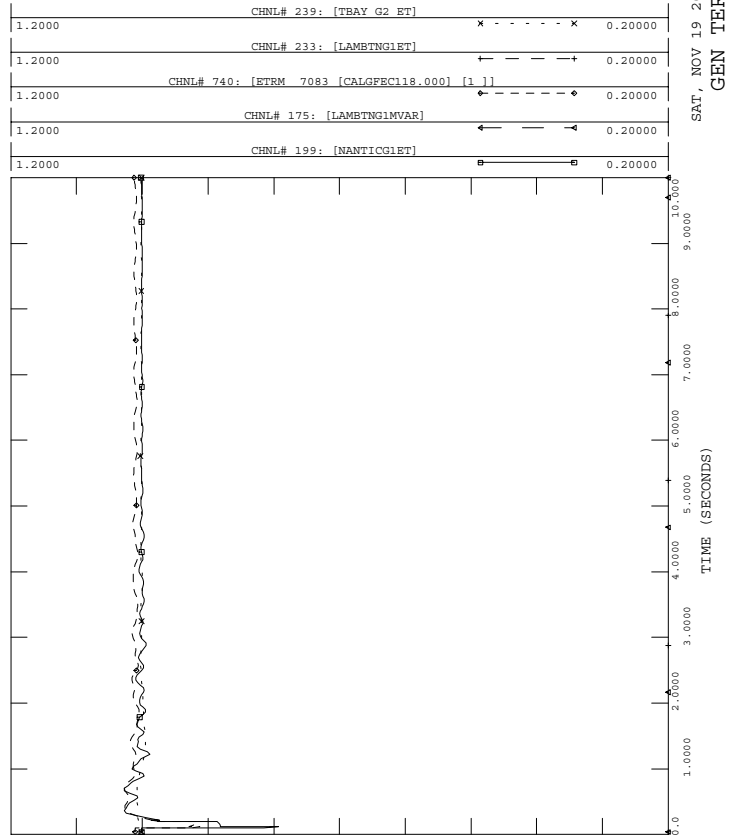


SAT, NOV 19 2005 5:18
GEN ANGLES



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: C:\HYDRO-ONE\DYNAMICS-WORST-FAULT-POINT\3PH-46443-7000-1.OUT



SAT, NOV 19 2005 5:18
GEN TERM VOLT

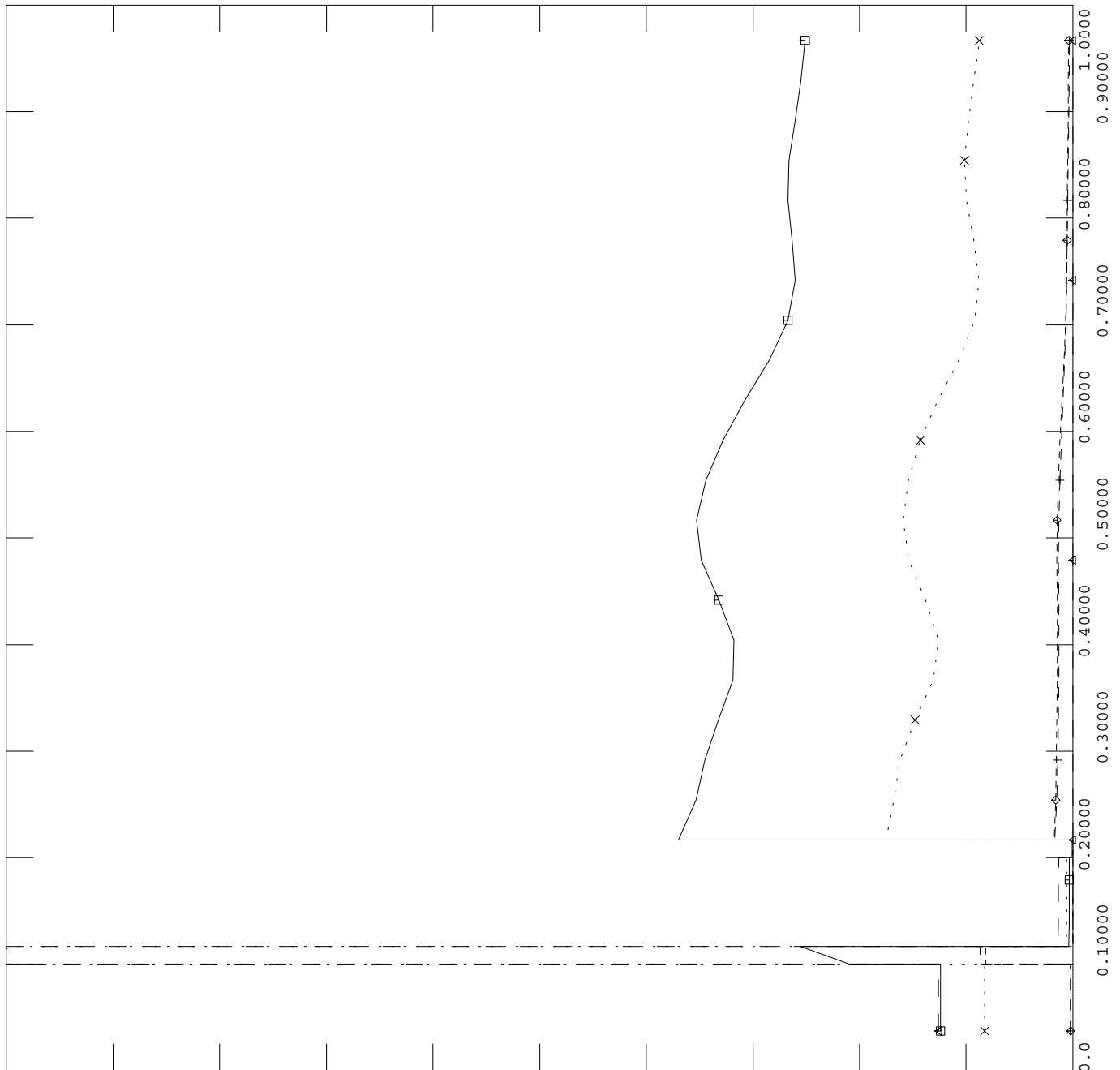
FIGURE G-90



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: C:\HYDRO-ONE\DYNAMICS-WORST-FAULT-POINT\3PH-46443-7000-1.OUT

0.50000	CHNL#'S 1190,1191: ABS ([V-TLBG1] - [V-TLBG2])	X - - - - - X	0.0
0.50000	CHNL#'S 1187,1189: ABS ([V-BLWD1] - [V-BLWD2])	+ - - - - +	0.0
0.50000	CHNL#'S 1186,1188: ABS ([V-BLWD3] - [V-BLWD4])	◇ - - - - ◇	0.0
0.50000	CHNL#'S 1183,1185: ABS ([V-GRBND3] - [V-GRBND4])	← - - - - →	0.0
0.50000	CHNL#'S 1182,1184: ABS ([V-GRBND1] - [V-GRBND2])	□ - - - - □	0.0



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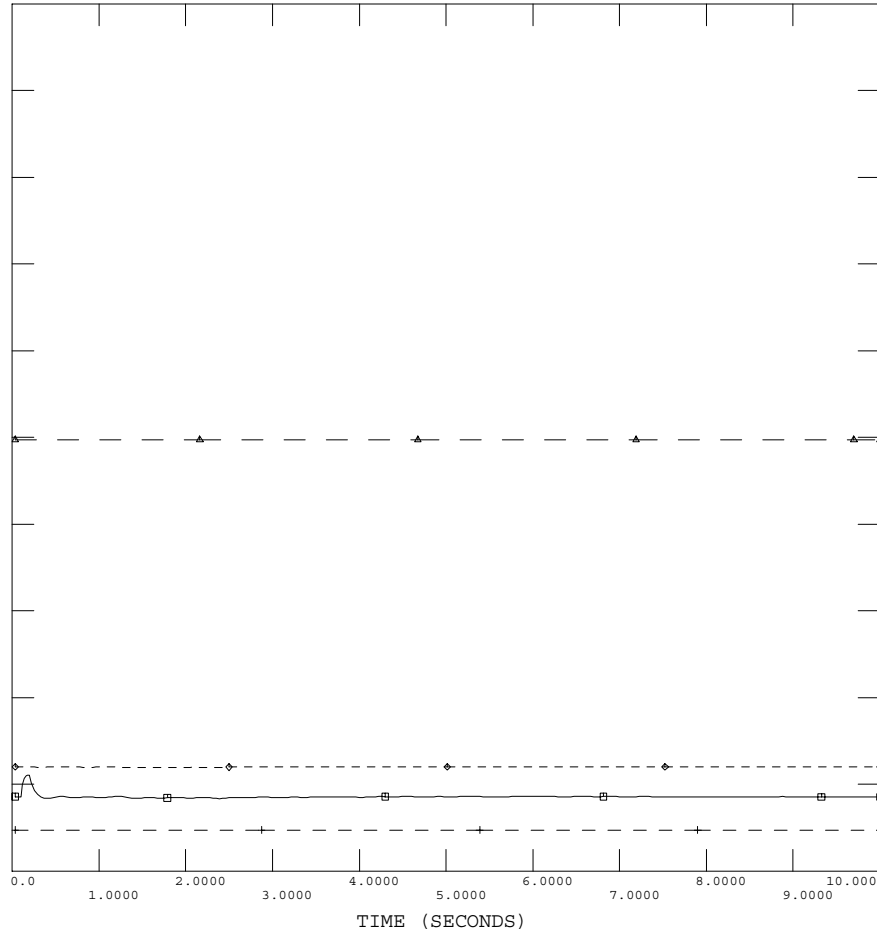
FIGURE G-91



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: C:\HYDRO-ONE\DYNAMICS-WORST-FAULT-POINT\3PH-46443-7000-1.OUT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	▢ - - - ▢	0.0



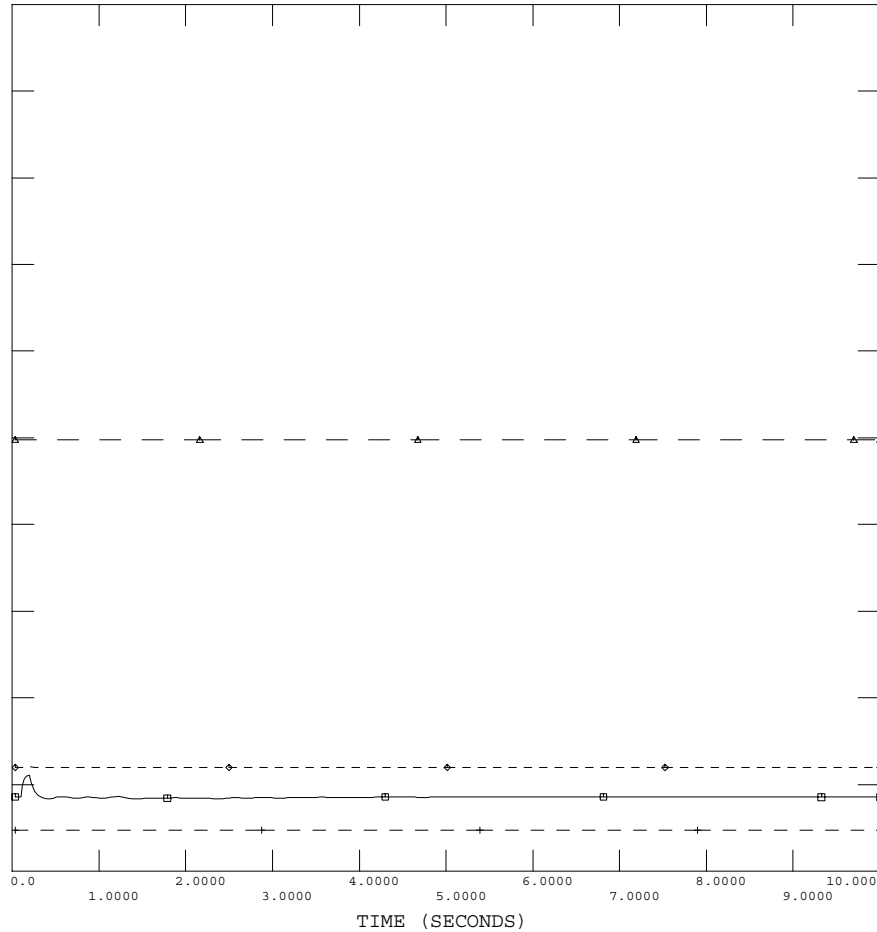
SAT, NOV 19 2005 5:18
INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'WILCJ563' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: C:\HYDRO-ONE\DYNAMICS-WORST-FAULT-POINT\3PH-46443-7000-1.OUT

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10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	▢ - - - ▢	0.0



SAT, NOV 19 2005 5:18
INTERFACE MVAR

FIGURE G-92

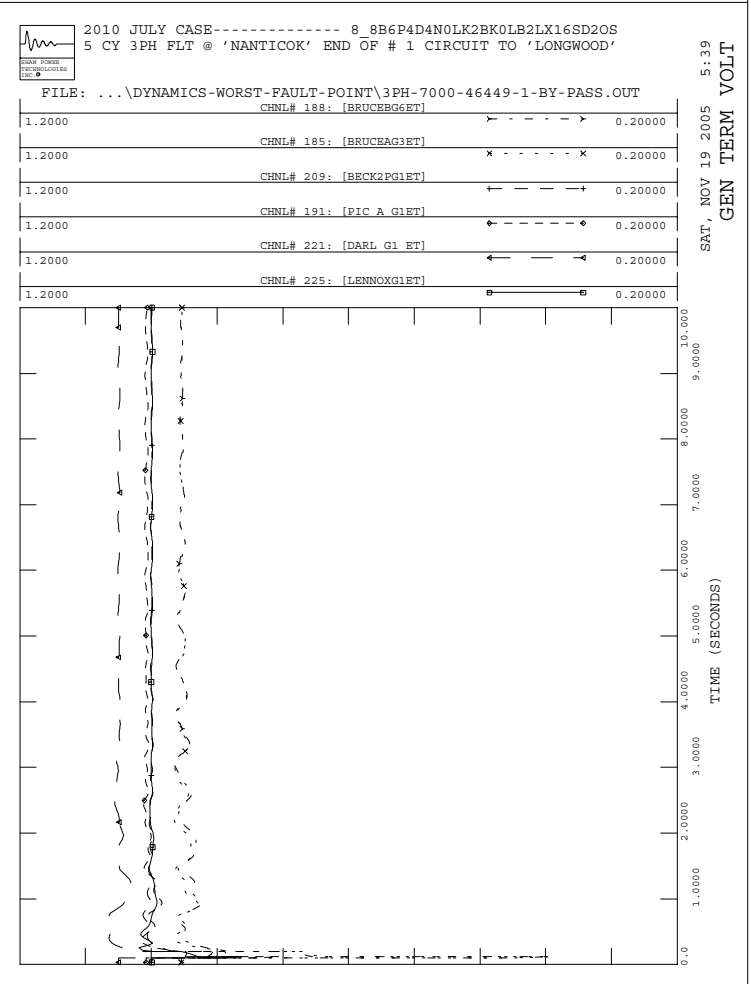
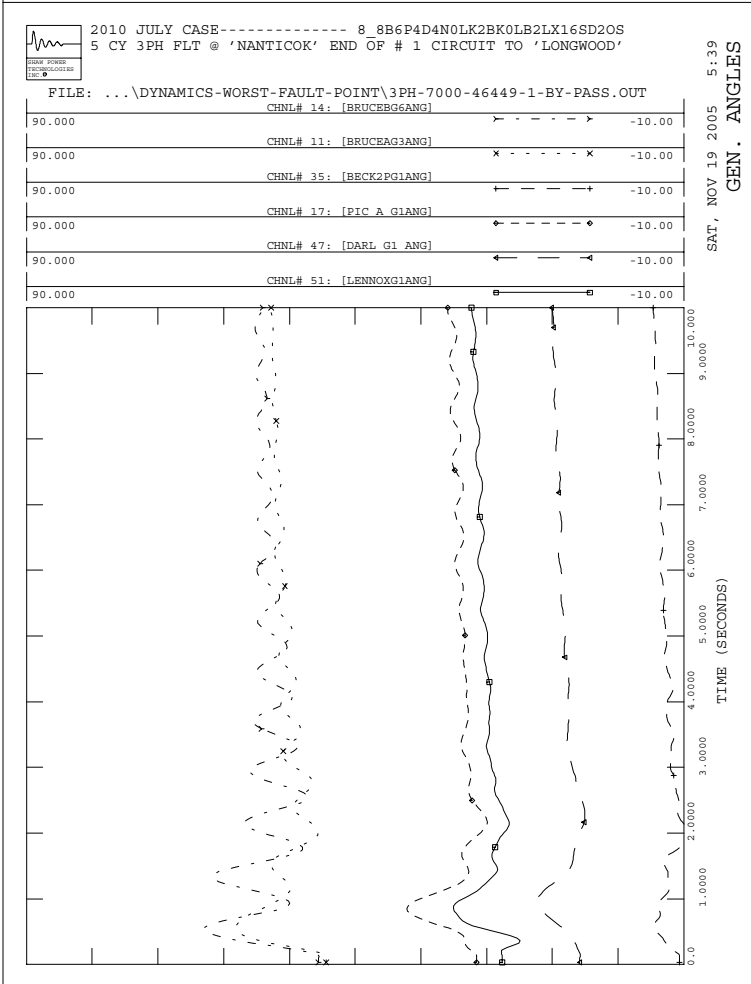
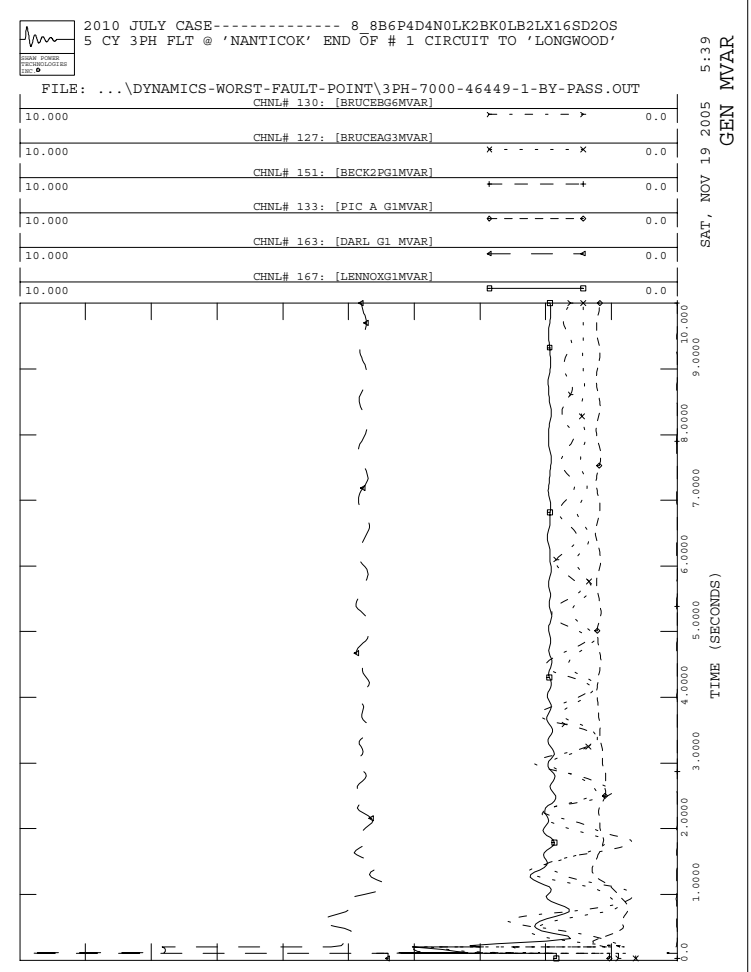
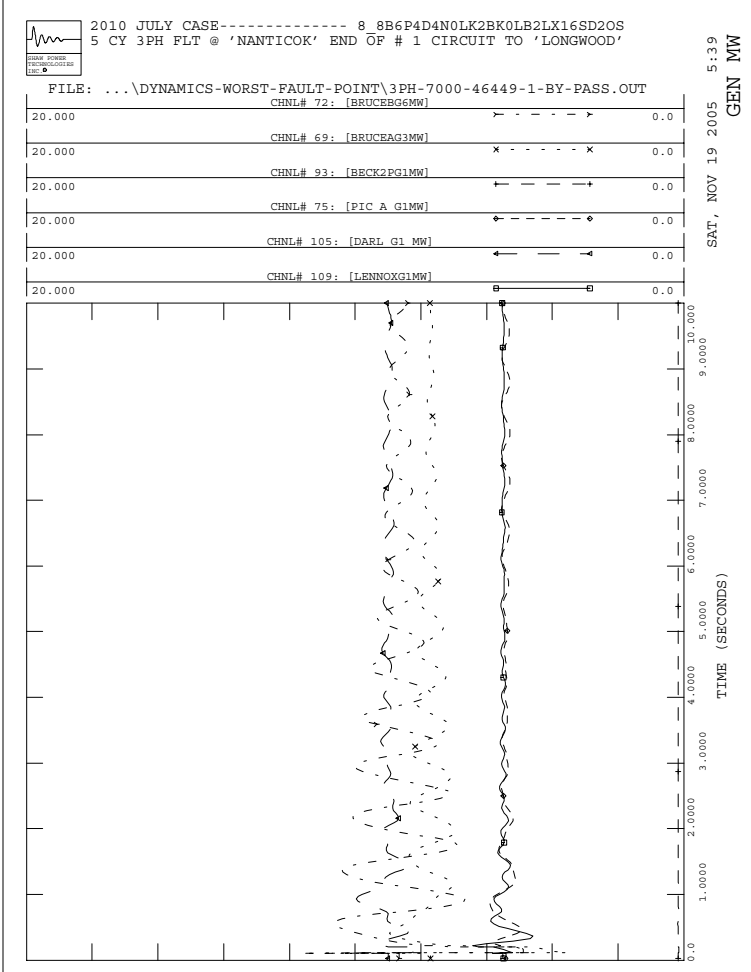


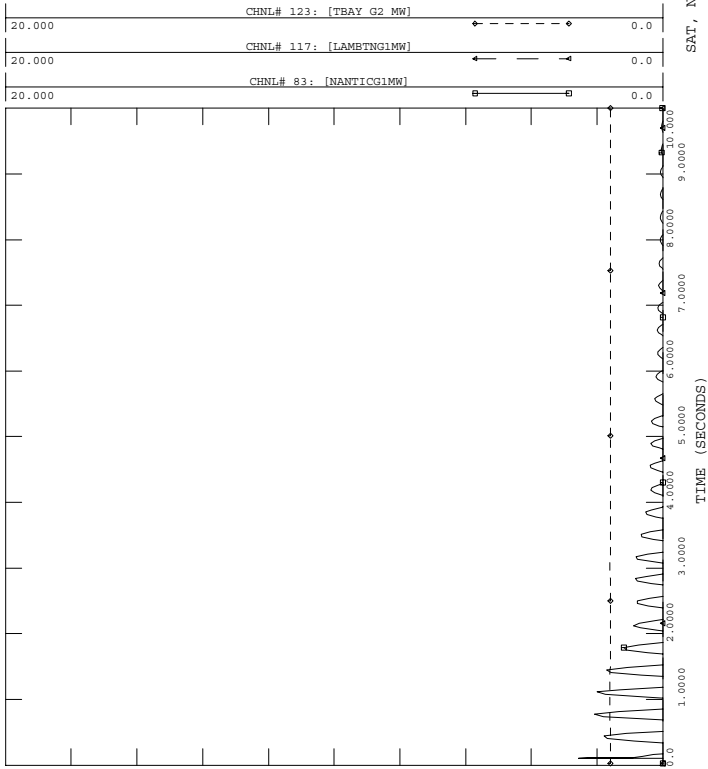
FIGURE G-93



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD2OS
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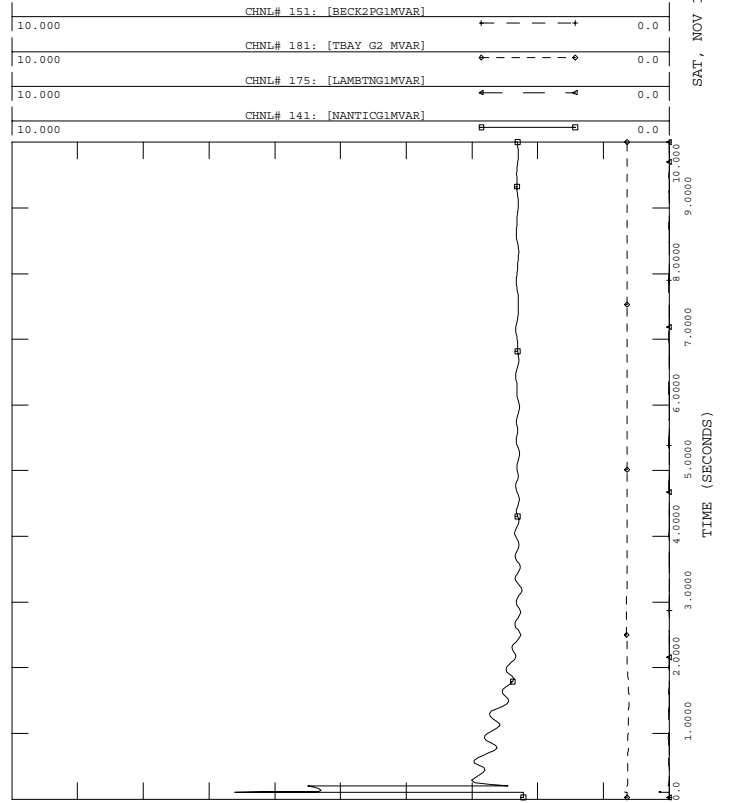
SAT, NOV 19 2005 5:39
GEN MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD2OS
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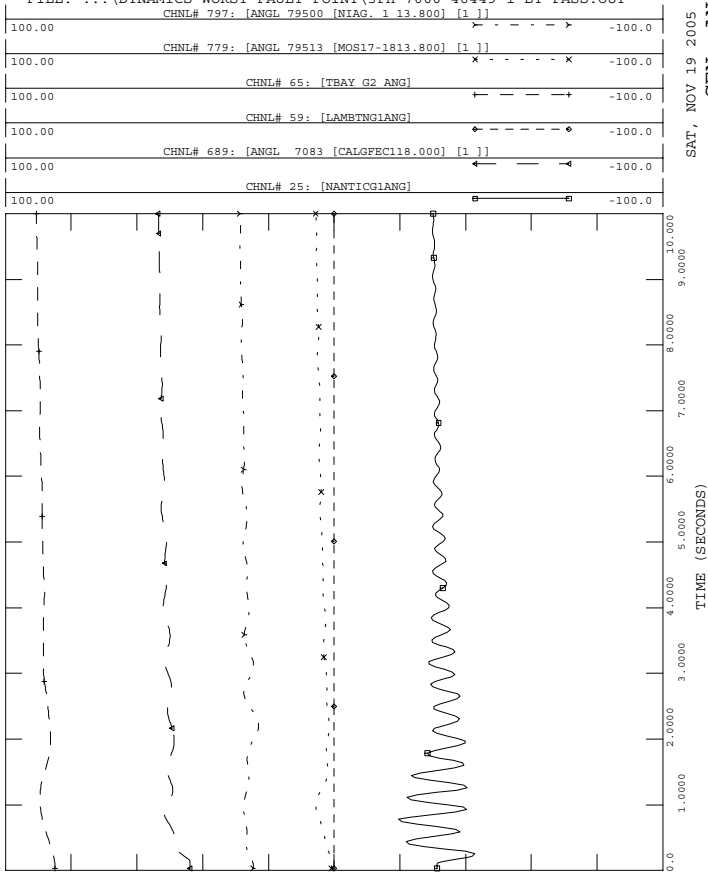
SAT, NOV 19 2005 5:39
GEN MVAR



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'NANTICOK' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: ...\\DYNAMICS-WORST-FAULT-POINT\\3PH-7000-46449-1-BY-PASS.OUT

SAT, NOV 19 2005 5:39
GEN. ANGLES



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD2OS
5 CY 3PH FLT @ 'NANTICOK' END OF # 1 CIRCUIT TO 'LONGWOOD'

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SAT, NOV 19 2005 5:39
GEN TERM VOLT

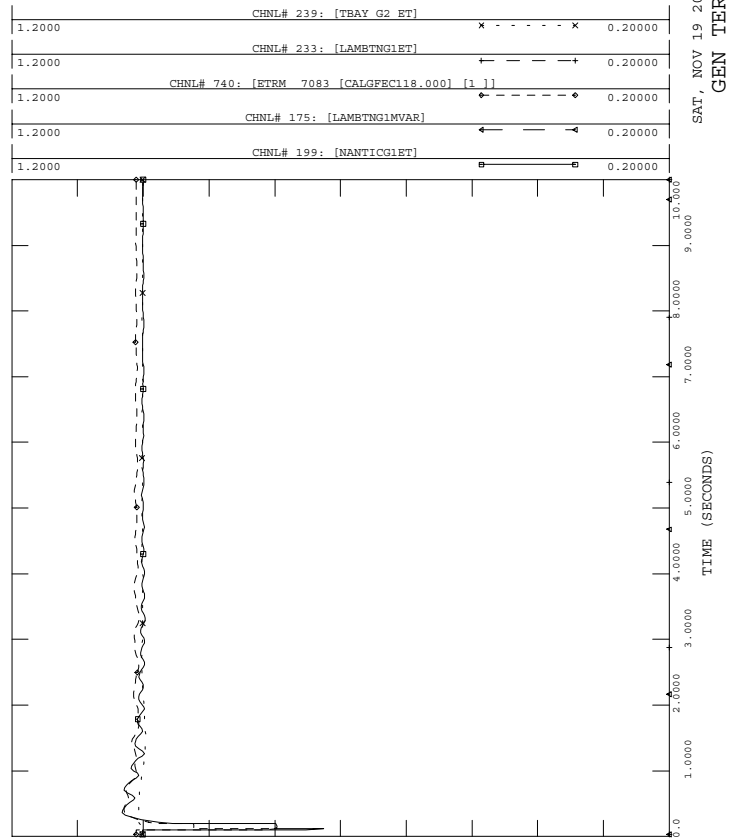
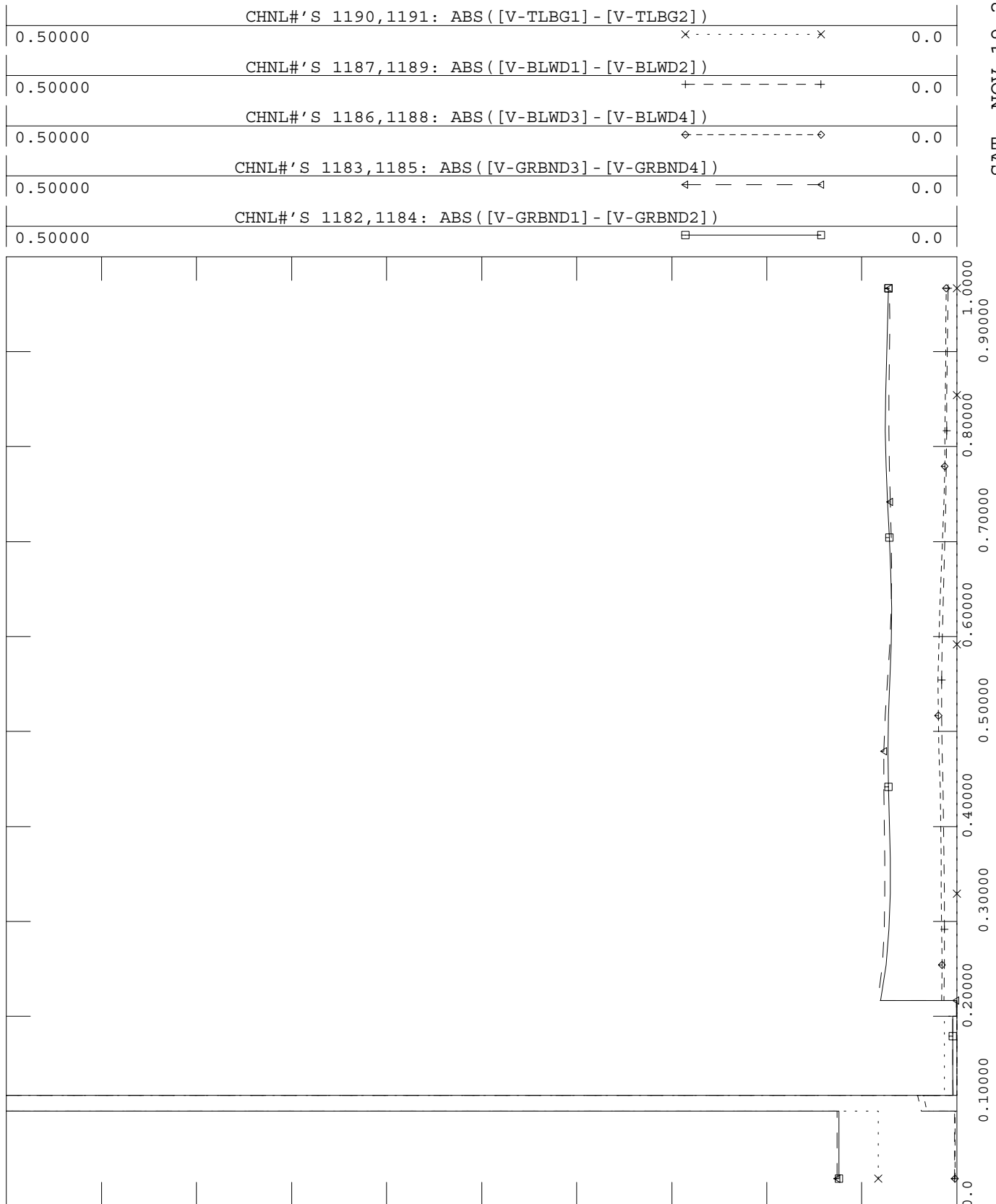


FIGURE G-94



2010 JULY CASE----- 8_8B6P4D4N0LK2BK0LB2LX16SD2OS
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DV-ACROSS-S-CAPS

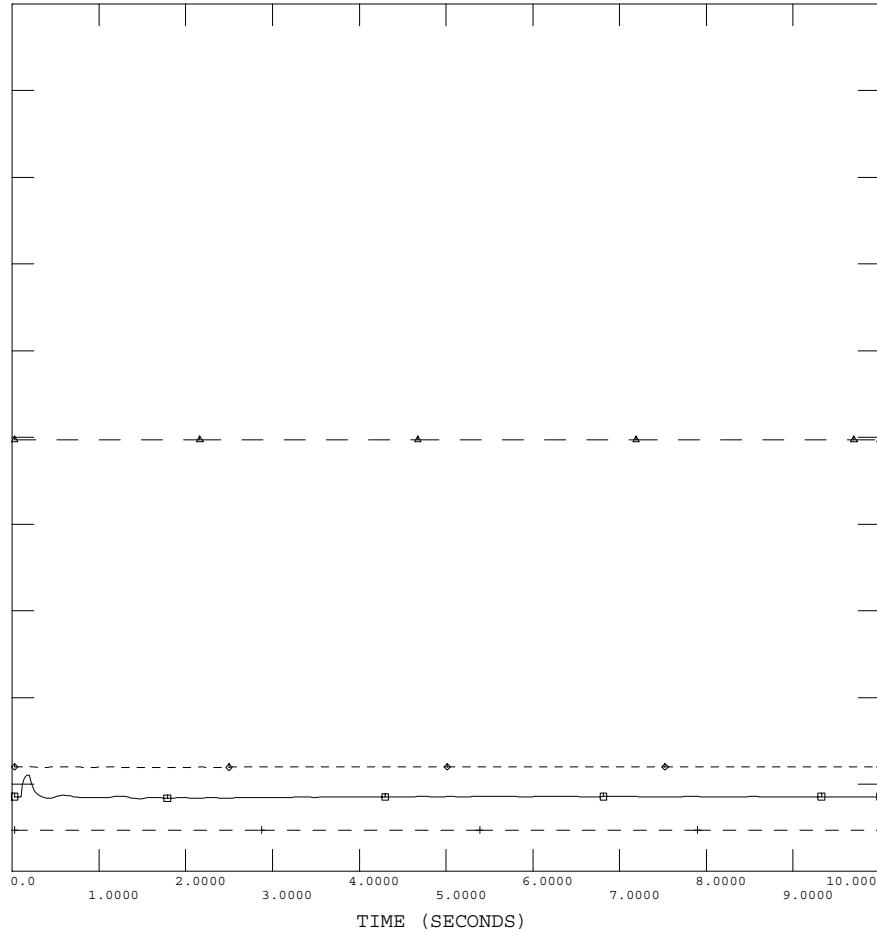
FIGURE G-95



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'NANTICOK' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: ... \DYNAMICS-WORST-FAULT-POINT\3PH-7000-46449-1-BY-PASS.OUT

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10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	□ - - - □	0.0



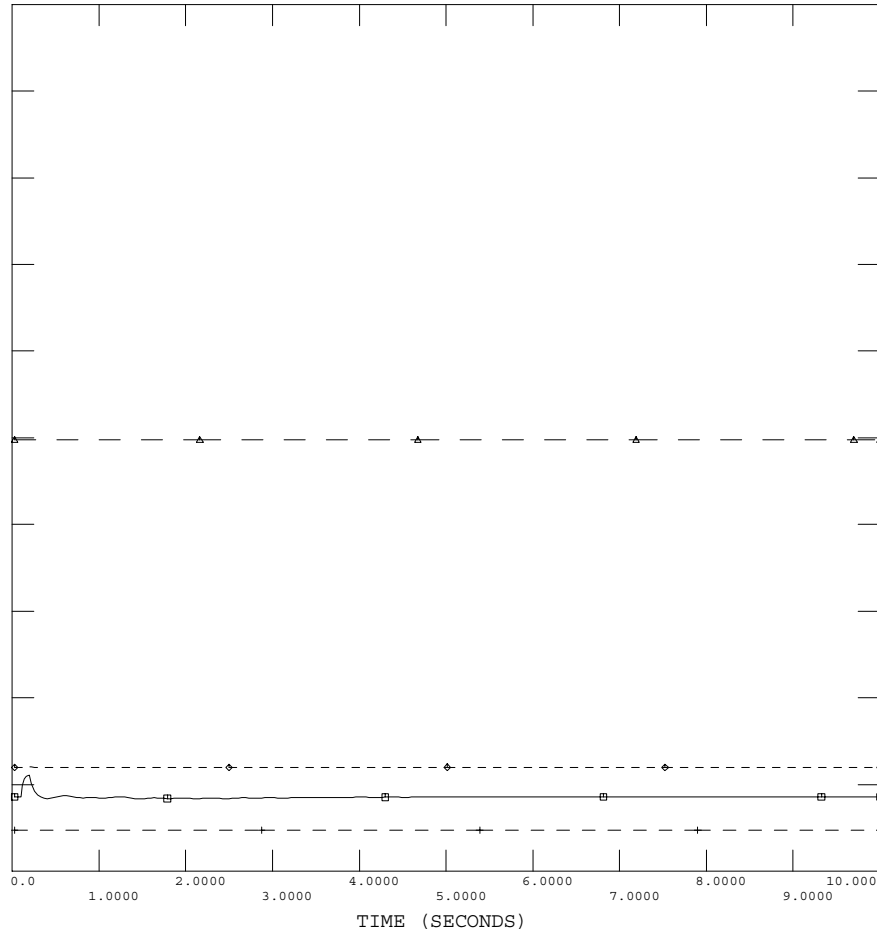
SAT, NOV 19 2005 5:40
INTERFACE MW



2010 JULY CASE----- 8 8B6P4D4N0LK2BK0LB2LX16SD20S
5 CY 3PH FLT @ 'NANTICOK' END OF # 1 CIRCUIT TO 'LONGWOOD'

FILE: ... \DYNAMICS-WORST-FAULT-POINT\3PH-7000-46449-1-BY-PASS.OUT

10.000	CHNL# 7: [MW FABC]	+ - - - - +	0.0
10.000	CHNL# 5: [MW FSPABC]	◇ - - - - ◇	0.0
10.000	CHNL# 3: [MW FEPABC]	← - - - →	-10.00
10.000	CHNL# 1: [MW BLIP]	□ - - - □	0.0



SAT, NOV 19 2005 5:40
INTERFACE MVAR

FIGURE G-96

Filed: February 28, 2008
EB-2007-0050
Exhibit C
Tab 4
Schedule 1
Attachment 3-3

1 Attachment 3-3
2 Series Capacitor Application in Ontario: SSR Mitigation Final Report by ABB - Jan 31 2006
3
4 Because the original Acrobat file is protected it could not be merged into this file. At least
5 temporarily, it has been kept as a separate file.

Pappas INTERROGATORY #2 List 1

Interrogatory

Issues:

1.1 Has the need for the proposed project been established?

2.1 Have all reasonable alternatives to the project been identified and considered?

2.2 Has an appropriate evaluation methodology been applied to all the alternatives considered?

2.4a Have appropriate evaluation criteria and criteria weightings been utilized in the evaluation process for the alternatives and the proposed project and what additional criteria/weightings could be considered?

3.1 Are the proposed near term and interim measures as outlined in the application appropriate?

Ref

1. APPENDIX A to Procedural Order No. 5.IN THE MATTER OF Leave to Construct Application by Hydro One Networks.EB-2007-0050.DATED February 25, 2008
2. Direction of Board from Issues Day and Schedule Hearing, February.21, 2008.

Preamble:

The following documents are, in my estimation, entirely relevant and necessary for the understanding of the Board, and the Interveners, of the Application, the Applicant's preferred option and how that option was deemed to be superior to the alternatives. As was determined at the Issues Day and Schedule Revision hearing [Feb.21, 2008], it is in the best interests of all parties, and the Application process, that these be made immediately available to the Interveners and the Board for review and consideration. Also, at this time it was, apparently, determined that two of these documents were definitely produced with public availability understood, and that there was no matter of confidentiality for any of the first three documents requested. The Applicant voiced no objection to any of this at the hearing [Feb. 21, 2008]. I must state, here, that I will view non-compliance regarding these initial five interrogatories as a matter of Motion, and will request a Motions day on this basis. As I understand, the following requests were, however, to be framed as Interrogatory. So that there will be no chance of refusal based on my earlier written request not being precisely framed in Interrogatory format I have revised them, as follows.

Filed: February 28, 2008

EB-2007-0050

Exhibit C

Tab 4

Schedule 2

Page 2 of 2

Request:

Will, the Applicant and it's Proponents [OPA, IESO] provide these documents, below, immediately, as it is absolutely necessary for the Interveners to be able to frame Interrogatories based on these and appropriate time for review and production?

1. IESO_REP_0245v2.0
10-YEAR OUTLOOK:
An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario From January 2006 to December 2015
[release date: August 15, 2005]
2. IESO_REP_0299
CONNECTION ASSESSMENT & APPROVAL PROCESS SYSTEM IMPACT
ASSESSMENT REPORT
For the Proposed Installation of Series Capacitors in the 500kV Circuits between the Bruce Complex & Nanticoke GS
Applicant: Hydro One Networks Inc.
CAA ID No. 2005 200
Transmission Assessments & Performance Department
FINAL Version
Date: 11th April 2006
3. From: Pg. 38 of the SIA REPORT: INSTALLATION OF 500kV SERIES
COMPENSATION.[#2, above]
The study, cited under: 16.2 Recommendations.
•The ABB Study that was commissioned by Hydro One.

Response

Yes

Pappas INTERROGATORY #3 List 1

Interrogatory

Issues:

1.1 Has the need for the proposed project been established?

2.1 Have all reasonable alternatives to the project been identified and considered?

2.2 Has an appropriate evaluation methodology been applied to all the alternatives considered?

2.4a Have appropriate evaluation criteria and criteria weightings been utilized in the evaluation process for the alternatives and the proposed project and what additional criteria/weightings could be considered?

3.1 Are the proposed near term and interim measures as outlined in the application appropriate?

Ref

1. APPENDIX A to Procedural Order No. 5.IN THE MATTER OF Leave to Construct Application by Hydro One Networks.EB-2007-0050.DATED February 25, 2008
2. Direction of Board from Issues Day and Schedule Hearing, February.21, 2008.

Preamble:

The following documents are, in my estimation, entirely relevant and necessary for the understanding of the Board, and the Interveners, of the Application, the Applicant's preferred option and how that option was deemed to be superior to the alternatives. As was determined at the Issues Day and Schedule Revision hearing [Feb.21, 2008], it is in the best interests of all parties, and the Application process, that these be made immediately available to the Interveners and the Board for review and consideration. Also, at this time it was, apparently, determined that two of these documents were definitely produced with public availability understood, and that there was no matter of confidentiality for any of the first three documents requested. The Applicant voiced no objection to any of this at the hearing [Feb. 21, 2008]. I must state, here, that I will view non-compliance regarding these initial five interrogatories as a matter of Motion, and will request a Motions day on this basis. As I understand, the following requests were, however, to be framed as Interrogatory. So that there will be no chance of refusal based on my earlier written request not being precisely framed in Interrogatory format I have revised them, as follows.

Filed: February 28, 2008

EB-2007-0050

Exhibit C

Tab 4

Schedule 3

Page 2 of 2

Request:

Will the Applicant and its Proponents [OPA, IESO] provide these documents, below, as a matter of the record?

1. IESO_REP_0245v2.0
10-YEAR OUTLOOK:
An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario From January 2006 to December 2015
[release date: August 15, 2005]
2. IESO_REP_0299
CONNECTION ASSESSMENT & APPROVAL PROCESS SYSTEM IMPACT
ASSESSMENT REPORT
For the Proposed Installation of Series Capacitors in the 500kV Circuits between the Bruce Complex & Nanticoke GS
Applicant: Hydro One Networks Inc.
CAA ID No. 2005 200
Transmission Assessments & Performance Department
FINAL Version
Date: 11th April 2006
3. From: Pg. 38 of the SIA REPORT: INSTALLATION OF 500kV SERIES
COMPENSATION.[#2, above]
The study, cited under: 16.2 Recommendations.
•The ABB Study that was commissioned by Hydro One.

[Response](#)

Yes

Pappas INTERROGATORY 4 List 1

Interrogatory

Issues:

1.1 Has the need for the proposed project been established?

2.1 Have all reasonable alternatives to the project been identified and considered?

2.2 Has an appropriate evaluation methodology been applied to all the alternatives considered?

2.4a Have appropriate evaluation criteria and criteria weightings been utilized in the evaluation process for the alternatives and the proposed project and what additional criteria/weightings could be considered?

3.1 Are the proposed near term and interim measures as outlined in the application appropriate?

Ref

1. APPENDIX A to Procedural Order No. 5.IN THE MATTER OF Leave to Construct Application by Hydro One Networks.EB-2007-0050.DATED February 25, 2008
2. Direction of Board from Issues Day and Schedule Hearing, February.21, 2008.

Preamble:

The following documents are, in my estimation, entirely relevant and necessary for the understanding of the Board, and the Interveners, of the Application, the Applicant's preferred option and how that option was deemed to be superior to the alternatives. As was determined at the Issues Day and Schedule Revision hearing [Feb.21, 2008], it is in the best interests of all parties, and the Application process, that these be made immediately available to the Interveners and the Board for review and consideration. Also, at this time it was, apparently, determined that two of these documents were definitely produced with public availability understood, and that there was no matter of confidentiality for any of the first three documents requested. The Applicant voiced no objection to any of this at the hearing [Feb. 21, 2008]. I must state, here, that I will view non-compliance regarding these initial five interrogatories as a matter of Motion, and will request a Motions day on this basis. As I understand, the following requests were, however, to be framed as Interrogatory. So that there will be no chance of refusal based on my earlier written request not being precisely framed in Interrogatory format I have revised them, as follows.

Filed: February 28, 2008

EB-2007-0050

Exhibit C

Tab 4

Schedule 4

Page 2 of 2

Request:

Will the Applicant and its Proponents [OPA, IESO] also provide these documents, below, as hardcopy [printed], so that they can be included in the Application binder with the other documentation relevant to this application, which the Applicant previously provided?

1. IESO_REP_0245v2.0
10-YEAR OUTLOOK:
An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario From January 2006 to December 2015
[release date: August 15, 2005]
2. IESO_REP_0299
CONNECTION ASSESSMENT & APPROVAL PROCESS SYSTEM IMPACT
ASSESSMENT REPORT
For the Proposed Installation of Series Capacitors in the 500kV Circuits between the Bruce Complex & Nanticoke GS
Applicant: Hydro One Networks Inc.
CAA ID No. 2005 200
Transmission Assessments & Performance Department
FINAL Version
Date: 11th April 2006
3. From: Pg. 38 of the SIA REPORT: INSTALLATION OF 500kV SERIES
COMPENSATION.[#2, above]
The study, cited under: 16.2 Recommendations.
•The ABB Study that was commissioned by Hydro One.

[Response](#)

Except for item 3 above the requested reports are being provided today by CD and hard copy. Due to the size of the material, hardcopy version of item 3 will follow shortly.

Pappas INTERROGATORY 5 List 1

Interrogatory

Issues:

1.1 Has the need for the proposed project been established?

2.1 Have all reasonable alternatives to the project been identified and considered?

2.2 Has an appropriate evaluation methodology been applied to all the alternatives considered?

2.4a Have appropriate evaluation criteria and criteria weightings been utilized in the evaluation process for the alternatives and the proposed project and what additional criteria/weightings could be considered?

3.1 Are the proposed near term and interim measures as outlined in the application appropriate?

Ref

1. APPENDIX A to Procedural Order No. 5.IN THE MATTER OF Leave to Construct Application by Hydro One Networks.EB-2007-0050.DATED February 25, 2008
2. Direction of Board from Issues Day and Schedule Hearing, February.21, 2008.

Preamble:

The following documents are, in my estimation, entirely relevant and necessary for the understanding of the Board, and the Interveners, of the Application, the Applicant's preferred option and how that option was deemed to be superior to the alternatives. As was determined at the Issues Day and Schedule Revision hearing [Feb.21, 2008], it is in the best interests of all parties, and the Application process, that these be made immediately available to the Interveners and the Board for review and consideration. Also, at this time it was, apparently, determined that two of these documents were definitely produced with public availability understood, and that there was no matter of confidentiality for any of the first three documents requested. The Applicant voiced no objection to any of this at the hearing [Feb. 21, 2008]. I must state, here, that I will view non-compliance regarding these initial five interrogatories as a matter of Motion, and will request a Motions day on this basis. As I understand, the following requests were, however, to be framed as Interrogatory. So that there will be no chance of refusal based on my earlier written request not being precisely framed in Interrogatory format I have revised them, as follows.

Request:

Will the Applicant and its Proponents [OPA, IESO] provide the Board and the interveners with the parameters they set for the ABB Study, with all associated communications between the Applicant and ABB [the consultant]. regarding initiation, terms of reference, parameters, limitations, and undertaking of the consultation/study?

1. IESO_REP_0245v2.0
10-YEAR OUTLOOK:
An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario From January 2006 to December 2015
[release date: August 15, 2005]
2. IESO_REP_0299
CONNECTION ASSESSMENT & APPROVAL PROCESS SYSTEM IMPACT
ASSESSMENT REPORT
For the Proposed Installation of Series Capacitors in the 500kV Circuits between the Bruce Complex & Nanticoke GS
Applicant: Hydro One Networks Inc.
CAA ID No. 2005 200
Transmission Assessments & Performance Department
FINAL Version
Date: 11th April 2006
3. From: Pg. 38 of the SIA REPORT: INSTALLATION OF 500kV SERIES
COMPENSATION.[#2, above]
The study, cited under: 16.2 Recommendations.
•The ABB Study that was commissioned by Hydro One.

