Regional Incremental Generation Outlet Study (RIGO)

Transmission System Planning and Reliability Assessment

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1: Background & Scope of Study

This electric transmission study was conducted by Northern States Power Company, a Minnesota corporation ("NSPM" or "Xcel Energy"), and addresses the development of transmission outlet capacity for additional electric generation. The generation pattern assumed for the purpose of this study is based on Midwest Independent Transmissions System Operator ("MISO") queue data relating to interconnection requests outside of the "Buffalo Ridge Area", primarily in the western and southeastern portion of Minnesota. The study effort concentrated on developing and evaluating smaller scale (115-161 kV) transmission options that could:

- provide several hundred megawatts ("MW) of incremental generation outlet capacity
- be implemented by the 2010 timeframe; and
- integrate well with the proposed CapX2020 Group 1 projects[1]

The existing transmission system and several transmission system improvement options were evaluated to identify the steady-state (thermal and voltage) limitations that would be successively encountered if additional increments of generation capacity were installed in the southeastern and western portions of Minnesota, subject to the following principal assumptions:

- a total of 1175 MW of generation (nameplate rating) has already been installed in the Buffalo Ridge area prior to the period of interest;
- 1175 MW of generation has been integrated into the power system by construction of the Buffalo Ridge Incremental Generation Outlet ("BRIGO") transmission facilities:
  -- Fenton-Nobles 115 kV #2
  -- Lake Yankton-Southeast Marshall 115 kV #1
  -- Nobles 345/115 kV transformer #2
  -- Yankee-Brookings County 115 kV #2
  -- Brookings County 345/115 kV transformer #2
  -- related 161, 115 & 69 kV line reconductors & rebuilds
  -- related substation upgrades
- it is desired to identify the limiters that would be incrementally encountered with additional wind generation;
- under both system intact and first-contingency (N-1) conditions, facility loadings and bus voltage levels will be maintained within applicable established performance criteria, for both peak and off-peak load conditions, without resorting to tripping of generation or curtailment of deliveries to load;

[1] The CapX2020 Group 1 projects include four projects: 1) Bemidji – Grand Rapids 230 kV line; 2) Twin Cities-Fargo Project; (3) Twin Cities-Brookings County 345 kV Project and (4) Twin Cities-La Crosse 345 kV Project. Certificate of need applications are pending for all four projects in two separate dockets. The Bemidji – Grand Rapids 230 kV Project is pending in Docket No. E017, E015, ET-6/CN-07-1222. The other three projects are pending in Docket No. E002/CN-06-1115.

- all new generation located in southeastern and western Minnesota will have dynamic and steady-state reactive power control characteristics (power factor controllable in range of .90 lead to .90 lag) in conformance with the 1999-vintage NSP reactive power/voltage control standard; and
- Present Midwest Reliability Organization ("MRO") and MISO standards and policies will continue to apply with respect to constrained interface impacts, non-degradation of existing transfer capabilities, and generation accreditation procedures.

This Study's analysis also does not address mitigation of all remote interface impacts. Although interfaces traditionally of relevance to the Minnesota area were monitored, it is possible that incremental loading of remote interfaces, (either existing or defined in the future) may require mitigation.

The technical and economic analyses were performed for the purpose of identifying a preferred plan to achieve the specific goal of providing generation outlet capacity for several hundred MW of additional generation development "off Ridge" in the greater Minnesota area. It is recognized that many other potential generation developments--possibly aggregating to thousands of MW--are in preliminary stages of study by various entities. Generation developments may significantly affect overall future transmission requirements in this region.

2: Conclusions & Recommended Plan

The Preferred Plan is Option 1213BCC which adds the following facilities:

- Pleasant Valley-Byron 161 kV line
- Pleasant Valley 345/161 kV transformer #2
- Pleasant Valley-South Rochester Substation 161 kV line
- Double Circuit 161 kV line from Byron-Maple Leaf-West Side Energy Park

This option appears to offer the best overall results with respect to:

- power system performance (system intact & contingent loadings & voltages)
- practicality (logistics of construction and operation)
- price (cumulative present worth cost)
- consistent with off ridge generation assumption

These facilities provide the bulk system improvements to make the interconnection possible for energy resource. There are other limiters that show up in the Transfer Limit Table Generator ("TLTG") analysis and there will likely be other upgrades required for specific projects to deliver power to specific customers.. It assumed that those limiters and deliverability would be handled through the MISO interconnection studies.

3: Study History & Participants

Following an introduction meeting in July 2007, progress review meetings were held periodically during the study:

July 16, 2007	Minneapolis, MN	Xcel Energy's Office (Missouri Basin SPG meeting)
September 20, 2007	Elk River, MN	Great River Energy's Offices
October 3, 2007	Sioux Falls, SD	Missouri River Energy Services Offices
December 4, 2007	Elk River, MN	Great River Energy's Office

In addition to the Study Group meetings, updates were also presented to the Mid-Continent Area Power Pool ("MAPP") Missouri Basin ("MB") and Northern MAPP ("NM") Sub-regional Planning Groups ("SPGs") during their regularly scheduled meetings.

The study group benefited from participation of technical staff of the following transmission entities:

MISO	Midwest Independent System Operator	Carmel, IN
DPC	Dairyland Power Cooperative	La Crosse, WI
RPU	Rochester Public Utility	Rochester, MN
SMMPA	Southern Minnesota Muni Power Agency	Rochester, MN
GRE	Great River Energy	Elk River, MN
OTP	Otter Tail Power Co	Fergus Falls, MN
XEL	Xcel Energy	Minneapolis, MN

Xcel Energy technical staff and consultants performed the powerflow simulations, economic analyses, and tabulation of results. These results were presented and reviewed at the study group's meetings, at which comments, conclusions, and recommendations were developed to guide each successive stage of analysis.

4: Analysis

4.1: NERC Criteria

In conducting the Study, planning engineers evaluated the electrical system for conformance with the applicable North American Electric Reliability Council ("NERC") criteria described below.

The Category A i.e., NERC Standard TPL-001, planning standard requires analysis on the power flow base case system violations without any contingency conditions. The PSS™E and MUST reports of the load flow case were used to identify any system violations in the system models.

The Category B i.e., NERC Standard TPL-002, planning standard requires analysis on n-1 single contingencies. A Category B contingency file was developed for Category B analysis for the RIGO study.

The Category C i.e., NERC Standard TPL-003 planning standard requires analysis multiple contingencies that would produce the most severe system conditions. MISO has created and maintained a file for assessing the power system and determining the Category C (and in some cases Category D) contingencies that the operations planning staffs in the region have determined to be the most detrimental to the reliability of the system. The Category C contingency files were originally defined by the Northern Mid-Continent Area Power Pool ("MAPP") Operations Review Group and included the Xcel Energy portion of the system.

4.2: Models employed

4.2.1: Steady State models

The powerflow models employed were developed by the MRO model building group. The models are based on the 2006 Series MRO models, Year 2011 and 2016 summer peak and summer off peak, as updated:

- to reflect system changes by appropriate study year.
- to reflect the Post CAPX2020 Group 1 facilities by appropriate study year.

A post Group 4 MISO study case model was also used to compare results gained in the MRO models.

4.2.2: Dynamics models

Stability analysis was performed on a model adapted from the MISO Group 4, G362 interconnection study effort. This model represents Year 2010 peak load conditions. Because this was a MISO Group stability model, there are numerous hypothetical queued generation projects present in the case.

The dynamic stability analysis effort utilized the Northern MAPP Operating Review Working Group ("NMORWG") 2005 Study Package, developed from the previous NMORWG 2003 Study Package and from the 2004 Series MAPP models:

> PSS/E Rev 29.4, PC Platform Version (Compaq 6.6B Compiler)
> Works on Rev 29.5
>
> Current Version: 09/28/05 PRELIM Approval Status: Preliminary;
> Not yet approved by NMORWG

The dynamic stability analysis included the regional faults for the northern MAPP region, plus several new faults related to the new transmission facilities involved in each of the transmission configurations under evaluation.

All disturbances simulated during the transient stability study are identified by a three-letter name. These fault abbreviations, along with their corresponding fault descriptions can be found in Appendix J.

The export levels across the North Dakota ("NDEX"), Manitoba ("MHEX"), and Minnesota-Wisconsin ("MWSI")[2] interfaces were set to their maximum simultaneous transfer limits of 2080 MW, 2175 MW, and 1480 MW, respectively prior to the proposed Big Stone II generation and transmission additions. This ensures that power system stress is at levels corresponding to present-day "maximum simultaneous levels", regardless of the actual flows that may be measured on the NDEX ties following the addition of the Big Stone outlet transmission.

4.3: Conditions studied

4.3.1: Steady-state modeling assumptions

The technical analysis was performed based upon year 2011 and 2016 summer peak and off peak cases from the 2006 MRO series powerflow models. The base models were adjusted to represent the latest available forecast data for summer season peak (100%) and off-peak (70%) load conditions. The off-peak model simulates a high transfer condition corresponding to approximately 100% of the presently-recognized simultaneous North Dakota/Manitoba transfer limit as established by the NMORWG, while the on-peak model represents only identified firm power transactions. Table 1 shows these modeling assumptions.

Table 1 Modeling Assumptions

					Net generation, MW				
Condition	Load Level	NDEX[1]	MHEX[2]	MWSI[3]	Wind	Anson	MEC	Lake Field	Cannon Falls
Peak	100%	587	1467	1271	1175	377	379	550	357
Off-peak (NMORWG LIMIT)	70%	2080	2175	1480	1175	417	379	550	357

Relevant contingencies are provided in Appendix C.

Notes
1) NDEX= sum of flows on the 18 lines comprising the "North Dakota Export" boundary;
2) MHEX= sum of flows on the 4 Manitoba Hydro-U.S. 230 & 500 kV tie lines;
3) MWSI = sum of flows on Minnesota-Wisconsin Stability Interface (Prairie Island-Byron, Eau Claire Arpin 345 kV)

In addition, the MISO Group 4, 2010 summer peak model was used to verify options and results to ensure consistency.

4.3.2: Steady state contingencies modeled

[2] The MWSI was defined as the sum of flows on the Minnesota-Wisconsin Stability Interface (Prairie Island-Byron, Eau Claire-- Arpin 345 kV) This interface was in the process of being reevaluated to include the Arrowhead-Weston 345 kV line during this study.

For this study we included all N-1 and tie line contingencies for the Xcel Energy, SMMPA, GRE, WAPA, OTP, DPC and Alliant West areas. In addition, we ran all the Category C contingencies listed in the wind1225.con file based on the MISO.con file.

4.4: Options evaluated

The following transmission improvement options were evaluated:

Option 1 "Morris-Kerkhoven-Willmar 115 kV & Paynesville-Wakefield 230 kV conversion"
This option establishes a new 115 kV line from the Morris substation to the Kerkhoven substation to the Willmar substation. This option includes operating the Paynesville-Wakefield 115 kV line at 230 kV (currently operated at 115 kV operation, but built to 230 kV specifications).

Option 2 "Waldon-Paynesville 115 kV"
This option establishes a new 115 kV line from the Waldon substation to Paynesville substation.

Option 3 "Waldon-Willmar-Big Swan 115 kV"
This option establishes a new Waldon-Willmar-Big Swan 115 kV line.

Option 4 "Waldon-Willmar 115 kV"
This option establishes a new 115 kV line from Waldon to Willmar.

Option 5 "Owatonna-Austin Corner 161 kV"
This option constructs a new 161 kV line from Owatonna to Austin Corner. Austin Corner is a new 161 kV substation that taps the 161 kV line between Austin and Hayward.

Option 6 "Pleasant Valley Radial 161 kV"
This option adds a 161 kV radial tap from Pleasant Valley.

Option 7 "Byron Radial 161 kV"
This option adds a 161 kV radial tap from Byron.

Option 8 "Blue Earth-Loon Lake 161/115 kV"
This option establishes a new Blue Earth to Loon Lake 161 kV line. This option also includes a new 161/115 kV transformer at the Loon Lake substation.

Option 9 "Pleasant Valley-Blue Earth 161 kV"
This option establishes a new 161 kV line from Pleasant Valley to the Blue Earth substation.

Option 10 "Morris-Paynesville 230 kV"
This option establishes a new 230 kV line from the Morris substation to the Paynesville substation.

Option 11 "Jackson-Loon Lake 161 kV"
The option establishes a new 161 kV line from the new City of Jackson substation to the Loon Lake 115 kV substation. This option includes a 161/115 kV transformer at Loon Lake.

Option 12 "Pleasant Valley-Byron 161 kV"
This option adds a new 161 kV line from the Pleasant Valley substation to the Byron substation. This line originated from the MISO interconnection study G362.

Option 13 "Pleasant Valley-South RPU and Double Circuit Byron-Maple Leaf-West Side Sub 161 kV"
This option adds a new 161 kV line from Pleasant Valley-New South RPU substation. This option also includes a double circuit 161 kV line from Byron-Maple Leaf-new West Side substation.

Option 5b9 "Owatonna-Austin Corner 161 kV and Pleasant Valley-Blue Earth 161 kV, with a 2nd Pleasant Valley 345/161 kV transformer"
This is a combination option to see if there is any benefit to generation outlet by adding two 161 kV lines in the southeastern Minnesota area. The second Pleasant Valley 345/161 kV transformer was included because showed up as a limiter in almost all the southeastern options.

Option 89 "Blue Earth-Loon Lake 161 kV and Pleasant Valley-Blue Earth 161 kV"
This is a combination option to see if there is any benefit to generation outlet by adding two 161 kV lines in the southeastern Minnesota area.

Option 5b12 "Owatonna-Austin Corner 161 kV and Pleasant Valley-Byron 161 kV"
This is a combination option to see if there is any benefit to generation outlet by adding two 161 kV lines in the southeastern Minnesota area.

Option 58 "Owatonna-Austin Corner 161 kV and Blue Earth-Loon Lake 161 kV"
This is a combination option to see if there is any benefit to generation outlet by adding two 161 kV lines in the southeastern Minnesota area.

