

# 2006 Midwest ISO Transmission Expansion Plan - Load Deliverability Study Report

Information in this document compiled from the following final MTEP06 Report sections:

- 5.2.7 Load Deliverability Analysis
- 6.1.3 Central Planning Region Load Deliverability Analysis
- 6.2.3 East Planning Region Load Deliverability Analysis
- 6.3.3 West Planning Region Load Deliverability Analysis

## Load Deliverability Analysis

### Study Objective

As part of the Midwest ISO Transmission Expansion Plan 2006 (MTEP06) Baseline Reliability Study, Midwest ISO is performing a Load Deliverability study ("LD Study") for the 2006 and 2011 years. This study is intended to analyze generation adequacy and import requirements. The Loss of Load Probability (LOLP) for both the current year (2006) and the future year (2011) will be calculated. Zones that do not have sufficient imports to maintain the 1-day in 10-years reliability criteria will be identified.

### Definitions

#### **LOLE** – Loss of Load Expectation

The probability of load demand not met in a given hour. The conceptual approach shown in the background section involves plotting the load level against the composite generation capacity curve.

#### **LOLH** – Loss of Load Hours

Is the sum of LOLE over a predefined period. For example, we could sum the LOLE over the peak hours of the days, or every hour of the year.

#### **LOLP** – Loss of Load Probability

Is the sum of LOLE of daily peak hours over a certain period. In this study, the LOLP is composed of LOLE of daily peak hours for a year. LOLP is a special case of LOLH.

#### **EUE** – Expected Un-served Energy.

For one hour, it is the product of energy shortage and the probability of the shortage. It is usually calculated for all hours, summed over a year.

#### **FCITC** – First Contingency Incremental Transfer Capability

The amount of power, incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where first contingency transfer limits reach ratings of a facility.

#### **FCTTC** – First Contingency Total Transfer Capability, $FCTTC = FCITC + \text{Base Case Transfers}$

The total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two control areas of the interconnected transmission systems in a reliable manner.

#### **FOR** – Forced Outage Rate

#### **EFOR** – Equivalent Forced Outage Rate

The basic definition of forced outage rate is outage hours (less planned maintenance) divided by service hours (less planned maintenance) that covers a specific time period.

## Forced Outage Rate Equations:

### North American Electric Reliability Council (NERC) Generating Availability Data System (GADS) EFOR =

$$\frac{\text{Forced Outage Hours} + \text{Effective Forced De-rated Hours}}{\text{Forced Outage Hours} + \text{Service Hours} + \text{Effective Forced De-rated Hours during Reserve Shutdown}}$$

### Institute of Electrical and Electronics Engineers (IEEE) FOR =

$$\frac{\text{Forced Outage Hours} + \text{Maintenance Outage Hours} + \text{Maintenance Outage Extension Hours}}{(\text{Forced Outage Hours} + \text{Maintenance Outage Hours} + \text{Maintenance Outage Extension Hours} + \text{Service Hours} + \text{Reserve Shutdown Hours})}$$

### New Energy's PowerBase EFOR (the definition used in this study, five year historical data) =

$$\frac{(\text{Forced Outage Hours} + \text{Maintenance Outage Hours} + \text{Maintenance Outage Extended Hours} + \text{Equivalent Forced De-rated Hours} + \text{Equivalent Scheduled De-rated Hours} + \text{Equivalent Forced De-ration During Reserve Shutdown Hours})}{\text{Period Hours} - \text{Planned Outage Hours} - \text{Planned Outage Extension Hours}}$$

## Analysis Tools – Description & Background

This section provides a brief description and background of the tools utilized to calculate LOLP for this study. The following is a list of tools used and the vendors that support them:

NewEnergy Associates, LLC

PowerBase<sup>®</sup> – Database

PROMOD IV<sup>®</sup> – Market Simulation Software

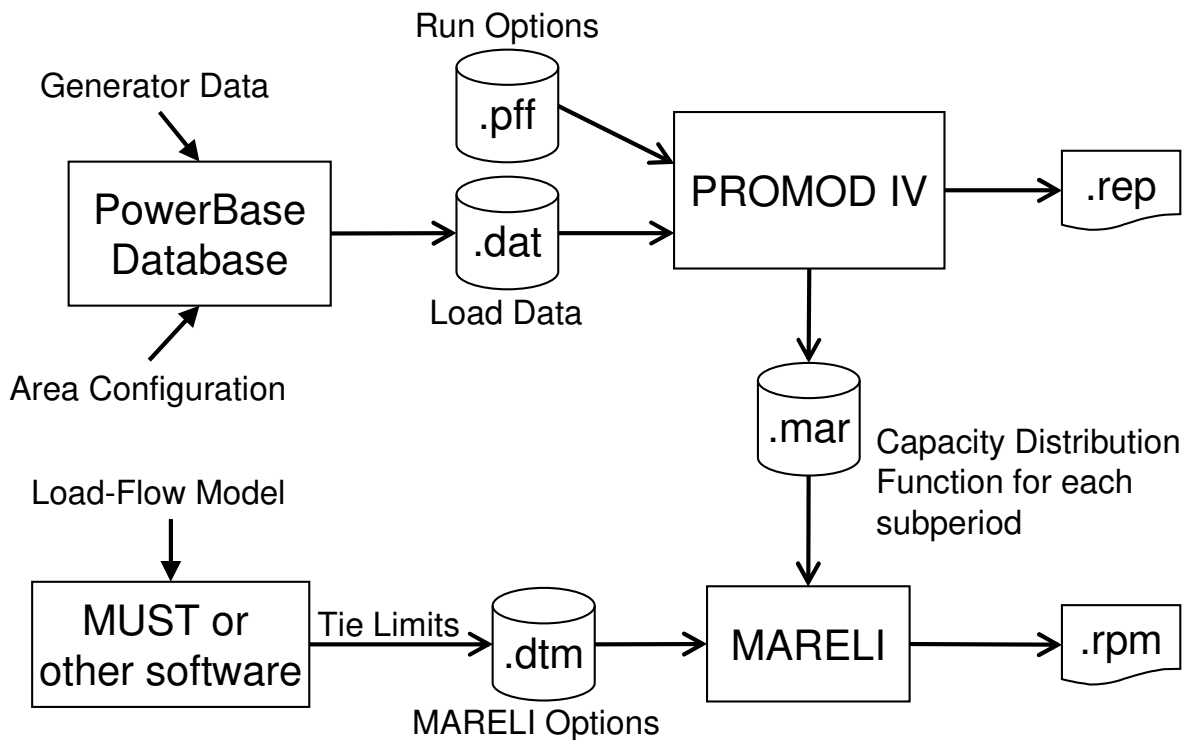
MARELI<sup>™</sup> – Multi-Area Reliability Module

Siemens Power Transmission & Distribution, Inc., Power Technologies International

PSS/MUST<sup>™</sup> – Managing and Utilizing System Transmission

Generator data like unit capacity, forced outage rates, commission dates, retirement dates and other data is stored in the PowerBase (“PB”) database. PowerBase is the database for all NewEnergy Associates (“NEA”) software tools like PROMOD, Strategist, MARELI and MarketPower software tools. The intended study area is specified in the area filter. When the data from PowerBase database is translated into PROMOD it creates a dataset. This dataset contains capacity curves for all the generators in the study area among other generator and load data. (What is the other data that gets translated?) This dataset helps create a binary file (.mar extension) when PROMOD APD module is run. There are 2 modules within PROMOD. One is the Analytic Probabilistic Distribution (APD) module, which is an hourly probabilistic solution. It has a hub and spoke type transmission model. The second module is called Hourly Monte Carlo (HMC), which is an hourly deterministic dispatch type solution.

