O'Reilly, Ann (OAH)

From:	Luis Contreras <doccontreras@gmail.com>
Sent:	Wednesday, December 03, 2014 2:41 PM
To:	*OAH_Routecomments.oah
Cc:	grnews@mx3.com; msfair@northwinds.net; norlight@wiktel.com; wpioneer@centurytel.net
Subject:	< Public Comment - E-015/CN-12-1163 and OAH 65-2500-31196 > one
Attachments:	Public Comment E-015 CN-12-1163 and OAH 65-2500-31196 Luis Contreras.pdf

Honorable Ann O'Reilly,

Attached, please find my comments for the Certificate of Need application for the "Great Northern Transmission Line." - docket numbers E-015/CN-12-1163 and OAH 65-2500-31196

Respectfully,

Dr. Luis Contreras

Eureka Springs, AR

EXHIBIT

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E-015/CN-12-1163 and OAH 65-2500-31196

Public comment for a Certificate of Need

"Great Northern Transmission Line"

Dr. Luis Contreras

December 3, 2014

Greed, No need

Local Solar Generation is the best solution: Clean, Low cost, secure, installed in days, one panel at a time

Homeland Security: transmission lines are a hazard

Project Scope is undefined

Engineering design issues:

- GNTL is overdesigned
- the line specification is the wrong type

MISO MTEP does not include GNTL in MISO Grid Reliability plans

Conclusion: Please deny the application

References

Greed, not Need

The Great Northern Transmission Line (GNTL) is a poor investment for the people of MN. The poles and wires of transmission lines do not create value; all they do is move electrons generated far away. Only transmission line contractors benefit from miles of destruction.

GNTL is not a Clean Line. The project website video claims the **transmission line** will provide clean power.

The project is about a 500 kV line using poles and wires, it is not about hydro generation in **Canada**. The total carbon footprint of the line and substation is not disclosed in the proposal.

MISO MTEP does not include GNTL in MISO Grid Reliability plans

The FERC approved PPA has nothing to do with grid reliability. A PPA is a contract to sell and buy power; that is all!

Remote bulk power of any type is not good for the environment. The transmission lines carbon footprint is ignored, forgetting trees are the only carbon capture and storage (CCS) that works, and the erosion and water contamination from herbicides sprayed on the ROW.

Granting the power of Eminent Domain to highly speculative, private business, for taking private property by force for this proposal, would be a serious violation of private property rights. How can we ignore the social cost for the families traversed and near transmission lines, a permanent change to the quality of life?

GNTL is not a public project, and it is not in the public interest.

Minnesota Power proposes a transmission line, not building a hydro dam. The suggestion hydro does not pollute the air is irrelevant for this project, it is out of scope. Minnesota Power knows local solar generation is the only clean energy.

Local and Remote Bulk Power Generation

Rooftop power generation eliminates the waste of over-generation, transportation and distribution. Local and community solar power generation with low cost, high efficiency solar panels and advanced inverters are the best option: simple, affordable, installed in hours, secure and reliable.

Bulk power generation at remote plants, including hydro, promotes waste of over-generation, transportation distribution, and stand-by power units, with substantial power losses along the way. With ratepayers funding the total cost of these facilities plus a guaranteed profit of over 12 percent for the utilities, there are no incentives for efficiency. In the utility world the more they spend, the higher the profits.

Solar local power generation is the best solution for Global climate change

- We are on a race against time with climate change: Solar systems are installed in days; bulk generation of any type takes years.
- Low cost: rooftop systems eliminate transmission and distribution.
- Modular design: adding solar panels as needed avoids excess generation.
- Under a historic climate agreement with the U.S., China is installing **eight gigawatts** of rooftop solar systems this year: China had almost 20 gigawatts of solar capacity at the end of 2013, a figure comparable to about 20 nuclear reactors. Most of that came from massive solar farms in remote locations. Policy makers are now promoting rooftop systems, where they're needed. The push to promote wider use of rooftop solar comes amid growing health concerns tied to smog within its own population and from foreign companies.

PPA's are transmission line financing tools

A power purchase agreement (PPA) is a contract between two parties, one who generates electricity (the seller) and one who is looking to purchase electricity (the buyer). PPA defines all of the commercial terms for the sale of electricity between the two parties, including when the project will begin commercial operation, schedule for delivery of electricity, penalties for under delivery, payment terms, and termination. PPA is the agreement that defines the revenue and credit quality of a generating project and is thus an **instrument of project finance.**

Having a PPA for 500 MW is no indication the project is needed to improve grid reliability.

Unlike other commodities, electrons have to be used right away; grid storage is expensive and unavailable. Adding 500 MW would create, not solve problems for the grid.

Why 500 MW and not 1000 MW? There are no studies showing what 500 MW would provide. Grid planning must be based on demand requirements and flow reliability studies, not on capacity available for sale.

There better ways to meet public needs and public policy objectives than this transmission line:

- energy conservation
- energy efficiency
- load-management

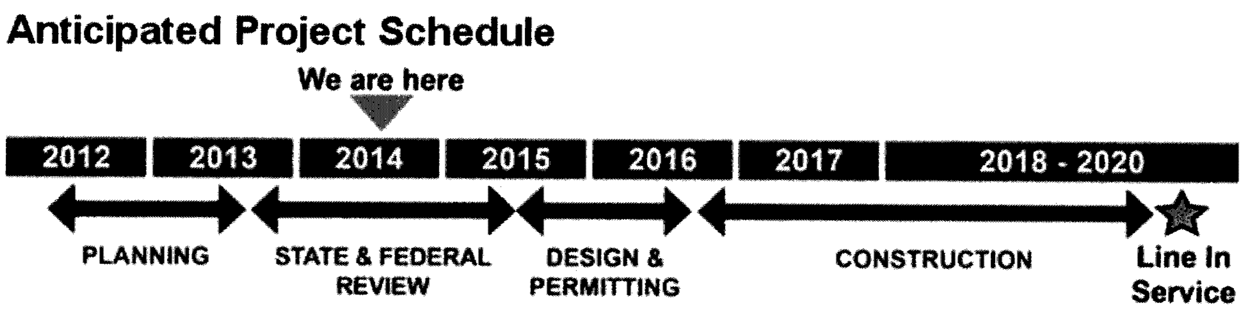
Additional power can be provided by solar PV local and community generation, one panel at a time!

Local Solar Generation is the best solution

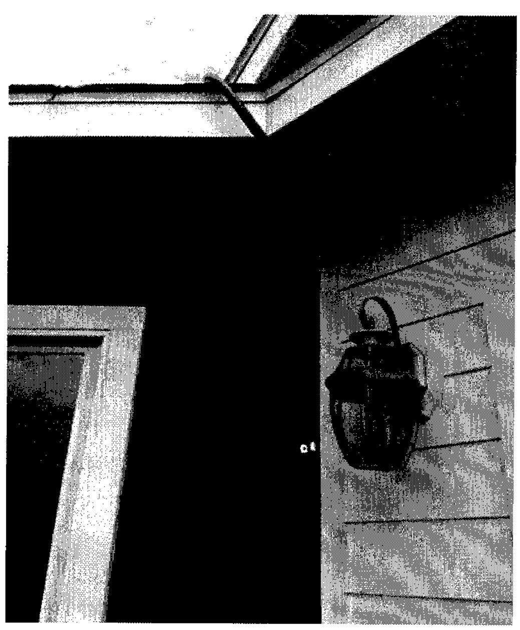
Low cost, secure, installed in days, one panel at a time

Minnesota Power has a project for the National Guard

GNTL transmission line is sold as "clean" to **avoid a grid reliability** study using 2012 data to project grid requirements 10 years later. Transmission line projects are not driven by real demand; no one knows the demand and the technology will be 10 years in the future.

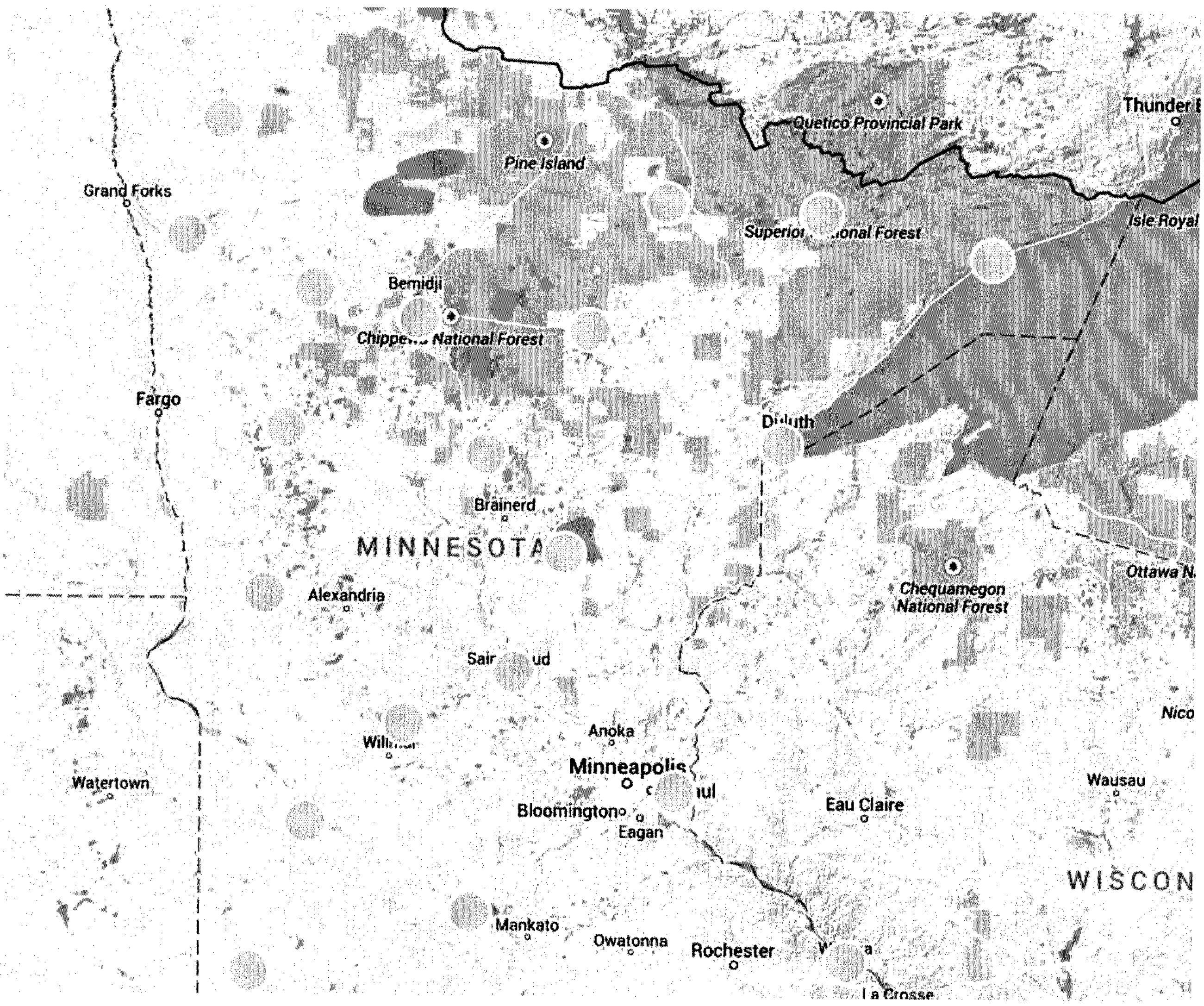


Solar PV systems are installed in **days**. There is no guessing about the size of the array; the modular design makes it easy to add panels as needed. Here is a picture of my home "line" from my rooftop 5.5 kV system, installed in 8 hours: a 25 foot conduit.



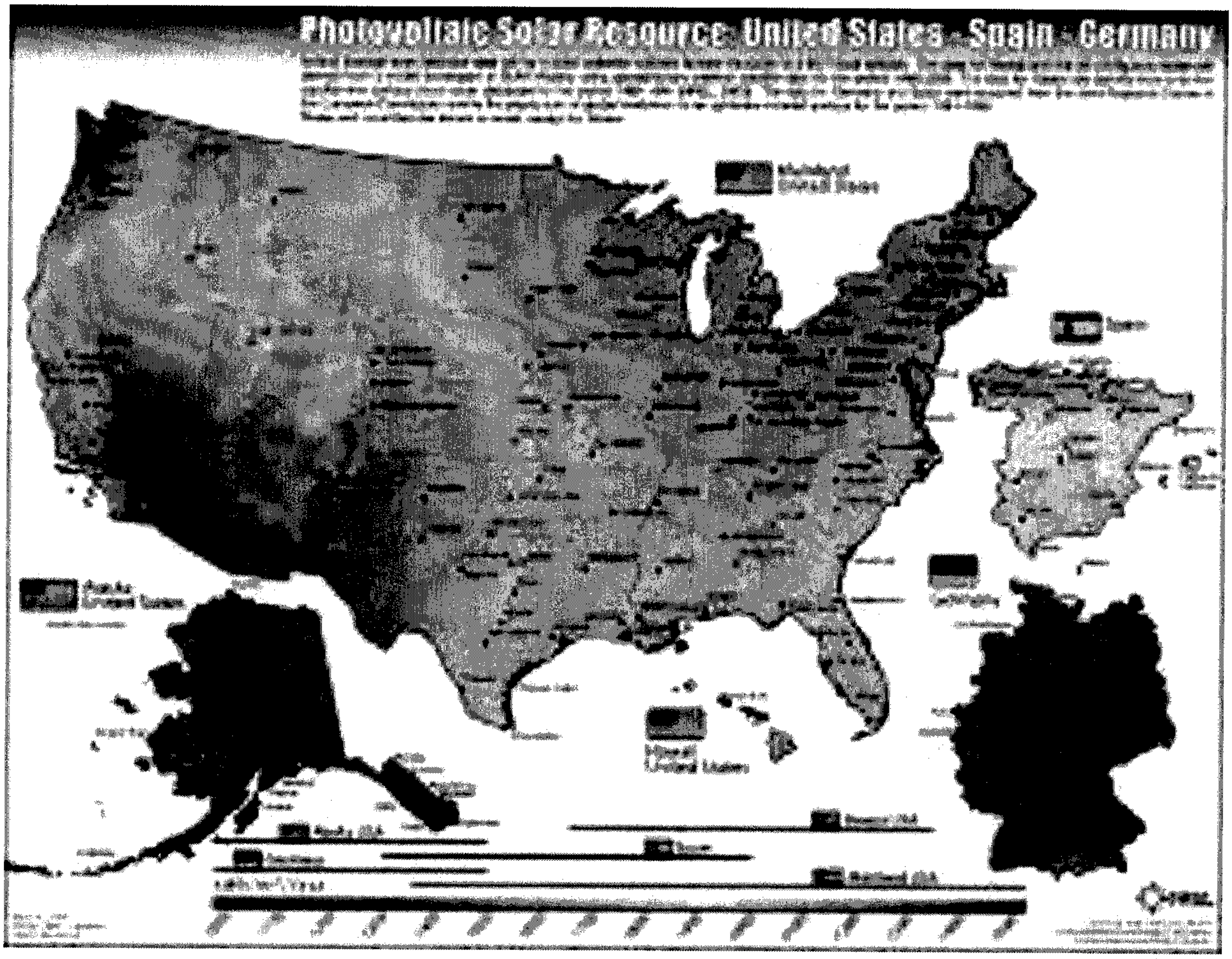
A common misconception is solar works in Florida and Arizona, but not in Minnesota.

Solar photo voltaic is about capturing sunlight. It works best in cold temperatures, and snow light reflection is ideal. The yellow circles show current clusters of solar systems in MN:



http://www.cleanenergyresourceteams.org/mn-solar-projects-map

Germany is a solar leader with few hours of sunshine:



Homeland Security

All military installations are going local solar. They can't rely on power grid. Same as large data centers, hospitals and any critical facility.

U.S. electric power grid "inherently vulnerable" to terrorist attacks

November 16, 2012

http://www.homelandsecuritynewswire.com/dr20121116-u-s-electric-power-grid-inherently-vulnerable-to-terrorist-attacks-report

The U.S. electric power delivery system is vulnerable to terrorist attacks which could cause much more damage to the system than natural disasters such as Hurricane Sandy, blacking out large regions of the country for weeks or months, and costing many billions of dollars, says a newly released report by the National Research Council.

The important thing to notice is the date of the Homeland Security report, 2012. Nothing has changed; a larger grid will increase the risk of a terrorist attack. *Most substations are "secured" with a six-foot tall chain link fence and a padlock!*

America's electric grid remains a juicy terror target

July 17, 2014

http://spectator.org/articles/59979/power-failure

The persistent vulnerability of the U.S. electric grid – and by extension, the economy and critical infrastructure dependent upon it – to a catastrophic event, whether deliberate attack or natural hazard. This failure of imagination with respect to electric grid security is all the more inexplicable, however, when we consider that *threats to the grid are far from theoretical.* They are real and they are multiplying, and in some cases, we have only quite narrowly – even unintentionally – avoided what could have been major disasters.

In what was a wildly underreported incident at the time, in April 2013 a group of unknown individuals infiltrated a PG&E substation on the outskirts of San Jose, California, cut a series of underground fiber-optic cables then opened fire with high-powered rifles on seventeen high-voltage transformers. The assailants got away and have yet to be identified or apprehended.

Minnesota Power Joins Forces with Military to Build 10-Megawatt Solar Energy Project at Camp Ripley

August 267, 2014

http://www.advfn.com/news Minnesota-Power-Joins-Forces-with-Military-to-Buil 63384211.html

Minnesota Power and the Minnesota National Guard will join forces to build a major solar energy project at Camp Ripley, the largest military base in Minnesota.

Duluth-based Minnesota Power, a division of ALLETE, Inc., and the Minnesota National Guard today signed a memorandum of understanding outlining plans to build a *10-megawatt utility-scale solar energy array* at the central Minnesota camp. The project will be the largest solar energy installation on military property in the state. The utility will also identify ways to help Camp Ripley reduce its energy usage by 30 percent and install backup generation for energy security.

Minnesota Power has been the energy provider to Camp Ripley, located near Little Falls, for decades. The 53,000-acre regional training facility was established in 1856. The solar project envisioned by Minnesota Power and the Guard, subject to regulatory approval, would cover nearly 100 acres of underutilized government property at the Camp with photovoltaic panels on racks.

Army 90MW of Solar for Less than the 'Avoided Cost' of Fossil Fuels

May 19, 2014

http://www.greentechmedia.com/articles/read/georgia-power-to-build-solar-for-the-u.s.-army-at-below-the-cost-of-other-s

Georgia Power, the state's biggest electricity supplier, is planning to build three 30-megawatt PV solar installations for the U.S. Army for a remarkably low cost. "That's a big deal, especially deep in coal country."