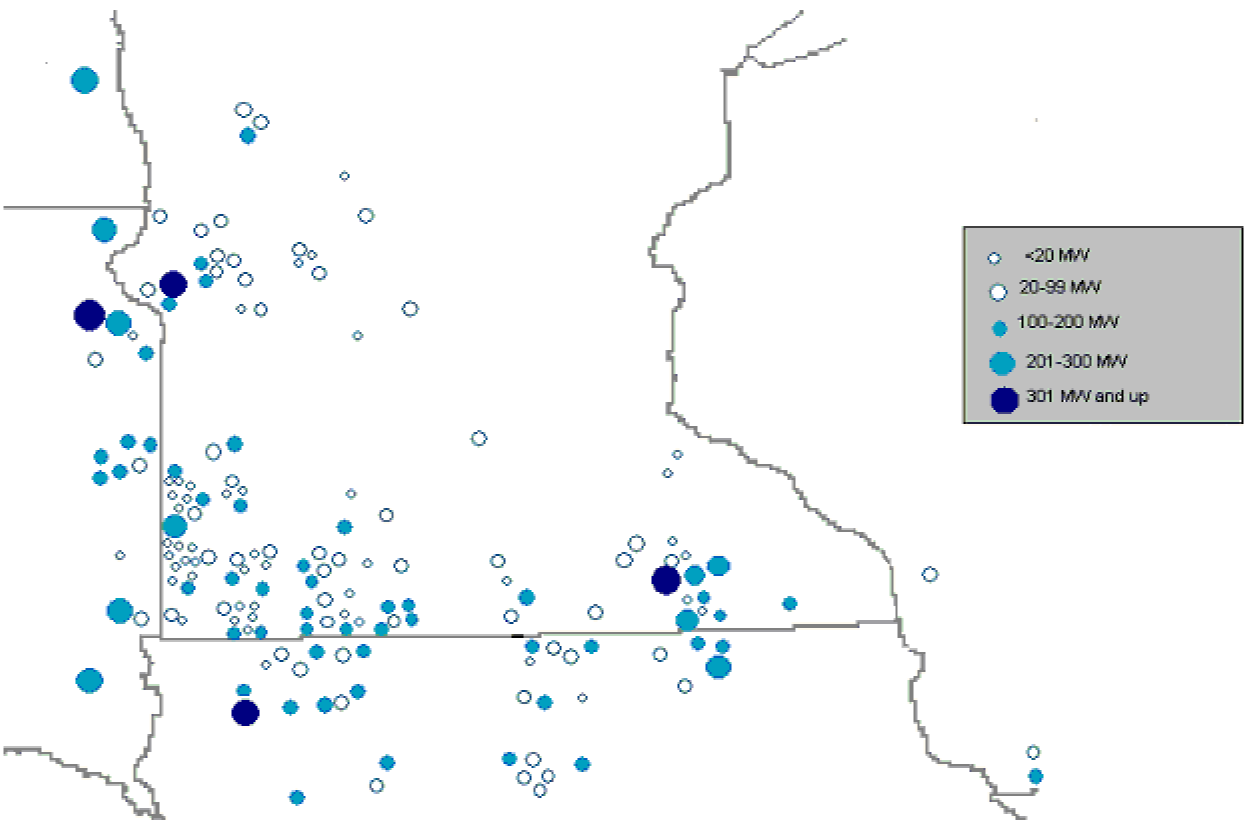
Option 1213 "Pleasant Valley-Byron 161 kV and Pleasant Valley-South RPU substation and Dbl Ckt Byron-Maple Leaf-Cascade Creek (new West Side substation)"
This option of 161 kV line additions was examined to see if greater outlet capabilities could be achieved by a comprehensive plan for the Pleasant Valley area.

The above transmission options were designed to be representative of a broad range of theoretically possible power system improvement strategies that would meet the "modest, quickly implementable" objective. In addition to these "simple" options, several "combination" options were also developed, following the "first cut" evaluation of the above options. The combination options were examined to determine whether it may be advantageous to implement more than one of the originally identified transmission options.

4.5: Selection of termini and intermediate connection points

The selection of the termination points for each of the options evaluated was based on generation assumptions. Planning engineers used the MISO interconnection queue map to determine where the greatest number of MW of generation requests were grouped to come up with the most logical outlet points. See Map 1 below. There are large amount of requests in the western portion of Minnesota/South Dakota and well as southeastern Minnesota/Iowa. Keeping in the spirit of "off Ridge" outlet solutions, we chose options that would provide the most outlet capability with the fewest line additions.

Map 1 – MISO Queue Requests by Area



4.6: Performance evaluation methods

Power system performance simulation was performed with the aid of the Managing and Utilizing System Transmission ("MUST") digital computer powerflow program (Version 8.1) as supplied by Power Technologies, Inc. System intact and first-contingency analysis was performed primarily using PSS™E-MUST (Version 8.1) activity TLTG. TLTG performs automated contingency analysis while progressively incrementing power transfer between a defined "source" and "sink" location.

For both the TLTG analyses, the following apply:

Monitored facilities:

All transmission lines and transformers 69 kV and above in the model areas:

NSP	WAPA
Alliant	OTP
GRE	SMMPA
DPC	

Study area (facilities subject to outage):

All transmission lines and transformers 69 kV and above in the model zones:

NSP	WAPA
Alliant	OTP
GRE	SMMPA
DPC	

Activity TLTG achieves computational efficiency by extensive use of Power Transfer Distribution Factors ("PTDFs") and Line Outage Distribution Factors ("LODFs"), concepts applicable to linear, time-invariant systems. These methods are appropriate for power system analysis, provided it is recognized their accuracy is constrained by their inherent limitations arising from non-linear effects such as exhaustion of reactive power supply and LTC transformer range limits. Consequently, the resultant reported transfer limits from TLTG are thus approximate.

Facilities identified in the TLTG outputs are considered valid limiters if they:

- have a PTDF of 5.0% or greater (system intact) or
- have an OTDF of 3.0% or greater (outage condition)

The 5.0% PTDF and the 3.0% OTDF were selected in accordance with the MISO's cutoff level for system impact analyses. Very large reductions in generation (greater than 50:1) are required in order to achieve a perceptible amount of loading relief. Consequently, PTDFs lower than 5.0% system intact and OTDFs lower than 3.0% N-1, strongly indicate that other power system adjustments are likely to be much more effective in producing the desired ameliorative effect than would generation adjustments in the study area. Refer to Section 5.2 for further discussion on evaluation of incremental loadings on constrained interfaces ("flowgates") and non-flowgate facilities.

5: Results of detailed analyses

5.1: Powerflow (system intact & contingency)

Appendix B provides the "raw" TLTG outputs for the transmission Options. Appendix B also contains a summary table derived from the “raw” TLTG outputs. This table lists only limiting facilities exceeding the 5% PTDF/3% OTDF cutoffs.

For this study an overall MW level was not identified because of the differences in geographic location for each of the options. TLTG was used to evaluate each option to determine a natural stopping point. Both pre- and post-CapX 2020 Group 1 projects scenarios were evaluated as well as summer peak and off peak conditions to determine the true outlet capability of each option and to determine how each option would function in a post-Group 1 case.

For example, in Option 5 for the summer peak, pre-Group 1 projects scenario, the raw TLTG output an outage shows that outage of the 345/161 kV transformer at the Pleasant Valley Substation results in an overload of the Austin Corner-Pleasant Valley 161 kV line at the 53.4 +200 (assumed at Pleasant Valley) = 253.4 MW level. By adding a second 345/161 kV transformer at Pleasant Valley, it would push the next limiter to loss of the Blue Earth Tap-Winnebago 161 kV line, thereby increasing the outlet capability to 507.8 + 200 (assumed at Pleasant Valley) = 707.8 MW for a summer peak, pre-Group 1 case. Examining the same option in an off peak case yields a –38 MW reduction in outlet capability, so –38 + 200 MW = 162 MW of overall outlet capability from the area.

5.2: “First Cut” Screening

To keep the amount of technical analysis required at a manageable level, a "first cut" screening analysis was undertaken to identify any options that were technically or economically significantly weaker than the others, and for which further detailed analysis would not be warranted.

Table 2 below shows a summary TLTG table for all the options examined. The bold numbers are the maximum MW outlet achieved for each of the options and variations.

Table 2 TLTG Summary

		Pre CapX		Post CapX	
		sp	op ht	sp	op ht
Option		Capacity (MW)		Capacity (MW)	
Option 1	Morris-Kerkhoven-Willmar 115 kV line, 230 conversion	105	19	105	**7**
1a	above w/reconductor Grant Co-Morris 115 kV	204	19	105	**7**
1ab	above w/Reconductor Morotp-Morris 115 kV	236	**19**	105	198
1abc	above w/Reconductor of Kerkhoven-Kerkhoven Tap 115	237	**19**	105	198
1c	1 w/Reconductor of Kerkhoven-Kerkhoven Tap 115	237	**41**	204	55
1cd	1c w/Reconductor of Minn Valley-Red Falls Tap 115 kV	237	**41**	204	195
Option 2	Waldon-Paynesville 115 kV line	168	**50**	212	89
Option 3	Waldon-Willmar-Big Swan 115 kV line	163	**54**	196	72
3a	above w/Reconductor of Kerkhoven-Kerkhoven Tap 115	163	**76**	298	139

Option 4	Waldon-Willmar 115 kV line	142	**49**	215	63
Option 5	Owatonna-Austin Corner 161 kV line	**53**	105	54	101
5a	5 w/trip og generation for loss of Pl Valley 345/161 tx	53	**138**	406	**138**
5b	5 w/Pleasant Valley 345/161 tx #2	508	**308**	508	528
Option 6	Pleasant Valley Radial = 0, for this study's purpose.				
Option 7	Byron Radial = 0, for this study's purpose.				
Option 8	Blue Earth-Loon Lake 161 kV line	362	232	349	**220**
Option 9	Pleasant Valley-Blue Earth 161 kV line	338	**43**	278	59
9a	above w/Austin-Pl Valley 161 kV ckt 2	338	**174**	278	182
9b	9 w/Pleasant Valley 345/161 tx #2	531	**368**	278	792
Option 10	Morris-Paynesville 230 kV line	158	**101**	146	**70**
10a	above w/reconductor of Minn Valley-Red Falls Tap 115	158	102	146	**82**
10ab	above w/Reconductor of Kerkhoven-Kerkhoven Tap 115	188	**110**	204	192
10abc	above w/Reconductor Kerkhoven-Benson 115 kV	260	102	260	**195**
10abcd	above w/Reconductor Morotp-Morris 115 kV	236	102	219	**219**
10abcde	above w/reconductor Grant Co-Morris 115 kV	204	**102**	223	222
Option 11	Jackson-Loon Lake 161 kV line	394	130	**124**	165
11a	option 11 w/reconductor Lakefield-Triboji 161	394	**255**	124	388
11ab	above w/reconductor Traverse-Travers S 69 kV	478	**312**	124	388
11abc	above w/reconductor NWSWDTP-Travers S 69 kV	564	**345**	124	388
11d	Option 11 w/reconductor Heron Lk-Lakefield 161	394	130	**145**	165
11de	11d w/reconductor of Lake Marian-Kenrick	394	130	443	**306**
Option 5b9	Option 5b and Option 9	583	**268**	583	429
5b9a	above w/building second line to Maple Leaf-Byron 161	583	**412**	583	429
5b9b	5b9 w/trip og generation for loss of Pl Valley 345/161 tx	583	412	583	**689**
Option 89	Option 8 and Option 9	360	**47**	357	61
	above w/Pleasant Valley 345/161 tx #2	672	**365**	681	685
	above w/Maple Leaf-Byron ckt 2	672	**572**	681	685
Option 12	Pleasant Valley-Byron 161 kV line	508	**158**	234	299
12a	above w/Maple leaf-Byron 161 kV ckt 2	508	326	**234**	299
12ab	above w/Pleasant Valley 345/161 tx #2	508	**334**	508	853
12abc	above w/Maple leaf-Cascade Creek 161 kV ckt 2	**508**	589	**508**	853
Option 5b12	Byron-Pleasant Valley, Austin Corner-Owatonna 161 kV line	508	**158**	509	518

5b12a	above w/Maple leaf-Byron 161 kV ckt 2	508	**323**	509	518
5b12ab	above w/Maple leaf-Cascade Creek 161 kV ckt 2	**508**	567	509	518
5b12abc	above w/reconductor Pleasant Valley-Austin Corners 161 kV	**508**	643	509	518
5b12abcd	above w/gen tripping or Pleasant Valley tx 3	**508**	816	509	891
Option 13	Pleasant Valley-South RPU 161 kV line, Dbl Ckt fix	868	627	821	**570**
Option1213BCC	Option12&13 w/ Byron-Cascade Ck double ckt	1110	779	1081	**722**
Option1213IBM	Option12&13 w/ Byron-IBM tap double ckt	1124	756	1083	**724**
Option1213WNH	Option12&13 w/ Byron-Nothhills double ckt	1124	756	1083	**724**
Option 58	Blue Earth-Loon Lake Austin Corners-Owatonna	**53**	107	**54**	106
	w/Pleasant Valley tx 2	723	**308**	696	**529**

The bold numbers represent the level of outlet capability at the natural stopping point for each option, after which level some major “fix” is needed to increase outlet. For example, with the option 1213BCC, the natural stopping point was a third 345/161 transformer located at Pleasant Valley. For some of the options, there were prior limiters, but they were not considered the outlet limit for an option because they are of a smaller size such that would typically be handled through the MISO interconnection process.

This analysis showed that the western options, 1, 2, 3, 4, and 10, provide very little outlet relative to the other options. The main problem with adding another line or lines stern part of the state is the through flow on the Dorsey-Forbes 500 kV line which limits generation outlet capability. Without a major new bulk transmission addition in the southwest part of the state, the 500 kV loading issue will continue to be a limiter. The analysis also showed that the other options, located in the southeastern portion of the State, generally provided the greatest amount of generation outlet. Consequently the western options were dropped from further analysis.

5.3: Dynamic Stability

Dynamic stability performance was examined with the PSS™E Revision 30.3 stability program using a model derived from the MISO Group 4, G362 interconnection stability model. The three proposed lines were added and the generation was adjusted to the 900 MW level. A summary of the faults and the results are listed in Vol. 3 Appendix J.

Please also reference the R39-07 MISO G362 Stability Report_8_10_2007.pdf report for the G362 Grand Meadows interconnection.