MARELI program utilizes the APD module within PROMOD. HMC module with full transmission model is utilized for detailed transmission studies. MARELI program takes the Capacity Distribution Function data from PROMOD (.mar file) as an input along with tie line values from MUST in the form of a .dtm file, and calculates LOLP, LOLH, and EUE values as shown in Figure 1. In MARELI there are two loss sharing options: no loss sharing and full loss sharing. For the purpose of this study, the no loss sharing option was selected wherein a LOLE zone A will support a LOLE zone B only when zone A has surplus capacity. A full loss sharing option will distribute the deficiency of zone B such that zone B's LOLP will be same as pool LOLP.

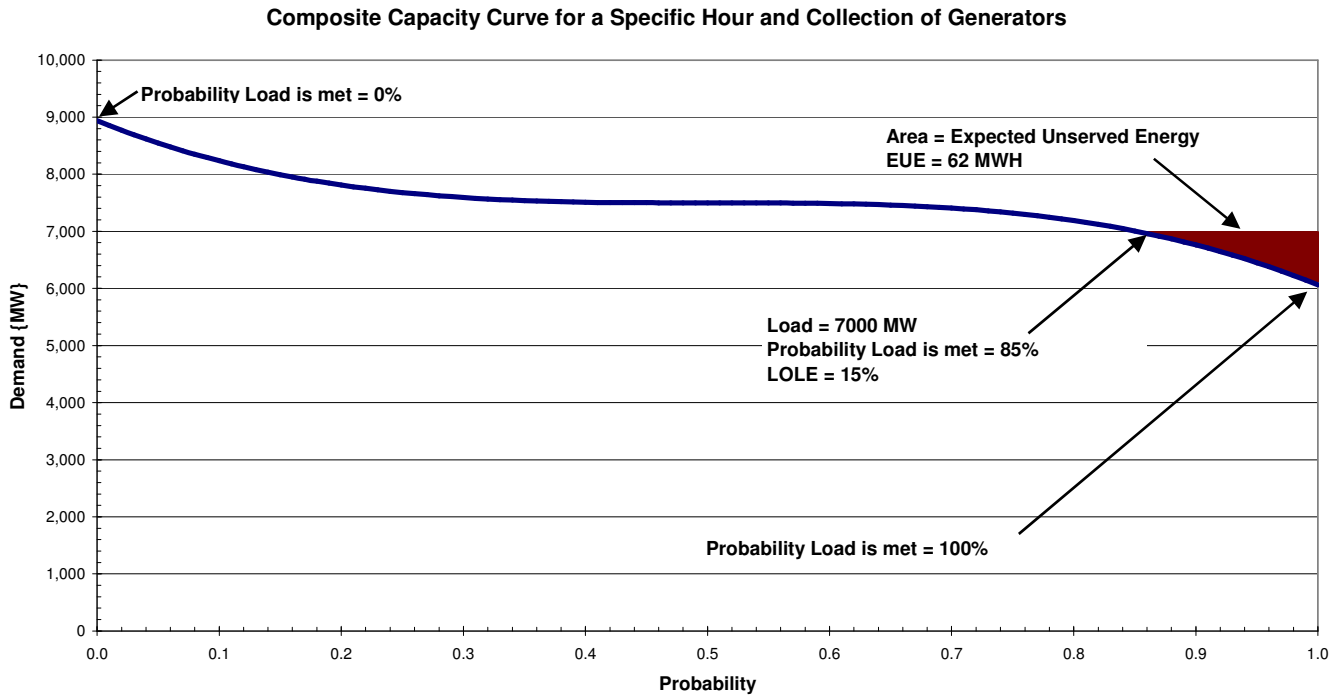


**Figure 1: Flowchart of Analysis Tools**

MARELI creates a composite capacity curve using the generators' Maximum Capacities and Forced Outage Rates within an area. The composite capacity curve is a probabilistic function that the total capacity of the collection of generators is greater than a certain demand MW (y-axis in figure 2). For a specific hour, figure 2 shows the composite capacity curve for a collection of generators. If in the same hour, the load to be served by this collection of generators is 9000 MW or more, the Loss of Load Expectation (LOLE) for this hour is 1, i.e. load will not be met for this hour. If the load is less than 6000 MW, then the LOLE is 0. If the load is 7000 MW, then the LOLE is 0.15 (1-0.85, as read from the graph).

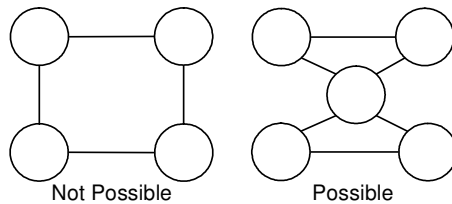
The Expected Un-served Energy (EUE) is the product of the MW shortage and the probability that it is short. Using an example of 7000 MW load, the EUE is the area of the little area to the right of the 0.85 probability point under 7000 MW, or approximately 62 MWH (for this hour).

Variations of this include how many hours to run during a year, unit maintenance scheduling (deterministic vs. duration), or using load duration curve as opposed to hourly load, etc. In some implementations, inter-area transfers can be modeled so surplus of one area can be used to increase reliability of the other area, limited by transfer capability. In most commercial implementations today, it is difficult to capture the full transmission network with individual line impedances. The transfer capability referred here is a hub-and-spoke model within the LOLE study, although the tie capacities are obtained using a full network analysis under first contingency in this study.



**Figure 2: Composite Capacity Curve**

In MARELI, the configuration of multi-area ties is limited to no more than three node loops. As shown in figure 3, MARELI is not intended for detailed transmission studies.



**Figure 3: MARELI Limitation**

## Data Assumptions

### Models

For the current year LOLP analysis, the 2006 MISO Series, 2006 Summer Peak Load-Flow model is being utilized in conjunction with the PowerBase dataset. This model was built by Midwest ISO staff from the 2005 NERC MMWG series models and has undergone a review process by the Midwest ISO Model Building Working Group (MBWG) stakeholder group. The review from participating member's included validation of: transmission detail, control area loads, generator capacity and area transfers. Based on the 2006 Summer Peak Load-Flow model, 2006 PROMOD and PowerBase models are developed.

For the future year analysis there were two MTEP06 2011 Summer Peak Baseline Reliability Plan (Phase 2) Load-Flow models developed. The models only differed in the way that generation was dispatched to meet load. The contractual dispatch model contains a traditional transmission owner (TO), NERC MMWG type dispatch. The MISO-Wide dispatch model contains economic

dispatch of generators. The contractual dispatch case was used for the 2011 import limits analysis because of modeling only firm transactions. The MTEP Baseline Reliability Plan models were reviewed by the Regional Study Groups (RSG) and Expansion Planning Working Group (EPWG). The 2011 contractual dispatch load-flow model has been mapped and linked to the PowerBase database.

### **Generator Data**

Generator data, like max capacity and retirement dates, unless otherwise specified in this document is from the default information provided in PowerBase database. The source for that information is Platts NewGen database, EIA 411 reports and other public information. Future generators are checked with the Midwest ISO Generator Inter-Connection Queue for inclusion in the model.

The calculation for LOLP is highly dependent on the FORs of the generators that make up the study regions. An extra step was taken to ensure that the FORs used were accurate. Generator owners were asked to review the FORs included in the PowerBase database. The original source for this information was NERC GADS data. Any generator data provided to Midwest ISO for inclusion in this study is deemed confidential. The method of calculating FOR used for this study is consistent with the method used in PowerBase, which is calculated using five years historical data. The current database contains FOR calculated from NERC GADS data covering periods 1999-2003.

