Facilities Study Report
(Customer XXXXXXX)
Generation Interconnection Request GI-0108

1.0 Background:

Western Area Power Administration (Western) Upper Great Plains Region (UGPR) received a generation interconnection/transmission service request from XXXXXXX (CUSTOMER) for a 200-MW wind generation interconnection to the Western/Basin Electric Power Cooperative (Basin)/Heartland Consumers Power District (Heartland) Integrated System (IS). This request is identified as request GI-0108 in the IS generation interconnection queue. The new generation is in the vicinity of White, South Dakota, and the requested point of interconnection is a connection to Western's White 345-kV Substation.

The details of the Generation Interconnection Request are as follows:

Generation Interconnection Request:	GI-0108
Location of Generation:	New connection to White 345-kV substation
Customer requested in-service Date:	12/16/2006
Generation size:	200 MW (102 – 2 MW turbines)
New load:	None. (Review wind turbine station service requirements)

Western UGPR provides administration of the IS Tariff on behalf of the other IS parties Basin and Heartland. Western and the other parties in the IS are all members of the Mid-Continent Area Power Pool (MAPP), and are required to observe MAPP policies and procedures when providing interconnections or selling transmission services.

Western determined that system additions or modifications are required to accommodate the generation interconnection.

2.0 Status of Existing Studies applicable to Request:

A system impact study (SIS) was performed and the SIS Report forwarded to CUSTOMER. The SIS performed was an "interconnection only" study for the 200-MW wind farm interconnection. The SIS concluded that the generation interconnection at Western's White 345-kV Substation could be accommodated on the IS. It should be noted that the SIS did not fully resolve the following issues during the SIS Phase of the study, however these issues have been reviewed and the results are attached to this report.

a) The recommended White 345-kV Substation configuration to incorporate the wind farm
b) The contractor (ABB) did not complete all of the local breaker failure faults
c) The final shunt reactive requirements for the wind farm for power factor correction
d) The ability of the wind farm to interconnect if the assumed network additions in the immediate vicinity (e.g. "Xcel Energy 825-MW expansion plan facilities as noted in the SIS report) did not get built. Partial analysis was performed (per Task 6 of the combined WAPA/MISO Group 1 study) to identify any dependencies on the Xcel White 115-kV interconnection for the wind interconnection. A limited amount of additional analysis (stability sensitivity) will need to be performed to confirm that the CUSTOMER wind farm can interconnect regardless of the status of the Xcel expansion plan, or prior to the in-service date of the area expansion facilities.

e) Review of the final customer proposed wind turbine (2 MW unit) based upon feedback from the Customer after the completion of the SIS.

No delivery service from the new 200-MW wind farm has been evaluated to date. NO transmission delivery component is approved or considered with this interconnection request. An Interconnection Agreement and operating procedures will be required before the interconnection will be allowed to operate. The Interconnection Agreement will be developed and forwarded for signature after the Construction Contract is signed and construction invoice paid.

3.0 Study Requirements:

Western performed a Facilities Study to determine a good faith estimate of (i) the costs of Direct Assignment Facilities to be charged to the interconnected customer, (ii), the customer's appropriate share of the cost of any required upgrades as determined pursuant to Step 3 of the General Requirements for Interconnection, and (iii) the time required to complete such construction and initiate the Requested Service. In addition, the Facilities Study reviewed the outstanding issues outlined in Section 2.0 above.

Further, based on the electrical size of the wind farm project proposed, Western determined an Environmental Impact Study (EIS) is required and is being pursued on a separate path. Environmental discussions are currently ongoing. Western anticipates at least one year will be required to complete a full EIS. Western is the lead agency for the environmental impact task. A good faith estimate of the (i) cost of environmental study work; (ii) the time required to complete such environmental work is also included. The environmental work and associated report is a cost borne solely by the Customer.

4.0 Facilities Study Results/Conclusions:

Transmission System Planning (B4400) performed follow-up sensitivity analysis, as outlined in Section 2.0 above, and a copy of the final report titled "*Generation Interconnection Study, Project GI-0108, XXXXXXX, White 200 MW Wind Farm, Facilities Study, Additional Power Flow and Stability Study Work, October 29, 2004*" is included as Attachment #1.

The results of the Facilities Study, based upon the sensitivity study work and preliminary design review are as follows:

4.1 Based upon the steady state model of the proposed new 2.0 MW wind turbines, which will incorporate power factor correction at the wind turbines to 1.0 pf, an additional 40 MVar of shunt capacitors will be required on the Customer's 34.5kV bus. CUSTOMER shall install the capacitors, at its expense, in their substation to provide acceptable power factor for the wind farm at the point of interconnection to the IS. The shunt capacitor can be configured as a single 40 Mvar bank or as 2-20 Mvar banks to limit the voltage switching steps on the Customer's equipment. Status of the capacitors shall be provided to Western Dispatch, and the capacitors shall be switched as directed by Western Dispatch.

4.2 The Customer's generation can be incorporated into Western's White substation with an expansion of the existing 345kV ring bus to a four breaker ring bus. The four breaker ring bus would be constructed for future expected conversion to a breaker-and-a-half arrangement. The proposed addition to the White 345kV Substation is shown on Attachment #2 "White Substation, Switching Diagram (Proposed Addition)". Pending other concurrent development at the White Substation, the conversion to a breaker-and-a-half arrangement may need to be incorporated into this stage of construction. The potential breaker-and-a-half arrangement is shown on Attachment #3 "White Substation, Switching Diagram (Proposed Addition #2)" and is subject to change based upon expansion requirements to accommodate other interconnection requests at White substation.

4.3 Cost estimates for Western labor, overheads, equipment additions, modifications, and other miscellaneous costs are outlined for the two potential bus configurations. Attachment #4 outlines the estimated cost of $2,663,859 for the proposed four breaker ring bus arrangement. These costs would be allocated to the Customer, and the Customer would need to advance funds for these facility expansion requirements. This cost estimate would be the minimum requirement for the Customer's interconnection. Other developments at White may require converting to a breaker-and-a-half scheme. Attachment #5 outlines an estimated cost of $3,334,867 for the potential breaker-and-a-half arrangement. The incremental cost between the four breaker ring and the breaker-and-a-half arrangement would not be the responsibility of the Customer, if they are required only to accommodate other subsequently queued interconnection requests at White substation.

4.4 Attachment #6 outlines Western's estimated schedule for Western construction of the facilities required in the White Substation to accommodate the Customer's interconnection request. Based upon the proposed facility additions, Western projects that the interconnection facilities in the White substation can be installed and commissioned by the end of September 2006. The latest information provided to Western by CUSTOMER indicates that CUSTOMER plans to construct their substation and wind farm between 4/1/06 to 11/15/06, complete commissioning for the wind farm between 10/1/06 to 12/15/06, and commence operations by 12/16/06. Western's proposed schedule for the White facilities will coordinate with CUSTOMER's desired schedule.

4.5 A construction contract will be subsequently drafted and submitted to CUSTOMER. An interconnection contract will also be required before energization of the facilities, which will include Operating Procedures developed by Western's Operations Office in coordination with the Customer. CUSTOMER will be requested to advance the estimated costs for the project. The facility additions funded by CUSTOMER that are determined to be part of the Integrated System network transmission facilities, in Western's sole discretion, may be eligible for credits against transmission service taken by CUSTOMER, pursuant to Western's Tariff and Tariff Business Practices.

4.6 Western's generation metering requirements must be met. A copy of the metering requirements is included as Attachment #7.

4.7 Prior to energization and interconnection of the wind farm to Western's transmission system, an Operating Guide will be developed by Western to outline the necessary operating restrictions on the wind farm.

4.8 An Environmental Impact Statement (EIS) is required and Western's costs for the environmental work, to be borne by the Customer, are included in the attached cost estimates.

4.9 Due to problems utilizing the Customer's latest provided wind turbine model for the 2 MW Gamesa G80 wind turbine, as outlined in the sensitivity study report referenced above and communicated to the Customer, some additional sensitivity work will still need to be performed subsequent to the Facilities Study once a fully functional and accurate dynamic model/study package is developed for the CUSTOMER wind farm. This additional sensitivity study work may impact the facility additions required to interconnect the Customer's wind farm. This Facilities Study report outlines Western's best estimate of required facilities and associated costs/schedule given the information and functional modeling information available to Western.

Attachment #1

Generation Interconnection Study
Project GI-0108

<Customer>
White 200 MW Wind Farm

Facilities Study
Additional Power Flow and Stability Study Work

October 29, 2004

Completed by:
Western Area Power Administration
Upper Great Plains Region
Transmission System Planning
Billings, MT

1.0 Background

Western Area Power Administration (Western) Upper Great Plains Region (UGPR) received a generation interconnection/transmission service request from Customer (Customer) for a 200-MW generation interconnection to the Western / Basin Electric Power Cooperative (Basin) / Heartland Consumers Power District (Heartland) Integrated System (IS). This request is identified as request GI-0108 in the IS generation interconnection queue. The new generation is in the vicinity of White, South Dakota, and the requested point of interconnection is a connection to Western's White 345-kV substation, as shown in Figure 1.1 below.

The details of the Generation Interconnection Request are as follows:

Generation Interconnection Request:	GI-0108
Location of Generation:	New connection to White 345-kV substation
Requested in-service Date:	9/30/2006 (Original date)
Generation size:	200 MW

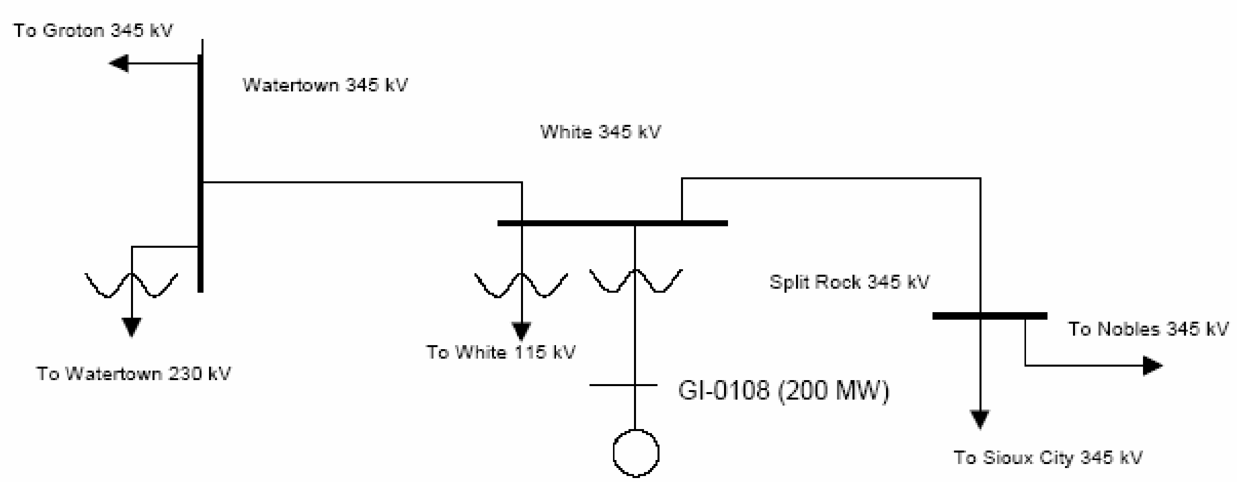


Fig 1.1: Interconnection Diagram for GI-0108

Western performed a System Impact Study (SIS) titled "***Generation Interconnection Study Project # GI-0108 – Queue 37110-01" (March 2004)*** and the SIS Report was forwarded to Customer. The SIS performed was an "interconnection only" study for the 200 MW wind farm interconnection. The SIS concluded that the generation interconnection at the White 345kV substation could be accommodated on the IS; however several issues were not fully resolved and were deferred for the Facilities Study (FS) when the customer could provide better modeling information on the proposed wind turbines to be installed:

a) Issue #1: Review and update the modeling for the customer's final wind turbine recommendation;
b) Issue #2: Identify the required White 345-kV substation configuration;
c) Issue #3: Review local breaker failure faults based upon proposed configuration;

d) Issue #4: Identify final shunt reactive requirements for the wind farm; and,
e) Issue #5: Review the ability of the wind farm to interconnect if the assumed Xcel Energy "825 MW expansion plan facilities" in the immediate vicinity are not yet in-service.

Regarding Issue #5, partial analysis was performed (per Task 6 of the combined WAPA/MISO Group 1 Study Report) to identify any dependencies on the Xcel White 115kV interconnection for the Customer White wind interconnection. However, a limited amount of additional analysis (stability sensitivity) will need to be performed to confirm that the Customer wind farm can interconnect regardless of the status of the Xcel expansion plan, or prior to the in-service date of the area expansion facilities.

The purpose of this additional power flow and stability study work, which will be included in the Facilities Study report, is to review and provide feedback and recommendations on the five issues outlined above.