Response

The following documents related to the ABB study are included as Attachments 1 to 4 in the CD being provided and as hardcopy:

- 1 –RFP
- 2 --Technical Requirements
- 3 --Commercial Conditions
- 4 --Form of Proposal

The above documents reflect information concerning the initiation, terms of reference, parameters, limitations and undertaking of the study. In Hydro One's view, these documents provide an adequate background to the study and the information being requested. Hydro One is not prepared to file "all associated communications" between the Applicant and ABB, as the Interrogatory requests, due to the broadness of the request and the time and effort required for production of the information.

HYDRO ONE NETWORKS INC.

REQUEST FOR PROPOSAL

FOR

Southwestern Ontario Transmission 500kV Series Compensation Technical Study Consulting Services

REFERENCE # 13651

DATED: July 7th, 2005

Submit Proposals to

Proposal Depository – Hydro One Networks Inc
483 Bay Street, 15th Floor, North Tower, Toronto, Ontario M5G 2P5

No later than

4:00 PM EST on Friday, July 22nd, 2005

Direct ALL RFP questions and comments ONLY to Steven Grochowski via email at:
steven.grochowski@inergi.ca

***Proprietary Rights:** This document is the sole property of Hydro One Networks Inc. and shall not be reproduced or redistributed in whole or in part, electronically or in paper form or in any other form, for any purposes other than that for which it is intended, i.e. submission of proposals and/or Proposals and submission of work. All other use of this document or portion thereof shall require the prior written approval of Hydro One Networks Inc.

INVITATION AND RFP TERMS & CONDITIONS

Table of Contents

1. Glossary	3
2. Background	3
3. Introduction	3
4. Form of Proposal	4
5. RFP schedule & process	4
6. Confidentiality	8
7. Inquiries	8
Appendix A – Technical Requirements	
Appendix B – Commercial Conditions	
Appendix C – Form of Proposal	

1. GLOSSARY

In this document the following terms are used:

Contract: a signed agreement between Hydro One Networks Inc. (hereinafter referred to as “Hydro One”) and a Vendor, comprising (among other documents) this RFP.

Where there is a conflict between (a) Appendix A and (b) the main body of this RFP (together with Appendices B and C of this RFP), (b) shall take precedence.

Closing Time: as set out in section 5.7 below.

Hydro One: refers to Hydro One Networks Inc.

Inergi: refers to Inergi LP, the limited partnership to which Hydro One’s supply management services have been outsourced. For the purposes of this RFP, “Inergi” means “Inergi LP as agent for Hydro One Networks Inc.”.

RFP: this Request for Proposal, including all Appendices attached hereto, including any Addenda.

Proponent: any person, including a partnership or a corporation, which submits a Proposal in response to this RFP.

Proposal: an offer made by a Proponent in accordance with the terms of the RFP (note: a Proposal is merely an offer and does not constitute a Contract unless and until it is formally accepted and signed by Hydro One).

Vendor: a Proponent whose Proposal has been accepted and incorporated by reference in a Contract.

2. BACKGROUND

Hydro One owns and operates Ontario's largest high-voltage electricity transmission system and a largely rural low-voltage distribution system throughout the Province. Hydro One’s distribution system serves approximately 1.2 million retail electricity customers, comprised of residential, commercial, industrial and agricultural consumers of electricity and also serves smaller local distribution companies. Based on Hydro One’s fixed assets of approximately \$11 billion, Hydro One owns and operates one of the ten largest electricity transmission and distribution systems in North America.

3. INTRODUCTION

This RFP for Southwestern Ontario transmission 500 kV series compensation technical study consulting services solicits Proposals from entities who have considerable experience in the industry and with series compensation studies in particular. The Proponent is invited to submit a Proposal response.

The objective of the RFP is to select the Proponent(s) who have the greatest potential to supply the requirements identified, while also working to decrease the total cost of ownership.

Proponents participating in this RFP will not be excluded from participating in any subsequent RFP or other procurement process, for supply of the equipment to implement any eventual project to install series compensation in southwestern Ontario. Proponent's proposals and the recommendations of the technical study performed pursuant to any contract awarded under this RFP shall be sufficiently generic that multiple qualified suppliers would be able to supply the equipment.

Hydro One will be the Purchaser for the purpose of this RFP and any resulting award or Contract.

4. SUBMISSION OF PROPOSALS

This section identifies the mandatory Proposal preparation and submission requirements. Failure to follow these instructions may be grounds for elimination from consideration.

4.1 PROPOSAL FORMAT: All Proposals shall be submitted only in the prescribed form, as per Appendix C of this RFP. Clauses and terms within this RFP require specific responses and information from the Proponent, in its Proposal. Appendix C, Form of Submission, provides for appropriate spaces in which the Proponent can submit such response and information. Any other form of submission may result in the rejection and disqualification of the Proposal, by Hydro One, in its sole discretion.

4.2 PROPOSAL DEPTH: Each Proponent shall ensure that its Proposal provides complete and appropriate information as requested. Proponents shall address each topic in sufficient depth to permit a complete analysis and assessment by the evaluation team. Each Proponent shall use examples to demonstrate compliance so as to enable a fair and appropriate evaluation of its Proposal. While Hydro One may attempt to seek clarification and further information wherever necessary, Hydro One does not promise that such clarifications will be sought in all cases. Hydro One is not obligated to seek any clarification(s). Incomplete Proposals may be rejected as non-compliant, by Hydro One, in its sole discretion.

4.3 ALTERNATIVE SOLUTIONS: A Proposal may address additional topics and present alternative solutions that may provide additional value to Hydro One. To ensure consideration, Proponents must respond to the identified requirements at a minimum.

4.4 REQUIRED NUMBER OF PROPOSAL SUBMISSION COPIES: Proponents shall submit two (2) signed original copies (paper) and two (2) electronic (CD ROM format) copies. The content of the hard copy response must be identical to the electronic response. Proposals must be submitted in sealed packages, at the place, date and time specified in section 5 of this RFP.

5. RFP PROCESS AND SCHEDULE

5.1 INTENT OF THE RFP: Proposals submitted in response to this RFP may be accepted without further negotiation by Hydro One and will then be binding upon the selected Proponent(s). Hydro One will evaluate each Proposal considering the Proponent's ability (as must be sufficiently represented directly in the Proposal) to meet each of Hydro One's requirements as defined in the RFP. Hydro One does not represent that it will accept any Proposal, accept the lowest-priced Proposal, or be precluded from accepting any Proposal or other offer. Hydro One reserves the right to negotiate Proposals.

5.2 FULL SCOPE RESPONSE: Hydro One would prefer a single Contract to manage its requirements. Hydro One anticipates that Proponents may partner with third parties, including manufacturers and local distributors as necessary, to meet all of Hydro One's requirements. If two or more parties submit a single Proposal, a prime contractor must

be designated as the Proponent which, if selected by Hydro One, will execute and deliver the Contract and be fully responsible for the performance of the Contract in the event of the non-prime contractor's or subcontractor's failure to perform.

Alternatively, Hydro One reserves the right to Contract with multiple Proponents.

5.3 NOTICE: Some of the Proponents who are participating in the Proposal may have participated in general inquiries for the purpose of reviewing the marketplace. The intent is to keep requirements as generic as practically possible to encourage the spirit of competition. Proponents are invited to identify any requirements which are perceived as containing proprietary elements, for the purpose of maintaining more open standards. This can be managed through the defined inquiry process in section 7.

5.4 INTENT TO SUBMIT A PROPOSAL: Proponents who intend to submit a Proposal shall submit, via email to Hydro One's Inquires contact (see section 7), notice of their intent to submit a Proposal. The notification shall include a primary contact for the Proponent, including the contact's name, title, full legal company name, mailing address, telephone number, fax number and email address.

5.5 AMENDMENTS TO THE RFP: Hydro One reserves the right to modify, cancel or withdraw this RFP, and/or to issue a subsequent RFP, in its sole discretion at any time and for any reason whatsoever, without any obligation or reimbursement to the Proponents. Any additional information regarding this RFP will be provided to all Proponents who have indicated their intent to respond to this RFP.

5.6 WHERE TO SUBMIT PROPOSALS: Proposals are to be delivered only to the following address:

Proposal Depository – Hydro One Networks Inc
483 Bay Street, 15th floor, North Tower
Toronto, Ontario, M5G 2P5

5.7 DEADLINE FOR SUBMISSION: Proposals must be delivered to the address above by **4:00 PM EST on July 22nd, 2005** (such date and time are referred to herein as the "Closing Time"). Each Proponent is responsible for ensuring that its Proposal is received by the contact at the address given above by the Closing Time. Proposals received at any time after the Closing Time may not be considered by Hydro One. Hydro One accepts no responsibility for the timely delivery or receipt of Proposals.

5.8 SCHEDULE: The schedule for this RFP is as set out below. Hydro One may request a meeting on short notice during these period(s). Proponents who request to participate in the RFP process after the issue date will be provided with the RFP, but the Closing Time shall remain firm unless it is extended by the Purchaser by written notice supplied to all Proponents.

Milestone	Target Date
1. RFP issue date	July 7 th , 2005
2. Confirm intent to submit a Proposal	July 15 th , 2005
3. Last day to submit inquires for clarification	by 1:00 PM EST July 15 th , 2005
4. RFP Closing Time	by 4:00 PM EST July 22 nd , 2005

5. Proposal evaluation and clarification period	Week of July 25 th , 2005
6. Award	following evaluation & clarification

5.9 EVALUATION AND NEGOTIATION: Proposals will be evaluated on the criteria fully identified in Appendix C. Mandatory requirements are: financial viability, compliance with code of conduct, proof of ability sections a) and b), responsibilities of vendor and signature.

Criteria will be evaluated as to the Proposal's:

- ◆ Clarity of presentation (including demonstrated ability)
- ◆ Completeness of presentation
- ◆ Clarity of topic by topic response
- ◆ Inclusion of relevant supporting data (including use of appropriate references)

Hydro One reserves the right to consider modifications to a Proposal if the Proposal was originally submitted on time and if the modifications make the terms of the Proposal more favourable to Hydro One.

Hydro One may, in its sole discretion:

- ◆ Choose to meet with some or all of the Proponents to discuss aspects of their Proposal.
- ◆ Require one or more Proponents to submit supplementary documentation clarifying any matters contained in their Proposal and the supplementary documentation accepted by Hydro One shall be considered to form part of the Proposal of that Proponent, without giving other Proponents the opportunity to submit supplementary information.
- ◆ Negotiate any of the provisions of a Proposal with a Proponent, which negotiations may result in changes to a Proposal, without entering into similar negotiations with any or all of the other Proponents
- ◆ Negotiate with more than one Proponent at one time
- ◆ Award the RFP to more than one Proponent

5.10 EXCEPTIONS: The Proponent shall unequivocally state all exceptions to the terms and conditions and technical specifications of this RFP, in Appendix C, in the section "Exceptions", provided for this purpose. The Proponent shall be deemed to have accepted all the terms and conditions of this RFP, including the technical specifications, unless explicitly stated as and where provided herein. Any exceptions elsewhere are hereby rejected. Notwithstanding the Proponent's compliance with this clause, Hydro One may determine any exceptions and/or the Proposal as a consequence of such exceptions, to be unacceptable.

5.11 CLARIFICATION: Hydro One reserves the right to seek clarification and further information wherever necessary. Hydro One does not promise that such clarifications will be sought in all cases. Incomplete Proposals may be rejected as non-compliant, by Hydro One, at its sole discretion.

5.12 PRODUCT TESTING AND PROPONENT EVALUATION: Hydro One reserves the right to qualify the Proponent(s) before award of business. The qualification process may include, but is not limited to; (a) Review of manufacturing capabilities, including product range, (b) Review of specific techniques and process, (c) Review of management

organization - quality policies, (d) Review of quality program status and its effectiveness, (e) review of perceived constraints regarding technical requirements, (f) review of union contract status. This qualification process will be conducted by Inergi and Hydro One. In the event that the Proponent does not meet the requirements of Hydro One, no award will be issued.

5.13 AWARD AND EXECUTION OF CONTRACT: At the conclusion of the evaluation, clarification and testing (as applicable) process, and provided that Hydro One executive approval is obtained, each successful Proponent will be notified in writing that Hydro One wishes to enter into a binding Contract with the Proponent.

5.14 IMPLEMENTATION PLAN: The successful Proponent(s) shall work with Hydro One to finalize an implementation plan to manage product testing and evaluation, and, unless Hydro One has accepted the Proposal in accordance with the first sentence of section 5.1 above, to finalize the Contract. The plan will include elements such as start date to commence business, test schedule, delivery schedules and lead times, etc.

5.15 NO OBLIGATION: Hydro One is not obligated to seek clarification of any aspect of a Proposal. Hydro One reserves the right, in its sole discretion, to reject all Proposals, whether or not they contain all required information and whether or not they are properly completed, and to waive irregularities therein. Hydro One shall in no way be committed to accept the lowest priced Proposal or any Proposal, and is not liable to give any reason for its decision. Each Proponent agrees that the exercise of any right described herein shall be without liability on the part of Hydro One for any damage or claim brought by a Proponent because of same nor shall the Proponent seek any recourse of any kind against Hydro One because of Hydro One's exercise of such right.

5.16 COSTS: The costs and expenses for the preparation and submission of a Proposal, pre-Contract meetings, demonstrations, and all other costs and expenses incurred by the Proponent relating to this RFP shall be borne by the Proponent. Neither Inergi nor Hydro One shall be liable to pay for such costs and expenses or to reimburse or compensate any Proponent in any manner whatsoever or under any circumstances including, without limitation, in the event of rejection of any or all Proposals.

5.17 DEBRIEFING: Proponents eliminated from the selection process may request feedback from the evaluation team regarding the deficiencies of their offer, but Hydro One shall have no obligation to provide such feedback. This feedback must be requested through the Inquires process in section 7.

5.18 OFFERS TO REMAIN OPEN: Proposals shall be irrevocable and open for acceptance at any time within 150 days after the Closing Time.

5.19 ADDITIONAL RFP GENERAL TERMS AND CONDITIONS:

5.19.1 Hydro One may adjust any Proponent's proposed prices to Hydro One, for evaluation purposes, based on a determination that selecting a particular Proponent will involve incurring additional costs.

5.19.2 Hydro One will not be responsible for any verbal information or advice or any errors or omissions which may be contained in this RFP or any documentation, disclosed or otherwise provided by or with this RFP. Neither Hydro One nor any of its affiliates, directors, officers, employees or agents makes any representations or warranties, either express or implied, with respect to the completeness or accuracy of

this RFP and supporting documentation or any information or opinion contained herein. Any use or reliance on this RFP or on any information or opinion contained herein or documentation disclosed or otherwise provided by or with this RFP is at the risk of the Proponent, and neither Hydro One nor any of its affiliates, directors, officers, employees or agents shall be liable for any action, cost, loss, damage, injury and/or liability whatsoever incurred by any person arising out of same.

5.19.3 All written instructions and specifications will be considered clear and complete unless written attention is called to any apparent discrepancies or incompleteness before submission of a Proposal. The Proponent is responsible for obtaining its own independent legal, accounting, engineering and other advice with respect to this RFP, any information included in this RFP and in any documentation disclosed or otherwise provided by or with this RFP.

5.19.4 This RFP does not constitute a commitment by Hydro One to purchase any equipment or services.

6. Confidentiality

All requirements, documentation and information obtained by the participants in connection with this RFP are the property of Hydro One and must be treated as confidential information and not used for any purpose other than for replying to this RFP, and for fulfillment of any subsequent Contract(s) if awarded. No part of the RFP may be duplicated or distributed, in any form, to any other company or third party, or otherwise disseminated in any manner whatsoever. Should you choose not to participate in this evaluation, please destroy all electronic and paper forms of this RFP, including any supporting documents. Proponents must not disclose any details pertaining to their Proposal, this RFP and/or the selection process in whole or in part to anyone not specifically involved in their Proposal without Hydro One's prior written approval. Proponents shall not issue a news release or other public announcement pertaining to details of their Proposal, this RFP and/or the selection process without Hydro One's prior written approval.

7. INQUIRIES

It is each Proponent's responsibility to ensure that it has all necessary information concerning the intent and requirements of this RFP. It is the Proponent's responsibility to learn all aspects of the RFP requirements. Should any details necessary for a clear and comprehensive understanding be required, it is the Proponent's responsibility to obtain clarifications before submitting a Proposal. Hydro One may not be able to answer every request for further information and shall not be obligated to modify the schedule for receipt and evaluation of Proposals in order to accommodate such requests.

All inquiries regarding administrative or technical aspects of this RFP must be submitted in writing via email to the appropriate authority identified below as early as possible after issuance of the RFP. Inquiries must be received before 1:00 PM EST on July 15th, 2005.

ALL inquiries regarding this RFP must be directed via email solely to:
steven.grochowski@inergi.ca

No individual other than the person designated above is authorized to comment on any portion of this RFP or the work (as described in Appendix A). Inergi and Hydro One will

not be liable for any actual or potential Proponent, or any person claiming through him, her or it, with respect to any information regarding this RFP.

A Proponent who makes inquiries to an unauthorized person may be deemed to be non-compliant and no further consideration will be given to its Proposal. Information obtained from past communications with Hydro One should not be considered relevant to this RFP.

Inquiries will be answered to the best of Hydro One's ability and as quickly as possible. However, Hydro One is not obligated to respond to any questions. To ensure the consistency and quality of information provided to Proponents, Inergi will provide, simultaneously to all Proponents, any information with respect to significant inquiries received and the replies to such inquiries, without revealing the sources of the inquiries.

Any correspondence that may be required to be exchanged pursuant to this RFP shall carry Hydro One's RFP project name and document number.

HYDRO ONE NETWORKS INC.

REQUEST FOR PROPOSAL

FOR

Southwestern Ontario Transmission 500kV Series Compensation Technical Study Consulting Services

Reference # 13651

APPENDIX A

TECHNICAL REQUIREMENTS

Southwestern Ontario Transmission 500 kV Series Compensation **Scope of Work for Technical Studies**

1.0 Background

Since January 2005, Hydro One Networks Inc. (Hydro One) has been working with stakeholders to explore options to increase the transmission capability of the network throughout southwestern Ontario with the goal of enabling the shutdown of the OPG coal-fired generating stations at Nanticoke GS and Lambton GS. With the possible return of all the nuclear units and the potential for significant new generation in the Bruce area, there is a need to increase the transmission capability of the 500kV system out of the Bruce area.

To meet these transmission needs, Hydro One is considering the installation of new series capacitors on three Hydro One 500 kV transmission paths:

1. Bruce GS to Longwood TS on circuits B562L & B563L
2. Nanticoke GS to Longwood TS on circuit N582L
3. Bruce GS to Claireville TS and Milton TS on circuits B560V & B561M respectively

See Figure 1.0 showing the southwestern Ontario transmission system and the circuits to be compensated. This diagram also shows that the series capacitor sites are to be located approximately in the middle of each circuit.

Preliminary planning studies performed by Hydro One suggest the need for the following 500kV series compensation facilities:

- Provide 70% series compensation on the B562L and B563L circuits
- Provide 70% series compensation on the N582L circuit
- Provide about 10% compensation on the B560V and B561M circuits

These compensation levels were selected to maximize the transfer capability between the Bruce area and the major load centres in south-central Ontario that includes the Greater Toronto Area. Hydro One assumes that 70% represents the highest practical level of series compensation used by the industry for bulk power transmission. Such compensation levels are required on the B562L, B563L, and N582L circuits to permit high post contingency transfers for the loss of the B560V and B561M circuits. The power transfer capability out of the Bruce area to south-central Ontario is presently constrained by voltage instability, and the loss of the B560V and B561M circuits represents the limiting contingency. Much lower levels of compensation are required on the B560V and B561M circuits as these circuits have more post contingency capacity for high transfer levels on the BLIP interface. The 10% compensation level was initially selected to maintain the existing transfer capability of the BLIP interface.

There are major nuclear and thermal generating stations presently connected to the 500kV transmission system in southwestern Ontario. These existing generating facilities include:

1. Bruce GS – up to 8 nuclear units, total capacity up to 6600MW
2. Nanticoke GS - 8 coal-fired units, total capacity 4000MW (which are expected to shut-down by 2009, but which may to an extent be run after the installation of series compensation and some of which may be run as synchronous condensers on an ongoing basis)
3. Darlington GS – 4 nuclear units, total capacity 4000MW

With the high levels of series compensation proposed and the generation facilities connected to the 500kV system, a thorough assessment for potential sub-synchronous resonance (SSR) impacts will be required. The assessment is to identify conditions under which SSR can occur, assess their impacts and risk, and recommend mitigation measures if necessary.

2.0 SCOPE OF WORK

The Contractor will conduct the necessary power system studies to assess and provide recommendations on the series compensation proposal with respect to sizing, location, and design parameters. This will also include the review of studies performed by Hydro One and the IESO.

The Contractor will conduct a technical study that reviews all aspects of SSR associated with the proposed series compensation on the southwestern Ontario 500kV transmission lines. Where SSR issues are identified, an assessment of potential mitigation measures along with a recommendation of the mitigation approach will be required. The technical description of the recommended mitigation approach will be of sufficient detail to allow Hydro One to prepare planning and performance specifications for purchase of new facilities required to provide the necessary mitigation. Recommended facilities must have a proven track record in achieving the required mitigation.

The Contractor will be required to interact with Bruce Power and OPGI to review and validate as necessary the generator, excitation and turbine mechanical data required to perform the SSR analysis and simulations. Hydro One and the IESO will contribute assistance to the study as specified below. The SSR analysis will be reviewed by Bruce Power and OPGI, and possibly by other potentially affected generators.

The required completion date for this study is November 30, 2005.

2.1 Power flow and Stability Studies

The Contractor will perform the following:

- Review the power flow and stability studies performed by Hydro One and the IESO, and provide comments on the system modeling or system performance results that may affect the series compensation proposal
- Provide recommendations on the optimum sizing including percentage compensation, location, and design parameters for the proposed series compensation facilities to maximize the transfer capability of the southwestern Ontario 500kV system.
- Conduct additional power flow and stability studies as necessary to identify adverse system stability or operational issues and to confirm the transfer capability improvement of the proposed series compensation facilities.

Hydro One will provide the power flow base case used in Hydro One's preliminary analysis, as well as the necessary short circuit data and requirements. The IESO will also provide supporting data as detailed in Section 3.0.

The preliminary technical specifications for the series compensation facilities are shown in Appendix A.

2.2 Sub-Synchronous Resonance Studies

The Contractor is to perform all necessary analysis to identify and assess potential SSR issues, their impacts and risk levels on the southwestern Ontario 500kV system. The assessment of SSR issues must include a description of the:

1. SSR problem types such as torsional interactions, induction generator effects etc.
2. Generators affected
3. Number of turbine-generator modes excited
4. System conditions and contingencies which result in the SSR problem
5. Degree of undamping
6. Degree of torque amplification

The assessment must include a complete review of all generation facilities that may be impacted by SSR in southern Ontario including any new generators under construction or committed (to be identified by the IESO and Hydro One). At a minimum, a separate discussion and review of potential SSR impacts at the Bruce, Nanticoke, Darlington and Pickering generating stations must be included, along with a separate discussion of any other generator that is affected as identified by the review.

The SSR studies are to include but not be limited to the following analysis:

1. Frequency Scan Analysis
2. Transfer Function / Eigenvalue Analysis
3. Transient Shaft Torque and Torque Amplification Analysis

The SSR frequency scan screening analysis is to be conducted for generating plants throughout southern Ontario. A discussion of the rationale for excluding any generating plant from this analysis is required. The frequency scan analysis should assess such concerns as induction generator effects, torsional interactions and the potential for torque amplification. For the system conditions of concern, sensitivity analysis for different levels of compensation should be included.

The transfer function or eigenvalue analysis will assess the torsional interactions and small-signal control response effects. It will also review the SSR concerns identified by the frequency scanning analysis. The analysis should be conducted with and without potential SSR mitigation measures for the critical conditions or cases. An assessment of the improvements in the damping characteristics should be included.

The transient shaft torque analysis will assess SSR effects that may be excited by faults, line switching and other transient phenomena. The analysis will also identify potential torque amplification situations that can lead to excessive generator shaft fatigue. Where significant impacts are identified, the analysis should be conducted with and without potential SSR mitigation measures. It would be preferable if the time-domain transient simulations for the shaft torque analysis is performed using the EMTP software. EMTP is used extensively at Hydro One and therefore Hydro One can more readily provide modeling support and data for this analysis.

The consultant is also to provide recommendations as to any other analyses of SSR that should be carried out, and upon agreement with Hydro One, is to carry out these analyses as well.

2.3 Review and Recommendations on SSR Mitigation Measures

The Contractor will review the effectiveness and feasibility of the relevant alternative mitigation measures or strategies to address each of the SSR issues identified in the SSR analysis. The Contractor will provide recommendations on how best to address the SSR issues. The recommended measures should take into consideration system design, operations, and protection issues. Major protection issues, if any, should be identified along with recommendations on how to deal with them.

If additional facilities are recommended, such as thyristor controls, filters, or capacitor by-passing schemes, the Contractor is to provide a technical description of such facilities and their design that has sufficient detail for Hydro One to develop a planning and performance specification for the purchase of such facilities.

It is desirable to employ SSR mitigation measures which do not require additional facilities or modifications at generating stations. If additional facilities or modifications at generating stations are recommended, the Contractor will provide a discussion of the benefits and advantages over other mitigation measures which do not involve generating facilities.

3.0 Data Responsibility and Requirements

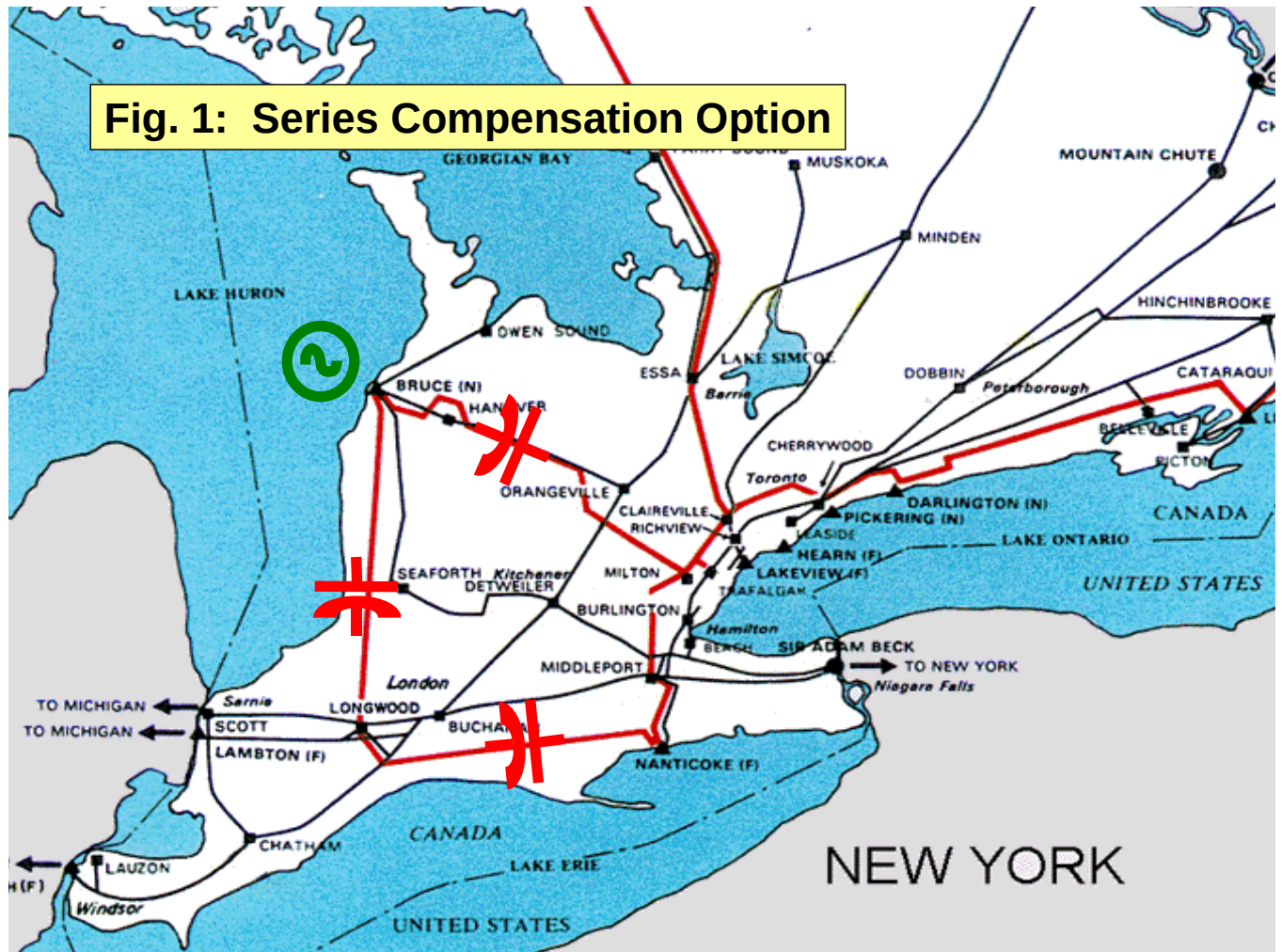
The contractor will be responsible for the development of all simulation models required to perform the SSR analysis. This includes but not limited to models required for frequency scan analysis, eigenvalue analysis and EMTP analysis. Hydro One will provide all relevant transmission data, the base power flow case used in the preliminary analysis, and system short circuit data required for the study work. The IESO will provide data on system security (critical contingencies) and capability issues (limits), along with existing generator modeling used for dynamic studies, assumptions for base generation dispatch scenarios, and any significant powerflow updates outside the Hydro One system. Other relevant, available studies will also be provided by Hydro One, the IESO, and the generators, as applicable.

The contractor is to establish the list of data requirements for developing the necessary generator-turbine spring-mass models. Contractor will consult with OPGI and Bruce Power to review the generator-turbine modeling data for completeness and suitability. Contractor will identify key assumptions made regarding such data and provide an assessment on the limitations of such assumptions and their significance on the results.

4.0 Deliverables

1. Interim report to be based on initial review and studies performed by the contractor, understanding that some of the findings may be subject to confirmation by further studies. The initial review and studies are to include collection and validation of generator and machine data for all necessary simulations. The report will:
 - be provided by September 30, 2005

- document initial recommendations on proposed series compensation regarding size, location and overall design
 - identify major variations from the results or recommendations from the initial studies performed by Hydro One and the IESO, and the implications of these
 - identify major SSR issues and implications, particularly from the initial frequency scan analysis, particularly from the perspective of the need to protect generator's assets
 - identify any other material issues identified, and make recommendations / request direction as appropriate
2. Final report will:
- be provided by November 30, 2005
 - fully address requirements identified in Scope of Work, and will summarize the major findings and recommendations in an Executive Summary



Appendix A: Preliminary Specifications for Series Compensation Proposal

Series Compensation Ratings

Table 1 below indicates the preliminary data on general location, amount compensation and ratings of the series capacitors.

Table 1: Preliminary Data

Site	Circuit	Amount of Compensation %	Impedance Ω	Continuous Current (summer), Amps	Momentary Rating kiloAmps	MVAR Three Phases MVAR
Grand Bend	B562L	70%	41.5 Ω	3760 A	95 kA	1760 MVAR
Grand Bend	B563L	70%	41.5 Ω	3760 A	91 kA	1760 MVAR
Tillsonburg	N582L	70%	35.2 Ω	3760 A	95 kA	1490 MVAR
Lake Bellwood	B560V	10%	6.6 Ω	3760 A	9 kA	280 MVAR
Lake Bellwood	B561M	10%	5.5 Ω	3760 A	5 kA	235 MVAR

System Ratings and Performance

Table 2 below features the series compensation system ratings and performance that are required.

Table 2: Series Compensation System Ratings and Performance

System Voltage Class	500 kV
Normal Max. System Voltage	550 kV
Emergency System Voltage	575 kV
Rated frequency	60 Hz.
Rated Cont. Current	3760 A/ph rms
Maximum Emergency Current	4070 A/ph rms
Duration of Emergency Current	15 Minutes
Normally Cleared Fault duration	88 milliseconds
Zone 2 Fault duration (communication failure)	488 milliseconds
Breaker fail duration	200 milliseconds
Platform BIL	1800 kV peak
Platform SIL	1300 kV peak
Platform 60Hz Withstand (Dry)/duration	860 kV rms/120 secs
Platform 60Hz Withstand (Wet)/duration	775 kV rms/10 secs

Figure 1 shows the one line diagram of a typical series capacitor installation.

Figure 2 provides the proposed general locations for the Southwestern Ontario Series Compensation.

Momentary Rating

Appendix B: Short Circuit Ratings for the 500 kV Series Capacitors, contains the results of the initial short circuit study.

Overvoltage Protection

Voltage across the series capacitor will be limited to about 2 p.u. of the rated voltage during system fault conditions. The devices limiting the voltage across the capacitor – (C) consist of MOV – Metal Oxide Varistor – (Z), transient current limiting circuit (D), triggered spark gaps (G), and a bypass breaker (B) as shown in Figure 3: Series Capacitor Banks. A control circuit will coordinate the overvoltage protection.

Reinsertion Time

Reinsertion is to occur within 500 ms of being bypassed.

HYDRO ONE NETWORKS INC.

REQUEST FOR PROPOSAL

FOR

Southwestern Ontario Transmission 500kV Series Compensation Technical Study Consulting Services

Reference # 13651

APPENDIX B

COMMERCIAL CONDITIONS

SUPPLEMENTAL COMMERCIAL CONDITIONS

1. REPRESENTATIONS AND WARRANTIES OF THE CONSULTANT

The Consultant represents and warrants that:

- A. it shall perform the work in a diligent and professional manner and otherwise in accordance with the Contract;
- B. all personnel employed in the performance of the work shall have the requisite qualifications, expertise and experience to perform the work;
- C. it has the necessary corporate power, authority and capacity and good and sufficient right to enter into the Contract on the terms and conditions herein set forth, and has the financial and other ability and authority to fulfil its obligations hereunder and to carry out the terms of the Contract;

2. FAILURE TO SUPPLY

In the event that the Consultant fails to consistently meet delivery time as specified in the Contract, the Purchaser reserves the right to terminate the Contract, and the Purchaser shall have no liability to the Consultant for so doing, nor shall the Purchaser be liable for any finished or unfinished work which may have been prepared by the Consultant for performance of the Contract or for any time or labour spent by the Consultant after the Consultant receives notice of termination.

3. CONTRACT CANCELLATION

The Purchaser shall have the right to terminate the Contract at any time in its duration, without specifying any reason, upon providing 30 days' written notice to the Consultant, and the Purchaser shall not be liable to the Consultant for so doing, nor shall the Purchaser be liable for any time or labour spent, or any forward commitments made, by the Consultant after receiving the said written notice.

4. INDEMNITY/HOLD HARMLESS

The Consultant agrees to indemnify and hold harmless the Purchaser and its employees from and against all liability, claims, judgements or demands for loss, damage or injury including loss of life, to persons or property occasioned by the negligent or improper acts or omissions of the Consultant. Notwithstanding the foregoing, Consultant's liability hereunder for breach of contract (except with respect to claims for infringement of the intellectual property rights of a third party or pursuant to this indemnity clause) shall be limited to \$5 million.

5. INSURANCE

When used in these insurance provisions, the term "Contractor" shall mean the Purchaser's opposite party, whether described as the Company, Consultant or otherwise in this agreement. Contractor agrees to provide and/or cause its subcontractors to provide and maintain in full force and effect with financially responsible insurance carriers the following insurance which shall take effect as of the date of this agreement and shall remain in effect during the term hereof or any extension thereof or as otherwise specified herein:

1. Worker Compensation: Contractor and/or subcontractors shall qualify under and shall satisfy all the workers compensation laws of all jurisdictions in which the "Work" and any portion of the Work is to be performed and any other applicable provisions of said laws. (Note: For U.S. employees, appropriate State Workers Compensation must be carded including Employees Liability for a minimum limit of \$1,000,000 U.S., with a Foreign Coverage Endorsement and, to the extent applicable, Jones Act and U.S. Longshoreman's and Harbor Workers coverage and FELA).
2. Automobile Liability Insurance, covering all licensed vehicles owned, (and non-owned auto for policies written in U.S.), rented or leased and used in connection with the work to be performed under this agreement. Coverage shall include Bodily Injury and Property Damage Liability, mandatory Accident Benefits and if applicable attached machinery, to a combined inclusive minimum limit of \$5,000,000. To achieve the desired limits, Excess or Umbrella coverages may be used.
3. Commercial General Liability Insurance with limits of \$5,000,000 inclusive for both bodily injury, including death, personal injury and damage to property, including loss of use thereof, for each occurrence. To achieve the desired limits, Excess or Umbrella coverages may be used. Coverage shall specifically include but not be limited to the following:
 - Blanket Contractual Liability;
 - Damage to property of the Purchaser including loss of use thereof,
 - Liability arising out of unlicensed equipment;
 - Pollution Liability coverage on at least a Sudden and Accidental basis;
 - Products & Completed Operations to be continuously maintained through the operational liability insurance
 - Employer's Liability;
 - Non-Owned Automobile Liability; Not applicable where company's auto liability insurance covers non-owned autos as in U.S. policies

- Broad Form Property Damage
 - XCU endorsement (if applicable to the services being provided under the contract)
 - Blasting (if applicable to the services being provided under the contract)
4. Errors and Omissions Insurance. If Contractor provides any design, engineering, contract management or other professional services and its professional errors or omissions could result in loss, damages to, or claims against, the Purchaser, then the Contractor shall carry \$5.0 million of Errors and Omissions Insurance with insurers satisfactory to the Purchaser and shall ensure that such policy or policies do not exclude any liability that could result from its professional errors or omissions in connection with the work. Without limiting the generality of the foregoing, the policy will not contain a design/build exclusion if the Contractor is carrying out designing and building activities in connection with this contract. Coverage shall remain in effect for no less than 3 years following final completion of work.

CERTIFICATES OF INSURANCE:

1. The Contractor will supply and cause its subcontractors to supply Purchaser a certificate of insurance completed by a duly authorized representative of their respective insurers certifying that at least the minimum coverages required here are in effect and that the coverages will not be cancelled, restricted or reduced without 30 days advance written notice by registered mail, receipt required, to:

Steven Grochowski, Supply Chain Specialist,
483 Bay Street, 12th Floor TCT14
Toronto, ON M5G 2P5

(with copy to Hydro One Inc., Risk & Insurance Department, 483 Bay Street, TCT 08, South, Toronto, Ontario. M5G 2P5)

- (a) Failure of Purchaser to demand such certificate or other evidence of full compliance with these insurance requirements or failure of Purchaser to identify a deficiency from evidence provided will not be construed as a waiver of the Contractors obligation to maintain such insurance.
 - (b) The Purchaser's acceptance of delivery of any certificate of insurance evidencing the required coverages and limits does not constitute approval or agreement by the Purchaser that the insurance requirements have been met or that the insurance policies shown in the certificates of insurance are in compliance with the requirements.
 - (c) The Contractors failure to maintain the required insurance as set forth here may result in termination of this contract at Purchaser's option.
 - (d) If any of the coverages are required to remain in force after final payment, an additional certificate evidencing continuation of such coverage will be submitted with the Contractors final invoice.
 - (e) Certificates of insurance will be provided within 14 days of award of the contract.
2. All deductibles shall be to the account of the Contractor and/or its subcontractors.
3. With the exception of Automobile Liability Insurance, all insurance noted above shall specify that it is primary coverage and not contributory with or in excess of any other insurance that may be maintained by Purchaser.
4. All limits and deductibles are expressed in Canadian dollars.
5. Purchaser, shall be included as an Additional Insured under coverages noted in Commercial General Liability and Excess/Umbrella Liability but only with respect to their rights and interest in the operations of the Contractors and shall be added a Loss Payee as Purchaser's interest may appear, under-coverage All Risks' Installation Floater.
6. Coverages noted in Commercial General Liability and Excess/Umbrella Liability shall contain a Cross Liability clause and a Severability of Interests clause.
7. Coverage provided for the Purchaser shall not be invalidated or vitiated by actions or inactions of others.

The aforementioned insurance requirements shall be in force prior to the commencement of services under the contract and shall remain in force during the entire term of the contract. Notwithstanding anything else in the contract:

- (a) the Contractor shall not commence providing the said services prior to the Purchaser's receipt of a valid Standard Insurance Certificate evidencing compliance with all terms of this clause;
- (b) if the required insurance coverage expires during the term of the contract, the Contractor shall not continue providing the said services prior to the Purchaser's receipt of a valid Standard Insurance Certificate evidencing continued compliance with all terms of this clause; and
- (c) in addition to any other remedy that the Purchaser may have against the Contractor as a result of the Contractor's failure to comply with all the terms of this clause, the Contractor shall, to the extent that delay in providing the said services occurs as a result of the non-delivery of Standard Insurance Certificates as required by (a) and (b), be liable to the Purchaser for all damages arising out of the said delay.

6. WORKPLACE SAFETY AND INSURANCE BOARD CLAIMS

The Consultant will be solely responsible for all Workplace Safety and Insurance Board claims, related to the Consultant, during any work that is performed for the Purchaser within the scope of this agreement. The Consultant covenants and agrees to indemnify the Purchaser in respect of any such claims.

7. CONFLICT OF INTEREST

The Consultant represents and warrants that there is no conflict of interest between the performance of the work scope outlined in the Contract and its performance of work and provision of services to other customers, and this warranty shall survive the execution of this contract.

8. CONSULTANT'S EMPLOYEES

All individuals engaged by the Consultant to perform work under the Contract shall be subject to the prior approval of the Purchaser. All individuals hired by the Consultant shall be deemed employees of the Consultant and not shall not at any time be or be deemed to be an agent, servant or employee of the Purchaser.

The Consultant and all of its supervisors, employees, representatives, agents and subcontractors shall be qualified and competent to do the work. The definitions of qualified and competent are:

"Qualified" Accepted as satisfactory in reference to experience, personal competency, and familiarity with rules, procedures, apparatus, and dangers involved in the work.

"Competent" A person who:

- (a) is qualified, because of his or her knowledge, training and experience, to organize and perform the work;
- (b) is familiar with the provisions of Ontario's Occupational Health and Safety Act and the Purchaser's corporate policies and procedures set forth herein that apply to the work;
- (c) has the requisite knowledge of any potential or actual danger to health and safety in the workplace; and
- (d) is at least 18 years of age.

9. INDEPENDENT CONTRACTOR

Consultant shall be an independent contractor for all purposes hereof and shall not at any time be, or be deemed to be, an agent or employee of the Purchaser.

10. ASSIGNMENT OR SUBLETTING

A-29-03 Section 7 is replaced with the following:

The Consultant shall not assign the contract or any portion thereof. The Purchaser may assign the contract or any portion thereof upon obtaining the Consultant's consent, which consent may not be unreasonably withheld or delayed. Upon such assignment, Consultant hereby releases Purchaser from all liability under the contract. Notwithstanding the foregoing, the Purchaser may, without the Consultant's consent, assign the contract or any portion thereof to an affiliate.

2.1.511. INTERPRETATION AND DISPUTE RESOLUTION

Notwithstanding A-29-03 s. 3, the Contract shall be governed by and interpreted in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein.

Notwithstanding any arbitration provision in any Contract document, the parties hereby specifically attorn to the exclusive jurisdiction of the courts of Ontario at Toronto to determine all disputes arising out of the Contract or the interpretation thereof.

12. PURCHASER'S LIMITATION OF LIABILITY

Subject to all other exclusions and limitations in the Contract documents, the Purchaser's maximum liability to the Consultant shall not exceed an amount equal to the Contract price, and in no event shall the Purchaser be responsible for any loss or damages that are indirect, consequential, punitive, or for economic loss, loss of revenues, loss of profits, or as a result of fines levied by governmental or governmental authorities.

13. PUBLIC RELATIONS

The Consultant and its employees and subcontractors shall conduct themselves in a manner conducive to the maintenance of good public relations for the Purchaser.

Appendix B – Commercial Conditions

If during the performance of the work the Consultant or its employees or subcontractors receive complaints or enquiries to which they are not qualified to respond, the recipient of the enquiry shall record details of the complainant or the person making the enquiry, as well as such person's name address and telephone number, and shall report the incident to the Purchaser's Contract Administrator.

14. CONFIDENTIALITY

During and after the term of the services under the Contract, the Consultant shall treat as confidential, and ensure that its employees, agents and subcontractors treat as confidential, all Confidential Information to which they may become privy. The Consultant is responsible for all information disseminated to its subcontractors.

STANDARD COMMERCIAL CONDITIONS



A29-03.doc



A5-2003.doc

double click on the icon to access

[insert Proponent's name]

APPENDIX C - FORM OF PROPOSAL

Dated: [insert date]

For

Hydro One Networks Inc.
(hereinafter referred to as "Hydro One")

Request For Proposal

For

**Southwestern Ontario Transmission 500kV
Series Compensation Technical Study
Consulting Services**

Reference # 13651

**PROPOSERS MUST USE THIS FORM FOR SUBMISSION OF PROPOSALS. PROPOSERS MUST
USE BOTH THE ORIGINAL NUMBERING SYSTEM AND THE STATEMENTS FOR REQUIREMENTS.**

**REFER TO SECTION 4 & 5 OF THE INVITATION FOR SUBMISSION OF PROPOSALS
REQUIREMENTS**

TABLE OF CONTENTS

1. DECLARATION.....	3
2. BUSINESS PROFILE, FINANCIAL VIABILITY & CODE OF CONDUCT.....	4
3. PROOF OF ABILITY / REFERENCES.....	4
4. TECHNICAL COMPLIANCE.....	5
5. SUBCONTRACTORS / DECLARATION AS TO SOURCE	5
6. PRICE SCHEDULE.....	5
7. DELIVERY SCHEDULE / IMPLEMENTATION	6
8. ALTERNATIVES WHICH IDENTIFY OPPORTUNITIES FOR VALUE ADDED	6
9. QUALITY CONTROL PROGRAM	6
10. LOCAL PRESENCE	6
11. COMMERCIAL COMPLIANCE: EXCEPTIONS TO THE RFP (IF ANY)	6
12. RESPONSIBILITIES OF THE VENDOR.....	7
13. SIGNATURES	7

1. Declaration

FORM OF PROPOSAL

To: Proposal Depository – Hydro One Networks Inc
483 Bay Street, 15th floor (TCT 15)
Toronto, Ontario
M5G 2P5

Gentlemen:

DECLARATION

(Name of Proponent)

(Full Address)

(Telephone number including area code)

(Fax number including area code)

(Proponent's GST Registration number, if applicable)

(Proponent's reference number)

The undersigned, hereby declare that the Proponent is:

(a) A corporation incorporated under the laws of _____.

OR

(b) An individual or partnership carrying on business under the firm name and style above stated, the name and places of incorporation or registration, if any, of the partnership or joint venture being the following:

(Strike out subclause (a) or (b), whichever does not apply.)

2. Business Profile, Financial Viability & Code of Conduct

The Proponent MUST be of sound financial condition. To enable Hydro One to assess the Proponent's financial condition, the Proponent must provide the information requested below in its Proposal. Proposals which do not supply this information may be disqualified as non-compliant.

BUSINESS PROFILE

- a) Contact Information and Location: Provide the contact name, title, e-mail address, telephone number, mailing address, and facsimile number of the primary contact person for any inquiries relating to this RFP.
- b) Facility Locations: Hydro One may inspect the Proponent's facilities to provide assurances of capacity and quality. The Proponent shall list address and contact information of all facilities, including those of subcontractors, involved in this proposal. Any inspection by Hydro One will be prearranged with the Proponent.
- c) Proponent's Company Philosophy Statement: Provide a brief statement of your corporate purpose and philosophy.
- d) Proponent's Company Background: Provide a brief overview of your company history and background.
- e) Proponent's Company Organizational Structure: Describe the structure and management of your organization. Include an organizational chart for the company.
- f) Proponent's Company Size: Provide the total number of company employees and an estimate indicating the percentage of these employees who are directly related to the scope of this RFP. Describe the key personnel proposed for this project and their respective qualifications.

FINANCIAL VIABILITY

- f) Proponent's Company Ownership: Describe how your company is owned and financed. Describe any extended financial relationships, such as parent company, etc. Provide your D&B DUNS number and banking references.
- g) Proponent's Company Revenue: Provide your company's total gross revenue figures for 2003, 2004, and a projection for 2005 indicating the percentage of these gross revenues that were related directly to the scope of this RFP.
- h) Proponent's Financial Data: Provide your company's last two audited Financial Statements and Annual Reports (if any).
- i) Litigation: Provide a listing of any pending claims, lawsuits and/or judgements against your company and affiliates.
- j) Disclosure of Acquisition/Merger: Provide information concerning any plans or discussions of acquisition or merger affecting your company's ownership.
- k) Conflict of Interest: Provide information on all potential conflicts of interest between your company and Hydro One. This includes financial interests and influential personal relationships between your company and Hydro One and their employees, agents, suppliers, subsidiaries, and parent organizations.

CODE OF CONDUCT

- l) Code of Conduct: Confirm that you have reviewed and comply with Hydro One's Code of Conduct.
http://www.hydroone.com/en/about/code_of_business

3. Proof of Ability / References / Qualifications

Mandatory and Weighted

Demonstrated experience with series compensation studies, SSR analysis and SSR mitigation measures on major 500kV systems with series compensation

- a) Provide three references to projects completed of a type and scope similar to Hydro One's requirements. Include the following information: contract date & duration, purchaser company name, contact name, phone numbers and brief description of the project.
- b) Provide a list of similar studies performed where series compensation was actually installed, identifying the system where the series compensation was installed, and a providing a brief overview of the generation characteristics of that system (e.g. type of generation). Please list at least 10 such studies, or if less than 10 studies have been done by the proponent list all such studies done.

Weighted

- c) Preference will be given to proponents who have experience with studies of series compensation on 500kV systems with nuclear and/or thermal generation connected. Describe and demonstrate relevant experience.
- d) Where SSR issues exists, applications such as thyristor-controlled series capacitors that would mitigate all SSR issues may be desirable. Therefore, experience in the studies and design of TCSC facilities for SSR mitigation would be an asset. Describe and demonstrate relevant experience.

4. Technical Compliance

Demonstrate your ability to comply with the technical requirements identified in Appendix A. Proponents must review each requirement in "Scope of Work", "Data Responsibility and Requirements", and "Qualifications" in Appendix A in detail and, item by item, concept by concept, provide sufficient and appropriate information so as to demonstrate compliance and to permit a complete analysis and assessment of your proposed solution by the evaluation team.

Format of response: For ease of review, Hydro One requires Proponents to respond to this section by using the format of Appendix A, maintaining the original requirement statement, and responding immediately below. Title this response Appendix A and attach it at the back of your Form of Proposal submission.

5. Subcontractors / Declaration as to Source

a) Major Suppliers/ Subcontractors:

Identify any and all subcontractors that will be used to assist the Proponent in fulfilling requirements offered in its Proposal. Subcontractor's company name, address, contact name, relationship to prime bidder, and work to be contracted to subcontractor must be provided in Table 1 below. The Proponent is asked to provide information about the business association, to describe the service and how it integrates into the total solution. The level of information supplied regarding partner services must be consistent with that supplied for the Proponents own services, including pricing.