All non-nuclear generator maintenance schedules are determined by the PROMOD automatic maintenance scheduler function. PROMOD optimizes maintenance schedules based on maintenance requirements and overall system reliability. This is a “best case” scenario compared to the loosely coordinated unit maintenance scheduling currently in practice. PROMOD avoids scheduling generator maintenance when loss of load expectation is high. Nuclear generator maintenance schedules are pre-determined based on Nuclear Regulatory Commission (NRC) data and not automatically scheduled.

### **Load Data**

Load data for this study comes from the load-flow models described previously in the models section. This data is also compared against the peak load data of PowerBase default database. The original source for both load data sets is FERC 714 filings. The PowerBase hourly load shapes were based off 2002 hourly load profiles.

### **DC Line Outages**

In the Northern Midwest Reliability Organization (MRO) region, couple of units are behind long DC transmission lines. Forced outage of the DC line will cause the unit to reduce generation or trip. Hence default FOR values for these generators in the database were changed.

- A. For Manitoba Hydro (MH) units of Limestone, Long Spruce and Kettle, the default FOR values were increased by 0.356%.
- B. For the Coal Creek units 1 and 2 in Great River Energy (GRE) area, 0.9% was added to their default FOR values. Also based on GRE's comments, both the units were de-rated by 7% to reflect peak capacity loss over the outlet lines. The new lower ratings for Coal Creek units 1 and 2 are 506 MW and 512 MW respectively.

- C. The following changes were made to the Milton R. Young units in Minnkota Power Cooperative, Inc. (MPC) area:
- For 2006, Unit 2 was de-rated to 455 MW, since Unit 2 is a jointly owned unit it was split 156 MW for MPC and 299 MW for Minnesota Power (MP)
  - For 2011, Unit 2 was de-rated to 455 MW and split accordingly to 50/50 joint ownership between MPC and MP starting in 2009.

## **Wind Capacity**

For wind units, which are largely energy resources, only a portion of their maximum generation is considered capacity. Hence wind units in the study were capacity rated as 15% for summer months (May through Sep) and 20% for winter months (Oct thru April). The capacity for wind in Manitoba is 0 MW at winter peak because the wind turbines are designed to shut down below -30C temperatures. These percentages were based on member comments from MTEP 05 and are consistent with MRO study methodology.

## **Methodology**

The following is a brief summary of the study methodology and the subsequent sections will explain in more detail the ideas presented here and tool options selected.

First using MARELI, LOLPs were calculated on a stand-alone basis, ignoring transmission interconnection ties. Zones not meeting the 1-day in 10-years reliability criteria were identified. Next using MUST software tool First Contingency Incremental Transfer Capability (FCITC) was calculated for all the study zones. The FCITCs were added to the base case imports to arrive at the First Contingency Total Transfer Capability (FCTTCs). Lastly a second MARELI run was conducted with the tie limits modeled in a multi-area mode of MARELI software tool. This final step is to verify the zones that did not meet the criteria on a stand-alone basis will meet the criteria with the added tie line support, and the zones providing support still meet the criteria as well.

## **Study Area Definition**

The following area configuration is studied in this analysis. Zones studied here are based on individual balancing authorities (control areas), transmission companies, and NERC regional boundaries. These zones were derived from the Capacity Benefit Margin (CBM) zonal definitions and are similar to the MTEP05 zones. Reserve margin requirements were not a factor on the formation of these study zones.

## Study Zone Definition

### Internal Areas

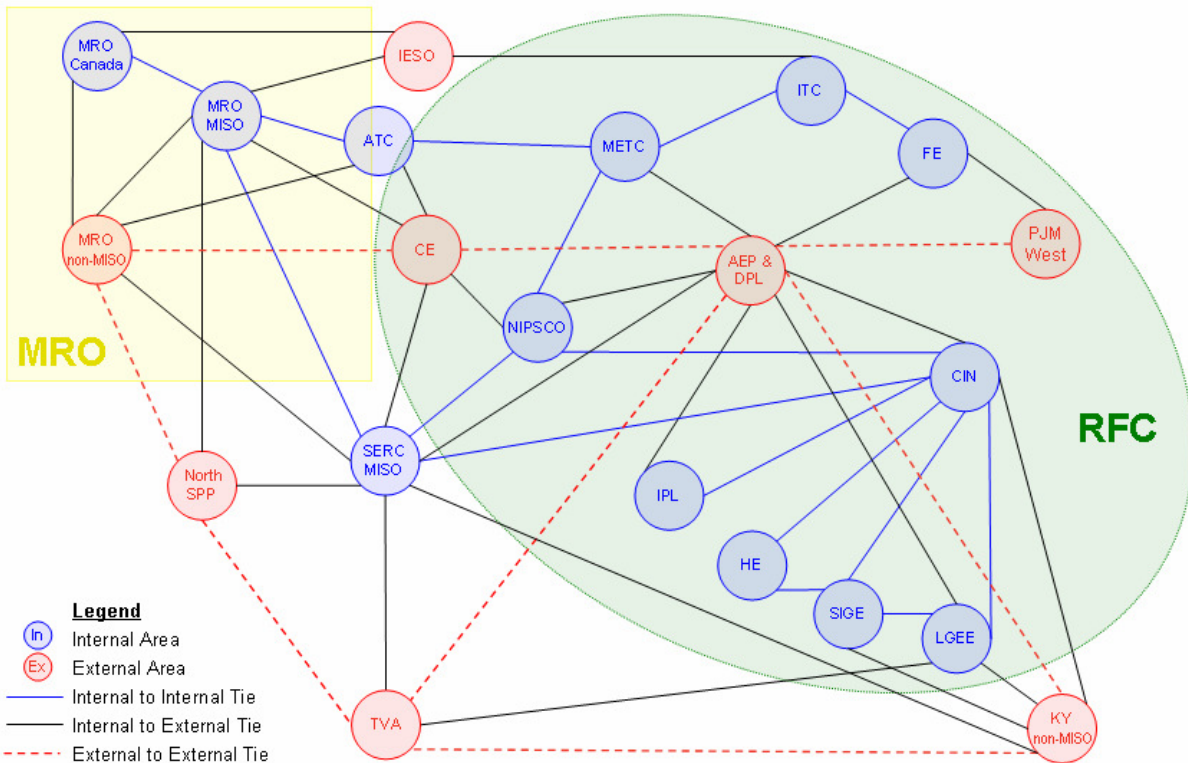
MRO-MISO	ALTW, GRE, MDU, MPL, NSP, OTP & SMMP
MRO-Canada	Manitoba Hydro(MH) & Saskatchewan Power(SASK)
ATC	American Transmission Company (ALTE, MGE, UPPCO, WE, WPPI & WPS)
SERC-MISO	AMRN(CIPS & AUPE), CILCO, CWLP, ILPC & SIPC
NIPSCO	Northern Indiana Public Service Co.
METC	Michigan Electric Transmission Company (CEC, LBWL & WPSC)
ITC	International Transmission Company (DETED)
FE	FirstEnergy Corp.
CIN	Cinergy Services, Inc. (CGE & PSI)
IP&L	Indianapolis Power & Light Co.
HE	Hoosier Energy Rural Electric Coop, Inc.
SIGE	Southern Indiana Gas & Electric Co. (Vectren)
LG&E	Louisville Gas & Electric Co.