2.0 Updated Wind Farm Modeling

The original SIS was performed by Western's contractor ABB using the NMORWG Stability Package for PC, version 9/19/03. Power flow models and snapshots developed for the Group #1 studies were used as a basis for developing the cases for this study. In the original studies, the GI-0108 wind farm was modeled as a conventional induction generator using the CIMTR3 stability model. The original power flow and stability model parameters were documented in Appendix H of the study report "*Generation Interconnection Study Project # GI-0108 – Queue 37110-01*" *(March 2004)*.[1]

This updated study work was **partially** performed from modeling derived from the Version 3.3 of the G8X_60Hz.IRF (executable PSS/E IPLAN program) as supplied by Customer, and updated modeling information provided by XXXXXXX (Customer) in his 10/14/04 and 10/15/04 emails to Western. **Due to problems with the incorporation of the stability model for the new units, the stability analysis in this report was performed on the existing classical assumption, and some analysis has been deferred until an accurate and fully functional final dynamic model is obtained from the Customer.**

The 345/34.5-kV substation transformer was modeled as a 133/166/220 MVA rated bank with a 10% impedance on a 133 MVA base. On the PSS/E modeled 100 MVA base, the impedance was modeled as 0.00800 + j0.07519 p.u. (where the real value was an approximation set by Western).

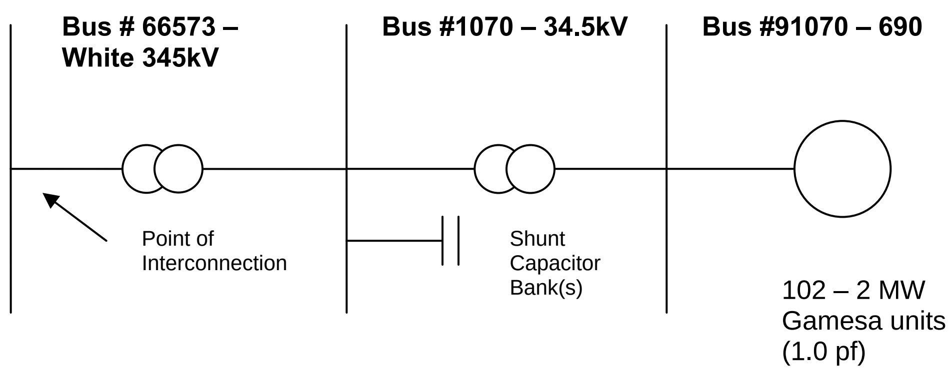
The wind farm was modeled with 102 – 2 MW Gamesa wind turbine units represented as a single combined unit based upon the model provided by the G8X_60Hz.IRF

[1] [1] The original machine specification provided by Customer was for Gamesa Eolica G80 1800 kW units (with 0.98 pf minimum power factor w/external capacitors). 111 units were originally proposed to be installed.

program. The default “machine_param_G8X_60.dat”, as provided by the customer, was utilized to developing the equivalent single wind unit model. The transcript of the IPLAN program execution, and listing of the input files, is included in Appendix A for information. The basic power flow model data is documented in Appendix B. The updated dynamic data for the wind farm (PSS/E DYRE data) utilized in these studies is shown in Appendix C.

The composite wind farm was added to the various power flow models by adding a single 34.5kV “collector” bus (bus # 1070) and a 690 Volt wind unit bus (bus # 91070) as shown below in Figure 2.1.

Figure 2.1 - Customer White Wind Farm Power Flow Equivalent



3.0 Substation Bus Configuration Requirements

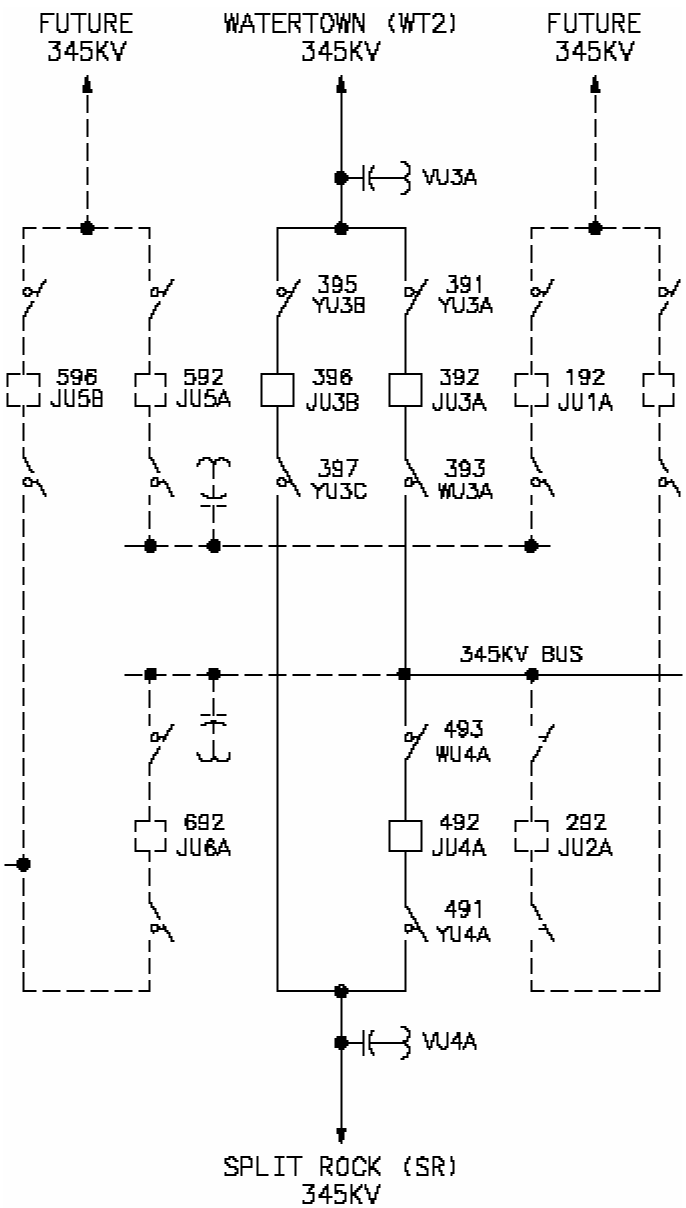
The initial SIS report did not specifically review the required substation bus configuration at the White 345kV bus for interconnection of the new 345kV interconnection to the Customer Wind Farm. As shown in Figure 3.1 below, the White 345kV bus is designed for an ultimate breaker-and-a-half layout, and presently is configured as a 3 position ring bus, with the Watertown and Split Rock 345kV lines separated by a common breaker 396 (JU3B). In its present configuration, any breaker failure isolates the White 115kV substation from the 345kV source.

With the addition of the 200 MW Customer Wind Farm, the White 345kV substation bus can be configured as a 4 position ring bus, where the wind farm is connected via an additional 345kV breaker, where the wind farm is separated by a common breaker with the Watertown 345kV line and also separated by another common breaker with the Split Rock 345kV line. With this 4 position ring bus configuration, the following breaker failure events would be possible:

1. BF at BKR 396, Watertown 345kV line and Wind Farm tripped
2. BF at BKR 596 (new breaker), Split Rock 345kV line and Wind Farm tripped

3. BF at BKR 392, Watertown 345kV line and 345/115kV transformer tripped, Wind Farm left radially connected to the Split Rock 345kV line
4. BF on BKR 492, Split Rock 345kV line and 345/115kV transformer tripped, Wind Farm left radially connected to the Watertown 345kV line

Figure 3.1 Single Line Diagram for White 345kV



There are also potential other interconnection requests at the White 345kV substation by other parties, and therefore, the substation bus may need to be re-configured as a breaker-and-a-half layout in the very near future. In the event that occurs, the Watertown and Split Rock 345kV lines should not be separated by a common breaker, such that both 345kV lines can be lost for a single breaker failure event, and the

Customer Wind Farm and one of the 345kV lines should be separated by a common breaker such that the Wind Farm will be tripped along with one of the 345kV outlets. Further analysis will need to be performed in subsequent studies for the other potential interconnecting parties to recommend the optimum bus layout considering additional 345kV interconnections and/or additional interconnections on the White 115kV bus.

4.0 Stability Study Sensitivity for Local Breaker Failure Events

The prior study work evaluated local 3-phase faults with loss of each of the 345kV outlets based upon the classical modeling and no issues were identified. The initial four breaker ring bus arrangement recommended will result in the wind farm tripping for breaker failures that result in loss of one of the 345kV outlets, and therefore no significant issues are expected.

Note: Final studies for the local breaker failure events will be completed when a fully functional dynamic model of the proposed 2.0 MW Gamesa G80 wind turbines is available and incorporated into the study package.

5.0 Shunt Reactive Requirements

As outlined in Western's "General Requirement for Interconnection" [2] generation interconnections utilizing equipment that does not provide dynamic voltage regulation must provide, at a minimum, power factor correction to unity power factor at the point of interconnection, which is at the White 345kV bus. It should be noted that dynamic voltage regulation is preferred to better address voltage issues on the Customer's system, as well as providing improved performance of the bulk transmission system.

Power flow analysis was performed for a number of operating conditions to determine the necessary shunt reactive requirements. The analysis was based upon the customer feedback that the wind units will be fully compensated (1.0 power factor) and the impedances of the equivalent wind turbine step up transformers and underlying 34.5kV collector facilities as modeled by the customer supplied G8X_60Hz.IRF IPLAN program. The summary of this additional analysis is summarized below in Table 5.1.

Table 5.1 (Shunt Reactive Requirements)

Case	Description	White 345 GI0108 P/Q MVA 345/34.5 tap	White 345kV Volt/GI0108 34.5 Cap(nom)	GI0108 34.5/.69 Volt	GI0108 .69 P/Q	GI0108 345/34.5 Lowside P/Q/MVA	White 115kV Volt 345/115 P/Q/MVA	WT SVC Mvar WT SVS Caps

[2] "Induction generators or other generators— including wind turbines—without VAR control absorb VARs and therefore require reactive power support from Western's facilities. For generators larger than 40 kilowatts, Western will require power factor correction. Power factor correction capacitors must be installed either by the owner of the generation or by Western at the owner's expense. Switched capacitors supplied by the generation owner shall be switched on and off at the request of Western. Owners of interconnected induction generators shall provide, at a minimum, sufficient reactive power capability to deliver the generator output at unity power factor at the point of interconnection." (pg 18)

Case	Description	White 345 GI0108 P/Q MVA 345/34.5 tap	White 345kV Volt/GI0108 34.5 Cap(nom)	GI0108 34.5/.69 Volt	GI0108 .69 P/Q	GI0108 345/34.5 Lowside P/Q/MVA	White 115kV Volt 345/115 P/Q/MVA	WT SVC Mvar WT SVS Caps
Group 1 All units on	High Export	-200.1/-3.7 200.1 1.000	1.0251/37.0	**1.0536/1.0572**	204.0/0.0	203.1/32.3 205.7	1.0198 168.8/-2.3 168.9	16.1 23.8/81.4
Same	Same	-199.9/0.3 199.9 **1.025**	1.0244/37.0	1.0262/1.0298	204.0/0.0	203.1/29.7 205.2	1.0195 168.8/-1.7 168.8	18.2 23.9/81.4
Same	Same	-199.9/-3.2 199.9 **1.025**	1.0250/**40.0**	1.0294/1.0329	204.0/0.0	203.1/33.2 205.8	1.0198 168.8/-2.2 168.9	16.4 23.8/81.4
Same	Same	-199.6/41.7 203.9 **1.025**	1.0167/**0.0** **37 Mvar** **Δ = -0.0077** **40 Mvar** **Δ = -0.0083**	0.9885/0.9922 **37 Mvar** **Δ = -0.0377** **Δ = -0.0376** **40 Mvar** **Δ = -0.0409** **Δ = -0.0407**	204.0/0.0	203.0/-9.9 203.3	1.015 168.2/3.4 168.2	41.9 25.0/81.4
Same, With White-Yankee open	Same	-199.9/-3.8 200.0 **1.025**	1.0291/**40.0**	1.0336/1.0372	204.0/0.0	203.1/33.6 205.9	1.0307 -50.6/4.2 50.8	12.6 23.7/81.4
Same	Same	-199.7/41.4 203.9 **1.025**	1.0203/**0.0** **40 Mvar** **Δ = -0.0088**	0.9922/0.9959 **40 Mvar** **Δ = -0.0414** **Δ = -0.0413**	204.0/0.0	203.1/-9.9 203.3	1.0237 -50.1/7.0 50.6	40.1 24.9/81.4
Group 1 Only GI0108 Wht-Yank In	2007 Summer Peak	-200.0/-5.8 200.1 **1.025**	1.0415/**40.0**	1.0466/**1.0502**	204.0/0.0	203.1/34.9 206.1	1.0190 -8.1/-7.1 10.8	49.0 20.8/81.4
Same	Same	-199.8/40.4 203.8 **1.025**	1.0333/0.0 **40 Mvar** **Δ = -0.0082**	1.0054/1.0090 **40 Mvar** **Δ = -0.0412** **Δ = -0.0412**	204.0/0.0	203.0/-9.6 203.3	1.0140 -8.0/-1.9 8.2	27.4 21.8/81.4
Same	High Export WT-White 345kV PO	-200.1/-3.7 200.1 1.000	1.0253/37.0	**1.0539/1.0574**	204.0/0.0	203.1/32.3 205.7	1.0125 238.3/-6.6 238.4	17.0 23.9/81.4
Same	Same	-199.9/0.4 199.9 **1.025**	1.0237/37.0	1.0256/1.0292	204.0/0.0	203.1/29.7 205.2	1.0116 238.1/-5.5 238.1	17.5 23.9/81.4
Same	Same	-199.9/-3.2 199.9 **1.025**	1.0252/**40.0**	1.0295/1.0331	204.0/0.0	203.1/33.2 205.8	1.0124 238.3/-6.4 238.4	17.0 23.9/81.4
Same	Same	-199.5/42.6 204.0 **1.025**	1.0072/**0.0** **37 Mvar** **Δ = -0.0165** **40 Mvar** **Δ = -0.0180**	0.9788/0.9825 **37 Mvar** **Δ = -0.0468** **Δ = -0.0467** **40 Mvar** **Δ = -0.0507** **Δ = -0.0506**	204.0/0.0	203.1/-10.1 203.2	1.0017 235.4/5.3 235.5	23.0 24.1/81.4
Same	High Export White-Split Rock 345kV PO	-200.2/-5.9 200.3 1.000	1.0395/37.0	**1.0689/1.0724**	204.0/0.0	203.1/33.8 205.9	1.0342 -2.1/-8.5 8.8	-2.3 23.0/81.4
Same	Same	-200.0/-1.8 200.0 **1.025**	1.0384/37.0	1.0408/1.0444	204.0/0.0	203.1/31.1 205.5	1.0337 -2.0/-7.5 7.8	0.7 23.1/81.4
Same	Same	-200.0/-5.4 200.1	1.0394/**40.0**	1.0443/1.0479	204.0/0.0	203.1/34.7 206.1	1.0341 -2.0/-8.4	-2.0 23.0/81.4

