St. Leon Wind Farm
Interconnection Facilities Study

Performed by:

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System Planning Department

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Executive Summary

An Interconnection Facilities Study (IFS) has been performed to determine the Manitoba Hydro Interconnection Facilities and Interconnection System and Network Upgrades necessary to connect up to 100 MW of wind generation to the 230 kV St. Leon ring bus from the point designated for the location of the generation facility near the town of St. Leon, Manitoba. The Manitoba Hydro Interconnection Facilities and Interconnection System and Network Upgrades required for an ultimate wind farm size of 200 MW are determined for information purposes.

The Interconnection Evaluation Study (IES) identified several thermal overloads that required further investigation. The Interconnection Facilities Study has determined solutions to these reliability limitations, and produced a list of equipment upgrades (and associated costs) and/or short-term overload (no cost) requirements. It also determined at what point the mitigation would be required, i.e. today (existing problem) or after connecting 100 MW or 200 MW of wind generation. Connecting a 100 MW wind farm does not require any Interconnection System or Network Upgrades. Connecting a 200 MW wind farm requires a Network Upgrade consisting of reconductoring a 3.15 km section of line YV5 by 2006, which has an estimated cost of $85 050.

A detailed powerflow evaluation of the St. Leon 230 kV ring bus was conducted to determine the ability of the ring bus to accommodate up to 100 MW and up to 200 MW. No thermal overloads were observed for the ring bus or the 230 kV lines. For both 100 MW and 200 MW, if the ring bus is open in certain positions, there is the possibility to overload the 230-66 kV transformers and/or isolate the wind generation onto the 66 kV load and black-out the St. Leon 66 kV system. Protection logic will be installed to trip the wind generation if the St. Leon ring becomes open in breaker positions R2 and R3, R2 and R5 and R6 and R3.

The IFS has determined that the Generator must provide reactive supply that is able to control the voltage level at the St. Leon 230 kV bus by adjusting the machine's power factor between a minimum of 0.95 overexcited and 0.95 underexcited at the generator intermediate bus with a minimum response time of 15 seconds. The Generator will install sufficient reactive power on each turbine's 600 V to maintain unity power factor (i.e. 48 MVAr) and four switched 10 MVAr capacitor banks on the 34.5 kV intermediate bus.

In order for the wind turbine to remain connected during transient undervoltages and overvoltages, a wind turbine with fault ride-through capability will be installed. In addition, the main transformer will be equipped with a +/-10% on-load tap changer. The tap changer will control the 34.5 kV bus voltage and will be set at 0.99 pu (+/-2.5%).

The MH system operator will provide a 230 kV bus voltage setpoint for the 34.5 kV capacitors and a power factor setpoint for the 600 V capacitors. The initial voltage setting for the 34.5 kV capacitors is 1.04 pu and the initial power factor setting is unity. The

automatic capacitor voltage controller will have the ability to trip/insert one or two 34.5 kV capacitors at a time. The following initial 230 kV voltage settings are recommended:

- Trip 2 capacitors: 1.08 pu
- Trip 1 capacitor: 1.05 pu
- Insert 1 capacitor: 1.03 pu
- Insert 2 capacitors: 1.0 pu

The 600 V capacitors will be set to trip coincident with a trip of the wind turbine to minimize the change in voltage on the St. Leon 230 kV bus.

An overvoltage relay will be provided to trip all capacitors. The Generator will coordinate the setting with MH.

The IFS has not shown the need for an undervoltage relay or special telemetry signal to be provided to insert all capacitors for a 100 MW wind farm. However, this may be required if the wind farm plans to expand in the future. An undervoltage relay should be provided to block capacitor insertion if a fault is detected. If an undervoltage relay is provided to insert all capacitors, the setting must be coordinated with MH.

The wind turbine's overfrequency and underfrequency capabilities meet the Manitoba Hydro interconnection requirements.

Wind generator curtailment scenarios and associated unavailability times were calculated. Based on data in the CEA report titled, "Forced Outage Performance of Transmission Equipment", it can be expected that the Generator Facility will be forced out of service 0.522% of the time each year, or 45.3 hours per year. This corresponds to a 99.48% availability rate, not including planned outages.

A detailed cost estimate of the Manitoba Hydro Interconnection Facilities necessary to connect a 100 MW wind farm to the St. Leon 230 kV station bus was calculated. These total costs were estimated to be $ 3,802,891.15.

The estimated date for completion and energizing of Manitoba Hydro Interconnection Facilities is May 31, 2005. Manitoba Hydro will make reasonable efforts to meet an earlier in-service date of October 22, 2004. A detailed project schedule for the meeting the earlier in-service date is attached.

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1.0 Introduction

1.1 Background Information

This report documents the results of an Interconnection Facility Study for a 100 MW wind farm near the town of St. Leon, Manitoba. The Manitoba Hydro Interconnection Facilities and Interconnection System and Network Upgrades will be determined for an ultimate wind farm size of up to 200 MW.

The Generator proposed an in-service date of December 2004 in their original interconnection request and desires that reasonable efforts be expended to obtain an October 22, 2004 in-service date for the Manitoba Hydro Interconnection Facilities.

A direct connection to the St. Leon 230 kV station bus has been chosen as the option for connecting the wind farm to the MH network. Appendix B provides a single line diagram of the major Manitoba Hydro Interconnection Facilities required to connect the wind farm into the 230 kV station bus. One 230 kV circuit breaker and two disconnects plus a 3.15 km line (along with associated protection, control and communications equipment) are required. The line is assumed to have a 954 MCM ACSR conductor, 100 deg C thermal rating (393 MVA summer, 515 MVA winter rating). The identified direct connection facilities should be adequate for the ultimate proposed 200 MW wind farm. A detailed Manitoba Hydro Interconnection Facilities cost estimate is provided in Section 8.0. The assumptions behind the cost estimate are provided in Appendix A.

1.2 Objectives

The Interconnection Facilities Study objectives are to:

- address the system reliability limitations identified in the IES
- determine a good faith cost estimate of all the interconnection facilities
- determine a good faith construction schedule estimate
- determine special protection requirements (e.g. breaker fail, generator cross trip)
- determine communication requirements
- satisfy any requirements of the Regional Transmission Authority

1.3 MH Technical Requirements for Generator Interconnection

Please refer to Appendix C for additional technical requirements not discussed in the body of the report.

2.0 Interconnection System and Network Upgrades

This IFS is for connecting up to 100 MW at the St. Leon 230 kV Station, however the Manitoba Hydro Interconnection Facilities will be designed to accommodate up to 200 MW. The Interconnection System and Network Upgrades identified for the 200 MW wind farm are for information only. There are currently two other Generator Interconnection Requests higher in the connection queue. If these projects proceed, the Interconnection System and Network Upgrades for the additional 100 MW connection at St. Leon will be different.

The Generator and energy purchaser have requested that the 100 MW wind farm be considered a Manitoba Hydro network resource. As a network resource, the impacts of scheduling to generation and load within Manitoba were evaluated. Any necessary Network Upgrades are separately identified.

Interconnection System Upgrades are the minimum necessary upgrades required to interconnect to the MH system and meet reliability criteria. A redispatch to the nearest existing Manitoba Hydro network resource is used as a test for Interconnection System Upgrades. For St. Leon, the nearest MH network resource is Dorsey.

2.1 Planning Criteria – Transmission Line Overloads

To date, Manitoba Hydro does not have published criteria that define 30-minute short-term overload ratings for transmission lines in excess of the steady-state thermal rating. A study is currently underway that may re-define the method used to calculate transmission line ampacities. The ampacity changes will depend on conductor type and design temperature rating. However, for the purposes of this report, short-term overload ratings for all conductors will be defined as follows:

- 115% if caused by a common tower contingency,
- 110% if caused by a single contingency.

If the overloaded segment of transmission line is station equipment rather than the line conductor, the overload capability for that piece of equipment will be individually assessed.

If a short-term overload rating is applied, it is necessary to be able to reduce the line loading to within its steady-state thermal rating within 30 minutes of the overload occurrence.

In the IES, DC power flow analysis tested four different locations to which the new wind generation was scheduled. Most of the overloads occurred if the wind generation was scheduled to Winnipeg River generation or to an increase in Manitoba load. For several lines, the overload is present even before wind generation is added. In these cases it will be Manitoba Hydro's responsibility to address the thermal overloads as required for future or current load-serving purposes.

The Power Transfer Distribution Factors (PTDFs) listed in the upcoming sections approximately represent the wind generator's contribution to loading on the given line, and hence define the impact of wind generation on the overload.

2.2 Mitigation for Reliability Limitations

Several thermal overloads were identified in the Interconnection Evaluation Study (IES) that require further investigation. These reliability limitations were identified in the IES through steady-state DC power flow analysis (PSS/E activity TLTG) and are listed below.

a) 110 kV Laverendrye to St. Vital (YV5) thermal overload
b) 110 kV Cornwallis to Brandon (CB42) thermal overload
c) 230 kV Dorsey to Brandon (D5R) thermal overload
d) 110 kV St. James to Rosser (RS51) thermal overload
e) 110 kV Mohawk to St. Vital (XV39) thermal overload
f) 110 kV Rosser to Griffin Steel (TR5) thermal overload
g) 110 kV Brandon to Victoria (BE3) thermal overload

There were no thermal overloads resulting from redispatching to the nearest MH network resource (i.e. Dorsey). Therefore any upgrades required will be considered Network Upgrades.

2.2.1 Laverendrye to St. Vital 110 kV line YV5

Contingency	Loading (%Rate C)			PTDF (%)	Year	Case	Sink
	No Wind	100 MW Wind	200 MW Wind				
YX47+YX48	105.2	111.3	119.1	7.16	2004	13	MH load
R23R	92.0	97.0	102.4	5.72	2008	41	Wpg Riv
YX47+YX48	98.0	105.4	111.3	7.11	2004	19	Wpg Riv
YX47+YX48	105.1	111.7	117.7	7.10	2008	41	Wpg Riv

The thermal rating of line YV5 is 110.1 MVA. A 3.15 km section of line conductor is the limiting element and it has already been sagged to 100 deg C. The conductor type is 336.4 MCM ACSR 30/7. After applying short-term overload ratings the following overloads still result:

Contingency	Loading (%Rate C + short-term overload)			PTDF (%)	Year	Case	Sink
	No Wind	100 MW Wind	200 MW Wind				
YX47+YX48	90.2	96.3	104.1	7.16	2004	13	MH load
R23R	82.0	88.0	92.4	5.72	2008	41	Wpg Riv
YX47+YX48	83.0	90.4	96.3	7.11	2004	19	Wpg Riv
YX47+YX48	90.1	96.7	102.7	7.10	2008	41	Wpg Riv

For a **100 MW** wind connection, short-term overload ratings will be applied and no fixes are required. The overload will need to be mitigated within 30 minutes by operator control.

For a **200 MW** wind connection, the overloads become too high to apply short-term overload ratings by approximately the year 2006. By 2006, in order to eliminate the overloads, the line would need to be re-conductored. The cost estimate to re-conductor the line with the same size ACSS conductor is as follows:

3.15 km x $27000/km = $85 050

This thermal overload can occur solely due to a Manitoba load increase, whether wind is present or not. However, equipment upgrades will be required sooner with wind than would have occurred with normal load growth. A 200 MW wind connection would require YV5 to be re-conductored by 2006.

2.2.2 Cornwallis to Brandon 110 kV line CB42

Contingency	Loading (%Rate C)			PTDF (%)	Year	Case	Sink
	No Wind	100 MW Wind	200 MW Wind				
Cornwal. Bk3	97.4	102.4	108.1	-6.58	2004	15	MH load
Cornwal. Bk3	99.4	103.4	106.1	-3.90	2008	37	Gr. Rpds
Cornwal. Bk3	99.4	102.4	105.8	-4.21	2008	37	Wpg Riv

The thermal rating of line CB42 is 115.6 MVA. The rating is limited by risers at the Brandon end of the line. Replacing the risers at Brandon would increase the thermal rating by 15.4% to 133.4 MVA, which is the limit of risers at the Cornwallis end of the line.

This overload can occur solely due to Manitoba load increase. Manitoba Hydro is aware that these risers will be overloaded with 2005 summer peak loading, and there is already a recommendation in place to replace the risers by then.

2.2.3 Dorsey to Rosser 230 kV line D5R

Contingency	Loading (%Rate C)			PTDF (%)	Year	Case	Sink
	No Wind	100 MW Wind	200 MW Wind				
D13R+D16R	92.0	98.0	104.2	26.85	2004	15	Wpg Riv
D13R+D16R	92.0	97.0	101.1	26.43	2008	37	Gr. Rpds

The thermal rating of line D5R is 426.3 MVA. The rating is limited by risers at the Dorsey end of the line. The risers are currently rated at 70 deg C.

For a **100 MW** wind connection, there are no overload issues.

For a **200 MW** wind connection, the risers can be re-rated to 80 deg C to provide adequate thermal capacity.