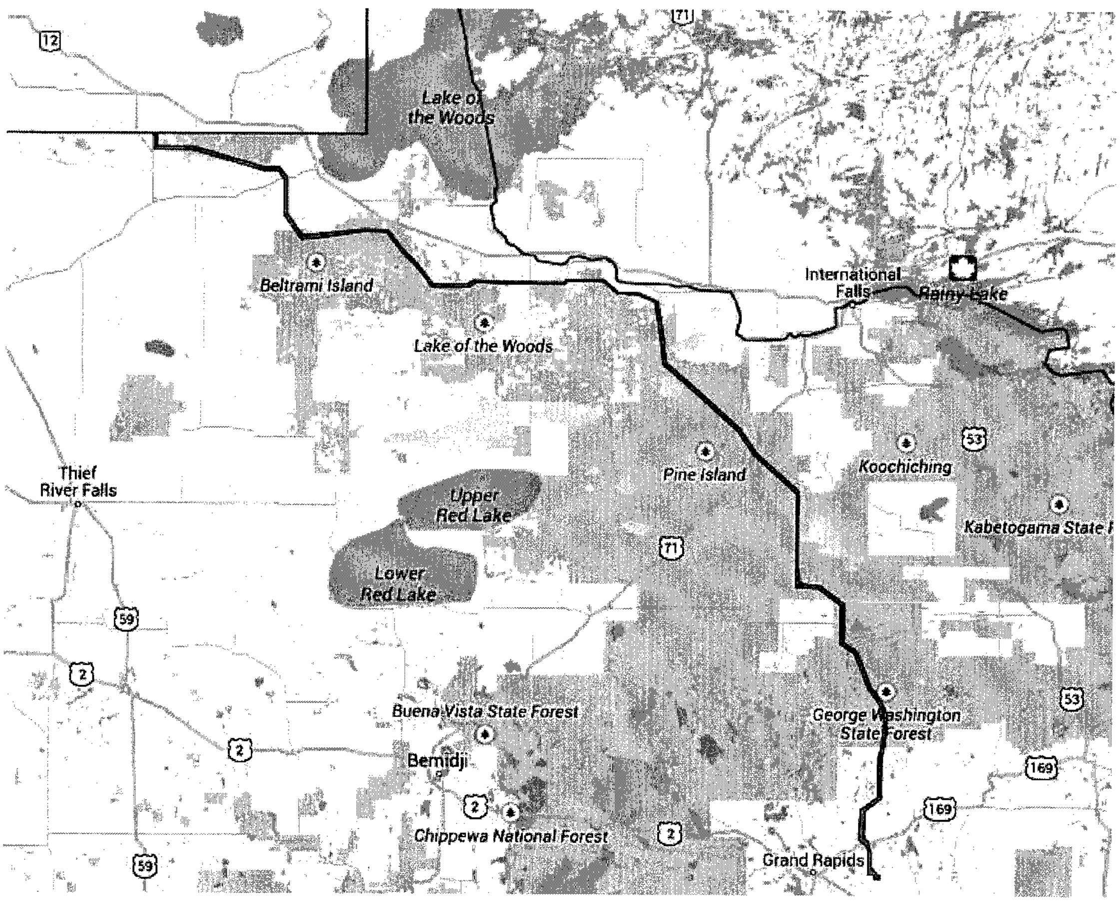
The Army's Georgia 3x30 initiative will build installations at Fort Stewart, Fort Gordon and Fort Benning. The forts will supply land for the arrays and distribution lines. The Army will be the offtaker through an existing contract with Georgia Power.

The utility will work with the U.S. Army Energy Initiatives Task Force to get the solar into commercial operation before the end of 2016. The projects will bring the renewables share of the Army's Georgia energy consumption to 18 percent.

More importantly, the utility sees the projects as "cost-effective," according to Renewable Development VP Norrie McKenzie. "The three projects will be brought on-line at or below the company's avoided cost, the amount it is estimated to cost the company to generate comparable energy from other sources."

Project Scope is undefined

The route map shown on the project website shows a **line from Manitoba to Grand Rapids**, stating: The Great Northern Transmission Line will consist of a 500 kV transmission line from the Minnesota-Manitoba border to the Blackberry 500 kV Substation near Grand Rapids, Minnesota, as well as associated substation facilities and transmission system modifications at the Blackberry 500 kV Substation site.



However, the true project ***relies*** on studies of transmission *additions*:

- Manitoba through Minnesota and Wisconsin into Michigan
- Manitoba to Duluth

This is a serious inconsistency.

Why would Minnesota Power use studies of transmission additions to *justify* the line to the Blackberry 500 kV Substation?

Looking at a map showing Minnesota, Wisconsin, and Michigan, it makes one wonder if the line to Blackberry by is needed at all. The short answer is NO.

Conclusions

The Minnesota Power Proposal should be denied

Minnesota Power is being deceptive selling this project as a CLEAN LINE, hiding the true scope and purpose of the proposal. Minnesota Power is misleading the PUC and the public. This project is about *corporate greed, not public need.*

A Power Purchase Agreement does not prove public need. Sending additional hydropower to other utilities in the United States does prove the need for the line for Minnesota.

An Integrated Resource Plan does not prove public need.

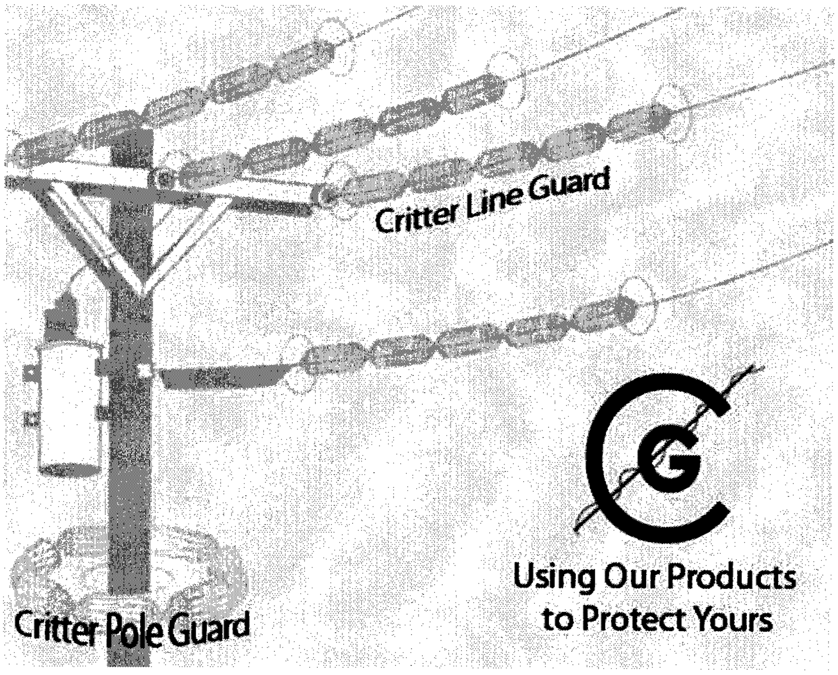
This project is not about reliability. Minnesota ratepayers already enjoy an **uninterrupted**, adequate, quality supply of electric power. Power outages are caused by extreme weather and poor distribution line maintenance. The most effective gains are with daily line maintenance, and squirrel proofing the lines and substations.

EEI EDISON ELECTRIC INSTITUTE

The Association of Shareholder-Owned Electric Companies

Major Cause of Power Outages in U.S.*

70%	Weather-related
11%	Animals contacting wires
11%	Unknown
4%	Auto accidents
4%	Utility maintenance (Pre-arranged by utility)



Minnesota Power is being deceptive in putting Phase II on hold. **American Transmission Company**, the silent partner with Minnesota Power, in a letter dated October 31, 2014, has endorsed Phase I.

The Environmental Report prepared by Minnesota Department of Commerce shows the scope of this proposal and discusses the potential for **bulk power transfers**.

Line capacity of is greater than750MW, as shown by the type of conductors for the line. 750MW exceeds any claimed need for increased power in Minnesota.

References

MTEP11 Report

MTEP11 Appendices ABC

MTEP11 Appendices

Full MTEP12 Report (pdf)

Appendices A, B, and C

Appendices A1, A2, and A3

Full MTEP12 Report (pdf)

Appendices A, B, and C

Appendices A1, A2, and A3

O'Reilly, Ann (OAH)

From:	Luis Contreras <doccontreras@gmail.com>
Sent:	Wednesday, December 03, 2014 2:47 PM
To:	*OAH_Routecomments.oah
Cc:	grnews@mx3.com; msfair@northwinds.net; norlight@wiktel.com; wpioneer@centurytel.net
Subject:	Re: < Public Comment - E-015/CN-12-1163 and OAH 65-2500-31196 > attachments for my comment
Attachments:	MTEP11 Appendix A4_New_Appendix_A_Projects.pdf; MTEP11 Appendix E1 Reliability Methodology.pdf; MTEP11 Appendix A-1_2_3.xlsx; MTEP11 Report.pdf

On Wed, Dec 3, 2014 at 2:40 PM, Luis Contreras <doccontreras@gmail.com> wrote:

Honorable Ann O'Reilly,

Attached, please find

the attachments to my
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Respectfully,

Dr. Luis Contreras

Eureka Springs, AR

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Appendix A.4: MTEP11 New Appendix A Projects

Planning Region	Geographic Location by TO Member System	PrjID	Project Name	Project Description	States	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD (Max)
Central	AmerenIL	2239	Proposed MVP Portfolio 1 - Sidney to Rising 345 kV line	Sidney to Rising 345 kV line, plus 345 kV ring bus at Rising and breaker-and-a-half arrangement at Sidney.	IL	MVP	Shared		$83,230,000	11/15/2016
Central	AmerenIL	3017	Proposed MVP Portfolio 1 - Palmyra Tap-Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV Line	Palmyra Tap to Quincy to Meredosia to Ipava 345 line and Meredosia to Pawnee 345 kV line. Install additional transformers at Quincy, Meredosia and Pawnee. 345 kV ring bus at Quincy, Meredosia, and Ipava, with breaker-and-a-half arrangement at Pawnee and Palmyra Tap Substations.	IL	MVP	Shared		$432,160,000	11/15/2017
Central	AmerenIL	3169	Proposed MVP Portfolio 1 - Pawnee to Pana - 345 kV Line	Pawnee to Pana 345 kV, 31 mile line including additional transformer at Pana	IL	MVP	Shared		$99,360,000	11/15/2018
Central	AmerenIL, DEM	2237	Proposed MVP Portfolio 1 - Pana - Mt. Zion - Kansas - Sugar Creek 345 kV line	Pana to Mt. Zion to Kansas to Sugar Creek 345 kV line. Install transformers at Mt. Zion and Kansas, with 345 kV ring bus at Mt. Zion and breaker-and-a-half arrangement at Kansas and Pana.	IL	MVP	Shared		$318,410,000	11/15/2019
Central	AmerenIL, MEC	3022	Proposed MVP Portfolio 1 - Fargo-Galesburg-Oak Grove 345 kV Line	Fargo-Galesburg-Oak Grove (MEC) 345 kV Line - New 70 mile, 3000 A summer emergency capability line. 345 kV ring bus at Fargo.	IA, IL	MVP	Shared		$272,249,969	11/15/2019
Central	AmerenMO	3170	Proposed MVP Portfolio 1 - Adair-Palmyra Tap 345 kV Line	Adair - Palmyra 345 kV, 58 miles of line; Establish Palmyra Tap Substation	MO	MVP	Shared		$112,790,000	11/15/2020
Central	AmerenMO, ITCM	2248	Proposed MVP Portfolio 1 - Adair - Ottumwa 345	Adair Substation - New 560 MVA, 345/161 kV Transformer. New 71 mile 345 kV line from Adair to Ottumwa with 3000 A summer emergency capability. 345 kV ring bus at West Adair	IA, MO	MVP	Shared		$244,627,764	11/15/2020
Central	DEM, NIPS	2202	Proposed MVP Portfolio 1 - Reynolds to Greentown 765 kV line	Reynolds to Greentown 765 kV line	IN	MVP	Shared		$186,875,000	8/1/2018
East	NIPS	3203	Proposed MVP Portfolio 1 - Reynolds to Burr Oak to Hiple 345 kV	Reynolds to Burr Oak to Hiple 345 kV line and tie in second AEP 345 kV circuits at Reynolds and Hiple	IN	MVP	Shared		$271,000,000	12/31/2019

Planning Region	Geographic Location by TO Member System	PrjID	Project Name	Project Description	States	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD (Max)
West	ATC LLC	2844	Proposed MVP Portfolio 1 - Pleasant Prairie-Zion Energy Center 345 kV line	Construct a new Pleasant Prairie-Zion Energy Center 345-kV line	WI/IL	MVP	Shared		$28,856,000	3/16/2014
West	ATC LLC, XEL, ITCM	3127	Proposed MVP Portfolio 1 - N LaCrosse-N Madison-Cardinal - Spring Green - Dubuque area 345-kV	N LaCrosse- N Madison - Cardinal 345-kV & Dubuque County - Spring Green - Cardinal 345 kV line. Spring Green and Briggs Road transformers	WI, IA	MVP	Shared		$679,260,000	12/31/2020
West	MEC, ITCM	3205	Proposed MVP Portfolio 1: Lakefield Jct. - Winnebago - Winco - Burt area & Sheldon - Burt Area - Webster 345 kV line	New 345 kV line from Lakefield Junction to Burt via Winnebago and Winco and a new 345 kV line from Sheldon to Webster via Burt. Includes 161 kV rebuild as underbuild along portions of the route.	MN, IA	MVP	Shared		$514,069,787	12/1/2016
West	MEC, ITCM	3213	Proposed MVP Portfolio 1 - Winco to Hazelton 345 kV line	Winco to Lime Creek to Floyd to Blackhawk to Hazelton 345 kV line and Lime Creek, Floyd and Black Hawk transformers	IA	MVP	Shared		$591,551,532	12/31/2015
West	OTP, MDU	2220	Proposed MVP Portfolio 1 - Ellendale to Big Stone South	Big Stone to Ellendale 345 kV double circuit line	ND, SD	MVP	Shared		$326,164,000	12/31/2019
West	OTP, XEL	2221	Proposed MVP Portfolio 1 - Big Stone South to Brookings	Brookings to Big Stone 345 kV double circuit	SD	MVP	Shared		$226,720,000	12/31/2017
West	XEL, GRE	1203	Proposed MVP Portfolio 1 - Brookings, SD - SE Twin Cities 345 kV	Brookings Cty-Lyon Cty (Single Ckt 345 kV); Lyon Cty-Cedar Mountain-Helena (Double Ckt 345 kV); Helena-Lake Marion-Hampton Corner (Single Ckt 345 kV); Lyon Cty-Hazel (Single Ckt 345 kV); Hazel-Minnesota Valley (Single Ckt 345 kV, initially operate at 230 kV); Cedar Mountain-Franklin (Single Ckt 115 kV)	MN, SD	MVP	Shared		$738,400,000	2/16/2015
Central	AmerenIL	2065	Stallings 345/138 kV Sub - Replace 560 MVA 345/138 kV transformer	Stallings 345/138 kV Substation-Replace 560 MVA, 345/138 kV Transformer with 700 MVA unit. Install a 345kV ring bus	IL	BaseRel	Shared		$10,075,000	6/1/2012

Planning Region	Geographic Location by TO Member System	PrjID	Project Name	Project Description	States	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD (Max)
Central	AmerenIL	2980	Tazewell-San Jose Rail - Reconductoring	Tazewell-San Jose Rail Substation section of East Springfield-Tazewell-1384 138 kV Line - Reconductor 3.67 miles of 927 kcmil ACAR conductor at the Tazewell end of the line with conductor capable of carrying at least 1278 A under summer emergency conditions	IL	BaseRel	Not Shared		$3,251,000	6/1/2013
Central	AmerenIL	2981	McLean-Oglesby 138 kV Reconductor	Replace 9.72 miles of 138 kV line on L1382, from McLean County Substation to El Paso Tap to a minimum 1200A SE capability	IL	BaseRel	Not Shared		$5,100,000	9/1/2013
Central	AmerenMO	2306	Nortwest Cape Area 345/161 kV Substation	Install 560 MVA, 345/161 kV Transformer. Provide 345 kV supply from 11 mile 345 kV line extension from Lutesville Substation	MO	BaseRel	Shared		$30,751,000	6/1/2016
East	ITC	2931	Adams-Spokane/Burns1-Jewel 120 kV Rebuild	Rebuild 2.4 miles of DC 3/0 Cu 120 kV lin to 1431 ACSR 230 kV construction.	MI	BaseRel	Not Shared		$3,200,000	6/30/2012
East	ITC	3285	Fermi & Shoal 120kV Capacitors	33.3 Mvar Capacitors at Fermi and Shoal 120kV	Mi	BaseRel	Not Shared		$3,800,000	6/1/2014
East	METC	1809	Keystone-Hodenpyl 138 kV Rebuild	Rebuild the 27 mile Keystone to Hodenpyl 138 kV line to 954 ACSR (Pre-build to 230 kV construction).	Mi	BaseRel	Shared		$32,600,000	12/31/2013
East	METC	2812	Twining - Alcona 138kV Rebuild	Rebuild the Twining-Mio 138kV 38 mile line to 954 ACSR future-double-circuit (pre-built to 230kV)	MI	BaseRel	Shared		$43,300,000	5/31/2012
East	METC	3303	Cottage Grove-East Tawas 138 kV Rebuild	Rebuild 12.3 miles of 138 kV line	MI	BaseRel	Shared		$11,400,000	6/1/2015
East	METC	3304	Croton-Nineteen Mile 138 kV Rebuild	Rebuild 21.5 miles of 138 kV 110 CU to 954 ACSR (Pre-build to 230 kV construction).	Mi	BaseRel	Shared		$26,600,000	12/31/2013
East	METC	3520	NERC Alert Facility Ratings for 2011: Eureka - Vestaburg 138 kV line upgrade	Eureka - Vestaburg 138 kV line upgrade: Remediate sag limits to conductor rating of circuit	Mi	BaseRel	Not Shared		$1,100,000	6/1/2012
East	METC	3521	NERC Alert Facility Ratings for 2011: Bullock - Summerton 138 kV line upgrade	Bullock - Summerton 138 kV line upgrade: Remediate sag limits to conductor rating of circuit	Mi	BaseRel	Not Shared		$3,600,000	6/1/2012
West	ATC LLC	1729	Uprate Straits-McGulpin 138 kV	Uprate overhead portions of Straits-McGulpin 138-kV circuits #1 & #3 to 200 F degree summer emergency ratings	MI	BaseRel	Not Shared		$300,000	4/20/2011

