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December 23, 2011

William Fannucchi via email: william.fannucchi@wisconsin.gov
Docket Coordinator
Public Service Commission
P.O.Box7854
Madison, WI 53707-7854

RE: NoCapX Comments on DEIS
CapX 2020 **Hampton-Rochester-LaCrosse** Transmission Project
PSC Docket No.: 05-CE-136

Dear Mr. Fannucchi:

Thank you for the opportunity to submit comments on this Draft Environmental Impact Statement for the CapX 2020 Hampton-Rochester-LaCrosse Transmissionm Project.

Cover page - Starting with the title page of the DEIS, the project as named on the DEIS is not consistent with the name of the project applied for. The Application is for the “Hampton-Rochester-LaCrosse” transmission project. Please correct the title page. Labeling it as the “Alma-LaCrosse” transmission project can be misleading about the character and purpose of the application.

Executive Summary (recognizing that this is a summary, the meat is later)

p.XV – Project description must include the specs and capacity of the line. Aff of McKay, Ex. B, IR 3.

P. XV – To the extent that the statement of three purposes of the project is “need” it should more accurately reflect the three need claims of applicant (see Application, i-1, and p. 1-8 – 1-12):

1) Community Reliability Needs for LaCrosse-Winona and Rochester area
2) Regional Reliability
3) Generation Outlet/Renewable Energy Support

p.XVI – Regarding “final ownership” it should state that “Applicants have not disclosed final ownership of the project.” It is implied, but not stated. Assessment of cost and rate implications is impossible without disclosure of ownership.

p. XVI – Need, 1st paragraph, community load serving needs, there is a list of communities, including counties and cities and "surrounding rural areas" that the EIS claims will be served. However, Applicants have couched "local load serving needs" in terms of LaCrosse and Rochester (see Applicants, Figure 6 for "Affected Area." There is no plan for a substation near Alma, and the area would not be served.

p. XVI – population growth in LaCrosse/Winona and peak load growth – this should reference most recent EIA projections (demand projected to be down). The MISO Rate of O.78% is overstated.

p.XVII – Table ES-2 – It is my understanding that the Genoa Unit 3 is off line more than on, and that the Alma plant may be shut down. This table should have column with capacity factor percentages, design and actual, and date of shut down, if any.

p. XVIII – first partial paragraph, "The applicants also state that neither DSM nor the addition of local generation can provide the bulk transmission capability across the Minnesota/Wisconsin border that could enable future power transfers into Wisconsin…" should address how "bulk transmission capability" that "could enable future power transfers" is related to any of the three need claims.

p. XVIII – references to biomass should address emissions, particularly formaldehyde and NOx.

p.XIX – TableES-3 - Transmission Losses Cost, the losses cost for the 345kV is not accurate, losses cost is not zero. There are losses associated with this project, with any transmission project that should be disclosed. Line losses are inherent in any project. Losses for the project should be calculated for the full length of the project, as applied for, Hampton-Rochester-LaCrosse, with the double circuited 345kV bundled 954 kcmil conductor running at 75% capacity at the very least (based on desire for 3-5,000 MW transfer capacity).

p. XXII – Table ES-4 – "New ROW (acres)" and "Percent of ROW Length Shared)" should be clarified as to what types of ROW, how ROW is defined. If p. 7, 1.2.2.3 defines ROW, i.e., a, b, c are regarded as corridor, and d is "New corridor" that would be helpful. Is a recreational rail ROW?

p. 1 – The first and second paragraphs are grossly misleading. As above, the Application is for the "Hampton-Rochester-LaCrosse" transmission project. The Applicants call it the Hampton-Rochester-LaCrosse" project. Labeling it as the "Alma-LaCrosse" or "LaCrosse" transmission project is misleading about the character and purpose of the application. Please correct the title page.

p. 10 – Provide link to WisDOT's Policy of Utility Accomodation.

p. 11 – RUS Environmental Information – the RUS Macro Corridor Study and Alternative Evaluation Study should be included and incorporated into the PSC's EIS:
AES (March 2009): http://www.usda.gov/rus/water/ees/pdf/Dairyland%20CapX2020%20345%20AES%200509.pdf
MCS (May 2009): http://www.usda.gov/rus/water/ees/pdf/Dairyland%20CapX%202020%20MCS%200509.pdf

p. 12 – the ALJ's report is overdue and the MPUC's decision will not be in 2011. Please update

p. 15 – as with ES-2, the table should have additional columns for expected capacity factor and actual capacity factor – it is my understanding that these plants are frequently off line.

p. 15-16 – Area load forecast – this should compare the area load forecast of the Certificate of Need with the various iterations provided to the PSC. The basis for this project, the study work, was conducted in 2004-2005 and much has changed since then.

p. 16 "… the projected annual percentage peak load growth rate of 1.7 percent used in the CPCN application is high." This cries out for a modifier, i.e., "too" high, or "unreasonably" high.
p. 19 – needs section **2.6.3 Impact of project on system stability"** and a discussion of the need for Badger-Coulee transmission eastward from LaCrosse if this project is built, to preserve system stability, prevent thermal overload, and provide outlet for trapped generation. The Western Wisconsin Reliability Study demonstrates that the Hampton-Rochester-LaCrosse does not provide reliability, instead, it brings system instability to LaCrosse, necessitating extension of transmission eastward.
See Western Wisconsin Reliability Study:

ATC's Western Wisconsin Transmission Reliability Study - September 20, 2010

See April 3, 2009 Press Release.

http://nocapx2020.info/wp-content/uploads/2011/11/atc-xmsnstudy-pcdocs-3993093-v1-xcella-crosseattachment-52b-1-nocapx2.pdf

See ATC's Western Wisconsin Reliability Study Powerpoint:
http://www.atc10yearplan.com/documents/2011StakeholderReliabilityPresentation-011911.pdf

- Without the addition of the Badger Coulee 345 kV line, the above Reactive Support would be needed to prevent voltage collapse. At a cost of $82.7M. (p. 12)
- Without the addition of the Badger Coulee line the ten transmission lines above, in ATC's area, would need to be rebuilt for thermal overload support. Cost = $54.7M. (p. 13)

p. 19 – needs section "**2.7 Market Drivers"** to explain economic dispatch, increasing transfer capacity, and market drivers for this project.

p. 20 – Alternatives – The applicants also state that neither DSM nor the addition of local generation itself can provide "foundation bulk transmission facilities across the Minnesota/Wisconsin border to enable future power transfers into Wisconsin" to support generation development elsewhere." The purpose of an alternatives analysis is to determine what options there are, individually or in combination, to address a claimed need. That should be stated. The statement by applicants is a moving target, stating that alternatives that can obviate one type of need don't provide what they really want, which is "foundation bulk transmission facilities" which is NOT a type of need.

p. 21 – Load reduction: "no regulatory authority" and "no mechanism has been identified that would ensure adequate participation over time." The FEIS should state that "load reduction can effectively reduce demand and that regulatory authority and/or mechanism to ensure adequate participation over time should be identified."

p. 21 – cost of load reduction – should state 'load reduction is recognized as the most economic of alternatives, because the least costly megawatt is the one you don't generate." Specific cost estimates for a MW of load reduction are readily available online.

p. 21 – wind power variability. This must address siting wind near gas peaking generation to utilize existing transmission infrastructure, existing transmission reservations, and for use as backup to firm wind generation.

p. 22 – Solar power – solar power should be considered, not large central station facilities, but widely broadcast rooftop solar on the many buildings in area where electricity is "needed."

p. 23 – 3.2.3.3 Biomass. This section should address the feedstock problems with "biomass plants" and the significant air emissions and permit violations. See e.g.:

Fibrominn: Poop Power in the WSJ;
Laurentian (Hibbing)**:** Laurentian "biomass" Air Permit Draft (second time around))

"Biomass" violates air permit - fines likely

Powerpoint on emissions of biomass plants:

Muller - Saying NO! to permits for Kandiyohi's Midtown Burner

(Air emissions info on slide 22)

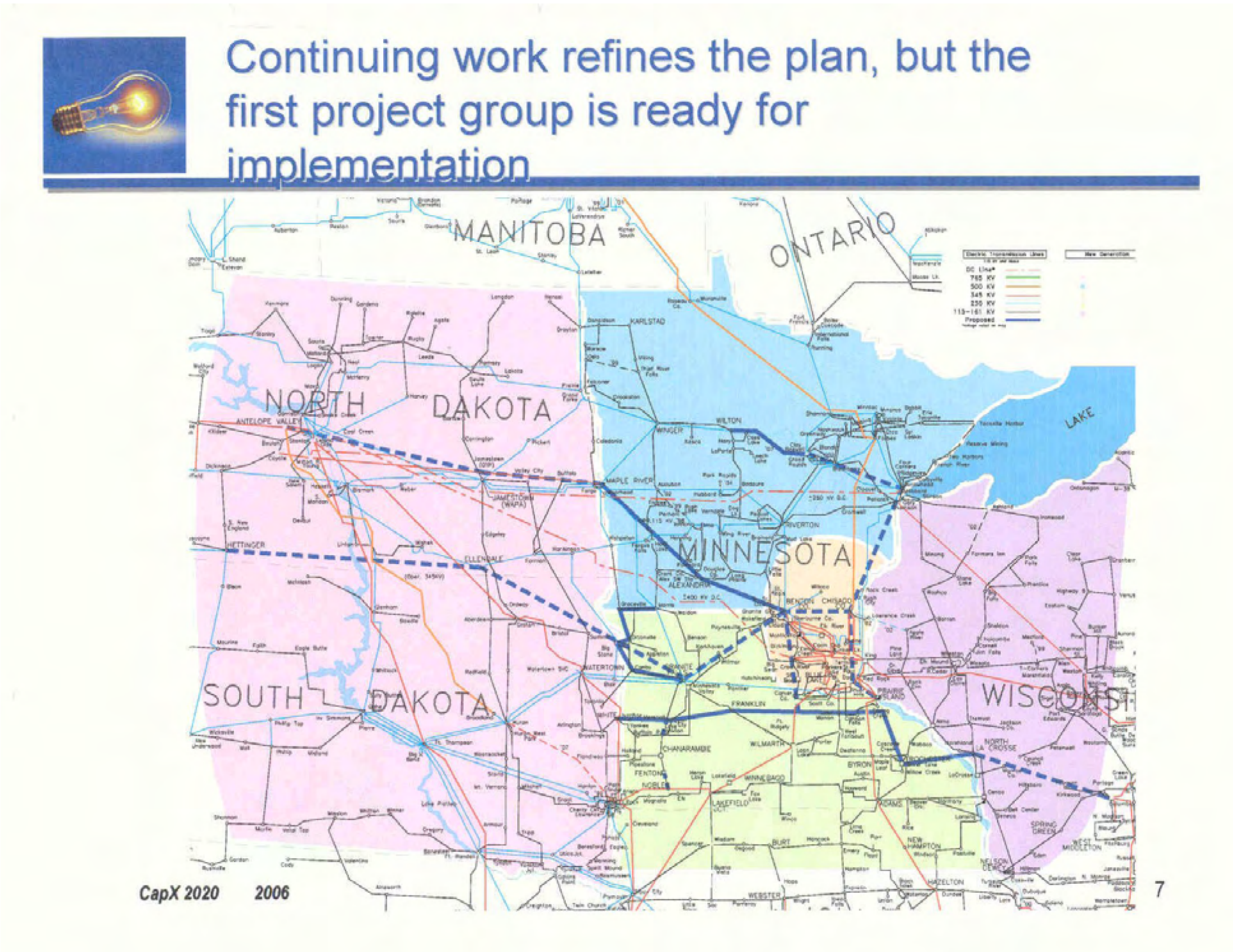
p.23 – 3.2.3.4 Landfill gas – this is methane. The EIS should reflect that landfill gas is methane, and that methane is an extremely potent greenhouse gas.

p. 24 – the DEIS states that "applicants also emphasize that the proposed project would prove pivotal for future expansion…" This section must disclose the full "CapX 2020 Vision Plan" together with the map showing the Phase I CapX 2020 projects and the chart of the CapX 2020 Vision Plan:

Facility Name				
From	**To**	**V olt (kV)**	**Miles**	**Cost ($M)**
Alexandria, MN	Benton County (St. Cloud, MN)	345	80	60
Alexandria, MN	Maple River (Fargo, ND)	345	126	94.5
Antelope Valley (Beulah, ND)	Jamestown, ND	345	185	138.75
Arrowhead (Duluth, MN)	Chisago County (Chisago City, MN)	345	120	90
Arrowhead (Duluth, MN)	Forbes (Northwest Duluth, MN)	345	60	45
Benton County (St.Cloud, MN)	Chisago County (Chisago City, MN)	345	59	44.25
Benton County (St. Cloud, MN)	Granite Falls, MN	345	110	82.5
Benton County (St. Cloud, MN)	St. Bonifacius, MN	345	62	45.5
Blue Lake (Southwest Twin Cities, MN)	Ellendale, ND	345	200	150
Chisago County (Chisago City, MN)	Prairie Island (Red Wing, MN)	345	82	61.5
Columbia, WI	North LaCrosse, WI	345	80	60
Ellendale, ND	Hettinger, ND	345	231	173.25
Rochester, MN	North LaCrosse, WI	345	60	45
Jamestown, ND	Maple River (Fargo, ND)	345	107	80.25
Prairie Island (Red Wing, MN	Rochester, MN	345	58	43.5
TOTAL			**1620**	**$1,215 ($M)**

Exhibit 17, Portion of the 2005 Biennial Report Filed by Transmission Utilities, p. 36; Ex. 1, Application, App. A-1, Technical Update October 2005; see also Exhibit 12, CapX 2020 Update, June 14, 2006; Rogelstad, Vol. 2A, p. 69-74; Rogelstad, Direct Testimony p. 17; Rogelstad, Tr. Vol 2A, p. 39 et seq.

And the 2005 big picture map of these lines above that includes the Hampton-Rochester-LaCrosse and Badger-Coulee lines:



The Hampton-Rochester-LaCrosse transmission project is but a small part of a much larger picture, and evaluation of just a small piece without addressing the larger context is misrepresentation of the nature and impacts of this project.

p. 24, Section 3.3 Transmission Alternatives – Descriptions. Transmission alternatives presumes transmission is necessary and that presumption has not been established.

p. 24, 3.3.1 - as above, the description of the project must include the specifications and capacity of the line, i.e., double circuited bundled 954 kcmil ACSS – MVA 2,050 per circuit x 2 = 4,100 MVA.

p. 24 – 3.3.1 – the statement that "the proposed project would serve the LaCrosse/Winona area load up to 750 MW and up to 890MW with the operation…" is absurd in light of the potential capacity for this project and the stated desire of 3-5,000MW of transfer capacity. The potential MVA for this line should be stated in this paragraph, and that the 790MW is a very small portion of this capacity, that the project as proposed is unreasonable in light of need claimed, not to mention demonstrated.

p. 25 - 3.3.2 – Reconductor Option. The "reconductor option" is too limited in scope. The point of this project is increasing transfer capacity into Wisconsin. The Reconductor Option section should address a "345k V reconductoring option," reconductoring the 345kV lines that make up that export interface, the

King-Eau Claire-Airpin; Prairie Island-Byron-Adams; and Arrowhead-Weston. If those lines were reconductored with double circuit bundled 345kV 954 kcmil with potential capacity of ~4,100 MVA, what would impact be on regional reliability, transfer capacity, etc.

p. 25 – 3.3.3 – 161kV Red Wing-LaCrosse transmission line option. The FEIS should note that "the route of the 161kV Red Wing-LaCrosse transmission line option would cross "Site P," the site NSP chose in Florence Township for nuclear waste." Increasing voltage and capacity of this transmission line through Florence Township would encounter opposition beyond Xcel Energy's wildest nightmares.

p. 27, Table 3.4-1 – as above regarding TableES-3 - Transmission Losses Cost, the losses cost for the 345kV is not accurate, losses cost is not zero. There are losses associated with this project, with any transmission project that should be disclosed. Line losses are inherent in any project. Losses for the project should be calculated for the full length of the project, as applied for, Hampton-Rochester-LaCrosse, with the double circuited 345kV bundled 954 kcmil conductor running at 75% capacity at the very least (based on desire for 3-5,000 MW transfer capacity).

p. 35 – 4.3 Title must be corrected – a "Hampton-Rochester-LaCrosse" transmission project has been applied for, delete "Project Endpoint" from the heading.

p. 35 – description of the Alma crossing – this should state that there is no substation planned for Alma.

p. 36 – Minnesota Environmental Review – this section contains a paragraph that is false and bizarre, with no relation to history, the record, or any other documentation:

> *The applicants' decision on the proposed crossing was reinforced during the state of Minnesota EIS scoping process in the spring of 2010.The Minnesota Office of Energy Security (OES) convened two advisory task forces and a public scoping comment period on the issues and route alternatives that should be evaluated in the Minnesota EIS. If the comments from the task forces and the public did not indicate that the LaCrosse crossing should be reevaluated in addition to the Alma crossing, then the scope of the Minnesota EIS would include the Alma crossing as the only crossing. The OES scoping decision in August 2010 confirmed the Alma crossing as the one to be carried through the two states' review processes. See appendix D, the Executive Summary of the Minnesota EIS, page 1*[1].

First, the statement that "***If the comments from the task forces and the public did not indicate that the LaCrosse crossing should be reevaluated in addition to the Alma crossing, then the scope of the Minnesota EIS would include the Alma crossing as the only crossing"*** **<u>is not true and is a gross misrepresentation of the Minnesota record</u>** Also, this statement is not supported by the DEIS citation to the FEIS Executive Summary, "Section 6" and/or any documents in the record in Minnesota. Many comments were made requesting that more than one Mississippi River crossing be considered. These comments are documented below.

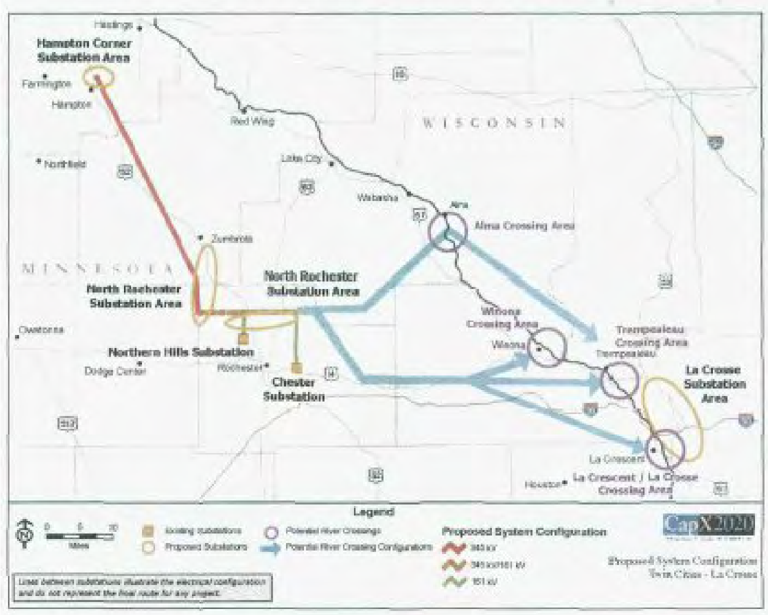
Second, the statement that "*The OES scoping decision in August 2010* ***confirmed*** *the Alma crossing as the one to be carried through the* ***two states'*** *review processes"* is **<u>false</u>** in two ways. First, the OES scoping decision does not "confirm" anything, it is a decision as to the scope of the EIS. See FEIS, Executive Summary, p. 1 ("…Director of EFP **<u>finalized</u>** the scope…") Secondly, the scoping decision does not in any way determine what will occur in "two states' review process." The OES scoping

[1] Section 6 of the Minnesota OES EIS discusses the factors supporting the "Kellogg Crossing" at Alma in detail. It also discusses alternative crossing methods. CapX Hampton-Rochester-LaCrosse345kVand161kV Transmission Lines Project Environmental Impact Statement, August 2011. (footnote from PSC DEIS, p. 36)

decision addresses what is to be included in Minnesota. It has nothing to do with Wisconsin. Wisconsin makes its own scoping decisions and makes its own determinations as to whether an application with only one Mississippi River crossing is complete.

When this project was granted a Certificate of Need, four river crossings were proposed for consideration, Alma, Winona, Trempeauleau and LaCrosse:

Figure 2-1: Map of Twin Cities – La Crosse 345 kV Project Area



Source: Certificate of Need Application, p. 2.4 (August 2007).

In the RUS Macro-Corridor Study for the Hampton-Rochester-LaCrosse Transmission Project, crossings were proposed for Alma, Winona, and LaCrosse:

Source: RUS MCBS Figure 7-1: Final Macro-Corridors

Below is a list of many statements in the record regarding the need for more than one river crossing in the project proposal and to be evaluated by the state in the EIS and project review (see also comment of Joyce Osborn, United Citizens Action Network):

<u>Completeness Determination</u>

February 23,2010 NoCapX 2020 and U-CAN Comments on Completeness

> *Under Minn. Stat. § 216E.03, Subd. 3, the January 19, 2010 application is not complete because there are not two distinct corridors. The Applicants have not met one of the most basic application criteria. NO CAPX 2020 and United Citizens Action Network (U-CAN) request that the Commission declare the Application incomplete unless and until at least two separate and distinct routes are provided.*

February 24, 2010 Maccabee Comments on Completeness

> *I have represented Citizens Energy Task Force in the certificate or need proceedings pertaining to the CapX2020 La Crosse Project. I am writing herein as a member of the public to request that the Public Utilities Commission reject the route permit application in the above-captioned matter as incomplete and in violation of Minnesota Statutes 216E.03, Subd. 3 and Minnesota Rules 7850.1900, Subp. 2.C mandating the following:*
>
> *Any person seeking to construct a large electric power generating plant or a highvoltage transmission line must apply to the commission for a site or route permit. The application shall contain such information as the commission may require. The applicant shall propose at least two sites for a large electric power generating plant and two routes for a high-voltage transmission line. (Minn. Stat. 216E.03, Subd. 3) An application for a route permit for a high voltage transmission line shall contain the following information:*
>
> > *C. at least two proposed routes for the proposed high voltage transmission line and identification of the applicant's preferred route and the reasons for the preference. (Minn. R. 7850, Subp. 2).*
>
> *In the Application for a Route Permit for the CapX2020 La Crosse Project, the failure to provide at least two proposed routes for the high voltage transmission line is a very substantial deviation from legal requirements. The proposed overhead route at Alma is within the Upper Mississippi River National Wildlife and Fish Refuge and would place migratory birds, nesting eagles and habitat at risk. Yet there is only one route proposed at this critical Mississippi River crossing.*

March 9, 2010 PUC Completeness determination: Order by Commission for ATFs, upon Motion that more than one is necessary, two were established, one that shall "*examine issues at the Mississippi River crossing*" (#3). Also, the Commission stated in the order:

V. *In light of the expressed and anticipated public interest in the Mississippi River crossing issues and due to the sensitivity of the environment and inter-governmental issues raised by any such crossing, the charge of at least one of the task forces should consist of or include examination of the issues surrounding the line's Mississippi River crossing to Wisconsin, above ground, underground, at Alma, or elsewhere.*

March 10, 2010 Mississippi River Revival and Citizens Energy Task Force request for task force regarding Mississippi River crossing:

2) The charge of this Advisory Task Force, consistent with previous communications from the US Fish and Wildlife Service to Xcel Energy on February 19, 2008 and May 4, 2009, would be to conduct a comprehensive examination of an underground alternative to minimize impacts on the River, the Refuge and flora and fauna of concern. The Task Force would obtain information on impacts of overhead transmission lines on birds using the Mississippi River Flyway as well as visual and other environmental impacts on the River, Refuge and surrounding communities. The Task Force would review benefits and costs of underground crossings at any point along the river from Alma to La Crescent. Staff would seek information on underground crossings from sources other than the Applicants, including contractors with experience in constructing underground transmission lines in sensitive environmental locations.

20103-47862-01 PUBLIC 09-1448 TL MISSISSIPPI RIVER REVIVAL AND CITIZENS ENERGY TASK FORCE LETTER 03/10/2010

EIS Scoping Comments

June 3, 2010 North Rochester-Mississippi Advisory Task Force. Comments on the Applicants preferred 345 kv route:

Only one location for the crossing of Mississippi River proposed by Applicant; ***need to look at additional options****; going underground (a line was placed under the St. Croix Wild and Scenic Riverway); additional crossing points for the Mississippi River need to be considered.*

MINNESOTA EIS SCOPING COMMENTS REFERENCING RIVER CROSSING OPTIONS
(online at: http://energyfacilities.puc.state.mn.us/resource.html?Id=28492)**:**
Pg 5- Mississippi River Parkway Commission of MN- "underground river crossing should not be ruled out as a possibility".

Pg 8- MN DNR. Comment page 4. 'A thorough analysis of underground engineering of possible crossings is recommended. This analysis may include locations other than previously described aerial crossings if engineering for underground configuration is more practical at another location." Jamie Schrenzel. April 29, 2011

Pg 11- MN DNR. Comment page 4. "The DEIS should include a robust description of possible underground crossings of the Mississippi River……Underground route crossing options discussed in the DEIS should not only include an underground crossing at the location(s) best suited for considering aerial crossings, but should include an underground route at the location(s) best suited for engineering an underground route, which may or may not be in the same location as the Alma crossing. …A comparison of impacts and mitigation should be included for aerial and underground crossings of the Mississippi …… It would be informative if the DEIS contained a brief discussion of the possible extent of impacts in Wisconsin, particularly related to how the choice of the Mississippi River crossing location affects routing in Wisconsin and Minnesota…." Jamie Schrenzel. May 10, 2010.

SCOPING MEETINGS: May, 2010 – Comments regarding River Crossings (available online at: http://energyfacilities.puc.state.mn.us/resource.html?Id=28492)

May 4. Plainview. 6:30 PM.
Laura Kreofsky. Questioning why Alma? In comparison to other crossings? Hillstrom lengthy explanation of why Alma chosen by Applicants

Steve Walker. LaCrosse now too expensive to "buy" trucking company on industrial land. At one time the route was going 90 to LaCrosse

May 6.Cannon Falls 1:30.
Michael Collins. Why not use 52 to I-90 into LaCrosse using path already cut (check RPA Appendix for I-90 to LaCrosse route study…)

APPEAL OF SCOPING DECISION
NoCapX 2020 and U-CAN appealed the Scoping Decision, specifically regarding its failure to include more than one Mississippi River crossing:

> **2. The EIS must include analysis of more than one river crossing**
>
> The scoping decision includes only one river crossing, the solitary Alma river crossing proposed by applicants. This is not sufficient alternatives analysis under MEPA. A project this large, with impacts legally acknowledged as significant, must include additional alternatives. This request for review and analysis additional options to be included in the EIS was raised in the Task Force that covered the river crossing, yet I cannot find any alternative to the Alma crossing in the scoping decision. This is such an obvious scoping flaw that it's difficult to see a need for additional words! The RUS EIS is analyzing at least three locations, in Alma, Winona, and LaCrosse, and technical alternatives as well – this information is available online, at the link cited above. The Scoping decision should include river crossing options included in the RUS EIS.

20108-53324-01 PUBLIC 09-1448 TL NOCAPX 2020 AND UCAN OTHER--APPEAL OF EIS SCOPING DECISION 08/09/2010

DEIS Comments

FEIS-DEIS COMMENTS/TESTIMONY: 2011 (See MOES' FEIS Appendix O)
ID#1- Appendix O. Dept. of Interior. "All three river crossings……" paragraph 2
ID # 123. Pg O-282. Denise Leedham. Utilize highwyays 52 and I-90.
ID# 162. Pg. O-362. Lee Naus. Utilize Highways 52 & I-90 (across Mississippi).
ID# 168. Pg. O-379. US Dept of Interior. 2008. First and second choices of Mississippi crossing….. Also the "I-90 corridor" on second page of this letter…
ID# 168. Pg. O-399. NoCAPX and UCAN . Multiple crossings….168E.
ID# 204. Pg. O-477. Patricia Steffes. Utilize Hwy. 52 & I-90, facility in LaCrosse.
ID# 211. Pg. O-493. Tina Trihey Porter. Utilize I-90 (across Mississippi).
ID# 216. Bob Wallace. Pg. O-500. Assumed that I-90 corridor was being considered….
ID# 224. Joe Morse. Pg. O-517. More than one Mississippi River crossing.
ID# 238. Mike Collins. Pg. O-550. Utilize Hwy. 52 to I-90, and east (across Mississippi to LaCrosse…)
ID# 242. Kia Hackman. Pg. O-557. Utilize Highways 52 & 90 (across Mississippi)..
ID# 251. Larry Paul. Pg. O-577. Utilize Hwy 52 & I-90 to LaCrosse (across Mississippi)..
ID# 263. Carolyn Campbell. Pg. O-606. Thought the alternate route was Interstate 90.
ID# 271. Alan Muller. Pg. O-648. No build alternative. I never got this before, and thought this was good! After review of RUS…..

Comments at hearings

ALJ PUBLIC HEARINGS: 2011 (available online at: http://energyfacilities.puc.state.mn.us/documents/25731/CapX%20DEIS%20Comment%20Speadsheet_web_20110513.pdf)

Dave Sykora, MN/DOT. June 15. Pine Island. 6:30. Starts on Pg 69. "I have a general sense there is a feeling among many people in the community that the reason this route doesn't go down to I-90 and over to LaCrosse is because MNDOT said you can't go there. And I'd like to clarify that. That did not happen." Contunues to talk about using the I-90 corridor… So in the meetings, he, too, was hearing about I-90 across the Mississippi River to LaCrosse……

June 14. Plainview. 1:30. Robert Wallace. Pg 59. "I hear of this project over a year ago, but at the time routes being considered were along the I-90 corridor in the Winona and Houston County area…"

June 14. Plainview. 6:30. Pat Melvin. 'I support the transmission line from the 52 corridor to the I-90 to LaCrosse corridor…"

Barb Stussy. June 15. Pine Island 1:30. Pg 66. First USDA rural development. It was a macro corridor study…"

As noted above ad nauseum, there were many comments requesting more than one Mississippi River be considered and analyzed. The paragraph on p. 36 should be deleted in its entirety, and something true be put in its place.
+++++++++++++++++++++++++++
Back to the DEIS:
p. 37 – Cost of undergrounding – the $90 million for 1.3 miles should also be expressed in an percentage cost increase with the cost measured over the full Hampton-Rochester-LaCrosse route (miles and cost).

p. 37 – Evaluation and analysis of underground should be more detailed, including information on conditions that add weight to undergrounding as an option, at what point do the benefits outweigh costs, is the largest migratory flyway in North America significant enough to warrant undergrounding, if not, why not.

p. 39 – "No landscaping is anticipated at the proposed East or West sites."

- Why is no landscaping anticipated?
- The EIS should disclose the sound levels that are anticipated.
- Lighting of the substation should be addressed.
- A photo of similar substation should be provided and aesthetics addressed.
- Figure 4.4.1 shows several positions open. The type and use and plans for the open positions should be discussed.

p. 40 – The EIS should take salvage value into account.

p. 41- Discussion of exclusion of "pre-certification costs." Should include a discussion of "Construction Work in Progress" available to utilities in Wisconsin (and Minnesota due to Minnesota portion of this project).

p. 42 – "Other Costs" should also include breakdown of these costs by local units of government.

p.43 – have local governments (counties, towns, villages, cities) been notified of potential for and estimated amounts of One-Time fee under Wis. Admin. Code §ADM 46.05, and Annual fees.

p. 44 – Cost Allocation – the EIS should include a table showing dollar amounts of cost and distribution for the 20% on basis of load ratio shares, and the distribution of cost for the 80% between recipient utilities using Line Outage Distribution Factor methodology.

p. 45 – EIS should disclose per-tree cost of trees according to WisDOT, not Applicants.

p.55- the DEIS must address visual impacts from the Mississippi River as provided by Wis. Stat. ch. 30.

p. 55 – "Aesthetics are to a great extent based on individual perceptions." Aesthetic evaluation is a known and quantifiable process, and this improperly dismisses aesthetic concerns. The EIS must include a thorough aesthetic evaluation of the length of the route, with additional attention to those areas in and near scenic easements, scenic areas, visible from scenic lookouts, and in and near the Great River Road.

p. 55 and Appendix B – the discussion on EMF is inadequate. I don't see any information on what levels of magnetic fields are anticipated. The EMF charts in the application, Appendix U, are misleading at best, because magnetic fields are based on current in the line, and the amps used in modeling are grossly understated. See Affidavit of McKay, and Exhibits, Attached, for estimates of magnetic fields associated with the Hampton-Rochester-LaCrosse project.

NoCapX 2020 adopts as if fully related here the many comments of the WisDOT regarding scenic easements. Scenic easements were a determinative issue in the CapX 2020 Brookings case, where Applicants proposed a route that, due to scenic easements, was not permittable, and this was not openly part of the record until a very late date in the process, during public hearings just before the evidentiary hearing, long after discovery had been done. MN/DOT comments were not readily available and the existence of these easements was not disclosed. Upon public entry of the scenic easement in question into the record, the Applicants tried to introduce a new route option (Myrick Road) despite failure to include it in the EIS scope, no environmental review, and inadequate notice to landowners. NoCapX urges consideration of the issues raised by the WisDOT so as not to end up in a "Brookings" situation.

In this case, it appears that new route options were introduced at this late date by Applicants in their DEIS comments. NoCapX 2020 reserves the right to submit additional comments if necessary upon review.

- Landowners must be notified of the new routes and notices filed.
- Landowners must be given adequate time to learn what this means and intervene in this docket.
- PSC staff must be given time to adequately review these options prior to acceptance as a "route."

Thank you for the opportunity to submit Comments on the DEIS.

Very truly yours,

Carol A. Overland

Carol A. Overland
Attorney at Law

cc: ERF and email to Parties

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Route Permit Application by Xcel Energy, Dairyland Power Cooperative, Souther Minnesota Municpal Power Agency, Rochester Public Utilities , and WPPI Energy for a 345 kV Transmission Line from Hampton, Minnesota, to Rochester, Minnesota, to La Crosse, Wisconsin	OAH DOCKET NO. 3-2500-21181-2 PUC DOCKET NO. E002/TL-09-1448

AFFIDAVIT OF BRUCE McKAY, P.E.

Bruce McKay, P.E., after affirming or being duly sworn on oath, states and deposes as follows:

1. My name is Bruce McKay. I am an electrical engineer, and licensed Professional Engineer, in the state of Minnesota.

2. My experience is primarily in the areas of industrial power distribution and industrial automation and control. I have 16 years experience in these areas as a licensed Master Electrician, followed by 14 years as a licensed Professional Engineer to date.

3. I am a landowner near Henderson, MN, and therefore am not directly affected by the proposed Hampton-Rochester-La Crosse 345 kV Transmission Project.

4. I have participated in CapX2020 Task Force meetings held in Henderson, attended one day of PUC hearings in St. Paul, and attended, including making comments and submitting statements, all but one of the Public Hearings held in the Le Sueur-Henderson area over the last few years.

5. Attached as Exhibit A is a true and correct copy of the CapX2020 Engineering, Design, Construction, and Operational Characteristics, Section 3.1.1 Hampton-Rochester-La Crosse 345 kV Transmission Line, found on page 3-3 of the January 15, 2010, Route Permit Application for the Hampton-Rochester-La Crosse 345 kV Transmission Project, wherein it states that “Two 954 Aluminum Conductor Steel Supported (ACSS) conductors will be used per phase.”

6. Attached as Exhibit B is a true and correct copy of Direct Testimony of Larry L. Schedin, Attachment J, showing various conductor specifications, including:

    a. In the chart on page 3, Summer Thermal Ratings for a Twin bundled 954 kcm 54/19 ACSS, 345 KV, of 3700 amps and 2211 MVA.
    b. In the chart on page 5, Winter Thermal Ratings for a Twin bundled 954 kcm 54/7 ACSS, 345 KV, of 4064 amps and 2428 MVA.

c. For the purposes of this Affidavit, I am using the Summer Ratings, but it should be noted that Winter Ratings are approximately an additional 9.8% higher than the Summer Ratings.

7. The first purpose of this statement is to point out the fact that the CapX2020 Magnetic Field tables and charts that I've been able to find in Hampton-Rochester-La Crosse 345 kV Transmission Project documents all fail to address the full potential Magnetic Field along the transmission lines. Each table and chart that I've seen displays Magnetic Field data calculated from estimated Peak and estimated Average System Conditions (Current (Amps)) rather than from transmission line design capacities. An example of such a table is presented in the attached Exhibit C, a true and correct copy of the CapX2020 Engineering, Design, Construction, and Operational Characteristics, Table 3.6-2: Calculated Magnetic Fields (mG) for Proposed 345 kV Transmission Line Designs (3.28 Feet Aboveground), found on pages 3-28 and 3-29 of the January 15, 2010, Route Permit Application for the Hampton-Rochester-La Crosse 345 kV Transmission Project.

8. The second purpose of this statement is to point out the fact that a table such as Exhibit C underestimates the Magnetic Field that would be created if the transmission line was utilized to its full potential capacity, or to 80% of its full potential capacity. The attached Exhibit D is a true and correct copy of "McKay Magnetic Field Calculations" which presents an example of Magnetic Field calculations based on estimated transmission line currents as compared to Magnetic Field calculations based on future potential (design) transmission line currents.

   a. By following through STEPS 1, 2, 3-Single Circuit, and 4-Single Circuit in Exhibit D, you can see that with one Circuit in Service, for 2015 PEAK, the Calculated PEAK MAGNETIC FIELDS increase by 1323% and for 2015 AVERAGE, the Calculated AVERAGE MAGNETIC FIELDS increase by 1323% when design capacities are used for the calculations rather than using estimated load currents.
   b. By following through STEPS 1, 2, 3-Double Circuit, and 4-Double Circuit in Exhibit D, you can see that with two Circuits in Service, for 2015 PEAK, the Calculated PEAK MAGNETIC FIELDS increase by 2646% and for 2015 AVERAGE, the Calculated AVERAGE MAGNETIC FIELDS increase by 2646% when design capacities are used for the calculations rather than using estimated load currents.
   c. Please Note: Exhibit D is presented as a conceptual example. Actual design capacities and associated Magnetic Field calculations would need to be and should be provided by the Applicants.

9. The third purpose of this statement is to stress that right-of-way widths to protect the health and safety of those along the proposed transmission line need to be based on Calculated Magnetic Field's derived from design capacities, NOT on Calculated Magnetic Field's derived from estimated transmission line currents. A right-of-way based on the Applicant's low transmission line current estimates does not sufficiently protect people near the transmission lines.

10. Please feel free to contact me with any comments or questions you have.

Further your affiant sayeth naught.

Dated: April 20, 2011

Bruce McKay

Bruce McKay, PE
e-mail: bmckay.aces@gmail.com
cell: 612-386-5983

Signed and sworn to before me this
20 day of April, 2011.

Notary Public

WERNER H. GIESEN
Notary Public
State of Minnesota
My Commission Expires
January 31, 2015

EXHIBIT A

Line Configurations and Specifications

Hampton-LaCrosse Application

Section 3 Project Description

p. 3-3

3.1.1 Hampton–Rochester–La Crosse 345 kV Transmission Line

For the Project's proposed 345 kV line, the Applicant proposes primarily to use single-pole, self-weathering steel, double-circuit capable structures. Self-weathering steel alloys were developed to eliminate the need for painting and are commonly used by the Applicant and throughout the industry. The steel alloy develops a stable, rust-like appearance (dark reddish-brown color) when exposed to the weather for several years. The wetting and drying cycles cause rust to form a protective layer on its surface, preventing further rusting. The layer develops and regenerates continuously when subjected to the influence of the weather.

These single-pole steel structures would range from 130 to 175 feet in height. Spans could range from 600 to 1,000 feet, but would typically be 700 to 1,000 feet. In some areas, only one circuit would be strung and the other side of the pole would be available for adding a second circuit in the future, when conditions warrant. In other areas, the unused side of the 345/345 kV structure would be used to carry a lower voltage line on the second set of arms until a second 345 kV circuit is needed. Tubular steel pole structures are typically placed on large pier foundations of cast-in-place, reinforced concrete.

Two 954 Aluminum Conductor Steel Supported (ACSS) conductors will be used per phase. One or two shield wires will be used to protect the conductors from lightning strikes. One of these shield wires will incorporate fiber optic to facilitate relay control communications between substations and between substations, utility offices such as control centers. Fiber optics will be used only for utility purposes.

Figure 3.1-1 depicts a representative double-circuit 345 kV single pole structure.

The Mississippi River presents unique considerations that will require the use of multiple-circuit, specialty structures. A portion of this crossing is on Upper Mississippi River Wildlife Refuge lands managed by the USFWS. A Special Use Permit will be required to cross the Refuge and the Applicant will work closely with the USFWS to identify the most appropriate structure design.

An existing double-circuit transmission line crosses the Mississippi River and Refuge at the Project's proposed crossing location. The existing line crosses approximately 0.5 mile of Refuge lands and includes two structures on Refuge property. The line is constructed on a 180-foot-wide permitted ROW. An area approximately 125 feet wide and 1,900 feet long is maintained cleared of trees. The two main river crossing structures are 180 feet tall.