5.4: Constrained Interface Analysis

Constrained interface analysis was not performed as part of this study. Constrained interface analysis will be performed during the MISO system impact study.

5.5: Reactive Power Requirements

AC Contingency Checker ("ACCC") analysis was conducted at the 200 MW and 900 MW outlet levels to determine if any voltage support is needed. It was observed through the ACCC analysis that there were no reactive requirements needed as a result of adding option 1213BCC at the 200 MW or 900 MW level.

These findings are consistent with the results of the MISO G362, 200 MW system impact study that found no voltage violations. Please reference the G362_Draft_SIS_Thermal_Report_20070817.pdf for the Grand Meadows interconnection for more information.

5.6: Losses: Technical Evaluation

An analysis was performed on all post first-cut options to determine the effects on the overall transmission system losses. A base case without any improvements was used for a comparison case. A losses analysis showed that the impact of each option on the system losses are within the solution tolerances for PSS™E and are not statistically significant. This result is consistent with what would be expected of modest 115-161 kV improvements. Larger bulk transmission lines typically provide a larger transmission loss reduction by unloading the underlying transmission system.

5.7: Losses: Economic Evaluation

Because the technical losses evaluation showed no statistically significant differences in losses between the options identified, no economic evaluation was performed.

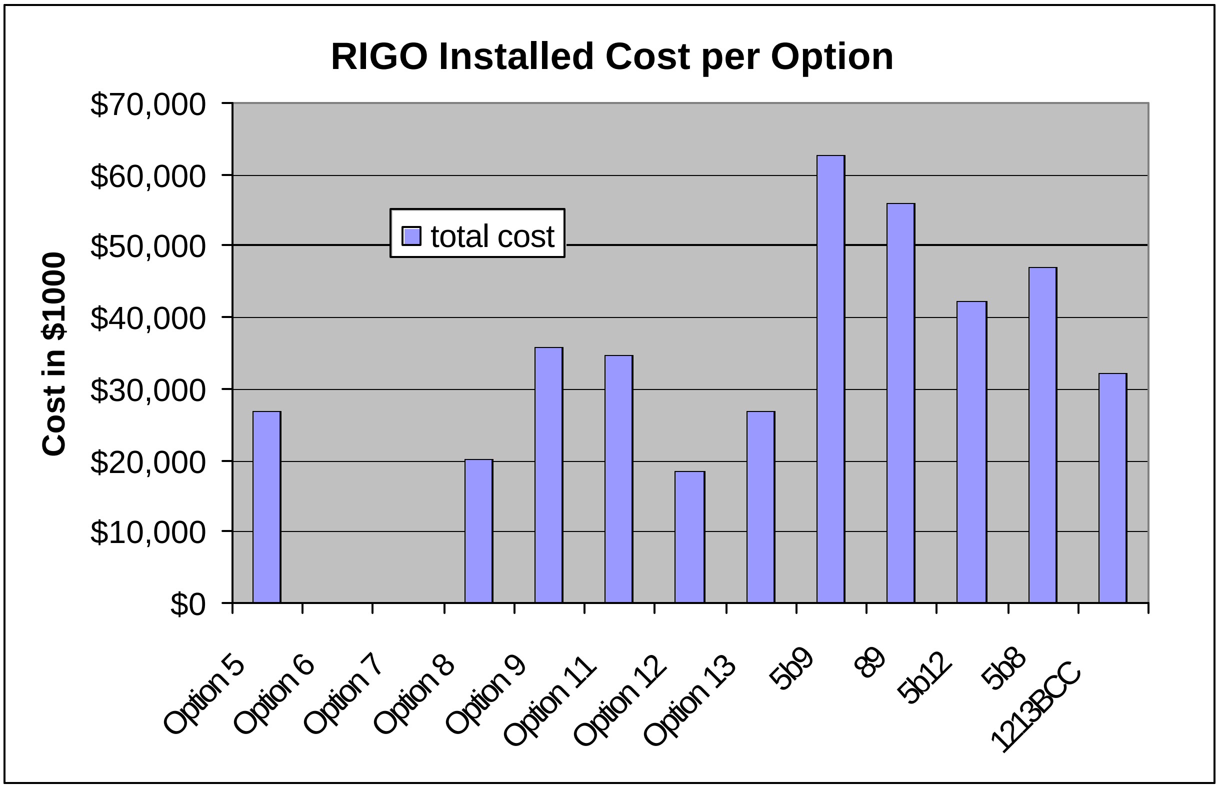
6: Economic Analysis

Economic analyses were undertaken on the basis of installed cost of required facilities. Present value analysis was not necessary, as it is presumed that the in-service dates (and hence expenditure patterns) do not vary significantly (more than 1 year) among the options.

6.1: Installed Cost

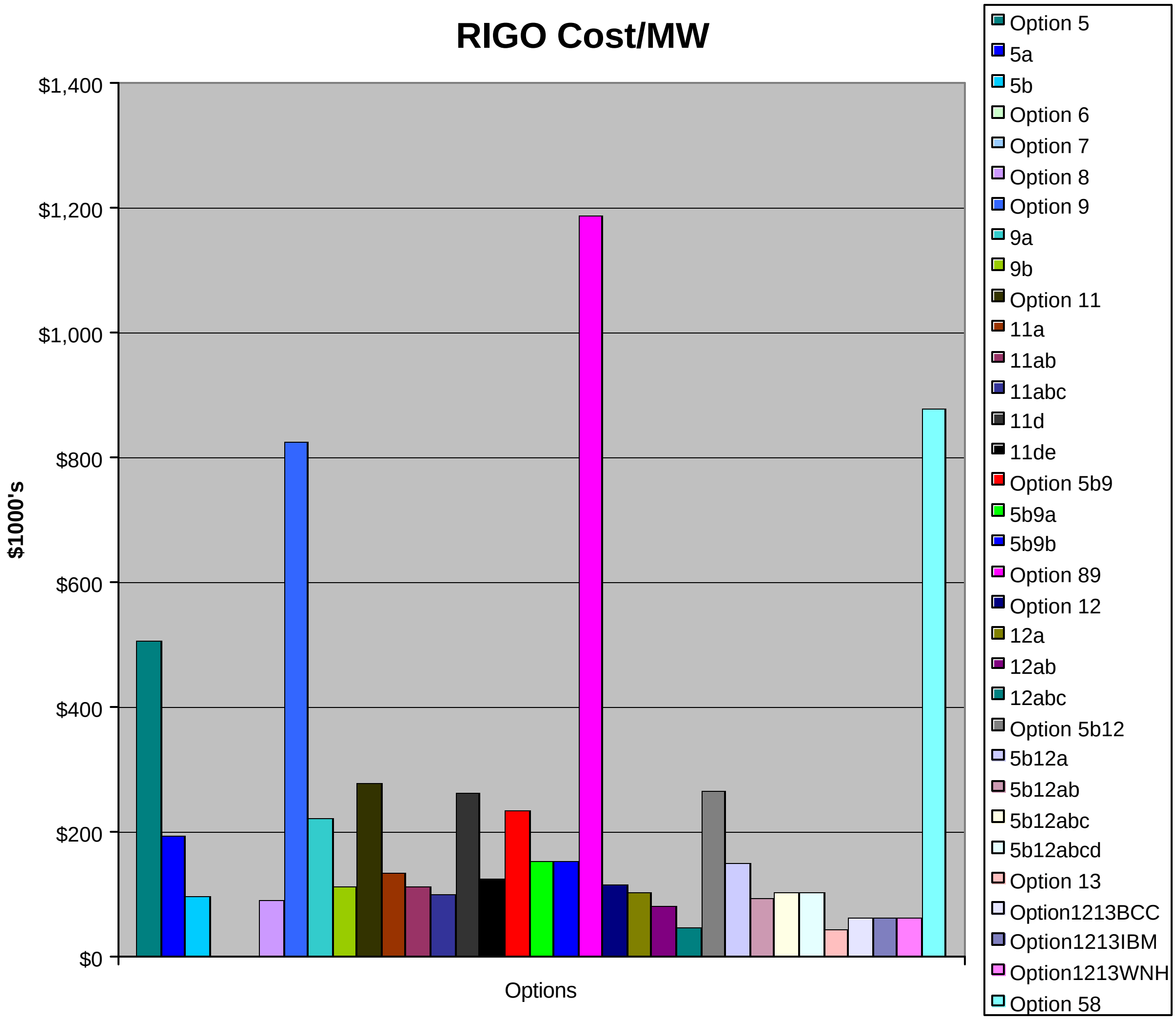
Graph 1 shows the installed costs of each of the RIGO options that were evaluated.

Graph 1



Options 1-4 and option 10 were based on a western flow assumption. The other options were based on a southeastern flow assumption. Because of these different flow assumptions it is impossible to compare them against each other one on one. The western options have a different set of limiters and natural stopping points than the southeastern options.

Consequently, planning engineers calculate a cost per MW for each of the options for comparison purposes. Table 2 shows the total installed cost per MW gain.



From this graph, it is observed that

- Western options have the highest cost/MW.
- Options 12, 13, and the combination of both provide the greatest amount of outlet per installed costs.

As a result of this analysis and the p

6.2: Evaluated Cost (with losses)

Evaluated costs with losses were not relevant to this study since the overall loss reductions observed were not statistically significant.

7: Relevant Concerns

7.1: Load-Serving Issues

Rochester Public Utilities ("RPU"), Dairyland Power Cooperative ("Dairyland") and Dairyland's distribution cooperative, Peoples Cooperative Services, provide retail electrical service to the Rochester area. Power is transmitted to the area by three 161 kV transmission lines, one from the west, Byron – Maple Lake 161 kV transmission line that connects the city to the Prairie Island – Bryon 345 kV transmission line; another from the northeast from the Alma Substation, and one from the south from the Adams Substation. The area also has 181 MW of generation located within the City of Rochester that can provide temporary support to the transmission system: four gas/coal units at Silver Lake totaling 102 MW, two hydro units on the Zumbro River totaling 2.4 MW and two natural gas/oil units at Cascade Creek totaling 77 MW. The Peoples Cooperative Services load is served out of the Rochester Substation (Dairyland owned) and the Maple Leaf Substation owned by Southern Minnesota Municipal Power Agency ("SMMPA") through 69 kV transmission lines which are routed to the North and South of the City of Rochester.

Anytime the demand for electrical power exceeds 181 MW in the Rochester area, the failure of a single transmission line could cause service interruptions. This limitation occurs if the Byron – Maple Leaf 161 kV line is out of service, because the remaining transmission system can only reliably deliver 181 MW of power to area substations. RPUS's ability to import power to serve its load during certain contingencies is restricted by the "Rochester Area Import Prior Outage Standing Operating Guide" of the MISO, which requires RPU to use local generation when their system demand exceeds 145 MW to prepare for the next contingency.

While local generation operated in advance of the next contingency may support additional demand, using generation for system support is not a desirable long-term solution because it is less reliable than transmission and more prone to outages and must be turned on in advance of and operated at a level sufficient to withstand the dynamic impacts of the next contingency, even if the power is not needed locally. Even if all 181 MW of generation were operated for system protection, the electrical system could only reliably serve 362 MW.

In Rochester, demand for power has already exceeded the capacity of the transmission system alone (181 MW) and will soon exceed the capacity of the existing transmission system fully supported by area generation (362 MW).

The preferred alterative in this Study will alleviate certain limitations on the transmission system in the area to allow for additional generation development in a wind-rich area of the State. If constructed, it is estimated that the transmission system would be able to serve approximately 65 MW of additional load for a total of 246 MW, a level that exceeds the current load in the area. A project being planned by Dairyland will add further support. Dairyland intends to reconductor the Rochester – Adams 161 kV line to facilitate wind outlet. If the RIGO lines and the reconductor project were constructed, the transmission system would be able to reliably service approximately 468 MW in the Rochester area, a level expected to be reached in approximately 2018.

One of the Group 1 projects, the 345 kV line from a new Hampton Corner Substation in southeastern Twin Cities to the La Crosse area, will further enhance the load serving ability of the system beyond the year 2040.

7.2: Constructability & Schedule Considerations

The transmission options under evaluation differ significantly with respect to the number and type of construction activities required. These differences have ramifications with respect to the lead times involved in implementing the series of improvements required.

Simpler options are easier to build. Options which require large amounts of reconductoring and rebuilding require disproportionately more time. This difference arises because power system reliability considerations limit the number of circuits within a geographical sub-area that can be simultaneously out of service for upgrade or replacement, since many of the circuits involved are to some degree electrically in parallel. Construction cannot be undertaken simultaneously on more than a few existing circuits per season; rather, sequential construction is required. In contrast, options that rely less heavily on reconductors and rebuilds encounter fewer construction outage constraints.

Table 7 summarizes the types of transmission line work involved for the best performing options and gives an estimated duration of work, based on a January, 2009 start date.

Table 7
Constructability & Schedule Considerations

		miles of transmission				
Option	Description	New	Record	Rebuild	Total	Years
5	Owatonna-Austin Corner 161 kV	34	0	0	34	2.0
8	Blue Earth-Loon Lake 161 kV	40	0	0	400	2.0
9	Pleasant Valley-Blue Earth 161 kV	90	0	0	90	2.5
11	Jackson-Loon Lake 161 kV	80	0	0	80	2.5
12	Pleasant Valley-Byron 161 kV	25	0	0	24	2.0
13	Pleasant Valley-South RPU 161 kV	22	0	0	22	2.0
5b9	5b + 9	124	0	0	124	2.5
89	8 + 9	130	0	0	130	2.5
5b12	5b + 12	59	0	0	59	2.0
1213BCC	12 + 13	47	0	0	47	2.0
58	5 + 8	74	0	0	74	2.0

Notes:

1. The reconductor and rebuild transmission line mileage is assumed zero for the base options. These numbers would largely depend on how much outlet was desired from each option.

2. The smaller reconductor or rebuild projects would be handled through the MISO interconnection study process.

7.3: Double-Circuit Line Considerations

Option 1213BCC, which has been identified as the "Preferred Plan", involves adding a second Byron-Maple Leaf-West Side 161 kV line and a parallel 161 kV line from Byron-Pleasant Valley. Implementation of these circuits requires consideration of whether it is desirable or acceptable to construct these pairs of circuits on double-circuit structures.