Case	Description	White 345 GI0108 P/Q MVA 345/34.5 tap	White 345kV Volt/GI0108 34.5 Cap(nom)	GI0108 34.5/.69 Volt	GI0108 .69 P/Q	GI0108 345/34.5 Lowside P/Q/MVA	White 115kV Volt 345/115 P/Q/MVA	WT SVC Mvar WT SVS Caps
		1.025					8.7	
Same	Same	-199.7/40.9 203.9 **1.025**	1.0267/**0.0** **37 Mvar** **Δ = -0.0117** **40 Mvar** **Δ = -0.0127**	0.9987/1.0024 **37 Mvar** **Δ = -0.0421** **Δ = -0.0420** **40 Mvar** **Δ = -0.0456** **Δ = -0.0455**	204.0/0.0	203.0/-9.7 203.3	1.0280 -1.6/2.1 2.7	35.3 24.7/81.4
Group 2 All Units on	High Export	-199.8/-2.1 199.8 **1.025**	1.0222/**40.0**	1.0222/1.0258	204.0/0.0	203.1/32.5 205.7	1.0292 60.6/18.0 63.2	42.5 25.0/81.4
Same	Same	-199.6/42.2 204.0 **1.025**	1.0118/**0.0** **40 Mvar** **Δ = -0.0104**	0.9836/0.9872 **40 Mvar** **Δ = -0.0386** **Δ = -0.0386**	204.0/0.0	203.0/-10.0 203.2	1.0252 60.7/21.7 64.4	62.6 25.9/81.4
2003 Spring Light Load Only GI0108	Low Export	-200.2/-6.9 200.3 **1.025**	**1.0723/37.0**	**1.0759/1.0795**	204.0/0.0	203.2/34.4 206.1	1.0534 -33.8/0.4 33.8	-85.0L 20.4/86.4
Same	Low Export	-200.0/38.3 203.6 **1.025**	**1.0597/0.0**	1.0322/1.0358	204.0/0.0	203.1/-9.1 203.3	1.0427 -33.4/3.2 33.6	-85.0L 20.2/85.4
2009 Peak (04 Series) No Group 1 units	Peak / Low Export No Xcel Facilities	Off	1.0239/**0.0**	Off	Off	Off	1.0230 -68.4/1.1 68.4	14.3 23.7/81.4
Same	Same	-199.9/-3.5 199.9 **1.025**	1.0270/**40.0**	1.0315/1.0351	204.0/0.0	203.1/33.4 205.8	1.0261 -80.6/1.7 80.7	-1.1 23.0/81.4
Same, GI0108 on-line	Same	-199.6/41.5 203.9 **1.025**	1.0190/**0.0** **40 Mvar** **Δ = -0.0080**	0.9909/0.9945 **40 Mvar** **Δ = -0.0406** **Δ = -0.0406**	204.0/0.0	203.0/-9.9 203.3	1.0199 -80.0/4.6 80.1	22.8 24.1/81.4

Based upon this analysis, and the range of potential system operating conditions at the White 345kV substation, the following conclusions and recommendations are noted:

1. A 40 Mvar shunt capacitor must be installed on the customer's 34.5kV bus to provide power factor correction. It is recommended that the shunt be installed as two (2) 20 Mvar banks to limit the voltage step on the customer's 34.5kV and 690 Volt buses, as voltage steps of 4-5% are expected on the 34.5kV and 690 Volt buses with a 40 Mvar shunt capacitor. The 40 Mvar shunt capacitor can be switched as a single bank and meet Western's voltage step criteria on the White 345kV bus. It is recommended that Western remotely control the 34.5kV shunt capacitor bank(s), however at a minimum Western Dispatch must have real-time status of the shunts and the immediate control of the shunts via a call to the customer's real-time dispatcher.

2. The 345/34.5kV substation transformer must have sufficient off-nominal taps (+/- 2.5% and +/- 5% taps at a minimum) to allow for controlling the range of voltages experienced on the low side buses for the range of operating conditions in the area. The “high side” 345kV transformer tap on the 345/34.5kV substation transformer should be set at a minimum of 1.025 pu (353.625/34.5kV) to reduce the expected voltages on the 34.5kV and 690 Volt buses. It should be noted that the White 345kV bus voltage can vary significantly between heavy and light load conditions. The customer should review the historic range of voltages that occur on the White 345kV bus in the design of the wind farm to ensure that acceptable voltages will be maintained on that low side buses. Unacceptable voltages on the 34.5kV and 690 Volt buses will occur with a unity tap (1.000 pu) on the 345/34.5kV transformer.

3. The customer’s proposed 345/34.5kV substation transformer rating[3] of 133/166/220 MVA should be acceptable. This same rating was assumed for both the high-side (345kV) and low-side (34.5kV) windings. The originally proposed 200 MVA top-end rated transformer would not be sufficient. As noted in the summary of study results in the table above, the continuous low-side 34.5kV winding loading is expected to be in the neighborhood of 206 MVA with the power factor correction capacitor on-line.

4. Based upon the significantly high voltages that can be experienced on the White 345kV bus, Western will require that the shunt capacitor bank(s) be de-energized at times, even if the Customer Wind Farm is at full output to maintain desired voltages in the area.

5. Based upon the modeled real losses in the unit step-up and substation transformers, the 204 MW of potential wind output is reduced to approximately 200 MW at the point of interconnection at the White 345kV bus.

6.0 Sensitivity Studies for Interconnection prior to “Xcel 825 MW Facilities”

Additional sensitivity work was run on the Buffalo Ridge area “Group 1” 2007 summer off-peak high transfer model with the 115kV tie between Buffalo Ridge and White and the 345kV line between Split Rock and Lakefield taken out of service. The pg1-so03aa.uyVV4V4.sav case was utilized as the base case.

The GI-0108 unit was added to the pg1 model and sunk to the MAIN load, and renamed as the “g1x” model. The “g1y” model was then created by opening the Xcel 115kV and 345kV lines noted above.

The final exports for the two cases were: g1x (NDEX=1950 MW, MHEX_S=2171 MW, MWSI=1481 MW); and g1y (NDEX=1954 MW, MHEX_S=2165 MW, and MWSI=1477 MW).

[3] Per XXXXXXX (Customer) 10/15/2004 email to Western.

The study results for the two cases are summarized in Table 6.1.

Table 6.1

Case	**Disturbance**	**Groton 345kV Crit=0.70**	**Watertown 345kV Crit=0.75**	**Wahpeton 115kV Crit=0.80**	**Arrowhead 230kV Crit=0.82**	**Riverton 230kV Crit=0.75**	**Willmar 230kV Crit=0.70**
g1x	ei2	0.84	0.89	0.85	n/a	n/a	n/a
g1y	ei2	0.83	0.87	0.85			
g1x	nbz	0.81	0.85	0.82	**0.79**	0.75	n/a
g1y	nbz	0.80	0.83	0.81	**0.77**	**0.73**	n/a
g1x	nmz	0.82	0.87	0.84	0.88	0.79	>0.70
g1y	nmz	0.82	0.85	0.83	0.87	0.78	**0.69**

As seen from these initial study results, a slight degradation of area transient voltages occurs without the Xcel facilities (due primarily to the 345kV line removal between Split Rock and Lakefield). This sensitivity work was run with an assumed worst case sink of MAIN load in both cases. The Group 1 studies did not show violations for the NBZ/NMZ disturbance until after the addition of all the Group 1 projects, and therefore, the initial study concluded that the proposed GI-0108 wind farm did not degrade regional stability performance.

Based upon these results, there may be scenarios at low probability, high simultaneous exports where the wind farm may impact regional stability prior to and after the Xcel transmission expansions are added. Western attempted to perform more detailed analysis of the impacts using the latest dynamic model for the wind farm, but due to problems with the G80-2MW model and incompatibilities with the other wind models in the study package this work has not yet been completed. *Therefore, once the fully functional dynamic model is developed and incorporated into the MAPP stability study package, Western will need to perform additional study work to clarify any operating restrictions on the GI-0108 project if it is energized prior to the completion of the Xcel transmission additions in the area, as well as to identify any impacts of the actual wind units to the "system intact" condition with all expected transmission additions in place.*

7.0 Outstanding Analysis Requirements

The following issues were not completed during the SIS or FS and still need to be resolved prior to the wind farm being energized, provided the Customer proceeds with the generation interconnection request:

a) Development of a final fully functional dynamic model that accurately reflects the response of the proposed wind turbines. Additional sensitivity study work with the final model to confirm the assumptions and recommendations set forth in this study report, the actual expected impacts of the proposed wind turbine units on regional stability. This work, once the model is incorporated and work correctly, is estimated to take approximately 1 week. This additional sensitivity study work may impact the facility additions required to interconnect the Customer's wind farm. This report outlines Western's best estimate of required facilities given the information and functional modeling information available to Western.

b) Determination of Prior Outage generation limits for outages of the transmission outlet facilities from the White Substation
c) Development and approval of an Operating Guide for the Wind Farm
d) Given the limited regulation capability of Western's system, resolution of control area metering and dynamic scheduling for Wind Farm.