Planning Region	Geographic Location by TO Member System	PrjID	Project Name	Project Description	States	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD (Max)
West	ATC LLC	1950	2nd Kewaunee 345-138 kV Transformer	Reconfigure Kewaunee 345/138 kV switchyard and install a 2nd Kewaunee 345-138 kV transformer of 500 MVA.	WI	BaseRel	Shared		$17,697,000	3/17/2011
West	ATC LLC	2800	Uprate Arpin-Hume 115-kV	Marshfield Electric & Water Department project to increase ground clearance to operate the line at 200 Deg F	WI	BaseRel	Not Shared		$191,000	9/10/2010
West	ATC LLC	2846	Straits power flow control	Install AC-DC-AC Back to Back Voltage Source Converterpower (VSC) flow controller at the Straits 138-kV substation	MI	BaseRel	Shared		$90,000,000	5/1/2014
West	ATC LLC	3427	Nordic-Perch Lk Uprate (AM)	Increase ground clearance for the Nordic-Perch Lk 138 kV line	MI	BaseRel	Not Shared		$1,543,040	3/7/2011
West	ATC LLC	3459	A-157 Hume-Wildwood 115kV Uprate	Increase ground clearance on the Hume-Wildwood 115kV line	WI	BaseRel	Not Shared		$50,000	4/12/2011
West	ATC LLC	3461	N-144 McMillan-Wildwood 115kV Uprate	Increase ground clearance on the McMillan-Wildwood 115kV line	WI	BaseRel	Not Shared		$50,000	2/28/2011
West	DPC	3397	Genoa to La Crosse Tap 161 Rebuild	Rebuild of the 161 kV line from Genoa to the La Crosse tap.	WI	BaseRel	Shared		$18,000,000	6/1/2014
West	GRE/MP	2634	Savanna-Cromwell	Savanna-Cromwell	MN	BaseRel	Shared		$30,000,225	12/1/2014
West	ITCM	3410	Bridgeport Terminal Upgrades	Upgrade the Bridgeport-Ottumwa 161kV terminal equipment	IA	BaseRel	Not Shared		$200,000	12/31/2011
West	ITCM	3415	Marion Termianl Upgrades	Uprate 115 kV breaker 3710 terminal equipment at Marion.	IA	BaseRel	Not Shared		$10,000	12/31/2011
West	ITCM	3499	NERC Alert Facility Ratings for 2011	Verify and remediate facilities as required due to the industry-wide NERC alert	IA	BaseRel	Not Shared			12/31/2011
West	MEC	3268	Lehigh: 345 kV 50 MVAr Reactor	Add a 345 kV, 50 MVAr reactor	IA	BaseRel	Not Shared		$2,750,000	11/1/2012
West	MP	3373	9 Line	Thermal Upgrade	MN	BaseRel	Shared		$8,000,000	12/30/2012
West	OTP	3481	Buffalo - Casselton 115 kV Line	Construct 16 mile 115 kV line from Buffalo - Casselton (ND); Replace Buffalo 345/115 kV Transformer; Rebuild portion of Sheyenne - Mapleton 115 kV Line	ND	BaseRel	Shared		$14,000,000	12/31/2014
West	XEL	3309	Buffalo Ridge Substation Equipment Upgrade	Upgrade the wave traps and line switches at Buffalo Ridge to 2000 A going to Lake Yankton and Pipestone. Retap the Pipestone CTs to 2000 A going to Buffalo Ridge.	MN	BaseRel	Not Shared		$286,000	8/1/2011
West	XEL	3312	Minn Valley - Maynard - Kerkhoven tap upgrade	This project is to upgrade the Minn Valley - Maynard - Kerkhoven tap 115 kV line to 795 ACSS conductor	MN	BaseRel	Shared		$13,660,000	6/1/2014

Planning Region	Geographic Location by TO Member System	PrjID	Project Name	Project Description	States	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD (Max)
West	XEL	3314	Kohlman Lake - Long Lake 2nd circuit	This project is to convert the Kohlman Lake - Long Lake 115 kV bifurcated line to double circuit with separate line terminations at Kohlman Lake and Long Lake	MN	BaseRel	Not Shared		$3,000,000	6/1/2014
West	XEL	3315	Chisago County 2nd 345/115 kV transformer	This project is to install a 2nd 345/115 kV transformer at Chisago County	MN	BaseRel	Not Shared		$7,000,000	6/1/2014
West	XEL	3316	Riverside - Apache lie upgrade	This project is to upgrade Riverside - Apache line to 360 MVA and upgrade Apache switch to 2000A	MN	BaseRel	Not Shared		$3,000,000	6/1/2014
West	XEL	3317	Goose Lake - Kohlman Lake 2nd circuit	This project is to convert the single circuit line between Goose Lake and Kohlman Lake to double circuit.	MN	BaseRel	Shared		$6,000,000	6/1/2014
West	XEL	3318	Parkers Lake Overstressed Breakers	This project replaces some of the 115 kV breakers at Parkers Lake with 63 kA rated breakers	MN	BaseRel	Not Shared		$1,900,000	10/1/2011
West	XEL	3319	Split Rock Overstressed Breakers	This project replaces some of the 115 kV breakers at Split Rock with 63 kA rated breakers	SD	BaseRel	Not Shared		$1,344,000	12/1/2011
West	XEL	3320	Split Rock Reactor Replacement	This project is needed to replace the failed 50 MVAR reactor and associated breaker.	SD	BaseRel	Not Shared		$100,000	12/1/2011
West	XEL	3321	Chemolite Breaker Addition	This project adds two breakers at Chemolite to insure only one line at a time will be removed from service during a breaker failure.	MN	BaseRel	Not Shared		$580,000	1/14/2011
West	XEL	3326	Black Dog Outlet	This line will rebuild the 115 kV line from Black Dog to Savage to 795 ACSS conductor.	MN	BaseRel	Not Shared		$4,564,000	6/1/2012
West	XEL	3475	Prairie 3rd transformer	This project is to install a 3rd 230/115 kV transformer at Prairie substation	ND	BaseRel	Not Shared		$12,000,000	6/1/2014
West	XEL	3476	Maple River - Cass County 345 kV line	This project is to build a new 4.5 mile 345 kV line from Maple River to Cass County substation along with the 345/115 kV transformer at Cass County substation.	ND	BaseRel	Not Shared		$13,226,000	6/1/2014
Central	AmerenIL	3337	G931 Paxton-Gilman Reconductoring	Reconductor to 1200 A summer emergency capability	IL	GIP	Not Shared		$7,390,000	12/1/2013
Central	AmerenIL	3357	Hennepin-E. Kewanee L1552 - Increase Ground Clearance	G545 and G569 Increase ground clearance on 477 kcmil ACSR conductor to permit operation at 120 degrees C. Upgrade E. Kewanee breaker and terminal equipment to 1200 A capability	IL	GIP	Not Shared		$3,180,000	12/31/2012
Central	AmerenIL	3358	G545 Generator connection and bus rearrangement - E. Kewanee	Rearrange 138 kV bus at E. Kewanee and install terminal equipment (including 1200 A breaker) to connect wind farm (G545)	IL	GIP	Not Shared		$1,501,000	10/15/2012

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Central	AmerenIL	3359	G569 Generator connection and bus upgrade - E. Galesburg	Upgrade 138 kV bus at E. Galesburg and install terminal equipment, including 1200 A breaker, to facilitate connection of wind farm (G569).	IL	GIP	Not Shared		$834,000	10/1/2012
Central	AmerenIL	3360	G931 Generator connection and Establishment of Sheldon Soth Switching Station	Construct a new 138 kV switching station to connect a new wind farm (G931) to the Watseka-Morrison Ditch-1 138 kV line. Upgrade relaying at Watseka terminal.	IL	GIP	Not Shared		$4,425,000	5/6/2011
Central	AmerenIL	3361	G996 Generator connection and bus upgrade - Paxton, South	Install terminal equipment, including 2000 A breaker, to facilitate connection of wind farm (G996). Install 2000 A bus-tie breaker	IL	GIP	Not Shared		$1,512,200	7/26/2011
Central	DEM	3387	Tri-County Wind Energy 230kV Station - DPP J028	J028 - 230kV - Gen. interconnect sub - install three brkr ring bus for 200MW wind farm between Attica and Lafayette in the 23027 ckt.	IN	GIP	Not Shared		$3,778,246	6/1/2013
East	ITC	3516	J025-Macomb County LF Gas Gen. Facility	12.8 MW LF Gas Gen. tapping the Carbon Tap on the 120kV Jewell - St. Clair 120kV line.	MI	GIP	Shared		$485,000	9/1/2011
East	METC	3517	G905-Gratiot County Wind Generation	200 MW wind farm connecting at the new METC owned Redstone substation	MI	GIP	Shared		$21,630,500	12/31/2012
East	METC	3518	G809-MCV	190 MW increase of the existing MCV Co-generation plant	MI	GIP	Shared		$64,000	6/1/2012
West	ATC LLC	1143	G282, 37628-02	Net: rating of HILLMAN 138/69 kV TRANSFORMER 1 is upgraded to 100 MVA. Int: The Generator is required to provide a 138/34.5kV transformer, a circuit breaker and a disconnect switch on the high side of the 138/34.5kV transformer and 34.5kV facilities to c	WI	GIP	Not Shared		$4,200,000	12/31/2012
West	ATC LLC	3160	G706-H012 Line X-6 Portage-Hamilton-Staff-Friesland-North Randolph 138 kV Uprate	G706-H012 Line X-6 Portage-Hamilton-Staff-Friesland-North Randolph 138 kV Uprate	WI	GIP	Not Shared		$1,447,679	12/31/2011
West	ATC LLC	3161	G749 EcoMont Wind Farm	New EcoMont substation tapped into Belmont Tap-Rewey Tap 69 kV Line for G749	WI	GIP	Not Shared		$4,569,183	11/30/2012

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West	ATC LLC	3206	G833-4_J022-3 Long Term Solution	1) Construct a new Barnhart 345 & 138 kV substation 2) Install a new 345/138 kV transformer at Barnhart 3) Loop Edgewater-South Fond du Lac, Edgewater-Cedarsauk, Sheboygan Energy Center-Granville 345 kV lines into Barnhart 4) Loop the South Sheboygan Falls-Mullet River 138 kV line into Barnhart 138 kV 5) Construct a new 138 kV line from Barnhart to Plymouth #4 6) Construct a new 138 kV line from Plymouth #4 to Howards Grove 7) Construct a new 138 kV line from Howards Grove to Erdman 8) Convert the existing Forest Junction-Howards Grove-Plymouth #4 138 kV line and the northern portion of the existing Plymouth #4-Holland 138 kV line to 345 kV 9) Terminate the not-converted Holland 138 kV line at Barnhart 138 kV 10) Terminate the southern end of the converted 345 kV line at Barnhart 11) Construct a new Branch River 345 kV substation 12) Loop the converted 345 kV line into Branch River 345 kV substation 13) Loop the Point Beach-Forest Juction, Point Beach-Sheboygan Energy Center 345 kV lines into Branch River 14) Uprate Barnhart-Cedarsauk 345 kV line to 960 MVA for	WI	GIP	Shared		$173,309,000	6/1/2018
West	ATC LLC	3457	GIC J060 Garden City Wind Phase I	Interconnect GIC J060 Garden City Wind	MI	GIP	Not Shared		$4,779,758	12/30/2011
West	GRE	3467	MISO G604	Connect Oak Glen Wind Farm to 69 kV system	MN	GIP	Not Shared		$1,722,464	7/1/2011
West	GRE	3468	MISO H062	Connect H062 Wind Generation	MN	GIP	Not Shared		$1,312,741	9/1/2011
West	GRE	3469	MISO H061	Connect H061 Wind generation	MN	GIP	Not Shared		$192,530	10/1/2011
West	ITCM	3191	G164-Lakefield Jct 345 kV Breaker & Half	Convert the Lakefield 345kV ring bus to breaker and a half.	MN	GIP	Shared		$8,148,000	4/29/2011

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West	ITCM	3192	G604-Ellendale 69 kV Switch Station	Construct a new Ellendale 69kV four terminal breaker station. The Hayward-West Owatanna 69kV line will be rerouted into the Ellendale breaker station. Then change the N.O. point on the line to closed.	MN	GIP	Shared		$1,913,706	12/31/2011
West	ITCM	3193	G741-Martin Co Waste Heat	Construct a new 69kV tap to the G741 customer. Tap the Trimont (IPL)-Sherburn(SCREC) 69kV line.	MN	GIP	Shared		$223,884	10/1/2010
West	ITCM	3194	G798-Story County Upgrades	Expand the ring bus at Story County.	IA	GIP	Shared		$422,664	7/31/2010
West	ITCM	3195	G870-Freeborn	Tap the Hayward-Winnebago Jct 161kV and construct a new Freeborn 161kV three terminal breaker station. Approximately 4 mile tap will connect Freeborn to the new G870 customer substation.	MN	GIP	Shared		$3,516,163	10/1/2010
West	ITCM	3196	H007-Bond Breaker Station	Tap the Hayward-Winnebago Jct 161kV and construct a new Bond 69kV three terminal breaker station.	IA	GIP	Shared		$3,560,163	7/1/2011
West	MDU	3199	G359, 38073-01	230 kV line from project interconnection to Ellendale Jct substation and new 230/115 kV transformer at Ellendale	ND	GIP	Not Shared		$19,130,000	12/1/2011
West	OTP	3466	Project J-035 5 MW Wind Farm on OTP Doran 41.6 kV line.	Add 3 Way Switch on 41.6 kV line between Doran 41.6 kV substation to Doran Jct.	MN	GIP	Not Shared		$140,000	8/1/2012
Central	AmerenIL	3370	Oreana Substation - Add 138-69 kV Transformer	To accommodate the installation of a new 138-69 kV transformer at Oreana, install 1-2000 A breaker and 2-2000 A disconnect switches to expand ring bus. Install 138 kV, 600 A motor operated disconnect switch at high-side of new 138-69 kV transformer.	IL	Other	Not Shared	Condition	$750,000	6/1/2012
Central	AmerenMO	3355	Labadie Breaker Replacements	Replace Breakers on Bland and Montgomery line positions with 3000 A, 50 kA breakers	MO	Other	Not Shared	Reliability	$2,610,000	12/31/2011
Central	AmerenMO	3368	Bailey Substation	Install 2-2000 A bus-tie breakers and 2-138 kV circuit switchers	MO	Other	Not Shared	Reliability	$4,000,000	6/1/2012
Central	DEM	3377	Scottsburg 69kV - 28.8MVAR Capacitor	Replace Scottsburg 69kV - 7.2Mvar capacitor with a 28.8 Mvar capacitor and upgrade 69kV capacitor switching equipment	IN	Other	Not Shared	Reliability	$500,000	12/31/2015
Central	DEM	3378	Canal 69kV Dist Sub	Canal Sub - Purchase land and build 22.4MVA, 69/12kV sub near Canal Road and Allison Street in the 5762 ckt.	OH	Other	Not Shared	Reliability	$756,196	6/1/2012
Central	DEM	3379	Shelbyville McKay Rd. 69kV Dist Sub	Shelbyville McKay Rd. - add new 69/12kV distribution sub in the 6976 ckt. Loop through with 954acsr and a set of 1200A line switches.	IN	Other	Not Shared	Reliability	$303,710	6/1/2014

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Central	DEM	3380	Noblesville Sta. 138kV Brkrs and 345kV Ckt Sws	Noblesville Gen. Sta. - Replace 138KV OB OCB: 138TR, 13869-9, 138230-7, 13886 and Circuit Switchers: 345230-11, 34519.	IN	Other	Not Shared	Condition	$2,909,606	12/31/2011
Central	DEM	3383	H.E. Rocklane Alternate 69kV Feed	Ckt. 6999 new Sherman Rd. Jct. to H.E. Rocklane line section. Replace DEM 69kV poles to accommodate new H.E. tap line. This will be an alternate feed to Rocklane - operated N.O. - built and owned by HE, inside DEM area.	IN	Other	Not Shared	Reliability	$64,568	2/6/2011
Central	DEM	3384	Hortonville to Marathon Jct. 69kV Reconductor	Hortonville to Marathon Jct. section of ckt. 6917 - Replace 336ACSR and 477ACSR with 954ACSS@200C. Upgrade Marathon Jct 600A switches to 1200A.	IN	Other	Not Shared	Reliability	$1,409,099	12/1/2012
Central	DEM	3385	Carmel Homeplace to Springmill Jct 69kV Reconductor	Carmel Homeplace to Springmill Jct. section of ckt. 69155 - Reconductor with 954ACSS@200C	IN	Other	Not Shared	Reliability	$1,691,315	12/31/2012
Central	DEM	3386	Carmel Springmill Rd. to Hortonville 69kV Line and Brkrs	Carmel Springmill Rd. Sub - Add 3-69kV breakers in straight bus config and build new .23 mile 69kV 954ACSS@200C line from Springmill Sub to old Springmill Jct. to complete circuit to Hortonville. Change operating mode at Homeplace to close loop from 146th to Springmill.	IN	Other	Not Shared	Reliability	$3,000,000	6/1/2016
Central	DEM	3388	Walton to Logansport S. 69kV Reconductor	Walton to Logansport S. - Reconductor 69kV - 69110 line with 477acsr at 100C	IN	Other	Not Shared	Reliability	$1,900,000	6/1/2015
Central	DEM	3389	WVPA Center Valley 138kV Dist Sub	DEM to install new line switching in the 138kV - 13867 ckt. at intersection with SR39 for tap line to radially feed new WVPA Center Valley dist sub	IN	Other	Not Shared	Reliability	$236,677	12/1/2011
Central	DEM	3390	Inland Container to Hillsdale 69kV Line Rebuild	Rebuild 69kV - 6906 line from Inland Container to WROW Jct. to Hillsdale - 477acsr26x7 at 100C	IN	Other	Not Shared	Condition	$3,663,434	12/31/2011
Central	DEM	3391	Elnora to Newberry 69kV Line Rebuild	Rebuild 69kV - 6959 line section from Elnora to Newberry - 477acsr26x7 at 100C	IN	Other	Not Shared	Condition	$1,716,818	12/31/2011
Central	DEM	3392	DEM Speed to LGEE Paddys West 345kV tie	New DEM Speed to LGEE Paddys West 345kV tie line	IN	Other	Not Shared	Reliability	$15,000,000	12/31/2012
Central	IPL	3273	Southwest - Stout CT Line Rating Upgrade	Increase line rating above 322 MVA to mitigate the potential overload	IN	Other	Not Shared	Reliability	$300,000	6/1/2011
Central	IPL	3274	South - Stout S Line Rating Upgrade	Increase line rating above 272 MVA to mitigate the potential overload	IN	Other	Not Shared	Reliability	$350,000	6/1/2011
Central	Vectren (SIGE)	2460	Leonard Rd 69kV Substation	Add new 69kV switching substation near Leonard Rd	IN	Other	Not Shared	Reliability	$2,150,000	6/1/2013
Central	Vectren (SIGE)	2462	Y53 Stringtown to Folz Reconductor	Reconductor existing 69kV line for more capacity	IN	Other	Not Shared	Condition	$2,500,000	6/1/2013