TABLE 1: Major Suppliers / Subcontractors

Proposed Major Suppliers or Subcontractors	Work Subcontracted

[Insert as many lines as necessary to provide the required information.]

6. Price Schedule

Pricing must comply with the Commercial Conditions. Proposed pricing must contain a minimum level of detail as outlined below: Proponents must identify all cost components of their Proposal in this section.

- a) Provide a fixed price for the delivery of a complete assessment, which meets all of Hydro One's requirements, including all costs.
- b) Provide a complete breakdown of the pricing above by key cost items. Also identify any aspects which may include any potential for variable price and identify estimated ranges.
- c) State the hourly rates applied in the proposal. Hydro One reserves the right to manage any minor additional scope during the term of any resulting contract, if any, at these rates.

7. Delivery Schedule / Implementation

- a) Warrant your ability to provide the proposed solution to meet Hydro One's requirements no later than November 30th, 2005.
- b) Provide a detailed implementation schedule and include a supporting explanation of the process.

8. Alternatives which Identify Opportunities for Value Added

The purpose of this section is to fully identify any alternatives which offer value added opportunities.

- a) Alternatives: In addition to price, state differences in performance between the alternatives and the main offer and/or Hydro One's specified requirements. Any differences must be clearly identified. Include attachments as necessary, specify complete technical details, applicable Contract price, and schedule for each alternative. Identify any other alternatives in sufficient detail to enable Hydro One to effectively evaluate the potential impact(s) of the alternative. State guarantees regarding completion of work on-time and within budget while meeting overall technical specifications.

9. Quality Control Program

Our existing quality control program conforms to a minimum of the quality assurance standard ISO 9002, or reasonable equivalent. We will maintain this program in accordance with this standard and comply with all other Hydro One quality program requirements, including section 5.12 Product Testing and Proponent Evaluation, for the duration of this Contract. Confirm your compliance with these requirements and provide a copy of your certificate. Describe your quality control program.

10. Local Presence

Please provide information on offices, service locations or any other form of representation in Ontario or elsewhere in Canada.

11. Commercial Compliance: Exceptions to the RFP (If Any)

By submitting a Proposal, we acknowledge that we have reviewed the RFP and that we understand that failure to explicitly express any exception(s) in this space will be deemed as acceptance. Any exceptions contained elsewhere than in this section are rejected. Any exceptions must use Table 2 to fully identify the exception and propose alternatives in sufficient detail to enable evaluation of the potential impact to Hydro One. Hydro One reserves the right to reject Proposals which do not comply with the requirements of this section.

Table 2: Exceptions

Page Number Reference	Section Number	Requirement, or portion of the requirement, which the exception is applicable to	Compliance status N / P (No, Partial)	Alternative Proposed (level of detail MUST be sufficient)

12. Responsibilities of the Vendor

If selected as the Vendor, we will be fully responsible for the performance of the Contract in the event of a subcontractor's (if any) failure to perform. Clearly confirm your compliance with this requirement.

13. Signatures

We hereby offer to Hydro One to supply those portions of the work for which a Contract is awarded, as described or shown in the above documents, for the prices stated in the Price Schedule.

We have thoroughly examined Hydro One's invitation and RFP documents (including all appendices thereto), and addenda as listed hereunder, and are fully informed as to the nature of the work and conditions for its performance.

Addendum

Dated

No. _____

No. _____

No. _____

The undersigned is duly authorized to bind the Supplier and hereby warrants and represents the following:

- ◆ this Proposal is valid for acceptance for a period of one hundred fifty (150) days from the last date and time fixed for receipt of Proposals and that Hydro One may at any time within the said period accept this Proposal whether or not any other Proposal has been previously accepted.
- ◆ the data provided pursuant to this Proposal is accurate in all respects,
- ◆ we have the current capability to provide the proposed solution,

SIGNATURE

NAME

TITLE

COMPANY NAME

DATE

Pappas INTERROGATORY 6 List 2

Interrogatory

Issues:

- 1.1 Has the need for the proposed project been established?
- 2.1 Have all reasonable alternatives to the project been identified and considered?
- 2.2 Has an appropriate evaluation methodology been applied to all the alternatives considered?
- 2.4a Have appropriate evaluation criteria and criteria weightings been utilized in the evaluation process for the alternatives and the proposed project and what additional criteria/weightings could be considered?
- 3.1 Are the proposed near term and interim measures as outlined in the application appropriate?

Ref

1. APPENDIX A to Procedural Order No. 5. IN THE MATTER OF Leave to Construct Application by Hydro One Networks. EB-2007-0050. DATED February 25, 2008
2. Technical Conference, Day 1 [Oct. 15, 2007]: Transcript - Mr. McKay.

Preamble:

Following, is an excerpt from the Transcript of the Technical Conference, Day 1, Oct. 15, 2007.

MR. McKay's comments regard the Series Compensation Due Diligence Study. I maintain that this study is an absolute prerequisite to the advancement and approval or denial of this Application. This study involves matters of both the project alternatives and possible near term and Interim measures.

Questions by Mr. McKay

MR. McKay: I will be very quick. Can you turn up on your slides the summary of options for screening results? That is the matrix. Can you give us a bit more explanation on the category for limited effects on other paths, in terms of what that criteria is and what it is used in terms of how you use it to evaluate in terms of eliminating certain of these alternatives.

MR. CHOW: The southwestern Ontario network is quite interconnected in terms of it is not an isolated system. It affects many other paths. When we look at this in combination with providing required capability - and in this case you look at it together, side by side - it gives you an indication that, one, does it have the capability; two, when you actually have that system, does it affect, in this case, negatively on other paths? So in the case of Bruce to Essa, that's an easy one. The power from Bruce is being sent up to Barrie, to Essa. There it's getting combined with the flow for northern Ontario and it all shares the same path from Essa down to Claireville, Barrie to Toronto.

1 So in that case there, its impact is going to reduce the transfer capability on that path by 1000
2 megawatts.. So it is a consideration because it is negatively affecting other paths. In the case of
3 series capacitors on the 500 kV line and the Bruce-to-Longwood-to-Middleport, the path is
4 affecting to a large degree the flow coming from west to east through the London area. Because
5 you lose the Bruce-to-Milton line, the power from Bruce going down the Bruce-Longwood line is
6 combined with the flow coming in from the Sarnia and Windsor area, and together they travel the
7 path between London and Nanticoke.

8 So, again, it has a negative impact on the ability -- in other words, they share the power one way
9 or the other. The one path requires the power. The other one has to back off.

10 So in a way, it is a negative, but the way we look at it is a combination of both the first column
11 and the second column.

12 MR. McKAY: On that basis, I guess one criteria, you discounted the series capacitors as a long-
13 term solution; that and the fact that it doesn't have the capacity?

14 MR. CHOW: Mainly that it doesn't have the capacity. It is capable of seven units versus 700
15 megawatts of wind.

16 MR. McKAY: When you did that analysis, were you including generation rejection?

17 MR. CHOW: No, because we are looking at this set as a long-term solution.

18 MR. McKAY: That is an isolated analysis on simply the series capacitors?

19 MR. CHOW: Yes.

20 MR. McKAY: So you rejected the series capacitors on a long-term basis, and then from the
21 green-line graph that we have seen today, you have made it quite clear that you don't need it on
22 an interim basis with the near-term and the interim measures you want to put in place. So the
23 question I have is: Why are you continuing with the study? You don't need it in the long term,
24 and it's pretty clear that you don't need it to meet the interim requirements.

25 MR. CHOW: The answer is on the next slide after that, on the interim. The decision on series
26 compensation will be made in consideration of the line-in-service date. In other words, will it be
27 late, the effectiveness of the other measures. We believe that the GR, in combination with the
28 other measures, will provide us the necessary capability. When we actually end that phase there,
29 we want to see how close we are, and also the progress of generation additions on the system.

30 MR. McKAY: That's a change in the evidence; right?

31 MR. CHOW: At that time, series compensation is a possibility. I am indicating here it is still a
32 possibility, with those considerations. So it is always looked at as a back-pocket solution that we
33 would put in if certain conditions are met.

34 MR. McKAY: As a final question, a lot of talk today about this study that's being done. I'm
35 assuming that there were some form of terms of reference or something that put some bounds
36 around what this study is, what it is supposed to produce, what you expect. Is that available if we
37 ask that in an interrogatory?

38 MR. CHOW: This is related to the due-diligence study on series compensation?

39 MR. McKAY: Yes.

40 MR. CHOW: Yes. Its terms of reference were developed for the consultant. It would be a part of
41 the attachment of the report, and, yes, on request in an interrogatory.

42 MR. McKAY: Can we get it now or get it within a couple of weeks?

43 MR. NETTLETON: The trouble that I am having is the message that we have communicated to
44 all of the parties has been that we are prepared to look at these requests for additional information
45 through the interrogatory process.

46 I will have to check the procedural order, but I think there is a due date on when IRs are due and
47 there is a due date on when the responses are due.

1 So I think if people want to ask us interrogatories now, they could; and we can hopefully get
2 through the interrogatories as fast as possible. If your interrogatory came in with that request, we
3 would be able to get it done sooner rather than later.

4 MR. McKAY: No. I appreciate that, Mr. Nettleton, but I guess the question was, I'm assuming
5 that in order to get this report done, you would have had to put terms of reference together. That
6 document, I'm assuming, is available today, now; obviously we're not going to ask to produce it
7 here today, but as an interrogatory, it would be good to have the confidence that you wouldn't
8 object to it being filed as an answer to an interrogatory.

9 MR. NETTLETON: I'm not hearing any objection from OPA.

10 MR. McKAY: Thanks.

11
12 Request:

13
14 Will, the Applicant and its Proponents [OPA, IESO] provide the Interveners, and the Board, with
15 the relevant documents, studies, communications, consultations or reports, draft or final,
16 regarding the OPA due diligence report on Series Compensation [capacitors]?
17
18

19 **Response**
20

21 The OPA's Due Diligence Report is included as Attachment 1. The Terms of Reference to that
22 report is also being provided as Exhibit C Tab 4 schedule 9 Attachment 1 (Please refer to
23 Exhibit C-4-9 in response to Pappas Interrogatory #9). Other than the Terms of Reference,
24 Hydro One is not prepared to file the requested additional documents, studies, communications,
25 consultations or reports, draft or final, regarding the OPA due diligence report on Series
26 Compensation [capacitors], due to the broadness of the request and the time and effort required
27 for the production of the information. In Hydro One's view, the documents which have been
28 produced provide an adequate background to the subject-matter and as this relates to the Issues
29 List.
30

Final Report

Due Diligence Study and Development of

High Level Planning Specifications for the

Installation of 500 kV Series Capacitor Banks in the

Southwestern Ontario Transmission Network

For the
Ontario Power Authority
OPA Purchase Order No. 50000488
OPA Project Manager: Jim Lee

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October 5, 2007

Summary

This report evaluates specific use of series capacitors on the 500 kV network in the Southwestern Ontario (SWO) electricity system. Previous investigations have been reported on series capacitor applications by ABB [1] and the IESO [2], [3]. Although series capacitors applied to high voltage transmission systems is a mature technology with hundreds of successful installations in service in North America and around the world, the resulting impact they may have on the ac system is complex and severe. The main issues are:

1. **System Reliability.** Generally, adding series capacitors to existing transmission lines without adding additional circuits to accommodate increased power flow causes parallel circuits to be more highly loaded under contingency conditions. This results in a higher average line and transformer loading which can be thought of as an ever growing stress on the network. This wide spread stress exacerbates the impacts of routine contingencies and the latent failures and grid imperfections that compound them.

Generally, adding series capacitors instead of additional circuits tend to speed the transition from one worse case contingency event and one worst case limiting element to multiple worst case events and multiple limiting elements, making grid failures from severe contingency events more likely. The series compensated and, seemingly robust network carrying ever more power is not only less reliable for the above reasons, but opens the door to impacts of contingencies and cascading over larger areas. Careful design of the Bruce special protection system (BSPS) can counteract reduced system reliability when adding series capacitors for these increased power flows but is a complex adjustment to do successfully. In addition, careful design applied to each series capacitor bank can minimize the impact of failure modes within the bank and its consequential negative influence on system reliability.

2. **Sub-synchronous resonance (SSR).** SSR is one of the most significant aspects that require attention. Although the undesired overlap of generator shaft torsional modes with the complementary electrical resonance is less likely the lower the level of series compensation applied, there is no guarantee that sub-synchronous resonance can be avoided altogether. With the 30% level of series compensation considered for application in Southwestern Ontario (SWO), it appears the Nanticoke generators under transmission contingency conditions will be more susceptible to sub-synchronous resonance than the units at Bruce under contingency conditions. For the period of time that the Nanticoke generators will be in operation after the

series capacitors are installed, a strategy to mitigate SSR will need to be put in place, that might consist of operating restrictions, shaft torsional damping through the unit exciters, and application of torsional stress relays. When these generators are decommissioned and four units possibly retained as decoupled synchronous compensators, it is expected that as decoupled units, these torsional modes of shaft resonance will no longer exist except the generator and exciter mode should be checked. Attention will need to be paid to the Lambton units, but the impact of SSR on them appears less than at Nanticoke.

The Bruce generators would not have their complementary torsional frequencies within range of resonant frequencies created by 30% series compensation, based on critical contingencies. Nevertheless a detailed design study for the proposed series capacitor installations should be considered to ensure adequate damping of any sub-synchronous resonances with generators is achieved. However, it would not need to be undertaken with the comprehensiveness of the ABB study [1], but concentrate on the Bruce units with 30% series compensation on B562L, B563L and N582L transmission lines. At this stage no SSR mitigation design is recommended for the series capacitor banks but operating restrictions be defined and put in place, and possibly tuning the unit's exciters to increase torsional damping. Finally, it is recommended that consideration be given to adding torsional stress relays to all Bruce and Lambton units, as well as to any Nanticoke units retained as generators after the installation of the series capacitors. This is not an insignificant cost, and would amount to several millions of dollars.

3. **Reactive Power.** The reactive power requirements of the SWO system with the increased loading on the series compensated transmission lines, particularly under contingency conditions will require significant additional reactive power support that needs to be quantified and characterized as to whether it is installed with fixed, switched or dynamic compensation and where it is to be installed.
4. **Engineering Complexity.** In spite of the precautionary measures that must be undertaken, series capacitors are an appropriate engineering facility that can be added to major transmission lines in the SWO network to increase power transfer capability. The technical issues that must be addressed such as those outlined above and in this report can be addressed with judicious due diligence and well established and accepted engineering practice.

To provide a guide to the process of acquiring the series capacitors, a check list of activities and studies is supplied. A high-level preliminary planning specification is provided as well as a draft technical specification.

Acknowledgements

Appreciation is expressed to Jim Lee and Ben Li for providing the necessary support to our team for this project, and to Bob Chow for providing the background for this work. The comments received from OPA, Hydro One and IESO significantly enhanced this work. The final comments received from OPA have significantly added to this report.

Table of Contents

SUMMARY	- 2 -
ACKNOWLEDGEMENTS	- 4 -
TABLE OF CONTENTS	- 5 -
INTRODUCTION	- 7 -
1. SERIES CAPACITOR (SCAP) APPLICATION FOR SWO	- 7 -
1.1 RISKS WITH SERIES CAPACITORS	- 7 -
1.1.1 Appropriateness of Employing Series Capacitors.....	- 7 -
1.1.2 Potential Risks of Applying Series Capacitors.....	- 8 -
1.1.3 Further System Studies to Identify Probable Risk Situations.....	- 10 -
1.1.4 Application of Suitable Mitigation Measures.....	- 11 -
1.2 SUMMARY OF MAJOR SERIES CAPACITOR INSTALLATIONS WORLD WIDE	- 11 -
1.2.1 High Voltage Series Capacitor Installations	- 11 -
1.2.2 Series Capacitor Applications	- 12 -
1.2.3 Compensation Levels	- 12 -
1.2.4 Installation Time Lines	- 13 -
1.2.5 Special Features	- 14 -
2. SPECIFIC PERFORMANCE AND RELIABILITY CONSIDERATIONS – SYSTEM ASPECTS..	- 16 -
2.1 VOLTAGE CONTROL ISSUES ASSOCIATED WITH ADDING SCAP BANKS	- 16 -
2.2 TEMPORARY OVERVOLTAGES (TOV)	- 18 -
2.3 IMPLICATIONS OF OVERVOLTAGE EFFECTS ON THE SCAP BANKS AND ON EXISTING FACILITIES.....	- 20 -
2.4 IMPACT OF SERIES CAPACITORS ON SYSTEM DAMPING	- 21 -
2.5 IMPACT OF SERIES CAPACITORS ON THE BRUCE SPECIAL PROTECTION SCHEME	- 21 -
2.6 INTERACTION OF SWO SCAPS WITH FUTURE SHUNT CAPACITOR BANKS, STATIC VAR COMPENSATORS AND SYNCHRONOUS COMPENSATORS.....	- 23 -
2.7 RESONANCE CONDITIONS BETWEEN SERIES CAPACITORS AND EXISTING SHUNT COMPENSATION.....	- 24 -
2.8 IMPACT OF SERIES CAPACITORS ON SHORT CIRCUIT LEVELS	- 25 -
3. SPECIFIC PERFORMANCE AND RELIABILITY CONSIDERATIONS – EQUIPMENT ASPECTS.-	26 -
3.1 FAILURE MODES OF A SERIES CAPACITOR INSTALLATION	- 26 -
3.1.1 Internal Failure Modes	- 26 -
3.1.2 Consequences of Failures	- 26 -
3.1.3 Failure Statistics	- 26 -
3.1.4 Failure Mitigation.....	- 27 -
3.2 NATURE OF SERIES CAPACITOR EQUIPMENT FAILURES	- 27 -
3.2.1 Equipment Failure Modes.....	- 27 -
3.2.2 Safety.....	- 28 -
3.2.3 Failure Prevention	- 29 -
3.3 AVAILABILITY OF SERIES CAPACITOR INSTALLATIONS	- 31 -
3.3.1 Availability Statistics.....	- 31 -
3.3.2 Unavailability.....	- 32 -
3.3.3 Unavailability Mitigation.....	- 33 -
3.4 RELAYING AND LINE PROTECTION ISSUES WITH SERIES COMPENSATION.....	- 33 -
3.5 VOLTAGE PROTECTION WITH SERIES COMPENSATION.....	- 35 -
3.6 REQUIREMENTS FOR CURRENT RATING OF PROPOSED SERIES CAPACITOR BANKS	- 36 -
4. SUB-SYNCHRONOUS RESONANCE (SSR) CONSIDERATIONS.....	- 38 -
4.1 POTENTIAL FOR SSR ON BRUCE, NANTICOKE AND LAMBTON GENERATORS.....	- 38 -
4.2 TEST SCOPE AND MODELLING OF PREVIOUS SSR STUDIES	- 38 -
4.3 FURTHER STUDIES ON SSR IN SOUTHWESTERN ONTARIO	- 39 -
4.3.1 Expanding the Number of Operating Generators	- 40 -
4.3.2 Protection Against SSR with a Torsional Stress Relay.....	- 40 -

4.3.3 Checklist of Actions Regarding SSR.....	- 40 -
5. HIGH LEVEL PLANNING SPECIFICATIONS FOR THE SOUTHWESTERN ONTARIO SERIES CAPACITORS.....	- 41 -
5.1 HIGH LEVEL PLANNING SPECIFICATION	- 41 -
5.2 SPECIAL REQUIREMENTS TO MITIGATE SSR.....	- 42 -
5.3 OTHER MEASURED CONSIDERATIONS DRIVING MID-POINT LOCATION	- 44 -
5.4 STUDIES REQUIRED FOR SERIES CAPACITOR INSTALLATIONS.....	- 45 -
5.4.1 Pre-feasibility Studies	- 45 -
5.4.2 System Impact Studies	- 46 -
5.4.3 Facilities Study.....	- 47 -
5.4.4 Action Checklist	- 49 -
CONCLUSIONS.....	- 52 -
REFERENCES	- 53 -
LIST OF APPENDICES	- 54 -

Introduction

This report is prepared in response to a request from the Ontario Power Authority (OPA) for consulting services to evaluate specific use of series- capacitors on the 500 kV network in the Southwestern Ontario electricity system. Studies have already been undertaken by ABB [1] and the IESO [2], [3] on proposed transmission developments in Southwestern Ontario (SWO), and comments based on experience and knowledge of series compensation and related issues are to be provided. Additionally, data for a high level technical specification is to be supplied as a deliverable.

The above referenced ABB and IESO reports contain a significant amount of information on the option to series compensate the two 500 kV transmission lines from Bruce to Longwood (B562L and B563L) as well as the single transmission line from Longwood to Nanticoke (N582L). It was concluded that generating units at Bruce and Nanticoke were susceptible to sub-synchronous resonance conditions under certain contingencies. This study reviews the technical aspects of applying series capacitors to the Southwestern Ontario (SWO) system and provides a high level planning specification for the purchase, installation and commissioning of series capacitors. To reduce the threat of sub-synchronous resonance, the application of series capacitors at the 30% compensation is considered.

1. Series Capacitor (SCAP) Application for SWO

1.1 Risks with Series Capacitors

1.1.1 Appropriateness of Employing Series Capacitors

Uncompensated transmission assets are normally under utilized, particularly if their length is such that their power transfer capacity is impedance and stability limited (through voltage collapse or angular instability) rather than thermally limited. Applying series compensation with series capacitors (SCAP) is an accepted method of increasing the transfer capacity of a high voltage transmission line that is impedance limited. The transmission impedance is reduced allowing more power to be transferred along the line.

Series capacitors have been successfully applied to high voltage transmission lines since 1948. Over those years the effectiveness of series capacitors has been substantially improved with metal oxide varistors (MOVs) or surge arresters, improved protection, damping of sub-synchronous resonance

(SSR), and application of power electronics to improve damping of angular stability oscillations and also provide damping of SSR. The application of MOVs since the early 1980s has eliminated the technical challenges of re-insertion following an ac system fault.

Series capacitor application to high voltage transmission lines, and at 500 kV is a mature technology in North America and around the world. In Canada, BC Hydro (now BCTC) was the first to apply series capacitors at 500 kV. The 500 kV Winnipeg to Twin Cities 500 kV interconnection between Manitoba and Minneapolis was series compensated as a staged upgrade, increasing the power transfer capability from 1000 MW to 1,500 MW. Hydro Quebec added series capacitors to their 735 kV transmission network to achieve increased power transfer capability and improved contingency performance.

An important side benefit of the Manitoba Hydro and Hydro Quebec series capacitor upgrades was the substantial reduction in impact of geomagnetic currents. Severe geomagnetic storms had caused operational problems in both Manitoba and Quebec. In the late 1980's a severe geomagnetic storm precipitated a system wide blackout in Quebec that the later installation of series capacitors has all but eliminated such a disturbance reoccurring again.

Geomagnetic storms induce currents in grounded transmission systems, which if severe enough cause power transformers and instrument transformers to saturate. The consequential distorted currents that flow through the transmission system may overheat the saturated transformers and cause protective relays to falsely operate. The effect is most severe in northern locations. Series capacitors fully protect a transmission line from geomagnetic induced currents. However, the SWO system although subject to a limited effect of geomagnetic induced currents with its absence of series capacitors, has not had its operation limited or restricted by them. Thus series capacitors appear to not be essential for protection of the SWO system against geomagnetic induced currents.

1.1.2 Potential Risks of Applying Series Capacitors

Expanding transmission capacity between available generation in order to meet increasing load such as in SWO has traditionally and preferably been accomplished with new transmission lines.

Additional transmission lines preserve reliability of supply under transmission outages as well as minimize losses. A limited option to new transmission is the use of series capacitors on existing transmission as a way to increase transfer capacity, or as a bridging measure before new transmission is built. However, system losses increase compared to having a new transmission line which when capitalized will diminish the economic gains the relatively low cost series capacitors appear to offer.

Adding series capacitors to existing transmission lines without adding additional circuits to accommodate increased power flow causes parallel circuits to be more highly loaded under contingency conditions. This results in a higher average line and transformer loading which can be thought of as an ever growing stress on the network. This wide spread stress exacerbates the impacts of routine contingencies and the latent failures and grid imperfections that compound them.

Generally, adding series capacitors instead of additional circuits tend to speed the transition from one worse case contingency event and one worst case limiting element to multiple worst case events and multiple limiting elements, making grid failures from N-2 events more likely. The ever larger and, seemingly robust network carrying ever more power is not only less reliable for the above reasons, but opens the door to impacts of contingencies and cascading over larger areas.

Series capacitors need to be applied with considerable care to ensure that they do not result in severe damage to thermal generators such as at Bruce and Nanticoke. Most significant is sub-synchronous resonance [1], which is more likely when a generating plant under contingency operation, is radial, or dominantly radial through the series compensated transmission line. If the electrical series resonance of the generators and transmission lines are complementary to a mechanical resonant modal frequency of the generator shaft, then negative damping of the shaft torsional oscillations may occur, which will lead to shaft damage if not remedied.

Fortunately the mechanism of SSR, its analysis and design for prevention is now well known and a number of mitigating measures exist to address this issue (see Section 1.1.4). Generally it is true that the lower the proportion of series compensation on a transmission line, the less likely the electrical series resonance will decrease damping of complementary shaft torsional resonant modes and cause shaft damage. Failures of a steam turbine shaft noticeably occurred on the Mohave Generator in Nevada in December 9, 1970 and October 26, 1971. These failures were directly attributable to network switching conditions that instigated SSR with the level of series compensation of the 500 kV transmission at 70% [10]. Consequently, due diligence on SSR as it might adversely impact the SWO generation when series capacitors are added to the SWO 500 kV transmission system is imperative and has been instigated [1], [2], [3]. Series capacitors, even if not resonant at a frequency complementary to a generating shaft torsional frequency, can still reduce the damping of shaft resonant modes through reduced electrical damping. If significant, shaft aging may be accelerated if torsional oscillations normally invoked by transmission line switching and fault clearing will take longer to damp. This is like bending a wire back and forth, which if continued long enough will cause the wire to break.

1.1.3 Further System Studies to Identify Probable Risk Situations

The study undertaken by ABB [1] was a wide ranging investigation of all the potential operating contingencies that invoke the condition of SSR. It is recommended a similar study be repeated at the new level of series compensation selected at 30% for lines B562L, B563L and N582L. The system studies that can be undertaken include:

1. The impact on torsional damping of the shafts of the generating units at risk because of electrical damping effects from the ac network needs to be re-evaluated. Any network line switching or fault clearing in the vicinity of impacted generators will instigate shaft torsional oscillations that are required to be always positively damped so that they die out quickly. If shaft torsional damping for any mode is negative, then SSR is likely and the contingencies and conditions that created this undesirable state must be remedied with a suitable design or operating procedure. This study is required to ensure that nothing is overlooked with the specific level of series compensation proposed.
2. A supplementary study can be undertaken to examine the impact on generator shaft life if reduced damping is evident on one or more torsional modes of impacted generators. Reduced damping results in extended shaft torsional oscillations that add to shaft fatigue. This is done by estimating the number of line switchings and faults that are applied and cleared in the vicinity of generating units that could accumulate shaft fatigue.
3. Capacitor rating for steady state, short time overload, system faults and delayed fault clearing. This information is required to finalize the technical specification.
4. Bruce Special System Protection Review Study. This essential study will determine how the special protection system must be updated to accommodate the increased stresses on the power system from increased power flows.
5. Energy ratings of the MOV (varistor) protective devices. This information will be determined by the supplier of series capacitors as part of the design process and contribute to their overall costs. The varistor energy ratings will be impacted by line clearing times and whether reclosing will apply on the series compensated transmission lines.
6. Line profile voltage assessment.
7. Temporary over voltages, transient over voltages.
8. Protection Co-ordination Study

This report investigates and expands on the probable risk situations identified above.

1.1.4 Application of Suitable Mitigation Measures

When SSR problems are determined to be a risk, mitigation methods that can be applied in order of practicality and cost include:

1. Operating restrictions upon detection specific transmission contingencies.
2. Excitation system damping of SSR.
3. Ensure any power electronic controller in the vicinity of an impacted generator provides positive electrical damping to the torsional frequencies of the shaft. Such a controller could be a static var compensator (SVC) or STATCOM.
4. AC filters tuned to SSR electrical frequencies.
5. Damping circuit added to portion of the series capacitor (such as a thyristor controlled series capacitor (TCSC) or NGH damping controller).
6. Conversion of series capacitor to a solid state series capacitor (SSSC).

Damping controllers can be of a “broad-band” design or can target narrow frequency ranges to isolate specific modal frequencies. If the torsional data for the problematic generator is available, then a narrow frequency range solution is preferred to localize the control changes to the local machine and frequency range. If the shaft data is not available, then broad-band mitigating methods will be devised but should be used cautiously since they could potentially have negative impacts elsewhere in the system.

Finally, after successful mitigation measures have been designed, the generators at risk to SSR should all be protected with a torsional stress relay as a safety net.

1.2 Summary of Major Series Capacitor Installations World Wide

1.2.1 High Voltage Series Capacitor Installations

A survey of five major suppliers of series capacitor installations resulted in responses from four (4). Appendix A provides a list of the series capacitor installations provided from each of the responding suppliers. A summary of the data shown in Appendix A is included in Table 1.2.1.

Table 1.2.1

Summary of World Wide Series Capacitor Installations

Supplier	MVAR Supplied	Number of Installations	Maximum Voltage	Maximum MVAR	Maximum MOV/Phase
ABB	76,352	265	760 kV	2,096	Not Stated
GE	52,776	157	735 kV	1,242	196.4 MJ
Nokian	26,506	75	750 kV	1,056	75 MJ
Siemens	22,076	65	765 kV	765	59 MJ
Total	177,710	562			

1.2.2 Series Capacitor Applications

Suppliers of series capacitor installations do not generally document the application for which their equipment is being used by the host utility. However, based on past experience of team members preparing this report it is the consensus that most applications of series capacitors are for improving power flow on critical transmission paths and also for transient stability improvements.

1.2.3 Compensation Levels

Appendix A provides a summary list of series compensation sizes (MVAR) provided by suppliers. The list does not include the percentage compensation that the individual installations provide but rather the MVAR ratings. In general, if the total MVAR of series compensation listed in Table 1.2.1 is divided by the total number of installations, an average MVAR/installation would be approximately 316 MVAR/installation, which is slightly less than the assumed 30% compensation for the B562L, B563L and N582L lines.

In North America, there are no series compensated transmission lines that connect thermal generators radially to the network under a no contingency condition. However, since they are installed in a meshed network, they may revert to a radial connection under contingency conditions. The series capacitors on the 735 kV transmission system in Quebec are in radial transmission lines but from hydroelectric generators, which are not prone to SSR. The significance of a radial connection is that all the power from the generator passes through the series capacitor. If the generator is connected to a meshed network, then some portion of generated power is diverted or attenuated into other circuits so that the severity of SSR is diminished. Hydroelectric generators have very stiff shafts compared to the

shafts of steam turbines and are virtually impervious to SSR even when radially connected through series compensated transmission lines.

1.2.4 Number of Installations

Although the initial series capacitor installation occurred in 1928, it would take until the 1960's before the technology began to expand. Figure 1.2.4.1 indicates a time line beginning in 1948 when 55 MVAR of series capacitors were delivered through 2007 when approximately 3,045 MVAR were in delivered. In 2003 the delivery of series capacitors peaked with approximately 13,045 MVAR produced on a world wide market.

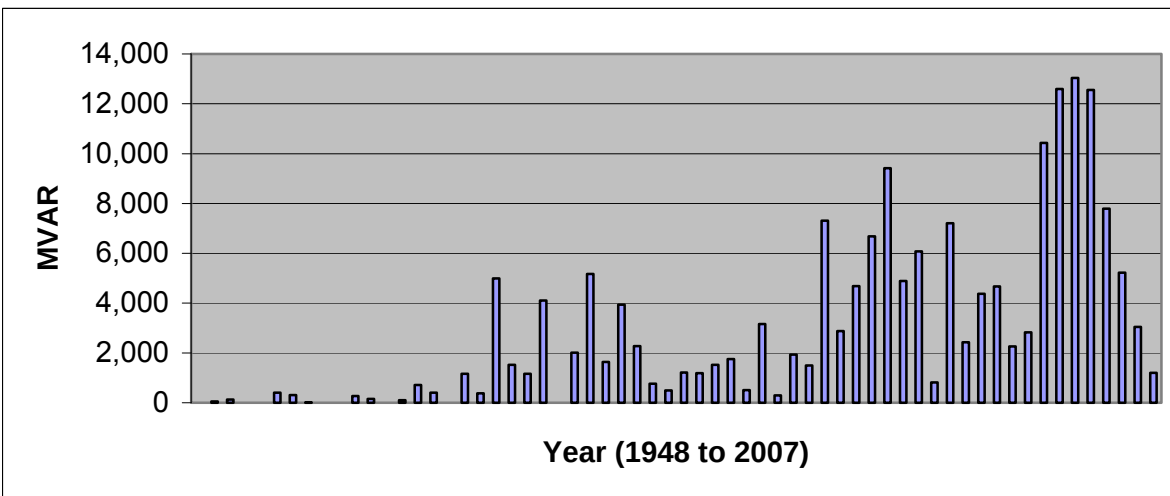


Figure 1.2.4.1

Annual World Wide Series Capacitor Deliveries

An overview of a sample series capacitor project time-line is shown in Figure 1.2.4.2. Task 1.0 (Specification Preparation) and Task 2.0 (Request for Proposals & Award) can require a significant amount of time depending on staff availability and work load of the purchasing utility. A twelve (12) month period has been allocated to Tasks 1.0 and 2.0 following project authorization and approval. Tasks 1.0 and 2.0 would include the following major efforts:

Task 1.0 – Specification outline, system studies, technical specification and procurement coordination.

Task 2.0 – Issue Request for Proposal (RFP), pre-bid meeting, supplier proposal preparation, proposal evaluation, supplier clarifications, negotiations and contract award.

Following contract award an eighteen (18) month period has been allocated to Task 3.0 (Design & Engineering) through Task 8.0 (Commercial Operation). Tasks 3.0 through 8.0 would include the following activities:

Task 3.0 – Final system studies, equipment studies, protection and control design, site design and project review meetings. This would also involve design support from the utility.

Task 4.0 – Manufacturing of capacitor units, protection and control hardware, other platform equipment, platform structure and other needed equipment.

Task 5.0 – Factory testing of all equipment including protection and control, real time digital simulator (RTDS) testing, shipping and on-site receipt of equipment.

Task 6.0 – Site work would include grading, foundations, fencing, building construction, inspection, cabling and all equipment installation.

Task 7.0 – Commissioning activities include operator and maintenance training, pre-commissioning of subsystems, high voltage energization, acceptance testing and trial operation tests.

Task 8.0 – Commercial operation would signal the start of the warranty period during which the installation would be monitored by the utility to ensure contract performance requirements are being met.

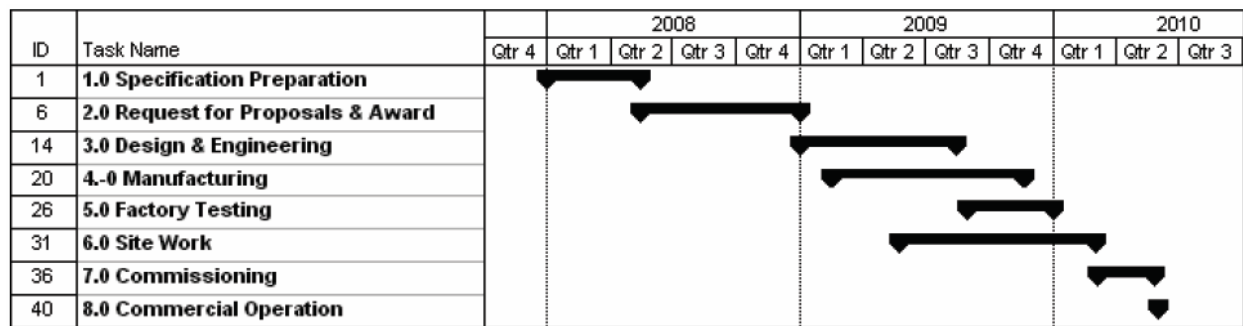


Figure 1.2.4.2
Sample Project Time-Line

1.2.5 Special Features

Special features that have been incorporated into series compensation systems over the years include advancements in hardware, software and analytic capabilities. These advancements have improved the performance of series compensation systems and reduced their level of maintenance to the point that transmission line applications that improve power flow and system stability have become widespread. Early installations had performance and maintenance problems. Now the advancements have dealt effectively using special features that include the following:

1. Planning capabilities have improved by use of analytic tools that model the power system and associated equipment more accurately. As a result, series capacitor hardware can be specified and designed to withstand emergency contingency conditions not easily foreseen in the past.
2. Standards for critical components associated with series capacitor installations have evolved and now include factory and type testing techniques that cover special features associated with fault recovery requirements.
3. Software and hardware advances have allowed economic implementation of redundant control and protection systems for series compensation schemes that improve performance related availability and reliability. As a result, maintenance requirements are also reduced.
4. Overvoltage protection across series capacitors has been greatly improved with the use of metal oxide varistor (MOV) technology. This is a passive type protection that typically involves several parallel and series connected MOVs units that are highly reliable if sized correctly. The normal spare philosophy is to initially install extra MOV units thus providing an initial derating factor, higher reliability and eliminating the need for storing additional spare units. MOV characteristics (voltage vs. current) change over their installed life with exposure to voltage. As a result of these changing characteristics individual MOV units can not be replaced over the life of the installation, but rather the whole MOV bank of arresters would need to be replaced.
5. Spark gaps can provide an effective means of overvoltage protection when MOV energy levels needed to protect the capacitors becomes excessive. Spark gaps are fast and typically forced triggered by the control and protection system via fiber optic signal columns. Once triggered, the protective by-pass circuit breaker is closed and current through the spark gap is diverted through the breaker.
6. Special protective features of series capacitor banks include capacitor unbalance, capacitor overload, fault-to-platform, spark gap protection, MOV energy and failure protection, sub-harmonic protection and SSR protection (if needed). Providing instrumentation power for platform mounted electronic equipment has been addressed in the past by use of on-line current transformers. Modern installations now use optical means of providing power to platform electronic equipment.

7. The introduction of thyristor valves into series compensation schemes has produced a means of mitigating SSR issues and also capacitor bank overvoltage protection features. These special features require detailed transient voltage studies using some of the analytic tools and modeling techniques cited above.

2. Specific Performance and Reliability Considerations – System Aspects

2.1 Voltage Control Issues Associated with Adding SCAP Banks

Series capacitors reduce the inductive series impedance of the transmission line they are installed in. This inherently improves ac voltage control by “stiffening” the network. However as power flow increases to take advantage of the reduced impedance, any benefit in voltage control diminishes with increased power flow. A series compensated transmission line has reduced reactive power requirement than a transmission line with no series compensation for the same power flow. This is illustrated in Figure 2.1.1 where N582L is considered by way of example with 30 % series compensation. Here, approximately 310 MVAR less is demanded by N582L at one end only of the transmission line when operating at a loading level of 3,660 amperes which is below the line’s short-term emergency rating (STE).

Another way to view the control issue with series compensation referring to Figure 2.1.1 is that at this loading level of N582L, the power system has to supply approximately 610 MVARs to one end of the series compensated transmission line when 30% series compensated, and 920 MVAR without series compensation. This means the range of reactive power that has to be supplied by the power system to the line end is less by the significant amount of 310 MVAR. From this it can be deduced that the reactive power variation required by the transmission line over its range of operation is less for the series compensated line which means ac voltage variation at line ends is also less and thus better regulated.

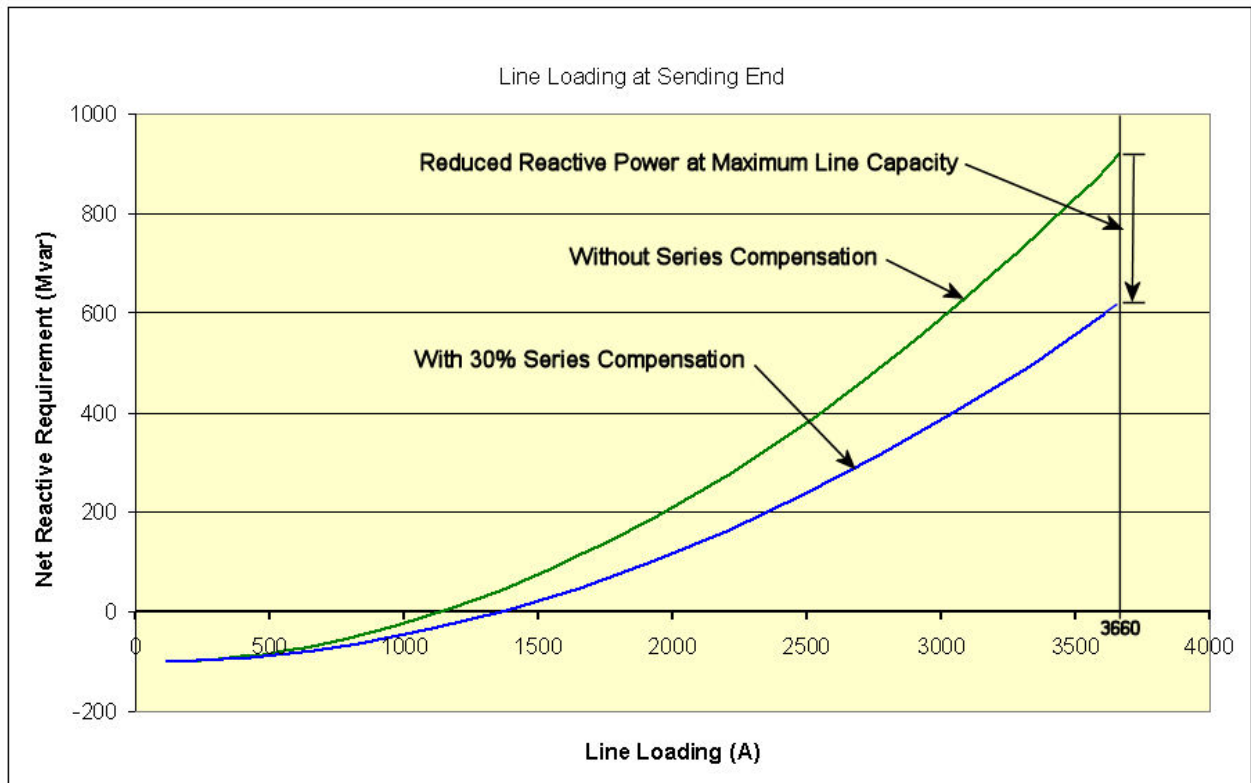


Figure 2.1.1: Variation of reactive power required at one end of the 500 kV transmission line N582L, with and without 30% series compensation.

However, the real issue is the very large amount of reactive power that the power system has to supply to the transmission network at this limited time emergency (LTE) loading level (3,660 amperes at 127°C) or even at the maximum continuous load level (2,815 amperes at 93°C)¹. For just one series compensated transmission line N582L operating at the short term emergency (STE) loading level¹, it requires 610 MVAR additional reactive power support, and approximately twice this amount (over 1,200 MVAR) if both ends of the transmission line are considered. This large amount of reactive power does not include what would be required by other nearby transmission lines as well. If this reactive power is not available, then voltage cannot be maintained and the STE loading level will not be reached.

This substantial reactive power requirement for the combination of series compensated transmission lines and ac network will generally be provided by mechanically switched shunt capacitors that are rated to meet contingency conditions under increased power schedules. This is an increased cost that applies to the series compensation option, to provide the necessary voltage support under stressed conditions.

¹ See Section 3.6 Requirements for Current Rating of Proposed Series Capacitor Banks.

2.2 Temporary Overvoltages (TOV)

Temporary overvoltages may occur following a transmission line opening, and the resulting transmission load rejection. In particular, the critical contingency of simultaneously losing both the Bruce to Milton (B561M) and Bruce to Claireville (B560V) double circuit transmission line was of concern. This was tested on a PSCAD² simulation of the SWO system translated from the PSS/E case representing this critical contingency. No significant overvoltage was observed as the power to the Greater Toronto Area (GTA) is transferred onto the series compensated lines B562L, B563L and N582L. The increased reactive power demand to these post contingency heavily loaded lines helps prevent any significant temporary overvoltage occurring. The simulation result of this disturbance at the Bruce B 500 kV busbar is shown in Figure 2.2.1.

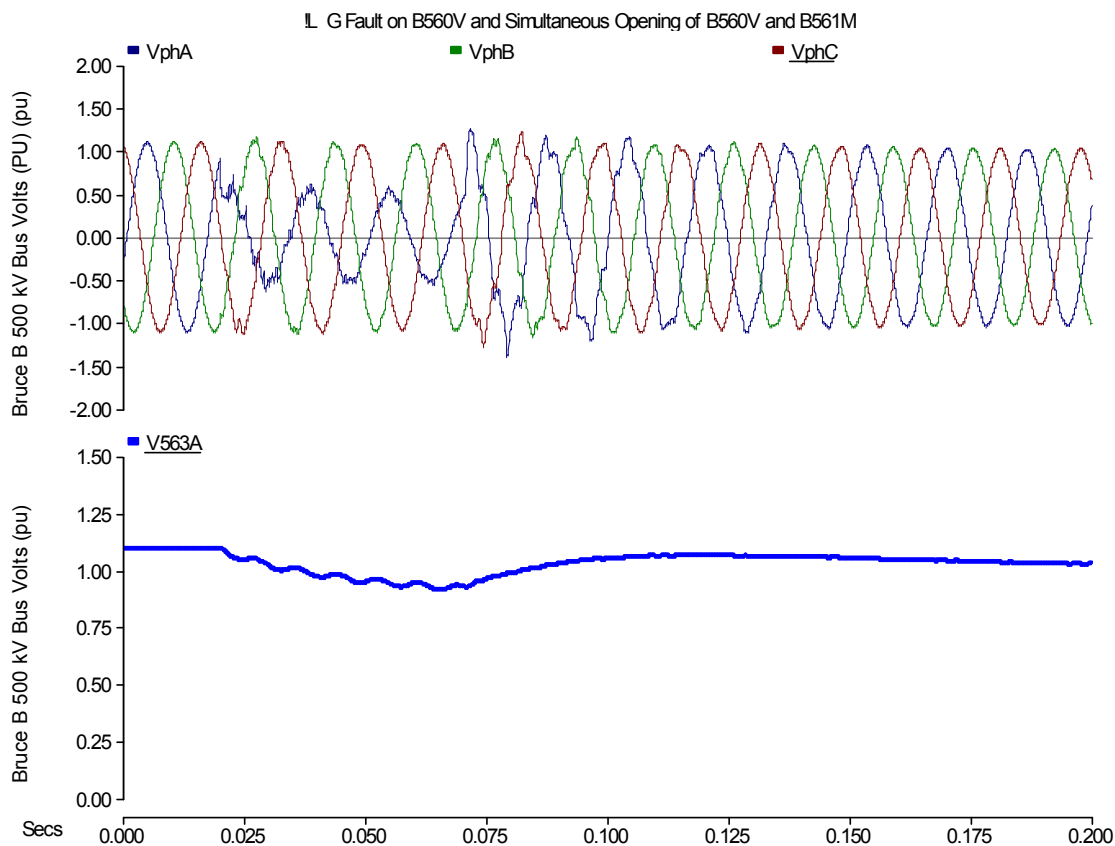


Figure 2.2.1: Temporary overvoltage at Bruce B following 1L-G fault on B560V and simultaneous opening of B560V and B561M

² PSCAD is an electromagnetic transient simulation package of Manitoba Hydro and the Manitoba HVDC Research Centre.

A further study was undertaken to examine the impact of series capacitors on the severity of switching surge voltages. Using PSCAD, B562L was randomly energized 100 times in simulation from Bruce A both with and without the 30% series capacitors in-service on that line. The statistical result of the observed peak switching surge voltages is summarized in Table 2.2.1.

Table 2.2.1: Effect of series capacitors on switching surge overvoltages when energizing B562L

Statistical Quantity Derived from 100 Line Energizations	Per Unit Voltage	
	No Series Capacitors	30% Series Capacitors
Minimum	2.175	2.167
Maximum	2.838	2.844
Mean	2.451	2.437
Standard Deviation	0.172	0.170
2% Level	2.098	2.087
98% Level	2.803	2.787

The observation from the switching surge results shown in Table 2.2.1 is that the series capacitors do not cause line energizing switching surges to increase. This is an important conclusion so far as the transmission tower design is concerned. At 500 kV, switching surge voltages are a factor in the probability of flashover from conductor to tower. The distribution of switching surge overvoltages is not changed by any significant amount. Consequently, the risk of faults on the series compensated transmission lines due to switching transients should not increase.

When the series capacitor banks are being designed for the three designated 500 kV transmission lines, a more detailed transient over voltage study is required to confirm this conclusion. In addition, the series capacitor banks must be designed and protected against switching surges and faults. An initial (pre-specification and facilities) transient network analysis study should determine whether existing substation and transmission line facilities can accommodate the addition of the series capacitors and include the following:

1. Confirm that switching surges on the subject transmission lines are not increased by any significant amount so that the probability of flashover on the transmission line is not increased when energized.
2. Determine whether existing line end surge arresters are adequately rated.

3. Observe whether clearing of faults at or near the terminating substations of the series compensated transmission lines invoke any resonant overvoltages on transformer terminals or across the series capacitor banks.
4. Evaluate the increased short circuit currents that circuit breakers at the terminating substations must clear, and determine what breakers if any need to be replaced.

To undertake these pre-specification studies, the series capacitors and their surge arrester (MOV) ratings defined in the high level planning specification³ can be used. The adequacy of the MOVs protecting for the series capacitor banks against switching surges and faults can also be investigated in this initial transient network analysis study.

2.3 Implications of Overvoltage Effects on the SCAP Banks and On Existing Facilities

A fault on a series compensated transmission line results in increased fault current through the series capacitor into the fault and increased overvoltage across the capacitors. This is because the impedance of the series capacitor subtracts from the ac system impedance resulting in an overall reduced short circuit impedance and hence increased fault current. The fault current is tempered however by the by-pass action of the surge arresters protecting the series capacitors from overvoltage with the result that the greater the fault current through the bank, the higher the rating that is required of these surge arresters.

Generally it is desirable to locate a series capacitor bank in the centre of a transmission line for several reasons. The first is that at 30% series compensation, fault current through the capacitors for any line fault is minimized and so the energy absorption rating and costs of the protective surge arresters are also minimized. There is no fault location along the transmission line where the series negative impedance of the capacitor bank is greater than the positive line impedance between the fault location and either end of the transmission line if the series capacitor is located at line centre. This would not be the case if the series capacitor is located at or near one end where a close by line fault may result in a very small fault impedance because the negative (capacitive) impedance subtracted from the positive system impedance could be close to zero resulting in an effective short circuit impedance to the fault

³ Section 5.1 of this report: High Level Planning Specification. The example design parameters for the series capacitors and MOVs as presented in Table 5.1.2 can be used for this initial study.

that is resonant at fundamental frequency. The surge arresters must have a large energy absorption rating to protect the series capacitors from overvoltage under these conditions.