EXHIBIT B

Amps and MVA for Line Configurations and Specifications

Direct Testimony of Larry L. Schedin, Attachment J
CapX 2020 Certificate of Need
PUC Docket E002, ET2/CN-06-1115

☐ **Non Public Document – Contains Trade Secret Data**
☐ **Public Document – Trade Secret Data Excised**
☒ **Public Document**

Xcel Energy
Docket No.: E002, ET2/CN-06-1115
Response To: Elizabeth Goodpaster and Mary Marrow MCEA/Wind on the Wires — Information Request No. 3
Date Received: March 27, 2008

Question:

With reference to the Application Volume I, Sec. 2.4 (pages 2.9) entitled "Transmission Line Characteristics" and Applicants' response to DOC/OES Information Rquest No. 2, please provide thermal MVA ratings, surge impedance loadings (SIL), MVA and thermal ampere capacity ratings (amplacities) under summer normal, summer emergency, winter normal and winter emergency conditions for the following conductors and voltages:

(a) Single 795ACSR, 115 KV
(b) Single 795 ACSS, 115 KV
(c) Twin bundled 795 ACSR, 115 KV
(d) Twin bundled 795 ACSS, 115 KV
(e) Single 954 ACSS, 115 KV
(f) Single 795 ACSS, 161 KV
(g) Single 954 ACSS, 161 KV
(h) Single 795 ACSR, 230 KV
(i) Single 795 ACSS, 230 KV
(j) Single 954 ACSS, 230 KV
(k) Twin bundled 795 ACSR, 345 KV
(l) Twin bundled 954 ACSS, 345 KV
(m) Triple bundled 954 ACSS, 500 KV
(n) Triple bundled conductor as used on the Forbes – Chisago 500 KV line

<u>In your response, please define the conditions for summer normal, summer emergency, winter normal and winter emergency conditions (ambient temp, wind speed, degree rise, allowable sag. etc.), and specify the regulatory authority setting the foregoing standards and the reference to applicable rules.</u>

<u>Response</u>:

The thermal ratings of the requested conductors and voltages are noted in the table below. Conductor ratings are based on the "IEEE Standard for calculation of Bare Overhead Conductor Temperature and Ampacity Under Steady-State Conditions," ANSI/IEEE Standard 738. Alcoa SAG10 Ratekit was used to calculate conductor ratings.

A regulatory authority does not set the conductor steady state thermal rating variables. The CapX2020 Member Utilities Transmission Line Standards Committee ("Committee") developed the conductor steady state thermal rating variables for summer ratings based upon member utilities' standard of practice..

The summer steady state thermal rating variables are as follows:

- Conductor orientation relative to north: 90 degrees
- Atmosphere: Clear
- Air Temperature: 40 degrees C for Summer
- Wind Speed: 2 ft/sec
- Wind angle relative to conductor: 90 degrees
- Elevation above sea level: 1000 ft
- Latitude: 45 degrees N
- Date: July 8
- Solar time: 12 hours
- Coefficient of emissivity: 0.7
- Coefficient of absorption: 0.9
- 200 degrees C maximum operating temperature for ACSS
- 100 degrees C maximum operating temperature for ACSR

The Committee defined the Emergency Line Rating as equal to the steady state thermal rating.

The Committee specified that conductors meet minimum clearances to ground based upon voltage and nature of surface under the conductor (*i.e.*, roads, interstate highway, railroads, etc.). The minimum specified clearances were chosen to assure that the final constructed lines meet or exceed the National Electrical Safety Code ("NESC") minimum clearances. Conductor sags are to be calculated based upon conductor size, conductor temperature, span length, design tension, structure heights and loading conditions. Vertical clearances shall be applied to the greatest sag resulting from either the maximum operating temperature of 200°C (for the ACSS conductor) and 100°C (for the ACSR conductor) or the maximum loaded condition (ice plus wind).

Conductor	**Summer Thermal Ampacity Rating**	**Summer Thermal MVA Rating**
Single 795 kcm 26/7 ACSR, 115 KV	965 amps	192 MVA
Single 795 kcm 26/7 ACSS, 115 KV	1655 amps	330 MVA
Twin bundled 795 kcm 26/7 ACSR, 115 KV	1930 amps	384 MVA
Twin bundled 795 kcm 26/7 ACSS, 115 KV	3310 amps	659 MVA
Single 954 kcm 54/19 ACSS, 115 KV	1850 amps	368 MVA
Single 795 kcm 26/7 ACSS, 161 KV	1655 amps	462 MVA
Single 954 kcm 54/19 ACSS, 161 KV	1850 amps	516 MVA
Single 795 kcm 26/7 ACSR, 230 KV	965 amps	384 MVA
Single 795 kcm 26/7 ACSS, 230 KV	1655 amps	659 MVA
Single 954 kcm 54/19 ACSS, 230 KV	1850 amps	737 MVA
Twin bundled 795 kcm 26/7 ACSR, 345 KV	1930 amps	1153 MVA
Twin bundled 954 kcm 54/19 ACSS, 345 KV	3700 amps	2211 MVA
Triple bundled 954 kcm 54/19 ACSS, 500 KV	5550 amps	4806 MVA
Triple bundled conductor as used on the Forbes – Chisago 500 KV line (Triple bundled 1192.5 kcm 45/7 ACSR)	3648 amps	3159 MVA

The Committee did not develop steady state thermal rating variables for winter ratings. Xcel Energy – NSP Operating Territory uses 0°C for the winter rating air temperature for calculating the rating during the winter operating season of November 1 to April 30. The April 30 date produces the lowest allowable line rating of the winter rating period, so it is used in the following table. The April 30 date and 0°C air temperature were used in conjunction with the other steady state thermal rating variables developed by the Committee to develop the following winter rating table.

The winter steady state thermal rating variables used for the following Xcel Energy – NSP Operating Territory/ CAPX2020 Member Utilities Transmission Line Standards Committee rating table are as follows:

- Conductor orientation relative to north: 90 degrees
- Atmosphere: Clear
- Air Temperature: 0 degrees C for Winter
- Wind Speed: 2 ft/sec
- Wind angle relative to conductor: 90 degrees
- Elevation above sea level: 1000 ft
- Latitude: 45 degrees N
- Date: April 30
- Solar time: 12 hours
- Coefficient of emissivity: 0.7
- Coefficient of absorption: 0.9
- 200 degrees C maximum operating temperature for ACSS
- 100 degrees C maximum operating temperature for ACSR

Conductor	**Winter (April 30) Thermal Ampacity Rating**	**Winter (April 30) Thermal MVA Rating**
Single 795 kcm 26/7 ACSR, 115 KV	1286 amps	256 MVA
Single 795 kcm 26/7 ACSS, 115 KV	1819 amps	362 MVA
Twin bundled 795 kcm 26/7 ACSR, 115 KV	2572 amps	512 MVA
Twin bundled 795 kcm 26/7 ACSS, 115 KV	3638 amps	725 MVA
Single 954 kcm 54/7 ACSS, 115 KV	2032 amps	405 MVA
Single 795 kcm 26/7 ACSS, 161 KV	1819 amps	507 MVA
Single 954 kcm 54/7 ACSS, 161 KV	2032 amps	567 MVA
Single 795 kcm 26/7 ACSR, 230 KV	1286 amps	512 MVA

Conductor	**Winter (April 30) Thermal Ampacity Rating**	**Winter (April 30) Thermal MVA Rating**
Single 795 kcm 26/7 ACSS, 230 KV	1819 amps	725 MVA
Single 954 kcm 54/7 ACSS, 230 KV	2032 amps	809 MVA
Twin bundled 795 kcm 26/7 ACSR, 345 KV	2572 amps	1537 MVA
Twin bundled 954 kcm 54/7 ACSS, 345 KV	4064 amps	2428 MVA
Triple bundled 954 kcm 54/7 ACSS, 500 KV	6096 amps	5279 MVA
Triple bundled conductor as used on the Forbes – Chisago 500 KV line (Triple bundled 1192.5 kcm 45/7 ACSR)	4875 amps	4222 MVA

Surge Impedance

The following table shows typical ranges of surge impedances found on the CapX2020 member systems. Designs for the proposed CapX2020 transmission lines are not far enough along to provide more accurate surge impedances for these lines.

Conductor Configuration	**Surge Impedance**
Single Bundled Conductor – 115, 161 & 230 KV Configurations a, b, f & h	350 – 375 Ohms
Twin bundled Conductor - 115 KV Configurations c & d	250 - 300 Ohms
Twin bundled Conductor - 345 KV Configurations k & l	270 –285 Ohms
Triple bundled Conductor - 500 kV Configuration n	250 – 300 Ohms
Configurations e, g, i, j and m	Not Used

Response By:	Brad Hill/David K. Olson
Title:	Principal Specialty Engineer
Department:	Transmission Engineering/Substation Engineering
Company:	Xcel Energy
Telephone:	612-330-6826/612-330-5909
Date:	April 21, 2008

2157846v1

EXHIBIT C

Applicant Magnetic Field Calculations

Table 3.6-2: Calculated Magnetic Fields for Proposed 345kV Transmission Line Designs
Hampton-LaCrosse Project RoutingApplication p. 3-28 - 3-29

Table 3.6-2:
Calculated Magnetic Fields (mG) for Proposed 345 kV Transmission Line Designs (3.28 Feet Aboveground)

Structure Type	Geographical Segment	System Condition	Current (amps)	-300	-200	-100	-75	-50	0	50	75	100	200	300
Single- Pole Davit Arm 345/345 kV Double-Circuit with one Circuit In Service	Preferred Route: Hampton to Cannon Falls; Non-US-52 segments Zumbrota area to North Rochester Alternate Route: Hampton to North Rochester	2015 Peak	140 A	0.38	0.79	2.35	3.41	5.24	13.58	9.64	5.88	3.77	1.04	0.46
		2015 Average	112 A	0.30	0.63	1.88	2.73	4.19	10.87	7.71	4.71	3.01	0.83	0.37
		2025 Peak	132 A	0.36	0.74	2.22	3.22	4.94	12.81	9.09	5.55	3.55	0.98	0.43
		2025 Average	106 A	0.29	0.60	1.78	2.58	3.97	10.29	7.30	4.45	2.85	0.79	0.35
Single-Pole Davit Arm 345/345 kV with 69 kV Underbuild with 1 Active 345 kV Circuit	Preferred Route: US-52 segments Cannon Falls to Zumbrota area	2015 Peak	140/325	0.74	1.65	6.20	10.42	20.73	70.89	8.50	3.77	2.51	1.01	0.52
		2015 Average	112/260	0.59	1.32	4.96	8.33	16.58	56.71	6.80	3.02	2.01	0.81	0.41
		2025 Peak	132/328	0.73	1.62	6.14	10.36	20.71	71.85	8.89	3.92	2.54	0.99	0.50
		2025 Average	106/262	0.58	1.30	4.91	8.28	16.55	57.37	7.09	3.12	2.03	0.79	0.40
Single-Pole Davit Arm 345/345 kV Double-Circuit with one Circuit in Service	N. Rochester to Alma	2015 Peak	403 A	1.12	2.33	6.97	10.11	15.54	40.27	28.58	17.44	11.17	3.09	1.35
		2015 Average	322 A	0.87	1.81	5.41	7.85	12.06	31.24	22.17	13.53	8.67	2.40	1.05
		2025 Peak	415 A	1.12	2.33	6.97	10.11	15.54	40.27	28.58	17.44	11.17	3.09	1.35
		2025 Average	332 A	0.90	1.87	5.57	8.09	12.43	32.21	22.86	13.95	8.94	2.47	1.08

Table 3.6-2:
Calculated Magnetic Fields (mG) for Proposed 345 kV Transmission Line Designs (3.28 Feet Aboveground)

Structure Type	Geographical Segment	System Condition	Current (amps)	-300	-200	-100	-75	-50	0	50	75	100	200	300
Single-Pole Davit Arm 161 kV Single-Circuit	N. Rochester to Northern Hills	2015 Peak	95 A	0.20	0.43	1.50	2.42	4.39	14.29	5.41	2.79	1.65	0.42	0.18
		2015 Average	76 A	0.16	0.34	1.20	1.94	3.51	11.43	4.33	2.23	1.32	0.33	0.14
		2015 Peak	96 A	0.20	0.43	1.52	2.45	4.43	14.44	5.47	2.82	1.66	0.42	0.18
		2015 Average	77 A	0.16	0.34	1.22	1.96	3.56	11.58	4.38	2.26	1.33	0.34	0.15

EXHIBIT D

McKay Magnetic Field Calculations

Calculated Magnetic Field Tables for Proposed 345 kV Transmission Line Designs

STEP 1

THIS TABLE CONTAINS THE COLUMN HEADINGS AND DATA FROM THE TOP ENTRY IN THE TABLE FROM EXHIBIT C

TABLE 3.6-2:

Calculated Magnetic Fields (mG) for Proposed 345 kV Transmission Line Designs (3.28 Feet Aboveground)

STRUCTURE TYPE	GEOGRAPHICAL SEGMENT	SYSTEM CONDITION	CURRENT (AMPS)	-300'	-200'	-100'	-75'	-50'	0'	50'	75'	100'	200'	300'
SINGLE- POLE	PREFERRED ROUTE:	2015 PEAK	140.00	0.38	0.79	2.35	3.41	5.24	13.58	9.64	5.88	3.77	1.04	0.46
DAVIT ARM	HAMPTON TO	2015 AVERAGE	112.00	0.30	0.63	1.88	2.73	4.19	10.87	7.71	4.71	3.01	0.83	0.37
345/345 kV DOUBLE-	CANNON FALLS;													
CIRCUIT WITH ONE CIRCUIT	NON-US-52													
IN SERVICE	SEGMENTS													
	ZUMBROTA AREA TO													
	NORTH ROCHESTER													
	ALTERNATE ROUTE:													
	HAMPTON TO NORTH													
	ROCHESTER													

STEP 2

MVA CALCULATED FROM THE CURRENTS IN TABLE 3.6-2:

345.00	kV
140.00	Amps PEAK ESTIMATED
1.73	3 Phase
83.56	MVA PEAK CALCULATED
345.00	kV
112.00	Amps AVERAGE ESTIMATED
1.73	3 Phase
66.85	MVA AVERAGE CALCULATED

STEP 4- SINGLE CIRCUIT

THIS TABLE CONTAINS DATA SCALED FROM THE TABLE IN STEP 1 USING CURRENTS CALCULATED IN STEP 3- SINGLE CIRCUIT

TABLE 3.6-2 SCALED for SINGLE CIRCUIT DESIGN CAPACITY:

Calculated Magnetic Fields (mG) for Proposed 345 kV Transmission Line Designs (3.28 Feet Aboveground)

STRUCTURE TYPE	GEOGRAPHICAL SEGMENT	SYSTEM CONDITION	CURRENT (AMPS)	-300'	-200'	-100'	-75'	-50'	0'	50'	75'	100'	200'	300'
SINGLE- POLE	PREFERRED ROUTE:	2015 PEAK	1852.22	5.03	10.45	31.09	45.11	69.33	179.67	127.54	77.79	49.88	13.76	6.09
DAVIT ARM	HAMPTON TO	2015 AVERAGE	1481.78	3.97	8.34	24.87	36.12	55.43	143.81	102.00	62.31	39.82	10.98	4.90
345/345 kV DOUBLE-	CANNON FALLS;													
CIRCUIT WITH ONE CIRCUIT	NON-US-52													
IN SERVICE	SEGMENTS													
	ZUMBROTA AREA TO													
	NORTH ROCHESTER													
	ALTERNATE ROUTE:													
	HAMPTON TO NORTH													
	ROCHESTER													

STEP 3- SINGLE CIRCUIT

CURRENT CALCULATED FROM SINGLE CIRCUIT MVA DESIGN CAPACITY:

1105.50	*MVA PEAK DESIGN
345.00	kV
1.73	3 Phase
1852.22	Amps PEAK CALCULATED
884.40	**MVA AVERAGE DESIGN
345.00	kV
1.73	3 Phase
1481.78	Amps AVERAGE CALCULATED

STEP 4- DOUBLE CIRCUIT

THIS TABLE CONTAINS DATA SCALED FROM THE TABLE IN STEP 1 USING CURRENTS CALCULATED IN STEP 3- DOUBLE CIRCUIT

TABLE 3.6-2 SCALED for DOUBLE CIRCUIT DESIGN CAPACITY:

Calculated Magnetic Fields (mG) for Proposed 345 kV Transmission Line Designs (3.28 Feet Aboveground)

STRUCTURE TYPE	GEOGRAPHICAL SEGMENT	SYSTEM CONDITION	CURRENT (AMPS)	-300'	-200'	-100'	-75'	-50'	0'	50'	75'	100'	200'	300'
SINGLE- POLE	PREFERRED ROUTE:	2015 PEAK	3704.45	10.05	20.90	62.18	90.23	138.65	359.33	255.08	155.59	99.76	27.52	12.17
DAVIT ARM	HAMPTON TO	2015 AVERAGE	2963.89	7.94	16.67	49.75	72.24	110.88	287.66	204.03	124.64	79.65	21.96	9.79
345/345 kV DOUBLE-	CANNON FALLS;													
CIRCUIT WITH ONE CIRCUIT	NON-US-52													
IN SERVICE	SEGMENTS													
	ZUMBROTA AREA TO													
	NORTH ROCHESTER													
	ALTERNATE ROUTE:													
	HAMPTON TO NORTH													
	ROCHESTER													

STEP 3- DOUBLE CIRCUIT

CURRENT CALCULATED FROM DOUBLE CIRCUIT MVA DESIGN CAPACITY:

2211.00	*MVA PEAK DESIGN
345.00	kV
1.73	3 Phase
3704.45	Amps PEAK CALCULATED
1769.00	**MVA AVERAGE DESIGN
345.00	kV
1.73	3 Phase
2963.89	Amps AVERAGE CALCULATED

NOTES:
1. MVA = (kV * Amps * 1.73) /1000
2. Amps = (MVA * 1000) / (kV * 1.73)
3. For a given physical and electrical configuration, milligauss at one location is proportional to current (Amps) (for example, double the current and the milligauss level also doubles).
4. For a given physical and electrical configuration and constant current, the milligauss level changes as the inverse square of the distance from away from the source (for example, move 2 times as far away and the milligauss level decreases to 1/4 of what it was).

*. MVA PEAK DESIGN CAPACITY IS FROM A COMBINATION OF THE DATA PRESENTED IN EXHIBITS A, B, AND C.

**. MVA AVERAGE DESIGN CAPACITY WAS CHOSEN TO BE ABOUT 80% OF PEAK DESIGN CAPACITY

ATTACHMENT 52b-1

Public Version

AMERICAN TRANSMISSION COMPANY
THE ENERGY ACCESS COMPANY

Western Wisconsin Transmission Reliability Study

Final Report

September 20, 2010

By:
Sonja Golembiewski
Patrick Shanahan
Nate Wilke

Approved By:
Flora Flygt
Director of Strategic Projects

Transmission – Transmission Planning Analysis
Attachment FF- ATCLLC of the
Midwest ISO Tariff

Study Participants

American Transmission Company, LLC
Sonja Golembiewski, Chris Hagman, Kerry Marinan,
Patrick Shanahan, Damien Sommer, Nate Wilke, Wenchun Zhu

Dairyland Power Cooperative
Steve Porter, Terry Torgerson

Xcel Energy
Jason Espeseth, Amanda King, Jason Standing, Warren Hess

International Transmission Company, Midwest
Joe Berry, Jeff Eddy

Great River Energy
Jay Porter

CapX2020
Jared Alholinna,

Southern Minnesota Municipal Power Agency
Richard Hettwer

Midwest ISO
Liangying (Lynn) Hecker
Ming Ni

Table of Contents

EXECUTIVE SUMMARY

This Transmission Study assesses the reliability needs of the western Wisconsin area, shown in Figure I, which has unique reliability-related characteristics. It includes several load centers such as Rochester, Minneapolis and St. Paul in Minnesota, La Crosse, Eau Claire, Madison, Stevens Point, Wisconsin Rapids and Wisconsin Dells in Wisconsin, and Dubuque in Iowa. This Transmission Study is part of a larger "combination of benefits" analysis that takes into account the reliability needs of the study area through this study, the economic savings created by the projects under study and the public policy benefits that would be created by these options.

The transmission facilities located in western Wisconsin are important to reliably serve load and to facilitate reliable power transfers between and through these upper Midwest states. The reliable operation of the existing transmission facilities can be impacted by heavy power through-flows in various directions especially the flow of power from west to east, often referred to as the "west to east bias." This flow bias causes additional stress to the area's transmission network. The west to east transfer capability of the existing transmission facilities through the Minnesota-Wisconsin Export (MWEX) interface is presently limited due to voltage stability and transient voltage recovery limitations. Wind-powered generation has been and will continue to be added in the upper Midwest to meet state Renewable Portfolio Standard (RPS) requirements in the geographical region and beyond. These generation additions will most likely increase the levels of the west to east flows, particularly during off-peak load periods.

The purpose of the Western Wisconsin Transmission Reliability Study is to identify and document the reliability needs in the western Wisconsin area in the eight- to ten-year-out time frame and also to evaluate the extent to which different transmission options would meet these needs using various reliability measures.

The steady-state power flow analyses used three 2018 Summer Peak and Off-peak (70% peak load) models. The existing, planned and future wind generation included in the Midwest ISO (MISO) region in the study models is 13,277 MW. Total wind generation included in North Dakota (ND) and South Dakota (SD) within the MISO region is 583 MW. Total wind generation included in Minnesota (MN), Iowa (IA) and Wisconsin (WI) within the MISO region is 10,006 MW, which is approximately the amount of wind needed to meet the RPS requirements of the Minnesota, Wisconsin and Iowa in 2020[1]. The steady-state power flow analyses include power flow AC contingency analysis, First Contingency Incremental Transfer Capability (FCITC) analysis and Power-Voltage (PV) stability analysis. The study also includes a transient stability analysis using a 2014 light load model.

This study includes two phases: the initial screening and the detailed analysis. The initial screening evaluated the base case and 15 different transmission options using AC contingency analysis. Options that did not have significant and positive impact on the reliability of the

[1] Based on Midwest ISO Regional Generation Outlet Study (RGOS) Phase I & II survey data (with modifications to correct the data anomalies identified by American Transmission Company, LLC) .

western Wisconsin study area were excluded from further detailed analysis. Of the 15 different transmission options that were initially evaluated, seven provided sufficient impact on the reliable operation of the transmission system in the study cases to warrant further detailed evaluation. These are the seven transmission options evaluated in detail:

- Option 1: North La Crosse – Hilltop – Spring Green – Cardinal 345 kV project
- Option 1a: North La Crosse – Spring Green – Cardinal 345 kV project
- Option 1b: North La Crosse – North Madison – Cardinal 345 kV project
- Option 8: Dubuque – Spring Green – Cardinal 345 kV project
- Option 7c: North La Crosse – North Madison – Cardinal and
  Dubuque – Spring Green – Cardinal 345 kV projects
- Low Voltage Option: a collection of 69 kV, 138 kV and 161 kV facilities
- 765 kV Option: Genoa – North Monroe 765 kV project and supporting 345kV[2]

Full descriptions of the seven transmission options studied in the detailed analysis can be found in Appendix A. Three of the options (Options 1, 1a, and 1b) connect to the CapX2020 [3] "Group 1" Hampton Corners – North La Crosse 345 kV line, which has a targeted in-service date between 2013 and 2015, to the Cardinal substation (formerly named West Middleton) in Middleton, Wisconsin, forming network interconnections with the 345 kV facilities in the Madison area. Hilltop is an existing substation in the ATC area with multiple 69 kV lines.

The results as summarized in Table ES-1 show that the Low Voltage Option has the lowest rankings for all aspects of the reliability performance evaluated using non-monetized measures. These aspects include system voltage performance under Category B and C contingencies, severe local low voltages under a Category C2 contingency, voltage stability and robustness and system transient stability. These rankings are further described within the report at their respective sections.

[2] As stated in Appendix A , supporting 345kV facilities for the 765kV option include a N. LaCrosse-Genoa 345kV, Adams-Genoa 345 kV, double circuit N. Monroe-Paddock 345 kV lines and transformers at Genoa and N. Monroe
[3] CapX2020 is a joint initiative of 11 transmission-owning utilities in Minnesota and the surrounding region to expand the electric transmission grid to ensure continued reliable and affordable service. www.capx2020.com

Table ES.1 – Summary of non- monetized reliability performance measures

Rankings of benefits not captured by cost analysis (1=Lowest, 5=Highest)	Low Voltage	NLAX-HLT-SPG-CDL (1)	NLAX-SPG-CDL (1a)	NLAX-NMA-CDL (1b)	DBQ-SPG-CDL (8)	NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	Genoa-NOM 765 kV
Voltage performance under Cat-B contingencies	1	4	4	4	4	5	3
Voltage performance under converged Cat-C contingencies	1	5	4	3	4	5	2
Alleviate Cat-C2 severe local low voltages	1	5	5	1	5	5	1
Support voltage stability and robustness	1	3	2	2	3	5	4
Support system transient stability	1	3	1	4	1	5	1

For these aspects, the Low Voltage Option consistently performs at inferior levels compared to the EHV options. As shown in Table ES.2 below, for the reliability aspects evaluated using the monetized measure, the Low Voltage Option is less costly than the EHV options. However, because of their advantages in supporting system voltages, voltage stability and transient stability, the EHV options are preferred over the Low Voltage Option.

The 765 kV Option would represent the first 765 kV element in the western Wisconsin area. The results show that the overall reliability rankings are lower for the 765 kV Option than the 345 kV options for those aspects evaluated using non-monetized measures. For the reliability aspects evaluated using the monetized measure, the 765 kV Option is shown to have the highest cost.

Three of the seven options are in the corridor between North LaCrosse to Madison. These options (Options 1, 1a, and 1b) are comparable from an overall reliability performance perspective and Option 1b (North LaCrosse-North Madison-Cardinal) has the lowest overall cost of the three options. A 345kV line in this corridor provides the voltage stability and interconnection to Minnesota which is one of the desired benefits of this study.

Option 8 (Dubuque-Spring Green-Cardinal) also performs well from a reliability perspective. It has a slightly lower cost than Option 1b (North LaCrosse-North Madison-Cardinal) but does not provide the transient stability that is desired. Option 7c – the combination North La Crosse-North Madison-Cardinal and Dubuque-Spring Green-Cardinal 345 kV project – performed the best across all aspects of the reliability analyses. Option 7c also provides additional benefits over and above the single 345 kV options such as providing the highest level of transfer capability for wind generation in Minnesota and Iowa.

The conclusion of this study is that Option 7c provides the most reliability benefit to the western Wisconsin area; Option 1b provides a portion of the benefit realized in Option 7c and includes the additional interconnection to Minnesota. Option 8 provides significant reliability benefits to western Wisconsin as well but not the needed reinforcements for Minnesota

The transmission maps of the western Wisconsin study area, and Options 1b and 7c are shown in Figures I, II and III. Transmission maps for all studied options can be found in Appendix B.

The summary presented below in Table ES-2 is also found in Section 6, Conclusions.

Finally, it is critical to note that this study evaluates only the reliability benefits of the projects under study. It does not take into account any other benefits of these options, including energy and loss savings, and other economic and policy benefits such as the ability to integrate and deliver renewable energy. ATC believes that the total combination of benefits versus costs, as well as information from the Midwest ISO's Regional Generator Outlet Study, should be taken into account in making a choice to pursue any of the options listed above. ATC has been analyzing the combined reliability, economic, and policy benefits of these options for approximately two years and has determined that a 345 kV project from the La Crosse area to the greater Madison area (the Badger Coulee Project) would provide multiple benefits. ATC has recently announced its intention to finalize its evaluation of these combined benefits and to begin public outreach on the Badger Coulee Project.[4]

[4] Further information about this announcement is located at: http://www.atc-projects.com/BadgerCoulee.shtml

Table ES.2 – Summary of the comparisons of the reliability performance using monetized measures

Summary of project costs in 2010 dollars			Low Voltage	NLAX-HLT-SPG-CDL (1)	NLAX-SPG-CDL (1a)	NLAX-NMA-CDL (1b)	DBQ-SPG-CDL (8)	NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	Genoa-NOM 765 kV
EHV projects			**Opt LV**	**Opt1**	**Opt1a**	**Opt1b**	**Opt8**[1]	**Opt7c**	**Opt 765**
			$0	$454,492,920	$377,454,200	$357,590,989	$304,187,200	$672,785,400	$880,598,000
Category B Supporting Facilities	**Loading**	**ATC Facilities**	$173,768,164	$118,661,663	$131,603,921	$119,001,306	$101,420,588	$86,326,549	$136,878,643
	Loading	**Non-ATC Facilities**	$95,397,350	$38,281,800	$52,036,800	$69,696,850	$103,972,600	$57,625,100	$43,168,200
		Total	**$269,165,514**	**$156,943,463**	**$183,640,721**	**$188,698,156**	**$205,393,188**	**$143,951,649**	**$180,046,843**
Category C Supporting Facilities	**Loading**	**ATC Facilities**	$0	$0	$0	$0	$0	$0	$0
	Voltage	**ATC Facilities**	$82,758,813	$0	$0	$0	$0	$0	$0
	Loading	**Non-ATC Facilities**	$0	$0	$0	$0	$0	$0	$0
	Voltage	**Non-ATC Facilities**	$0	$0	$0	$0	$0	$0	$0
		Total	**$82,758,813**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Category B & C Supporting Facilities		**ATC Facilities**	$256,526,977	$118,661,663	$131,603,921	$119,001,306	$101,420,588	$86,326,549	$136,878,643
		Non-ATC Facilities	$95,397,350	$38,281,800	$52,036,800	$69,696,850	$103,972,600	$57,625,100	$43,168,200
		Total	**$351,924,327**	**$156,943,463**	**$183,640,721**	**$188,698,156**	**$205,393,188**	**$143,951,649**	**$180,046,843**
Total cost estimates for project packages (main + support)			**$351,924,327**	**$611,436,383**	**$561,094,921**	**$546,289,145**	**$509,580,388**	**$816,737,049**	**$1,060,644,843**

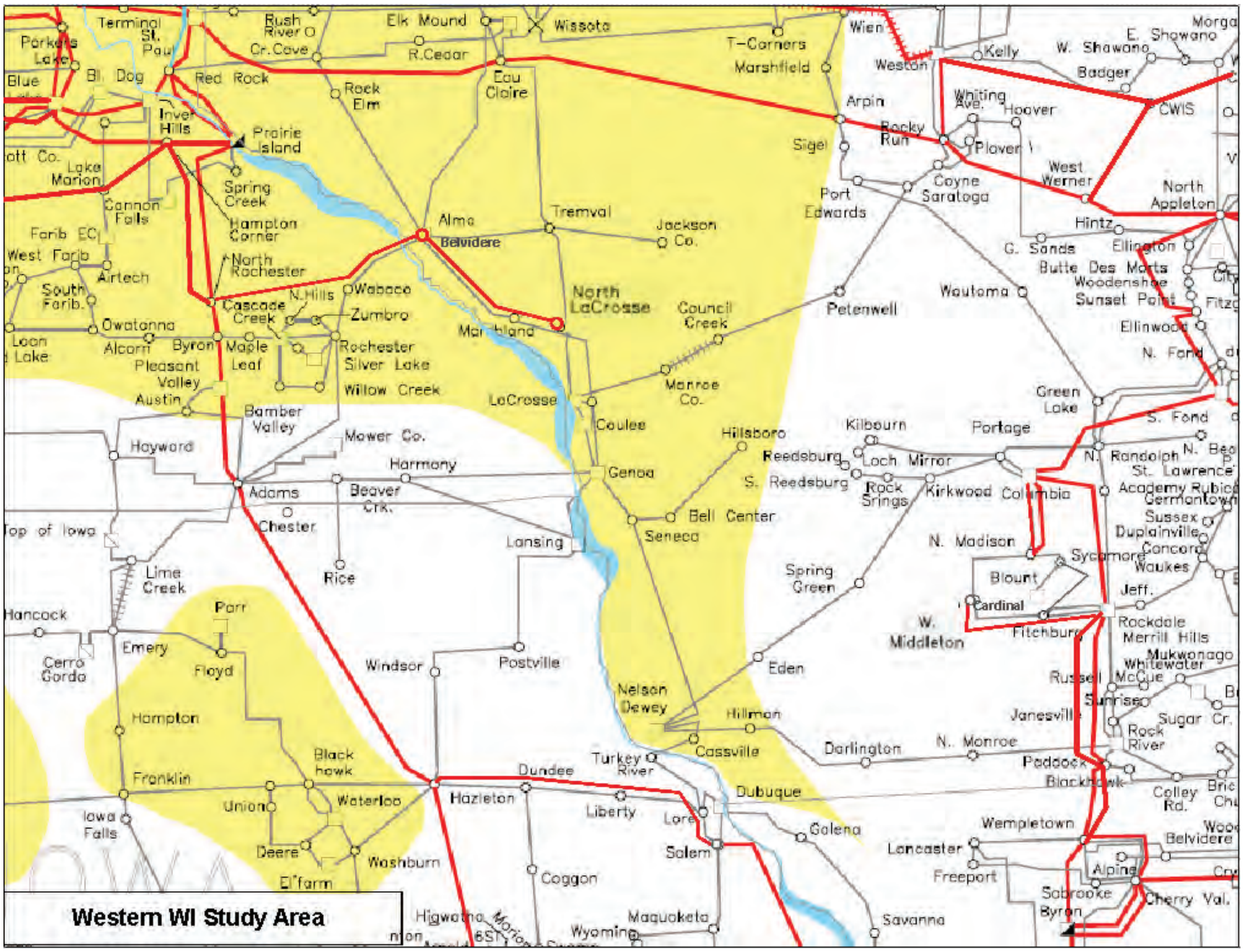


Figure I – Western Wisconsin study area[5]

[5] Yellow shaded area on Option maps represents the Mid-Continent Area Power Pool (MAPP) region.

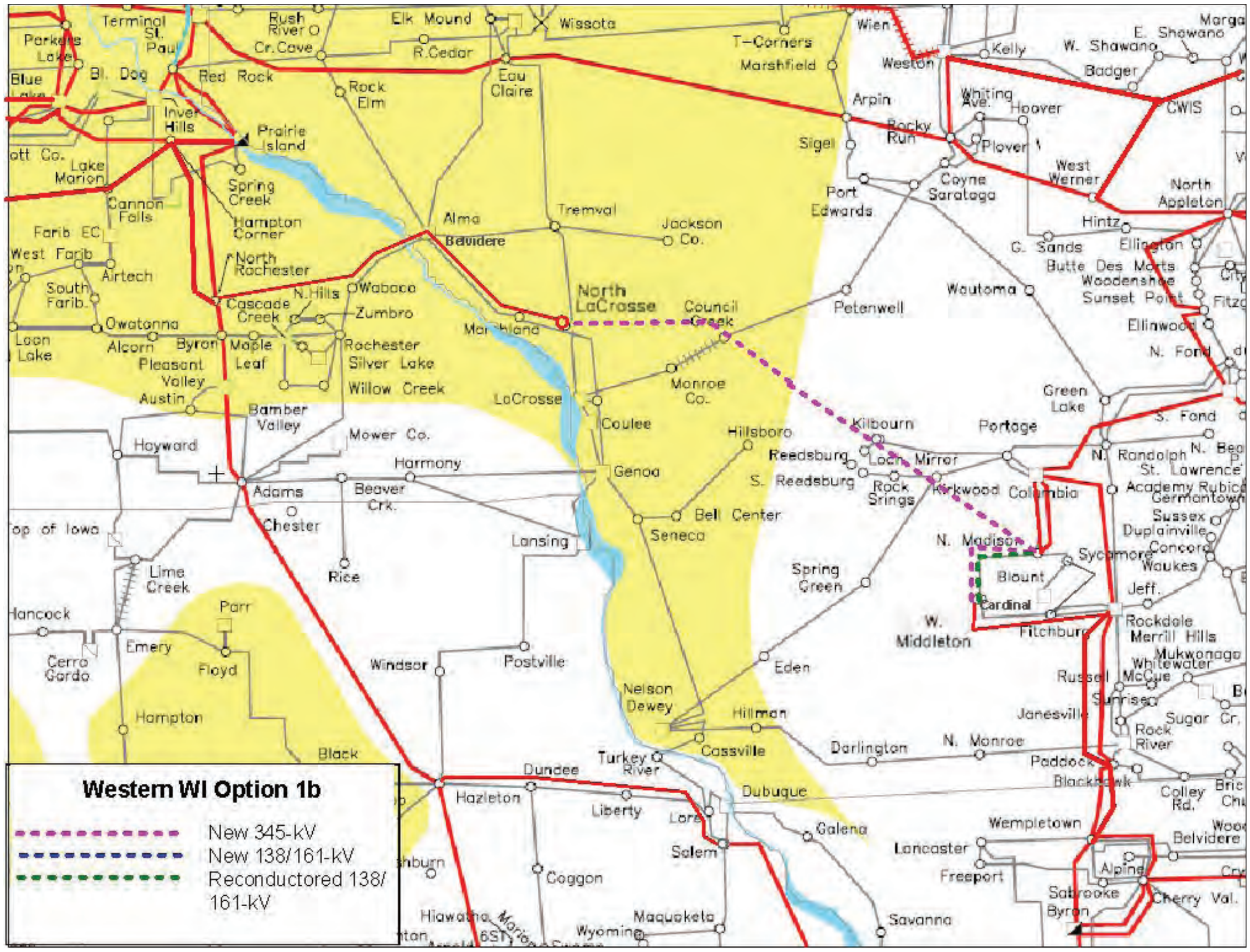


Figure II – North La Crosse - North Madison – Cardinal 345 kV project (Option 1b)[6]

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[6] Yellow shaded area on Option maps represents the Mid-Continent Area Power Pool (MAPP) region.

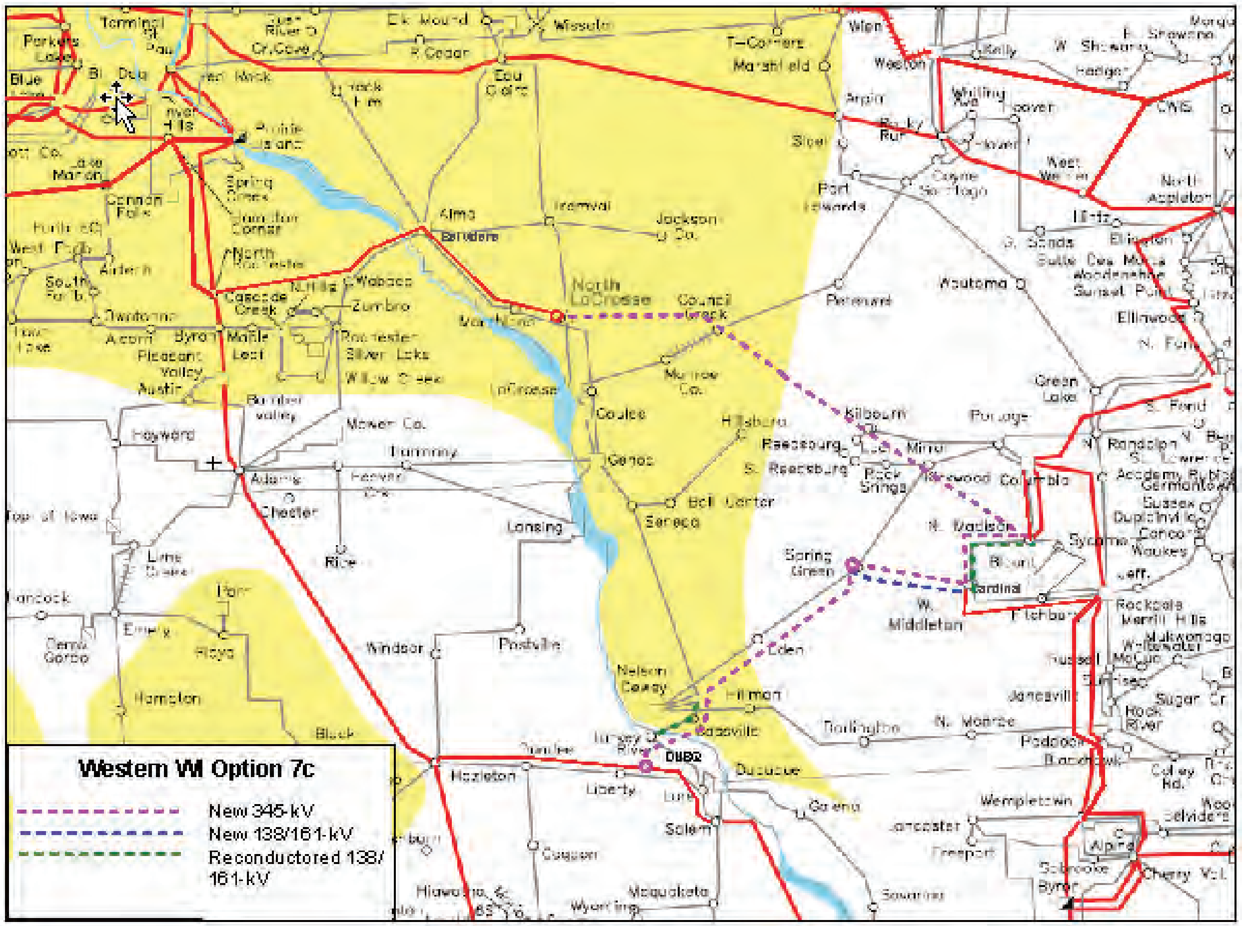

Figure III – North La Crosse-North Madison-Cardinal and Dubuque-Spring Green-Cardinal 345 kV project (Option 7c)[7]

[7] Yellow shaded area on Option maps represents the Mid-Continent Area Power Pool (MAPP) region.

1. Introduction

1.1 Background

The CapX2020 Group I project Hampton Corners – North Rochester – North La Crosse 345 kV line (targeted in-service date 2013 – 2015) addresses the load serving needs in the Rochester and La Crosse areas. It was anticipated that extending this 345 kV line to interconnect with the existing Wisconsin 345 kV network will be beneficial to regional reliability as well as the western Wisconsin area.

The western Wisconsin area, shown in Figure I, has unique characteristics. It includes several load centers such as Rochester, Minneapolis and St. Paul in Minnesota; La Crosse, Eau Claire Madison, Stevens Point, Wisconsin Rapids and Wisconsin Dells in Wisconsin; and Dubuque in Iowa. The western Wisconsin area interconnects the transmission network between Minnesota, Iowa and Wisconsin. A robust transmission network in the area is important to reliably serve the load and also to facilitate reliable power transfers between and through these upper Midwest states.

The western Wisconsin area can be impacted by heavy power flows in various directions; particularly well noted is the west to east flow bias. These flow biases cause additional stress to the area's transmission network. The west to east transfer through the Minnesota-Wisconsin Export (MWEX) interface is currently limited due to voltage stability and transient voltage recovery limitations. Wind-powered generation has been and will continue to be added in the upper Midwest to meet the state Renewable Portfolio Standard (RPS) requirements in the geographical region and beyond. These additions will most likely increase the levels of the west to east flows, particularly during off-peak load periods.