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Central	Vectren (SIGE)	2463	Y31 Mt Vernon to Givens 69kV recond.	Reconductor existing 69kV line for more capacity	IN	Other	Not Shared	Condition	$5,700,000	6/1/2013
Central	Vectren (SIGE)	2464	Y33 Mt Vernon to New Harmony 69kV recond.	Reconductor existing 69kV line for more capacity	IN	Other	Not Shared	Condition	$10,600,000	6/1/2014
East	ITC	1868	Cato GIS replacement	Replace GIS Equipment	MI	Other	Not Shared	Condition	$5,400,000	12/1/2012
East	ITC	3276	ITCT Annual Breaker Replacement Program for 2013	Annual Breaker Replacement Program	Mi	Other	Not Shared	Condition	$9,000,000	12/31/2013
East	ITC	3277	ITCT Annual NERC Relay Loadability Compliance Program for 2013	Annual NERC Relay Loadability Program	Mi	Other	Not Shared	Reliability	$2,400,000	12/31/2013
East	ITC	3278	ITCT Annual Potential Device Replacement Program for 2013	Annual Potential Device Replacement Program	Mi	Other	Not Shared	Condition	$300,000	12/31/2013
East	ITC	3279	ITCT Annual Relay Betterment Program for 2013	Annual Relay Betterment Program	Mi	Other	Not Shared	Condition	$1,800,000	12/31/2013
East	ITC	3280	ITCT Annual Wood Pole Replacement Program for 2013	Annual Wood Pole Replacement Program	Mi	Other	Not Shared	Condition	$3,000,000	12/31/2013
East	ITC	3281	Lima Substation	Distribution Interconnection Request	Mi	Other	Not Shared	Distribution	$8,400,000	12/31/2012
East	ITC	3283	Dexter Township Substation	Distribution Interconnection Request	Mi	Other	Not Shared	Distribution	$2,676,000	11/1/2012
East	ITC	3284	ITCT Customer Interconnections - Year 2015	Distribution Interconnection Request	Mi	Other	Not Shared	Distribution	$2,000,000	12/31/2015
East	ITC	3286	Fermi 345kV Disconnect Replacement Project - 3rd Row	Replace 345kV Disconnects, add 3rd 345kV Row	Mi	Other	Not Shared	Condition	$5,050,000	12/31/2013
East	ITC	3495	NERC Alert Facility Ratings for 2011	Verify and remediate facilities as required due to the industry-wide NERC alert	MI	Other	Not Shared	Reliability	$1,700,000	12/31/2011

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East	ITC	3503	Air Flow Spoilers Installation	Install air flow spoilers on approximately 15 miles of the targeted areas of the Belle River-Greenwood-Pontiac and Belle River-Blackfoot 345 kV double circuit tower lines.	MI	Other	Not Shared	Reliability	$1,620,000	12/31/2012
East	METC	3139	Tippy-Wexford 138 kV Circuit Uprgrade	Terminal Equipment upgrade at Tippy	MI	Other	Not Shared	Reliability	$20,000	6/1/2012
East	METC	3287	Riggsville Rebuild	Rebuild 138 kV bus and switches	Mi	Other	Not Shared	Condition	$4,600,000	9/30/2011
East	METC	3288	METC Annual Breaker Replacement Program for 2013	Annual Breaker Replacement Program	Mi	Other	Not Shared	Condition	$6,000,000	12/31/2013
East	METC	3289	METC Annual NERC Relay Loadability Compliance Program for 2013	Annual NERC Relay Loadability Program	Mi	Other	Not Shared	Reliability	$2,400,000	12/31/2013
East	METC	3290	METC Annual Potential Device Replacement Program for 2013	Annual Potential Device Replacement Program	Mi	Other	Not Shared	Condition	$300,000	12/31/2013
East	METC	3291	METC Annual Relay Betterment Program for 2013	Annual Relay Betterment Program	Mi	Other	Not Shared	Condition	$1,200,000	12/31/2013
East	METC	3292	METC Annual Wood Pole Replacement Program for 2013	Annual Wood Pole Replacement Program	Mi	Other	Not Shared	Condition	$4,800,000	12/31/2013
East	METC	3293	METC Annual Battery Replacement Program for 2013	Annual Battery Replacement Program	Mi	Other	Not Shared	Condition	$100,000	12/31/2013
East	METC	3294	METC Annual Power Plant Control Relocation Program for 2013	Annual Power Plant Control Relocation Program	Mi	Other	Not Shared	Operation	$3,120,000	12/31/2013
East	METC	3295	METC Sag Clearance Program for 2013	Sag Clearance Program	Mi	Other	Not Shared	Clearance	$3,600,000	12/31/2013
East	METC	3296	METC Spill Prevention Control and Countermeasure Program for 2011	Annual SPCC Program	Mi	Other	Not Shared	Condition	$3,100,000	12/31/2011

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East	METC	3297	METC Spill Prevention Control and Countermeasure Program for 2012	Annual SPCC Program	Mi	Other	Not Shared	Condition	$3,100,000	12/31/2012
East	METC	3298	METC Spill Prevention Control and Countermeasure Program for 2013	Annual SPCC Program	Mi	Other	Not Shared	Condition	$3,100,000	12/31/2013
East	METC	3299	METC Customer Interconnections - Year 2015	Distribution Interconnection Request	Mi	Other	Not Shared	Distribution	$2,500,000	12/31/2015
East	METC	3306	Karn-Cottage Grove 138 (Karn Position 488) Relay Replacement Project		Mi	Other	Not Shared	Reliability	$200,000	6/1/2012
East	METC	3308	Livingston to Gaylord 138 kV Dual Pilot Relay Protection Scheme Installation	Install new dual pilot relay scheme on 138kV circuit	Mi	Other	Not Shared	Reliability	$315,000	12/31/2012
East	METC	3491	NERC Alert Facility Ratings for 2011	Verify and remediate facilities as required due to the industry-wide NERC alert	MI	Other	Not Shared	Reliability	$2,100,000	12/31/2011
East	METC	3505	Eaton Rapids Load Interconnection	Serve new load in Eaton Rapids with 2 new 138kV circuits from Clinton Jct. and the Delhi-Tompkins circuit	MI	Other	Not Shared	Distribution	$28,500,000	1/1/2013
East	WPSC	3328	Barryton	New Distribution Interconnection from the Hersey to Weidman circuit	MI	Other	Not Shared	Distribution	$100,000	12/31/2011
East	WPSC	3329	Burnips to Wayland	Rebuild the Burnips to Wayland line section with a larger conductor	MI	Other	Not Shared	Reliability	$7,250,000	12/31/2013
East	WPSC	3330	Cansovia Capacitor Bank	Install a Capacitor Bank tap at the Casnovia substation	MI	Other	Not Shared	Reliability	$260,000	12/31/2011
East	WPSC	3331	Redwood to Hart	Rebuild the Redwood to Hart line section with a larger conductor	MI	Other	Not Shared	Reliability	$750,000	12/31/2015
East	WPSC	3332	Bass Lake Transmission Upgrade	Install Relaying	MI	Other	Not Shared	Reliability	$250,000	2/28/2011
East	WPSC	3333	Lemon Junction Transmission Station	Construct a single breaker station	MI	Other	Not Shared	Reliability	$350,000	12/31/2011
East	WPSC	3334	Casnovia to Sternberg	Rebuild a portion of the line for Distibution Underbuild	MI	Other	Not Shared	Reliability	$400,000	6/30/2011

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East	WPSC	3335	Burnip Transmission Station Upgrade	Upgrade to replace outdated equipment. Bus, breakers, relays, and other equipment as necessary.	MI	Other	Not Shared	Condition	$900,000	12/31/2013
West	ATC LLC	174	Canal-Dunn Road 138 kV	Construct a 7.7 mile Canal - Dunn Road 138 ckt , Sum rate 400; install a new 138/69 kV transformer at Dunn Road substation.	WI	Other	Not Shared	Reliability	$24,763,300	3/1/2012
West	ATC LLC	333	Hiawatha-Indian Lake conversion to 138 kV	Hiawatha-Indian Lake conversion to 138 kV	MI	Other	Excluded	Condition	$4,900,000	6/1/2013
West	ATC LLC	1699	Mckenna & Chaffee Ck Capacitor Banks Upgrades	Upgrade Mckenna 6.3 MVAR capacitor bank to 15.3 MVAR and upgrade Chaffee Ck 10.8 MVAR to 14.4 MVAR capacitor bank	WI	Other	Not Shared	Reliability	$686,750	7/31/2011
West	ATC LLC	1705	Bass Creek area upgrades	Install a 138/69 kV transformer at Bass Creek substation, Uprate Townline Road-Bass Creek 138 kV line	WI	Other	Not Shared	Reliability	$6,975,946	4/1/2011
West	ATC LLC	2036	Uprate Y-40 Gran Grae-Boscobel 69 kV	Increase line clearance to 200/300 deg F SN/SE	WI	Other	Not Shared	Condition	$5,291,028	12/15/2011
West	ATC LLC	2037	Rebuild Dane-Okee 69 kV	Rebuild Dane-Okee 69 kV	WI	Other	Not Shared	Reliability	$6,798,033	6/19/2012
West	ATC LLC	2055	Clear Lake-Woodmin 115 kV	Construct a 7.5 mile 115 kv line from Clear Lake to a new Woodmin distribution substation	WI	Other	Not Shared	Reliability	$21,331,000	6/1/2012
West	ATC LLC	2820	Replace Bluemound 230/138kV transformerT1	Replace Bluemound 230/138kV transformer T1 with a 400 MVA unit	WI	Other	Not Shared	Condition	$8,200,000	5/31/2012
West	ATC LLC	2842	Uprate Spring Green-Stage Coach 69-kV	Uprate Spring Green-Stage Coach 69-kV	WI	Other	Not Shared	Reliability	$6,957,394	4/8/2011
West	ATC LLC	3095	Uprate 9Mile-Roberts 69 kV line 6952	Increase ground clearance for the 9Mile-Roberts 69 kV line 6952 to 176 deg f clearance for all seasons & Install Arresters, Replace Select Components	MI	Other	Not Shared	Reliability	$19,743,032	4/1/2012
West	ATC LLC	3108	Rebuild Pine River-Straits 69kV dbl ckt line	Rebuild Pine River-Straits 69kV dbl ckt line with t2-477 ACSR	MI	Other	Not Shared	Reliability	$40,804,513	6/1/2014
West	ATC LLC	3126	Install a 2nd Chandler Transformer	Install a 2nd Chandler Transformer & reconfigure bus to 138 kV Ring bus	MI	Other	Not Shared	Reliability	$9,700,000	12/9/2012
West	ATC LLC	3157	Line Y-95 Fount Valley-Fountain Valley Tap-Red Granite Tap-ACEC Spring Lake Tap-Silver Lake-Wautoma Uprate	Line Y-95 Fount Valley-Fountain Valley Tap-Red Granite Tap-ACEC Spring Lake Tap-Silver Lake-Wautoma Uprate	WI	Other	Not Shared	Reliability	$362,468	6/17/2011
West	ATC LLC	3188	Pleasant Prairie-Zion 345-kV uprate	Replace 345kV Wave traps at the ComEd Zion SS and Jumpers	WI/IL	Other	Not Shared	Economic	$1,544,571	3/25/2011

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West	ATC LLC	3395	Milwaukee Co T-D	Install a new Milwaukee Co T-D substation by looping in line 5042 (Bluemound-Everett 138kV)	WI	Other	Not Shared	Distribution	$33,500,000	4/1/2015
West	ATC LLC	3396	Uprate Blue River Tap-Muscoda 69 kV	Uprate Blue River Tap-Muscoda 69 kV line by increasing clearance at a distribution crossing to 564 Amps	WI	Other	Not Shared	Condition	$580,000	11/15/2010
West	ATC LLC	3428	Stage Coach-Timberlane 69kV uprate	Increase ground clearance for the Stage Coach-Timberlane 69kV line	WI	Other	Not Shared	Reliability	$35,000	4/8/2011
West	ATC LLC	3432	Uprate Stoughton-Oregon 69kV line	Uprate Stoughton-Oregon 69kV line	WI	Other	Not Shared	Reliability	$570,000	4/21/2011
West	ATC LLC	3433	Uprate Stagecoach-Mt Horeb NE-Mt Horeb 69 kV line Y-128	Uprate Stagecoach-Mt Horeb NE-Mt Horeb 69 kV line Y-128	WI	Other	Not Shared	Reliability	$36,505	12/31/2011
West	ATC LLC	3447	Ontonagon 138/69kV Tr uprate	Retap CT related to Ontonagon 138/69 kV Tr to obtain a higher rating	MI	Other	Not Shared	Reliability	$12,410	12/7/2010
West	ATC LLC	3448	Ontonagon 138/69kV Tr Replacement	Replace the Ontonagon 138/69 kv Tr with a larger unit	MI	Other	Not Shared	Reliability	$935,786	12/1/2011
West	ATC LLC	3449	Rebuild the Atlantic-M38 69kV line	Rebuild the Atlantic-M38 69kV line with a larger conductor	MI	Other	Not Shared	Reliability	$18,878,963	12/31/2013
West	ATC LLC	3451	Y-136 Mt Horeb-Verona 69kV Rerate	Increase ground clearance on the Mt Horeb-Verona 69kV line	WI	Other	Not Shared	Reliability	$710,000	11/1/2011
West	ATC LLC	3452	Y-158 Bass Ck-Sheepskin 69kV Rerate	Increase ground clearance on the Bass Ck-Sheepskin 69kV line	WI	Other	Not Shared	Reliability	$920,000	11/1/2011
West	ATC LLC	3453	Y-25 Waupun-S Fond du Lac 69kV Rerate	Increase ground clearance on the Waupun-S Fond du Lac 69kV line	WI	Other	Not Shared	Reliability	$2,186,630	2/28/2012
West	ATC LLC	3458	Aurora 115-69kV T3 Replacement	Aurora 115-69kV T3 Replacement	WI	Other	Not Shared	Condition	$2,958,914	6/3/2011
West	ATC LLC	3460	Y-93 Berlin-Ripon 69kV Uprate	Increase ground clearance on the Berlin-Ripon 69kV line	WI	Other	Not Shared	Reliability	$1,389,745	2/28/2011
West	ATC LLC	3472	Pleasant Prairie Bus Reconfiguration	Construct a new 6-rung breaker-and-a-half 345 kV bus at the P4 site adjacent to the existing P4 yard.	WI	Other	Not Shared	Reliability	$39,400,000	3/22/2013
West	ATC LLC	3479	Progress-Aviation 138 kV Uprate	Increase ground clearance for the Progress-Aviation line to 187 degrees F	WI	Other	Not Shared	Condition	$492,563	3/1/2012
West	ATC LLC	3480	Engadine Load Move	Construct a new radial 69-kV tap from the existing Indian Lake-Hiawatha 69-kV line 6913 to the Engadine Substation	WI	Other	Not Shared	Reliability	$810,804	10/1/2012
West	ATC LLC	3488	Uprate Brick Church to Walworth 69 kV line	Asset management project to uprate Y-159 from Brick Church to Walworth 69 kv Line	WI	Other	Not Shared	Condition	$532,000	3/1/2012

Planning Region	Geographic Location by TO Member System	PrjID	Project Name	Project Description	States	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD (Max)
West	ATC LLC	3489	UprateY-34 Jennings Road to Darlington 69 kV line	Asset management project to uprate Y-34 from Jennings Road to Darlington 69 kv Line	WI	Other	Not Shared	Condition	$314,000	3/1/2012
West	ATC LLC	3504	Y-80 Omro to Winneconne Rerate	Rerate Line Y-80 conductor from Omro sub to Winneconne sub to a rating of 580 amps	WI	Other	Not Shared	Condition	$205,000	12/1/2012
West	DPC	3434	Lufkin 161 kV substation	Build a new 161 kV substation on the Alma to Elk Mound 161 line in the Eau Claire area.	WI	Other	Not Shared	Reliability	$2,164,000	9/1/2012
West	GRE	2571	MN Pipeline-Menahga 8.0 mile line	MN Pipeline-Menahga 8.0 mile line. Built 115 kV but will be operated at 34.5.	MN	Other	Not Shared	Distribution	$4,199,990	11/15/2014
West	GRE	2599	Shell Lake (IM) 5.0 mile, 115 kV line	Shell Lake (IM) 5.0 mile, 115 kV line	MN	Other	Not Shared	Distribution	$4,201,000	10/31/2014
West	GRE	2643	Parkers Prairie 115 kV conversion	Parkers Prairie 115 kV conversion, New Distribution tap	MN	Other	Not Shared	Distribution	$1,220,998	5/1/2013
West	GRE	2679	Ramsey-Grand Forks (81.02 mi.) 230 kV Rebuild	Ramsey-Grand Forks (81.02 mi.) 230 kV Rebuild	MN	Other	Not Shared	Condition	$40,500,000	11/1/2019
West	ITCM	3406	Adams-Rochester Terminal Upgrades	Upgrade the Adams terminal equipment to winter conductor limit	MN	Other	Not Shared	Reliability	$360,000	4/29/2011
West	ITCM	3407	Bluff Substation Additions	Add 69kV breakers to the Bluff Substation 69kV and install associated relay equipment.	IA	Other	Not Shared	Distribution	$1,920,000	12/31/2011
West	ITCM	3408	BooneQuartz Sustation	This project performs the conversion of the Boone Quartz substation from 34.5kV to 69kV as part of the overall rebuild and conversion of the 34.5kV system. The Boone Quartz substation was constructed with a dual high side transformer and the high side was laid out for 69kV operation in preparation for the conversion. Two 69kV line breakers will be installed at the Boone Quartz substation. Existing 69kV lines and 34.5kV lines already constructed for 69kV operation will be re-configured along with installation of 69kV taps into the Boone Quartz substation to make the change to 69kV. No new load is being added during the conversion to 69kV.	IA	Other	Not Shared	Reliability	$1,700,000	12/31/2011
West	ITCM	3409	Bricelyn-Walters Rebuild	The recommended project is to completely rebuild a 5 mile section of the Bricelyn - Walters 69 kV line with standard T2-477 construction and shield wire.	IA	Other	Not Shared	Condition	$2,625,000	12/31/2013