2.2.4 St. James to Rosser 110 kV line RS51

Line Section	Contingency	Loading (%Rate C)			PTDF (%)	Year	Case	Sink
		No Wind	100 MW Wind	200 MW Wind				
St. James-Inkster	YX47+YX48	96.6	98.0	102.7	-3.68	2004	13	MH load
Rosser-Inkster	YX47+YX48	98.0-cond 101.3-riser	100.0-cond 103.3-riser	104.7-cond 108.3-riser	5.46	2004	13	MH load

The thermal rating of the St. James – Inkster section of line RS51 is 160.0 MVA. The rating is limited by the section of underground cable from St. James to Inkster. The underground cable would need to be replaced by 2006 if 200 MW of wind is added, as the cable has no short-term overload capability. Since the PTDF is only slightly above 3%, it will be Manitoba Hydro's responsibility to look into fixing or mitigating the overloads on the underground cable.

The thermal rating of the Rosser-Inkster section of line RS51 is 180.6 MVA. The limiting elements are risers at the Rosser end of the line. The line conductor is the next limiting element at 186.7 MVA. It has already been sagged to 100 deg C. The conductor type is 795 MCM ACSR. The short-term overload rating would be adequate to allow 30 minutes for operator intervention to alleviate the overloads on the line conductors. The risers can be re-rated to provide adequate thermal capacity.

It may be possible to adjust the Winnipeg area phase shifters to reduce loading to within the present steady state ratings for both sections of line RS51. This thermal overload can occur simply due to a Manitoba load increase, whether wind is present or not. Manitoba Hydro will pursue this future load-serving reliability issue by applying operating guidelines that adjust Winnipeg area phase shifters if the YX47 and YX48 common tower contingency occurs.

2.2.5 Mohawk to St. Vital 110 kV line XV39

Line Section	Contingency	Loading (%Rate C)			PTDF (%)	Year	Case	Sink
		No Wind	100 MW Wind	200 MW Wind				
Mohawk-Dakota	YX47+YX48	107.7-cond 102.7-riser	111.5-cond 106.5-riser	115.9-cond 110.9-riser	-3.51	2004	13	MH load
St. Vital-Dakota	YX47+YX48	132.3-cond 127.3-riser	137.6-cond 132.6-riser	143.7-cond 138.7-riser	5.18	2004	13	MH load

The thermal rating of line XV39 is 110.1 MVA. The line conductor is the limiting element and it has already been sagged to 100 deg C. The conductor type is 336.4 MCM ACSR. There are also 115.6 MVA risers at both ends of the line that will experience overloads that are 5% less than the line conductor overloads. After applying short-term overload ratings, the following conductor overloads still result:

Thermal Rating (MVA)	Contingency	Loading (%Rate C + short-term overload)			Year	Case	Sink
		No Wind	100 MW Wind	200 MW Wind			
110.1 Mohawk-Dakota	YX47+YX48	92.7	96.5	100.9	2004	13	MH load
110.1 St. Vital-Dakota	YX47+YX48	117.3	122.6	128.7	2004	13	MH load

This thermal overload is a base case problem, and can occur solely due to a Manitoba load increase, whether wind is present or not. Manitoba Hydro is pursuing this load-serving reliability issue. Equipment upgrades are already required without wind, and will be made worse once wind generation is added. Short term overload ratings can be applied to the Mohawk-Dakota section of line XV39. For the section from St. Vital to Dakota, we are accepting the overloads today, but there is a program in place to upgrade the line by 2006. The section from St.Vital to Dakota must be re-conductored. In addition, the risers must be re-rated at the Mohawk end and replaced at the St. Vital end of the line in order to eliminate the overloads.

In the meantime before the line can be upgraded, it is possible to adjust the Winnipeg area phase shifters to reduce loading to within the present steady state ratings for both sections of line XV39.

2.2.6 Rosser to Griffin Steel 110 kV line TR5

Contingency	Loading (%Rate C)			PTDF (%)	Year	Case	Sink
	No Wind	100 MW Wind	200 MW Wind				
TV1+TV2	63.0	84.0	101.0	17.61	2004	17	Wpg Riv
TV1+TV2	71.0	92.0	108.8	17.62	2008	41	Wpg Riv

The thermal rating of the line TR5 is 93.2 MVA. The line conductor is the limiting element and it has already been sagged to 100 deg C. The conductor type is 266.8 MCM ACSR 6/7.

For a **100 MW** wind connection, there are no overload concerns.

For a **200 MW** wind connection, a short-term overload rating of 115% can be applied. In order to mitigate the overloads within 30 minutes, it may be possible to adjust the Winnipeg area phase shifters to alleviate loading to within the present steady state ratings for line TR5. An operating guideline will need to be put in place to adjust the Winnipeg area phase shifters if the TV1 and TV2 common tower contingency occurs.

2.2.7 Brandon to Victoria 110 kV line BE3

Contingency	Loading (%Rate C)			PTDF (%)	Year	Case	Sink
	No Wind	100 MW Wind	200 MW Wind				
BE1+BE2	120.7	128.4	137.4	6.53	2004	13	MH load

The thermal rating of line BE3 is 81.2 MVA. The rating is limited by the line conductor, which is sagged to 75 deg C. The conductor type is 336.4 MCM ACSR. Short-term overload ratings are inadequate to cover the above overloads. In order to eliminate the overloads, line BE3 would need to be re-sagged to 100 deg C. This would increase the thermal rating by 35.6% to 110.1 MVA.

Since the overloads are a base case problem and are present before wind is added, it is up to Manitoba Hydro to fix line BE3. We are accepting the overloads today, but have a program in place to upgrade the line by 2006. Re-sagging the line would solve any overload issues for wind generation up to 100 MW. A 200 MW wind connection can still result in a 1.8% overload, however a short-term overload rating could be applied in this situation.

2.3 Summary of Network Upgrades

A summary of the need for upgrades or operating guides as the size of the wind farm increases is summarized in Table 1.

Table 1. Mitigation for Reliability Limitations.

Facility	Equipment Upgrades / Operating Guidelines	Necessary ?		
		No Wind	100 MW Wind	200 MW Wind
YV5	Re-conductor line YV5 (3.15 km section from Laverendrye to YV5 tap).	NO	NO	YES
CB42	Already recommendations in place to replace risers at the Brandon end of line CB42 by 2005 summer peak loading.	YES	-	-
D5R	Re-rate the risers at the Dorsey end of D5R.	NO	NO	YES
RS51	Re-rate the risers at the Rosser end. Apply short-term overloads and mitigating operating guideline - adjust Wpg area phase shifters for YX47+YX48 contingency.	YES	YES	YES
XV39	Re-conductor the line from St. Vital - Dakota and replace the risers at St. Vital end. Apply short-term overload rating for section from Mohawk – Dakota and re-rate the risers at Mohawk. In meantime, operating guideline – adjust Wpg area phase shifters for YX47+YX48 cont.	YES	-	-
TR5	Apply short-term overloads and mitigating operating guide - adjust Wpg area phase shifters for TV1+TV2 contingency.	NO	NO	YES
BE3	Re-sag line BE3. In meantime, apply short-term overloads and operating guideline to eliminate the overloads for the BE1+BE2 contingency.	YES	-	-

A **100 MW** wind connection does not require any Network Upgrades.

A **200 MW** wind connection requires the following Network Upgrade:

- Re-conductor 3.15 km section of line YV5 by 2006
  Cost estimate: \$27 000/km x 3.15 km = \$85 050
  PTDF: 7.16%

3.0 Capability of St. Leon 230 kV Ring Bus

The St. Leon 230 kV ring bus is shown in the single line diagram given in Appendix B. The thermal rating of the existing ring is limited to 398.4 MVA. The two 230-66 kV transformer banks 3 and 4 are each limited to 93 MVA.

Power flow analysis was used to investigate the thermal capability of the St. Leon 230 kV ring bus to accommodate wind generation of 100 MW and 200 MW. All combinations of breaker and line prior outages followed by all single contingencies, as well as breaker fail cases were analyzed in terms of power flows through the ring bus, transformers and St. Leon 230 kV lines.

No limitations were observed for the ring bus or the lines.

If there is a prior outage of breaker 6 or breaker 5, followed by a trip of breaker 3 or breaker 2 respectively, the corresponding 230-66 kV transformer bank 3 or bank 4 will overload unless the wind generation is limited to 93 MVA. In both of these scenarios, loop flows occur through the transformer from the 230 kV bus to the 66 kV bus and back up through the other transformer. The St. Leon 230-66 kV transformers are equipped with reverse current protection to protect against reverse power overloads and to protect 66 kV customers from undervoltage. The reverse current protection is set to a lower MVA level than 93 MVA. Therefore, even if the wind was limited to 93 MVA in certain open ring scenarios, a reverse current could still flow through the other transformer, possibly causing it to trip off. This would leave the wind generation isolated onto the 66 kV load, which would then lead to a black-out the 66 kV system at St. Leon.

In order to prevent the wind generation from becoming isolated onto the 66 kV St. Leon system, protection logic will be installed to trip off the wind farm if the ring bus becomes open in positions R2 and R5 (by tripping R6), R3 and R6 (by tripping R5), or R2 and R3 (by tripping R5 and R6).

4.0 Wind Turbine Models

The Generator has finalized selection of the wind turbines for the St. Leon project and will be installing NEG Micon NM82 1.65 MW turbines with voltage fault ride-through capability. A more detailed set of user models was provided by the Generator under confidentiality agreement to Manitoba Hydro. The models consist of:
CIMTSS: single cage induction generator model
TSHAFT2: 2-mass shaft model
NM72PC: pitch angle control model
FRQTRP: under/over frequency tripping model
VTGTRP: under/over voltage tripping model

The two mass shaft model introduces oscillations compared with the PSS/E CIMTR3 model used in the IES. The two mass model represents the large inertia turbine rotor and the small inertia generator connected via a gearbox and shaft with finite stiffness. Appendix F contains comparison plots between the IES and IFS models for a 5-cycle 3-phase St. Leon 230 kV fault. Damping is within MAPP and MH criteria.

A comparison of the data used to model the single cage induction generator between the IES and the present study is given in Table 2.

Table 2: Comparison of Wind turbine Dynamics Data

Parameter	**CIMTR3 Value**	**CIMTSS Value**
Zsorce	0.222 pu = X’	0.17587 pu = X’
T’ (sec.)	1.073	1.11227
T” (sec)	0.0	0.0
H	5.26 MW-sec./MVA	0.7475 pu
X (pu)	4.18	4.02782
X’ (pu)	0.222	0.17587
X’’ (pu)	0.0	0.0
Xl (pu)	0.143	0.10195
E1	1.0	1.0
S(E1)	0.17	0.06
E2	1.2	1.2
S(E2)	0.44	0.15
Switch.	0.0	0.0
SYN-POW	0	0

The Generator changed from a two transformer connection as assumed in the IES to a single 230-34.5 kV 100/133/167 MVA transformer bank. An investigation was undertaken to determine the impacts of varying the transformer impedance between 7% and 12.5% in order to aid the Generator in selection of an appropriate size. Results are given in Section 6.1.

5.0 Frequency, Voltage and Reactive Power Requirements

5.1 Turbine Overfrequency / Underfrequency Ride-Through Capability

The wind turbine has the capability to operate between 57 Hz and 62 Hz continuously and will trip off within 100 ms if the frequency is less than 57 Hz or greater than 62 Hz [2].

A typical generator connected to the MH network should stay connected if the frequency remains within the limits given in Table 3.

Table 3. MH Frequency Ride-Through Requirements.

Time	Underfrequency	Overfreqency
Continuous	60.0-59.0 Hz	60.0-61.5 Hz
10 minutes	59.0-58.7 Hz	61.5-62.0 Hz
30 seconds	58.7-57.5 Hz	62.0-63.5 Hz

The wind turbine has adequate underfrequency ride-through capability. The MH Transmission System Interconnection Requirements document [1] states that the Generation Facility is to remain connected if the frequency is in the range of 62.0-63.5 Hz for 30 seconds. MH has agreed that the wind turbine's overfrequency capability of 62 Hz will be adequate for connecting to the MH transmission grid.

5.2 Turbine Overvoltage / Undervoltage Ride-Through Capability

The wind turbine has the capability to operate up to 115% voltage for 5 seconds. The wind turbine will trip off within 100 ms if the voltage at the wind turbine 600 V bus exceeds 115% [2]. The wind turbine will remain connected as long as the voltage does not drop below 70% for more than 2.5 seconds or 15% for more than 0.7 seconds. Within 5 seconds, the voltage should recover to a minimum of 90%. The turbine can operate continuously between 90% and 110% voltage [2].

Table 4 summarizes the overvoltage and undervoltage requirements at the St. Leon 230 kV bus during local and remote disturbances. The worst undervoltage cases occur during 230 kV faults near the St. Leon station. The worst overvoltage cases occur when large amounts of power from the HVdc system are lost (e.g. trip of Manitoba-USA 500 kV line followed by an HVdc reduction, or a permanent or temporary block of a bipole).

Table 4. MH Over- and Undervoltage Ride-Through Requirements at the POI.