### External Areas

MRO-NonMISO	DPC, LES, MIDAM, MPW, NPPD, OPPD & WAPA
COED	Commonwealth Edison Co.
AEP-&-DPL	American Electric Power, Dayton Power & Light & Ohio Valley Electric Corp.
NorthSPP-&-AECI	AECI, EES, KCPL, MIPU & SWPA
Kentucky-NonMISO	Big Rivers Electric Corp.(BREC) & East Kentucky Power Coop, Inc.(EKPC)
PJM-West	Allegheny Energy, Duquesne Light, GPU Corp. WEST & PPL Electric Utilities
TVA	Tennessee Valley Authority
IESO	Independent Electricity System Operator (ONHY)

### Ties taken from 2006 Summer MISO Model

- note: Ties outside study area are not shown



Study Zone Configuration

### Internal Zone Reserve Margins<sup>(1)</sup>

Zone	2006 Max Capacity(MW) <sup>(2)</sup>	2006 Peak Load(MW)	2006 Reserve Margin (%)	2011 Max Capacity(MW) <sup>(2)</sup>	2011 Peak Load(MW)	2011 Reserve Margin (%)
MRO-MISO	21,153	20,670	2.3%	23,863	22,536	5.9%
MRO-Canada	9,074	6,925	31.0%	9,546	7,290	30.9%
ATC	15,804	14,008	12.8%	18,309	15,566	17.6%
SERC-MISO	25,353	18,074	40.3%	26,324	19,295	36.4%
NIPSCO	3,438	3,058	12.4%	3,438	3,767	-8.7%
METC	13,744	10,965	25.3%	13,744	12,663	8.5%
ITC	12,985	12,896	0.7%	12,818	14,125	-9.3%
FE	13,836	14,161	-2.3%	14,073	15,323	-8.2%
CIN	14,729	11,946	23.3%	14,729	12,212	20.6%
IP&L	3,519	3,145	11.9%	3,677	3,349	9.8%
HE	1,775	1,207	47.0%	1,863	1,354	37.6%
SIGE	2,133	1,926	10.7%	2,091	1,998	4.7%
LG&E	9,032	6,680	35.2%	9,764	7,496	30.3%

### Internal Zone Reserve Margins<sup>(1)</sup>

(1) Calculation includes only zone's installed internal capacity with no outside purchase or sale transactions

(2) Includes interruptible load

### Stand-Alone LOLP Analysis

The first step is to run MARELI for the full study year to calculate stand-alone LOLPs for the selected zones. There were no transmission interconnection ties modeled between any regions, so every study zone was its own island. This step is performed to identify those zones that need imports to meet the 1-day in 10-years reliability criteria and those zones that do not. Also, MARELI reports the time of the expected lost of load. These MARELI results were then carried forward to the next step of the study.

The options selected for the MARELI analysis are as follows:

#### Loss Sharing Option

By default MARELI assumes both surpluses and deficiencies can be shared among areas. For this study the **No Loss Sharing** option was selected. Only surpluses can be shared when tie and transfer limits permit.

#### LOLP or LOLH Calculation

By default, every hour's load is used to calculate LOLH. **Daily peak load hours** are selected to calculate LOLP. Selecting this option, results in a faster run time without sacrificing any accuracy, since peak loads contribute the most to an area's inability to meet load.

#### Peak Load Definition

The LOLP calculation is dependent on the definition of peak load. By default all the combined peak load of all areas is used. Alternatively the individual area's peak load can be selected for the calculation, as was done for this study. This requires individual MARELI runs for all internal study areas, as their peak load definition is used to calculate their own LOLE. External and internal areas not tied to the reference area can be skipped during the LOLP calculation to increase run time. This method is more significant to the individual areas because a LOLE calculated during a non-peak hour for an area (but a peak hour for the system) is less significant than a LOLE calculated during the area's peak load hour.

## Transfer Analysis

The next step after finding which study zones (sinks) need additional capacity to meet the 1-day in 10-years reliability criteria was to calculate the import capabilities. The transfer between the source and sink was tested using FCTTC analysis. Any zones having an import capability of less than their needed amount calculated during the Stand-Alone LOLP Analysis were identified.

### Source Zone Selection

All first tier neighboring zones to the sink zone were first chosen as the source. All source zones were combined into one subsystem and then MUST transfer analysis was performed. For those zones where a first tier source system was unreasonable, a larger full study region source was used. The calculated transfer limit was then divided amongst the neighboring zones based on tie line connectivity as described in the FCTTC Calculation section below.

### MUST Analysis – FCTTC Calculation

The FCITC was calculated between the sink and source/s. This value added to the base transfers provided the FCTTC, which was the transfer limitation the sink zone can import. In the cases where more than one source zone was needed, the sources were combined into one subsystem to capture the effects for all transfers simultaneously. Then the calculated transfer limit was then divided among the sources based on the tie line connectivity between the source and sink zone. These multiple transfer limits were then carried on into the last step where multi-zone LOLP analysis with import support is performed.

The following is an example of how tie line connectivity to multiple source zones is tabulated:

- 115 kV (3 ties) assigned a value of 1
- 345 kV (each) assigned a value of 2
- 500 kV (each) assigned a value of 4
- 765 kV (each) assigned a value of 8

The ratio of these relative values is used to determine the ratio of transfer into the sink zone from the multiple source zones. For example, if zone A has two 345kV lines from the zone B and four 345 kV lines from the zone C, the ratio of the simultaneous transfer will be 33.3% from zone B and 66.7% from zone C. In the case where no 345kV line exists, but at least three 115 kV lines exists between those two areas, a value of 1 will be assigned.

The options and inputs selected for the MUST analysis are as follows:

- Outage Transfer Distribution Factor (OTDF) cutoff was 3%.
- Contingency and the monitored elements lists are identical to those modeled in the baseline study. NERC Category B outages were modeled.

### Scaling Methodology

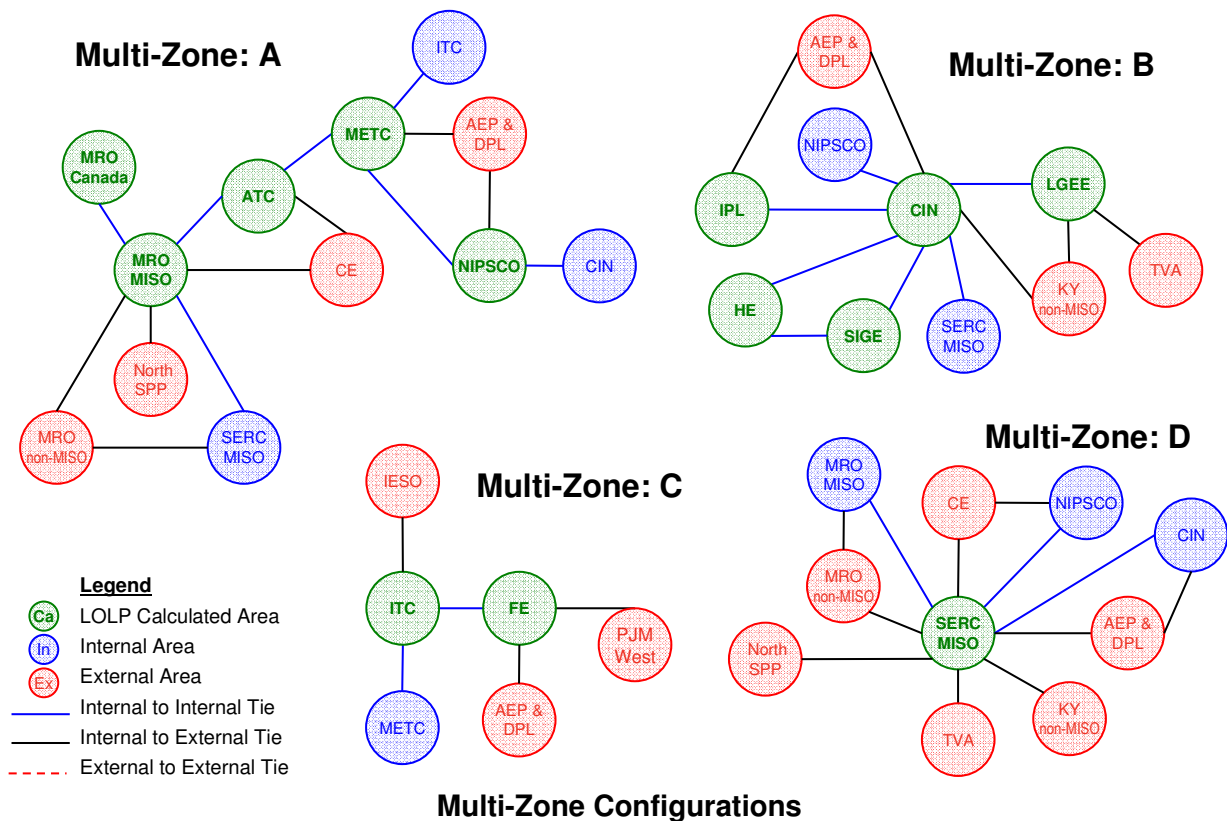
- Reduce generation in sink zone
- Increase generation in source zone until the maximum value of each generator is reached, then reduce load in source zone