The purpose of the Western Wisconsin Transmission Reliability Study is to identify and document the reliability needs in the eight- to 10-year time frame and also to identify potential transmission solutions to meet the reliability needs.

Several Transmission Owners (TOs) whose existing transmission facilities could be potentially impacted by transmission additions in the western Wisconsin area initiated a joint transmission reliability study. The study is led by American Transmission Company, LLC (ATC). The following Transmission Owners and the Midwest ISO participated in the study:

CapX2020 (CapX)
Dairyland Power Cooperative (DPC)
Great River Energy (GRE)
International Transmission Company, Midwest (ITCM)
Southern Minnesota Municipal Power Agency (SMMPA)
Xcel Energy (Xcel)

The TO group coordinated the model building efforts with the Midwest ISO. The Midwest ISO assisted in creating the Security Constrained Economic Dispatches (SCED) for the study models. Also, it should be noted that the study participants collaborated on this regional transmission planning study in accordance with the regional planning coordination requirement of FERC Order No. 890[8] and in accordance with ATC's planning requirements under Attachment FF-ATCLLC of the Midwest ISO Tariff.[9]

1.2 Scope

This reliability study includes AC power flow contingency analysis of NERC Category A, Category B and Category C contingencies; First Contingency Incremental Transfer Capability (FCITC) analysis to identify thermal constraints under increasing levels of west to east transfers; P-V voltage stability analysis to evaluate voltage stability and robustness under increasing levels of west to east transfers; transient stability analysis; and an analysis of the estimated comparative costs of the transmission options. The three study models used for steady state power flow analysis are 2018 Summer Peak, 2018 Summer Off-peak (70% Load) with 35-45% wind output, and 2018 Summer Off-peak (70% Load) with 90% wind output. The transient stability analysis used a 2014 light load model.

1.3 Studied Options

This study includes two phases: the initial screening and the detailed analysis. The initial screening evaluated the base case and 15 different transmission options using AC contingency analysis. These options are listed in Table 1.1. Further details of all studied transmission options can be found in Appendix A. The transmission maps for all studied options are included in Appendix B.

The initial screening showed that some of the options did not have notable impact on the western Wisconsin study area and these options were excluded from further detailed analysis. Options that were evaluated in further detail are highlighted in yellow in Table 1.1.

[8] *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119 (2007) at PP 523 and 528. FERC put in place the "Regional Participation" principle that states that "each transmission provider will be required to coordinate with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources..." The coordinated regional planning must "address both reliability and economic considerations."

[9] Midwest ISO FERC Electric Tariff, Fourth Revised Volume No. 1, Original Sheet No. 3387

Table 1.1 – List of studied options

Option #	Option Name
Opt 1	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV project
Opt 1a	North La Crosse–Spring Green–Cardinal 345 kV project
Opt 1b	North La Crosse–North Madison–Cardinal 345 kV project
Opt 8	Dubuque–Spring Green–Cardinal 345 kV project
Opt 7c	North La Crosse-North Madison-Cardinal 345 kV and Dubuque-Spring Green-Cardinal 345 kV project
Opt 765	Genoa–North Monroe 765 kV project
Opt LowV	Low Voltage option
Opt 2	North La Crosse-Dubuque 345 kV project
Opt 2a	North La Crosse-Genoa-Dubuque 345 kV project
Opt 3	Eau Claire-North La Crosse 345 kV project
Opt 4	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV and Eau Claire-North La Crosse 345 kV project
Opt 5	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV and North La Crosse-Dubuque 345 kV project
Opt 6	North La Crosse-North Cassville-Dubuque 345 kV and North Cassville-Spring Green-Cardinal 345 kV project
Opt 7	North La Crosse-Hilltop-Spring Green-Cardinal 345 kV and Dubuque-Spring Green 345 kV project
Opt 7a	North La Crosse-Spring Green-Cardinal 345 kV and Dubuque-Spring Green 345 kV project
Opt 7b	North La Crosse-Spring Green-Cardinal 345 kV and Dubuque-Spring Green-Cardinal 345 kV project

2. Study Assumptions, Methodology and Criteria

2.1 Steady State Power Flow Analyses

Study Models

The base models (starting points) for the steady state power flow analyses are the 2018 summer peak and off-peak models developed for the Midwest ISO Transmission Expansion Plan 2008 (MTEP08). The model is described in MTEP08 report in the following manner: "The regional resource forecasted units developed for the Reference Generation Portfolio future" (through the first two steps in the MTEP08 economic study process) "are sited in the models. The 2018 off peak model has 70% of summer peak load level in Midwest ISO footprint and has the same transmission topology as the 2018 summer peak model. Generation dispatch in Midwest ISO footprint was based on Security Constrained Economic Dispatch (SCED) to mitigate all possible N-1 constraints in Midwest ISO 200 kV and above systems. Wind generation in the Midwest ISO footprint is dispatched at 15% of its capacity in 2018 summer peak model and 100% of its capacity in 2018 off peak model."[10]

System topologies and load in the original models were updated for the western Wisconsin study area. The non-wind types of future/conceptual generating units sited inside the study area were removed. The following three study models were created including the Security Constrained Economic Dispatches (SCED) that was created. The Minnesota-Wisconsin Export Interface (MWEX) flow, the ATC western interface flow, the MRO export and the ATC import in these three study models are as follows:

- 2018 Summer Peak (SUPK)
  - Wind generation at 20% of nameplate capacity
  - MWEX interface = 485 MW
  - ATC Western Interface = 540 MW Import
  - MRO Export = 1175 MW
  - ATC Import = 1218 MW
- 2018 Summer Off-peak (70% of peak load) (SUOP)
  - Wind generation at 35-45% of nameplate capacity (45% in ND, SD, MN and IA; 35% for the rest of the MISO region)
  - MWEX interface = 928 MW
  - ATC Western Interface = 1330 MW Import
  - MRO Export = 1150 MW
  - ATC Import = 1318 MW
- 2018 Summer Off-peak (70% of peak load) with 90% wind output (SUOP90)
  - Wind generation at 90% of nameplate capacity
  - MWEX interface = 1029 MW
  - ATC Western Interface = 1440 MW Import
  - MRO Export = 1585 MW
  - ATC Import = 1263 MW

[10] MTEP08 Report, Section 4.3.2 http://www.midwestiso.org/page/Expansion+Planning

It can be observed that the west to east flows through the MWEX interface and the ATC western interface are higher in the off-peak cases than in the summer peak case. Also, the west to east flows are higher in the 90% wind output case than in the 35-45% wind output case. Since many wind units are located in the western part of the Midwest ISO region, increasing wind unit output resulted in increased west to east flows. Note that the above documented west to east flows are for the base cases without addition of any studied transmission options. It was observed that with the addition of a 345 kV or 765 kV option, the west to east flow through the ATC western interface increases, although in general flows on the existing facilities of the interface are reduced to a certain extent.

The total amount of existing, planned and future wind generation included in the study models is 13,277 MW for the Midwest ISO region. Most of the wind units are sited in the western part of the Midwest ISO region. Table 2.1 summarizes total wind generation by locations within the Midwest ISO region included in the study models. Table 2.2 summarizes the locations and sizes of the future wind units in Minnesota, Iowa and Wisconsin within the Midwest ISO region included in the study models. The existing, planned and future wind units in the western part of the Midwest ISO region are also marked on a transmission map as shown in Figure 2.1.

Table 2.1 – 2018 wind generation included in the Midwest ISO region

Location	**Wind generation, MW**
SD	0
ND	583
IA	2,401
WI	2,823
MN	4,782
Sub-total for study area	**10,006**
Total in MISO region	**13,277**

Table 2.2 – Future wind units included in the Midwest ISO region

Substation	**Control Area**	**Wind generation MW**
Burlington 138 kV	WEC 295	100
Hillman 138 kV	ALTE 694	100
Rocky Run 345 kV	WPS 696	300
South Fond du Lac 345 kV	ALTE 694	800
Adams 345 kV	XEL 600	1000
Wilmarth 345 kV	XEL 600	500
Lakefield 345 kV	ITCM 627	400
Magnolia 161 kV	ITCM 627	350
Total		**3550**

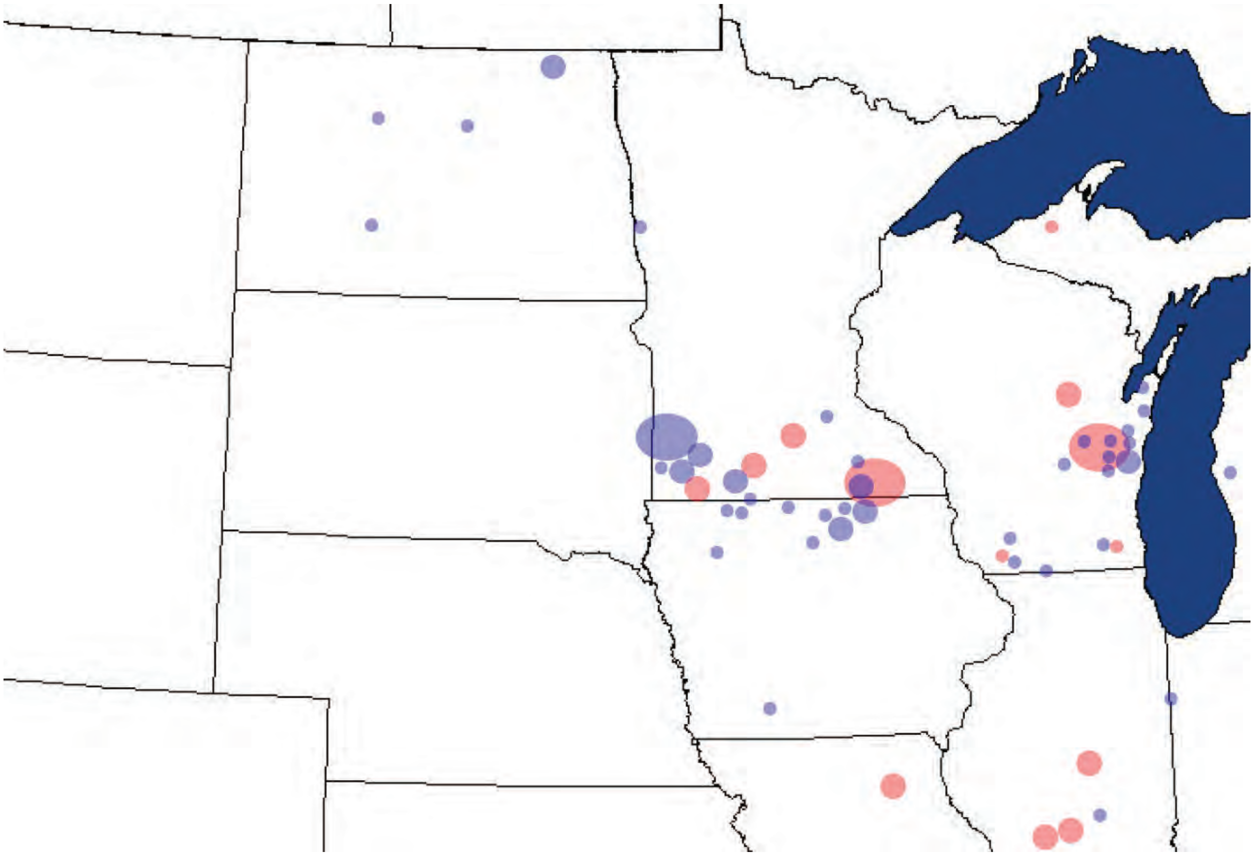

Figure 2.1 – Existing, planned and future wind generation included in the study models for the western part of the MISO region
Blue = existing/proposed, Red = Conceptual
Small/Medium/Large Ovals = 0-200, 201-750, 751-1000 MW

Study Area

The study area, as shown in Figure I, is defined according to the following:

- Xcel Energy facilities from the Twin Cities south and east in Minnesota
- Xcel Energy facilities from the Hayward area south (Stone Lake Substation) in Wisconsin
- ITC Midwest facilities in southeast Minnesota and northern Iowa
- MEC facilities in northern Iowa
- DPC facilities in Minnesota, Wisconsin, Iowa and Illinois
- GRE facilities in southeast Minnesota
- SMMPA facilities in southeast Minnesota
- ATC facilities from Wausau south and west of North Appleton
- RPU facilities in Minnesota

The Monitored Facilities Subsystem includes the following facilities:

- SMMPA Zone 631 69 kV – 345 kV facilities
- SMMPA Area 613 69 kV – 345 kV facilities
- XEL-MN Zone 601 69 kV – 345 kV facilities
- XEL-WI Zone 604 69 kV – 345 kV facilities
- DPC Area 680 69 kV – 345 kV facilities
- GRE Area 615 100 kV – 345 kV facilities
- ITCM Area 627 100 kV – 345 kV facilities
- MEC Area 635 100 kV – 345 kV facilities
- ATC Zone 1696 69 kV – 345 kV facilities[11]

The Contingent Facilities Subsystem includes the following facilities:

- SMMPA Zone 631 69 kV – 345 kV facilities
- SMMPA Area 613 100 kV – 345 kV facilities
- XEL-MN Zone 601 100 kV – 500 kV facilities
- XEL-WI Zone 604 100 kV – 345 kV facilities
- DPC Area 680 100 kV – 345 kV facilities
- GRE Area 615 100 kV – 345 kV facilities
- ITCM Area 627 100 kV – 345 kV facilities
- MEC Area 635 100 kV – 345 kV facilities
- ATC Zone 1696 69 kV – 345 kV facilities
- ATC Zone 1686 230 kV – 345 kV facilities[12]
- ComEd Area 222 345 kV – 765 kV facilities

Types of Contingencies Studied

Category B contingencies:

- All contingencies specified by study participants
- All single elements defined in the Contingent Facilities Subsystem
- All 100 kV -765 kV ties to the defined Contingent Facilities Subsystem

[11] ATC Zone 1696 was defined to represent the ATC region in the western Wisconsin study area.
[12] ATC Zone 1686 includes all 230 kV and above facilities in ATC region and ties to ATC region.

Specified Category C contingencies:

- 1,141 study participant specified Category C1, C2 and C5 contingencies. Most N-2 contingencies include the outage of at least one generator.

Enumerated N-2 contingencies:

- N-2 combinations of transmission lines and transformers in Minnesota, Iowa, northern ComEd and ATC regions:
  - 5,995 northern ComEd 345 kV and above transmission line and transformer pairs.
  - 861 Iowa transmission line and transformer pairs consisting of Area 680 and 627 345 kV facilities, transformers from 345 kV to 230/161/138/115 kV and the studied transmission option segments.
  - 6,105 Minnesota transmission line and transformer pairs consisting of Area 613, 615, 680 and Zone 601 and 604 345 kV facilities, transformers from 345 kV to 230/161/138/115 kV and the studied transmission option segments.
  - 7,626 ATC region transmission line and transformer pairs consisting of ATC 345 kV facilities, ATC transformers from 345 kV to 230/161/138/115 kV and the studied transmission option segments.

Major Planned or Proposed Projects Included in the Base Models

The following major transmission line projects within or in proximity to the study area are included in the study base models[13]:

- Gardner Park – Highway22 – Werner West 345 kV (ATC)
- Highway22 – Morgan 345 kV (ATC)
- Paddock – Rockdale – Cardinal 345 kV (ATC)
- Fargo – Twin Cities 345 kV project (CapX2020)
- Hampton Corner – North Rochester – North La Crosse 345 kV (CapX2020)
- Brookings County – Lyon County – Cedar Mountain (Franklin) – Helena – Lake Marion–Hampton Corner 345 kV (CapX2020)
  - Lyon County-Cedar Mountain-Helena are double circuited
- Hazel Creek-Panther-McLeod-Blue Lake 345 kV (Minnesota “Corridor” project)
  - Double circuited, second line Hazel Creek-Blue Lake 345 kV
  - McLeod 345/115 kV Transformer #1
  - Panther 345/69 kV Transformer #1
  - Remove Hazel Creek-Minn Valley Tap 230 kV
- Byron-Pleasant Valley 161 kV (Xcel)
- Pleasant Valley 345/161/13.8 kV transformer #2 (Xcel)
- Hazelton-Salem 345 kV (ITCM)
- Arpin-Rocky Run 345 kV line rebuild (ATC)
- Monroe Co-Council Creek 161 kV (ATC)

[13]The Big Stone II 670 MW generation and transmission facilities were included in the study cases. The study cases were created before the Big Stone II generation project cancellation announcement, on November 2, 2009. Since these facilities are far away from the western Wisconsin study area, the study participants did not think removing these facilities from the study cases would have notable impact on the study results.

Study Methodology and Criteria

Siemens PTI, PSS™ MUST version 8.3.2 was used for the AC power flow contingency analysis. This software was also used for the First Contingency Incremental Transfer (FCITC) analysis. A 3% Distribution Factor (DF) threshold was used for the FCITC analysis. The PowerTech Labs VSAT program was used for voltage stability analysis. See *Section* 4 and *Section* 5 for further details of the methodologies used in various reliability analyses performed in this study. The study results were evaluated in accordance with the NERC TPL Standards. ATCs' Planning Criteria was used for this study, neighboring Transmission Owners may have a different criteria than what was evaluated in this study.

Thermal Loading Criteria: For intact system facility Normal Ratings (Rate A) were used. Under contingencies facility Emergency Ratings (Rate B) were used.

Steady State Voltage Criteria: The acceptable voltage range is 95 percent to 105 percent of nominal voltage in the intact system and 90 percent to 110 percent under contingencies.

2.2 Transient Stability Analysis

Study model

The base model (starting point) for the transient stability analysis is the MTEP09 2014 Light Load (40% of peak load) stability model and data set[14]. This model includes 6,000 MW of wind generation. The following modifications were made to the starting model to fit the purpose of this study:

- Major planned and proposed projects included in the power flow models for steady state analysis as discussed in *Section* 2.1 are also verified or included in the 2014 light load model for transient stability analysis.
- An additional 3,150 MW of future wind generation was added to the starting model. Total wind generation included in the stability model is 9,150 MW in the Midwest ISO region. The locations and sizes of the future wind generation included in the stability case are shown in Table 2.3. Part of the added wind generation was offset by re-dispatching non-wind generation in the same control areas in which the future wind generation was added. Part of the added wind generation was offset by export generation to the eastern part of the MISO region.

Table 2.3 – Future wind units added to the stability case

Substation	Control Area	Wind generation (MW)
Hillman 138 kV	ALTE 694	100
South Fond du Lac 345 kV	ALTE 694	800
Adams 345 kV	XEL 600	1000
Wilmarth 345 kV	XEL 600	500
Lakefield 345 kV	ITCM 627	400

[14] See MTEP09 Report, Section 6.1.3 for MTEP09 model building methodology. http://www.midwestiso.org/page/Expansion+Planning

Magnolia 161 kV	ITCM 627	350
Total		**3150**

Study Methodology and Criteria

The transient stability analysis was performed using the Dynamics Simulation and Power Flow modules of the Power System Simulation/Engineering-30 (PSS/E, Version 30.5.1) program from Power Technologies, Inc (PTI).

Angular Stability Criteria

Critical Clearing Time (CCT) is a period relative to the start of a fault, within which all generators in the system remain stable (synchronized). CCT is obtained from simulation. Maximum Expected Clearing Time (MECT) determines a period of time that is needed to clear a fault using the existing system facilities. MECT is dictated by the existing system facilities. In any contingency, if the computed CCT is less than the MECT plus a margin determined by a Transmission Owner, it is considered an unstable situation and is unacceptable. Otherwise, it is considered acceptable transient stability performance. The ATC Planning Criteria requires 1.0 cycle margin for studies using estimated generator data and 0.5 cycle margin for studies using confirmed generator data. The 0.5 cycle margin is applicable to the generating units in the ATC region for this study. The 1.0 cycle margin is used as a proxy for generating units outside of the ATC region. Further refinement can be made to the 1.0 cycle margin based on additional information from the TO participants.

Transient Voltage Recovery

According to ATC Planning Criteria, voltages of all transmission system buses must recover to be at least 70% of the nominal system voltages immediately after fault removal and 80% of the nominal system voltages in 2.0 seconds after fault removal. Transient voltage recovery was checked for generation units in the ATC region using this criterion. This criterion was also used as a proxy for checking generation units outside the ATC region but located in the study area. Further refinement can be made based on additional information from the Transmission Owner participants.

3. Overall Approach for the Reliability Analysis

This study includes two phases: the initial screening and the detailed analysis. The initial screening evaluates the base case and 15 different transmission options using AC contingency analysis of Category B and specified Category C contingencies (see *Section* 2.1.2 for discussions of the studied contingencies). Options that did not show positive notable impacts on the western Wisconsin study area were excluded from further detailed analysis. The detailed analysis further compares seven selected transmission options using results of AC contingency analysis, FCITC analysis, voltage stability analysis, transient stability analysis and the costs of constructing the transmission options.

4. Initial Screening

The initial screening evaluated the base case and 15 different transmission options using AC contingency analysis of Category B and specified Category C contingencies. These 15 transmission options are listed in Table 4.1 below. Further details on and the transmission maps of these options can be found in Appendix A and B respectively. The three study cases, as discussed in *Section* 2.1.1, are used in this evaluation.

Table 4.1 – Transmission options evaluated in initial screening

Option #	**Abbreviated Name**	**Full Name**
Opt 1	NLAX-HLT-SPG-CDL	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV project
Opt 1a	NLAX-SPG-CDL	North La Crosse–Spring Green–Cardinal 345 kV project
Opt 1b	NLAX-NMA-CDL	North La Crosse–North Madison–Cardinal 345 kV project
Opt 8	DBQ-SPG-CDL	Dubuque–Spring Green–Cardinal 345 kV project
Opt 2	NLAX-DBQ	North La Crosse-Dubuque 345 kV project
Opt 2a	NLAX-GENOA-DBQ	North La Crosse-Genoa-Dubuque 345 kV project
Opt 3	EAU-NLAX	Eau Claire-North La Crosse 345 kV project
Opt 4	NLAX-HLT-SPG-CDL & EAU-NLAX	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV and Eau Claire-North La Crosse 345 kV project
Opt 5	NLAX-HLT-SPG-CDL & NLAX-DBQ	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV and North La Crosse-Dubuque 345 kV project
Opt 6	NLAX-NCAS-DBQ & NCAS-SPG-CDL	North La Crosse-North Cassville-Dubuque 345 kV and North Cassville-Spring Green-Cardinal 345 kV project
Opt 7	NLAX-HLT-SPG-CDL & DBQ-SPG	North La Crosse-Hilltop-Spring Green-Cardinal 345 kV and Dubuque-Spring Green 345 kV project
Opt 7a	NLAX-SPG-CDL & DBQ-SPG	North La Crosse-Spring Green-Cardinal 345 kV and Dubuque-Spring Green 345 kV project
Opt 7b	NLAX-SPG-CDL & DBQ-SPG-CDL	North La Crosse-Spring Green-Cardinal 345 kV and Dubuque-Spring Green-Cardinal 345 kV project
Opt 7c	NLAX-NMA-CDL & DBQ-SPG-CDL	North La Crosse-North Madison-Cardinal 345 kV and Dubuque-Spring Green-Cardinal 345 kV project
Opt 765	GENOA-NOM 765 kV	Genoa–North Monroe 765 kV project

Three single event Category C contingencies (C5 or C2), were found to cause divergence or converged to severe low voltages for some of the studied cases.

,

Contains Critical Energy Infrastructure Information

These results indicate potential voltage collapse conditions under the three single event Category C contingencies in the base case without a transmission option included. The results also indicate that Option 2 (NLAX-DBQ), Option 2a (NLAX-GENOA-DBQ), and Option 3 (EAU-NLAX) are not effective in controlling the identified voltage collapse conditions.

4.2 Severity Index

Contains Critical Energy Infrastructure Information

Contains Critical Energy Infrastructure Information

Contains Critical Energy Infrastructure Information

4.3 Initial Screening Results

Category B Thermal Loading Results

The Severity Index evaluation of the AC contingency analysis thermal loading results under Category B contingencies are shown in the charts below.

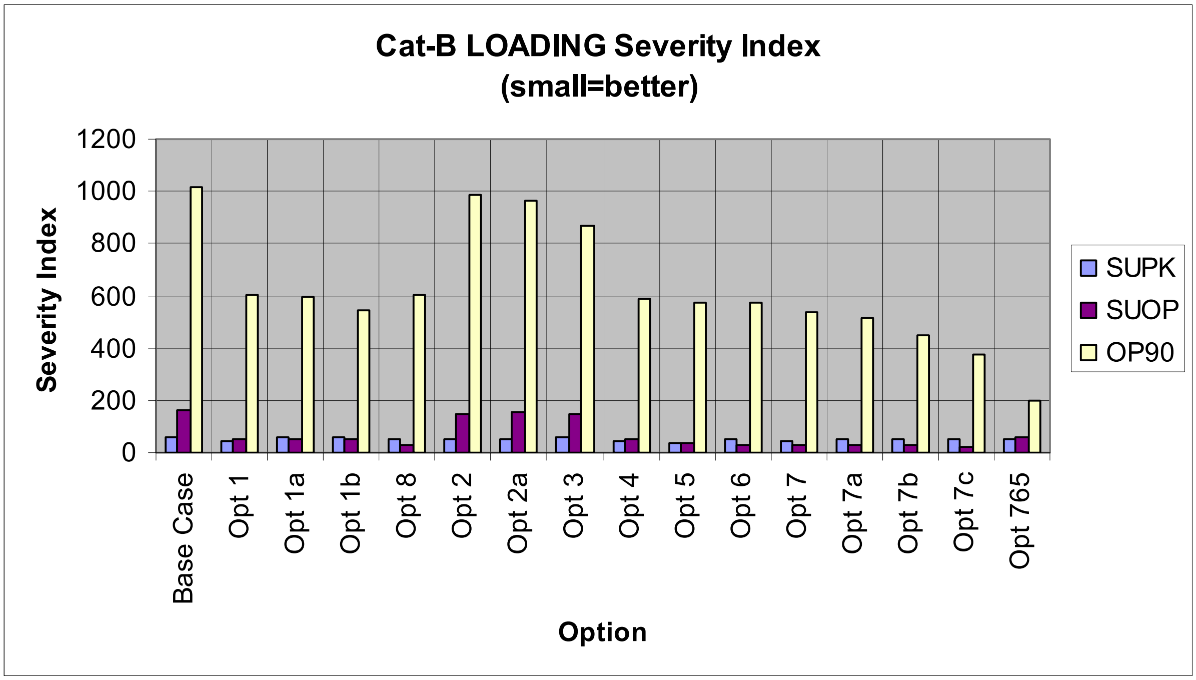

Figure 4.1 – Category B thermal loading results Severity Index review

Figure 4.1 shows the thermal loading Severity Indices for the base case and the cases with the studied transmission options under Category B contingencies for all three study models. It shows that compared to Summer Peak (SUPK) and Summer Off-Peak (SUOP) model overall thermal limitations are worst in the Off-Peak with 90% (OP90) wind output model, which has the most west to east flow bias through the western Wisconsin study area (see *Section* 2.1.1 for discussions of the three study models).

Figure 4.2 shows all positive thermal loading Severity Index changes comparing the option cases to the base case for all three study models. This indicates that overall the transmission options reduce the thermal loading limitations under the studied Category B contingencies. The varying values of the Severity Index change indicate varying degrees of the effectiveness of the transmission options.

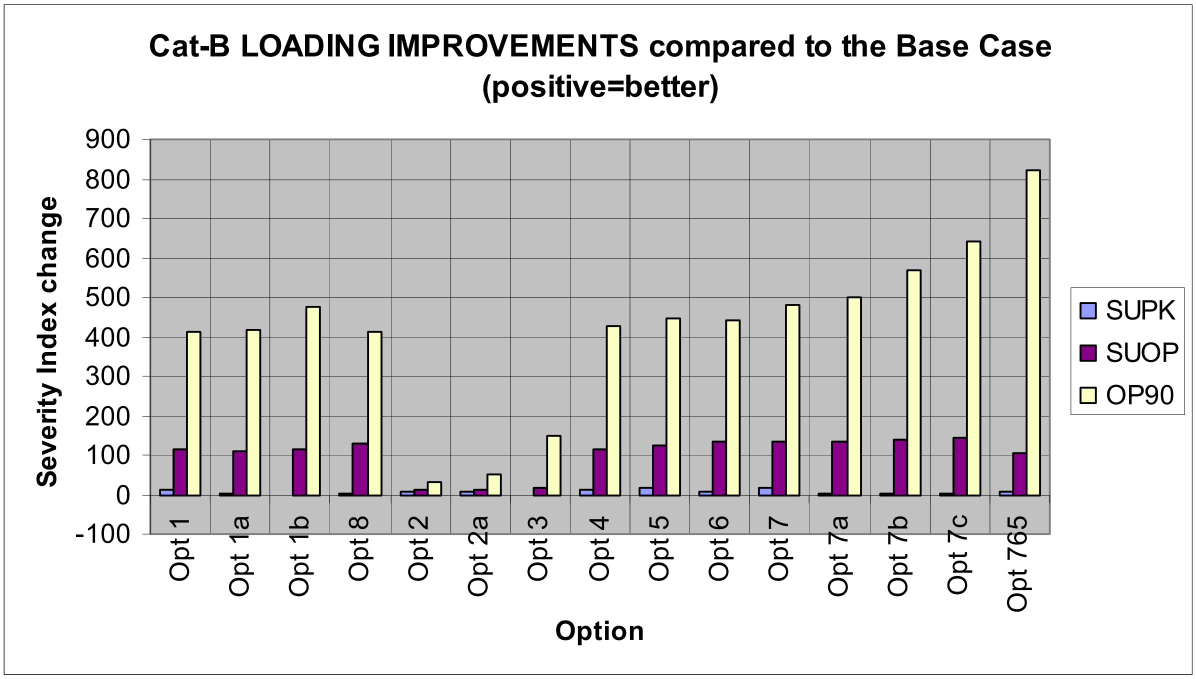

Figure 4.2 – Category B thermal loading results Severity Index review

The Category B thermal results were also reviewed using a measure that compares the loading difference between the base case and an option case for unique monitored elements. This analysis applies to facility loadings of 90% and above. A 10% loading difference threshold was applied in the results shown in Figure 4.3. This means that the loading difference between the base case and an option case needs to be at least 10% (in either direction) in order to be captured in the analysis result. Figure 4.3 shows a number of unique monitored elements, the loading of which are increased or decreased by at least 10% comparing an option case and the base case. A positive number is associated with a reduction in loadings in an option case compared to the base case. A negative number is associated with an increase in loadings in an option case compared to the base case. The 10% threshold used in this result captures relatively large changes in loadings between the base case and an option case. It shows that overall the studied transmission options have a positive impact in reducing the loadings, some options more effectively than others. The studied transmission options are also shown to have some negative impact to facility loadings, but to a much lesser extent when compared to the positive impact.

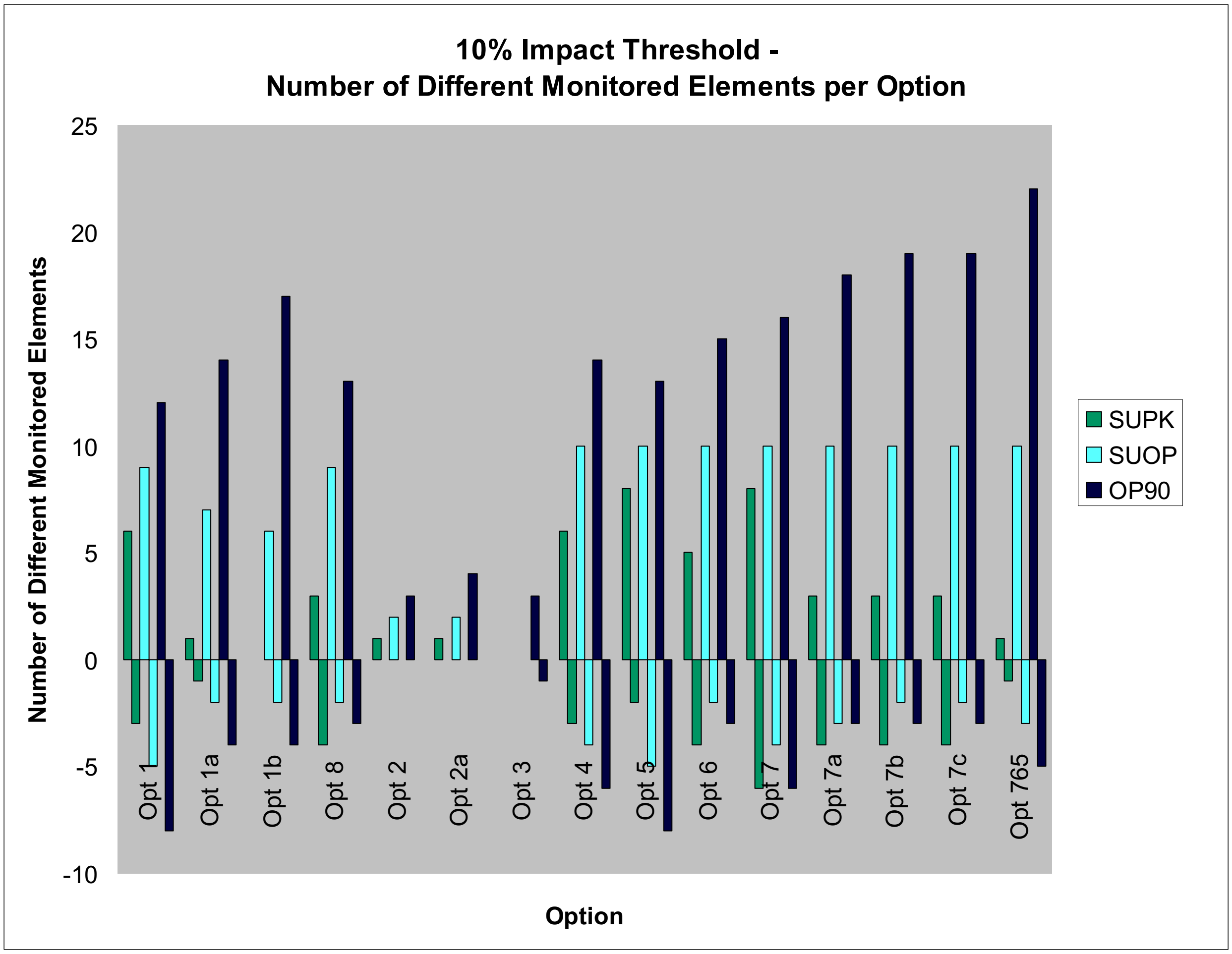

Figure 4.3 – Loading difference between the base case and option cases using 10% threshold for unique monitored elements

Category B voltage performance results

Only minor low voltage violations were identified under Category B contingencies in the Summer Peak and Off-peak models. No valid low voltage violations were identified in the Off-peak with 90% wind output model. No valid high voltage violations under Category B

Table 4.5 – Category B worst low voltage violations in the base case and Summer Peak model

From Area	To Area	Base case low voltages Bus Num	Bus Name	KV	Area	Voltage	Worst of
697	697	698136	PLV 138	138	694	0.8949	4

Table 4.6 – Category B worst low voltage violations in the base case and Off-peak model

			Base case low voltages					
	From Area	To Area	Bus Num	Bus Name	KV	Area	Voltage	Worst of
Contains Critical Energy Infrastructure Information	694	694	699048	BLK 138	138	694	0.8963	4

Figure 4.4 shows mostly positive voltage Severity Index changes comparing the option cases to the base case for all three study models.

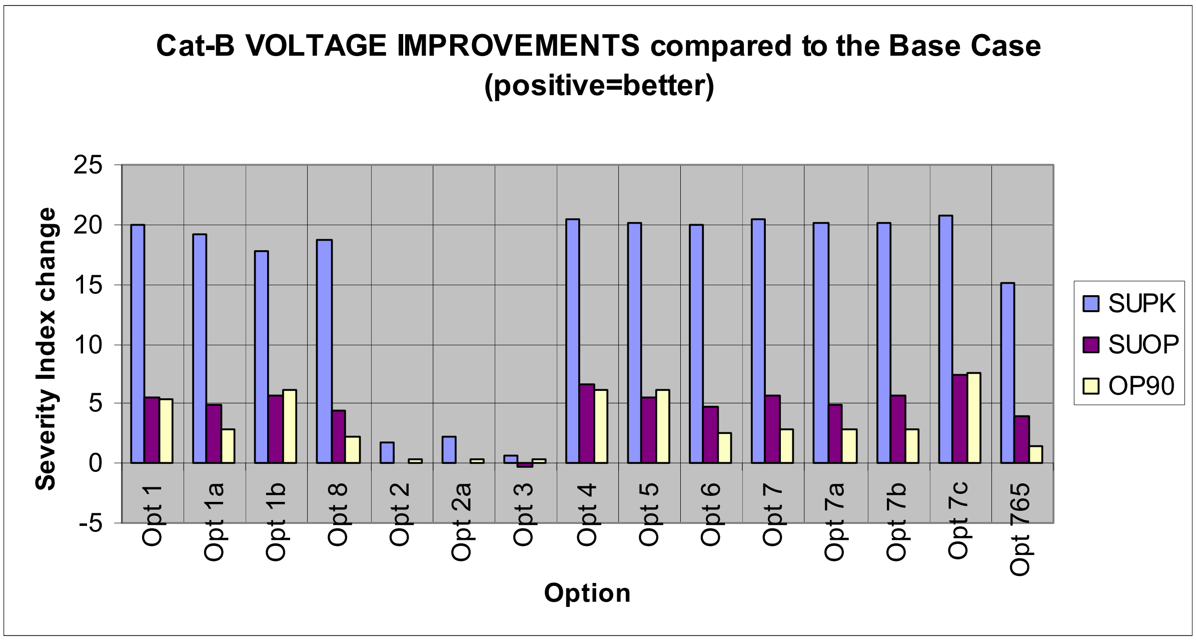

Figure 4.4 – Category B voltage performance results Severity Index review

Category C Thermal Loading Results

For the specified Category C contingencies, the thermal limitations were observed to be worse in the Off-peak models than in the Summer Peak model and worst in the Off-peak with 90% wind output model. This is similar to what was observed from the Category B thermal results. Note that non-converged contingencies were excluded equally from the Severity Index review of each option. Figure 4.5 shows mostly positive thermal loading Severity Index changes comparing the option cases to the base case. This indicates that overall the transmission options reduce the thermal loading limitations under the specified Category C contingencies. The varying values of the Severity Index change indicate varying degrees of the effectiveness of the transmission options.

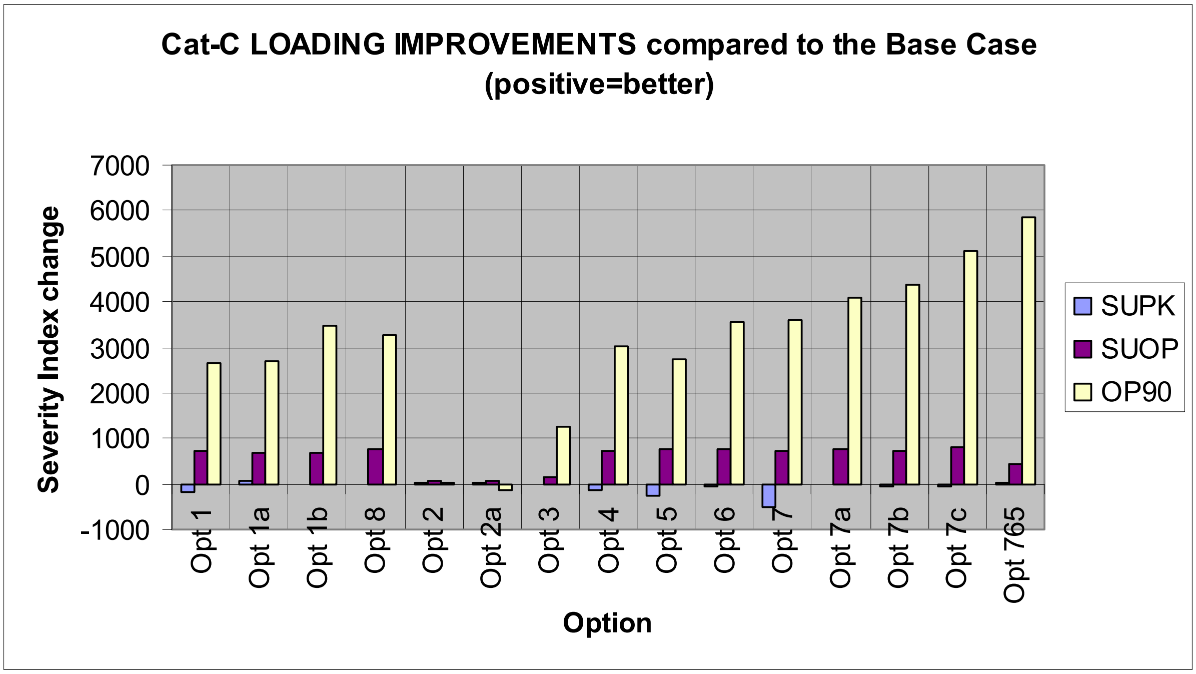

Figure 4.5 – Category C thermal loading results Severity Index review

Category C voltage performance results

Figure 4.6 shows mostly positive voltage Severity Index changes comparing the option cases to the base case for all three study models.