Appendix A

```
 ACTIVITY?
 Executing activity exec g8x_60hz.irf

exec g8x_60hz.irf

 ACTIVITY?

 ***********************************************************************
 *                         PROGRAM G8X_60Hz                             *
 * IPLAN PROGRAM FOR MODELING GAMESA G8X 2MW WIND TURBINE GENERATORS   *
 *                  AT DESIGNATED COLLECTOR BUSES                      *
 *                                                                     *
 ***********************************************************************



 ADDING BUS  91070 TO POWERFLOW CASE ...

 READING DATA FILE CONTAINING POWER CURVE INFORMATION..

 HOW WOULD YOU LIKE TO DISPATCH THE UNITS?

      1. USE WIND SPEED AS AN INPUT
      2. DISPATCH DIRECTLY
      Q. EXIT THE PROGRAM

 ENTER 1 OR 2, OR Q TO QUIT :

 UNITS WILL BE DISPATCHED DIRECTLY BY OUTPUT PERCENTAGE

 ENTER THE PERCENTAGE OF RATED OUTPUT FOR DISPATCH (E.G. ENTER 100.0 FOR 100%)

 SELECT OPERATING MODE OF WIND FARM:

      1. POWER FACTOR CONTROL MODE
      Q. EXIT THE PROGRAM

 ENTER 1 OR Q TO QUIT:

 WIND FARM IN POWER FACTOR CONTROL MODE

 ENTER DESIRED POWER FACTOR FOR COLLECTOR BUS   1070: (DEFAULT VALUE IS 1.0)
 USE POSITIVE SIGN FOR LAGGING PF (OVER-EXCITATION), AND
     NEGATIVE SIGN FOR LEADING PF (UNDER-EXCITATION)
 POWER FACTOR CAN ONLY BE CONTROLLED WITHIN THE RANGE +0.95 AND -0.9.


 SELECT HOW TO INPUT GENERATOR PARAMETERS IN LOAD FLOW SIMULATION:

 1. INPUT PARAMETERS FROM A FILE
 Q. QUIT

 ENTER 1, 2, OR Q:
 1
 INPUT GENERATOR PARAMETERS FROM THE FILE.

 IPLAN REVISION:  16.0
 ADDING BUS  91070 TO POWERFLOW CASE...
RDCH
 ENTER INPUT FILE NAME (0 TO EXIT, 1 FOR TERMINAL): 1

 ENTER BUS DATA
 I, 'BUS NAME', BASKV, IDE, GL, BL, AREA, ZONE, VM, VA, OWNER

 91070 CLR_1 0.69 2, , , 652 654 1.019275 106.7794 1
0
```

```
 ENTER LOAD DATA
 I, ID, STATUS, AREA, ZONE, PL, QL, IP, IQ, YP, YQ, OWNER
0

 ENTER GENERATOR DATA
 I,ID,PG,QG,QT,QB,VS,IREG,MBASE,ZR,ZX,RT,XT,GTAP,STAT,RMPCT,PT,PB,O1,F1,..,O4,F4
 91070 1  204.0 0.0 0.0 0.0 1.0 0 204.0 0.0 0.152896,,, 1.0, 1,, 204.0 0.0
0

 ENTER NON-TRANSFORMER BRANCH DATA
 I,J,CKT,R,X,B,RATEA,RATEB,RATEC,GI,BI,GJ,BJ,ST,LEN,O1,F1,...,O4,F4
0

 ENTER TRANSFORMER DATA
 ENTER I,J,K,CKT,CW,CZ,CM,MAG1,MAG2,NMETR,'NAME',STAT,O1,F1,...,O4,F4
 1070 91070 0, 1
 ENTER R1-2,X1-2,SBASE1-2
 0.00235294 0.0235294 255.0
 ENTER WNDV1,NOMV1,ANG1,RATA1,RATB1,RATC1,COD,CONT,RMA,RMI,VMA,VMI,NTP,TAB,CR,CX
 1.0,,, 255.0
 ENTER WNDV2,NOMV2

 ENTER I,J,K,CKT,CW,CZ,CM,MAG1,MAG2,NMETR,'NAME',STAT,O1,F1,...,O4,F4
0

 ENTER AREA INTERCHANGE DATA
 I, ISW, PDES, PTOL, 'AREA NAME'
Q
 AREA151 [EES     ] HAS  9 TRANSFERS. SUM=  1214.0 MW BUT AREA PDES=   339.5
 AREA502 [CELE    ] HAS 10 TRANSFERS. SUM=   312.0 MW BUT AREA PDES=   225.7
 AREA515 [SWPA    ] HAS 20 TRANSFERS. SUM=   851.0 MW BUT AREA PDES=  1036.0
 AREA520 [AEPW    ] HAS 14 TRANSFERS. SUM=  -590.0 MW BUT AREA PDES= -1115.0
 AREA526 [SPS     ] HAS  4 TRANSFERS. SUM=     0.0 MW BUT AREA PDES=   150.0
 AREA534 [SUNC    ] HAS  6 TRANSFERS. SUM=   131.0 MW BUT AREA PDES=   127.0
 AREA541 [KACP    ] HAS 15 TRANSFERS. SUM=   184.0 MW BUT AREA PDES=   305.0
 AREA542 [KACY    ] HAS  4 TRANSFERS. SUM=     0.0 MW BUT AREA PDES=    20.0

 ACTIVITY?  ADDING BUS  91070 TO POWERFLOW CASE...
RDCH
 ENTER INPUT FILE NAME (0 TO EXIT, 1 FOR TERMINAL): 1

 ENTER BUS DATA
 I, 'BUS NAME', BASKV, IDE, GL, BL, AREA, ZONE, VM, VA, OWNER
 91070 CLR_1 0.69 2, , , 652 654 1.019275 106.7794 1
0

 ENTER LOAD DATA
 I, ID, STATUS, AREA, ZONE, PL, QL, IP, IQ, YP, YQ, OWNER
0

 ENTER GENERATOR DATA
 I,ID,PG,QG,QT,QB,VS,IREG,MBASE,ZR,ZX,RT,XT,GTAP,STAT,RMPCT,PT,PB,O1,F1,..,O4,F4
 91070 1  204.0 0.0 0.0 0.0 1.0 0 204.0 0.0 0.152896,,, 1.0, 1,, 204.0 0.0
0

 ENTER NON-TRANSFORMER BRANCH DATA
 I,J,CKT,R,X,B,RATEA,RATEB,RATEC,GI,BI,GJ,BJ,ST,LEN,O1,F1,...,O4,F4
0

 ENTER TRANSFORMER DATA
 ENTER I,J,K,CKT,CW,CZ,CM,MAG1,MAG2,NMETR,'NAME',STAT,O1,F1,...,O4,F4
 1070 91070 0, 1
 ENTER R1-2,X1-2,SBASE1-2
 0.00235294 0.0235294 255.0
 ENTER WNDV1,NOMV1,ANG1,RATA1,RATB1,RATC1,COD,CONT,RMA,RMI,VMA,VMI,NTP,TAB,CR,CX
 1.0,,, 255.0
 ENTER WNDV2,NOMV2

 ENTER I,J,K,CKT,CW,CZ,CM,MAG1,MAG2,NMETR,'NAME',STAT,O1,F1,...,O4,F4
0
```

```
 ENTER AREA INTERCHANGE DATA
 I, ISW, PDES, PTOL, 'AREA NAME'
Q
 AREA151 [EES     ] HAS  9 TRANSFERS. SUM=  1214.0 MW BUT AREA PDES=   339.5
 AREA502 [CELE    ] HAS 10 TRANSFERS. SUM=   312.0 MW BUT AREA PDES=   225.7
 AREA515 [SWPA    ] HAS 20 TRANSFERS. SUM=   851.0 MW BUT AREA PDES=  1036.0
 AREA520 [AEPW    ] HAS 14 TRANSFERS. SUM=  -590.0 MW BUT AREA PDES= -1115.0
 AREA526 [SPS     ] HAS  4 TRANSFERS. SUM=     0.0 MW BUT AREA PDES=   150.0
 AREA534 [SUNC    ] HAS  6 TRANSFERS. SUM=   131.0 MW BUT AREA PDES=   127.0
 AREA541 [KACP    ] HAS 15 TRANSFERS. SUM=   184.0 MW BUT AREA PDES=   305.0
 AREA542 [KACY    ] HAS  4 TRANSFERS. SUM=     0.0 MW BUT AREA PDES=    20.0

 ACTIVITY?

 DOUBLY-FED INDUCTION GENERATOR PARAMETERS:
 Ra  = 0.01022 (pu)
 La  = 0.14283 (pu)
 Lm  = 7.21137 (pu)
 R1  = 6.94532 (pu)
 L1  = 0.01008 (pu)
 H   = 0.17503 (sec.)
 DAMP= 4.2267 (pu)
 E1  = 0.03 (pu)
 SE1 = 0.08 (pu)
 E2  = 1.0829 (pu)
 SE2 = 0.27 (pu)
 REXT0 = 0.05028 (pu)
 REXT1 = 0.20114 (pu)
 REXT2 = 0.60341 (pu)
 T1 = 0.055 (pu)
 T2 = 0.07 (pu)
 T0 = 0.07 (pu)
 KS = 2.0 (pu)
 KI = 0.5 (pu)


 UNDER/OVER VOLTAGE PROTECTION SCHEME:

 DEFAULT VOLTAGE PROTECTION SCHEME FOR SIMULATION PERIODS LESS THAN 1 MINUTE:
 MONITOR BUS         : THE WIND TURBINE GENERATOR BUS
 VOLTAGE BELOW 15%   : 0.04 SECOND
 VOLTAGE 15% TO 30%  : 0.625 SECOND
 VOLTAGE 30% TO 45%  : 1.100 SECOND
 VOLTAGE 45% TO 60%  : 1.575 SECONDS
 VOLTAGE 60% TO 75%  : 2.050 SECONDS
 VOLTAGE 75% TO 90%  : 2.525 SECONDS
 VOLTAGE ABOVE 110%  : 0.06 SECOND

 1. USE THE DEFAULT PROTECTION SCHEME
 2. DO NOT INCLUDE UNDER/OVER VOLTAGE PROTECTION SCHEME.
 ENTER 1, 2, OR Q FOR QUIT:

 THE PARAMETERS FOR WIND TURBINE GENERATORS IN PSS/E LOAD FLOW:
 WTG_BASKV  =  0.6900
 WTG_MBASE  =  2.0000
 WTG_RSORCE =  0.0000
 WTG_XSORCE =  0.1529
 WTGXFR_BASE=  2.5000
 WTGXFR_R   =  0.0060
 WTGXFR_X   =  0.0600
 WTGXFR_GTAP=  1.0000
 WTG_PMAX   =  2.0000
 WTG_PMIN   =  0.0000

 ***************************************************************
 ****  WTG EQUIVALENTS HAVE BEEN DISPATCHED WITH STATUS ON  ****
 *** CASE NOT SOLVED. PLEASE SOLVE CASE MANUALLY USING PSS/E ***
 ***************************************************************

 INVALID ACTIVITY--PLEASE TRY AGAIN
```

```
ACTIVITY?  IPLAN ROUTINE G8X_60Hz FINISHED
```

Input file: machine_param_G8X_60.dat

```
0.690     / BASE KV
2.000     / WTG MBASE
2.5       / TRANSFORMER MBASE
0.0060    / TRANSFORMER R ON TRANSFORMER BASE
0.0600    / TRANSFORMER X ON TRANSFORMER BASE
1.0       / GTAP
2.0       / PMAX
0.0       / PMIN
0.01022   / RA
0.14283   / LA
7.21137   / LM DELTA
6.94532   / LM Y
0.01008   / RMACH
0.17503   / L1
4.2267    / INERTIA
0.03      / Tn
0.08      / Kp
1.0829    / Ir_max
0.27      / Vr_max
0.05028   / REXT0
0.20114   / REXT1
0.60341   / REXT2
0.055      / T1
0.07     / T2
0.07     / T0
2.0      / KS
0.50      / KI
167.12    / KPP, PID P GAIN of pitch control
83.58     / KIP, PID I GAIN of pitch control
0.0       / KDP, PID D GAIN of pitch control
0.2318    / TD,  PID time constant of pitch control
1.146     / KPC, PI P GAIN of pitch compensator
11.46     / KIC, PI I GAIN of pitch compensator
```

Input file: collector_bus.dat

```
1                      / NUMBER OF COLLECTOR BUSES
1070   102             / 1070 ORIGINAL UNITS AGGREGATED ON BUS 1070
```

Appendix B

PSS/E Power Flow modeling details for Wind Farm

(Note: Substation 345/34.5kV high side tap ratio varied in study work)

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      THU, OCT 21 2004  15:04
GR2-SO03AA.UYVV4V4.SAV;SUMMER;OP LD;SYSTEM INTACT
ND=1950,MH=2172,MW=1480,OHMH=-197,OHMP=150,EWTW=-202,BD=166

DATA FOR BUS 66537 [WHITE  3 345] RESIDING IN AREA 652, ZONE 654, OWNER   1:

CODE PLOAD   QLOAD   I - L O A D     Y - L O A D G-SHUNT B-SHUNT VOLTAGE  ANGLE
 1     0.0     0.0    0.0    0.0     0.0     0.0     0.0     0.0 1.01213 106.88

X-------TO-------X CKT   LINE R   LINE X CHARGING ST MET RATE-A RATE-B RATE-C LENGTH ZI OWN1 FRAC1 OWN2
FRAC2 OWN3 FRAC3 OWN4 FRAC4
60130 SPLTRTA3 345  1   0.00230  0.02760  0.44785  1  T   720.0 1308.0  792.0    0.0       1 1.000
66529 WATERTN3 345  1   0.00190  0.02220  0.37340  1  T   720.0  880.0  792.0    0.0       1 1.000

                                W M S C C C
X-------TO-------X CKT X-NAME-X 1 T T Z W M   R 1-2    X 1-2  WBASE1   MAG1    MAG2  RATE-A RATE-B RATE-
C OWN1 FRAC1 OWN2 FRAC2 OWN3 FRAC3 OWN4 FRAC4
 1070 GI0108  34.5  1           F F 1 1 1 1  0.00800  0.07519  100.0  0.0000  0.0000  200.0  200.0
0.0    1 1.000
66292 WHITE  T 345  1           F F 1 1 1 1  0.00070  0.06760  100.0  0.0000  0.0000  200.0  200.0
250.0    1 1.000
66337 WHITE2 7 115  P2          T T 1 1 1 1  0.00040  0.02560  100.0  0.0000  0.0000  448.0  448.0
515.2    1 1.000
66600 GI0108  34.5  1           F F 0 1 1 1  0.00154  0.06180  100.0  0.0000  0.0000  210.9  210.9
0.0    1 1.000

X-------TO-------X CKT WINDV1 NOMV1 ANGLE WINDV2 NOMV2 CN  RMAX   RMIN   VMAX   VMIN  NTPS X--CONTROLLED
BUS-X    CR      CX  TBL    NOMINAL R,X
 1070 GI0108  34.5  1  1.0000 0.000   0.0 1.0000 0.000  0 1.5000 0.5100 1.5000 0.5100   33
66292 WHITE  T 345  1  1.0000 0.000   0.0 1.0000 0.000  0 1.5000 0.5100 1.5000 0.5100  159
66337 WHITE2 7 115  P2 1.0000 0.000   0.0 1.0000 0.000  0 1.5000 0.5100 1.5000 0.5100  159
66600 GI0108  34.5  1  1.0000 0.000   0.0 1.0000 0.000  0 1.5000 0.5100 1.5000 0.5100  159


DATA FOR BUS  1070 [GI0108  34.5] RESIDING IN AREA 652, ZONE 654, OWNER   1:

CODE PLOAD   QLOAD   I - L O A D     Y - L O A D G-SHUNT B-SHUNT VOLTAGE  ANGLE
 1     0.0     0.0    0.0    0.0     0.0     0.0     0.0     0.0 1.00964 115.51

                                W M S C C C
X-------TO-------X CKT X-NAME-X 1 T T Z W M   R 1-2    X 1-2  WBASE1   MAG1    MAG2  RATE-A RATE-B RATE-
C OWN1 FRAC1 OWN2 FRAC2 OWN3 FRAC3 OWN4 FRAC4
66537 WHITE  3 345  1           T T 1 1 1 1  0.00800  0.07519  100.0  0.0000  0.0000  200.0  200.0
0.0    1 1.000
91070 CLR_1   .690  1           F F 1 1 1 1  0.00235  0.02353  255.0  0.0000  0.0000  255.0    0.0
0.0    1 1.000