Double-circuit construction is acceptable if the power system can reliably withstand simultaneous failure of both circuits. Double circuit construction therefore can be appropriate in situations where the two circuits serve different functions, connect different pairs of substations, split away and proceed in different directions, or where high capacity (but not redundancy) is required.

NERC Planning Standards recognize double-circuit line outages as a "single-contingency" type of event ("Category C-5") because both lines are at risk of a "common-mode" failure. Such failures include:

- electrical failure of line insulation due to lightning strike;
- mechanical failure of one or more structures;
- broken shield wire falling into power conductors;
- wind-blown debris causing conductor-conductor short circuits;
- insulator contamination due to road salt, soot, or agricultural chemicals;
- wind/sleet/ice conditions
- contact with aircraft or construction equipment (crane, dump truck)
- protective relaying malfunction ("sympathetic tripping" due to fault on adjacent circuit)

These common-mode failure mechanisms have all been experienced on the Xcel Energy/NSP transmission system, on double-circuit lines at all voltage levels from 69 kV to 345 kV.

Consequently, evaluation of electric transmission system capability is performed considering failure of both circuits of a double-circuit line as being a single-contingency event. Double-circuit lines therefore are not appropriate in situations where two independent circuits are required for reliability purposes.

The conclusion is that in the case of Byron-Pleasant Valley 161 kV line it is inappropriate to have these circuits on the same structures because the new line is designed to back up the Byron-Pleasant Valley 345 kV line. The system with Option 1213BCC is adequate to provide sufficient outlet in the event of an outage of the 345 kV line from Byron to Pleasant Valley. If Option 1214BCC facilities and the Byron – Pleasant Valley 345 kV were lost, outlet capability would be limited. Consequently, the 161 kV line from Byron-Pleasant Valley must be constructed in a manner that minimizes exposure to "common-mode" failures, which would simultaneously render both circuits unusable.

8: Detailed Listing of Recommended System Facilities

The Recommended Plan is the 1213BCC option. A total SE Minnesota-->Twin Cities power transfer capability of approximately 900 MW is expected to be achievable with installation of the following improvements:

Lines—new			
Byron-Pleasant Valley 161 kV		34	1 x 795 ACSS
Pleasant Valley-South RPU 161 kV		22	1 x 795 ACSS
Byron-Maple Leaf-West Side 161 kV (double circuited)		10	1 x 954 ACSR
	Total	66	
Lines-reconductor or rebuild			
None		0	
	Total	0	

Transformers		MVA
Pleasant Valley 345/161 kV transformer #2		1 x 500
	Total Increase	500
Reactive (voltage control) facilities		
Shunt Capacitors		MVAR
None		0
	Total Increase	0
Shunt Reactors		MVAR
None		0
	Total	0

Substations--new

South RPU 161 kV Substation (south on existing Rochester 161 kV loop)
West Side 161 kV Substation (west side on existing Rochester 161 kV loop)

Substations--modified

Pleasant Valley	add breakers (161 and 345 kV), modify bus configuration, 345/161 kV transformer #2
Byron	add breakers (161 kV), modify bus configuration
Maple Leaf	none

Year 2011 facilities presumed to be "existing system" as part of earlier improvements

Buffalo Ridge Incremental Generation Outlet (BRIGO) facilities

- Eagle Lk (Xcel Energy & GRE substations) 69 kV switches (replace with 1200 amp)
- Paynesville-Roscoe Tp-Munson Tp-Farm Tp 69 kV: rebuild 13.5 mi (future double circuit 115/69 kV)
- Winnebago Jct 161 kV shunt capacitors (2 x 30 MVAR)
- Nobles Co 345/115 kV transformer #2 (672 MVA)
- Nobles Co-Fenton 115 kV #2 (620 MVA)
- Lk Yankton-Marshall SW 115 kV

- Granite Falls-Willmar 230 kV uprate to 388 MVA

Southeast Minnesota facilities

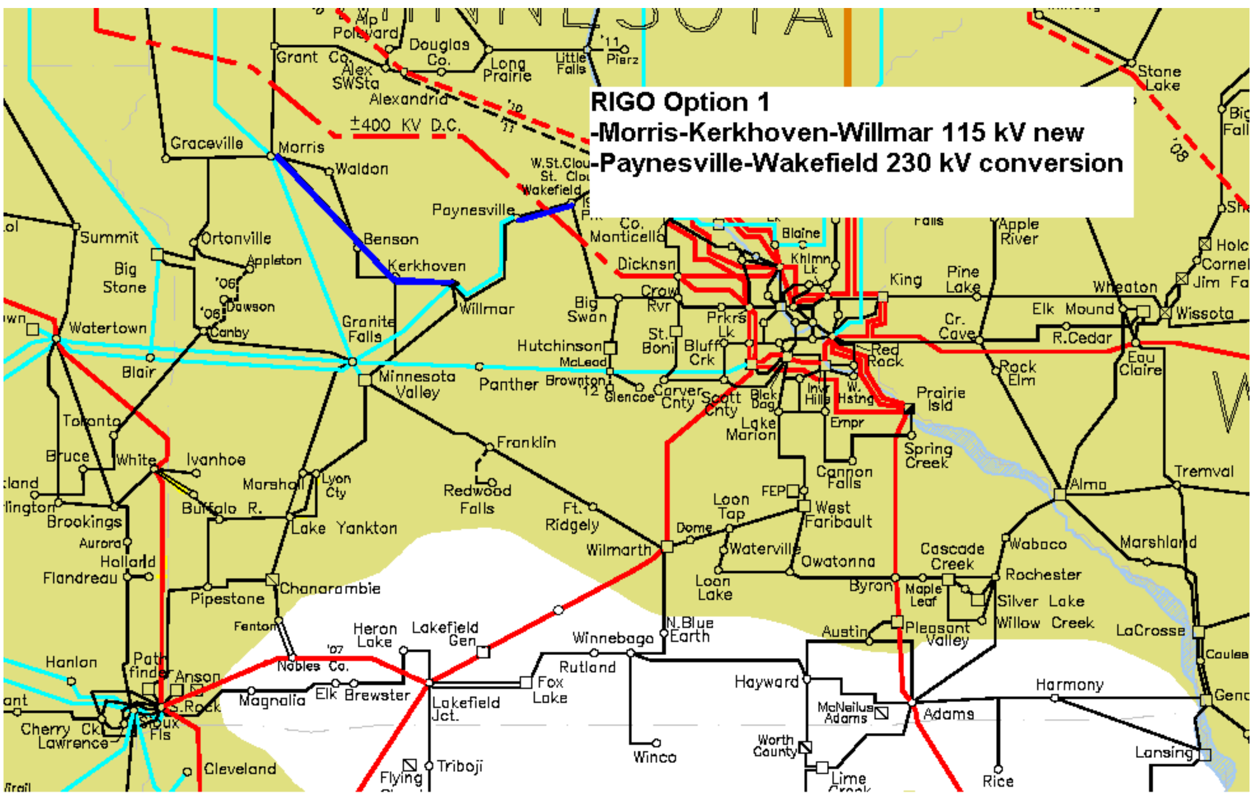
- Cannon Falls generation interconnection upgrades (refer to MISO G405 study for full details.

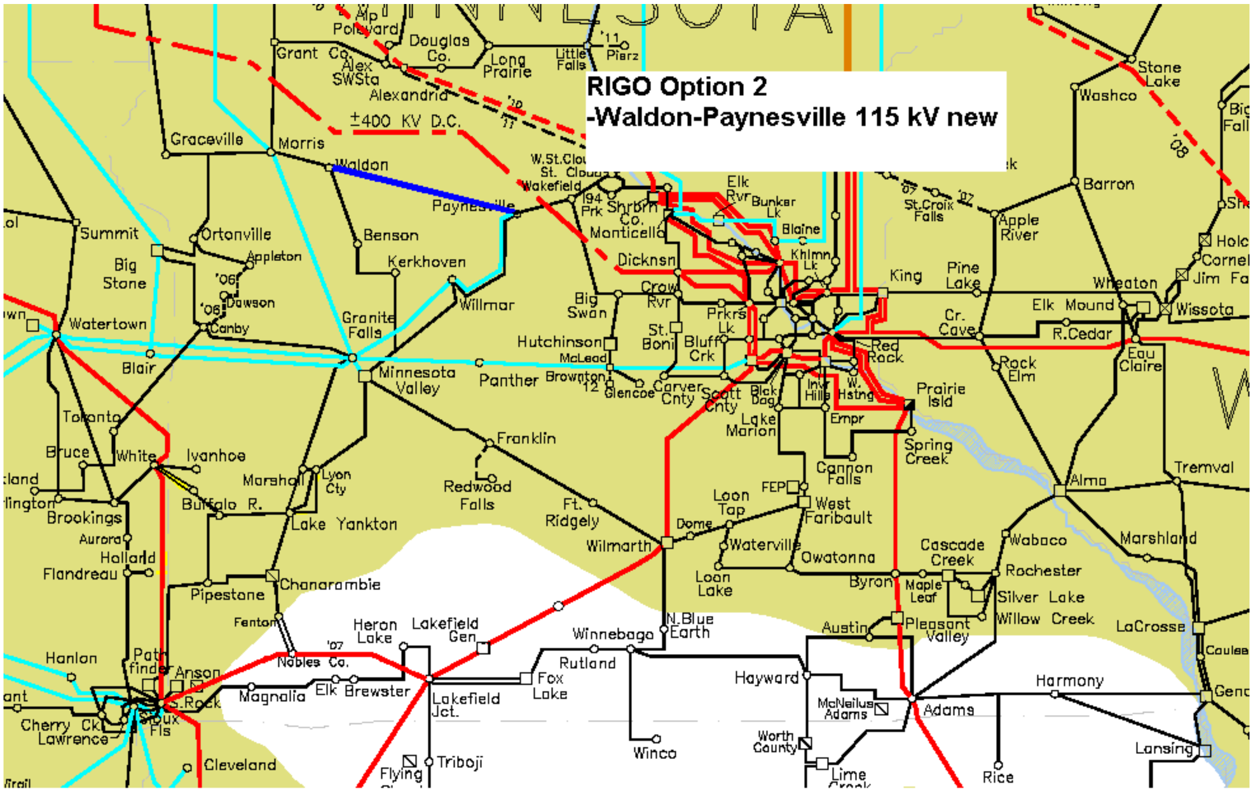
Local load-serving improvements

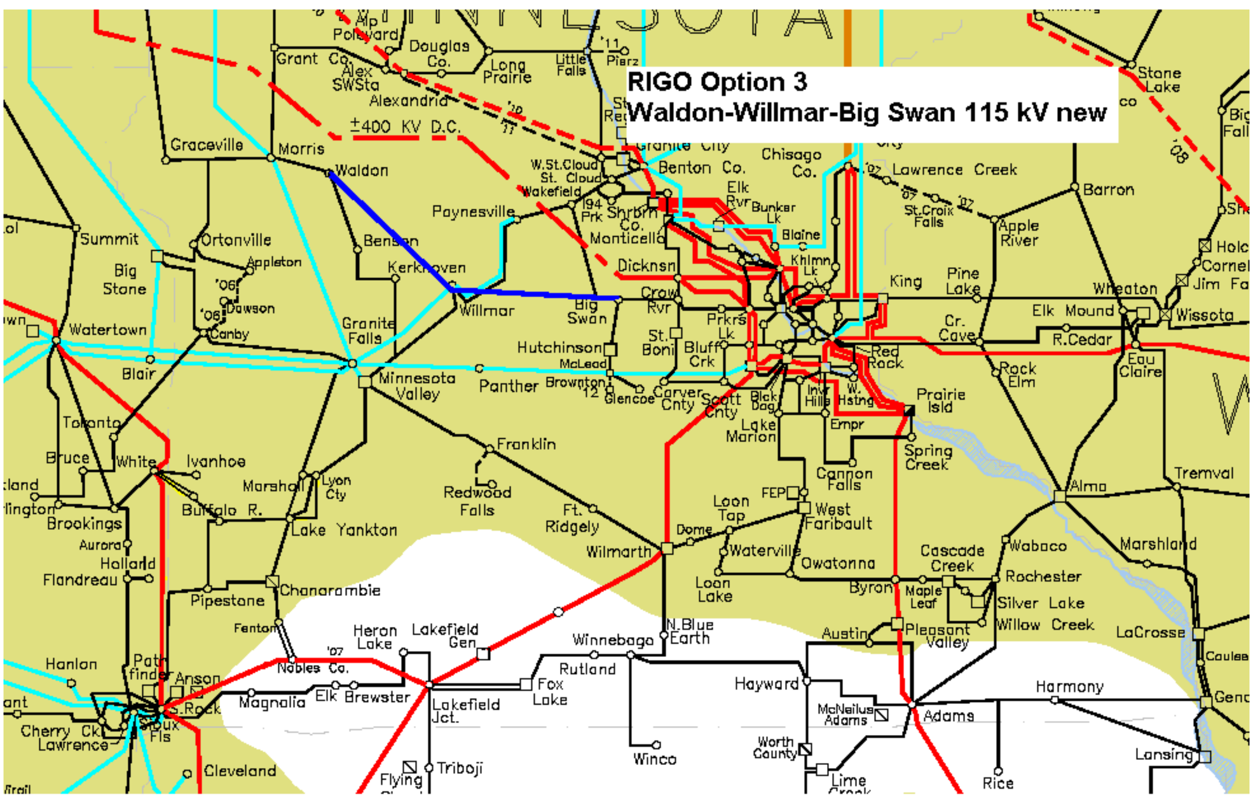
- Mankato 115 kV loop improvements (Xcel, GRE):