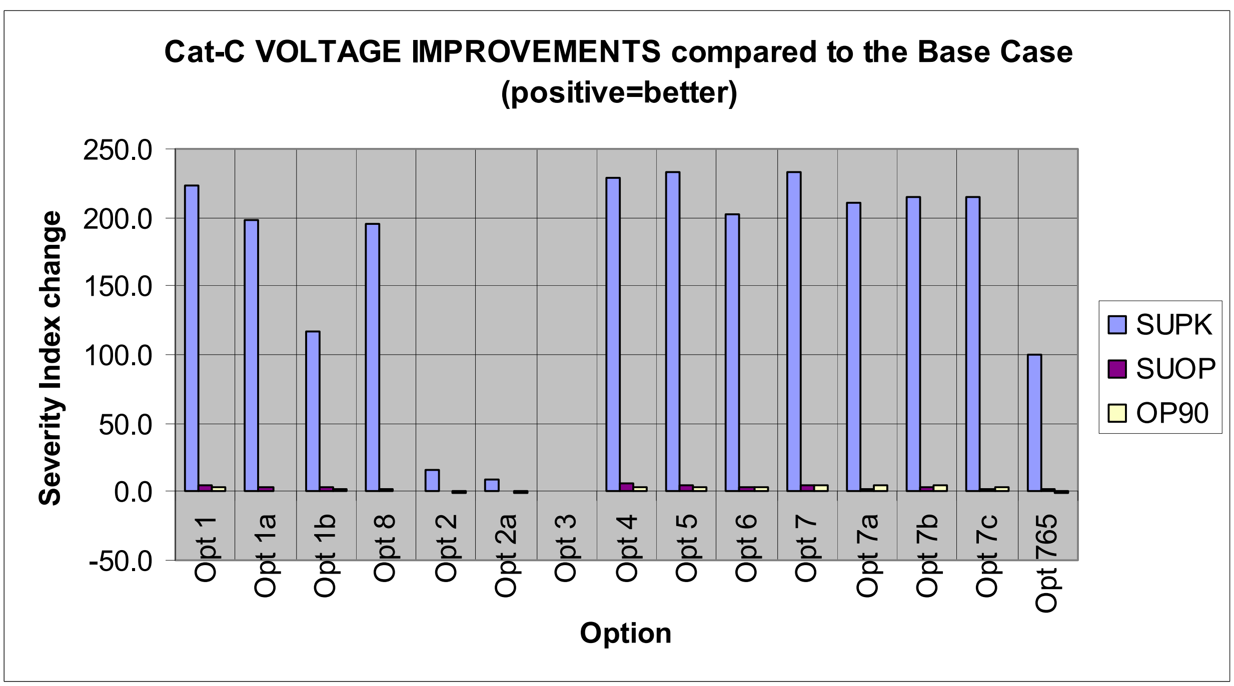

Figure 4.6 – Category C voltage performance results Severity Index review

Initial Screening Summary

The initial screening identified thermal loading and voltage performance limitations (including potential voltage collapse) in the base case without any transmission options for the system conditions simulated in the three study models. The base case and the cases with 15 transmission options were evaluated for Category B and specified Category C contingencies. One of the purposes of the initial screening was to select a few options for further detailed analysis. It was identified that out of the single element options (1, 1a, 1b, 8, 2, 2a and 3), Option 2, 2a, 3 (NLAX-DBQ, NLAX-GENOA-DBQ, and EAU-NLAX, respectively) did not seem to be effective in improving the reliability performance in the western Wisconsin study area. Option 7c (NLAX-NMA-CDL & DBQ-SPG-CDL) was shown to be the most effective 345 kV combination option in terms of improving reliability performance. The 765 kV Option was shown to perform positively for most of the reliability analysis categories. Based on the initial screening results, Options 1 (NLAX-HLT-SPG-CDL), 1a (NLAX-SPG-CDL), 1b (NLAX-NMA-CDL, 8 (DBQ-SPG-CDL), 7c (NLAX-NMA-CDL & DBQ-SPG-CDL) and the 765 kV Option (GENOA-NOM 765 kV) were selected for further detailed analysis and comparison.

Low Voltage Option

Based on the results of Category B thermal limitations, a Low Voltage option was also created. The Low Voltage option eliminates the identified thermal limitations under the Category B contingencies on a piece-by-piece basis. The Low Voltage option is a collection of lower than 345 kV facilities that include a new 161 kV line and upgrades of 48 individual facilities. Details of the Low Voltage option can be found in Appendix A. This option is also evaluated in the detailed analysis.

List of Options to be Evaluated in Detailed Analysis

All selected options evaluated in the detailed analysis are shown in Table 4.7 below.

Table 4.7 – Transmission options selected for further detailed analysis

Option #	Abbreviated Name	Full Name
Opt 1	NLAX-HLT-SPG-CDL	North La Crosse–Hilltop–Spring Green–Cardinal 345 kV project
Opt 1a	NLAX-SPG-CDL	North La Crosse–Spring Green–Cardinal 345 kV project
Opt 1b	NLAX-NMA-CDL	North La Crosse–North Madison–Cardinal 345 kV project
Opt 8	DBQ-SPG-CDL	Dubuque–Spring Green–Cardinal 345 kV project
Opt 7c	NLAX-NMA-CDL & DBQ-SPG-CDL	North La Crosse-North Madison-Cardinal 345 kV and Dubuque-Spring Green-Cardinal 345 kV project
Opt 765	GENOA-NOM 765 kV	Genoa–North Monroe 765 kV project
Opt LV	Low Voltage	A collection of lower than 345 kV facilities that include a new 161 kV line and upgrades of 48 individual facilities.

5. Detailed Analysis

The detailed analysis compares the seven selected transmission options based on costs and reliability performance in the AC contingency analysis, FCITC analysis, voltage stability analysis and transient stability analysis.

5.1 Monetized and Non-Monetized Measures

Monetized and non-monetized measures are applied to different aspects of the reliability study results for comparison between the seven options. The monetized measure is based on construction cost estimates and comparison. This type of measure was applied to the Category B thermal loading results, solution divergence under the three single event Category C contingencies and the FCITC results. The basic approach is to identify the supporting facilities that would be needed to address these reliability issues for each option; such that the reliability performance will be comparable between the options including these facilities. Costs are then compared between the options including the main EHV components and the supporting facilities. All costs referenced in this study are in 2010 dollars. Monetized measures were not applied to some aspects of the reliability analysis, such as voltage performance under Category B and converged specified Category C contingencies, voltage stability analysis and transient stability analysis. For each of these aspects of the reliability analyses, quantitative rankings were assigned to the studied options. To be consistent, rankings are all in the range of 1 to 5, with “1” representing the best performance and “5” representing the worst performance. The rankings may not be from 1 to 5 continuously. For example, if the results show a clear divide of better and comparable performance for a sub-group of the seven options, and worse and comparable performance for the rest of the options, then “1” is assigned to the options in the first sub-group and “5” is assigned to the rest of the options. The span of 5 is always used.

In the following sections, comparisons between the options using monetized or non-monetized measures for each studied aspect of the reliability analysis are discussed. At the end of *Section* 5, a summary table is provided that includes comparison of all studied aspects of the reliability analysis using monetized and non-monetized measures.

5.2 Construction Cost Estimates for the EHV Options

Cost estimates for the EHV components of the studied options are shown in Table 5.1.

Table 5.1 – Cost estimates for the EHV components

Options	**$ in 2010**
Low Voltage	$0
NLAX-HLT-SPG-CDL (1)	$454,492,920
NLAX-SPG-CDL (1a)	$377,454,200
NLAX-NMA-CDL (1b)	$357,590,989
DBQ-SPG-CDL (8)	$304,187,200
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	$672,785,400
Genoa-NOM 765 kV	$880,598,000

5.3 Supporting Facilities to Overcome Category B Thermal Loading Limitations

It should be noted that the EHV components alone in any option do not address all identified Category B thermal limitations. To compare the option costs on a level ground, supporting facilities were identified for each option such that all identified thermal limitations are eliminated in any of the option cases. Thermal loadings above 95% of applicable Ratings were captured in this evaluation; 95% was used instead 100% to capture near misses. For the Low Voltage Option, the facilities that eliminate the Category B thermal limitations were already identified, as shown in Appendix A. Cost estimates for these facilities are also included in Appendix A. The supporting facilities needed to eliminate all identified thermal limitations under Category B contingencies for the EHV options can be found in Appendix D. Cost estimates for these facilities are also included in Appendix D.

Table 5.2 summarizes the costs of the supporting facilities needed for each of the seven options to eliminate the identified Category B thermal limitations. The total cost of the Low Voltage Option also is included. Each EHV option needs supporting facilities, thus, they do not resolve all identified Category B thermal limitations by themselves. However, fewer supporting facilities were needed with the EHV options than those identified in the Low Voltage Option on a piece-by-piece basis. Also, it should be noted that if the only reliability concern is Category B thermal limitations, the Low Voltage Option would seem to be less expensive than the EHV options and the corresponding supporting facilities for each option. However, critical reliability concerns are not limited to just Category B thermal and voltage limitations for the western Wisconsin study area. Evaluations of several of these other key aspects are discussed in the following sections.

Table 5.2 – Costs of the supporting facilities for Category B thermal loading limitations

Options	**$ in 2010**
Low Voltage	$269,165,514
NLAX-HLT-SPG-CDL (1)	$156,943,463
NLAX-SPG-CDL (1a)	$183,640,721
NLAX-NMA-CDL (1b)	$188,698,156
DBQ-SPG-CDL (8)	$205,393,188
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	$143,951,649
Genoa-NOM 765 kV	$180,046,843

5.4 Voltage Performance under Category B and Specified Converged Category C Contingencies

Figures 5.1 and 5.2 show the voltage performance comparison between the seven options under Category B and specified converged Category C contingencies. It is shown that the 345 kV options are more effective in improving system voltage performance than the 765 kV Option or the Low Voltage Option. The Low Voltage Option showed the worst performance in this evaluation.

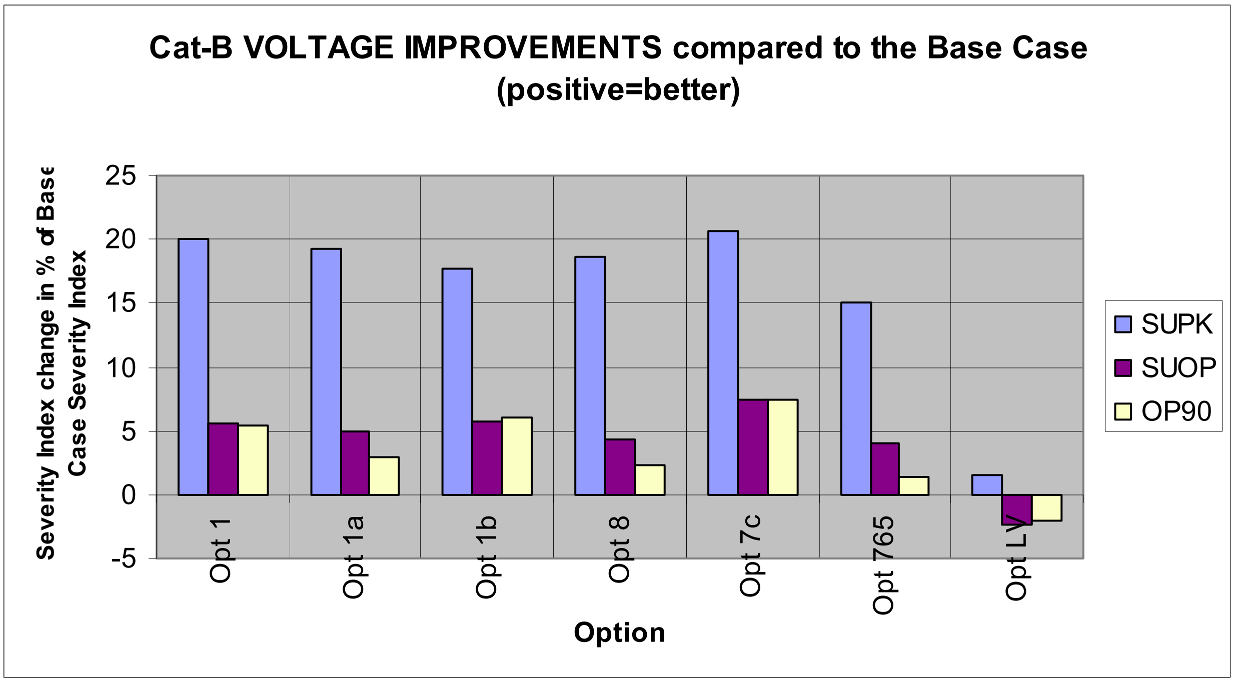

Figure 5.1 – Category B voltage performance results Severity Index review

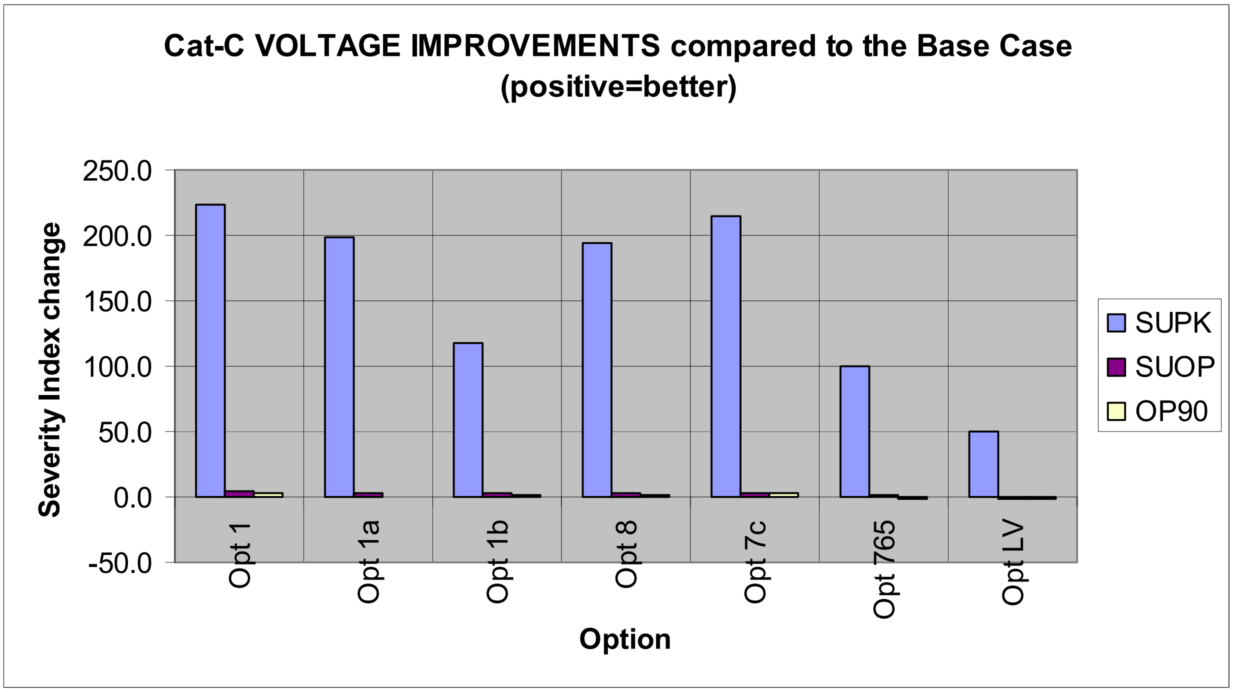

Figure 5.2 – Category C voltage performance results Severity Index review

Based on the results of this evaluation, rankings are given to the seven options, as shown in Table 5.3. A ranking of "1" represents the worst performance and "5" represents the best performance. These rankings were determined using engineering judgment and the charts above, comparing across all options.

Table 5.3 – Option rankings for the voltage performance under Cat-B, Cat-C contingencies

Options	Cat-B Ranking	Cat-C Ranking
Low Voltage	1	1
NLAX-HLT-SPG-CDL (1)	4	5
NLAX-SPG-CDL (1a)	4	4
NLAX-NMA-CDL (1b)	4	3
DBQ-SPG-CDL (8)	4	4
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	5	5
Genoa-NOM 765 kV	3	2

5.5 Review of Diverged Category C5 and C2 Contingencies

Three single event Category C contingencies (C5 or C2) were found causing solution divergence or solved with severe low voltages for some of the studied cases. A preliminary discussion was provided in *Section* 4.1. These conditions are indications of voltage collapse. Further evaluation was performed to determine reactive supports needed to control these conditions.

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These contingencies were evaluated for the base case and seven transmission options using all three study models.

Load shedding and opening of facilities were taken into account in this evaluation of potential cascading outages as a result of a multiple contingency. Each multiple contingency was applied and thermal loadings and voltage levels were monitored. The assumed tripping levels due to low voltage or thermal loading are described as follows. If the post contingent voltage of a bus was below 0.87 p.u., it was assumed the load connected to that bus would be automatically shed by relay action. Also, if post contingent thermal loading of a facility was greater than 125% of its emergency rating, that facility would be assumed to trip and be removed from service by either relay action or operator interaction. If both unacceptable low voltage and thermal loading were experienced, then load would be shed first to determine if it improved the voltage and/or the thermal loading. If the voltage was improved but the thermal loading remained, a facility would be opened to remove or reduce the flow. If low voltages remain, additional load connected to buses with voltages below 0.87 p.u. would be shed.

Option 1a (NLAX-SPG-CDL)

Contains Critical Energy Infrastructure Information

Contains Critical Energy Infrastructure Information created conditions where the switching criteria as discussed above were met. During the off-peak load conditions, a few facilities experienced thermal loadings greater than 125%. However, the loading concerns were eliminated by opening the facilities of concern. Upon opening of these facilities, all thermal loadings greater than 125% were removed and all voltages were above 0.87 p.u. No low voltage wide area cascading outage conditions were identified under this contingency.

Option 1b (NLAX-NMA-CDL)

Contains Critical Energy Infrastructure Information

Contains Critical Energy Infrastructure Information created conditions where the switching criteria as discussed above were met. During the off-peak load conditions a few facilities experienced thermal loadings greater than 125%. However, the loading concerns were eliminated by opening the facilities of concern. Upon opening of the facilities, all thermal loadings greater than 125% were removed and all voltages were at least 0.87 p.u. No low voltage wide area cascading outage conditions were identified under this contingency.

The contingency of Contains Critical Energy Infrastructure Information caused some severe low voltages. These can be mitigated by shedding load in the immediate vicinity of the outage. Contains Critical Energy Infrastructure Information Alternatively, Contains Critical Energy Infrastructure Information reactive support would be needed to correct the severe local low voltages

Contains Critical Energy Infrastructure Information

Option 8 (DBQ-SPG-CDL)

For Option 8, the contingency Contains Critical Energy Infrastructure Information Contains Critical Energy Infrastructure Information created conditions where the switching criteria as discussed above were met. During the off-peak load conditions a few facilities experienced thermal loadings greater than 125%. However, the loading concerns were eliminated by opening the facilities of concern. Upon opening of these facilities, all thermal loadings greater than 125% were removed and all voltages were at least 0.87 p.u. No low voltage wide area cascading outage conditions were identified under this contingency.

The contingency Contains Critical Energy Infrastructure Information caused minor low voltages in the local area, which can be corrected using reactive support:

Contains Critical Energy Infrastructure Information

765 kV Option (Genoa-NOM 765 kV)

For the 765 kV Option, the contingency Contains Critical Energy Infrastructure Information caused some severe low voltages. These can be mitigated by shedding load in the immediate vicinity of the outage. Contains Critical Energy Infrastructure Information Alternatively, the following reactive support would be needed to correct the severe low voltage condition without load shedding:

Contains Critical Energy Infrastructure Information

The contingency Contains Critical Energy Infrastructure Information caused minor low voltages in the local area, which can be corrected using the following reactive support:

Contains Critical Energy Infrastructure Information

Low Voltage Option

For the Low Voltage Option, the contingency Contains Critical Energy Infrastructure Information

Contains Critical Energy Infrastructure Information

Contains Critical Energy Infrastructure Information of load shed to control voltage collapse. The following reactive supports are needed to control the voltage collapse conditions, without load shedding, caused by the contingency: Contains Critical Energy Infrastructure Information

Contains Critical Energy Infrastructure Information

Contains Critical Energy Infrastructure Information These can be mitigated by shedding load in the immediate vicinity of the outage. Contains Critical Energy Infrastructure Information Alternatively, the following reactive support would without load shedding:

Contains Critical Energy Infrastructure Information

The voltage issues associated with the contingency Contains Critical Energy Infrastructure Information are addressed using the reactive supports

Option 1 (NLAX-HLT-SPG-CDL) and Option7c (NLAX-NMA-CDL + DBQ-SPG-CDL)

Detailed analysis was not performed for these two options. It was assumed that the reactive support needed for these two options are comparable to Option 1a. Option 1 is comparable to Option 1a since the only difference between the two options is Option 1 has an additional 345/138 kV transformer modeled at the Hilltop substation. Option 7c is comparable to Option 1a since both options have 345/138 kv transformers modeled at the Spring Green substation and an interconnection at the Cardinal substation.

Reactive Support Summary

Table 5.4 summarizes the costs of the reactive support needed to control low voltage wide area cascading outages under the identified single event Category C contingencies.

Contains Critical Energy Infrastructure Information

Table 5.4 – Costs of reactive supports or amount of load shed needed to control voltage collapse under Category C contingencies

Options	**Reactive support $ in 2010**	
Low Voltage	$82,758,813	
NLAX-HLT-SPG-CDL (1)	$0	
NLAX-SPG-CDL (1a)	$0	
NLAX-NMA-CDL (1b)	$0	Contains Critical Energy
DBQ-SPG-CDL (8)	$0	Infrastructure Information
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	$0	
Genoa-NOM 765 kV	$0	

Table 5.5 summarizes Contains Critical Energy Infrastructure Information Contains Critical Energy Infrastructure Information Costs of the alternative remedy of reactive supports needed to alleviate the condition are also shown in the table.

Table 5.5 – Amount of Contains Critical Energy Infrastructure Information of reactive support needed to control severe local low voltages under a Category C contingency

Options		Reactive support $ in 2010
Low Voltage	Contains Critical Energy Infrastructure Information	$54,569,472
NLAX-HLT-SPG-CDL (1)		$0
NLAX-SPG-CDL (1a)		$0
NLAX-NMA-CDL (1b)		$53,821,824
DBQ-SPG-CDL (8)		$0
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)		$0
Genoa-NOM 765 kV		$54,569,472

It could be argued from a cost perspective that local load shedding is preferred over installing SVC's to control severe local low voltages under Category C events. Both remedies are acceptable according to current NERC TPL Standards. To capture the merits of alleviating severe local low voltages using a non-monetized measure, the project options are ranked as shown in Table 5.6. A ranking of "1" represents the worst performance and "5" represents the best performance. Those with needed SVC's or Cap Banks received a ranking of 1 and those without a need received a ranking of 5.

Table 5.6 – Option rankings for alleviating severe local low voltages under a single event Category C contingency

Options	Rankings
Low Voltage	1
NLAX-HLT-SPG-CDL (1)	5
NLAX-SPG-CDL (1a)	5
NLAX-NMA-CDL (1b)	1
DBQ-SPG-CDL (8)	5
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	5
Genoa-NOM 765 kV	1

This evaluation shows that the 345 kV options are more effective in controlling the voltage collapse and for alleviating severe local low voltages than the 765 kV or the Low Voltage Option. The Low Voltage Option showed the worst performance in this evaluation.

5.6 Non-Converged N-2 Contingencies

The non-converged N-2 contingencies identified in any of the studied cases are listed in Appendix E. No conclusive comparisons have been obtained based on this result. Further analysis is needed in this aspect of the reliability analysis.

5.7 First Contingency Incremental Transfer (FCITC) Analysis

The western Wisconsin study area often experiences west to east flow biases that cause additional stress to the transmission system in the area. The FCITC analysis demonstrates the robustness of the system with each transmission option and compares the options with respect to thermal loading characteristics under increasing west to east transfers.

The following three transfer directions were evaluated in detail using the Off-peak with 35-45% wind output model:

- Minnesota to Wisconsin
- Iowa to Wisconsin
- Minnesota and Iowa to the Midwest ISO central and east planning sub-regions

Note that the supporting facilities to eliminate all identified Category B thermal limitations were taken into account in the FCITC analysis. The charts in Figures 5.3 through 5.5 show the FCITC results for the seven options. The results show that the 345 kV options are more effective than the Low Voltage Option in improving the west to east transfer capability. Option 7c is most effective. The 765 kV Option is not as effective as Option 7c, particularly for sub-regional transfers of MN to WI and IA to WI.

Higher FCITC capabilities indicate stronger robustness of the system to cope with thermal loading issues under flow biases. During initial screening, the three east to west transfers (opposite to the west to east transfers listed above) were also simulated. The level of congestion identified was much less compared with the west to east transfers. Therefore the detailed study focused on the west to east transfers.

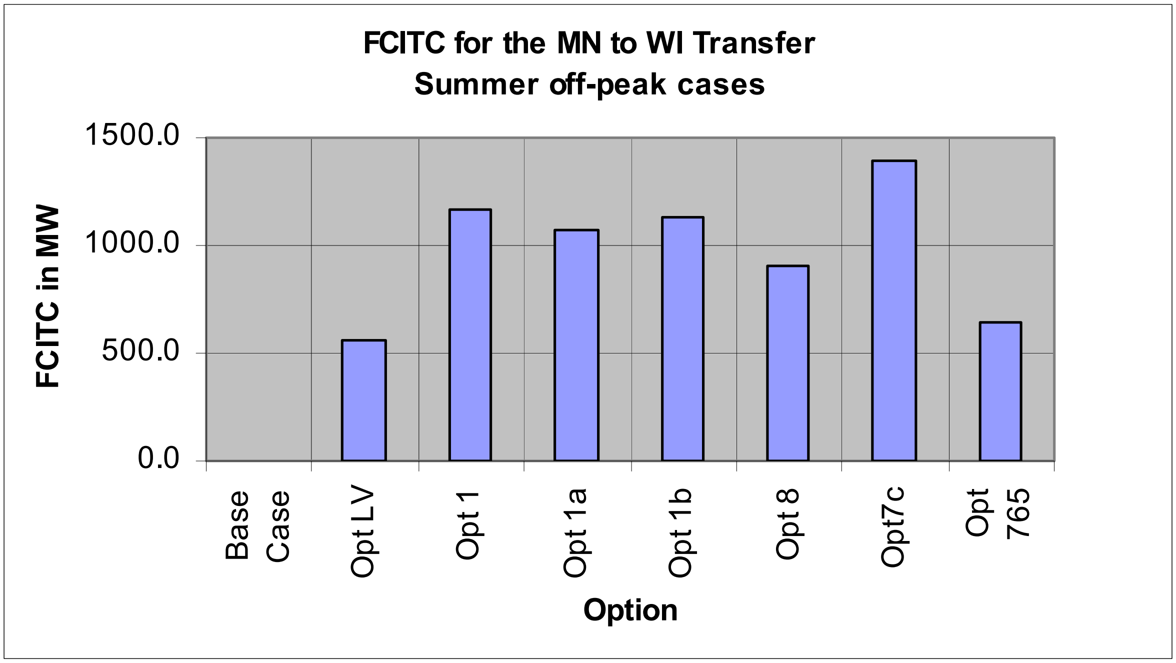

Figure 5.3 – FCITC for the MN to WI transfer

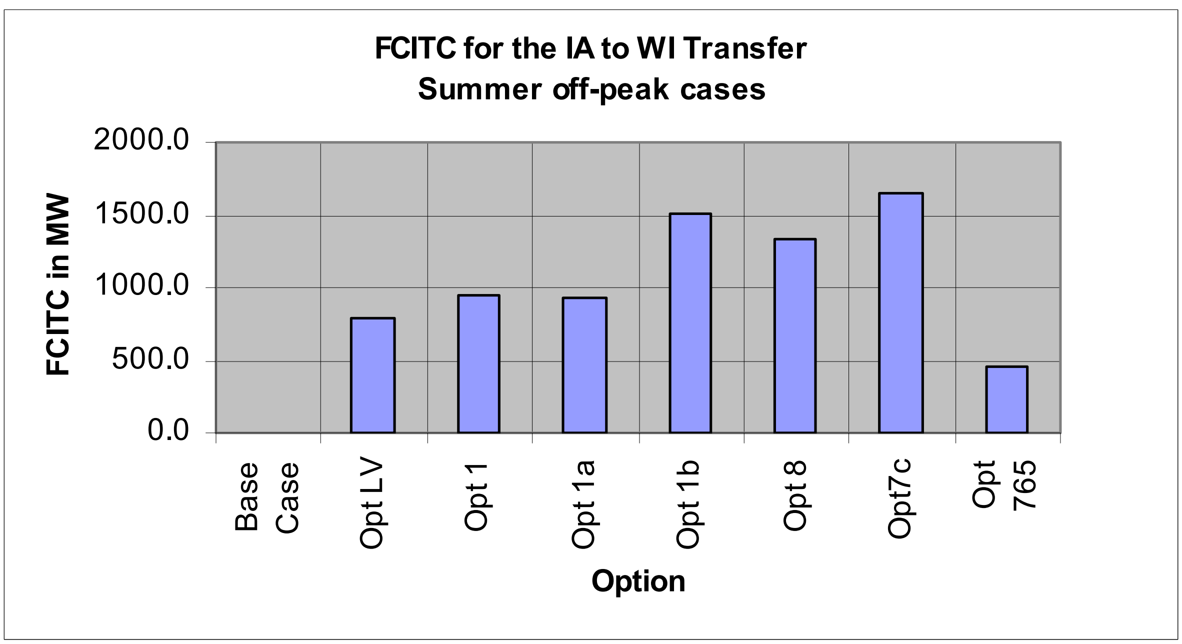

Figure 5.4 – FCITC for the IA to WI transfer

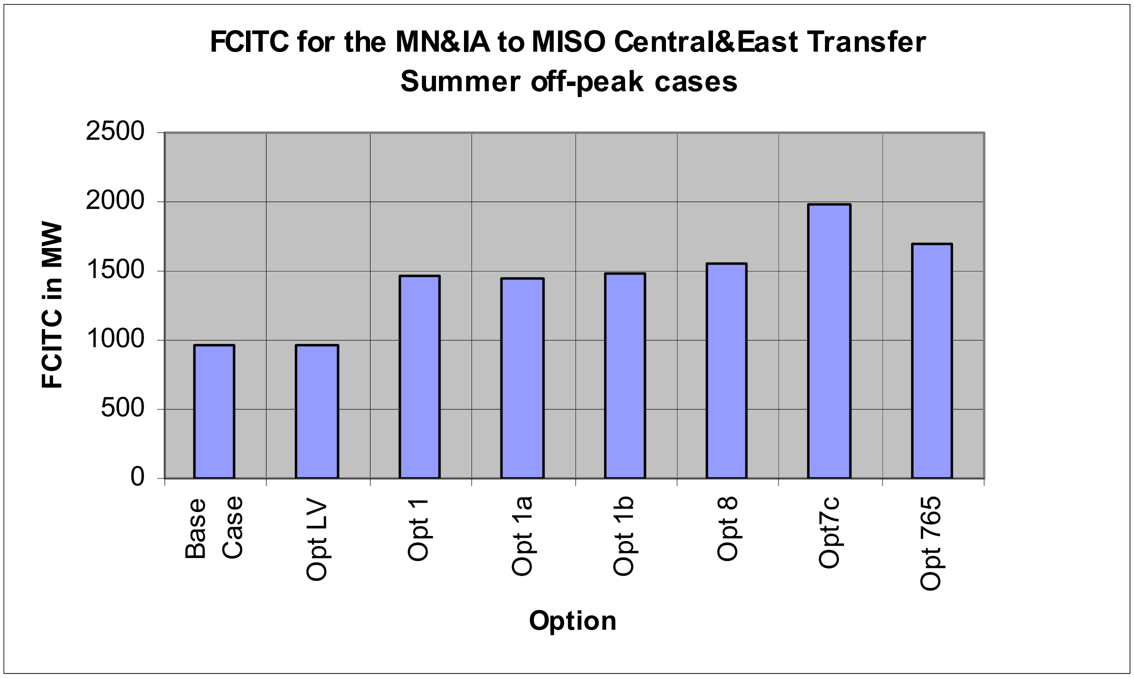

Figure 5.5 – FCITC for the MN&IA to MISO Central and East transfer

5.8 P-V Voltage Stability Analysis

Voltage stability is an important issue for the western Wisconsin study area. Currently, the Minnesota – Wisconsin Export interface (MWEX) is limited by voltage stability and transient low voltage recovery. The voltage stability analysis demonstrates the robustness of the system with each transmission option and compares between the options in respect to voltage stability characteristics under increasing west to east transfers.

The voltage stability results should not be interpreted as identifying a set of valid operating ranges. The voltage stability simulations ignore transmission overloads and push power flow transfers to levels where voltages become depressed and collapse. The results do attempt to correlate the characteristic power flow across an interface as an indicator of voltage stability. Demonstrating this is accomplished by means of a set of Power transfer vs. Voltage (PV) charts.
For the purpose of this study the produced charts focus on power flow across two interfaces: through the ATC western tie lines, and an interface which includes all ATC tie lines and represents ATC imports. Simulating voltage stability in this manner is consistent with industry practices using such tools.

This study compares simulations with and without the transmission options. For comparison of voltage stability characteristics, the baseline interface flows, voltage, and losses reported in this study are not as significant as the improvements in those values produced by each option.

Power transfer across the study interfaces has the potential to increase real (MW) and reactive (MVAR) losses on the system. Similar to the PV charts, this report will use Power vs. Loss (PL) charts to demonstrate how the real and reactive losses are expected to change as power flow increases across the study interfaces.

The various reported results demonstrate the characteristics that each option contributes toward the voltage stability and robustness of the study region.

PV Analysis - Study Conditions

The voltage stability analysis used two study models - the 2018 Summer Off-peak with 35-45% wind output (SUOP) model and the 2018 Summer Peak (SUPK) model. The voltage stability analysis tested the following:

Base	Base reference starting case
Option 1	N. La Crosse-Hilltop-Spring Green-Cardinal 345 kV
Option 1a	N. La Crosse-Spring Green-Cardinal 345 kV
Option 1b	N. La Crosse-North Madison-Cardinal 345 kV
Option 8	Dubuque-Spring Green-Cardinal 345 kV
Option 7c	N. La Crosse-North Madison-Cardinal 345 kV + Dubuque-Spring Green-Cardinal 345 kV
Option HV (765)[15]	Genoa-North Monroe 765 kV and supporting 345 kV
Option LV	Low Voltage Option

Several variations of the transmission options above were also tested with addition of all the reactive supports (SVCs and Capacitors) identified in the Category C reliability analysis, as discussed in *Section* 5.5 previously. These are the additional simulations (note that the notation "+caps" refers to capacitor additions and other reactive resource additions such as SVCs):

Base	(+caps)
Option 1b	(+caps)
Option 8	(+caps)
Option HV (765)	(+caps)
Option LV	(+caps)

The PowerTech Labs VSAT program was used to test voltage stability. To improve the solution convergence and provide a more robust set of results, various small adjustments were made to the study case. For example, some changes could include minor bus tie impedance changes, resolving voltage regulation conflicts. Many of the changes were remote from the study area, but were needed to provide a more robust set of results.

PV Analysis - Monitored Facilities

Selected buses within the study region were monitored for additional output. Some of these locations are used in the power transfer vs. voltage (PV) charts. A list of the locations is provided in Appendix F.

A number of interfaces were defined to examine the power transfers in the simulations. Examples of interfaces used include monitoring the ATC western WI tie lines, and monitoring an

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[15] Option HV in this section refers to the 765 kV Option as referenced throughout the report.

ATC import interface consisting of all ATC tie lines. When studying the various transmission options, these interfaces were augmented with any additional lines that are part of an option.

VSAT parameter settings were activated to report information regarding zonal MW and MVAR losses. The loss information is used to produce charts of power transfer vs. losses (PL).

The VSAT program provides additional output that is not discussed in this section, but can be made available as part of the supporting materials upon request.

PV Analysis - Contingencies Tested

Each VSAT run tested approximately 30-40 contingencies that were considered to be among the most severe for the study region. The tests did not include contingencies that were considered farther from the study area since they would have a poor correlation to the studied transmission options. The contingencies used included significant outages identified in the reliability results. An additional VSAT screening was also performed to include additional contingencies (above 161 kV) that may be significant. Within the study region selected unit outages and capacitor bank outages were also included. When studying the various transmission options, several additional contingencies were included to account for facilities of each option. A compete list of the tested contingencies can be found in Appendix F.

PV Analysis - Stability Settings

This section describes some of the VSAT program parameters used for each simulation. The simulations are set to ignore pre-contingency and post contingency overloads. The simulations do not attempt to assess or simulate cascading outage conditions. The simulations are not set to perform any operating steps or other overload mitigation methods other than the items mentioned in this report.

These are some of the more significant VSAT solution parameter file settings that are used in the simulations:

Limit Generator Reactive Var output within limits	(Always)
Transfer Analysis	(To First Limit)
Contingency Analysis	(To First Insecure)
Adjust ULTCs transformers for voltage control	(In pre-contingency)
Adjust phase-shifters for MW flow control	(In pre-contingency)
Adjust discrete switched shunts	(Always)
Adjust area interchange	(Never)

Because the model includes power flow features that model some load outside of its power flow control areas, the area interchange feature cannot readily be turned on in VSAT. Therefore, losses are handled by the system swing located within Tennessee Valley Authority in the east. Adjustments were made to the case to make it more robust so that the swing will not have EHV outlet issues when supplying losses to the system.

PV Analysis - Phase Shifter Operation

The Arrowhead phase shifter located near Duluth, Minnesota was set to be in operation in each of the power flow cases. Contains Critical Energy Infrastructure Information

Contains Critical Energy Infrastructure Information As mentioned, the simulation parameter was set to allow for pre-contingent adjustment of the phase shifters. Therefore the phase shifter can adjust to keep pre-contingent flow with the selected bandwidth. This is consistent with the description in the operating guide. However to prevent excessive utilization of the phase shifter and to hold back for post-contingent conditions, the phase shifter angle in the case was also limited to +/- 10 degrees.

PV Analysis - Transfer Assumptions

A full description of the transfer direction participation points can be made available as part of the supporting materials. This section provides a summary of the transfer directions.

The Summer Off-peak (SUOP) case was studied using two transfer directions:

SUOP Transfer 1 (West to East – primarily to ATC load)
Source: 70% from western wind (including wind in the ATC region)
30% from western generation units with reserve

Sink: 80% scaling up ATC region load (using constant power factor)
20% scaling up load in the eastern part of MISO region (using unity power factor)

SUOP Transfer 2 (West to East – primarily to ATC generation)
Source: 70% from western wind (including wind in the ATC region)
30% from western generation units with reserve

Sink: 50% follow a back-down order (with turn-off) of selected units within ATC (smaller and less economic)
20% scaling down of remaining units in ATC region (excluding wind)
30% scaling down of generation in the eastern part of MISO region

The Summer Peak (SUPK) case was studied using one transfer direction:

SUPK Transfer 3 (West to East – primarily to ATC gas generation)
Source: 70% from western wind (excluding wind in the ATC region)
30% from western generation units with reserve

Sink: 35% follow a back-down order (with turn-off) of select units within ATC (gas units excluding combined cycle)
20% follow a back-down order (with turn-off) of select units within ATC (gas combined cycle)
15% scaling down of remaining units in ATC region (excluding wind)
30% scaling down of generation in the eastern part of MISO region

PV Analysis - Results

Characteristic Strength during Transfer

The strength of each transmission option can be characterized in a number of ways. One way is by the amount of source to sink transfers achieved before voltage collapse. Another way is by the amount of transfers through an interface such as the ATC Western Ties interface or the ATC import interface achieved before voltage collapse. If a project alternative is effective, it will direct a larger percentage (or shift factor) of the power transfer through the interface as opposed to power flowing around the interface. The following bar charts depict the interface flows achieved before voltage collapse of each test transfer.