Overvoltage (pu)		Undervoltage (pu)	
Continuous	1.10	Continuous	0.90
2 sec	1.10-1.21	2 sec	0.70-0.90
200 ms	1.21	0.5 sec	0.70
		267 ms	0.0-0.50
		100 ms	0.0

Figure 1 below graphically represents the MH transient voltage criteria.

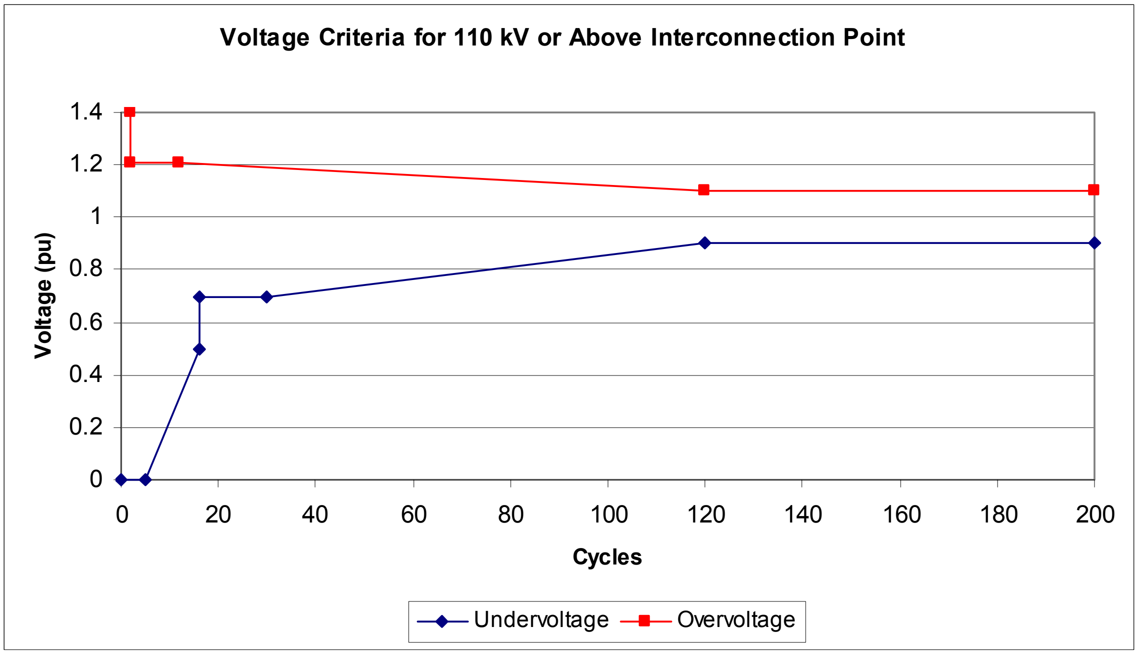


Figure 1. Voltage ride-through requirements for interconnection to St. Leon 230 kV bus.

The overvoltage ride through capability of the wind turbine does not meet Manitoba Hydro's overvoltage criteria. A voltage control scheme is required to ensure the voltage on the wind turbine's 600 V bus does not exceed 1.14 pu allowing a 0.01 pu voltage trip margin. This voltage control scheme will be described later in the report.

The undervoltage ride through capability of the turbine meets Manitoba Hydro's undervoltage criteria. The voltage at the turbine bus during nearby faults will be calculated for various transformer impedances in Section 6.1.

5.3 Reactive Power Requirements

The Manitoba Hydro Transmission System Interconnection Requirements document [1] states that any Generation Facility greater than 10 MW comprised of induction type generators (such as may be connected to wind turbines) shall provide reactive supply that is able to control the voltage level by adjusting the machine's power factor between a minimum of 0.95 overexcited and 0.95 underexcited as measured at the Generator intermediate bus. The power factor requirements could be larger depending on transient stability analysis.

Because the wind generators are not synchronous machines, stand-alone capacitors will need to be installed to provide the leading power factor requirement.

An additional 32.9 Mvar of capacitance is required to meet the 0.95 leading criteria for a 100 MW wind farm. This capacitance is in addition to the full load power factor correction (PFC) capacitors installed on the 600 V turbine buses totaling 47.9 MVAr. The total installed capacitance required to meet 0.95 leading power factor on the 34.5 kV intermediate bus is 80.8 MVAr.

A minimum of 66 MVAr of additional capacitance is required to meet the 0.95 leading criteria for a 200 MW wind farm. This capacitance is in addition to the full load PFC capacitors of 95.8 MVAr, making for a total capacitance requirement of 161.8 MVAr.

The Generator has agreed to install four 10 MVAr capacitor banks on the 34.5 kV bus in adition to the 47.9 MVAr PFC capacitors to meet the reactive power requirements for a 100 MW wind farm.

6.0 Stability Investigation

6.1 Impact of Transformer Impedance

A voltage control scheme is required to:

- keep the worst-case temporary overvoltage (TOV) at the 600 V wind farm bus below 1.14 pu and
- keep the transient voltage at the St. Leon 230 kV bus above 0.7 pu.

The voltage control scheme must be coordinated to satisfy both of these requirements, and ensure that the steady state operating voltage at the 600 V bus does not exceed its continuous rating. Table 5 summarizes the reactive power requirements and the allowable voltage control range at the 600 V turbine bus to satisfy the above requirements. The results are provided for 230-34.5 kV transformer impedances values between 7% and 12.5%.

Table 5. Reactive power requirements and 600 V bus voltage control ranges.

230-34.5 kV Transformer Impedance (%)	Reactive Power at 34.5 kV Bus (MVAr)	Reactive Power at 600 V Bus (MVAr)	Max 600 V Bus Voltage (pu)	Min 600 V Bus Voltage (pu)
12.5	30 switched caps[1]	50 fixed caps	1.04	Fail
12.5	30 SVC[1]	50 fixed caps	1.046	Fail
12.5	60 SVC	20 fixed caps	1.06	0.900
9.0	30 switched caps	50 fixed caps	1.043	0.980
8.0	30 switched caps	50 fixed caps	1.039	0.973
7.0[2]	30 switched caps	50 fixed caps	1.052	0.953

[1] Not acceptable – violates 0.7 pu MH transient voltage criteria at St. Leon 230 kV bus.
[2] close to violating fault ride-through (0.148 pu for 5 cycles).

The rows highlighted in yellow all provide acceptable solutions.

Summary of requirements:

- A 230-34.5 kV transformer impedance greater than 9% requires an SVC to prevent transient voltage violations. The exact ratio of 34.5 kV SVC MVARs to 600 V fixed capacitor MVARs will be dependent on the exact transformer impedance - the higher the transformer impedance, the higher the percentage of dynamic vars required.

- If the 230-34.5 kV transformer impedance is 9% or less the 30 MVAr reactive power requirement may be provided in the form of switched capacitors. These capacitors must be equipped with an undervoltage relay to prevent 0.7 pu transient voltage violations, if the 600 V bus is at the minimum end of the voltage range specified in Table 8.

- A three-phase fault at the St. Leon 230 kV bus resulted in a 600 V bus voltage of 0.148 pu, 0.164 pu and 0.2055 pu for transformer impedances of 7%, 8% and 12.5% respectively. The transformer impedance should be greater than 8% to ensure adequate fault ride through capability.

- Regardless of the 230-34.5 kV transformer impedance, there must be a voltage control scheme to control the 600 V bus voltages between the minimum and maximum values provided in Table 8. This voltage control could be a $\pm$5% on-load tap changer on the 230-34.5 kV transformer controlling the 600 V or 34.5 kV turbine bus voltages. The 34.5-0.6 kV transformer taps should be fixed at nominal. This will also ensure the turbine continuous voltage rating of 90%-110% is not exceeded.

6.1.1 Generator Facility Model

Based on the above analysis, the main 230-34.5 kV transformer has been ordered by the Generator and will have an 8.5% impedance and come equipped with a +/-10% on-load tap changer (step sizes of 5/8%), which will control the 34.5 kV bus.

Preliminary studies by the Generator's consultants indicate they plan to control the 34.5 kV bus voltage to 0.99 pu. Assuming there is not much more than a 1-1.5% voltage drop between the 34.5 kV bus and the turbine 600 V buses, this value is within the acceptable range presented in Table 8 above. The consultants have modeled the 34.5 kV collector system with R-L circuits and have not modeled the cable capacitance as it apparently is not significant enough to affect the 600 V bus voltages. The 34.5 kV capacitors will be used to control the 230 kV bus voltage.

6.2 Description of Wind Farm Voltage Control Scheme Equipment

6.2.1 Transformer On-load Tap Changer

Voltage regulation of the 34.5 kV bus is performed by the transformer on-load tap changer. It will keep the 34.5 kV voltage at a setpoint with a bandwidth of 5%. The OLTC control senses voltage and can change generation level or switch substation capacitors with an adjustable time delay of approximately 10 seconds. Shorter delays are not permissible due to excessive wear on the OLTC load-break contacts.

6.2.2 34.5 kV Switched 10 MVAr Capacitor Banks

Voltage regulation of the 230 kV incoming line is performed by four 10 MVAr switched capacitors connected to the 34.5 kV bus. The line voltage is measured and an Automatic Capacitor Controller (ACC) makes a decision to switch one or more station capacitors. There are three possible modes of operation: manual, power factor or voltage. The ACC automatically switches to manual after a voltage relay operation. Power factor control is used to switch capacitors to reduce demand billing charges for loads. Voltage control will be the normal mode of operation.

For small changes in voltage, one capacitor bank is switched after a 10-second time delay. If a single capacitor bank is insufficient, the next bank will be switched after an adjustable time delay (i.e. between 10-second and 5-minutes). The time delay should not be shortened below the value necessary to coordinate with the 2 capacitor bank switching setpoint.

For larger voltage variations, two capacitor banks may be switched with no time delay added to the inherent time delay (i.e. 5.5 second closing delay and 5 second opening delay). A minimum of 5 second is required to measure the voltage and relay the signal to the vacuum interrupter. The vacuum interrupter has a 0.5 second close delay and a few cycle opening delay.

Emergency voltage regulation of the 230 kV line is performed via a protective relay. An undervoltage (27) or overvoltage (59) relay element will cause all capacitor banks to be switched at once. This system can also respond to a telemetry signal from the wind farm or from Manitoba Hydro. The time delay of this system is reduced to a few cycles plus the vacuum interrupter delay.

A safety discharge time delay of 5 minutes is recommended for typical capacitor banks before re-energizing unless special discharge circuits are installed. It is possible to bypass the safety discharge time if required for infrequent emergency voltage regulation.

6.2.3 600 V Switched Capacitor Banks

Each wind turbine has five switched capacitor banks connected to the 600 V bus of sufficient size to control the power factor at the wind turbine bus to unity. Normally, the power factor setting will be unity. Loss of the wind turbine will also trip the 600 V capacitor banks. MH may request the wind turbine bus be controlled to a lagging pf depending on system conditions.

6.3 Voltage Control Settings

Table 6 summarizes the voltage control range of the two wind farm sizes with reactive support ranging from 0.95 overexcited to 0.95 underexcited. The base powerflow case used to determine the voltage control ranges started with a 1.0187 pu pre-wind voltage at the St. Leon 230 kV bus.

Table 6. Voltage control ability at point of interconnection: 0.95 lag to 0.95 lead.

Power Factor	100 MW	200 MW
	230 kV bus (pu)	230 kV bus (pu)
0.95 lag	0.9995	0.970*
1.0 unity	1.0210	1.0148
0.95 lead	1.0394	1.055*
Voltage control range at 230 kV bus	-2.15% to +1.84% **Total: 3.99%**	-4.48 % to +4.02% **Total: 8.50%**

*With transformer taps adjusted ±5% to ensure 600 V bus voltage within 90-110%.

For system intact conditions, each 10 Mvar step results in 0.6% voltage on the 230 kV bus and 1.6% change on the 34.5 kV bus. During a prior outage of one of the 230 kV lines, each 10 MVAr step results in a 0.8-1.0% change in voltage on the 230 kV bus and 1.8-2.1% change on the 34.5 kV bus

Typical voltage recordings taken at the St. Leon 230 kV station are shown in Appendix E. Over the past two years, the St. leon 230 kV bus voltage has varied between 1.02 and 1.07 pu with a typical value of 1.04 pu.

Based on the above information, the initial settings recommended for the voltage controller are:

- Trip 2 capacitors: 1.08 pu
- Trip 1 capacitor: 1.05 pu
- Insert 1 capacitor: 1.03 pu
- Insert 2 capacitors: 1.0 pu

The above settings will attempt to maintain the 230 kV voltage near 1.04 pu. The time delays for insertion and removal of the capacitors should be adjusted to achieve approximately a 15 second response time.

MH voltage fluctuation limits permit voltage changes of less than 2.0% 10 times per hour and between 2.0-2.4% twice per hour. The response time and size of the four 10 MVAr capacitors will not cause MH voltage fluctuation limits to be exceeded.

The overvoltage relay setting to turn off all capacitors could be set to 1.1 pu with a time delay of 5 seconds. The Generator will coordinate the overvoltage setting with MH.