Other benefits for locating the series capacitor bank mid-line include simpler line protection and series compensation is slightly more efficient with the capacitor located at line centre rather than at one end only due to long line effects. It would be convenient to locate the series capacitors at an established substation providing space is available to do so. However, benefits of maintenance and not requiring a new substation must be weighed against the extra costs of the series capacitor when not located at or near line centre.

2.4 Impact of Series Capacitors on System Damping

Series capacitors reduce transmission line impedance and consequently increase the frequency of electromechanical angular swings of generators following faults. Acceptable or improved damping of these swings using existing power system stabilizers may require their adjustment if the edge of their effective operational bandwidth is reached. Then they are not optimally tuned. Normally stabilizers must have adequate bandwidth to be effective in damping through various contingencies that do result in varying frequency of swings. The impact in this regard of the series capacitors is not unlike the impact of a new transmission line, which also reduces overall transmission line impedance between generators, and increases the frequency of electromechanical angular swings. Consequently, the same procedure is followed for series capacitors as with a new line to evaluate whether stabilizers need to be re-tuned for improved system damping. Tests with the transient stability program or electromechanical eigenanalysis program will indicate how system damping is effected and whether re-tuning is desired.

2.5 Impact of Series Capacitors on the Bruce Special Protection Scheme

The Bruce Special Protection System (BSPS) is identified in the Northeast Power Coordinating Council (NPCC) 1998 list of SPS as SPS #112, type I. The initiation of this SPS is based on various connections of 500 kV circuits between Bruce, Milton, Clairville, Longwood, Middleport, and Nanticoke. It can also be initiated by under voltage, over voltage and rate of voltage decay. In the IESO Report (IESO-REP-0299, CAA Id No. 2005-200, dated April 11, 2006, Section 7, Page 4 and 39) indicated that the BSPS would require enhancement for the following contingency and additional response conditions:

Contingency conditions that need to be added to BSPS:

- 500 kV Circuit N582L
- 230 kV circuits B4V & B5V: both single and double circuit contingencies
- 230 kV circuits B22D & B23D: both single and double circuit contingencies
- Cross-tripping of the 115 kV breaker A1A2 at Stayner TS
- Generation Rejection for selected groups of wind-turbine projects
- Switching of new shunt capacitors banks
- Additional load rejection selections (if the amount provided by the present selections is insufficient)

A BSPS response requiring further evaluation is when a series compensated line such as N582L as it is usually the most heavily loaded, is in service with its bypass circuit breaker or switch remains closed. Consequently the line is in service without its series capacitors. This would be classed as an N-1 event and not warrant any BSPS action. However, if other transmission lines are out of service then the failure to re-insert the series capacitor bank would be classified as an N-2 or greater event and can be considered for the BSPS. This event requires further study to assist in deciding whether a BSPS response is necessary.

The design and setting criteria for the BSPS should be reviewed by simulation study to evaluate the impact, once the final level of compensation has been selected. The IESO has stated that due to the extensive changes required for the Bruce SPS that the IESO would support changes of the entire BSPS to a matrix-based design. Significant changes or redesign of any Special Protection System involve careful preparation, study and extremely detailed installation and commissioning procedures due the large system impact that would result from a mis-operation of the protection system. The NPCC “Special Protection System Criteria” is found as NPCC Document A-11, dated November 14, 2002.

The option to apply series compensation in place of new transmission lines stresses the network more and the BSPS upgrade will improve reliability when applied to cover possible but improbable events. If applied to mitigate more likely contingencies as a cost-saving measure with the series capacitor option, risk of failure and complexity may increase. Even if the BSPS operates as expected to avoid direct impacts of the lower investment and complexity with the series capacitor option, the weakened grid due may contribute to degraded reliability. No studies have been undertaken to determine if reduced capital investment in transmission facilities accommodated by an SPS exceeds the expense of increased disturbances, but it remains a consideration. Nonetheless, such shortcuts lead to the danger of a less reliable network.

2.6 Interaction of SWO SCAPS with Future Shunt Capacitor Banks, Static VAR Compensators and Synchronous Compensators

The installation of series capacitors into an existing transmission system does require significant investigation to prepare for implementation. The practice of upgrading existing EHV transmission lines with series capacitors is not new and with adequate due diligence, is achieved successfully. Both neighboring Provincial Utilities to the Ontario power network have undertaken this in order to increase essential power transfer capability. Hydro Quebec during the early 1990s installed series compensation on their 735 kV transmission system feeding into lower Quebec. At the same time Manitoba Hydro were involved in series compensating their 500 kV interconnection to the United States. Both utilities have had successful and reliable operation of their series compensated systems.

Both Hydro Quebec and Manitoba Hydro series compensated transmission systems operate with Static Var Compensators (SVCs). Manitoba Hydro also has a large assembly of synchronous compensators and the Nelson River HVDC lines that terminate at the north end of their interconnection to the U.S.A. Although some degree of confidence is gained from the success of these and other installations of series capacitors, SWO is unique when considering interaction of the series capacitors with future shunt capacitor banks, static var compensators and synchronous compensators.

The potential for interaction of the SWO series capacitors with future shunt capacitor banks is a concern that applies with installation of any shunt capacitor bank, which is the participation in a harmonic resonance the shunt bank might contribute to that is excited on capacitor bank energization or from nearby faults. Such resonances may result whether or not nearby transmission lines are series compensated but the series capacitor may participate in any harmonic resonance involving shunt capacitor banks. In other words the due diligence that must accompany the contemplated installation of a new shunt capacitor bank is not changed with the series capacitors⁴.

New static var compensators (SVC) are under consideration in SWO to contribute supply to the increasing reactive power demand of the transmission network. Generally there should be no adverse interaction between the series capacitors and new SVCs if the controllers of the SVCs have been designed to accommodate nearby series capacitors. This includes the controls being robust enough to allow the varying system impedance of the series capacitor banks to be in or out of service, and to respond to step changes of such in a damped manner. If the SVCs are operating before nearby series

⁴ This due diligence study is similar to what is discussed in Section 2.7 Resonance Conditions between Series Capacitors and Existing Shunt Compensation. See also Section 5.4.3 Facilities Study, where Item 4.2 Electrical Harmonic Impedance Study is discussed.

capacitors are installed and their controls are not designed with the series capacitors considered, then a study of the response of the SVC to switching of the series capacitor banks should be undertaken with models that accurately reflect the controls of the SVC. The study would determine whether the SVC response is adequately damped when switching the series capacitor bank in or out. If the damping due to this action is not acceptable then this is clearly a weakness in the SVC controls design in not being robust enough to meet industry standards. Adjustment to the SVC controls is warranted under such conditions.

An additional concern with dynamic controls of an SVC is its combined impact with the series capacitors on the damping of torsional oscillations of the Bruce and Nanticoke generators. This is related to SSR and is covered in Section 4 of this report.

There should be no adverse interaction between new synchronous compensators and the series capacitor banks so long as the excitation systems of the synchronous compensators have been carefully designed and adjusted to minimize overshoot/undershoot for a wide range of operating conditions.

There is no indication that series capacitors will impact shunt capacitor and shunt reactor banks except through electrical harmonic impedance effects⁵. Facilities studies are undertaken to determine all the equipment required to accommodate the series capacitors and include shunt capacitor and reactor ratings, surge arrester ratings and insulation levels. Consequently, the facilities study for shunt capacitor and reactor installations should also address energization of the capacitor or reactor bank to ensure the energization transient and step change in voltage is acceptable. The stiffening of the ac system through nearby series capacitors may improve voltage transients from energization, but this needs to be investigated for each application.

2.7 Resonance Conditions between Series Capacitors and Existing Shunt Compensation

Whenever capacitors are added to an electric power transmission network whether in series or in shunt, resonant conditions are generated. It is when a resonance is excited by either a transient such as a circuit breaker switching action, or a driving current at the frequency of the resonance that overvoltages can occur. It is of concern when such overvoltages, which are oscillatory at the

⁵ The study for harmonic impedance effects is described in Section 5.4.3 Facilities Study under the paragraph entitled Electrical Harmonic Impedance Study.

frequency of the resonance and add onto the normal 60 Hz voltage, approach in magnitude the insulation levels of substation and transmission line equipment.

Resonant overvoltages may be excited from a switching or fault action at one location or busbar and manifest themselves elsewhere in the network. For example, a fault to ground near a transformer will be cleared by normal protection. The transformer in recovery back to normal ac voltages will usually be in saturation for periods of one second or more. While in this saturated condition, the magnetizing current that results contains all harmonics of 60 Hz and is quite capable of exciting a resonance at or near a harmonic frequency. This can be most evident right at the transformer busbar or several busbars away.

To determine if such resonance circuit conditions exist where the series capacitor bank interacts with the system impedance or shunt compensation several busses away, there are one or more procedures to undertake. The necessary studies must be comprehensive so that all possible contingencies are examined. A frequency scan test can be undertaken as a screening test, but is not as definitive as a comprehensive switching surge study. More detail on all studies is summarized in Section 5.4 Studies Required for Series Capacitor Installations.

2.8 Impact of Series Capacitors on Short Circuit Levels

The series capacitors reduce transmission impedance and as such increase the observable short circuit levels at substation busbars in the vicinity of the series capacitors for faults external to the series compensated transmission line. The series capacitors are protected with a parallel bank of varistors (surge arresters), which if forced to protect the series capacitor bank, will increase the effective transmission line impedance to be similar to the non-series compensated impedance of the line.

The worst case test on the impact of the series capacitors on the short circuit level of nearby busbars is to assume the series capacitors remain in service and because of the resulting reduced transmission line impedance, contribute towards increased fault level. Consequently, ratings of existing circuit breakers need to be checked⁶.

⁶ See Section 5.4.3 Facilities Study and the subsection on Angular Swing Effects.

3. Specific Performance and Reliability Considerations – Equipment Aspects

3.1 Failure Modes of a Series Capacitor Installation

A series capacitor bank is comprised of conventional power system components that may fail internally to the bank, or externally due to insulation failure that is detected by the line protection causing the transmission line and series capacitor bank to be tripped out of service. External failures are not considered further as they are a substation insulation design issue and not specific to series capacitor installations.

3.1.1 Internal Failure Modes

Instances in which series compensation systems have not operated as intended generally involve mis-operation of the protective system during internal faults. The protective system is comprised of the protective gap (if furnished), bypass circuit breaker, damping circuit and protective varistors (MOVs). Due to their inherent redundancy features, the control and protection equipment as well as capacitor units themselves are less prone to cause failure modes that would remove the compensation system off line.

3.1.2 Consequences of Failures

The consequence of a failure to the series compensation protective system can be significant and lead to bypassing the three-phase series capacitor bank with a resulting lock-out requiring on-site investigations into the cause. The system consequences of such a lock-out would be the unavailability of the series capacitors and a resulting decrease in the power transfer capability of the line until the lock-out has been reset.

3.1.3 Failure Statistics

Statistics that identify specific equipment failures of series compensation schemes do not appear to be published. However, the availability performance of series capacitor installations discussed in Section 3.3 below provides some insight. Based on a series capacitor availability performance metric of 99.6% to 99.7%, it would be reasonable to expect a forced outage time of between 26-hours to 35-hours annually. It should be noted that most series capacitor availability metrics are achieved only if recommended spare equipment and maintenance procedures are followed. In cases where spare equipment and maintenance recommendations have not been followed, it is not uncommon to have the series capacitor bank out of service for 12 to 15 months while waiting for spare part deliveries.

3.1.4 Failure Mitigation

Mitigation measures that can be implemented to minimize the impact of series capacitor bank failures include the following:

1. Redundant protection and control systems including dc battery power systems and chargers.
2. Install additional varistors initially to accommodate spares and provide derating.
3. Ensure there is an adequate supply of spare parts.
4. Periodic training of maintenance and operator personnel.
5. Continued maintenance and monitoring program over the life (>25 years) of the equipment.
6. Adequate alarm system in place.

The IEEE and CIGRE have not published statistics on failures in series capacitor installations as they have for HVDC transmission systems and SVCs and STATCOMs. This is an indication that failures in series capacitor installations have not reached a level of concern that would warrant such an investigation and publication. The reliability of modern series capacitor installations is confirmed by an internet search, particularly since 1979 when varistors were first applied to assist in re-insertion of the capacitors.

3.2 Nature of Series Capacitor Equipment Failures

3.2.1 Equipment Failure Modes

Major components in a series compensation scheme and their typical failure modes are as follows:

1. Capacitor bank: Capacitor units are arranged in parallel-series groups to obtain the required Mvar rating. They are equipped with internal discharge resistors with individual units selected to optimize the overall capacitor bank configuration. The capacitor bank is protected from overvoltages by means of a protective circuit (varistors and bypass breaker) with individual capacitor units sized to withstand the fundamental and harmonic currents on the line. Failure modes are normally associated with individual capacitor units becoming either partially or completely short circuited and the capacitor unit then removing itself from the capacitor bank by means of fuse links or internal design features. These failure modes are detectable by the protection system with alarms and bypassing provided depending on the number of failed capacitor units.
2. Varistors: Varistor units are connected in a series-parallel arrangement to obtain the required voltage-current energy ratings needed to protect the capacitor bank. Because the varistor

voltage-current characteristics change when exposed to voltages, spare varistors are initially installed and energized with the capacitor bank. Housings for varistor units can be of porcelain or polymer design. Varistor units when exposed to excessive currents may overheat resulting in a failure mode that can remove the unit from service. Factory type tests of the varistor and housing under overcurrent conditions are normally required to verify the housing vents excessive pressures and catastrophic explosive failures do not occur.

3. Bypass switch: Bypass switches are circuit breakers designed to have fast closing times. The fast closing times protect the varistors from overcurrent in the event of transmission line faults. Failure modes of the bypass switch are typical of those associated with normal circuit breakers except that fail-safe operation would be for the bypass breaker to fail in a closed position, thus bypassing the capacitor bank.
4. Damping circuit: A damping circuit is normally positioned to be inserted in series with the bypass switch and protective gap (if provided) to provide current limiting protection for the switch and gap. The inductor and resistor combination failure modes can be shorting of the inductor and opening of the resistor. Sensing of these abnormal conditions can be accomplished by monitoring currents and when design limits are exceeded the bypass switch would be closed and locked-out and the capacitor bank would be out-of-service.
5. Spark gaps: Spark gaps are used when it is more economical to reduce the number of varistor units in the capacitor bank protective system. The failure mode for these devices can be catastrophic in nature, requiring the capacitor bank to be removed from service until repairs or a replacement has been installed. The elimination of the spark gap improves reliability, avoids gap maintenance issues and increases the capacitor bank's availability and so is a design trade-off against the cost savings with less varistor units.
6. Control and Protection: Modern series compensation systems normally include a redundant control and protection scheme to improve reliability and reduce the chance of a hardware or software malfunction from occurring. In the event of a complete failure of the control and protection system, the series capacitor bank would be removed from service until repairs can be implemented.

3.2.2 Safety

In general, series capacitor installations are designed to meet applicable safety and environmental codes specified by the user. Guidance for personnel related safety issues are found in IEEE Std 824 and include:

1. Discharge devices.
2. Personnel protection.

3. Handling and disposal of capacitor units and fluid.

As is the case with most all utility connected equipment, there is the possibility of series capacitor equipment failures that can result in explosive discharges. Example of such equipment would include the bypass circuit breaker, varistors (arresters, MOV), gaps (if furnished), insulators and high voltage instrumentation. Modern day capacitor units are not prone to catastrophic failures due to extensive type testing, factory quality control measures and improved design features.

3.2.3 Failure Prevention

The detection and prevention of equipment failures is a critical diagnostic feature of series compensation systems. Diagnostic features typically include self monitoring, built-in protection, remote and local status reporting and full local/remote control capability. The detection of failures and associated points typically monitored would include those shown below in Table 3.2.2.

Table 3.2.2 – Monitor Points

Item	DFR and SER Capability (per phase)	Annunciation Points
1	Total capacitor current	Capacitor unbalance alarm per phase (set point #1)
2	Total varistor current	Capacitor unbalance alarm per phase (set point #2)
3	Bypass gap current (if furnished)	Capacitor unbalance trip per phase
4	Bypass breaker current	Capacitor over-current per phase
5	Total series capacitor current	Varistor conduction per phase
6	Total capacitor unbalance current	Varistor over-temperature per phase
7	Bypass breaker status	Varistor failure per phase
8	Arc Gap conduction (if furnished)	Gap conduction per phase (if furnished)
9	Bypass breaker trip bus high	Prolonged gap conduction per phase (if furnished)
10	Primary protective relay bypass (close)	Bypass breaker bypass initiate per phase
11	Backup protective relay bypass (close)	Bypass breaker trouble per phase
12	Fiber optic cable failure	Bypass breaker failure per phase
13	Capacitor unbalance alarm level 1	Bypass breaker pole disagreement
14	Capacitor unbalance alarm level 2	Bypass breaker lockout
15	Capacitor unbalance alarm & bypass (close)	Bypass breaker blocked closed
16		Bypass breaker low pressure per phase
17		Platform fault per phase
18		Fiber optic link loss of signal per phase
19		Auxiliary power failure
20		Controller failure
21		Platform flashover

With such a detection and alarm system in place and with adequate redundancy in components such as the capacitor, varistor units and controls, maintenance can be scheduled when convenient, thus minimizing unscheduled outages of the series capacitor bank.

Critical single units such as the by-pass switch, damping circuit and spark gaps (if installed) are alarmed and protection signals generated when failure occurs and the by-pass instigated as described in Table 3.2.2. The fail-safe operation of the by-pass switch to the normally closed position is the basic protection back-up. The failure of the by-pass switch to close when protection requires it to do so may result in component failure, which in some instances could be catastrophic.

3.3 Availability of Series Capacitor Installations

3.3.1 Availability Statistics

Typical availability statistics of series capacitor installations throughout the world are not published. However, it is not unusual for series compensation systems, including their ancillary equipment, to be specified with guaranteed availability performance requirements of 99.6% to 99.7%. The number and duration of scheduled maintenance outages of fixed series capacitor (FSC) banks each year typically do not exceed 1 outage for a maximum duration of 12 hours with no more than 2 forced outages per year. To realize the availability performance requirements it is necessary to identify some terms and definitions when purchasing the installation.

The following definitions could be applied:

1. Forced outages are outages caused by FSC bank equipment that result in loss of part or all of the FSC bank essential functions.
2. Scheduled outages are outages necessary for preventive maintenance to assure continued and reliable operation of the FSC bank.
3. Outage duration is the elapse time (in hours) from the instant the FSC bank is out of service to the instant it is ready to be returned to service. If the FSC bank becomes available for service during non-working periods, such time should not be included in the outage duration if the User elects not to return the FSC bank to service. The following should be included in outage duration:
 - a. Time required to determine the cause of an outage or to determine which equipment or units of equipment must be repaired or replaced.
 - b. Time required by system operators and technicians to disconnect and ground equipment in preparation for repair work and to remove grounds and reconnect equipment after repairs are completed. Delays caused by unavailability of qualified User personnel should be excluded from the outage duration.
 - c. If partial FSC bank ratings are available, the duration of equivalent outage should be calculated as the product of the derated condition duration and the proportion of the nominal output MVAR range which cannot be achieved during this period.

4. The annual equivalent availability for forced outage should be defined as follows:

$$\left[1 - \sum \frac{\text{Duration of equivalent outage}}{8760} \right] * 100\%$$

The objectives in the design of a FSC bank should be to achieve high levels of availability and reliability while minimizing maintenance. A thorough design review and study report should be provided by the Supplier documenting measures taken to minimize the risk of forced outages. Additionally, the Supplier should give careful attention to factors affecting the FSC bank performance including, but not limited to, protective relay coordination, proper setting of relays, spare parts and redundancy of design. In general, wherever possible, the following principles should be followed in the design:

- (a) Use of least complex design capable of performing required functions.
- (b) Use of components with proven reliability.
- (c) Use of pre-aged components with a burn-in period or other equivalent means.
- (d) Use of fail-safe and self-checking designs.
- (e) Use of software that has been thoroughly tested and proven resilient.
- (f) Provision for alarm, fault indication, monitoring and test facilities.
- (g) Diagnostic features, easily-read drawings and manuals that will ease trouble shooting, repair and maintenance.
- (h) Use of modular construction to permit rapid replacement of failed equipment.

It is recommended the User monitor the FSC bank availability, reliability and maintenance performance during a 5 year warranty period following acceptance of the installation.

3.3.2 Unavailability

Statistics that identify specific equipment items that contributed most to the unavailability of series compensation schemes do not appear to be published. Principles that can be applied to minimize unavailability of equipment items would include the following:

1. The use of redundant protection and control systems as well as communications links decreases the unavailability of this hardware and software while minimizing maintenance testing since this could be accomplished while the equipment is in service.
2. The use of fuseless capacitors with a proven design and in service history.
3. Use of a gapless protection system by implementing a conservative varistor designed scheme.

4. Consider the use of a dual platform power supply system to extend the laser life of ground based optical power supply systems. This is important if optical energy is used to power platform equipment.
5. Schedule annual maintenance during periods that minimize transmission impacts.

3.3.3 Unavailability Mitigation

Mitigation and minimizing unavailability, particularly during the first year, can be accomplished by instituting a monitoring program that documents the equipment performance and availability statistics. Remote monitoring systems (e.g., over the internet) can enable specialists to remotely check performance and provide advice when needed. This type of program can be of particular value when monitoring the series compensation system response to both internal and external network faults to ensure the network as well as the series compensation equipment function within design parameters.

Added flexibility can be gained by dividing each phase of the series capacitor installation into multiple segments. The added flexibility may have operational benefits that should be confirmed with system planning and dispatchers. Minimizing unavailability by implementation of multiple series capacitor segments can be a design specific option subject to a more detailed analysis since the number of equipment items increases and the control and protection scheme becomes more complicated. Multiple segments installations will be impacted by higher costs since they will require larger platforms, larger footprint, additional equipment (bypass breakers, damping circuits, instrumentation, bypass gaps, foundations) and increased maintenance over the life of the equipment.

3.4 Relaying and Line Protection Issues with Series Compensation

Special protection considerations are required for relay and line protection for lines with series compensation [4], [5], [6], [7], [8], [9].

A review of series compensated line protection issues are provided as follows. Additional information and descriptions are found in the references.

- The protection relays at line terminals of B562L, B563L and N582L will require detailed protection reviews due to the installation of SCAP and will require detailed design configuration of the series capacitor protection system. The protection review will require a good understanding of the transient system response and the transient behavior of the protection relay(s) utilized. Typically line protection uses distance or impedance relays. Series compensated lines add complexity to traditional protection methods and can

include phase comparison, current direction comparison schemes, with blocking units and transient blocking units.

- The series capacitor will experience overvoltage conditions during the duration of the fault and through fault currents tend to be increased. The series capacitor will be protected from overvoltage by various combinations of MOV, spark gaps and bypass devices. The protection level chosen for the MOV or varistor impacts several design issues. The design issues are discussed in [2] Section B.5.2 and summarized as follows:
 - Higher protective level increases insulation levels on the series capacitor platform
 - Higher protection levels require higher capacitor voltage withstand levels.
 - Lower protection levels increase the energy absorbing rating of the MOV or varistor device. The voltage occurring during power system swings and energy absorbing requirements for both external and internal faults are considerations. The energy requirements can be modified depending on whether a forced trigger bypass gap will short the series capacitors and under what conditions.
 - For SSR conditions, the voltage magnitude is limited by the protection level. A lower protection level will reduce SSR developed voltages, but it is noted that this reduces only the transient torque of SSR and does not add SSR damping.
 - TRV levels which occur during transient transmission line recovery are reduced with lower protection levels.

It is recommended [4, 6] the protective level for the series capacitors be determined by the manufacturer, unless there is a specific network requirement. The supplier is in the best position to optimize varistor and capacitors.

- Distance or impedance calculations with series capacitors are subject to the possibility of voltage and current reversals. The impedance of fault changes from inductive to capacitive. As a result the protection settings may over or under reach, identifying the incorrect protection zone. This voltage reversal effect may impact not only the series compensator line protection but line protection for other lines within the surrounding areas. Special care must be taken to accommodate that the line impedance and therefore the protection is different when the series compensation in circuit or bypassed. A more complex protection arrangement can accommodate this; either by depending on a permissive trip from the remote ends (Zone 2) or requires the status of the series

capacitors to modify the protection settings. In either case protection grade communication channels are required. The combination of a mid-line location and 50% or less compensation reduces the possibilities of voltage or current reversals [2]. Another concern is the decaying low-frequency oscillation caused by the resonance of the series capacitance and the system and line inductance. This causes the impedance estimate of a distance relay to oscillate causing over or under reach or directional discrimination problems.

- Line differential protection can be considered instead of impedance relaying for series compensated line. This would avoid the issues with the protection relays noted above.
- The calculation of fault current is not straightforward and is impacted significantly by the non-linearity introduced by the series capacitor overvoltage protection strategy. Calculations of fault currents are generally performed by emtp type studies. Special care must be taken in setting zone distance relays since the protected zone is modified by the inserted series capacitors but unmodified when the capacitors is bypassed [2]
- Impacts of single pole operation, high speed re-closing, unbalanced line and mutual impedance with the SCAP installation require consideration.
- Generally two high speed independent (different manufacturer) protection systems would be utilized for protecting a series compensated transmission line.

Considering the complexity of the series compensated system of SWO, it's highly recommended that an electromagnetic transients study be carried out to evaluate the protection scheme. The simulation studies would be followed by a digital transient network analysis (TNA) test program using the actual chosen protection hardware and settings for the protection systems. This factory (or field) test program would verify the relay settings especially for the ones for lines B562L, B563L and N582L.

Modern programmable protection relays have reached a level of sophistication that they can effectively meet the requirements for protecting any series capacitor installation, either applying distance protection or differential protection methods.

3.5 Voltage Protection with Series Compensation

Please refer to References [4], [5], [6], [7], [8], [9].

Insulation coordination issues exist for a series compensation installation. The line breaker will often experience an increase in transient recovery voltage (TRV) across its switch contacts. This is particularly true for series capacitors with MOV overvoltage protection. Reduction of the series compensation voltage protection level can reduce the TRV seen by the breaker but this will increase energy absorption level of MOV. Higher TRVs and higher fault currents generally occur for multi-phase faults. Alternatively another method to decrease TRV at the breaker is to apply arrestors on the line side of the breaker. For some situations it may be necessary to apply bus side arrestors or install a special purpose breaker. A detailed transient analysis is required to determine breaker requirements [6].

SCAP site location has significant impacts on design complexity and cost. The mid-line installation typically has advantages of better voltage profiles along the line, lower fault currents mostly in nearby fault (less stress for cap MOV) and less impacts for the existing relay system for the other transmission lines connected the end line terminals. However, it may require additional costs such as site construction, communication for microwave, power line carrier or optical cable.

Voltage reversal and current reversal issues are possibilities due to series compensation. Line impedance is calculated by voltage divided by current and is always inductive for a non-series compensated line. Depending on the amount of series compensation and the location of the series compensation it is possible that the inductive impedance may be capacitive. This voltage reversal effect can extend into the surrounding transmission system. Positioning all the series compensation at Longwood station may require protection changes (settings and possible hardware) for “all” the transmission terminating at Longwood, not just the lines where series compensation was added. The combination of a mid-line location and 50% or less compensation reduces the possibilities of voltage or current reversals [5].

3.6 Requirements for Current Rating of Proposed Series Capacitor Banks

The System Impact Assessment Report [2] determines that for 30% series compensation of the Bruce Complex to Longwood to Nanticoke 500 kV transmission lines (B562L, B563L and N582L), that the post contingency power flow loading on N582L is 3669A. This is sufficiently close to the 3660A Limited time emergency rating to avoid further upgrading of this circuit. The contingency applied is the severe N-1 case for tower loss of the B560V and B561M double circuit loss with an N-2 condition with 115 kV circuit S2S open at Stayner substation. In order to not limit the power transfers on these lines below the continuous and half hour thermal limits of the conductors, the series capacitor banks rating must equal or exceed the conductor current ratings. This certainly applies for N582L, which is

more heavily loaded than B562L and B563L for the severe contingency indicated above. The question is whether the series capacitor banks rating for these lines should be less than the rating of their conductors, or be the same as for N582L? The conductors on all three lines B562L, B563L and N582L have the same thermal ratings as follows based on a 35°C ambient temperature:

Continuous rating (93°C)	2815A
Half hour or limited time emergency LTE (127°C)	3660A
Three hour/year short term emergency STE (150°C)	4110A

Although subsequent power flow studies of other N-2 contingencies did not indicate that B562L and B563L loaded up to their respective conductor half hour ratings as observed on N582L, load currents that exceeded the continuous (93°C) were observed. Nevertheless it is recommended that the series capacitor banks on B562L and B563L also be sized to accommodate the continuous and half hour current ratings of the conductors of the lines they are to compensate. The specification of current ratings for each fixed series capacitor bank to accommodate this recommendation is shown in Figure 3.6.1.

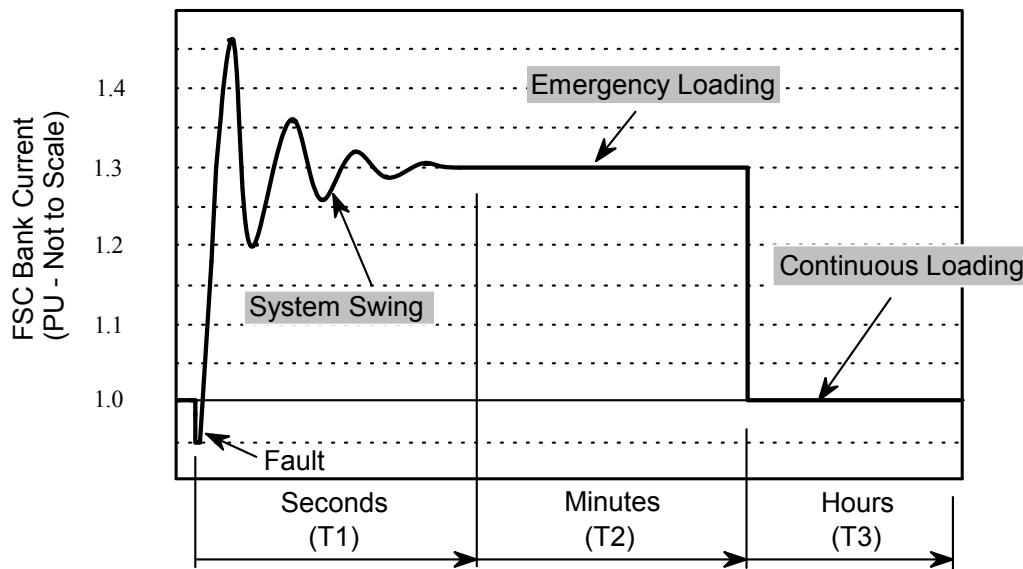


Figure 3.6.1: Current-time profile of a fixed series capacitor bank following external fault clearing.

The ratio of Emergency Loading to Continuous loading for the conductors of B562L, B563L and N582L is $3660/2815 = 1.3$. This same ratio is applied to the series capacitors as in Figure 3.6.1. The duration of the system swing effect is $T1 = 10$ seconds. The duration of the emergency duration loading of 3660A is 30 minutes and the duration of the continuous loading of 2815A is indefinite.

The magnitude of the system swing current is set at 4100A but this is subject to further investigation. The swing, emergency and continuous current loadings can be individually refined for each bank by undertaking further studies if it is considered necessary to do so.

4. Sub-Synchronous Resonance (SSR) Considerations

4.1 Potential for SSR on Bruce, Nanticoke and Lambton Generators

In order to obtain an initial assessment of the impact of 30% series compensating 500 kV transmission lines B562L, B563L and N582L on the Bruce, Nanticoke and Lambton generators, a preliminary investigation of the impact of 30 % series compensation was undertaken. The details of this investigation are included in Appendix C along with some pertinent results.

It is the complementary torsional frequencies ($60 - \text{Torsional Frequency}$) are compared with the electrical resonant frequencies observed in frequency scans of critical contingencies as shown in Appendix C. The electric system frequency scans as seen from the air gap of the respective generators show that the observable electric resonances all fall below 30 Hz. None of the complementary torsional frequencies of the Bruce generators fall in this range, based on these critical contingencies.

However, the Nanticoke generators G1 to G6 have a $60 - 35.3 = 24.7$ Hz complementary frequency that lines up with the electrical resonance for the critical contingencies. This does require detailed investigation and design to ensure there is adequate damping for the sub-synchronous resonance conditions.

4.2 Test Scope and Modelling of Previous SSR Studies

The ABB report [1] and the studies undertaken by the IESO [2], [3] have investigated the dominant issues associated with applying series capacitors to the Southwestern Ontario (SWO) system and have directed the focus to the application of 30% series compensation on 500 kV transmission lines B562L, B563L (from the Bruce Complex to Longwood) and N582L (Nanticoke to Longwood). The ABB report [1] concentrates its subsynchronous resonance (SSR) study based around applying 70% series compensation on these transmission lines. The subsequent IESO study [3] examines various reduced levels of series compensation where 30% series compensation is identified as a level where the emergency rating of the conductors on N582L of 3660A is reached for the serious and possible N-1 contingency of loss of B560V (the Bruce Complex circuit to Claireville) and B561M (the Bruce

Complex to Milton) 500 kV transmission lines. This contingency also includes the opening of the 115 kV circuit S2S at Stayner substation.

30% series compensation of B562L, B563L and N582L is a suitable option to consider as it is a level where these lines do not exceed the 3660A emergency rating. A higher level of series compensation on these lines requires either N582L be upgraded perhaps with expensive reconductoring, or as is more reasonable, to adjust the Bruce Special Protective System.

The ABB report [1] is an extensive examination of the risk of SSR for 70% series compensation centred on B562L, B563L and N582L. The risks for SSR reduce with 30% series compensation, and this is not covered to any extent. Our subsequent and preliminary study [4] indicated that the Bruce generators would not have their complementary torsional frequencies within this range created by 30% series compensation, based on these critical contingencies.

However, the Nanticoke generators G1 to G6 have a $60 - 35.3 = 24.7$ Hz complementary frequency that lines up with the electrical resonance for the critical contingencies. However, it is understood that these generators will be decommissioned and four units retained as decoupled synchronous compensators. It is expected that as decoupled units, these torsional modes of shaft resonance will no longer exist. The torsional data for the Lambton generator units have a complementary frequency of $60 - 34.83 = 25.17$ Hz which is also close to the electrical resonance. However, the contingencies to reach a condition of concern appear more unlikely to occur.

The procedure undertaken by ABB [1] is thorough and is up to what is expected today from a detailed SSR study. PSCAD which was originally developed by members of this study team was used by ABB as one of their study tools. We also use PSCAD for SSR studies and concur with the procedures that ABB applied in their study.

4.3 Further Studies on SSR in Southwestern Ontario

A preliminary study [4] indicates that SSR would be less likely for any Bruce generators with 30% series compensation on B562L, B563L and N582. However, the Nanticoke and Lambton generators under multi-level transmission contingencies will have electrical resonant frequencies whose complement values overlap the frequencies of shaft torsional modes. It is recommended that an SSR study be repeated⁷. However, it would not need to be undertaken with the comprehensiveness of the

⁷ See Section 5.4.2 System Impact Study and the subsection on Subsynchronous Resonance and Damping of Generator Shaft Torsional Oscillations.

ABB study, but concentrate on the Bruce, Nanticoke and Lambton units. If such a study is not undertaken, then as a protection install torsional stress relays on all Bruce A and B units as well as any Nanticoke units not retired at the time of the installation of the series capacitors. This is not an insignificant cost, and would amount to several millions of dollars.

4.3.1 Expanding the Number of Operating Generators

As Bruce generators are brought on-line after the series compensation is added and the mix of generators in SWO is changed, each new generator needs to be assessed as to its potential for damping of torsional modes of oscillations. It is important that the torsional data for the Bruce, Nanticoke and Lambton generators as used in the ABB study [1] be reviewed to ensure it is correct (see also Appendix C).

4.3.2 Protection Against SSR with a Torsional Stress Relay

A torsional stress relay is applied to a generator unit as a protection if there is a possibility that SSR can be invoked. The study undertaken in Appendix C for the Nanticoke units in particular demonstrates that under certain contingencies, SSR might be possible. For those units that may be advertently or inadvertently switched into a contingency configuration that leaves them exposed to SSR, torsional stress relays should be installed. An SSR study⁷ will determine on which units the torsional stress relay should be applied. They require the generating unit be out of service for installation and it is most convenient to do so during a scheduled maintenance outage.

If a Nanticoke unit for example is de-commissioned after it has been fitted with a torsional stress relay, the relay could be re-used on another unit coming on-line and re-set for that unit. Alternatively, if a generating unit is to be decommissioned at some time in the future after the series capacitors have been installed, then an option to installing a torsional stress relay is to instigate a special protection system that will trip the unit if it should ever revert to that contingency configuration.

4.3.3 Checklist of Actions Regarding SSR

In order to investigate SSR issues with the installation of the series capacitors, the following checklist can be used as a guide:

_____ Review previous studies of series compensation of transmission lines in the SWO area.

_____ Determine the transmission lines that will be series compensated.

_____ Determine the degree of series compensation to be applied to the transmission lines.

- _____ Review and check torsional data for the generating units of interest, including all the Bruce units, Nanticoke units expected to be on-line when the series compensation is installed, and Lambton units. Gather all other essential data including the generation expansion stages that are to be studied.

- _____ Prepare a specification for an SSR System Impact Study that has the objective in determining the vulnerability of the Bruce, Nanticoke units still operating and Lambton units to SSR and recommending what the solutions or remedies are. The specification is to follow the procedure of the ABB study [1] but focused on these generating units.

- _____ Include in the specification for the SSR System Impact Study, provision for evaluating how the series compensation will affect nearby wind farms that might be in place before the series capacitors are in service. If possible, the type and modeling data for the wind turbine generators should be provided so that they are considered in the study. The torsional mode data for the wind turbine generator may not be available or forthcoming from the suppliers of the wind turbine generators, but observed electrical SSR impacts on the wind turbine generators should be specified as required output from the study.

- _____ Invite requests for proposals to undertake the SSR study or select a trusted investigator with the skills to undertake the study and execute a contract to undertake the study.

- _____ Review recommendations from the study, and establish the necessary budget and schedule to implement the approved recommendations.

5. High Level Planning Specifications for the Southwestern Ontario Series Capacitors

5.1 High Level Planning Specification

A draft high level planning specification is included in Appendix B. This draft planning specification is submitted as a guide for modification as needed. The basic specification for the series capacitor banks for the three transmission line applications is summarized in Table 5.1.1. This basic specification and the draft planning specification in Appendix B are based on locating the series capacitors at line centre.

Table 5.1.1: Basic specifications for 30% series capacitors in B562L, B563L and N582L 500 kV transmission lines.

Parameter	Unit	B562L	B563L	N582L
Maximum system voltage (phase-phase)	kV rms	550	550	550
Nominal reactive power	MVar	419	419	359
Nominal capacitive reactance	Ω /phase	-j17.8	-j17.8	-j15.07
Rated line current	A	2,815	2,815	2,815
30-min overload current	A	3,660	3,660	3,660
10 second overload current	A	4,100	4,100	4,100
Maximum short circuit current	A	9,000	9,000	14,000
Rated continuous voltage	kV rms	50.1	50.1	42.4
30 minute overload voltage	kV rms	65.1	65.1	55.2
10-second overload voltage	kV rms	73	73	61.8

To provide an indication of additional design parameters for the series capacitor banks, an example was developed based on EXLIM P arresters by ABB. In reality the bidder would apply specific design strategies that would differ from what is shown below in Table 5.1.2. Some of these parameters have been included in the planning specification of Appendix B.

Table 5.1.2: Example design parameters for the 30% series capacitors proposed for B562L, B563L and N582L 500 kV transmission lines.

Parameter	Unit	B562L	B563L	N582L
Rated continuous current (1.0 pu)	kA rms	2.815	2.815	2.815
Rated ½ hr overload current	kA rms	3.66	3.66	3.66
Series capacitor impedance	Ω /phase	-j17.8	-j17.8	-j15.07
Rated series capacitor voltage	kV rms	50.1	50.1	42.42
Rated series capacitor voltage	kV peak	70.86	70.86	60
Peak capacitor voltage at maximum swing current	kV peak	103.2	103.2	87.4
Arrester rating U_r (single unit)	kV rms	90	90	78
Arrester MCOV	kV rms	72	72	63.1
Highest arrester energy	kJ	26,644	26,671	43,920
Fault clearing time (no reclose)	cycles	4	4	4
Peak voltage across capacitor bank	kV peak	159	159	136
Protective level of capacitor bank	pu of capacitor rating	2.24	2.24	2.27
Energy capability of single MOV unit	kJ/kv	10.8	10.8	10.8
Highest current in series capacitor	kA peak	21.5	22.1	16.5
Highest current in MOV (Total)	kA peak	33.2	33.1	17.1
No. of MOV units		54	54	104

These parameters are designed based on a 4 cycle opening time of the line end circuit breakers, with a 100 % margin. No high speed reclosing is applied as it is understood that high speed reclosing is not normally applied in Ontario. If for this application reclosing is a consideration, it is a significant factor to include in the specification as it has a large impact on the rating of the protective arresters.

5.2 Special Requirements to Mitigate SSR

The special requirements needed to mitigate SSR are determined as follows:

1. Undertake the SSR study as outlined in Sections 4.3.3 and 5.4.2 to confirm generator unit vulnerability and remedies that can be applied.
2. Decide on which recommendations from the study to mitigate SSR that might include:
 - 2.1. Do nothing if the contingencies that lead to SSR possibilities are considered too unrealistic. However, such a recommendation retains an element of risk that must be managed.
 - 2.2 Apply operating restrictions for certain contingency conditions. This is one way to manage the risk associated with possible SSR that occurs only with unlikely contingencies.
 - 2.3. Modify generator exciters on SSR prone units to improve torsional damping on such units if it can be demonstrated that such modification is effective.
 - 2.4. Install torsional stress relays on impacted generator units. If the possible but unlikely contingencies are realized, then the generator units will have a protection system in place, which will result in tripping the unit but protecting it against SSR damage.

Further explanation is offered as follows. Our review of the study documents [1], [2], [3] and our own studies [Appendix C] indicate that at 30% series compensation, there are no torsional modes on the Bruce units and Lambton units that would interact with the series resonance frequencies created by the series capacitors. However, if the Nanticoke units are left operational as generators and not decommissioned, then there is a reasonable probability that subsynchronous resonance could be invoked at specific contingency conditions. If these units are to be removed from operation with some units decoupled and operating as synchronous condensers, then the conflicting torsional mode will be removed and no longer be an issue. However, a check should be made to see if a torsional mode of oscillation between the decoupled generator and exciter exists and remains a concern.

This is a significant enough conclusion to warrant further confirmation. It is recommended that the SSR study be undertaken with the specific focus on Bruce and Lambton (and Nanticoke if not decommissioned) generators to confirm that all torsional modes are positively damped. This study should be undertaken before the specification for the series capacitors is released.

If Nanticoke units will not be decommissioned by the time the series capacitors are to be in-service, then SSR mitigation action is required as the studies to date indicate they are most vulnerable to SSR. Operating restrictions will be defined by the studies. These could include the N-4 contingency of loss of both Nanticoke to Middleport 500 kV lines and both 500/230 kV transformers at Nanticoke, which is the critical case for 500 kV units. The critical case for the 230 kV Nanticoke units is the N-6 contingency of loss of both Nanticoke to Middleport 500 kV lines and all four 230 kV lines out of Nanticoke 230 kV substation, with all four 500 kV units off-line (critical case for 230 kV units).

There is also the possibility of applying excitation system damping of torsional modes on all effective Nanticoke units. This requires design and testing. It is different to system damping applied through an excitation stabilizer. Its input signal is derived directly from a speed measurement of the generator and will only be effective if the generator is participating in the torsional mode(s) of interest.

Regardless of the operational status of the Nanticoke generators, it is recommended at this stage that torsional stress relays be added to all Bruce, Lambton and Nanticoke (if in service) generators. It is also recommended that unless the SSR study indicates otherwise, no special SSR mitigation measures be applied to the series capacitor banks so long as they remain less than or equal to 30% compensated.

5.3 Other Measured Considerations Driving Mid-Point Location

Although adding the series capacitors mid-line has certain technical benefits, it does require a new substation for the series capacitors located beside the transmission line. Key factors in this decision are:

1. Extra overall rating will be incurred if a single 30% series capacitor bank is located at one end. A preliminary investigation indicated that capacitor bank total arrester energy absorption rating required for overvoltage protection during faults on B562L and B563L increases by approximately 4.8 times if located at Longwood and over 10 times if located at the Bruce complex. Such an increase is because of the additional fault current that the series capacitor bank has to be rated for when located at a line end compared to line centre. For N582L, if the series capacitor was located at Longwood, the arrester energy requirement increased 2 times, and over 10 times if located at Nanticoke. In addition, the fault current through the capacitor banks increased and reflect in added cost to the capacitors. The additional cost of increased arrester energy rating must be evaluated against the convenience of locating all series capacitors at line end at Longwood substation.
2. There is a definite convenience in locating all three series capacitor banks at line end at Longwood substation if space is available. Maintenance would be facilitated, along with spares that could be stored at one convenient location. There is a substantial additional cost in locating the series capacitor banks at the Bruce Complex for B562L and B563L and at Nanticoke for N582L.
3. It is possible to divide each series capacitor bank into two and locate the halves at respective line ends. This too will incur additional cost, with the series capacitors located at the Bruce Complex and Nanticoke ends requiring a larger arrester energy rating than for the series capacitors located at the Longwood ends. Maintenance is less convenient with the banks spread out, but reliability will be increased in dividing each line series capacitor into two independent banks.

4. The existing relays protecting B562L, B563L and N582L transmission lines will need to be changed out and replaced by a protection scheme that would be recommended after further investigation⁸.

Taking all these points into account, our recommendation is to locate the series capacitors at line centre. This will result in two locations requiring new substations for the series capacitors with the assumption that the substations for lines B562L and B563L are located together. The mid-line series capacitor for N582L will be located at the second new substation.

So far as other facilities that are required for a mid-line location of all three series capacitors, there is very little that is required at the existing line ends. An insulation coordination study will confirm whether existing insulation levels are adequate at the Bruce, Longwood and Nanticoke substations. The increased fault levels at these substations will impact equipment, particularly circuit breakers and these should be checked.

5.4 Studies Required for Series Capacitor Installations

There are several stages of studies to be undertaken in contemplating and implementing the installation of series capacitors in the existing SWO transmission system. The background and need for such studies has been addressed in this report, and are listed and summarized as follows:

5.4.1 Pre-feasibility Studies

The pre-feasibility studies investigate the serious advantages and disadvantages of applying series capacitors to the SWO transmission network as an option to new transmission lines or in coordination with various generation development plans. These are largely power flow and dynamic stability assessments and are comprehensive in consideration of options and contingencies studied. The transmission lines to be upgraded with series capacitors are identified along with the percentage of compensation to be applied on each transmission line. Broad cost analysis can be undertaken that includes loss analysis for comparison of the options under study. The performance of each option should be comparable so that a similar basis for cost comparison is established. From this pre-feasibility study, one or several options are selected for further study.

This study is undertaken under the direction of experts familiar with the SWO system and involves interested parties. This work has already been undertaken in that the selection of transmission lines B562L, B563L and N582L for 30% series compensation has been selected as an option to constructing new transmission lines.

⁸ See Section 5.4.3 Facilities Study and the subsection on Line Protection Study.

Some initial transient network analysis may be warranted in the pre-feasibility assessment of the series capacitor banks

5.4.2 System Impact Studies

The system impact to SWO of the selected option(s) determined from the Pre-feasibility study is investigated. To refine the selected series compensation option of adding series capacitors to the B562L, B563L and N582L transmission lines, the following studies are undertaken:

1. Subsynchronous Resonance and Damping of Generator Shaft Torsional Oscillations. A study identifying the thermal generators at risk in SWO due to SSR and has been completed [1]. However, with the level of series compensation established and expansion plans for generation and load in SWO becoming more clearly defined, SSR should be re-visited. As Bruce units are brought on-line and Nanticoke units possibly not retired as early as first anticipated, the study should focus on confirming under what conditions is torsional damping reduced on any of the generators at risk. If torsional damping from electrical effects is reduced, it may contribute to loss of life for the shaft in that for a switching action or a fault nearby, torsional oscillations will be invoked and last longer if electrical damping is reduced, thereby increasing fatigue effects and subsequent accelerated aging. Increased torsional damping of a generator exposed to SRR might be possible with an input added to a solid state exciter directly from the measured speed of the generator.

The data that has been applied defining torsional modes of oscillation for the Bruce, Lambton and Nanticoke units is obtained from Appendix B of reference [1] and reproduced in Appendix C of this report. This data should be checked, and if necessary tested in order to ensure that there is confidence in the results of further SSR studies.

This study will also identify the contingencies that are of greatest concern if any, and recommend whether to put in place operating restrictions to avoid the consequences of such contingencies.

2. System power flow studies are continued in order to refine operating limitations under various contingencies. These studies examine the years through which the series capacitors are required based on various load growth scenarios. Determining the reactive power demand of the network that is needed to maintain system and voltage stability year by year is a major objective of system impact studies. Any wind farm applications that have been approved should also be included in the studies.

5.4.3 Facilities Study

The Facilities Studies identify and characterize the facilities that must be added to the SWO power system in order to implement the series capacitors. These studies determine the budget costs of the identified facilities and the parameters needed for the technical specifications. Facilities studies include:

1. **Reactive Power Facilities.** The reactive power requirements determined from the system impact study are refined to determine the type and location of reactive power facilities that are best applied for the SWO series capacitor application. These will be selected from fixed and switched shunt reactors and capacitors, SVCs, STACOMs and synchronous compensators.
2. **Angular Swing Effects.** Synchronous generators and synchronous compensators undergo angular swings following fault clearing and transmission line switching and is studied with a power system stability program. The frequency and severity of the swing is a modal function of the state of the transmission system to which the generator is connected to. Series capacitors added into the transmission system act to effectively strengthen the network through reduced system impedance. This in turn increases the modal frequency of angular swings of synchronous machines and reduces the post fault magnitude of the angular swing. Excitation stabilizers are tuned to respond effectively to a range of system impedances and corresponding range of angular swing frequencies. If the new state of the transmission system moves the electromechanical angular swing response into a less effective range than the excitation stabilizer is tuned to, then an investigation should be undertaken to re-design the tuning of the effected excitation stabilizers to maximize damping of angular swinging. Note that synchronous compensators normally do not have excitation stabilizers as they are ineffective for damping angular swings unless they are specifically designed to react with local load to create load damping.

The maximum swing current through the series capacitors (Figure 3.6.1) is determined as part of the Angular Swing Effects study and provides essential data for the technical specification for the series capacitor banks.

Adjustments to the Bruce Special Protection System are evaluated and recommendations made.

3. **Short Circuit Studies.** These studies can be undertaken with the traditional short circuit programs or power system analysis programs. As discussed in Section 2.8, fault locations that do not cause the by-pass of the series capacitors by the MOV or bypass breaker result in increased sort circuit

currents. Faults closer to the series capacitor banks that cause an MOV by-pass effectively does not increase the fault current level in nearby equipment such as circuit breakers or transformers. The actual fault current under such conditions can be checked with a transients study where the MOVs are accurately represented and their non-linear by-pass action can be more accurately represented. The short circuit capacity at busbars associated with the series compensated transmission lines is necessary data for the technical specification of the series capacitors and any new additional equipment contemplated at those busbars. The short circuit study also serves to determine if existing equipment is still within rating.