It is observed from the bar charts that the single element 345 kV options (1, 1a, 1b) increase the transfers through the ATC West Ties interface by approximately 372-609 MW. Option 8 performed slightly better as a single element 345 kV option (582-772 MW). Option 7c with 2-345 kV lines performed similar to the combined increases of its component projects Options 1b and 8. For example, in Transfer 2, Option 7c increases transfer through the West Ties interface by 1211 MW, compared to its individual components, Options 1b and 8, which had increases of 772 MW and 530 MW. The 765 kV Option performed better than the 345 kV single element options, but not as well as the double 345 kV option, Option 7c

Figure 5.6 - Transfer 1 ATC West Ties Interface Limit for Each Option

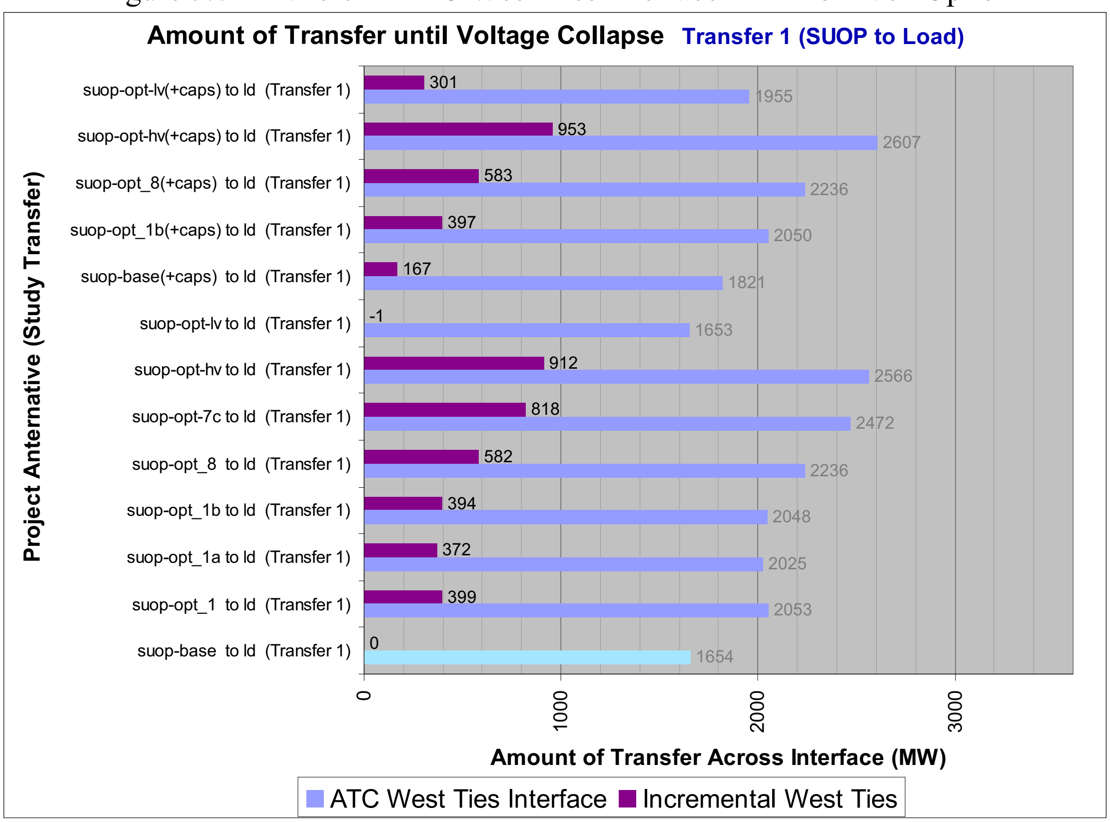


Figure 5.7 - Transfer 1 ATC Import Interface Limit for Each Option

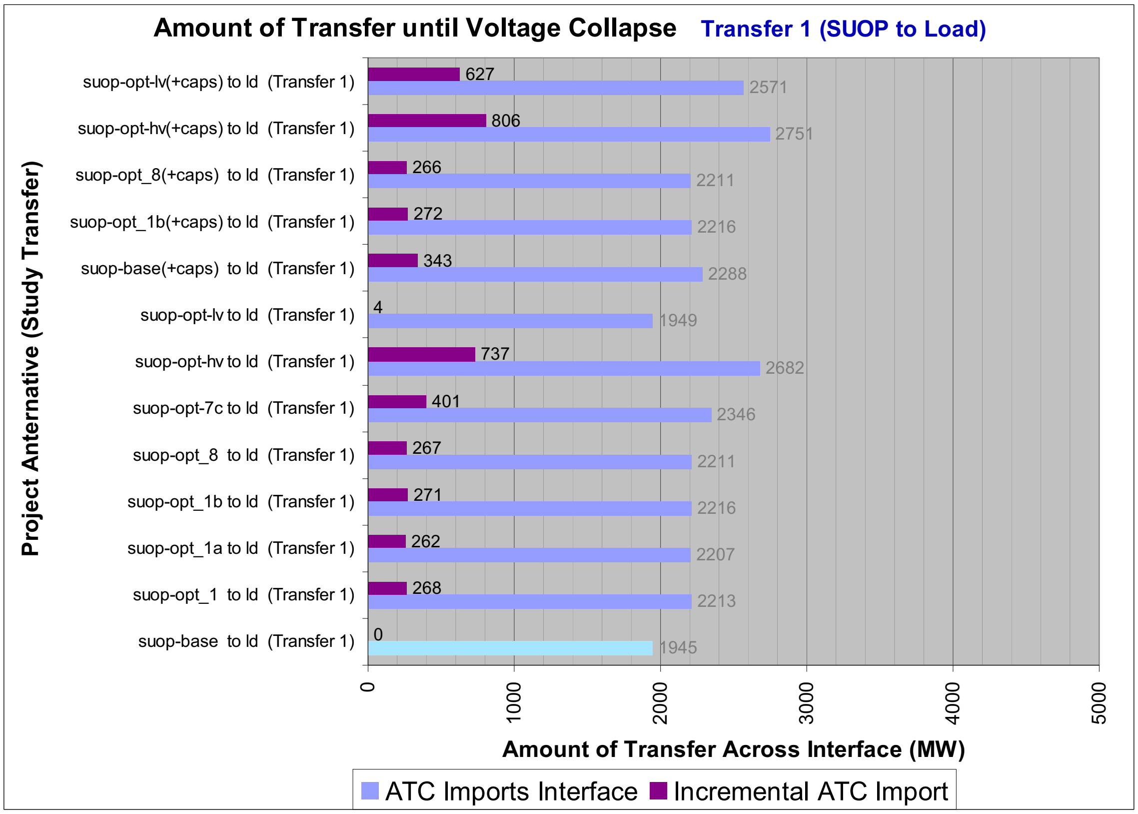


Figure 5.8 - Transfer 2 ATC West Ties Interface Limit for Each Option

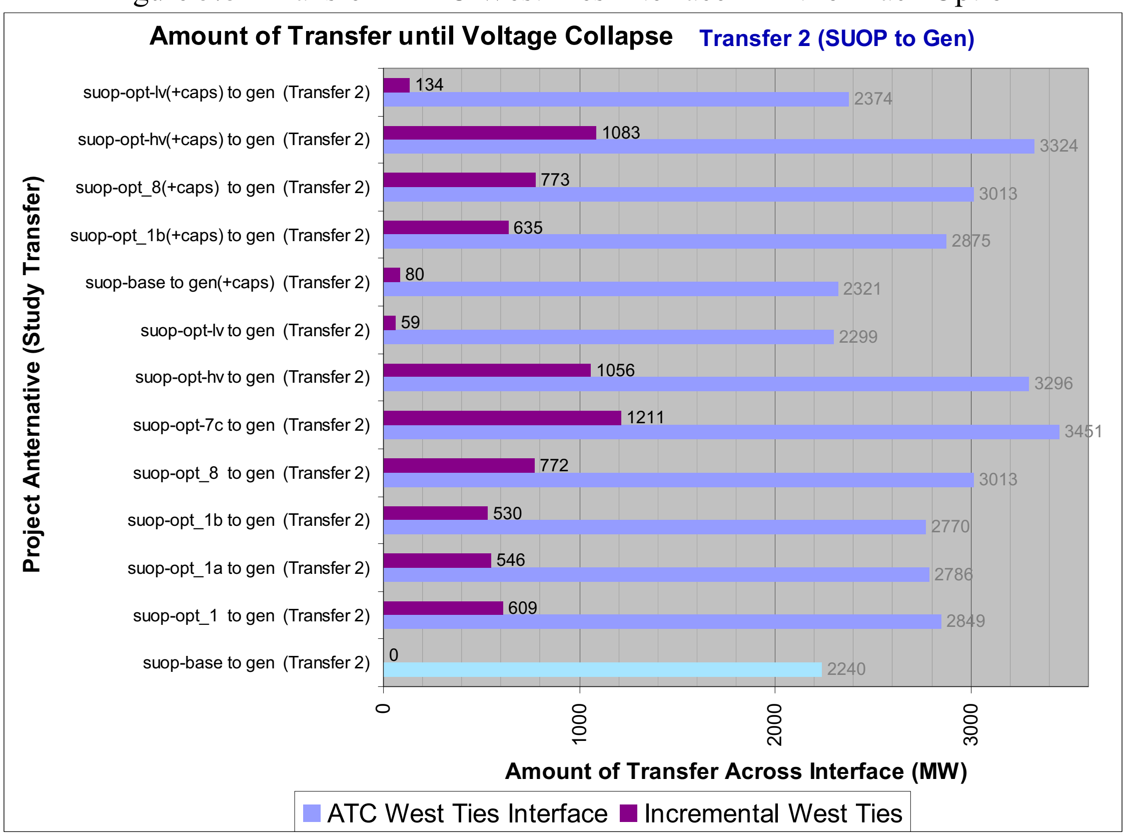


Figure 5.9 - Transfer 2 ATC Import Interface Limit for Each Option

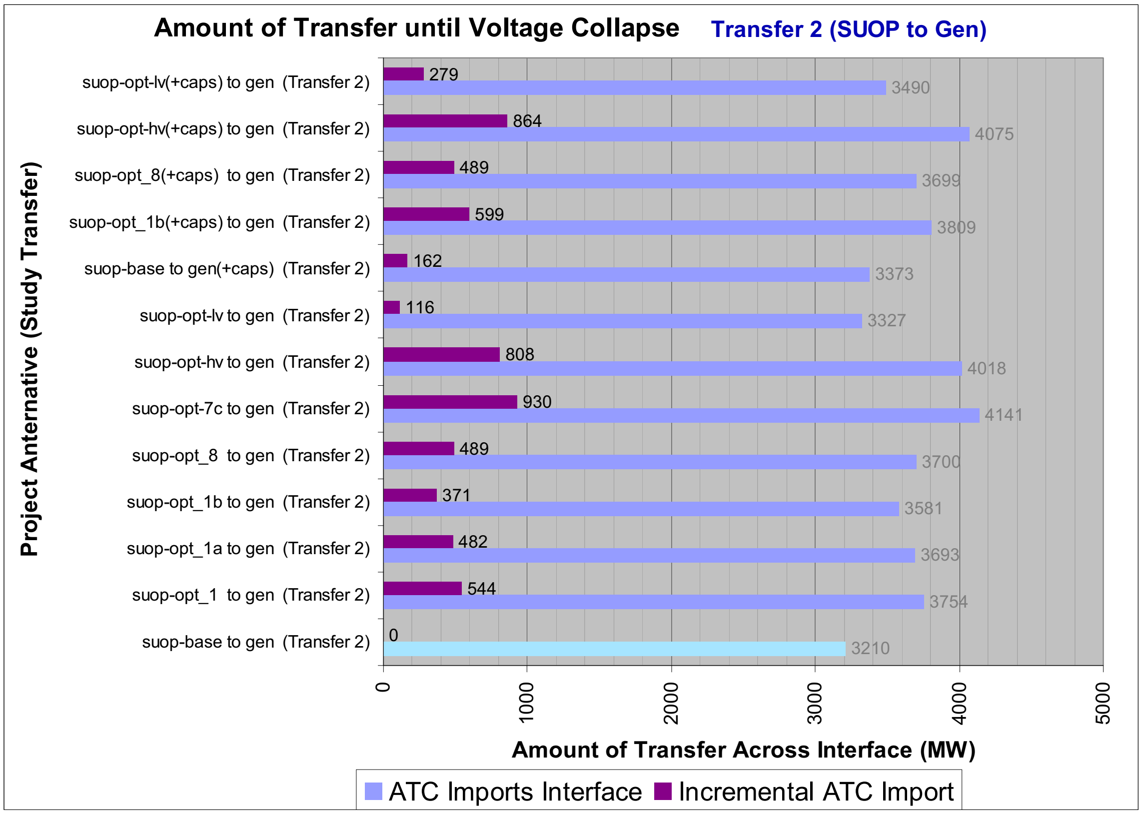


Figure 5.10 - Transfer 3 ATC West Ties Interface Limit for Each Option

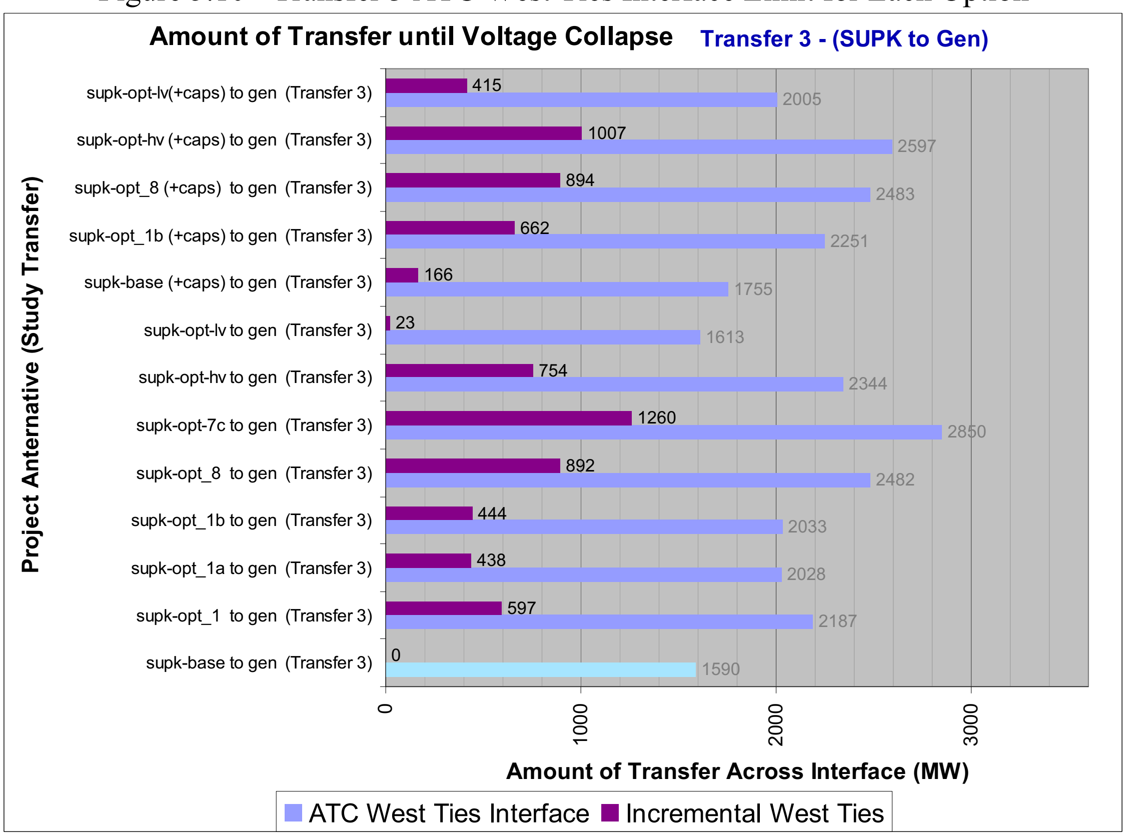
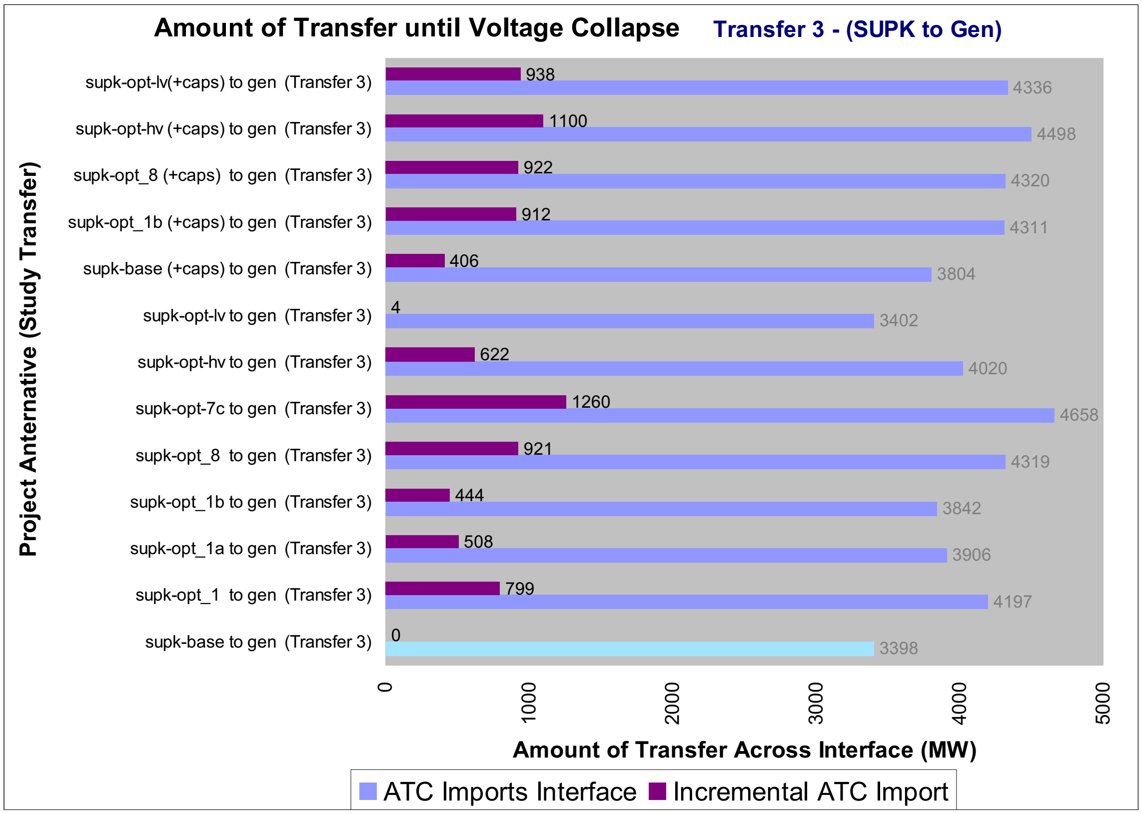


Figure 5.11 - Transfer 3 ATC Import Interface Limit for Each Option



The simulations increment the test transfer until one of the test contingencies or other criterion demonstrates voltage collapse. At that point the simulation is ceased for all contingencies.

Contains Critical Energy Infrastructure Information

The Transfer 1 simulations terminated at a lower transfer level than experienced for Transfers 2 and 3. Contains Critical Energy Infrastructure Information

Contains Critical Energy Infrastructure Information In the SUOP case, a number of generation reactive resources are not participating due to their economic dispatch for the off-peak period.

PV Analysis – Plot Interpretation

For this study, the PV charts show the voltage changes versus flows across multi-line interfaces. This report focuses on the flows across the ATC western WI tie lines interface, and the ATC import interface. However, as a simpler example, an interface may consist of a single line.

As the power transfer increases the reported voltage in the PV chart will eventually progress downward. The largest voltage drops may be seen at the points closest to the critical collapse, but the voltage reductions will also be seen to a lesser extent at other locations on the system. The limited number of charts provided in this report focus on the use of some locations (such as Spring Green) which are considered central to the impacted study region.

The interface flows in the PV chart may or may not start at the same amount. When plotted against ATC import levels, they all start at the same import amount, but when plotted against the ATC West Tie flows they do not. The definition of the West Tie flows is adjusted for each transmission option. The new facilities impact (increase) the starting flows across the interface when compared to the flows experienced in the base case.

For this study, charts are also provided that show changes in MW (or MVAR) losses versus flows across multi-line interfaces. As the power transfers increase, the reported losses will likely increase. Losses can decrease for situations where transfer may reduce flow, but the general trend will likely be upward at higher transfer levels.

The charts may have a less smooth progression that can be attributed to a number of possible conditions including but not limited to: transfers reducing some line flows; transfers reaching levels where some generators may be turned off; activation of switched shunts and capacitors; adjustments of transformer ratios; reaching the maximum range of reactive control devices and phase shifter adjustments. In general, the calculations have more variability to these influences as they approach the collapse transfer limit.

For the loss charts, the notation of “ATC” will denote the facilities within ATC. The notation of “non-ATC (WWI)” denotes the facilities external to ATC that are within the study region identified in the study scope.

PV Analysis - Losses and Voltage Drop

As power transfers through resistive line impedances, it experiences real MW losses. As power transfers through reactive line impedances, it experiences MVAR losses and is a large contributor toward voltage drop across the line.

Decoupling of power flow equations show that real power flow (MW) is strongly correlated to voltage angle, and reactive power flow (MVAR) is strongly correlated to voltage magnitude.

MW flow through resistive line impedances largely contributes to the real MW losses in proportion to the square of the current times the resistance (I^2R). Current is based on MVA flow consisting of MW and MVAR component flows. The MW flow will typically be the largest component of MVA flow. Therefore without decoupling, the actual MW losses are slightly higher when based on the current of MVA flow.

Similarly, MVAR flow through reactive line impedances are a large contributor toward voltage drop across the line. However, the movement of MVARs is encumbered by the MVAR losses on a line during high power flow. Assuming small MVAR flows, the current from MW flows passing through reactive line impedances largely contributes to the MVAR losses in proportion to the square of the current times the reactance (I^2X). Without decoupling, the actual MVAR losses are higher based on the current of MVA flow.

In contrast to MVAR losses, transmission lines also have a line charging characteristic that produces MVARs. The line charging is more significant at higher voltage levels. Depending on overhead construction type, at 345 kV it can be on the order of 0.8 MVAR - 1.0 MVAR per mile for overhead transmission. At 765 kV it can be on the order of 4 MVAR – 5 MVAR per mile for overhead. The line charging helps to support line voltage and offsets some of the reactive MVAR losses on the line. The theoretical point where line reactive losses are equal to the line charging is called the Surge Impedance Loading (SIL). Transfer of power above the SIL implies that the transmission line will need external compensation to help with the line flow. That compensation can come from other sources such as capacitors or generation MVAR support. At high power transfers above SIL, the square function of I^2X MVAR losses will grow at an increasing rate. Large reactive line losses are one of the characteristics that can lead to voltage collapse conditions. The SIL rating is based on line construction characteristics and is independent of line length. SIL ratings are an engineering line characteristic measure and they are not related to actual operating limits for the line which are usually higher. A typical 345 kV line may have a SIL of approximated 300 MW – 400 MW.

As an example of SIL properties, consider a 100-mile line with a SIL of 300 MW. Such a line may have line charging of about 90 MVAR. Using 100 MVA base, a 300 MVA (or MW) flow will have approximately a 3 per unit current. At 600 MVA (or MW) the per unit current will be about 6. Doubling the current will produce four times the reactive losses. The MVAR losses for the flow above 300 MW will need to be compensated. At 600 MW of flow (2 x SIL), 270 MVAR of external MVAR compensation may be required to serve the reactive line losses. At higher flows, the MVAR losses increase at ever higher rates.

PV Analysis - Charts

Output of the VSAT runs were compiled to produce various chart views that compare results across the various transmission options. Detailed charts are provided in Appendix F for each test transfer. Some charts show voltage performance for power transfer across interfaces. Other charts show how losses change as power flows across the interfaces. The charts provide some insight into the voltage stability simulations.

Contains Critical Energy Infrastructure Information

Contains Critical Energy Infrastructure Information

For each test transfer, the following Power vs. Voltage (PV) charts can be found in Appendix F:

ATC West Tie Flow (Contains Critical Energy Infrastructure Information
ATC West Tie Flow (
ATC West Tie Flow (

ATC Imports (Contains Critical Energy Infrastructure Information
ATC Imports (
ATC Imports (

Real (MW) and reactive (MVAR) losses increase as power flow increases across the Western ties interface or the ATC Import interface. For each test transfer, the following Power vs. Loss (PL) charts can be found in Appendix F:

ATC West Tie Flow (Contains Critical Energy Infrastructure Information vs. ATC(WWI) MW losses
ATC West Tie Flow (vs. Non-ATC(WWI) MW losses
ATC West Tie Flow ( ) vs. ATC(WWI) MW losses
ATC West Tie Flow (vs. ATC(WWI) MW losses

ATC West Tie Flow (Contains Critical Energy Infrastructure Information vs. ATC(WWI) MVAR line losses
ATC West Tie Flow (vs. Non-ATC(WWI) MVAR line losses
ATC West Tie Flow ( ) vs. ATC(WWI) MVAR line losses
ATC West Tie Flow (vs. ATC(WWI) MVAR line losses

ATC Imports (Contains Critical Energy Infrastructure) vs. ATC(WWI) MVAR line losses
ATC Imports (Information) vs. Non-ATC MVAR line losses

Contains Critical Energy Infrastructure Information (also located in Appendix F) are samples of the Power vs. s.

Contains Critical Energy Infrastructure Information

PV Analysis - Integrated Evaluation of Characteristic Strengths

This report objectively evaluates each transmission option by numerically scoring a sampling of voltage stability characteristic strengths. The characteristic strengths are broken up into three categories: transfer achieved before collapse, voltage performance and loss performance.

Each category is composed of various scores ranging from poorest (score of 0) to best (score of 5). Scoring is based on an improvement in performance compared to the base case. No change in performance is treated as a score of 1. Any decrease in performance is scored as 0. The following scoring tables show various selected characteristic attributes of voltage robustness. Table 5.8 summarizes the results for the Summer Off-Peak Transfer 1. Table 5.9 summarizes the results for the Summer Off-Peak Transfer 2. Table 5.10 summarizes the results for the Summer Peak Transfer 3.

The selected characteristics for scoring provide a balanced mix of characteristics that measure the amount of transfers before collapse, voltage performance at common transfer levels and loss performance. Each summarized characteristic is given a score and it is color coded. Comparing between projects, the high or low deviation from the base case reported values are used to determine the graduated scores from 1 to 5. A score of zero indicates that it performed worse than the base starting case. Voltage was scored slightly different in that some minimum and maximum voltage ranges were applied where results did not exceed those values. Voltage was scored with a low score value based on the lower of 0.95 p.u. and the base case value. Voltage was scored with a high score value based on the higher of the 1.0 p.u. and the best voltage.

The scoring tables evaluate an overall score using the weighting shown for each characteristic. The three scoring categories were chosen to be rather evenly weighted, but with a slightly higher weighting on the transfer capability. Voltage stability limits typically assign facility ratings based on voltage stability under transfer. The overall score places a 40% weighting on the transfer before collapse, a 30% weighting on voltage performance at common transfer levels and a 30% weighting on loss performance.

Table 5.8 - Summary of SUOP Transfer 1 Results

Category	Description: Evaluated Characteristic Improvement	Interface Or Location	Transfer Level	Contains Critical Energy Infrastructure Information	Wt	Opt 1	Opt 1a	**Opt 1b**	**Opt 8**	Opt 7c	**Opt HV**	**Opt LV**	Base + caps	Opt 1b + caps	Opt 8 + caps	Opt HV + caps	Opt LV + caps
	Transfer 1 -- SUOP to Load																
TRASFER 40%	**Incremental Transfer**	**Source Transfer**	at collapse level		10	2.3	2.3	2.3	2.3	3.0	4.7	1.0	2.7	2.3	2.3	5.0	4.0
	Transfer Limit	**ATC West Ties**	at collapse level		10	2.7	2.6	2.7	3.4	4.4	4.8	0.0	1.7	2.7	3.4	5.0	2.3
	Transfer Limit	**ATC Import**	at collapse level		10	2.3	2.3	2.3	2.3	3.0	4.7	1.0	2.7	2.3	2.3	5.0	4.1
	Differences in Regional Flow Through ATC																
	Regional Flow	(W. Ties) - (Imports)	at Base collapse		3.333	2.9	2.7	3.1	3.9	5.0	4.4	0.0	1.0	3.1	3.9	4.4	0.0
	Regional Flow	(W. Ties) - (Imports)	at Base collapse		3.333	2.7	2.6	2.7	4.0	5.0	4.0	0.0	1.0	2.7	4.0	4.0	1.0
	Regional Flow	(W. Ties) - (Imports)	at Base collapse		3.333	2.8	2.6	2.8	4.0	5.0	3.9	0.0	1.2	2.8	4.0	3.9	1.2
VOLTAGE PROFILE 30.0%	**p.u. Voltage**	Spring Green 138kV	at Base collapse		1	2.9	2.1	5.0	2.3	3.5	4.8	3.4	4.1	5.0	2.4	4.8	3.8
	p.u. Voltage	N. Monroe 138kV	at Base collapse		1	3.7	3.4	3.8	3.6	4.0	5.0	2.2	4.1	3.8	3.6	5.0	4.0
	p.u. Voltage	Hilltop 69kV	at Base collapse		1	3.9	3.9	4.2	3.8	3.8	3.6	3.0	3.2	4.1	3.9	3.6	3.2
	p.u. Voltage	Boscobell 69kV	at Base collapse		1	3.9	3.9	3.9	4.3	4.2	3.3	3.1	2.6	3.8	4.3	3.3	3.5
	p.u. Voltage	Paddock 138kV	at Base collapse		1	3.2	3.0	3.3	3.3	3.7	4.3	2.0	2.6	3.3	3.4	4.3	2.7
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	4.0	3.4	5.0	4.1	4.6	4.6	2.9	3.9	5.0	4.2	4.6	3.6
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	2.8	2.9	3.6	2.6	3.1	2.9	0.0	1.4	3.6	2.7	2.8	1.3
	p.u. Voltage	Hillsboro 161kV	at Base collapse		1.25	3.3	4.7	5.0	4.7	3.3	3.0	3.4	3.6	5.0	4.7	3.0	3.6
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	3.5	3.4	3.7	3.7	4.0	3.1	1.7	1.6	3.7	3.8	3.1	2.3
	p.u. Voltage	Richland Ctr 69kV	at Base collapse		1.25	3.5	3.8	4.6	4.1	4.0	3.4	2.4	2.7	4.6	4.1	3.4	2.9
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	1.9	1.1	4.1	1.3	2.8	4.1	0.0	2.9	4.2	1.4	4.1	2.5
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	3.0	3.3	3.4	3.1	3.4	2.9	0.0	2.0	3.4	3.1	2.9	2.0
	p.u. Voltage	Hillsboro 161kV	at Base collapse		1.25	3.4	4.9	5.0	5.0	3.4	3.1	3.6	4.0	5.0	5.0	3.1	4.1
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	3.6	3.6	3.6	3.9	4.1	3.2	1.6	2.0	3.6	4.0	3.2	2.8
	p.u. Voltage	Richland Ctr 69kV	at Base collapse		1.25	3.5	3.9	4.2	4.3	4.0	3.2	2.0	2.9	4.3	4.3	3.3	3.1
	p.u. Voltage	Paddock 138kV	at Base collapse		1.25	1.7	1.6	1.9	1.7	2.1	2.3	0.0	2.9	1.9	1.7	2.2	2.9
	p.u. Voltage	N. Monroe 138kV	at Base collapse		1.25	2.1	2.0	2.4	2.1	2.8	4.8	0.0	3.2	2.4	2.1	4.8	3.1
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	1.4	0.0	3.6	0.0	2.8	4.4	0.0	3.1	3.7	1.0	4.4	2.8
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	2.4	1.7	5.0	2.0	3.3	4.7	2.9	3.8	5.0	2.0	4.7	3.4
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	3.4	3.4	3.9	3.3	3.5	3.2	2.2	2.3	3.9	3.3	3.2	2.4
	p.u. Voltage	W. Middleton 138kV	at Base collapse		1.25	2.3	1.8	2.9	1.9	2.9	2.2	0.0	1.8	3.0	2.0	2.3	2.0
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	3.9	3.8	3.9	3.7	3.4	3.2	2.4	2.9	3.8	3.7	3.2	2.7
	p.u. Voltage	Hillsboro 161kV	at Base collapse		1.25	3.7	4.9	5.0	4.9	3.2	2.9	3.9	3.8	5.0	5.0	2.9	4.0
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	2.9	2.2	5.0	2.3	3.5	4.8	3.4	4.0	5.0	2.4	4.8	3.8
MW & MVAR LOSS 30%	**MW loss**	**ATC**	w/o transfer		2.5	5.0	4.3	3.9	3.2	4.6	3.4	1.8	1.1	4.0	3.3	3.4	2.0
	MW loss	ATC	at Base collapse		2.5	5.0	3.7	3.5	3.1	4.2	3.9	1.4	1.2	3.5	3.1	3.9	1.8
	MW loss	**External_WWI**	w/o transfer		2.5	0.0	0.0	0.0	2.0	1.3	4.9	0.0	1.1	0.0	2.0	5.0	0.0
	MW loss	External_WWI	at Base collapse		2.5	1.6	2.5	2.2	2.0	3.3	4.9	0.0	1.1	2.3	2.0	5.0	0.0
	MVAR line loss	ATC	**w/o transfer**		2	5.0	3.7	3.5	1.4	2.6	1.1	3.2	1.1	3.5	1.4	1.2	3.5
	MVAR line loss	**ATC**	**at Base collapse**		2	5.0	2.5	2.2	1.6	2.2	1.7	2.4	1.3	2.2	1.7	1.7	3.0
	MVAR line loss	ATC	at Base collapse		2	5.0	2.4	3.1	1.8	2.3	1.5	2.3	1.7	3.2	1.9	1.5	3.1
	MVAR line loss	ATC	at Base collapse		2	5.0	3.0	2.9	2.6	3.4	2.3	1.8	2.0	2.9	2.6	2.4	3.1
	MVAR line loss	ATC	at Base collapse		2	5.0	3.3	3.3	2.8	3.8	4.2	1.9	3.4	3.4	2.9	4.2	4.6
	MVAR line loss	**External_WWI**	w/o transfer		2	0.0	0.0	0.0	1.7	0.0	4.8	0.0	1.2	0.0	1.7	5.0	0.0
	MVAR line loss	**External_WWI**	at Base collapse		2	0.0	1.9	1.6	1.9	2.8	4.8	0.0	1.2	1.8	1.9	5.0	0.0
	MVAR line loss	External_WWI	at Base collapse		2	0.0	1.3	1.9	1.4	1.9	4.8	0.0	1.2	2.1	1.4	5.0	0.0
	MVAR line loss	External_WWI	at Base collapse		2	0.0	1.9	1.6	2.0	2.8	4.8	0.0	1.4	1.8	2.0	5.0	0.0
	MVAR line loss	External_WWI	at Base collapse		2	0.0	1.9	1.5	1.9	2.7	4.8	0.0	1.3	1.7	1.9	5.0	0.0
	Transfer 1 - Transfer Score		**Weighted Average**		40	2.5	2.5	2.5	3.0	3.9	4.6	0.5	2.0	2.6	3.0	4.8	2.8
	Transfer 1 - Voltage Score		**Weighted Average**		30	2.9	2.9	3.8	3.0	3.3	3.4	1.8	2.8	3.8	3.1	3.4	2.9
	Transfer 1 - Losses Score		**Weighted Average**		30	2.6	2.3	2.2	2.1	2.7	3.8	1.0	1.4	2.3	2.2	3.8	1.5
	Transfer 1 TOTAL		**Weighted Average**		100	2.7	2.6	2.8	2.8	3.4	4.0	1.1	2.1	2.9	2.8	4.1	2.4
						1	1a	1b	8	7c	HV	LV	B	1b	8	HV	LV

Score (0=Worse, 1=No Change, 5=Best)

Table 5.9 - Summary of SUOP Transfer 2 Results

Category	Evaluated Characteristic Improvement	Interface Or Location	Transfer Level	Contains Critical Energy Infrastructure Information	Wt	Opt 1	Opt 1a	Opt 1b	Opt 8	Opt 7c	Opt HV	Opt LV	Base + claps	Opt 1b + caps	Opt 8 + caps	Opt HV + caps	Opt LV + caps
	Transfer 2 -- SUOP to Gen																
TRANSFER 40%	**Incremental Transfer**	**Source Transfer**	at collapse level		10	3.4	3.1	2.6	3.1	5.0	4.5	1.5	1.7	3.6	3.1	4.8	2.2
	Transfer Limit	**ATC West Ties**	at collapse level		10	3.0	2.8	2.8	3.6	5.0	4.5	1.2	1.3	3.1	3.6	4.6	1.4
	Transfer Limit	**ATC Import**	at collapse level		10	3.3	3.1	2.6	3.1	5.0	4.5	1.5	1.7	3.6	3.1	4.7	2.2
	Differences in Regional Flow Through ATC																
	Regional Flow	(W. Ties) - (Imports)	at Base collapse		3.333	3.0	2.8	3.1	3.7	5.0	4.5	1.1	0.0	3.1	3.7	4.5	1.2
	Regional Flow	(W. Ties) - (Imports)	at Base collapse		3.333	2.8	2.6	2.8	3.8	5.0	4.3	0.0	1.0	2.8	3.8	4.3	1.0
	Regional Flow	(W. Ties) - (Imports)	at Base collapse		3.333	2.9	2.7	2.9	3.8	5.0	4.6	1.1	0.0	2.9	3.8	4.6	1.2
VOLTAGE PROFILE 30%	**p.u. Voltage**	Spring Green 138kV	at Base collapse		1	1.6	0.0	4.4	1.1	2.8	4.2	0.0	2.1	4.4	1.1	4.2	2.1
	p.u. Voltage	N. Monroe 138kV	at Base collapse		1	3.7	3.0	4.2	3.7	4.5	4.5	0.0	3.8	4.2	3.7	4.5	3.2
	p.u. Voltage	Hilltop 69kV	at Base collapse		1	2.1	2.7	2.9	2.0	2.9	2.6	1.1	1.3	2.9	2.0	2.6	1.3
	p.u. Voltage	Boscobell 69kV	at Base collapse		1	3.2	3.0	2.8	3.3	3.7	2.5	1.5	0.0	2.9	3.3	2.6	1.8
	p.u. Voltage	Paddock 138kV	at Base collapse		1	2.4	2.0	2.7	2.5	3.0	2.3	0.0	2.6	2.7	2.5	2.3	2.6
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	1.5	0.0	4.0	1.2	3.2	3.6	0.0	1.3	4.0	1.2	3.6	2.8
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	2.5	3.0	3.4	2.4	3.7	3.1	0.0	0.0	3.4	2.4	3.2	1.6
	p.u. Voltage	Hillsboro 161kV	at Base collapse		1.25	4.5	3.8	4.2	3.6	3.6	4.0	1.2	0.0	4.2	3.6	4.0	2.2
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	3.4	3.0	3.1	3.1	4.0	3.1	1.2	0.0	3.1	3.1	3.1	2.2
	p.u. Voltage	Richland Ctr 69kV	at Base collapse		1.25	3.7	3.0	3.6	3.1	3.8	3.3	0.0	0.0	3.6	3.1	3.3	2.0
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	2.1	1.5	3.7	1.9	3.1	4.0	0.0	2.3	3.8	1.9	3.8	3.2
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	2.5	3.0	3.1	2.6	3.4	3.0	0.0	1.9	3.1	2.6	2.7	2.1
	p.u. Voltage	Hillsboro 161kV	at Base collapse		1.25	2.6	4.2	4.4	4.1	3.1	2.3	2.1	2.6	4.4	4.1	2.0	3.2
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	3.2	3.1	2.9	3.4	3.9	2.9	1.4	1.4	2.9	3.3	2.8	2.7
	p.u. Voltage	Richland Ctr 69kV	at Base collapse		1.25	3.2	3.2	3.4	3.5	3.7	2.8	1.2	2.1	3.4	3.5	2.6	2.7
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	1.8	1.1	4.1	1.2	2.9	4.0	0.0	2.2	4.1	1.2	4.0	2.4
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	2.5	2.7	2.9	2.0	2.9	2.5	1.0	1.6	2.9	1.9	2.4	1.2
	p.u. Voltage	Council Cr 138kV	at Base collapse		1.25	2.9	4.0	4.3	3.8	4.4	4.4	1.7	2.4	4.2	3.8	4.3	1.8
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	3.2	3.1	2.8	3.2	3.7	2.5	1.7	0.0	2.8	3.3	2.5	1.9
	p.u. Voltage	Bell Center 161kV	at Base collapse		1.25	2.7	3.4	3.6	3.7	3.3	2.8	1.5	1.6	3.6	3.7	2.8	2.0
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	2.6	2.3	2.4	3.2	3.0	2.0	0.0	0.0	2.3	3.2	2.0	1.2
	p.u. Voltage	Richland Ctr 69kV	at Base collapse		1.25	3.0	3.3	3.6	3.8	3.2	2.6	1.5	2.0	3.6	3.8	2.7	1.9
	p.u. Voltage	W. Middleton 138kV	at Base collapse		1.25	2.3	1.7	3.2	1.9	3.3	1.7	1.0	2.7	3.2	1.9	2.0	2.8
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	1.7	0.0	4.4	1.3	3.3	3.8	0.0	2.3	4.4	1.3	4.0	2.6
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	2.0	2.7	3.0	2.1	3.1	2.4	0.0	1.3	3.0	2.0	2.5	1.4
MW & MVAR LOSS 30%	**MW loss**	**ATC**	w/o transfer		2.5	5.0	4.3	3.9	3.2	4.6	3.4	1.8	1.1	4.0	3.3	3.4	2.0
	MW loss	ATC	at Base collapse		2.5	5.0	3.6	3.7	2.9	4.1	3.7	1.3	1.4	3.7	2.9	3.7	1.8
	MW loss	**External_WWI**	w/o transfer		2.5	0.0	0.0	0.0	2.0	1.3	4.9	0.0	1.1	0.0	2.0	5.0	0.0
	MW loss	External_WWI	at Base collapse		2.5	2.0	2.6	2.6	1.9	3.4	5.0	0.0	1.2	2.6	1.9	5.0	0.0
	MVAR line loss	ATC	**w/o transfer**		2	5.0	3.7	3.5	1.4	2.6	1.1	3.2	1.1	3.5	1.4	1.2	3.5
	MVAR line loss	**ATC**	**at Base collapse**		2	5.0	2.1	2.1	1.4	1.7	0.0	2.3	1.6	2.1	1.4	0.0	3.0
	MVAR line loss	ATC	at Base collapse		2	5.0	1.9	2.1	1.6	2.2	0.0	2.1	1.3	2.1	1.6	0.0	3.0
	MVAR line loss	ATC	at Base collapse		2	5.0	2.7	2.7	2.4	3.1	1.6	1.7	2.1	2.7	2.4	1.6	3.1
	MVAR line loss	ATC	at Base collapse		2	5.0	2.3	2.2	1.5	1.9	0.0	2.3	1.8	2.3	1.5	0.0	3.0
	MVAR line loss	**External_WWI**	w/o transfer		2	0.0	0.0	0.0	1.7	0.0	4.8	0.0	1.2	0.0	1.7	5.0	0.0
	MVAR line loss	**External_WWI**	at Base collapse		2	0.0	2.3	2.2	1.9	3.1	4.9	0.0	1.3	2.3	1.9	5.0	0.0
	MVAR line loss	External_WWI	at Base collapse		2	0.0	2.3	2.2	1.8	2.7	4.9	1.1	1.1	2.3	1.8	5.0	1.2
	MVAR line loss	External_WWI	at Base collapse		2	0.0	2.3	2.2	2.0	3.2	4.9	0.0	1.3	2.3	2.0	5.0	0.0
	MVAR line loss	External_WWI	at Base collapse		2	0.0	2.6	2.5	2.2	3.2	4.9	0.0	1.4	2.6	2.2	5.0	0.0
	Transfer 2 - Transfer Score		**Weighted Average**		40	3.2	2.9	2.7	3.4	5.0	4.5	1.2	1.3	3.3	3.4	4.6	1.7
	Transfer 2 - Voltage Score		**Weighted Average**		30	2.7	2.5	3.5	2.7	3.4	3.1	0.7	1.5	3.5	2.7	3.1	2.2
	Transfer 2 - Losses Score		**Weighted Average**		30	2.7	2.4	2.3	2.0	2.7	3.2	1.1	1.3	2.3	2.0	3.3	1.4
	Transfer 2 TOTAL		**Weighted Average**		100	2.9	2.6	2.8	2.8	3.8	3.7	1.0	1.3	3.1	2.8	3.8	1.8
						1	1a	1b	8	7c	HV	LV	B	1b	8	HV	LV