X-------TO-------X CKT WINDV1 NOMV1 ANGLE WINDV2 NOMV2 CN  RMAX   RMIN   VMAX   VMIN  NTPS X--CONTROLLED
BUS-X    CR      CX  TBL    NOMINAL R,X
66537 WHITE  3 345  1  1.0000 0.000   0.0 1.0000 0.000  0 1.5000 0.5100 1.5000 0.5100   33
91070 CLR_1   .690  1  1.0000 0.000   0.0 1.0000 0.000  0 1.1000 0.9000 1.1000 0.9000   33


DATA FOR BUS 91070 [CLR_1   .690] RESIDING IN AREA 652, ZONE 654, OWNER   1:

CODE PLOAD   QLOAD   I - L O A D     Y - L O A D G-SHUNT B-SHUNT VOLTAGE  ANGLE
-2     0.0     0.0    0.0    0.0     0.0     0.0     0.0     0.0 1.01327 118.20

PLNT PGEN    QGEN    QMAX    QMIN  VSCHED X-    REMOTE BUS     VOLTAGE  Q PCT-X
    204.0     0.0     0.0     0.0 1.00000                            100.00
```

```
ID ST  PGEN   QGEN   QMAX   QMIN  MBASE  Z S O R C E    X T R A N   GENTAP   PMAX   PMIN OW1 FRAC1 OW2
FRAC2 OW3 FRAC3 OW4 FRAC4
1  1  204.0    0.0    0.0    0.0  204.0 0.0000 0.1529 0.0000 0.0000 1.0000  204.0    0.0   1 1.000

                                W M S C C C
X-------TO-------X CKT X-NAME-X 1 T T Z W M   R 1-2    X 1-2  WBASE1   MAG1    MAG2  RATE-A RATE-B RATE-
C OWN1 FRAC1 OWN2 FRAC2 OWN3 FRAC3 OWN4 FRAC4
 1070 GI0108  34.5  1           T T 1 1 1 1  0.00235  0.02353  255.0  0.0000  0.0000  255.0    0.0
0.0    1 1.000

X-------TO-------X CKT WINDV1 NOMV1 ANGLE WINDV2 NOMV2 CN  RMAX   RMIN   VMAX   VMIN  NTPS X--CONTROLLED
BUS-X    CR      CX  TBL    NOMINAL R,X
 1070 GI0108  34.5  1  1.0000 0.000   0.0 1.0000 0.000  0 1.1000 0.9000 1.1000 0.9000   33
```

PSS/E Activity POUT Listing for Wind Farm

(Note: Unity tap on 345/34.5kV substation transformer and no shunt capacitor applied to bus #1070 yet in the following listing.)

```
     PTI INTERACTIVE POWER SYSTEM SIMULATOR--PSS/E      THU, OCT 21 2004  15:05
GR2-SO03AA.UYVV4V4.SAV;SUMMER;OP LD;SYSTEM INTACT                        RATING
ND=1950,MH=2172,MW=1480,OHMH=-197,OHMP=150,EWTW=-202,BD=166               SET A

BUS 66537 WHITE  3 345 AREA CKT    MW     MVAR     MVA  %I 1.0121PU 106.88 66537
                       652                                 349.18KV
 TO  1070 GI0108  34.5 652  1   -199.8    40.0   203.8 101 1.0000LK
 TO 60130 SPLTRTA3 345 600  1    725.9   -35.0   726.7 100
 TO 66292 WHITE  T 345 652  1    -60.6   -19.0    63.5  31 1.0000LK
 TO 66337 WHITE2 7 115 652  P2  -437.6    83.1   445.4  98 1.0000UN
 TO 66529 WATERTN3 345 652  1    -27.8   -69.0    74.4  10

BUS  1070 GI0108  34.5 AREA CKT    MW     MVAR     MVA  %I 1.0096PU 115.51 1070
                       652                                 34.833KV
 TO 66537 WHITE  3 345 652  1    203.0    -9.5   203.3 101 1.0000UN
 TO 91070 CLR_1   .690 652  1   -203.0     9.5   203.3  79 1.0000LK

BUS 91070 CLR_1   .690 AREA CKT    MW     MVAR     MVA  %I 1.0133PU 118.20 91070
 GENERATION            652       204.0     0.0H  204.0 100 0.6992KV
 TO  1070 GI0108  34.5 652  1    204.0     0.0   204.0  79 1.0000UN
```

Appendix C

Updated Stability Modeling (DYRE Input Data)