6.4 Transformer Tap Changer Setting

6.4.1 Ability to Withstand Overvoltages

The wind turbine has an overvoltage ride-through capability of 115% for 100ms. The 1.21 pu temporary overvoltage (TOV) at St. Leon exceeds the capability of the wind turbines. A simulation was run to test the system overvoltages resulting from a trip of the Manitoba – USA 500 kV tie line followed by an HVdc reduction. The TOV at the Dorsey bus reached 1.28 pu. The voltage was attenuated to 1.21 pu at the St. Leon 230 kV bus. It is critical that the wind farm does not trip out during this disturbance. Loss of the 500 kV line is the largest disturbance in MAPP and therefore spinning reserve requirements are calculated based on this worst-case disturbance. If the wind farm trips out, MH may be responsible for supplying an extra 100 MW of spinning reserve, and the Generator would be required to pay this cost. Since this is very expensive, mitigation options were investigated to reduce the TOV seen at the wind turbine so the wind farm remains connected for TOVs up to 1.21 p.u. for 200 milliseconds at the St. Leon 230 kV bus.

The magnitude of the TOV at the 600 V bus is highly dependent upon the pre-disturbance steady state voltage at the 600 V turbine bus. The steady state 600 V bus voltage is highly dependent upon the 230-34.5 kV transformer impedance and the wind farm power factor and tap changer setting. It was found that if the steady state 34.5 kV bus voltage was kept below 1.037 pu, then the worst-case TOV at the turbine bus remained below 114%.

The 34.5-0.6 kV generator transformer taps should be fixed at nominal.

Appendix F contains the power flow and stability simulation showing the worst case overvoltages. With all capacitors connected, and the 34.5 kV bus voltage controlled to 1.037 pu, the maximum 600 V transient voltage is 1.137 pu.

These mitigation tests were performed for a 100 MW connection only. Similar detailed investigations into the TOV issue will be performed for the 200 MW connection at some point in the future if the additional 100 MW connection request proceeds. These detailed studies for a 200 MW connection are beyond the scope of this study.

6.4.2 Ability to Withstand Voltage Collapse

The IES identified a disturbance that resulted in voltage collapse. This disturbance is a single line-to-ground fault on 230 kV line D14S with stuck breaker R4 and a subsequent trip of 230 kV line S53G. The IES found that voltage collapse occurred for wind farms greater than 130 MW.

The IES performed stability studies using the PSS/E CIMTR3 induction generator model to model the wind generators. Detailed wind generator models as described in Section 3.0 were provided for use in the IFS. When using the detailed wind generator models, the stuck breaker SLGF disturbance did not result in voltage collapse for the 100 MW wind farm, however it did result in violations of MH's 0.7 pu transient voltage criteria.

The magnitude of the TOV at the 600 V bus is highly dependent upon the pre-disturbance steady state voltage at the 600 V turbine bus. It was found that if the steady state 600 V bus voltage was kept above 0.933 pu, then the transient voltage at the 230 kV St. Leon bus would remain within the 0.7 pu MH criteria.

With no capacitors connected and the voltage controlled to 0.93 pu on the 34.5 kV bus, the resulting transient voltage is 0.686 pu, which violates the 0.7 pu criteria. With at least 20 MVAr connected, the transient voltage can be maintained above 0.7 pu. Appendix F contains this power flow and stability simulation. Alternatively, the tap changer can control the voltage to a higher value.

Appendix F also contains a post-disturbance power flow for this disturbance, showing restoration of voltage within criteria.

These mitigation tests were performed for a 100 MW connection only. Similar detailed investigations into the voltage violation and/or voltage collapse issue will be performed for the 200 MW connection at some point in the future if the additional 100 MW connection request proceeds. These detailed studies for a 200 MW connection are beyond the scope of this study.

6.4.3 Summary

Based on the capability of the OLTC and on undervoltage and overvoltage investigations discussed above, the OLTC is recommended to control the 34.5 kV voltage to 0.99 pu (+/- 2.5%). If the voltage is at the extreme range (0.99+0.025) and a 10 MVAr capacitor bank switches, the 34.5 kV voltage remains below the maximum permissible voltage of 1.037 pu.

For a 100 MW wind farm, it is not necessary to send a special signal to the capacitor controller to insert the 40 MVAr of capacitance following loss of D14S and S53G. Larger wind farms may require such a signal to prevent transient voltage violations or voltage collapse. The controller should be designed to accept a future telemetry signal from MH.

7.0 Grounding Study

This portion of the studies will be performed in April 2004 and will determine if modifications to the ground grid of the existing substation are necessary to keep grid voltage rises within safe levels. This may have cost implications.

8.0 St. Leon 230 kV Fault Levels

The fault levels at the St. Leon 230 kV station for both the in-service date (ISD) and the ultimate horizon year are provided in Table 7.

Table 7. St. Leon 230 kV Fault Levels.

Fault Level	In-Service Date	Ultimate
Single line-to-ground fault	2733 MVA / 6.9 kA	5216 MVA / 13.1 kA
3-phase fault	2495 MVA / 6.3 kA	5081 MVA / 12.8 kA

9.0 Wind Generation Curtailment due to Forced Outages

The wind Generator Facilities will be tripped off for the following scenarios:

1. 230 kV wind farm line outage
2. Breaker R6 failure when tripping transformer bank 4
3. Breaker R5 failure when tripping transformer bank 3
4. Prior outage of breaker R6 or R2, followed by:
   a) Inadvertent trip of breaker R5
   b) Inadvertent trip of breaker R3
   c) Trip of line D14S
   d) Trip of transformer bank 3
5. Prior outage of breaker R3 or R5, followed by:
   a) Inadvertent trip of breaker R6
   b) Inadvertent trip of breaker R2
   c) Trip of line S60L
   d) Trip of transformer bank 4

Table 8 summarizes the probabilities and durations of each forced wind generation curtailment scenario. These numbers are based on the CEA Report, “Forced Outage Performance of Transmission Equipment.” These unavailability percentages do not include planned outages.

It can be expected that the wind Generator Facilities will be forced out-of-service for 0.522% of the time each year, or 45.3 hours per year. This corresponds to an availability rate of 99.48%.

Table 8. CEA Probabilities of Equipment Forced Outages.

Summary of Wind Curtailment Scenarios			
Event	Probability of 1 Outage Every Number of Years	Mean Duration	% of Time per year wind will be forced out
230 kV Wind Farm line outage (3.15 km)			
	Transient - 52 years Line-related - 75 years Term-related -6.2 years	< 1min 20.3 hr 11.3 hr	~0 0.003 0.02
			Total: 0.023
Prior Outage breaker 6 or breaker 2 – each 1 per 8.32 years, 109.9 hr, total 1 per 4.16 years			
<u>AND</u> Trip breaker 5	8.32 years	109.9 hr	0.01
<u>AND</u> Trip breaker 3	8.32 years	109.9 hr	0.01
<u>AND</u> trip line D14S (129 km)	Transient – 1.3 years Line-related – 1.84 yrs Term-related – 6.2 yrs	< 1min 20.3 hr 11.3 hr	~0 0.0127 0.00258
<u>AND</u> trip transformer bank 3	8.2 years	121.5 hr	0.018
			Total: 0.0533
Prior Outage breaker 3 or breaker 5 – each 1 per 8.32 years, 109.9 hr, total 1 per 4.16 years			
<u>AND</u> Trip breaker 6	8.32 years	109.9 hr	0.01
<u>AND</u> Trip breaker 2	8.32 years	109.9 hr	0.01
<u>AND</u> trip line S60L (100 km)	Transient – 1.64 years Line-related – 2.38 yrs Term-related – 6.2 yrs	< 1min 20.3 hr 11.3 hr	~0 0.00985 0.002
<u>AND</u> trip transformer bank 4	8.2 years	121.5 hr	0.018
			Total: 0.0499
Trip Transformer Bank 3 – 1 per 8.20 years, 121.48 hr			
<u>AND</u> Breaker 5 failure	8.32 years	109.9 hr	0.036
			Total: 0.036
Trip Transformer Bank 3 – 1 per 8.20 years, 121.48 hr			
<u>AND</u> Breaker 5 failure	8.32 years	109.9 hr	0.036
			Total: 0.036

TOTAL UNAVAILABILITY: <u>0.5222 % = 45.3 hrs/year</u>

10.0 Manitoba Hydro Interconnection Facilities Cost Estimate & Schedule

Department	Subtotal	Material / Contract	Subtotal
Structures Equipment and Grounding	$33,392.52	$79,300.00	$112,692.52
SEG grounding study		$31,260.00	$31,260.00
Apparatus	$80,515.97		$80,515.97
230kV breakers (1)		$205,000.00	$205,000.00
230kV CT's (3)		$66,600.00	$66,600.00
230kV CVT's (3)		$26,640.00	$26,640.00
230kV disconnects (2)		$48,840.00	$48,840.00
Communications			
Light wave and Microwave		$585,000.00	$585,000.00
Fiber Cable (OPGW)		$190,000.00	$190,000.00
Line Protection		$225,000.00	$225,000.00
Protection Design	$18,862.18		$18,862.18
Breaker fail relay (1)		$1,500.00	$1,500.00
Line current differential (2)		$30,000.00	$30,000.00
HVDC reduction material		$1,000.00	$1,000.00
Protection Control and Metering			
PCM design	$40,787.65		$40,787.65
PCM draft	$46,755.28	$30,361.00	$77,116.28
SCADA	$63,207.52	$35,000.00	$98,207.52
Civil Design			
Steel design	$11,243.28		$11,243.28
Steel draft	$11,549.91	$79,000.00	$90,549.91
inspection	$3,066.35		$3,066.35
Concrete design	$5,110.58		$5,110.58
Concrete draft	$6,643.75	$9,000.00	$15,643.75
Civil Construction			
Field labour	$128,597.76		$128,597.76
Office labour	$6,929.60	$6,000.00	$12,929.60
Concrete		$15,000.00	$15,000.00
Equipment Rental			
Transmission Line Design and Construction			
Engineering		$103,000.00	$103,000.00
Materials		$451,000.00	$451,000.00
Construction		$161,000.00	$161,000.00
Property		$145,000.00	$145,000.00
Electrical construction field	$253,494.53	$2,000.00	$255,494.53
Electrical construction office	$33,187.12		$33,187.12
Line Construction	$84,716.80		$84,716.80
Material services	$16,408.51		$16,408.51
Apparatus Mtce. South	$15,030.40		$15,030.40
Project Coordination	$197,273.02		$197,273.02
System Support/Recorder	$6,162.46		$6,162.46
System Support/Relay and Metering	$13,230.66		$13,230.66
Insulation Testing	$3,513.60		$3,513.60
Haulage	$13,774.78		$13,774.78
Licensing and Env. Assessment	$12,271.68		$12,271.68
Commissioning	$84,597.24		$84,597.24
Contingency	$86,067.00		$86,067.00
Project Total includes contingency & OH.	**$1,276,390.15**	**$2,526,501.00**	**$3,802,891.15**

Notes:
*** indicates no labour hours and material breakdown, only lump sum value.**
Rev 2 estimated/ by Grant Reilly
No interest or escalation added into est.
Contingency of 20% added into PCM,EC,Comm.
Added in applicable overheads to mat. And labour costs.

Please refer to Appendix A for a listing of assumptions used to calculate the Manitoba Hydro Interconnection Facilities cost estimate.

The estimated date for completion and energizing of Manitoba Hydro Interconnection Facilities is May 31, 2005. Manitoba Hydro will make reasonable efforts to meet an earlier in-service date of October 22, 2004. A detailed project schedule for the meeting the earlier in-service date is included in Appendix D.

11.0 References

[1] Manitoba Hydro Transmission System Interconnection Requirements, Revision 0, December 2003, http://www.hydro.mb.ca/business_customers/tariffsummary.shtml

[2] St. Leon Wind Farm –Manitoba Hydro Turbine Controller Voltage and Frequency Verification Test, Factory Acceptance Test Report, Neg MICON Control Systems, February 2004.

Appendix A:

Cost Estimate Assumptions

From G.W.Reilly
Resource Evaluator
Project Coordination Section
Station Design Department

Date 2003-09-02

File St.Leon Wind Generation Addition.

Subject: Estimate to design supply and install a 230kV line into St Leon Station.

Class 2 scope of work

Assumptions:

1) Install a 3.15 km 230kV line up to Sequoia's Wind Power Station.
   Transmission Line:

   a) The proposed transmission line connects the existing St.Leon Station with the proposed Sequoia Wind Power Station. Transmission line distance is assumed to be 3.15 km, based on the location of the Sequoia Wind Power Station east of and adjacent to the existing D14S 230kV transmission line in NW ¼ SEC.3-5-9W.
   b) Structure types and quantities: ten self supporting "Gulfport" wood pole structures matching locations of the existing structures on the D14S transmission line. Four self-supporting tubular steel angle structures (two at each end).
   c) Conductor types: Phase conductor: 954 kcmil 54/7 ACSR "Cardinal" (three phases). Ground conductors size nine-mm Galvanized Steel Strand.