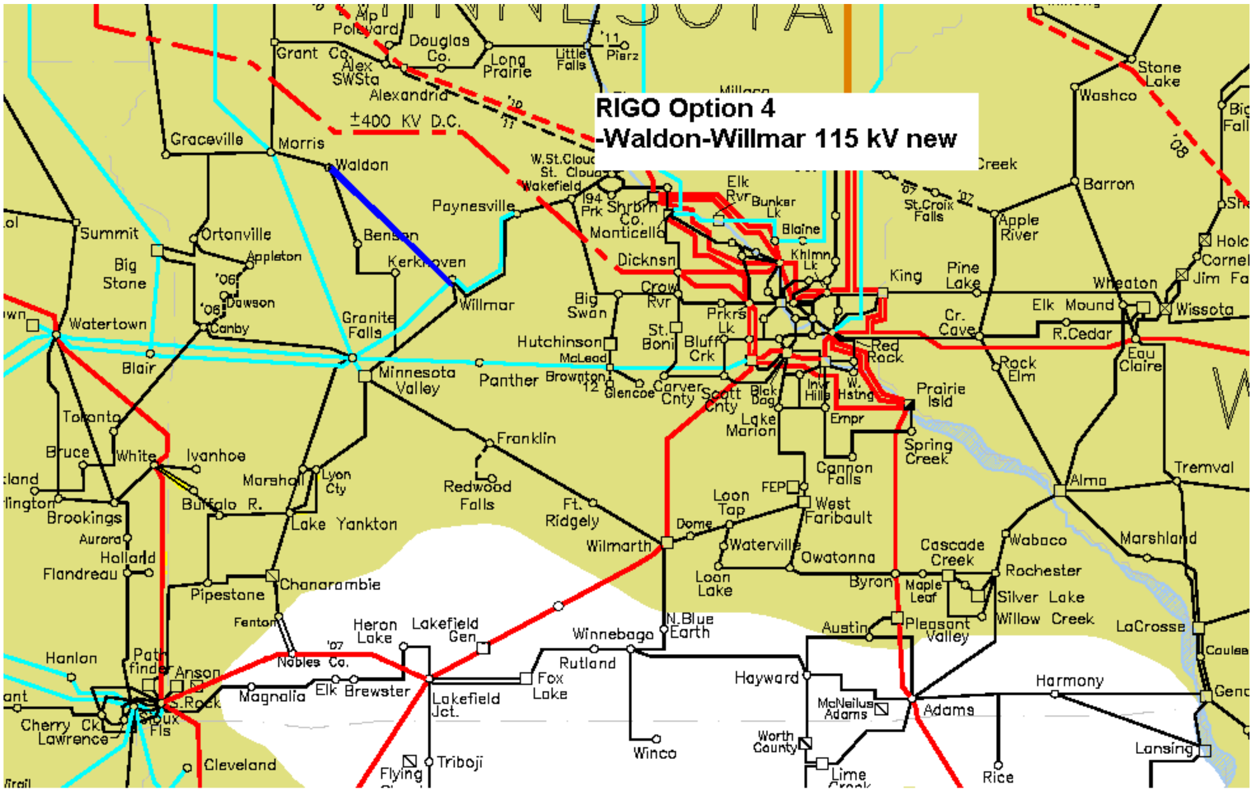
- Xcel Energy will build a new 161/115/69 kV substation at South Bend township south of Mankato, operating the existing 161 kV line between South Bend and Wilmarth at 115 kV, converting the existing 69 kV line from South Bend to Stony Creek to 115 kV. GRE will build a new 115/69 kV substation at Stony Creek and serve Sibley Park and other 69 kV loads to the South from Stony Creek, converting the existing 69 kV line from Stony Creek–Pohl tap–Pohl–Eastwood to 115 kV along with Pohl substation. upgrade.

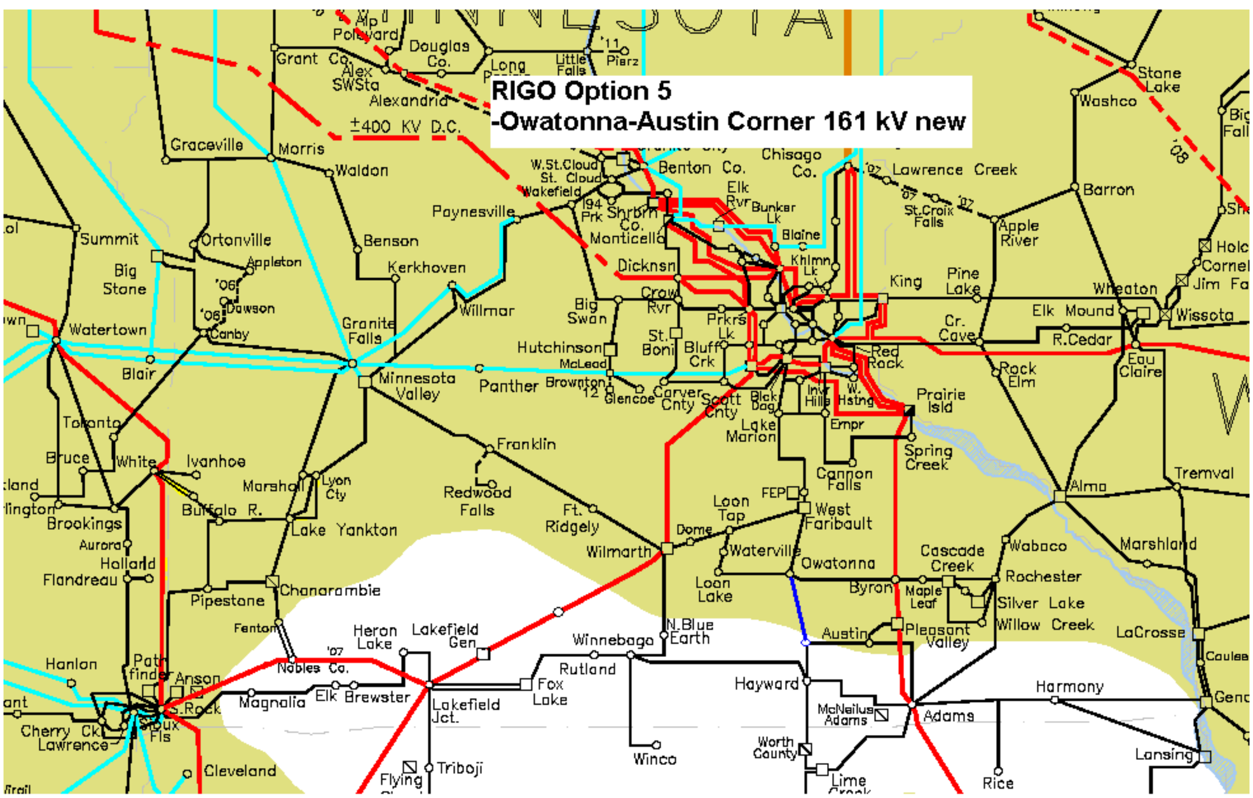
Appendix A: Maps (Base Plan & System Alternatives)

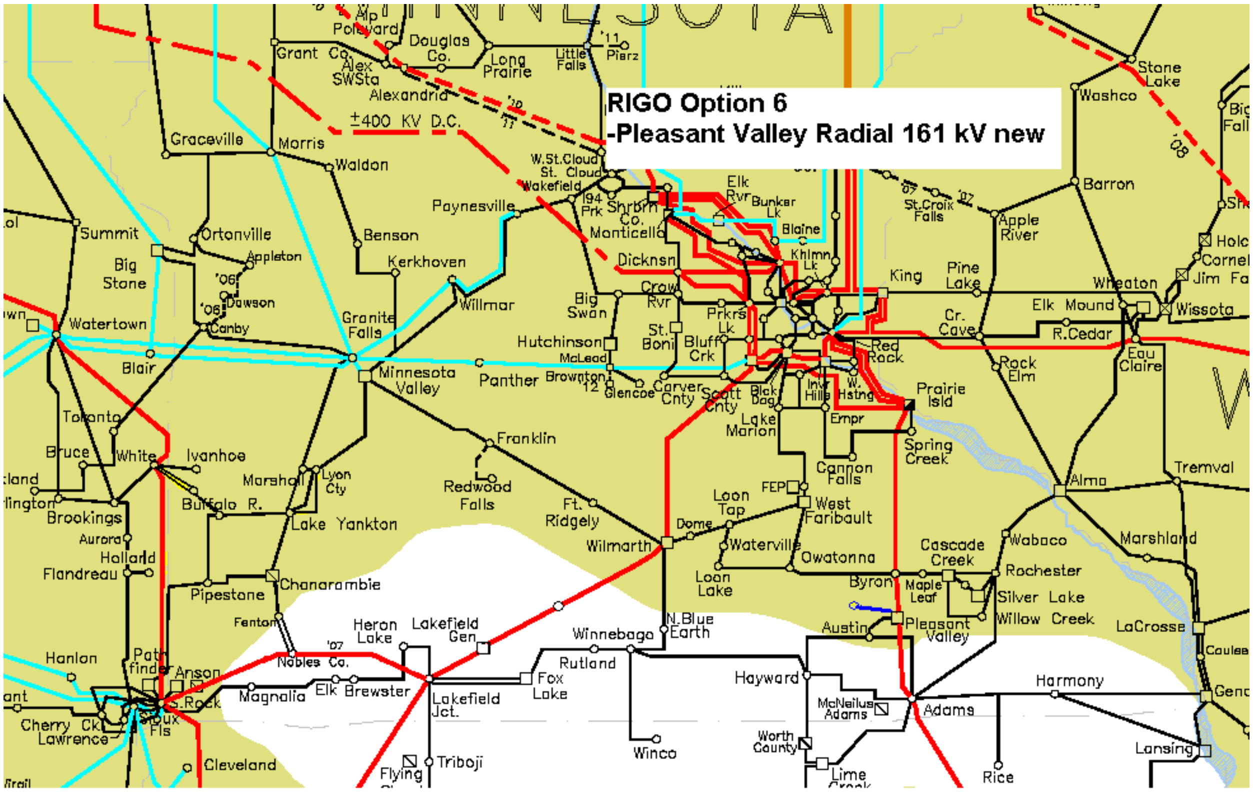


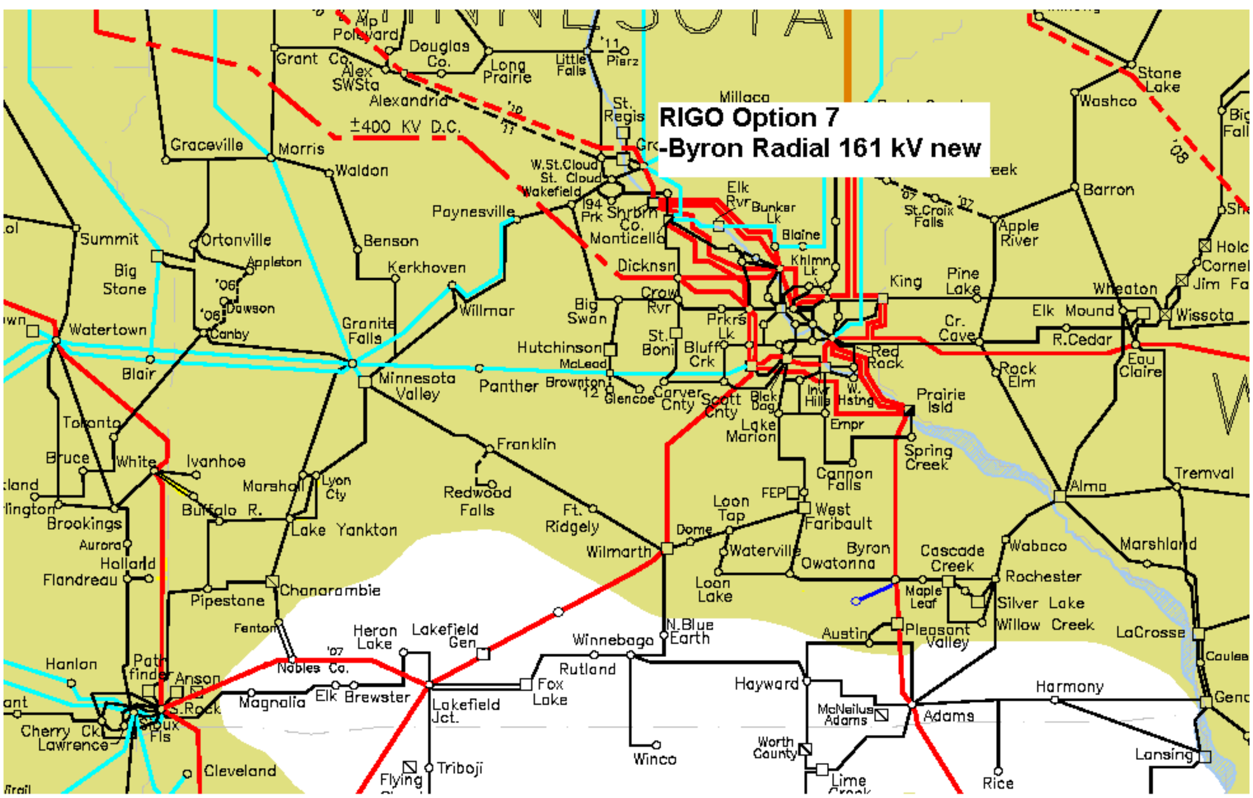

RIGO Option 2
-Waldon-Paynesville 115 kV new
±400 KV D.C.
Graceville
Morris
Waldon
Paynesville
Benson
Kerkhoven
Willmar
Grant Co.
Alex SWSta
Alexandria
Douglas Co.
Long Prairie
Pollyard
Summit
Ortonville
Appleton
Big Stone
Dawson
Canby
Watertown
Granite Falls
Minnesota Valley
Blair
Toronto
Bruce
White
Ivanhoe
Marshall
Lyon Cty
Brookings
Buffalo R.
Lake Yankton
Aurora
Holland
Flandreau
Pipestone
Chanarambie
Fenton
Heron Lake
Lakefield Gen
Nobles Co.
Hanlon
Pathfinder
Anson
Magnolia
Elk
Brewster
Lakefield Jct.
Cherry Ck
Lawrence
Sioux Fls
Cleveland
Triboji
Flying
Franklin
Redwood Falls
Ft. Ridgely
Wilmarth
Panther
Hutchinson
McLeod
Brownton
Glencoe
Carver Cnty
Scott Cnty
St. Boni
Bluff Crk
Big Swan
Crow Rvr
Dicknsn
Monticello
Sherburne Co.
Elk Rvr
Bunker Lk
Blaine
King
Pine Lake
Cr. Cave
Red Rock
Prairie Isld
Spring Creek
Cannon Falls
West Faribault
Loon Lake
Waterville
Owatonna
Dome
Winnebago
N. Blue Earth
Rutland
Fox Lake
Winco
Hayward
Austin
Pleasant Valley
McNeilus Adams
Adams
Worth County
Lime Creek
Rice
Harmony
Lansing
Byron
Maple Leaf
Cascade Creek
Rochester
Silver Lake
Willow Creek
LaCrosse
Wabaco
Alma
Marshland
Tremval
Rock Elm
Eau Claire
R.Cedar
Elk Mound
Wheaton
Wissota
Barron
Apple River
St.Croix Falls
Washco
Stone Lake