Planning Region	Geographic Location by TO Member System	PrjID	Project Name	Project Description	States	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD (Max)
West	ITCM	3411	Bridgeport T8	Add a 69kV breaker to the Bridgeport North 69kV ring and install associated relay equipment.	IA	Other	Not Shared	Distribution	$360,000	12/31/2011
West	ITCM	3412	Fort Madison Interconnection	Install tap capable of double circuit 69kV to Fort Madison substation and install associated relay equipment.	IA	Other	Not Shared	Distribution	$360,000	12/31/2012
West	ITCM	3413	Gladbrook 161kV tap	Install a 161kV tap pole in the Marshalltown to Traer line with two line switches. Construct a 161kV tap line to the new Gladbrook substation.	IA	Other	Not Shared	Distribution	$300,000	12/31/2013
West	ITCM	3414	Magnolia 7.1 MVAR 69kV Cap	ITCM will move the existing Lewisville 69kV 7.1 MVAR capacitor to the 69kV bus at Magnolia. Recent system changes have opened up a 69kV bay at Magnolia and this will be used for the capacitor bank and 69kV breaker.	IA	Other	Not Shared	Reliability	$480,000	12/31/2012
West	ITCM	3416	Marion Circuit 0410 Rebild to 69kV	This project rebuilds the sections (approximately 25 miles) of Marion circuit 0410 that will be utilized in the overall 34.5kV to 69kV conversion plan but have not yet been constructed for 69kV operation.	IA	Other	Not Shared	Distribution	$10,500,000	12/31/2012
West	ITCM	3417	Marshalltown East Nevada	Construct a 1-2 span 34.5kV tap, install new relays for Marshalltown circuits 1810 and 2620, and upgrade terminal limit to address overload during contingency. Remove two normally open switches to limit system configuration to address system protection coordination issues which can occur when rural and city circuits are tied together.	IA	Other	Not Shared	Reliability	$280,000	12/31/2011
West	ITCM	3418	Mount Vernon Circuit 6420 Rebild to 69kV	This project rebuilds the sections (approximately 17 miles) of Mount Vernon circuit 6420 that will be utilized in the overall 34.5kV to 69kV conversion plan but have not yet been constructed for 69kV operation.	IA	Other	Not Shared	Distribution	$7,150,000	12/31/2013
West	ITCM	3419	Bertram161kV tap	The new transformer high side voltage is 69/34.5kv; it will need a 0.5 mile tap line built to the substation from the existing 34.5kV system with the future plans of 69kV rebuild. Adding the double-circuit tap to the substation will allow connection to the new transformers. The double circuit tap will provide additional reliability, with switching, to have the ability to separate the parallel transformers in the situation a transformer fails, no load will be lost.	IA	Other	Not Shared	Distribution	$270,000	12/31/2012

Planning Region	Geographic Location by TO Member System	PrjID	Project Name	Project Description	States	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD (Max)
West	ITCM	3420	OGS Breaker	Install new 345kV breaker in the Ottumwa Generating Station substation to replace the failed 345kV circuit switcher. Replace the transformer lockout/breaker control panel. Replace the existing 345kV relay panel with two new panels and one lockout panel, which will allow for the retirement of an existing transfer trip scheme. The new line panels will implement a new redundant transfer trip scheme. Install second set of battery back up.	IA	Other	Not Shared	Condition	$1,350,000	12/31/2011
West	ITCM	3421	Centervile 7.1 MVAR 69kV Cap	nstall a 7 MVAR 69 kV capacitor, breaker with synchronous closing control, switch, and 0.5 mH reactor. 69 kV breakers 0-6961-1 and 0-6921-2 will be replaced due to condition. A 69 kV bus tie breaker and switch will be added for reliability between transformers 2 and 3.	IA	Other	Not Shared	Reliability	$1,350,000	12/31/2011
West	ITCM	3422	South Broadway TEQ	Install Sub	IA	Other	Not Shared	Distribution	$150,000	12/31/2012
West	ITCM	3423	Truro Line Rebuild	Rebuild the line between the Truro substation and the White Oak tap and operate the line at 69 kV.	IA	Other	Not Shared	Reliability	$3,360,000	12/31/2011
West	ITCM	3425	VMEU Interconnect	Install line switches at the interconnection point.	IA	Other	Not Shared	Reliability	$110,000	12/31/2011
West	ITCM	3426	DPC/ITC Interconnect move	The recommended project is to move the existing interconnection point approximately 0.6 miles south. ITC will install a laminate structure and associated equipment to accommodate DPC's project.	IA	Other	Not Shared	Distribution	$0	12/31/2013
West	MEC	3270	CBEC-River Bend 161 kV Rebuild	Increase 161 kV line rating.	IA	Other	Not Shared	Reliability	$675,000	6/1/2011
West	MEC	3271	River Bend-Bunge 161 kV Rebuild	Increase 161 kV line rating.	IA	Other	Not Shared	Reliability	$700,000	6/1/2011
West	MEC	3272	Raun 345 kV Breaker Replacement	Replace existing SFA 345 kV breaker 0170 with a new unit.	IA	Other	Not Shared	Condition	$500,000	6/1/2011
West	MP	2549	15L Upgrade	Thermal Upgrade of MP Line #15	MN	Other	Not Shared	Reliability	$3,179,000	6/1/2014
West	MP	3374	Greenway	Re-energize existing 115/23 kV substation	MN	Other	Not Shared	Distribution	$700,000	11/1/2012
West	OTP	2856	Victor-New Effington 41.6 kV Line Upgrade	Rebuild Existing 4-Mile 41.6 kV Line	SD	Other	Not Shared	Reliability	$200,000	6/30/2011

Planning Region	Geographic Location by TO Member System	PrjID	Project Name	Project Description	States	Allocation Type per FF	Share Status	Other Type	Estimated Cost	Expected ISD (Max)
West	XEL	3310	Highway 212 Corridor upgrade	This project is to complete the conversion of 69 kV line between Scott County and West Waconia substation to 115 kV. The scope also involves building new West Creek distribution substation and converting the Chaska, Victoria and Augusta substations to 115 kV.	MN	Other	Not Shared	Distribution	$19,450,000	6/1/2012
West	XEL	3313	New Prague switch	This project is to install a 69 kV 1 way switch to provide SMMPA's New Prague substation a new interconnection point. The existing interconnection would require cutting the line jumpers phisically when the New Prague - Veslie line is out of service.	MN	Other	Not Shared	Reliability	$180,000	6/1/2012
West	XEL	3322	Cedar Falls - Clear Lake Rebuild	Rebuild 43 Miles of 69 kV line to 477 ACSR	WI	Other	Not Shared	Reliability	$14,000,000	6/1/2013
West	XEL	3323	Park Falls Bio-Refinery	Build radial 115 kV line from Park Falls sub to a new customer and install a new distribution sub for the customer	WI	Other	Not shared	Distribution	$23,769,000	6/1/2013
West	XEL	3324	Eau Claire Overstressed Breakers	Replace overstressed Eau Claire 69 kV breakers. 4E185, 4E186, 4E187, 4E188, 4E189, 4E190, 4E191, 4E192, 4E193, 4E195.	WI	Other	Not Shared	Reliability	$1,683,000	12/1/2011
West	XEL	3325	Orono 115 kV conversion	This project will move the supply for Orono from its current 69 kV supply to the 115 kV line from Medina to Crow River	MN	Other	Not Shared	Reliability	$5,340,000	12/1/2012
West	XEL	3327	Eau Claire - Madison Street Rebuild	This project will replace 1 mile of 4/0 Cu conductor with 795 ACSS on the 69 kV line between Eau Claire - Sterling - Madison St.	WI	Other	Not Shared	Reliability	$1,600,000	12/1/2011
West	XEL	3473	Sioux Falls 115 kV Phase 1	This project re-constructs 10 miles of existing 69 kV line in Sioux Falls, SD to 115 kV; 6 miles of the new line will be double circuit with existing 69 kV.	SD	Other	Not Shared	Reliability	$35,000,000	6/1/2014
West	XEL	3474	Adams 345 kV Reactor Installation	Installing a 50 MVAR reactor at Adams substation on the Pleasant Valley line, along with a breaker and disconect switch	MN	Other	Not Shared	Reliability	$2,260,000	6/1/2012
West	XEL	3509	Stinson to Bayfront 115 kV line rebuild	Rebuild approximately 33 miles of 115 kV line from 336 ACSR to 795 ACSR	WI	Other	Not Shared	Condition	$15,400,000	1/1/2013
West	XEL, GRE	3454	Hollydale 115 kV upgrade	This project will upgrade the 69 kV line from GRE's Medina to Plymouth substations. A new switching station will be added on GRE's 115 kV line between Parkers Lake and Elm Creek north or south of the Plymouth Substation depending on the permitted location. Joint project with GRE P3394 at Medina	MN	Other	Not Shared	Reliability	$24,676,164	6/1/2013

Appendix E1: Reliability Planning Methodology

1.1 Reliability Planning Methodology Overview

MISO performs many types of reliability analyses in its MTEP studies. The reliability assessment tests the existing plan using appropriate North American Electric Reliability Corp. (NERC) Table 1 events, determines if the system, as planned, meets Transmission Planning (TPL) standards, develops and tests additional transmission system upgrades to address any identified issues, and then tests the performance of the mitigation plan. This section describes the study process used to make an assessment of system reliability. The North American Reliability Corp. (NERC) TPL Standards can be found on the NERC website at:

http://www.nerc.com/~filez/standards/Reliability_Standards_Regulatory_Approved.html

1.1.1 Baseline Reliability Assessment Methodology

This section describes how the analyses and assessment performed by MISO meets the requirements of NERC TPL standards. The section is organized by TPL-002-0 (Category B) requirements, which are also representative of Category A, B, C and Category D requirements, although TPL-001 and TPL-004 requirements are not numbered identically. Additional elements of the study process are also described.

R1 The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecasted system demands, under the contingency conditions as defined in Category A, B, C and D of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall include the following:

MISO demonstrates a valid assessment performed annually through its MISO Transmission Expansion Plan (MTEP) Report. It is part of MISO planning practices to create Planning models used in the simulations modeling all projected customer demands and firm transmission transactions. The valid assessments through the ten-year planning horizon are made and demonstrated in each MTEP report by utilizing results from simulations performed both in the current MTEP cycle and from recently performed simulations in prior MTEP cycles. To date, MTEP has assessed the system performance for the following years through simulations: 2009 (MTEP 05), 2011 and 2016 (MTEP 06), 2013 and 2018 (MTEP 07), 2011, 2014 and 2019 (MTEP 09), 2015 (MTEP10), 2013, 2016, and 2021 (MTEP11). Simulations to support assessments of the 10 year planning horizon are based on comprehensive models developed with our membership and derived from NERC ERAG cases. Results are tabulated in the reports, and any mitigation needed is also documented in the reports and their appendices (A and B). Mitigation options, including transmission expansion projects and planned and controlled system adjustments are available for all identified constraints for all Category A, B, C and D contingencies studied in MTEP11. Therefore, MISO concludes in years 1 through 10 that the transmission network can be reliably operated to supply projected customer demands and firm transmission services over the range of forecast system demands under the Category A, B, C and D contingency conditions defined in TPL table 1. See sub-requirements for details on models, contingencies and system conditions tested.

The MTEP performs a series of evaluations of the system with Planned and Proposed transmission system upgrades, as identified in the expansion planning process, to ensure that the transmission system upgrades are sufficient and necessary to meet NERC and regional planning standards for reliability. This assessment is accomplished through steady-state and dynamic stability simulations at multiple demand levels, and load and generator deliverability, voltage-stability analysis of the transmission system performed by MISO staff and reviewed in an open stakeholder process. Small-signal stability analysis is also performed periodically. Additional details on how the assessment is accomplished are described in the following requirements.

R1.1 Be made annually.

As noted earlier, the MISO performs an annual assessment and that assessment is documented in each year's MTEP report. MTEP reports such as this MTEP11 have been published since 2005 (or MTEP05).

R1.2 Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

Section 4.3 of MISO Transmission Planning Business Practices Manual (TP-BPM) states that "Short-term planning addresses identification of needs and solutions in the time frame of 1 to 10 years, with particular focus on the next 5 years. Screening reliability analyses are performed in the 6-10 year period to identify possible issues that may require longer lead-time solutions, as required by the NERC standards."

In MTEP11, assessment was conducted for the period 2011 through 2021. This valid assessment has been based on power flow simulations representative of various system conditions in years 2011, 2013, 2014, 2015, 2016, 2018, 2019 and 2021. The MTEP11 simulations were conducted for the years 2013, 2016, and 2021. Simulations for the other years in the planning horizons have been performed in the recent prior MTEP cycles.

R1.3 Be supported by a current or past study, and/or system simulation testing, that addresses each of the following categories, showing system performance following Category A, B, C and D of Table 1. The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

In MTEP11, assessment was conducted for the period 2011 through 2021. Overall, this valid assessment has been based on power flow simulations representative of various system conditions in years 2011, 2013, 2014, 2015, 2016, 2018, 2019 and 2021. The MTEP11 simulations were conducted for the years 2013, 2016, and 2021. Simulations for the other years in the planning horizons have been performed in the recent prior MTEP cycles. Category A, Category B, Category C and Category D events per Table 1 were analyzed. Section E1.1.4 below provides additional details on contingencies analyzed. Thermal and voltage issues were flagged using Transmission Owner's design criteria limits per Section E1.1.2.

R1.3.1 Be performed and evaluated only for those Category B, C and D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

Section 4.3.6 of MISO TP-BPM states that "The MISO applies the following principles in contingency selection:

- Where possible, evaluate all contingencies system wide within each Category
- Consider the input and expertise of MISO member Transmission Planners by incorporating their explicit contingency lists
- Supplement the explicit lists provided by MISO members with automated contingency generation to increase coverage
- For contingencies involving loss of more than one contingency, evaluate an extensive list of contingency combinations focusing on combinations of facilities that have a greater chance of impacting each other producing more severe results

See Section E1.1.4 for more details on contingencies analyzed.

R1.3.2 Cover critical system conditions and study years as deemed appropriate by the responsible entity.

Critical system conditions deemed appropriate by MISO with input from our member systems are evaluated in each annual MTEP study. Section 3.2.2 of the TPBPM describes the typical models created for annual evaluation which include 5 and 10 year out models and peak and off peak cases as critical system load conditions. Section 4.3.5 of the MISO TP-BPM states that, The MISO Baseline Reliability study models will typically include power flow models reflective of five-year out and ten-year out system conditions. Other variations of these may also be used as appropriate, based on the stakeholder input for a given planning cycle." Contingencies for TPL 002-4 are based on critical events as well as automated coverage.

We also evaluate critical dispatch scenarios as deemed appropriate for certain areas such as generation dispatch import scenarios based on Loss of Load Expectation (LOLE) analyses, and critical interface transfer analyses for select interfaces based on experience, and off peak dynamics evaluations.

In MTEP11 for example, analyses were performed using 2013 summer peak, 2016 summer peak, 2016 shoulder peak, shoulder peak 2016 light load, 2016 winter peak, 2021 summer peak, 2021 shoulder peak and 2021 light load power flow models. All steady state contingencies evaluated in summer peak models were also evaluated in the shoulder peak load models in Steady State Analyses. Transient Stability Analysis was performed in shoulder peak load (West Region) and light load (Central and East Regions) models. Both shoulder peak and light load cases modeled Wind Generation at 90% of Name Plate. With wind generation at higher output and other Baseload units dispatched on market wide economics, these two models represent different variations of actual market operation when higher West (larger concentration of wind generation) to East (larger concentration of load) transfers within the MISO footprint are seen. When select disturbances are tested on these system conditions, it is believed to show pronounced system oscillatory behavior. These models also represent a system that is more stressed from a reactive power standpoint thus representing a more severe condition to test excitation system response to critical faults tested. See Section E1.1.4 under Dynamic Stability for details on disturbances tested. All models were dispatched to represent MISO market conditions with generators dispatched per market wide regional merit order.

In addition in select areas of the system, transfer conditions deemed critical are evaluated for voltage stability. Voltage Stability Analysis was performed in the 2016 summer peak as well as 2016 shoulder peak models. Transfers selected are based on past analysis or input from real-time operations believed to represent critical conditions that may result in marginal reactive system performance.

R1.3.3 Be conducted annually, unless changes to system conditions do not warrant such analyses.

As noted earlier, the MISO performs an annual assessment and that assessment is documented in each year's MTEP report. Each annual assessment includes simulations that are conducted annually. MTEP reports have been published since 2005 (MTEP05, MTEP 06, MTEP 07, MTEP 08, MTEP 09, MTEP10 and MTEP11). Each MTEP report includes updated simulations of selected years.

R1.3.4 Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

As described in Section 1.3 above, MTEP11 assessment was based on power flow simulations conducted in the current planning cycle, as well as simulations conducted in prior recent MTEP cycles. There are specific simulations for two years (2015 and 2020) within the 10 year planning horizon from the MTEP10 assessment. System conditions in particular load growth has not significantly changed since the MTEP10 annual assessment to warrant repeating simulations for the out year within the 10 year planning horizon in MTEP11. In fact total load within the MISO footprint is lower in 2021 in current load forecast than 2019 aggregate load from prior year load forecast. All constraints identified in MTEP10 with committed generation modeled in the out-year models were mitigated.

R1.3.5 Have all projected firm transfers modeled.

The models used in MTEP analysis are derived from ERAG and RRO models that have all projected Firm transfers agreed to in order to establish interchange. In more recent MTEPs, the generation dispatch represents a market dispatch model for the MISO footprint which maintains the interchange to external entities from the ERAG / RRO models, but applies a market merit order based dispatch internally. Transmission Planning Business Practice Manual (TPBPM) documents the model building process, and transaction analyses for interchange determination. See Section E1.1.3 for detailed discussion on model assumptions.

R1.3.6 Be performed and evaluated for selected demand levels over the range of forecast system demands.

Reliability analyses were performed at selected demand levels. Section 3.3.2 of TP-BPM states that "Load Demand will generally be modeled as the most probable (50/50) coincident load projection for each Transmission Owner service territory, for the study horizon under study...". While it is MISO practice to generally include a 50/50 coincident load, MISO planning evaluates the need to study a 90/10 coincident load level on an as needed basis. In some specific instances where significant system changes may occur between 50/50 and 90/10 forecast load levels such as voltage collapse, these are studied within the MTEP Voltage Stability Analysis.