```
91070 'USRMDL' 1 'G8XDFG' 1 1 1 21 5 26 0 0.01022 0.14283 7.21137 6.94532 0.01008 0.17503 4.2267
0.03 0.08 1.0829 0.27 0.2 0.05028 0.20114 0.60341 0.055 0.07 0.07 2.0 0.5 1.0 /
 91070 'USRMDL' 1 'G8XCNT' 4 0 3 16 6 12 91070 0 1 0.0 0.0 0.0 0.0 0.0 0.07 21.1697 10.15926 1.0
0.0 0.67197 -0.26389 1.11 0.05 0.5 -0.195/
 0 'USRMDL' 0 'TWIND1' 8 0 2 7 0 3 91070 '1' 17.0 9999.0 5.0 30.0 9999.0 9999.0 30.0 /
 0 'USRMDL' 0 'G8XAER' 8 0 3 6 1 4 91070 '1' 0  17.0 19.5 0.0 50.0 0.0 0.5 /
 0 'USRMDL' 0 'G8XPTC' 8 0 3 12 5 11 91070 '1' 0   0.1 167.17 83.58 0.0 0.2318 1.146 11.46 0.0
50.0 -7.5 7.5 1.0 /
 0 'USRMDL' 0 'VTGTRP' 0 2 5 4 0 1 91070 91070 0 0 0 0.15 5.0 0.04 0.05 /
 0 'USRMDL' 0 'VTGTRP' 0 2 5 4 0 1 91070 91070 0 0 0 0.3 5.0 0.625 0.05 /
 0 'USRMDL' 0 'VTGTRP' 0 2 5 4 0 1 91070 91070 0 0 0 0.45 5.0 1.1 0.05 /
 0 'USRMDL' 0 'VTGTRP' 0 2 5 4 0 1 91070 91070 0 0 0 0.6 5.0 1.575 0.05 /
 0 'USRMDL' 0 'VTGTRP' 0 2 5 4 0 1 91070 91070 0 0 0 0.75 5.0 2.05 0.05 /
 0 'USRMDL' 0 'VTGTRP' 0 2 5 4 0 1 91070 91070 0 0 0 0.9 5.0 2.55 0.05 /
 0 'USRMDL' 0 'VTGTRP' 0 2 5 4 0 1 91070 91070 0 0 0 0.0 1.1 0.06 0.05 /
```

Attachment #2

REACTORS

DESIGNATION	KV	MVAR	SPEC OR STAGE NO.
KW32A	13.2	30	STAGE 01

RESISTORS

DESIGNATION	V	AMP	OHMS	SPEC OR STAGE NO.
RW30A	208	40	5.5	STAGE 01
RW32A	15000	2.5	55	[*]

SERIES CAPACITOR

DESIGNATION	KV	MVAR	SPEC OR STAGE NO.
PW32A	15	50	[*]

CURRENT TRANSFORMERS

DESIGNATION	KV	RATIO	SPEC OR STAGE NO.
OY24A	115	200/400:5	WC-9-15001-1 [01]

VOLTAGE TRANSFORMERS

DESIGNATION	KV	RATIO	SPEC OR STAGE NO.
VY21A	115	600/1000:1 & 600/1000:1	STAGE 01
VW32A	15	70:1	STAGE 01

COUPLING CAPACITOR VOLTAGE TRANSFORMERS

DESIGNATION	KV	RATIO	SPEC OR STAGE NO.
VU1A,3A,4A	345	1800/3000:1 1800/3000:1 & 1800:1	STAGE 01
VY21B1,22A1,24A1	115	600/1000:1 & 600/1000:1	STAGE 01

UNIT SUBSTATION

DESIGNATION	KV	SPEC OR STAGE NO.
DWA (KWA)	13.8	STAGE 01

DISCONNECTING SWITCHES

DESIGNATION	KV	CONT AMP	SPEC OR STAGE NO.
WU3A,4A YU3A,3B,3C,4A	345	2000	STAGE 01
WY21A,21B,22A,22B WY23A,23B,24A,24B YY22A,24A	115	1200	STAGE 01
WW32A	15	2000	STAGE 01

POWER CIRCUIT BREAKERS

DESIGNATION	KV	CONT AMP	INTRPT CAP KA	TIME CYCLE	SPEC OR STAGE NO.
JU3A,3B,4A	345	2000	40	3	83WP15849 [01]
JY22A,23A,24A	115	1200	20	3	83WP15795 [01]
JW32A	15	2000	40	5	83WP15847 [01]

FUSE DISCONNECTING SWITCHES

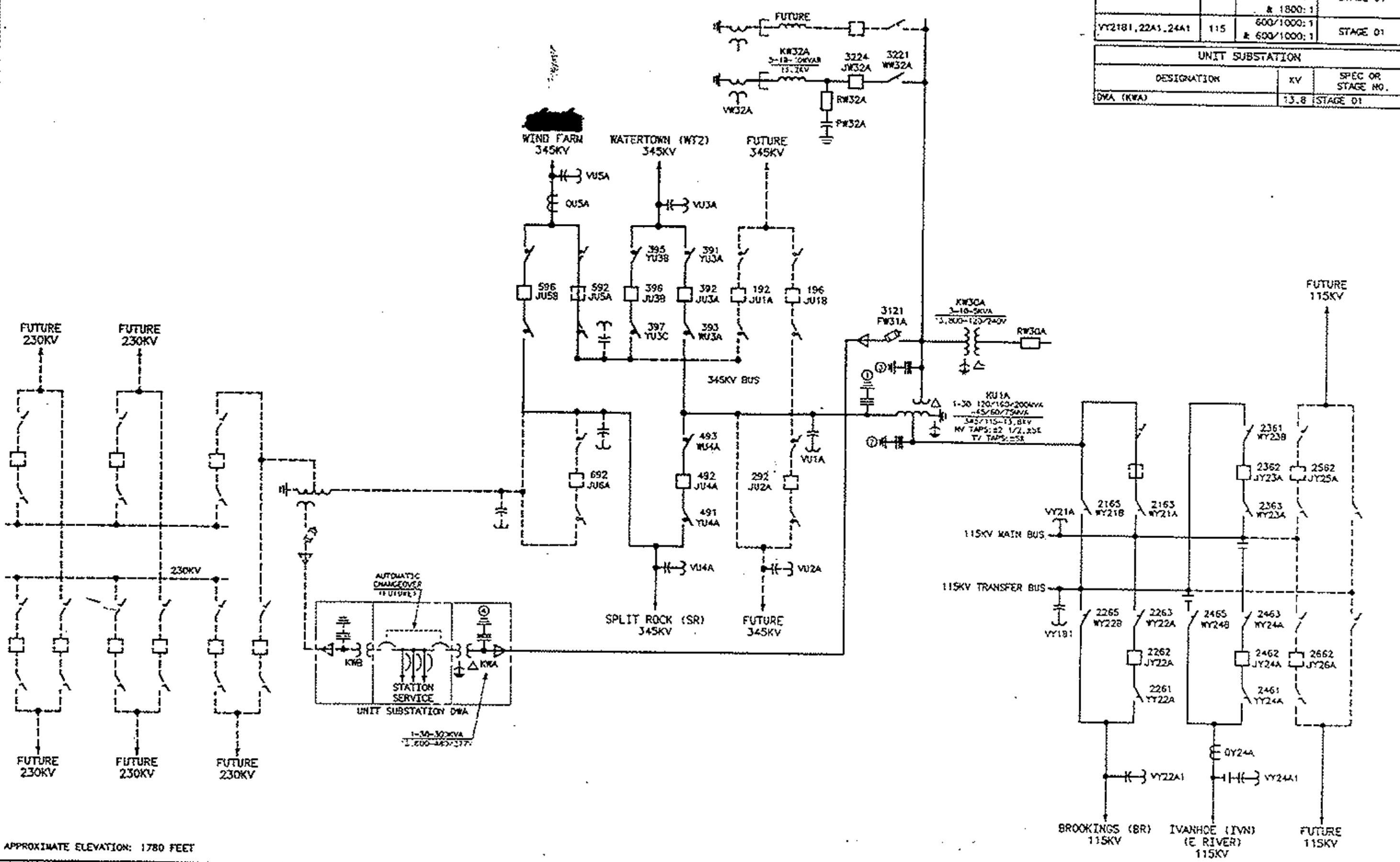
DESIGNATION	KV	INTRPT AMP (SYM)	SPEC OR STAGE NO.
FW31A	15	40,000	STAGE 01

TRANSFORMERS

DESIGNATION	KV	SPEC OR STAGE NO.
KU1A	345	83WP15781 [01]
KW30A	15	STAGE 01

SURGE ARRESTERS

DESIGNATION	KV (SYS)	CLASS	SPEC OR STAGE NO.
1	345	STATION	83WP15781 [01]
2	115	STATION	83WP15781 [01]
3	13.8	STATION	83WP15781 [01]
4	13.8	STATION	STAGE 01



EXPLANATION

STAGE 01 ---- EQUIPMENT FURNISHED AND INSTALLED UNDER CONTRACT 84WP15895.

[01] -------- GOVERNMENT FURNISHED EQUIPMENT INSTALLED UNDER STAGE 01.

[*] -------- GOVERNMENT FURNISHED EQUIPMENT INSTALLED UNDER KW32A TRANSIENT SUPPRESSOR INSTALLATION.

REFERENCE DRAWINGS

GENERAL PLOT PLAN ---------------- WHT 0010

UNIT SUBSTATION DWA WIRING DIAGRAM -------- WHT 1051

PROPOSED ADDITION

C REDRAWN.

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
HEADQUARTERS - GOLDEN, COLORADO

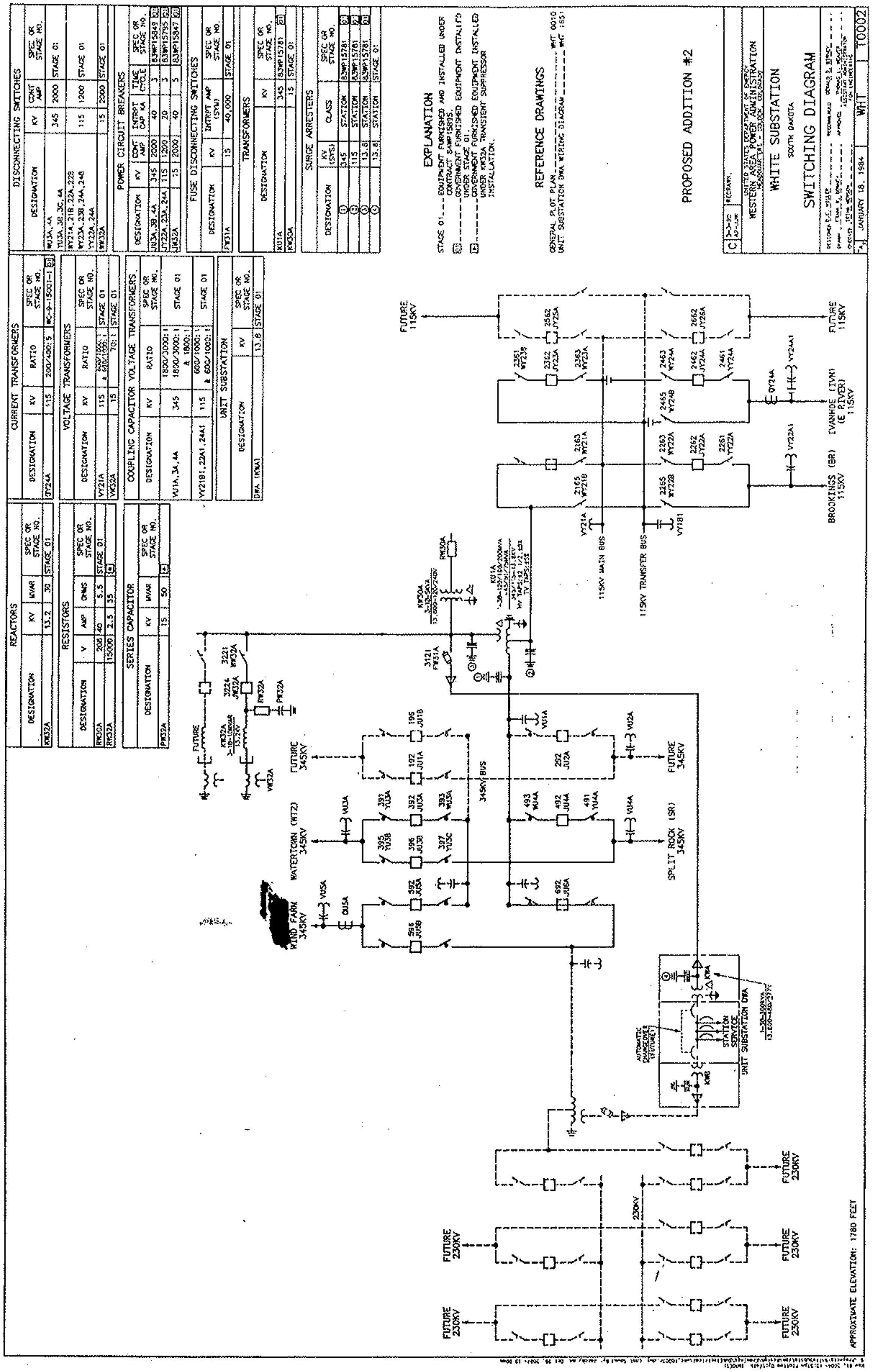
WHITE SUBSTATION

SOUTH DAKOTA

SWITCHING DIAGRAM

JANUARY 18, 1984 | WHT | T0001

Attachment #3



Attachment #4

Facility :	WHITE [redacted] 345-kv Bay	ACTUALS	FY 05	FY 06	
Date:	10/20/04 tf	*Program Direction*			
Filename:	[redacted]	*Other (C&R)*			
get Activities:	WHT.....000?C (BCPS)				
		BUDGET YEAR SUBMITTAL	FY 05	FY 06	
		Program Direction	$ -	$ 38,590	
		Other (C&R)	$ -	$ -	
		CURRENT YEAF	FY 05	FY 06	CHK TOTALS
		Program Direction	$ 638,012	$ 273,297	$ 911,309
		Other (C&R)	$ 1,648,600	$ 103,950	$ 1,752,550
			$ 2,286,612	$ 377,247	
Total Cost:	$ 2,663,859				$ 2,663,859

Development Activities (tasks)	Comments/notes	Break-out	Estimated Cost	Cost Origin	Fiscal Year 2005	Fiscal Year 2006	FY Row Totals
Planning (FDS)	B5550.HU	gov't labor	$ 5,100	12 days	[redacted]	[redacted]	
	Planning	GPR Overhd	$ 3,948				
(300 10)		Other	$ 905	10% labor			
	30010	Total	$ 9,953		$ 9,953		$ 9,953
Schedule							
Environmental (cx)	Environmental EIS B0400.BL	gov't labor	$ 129,625	305 days	[redacted]	[redacted]	
		UGPR Overhd	$ 100,345				
	30011	Other	$ 22,997	10% labor			
		subtotal	$ 252,967		$ 228,085	$ 24,882	
(300 11)		gov't labor	$ -	0 days	[redacted]	[redacted]	
	B0400.BL	UGPR Overhd	$ -				
		Other	$ -	10% labor			
		subtotal haz	$ -		$	$	
	Environmental Contracts	Total	[redacted]	Lump Sum estimate			
		Total	$ 252,967		$ 228,085	$ 24,882	$ 252,967
Schedule							
Field Data/PM (300 12)	B5500 30012 30022	gov't labor	$ 21,250	50 days	[redacted]	[redacted]	
		UGPR Overhd	$ 16,450				
		Other	$ 3,770	10% labor			
		Total	$ 41,470		$ 20,735	$ 20,735	$ 41,470
Schedule							
Land & Rights (00 350 00)	B5520.HU	gov't labor	$ 2,125	5 days	[redacted]	[redacted]	
		UGPR Overhd	$ 1,645		$ 1,645		
		Other	$ 377	10% labor	$ 377		
		subtotal haz	$ 4,147		$ 4,147		
		Right of Entry	[redacted]	Lump Sum estin	$		
		Title Insur.		Lump Sum estin	$		
		Land		Lump Sum estin	$		
		Total	$ 4,147		$ 4,147		$ 4,147
Schedule							
Design & Specs (300 13)	A7900 Design	gov't labor	$ 161,500	360 days	[redacted]	[redacted]	
		CSO Ovrhd	$ 70,300	Note 1			
		Other	$ 23,180	10% labor			
		Subtotal	$ 254,980		$ 254,980	$	
	B5500 Design	gov't labor	$ 6,375	15 days	[redacted]	[redacted]	
		UGPR Ovrhd	$ 4,935				
		Other	$ 1,131	10% labor			
		Subtotal	$ 12,441		$ 12,441	$	
	B5300 Design	gov't labor	$ 14,450	34 days	[redacted]	[redacted]	
		UGPR Ovrhd	$ 11,186				
		Other	$ 2,564	10% labor			
		Subtotal	$ 28,200		$ 28,200	$	
	B5600.HU Spec Prep Review & Distribution	gov't labor	$ 34,000	80 days	[redacted]	[redacted]	
		UGPR Ovrhd	$ 26,320				
		Other	$ 6,032	10% labor			
		Subtotal	$ 66,352		$ 66,352	$	
	B5500 Spec Review	gov't labor	$ 2,125	5 days	[redacted]	[redacted]	
		UGPR Ovrhd	$ 1,645				
		Other	$ 377	10% labor			
		Subtotal	$ 4,147		$ 4,147	$	
	State Maint Spec Review B5100/B5200/B5300	gov't labor	$ 2,125	5 days	[redacted]	[redacted]	
		UGPR Ovrhd	$ 1,645				
		Other	$ 377	10% labor			
		Subtotal	$ 4,147		$ 4,147	$	
	A&E Design Contract	Total	[redacted]	Lump Sum			
		Total	$ 370,267		$ 370,267	$ -	$ 370,267
Schedule							

[redacted]

Development Activities (tasks)	[redacted] Comments/notes	Break-out	Estimated Cost	Cost Origin	Fiscal Year 2005	Fiscal Year 2006	FY Row Totals
Contract (352 20)		Construction	[redacted]	From Basis she	$ 1,218,000		
			42 wb days 22 eng days		[redacted]		
(353 00)		govt costs	[redacted]	From Basis she	$	$ 48,256	$ 48,256
(353 00)	[redacted]	GFE 1	[redacted]	From Basis she	$		
(353 00)		GFE 2		From Basis sheet		$ 80,000	
(353 00)		GFE 3		From Basis she	$ 170,000		
(353 00)		GFE 4		From Basis sheet		$ 500	
(353 00)		GFE 5		From Basis sheet		$ 34,000	
(353 00)		GFE 6				$	
(353 00)		GFE 7				$	
(353 00)		GFE 8				$	
(353 00)		GFE 9				$	
(353 00)		GFE 10				$	
		GFE Subtotal	$ 264,500				
	Contingency %	10%	$ 121,800	Construction	$ 121,800		
		10%	$ 26,450	GFE	$ 17,000	$ 9,450	
		10%	$ 4,826	gov't costs	$ 4,826		
	Inflation Factor	10%	$ 121,800	Construction	$ 121,800		
		0%	$ -	GFE			
	Construction Contract TOTAL		$ 1,461,600				
	Government Labor TOTAL		$ 53,082				
	GFE TOTAL		$ 290,950		$ 1,653,426	$ 152,206	$ 1,805,632
Schedule							
Force Account	Commissioning	wage board	$ 11,050	26 days	[redacted]		
		engineers	$ 11,050	26 days			
(300 21)		UGPR Ovrhd	$ 17,108				
		Other	$ 2,816	10% labor			
		Subtotal	$ 42,024			$ 42,024	
(300 16)	(lump sum)	Safety	[redacted]	Lump Sum for all projects		$ 1,000	
		Total	$ 43,024			$ 43,024	$ 43,024
Schedule						ON	
Const. Supv.	B5600.HU	gov't labor	$ 62,000	4 months	[redacted]		
(300 14)	Overhead	1.2 x labor	$ 74,400	$15,500 per month x X months			
(300 15)		Subtotal	$ 136,400			$ 136,400	
		Total	$ 136,400			$ 136,400	$ 136,400
Schedule					JJAS		

CSO Daily Overhead= $185
UGPR Daily Overhead= $329
Daily Labor Rate= $425

CSO Total= $610
UGPR Total= $754

NOTES:
1. "Other" is travel & vehicle expenses and distributive costs.
2. GFE 10% contingency includes miscellaneous material expenses.
3. Government costs 10% contingency includes travel, pd, heavy equipment use, and vehicle expense.

Attachment #5

Facility : WHITE[redacted]345-kv Bay One-and-Half B

Date: 10/20/04 tf

Filename[redacted]

Budget Activities: WHT.....0007C (BCPS)

ACTUALS	FY 05	FY 06	
Program Direction			
Other (C&R)			
BUDGET YEAR SUBMITTAL	**FY 05**	**FY 06**	
Program Direction	$ -	$ 38,590	
Other (C&R)	$ -	$ -	
CURRENT YEAR	**FY 05**	**FY 06**	**CHK TOTALS**
Program Direction	$ 707,227	$ 397,141	$ 1,104,367
Other (C&R)	$ 2,126,000	$ 104,500	$ 2,230,500
	$ 2,833,227	$ 501,641	

Total Cost: $ 3,334,867 — $ 3,334,867

Development Activities (tasks)	Comments/notes	Break-out	Estimated Cost	Cost Origin	Fiscal Year 2005	Fiscal Year 2006	FY Row Totals
Planning (FDS)	B5550.HU	gov't labor	$ 6,375	15 days			
	Planning	GPR Overhd	$ 4,935				
(300 10)		Other	$ 1,131	10% labor			
	30010	Total	$ 12,441		$ 12,441		$ 12,441
Schedule							
Environmental	Environmental EIS	gov't labor	$ 129,625	305 days			
(cx)	B0400.BL	UGPR Overhd	$ 100,345				
	30011	Other	$ 22,997	10% labor			
		subtotal	$ 252,967		$ 228,085	$ 24,882	
(300 11)		gov't labor	$ -	0 days			
	B0400.BL	UGPR Overhd	$ -				
		Other	$ -	10% labor			
		subtotal haz	$ -		$	$	
	Environmental Contracts	Total		Lump Sum estimate			
		Total	$ 252,967		$ 228,085	$ 24,882	$ 252,967
Schedule							
Field Data/PM	B5500	gov't labor	$ 25,500	60 days			
(300 12)	30012	UGPR Overhd	$ 19,740				
	30022	Other	$ 4,524	10% labor			
		Total	$ 49,764		$ 24,882	$ 24,882	$ 49,764
Schedule							
Land & Rights	B5520.HU	gov't labor	$ 2,125	5 days			
(00 350 00)		UGPR Overhd	$ 1,645		$ 1,645		
		Other	$ 377	10% labor	$ 377		
		subtotal haz	$ 4,147		$ 4,147		
		Right of Entry		Lump Sum estimate	$		
		Title Insur.		Lump Sum estimate	$		
		Land		Lump Sum estimate	$		
		Total	$ 4,147		$ 4,147		$ 4,147
Schedule							
Design & Specs	A7900 Design	gov't labor	$ 178,500	420 days			
(300 13)		CSO Ovrhd	$ 77,700	Note 1			
		Other	$ 25,620	10% labor			
		Subtotal	$ 281,820		$ 281,820	$	
	B5500 Design	gov't labor	$ 6,375	15 days			
		UGPR Ovrhd	$ 4,935				
		Other	$ 1,131	10% labor			
		Subtotal	$ 12,441		$ 12,441	$	
	B5300 Design	gov't labor	$ 14,450	34 days			
		UGPR Ovrhd	$ 11,186				
		Other	$ 2,564	10% labor			
		Subtotal	$ 28,200		$ 28,200	$	
	B5600.HU Spec Prep Review & Distrbution	gov't labor	$ 51,000	120 days			
		UGPR Ovrhd	$ 39,480				
		Other	$ 9,048	10% labor			
		Subtotal	$ 99,528		$ 99,528	$	
	B5500 Spec Review	gov't labor	$ 2,125	5 days			
		UGPR Ovrhd	$ 1,645				
		Other	$ 377	10% labor			
		Subtotal	$ 4,147		$ 4,147	$	
	State Maint Spec Review B5100/B5200/B5300	gov't labor	$ 2,125	5 days			
		UGPR Ovrhd	$ 1,645				
		Other	$ 377	10% labor			
		Subtotal	$ 4,147		$ 4,147	$	
	A&E Design Contract	Total		Lump Sum			
		Total	$ 430,283		$ 430,283	$ -	$ 430,283
Schedule							

Development Activities (tasks)	Comments/notes	Break-out	Estimated Cost	Cost Origin	Fiscal Year 2005	Fiscal Year 2006	FY Row Totals
Contract							
(352 20)		Construction	[redacted]	From Basis she	$ 1,460,000		
			64 wb days 34 eng days		[redacted]	[redacted]	
(353 00)		govt costs	[redacted]	From Basis she	$	$ 73,892	$ 73,892
(353 00)	[redacted]	GFE 1	[redacted]	From Basis she	$		
(353 00)		GFE 2		From Basis shee		$ 60,000	
(353 00)		GFE 3		From Basis she	$ 340,000		
(353 00)		GFE 4		From Basis shee		$ 1,000	
(353 00)		GFE 5		From Basis shee		$ 34,000	
(353 00)		GFE 6				$	
(353 00)		GFE 7				$	
(353 00)		GFE 8				$	
(353 00)		GFE 9				$	
(353 00)		GFE 10				$	
		GFE Subtotal	$ 435,000				