Score (0=Worse, 1=No Change, 5=Best)

Table 5.10 - Summary of SUPK Transfer 3 Results

	Description: Evaluated Characteristic Improvement	Interface Or Location	Transfer Level	Contains Critical Energy Infrastructure Information	Wt	Opt 1	Opt 1a	Opt 1b	Opt 8	Opt 7c	Opt HV	Opt LV	Base + caps	Opt 1b + caps	Opt 8 + caps	Opt HV + caps	Opt LV + caps
	Transfer 3 -- SUPK to Gen																
TRANSFER 40%	**Incremental Transfer**	**Source Transfer**	at collapse level		10	3.5	2.6	2.5	3.9	5.0	3.0	1.0	2.3	3.9	3.9	4.5	3.9
	Transfer Limit	**ATC West Ties**	at collapse level		10	2.9	2.4	2.4	3.8	5.0	3.4	1.1	1.5	3.1	3.8	4.2	2.3
	Transfer Limit	**ATC Import**	at collapse level		10	3.5	2.6	2.4	3.9	5.0	3.0	1.0	2.3	3.9	3.9	4.5	4.0
	Differences in Regional Flow Through ATC																
	Regional Flow	(W. Ties) - (Imports)	at Base collapse		3.333	2.7	2.5	2.8	4.1	5.0	4.0	1.2	1.3	2.8	4.1	4.0	1.2
	Regional Flow	(W. Ties) - (Imports)	at Base collapse		3.333	2.6	2.4	2.7	4.2	5.0	3.7	1.2	1.1	2.7	4.2	3.7	1.3
	Regional Flow	(W. Ties) - (Imports)	at Base collapse		3.333	2.5	2.4	2.6	4.2	5.0	3.4	1.1	1.3	2.6	4.2	3.4	1.2
VOLTAGE PROFILE 30.0%	**p.u. Voltage**	Spring Green 138kV	at Base collapse		1	1.9	1.3	3.3	1.0	2.7	2.9	1.6	2.0	3.3	1.0	3.1	2.2
	p.u. Voltage	Hilltop 69kV	at Base collapse		1	3.3	2.5	2.7	2.4	3.2	2.6	1.4	1.3	2.7	2.4	2.7	1.6
	p.u. Voltage	Boscobell 69kV	at Base collapse		1	3.6	3.4	3.2	3.8	4.5	3.0	2.4	1.8	3.2	3.8	3.1	2.8
	p.u. Voltage	Richland Ctr 69kV	at Base collapse		1	4.3	3.7	4.0	4.0	4.5	3.8	3.2	3.1	4.0	4.0	4.0	3.5
	p.u. Voltage	**Verona 138kV**	at Base collapse		1	1.7	1.5	1.8	1.5	2.0	1.4	0.0	1.3	1.8	1.5	2.2	2.5
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	1.7	1.1	3.0	1.3	2.7	2.7	0.0	1.6	3.0	1.3	2.8	2.1
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	3.0	2.5	2.6	2.4	3.1	2.6	1.3	1.4	2.6	2.4	2.6	1.7
	p.u. Voltage	Hillsboro 161kV	at Base collapse		1.25	4.0	2.8	2.9	3.0	3.6	2.9	1.6	1.7	2.9	3.0	2.9	2.0
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	3.5	3.3	3.3	3.7	4.3	3.1	1.9	1.6	3.3	3.7	3.1	2.5
	p.u. Voltage	Richland Ctr 69kV	at Base collapse		1.25	3.4	2.8	3.2	3.2	3.9	3.1	1.8	1.8	3.2	3.2	3.1	2.5
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	3.4	3.0	3.7	3.0	3.7	3.7	1.4	2.4	3.7	3.0	3.8	3.5
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	3.7	3.3	3.3	3.4	3.8	3.4	1.5	2.0	3.3	3.4	3.5	2.8
	p.u. Voltage	Hillsboro 161kV	at Base collapse		1.25	4.4	3.4	3.5	3.8	4.2	3.5	1.7	2.0	3.5	3.8	3.6	2.8
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	4.1	3.9	3.7	4.2	4.5	3.7	1.9	2.2	3.8	4.2	3.8	3.4
	p.u. Voltage	Richland Ctr 69kV	at Base collapse		1.25	4.1	3.7	3.8	4.0	4.3	3.8	2.0	2.4	3.9	4.0	3.9	3.5
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	1.6	0.0	2.9	0.0	2.3	2.5	0.0	1.7	2.9	0.0	2.7	1.8
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	3.2	2.1	2.4	2.2	2.9	2.3	1.1	1.2	2.4	2.2	2.3	1.4
	p.u. Voltage	Council Cr 138kV	at Base collapse		1.25	3.7	4.2	4.4	4.4	5.0	4.6	3.0	3.4	4.4	4.3	4.7	3.1
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	3.4	3.1	2.9	3.6	4.2	2.7	1.7	1.5	2.9	3.6	2.7	2.3
	p.u. Voltage	Bell Center 161kV	at Base collapse		1.25	3.8	2.9	3.0	3.5	3.7	3.0	1.5	2.1	3.0	3.5	3.0	1.8
	p.u. Voltage	Boscobell 69kV	at Base collapse		1.25	3.2	2.8	2.8	3.4	3.8	2.6	1.1	1.4	2.8	3.4	2.6	1.6
	p.u. Voltage	Richland Ctr 69kV	at Base collapse		1.25	3.8	3.1	3.4	3.7	4.1	3.3	1.6	2.5	3.5	3.7	3.4	2.1
	p.u. Voltage	Hilltop 69kV	at Base collapse		1.25	3.5	2.2	2.3	2.1	2.5	2.4	0.0	1.1	2.4	2.2	2.4	1.1
	p.u. Voltage	Hillsboro 161kV	at Base collapse		1.25	4.1	2.2	2.4	2.4	2.8	2.4	1.2	1.0	2.4	2.4	2.4	1.3
	p.u. Voltage	Spring Green 138kV	at Base collapse		1.25	1.9	1.3	3.1	1.2	2.6	2.7	1.2	1.6	3.1	1.2	2.9	1.8
MW & MVAR LOSS 30%	**MW loss**	**ATC**	w/o transfer		2.5	3.8	3.5	1.7	4.7	5.0	1.6	1.7	0.0	1.8	4.7	1.8	1.5
	MW loss	ATC	at Base collapse		2.5	5.0	3.9	3.3	3.8	4.9	1.7	0.0	1.2	3.4	3.8	1.8	1.4
	MW loss	**External_WWI**	w/o transfer		2.5	1.3	0.0	0.0	1.7	2.0	5.0	0.0	0.0	0.0	1.7	5.0	1.0
	MW loss	External_WWI	at Base collapse		2.5	1.6	1.7	1.7	2.1	2.8	5.0	1.4	1.0	1.8	2.1	5.0	1.4
	MVAR line loss	ATC	**w/o transfer**		2	4.4	3.7	2.0	4.8	5.0	1.2	1.4	0.0	2.0	4.7	1.5	0.0
	MVAR line loss	**ATC**	**at Base collapse**		2	5.0	3.0	2.4	2.6	3.4	0.0	0.0	1.1	2.4	2.6	0.0	1.5
	MVAR line loss	ATC	at Base collapse		2	5.0	3.0	2.7	3.3	3.7	0.0	1.1	1.9	2.7	3.3	0.0	1.8
	MVAR line loss	ATC	at Base collapse		2	5.0	3.9	3.6	4.1	4.6	2.5	1.5	2.4	3.7	4.1	2.6	3.1
	MVAR line loss	ATC	at Base collapse		2	5.0	3.0	2.5	3.1	3.6	0.0	1.0	1.7	2.5	3.1	0.0	1.7
	MVAR line loss	**External_WWI**	w/o transfer		2	1.2	0.0	0.0	1.2	1.6	5.0	1.2	0.0	0.0	1.3	5.0	1.2
	MVAR line loss	**External_WWI**	at Base collapse		2	0.0	1.4	1.4	2.0	2.5	5.0	1.3	0.0	1.4	2.0	5.0	1.3
	MVAR line loss	External_WWI	at Base collapse		2	0.0	0.0	0.0	2.4	1.5	5.0	1.5	2.0	0.0	2.4	4.8	1.5
	MVAR line loss	External_WWI	at Base collapse		2	0.0	1.9	1.8	3.1	3.0	5.0	1.4	1.4	1.9	3.1	5.0	1.9
	MVAR line loss	External_WWI	at Base collapse		2	0.0	1.4	1.4	2.9	2.8	5.0	1.3	1.9	1.4	2.9	5.0	1.4
	Transfer 3 - Transfer Score		**Weighted Average**		40	3.1	2.5	2.5	4.0	5.0	3.3	1.1	1.8	3.4	4.0	4.2	2.9
	Transfer 3 - Voltage Score		**Weighted Average**		30	3.3	2.7	3.1	2.9	3.6	3.0	1.4	1.9	3.1	2.9	3.1	2.3
	Transfer 3 - Losses Score		**Weighted Average**		30	2.7	2.2	1.8	3.0	3.3	3.0	1.0	1.0	1.8	3.0	3.1	1.5
	Transfer 3 TOTAL		**Weighted Average**		100	3.0	2.5	2.5	3.3	4.1	3.1	1.2	1.6	2.8	3.3	3.5	2.3
						1	1a	1b	8	7c	HV	LV	B	1b	8	HV	LV

Score (0=Worse, 1=No Change, 5=Best)

To be comparable, some characteristics are measured at a common transfer level. The base case collapse transfer amount is considered the highest comparable point. At comparable transfer levels, the ATC import measure will be equivalent for each project, but the ATC West Ties interface flow will differ for each project.

The Transfer category examines the limits before collapse for the ATC West Ties interface, the ATC Import interface and the Source Transfer. The Source Transfer measures the amount of power transferred from source generation to sink location. As described above, the Source Transfer sinks mostly to ATC and partly to systems in the eastern part of the MISO region. A final measure of "ATC West Ties minus the ATC Imports" was included in the Transfer category to give a measure of regional value. This measure was evaluated at the base collapse point to give an indication of the amount of incremental power that can flow through the ATC system and out the ATC southern ties and Upper Peninsula Straits ties. It can also be described as a reduced dependency on the ATC southern (+Straits) ties for serving ATC imports. An ATC southern interface was not directly monitored, but rather it is calculated from the ATC West Ties and ATC Imports interfaces.

Figure 5.15 – Regional flow evaluation (ATC West Ties minus ATC Imports)

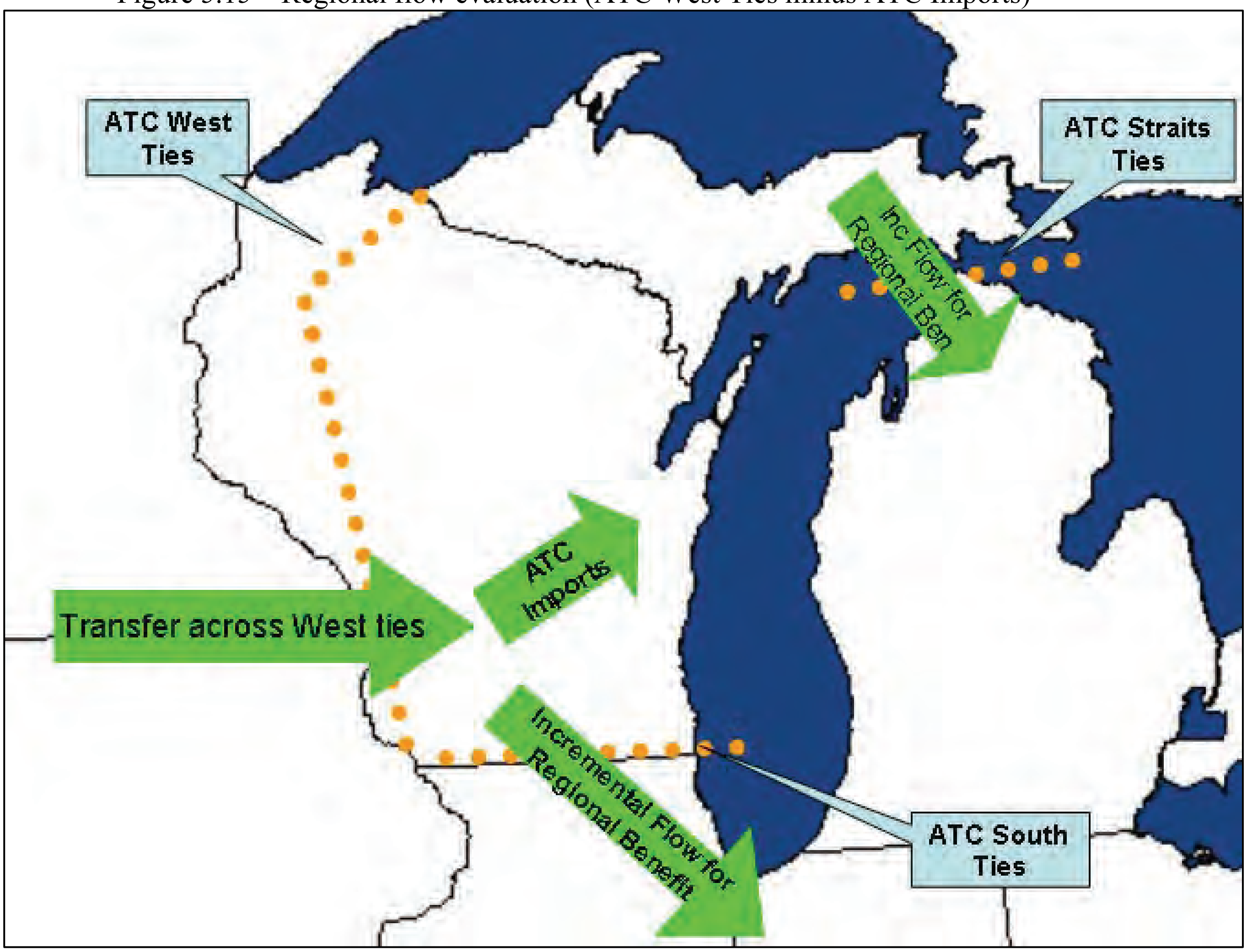


Table 5.11 shows the scoring category breakdown and the overall scoring of each project. Each transfer is weighted equally to determine the overall score.

Table 5.11 - Overall Summary of Voltage Performance

Description				Score (0=Worse, 1=No Change, 5=Best)											
Evaluated Characteristic Improvement	Interface Or Location	Transfer Level	Outage	Opt 1	Opt 1a	**Opt 1b**	**Opt 8**	Opt 7c	**Opt HV**	**Opt LV**	Base + caps	Opt 1b + caps	Opt 8 + caps	Opt HV + caps	Opt LV + caps
Transfer 1 - Transfer Score		**Weighted Average**		2.5	2.5	2.5	3.0	3.9	4.6	0.5	2.0	2.6	3.0	4.8	2.8
Transfer 1 - Voltage Score		**Weighted Average**		2.9	2.9	3.8	3.0	3.3	3.4	1.8	2.8	3.8	3.1	3.4	2.9
Transfer 1 - Losses Score		**Weighted Average**		2.6	2.3	2.2	2.1	2.7	3.8	1.0	1.4	2.3	2.2	3.8	1.5
Transfer 1 TOTAL		**Weighted Average**		2.7	2.6	2.8	2.8	3.4	4.0	1.1	2.1	2.9	2.8	4.1	2.4
Transfer 2 - Transfer Score		**Weighted Average**		3.2	2.9	2.7	3.4	5.0	4.5	1.2	1.3	3.3	3.4	4.6	1.7
Transfer 2 - Voltage Score		**Weighted Average**		2.7	2.5	3.5	2.7	3.4	3.1	0.7	1.5	3.5	2.7	3.1	2.2
Transfer 2 - Losses Score		**Weighted Average**		2.7	2.4	2.3	2.0	2.7	3.2	1.1	1.3	2.3	2.0	3.3	1.4
Transfer 2 TOTAL		**Weighted Average**		2.9	2.6	2.8	2.8	3.8	3.7	1.0	1.3	3.1	2.8	3.8	1.8
Transfer 3 - Transfer Score		**Weighted Average**		3.1	2.5	2.5	4.0	5.0	3.3	1.1	1.8	3.4	4.0	4.2	2.9
Transfer 3 - Voltage Score		**Weighted Average**		3.3	2.7	3.1	2.9	3.6	3.0	1.4	1.9	3.1	2.9	3.1	2.3
Transfer 3 - Losses Score		**Weighted Average**		2.7	2.2	1.8	3.0	3.3	3.0	1.0	1.0	1.8	3.0	3.1	1.5
Transfer 3 TOTAL		**Weighted Average**		3.0	2.5	2.5	3.3	4.1	3.1	1.2	1.6	2.8	3.3	3.5	2.3
				1	1a	1b	8	7c	HV	LV	B	1b	8	HV	LV
Overall Weighted Average (of Transfer 1, 2, 3)				2.9	2.6	2.7	3.0	3.8	3.6	1.1	1.7	2.9	3.0	3.8	2.2
Overall Weighted Average (of Transfer 2, 3) to Gen				3.0	2.5	2.6	3.1	4.0	3.4	1.1	1.5	2.9	3.1	3.6	2.0

For overall evaluation, the scoring is shown with and without the impact of Transfer 1 included.

PV Analysis - Additional Observations

Option 1 (NLAX-HLT-SPG-CDL) performed well with regard to voltage performance at common transfer levels and losses in the Hilltop area. This can be attributed in part to the Hilltop transformer and Hilltop low voltage outlet facilities. While Option 1 reduces MW and MVAR losses within the ATC portion of the study region, it increases MW and MVAR losses in the study region external to ATC. The external loss differences can be attributed in part to the impact of the additional power that is channeled through the ATC West Ties interface.

For the 765 kV Option, voltage performed well in Transfer 1.
Contains Critical Energy Infrastructure Information
includes a 765 kV line to North Monroe and double circuit 345 kV from North Monroe to Paddock. Contains Critical Energy Infrastructure Information

The non-ATC MW and MVAR losses for the 765 kV Option performed well, while the ATC MVAR losses in the ATC region performed poorly. Examining the detail of the ATC MVAR losses shows that loss efficiencies at higher voltage levels are partially offset by higher losses on facilities below 100 kV. The higher ATC losses can be attributed in part to some of the losses associated with the 765 kV and 345 kV facilities placed in the ATC region for the analysis and the additional flow pressure that is placed on the 138 kV in the vicinity of North Monroe. The external loss differences can be attributed in part to the additional 345 kV facilities in eastern Iowa that are included as part of the complimentary facilities that channel power into the 765 kV line. In doing so, they likely relieve losses on non-ATC lower voltage facilities.

The Low Voltage Option mainly consists of rating increases of existing facilities that do not aid in increasing the voltage stability characteristics of the region. Although they may help prevent line overloads, as expected the Low Voltage Option did not perform much better than the base case option. When the Low Voltage Option was tested with additional reactive resources, it performed better, but still not as well as the other options.

Figure 5.8 – 5.11 indicate that the dual 345kV line Option 7C and the 765kV option were among the projects showing the best combined MW and Mvar loss performance. The Hilltop connection to the 69kV and 138 kV in Option 1a was largely responsible for the good MW and Mvar loss performance for that option. The 765kV option performed particularity well under the Mvar loss conditions under pre and post-contingency. The 765kV option performed well for MW losses external to ATC, in part because the option includes additional 345kV connections in Iowa that are not in the other tested options. As anticipated, the Low Voltage option did not reflect good MW performance. The Mvar performance for the Low Voltage option was poor, but improved with ATC with reactive resource additions. Loss evaluation contributes to the ranking reflected in Table 5.12.

PV Analysis - Conclusion

Based on the overall scoring shown in Table 5.11, option rankings were created for comparison purposes. The scores for the average of three transfers were used for ranking purposes to take into account all three transfer scenarios. The scores for the EHV options without added reactive supports were used. The score for the Low Voltage Option with the reactive support was considered. Even with the reactive support, the Low Voltage Option still performs much worse than the EHV options. The option rankings for supporting voltage stability and robustness are shown in Table 5.12 below. A ranking of "1" represents the worst performance and "5" represents the best performance.

Table 5.12 – Option rankings for voltage stability and robustness performance

Options	Option rankings
Low Voltage	1
NLAX-HLT-SPG-CDL (1)	3
NLAX-SPG-CDL (1a)	2
NLAX-NMA-CDL (1b)	2
DBQ-SPG-CDL (8)	3
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	5
Genoa-NOM 765 kV	4

5.9 Transient Stability Analysis

The transient stability analysis was performed using the Dynamics Simulation and Power Flow modules of the Power System Simulation/Engineering-30 (PSS/E, Version 30.5.1) program from Power Technologies, Inc (PTI). This program is accepted industry-wide for dynamic stability analysis. The study model is a 2014 light load model. See *Section* 2.1.1 for discussions of the study model.

Stability Analysis - Studied generating stations

Six generating stations in the western Wisconsin study area were selected for transient stability analysis: Columbia, Nelson Dewey, Prairie Island, Alma, JPM and Arnold.

These are some of the largest non-wind generating stations in the study area. The objective is to investigate the transient stability of these representative units in the study area under the conditions of light load and relatively high wind penetration. These conditions represent the worst system conditions with respect to generator transient stability.

Stability Analysis - Simulated Contingencies

Category B, C and D contingencies were chosen at the six generating stations for transient stability simulations. Detailed descriptions of these contingencies can be found in Tables G.1, G.2 and G.3 in Appendix G. An outline of the contingencies is provided below.

Contains Critical Energy Infrastructure Information

Note: Faults are on from end of the listed facilities.

Category C contingencies

Contains Critical Energy Infrastructure Information

Contains Critical Energy Infrastructure Information

Stability Analysis - Simulation Results

The Critical Clearing Times (CCT's) for the studied Category B, C and D faults and the seven transmission options were obtained through transient stability simulations. The results are listed in Tables G.4 through G.6 in Appendix G.

For the Category B contingencies the system was stable under all simulated faults for all cases with at least a 1.0 cycle stability margin. The results show that for faults near Contains Critical Energy Infrastructure Information Contains Critical Energy Infrastructure Information Option 7c (NLAX-NMA-CDL + DBQ-SPG-CDL) provided the most stability margins, followed by Option 1b (NLAX-NMA-CDL). The other options seemed to have comparable performance. For some faults near Contains Critical Energy Infrastructure Information, the Low Voltage Option provided better stability margins than the other options, largely due to the added facilities of Contains Critical Energy Infrastructure Information Contains Critical Energy Infrastructure Information . Option 1b was shown to provide slightly less stability margins than the other 345 kV options for some faults near Contains Critical Energy Infrastructure Information. Since all cases are stable with at least a 1.0 cycle stability margin, no supporting facilities are recommended based on the Category B results.

For the Category C contingencies the system was stable under all simulated faults for all cases with at least a 1.0 cycle stability margin, except for one fault associated with the base case. The same trends identified from the Category B results continued with the Category C results. The results show that for faults near Contains Critical Energy Infrastructure Information, Option 7c provided the most stability margins, followed by Option 1b. The other options seemed to have comparable performance. For some faults near Contains Critical Energy Infrastructure Information, the Low Voltage Option performed better, largely due to the added facilities of Contains Critical Energy Infrastructure Information Contains Critical Energy Infrastructure Information. Option 8 (DBQ-SPG-CDL) did show slightly larger stability margins than the other 345 kV options for some faults near Contains Critical Energy Infrastructure Information. Option 1b was shown to provide slightly less stability margins than the other options for some faults near Contains Critical Energy Infrastructure Information. Since all studied transmission options provided stability for all simulated faults with at least a 1.0 cycle margin, no supporting facilities are recommended based on Category C results.

For the Category D contingencies, the system is unstable for Contains Critical Energy Infrastructure Information. ATC has observed the stability issues in the Contains Critical Energy Infrastructure Information and is currently performing a separate study for this area, which may lead to recommendations of system reinforcements, such as relay upgrades and/or breakers replacement, that will improve equipment clearing time. It is anticipated that with these potential improvements, Contains Critical Energy Infrastructure Information. This is considered an existing system issue. Therefore no supporting facilities will be recommended in this study for the Contains Critical Energy Infrastructure Information. As a sensitivity test, Contains Critical Energy Infrastructure Information Contains Critical Energy Infrastructure Information Contains Critical Energy Infrastructure Information. The simulation results are shown in Table G.7 in Appendix G. The results show improvement to CCTs for a number of tested Category B, C and D contingencies. This sensitivity test is for informational purposes only.

Instability issues were also identified for Category D faults in Contains Critical Energy Infrastructure Information. For the non-transformer fault (D2-01), relay adjustments were identified that will improve the equipment clearing time and will mitigate the instability with at least a 1.0 cycle stability margin for Options 1, 1b and 7c. For the other options (1a, 8, 765 kV and Low Voltage) additional reinforcements are needed to meet the stability criteria. One set of facilities were tested as an example, which includes a Contains Critical Energy Infrastructure Information Contains Critical Energy Infrastructure Information. The simulation results are included in Table G.8 in Appendix G. The results show that with these additions, Options 1a, 8, the 765 kV Option and the Low Voltage Option will meet the stability criteria with at least a 1.0 cycle margin. These fixes are not likely the least expensive fixes solely for the instability issue. This study does not present conclusions on the preferred fixes. Rather, the focus of the stability analysis is comparing between the studied options and is more for informational purposes. For the Category D Contains Critical Energy Infrastructure Information, 2-cycle breaker replacements would reduce the equipment clearing time and provide at least a 1.0 cycle stability margin for all studied options.

Stability Analysis - Summary

Based on the study results, the studied transmission options are ranked for their ability to support system transient stability, e.g., improving stability margins. More importance is given to stability at Contains Critical Energy Infrastructure Information, since unacceptable Critical Clearing Times were identified under two Category D contingencies and small (still acceptable) stability margins were identified for one prior outage Category C contingency in the area. Improvement in stability margins for Contains Critical Energy Infrastructure Information is shown to be important. The rankings are shown in Table 5.16 below. A ranking of "1" represents the worst performance and "5" represents the best performance.

Table 5.16 – Option rankings for supporting system transient stability

Options	Rankings
Low Voltage	1
NLAX-HLT-SPG-CDL (1)	3
NLAX-SPG-CDL (1a)	1
NLAX-NMA-CDL (1b)	4
DBQ-SPG-CDL (8)	1
NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	5
Genoa-NOM 765 kV	1

6. Conclusions

The Western Wisconsin Transmission Reliability Study identified thermal and voltage limitations (including potential voltage collapse) in the base case without any studied transmission options. Out of the initial 15 transmission options, seven were chosen for detailed analysis. Monetized (costs) and non-monetized measures were used for evaluating different aspects of the reliability performance and for comparing between the seven options. Table 6.1 provides a summary of the comparisons of all aspects discussed in the previous sections, including costs and performance rankings.

The results as summarized in Table 6.1 show that the Low Voltage Option has the lowest rankings for all aspects of the reliability performance evaluated using non-monetized measures. These aspects include system voltage performance under Category B and C contingencies, severe local low voltages under a Category C2 contingency, voltage stability and robustness and system transient stability. For these aspects, the Low Voltage Option consistently performs at inferior levels compared to the EHV options. For the reliability aspects evaluated using the monetized measure, the Low Voltage Option is less costly than the EHV options. However, because of its inability to support system voltages, voltage stability and transient stability, the 345 kV options are preferred over the Low Voltage Option.

The 765 kV Option would represent the first 765 kV element in the western Wisconsin area. The results show that the overall rankings are lower for the 765 kV Option than the 345 kV options for those aspects evaluated using non-monetized measures. For the reliability aspects evaluated using the monetized measure, the 765 kV Option is shown to have the highest cost.

A 345 kV reinforcement in the western Wisconsin area from La Crosse to Madison would strengthen the transmission networks in the area and would be expected to enhance the performance of any potential future 765 kV and/or HVDC facilities through the area should the need drivers for such projects be established.

Three of the seven options were in the corridor between North LaCrosse to Madison. These options (Options 1, 1a, and 1b) are comparable from an overall reliability performance perspective and Option 1b (NLAX_NMA-CDL) option has the lowest overall cost of the three options. A 345kV line in this corridor provides the voltage stability and interconnection to Minnesota which is one of the desired benefits of this study.

Option 8 (DBQ-SPG-CDL) also performs well from a reliability perspective. It has a slightly lower cost than Option 1b (NLAX-NMA-CDL) but does not provide the transient stability that is desired. Option 7c (NLAX-NMA-CDL & DBQ-SPG-CDL) performed the best across all aspects of the reliability analyses, and is expected to provide additional benefits over and above any of the singular 345 kV options including a higher increase in transfer capability for additional wind generation in MN and IA.

The conclusion of this study is that Option 7c provides the most reliability benefit to the western Wisconsin area and that Option 1b provides a portion of the benefit realized in Option 7c and includes the additional interconnection to Minnesota. Option 8 provides significant reliability benefits to western Wisconsin as well but not the needed reinforcements for Minnesota ATC believes that the total combination of benefits versus costs, as well as information from the Midwest ISO's Regional Generator Outlet Study, should be taken into account in making a choice to pursue any of the options listed above. ATC has been analyzing the combined reliability, economic, and policy benefits of these options for approximately two years and has determined that a 345 kV project from the La Crosse area to the greater Madison area (the Badger Coulee Project) would provide multiple benefits. ATC has recently announced its intention to finalize its evaluation of these combined benefits and to begin public outreach on the Badger Coulee Project.[16]

[16] Further information about this announcement is located at: http://www.atc-projects.com/BadgerCoulee.shtml

Table 6.1 – Summary of the comparisons of the reliability performance using monetized and non-monetized measures

Summary of project costs in 2010 dollars			Low Voltage	NLAX-HLT-SPG-CDL (1)	NLAX-SPG-CDL (1a)	NLAX-NMA-CDL (1b)	DBQ-SPG-CDL (8)	NLAX-NMA-CDL + DBQ-SPG-CDL (7c)	Genoa-NOM 765 kV
EHV projects			**Opt LV**	**Opt1**	**Opt1a**	**Opt1b**	**Opt8**	**Opt7c**	**Opt 765**
			$0	$454,492,920	$377,454,200	$357,590,989	$304,187,200	$672,785,400	$880,598,000
Category B Supporting Facilities	**Loading**	**ATC Facilities**	$173,768,164	$118,661,663	$131,603,921	$119,001,306	$101,420,588	$86,326,549	$136,878,643
	Loading	**Non-ATC Facilities**	$95,397,350	$38,281,800	$52,036,800	$69,696,850	$103,972,600	$57,625,100	$43,168,200
		Total	**$269,165,514**	**$156,943,463**	**$183,640,721**	**$188,698,156**	**$205,393,188**	**$143,951,649**	**$180,046,843**
Category C Supporting Facilities	**Loading**	**ATC Facilities**	$0	$0	$0	$0	$0	$0	$0
	Voltage	**ATC Facilities**	$82,758,813	$0	$0	$0	$0	$0	$0
	Loading	**Non-ATC Facilities**	$0	$0	$0	$0	$0	$0	$0
	Voltage	**Non-ATC Facilities**	$0	$0	$0	$0	$0	$0	$0
		Total	**$82,758,813**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Category B & C Supporting Facilities		**ATC Facilities**	$256,526,977	$118,661,663	$131,603,921	$119,001,306	$101,420,588	$86,326,549	$136,878,643
		Non-ATC Facilities	$95,397,350	$38,281,800	$52,036,800	$69,696,850	$103,972,600	$57,625,100	$43,168,200
		Total	**$351,924,327**	**$156,943,463**	**$183,640,721**	**$188,698,156**	**$205,393,188**	**$143,951,649**	**$180,046,843**
Total cost estimates for project packages (main + support)			**$351,924,327**	**$611,436,383**	**$561,094,921**	**$546,289,145**	**$509,580,388**	**$816,737,049**	**$1,060,644,843**
Rankings - benefits not captured by cost analysis									
Voltage performance under Cat-B contingencies			1	4	4	4	4	5	3
Voltage performance under converged Cat-C contingencies			1	5	4	3	4	5	2
Alleviate Cat-C2 severe local low voltages			1	5	5	1	5	5	1
Support voltage stability and robustness			1	3	2	2	3	5	4
Support system transient stability			1	3	1	4	1	5	1

Appendices

Appendix A. Details of the Studied Transmission Options

Appendix B. Maps of the Studied Transmission Options

Appendix C. ATC Severity Index Tool Write-Up

Appendix D. Supporting Facilities for the EHV (345 kV and 765 kV) Options- Category B Loading Limitations

Appendix E. List of Non-Converged N-2 Contingencies

Appendix F. Voltage Stability Tables

Appendix G. Transient Stability Analysis Contingencies and Results

Appendix A

Details of the Studied Transmission Options

Public Version

Appendix A: Transmission option details for Western Wisconsin Transmission Reliability Study

Notes –

1. Total 15 transmission options.
2. Some of the options did not show to have notable impact to the western Wisconsin study area and were excluded from the detailed analysis. Those transmission options that were evaluated in details are highlighted in Yellow. Cost estimates were obtained for these options.
3. In the Low Voltage Option, facilities highlighted in Green are outside ATC footprint.

Public Version

Appendix A: Transmission option details for Western Wisconsin Transmission Reliability Study

Num	Option #	Option full names	Detailed Description	Mileage	Preliminary Cost Estimates
1	**Opt 1**	**North La Crosse–Hilltop–Spring Green–Cardinal 345 kV project**			**$454,492,920**
			Construct a North La Crosse –Hilltop – Spring Green – Cardinal 345 kV line	158	
			String a Council Creek – Hilltop – Birchwood 138 kV line on the 345kV poles	50	
			Reconductor Kirkwood - Spring Green 138 kV line and string on the 345kV poles	26.4	
			Convert Spring Green – Cardinal 69 kV line to 138 kV and string on the 345kV poles	30	
			Install a Spring Green 345-138 transformer	500 MVA	
			Install a Hilltop 345-138 transformer	500 MVA	
			Install a Hilltop 138-69 transformer	187 MVA	
			New 345/138/69 kV sub at Hilltop		
			Modify Spring Green sub to be 345 KV		
			Modify Cardinal sub		
			Modify La Crosse sub		
			Other - balance compared to the PCO final total estimate		
2	**Opt 1a**	**North La Crosse–Spring Green–Cardinal 345 kV project**			**$377,454,200**
			Construct a North La Crosse – Spring Green – Cardinal 345 kV line	158	
			Reconductor Kirkwood - Spring Green 138 kV line and string on the 345kV poles	26.4	
			Convert Spring Green – Cardinal 69 kV line to 138 kV and string on the 345kV poles	30	
			Install a Spring Green 345-138 transformer	500 MVA	
			Modify Spring Green sub to be 345 kV		
			Modify Cardinal sub		
			Modify La Crosse sub		
			Other - balance compared to the PCO final total estimate		

3	**Opt 1b**	**North La Crosse–North Madison–Cardinal 345 kV project**			**$357,590,989**
			Construct a North La Crosse – North Madison – Cardinal 345 kV line	157	
			Reconductor North Madison – West Middleton 138 kV line and string on the 345kV poles	20	
			Modify North Madison sub		
			Modify Cardinal sub		
			Modify La Crosse sub		
			Other - balance compared to the PCO final total estimate		
4	**Opt 8**	**Dubuque–Spring Green–Cardinal 345 kV project**			**$304,187,200**
			Construct a Dubuque – Spring Green – Cardinal 345 kV line	103	
			Reconductor Turkey River - Cassville - Nelson Dewey 161 kV line	5	
			Convert Spring Green – Cardinal 69 kV line to 138 kV and string on the 345kV poles	30	
			Install a Spring Green 345-138 transformer	500 MVA	
			New 345 kV switching station at Dubuque		
			Modify Spring Green sub to be 345 kV		
			Modify Cardinal sub		
			river crossing adder		
			Reconductor Spring Green to 1.1 miles northeast of Nelson Dewey 138-kV line	75	
			Other - balance compared to the PCO final total estimate		
5	**Opt 7c**	**North La Crosse-North Madison-Cardinal 345 kV and Dubuque-Spring Green-Cardinal 345 kV project**			**$672,785,400**
		Note: This Option is Option 1b + Option 8 with minor variations	Construct a North La Crosse – North Madison – Cardinal 345 kV line	156	
			Construct a Dubuque – Spring Green - Cardinal 345 kV line	103.13	
			Reconductor North Madison – West Middleton 138 kV line and string on the 345kV poles	20	

			Reconductor Turkey River - Cassville - Nelson Dewey 161 kV line and string on the 345kV poles (does not include Q-2D/E Tap to Nelson Dewey)	5.23	
			Convert Spring Green – Cardinal 69 kV line to 138 kV and string on the 345kV poles	30	
			Install a Spring Green 345-138 transformer	500 MVA	
6	**765 Opt**	**Genoa–North Monroe 765 kV project**			**$880,598,000**
			Construct a Genoa – North Monroe 765 kV line	136	
			200 Mvar at line end of Genoa 765 kV bus	reactor	
			200 Mvar at line end of North Monroe 765 kV bus	reactor	
			Genoa 765 kV substation	new sub	
			North Monroe 765 kV substation	new sub	
			Construct a North La Crosse – Genoa 345 kV line	18	
			Construct North Monroe – Paddock 345 kV Double Circuits	32	
			Construct an Adams – Genoa 345 kV line	73	
			Install a Genoa 765-345kV transformer	2767 MVA	
			Install a Genoa 345-161kV transformer	336 MVA	
			Install a North Monroe 765-345kV transformer	2767 MVA	
			Install a North Monroe 345-138 transformer	500 MVA	
			Other – pre-cert @ 7%		
7	LowV Opt	**Low Voltage option**			**$269,165,514**
			Construct a Nelson Dewey - Liberty 161 kV tie line		$28,388,123
			Rebuild following lower voltage facilities		
			348915 4E GALESBG N 138 636672 GALESBR5 161 2 [1]		$0
			601043 NLAX 5 161 602026 MAYFAIR5 161 1		$4,095,000
			605296 WSTSALE8 69.0 605316 LAX 8 69.0 1		$3,850,000

[1] Far from the center of the study footprint (from, to - MEC, AMIL). Assumed this constraint will be fixed by entities outside study participants.

			630297 SANDRDG8 69.0 680066 MENOMINE 69.0 1		$280,000
			631047 LIME CK5 161 631048 EMERY 5 161 1		$8,868,600
			631056 LORE 5 161 631060 TRK RIV5 161 1 [2]		$0
			631057 SALEM N5 161 631120 JULIAN 5 161 1		$5,937,750
			631058 SO.GVW.5 161 631059 8TH ST.5 161 1		$1,246,050
			631058 SO.GVW.5 161 631061 SALEM S5 161 1		$3,082,950
			631059 8TH ST.5 161 631125 KERPER 5 161 1		$1,521,000
			631060 TRK RIV5 161 681519 CASVILL5 161 1 [3]		$0
			631095 E CALMS5 161 631096 GR MND 5 161 1		$1,404,000
			631123 ADAMS_S5 161 681527 BVR CRK5 161 1		$8,833,500
			636636 OAKGROV5 161 636672 GALESBR5 161 1 [4]		$0
			637191 HAMPTON5 161 637193 HAMPTON8 69.0 1		$3,380,000
			637201 SHEFFLD5 161 637205 WSHEFFLD 69.0 1		$3,380,000
			680061 HARRISON 69.0 680067 KAISER 69.0 1		$2,485,000
			680061 HARRISON 69.0 680070 LANCASTE 69.0 1		$2,415,000
			680066 MENOMINE 69.0 680068 T KIELER 69.0 1		$280,000
			680067 KAISER 69.0 680068 T KIELER 69.0 1		$490,000
			680070 LANCASTE 69.0 680079 HURICAN 69.0 1		$2,345,000
			680075 BELLCNTR 69.0 680084 T SG 69.0 1		$1,785,000
			680079 HURICAN 69.0 680455 MTHOP TP 69.0 1		$3,815,000
			680084 T SG 69.0 680086 BOAZ 69.0 1		$3,920,000
			680086 BOAZ 69.0 680087 DAYTON 69.0 1		$420,000
			680242 LUBLIN 69.0 680505 LAKEHEAD 69.0 1		$420,000
			680481 LUBLINTP 69.0 680505 LAKEHEAD 69.0 1		$4,760,000
			681519 CASVILL5 161 699010 NED 161 161 1 [5]		$0
			681523 GENOA 5 161 681531 LAC TAP5 161 1 [6]		$0
			681539 ELK MND5 161 681543 ALMA 5 161 1		$26,383,500

[2] Use a new NED-LIB 161 kV line

[3] Use a new NED-LIB 161 kV line

[4] Far from the center of the study footprint (from, to - MEC, MEC). Assumed this constraint will be fixed by entities outside study participants.