2) Install one 230kV breaker with external CTs.

3) Install one 230kV center break Mod.

4) Install two 230kV selector switches with interlocking.

5) Install three 230kV CVTs.

6) Install three Bay positions of 230kV upper bus with hardware.

7) Install one Bay position of 230kV intermediate bus with hardware.

8) Install Station lighting into the new 230kV Bay positions.

Structure Equipment and Grounding:

a) SEG will complete all design work, and order the material for all the 230kV Bay positions.
b) SEG will complete the ground study.

9) Install standard Protection and Control in the existing Relay building.
Protection scope:

a) Add breaker fail protection relay for new 230kV breaker R5. Modify breaker R3 and R6 breaker fail tripping. New redundant, dual route bi-directional breaker fail transfer tripping channels from the generation site to St. Leon Station are required.
b) Add redundant 230kV current differential line protection relays complete with redundant, dual route bi-directional data channels from generation site to St. Leon Station. **Note:** Distance protection may be applicable based on line length/impedance and source impedance variations. Three phase CVTs are required for syncro-check, recording, and metering, as well as for distance based back up protection in current differential relays.
c) Reconnect existing Bank 3 protection to reflect re-termination between breakers R3 and R5.
d) Add breaker R5 into existing S60L HVDC reduction logic.

Protection Control and Metering:

a) Existing AC/DC distribution zone boxes for 230kV Bay #2 are adequate
b) Assumes redundant line protection & associated test facilities to fit on lower portion of 230kV panel R014.
c) Assumes breaker fail relay to fit on existing breaker fail panel.
d) All new metering & associated alarms to HMI/RTU via existing serial Modbus link.
e) RTU/HMI reprogramming by SCADA design section.
f) Assumes diode pins are available for A&B trip matrixes.
g) All time & costs based on normal project schedule and in house design with no overtime.
h) Please note that with the addition of this line all space in the 230/66kV control panels CR01/02 is used. There is no additional space available for future control points. Future conversion to PLC/HMI control will be the only option available if continued expansion as indicated on the SLD is to be achieved.

Protection Control and Metering scope:

a) Add two solid state miniature control cards into existing card bins for new 230kV breaker & line MOD, wire in associated 43S switches.
b) Add 52ax, bx & 89ax, bx &SIX relays for new control points into existing ABB Combiflex card bins.

c) Add redundant line protection packages & associated test facilities to lower portion of 230kV panel R014.
d) Add new breaker fail relay & associated auxiliary relay & test switch to existing breaker fail panel.
e) Install new 230kV metering PLC based on standard Modicon Momentum design (PLCM-ZK) in 230kV metering & recording panel (temporary mount required until existing analog points are salvaged). Interfaces via Modbus Plus communication link to existing digital metering system (STMAS &PLCM-ZK). Dialup access is provided for all metering (communication circuit existing).
f) Install new 230kV digital meters for S53G,D14S,S60L & new 230kV line addition in panel R003 (temporary mount required until existing analog points are salvaged).
g) Wire PT/CT circuits to new 230kV line digital meter from existing spare PK blocks on panel R003.
h) Swing existing PT/CT circuits for existing analog xcdrs to new digital meters on per element basis to facilitate testing/commissioning (all wiring changes are on load side of PK test blocks).
i) Add Pt box for new 230kV three phase line PTs & cable to building.
j) Add cabling for circuit breaker & line MOD controls to building.
k) Add cabling for circuit breaker & line MOD AC/DC supplies to zone box.
l) After new digital 230kV metering points are commissioned: salvage existing analog display meters from control panel CR01, salvage existing analog transducers from 230kV metering panel R003.
m) Install new 230 kV digital revenue metering in Generator facility. Provide dial-up access.

SCADA:

a) Need to communicate directly to the generator controls/alarms/metering(will have to use the St. Leon RTU as an interface point).
b) Communications will have to supply a connection over the mux.
c) Install another Modbus Host into RTU for Polling generator metering, alarms, controls.
d) Integrate generator metering, alarms, and controls to RTU data base.
e) Provide control and supervision to SCC.
f) New breaker, Mod, Digital metering.
g) Connect all alarm controls & metering in the St. Leon substation for the 230kV (Breaker & Mod) points (PCM to provide the substation wiring to the new points) to the existing RTU.
h) Use existing Modbus Host in RTU for polling new digital metering and transducer alarms from metering PLC previously installed by PCM.
i) Add alarm legends for alarms, protection.
j) Modify existing and add new alarm grouping to SCC.
k) Add sequence of Events points for new protection.
l) Purchase replacement status input cards for the RTU.
m) Provide control and supervision to SCC.

n) Modify site HMI to add new points.
o) Design and install TFR.

10) Install dual route communications for new line protection and station control & metering.

Communications:

a) The wind generator site includes a suitable shelter for communications equipment, 129 or 48Vdc battery supply, and property adjacent to the shelter suitable for installation a mast for a microwave antenna.
b) Two phone circuits, four modem circuits and two digital line protection circuits over each route are included.
c) The overall length of the buried fibre optic cable is estimated to be 3.5 km.

11) Winter Construction will be required for Civil Construction, all other Construction groups to complete there work in the summer season.
12) No overtime hours have been entered for any work groups. A contingency of 20 percent on labor has been added for PCM, Commissioning and Electrical Construction groups to accommodate factors which could require overtime, consultants or additional crews, beyond what was estimated.
13) Commissioning section has hours into there estimate for Acceptance test write ups and for all the work groups that will be involved with the operational and energization.
14) Electrical Const. estimated to install and wire all major equipment and panels, and assist other work groups as needed.
15) Line Const. estimated to install all buswork, complete with steel and disconnects.
16) Civil Const. estimated to install all foundations and grounding as required.
17) Site improvements estimated to be completed by Civil Construction and only pertain to equipment installed.
18) System Support will test all relays, and wire check panels as required and assist with operational checks.
19) Electrical Maintenance estimated to assist with switching, and Commissioning and complete the Station write ups.
20) Estimate is in 2003/04 dollars. No interest or escalation added into estimate.
21) Estimate is based on adding new equipment /facilities that can accommodate 198 MW of potential new wind generation. Design is based on using existing equipment that can accommodate 99 MW of proposed new wind generation.
22) All Station equipment other than what has been listed will be deemed acceptable for the installation of the 230kV Wind Generation line and therefore has not been estimated to be replaced.

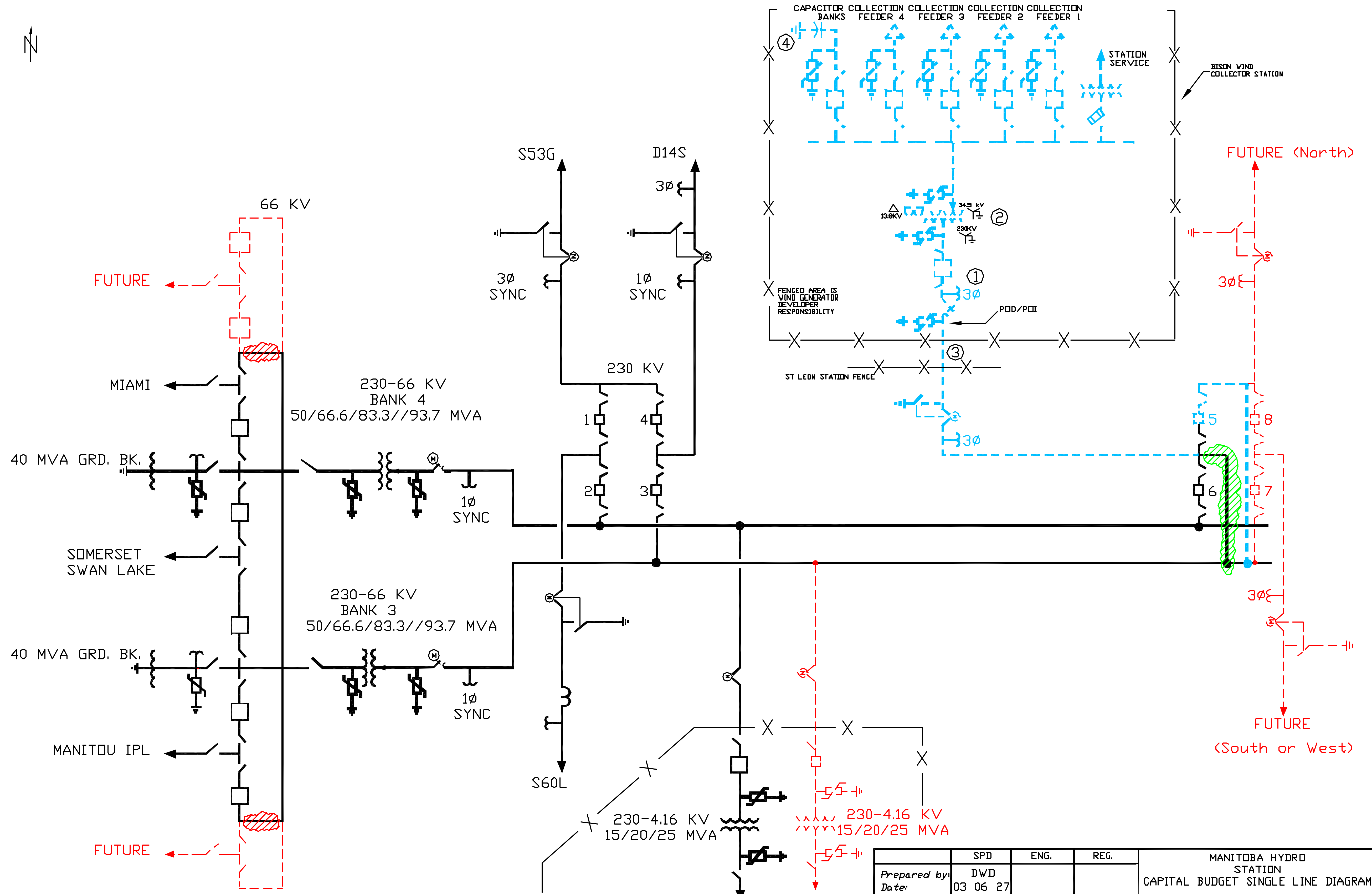
Appendix B:

MH Interconnection Facilities Single Line Diagram

d:\autoCAD drawings\STLeon wind.dwg ddlaklw - UPDATED 04-02-17 3:26

FOR MICROFILM USE ONLY

B SIZE - 279 x 394



NOTE: Wind developer to cover costs of installation and all required equipment.

REMARKS:

1. Metering to be supplied and installed by Manitoba Hydro on the high side of the transformer.
2. Transformer Banks are 230/34.5 kV grounded Y-Y with OLTC +/- 10% range. Rated 100/133/167 MVA.
3. 3 km line connecting the two stations. Line designation B78S.
4. Capacitor banks will consist of 4 x 10 MVAR.

DESIGN

SITE: New ☐ Exist. ■ Rural ☐ Res. ☐ Comm. ☐ Fence ☐ Wall ☐ Area ______ Contaminated Area ☐

BASES: Exist. ☐ New ■

STRUCTURE: Wood ☐ Steel ■ Swgr. ☐ New ☐ Ext'n. ☐ Exist. ☐ Bays (Qt'y.) ______

BUILDING: Exist. ■ New ☐ Add'n. ☐ Type ______ Size ______

COMMUNICATIONS: PLC ☐ Wt/Line MICW ☐ Pilot Wire ☐ None ☐ VF Cable ☐ Super'y. ■

PROTECTION: Relays - Exist. ☐ New ■ Bkr.CT-s Req'd ■ Tr.CT-s Req'd ☐ Channel(s) Req'd ☐

METERING: PSA ☐ Oper. ☐ Cust. ■

EQUIPM'T. REPLACEM'T:

PLANNING

S.C. kA

KV	AT I.S.D 3ø	AT I.S.D SLG	ULTIMATE 3ø	ULTIMATE SLG
230	6.26	6.86	9.98	9.69

LEGEND: Existing, Proposed, Future, Salvaged

REVISIONS

No.	Date	SPD	ENG.	REG.

	SPD	ENG.	REG.
Prepared by: Date:	DWD 03 06 27		
Checked By: Date:	DAJ 04 01 30		
Approved By: Date:	DAJ 04 01 30		

MANITOBA HYDRO STATION CAPITAL BUDGET SINGLE LINE DIAGRAM

ST. LEON STATION WIND GENERATION ADDITION

I.M. NO: 1.1.2.25.1.50

WBS NO: P:07447

NETWORK NO.: 236656

IN SERVICE DATE: 2004 10 31

Appendix C:

Reference to MH transmission System Interconnection Requirements as determined by Interconnection Studies

Please refer to the MH document titled "Transmission System Interconnection Requirements" for details regarding the technical requirements for connecting Generation Facilties to the MH Interconnected Transmission System.