	Contingency %	10%	$ 146,000	Construction	$ 146,000		
		10%	$ 43,500	GFE	$ 34,000	$ 9,500	
		10%	$ 7,389	gov't costs	$ 7,389		
	Inflation Factor	10%	$ 146,000	Construction	$ 146,000		
		0%	$ -	GFE			
	Construction Contract TOTAL		$ 1,752,000				
	Government Labor TOTAL		$ 81,281				
	GFE TOTAL		$ 478,500		$ 2,133,389	$ 178,392	$ 2,311,781
Schedule							
Force Account	Commissioning	wage board	$ 17,850	42 days	[redacted]	[redacted]	
		engineers	$ 17,850	42 days			
(300 21)		UGPR Ovrhd	$ 27,636				
		Other	$ 4,549	10% labor			
		Subtotal	$ 67,885			$ 67,885	
(300 16)	(lump sum)	Safety	[redacted]	Lump Sum for all projects		$ 1,000	
		Total	$ 68,885			$ 68,885	$ 68,885
Schedule						ON	
Const. Supv.	B5600.HU	gov't labor	$ 93,000	6 months	[redacted]	[redacted]	
(300 14)	Overhead	1.2 x labor	$ 111,600	$15,500 per month x X months			
(300 15)		Subtotal	$ 204,600			$ 204,600	
		Total	$ 204,600			$ 204,600	$ 204,600
Schedule							

CSO Total= $610
UGPR Total= $754

CSO Daily Overhead= $185
UGPR Daily Overhead= $329
Daily Labor Rate= $425

NOTES:

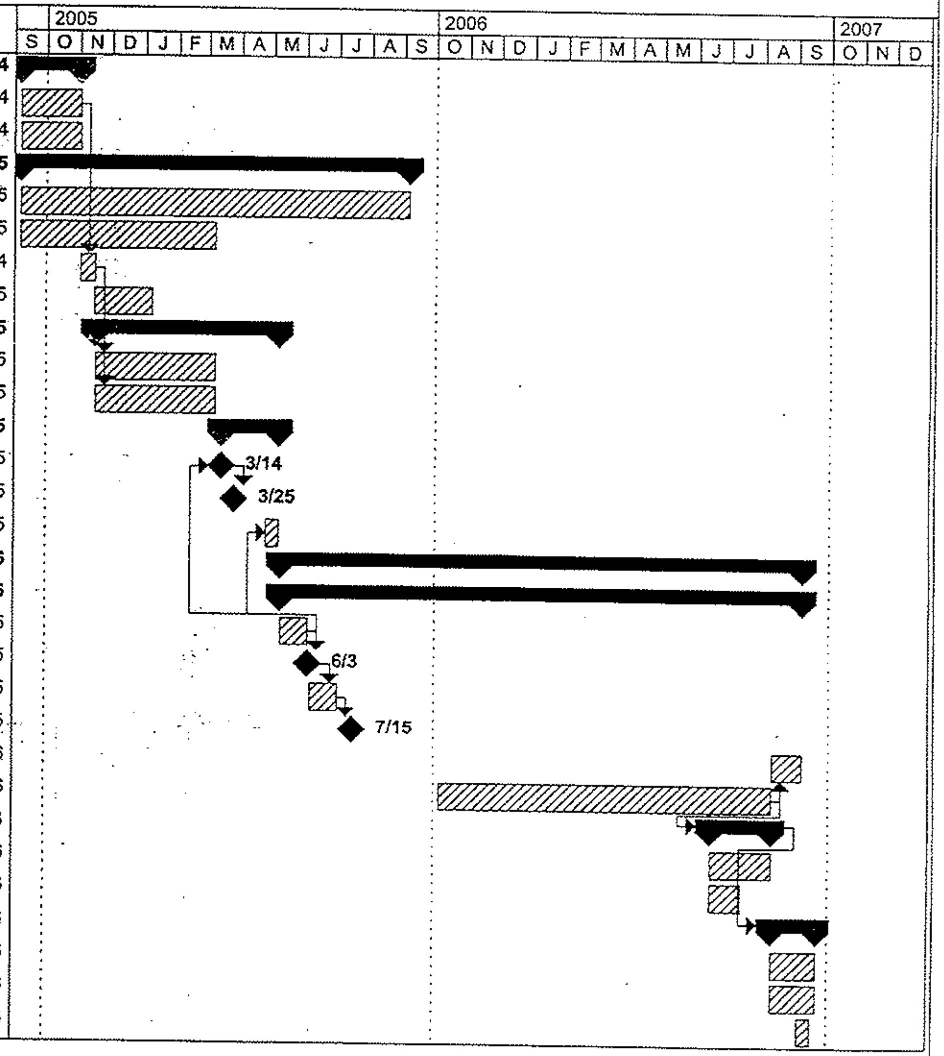
1. "Other" is travel & vehicle expenses and distributive costs.
2. GFE 10% contingency includes miscellaneous material expenses.
3. Government costs 10% contingency includes travel, pd, heavy equipment use, and vehicle expense.

Attachment #6

Work Order No.:B 000?C______
Project: WHT 345-kv Bay
Location: UGPR SDMO

Facility: White Substation Navitas 345 Interconnection Bay
Project Manager: Twyla Folk

ID	Task Name	Duration	Start	Finish
1	**PLANNING (30010)**	**8 wks**	**Tue 9/7/04**	**Mon 11/1/04**
2	Facility Dev. Document	8 wks	Tue 9/7/04	Mon 11/1/04
3	C&R Budget Sheet	8 wks	Tue 9/7/04	Mon 11/1/04
4	**ENVIRONMENTAL (30011)**	**52 wks**	**Tue 9/7/04**	**Mon 9/5/05**
5	NEPA	52 wks	Tue 9/7/04	Mon 9/5/05
6	HAZ MAT	26 wks	Tue 9/7/04	Mon 3/7/05
7	**FIELD DATA (30012)**	2 wks	Tue 11/2/04	Mon 11/15/04
8	**LANDS (35000)**	8 wks	Mon 11/15/04	Fri 1/7/05
9	**DESIGN (30013)**	**24.8 wks**	**Tue 11/16/04**	**Fri 5/6/05**
10	Overall Design	16 wks	Tue 11/16/04	Mon 3/7/05
11	**GFE**	16 wks	Tue 11/16/04	Mon 3/7/05
12	**Construction Specificatic**	**8 wks**	**Mon 3/14/05**	**Fri 5/6/05**
13	Data Pkg to B5600	0 wks	Mon 3/14/05	Mon 3/14/05
14	Drawings to B5600	0 wks	Fri 3/25/05	Fri 3/25/05
15	Draft Spec Review	2 wks	Mon 4/25/05	Fri 5/6/05
16	**CONSTRUCTION CONTRACT**	**69.6 wks**	**Mon 5/9/05**	**Wed 9/6/06**
17	**Contract Admin. (30015)**	**69.6 wks**	**Mon 5/9/05**	**Wed 9/6/06**
18	Issue/Advertise	4 wks	Mon 5/9/05	Fri 6/3/05
19	Bid Opening	0 wks	Fri 6/3/05	Fri 6/3/05
20	Award	4 wks	Mon 6/6/05	Fri 7/1/05
21	Notice to Proceed	0 wks	Fri 7/15/05	Fri 7/15/05
22	Contract Closeout	4 wks	Thu 8/10/06	Wed 9/6/06
23	Construction Supervision (:	44 wks	Thu 10/6/05	Wed 8/9/06
24	**EQUIPMENT INSTALLATION**	**8 wks**	**Thu 6/15/06**	**Wed 8/9/06**
25	Protection Eqpmnt Installat	8 wks	Thu 6/15/06	Wed 8/9/06
26	Communication Modificatic	4 wks	Thu 6/15/06	Wed 7/12/06
27	**Commissioning**	**6 wks**	**Thu 8/10/06**	**Wed 9/20/06**
28	Outdoor Elec Eqpmnt	6 wks	Thu 8/10/06	Wed 9/20/06
29	Protection Eqpmnt	6 wks	Thu 8/10/06	Wed 9/20/06
30	Comm Equpmnt	2 wks	Mon 9/4/06	Fri 9/15/06



Mon 11/1/04

UPPER GREAT PLAINS METER POLICY

SUBJECT: Meter Policy

PURPOSE: Establish a policy for the Upper Great Plains Region (UGPR) meter responsibilities and requirements. Western Area Power Administration (Western) recognizes it does not currently own all the revenue meters used for our billing purposes and that specific circumstances may require deviating from this policy statement; however, the UGPR prefers these arrangements and conditions and will work with our customers to achieve them.

1. TECHNICAL REQUIREMENTS

1. All meters, whether owned and maintained by Western, its customers, or a third party, shall comply with the requirements in this policy, with those listed in the General Requirements for Interconnection and, if applicable, shall comply with the latest revision of section 6 (Metering) of the General Power Contract Provisions (GPCP). In the event the requirements stated in this policy differ from the requirements stated in the GPCP or an executed Contract, the GPCP or Contract requirements shall prevail.

2. All meters shall meet an accuracy of ∀0.3 percent at unity power factor with 100 percent, 50 percent, and 10 percent current and ∀0.7 percent at 50 percent power factor with 100 percent current. Any new meters or replacement meters will have multi-level password protections, this will allow access to the meter readings while protecting the meter setting parameters with a different password.

3. All meters and instrument transformers will be installed to correctly measure power (kW) and energy (kWh) for all unbalances and will not be bypassed without approval by Western. Meters at all deliveries shall be 3-element. It is recognized there are several locations that employ 2-element metering. Those locations that are 2-element metering and are on a delta or ungrounded wye connected delivery, may remain in service until they are scheduled to be replaced.

4. Current Transformers (CT) shall be a wound or bushing type that meets the ANSI standard C57.13 of 0.3 percent at burdens B-0.1, B-0.2, B-0.5, B-0.9, and B-1.8. The CTs shall have a continuous thermal rating factor of at least 1.5. Multi-ratio CTs are required to meet the accuracy stated on the ratio being used. The CT will be loaded to at least 10 percent of the winding ratio unless differences are specifically allowed in a contract or agreement with Western.

5. Potential Transformers shall meet ANSI standard C57.13 of 0.3 percent accuracy class at the following burdens:

UPPER GREAT PLAINS METER POLICY

1. At system voltages below 25-kV with burdens of W, X, and Y.

2. At system voltages 25-kV and above with burdens W, X, Y, Z, and ZZ.

6. Load control boundary meters shall provide the analog and digital outputs compatible with Western's load control system and shall comply with the following:

   1. Instantaneous telemetering to the Watertown Operations Office (WOO) from all load control boundary interconnections.

   2. Hourly watt-hour telemetering, preferably digital watt-hour telemetering, to the WOO from all load control boundary interconnections.

   3. All 345-kV and higher interconnections shall be individually telemetered to the WOO. Quantities metered at 230-kV and 161-kV will normally require individual telemetering unless the Manager, System Reliability and Transmission Operations, concurs in a specific totalizing arrangement.

   4. Totalizing of multiple deliveries to each separate load control area at one substation will normally be permitted. Remote totalizing of quantities from more than one foreign load control area shall be avoided.

   5. To the extent possible, the same meter and transmitter should be used to provide the analog and digital metering information.

7. All meters shall be solid state models from which Western can collect data by:

   1. Remote interrogation using Utility Translation System MV-90 translation program.

   2. Local interrogation - the data can be collected at the meter sites:

      1) by using a PC and then uploading the data to the translator over a normal telephone line.

      2) by removing the recorder cartridge and mailing it to the translator operator where applicable.

      3) by using a portable meter reader and then uploading data from the portable reader to the translator over a normal telephone line.

   3. The make and model of the meters used in the UGPR will be approved by the State Maintenance Managers and the Maintenance Engineering Manager.

8. All customer supplied meters must be compatible with existing Western equipment

(hardware, software, test equipment) and approved by the State Maintenance Manager responsible for the delivery point.

9. Location of metering PTs and CTs shall be designed and installed so that it is possible to maintain power to the meter during breaker bypass configurations.

10. A properly designed space that meets appropriate State and Federal Safety and Health Regulations shall be provided to protect meters and other communication equipment from the environment.

2. REVENUE AND LOAD CONTROL BOUNDARY METERS

1. Western will be responsible for reading, testing, calibrating, maintaining, and replacing Western-owned meters.

2. Western will continue its policy to own all revenue meters on deliveries to Western customers. Ownership of load control boundary points meters are determined during contractual negotiations with the interested parties.

   1. Revenue: Metering associated with an existing customer=s desire to establish a new delivery point will be the financial responsibility of the customer. Generally, Western will own, maintain, and replace the meter, at the expense of the customer. It is preferable the meters, for any new delivery, be furnished by Western at the customer=s expense. If a meter is furnished by the customer, it must be approved by the State Maintenance Office ultimately responsible for its installation and maintenance. When new delivery points are established, the customer will also be responsible for the communications necessary to facilitate remote interrogation.

   2. Load Control: Financial responsibility for the metering system at new load control boundary points will be determined during negotiations for the new interconnections. This will include ownership, maintenance, replacement, and modification (MRM) responsibilities for the meter, instrument transformers, and communications and telemetering needed for remote interrogation of the meter.

3. The meter points will be reviewed by the Power Billing/Energy Accounting and Dispatch functions annually to ensure any changes have been accounted for properly. Any requests for load control metering changes will be coordinated with WOO and ample time given to review and respond to the effects of the change. The Maintenance organization will review load control boundary meters, within Western facilities, and all revenue metering systems to ensure accurate readings are being provided at the same interval as required for testing the meter. The following test intervals shall be used:

   1. Revenue Meters: All revenue meters that serve loads less than 100 kVA and single-phase meters shall be tested and calibrated once every 5 years. All solid

state 3-phase meters shall be tested at least once every 3 years.

2. Load Control Boundary Meters: All single-phase load control boundary meters shall be tested and calibrated once every 5 years. All solid state 3-phase meters shall be tested at least once every 3 years.

4. Any meter above 120 volts that is not instrument rated shall be provided with a disconnect device on the line side of the meter to facilitate the safe maintenance and repair of the meter. Using a socket type meter in place of the disconnect device is not acceptable. If delivery can sustain short outages while the disconnect device is open for maintenance and testing, the 480-volt meters are acceptable. If these conditions cannot be met, the customer will be responsible for all costs to change to a 120-volt meter when Western takes over responsibilities for 480-volt meters.

5. At points of delivery, points of input, or load control boundary points where another entity owns the meter, Western requires the right to be notified, in advance, of the date and time for the meter test and will be present for testing. The supplemental power supplier will provide Western with two copies of the meter test report. The meter data will be made available each month to Western's billing department. Western also reserves the right to request that a meter be tested.