## Multi-Zone LOLP Analysis with Import Capabilities modeled

The last step was to run MARELI for the full study year a final time to check if those zones that did not meet the 1-day in 10-years reliability criteria on a stand-alone basis (without transmission interconnections), do in fact meet the criteria with the import capability values calculated in MUST. Various support configurations were utilized where the deficient zones found in the first step were modeled tied to their perspective sources found in the second step. This allowed them to lean on their tie lines for support during the times when internal generation is not available to meet load. The multi-zone support configurations determined during this study process tried to accurately replicate real world topology while working around the MARELI limitation of area tie loops of no more than three nodes. The zones that did meet the criteria in the stand-alone analysis were also checked to verify they still maintain reliability while providing support. From the multi-zone analysis any zone with a LOLP greater than the 1-day in 10-years reliability criteria was identified.

The MARELI options selected for this step that differ from those used in the first step are:

- The use of multi-zone support configurations with the inclusion of calculated tie limits.
- Peak Load Definition based on the combined multi-zone configuration in the various MARELI runs as opposed to the individual zone peak load definitions used in the Stand-Alone runs.



## **Sensitivities**

The following is a list of the study sensitivities that were examined using the MARELI software.

Load Change: A load change of plus and minus 5% for the 2011 study year was conducted. This was considered to identify differences due to load forecast assumptions.

FOR Change: A 10% forced outage rate was used for all nuclear and fossil fuel generating units for the 2011 study year. This sensitivity was modeled to test the effects of using the same force outage rate on all units. A FOR of 10% was chosen because it is slightly higher than the system average of 7%.

## Central Planning Region Load Deliverability Analysis

The load deliverability study zones that make up the Central region and are referred to in the result tables of this section include:

CIN: Cinergy Services, Inc. (Duke Energy Indiana) {includes PSI Energy and Cincinnati Gas & Electric}  
 HE: Hoosier Energy Rural Electric Coop, Inc.  
 IP&L: Indianapolis Power & Light Co  
 SERC-MISO: Ameren (including its operating companies of AmerenCIPS, Ameren CILCO, AmerenIP, and AmerenUE)  
 CWLP: City Water Light & Power (Springfield, IL)  
 CWLD: Columbia (MO) Water & Light Department  
 SIPC: Southern Illinois Power Coop  
 SIGE: Southern Indiana Gas & Electric Co. (Vectren)

This Load Deliverability analysis was performed on the 2006 Summer Peak model and the 2011 Summer Peak Baseline Reliability Plan Contractual Dispatch Phase 2 model. The results are tabulated below.

**2006 - Load Deliverability Results Table**

Zone	Stand-Alone		Import Capability {MW} (+ Import) (- Export)			Multi-Zone LOLP {days/year}
	LOLP {days/year}	Needed Support {MW} for LOLP = 0.1	Base	FCITC	FCTTC	
CIN	0.15	132	-195	8,068	7,873	0.00
HE	5.76	527	-928	1,468	539	0.02
IP&L	3.68	677	-49	854	805	0.02
LG&E	0.02					0.00
SERC-MISO	0.00					0.00
SIGE	16.14	625	109	296	405	0.31
<b>LOLP &gt; 1 Day in 10 Years {or 0.1 Day in 1 Year}</b>		<b>Import Capability less than Needed Support</b>				

**2011 - Load Deliverability Results Table**

Zone	Stand-Alone		Import Capability {MW} (+ Import) (- Export)			Multi-Zone LOLP {days/year}
	LOLP {days/year}	Needed Support {MW} for LOLP = 0.1	Base	FCITC	FCTTC	
CIN	0.39	416	-82	3,605	3,523	0.00
HE	7.23	586	-1,184	1,795	611	0.01
IP&L	4.55	725	44	218	262	1.25
LG&E	0.06					0.00
SERC-MISO	0.00					0.00
SIGE*	32.61	746	204	257	461	0.52
<b>LOLP &gt; 1 Day in 10 Years {or 0.1 Day in 1 Year}</b>		<b>Import Capability less than Needed Support</b>				

\* Results for 2011 BRP CD Phase 2 model without Planned transmission upgrades in SIGE

**2011 Stand-Alone Sensitivities Table**

Zone	(-) minus 5% Load Change		(+) plus 5% Load Change		10% Forced Outage Rate	
	LOLP {days/year}	Support {MW} for LOLP = 0.1	LOLP {days/year}	Support {MW} for LOLP = 0.1	LOLP {days/year}	Support {MW} for LOLP = 0.1
CIN	0.05		2.11	1,026	2.37	1,151
HE	4.71	518	10.71	653	10.36	632
IP&L	2.37	558	10.54	893	22.80	1,255
LG&E	0.01		0.26	250	0.35	342
SERC-MISO	0.00		0.00		0.00	
SIGE*	22.12	675	48.41	816	56.15	911

\* Results for 2011 BRP CD Phase 2 model without Planned transmission upgrades in SIGE

• The sensitivity cases are studied to see the margin of load deliverability requirement.

### Central Study Region - Load Deliverability Assessment

For the IP&L during the 2011 analysis it was shown that the first-contingency import transfer limit wasn't enough to meet the amount of imports required to get a LOLP of less than 1 day in 10 years. This remained unchanged with a 5% decrease in load sensitivity for 2011.

The IP&L system is expected to meet the 2011 Contractual Dispatch import capability LOLP of one day in ten years by IP&L facility rating changes. The main IP&L facilities limiting the IP&L 2011 import capability LOLP are the Hanna-Southeast 138KV transmission line and various 345/138KV autotransformers. The Hanna-Southeast 138KV transmission line limitation was removed in September, 2006 when the rating was changed from 286MVA to 350MVA. A 138KV breaker in that line failed during a major storm event and was replaced. The ratings of the IP&L 345/138KV autotransformers have been under review and changes are expected in the next MTEP cycle. In addition, IP&L import capability is higher when the majority comes from AEP resources in PJM rather than when the bulk of the imports come from Midwest ISO resources shown in the table.

The sensitivity analysis shows that for the study zone HE with a 5% increase in load or 10% generator forced outage rate, the imports needed to meet the criteria would be greater than the calculated import capability.