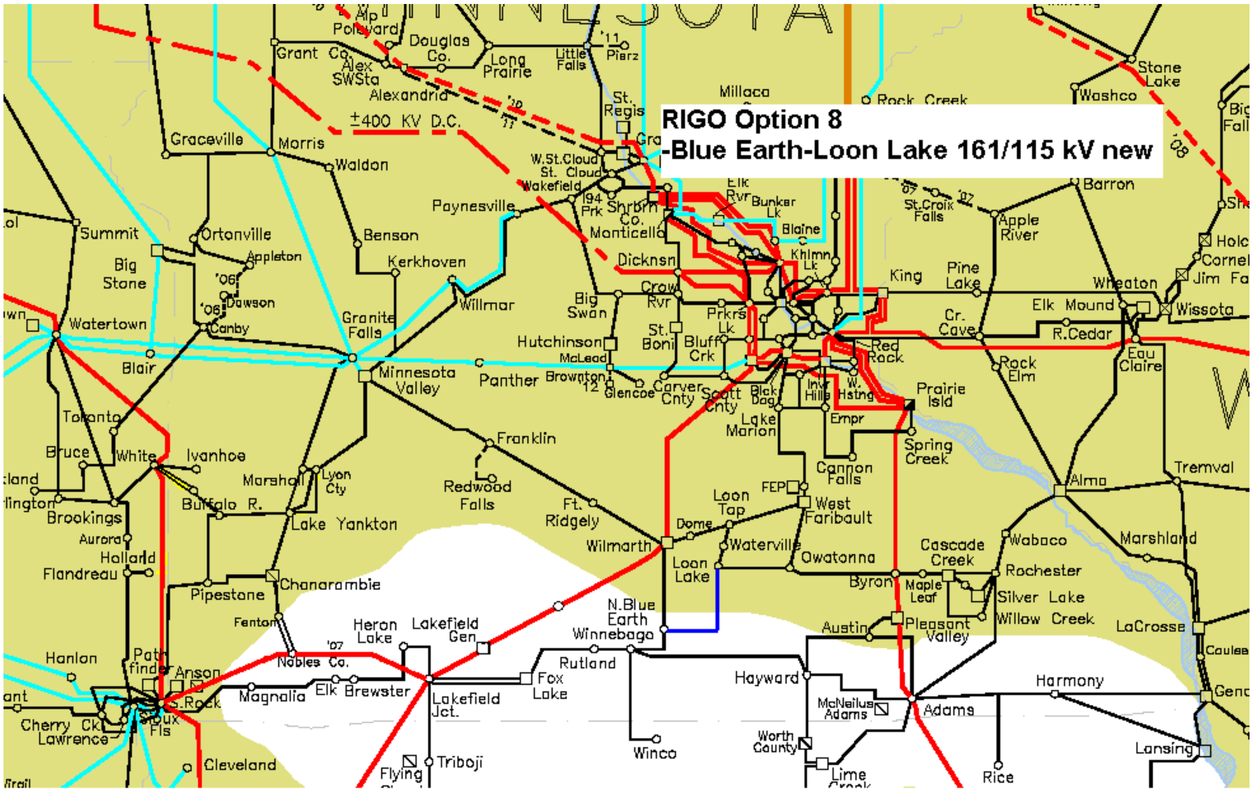

RIGO Option 3
Waldon-Willmar-Big Swan 115 kV new
±400 KV D.C.
Graceville
Morris
Waldon
Paynesville
Benson
Kerkhoven
Willmar
Big Swan
Granite City
Benton Co.
Chisago Co.
Lawrence Creek
Grant Co.
Alexandria
Douglas Co.
Summit
Ortonville
Big Stone
Watertown
Granite Falls
Minnesota Valley
Brookings
Pipestone
Chanarambie
Heron Lake
Lakefield Gen
Nobles Co.
Sioux Fls
Cleveland
Franklin
Redwood Falls
Wilmarth
Hutchinson
Monticello
Red Rock
Prairie Isld
Owatonna
Rochester
LaCrosse
Adams
Harmony
Lansing
Eau Claire
Barron
Apple River

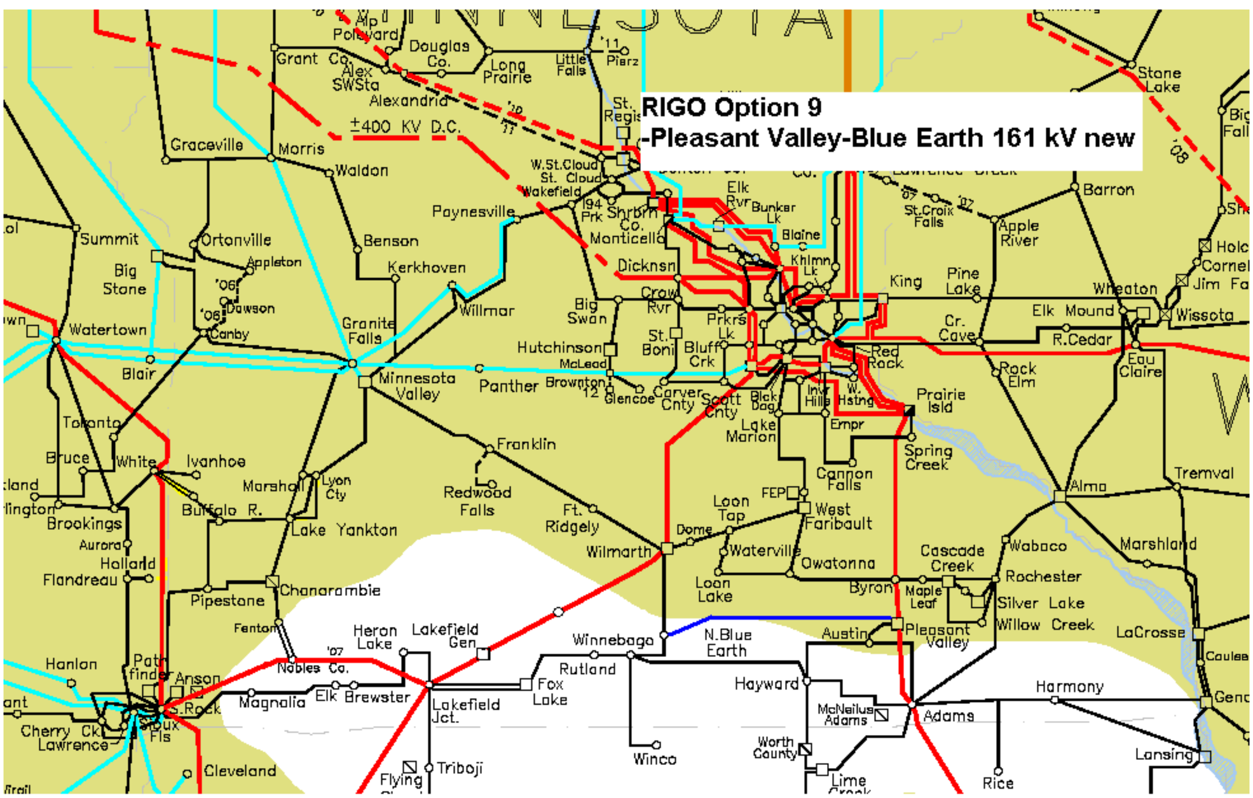

RIGO Option 4
-Waldon-Willmar 115 kV new
±400 KV D.C.

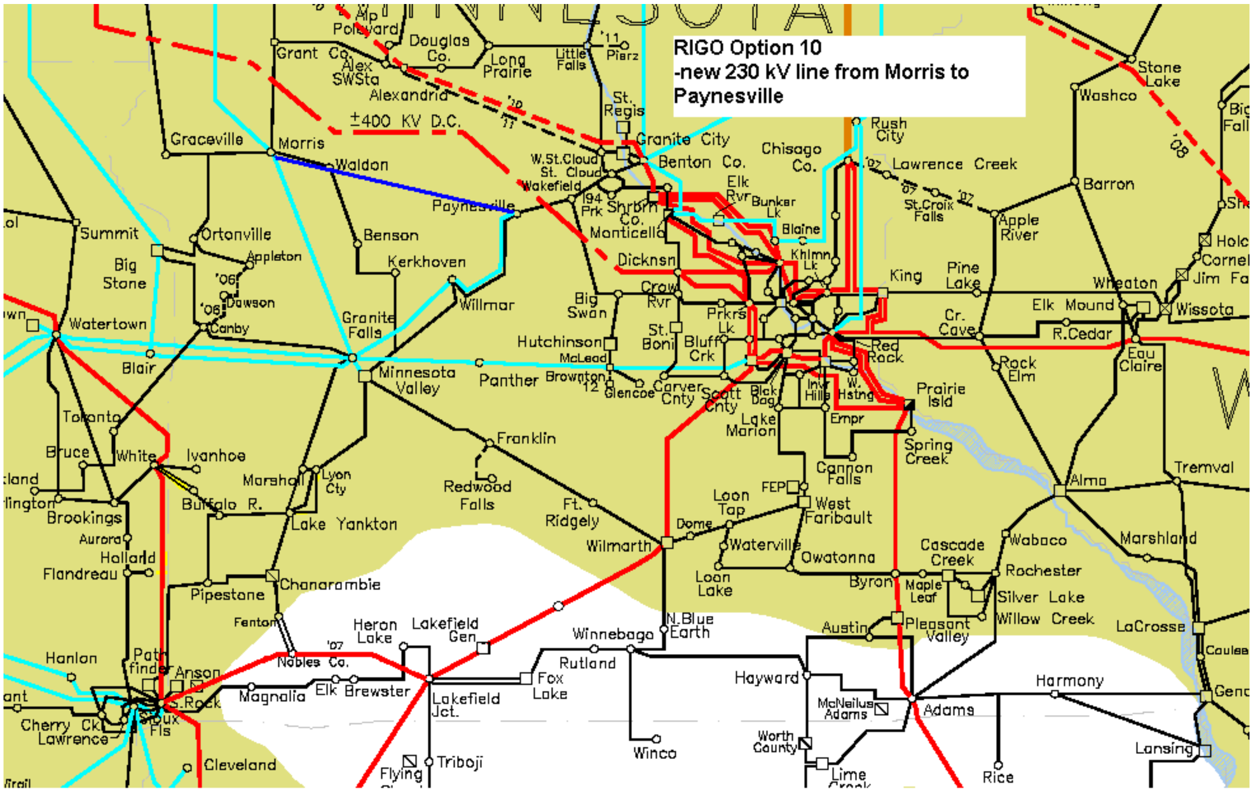

RIGO Option 5
-Owatonna-Austin Corner 161 kV new
±400 KV D.C.