Section 3 of the document, "Generator Interconnection Requirements", defines the requirements applicable for generators applying to connect to the 66 kV, 115 kV, 138 kV, 230 kV and 500 kV nominal voltage levels on the MH Interconnected Transmission System. Section 3 states that some of the requirements are to be defined/determined by the Interconnection Studies. Table C.1 below makes reference to only these requirements, and provides information for those requirements that were to be determined by Interconnection Studies. All remaining requirements not to be determined by the Interconnection Studies are defined in the MH document.

Table C.1. Interconnection Requirements to be determined by Interconnection Studies.

No.	Item	Requirement
3.1	Connection Location and Voltage Level	As discussed in IES Section 1 and IFS Section 1.
3.2	Operating Constraints	As discussed in IES & IFS.
3.3	Reactive Power Requirements	As discussed in IFS Section 4.
3.4	Voltage Variations	As discussed in IFS Section 4.
3.5	Frequency Variations	As discussed in IFS Section 4.
3.6	Inertia Constant (H)	Stability studies demonstrated the ability of the generator unit to maintain connected for typical fault-clearing times assuming the fault ride-through is provided.
3.7	Generator Controls	
	3.8.1 Voltage Regulation	Will be provided with switched capacitors having a voltage response time of 15 sec. as discussed in IFS Section 4.
3.10	SPS or RAS	Not required.
3.11	Black Start Capability	Not required.
3.13	Protective Equipment and Relaying System Requirements	The Generator will be required to install breaker failure protection on the 230 kV breaker. Additional protection to avoid islanding of the Generation Facility onto local load (as discussed in Section 3.0 of the IFS) will be installed by MH at the expense of the Facility Owner.
3.14	Communications	Redundant communications are required at the 230 kV voltage level.
3.16	Supervisory Control and Data Acquisition (SCADA)	The following signals are needed by the SCADA system: ▪ 230 kV breaker and disconnect status ▪ MW ▪ MVAR

		▪ MWh (hourly and monthly) ▪ 230 kV bus voltage ▪ Voltage regulator setpoint and status
3.17	Disturbance Monitoring	A TFR with DSR functionalities is required at the St. Leon end of the line. A TFR is required at the generator end of the line.
3.19	Short Circuit Levels	As discussed in IES Section 6.0 & IFS Section 6.0
3.20	Grounding	To be completed April 2004.
3.26	Isolation	It is preferred to have a safety ground switch, however if not provided MH will use temporary grounding to facilitate line maintenance.

Appendix D:

Project Schedule

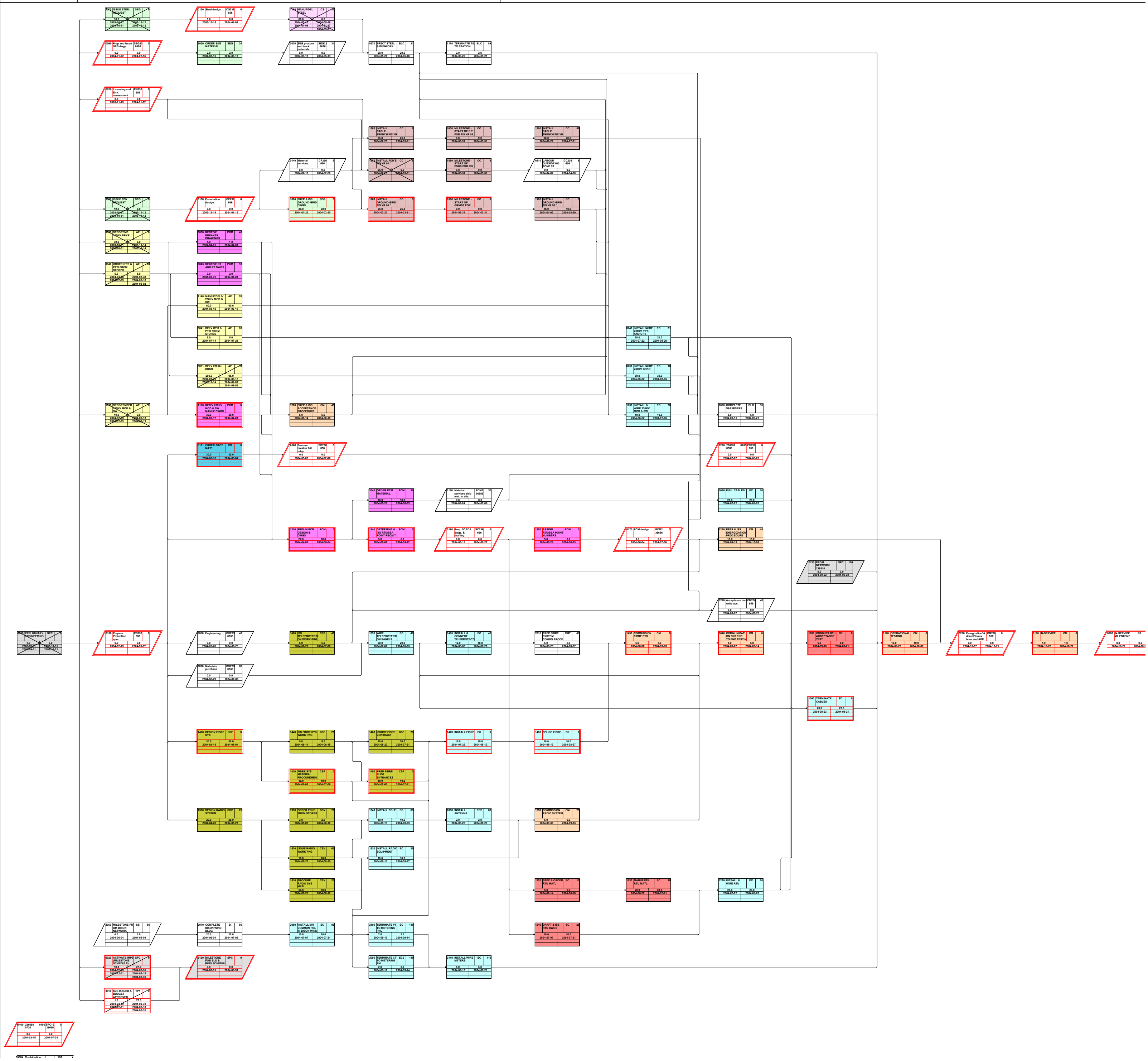
ST.LEON - WIND GENERATION

NETWORK: 236656

COORDINATOR: R. DOIRON

LEGEND

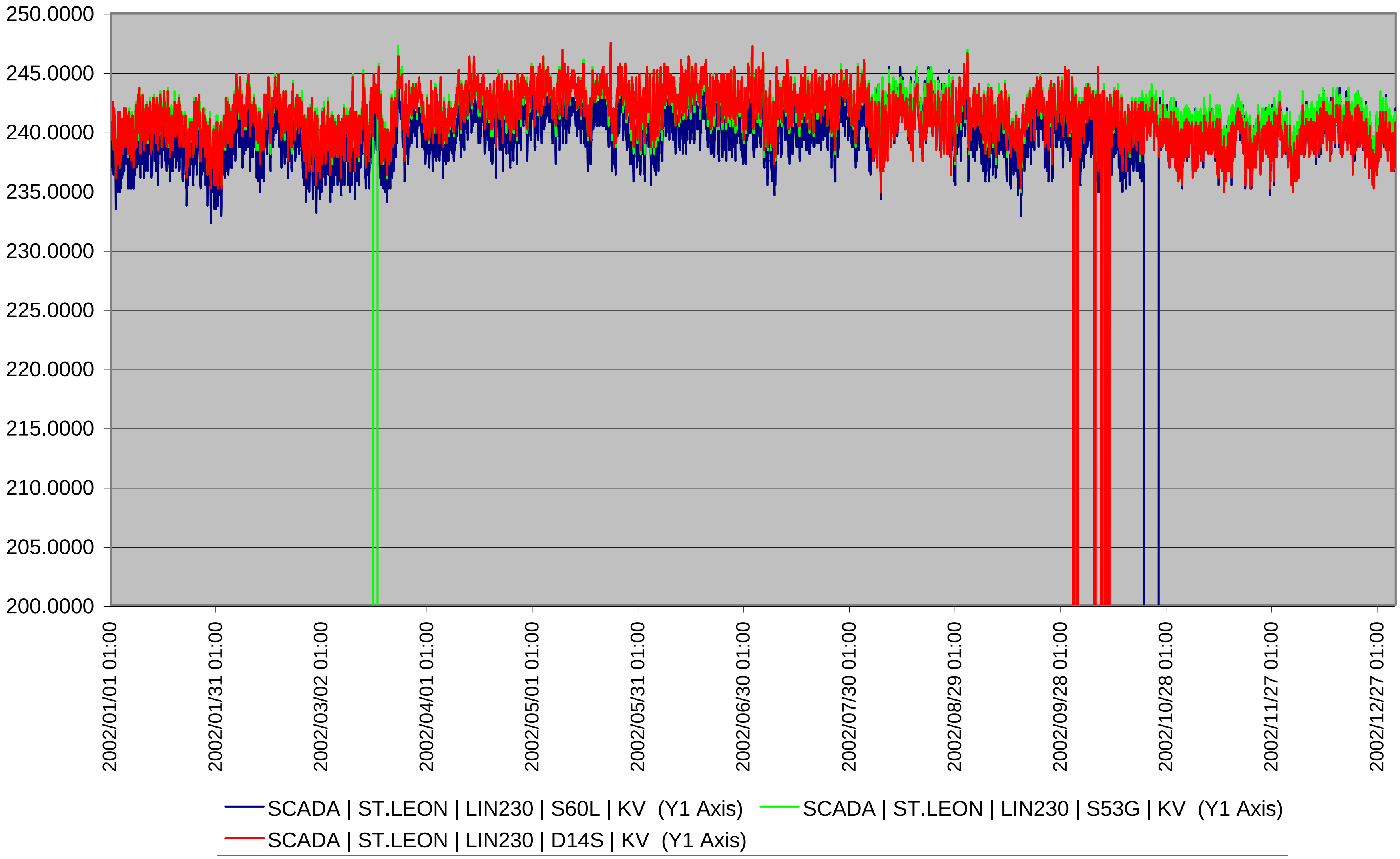
Standard | critical | Completed | Started | MILESTON | AE | CC,TC | CD,CF,C | CM | EC | PCM | PD | SC | SEG | SPC | CSP,CS



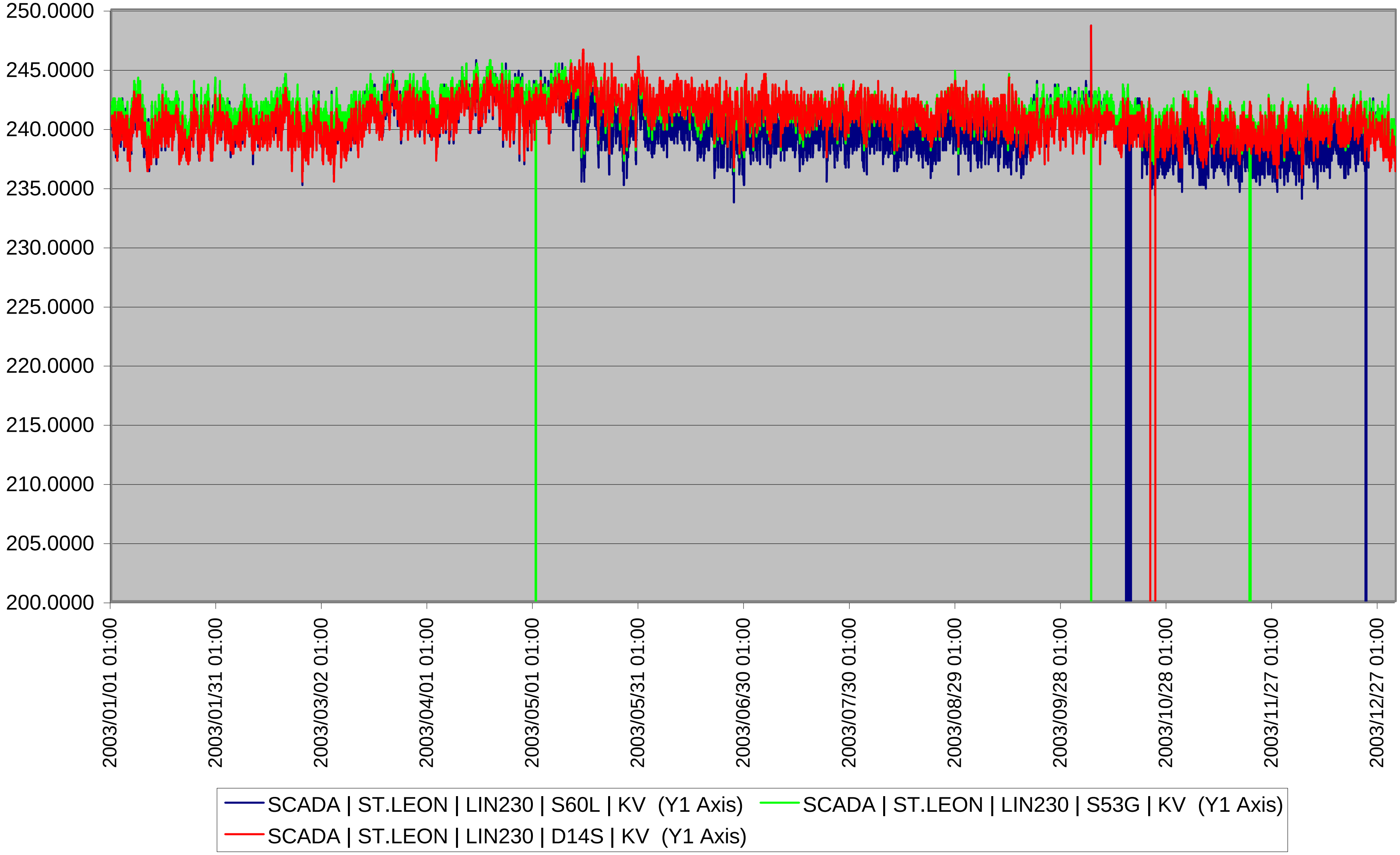
Appendix E:

St. Leon Voltage Recordings

St. Leon Voltage Profile for Year 2002



St. Leon Voltage Profile for Year 2003



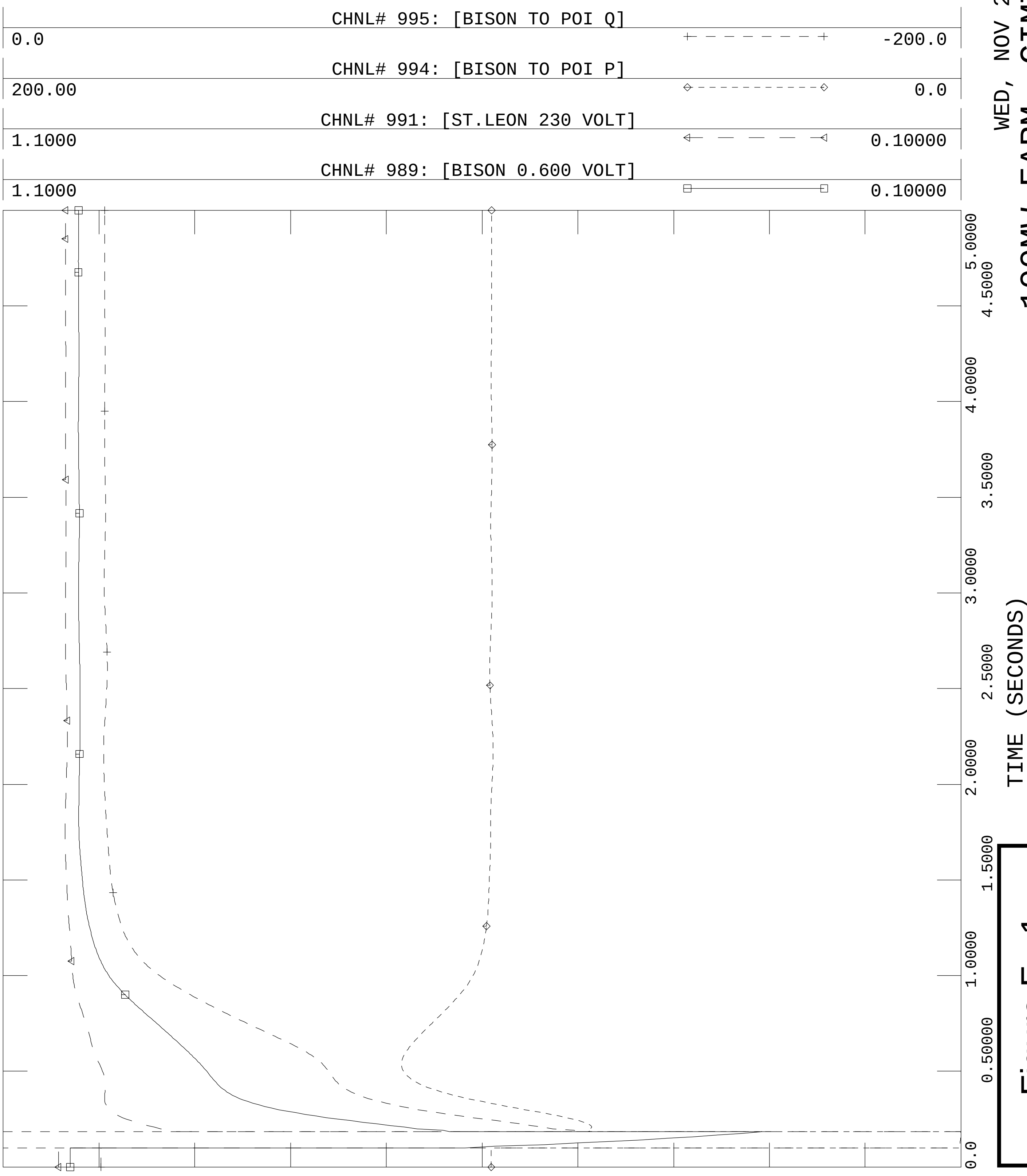
Appendix F:

Stability & Power Flow Plots

CU1-SO03AA.UZVV4V4.SAV;SUMMER;OP LD;SYSTEM INTACT
ND=1951,MH=2176,MW=1480,OHMH=-196,OHMP=150,EWTW=-201,BD=164

POWER TECHNOLOGIES INC.®

FILE: C:\UIP\work-100MW-orig\sa3.out



WED, NOV 26 2003 9:08
100MW FARM, CIMTR3 MODEL

Figure F - 1
IES Model

CU1-SO03AA.UZVV4V4.SAV;SUMMER;OP LD;SYSTEM INTACT
ND=1951,MH=2176,MW=1480,OHMH=-196,OHMP=150,EWTW=-201,BD=164

POWER TECHNOLOGIES INC.®

FILE: C:\UIP\work-100MW\sa3-no-vtrip.out

WED, NOV 26 2003 9:07
100MW FARM, NM72 MODEL

CHNL# 993: [BISON TO POI Q]		
0.0	+ - - - - - - - - +	-200.0
CHNL# 992: [BISON TO POI P]		
200.00	◇- - - - - - - - -◇	0.0
CHNL# 991: [ST.LEON 230 VOLT]		
1.1000	◁ — — — — ◁	0.10000
CHNL# 989: [BISON 0.600 BUS]		
1.1000	□————□	0.10000

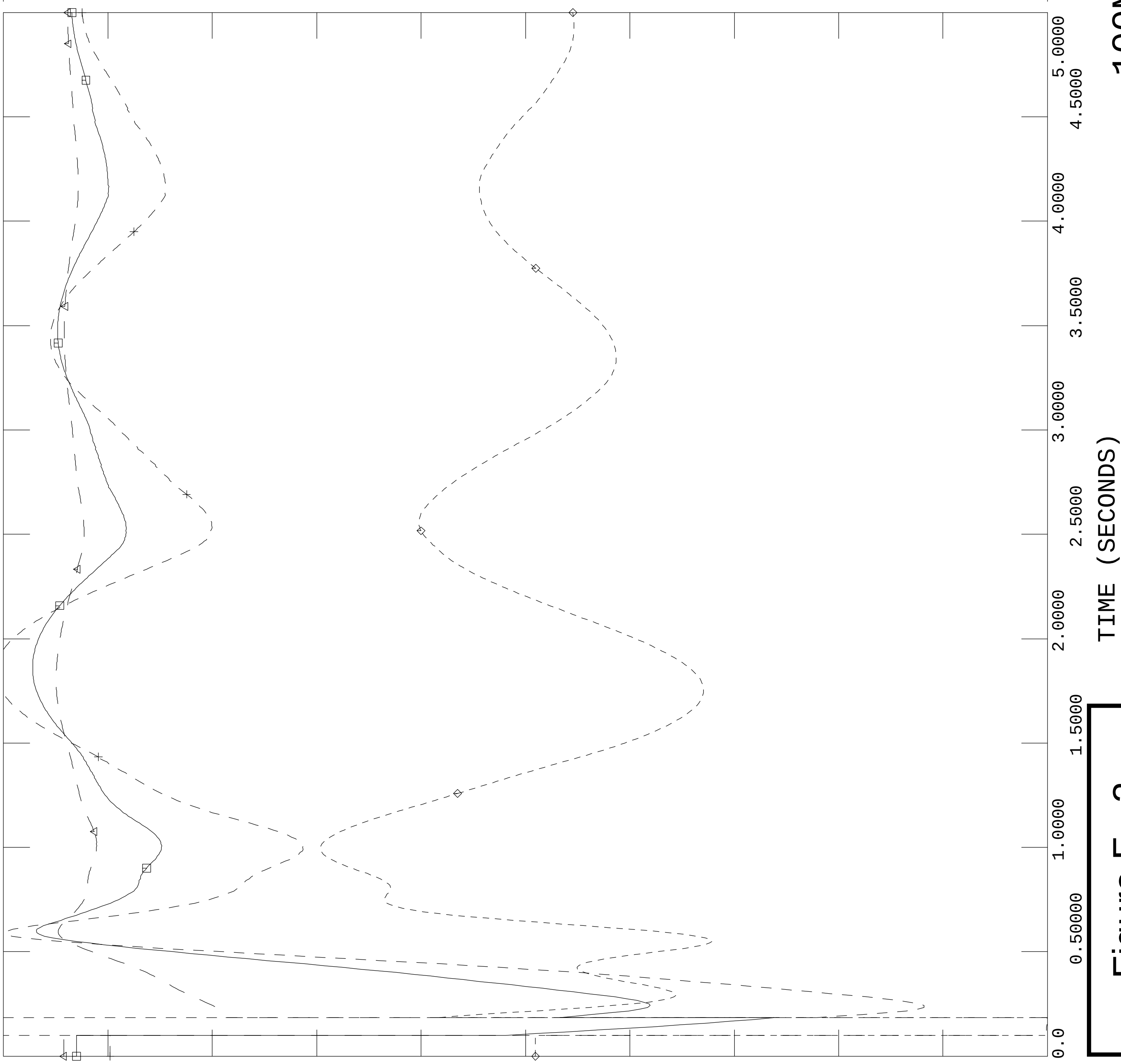


Figure F - 2
IFS Model

Appendix F
Power Flows

TABLE 1

Figure	Loadflow	Comment	Outage	Based on Fault	230-34.5 Tap	ratio	Voltage (pu) 230kV	34.5kV	600V
F - 3	m04-so03aa.uzvV4V4.sav	Base pre-contingency high voltage at 600 V bus	Intact	---	Stepping	1.0625	1.065	1.037	1.038
F - 4	f00-so03aa.uzvV4V4.sav	Base pre-contingency low voltage at 600 V bus	Intact	---	Stepping	1.0625	1.030	0.933	0.915
F - 5	f00-so03xx.uzvV4V4.sav	Post-disturbance developed from case above	D14S and SG3G	scz	Stepping	0.9875	0.962	0.938	0.920

Note: Power flow drawings provided for all cases

99 MW WIND FARM

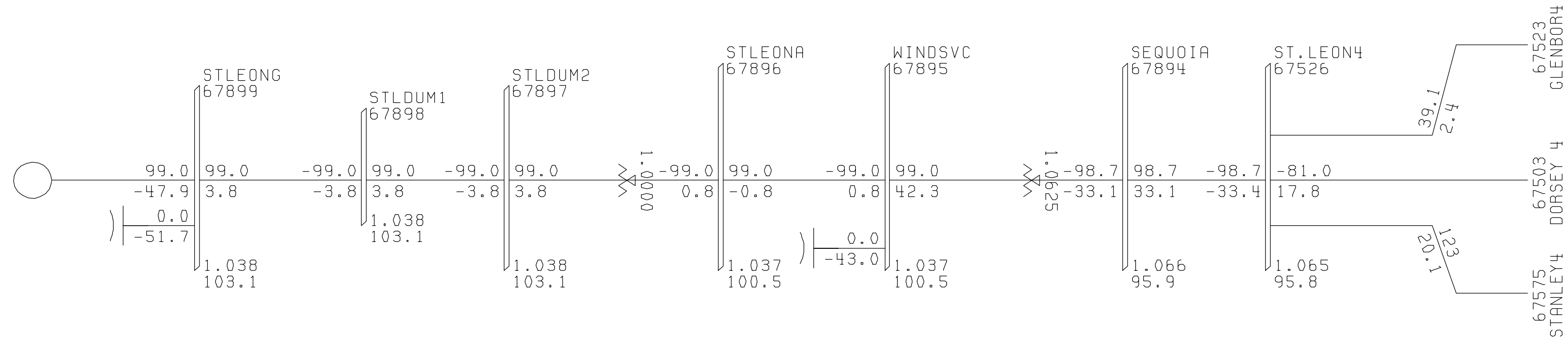


Figure F - 3
System Intact

GLAN

M04-SO03AA.UZVV4V4.SAV;SUMMER;OP LD; WIND 99, 4 CAPS ON 34KV
ND=1951,MH=2176,MW=1480,OHMH=-196,OHMP=150,EWTW=-201,BD=164
ST LEON SUN, MAR 07 2004 16:00