For 2006, only the SIGE zone is deficient in LOLP. The 2011 results show that the SIGE and IP&L zones are deficient. Transmission upgrades described bellow address the SIGE LOLP needs.

This grouping of projects in the Vectren area provide for the 625 MW of import capability needed by Vectren as demonstrated in the LOLP analysis for 2006 and beyond. As the system changes, this import need is expected to be 746 MW by 2011. Vectren has an internal generation capability of 1944 MW in 2006, provided by 16 units at 6 separate sites. The probabilistic import need of 625 MW correlates to a generation outage on a one day in ten year basis of about 781 MW or about 35% of the Vectren capacity. This level of outage could be sustained with loss of the three largest units in the Vectren system.

The Vectren system is surrounded by 345 kV to the north on the Duke Energy system, and to the south on non-Midwest ISO systems and is located electrically between a large quantity of 345 kV generation and load points. There is about 7,000 MW of generation on these 345 kV systems in the vicinity (Gibson 3200 MW, Petersburg 1687 MW, Edwardsport 740 MW, and Merom 1382

MW) that contributes to loading of the underlying 138 kV system of Vectren during line contingencies involving the area 345 kV system. This contributes to heavy loading of the Vectren system and inability under first contingency conditions to import during times of generation deficiencies within the Vectren system, as needed to meet loss of load probability targets. Projects needed to resolve these issues are described below.

#### Francisco 345/138 kV Substation

The project (PrjID 1004) is a newly constructed 345/138 kV substation scheduled for 2007. It is needed to help Vectren to achieve the required import capability to maintain an LOLP within criteria. Without the project, the import transfer capability will be limited to 444 MW by the Duff 345/138 kV transformer constraint for the contingent loss of the Ramsey – Duff 345kV line. The new construction increases the transfer capability to 473 MW but doesn't achieve the desired 625 MW transfer needed for LOLP criteria.

#### Dubois – Newtonville 138kV Line

The 2007 Project (PrjID 1259) is a newly constructed 138kV line from the existing Dubois 138kV Substation to the existing Newtonville 138kV Substation. This new construction relieves the Cully – Dubois 138kV 101% constraint for 473 MW of transfers into the Vectren system. The increase in transfer capability is due to an additional North to South flow path. This project along with the aforementioned PrjID 1004 contribute to an increase in import capability but doesn't achieve the required 625MW.

#### Northeast – Oak Grove – Culley 138 kV Line

The project (PrjID 1002) is to construct a new line from Culley 138 kV Sub to Northeast 138 kV Sub by 2009. The project also relieves the Culley – Grimm 138kV transfer constraint. The constraint occurs at a transfer level of 480MW for the contingent loss of the Culley – Castle 138kV line. After the completion of this line the import capability is 684 MW in 2009. In addition, this new construction is needed in 2009 to accommodate load growth in the Burkhardt, I-162, and Epworth Road areas, according to Vectren.

#### Gibson – AB Brown – Reid 345 kV Line

The project (PrjID 1257) is to construct a new 345 kV Substation at AB Brown along with ties to Gibson (Duke) and Reid (BREC). The new construction increases the Vectren import capability in 2011 from 386 MW to 736 MW by relieving the 100.2% overload on Gibson – Francisco for the loss of the Edwardsport – Amo 345 kV line. The import capability in 2011 is 386 MW prior to the projects due to the addition of approximately 600 MW of generation at Edwardsport generating station. The loading is relieved because the projects provide another needed outlet for the 3200 MW of generation flowing from the Gibson units.

## East Planning Region Load Deliverability Analysis

This section describes the results of the load deliverability analysis performed on 2006 summer peak and 2011 summer peak BRP Phase 2 models. The load deliverability study zones that make up the East region appearing in the result tables of this section include:

FE - FirstEnergy Corp.

ITC - International Transmission Company

METC - Michigan Electric Transmission Company

NIPSCO - NiSource (Northern Indiana Public Service Company)

### 2006 - Load Deliverability Results Table

Zone	Stand-Alone		Import Capability {MW} (+ Import) (- Export)			Multi-Zone LOLP {days/year}
	LOLP {days/year}	Needed Support {MW} for LOLP = 0.1	Base	FCITC	FCTTC	
FE	25.19	3,242	1,719	3,060	4,779	0.00
ITC	16.98	2,830	1,668	1,285	2,954	0.05
METC	0.04					0.00
NIPSCO	19.12	1,176	418	2,078	2,497	0.00
LOLP > 1 Day in 10 Years {or 0.1 Day in 1 Year}		Import Capability less than Needed Support				

### 2011 - Load Deliverability Results Table

Zone	Stand-Alone		Import Capability {MW} (+ Import) (- Export)			Multi-Zone LOLP {days/year}
	LOLP {days/year}	Needed Support {MW} for LOLP = 0.1	Base	FCITC	FCTTC	
FE	46.55	4,261	2,066	2,185	4,250	0.09
ITC (1)	27.99	4,092	-160	3,147	2,987	1.84
METC	3.15	1,435	-441	3,290	2,849	0.06
NIPSCO	130.67	1,898	409	2,035	2,444	0.00
LOLP > 1 Day in 10 Years {or 0.1 Day in 1 Year}		Import Capability less than Needed Support				

(1) Preliminary results with most current information show ITC with 2,917 MW of need and 2,400 MW of import capability

### 2011 Stand-Alone Sensitivities Table

Zone	(-) minus 5% Load Change		(+) plus 5% Load Change		10% Forced Outage Rate	
	LOLP {days/year}	Support {MW} for LOLP = 0.1	LOLP {days/year}	Support {MW} for LOLP = 0.1	LOLP {days/year}	Support {MW} for LOLP = 0.1
FE	25.53	3,495	81.96	5,027	79.75	5,183
ITC	21.65	3,386	35.58	4,798	37.14	4,957
METC	0.81	803	8.89	2,069	8.27	2,339
NIPSCO	89.16	1,709	180.83	2,086	158.97	2,154

## East Study Region - Load Deliverability Result Assessment

For 2006, all east study zones demonstrate the ability meet the less than 1 day in 10 years loss of load probability with import capability.

For 2011, the study zone FE meets the reliability criteria marginally. The multi-zone LOLP indicates that the first-contingency import capability is sufficient enough to achieve a less than 1 day in 10 years loss of load probability, but this can be misleading. The stand-alone values were calculated with the FE peak definition while the multi-zone values were calculated based on the combined peak definition. However peak hours of the individual zone when LOLP is calculated do not occur at the same time as the combined multi-zone configuration. The sensitivity analysis shows that for the study zone FE with a 5% decrease in load for 2011 the first-contingency total transfer capability is greater than the needed amount to meet criteria.

For zone ITC during the 2011 analysis it was shown that the first contingency import transfer limit was insufficient to meet the level of imports required to get a LOLP of less than 1 day in 10 years. This result remained unchanged with a 5% decrease in load sensitivity for 2011.

For METC the multi-zone LOLP indicates that the neighboring zones do not have surplus capacity to share even though the first-contingency total transfer capability (FCTTC) is greater than amount needed. Zones only support their neighbors during hours when their LOLP is within the target.

The sensitivity analysis shows that for the study zone METC with a 5% increase in load or 10% generator forced outage rate the amount needed to meet the criteria would be greater than the calculated import capability.

Note that the 2011 results were calculated with the original MTEP 06 load forecast. Currently additional 2011 load deliverability analysis is being conducted with an updated Michigan load forecast. These new reduced load forecast assumptions should lead a to lower amount of needed support to maintain the less than 1 day in 10 years loss of load probability criteria as the 5% load decrease sensitivity suggests. Preliminary results of the revised LOLP analysis for the ITC zone indicate that there is about 500 MW import deficiency in 2011 for the ITC zone. Proposed ITC projects, some of which address this deficiency are listed bellow.