In MTEP11 steady state analyses were performed using 2013 summer peak, 2016 summer peak, 2016 shoulder peak, 2016 light load, 2021 summer peak, and 2021 shoulder peak power flow models. MTEP11 transient stability analyses were performed using the 2016 Shoulder and light load models. See Section E1.1.3 for additional details. Sensitivity models representing other demand levels and system conditions may be used as part of the transmission project review process. An example of this is to capture the breadth of all transmission system issues for different levels of the Ludington Pumped Storage Power Plant in Michigan and flows between ITC Transmission and IESO; additional cases were developed to evaluate critical contingencies:

- 2016 peak load with 6 Units at Ludington operating in Generating Mode and maximum firm interchange of 924 MW scheduled across Michigan-IESO Phase Angle Regulators
- 2016 peak load with 6 Units at Ludington operating in Generating Mode and minimum firm interchange of 0MW scheduled across Michigan -IESO Phase Angle Regulators
- 2016 peak load with 6 Units at Ludington operating in Generating Mode and non-firm interchange of -1300 MW scheduled across Michigan -IESO Phase Angle Regulators
- 2016 85% Load with 5 Units at Ludington operating in Generating Mode and maximum firm interchange of 924 MW scheduled across Michigan -IESO Phase Angle Regulators
- 2016 85% Load with 5 Units at Ludington operating in Generating Mode and less than firm interchange of 350MW scheduled across Michigan -IESO Phase Angle Regulators
- 2016 85% Load with 5 Units at Ludington operating in Generating Mode and non-firm interchange of -1200 MW scheduled across Michigan -IESO Phase Angle Regulators
- 2016 85% Load with 1 Unit at Ludington operating in Pumping Mode and maximum firm interchange of 924 MW scheduled across Michigan -IESO Phase Angle Regulators
- 2016 85% Load with 1 Unit at Ludington operating in Pumping Mode and less than firm interchange of 350 MW scheduled across Michigan -IESO Phase Angle Regulators
- 2016 85% Load with 1 Unit at Ludington operating in Pumping Mode and non-firm interchange of -1200 MW scheduled across Michigan -IESO Phase Angle Regulators
- 2016 70% Load with 4 Units at Ludington operating in Pumping Mode and maximum firm interchange of 924 MW scheduled across Michigan -IESO Phase Angle Regulators
- 2016 70% Load with 4 Units at Ludington operating in Pumping Mode and less than firm interchange of 200 MW scheduled across Michigan -IESO Phase Angle Regulators

- 2016 70% Load with 4 Units at Ludington operating in Pumping Mode and non-firm interchange of -1000 MW scheduled across Michigan -IESO Phase Angle Regulators

Additionally, MTEP11 Voltage Stability Analysis included evaluation of voltage stability issues arising from load in some areas scaled beyond the 50/50 to 90/10 level. No voltage stability issues were found.

R1.3.7 Demonstrate that system performance meets Category A, B, C and D contingencies.

Section 6 of this report describes projects moving to Appendix A (moving from proposed to planned) in MTEP11. Appendix D1 of this report documents effectiveness of the projects.

MTEP11 Reliability analysis was conducted with models containing all planned and proposed projects. Some thermal and voltage criteria violations were seen for all Category A, B, C and D contingencies and are documented in Appendix D3 (Steady State Analysis), D4 (Voltage Stability Analysis) and D5 (Transient Stability Analysis). The table also documents associated mitigations for all violations involving system adjustments such as generation redispatch. These tables also constitute the MISO SOL tables. IROL tables are derived as a subset of these tables per the MISO SOL-IROL Methodology in support of NERC FAC10 and FAC14 standards.

R1.3.8 Include existing and planned facilities.

Models used in MTEP Reliability Analysis contain existing and planned transmission facilities. The topological starting point of MTEP11 analysis is projects with documented system needs in Appendix A and Appendix B from prior MTEP's as well as future facilities expected to be approved in MTEP11. In the event that project effectiveness cannot be demonstrated within the current MTEP cycle, these are removed from the final model. The final model also contains additional projects that have been identified as needed to mitigate constraints identified in the current MTEP reliability analysis.

R1.3.9 Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

The models used in MTEP analyses include generator reactive capabilities, fixed shunt capacitors, switched shunt capacitors, synchronous condensers, static VAR compensators, and other VAR sources. If analyses show steady state voltage violations or voltage instabilities requiring an upgrade, MTEP Appendix A to MTEP will show the upgrade.

R1.3.10 Include the effects of existing and planned protection systems, including any backup or redundant systems.

The MTEP models, contingency files and disturbance files used in this analysis include effects of existing and planning protection systems. MISO also uses a list of Standard Operating Guides in evaluation of preliminary list constraints identified in contingency analyses.

R1.3.11 Include the effects of existing and planned control devices.

The power flow models used in MTEP analysis contain existing and planned control devices, such as, Load Tap Changing (LTC) transformers, phase angle regulating transformer controls, generator voltage controls, Direct Current line controls, and switched shunts controls. These controls are enabled during solutions. Base cases are solved with area interchange also.

R1.3.12 Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The power flow models used in MTEP analysis generally assume that planned outages are not scheduled during peak load periods. However, areas within the system may include outages to the extent that actual operating experience indicates that these areas experience difficulty in scheduling outages. Additionally, in MTEP reliability analysis, contingent events include combination of planned and forced outages and are generally studied using off-peak MTEP models such as at shoulder peak load model as outages are expected to be performed at these levels and system performance for single forced outage is expected to meet performance requirements of Table 1. Some planned upgrades have been developed in part based upon this criterion.

In MTEP11, in addition to the shoulder peak load model, various light load models representing different system conditions were developed (See R1.3.6). Contingent events, including planned and forced outages, were analyzed using these models.

R1.4 Address any planned upgrades needed to meet the performance requirements of Category A, B, C and D of Table I.

Section 6 of this report describes projects moving to Appendix A (moving from proposed to planned) in MTEP11. Appendix D1 of this report documents effectiveness of the projects. MTEP10 Reliability analysis was conducted with models containing all planned and proposed projects.

Some thermal and voltage criteria violations were seen for all Category A, B, C and D contingencies and are documented in Appendix D3 (Steady State Analysis), D4 (Voltage Stability Analysis) and D5 (Transient Stability Analysis). The table also documents associated mitigations for all violations involving system adjustments such as generation redispatch. These tables also constitute the MISO SOL tables. IROL tables are derived as a subset of these tables per the MISO SOL-IROL Methodology in support of NERC FAC10 and FAC14 standards.

With all mitigation plans applied as necessary, no outstanding reliability issues were seen in MTEP11. Some plans such as planned / controlled loss of load or redispatch of network resources applied as mitigation measures for Category C violations in this cycle may be reviewed in the next cycle to determine cost effectiveness compared with transmission projects.

R1.5 Consider all contingencies applicable to Category B, C and D.

The MTEP11 study analyzed these events. See Section E1.1.4 for additional details on contingencies analyzed. Thermal and voltages issues were flagged using Transmission Owner's design criteria limits.

R2 When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

In the MTEP planning cycle, the MISO works collaboratively with Transmission Owners and stakeholders to develop mitigation plans for identified issues. These plans are tested by MISO staff for effectiveness. The mitigation plans are developed to meet the requirements 2.1 and 2.2 below.

R2.1 Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

The MTEP report summarizes the mitigation plans required to maintain adequate system performance in Appendix A and B of this study. Documentation of such plans is included in Appendix D1. Projects in Appendix C may address identified issues, but MISO staff has yet to document their effectiveness.

R2.1.1 Including a schedule for implementation.

MTEP Appendix A and B has for each project facility an expected in service date which forms a schedule for implementation. Proposed In-Service dates are finalized as part of project review process. Some in-service dates may be pushed out or advanced based on when constraint is expected to appear.

R2.1.2 Including a discussion of expected required in-service dates of facilities.

MTEP Appendix A, B, and C have expected in-service dates for each project facility.

R2.1.3 Consider lead times necessary to implement plans.

At the start of the MTEP planning cycle, MISO staff reviews project in service dates and estimated lead times for construction. Any concerns on timely implementation of plans are discussed with Transmission Owners and in-service dates revised in-order to put the project, or alternate near term op-guides, in place before transmission constraint is expected to arise.

R2.2 Review in subsequent annual assessments (where sufficient lead-time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

MISO collaborates with Transmission Owners to determine the continuing need for approved system facilities on as need basis. In some instances, system changes such as large generator interconnections may warrant replacing smaller projects, such as line re-conductor and terminal upgrades, in preference over entire line rebuilds. Load Forecast changes may also demonstrate that project in-service dates may need revisions.

In the MTEP process, projects moving from Appendix B to Appendix A are reviewed by MISO staff. During this project review process, staff may not determine the need for the project. This in some instances is an outcome of other planned projects in the area. Likewise, during the process if other past approved projects in the area may be deferred, MISO staff coordinates with Transmission Owners to help revise in-service dates of those facilities. If time permits, proposed projects in Appendix B are not included in initial MTEP models, enabling the continuing need for the project to be documented.

R3 The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

MISO documents the results of the Reliability Assessment in the MTEP report such as this MTEP11 report. The final step of an annual planning cycle is to provide this MTEP report to the respective Regional Reliability Organizations per their requirements. For FERC Order 890 compliance, MISO has adopted numerous other measures to make the local planning process more inclusive, open and transparent to all stakeholders. One such measure was institution of MTEP Sub Regional Planning Meetings. A document listing various milestones and schedules involved in the MTEP Sub Regional Planning Process is posted on the MISO website at:
https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlan2011.aspx.
The MISO Transmission Plan and Draft Report are additionally reviewed in open forums at various stages during the planning cycle by the MISO Planning Subcommittee and Planning Advisory Committee. A document listing MTEP report deliverables to open stakeholder forums is posted on the MISO website at the below link:
https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/TransmissionExpansionPlanning.aspx.
The final report is also made available on MISO public website and announced via formal press release.

1.1.2 Planning Criteria and Monitored Elements

In accordance with the MISO Transmission Owners Agreement, the MISO Transmission System is to be planned to meet local, regional and NERC planning standards. The baseline reliability analysis, performed by the MISO staff, tested the performance of the system against the NERC Standards, leaving the compliance to local requirements to the Transmission Owners where those standards may exceed NERC standards. The specific branch loading and bus voltage thresholds of each member's criteria (local flagging criteria) were applied to accurately reflect the different system design standards of the MISO members in this assessment.

All system elements, 100 kV and above, within the MISO Planning regions, as well as tie lines to neighboring systems, were monitored. Some non-MISO member systems were monitored if they were within the MISO Reliability Coordination Area.

1.1.3 Baseline Modeling Methodology

In MTEP11 power flow models were developed to represent various system conditions in the 5 year out and 10 year out planning horizon. 2013 summer peak, 2016 summer peak, 2016 shoulder peak, 2016 light load, 2021 shoulder peak and 2021 summer peak power flow models were developed. MISO coordinated with external seam regions: TVA, SPP, MAPP and PJM to reflect corresponding regions latest topology in the MTEP models. For all other areas, modeling data of corresponding year or closer match from Eastern Interconnection Regional Reliability Organization (ERAG) 2010 series model were applied. This section describes model assumptions used in MTEP analysis.

1.1.3.1 Model Assumptions

Transactions

All models were dispatched by MISO wide regional tiered merit order. In order to determine interchanges for these models, the following approach is used:

1. Total Load is determined based on input from all MISO Transmission Owners via the Model on Demand (MOD) tool
2. Losses for each MISO area are estimated based on corresponding year ERAG models.
3. All firm drive-in and drive-out transactions between MISO member control areas with external control areas are added up from the 2009 series Multi-Area Modeling Working Group (MMWG) Interchange data. This determines MISO net interchange with external system (In all models, this number was negative implying a net import).
4. Total Generation needed to serve MISO load is then determined:
   Load + Losses – Import
5. Using regional merit order dispatch methodology described in further detail under the Generation dispatch section, MISO units are dispatched. Depending on how much generation is picked up in individual control areas, individual control area interchanges all adding up to the net MISO import are determined:
   Generation – (Load + Losses)

A Security Constrained Economic Dispatch (SCED) within MISO is then applied to all models for reliability analyses. These cases do not include any explicit MISO internal transactions (drive-within) modeled but will retain the Firm transactions to external parties modeled in the contractual dispatch case. This modeling philosophy enables MISO to plan the system based on how the market operates, still ensuring that the system is planned such that obligation of all Network Resources to serve all Network loads are met.

Losses

Individual control area losses are calculated after the model is solved. If losses initially assumed (Step 2) are higher, such that the area swing machines over generate, these are corrected by dispatching other units, such that the total Generation dispatched in the MISO footprint covers all load and losses, after accounting for any imports.

Load

As noted earlier, 2013 summer peak, 2016 summer peak, 2016 shoulder peak, 2016 light load, 2021 shoulder peak and 2021 summer peak, shoulder peak, and light load power flow models were developed. All load data is based on 50/50 coincident load forecast by control area submitted to the MISO Model on Demand (MOD) tool by Transmission Owners. Load forecasts in the models include existing demand side management and conservation programs.

Table 1.1-1: Aggregate Load

MTEP Cycle	Aggregate summer peak Load (MW) in Planning Models							
	Year 2011	Year 2013	Year 2014	Year 2015	Year 2016	Year 2018	Year 2019	Year 2021
MTEP11*		108,425			111,567			113,815
MTEP10				122,851				
MTEP09	116,636		120,600				126,800	
MTEP08		123,624				130,988		
MTEP07		123,624				130,988		
MTEP06	125,935				134,404			

*MTEP 11 loads do not include First Energy

Generation

All models were dispatched to represent MISO market conditions with generators dispatched per market wide regional merit order. Block order of units based on PROMOD® cost curves were then separated into seven tiers, with Level 0 units the first, and Level 6 the last, to be dispatched.

Level_0: Must Run, Self-Scheduled, Wind (modeled at 5% nameplate in peak cases and 90% nameplate in shoulder peak and light load cases), Hydro, Loads, SVC's, Non-MISO which are on-line

Level_1: Network Resources

Level_2: Energy Resources

Level_3: Future Gens without IA

Level_5: Fake or Retired (things not used or changed)

Level_6: Non-MISO Off-line. MISO units missing data

Assumptions

Level_0, Sort units by Fuel type, then Pmax decreasing

Level_1 has $0 cost blocks. For all $0 cost units sort by Pmax decreasing and have Coal before Gas

Based on Load, Losses and Net Interchange, the following amount of total generation was dispatched in each model:

Demand level	Total Dispatched Generation (MW) in Planning Models		
	Year 2013	Year 2016	Year 2021
Summer Peak	105,317	109,923	109,788
Shoulder Peak		86,451	87,136
Light Load		59,553	

Reactive Resources

Power flow models used in the analysis contain existing and planned reactive resources, specifically: generator reactive capabilities, fixed shunt capacitors, switched shunt capacitors, synchronous condensers, static VAR compensators, and other VAR sources. Note that only on-line generators will provide reactive support according to controls.

Control Devices

Power flow models contain existing and planned control devices, such as, Load-Tap Changing (LTC) transformers, phase angle regulating transformer controls, generator voltage controls, area interchange controls, Direct Current line controls, and switched shunts controls. Note that area interchange is not used during contingency analysis.

Model Topologies

The different model phases reflect different topologies dependent on which future projects were included in the models. The transmission system topology contains existing and planned transmission facilities. Future facilities with expected in service dates after summer 2016 were not modeled in the five year out models and future facilities with expected in service dates after summer 2021 were not modeled in the ten year out models. The final model containing the list of all MTEP11 Appendix A and B projects was posted at the MTEP ftp site (ftp://mtep.midwestiso.org/mtep11/Models/Final_Models/). See Appendix D2 for modeled future facility documentation of the models.

1.1.4 Contingencies Examined

Regional contingency files were developed by MISO Staff collaboratively with Transmission Owner and Regional Study Group input. NERC Category A, B, C and D contingency events on the transmission system under MISO functional control were analyzed. In general, contingencies on the MISO members' transmission system at 100 kV and above were analyzed in MTEP10, although some 69 kV transmission was also analyzed.

1.1.4.1 Steady State Analysis – Contingencies Studied

Category B Events {Total: 12,398

- All NERC Category B (single line, single transformer, or single generator outage) contingency events were analyzed in AC contingency analysis.

Category C Events

- All critical NERC Category C1, C2, C4 and C5 events were analyzed. Rationale for defining these as more severe than others not selected have been documented in Appendix D7 by regional planners. {Total: 11,700}
- In addition to the above explicitly defined Category C events, the single events studied were paired up to study impact of two independent outages (n-1-1). The events of this type documented below were deemed more severe than other C3's not considered in MTEP10.
  - C3: Double Generator, Generator + Branch and Double Branch in two separate adjacent control areas. Single events in each MISO control area are paired up with other single events in its adjacent control areas regardless of the adjacent control area RTO affiliation. Selection of these events was determined per the following thresholds: Generators above 200 MW, Transmission lines above 200 kV and transformers with low side above 200 kV. {Total: 513,086}
  - C3: Double Generator, Generator + Branch and Double Branch within the same control area selected per the following thresholds: Generators above 100 MW, Transmission lines above 100 kV and transformers with low side above 100 kV. { About 2.3 million}

Category D Events

- D10: Loss of all generating units at a station was considered for large generating plants. {285}
- D8: Loss of a stubstation {4,535}

In total, approximately over 2.8 million contingencies were analyzed in steady state analysis.

A NERC Category C3 event is defined as a Category B event, followed by manual system adjustment, followed by another Category B event. In the MTEP process, two Category B events are analyzed (automated doubles) without the allowed manual system adjustment between the two events. NERC Planning Standards allow Category C analysis to focus on the most severe events. MISO requested that its members draw on their past studies and system knowledge to provide the severe Category C events. Those events were analyzed in this study. MISO expects that the selection of contingencies to be studied in any one MTEP will vary, so that over several MTEP studies, all areas of the system will be thoroughly tested. MISO also expects to add additional contingencies going forward based on MISO operating and planning experience. In addition, MISO staff performed independent screening analyses of multiple element outage events to help identify areas potentially vulnerable to voltage instability. See MTEP10 Appendices D3-D5 for a list of issues identified in reliability analysis and associated mitigation plans, which may be a project in Appendix A or B or other applicable actions. MTEP11 Appendix D1 also demonstrates project mitigation plan effectiveness.

1.1.4.2 Dynamics Stability Analysis – Disturbances Studied

MISO simulated the following disturbances on members' systems for studying different Dynamic/Transient Stability issues.

1. **First swing transient stability**

   First swing transient stability is the A-periodic drift due to large disturbances. The recommended events include:

- B1 generator 3-phase faults with normal clearing for units >100 MW
- B2 trip of long, heavily loaded interface lines with large phase angle difference across the interface
- C6, C7, C8, C9 Faults with delayed clearing near large units (>200 MW). Most severe event near the unit. If C8 is the most severe, provide C8. If C9 is the most severe, provide C9.

- In MTEP11, C8 faults were tested on the most heavily loaded 345 kV transmission lines out of large generating stations (>200 MW).