[5] Use a new NED-LIB 161 kV line

[6] DPC comment: this is a DPC planned project

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Appendix A: Transmission option details for Western Wisconsin Transmission Reliability Study

			698003 HLM 69 69.0 699031 HLM 138 138 1		$2,531,712
			698016 EEN 69 69.0 698017 MIP 69 69.0 1		$5,575,491
			698032 SME 69 69.0 698033 BRN 69 69.0 1		$7,307,102
			698033 BRN 69 69.0 699902 JEN 69 69.0 1		$7,737,848
			698034 WIO 69 69.0 698035 GTT 69 69.0 1		$3,900,659
			698034 WIO 69 69.0 699902 JEN 69 69.0 1		$1,912,515
			698114 WKA 69 69.0 698115 BOS 69 69.0 1		$12,719,751
			698114 WKA 69 69.0 699959 GRANGRAE 69.0 1		$7,737,848
			698122 PIR 69 69.0 698300 BREWER 69.0 1		$1,059,979
			698187 RKT 138 138 698941 ART#1 13 138 1		$6,395,745
			698187 RKT 138 138 699144 KIR 138 138 1		$9,530,914
			698313 SALT 69 69.0 699940 SAL 69 69.0 1		$105,998
			698318 LPS 69 69.0 698321 A07 69 69.0 1		$1,377,973
			698321 A07 69 69.0 698322 MCK 69 69.0 1		$5,617,890
			698333 HLT 69 69.0 698337 WMT 69 69.0 1		$879,783
			698351 PET 69 69.0 699808 PETENWEL 138 1		$3,825,075
			698375 WHB 69 69.0 699699 WHITCOMB 115 1		$3,825,075
			698660 HARRISON 69.0 699792 HARRISON 138 1		$3,825,075
			698668 WMD 69 69.0 698674 WTNM 69 69.0 1		$12,263,239
			698668 WMD 69 69.0 698684 BLKM69 69.0 1		$3,703,806
			699010 NED 161 161 699021 NLD 2 138 1		$4,180,636
			699033 DAR 138 138 699036 NOM 138 138 1		$30,574,914
			699059 PAD 138 138 699141 TOWNLINE 138 1		$8,791,014
8	Opt 2	**North La Crosse-Dubuque 345 kV project**			
			Construct a North La Crosse - Dubuque 345 kV line	103	
			Reconductor North La Crosse – Turkey River 161 kV line	85	
9	Opt 2a	**North La Crosse-Genoa-Dubuque 345 kV project**			
			Construct a North La Crosse - Genoa - Dubuque 345 kV line	103	
			Reconductor North La Crosse - Turkey River 161 kV line and string on the 345kV poles	85	

			Install a Genoa 345-161 kV transformer	448 MVA	
10	Opt 3	**Eau Claire-North La Crosse 345 kV project**			
			Construct an Eau Claire - North La Crosse 345 kV line	73.2	
			Reconductor Eau Claire - North La Crosse 161 kV line and string on the 345kV poles	73.2	
11	Opt 4	**North La Crosse–Hilltop–Spring Green–Cardinal 345 kV and Eau Claire-North La Crosse 345 kV project**			
		Note: This Option is Option1 + Option 3	Construct a North La Crosse –Hilltop – Spring Green – Cardinal 345 kV line	158	
			String a Council Creek – Hilltop – Birchwood 138 kV line on the 345kV poles	50	
			Reconductor Kirkwood - Spring Green 138 kV line and string on the 345kV poles	26.4	
			Convert Spring Green – Cardinal 69 kV line to 138 kV and string on the 345kV poles	30	
			Install a Spring Green 345-138 transformer	500 MVA	
			Install a Hilltop 345-138 transformer	500 MVA	
			Install a Hilltop 138-69 transformer	187 MVA	
			Construct an Eau Claire - North La Crosse 345 kV line	73.2	
			Reconductor Eau Claire - North La Crosse 161 kV line and string on the 345kV poles	73.2	
12	Opt 5	**North La Crosse–Hilltop–Spring Green–Cardinal 345 kV and North La Crosse-Dubuque 345 kV project**			
		Note: This Option is Option1 + Option 2	Construct a North La Crosse –Hilltop – Spring Green – Cardinal 345 kV line	158	
			String a Council Creek – Hilltop – Birchwood 138 kV line on the 345kV poles	50	
			Reconductor Kirkwood - Spring Green 138 kV line and string on the 345kV poles	26.4	
			Convert Spring Green – Cardinal 69 kV line to 138 kV and string on the 345kV poles	30	
			Install a Spring Green 345-138 transformer	500 MVA	

			Install a Hilltop 345-138 transformer	500 MVA	
			Install a Hilltop 138-69 transformer	187 MVA	
			Construct a North La Crosse - Dubuque 345 kV line	103	
			Reconductor North La Crosse - Turkey River 161 kV line and string on the 345kV poles	85	
13	Opt 6	**North La Crosse-North Cassville-Dubuque 345 kV and North Casville-Spring Green-Cardinal 345 kV project**			
		Note: This Option is Option 2 + Option 8 with minor variations	Construct a North La Crosse - Cassville - Dubuque 345 kV line	103	
			Construct a North Cassville - Spring Green - Cardinal 345 kV line	86.5	
			Reconductor Nelson Dewey - Spring Green 138 kV line and string on the 345kV poles	59	
			Reconductor North La Crosse - Turkey River 161 kV line and string on the 345kV poles	90.1	
			Convert Spring Green – Cardinal 69 kV line to 138 kV and string on the 345kV poles	30	
			Install a Spring Green 345-138 transformer		
14	Opt 7	**North La Crosse-Hilltop-Spring Green-Cardinal 345 kV and Dubuque-Spring Green 345 kV project**			
		Note: This Option is Option 1 + Option 8 with minor variations	Construct a North La Crosse –Hilltop – Spring Green – Cardinal 345 kV line	158	
			Construct a Dubuque – Spring Green 345 kV line	75.13	
			String a Council Creek – Hilltop – Birchwood 138 kV line on the 345kV poles	50	
			Reconductor Kirkwood - Spring Green 138 kV line and string on the 345kV poles	26.4	
			Reconductor Turkey River - Cassville - Nelson Dewey 161 kV line and string on the 345kV poles (does not include Q-2D/E Tap to Nelson Dewey)	5.23	
			Reconductor Nelson Dewey - Spring Green 138 kV line and string on the 345kV poles	59	
			Convert Spring Green – Cardinal 69 kV line to 138 kV and string on the 345kV poles	30	

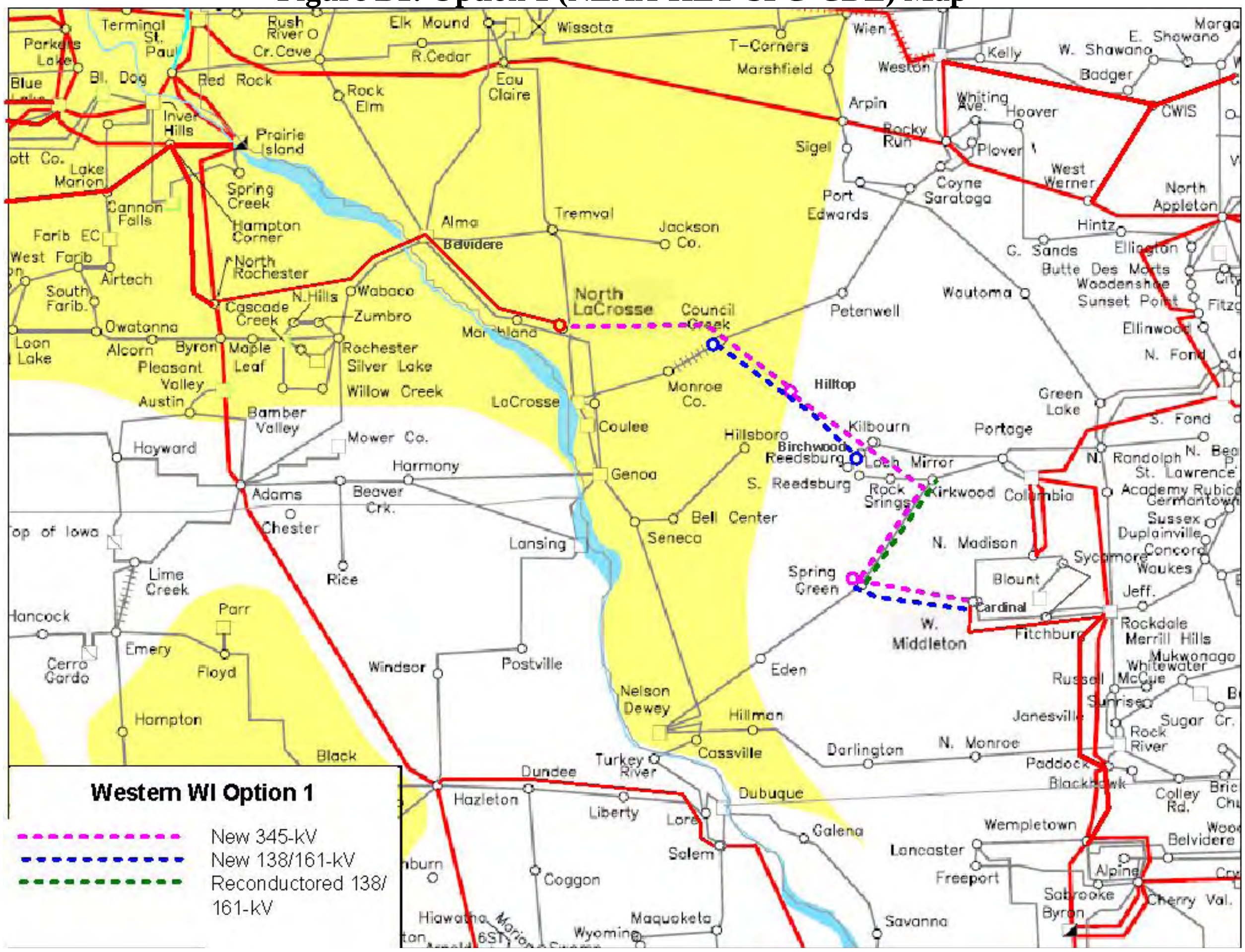
			Install a Spring Green 345-138 transformer	500 MVA	
			Install a Hilltop 345-138 transformer	500 MVA	
			Install a Hilltop 138-69 transformer	187 MVA	
15	Opt 7a	**North La Crosse-Spring Green-Cardinal 345 kV and Dubuque-Spring Green 345 kV project**			
		Note: This Option is Option 1a + Option 8 with minor variations	Construct a North La Crosse – Spring Green – Cardinal 345 kV line	158	
		Note: Single 345 kV between Spring Green and Cardinal	Construct a Dubuque – Spring Green 345 kV line	75.13	
			Reconductor Kirkwood - Spring Green 138 kV line and string on the 345kV poles	26.4	
			Reconductor Turkey River - Cassville - Nelson Dewey 161 kV line and string on the 345kV poles (does not include Q-2D/E Tap to Nelson Dewey)	5.23	
			Convert Spring Green – Cardinal 69 kV line to 138 kV and string on the 345kV poles	30	
			Install a Spring Green 345-138 transformer	500 MVA	
16	Opt 7b	**North La Crosse-Spring Green-Cardinal 345 kV and Dubuque-Spring Green-Cardinal 345 kV project**			
		Note: This Option is Option 1a + Option 8 with minor variations	Construct a North La Crosse – Spring Green – Cardinal 345 kV line	158	
		Note: Double circuit 345 kV between Spring Green and Cardinal	Construct a Dubuque – Spring Green - Cardinal 345 kV line	103.13	
			Reconductor Kirkwood - Spring Green 138 kV line and string on the 345kV poles	26.4	
			Reconductor Turkey River - Cassville - Nelson Dewey 161 kV line and string on the 345kV poles (does not include Q-2D/E Tap to Nelson Dewey)	5.23	
			Convert Spring Green – Cardinal 69 kV line to 138 kV and string on separate 138kV poles	30	
			Install a Spring Green 345-138 transformer	500 MVA	

Appendix B

Maps of the Studied Transmission Options

Public Version
Appendix B: Maps for the Western Wisconsin Transmission Reliability Study

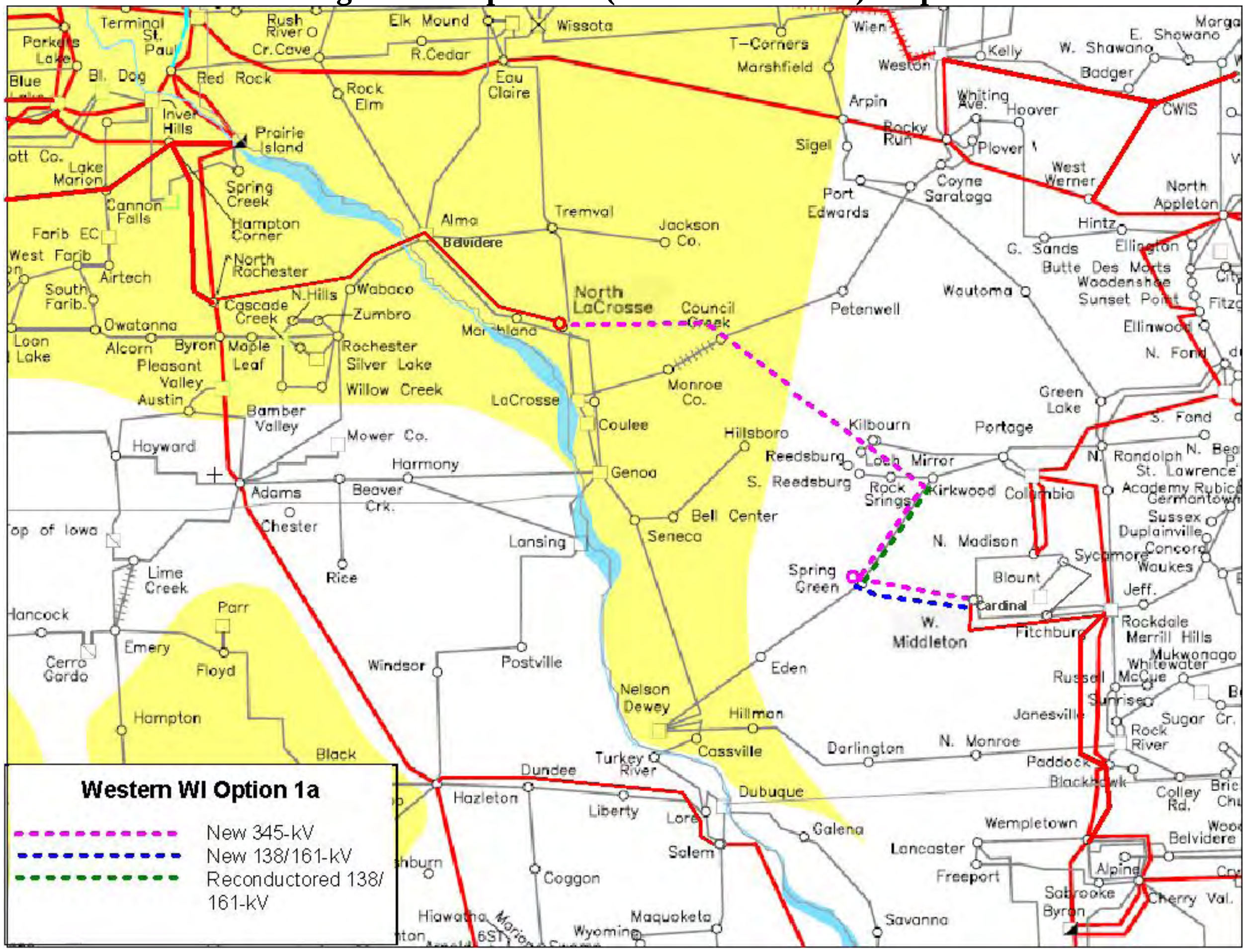
Figure B1: Option 1 (NLAX-HLT-SPG-CDL) Map



Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

Public Version
Appendix B: Maps for the Western Wisconsin Transmission Reliability Study

Figure B2: Option 1a (NLAX-SPG-CDL) Map



Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

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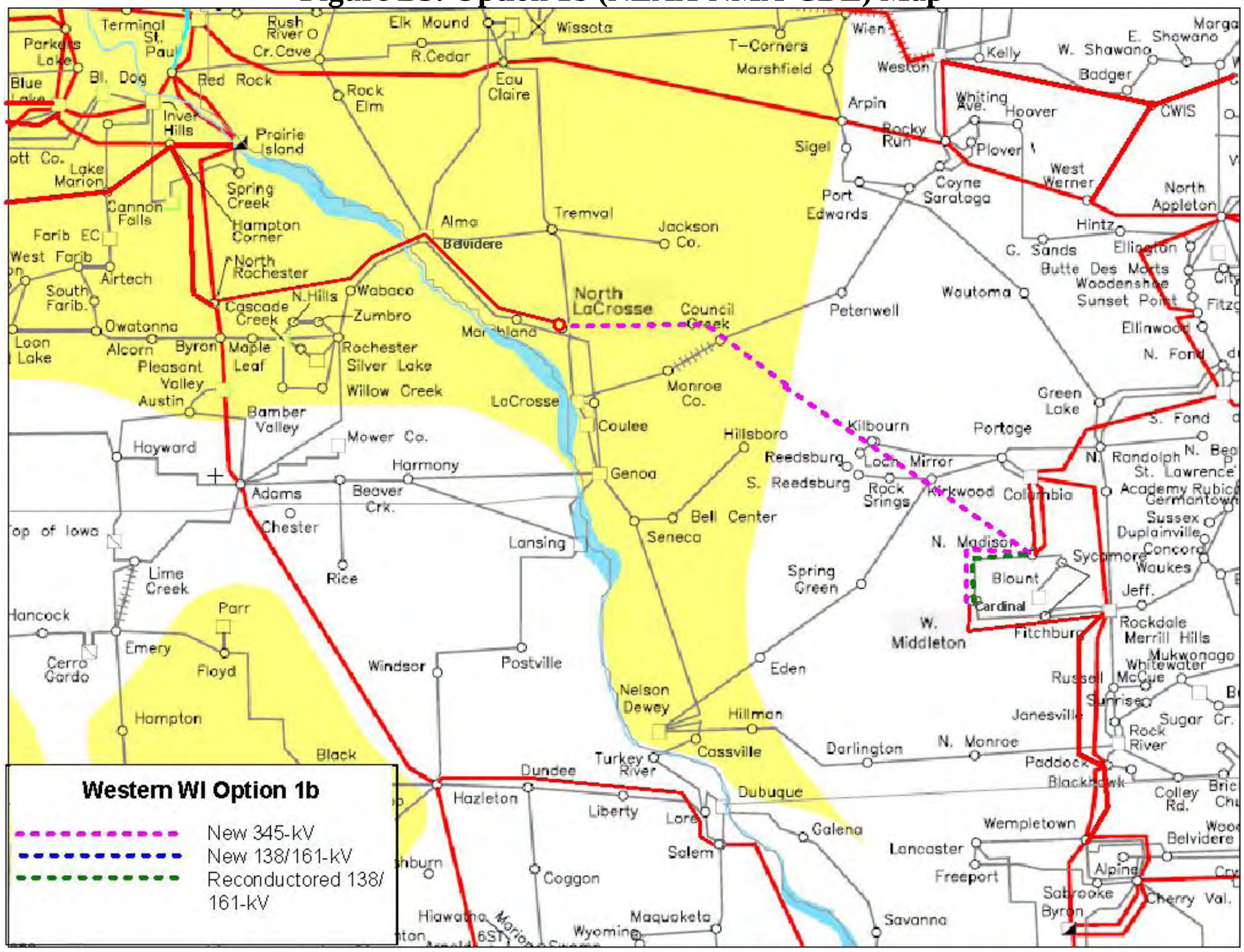
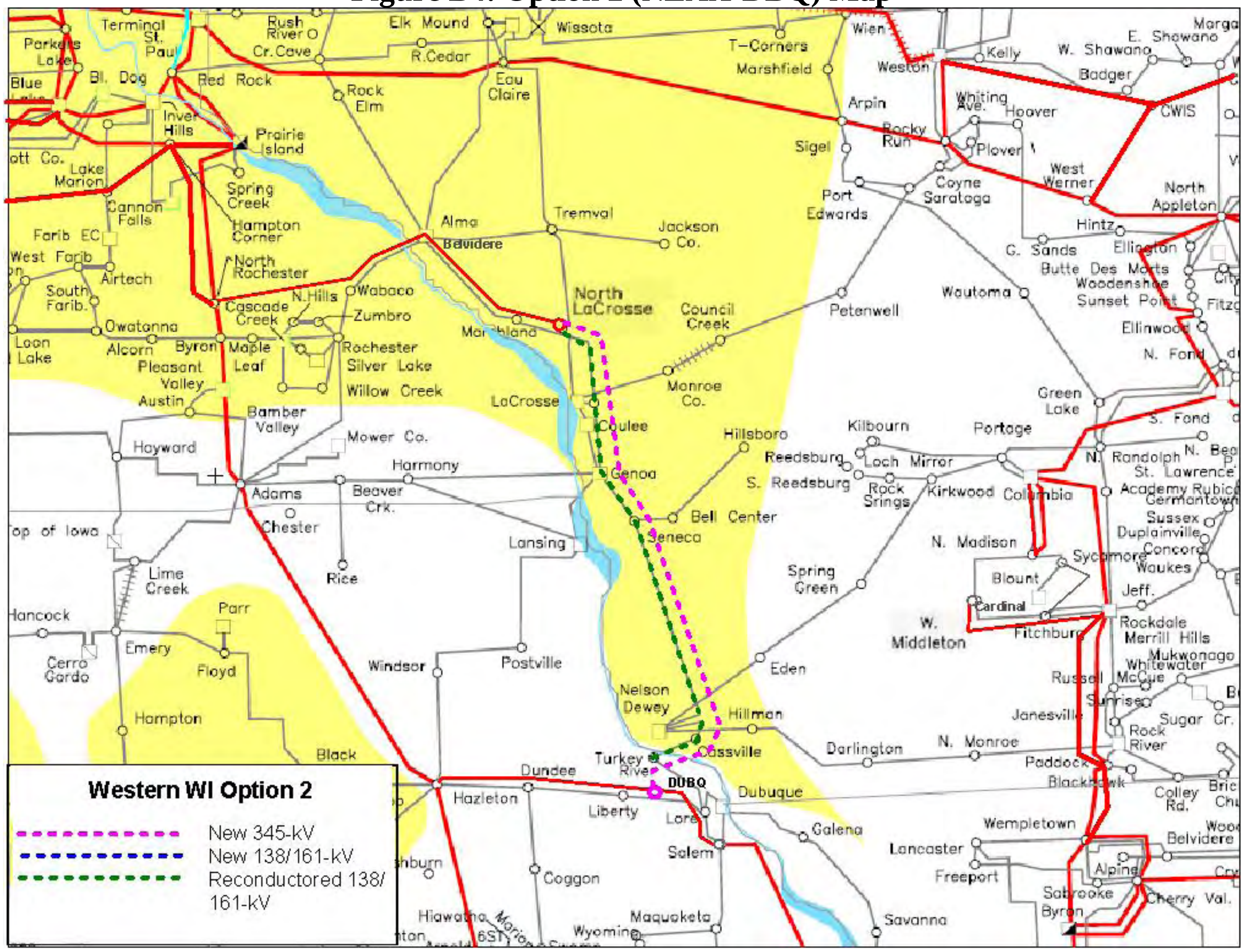
Appendix B: Maps for the Western Wisconsin Transmission Reliability Study

Figure B3: Option 1b (NLAX-NMA-CDL) Map



Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

Figure B4: Option 2 (NLAX-DBQ) Map



Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

 Posted: 01/13/2011

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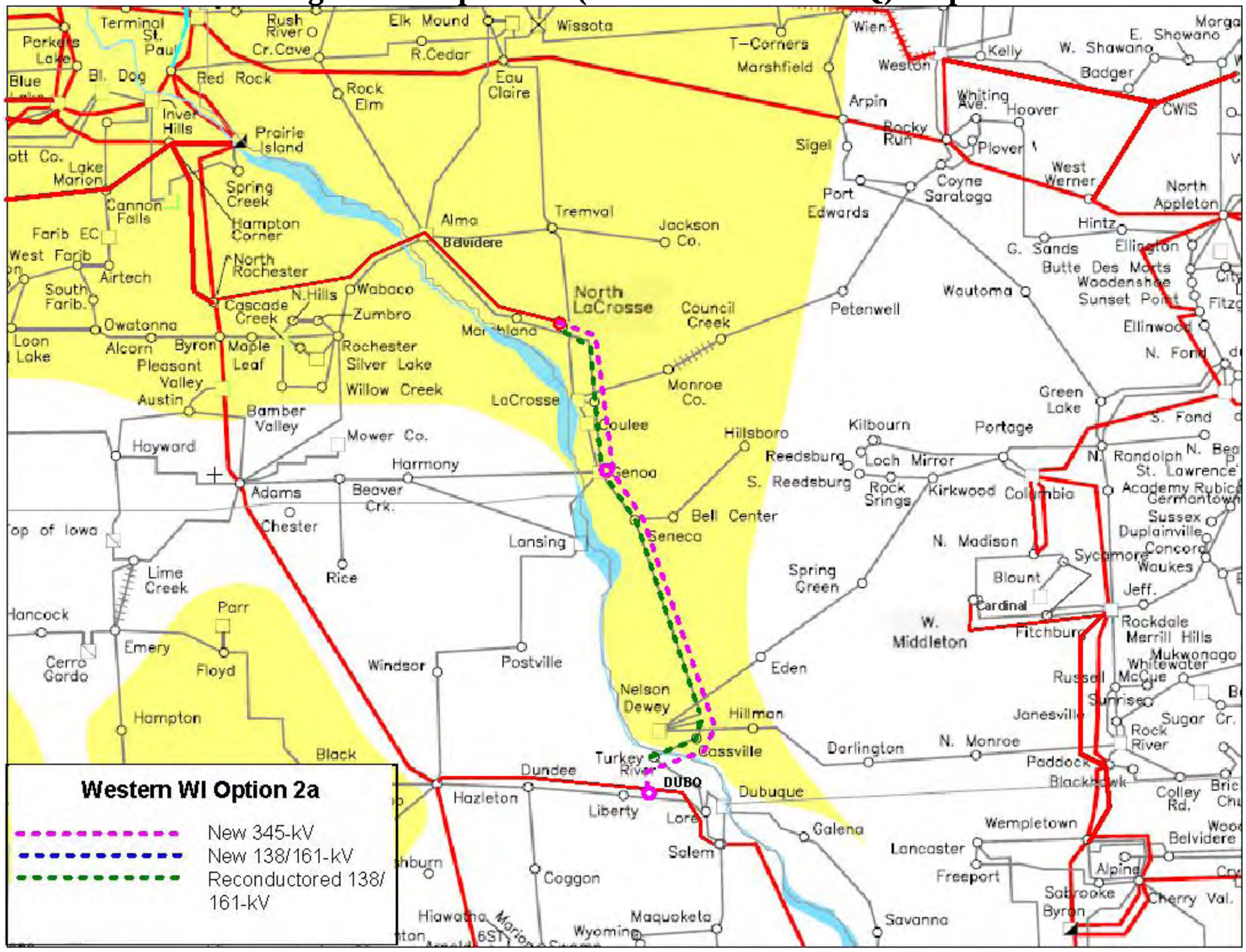
Appendix B: Maps for the Western Wisconsin Transmission Reliability Study

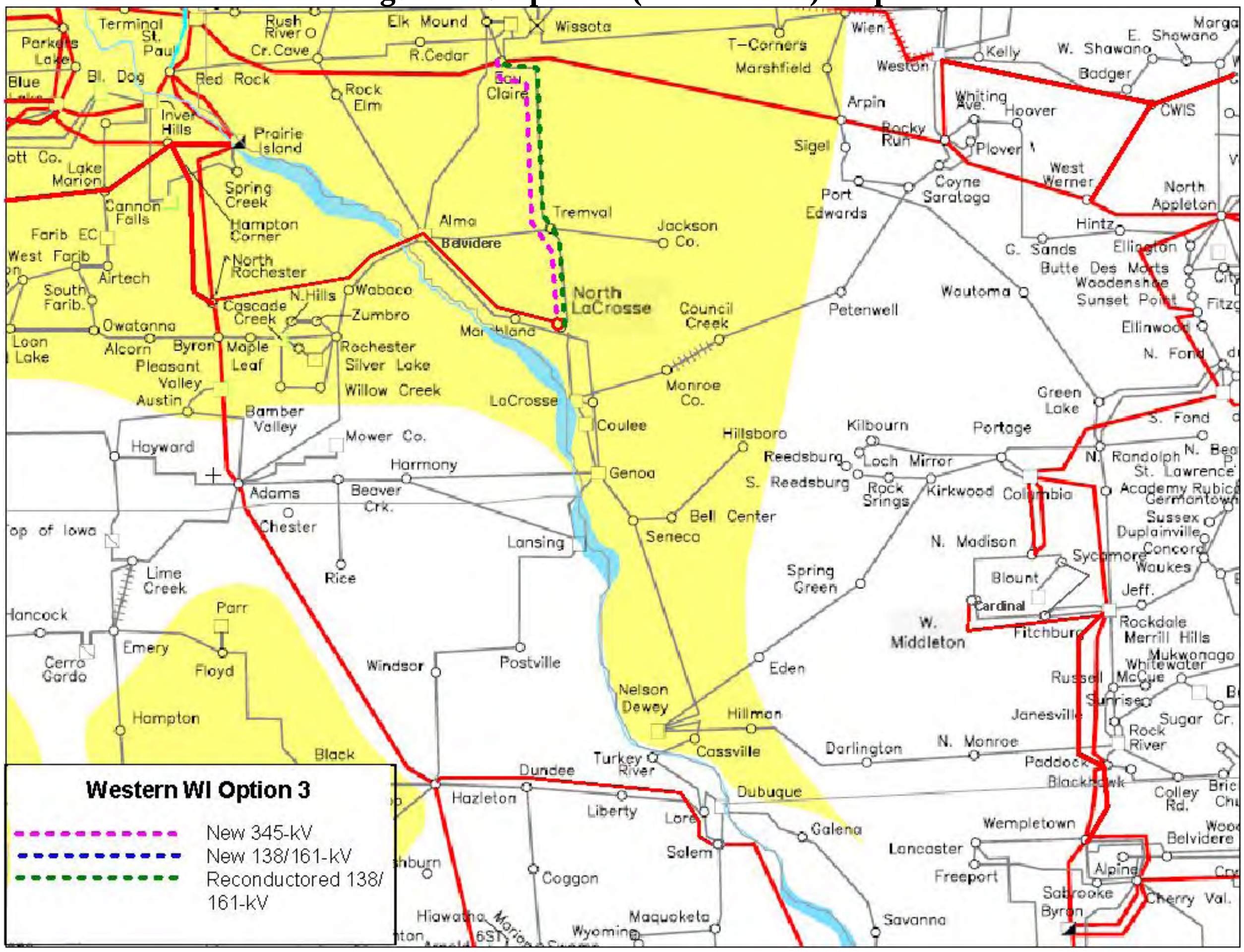
Figure B5: Option 2a (NLAX-GENOA-DBQ) Map



Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

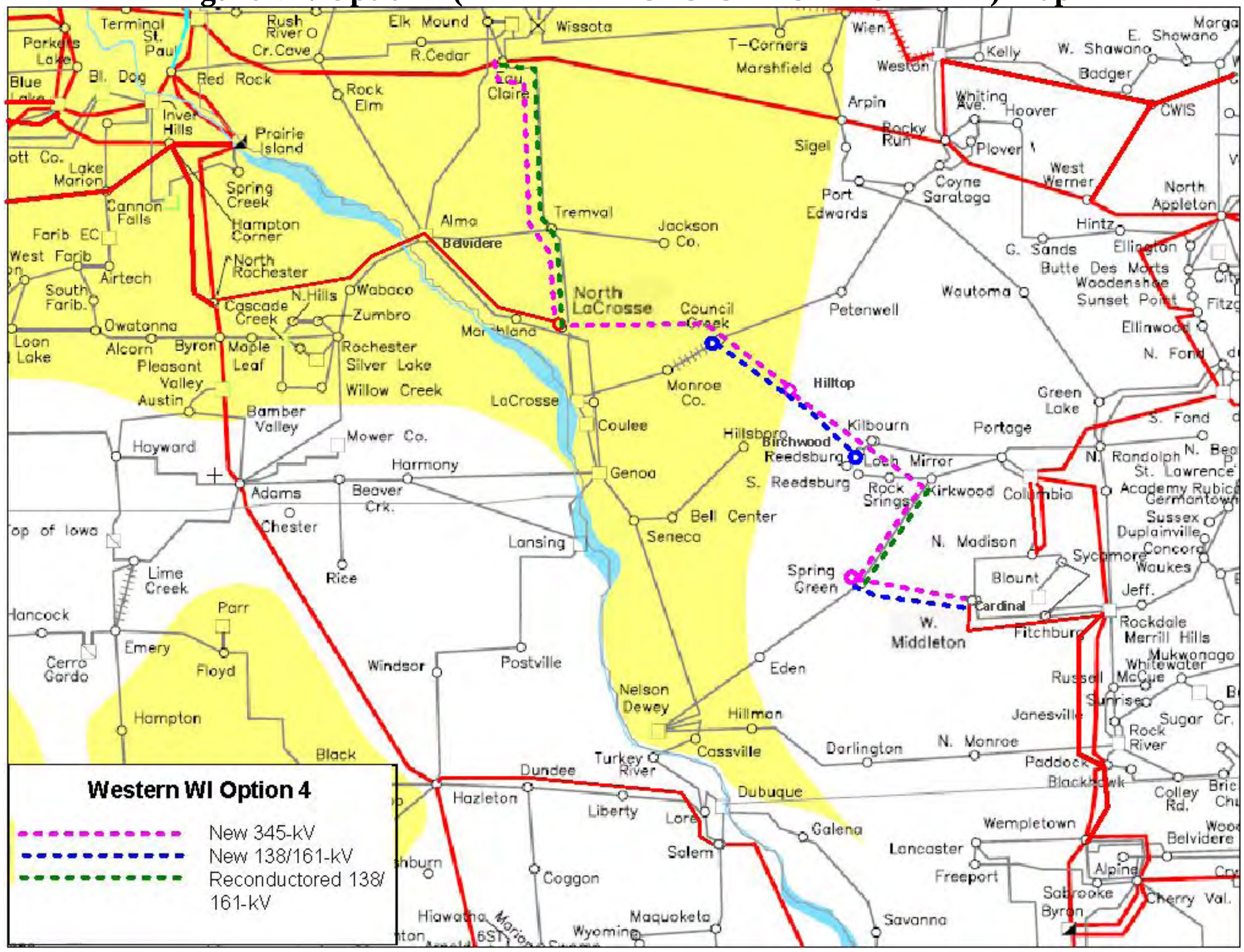
Public Version
Appendix B: Maps for the Western Wisconsin Transmission Reliability Study

Figure B6: Option 3 (EAU-NLAX) Map



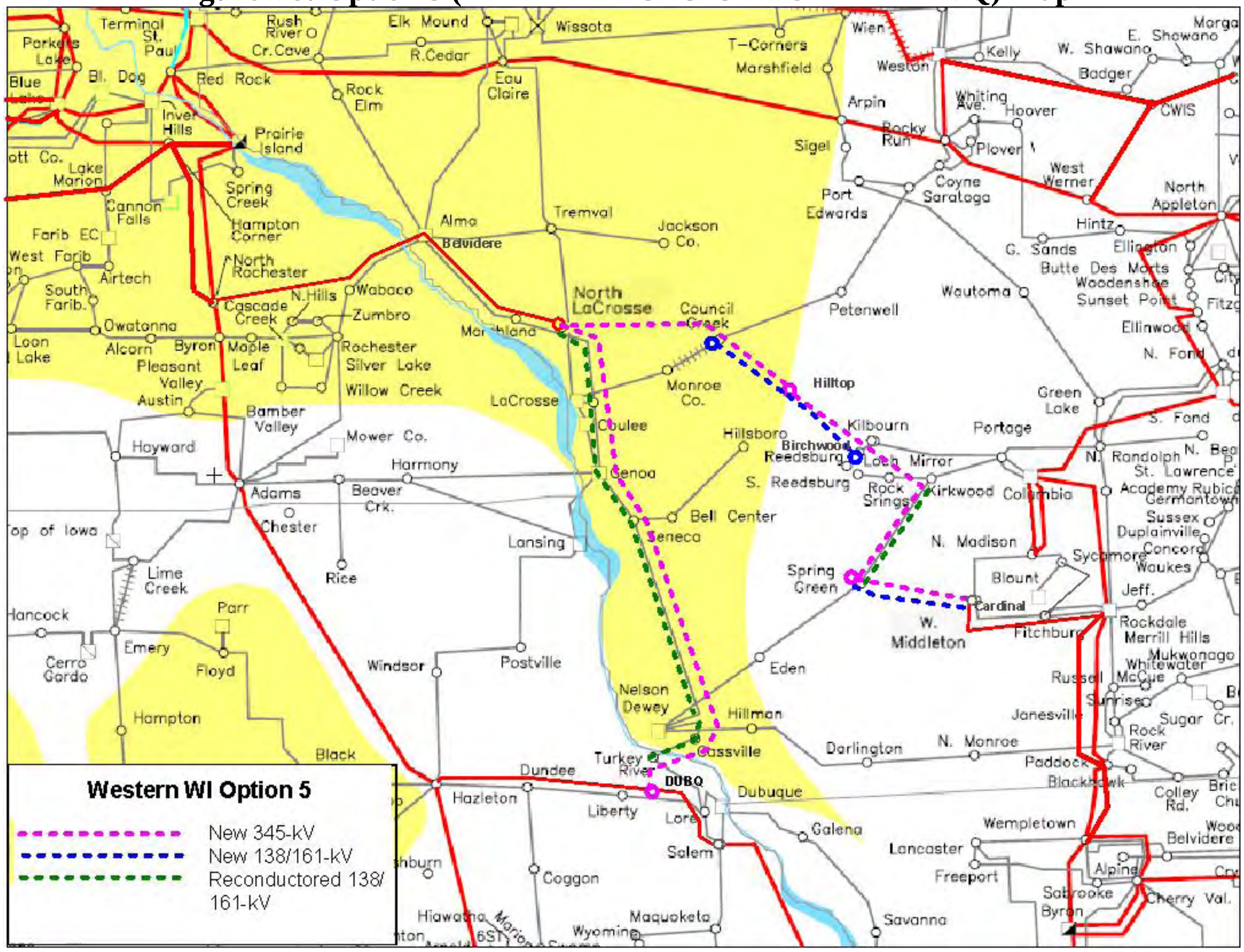
Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

Figure B7: Option 4 (NLAX-HLT-SPG-CDL & EAU-NLAX) Map



Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

Figure B8: Option 5 (NLAX-HLT-SPG-CDL & NLAX-DBQ) Map



Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

Public Version
Appendix B: Maps for the Western Wisconsin Transmission Reliability Study

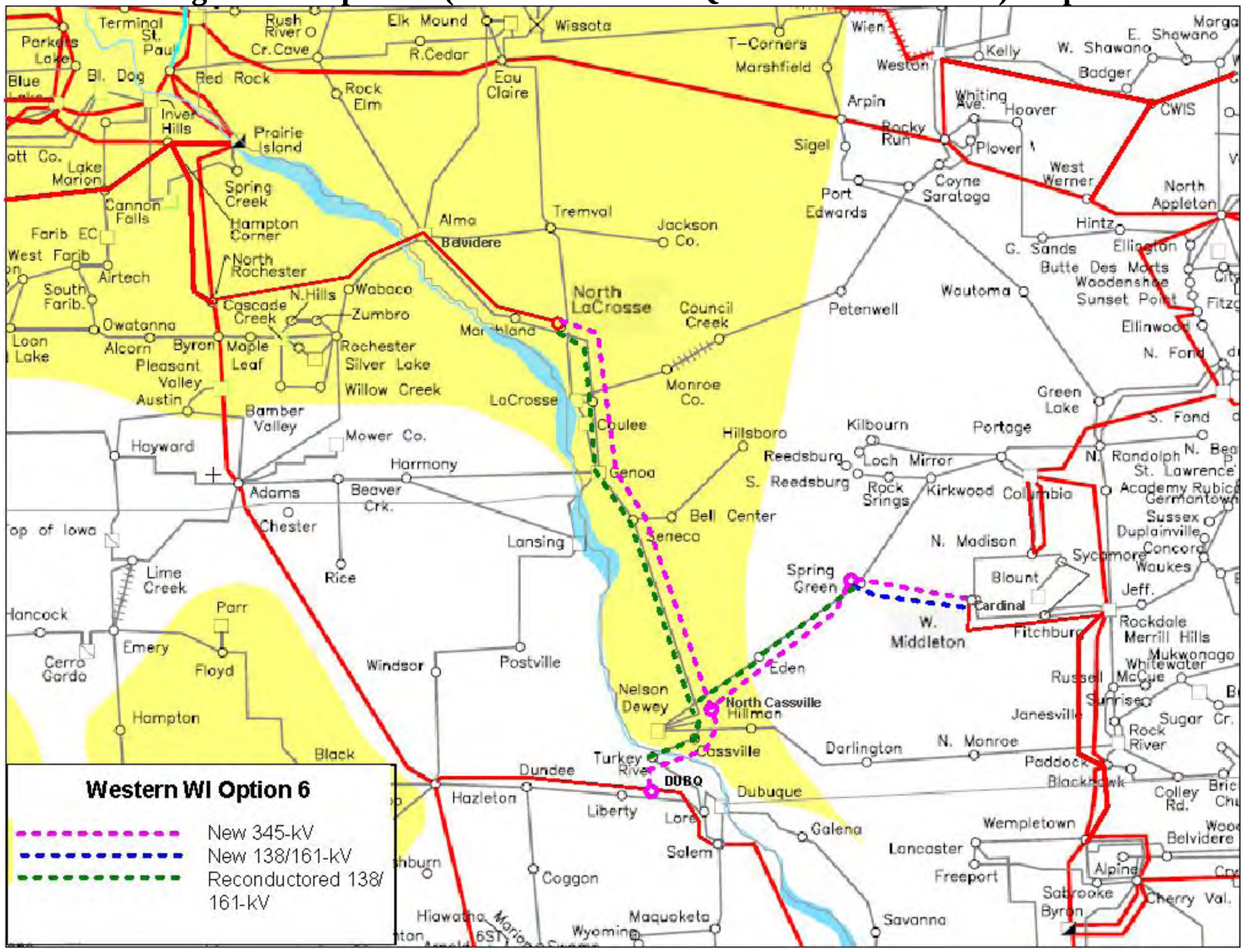
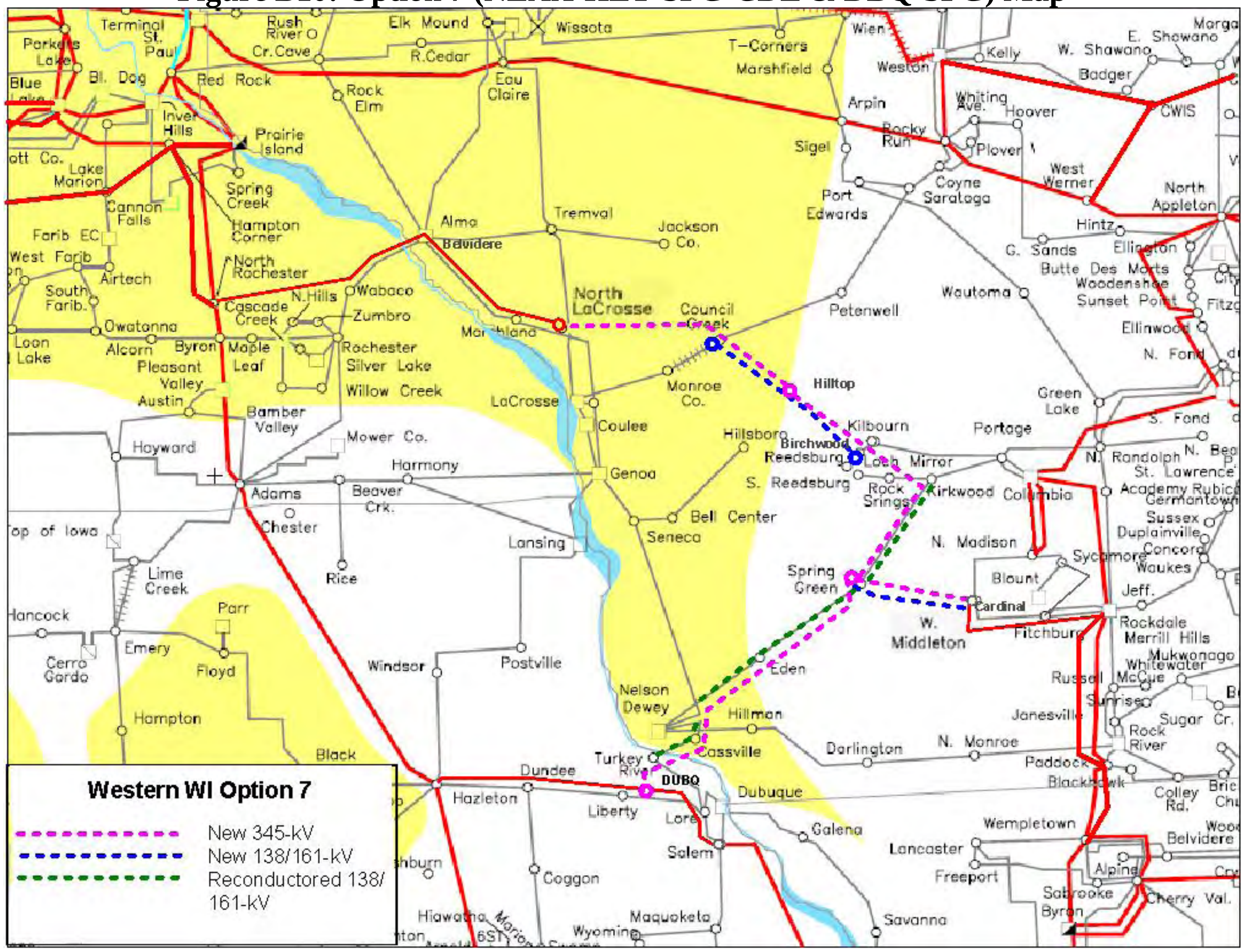