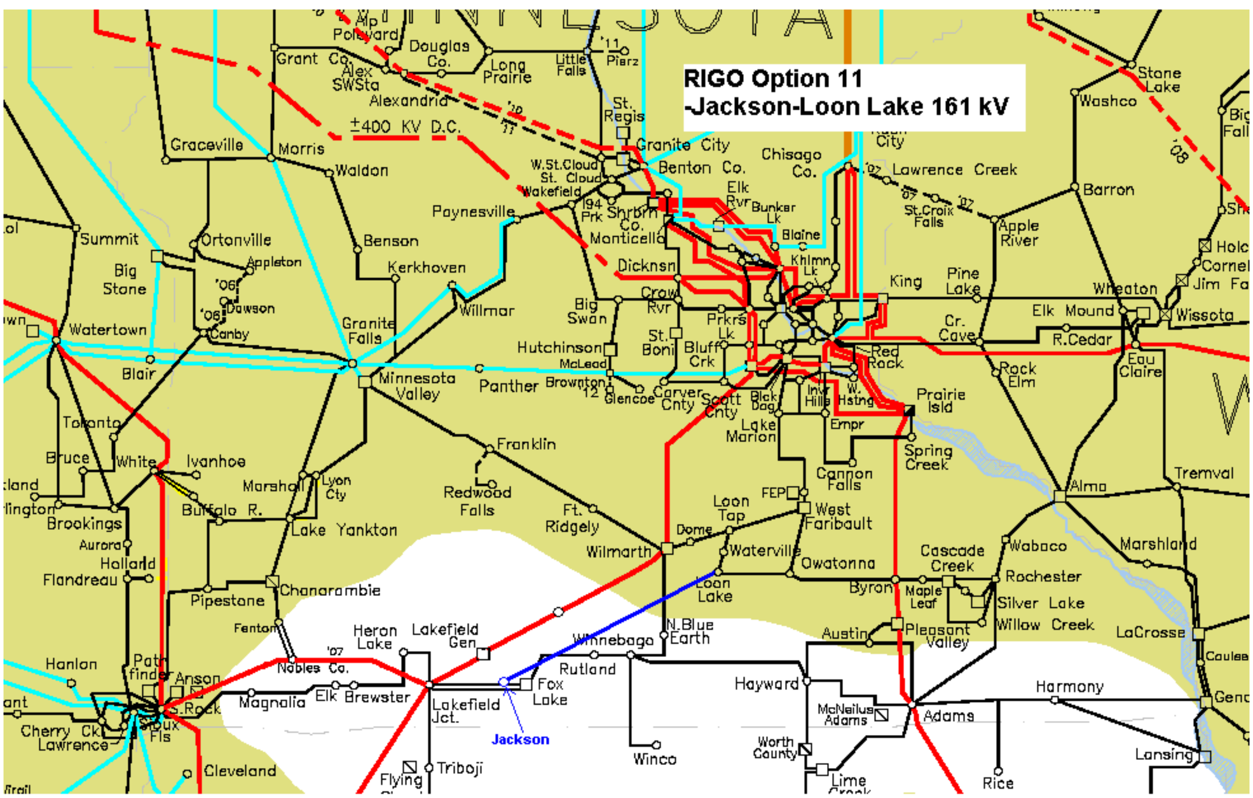

RIGO Option 6
-Pleasant Valley Radial 161 kV new

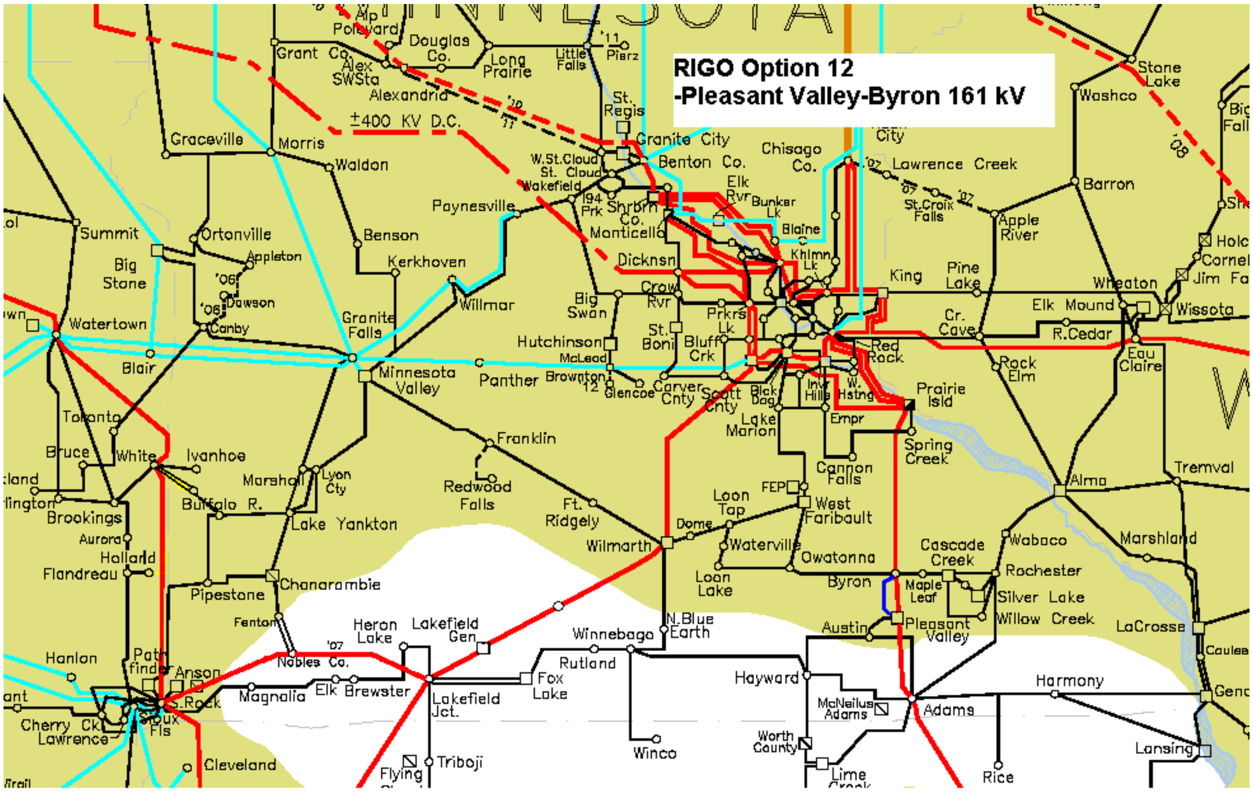

RIGO Option 7
-Byron Radial 161 kV new

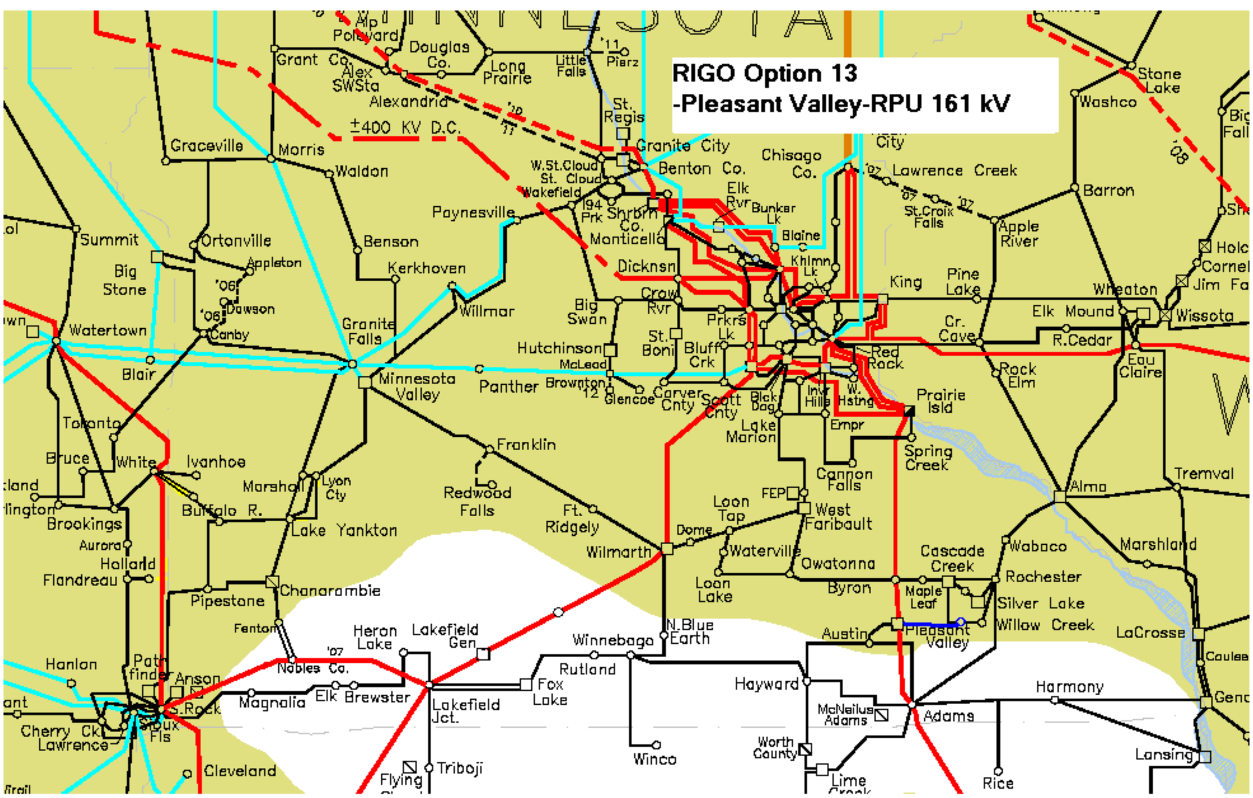

RIGO Option 8
-Blue Earth-Loon Lake 161/115 kV new

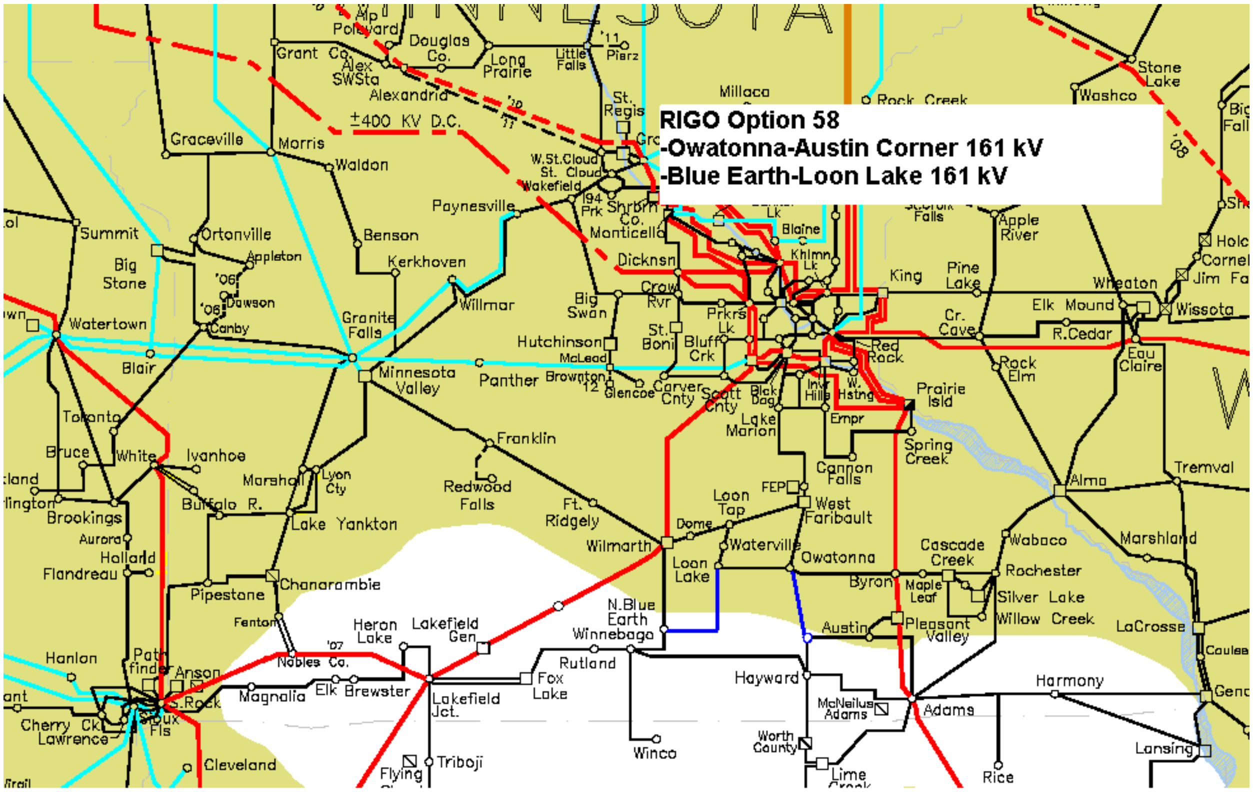

RIGO Option 9
-Pleasant Valley-Blue Earth 161 kV new

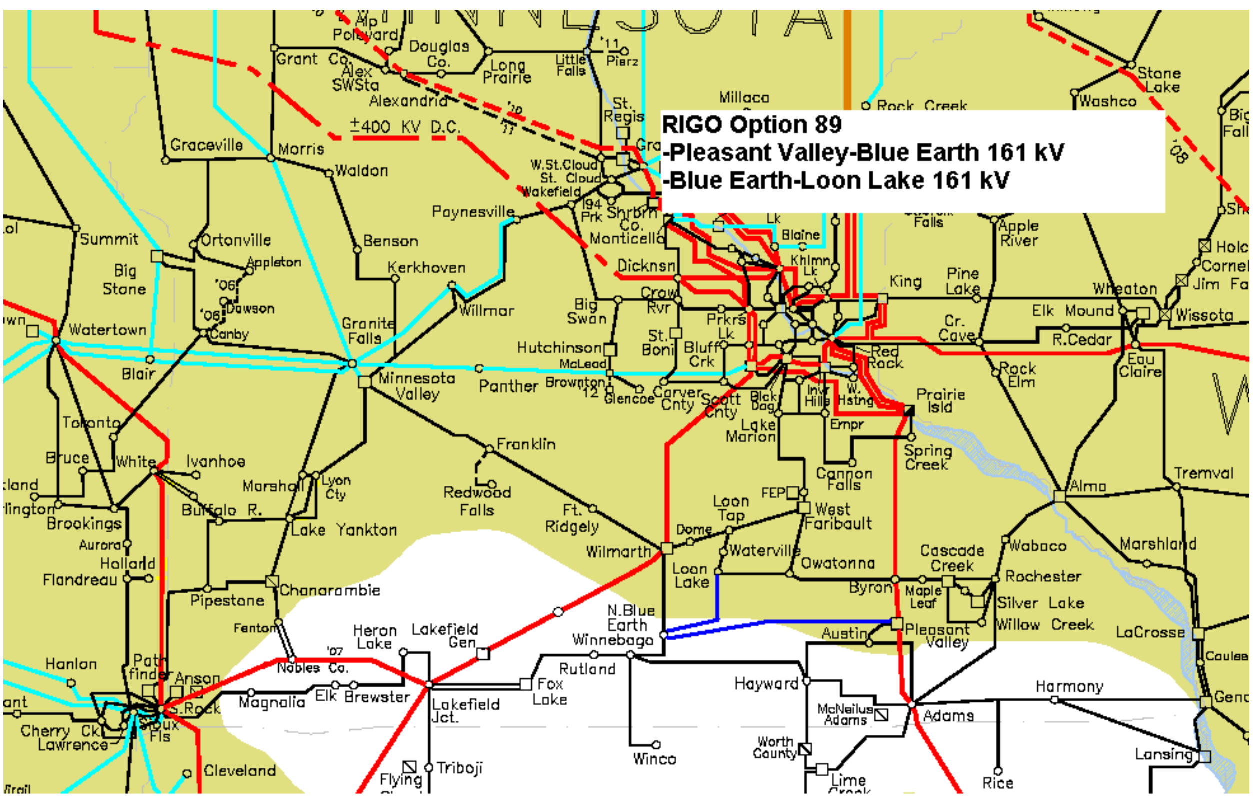

RIGO Option 10
-new 230 kV line from Morris to Paynesville
±400 KV D.C.
Graceville
Morris
Waldon
Paynesville
Benson
Kerkhoven
Willmar
Ortonville
Summit
Big Stone
Watertown
Granite Falls
Minnesota Valley
Hutchinson
Panther
Franklin
Redwood Falls
Lake Yankton
Brookings
Pipestone
Chanarambie
Heron Lake
Lakefield Gen
Nobles Co.
Magnolia
Elk
Brewster
Lakefield Jct.
Triboji
Fox Lake
Rutland
Winnebago
Wilmarth
N.Blue Earth
Loon Lake
Waterville
Owatonna
West Faribault
Cannon Falls
Spring Creek
Prairie Isld
Byron
Rochester
Pleasant Valley
Austin
Hayward
Adams
Harmony
Winco
LaCrosse
Lansing
Rice
Alma
Wabaco
Tremval
Eau Claire
Rock Elm
Cr. Cave
King
Pine Lake
Apple River
Barron
Washco
Stone Lake
Wheaton
Elk Mound
R.Cedar
Chisago Co.
Lawrence Creek
Granite City
Benton Co.
Monticello
Blaine
Red Rock
Cleveland
Hanlon
Flandreau
Ivanhoe
Marshall
Buffalo R.
Ft. Ridgely
Rush City
Douglas Co.
Grant Co.
Alexandria
Long Prairie
St. Regis