- Historically severe events

2. Oscillation stability

This category of disturbances is to evaluate the eastern interconnection-wide oscillation disturbances by branch outages. Disturbances will trip branches related to inter-area modes with lower damping. MTEP07 small signal analysis results were used to identify the lower damped modes and branches influencing these modes. MISO staff built the disturbances for the identified lower damped modes. Recommended events include Category C3 or N-3. Additional disturbances were received from TO's based on their experience and historically severe events.

3. Voltage/reactive power related issues

MISO staff will build this category of disturbances based on the MTEP11 AC analysis results. Non-converged steady state contingencies were also tested in Dynamic Stability.

4. Others: DC lines, SPS failures

Additional disturbances modeling B4 DC single pole, C4 DC bipole and D12 SPS failure were simulated.

1.1.5 Load Deliverability Analysis

In 2011 MISO completed its third annual LOLE study under accepted tariff provisions, designed to meet emerging Reliability Entity (RE) requirements. Previously, in 2008, MISO participated in the LOLE Study where Planning Reserve Margins (PRM) were determined for members of the Midwest Planning Reserve Sharing Group (MPRSG).

1.1.5.1 MISO LOLE Study

On December 28, 2007, MISO submitted major revisions to its EMT to the Federal Energy Regulatory Commission (FERC) that involve Module E regarding Resource Adequacy Requirements (RAR); these revisions were conditionally accepted by FERC on March 26, 2008. The filing along with subsequent clarifications and drafting of the Business Practice Manual (BPM) have laid the ground work for establishing a process by which LOLE study zones are determined. Zones of interest are based on identifying congestion in the transmission system. These congestion driven zones are utilized in modeling the calculation of planning reserve margins, and allow quantitative evaluation of load deliverability and aggregate generation deliverability.

The process of defining zones enhances the load deliverability study by identifying potential areas where load deliverability could be at higher risk due to constraints and also identifies where generation may have limits to being deliverable outside of specific zones (i.e. constrained generation). The congestion based zones and the associated transmission system limitations are the key inputs to a probabilistic application use for the LOLE study. The generator outage data needed for the LOLE study, and the requirements to report such data, are also part of the Module E filing. The LOLE calculation verifies if the load in the study zones is at risk of exceeding the one day in ten years criteria. Stakeholder participation or awareness about the MISO LOLE studies is possible through participation or tracking of the activities of the Loss of Load Expectation Working Group (LOLEWG) that was established in May 2008 to conduct the LOLE studies in accordance with the Tariff and related business practices. The study is done annually to set the PRM each year, and means that the PRM is primarily a function of four drivers:

- The reliability performance of the generators in MISO
- The probability of the load varying from the base 50/50 forecast
- The transmission network and the relative location of load and generation throughout the network.
- The amount of assistance that can be reliably obtained from outside MISO.

The results of the 2011-2012 LOLE Study Report are discussed in Section 5.1 of this report.

Subsequently, MISO again submitted major revisions to its EMT to the FERC on July 20, 2011, and if approved, MISO would expect those changes to be reflected in the LOLE Study for 2013.

1.1.6 Generator Deliverability Analysis

The Generator Deliverability analysis determines the ability of groups of generators in an area to operate at their maximum capability without being limited by transmission constraints, that is, without being bottled-up. This test is performed as part of the generators interconnection study process on new generators before granting Network Resource (NR) status. The generator is required to fix any transmission constraints limiting deliverability, in order to be treated as a Network Resource. A generator that is certified deliverable (not bottled-up) could be designated by any Load Serving Entity (LSE) within the Midwest Market Footprint to satisfy its Resource Adequacy requirement as specified in Module E of the MISO Energy Market Tariff.

The deliverability levels of already granted Network Resources may deteriorate over time as a result of load growth and other changes to the transmission system. A Baseline Generator Deliverability Study is performed in order to identify and address any new transmission constraints to ensure ongoing deliverability of Network Resources. Also, baseline generator deliverability upgrades represent a reliability need to ensure the continued ability to count on Network Resources nominated to meet reserves.

In MTEP11, the Baseline Generator Deliverability analysis was performed using the MTEP11 2016 summer peak model and by applying single transmission contingencies to deliverability dispatch patterns. The general generator deliverability study assumptions, as described under Section 5.1.1.2 of the Business Practices Manual for Generation Interconnection, were used for the analysis. The deliverability was tested only up to the granted Network Resource levels of the Network Resource units modeled in MTEP11 2016 summer peak case. Results of the generator deliverability test including outstanding constraints were documented in Section 6 of MTEP11 Report. Subsequently in MTEP10 a Technical Review Group (TRG) comprising of MISO stakeholders was created to identify solutions to address transmission constraints resulting in reduced deliverability of aggregate deliverable Network Resources. Solutions to address transmission constraints resulting in reduced deliverability of aggregate deliverable Network Resources were identified in MTEP10 and documented in Section 6 of the MTEP11 Report. The list of constraints was prioritized based on proportion of each constraint on the overall restricted Network Resource generation. The solutions to those constraints were incorporated into the MTEP10 2015 summer peak case and their effectiveness in mitigating those constraints were evaluated. As part of this process some constraints were identified to be invalid. Mitigations for the outstanding constraints from MTEP10 that were proven effective are documented in Section 6.

The second effort in MTEP11 was to roll-up all mitigations proven effective in mitigating aggregate deliverability constraints into the MTEP11 models and test for outstanding deliverability constraints. These results were shared with stakeholders on August 18, 2011. The outstanding list of constraints has been documented in Section 6. We are actively collaborating with our stakeholders to address these constraints.

1.1.7 Mitigation Plan Development

MISO staff works collaboratively with Transmission Owners and stakeholders to review and develop mitigation plans. MISO staff presented the MTEP11 projects to stakeholders at the first round of Subregional Planning Meetings in December. Proposed plans were then reviewed again in additional detail at the 2nd round of Subregional Planning Meetings (SPM) in April, after MISO staff had reviewed and performed preliminary analysis of the project proposals, submitted earlier, at the beginning of the planning cycle. Feedback from stakeholders was incorporated into the project review process. The 3rd and final round of SPMs were then held in June for each of the three Planning regions, presenting the final list and details of projects moving forward for MISO Board of Directors (BOD) approval in 2011. Preliminary cost allocation of all RECB eligible projects was also presented at this meeting. Final MTEP11 Cost Allocation Meeting was held on August 11thto present all new RECB eligible MTEP11 Appendix-A projects. Details on information requirements and timelines are documented in Section E1.1.1.

The MISO transmission system is divided into three Planning regions – West, Central, and East - to facilitate the MTEP study and Subregional Planning Meetings. MISO Staff members are assigned Transmission Owners in each planning region. MISO Transmission Owning members and other interested stakeholders participated in the MTEP study and development of mitigation plans.

During the MTEP planning cycle, the Planning Subcommittee (PS) stakeholder group reviews MTEP analysis, project recommendations, and the MTEP report. Review of cost allocation of projects recommended for the MISO Board of Director approval, via the MTEP study, is done by the Planning Subcommittee and a specific stakeholder meeting for the purpose of reviewing the projects eligible for regional cost allocation. The last step in development of the mitigation plan is presentation of the final plan to the MISO Board of Directors for their review and approval.

1.1.8 Planning for Long-Term Transmission Rights

Long Term Transmission Rights (LTTR's) are Auction Revenue Rights (ARR's) allocated during Stage 1A & Restoration of the annual allocation.

- As long as they are requested, the allocation of last year's LTTRs is guaranteed, even if deemed infeasible.
- The cost of funding infeasible LTTRs is uplifted across all LTTR holders.

FERC requires each transmission organization with an organized electricity market to implement a transmission planning process that accommodates the LTTRs that are awarded by ensuring that they remain feasible. The MISO has developed, through stakeholder discussions with the Long Term Transmission Rights Planning Working Group and the Planning Advisory Committee, a series of analytical steps to evaluate the reasons for LTTR infeasibility, and to determine the best approach to addressing these infeasibilities. These analyses link LTTR binding constraints to upgrades to be developed through the planning process.

Present planning practices ensure that all base load generation can be delivered to loads reliably. It is recognized that there are some differences in the Infeasible LTTR Study and planning models that can lead to infeasibility where no planned upgrade is identified

- Differences in the modeling of planned outages (included in seasonal Infeasible LTTR Study)
- Modeling detail - Loop flow modeling
- Variation in the nomination patterns.
  - A Market Participant may choose not to re-nominate existing LTTRs, which may cause infeasibility of other LTTRs. New Stage 1A requests that did not exist in the previous allocation may cause the curtailment of LTTRs.
- Expiration of an existing right that provided counterflow to other rights
- Nomination of rights that do not correspond to a physical source in the planning models

Stakeholders agreed that upgrades should not be built to accommodate feasibility of LTTR where no reliability or congestion issue can be identified in real-time or planning studies.

1.1.8.1 MISO Planning approach

- Identify infeasibility and near-infeasibility that has a corresponding planned upgrade that will increase feasibility
- Identify planned upgrades that could benefit LTTR feasibility when implemented or if advanced
- Factor increased feasibility cost benefits (reduced uplift) into the consideration of planning alternatives to an economic or reliability constraint identified in the planning process
- Identify uplifted revenue associated with each binding constraint

In order to include LTTR feasibility considerations in the MISO transmission expansion planning process, an information exchange has been established between the FTR & Pricing Administration (FPA) group performing the ARR Allocation and the Expansion Planning (EP) group responsible for long term transmission planning. The following information is to be provided to the MTEP group by the FPA each year after annual auction:

- A list of curtailed LTTRs in each of the eight allocation cases
- A list of binding constraints causing LTTR curtailment
- A list of the "near-infeasible," most heavily loaded, branches in the Infeasible LTTR Study
- A list of planned outages included in the ARR allocation studies
- Uplift cost associated with the funding of infeasible LTTRs

1.1.8.2 Results from MTEP 11 Planning Cycle

Section 6 provides the results of the following analyses:

- Upgrades (Planned and Proposed Reliability Projects or economic proposed projects) that are associated with infeasible LTTRs in 2011 allocation
- Constraints with uplifted LTTR revenue that are non-MISO constraints that may be addressed in Joint Planning Processes with other entities

- Constraints with uplifted LTTR revenue that do not correlate to real-time or projected reliability or congestion issues

Appendix A-3. ***Indicative*** **Multi-Value Project (MVP) Schedule 26-A Annual Charges by MISO Local Balancing Authority (LBA) for Approved and Pending Approval MVPs**

THE VALUES SHOWN BELOW (IN 2011$) ARE INTENDED TO BE INDICATIVE ONLY, ARE BASED UPON MISO PROJECTIONS, ARE NOT INTENDED BY MISO TO BE RELIED UPON FOR SETTLEMENT OR RATEMAKING PURPOSES. THE VALUES ARE SUBJECT TO CHANGE DEPENDING UPON ACTUAL PROJECT COSTS INCLUDING CONSTRUCTION WORK IN PROGRESS, ACTUAL IN-SERVICE DATES, AND ACTUAL ANNUAL CHARGE RATES FOR TRANSMISSION OWNERS

Figure A-3.1 Approved and Pending Approval MVPs

Project ID	Project Name	Geographic Location by TO Member System	Estimated In-Service Date	Estimated Project Cost (2011$)	Approval Status
[1]	[2]	[3]	[4]	[5]	[6]
1203	Brookings, SD - SE Twin Cities 345 kV	XEL/GRE/OTP/MRES/CMMPA	2/16/2015	$695,000,000	Conditionally Approved June 2011
2202	Reynolds to Greentown 765 kV line	DUK/NIPS	8/1/2018	$245,300,000	Pending Dec 2011
2220	Ellendale to Big Stone South	OTP, MDU	12/31/2019	$260,700,000	Pending Dec 2011
2221	Big Stone South to Brookings	OTP, XEL	12/31/2017	$190,800,000	Pending Dec 2011
2237	Pana - Mt. Zion - Kansas - Sugar Creek 345 kV line	AMIL	11/15/2019	$284,100,000	Pending Dec 2011
2239	Sidney to Rising 345 kV line	AMIL	11/15/2016	$90,100,000	Pending Dec 2011
2248	Adair - Ottumwa 345	AMMO, ITCM, MEC	11/15/2018	$152,037,000	Pending Dec 2011
2844	Pleasant Prairie-Zion Energy Center 345 kV line	ATC	3/6/2014	$26,400,000	Pending Dec 2011
3017	Palmyra Tap -Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV Line	AMIL	11/15/2017	$392,400,000	Pending Dec 2011
3022	Fargo-Galesburg-Oak Grove 345 kV Line	AMIL, MEC	6/1/2019	$193,200,000	Pending Dec 2011
3127	N LaCrosse-N Madison-Cardinal -Spring Green - Dubuque area 345-kV	ATC, XEL, ITCM	12/31/2020	$714,430,000	Pending Dec 2011
3168	Michigan Thumb Wind Zone	ITC	12/31/2015	$510,000,000	Approved MTEP 10
3169	Pawnee to Pana - 345 kV Line	AMIL	11/15/2018	$88,100,000	Pending Dec 2011
3170	Adair-Palmyra Tap 345 kV Line	AMMO	11/15/2018	$97,600,000	Pending Dec 2011
3203	Reynolds to Burr Oak to Hiple 345 kV	NIPS	12/31/2019	$271,200,000	Pending Dec 2011
3205	Lakefield Jct. - Winnebago - Winco - Burt area & Sheldon - Burt Area - Webster 345 kV line	MEC, ITCM	12/1/2016	$505,650,000	Pending Dec 2011
3213	Winco to Hazelton 345 kV line	MEC, ITCM	12/31/2015	$480,050,000	Pending Dec 2011
			Total	$5,197,067,000	

Figure A-3.2 *Indicative* MVP Usage Rates for Approved and Pending Approval MVPs (2011 dollars)

Year (2012-2021)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Indicative MVP Usage Rate ($/MWh)	$0.02	$0.14	$0.29	$0.46	$0.68	$0.92	$1.06	$1.19	$1.43	$1.45

Year (2022-2031)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Indicative MVP Usage Rate ($/MWh)	$1.41	$1.38	$1.34	$1.30	$1.27	$1.23	$1.20	$1.16	$1.13	$1.10

Year (2032-2041)	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Indicative MVP Usage Rate ($/MWh)	$1.06	$1.03	$1.00	$0.96	$0.93	$0.90	$0.87	$0.84	$0.81	$0.78

Year (2042-2051)	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Indicative MVP Usage Rate ($/MWh)	$0.75	$0.73	$0.70	$0.67	$0.64	$0.62	$0.59	$0.57	$0.54	$0.52

Notes:

1) Indicative MVP Usage Rate based on the approved and pending approval MVPs listed in Figure A-3.1.

2) Annual MISO Withdrawals based on 2010 values with years 2012-2051 escalated assuming an annual energy growth rate of 1.42% consistent with the assumed energy growth rate used in the MTEP 11 Business as Usual Future with historical energy growth rates.

3) Annual Revenue Requirement calculated using an estimated Annual Charge Rate for each Transmission. Annual Charge Rate estimated using Transmission Owner's Attachment O data as of January 2011 and assumes 40-year straight-line depreciation.

4) Construction Work in Progress (CWIP) charges are assumed only for projects that have FERC approval for CWIP recovery. Estimated annual CWIP charges are based on an assumed phase-in schedule depending on the in-service date. For example, if a project has an in-service date in 2016 then CWIP charges occur as follows: 2012 = 7.5% of estimated project cost; 2013 = 20%; 2014 = 45%; 2015 = 75%; 2016=100%. The annual charge rate is reduced by 2.5% during the years of CWIP recovery to reflect that depreciation expense reletated charges are not incurred.

5) For the Michigan Thumb MVP the project is assumed to be phased in-service equally over the 2013-2015 period.

6) The Indicative MVP Usage Rate for the Michigan Thumb project reflects First Energy's obligation for a portion of the Michigan Thumb project.

7) Please contact Jeremiah Doner at jdoner@misoenergy.org with any questions.

Figure A-3.3 *Indicative* Annual MVP Charges for Approved and Pending Approval MVPs by Local Balancing Authority for 2012-2021 (in Millions of 2011 Dollars)

LBA	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
ALTE	$0.23	$1.82	$3.68	$6.07	$9.01	$12.32	$14.46	$16.44	$20.12	$20.59
ALTW	$0.37	$2.95	$5.97	$9.84	$14.61	$19.98	$23.44	$26.67	$32.63	$33.40
AMIL	$0.85	$6.86	$13.88	$22.90	$33.97	$46.47	$54.52	$62.02	$75.90	$77.67
AMMO	$0.80	$6.40	$12.93	$21.34	$31.66	$43.31	$50.82	$57.81	$70.75	$72.40
BREC	$0.06	$0.71	$1.92	$3.17	$4.70	$6.43	$7.54	$8.58	$10.50	$10.75
CIN	$1.23	$9.87	$19.97	$32.95	$48.88	$66.87	$78.46	$89.24	$109.22	$111.78
CONS	$0.80	$6.45	$13.04	$21.51	$31.92	$43.66	$51.23	$58.27	$71.31	$72.98
CWLD	$0.03	$0.21	$0.43	$0.71	$1.06	$1.45	$1.70	$1.94	$2.37	$2.42
CWLP	$0.04	$0.29	$0.59	$0.98	$1.46	$1.99	$2.34	$2.66	$3.25	$3.33
DECO	$0.96	$7.73	$15.64	$25.80	$38.28	$52.36	$61.44	$69.89	$85.53	$87.53
DPC	$0.10	$0.83	$1.68	$2.77	$4.11	$5.62	$6.59	$7.50	$9.17	$9.39
GRE	$0.23	$1.82	$3.69	$6.08	$9.02	$12.34	$14.48	$16.47	$20.16	$20.63
HE	$0.01	$0.06	$0.12	$0.20	$0.29	$0.40	$0.47	$0.53	$0.65	$0.67
IPL	$0.28	$2.26	$4.58	$7.55	$11.20	$15.32	$17.98	$20.45	$25.03	$25.61
MDU	$0.05	$0.39	$0.79	$1.31	$1.94	$2.65	$3.11	$3.54	$4.33	$4.44
MEC	$0.44	$3.55	$7.18	$11.84	$17.57	$24.03	$28.20	$32.07	$39.25	$40.17
MGE	$0.06	$0.51	$1.03	$1.69	$2.51	$3.43	$4.03	$4.58	$5.61	$5.74
MP	$0.19	$1.55	$3.14	$5.18	$7.69	$10.52	$12.34	$14.04	$17.18	$17.58
MPW	$0.02	$0.13	$0.26	$0.44	$0.65	$0.88	$1.04	$1.18	$1.44	$1.48
NIPS	$0.35	$2.79	$5.65	$9.32	$13.83	$18.92	$22.20	$25.25	$30.90	$31.62
NSP	$0.86	$6.91	$13.97	$23.06	$34.21	$46.80	$54.91	$62.46	$76.44	$78.23
OTP	$0.14	$1.16	$2.34	$3.86	$5.72	$7.83	$9.18	$10.45	$12.78	$13.08
SIGE	$0.14	$1.16	$2.35	$3.87	$5.74	$7.86	$9.22	$10.49	$12.83	$13.13
SIPC	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SMP	$0.03	$0.25	$0.50	$0.83	$1.23	$1.68	$1.97	$2.24	$2.74	$2.80
UPPC	$0.02	$0.17	$0.34	$0.56	$0.83	$1.14	$1.34	$1.52	$1.86	$1.90
WEC	$0.62	$4.98	$10.07	$16.61	$24.65	$33.72	$39.57	$45.00	$55.07	$56.36
WPS	$0.26	$2.09	$4.22	$6.97	$10.34	$14.15	$16.60	$18.88	$23.11	$23.65
Exports and Wheel-Throughs excluding those sinking in PJM	$0.21	$1.67	$3.38	$5.58	$8.28	$11.33	$13.29	$15.12	$18.50	$18.93
Total	$9.37	$75.58	$153.33	$253.00	$375.36	$513.46	$602.48	$685.26	$838.64	$858.29