4. Transients Studies. The insulation coordination of existing facilities including the series compensated transmission lines and substation equipment is examined to determine if existing surge arresters are adequate or need replacing. Transients studies are wide ranging and include the following investigations.

- 4.1 Switching Surge Study. This is the more traditional method of examining overvoltages which involves an electromagnetic transients study usually undertaken to coordinate insulation levels. Various faults and disturbances are applied and cleared around the transmission line and substations of interest and at varying points on wave for different operating contingencies. This involves thousands of cases in search of the most severe overvoltages and the statistical characterization of them. This is an automated procedure but takes some time to set up and test. Any resonant conditions between series capacitor and shunt compensation banks will contribute to the observed overvoltages. If insulation levels or arrester energy ratings are exceeded, then appropriate mitigation must be applied, which may involve re-rating surge arresters. These studies are also undertaken to determine possible surge arrester protective levels and energy dissipation rating across the series capacitor banks for use in further studies.

- 4.2 Electrical Harmonic Impedance study. Frequency scans of impedance from various busbars where harmonic generating equipment is located is undertaken to observe where possible resonant overvoltages may build up. Nearby transformers are at one location where such investigations should be undertaken. Transformers are a specific source of harmonic current after a nearby ac system fault is cleared. The resulting transformer magnetic inrush current, which usually lasts for approximately a second, is rich in harmonics that can drive any nearby impedance that is resonant at such a harmonic frequency. Although such effects are usually well contained by surge arresters, transformers as a source of the harmonic effects may also be affected by any resulting harmonic overvoltages. Of greatest concern in this respect is if in the post fault condition the transformer is left radially connected to a series compensated

transmission line. Then the transformer saturation effects that generate the magnetic inrush currents may be sustained and evolve into one of several forms of ferroresonance, which if prolonged can destroy the transformer.

An aspect of the electrical harmonic impedance study is to search for electrical resonant modes in which the series capacitors or any nearby shunt capacitors significantly participate when excited from a known harmonic current source such as a saturating transformer. This is undertaken in the study model by injecting defined harmonic currents at substation busbars of interest where sources of harmonics are located (such as a transformer busbar). Currents of the same frequency are measured through the series and shunt capacitors of concern. Consider for example a series capacitor bank. If a one amp current is injected at a busbar at a particular frequency and a current at the same frequency is measured through a series capacitor bank that is greater than one amp, then the series capacitor is parallel resonant or near parallel resonant with the network at that frequency. The current injection is done both at positive and at zero sequence over a frequency range from 5 Hz to 2000 Hz and for various transmission and generation contingencies. When a resonance or near resonance condition involving the series capacitor is detected, it is defined by determining the principal components participating in the resonance, and tested with a switching surge study that excites these principal components and tests insulation and arrester energy levels. This is in effect an electrical circuit Eigen analysis study that can be used if such software is available. In any case, any resonant modes detected that involve significant participation by the series capacitors needs to be tested in the time domain with the non-linearity of transformer saturation represented to determine if impacted surge arresters at the series capacitor banks and transformer connections are adequately rated.

4.3 Line Protection Study. This study is undertaken to establish the type of protection system to be applied. This study is to determine the type of protection system to be applied, whether distance or line differential protection. A transients study using a modern electromagnetic transients program can be carried out to evaluate the protection scheme. The simulation studies would be followed by a digital TNA test program using the actual chosen protection hardware and settings for the transmission. This factory (or field) test program would verify the relay settings especially for the ones for lines B562L, B563L and N582L.

5.4.4 Action Checklist

The checklist of actions to bring into effect the technical specification for the SWO series capacitor installations is:

Pre-Feasibility Study

- ☒ Review all reports pertaining to the SWO series capacitor project. From the recommendations and conclusions of these studies, select the lines to be compensated and the amount of series compensation (%) to be applied. See SSR checklist Section 4.3.3.
- ☐ Undertake any studies and investigations to confirm the transmission lines to be series compensated, the amount (%) of series compensation to be applied and the location of the series capacitor banks (centre line or line end, noting that centre line is recommended at this stage). See SSR checklist Section 4.3.3.
- ☐ Determine the schedule for installation of the series compensation for the selected transmission lines, which is coordinated with generation retirements and units brought on-line. Review budget and operational costs for the proposed installation. Undertake loss analysis for the system and evaluate overall costs for comparison with various options including a new transmission line.
- ☐ Based on results from the pre-feasibility study, and other factors such as the permitting of a new transmission line option(s), a decision point is reached on whether to proceed with the series capacitors installation.

System Impact Study

- ☐ Undertake the SSR System Impact study as outlined in Section 4.3.3, which includes:
 - ☐ Review and check torsional data, testing the Bruce, Nanticoke and Lambton units if necessary.
 - ☐ Prepare a specification for an SSR System Impact Study.
 - ☐ Include impact of SSR on wind farms in the specification for the SSR System Impact Study.
 - ☐ Send out RFP for the SSR study
 - ☐ Schedule action on recommendations of the SSR study.
- ☐ Undertake system power flow studies to evaluate operating contingencies, generation in service, wind farms, and corresponding reactive power requirements for the SWO system.

Facilities Study

- _____ Reactive power facilities study. Determine the fixed, switched and dynamic reactive power requirements of the SWO system to support the series compensation and associated transmission loading.

- _____ Angular swing effects which includes:
 - _____ Evaluate system stability and if improved performance is possible and required from excitation system stabilizers.
 - _____ Refine contingency conditions and evaluate adjustments to the Bruce Special Protection System.
 - _____ Recommendation on adjustments to the BSPS.
 - _____ Determine the maximum swing current through the series capacitor banks for inclusion in the technical specification.
 - _____ Establish the transient ratings of dynamic reactive power compensators which might include SVCs, STATCOMs or synchronous compensators.

- _____ Short circuit study to determine the fault currents the series capacitor must be designed to, for inclusion in the technical specification. Determine whether existing circuit breakers and transformers are rated to withstand the increased short circuit capacity caused by the series capacitors.

- _____ Transients study for insulation coordination which includes:
 - _____ Switching surge studies to determine what additional voltage stresses if any are placed on existing transmission lines, surge arresters, transformers and any other substation equipment and to ensure insulation remains properly coordinated.
 - _____ Estimate the energy dissipation requirements of the varistors protecting the series capacitors. This will be ultimately determined by the supplier of the series capacitors, but a value for pre-specification studies is required. The energy dissipation requirements of the varistors will be impacted by the reclosing strategy, which needs to be determined for inclusion in the technical specification.
 - _____ Electrical Harmonic Impedance Study to evaluate resonant conditions and interactions.
 - _____ Line protection study to determine the replacement protection systems for the series compensated transmission lines.

Equipment Specifications

- _____ From the Facilities Study, finalize the list of facilities that require addition and replacement. Prepare a schedule for purchase and installation, and set up appropriate budgets and purchasing policies, and project management.
- _____ Prepare the technical specifications for the series capacitor installations.
- _____ Prepare of the technical specifications for the additional facilities identified in the Facilities Study including fixed, switched and dynamic compensation, replacement transmission line protection systems, updating of the BSPS and replacement of any existing facilities such as surge arresters, circuit breakers and instrument transformers.
- _____ Proceed with the purchase of all necessary facilities including land acquisitions.
- _____ Construct, test, commission and accept of all new and replacement facilities.
- _____ Adjust settings of existing equipment if changes are necessary including excitation stabilizers for increased system damping, exciters with improved SSR damping functions, and any protection relays the would benefit from revised settings.
- _____ Consider the installation of torsional stress relays if SSR studies indicate a need.

The sequence of the checklist items may be adjusted to accommodate the overall schedule of the project.

Conclusions

The main conclusions are:

1. Series compensation is a mature technology that has been effectively and reliably applied for many decades.
2. The rating of the series capacitor banks is based on equaling the conductor rating so that they are not limiting power transfer capability.
3. By restraining the degree of series compensation to 30%, there appears to be no torsional mode conflicts with any of the Bruce generators. There are torsional conflicts with the Nanticoke units, which if retained in service after the series capacitors are in operation, require further

investigation with respect to subsynchronous resonance. The Lambton units also may be exposed to SSR but not as severely as Nanticoke.

4. It is recommended that the series capacitors be located midline to minimize equipment ratings of the installations.
5. An SSR study should be undertaken focused on Bruce and Lambton generators. If Nanticoke units are to remain in-service with the series capacitors, they should be included in the study too. This study would be to confirm the recommendation or otherwise that no special SSR protection be applied to the series capacitor banks. Instead, operating restrictions be defined and applied, SSR damping be incorporated with the exciters of the subject generators, and torsional stress relays added to those generating units as well. Before the SSR study commences, the torsional oscillation data of the units of these generating stations should be checked and tested if necessary.
6. There are responses that need to be added to the Bruce special protection system. The design and setting criteria for the BSPS should be reviewed by simulation study to evaluate the impact of these changes.
7. The addition of 30% series compensation to B562L and B563L and N582L transmission lines should be achieved with minimum additional equipment and setting adjustments to the existing systems. However, loading these lines to levels that the series capacitors can accommodate under contingency conditions will require significant additional reactive power support that needs to be quantified and characterized as to whether it is installed with fixed, switched or dynamic compensation and where it is to be installed.

References

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8. IEEE Paper 0-7803-1319-4/94: Testing 500 kV Line Relays for a Series Compensation Upgrade, McLaren et al.
9. GE Power Management GER 3972: Series Compensated Line protection Issues, S. Wilkinson
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List of Appendices

Appendix A

A-1 Series Capacitor Installations – ABB

A-2 Series Capacitor Installations – GE

A-3 Series Capacitor Installations – Nokian

A-4 Series Capacitor Installations - Siemens

Appendix B

Draft Planning Specification

Appendix C

SSR Considerations with 30% Series Compensation on B562L, B563L and N582L

Appendix A-1

Series Capacitor Installations – ABB

ABB pioneered the use of series capacitors in electric power systems in the late 1940s. The ABB series capacitors have a well proven design and have over the years demonstrated extraordinarily good reliability. This is essential as the installations are unmanned and often located in remote areas far away from service centres.

ABB's success in the series compensation field is best illustrated by the confidence in our solutions evidenced by customers. Today, 266 installations located all over the world are in service or under construction. This represents 76400 Mvar, equal to 51% of the world total.

ABB Series Capacitor projects Worldwide

29-jun-06

A02-0137 E Page 1

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
Power Grid India - Ranchi	India	400 kV	398 Mvar	DG	2006
Power Grid India - Ranchi	India	400 kV	398 Mvar	DG	2006
San Diego Gas&Electric - Imperial Valley East Upgrade	USA	500 kV	150 Mvar	MOV	2006
Abengoa AS - S.João do Piauí	Brazil	500 kV	374 Mvar	MOV	2005
Abengoa SA - Ribeiro Goncalves	Brazil	500 kV	462 Mvar	MOV	2005
Abengoa SA - Ribeiro Goncalves	Brazil	500 kV	425 Mvar	MOV	2005
Eskom - Cape Strengthening Bacchus No.1	South Africa	400 kV	248 Mvar	MOV	2004
Eskom - Cape Strengthening Proteus No.1	South Africa	400 kV	229 Mvar	MOV	2004
Eskom - Cape Strengthening Komsberg No.2	South Africa	400 kV	656 Mvar	MOV	2004

*) SG: Single-gap MOV: Metal Oxide Varistor
 DG: Dual-gap SIC: Silicon carbide varistor

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29-jun-06

A02-0137 E Page 2

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
Eskom - Cape Strengthening Komsberg No.1	South Africa	400 kV	704 Mvar	MOV	2004
PG&E - Midway, phase 3	USA	500 kV	503 Mvar	MOV	2004
Electricity of Vietnamn - Tan Dinh	Vietnam	500 kV	101 Mvar	MOV	2004
Transener S.A. - 3rd&4th Line SC Extension	Argentina	500 kV	580 Mvar	MOV	2003
Power Grid Corp. of India - Raipur Rourkela 2 TCSC	India	400 kV	59 Mvar	MOV	2003
Power Grid Corp. of India - Raipur-Rourkela 1 TCSC	India	400 kV	59 Mvar	MOV	2003
Power Grid Corp. of India - Raipur Rourkela 2	India	400 kV	394 Mvar	MOV	2003
Power Grid Corp. of India - Raipur-Rourkela 1	India	400 kV	394 Mvar	MOV	2003
SCECO - SCECO East	Saudi Arabia	380 kV	588 Mvar	MOV	2003
SCECO - SCECO East	Saudi Arabia	380 kV	495 Mvar	MOV	2003
SCECO - SCECO East	Saudi Arabia	380 kV	495 Mvar	MOV	2003
SCECO - SCECO East	Saudi Arabia	230 kV	189 Mvar	MOV	2003
Nevada Power - McCullough	USA	500 kV	452 Mvar	MOV	2003
PG&E - Vaca Dixon Upgrade	USA	500 kV	384 Mvar	MOV	2003
Idaho Power Company - Goshen SC	USA	345 kV	380 Mvar	MOV	2003
San Diego Gas & Electric - Imperial Valley	USA	550 kV	307 Mvar	MOV	2003
BC Hydro - McLeese 1 Refurb.	Canada	500 kV	616 Mvar	MOV	2002

*) SG: Single-gap MOV: Metal Oxide Varistor
 DG: Dual-gap SiC: Silicon carbide varistor

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29-jun-06

A02-0137 E Page 3

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
BC Hydro - McLeese 2 Refurb.	Canada	500 kV	616 Mvar	MOV	2002
Hydro Quebec - Bergeronnes extension	Canada	760 kV	516 Mvar		2002
PG&E - PG&E Alliance Fas 2	USA	500 kV	544 Mvar	MOV	2002
PG&E - PG&E Alliance Fas 2	USA	500 kV	503 Mvar	MOV	2002
PG&E - PG&E Alliance Fas 2	USA	500 kV	503 Mvar	MOV	2002
PG&E - PG&E Alliance Fas 2	USA	500 kV	544 Mvar	MOV	2002
Eletronorte - North - North East III	Brazil	500 kV	315 Mvar	MOV	2001
Eletronorte - North - North East III	Brazil	500 kV	435 Mvar	MOV	2001
Eletronorte - North - North East III	Brazil	500 kV	435 Mvar	MOV	2001
Eletronorte - North - North East III	Brazil	500 kV	279 Mvar	MOV	2001
PG&E - Round Mountain 1	USA	500 kV	444 Mvar	MOV	2001
PG&E - Table Mountain 2	USA	500 kV	444 Mvar	MOV	2001
PG&E - Round Mountain 2	USA	500 kV	444 Mvar	MOV	2001
PG&E - Gates 1	USA	500 kV	584 Mvar	MOV	2001
PG&E - Gates 4	USA	500 kV	544 Mvar	MOV	2001
PG&E - Gates 3	USA	500 kV	544 Mvar	MOV	2001
PG&E - Gates 2	USA	500 kV	584 Mvar	MOV	2001
PG&E - Table Mountain 1	USA	500 kV	444 Mvar	MOV	2001
Enelven - El Tablazo 2	Venezuela	400 kV	126 Mvar	MOV	2001
Enelven - Yaracuy 2	Venezuela	400 kV	197 Mvar	MOV	2001

*) SG: Single-gap MOV: Metal Oxide Varistor
 DG: Dual-gap SIC: Silicon carbide varistor

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29-jun-06

A02-0137 E Page 4

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
Eneleven - Yaracuy 1	Venezuela	400 kV	197 Mvar	MOV	2001
Eneleven - El Tablazo 1	Venezuela	400 kV	126 Mvar	MOV	2001
Enelven - El Tablazo 3	Venezuela	400 kV	126 Mvar	MOV	2001
Enelven - 400 kV Series Compensation Project	Venezuela	400 kV	2096 Mvar	MOV	2001
Transener - Recreo	Argentina	500 kV	245 Mvar	MOV	2000
NCEPG - Dafang SC	China	500 kV	744 Mvar	MOV	2000
SOGEM - Mali-Senegal, Matam	Mali	225 kV	45 Mvar	MOV	2000
SOGEM - Mali-Senegal, Kayes	Mali	225 kV	22,5 Mvar	MOV	2000
Trönder Energi - Trönder Energi	Norway	22 kV	1 Mvar	MOV	2000
Virginia Power Co. - Midlothain MINICAP	USA	34 kV	9 Mvar		2000
Enelven - La Paz MINICAP	Venezuela	24 kV	1 Mvar		2000
Transener - Recreo	Argentina	500 kV	240 Mvar	MOV	1999
SOGEM - Mali-Senegal Dagana	Mali	225 kV	45 Mvar	MOV	1999
Idaho Power Company - Ontario	USA	230 kV	135 Mvar	MOV	1999
Transener - 4th line	Argentina	500 kV	430 Mvar	MOV	1998
FURNAS - Ivaipora	Brazil	800 kV	1056 Mvar	MOV	1998
Western Power - Bullabulling	Australia	33 kV	10 Mvar	MOV	1997
Eletronorte - N/S Intertie-Colinas	Brazil	500 kV	322 Mvar	MOV	1997
Eletronorte - N/S Intertie-Imperatriz TCSC	Brazil	500 kV	107 Mvar	MOV	1997
Eletronorte - N/S Intertie-Marabá	Brazil	500 kV	348 Mvar	MOV	1997

*) SG: Single-gap MOV: Metal Oxide Varistor
 DG: Dual-gap SIC: Silicon carbide varistor

ABB Power Technologies AB



29-jun-06

A02-0137 E Page 5

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
Eletronorte - N/S Intertie-Miracena	Brazil	500 kV	161 Mvar	MOV	1997
Eletronorte - N/S Intertie-Imperatriz	Brazil	500 kV	161 Mvar	MOV	1997
PG & E - Round Mountain North	USA	500 kV	770 Mvar	MOV	1997
Colbun SA - Colbun	Chile	230 kV	504 Mvar	MOV	1996
Svenska Kraftnät - Isovaara	Sweden	400 kV	500 Mvar	MOV	1996
Båkab Energi AB - Granbo Minicap	Sweden	22 kV	4,6 Mvar	MOV	1996
TRANSENER S.A. - Retrofit	Argentina	500 kV	1280 Mvar	MOV	1995
Hydro-Quebec - Wenindji - Minicap	Canada	25 kV	3,4 Mvar	MOV	1995
BC-Hydro - Chapman-Retrofit Control	Canada		0 Mvar		1995
BC Hydro - McLeese	Canada	500 kV	605 Mvar	MOV	1993
Hydro-Quebec - Chamouch. Nord I	Canada	800 kV	243 Mvar	MOV	1991
Hydro-Quebec - Abitibi III	Canada	800 kV	397 Mvar	MOV	1991
Hydro-Quebec - Chamouch. Nord II	Canada	800 kV	243 Mvar	MO	1991
Hydro-Quebec - Abitibi I	Canada	800 kV	397 Mvar	MOV	1991
Hydro-Quebec - Abitibi II	Canada	800 kV	397 Mvar	MOV	1991
Hydro-Quebec - Chamouch. Nord III	Canada	800 kV	243 Mvar	MOV	1991
Landsvirkjun - Holar	Iceland	132 kV	43 Mvar	MOV	1991
SSPB - Stöde	Sweden	400 kV	493 Mvar	MOV	1991
SSPB - Tandö	Sweden	400 kV	554 Mvar	MOV	1991

*) SG: Single-gap MOV: Metal Oxide Varistor
 DG: Dual-gap SiC: Silicon carbide varistor

ABB Power Technologies AB



29-jun-06

A02-0137 E Page 6

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
Hydro-Quebec - Arnaud Nord II	Canada	800 kV	363 Mvar	MOV	1990
Hydro-Quebec - Arnaud Sud II	Canada	800 kV	363 Mvar	MOV	1990
Hydro-Quebec - Arnaud Nord III	Canada	800 kV	363 Mvar	MOV	1990
Hydro-Quebec - Arnaud Sud III	Canada	800 kV	363 Mvar	MOV	1990
Hydro-Quebec - Arnaud Nord I	Canada	800 kV	363 Mvar	MOV	1990
Hydro-Quebec - Bergeronnes III	Canada	800 kV	238 Mvar	MOV	1990
Hydro-Quebec - Saguenay Nord	Canada	800 kV	238 Mvar	MOV	1990
Hydro-Quebec - Perigny	Canada	800 kV	238 Mvar	MOV	1990
Hydro-Quebec - Bergeronnes I	Canada	800 kV	238 Mvar	MOV	1990
Hydro-Quebec - Arnaud Sud I	Canada	800 kV	363 Mvar	MOV	1990
Hydro-Quebec - Bergeronnes II	Canada	800 kV	238 Mvar	MOV	1990
SSPB - Djurmo EK2	Sweden	400 kV	538 Mvar	MOV	1990
Hidronor - Choele Choe I	Argentina	500 kV	215 Mvar	MOV	1989
Hidronor - Olavarria II	Argentina	500 kV	135 Mvar	MOV	1989
Hidronor - Choele Choe IV	Argentina	500 kV	170 Mvar	MOV	1989
Hidronor - Choele Choe III	Argentina	500 kV	180 Mvar	MOV	1989
Hidronor - Olavarria IV	Argentina	500 kV	135 Mvar	MOV	1989
Hidronor - Choele Choe II	Argentina	500 kV	170 Mvar	MOV	1989
Hidronor - Olavarria I	Argentina	500 kV	245 Mvar	MOV	1989
Hidronor - Olavarria III	Argentina	500 kV	245 Mvar	MOV	1989

*) SG: Single-gap MOV: Metal Oxide Varistor
 DG: Dual-gap SiC: Silicon carbide varistor

ABB Power Technologies AB



29-jun-06

A02-0137 E Page 7

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
Furnas - Ivaipora V	Brazil	800 kV	1017 Mvar	DG	1989
Swedish State Power B. - Djurmo EK4	Sweden	400 kV	603 Mvar	MOV	1989
AEP - Kanawha River	USA	345 kV	788 Mvar	MOV	1989
El Paso Electric - Luna, N. Mexico	USA	345 kV	123 Mvar	SG	1988
Tucson Gas - Vail II	USA	345 kV	102 Mvar	SG	1988
Furnas - Ivaipora I	Brazil	800 kV	1017 Mvar	DG	1987
Furnas - Itabera I	Brazil	800 kV	1242 Mvar	SG	1987
Furnas - Ivaipora II	Brazil	800 kV	1017 Mvar	DG	1987
Furnas - Ivaipora IV	Brazil	800 kV	1056 Mvar	DG	1987
Furnas - Ivaipora III	Brazil	800 kV	1056 Mvar	DG	1987
Furnas - Itabera II	Brazil	800 kV	1242 Mvar	SG	1987
Eade - Apartado	Colombia	110 kV	16 Mvar	SG	1987
TEK - Bolu	Turkey	380 kV	256 Mvar	MOV	1987
TEK - Sincan II	Turkey	380 kV	190 Mvar	MOV	1987
TEK - Sincan I	Turkey	380 kV	190 Mvar	MOV	1987
TEK - Kayabasi I	Turkey	380 kV	207 Mvar	MOV	1986
TEK - Kayabasi III	Turkey	380 kV	207 Mvar	MOV	1986
TEK - Kayabasi II	Turkey	380 kV	207 Mvar	MOV	1986
Hydro-Quebec - Kamouraska IV	Canada	315 kV	192 Mvar	MOV	1985
Hydro-Quebec - Joutel	Canada	120 kV	25 Mvar	SG	1985
Hydro-Quebec - Kamouraska I	Canada	315 kV	192 Mvar	MOV	1985
Hydro-Quebec - Kamouraska II	Canada	315 kV	192 Mvar	MOV	1985
Hydro-Quebec - Kamouraska III	Canada	315 kV	192 Mvar	MOV	1985

*) SG: Single-gap MOV: Metal Oxide Varistor
 DG: Dual-gap SIC: Silicon carbide varistor

ABB Power Technologies AB



29-jun-06

A02-0137 E Page 8

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
NVE - Arendal	Norway	300 kV	234 Mvar	MOV	1985
NVE - Evje	Norway	300 kV	432 Mvar	MOV	1985
SDG&E - Imper. Valley I	USA	500 kV	150 Mvar	MOV	1984
SDG&E - Imper. Valley II	USA	500 kV	150 Mvar	MOV	1984
BPA - Garrison III	USA	500 kV	281 Mvar	MOV	1983
BPA - Garrison II	USA	500 kV	281 Mvar	MOV	1983
PG&E - Vaca Dixon	USA	500 kV	384 Mvar	MOV	1983
PG&E - Table Mountain IV	USA	500 kV	384 Mvar	MOV	1983
BPA - Garrison I	USA	500 kV	281 Mvar	MOV	1983
PG&E - Tesla	USA	500 kV	600 Mvar	MOV	1983
BPA - Garrison IV	USA	500 kV	281 Mvar	MOV	1983
PG&E - Table Mountain III	USA	500 kV	600 Mvar	MOV	1983
CFE - Temascal II	Mexico	400 kV	259 Mvar	DG	1982
CFE - Temascal I	Mexico	400 kV	259 Mvar	DG	1982
BPA - Columbia II	USA	500 kV	276 Mvar	MOV	1981
BPA - Columbia I	USA	500 kV	276 Mvar	MOV	1981
CFE - Coatzacoalcos	Mexico	400 kV	37 Mvar	SG	1980
CFE - Minatitlan II	Mexico	400 kV	37 Mvar	SG	1980
CFE - Minatitlan I	Mexico	400 kV	37 Mvar	SG	1980
CFE - Tecali II	Mexico	400 kV	142 Mvar	DG	1980
CFE - Tecali I	Mexico	400 kV	66 Mvar	DG	1980
CFE - Puebla II	Mexico	400 kV	244 Mvar	DG	1980
CFE - Puebla I	Mexico	400 kV	244 Mvar	DG	1980
TEK - Seydisehir	Turkey	400 kV	65 Mvar	DG	1979

*) SG: Single-gap MOV: Metal Oxide Varistor
 DG: Dual-gap SIC: Silicon carbide varistor

ABB Power Technologies AB



29-jun-06

A02-0137 E Page 9

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
TEK - Osmaniye	Turkey	400 kV	65 Mvar	DG	1979
TEK - Nevsehir I	Turkey	400 kV	164 Mvar	DG	1979
TEK - Nevsehir II	Turkey	400 kV	164 Mvar	DG	1979
PP&L - Burns	USA	500 kV	603 Mvar	SG	1978
PP&L - Midpoint	USA	500 kV	603 Mvar	SG	1978
CFE - Culican	Mexico	230 kV	78 Mvar	SG	1977
CFE - Durango	Mexico	230 kV	78 Mvar	SG	1977
TG&E - McKinley I	USA	345 kV	78 Mvar	SG	1977
TG&E - McKinley II	USA	345 kV	78 Mvar	SG	1977
USBR - Ault	USA	345 kV	97 Mvar	SG	1977
USBR - Archer	USA	230 kV	63 Mvar	SG	1977
ESCOM - Luckhoff II	South Africa	400 kV	246 Mvar	SG	1976
Hidronor - Henderson II	Argentina	500 kV	182 Mvar	MOV	1975
Hidronor - Henderson I	Argentina	500 kV	182 Mvar	SG	1975
Hidronor - Puelches I	Argentina	500 kV	182 Mvar	SG	1975
Hidronor - Puelches II	Argentina	500 kV	182 Mvar	MOV	1975
ESCOM - Kronos	South Africa	400 kV	137 Mvar	SG	1975
ESCOM - Aurora	South Africa	400 kV	137 Mvar	SG	1975
ESCOM - Helios	South Africa	400 kV	137 Mvar	SG	1975
ESCOM - Juno	South Africa	400 kV	137 Mvar	SG	1975
ESCOM - Aires	South Africa	400 kV	137 Mvar	SG	1975
PP&L - Jim Bridger II	USA	345 kV	178 Mvar	SG	1975
PP&L - Jim Bridger III	USA	345 kV	178 Mvar	SG	1975
Arizona Public Service - Saguaro	USA	500 kV	105 Mvar	SG	1975
PP&L - Jim Bridger I	USA	345 kV	178 Mvar	SG	1975

*) SG: Single-gap MOV: Metal Oxide Varistor
 DG: Dual-gap SiC: Silicon carbide varistor

ABB Power Technologies AB



29-jun-06

A02-0137 E Page 10

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
Arizona Public Service - Cholla III	USA	500 kV	105 Mvar	SG	1975
ESCOM - Nestor II	South Africa	400 kV	212 Mvar	SG	1974
Idaho Power Company - Kimport	USA	345 kV	178 Mvar	SG	1974
Utah P&L - Goshen	USA	345 kV	178 Mvar	SG	1974
TG&E - Greenlee	USA	345 kV	158 Mvar	SG	1974
TG&E - Vail	USA	345 kV	56 Mvar	SG	1974
Bl. Hills P&L - Hot Springs	USA	230 kV	106 Mvar	SG	1974
Idaho Power Company - Borah	USA	345 kV	178 Mvar	SG	1974
USBR - Mead	USA	345 kV	110 Mvar	SG	1974
USBR - Liberty	USA	345 kV	110 Mvar	SG	1974
Bl. Hills P&L - Spearfish	USA	230 kV	80 Mvar	SG	1974
ESCOM - Luckhoff I	South Africa	400 kV	246 Mvar	SG	1973
ESCOM - Luckhoff II	South Africa	400 kV	246 Mvar	SG	1973
ESCOM - Victoria I	South Africa	400 kV	222 Mvar	SG	1973
ESCOM - Victoria II	South Africa	400 kV	222 Mvar	SG	1973
Arizona Public Service - Westwing I	USA	500 kV	104 Mvar	SG	1973
Arizona Public Service - Westwing II	USA	500 kV	104 Mvar	SG	1973
NVE - Majavatn	Norway	275 kV	115 Mvar	SG	1972
ESCOM - Komsberg II	South Africa	400 kV	315 Mvar	SG	1972
ESCOM - Nestor III	South Africa	400 kV	212 Mvar	SG	1972
ESCOM - Komsberg I	South Africa	400 kV	315 Mvar	SG	1972
ESCOM - Nestor I	South Africa	400 kV	212 Mvar	SG	1972

*) SG: Single-gap MOV: Metal Oxide Varistor
 DG: Dual-gap SIC: Silicon carbide varistor

ABB Power Technologies AB



29-jun-06

A02-0137 E Page 11

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
SSPB - Stöde	Sweden	400 kV	500 Mvar	SG	1972
TEK - Kayseri I	Turkey	400 kV	116 Mvar	DG	1972
TEK - Kayseri II	Turkey	400 kV	116 Mvar	DG	1972
SCE - Vincent	USA	500 kV	286 Mvar	SG	1972
PG&E - Midway III	USA	500 kV	322 Mvar	SG	1972
Arizona Public Service - Navajo III	USA	500 kV	201 Mvar	SG	1971
Arizona Public Service - Navajo I	USA	500 kV	20 Mvar	SG	1971
LADWP - McCallough I	USA	500 kV	314 Mvar	SG	1971
LADWP - Victorville	USA	500 kV	264 Mvar	SG	1971
Arizona Public Service - Moenkopi III	USA	500 kV	109 Mvar	SG	1971
Arizona Public Service - Pinnacle Peak IV	USA	345 kV	133 Mvar	SG	1971
LADWP - McCallough II	USA	500 kV	314 Mvar	SG	1971
Arizona Public Service - Moenkopi IV	USA	500 kV	109 Mvar	SG	1971
Arizona Public Service - Pinnacle Peak III	USA	345 kV	133 Mvar	SG	1971
Arizona Public Service - Navajo II	USA	500 kV	201 Mvar	SG	1971
USBR - Pinnacle Peak I	USA	345 kV	121 Mvar	SG	1968
USBR - Flagstaff II	USA	345 kV	121 Mvar	SG	1968
USBR - Flagstaff I	USA	345 kV	121 Mvar	SG	1968
USBR - Pinnacle Peak II	USA	345 kV	121 Mvar	SG	1968
SSPB - Tandö	Sweden	400 kV	600 Mvar	SG	1967
Idaho Power Company - Boise Bench II	USA	230 kV	137 Mvar	SG	1967

*) SG: Single-gap MOV: Metal Oxide Varistor
 DG: Dual-gap SiC: Silicon carbide varistor

ABB Power Technologies AB



29-jun-06

A02-0137 E Page 12

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
Idaho Power Company - Boise Bench I	USA	230 kV	137 Mvar	SG	1967
Idaho Power Company - Boise Bench III	USA	230 kV	137 Mvar	SG	1967
Idaho Power Company - Boise Bench IV	USA	230 kV	137 Mvar	SG	1967
CADAFE - Bolivar II	Venezuela	230 kV	41 Mvar	SG	1967
CADAFE - Barbacoa II	Venezuela	230 kV	54 Mvar	SG	1967
CADAFE - Bolivar I	Venezuela	230 kV	41 Mvar	SG	1967
CADAFE - Barbacoa I	Venezuela	230 kV	54 Mvar	SG	1967
PG&E - Round Mountain II	USA	500 kV	243 Mvar	SG	1966
BPA + PG&E - Ft Rock I	USA	500 kV	232 Mvar	SG	1966
PG&E - Round Mountain I	USA	500 kV	243 Mvar	SG	1966
BPA - Bake Oven III	USA	500 kV	153 Mvar	SG	1966
PG&E - Midway I	USA	500 kV	324 Mvar	SG	1966
BPA - Bake Oven IV	USA	500 kV	153 Mvar	SG	1966
SCE - Eldorado	USA	500 kV	283 Mvar	SG	1966
Arizona Public Service - Moenkopi I	USA	500 kV	199 Mvar	SG	1966
Arizona Public Service - Four Corners	USA	500 kV	152 Mvar	SG	1966
BPA + PG&E - Sand Springs I	USA	500 kV	232 Mvar	SG	1966
BPA + PG&E - Sand Springs II	USA	500 kV	232 Mvar	SG	1966
BPA + PG&E - Ft Rock II	USA	500 kV	232 Mvar	SG	1966
Arizona Public Service - Moenkopi II	USA	500 kV	199 Mvar	SG	1966
BPA + PG&E - Sycan II	USA	500 kV	232 Mvar	SG	1966

*) SG: Single-gap MOV: Metal Oxide Varistor
 DG: Dual-gap SIC: Silicon carbide varistor

ABB Power Technologies AB



29-jun-06

A02-0137 E Page 13

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
BPA + PP&L - Malin II	USA	500 kV	194 Mvar	SG	1966
PG&E - Table Mountain II	USA	500 kV	162 Mvar	SG	1966
BPA - Bake Oven II	USA	500 kV	153 Mvar	SG	1966
PG&E - Table Mountain I	USA	500 kV	162 Mvar	SG	1966
PG&E - Midway II	USA	500 kV	324 Mvar	SG	1966
BPA + PP&L - Malin I	USA	500 kV	184 Mvar	SG	1966
BPA - Bake Oven I	USA	500 kV	153 Mvar	SG	1965
BPA + PG&E - Sycan I	USA	500 kV	232 Mvar	SG	1965
SSPB - Vittersjö II	Sweden	400 kV	802 Mvar	SG	1964
Idaho Power Company - Midpoint II	USA	230 kV	83 Mvar	SG	1964
Idaho Power Company - Midpoint I	USA	230 kV	83 Mvar	SG	1964
Idahow Power Company - Midpoint I	USA	230 kV	83 Mvar	SG	1964
Arizona Public Service - Cholla II	USA	345 kV	204 Mvar	SG	1962
Arizona Public Service - Cholla I	USA	345 kV	204 Mvar	SG	1962
SSPB - Djurmo II	Sweden	400 kV	600 Mvar	SG	1961
PP&L - Walla Walla	USA	230 kV	114 Mvar	SG	1961
SSPB - Haverö II	Sweden	400 kV	155 Mvar	SG	1958
SSPB - Kättbo	Sweden	400 kV	216 Mvar	SG	1957
SSPB - Vittersjö I	Sweden	400 kV	305 Mvar	SG	1953
SSPB - Djurmo I	Sweden	400 kV	213 Mvar	SG	1952
SSPB - Haverö I	Sweden	400 kV	200 Mvar	SG	1952
BPA - Rocky Ford	USA	230 kV	81 Mvar	SG	1949

*) SG: Single-gap MOV: Metal Oxide Varistor
 DG: Dual-gap SIC: Silicon carbide varistor

ABB Power Technologies AB



29-jun-06

A02-0137 E Page 14

Customer	Location	System Voltage	Rated Power	Protection Scheme *)	Order year
BPA - St Andrews	USA	230 kV	48 Mvar	SG	1949
SSPB - Alfta	Sweden	230 kV	31 Mvar	SG	1948
BPA - Chekalis	USA	230 kV	24 Mvar	SG	1948

Number of installations: **266** Total installed power: **76 352** Mvar

A-2 Series Capacitor Installations – GE

GE Series Capacitor Experience

Updated: April, 2007

GE Series Capacitor Experience

GE's extensive series compensation experience extends over more than seven decades from the initial supply of the first series capacitor installation in the United States for NY Power & Light in 1928. Since then, GE has continued to provide utilities worldwide with reliable systems to increase power transfer and improve stability.

Today's technology for series compensation is based on primary overvoltage protection provided by Metal Oxide Varistors (MOV), with Triggered Air Gaps (TAG) to limit the energy duty on the MOVs. A brief summary showing GE's broad experience range, flexibility and capabilities in these equipments is:

- First prototype equipment placed in service in 1979 at the North John Day substation
- Transmission line voltages from 220 to 765 kV
- Power ratings from 29 to 1242 MVar three-phase
- MOV energy ratings from 4 to over 300 MJ per phase
- Protective level voltages for single switching steps with TAGs up to 311 kV peak
- Externally Fused, Internally Fused and Fuseless capacitor units
- Over 100,000 capacitor units in service
- Protection systems with Triggered Air Gaps and Gapless
- Fixed and Thyristor Controlled Series Capacitors
- Installed MOV base over 15,000 MJ, 500,000 Zinc Oxide disks, 130,000 MJ-Years

The following is a list of the major series capacitor projects that GE has provided to our utility customers over the years.

GE SERIES COMPENSATION EXPERIENCE LIST (PROTECTION WITH GAP ONLY)				
Service Year	Customer	Substation	Circuit kV	Three-Phase MVar
1928	New York Power & Light	Ballston Spa	33	1.2
1954	Los Angeles Department of Water & Power	Los Angeles	287	15
1957	Louisiana Power & Light	Bogalusa	115	57.8
1960	Bonneville Power Admin.	North John Day	345	108
1967	Idaho Power Company	Copperfield	230	180
1968- 1969	Pacific Gas & Electric	Telsa	500	365
		Los Banos	500	229
		Los Banos	500	229
		Table Mountain	500	262

		Table Mountain	500	175
		Round Mountain	500	175
		Round Mountain	500	175
		Vaca Dixon	500	175
1968-1969	Southern California Edison	Midway	500	318
		Midway	500	318
		Vincent	500	318
		Vincent	500	318
		Lugo	500	283
		Lugo	500	283
		Eldorado	500	283
		Eldorado	500	283
1981	Pacific Power & Light	Burns	500	602
		Midpoint	500	602

GE SERIES COMPENSATION EXPERIENCE LIST (GE MOV PROTECTION & ALL FILM CAPACITORS)					
Service Year	Customer	Substation	Circuit kV	Three-Phase MVar	Energy MJ/phase
1979	Bonneville Power Administration	North John Day	345	Protective System Only	
1985	Montana Power Company	Broadview I	500	235	12.0
		Broadview II	500	235	12.0
1986	Arizona Public Service	North Gila	500	198	7
1986	Southern California Edison	Palo Verde	* 500	253	46.0
		Devers	* 500	389	50.0
1988	Pacific Gas & Electric	Vaca Dixon	500	576	158
1988	Pacific Power & Light	Walla Walla	230	Protective System Only	4.0
1989	Swedish State Power Board	Gustafs	400	778	25.7
1990	Western Area Power Administration	Flagstaff I	345	295	32.0
		Flagstaff II	345	295	32.0
		Pinnacle Peak I	345	253	58.0
		Pinnacle Peak II	345	253	58.0
1990	Swedish State Power Board	Kattbo	400	330	14.0
1991-1992	Portland General Electric	Fort Rock II	* 500	363	46.6
		Sand Springs II	* 500	546	97.4
		Sycan II	* 500	546	83.9
1991	Swedish State Power	Vittersjö EK5	400	1106	37.5

	Board				
1992	Swedish State Power Board	Vittersjö EK 3	400	421	24.3
1992	Bonneville Power Administration	Sand Springs I	* 500	546	102.0
		Sand Springs III	* 500	546	121.2
		Sycan I	* 500	546	93.3
		Sycan III	* 500	470	101.1
		Fort Rock I	* 500	363	43.5
		Fort Rock III	* 500	363	63.0
		Captain Jack	500	547	54.0
1993	Bonneville Power Administration	Alvey	* 500	302	78.5
1993	Northern States Power	Roseau I	500	498	30.4
		Roseau II	500	498	30.4
		Chisago	500	498	116.5
1993	Western Area Power Administration	Tracy	500	560	301.3
		Maxwell	* 500	658	73.2
		Olinda North	* 500	609	190.1
		Olinda South	* 500	547	199.4
1993	Pacific Power & Light	Meridian	* 500	205	101.3
		Dixonville	* 500	193	52.1
1993	ENDE - Bolivia	Vinto	*230	54.9	33.6
1993	Electric Power Research Institute	Slatt	500	202 TCSC	14.8
1994	Hydro Quebec - Canada	Chibougamau	735	271	23.4
		Chibougamau	735	271	23.4
		Chibougamau	735	271	23.4
1995	Hydro Quebec - Canada	Némiskau	735	232	26.4
		Némiskau	735	232	26.4
		Némiskau	735	232	26.4
		Albanel	735	324	19.0
		Albanel	735	324	20.2
		Albanel	735	232	20.2
		La Vérendrye	735	690	34.8
		La Vérendrye	735	690	34.8
		La Vérendrye	735	690	34.8
1995	TEK - Turkey	Agacoren	400	346	49.2
		Agacoren	400	346	49.2
		Goksun	400	346	49.2
		Goksun	400	346	49.2
		Dokurcun	400	196	35.3
1996	Salt River Project	Perkins	500	276	64.4

1996	Mead-Adelanto Project	Marketplace	500	486	101.2
1996	Western Area Power Administration	Mead	500	276	64.4
1996	Bonneville Power Administration	Malin	500	384	52.5
1997	Public Service - New Mexico	Rio Puerco FW	345	+ 273	57.2
		Rio Puerco WW	345	+ 273	39.6
1997	Landsvirkjun - Iceland	Sandskeið	242	# 29	* 7.8
1998	CFE Apysca - Mexico	Donato Guera 1	400	97	6.3
		Donato Guera 2	400	97	6.3
		Donato Guera 3	400	235	8.1
1998	GPU PowerNet - Australia	South Morang	330	+ 186	52.6
		South Morang	330	+ 186	52.6
1998	Eletronorte - Brazil	Imperatriz	500	+ 451	23.2
		Presidente Dutra	500	+ 451	23.2
1999	Nevada Power Co.	Crystal	500	438	29.3
2000	Constructores TransMantaro - Peru	Cotaruse N	220	+ 65	* 28.1
		Cotaruse N	220	+ 65	* 28.1
		Cotaruse S	220	+ 87	* 32.3
		Cotaruse S	220	+ 87	* 32.3
2001	BC Hydro - Canada	Creekside	500	Protective Sys Only #	* 116.0
2001	American Electric Power	Rio Hondo	345	+ 318	20.0
		North Edinburg	345	+ 318	20.0
2002	Eskom - So. Africa	Luckoff #1	400	+ 524.2	* 80.9
		Luckoff #2	400	+ 569.7	* 83.1
		Luckoff #3	400	+ 569.7	* 83.1
2002	Furnas S.A. - Brazil	Itabera	765	1242	27.8
2003	Furnas S.A. - Brazil	Samambaia	500	272	22.4
2003	Arizona Public Service	Moenkopi	500	+ 336	38.9
2003	Bonneville Power Administration	Columbia 1	500	+ 575	43.2
		Columbia 2	500	+ 575	43.2
		Schultz 1	500	+ 912	71.6
		Schultz 2	500	+ 912	71.6
		Dworshak	500	+ 336	45.9
2003	Enel Power - Brazil	Gurupi North	500	160.7	30.2
		Gurupi South	500	160.7	31.2
		Miracema South	500	160.7	31.0
2004	Electricity of Vietnam	Pleiku #2	500	# 138	11.0
		Phulam	500	# 138	11.0
		Pleiku #1	500	# 258	19.4

		Danang	500	# 258	19.4
2004	Enel Power - Brazil	Colinas North	500	160.7	30.9
		Colinas South	500	160.7	42.1
		Imperatriz South	500	160.7	27.5
		TCSC Serra da Mesa	500	107	13.4
		TCSC Imperatriz	500	107	13.4
2004	Transelec - Chile	Alto Jahuel-1	500	+ 392.2	15.3
		Alto Jahuel-2	500	+ 314.5	13.5
		Charrua-1	500	+ 226.5	13.9
		Charrua-2	500	+ 256.4	13.0
2004	Bonneville Power Administration	Garrison-Taft 1	500	+ 346	28.4
		Garrison-Taft 2	500	+ 346	28.4
		Garrison-Broadview 1	500	+ 474	34.1
		Garrison-Broadview 2	500	+ 474	34.1
		Bell	500	+ 365	44.3
2004	Electricity of Vietnam	Danang (Hatinh)	500	# 91.5	15
		Pleiku (Doc Soi)	500	# 91.5	15
		Danang (Pleiku)	500	# 56.5	15
2005	Electricity of Vietnam	Nho Quan #1 (Hatinh)	500	# 69	23
		Nho Quan #2 (Hatinh)	500	# 69	23
2005	Hydro Quebec - Canada	Bergeronnes 1	735	+ 303	17.3
		Bergeronnes 2	735	+ 303	17.3
		Bergeronnes 3	735	+ 303	17.3
		Cholla C17	345	+ 140.6	15
		Cholla C18	345	+ 140.6	15
2005	South China	Mawo – Baise	500	+ 542.1	70.8
		Louping – Baise	500	+ 669.4	59.0
2005	CFE (Mexico)	Tecali	400	149	10.4
2006	Arizona Public Service	North Gila C19	500	+489.3	54.6
		Moenkopi C6	500	+115	29.4
		Moenkopi C7	500	+246	25.6
2006	Southern Cal Edison	Devers	500	+875	*196.2
		Palo Verde	500	+569	*196.4
2006	Electricity of Vietnam	Pleiku	500	+366	33.6
		Danang	500	+228	16.8
2007	Arizona Public Service	Westwing C9	500	+236	98.3

2007^	Bangor Hydro Electric	Orrington	345	+469	42
2007^	XCEL Energy	Fieldon	345	+240	43
2007^	South China	Louping – Baise	500	+ 669.4	59.0
2008^	Arizona Public Service	Navajo C3	500	+372	11.1
		Navajo C1	500	+835	35.3

- * “Gapless” protection system
- + Fuseless design
- # Internally Fused capacitors
- ^ Projected Completion Dates
- F Fault Tested

A-3 Series Capacitor Installations – Nokian

		REFERENCE LIST of Series Capacitor Banks					2007		
Name of power station, Customer	Country	Year of Installation	Description	Nr of Banks/E quip.	Rated voltage (kV)	Freq. (Hz)	SVC Rated power (Mvar)/ SC 3-phase Power Output (Mvar)	Type	Notes
SMTE/Cobelux da Mesa II	Brazil	2007	Nominal Current(A): 1850 1-phase MOV(MJ): 27	1	500	60	248	SC	Note 11
SMTE/Cobelux Luziania	Brazil	2007	Nominal Current(A): 1850 1-phase MOV(MJ): 24,3	1	500	60	248	SC	Note 11
Vuolijoki SC4, Fingrid extension of the bank	Finland	2007	Nominal Current(A): 1400 1-phase MOV(MJ): 17,3	1	400	50	149.9	SC	Note 11
Vuolijoki SC5, Fingrid extension of the bank	Finland	2007	Nominal Current(A): 1400 1-phase MOV(MJ): 36,6	1	400	50	149.9	SC	Note 11
Uusnivala SC1, Fingrid extension of the bank	Finland	2007	Nominal Current(A): 1400 1-phase MOV(MJ): 20,3	1	400	50	158.8	SC	Note 11
Uusnivala SC2, Fingrid extension of the bank	Finland	2007	Nominal Current(A): 1400 1-phase MOV(MJ): 19,4	1	400	50	317.5	SC	Note 11
Uusnivala SC3, Fingrid extension of the bank	Finland	2007	Nominal Current(A): 1400 1-phase MOV(MJ): 27,6	1	400	50	158.8	SC	Note 11
Khandwa Power Grid	India	2006	Nominal Current(A): 3000 1-phase MOV(MJ): 10,8	2	400	50	1006	SC	Note 12
Itumbalara, Furnas	Brazil	2006	Nominal Current(A): 1100 1-phase MOV(MJ): 11	1	230	60	183	SC	Note 8,12
Rondonopolis, Eletronorte	Brazil	2005	Nominal Current(A): 1000 1-phase MOV(MJ): 15	1	230	60	91	SC	Note 12
Wanquan-Shunyi Transmission line III, NCGC	China	2005	Nominal Current(A): 2400 1-phase MOV(MJ): 55	2	500	50	500	SC	Note 12
Guichon, BCPHA	Canada	2003	Nominal Current(A): 2400 1-phase MOV(MJ): 63	1	500	60	420	SC	Note 11
Wanquan-Shunyi Transmission line I&II, NCPGC	China	2003	Nominal Current(A): 2400 1-phase MOV(MJ): 55	2	500	50	445	SC	Note 12
Fengzhen, NCPGC	China	2003	Nominal Current(A): 2400 1-phase MOV(MJ): 75	2	500	50	259	SC	Note 12
Ibluna, Furnas	Brazil	2002	Nominal Current(A): 2230 1-phase MOV(MJ): 8,7	1	500	60	765	SC	Note 8, 11
Samambala, Furnas	Brazil	2002	Nominal Current(A): 1630 1-phase MOV(MJ): 19,7	1	500	60	252	SC	Note 8, 11
Vuolijoki, Fingrid	Finland	2001	Nominal Current(A): 1400 1-phase MOV(MJ): 6,61	2	400	50	100	SC	Note 11
Uusnivala, Fingrid	Finland	2001	Nominal Current(A): 1400 1-phase MOV(MJ): 12,54	2	400	50	106	SC	Note 11
Uusnivala, Fingrid	Finland	2001	Nominal Current(A): 1400 1-phase MOV(MJ): 8,13	1	400	50	212	SC	Note 11