### Stephens - Erin 120 kV line #3 (Project ID: 586, 12/2007, \$34 million)

This was a proposed project in MTEP05. The project constructs a new 120 kV underground cable from Stephens to Erin (circuit 3).

It relieves severe overloads of circuits in the Erin loop for the common tower failure of Erin-Stephens 1 and 2. It thereby reduces the risk of dumping 300+ MW of load for a single outage. It helps relieve 154% overload on Beck to Medina and 148% overload on Beck to Stephens 120 kV lines for category C contingencies.

### Majestic 345/120 kV switching station (Project ID: 686, 12/2007, \$13 million)

This was a proposed project in MTEP05. The project involves creating a Majestic-Madrid 120 kV circuit by un-six wiring the existing Majestic-Madrid 345 kV circuit and connecting the available conductor to a new 120 kV bus and position off the Madrid 120 kV bus and the new 120 kV substation via a 345/120 kV transformer at Majestic station.

Madrid 345-120 #1 transformer overloads to 101% of its emergency rating for loss of Cody to Nolan 120 kV line (NERC Category B contingency). The project also helps solve existing pre and post contingency voltage violations in the Genoa 120 kV area when transferring more than 1500 MW from METC to ITC at peak conditions. The loss of the Madrid 345/120 kV transformer causes the Genoa area voltages to fall to 0.9 p.u. The project also adds 600 MW of transfer capability on the METC-ITC interface at peak.

Bismarck-Troy 345 (Project ID: 692, 12/2009, \$150 million)

This was a proposed project in MTEP05. The project involves building a new 13.94 mile 345 kV line (2.3 overhead and 11.64 underground) from Troy from to Bismarck connected to the Troy 120 kV by a 300/400/500 MVA 345 / 120 kV transformer.

It relieves 101% overload on Pontiac transformer in base and N-1 conditions, 102% overload on Lincoln-Northeast-Northwest 120 kV line for category B contingency and 104% overload on Bloomfield to Auburn Heights 120 kV line for a number of category B contingencies. In addition, ITC determined 113% overload on Lincoln-Northeast-Northwest 120 kV line for category B contingencies, 104% overload on Bloomfield Northeast to Pluto 120 kV line for a category B contingency and 128% overload on Lincoln-Northeast-Northwest 120 kV line for category C3 contingency.

Marysville Decommissioning (Project ID: 905, 12/2006)

The project decommissions Marysville Station, expands Bunce Creek Station creating new Bunce Creek - Cypress, Bunce Creek - Menlo, Bunce Creek - Wabash 2 120 kV lines. It allows for the removal of Marysville Station and its associated equipment from the ITC system as the station and power plant are planned to be shutdown. It also allows for the interconnection of 2 distribution transformers at Bunce Creek to replace capacity

Coventry Station Upgrade (Project ID: 910, 12/2007)

The project involves building a new 230 kV line from Coventry-Cody 230 kV, new 345/230 kV transformer at Coventry along with a 230/120 kV transformer at Cody and expansion of the Coventry 345 kV station. ITC's Import requirement for 2011 year is 2917. ITC's import capability without this project is 2381, deficient in 2011 by 536 MW. With the reconductoring of two First Energy lines (Naomi to Richland and Richland to Ridgeville – Proposed Project ID: 1383) and addition of the Coventry project, ITC's import capability goes up to 3221 MW, meeting its import requirement for 2011. Project verification was conducted using the revised reduced Michigan load forecast.

Goodison Station (Project ID: 907, 12/2009, \$50 million)

This was a proposed project in MTEP05. The project involves building Goodison 345 kV Station by splitting the existing 345 kV line from Belle River to Goodison to create Belle River-Goodison 345 kV and Pontiac-Goodison 345 kV, a new 345/120 kV Goodison transformer and a new Pontiac-Goodison 120 kV line. Project also involves splitting the existing 120 kV line from Sunbird to Tienken to Sunbird to Goodison and Goodison to Tienken and a line from Tienken to Spokane.

The project relieves 111% overload on Bloomfield – Hamlin 120 kV under Category C3 conditions (Addition of Pontiac to Goodison 120 kV line, splitting Sunbird - Tienken 120 kV line to Sunbird - Goodison and Goodison - Tienken lines and Tienken-Spokane 120 line help redirect flow on the 120 kV lines south of Pontiac via Sunbird, Tienken and Spokane thereby relieving overload on Bloomfield – Hamlin 120 kV line). The project also helps relieve loading on the heavily loaded Pontiac 345/120 kV transformers that are close to 100% of emergency rating one for loss of the other (Instead of adding additional transformation at Pontiac and further loading the 120 kV lines

south of Pontiac, addition of 345 / 120 kV transformer at Goodison, adding a line from Pontiac to Goodison 120 kV line and splitting Sunbird to Tienken 120 kV line to Sunbird – Goodison and Goodison to Tienken not only helps relieve overload on the Pontiac transformer but also helps relieve loading on Pontiac to Sunbird 120 kV line by providing a new source of flow from Goodison 120 kV station to Sunbird). This project also provides 120 kV source for a new distribution substation interconnection request that relieves distribution overloads and 40 kV sub transmission overloads (The Goodison 120 kV station provides an interconnection point for a new 120/13.2 and 120/41.6 kV distribution substation, requested by DTE. In absence of Goodison 120 kV station, DTE's needs in the area could be met only by building 120 kV lines from long distances as ITC has only 345 kV in the area that DTE needs an interconnection point). Project verification was conducted using the revised reduced Michigan load forecast.

Placid 345 /120 kV transformer (Project ID: 911, 5/2007, \$10 million)

The project involves construction of a second 345/120 kV transformer at the Placid station. Project also involves expansions at both Placid 120 kV and 345 kV stations.

Project eliminates voltage criteria violations where Placid, Proud, and Prizm 120 buses voltage fall below 85% for the following category B contingencies: Loss of Placid 345/120 transformer 1 and Loss of Placid-Pontiac 345.

Durant to Genoa 120 kV (Project ID: 1011, 12/2007, \$19 million)

The project involves construction of a new 120 kV Durant sub-station with a new circuit from Genoa to Durant, and also breaks up 3-ended Prizm-Proud-Placid 120 kV line.

This project is driven by DTE's Interconnection request with ITC for GM Milford Darlington Hills facility and Hurst Substation. The existing 40 kV serves as a hot standby to the 120 kV Placid to Proud line outage. Existing capacity on the 40 kV is 43 MVA and increased loading in the area is creating N-1 overloads on the 40 kV system. Low voltages at site are also observed under these conditions and problems would be worse with anticipated load growth at Milford site. Continuing load growth in area requires another transmission to subtransmission interconnection at Hurst to resolve. Breaking the three ended Prizm-Proud-Placid 120 kV line to two lines: Placid to Durant and Placid to Proud also helps create two independent feeds into Durant substation thereby increasing reliability

Caniff Station Upgrade (Project ID: 1305, 5/2007, \$14.4 million)

The project involves replacing gas insulated switchgear and all breakers at Caniff and also creates a ring bus configuration.

The current gas insulated switchgear installed at Caniff was nearing end of life and is leaking causing recurring alarms/failures (34 alarms since 1/2004). The leaking gas is an environmental issue as well. GIS is 35 years old and is nearing end of life. Going forward with the existing equipment would require high maintenance costs. Caniff feeds downtown Detroit, and under current configuration, 1 section breaker failure can result in the loss of the entire station. This would cause the cables feeding the city from the south to overload at peak. Therefore a ring bus configuration is optimal.