Appendix A-2.1. _Indicative_ Schedule 26 Annual Charges by MISO Pricing Zone for new MTEP 12 Baseline Reliability, Generation Interconnection, and Market Efficiency Projects Subject to Approval for Appendix A

THE VALUES SHOWN BELOW (IN NOMINAL $) ARE INTENDED TO BE INDICATIVE ONLY, ARE BASED UPON MISO PROJECTIONS, ARE NOT INTENDED BY MISO TO BE RELIED UPON FOR SETTLEMENT OR RATEMAKING PURPOSES. THE VALUES ARE SUBJECT TO CHANGE DEPENDING UPON ACTUAL PROJECT COSTS INCLUDING CONSTRUCTION WORK IN PROGRESS, ACTUAL IN-SERVICE DATES, AND ACTUAL ANNUAL CHARGE RATES FOR TRANSMISSION OWNERS

	Year									
Pricing Zone	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
AMIL	66,458	115,586	214,402	449,580	613,746	604,090	594,434	584,777	751,228	988,121
AMMO	63,774	110,916	205,740	372,303	530,727	522,352	513,977	505,602	666,219	894,433
ATC	3,164,418	8,751,545	20,794,030	33,461,426	49,195,545	49,037,480	48,248,412	47,459,345	46,913,319	46,464,509
BREC	12,482	21,708	40,267	286,134	313,926	309,073	304,220	299,367	327,589	369,040
CWLD	2,436	4,237	7,859	14,222	20,274	19,954	19,634	19,314	25,450	34,168
CWLP	2,912	5,065	9,396	19,702	26,896	26,473	26,050	25,627	32,921	43,303
DEI	52,829	91,881	170,432	1,211,075	1,328,708	1,308,167	1,287,625	1,267,084	1,386,533	1,561,979
DPC	8,308	14,450	449,665	464,360	477,996	469,901	461,807	453,712	467,633	490,360
GRE	9,335	16,235	55,792	79,746	102,510	100,858	99,207	97,555	120,639	153,618
HE	5,202	9,047	16,782	119,254	130,837	128,815	126,792	124,769	136,531	153,807
IPL	22,610	39,324	72,943	518,327	568,673	559,881	551,090	542,298	593,421	668,510
ITC	872,371	915,725	1,015,880	1,201,494	1,377,413	1,354,632	1,331,850	1,309,069	8,793,063	19,279,768
ITCM	2,670,942	2,783,291	4,058,151	5,496,196	5,552,930	5,458,080	5,363,231	5,268,381	5,243,208	5,245,905
MDU	5,862	10,195	18,911	34,221	48,783	48,013	47,243	46,473	61,237	82,213
MEC	38,395	68,980	130,455	235,139	337,866	332,535	327,203	321,871	411,985	540,278
METC	2,050,429	2,065,181	2,124,799	6,034,632	9,936,807	9,786,791	9,636,775	9,486,759	9,496,437	9,569,992
MI13AG	2,696	5,990	12,589	24,162	35,170	34,615	34,060	33,505	44,666	60,512
MI13ANG	1,159	2,015	3,738	6,764	9,642	9,489	9,337	9,185	12,103	16,249
MP	15,763	27,527	620,326	652,230	682,329	670,812	659,296	647,779	677,715	724,233
MPW	1,130	1,966	3,646	6,633	9,441	9,292	9,143	8,994	11,840	15,884
NIPS	26,709	46,452	86,165	612,285	671,757	661,372	650,987	640,601	700,992	789,692
NSP	116,497	243,929	4,945,808	5,238,222	5,592,028	5,497,921	5,403,814	5,309,707	5,406,256	5,579,066
OTP	11,023	19,172	40,407	69,117	96,420	94,892	93,365	91,837	119,519	158,886
SIPC	3,469	6,033	11,191	23,466	32,035	31,531	31,027	30,523	39,211	51,575
SMMPA	2,209	3,842	7,127	12,896	18,384	18,094	17,804	17,514	23,077	30,982
VECT	9,362	16,282	30,203	214,617	235,463	231,822	228,182	224,542	245,710	276,801
MISO Total	**9,238,778**	**15,396,575**	**35,146,703**	**56,858,203**	**77,946,305**	**77,326,935**	**76,076,563**	**74,826,192**	**82,708,502**	**94,243,886**

Notes:

1) The indicative annual charges shown only reflect new MTEP 12 projects and would be additive to the indicative annual Schedule 26 charges shown in the posted spreadsheet at the following link on the MISO website under the MTEP Study Information section:

https://www.misoenergy.org/Planning/TransmissionExpansionPlanning/Pages/MTEPStudies.aspx

2Annual Revenue Requirement calculated using an estimated Annual Charge Rate for each constructing Transmission Owner based on the methodology described in Attachment GG. Annual Charge Rate estimated using Transmission Owner's Attachment O data as of January 2012 and assumes 40-year straight-line depreciation.

3) For approved projects with recovery for Construction Work in Progress, charges are phased-in based on an assumed schedule, see posted spreadsheet referenced in note one.

4) For approved projects without approval for Construction Work in Progress recovery, charges start based on the estimated in-service date and whether the constructing Transmission Owner uses forward-looking or historic rate formulas. First year charges are adjusted according to the month the project goes in-service and whether the constructing Transmission Owner used forward-looking or historic rate formulas.

5) Please contact Jeremiah Doner at jdoner@misoenergy.org with any questions.

Appendix A-2.2. _Indicative_ MTEP 06 through MTEP 12 Cost Allocation Summary for Baseline Reliability, Generation Interconnection, and Market Effficiency Projects

Pricing Zone	Total Approved Cost Shared Transmision Investment	Costs Allocated for Projects Located Outside Pricing Zone	Costs Allocated for Projects Located within the Pricing Zone	Total Project Cost Allocated to Pricing Zone
[1]	[2]	[3]	[4]	[5] = [3] + [4]
AMIL	149,223,042	40,647,637	122,544,094	163,191,732
AMMO	88,753,929	31,149,664	82,737,194	113,886,858
ATC	1,014,444,276	92,245,819	835,613,137	927,858,956
BREC	-	2,297,305	-	2,297,305
CWLD	-	1,008,288	-	1,008,288
CWLP	3,537,623	1,651,955	3,537,623	5,189,578
DUK*	22,130,000	3,707,171	10,439,556	14,146,727
DPC	47,652,950	95,133,453	43,529,485	138,662,938
FE*	16,547,008	38,132,309	14,698,279	52,830,588
GRE	163,634,045	28,743,463	9,039,288	37,782,751
HE	-	11,869,904	-	11,869,904
IPL	27,900,000	17,302,753	5,435,672	22,738,426
ITC	168,362,804	38,892,275	147,210,132	186,102,407
ITCM	141,745,240	59,824,391	126,890,503	186,714,894
MDU	11,000,000	8,635,975	10,756,475	19,392,450
MEC	658,000	4,265,421	34,384	4,299,805
METC	429,478,850	90,210,878	415,101,963	505,312,841
MI13AG	-	2,431,964	-	2,431,964
MI13ANG	-	2,900,565	-	2,900,565
MP	145,272,160	87,396,993	56,093,603	143,490,596
MPW	-	109,778	-	109,778
NIPS	21,528,237	19,921,715	20,400,450	40,322,165
NSP	697,062,973	243,276,255	386,425,694	629,701,949
OTP	174,186,576	118,542,803	40,803,646	159,346,449
SIPC	-	1,816,629	-	1,816,629
SMMPA	-	26,113,860	-	26,113,860
VECT	139,903,859	6,199,774	57,301,395	63,501,169
Total	**$3,463,021,572**	**$1,074,428,997**	**$2,388,592,575**	**$3,463,021,572**

Note: That the Duke Pricing Zone includes the withdrawn DEO and DEK TOs. Also, FE is listed as a Pricing Zone but has withdrawn.

Appendix A-3. *Indicative* Multi-Value Project (MVP) Schedule 26-A Annual Charges by MISO Local Balancing Authority (LBA) for Approved and Pending Approval MVPs

THE VALUES SHOWN BELOW (IN 2011$) ARE INTENDED TO BE INDICATIVE ONLY, ARE BASED UPON MISO PROJECTIONS, ARE NOT INTENDED BY MISO TO BE RELIED UPON FOR SETTLEMENT OR RATEMAKING PURPOSES. THE VALUES ARE SUBJECT TO CHANGE DEPENDING UPON ACTUAL PROJECT COSTS INCLUDING CONSTRUCTION WORK IN PROGRESS, ACTUAL IN-SERVICE DATES, AND ACTUAL ANNUAL CHARGE RATES FOR TRANSMISSION OWNERS

Figure A-3.1 Approved and Pending Approval MVPs

Project ID	Project Name	Geographic Location by TO Member System	Estimated In-Service Date	Estimated Project Cost (2011$)	Approval Status
[1]	[2]	[3]	[4]	[5]	[6]
1203	Brookings, SD - SE Twin Cities 345 kV	XEL/GRE/OTP/MRES/CMMPA	2/16/2015	$695,000,000	Conditionally Approved June 2011
2202	Reynolds to Greentown 765 kV line	DUK/NIPS	8/1/2018	$245,300,000	Pending Dec 2011
2220	Ellendale to Big Stone South	OTP, MDU	12/31/2019	$260,700,000	Pending Dec 2011
2221	Big Stone South to Brookings	OTP, XEL	12/31/2017	$190,800,000	Pending Dec 2011
2237	Pana - Mt. Zion - Kansas - Sugar Creek 345 kV line	AMIL	11/15/2019	$284,100,000	Pending Dec 2011
2239	Sidney to Rising 345 kV line	AMIL	11/15/2016	$90,100,000	Pending Dec 2011
2248	Adair - Ottumwa 345	AMMO, ITCM, MEC	11/15/2018	$152,037,000	Pending Dec 2011
2844	Pleasant Prairie-Zion Energy Center 345 kV line	ATC	3/6/2014	$26,400,000	Pending Dec 2011
3017	Palmyra Tap -Quincy-Meredosia - Ipava & Meredosia-Pawnee 345 kV Line	AMIL	11/15/2017	$392,400,000	Pending Dec 2011
3022	Fargo-Galesburg-Oak Grove 345 kV Line	AMIL, MEC	6/1/2019	$193,200,000	Pending Dec 2011
3127	N LaCrosse-N Madison-Cardinal -Spring Green - Dubuque area 345-kV	ATC, XEL, ITCM	12/31/2020	$714,430,000	Pending Dec 2011
3168	Michigan Thumb Wind Zone	ITC	12/31/2015	$510,000,000	Approved MTEP 10
3169	Pawnee to Pana - 345 kV Line	AMIL	11/15/2018	$88,100,000	Pending Dec 2011
3170	Adair-Palmyra Tap 345 kV Line	AMMO	11/15/2018	$97,600,000	Pending Dec 2011
3203	Reynolds to Burr Oak to Hiple 345 kV	NIPS	12/31/2019	$271,200,000	Pending Dec 2011
3205	Lakefield Jct. - Winnebago - Winco - Burt area & Sheldon - Burt Area - Webster 345 kV line	MEC, ITCM	12/1/2016	$505,650,000	Pending Dec 2011
3213	Winco to Hazelton 345 kV line	MEC, ITCM	12/31/2015	$480,050,000	Pending Dec 2011
			Total	$5,197,067,000	

Figure A-3.2 *Indicative* MVP Usage Rates for Approved and Pending Approval MVPs (2011 dollars)

Year (2012-2021)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Indicative MVP Usage Rate ($/MWh)	$0.02	$0.14	$0.29	$0.46	$0.68	$0.92	$1.06	$1.19	$1.43	$1.45

Year (2022-2031)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Indicative MVP Usage Rate ($/MWh)	$1.41	$1.38	$1.34	$1.30	$1.27	$1.23	$1.20	$1.16	$1.13	$1.10

Year (2032-2041)	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Indicative MVP Usage Rate ($/MWh)	$1.06	$1.03	$1.00	$0.96	$0.93	$0.90	$0.87	$0.84	$0.81	$0.78

Year (2042-2051)	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051
Indicative MVP Usage Rate ($/MWh)	$0.75	$0.73	$0.70	$0.67	$0.64	$0.62	$0.59	$0.57	$0.54	$0.52

Notes:

1) Indicative MVP Usage Rate based on the approved and pending approval MVPs listed in Figure A-3.1.

2) Annual MISO Withdrawals based on 2010 values with years 2012-2051 escalated assuming an annual energy growth rate of 1.42% consistent with the assumed energy growth rate used in the MTEP 11 Business as Usual Future with historical energy growth rates.

3) Annual Revenue Requirement calculated using an estimated Annual Charge Rate for each Transmission. Annual Charge Rate estimated using Transmission Owner's Attachment O data as of January 2011 and assumes 40-year straight-line depreciation.

4) Construction Work in Progress (CWIP) charges are assumed only for projects that have FERC approval for CWIP recovery. Estimated annual CWIP charges are based on an assumed phase-in schedule depending on the in-service date. For example, if a project has an in-service date in 2016 then CWIP charges occur as follows: 2012 = 7.5% of estimated project cost; 2013 = 20%; 2014 = 45%; 2015 = 75%; 2016=100%. The annual charge rate is reduced by 2.5% during the years of CWIP recovery to reflect that depreciation expense reletated charges are not incurred.

5) For the Michigan Thumb MVP the project is assumed to be phased in-service equally over the 2013-2015 period.

6) The Indicative MVP Usage Rate for the Michigan Thumb project reflects First Energy's obligation for a portion of the Michigan Thumb project.

7) Please contact Jeremiah Doner at jdoner@misoenergy.org with any questions.

Figure A-3.3 *Indicative* Annual MVP Charges for Approved and Pending Approval MVPs by Local Balancing Authority for 2012-2021 (in Millions of 2011 Dollars)

LBA	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
ALTE	$0.23	$1.82	$3.68	$6.07	$9.01	$12.32	$14.46	$16.44	$20.12	$20.59
ALTW	$0.37	$2.95	$5.97	$9.84	$14.61	$19.98	$23.44	$26.67	$32.63	$33.40
AMIL	$0.85	$6.86	$13.88	$22.90	$33.97	$46.47	$54.52	$62.02	$75.90	$77.67
AMMO	$0.80	$6.40	$12.93	$21.34	$31.66	$43.31	$50.82	$57.81	$70.75	$72.40
BREC	$0.06	$0.71	$1.92	$3.17	$4.70	$6.43	$7.54	$8.58	$10.50	$10.75
CIN	$1.23	$9.87	$19.97	$32.95	$48.88	$66.87	$78.46	$89.24	$109.22	$111.78
CONS	$0.80	$6.45	$13.04	$21.51	$31.92	$43.66	$51.23	$58.27	$71.31	$72.98
CWLD	$0.03	$0.21	$0.43	$0.71	$1.06	$1.45	$1.70	$1.94	$2.37	$2.42
CWLP	$0.04	$0.29	$0.59	$0.98	$1.46	$1.99	$2.34	$2.66	$3.25	$3.33
DECO	$0.96	$7.73	$15.64	$25.80	$38.28	$52.36	$61.44	$69.89	$85.53	$87.53
DPC	$0.10	$0.83	$1.68	$2.77	$4.11	$5.62	$6.59	$7.50	$9.17	$9.39
GRE	$0.23	$1.82	$3.69	$6.08	$9.02	$12.34	$14.48	$16.47	$20.16	$20.63
HE	$0.01	$0.06	$0.12	$0.20	$0.29	$0.40	$0.47	$0.53	$0.65	$0.67
IPL	$0.28	$2.26	$4.58	$7.55	$11.20	$15.32	$17.98	$20.45	$25.03	$25.61
MDU	$0.05	$0.39	$0.79	$1.31	$1.94	$2.65	$3.11	$3.54	$4.33	$4.44
MEC	$0.44	$3.55	$7.18	$11.84	$17.57	$24.03	$28.20	$32.07	$39.25	$40.17
MGE	$0.06	$0.51	$1.03	$1.69	$2.51	$3.43	$4.03	$4.58	$5.61	$5.74
MP	$0.19	$1.55	$3.14	$5.18	$7.69	$10.52	$12.34	$14.04	$17.18	$17.58
MPW	$0.02	$0.13	$0.26	$0.44	$0.65	$0.88	$1.04	$1.18	$1.44	$1.48
NIPS	$0.35	$2.79	$5.65	$9.32	$13.83	$18.92	$22.20	$25.25	$30.90	$31.62
NSP	$0.86	$6.91	$13.97	$23.06	$34.21	$46.80	$54.91	$62.46	$76.44	$78.23
OTP	$0.14	$1.16	$2.34	$3.86	$5.72	$7.83	$9.18	$10.45	$12.78	$13.08
SIGE	$0.14	$1.16	$2.35	$3.87	$5.74	$7.86	$9.22	$10.49	$12.83	$13.13
SIPC	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SMP	$0.03	$0.25	$0.50	$0.83	$1.23	$1.68	$1.97	$2.24	$2.74	$2.80
UPPC	$0.02	$0.17	$0.34	$0.56	$0.83	$1.14	$1.34	$1.52	$1.86	$1.90
WEC	$0.62	$4.98	$10.07	$16.61	$24.65	$33.72	$39.57	$45.00	$55.07	$56.36
WPS	$0.26	$2.09	$4.22	$6.97	$10.34	$14.15	$16.60	$18.88	$23.11	$23.65
Exports and Wheel-Throughs excluding those sinking in PJM	$0.21	$1.67	$3.38	$5.58	$8.28	$11.33	$13.29	$15.12	$18.50	$18.93
Total	$9.37	$75.58	$153.33	$253.00	$375.36	$513.46	$602.48	$685.26	$838.64	$858.29