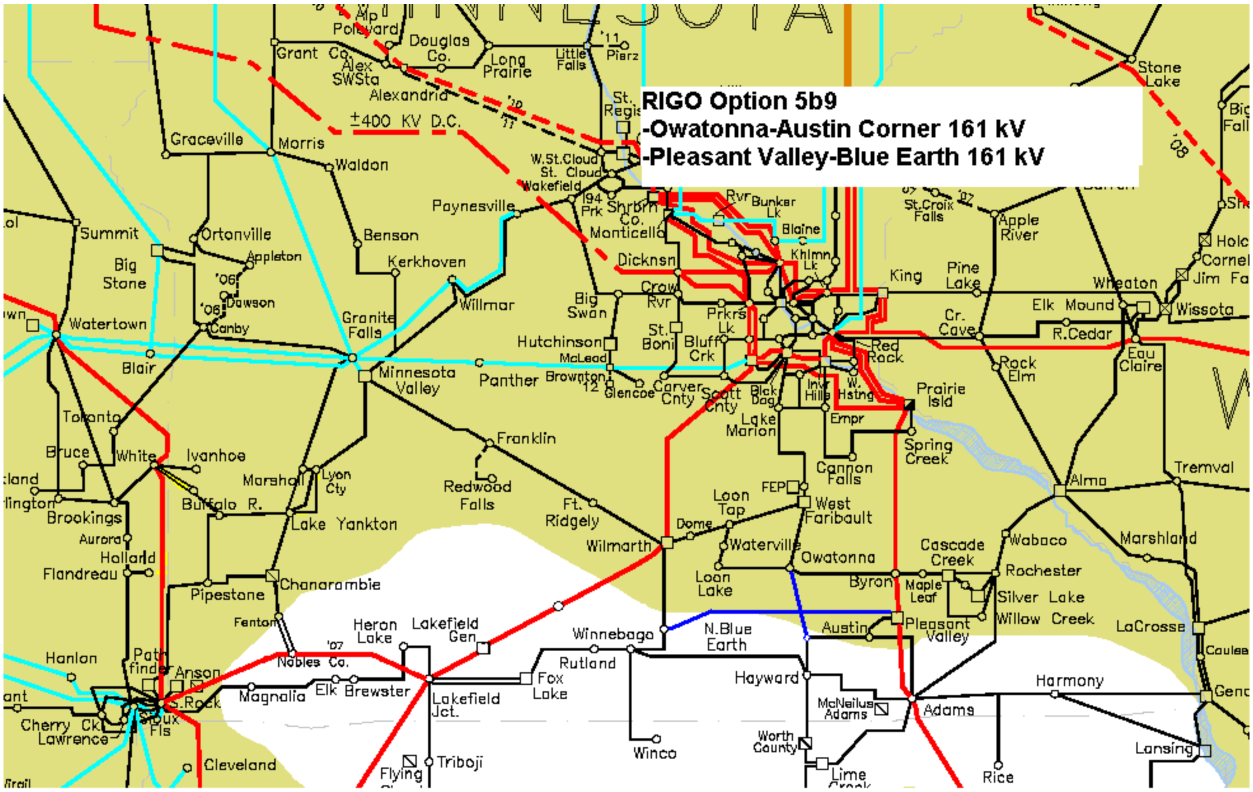

RIGO Option 11
-Jackson-Loon Lake 161 kV
±400 KV D.C.
Graceville
Morris
Waldon
Paynesville
Benson
Kerkhoven
Willmar
Ortonville
Summit
Big Stone
Watertown
Granite Falls
Minnesota Valley
Hutchinson
Panther
Franklin
Redwood Falls
Lake Yankton
Brookings
Pipestone
Chanarambie
Heron Lake
Lakefield Gen
Nobles Co.
Magnolia
Elk
Brewster
Lakefield Jct.
Jackson
Triboji
Fox Lake
Rutland
Winnebago
Wilmarth
N.Blue Earth
Loon Lake
Waterville
Owatonna
West Faribault
Cannon Falls
Spring Creek
Prairie Isld
Byron
Rochester
Pleasant Valley
Austin
Hayward
Adams
Harmony
Winco
LaCrosse
Lansing
Rice
Alma
Wabaco
Tremval
Eau Claire
Rock Elm
Cr. Cave
King
Pine Lake
Apple River
Barron
Washco
Stone Lake
Wheaton
Elk Mound
R.Cedar
Chisago Co.
Lawrence Creek
Granite City
Benton Co.
Monticello
Blaine
Red Rock
Cleveland
Hanlon
Flandreau
Ivanhoe
Marshall
Buffalo R.
Ft. Ridgely
Douglas Co.
Grant Co.
Alexandria
Long Prairie
St. Regis

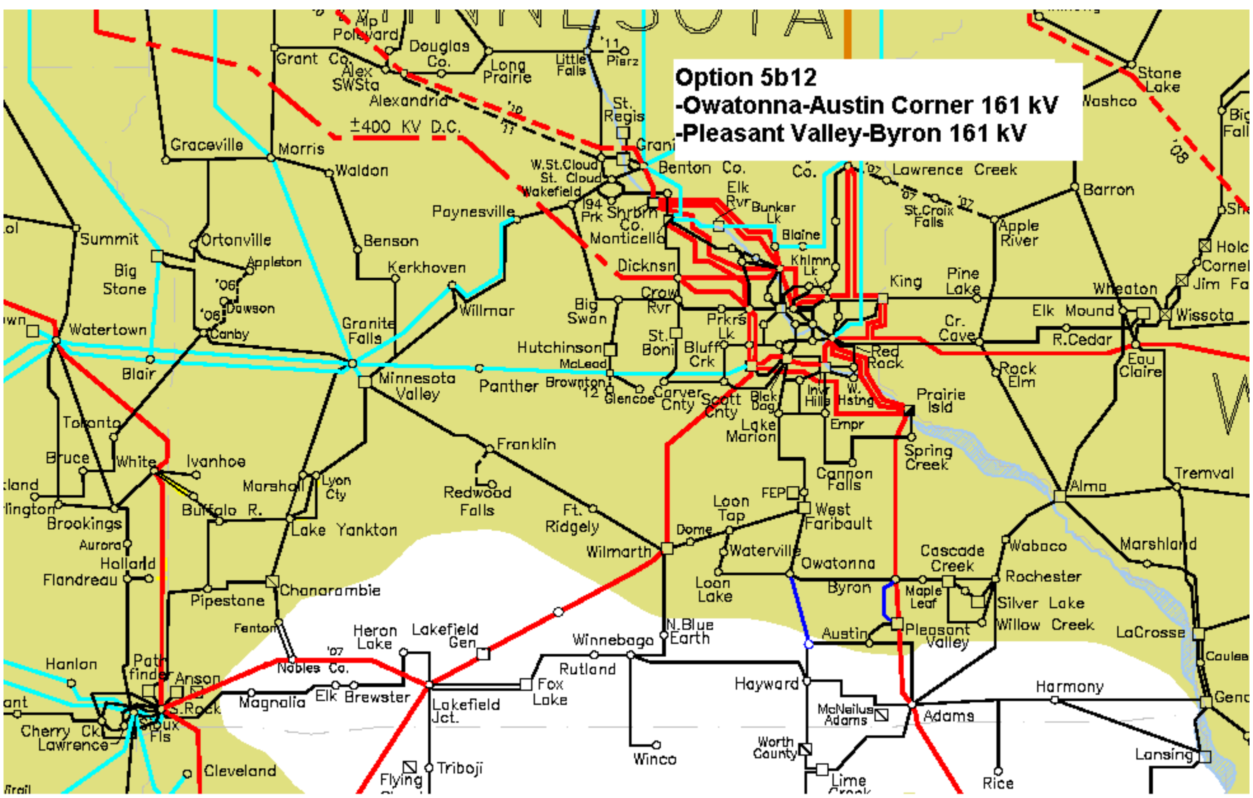

RIGO Option 12
-Pleasant Valley-Byron 161 kV

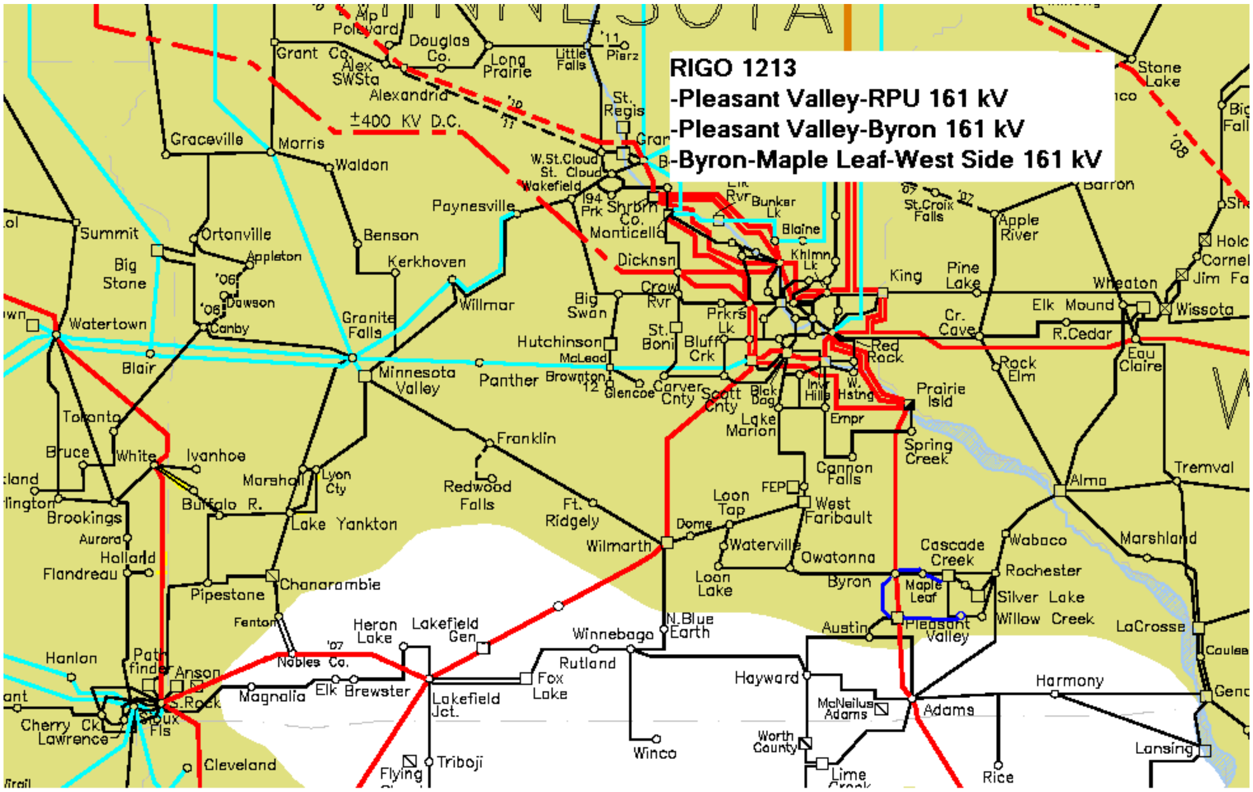

RIGO Option 13
-Pleasant Valley-RPU 161 kV


RIGO Option 58
-Owatonna-Austin Corner 161 kV
-Blue Earth-Loon Lake 161 kV
±400 KV D.C.


RIGO Option 89
-Pleasant Valley-Blue Earth 161 kV
-Blue Earth-Loon Lake 161 kV
±400 KV D.C.


RIGO Option 5b9
-Owatonna-Austin Corner 161 kV
-Pleasant Valley-Blue Earth 161 kV


Option 5b12
-Owatonna-Austin Corner 161 kV
-Pleasant Valley-Byron 161 kV


RIGO 1213
-Pleasant Valley-RPU 161 kV
-Pleasant Valley-Byron 161 kV
-Byron-Maple Leaf-West Side 161 kV
±400 KV D.C.
Douglas Co.
Long Prairie
Little Falls
Grant Co.
Alexandria
St. Regis
W.St.Cloud
St. Cloud
Wakefield
Graceville
Morris
Waldon
Paynesville
Monticello
Dicknsn
Blaine
King
Pine Lake
Apple River
St.Croix Falls
Stone Lake
Barron
Wheaton
Wissota
Elk Mound
R.Cedar
Eau Claire
Cr. Cave
Rock Elm
Prairie Isld
Red Rock
Summit
Big Stone
Ortonville
Appleton
Dawson
Canby
Benson
Kerkhoven
Willmar
Granite Falls
Watertown
Blair
Minnesota Valley
Panther
Hutchinson
McLeod
Brownton
Glencoe
Carver Cnty
Scott Cnty
Big Swan
Crow Rvr
St. Boni
Bluff Crk
Prkrs Lk
Blck Dog
Inv Hills
W. Hstng
Empr
Lake Marion
Spring Creek
Cannon Falls
FEP
West Faribault
Loon Tap
Dome
Waterville
Owatonna
Toronto
Bruce
White
Ivanhoe
Marshall
Lyon Cty
Buffalo R.
Brookings
Aurora
Holland
Flandreau
Lake Yankton
Redwood Falls
Franklin
Ft. Ridgely
Wilmarth
Chanarambie
Pipestone
Fenton
Heron Lake
Lakefield Gen
Nobles Co.
Winnebago
N.Blue Earth
Rutland
Fox Lake
Hayward
Austin
Byron
Maple Leaf
Pleasant Valley
Cascade Creek
Rochester
Silver Lake
Willow Creek
Wabaco
Alma
Tremval
Marshland
LaCrosse
Coulee
Harmony
Adams
McNeilus Adams
Worth County
Lime Creek
Rice
Lansing
Winco
Hanlon
Pathfinder
Anson
S.Rock
Sioux Fls
Cherry Ck
Lawrence
Magnalia
Elk
Brewster
Lakefield Jct.
Triboji
Flying
Cleveland