Name of power station, Customer	Country	Year of Installation	Description	Nr of Banks/E quip.	Rated voltage (kV)	Freq. (Hz)	SVC Rated power (Mvar)/ SC 3-phase Power Output (Mvar)	Type	Notes
Creekside, BCHPA	Canada	2000	Nominal Current(A): 1900 1-phase MOV(MJ):	1	500	50	404	SC	Note 10
Brevik, Øye Smelteverk	Norway	2000	Nominal Current(A): 577 1-phase MOV(MJ):	1	13.1	50	22.65	SC	Note 12
Gurupi, Furnas	Brazil	1998	Nominal Current(A): 1500 1-phase MOV(MJ): 31,1	2	500	60	161	SC	Note 8,11
Marabá 2, Eletronorte	Brazil	1998	Nominal Current(A): 2300 1-phase MOV(MJ): 30,4	1	500	60	283	SC	Note 8,11
Atacama, Chilgener	Chile	1998	Nominal Current(A): 1800 1-phase MOV(MJ):	1	345		490	SC	Note 9
Chapmans, BCHPA	Canada	1998	Nominal Current(A): 1900 1-phase MOV(MJ):	1	500		550	SC	Note 10
Keminmaa, IVS	Finland	1997	Nominal Current(A): 1800 1-phase MOV(MJ): 23,2	2	400	50	301	SC	Note 11
San Marcos, ISA	Colombia	1995	Nominal Current(A): 700 1-phase MOV(MJ): 20	2	230		700	SC	Note 12
Hoa Binh, Ministry of Energy	Vietnam	1993-1994	Nominal Current(A): 1000 1-phase MOV(MJ): 15,6	1	500		91.5	SC	Note 12
Ha Tinh, Ministry of Energy	Vietnam	1993-1994	Nominal Current(A): 1000 1-phase MOV(MJ): 7,8	2	500		91.5	SC	Note 12
Da Nang, Ministry of Energy	Vietnam	1993-1994	Nominal Current(A): 1000 1-phase MOV(MJ): 5,2	2	500		91.5	SC	Note 12
Da Nang, Ministry of Energy	Vietnam	1993-1994	Nominal Current(A): 1000 1-phase MOV(MJ): 5,4	2	500		64.5	SC	Note 12
Plei Ku, Ministry of Energy	Vietnam	1993-1994	Nominal Current(A): 1000 1-phase MOV(MJ): 4,5	2	500		124.5	SC	Note 12
Plei Ku, Ministry of Energy	Vietnam	1993-1994	Nominal Current(A): 1000 1-phase MOV(MJ): 5,1	2	500		64.5	SC	Note 12
Phu Lam, Ministry of Energy	Vietnam	1993-1994	Nominal Current(A): 1000 1-phase MOV(MJ): 6,8	1	500		124.5	SC	Note 12
Montaignas, HQ	Canada	1991-1992	Nominal Current(A): 2300 1-phase MOV(MJ): 21	3	735		476	SC	Note 6
Kayenta, WAPA	USA	1991-1992	Nominal Current(A): 1000 1-phase MOV(MJ):	2	230		165	SC	Note 6, 7
American Creek, BCHPA	Canada	1990	Nominal Current(A): 2120 1-phase MOV(MJ): 30	2	500		539	SC	Note 12
Ivalpore, Furnas/ASEA		1988	Nominal Current(A): 2780 1-phase MOV(MJ):	1	750		1056	SC	Note 5
Ivalpore, Furnas/ASEA		1988	Nominal Current(A): 2780 1-phase MOV(MJ):	1	750		1017	SC	Note 5
Wahpoh, BHEL	India	1987	Nominal Current(A): 400 1-phase MOV(MJ):	2	132		20.8	SC	Note 4

Name of power station, Customer	Country	Year of Installation	Description	Nr of Banks/E quip.	Rated voltage (kV)	Freq. (Hz)	SVC Rated power (Mvar)/ SC 3-phase Power Output (Mvar)	Type	Notes
Handia, BHEL	India	1986	Nominal Current(A): 600 1-phase MOV(MJ):	2	220		37.5	SC	Note 3
Norges Statsbaner	Norway	1983-1986	Nominal Current(A): 1-phase MOV(MJ): Single phase series capacitor banks	6	16		5.4	SC	Note 12
Tumbler Ridge, BCRAIL	Canada	1983	Nominal Current(A): 917 1-phase MOV(MJ): Single phase series capacitor banks	1	50		12	SC	Note 12
Kozhikode, BHEL	India	1983	Nominal Current(A): 917 1-phase MOV(MJ):	2	220		45.7	SC	Note 3
Kennedy, BCHPA	Canada	1980	Nominal Current(A): 2300 1-phase MOV(MJ):	1	500		722	SC	Note 12
Kennedy, BCHPA	Canada	1979	Nominal Current(A): 2300 1-phase MOV(MJ):	2	500		725	SC	Note 12, Stage 4
Norges Statsbaner	Norway	1979	Nominal Current(A): 1-phase MOV(MJ): Single phase series capacitor banks	1	16		5.4	SC	Note 12
Elkem-Spigerverket	Norway	1978	Nominal Current(A): 1-phase MOV(MJ):	1	6		3.7	SC	Note 12
China National Machinery Import & Export Corp.	China	1977	Nominal Current(A): 1-phase MOV(MJ):	1	220		32	SC	Note 3
Jörstadelva, NVE	Norway	1976	Nominal Current(A): 1600 1-phase MOV(MJ):	1	275		165.5	SC	Note 12
Eldum, NVE	Norway	1976	Nominal Current(A): 1600 1-phase MOV(MJ):	1	275		92.2	SC	Note 12
Rindal, NVE	Norway	1976	Nominal Current(A): 1600 1-phase MOV(MJ):	1	275		165.5	SC	Note 12
Temascal, CFE	Mexico	1976	Nominal Current(A): 1090 1-phase MOV(MJ):	2	400		93	SC	Note 12
Berg, SSPB	Sweden	1975	Nominal Current(A): 1-phase MOV(MJ):	1	45		13	SC	Note 1
Bakeoven, BPA	USA	1975	Nominal Current(A): 1600 1-phase MOV(MJ):	1	500		102	SC	Note 1
Kennedy, BCHPA	Canada	1974	Nominal Current(A): 2700 1-phase MOV(MJ):	2	500		1000	SC	Note 12, Stage 3
McLeese, BCHPA	Canada	1974	Nominal Current(A): 1950 1-phase MOV(MJ):	2	500		617	SC	Note 12, Stage 3
Chapmans, BCHPA	Canada	1974	Nominal Current(A): 1900 1-phase MOV(MJ):	1	500		550	SC	Note 12, Stage 2
Creekside, BCHPA	Canada	1974	Nominal Current(A): 1900 1-phase MOV(MJ):	1	500		404	SC	Note 12, Stage 2
Stöde, SSPB	Sweden	1973	Nominal Current(A): 1600 1-phase MOV(MJ):	1	400		500	SC	Note 1

Name of power station, Customer	Country	Year of Installation	Description	Nr of Banks/E qulp.	Rated voltage (kV)	Freq. (Hz)	SVC Rated power (Mvar)/ SC 3-phase Power Output (Mvar)	Type	Notes
Djumo, SSPB	Sweden	1972	Nominal Current(A): 1600 1-phase MOV(MJ):	1	400		600	SC	Note 1
Arvidsjaur, SSPB	Sweden	1972	Nominal Current(A): 1-phase MOV(MJ):	1	40		1.75	SC	Note 1
Kennedy, BCHA	Canada	1972	Nominal Current(A): 1600 1-phase MOV(MJ):	2	500		233	SC	Note 12, Stage 1
Kennedy, BCHA	Canada	1972	Nominal Current(A): 2150 1-phase MOV(MJ):	2	500		642	SC	Note 12, Stage 2
McLeese, BCHA	Canada	1972	Nominal Current(A): 1200 1-phase MOV(MJ):	2	500		154	SC	Note 12, Stage 1
McLeese, BCHA	Canada	1972	Nominal Current(A): 1700 1-phase MOV(MJ):	2	500		469	SC	Note 12, Stage 2
Chapmans, BCHA	Canada	1972	Nominal Current(A): 1450 1-phase MOV(MJ):	1	500		322	SC	Note 12, Stage 1
Creekside, BCHA	Canada	1972	Nominal Current(A): 1450 1-phase MOV(MJ):	1	500		236	SC	Note 12, Stage 1
Kangasala, Imatra Power Co	Finland	1971	Nominal Current(A): 1200 1-phase MOV(MJ):	1	400		216	SC	Note 12, Stage 3
Ringarum, SSPB	Sweden	1969	Nominal Current(A): 1-phase MOV(MJ):	1	45		6	SC	Note 1
Tandö, SSPB	Sweden	1969	Nominal Current(A): 1600 1-phase MOV(MJ):	1	400		600	SC	Note 1
Kättbo, SSPB	Sweden	1968	Nominal Current(A): 1-phase MOV(MJ):					SC	Note 1
GarniebySSPB	Sweden	1967	Nominal Current(A): 1-phase MOV(MJ):	1	45		7.2	SC	Note 1
Kangasala, Imatra Power Co	Finland	1966	Nominal Current(A): 1000 1-phase MOV(MJ):	1	400		180	SC	Note 12, Stage 2
Vitersjö, SSPB	Sweden	1966	Nominal Current(A): 1600 1-phase MOV(MJ):	1	400		525	SC	Note 1
Kandasala, Imatra Power Co	Finland	1964	Nominal Current(A): 800 1-phase MOV(MJ):	1	400		115.2	SC	Note 12, Stage 1
				109			22 206		

Name of power station, Customer	Country	Year of Installation	Description	Nr of Banks/E quip.	Rated voltage (kV)	Freq. (Hz)	SVC Rated power (Mvar)/ SC 3-phase Power Output (Mvar)	Type	Notes
			Notes:						
			1 The Swedish State Power Board has designed and assembled the series capacitor banks. The components required have been purchased from						
			2 Nokian Capacitors has supplied a non-linear protection and control scheme for an existing installation. This job was carried out as a R & D work						
			3 Nokian Capacitors has supplied the protection and control scheme for capacitor bank delivered by others.						
			4 Nokian Capacitors has supplied the main protection equipment.						
			5 Nokian Capacitors has delivered to Furnas the capacitor units, racks, internal wiring, support insulators and buswork as ASEA's subcontractor.						
			6 Consortium delivery by Nokian Capacitors and Siemens.						
			7 One of the banks has MOV-scheme. The other bank has Advanced Series Capacitor (ASC) scheme with thyristor valve control of the bank						
			8 Delivery with Schneider Electric Alta Tensao (VA TECH) Ltd. Brasil.						
			9 Special strict seismic requirements. Layout design and seismic studies made by Nokian Capacitors. The bank has spring dampers and shock						
			10 PCB-replacement						
			11 Complete turn-key project including studies, design, civil works, equipment delivery, installation and commissioning.						
			12 Turn-key project including studies, design, equipment delivery and commissioning.						
Stage 1: Original Installation									
Stage 2-4: Additions to the banks as power increases, etc.									
Explanations:									
	SSPB	Swedish State Power Board, Sweden							
	BCHPA	British Columbia Hydro and Power Authority, Canada							
	BPA	Bonneville Power Administration, U.S.A.							
	NVE	NVE - State Power System, Norway							
	CFE	Federal Commission of Electricity, Mexico							
	BCRAIL	British Columbia Railway, Canada							
	BHEL	Bharat Heavy Electricals Limited, India							
	WAPA	Western Area Power Administration, U.S.A.							
	HQ	Hydro Quebec, Canada							
	ISA	Interconexion Electrica SA, Colombia							
	IVS	Fingrid, Finland							
	Furnas	Furnas Centrais Eletricas, Brasil							
	Eletronorte	Centrais Eletricas do Norte do Brazil, Brazil							
	NCPGC	North China Power Group Corp., China							
	NCGC	North China Grid Company (former NCPGC)							

A-4 Series Capacitor Installations - Siemens

SIEMENS

Power Transmission and Distribution

Reactive Power Compensation Projects
Reference List

Abbreviations:

ASC	A dvanced S eries C ompensation	RPC	R eactive P ower C ontrol
DS	D ynamic S tability	SSR	S ub s ynchronous R esonance
DTF	D ouble t uned F ilter	SSRD	S ub s ynchronous R esonance D amper
EDS	E xternal D evice S witching	STF	S ingle T uned F ilter
FC	F ixed C apacitor	SVC	S tatic V ar C ompensator
Fin	F ilter tuned to n th harmonic	SVG	S tatic V ar G enerator
FSC	F ixed S eries C ompensation	TCR	T hystor C ontrolled R eactor
GPFC	G rid P ower F low C ontroller	TCSC	T hystor C ontrolled S eries C ompensation
IPTC	I ncrease P ower T ransfer C apability	TPSC	T hystor P rotected S eries C ompensation
ISS	I mprove S ystem S tability	TSC	T hystor S witched C apacitor
MSC	M echanically S witched C apacitor	TSR	T hystor S witched R eactor
PSDC	P ower S ystem D amping C ontrol	VC	V oltage C ontrol
RC	R efurbishment C ontract		

Year	Customer	Type / Station /Scope	Voltage	Configuration	Use / Remarks
2006	ELETRONORTE Centrais Elétricas do Norte do Brasil S.A. Brazil	FSC 3 x FSC Barra do Peixe	230 kV	Rating: FSC 120 MVar FSC 37 MVar FSC 35 MVar	Turnkey Project
2005	FURNAS Centrais Elétricas S.A. Brazil	FSC Rio Verde	230 kV	Rating 216 MVar	Turnkey Project
2005	State Grid Corporation Beijing - China	2 x FSC Fengjie FSC Station Wanxian	500 kV	Rating 2 x 610Mvar	35MJ MOV per Phase
2005	Power Grid Corporation of India Limited	2 x FSC Lucknow	400kV	Rating: 2 x FSC 436MVar	Turnkey Project
2005	Sichuan Electric Power Corporation Chengdu - China	PUTI Grid Station Ertan – Puti Line 1	500 kV	Rating 315Mvar	59MJ MOV per Phase
2005	Sichuan Electric Power Corporation Chengdu - China	PUTI Grid Station Ertan – Puti Line 2	500 kV	Rating 315Mvar	59MJ MOV per Phase
2005	Sichuan Electric Power Corporation Chengdu - China	PUTI Grid Station Ertan – Puti Line 3	500 kV	Rating 315Mvar	59MJ MOV per Phase

Year	Customer	Type / Station /Scope	Voltage	Configuration	Use / Remarks
2004	Southern California Edison Los Angeles USA	1 x TPSC, 1 x FSC Eldorado - Lugo Turnkey	500 kV	Rating 397.5Mvar	DS, IPTC
2004	Southern California Edison Los Angeles USA	1 x TPSC, 2 x FSC Eldorado - Moenkopi Turnkey	500 kV	Rating 486.3Mvar	DS, IPTC
2004	Power Grid Corporation of India Limited	2 x FSC 400kV S/S Purnea	400kV	Rating: FSC 740MVar	Turnkey Project
2004	Power Grid Corporation of India Limited	2 x TCSC 400kV S/S Purnea	400kV	Rating: TCSC 112MVar	Turnkey Project
2004	Power Grid Corporation of India Limited	2 x FSC 400kV S/S Gorakhpur	400kV	Rating: FSC 716MVar	Turnkey Project
2004	Power Grid Corporation of India Limited	2 x TCSC 400kV S/S Gorakhpur	400kV	Rating: TCSC 107MVar	Turnkey Project
2004	Entergy Services, Louisiana, USA	1 x FSC Dayton	230kV	Rating: 258MVar	Gapless scheme
2004	Electricity of Vietnam	1 FSC	500kV	Rating: 1 x 101 MVar	
2004	Electricity of Vietnam	1 FSC	500kV	Rating: 1 x 202 MVar	
2004	Southern California Edison Los Angeles USA	1 TPSC Midway #2 Turnkey	500 kV	Rating 401 Mvar	DS, IPTC
2003	Southern California Edison Los Angeles USA	2 TPSC Midway #1 and #3 Turnkey	500 kV	Rating 401 Mvar	DS, IPTC
2003	CHESF - Brazil	2 FSC 500kV S/S S/S São João do Piauí	500kV	Rating: 485MVar 483MVar	Turnkey Project
2003	Power Grid of India	2 FSC 400kV S/S Gooty 2 FSC 200kV S/S Chuddapah	400kV	Rating: 181MVar 201MVar	Turnkey Project

Year	Customer	Type / Station /Scope	Voltage	Configuration	Use / Remarks
2003	ENTE – Empresa Norte de Transmissão de Energia (Shahin / Alusa), Brazil	1 FSC 500kV S/S Marabá 1 FSC 500kV S/S Açailândia	500kV	Rating: 279MVar 314MVar	
2002	State Power South Company – Guangzhou / China	2 FSC 500kV S/S Hechi	500kV	Rating: 762MVar	
2002	State Power South Company – Guangzhou / China	2 TCSC 500kV S/S Pinguo 2 FSC	500kV	Rating: TCSC 55MVar FSC 350MVar	TCSC and FSC located on same platform
2002	Dominion Virginia Power	1 FSC Lexington 1 FSC Valley	500kV	Rating: 355MVar 505MVar	MOV protection only
2002	CFE – Comisión Federal de Electricidad / Mexico	2 FSC S/S Tecali 3 FSC S/S Juile	400kV	Rating: 5 x 150MVar	DS
2002	Motraco Mozambique	1 FSC Maputo, Mozambique Turnkey	400kV	Rating: 344MVar	DS, IPTC
2002	Motraco Mozambique	1 FSC Barberton, RSA Turnkey	400kV	Rating: 535MVar	DS, IPTC
2001	Fumas Centrais Elétricas S.A. Brazil	1 FSC Samambaia Turnkey	500kV	Rating: 252MVar	DS, IPTC
2001	Fumas Centrais Elétricas S.A. Brazil	1 FSC Ibiuna Substation Turnkey	500 kV	Rating 765 MVar	DS, IPTC
2000	Southern California Edison Los Angeles USA	2 TPSC Vincent #1 and #2 Turnkey	500 kV	Rating 401 Mvar	DS, IPTC
2000	Entergy USA	1 FSC Jacinto substation Turnkey	230 kV	Rating 223 MVar	DS, IPTC

Year	Customer	Type / Station /Scope	Voltage	Configuration		Use / Remarks
2001	Furnas Centrais Elétricas S.A. Brazil	1 FSC Ibiuna Substation Turnkey	500 kV	Rating	765 MVar	DS, IPTC
2000	Southern California Edison Los Angeles USA	2 TPSC Vincent #1 and #2 Turnkey	500 kV	Rating	401 Mvar	DS, IPTC
2000	Entergy USA	1 FSC Jacinto substation Turnkey	230 kV	Rating	223 MVar	DS, IPTC
1999	China National Construction & Energy Import/Export Co. China	2 FSC Yangcheng Substation	500 kV	Rating Each:	500 MVar	DS, IPTC
1999	Southern California Edison Los Angeles USA	TPSC Vincent #3 Turnkey	500 kV	Rating	401 Mvar	DS, IPTC

1997	Abengoa/Gener Atacama Chile	FSC Atacama Substation HVAC Salta – Zaldivar	345kV	Rating 490 MVar	DS FSC system at 2840m altitude without gap
1997	ELETRONORTE Centrais Elétricas do Norte do Brasil S.A. Brazil	FSC SE Presidente Dutra	550 kV	Rating 390 Mvar Arrester Energy 37 MJ Triggered spark gap 40 kA	DS
1997	ELETRONORTE Centrais Elétricas do Norte do Brasil S.A. Brazil	FSC SE Imperatriz	550 kV	Rating 390 Mvar Arrester Energy 37 MJ Triggered spark gap 40 kA	DS
1997	FURNAS Centrais Elétricas S.A. Brazil	TCSC SE Serra da Mesa	550 kV	Rating continuously 30 min 107 Mvar 241 Mvar Arrester Energy 21 MJ Triggered spark gap 40 kA	DS; POD

Year	Customer	Type / Station /Scope	Voltage	Configuration	Use / Remarks
1990	Hydro Québec (HQ) Montréal, PQ Canada	3 FSC Poste Montagnais Supply & Commissioning	765 kV	Rating each station 476 Mvar Arrester Energy 44 MJ Triggered spark gap 40 kA	DS Siemens' first series compensation
1990	Western Area Power Administration (WAPA) Golden, Co USA	ASC Kayenta Substation Turnkey Project	230 kV	Rating 2 x 165 Mva FSC 165 Mvar ASC 120 Mvar 45 Mvar	PFC, SSR
1981	Southern California Edison (SCE) Los Angeles USA	SSRD Lugo Substation	500 kV	Thyristor controlled capacitor segment	SSRD, IPTC

Appendix B

Draft Planning Specification

Planning Specification
Ontario Power Authority (OPA)
Series Capacitor Application (SCAP)
Southwestern Ontario (SWO)

Draft – May 31, 2007

TABLE OF CONTENTS

SECTION

1. OVERVIEW.....	- 92 -
1.1 SCOPE	- 92 -
1.2 PURPOSE	- 92 -
1.3 APPLICATION	- 92 -
2. SCOPE OF SUPPLY.....	- 92 -
2.1 UTILITY FURNISHED	- 92 -
2.2 CONTRACTOR FURNISHED	- 93 -
2.3 SCHEDULE.....	- 93 -
2.4 PROJECT MANAGEMENT	- 94 -
3. REFERENCES	- 94 -
3.1 INDUSTRY PUBLICATIONS	- 94 -
3.2 UTILITY PUBLICATIONS	- 95 -
4. ABBREVIATIONS AND DEFINITIONS.....	- 95 -
4.1 ABBREVIATIONS	- 95 -
4.2 DEFINITIONS	- 96 -
5. SITE CONDITIONS	- 96 -
5.1 LOCAL.....	- 96 -
5.2 AMBIENT	- 97 -
6. TECHNICAL REQUIREMENTS	- 97 -
6.1 SYSTEM PARAMETERS	- 97 -
6.2 PROTECTIVE LEVEL AND VARISTOR RATING	- 99 -
6.3 INSULATION COORDINATION	- 101 -
6.4 AUDIBLE AND ELECTRICAL NOISE	- 101 -
6.5 COMPUTER MODEL	- 102 -
6.6 STUDIES	- 102 -
6.7 FUTURE SYSTEM	- 103 -
6.8 SSR.....	- 103 -
6.9 PERFORMANCE	- 103 -
7. MAIN COMPONENT AND FACILITY REQUIREMENTS	- 107 -
7.1 CODES, STANDARDS AND TERMINOLOGY	- 107 -
7.2 CAPACITOR UNITS	- 107 -
7.3 PROTECTIVE SYSTEM	- 109 -
7.4 DISCHARGE CURRENT LIMITING AND DAMPING EQUIPMENT.....	- 114 -
7.5 PLATFORM	- 115 -
7.6 INSTRUMENT TRANSFORMERS	- 116 -
7.7 CONTROL AND PROTECTION	- 116 -
7.8 INSULATORS, BUSHINGS AND ELECTRICAL CLEARANCES	- 117 -
7.9 BUS WORK AND ELECTRICAL	- 118 -
7.10 CIVIL WORKS.....	- 119 -
7.11 GROUND LEVEL EQUIPMENT AND FSC BANK BUILDING	- 120 -
7.12 GROUNDING	- 121 -
7.13 SAFETY	- 121 -
7.14 MISCELLANEOUS	- 121 -

8. CONTROL AND PROTECTION REQUIREMENTS	- 121 -
8.1 LOCAL, REMOTE OR AUTOMATIC, SCADA/RTU	- 121 -
8.2 EXTERNAL BYPASS, ISOLATING AND GROUNDING SWITCHES.....	- 121 -
8.3 RECLOSE/LOCKOUT	- 122 -
8.4 EXTERNAL FAULT BYPASS GAP/BREAKER OPERATION	- 122 -
8.5 AUTOMATIC BYPASS AND INSERTION	- 122 -
8.6 INTERLOCKS.....	- 122 -
8.7 BANK CONTROL HARDWARE AND GRAPHICAL USER INTERFACE (GUI)	- 122 -
8.8 PROTECTION REDUNDANCY	- 122 -
8.9 PROTECTION FUNCTIONS	- 122 -
8.10 PLATFORM PROTECTION EQUIPMENT.....	- 123 -
8.11 PROTECTIVE RELAY COORDINATION	- 123 -
8.12 SPECIALIZED PROGRAMMING TOOLS FOR THE CONTROL AND PROTECTION	- 124 -
9. OPERATIONAL AND COMMUNICATIONS REQUIREMENTS.....	- 124 -
9.1 FIBER OPTIC SIGNAL TRANSMISSION	- 124 -
9.2 PLATFORM CURRENT TRANSFORMERS.....	- 124 -
9.3 ANNUNCIATOR POINTS	- 124 -
9.4 DATA RECORDINGS AND SER.....	- 124 -
9.5 COMMUNICATIONS (SCADA/RTU).....	- 124 -
10. TESTING, COMMISSIONING AND INSPECTION.....	- 125 -
10.1 GENERAL	- 125 -
10.2 FACTORY TESTING (INCLUDING RTDS).....	- 126 -
10.3 PRECOMMISSIONING TESTS.....	- 127 -
10.4 SUBSYSTEM TESTS	- 128 -
10.5 SYSTEM TESTS	- 128 -
10.6 TESTING AND COMMISSIONING RESPONSIBILITIES	- 130 -
10.7 TEST EQUIPMENT ON SITE.....	- 130 -
11. TECHNICAL DOCUMENTATION	- 130 -
12. SPARE PARTS, SPECIAL TOOLS AND STORAGE SPACE	- 131 -
12.1 SPARE PARTS	- 131 -
12.2 SPECIAL TOOLS.....	- 131 -
12.3 STORAGE SPACE	- 131 -
13. TRAINING.....	- 131 -
13.1 GENERAL	- 131 -
13.2 OPERATOR TRAINING	- 132 -
13.3 MAINTENANCE TRAINING.....	- 132 -
13.4 TRAINING DURING COMMISSIONING.....	- 132 -
14. PROPOSAL REQUIREMENTS	- 133 -
14.1 GENERAL	- 133 -
14.2 BASIS OF CONTRACT AWARD	- 133 -
14.3 TECHNICAL APPROACH.....	- 133 -
14.4 CORPORATE EXPERIENCE AND PAST PERFORMANCE.....	- 135 -
14.5 PROJECT MANAGEMENT AND SCHEDULE.....	- 135 -
14.6 EXCEPTIONS, OPTIONS AND ALTERNATIVES	- 136 -
14.7 ELECTRICAL LOSS EVALUATION.....	- 136 -
14.8 MILESTONES AND PROGRESS PAYMENTS.....	- 136 -
14.9 POSSIBLE TERMS AND CONDITIONS	- 137 -
15. ATTACHMENTS.....	- 137 -
15.1 DRAWINGS.....	- 137 -
15.2 SYSTEM DATA	- 137 -
15.3 ANNUNCIATOR POINTS	- 137 -

15.4 MONITOR POINTS.....	- 137 -

FIGURES

Figure 6.1.1 – AC system frequency variations	- 99 -
Figure 6.1.2 – Current-time profile of FSC bank following external line fault clearing	- 99 -
Figure 15.1.1 – Bruce A One Line Diagram.....	- 138 -
Figure 15.1.2 – Bruce B One Line Diagram.....	- 138 -
Figure 15.1.3 – Longwood One Line Diagram	- 138 -

TABLES

TABLE 5.2 – AMBIENT	- 97 -
TABLE 6.1.2 – RATINGS	- 98 -
TABLE 6.1.3 – FAULT CURRENTS	- 98 -
TABLE 6.2.1 – VARISTOR ENERGY	- 100 -
TABLE 6.6 - DESIGN STUDY SUMMARY	- 102 -
TABLE 6.9.2 – FSC BANK LOSSES	- 106 -
TABLE 7.8 – FSC BANK CLEARANCES	- 118 -
TABLE 7.10 – CIVIL WORKS	- 119 -
TABLE 14.8 – MILESTONES AND PROGRESS PAYMENTS	- 136 -

1. Overview

1.1 Scope

The scope of this document covers the technical aspects for three (3) fixed series capacitor (FSC) bank installations using overvoltage protection based on metal oxide varistors with or without a protective gap. The scope does not include the use of power electronic devices for the insertion, bypassing, protection or control of the capacitor bank.

Commercial aspects related to the specific project associated with these applications are outside the scope of this document.

1.2 Purpose

The purpose of this document is to provide a high level planning purpose specification with technical sections that may be used as a basis for a future detailed specification and request for proposals (RFP).

1.3 Application

This document applies to three series capacitor (SCAP) bank applications in Southwestern Ontario (SWO) where the reactance inserted into the transmission network is determined solely by the 60 Hz reactance of the capacitor bank.

The applications require a high level of availability, dependability and security of operations. Specific issues addressed in this document include sub-synchronous resonance (SSR) mitigation, protective relaying and control systems.

2. Scope of Supply

It should be noted that the Utility and Contractor furnished items listed in this Section are subject to changes once the project scope is fully defined and specific sites selected.

2.1 Utility Furnished

Facilities, materials and services to be provided by Utility may include the following:

1. Finished grade and leveled substation sites for the FSC banks.
2. Space in Utility Substation control buildings for Contractor furnished control and protection equipment unless Contractor provides a separate building for the FSC bank control and protection equipment.
3. Termination of Contractor furnished FSC bank control, power and fiber optic cables within the Substation control buildings with supervisory assistance from the Contractor.
4. Audible and electrical noise measurements before and after commissioning of the FSC banks.

5. The external bypass disconnect switches, the external isolating disconnect switches and the external grounding switches, as shown in Figure 1 of IEEE Std 824-2004 (referenced as items 10, 11 and 12).
6. Supply of ground level 120/240-volt ac, single-phase, three-wire, 60 Hz and 125-volt dc auxiliary power for the FSC banks.
7. Four-hole NEMA pads to connect the Contractor furnished FSC bank 500 kV conductors and connecting pads to the transmission system.
8. Overhead lightning protection.
9. Unsecured outdoor storage area for Contractor furnished equipment and material during site construction, erection and commissioning.

2.2 Contractor Furnished

Facilities, materials and services to be provided by the Contractor may include the following:

1. Design, site construction, equipment delivery, erection, testing, commissioning, training and documentation for the FSC banks.
2. Maintenance access provisions for the FSC banks.
3. Design, material, installation and testing of three (3) FSC bank grounding systems, all interlocks and protective fencing.
4. Conductors and connecting pads from the FSC banks to the Substation 500 kV four-hole NEMA pads for connection by Utility.
5. FSC buildings (if provided) for housing the three (3) FSC bank ground level control, protection, instrumentation, power distribution and panels that interface with the FSC banks and Substation control buildings as well as facilities for spare parts.
6. Design, material, installation and testing of the three (3) FSC bank platform power, lighting and access provisions for maintenance.
7. Design, material, installation and testing of the three (3) FSC bank outdoor power and dark sky lighting provisions for maintenance.
8. Design, material, installation and testing of the three (3) FSC bank cables, inner duct for fiber optic cables and interface panel terminations between the FSC banks and Substation control buildings. All cables and inner duct for fiber optic cables shall include an extra 200 feet from the Substation control building cable entrances to the final termination point within the Substation control buildings.
9. FSC spare parts.
10. Spare capacitor units stored on FSC bank platforms.
11. Spare varistor units installed and operational on FSC bank platforms.
12. On-site office (if needed) and security thereof.
13. On-site sanitation facilities and maintenance thereof.
14. Equipment transportation, site receiving/inspection, site storage, site security and inventory control.
15. Quality control.

2.3 Schedule

2.3.1 Completion Period

The Contractor shall begin work within 10 calendar days after the date of notice of award and shall complete all of the work leading to acceptance (see Section 10.5.2) by Utility within 18 months.

2.3.2 Project Schedule

Within 30 calendar days after the date of notice of award, the Contractor shall submit to Utility for approval a complete project schedule. The Contractor shall update the project schedule monthly and shall enter actual progress at the end of each month.

The project schedule shall include the following information:

1. Sequence of operations.
2. Dates for commencing and completing work on several controlling features of the project.
3. Dates of issuance or orders for procurement of Contractor furnished materials and equipment and their factory testing, delivery, installation and commissioning dates.
4. Design review meetings.
5. Dates on which each item of Utility furnished facilities, materials and services will be required.

2.4 Project Management

The Contractor shall assign qualified individual(s) to be responsible for managing the FSC bank project subject to review and approval of resumes and qualifications by Utility. The Contractor's project manager(s) shall be responsible for the technical aspects of the FSC bank project including design, construction, erection, subcontractors, testing, training, commissioning and documentation. After approval of the Contractors project schedule and project manager(s), any changes to the Contractor's project manager(s) shall be approved by Utility.

3. References

3.1 Industry Publications

AISC, *Manual of Steel Construction*

ANSI/IEEE C2, *National Electrical Safety Code*

ANSI C57.13, *IEEE Standard Requirements for Instrument Transformers*

ANSI C57.16, *IEEE Standard Requirements, Terminology and Test Code for Dry-Type Reactors*

ANSI/IEEE C62.11, *IEEE Standard for Metal-oxide Surge Arresters for AC Power Circuits*

IEC 60871-2, *Shunt Capacitors for ac Power Systems Having a Rated Voltage Above 1000 V*

IEEE Std C62.11, *IEEE Standard for Metal-Oxide Surge Arresters for AC Power Circuits*
IEEE Std 80, *IEEE Guide for Safety in AC Substation Grounding*
IEEE Std 824, *IEEE Standard for Series Capacitor Banks in Power Systems*
IEEE Std 100, *Authoritative Dictionary of IEEE Standards Terms*
IEEE Std 519, *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*
IEEE Std 693, *IEEE Recommended Practice for Seismic Design of Substations*
OSHA 1926.957, *Construction in Energized Substations*
NEMA SG-4, *Alternating-Current High Voltage Circuit Breakers*
NFPA 70, *National Electric Code*

3.2 Utility Publications

This Section is reserved to list any Utility design guidelines and standards that are to be included with the specification.

4. Abbreviations and Definitions

4.1 Abbreviations

The following abbreviations apply to these specifications:

ac	alternating current
AISC	American Institute of Steel Construction
ANSI	American National Standards Institute
BIL	basic insulation level
CD	compact disc
C-O-C	close-open-close
CT	current transformer
°C	degree centigrade
dc	direct current
DXF	document exchange format
FCC	Federal Communication Commission
FTP	file transfer protocol
FSC	fixed series capacitor
GHz	gigahertz
GUI	graphical user interface
Hr	hour
HVAC	heating, ventilation and air conditioning
Hz	hertz
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
kHz	kilohertz
kV	kilovolts
kW	kilowatts
L-L-G	line-to-line-to-ground
L-G	line-to-ground
MJ	megajoules

M ²	square metres
MVAR	megavars
μV/M	microvolts/meter
NEMA	National Electrical Manufacturers Association
NFPA	National Fire Protection Agency
OPA	Ontario Power Authority
OSHA	Occupational Safety and Health Administration
PCB	polychlorinated biphenyls
PLC	programmable logic controller
ppm	parts per million
PU	per unit
RFP	request for proposal
RMS	root-mean-square
RTDS	real time digital simulator
RTU	remote terminal unit
SCADA	supervisory control and data acquisition
SCAP	series capacitor
SER	sequence of events recorder
SSR	sub-synchronous resonance
Std	standard
SWO	Southwestern Ontario
VDC	volts dc

4.2 Definitions

The following definitions apply to these specifications:

1. “stated” means the value stated in the Contractor’s proposal.
2. “supplier” used synonymously and interchangeable with Contractor.
3. “option” refers to additional functionality or capability **that is** identified in the specification and offered by the Bidder along with a corresponding price.
4. “alternative” refers to additional functionality or capability **not** identified in the specification and offered by the Bidder along with a corresponding price.
5. “exception” refers to **non-compliance** with specified requirements and not included in Bidder’s corresponding pricing.

5. Site Conditions

5.1 Local

There can be several local site conditions that may be specific to a utility’s standard terms, conditions and design practices that have not been included in this document but could be added prior to any procurement activities when preparing a RFP. These conditions may include, (1) specific right-of-way issues, (2) access to the work site, (3) haul routes, (4) land use for project purpose, (5) existing facilities, (6) protection of existing installations, (7) power and water for project construction, (8) environmental protection and (9) geologic investigations.

5.2 Ambient

The following ambient temperatures should be included in the specification once final site locations have been determined.

Table 5.2 – Ambient

Rating	Bruce A	Bruce B	Longwood
Maximum temperature ($^{\circ}\text{C}$)			
Minimum temperature ($^{\circ}\text{C}$)			
Daily average temperature ($^{\circ}\text{C}$)			
Maximum relative humidity (percent)	100	100	100
Maximum wind velocity (miles/hour)			
Maximum ice loading (inches)			
Average annual precipitation (inches)			
Maximum frost depth (inches)			
Maximum ground snow depth (inches)			
Site elevation above sea level (feet)			
Site isokeraunic level (days/year)			
Solar radiation ($\text{kW}\cdot\text{hr}/\text{m}^2/\text{day}$)			
Seismic (zone)			

6. Technical Requirements

6.1 System Parameters

- Voltage/Frequency
 - Rated System Voltage----- 500 kV
 - System Continuous Operating Voltage----- ____ kV to ____ kV
 - System Basic Insulation Level (BIL)----- ____ kV
 - Rated Frequency----- 60 Hz
 - System Continuous Frequency Range ----- ± 0.05 Hz
 - System Frequency Variations----- see Figure 1

2. Ratings

Table 6.1.2 – Ratings

Rating	Bruce A	Bruce B	Longwood	Note
Rated continuous current (Amperes RMS)	2815	2815	2815	1
Emergency loading current (Amperes RMS)	3660	3660	3660	1
System swing current (Amperes RMS)	4100	4100	4100	1
Rated reactance (Ohms/Phase)	17.8	17.8	15.1	
Reactance tolerance	+3%	+3%	+3%	
Reactance balance between phases	1%	1%	1%	
Rated continuous voltage (kV)	50.1	50.1	42.5	1
Emergency loading voltage (kV)	65.1	65.1	55.3	1
Swing voltage (kV)	73	73	62	1
Reactive 3-phase power rating (MVAR)	419	419	359	
Transmission line length (km)	187	187	159	
Line compensation (Percent)	30%	30%	30%	2
Number of segments				3
Line reclosing requirements				3
SSR requirements	Yes	Yes	Yes	
Method of Substation grounding				3

Note 1: Initially at 100% rated current followed by the system swing, emergency loading and continuous loading currents shown in Figure 2, where T1 = 10 Seconds, T2 = 30 Minutes and T3 = continuous.

Note 2: Line compensation percentage is approximate. The amount of compensation required is the Ohms per phase.

Note 3: These parameters to be completed by utility

3. Fault Currents

Table 6.1.3 – Fault Currents

	Bruce A	Bruce B	Longwood	Note
Bank Inserted				1
Generation side L-L-G fault/duration				
Generation side L-G fault/duration				
Line side L-L-G fault/duration				
Line side L-G fault/duration				
Bank Bypassed				2
L-L-G fault/duration				
L-G fault/duration				

Note 1: Fault currents are based on Utility studies with the FSC bank inserted and without a protective system. It is the Contractor's responsibility to determine the FSC bank fault currents and design

their equipment to withstand fault current conditions based on the system data specified.

Note 2: Fault currents are based on Utility studies with the FSC bank bypassed by the external bypass switch. It is the Contractor's responsibilities to determine the FSC bank fault currents and design their equipment to withstand fault current conditions based on the system data specified.

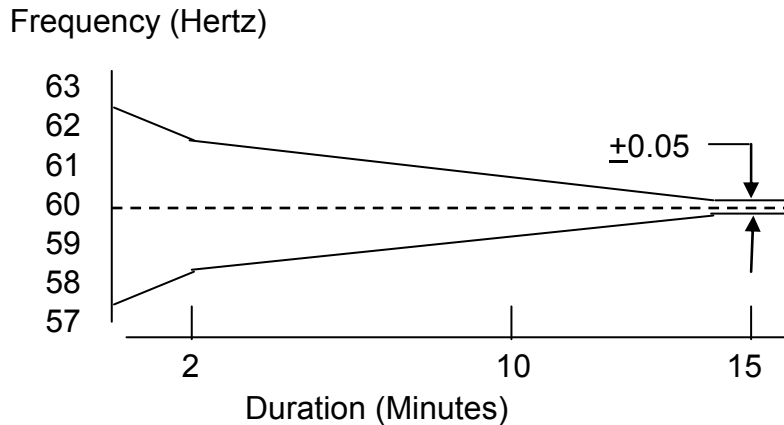


Figure 6.1.1 – AC system frequency variations

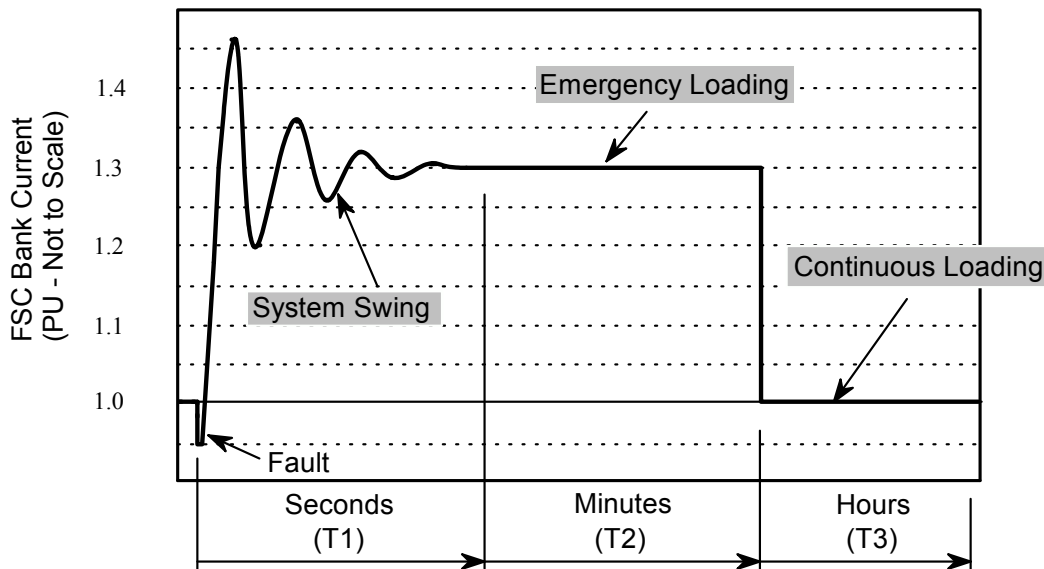


Figure 6.1.2 – Current-time profile of FSC bank following external line fault clearing

6.2 Protective Level and Varistor Rating

6.2.1 Protective Level

The protective level of the three (3) FSC bank varistors shall be determined by the Contractor and stated in their proposal.

6.2.2 Varistor Rating

The varistor energy ratings for the three (3) FSC banks will be the responsibility of the Contractor based on the protective level and protective bypass system chosen. The varistor energy requirement shall be stated in the Bidder's proposal. Section 15.2 provides system data to be used by Bidder's for initial studies to determine the varistor energy ratings.

Based on preliminary studies by Utility, the varistor energy duty per phase for faults external to FSC banks that were cleared in 4 cycles are approximately those values shown in Table 6.2.1.

Table 6.2.1 – Varistor Energy

	Bruce A	Bruce B	Longwood
Protective level (PU of rated voltage)	2.24	2.24	2.27
Varistor energy (MJ/phase)	26.7	26.7	44

6.2.3 Maximum Peak Varistor Current at Protective Level

Determining the maximum peak varistor current will be the responsibility of the Contractor based on the protective level chosen.

6.2.4 Varistor Rating Study

The Contractor shall conduct detailed studies modeling the actual varistor characteristics and protective system to verify the amount of varistor energy required for the design.

Within 60 calendar days after contract award, the Contractor shall provide results of the detailed varistor study that shall include as a minimum, the following:

1. Protective level of the varistor.
2. Voltage-current characteristic of the varistor.
3. Energy discharged into the varistor during the most severe faults.
4. Voltage and current waveforms for the capacitor and varistor during the faults.

6.2.5 Varistor Rating Results

Bidders shall clearly state in their proposal, a dollars per megajoule price that will apply to any variation in the amount of varistor energy supplied compared to that proposed as a result of the varistor rating

study. This will apply only if the change in varistor energy rating is the result of a change in the system data from that used in the proposal.

6.3 Insulation Coordination

The Contractor shall be responsible for insulation coordination of all FSC bank equipment to meet the requirements of this specification. It is the responsibility of the Contractor to coordinate the FSC bank insulation capabilities with that of Utility equipment, where such capabilities are not given in these specifications, or to have stated in their proposal, what minimum ratings and capabilities are required.

The Contractor shall provide a study that shows the insulation coordination of the FSC bank is adequate and capable of withstanding the steady state, dynamic and transient overvoltages to which the FSC bank may be subjected including coordination of varistor protective levels. Events to be used for the insulation coordination study shall include normal and abnormal occurrences not only in the FSC bank, but also in the surrounding ac network.

6.4 Audible and Electrical Noise

6.4.1 Audible Noise

The audible level produced by the FSC bank at the FSC Substation fence under any operating condition shall not exceed levels required by local authorities or authorities having jurisdiction. The ambient audible levels shall be established by Utility measurements at the substation fence before energizing and during operation of the FSC bank.

6.4.2 Electrical Noise

The FSC bank electrical noise levels under fair weather conditions shall not exceed the ambient level by more than ____ μ V/M over the range of ____ kHz to ____ GHz when measured by Utility at the FSC bank Substation fence (**Utility furnished limits based on local area sensitivity codes**). The ambient electrical noise level shall be that level prior to energizing the FSC bank and shall include all radiated noise from the FSC bank Substation transmission lines, structures, and other nearby substation equipment.

The Contractor shall take the necessary precautions in the form of noise suppression techniques, shielding and filtering devices to prevent harmful interference from the FSC bank to any of Utility's communications and control systems installed at the FSC bank Substation.

Additionally, the Contractor shall ensure that all Federal Communication Commission (FCC), State, municipal and military regulation and guidelines concerning interference limits are met.

6.5 Computer Model

The Contractor shall provide as part of the contract documentation a computer model of the three (3) FSC banks using the PSS/E Load Flow and Stability Program. The dynamic model will be used for system stability studies and shall include all protections and settings that will trip the FSC banks off line due to overvoltage, undervoltage and ac system disturbances for use in system stability studies. Any adjustable settings of the controls and protections shall be adjustable in the model. A description of the model, its use and block diagram of its controls and protections and configuration shall also be delivered. The model shall be used by the Contractor and a study report provided to demonstrate system swing currents and varistor energy levels for eight (8) mutually agreeable cases.

The Contractor shall provide a detailed emtp model including the implementation of the voltage protective devices, MOV rating, Bypass controls, and FSC protection circuitry of the three (3) FSC banks using XXXX (Insert name of Utility's preferred program) emtp program. This model will be suitable for fault current studies and transient voltage studies for 3 phase and single phase fault cases, including the development of transient protection waveforms to be utilized in the protection system testing.

6.6 Studies

Within 10 calendar days after contract award, the Contractor shall request from Utility a complete package of system data needed to complete the design of the three (3) FSC banks. Within 10 business days after receipt of the system data request, Utility will furnish the requested system data for use in detailed studies. The results of all Contractor studies shall be provided to Utility.

A summary of the design studies required include those shown in Table 6.6.

Table 6.6 - Design Study Summary

Item	Study	Section	Contractor	Utility
1	Varistor Rating	6.2.4	Submittal	Approval
2	Insulation Coordination	6.3 & 7.5	Submittal	Approval
3	Audible and Electrical Noise	6.4	Review	Measurements
4	Computer Model	6.5	Submittal	Approval
5	SSR	6.8	Submittal	Approval
6	Availability, Reliability, and Maintainability	6.9.1 & 6.9.1.2	Submittal	Approval
7	Electrical Losses	6.9.2	Submittal	Approval
8	Main Component Rating	7.	Submittal	Approval
9	Damping Reactor Harmonics	7.4	Submittal	Approval
10	Seismic and Wind Analysis	7.5	Submittal	Approval
11	Ac & dc Auxiliary Power	7.11	Submittal	Approval

12	Building Concept (if provided)	7.11	Submittal	Approval
13	Grounding	7.12	Submittal	Approval
14	Protective Relay Coordination	8.11	Submittal	Approval
15	Testing and Commissioning Plan	10.1	Submittal	Approval

6.7 Future System

(Any future system additions that should be brought to the attention of the Bidders should be included in the specification)

6.8 SSR

This Section will be completed later based on results of the SSR screening tests. Any suggestions welcome.

6.9 Performance

6.8.1 Availability, Reliability and Maintainability

The objectives in the design of the three (3) FSC banks shall be to achieve high levels of availability and reliability while minimizing maintenance. The Contractor shall conduct a thorough design review and provide a study report documenting the measures taken to minimize the risk of forced outages. The Contractor shall give careful attention to factors affecting the three (3) FSC bank's performance including, but not limited to, protective relay coordination, proper setting of relays, spare parts and redundancy of design. In general, wherever possible, the following principles shall be followed in the design of the design:

1. Use of least complex design capable of performing required functions.
2. Use of components with proven reliability.
3. Use of pre-aged components with a burn-in period or other equivalent means.
4. Use of fail-safe and self-checking designs.
5. Use of software that has been thoroughly tested and proven resilient.
6. Provision for alarm, fault indication, monitoring and test facilities.
7. Diagnostic features, easily-read drawings and manuals that will ease trouble shooting, repair and maintenance.
8. Use of modular construction to permit rapid replacement of failed equipment.

6.9.1.1 Definitions

The following definitions shall apply:

4. Forced outages are outages caused the by FSC bank

equipment that result in loss of part or all of the FSC bank essential functions.

5. Scheduled outages are outages necessary for preventive maintenance to assure continued and reliable operation of the FSC bank.
6. Outage duration is the elapse time (in hours) from the instant the FSC bank is out of service to the instant it is ready to be returned to service. If the FSC bank becomes available for service during non-working periods, such time will not be included in the outage duration if Utility elects not to return the FSC bank to service. The following will be included in outage duration:
 - d. Time required to determine the cause of an outage or to determine which equipment or units of equipment must be repaired or replaced.
 - e. Time required by system operators and technicians to disconnect and ground equipment in preparation for repair work and to remove grounds and reconnect equipment after repairs are completed. Delays caused by unavailability of qualified Utility personnel will be excluded from the outage duration.
 - f. If partial FSC bank ratings are available, the duration of equivalent outage shall be calculated as the product of the derated condition duration and the proportion of the nominal output MVAR range which cannot be achieved during this period.
5. The annual equivalent availability for forced outage shall be defined as follows:

$$\left[1 - \sum \frac{\text{Duration of equivalent outage}}{8760} \right] * 100\%$$

6.9.1.2 Availability and Reliability Calculations

Within 120 calendar days after award of contract, the Contractor shall submit to Utility for approval a detailed study report with calculations to demonstrate that the design will meet the stated availability, reliability and maintenance requirements. The calculations shall be based on the

availability of the FSC bank spare equipment stated by the Contractor in their proposal. Should the study report show that the stated availability, reliability and maintenance requirement will not be met, the Contractor shall modify the FSC bank design to meet the stated availability, reliability and maintenance requirements and resubmit the study report.

6.9.1.3 Availability, Reliability and Maintainability Performance Requirements

The Contractor shall provide technical and pricing options that warrant the following FSC bank availability, reliability and maintainability performance requirements for a period of 5 years commencing on the successful completion date of the acceptance requirements specified in Section 10.5.2.

1. Bidders shall provide three (3) options for Utility's evaluation that warrant the three (3) FSC bank annual equivalent availability for forced outages of at least (a) 98%; (b) 99%; and (c) 99.5%.
2. There shall be no more than 2 forced outage of each FSC bank per year.
3. The number and duration of scheduled maintenance outages of each FSC bank per year shall not exceed 1 outage for a maximum duration of 12 hours.