   Also, if the meter owner modifies meter facilities, Western reserves the right to review and approve meter facility modifications prior to implementation, and be present at the site when the modifications are accomplished.

6. When a request is made for a meter function that is not currently available with the existing meter, the entity making the request will be financially responsible for any modifications needed to meet the request.

   1. If the meter is not owned by Western, the requester will obtain approval to make the modification from all parties associated with the meter.

   2. If the original meter was owned by Western, ownership of the new meter will transfer to Western, at no cost, after the installation is complete. Responsibility for maintenance and replacement for the new meter will be the same as for the meter being replaced.

3. GENERATION METERS

1. Meters shall meet the technical requirements of Section A, Technical Requirements. These requirements apply to generation operating inside the UGPR control area even if not directly connected to Western transmission facilities.

2. Generating meters will be owned, maintained, and replaced by the owner of the generation.

3. Instantaneous megawatt and hourly MWH data and generation status indication will be remotely provided to our WOO.

4. The customer will provide a communication circuit needed to transmit the data from the generating facility to WOO.

5. The customer will be responsible for providing an interface that is compatible with the equipment at WOO and to ensure that no MWH data is lost in hourly reporting.

6. Western requires the right to be notified, in advance, of the date and time for the meter test and will be present for testing. Western will be provided with two copies of the meter test report. Western also reserves the right to request that a meter be tested.

4. NEW INTERCONNECTIONS AND NEW REVENUE METER DELIVERY POINTS

The party requesting the interconnection will be responsible for providing:

1. Instrument transformers that meet Western's engineering standards and the technical requirements in Section A.

2. Communication and telemetering equipment for a load control boundary point if necessary.

3. A reliable communication circuit for remote interrogation of the meter if the metered quantities are needed for billing calculations or if information from the meter is needed by Western to fulfill requests for information from customers.

4. Meters according to the technical standards detailed in Section A. If the meter serves a load of 100-kVA or greater ownership of the meter will transfer to Western. For meters serving loads less than 100-kVA, ownership will remain with the customer.

5. Maintenance, replacement or modifications (MRM) of equipment listed in Sections D1., D2., D3. , and meters serving a load of less than 100-kVA installed in a customer's facility.

6. Monies to Western for Western to perform MRM of equipment listed in Sections D1., D2., D3., and D4. Installed in a Western substation and for meters serving a load of 100-kVA or greater installed in a customer facility.

7. Appropriate set of drawings for the delivery point. An "A" size 1-line diagram and full-size 3-line diagrams of the CT, PT, and panel layout drawings are required for approval

prior to installation of the meter. Nameplate data on the CT and PT shall be included with the approval drawings. Western shall be notified prior to any modifications to the CT and PT circuits. The design will include the following:

1. The use of shorting terminal blocks on CT installations. The shorting blocks will be ahead of any metering test blocks, preferably at the CT location, to allow the safe installation and modification of the metering circuits.

2. A means of disconnecting PT circuits ahead of the metering test block. Western prefers the use of potential fuses for this purpose.

5. REPLACEMENT OF EXISTING INSTRUMENT TRANSFORMERS (ITs)

The instrument transformer=s location, reason for change, and ownership determine the responsibility for maintenance and replacement. As a general rule, the customer will be responsible for any instrument transformer costs resulting from load growth or other modifications or improvements to their system. This would include the replacement of instrument transformers resulting from a delivery voltage change by the customers supplemental power supplier or wheeling agent.

Customers shall notify their Power Marketing representative and the Power Billing department located at the WOO in Watertown, SD, of any equipment failures immediately upon discovery so all necessary adjustments can be made and arrangements can be made for repair or replacement.

Except in an emergency, a customer shall not replace any failed instrument transformers or change CT ratios without first notifying Western. Notification should be in writing at least 10 working days prior to the scheduled transformer change.

Every effort will be made to complete the replacement of failed equipment as soon as possible after its discovery.

Any failed instrument transformers owned by Western must be returned to Western for proper environmental disposal.

Western will use multi-level password protected meters when installing new meters and when existing meters warrant replacement.

The following situations further illustrate how responsibilities will be determined:

1. FINANCIAL RESPONSIBILITY FOR INSTRUMENT TRANSFORMERS

   1. Western-owned instrument transformers will be purchased or furnished by

Western.

2. Customer-owned instrument transformers will be purchased or furnished by the Customer.

3. Any changes resulting from the customers load growth will be the responsibility of the customer.

4. Any new or additional metering point requested or required by the customer will be the responsibility of the customer.

5. Any changes resulting from a change by the customers supplemental supplier or a third party wheeling agent will be the responsibility of the customer.

2. REPLACEMENT RESPONSIBILITY FOR INSTRUMENT TRANSFORMERS

1. Customer-owned instrument transformers installed in Western facilities will be replaced by Western personnel.

2. Customer-owned instrument transformers installed in customer facilities will be the responsibility of the customer.

3. Customer-owned instrument transformers installed in a supplemental supplier or wheeling agents facility will be the responsibility of the customer.

4. Western-owned instrument transformers installed in Western facilities will be replaced by Western personnel.

5. Western-owned instrument transformers installed in customer facilities will be furnished by Western for replacement by the customer.

6. Western-owned instrument transformers installed in third party facilities will be replaced under a negotiated agreement with the third party.

6. TRANSFORMER/LINE LOSS COMPENSATION

The choices listed below are available for adjusting the energy (kWh) delivered to or received from the customer when the points of delivery and measurement are different. The customer, with Western's concurrence, can choose to either:

1. Use the standard 2 percent transformer loss adjustment factor plus a line loss if applicable, in preparation of the power bill.

2. Use a negotiated transformer loss factor plus a line loss, if applicable, in the preparation

of the power bill. The customer must obtain a written agreement from supplemental power supplier(s) and/or wheeling agent(s) stating the mutually agreed value. The choices in Sections F1. and F2. would have the power bill's delivered value increased by the appropriate loss factor for Western supplying power to the customer, and if applicable, decreased by the same loss factor for the received value when Western receives power from the customer.

3. Use a transformer and/or line loss compensating meter. The customer, with Western's concurrence, must obtain written agreement from the supplemental power supplier(s) and/or wheeling agent(s) to use a loss compensating meter, for the values used in the meter formula to calculate the percent kWh's loss compensation, and for a value of transformer and/or line loss in the event the meter fails. The application of the transformer loss compensating meter is technically correct ONLY when:

   1. A certified copy of the transformer test report either from the transformer manufacturer or a third party transformer test shop is available from which to obtain the appropriate losses necessary to program the meter.

   2. Only one transformer serves the metered load.

   3. And only one delivery is served from the transformer.

   If the above conditions are not met, Western recommends either Section F1. or F2. be chosen.

   If the customer requires transformer and/or line loss compensation and the existing meter does not have transformer loss compensation ability, the customer will bear the financial responsibility to either replace or modify the existing meter for providing transformer and/or line loss compensation, including the cost of installing the meter. The new meter with transformer and/or line loss compensation will meet the technical specification of this policy and Western will accept ownership of the meter. Financial responsibility for future calibration, maintenance, repair, and replacement of the new meter will belong to the entity that had this responsibility prior to the replacement. The customer shall not be credited for providing Western with a loss compensating meter. At existing deliveries where Western's meter is replaced, the old meter will be returned to Western.

7. REMOTE ACCESS TO METERS

Western will allow access to Western-owned meters under the conditions defined below. The requesting party is responsible for providing communications to the meter and compensating Western for any additions equipment needed to communicate with the meter. The requestor can either provide their own communications path to the meter or negotiate with Western or another entity providing a communications path to the meter site.

1. The existing meter has multiple levels of password protected access that would allow the requester to access through a level of control that would not allow them to alter the meters parameters. In addition it would be acceptable, if the meter and the software used to access the meter allows access and prevents the alteration of the meters parameters without needing a password.

    1. Access would be provided at no charge.

2. The meter does not meet the conditions in section G.1.

    1. Access would not be granted unless the requestor assumes responsibility for all costs associated with obtaining a multi-level password protected meter that meets the technical requirements of this policy.

        1) If the meter is used by Western for revenue/load control purposes, the new meter would be installed by Western and the requestor would compensate Western for the installation cost.

        2) Ownership of the new meter would transfer, at no cost, to Western. after the installation is completed. Responsibility for Maintenance, replacement, or modifications (MRM) of the meter would be the same as the meter being replaced.

When remote access privileges are granted to another entity, Western will reserve the right to immediately revoke the access privilege if the meter=s security has been breached and meter equipment parameters and/or billing data has been changed or corrupted by the customer or their representative.

APPROVED: ______________________________ DATE:____________

Gerald C. Wegner
Regional Manager