Midtown Station Upgrade (Project ID: 1306, 12/2007, \$6 million)

The project involves replacing gas insulated switchgear and all breakers at Midtown and also creates a ring bus configuration.

The current gas insulated switchgear installed at Midtown was nearing end of life and is leaking causing recurring alarms/failures (13 alarms since 1/2004). The leaking gas is an environmental issue as well. GIS is 35 years old and is nearing end of life. Going forward with the existing equipment would require high maintenance costs. With the current configuration at Midtown, one section breaker failure can result in the loss of the entire station, as well as bus 103 at Frisbee station. Therefore a ring bus configuration is optimal at Midtown, and does not add any additional cost to the project.

B3N Interconnection (Project ID: 1308, 12/2007, \$25.5 million)

The project returns the Bunce Creek to Scott 220 kV circuit to service, and replaces the failed Phase Angle Regulator with 2 new PAR's in series. This failed transformer is part of the northern most interconnection with Canada.

The new phase shifting transformers will increase both MVA capability and phase angle control. Midwest ISO reviewed the impact on system performance of system operation with and without the B3N tie between ITC and IMO in service. The review was based both on review of the recent 2010 study reported to ECAR by ITC, and on independent review of contingent conditions. There a substantial number of contingencies involving multiple elements that can result in significant system overloads without the B3N circuit, which would not occur with the B3N circuit available. Contingencies that have the most significant impact are shown in the table below:

- 116% for St Clair - Cypress 120 kV & St Clair - Bunce Creek 120 kV DCT
- 112% for Jewell-Spokane 345-230-120 kV & Apache-Troy 120 kV
- 102% for Jewell-Spokane 345-230-120 kV & Dean (all)
- 101% for Caniff-Northeast 120 kV & Conners Creek (all)
- 130% for Greenwood 120-345 kV & Atlanta-Tuscola 120 kV
- 104% for Pontiac 345-120 kV #303 & Pontiac-Sunbird 120 kV
- 115% for Both St.Clair-Lambton lines

Following Phase 2 analysis, there were 129 outstanding violations, 7 of which were category B violations. Proposed projects were modeled to relieve the thermal overloads on ITC system. Subsequent analysis in MTEP06 demonstrated the project's effectiveness in addressing the system needs. Midwest ISO recommends the proposed projects become planned projects. Details on the proposed projects are discussed in the following section.

ITC will coordinate with DTE on category B voltage violations. Remaining category C violations were mitigated by means of load shedding. The exact amount and load locations may differ.

There are no open reliability issues on the ITC system.

## West Planning Region Load Deliverability Analysis

The load deliverability study zones that make up the West Planning Region and are referred to in the result tables of this section include:

ATC: American Transmission Company  
 ALTE: Alliant Energy East  
 MGE: Madison Gas & Electric Co.  
 UPPCO: Upper Peninsula Power Co.  
 WEC: Wisconsin Electric Power Co.  
 WPS: Wisconsin Public Service Corp.

MRO-MISO: ALTW: Alliant Energy West  
 XEL: Xcel Energy  
 GRE: Great River Energy  
 MDU: Montana Dakota Utilities Co.  
 MP: Minnesota Power, Inc.  
 OTP: Otter Tail Power Co.  
 SMMPA: Southern Minnesota Municipal Power Agency

MRO-Canada: MH: Manitoba Hydro  
 SPC: Saskatchewan Power

This Load Deliverability analysis was performed on the 2006 Summer Peak model and the 2011 Summer Peak Baseline Reliability Plan Phase 2 Contractual Dispatch model. The results are tabulated below.

**2006 - Load Deliverability Results Table**

Zone	Stand-Alone		Import Capability {MW} (+ Import) (- Export)			Multi-Zone LOLP {days/year}
	LOLP {days/year}	Needed Support {MW} for LOLP = 0.1	Base	FCITC	FCTTC	
ATC	0.57	534	1,265	1,447	2,712	0.00
MRO-MISO	14.51	2,576	3,234	1,014	4,248	0.00
MRO-Canada	0.03					0.03
LOLP > 1 Day in 10 Years {or 0.1 Day in 1 Year}		Import Capability less than Needed Support				

**2011 - Load Deliverability Results Table**

Zone	Stand-Alone		Import Capability {MW} (+ Import) (- Export)			Multi-Zone LOLP {days/year}
	LOLP {days/year}	Needed Support {MW} for LOLP = 0.1	Base	FCITC	FCTTC	
ATC	0.10	9	1,100	2,207	3,307	0.00
MRO-MISO	7.42	2,166	2,435	-576	1,859	0.05
MRO-Canada	0.03					0.03
LOLP > 1 Day in 10 Years {or 0.1 Day in 1 Year}		Import Capability less than Needed Support				

### 2011 Stand-Alone Sensitivities Table

Zone	(-) minus 5% Load Change		(+) plus 5% Load Change		10% Forced Outage Rate	
	LOLP {days/year}	Support {MW} for LOLP = 0.1	LOLP {days/year}	Support {MW} for LOLP = 0.1	LOLP {days/year}	Support {MW} for LOLP = 0.1
ATC	0.01		0.88	676	1.28	1,109
MRO-MISO	1.51	1,039	16.88	3,292	13.73	3,426
MRO-Canada	0.01		0.18	123	0.06	

### West Region Load Deliverability Assessment

The LOLP results for the West Region indicate that for 2006, each of the analyzed zones have sufficient import capabilities to meet an LOLP of .1. For the 2011 case, the MRO-MISO zone needs a Stand-alone import capability of 2166 MW. This compares to the calculated FCTTC of 1859 MW, an apparent deficiency of 307 MW of import capability. In addition, the Base transfers for the 2011 case are 2435 MW which is 579 MW in excess of the FCTTC. This Base transfer violation was also detected in the NERC Category B contingency analysis, and upgrades have been identified to address this need. The table below illustrates the import limit of MRO-MISO after system improvements remove the N-1 Category B constraints.

### 2011 MRO-MISO zone FCTTC after Upgrades

2011 MRO-MISO zone FCTTC after Upgrades									
FCITC	FCTTC	Limiting Constraint	Contingent						
			Flows	Rating	Comments				
-576	1,859	60204 COTTAGE7 115 60238 REDROCK7 115 1	-233	-210	Project 1203 mitigates overload				
-158	2,277	60150 MNVLTAP4 230 66550 GRANITF4 230 1	-356	-350	New 387/426 MVA Rating fix				
94	2,529	60200 BLK DG27 115 60258 WILSON 7 115 2	-176	-183	Limit after system improvements				

With these upgrades in place, the FCTTC into the MRO-MISO zone is 2529 MW and above the necessary standalone requirement of 2166 MW and will result therefore in an LOLP of less than 0.1.

The table above indicates that the 2011 multi-area LOLP for this zone is less than .1 even though the FCTTC is less than the import requirement. This is because the multi-area analysis approach considers the combined load shapes of the MRO-MISO zone and the connected areas in determining the LOLP for the multi-area configuration. This results in a somewhat lower LOLP when the generation outages of the multi-area interconnection are convolved with the associated loads to develop the LOLP. Thus the multi-area analysis does not indicate that additional import capability would be needed by 2011 for LOLP purposes, however, the upgrades needed for NERC Category B contingency analysis will also result in higher import capability.

The sensitivity analysis shows that for the study zone MRO-MISO with a 5% decrease in load for 2011 the first-contingency total transfer capability is greater than the needed amount. The other study zones still meet the criteria under the stressed sensitivities of a 5% increase in load and 10% generator force outage rate.