6.9.1.4 Performance Evaluation Period

Utility will monitor the availability, reliability and maintenance performance of each FSC bank during the 5 year warranty period. During the performance evaluation period, the Contractor shall repair and/or replace all failed equipment in a timely manner and without additional cost to Utility. The 5 year warrant shall cover full replacement costs for all FSC bank equipment, labor overheads, shipping, replacement, testing, installation and other costs incident to the failure. All equipment and materials utilized from spare parts stock during the warranty evaluation period shall be replaced by the Contractor without additional cost to Utility.

The Contractor shall stamp the warranty expiration date on the equipment nameplate or a separate warranty plate installed on the equipment.

6.9.2 Electrical Losses

The Contractor shall guarantee that the total value of electrical losses for each of the three (3) FSC banks will not exceed those stated in

their proposal when calculated in accordance with this section. Electrical losses shall be based on an ambient temperature of 25 °C, a nominal ac system voltage of 500 kV and the continuous line currents and operating conditions indicated in Table 6.9.2.

AC and dc auxiliary power requirements shall be based on nominal ac and dc supply voltages. Although the FSC banks may not operate continuously at these conditions, they will be used as a common base for evaluation.

AC and dc auxiliary power requirements for the FSC banks shall be based upon the total electrical power required for the FSC auxiliary supply and bus voltages, as applicable. Losses in switchgear, busbars, cables, clamps, connectors, etc., are excluded. Losses associated with harmonic currents shall also be omitted from loss calculations for evaluation purposes, although they shall be considered to determine ratings of equipment.

The guaranteed total value of electrical losses stated by the Bidders will be used for evaluation of bids. The Contractor shall provide a study report that documents the guaranteed total electrical losses compared to actual total electrical losses. If the guaranteed total value of electrical losses stated is exceeded, the Contractor shall pay Utility the amount that the actual total value of electrical losses exceeds the guaranteed amount based on the dollar values stated in this section. Such sums may be deducted from the total contract price.

Table 6.9.2 – FSC Bank Losses
(Percentages and durations to be provided by Utility)

Item	Parameter	Units	Bruce A		Bruce B		Longwood	
			Point 1 (__%)	Point 2 Bypass	Point 1 (__%)	Point 2 Bypass	Point 1 (__%)	Point 2 Bypass
FSC	1	Current	Amperes	Rated	Rated	Rated	Rated	Rated
	2	Duration	%					
	3	Loss Value	\$/kW					
	4	Max Losses	kW					
	5	Max Loss Value	\$ (b*c*d)					
AC Aux Pwr	6	Max Power	kW					
	7	Duration	%					
	8	Loss Value	\$/kW					
	9	Max Loss Value	\$ (a*b*c)					
DC Aux Pwr	10	Max Power	kW					
	11	Duration	%					
	12	Loss Value	\$/kW					
	13	Max Loss Value	\$ (a*b*c)					

Total Max Loss Value	\$ (5+9+13)						
Maximum Total Loss Value Guaranteed	\$ (Point 1) +(Point 2)						

7. Main Component and Facility Requirements

The three (3) FSC banks shall be 60 Hz outdoor equipment designed and tested in accordance with IEEE Std 824, including a protective system using varistors, triggered protective device (if furnished), a bypass switch (breaker), capacitor discharge damping reactor, instrument transformers, protective relaying, control and annunciation, platform to ground signal transmission system, ground level control and relay panels, and all necessary connections between various components within the FSC bank.

Varistors shall be connected in parallel with the FSC bank capacitors as required to limit the voltage across the capacitors during system swing, emergency loading and line fault conditions.

All insulation levels, ratings and performance requirements shall be met at the specified ambient conditions including installed elevation and ambient temperatures.

The voltage and kilovar rating of capacitor units and bank protective scheme shall be the responsibility of the Contractor within the limits and requirements as specified.

A design study report shall be furnished by the Contractor summarizing the FSC bank main component ratings and clearly indicating the power system characteristics and conditions used to determine the ratings.

7.1 Codes, Standards and Terminology

Except as required otherwise by this material specification, the three (3) FSC bank specified herein shall be furnished in complete accordance with the latest applicable industry codes; ANSI, OSHA, IEC, IEEE, and NEMA standards; and Utility standards and material specifications in effect on the date of invitation to bid.

All values of voltage and current in this material specification are ac RMS unless otherwise specified.

7.2 Capacitor Units

The FSC bank design shall utilize fuseless or internally fused capacitors units arranged in a series and parallel arrangement of interchangeable units to provide the required capacitive reactance at the continuous rating of the FSC bank. The FSC banks shall also be designed to withstand the system swing, emergency loading, continuous loading and power system faults with

the maximum capacitor unbalance condition for which the control and protection system will allow the banks to remain in service.

Each capacitor unit shall be provided with an internal discharge resistor which will reduce the residual voltage to 50 volts or less within 5 minutes after the capacitor is de-energized.

7.2.1 Dielectric

1. Dielectric Requirements: The dielectric shall consist of a synthetic film and a dielectric fluid that complies with OSHA Class III Flammability Requirements. A statement on the nameplate or a permanent tag attached next to the nameplate shall indicate (1) the full trade name of the dielectric fluid furnished, and (2) that the dielectric fluid is certified to be less than one ppm polychlorinated biphenyl (PCB).
2. Non-PCB Label: A blue and white non-PCB label shall be placed on each capacitor unit to certify that the dielectric fluid contains less than 1 ppm PCB. The label shall cover no less than 4 square inches. The label shall be clearly visible from the ground when the capacitor is mounted in a rack (either horizontally edge-mounted or upright mounted).

7.2.2 Case

The case material shall be grade 409 stainless steel. The case shall be coated with a primer and painted with a well-bonding, flexible paint.

7.2.3 Exterior Finish and Porcelain Color

The case exterior paint finish and the bushing porcelain shall be light gray.

7.2.4 Bushings

1. Number and Arrangement: The capacitor units shall be furnished with either one or two porcelain bushings.
2. Insulator and Bushing BIL & Creep Distance: The insulation levels of the capacitor unit bushings and insulators shall be the minimum as defined in IEEE Std 824 taking into account the installed elevation.

7.2.5 Lifting Provisions

The capacitor shall be furnished with lifting eyes or similar provisions for lifting the capacitor for installation in or removal from the rack.

7.2.6 Testing Requirements

The capacitor units shall be subjected to the design and production tests per IEEE 824 and an endurance test per IEC 60871-2. The design tests shall include:

1. Capacitance change vs. temperature test.
2. Thermal stability test.
3. Radio influence voltage test.
4. Short-circuit discharge test.
5. Voltage decay test.
6. Terminal-to-terminal dielectric test.
7. Terminal-to-case test.
8. Impulse withstand test.
9. Capacitor bushing test.
10. Design endurance test per IEC 60871-2, Sections 2.1.3 and 2.1.4 with the lowest limit of temperature at -50°C .

The production tests shall include:

11. Terminal-to-terminal dielectric test.
12. Terminal-to-case dielectric test.
13. Capacitance test.
14. Leakage test.
15. Discharge resistor test.
16. Loss determination test.

7.3 Protective System

7.3.1 General

The three (3) FSC bank shall be furnished with an automatic A&B redundant protective system to protect capacitor units from system overload, overcurrent, overvoltage, and other abnormal conditions. The protective system shall include varistor protection, a triggered protective device (if furnished), and a bypass circuit breaker. The automatic protective system will not be required to operate with single-pole tripping and reclosing. The A&B protection system is to utilize protection devices from different manufacturers.

7.3.2 Operating Requirements

By defining an internal line fault as one which occurs on the line section having the FSC bank, and an external fault as one which occurs outside of the line having the FSC bank, the following operating conditions are required:

1. Internal Line Faults:

The series capacitor banks and varistors may be bypassed for internal line faults. However, the energy duty of the varistors must be based on the energy accumulation during the time necessary for the capacitor bank protective system to bypass the capacitors and varistors.

Following line de-energization for an internal fault, the line will be re-energized with the FSC bank bypassed in the following sequence:

- Substation line breaker at one end closed after 0.9 seconds.
- Substation line breaker at other end closed (with synchro-check) 1.0 seconds after line is energized from other end.
- In the absence of a fault, the FSC bank will be reinserted 1.0 seconds later.

2. External Line Faults:

For external multi-phase faults, the FSC banks shall not be bypassed; however, the varistor may conduct and shall have an energy rating capable of absorbing the energy during external line faults that are cleared within 4 cycles. Bypassing will be allowed if an external fault exceeds 4 cycles and the energy duty of the varistor is exceeded, in which case, the lines will be de-energized and will be re-energized with the FSC bank bypassed in the following sequence:

- Substation line breaker at one end closed after 0.9 seconds.
- Substation line breaker at other end closed 1.0 seconds (with synchro-check) after line is energized.
- In the absence of a fault, the FSC bank will be reinserted 1.0 seconds later.

7.3.3 Varistor

The varistor shall be the primary capacitor overvoltage protection. The varistor shall be designed with a thermal capability (energy duty) to dissipate the heat generated by the worst time duration conditions of continuous, swing, emergency and fault currents for either internal or external fault sequences to which the varistor can be subjected.

The varistor shall be made up of series-parallel groups of metal-oxide varistor units. The varistor units shall be housed in porcelain enclosures sealed to eliminate the effects of weather (including icing) and contaminants on the varistors. No maintenance of the porcelain enclosures shall be required. Each porcelain enclosure shall be provided with a pressure relief device sufficient to relieve the internal pressure buildup due to a sustained 60-Hz power current discharge without causing violent rupture of the enclosure. The enclosure shall meet the requirements of ANSI/IEEE C62.11-1987.

The varistor shall be capable of handling the specified fault duties for external faults at the specified elevation and maximum ambient temperature with no operations of the triggered protective device (if provided) or bypass breaker.

A varistor over temperature protection scheme shall monitor ambient temperature and the current through the varistor units.

The Contractor shall provide installed spare varistor columns (with matched characteristics) on each phase with a minimum 10% of the total varistor energy rating per phase and consisting of at least one complete varistor porcelain housing per phase. This is in addition to an area on each platform that shall be provided for a minimum of 10% (minimum of one complete varistor housing) additional future varistors.

The varistor shall be subjected to the design and production tests per IEEE 824. The design tests shall include:

1. Accelerated aging procedure.
2. Discharge voltage test.
3. Energy absorption and thermal recovery tests.
4. Pressure relief tests.

The production tests shall include:

5. Energy absorption.
6. Current sharing.
7. Protective level.
8. Verification of low-current characteristics.
9. Ionization voltage test.
10. Seal integrity test.

7.3.4 Protective Device and Circuit Breaker

To protect the FSC bank varistor from exceeding its thermal capability, a triggered protective device (if furnished) and protective bypass circuit breaker shall operate to bypass the capacitors.

7.3.4.1 Triggered Protective Device (If Furnished):

The FSC bank may have a triggered protective device for bypassing of the varistor and capacitors. This device shall be triggered by relays that monitor the energy into the varistor and trigger the protective device if the varistor energy duty ratings are exceeded. In addition, the protective device shall be capable of being externally triggered by protective line relays. The current/energy monitoring relays, circuitry, and associated current transformers for the varistor protection shall be redundant and operated in parallel to enhance reliable firing of the triggered device.

The triggered device shall be capable of withstanding the specified fault currents without damage. The triggered device shall withstand the protective voltage levels without breakdown/arcing.

The triggered device and its associated control shall provide instantaneous protection of the varistor from exceeding its thermal energy limit, but should not limit the duty of the varistor by premature triggered operation during specified external faults.

The triggered device shall be capable of bypassing at least 100 times without affecting its capability or requiring maintenance. The device enclosure shall be designed to allow easy access for inspection and maintenance.

The triggered device shall be capable of completely shunting the FSC bank charged to the specified protective level.

The protective voltage level of the triggered device circuit shall be independent of atmospheric conditions.

A counter visible from ground level shall be provided to record the number of operations of each triggered device.

The triggered device shall not operate for any faults external to the line except for conditions where the thermal capability of the varistor is exceeded.

If two or more series connected protective devices per phase are employed, a protective firing of one device shall

cause all other series connected devices of the same phase to trigger within 50 microseconds.

The triggered protective device shall be subjected to the design and production tests per IEEE 824. The design tests shall include:

1. Discharge current test.
2. Fault current test.
3. Recovery voltage test.
4. Overall bypass gap controlled triggering test.

The production tests shall include:

5. Verification components are of the proper ratings.
6. Adjustment and testing of the trigger circuit.

7.3.4.2 Protective Bypass Circuit Breaker

The protective equipment shall include an automatic ground-mounted bypass circuit breaker connected in parallel with the FSC bank capacitors that can be closed to short out the triggered protective device (if furnished) and varistor.

The circuit breaker shall be designed, tested and capable of performing in accordance with ANSI C37 symmetrical rating requirements. The breaker shall be in accordance with ANSI C37 and NEMA SG4, unless otherwise specified herein.

The circuit breaker shall be suitable for remote electrical closing and tripping. The circuit breaker shall be furnished with a supporting structure, complete with gas, controls, piping, conduit, wiring, pole-to-pole cables, and other accessories needed for three-pole operation. The breaker shall be SF6 gas-filled, single-pressure puffer type.

The breaker shall have an operating sequence (from an open position) of C-O-C without recharge of the operating mechanism.

The FSC bank bypass breaker shall have one (1) insert coil and two (2) bypass coils per operating mechanism. Each coil shall be controlled independently from each protection system (see Section 8.8).

A switch and a green and red light shall be provided on the bypass breaker for local operation and indication.

A minimum of ten “a” and ten “b” extra breaker auxiliary contacts shall be provided with the bypass breaker and shall be wired to the breaker control terminal block.

The bypass circuit breaker shall be capable of opening without restriking for insertion of capacitors and closing for bypassing capacitors, and shall be able to withstand any transient current and voltages resulting from performance of those functions.

The bypass circuit breaker shall have voltage withstand capability when in open position such that it will not flash over at the maximum protective level of the varistor. This voltage withstand capability in kV shall be stated by the Contractor.

The bypass breaker shall be capable of performing 5,000 open and 5,000 close operations without maintenance.

The bypass circuit breaker shall be subjected to the design and production tests per IEEE 824. The design tests shall include:

1. Discharge test.
2. Fault current test.
3. Temperature rise test.
4. Insertion test.
5. Dielectric tests.
6. Closing time

The production tests shall include:

7. Operated with controls to verify all mechanical, electrical and pneumatic or hydraulic devices are functioning correctly.
8. Dielectric test to control circuit insulation.

7.4 Discharge Current Limiting and Damping Equipment

Discharge current limiting equipment shall consist of a reactor or a reactor/resistor combination to reduce the capacitor discharge when the FSC bank is removed from service by either the protective device or the bypass breaker. The reactor shall conform to ANSI C57.16 and shall be rated for the continuous, emergency, swing and fault currents specified.

The Contractor shall provide a study to demonstrate that the sizing of the damping reactor and the natural frequency produced when it is paralleled with the FSC bank has been considered so as to avoid all even and odd

harmonics of 60 Hz. The study information shall demonstrate that the calculation of the natural frequency includes stray capacitances and self inductance of the bus runs and shall represent the actual ringing frequency measured on-site. The specific requirements provided to the reactor manufacturer shall address the harmonic issue to insure the ampacity of the 500 kV transmission line is not impacted when the FSC bank is bypassed and avoid any damage to the reactor due to vibration levels and eddy current heating of the winding insulation.

A protective function shall be implemented to close the Utility furnished external bypass disconnect switch in the event of excess harmonic current in the discharge current limiting reactors.

The discharge current limiting reactor and damping equipment shall be subjected to the design and production tests per IEEE 824. The design tests shall include:

1. Discharge test.
2. Fault current test.
3. Temperature rise.

The production tests shall include:

4. Measurement of winding dc resistance.
5. Measurement of inductance and damping equipment parameters.
6. Measurement of losses and Q-factor
7. Lightning impulse test or turn-to-turn overvoltage test.

7.5 Platform

The three (3) FSC bank platforms shall utilize open rack construction, be self-cooled, and suitable for continuous operation under the specified conditions. During final inspection at the factory, each series capacitor platform structure shall be fully assembled and placed upon station post insulator risers to simulate the field installation (with or without platform equipment installed). The platforms shall be labeled to reflect field matching assemblies, disassembled, and shipped in units as large as possible while allowing for safe transportation and ease of installation at the jobsite.

A means to connect an external ac ground power source to the platform power supply system during maintenance shall be provided. The Contractor shall provide interlocking, where necessary, to prevent back feeding any platform supply power when ground power sources are used and to prevent energizing the FSC bank until the external power source has been removed.

Platform access for maintenance shall be provided via a permanent mounted and grounded push-up ladder. Decking shall be provided over the entire platform to allow personnel access to all equipment on the platform

from the ladder access point. All walkways shall be at least 3 feet wide. Safety handrails and kick-plates shall be provided around the perimeter of the platform for personnel safety. Safety handrails, access gate, and kick-plates shall also be provided around floor openings/access holes. Access-hole railings shall be removable.

Non-ceramic insulators are acceptable for bracing.

The Contractor shall furnish one complete set of any special slings, tools, wrenches or equipment that is required for assembling, dismantling, subsequent field testing or maintenance of the equipment.

The bank design shall be as low profile as practical.

Platform-to-ground dielectric design tests shall be performed or a study report provided per IEEE 824 to demonstrate the platform support insulators and platform-to-ground communication insulators meet the insulation levels specified at the installed ambient conditions.

The Contractor shall provide a study for approval by Utility indicating the wind and seismic design parameters for design of the three (3) FSC bank foundations and anchor rods to Utility. The shall indicate the location, number, type and size of rods required.

7.6 Instrument Transformers

The Contractor shall supply all necessary voltage and current transformers. All current transformers shall have a continuous thermal current rating factor of 2.0. Instrument transformers can be mounted on the ground or on the insulated platform depending on the application.

The design and factory tests of instrument transformers shall be made in accordance with ANSI 57.13. When voltage transformers are applied in parallel with capacitors, the transformers shall be tested to demonstrate the ability to withstand the discharge of the capacitors charged to the protective level.

7.7 Control and Protection

The FSC bank control and protection equipment shall meet the (1) control and protection requirements and (2) operation and communications requirements of Section 8 and Section 9 in this specification.

Contractor furnished control panels and cubicles for installation in the Substation control building shall be ___ cm maximum width and ___ cm maximum height **(These dimensions should be provided by the Utility).**

All Contractor furnished control, protection, alarming, communications and data recording equipment shall be immune to interference from such sources as:

1. Abnormally high and unbalanced power frequency currents flowing in bus bars and ground grid as a result of ground faults within the substation.
2. Radiated frequency (up to hundreds of kilohertz) from voltage and current transients as a result of switching high voltage switches and circuit-breakers in the ac substation, including switching of large capacitive and reactive loads.
3. Transients resulting from switching of contactors and relays feeding inductive loads.
4. Radiated signals from "walkie-talkie" radios, with transmitter power output levels up to five watts used for voice communication within the substation.
5. Radiated signals from cellular telephones being used in the substation.

Where sensitive equipment and circuitry requires special shielding, the Contractor shall use cubicle cabinets for such purposes, and shall provide any needed filtering isolation and appropriate grounding of signals and shields on all signal line cables. The use of separate shielded rooms for isolating such equipment from electromagnetic interference should be avoided.

7.7.1 Design and Factory Tests

The design and factory tests of the control and protection equipment shall be made in accordance with IEEE Std 824. The design tests shall include:

1. Functional tests.
2. Environmental tests.
3. Electrical, surge and electromagnetic interference tests.

The production tests shall include:

4. Manufacturing quality of all components and complete assembly.
5. Verify all hardware and software settings.
6. Output power of optical transmitters.
7. Optical loss test on each fiber.
8. Control and protection subsystem tests per Section 11.2.3.

7.8 Insulators, Bushings and Electrical Clearances

The minimum electrical clearances specified in Table 7.8 shall be furnished between the FSC bank metal parts having a voltage difference, to minimize the possibility of animals bridging these metal parts.

Table 7.8 – FSC Bank Clearances

Voltage Between Points (kV)	Striking Distance Between Parts (inches)	Insulator & Bushings	
		BIL (kV)	Creep (inches)
$15/\sqrt{3}$	10	110	12
$25.8/\sqrt{3}$	11	150	20
$38/\sqrt{3}$	15	200	28
$48.3/\sqrt{3}$	21	250	36
$72.5/\sqrt{3}$	29	350	52
$121/\sqrt{3}$	44	550	99
$145/\sqrt{3}$	54	650	108
$169/\sqrt{3}$	58	750	132
$230/\sqrt{3}$	83	900	158
$345/\sqrt{3}$	108	1300	234
$500/\sqrt{3}$	xxx	xxx	xxx

7.9 Bus Work and Electrical

7.9.1 Buswork

The Contractor shall design, furnish and install all materials required to complete any strain or rigid bus installations for the three (3) FSC banks. The bus shall be designed with adequate margins of safety with respect to the current-carrying capacity and mechanical strength to withstand electrical and mechanical stress. Sufficient flexibility in the buswork and connectors shall be provided to allow for thermal expansion and contraction.

All buswork including bus, support clamps, connectors and associated fittings and corona shields shall be designed to be free of visual and audible corona at a test voltage 30 percent above its corresponding maximum operating voltage to ground.

7.9.2 Overhead Shielding

The Contractor shall furnish and install overhead shielding for protection of the FSC bank against lightning.

7.9.3 Cabling

All cabling and cabling systems, including cable trays, raceways, conduit, pull-boxes, duct banks, fiber optic cable inner duct, wiring, termination fittings and tools required for the interconnection of the

FSC bank equipment to the Substation control building shall be designed, furnished and installed by the Contractor.

The Contractor shall furnish interface panel(s) in the FSC bank building (if provided) and complete the termination of all interconnecting cables in the FSC bank building (if provided).

Spare cable and terminations shall be provided of between 10% or 15% of the number of required conductors except not less than one spare conductor per application.

Utility will provide the cable installation and terminate all cables in the Substation control building with supervisory assistance from the Contractor.

The Contractor shall provide a minimum of 200 feet of extra cable and fiber optic cable inner duct at the cable trench entrance to the Substation control building. Cable shall be clearly marked and identified.

7.9.4 Fiber Optics

All fiber optic cables and terminations shall be designed, specified, furnished and installed by the Contractor shall include a copy of all specifications to Utility including cable and terminations.

7.9.5 Outdoor Lighting

The Contractor shall furnish and install dark sky outdoor manually operated maintenance lighting fixtures subject to Utility approval.

7.10 Civil Works

The site civil works for the FSC equipment installation shall be coordinated with Utility as shown in Table 7.10.

Table 7.10 – Civil Works

Description	Contractor			Utility
	Design	Furnish	Supervise Installation	Coordination
Chain-link fence	X	X	X	X
Rock surfacing		X	X	X
Structures	X	X	X	X
Building (if provided)	X	X	X	X
Maintenance access	X	X	X	X
Cable trench	X	X	X	X
Cable	X	X	X	X

Excavation	X	X	X	X
Foundations	X	X	X	X

7.11 Ground Level Equipment and FSC Bank Building

The Contractor shall design and furnish FSC bank buildings (if provided) complete with lighting, electrical outlets, fire detection (thermal and smoke), fire extinguishers and HVAC auxiliary systems.

Utility will provide ac and dc auxiliary power for the FSC bank equipment. The Contractor furnished equipment shall be designed for operation on a nominal 230/115 volt, 60 Hz, single phase alternating current system and 125 volt dc. The equipment shall operate at any voltage from 100 to 130 volts ac and 105 to 145 volts dc. The Contractor shall furnish a study report that indicates the maximum ac and dc auxiliary power required and design concept of the FSC buildings (if provided) for Utility approval.

The FSC bank buildings (if provided) materials, equipment and fittings shall be suitable for industrial use and require minimal maintenance. Materials, equipment and fittings which are available in the Canada are preferred to facilitate future maintenance.

The Contractor shall supply all ground level equipment for the three (3) FSC banks in cubicles that can fit into the space allowed in the Contractor furnished building (if provided). The building supplied by the Contractor must be large enough to house all the FSC bank equipment and spare parts (except spare capacitors, varistor and reactors) plus 40 square feet of additional for space for Utility use. Reactors will be stored outdoors in an unprotected area.

The FSC bank buildings (if provided) shall provide adequate space for operating, maintaining and accessing the FSC bank building equipment including the control and protection equipment, HVAC, building services, distribution panels and spare parts.

The FSC bank buildings (if provided) and HVAC auxiliary systems shall be designed so that preventative maintenance can be carried out without affecting operation of the FSC bank equipment.

The FSC bank building (if provided) exterior color shall be grey to match the Substation control building as close as possible, finished in a low maintenance finish. If the building exterior walls are metal, the finish shall be baked-on with a guaranteed life of at least 30 years.

Electronic control panels shall not require fans for cooling in order to operate successfully and correctly at the maximum ambient temperature. However, fans are permitted in the equipment in order to allow components to operate at a cooler temperature level and thus lessen the derating of components in the design and prolong equipment life.

7.12 Grounding

Grounding for the three (3) FSC banks and associated equipment shall be in accordance with IEEE Std 80 and Utility's Standards.

Contractor shall design the FSC bank building (if provided) grounding system in accordance with IEEE Std 80. The FSC bank building grounding system shall be interconnected with the Substation grounding system via a minimum of one grounding pad at each corner of the building, providing for the termination of a single #4/0 grounding cable at each corner for connecting the building ground system to the substation ground grid.

Contractor shall provide a ground pad for grounding each leg of the FSC bank support structure providing for the termination of a single #4/0 grounding cable from the substation ground grid.

The Contractor's FSC bank building and FSC bank grounding system design shall be submitted to Utility for review and approval.

7.13 Safety

The Contractor shall ensure that equipment and practices conform to the provisions of IEEE Std 824 and the Occupational Safety and Health Act (OSHA).

7.14 Miscellaneous

There are several miscellaneous items that are specific to a utility's standard design practices that have not been address but could be added prior to any procurement activities when pursuing a RFP. These items include, (1) fasteners and fittings; (2) high voltage connectors; (3) exterior finishes; (4) porcelain color; (5) nameplates; (6) welding; (7) wiring; (8) terminals and terminal blocks and (9) signage.

8. Control and Protection Requirements

8.1 Local, Remote or Automatic, SCADA/RTU

The FSC banks shall have provisions to allow for bypassing and insertion by local manual control and remote manual or automatic control via the Utility's SCADA and RTU system.

8.2 External Bypass, Isolating and Grounding Switches

The FSC banks external isolating, grounding and bypass switches (not including protective bypass circuit breakers) will be provided by Utility. They will be motor/manually gang-operated whose sequence of operation shall be key-interlocked with the operation of the FSC banks. The key-interlock system provided by Contractor shall be coordinated with and approved by Utility and specified for use on the external isolating, grounding and bypass switches that are provided by Utility. The operation of the external bypass switch will be permitted only after the Contractor furnished

bypass breakers have been placed in the proper position. The operation of the external isolating switches will be permitted only after the external bypass switches have been placed in the proper position. Separate FSC bank manual external grounding switches shall be key-interlocked with the external isolating switches to ground both sides of the bank after all external isolating switches have been opened.

8.3 Reclose/Lockout

On an internal fault the line protection scheme will allow for one reclose attempt before lock out.

8.4 External Fault Bypass Gap/Breaker Operation

The FSC banks shall be designed not to bypass through the bypass gap (if furnished) or bypass breaker during an external fault, under all ambient temperature ranges.

8.5 Automatic Bypass and Insertion

The FSC banks shall be designed to remain inserted and protected and not automatically bypass when there is no line current present following normal insertion.

8.6 Interlocks

The FSC bank control interlocks and permissives shall not preclude the manual operation of the bypass breakers during periods of maintenance.

8.7 Bank Control Hardware and Graphical User Interface (GUI)

The FSC bank controls shall utilize a self-monitoring industrial grade computer-based or PLC-based system. The ground control functions shall utilize a Graphical User Interface (GUI), control relays, power supplies and associated monitoring equipment. Equipment shall be rated for 125 VDC operation.

8.8 Protection Redundancy

The FSC bank protection shall utilize a self-monitoring, fully redundant computer-based or PLC-based design compatible with the control and operational requirements.

The FSC banks shall utilize a two-protection-system design. If a problem develops involving one of the two protection systems, an alarm shall be sent and the second protection system shall take over automatically. If the failure occurs when the other system is not in service, the bypass breaker shall be closed and locked out. The GUI shall be common to both protection systems.

8.9 Protection Functions

The FSC bank protection shall provide but not be limited to the protection functions per phase as described in this section.

1. Capacitor Bank Unbalance Protection: The capacitor bank unbalance protection shall provide at least three (3) operation levels settings (settings shall be coordinated with Utility) with independent time delays. The levels are alarming for minor capacitor cans over-voltage and bypass to lockout for capacitor can voltages exceeding 110% of rated capacitor can voltage.
2. Flashover to Platform Protection: The flashover to platform protection shall be current based, measuring the current between the main components on the platform and the platform itself. Operation shall cause a bypass to lockout condition and phase indication.
3. Bypass Gap Protection (if furnished): The bypass gap protection shall be a current based system with time delay to monitor the current in the gap. In the case of prolonged gap arcing, the FSC bank shall be bypassed to lockout with phase indication.
4. Bypass Breaker Failure Protection (during a control operation): The bypass breaker failure protection shall provide for both failure to bypass (close) and failure to insert (open). After the expected operating time of the breaker expires, a failure to bypass (close) shall result in the system either only alarming or inserting (open) each phase. Failure to insert (open) shall bypass (close) each phase with alarming.
5. Varistor Overload Protection: The varistor overload protection shall bypass, alarm, and lockout for a varistor overload condition.
6. Varistor Failure Protection: The varistor failure protection shall be a current based system with two setting levels, each having a time delay to detect abnormal levels through the varistors continuously. Upon detection the bank shall be bypassed to lockout.

8.10 Platform Protection Equipment

All platform protection equipment shall be housed in a weatherproof cabinet. The FSC banks shall be fully protected when either inserted or bypassed for power reversals on the 500 kV transmission line. During power reversals, the line current could be zero (0.0) for several hours. No batteries will be permitted on the platform.

8.11 Protective Relay Coordination

The Contractor shall provide a protective relay coordination study that presents the protection coordination principles, relay protection setting calculations and a summary list of protection settings.

8.12 Specialized Programming Tools for the Control and Protection

The Contractor shall provide all specialized programming tools required to operate and maintain the FSC bank control and protection systems.

9. Operational and Communications Requirements

9.1 Fibre Optic Signal Transmission

The FSC banks shall utilize a fiber optic signal transmission system between ground control and the FSC bank platforms with redundant fibre optic columns and signal conversion equipment on each phase. Fibre optic cable problems or fibre optic interface problems shall be alarmed in the ground control station. Spare fibres in each column shall be provided and the quantity available stated by Bidders. The Contractor shall provide all fibre optic cable required for FSC bank installations.

9.2 Platform Current Transformers

Separate current transformer (CT) functions shall be provided for each phase for each protection system. CTs shall function to provide condition information about, but not necessarily limited to, capacitor current, bypass breaker current, capacitor unbalance current, varistor current, gap current (if furnished) and platform fault current.

9.3 Annunciator Points

The annunciator points shown in Section 15.3 shall be provided at the FSC bank master station controls and available on the GUI. Provisions shall also be made for parallel output contacts of annunciator points for remote indication or auxiliary functions. Contacts shall be dry type rated for at least 10 amps at 130VDC.

9.4 Data Recordings and SER

The Contractor shall supply digital fault recorder and sequence of event recorder capability for at least those points shown in Section 15.4.

9.5 Communications (SCADA/RTU)

The FSC banks shall be designed for remote operation by supervisory control from Utility's operation center. A remote terminal unit (RTU) furnished and installed by Utility will be located in the Substation control building.

The wiring interface between the RTU and FSC banks will be at the RTU. The Contractor shall coordinate with Utility to establish specific Contractor furnished interface panel(s), cabling and cable terminations for all cables interconnecting with the RTU for installation by Utility. The interface panel(s) signals to the RTU may include status and alarm signals, metering signals,

commands and control signals necessary to operate the FSC bank and perform remote diagnostics of the FSC banks.

10. Testing, Commissioning and Inspection

10.1 General

Testing and commissioning the three (3) FSC bank installations requires planning of test sequences, procedures and system load schedules. A testing and commissioning plan shall be developed by the Contractor for Utility approval prior to commencing testing. The testing and commissioning plan shall include a testing schedule indicating the order in which tests should be conducted and test methods to be used for off-site factory and on-site precommissioning, subsystem and system tests.

Production and design tests shall be performed by the Contractor to verify proper performance of equipment prior to shipment to the site. Production tests shall be made on each piece of equipment for quality control in accordance with industry standards. Design tests shall be made to verify that equipment design meets the assigned ratings and will operate satisfactorily under required service conditions.

Precommissioning tests shall be performed by the Contractor and involve on-site localized testing and checkout of individual equipment items. These tests are performed after equipment items are installed at the site to verify proper installation, adjustment and local manual operation of an individual piece of equipment or apparatus. Testing of transducers, capacitors, reactors, resistors, disconnect switches, circuit breakers, building systems, fiber optics, cabling, grounding switches, and control and protection panels shall be included.

Subsystems tests shall be performed by the Contractor on equipment items that are grouped together to perform a common function. The purpose of subsystem tests is to independently check the necessary functional performance of all FSC bank subsystems before starting system testing.

FSC bank system testing shall be performed by the Contractor to verify that subsystems interact and function according to specified requirements. These tests involve high voltage energization of equipment and require coordination with Utility's system operators. System tests include testing the FSC bank installation with various transmission system power flows. Transmission system configurations and power flow levels will be configured to test the FSC bank installation operational parameters to confirm specified performance can be achieved. System tests include a period of trial operation followed by acceptance tests.

Documentation that shall be available and used during the on-site commissioning process includes inventory lists, equipment specifications,

drawings, software diagrams, system study results, off-site test results and manufacturer operation and maintenance manuals.

Relevant safety requirements and responsibilities for all on-site commissioning tests shall be documented by the Contractor for Utility approval and shall be available on-site during testing and commissioning. The documentation shall provide information that identifies precautions needed to prevent damage to equipment or any danger to human life. Utility's safety manuals will be available.

Documentation of on-site commissioning test results shall include a report describing each test series together with all relevant test data (sequence of event recorder printouts, transient fault recorder recordings, etc.). The report shall also include detailed descriptions of unsuccessful tests, outages or malfunctions and diagnostic tests leading to any modifications implemented for corrections. Final data showing results of any modifications shall be documented with appropriate reference to the unsuccessful tests as well as other impacted FSC bank documentation changes.

10.2 Factory Testing (including RTDS)

The Contractor shall factory test individual items of equipment in accordance with the approved testing and commissioning plan. The tests shall include all design and production tests specified under the corresponding equipment specification and applicable standards listed herein.

10.2.1 Factory Production Tests

All equipment supplied for the FSC bank shall be subjected to and pass specified production tests in the factory of manufacture.

All production tests shall be witnessed by Utility's representative, unless written authority to proceed with the tests without the witness has been received from Utility.

All results of production tests shall be submitted to Utility for approval.

10.2.2 Factory Design Tests

All equipment to be supplied by the Contractor shall be subjected to and pass the specified design tests. All design tests shall be witnessed by the Utility's representative, unless written authority to proceed with the tests in his absence has been received from Utility.

Design tests may be waived at Utility's discretion after submission of certified design test reports. A statement shall be included that the equipment being supplied is identical in all respects to the

equipment on which the particular test was performed or, if not identical, the differences shall be clearly stated. Utility's decision as to the acceptability of such design test reports applying to any equipment will be based on the quality and completeness of the reports and whether there are important modifications, or significant design differences in the equipment to be supplied from that tested.

10.2.3 Factory Control and Protection Subsystem Tests

Factory control and protection subsystem tests shall include functional and dynamic performance tests with the FSC bank control and protection hardware and software configured as close as possible to the delivered configuration. The FSC bank control and protection settings shall be set as far as practical in the factory so that only minor adjustment will be required at site. The FSC bank control and protection equipment shall be connected and tested as a subsystem in the factory to verify FSC bank performance objectives can be met by use of a Real Time Digital Simulator (RTDS) or equivalent method.

10.3 Precommissioning Tests

Precommissioning tests shall be carried out on all items of equipment in accordance with the relevant approved testing and commissioning plan. These tests shall ensure that the equipment has sustained no damage in transit, have been properly installed in the field, are safe to energize, load or start-up, and will perform and operate as designed prior to subsystem tests. Precommissioning tests do not require high voltage energization but may require auxiliary power (ac and dc).

Pre-commissioning tests shall include but not be limited to the following:

1. Verify equipment is installed in accordance with manufacturer's instruction books and station design drawings.
2. Check wiring, fiber optics and grounding connections.
3. Confirm capacitance, reactance and resistance parameters.
4. Dielectric and insulation resistance checks on primary equipment consisting of power factor tests and hi-pot tests.
5. Resistance measurements of reactors, resistors, and measuring equipment.
6. Ratio and polarity checks on measuring devices.
7. Timing checks on circuit breakers and switches.
8. Contact resistance of bus connections, circuit breakers and disconnect switches.
9. Functional tests on auxiliaries including ac and dc power equipment.
10. FSC bank building (if provided) air handling system balancing,

- humidity, sealing and temperature checks.
11. Functional tests including relay and control settings on control, protection, and alarm circuits.
 12. Dynamic balancing, alignment and performance checks of all rotating equipment.
 13. Functional check of all interlocks.
 14. Wiring continuity and insulation resistance tests.
 15. Power supply abnormality tests for electronic equipment.
 16. Grounding system.
 17. System switchover (between redundant systems) functions.
 18. Diagnostic software functional demonstration.
 19. Communication, remote control and operator interface.

10.4 Subsystem Tests

After successful completion of the precommissioning tests, all independent subsystems shall be energized or started up in accordance with the approved testing and commissioning plan. These tests shall prove that a group of components work satisfactorily together as a functional unit. These tests shall be carried out in progressive stages until all related elements have been functionally checked without high voltage being applied. The tests shall include off-line testing of all interlocking sequences and final protection trip testing prior to energization. During these tests, operation of main equipment (breakers, disconnect switches, etc.) shall be minimized by utilization of suitable simulation test devices.

10.5 System Tests

After successful completion of precommissioning and subsystem tests, system testing shall be performed in accordance with the approved testing and commissioning plan. These tests involve energizing the FSC bank with the 500 kV system network. Staged fault testing will not be required.

System testing shall include testing the FSC bank under normal operating conditions and, as conditions permit, under network contingency operating conditions.

Transmission tests shall include:

1. FSC bank insertion and bypass sequences.
2. Substation and transmission line switching sequences.
3. Steady state operation at the FSC bank rated voltage and current.
4. Emergency load conditions.
5. Control and protection performance evaluation.
6. Harmonic performance measurements.

7. Audible and electrical interference noise measurements (by Utility).

10.5.1 Trial Operation

During trial operation of the three (3) FSC banks, an uninterrupted period of operation of not less than 30 calendar days is required during which the FSC bank equipment shall be fully operational. Trial operation shall verify that the FSC bank installations are capable of reliable operation with the connected ac system for an extended period of time without misoperation. During trial operation, the FSC bank installations shall be operated by trained Utility operators and dispatchers without Contractor assistance.

During trial operation, the FSC bank installations shall demonstrate its capability to perform as specified during any disturbances in the ac system or communication system that the FSC banks are designed or specified for. While it is not the intention to stage line faults or ac disturbances during trial operation, such events, if they occur during the trial operation period, shall be used to evaluate the proper performance of the FSC banks. All disturbances during trial operation shall be monitored, recorded and analyzed by the Contractor to determine the causes and their impact. All alarms shall be investigated and proper operation verified by the Contractor.

Criteria for successfully completing the trial operation period shall include the following:

1. No main circuit equipment failure or fault.
2. No switchover to redundant control and protection system.
3. No protection malfunctions.
4. Stable operation of FSC bank for all system configurations.

If any item of equipment furnished by the Contractor fails to pass any of the above criteria or shows any signs of damage or failure, it shall be repaired and defective parts replaced or redesigned. The equipment shall then be retested by the Contractor without additional cost to Utility. The retesting shall include the test under which the failure occurred (if possible), as well as all of the tests already completed which might be affected by the repair, or as required by Utility. Any redesigned equipment items furnished, including spares, shall be provided at no additional cost to Utility.

10.5.2 Acceptance

Documentation that will result in Utility acceptance of the three (3) FSC bank installations for commercial operation includes verification that the following requirements have been met:

1. All system tests and trial operation completed.
2. Final report for all testing and commissioning complete and approved by Utility.
3. Steady state ratings verified.
4. Electrical losses performance report.
5. Technical documentation submittals completed and approved.

10.6 Testing and Commissioning Responsibilities

All equipment furnished by the Contractor shall be commissioned at site and brought into commercial operation by the Contractor with the assistance of Utility.

The Contractor shall provide a qualified commissioning coordinator and qualified commissioning staff sufficient to commission the equipment in accordance with the project schedule and approved testing and commission plan.

Utility's clearance and safety procedures shall apply during commissioning. The Contractor shall coordinate matters relating to system operation and control with Utility.

Utility's operating and maintenance staff shall take part in the commissioning process.

10.7 Test Equipment on Site

All test equipment supplied by the Contractor for use on site shall be properly adjusted and calibrated against applicable national standards.

Utility may supply the common tools and test instruments required for operation and maintenance use during commissioning. Bidders shall state in their proposal any common tools and test instruments that would be required from Utility during commissioning. The Contractor shall provide all specialized tools and test equipment. Upon completion of the commissioning, all Utility tools and test equipment, and any specialized tools or test equipment required for operation and maintenance of the FSC banks, shall be handed over to Utility in good condition, properly adjusted and calibrated. Tools and test equipment which are damaged shall be either repaired or replaced at the expense of the Contractor.

11. Technical Documentation

Technical documentation for the three (3) FSC bank installations shall include the following:

1. Site location and installation drawings.
2. Test plans and all test reports.
3. As-built drawings.

4. Instruction manuals.
5. Equipment specifications.
6. Nameplate drawings.
7. Schematic and wiring diagrams.
8. Training manuals.
9. Study reports and modeling.
10. Spare parts list.

12. Spare Parts, Special Tools and Storage Space

12.1 Spare Parts

The Contractor shall recommend and furnish spare parts for the three (3) FSC banks needed for maintenance and parts exchange within the FSC banks. Spare parts shall be coordinated to meet the availability, reliability and maintainability performance requirements of FSC banks.

The Contractor shall replace all spares consumed or damaged during commissioning and the reliability, availability and maintainability performance evaluation period.

All equipment supplied for use as spares shall be interchangeable with, and of the same or better material, workmanship and design as the corresponding parts of the original equipment.

12.2 Special Tools

The Contractor shall provide all special tools and maintenance equipment required for the proper operation and maintenance of the FSC banks. Special tools and maintenance equipment shall include all tools or maintenance equipment normally available from only the Contractor or a subcontractor.

12.3 Storage Space

The Contractor shall provide storage space for spare parts and special tools as follows:

1. Platform: A minimum of 10% minimum spare capacitor units shall be stored on the platform plus an area provided sufficient for future 10% growth of the installed capacitor units and varistor porcelain housings.
2. FSC bank building (if provided) or substation control building: All other spare equipment and special tools shall be stored at Substation.

13. Training

13.1 General

The Contractor shall organize and conduct a training program for the operating and maintenance personnel who will be assigned by Utility. The Contractor shall provide all material and equipment, as well as qualified fluent English speaking instructors to conduct the training program. Instructors shall be experienced and

well-versed in series capacitor operating theory, design, software, hardware and required maintenance of the equipment being furnished.

The Contractor shall submit an outline of the proposed training programs to Utility for approval at least 90 calendar days prior to the training classes.

Training manuals shall be provided by the Contractor to each trainee attending each course at least 30 calendar days prior to the start of the training program. At the completion of each course, the training manuals, workbooks and other training material shall be updated (as needed) and become the property of Utility.

13.2 Operator Training

Operator training shall be conducted at Utility's office. The training shall thoroughly familiarize operating personnel with the operating features of the FSC bank, so that at the completion of each training session they will be able to completely and properly operate the FSC bank equipment without Contractor assistance. Approximately 12 operating personnel are expected to attend the operator training program. The training shall be scheduled in two (2) separate one day sessions to allow all operators to attend. The training shall include the following:

1. Description of the FSC bank system objective and function.
2. Control and operator interface.
3. Protection principles.
4. Operations manuals.

13.3 Maintenance Training

Maintenance training shall be conducted at Utility's office. The training shall thoroughly familiarize maintenance personnel with the features of the FSC bank, so that at the completion of the stated training session(s) they will be able to completely and properly maintain the FSC bank equipment without Contractor assistance. Approximately 12 maintenance personnel are expected to attend the maintenance training program. The training shall include the following:

1. Basic description of the FSC bank system objectives.
2. Periodic and preventative maintenance, trouble shooting and safety.
3. Control and protection system maintenance and diagnostics.
4. Special tools, spare parts and test equipment.
5. Maintenance manuals and factory test data.

13.4 Training During Commissioning

Utility's maintenance personnel shall be given instruction and training on the actual equipment during testing and commissioning of the three (3) FSC banks, so that they may familiarize themselves with the equipment.

14. Proposal Requirements

14.1 General

A proposal addressing the Bidders technical and management approach to meet the requirements of this specification shall be prepared that follows the format and requirements of this Section. Proposals should be specific and complete in every detail while providing a straightforward concise delineation of what is being offered to satisfy the technical requirements. Cost data or cost estimates shall not appear in any portion of the technical proposal.

All exceptions, options and alternatives to the technical specification and to Utility's General Terms and Conditions must be listed in the Bidder's Proposal.

Technical proposals and all related documentation, drawings and data shall be submitted in the English language.

14.2 Basis of Contract Award

Each proposal should be submitted to present the most favorable terms from a technical and cost standpoint. Bidder's proposals will be evaluated as follows and in the order listed:

1. Technical approach and understanding of work.
2. Experience and past performance.
3. Project management and schedule.
4. Compliance with technical specification including all exceptions, options and alternatives.

Pricing proposals will be evaluated separately from the technical proposals and will include an evaluation of stated losses and compliance with Utility "Terms and Conditions".

14.3 Technical Approach

Bidders shall provide information, descriptions and calculations of the proposed FSC banks that meet the requirements of specification including:

1. A one-line diagram showing the three (3) FSC bank arrangements and description of how the continuous, emergency and swing current ratings will be met under the specified ambient conditions. The power circuit arrangement should show the ratings of all major equipment including disconnect switches, circuit breakers, triggered protective device (if furnished), ground switches, voltage transformers, varistors, reactors, damping equipment and capacitors. Technical information should be provided on the major equipment including type, ratings, physical features, maintenance requirements, previous experience and manufacturer location.

2. Provide a brief description of the proposed FSC bank control, protection, operational, alarming, communication and data recording systems including proposed locations, panel/enclosure sizes (width/depth/height) for the control building/platform, cabling and maximum ac and dc power consumption. The information shall include any microprocessor and/or computer based system hardware, software and communication protocol with Utility equipment as well as a description of self-diagnostic features, maintenance requirements, factory test program and interface features to or within the Utility's Substation control building.
3. Provide a brief description of the proposed strategy to fully protect the three (3) FSC banks when either inserted or bypassed for power reversals on the 500 kV transmission line when line currents could be zero (0.0) for several hours.
4. A general description of the proposed ground based and platform electrical auxiliary power systems including a single line diagram, rating of main components and loads, principles of protection, voltage tolerances, physical features and maintenance requirements.
5. A description of the parameters used to determine the protective characteristics and rating of the proposed varistor.
6. Information and data shall be provided on insulation coordination including BIL and switching impulse withstand levels to ground of all insulators and equipment, and where applicable, across platform equipment for the installed elevation. Any minimum ratings and capabilities of Utility equipment shall be stated.
7. Calculations shall be provided that clearly demonstrate the stated availability, reliability and maintainability requirements can be met for the three (3) options requested. Additionally, the bidder shall indicate the level of support that will be provided during the 5-year performance evaluation period.
8. Overall layout drawings showing the proposed general layout of the three (3) FSC banks providing dimensions and information on the following: overall dimensions of the FSC bank facilities, sectional drawings, building (if provided), access for maintenance, fencing, bus arrangement, cable trench layout, control cabling and high voltage interconnections.
9. Description of the general location and approximate size of concrete structures and anchor bolts for the proposed FSC bank facilities.
10. A description and drawings of the proposed FSC bank building (if provided) including the following: architectural design concept including plans and elevations; type of construction; exterior and interior wall sections and details to explain the design concept; layout and proposed grouping of control and protection cubicles; layout of electrical services;

access for maintenance of equipment and spare equipment storage; and preliminary heating and cooling load calculations.

11. Brief description of the proposed system operating and maintenance training programs including an estimate of the number of hours of instruction and the proposed training during commissioning.
12. A description of the proposed program for factory tests, site testing and commissioning including an organization diagram showing the number of on-site contractor's personnel and how Utility personnel will participate. The description shall include a list of test equipment to be provided by the Contractor and any common tools and test instruments that need to be provided by Utility. Additionally, Bidders shall indicate the extra cost per day that would be incurred by Utility if testing and commissioning being performed under these specifications is delayed due to conditions making the ac system temporarily unavailable to continue with the approved testing and commission plan.
13. A list of studies that will be performed with a proposed submittal schedule and location where the studies will be performed of the technical specification. The list shall include the control and protection simulator studies that will be performed and a brief description of the tools to be used and cases to be studied.

14.4 Corporate Experience and Past Performance

Bidders shall provide information related to their corporate experience in designing, manufacturing, testing, installing, commissioning, training and documentation of the equipment specified.

The bidder shall provide a list of those personnel (both Contractor and subcontractor) who will be "key" to the Utility contract. Once assigned, these "key" personnel shall be exclusively committed to the successful performance of this contract or the appropriate portion thereof. Changes to "key" personnel shall be subject to approval by Utility.

Bidders shall provide information with respect to the depth and breadth of corporate past performance in providing the same or similar types and quantities of series capacitor banks that have a documented history of successful operating performance. A list of recent series capacitor projects (last 8-years) shall be provided giving the project start and completion dates, main component ratings, protection scheme and customer contact information (name, address, phone, email, FAX) as well as the Bidder's "key" personnel involved with these projects.

14.5 Project Management and Schedule

The bidder shall provide a preliminary project management plan and schedule for all work to be performed that includes, but not limited to all engineering, design, manufacturing, testing, packaging, shipping, delivery, Utility furnished facilities/materials/services, installation supervision, testing and commissioning

of the three (3) FSC bank. Bidders shall also include any additional tasks to ensure all aspects of the requirements of this specification are met. The schedule shall be broken out by months such as Month 1, Month 2, etc., and not actual calendar dates. The schedule shall also include planning for submittals, review and comments, assuming review by the Utility will take 20 calendar days.