Figure B9: Option 6 (NLAX-NCAS-DBQ & NCAS-SPG-CDL) Map

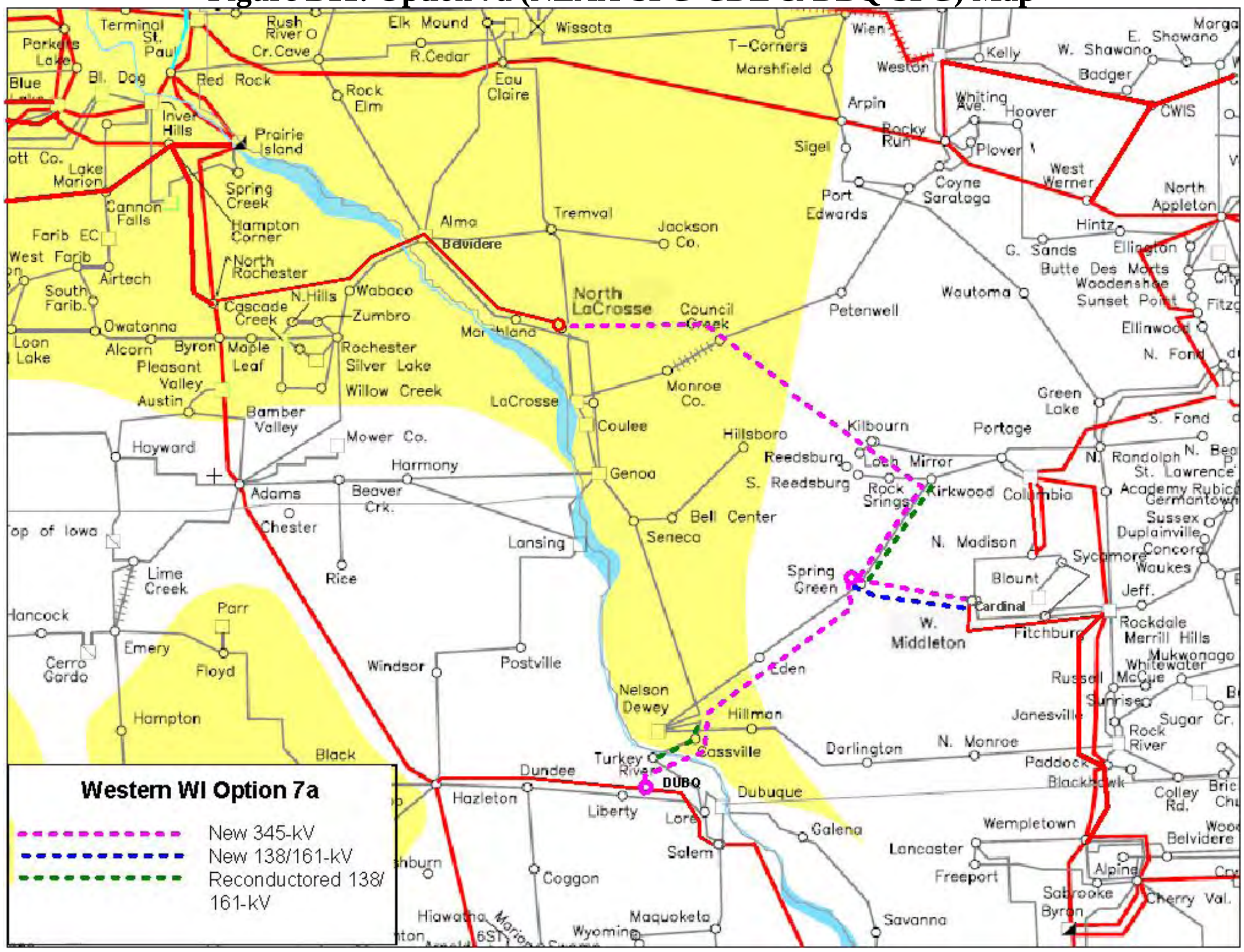
Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

Figure B10: Option 7 (NLAX-HLT-SPG-CDL & DBQ-SPG) Map



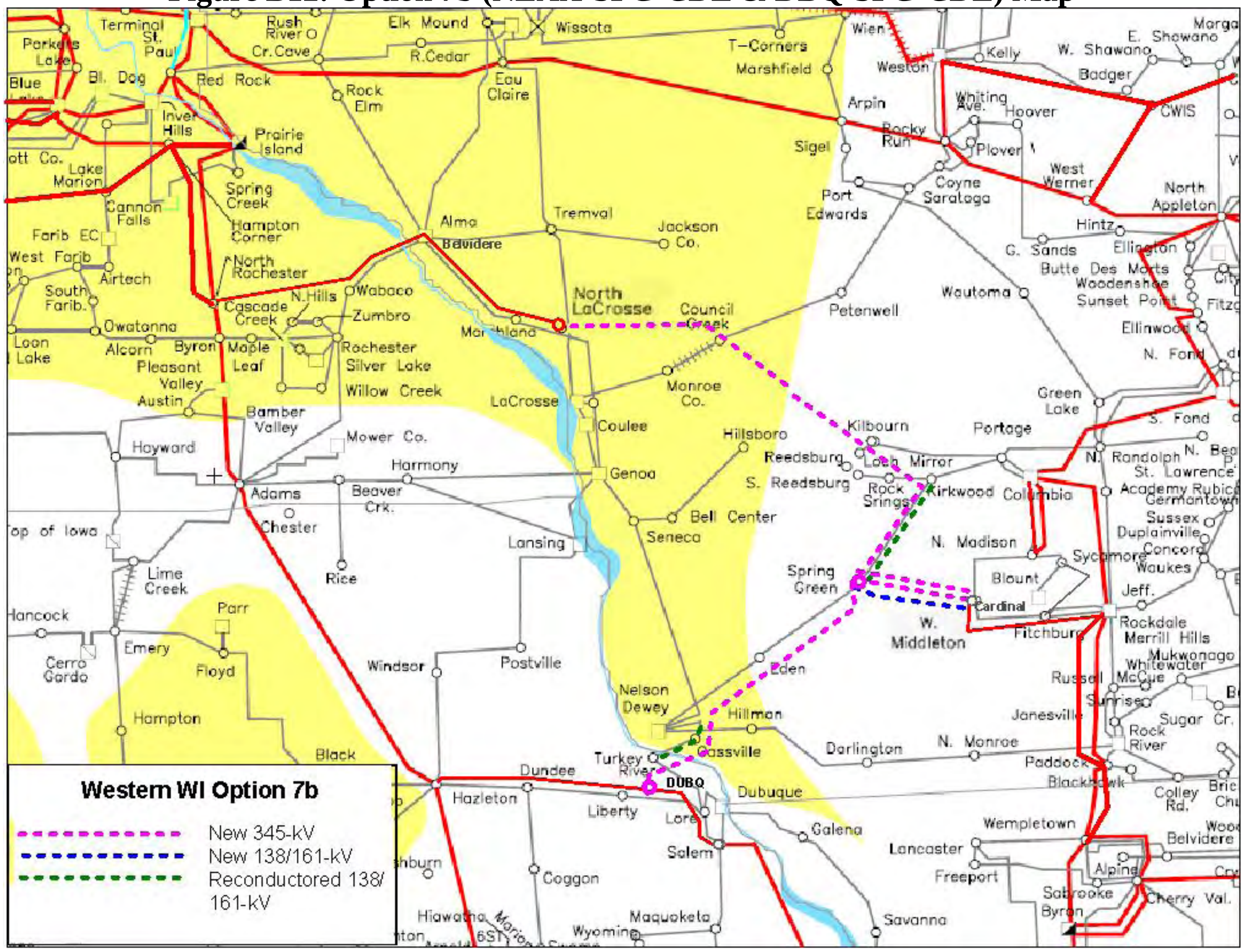
Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

Figure B11: Option 7a (NLAX-SPG-CDL & DBQ-SPG) Map



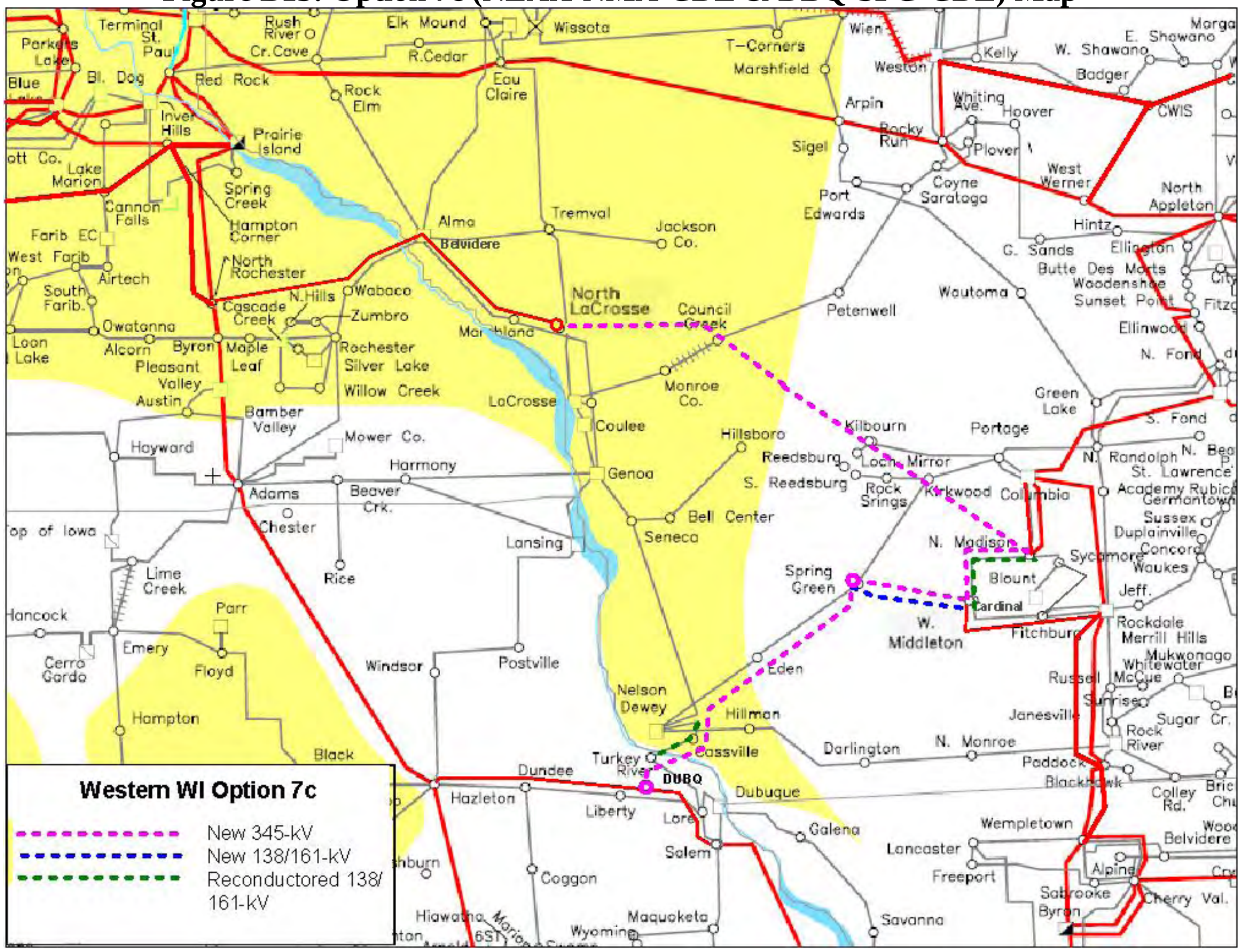
Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

Figure B12: Option 7b (NLAX-SPG-CDL & DBQ-SPG-CDL) Map



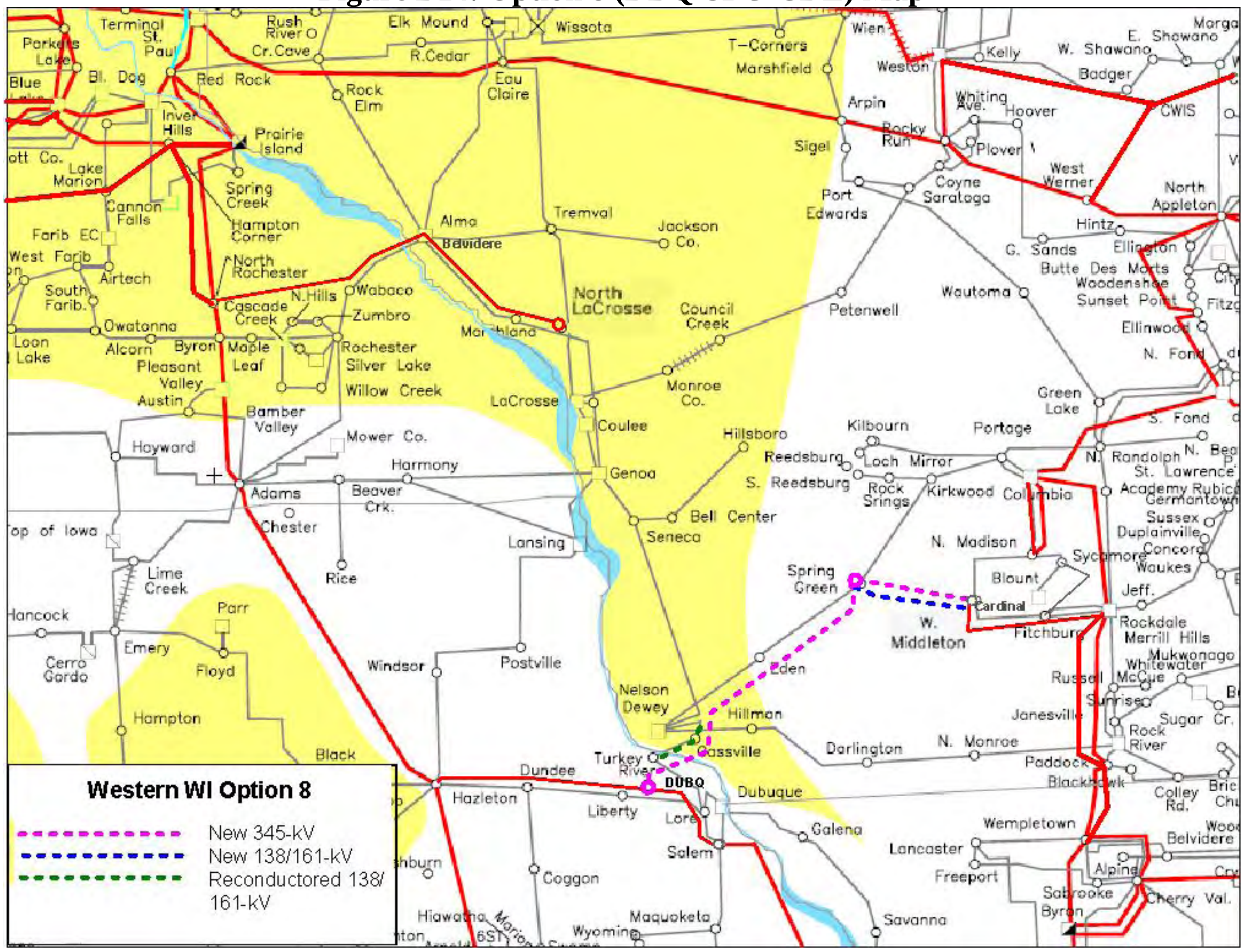
Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

Figure B13: Option 7c (NLAX-NMA-CDL & DBQ-SPG-CDL) Map



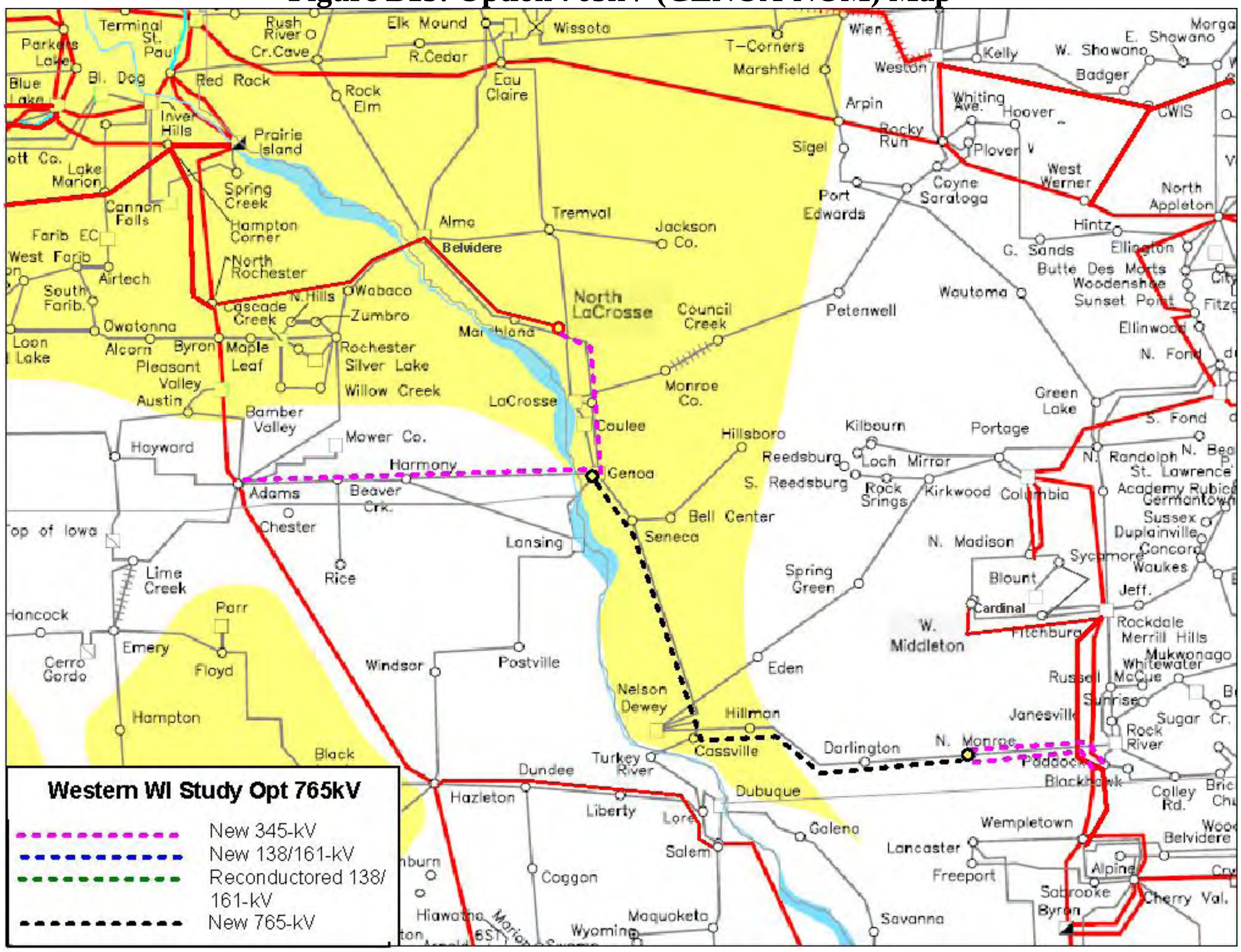
Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

Figure B14: Option 8 (DBQ-SPG-CDL) Map



Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

Figure B15: Option 765kV (GENOA-NOM) Map



Yellow shaded area on maps represents the mid-continent area power pool (mapp) footprint

Appendix C

ATC Severity Index Tool Write-up

Contains Critical Energy Infrastructure Information

Appendix D

Supporting Facilities for the EHV (345 kV and 765 kV) Options – Category B Loading Limitations

Public Version

Appendix D: Category B Loading Limits for Western Wisconsin Transmission Reliability Study

Notes:
1. Blue highlighted rows are facilities outside AC footprint.
2. Costs are in 2010 dollars.
3. Upgrades of the facilities listed in the tables below are rebuilds unless otherwise noted.

Table D.1 – Supporting facilities for NLAX-HLT-SPG-CDL (Opt 1)

** From bus ** ** To bus ** CKT	Costs
New Nelson Dewey-Liberty 161 kV Line	$28,388,123
348915 4E GALESBG N 138 636672 GALESBR5 161 2 [1]	$0
630297 SANDRDG8 69.0 680066 MENOMINE 69.0 1	$280,000
631047 LIME CK5 161 631048 EMERY 5 161 1	$8,868,600
631056 LORE 5 161 631060 TRK RIV5 161 1 [2]	$0
631057 SALEM N5 161 631120 JULIAN 5 161 1	$5,937,750
631058 SO.GVW.5 161 631061 SALEM S5 161 1	$3,082,950
631060 TRK RIV5 161 681519 CASVILL5 161 1 [3]	$0
631095 E CALMS5 161 631096 GR MND 5 161 1	$1,404,000
631123 ADAMS_S5 161 681527 BVR CRK5 161 1	$8,833,500
636636 OAKGROV5 161 636672 GALESBR5 161 1 [4]	$0
637191 HAMPTON5 161 637193 HAMPTON8 69.0 1	$3,380,000
637201 SHEFFLD5 161 637205 WSHEFFLD 69.0 1	$3,380,000
680066 MENOMINE 69.0 680068 T KIELER 69.0 1	$280,000
680067 KAISER 69.0 680068 T KIELER 69.0 1	$490,000
680070 LANCASTE 69.0 680079 HURICAN 69.0 1	$2,345,000
681519 CASVILL5 161 699010 NED 161 161 1 [5]	$0
681523 GENOA 5 161 681531 LAC TAP5 161 1 [6]	$0
698003 HLM 69 69.0 699031 HLM 138 138 1	$2,531,712
698016 EEN 69 69.0 698017 MIP 69 69.0 1	$5,575,491
698034 WIO 69 69.0 698035 GTT 69 69.0 1	$3,900,659
698318 LPS 69 69.0 698321 A07 69 69.0 1	$1,377,973
698321 A07 69 69.0 698322 MCK 69 69.0 1	$5,617,890
698322 MCK 69 69.0 698332 A13 69 69.0 1	$7,000,439
698331 CAR 69 69.0 698332 A13 69 69.0 1	$1,286,253
698375 WHB 69 69.0 699699 WHITCOMB 115 1	$3,825,075
698660 HARRISON 69.0 699792 HARRISON 138 1	$3,825,075
698668 WMD 69 69.0 698674 WTNM 69 69.0 1	$12,263,239
698668 WMD 69 69.0 698684 BLKM69 69.0 1	$3,703,806
699033 DAR 138 138 699036 NOM 138 138 1	$30,574,914
699059 PAD 138 138 699141 TOWNLINE 138 1	$8,791,014
Total	**$156,943,463**

[1] Far from the center of the study footprint (from, to - MEC, AMIL). Assumed this constraint will be fixed by entities outside study participants.
[2] Use a new NED-LIB 161 kV line
[3] Use a new NED-LIB 161 kV line
[4] Far from the center of the study footprint (from, to - MEC, MEC). Assumed this constraint will be fixed by entities outside study participants.
[5] Use a new NED-LIB 161 kV line
[6] DPC comment: this is a DPC planned project

Table D.2 – Supporting facilities for NLAX-SPG-CDL (Opt 1a)

** From bus ** ** To bus ** CKT	Costs	Notes
New Nelson Dewey-Liberty 161 kV Line	$28,388,123	
348915 4E GALESBG N 138 636672 GALESBR5 161 2	$0	See FN 1 on p1
630297 SANDRDG8 69.0 680066 MENOMINE 69.0 1	$280,000	
631047 LIME CK5 161 631048 EMERY 5 161 1	$8,868,600	
631056 LORE 5 161 631060 TRK RIV5 161 1	$0	See FN 2 on p1
631057 SALEM N5 161 631120 JULIAN 5 161 1	$5,937,750	
631058 SO.GVW.5 161 631061 SALEM S5 161 1	$3,082,950	
631060 TRK RIV5 161 681519 CASVILL5 161 1	$0	See FN 3 on p1
631095 E CALMS5 161 631096 GR MND 5 161 1	$1,404,000	
631123 ADAMS_S5 161 681527 BVR CRK5 161 1	$8,833,500	
636636 OAKGROV5 161 636672 GALESBR5 161 1	$0	See FN 4 on p1
637191 HAMPTON5 161 637193 HAMPTON8 69.0 1	$3,380,000	
637201 SHEFFLD5 161 637205 WSHEFFLD 69.0 1	$3,380,000	
680066 MENOMINE 69.0 680068 T KIELER 69.0 1	$280,000	
680067 KAISER 69.0 680068 T KIELER 69.0 1	$490,000	
680070 LANCASTE 69.0 680079 HURICAN 69.0 1	$2,345,000	
680075 BELLCNTR 69.0 680084 T SG 69.0 1	$1,785,000	
680077 T EAST 69.0 680455 MTHOP TP 69.0 1	$3,815,000	
680079 HURICAN 69.0 680455 MTHOP TP 69.0 1	$3,815,000	
680084 T SG 69.0 680086 BOAZ 69.0 1	$3,920,000	
680086 BOAZ 69.0 680087 DAYTON 69.0 1	$420,000	
681519 CASVILL5 161 699010 NED 161 161 1	$0	See FN 5 on p1
681523 GENOA 5 161 681531 LAC TAP5 161 1	$0	See FN 6 on p1
698003 HLM 69 69.0 699031 HLM 138 138 1	$2,531,712	
698016 EEN 69 69.0 698017 MIP 69 69.0 1	$5,575,491	
698032 SME 69 69.0 698033 BRN 69 69.0 1	$7,307,102	
698034 WIO 69 69.0 698035 GTT 69 69.0 1	$3,900,659	
698122 PIR 69 69.0 698300 BREWER 69.0 1	$1,059,979	
698187 RKT 138 138 698941 ART#1 13 138 1	$6,395,745	
698187 RKT 138 138 699144 KIR 138 138 1	$9,530,914	
698313 SALT 69 69.0 699940 SAL 69 69.0 1	$105,998	
698351 PET 69 69.0 699808 PETENWEL 138 1	$3,825,075	
698375 WHB 69 69.0 699699 WHITCOMB 115 1	$3,825,075	
698660 HARRISON 69.0 699792 HARRISON 138 1	$3,825,075	
698668 WMD 69 69.0 698674 WTNM 69 69.0 1	$12,263,239	
698668 WMD 69 69.0 698684 BLKM69 69.0 1	$3,703,806	
699033 DAR 138 138 699036 NOM 138 138 1	$30,574,914	
699059 PAD 138 138 699141 TOWNLINE 138 1	$8,791,014	
Total	**$183,640,721**	

Table D.3 – Supporting facilities for NLAX-NMA-CDL (Opt 1b)

** From bus ** ** To bus ** CKT	Costs	Notes
New Nelson Dewey-Liberty 161 kV Line	$28,388,123	
348915 4E GALESBG N 138 636672 GALESBR5 161 2	$0	See FN 1 on p1
630297 SANDRDG8 69.0 680066 MENOMINE 69.0 1	$280,000	
631047 LIME CK5 161 631048 EMERY 5 161 1	$8,868,600	
631056 LORE 5 161 631060 TRK RIV5 161 1	$0	See FN 2 on p1
631057 SALEM N5 161 631120 JULIAN 5 161 1	$5,937,750	
631058 SO.GVW.5 161 631059 8TH ST.5 161 1	$1,246,050	
631058 SO.GVW.5 161 631061 SALEM S5 161 1	$3,082,950	
631059 8TH ST.5 161 631125 KERPER 5 161 1	$1,521,000	
631060 TRK RIV5 161 681519 CASVILL5 161 1	$0	See FN 3 on p1
631095 E CALMS5 161 631096 GR MND 5 161 1	$1,404,000	
631095 E CALMS5 161 636616 DAVNPRT5 161 1	$10,413,000	
631123 ADAMS_S5 161 681527 BVR CRK5 161 1	$8,833,500	
636636 OAKGROV5 161 636672 GALESBR5 161 1	$0	See FN 4 on p1
637191 HAMPTON5 161 637193 HAMPTON8 69.0 1	$3,380,000	
637201 SHEFFLD5 161 637205 WSHEFFLD 69.0 1	$3,380,000	
680061 HARRISON 69.0 680067 KAISER 69.0 1	$2,485,000	
680061 HARRISON 69.0 680070 LANCASTE 69.0 1	$2,415,000	
680066 MENOMINE 69.0 680068 T KIELER 69.0 1	$280,000	
680067 KAISER 69.0 680068 T KIELER 69.0 1	$490,000	
680070 LANCASTE 69.0 680079 HURICAN 69.0 1	$2,345,000	
680075 BELLCNTR 69.0 680084 T SG 69.0 1	$1,785,000	
680077 T EAST 69.0 680455 MTHOP TP 69.0 1	$3,815,000	
680079 HURICAN 69.0 680455 MTHOP TP 69.0 1	$3,815,000	
680084 T SG 69.0 680086 BOAZ 69.0 1	$3,920,000	
681519 CASVILL5 161 699010 NED 161 161 1	$0	See FN 5 on p1
681523 GENOA 5 161 681531 LAC TAP5 161 1	$0	See FN 6 on p1
698003 HLM 69 69.0 699031 HLM 138 138 1	$2,531,712	
698122 PIR 69 69.0 698300 BREWER 69.0 1	$1,059,979	
698187 RKT 138 138 698941 ART#1 13 138 1	$6,395,745	
698187 RKT 138 138 699144 KIR 138 138 1	$9,530,914	
698313 SALT 69 69.0 699940 SAL 69 69.0 1	$105,998	
698351 PET 69 69.0 699808 PETENWEL 138 1	$3,825,075	
698375 WHB 69 69.0 699699 WHITCOMB 115 1	$3,825,075	
698660 HARRISON 69.0 699792 HARRISON 138 1	$3,825,075	
698668 WMD 69 69.0 698674 WTNM 69 69.0 1	$12,263,239	
698668 WMD 69 69.0 698684 BLKM69 69.0 1	$3,703,806	
699010 NED 161 161 699021 NLD 2 138 1	$4,180,636	
699033 DAR 138 138 699036 NOM 138 138 1	$30,574,914	
699059 PAD 138 138 699141 TOWNLINE 138 1	$8,791,014	
Total	**$188,698,156**	

Table D.4 – Supporting facilities for DBQ-SPG-CDL (Opt 8)

** From bus ** ** To bus ** CKT	Costs	Notes
36384 QUAD3-11 345 631141 ROCK CK3 345 1	$9,481,000	
605296 WSTSALE8 69.0 605316 LAX 8 69.0 1	$3,850,000	
630003 LANSING8 69.0 631053 LANSING5 161 1	$3,380,000	
630234 DECORAH8 69.0 680023 CANOE TP 69.0 1	$2,135,000	
631047 LIME CK5 161 631048 EMERY 5 161 1	$8,868,600	
631051 HAZL S 5 161 631101 DUNDEE 5 161 1 [7]	$0	
631095 E CALMS5 161 631096 GR MND 5 161 1	$1,404,000	
631095 E CALMS5 161 636616 DAVNPRT5 161 1	$10,413,000	
631102 TRIBOJI5 161 631124 DKSN_CO5 161 1	$1,398,150	
631123 ADAMS_S5 161 681527 BVR CRK5 161 1	$8,833,500	
637191 HAMPTON5 161 637193 HAMPTON8 69.0 1	$3,380,000	
637191 HAMPTON5 161 637201 SHEFFLD5 161 1	$8,780,850	
637201 SHEFFLD5 161 637205 WSHEFFLD 69.0 1	$3,380,000	
680070 LANCASTE 69.0 680079 HURICAN 69.0 1	$2,345,000	
680075 BELLCNTR 69.0 680084 T SG 69.0 1	$1,785,000	
680079 HURICAN 69.0 680455 MTHOP TP 69.0 1	$3,815,000	
680084 T SG 69.0 680086 BOAZ 69.0 1	$3,920,000	
680242 LUBLIN 69.0 680505 LAKEHEAD 69.0 1	$420,000	
681523 GENOA 5 161 681531 LAC TAP5 161 1	$0	See FN 6 on p1
681539 ELK MND5 161 681543 ALMA 5 161 1	$26,383,500	
698003 HLM 69 69.0 699031 HLM 138 138 1	$2,531,712	
698016 EEN 69 69.0 698017 MIP 69 69.0 1	$5,575,491	
698034 WIO 69 69.0 698035 GTT 69 69.0 1	$3,900,659	
698122 PIR 69 69.0 698300 BREWER 69.0 1	$1,059,979	
698187 RKT 138 138 698941 ART#1 13 138 1	$6,395,745	
698187 RKT 138 138 699144 KIR 138 138 1	$9,530,914	
698321 A07 69 69.0 698322 MCK 69 69.0 1	$5,617,890	
698351 PET 69 69.0 699808 PETENWEL 138 1	$3,825,075	
698375 WHB 69 69.0 699699 WHITCOMB 115 1	$3,825,075	
698660 HARRISON 69.0 699792 HARRISON 138 1	$3,825,075	
698668 WMD 69 69.0 698674 WTNM 69 69.0 1	$12,263,239	
698668 WMD 69 69.0 698684 BLKM69 69.0 1	$3,703,806	
699033 DAR 138 138 699036 NOM 138 138 1	$30,574,914	
699059 PAD 138 138 699141 TOWNLINE 138 1	$8,791,014	
Total	**$205,393,188**	

[7] ITC comment: this line will be rebuilt as part of the Hazelton - Salem 345 kV project

Table D.5 – Supporting facilities for NLAX-NMA-CDL & DBQ-SPG-CDL (Opt 7c)

** From bus ** ** To bus ** CKT	Costs	Notes
36384 QUAD3-11 345 631141 ROCK CK3 345 1	$9,481,000	
631047 LIME CK5 161 631048 EMERY 5 161 1	$8,868,600	
631095 E CALMS5 161 631096 GR MND 5 161 1	$1,404,000	
631095 E CALMS5 161 636616 DAVNPRT5 161 1	$10,413,000	
631123 ADAMS_S5 161 681527 BVR CRK5 161 1	$8,833,500	
637191 HAMPTON5 161 637193 HAMPTON8 69.0 1	$3,380,000	
637201 SHEFFLD5 161 637205 WSHEFFLD 69.0 1	$3,380,000	
680070 LANCASTE 69.0 680079 HURICAN 69.0 1	$2,345,000	
680075 BELLCNTR 69.0 680084 T SG 69.0 1	$1,785,000	
680079 HURICAN 69.0 680455 MTHOP TP 69.0 1	$3,815,000	
680084 T SG 69.0 680086 BOAZ 69.0 1	$3,920,000	
681523 GENOA 5 161 681531 LAC TAP5 161 1	$0	See FN 6 on p1
698003 HLM 69 69.0 699031 HLM 138 138 1	$2,531,712	
698122 PIR 69 69.0 698300 BREWER 69.0 1	$1,059,979	
698187 RKT 138 138 698941 ART#1 13 138 1	$6,395,745	
698187 RKT 138 138 699144 KIR 138 138 1	$9,530,914	
698351 PET 69 69.0 699808 PETENWEL 138 1	$3,825,075	
698375 WHB 69 69.0 699699 WHITCOMB 115 1	$3,825,075	
698660 HARRISON 69.0 699792 HARRISON 138 1	$3,825,075	
698668 WMD 69 69.0 698674 WTNM 69 69.0 1	$12,263,239	
698668 WMD 69 69.0 698684 BLKM69 69.0 1	$3,703,806	
699033 DAR 138 138 699036 NOM 138 138 1	$30,574,914	
699059 PAD 138 138 699141 TOWNLINE 138 1	$8,791,014	
Total	**$143,951,649**	

Public Version

Appendix D: Category B Loading Limits for Western Wisconsin Transmission Reliability Study

Table D.6 – Supporting facilities for GENOA-NOM 765 kV (765 Opt)

** From bus ** ** To bus ** CKT	Costs	Notes
630297 SANDRDG8 69.0 680066 MENOMINE 69.0 1	$280,000	
631057 SALEM N5 161 631120 JULIAN 5 161 1	$5,937,750	
631058 SO.GVW.5 161 631061 SALEM S5 161 1	$3,082,950	
631060 TRK RIV5 161 681519 CASVILL5 161 1	$0	
631095 E CALMS5 161 631096 GR MND 5 161 1	$1,404,000	
631123 ADAMS_S5 161 681527 BVR CRK5 161 1	$8,833,500	
636636 OAKGROV5 161 636672 GALESBR5 161 1	$0	See FN 4 on p1
637191 HAMPTON5 161 637193 HAMPTON8 69.0 1	$3,380,000	
637201 SHEFFLD5 161 637205 WSHEFFLD 69.0 1	$3,380,000	
680066 MENOMINE 69.0 680068 T KIELER 69.0 1	$280,000	
680067 KAISER 69.0 680068 T KIELER 69.0 1	$490,000	
680070 LANCASTE 69.0 680079 HURICAN 69.0 1	$2,345,000	
680075 BELLCNTR 69.0 680084 T SG 69.0 1	$1,785,000	
680077 T EAST 69.0 680455 MTHOP TP 69.0 1	$3,815,000	
680079 HURICAN 69.0 680455 MTHOP TP 69.0 1	$3,815,000	
680084 T SG 69.0 680086 BOAZ 69.0 1	$3,920,000	
680086 BOAZ 69.0 680087 DAYTON 69.0 1	$420,000	
698003 HLM 69 69.0 699031 HLM 138 138 1	$2,531,712	
698028 NOM 69 69.0 698031 IDH 69 69.0 1	$4,345,915	
698028 NOM 69 69.0 699036 NOM 138 138 1	$3,393,954	
698122 PIR 69 69.0 698300 BREWER 69.0 1	$1,059,979	
698187 RKT 138 138 698941 ART#1 13 138 1	$6,395,745	
698187 RKT 138 138 699144 KIR 138 138 1	$9,530,914	
698313 SALT 69 69.0 699940 SAL 69 69.0 1	$105,998	
698351 PET 69 69.0 699808 PETENWEL 138 1	$3,825,075	
698375 WHB 69 69.0 699699 WHITCOMB 115 1	$3,825,075	
698660 HARRISON 69.0 699792 HARRISON 138 1	$3,825,075	
698668 WMD 69 69.0 698674 WTNM 69 69.0 1	$12,263,239	
698668 WMD 69 69.0 698684 BLKM69 69.0 1	$3,703,806	
699033 DAR 138 138 699036 NOM 138 138 1	$30,574,914	
699036 NOM 138 138 699037 ALB 138 138 1	$11,549,963	
699037 ALB 138 138 699897 BASSCRK 138 1	$14,898,324	
699059 PAD 138 138 699141 TOWNLINE 138 1	$8,791,014	
699141 TOWNLINE 138 699897 BASSCRK 138 1	$14,672,591	
Total	**$180,046,843**	