BUS - VOLTAGE(PU)/ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

99 MW WIND FARM

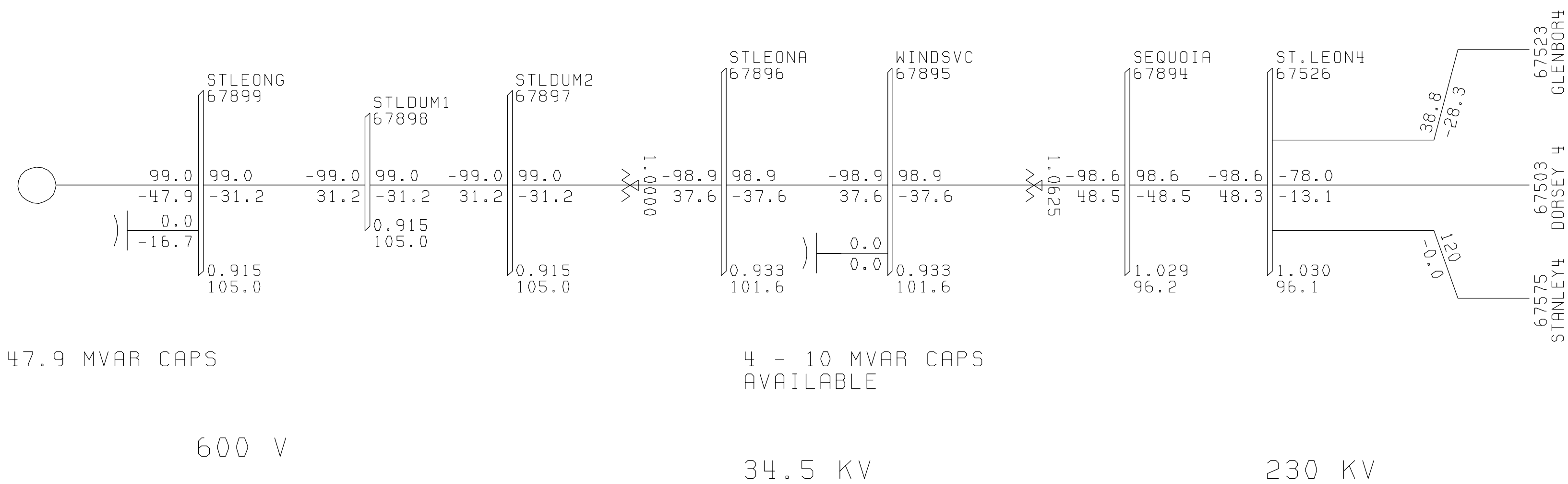


Figure F - 4
System Intact

GLAN

F00-SO03AA.UZVV4V4.SAV;SUMMER;OP LD; WIND 99, 0 CAPS ON 34KV
ND=1951,MH=2176,MW=1480,OHMH=-196,OHMP=150,EWTW=-201,BD=164
ST LEON   SUN, MAR 07 2004 15:59

BUS - VOLTAGE(PU)/ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

99 MW WIND FARM

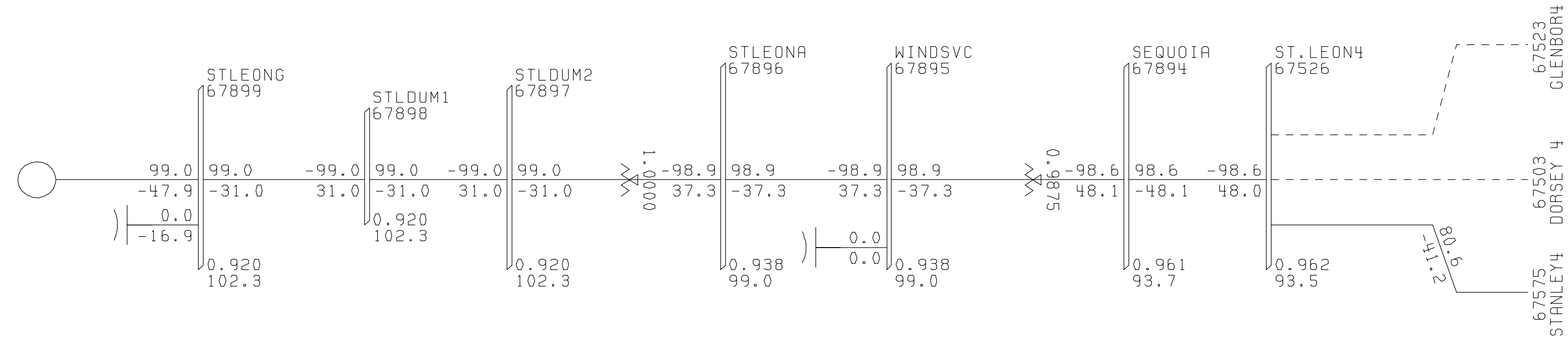


Figure F - 5
Post - disturbance
Loss of lines D14S and S53G

GLAN

FO0-SO03XX.UZVV4V4.SAV;SUMMER;OP LD;   D14S AND S53G OPEN
ND=1951,MH=2176,MW=1480,OHMH=-196,OHMP=150,EWTW=-201,BD=164
ST LEON   SUN, MAR 07 2004 16:00

BUS - VOLTAGE(PU)/ANGLE
BRANCH - MW/MVAR
EQUIPMENT - MW/MVAR

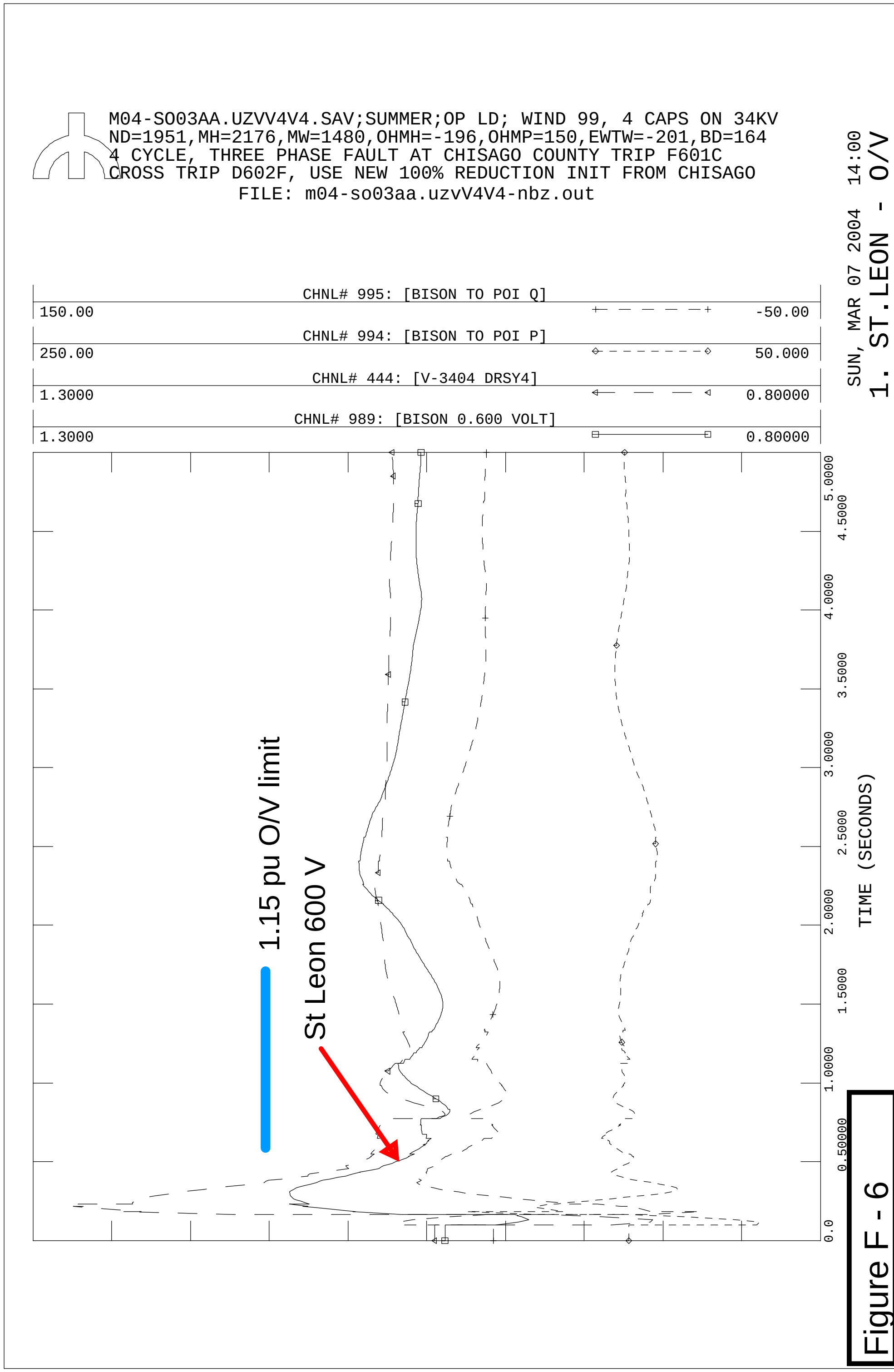


Figure F - 6

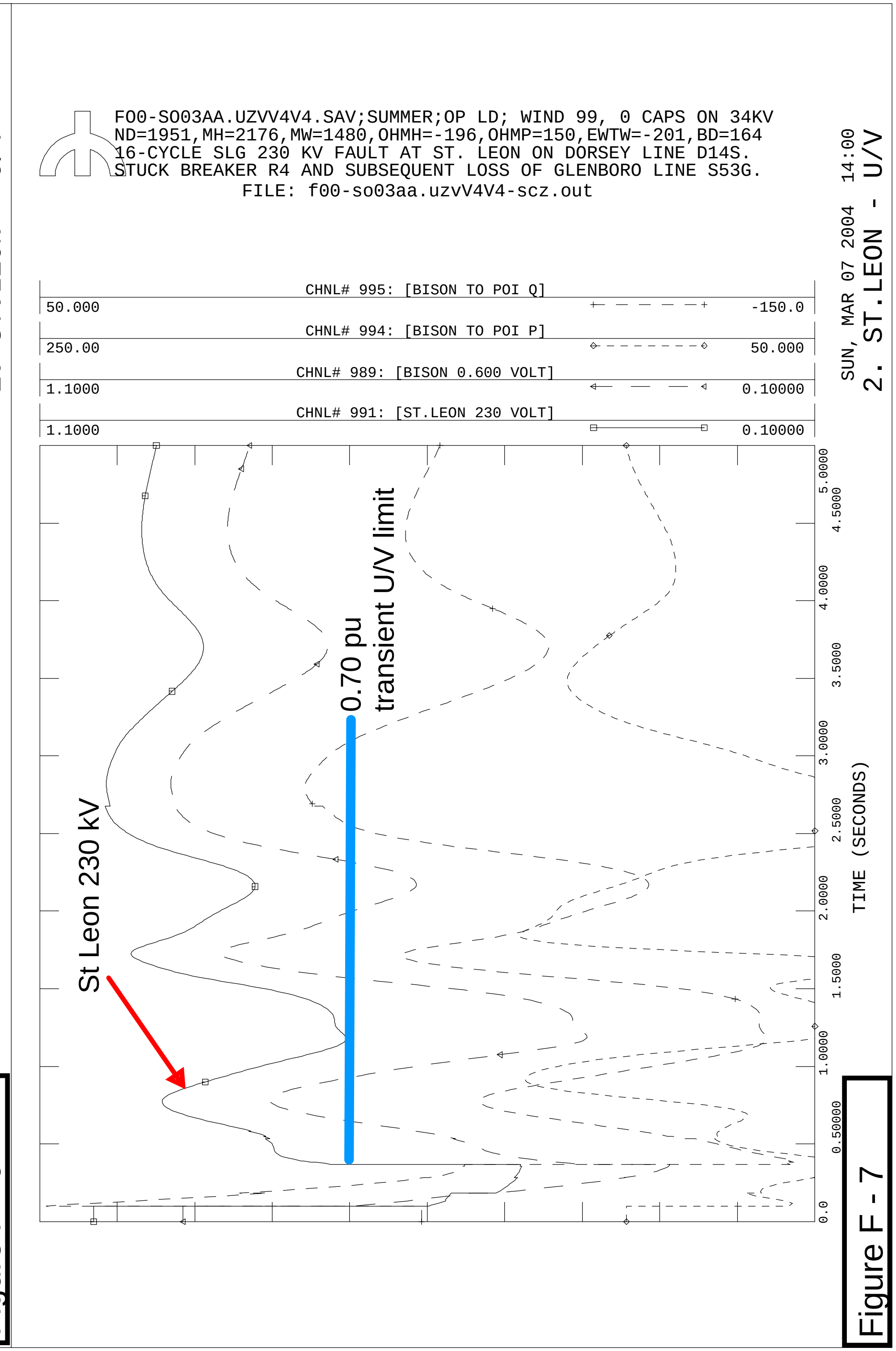


Figure F - 7