14.6 Exceptions, Options and Alternatives

1. Bidders shall submit with their proposal a table identified as “Exceptions To The Specifications” with an item-by-item list of all exceptions taken to the technical specification. Exceptions refer to non-compliance with specified requirements and not included in Bidder’s corresponding pricing. A detailed narrative of the non-compliance shall be provided along with the Bidder’s proposed substitute for the non-compliance. Failure to list any and all exceptions may result in rejection of the proposal.
2. Bidders shall submit with their proposal a table identified as “Options” with an item-by-item list of all options proposed for consideration by Utility including the reliability, availability and maintainability options, optional SSR studies and a sub-harmonic protection option (if required by Utility). Options refer to additional functionality or capability that is identified in the specification and offered by the Bidder along with a corresponding price. A detailed narrative of the proposed option shall be provided along with pricing.
3. Bidders shall submit with their proposal a table identified as “Alternatives” with an item-by-item list of all alternatives proposed for consideration by Utility. Alternatives refer to additional functionality or capability not identified in the specification and offered by the Bidder along with pricing.

14.7 Electrical Loss Evaluation

Information and data shall be provided that states the three (3) FSC bank guaranteed station losses.

14.8 Milestones and Progress Payments

Table 14.8 is a suggested milestone and progress payments schedule on which to base payments that are correlated to milestones. Bidders should fill-in the estimated months.

Table 14.8 – Milestones and Progress Payments

Item	Milestone	Estimated Month by Bidders	Payment	Subtotal Percentage
1	Mobilization	0	5%	5%
2	Final design and approval of all studies	—	10%	15%
3	Release purchase orders for main components and facilities	—	20%	35%

4	All spare parts, main components and facilities on-site	—	30%	65%
5	Installation and erection complete and ready for subsystem tests	—	10%	75%
6	Successful completion of system tests	—	10%	85%
7	Successful completion of trial operation and acceptance (Section 10.5.2)	—	5%	90%
8	Final technical documentation complete	—	2%	92%
9	Contract closeout	—	3%	95%
10	5 year performance evaluation	—	5%	100%

14.9 Possible Terms and Conditions

Possible terms and conditions that will be at the discretion of the Utility may include those listed below.

- a. Inspection Clauses
- b. Liquidated Damages
- c. Billing Instructions
- d. Modification Authority
- e. New Material Required
- f. Type of Contract
- g. Quality Assurance Program
- h. Safety
- i. Sanitation
- j. Proposal - Period of Acceptance
- k. Instructions for RFP - Questions from Bidders
- l. RFP Letter to Bidders
- m. Clarify if Site Visit and Pre-Bid Meetings are Planned
- n. Establish Proposals Due Date & Expected Award Date
- o. Clarify Quantity of Electronic and/or Hard Copies of Proposals
- p. Instruct Bidders to Provide Separate Technical and Cost Proposal Information

15. Attachments

15.1 Drawings

15.2 System Data

15.3 Annunciator Points

15.4 Monitor Points

15.1 Drawings

Drawing should be added to final specification by Utility

Figure 15.1.1 – Bruce A One Line Diagram

Drawing should be added to final specification by Utility

Figure 15.1.2 – Bruce B One Line Diagram

Drawing should be added to final specification by Utility

Figure 15.1.3 – Longwood One Line Diagram

15.2 System Data

(System data to be added to final specification by Utility)

15.3 Annunciator Points

1. Capacitor unbalance alarm per phase (set point #1).
2. Capacitor unbalance alarm per phase (set point #2).
3. Capacitor unbalance trip per phase.
4. Capacitor over-current per phase.
5. Varistor conduction per phase.
6. Varistor over-temperature per phase.
7. Varistor failure per phase.
8. Gap conduction per phase (if furnished).
9. Prolonged gap conduction per phase (if furnished).
10. Bypass breaker bypass initiate per phase.
11. Bypass breaker trouble per phase.
12. Bypass breaker failure per phase.
13. Bypass breaker pole disagreement.
14. Bypass breaker lockout.
15. Bypass breaker blocked closed.
16. Bypass breaker low pressure per phase.
17. Platform fault per phase.
18. Fiber optic link loss of signal per phase.
19. Auxiliary power failure.
20. Controller failure.
21. Platform flashover

15.4 Monitor Points

ANALOG:

1. Phase A, total capacitor current
2. Phase A, total varistor current
3. Phase A, bypass gap current (if furnished)
4. Phase A, bypass breaker current
5. Phase A, total series capacitor current
6. Phase A, total capacitor unbalance current
7. Phase B, total capacitor current
8. Phase B, total varistor current
9. Phase B, bypass gap current (if furnished)
10. Phase B, bypass breaker current
11. Phase B, total series capacitor current
12. Phase B, total capacitor unbalance current
13. Phase C, total capacitor current
14. Phase C, total varistor current
15. Phase C, bypass gap current (if furnished)
16. Phase C, bypass breaker current
17. Phase C, total series capacitor current
18. Phase C, total capacitor unbalance current

DISCREET (DIGITAL) SIGNALS:

1. Phase A, bypass breaker status
2. Phase A, arc Gap conduction (if furnished)
3. Phase A, bypass breaker trip bus high
4. Phase A, primary protective relay bypass (close)
5. Phase A, backup protective relay bypass (close)
6. Phase A, fiber optic cable failure
7. Phase A, unbalance alarm level 1
8. Phase A, unbalance alarm level 2
9. Phase A, unbalance alarm and bypass (close)
10. Phase B, bypass breaker status
11. Phase B, arc Gap conduction (if furnished)
12. Phase B, bypass breaker trip bus high
13. Phase B, primary protective relay bypass (close)
14. Phase B, backup protective relay bypass (close)
15. Phase B, fiber optic cable failure
16. Phase B, unbalance alarm level 1
17. Phase B, unbalance alarm level 2
18. Phase B, unbalance alarm and bypass (close)
19. Phase C, bypass breaker status
20. Phase C, arc Gap conduction (if furnished)
21. Phase C, bypass breaker trip bus high

- 22. Phase C, primary protective relay bypass (close)
- 23. Phase C, backup protective relay bypass (close)
- 24. Phase C, fiber optic cable failure
- 25. Phase C, unbalance alarm level 1
- 26. Phase C, unbalance alarm level 2
- 27. Phase C, unbalance alarm and bypass (close)

Appendix C

SSR Considerations with 30% Series Compensation on B562L, B563L and N582L

A preliminary investigation of the impact of 30 % series compensation on B562L, B563L and N582L 500 kV ac transmission lines was undertaken. Network data was derived from the PSS/E 2010 power flow data titled: 2010HURONTARIO WTGA PORTLANDS. The network data was converted to PSCAD⁹ electromagnetic transients program via the E-TRAN¹⁰ translation software.

The PSCAD network model consisted of 61 three phase busses of the Southwestern Ontario 500 kV and 230 kV system, with each generator at Bruce, Nanticoke and Lambton represented individually. The remainder of the power system was reduced to a multi-port equivalent.

The test of the model was to compare the positive sequence three phase short circuit currents for selected busbars similar to what ABB applied for their test (see Appendix U in reference [1]). The ABB short circuit test results and the PSCAD test results are shown below for comparison. It is possible that the network data base used for this test was different than what ABB, IESO and Hydro One used.

Bus Number	3-ph fault current (A rms) for ABB simplified model	3-ph fault current (A rms) for full system model from IESO and Hydro One	PSCAD Model
6400	27,842	28,153	26,530
7000	16,613	16,759	16,040
7108	34,727	34,619	32,700
6500	29,426	30,425	29,120
4000	39,996	39,886	42,260
4100	57,505	57,505	51,190*
5105	44,316	47,685	44,030

*Split bus, single bus value

The ABB report concluded that the following contingencies were the most critical conditions:

Bruce B

N-1 - loss of Bruce A to B 500 kV line

N-2 - loss of Bruce A to B and Bruce B to Milton 500 kV lines

Bruce A

N-1 - loss of Bruce A to B 500 kV line

N-2 - Loss of Bruce A to B and Bruce A to Clairville 500 kV lines (for 230 kV units with all 500 kV units off line)

N-5 - Loss of Bruce A to B and Bruce A to Clairville 500 kV lines and all three 500/230 kV transformers (critical case for 500 kV units)

Nanticoke

⁹ PSCAD is electromagnetic transient simulation software distributed by the Manitoba HVDC Research Centre on behalf of Manitoba Hydro

¹⁰ E-TRAN is translation software to PSCAD distributed by Electranix Corporation, Winnipeg.

- N-4 - loss of both Nanticoke to Middleport 500 kV lines and both 500/230 kV transformers at Nanticoke (critical case for 500 kV units)
- N-6 - loss of both Nanticoke to Middleport 500 kV lines and all four 230 kV lines out of Nanticoke 230 kV substation, with all four 500 kV units off-line (critical case for 230 kV units)

In order to examine the possible impact of 30 % series compensation on the B562L, B563L and N582L transmission lines on the Bruce, Nanticoke and Lambton generators, the subsynchronous torsional modes of oscillation for these units is obtained from Appendix B of reference [1]. Reproduced below as follows:

Power Plant	Subsynchronous Modes (Hz)	Torsional	Comments
Bruce A	8.66, 16.06, 23.89 and 23.27		Confirmed by Siemens, however, manufacturer indicated that testing in the field performed at some stage (details unknown) showed the first torsional mode to be at 9.17 Hz. Since there is little information on the test data, for the purposes of this study the calculated modes based on manufacturer supplied data was used. All four units are identical.
Bruce B	7.5, 14.19, 19.31 and 22.25		These numbers were received 10/12/05, and are pending some review and possible revision. The four units are all identical.
Nanticoke	15.1, 28.8, 35.3 and 56.2 (G1 – 6) 14.3, 25.9, 30.3 and 53.7 (G7 – 8)		Waiting on confirmation and spring-mass models. Units 1 to 6 are identical mechanically and units 7 & 8 are also identical mechanically, but the two groups are different from each other. Electrically, units 1, 3, 6 and 8 are identical and units 2, 4, 5 and 7 are identical but the two groups differ from each other.
Lambton	16.88, 26.93, 34.83 and 56.30		Only available data at this point. All units identical.

It is the complementary frequencies ($60 - \text{Torsional Frequency}$) that can be compared with the frequency scans of critical contingencies as reproduced below. The electric system frequency scans as seen from the air gap of the respective generators show that the observable electric resonances all fall below 30 Hz. None of the complementary torsional frequencies of the Bruce generators fall in this range, based on these critical contingencies. See Figures C-1 to C-4 below.

The Nanticoke generators G1 to G6 have a $60 - 35.3 = 24.7$ Hz complementary frequency that lines up with the electrical resonance for the critical contingencies. See Figure C-5 below. If these units are to be removed from operation with some units decoupled and operating as synchronous condensers, then the torsional modes will be removed and no longer an issue.

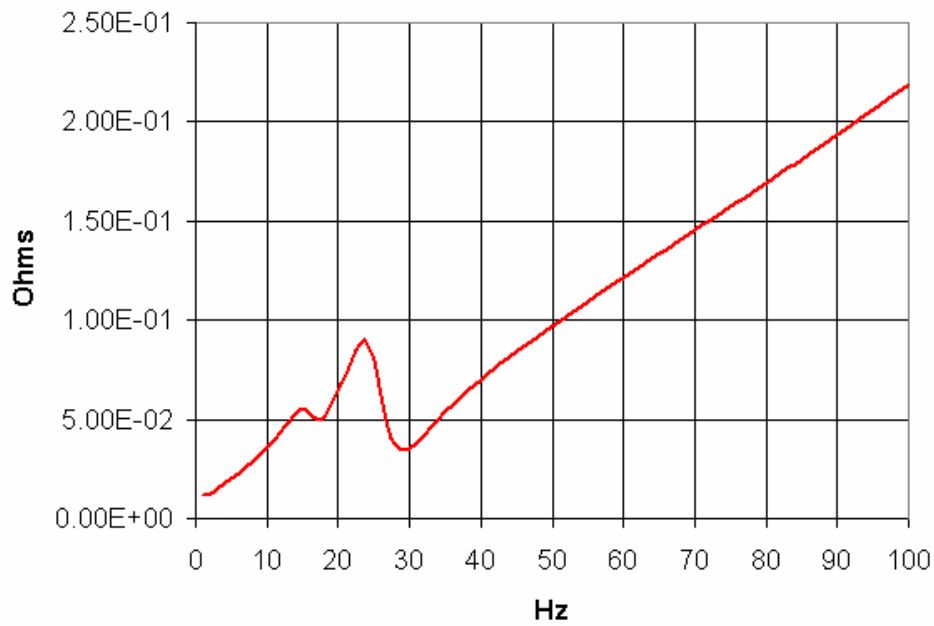


Figure C-1: SSR frequency scan for Bruce B generators for N-1 loss of Bruce A to B 500 kV line

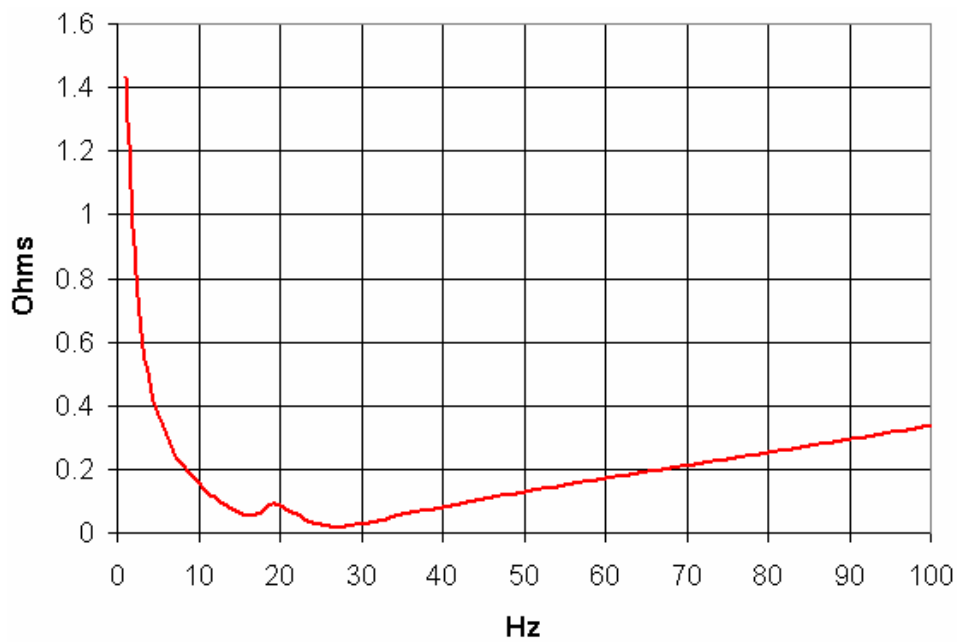
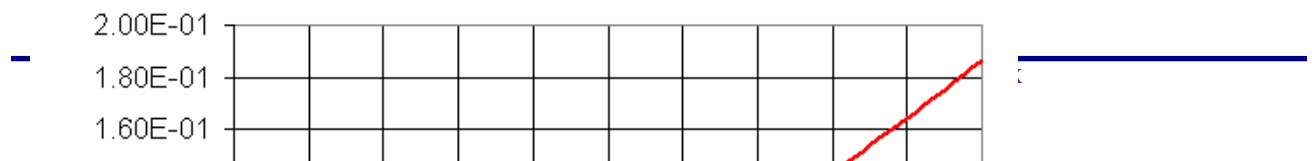


Figure C-2: SSR frequency scan for Bruce B generators for N-2 loss of Bruce A to B 500 kV line and Bruce B to Milton 500 kV lines



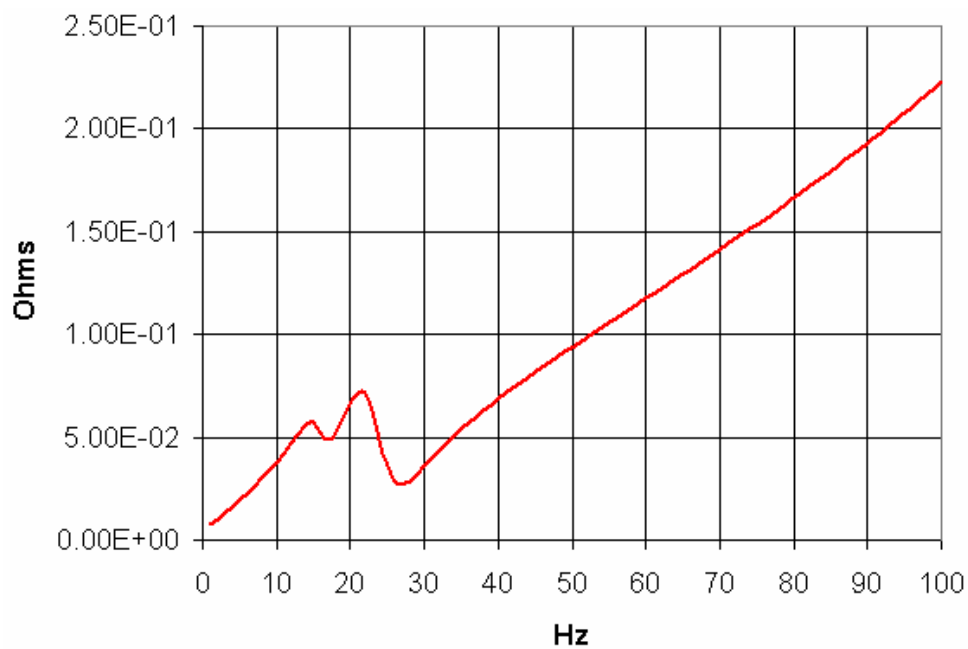


Figure C-4: SSR frequency scan for Bruce A generators for N-2 loss of Bruce A to B 500 kV line and Bruce A to Clairville 500 kV line (for 230 kV units with all 500 kV units off line)

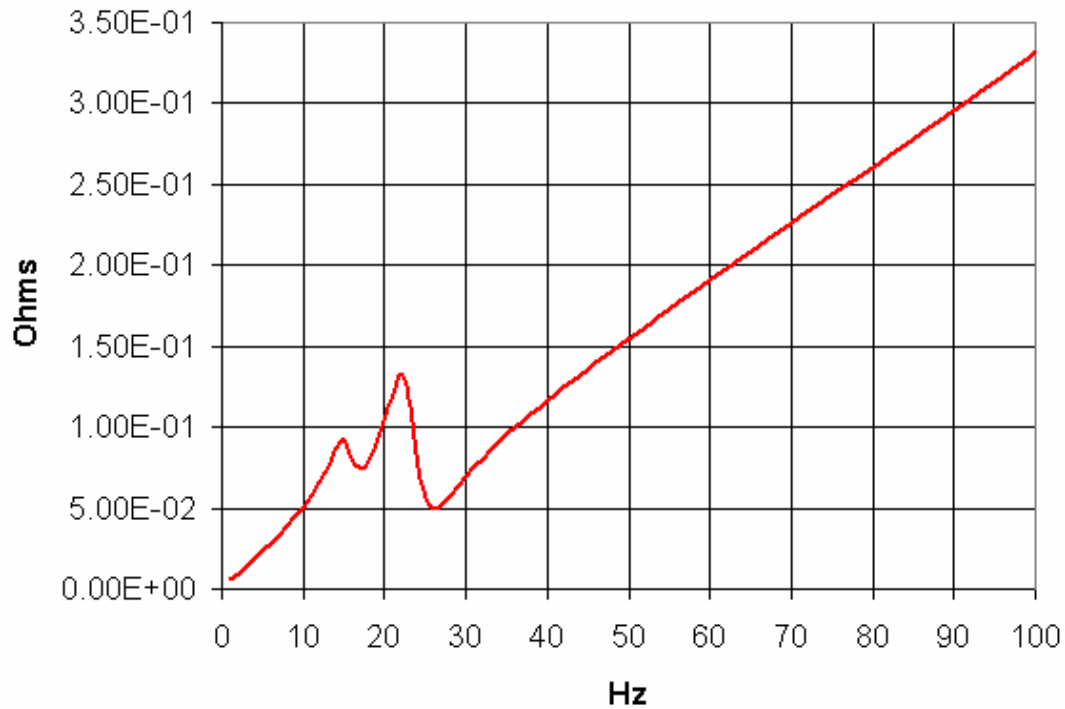


Figure C-5: SSR frequency scan for Nanticoke 500 kV generators units 5 and 6 for N-4 loss of both Nanticoke to Middleport 500 kV lines and both 500/230 kV transformers at Nanticoke (critical case for 500 kV units)

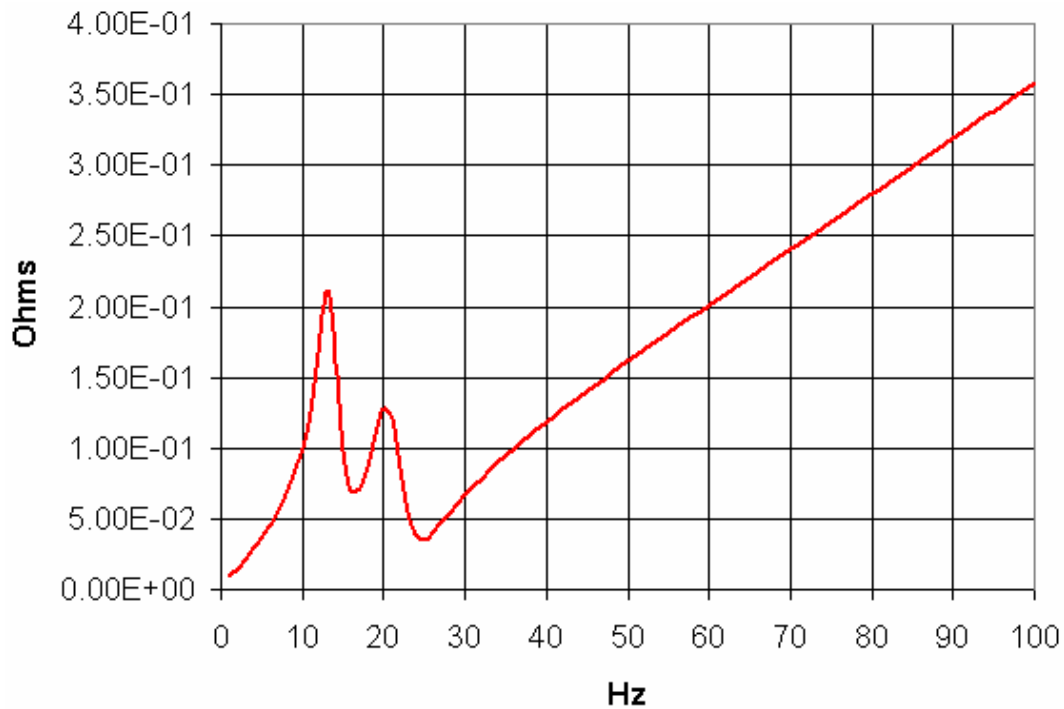


Figure C-6: SSR frequency scan for Nanticoke 500 kV generators units 7 and 8 for N-4 loss of both Nanticoke to Middleport 500 kV lines and both 500/230 kV transformers at Nanticoke (critical case for 500 kV units)

Pappas INTERROGATORY 7 List 2

Interrogatory

Issues:

- 1.1 Has the need for the proposed project been established?
- 2.1 Have all reasonable alternatives to the project been identified and considered?
- 2.2 Has an appropriate evaluation methodology been applied to all the alternatives considered?
- 2.4a Have appropriate evaluation criteria and criteria weightings been utilized in the evaluation process for the alternatives and the proposed project and what additional criteria/weightings could be considered?
- 3.1 Are the proposed near term and interim measures as outlined in the application appropriate?

Ref

1. APPENDIX A to Procedural Order No. 5. IN THE MATTER OF Leave to Construct Application by Hydro One Networks. EB-2007-0050. DATED February 25, 2008
2. Technical Conference, Day 1 [Oct. 15, 2007]: Transcript - Mr. McKay.

Preamble:

Following, is an excerpt from the Transcript of the Technical Conference, Day 1, Oct. 15, 2007.

MR. McKay's comments regard the Series Compensation Due Diligence Study. I maintain that this study is an absolute prerequisite to the advancement and approval or denial of this Application. This study involves matters of both the project alternatives and possible near term and Interim measures.

Questions by Mr. McKay

MR. McKay: I will be very quick. Can you turn up on your slides the summary of options for screening results? That is the matrix. Can you give us a bit more explanation on the category for limited effects on other paths, in terms of what that criteria is and what it is used in terms of how you use it to evaluate in terms of eliminating certain of these alternatives.

MR. CHOW: The southwestern Ontario network is quite interconnected in terms of it is not an isolated system. It affects many other paths. When we look at this in combination with providing required capability - and in this case you look at it together, side by side - it gives you an indication that, one, does it have the capability; two, when you actually have that system, does it affect, in this case, negatively on other paths? So in the case of Bruce to Essa, that's an easy one. The power from Bruce is being sent up to Barrie, to Essa. There it's getting combined with the flow for northern Ontario and it all shares the same path from Essa down to Claireville, Barrie to Toronto.

1 So in that case there, its impact is going to reduce the transfer capability on that path by 1000
2 megawatts.. So it is a consideration because it is negatively affecting other paths. In the case of
3 series capacitors on the 500 kV line and the Bruce-to-Longwood-to-Middleport, the path is
4 affecting to a large degree the flow coming from west to east through the London area. Because
5 you lose the Bruce-to-Milton line, the power from Bruce going down the Bruce-Longwood line is
6 combined with the flow coming in from the Sarnia and Windsor area, and together they travel the
7 path between London and Nanticoke.

8 So, again, it has a negative impact on the ability -- in other words, they share the power one way
9 or the other. The one path requires the power. The other one has to back off.

10 So in a way, it is a negative, but the way we look at it is a combination of both the first column
11 and the second column.

12 MR. McKAY: On that basis, I guess one criteria, you discounted the series capacitors as a long-
13 term solution; that and the fact that it doesn't have the capacity?

14 MR. CHOW: Mainly that it doesn't have the capacity. It is capable of seven units versus 700
15 megawatts of wind.

16 MR. McKAY: When you did that analysis, were you including generation rejection?

17 MR. CHOW: No, because we are looking at this set as a long-term solution.

18 MR. McKAY: That is an isolated analysis on simply the series capacitors?

19 MR. CHOW: Yes.

20 MR. McKAY: So you rejected the series capacitors on a long-term basis, and then from the
21 green-line graph that we have seen today, you have made it quite clear that you don't need it on
22 an interim basis with the near-term and the interim measures you want to put in place. So the
23 question I have is: Why are you continuing with the study? You don't need it in the long term,
24 and it's pretty clear that you don't need it to meet the interim requirements.

25 MR. CHOW: The answer is on the next slide after that, on the interim. The decision on series
26 compensation will be made in consideration of the line-in-service date. In other words, will it be
27 late, the effectiveness of the other measures. We believe that the GR, in combination with the
28 other measures, will provide us the necessary capability. When we actually end that phase there,
29 we want to see how close we are, and also the progress of generation additions on the system.

30 MR. McKAY: That's a change in the evidence; right?

31 MR. CHOW: At that time, series compensation is a possibility. I am indicating here it is still a
32 possibility, with those considerations. So it is always looked at as a back-pocket solution that we
33 would put in if certain conditions are met.

34 MR. McKAY: As a final question, a lot of talk today about this study that's being done. I'm
35 assuming that there were some form of terms of reference or something that put some bounds
36 around what this study is, what it is supposed to produce, what you expect. Is that available if we
37 ask that in an interrogatory?

38 MR. CHOW: This is related to the due-diligence study on series compensation?

39 MR. McKAY: Yes.

40 MR. CHOW: Yes. Its terms of reference were developed for the consultant. It would be a part of
41 the attachment of the report, and, yes, on request in an interrogatory.

42 MR. McKAY: Can we get it now or get it within a couple of weeks?

43 MR. NETTLETON: The trouble that I am having is the message that we have communicated to
44 all of the parties has been that we are prepared to look at these requests for additional information
45 through the interrogatory process.

46 I will have to check the procedural order, but I think there is a due date on when IRs are due and
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6 document, I'm assuming, is available today, now; obviously we're not going to ask to produce it
7 here today, but as an interrogatory, it would be good to have the confidence that you wouldn't
8 object to it being filed as an answer to an interrogatory.

9 MR. NETTLETON: I'm not hearing any objection from OPA.

10 MR. McKAY: Thanks.

11
12 **Request:**

13
14 Will, the Applicant and its Proponents [OPA, IESO] provide the Board and the Interveners with
15 those documents, studies, communications, consultations or reports, draft or final, regarding the
16 OPA due diligence report on Series Compensation.[capacitors] immediately, as it is absolutely
17 necessary for the Interveners to be able to frame Interrogatories based on these and have
18 appropriate time for review and production?

19
20
21 **Response**

22
23 Yes, please refer to Exhibit C-4-6 in response to Pappas Interrogatory #6
24

Pappas INTERROGATORY 8 List 2

Interrogatory

Issues:

- 1.1 Has the need for the proposed project been established?
- 2.1 Have all reasonable alternatives to the project been identified and considered?
- 2.2 Has an appropriate evaluation methodology been applied to all the alternatives considered?
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10 MR. McKAY: Thanks.

11
12 Request:

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15 these documents, studies, communications, consultations or reports, draft or final, regarding the
16 OPA due diligence report on Series Compensation.[capacitors] as hardcopy [printed], so that they
17 can be included in the Application binder with the other documentation relevant to this
18 application, which the Applicant previously provided?

19
20
21 Response

22
23 Please refer to Exhibit C-4-6 in response to Pappas Interrogatory #6

Pappas INTERROGATORY 9 List 2

Interrogatory

Issues:

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8 object to it being filed as an answer to an interrogatory.

9 MR. NETTLETON: I'm not hearing any objection from OPA.

10 MR. McKAY: Thanks.

11
12 Request:

13
14 Will the Applicant and its Proponents [OPA, IESO] provide the Board and the Interveners with
15 the parameters they set for the OPA Due Diligence Study on Series Compensation [capacitors]
16 and all associated communications between the Applicant, OPA, IESO and any consultants,
17 regarding the initiation, terms of reference, parameters, imitations, and undertaking of the
18 consultation/study?

19
20
21 Response

22
23 The Terms of Reference for the OPA's Due Diligence Report on Series Capacitors is included as
24 Attachment 1 in the CD being provided and as hardcopy.

25
26 The Terms of Reference reflects the parameters of the study as well as its initiation, limitations
27 and undertaking. In Hydro One's view, these documents provide an adequate background to the
28 study and the information being requested. Hydro One is not prepared to file "all associated
29 communications" between the Applicant, OPA, IESO and any consultants, as the Interrogatory
30 requests, due to the broadness of the request and the time and effort required for production of the
31 information.

March 1, 2007

Consulting Services related to:

A Due Diligence Study and Development of High Level Planning Specifications for the Installation of 500 kV Series Capacitor Banks in the Southwestern Ontario Transmission Network

Purpose

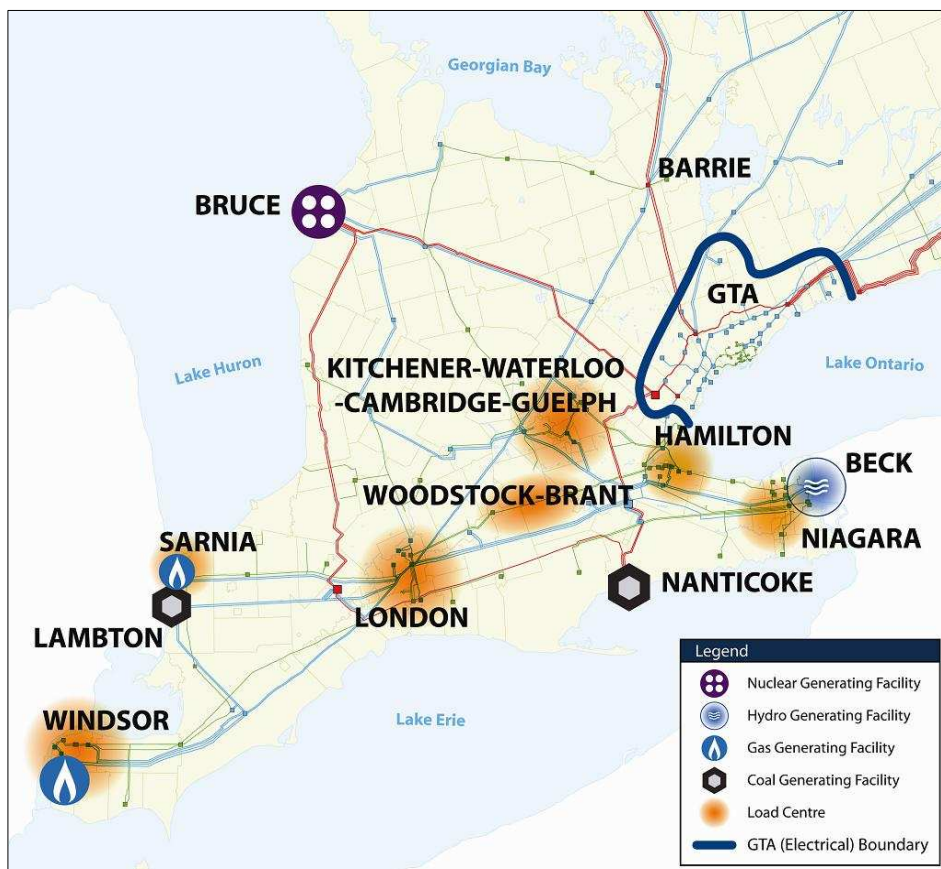
The Ontario Power Authority (“OPA”) seeks consulting services with respect to a specific use of series capacitors on the 500 kV system in the Ontario electricity system.

OPA seeks consulting services to:

- Review and make recommendation on the appropriateness of the proposed series capacitor application for Ontario's southwestern system.
- Provide information on specific performance and reliability concerns on the series capacitors.
- Review a consultation study on sub-synchronous-resonance completed for Hydro One Networks Inc., the major transmission company in Ontario, and provide recommendation on the appropriateness of relying on the study for these purposes.
- Prepare high-level preliminary planning specifications for the series capacitors.

Background

Southwestern Ontario (SWO) is the region of southern Ontario that lies west of the Greater Toronto Area (GTA) and the Barrie area. The transmission system in SWO is illustrated in Figure below.



The critical elements of this SWO system are:

- four 500 kV circuits on two tower lines out of Bruce – two circuits to the London area, and two circuits to the GTA
- one 500 kV circuit from the London area to Nanticoke
- two 500 kV circuits from Nanticoke to the GTA
- the 500 kV transformer stations at Bruce (north of Kincardine), Longwood (west of London), Nanticoke (east of Port Dover) and Middleport (east of Brantford)

- an underlying 230 kV network

The SWO system interconnects the major generating and load centres in SWO, and SWO with the transmission system in the GTA, the Barrie area and the states of New York and Michigan. The major generation centres in SWO include: Bruce (5,060 MW), Nanticoke (3,945 MW), Lambton (1,972 MW) and the Beck Niagara Complex (2,006 MW). With the gas fired generating stations in Windsor and Sarnia area, the generation capacity in the area totals about 15,000 MW.

Currently there are 6 out of 8 nuclear units in service at Bruce GS. With the planned return of two nuclear units at Bruce GS and a potential for significant new wind generation in the Bruce area, there is a need to increase the capability of the transmission system to accommodate the generation in the Bruce area. Bruce GS is expected to achieve a full 8 unit operation in early 2012. As well by then, about 725 MW of new wind generation is expected to be connected to the transmission system connecting Bruce GS. This will result in total Bruce area generation to be in the 7300 MW range. Although the transmission system was originally designed to accommodate 8 units at Bruce GS, it was designed with prevailing power transfers westbound into Michigan on four interconnection lines. However, the generation situation in Ontario and in the U.S. has changed resulting in the power transfer in the area being more eastbound towards GTA. This has reduced the ability to transfer the Bruce area generation to GTA, the major load centre. This situation is exacerbated by the development of wind generation in the Bruce area.

The preferred solution to increase the power transfer capability out of Bruce area is a new 500 kV line from Bruce GS to GTA. This project will be underway very soon. However, this project will involve regulatory approvals including the Environmental Assessment which can involve a lengthy period. To address the possibility of a delay in the in-service date of the line, mitigating measures are being considered.

Currently the most critical contingency is the loss of the double-circuit 500 kV line connecting Bruce GS to stations in GTA. To increase the capability of the existing system, installation of reactive power facilities is planned for SWO. These facilities would be a combination of high voltage shunt capacitor banks and static VAR compensators (SVCs). A study is underway to determine the optimum reactive power implementation plan. As the transfer capability is increased with the use of the reactive power facilities, a 230 kV line section becomes the critical element. This line section will be upgraded to allow higher transfer capability.

Two additional measures are also being considered. One involves the use of the generation rejection (G/R) scheme and the other involves installation of series capacitors on the 500 kV lines. There are existing G/R facilities in place for the generation from Bruce GS. These facilities will be enhanced for their use with the expected system.

The use of series capacitors in Ontario system has been considered in the past. Currently, there is a plan to use them on two 500 kV single-circuit lines connecting the Barrie area to the Sudbury area in northern Ontario. This application is a more conventional type involving 50% compensation on long lines connecting two areas. Accordingly, while OPA is familiar with the conventional use of this technology, it is interested in receiving advice on the specific use proposed in SWO to accommodate higher generation output from the Bruce area. This application involves a critical system with large nuclear and thermal generating units and major load centres.

This application involves the installation of new series capacitors on three 500 kV transmission circuits:

1. Two Bruce GS to Longwood TS circuits (B562L & B563L)
2. One Nanticoke GS to Longwood TS circuit (N582L)

Compensation level of 30% is being considered on these three 500 kV circuits. The plan does not include series capacitors on the Bruce GS to Claireville TS and Milton TS circuits (B560V & B561M, respectively).

Potential sub-synchronous resonance (SSR) impacts were a concern, especially when 70% compensation was under consideration. There are major nuclear and thermal generating stations presently connected to

the 500kV transmission system in southwestern Ontario. They are Bruce GS (with 8 nuclear units when refurbishments are completed on the two units) and Nanticoke GS (8 coal-fired units). In addition, Darlington GS with 4 nuclear units and total capacity of 4000MW total is connected to the 500 kV system just east of GTA. Part of the task of this RFP involves the review of a SSR study prepared by another consultant and providing a recommendation on the appropriateness of relying on this study.

Another aspect of concern is specific performance and reliability of series capacitor in the proposed application. For example, reduced transfer capability due to unavailability of series capacitors themselves or related equipment would result in very high transmission congestion cost to electricity users in Ontario. Also, due to tight schedules involved in the deployment of the plan to address the possibility of delay on the installation of new 500 kV line, there will be limited time available for the phase-in period. Part of the task of this RFP includes identification of matters that can result in a long phase-in period and appropriate measures to mitigate such matters.

Finally, valued input in developing the specifications from the system and equipment perspectives are of interest. The following sections describe the required tasks in more detail.

Scope and Tasks

1. Series Capacitor (SCAP) Application for SWO

- 1.1. Comment on the appropriateness of employing series capacitors on the 500 kV circuits, at the 30 % compensation level, in the SWO system to increase the transfer capability out of the Bruce GS, considering the criticality and complexity of this part of the Ontario system, and the potential risk to the units at the Bruce, Nanticoke and Lambton generating plants. Provide advice on what further system studies, if any, would be useful for identifying probable risk situations not considered and developing suitable mitigation measures.
- 1.2. Provide information, to the extent it is available, on major high voltage (200 kV or higher) series capacitor installations around the world. Summarize for each, the nature of application (e.g. incorporation of remote hydro plants, nuclear plants, etc), the size (voltage, current and MVAR ratings, etc), the level of compensation, the in-service date, manufacturer, special features incorporated, and other pertinent information.

2. Specific Performance and Reliability Considerations – System Aspects

- 2.1. Comment on the potential voltage control and steady-state over-voltage (>550 kV) issues related to the proposed SCAP installations in SWO. In addition, comment on the possible mitigation measures.
- 2.2. Similar to 2.1 except as applied to temporary over-voltages following transmission outages (in particular, the critical contingency of losing the Bruce X Milton/Bruce X Claireville 500 kV double-circuit line). In addition, comment on the possible mitigation measures.
- 2.3. Comment on the implications of 2.1 and 2.2 on the location of the SCAP banks (i.e. at mid line versus at the Longwood terminal station), and on existing facilities at the terminal stations (i.e. Bruce, Longwood and Nanticoke).
- 2.4. Comment on the impact the SWO SCAPs may have on system damping and the need to retune stabilizers on the Bruce, Nanticoke and Lambton units.
- 2.5. Comment on the potential impact and complexity (e.g. SPS timing and SCAP operation, coordination issues, etc) the SWO SCAP banks may have on the special protection scheme at Bruce. The Bruce Special Protection Scheme (BSPS) provides for rapid post contingency reactor switching, generation rejection, and load rejection when selected.
- 2.6. Comment on the interaction of the SWO SCAPs with future large shunt capacitors or SVC installations in SWO (possibly at the Nanticoke, Middleport, Detweiler stations), and/or uncoupled synchronous condenser operation of some of the Nanticoke units.
- 2.7. Comment on the potential for resonance conditions between the SWO SCAPs and the existing shunt reactors installed at Bruce and Longwood, shunt capacitors at Longwood, and large 500/230 kV autotransformers at Longwood, Bruce and Nanticoke.

- 2.8. Comment on the impact of SCAPs on short circuit levels in the SWO and Greater Toronto Area systems. Identify modelling considerations in performing short circuit studies with the SCAPs

3. Specific Performance and Reliability Considerations – Equipment Aspects

- 3.1. Identify known cases and the typical failure modes of when a SCAP did not operate as intended following contingencies. Discuss the system consequences that followed. Provide statistics or relate experiences of such failures. Comment on how such failures can be mitigated.
- 3.2. Discuss the nature of SCAP equipment failures including but not limited to the usual causes, typical mode of failure and the equipment involved (explosive or not), safety concerns, detectability, preventability, etc
- 3.3. Provide information on the availability of high voltage (200kV and above) SCAP installations including their associated ancillary equipment, in the first year of service, and in the longer term. Identify the nature or equipment that contributed to equipment unavailability. Comment on how unavailability can be mitigated, in particular, in the early phase following its in-service (i.e. front end of the bath-tub curve).
- 3.4. Comment on the pertinent relaying and line protection issues associated the proposed SCAP installations including but not limited to those related to the type and design of the protection required, clearing time implications, telecommunication requirements, and backup protection. Include a discussion of the appropriateness and considerations of line differential schemes on line equipped with SCAP.
- 3.5. Comment on the need to modify the voltage protection on existing equipment in SWO (BIL, SIL, power frequency over-voltages, resonance, harmonics, etc) with the installation of the proposed SCAPs in SWO. Comment on any special insulation coordination considerations and mitigation measures. Comment on the implications of mid-line vs Longwood location on this matter.
- 3.6. Comment on the requirements for high steady state current rating for the proposed capacitor banks and its implication on the SCAP bank design.

4. SCAP application and Sub-Synchronous Resonance (SSR) Considerations

- 4.1. Based on the IESO and ABB studies, comment on the potential for SSR as affecting the Bruce, Nanticoke, Lambton and other generating units in SWO at the 30% compensation level. Comment on the adequacy of the test scope and appropriateness of the modeling employed.
- 4.2. Comment on the type of mitigation measures that could be installed should SSR be of sufficient concern.

5. High Level Planning Specifications for the SWO SCAP

- 5.1. In consideration of the discussions and comments in Parts 1 to 4 above, develop a high level planning specifications, including 1-line diagrams, for the SCAPs proposed for SWO to achieve a high level of availability, dependability and security of operations. The specifications are to include but not limited to:

Table 1: Basic Specifications – SCAP Banks for Bruce x Longwood, and Longwood x Nanticoke

Parameter	Value	Unit
Maximum system voltage (phase-phase)		kV
Nominal reactive power		MVar
Nominal capacitive reactance		Ω/ph
Rated line current		A
30-min overload current		A
10-s overload current		A
Maximum short-circuit current		kA
Rated continuous voltage		kV
30-min overload voltage		kV

10-s overload voltage		kV

- 5.2. Identify, as part of the specifications, special requirements, if any, to mitigate SSR.
- 5.3 Identify other system changes, at a high level, such as relay and protection systems, etc, that major modifications would be required to accommodate the SWO SCAPs

Freedom of Information and Protection of Privacy Act

Information provided by a respondent to this RFP may be released in accordance with the *Freedom of Information and Protection of Privacy Act*, R.S.O. 1990 C. F31, as amended. Respondents should identify any information in their proposal or any accompanying documentation that is supplied in confidence and for which confidentiality is to be maintained by OPA. The confidentiality of such information will be maintained by OPA except where an order by the Information and Privacy Commission or a court requires otherwise. Respondents are advised that their proposals will, as necessary, be disclosed on a confidential basis, to advisors retained by OPA for the purpose of evaluating or participating in the evaluation of this proposal.

Deliverables

Mid-term progress report	April 13, 2007
Draft report submitted to OPA for review	by May 18, 2007
Final report submitted to OPA	by May 25, 2007

Confidentiality

All documentation and information obtained by the participants in connection with this consulting service are the property of OPA and must be treated as confidential and must not be used for any other purpose.

Pappas INTERROGATORY 10 List 2

Interrogatory

Issues:

- 1.1 Has the need for the proposed project been established?
- 2.1 Have all reasonable alternatives to the project been identified and considered?
- 2.2 Has an appropriate evaluation methodology been applied to all the alternatives considered?
- 2.4a Have appropriate evaluation criteria and criteria weightings been utilized in the evaluation process for the alternatives and the proposed project and what additional criteria/weightings could be considered?
- 3.1 Are the proposed near term and interim measures as outlined in the application appropriate?

Ref

1. APPENDIX A to Procedural Order No. 5.IN THE MATTER OF Leave to Construct Application by Hydro One Networks. EB-2007-0050.DATED February 25, 2008
2. Technical Conference, Day 1 [Oct. 15, 2007]: Transcript - Mr. McKay.

Preamble:

Following, is an excerpt from the Transcript of the Technical Conference, Day 1, Oct. 15, 2007.

MR. McKay's comments regard the Series Compensation Due Diligence Study. I maintain that this study is an absolute prerequisite to the advancement and approval or denial of this Application. This study involves matters of both the project alternatives and possible near term and Interim measures.

Questions by Mr. McKay

MR. McKAY: I will be very quick. Can you turn up on your slides the summary of options for screening results? That is the matrix. .Can you give us a bit more explanation on the category for limited effects on other paths, in terms of what that criteria is and what it is used in terms of how you use it to evaluate in terms of eliminating certain of these alternatives.

MR. CHOW: The southwestern Ontario network is quite interconnected in terms of it is not an isolated system. It affects many other paths. When we look at this in combination with providing required capability - and in this case you look at it together, side by side - it gives you an indication that, one, does it have the capability; two, when you actually have that system, does it affect, in this case, negatively on other paths? So in the case of Bruce to Essa, that's an easy one. The power from Bruce is being sent up to Barrie, to Essa. There it's getting combined with the

1 flow for northern Ontario and it all shares the same path from Essa down to Claireville, Barrie to
2 Toronto.

3 So in that case there, its impact is going to reduce the transfer capability on that path by 1000
4 megawatts.. So it is a consideration because it is negatively affecting other paths. In the case of
5 series capacitors on the 500 kV line and the Bruce-to-Longwood-to-Middleport, the path is
6 affecting to a large degree the flow coming from west to east through the London area. Because
7 you lose the Bruce-to-Milton line, the power from Bruce going down the Bruce-Longwood line is
8 combined with the flow coming in from the Sarnia and Windsor area, and together they travel the
9 path between London and Nanticoke.

10 So, again, it has a negative impact on the ability -- in other words, they share the power one way
11 or the other. The one path requires the power. The other one has to back off.

12 So in a way, it is a negative, but the way we look at it is a combination of both the first column
13 and the second column.

14 MR. McKAY: On that basis, I guess one criteria, you discounted the series capacitors as a long-
15 term solution; that and the fact that it doesn't have the capacity?

16 MR. CHOW: Mainly that it doesn't have the capacity. It is capable of seven units versus 700
17 megawatts of wind.

18 MR. McKAY: When you did that analysis, were you including generation rejection?

19 MR. CHOW: No, because we are looking at this set as a long-term solution.

20 MR. McKAY: That is an isolated analysis on simply the series capacitors?

21 MR. CHOW: Yes.

22 MR. McKAY: So you rejected the series capacitors on a long-term basis, and then from the
23 green-line graph that we have seen today, you have made it quite clear that you don't need it on
24 an interim basis with the near-term and the interim measures you want to put in place. So the
25 question I have is: Why are you continuing with the study? You don't need it in the long term,
26 and it's pretty clear that you don't need it to meet the interim requirements.

27 MR. CHOW: The answer is on the next slide after that, on the interim. The decision on series
28 compensation will be made in consideration of the line-in-service date. In other words, will it be
29 late, the effectiveness of the other measures. We believe that the GR, in combination with the
30 other measures, will provide us the necessary capability. When we actually end that phase there,
31 we want to see how close we are, and also the progress of generation additions on the system.

32 MR. McKAY: That's a change in the evidence; right?

33 MR. CHOW: At that time, series compensation is a possibility. I am indicating here it is still a
34 possibility, with those considerations. So it is always looked at as a back-pocket solution that we
35 would put in if certain conditions are met.

36 MR. McKAY: As a final question, a lot of talk today about this study that's being done. I'm
37 assuming that there were some form of terms of reference or something that put some bounds
38 around what this study is, what it is supposed to produce, what you expect. Is that available if we
39 ask that in an interrogatory?

40 MR. CHOW: This is related to the due-diligence study on series compensation?

41 MR. McKAY: Yes.

42 MR. CHOW: Yes. Its terms of reference were developed for the consultant. It would be a part of
43 the attachment of the report, and, yes, on request in an interrogatory.

44 MR. McKAY: Can we get it now or get it within a couple of weeks?

45 MR. NETTLETON: The trouble that I am having is the message that we have communicated to
46 all of the parties has been that we are prepared to look at these requests for additional information
47 through the interrogatory process.

1 I will have to check the procedural order, but I think there is a due date on when IRs are due and
2 there is a due date on when the responses are due.

3 So I think if people want to ask us interrogatories now, they could; and we can hopefully get
4 through the interrogatories as fast as possible. If your interrogatory came in with that request, we
5 would be able to get it done sooner rather than later.

6 MR. McKAY: No. I appreciate that, Mr. Nettleton, but I guess the question was, I'm assuming
7 that in order to get this report done, you would have had to put terms of reference together. That
8 document, I'm assuming, is available today, now; obviously we're not going to ask to produce it
9 here today, but as an interrogatory, it would be good to have the confidence that you wouldn't
10 object to it being filed as an answer to an interrogatory.

11 MR. NETTLETON: I'm not hearing any objection from OPA.

12 MR. McKAY: Thanks.

13
14 Request:

15
16 Will the Applicant and its Proponents [OPA, IESO] provide the Board and the Interveners with
17 the parameters they set for the OPA Due Diligence Study on Series Compensation [capacitors]
18 and all associated communications between the Applicant, OPA, IESO and any consultants,
19 regarding the initiation, terms of reference, parameters, limitations, and undertaking of the
20 consultation/study, immediately, as it is absolutely necessary for the Interveners to be able to
21 frame Interrogatories based on these and appropriate time for review and production?

22
23
24 [Response](#)

25
26 Please refer to Exhibit C-4-9 in response to Pappas Interrogatory #9
27

Pappas INTERROGATORY 11 List 2

Interrogatory

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20 of the consultation/study as hardcopy [printed], so that they can be included in the Application
21 binder with the other documentation relevant to this application, which the Applicant previously
22 provided?

23
24
25 Response

26
27 Please refer to Exhibit C-4-9 in response to Pappas Interrogatory #9